DRAX GROUP
(DRX LN)

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27 March 2024

Price (p)	**497.30**
Shares in issue (m)	385
Mkt Cap (£m)	1,913
Net debt (£m)	1,183
EV (£m)	3,096
BVPS (p)	330.7

Share price performance

1m	19.2%
3m	2.5%
12m	-14.1%
12 m high/low	656/395
Ave daily vol (30D)	1,023,590

Shareholders

Invesco Ltd	7.4%
Orbis Allan Gray Ltd	5.0%
Vanguard Group	4.9%
Blackrock Inc	4.4%
Bank Of America	4.3%
Schroders Plc	4.1%
Royal London	3.6%
Jupiter	3.4%
M&G Plc	3.1%
Dimensional Fund	3.0%
Total for top 10	43.1%
Free float	99.7%
Source: Bloomberg	*26 Mar 24*

Next news Ints Q3

Business description

Integrated biomass, hydro and storage IPP

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DRAX'S ROLE IN ENERGY SECURITY

Drax's importance in the UK's energy mix has been recently highlighted by the Government's decision to rule out mothballing in the consultation on transitional support for the biomass units. We see this as emphasising a growing demand for the type of assets Drax has, with a multiyear pinch point likely in the second half of the decade where Drax can benefit from growing system balancing revenues. Drax is targeting at least £250m of recurring revenue from Flexible Generation and Energy Solutions post 2027 which our analysis suggests is very achievable. We have revised our long-term forecasts accordingly and our central case valuation increases to 1,077p from 1,018p.

Pressure on System Stability Set to Grow

Keeping Britian's lights on will become more difficult over the medium term as more intermittent energy sources are added to the system. New renewable generation tends to have a more distributed pattern and cannot help maintaining frequency. Frequency supporting synchronous generation is set to drop as the closure of older nuclear and gas plants fails to be sufficiently compensated by new gas generation.

All Drax Assets Contributing to System Support

In this environment Drax will play an increasingly important role thanks to a unique asset mix that enables it to take advantage of opportunities that are already arising from market stress. Its assets are all flexible, dispatchable, synchronous and well located. Revenue from balancing mechanism activities, ancillary services and portfolio optimisation has already risen significantly and the very flexible Cruachan pumped storage and other hydro plant have contributed 19% of group adjusted EBITDA in FY 23. The problems of lithium-ion battery storage projects reflected in recent yieldco dividend surprises are not noticeable at Drax because its assets serve a greater range of system stability needs.

Need Recognised in Transitional Consultation

Perhaps most importantly of all, Drax power station is recognised as a key asset in the UK's energy mix. This was reflected in the biomass transitional support consultation which effectively ruled out the option of mothballing the Drax biomass units until BECCS support becomes available. Without this capacity the government recognised that it would need to contract higher emitting new gas generation with a more limited useful life in a decarbonising environment. As a result, we think a sensible support will emerge that allows Drax to continue to run its biomass units.

£,000 Dec	2022a	2023a	2024e	2025e	2026e	2027e
Sales	8,159	7,842	5,457	5,324	4,809	5,024
EBITDA	709	1,009	881	899	641	862
PBT	405	665	526	544	292	514
EPS	85.1	119.6	90.5	95.1	57.6	100.0
CFPS	25.2	121.7	72.8	91.4	59.9	157.9
DPS	21.0	23.1	25.4	27.9	30.7	33.8
Net Debt (Cash)	1,356	1,183	1,072	878	806	358
Debt/EBITDA	1.9	1.2	1.2	1.0	1.3	0.4
P/E	5.8	4.2	5.5	5.2	8.6	5.0
EV/EBITDA	4.6	3.1	3.4	3.1	4.2	2.6
EV/sales	0.4	0.4	0.6	0.6	0.7	0.7
FCF yield	5.1%	24.5%	14.6%	18.4%	12.0%	31.8%
Div yield	4.2%	4.6%	5.1%	5.6%	6.2%	6.8%

DRAX – KEY TO SYSTEM STABILITY IN THE UK

Drax has an almost unique position in the GB (UK ex Northern Ireland) power market as a large flexible low carbon generation operator with potentially negative carbon potential. Its importance in keeping the lights on has been highlighted in the UK Government's recent biomass consultation paper which ruled out any option of mothballing the Drax biomass units between 2027 when the current Renewables Obligation support runs out and 2030 when it is planned to add carbon capture and storage (CCS) under a new system of policy support.

