SIMPLE NOT EASY

OPPORTUNITIES IN ACTIVE NET ZERO

INDUSTRY BACKGROUND FROM LONGSPUR RESEARCH

18 February 2021
Adam Forsyth
adam.forsyth@longspur.com
+44 (0) 131 357 6770

Industry background research available to all professional investors under MiFID II as a minor non-monetary benefit

---

Selected Companies

Bioenergy and CCS

Drax Group (DRX LN)*

Velocys (VLS LN)*

SIMEC Atlantis (SAE LN)*

Efficiency

Swedish Stirling (STRLNG SS)*

SIT (SIT IM)*

eEnergy Group (EAAS LN)

SDCL En'gy Efficiency (SEIT LN)

SMS (SMS LN)

Triple Point (TEEC LN)

Hydrogen

Powerhouse Energy (PHE LN)*

ITM Power (ITM LN)

AFC Energy (AFC LN)

Ceres Power (CWR LN)

Advent Technologies (ADN US)*

Renewables

SIMEC Atlantis (SAE LN)*

Next Energy Solar (NESF LN)*

JLEN Envir'l Assets (JLEN LN)

Active Energy Group (AEG LN)

EQTEC (EQT LN)

Good Energy (GOOD LN)

Verditek (VDTK LN)

Storage

Talga Group (TLG AU)*

Gore St Storage (GSF LN)*

Gresham Hs St'ge (GRID LN)

Invinity Energy (IES LN)

CAP-XX (CPS LN)

Ilika (IKA LN)

Engie EPS (EPS FP)

**Longspur Research client*

SIMPLE NOT EASY

Achieving global net zero emissions is simple in concept but not easy in practice. Simple in concept because pathways have already been evaluated and solutions identified. Not easy because there are challenges in executing these solutions. Fortunately, the problems can be resolved and this in turn creates additional opportunities for investors. These active net zero opportunities are in renewables, storage, hydrogen, efficiency and BECCS. Our market size estimates of these show demand above expectations.

Solutions to achieving net zero

Cutting emissions simply requires renewables for stationary energy demand, batteries for transport and hydrogen for industry. Beyond that, efficiency, carbon capture and storage (CCS), and land use change can get us to net zero. Unfortunately, it is not that easy. Renewables bring problems of market integration. This can be solved, with storage being key and we think demand for storage is underestimated. We forecast 10TWh of energy storage demand by 2050, 14% above other key forecasts in the market.

Hydrogen is a major solution

Renewables also have issues of timing and in particular do not provide much needed system inertia. This can also be solved, with hydrogen gas turbines, nuclear power and biomass being the key options. Nuclear power can create further demand for hydrogen. Batteries for transport also have limitations especially over range. Again, these can be overcome by hydrogen solutions in most cases, and biofuels in areas such as long-haul aviation. We forecast 781Mtpa of hydrogen demand by 2050, 12% above other forecasts.

Demand for hydrogen increases demand for renewables

Hydrogen can be "blue" or "green" and green will need additional renewables. So we think demand for renewables will be greater than market expectations. We forecast 22.5TW of renewable energy capacity by 2050, 11% above other forecasts. Electrification alone will not get us to net zero and efficiency and negative emission technologies (NETs), principally bioenergy carbon capture and storage (BECCS), will be needed to bridge the gap. We forecast 800GW of BECCS being required.

Demand is not the same as value

Demand is strong but investors need to factor in risk. Our risk framework for clean energy is based on three key risks; technology, competition and policy. Innovators are cleantech companies where technology risk is key. Manufacturers make proven low carbon technologies and deal with market risk, especially competition. Finally, developer/operators face policy risk either directly or through market structure. All can offer attractive investment opportunities provided these risks can be mitigated.

Industry background from Longspur Research

This is one in a series of industry research notes provided by Longspur Research as background to our issuer-sponsored research service and contains no investment recommendations. For companies, we offer specialist investment research in new energy and clean technology, available to all professional investors under MiFID II and widely distributed to the most appropriate investors. Visit www.longspurresearch.com.

18 February 2021

Adam Forsyth

adam.forsyth@longspur.com
+44 (0) 131 357 6770

CONTENTS

Simple Not Easy - Executive Summary

The IPCC Special Report on Global Warming of 1.5°C requires the world to eliminate net greenhouse gas emissions by 2050 if it is to keep global warming to within 1.5oC of pre-industrial levels and avoid the worst impacts of climate change. Pursuing this target is consistent with the Paris Agreement and countries representing 48% of global emissions have already announced net zero targets including the EU, China, Canada, Japan and South Korea.

US change of policy brings a major shift in support for net zero

All the G7 countries except Italy and the USA have announced net zero targets. With Joe Biden now in the White House, a US commitment to net zero appears likely and the country has already begun the process of rejoining the Paris Climate Agreement.

The IPCC report shows that anything less than net zero will leave the world and its economies exposed to severe risk. We believe investors who want the environment to be considered in their investment strategies will want those investments to be consistent with a net zero approach.

Active Net Zero

The Institutional Investors Group on Climate Change (IIGCC) represents over 70 members with over US$16tr of assets. It sees two dimensions for investors to be considered in alignment with the temperature goals of the Paris Agreement.

Two dimensions for investors

↘ **Decarbonising investment portfolios** in a way that is consistent with achieving this net zero goal

↗ **Increasing investment in 'climate solutions'** required to meet that goal, such as renewable energy, low carbon buildings, and energy efficient technologies

Source: IIGCC

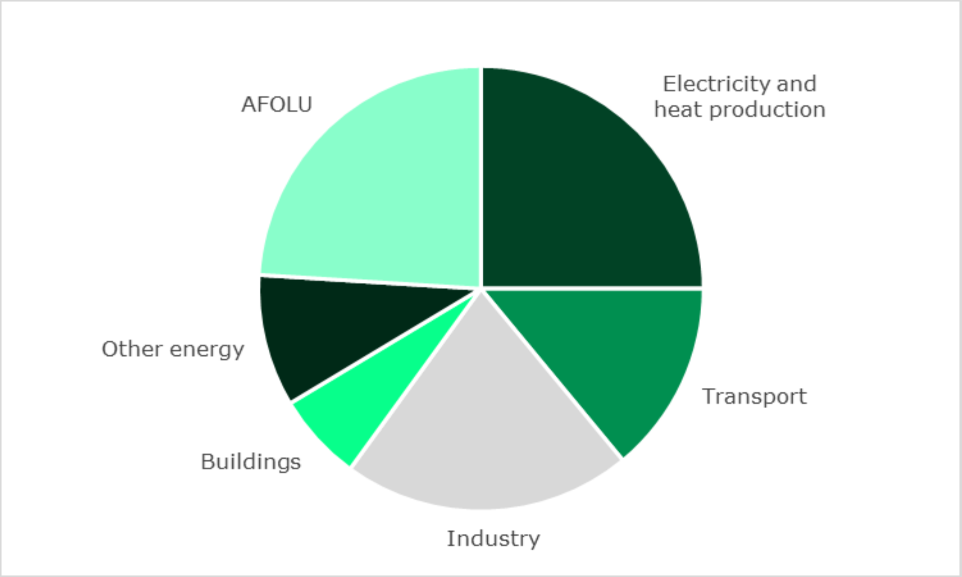
We describe companies in the second dimension as Active Net Zero companies. Active net zero companies are those companies actively working to deliver a net zero solution. This report identifies the key activities which define active net zero companies.

Targeting emission reductions

The IPCC 1.5°C report studied 90 pathways to achieve a net zero solution. We have taken the median outcome of this work as a guide to where investment opportunities in this area are likely to be found.

If we look at where emissions are generated, we can see that roughly a quarter are from electricity and heating, a quarter from agriculture, forestry and other land use (AFOLU), a fifth from industry, a seventh from transport and the rest from other industry and buildings.

Global GHG emissions by sector (2015)



Source: IPCC

HOW WE CAN REDUCE EMISSIONS

Electrification through renewables is key

Electricity and heating emissions can be eliminated largely through the use of renewable electricity. Heating has certain challenges, but a number of options exist, and most are a form of electrification; heat pumps, infrared and green hydrogen, can all be driven by renewable electricity. Blue hydrogen is the only major solution not to rely on electricity.

Renewables have issues of place, price and timing

Despite strong progress, it is not easy to replace fossil fuelled electricity with renewables. While locational changes to the electricity system can be met by investment in power grids, market structure issues are more problematic. The near zero marginal cost attributes of renewables can result in “missing money” leading to lack of investment. There are solutions to this, the most obvious of which is to combine renewables with storage increasing demand for storage.

Renewables also reduce the ability of networks to maintain a set frequency. Deviation from this can lead to system failure and damage connected equipment. Generation which provides spinning reserve is the key solution here and includes nuclear, hydrogen gas turbines and biomass. Nuclear’s inflexibility can itself be solved by matching it with hydrogen electrolysers. Overall, these lead to increased demand for hydrogen and biomass.

Storage enables transport solutions but again there are issues

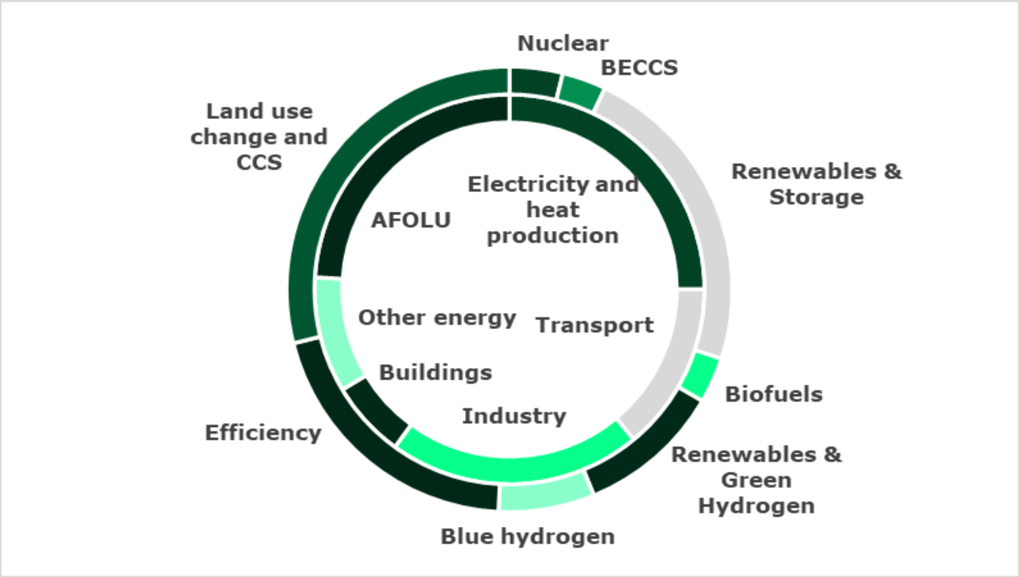
Transport emissions can be eliminated though electrification which means battery electric vehicles for light duty and medium range applications including the bulk of passenger cars. This will drive demand for lithium-ion batteries. However, lithium ion and other battery technologies do not scale well with range and hydrogen fuel cells are more appropriate for heavier duty applications. This extends to short haul aviation where hydrogen solutions are making progress using existing airframes. For longer haul aviation biofuels are the key solution.

Industry and land use have solutions but we will need NETs

Industrial emissions can be replaced by some electricity. Efficiency is also a major driver here, but hydrogen is perhaps the biggest opportunity. Land use change is the final opportunity for a significant decarbonisation of emissions. Beyond this we need to rely on negative emission technologies (NETs) of which the key are in biomass energy and carbon capture and storage (BECCS).

Putting this together and comparing with existing emissions shows where the solutions lie, broadly matched with the specific emission problems they solve.

Global Emissions and Solutions



Source: IPCC, Longspur Research

We translate this energy demand into capacity needs on a 2050 timeframe. We can compare these forecasts to a number of others in the market with those from BNEF and IRENA being perhaps the most comprehensive. We are ahead of almost all of these.

Implied 2050 capacity for global net zero

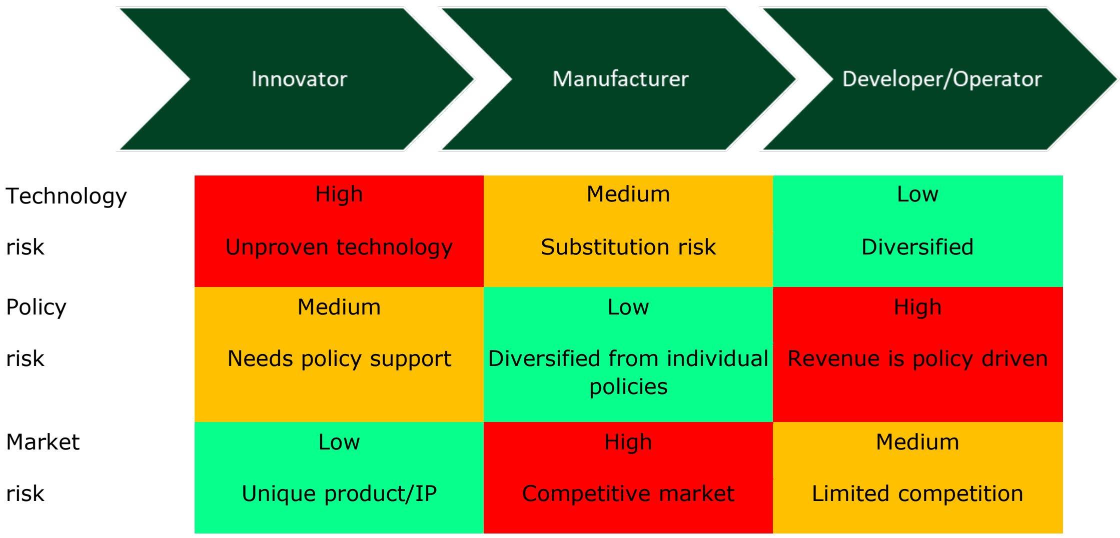
	Longspur	BNEF	IRENA
Renewable Energy (GW)	22,486	20,301	18,377
Storage EV (BEVs, m units)	1,090	414	1,109
Storage ESS (GWh)	10,304	5,827	9,000
Hydrogen production (Mt)	781	697	240
Green hydrogen (GW)	4,957		1,700
BECCS (GW)	807		
Nuclear (GW)	864		
Biofuels (TWh)	5,864		
Efficiency (TWh)	35,897		
Land use change (TWh)	39,536		

Source: Longspur Research, BNEF, IRENA

INVESTING IN ACTIVE NET ZERO SOLUTIONS

Demand is therefore strong, but investors need to understand risk as well. We present a risk framework for clean energy companies based around three key risks of technology, competition, and policy.

Longspur clean energy value chain



	Innovator	Manufacturer	Developer/Operator
Technology risk	High Unproven technology	Medium Substitution risk	Low Diversified
Policy risk	Medium Needs policy support	Low Diversified from individual policies	High Revenue is policy driven
Market risk	Low Unique product/IP	High Competitive market	Medium Limited competition

Source: Longspur Research

Innovators are classic clean tech companies where technology risk is key. Manufacturers provide proven low carbon technologies and principally deal with market risk, especially competition. Finally, developers mainly face policy risk. All three groupings can offer attractive investment opportunities provided these risks can be mitigated. We show below examples of companies within this framework.

Example Active Net Zero companies

	Innovator	**Manufacturer**	**Developer/Operator**
Renewables PV	Midsummer	First Solar	**NESF**
Renewables Wind	Windar Photonics	Vestas	Orsted
Renewables Other	AEG	**SIMEC Atlantis**	**SIMEC Atlantis**
Storage li-ion	Nano One	**Talga Group**	**Gore Street**
Storage other	Invinity	Cap-XX	**Drax Group**
Hydrogen	**Advent Technologies**	ITM	Everfuel
BECCS/CCS	**Velocys**	Occidental	**Drax Group**
Efficiency	**Swedish Stirling**	**SIT**	Smart Metering Systems

Source: Longspur Research (Longspur Research Clients shown in **bold**)

HAVE CLEAN ENERGY COMPANIES BECOME OVERVALUED?

Valuation across the clean energy space is complicated by the fact that many companies are early stage and are either unprofitable or are still pre-revenue. Less than half of 128 pan-European active net zero companies have a consensus revenue forecast on Bloomberg.

The Wilder Hill New Energy Global Innovation Index shows growth of 141% in the past twelve months. However, of 134 pan-European active net zero companies, only 25 have met or beaten this performance, almost half have not beaten the MSCI World Index performance of 16% and 42 have seen their share prices fall.

Share price performance over 1 year

Total active net zero companies	134	100%
Number outperforming NEX	25	19%
Number underperforming MXWO	61	46%
Number with SP return <0	42	31%

Source: Longspur Research, Bloomberg

The strongest growth has been in companies with solutions based on hydrogen technology. A year ago, hydrogen was still largely out of favour and its contribution to a net zero solution not considered by many. Even the IPCC 1.5 degree report tends to favour bioenergy over hydrogen solutions. In our view all these companies were materially undervalued. The recent performance in these companies has largely been driven by a reappraisal of the contribution that hydrogen can make. Just because the performance has been strong does not necessarily mean that they are now overvalued.

Average (unweighted) share price performance (%)

	1M	**3M**	**1Y**
Indices			
NEX Index	3	45	141
MXWO Index	4	10	16
Segments			
Hydrogen	-1	118	246
Bioenergy	-3	59	102
Renewables	0	19	36
Efficiency	3	18	29
Storage	4	48	85
Categories			
Innovator	3	70	153
Manufacturer	-1	32	74
Developer	0	27	35
Operator	1	2	0

Source: Longspur Research, Bloomberg

In our view, the key valuation consideration for these companies is the size of the total addressable market. Much of this note identifies where the market opportunities lie and on the whole these potential markets are large and, if anything, currently underestimated if we are to reach a net zero position by 2050.

GLOBAL NET ZERO

Net zero is consistent with the Paris agreement which saw 195 nations agree to strengthen the global response to the threat of climate change by:

'holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels'.

The UN Intergovernmental Panel on Climate Change (IPCC) produced its Special Report on Global Warming of 1.5°C in 2018. As with most IPCC reports this is essentially a summary of recent research with over 6,000 scientific references and 91 expert authors. The 1.5°C level is seen as a level consistent with still being able to achieve goals such as the UN Sustainable Development Agenda. Taking temperatures above this level is seen as leading to irreversible loss of the most fragile ecosystems and create crises for the most vulnerable people and societies.

To limit warming to 1.5°C, CO2 in the atmosphere needs to be limited to 430ppm. Because CO2 persists in the atmosphere and we are still emitting it, hitting this level means we need to effectively stop adding CO2 completely by 2050 with a reduction of c.45% from 2010 levels by 2030. This is why net zero must result in no net emissions of CO2 being emitted into the atmosphere. If they are, an equivalent amount must be removed. Even with rapid development of negative emission technologies at scale, this still means that most source of emissions must be replaced with zero or very low carbon alternatives.

UK per capita emissions compatible with the Paris temperature goal

	Well below 2°C	**1.5°C**
Global 2050 GHG emissions per person (tCO2e/year)	0.8 - 3.2	-2.1
Equivalent reduction in total UK GHG emissions from 1990 for same per capita emissions - the UK should go beyond the global average	72% - 93%	85% - 104%

Source: Committee on Climate Change (UK)

THIS TIME IT'S DIFFERENT

Those with long enough memories will remember a number of share price bubbles in clean tech names. The Wilder Hill New Energy Global Innovation index (NEX) shows the last two of these in 2000 and 2007 and we are now seeing share prices on the move again.

Wilder Hill New Energy Global Innovation Index

Source: Bloomberg

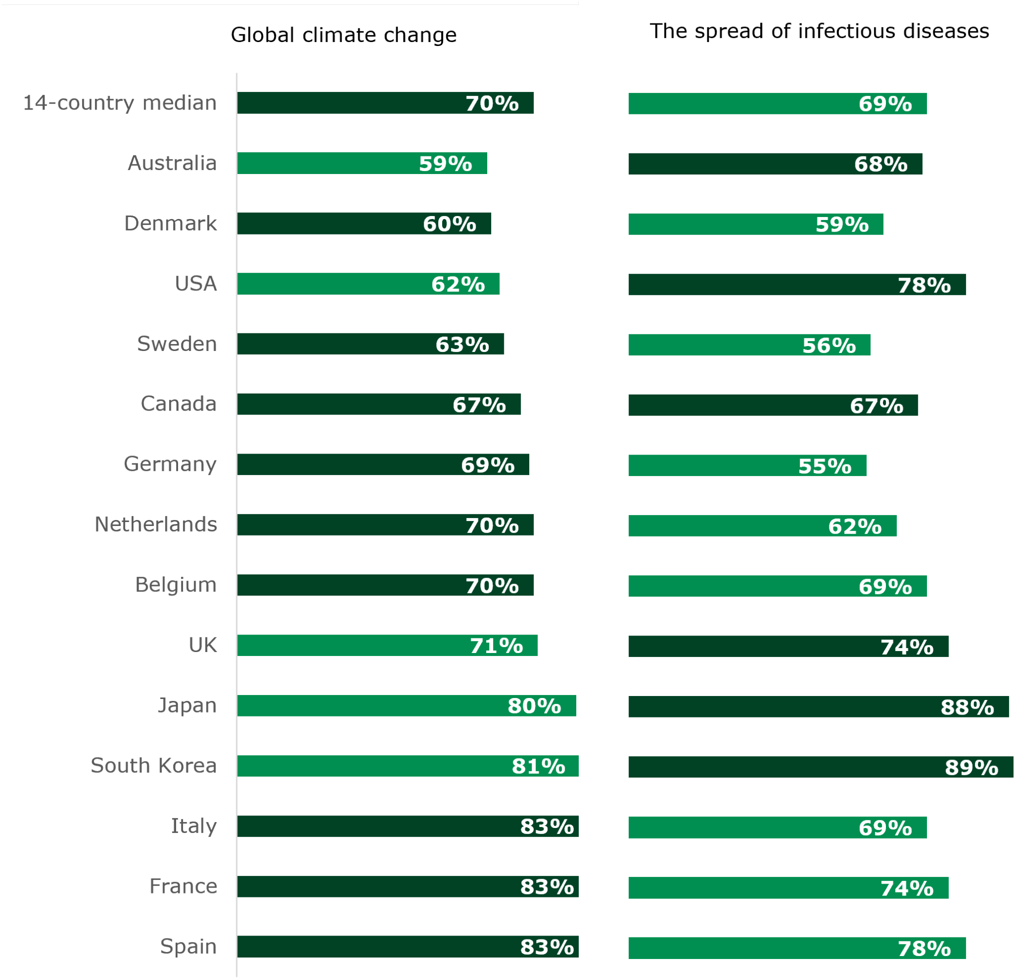
The 2000 bubble was largely part of the wider technology boom of the time and suffered along with other tech stocks when the market recognised that valuations had been stretched. There then followed another growth period driven in part by optimism that the new Obama presidency in the USA would strongly support cleantech. While some policies did help, the administration's other priority, healthcare reform, meant progress was slow with the Waxman-Markey Bill failing and the industry was not strong enough to mitigate the impact of the financial crisis of 2008. Since then, progress has been slow but recent moves have started to drive another wave of optimism.

WHAT HAS CHANGED

The Paris Agreement heralded significant changes, most notably a country-by-country approach to decarbonisation. This has allowed leading nations to move ahead with quite ambitious legislation. In our view it is this legal approach that makes the current environment more sustainable than previous periods.

Added to this has been a shift in public sentiment towards action. In the middle of the COVID 19 pandemic polling by the Pew Center shows that in eight out of fourteen major economies climate change is seen as a greater threat than the spread of infectious disease.

% who say ____ is a major threat to their country



Source: Pew Research Center Summer 2020 Global Attitudes Survey. Q13a, d.

A MOVE FROM WHAT WE EXPECT TO WHAT WE NEED

We see the new environment as representing a move towards a more normative outlook. The frontispiece of the IPCC's 1.5° report has the following quote from Antoine de Saint Exupéry's 1948 book, Citadelle; "Pour ce qui est de l'avenir, il ne s'agit pas de le prévoir, mais de le rendre possible." (As for the future, your task is not to foresee it, but to enable it.) In other words, policy makers are now attempting to shape the future than ride with it.

The EU occupational pensions directive IORP II in Article 21 requires pension schemes to have a proportionate, effective system of governance in place which includes consideration of environmental, social and governance factors (ESG) in investment decisions. In the UK this has been reflected in the Occupational Pensions Schemes (Governance) (Amendment) Regulations 2018 and this is likely to remain post Brexit. The regulations require that trustees of every pension fund consider ESG in their formal statement of investment principles. This puts pressure on fund managers and in turn drive demand for ESG positive investments.

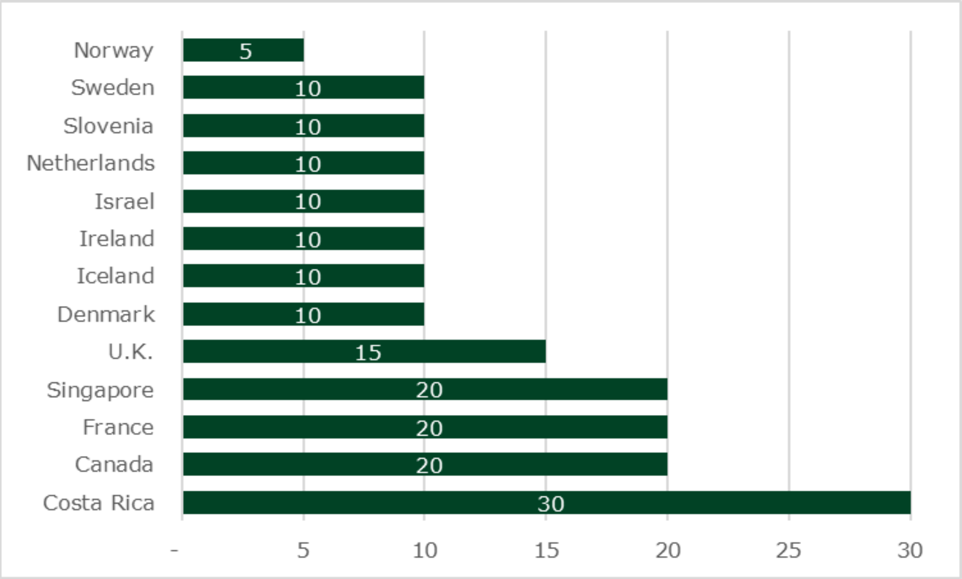
Additionally, we are seeing direct policy support for decarbonisation. In the UK the Climate Change Act 2008 (2050 Target Amendment) Order 2019 and the Climate Change (Emissions Reduction Targets) (Scotland) Bill 2019 have set net zero targets for the UK. In continental Europe, the European Commission Action Plan on Sustainable Finance and the New Green Deal pave the way for member states to adopt net zero targets. France and Germany have already passed net zero laws.

The re-election of Justin Trudeau in Canada saw a policy commitment to net zero and Japan, South Africa and South Korea have made similar moves. Most significantly the world's largest emitter of greenhouse gases, China, now aims to have CO2 emissions peak before 2030 and achieve carbon neutrality before 2060. In total, countries representing almost half of global emissions have made some kind of commitment to a net zero position.

The recent election of Joe Biden in the USA has already seen the US initiate steps to rejoin the Paris agreement. The Biden Plan for a Clean Energy Revolution and Environmental Justice commits the current administration to net zero emission no later than 2050. While Congress is somewhat balanced in both the Senate and the House, Democrats have a majority in both and there should be sufficient bilateral support to ensure that a proper net zero policy can be enacted. This would increase the global commitment to net zero to countries representing over 60% of CO2 emissions.

In addition to policies supporting a net zero outcome, one of the other main policies driving decarbonisation is the phase out of vehicles powered by internal combustion engines (ICEs). Seventeen governments have now set ICE vehicle phase out targets. Even China is researching a timetable for phase out.

