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Large-scale electricity storage
Launch workshop

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Time	Session	Speakers
10.30	Welcome and introduction	Peter Bruce
10.40	Overview of the findings of the report	Chris Llewellyn Smith
11.10	Presentations on: 1. The effects of weather and climate change 2. Modelling including multiple stores 3. The economics of storage	Chair: Sara Walker Tony Roulstone Seamus Garvey John Rhys
11.45	**Break**	
12.00	Large-scale storage technologies presentations: 1 Hydrogen and ammonia 2 Non-chemical storage technologies	Chair: Sara Walker Mike Muskett Phil Eames
12.25	Plenary discussion/Q&A session with panel of previous speakers	Chair: Peter Bruce
13.00	**Lunch**	
14.00	Breakout sessions looking at the implications of the report: 1 Economics of storage, market changes and Regulator controls 2 Grid and system impacts 3 Likely developments in hydrogen and ammonia technology 4 Likely developments in medium duration storage	Breakout chairs: Cameron Hepburn Maxine Frerk Nilay Shah Yulong Ding
14.45	**Break**	
15.00	Plenary feedback from the breakout sessions & discussion	Chair: Chris Llewellyn Smith
15.30	Government policy impacts	Catherine Bremner
15.50	Summary and close	Peter Bruce, Chris Llewellyn Smith

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Large-scale* Electricity Storage

Chris Llewellyn Smith

***meaning storage that can meet a significant fraction of demand, i.e. covers small stores cycled rapidly as well as large stores cycled slowly**

Contributors include - Tony Roulstone, Paul Cosgrove, Richard Nayak-Luke, Mike Muskett, Seamus Garvey, Nilay Shah, Phil Eames, Paul Shearing*, Ian Metcalfe, Keith Bell*, Royal Society staff, ...

***unable to attend; Paul led work on batteries, Keith on the grid**

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Context

- As Great Britain's electricity supply is decarbonised, an increasing fraction will be provided by wind and solar energy because they are the cheapest form of low-carbon generation
- Should aim for a minimum-cost genuinely net-zero electricity system (if possible – *it is*)
  - reserve off-setting for harder to abate sectors
- Electricity supply and demand must *exactly* balance at all times – or the lights go out
- Wind and solar vary on time scales from minutes to decades. Can install more than enough to meet demand on average, but there are times when there is none

  → must complement wind & solar by storing excess for later use
  and/or adding large-scale zero or low-carbon flexible sources (nuclear, BECCS, gas + CCS,...)
- Approach: start by identifying essential large-scale storage needs for zero carbon power in 2050, before considering how to get there. Working forward may not lead to the right destination.

* The need for, and provision of, storage depends on climate, geography, and geology. Focus on storage in Great Britain in 2050 – although methodology and conclusions on technologies are general

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The Need for Storage

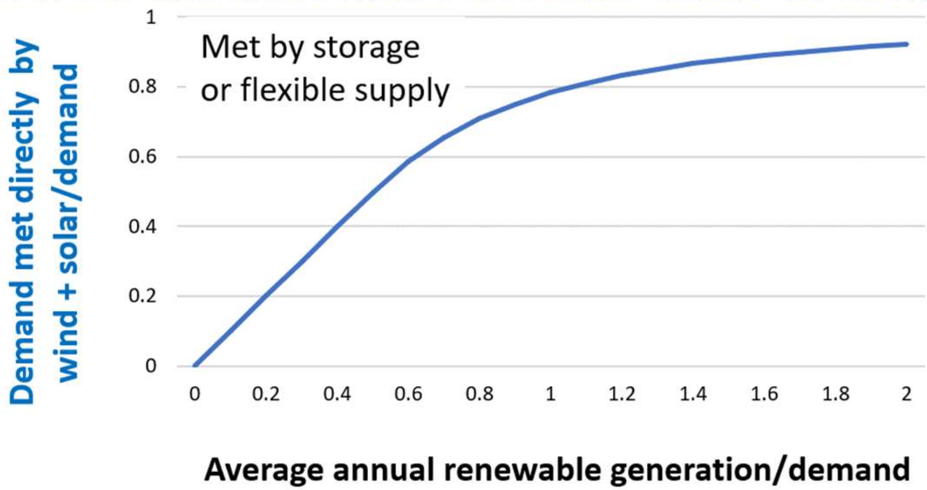
- To evaluate the need for flexible supply/storage: must **compare** hour by hour (best resolution available) **models of**

  - wind + solar supply (Ninja Renewables data for 1980-2016*, 80% wind/20% solar - minimises curtailment) and

  - demand (AFRY model of 570 TWh/year ≈ 2 x today: with higher and lower levels find very similar costs)

* Studies based on less than several decades of wind and solar supply seriously underestimate the need for storage *and* overestimate the need for wind and solar and other flexible supply

- However much wind and solar installed they can never meet all demand directly:

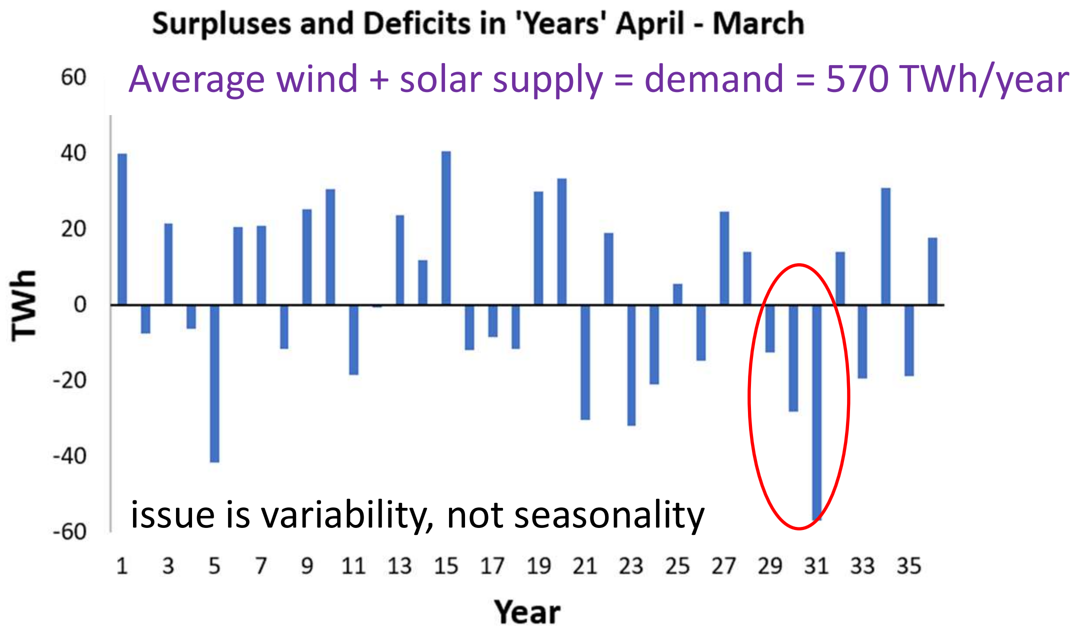


Wind varies on very long time scales:

Need to store tens of TWh for decades

→ *large amount of storage with low cost/energy stored -* ***hydrogen is best option in GB***

Could not conceivably be provided by batteries
1000 times more that GB's pumped hydro capacity

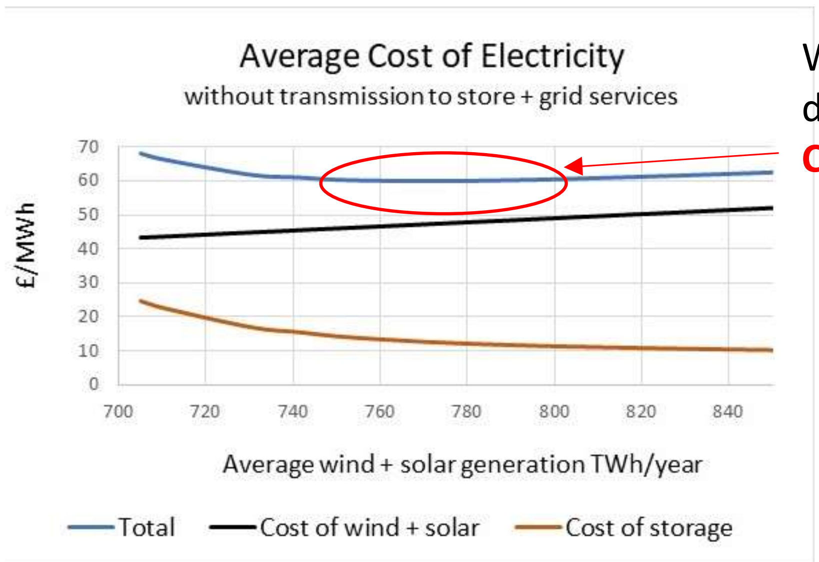


Energy is lost in converting electricity to a storable form, e.g.

electricity → hydrogen: lose ~ 26%
hydrogen → electricity: lose ~ 45%

→ need to over-build wind + solar supply (by > 23% in this case) to allow storage to meet demand

Does not change the need to store 10s of TWh for decades



With central costs described later
Cost minimum

Start with **Benchmark Model**

Wind, solar and hydrogen storage (+ small amount of something - batteries? - that can respond very fast), which could do everything → **benchmark against which to judge other options for 2050**

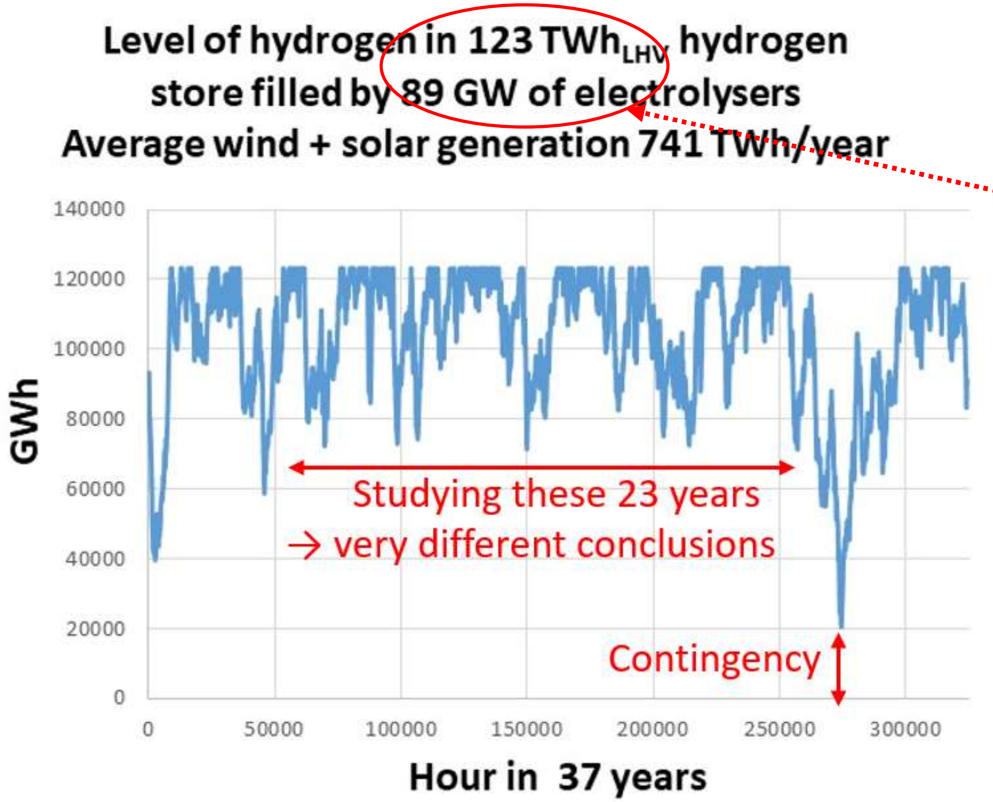
although (see later) adding some higher capital cost but more efficient storage may lower the cost, and there will be some nuclear, biomass, hydro, interconnectors, and perhaps gas with CCS

Level of hydrogen in store:

Studies of less than several decades of wind and solar seriously underestimate the need for storage,
- and overestimate the need for other flexible supply and wind and solar

Issues

- Is 37 years enough? **No** – Met Office
  → add 20% contingency (adds £1/MWh)
- Climate change: effects uncertain
  - hope covered by contingency