The reason for ruling out mothballing is that not running the Drax biomass units would require more gas fired generation to be delivered via the Capacity Market. This has a higher carbon outcome on a lifecycle basis and is seen as adding unnecessarily to costs.

As a group, Drax derives flexibility from the Drax power station in Yorkshire, the Cruachan Pumped Storage hydro project in Argyle and the run of river hydro projects in Galloway and Lanark. Additionally, the company has three small open cycle gas turbines (OCGT) as back up units at the Drax site and three larger OCGT projects being developed which are also highly flexible assets designed to support system stability.

- Drax Power Station, 2,595MW biomass units and 96MW gas fired back up
- Cruachan, 440MW pumped storage hydro, with planning to take to 1,080MW
- Galloway and Lanark, 126MW run of river hydro
- OCGTs, three new projects totalling 897MW

Drax is further responding to the attractiveness of flexibility markets through the option to invest in a significant capacity expansion at Cruachan adding 600MW. But even before that the refurbishment and 40MW capacity increase at the site, backed by a fifteen-year Capacity Market contract with c.£221m of revenues between 2027 and 2042, adds important additional capacity in this valuable market.

The run of river (RoR) hydro projects are perhaps the most overlooked and at 126MW have the smallest capacity in the group. That said they also have much of the flexibility of the other assets. As run of river hydro they have less limitations that the more common UK hydro experience of dam impoundment. While we do not have individual plant load factors, 2022 saw small scale hydro which includes more RoR with a load factor of 38.3% compared to large scale which is more likely to be impoundment with a load factor of 32.7%.

The recent full year results statement included an outlook statement for the Flexible Generation assets together with Energy Solutions targeting a post 2027 recurring adjusted EBTIDA of at least £250m. Flexible Generation should contribute at least £150m of that figure. Our analysis of Drax's flexible generation shows that this is very achievable.

Volatility means last year's £230m contribution from pumped storage and hydro alone may not be repeated in the next couple of years but as the GB power market beyond 2027 comes under strain the potential for periods of even higher income is meaningful in our view and we see the £250 target as a solid base for recurring income.

The pressure on the market has effectively been recognised in the recent second UK government consultation on Revised Electricity Market Arrangements (REMA). This includes a plan to extend the life of some ageing unabated gas assets and to add a limited amount of new build unabated gas capacity both in order to provide much needed flexible capacity in the short-term. However, the last Capacity Market auction failed to attract any new build gas turbines and long term uncertainty makes investment in these assets challenging as both the current government and potential new governments are likely to remain committed to clear decarbonisation pathways for gas to prepare the electricity system for full decarbonisation by 2035.

The REMA consultation also envisages a requirement for 55GW of short duration flexibility and 30GW to 50GW of long duration flexibility by 2035. These are significant numbers and represent an investment opportunity provided the markets are suitably designed to reward this investment. This is echoed in a call for more long duration storage from the Lords Science and Technology Committee in a report titled "Get on with it".

The key features of all of Drax Group's assets are as follow:

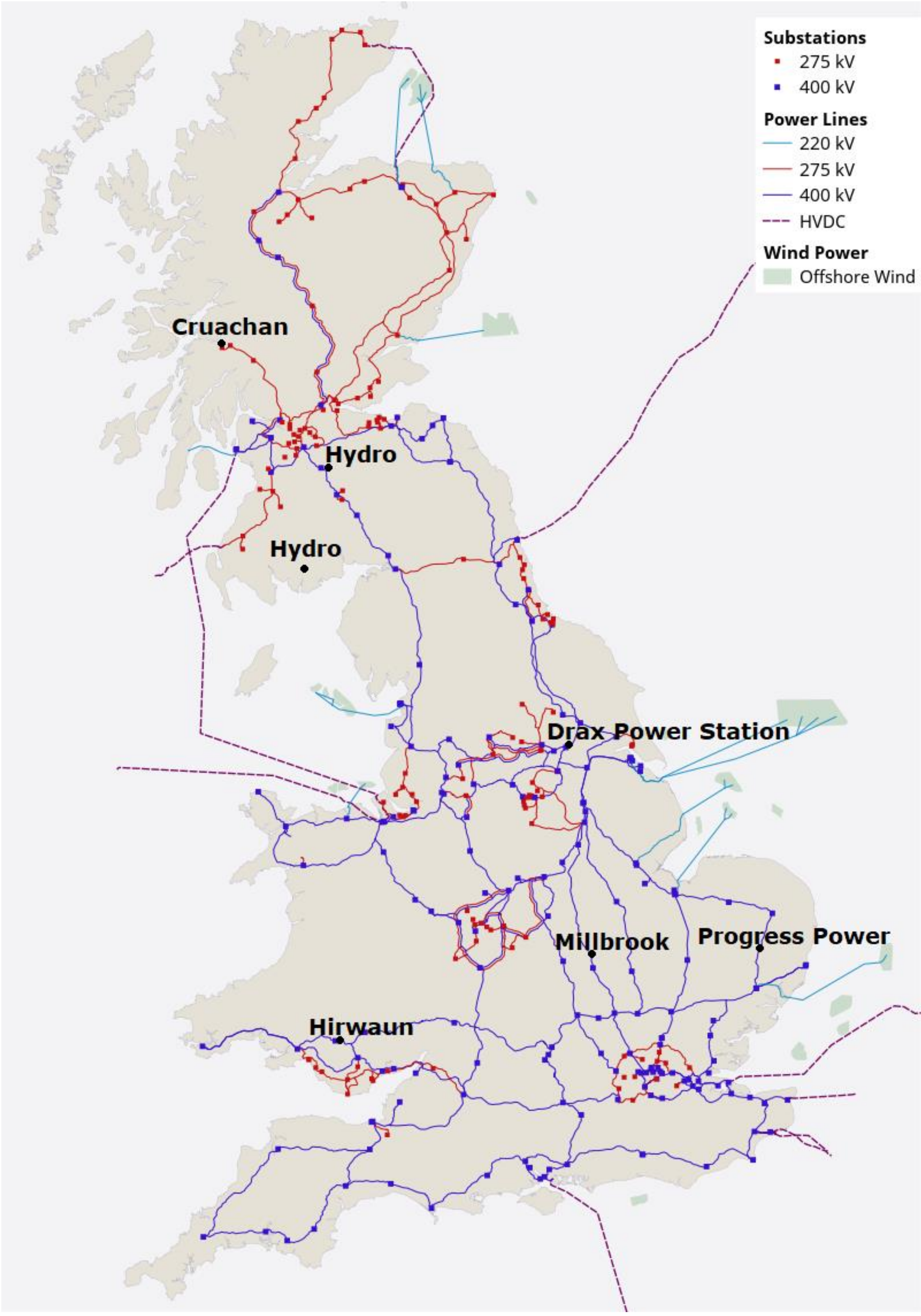
- All the assets are dispatchable - when the grid wants them to run, they can run
- All are flexible which means they can be ramped up and down quickly
- All represent synchronous spinning reserve. This is a bit more technical but means they can help keep the system frequency at 50Hz
- All are well sited on the grid

Drax UK asset summary

Site	Nameplate Capacity (MW)	Type	Fuel	Location	Grid region
Drax 1	660	Steam	Biomass	S Yorks	P4
Drax 2	645	Steam	Biomass	S Yorks	P4
Drax 3	645	Steam	Biomass	S Yorks	P4
Drax 4	645	Steam	Biomass	S Yorks	P4
Drax 9	32.0	OCGT	Fuel Oil	S Yorks	P4
Drax 10	32.0	OCGT	Fuel Oil	S Yorks	P4
Drax 12	32.0	OCGT	Fuel Oil	S Yorks	P4
Cruachan	440	Pumped hydro	None	N Central Scot	S5
Lanark	17	RoR hydro	None	S Central Scot	S6
Galloway	109	RoR hydro	None	S Central Scot	S6
Hirwaun	299	OCGT	Natural gas	S Wales	H6
Millbrook	299	OCGT	Natural gas	Midlands	J6
Progress	299	OCGT	Natural gas	East Anglia	J3

