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

Post-Pandemic Economic Growth

Storelectric's response to BEIS Call for Evidence on Post-Pandemic Economic Growth.

Contents

Associated Documents

Guiding Principles

The guiding principles for Post-Pandemic Economic Growth should include:

1. Climate Change 2050 compliant:
   - ♦ Not going for technologies to help us meet 2030 or 2040 goals as they will become stranded assets and wasted investments by 2050.
   - ♦ Consistent with Net Zero in energy.
2. Growing the UK economy:
   - ♦ We spend too much of our money supporting technologies that are based overseas, buying in from abroad just because we don't want to take the "risk" of building first-of-a-kind full-scale plants etc.

- Too many innovative UK companies either go bust in the “valley of death” (first full-scale commercial plant or equipment or product) or have to go overseas.

3. Developing UK-based manufacturing and other capabilities:
   - As above, but including scale-up / ramp-up: the UK is great at developing technologies and then failing to capitalise on them – there should be tax breaks to encourage scale-up investments without the innovative companies having to sell out their independence.
   - Manufacturing jobs in leading industries are high-value jobs that each sustain 2-5 more jobs in supporting companies and services.
   - Merely developing “integration expertise” (e.g. community renewables integration) will not provide for UK industry and exports, as other countries will develop it too.
4. Developing export industries:
   - Focus on IP without manufacturing and other physical industries hollows out any technology and drives it overseas. An example was mining: when we closed mining, we said we’d continue to lead the world in high-value mining technologies – but that followed mining overseas. The same has happened with dozens of other industries and is currently happening with pharmaceuticals, automotive, aerospace, heavy engineering and other industries.
   - Unless the country earns money by selling more goods and services than it buys, we can only continue by selling off our companies – “the family silver” which, once gone, is gone and nothing will remain.
5. Focusing on fields in which the UK is among world-leading countries:
   - Too frequently we waste money by jumping onto bandwagons (e.g. lithium batteries with the Faraday Challenge and current plans for a Gigafactory) 20 years behind the rest of the world: these will never yield world-leading industries.
   - We are in or near the lead in many industries, which desperately need investment and governmental enabling, or they’ll have to go abroad; such as:
     - Large-scale electricity storage
     - Wave power
     - Tidal power
     - Process industries’ energy-efficient or zero-carbon innovations
     - Pharmaceuticals
     - Energy-efficient aerospace
   - Other challenges are crying out for solutions, or have businesses that can be attracted to this country by suitable inducements, such as:
     - Non-membrane hydrogen electrolysis for industrial scale
     - Hydrogen infrastructure and handling plant
     - Fuel cells for vehicles – other countries are leading but the lead is not too great to catch up
   - We must ignore the special pleading of incumbent industries that demand billions to be sunk into technologies that will never scale cost-effectively,

such as CCS for power stations (though CCS for process industries and related infrastructure is a different matter: essential for those industries).

Clean Growth

All investment in technologies and infrastructure that is not compliant with 2050 climate change goals and commitments will be wasted money that builds future-stranded assets and develops businesses that will expire after a short life. Therefore all investment must go to technologies that are not just consistent with 2030 and 2040 emissions reduction goals, but 2050 ones too: 2050 is only 30 years away, well within the lifetime of infrastructure investments, product ranges (and their successors), factories etc. which should therefore be built with longer intended lives.

Government Funding

Within the next few weeks, the government should implement a meaningful Carbon Tax, based on Value Added Tax – call it an Emissions Added Tax (so, for example, methane emissions can be charged more than carbon dioxide as it causes more environmental harm).

Now is the time to do it because world hydrocarbon prices have plummeted: people won't notice the "hit" if it's sized to take us back to prices that applied in January and February this year. It would be:

- Additional to other taxes (e.g. fuel duty), or big enough to replace them as well;
- Credited to exporters (to take it down to equivalent levels of the importing country) so as not to penalise British industry in the world market;
- Charged to importers (the difference between the exporting country's tax burden and the UK one) so as not to penalise British industry in the home market.

The proceeds would pay for:

1. Compensating the poor who lose out – but in a way that doesn't negate the low-carbon incentive, e.g. a tax break for taxis, not a subsidy on their fuel consumption;
2. Public transport – again, in ways that don't negate the low-carbon incentive;
3. Innovation, especially the "valley of death" (first full-scale, commercial);
4. Paying down COVID debt.

Direct Support Measures

The most important support measures are for "valley of death" first full-scale, commercial products / plants / production lines. These take large amounts of capital (often, tens of millions) of which the government would put in a substantial proportion. This is because the finance industry will not invest such sums in anything that they say carries "technical risk" which they define as the first-of-anything.

Another important support measure is early-stage long-duration contracts for the services / output. Consider the electricity industry: new-technology storage installations would be greatly incentivised by 15-year contracts for optimised revenue stacks using the contracts and prices that apply at the time. This implies zero subsidy, just commitment given only to first-of-a-kind. Any financial support would be additional but the need for it would be greatly reduced by such contracts. A legally enforceable Letter of Intent to put in place such contracts could be awarded, and maintained subject to suitable progress being made, to incentivise such technologies at earlier stage (e.g. pre-planning). Lead times must be flexible, e.g. if it needs a new transmission grid connection, then lead times for those can be very long for reasons out of the control of the innovative company. An example is given in the attached document, A 21st Century Electricity System.

All support should be conditional on the business being or becoming British, or basing its relevant divisional headquarters and (initial and a suitable proportion of ongoing) development / manufacturing in the UK.

Where development lead times depend on factors outside the innovative company's control (e.g. regulatory approval; new grid connections), then all support should allow for this additional and/or uncertain lead time.

Grants and other innovation incentives are very poorly designed and managed, and should be overhauled completely.

1. "Calls" for funding should be few and directed only to innovative potential that is currently being unaddressed, such as non-membrane large-scale electrolysis. This is because such calls:
   - Rely on civil servants knowing what's needed and what technologies are out there – innovators and entrepreneurs usually know better;
   - Distort the timing of innovation, compelling applications for funding either to come prematurely or to be delayed, thereby (in both cases) gravely impacting the business and the innovation;
   - Distort the structure of innovation by compelling square pegs (the innovations) to fit into round holes of pre-defined structure / scale / stage of development / sequence of development steps;
   - Cause multiple stops in the development programme as funding is given for one stage, then needs to wait until it's given for the next stage (with a certain probability of failure of each application), which gravely disrupts teams and disadvantages small and start-up companies – indeed, Feasibility grants cost more than their value due to such hiatuses and the costs of the salaries during such periods.
2. Grants should be "always available", so that innovators can seek the grants when the innovation needs it.
3. Grants should be defined in conversation between innovators and government, so that the structure of the grant (and follow-on grants) is suitable for the technology.
4. They should be awarded in conversation with inventors.

- The two qualifications for assessors is that they are “experts in their field” and that they did not invent it. Therefore they will have numerous preconceptions and prejudices, which even result in them claiming things are impossible when engineering multinationals say not only that they are possible but that they can be built with existing catalogue equipment.
- There are numerous misunderstandings that lead assessments to be mutually contradictory or just plain wrong, which could easily be cleared up by a conversation.

5. An objection to all this is that it would take up too much resource. This is false because:
    - The current system yields large numbers of applications that are unsuitable in the hopes that one of them will be granted;
    - Technologies generate multiple repeated applications, whereas one “in conversation” approach would replace them all;
    - Applications for different stages would be eliminated;
    - The quality of grants and projects would be so much higher that any additional cost would be very worthwhile.

Without decreasing support to all the asset-light innovations that are very well supported currently, new money should focus on asset-heavy developments.

- While virtual solutions optimise the world’s capabilities, only asset-heavy developments provide those capabilities to be optimised.
- There is plenty of private innovation funding for virtual and asset-light innovations and business development; whereas there is next to none for asset-heavy ones (unless they’re being done by major companies that can support such things from their own balance sheets), and governments should be in the business of making up for market failures, not doubling up on what is already being done.
- People live in the real world, not in the virtual world.

Indirect Measures

Currently tax incentives for investing in new businesses (e.g. EIS, SEIS) pay no regard to the innovative nature of the business. There should be at least double incentive if the business is technically innovative – this could be paid for by a small reduction in the support for new businesses that are not technically innovative.

Tax incentives only incentivise new ventures; they don’t incentivise scale-up to becoming strong exporting firms in manufacturing and/or services. They should do so: too many British companies are gobbled up by foreign companies because they can’t finance their growth. So there need to be tax incentives for investment in UK growth firms. These will more than pay for themselves as their tax domicile would remain in this country.

Regulations should be adapted to incentivise businesses properly, for example:

1. All too often, government departments claim falsely that their policies are "not backing winners" and "level playing field": these falsehoods should be recognised and the support modified accordingly. For example:
   - Mis-defining storage as generation effectively subsidises foreign electricity generation via interconnectors at the cost of British generation and storage – see the attached Regulatory Definition of Storage;
   - A regulatory system that sets 2-year contracts favours incumbents against new investment – see the attached A 21st Century Electricity System;
   - A regulatory system that provides no assistance to a first-of-a-kind favours incumbents due to financiers' aversion to "technical risk";
   - A support system that is heavy and/or complex favours large businesses against small start-ups.
2. In utilities, the only major capital investment since privatisation has been against long-term assured revenue streams such as regulated asset base revenues, CATOs, OFTOs, CfDs, ROCs and so on. Each such scheme has rules which, of their nature, constitute market distortions. Regulatory regimes should be changed so that such incentivisation is incorporated in normal business – see, for example, A 21st Century Electricity System, attached.
3. Defining electricity storage as generation is grossly harmful to development of large-scale long-duration storage and has prevented its development for almost a decade: it should be properly defined as storage, with its regulatory system based on that of interconnectors.

Poor regulatory principles seek "least cost for the consumer" for regulated utilities, without giving a timescale: for regulatory purposes least-cost should focus primarily on consumers of 30 years hence, with only a secondary focus on today's consumers: challenges such as fuel poverty are the proper remit of governments, much more than of regulators. When the grid was privatised, this short-term focus brought down prices fast, so the government celebrated publicly that our energy prices were among the lowest in Europe. But they are now among the highest in Europe due to that short-term focus. The reason is simple:

- The cheapest way to fulfil a 2-year contract is to patch up a fully amortised power station.
- At the end of that contract, the action is repeated, except that prices increase and performance deteriorates:
  - ◊ The power station is more clapped-out than before;
  - ◊ It's more expensive, more emitting and less efficient to keep going;
  - ◊ It's less reliable.
- Eventually, with enough repeats, the power station dies of old age and no replacement will have been paid for: it's chasing good money after bad.
- Over 20 years, the prices will have escalated such that over the 20-year period it will be more costly than letting a 20-year contract.
- The cheapest way to fulfil a 20-year contract is to build a new and more efficient power station.
- This way, for less cost over the 20-year term, the grid will have been renewed.

- See the attached document, A 21st Century Electricity System for more details and ***a very simple solution that can be implemented incrementally without disrupting current regulatory frameworks***.

The short-term RIIO frameworks (recently dropped from 8 to 5 years) embeds this short-termism into the very management of grids: contracts can only be let and cost recovery can only be granted over such short timescales which prevent major capital investment and innovation. Worse, being fixed periods, when half-way through the period the maximum time over which to cover the costs is only 2.5 years, which is totally impractical. There is no real-world business that has to re-set its entire strategy and direction every 5 years (that died out with Communist 5-year plans – RIIO is the last bastion of such Stalinism) without visibility of what lies before, and without being able to undertake commitments or amortise assets through that barrier. Without a longer strategic focus, the country's gas, electricity, water etc. grids would never have been built in the first place. Instead, RIIO should have a rolling 30-year focus, with intermediate targets at a rolling 5 and 15 years.

Poor regulation of the electricity system was costing the country (in 2017 when the analysis was done – it's much more now) over £2bn p.a. in direct, indirect and hidden subsidies of fossil fuelled power stations and of other inefficiencies in the system – see the attached document Curtailment – The Tip of a Growing Iceberg. This is additional to the ever-increasing costs of electricity due to the short-term contracts that are let. Similar costs may apply to other utilities.

Government and regulators alike should drop their "management by fad" and "small is beautiful" obsession. In the electricity industry the fads are: distributed, virtual, batteries:

- Distributed cannot be the sole way forward: every distributed system relies on the grid for back-up, so what's on the grid providing that back-up both now and in future?
- Virtual systems optimise real-world capabilities, but there need to be real-world assets and technologies providing those capabilities.
- Batteries are great for their own strengths, but are being relied upon for things that are really beyond their core capabilities, such as inertia, grid stability solutions and longer-duration storage; the correct landscape would include batteries, but only as one of a range of technologies – see the attached article, GW Scale Storage for GW Scale Renewables, published in the Journal for Energy and Power Engineering.

Regional / Levelling-Up Investments

While initial technology development should be wherever the innovator is, it makes sense to incentivise the next-stage development to be in less-advantaged regions. This should not be a go / no-go factor for assistance, but rather an offer to increase support by (for example) 25% or 50% if the investment finances development in such regions. There could be multiple thresholds; for example, different locations qualify for uplifts of 0, 10%, 20%, 30%, 40% and 50%. These locations should be publicly known; the business could therefore take a commercial decision on the location to select, which would not only be for reasons of such support but would also include considerations such as proximity to industry clusters or universities with suitable strengths.

Just as Patent Box allows companies to nominate the start date of tax incentives for a patented technology, so regional development tax breaks (e.g. a time-limited incentive such as a 10% [absolute, not relative] reduction in corporation tax, or waiving company National Insurance payments) should apply when companies decide. There would be a pre-qualification (e.g. when the company is founded); then the business would nominate its start-of-incentive (e.g. when it starts substantial recruitment, or gets traction in its market).

Lessons from COVID

The biggest lesson from COVID is the futility of an economic development model wherein we don't favour UK-based capability over overseas-based capability. Where, for example, is our vaccine or protective equipment manufacturing?

The same applies to military resilience. We pride ourselves on being able to make our own military equipment, but how useful is that if we don't have a single manufacturer of nuts, bolts, nails, batteries…?

COVID is giving us a trial run of some aspects of the 2030s grid – see the attached document: The Lockdown - A Partial Test of the 2030s Grid.

Government As A Shareholder

The best model for government as a shareholder is the German model. Essentially, the businesses run themselves and there is no government support for (for example) loss-making or excessive wage settlements. However there is government interest in where the investment is placed, to strengthen regional and national businesses within the global economy, and to maintain corporate independence.

Supporting Consumer Confidence and Growth

There should be no short-term stimulus to consumer confidence and growth: that will just create more household debt and suck in more imports, both of which will adversely impact the medium- and long-term future of the country.

Instead, the entire stimulus should be directed towards business and innovation, particularly taking new capital-heavy innovations to market both nationally and internationally. It is only if consumers have confidence in the future of the country that they will be stimulated sustainably.

The European Economic Area accounts for 55% of all the UK's trade and is our natural market. It also enables us to get better trade terms with other countries: for example,

- China has already stated that a non-EU United Kingdom will get a much worse deal; the one cited is that for Switzerland which was considered "good" but in which Switzerland had to open its borders to Chinese goods immediately whereas China would only reciprocate in a decade.
- India has said that they will only give us a good trade deal if we accept big increases in immigration from there.
- America has made acceptance of their health-and-safety (think of chlorine-washed chicken), environmental (think of GM crops) and commercial (think of US take-overs of NHS capabilities) principles into pre-requisites before we enter into any negotiations with them, remembering that such negotiations entail further compromises.
- Every Commonwealth country that expressed a view asked for us to remain in Europe so (a) we can continue to represent them there, (b) we can be an entry point for their trade and (c) we can insist that they are not disadvantaged by trade terms.

