DRAX GROUP
(DRX LN)

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Price (p)	290
Shares in issue (m)	397
Mkt Cap (£m)	1,151
Net debt (£m)	874
EV (£m)	2,025
BVPS (p)	453.9

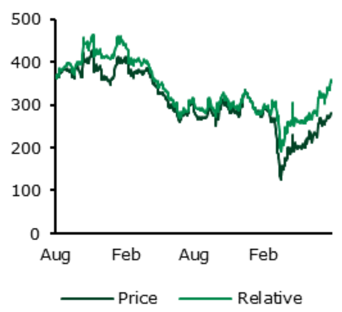
Share price performance	
1m	7.6%
3m	42.1%
12m	1.1%
12 m high/low	364.6/118.9
Ave daily vol (3m)	912

Shareholders	
Invesco Ltd	13%
Schroders Plc	10%
Jupiter	7%
Blackrock	6%
Artemis Investment	5%
Orbis Holdings	5%
Total for top 6	46%
Free float	99.8%

Next news Prelims Q1

Business description

Integrated biomass, hydro and gas IPP



ENABLING THE ENERGY TRANSITION

Drax is a major enabler of the energy transition. It is the only UK investment opportunity of scale that can offer exposure to BECCS, long duration storage and low carbon spinning reserve, all essential to deliver what is now a legal requirement for net zero emissions by 2050. We initiate coverage with a central case valuation of 505p.

Carbon negative by 2030

Drax is planning to be carbon negative by 2030. This a quite a transformation from a company that seven years ago was almost entirely based on coal fired generation. We see a similar story here to that of Orsted which has successfully turned itself from an oil and gas company into one of the world's leading renewable energy companies. The difference here is that Drax has been able to re-engineer its existing assets and add to these to deliver its transformation. While Orsted may be low carbon, Drax can be negative carbon which is a real distinction.

Enabling the UK's net zero target

While this is a major commitment, in getting to this point we see Drax as facilitating a decarbonisation of the whole UK system in a number of key and rather technical ways. It is leading on carbon negative as an exemplar. It offers long duration storage to balance the system. It offers low carbon spinning reserve to keep the system frequency stable. And it does all this whilst still producing 5% of the UK's electricity. At COP25 in Madrid, CEO Will Gardiner committed Drax to becoming carbon negative by 2030. However, it is not simply that Drax itself becomes a negative carbon power company but that it also brings essential services that allow the entire UK power industry to be zero carbon.

Value and risk

Drax is currently trading well below its NAV of 434p. It is being valued alongside utilities with high carbon legacy assets. A re-rating in line with low carbon companies would more than double its valuation. Our DCF and SOP valuations broadly confirm this with a central case valution of 505p. Policy risk is the main consideration in our view with the Energy White Paper having the potential to change the key revenue sources for the company. Nor is the company immune to competition and pricing risk. But Drax represents a portfolio of key assets in the UK's drive to net zero and has competitively placed both factors that should help to mitigate these risks.

£,m Dec	2018a	2019a	2020e	2021e	2022e	2023e
Sales	4,237	4,703	4,108	4,560	4,691	4,900
EBITDA	250	410	390	380	376	440
PBT	37	142	143	130	132	210
EPS	10.4	29.9	30.9	28.6	29.7	44.5
CFPS	49.2	-101.8	13.0	53.0	22.9	40.1
DPS	14.1	15.9	17.1	18.4	19.8	21.3
Net Debt (Cash)	319	874	947	871	908	884
Debt/EBITDA	1.3	2.1	2.4	2.3	2.4	2.0
P/E	27.9	9.7	9.4	10.1	9.8	6.5
EV/EBITDA	5.9	4.9	5.4	5.3	5.5	4.6
EV/sales	0.3	0.3	0.4	0.3	0.3	0.3
FCF yield	17.0%	-35.1%	4.5%	18.3%	7.9%	13.8%
Div yield	4.9%	5.5%	5.9%	6.3%	6.8%	7.3%

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INVESTMENT SUMMARY

Drax biomass is low carbon. A survey of the most recent academic work finds that, where there are efficient investments in forestry management, bioenergy leads to a net increase in carbon sequestration. This is the case for Drax. Wind turbines can show a longer carbon payback period than well-managed biomass.

Biomass can be profitable without subsidy. Our post subsidy analysis shows that biomass generation can precede gas in the merit order and make a positive bark spread as well as benefit from ancillary services including inertia.

Biomass and pumped storage are already making money from flexibility. Both provide both flexibility and low carbon spinning reserve to the system. The COVID 19 lockdown has shown a growth in balancing market actions which points to stronger revenues in future.

Cruachan is a key asset. The Cruachan pumped storage scheme can protect trading margins even with significantly more storage entering the system and benefit from inertia and other ancillary services.

BECCS is deliverable with the right policy support. Bio Energy Carbon Capture and Storage (BECCS) technology using amine capture is proven although cheaper technologies may become available and Drax is working with developers on these and is an eqiuty partner in C-Capture. Our analysis of costs and potential funding solutions suggests BECCS this is deliverable in the timeframe Drax requires.

Biomass pelletisation captures significant upstream value. With BECCS a major part of net zero strategies globally, demand for sustainable and efficiencly sourced biomass will grow whether internally or from other biomass generators. Drax is now in the top four suppliers globally.

Gas assets have a future. While CCGT gas plant will increasingly rely on the capacity market, options for conversion to hydrogen (H2GTs) adds potential to these assets.

The whole is greater than the sum of the parts. Vertical integration downstream to energy supply and upstream to fuel supply de-risks the portfolio and adds optionality.

The valuation appears anomalous. Drax is being valued as a stranded asset which appears at odds with its operations. Valuation based on comparative EV/EBIDTA multiples suggests the company is not seen as a contributor to the energy transition. We think it is a key enabler of the energy transition in the UK.

6% forward yield. Even without renewable support income we forecast that the company can offer real dividend growth and cover the dividend beyond 2027.

BULL POINTS

- Low carbon spinning reserve as demand for inertia grows
- Long duration fast reacting storage as market becomes more volatile
- Exposure to carbon capture and storage at scale
- Major player in sustainable biomass supply

BEAR POINTS

- Exposed to policy changes
- BECCS technology still expensive
- Low carbon biomass argument not fully settled

CATALYSTS

- Final closure of coal units
- Growth in flexibility income
- Biomass argument settled

Drax has committed itself to becoming a carbon negative company by 2030. To do this it is closing its remaining two coal fired generation units at the Drax Power Station in Yorkshire. These are scheduled to close in 2022, ahead of the government mandated closure target of 2025. The remaining four units at the Drax site have been converted to biomass and running successfully for a number of years.

This biomass is low carbon. There has been a lot of debate about the environmental impact of biomass generation but the most recent academic work shows that it can achieve carbon payback periods as low as wind or solar generation. It is deemed renewable by both UK and EU legislation.

The gas fired generation units acquired from Iberdrola in 2019 burn natural gas but are currently an essential part of the UK energy mix, providing power when intermittent renewables are weak as a result of low wind or at night. However, they are not themselves low carbon.

While the low carbon biomass generaton mitigates this, it does not offset the emissions. To achieve this, Drax will deploy carbon capture technology. With the units running at 90% availability this can capture 16 million tonnes of CO_2 annually leaving the company net negative.

In addition, the pumped hydro project at Cruachan delivers long duration storage to help keep the UK system in balance and gives the company significant power trading opportunities, providing optionality and risk management across the group. Further optionality is provided by vertical integration both upstream into biomass fuel production and sourcing, and downstream through the energy supply businesses Haven and Opus.

Our analysis shows that the biomass units can earn a postive margin beyond 2027 when their subsidies end. They can also make additional returns from the provision of inertia, the damping of frequency disturbance by larger synchronised generators. The behavior of the market under the COVID 19 lockdown is giving us a glimpse of a future with a greater proportion of electricity demand met by intermittent renewables. The lessons here are postive for Drax across the portfolio and highlight the value of its low carbon spinning reserve in the market.

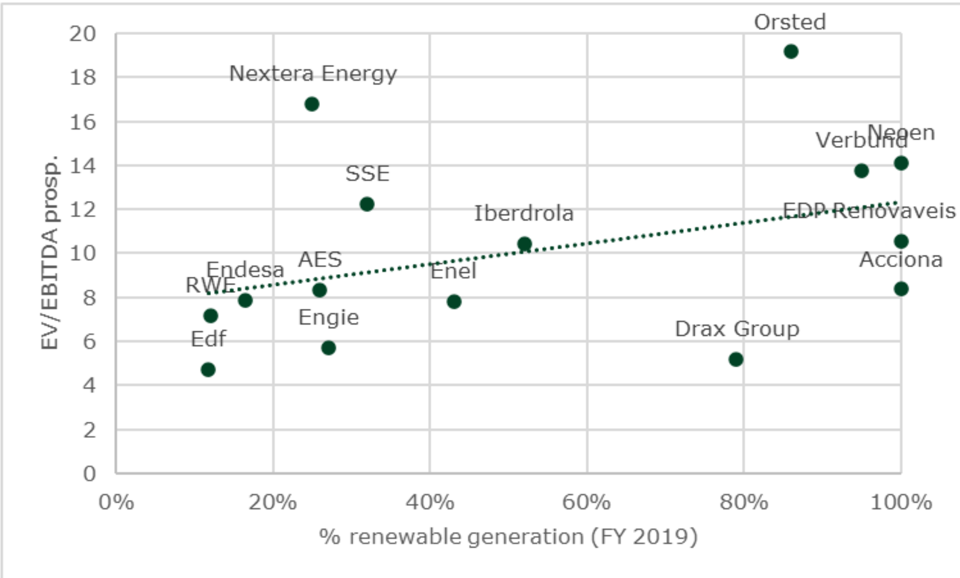
We also think that BECCS can be achieved at a cost in line with existing carbon taxation, potentially providing a return to Drax for investment here if government can make the right levels of support available. Similarly we see a longer term future for the gas assets if a hydrogen solution is supported.

Finally, we think the pumped storage capacity can continue to make a trading return even with significant new entry into the storage market. Drax has a strong asset in Cruachan that is more flexible than others in the market and offers scope for expansion. It uses compressed air to deliver a very fast response time and with 15 hours of storage has the longest duration of any storage asset in the UK.

VALUATION

Drax trades on a multiple that suggests it has legacy issues and will be compromised in the energy transition. Yet our appraisal suggests that it does well in the energy transition for the simple reason that it is an essential component of it.

EV/EBITDA versus % of low carbon generation



Source: Longspur Research, Bloomberg

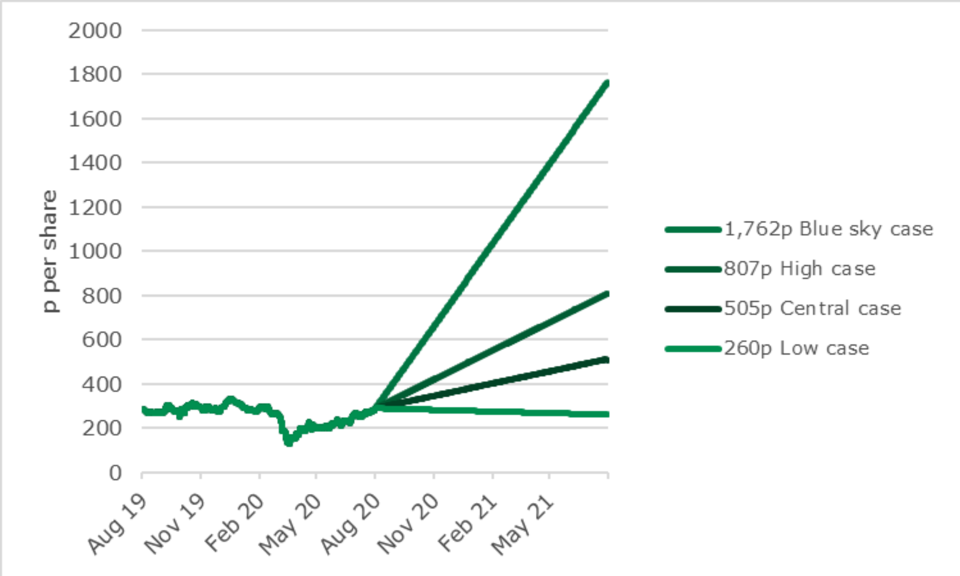
We have valued Drax under four key scenarios using both a DCF and a sum of the parts/annuity model. A low case with no useful life for gas after 2025 and no useful life for biomass after 2027 is only slightly below the current share price. A central case is slightly above the company's NAV. An achieveable high case offers strong upside but still in line with typical multiples for low carbon generators. Finally a "blue sky" case assumes a high carbon tax and adds value for CCS.

Valuation Scenarios

	Blue sky	High	Central	Low
Project closure dates				
Biomass	2050	2050	2039	2027
Hydro	2050	2050	2050	2050
CCGT	2050	2050	2039	2025
Market pricing				
Wholesale	As today	As today	As today	As today
Capacity market	Increase	Increase	As today	No further contracts
Ancillary services	Increase	Increase	Increase	As today
Balancing mechanism	Increase	Increase	Increase	As today
Carbon price	£100/t	As today	As today	As today
Valuation (£m)				
Biomass	3,916	2,223	1,512	1,203
Pumped storage	964	852	754	529
CCGT	996	711	350	133
Hydro	167	150	122	96
Pellet production	391	391	391	196
Customers	97	97	97	97
CCS	1,684	0	0	0
Central costs	-348	-348	-348	-348
Total EV	7,867	4,075	2,877	1,905
Debt	874	874	874	874
Market value	6,993	3,202	2,003	1,032
Shares in issue	397	397	397	397
Value per share (p)	1,762	807	505	260

Source: Longspur Research

Share Price and Valuation Points



Source: Bloomberg, Longspur Research

A CLEAN ENERGY IPP

DRAX IN 2020

Drax owns and operates over 6GW of power capacity in the GB market. Of the six main units at the 4GW Drax power station site in Yorkshire, four have been converted to burn biomass and associated safe fuel handling has been installed with appropriate levels of fire suppression. Wood dust has been a source of failure at other biomass projects in the UK. The remaining two units continue to burn coal but are scheduled to close in 2022.

Drax has created a degree of vertical integration with two retail businesses services, one serving large commercial and industrial customers and one targeting smaller enterprises. It has also built a biomass supply business to support its biomass generation.

Last year Drax acquired a portfolio of generation plant from Iberdrola bringing the 440MW Cruachan pumped storage scheme in Argyllshire and 2,000MW of CCGT plant. Two hydro schemes and a waste to energy scheme were also included.

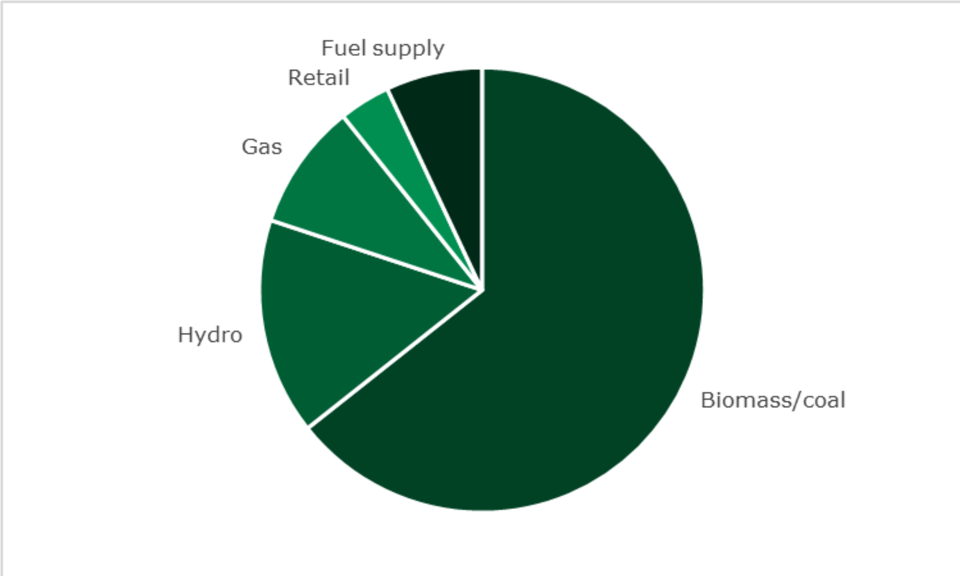
Drax asset roster

Unit	Nameplate Capacity (MW)	COD	Type	Markets
Drax 1	660	Dec-73	Biomass	CfD
Drax 2	645	Dec-73	Biomass	RO
Drax 3	645	Dec-74	Biomass	RO
Drax 4	645	Dec-86	Biomass	RO
Drax 5	645	Dec-86	Coal	Merchant, capacity market
Drax 6	645	Dec-86	Coal	Merchant, capacity market
Drax 9	32	Dec-86	Oil	Merchant, capacity market
Drax 10	32	Dec-86	Oil	Merchant, capacity market
Drax 12	32	Dec-86	Oil	Merchant, capacity market
Cruachan	440	Oct-65	PSH	Merchant, capacity market
Galloway and Lanark	126	Dec-36	Hydro	Merchant, capacity market
Damhead Creek	805	Dec-01	CCGT	Merchant, capacity market
Rye House	715	Nov-93	CCGT	Merchant, capacity market
Shoreham	420	Dec-02	CCGT	Merchant, capacity market
Blackburn Mill	60	Dec-02	CCGT	Merchant
Daldowie	50	Dec-02	WTE	Merchant

Source: Drax Group

The key generation units for valuation are the biomass units, pumped storage (Cruachan) and the CCGTs. In addition the biomass pellet business and the retail supply business add value and provide optionality.

EBITDA Split 2019



Source: Drax Group

Biomass

The wholesale market should remain attractive to the biomass units between now and 2027. The RO units could be affected by lower prices although the company is well contracted in the near term. Further out, biomass cost efficiencies should more than offset any wholesale market price weakness. The CfD unit will of course be largely unaffected thanks to the working of its support mechanism.

Post 2027, the biomass units should be operating with a short run marginal cost of £50/MWh thanks to efficiencies targetted in the biomass supply chain. We calculate that they will be in merit when gas fired units are setting the price at an estimated £60/MWh resulting in a "bark spread" of £10/MWh.

Additionally, these units are likely to continue to win ancillary contracts in areas not overly bid by other units. These may end up as one of the few suppliers of black start, voltage support and reaction power. They are capable of providing all of the services below.

- Headroom (turn up) on and footroom (turn down)
- All forms of frequency response, including Enhanced Frequency Response
- Black Start capability
- Inertia to support system stability
- Voltage management

Hydro

The Cruachan pumped storage project has capacity to store up to 16 hours of electricity. Thanks to a compressed air system its turbines can respond in 30 seconds making it a highly responsive and flexible plant. The unit has bid successfully in the capacity market and provides a number of ancillary services. It was successful in the recent synchronous compensation auction. We also think the plant has a major opportunity in energy trading.

Drax also owns two hydro electric projects at Lanark on the River Clyde with two generating plants and in Galloway comprising six generation sites and stretching the length of the Dee/Ken/Doon river system. Lanark is a run of river system making it intermittent in nature and Galloway is captive with a number of dams.