Years remaining until ICE phase out



Source: Bloomberg New Energy Finance

Countries with some form of net zero commitment

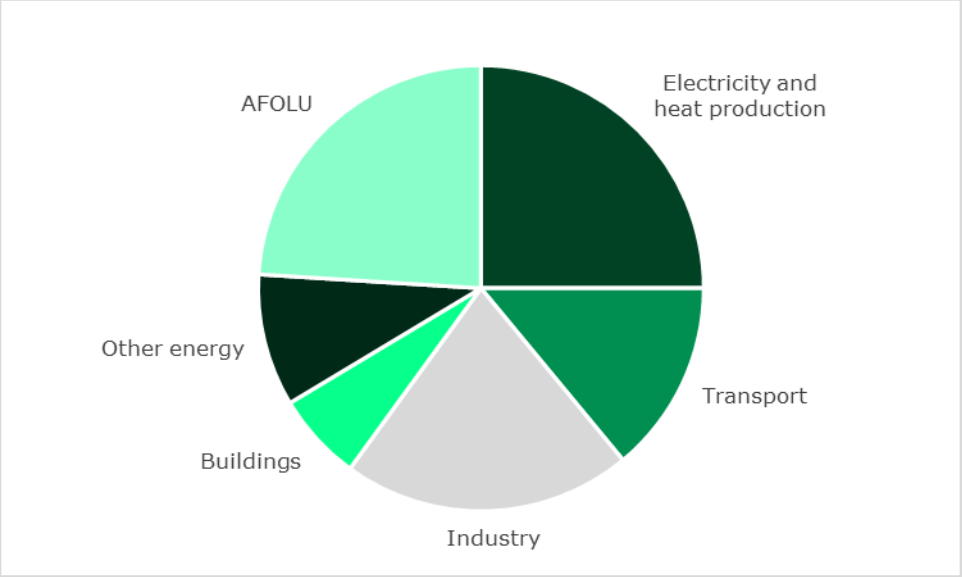
	Target date	Status	CO2 2018	GHG 2015
Austria	2040	Policy position	0.19%	0.18%
Bhutan	Now	Pledged towards Paris Agreement	0.00%	0.00%
California	2045	Executive order	0.93%	0.90%
Canada	2050	Policy position	1.57%	1.59%
Chile	2050	Policy position	0.24%	0.24%
China	2060	Statement of intent	29.71%	26.61%
Costa Rica	2050	Submission to UN	0.02%	0.03%
Denmark	2050	In law	0.09%	0.10%
EU	2050	Submission to UN	9.13%	9.16%
Fiji	2050	Submission to UN	0.00%	0.01%
Finland	2035	Coalition agreement	0.13%	0.16%
France	2050	In law	0.85%	0.92%
Germany	2050	In law to "pursue"	1.99%	1.89%
Hungary	2050	In law	0.14%	0.14%
Iceland	2040	Policy position	0.01%	0.01%
Ireland	2050	Coalition agreement	0.10%	0.13%
Japan	2050	Statement of intent	3.16%	2.77%
Marshall Is.	2050	Pledged towards Paris Agreement	0.00%	0.00%
New Zealand	2050	In law	0.10%	0.17%
Norway	2030/2050	Policy position	0.13%	0.15%
Portugal	2050	Policy position	0.14%	0.14%
Singapore	2nd half of century	Submission to UN	0.15%	0.12%
Slovakia	2050	Policy position	0.10%	0.09%
South Africa	2050	Policy position	1.26%	1.18%
South Korea	2050	Policy position	1.84%	1.43%
Spain	2050	Draft law	0.73%	0.71%
Sweden	2045	In law	0.12%	0.14%
Switzerland	2050	Policy position	0.11%	0.11%
UK	2050	In law	0.98%	1.14%
Uruguay	2030	Contribution towards Paris Agreement	0.02%	0.08%
Total (EU net)			48.38%	44.56%
USA	2050	Policy of incoming administration	13.92%	13.12%
New total			61.37%	56.78%

Source: Longspur Research

ACHIEVING GLOBAL NET ZERO

If we look at where emissions are generated, we can see that roughly a quarter are from electricity and heating, a quarter from agriculture, forestry, and other land use (AFOLU), a fifth from industry, a seventh from transport and the rest from other industry and buildings.

Global GHG emissions by sector (2015)



Source: IPCC

If we are to hit the 1.5 degree target then all of these emissions have to either be eliminated or offset. This is an enormous task, but we believe that there are solutions either currently available or very close to being available to meet these needs.

WHERE EMISSION REDUCTIONS CAN COME FROM

We have taken the IPCC 1.5 degree report as our basis for analysis. This assessed over 6,000 recent academic papers including 90 mitigation pathways, developed with integrated assessment models, and consistent with delivering a 1.5 degree temperature rise by 2050.

The more recent World Energy Outlook 2020 from the International Energy Agency (IEA) also undertakes a comprehensive energy scenario based on hitting net zero emissions by 2050. There are some key differences between the two with the IEA broadly assuming more energy demand growth and, at least to 2030, more renewables and less nuclear, fossil fuel or CCS. Overall, we see the IPCC median outcome as possibly a harsher reality and as such a better base to build our assumptions from.

IPCC and WEO near term assumptions compared

	IPCC 1.5	IEA WEO 2020
Population and economic growth	Less	More
Primary energy demand	Less	More
Nuclear power growth	More	Less
Share of renewables	Less	More
Fossil fuel use	More	Less
CCUS and BECCS	More	Less

Source: IPCC Special Report; Global Warming of 1.5°C, IEA World Energy Outlook 2020

These 90 pathways in the IPCC report include 53 model pathways with no or limited temperature overshoot and 37 scenarios that have a higher overshoot. A low overshoot where the target is initially missed (the overshoot) but brought back in line over time. The scenarios for higher overshoots essentially require more carbon removal solutions such as BECCS to be adopted.

We have used the median low overshoot data as we see this as more useful in identifying active net zero investment opportunities and representing the likely thrust of policy and rewards over the next ten years. If it becomes apparent that we are heading for a high overshoot, we do not see policy changing other than creating additional incentives for carbon removal.

The median energy breakdown for these scenarios across the key energy sectors is shown in table 2.6 of the IPCC report.

Median primary energy supply for <1.5°C and low-OS pathways

EJ	2020	2030	2050
Total primary energy	565.33	464.5	553.23
Renewables	87.14	146.96	291.33
Biomass	60.41	77.07	152.30
Non biomass	26.35	62.58	146.23
Wind and PV	10.93	40.14	121.82
Nuclear	10.91	16.26	24.51
Fossil	462.95	31.36	183.79
Coal	136.89	44.03	24.15
Gas	132.95	112.51	76.03
Oil	197.26	156.16	69.94

Source: IPCC Special Report; Global Warming of 1.5°C

These figures show where energy is delivered in the median scenario. This gives us a good feel for where the likely outcomes are seen in the IPCC's work. We make a number of adjustments to outcomes where we think certain technologies are more likely to be deployed than those suggested by the IPCC.

Table 2.7 gives additional data on electricity supply and we have used this to provide additional granularity to our analysis.

Median primary electricity supply for <1.5°C and low-OS pathways

EJ	2020	2030	2050
Total generation	98.45	115.82	215.58
Renewables	26.28	63.30	145.50
Biomass	2.02	4.29	20.35
Non biomass	24.21	57.12	135.04
Wind and PV	1.66	8.91	39.04
Nuclear	10.84	15.46	21.97
Fossil	59.43	36.51	14.81
Coal	31.02	8.83	1.38
Gas	24.07	22.50	12.79
Oil	2.48	1.89	0.10

Source: IPCC Special Report; Global Warming of 1.5°C

We have used the information in these table to derive assumptions for the split of low carbon energy solutions required by 2050. We can break down the energy solutions as follows:

- Nuclear
- Bioenergy including biomass, waste to energy, biofuels and BECCS
- Renewables and energy storage
- Renewables and green hydrogen
- Blue hydrogen
- Efficiency
- CCS
- Land use change

Nuclear

We have assumed that nuclear is as per the IPCC median scenarios which is roughly in line with a small expansion of current capacity. We see relatively inflexible nuclear as creating issues for increasingly volatile electricity systems, but we also see solutions here, principally hydrogen electrolysis to capture electricity that might otherwise be curtailed.

Bioenergy

The IPCC scenarios assume a major role for biomass and biofuels. In part this is based on the difficulties in decarbonising longer range and heavier duty transport, but the IPCC assumes even cars and LDVs have a biofuel component. Battery electric vehicles remain the key solution for LDVs and hydrogen a more likely solution for HDVs and other long-distance travel. While the energy for BEVs is accounted for as renewable energy, the biofuel assumption in the IPCC report should be weighted towards hydrogen in our view. The IPCC breaks down transport assumptions in table 2.8 of its report.

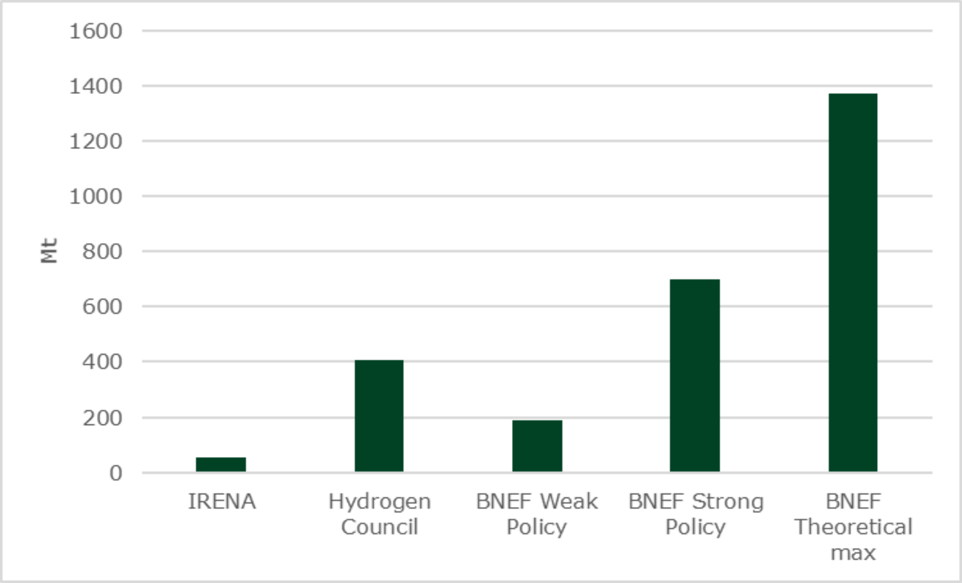
Transport Emissions and Solutions

	Share of each mode (%)			Reduction from 2014 (%)	
	Energy	Biofuel	CO2	Energy	CO2
LDV	36	17	30	51	81
HDV	33	35	36	8	56
Rail	6	0	-1	-136	107
Aviation	12	28	14	14	56
Shipping	17	21	21	26	29

Source: IPCC

Because the biofuel component and energy components are not equal, we have reallocated some of the biofuel to hydrogen in the mix. We have assumed that the biofuel content for non-LDV transport is supplied by hydrogen rather than biofuel. This suggests total hydrogen fuelled energy equal to 110EJ. Checking against other forecasts in the market with the Hydrogen Council at 78EJ and BNEF at 99EJ, this seems reasonable for a full net zero solution. As we shall show later in this note, hydrogen is also a strong solution for inertia and balancing nuclear we think our higher end forecast is valid.

Hydrogen demand in 2050



Source: IRENA, Hydrogen Council, BNEF

Waste to energy

A major component of biomass generation may be in the form of waste to energy which can typically have a biogenic content of 50%. As this also achieves a solution to the other major sustainability problem of plastic waste, we see this as being a major component of bio energy. It is also a potential source of negative emissions if combined with CCS.

Bioenergy with Carbon Capture and Storage (BECCS)

This is the major solution to negative emissions and in high overshoot scenarios is likely to play a major role. Even in low overshoot scenarios it is significant. We have assumed that all biomass electricity generation identified in table 2.7 will be BECCS. This is a low estimate with the 20EJ of energy on which it is based within the range of what can be achieved with sustainably available forestry. In fact, this represents a point of high agreement in the academic literature on what is sustainably available. As stated above we also assume that this category includes waste to energy with CCS.

Renewables for power and heat (with storage)

We have assumed all the non-biomass renewables presented by the IPCC scenarios. With mainstream wind and solar technologies now the cheapest forms of power generation in most geographies, we think this is a reasonable assumption. This is the key solution for power and heat but also a major component in transport as the charging source for BEVs. As we will describe, we see a number of problems with intermittent renewable energy. We see storage, both short and long duration, as largely overcoming these problems and creating substantial demand for stationary energy storage systems (ESSs). Renewables and storage are also the combined solution behind BEVs with the storage in the vehicle itself. As a result, we combine renewables and storage as a single solution.

Renewables for transport and industry using hydrogen

Hydrogen production from the electrolysis of water using renewable electricity further increases demand for renewables. Above all we see this as driving demand for renewables beyond current expectations. We have split out this “green hydrogen” as a separate solution based on our hydrogen assumptions above. Blue hydrogen using steam methane or autothermal reforming and combined with CCS is another route to creating low carbon hydrogen although there is much debate here. We have used the Hydrogen Councils broad 60/40 split between green and blue and separated out a blue hydrogen solution.

Efficiency

The IPCC figures show a reduction in primary energy demand between 2020 and 2050 which must be delivered by efficiency. However, to estimate the scale of for efficiency as a solution, we need to consider what primary energy demand would be under a business-as-usual outcome. We have assumed that the underlying growth in energy demand is based on the increase in electricity generation forecast by the IPCC and then added the reduction in primary energy assumed by the IPCC above. This should give us a reasonable estimate of the contribution to the total from energy efficiency measures.

Land use change and carbon capture and storage

The IPCC assumes a fairly significant 184EJ residual fossil fuel component in the energy mix. This must be balanced off by either carbon capture and storage or land use change.

We assume most large-scale biomass combustion plants will adopt CCS post capture technology (or possibly oxy combustion in some cases). We also assume that aviation biofuel will be produced using CCS technologies (we think HDFC based biofuels will not find enough feedstock for this purpose). These are included in our BECCS and biofuels solutions but as they are negative emission solutions we also include the CCS element as a separate solution. Blue hydrogen uses CCS to reduce its emissions burden, so we do not separate it.

This gives a CCS figure of 41EJ. We deduct this from the fossil fuel residual and assume that the gap is covered by land use change. This suggests that land use change accounts for 22% of emission reductions. The IPCC's work on land use change gives quite a range for emission reductions with a maximum of 40%. Against this, 22% seems reasonable.

The final outcome is as follows.

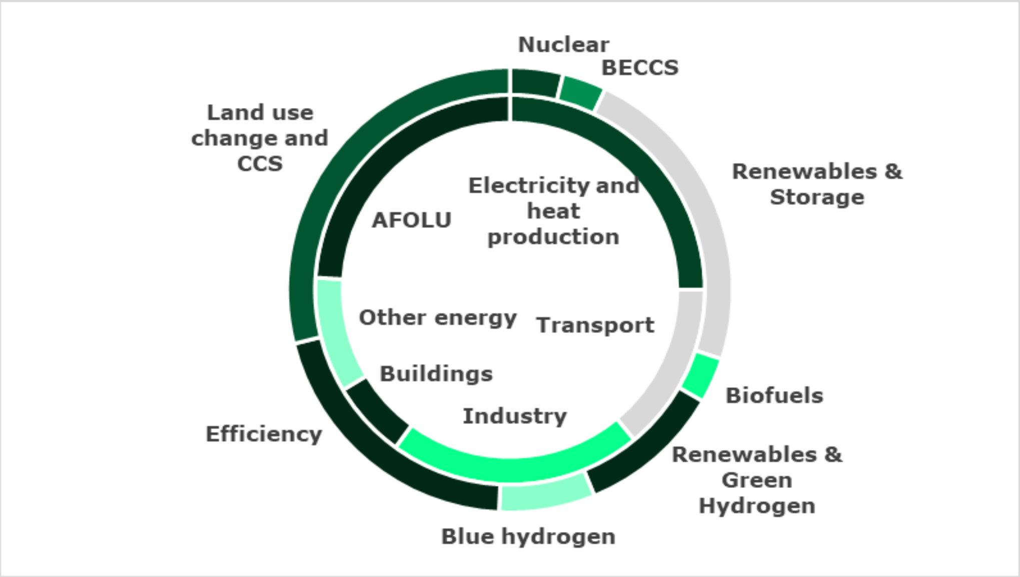
A net zero energy mix

	EJ	TWh	%
Nuclear	25	6,808	4%
BECCS	20	5,653	3%
Renewables & Storage	146	40,619	23%
Biofuels	21	5,864	3%
Renewables & Hydrogen	67	18,473	10%
Blue Hydrogen	44	12,315	7%
Efficiency	129	35,897	20%
CCS	41	11,517	7%
Land use change	142	39,536	22%
Total	636	176,683	100%

Source: Longspur Research

We can show this against the relative emission sources which helps to show which solution fits which source.

Global Emissions and Solutions



Source: IPCC, Longspur Research

HOW MUCH CAPACITY DOES THIS ENTAIL?

Each solution is different, but we can make an estimate of the capacity is required for each one. In some cases, the solution can be quantified in terms of the energy in EJ or TWh. Most require a calculation to determine the amount of capacity required to deliver this energy.

Renewables will depend on the load factor of the technology. Generation is not always available to meet demand and there can be curtailment of excess energy. If curtailed energy can be stored, this problem is partly overcome increasing utilisation. We use an overall 30% utilisation factor for renewables being used to replace fossil fuelled electricity and heating demand. This is well ahead of the 23% implied in BNEF forecasts and reflects a mix of low PV and higher wind including offshore. This gives 22.5TW of capacity. This is higher than forecasts from IRENA at 18.4TW and BNEF at 20.3TW.

For energy storage systems we have assumed that 50% of renewable capacity used for heating and electricity is matched by a minimum of 1 hour and 20 minutes of storage based on an hour of trading and 20 minutes of response services. Later on in this note we show that up to 50% of capacity could be economically matched with storage. This represents capacity of 10.3TWh. This is 14% ahead of IRENA's forecast 9TWh and broadly confirms the figure given by Tesla at their Battery Day 2020. Nuclear utilisation is simply assumed at 90% in line with its baseload characteristics to give 864GW of capacity.

Storage for EV requires assumptions to be made about the number of EVs on the road that will utilise this energy. We have assumed 23.3 cycles per annum based on a typical EV range of 300km, average annual milage of 8,761km and a seven-year average vehicle life. This gives us a battery demand of 32.2TWh. We think average battery sizes will reduce and using a battery size of 50kWh battery this gives us a BEV fleet estimate of 1,090m units. This compares with an IRENA estimate of 1,109m units. The current passenger car global fleet is at 1.4bn.

Green hydrogen production is based on an electrolyser efficiency of 50kWh/kg and a 54% utilisation factor. This gives a capacity figure of 5.0TW of electrolyser capacity well ahead of the 1.7TW forecast from IRENA. BECCS is based on a utilisation figure of 80% to get a capacity of 807GW. Finally, non-BECCS CCS and efficiency are just taken at their energy levels of 32.0TWh and 35.9TWh respectively.

The outcomes are shown below against estimates from Bloomberg New Energy Finance (BNEF) and the International Renewable Energy Agency (IRENA). This suggests our estimates are at the top end of, or slightly above, current expectations.

Implied 2050 capacity for global net zero

	Longspur	BNEF	IRENA
Renewable Energy (GW)	22,486	20,301	18,377
Storage EV (BEVs, m units)	1,090	414	1,109
Storage ESS (GWh)	10,304	5,827	9,000
Hydrogen production (Mt)	781	697	240
Green hydrogen (GW)	4,957		1,700
BECCS (GW)	807		
Nuclear (GW)	864		
Biofuels (TWh)	5,864		
Efficiency (TWh)	35,897		
Land use change (TWh)	39,536		

Source: Longspur Research, BNEF, IRENA

HOW MUCH WILL THIS COST?

The cost of these pathways has been set out in the IPCC report in figure 2.27 and shows an average annual investment expenditure of US$3.1tr per annum to reach a net zero outcome over the period 2016-2050. However, this needs to be compared against existing energy expenditure. The exploitation of fossil fuels requires continued exploration and development, which will include items such as the sunk cost of dry wells. The IPCC report puts a baseline expenditure at US$2.3tr so the net incremental expenditure to reach net zero is US$0.8tr per annum.

This is pretty much the same figure identified by IRENA, in their paper *Global Energy Transformation: A Roadmap to 2050*, who see an additional investment requirement of US$27tr between 2015 and 2050 which also gives US$0.8tr per annum.

However, these estimates only consider investment. Against this it should be remembered that opex for new energy solutions is broadly lower than for the fossil fuel-based baseline as there are no fuel costs for renewable energy. In fact, a key issue with the energy transition is that we are moving towards solutions which are capital heavy but opex light. Ongoing production costs for renewable energy, green hydrogen and energy efficiency are all extremely low when compared with the fossil fuel alternatives. With no fuel to purchase, opex is limited to O&M costs and ground rent.

Using the global consumption figures in the BP statistical review for oil, gas and coal, together with current spot commodity prices we estimate a total fuel cost under a business-as-usual scenario as US$2.8tr. These costs will not all be removed in a net zero world as there will still be an element of fossil fuel production under the IPCC median outcomes. Taking the proportional energy derived from these sources, the fuel opex cost drops to US$1.0tr.

Incremental investment and opex to reach net zero

US$tr	Baseline	1.5 degrees	Incremental
Investment	2.3	3.1	0.8
Fuel opex	2.8	1.0	-1.8
Other opex (est. for equivalence)	n.a.	1.0	1.0
Total	5.1	5.1	0.0

Source: Longspur Research, IPCC, BP Statistical Review of World Energy 2020, Bloomberg

Taken against the incremental investment expenditure required to hit net zero of US$0.8tr this means our renewable and other solutions would need to spend $1tr on O&M for a net zero solution to cost more than the baseline case. With typical O&M costs for wind being 3% of capex and 1% for PV this figure at 30% of the total investment figure seems unlikely, suggesting that a net zero solution could actually be cheaper than the baseline, even before the consideration of the negative costs of climate change.

While this seems all positive for low carbon solutions, the near zero marginal cost characteristics of these technologies creates problems for market structure which we will discuss later in this note.

DEMAND IS IMMENSE

From our analysis it can be seen that renewable electricity is going to become the main source fuel for LDVs, domestic heating and industry in addition to all the areas we already use electricity for. To hit net zero, all current electricity demand needs to be low carbon, but additional demand is created by the need to charge EVs and to generate hydrogen for long haul transport and industry. As a result, we believe that most current forecasts of demand for renewable capacity are understated if we are to achieve 1.5 degrees.

We also think that much renewable capacity will need to be complemented by storage. While lithium ion can provide much of this, it becomes less efficient where longer storage durations are required and we see a major role for other technologies including pumped hydro, hydrogen storage, flow batteries, compressed air and gravity systems.

Hydrogen becomes a key solution for longer distance and heavy-duty travel and also for a number of key industrial solutions. Beyond this, key opportunities lie in efficiency and in carbon capture and storage.

However, there are a number of challenges notably for renewables and lithium ion based transport.

Issues for renewables

While renewable energy can decarbonise electricity and heat, problems of place, time and price create new problems which require solutions with storage, nuclear, hydrogen and biomass being the main sources.

Issues for storage

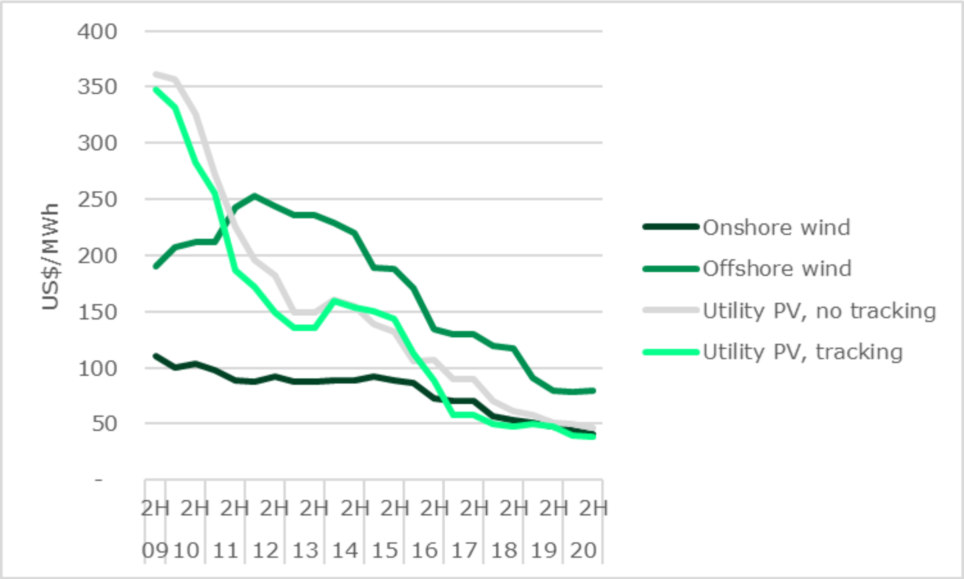
EVs are a solution for much of transport, but problems of range, infrastructure and supply chain mean that other solutions are needed to reach net zero, notably hydrogen for longer range applications.

ISSUES FOR RENEWABLES

The energy required for electricity and to an extent heating can be provided by renewable energy. Nuclear, hydrogen and biomass, especially with carbon capture and storage also have a role here as we shall explain.

Renewables are already the go to solution with levelized costs now below fossil fuel generation in many geographies. Costs for both wind and PV have dropped dramatically over the past ten years. As a result, renewables are now often the cheapest form of power generation, a fact noted by the IEA in their recent Renewables 2020 report.

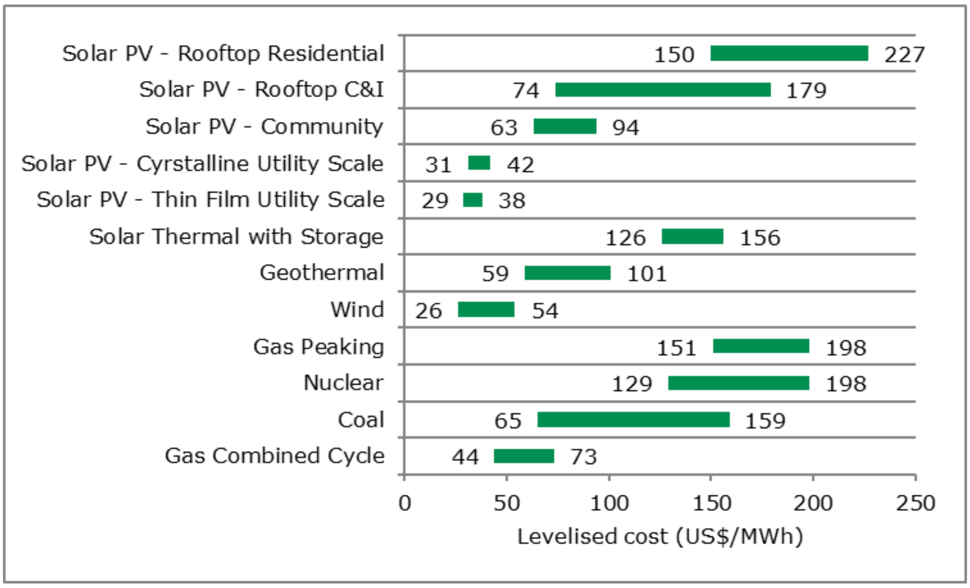
Levelised costs of energy (2019 real)



Source: BNEF

Renewables are the go-to solution but they do face number of challenges. There are major changes in the location of supply and demand as renewables replace large scale fossil fuel power plants and also as EV charging creates new sources of demand. We also note market structure issues which impact the pricing of renewables. Finally, there are major timing issues created by intermittent supply and also at a micro scale from the inability of most renewables to provide system inertia. Put simply they suffer from being in the wrong place, at the wrong price and at the wrong time.