Therefore please get the best possible deal with Europe:

1. Mutual barrier- and tariff-free trade.
2. Acceptance of common standards, without which such barrier- and tariff-free trade cannot happen.
3. Remain within various European actions that have greatly benefitted Britain, including:
   - All R&D activities, whether Horizon, Connecting Europe Facility or academically focused;
   - Many cross-border coordination groupings, such as ENTSO-E, Euratom, regulatory bodies such as for pharmaceuticals.

A 21st Century Electricity System

By Mark Howitt, Director, Storelectric Ltd, 07910 020 686, mhowitt@storelectric.com

Introduction

The current regulatory and contractual framework is designed around a 20th century industry (baseload coal and nuclear, dispatchable gas, all other bits are add-ons). The cost of electricity is diverging increasingly from its price: already around half of commercial customers' bills consists of levies and system charges, with only around half (this being a decreasing portion) being for the electricity consumed. In a well designed system, the price of electricity should account for between 75% and 80% of its cost. Thus the headline prices may need to increase, without necessarily affecting the cost of electricity to customers.

A 21st century regulatory and contractual framework must be designed around renewables and storage (with or without nuclear) supported by distributed generation and storage, interconnectors and Demand Side Response. Features of a 21st century system would include the following.

Regulatory Framework

Until RIIO was developed, National Grid was incentivised on cheapest electricity over a 2-year period. That provided cheap headline prices but without any concern for the future of the system. When RIIO was brought in, an 8-year horizon with attendant incentives were brought in, which was a big, but insufficient, improvement.

To ensure system reliability and cost-effectiveness over 15 years requires 15-year timescales. Ditto any other period. This is because the cheapest way to deliver a 2-year contract is to patch up a clapped-out and fully amortised plant. For the next 2-year period the same is done again, and again until the plant dies of old age. But with each repeat, the plant is older, less reliable and more costly to patch up. So over 15 years the total cost of electricity would be higher than under a 15-year contract because the latter would have been delivered by building a new plant. The short term timescales alone therefore ensure that investments with long lives and long term pay-backs are penalised financially, and also are added to the commercial risks that are put against the SO's balance sheet.

Therefore, in addition to the 2- and 8-year regulatory and rewards regimes, there also need to be 15- and 30-year timescales. The shorter timescales would have greater emphasis on consumer prices and lesser emphasis on system integrity, gradually reversing as timescales extend. This will ensure that not only is the grid cost-effective now, but also that it will be both cost-effective and systematically sound in 30 years' time, with all long term investment undertaken as needed.

Another RIIO problem is that every 8 years all "base cases" are re-set. Thus at the beginning of a RIIO period, investments can be made with an 8-year amortisation life; half way through, this drops to 4 years; and towards the end of the period, significant investment is almost impossible. This should be changed to a “regulatory amortisation” of each investment over the viable life of the asset, or over a reasonable lifetime determined by the regulator. Accountants manage such amortisations for large businesses very happily even though every plant is being amortised from a different date for a different period (or one of a set of permitted periods): therefore the regulator should be able to manage “regulatory amortisation” similarly.

Contract Structure

No major investment is possible without long term contracts or other form of revenue assurance. The only capital investments in major infrastructure have come on the back of special arrangements that offer such assurances, e.g. CfDs, ROCs, OFTOs, CATOs.

Without long term contracts, a 2-year contract will appear to be the cheapest way of procuring electricity over a 2-year period. But it will be bid on marginal cost and delivered by patching up a clapped-out and fully amortised plant. On the next 2-year cycle the same will happen again, though the plant will be older, more worn, more expensive to patch up and more prone to break-downs. Over a 20-year period the country will have paid more overall for its electricity than if 20-year contracts had been let, which would have been delivered by new plant – and in the meantime no new plant is built, the old plant dies of old age and the system’s capabilities plummet. Meanwhile, in order to incentivise investment there need to be special mechanisms (subsidies by another name) put in place which mean that the total cost of delivering electricity (including subsidies) is greater even in the short term than would be the case under longer term contracts.

A truly sustainable grid will engage most or all services under contracts of lengths that both encourage investment and minimise cost. Such a structure could include:

- ♦ 1/3 of energy under 15-20 year contracts, with delivery to start following grid connection, these contracts only being available for new build;
- ♦ 1/3 of energy under 5-8 year contracts, with a split between new and existing plant to be decided according to the reviews of the system from time to time;
- ♦ 1/3 of energy under contracts of up to two years, for all plant.

There is indeed some measure of uncertainty as to future demand. This can be accommodated by (a) letting such contracts in rolling annual or biennial auctions and (b) flexing the exact amount of mid- and short-duration contracts.

The entire subsidy regime and scheme of access charges need to be re-thought:

- ♦ Incentivise cleanness of technology, for example with longer contracts going to cleaner technology. An example would be full-length (as above) contracts for zero emissions generation; half-length contracts for CCGTs, with durations on a sliding scale directly proportionate to emissions between the two, that scale continuing to diminish contract length for technologies with worse emissions than CCGTs.

- ◊ Include ancillary emissions in the calculation of the emissions of a given technology: mining, harvesting, refining or otherwise processing, manufacturing, transporting, recycling, disposing of equipment (both main and ancillary, including considerations of operational life), components, materials and fuel.
- ◊ Ensure that imported electricity is deemed to have the emissions performance of the electricity that is delivered to the interconnector. Where that is difficult to determine, default to the average emissions performance of the source country and, if appropriate (e.g. Belgium, Netherlands) considering a proportion of the electricity to come from their neighbouring countries, at their average emissions performance. This would apply to carbon pricing and any other incentivisation scheme including contract duration.

- Incentivise dispatchability with a price premium that reflects the balancing costs avoided (or a large proportion of them, so both sides benefit).

Ensure that all capabilities can be monetised, e.g.

- Permitting real inertia to compete in the EFR market with a premium based on the fact that it is instant and requires no grid intervention, whereas EFR has milliseconds' delay and requires grid intervention. Ditto reactive power.
- There is currently no contract scheme for long term storage. If such a provision were made, then negotiated bilaterally for e.g. the first 1TWh stored (with a minimum installation size of 100GWh) prior to creating an auction for it, then this would enable the scheme to be available when the technology is developed to use it - and would thereby incentivise the development of that technology. It would also enable the contracts to be structured around the actual costs and benefits of the technology, rather than around a theoretical exercise. Similar mechanisms could be used for other services as their need is identified.
- Ensure that the various services are co-ordinated so that any plant that can deliver multiple services is able to contract to do so.

Eliminate the Capacity Market, which is a subsidy for fossil fuelled generation.

Contract Simplicity

There are currently 15 different contracts under which balancing and ancillary services are purchased, and this number is increasing steadily. Germany, for all its faults, has 3. Large scale storage needs a stack of 8-10 contracts in order to earn full returns on investment; small scale storage stacks 6-8, and demand side response almost as many. Even generation, which used to have one contract, now has many. All except one (Capacity Market or EFR, depending on technology) of these has a duration of between 6 months and 2 years. Assuming an average duration of 1.5 years, this means that, at best, large scale storage has to fund an overhead to bid for 8-10 contracts every 1.5 years. And every contract type is different, with different terms, conditions and specifications, all of which have to be understood and juggled not only by the bidding bureaucracy but also by plant operators who have to fulfil all those contracts, and by spot traders who have to know exactly what will be surplus at what time. And it entails similar complexity and overhead in the System Operators Contracts team and control centre.

However each bid carries the risk of losing the bid. This will entail a costly hiatus in contractual cover while another (usually less remunerative) service is bid for. This can double the already huge administrative overhead of bidding. It also means that there is a financial risk, which adds to the risk premium on the investment and therefore to the capital cost of the plant. These risk premia also lead to high levels of profits when things do not go wrong, leading in turn to screaming tabloid headlines and high political risk.

The system needs simplifying. A plant should be able to tender all its services as an individual plant in one tender – or two, if demand side (DSR, demand turn-up) is included. Individual services should only be tendered if there is a specific resultant shortfall in the capabilities that have been engaged – which there shouldn't be, as there is some flexibility in capabilities, such as primary frequency response assets continuing for the duration of secondary response and even fast reserve.

The Most Cost-Effective Contracting Sequence

Letting contracts for such services individually causes major issues and maximises the cost and complexity of letting, administering and delivering the contracts, for both grids and service providers. The biggest problem that it causes is to flexible plants that deliver many services, such as inertial plant which cannot deliver electricity without inertia and other related services.

- What happens if a plant is unable to deliver services A, B and C separately and wins contracts for A and B but not C? Do they have to "give away" C without remuneration, putting them at a commercial and financial disadvantage? Are they penalised for excessive delivery of C?
- What happens if, in delivering A, B and C they are vastly cheaper than the competition in delivering D? The total of A-D is cheaper than any other means of procuring them, but A-C on their own are more expensive. Should the system pay extra to procure them separately or should it aggregate A-D to provide all the services more cost-effectively?

The most cost-effective contracting sequence would be:

1. Let the longest-duration and hardest-to-place contracts first;
2. See what else the winning plants can deliver cost-effectively, and award those contracts to such plants;
3. Only auction off the next-hardest-to-place contracts that remain outstanding after step 2, and repeat.

This will ensure that each plant that wins contracts can amortise its costs over the widest range of contract types for which it is cost-effective. This in turn enables those contract prices to come down due to contractual coverage and revenue security, and also because fewer plants are needed in the system to deliver the requisite energy and services.

For example, of the reverse were to be done, then:

1. Large numbers of peaking plants and batteries would be built to cream of the biggest revenue streams;
2. Harder-to-place contracts would be more expensive as these parts of the revenue streams are no longer available to them;
3. Plants for these harder-to-place (including longer-duration services) contracts will not be built without much higher prices as they cannot be justified on the back of the easier-to-place contracts, and won't already have the other contracts "in the bag" to be able to spread the amortisation of their costs.

Incentivising Clean Energy
All the above is regardless of energy technology. However clean energy can be incentivised, without subsidy or price premium, by superimposing cleanliness-related contract length.

To do so, the base contract lengths would need to be extended so that imperfectly clean technologies can also have sufficient contract duration to enable investment. Thus for a 100% clean / renewable technology, the longer two contract lengths would be 20 years and 10 years. For a diesel or coal (whichever is more polluting for the service being contracted) fired power station, contract lengths would be half of that for the clean technology, i.e. 10 years and 5 years. Maximum contract durations for technologies with intermediate levels of cleanliness between these two end-points would be linearly proportionate between those durations. So a new build with half the emissions of a coal fired power station could have a contract of up to 15 years, and a refurbishment up to 7.5 years. It may be politic to let contracts in steps of whole numbers of years, in which case the refurbishment would have a contract length of either 7 or 8 years depending on whether the decision is to round up, down or to the nearest integer.

The emissions performance should be calculated as a whole-system (or, in the case of storage, round-trip including all energy inputs and useful energy outputs) efficiency *for the particular duty cycle being tendered*, rather than a standard figure being applied for all duty cycles. This is because, for example, a 60% efficient gas-fired power station would be a very high performance for frequency response, but not as good for baseload.

For stand-alone storage, the calculation would take into account two factors: cleanliness and efficiency. In order to be considered on a level playing field with generation, both "inefficiency" and "dirtiness" should be factored down by 50% and then added to obtain the "undesirability factor" which is then subtracted from 100%. Thus a 60% efficient (i.e. 40% inefficient) storage system that creates 20% of the emissions of a coal/diesel fired plant would be factored down by 20% for inefficiency + 10% for dirtiness, total 30% undesirability, for a contract length equivalent to a 70% clean plant, resulting in maximum contract lengths of 17 years for new and 8.5 years for refurbishment. The justification for this factoring down is that storage provides a balancing service that maximises the efficiency of the whole system, and does so more effectively as the proportion of renewable energy in the system grows. Thus efficiency is incentivised, as well as cleanliness.

Incentivising Dispatchability
Dispatchability could be incentivised similarly to cleanliness of batteries, in that a non-dispatchability factor could be added to the dirtiness factor. Thus there could be (say) a 10% reduction for long term predictable variability (e.g. tidal lagoons and tidal flow turbines, 4 generation slots per day), 20% for only short term predictable variability (e.g. wind and solar generation). There could be an intermediate step for medium term variability such as wave power at 15% factor, if deemed appropriate.

Where dispatchability is increased by co-location, near-location or contracting with storage, then generation and storage patterns and efficiencies should be modelled to identify the forecast true output and dispatchability figures, and the dispatchability factor scaled accordingly. Where such storage is of limited capacity (e.g. less than the nameplate capacity of the generation) or limited duration (e.g. fewer than 5 hours at nameplate capacity of the storage), then the storage only partially creates dispatchability. In such cases, the storage would not be evaluated separately as stand-alone storage. One could conceive of a storage facility contracting a proportion of its capacity to a dispatchable generator and the remainder as stand-alone, in which case a compound figure could be calculated.

Non-Financially Incentivising Innovation and New Technologies
New technologies from innovative start-ups are actively prevented from developing their plant as contracts are only considered following grant of planning permission, which itself follows the study and reservation of grid connections. Therefore for a large plant, millions of pounds (which an innovative start-up does not have) are needed before the contractual cover is offered which would provide the revenue underpinning required for investors to put in the money needed for the grid connection and planning applications. It's a Catch 22. A second Catch 22 is that many investors won't invest without a reasonable expectation of long term contractual underpinning of revenues, which cannot be granted unless the technology is developed.

A simple way to break through these barriers and to incentivise innovation and new technologies without money (though it would best be done in conjunction with the other incentives, below) would be by early official memoranda of understanding (MOU) and letters of intent, and progress monitored to ensure that the SO understands its impact, likelihood and timing as the project develops. With these, our potential financial backers would almost certainly open their purse strings.

- For a proposal to build a first-of-a-kind plant, a letter of intent from the System Operator to state that provided certain conditions are met (those being specific to the plant being developed, e.g. FEED Study complete and supporting the previously claimed minimum performance, planning permission granted, grid connection application granted), then it is the intention of the SO to grant a 15-year contract at the rates applicable at the time.

- For such a proposal, a memorandum of understanding from the Network Operator to say that prima facie a grid connection (specified) would be available within a specified cost and timescale, unless other applications were received between the date of the MOU and that of the formal grid connection application. This helps to shorten timescales and liberate funds because currently grid connections can only be applied for following grant of planning permission which, for a transmission grid connected scheme, will cost ~£2m and take ~2-3 years. The prospect of an affordable grid connection will help liberate the private funding for the design and planning process.
  - Permitting grid connection applications to be applied for prior to grant of planning would considerably reduce the up-front risks and timescales of any project.
- For an earlier stage innovation, if it would create a technology useful to the SO, then a less binding memorandum of understanding from the SO that if the technology achieves specified milestones (demonstration on paper of technical and commercial viability), then the above letters of intent will be forthcoming. This will provide the support to the project that will show to early stage funders that the technology has a commercial future if it can be developed as claimed.

Additionally, permit system operators to invest in new generation / storage technologies and to own the consequent plant for a limited period, e.g. 5 or 10 years (possibly depending on size of plant / investment) between commissioning and sale. The proportion of the plant they can own could depend on the proportion of innovation in the plant. Any IP should have to be licensed to all who wish, but with royalty revenues accruing to the system operator as per normal commercial R&D investment.