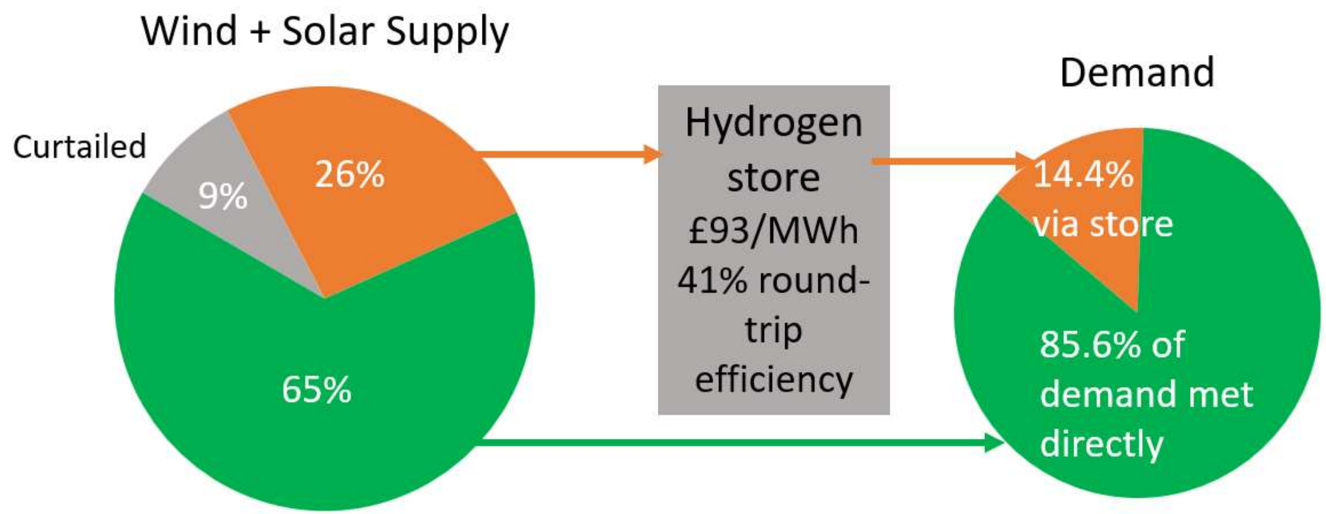


Note scale of storage system

Costs

Example in benchmark case (central 2050 projection of storage costs - sensitivity on next slide) in 2021 prices

With hydrogen storage only, the average cost of electricity is a minimum with wind + solar supply ≈ 1.33 x demand:



If wind + solar generation costs £35/MWh:

Average cost of electricity
=£(1.33 x 35 + 0.144 x 93) = **£60/MWh**

\+ cost of
- Transmitting wind and solar to store (£3/MWh)
- Batteries (£1/MWh) to provide grid services

System average costs not very sensitive to cost of storage

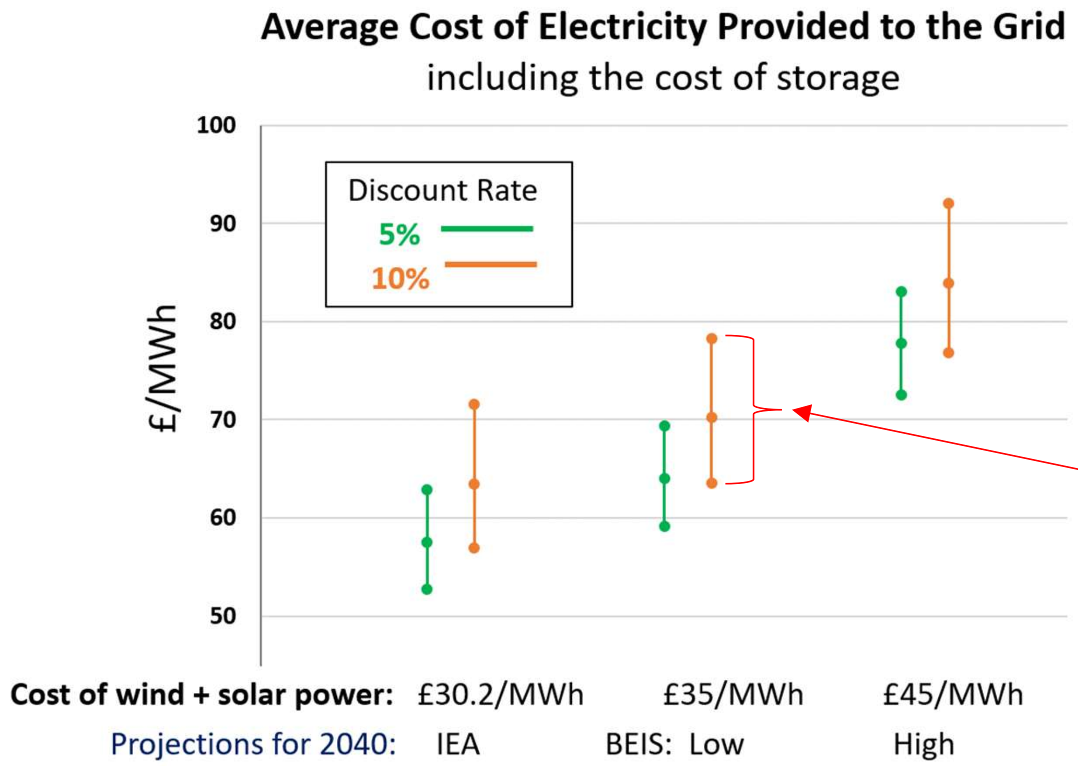
Electricity from store is very expensive:

if solar + wind cost £35/MWh: direct supply costs £38.6/MWh, electricity from storage costs £188/MWh

partly because it must be able to meet full demand when wind + solar ≈ 0 → very low (14%) load factor - this is true of *whatever* complements wind and solar → ***alternatives look more expensive***

Will investors be willing to fund the (essential – but expensive, rarely used) large-scale storage that will be needed?

H2 (+ battery storage) only – sensitivity to assumptions



2021 prices
Includes:
£1/MWh for batteries → grid services
+ £3/MWh for transmission from wind/solar farms to stores
+ 20% contingency in size of store (contributes ~ £1/MWh)

range of storage costs (low/base/high)

Comparison: wholesale price around £46/MWh in last decade

Over £200/MWh in most of 2022

Additional/ alternative storage technologies studied

Looked in most detail at

- **Li-ion batteries**
- **ACAES** as exemplar of technologies in second category
- **Hydrogen**

and their costs

Large-Scale Electricity Storage Technologies			
Technology	**Unit Capacity**	**Round-trip Efficiency**	**Technology Readiness Level + Comments**
Cycle time: minutes to hours – limited by need to recover investment			
Batteries	Largest today 1.6 GWh	≲ 90%	Lithium-ion + some other chemistries - TRL 9
Cycle time: up to weeks, in some cases months			
Flow batteries	Single battery many GWh	70-80%	TRL 7-8
ACAES	Single cavern ≲ 10 GWh	≲ 70%	Compressors, Expanders, storage caverns and thermal storage TRL 9. Complete systems 7-8.
Carnot battery	GWh	≲ 45%	TRL 7 with resistive heating
Pumped Thermal	< GWh	50%	TRL 4-6
Liquid Air	< GWh	≲ 60%	Systems in operation - TRL 8. Larger/more advanced systems - TRL 7
Able to provide months or years of storage			
Synthetic fuels	Single tank ~ TWh	≲ 30%	TRL 7-9 - outclassed by ammonia and hydrogen for electricity storage
Ammonia	Single large tank ~ 250 GWh	≲ 35%	Production and storage - TRL 9. Conversion of pure ammonia to power – TRL 5. More expensive than hydrogen, but could be deployed across GB
Hydrogen	Single large cavern 200 ~ GWh	~ 40%	Electrolysers, storage caverns and PEM cells - TRL 9. Conversion to power by 4-stroke engines TRL 6-7. Potential onshore storage sites limited to E Yorkshire, Cheshire and Wessex.

Details in Report

Alternatives and additions to hydrogen storage

- **Alternatives**

  Ammonia could do the whole job and be located anywhere, **but** more than £5/MWh more expensive

- **Additional storage**

  - **Advanced Compressed Air Energy Storage -** more efficient but higher volumetric storage cost

    Cannot provide all storage, but combined with hydrogen would very possibly (but not certainly) lower the cost

    - would reduce the need for large-scale hydrogen storage (by ~ 15% ?) but *would not remove it*

  - **Li-ion batteries** for peak shaving/arbitrage (as well as rapid response to stabilise the grid)?

    - find that once hydrogen and ACAES are available, it will be cheaper to use them, rather than Li-ion

Note:

With several types of store, need a protocol for scheduling their use that minimises the cost: implementation will require an unprecedented level of collaboration between generators and operators of storage

Additional Supply

- **Interconnectors –** should help manage system, **but** there are pan-European wind droughts, accompanied by cold periods: should not design a system that cannot meet demand when imports not available
- **Nuclear baseload** - increases the average cost of electricity ***unless*** *nuclear costs less per MWh than the average cost per MWh without it* - only advantageous if hydrogen storage costs high and nuclear costs low

  Lowers storage requirements, e.g. in central H2 case, 200 TWh/year reduces electrolyser power/storage capacity by 40%/27%

  Nuclear cogeneration of hydrogen only helps if nuclear cost is low: e.g. below £60/MWh with 10 GW nuclear and central storage costs
- **Flexibly operated gas + CCS**

  Cannot replace storage – high emissions + higher costs

  Combined with hydrogen - *could* lower costs* without leading to very large emissions

  e.g. model of 20 GW_e → 2 Mt CO_2/year + 5 Mt/year CO_2 equivalent from methane leakage

  *depending on the costs of storage, wind and solar power, and gas plus CCS, and the price of gas and the carbon price. Have not explored the sensitivities in detail (multiple unknowns) + prefer to aim for a net-zero

  Would **not** remove the need for large-scale long-term storage - but would reduce the required scales of storage (by 30%?) and of wind plus solar supply

  Would provide diversity, but expose GB's electricity costs to fluctuations in the price of gas,
  and increasing reliance on imports as GB's gas reserves decline

Further steps

- **Whole-system modelling that takes account of**
  - location of demand, supply and storage → implications for the grid
  - contributions of nuclear, hydro, biomass, interconnectors
  - other needs for green hydrogen (on which opinions differ widely): requires model of temporal profile & flexibility. Will lower cost.
- **Work on**
  - markets that will incentivise the deployment of large-scale storage & ensure it's there when needed
  - scheduling with several types of store and flexible sources: use long-term (as well as weather) forecasts,...
  - scale of the need for contingency
  - cost estimates: need underpinning by detailed engineering estimates
- **R&D**

  'New science' can't make a major contribution by 2050, but important for the long term, e.g. cheap direct synthesis of ammonia from air and water would be transformative . Meanwhile
  - Huge scope for improving existing technologies, and combining them in new ways, e.g. in wind-integrated-storage, reversible electrolysers/fuel cells and compressors/expanders
  - Reduce/eliminate iridium in PEM electrolysers (only [?] fundamental resource issue),...
- **Demonstrators**

  Large scale demonstrations of many storage technologies still needed, but **hydrogen is ready now**

Conclusions

- **Studies of storage that look at wind and solar over less than several decades seriously *underestimate* the need for storage, and *overestimate* the need for other flexible supply and wind + solar supply***
- GB's 2050 electricity demand could be met by wind and solar supported by large-scale storage, at a cost that compares favourably with cost of using the only large-scale low-carbon alternatives - natural gas generation with CCS and nuclear (both expensive - especially if operated flexibly)
- **Hydrogen benchmark case → upper bound on costs.** Adding other types of store quite likely → lower cost, as will coproduction of hydrogen for all purposes
- **Caveat – all costs in 2021 prices;** sensitive to increases in commodity prices, projections of wind + solar costs, general inflation, market conditions, etc ....
- The need for large-scale storage should be evaluated periodically using whole systems models and the latest projections of costs and demand
- It is already clear that GB will need 10s of TWh of hydrogen storage in the net-zero era
  - **should start building it now,** and
  - **develop/deploy appropriate business models,** with the incentives/guarantees required to ensure the investment that will be needed

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*e.g. study used by CCC which looked at individual years and did not allow storage to transfer energy between years

The effects of weather and climate change

Tony Roulstone
University of Cambridge

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Renewable Energy System
Weather Effects & Energy Storage