Levelised costs of energy (unsubsidised)

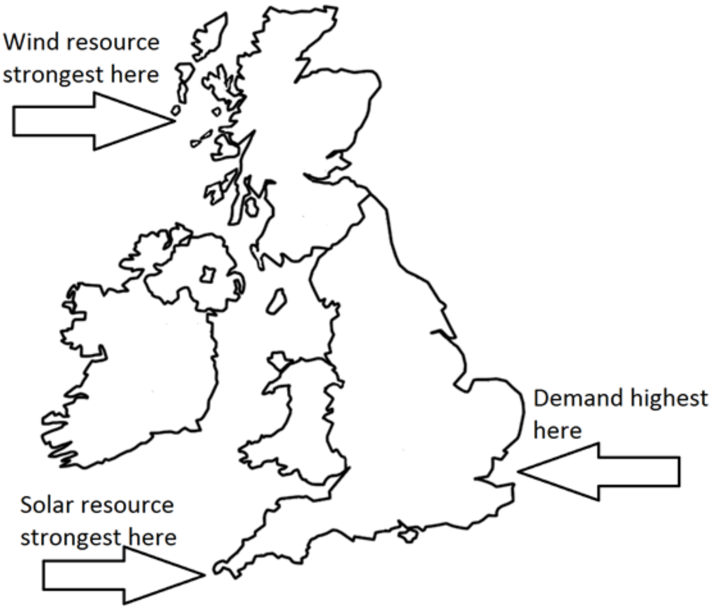


Source: Lazard

LOCATIONAL CONSIDERATIONS

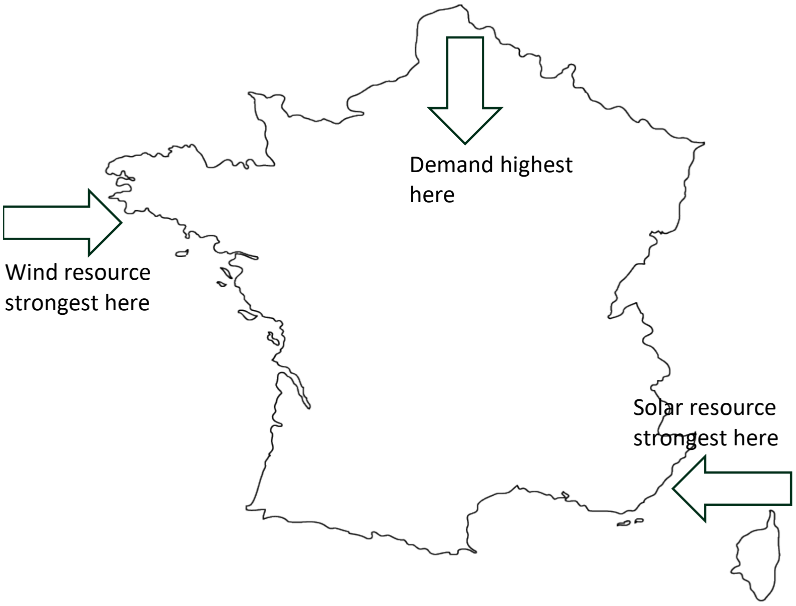
Because much of the growth in renewables is being driven by socket parity, it is by necessity decentralised generation, sited at the extremes of the power grid rather than the centre. In many countries including the UK the strongest renewable resources have been at the extreme ends of the grid (sun in Cornwall, wind in Scotland and Wales). Most power grids have been designed for centralised generation. These grids are now being disrupted by the growth in distributed and remote generation and are finding increased demand for related reinforcement of transmission and distribution capacity.

Simple View of UK Renewable Resources and Demand



Source: Longspur Research

Simple View of French Renewable Resources and Demand



Source: Longspur Research

This problem has an obvious solution in the form of additional expenditure on transmission and distribution grids. This creates opportunities for grid and distribution companies, although most of these companies are fully regulated and returns may be limited.

More efficient solutions such as smart grids including smart metering also help to solve these locational issues and there are major investment opportunities in this area.

The additional needs of EV charging in creating a mobile demand load with additional prediction issues creates further problems. Again, this creates opportunities for solutions including smart charging and vehicle to grid.

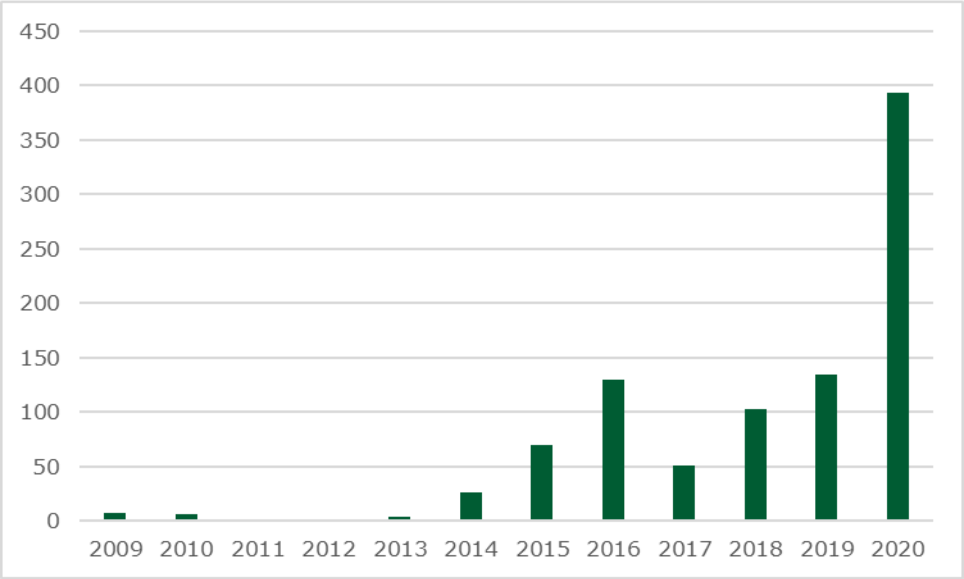
EFFICIENCY AS A LOCATIONAL SOLUTION

While efficiency can be simply driven by non-locational issues a lot is very site specific and can include a changing interaction with the grid. On site efficiency can often include solutions which relate to local grid connections and can include the ability to provide demand side response as a service back to the grid.

STORAGE SOLVES MARKET STRUCTURE ISSUES

Liberalised electricity markets normally work on some kind of bidding arrangements where marginal costs are a key determinant of who will win bids. Most renewable energy technologies are characterised by high capital costs but low operating costs. This is the benefit of not requiring any fuel so that the only significant cash cost item is maintenance costs. As a result, marginal cost per unit can be very low compared with other generation technologies. This is often compounded by support policies. Where there is a feed-in-tariff or green certificate scheme, these can be seen as negative costs that effectively put the marginal cost into negative territory. In other words, renewable generators will be prepared to bid a negative price in order to receive at least some of their policy support. This has resulted in negative pricing events in some markets, and this is likely to grow with renewable penetration.

UK Balancing Market Negative Pricing Events



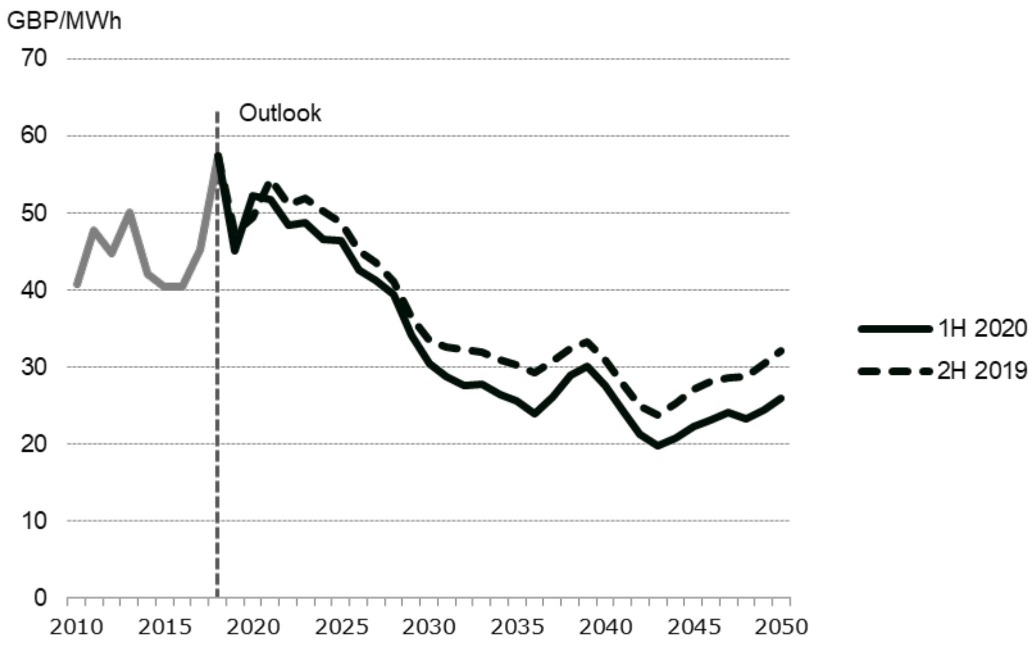
Source: Elexon

When enough low marginal cost assets are present in a market, low or negative prices result in uneconomic returns (missing money) for generators. As a result, this puts pressure on incumbent generators who suffer from low prices. It is also likely to lead to low investment, exacerbating security of supply issues in the medium and longer terms. Most markets have been designed to reward integrated players on a marginal basis. The changing nature of power markets is resulting in a “missing money” problem. While some attempts are being made to address this through capacity markets, these are not necessarily sufficient to forestall many of the problems.

MISSING MONEY

Bloomberg New Energy Finance has been particularly focused on this issue with its H1 UK energy outlook forecasts showing the phenomenon leading to a lowering of average electricity prices with the wholesale price (time weighted annual average) dropping from £57/MWh in 2018 to £30/MWh in 2030 and then to £20/MWh by 2043 before recovering slightly to £27/MWh in 2050.

BNEF H1 UK Power Market Outlook Power Price Forecast

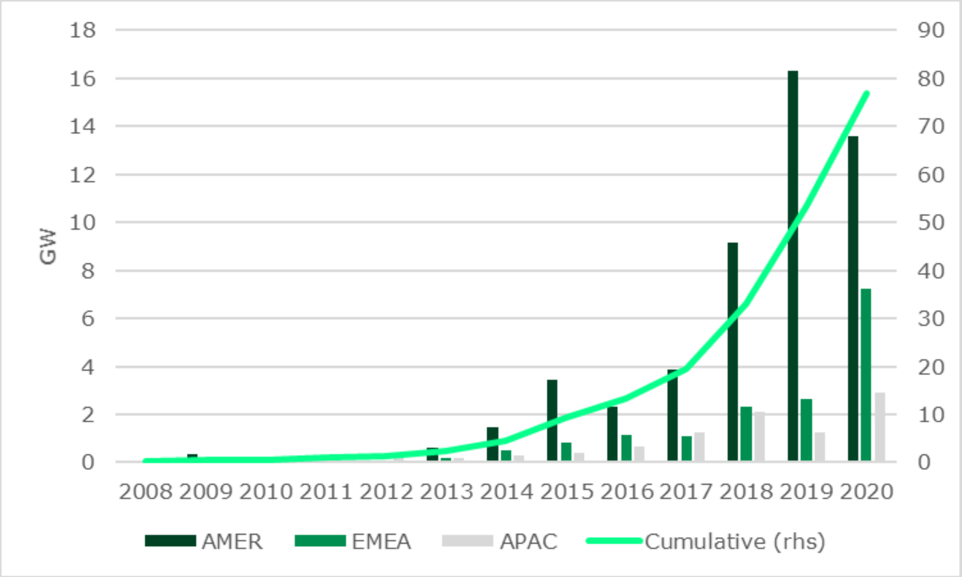


Source: BNEF

Aurora Consulting has countered this argument by suggesting that new investment in intermittent generation will cease if the returns are too low. This is a valid point except that participants have a better option than simply not to build new capacity.

A better market solution is for renewable generators to insulate themselves from the problem by either investing in storage or by integrating downstream with retail businesses. These moves can be done physically or virtually through contract structures. In many ways the surge in private PPAs reflects a contractual insulation from downstream integration.

Global corporate PPA volumes



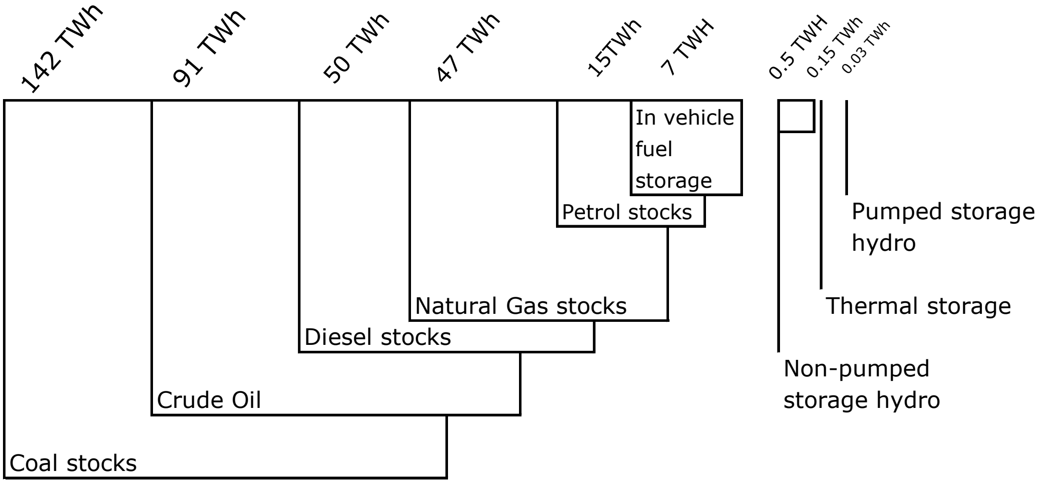
Source: BNEF

However, most contracts are of fixed duration and we see integration with storage as a more reliable and logical response to what are actual market needs. In many ways this reflects the physical picture where it can just as readily be seen that storage is needed to make renewables work.

STORAGE AS A SOLUTION TO MISSING MONEY

In the past, chemical energy storage was always a major part of the energy mix, representing 76% of UK capacity in 1999. This was energy storage chemically contained in the coal stocks and gasometers and line stack of natural gas. However, the coal is all going, and it is likely that gas will follow if we are to hit net zero emissions. If we look at the total energy market, a move to net zero will entail the loss of 352TWh of mainly chemical energy storage in the UK market alone.

Energy Storage in the UK, 2015

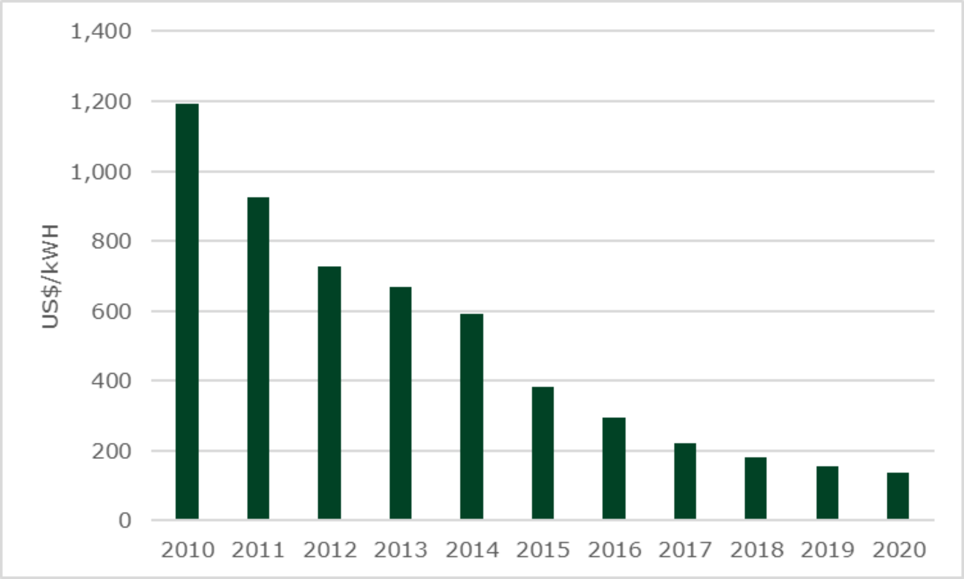


Source: Simon Gill, University of Strathclyde, 2015

The lithium-ion revolution

As a result of dramatically reducing costs, lithium ion has emerged as a solution to at least some of these storage needs.

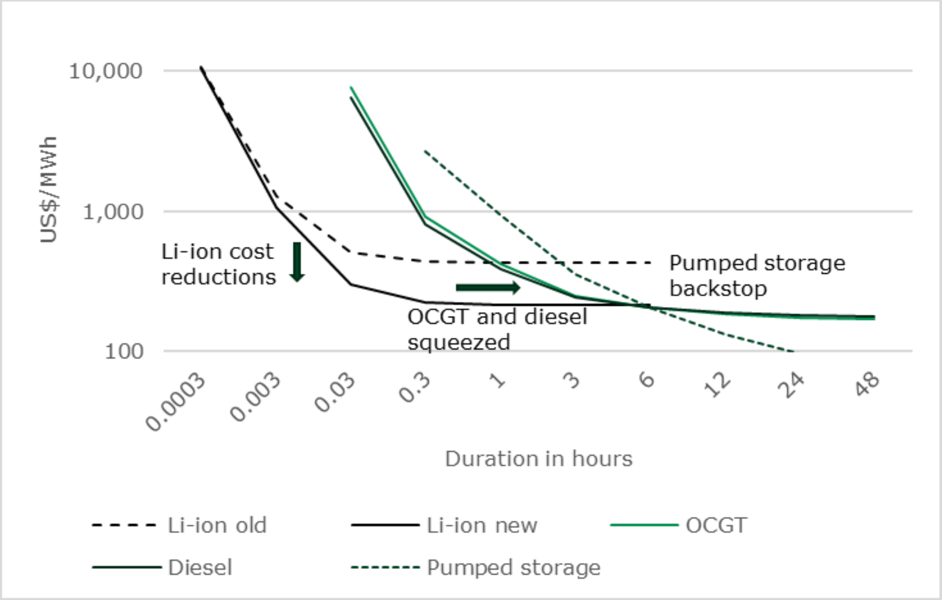
Lithium ion battery pack prices



Source: BNEF

Lithium ion has been the big story in energy storage, but storage is not a single market. To date, storage in the UK electricity market has been dominated by pumped hydro. However, lithium ion is now cheaper than pumped storage provided the storage duration is not too great. Essentially lithium ion has emerged as an economic solution at shorter durations of up to four hours and, if anything, is displacing open cycle gas turbines and gas or diesel reciprocating engines. But it is not scalable with duration and beyond about 4 hours current lithium-ion technology is uneconomic compared with pumped storage and newer technologies such as flow batteries, compressed air storage and liquified air storage.

Levelised cost of storage against duration



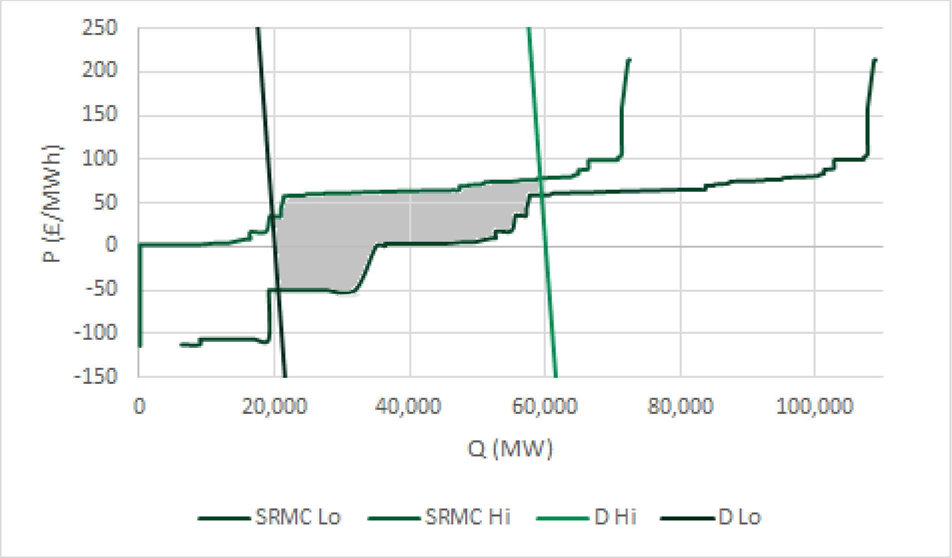
Source: Longspur Research

THE WHOLESALE MARKET OPPORTUNITY FOR STORAGE

Taking the UK (GB) wholesale electricity market as an example we can show supply and demand for this market in a traditional supply and demand graph. Because of the instantaneous nature of the market with demand changing every 20 ms (in a 50Hz system) we really need to show two demand curves, one with the peak demand in the year and one with the minimum demand. Also, because intermittent renewable supply varies, we think it helpful to show the limit points in two supply curves, one with all renewable capacity available and one with no renewable capacity available.

Prices across the year should all fall in the shaded area between the curves.

GB electricity market supply and demand



Source: Longspur Research, BNEF, National Grid FES

The average price for the year will be roughly in the middle of this area. It can be estimated using assumptions of average demand and supply. Full forecasts are available using Monte Carlo simulation techniques to capture the variation in demand and weather-related supply to pinpoint the exact point in the middle of this area. However, this is data and calculation heavy with one consultant reporting a ten-hour run time to prepare a forecast.

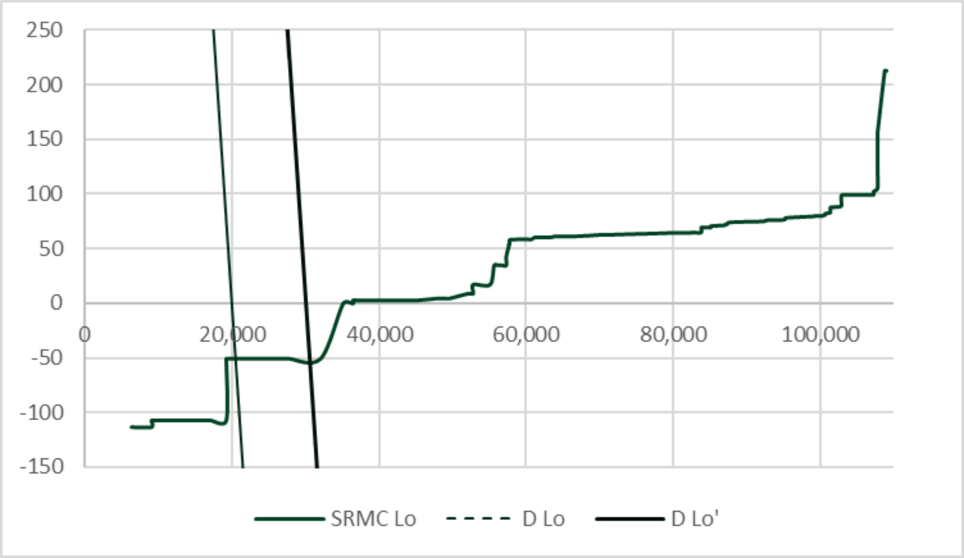
The low supply curve includes renewables with negative short run marginal costs. This is a result of subsidy programmes. The generators only get the subsidy when they run so should be prepared to bid negatively down to the level of subsidy. This may be rare but does happen and is on the increase as more renewables are added to the system.

Adding storage

Storage is both a source of demand and supply. When storage charges it is demand and when it discharges it is supply. Charging will ideally take place when supply is at a maximum and demand at a minimum. With negative pricing, batteries could be paid to charge, although in practice we think the actual low charging point will be zero.

Discharging will try to take place when demand is at a maximum and supply at a minimum. While storage will also sell services to the ancillary markets and the capacity market, it can make money from trading the difference between the high demand/low supply periods and the low demand/high supply periods. If we add storage capacity two things happen. The capacity moves the low period demand curve to the right to represent the additional demand caused by charging.

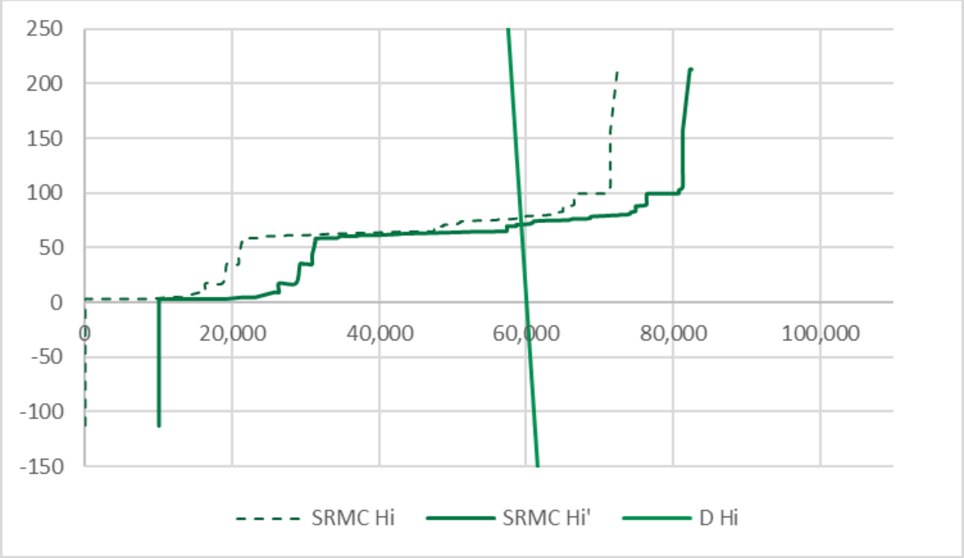
Impact of 10GW of storage charging



Source: Longspur Research

Then the high period supply curve is moved to the right (new supply is added), representing discharging.

Impact of 10GW of storage discharging



Source: Longspur Research

Looking at these graphs we can see that we can add over 30GW of new storage before the charging cost rises materially above zero and before the discharge price falls below £50/MWh. We would caution that this is the extreme range available, but it does give a useful illustration of the fact that trading spreads can remain attractive even with a lot of new storage capacity in the market.

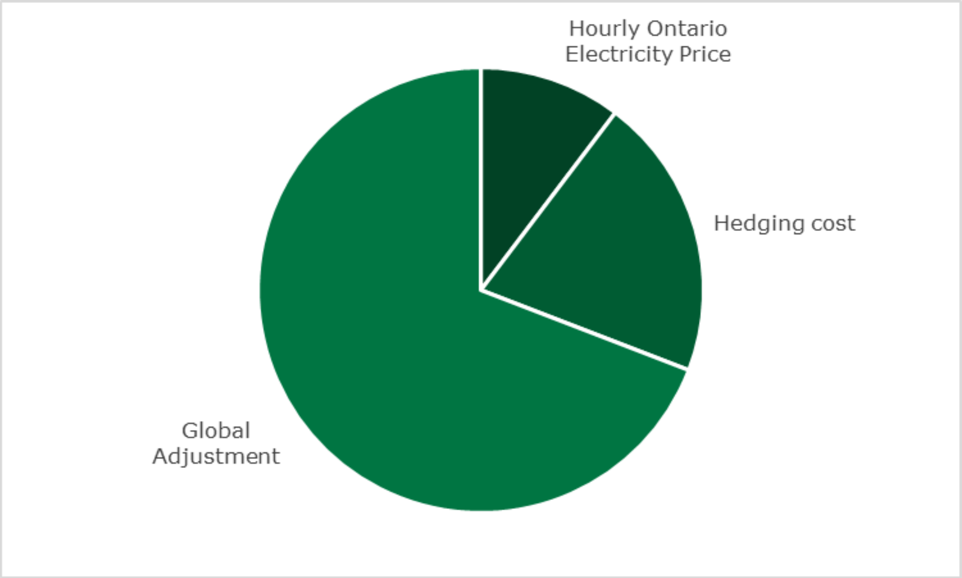
30GW represents c.50% of the peak demand in the market. This is a significant opportunity and if this opportunity presents itself in other similar markets, we are underestimating the opportunity for stationary energy storage systems.

POLICY SOLUTIONS TO MARKET STRUCTURE ISSUES

The missing money problem is really a problem of market structure. Most markets are established and regulated on the assumption that there is demand for electricity. In fact, there is very little demand for electricity, most demand is for *reliable* electricity. If we ignore this, we end up with sub optimal solutions of which missing money is one.

One risk area around market structure is that, if renewable energy providers are unable to address the missing money issue by contracting or using storage, new entry may dry up before the demands of a net zero solution can be met. This may push policy makers to adopt more regulated market solutions. We are a little concerned by the experience in Ontario where almost 70% of the wholesale market is now effectively regulated through the Global Adjustment (GA) surcharge which has led to reduced competition and distorted price signals. This has led to high prices for consumers with retail prices increasing 71% between 2008 and 2016 and consumers now paying an average of 22% more than other Canadians. We see this as a danger signal that policy moves to support renewables can go wrong, with renewable developers likely to be most affected.

Ontario electricity commodity price breakdown

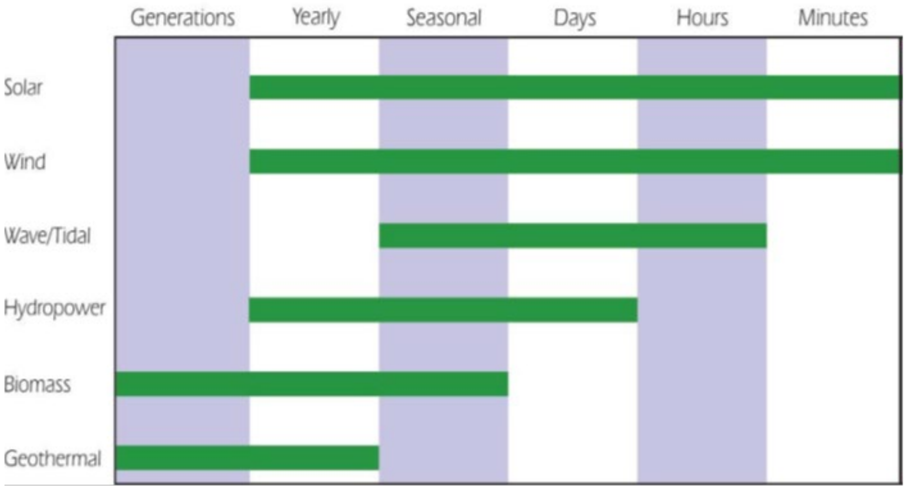


Source: LAS

AN ISSUE OF TIMING

Wind generation only generates power when the wind blows, and the wind does not blow all the time (except possibly in Shetland). Solar obviously does not generate power at night but also sees output vary with cloud cover. These variations in output are referred to as intermittency. The problem of intermittency is exacerbated by difficulties in predicting the timing of that intermittency. While there are now better forecasting techniques available, they do not remove all of the uncertainty in output from these types of generation. This is true of both wind where wind speeds can vary continuously and solar where unpredictable cloud cover can reduce output by as much as 90%.