Both the biomass units and Cruachan provide inertia to the system. While inertia has been seen as effectively a free good, recent balancing mechanism actions have suggested that balancing mechanism actions to avoid constraints are effectively being undertaken to ensure there is sufficient inertia on the system. Drax should benefit from this.

Gas

The Iberdrola acquisition included four combined cycle gas turbine (CCGT) projects at Shoreham, Damhead Creek, Ryehouse and Blackburn Mill.

Drax CCGT portfolio

	Capacity	Efficiency	COD	Turbines	Configuration
Damhead Creek	805	55.0%	Dec-01	Mitsubishi 701F	Separate shafts
Rye House	715	50.0%	Nov-93	Siemens V94.2	Separate shafts
Shoreham	420	57.5%	Dec-02	Upgrading to GT 26 HW	Single shaft
Blackburn Mill	60	50.0%	Dec-02	Siemens SGT800	Separate shafts

Source: Drax Group

Ryehouse and Blackburn Mill are older projects with thermal efficiencies of around 50% making them less attractive than the other two projects. Damhead Creek has the gas and steam cycles on separate shafts which gives a flexibility benefit. Shoreham is single shaft which improves efficiency and the project has an option for a turbine upgrade which should result in an overall efficiency of 57.5%.

WTE

Drax also acquired a waste to energy project with the Iberdrola acquisition. The Daldowie project near Glasgow turns sewage sludge into a dry fuel pellet using centrifuges. The fuel pellets are currently used to heat cement kilns. They could be burnt in biomass units but their waste status would require additional permitting at the Drax Power Station which is not a priority at present especially as the project has a long term contract with Scottish Water to 2027.

THREE MARKETS FOR ELECTRICITY

There are three main power markets in the UK.

Energy Market including the wholesale markets and balancing mechanisms

This is what people mean when they talk about electricity prices.

Capacity market

Can be seen as an insurance premium to keep the lights on.

Ancillary services markets

A range of services provided to the system operator to keep the system running

Drax asset groups and their market positions

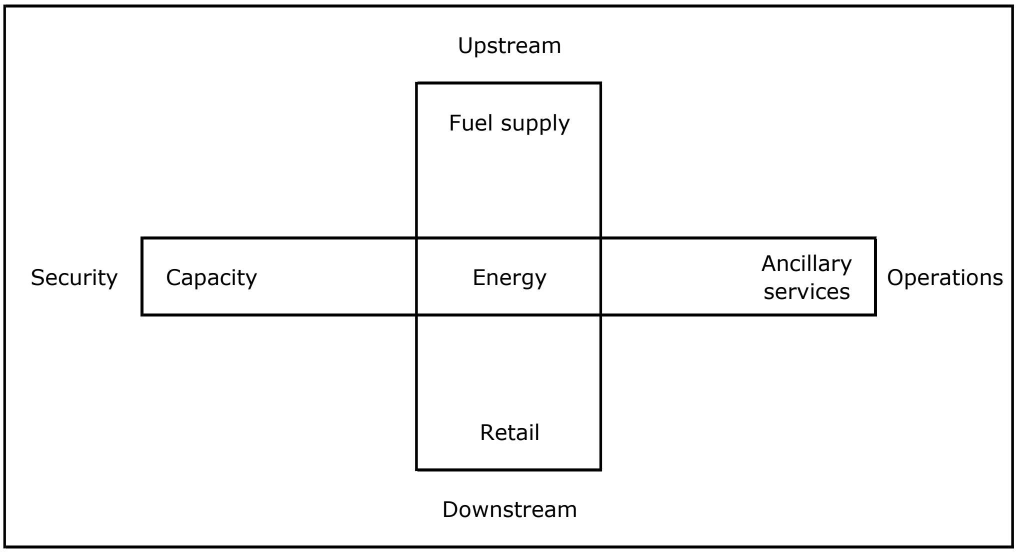
	Wholesale	Capacity market	Ancillary services	New opportunities
Biomass	**	*	***	CCS
Hydro	***	**	***	Arbitrage
CCGTs	*	**	**	Hydrogen

Source: Longspur Research

OPTIONALITY

We believe the generation mix in the Drax portfolio offers considerable optionality across the market both now and as it evolves. Drax has also created optionality up and down the market through vertical integration. Down the market, this is through the two B2B energy supply businesses, Haven and Opus. Upstream, the development of a biomass pellet production and sourcing business secures feedstock for the biomass units.

Vertical and horizontal integration



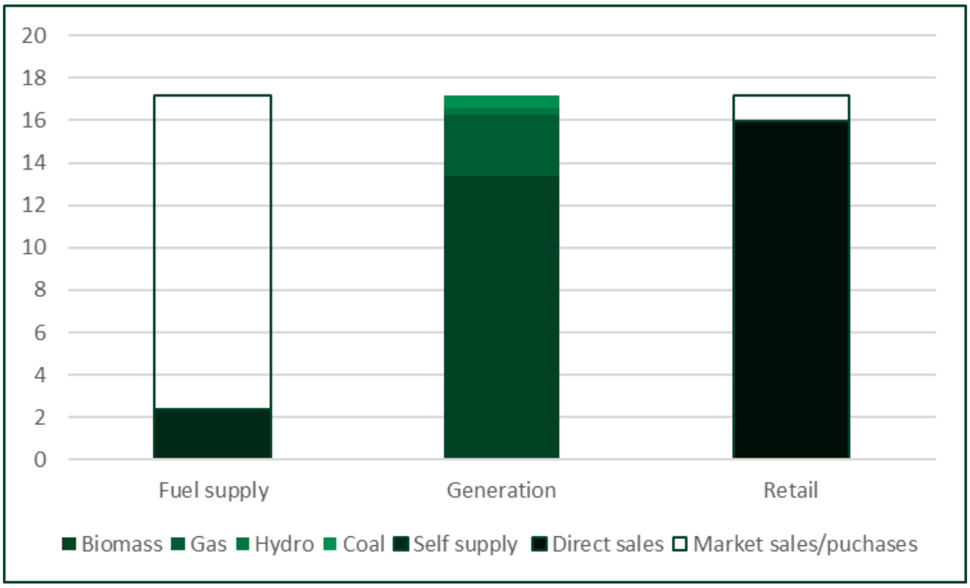
Source: Longspur Research

Upstream and Downstream Integration

Drax now sells over 90% of its net output through its own energy supply businesses Haven and Opus. These target commercial and industrial customers with Haven concentrating on larger customers and Opus on SMEs. While energy retailing is a highly competitive space, the typical sales contracts allow a degree of price stability helping to insulate the company from the wilder, short term moves in energy prices.

At the same time the company has secured biomass sourcing and pellet production. At present this only accounts for 14% of its generation needs. The company has plans to increase this to 5mt of biomass, over 70% of current demand and at the same time reduce costs by a third.

Vertical integration



Source: Longspur Research, Drax Group

In both cases these businesses add value in their own right with supply generating £17m of EBITDA and biomass supply £32m in FY 2019. Both can operate independently of the generation business. In this regard, pellet production is identifying opportunities to supply others in the market.

We see vertical integration as important both in providing commercial discipline to these businesses and also to optimising the company across the value chain. Hidden behind these assets is a trading business. For many years, Drax has traded its own output. We see this as a key advantage, allowing the company to take full advantage of its positions across the market.

Biomass supply an important source of value in its own right

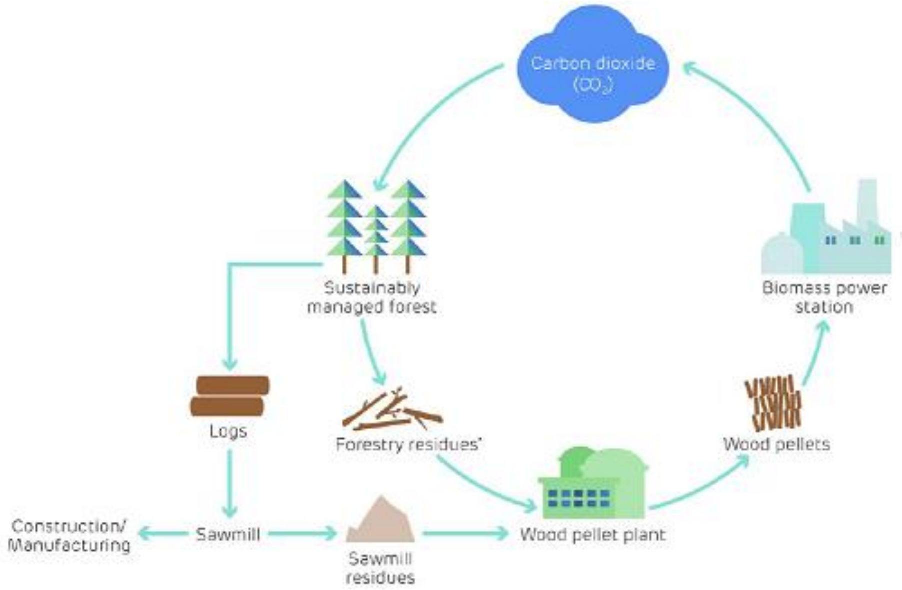
The pellet production and logistics business is now the fourth largest supplier of biomass pellets in the world. BECCS is a major solution to deliver net zero emissions globally. We estimate that it can account for 10% of all mitigation and as a result we expect demand for sustainably managed biomass to grow. In the pellets business, Drax can both manage its own feedstock needs as well as drive value from this growing market.

BIOMASS – SEEING THE WOOD FOR THE TREES

BIOMASS IS LOW CARBON

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 at the Drax biomass units therefore releases CO2 but by using wood from forests that are continually growing, and replacing the biomass burt 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.

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.

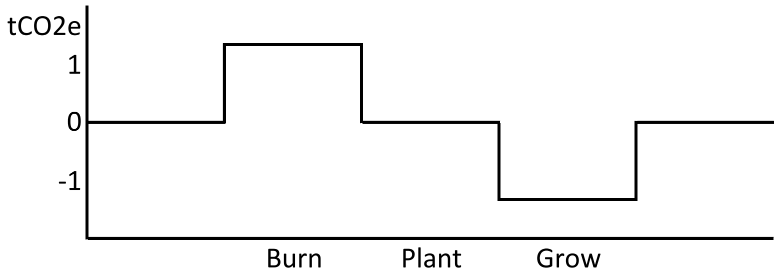
There is a concern that it takes time to recapture the emissions from burning the tree in new forest growth and there is a lot of opposition to biomass based on this concern. However, the most recent studies all show that biomass is a genuine source of low carbon generation. Despite its many advantages, 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 CO_2. 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 CO_2 from the atmosphere.

Emissions from a simplified biomass cycle



Source: Longspur Research

The gap between the release of CO_2 and its subsequent capture is the problem. If we worsen the climate by initially releasing CO_2, knock on secondary effects on the climate may be difficult to recover from even if we subsequently remove the CO_2.

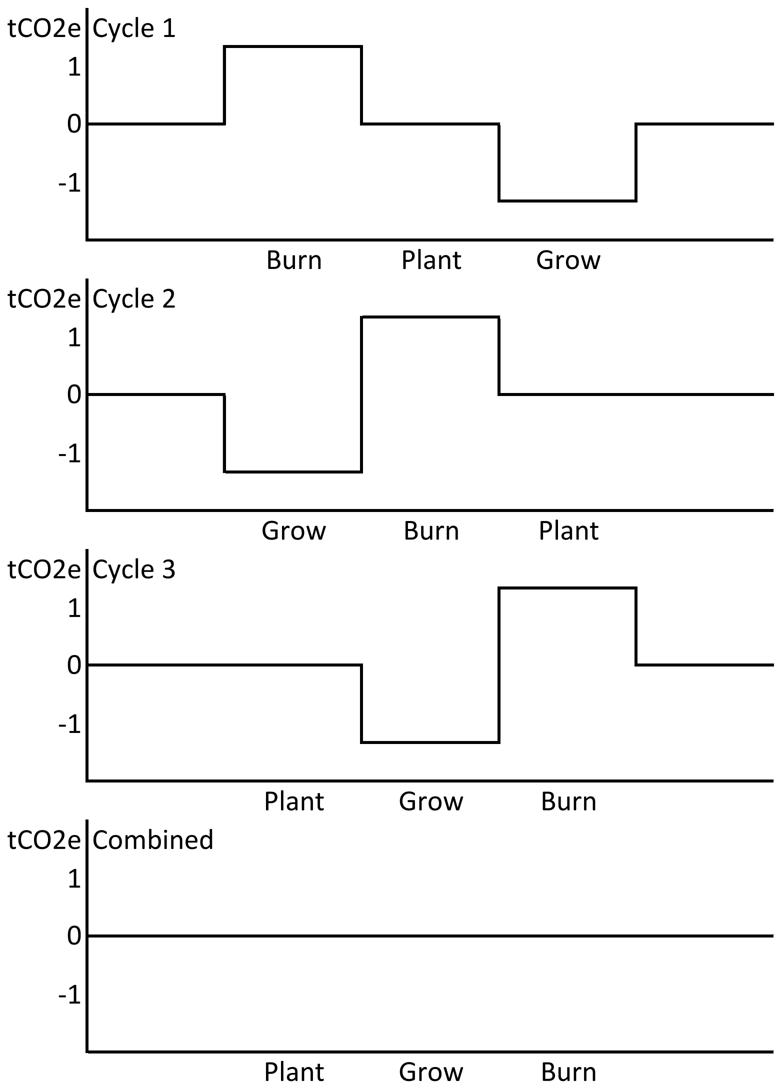
The problem here is that this simple model is too simple. Essentially it looks at a single stand of tress rather than considering the whole forest.

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 the 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 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 conclude 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)."

Drax 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 a number of assumptions that do not reflect actual and future practice in an environment where biomass is growing.

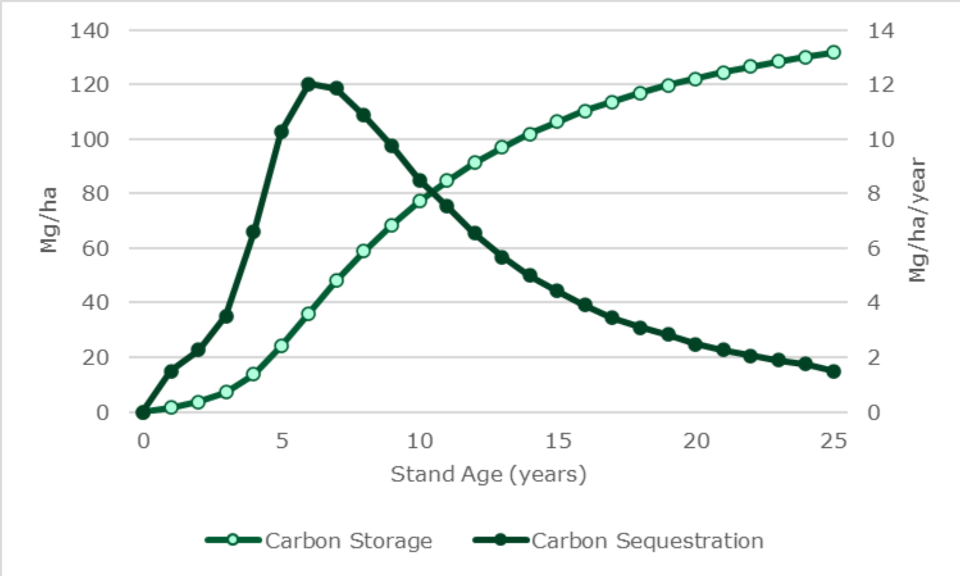
Forests need to be seen as dynamic systems and analysed accordingly. Carbon capture is maximised when these systems are properly managed and in this regard it is worth stressing that the forests of the US Southeast have been continuously managed for centuries and is currently growing its carbon stocks. 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 used by Drax, 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 depending on management approach, with the research concluding that convergent management pespectives with wood pellets relative to a no-harvest baseline show a break-even period of about three years.

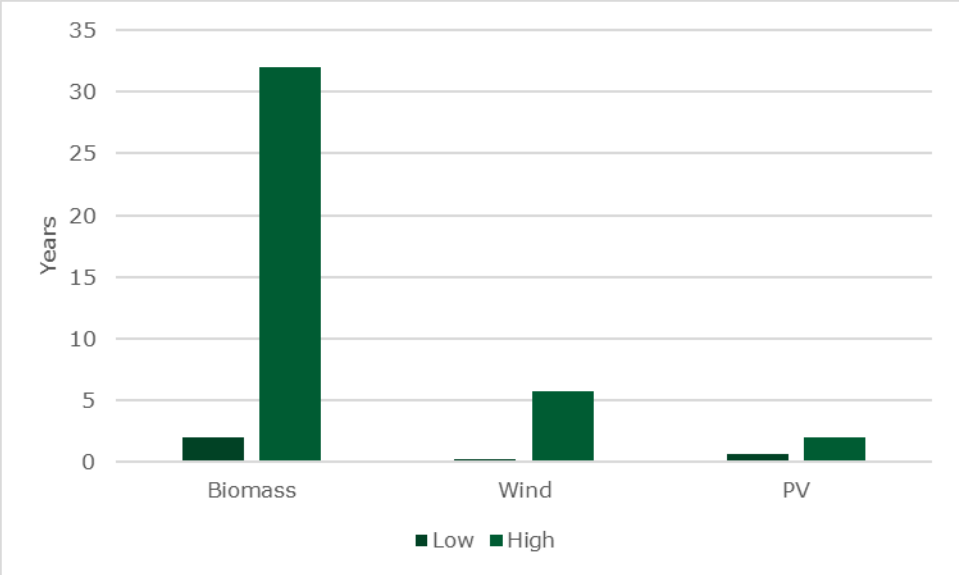
Older research concurs:

"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.

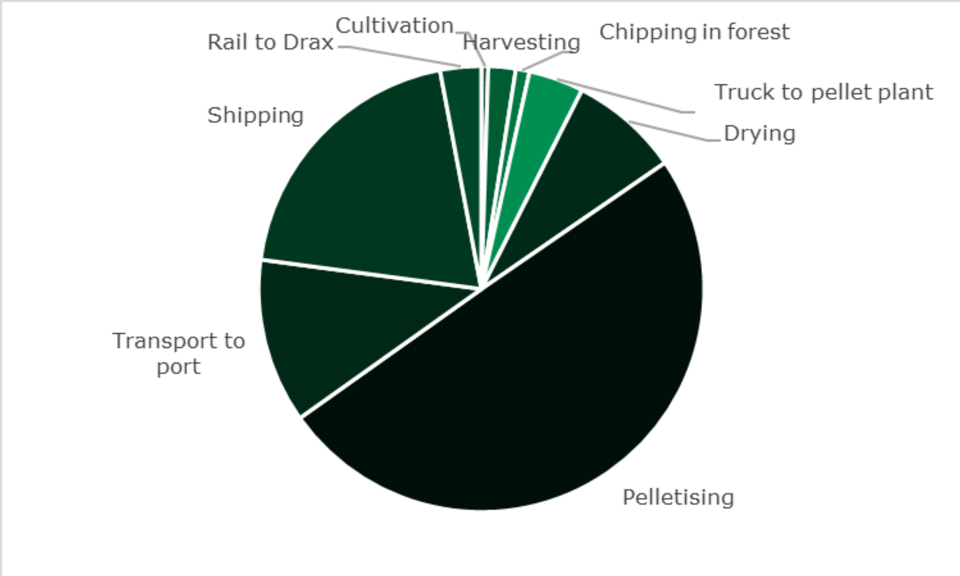
ESG – EU TAXONOMY

Drax biomass is therefore a low carbon form of generation. At present we would expect it to meet the criteria for a low carbon investment and its status has already been recognised by Norway's US$1tn sovereign wealth fund which removed the company from its investment blocklist having originally blocked it as a result of the now closing coal generation business.