Royal Society - Long Duration Energy Storage – Sep 2023

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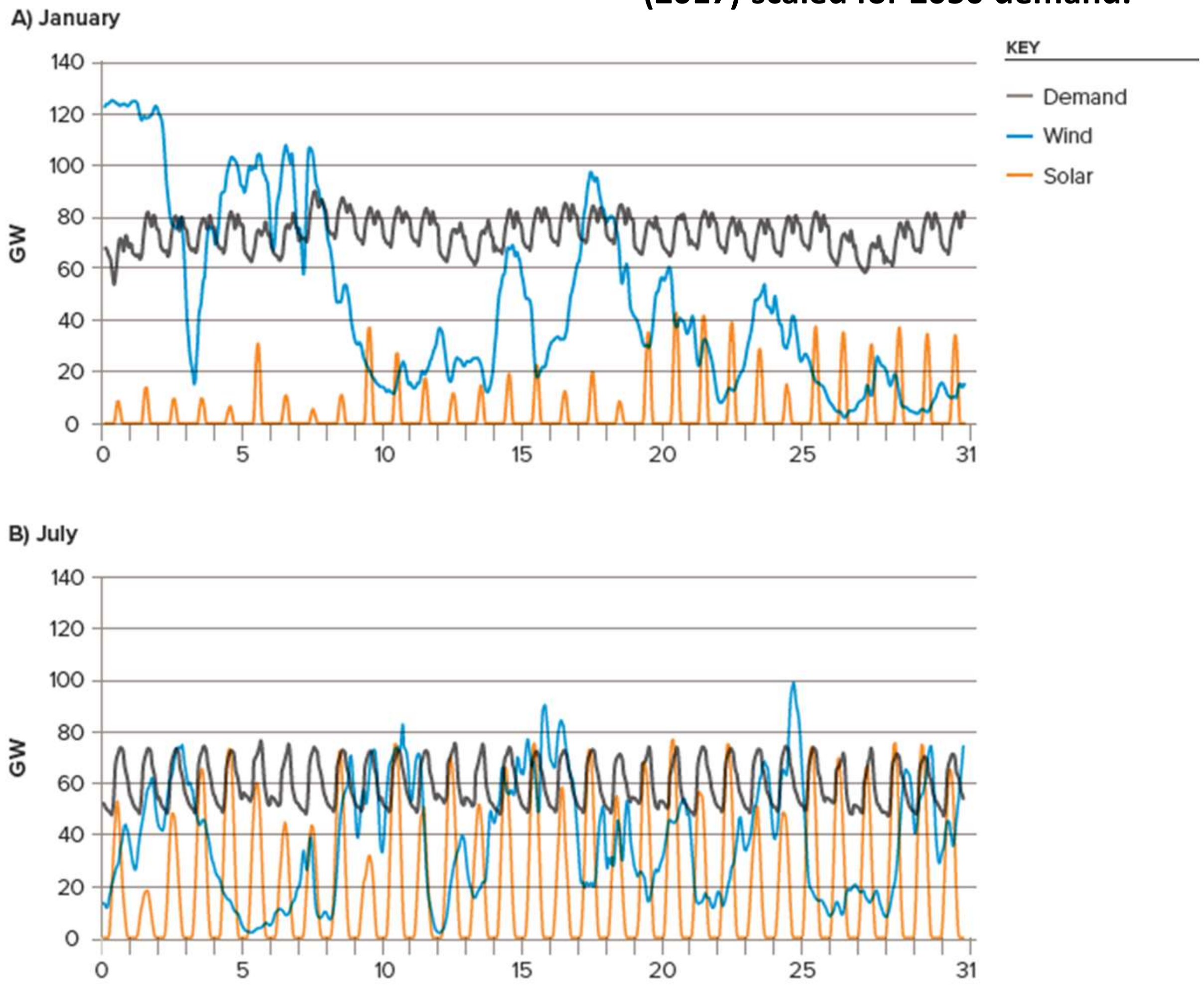
Renewable energy studies

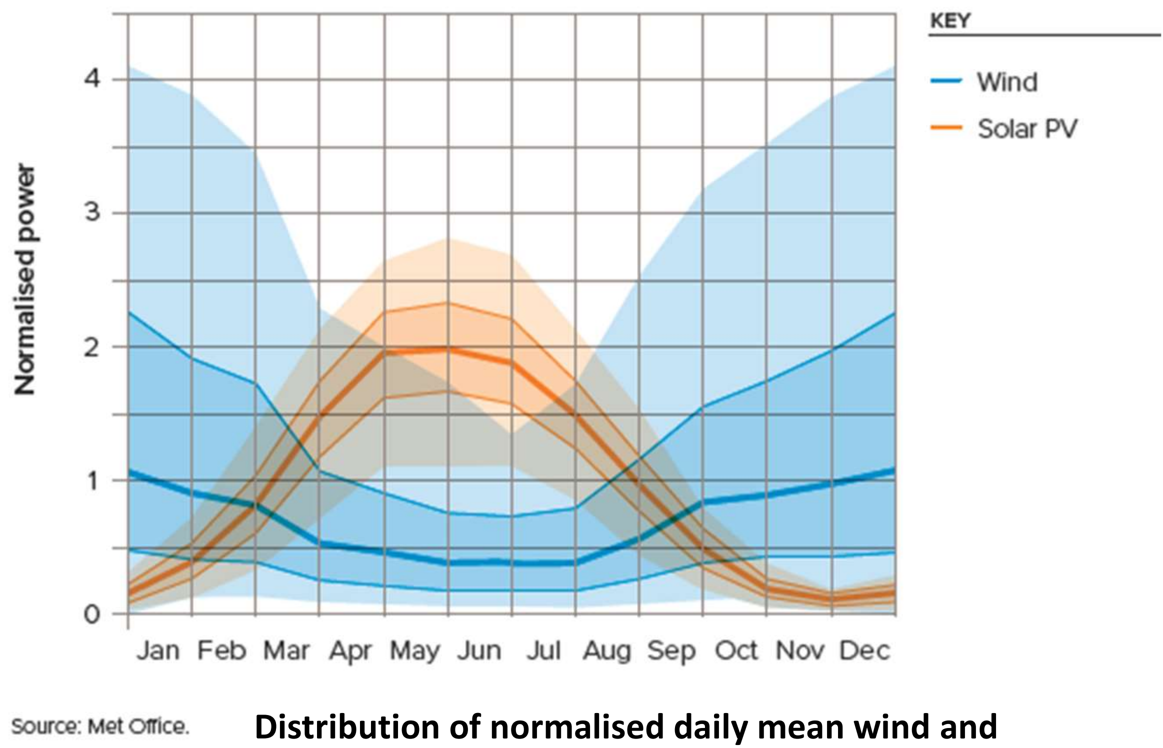
- 2050 demand (570 TWh) mean power 65 GW +/- 20 GW;
- Supply: Wind + Solar varies 10-180 GW;
- Grid's future role: from meeting demand to controlling supply;
- Many weather studies – How are ours different?
  - High renewable supply shares > 60%;
  - Net-zero -> no dispatchable fossil fuel to balance system;
  - Days, weeks, seasons & many years – continuous sequence of weather data;
  - Seeks to understand *physical behaviour* before *economics*;
  - System information visible - not lost in complex models – hard to interrogate.

Demand & Supply - today's weather (2017) scaled for 2050 demand.



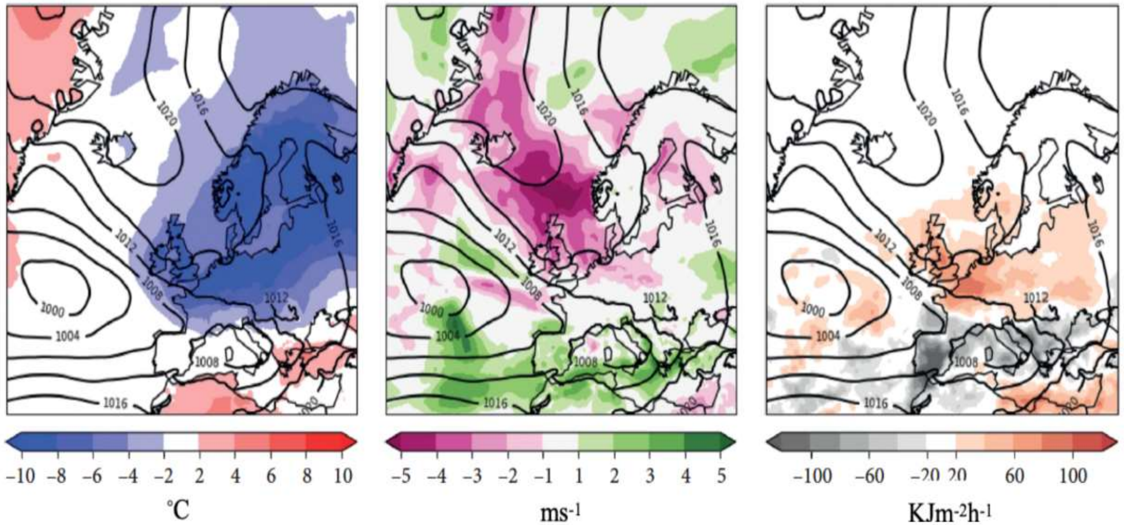
Renewable supply variability

- Range of daily-mean variations within month (5^{th} percentile) - large:
  - Solar x 2.5
  - Wind x 8
- Annual range (5^{th} percentile) larger:
  - Solar x 25
  - Wind x 40
- Mean wind and solar power are to some degree complementary;
- Hence solar/wind mix is important – 20/80 is found to be optimal – renewable supply deficit and energy storage size minimised.



Distribution of normalised daily mean wind and solar generation 1979 to 2013 with 5th and 25th percentiles

Extreme weather stress events



Average of top ten periods of residual demand 1980-2019 - deviation from the mean:

Temperatures at 2 m, Wind speed at 100m, and Solar irradiance.

Met Office

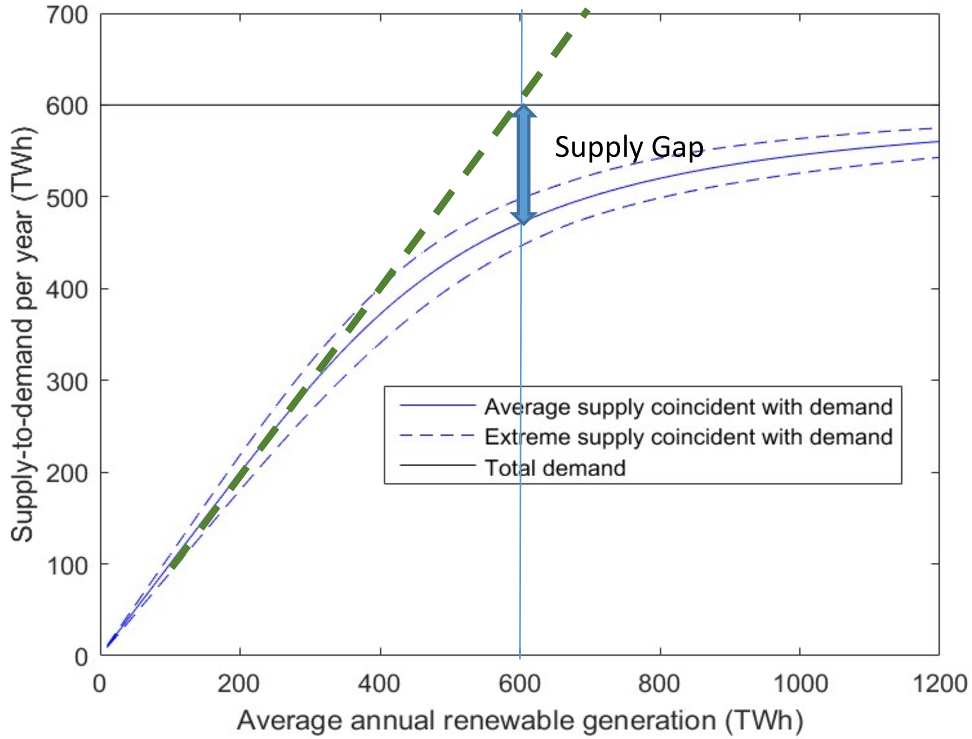
Stress events	Description	Frequency
Summer wind drought – frequent	One full day of very low wind speed in summer	One or two per year
Summer wind drought – infrequent	Up to four weeks of very low wind speed in summer	Once every 10 years
Winter wind drought	Up to a week of very low wind speed in winter	Every few years