Timing Impact of Intermittency



Source: IEA

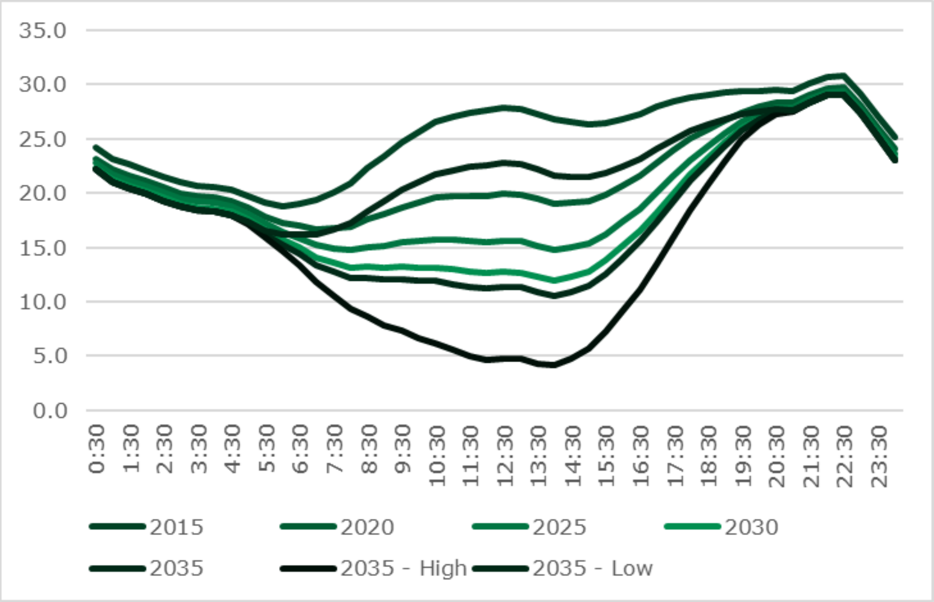
The renewables industry usually counters criticism of intermittency with the proposition that intermittency is reduced or even eliminated by the geographical diversification that comes with large portfolios of projects at different locations. However, the most recent academic work suggests that this effect is overplayed and that grid scale fluctuations in output are correlated between projects.

Even if output is assumed to be completely predictable, the timing of solar in particular can create significant problems for girds.

The Duck Curve

One impact of increased renewable energy capacity and in particular solar is the creation of a “Duck Curve” in the daily demand profile. The potential impact of significant solar capacity on demand was first raised by the California Independent System Operator (“CAISO”). California used to see energy demand on the grid rise in the middle of the day and be fairly flat across the afternoon before rising to a peak in the early evening. Solar is recognised as negative demand because of its distributed nature. With considerable solar on the Californian system, demand now begins to fall from 11am as this capacity kicks in. Then in the late afternoon, as the sun wanes and solar starts to come off, demand rises very steeply into the early evening peak. This can be represented on a demand graph showing how demand is expected to behave as even more planned solar capacity is added out to 2020. The shape is said to resemble something that quacks.

Duck Curve



Source: National Grid

The key message of the duck curve is that the grid used to have to deal with a small ramp up in demand in the later afternoon or early evening but now has to deal with a much more marked ramp up. This puts pressure on the system and increases demand for flexible and responsive capacity.

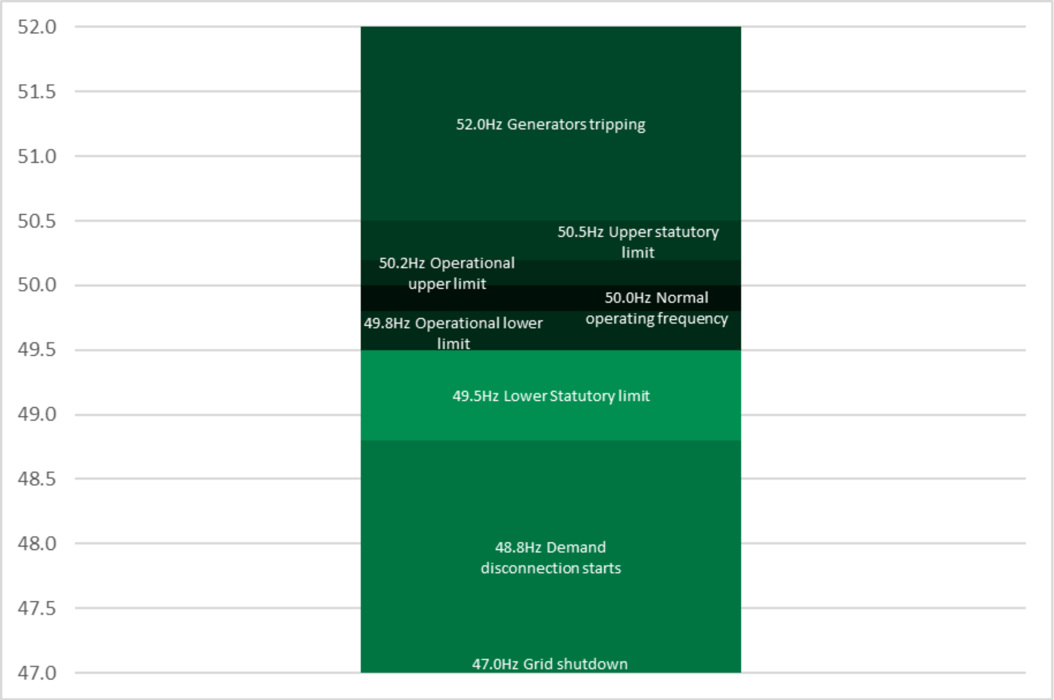
However, the biggest timing issue is at a more micro scale and involves keeping the frequency of the AC current stable.

THE PROBLEM OF INERTIA

Electricity systems need to stay in balance in real time. This balancing is a large part of the job of system operators ("SO's") such as the UK's National Grid ESO. If there is imbalance the system frequency moves away from its nominal level. If it moves too far it will create serious problems for the grid. Major moves away from the nominal frequency will impact the whole grid and can trigger cascading failure resulting in partial or total system blackouts.

In the UK, as in other markets, there is a statutory requirement for National Grid ESO to keep the frequency of the electricity system within a narrowly defined range. The nominal frequency is set at 50Hz and the SO must keep actual frequency to +/- 1% of the 50Hz standard.

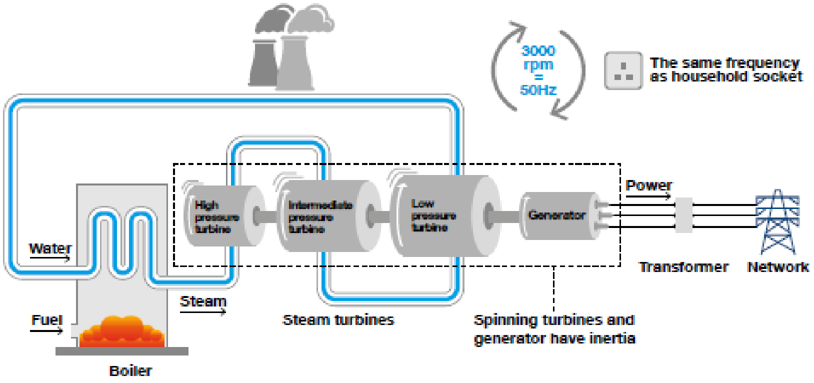
Frequency trigger points



Source: National Grid

ESO will also be fined if frequency moves outside the 1% band. In order to avoid these fines, and to prevent blackouts and system damage, ESO uses a number of services to maintain frequency. Key is the use of synchronised generation. Essentially this is the traditional steam driven generators of the large coal, gas, and nuclear power stations. The inertia represented by their spinning generators damps down any frequency interruptions.

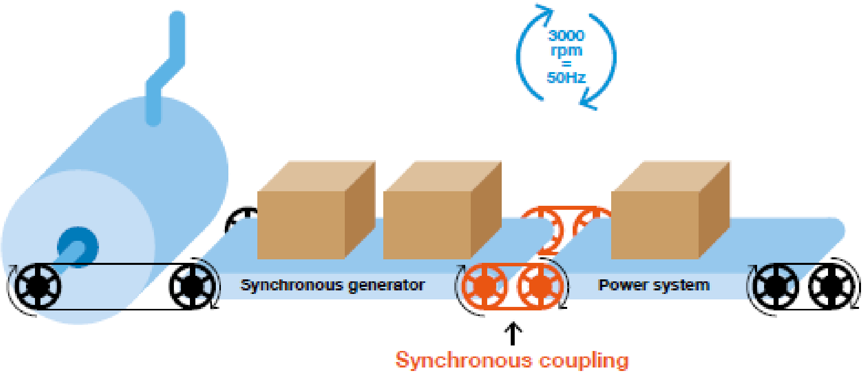
Synchronous Generation Creates Inertia



Source: National Grid

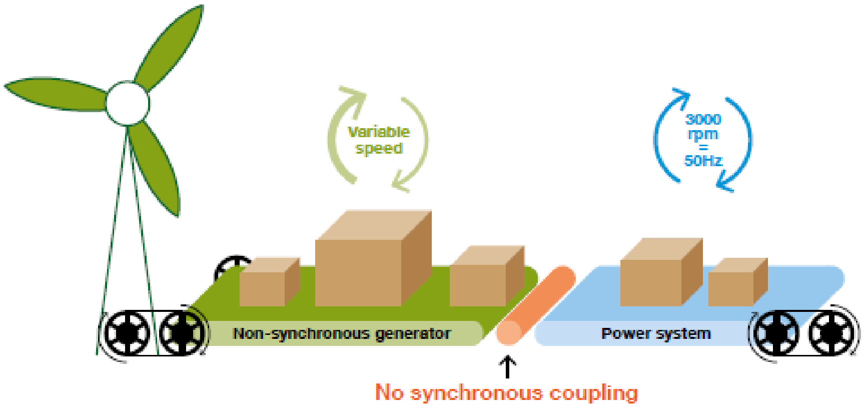
This worked reasonably well when most of the system's generators were synchronous. Unfortunately, the main forms of renewable generation, wind, and solar PV, do not provide inertia to the system. Their generation output varies continuously as wind rises and falls and as cloud cover materialises and disperses. Because renewable generation varies continuously it cannot have a synchronous connection with the grid and so does not provide inertia.

Generator with synchronous coupling



Source: National Grid

Generator with non-synchronous coupling

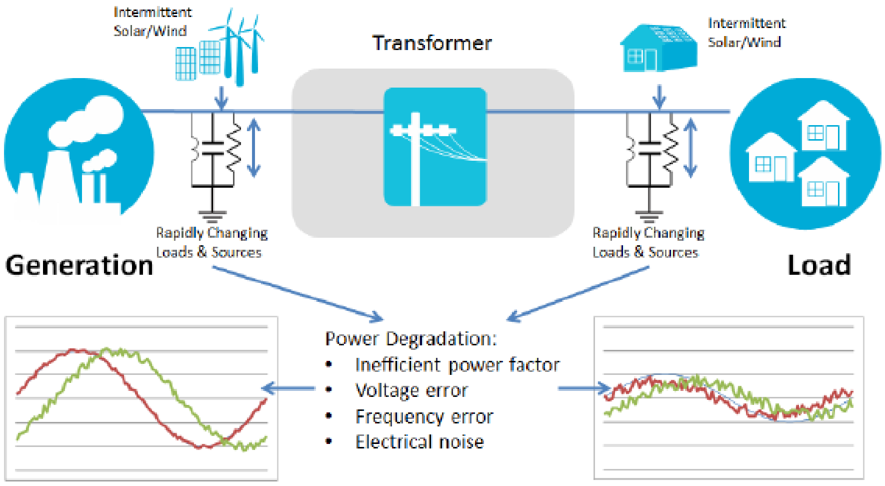


Source: National Grid

Intermittency and volatility

The intermittency problems created by renewable generation are well known in terms of the longer duration issues of daytime versus night-time for solar and windy days and calm days for wind. However, short term volatility is less generally understood outside the industry. In terms of value, it is potentially as large an issue. Output from renewables is constantly varying and, despite sophisticated inverters and other controls, this puts pressure on system frequency. So in addition to displacing the synchronous generation which minimises frequency imbalance, renewable generation makes it worse by sending out a volatile supply to the grid.

Volatility in the system

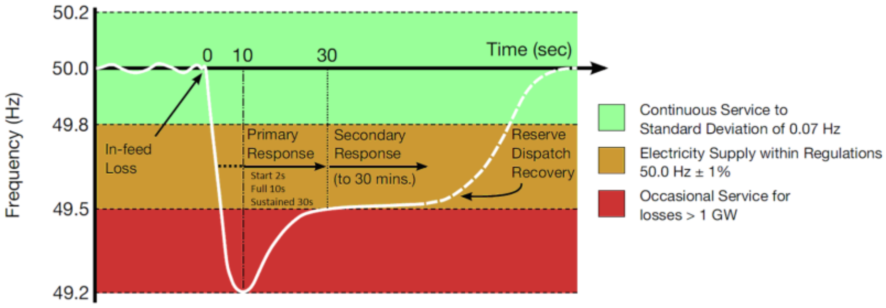


Source: Faraday Grid

WHY STORAGE IS NOT A SOLUTION TO THE PROBLEM OF VOLATILITY

While battery based energy storage is a solution to the problems of intermittent renewables, it does not really solve the volatility issue. Standard energy management systems used with battery storage can only respond in the microsecond range with the Master Controller or Energy Management System of a typical battery storage installation reacting on average between 200 and 400ms. However, a frequency drop causing an outage can occur in less than 40ms, although large drops will normally take longer. Technically, response needs to occur within one wavelength. For a 50Hz system this is 1/50 = 0.02s or 20ms. This means that battery systems are only useful as a response to frequency issues rather than instantly damping them.

Frequency response – a matter of timing



Source: National Grid

Other available solutions do not adequately address the issues

The issue of timing is key. Fast Frequency Response ("FFR") solutions including storage but also new frequency stabiliser technologies that provide so-called synthetic inertia are being targeted by SOs to mitigate frequency issues. These can be fast but are currently not fast enough, with for example the Australian Energy Market Operator ("AEMO") targeting response times of 500ms.

Fast Frequency Response Needs and Solutions

Power system events	Minimum	Maximum
50 Hertz AC cycle	20 ms	N/A
Protective relay operation	20 ms	80 ms
Inertial response	20 ms	3 seconds
Under frequency load shedding	100 ms	400 ms
Existing frequency control services	6 seconds	5 minutes
5 minute dispatch	5 minutes	N/A
Service restoration from outages	1 hours	8 hours
Fast frequency response (under development)	500 ms	3 seconds

Source: AEMO

We are aware of one proprietary solution from Engie EPS (EPS FP) that can respond in 128µs as well as providing virtual inertia, but this is rare. It is also a relatively more expensive option better suited to microgrids where it is part of a solution replacing expensive diesel-based generation.

It is also possible to configure wind turbines to provide what is known as emulated inertia which effectively re-establishes the link to the rotating generator in times when frequency response is required. However, there are limitations to the effectiveness of this solution given the variability of the turbine rotation.

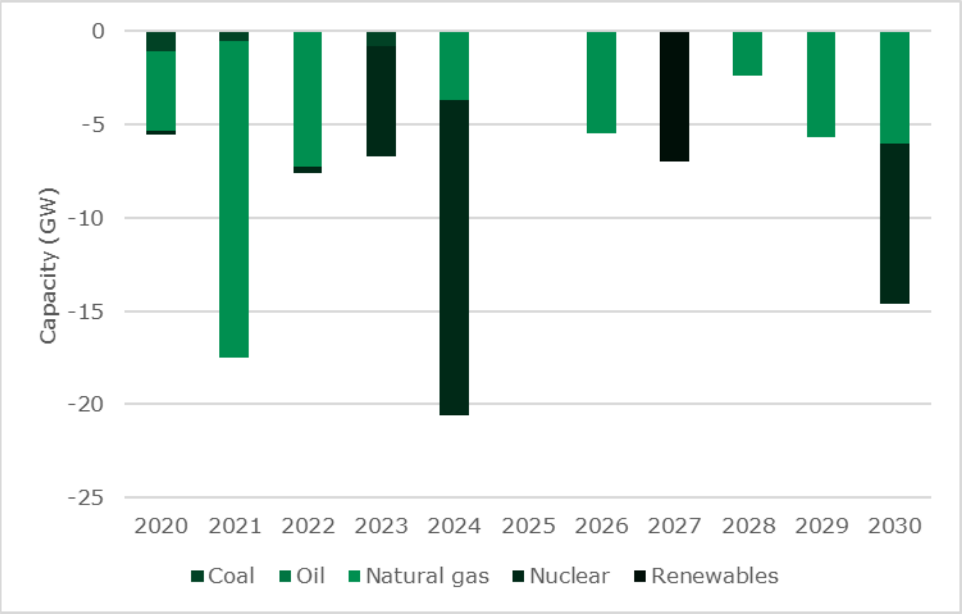
The current state of the market is best summed up by DGA Consulting in their International Review of Frequency Control Adaption, undertaken for the Australian Energy Market Operator in 2016.

"The international literature is clear that FFR alone is not sufficient; it is not now possible to operate a large power system without any synchronous inertia, and synthetic/emulated inertia does not provide a direct replacement."

FORECAST LOSS OF INERTIA

As renewable power increases in proportion and as synchronous generation falls due to closures of traditional generation, the amount of inertia available to ESO falls. In the UK, it is expected to fall rapidly as we close down large quantities of spinning reserve.

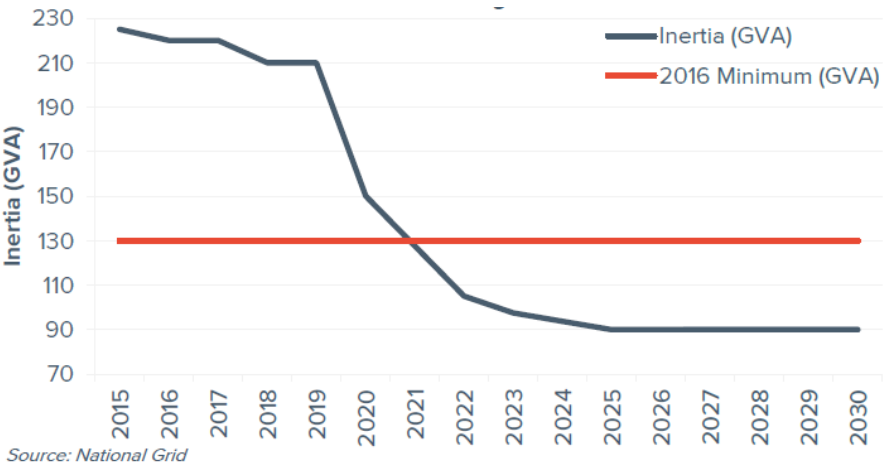
Capacity closures



Source: National Grid

Inertia is measured in volt amperes ("VA"), essentially a measure of apparent power in any circuit. National Grid has forecast inertia in the UK market and expects it to fall dramatically in 2019 and beyond. Currently system inertia can be no lower than 130GVA after any fault without deloading nuclear generators or issuing emergency instructions to disconnect inflexible generators. The lowest inertia seen recently was 135GVA on 7 August 2016, but inertia is forecast to fall below 130GVA as early as this year.

GB inertia forecast



Source: Cornwall Insights based on National Grid

This forecast is based on the National Grid's "Slow Progression" scenario, one of four scenarios used for future planning. That scenario does not include the highest penetration levels of renewable generation. Other scenarios suggest more renewables which will lead to an even bigger problem. We think more renewables and less synchronous generation than these forecasts are highly likely.

H2GTS, NUCLEAR, BIOMASS SOLVE INERTIA

There are solutions to this inertia problem. Inertia can be provided by large spinning reserve and there are four low carbon options to do this.

- Synchronous compensators
- Hydrogen gas turbines (H2GTs)
- Nuclear
- Biomass

SYNCHRONOUS COMPENSATORS

The immediate solution to inertia is investment in synchronous compensators. These are effectively large electric motors that can act as spinning reserve and deliver inertia to the system. Using renewable electricity would effectively make them a low carbon solution.

However, they are costly to procure and have internal losses which represent a continual operating cost. A 75MVA unit including auxiliary equipment is likely to cost c.£2,750,000 or £37/kVA. While this may become an option, other routes look likely to be cheaper if there is spinning reserve to take part.

HYDROGEN FOR POWER

The retrofitting of existing CCGTs to burn hydrogen or ammonia is possible, creating hydrogen fuelled combined cycle gas turbines or H2GTs. New diffusion burners would be required which could burn these gases. Additionally, retrofitting would require additional pipework to cope with the higher volumes of gas per unit of energy and the installation of Selective Catalytic Reduction (SCR) technology to manage the emissions of nitrogen dioxide. The investment would allow the combustion of "green" low carbon hydrogen or ammonia.

Overall economics

Bloomberg New Energy Finance (BNEF) forecasts that the cost of hydrogen from large scale alkaline electrolysers could fall to a low of US$1.38/kg by 2030. We estimate this would deliver a short run marginal cost of £81.53/MWh for a hydrogen gas turbine, making it viable with a carbon price of €85/t. While that is well above current levels, the tightening of allocations in the EU Emissions Trading Scheme (EU ETS) could easily get prices to that level, and the UK remains committed to either an ongoing link to the EU ETS or an effective equivalent UK ETS.

SRMC cost of H2GT versus CCGT

	H2GT	CCGT	Notes
GJ/tonne / GJ/therm	130	0.106	
Fuel emissions factor	0.06	0.06	kgCO2/MJ
Full load efficiency	50%	50%	DUKES
Part load efficiency factor	75%	75%	@36% plf
Part load efficiency	38%	38%	
Gas price	1.10	44.80	£/kg / p/therm
Fuel cost	81.53	40.76	£/MWh
Carbon price	0.00	85.00	€/t
Carbon cost	0.00	41.16	£/MWh
Marginal cost	81.53	81.92	£/MWh

Source: Longspur Research

If this pricing can be achieved, there could be room for H2GT as marginal plant, especially if carbon pricing pushes the cost of natural gas fired CCGTs above this level.

THE NUCLEAR OPTION

Nuclear energy is a genuine low carbon generation source. However, in our view it has issues in complementing a market faced with increasing levels of intermittent generation and also with more volatile demand. With very high capital costs to be recovered and slow ramp up times and shut down times, nuclear tends to be inflexible in operation, preferring to be always on. Small modular reactors (SMRs) can be designed for flexibility but still need to cover high capital costs. Nuclear therefore runs baseload while flexibility in the market is provided by other generating assets. In a market with a major element of intermittent renewables, this can potentially lead to an increase in curtailed output when nuclear and renewables are competing for the same level of demand.

This is not necessarily bad if there are opportunities to use the curtailed power such as the production of hydrogen or if it can be stored in long term storage capacity. Without such opportunities we see nuclear as tending to increase price volatility especially at the low pricing points. We note that during the COVID 19 lockdown last spring, National Grid did a deal with EdF to reduce the output of Sizewell B, halving its output for six weeks in order to make balancing the system easier for the system operator.

HYDROGEN AND NUCLEAR

There are four pathways for producing hydrogen from nuclear power.

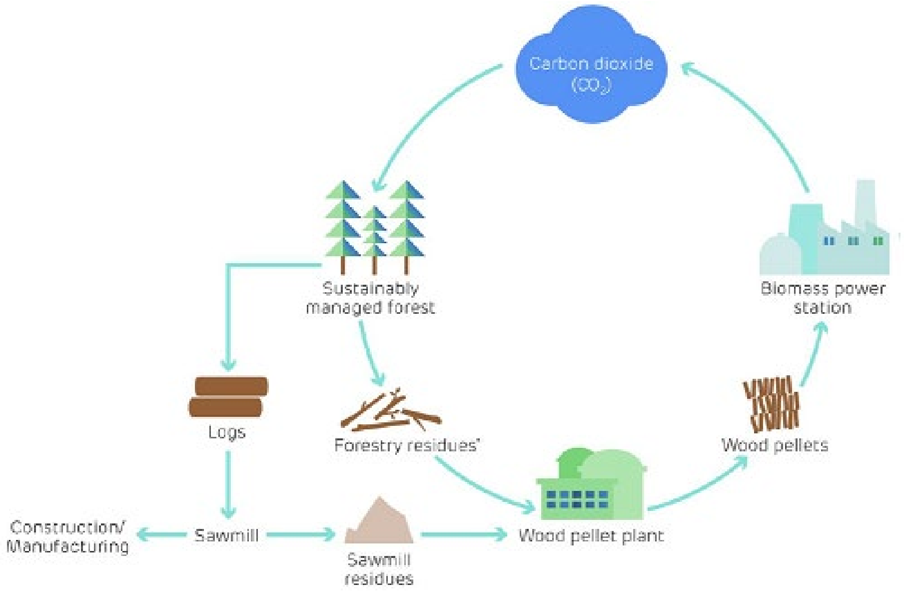
- Water electrolysis using any of the electrolysers currently available on the market. However, fast reacting PEM electrolysers would allow rapid reaction to demand changes and maximise revenue here. This is available technology now and therefore likely to be the first adopted solution. EdF is already evaluating the concept of “night-time nuclear” using water electrolysis.
- Steam electrolysis is far more efficient but would require more sophisticated electrolysers such as solid oxide for superheated steam or perhaps high temperature PEM for lower temperature steam. In either case the steam is available from the reactor to drive the electrolysis.
- Thermochemical processes including sulphur-iodine cycle, hybrid sulphur cycle and copper chlorine cycle are early-stage process currently undergoing evaluation.
- Reforming natural gas using heat from the nuclear reactor with CCS, effectively creating blue hydrogen.

The immediate opportunity is in water electrolysis with fast reacting (PEM electrolysers) hydrogen capturing nuclear output when demand falls away. We think this is one of the relatively understated benefits of a hydrogen economy. The 25EJ of nuclear identified in the IPCC median outcome could represent a similar amount of electrolyser capacity for the hydrogen market. As with storage being used with renewables, it may be less than 100% of capacity that makes use of this, but we can see a case for 50%.

BIOMASS – SEEING THE WOOD FOR THE TREES

As a tree grows, photosynthesis removes CO2 from the atmosphere and converts it to carbon in the wood. Burn a tree and that CO2 goes back into the atmosphere. Biomass combustion therefore releases CO2 but by using wood from forests that are continually growing, and replacing the biomass burnt with new biomass, results in a theoretically carbon neutral outcome as the CO2 released on burning is taken out again by the new biomass growth. This is also true of other non-combustion processes such as the Velocys waste to biofuel technology.

CO2 Cycle for a Normal Biofuel



Source: Drax Group

Of course, this only makes sense if you manage the forests in a sustainable way. There are also losses along the way, notably in pelletisation and transport that mean it is not a carbon neutral process, although done properly it can be a very low carbon process in practice.

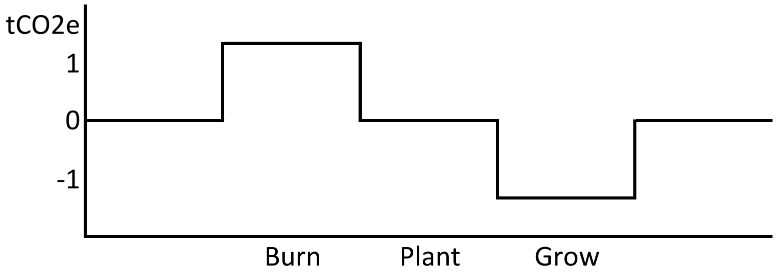
There is a concern that it takes time to recapture the emissions from burning the tree in new forest growth and there is a lot of opposition to biomass based on this concern. However, the most recent studies show that biomass is a genuine source of low carbon generation. Despite its many advantages, biomass has attracted many critics over the years with the two major criticisms being ‘carbon debt’ and ‘supply response’.