Biomass for climate mitigation has been recognised as sustainable in the underlying agreement on the EU Taxonomy on Sustainable Investment. The final legislation including detailed criteria is due in the Autumn. Drax is feeding into the process and hopes to be recognised in the taxonomy. Under the Renewable Energy Directive II (RED II) biomass needs to show an 80% reduction emissions against a fossil fuel benchmark. For the Drax biomass units we estimate this level at 132g CO_2e/kWh. Drax is currently running at 124gCO_2e/kWh so should comply. There is some risk here. A technical experts group has recommended an additional technology agnostic emissions threshold of 100gCO_2e/kWh. We think there are good arguments against using this for biomass and we also see Drax being able to get below the threshold in time.

While the biomass itself is treated as zero emission under ISO 14044 the supply chain emissions do count. These total 124gCO_2e/kWh and are split as follows.

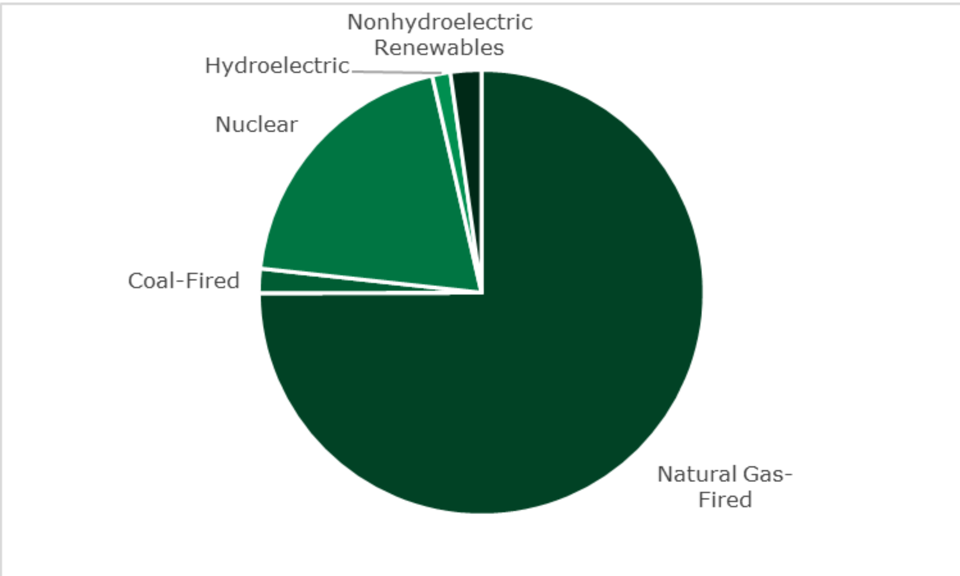
Biomass emissions breakdown



Source: Drax Group

Roughly half the emissions are created from pelletisation. This is because the pelleting process imports electricity to drive the mill. The electricity has to be assumed to have been generated using the state average generation mix and the relevant emissions are derived from that mix. In Louisiana roughly three quarters of the generation mix is gas fired leading to relatively high emissions. This is similar to the comments that electric vehicles are coal powered if they charge from a grid where the generation mix is predominantly coal. It does not mean that either Drax or EVs are not contributors to the energy transition.

Louisiana electricty sources



Source: US Energy Information Agency

Drax can overcome this in several ways. It is already working to create efficiencies in the transportation elements of the supply chain. It is also sourcing additional biomass that does not require pelletisation. We think that emissions are close enough to the baseline that compliance is a matter of time.

Perhaps a bigger consideration for investors is that supporting Drax now will lead it to become a negative emissions company in time. Speaking at last year's CFA ESG Conference, Fiona Reynolds of the Principles for Responsible Investment said

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

Investing in Drax is a way to make sure it does exist.

IS THERE ENOUGH BIOMASS?

US forestry biomass

The USA has over 750m acres of forest land representing 35% of its total landmass. It currently supplies more than 25% of global industrial wood production. The forest resource has been growing annually since the 1950's and is protected by statutes, regulation and certification with best practice in forest management and sustainability.

USA Forestry Overview

Type of land	United States	Conterminous United States
Total land	2.3 billion acres	1.9 billion acres
Forestland	751 million acres	623 million acres
Timberland	514 million acres	475 million acres

Source: USDA US Forest Service

The southeast is a key fibre basket with vast resources of sustainable forestry. Inventories have increased by at least 50% since 1950 and the commercial forestry industry is well established.

Drax plans to self source 5mt of its biomass needs by 2027 or 5.5m dry tons. The US Department of Agriculture Forest Service estimates that at a price of US$60/dry ton, there will be 61.6m available dry tons on non-federal land in the USA in 2030. Simple maths suggests that Drax will account for 9% of this supply which is significant but we do not believe problematic. Drax also sources outside the US with 35% of fibre currently coming from other countries which would reduce this figure to 6%.

Forecast Wood Biomass Availabilty at $60/t

	2017	2022	2030	2040
All land				
Logging residues	17.9	19.4	21.4	20.7
Whole-tree biomass	69.9	73.7	59.8	60.7
Federal land excluded				
Logging residues	15.7	17.1	18.8	18.4
Whole-tree biomass	52.3	55.4	42.7	46.1
Total: Baseline (all land)	87.8	93.1	81.1	81.5
Total: Baseline (no federal)	68.1	72.5	61.6	64.5

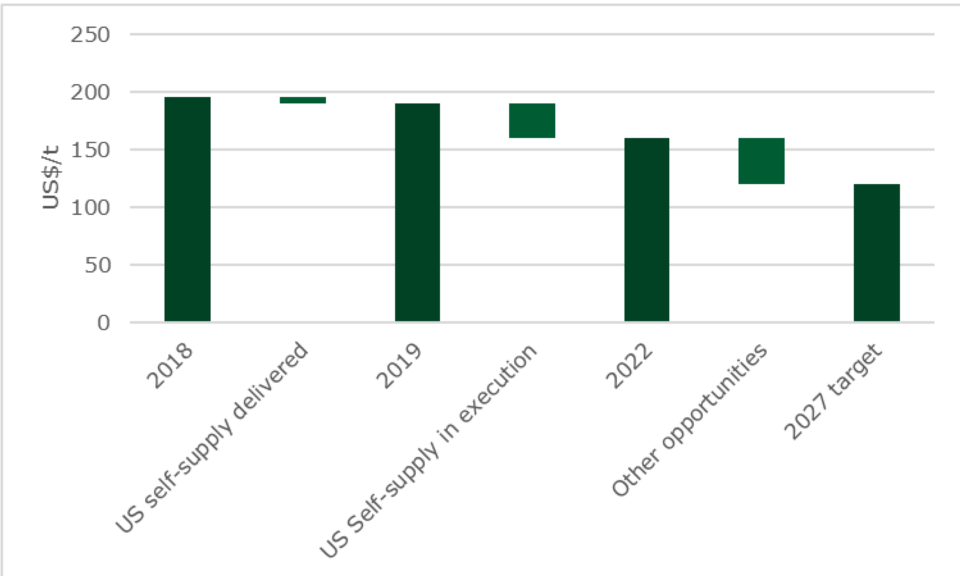
Source: USDA US Forest Service, Forest biomass and wood waste resources 2016

A DEVELOPED BIOMASS LOGISTICS CHAIN

Drax has targeted a fuel cost of £50/MWh by the time the Renewables Obligation support comes off in 2027. Until then the Drax biomass units can achieve strong positive cashflows with £294m of EBITDA generated in 2019. Even in the COVID 19 lockdown the value of flexibility means that the biomass units should remain attractive.

The current pellet operations are delivering fuel at a cost of £75/MWh to £80/MWh based on a cost of fuel of US$210/t. The company is targeting a 30% cost reduction across the supply chain to bring the cost down to £50/MWh or US$140/t. Drax has presented a detailed and in our view viable plan for achieving this. The recent interims confirmed that progress is being made in line with the plan.

Biomass cost trajectory



Source: Drax Group

Examples of the opportunities are shown in the following table.

Biomass cost saving initiatives

	US$/t	£/MWh	Tonnes affected
Specific US cost savings (total)	**35**	**13**	**1.85**
Sawmill co-location	10	4	0.45
Forestry and harvesting	4	2	1.1
Woodyard decommissioning	5	2	0.45
Die and roll life extension	1	0	1.5
Capacity expansion	50	19	0.35
Rail spur	15	6	0.45
Rail chambering yard	3	1	1
Trailer drop programme	2	1	0.5
Satelite plants	40	15	0.5

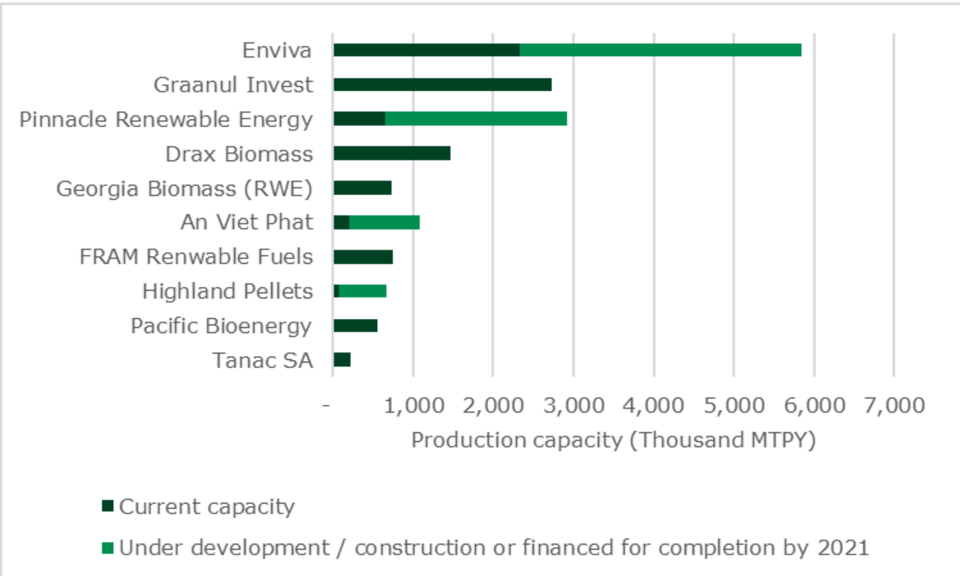
Source: Longspur Research based on Drax Group disclosures

PELLET PRODUCTION

In addition to creating a low cost fuel supply for the biomass units, Drax sees the pellet production business as a source of value in its own right. With BECCS a major part of meeting the Paris climate goals, this makes sense and we think the optionality provided here is another example of Drax de-risking its business and creating opportunity. Whatever happens with Drax in the UK, there will be routes to market for pellets produced by Drax in Louisiana.

As a business in its own right, the Drax pellet production business is already the fourth largest pellet producer globally.

Wood pellet production capacity



Source: Enviva based on Hawkins Wright

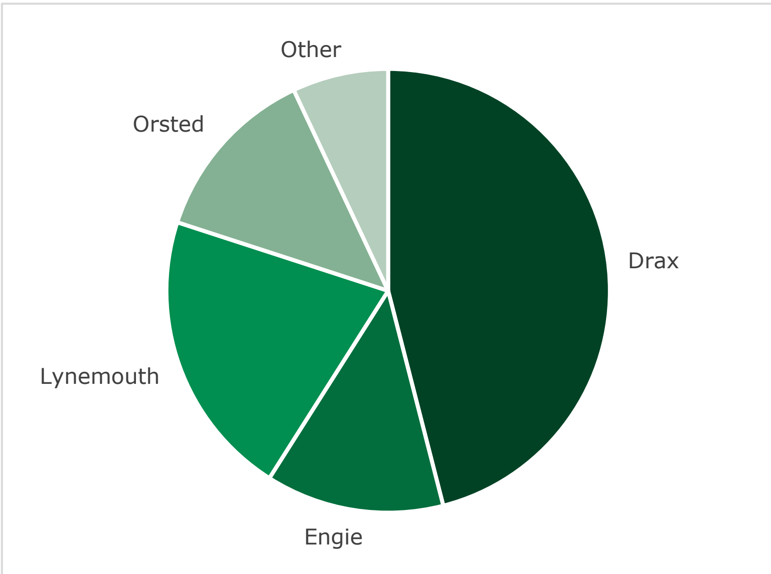
The market is currently attractive and likely to remain so. While this could put pressure on the biomass generation business we think the Drax optionality can keep pricing sensible for both generation and pellet production.

Wood pellet market balance

Source: Enviva

This optionality benefit of integrated pellet production is that it gives Drax a degree of market power in negotiations with other suppliers. At present Drax sources from a number of the major pellet producers including Enviva. In the case of Enviva Drax is a major customer.

Enviva contract mix 2019



Source: Enviva

While contract development means that Enviva will achieve greater diversification of customer over the next few years, Drax is likely to remain important.

£50/MWH COST CAN MAKE MONEY WHEN TODAYS PRICE IS £30/MWH

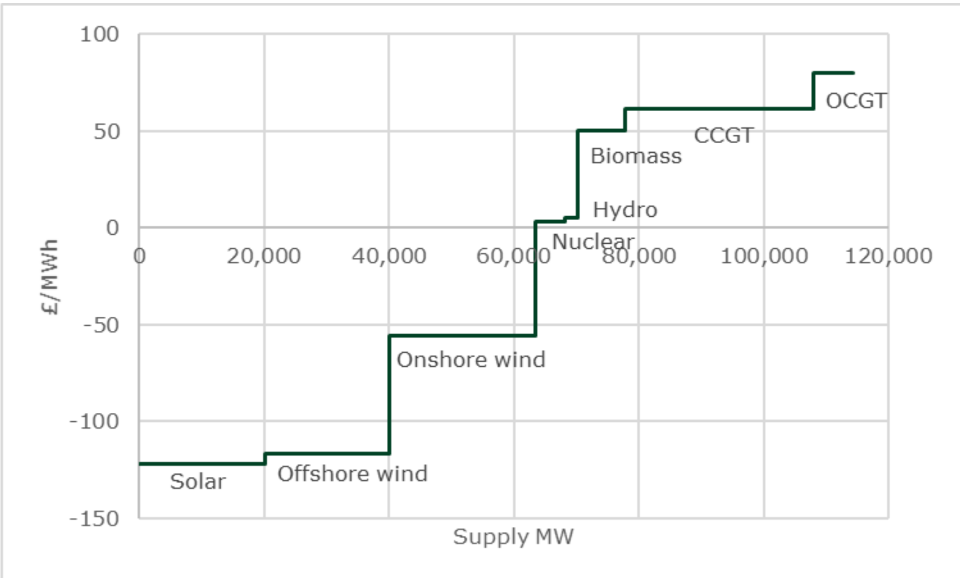
Drax is targeting getting its cost of biomass fuel to £50/MWh by 2027 when the existing ROC subsidy support comes to an end. However the electricity price during the COVID 19 lockdown has averaged £25.5/MWh suggesting the biomass units would not be profitable. Additionally long term forecasts such as the BNEF H1 2019 forecast suggests a 2027 price of £41/MWh and £30/MWh by 2030, again both below the £50/MWh target. However it should be stressed that both the current price and the BNEF forecast are based on average prices for baseload generation.

It is likely that, given the significant quantity of renewables on the system by 2027, the Drax biomass units will run at about 50%. This running will be at the times when there are less renewables on the system and pricing will be stronger at those times.

BNEF itself forecasts the deviation around the average price to widen as a result of more renewables on the system. For Drax, pricing should be well above the average. However, these price forecast are dependent on the competitive position of generation units at the forecast data and it is more instructive to examine this.

We expect the merit order in 2027 to look like the following.

Forecast merit order 2027

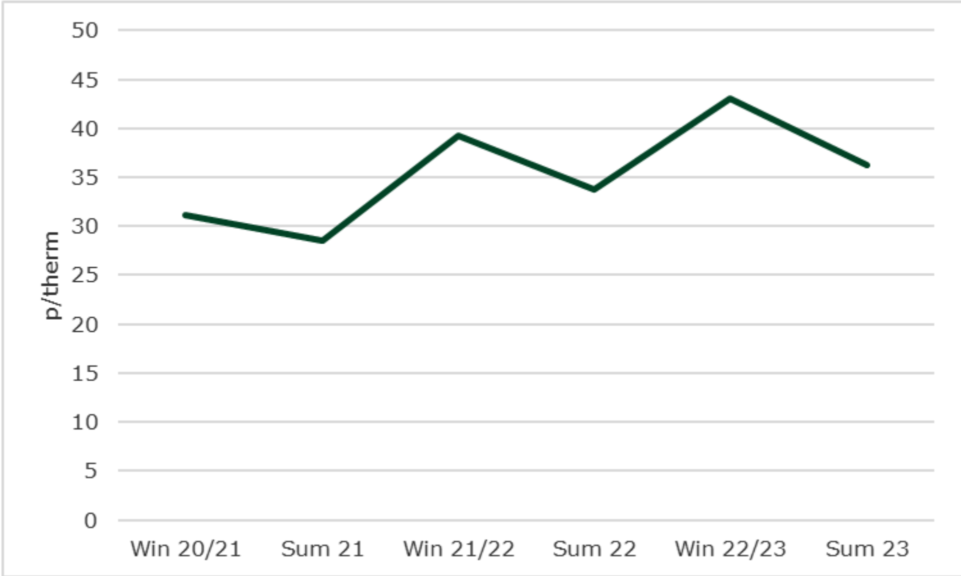


Source: Longspur Research, BNEF

Biomass will either come before or after CCGTs so an examination of the short run marginal cost of a CCGT in 2027 will determine whether biomass at £50/MWh runs in merit or not.

Current gas prices are at an all time low thanks to the demand "holiday" resulting from COVID 19 lockdowns. The forward curve assumes some recovery with demand into 2021.

Gas (NBP) forward curve



Source: Bloomberg

The current low prices as well as pressure on the oil and gas industry from the partly related low oil price mean a general lack of investment that may drive higher prices in the medium term. Even without this driver we feel that the current curve is likely to represent a low point given the combination of factors that have led to its current position. If we inflate the current forward curve we get 45.24p/therm in 2027.

Carbon tax

We also need to consider carbon taxation which CCGTs are likely to pay and biomass is not.