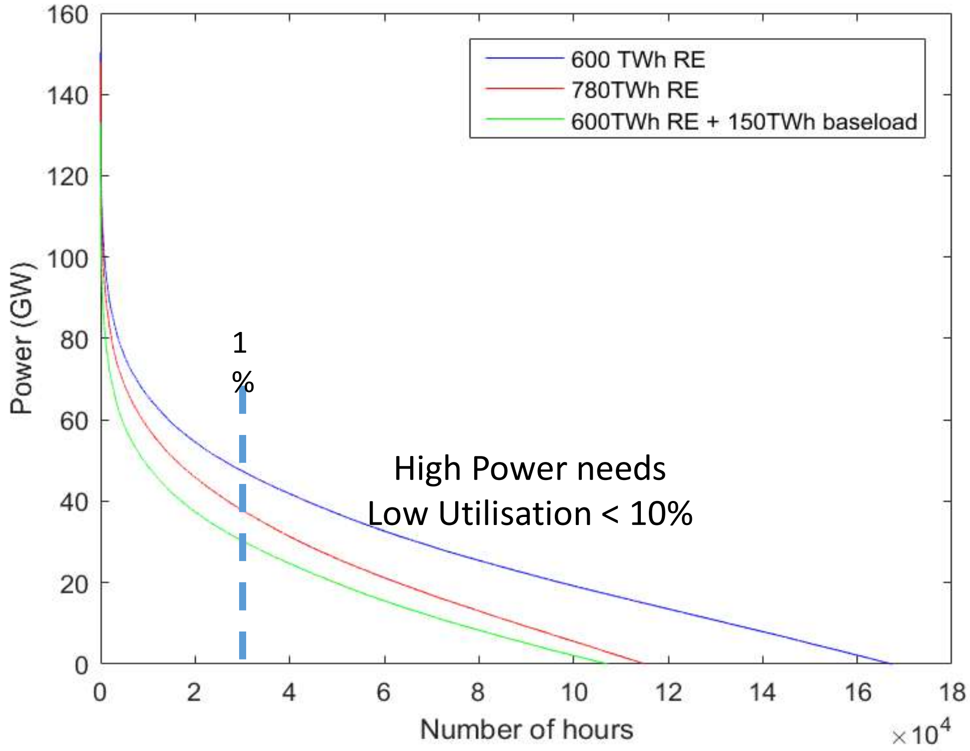
Weather – Extreme Stress Events

Met Office

Mistiming of renewable supply v demand

600 TWh
Solar/Wind: 20/80
On/Offshore: 30/70

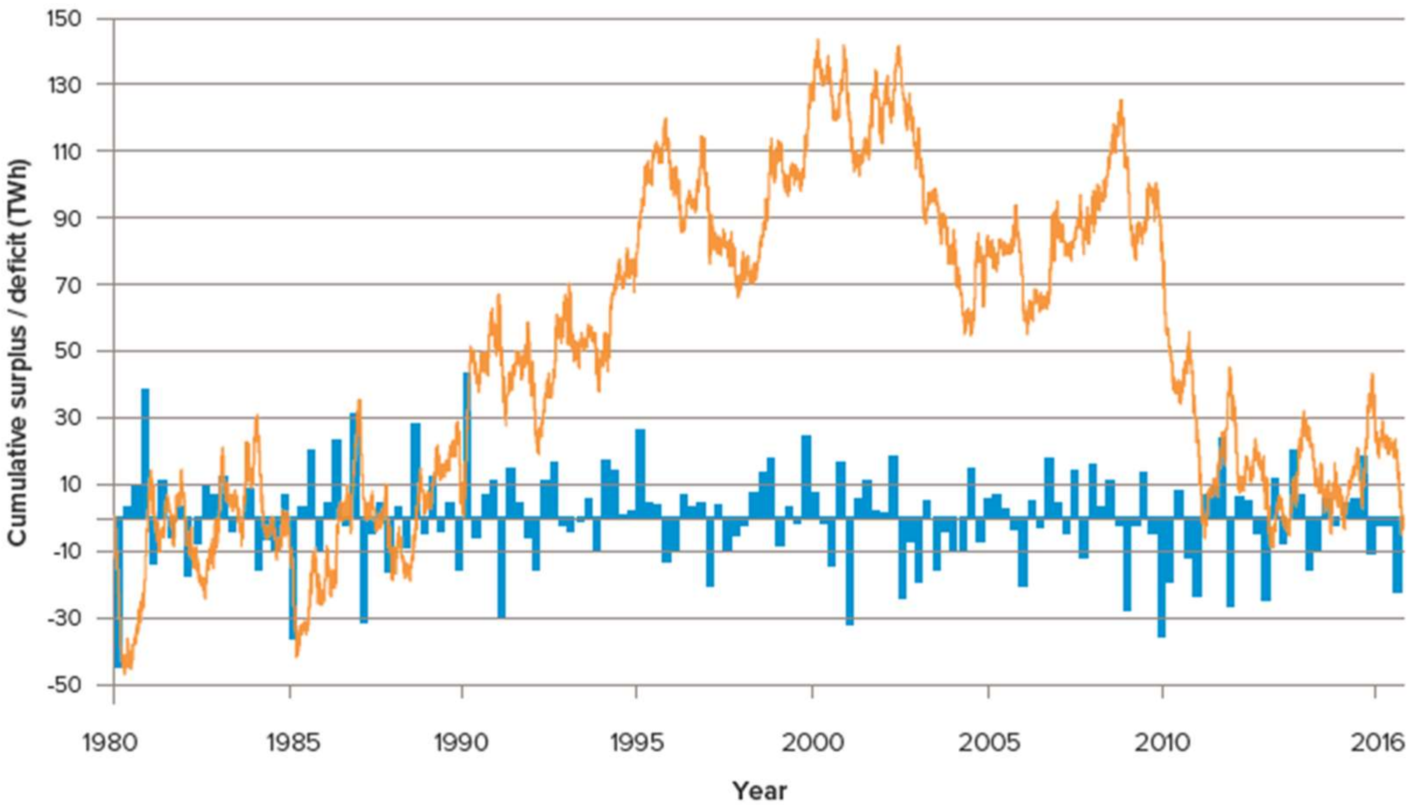




- When mean supply equals demand >120 TWh is mistimed – not available for supply and is surplus;
- High complementary power requirements - above 100 GW - very few hours in period 37 years.
- Grid to match generation (North) to demand (South) and much higher level of circulating power ~200 GW

Long term energy surpluses & deficits

- Variations in quarterly and annual residual supply not evenly distributed;
- Continuous sum of residual supply shows decadal trend – for 570 TWh pa supply system max deficit ~150 TWh;
- One year of data is not enough – multi-decadal studies (UK, Germany, US) show storage volume needs are double mean year;
- Deficit reduced but not eradicated by additional renewable capacity.



Cumulative differences between supply and demand for 2050 – quarterly & 37 years

Filling the gaps in renewable supply

Approach	Method	Scope	Pros	Cons
Ameliorate	**Demand-Side Response**	Peak-lop - incentives, digital grid & EV batteries. Emergency	Low cost Grid supply maintained.	Limited in power range & duration 20+GW few hours Can seldom be implemented – political risk.
	Interconnector to EU	20 GW planned 30 GW possible	Geographic dispersion - hedge against supply variability.	Extreme weather affect many countries across EU. Depend excess supply & capacity being available.
Baseload	**Bio-Energy CCS**	50 TWh pa limited by fuel availability	Scale of supply variation reduced. Secures a share of supply.	Power costs higher. Uncertainty of timely delivery of new capacity.
	Nuclear	Plans for 25% nuclear supply before 2050		
Flexible complementary	**CCGT & CCS**	100 GW of new plant – utilisation <10%	Technology demonstrated at scale	Some carbon & upstream fugitive emissions. High energy cost.
	Energy Storage	100 TWh of storage with 100 GW power	Not require new technology	Not demonstrated at scale. High capital costs.

Storage needs - Weather-driven periodicity

- Storage moves energy from time of excess to times when there is a deficit

  How much energy and How long stored?

  Storage Volume proportional to **Power range** x **Duration** of storage/Output **efficiency**
- Characteristics of daily, weekly and seasonal/multi-year storage needs for three selected periods
- Fully renewable - 30% overcapacity & 20/80 Solar/Wind - implicit period efficiencies 90/70/40%

Storage period	Stored volume	Power needs	Energy from store pa	Full cycles pa
Short - 6 hours	200 GWh	60 GW	8 TWh pa	40-50
Medium – 1 week	2.8 TWh	> 100 GW	52 TWh pa	22
Long term	55 TWh	> 100 GW	22 TWh pa	Less than one

- Minimum storage volume 26 days of mean demand but large power overlap –> uneconomic.
- Very few cycles of longer duration stores -> affects case for investment – smarter scheduling required.

Modelling Including Multiple Stores.

Seamus Garvey,
University of Nottingham

Why Multiple Stores Lead to Reduced Cost

Energy Storage systems have four main metrics:

- Cost per unit of rated input power $(£/kW(e_{input}))$
- Cost per unit of rated output power $(£/kW(e_{output}))$
- Cost per unit of storage capacity (*volume*) $(£/kWh(e_{output}))$
- Round-trip efficiency (%)

Different systems are good in different ways. No one system is ideal for all purposes. At large scales, these metrics are constants.

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Understanding Multiple Stores – Start with the Single Store Case.

Consider, initially, that we have just one store in the system.

Four distinct parameters determine both the system cost and whether that system will meet all demand.

• Rated input power	G	(GW(e_{input}))
• Rated output power	H	(GW(e_{output}))
• Storage capacity (*volume*)	V	(GWh(e_{output}))
• Over-generation factor*	X	( )

If parameters (G, H, V) lie within reasonable bounds, then there will be some minimum value X or which all demand is met ($X = X_{min}$).

* X=1.2 indicates: *total quantity of electrical energy generated in the record exceeds the total quantity of electrical energy consumed by 1.2.*

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Testing Whether a Single-Store System is Adequate to Meet Demand.

Any given single-store system is described by the 4-tuple, (G, H, V, X).

We can test whether this system will meet all demand by

- Initialising the energy in store at some value such as $0.7 \times V$
- Stepping through each (1-hour?) period in the record and …
- If supply exceeds demand, put (some of?) the excess into store
- If demand exceeds supply, draw (some of?) the shortfall from store
- Adjust the energy level in the store

We might check that the energy in store at the end is close to or equal to the energy that was in store at the start of the record.

No “scheduling” problem here and no purpose for “forecasting”.

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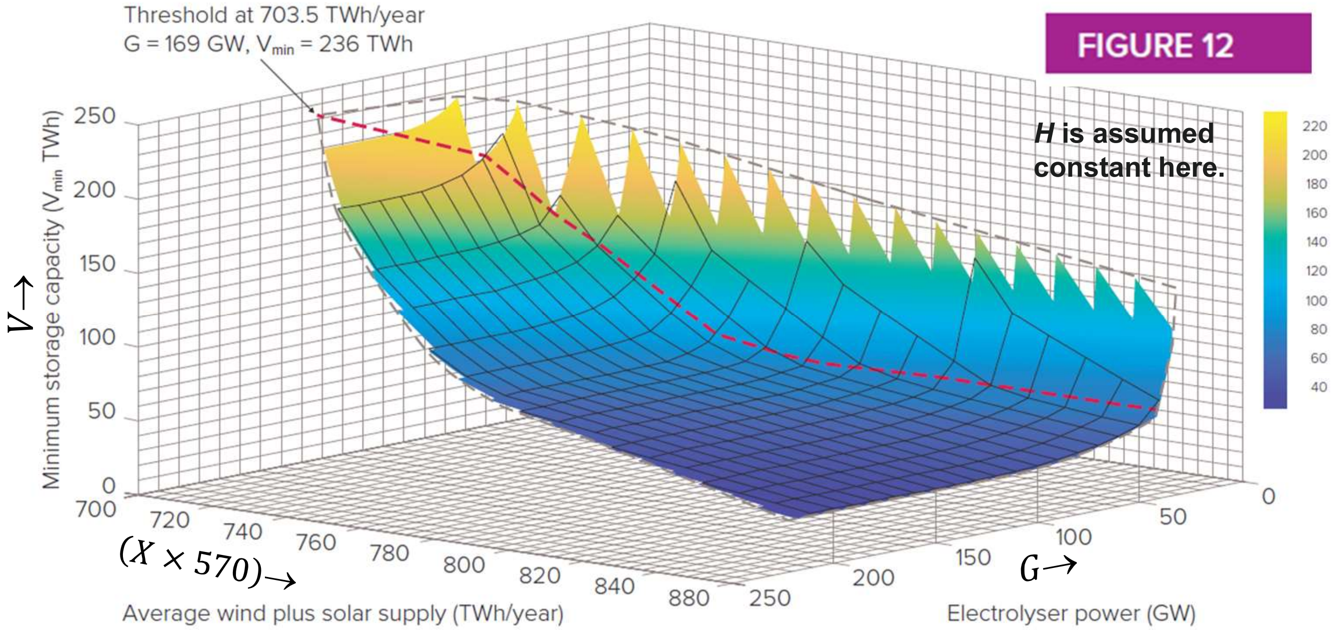
Optimising the System with a Single Store

Any given single-store system could be optimised by exploring the 3D space … (G, H, V). For each “point” in this space, we calculate the associated value X_{min} as a dependent variable.