Financially Incentivising Innovation and New Technologies
To encourage new technologies, replace ROCs and CfDs with a price supplement (pence per kW) for early stage installations of new technologies, e.g. add to all revenues 50p/kW for a first-of-a-kind plant (that is, full scale rather than experimental), diminishing linearly to zero for the 6th of a kind. If the differences from other plant types are smaller, then this premium can be reduced accordingly, but should still remain in order to incentivise innovation.

- By incentivising first-of-a-kind plant, it encourages these to be built in Britain. This incentive could be made contingent on (or proportional to) the development, engineering and manufacturing of the technology being located in Britain - which would incentivise innovative foreign companies to move in.

Create a branch of the NIA / NIC investment fund to be administered centrally by Ofgem to incentivise R&D which would benefit the electricity system as a whole but not the grid operators individually due to regulatory or commercial constraints. It should be administered to favour UK-based R&D, manufacturing etc., maybe with the proportion of costs covered being proportionate to the UK-based work (excluding installation - which is a gateway factor) as a percentage of the whole.

Other incentives for the development and introduction of new technologies should be considered, not only at the innovation stage but at the pilot and first grid connected plant stages where there is a dismal shortfall in both money and non-financial support to flex the contractual and regulatory regimes (even if only on a one-off basis to test the benefits to the grid) to enable and encourage them.

Conditional contracts would greatly assist fund raising. They could be phrased along the lines of: "if this plant can be built and deliver these services at these prices, then it is the intention of the System Operator to enter into a contract at the higher of these prices and the market prices applying at the time."

Time to Start of Delivery
Building new plants in new locations requires grid connection. Such grid connection can entail significant grid reinforcement. However the reinforcement can take 5-10 years to plan and implement, which exceeds the longest possible time allowable under the RIIO framework. Contracts for new build need to permit suitable delays to start of delivery of the multi-year contracts, in order to enable new construction.

Some discretion may be given to the System Operator as to whether or not a plant is wanted to be connected to that part of the grid. And the issue is moot for plants that use existing grid connections provided those existing connections retain their access capacity.

Grid Access
Ensure that all generation, whether UK or overseas, pays the same grid access and usage charges.

Treat storage as a grid service, not as generation or consumption – or, at worst, allow storage to pay for charges after netting generation against consumption, which would incentivise efficiency.

Instigate a methodology for ensuring that grid reinforcement costs also capture the benefits of reinforcement deferral arising from some investments (e.g. generation on a particular side of a bottleneck) and sharing those benefits with the investor, e.g. 2/3 to the investor and 1/3 to the grid operator. Some of these benefits may be reflected by one-off payments, others by annual payments: in order to maximise the incentive to build such plant, and to reflect the timing of the benefits to the grid operator, they should be paid in advance; any adjustments can be made the following year to reflect actual usage and/or performance.

Grid Definition of Storage
Create a grid definition of storage modelled on that for interconnectors. This will permit and regulate:

- Contracting for services which are delivered off peak from storage that is replenished when market price differentials are not as high as between delivering at peak and replenishing at trough prices;

- Contracting for storage services per se;
- Ownership and investment into storage systems – maybe for only a fixed period, say 5 or 10 years from start of operation to deadline to sell the plant.

It will also eliminate:

- Over-charging for grid connections and reinforcement, indeed creating a mechanism for payments to developers to reflect a large part (2/3?) of the savings from grid upgrade deferral;
- Double charging for grid access for both charging and discharging;
- Having to pay market premia (profits, mark-ups etc.) for both buying and selling electricity.

Whole-Operation Contracting
Consideration should be given to whether System Operators (SOs) should be permitted to contract with a given storage provider / installation for “all services”. This is because the number of services offered by storage far exceeds that offered by generation, and such a contract would maximise the ability of the SO to use each service from storage in the most cost-effective manner. The main issues to be considered are whether and to what extent this would make the SO into a storage system operator, and whether or not such a change would be desirable.

CAES (Compressed Air Energy Storage), for example, can offer:

1. Various embedded benefits;
2. Firm Frequency Response (Secondary, and possibly some primary);
3. Fast Reserve;
4. Short Term Operating Reserve (STOR)
5. Supplementary Balancing Reserve
6. Reactive Power MVAr
7. Demand TurnUp
8. Wholesale Peak
9. Wholesale Off-Peak
10. Balancing Mechanism
11. Capacity Mechanism
12. Black Start

While batteries cannot offer the long generation durations required by STOR and the Balancing Mechanism, they can offer Enhanced Frequency Response and Firm Frequency Response (primary).

There are various models and precedents for such contracts, including CATOs and OFTOs.

Another benefit is that SOs require such services during off-peak times as well as peak times. If required at off-peak times, then the storage would have to re-charge at higher prices while generating its revenues at lower prices, making it unprofitable. Such whole-operation contracts would enable the provision of these services at off-peak times to be profitable for the storage provider.

Regulatory Definition of Storage

What Is Storage?
Storage stores electricity. It does not generate new electricity (except for traditional CAES, see next paragraph): it only re-sells the electricity (minus losses) that it purchased. It is therefore not generation. It moves electricity in time, much as interconnectors move it in location.

Traditional CAES alone is a mix of generation and storage, because it burns fuel to re-heat the air. It can be treated partly as storage and partly as generation, in proportion to the percentage of the output energy that derives from the fuel. Adiabatic CAES does not have this issue: it is pure storage.

Triple Charging
There is a general mis-perception that storage is double-charged for grid access charges: paying for consumption and again for generation. It does, but also the electricity purchased has also already paid charges, so storage is actually triple-charged.

Interconnectors do not pay for grid access, though the electricity they carry has already had grid access charges paid. This is correct: they are merely an extension of the grid, providing grid services. The same is true of storage: it merely provides grid services and therefore should not be charged for grid access.

How the Decision Was Made
Naturally the incumbent generators want to keep it this way, to keep the playing-field tilted sharply in their favour. Storage companies want “zero charging” (i.e. reduce to charging only for the purchased electricity) on the grounds that storage doesn’t generate. So Ofgem decided to split the difference and define storage as generation.

They stated that this was a partial solution, adopted because it didn’t need primary legislation; when the opportunity for primary legislation would occur, then they would seek to create a true definition of storage[1]. However now they are proposing to

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

- "In line with the plans both Government and Ofgem set out last year, we have considered a range of options to deliver a smart energy system, including: removing barriers to storage and DSR; ..." Towards a smart, flexible energy system para.20.
- "We have found that storage faces a number of barriers", as an introduction to a request for ideas to remove those barriers. Towards a smart, flexible energy system para.22.
- "Government has identified a number of potential priority areas over the next 5 years: ... storage costs. ..." Towards a smart, flexible energy system para.50.
- Towards a smart, flexible energy system, Table 1:
    - "In the final plan we will set out implementation tasks and timelines for: Any further measures to make it easier for storage to connect to the network - A decision on regulatory definition for storage and whether a new licence is required".
    - "Our aim: a level playing field for DSR and storage competing with other forms of flexibility and more traditional solutions."

define storage in primary legislation, which defeats the purpose of the interim solution and prevents a correct definition.

They now say that they wish to define it as storage because they can base the definition on existing regulatory categories. But that would be the case equally if they based the definition of storage on that of interconnectors – and with fewer modifications needed.

I am told that the industry is happy with the current proposal. Given that the industry is dominated by incumbent generators, that does not surprise me. However the need for change was also identified by the National Infrastructure Commission[2].

Problems with Defining Storage as Generation
There are many problems with defining storage as generation, which can be summarised as:

1. Charging
2. Grid Code Requirements
3. Grid Operator Constraints
4. Grid Connection Costs
5. Contractual
6. HM Treasury
7. Sundry Regulations

1. Charging
As cited at the beginning of this document, storage is triple-charged for grid access; the proposal is to move it to double-charged. This keeps the playing-field tilted in favour of generation and interconnectors, which are both single-charged – generation as generation and interconnectors within the price of electricity purchased. This therefore subsidises generation at the cost of the bill-payer. It provides even more subsidies to foreign generation and of the UK bill-payer, as grid connection charges for generation are lower on the continent than in the UK and the UK does not charge differential fees (i.e. the difference). It is the bill-payer who loses

[2] In the National Infrastructure Commission's report on Smart Power recommendation 2a) was that "DECC and Ofgem should review the regulatory and legal status of storage to remove outdated barriers and to enable storage to compete fairly with generation across the various interlinked electricity markets. The reforms should be proposed by Spring 2017 and implemented as soon as possible thereafter."
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/505218/IC_Energy_Report_web.pdf - note 17 to Introduction, Table 2.

2. Removing policy and regulatory barriers, 2.1 Enabling storage

- "1. There is increasing interest in energy storage as a potential source of flexibility for our energy system"
- "2. Falling costs are one element of bringing forward large scale storage projects – the market and its structures must also recognise and reward storage for the value it brings to the energy system."
- "3. We are seeking views on solutions; both for individual barriers and whether some solutions could address multiple barriers e.g. regulatory clarity."

out most because it disadvantages the most cost-effective means of balancing the grid.

2. Grid Code Requirements
The grid code for generation is loaded with requirements that are suitable for generation (e.g. 15% over-generation capability) but unsuitable for storage. This is right and proper owing to the nature of the generation asset being regulated – but therefore not right or proper for storage. The code for interconnectors does not have most of these, and therefore is much more suitable for storage.

Ofgem says that the grid code is determined by the industry, and therefore the grid code consequences of the regulatory mis-definition of storage are not their responsibility. But this overlooks that (a) the grid code is built on the regulatory definitions and reflects them, and (b) those with the greatest input into grid code matters are the large incumbent generators who have sufficient resources and who also have little interest in storage in comparison with their interest in generation.

3. Grid Operator Constraints
Both transmission and distribution operators are banned from owning generation, with a derogation of up to 6MW for DNOs. Yet both see huge potential benefits from storage, in balancing the grid, in providing stabilisation services, and in alleviating constraints and deferring capital investment. Both would invest in storage if permitted. And both would wish to support storage with NIC / NIA funding, which they are not permitted to do while storage is defined as generation.

Defining storage as storage would enable this. But it would also give the flexibility of allowing, disallowing and/or constraining such ownership and/or operation, as regulations (rather than primary legislation) can be used to do so – if storage is defined as storage rather than as generation.

And the ability to invest NIA / NIC funds in storage and in the issues relating to it (e.g. developing a standard system for calculating its effects on grid capacity, such as alleviating congestion like the Leighton Buzzard and Orkney plants) would greatly assist the network to adjust to a zero-carbon future.

4. Grid Connection Costs
Currently the effects of a proposed plant on grid loads is to calculate its operation as consumption, and again to calculate it as generation. This maximises the cost and lead time of grid connections, thereby making storage much more expensive and severely constraining the locations in which it can cost-effectively be built.

Storage mostly acts counter-cyclically, alleviating rather than creating grid congestion. It is on this basis that the batteries in Leighton Buzzard, Orkney and Eigha were proposed. Therefore grid connection requirements should be calculated based on storage being storage, not on it being generation and/or consumption. Doing so would reduce connection costs and lead times, consequently increasing its roll-out and reducing consumer costs.

Likewise, operational grid access charges would need their own computation to encourage storage to alleviate grid challenges, and thereby speed roll-out and reduce consumers' bills.

Creating such models would be ideal subjects for NIA / NIC projects. There may be a conclusion whereby different constraints in operating modes of storage would incur different connection construction costs and ongoing charges.

5. Contractual

National Grid is unable to enter into a contract for "storage services" which cuts across many current and proposed contract types, because storage is not legally defined as such. This means that storage has to bid for a huge revenue stack of separate services, every 2 years or less, with many adverse consequences, including:

- The TSO / DSO has huge administrative and grid control burdens as they can't just ask the storage to respond to a situation – they have to select from a vast menu of situations and responses before triggering each one individually.
- We are eligible for a stack of 12 contracts, with another 4-6 being mooted at present. This means that we have to administer 12-18 contracts concurrently, ensuring correct compliance, invoicing and contract management for each, adding enormously to our administrative costs which we would have to reflect in our prices, which ultimately will cost the consumer a lot.
- Each of these revenue streams needs to be re-bid every 6-24 months, with consequent administrative burden on both us and the TSO / DSO, again adding to consumer costs.
- Each of these bids has a chance of failing to win a contract, meaning that –
    - We have to price in the possibility of failure, having to operate for a period without a contract or having to fill that "slot" with a lesser-paying contract;
    - We also have to price in the additional administrative costs of having to bid for more contracts than we win;
    - Our financing costs will be higher owing to the commercial risk;
    - And all these costs will ultimately be passed on to the consumer.

With a regulatory definition of storage as storage, the TSO / DSO would be able to let contracts for "storage services", maybe split into primary and secondary to reflect different storage types and characteristics – PHES and CAES as primary and batteries / DSR as secondary, with flow batteries maybe being able to choose.

6. HM Treasury

The Treasury offers certain incentives for investment, such as the Enterprise Investment Scheme (EIS), which explicitly list generation as ineligible. The Treasury uses the regulatory definition of storage (currently generation plus consumption) as its own definition. Therefore defining storage as generation will greatly reduce investment into storage, and increase the returns that investors require for doing so, and thereby increase the cost of de-carbonising the grid.

7. Sundry Regulations
Other regulations, such as planning regulations, also base some of their rules on whether or not a plant is or will be generation. Mis-defining storage as generation would continue to ensure that storage is judged by characteristics that it does not possess, often to its (and thus the grid's and consequently the consumer's) disadvantage.

Proposal
Define storage, in primary legislation, as storage.

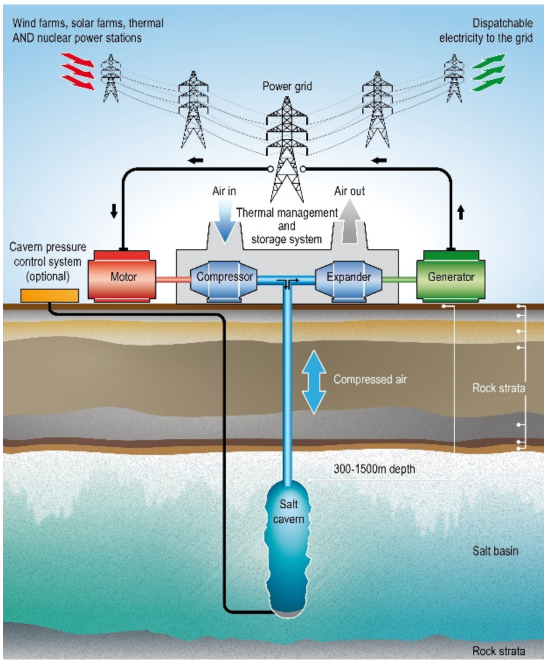
Base the definition on that of interconnectors.

The grid code would therefore be modified, based on interconnectors rather than trying to fit a round storage peg into a square generation hole.

Enable contracts for "storage services" to be let by the TSO and DSOs.

About Storelectric

Storelectric (www.storelectric.com) is developing transmission and distribution grid-scale energy storage.



- ♦ Innovative adiabatic Compressed Air Energy Storage (TES CAES). Our 500MW, 2.5-21GWh installations 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.
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The potential to store the entire continent's energy requirements for over a week; potential globally is greater still. In the future, Storelectric will further develop both these and hybrid technologies, and other geologies for CAES.