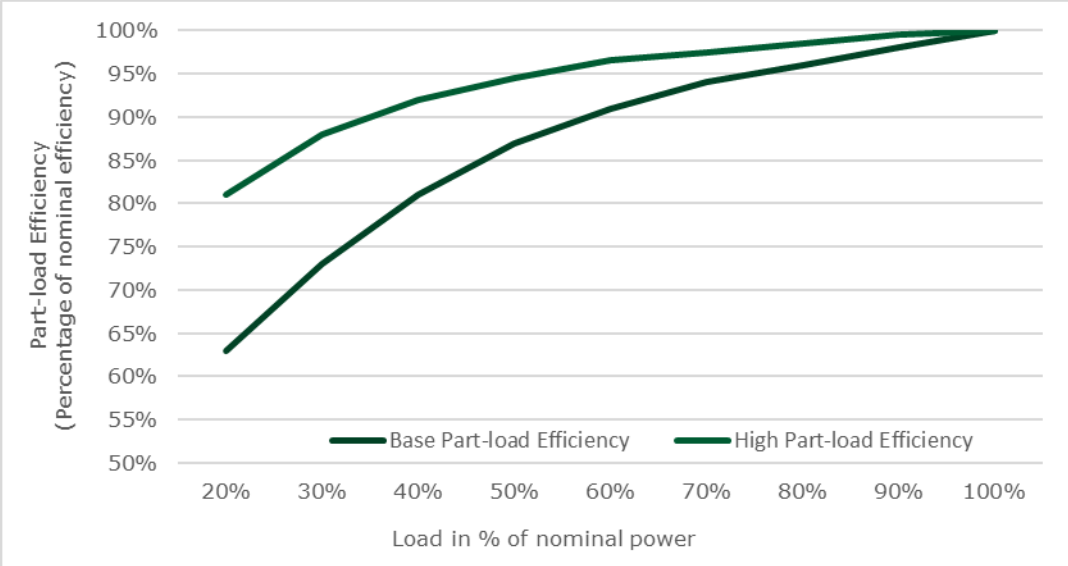
On 1 June the UK government published proposals for a UK-wide Emissions Trading System (ETS) to be implemented from 2021 that replaces the EU ETS, which the UK will leave as part of Brexit. The UK ETS will look similar to the EU ETS, with coverage of energy intensive industries including power generation, refining, heavy industry, manufacturing and aviation. The auctioning of allowances will continue to be the primary means of introducing allowances into the market, with an auction reserve price of £15 to ensure a strong carbon price and provide continuity during the initial years of the scheme. Assuming the carbon support price element of the carbon price floor is retained at £18/tCO2 this gives a total carbon price of £33/tCO2 in 2020 prices.

We see this as a minimum figure and note widespread talk of higher levels of carbon pricing. For example BP is now using a US$100/t price assumption for 2030.

SRMC as baseload

Together this gas price and carbon price combination would give a short run marginal cost of £46/MWh in a 50% efficiency CCGT. However this misses a key point. We would expect the load factor of the marginal plant to be somewhere between 50% and 70%. CCGT suffer an efficiency fall off at part load. Even at 70% we would expect the efficiency to be 90% of the maximum and at 50% this falls to 85%. BNEF has max CCGT plf at 36%. Part load efficiency graph suggests only 75% of efficiency at this level of part running.

CCGT part load efficiency



Source: Strbac and Aunedi, Imperial College, 2016

Using this efficiency gives a SRMC of £62/MWh. If this is the power price when the biomass units run they would get a bark spread of £12/MWh (£62/MWh - £50/MWh).

Forecast CCGT SRMC in 2027

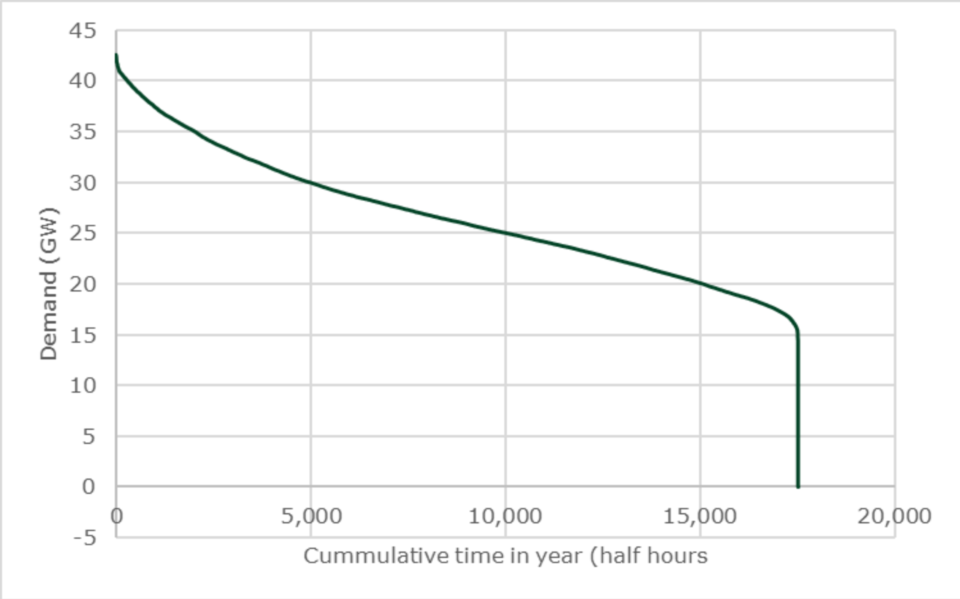
	Value	Notes
GJ/therm	0.106	
Fuel emissions factor	0.06	kgCO2/MJ
Full load efficiency	50%	DUKES
Part load efficiency factor	75%	@36% plf
Part load efficiency	38%	
Gas price	45.24	p/therm
Fuel cost	41.16	£/MWh
Carbon price	43.24	€/t
Carbon cost	20.94	£/MWh
Marginal cost	62.11	£/MWh

Source: Longspur Research

How much of the market is left for the BM units?

To get a better view of the actual load factor at the margin we can look at how capacity stacks up under the load duration curve in 2027. This shows load against cumulative time across a year.

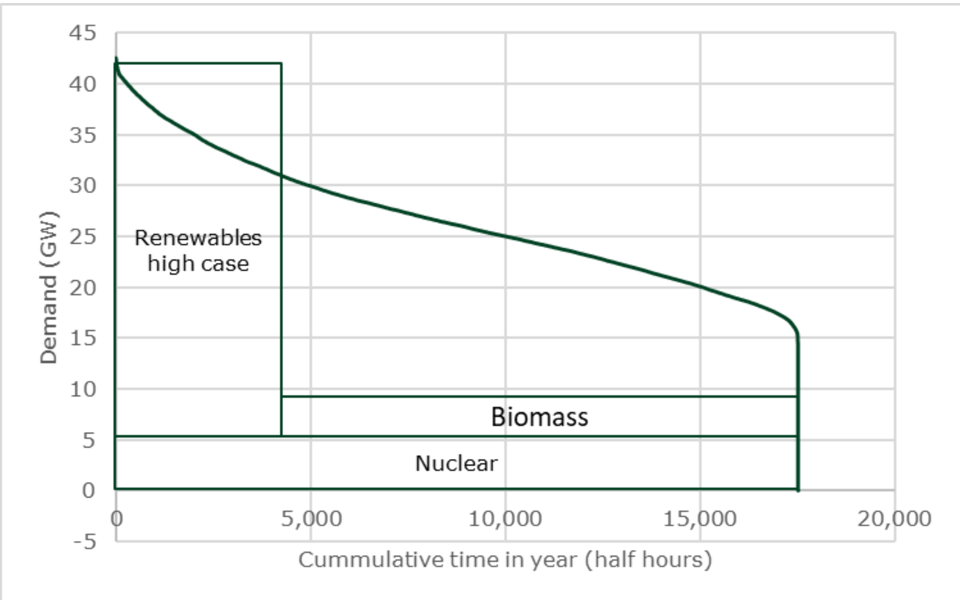
Forecast load duration curve 2027



Source: Longspur Research

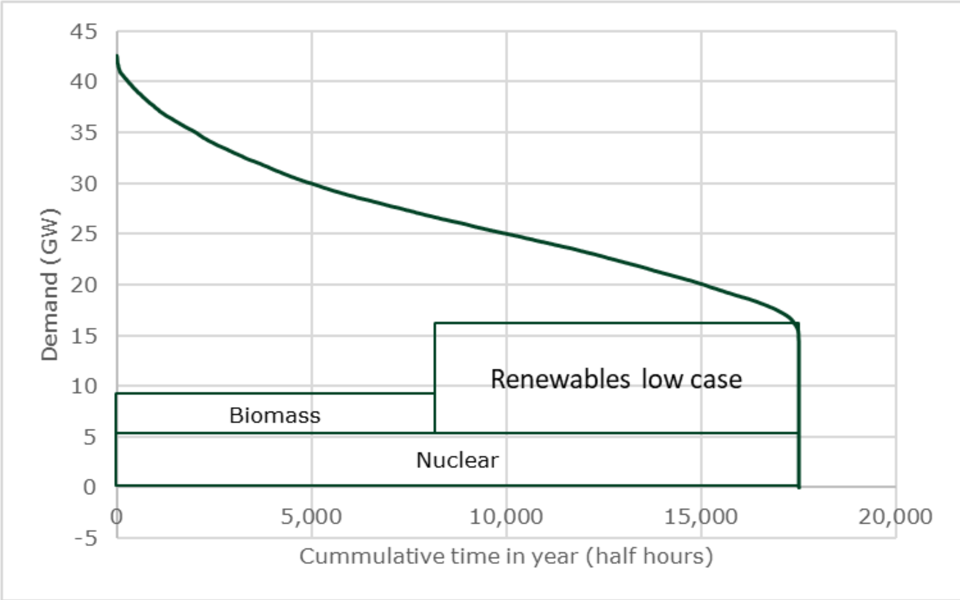
We can show how generation meets this demand using the graph but the problem with renewables is that we don't know when they will run. We can assume that solar will tend to run in the centre left of the graph because it will run during the daytime when demand is higher. However, it will not touch the left hand end of the graph because peak demand will be in winter after sunset. Wind is much more random. True modelling uses Monte Carlo simulations to get an average price but we can look at extremes to determine an envelope. Simply adding expected intermittent renewables with either all running full out at peak periods or all running at half load at off peak periods suggests a load factor of between 50% to 75%. Average is 62.5% which is not too different from the 2019 biomass average load factor of 59%.

Renewables high case



Source: Longspur Research

Renewables low case



Source: Longspur Research

Running at the low point and in conjunction with gains from sales of inertia and ancillary services we think biomass could deliver an EBITDA of £185m beyond 2027 and even without these other market gains we still expect a postive EBITDA of £30m. In this assumption we have assumed the CdF unit is inluded in this calculation as a merchant unit but in reality it will receive a premium revenue stream until 2031. We see intertia as a growing market opportunity for the biomass units.

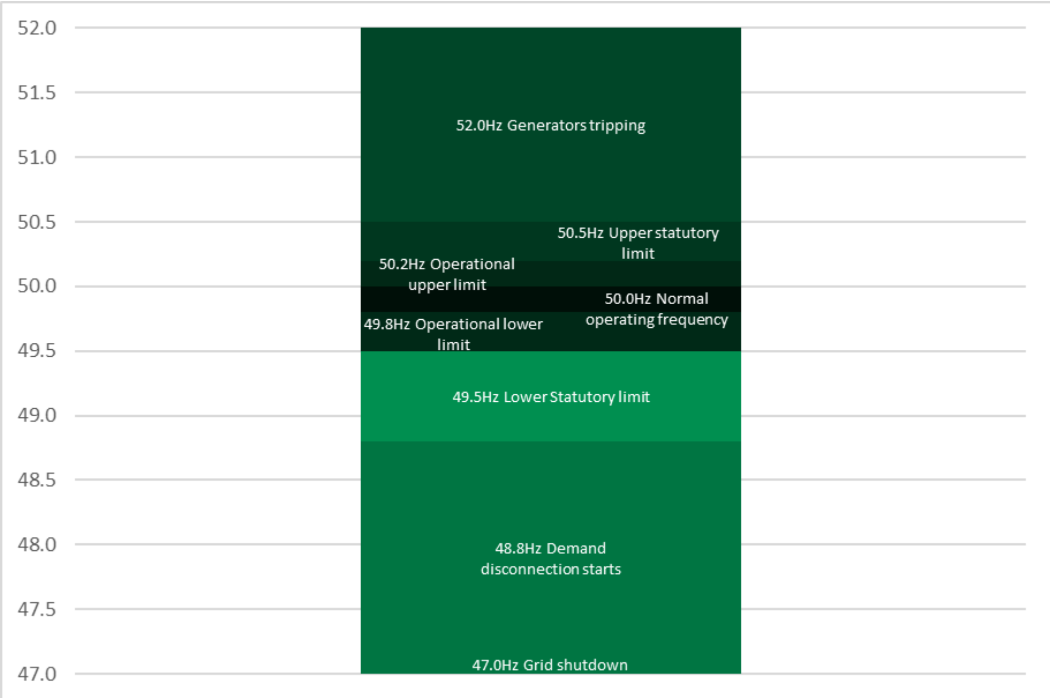
BIOMASS, CRUACHAN AND INERTIA

LOW CARBON SPINNING RESERVE

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.

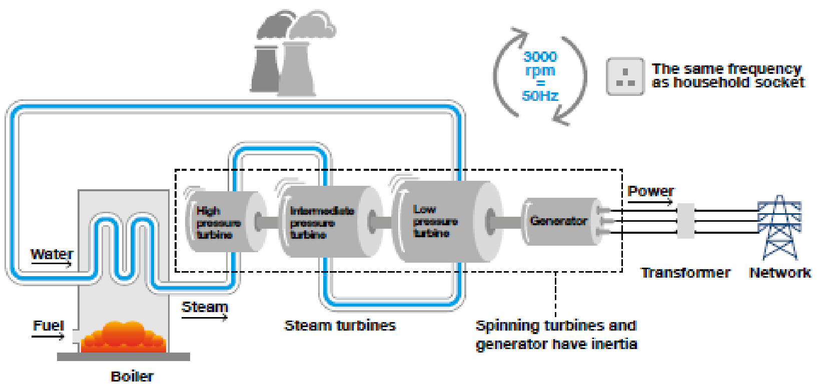
Frequency trigger points



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.

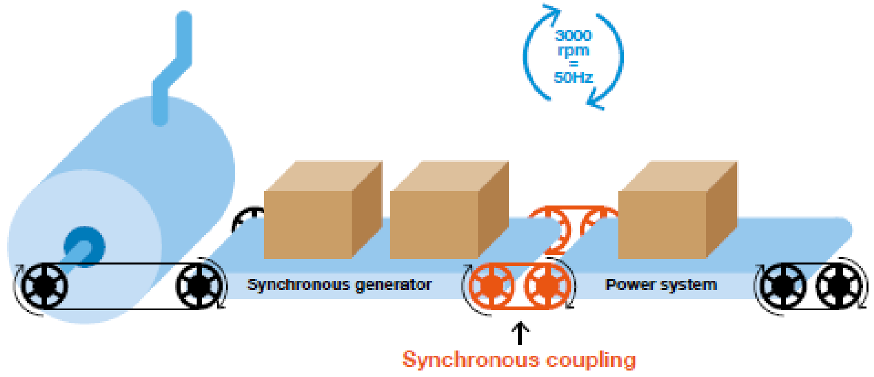
Synchronous Generation Creates Inertia



Source: National Grid

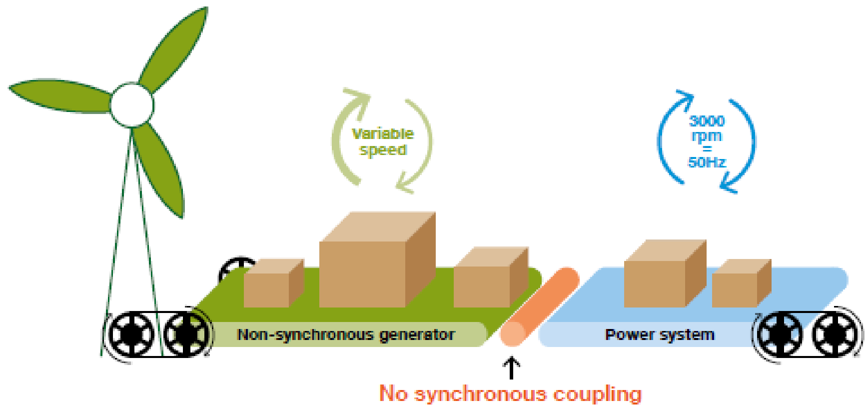
This worked reasonably well when most of the system's generators were synchronous. Unfortunately the main forms of renewable generation, wind and solar PV, do not provide inertia to the system. Their generation output varies continuously as wind rises and falls and as cloud cover materialises and disperses.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

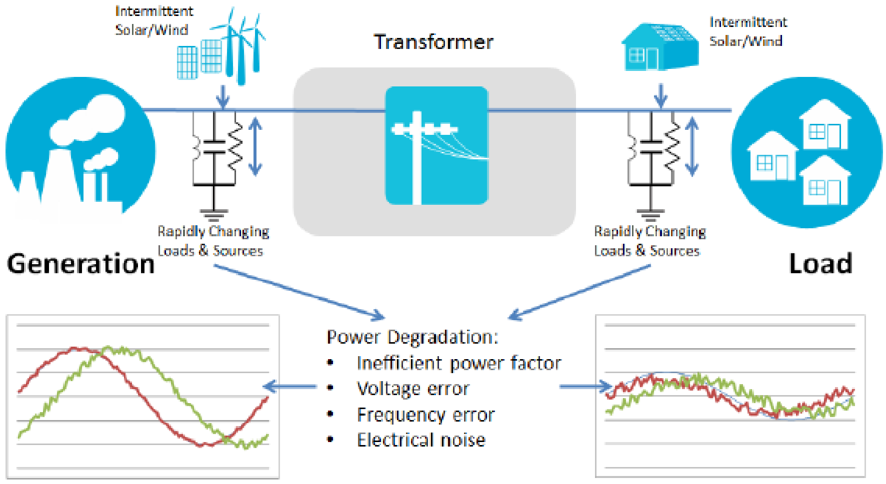


Source: National Grid

Intermittency and volatility

The intermittency problems created by renewable generation are well known in terms of the longer duration issues of day time 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



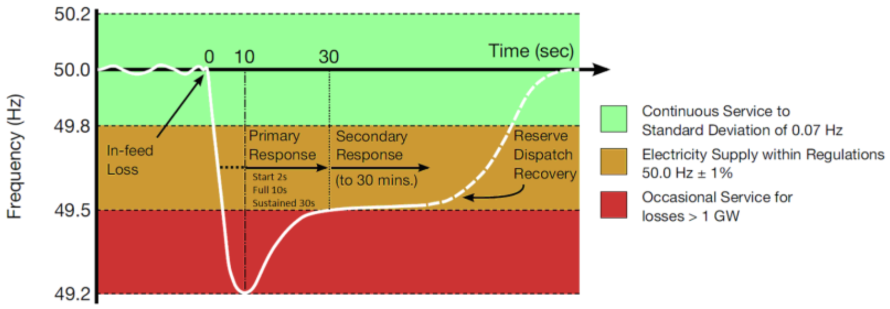
Source: Faraday Grid

WHY STORAGE IS NOT A SOLUTION TO THE PROBLEM OF VOLATILITY

The market is extremely interested in battery based energy storage as a solution to the problems of intermittent renewables. The UK's Enhanced Frequency Response auction saw 201MW of mainly lithium ion capacity bid into the market. However this storage does not really solve the volatility issue. Standard energy management systems used with battery storage can only respond in the micro second 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 Electro Power Systems (EPS FP – BUY – TP €15.3) that can respond in 128us 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 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.