Source: Drax Group, National Grid

Drax asset locations



Source: National Grid, Longspur Research

NETWORK RELIABILITY IS UNDER THREAT

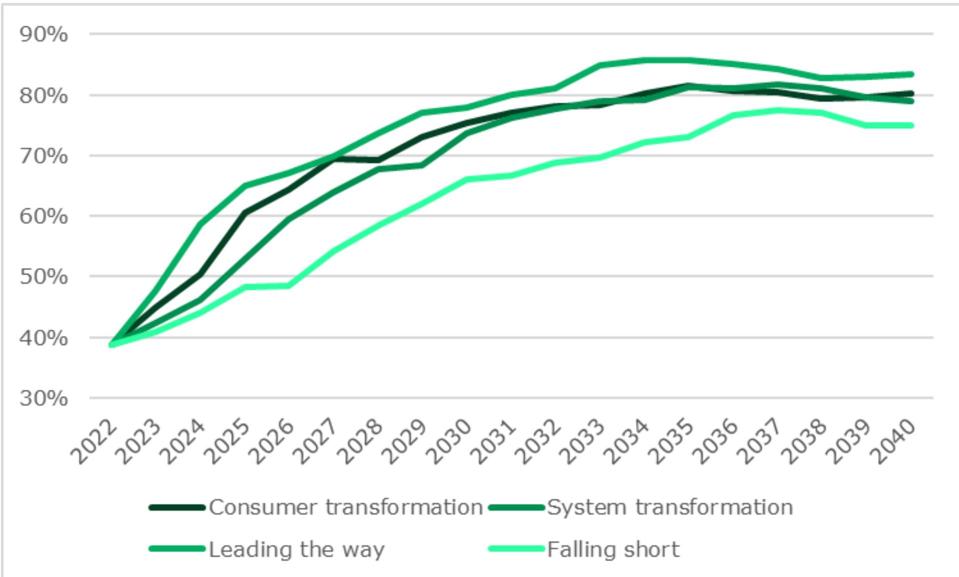
The reason the UK government is pursing a strategy that includes flexible biomass assets despite these being widely misunderstood is that they are essential to providing stability to the GB power network as other sources of this stability are reducing.

We need the electricity system to be reliable. An unreliable system results in power outages to use the industry term for what the public calls power cuts. This is important to the government. We have long held that the Value of Lost Load (VoLL - an economic term setting a value on keeping the lights on) is equal to one government, as Ted Heath found out in the early seventies. Reliability is under threat as we decarbonise. Low carbon wind and solar generation are essential to decarbonising the system but they have a few issues. These all have solutions and within these are opportunities for Drax.

Intermittent generation growing rapidly

There is a significant amount of intermittent renewable capacity forecast to be added to the GB electricity network. The National Grid Electricity System Operator (ESO) issues an annual Future Energy Scenarios (FES) paper which includes forecasts to 2050 under four scenarios. All of these scenarios show intermittent renewable energy growing to over 75% of the market with the more aggressive cases growing to over 85%.

GB renewable energy penetration (%)



Source: National Grid

National Grid ESO has characterised the issues of the developing GB electricity system as