System cost is then determined from the 4-tuple (G, H, V, X_{min}).

‘Straightforward to put this into an optimisation for minimum cost.



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Understanding Multiple Stores – Now with 2 Stores.

Consider now that we have two stores in the system.

Seven distinct parameters determine both the system cost and whether that system will meet all demand.

• Rated input powers	G_1, G_2	(GW(e_{input}))
• Rated output powers	H_1, H_2	(GW(e_{output}))
• Storage capacities (*volumes*)	V_1, V_2	(GWh(e_{output}))
• Over-generation factor*	X	( )

If parameters (G_1, G_2, H_1, H_2, V_1, V_2) lie within reasonable bounds, then there will be some minimum value X or which all demand is met ($X = X_{min}$).

* X=1.2 indicates: *total quantity of electrical energy generated in the record exceeds the total quantity of electrical energy consumed by 1.2*.

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Testing Whether a 2-Store System is Adequate to Meet Demand.

Any given 2-store system is described by the 7-tuple,
(G_1, G_2, H_1, H_2, V_1, V_2, X).

We can test whether this system will meet all demand by

- Initialising the energy in each store #*i* at some value such as $0.7 \times V_i$
- Stepping through each (1-hour?) period in the record and …
- If supply exceeds demand, spread (some of?) the excess into stores
- If demand exceeds supply, draw (some of?) the shortfall from stores
- Adjust the energy levels in the stores

<u>Scheduling needed to decide which store has priority for filling/emptying</u>

A Primitive Scheduling Approach for a 2-Store System

A primitive approach for scheduling a 2-store system would be to prioritise the store with the higher round-trip efficiency at all times. Then:

- If supply exceeds demand, put as much as possible into the more-efficient store (respecting limits on input power and energy in store)
- If demand exceeds supply, draw as much as possible from the more-efficient store (respecting limits on output power and energy in store)

<u>This primitive approach does not lead to near-optimal solutions because the more-efficient store is often either full (or empty) so that its input (or output) power is not then *in-play*.</u>

A good scheduling approach ensures that the power-conversion machinery of both stores is nearly always *in-play*. Informally … <u>keep the state of charge of each store away from the limits</u>.

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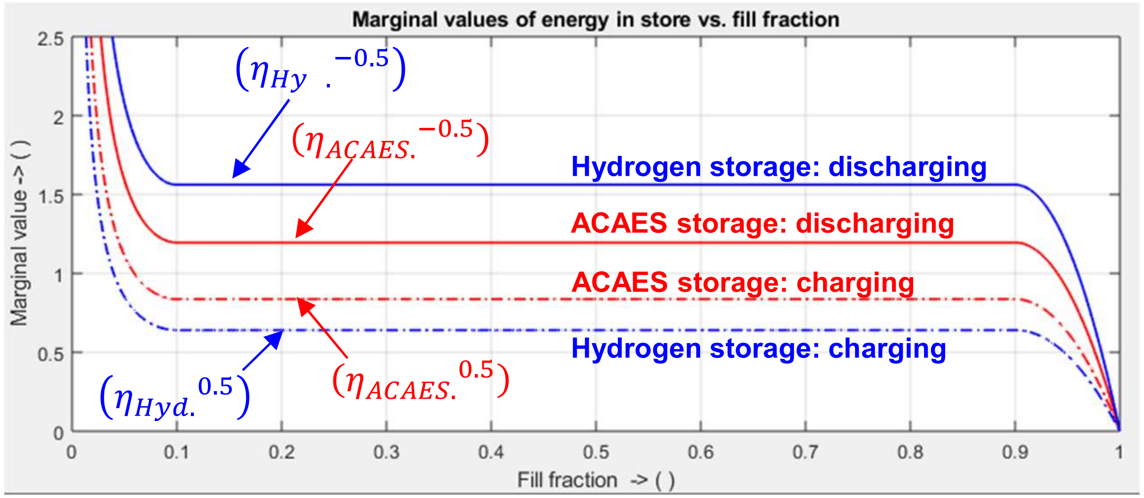
A Near-Optimal Scheduling Approach for Multiple Stores

A good scheduling approach for the operation of multiple stores in a system is described by Zachary *et al*. [1]



The scheduling algorithm is *greedy*.

Within constraints, energy is preferentially put into the stores with highest marginal value and energy is preferentially withdrawn from stores with lowest marginal value.

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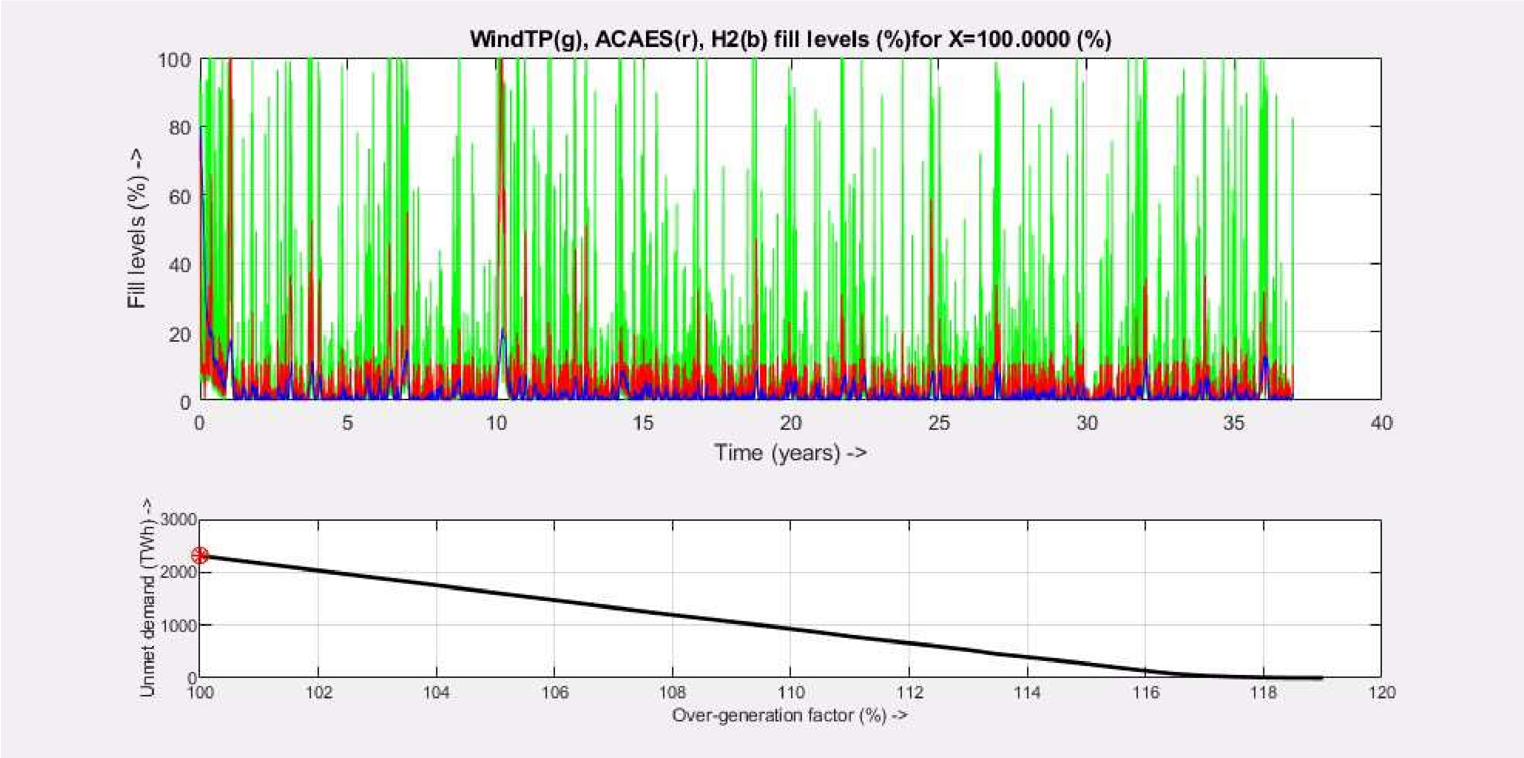
[1] Zachary, S. *Scheduling and dimensioning of heterogeneous energy stores with application to future GB storage needs.* In review. https://arxiv.org/abs/2112.00102.

Scheduling Illustration:

Illustration of scheduling working with a 3-store system:

#1: Wind-Integrated Storage. G_1=30GW, H_1=20GW, V_1= 1,050GWh, η_1=80%
#2: ACAES. G_2=15GW, H_2=10GW, V_2= 2,800GWh, η_2=65%
#3: Hydrogen Storage. G_3=37GW, H_3=65GW, V_3=80,000GWh, η_3=41%



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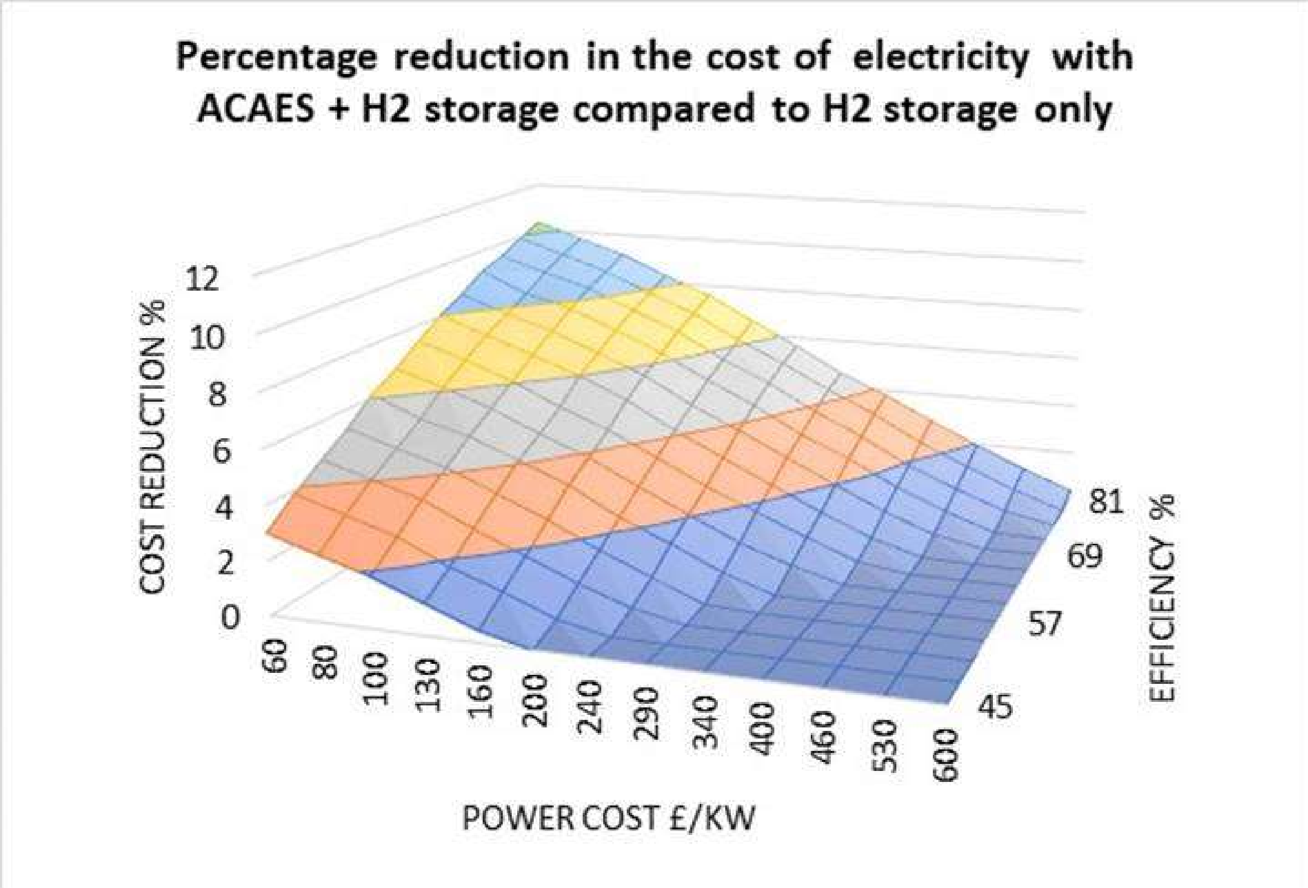
Optimisation Results for a 2-Store System

Combining ACAES with hydrogen-based storage provides for significant cost reductions – dependant on machinery costs and round-trip efficiency



Closing Remarks

Hydrogen storage will obviously be needed in very large measures in a cost-optimal Net-Zero UK. If we allow only 1 store, it must be hydrogen

<u>Blending stores could give significant cost reductions – credibly ~10%.</u>

Employing multiple stores requires a *scheduling* algorithm. A good one exists ([1]) but further improvements are possible.