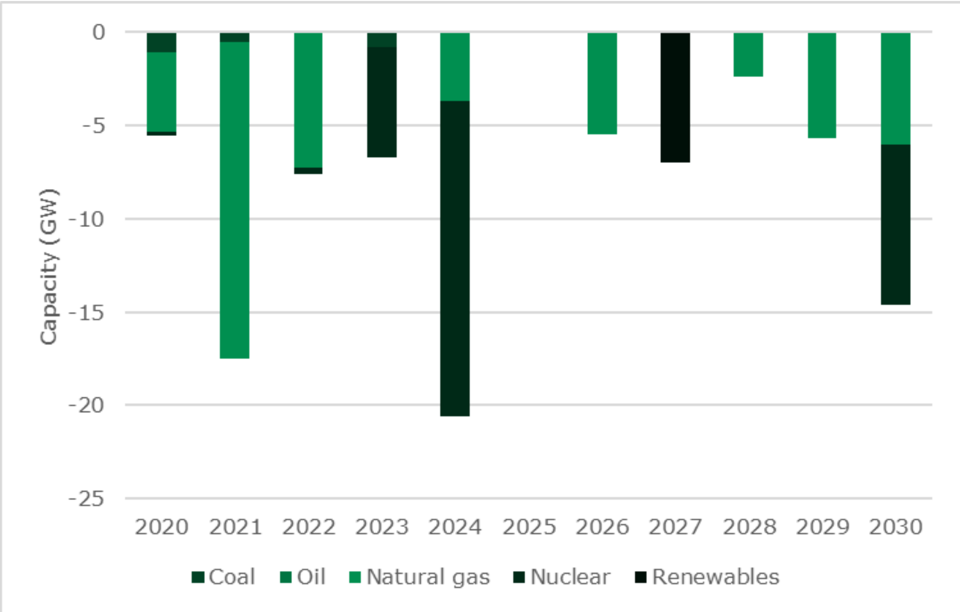
The current state of the market is best summed up by DGA Consulting in their International Review of Frequency Control Adaption, undertaken for the Australian Energy Market Operator in 2016.

"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 INTERTIA

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.

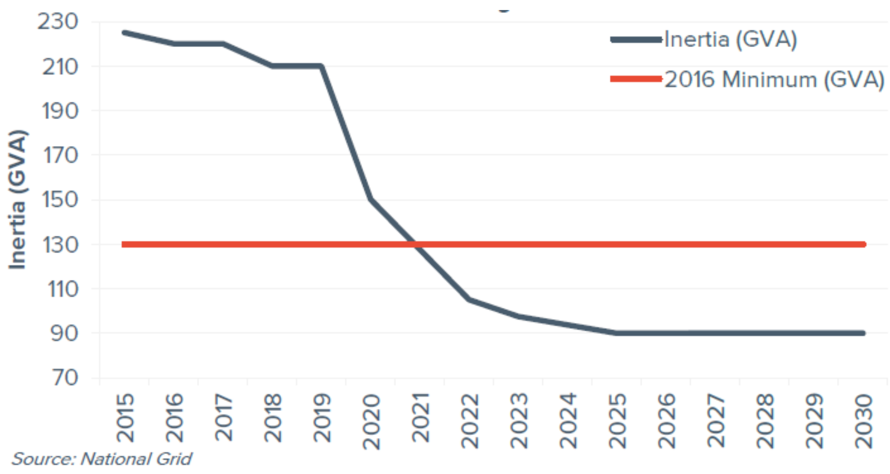
Capacity closures



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 2021.

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.

Sychronous Compensation Tender

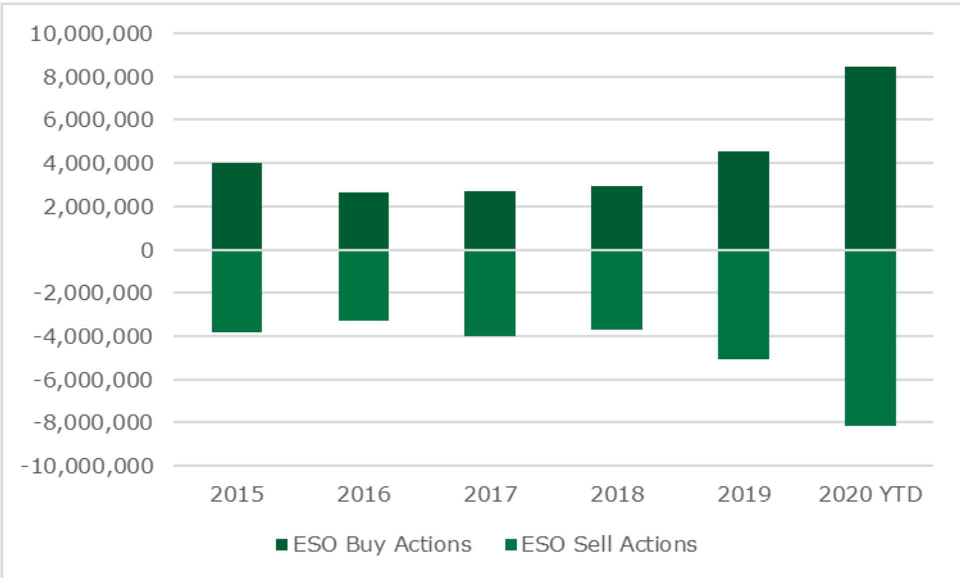
In order to address this loss of inertia, National Grid ESO is planning to pay directly for inertia services in the future in order to incentivise the construction of synchronous generators or synchronous compensators, both of which can provide inertia. ESO has already awarded contracts to the value of £328m under a phase one Sychronous Compensation Tender as part of its Stability Pathfinder project. Drax was successful with its Cruachan site but not with the biomass projects. This will mean incremental EBITDA of up to £5m pa over six years from Q2 2020. More tenders are likely and this could see the biomass units rewarded. However we think it is clear that they are already mechanisms rewarding intertia in the market.

HOW DRAX GETS PAID FOR INERTIA NOW

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 by examining what happens when there is not enough inertia on the system. 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 such as Drax 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 shear 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.

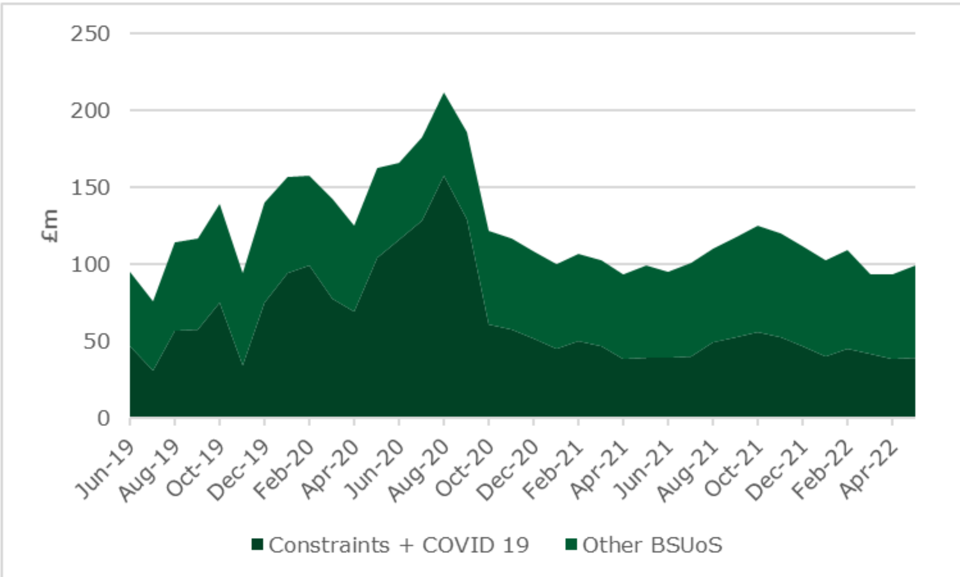
BSUoS Forecasts under COVID 19

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: Naitonal 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

To an extent these market behaviors have been reflected in a 33% increase in combined balancing mechanism, ancilary services and portfolio optimisation revenues in the recent Drax interim results. EBITDA has not followed this being only up 8% which we see as reflecting a move in the asssets serving this demand with more from biomass compared to pumped storage. We would expect the company to adapt in time to a more volatile environment and see the opporutnity growing at the EBITDA level as well as in sales.

While the COVID 19 market is not a perfect indication of the market beyond 2027, 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 the Drax biomass and CCGT 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 future. We estimate that Drax made over £65m from BM actions in 2019. We see the potential for this to double in time, adding additional revenue over the next 7 years.

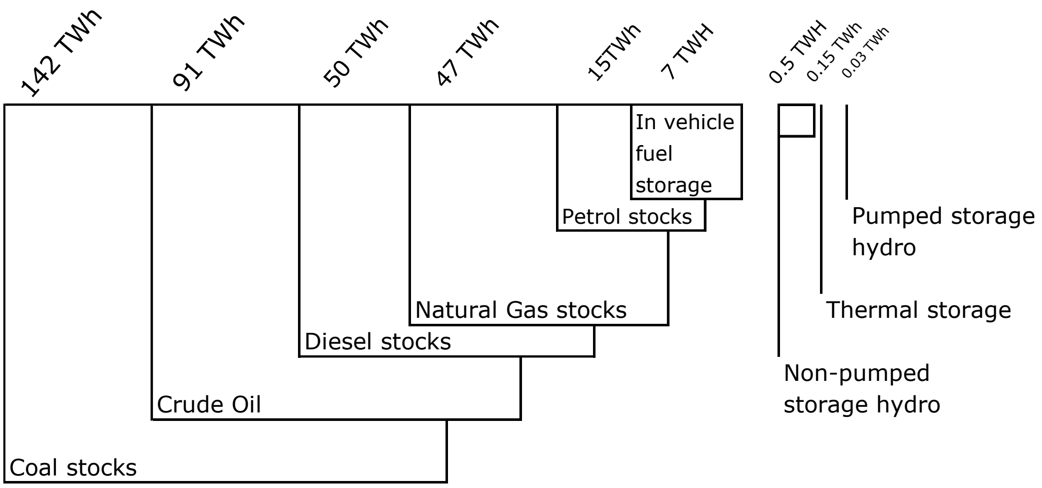
SYNCHRONOUS COMPENSATORS AS COMPETITION

The alternative 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. 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, the balancing mechanism route looks likely to be cheaper as long as there is spinning reserve to take part.

NEW STORAGE DOES NOT DENT CRUACHAN

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.

Energy Storage in the UK, 2015

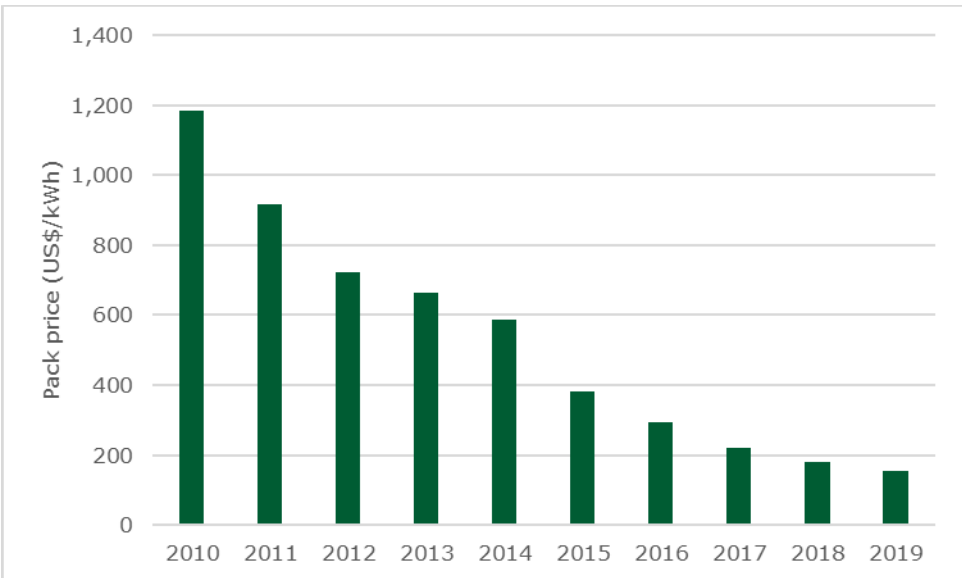


Source: Simon Gill, University of Strathclyde, 2015

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.

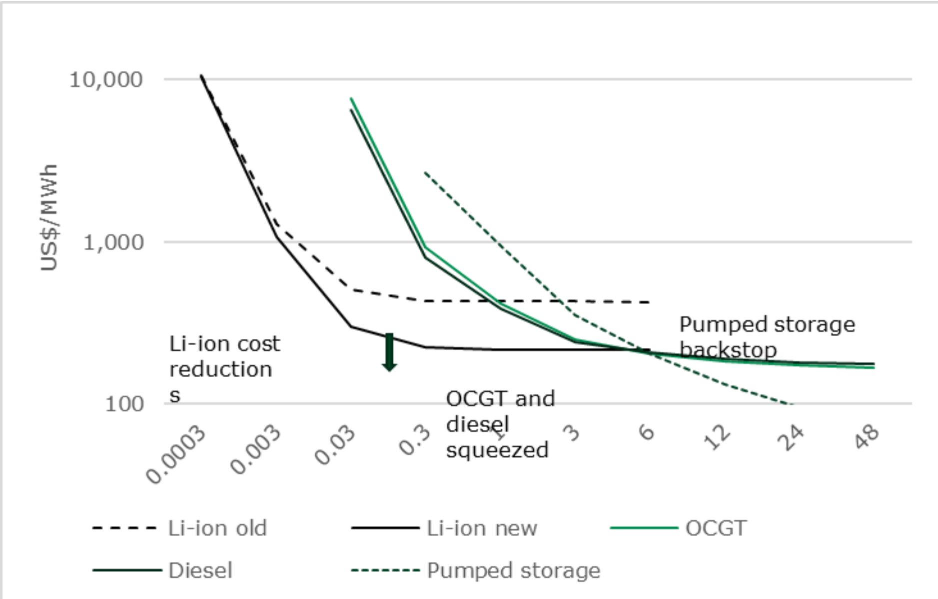
Lithium ion ESS EPC costs



Source: Bloomberg New Energy Finance

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 it is uneconomic compared with pumped storage.

Levelised cost of storage against duration



Source: Longspur Research

Drax has added immensely to its potential to provide long duration storage with its acquisition of the 440MW pumped hydro project at Cruachan in Argyllshire. This has the added benefit of compressed air injection which makes it very fast reacting as well as being able to store up to 16 hours of electricity.

Drax is evaluating whether to expand the capacity of Cruachan. It would be far cheaper than a new pumped hydro plant as much of the existing infrastructure can be re-used.

Cruachan has also been given a boost in terms of the charges paid to National Grid for use of the transmission system. To date it has paid these charges when both charging and discharging. OFGEM has recently rulled that it will now only pay when discharging. While this is a small benefit to battery storage because these charges are by the hour, this is a more siginficant benefit to long duration storage such as Cruachan.

Biomass as storage

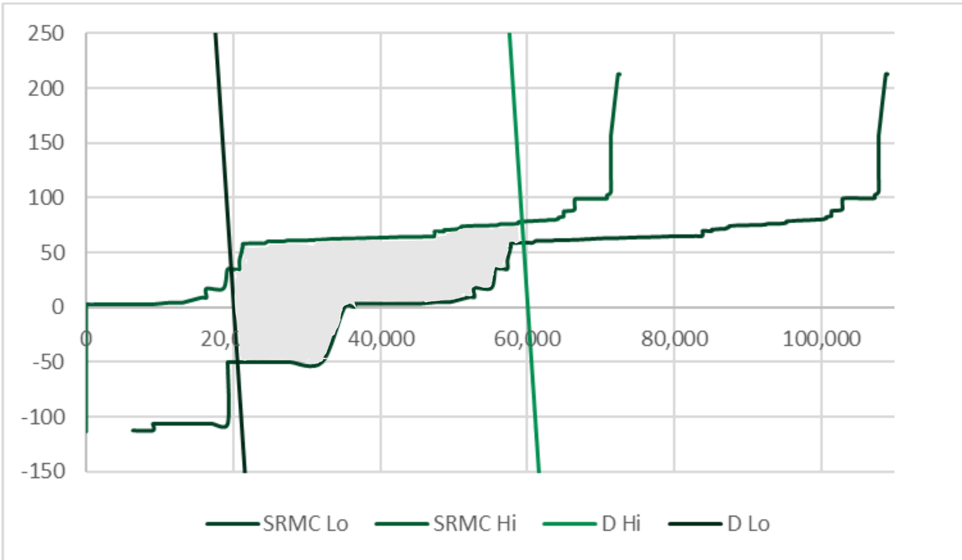
One other reason why we think there is value in the Drax biomass units is that they also represent storage. Drax Power Station has 300,000 tonnes of biomass storage capacity. The chemical energy contained in this biomass represents 650,000MWh of dispatchable energy.

THE WHOLESALE MARKET OPPORTUNITY FOR STORAGE

We can show supply and demand for the GB wholesale electricity 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.