Carbon debt

Carbon debt arises from the logic that the combustion of forest feedstocks releases emissions into the atmosphere, which cannot immediately be removed as it takes a number of years for the replacement trees to sequester the amount of carbon released, thus resulting in net negative carbon emissions in the short-term. Although there is sense in this logic, its basis is in arbitrary carbon accounting assumptions, which are increasingly seen as flawed.

If we take a very simplified model of a biomass cycle, many commentators start with burning of the biomass in the power station. Let us assume this releases 1t of CO2. Then a new tree must be planted and at first it will not capture much carbon. It does this during its growth phase when, if it is the same size as the tree that supplied the original fuel it will remove 1t of CO2 from the atmosphere.

Emissions from a simplified biomass cycle



Source: Longspur Research

The gap between the release of CO2 and its subsequent capture is the problem. If we worsen the climate by initially releasing CO2, knock on secondary effects on the climate may be difficult to recover from even if we subsequently remove the CO2.

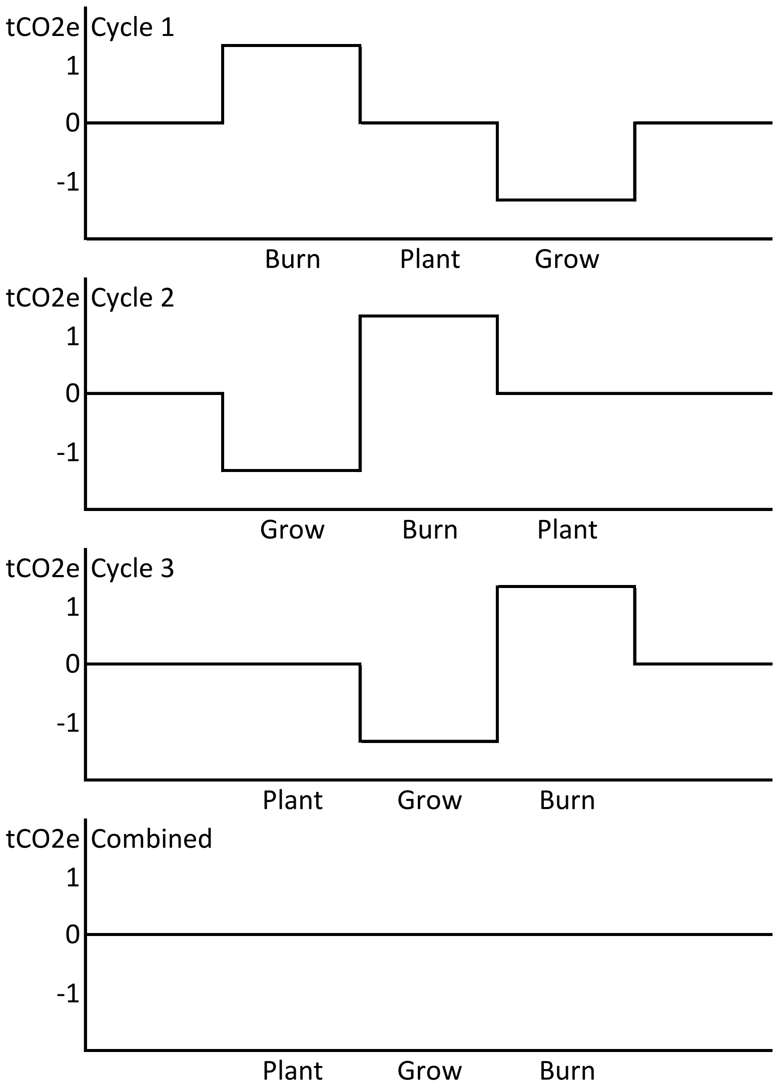
The problem here is that this simple model is too simple. Essentially it looks at a single stand of trees rather than considering the whole forest.

After the 1t of biomass is burnt in our model power station, it will want to burn some more so a second cycle is started. To allow continuous operation, this cycle take trees that have already been grown and therefore must start with the growth phase. After this cycle is complete a third is required. A tree must have already been planted and grown in order to supply a power station.

After three cycles a picture of emissions is built up that results in no temporal difference between phases and no overall emissions. Because burning goes on continuously, planting, and growing need to go on continuously.

Of course, this only works if there are enough cycles which implies a big enough forest with various stages of growth and harvesting. In our simple model the forest is harvesting 33% of its trees at any one time. Taking the key biomass growing region of the Southeast of the US as the example, only 2% of the forest is harvested in one year while the remaining 98% is kept in various stages of regrowth, resulting in a net increase in the amount of carbon stored in the forest every year, as more carbon is sequestered from growing trees than mature trees. Of this 2%, the vast majority is being used for construction timber which keeps the carbon sequestered over a long period of time. The fibre for biomass is principally sawmill residues, low grade roundwood, thinnings, branches, tops, and bark.

Emissions from a continuously operating biomass project



Source: Longspur Research

Supply response

The supply response criticism assumes that biomass simply depletes existing resources. However, in an environment where demand for biomass is growing, as is likely if BECCS is pursued as a solution to climate change, more land will be afforested with the carbon negative growth phase leading the cycles.

In both cases above we have simplified the arguments for clarity. Obviously, forests are complex systems and detailed research is needed. Recent research published this year includes a review of the literature (A. Favero, A. Daigneault, B. Sohngen, Forests: Carbon sequestration, biomass energy, or both? Science Advances, 2020; 6). The authors concluded that the expanded use of wood for bioenergy will result in net carbon benefits. They also stress the need for an efficient policy to regulate forest management and poor management assumptions is one of the reasons that some earlier studies have come out against biomass.

“Studies that assume there is little to no management response, or consider only use of the extensive margin, predict that bioenergy demand will increase carbon emissions (16, 17). Studies that allow efficient investments in forestry management find that bioenergy policies lead to a net increase in forest sequestration (18–22).”

Responsible biomass operators will need to ensure sourcing is appropriately managed. For example, Drax Group has built its sourcing policy on research from Forest Research, the research agency of the Forestry Commission. Their 2018 paper, "Carbon impacts of biomass consumed in the EU" also supports the view that well managed biomass for energy will reduce net emissions.

A lot of the negative research is based on several assumptions that do not reflect actual and future practice in an environment where biomass is growing.

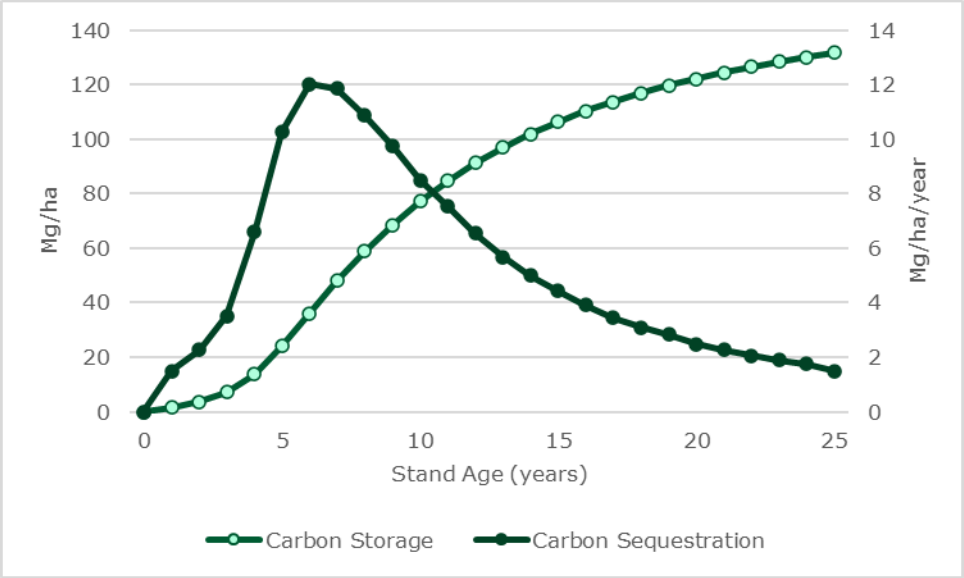
Forests need to be seen as dynamic systems and analysed accordingly. Carbon capture is maximised when these systems are properly managed and in this regard, it is worth stressing that the forests of the US Southeast have been continuously managed for centuries and are currently growing their carbon stocks. Most carbon is captured as the tree grows not when it is mature. This can be simply seen by looking at the carbon material in trees at different stages of their lives.

CO2 capture potential from trees at different stages

Source: Longspur Research

For one of the species most commonly used, loblolly pine, the maximum amount of carbon capture takes place around six years after planting and falls dramatically thereafter.

Carbon sequestration and storage for managed loblolly pine



Source: Carlos Gonzalez, University Of Florida

Carbon payback periods

Calculated properly on a forest basis, biomass can payback the emissions given out when the biomass is burnt in a reasonable timeframe. Carbon payback is a concept used to compare the emissions released in creating a renewable energy technology against the low or zero carbon benefit of its operation.

Again using recent research (P. Dwivedi, M. Khanna, M. Fuller, Is wood pellet-based electricity less carbon-intensive than coal-based electricity?, Environmental Research Letters, 2019; 14), for a forest using loblolly pine, the carbon payback ranges from 2 to 32 years depending on management approach, with the research concluding that convergent management perspectives with wood pellets relative to a no-harvest baseline show a break-even period of about three years.

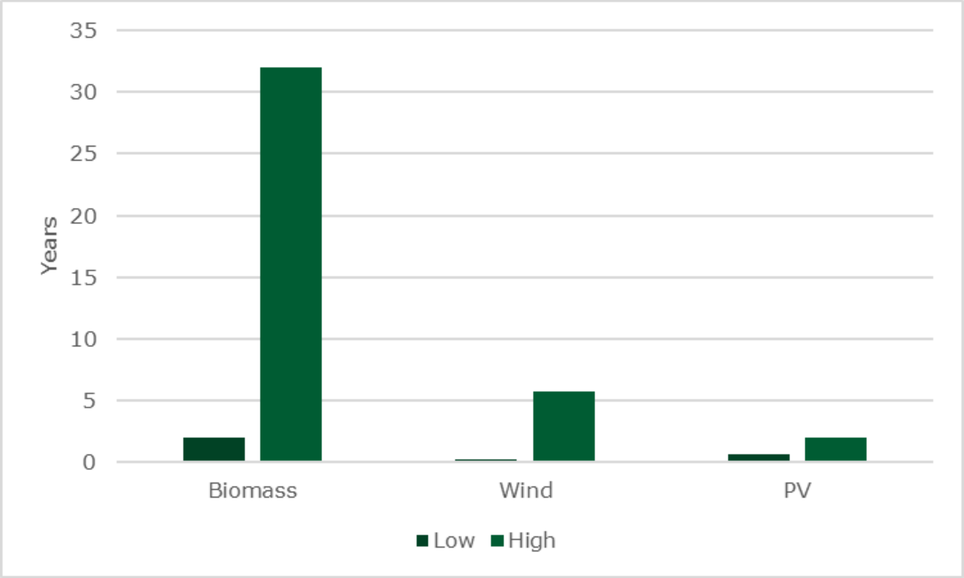
Older research concurs:

"We consider the landscape-level carbon debt approach more appropriate for the situation in the Southeastern United States, where softwood plantation is already in existence, and under this precondition, we conclude that the issue of carbon payback is basically nonexistent."

J. G. G. Jonker, M. Junginger and A. Faaij, Carbon payback period and carbon offset parity point of wood pellet production in the South-eastern United States, GCB Bioenergy (2014) 6, 371–389

When we look at the range of payback periods for other low carbon technologies, biomass can be shown to be as beneficial to a low carbon environment as any. Obviously, payback periods will vary from project to project. The values below are believed to be typical and are from a range of academic sources. While badly managed biomass has a long payback period, well managed biomass lies between the range of paybacks for other renewables.

Carbon payback periods



Source: P. Dwivedi, M. Khanna, M. Fuller, Is wood pellet-based electricity less carbon-intensive than coal-based electricity?, Environmental Research Letters, 2019; 14; C. Thomson, G. Harrison, Life Cycle Costs and Carbon Emissions of Onshore Wind Power. ClimateXChange, 2015; M. de Wild-Scholten, Energy payback time and carbon footprint of commercial photovoltaic systems, Solar Energy Materials and Solar Cells, 2013

Put simply, well managed biomass project can have a lower carbon payback than a badly designed windfarm sited on an upland peat bog.

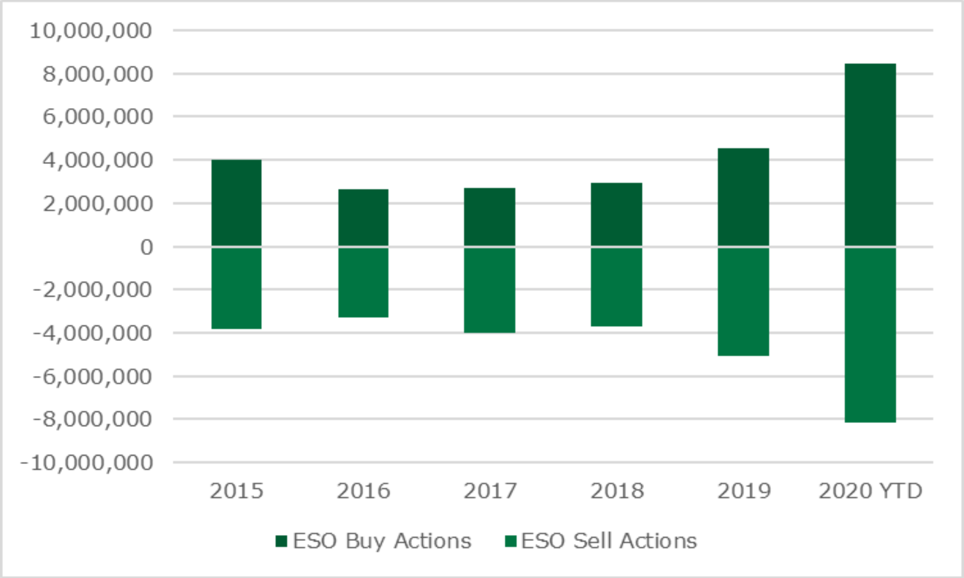
As such we see biomass generation as playing a strong role in providing both electricity and inertia to a net zero system. As we shall see, when this is combined with carbon capture and storage, this becomes a key solution to the challenge of reaching net zero.

GETTING PAID FOR INERTIA

In many markets, inertia has generally been assumed as a social good, provided without charge by generators with spinning reserve. However, a revenue stream for spinning reserve can be identified in some markets by examining what happens when there is not enough inertia on the system. In the UK market, after gate close, if the system operator (ESO) finds that there is a risk of there not being enough inertia, they can pay for non-inertia generation such as wind turbines not to run. These so-called constraint payments are undertaken as balancing market actions. ESO will then pay balancing market units with inertia to run and therefore provide inertia (and energy) into the system. While not all constraint payments are to bring inertia into the system, we believe a significant proportion are and we think recent events show what can happen when the system is largely relying on renewables.

With the lower electricity demand seen during the COVID 19 lockdown, a greater proportion of demand is met by renewables which are unable to provide inertia. What is interesting is that constraint payments have risen dramatically and are forecast to rise further. The sheer number of balancing mechanism actions in the year to date shows the extent of the demand for inertia in the market.

Balancing mechanism actions



Source: National Grid ESO

In fact, ESO is now forecasting a tripling of the value of balancing mechanism actions as a result of COVID 19.

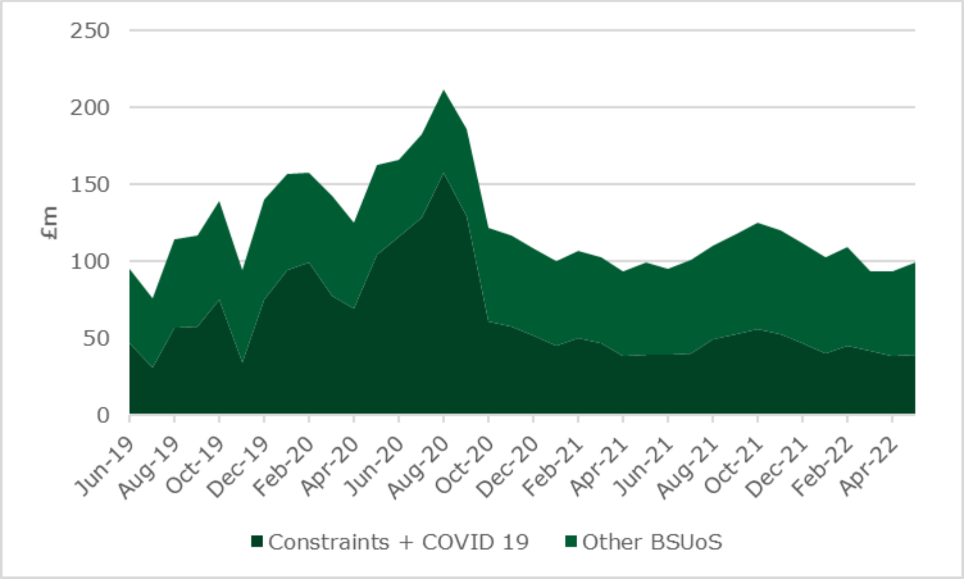
BSUoS Forecasts under COVID 19

Month	Outturn 2019	Pre Covid Forecast Baseline	15th May Forecast (15%-20% suppression)	5% Demand Suppression	10% Demand Suppression	15% Demand Suppression
May	64.4	121.3	166	163	163	163
June	89	103.8	207.7	129.8	147.2	166.5
July	71.7	110.4	214.9	139.7	160	183.1
August	108.7	120.2	217.7	160.1	185.3	212.3
Total	333.2	455.7	826.3	592.6	655.5	724.9
Sept		115.1		149.6	165.6	185.8

Source: National Grid ESO

While ESO is not explicit about whether the extra COVID 19 costs are constraints or other BM actions, we would suspect that they are largely constraint related. The impact can be seen most clearly in the following graph.

Actual and forecast BSUoS



Source: National Grid

While the COVID 19 market is not a perfect indication of the market in the longer term, it has many similar characteristics and we think that a market with more renewables and less spinning reserve will see higher balancing mechanism payments to manage inertia and existing spinning reserve including biomass, nuclear and H2GT units will benefit from this. The order of magnitude we are seeing in the market today gives a fair guide to the increase we might expect in the future. For example, Drax Group in the UK operates 2,595MW of biomass capacity. We estimate that Drax made over £65m from BM actions in 2019. If this triples, then additional annual revenue of £130m could be added over the next 7 years.

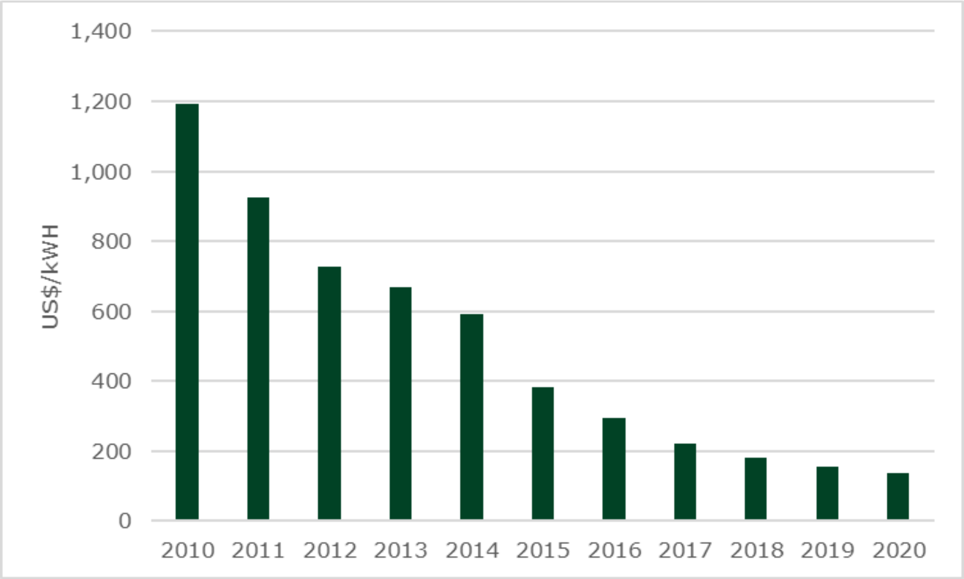
As such we see potential commercial support for all providers of inertia in similarly structured markets.

HYDROGEN FOR TRANSPORT AND MUCH MORE

Lithium ion and transportation

Lithium-ion batteries have allowed battery electric vehicles to emerge as a valid solution to low carbon transport. Costs have fallen and energy density (which drives vehicle range) has risen. Battery electric vehicles (BEVs) are likely to be the go-to solution for passenger cars and light duty commercial vehicles especially for urban duty cycles.

Lithium ion battery pack prices



Source: BNEF

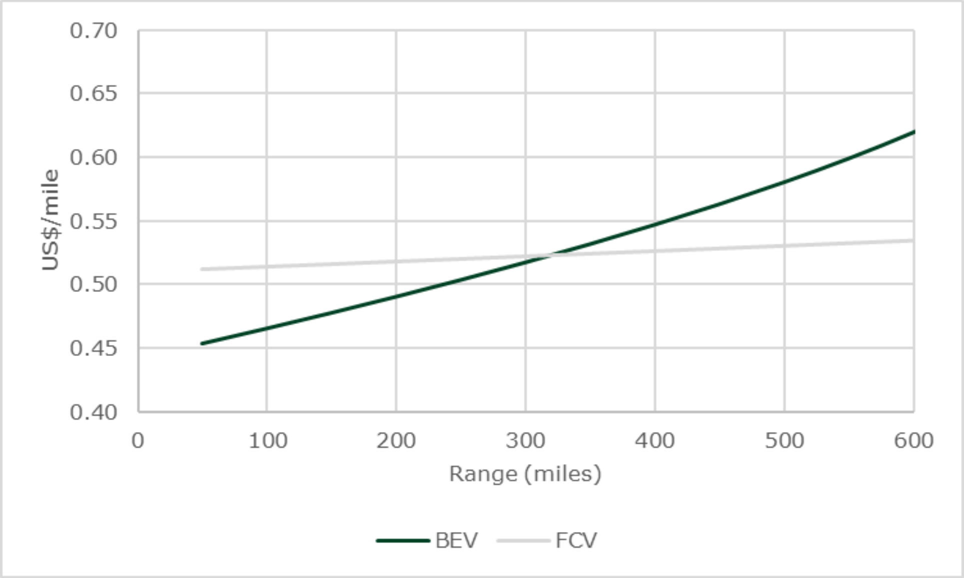
We think lithium ion is already testing its limits for transportation. The new Porsche Taycan was originally promoted with a 350kW charger but following feedback from battery supplier LG Chem have downgraded this to 270kW. For Porsche, performance over the life of the vehicle is important and battery degradation due to overly rapid charging is an issue.

New battery technologies can overcome issues but not quickly or completely

New battery technology can push these limits out in time, with silicon anodes and solid-state electrolytes the most likely areas of progress. However, electrochemistry is a difficult area and we do not expect new technologies in mainstream applications overnight. As a result, we see alternative solutions, notably those based on hydrogen, gaining ground especially in long range and high-power applications.

Batteries are already making strong inroads towards decarbonising transport but are limited by the way they scale with range. Physically the only way to get greater range with a battery is to add weight in a linear manner. As a result, efficiency falls off by comparison with traditional fossil fuelling or hydrogen fuel cell vehicles. The graph below from Bloomberg New Energy Finance shows their estimates of the cross over point for a heavy-duty truck in a supportive policy environment for hydrogen. This suggests that at ranges over 300 miles a fuel cell is a better option.

Total cost of ownership class 8 heavy duty truck (strong policy)



Source: BNEF

This is worsened for heavier, more powerful applications. We are already seeing a move by Chinese bus OEMs to make use of fuel cells notably for longer distance buses. There is also interest in trucking, including mining, and in areas such as forklift trucks and logistics vehicles, including airport or port service vehicles. All these benefit from the fact that they can be fuelled at their depots without the need for a hydrogen infrastructure.

There is debate about the extent to which fuel cell vehicles will from part of the energy transition, but we note that Chinese policy in particular is supportive, focusing on the fuel cell supply chain and developing hydrogen powered trucks and buses with a target of 1m fuel cell vehicles on the road by 2030.

We see the debate between batteries and hydrogen as rather simplistic with its assumption that there can be only one solution. This is not a VHS/Betamax analogy. A better guide would be fossil fuel propulsion where the automobile industry has lived with two competing technologies co-existing side by side for about a hundred years: the spark ignition petrol engine and the compression ignition diesel engine.

Transportation splits between short haul and long haul

As a result of these limitations, we see most transport markets being split between long-range heavy-duty applications and short-range light duty ones. For almost all short-range applications battery electric vehicles are the obvious answer. This will of course need to be matched by an increase in renewable generation to provide the low carbon electricity to charge these batteries.

This makes lithium-ion batteries the go-to solution for most domestic vehicles and light goods vehicles. For longer range applications we think hydrogen is the most suitable solution with the exception of long-haul aviation where we think biofuels are really the only viable option.

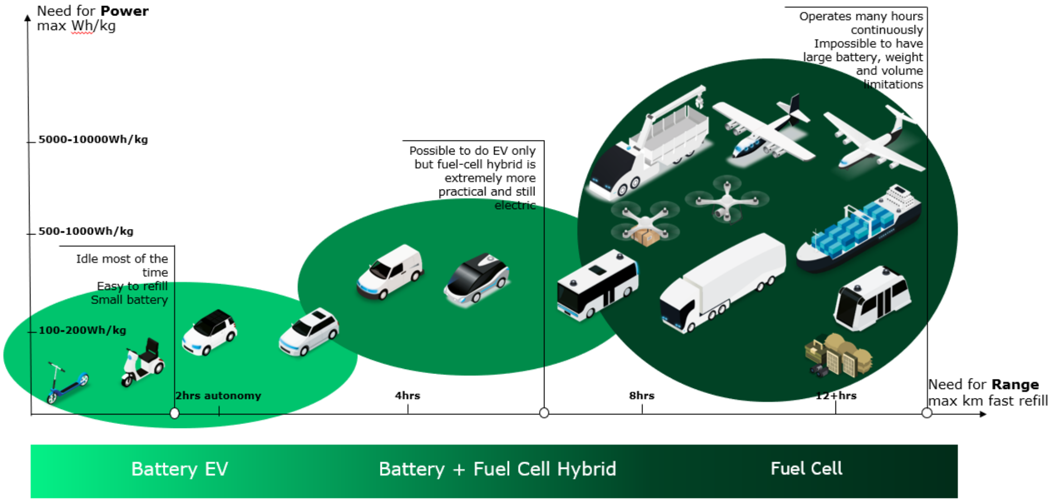
Road – cars, delivery vans and urban buses already have viable EV solutions. Charging can be an issue especially where grids require reinforcement, but this can be overcome by a mixture of grid reinforcement, storage, and distributed generation.

Longer distance travel such as intercity buses and haulage are likely to see hydrogen solutions. Rail is already heavily electrified and there is scope to do more. Some locations are unsuitable for electrification and here we see hydrogen solutions being applicable.

Near shore marine such as OSVs and ferries are very suitable for battery power and progress has already been made in this area. In fact, we think a ferry is perhaps one of the best applications for a battery given the dwell time at either port and the known duty cycle. Deep sea shipping is most likely to be a hydrogen solution with many industry commentators looking at ammonia as a carrier. Green ammonia can be produced from natural gas by the Haber Bosch process which captures the CO2 produced in the reactions.

Short haul light aviation can be electrified using hydrogen fuel cells and airborne freight in the form of autonomous drones is a very low emission form of delivery. However, much of aviation is more challenging. An element of efficiency is required here but real progress has also been made on zero carbon aviation biofuel and negative carbon aviation biofuel.