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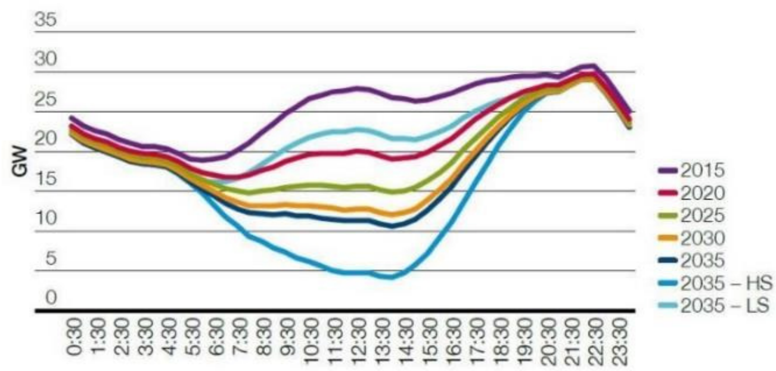
The Lockdown: A Partial Test of the 2030s Grid

The lockdown is providing a trial run of the "summer minimum" challenges of operating the grid as it will be in the 2030s and 2040s. Demand was historically low and renewable generation historically high on both the distribution and the transmission grids. Not only did this mean that electricity flows through the transmission grid dropped severely, but also inertia dropped to levels that required extensive intervention.

This reinforces the need for Storelectric's CAES to provide not only absorption of renewable energy when it exceeds demand, but also the real inertia and other related grid stability services that are currently being provided by gas-fired power stations.

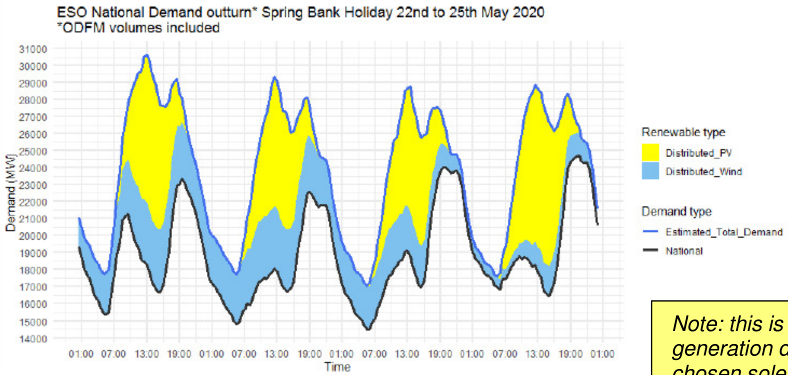
Minimum Energy Flows

Figure 96
Consumer Power summer transmission demand across years



Readers may recall that in their Future Energy Scenarios 2015, National Grid declared that to keep the grid out of black-start conditions they need at least 5GW flowing through it. Based on the distributed solar generation that they thought existed at the time, they believed that they risked dropping below the critical 5GW figure by 2035 in the worst-case scenario. However they had underestimated solar by 3GW and omitted to consider distribution-connected wind, so the first time they hit the 5GW threshold was actually in August that same year.

Bank Holiday Weekend (22nd to 25th May) | Demand Outturn



Date	Cardinal Point	Volume of ODFM enacted (increases ND) (MW)	National Demand inc ODFM (MW)	Dist. wind (MW)	Dist. PV (MW)
Fri 22nd May	1B	NONE	**15390**	2321	0
	3B	NONE	**16680**	3681	7330
Sat 23rd May	1B	999	**14813**	2909	31
	3B	1902	**16744**	3611	6530
Sun 24th May	1B	792	**14500**	2522	173
	3B	NONE	**16970**	2451	6340
Mon 25th May	1B	NONE	**16845**	622	254
	3B	1020	**16465**	1763	8170

Note: this is not the period of highest renewable generation during the pandemic. This period is chosen solely because National Grid evaluated the costs of their actions for it.

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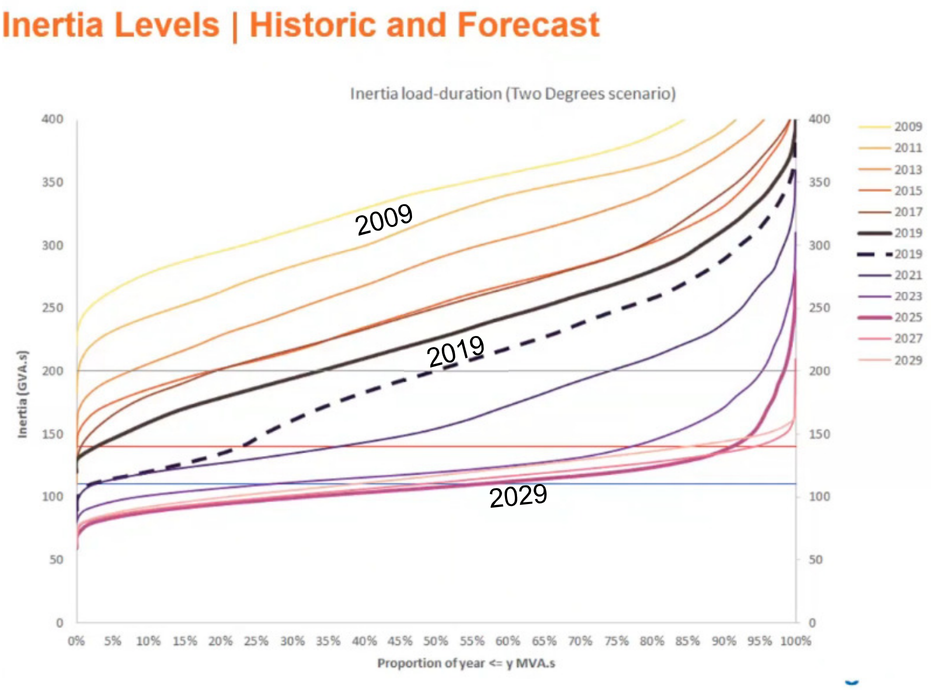
During the COVID-19 Lockdown, demand has plummeted as a small increase in domestic consumption has fallen far short of a huge decrease in industrial and infrastructure (e.g. trains) consumption. Simultaneously the weather was perfect for renewable generation for weeks on end, with unseasonably strong sunshine combining with persistently strong winds. As a result, afternoon minima dropped below overnight minima on the transmission grid.

Inertia and Grid Stability

As fossil fuelled power stations continued closing during the last decade, it became apparent that they were providing many more services than just energy. Prime among these was inertia, with related capabilities such as real reactive power / load, ROCOF (Rate Of Change Of Frequency) and Phase Locked Loops – and many that are still more esoteric.

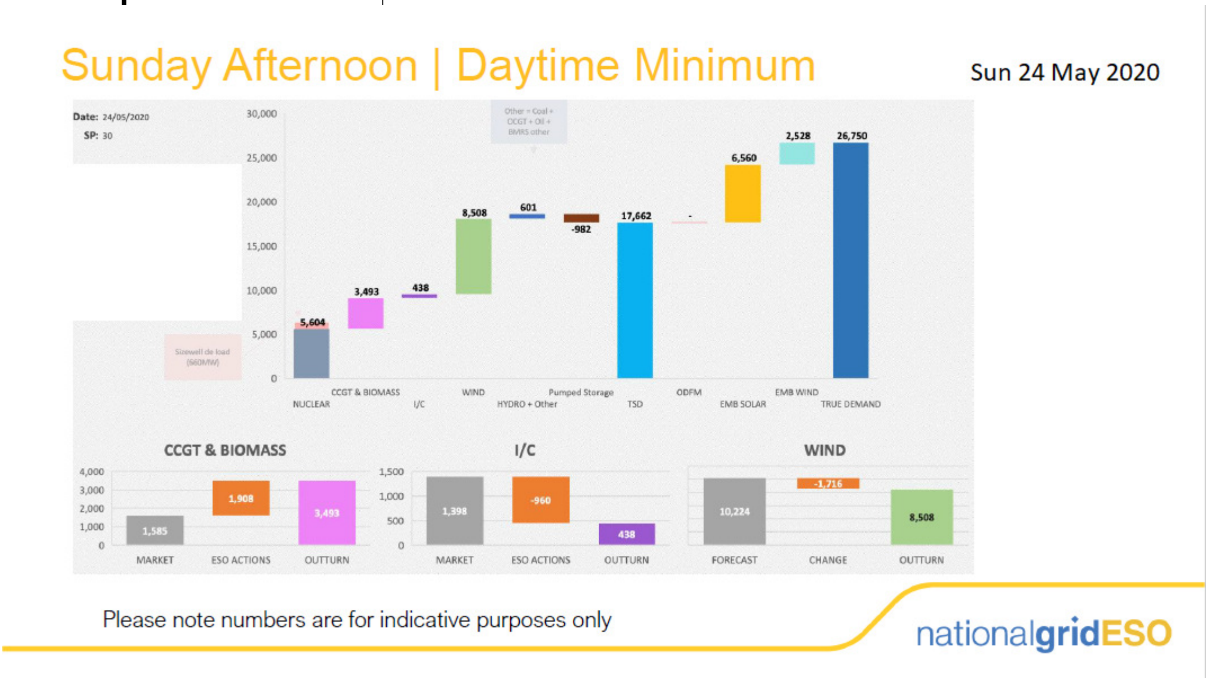
What is inertia? In a car, if the engine fails the weight of the car provides the momentum that means that it slows gently, enabling it to come to a save halt. Those in the car are protected. Without that momentum, the slow-down following the engine fault would be like hitting a brick wall. Inertia is momentum for rotating machines: power stations, being large rotating machines, have it in abundance whereas DC connected systems (including solar and wind generation, and interconnectors) don't.

Therefore as power stations close, replaced by DC-connected generation, inertia drops alarmingly. The fundamental cause of the black-outs across the UK on 9th August 2019 was that two initial trips, one in a power station and the other in a wind farm, turned into a cascade of subsequent trips around the country because there was insufficient inertia on the grid.



And inertia is dropping very fast: this graph shows how it's decreased over the last decade 2009-19, and is expected to continue to decrease 2020-29. National Grid has initiated many [investigations and activities]() into these, including a number of [new contract types]() and pathfinder activities (in the yellow box on the right of the first link) in order to contract for these system stability services. All versions of Storelectric's CAES can provide all these services 24/7, regardless of whether charging, discharging or neither.

Consequences for Grids



Therefore National Grid had to undertake a number of actions to preserve grid stability. These include:

1. Pay to increase 1.9GW contracted interconnector imports to 3.2GW

2. Pay for 5.0GW curtailment of wind
3. Pay to turn down nuclear ~0.7GW
4. Pay to turn on 3.4GW power station generation
5. Various other actions

The total cost of these, over a bank holiday weekend, was £51m:

Costs of Managing the Bank Holiday Weekend 22-25 May 2020

Very low demands with low synchronous generation mix

	Friday 22nd May	Saturday 23rd May	Sunday 24th May	Monday 25th May	Total
Overnight Minimum Demand*	15.4 GW	14.8 GW	14.5 GW	16.8 GW	-
Daytime Minimum Demand*	16.7 GW	16.7 GW	17.0 GW	16.5 GW	-
Overnight ODFM Instructed Volume	-	999 MW	792 MW	-	-
Daytime ODFM instructed Volume	-	1,902 MW	-	1,020 MW	-
Balancing Mechanism Costs	£16,000k**	£14,249k	£7,073k	£2,152k	**£39,474k**
Trading Costs	£600k	£1,420k	£1,624k	£466k	**£4,110k**
ODFM Costs	-	£4,700k	£1,400k	£1,200k	**£7,300k**
Total	**£16,600k**	**£20,369k**	**£10,096k**	**£3,818k**	**£50,833k**

These costs represent the impact low synchronous generation mix during a normal low demand weekend combined with the suppression of demand brought about by COVID-19. The demands this weekend were some of the lowest expected this year.

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*These demands include the additional demand from the ODFM service, **Constraint costs higher on Friday due to fire under a Transmission line
Please note that these numbers are subject to change.

And this was not the weekend with and greatest actions, as solar was not very high. *And these costs exclude increased imbalance costs and trading price volatility*, the total of which are likely to be considerably higher. Not only is all of this activity exceedingly expensive, but also it increases the grid's emissions. All of this would be completely unnecessary if there were sufficient of Storelectric's CAES on the grid.

And in the 2030s and 2040s?

By the 2030s and 2040s, more power stations will have closed – they may not even be available to be turned on if needed. Interconnectors and DC connected generation will have at least doubled in importance. this situation will be much more frequent – indeed, it is likely to be the normal state of affairs in summer, and quite usual in spring and autumn.

To the above "summer minimum" issues can be added the lack of electricity on the grid when renewables are not generating sufficient for demand and interconnectors cannot make up the shortfall, such as after sunset on a windless winter evening, or during weather patterns that extend such low-generation period to days or weeks – which will also be a frequent occurrence by the 2040s according to most European countries' energy transition plans. These are the subject of a separate brief.

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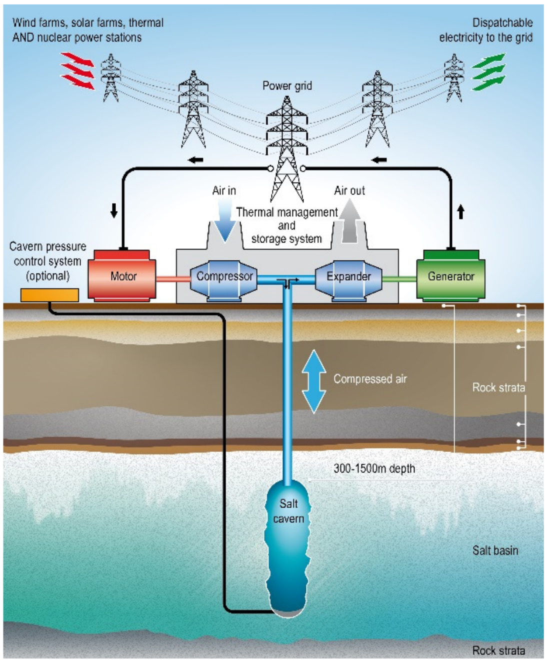

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Curtailment is the Tip of a Growing Iceberg

Electricity Services

The UK electricity grid consumes up to 54 Gigawatts (GW) of electricity at peak times. That's 54 million kilowatts – a lot of electricity. So all we need to produce is 54GW electricity, plus a bit in case anything goes wrong – say, 57-60GW, right?

Wrong. It's not as simple as that. Although all electricity is the same (electrons down a wire), we consume four types of service: baseload, dispatchable, balancing and ancillary.