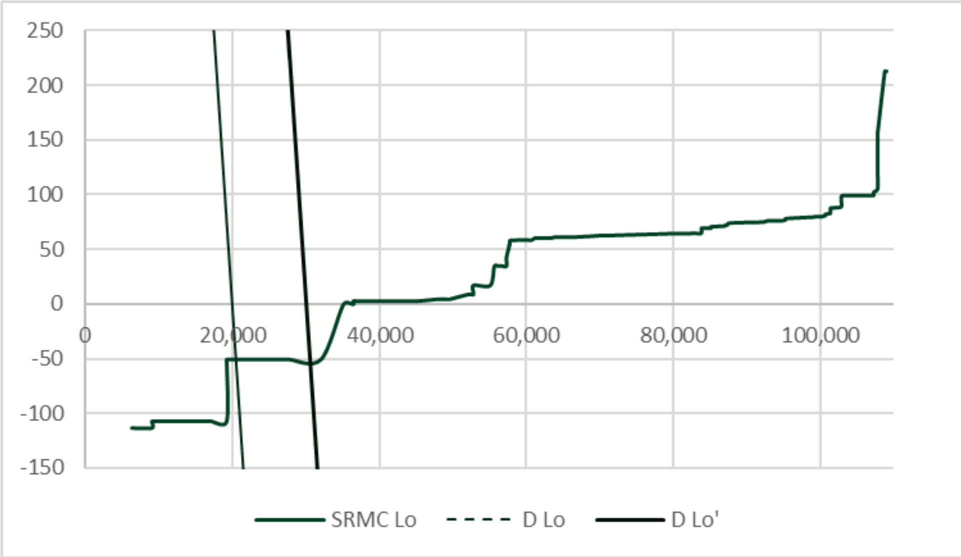
The low supply curve includes renewables with negative short run marginal costs. This is a result of subsidy programmes. The generators only get the subsidy when they run so should be prepared to bid negatively down to the level of subsidy. This may be rare but does happen and is on the increase as more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

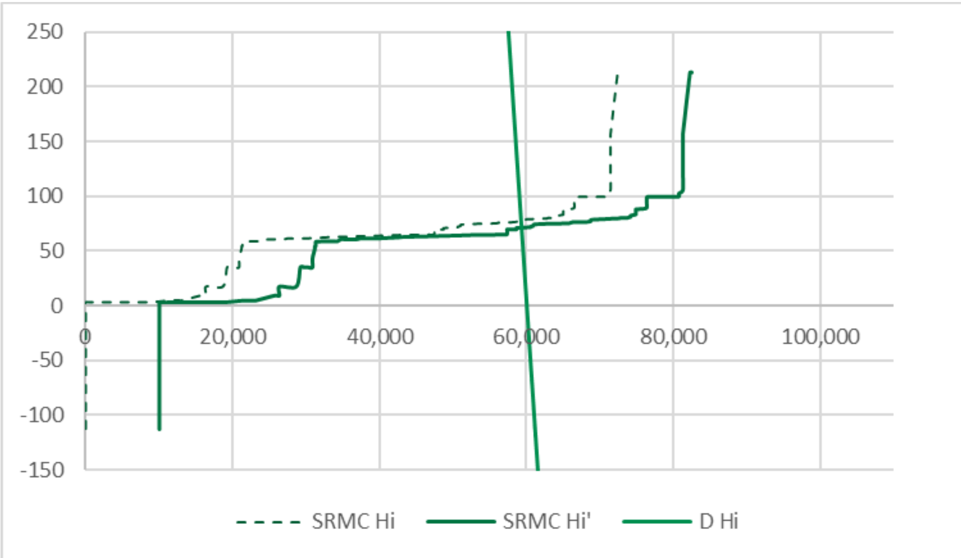
Impact of 10GW of storage charging



Source: Longsur 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 Reseach

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.

DELIVERING BECCS

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.

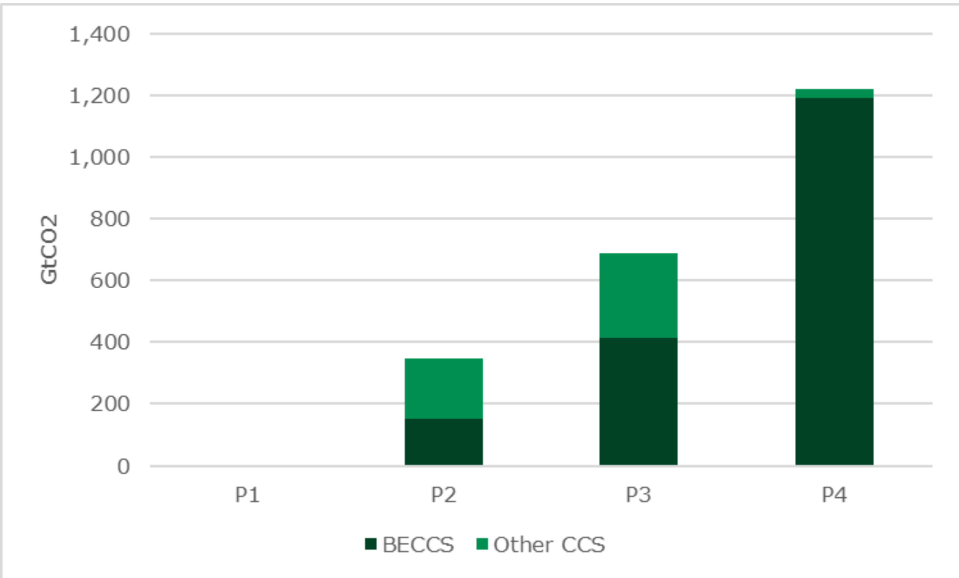
There are several stages to BECCS; biomass production and generation, carbon capture, and finally carbon storage. Drax is currently operating in biomass production and generation and it is actively working to deliver carbon capture. Carbon storage will be undertaken by partners but the Drax power station is extremely well sited for storage being proximate to active and depleted oil and gas reserves in the North Sea.

Why we need BECCS

The IPCC's 1.5 degree report groups 85 net zero pathways 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.

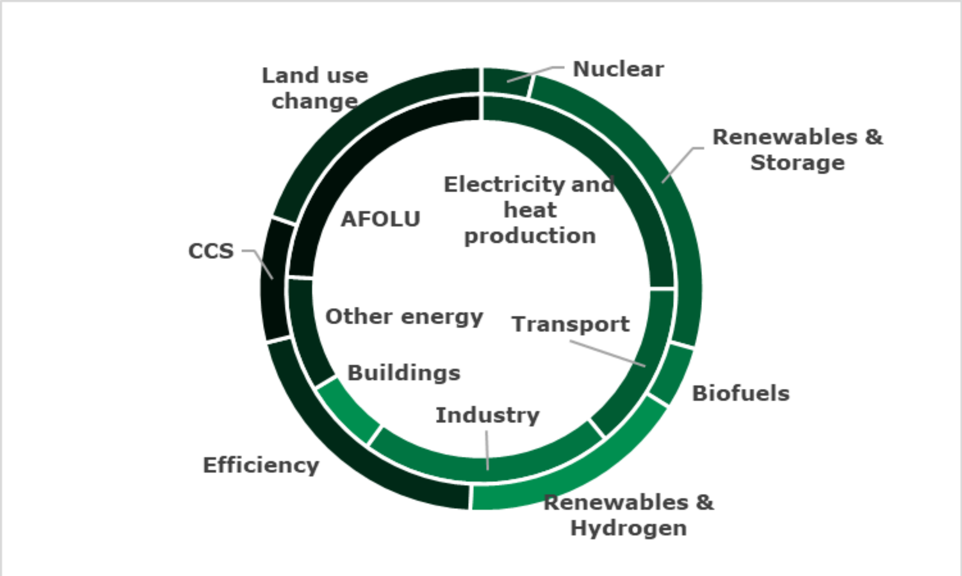
BECCS contribution to 1.5 degree pathways under four scenarios



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 or 10% of the total.

Global Emissions and Solutions

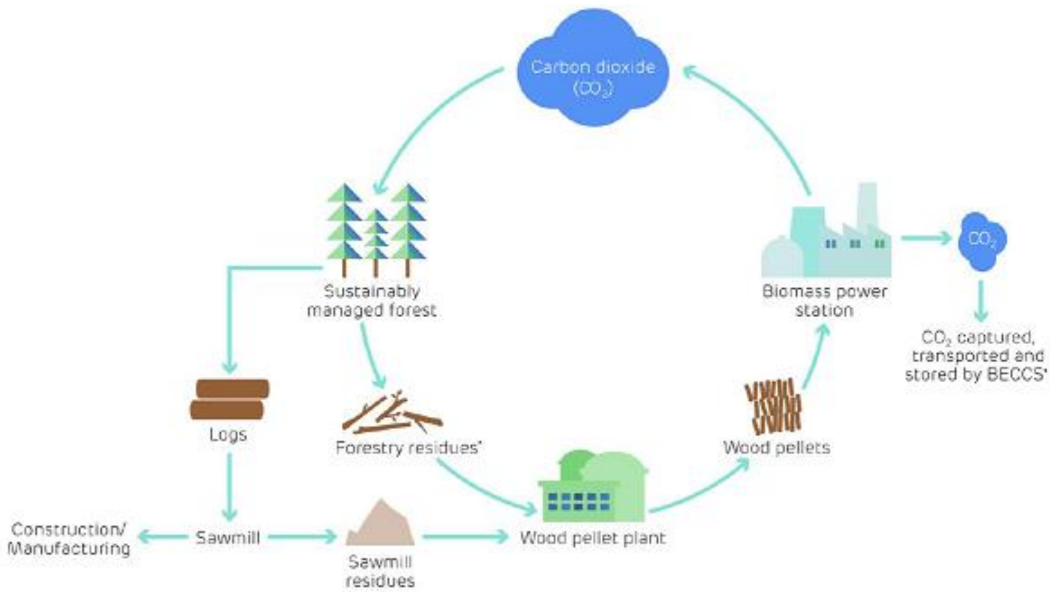


Source: IPCC, Longspur Research

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.

CO2 Cycle with CCS

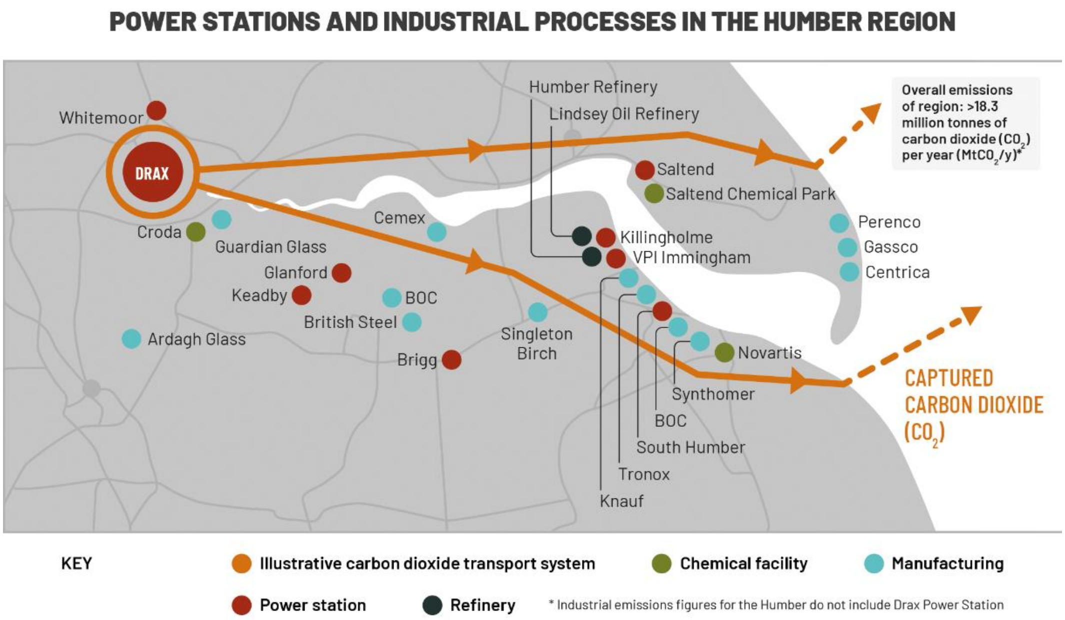


Source: Drax Group

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 from Drax's point of view.

Drax has location on its side in this regard and is a member of the Zero Carbon Humber initiative which aims to build the world's first zero carbon industrial cluster in the river Humber estuary region. The plan will include utilising existing users of CO2 and attracting others with the addition of CO2 transportation infrastructure which will eventually reach storage facilities in the southern North Sea sector of the UK continental shelf.

Zero Carbon Humber

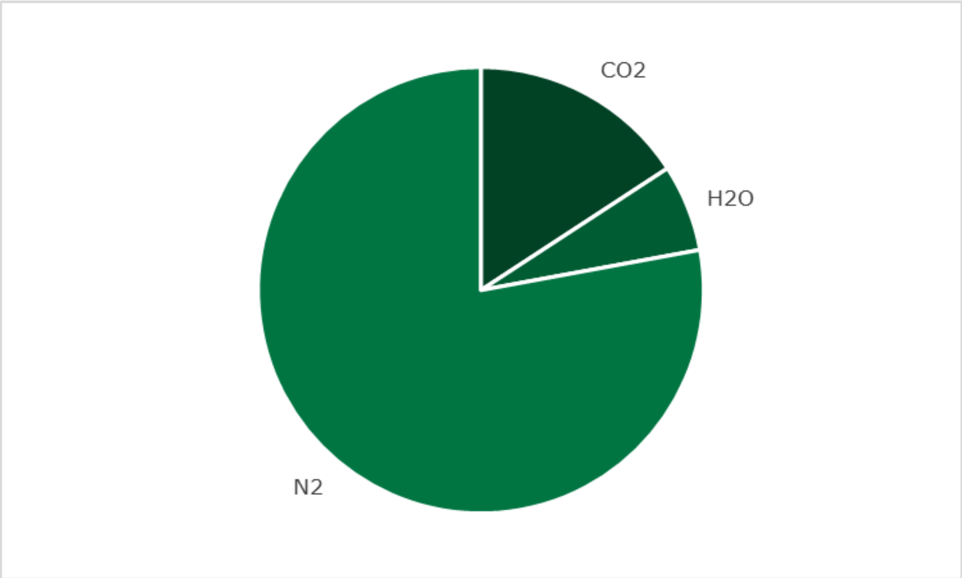


Source: Zero Carbon Humber

CARBON CAPTURE TECHNOLOGIES

The problem with capturing CO_2 from waste gases is that the waste gases are not comprised of pure CO_2. Less than a quarter of the flue gas will be CO_2 with water and nitrogen comprising much of the rest. The capture process essentially deals with splitting out the CO_2 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 CO_2. Essentially this 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 CO_2 flue gas. Effectively the other flue gases are removed at the oxygen separation stage necessary to produce the oxygen. Drax has already explored this technology as part of the White Rose partnership which [get history from notes]

Post combustion capture involves removing the CO_2 from the flue gases. This is the most likely solution for Drax.

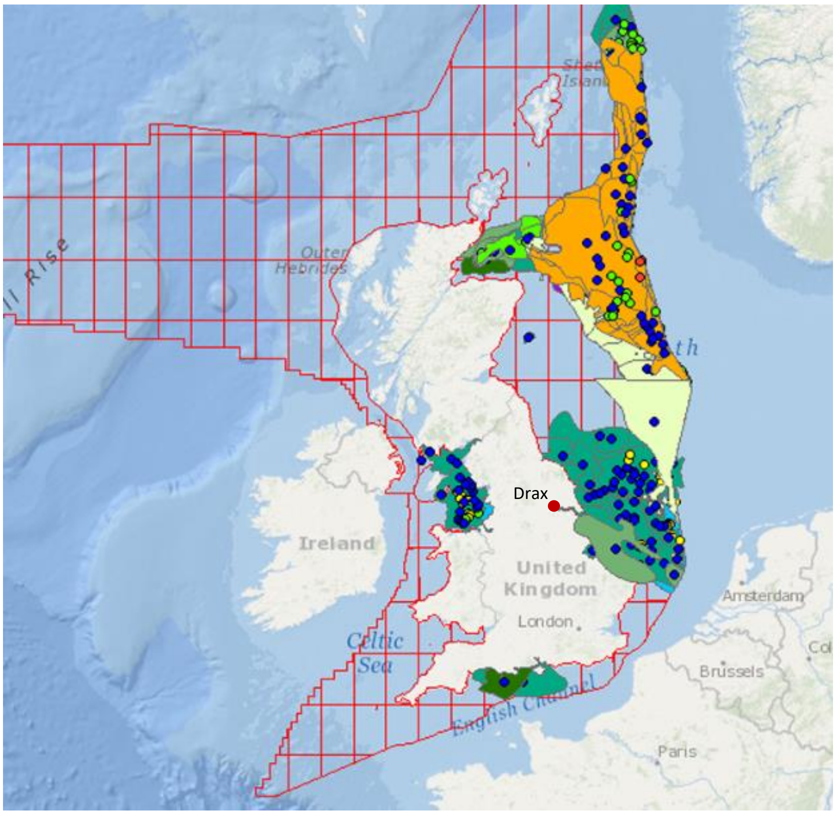
The use of amines (most commonly monoethanolamine, MEA) to take out the CO_2 is well proven technology, being used in the oil refining industry. This could be used today for CCS from biomass power stations. The barrier is simply cost. The main costs are threefold.

- 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. Drax's location with access to the Southern North Sea Basin is beneficial in this regard.

Potential CO2 Storage UKCS



Source: CO2 Stored

For now we assume that there will be willing offtakers of the CO2 at zero cost or who will offest any costs through their own subsidies. However this is not guaranteed and transmission and storage costs may need to be reflected in the level of support given at the capture level.

Drax is looking at several solutions, all of which are variations of post-combustion capture but which can reduce the overall cost.

Straightforward amine capture is currently the most viable technology on offer.

Drax is deploying a pilot with Misubishi Heavy Industries (MHI) at the CCUS incubation area. MHI also has an alternative solvent which can reduce both the cost of the solvent and the energy cost of the process.

Drax is also working with C-Capture, a Leeds University department of chemistry spin out, and has invested £1m into a JV. They are working on a post combustion capture technology with an alternative capture media to MEA. Because MEA requires significant quatities 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. Additionally, because the solvent is less corrosive, cheaper steel to be used to fabricate the reactor vessels reducing the capital cost of the project. 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.

Drax is also evaluating Fuel Cell Energy's molten carbonate fuel cell (MCFC) technology. 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.

Drax is still evaluating these and other solutions in detail. C-Capture already has a test unit on site at the Drax power station. We see the company building a thorough understanding of the technology before committing to full deployment. It is worth remembering that Drax started experimenting with Biomass at least as far back as 2004 and ran trials with over 60 biomass materials before fully committing to co-firing, ensuring that it had the right fuels and could deliver output efficiently and safely.

COST OF CCS

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

The Petra Nova CCS project in Texas was constructed for US$1.0bn and operates on a similar size unit to those at Drax although only processes 37% of the emissions. This is a reasonably recent project and gives us a start point for estimating capital costs with an equivalent cost for processing the 100% of emissions at US$2.7bn or £2.0bn. The market cost of monoethanolamine is currently around €1300/tonne and despite recycling the amine, 1.5kg is required to be made up for every tonne of CO_2 captured. The typical efficiency give up for CCS is 26 percentage points. We can used these factors to estimate a levelised cost of CO_2 capture.