With multiple stores, *cross-charging* sometimes helps to keep all power-conversion resource *in-play* and *forecasting* becomes relevant.

Optimisations indicate (as in [2]) that although hydrogen stores must be much larger in capacity (*volume*) than medium-duration storage such as ACAES, (~80TWh:~3TWh depending on assumptions), ~65% of all energy emerging from storage will come from the medium-duration store.

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[2] Cosgrove, P., Roulstone, T. and Zachary, S., 2023. *Intermittency and periodicity in net-zero renewable energy systems with storage*. Renewable Energy, 212, pp.299-307.

Thanks for listening

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Large-scale energy storage: Economic Implications and Questions

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LARGE-SCALE ENERGY STORAGE

Some Economic Implications and Questions.

Royal Society

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KEY MESSAGES FOR POLICY

- The **scale** of the storage requirement. Scale economies. Leads to familiar infrastructure questions of finance, ownership and regulation.
- The complexity of the interactions and choices, both **operational** and for **investment.** A coordination issue.
- Hitherto largely ignored questions of **conversion capacity** (in and out of storage)?
- Fundamental implications for how we address system reliability. Adequacy of stored energy **kWh** at least as important as adequate generating capacity **kW,** but poses very different questions.

THE MAJOR QUESTIONS

- How will major infrastructure be financed at a low cost of capital?
- How will very complex choices be coordinated? Both for investment and operations. Extensive storage adds complexity both through its intrinsically multi-period nature and its centrality in reliability management
- What is our policy for managing future reliability: how do we define criteria and determine needs? Economic and energy resilience.
- What does all this mean for organisation, regulation and markets?

SOLUTIONS. SOME COMBINATION OF …

- Novel market mechanisms and incentives to reward provision of storage capacity and conversion capacity.
- Elements of long-term contractual assurance for infrastructure providers, eg a regulated asset base approach, or government commitments
- Centrally driven coordination of investment plans. (eg France's EDF and Germany's Energiewende).
- Enhanced role for the National Grid
- The creation of a 'central buyer', to procure capacity, but also to buy power from generators and sell to retail suppliers and large consumers.
- Close cooperation between members of umbrella groups who implicitly assume responsibility for reliability (the US 'power pool' model)

Slide notes

I have been asked to talk about the economics of large-scale storage. Economics in this context is about securing the right combinations of generation and storage, the principles to guide our decisions, and the mechanics of getting where we want to be. The objective is to find market or other mechanisms for the outcomes we want, ie getting to low or zero carbon at an affordable cost compatible with an acceptable level of reliability and energy security.

This is not just about a theoretical optimisation, but also about national policies, institutions, coordination, markets, regulation and infrastructure?

There are several particularly important general lessons from the report that have general economic and policy implications:

1. First is the potentially huge scale of storage. With both scale and major economies of scale, we have typical infrastructure characteristics, that need to be financed as cheaply as possible.
2. Second, interactions between storage and generation choices and multiple other factors: including the demand side. The report illustrates just how complex this is.
3. Third, conversion capacity, for moving energy in and out of storage, will matter and has perhaps hitherto been largely overlooked.
4. Fourth is the whole issue of policy and planning for reliability of supply. Traditionally this was mostly about adequate margins of generation capacity required over peak demands – so-called needle peaks. But the new world demands a quite different understanding of reliability, when we are talking about, for example, wind drought. The issue then is of kWh energy rather than kW capacity – a major distinction.

So the report raises some very serious questions.

It is clear that the storage need has all the characteristics that we associate with large scale infrastructure. This possibly includes a natural monopoly, certainly substantial investment costs, long lived assets that are highly use specific, and a financial necessity for a cost of capital as low as possible. For private capital that would mean a high level of reassurance over future revenue streams and the future market and regulatory environment.

Second is the issue of some very complex choices, and their coordination, in systems that rely on storage. It's important to recognise that there are two distinct timescales here. One is **operational** - operating the system as efficiently and economically as possible with whatever is the current mix of assets. The second is about **necessary investment** - creating the best mix of assets for the future. In a perfect market efficient solutions on both timescales might be expected to result from market prices. But in the new low carbon world that looks increasingly like a pipe dream.

The conventional view of power sector markets was that the price signals in a competitive market derived from the immediate needs for the efficient operation of mainly generation assets, replicating what might happen in a fully optimised system such as the merit order. It also had to provide an incentive for adequate capacity. Various extra mechanisms have often been added that attempt to put a valuation on reliable supply; this is sometimes referred to as value of lost load or VOLL. In principle it was hoped that all this collectively would incentivise the right mix of assets, generation, networks and storage for efficient and affordable future systems. In practice the most that can be said is that experience has been mixed.

So what is new. Traditional spot markets were developed to deal with gas and coal powered generators, and to replicate a merit order based on SRMC. They were also largely designed by the employees of those generators They do not translate or adapt easily to low carbon technologies with more complex, probabilistic, intermittency and operating constraints. Storage adds new dimensions, by being intrinsically multi-period, requiring in addition that attention is paid to conversion capacities, and the very different nature of the reliability issue.

The simple metrics of short run cost that sit behind conventional market mechanisms **do not** capture the information or the complexity required. Investment choices, on the four-way balances between generation, transmission, storage, and conversion capacity, pose further questions, implying a need for coordination.

My third point may well be the most important public policy question for the future – the security and reliability of electricity supply. We all know that governments cannot stand aside from issues of energy security, and electricity security in particular, however much they might wish to. However, this is another dimension where the economic and policy calculus has to change radically, with some very different metrics.

Historically supply reliability in the UK has been about generating capacity – kW, and occasional insufficiency of kW to meet needle peaks. But future crises, if they relate to sustained weather related shortages, will be about kWh rather than kW. Threats of months of energy rationing require an entirely different way of thinking about reliability. Possibly once in a generation events, like the 1970s 3-day week, a covid crisis or curtailed gas supplies, may mean looking at not just energy supply planning but also the overall energy resilience of the economy.

Answering all these questions means great attention to the institutional and market structures of the sector. We have to decide who should own and operate large scale storage, on public or private ownership, integration with grid operation, guarantees for private capital, and so on.

All these issues are closely inter-related, and the report offers an indication of where we might find the answers. These must rest on some combination of the following:

- **Novel market mechanisms and incentives** to reward provision of storage capacity and conversion capacity.
- **elements of long-term contractual assurance for infrastructure providers,** e.g. a regulated asset base approach, or government guarantees.
- **Centrally driven coordination of investment plans**. Quite common internationally (e.g. France's EDF and Germany's Energiewende).
- Enhanced role for the National Grid
- The creation of a 'central buyer', to procure capacity, but also to buy power from generators and sell to retail suppliers and large consumers.
- Close cooperation between energy companies who implicitly assume collective responsibility for reliability (the US 'power pool' model)

In summary the economics for me is about:

- balancing the roles of markets, thus retaining a role for competition, and central coordination
- financing storage as essential infrastructure, and
- re-evaluating the policy approach to planning for reliable future systems

Possibly the most important observation of all, though, is that all these things take time, and the task is urgent. That means starting to address these issues now.

Hydrogen and ammonia: Technical assumptions

Mike Muskett

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Context for cost assumptions

- This presentation only covers hydrogen for energy storage
- Study optimisation modelling is based on costs disclosed in the literature, rather than actual completed project costs
- We are aware that the current cost environment for equipment is very volatile due, amongst other things, to :
    - Supply chain disruptions
    - Inflation
    - High demand for some equipment types, especially electrolysers
- The costs in the study are forecasts for 2050, and pre-date recent changes in the market. We quote costs in £ of 2021.
- Some of the changes in costs compared to today are significant, especially the costs of electrolysers and fuel cells
    - Electrolyser long term cost forecasts show a broad consensus, but all are based on extrapolation from a fairly small deployment base today
    - Cost is shown as a function of time, but is really a function of deployment
- There is therefore considerable uncertainty in some elements of the cost modelling which we have addressed by sensitivity analysis, and we believe our conclusions to be robust to these sensitivities
    - We also recommend more detailed engineering studies as one of our follow up actions
- Optimisation modelling does not include modification of the power transmission system
    - Grid will most likely need significant change in the future in any case because of increasing demand and changes in sources of power from power stations to renewables
    - Very difficult to quantify grid upgrade costs in a modelling study of this nature

FIGURE 7

Bulk storage of hydrogen.

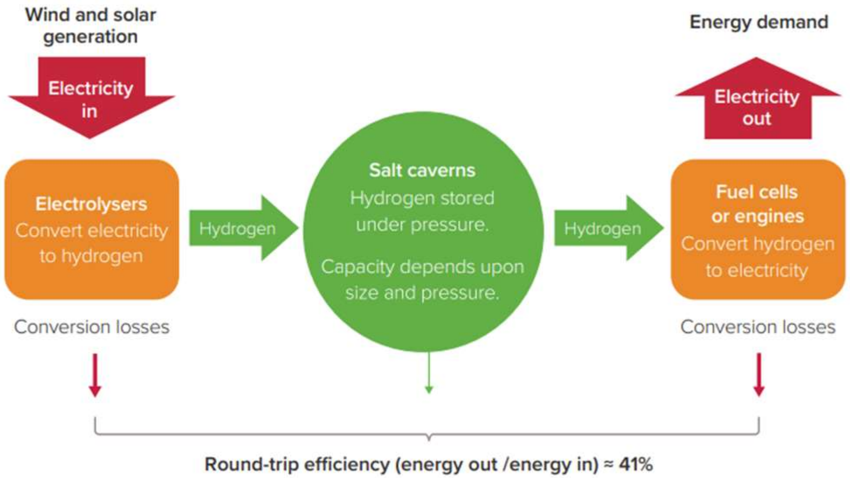
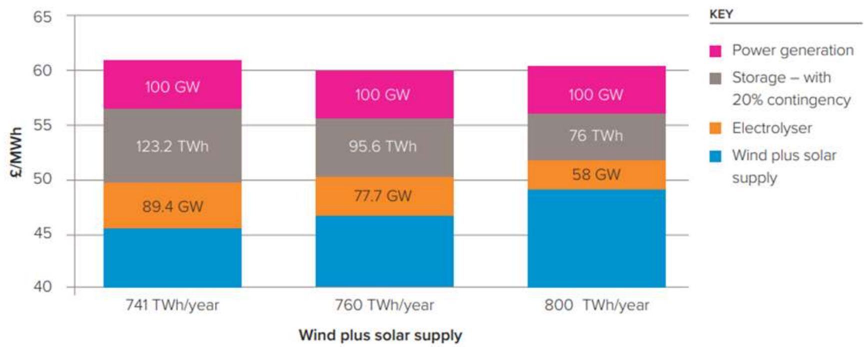


FIGURE 23

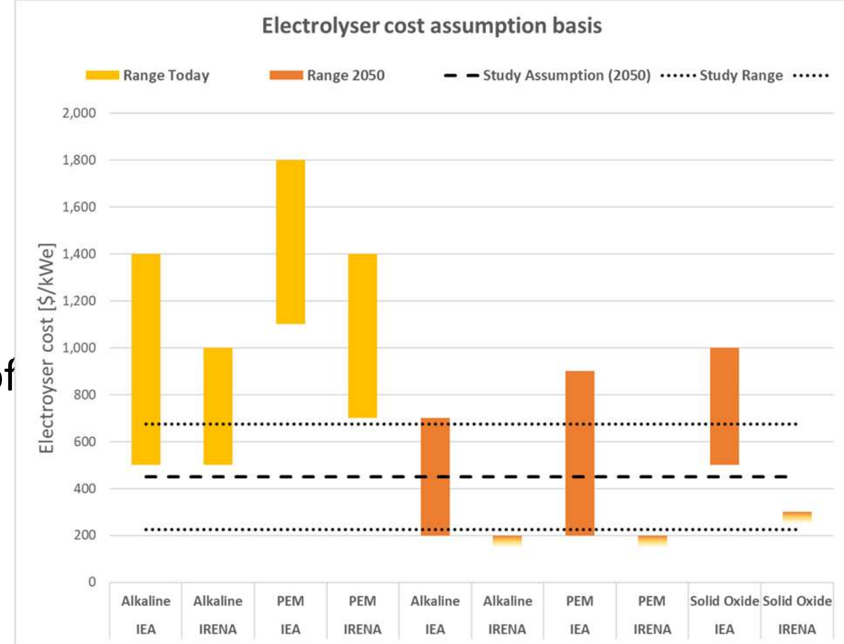
Breakdown of average cost of electricity.