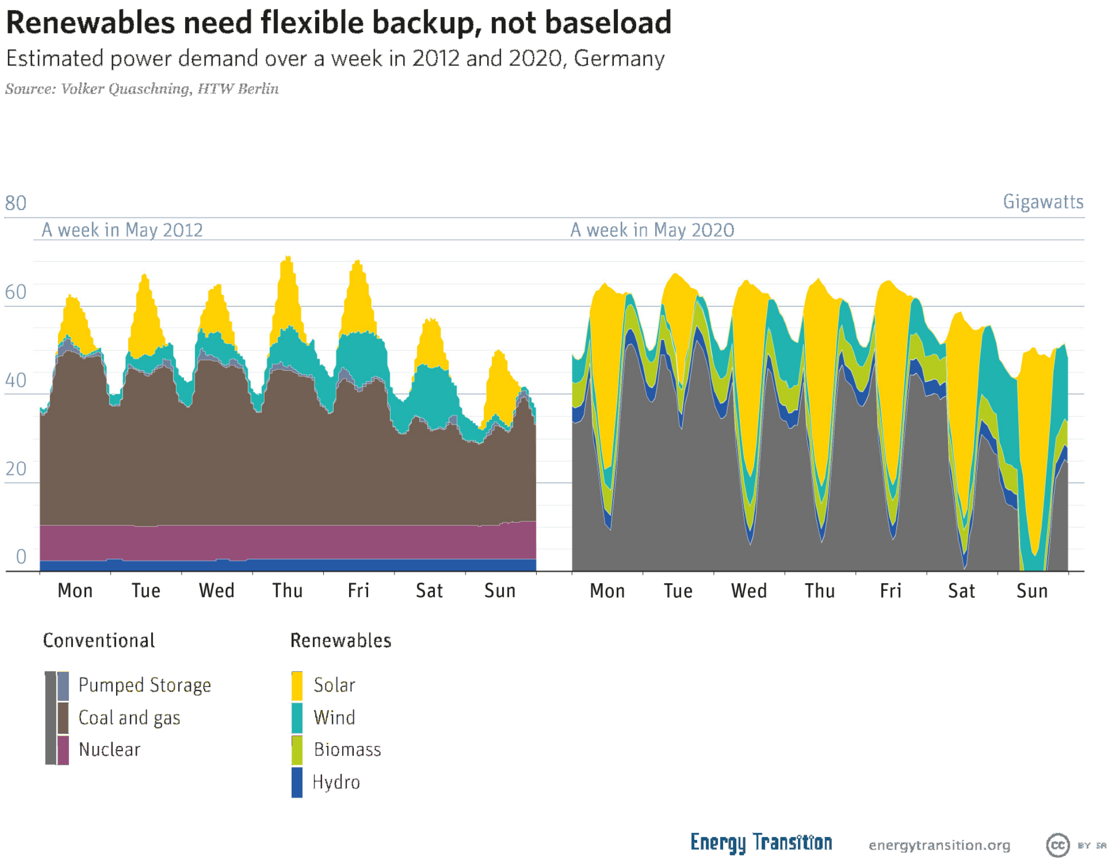
- Baseload is the minimum demand, that is, the always-on requirement. In the UK it's about 60% of peak so, in winter, that's around 32GW.
- "Dispatchable" means that it's there when we need it: we can turn it up or down at will. This accounts for the remaining 40% of peak demand.
- Balancing services are for when things get out of kilter: too much here, not enough there, a power station down for its annual service (this is the major one, in terms of energy needs) and so on.
- Ancillary services are for when things go wrong: rapid reaction when a fault develops, and suchlike.

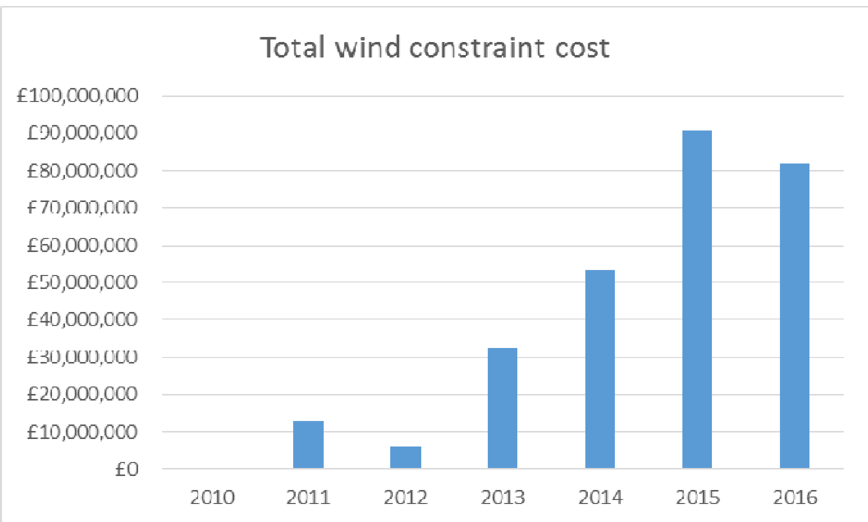
In the olden days of the Central Electricity Generating Board, we delivered baseload with coal and nuclear power stations while the rest was delivered by gas. How simple things were then! Now, because we realised that we're cooking the world with our emissions, we're replacing coal (first) and gas with renewable generation: mostly biomass, wind, solar, wave, tidal flow and tidal range. Of these, only biomass (with by far the smallest potential capacity of the five) is dispatchable or baseload. The rest are a new category of generation: intermittent.

Effects of Intermittent Generation

Intermittent generation doesn't mean that the generation is unpredictable: forecasting is excellent these days, and improving. But it does mean that it is there when it wants to be, not when we want it – forecasting just gives us better notice of the surpluses and shortfalls. As the Managing Director of Siemens Oil and Gas UK says[1], "the wind blows when the wind blows, but you want your dinner when you want your dinner". This means that sometimes it's generating when we don't want it, and it needs to be backed up when we want it and it's not generating. The former leads to curtailment (payment for the renewable generation not to generate) and the latter leads to ever increasing balancing and ancillary services costs. This graph[2] shows how intermittent generation would eliminate baseload generation in Germany, unless curtailed in some way.

[1] https://www.youtube.com/watch?v=m4UgOO_uhug
[2] https://book.energytransition.org/flexible-power-production-no-more-baseload





Curtailment is growing annually[3], reaching £80-90 million for each of the last two years for wind alone – thought that is the major portion of it. While it's fair to say that this is not a large problem, only being about 1% of the total cost of energy paid to wind farms over the year. But curtailment generates bad headlines, so the system is operated to minimise those headlines.

How is that done? By cycling the power stations increasingly aggressively, turning them down when intermittent sources are generating and up again when they stop. That is like drag racing your car around town instead of driving it sedately up a

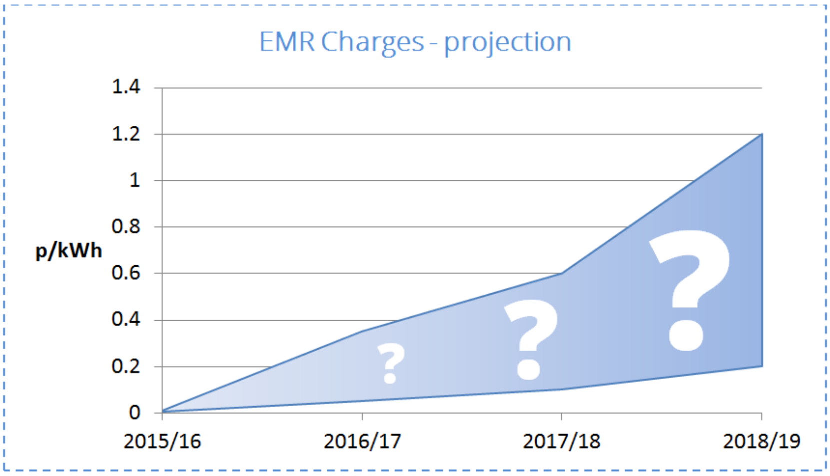
[3] http://www.ref.org.uk/constraints/indextotals.php

motorway: fuel efficiency plummets, emissions per unit output (miles for the car; megawatt-hours [MWh] for the power station) rocket, maintenance increases, plant longevity drops and chargeable output (miles / MWh) drops like a stone. And gas prices increase because the majority of usage tilts towards peak times when gas prices also peak. So almost every single element of costs increase while invoiceable power generation (MWh) decreases, making them unsustainable. That is why they are closing at a very rapid rate.

Costs of Balancing and Ancillary Services

So what does the government do to keep the lights on? There are two alternatives: keep the power stations open, or support the grid at large scale with zero-emissions balancing services. The British government and grid have chosen the former, though the latter is considerably cheaper over the medium to long term as well as being more sustainable (zero emissions).

How does the government keep the power stations open? Subsidies.



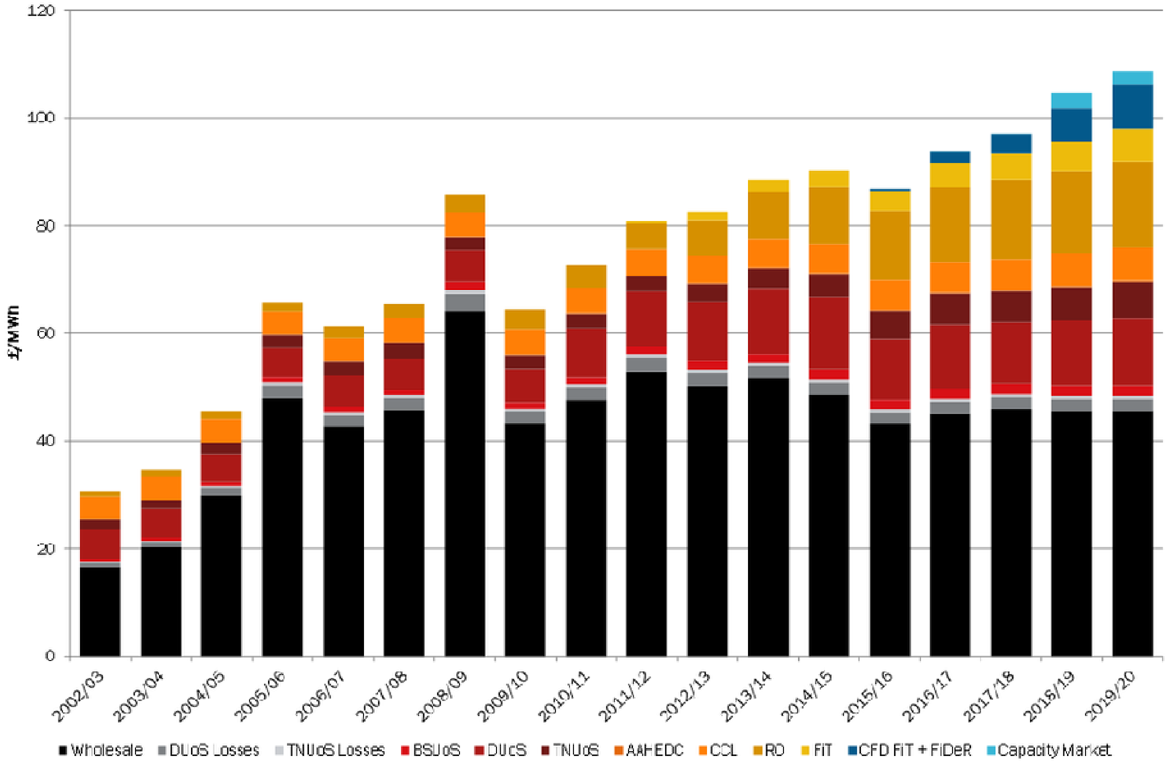
There are two general types of subsidy: overt and covert. Overt ones are out of fashion, so the government tries to disguise these with the word “market”. The main overt subsidy is the Capacity Market. These haven’t really hit us yet: the main costs are for four years ahead, and the market isn’t four years old yet. But these costs already contracted total £1bn per annum and are rising each year. This provides an increasing charge on electricity bills[4]. There is an argument that the Capacity Market is necessary to provide an incentive for new build[5], but this would be unnecessary if standard contracts were available with 15-year durations for new-build plants, especially if the start date of those contracts were to allow for grid connection time (transmission grid connections take 4-10 years).

The covert subsidies are, of their very nature, more difficult to spot. These are mainly known as “charges”. Of the charges depicted in this graph,

- Some (DUoS, TNUoS) are for using the grid and therefore not subsidies: we have to pay to maintain and upgrade the distribution and transmission grids. AAHEDC makes a bid difference to those who live in remote areas.

[4] http://www.costadvice.co.uk/latest-news/the-rise-and-rise-of-non-commodity-costs
[5] https://www.gov.uk/government/publications/cost-of-energy-independent-review p90-96

- A second group of charges (CCL, RO, FiT, CFD) are subsidies to encourage the development and roll-out of renewables. These are a ligitimate charge determined by our political priorities: do we want the world to cook, or not? And how much are we willing to pay to keep it at the right temperature?
- The smallest of these groups is the one we're interested in: BSUoS, Balancing Services use of System. This is the cost of balancing and ancillary services. Some of these will always be necessary, but their rapid and increasing growth indicates that they are spiralling out of control.



National Grid forecast "a growth in balancing tools and technologies such as energy storage and flexible demand"[6], all of which are paid for by these charges. Currently they total £1bn (having increased from £800m in 3 years), but National Grid forecast that this "could double to £2bn a year within five years due to the growth of renewable technologies"[7]. This is an increasing rate of change.

There is another category of hidden subsidy: bilateral contracts. Many of these enable National Grid to support things that it needs and that are not common enough to put into standard contractual conditions – including some innovative technologies being tried out on the system. But last year Fiddlers Ferry power station decided to close because it reckoned that the fines for failing to deliver its Capacity Market contracts were cheaper than the costs of fulfilling them. So National Grid

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[6] http://fes.nationalgrid.com/fes-document/fes-2017/ p63
[7] http://www.telegraph.co.uk/business/2016/06/26/balancing-demand-could-cost-national-grid-2bn/

entered into a bilateral contract at undeclared cost to keep it open[8] – and Eggborough did a similar deal[9]. These deals appear to be both new and rapidly increasing.

Therefore while it is not possible to determine total level of overt and covert subsidies that are required due to a failure to follow alternative routes to balancing intermittent generation, it is safe to suggest that it is already over £1bn and will double within 3-5 years.

The Challenge of Reducing Emissions

The urgent questions posed by climate change were addressed by the world's agreed reaction to it: to cut emissions sufficiently to keep global warming to within 2°C, and preferably 1.5°C[10]. Consequently the British government laid out its carbon budgets, which have the force of law. The fifth carbon budget, for the period 2028-32, requires that by 2030 the electricity sector can emit only one quarter of its 2010 emissions[11]. This means that we can emit no more CO_2 than was emitted by the gas-fired power stations at that time, having closed all the coal-fired ones – which precludes a second "dash for gas"[12].

The government's response to this is to seek a second "dash for gas"[13] (!) and a vast ramp-up in interconnectors[14]. But interconnectors are not truly dispatchable: our neighbours face similar generation shortfalls to the UK, and similar demand patterns, so if we need the electricity when they do then we will have to pay through the nose for it[15]. This was demonstrated last winter when 75% of French nuclear generation was down due to a combination of planned and unplanned outages, leading to price spikes of £1,500/MWh in the UK[16] – against an average price of under £50/MWh. And that's with only 4GW of interconnection: what would happen if we rely on interconnectors for 20GW of our demand? That's the forecast[17].

Worse, with Brexit we will be exiting the single market and the jurisdiction of the European Court of Justice[18]. (National Grid assume that there will be no change

[8] https://www.ft.com/content/3a72f256-f681-11e5-96db-fc683b5e52db
[9] http://uk.reuters.com/article/uk-eggborough-coal-extension/life-of-uks-eggborough-coal-plant-extended-to-march-2017-idUKKCN0VI0W2
[10] http://unfccc.int/paris_agreement/items/9485.php
[11] https://www.theccc.org.uk/publication/sectoral-scenarios-for-the-fifth-carbon-budget-technical-report/
[12] www.ukerc.ac.uk/publications/the-future-role-of-natural-gas-in-the-uk.html
[13] https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy and www.dailymail.co.uk/news/article-3472260/New-dash-gas-head-blackouts.html
[14] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors
[15] https://www.ofgem.gov.uk/publications-and-updates/electricity-capacity-assessment-report-2013 p41-44
[16] https://www.ice.org.uk/news-and-insight/the-civil-engineer/february-2017/what-caused-the-recent-spike-in-power-prices
[17] http://fes.nationalgrid.com/fes-document/fes-2017/ pp57-58, but most analysis needs to look at the supporting data that is also available through this website ("Charts Workbook").
[18] http://www.bbc.co.uk/news/uk-politics-41012265

arising from Brexit[19], which is the one scenario that cannot occur.) Therefore our neighbours will be able to say that their consumers are more important than ours at any price. But if we rely on them for 25-30% of our peak demand, that will lead to black-outs.