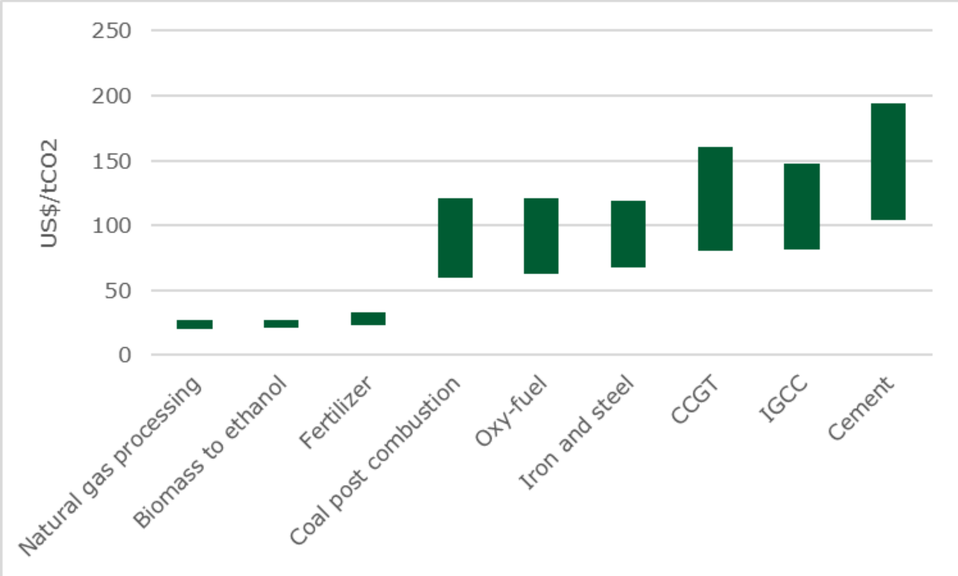
Amine post capture CCS cost estimates

	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 tonne of CO2	
Capital cost	55.1
Electricity cost	25.6
MEA cost	2.0
Levelised cost of CO2 per tonne	**82.7**
LCoCO2 US$/t	**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 site at Drax has certain advantages that may allow capital savings to be made. It is an existing industrial site with prepared ground. The first generation flue gas desulphurisation equipment is now largely unused and some of this could be repurposed. In many ways there are similarities between the processes and hence the potential for reutilisation of equipment as well as potential economies in steam utilisation.

The use of the cheaper solvent solution from MHI allows potential cost savings using technology available today. Beyhond this the C-Capture solution has the potential to reduce operating costs significantly in future. The solvent itself is cheaper but also the low pressure steam requirement is reduced. We also assume this similar system could be delivered at a lower capital cost as the solvent is less corrosive allowing cheaper steel to be used.

Revised post capture CCS cost estimates

	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 tonne 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 tonne	**82.7**	**44.2**
LCoCO2 US$/t	**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 generation two carbon credits per tonne of CO2.

This principle was effectively recognisesd 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 also 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.

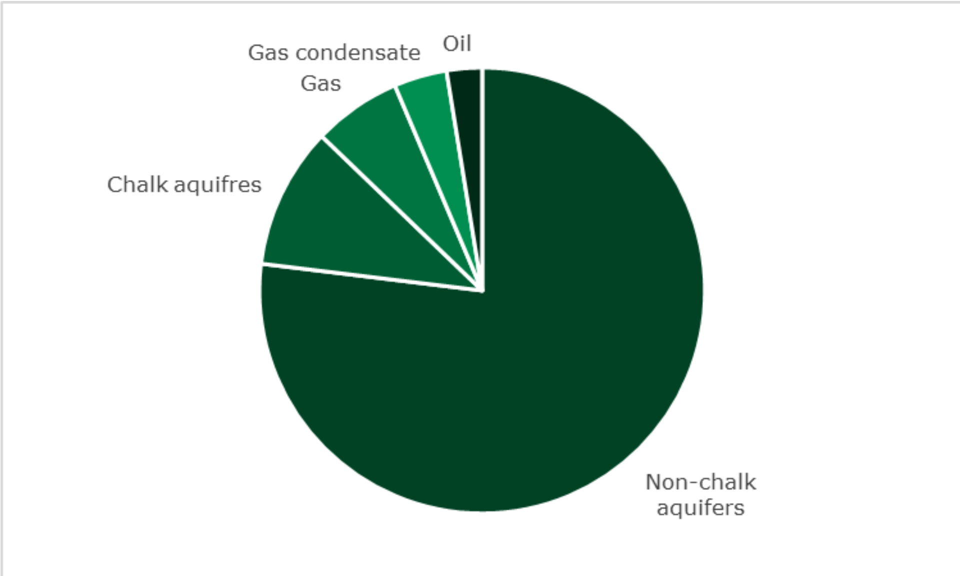
In summary, we think the CCS element of BECCS can be undertaken at a cost that allows proven support mechanisms to allow for funding and deployment. This is a very viable opportunity for Drax.

The UK Committee on Climate Change has recommended to Parliament that a BECCS support scheme should be published by H1 2021 targetting deployment in the second half of the current decade. It is also expectedd that this technology will be one priorities in the upcoming Energy White Paper due in Q4 2020. This quarter may also see the HM Treasury "Cost of Net Zero" review as well as draft heads of terms for CCS support.

IS THERE ENOUGH CO2 STORAGE?

Drax expects the first two units running at 90% availability to store 8 million tonnes of CO2 per annum. This will double to 16mt when all four biomass units add CCS. The UK has a P50 estimate of 78GT of storage capacity, primarily in saline acquifers.

CO2 storage capacity in the UK



Source: Energy Technologies Institute

In other words Drax would use 0.02% of available storage at full output. Or take 4,875 years to fill it.

VALUING CCS

Using our LCoCO2 model assumptions we can value the CCS opportunity for Drax. Our base CO2 price assumption of £15/t plus the carbon price floor of £18/t gives £33/t in 2020 prices. As our LCoCO2 model shows a FOAK unit could breakeven at this point assuming our cost assumptions are achievable. More interestingly a NOAK unit using a lower energy requirement solvent and with a higher CO2 price could value a single Drax unit at £421m. For the four units this would be £1,684m.

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
PV of cashflow	1,680	2,152
NPV	-320	902
NPV in 2020	-149	421
Value per share	-38	106

Source:Longspur Research

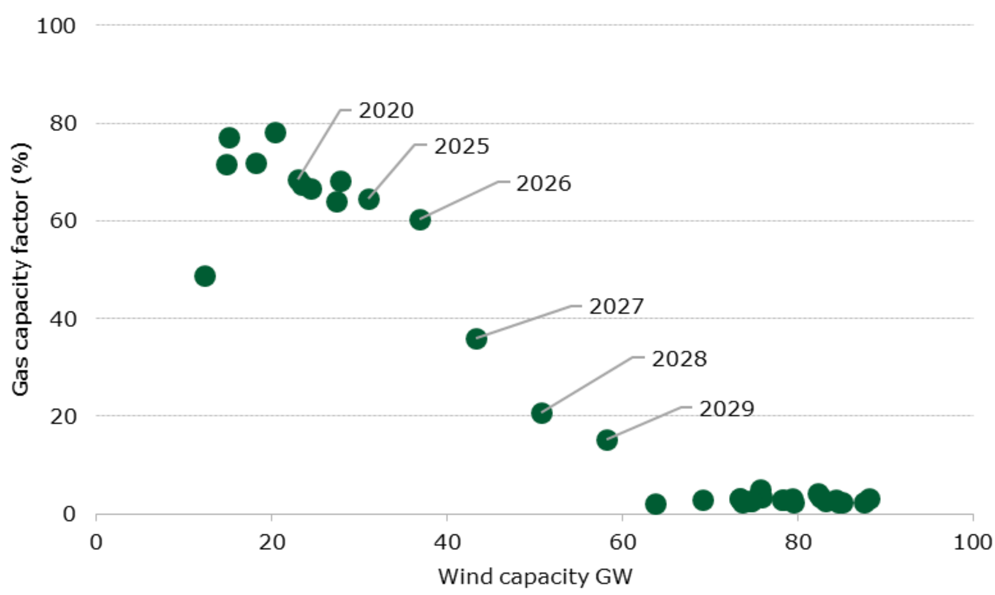
Note that the economic characteristics of CCS are a high capital cost and lower ongoing costs. To earn a return on the high initial spend, the projects must deliver a high gross margin. This is a similar profile to renewable energy. As such these projects could in time show the cash flow profiles that 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.

LOW CARBON GAS – H2GTS

The combined cycle gas turbines purchased from Iberdrola have operating lives out to 2025. They have successfully participated in the capacity market and as we are currently seeing are key components of the UK, providing flexible supply when renewables are unavailable.

However, as more renewables come onto the system, load factors are expected to fall. BNEF forecasts the average load factor to drop from 68% in 2020 to below 20% in 2030.

CCGT capacity factor reductions with wind pentration

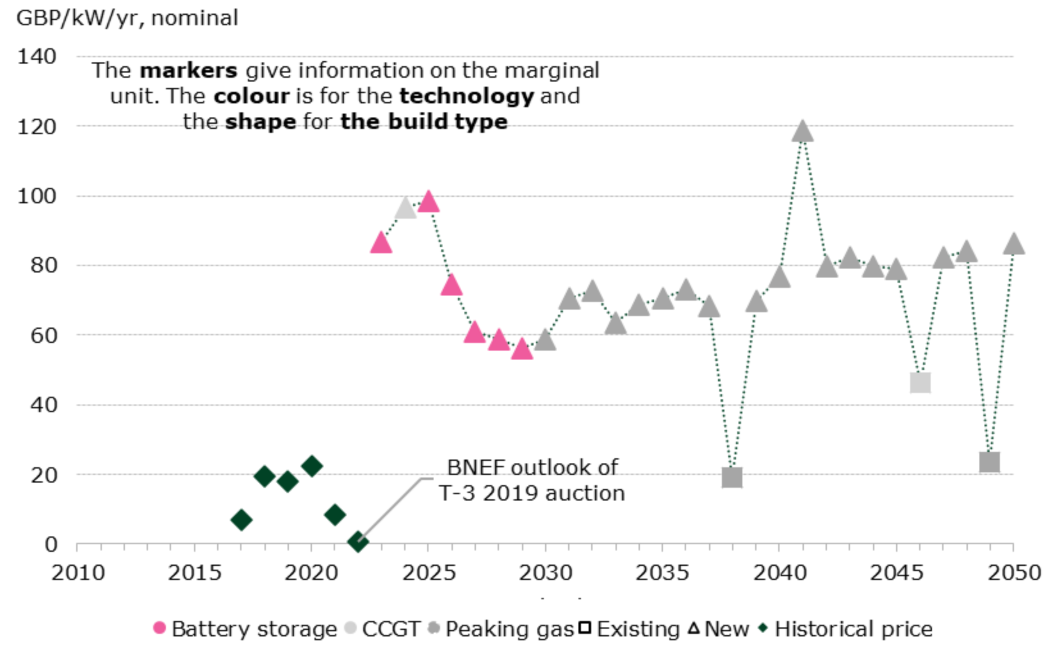


Source: Bloomberg New Energy Finance

Because of this lower running, the capacity market is likely to grow in its importance as a source of support for CCGTs. We expect better pricing here to emerge as both open cycle and combined cycle units seek a return from this market.

Bloomberg New Energy Finance forecasts a significant increase in capacity market auction prices going forward in order to reward new entry.

BNEF Capacity Market Price Forecasts



Source: Bloomberg New Energy Finance

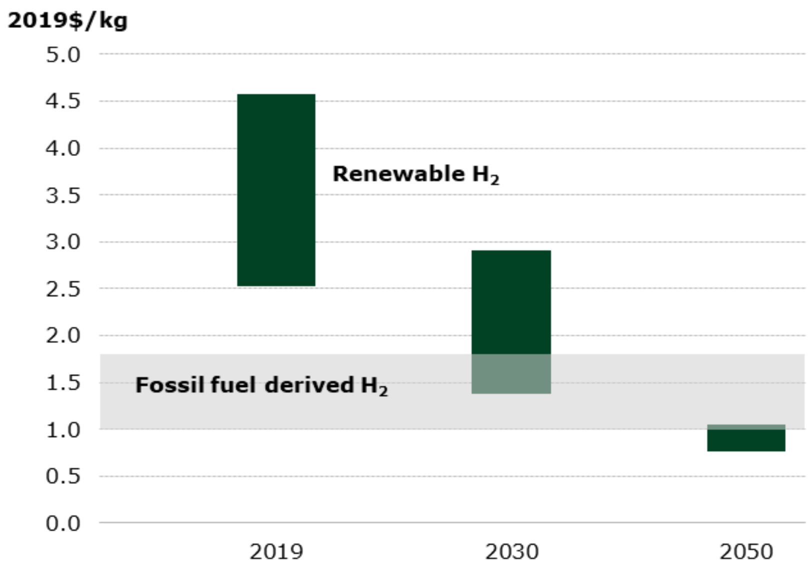
A LIFE BEYOND 2025?

While the capacity market can support long term operation of these units, a further opportunity may emerge. 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.

Cost of hydrogen

Green hydrogen is currently available from electrolysis at a cost of between US$2.53/t and US$4.57/t. The cost of large scale alkaline electrolysers from China is expected to take the these costs down to between US$1.38 and US$2.90 by 2030. Additionally steam methane reformation combined with CCS could also produce green hydrogen at low cost with some forecast suggesting costs down to US$0.76/t by 2050.

Levelised cost of hydrogen forecasts



Source: BNEF

Overall economics

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.

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. We estimate a carbon price of €85 would make H2GT competitive in the market.

FINANCIALS

EARNINGS OUTLOOK

Drax now

By combining reported data from the company with publicly available data for these types of generation assets and available market data, we can build up a good picture of the economics of the Drax portfolio in 2019 based on the full year annual report and accounts.

While EBITDA will evolve from 2019, the broad picture will not be too dissimilar. Market volumes will drop in 2020 due to the pandemic and prices have been hit although Drax is partly protected by contracting ahead and by the ROC and CFD income for biomass and hydro. The forward curve shows some recovery into 2021 and as the lockdown eases this would seem credible. Volatility in the system has increased and this creates opportunity for Drax in the balancing mechanism and in ancillary services which will be compounded by the closure of coal and nuclear assets elsewhere in the system. The supply businesses have taken a hit from bad debt. We expect a lower EBITDA in 2020 and some growth beyond. However, in the second half of the decade more substantial changes are likely.

Drax post renewable support

In 2027 the four biomass units come off renewable support. The company plans to reduce fuel cost to £50/MWh by then and as we have shown the units should achieve a positive bark spread as a result. We also expect the gas units to be relying largely on the capacity market by then and the entire portfolio to benefit from much stronger ancillary services revenue and balancing market activity. There is still something of a step change but we think the company can generate EBITDA not too far below current levels in 2028 and grow from there. This would be comprised of £279m from generation, £134m from pellet supply, £10m from retail less £54m of central costs to get £369m. This EBITDA level is before any additional returns on new investment in CCS, H2GT or further investment in pellet supply so could be a minumum achievable figure.

2019 Generation EBITDA breakdown

£m	**Biomass**	**Cruachan**	**CCGTs**	**Hydro**	**Coal**	**Total**
Total capacity (MW)	2595	440	2000	126	1290	6,451
Availability	88%	88%	88%	88%	88%	
Net capacity factor	59%	6%	17%	5%	3%	
Output sold (TWh)	13,400	245	2,900	55	339	16,939
Auxiliary power	6.5%	3.0%	6.5%	3.0%	6.5%	
Output generated (TWh)	14,332	252	3,102	57	363	18,105
Wholesale market						
Average price (£/MWh)	106	150	54	150	150	
Revenue	1,417	37	157	8	51	1,670
Balancing mechanism						
BM trade volume (TWh)	85	313	184	33	47	
Revenue	9	47	10	5	7	78
Capacity market						
Price (£/kW/year)	0	19	19	19	19	
Derating	0.00%	100.00%	100.00%	100.00%	100.00%	
Revenue	0	8	38	2	25	74
Ancillary services						
Availability Price (£/MW/hr)	4.0	4.0	4.0	4.0	4.0	
Available hours per day	6	6	6	6	6	
Revenue	20	3	15	1	10	50
Total revenue	**1,446**	**96**	**221**	**17**	**92**	**1,872**
Thermal efficiency	33%	100%	55%	100%	35%	
Calorific value (GJ/unit)	23.6	3.6	0.106	0.106	25.120	
Fuel cost (£/unit)	156.0	50.0	0.6	0.0	70.0	
Fuel cost (£/MWh)	72	50	37	0	29	
Fuel cost	**1,033**	**13**	**115**	**0**	**10**	**1,171**
Emissions factor (kgCO2/MJ)	0.00	0.00	0.06	0.00	0.11	
Carbon price (£/t)	18.00	18.00	18.00	18.00	18.00	
Carbon cost (£/MWh)	0.00	0.00	6.72	0.00	21.11	
Carbon cost	**0**	**0**	**21**	**0**	**8**	**28**
Total O&M	103	17	38	6	45	
Connection and UoS	27	7	7	0	14	
Operating costs	**131**	**24**	**45**	**6**	**58**	**264**
EBITDA	**282**	**59**	**41**	**11**	**16**	**408**

Source: Longspur Research

2027 Generation EBITDA breakdown

£m	**Biomass**	**Cruachan**	**CCGTs**	**Hydro**	**Total**
Total capacity (MW)	2595	440	1225	126	4,386
Availability	88%	88%	88%	88%	
Net capacity factor	59%	6%	17%	5%	
Output sold (TWh)	13,412	245	1,824	55	15,536
Auxiliary power	6.5%	3.0%	6.5%	3.0%	
Output generated (TWh)	14,344	252	1,951	57	16,605
Wholesale market					
Average price (£/MWh)	62.00	150.00	62.00	150.00	
Revenue	831.54	36.72	113.10	8.28	990
Balancing mechanism					
BM trade volume (TWh)	340	627	369	70	
Revenue	21.11	94.00	22.86	10.50	148
Capacity market					
Price (£/kW/year)	19.13	19.13	19.13	19.13	
Derating	85.81%	95.08%	90.00%	95.08%	
Revenue	42.59	8.00	21.09	2.29	74
Ancillary services					
Availability Price (£/MW/hr)	4.0	4.0	4.0	4.0	
Available hours per day	6	6	6	6	
Revenue	20.00	3.39	9.44	0.97	34
Total revenue	**915.24**	**142.11**	**166.49**	**22.04**	**1,246**
Thermal efficiency	33%	100%	55%	100%	
Calorific value (GJ/unit)	23.6	3.6	0.106	0.106	
Fuel cost (£/unit)	108.00	50.00	0.45	0.00	
Fuel cost (£/MWh)	49	50	28	0	
Fuel cost	**709.66**	**12.62**	**53.91**	**0.00**	**776**
Emissions factor (kgCO2/MJ)	0.00	0.00	0.06	0.00	
Carbon price (£/t)	38.30	38.30	38.30	38.30	
Carbon cost (£/MWh)	0.00	0.00	14.29	0.00	
Carbon cost	**0.00**	**0.00**	**27.88**	**0.00**	**28**
Total O&M	77.40	17.33	23.37	6.02	
Connection and UoS	27.25	6.95	4.04	0.00	
Operating costs	**104.65**	**24.28**	**27.41**	**6.02**	**162**
EBITDA	**100.93**	**105.21**	**57.29**	**16.02**	**279**

Source: Longspur Research

BALANCE SHEET AND FINANCE

Drax is well funded with total borrowing facilities of over £1.5bn and cash of £404m at 31 December 2019. At 30 June 2020 cash has risen to £482m. The ESG facility has also been extended to 2025.

Debt profile

Instrument	Facility	Drawn	Deferred costs	Net	Maturity
Fixed loan notes	350	350	-5	345	2022
US $500 million loan notes	380	380	-6	374	2025
Index-linked loan	38	38		37.9	2021
Infrastructure private placement	375	375	-9	366	2024-2029
ESG facility	125	125	-2	123	2025
Revolving credit facility	315	0			2021
Total borrowings	1583	1268	-22	1245	

Source: Drax Group

Capital spending will reflect continued maintenance and improvement of the asset base together with significant spend on the expansion of the pelletisation business. At some point there will also be capital spend on CCS and H2GT.