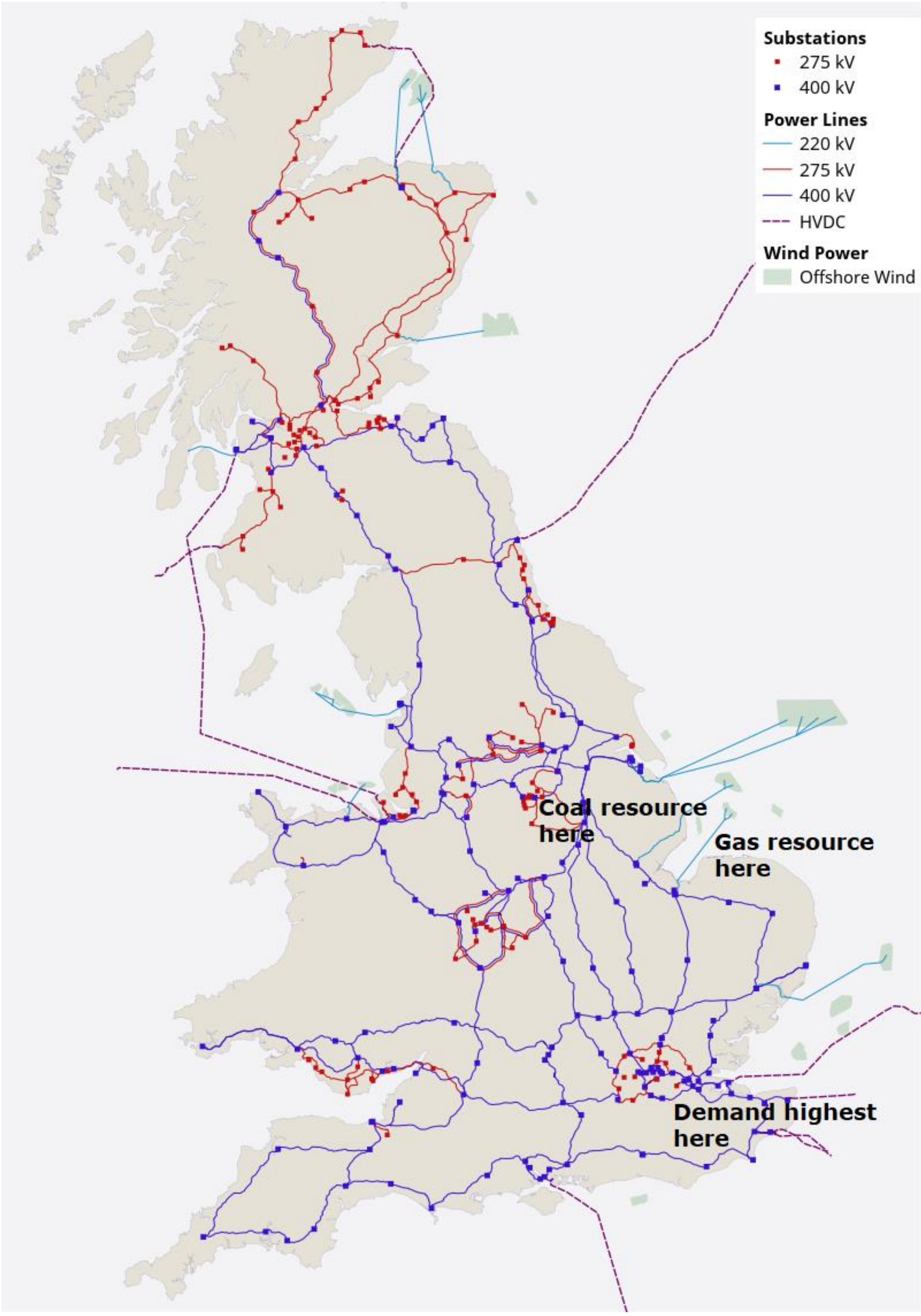
- Less dispatchable generation – wrong price/wrong time
- More asynchronous generation – wrong time
- More variable sources of generation – wrong time
- Generation moving to different areas - wrong place

These result in a variety of problems which we would characterise under three key areas, namely that renewables are in the wrong place, at the wrong time and at the wrong price.