Low carbon vehicle market segments



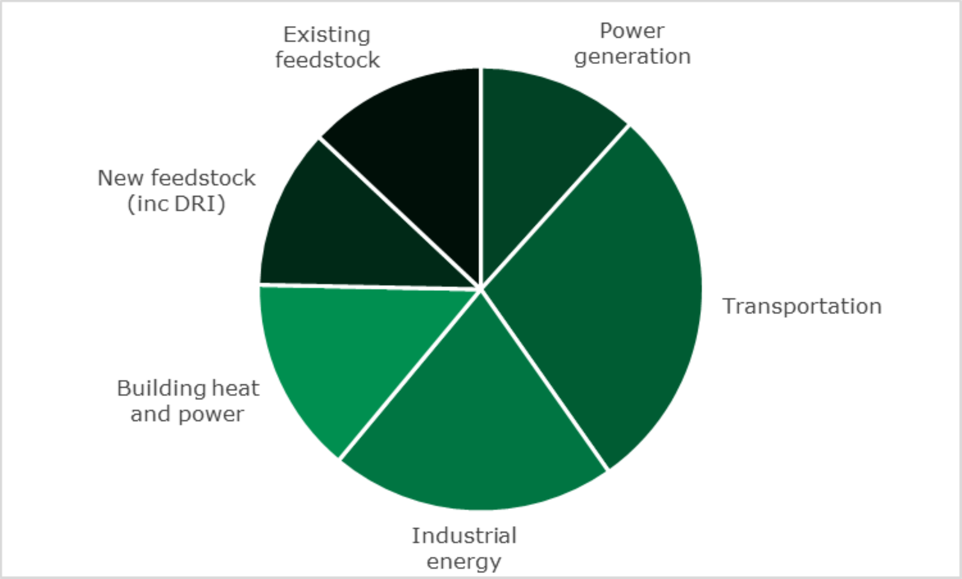
Source: Advent Technology

Increasingly hydrogen is seen as the go to solution for longer range and high-power transport. We have already identified its usefulness for solving inertia issues through H2GTs and for balancing nuclear. It is also key to decarbonising key sections of industry, as well as potentially a solution to domestic heating.

HYDROGEN FOR INDUSTRY

Additionally, hydrogen may be the only realistic way to decarbonise key industries including steel making. Hydrogen is already used for the direct reduction of iron ore which currently accounts for 7% of all steel production. Clearly there is an opportunity to increase this percentage. As a fuel it can also help to decarbonise industries requiring high temperatures including cement manufacture and is also of use as a source of direct heat in distributed industries where scale makes carbon capture costly or impractical.

Forecast uses of hydrogen in 2050



Source: The Hydrogen Council

HYDROGEN FOR DOMESTIC HEATING AND COOKING

Before 1968 UK domestic gas supply typically contained 50% hydrogen. This town gas was produced from coal and also contained carbon monoxide and methane all in varying quantities depending on the source coal. The hydrogen content was significant.

Currently all gas products in the EU are required to be able to burn gas with 23% hydrogen. Burners may require modification or replacement for higher levels. However, the big benefit to switching to a high hydrogen mix and even to 100% is that most of the existing infrastructure can be used. Projects in France (GRHYD), Italy (SNAM) and the UK (H21 Leeds City Gate and H21 North of England) have all proved successful.

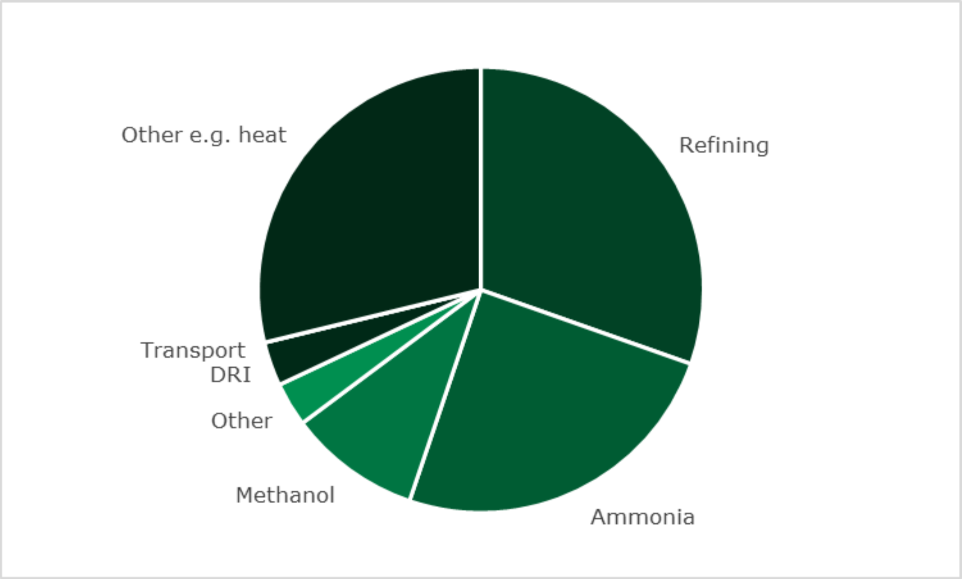
This is not the only low carbon option for domestic heating. All electric solutions including ground or air source heat pumps, infrared heating and traditional electric storage heating are all options. Clearly in countries and regions with low or no gas penetration these are likely to be the answer.

The adoption of hydrogen for domestic heating is an area of uncertainty. For investors, the demand for hydrogen is currently so strong even without this extra potential demand, that we see it as a nice to have rather than a must have. In our sizing analysis we have assumed the domestic electric heating option rather than the hydrogen one.

HYDROGEN PRODUCTION

The world currently produces around 50Mt of hydrogen annually. This is primarily used in the refining industry and for the production of ammonia and methanol.

Current uses of hydrogen



Source: Hydrogen Council

Currently, hydrogen is mainly produced by steam reformation of natural gas. Steam methane reformation is energy intense and a major emitter of CO_2. Carbon capture and storage (CCS) is an option to reduce or eliminate the CO_2 emissions, creating "blue" hydrogen. There is some debate about the application of blue hydrogen in net zero solutions. While the process can be low emission from the point of delivery of the natural gas, methane losses further upstream can result in a high emission outcome.

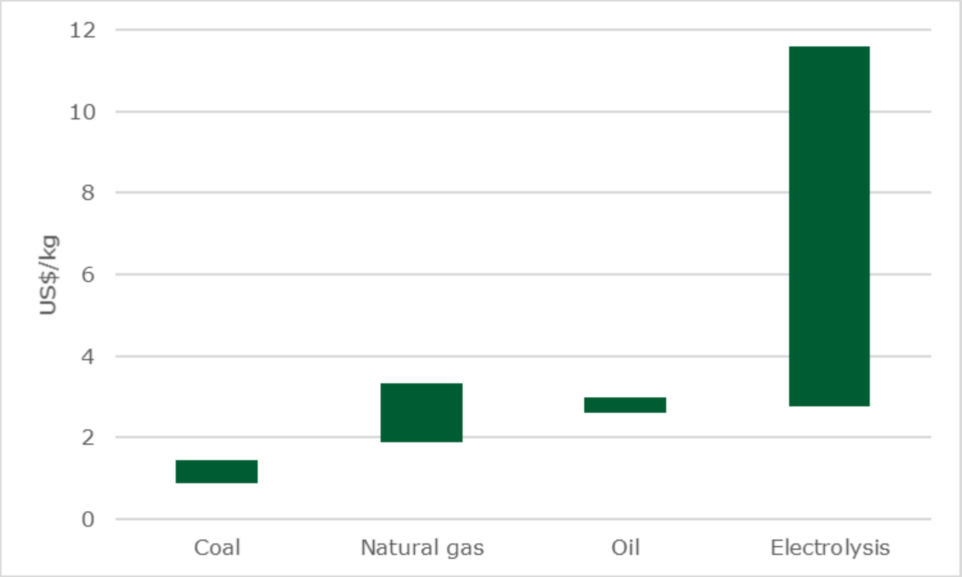
Low carbon, or green, hydrogen can be created from the electrolysis of water with renewable energy providing the electricity. There are two main types of electrolyser, proton exchange membrane (PEMs) or alkaline. PEMs are more responsive but higher cost thanks to the use of expensive catalysts. Alkaline electrolysers are cheaper but less responsive, taking longer to start up when needed.

Alkaline electrolyser technology is well proven with large scale alkaline units being operated since the 1920's. Driven by demand for hydrogen for ammonia production, many projects were completed with output in the 2-3 ton per hour (50 –70tpd) range. However, these were rendered uneconomic by steam methane reforming as plentiful natural gas became available.

The levelised cost of hydrogen from electrolyser technology is clearly dependent on the cost of the electricity. The ability to use otherwise wasted electricity from renewable generators at times of over supply or when the generators are otherwise curtailed means that the cost of electricity can be zero. However, while this results in free electricity, utilisation of the electrolyser is limited to those times when the generator is being curtailed. Our analysis of storage suggests that periods of very low-priced power may imply greater utilisation potential than mere curtailment opportunities would suggest. We need to avoid double counting this opportunity and allocating exclusively between hydrogen and battery storage and we have taken this into account in our capacity estimates.

Bloomberg New Energy Finance has published calculations of levelised costs of hydrogen for different electrolyser types and utilisations.

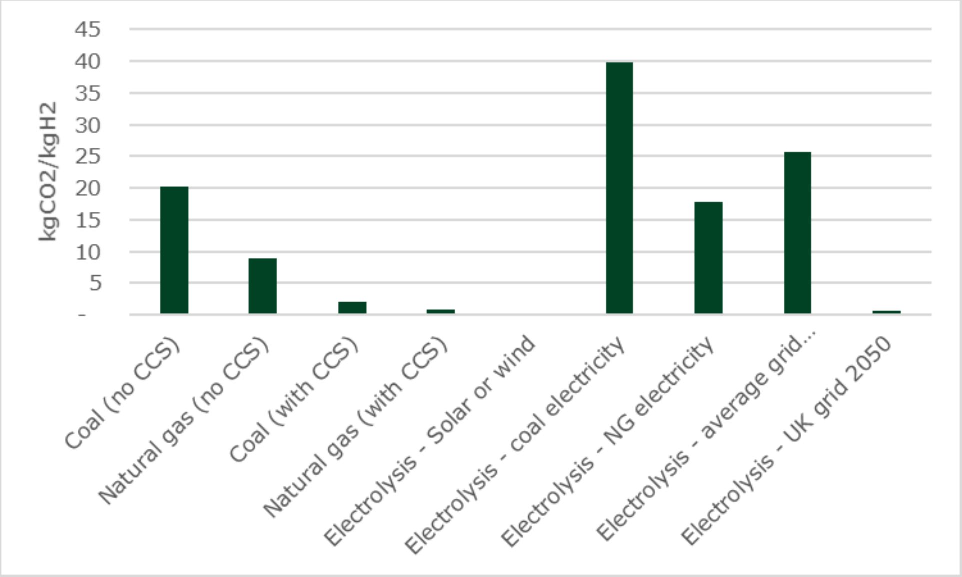
Levelised cost of hydrogen 2019



Source: BNEF

SMR is clearly the most economic method of producing hydrogen. However, it is a major source of greenhouse gas emissions. Even electrolysis represents emissions if the electricity is from fossil fuel sources although as we move to net zero this will disappear. As a result, the key pathway for low carbon hydrogen production is either electrolysis using renewable energy (green hydrogen) or SMR combined with carbon capture and storage to minimise the emissions problem (blue hydrogen). Adding the likely cost of CCS increases the cost of blue hydrogen.

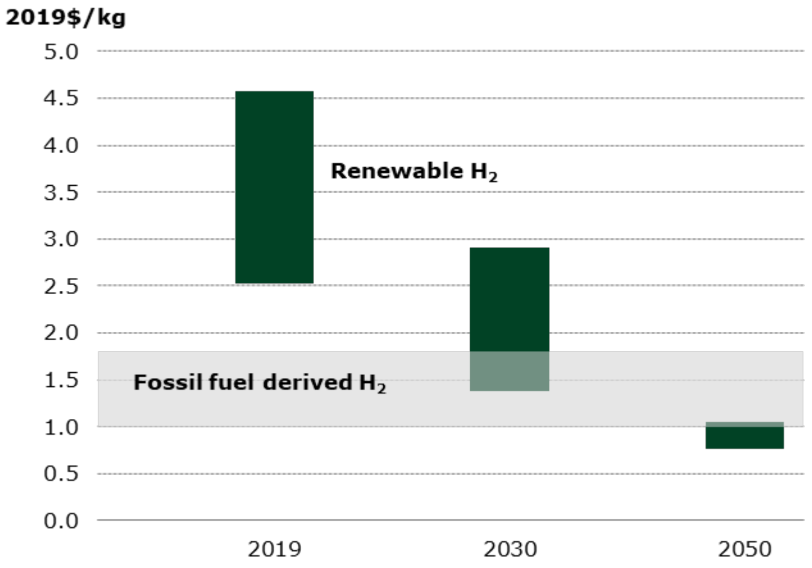
CO2 emissions from hydrogen production



Source: BNEF

Of these technologies, blue hydrogen appears the cheaper. However, costs are likely to fall for electrolysers and by 2030 green hydrogen could begin to compete with blue.

Levelised cost of hydrogen forecasts



Source: BNEF

Green hydrogen costs are impacted by the utilisation of the electrolyser. While surplus renewable energy may be available at a low or zero cost due to curtailment, this would suggest low utilisation. However, as we have identified, the missing money issue means that hydrogen generation becomes a competitive demand source for renewables at times other than just when curtailment would occur. We see electrolysis as especially relevant when paired directly with renewable energy and with nuclear energy.

Blue hydrogen utilises existing skills form the oil and gas industry as well as creating ongoing demand for natural gas. This may be politically attractive for countries who see significant employment in gas extraction and are committed to the concept of a just transition. It of course needs CCS to operate and as such helps to underpin a CCS cluster approach helping to provide sufficient scale to networks which will also enable BECCS. However fugitive emissions can be considerable especially where blue hydrogen is driven by gas from LNG trains. Unless the overall emissions can be properly controlled, this may not be an appropriate solution for a net zero outcome.

There remains a lot of debate about the merits of green and blue hydrogen. Overall, we think that there is sufficient demand for both green and blue hydrogen to have a role and in our forecasts, we have assumed a 60/40 green/blue split in line with assumptions from the Hydrogen Council.

BIOENERGY OPENS UP CCS - BECCS

"... we can't work out how you get to 1.5 degrees without negative emissions technology that doesn't currently exist ... " Fiona Reynolds, PRI

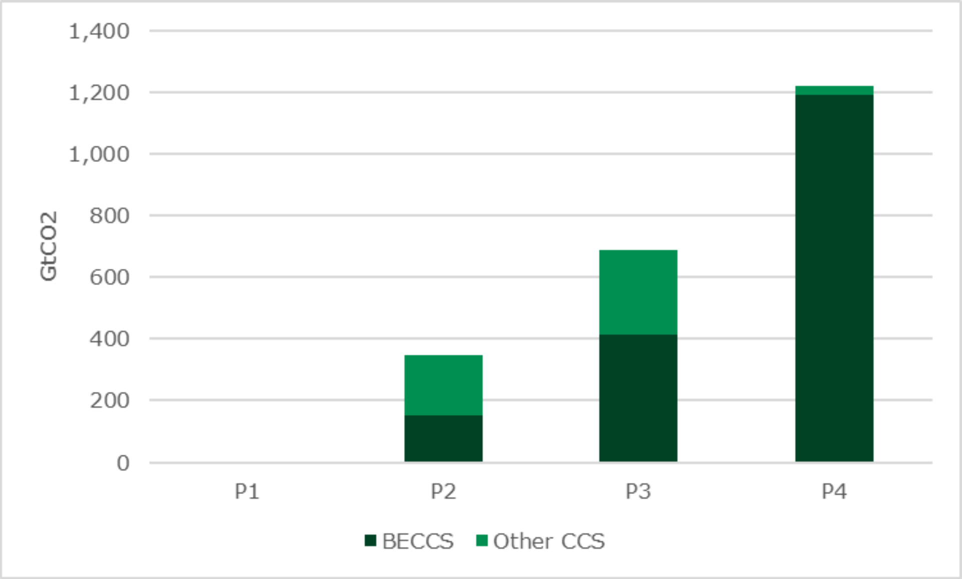
Bioenergy with carbon capture and storage results in carbon dioxide being removed from the atmosphere. It thus goes beyond zero emissions. Given that some greenhouse gas emissions are extremely difficult to avoid, the only way to get to zero is to have sufficient negative emissions to offset the unavoidable ones. Hence the "net" in net zero. BECCS is the leading technology solution likely to achieve this.

There are several stages to BECCS: biomass production and generation, carbon capture, and finally carbon storage.

Why we need BECCS

The IPCC's 1.5 degree report groups its 90 net zero scenarios under four illustrative model pathways. The first suggests that there is no need for BECCS at all, with residual GHG emissions being offset by changes in land use that absorb carbon. However, this is the most optimistic scenario and assumes early and sustained progress on decarbonising every area of current emissions. The other scenarios all require considerable use of BECCS.

BECCS contribution to 1.5 degree pathways under four scenarios

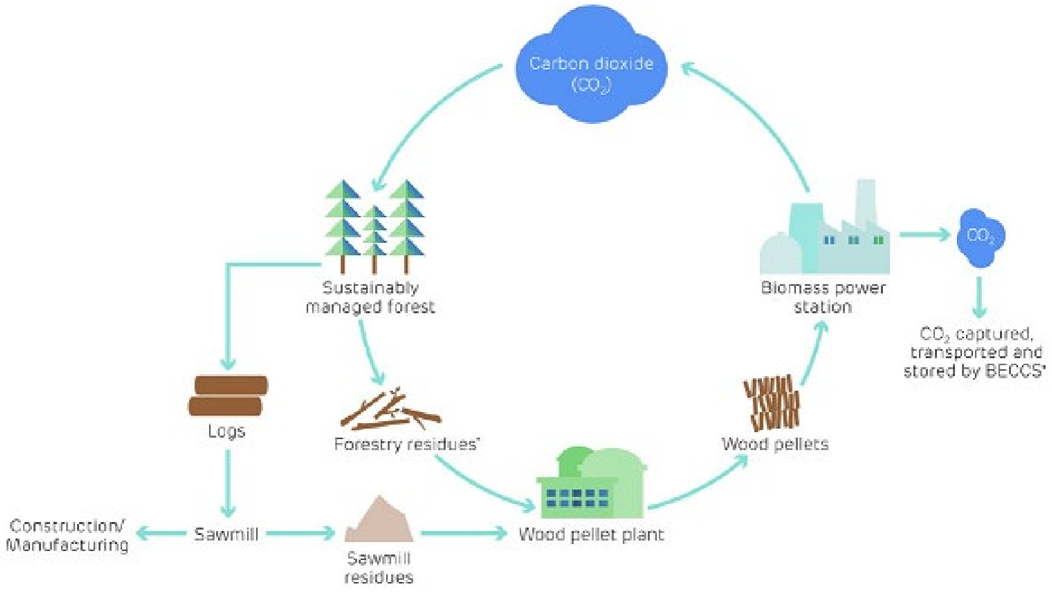


Source: IPCC

Our own assessment of the IPCC pathways and an analysis of an achievable case similar to the IPCC P2 case suggests that BECCS is needed to deal with around 4GtCO2e of emissions per annum. In the UK, the government's Committee on Climate Change (CCC) has strongly backed BECCS as a key tool in reaching net zero; *"using biomass with CCS to store carbon and produce a useful energy service is likely to deliver more abatement than most other potential end-uses."*

Taking the CO2 from the biomass generation process and storing it underground means that in principle, every tonne of CO2 captured by the growth of the tree is permanently removed from the atmosphere. In practice there are likely to be some losses, but these can be minimised through good design and management of the process.

CO2 Cycle with CCS



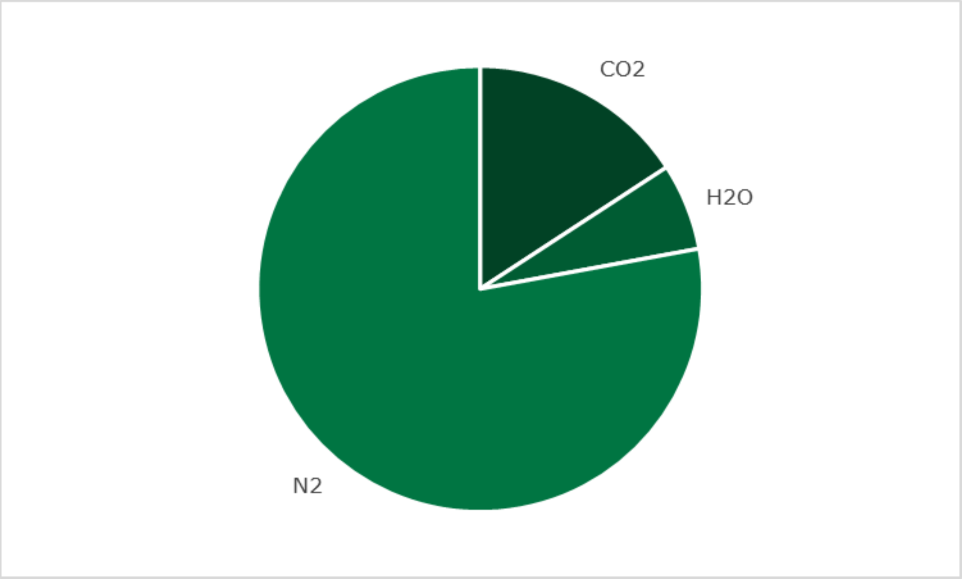
Source: Drax Group

It is one thing to capture CO2 but another to store it, effectively sequestering it where it cannot damage the atmosphere. Velocys PLC has found a solution and engaged with oil company Occidental who have an immediate need for CO2. Similarly, other companies with a need for CO2 are likely to create demand that can overcome the cost of sequestration.

CARBON CAPTURE TECHNOLOGIES

The problem with capturing CO2 from waste gases in biomass combustion is that the waste gases are not comprised of pure CO2. Less than a quarter of the flue gas will be CO2 with water and nitrogen comprising much of the rest. The capture process essentially deals with splitting out the CO2 from this gas stream.

Flue gas emissions



Source: Syed Muzaffar Ali, University of Boras

There are three principal methods of achieving carbon capture.

1. Pre-combustion capture

2. Oxy-fuel combustion

3. Post-combustion capture

Pre-combustion uses gasification or steam methane reformation of fossil fuel to create hydrogen and pure CO2. Gasification is the technology available to UK biomass to fuel company Velocys. The economics for creating a road fuel or aviation fuel make sense but would be harder to achieve for electricity production in the current environment.

Oxy-fuel combustion undertakes the fuel combustion in pure oxygen rather than in air. This results in a relatively pure CO2 flue gas. Effectively the other flue gases are removed at the oxygen separation stage necessary to produce the oxygen.

Post combustion capture involves removing the CO2 from the flue gases and is the most developed solution. The use of amines (most commonly monoethanolamide, MEA) to take out the CO2 is a proven technology used in oil refining. This could be used today for CCS from biomass power stations. The barrier is simply cost. The main costs are threefold.

- Capital costs

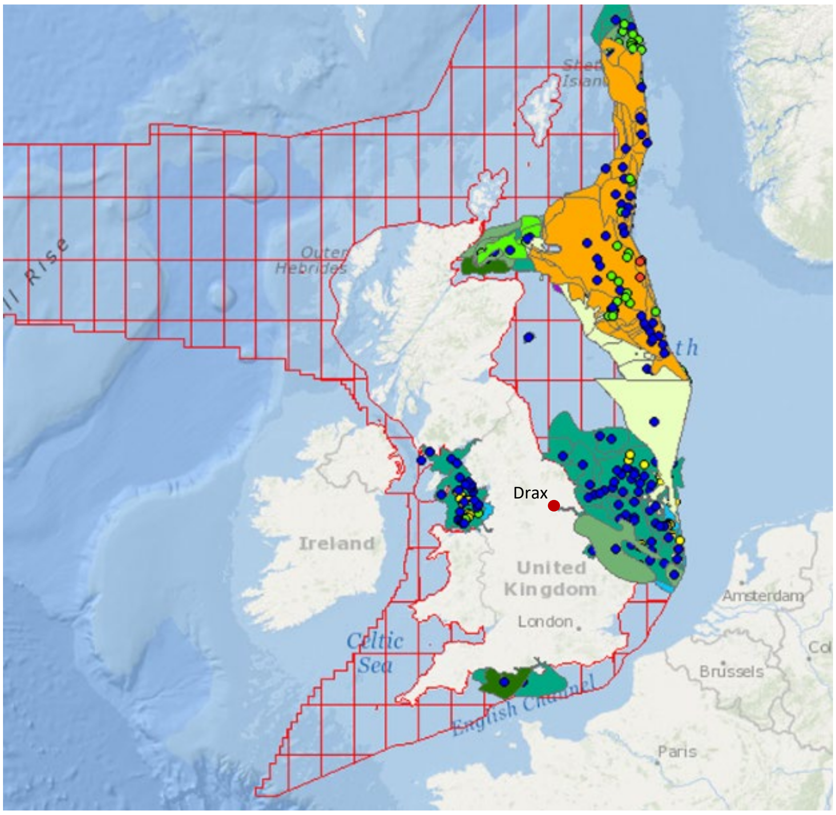
- Parasitic load and low-pressure steam from the host power station (represented by a loss of overall plant efficiency)

- Cost of the amines

The parasitic load energy penalty required for the extraction of low-pressure steam can be significant. Data from available studies (Smelster et al., 1991; Mimura et al., 1997; Bolland and Undrum, 1999; Marion et al., 2001; Hendriks, 1994) give a range of 22% to 30% for a retrofit plant. A new plant designed for CCS can reduce this range through design optimisation to between 9% and 22%.

Additionally, there is a cost in removing the CO2 and storing it. The CO2 itself has uses in a number of industries including (and perhaps ironically) the oil and gas industry where it is used for enhanced oil recovery. Given that there will still be a need for oil in the chemicals industry even in a net zero scenario, this is not all bad.

Potential CO2 Storage UKCS



Source: CO2 Stored

Straightforward amine capture is currently the most viable technology on offer for biomass generation with post combustion capture. However, a number of technology improvements are in the offing.

C-Capture, a Leeds University department of chemistry spin out, is working on a post combustion capture technology with an alternative capture media to MEA. Because MEA requires significant quantities of heat for regeneration of the solvent, the C-Capture replacement can reduce both the cost of the solvent and the energy cost of the process. Drax is an equity partner in C-Capture along with BP and IP Group. Drax has created an incubation area at the Drax power station to evaluate the C-Capture and other technologies. Mitsubishi Heavy Industries (MHI) also has an alternative solvent which can again reduce both the cost of the solvent and the energy cost of the process.

Fuel Cell Energy has developed its molten carbonate fuel cell (MCFC) technology for CCS. Unlike other fuel cells, MCFC requires CO2 at the cathode to replenish carbonate ions consumed in reactions at the anode. This can be provided in impure flue gases but the output from the cell (from the anode) is CO2 and water with the nitrogen in the flue gas expelled at the cathode. In the process the cell generates electricity, so the inefficiency seen in amine capture processes is essentially reversed. Fuel Cell Energy claim a cost of CO2 capture of below US$40/t.

COST OF CCS

As a starting point we can estimate the cost of normal amine capture.

The Petra Nova CCS project in Texas was constructed for US$1.0bn for a 645MW sized coal-fired generator although only processes 37% of the emissions (240MW). This is a reasonably recent project and gives us a start point for estimating capital costs. The market cost of MEA is currently around €1300/tonne and despite recycling the amine, 1.5kg is required to be made up for every tonne of CO2 captured. The typical efficiency give up for CCS is 26 percentage points. We can use these factors to estimate a levelised cost of CO2 capture for full CO2 capture at a 645MW power project.

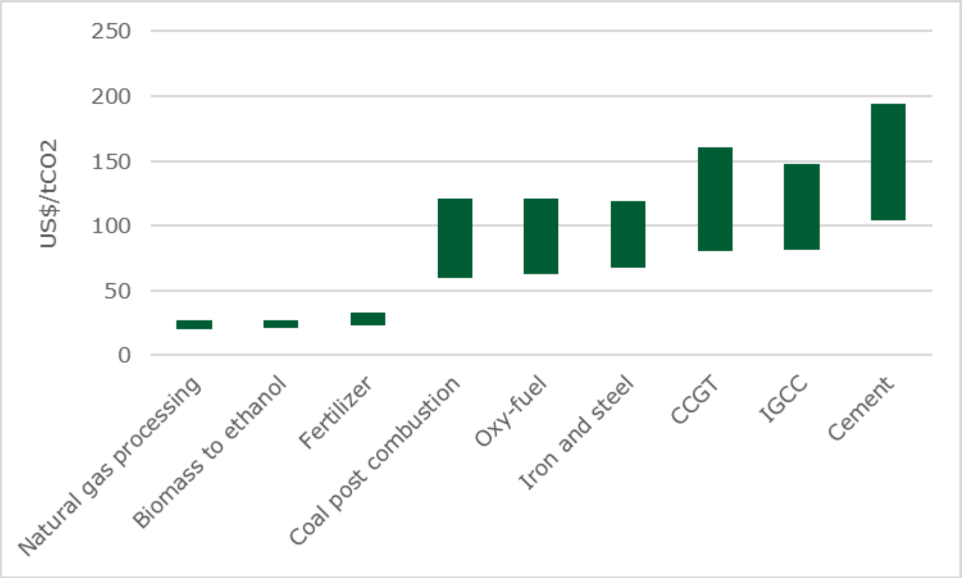
Typical amine post capture CCS costs

	FOAK
Life (years)	25
Availability	90.0%
Effective tax rate	19.0%
WACC	10.0%
Capital Recovery Factor	0.1102
Capacity (MW)	645.0
CO2 captured (mt)	4
Capital cost (£m)	2,000
Efficiency give up	33%
Electricity cost (£/MWh)	58
MEA make up (kg/tCO2)	1.5
MEA cost (€/t)	1,500
Costs per kg of CO2	
Capital cost	55.1
Electricity cost	25.6
MEA cost	2.0
Levelised cost of CO2 per kg	**82.7**
LCoCO2 US$/kg	**103.3**

Source: Longspur Research

This is consistent with findings from the global CCS Institute for coal post combustion which will be similar for these biomass units, having been converted from coal units.