And a second "dash for gas" depends on widespread roll-out of Carbon Capture and Storage[20] (CCS), which is a triumph of hope over experience as there are no ongoing initiatives in the power sector[21]: it was too expensive, and nobody would foot the ongoing risk liability[22] that would last until the tectonic plate is subducted. Yet FES 2017 depends on CCS for 15GW of generation by 2050.

Alternative Balancing of Intermittent Renewables
How can we balance the grid with no fossil fuel power stations? By a combination of balancing technologies:

- Large scale, long duration storage
- Grid connected batteries for shorter term spikes both up and down in demand
- Demand side response (DSR), ditto
- Interconnectors (yes, they do have a role)

In FES 2016[23] National Grid sized the potential for DSR at 1.8GW now (of which 2/3 is diesel generation and therefore must be discounted) plus 3.4GW by 2040, making a total (excluding diesel) of 4GW. But, put simplistically, if we turn off a fridge now we can't do so again in half an hour, so we have to split this capacity for a number of interventions, i.e. the maximum DSR available for any given intervention is 1-2GW.

Batteries average about 30 minutes' duration, but peaks last for 5 hours. So they too are suitable only for the shorter spikes in demand, whether those spikes be increases or decreases. And being of megawatt scale, they cannot deliver tens of gigawatts: it is reasonable to expect only 2GW of batteries also. More than this would jeopardise the system because then we are into longer spikes than 15-30 minutes.

The government identified a need for **new** storage of 27.4GW, 128GWh[24] – that is, 5 hours' average duration. Only pumped hydro and Compressed Air Energy Storage

[19] FES 2017 p66 "Given the lack of clarity on future trading provisions, our analysis currently assumes tariff free access to EU markets under all scenarios."
[20] Again, see FES 2017
[21] https://www.theguardian.com/environment/2017/jan/20/carbon-capture-scheme-collapsed-over-government-department-disagreements
[22] http://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0031&from=EN para.36 and chapter 4
[23] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Documents-archive/ 2016 FES pp.64-65
[24] https://www.carbontrust.com/resources/reports/technology/tinas-low-carbon-technologies/ Energy Networks and Storage report chart 2 p9 which splits it down into various technologies without considering the costs of doing so (batteries of all kinds with the required 5-hour durations and pumped hydro are much dearer than CAES) or availability (they exceed the country's pumped hydro potential), or the availability / practicality of the technology (thermal-to-electric stopped when Isentropic went into

can deliver this. But pumped hydro only has very limited potential in the UK, which is both remote and expensive. This leaves CAES.

Storelectric
Storelectric's CAES are the two most efficient and cost-effective forms of CCS available in the world:

- TES CAES (TES = Thermal Energy Storage) costs about the same as traditional CAES but has higher round trip efficiency (68-70% v 50-54%) and zero emissions (v 50-60% of the emissions of an equivalent sized CCGT)
- CCGT CAES (CCGT = Combined Cycle Gas Turbine) is much cheaper, is more efficient (~60%) than existing CAES, emits correspondingly less, and uniquely can be retro-fitted to existing CCGT or OCGT power stations, thereby reducing capital costs much further and giving a new lease of life (with new revenue streams) to existing stranded assets, and almost doubling the generation that is permissible within emissions limits.

Uniquely, both of these technologies generate double digit whole-project IRRs even under existing regulatory and contractual framework – which is improving all the time. This means that Storelectric's two CAES technologies do not add to the costs of the electricity system – as compared with the current strategy of ever-increasing subsidies building a system that will soon breach all carbon budgets and emissions limits. (And 27GW of CAES by 2050, as per the TINA report, is a very big business – and 100 times bigger still when rolled out globally.) Thus, working with the other clean balancing technologies, Storelectric's CAES can enable renewables to power the world cost-effectively.

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administration in 2016 http://www.eti.co.uk/programmes/energy-storage-distribution/distribution-scale-energy-storage, long before FES 2017 was published, despite £14m investment by ETI, http://www.eti.co.uk/news/eti-invest-14m-in-energy-storage-breakthrough-with-isentropic).

Journal of Energy and Power Engineering 12 (2018) 105-117
doi: 10.17265/1934-8975/2018.02.006

Gigawatt Scale Storage for Gigawatt Scale Renewables

Mark Howitt

Storelectric Ltd., 15 Weaver Close, Alsager, Stoke-on-Trent ST7 2NZ, England

Abstract: Multi-GW renewables need multi-GW storage, or fossil fuelled power stations will be needed to balance for intermittency. For the same reason, such balancing must be able to last for an entire evening peak if renewables are not generating at the same time. Batteries and DSR (demand side response) make very useful contributions and there is a large market for both, but without large scale and long duration storage, they cannot do the job. Interconnectors also contribute to the solution, and storage will make them more profitable, but (taking a UK perspective) Ofgem identified that all our neighbours have similar generation capacity crunches and similar demand patters, so if we need the electricity when they do, we'll have to pay through the nose for it. Last winter's £ 1,500/MWh prices proved that—even with only 4 GW interconnection. Following exit from the single market, our neighbours will be able to say "our consumers are more important than yours at any price". We need UK-based storage at the right scale, to store UK-generated electricity for UK use and for export—otherwise we lose security of supply. CAES (compressed air energy storage) and pumped hydro are the only technologies currently able to deliver this scale and duration of storage. Pumped hydro is cost-effective in the long term but there are few sites, and it is (location dependent) over 3*x* the cost of CAES. Storelectric has 2 versions of CAES: one is a comparable price to existing CAES, but much more efficient (~70% v 50%) and zero emissions (existing CAES emits 50%-60% of the gas of an equivalent sized power station). The other is retro-fittable to suitable gas power stations, is more efficient (~60% v 50%), almost halves their emissions, adds storage-related revenue streams and is much cheaper. Both are new configurations of existing and well proven technologies, supported by engineering majors.

Key words: Electricity storage, CAES, compressed air energy storage, adiabatic, grid balancing, renewable.

1. Introduction

Many people have suggested that batteries, demand side response and interconnectors are a viable way forward for balancing a future renewable grid in general, and for grid-scale electricity storage in particular, and some have cast doubt on whether there is a role for CAES (compressed air energy storage) or increased amounts of PHES (pumped hydro energy storage).

However CAES, batteries and the other storage technologies are very different technologies, for different scales, durations and duty cycles. There is a role for all of them, with each having its optimal niches. Therefore we consider them under the following headings, which are the headings of this report:

(1) The challenge;

(2) Power;

(3) Capacity;

(4) Response time, duty cycles, ancillary services.

There are also additional considerations, such as:

(1) Cost, lifetime and efficiency;

(2) Environmental considerations;

(3) Cost and performance summary;

(4) Global potential;

(5) Other analysts' views.

The final section looks at the quantity of storage required, and how the different technologies fit together.

This paper analyses the issues from a UK perspective, but the lessons apply equally to grids globally as they de-carbonise.

2. The Challenge

While many countries are targeting 80% reductions in greenhouse gas emissions by 2050 as compared with 2010 levels [1] (the EU is targeting 80-95% reduction [2]), different sectors of the economy face different

Corresponding author: Mark Howitt, BSc (Hons) Physics with Electronics, entrepreneur.

levels of difficulty in de-carbonising. Because ground-based power sector will find it easier to de-carbonise than (for example) aviation and shipping, the EU has identified that in order to achieve those targets across the entire economy, the power sector needs to de-carbonise completely [2]. Grids will simultaneously have to expand to support the de-carbonisation of other sectors, for example heating, transportation and manufacturing.

The challenge is to enable renewables to power an entire and growing grid, with or without nuclear. The difference that nuclear makes is how much baseload power renewables would supply—it is therefore a matter of quantity, not quality, so the following covers either case. The role of the balancing technologies is to enable intermittent generation to supply both variable and baseload demand.

The scenario on which most grid players (operators, regulators, generators, storage providers etc.) focus is to address the rapid ramp rates of renewables in (for example) gusty or intermittently cloudy weather (one aspect of the intermittency challenge), and also the similarly rapid ramp rates, both upwards and downwards, in demand (dispatchability). Batteries and DSR (demand side response) are well suited to this, over limited power ranges.

For longer term fluctuations the grid players rely on interconnectors. However this does not consider a number of factors, including:

(1) Energy flows through interconnectors are often contracted well in advance and to that extent cannot be varied according to shorter term conditions;

(2) Demand and supply are often highly correlated at both ends of an interconnector, so a shortfall at one end is matched with a shortfall at the other;

(3) Weather patterns can cover both ends of interconnectors, and wider regions, for up to a fortnight at a time;

(4) Where legally permissible (e.g. between nation states outside free trade pacts, such as post-Brexit Britain), each country would favour their own consumers' needs.

This leaves three scenarios that are not catered for by grid players' current plans: winter evening peaks, widespread shortfalls and widespread weather patterns.

2.1 Winter Evening Peaks Scenario

When the sun goes down on a windless winter afternoon, a long period of peak demand is in prospect with negligible renewable generation. The duration of this peak vastly exceeds the power and duration capabilities of batteries and DSR, and are likely to exceed the available (un-contracted) capacity of interconnectors.

2.2 Widespread Shortfalls Scenario

In May 2017, two-thirds of French nuclear power generation was down for a mix of planned and unplanned outages [3]. This caused knock-on effects throughout Western Europe despite the currently restricted sizes of the interconnectors with France. Imbalance prices shot up in the UK to over £ 1,500/MWh, against typical normal prices of £ 40-50/MWh.

2.3 Widespread Weather Patterns Scenario

Weather patterns often do not just cover one country, they can cover large proportions of a continent, and can do so for many days at a time—as they did at the end of February and early March this year [4]. Over such extended periods and geographies, most countries within a network of interconnectors are affected similarly, so the interconnectors do not help. And they are affected for a long time, so batteries and DSR do not stand a chance.

3. Power

Energy storage is required at a number of different scales. We divide them into five bands, as Table 1.

The largest battery currently installed anywhere is 100 MW, with 1 hour duration [5]. These are used to alleviate local and domestic line capacity constraints, and to provide a small amount of time-shifting of

Table 1 Scales of storage: size.

Scale	Power	Technologies best suited
Domestic	< 100 kW	Batteries, supercapacitors, flywheels
Local	< 1 MW	Batteries, supercapacitors, flywheels, cryogenic
Area	< 10 MW	Cryogenic, heat, poss. large batteries, poss. CAES
Regional	< 100 MW	CAES, pumped hydro, poss. heat
Grid	> 100 MW	CAES, pumped hydro

Table 2 Scales of storage: capacity.

Scale	Capacity	Technologies best suited
Domestic	< 250 kWh	Batteries, supercapacitors, flywheels
Local	< 5 MWh	Batteries, supercapacitors, cryogenic
Area	< 50 MWh	Cryogenic, heat, poss. large batteries, poss. CAES
Regional	< 500 MWh	CAES, pumped hydro, poss. heat
Grid	> 500 MWh	CAES, pumped hydro

energy, i.e. making it available at a time other than when it was generated.

It is possible to increase batteries' rated power cheaply, though this would entail reducing their capacity (duration of output at full power) proportionately. Thus a 20 MWh battery could produce 10 MW for 2 hours or 40 MW for 30 minutes, assuming that the electrical circuits and signal conditioning can take it.

Although there have been start-ups offering small-scale CAES, Storelectric and most other CAES companies believe that it is best suited to large-scale applications, of 100 MW or more. Storelectric offers efficient solutions rated from 40 MW to GW, with the potential for smaller ratings either in the future or with decreasing efficiency and cost-effectiveness. Power is determined by the design, specification and cost of all the surface systems, and is therefore the main driver behind the cost of a CAES plant—though the cost per MW of power decreases rapidly as size increases. A good rule of thumb is that whereas batteries increase in cost by ~85% when doubling either their power rating (at constant duration) or their duration (at constant rating), Storelectric's CAES increases by ~1/3.

4. Capacity

Energy storage is required at a number of different scales, which we define thus as Table 2.

All grid-connected batteries to date have had a storage capacity of between 0.25 and 2 hours' output at full rated power. Therefore they are best suited to applications that require such durations of output, or (better) less: if less, then they can produce output on multiple occasions between charges.

Doubling the capacity of a grid-connected battery costs at least 80% of the original cost, as twice the number of batteries are needed, and other system elements (such as air conditioning) need to be (approximately) doubled. Capacity is the main cost driver for batteries.

The total output of Tesla's Gigafactory (under construction) is 35 GWh p.a. by 2020. A single CAES plant could have this capacity.

Although there have been start-ups offering CAES storing energy in cylinders, Storelectric believes that such technologies are unlikely to be cost-effective in the near future. Geological storage is much larger scale and cheaper.

Storelectric can store its air in salt caverns now. Salt caverns are solution mined, a slow but relatively cheap process, depending on geology and geography: the geology must offer salt and mudstone strata sufficiently deep, and the geography must offer a source of water, and a destination (either industry or the sea) for brine. With these caveats, the cost of capacity is ~$6/kWh, or $6 m/GWh, to use the same surface equipment.

Notably, there are salt basins across the world; in Europe there are sufficient to store a week's worth of the continent's total energy demand; similar amounts could also be stored in North America, North Africa, the Middle East and elsewhere.

In future it will be able to store air in six other geologies, which would open up virtually the entire planet to CAES. Most of these are in porous rock (e.g. aquifers, depleted hydrocarbon wells) and therefore offer much larger scale storage, much more cheaply.

5. Response Time, Duty Cycles, Ancillary Services

5.1 Response Time

Batteries have a very rapid response time: they can usually be operational and synchronised with the grid within a second. They can also remain on standby with low energy consumption. Only supercapacitors and flywheels are faster, and these have much lower capacity (duration). The "virtual storage" derived from Demand Side Response can also match it, provided permission is not required before use.

CAES and Pumped Hydro are rather slower. They can respond with 30 seconds, though a smaller plant (of either type) optimised for speed of response could respond within 10 seconds if kept spinning and synchronised: CAES would do this using the generator (without load) as a motor, and therefore consuming little power.

5.2 Duty Cycles

Batteries are best suited to duty cycles that last from minutes to half an hour or more, repeating in order to provide levelling for intermittent generation, and to satisfy demand spikes without burdening the remainder of the grid.

CAES and pumped hydro are best suited to duty cycles from minutes to entire peak periods or even days, though can be optimised for quicker response times. This provides (with zero or very low emissions) the system back-up and resilience that are currently being provided by gas-fired peaking plants at great cost and with substantial emissions.

5.3 Other Ancillary Services

CAES, pumped hydro and flywheels offer another valuable service that batteries and supercapacitors cannot: inertia to increase loss-of-infeed tolerance and short circuit level, and stabilise the grid in other ways. This is the immediate inertial response of a system to rapid faults, which grid operators value very highly. Indeed, if they deem there to be insufficient inertia on the system (for example, excessive proportions of power coming from non-synchronous sources such as wind turbines, solar panels and interconnectors), they will invest millions to build plants solely to provide inertia. They also offer reactive load, and can help suppress voltage dips and harmonics.

6. Cost, Lifetime and Efficiency

6.1 Cost

According to Lazards' analysis (www.lazard.com/insights), comparing the costs of various power sources in America (where planning, construction, gas and coal prices are all cheap), CAES is much cheaper per MWh of power than batteries. Indeed, Storelectric's CAES is cheaper than an equivalent sized gas-fired peaking plant (OCGT), based on a plant generating 500 MW and a capacity of 6-21 GWh.

Note that there is no comparison of storage capacity. For batteries, a storage capacity of 1-2 hours' duration at peak load is assumed. The figures for CAES are for between 12 and 42 hours' duration.