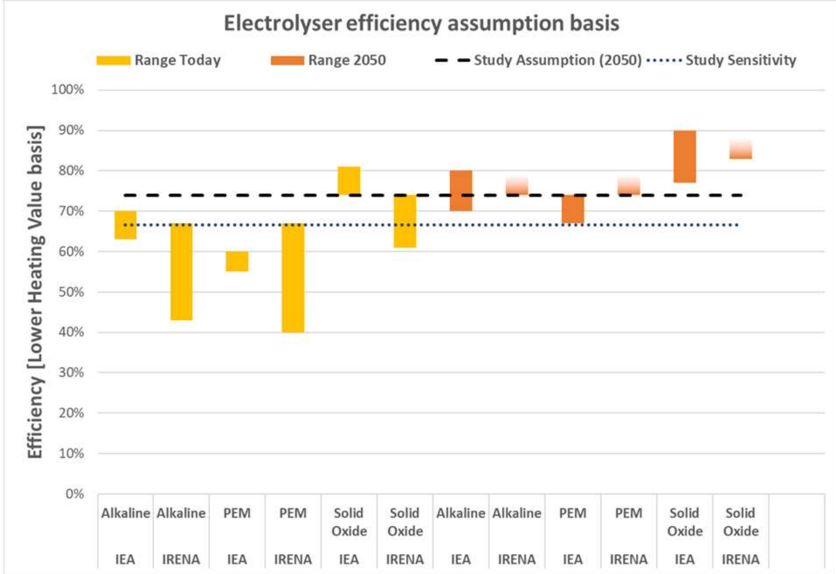
Breakdown of the average cost of electricity for different levels of wind and solar supply, with the base costs for hydrogen storage and a 5% discount rate. The cost of wind and solar supply dominates the total (note the suppressed zero).



Green hydrogen assumptions

- Key data sources are IEA Future of Hydrogen* and IRENA Green Hydrogen Cost reduction**
- Costs are intended to represent installed project costs per kW of power into the electrolysers
- Most if not all published studies forecast significant falls in electrolyser costs due to :
    - Manufacturing at multi-GW scale
    - Larger projects (going from 10’s of MW to 10’s of GW), leading to economies of scale
    - Technological advances
- Efficiency is also predicted to improve over time, as the technology continues to develop
- Our study is agnostic to electrolyser technology
    - Electrolyser response time is not a critical issue for this application, so choice is purely economic



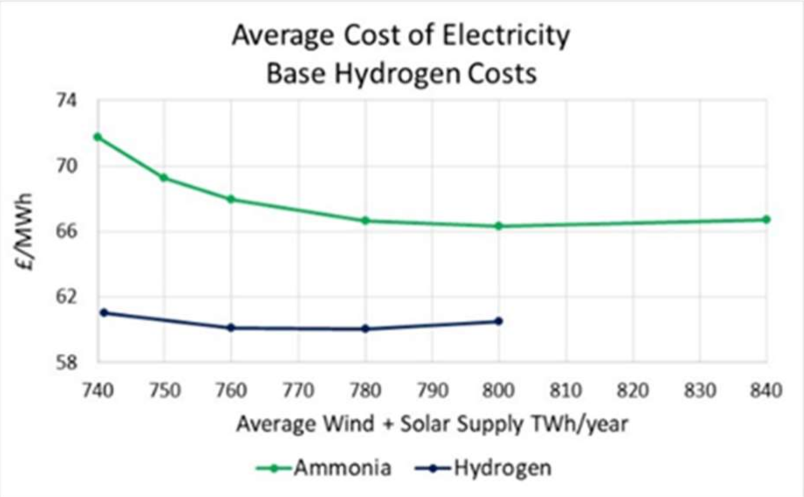


*IEA. 2019 The Future of Hydrogen. See https://www.iea.org/reports/the-future-of-hydrogen
**IRENA. 2020. Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal
https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pd

Hydrogen storage

- Hydrogen storage would be in salt caverns, formed by solution mining in one of three GB regions
  - East Yorkshire, Cheshire, Wessex
- Hydrogen storage caverns have been operated successfully for decades in the following locations in Teesside (1970's) and Texas (1983 and 2007) :
- It is believed that sufficient capacity exists in the UK, but suitable sites are quite localized
- Costs have been based on literature data, with a scaling factor for cavern size. The central case is based on H21 NoE study + 50% following literature review
  - Range of costs = £267/400/534 /MWh usable hydrogen stored (LHV basis)

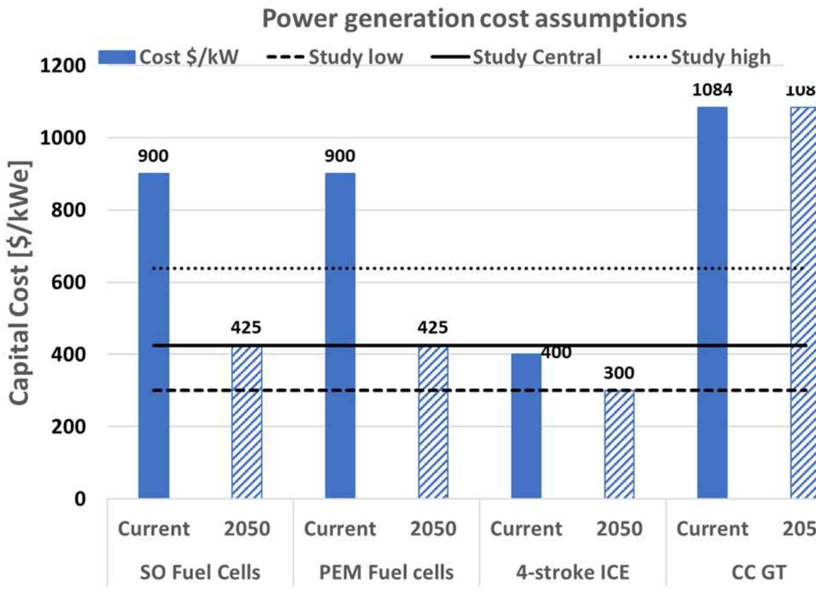
Ammonia

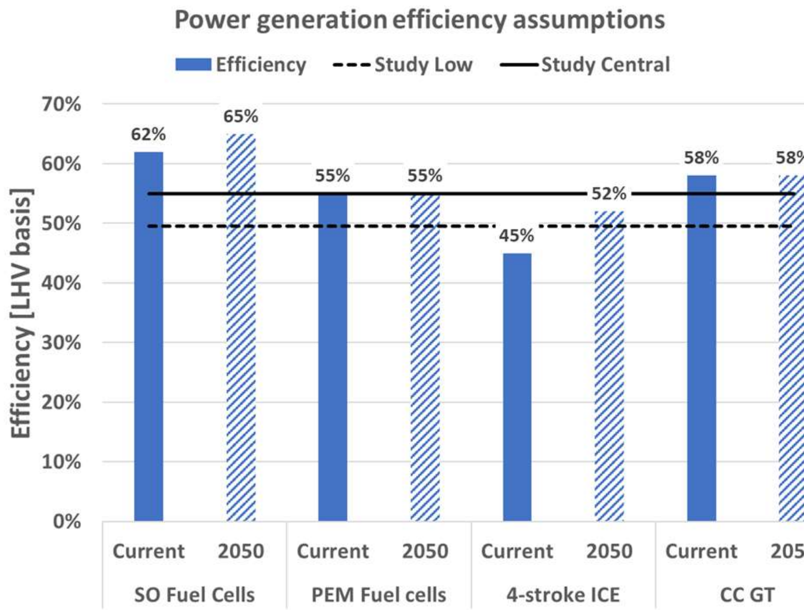


- Ammonia has been assessed as an alternative storage medium to green hydrogen, because it is easier and cheaper to ship and store than hydrogen
- There is a synthesis step following green hydrogen production, and nitrogen is supplied from an air separation unit
  - Assumed cost of ammonia synthesis and ASU = $900/annual te of ammonia today, and $760/annual te in 2050 at a scale of ~1 million tepa ammonia
  - Assumed cost of ammonia storage is £197/MWh_{LHV}
- Ammonia production / storage / power generation is not tied to geological storage locations
  - Hence ammonia may have a role mitigating infrastructure constraints, e.g. in areas remote from hydrogen storage regions
  - Ammonia also offers an option to import green energy into the UK
- Ammonia conversion to power is technically less well developed than hydrogen to power
  - We have assumed power generation costs from ammonia are the same as power generation costs from hydrogen
- We find that LCOE is higher when ammonia is used as the storage medium by ~£5/MWh

Power generation from hydrogen

- Study modelling assumes that all power delivered from stored hydrogen has to be generated by new investment
    - Generation capacity assumed to be equal to peak grid demand of 100 GW
    - Average utilization is 9-10%, but in peak years will be significantly higher
- The central assumption is that generation will be by grid-scale hydrogen fuel cells, installed at a cost of $425/kWe (2021 $) in 2050, with an efficiency of 55%*
    - Current FC costs are much higher, but are for small systems (kW-scale) and often include steam reforming of natural gas
    - Manufacturing scale-up will also reduce unit cost of fuel cells
    - Expect continued optimization of the technology
- Technology development and/or demonstration is needed for all hydrogen to power options – full scale demonstrations have yet to be established





* Lower Heating Value basis

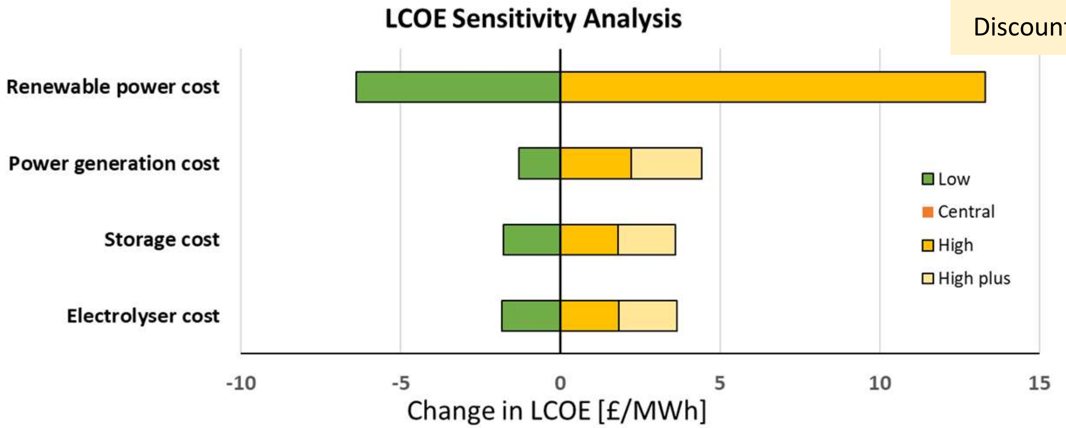
Impact of uncertainties in assumptions

Cost

- Impact of changes from base line assumptions shown below with high plus cases added
- Baseline LCOE = £60/MWh
- About 14% of the total power supplied to the system comes from storage – moderating the impact of differences from the assumed costs on LCOE
- These costs are at constant renewable power generation
- Impact will be moderated somewhat if system is optimized, except for power generation sensitivity