CCS costs of CO2 capture



Source: UK Parliament, adapted from Global CCS Institute

Improving the costings

The opportunity to retrofit CCS at existing biomass sites may allow capital savings to be made especially for existing industrial sites with prepared ground. As we have already noted both C-Capture and Mitsubishi are working to develop cheaper solvents to amine. This has the potential to reduce operating costs significantly. The solvent itself would be cheaper but also the low-pressure steam requirement is reduced. We also assume this similar system could be delivered at a lower capital cost.

Revised post capture CCS costs

	FOAK	**NOAK**
Life (years)	25	25
Availability	90.0%	90.0%
Effective tax rate	19.0%	19.0%
WACC	10.0%	10.0%
Capital Recovery Factor	0.1102	0.1102
Capacity (MW)	645.0	645.0
CO2 captured (mt)	4	4
Capital cost (£m)	2,000	1,250
Efficiency give up	33%	10%
Efficiency give up	33%	10%
Electricity cost (£/MWh)	58	58
MEA make up (kg/tCO2)	1.5	1.5
MEA cost (€/t)	1,500	1,500
Costs per kg of CO2		
Capital cost	55.1	34.4
Electricity cost	25.6	7.8
MEA cost	2.0	2.0
Levelised cost of CO2 per kg	**82.7**	**44.2**
LCoCO2 US$/kg	**103.3**	**55.2**

Source: Longspur Research

FUNDING CARBON CAPTURE

The US model

The USA is a leader in support for CCS through its 45Q tax credit programme. The Energy Improvement and Extension Act 2008 amended by the Bipartisan Budget Act 2018 allows tax credits for every tonne of CO2 stored or used, including for EOR. These tax credits can be used against a carbon storage operators tax liability or sold in the tax equity market. The value of the credits for EOR projects rise from US$19/tCO2 in 2019 to US$35/tCO2 in 2026. The values are higher where the CO2 is sequestered without any further utilisation with credits rising from US$31/tCO2 in 2019 to US$50/tCO2 in 2026.

45Q Tax Credit Values (US$/tCO2)

	2019	2020	2021	2022	2023	2024	2025	2026	2026 onwards
Dedicated geological storage	31	34	36	39	42	45	47	50	Indexed
CO2-EOR	19	22	24	26	28	31	33	35	to
Other CO2 utilization processes	19	22	24	26	28	31	33	35	inflation

Source: Global CCS Institute, The LCFS and CCS Protocol 2019

The International Energy Agency (IEA) estimated that the credit could spur $1bn of investment in 10m-30m tonnes of CO2 storage capacity.

Carbon credits

It should be possible to trade the negative emissions created by CCS to offset obligations under carbon taxes. The UK government has signalled that it will replicate the European Emissions Trading Scheme (EU-ETS) in the UK post Brexit. The ETS itself has seen prices remain resilient to the COVID 19 pandemic. While emissions have clearly fallen, the Market Stability Reserve (MSR) mechanism has kept prices high, and the outlook remains strong.

Both schemes work on the basis that qualified carbon avoidance can generate a carbon credit. CCS goes further than mere avoidance. The underlying logic is that any CCS project should generate two carbon credits per tonne of CO2.

This principle was effectively recognised under the NER300 mechanism set up under the ETS. This was aimed at encouraging CCS and set aside 300 mt of EUAs. Take up has been poor thanks in part to an extremely bureaucratic process and the decline in the value of EUAs prior to the introduction of the MSR.

If a similar principle was followed in the UK, CCS could benefit to the tune of £66/t of CO2.

CfDs

Leading power industry consultants, Cornwall Insight, together with international consultants, WSP, conducted a study of market-based frameworks for CCS funding for BEIS in 2019. This particularly focused on contract for difference (CfD) type support in line with current support for large scale renewables in the UK. Three options were examined, a baseload CfD, a hybrid CfD and a flexible CfD with a capacity payment. The third option was seen as the most viable. While the detail would be critical for success, our observation is that the CfD programme has been very successful in incentivising new offshore wind in the UK, and this could be a valid approach for CCS.

The UK Government has now published further guidance on its approach to funding CCS. The guidance splits carbon capture from CO2 transportation and storage (T&S) with the latter subject to regulatory price controls similar to other UK networks. This will give the transportation and storage provider a regulated price to charge carbon capture companies for the removal and storage of CO2.

Power providers who also capture carbon will be funded through a dispatchable power agreement (DPA) which is paid in addition to electricity revenues. The DPA will be funded by electricity consumers and will comprise an availability payment and a variable payment with the latter reducing at times when other low carbon generation is available. The variable payment effectively reduces the short run marginal cost of CCS generation in the wholesale markets, placing it ahead of unabated reference generation of the same technology by the amount of the additional variable costs of operating carbon capture.

Industrial CCS projects will then receive a fifteen-year ICC contract structure in a similar way to the current UK contract for difference (CfD) subsidy scheme for renewable energy. More specific support for BECCS is likely to emerge and has the potential to allow baseload running in order to maximise the company’s negative emissions capability.

In summary, we think the CCS element of BECCS can be undertaken at a cost that allows proven support mechanisms to allow for funding and deployment.

VALUING CCS

Using our LCoCO2 model assumptions we can value a BECCS generation unit. We have assumed a CO2 price at US$100/t. Our model shows that a first of a kind (FOAK) unit could be breakeven at this point assuming a 8% cost of capital. More interestingly a nth of a kind (NOAK) unit using a lower energy requirement solvent and with a higher CO2 price could see a single 645MW unit return a 19% IRR.

CCS Valuation

£m	FOAK	NOAK
Capacity (MW)	645	645
Availability	90%	90%
Power output (TWh)	5	5
CO2 captured (mt)	4	4
Capital cost (£m)	2,000	1,250
Efficiency give up	33%	10%
Electricity cost (£/MWh)	61	61
MEA make up (kg/tCO2)	1.5	1.5
MEA cost (€/t)	1500	1500
Carbon tax (US$/t)	100.0	100.0
GBPUSD	1.25	1.25
Revenue	320	320
Electricity cost	102	31
MEA cost	8	8
Total costs	110	39
EBITDA	210	281
Depreciation	80	50
PBT	130	231
Tax	25	44
Cashflow to equity	185	237
IRR ungeared	8%	19%

Source: Longspur Research

Note that the economic characteristics of CCS are a high capital cost and lower ongoing costs. To earn a return on the high initial spend, the projects must deliver a high gross margin. This is a similar profile to renewable energy. As such, these projects could in time show the cash flow profiles that have attracted pension funds and yieldcos to renewable projects. This could open up useful sources of funding once the technology has proved itself in the power industry. Given the fact that the technology has largely proven itself in the oil and gas industry, this could move quite quickly.

ENHANCED OIL RECOVERY

CO2 needs to be permanently sequestered in suitable geological formations. One option is to use CO2 in Enhance Oil Recovery (EOR). EOR entails injecting fluid into oil reservoirs in order to extract oil that cannot be recovered by other means.

While it may seem counter intuitive to use the CO2 to extract more fossil fuels, the benefit of doing so is that this will displace more carbon intense fossil fuel production and there will always be some demand for oil by the chemicals industry if not for energy.

Several techniques are used with varying success. These can be categorised as thermal, gas or chemical.

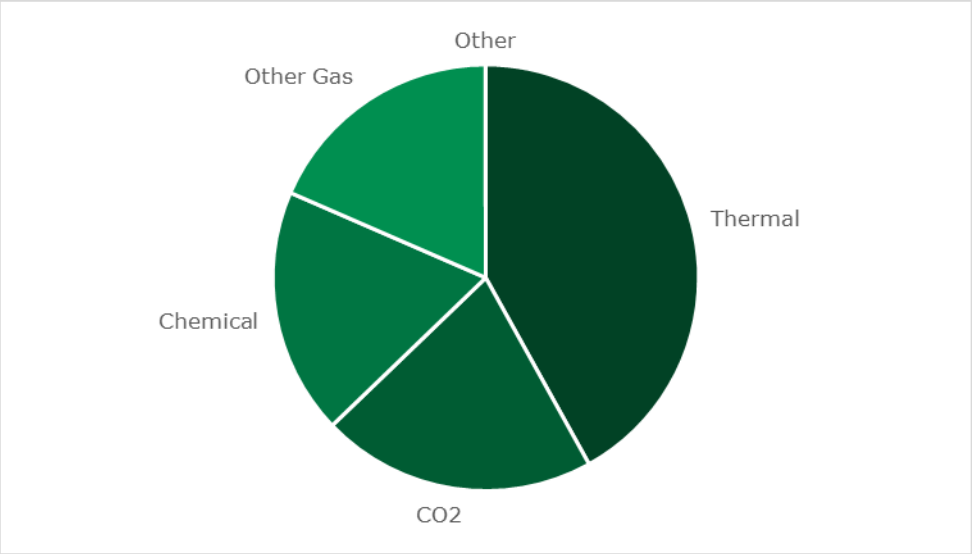
Thermal EOR uses steam to heat the oil in the ground, reducing its viscosity and making it easier to move. This is most often applied in heavy oil reservoirs.

CO2 EOR sees CO2 injected into the subsurface. In a miscible CO2 process, the CO2 mixes with, or dissolves into the oil, increasing its mobility and susceptibility to being pushed by water. In an immiscible process, the gas does not dissolve into the oil but rather pushes the remaining oil; this is often combined with water injection.

Other gas injection EOR is similar to CO2-EOR, but with other gases injected such as natural gas or nitrogen. There has been a recent trend in using field gas, essentially associated gas from the existing oil well. Chemical EOR uses water soluble polymers and/or surfactants which are added to water that is injected into the subsurface. Polymer-loaded water has a high viscosity and can push more oil out of the pores in the oil-bearing formation. Surfactants reduce the surface tension of the oil, improving its ability to be displaced by water.

There are some other EOR techniques including the use of injection of micro-organisms into the reservoir or combustion, which involves in-situ burning of some of the oil to generate both heat and gases that help the rest of the oil move more easily.

EOR Production by Type



Source: IEA EOR Project Explorer

CO2 already has some identifiable benefits over other EOR technologies. The miscibility of CO2 is a major advantage, and it is also a less expensive solution compared to other choices for miscible flooding. Of course, the fact that it can be used for CO2 capture is itself a major advantage.

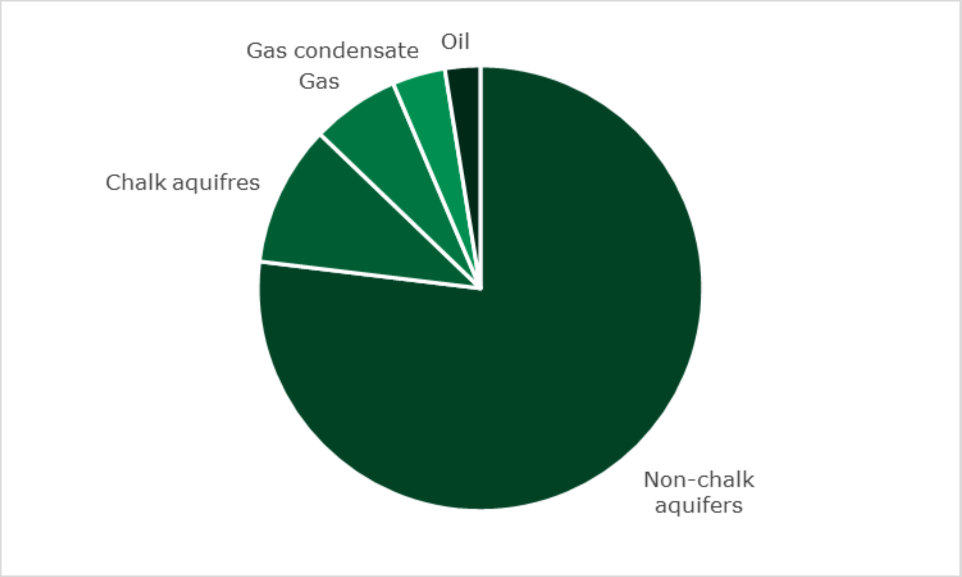
EOR in shale oil fields developed by fracking can be more challenging that traditionally developed oil fields. However, the opportunity to use CO2 as an EOR injectant is being identified as a major opportunity. There has been a noticeable shift towards CO2 in recent research activity. Independent industry researcher, Thunder Said Energy, has identified 46 papers into shale EOR showing the dominance of CO2 as an injectant.

It has been estimated that if 20kt to 30kt of CO2 could be sequestered during EOR in the Permian shale wells, then this field could become the lowest CO2 resource in the oil industry while maintaining its position at the bottom of the oil industry cost curve. Given that oil will still be required even in a net zero policy scenario, this is important.

THE BENEFIT OF CCS CLUSTERS

The UK government is focusing on supporting carbon capture and storage within clusters where multiple sites will capture CO2 and feed it to a shared pipeline infrastructure. This in turn leads to storage options. The UK continental shelf is well provided with potential storage with a P50 estimate of 78GT of storage capacity, primarily in saline aquifers.

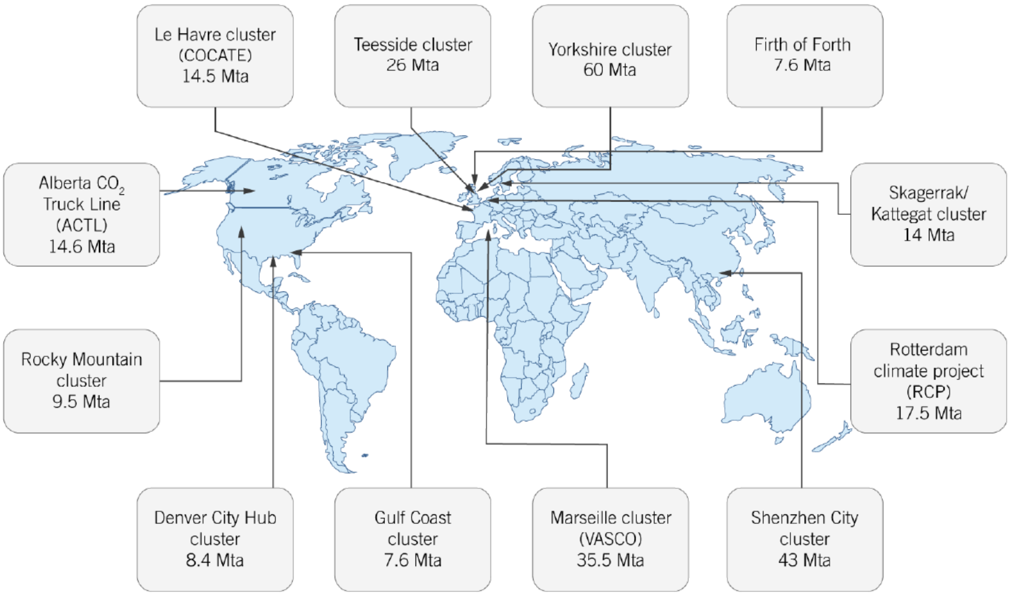
CO2 storage capacity in the UK



Source: Energy Technologies Institute

The hub and cluster concept is a well-established concept with a number of hubs being developed globally indicating a degree of consensus over this approach.

Major CCS Clusters



Source: Global CCS Institute, Adapted from IEAGHG 2015a and ZEP 2014 data

To quote the Global CCS Institute:

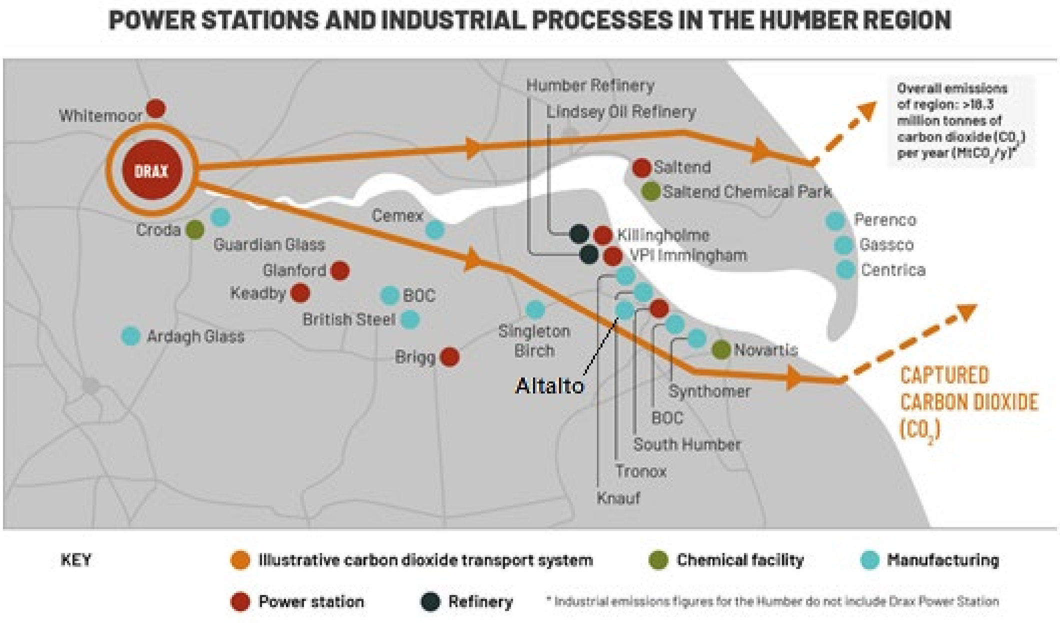
> *"Hub and cluster networks offer several distinct advantages for network participants, compared with 'point-to-point' projects. The hub and cluster approach reduces costs and risks for many potential CCS projects and enables CO2 capture from small volume industrial facilities."*

We see clusters as creating three key benefits:

- Attract public and private funding
- Create economies of scale
- Allow participation by companies of all sizes

The UK sites are all developing, with Zero Carbon Humber making significant strides. A key development here is the Equinor led Hydrogen to Humber (H2H) project at Saltend. This a blue hydrogen project converting natural gas to hydrogen and capturing CO2 for sequestration. The project is expected to capture up to 1.4mt of CO2 in its first year of operation which is expected to be 2027. This is still relatively small but begins to create the scale required to make the hub work. Beyond that, Drax is likely to capture 8mt from its initial two biomass units and, at that scale, the whole hub becomes meaningful with opportunities for large and small CO2 capture projects including potentially the Velocys Altalto sustainable aviation fuel project.

Zero Carbon Humber



Source: Zero Carbon Humber

A CLEAN ENERGY SEGREGATION

This demand for clean energy seems very exciting from an investment point of view. We would warn investors that making the demand case has seldom been a problem in the clean tech industry. The real issues that distinguish between good and bad investments are on the supply side and especially technology delivery, competitive position, and regulatory distortions.

In order to better identify risk issues, we use a Clean Energy Value Chain. This splits companies into innovators, manufacturers, and developer/operators. These categories have very different exposures to the main risks of technology, markets, and regulation.

Longspur clean energy value chain

	Innovator	Manufacturer	Developer/Operator
Technology risk	🟥 High Unproven technology	High/Medium: Medium Substitution risk	🟩 Low Diversified
Policy risk	Medium Needs policy support	🟩 Low Diversified from individual policies	🟥 High Revenue is policy driven
Market risk	🟩 Low Unique product/IP	🟥 High Competitive market	Medium Limited competition

Source: Longspur Research

Innovators are classic clean tech companies where technology risk is key. Manufacturers provide proven low carbon technologies and principally deal with market risk, especially competition. Finally, developers mainly face policy risk, not just where they receive subsidies but also market structure risk. All three groupings can offer attractive investment opportunities provided these risks can be mitigated. We show below examples of companies within this framework.

Example Active Net Zero companies

	Innovator	**Manufacturer**	**Developer/Operator**
Renewables PV	Midsummer	First Solar	**NESF**
Renewables Wind	Windar Photonics	Vestas	Orsted
Renewables Other	AEG	**SIMEC Atlantis**	**SIMEC Atlantis**
Storage li-ion	Nano One	**Talga Group**	**Gore Street**
Storage other	Invinity	Cap-XX	**Drax Group**
Hydrogen	**Advent Technologies**	**ITM**	Everfuel
BECCS/CCS	**Velocys**	Occidental	**Drax Group**
Efficiency	**Swedish Stirling**	**SIT**	Smart Metering Systems

Source: Longspur Research (Longspur Research Clients shown in **bold**)

DEVELOPERS – MANY TO CHOOSE FROM

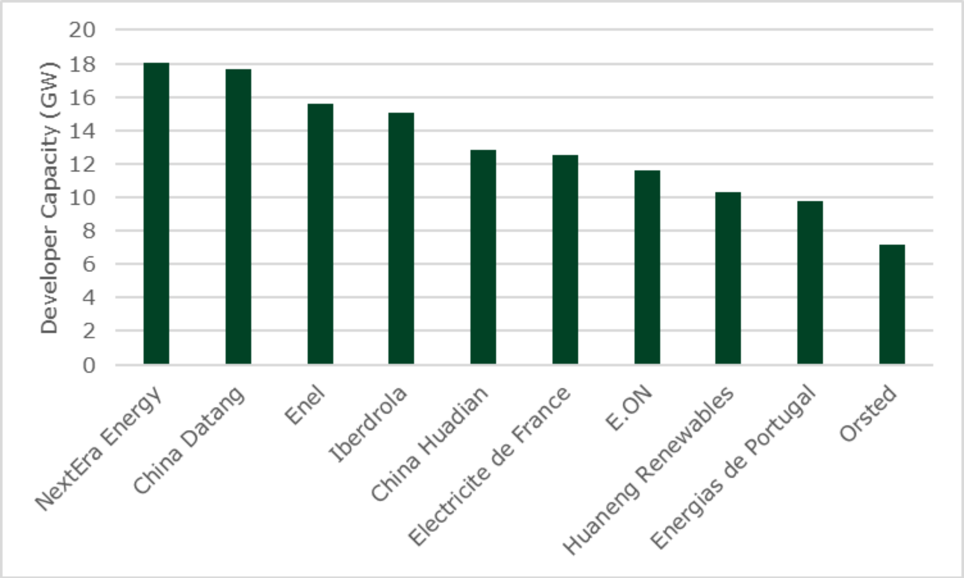
Zero carbon developers are principally active in wind energy, PV, hydro and storage although we also see opportunities in EV charging, waste to energy and BECCS. They can be very exposed to the missing money problem but as we have said we think this is only an issue if companies do not respond by integrating with storage or vertically integrating. Investors need to ensure that target companies have found a way to mitigate this risk.

Perhaps the bigger risk is that of policy, as markets can be severely distorted by regulation and other policies such as planning restrictions. Regulatory solutions to the missing money problem in particular could result in highly regulated markets. Planning and permitting are also essential requirements for developers and are themselves a subset of regulatory policy.

As a result, the exact nature of domestic markets in which companies operate is a key investment consideration.

We also note that finding pure plays in this field can be difficult as many of the larger players are utilities or similar with exposure to legacy fossil fuel assets. Offtake contracts, vertical integration, and asset mix (including storage) are also key to investment decisions in this area.

Top ten renewable energy developers



Source: BNEF

Yieldcos as operators

Many developers are owners, but a growing number find it more efficient to spin off developed assets into new structures. Key here are the yieldcos which own developed assets and harvest their cashflows, normally distributing these to create high income vehicles for investors. The key to these companies is their resilience to any change which might threaten their income stream and again this is primarily a regulatory risk. The one thing these companies avoid which other developers face is exposure to execution risk, principally in construction. However, we believe asset prices generally compensate early-stage developers for this risk.

MANUFACTURERS – COMPETITIVE RIVALRY

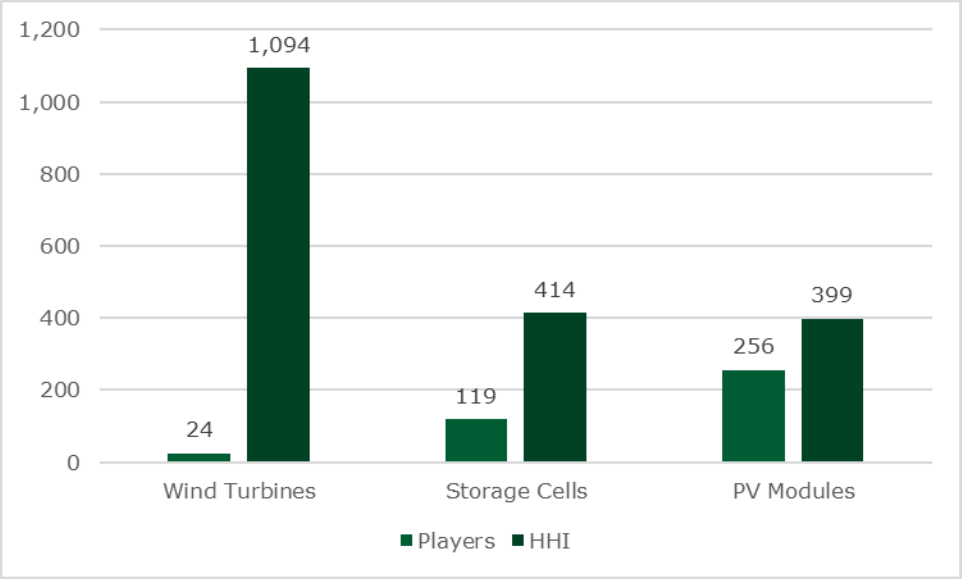
The experience of solar photovoltaic manufacturers is a cautionary tale for all companies involved in manufacturing low carbon solutions. The extent of competition, notably from state backed Chinese manufacturers, has been harsh. The demise of Yingli Green Energy is emblematic. This was one of the world's largest suppliers of solar cells yet has been loss making in recent years, liquidating its NYSE listed holding company and now in a major restructuring exercise.

That said, certain other companies have made good returns in the field of PV manufacturing. We see two routes to success. Firstly, having a differentiated technology can create winners. First Solar is a good example here. Its cadmium telluride cells are better performers in certain conditions such as temperate moist climates (e.g. India during the monsoon season) and has found a strong niche. Secondly, controlling markets through self-development can also be profitable, and we see Canadian Solar as a good example of this.

Away from PV, storage is at a different stage but feels as if it could follow PV. There are a large number of players with some strong Chinese manufacturers. However, a diversity of chemistries makes more First Solar type opportunities possible. With the exception of pumped hydro, long duration storage technologies are not fully developed, and we see most players here as technology companies rather than manufacturers.

Wind manufacturing is a very different proposition with a much more concentrated market. We are amused by the fact that current turbine technology was invented by a high school and brought to market by an agricultural machinery company. Essentially a school project put tractor parts up a steel tube. Yet this history masks what is actually very complex engineering which has created barriers to entry for the major players. Against the other key markets this is a more concentrated world with just 24 major players and a Herfindahl-Hirschman Index (HHI) of 1,094. We see the provision of turbines and services to the growing floating offshore market as a key opportunity here.