The company has a net debt to EBITDA target of 2.0 or less. The delay of £72m in cash payments from the Capacity Market as a result of the legal standstill period meant that the company showed a ratio of 2.1x in FY 2019. Adjusting for this, the ratio was 1.9x. While the current year has been challenged by the impact of COVID 19 on the retail business this has been offest by better performance elsewhere and the company says it is on track to hit the ratio at the year end. We also expect it to fall in future years.

Dividend policy

The company is committed to a sustainable and growing dividend while maintaining robust financial metrics to retain the credit rating in the BB+/BBB range and to allow investment in the core business. The company has signalled that if appropriate it would return any surplus capital to shareholders.

VALUATION

We see three key routes to valuation. A simple multiples based approach, a project level annuity valuation and a group DCF.

Multiples

There are many IPPs and utilities with substantial generation portfolios that one can compare Drax against. We see these splitting into two broad camps. Firstly, there are those that are entirely focused on the energy transition with assets that are exclusively part of the decarbonisation solution. Then there are those who have mixed portfolios and are in some way exposed to legacy assets and the possibility of stranded assets.

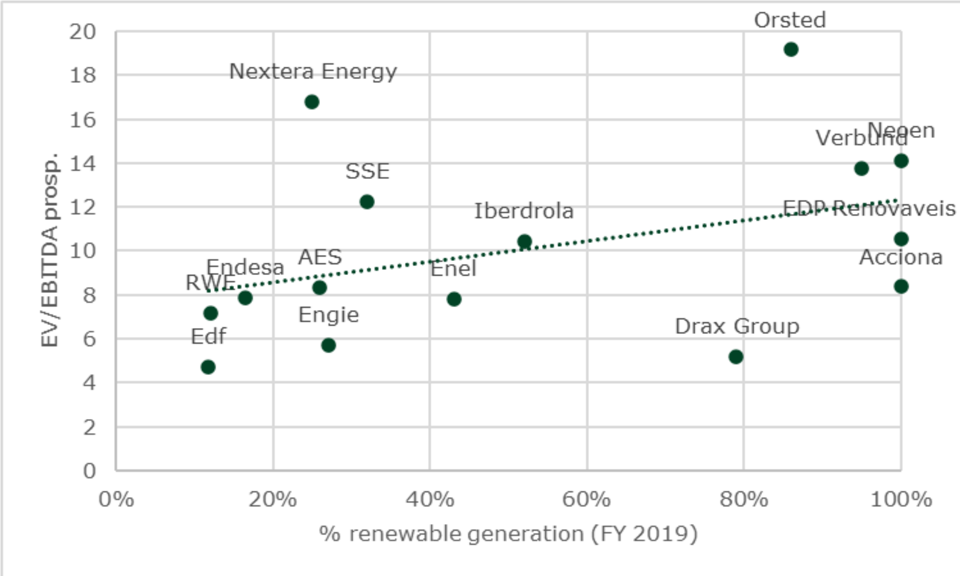
Drax Comparator Group

	PE cur.	PE prosp.	EV/EBITDA cur.	EV/EBITDA prosp.	Yield
Drax Group Plc	9.6	9.9	5.0	5.2	5.7
National Grid Plc	16.9	16.0	11.9	11.0	5.3
Sse Plc	16.9	15.7	12.9	12.2	6.1
Centrica Plc	10.0	8.9	4.1	4.5	na
Orsted A/S	53.4	42.4	23.3	19.2	1.2
Iberdrola Sa	19.6	18.5	11.1	10.4	2.9
Enel Spa	15.7	14.6	8.2	7.8	4.3
Verbund Ag	27.9	27.3	14.0	13.8	1.5
Nextera Energy Inc	31.3	28.9	18.3	16.8	2.0
Aes Corp	11.3	10.1	9.1	8.4	3.7
Engie	15.7	11.1	6.4	5.7	0.0
Neoen Sa	92.3	65.5	18.2	14.1	0.0
Edf	19.0	15.5	5.0	4.7	1.7
Edp Renovaveis Sa	36.3	30.9	11.5	10.6	0.6
Endesa Sa	15.0	14.7	8.1	7.9	5.0
Rwe Ag	19.9	16.2	8.0	7.2	2.5
Acciona Sa	21.9	16.5	9.3	8.4	0.0
Mean	25.4	21.3	10.8	9.9	2.6
Median	19.0	16.0	9.3	8.4	2.2
Max	92.3	65.5	23.3	19.2	6.1
Min	10.0	8.9	4.1	4.5	0.0

Source: Longspur Research

We see Drax as being primarily a company focused on the energy transition and with positive exposure to it as we have argued extensively in this note. Yet it is clearly being rated as a company with negative exposure to the energy transition. We note that the typical multiples of positively exposed companies are roughly double that of negatively exposed companies and very simply we think this reflects the correct valuation of Drax.

EV/EBITDA versus % of low carbon generation



Source: Longspur Research, Bloomberg

From the graph we should expect Drax to be valued at 10.5x prospective EBITDA. That would give us a valuation of 812p per share. Even taking our minumum FY28 forecast we would get a valuation of 756p per share.

Drax Valuation at 10x EBITDA

£m	**Prospective (FY20)**	**Subsidy free (FY28)**
EBITDA	390	369
EV @ 10.5x	4,095	3,875
Net debt	874	874
Market value	3,221	3,001
Shares in issue	397	397
Valuation per share (p)	812	756

Source: Longspur Research

Sum of the parts annuity valuation

We have used annuity valuations to strip out too much speculation on commodity price curves in project valuations. We have provided two stage valuations with an initial period broadly reflecting current economics and a second period reflecting a more speculative future view of the midterm.

Initial period valuations run to 2027 for the biomass units and 2025 for the CCGTs and Cruachan. Clearly the COVID 19 impacts on electricity and gas prices are unusual and we think the forward positions a year out are a fair pricing point for these assets over the next few years and we use these to drive initial valuations.

In the second periods we value biomass based on a bark spread of £12/MWh and gas on a clean spark spread of £0.60/MWh and assume that Rye House and Blackburn Mill do not run beyond 2025. Capacity market prices are based on the recent auction price of £19/kW/yr and balancing market trades are assumed in line with 2019.

We have valued the pellet business, the supply business and central costs using a DCF model with the group cost of capital outlined below. We get a value of £391m for the pellet business, £97m for supply and £348m for central costs.

Two period annuity valuation

£m	Biomass	Cruachan	CCGTs	Hydro	Total
EBITDA	282	59	41	11	
Tax rate	19%	19%	19%	19%	
Tax charge	54	11	8	2	
Ungeared cashflow	228	47	33	9	
WACC	7.66%	7.66%	7.66%	7.66%	
Life	7	7	7	7	
Annuity factor	5.27	5.27	5.27	5.27	
PV of cashflows	1,203	250	174	45	1,673
EBITDA	101	105	57	16	
Tax rate	19%	19%	19%	19%	
Tax charge	19	20	11	3	
Ungeared cashflow	82	85	46	13	
WACC	7.66%	7.66%	7.66%	7.66%	
Life	10	23	10	23	
Annuity factor	6.81	10.66	6.81	10.66	
PV of cashflows	557	909	316	138	
PV in 2020	309	503	175	77	1,064
Total for both periods	**1,512**	**754**	**350**	**122**	**2,737**
Pellet production					391
Supply					97
CCS					0
Central Costs					-348
Total					2,877
Net debt					874
Market value					2,003
Shares in issue					397
Valuation per share (p)					505

Source: Longspur Research

DCF

We have undertaken a group level DCF based on these assumptions. We use a nominal risk free rate of 4.0% and an equity market premium of 5.5%, based on recent UK Competition and Markets Authority cost of capital considerations. We have used a beta of 1.0. Our cashflow forecasts are cast exlicitly to 2040 and we use a annuity growth model to drive a terminal value based on a further cashflow period to 2050.

Cost of capital considerations

	CMA	Longspur
Real risk-free rate (%)	1.0	1.0
Nominal risk-free rate (%)	4.0	4.0
Equity risk premium (%)	4.0–5.5	5.5
Asset beta	0.5–0.6	1.0
Pre-tax Ke (%)	9.1–10.4	9.5
Pre-tax cost of debt (Kd) (%)	6.0–7.0	5.0
Gearing (%)	10.0–30.0	33.7
Tax rate (%)	27	19
Pre-tax WACC (%)	8.2–10.0	7.7

Source: CMA, Longspur Research

Discounted Cashflow Valuation

£m	20e	21e	22e	23e	24e	25e	26e	27e	28e	29e	30e
Operating cash inflow	247	367	347	413	539	682	779	955	482	405	508
Cash from associates	0	0	0	0	0	0	0	0	0	0	0
Tax paid	3	-21	-16	-14	-34	-57	-89	-109	-147	-29	-39
Interest tax shield	(12)	(13)	(11)	(11)	(11)	(8)	(6)	(5)	(2)	(3)	(2)
Capex & investments	-199	-136	-240	-240	-240	-240	-240	-240	-136	-136	-136
Free cashflow	39	197	80	148	254	376	444	601	197	238	331
Real WACC	5.0%										
Terminal valuation	1,336										
Terminal EV/EBITDA	3.7										
Implied EV	2,966										
Implied market cap.	2,093										
Implied share price	527										

Source: Longspur Research, Valuation based on projections to 2040e

The DCF gives a higher valuation than the annuity valuation, primarily due to timing differences including the benefit of biomass cost reductions while the units are still receiving support under the ROC mechanism. We can compare the valuations on an asset by asset basis below. There is some additional difference here resulting from allocation of flexibilty revenues.

DCF and annuity valuations compared

£m	**DCF**	**Annuity**
Biomass	1,533	1,512
Cruachan	824	754
CCGTs	435	350
Hydro	69	122
Pellets	391	391
Supply	97	97
Central costs	-383	-348
Implied enterprise value	2,966	2,877
Debt	874	874
Implied market cap.	2,093	2,003
Implied share price (p)	527	505

Source: Longspur Research

We have also looked at other scenarios either side of this base case.

SCENARIOS

Low Scenario

In our low scenario we attempt to reverse engineer the current share price. We assume that there is no life for the biomass units beyond 2027 and no life for the CCGTs beyond 2025. Pricing is as per 2019 including for the balancing mechanism, the capacity market and ancillary services. Only pumped storage and hydro contribute beyond 2027 although fail to benefit from growing volatility in the market.

Central scenario

Here we assume that the biomass units continue to run as outlined earlier in the note, capturing an wholesale price of £62/MWh and a bark spread of £12/MWh. The more efficient two CCGTs (Shoreham and Damhead Creek) can also make a profit at this price given their lower marginal cost. Both are assumed to run for a further ten years beyond 2027. Pumped storage and hydro continue to run to 2050.

We assume no change in capacity market revenue but we think the company can gain from growing volatility in the market in the balancing mechanism and through ancillary services. Both balancing mechanism and ancillary service opportunities continue to grow, doubling by 2028. In both cases we think these levels are conservatively consistent with the market developments we have outlined in this note.

High case

Both gas and biomass run on to 2050. This assumes a breakeven CCS deployment at our low carbon price assumption. While this adds no direct additional valuation, it confers a licence to operate on the biomass units that might be otherwise missing. Similarly we assume the gas generation assets can convert to hydrogen at a breakeven point. The capacity market pricing moves to £56/kW/yr based on the lowest BNEF forecast auction outcome before 2030.

Blue sky case

This is as the high case but we assume that the price of CO2 rises to £100/t. For low carbon generation this increases power prices at the margin by £25/MWh. It also increases the value of CCS as outlined in our modelling. CCGTs convert to H2GTs and benefit from the higher wholesale price.

Valuation Scenarios

	Blue sky	High	Central	Low
Project closure dates				
Biomass	2050	2050	2039	2027
Hydro	2050	2050	2050	2050
CCGT	2050	2050	2039	2025
Market pricing				
Wholesale	As today	As today	As today	As today
Capacity market	Increase	Increase	As today	No further contracts
Ancillary services	Increase	Increase	Increase	As today
Balancing mechanism	Increase	Increase	Increase	As today
Carbon price	£100/t	As today	As today	As today
Valuation (£m)				
Biomass	3,916	2,223	1,512	1,203
Pumped storage	964	852	754	529
CCGT	996	711	350	133
Hydro	167	150	122	96
Pellet production	391	391	391	196
Customers	97	97	97	97
CCS	1,684	0	0	0
Central costs	-348	-348	-348	-348
Total EV	7,867	4,075	2,877	1,905
Debt	874	874	874	874
Market value	6,993	3,202	2,003	1,032
Shares in issue	397	397	397	397
Value per share (p)	1,762	807	505	260

Source: Longspur Research

RISKS

Policy change

The UK electricity markets are all to a greater or lesser extent regulated and this leaves the company exposed to changing regulation and policy shifts. In particular a UK white paper on energy is due this year which may lead to changes in the operation of the markets. Despite this, we think that the fact that Drax can meet many of the needs of the GB electricity system means that it will continue to be rewarded one way or another for its activities.

Competition

All the markets in which Drax operate face competition. We have seen price falls for certain ancillary services as new players have participated and pricing in the capacity market has been weak in its early years of operation. New pumped storage projects are in planning and new build gas may be attracted if capacity market prices rise. However we see Drax in a good position, potentially dominating certain sections of the market and certainly not suffering the sort of price cannibalisation faced by intermittent renewables.

Commodity prices

Competition as discussed about clearly impacts on pricing but input prices especially gas are also important. While fuel-less renewables will come to dominate the market, price setting at the margin is still likely to be driven by gas fuelled assets for some time. A continuation of low gas prices could weaken the achieved bark spread by the biomass units beyond 2027.

FINANCIAL MODEL

Profit and Loss Account

£ '000, DEC	2018a	2019a	2020e	2021e	2022e	2023e
Turnover						
Power Generation	3,332	3,947	3,586	3,617	3,624	3,614
B2B Energy Supply	2,242	2,269	2,026	2,434	2,607	2,791
Pellet production	214	229	281	339	336	418
Central, int gp and depn	-1,550	-1,742	-1,786	-1,830	-1,876	-1,923
Total	4,237	4,703	4,108	4,560	4,691	4,900
Operating profit						
Power Generation	232	408	425	388	357	381
B2B Energy Supply	28	17	-39	-30	-4	3
Pellet production	21	32	49	69	71	105
Central, int gp and depn	-205	-253	-227	-228	-234	-219
Operating profit	76	204	209	199	190	270
P&L Account	**2018a**	**2019a**	**2020e**	**2021e**	**2022e**	**2023e**
Turnover	4,237	4,703	4,108	4,560	4,691	4,900
Operating Profit	76	204	209	199	190	270
Investment income	0	0	0	0	0	0
Net Interest	-39	-62	-65	-69	-58	-60
Pre Tax Profit (UKSIP)	37	142	143	130	132	210
Goodwill amortisation	0	0	0	0	0	0
Exceptional Items	-23	-145	-116	-10	-25	0
Pre Tax Profit (FRS3)	14	-3	27	120	107	210
Tax	6	3	-21	-16	-14	-34
Post tax exceptionals	0	0	0	0	0	0
Minorities	0	0	0	0	0	0
Net Profit	20	0	6	103	93	177
Dividend	-53	-60	-65	-70	-75	-81
Retained	-32	-59	-59	34	18	96
EBITDA	250	410	390	380	376	440
EPS (c) (UKSIP)	10.41	29.86	30.85	28.58	29.71	44.52
EPS (c) (FRS3)	5.02	0.13	1.55	26.06	23.41	44.52
FCFPS (c)	49.20	-101.82	13.02	53.01	22.87	40.13
Dividend (c)	14.10	15.90	17.10	18.40	19.80	21.30

Source: Company data, Longspur Research estimates

KEY POINTS

- EDBITA dip in FY 20 with COVID 19 impact on customer business
- Second dip in FY 22 with weaker capacity market prices
- Good recovery in FY 23 with capacity market price rises and pellets
- Net interest balanced between cashflow and capex
- Dividend remains covered throughout

Balance Sheet

£ '000, DEC	2018a	2019a	2020e	2021e	2022e	2023e
Fixed Asset Cost	3,418	3,547	3,746	3,882	4,122	4,362
Fixed Asset Depreciation	-1,071	-1,220	-1,401	-1,582	-1,768	-1,938
Net Fixed Assets	2,348	2,327	2,345	2,300	2,354	2,424
Goodwill	248	248	248	248	248	248
Other intangibles	229	207	207	207	207	207
Investments	329	232	232	232	232	232
Stock	439	455	497	552	568	593
Trade Debtors	474	609	532	590	607	634
Other Debtors	237	201	201	201	201	201
Trade Creditors	-941	-1,039	-1,008	-1,119	-1,151	-1,202
Other Creditors <1yr	-790	-254	-254	-254	-254	-254
Creditors >1yr	-378	-342	-342	-342	-342	-342
Provisions	-51	-54	-54	-54	-54	-54
Pension	0	0	0	0	0	0
Capital Employed	2,146	2,589	2,604	2,561	2,616	2,687
Cash etc	289	404	362	480	158	202
Borrowing <1yr	0	6	6	6	6	6
Borrowing >1yr	608	1,271	1,303	1,344	1,059	1,080
Net Borrowing	319	874	947	871	908	884
Share Capital	47	47	47	47	47	47
Share Premium	425	430	430	430	430	430
Retained Earnings	443	370	311	344	362	458
Other	912	869	869	869	869	869
Minority interest	0	0	0	0	0	0
Capital Employed	2,146	2,589	2,604	2,561	2,616	2,687
Net Assets	1,827	1,716	1,657	1,690	1,708	1,803
Total Equity	1,827	1,716	1,657	1,690	1,708	1,803

Source: Company data, Longspur Research estimates

KEY POINTS

- Working capital remains comfortable across period
- Net debt drops with cashflow

Cashflow

£ '000, DEC	2018a	2019a	2020e	2021e	2022e	2023e
Operating profit	76	204	209	199	190	270
Depreciation	174	208	181	181	186	170
Provisions	0	0	0	0	0	0
Other	-29	109	-116	-10	-25	0
Working capital	112	-51	-27	-3	-4	-26
Operating cash flow	333	470	247	367	347	413
Tax paid	-1	-10	3	-21	-16	-14
Capex (less disposals)	-133	-171	-199	-136	-240	-240
Investments	-1	-692	0	0	0	0
Net interest	-25	-48	-65	-69	-58	-60
Net dividends	-53	-59	-60	-65	-70	-75
Residual cash flow	121	-510	-73	76	-37	24
Equity issued	-47	2	0	0	0	0
Change in net borrowing	-48	555	73	-76	37	-24
Adjustments	-26	-47	0	0	0	0
Total financing	-121	510	73	-76	37	-24

Source: Company data, Longspur Research estimates

KEY POINTS

- Working capital modestly negative assuming no change in payment timings
- Capex slightly down in FY 20 as signalled by company
- Cash postive in most years

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