6.2 Lifetime

Depending on the temperatures and duty (load) cycles to which a battery is subjected, the average lifetime of a grid-connected battery is usually quoted as 5-8 years, Lithium chemistries being 5 years and lead-acid 8 years.

In contrast, the lifetime of a CAES or pumped hydro installation is expected to be 40 years for the top-side equipment (with a mid-life overhaul) and over 100 years for the caverns. Huntorf received a mid-life upgrade in 2006, aged 28 years, and is still operating—at a higher capacity (321 MW vs. 290 MW as first built) than originally.

6.3 Efficiency

CAES has various quoted levels of efficiency. Storelectric's is much better:

- Huntorf (traditional OCGT-based CAES): 42%;
- McIntosh (traditional CCGT-based CAES): 50%;
- Dresser Rand's Smart CAES (an evolution of McIntosh): up to 54%;
- Storelectric, with thermal energy storage: 68-70%.

Battery advocates often quote efficiencies of 85%-97%, but these are battery-only performances with small-scale installations. Large installations require huge parasitic/ancillary loads, especially air conditioning. Northern Power Grid's Customer-Led Network Revolution, which concluded in December 2014, measured the actual round trip efficiency of battery systems at the beginning of their life [6], shown in Table 3.

In a recent public presentation, a senior manager of Belectric stated "it is well known that" a 5-year-old grid connected battery requires three times as much air conditioning load as an otherwise identical new installation, due to the rate of deterioration of the battery. However there is little literature on this because the rate of deterioration depends on the temperatures and duty (load) cycles to which a battery is subjected.

Table 3 Quoted and actual battery efficiencies, actual costs.

	2.5 kVA, 5 MWh	100 kVA, 200 kWh	50 kVA, 100 kWh
Costexcl. installation	£ 3.76 m	£ 406 k	£ 331 k
£/MWh	£ 752 k	£ 2,030 k	£ 3,310 k
Costinc. installation	£ 4.62 m	£ 490 k	£ 422 k
£/MWh	£ 924 k	£ 2,450 k	£ 4,110 k
Nominal efficiency	83.2%	83.2%	83.2%
Measured efficiency	69.0%	56.3%	41.2%
Average parasiticload	29.5 kW	29.5 kW	29.5 kW

7. Cost and Performance Summary

The various technologies can be summarised (excluding durations) in Table 4:

Table 4 Comparing electricity storage technologies.

		Size (up to)				Grid Support				Efficiency	LCOE	Capex	
Technology	Type	10 MW	100 MW	1 GW	>1 GW	FFR	FR	SU	LT	%	$ /MWh	$k /kW	$ /kWh
Storelectric	CAES									68-70	100	1	116
Dresser Rand[1]	CAES									54 [1]	125	4.7	586
Pumped Hydro	PHES									75-82	185	5.8	725
Highview	Cryogenic									65?	210	1.36	340
Li-ion	Battery									41-75	125	6	5454
Va Redox[2]	Flow Batt.									60-70	460	6.5	1300
Flywheels	Flywheels						3			85-95	380	4.2	1700

Notes:
(1) Dresser rand has 50%-60% of the natural gas burn (and emissions) of an equivalent sized CCGT;
(2) Vanadium redox flow battery;
(3) Flywheels' normal duration is 5-15 minutes.

Key: Grid support
FFR: Fast frequency response;
FR: Frequency response;
SU: Start-up (e.g. back-up to wind);
LT: Long term (weekly or more).

Data sources for costs:
Storelectric Ltd., based on a 500 MW, 6 GWh plant after the first 3-5 plants when CAPEX costs will have stabilised.

Dresser Rand: DoE (American Department of Energy) http://www.sandia.gov/ess/publications/SAND2015-1002.pdf. Brayton installations;
Highview: Highview Power Cost Estimator, http://www.highview-power.com/market/#calc-jumper using their default values (100 MW, 4 hours, standalone system). Levelised cost from http://cleanhorizon.com/images/slides/20140916_CleanHorizon_white_paper_3.pdf;
Pumped Hydro: DoE (American Department of Energy) http://www.sandia.gov/ess/publications/SAND2015-1002.pdf;
Lithium Ion: Costs: DoE (American Department of Energy) http://www.sandia.gov/ess/publications/SAND2015-1002.pdf, taking the three batteries with duration >1 hour (the remainder had durations of 0.25 hours), averaging them at $6,000/kWh for a 1.1 hr battery;
Lithium Ion: Efficiencies: http://www.networkrevolution.co.uk/project-library/electrical-energy-storage-cost-analysis/. Best efficiency is 69% including parasitic loads (bottom of *p*6) for a 5 MW system; the figures in the table assume that efficiencies increase with size;
Va Redox: DoE (American Department of Energy) http://www.sandia.gov/ess/publications/SAND2015-1002.pdf;
Flywheels: DoE (American Department of Energy) http://www.sandia.gov/ess/publications/SAND2015-1002.pdf.

8. Environmental Considerations

Batteries need to be mined, refined, transported, manufactured, replaced every 5-8 years, and then recycled or disposed of. They all use elements and compounds that are toxic, explosive or both, and most use raw materials of which there would be a major shortage if exploited for global grid balancing (see next section).

Pumped hydro-electric schemes flood two valleys (unless using the sea, a lake or a river as the lower reservoir, an unusual set-up), which are usually remote from major generation and consumption (hence require very long transmission lines, with their losses and visual blight) and are open to large-scale evaporation (and are therefore not suited to hot climates). They also require a very special topography, which is not common—and even less so if one excludes areas of outstanding natural beauty or environmental importance. Such topologies are also usually remote from both generation and major demand, requiring long transmission line spurs.

Storelectric stores its power underground, invisibly. Its surface footprint is comparable with a gas-fired power station of equivalent size, and its subterranean footprint is of the order of a square kilometre per plant. The caverns are so deep that many activities (especially farming) can continue above them. The pressure at which the air is stored is determined by the weight of the rock above, which is therefore not in tension but is being kept in balance by the air pressure within. And air is benign, almost completely safe to store and to use, unlike the natural gas that is currently stored (with an outstanding safety record world-wide) in these same geologies at the same pressures.

9. Global Potential

According to the late David Mackay's book "Sustainable Energy—Without the Hot Air" [7] (David was Chief Scientific Officer for the British Government's Department of Energy and Climate Change), there is enough lithium in the ground (excluding the very low-grade stocks in the sea) globally to power either the world's cars or the world's grids—and that's without the world's portable devices. And this assumes that:

(1) We use lithium twice as efficiently as today, per MWh of storage;

(2) We can extract it all cost-effectively;

(3) There are no other uses for Lithium;

(4) Every battery lasts forever, whereas their true life is 5 years;

(5) No battery is ever wasted or destroyed, anywhere;

(6) Only today's number of vehicle-miles are driven, and only today's amounts of electricity are consumed, which disadvantages developing countries as well as preventing the electrification of heating (e.g. by heat pumps), industry and transportation;

(7) We ignore the scarcity of the other elements (manganese, cobalt, nickel, and alloying metals) that form an essential part of a modern lithium battery.

Clearly none of these assumptions is remotely sustainable, except the first which may be achievable in 10-20 years. The only reason why lithium prices were (until recently) dropping is because extraction technologies and volumes are still improving faster than demand: if demand was to grow to such global levels, scarcity pricing would soon start.

According to information from the economist, vehicles alone would exhaust the world's stock of lithium in 2-10 years for the number of battery vehicles forecast in 2040 [8][1]. This leaves nothing available for portable devices or grid applications.

And batteries require other, scarcer, materials too, such as cobalt and, somewhat less scarce, nickel.

In contrast, salt basins alone offer enormous potential for CAES, referring to Fig. 1.

Note that global salt basins are:

• On a scale that only shows one of the 10 UK basins;

• Only shown in countries that divulge their geology publicly; and

• Coincident with areas explored for petrochemicals: it is not normal to seek salt basins, they are found by accident;

• Therefore there are many more, often undiscovered as yet: we know of one three times the size of the Cheshire basin located west of New Delhi, India, and another in Queensland, Australia.

Moreover, the other six geologies in which CAES can be built (following minor R & D) extend potential areas globally, without necessarily having any impact on resources that people would otherwise use. These geologies are all currently used safely for storing methane:

• Saline and sweet water aquifers (deeper than used for drinking water);

• Depleted oil fields;

• Depleted gas fields;

• Chalk;

• Gypsum;

• Limestone.

However storing air in these geologies is not straightforward and needs to be analysed carefully; therefore salt caverns are the quick, safe and simple way forward initially.

10. Other Analysts' Views

We select a small number from among the hundreds of reports that have analysed a variety of storage technologies for their "sweet spots". Almost without exception, they support the above analysis. Note that none of them was aware of Storelectic's particularly high-potential technology when undertaking these analyses, and therefore base all their evaluations on Huntorf and McIntosh.

Chinese paper on combined pumped hydro and CAES [9].

The following four graphs (Figs. 2-5) provide different ways of looking at storage:

(1) By cost and technology maturity;

(2) By power output and energy stored;

(3) By power rating and discharge time (another view of the previous graph);

(4) By capital cost per unit energy.

All four show CAES comparable with pumped hydro, fulfilling similar functions, and therefore not competing with the other technologies. To compare with pumped hydro, one must consider proximity to

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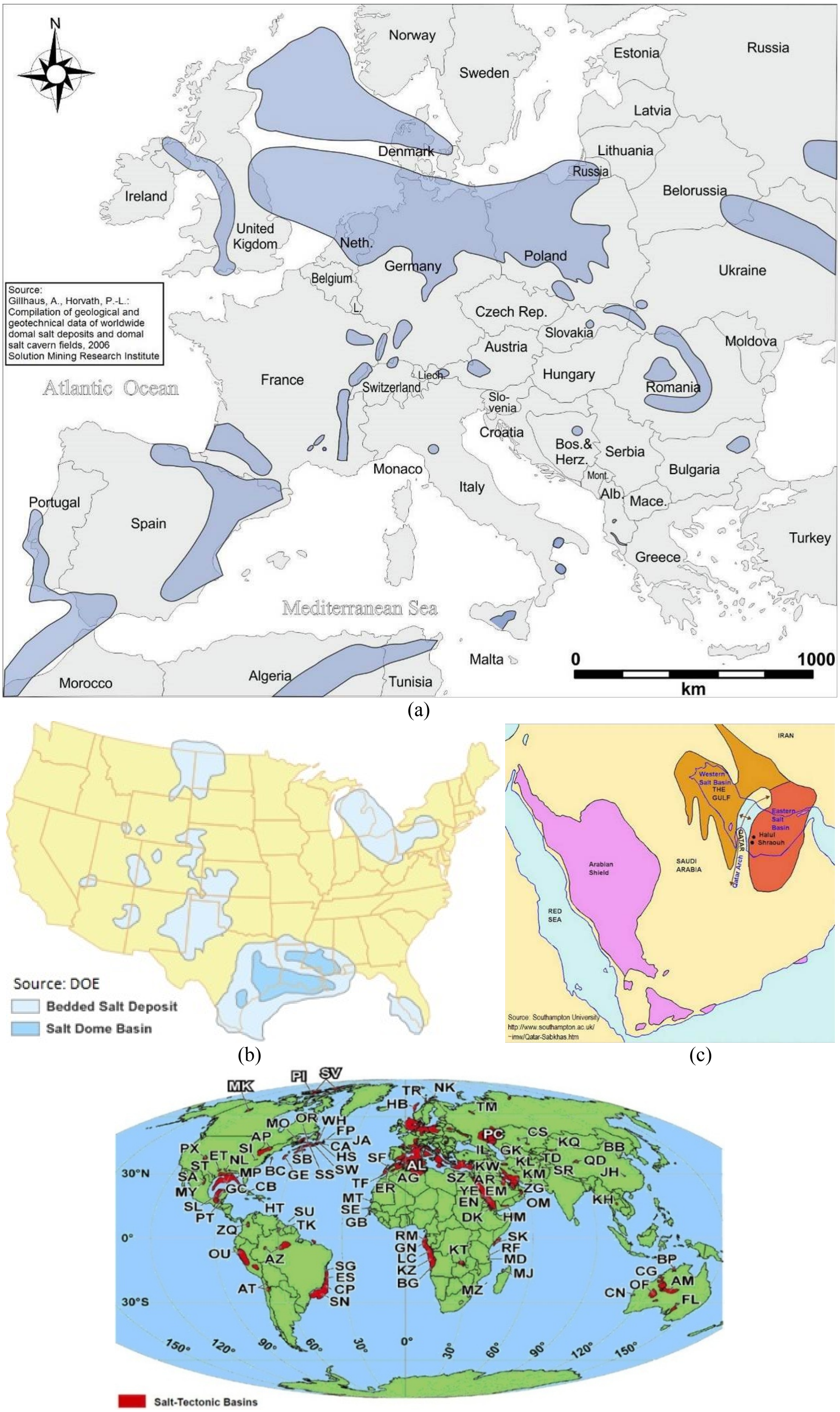
[1] https://www.economist.com/news/briefing/21726069-no-need-subsidies-higher-volumes-and-better-chemistry-are-causing-costs-plummet-after -

Vehicles, 2016		25 GWh	750,000 vehicles
Mid-range:	2040 Bloomberg	15,500 GWh	465,000,000 vehicles
	2040 OPEC	5,000 GWh	150,000,000 vehicles
	2040 ExxonMobil	3,000 GWh	90,000,000 vehicles
Total lithium, 2016		180,000	tonnes in one year
	2040 Bloomberg	111,600,000	tonnes in one year, just for vehicles
	2040 OPEC	36,000,000	tonnes in one year, just for vehicles
	2040 ExxonMobil	21,600,000	tonnes in one year, just for vehicles
Total available lithium in planet		210,000,000	tonnes
Years' output:	2040 Bloomberg	1.9	years, just for vehicles
	2040 OPEC	5.8	years, just for vehicles
	2040 ExxonMobil	9.7	years, just for vehicles



(d)

Fig. 1 Maps of salt basins in Europe, North America, the Middle East, and the world.

Table 5 Capital cost of installed storage plants.