Market structures in wind, PV and storage



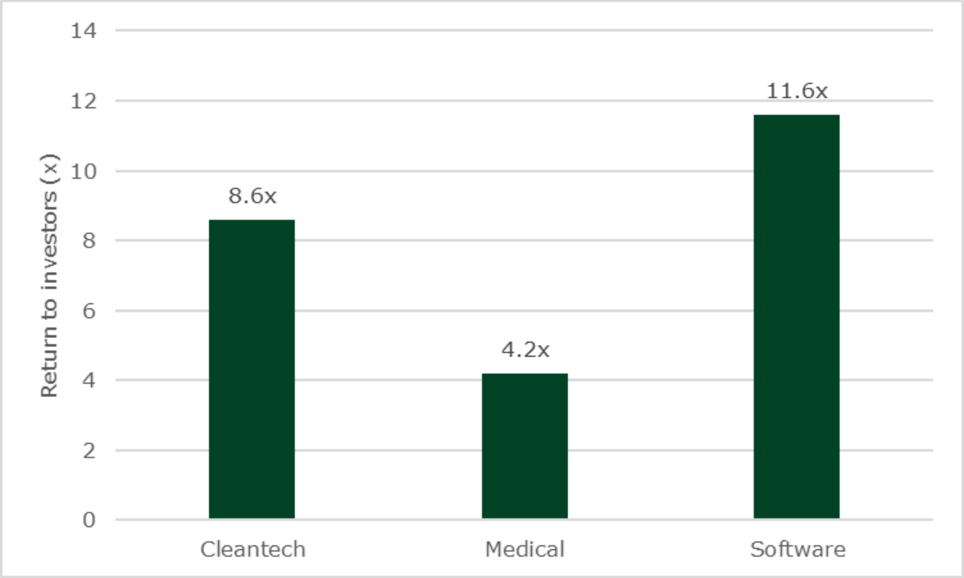
Source: BNEF, Longspur Research

Investors in clean tech manufacturers need to examine individual markets in detail and pay particular attention to competitive structure which will vary with the market. Undertaking a detailed five factor analysis or similar could be extremely useful here.

TECHNOLOGY HAS BEEN DIFFICULT

Technology innovators represent the classic cleantech play. The technologies being developed have the potential to become global solutions with significant sales. The listed space is not too different from the unlisted. A 2016 paper from the MIT Energy Initiative looked at returns in private cleantech versus medical tech and software*. Overall returns were disappointing, but the study also looked at how successful companies performed and this showed that cleantech could beat medtech.

Return to investors (2006-2011) from successful companies



Source: MIT

The results have been distorted by the success of NEST, the home control solution, in the data but it does not mean that successful cleantech cannot make high returns. In the listed space most of the problems have been around creating commercial traction. This of course is something that can benefit from a more favourable environment where buyers are more prepared to step up. We see this continuing as we emerge from the current crisis and see strong opportunities for investors.

The UK cleantech space has seen some strong moves in recent months and, despite the pandemic sell off, has remained resilient and performed strongly to date. Given that most companies have investment cases based on sales several year's out, this is rational.

The main problem has been that most clean technologies have taken too long to mature. This is in a large part due to underfunding and in particular under funding of marketing. Too many companies have fallen foul of what we call the Field of Dreams Fallacy. Unfortunately, "if you build it, they will come" is not a proven marketing strategy and too many cleantech companies have seen potentially viable products fail to gain traction as routes to markets were inadequately resourced or pursued.

We believe that there has been a change here with

- Licencing
- Corporate venturing and partnering
- Better funding

*Gaddy, B., Sivaram, V., O'Sullivan, F., 2016: Venture Capital and Cleantech: The Wrong Model for Clean Energy Innovation, MIT Energy Initiative Working Paper

LICENCING

Licencing removes the need to develop and fund manufacturing capacity when others may be better placed to do that. This allows the technology innovator to focus on what they do best. We use sustainable biofuels company Velocys as a case study in licencing. Velocys is adopting a technology licencing model with three key offerings.

Velocys as a case study in licencing

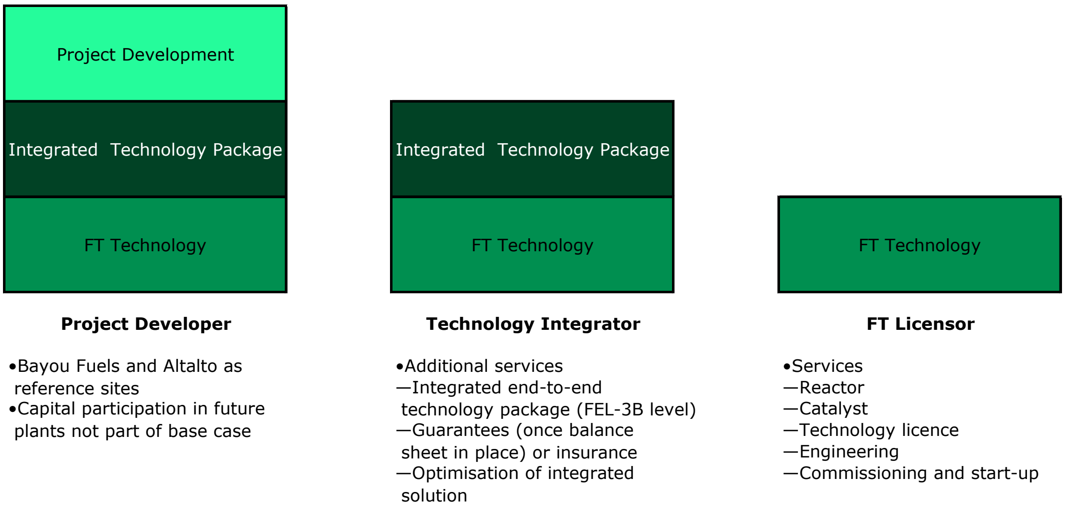
The core business is the licencing of the technology. A technology licence is sold to each new project together with engineering, commissioning and start up services. Velocys will also sell certain critical components which it has manufactured under contract. This includes a catalyst, and catalyst replacement provides an ongoing revenue stream over the life of the project. This enables Velocys to engage with market demand in a capital light model with manageable liabilities. This is likely to be the main model for the company going forward.

In addition to this basic licencing model, Velocys also offers an integrated technology package (ITP). This creates value from the company's experience in integrating its technology into full solutions and benefits from the considerable know-how built up over the company's history. During project development the company will charge an integrated package fee plus engineering service fees with additional commissioning and start up fees at financial close. An ongoing royalty will be based on the extent of decarbonisation achieved and an additional optimisation fee will be sought.

Finally, Velocys sees economic benefit from its involvement in the development of reference plants. This has been seen as necessary to prove the company's technology concept despite it being an exception to the otherwise capital light model. There is of course an opportunity for the company to sell down its interest in these projects once they are operational and, additionally, funding support from partners may reduce the overall capital requirements. These projects will bring in dividend income during operation but Velocys will also benefit from income from the projects under its other income models.

The different timing of payments means that the company will benefit from some early income during project development, at financial close and on start up, and also over the life of the projects.

Velocys Business Models



Source: Company Data

CORPORATE VENTURING AND PARTNERING

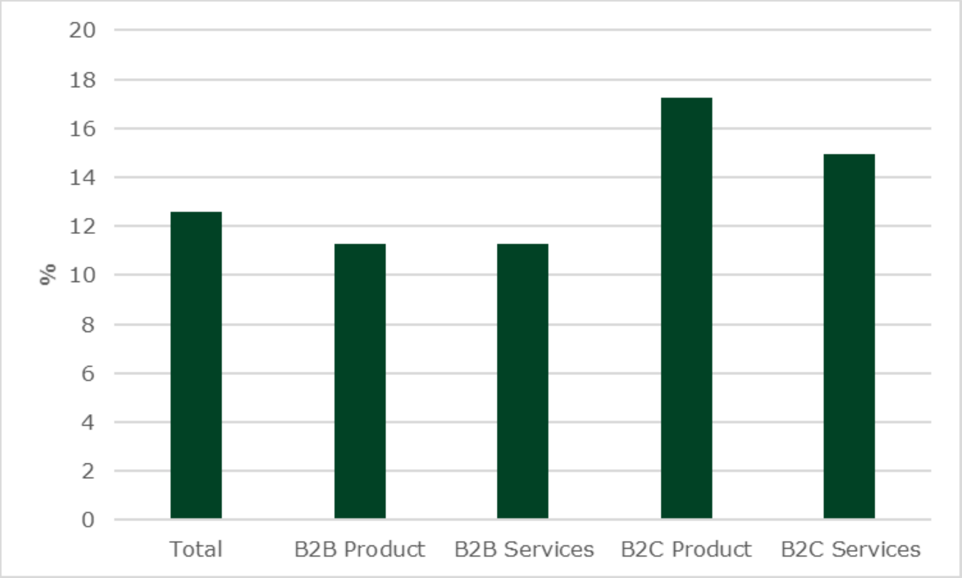
Corporate venturing and partnering where industry majors partner with and take minority stakes in cleantech companies has emerged as a theme in the sector in recent years. The ESG movement is pushing larger, established companies to take a greater role in the energy transition. Companies such as oil companies, who may find themselves redundant in a zero-carbon world, increasingly see the development of clean technologies as a matter of survival. They also know that the history of incumbents attempting to move to new business models has been a bad one. After all Kodak invented the digital camera, Blockbuster invented movie streaming, and both were killed off by their own inventions. The issue is generally one of culture and the answer is to develop new models outside of the corporate culture of an industry incumbent.

Genuine corporate venturing with minority stake investing and a hands-off approach can give majors exposure to the entrepreneurial cultures required to build new technologies and businesses. It also provides other investors with confidence as they see support and commitment from an existing industry expert. As such it can be seen as due diligence by proxy.

BETTER FUNDING

Just because clinical death is defined as the heart stopping does not mean everyone dies from cardiac arrest. Similarly, just because companies are defined as insolvent when they run out of money does not mean every company fails because it has no cash. The causes normally begin long before that point. However, we think undercapitalisation has been an issue for the clean tech sector especially since the 2008 global financial crisis. Many companies have raised only enough capital to develop a product. They have failed to raise enough to develop and sell a product. Selling is crucial. Many cleantech firms with viable products struggle to find traction yet marketing is a small percentage of overall spend. The average US company spends over 12% of its budget on marketing. Cleantech companies should do this but often lack the funding.

What % of your overall budget does marketing currently account for?



Source: The CMO Survey

The renewed interest in the sector resulting from the growth in ESG investing can only help here. While there will be companies that fail, better capitalisation, especially when it leads to better marketing, is likely to reduce the failure rate in our opinion.

There are many new clean technologies under development. We see technological readiness level 6 as a key investment point where a full prototype at scale is ready to move to the demonstration phase and may consider public market investment if the market potential justifies it.

Technologies at TRL 6 from the ETP Clean Energy Guide

TRL	Technology
6	Biodiesel > Gasification and Fischer-Tropsch
6	Building envelope > Wall, roof & façade > Building integrated solar thermal collector (BIST)
6	Integration > Virtual inertia/fast frequency response
6	Biodiesel > Alcohol-to-Jet
6	Automated and connected vehicles (level 4+) > Hardware
6	Cement kiln > CCUS > Oxy-fuelling
6	Solar > Photovoltaic > Organic thin-film solar cell
6	Geothermal > Kalina process
6	Coal > CCUS > Post-combustion/membranes polymeric
6	Natural gas or Coal > CCUS > Supercritical CO2 cycle
6	Hydrogen > Hybrid fuel cell-gas turbine system
6	Ammonia > Cracking into hydrogen for gas turbines
6	Methane pyrolysis/cracking
6	Liquid organic hydrogen carrier tanker
6	Hydrogen-fuelled engine > Passenger car
6	Hydrogen-fuelled engine > Light commercial vehicle
6	Hydrogen-fuelled engine > Truck
6	Hydrogen-fuelled engine > Urban transit bus
6	Methanol fuel cell electric vehicle
6	Hydrogen fuel cell electric vehicle > High temperature proton exchange membrane
6	Production > Biomass-based > Gasification
6	Production > Fossil-based > Methane pyrolysis
6	Production > Biomass-based > Lignin
6	Cement kiln > CCUS > Novel physical adsorption (silica or organic-based)
6	Cement kiln > CCUS > Direct separation
6	Cement kiln > Direct heat from variable renewables > Concentrated solar power-generated heat
6	Concrete fines recycling
6	High temperature heating > Direct heat from variable renewables > Concentrated solar power-gener
6	Building envelope > Wall, roof & façade > Building integrated phase change materials
6	Building layout > Fiber-optic daylighting
6	Solid DAC (S-DAC)
6	Liquid DAC (L-DAC)

Source: IEA

ACTIVE NET ZERO COMPANIES

We define active net zero activities as those which help others to achieve net zero, not simply a company achieving net zero in itself. We distinguish this from passive net zero where activities merely become net zero in themselves. Passive net zero is to be welcomed and encouraged but for investors who want to do more, active net zero is what is required to deliver global net zero. Increasingly, investors will shun negative net zero, those companies who contribute to greenhouse gas emission either directly or through the use of their products. Companies who make a significant contribution to net zero should be those for whom a majority of their activities are active net zero activities. The key pan-European active net zero companies are shown in the following tables according to their Clean Energy Value Chain category.

Active net zero companies - Innovators

Company	Ticker	Market	Price	Cap (£m)	EV (£m)
Active Energy Group plc	AEG	Bioenergy	1	19	35
Cortus Energy AB	CE	Bioenergy	0	69	76
EQTEC PLC	EQT	Bioenergy	2	140	160
Global Bioenergies SA	ALGBE	Bioenergy	8	93	84
Quantafuel AS	QFUELME	Bioenergy	73	1,200	141
Velocys plc	VLS	Bioenergy	7	77	78
Smart Grids AG	BGZ	Efficiency	0	0	0
Swedish Stirling AB	STRLNG	Efficiency	22	255	261
Waturu Holding AS	WATURU	Efficiency	n.a	n.a.	n.a.
AFC Energy plc	AFC	Hydrogen	66	446	444
Ceres Power Holdings plc	CWR	Hydrogen	1,488	2,562	2,459
PowerCell Sweden AB	PCELL	Hydrogen	393	2,457	2,408
Powerhouse Energy Group PLC	PHE	Hydrogen	8	325	325
Proton Motor Power Systems Plc	PPS	Hydrogen	91	706	783
Azelio AB	AZELIO	Renewables	69	859	811
Blue Shark Power System SA	MLBSP	Renewables	6	40	40
Midsummer AB	MIDS	Renewables	12	89	112
Minesto AB	MINEST	Renewables	22	340	334
SeaTwirl AB	STW	Renewables	147	44	45
Verditek Plc	VDTK	Renewables	5	18	18
Windar Photonics Plc	WPHO	Renewables	27	15	18
GreenMobility A/S	GREENM	Storage	182	87	101
Ilika plc	IKA	Storage	235	327	315
Invinity Energy Systems PLC	IES	Storage	208	181	204
SaltX Technology Holding AB Class B	SALTB	Storage	5	56	53

Source: Longspur Research, Bloomberg

Active net zero companies - Manufacturers

Company	**Ticker**	**Market**	**Price**	**Cap (£m)**	**EV (£m)**
Climeon AB Class B	CLIMEB	Efficiency	46	304	292
Dialight plc	DIA	Efficiency	259	84	115
FW Thorpe Plc	TFW	Efficiency	331	386	323
LED iBond International A/S	LEDIBOND	Efficiency	21	44	43
Luceco PLC	LUCE	Efficiency	261	419	442
Lucibel SA	ALUCI	Efficiency	1	17	19
SIT SpA	SIT	Efficiency	7	198	306
ITM Power	ITM	Hydrogen	640	3,524	3,505
McPhy Energy SA	MCPHY	Hydrogen	32	1,086	1,067
NEL ASA	NEL	Hydrogen	32	5,353	5,066
Absolicon Solar Collector AB	ABSL	Renewables	152	37	33
EEMS Italia S.p.A.	EEMS	Renewables	0	46	46
Enertime SA	ALENE	Renewables	3	31	31
Enertronica Santerno SpA	ENT	Renewables	1	9	38
Nordex SE	NDX1	Renewables	26	3,740	4,028
Savosolar Plc Class A	SAVOS	Renewables	2	12	1
Siemens Gamesa Renewable Energy	SGRE	Renewables	35	28,931	29,473
SMA Solar Technology AG	S92	Renewables	62	2,601	2,382
SolTech Energy Sweden AB	SOLT	Renewables	41	344	443
Tekmar Group Plc	TGP	Renewables	74	38	38
Vestas Wind Systems A/S	VWS	Renewables	1,367	44,936	5,738
Alelion Energy Systems AB	ALELIO	Storage	1	19	25
CAP-XX Limited	CPX	Storage	12	53	95
Eurobattery Minerals AB	BAT	Storage	23	44	40
Hybricon Bus System AB	HYCO	Storage	3	2	2
Inzile AB	INZILE	Storage	49	117	113
Leclanche SA	LECN	Storage	1	303	375

Source: Longspur Research, Bloomberg

Active net zero companies – Developers

Company	Ticker	Market	Price	Cap (£m)	EV (£m)
Agripower France	ALAGP	Bioenergy	10	30	24
Albioma	ABIO	Bioenergy	45	1,705	2,640
BiON	BION	Bioenergy	3	12	89
Drax Group	DRX	Bioenergy	393	1,560	2,385
EnviTec Biogas	ETG	Bioenergy	27	496	541
La Francaise de l'Energie	LFDE	Bioenergy	24	147	166
SIMEC Atlantis	SAE	Bioenergy	20	100	228
Calisen	CLSN	Efficiency	261	1,430	1,943
eEnergy Group	EAAS	Efficiency	19	47	48
Innovatec	INC	Efficiency	1	76	68
Smart Metering Systems	SMS	Efficiency	697	787	746
Sustainable Energy Solutions	SUST	Efficiency	1	3	10
Everfuel A/S	EFUELME	Hydrogen	116	1,072	1,069
7C Solarparken	HRPK	Renewables	4	367	619
Abengoa	ABG	Renewables	0	161	5,847
ABO Invest	ABO	Renewables	3	172	328
ABO Wind	AB9	Renewables	46	516	588
Acciona	ANA	Renewables	125	8,316	15,438
Aega	AEGA	Renewables	3	19	16
Agatos	AGA	Renewables	1	11	28
Akiles Corporation	AKI	Renewables	0	3	34
Alerion Clean Power	ARN	Renewables	13	822	1,413
Arendals Fossekompani	AFK	Renewables	226	1,499	1,409
Arise	ARISE	Renewables	46	206	270
Athena Investments A/S	ATHENA	Renewables	4	64	4
Audax Renovables SA	ADX	Renewables	2	1,122	1,495
BKW	BKW	Renewables	107	6,318	7,274
CARPEVIGO Holding AG	CV3	Renewables	1	5	6
Cloudberry Clean Energy AS	CLOUDME	Renewables	17	212	193
EAM Solar ASA	EAM	Renewables	9	8	1
Ecosuntek S.p.A.	ECK	Renewables	8	17	43
Edisun Power Europe AG	ESUN	Renewables	123	143	213
EDP Renovaveis SA	EDPR	Renewables	20	21,493	27,709
Encavis AG	CAP	Renewables	109	20,680	26,986

Source: Longspur Research, Bloomberg

Active net zero companies – Developers (continued)

Company	Ticker	Market	Price	Cap (£m)	EV (£m)
Energiedienst Holding AG	EDHN	Renewables	34	1,277	1,108
EnergieKontor AG	EKT	Renewables	58	1,006	1,264
Eolus Vind AB Class B	EOLUB	Renewables	218	654	605
Falck Renewables S.p.A.	FKR	Renewables	6	2,198	3,126
Frendy Energy SpA	FDE	Renewables	0	24	28
Freyer	FREYR	Renewables	19	452	453
Good Energy Group PLC	GOOD	Renewables	186	31	73
Greenalia SA	GRN	Renewables	19	488	760
Grenergy Renovables S.A	GRE	Renewables	38	1,121	1,233
Holaluz Clidom SA	HLZ	Renewables	9	233	239
HYDRO Exploitation SA	MLHYE	Renewables	82	12	9
Industrial Solar Holding Europe AB	ISHE	Renewables	6	8	5
Iniziative Bresciane S.p.A.	IB	Renewables	17	104	185
Inspired Energy PLC	INSE	Renewables	16	154	195
Intexa SA	ITXT	Renewables	3	4	1
Neoen S.A.	NEOEN	Renewables	53	5,478	7,946
New Sources Energy NV	NSE	Renewables	0	10	10
Orsted	ORSTED	Renewables	1,034	70,737	75,038
Otovo	OTOVO	Renewables	275	289	278
PNE AG	PNE3	Renewables	8	733	975
Renergetica SpA	REN	Renewables	4	38	43
Romande Energie Holding SA	HREN	Renewables	1,275	1,629	1,557
Scatec Solar ASA	SCATC	Renewables	299	5,627	6,236
Slitevind AB	SLITE	Renewables	78	55	95
Solaria Energia y Medio Ambiente, S.A.	SLR	Renewables	22	3,331	3,703
Solarpack Corporacion Tecnologica SA	SPK	Renewables	22	902	1,351
Terna Energy S.A.	TENERGY	Renewables	14	1,981	3,011
Valoe Corporation	VALOE	Renewables	0	32	48
Verbund	VER	Renewables	70	29,277	31,726
Vergnet S.A.	ALVER	Renewables	1	53	54
Voltalia	VLTSA	Renewables	24	2,748	3,354
Weya SA	MLWEY	Renewables	3	2	2
Douaisienne de Basse Tension SAS	ALDBT	Storage	0	49	48
Engie EPS SA	EPS	Storage	21	325	346

Source: Longspur Research, Bloomberg

Active net zero companies - Operators

Company	Ticker	Market	Price	Cap (£m)	EV (£m)
SDCL Energy Efficiency Income Trust	SEIT	Efficiency	107	724	611
Triple Point Energy Efficiency	TEEC	Efficiency	105	105	105
Aquila European Renewables Income	AERI	Renewables	1	418	418
Bluefield Solar Income Fund Ltd.	BSIF	Renewables	136	551	551
Downing Renewables and Infra Trust	DORE	Renewables	98	120	120
Foresight Solar & Technology VCT	FTSV	Renewables	69	4	4
Greencoat Renewables Plc	GRP	Renewables	1	1,061	1,377
Greencoat UK Wind Plc	UKW	Renewables	132	2,404	2,881
Impax Environmental Markets PLC	IEM	Renewables	497	1,352	1,383
JLEN Environmental Assets Group	JLEN	Renewables	115	629	627
NextEnergy Solar Fund Ltd	NESF	Renewables	103	603	584
Octopus Renewables Infrastructure	ORIT	Renewables	114	399	219
Renewables Infrastructure Group Limited	TRIG	Renewables	129	2,448	2,424
Gore Street Energy Storage Fund PLC	GSF	Storage	108	155	155
Gresham House Energy Storage Fund	GRID	Storage	114	396	396

Source: Longspur Research, Bloomberg

Equity Research Disclaimers

Non-independent research

This marketing communication has been prepared and issued by Longspur Research and is a Minor Non-monetary Benefit as set out in Article 12 (3) of the Commission Delegated Act (C2016) 2031 that may contain Investment Recommendations as defined by the Market Abuse Regulation (MAR). It is Non-Independent Research and a marketing communication under the FCA's Conduct of Business Rules. It is not Investment Research as defined by the FCA's Rules and has not been prepared in accordance with legal requirements designed to promote Investment Research independence and is also not subject to any legal prohibition on dealing ahead of the dissemination of Investment Research. We do not hold out this research material as an impartial assessment of the values or prospects of the company.

Notwithstanding this, Longspur Research has procedures in place to manage conflicts of interest which may arise in the production of Research, which include measures designed to prevent dealing ahead of Research.

Minor non-monetary benefit

This Research is a minor non-monetary benefit as set out in Article 12 (3) of the Commission Delegated Directive (EU) 2017/593.

Copyright

Copyright 2019 Longspur Capital. This Communication is being supplied to you solely for your information and may not be reproduced, redistributed or passed to any other person or published in whole or in part for any purpose without the prior consent of Longspur Research. Additional information is available upon request.

Regulated by FCA

Longspur Research is a trading name of Longspur Capital Limited, an appointed representative of Mirabella Advisers LLP, a limited liability partnership registered in England & Wales number OC384100 Authorised and Regulated by the Financial Conduct Authority, FCA FRN 606792. Longspur Capital is registered in England, company number 11011596.

No warranty as to accuracy or completeness

All information used in the publication of this report has been compiled from publicly available sources that are believed to be reliable, however we do not guarantee the accuracy or completeness of this report and have not sought for this information to be independently verified.

Opinions contained in this report represent those of the Longspur Research analyst at the time of publication. Forward-looking information or statements in this report contain information that is based on assumptions, forecasts of future results, estimates of amounts not yet determinable, and therefore involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of their subject matter to be materially different from current expectations. No representation or warranty is made as to the accuracy or completeness of the information included in this Research and opinions expressed may be subject to change without notice. Longspur Research does not undertake any obligation to revise such forward-looking statements to reflect the occurrence of unanticipated events or changed circumstances.

This report is solely for informational purposes and is not intended to be used as the primary basis of investment decisions. Longspur Research has not assessed the suitability of the subject company for any person. Because of individual client requirements, it is not, and it should not be construed as, advice designed to meet the particular investment needs of any investor. This report is not an offer or the solicitation of an offer to sell or buy any security.

Longspur Research has no authority whatsoever to make any representation or warranty on behalf of any of its corporate finance clients, their shareholders or any other persons similarly connected.

Information purposes only

This Research is designed for information purposes only. Neither the information included herein, nor any opinion expressed, are deemed to constitute an offer or invitation to make an offer, to buy or sell any financial instrument or any option, futures or other related derivatives. Investors should consider this Research as only a single factor in making any investment decision. This Research is published on the basis that Longspur Research is not acting in a fiduciary capacity. It is also published without regard to the recipient's specific investment objectives of recipients and is not a personal recommendation. The value of any financial instrument, or the income derived from it, may fluctuate.

Take own advice

The information that we provide should not be construed in any manner whatsoever as, personalised advice. Also, the information provided by us should not be construed by any subscriber or prospective subscriber as Longspur Research's solicitation to effect, or attempt to effect, any transaction in a security. The securities described in the report may not be eligible for sale in all jurisdictions or to certain categories of investors.

Longspur Research may have a position

At any time, Longspur Research or its employees may have a position in the securities and derivatives (including options or warrants) of the companies researched and this may impair the objectivity of this report. Longspur Research may act as principal in transactions in any relevant securities, or provide advisory or other services to any issuer of relevant securities or any company connected therewith.

Only for eligible counterparties and professional clients. Not for retail

This Communication is being distributed in the United Kingdom and is directed only at (i) persons having professional experience in matters relating to investments, i.e. investment professionals within the meaning of Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the "FPO") (ii) high net-worth companies, unincorporated associations or other bodies within the meaning of Article 49 of the FPO and (iii) persons to whom it is otherwise lawful to distribute it. The investment or investment activity to which this document relates is available only to such persons. It is not intended that this document be distributed or passed on, directly or indirectly, to any other class of persons and in any event and under no circumstances should persons of any other description rely on or act upon the contents of this document (nor will such persons be able to purchase shares in the placing).

MAR Formal disclosure of conflicts

This report has been commissioned by the issuer and prepared and issued by Longspur Research in consideration of a fee payable by the issuer. Fees are paid upfront in cash without recourse. A draft has been sent to the issuer for comment and it has been appropriately amended.

Neither Longspur Research nor the analyst have any holdings in the issuer. Longspur Research may from time to time provide the issuer with of consultancy advice.

See webpage for additional MAR disclosures.

GDPR

For further information about the way we use your personal data please see our Third Party Privacy Notice www.longspurresearch/xxx/ or at such other place as we may provide notice of from time to time. We may contact you about industry news, offers and information relating to our products and services which we think would be of interest to you. You can tell us you do not wish to receive such communications by emailing michelle.elsmore@longspur.com.

Laven Consulting Limited (incorporated and registered in England and Wales with company number 10918441) ("Laven") acting through its Paris branch located at 128 Rue La Boetie 75008, Paris, France as designated representative of Two Sigma Investments LP ("Company"), in accordance with art. 27 of the General Data Protection Regulation (the Regulation (EU) 2016/679) ("GDPR"). The Company has mandated Laven to be the European representative of the Company with regards to any communications or enquiry from the Supervisory Authority and/or data subjects on all issues related to the processing of personal data. Please contact Laven on info@eurorep.eu; the postal address is FAO EuroRep, c/o Laven Partners, 128 Rue La Boetie 75008, Paris, France. When contacting Laven regarding the Company please quote the name of the company and the Ref: 0085.

Severability Applicable law

Exclusion of Liability: To the fullest extent allowed by law, Longspur Research shall not be liable for any direct, indirect or consequential losses, loss of profits, damages, costs or expenses incurred or suffered by you arising out or in connection with the access to, use of or reliance on any information contained on this note.

Longspur Research

10 Castle Street,

Edinburgh. EH2 3AT

UK

Longspur Capital

20 North Audley Street,

London. W1K 6WE

UK

www.longspurresearch.com

Longspur Research

10 Castle Street,

Edinburgh. EH2 3AT

UK

Longspur Capital Markets

20 North Audley Street,

London. W1K 6WE

UK

Longspur Developments

110-640 8th Avenue SW,

Calgary, Alberta,

Canada. T2P 1