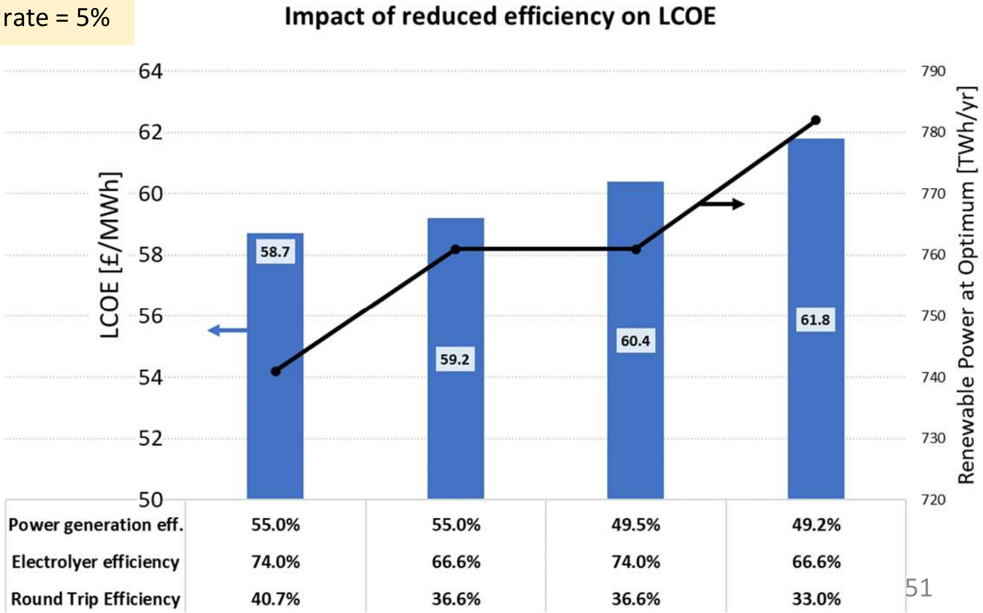
Efficiency

- Base line costs assumed in chart below, except for hydrogen store costs assumed to be low
- System has been optimised for each level of efficiency
- Effect of reducing round trip efficiency from 40.7% to 33% is ~5% of LCOE



		Low	Central	High	High plus
Electrolyser cost	$/kW	225	450	675	900
Storage cost	£/MWh H2	267	400	534	668
Power generation cost	$/kW	300	425	637.5	850
Renewable power cost	£/MWh e	30.2	35	45	45

Discount rate = 5%



Opportunities and challenges

- Further optimisation options include :
  - Demand side management to reduce peak load
  - Retrofit of existing CCGT power stations to hydrogen (depending on geography, especially costs of H_2 pipelines)
  - Internal combustion engines for power generation (promising results lately on efficiency, and potentially lower cost and flexible)
  - Reversible fuel cells/ electrolysers
  - Mixed technology solutions for power generation, deploying fuel cells for more frequent use and combustion engines for occasional use
- Technology readiness
  - Power generation from hydrogen at grid scale by fuel cells is relatively low TRL today
  - **Development and demonstration at scale is needed**
- Understanding infrastructure requirements
  - Future grid design will impact on optimum deployment of storage, for example determining the role of ammonia
  - Need to assess retrofit options to existing assets, such as possible re-use of natural gas pipelines for hydrogen in future

- Supply chain development
  - If the storage system is built over (say) 20 years, then ~5 GW/yr of fuel cells and ~4 GW/yr of electroylsers would be needed
  - Fuel cell sales in 2021 were 2.3 GW – increasing 70% over 2020, most growth in mobile applications
  - Electrolyser sales were 1.2 GW/yr in 2022 – double the sales in 2021
  - **Need to see significant scale up in these supply chains globally**
- Cavern construction
  - Thousands of caverns have been constructed globally, including 5 for hydrogen
  - Water source : large volumes required – sourcing strategy needed
  - Brine disposal : will most likely be at sea, which is already practiced, but must be done with care
  - Project duration ~5 years, with ~3 years of solution mining
  - Need to build 80 clusters of 10 caverns
  - **"…Building this many clusters by 2050 would be challenging, but the technical capabilities needed to execute such projects already exist in the UK"**

Non-chemical storage technologies

Phil Eames
Loughborough University

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Non-chemical and Thermal Energy Storage

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Options

- Advanced compressed air energy storage (ACAES)
- Thermal and pumped thermal energy storage, Carnot Batteries
- Liquid air energy storage
- Thermochemical heat storage
- Gravitational energy storage
- Storage to provide heat

ACAES

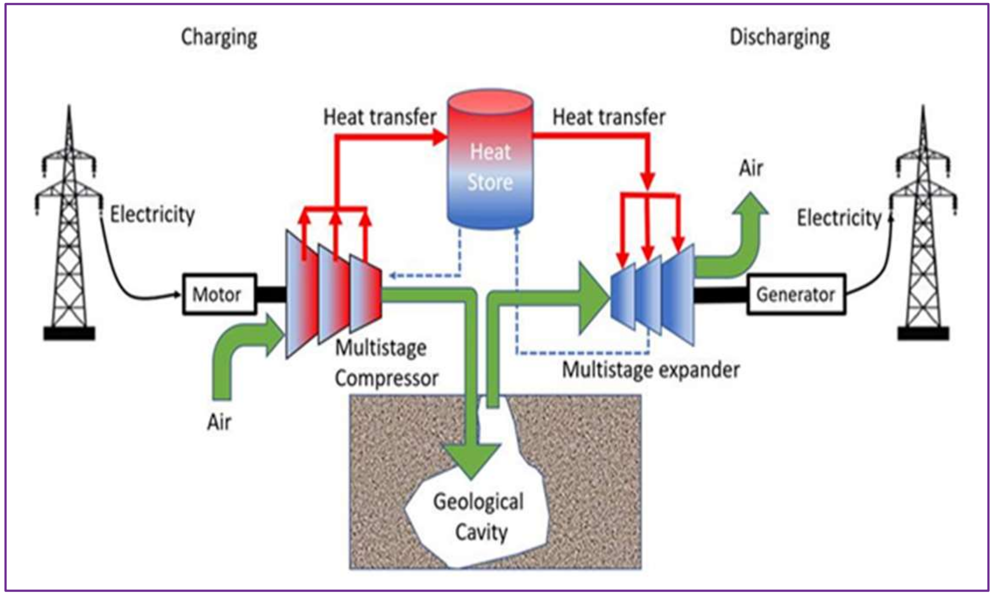
Three grid-connected ACAES plants using caverns now in operation in China, e.g.

- 50 MW_e /300 MWh_e plant (operating since May 2022)

- air stored in a salt cavern, heat in thermal oil
-

- 100 MW_e /300 MWh_e plant (operating since September 2022)

- air stored in a mined cavern, heat in supercritical water



- 10 MW_e/100 MWh_e plant (operating since September 2021)

- air stored in a salt cavern, heat in supercritical water

Cannot give generic cost: depends on several factors

- **pressure range** (~ determined by depth, unless in solid rock or container)
- **design:** number of stages of compression and expansion,
 (*heat stores most of the energy: compressed air mainly stores exergy*)

assumed multistage compression → limits temperature rise → store heat of compression in water (much cheaper than high temperature molten salt storage)

- **size of compressors:** rule of thumb → cost ~ $(\text{power rating})^{0.6}$

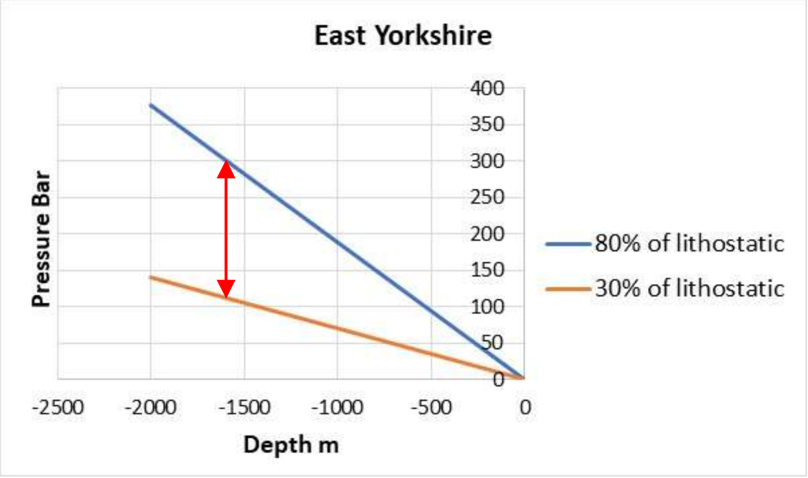
Underground capacity in GB

Perhaps sufficient for ACAES that would deliver 20 TWh_e storage– but this would start to encroach on other needs for underground storage
Requires 2000 caverns assuming 10GWh_e storage capacity

ACAES – Modelling and Cost Assumptions

Modelled 300,000 m^3 (H21) **caverns at 1000 m & 1700 m depth**

Assumed average: each cavern absorbs 10 GWh work of compression in 6 stages. Expansion in 6 stages, supported by 7.5 GWh of thermal storage can deliver 6.8 GWh_e



Costs estimated based on

- **1.5 x H21 cost for clusters of caverns**, without specific H_2 related costs
- **Water pit storage**: based on actual (full) costs from Denmark
- **Compressors/expanders**: have quotes from suppliers of $200/$kW_e$ for complete/crated 1 MW_e systems (but not for UK safety standards)

But want costs (which will fall when manufactured at scale) for six-stage ~ 60 MW systems, including cost of buying/preparing site, installation, share of management costs,...

- **Assumed £(100-500*)/kW for ~ 60 MW**

*****conservative if 0.6 law holds – for very different systems, over range 1 to 60 MW*

+ 4%/year O&M

Indicative costs:

- A cluster of 10 caverns of 300,000m^3 capacity £188.1M
- Heat storage, 10 pit stores at 140,000m^3 capacity, £70M
- Cost per kWh storage 2.6£/kWh$_e$ stored
- 233MW compressors and expanders for 10 Caverns at £500 kW each including site preparation, installation etc. £233M
- O&M costs, 4 % of capital costs per year.

Thermal Energy Storage

Andasol 1 Heat Storage: Molten salt

- $NaNO_3/KNO_3$ (60:40)
- Capacity around 1000 MWh thermal
- Operational store temperatures :-
  hot store 390ºC
  cold store 290ºC
- Approximately 14,000 m^3 of storage

Storage provides 7.5 hours output at $50MW_e$, $375MWh_e$

Operational temperature range could be increased to 550 ºC yielding $975MWh_e$ storage equivalent.

Larger stores have proportionately lower heat losses.

Loughborough University

Packed bed thermal energy storage

- Low-cost materials, igneous rock with stable properties at temperature of operation. (600°C +)
- Storage capacity increases with store volume, heat losses increase with store surface area. Favours large stores.
- High conversion efficiency of electricity to heat for charging.
- Heat to electrical conversion efficiency 45%+ possible.
- If low temperature heat can also be used for other applications, district heating, higher energy efficiency can be achieved.
- Large stores with capacities of 10’s of GWh_e can potentially achieve low costs per KWh_e storage. ($1-4 for modelled low and high-cost scenarios)

Concluding Remarks

Different approaches for energy storage are possible that are scalable to the multi GWh capacity with potentially low costs.

ACAES: round trip efficiencies of approximately 68 % were obtained from modelling with cost per kWh_e storage 2.6£/kWh_e

Heat: round trip efficiencies depend on temperature of storage, higher temperatures lead to higher efficiencies, 45-55% should be possible. Low costs per KWh_e are possible for large packed bed thermal stores using low cost abundant materials.

Provision of multiple services, heat/coolth in addition to electricity can increase total efficiencies to high levels.

The report, briefing document and a link to the supplementary information can be found at www.royalsociety.org/electricity-storage.

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