Type	Storage capital cost ($/kWh)	Plant capital cost ($/kW)	Storage capital (MWh)	Efficiency (%)	Operation and maintenance cost ($/kW/yr)	Hours (full power)	Power (MW)
CAES	> 3	> 425	5-100,000	> 70	1.35	1-10 min	0.5-2,700
Pumped hydro	> 10	> 600	20,000	> 70	4.3	10 s-4 min	300-1,800
Flywheel	300-25,000	280-360	0.0002-500	90-93	7.5	< 1 s	0.001-1
Superconducting Magnet	500-72,000	300	0.0002-100	95	1	< 1 s	0.001-2
Battery storage	1-15	500-1,500	0.0002-2	59	-	< 1 s	0.01-3

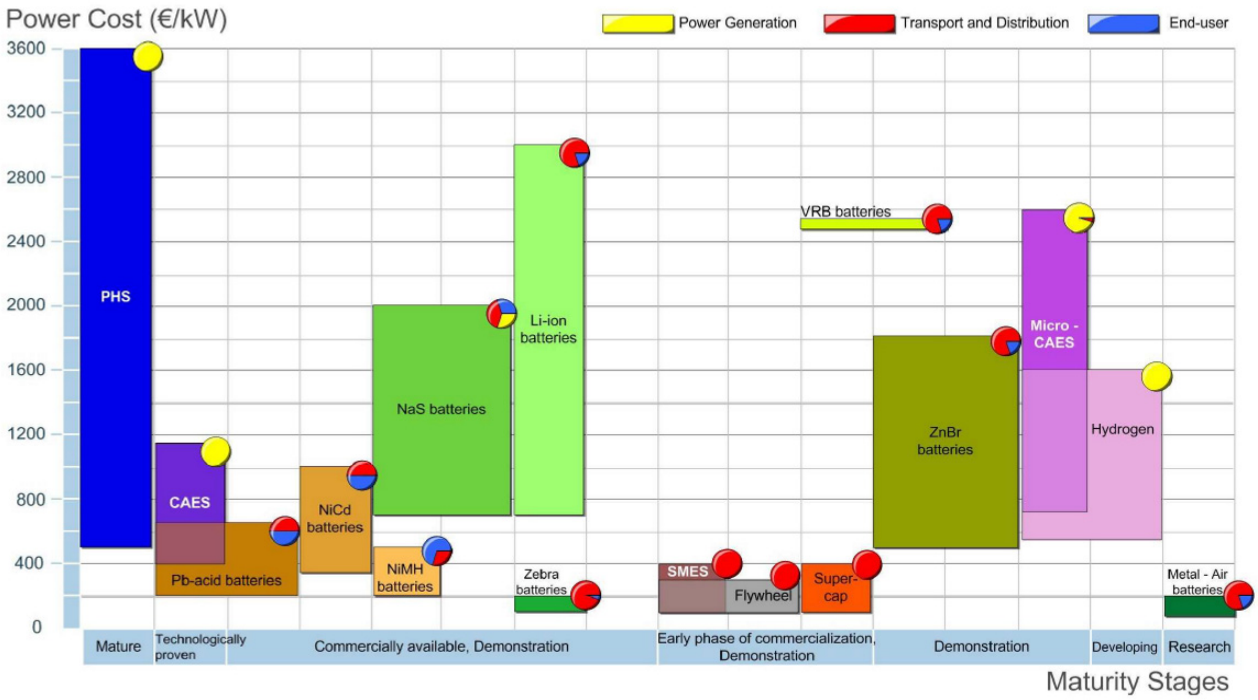


Fig. 2 Types of storage, by cost and technology maturity [11].

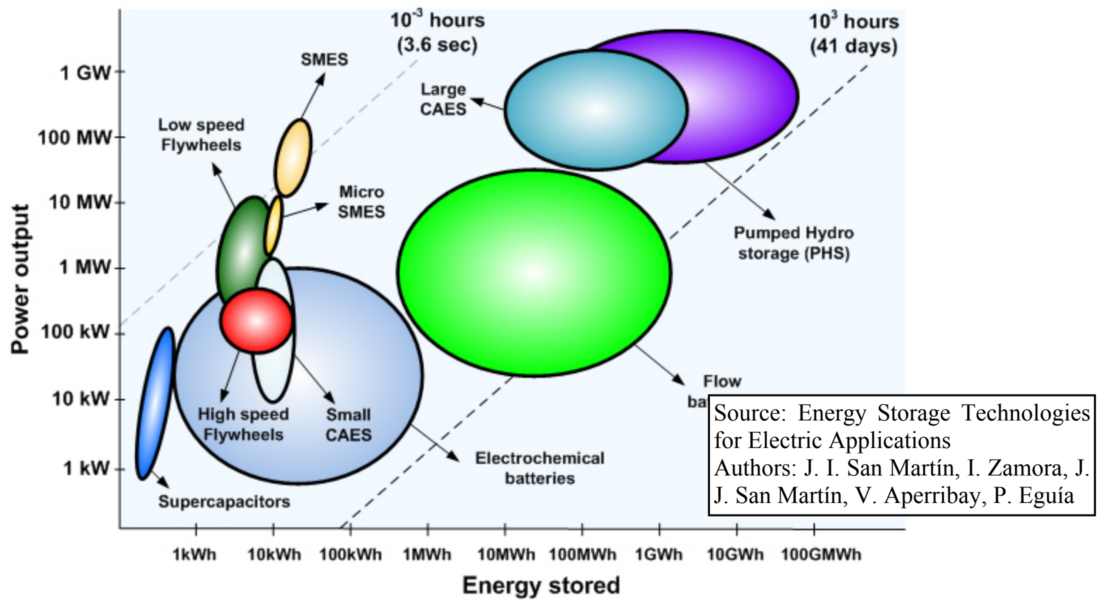


Fig. 3 Types of storage, by power output and energy stored.

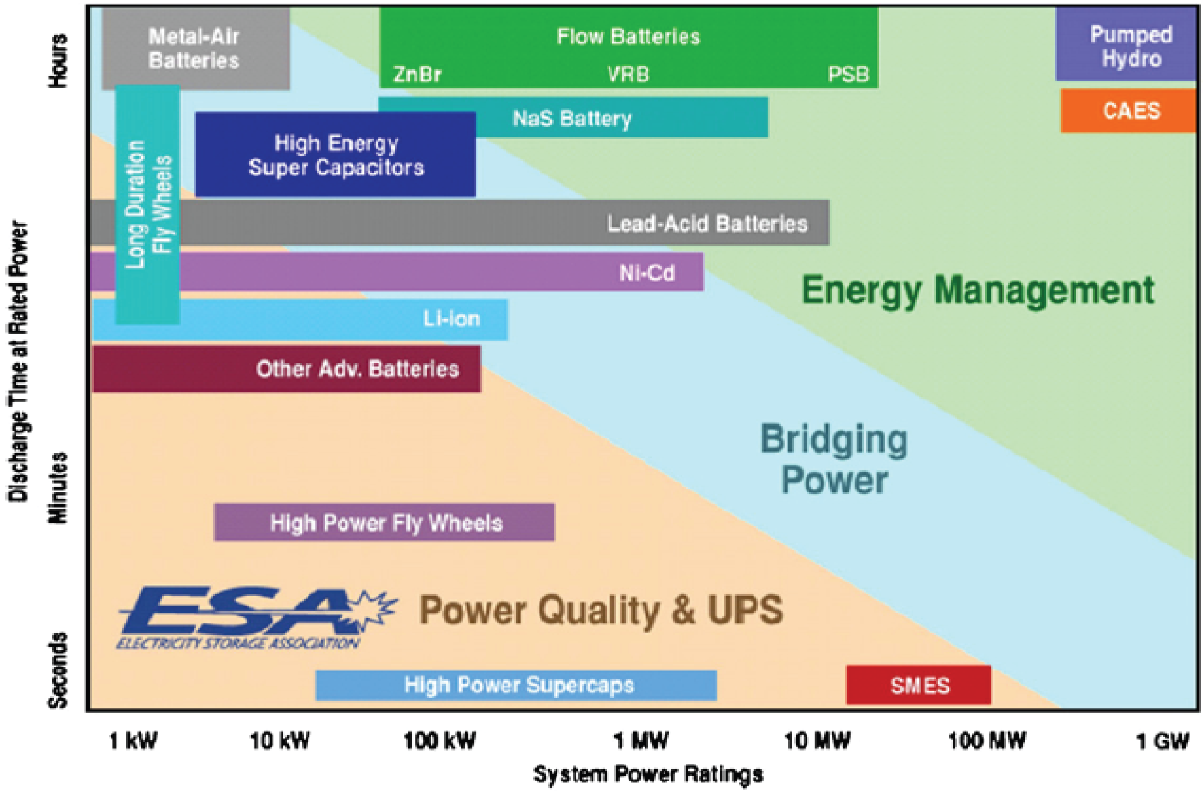


Fig. 4 Types of storage, by power rating and discharge time (another view of the previous graph).

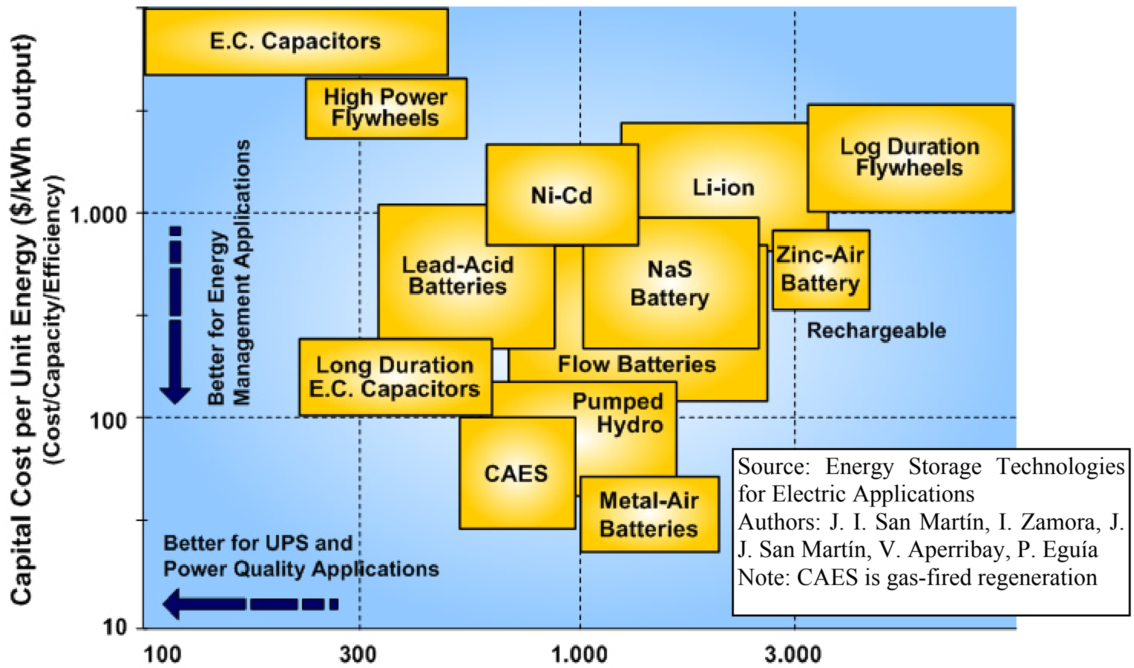


Fig. 5 Types of storage, by capital cost per unit energy.

electricity supply and demand, topography/geology, and environmental footprint as well as capital and revenue costs (c.f. Table 5).

KIC InnoEnergy, Thematic Field: Smart Grids and Electric Storage, Strategy and Roadmap 2014 (KIC = Knowledge and Innovation Community) [10].

"Electricity storage is identified as a key technology priority in the development of the European power system, in line with the 2020 and 2050 EU energy targets. Power storage has gained high political interest in the light of the development of renewables and distributed generation, as a way to reduce carbon emissions, to improve grid stability and to control the fluctuations of variable resources."

11. How Much from Each Technology?

According to the UK Government's TINA (Technology Innovation Needs Assessment) 2015 main projection, by 2050 the UK needs 27.4 GW, 128 GWh storage [12]. This is in a range of needs that extends to 59.2 GW, 286 GWh. It is notable that dividing the GWh figure by the GW figure, the government assesses that the average duration of storage needed is 5 hours, which cannot be delivered cost-effectively by solid state batteries. And this report only analyses the storage required to turn renewable generation into dispatchable electricity ("peak smoothing"), without considering delivering baseload or supporting the de-carbonisation of heating, industry and transportation.

Taking the main projection, these can be satisfied as follows, according to reasonable estimates of the potential of each:

Technology	Power (GW)	Capacity (GWh)
Pumped hydro	2 GW	20 GWh
Batteries	2-3 GW	2-3 GWh
Interconnectors	8-12 GW	n/a
Demand side response	2-3 GW	2-3 GWh
Unmet need for storage	7.4-13.4 GW	102-104 GWh

Storelectric's CAES is one of the only technologies capable of meeting this unmet need[2]—and certainly the only one to meet it cost-effectively and minimising environmental effects.

12. Conclusions

Electricity grids need to de-carbonise completely in order to enable economies to achieve their necessary carbon reduction targets. In order to do so, not only must all energy be generated renewable (with or without nuclear, depending on viewpoint), but also it needs to be backed up renewably too. Current plans revolve around interconnectors, grid-connected batteries and Demand Side Response. These are all part of the solution. However none of these will deal with all scenarios, for example weather patterns that cover whole regions, or multi-hour peak demand during low renewable generation periods. The big missing element in these plans is large scale long duration storage at the same scale as their renewable generation—i.e. at the scale of multi-GW and ranging

[2] Basis of these figures:
Pumped Hydro: 2,828 MW, 9 GWh current storage capacity. Total current projects: 1,960 MW. Therefore 6 GW, 12 GWh represents Storelectric's assessment of the reasonable maximum available in the UK, given that each installation floods two valleys. Current projects are (maximum sizes only):

Sloy:	60 MW conversion from hydro-electric
CoireGlas:	600 MW
Balmacaan:	600 MW
Cruachan:	600 MW increase from current 440 MW
Glyn Rhonwy:	100 MW

Batteries: assumes wide-scale roll-out of grid connected batteries with 1-2 hours' duration. Average size of current such batteries is under 1MW (ref. REA Energy Storage in the UK report 2016).
Current **interconnectors** are 4GW, with projects in planning to increase this to 9GW. But this includes the Norwegian interconnector (~5x our cost per MW) and the Icelandic one (>10x) – and interconnectors cannot be relied upon to deliver power exactly when needed, at reasonable prices.
Demand Side Response: Assumes that there are 4-6 GW (6-10% of peak demand) available at any time, that each call on resources continues for 30 minutes, and that any given resource cannot be called upon twice in quick succession. Therefore for 1 hour's usage, only half the power rating can be used at any time. Note: National Grid in FES 2015 estimated maximum DSR capability at ~5% of peak demand, http://nationalgridconnecting.com/2015-uk-future-energy-scenarios-published/ fig. 46 (not updated since).

from tens of GWh to multi-TWh depending on the country. There are currently only two technologies able to deliver such scales of storage: pumped hydro and Compressed Air Energy Storage. Traditional CAES still has emissions and low levels of round trip efficiency, but adiabatic CAES, such as that proposed by Storelectric, is almost as efficient as pumped hydro, a third of the cost and geographically much more widely implementable. Therefore grids, governments and industry should be developing large numbers of such projects in order to provide the energy the world needs, cost-effectively, cleanly and securely.

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[1] https://www.bloomberg.com/news/articles/2018-03-26/meeting-paris-agreement-targets-will-take-massive-cuts-in-emissions.

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About Storelectric

Storelectric (www.storelectric.com) is developing truly grid-scale energy storage using an innovative form of CAES. This is TES CAES (TES = thermal energy storage), licensed from TES CAES Technology Ltd. which is mostly owned by the same shareholders. It uses existing, off-the-shelf equipment to create installations of 500 MW, 6-21 GWh with zero or low emissions, operating at 68-70% round trip efficiency, at a cost of £ 350 m (€ 500 m) (estimated for 3rd-5th plant), and a levelised cost cheaper than that of gas-fired peaking plants (OCGT). CAPEX is one-third that of pumped hydro per MW and 1/75th/MWh; similar to 10-year target prices of batteries per MW and less than 1/1,000 th/MWh. There is sufficient geological potential in the UK to store the entire continent's energy requirements for over a week; potential in mainland Europe and the USA is greater still, with global roll-out planned. Returns on capital are expected to be of the order of 15% in today's market—and the market is improving each year.

Storelectric has a second technology, CCGT CAES, which uniquely is retro-fittable to either OCGT or CCGT power stations if over a suitable geology. The cost of conversion depends on what is there, but a new-build CCGT CAES would cost about 10-15% more than a CCGT power station and have very similar returns on capital to TES CAES.

The next stage is to build a 40 MW, > 100 MWh pilot plant with over 62% efficiency, using scale versions of the same technology, for which Storelectric is currently raising funds. Construction will take 2-3 years from funding, and the first large-scale plant a further 3-4 years. The consortium includes global multinationals who cover all the technologies involved, their installation, financial and legal aspects.