WRONG PLACE - THE CHALLENGES OF LOCATION

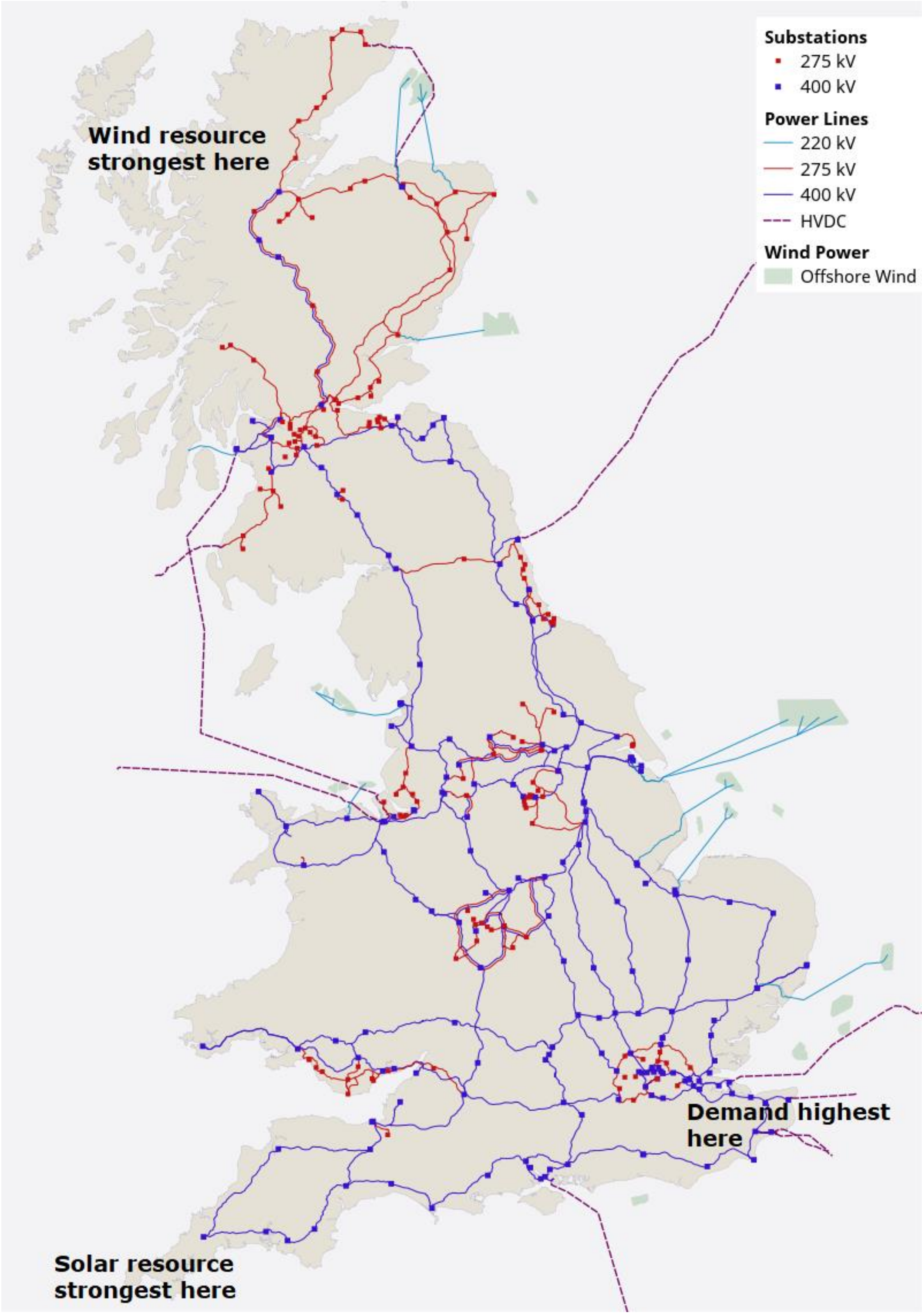
Much of the growth in renewables is sited at the extremes of the power grid rather than the centre. In the UK, the strongest renewable resources have been at the extreme ends of the grid; sun in Cornwall, wind in Scotland and Wales, yet the grids was largely designed for centralised generation. This is now being disrupted by the growth in distributed and remote generation and are finding increased demand for related reinforcement of transmission and distribution capacity.

Old GB power locations (simplified)



Source: National Grid, Longspur Research

New GB power locations (simplified)



Source: National Grid, Longspur Research

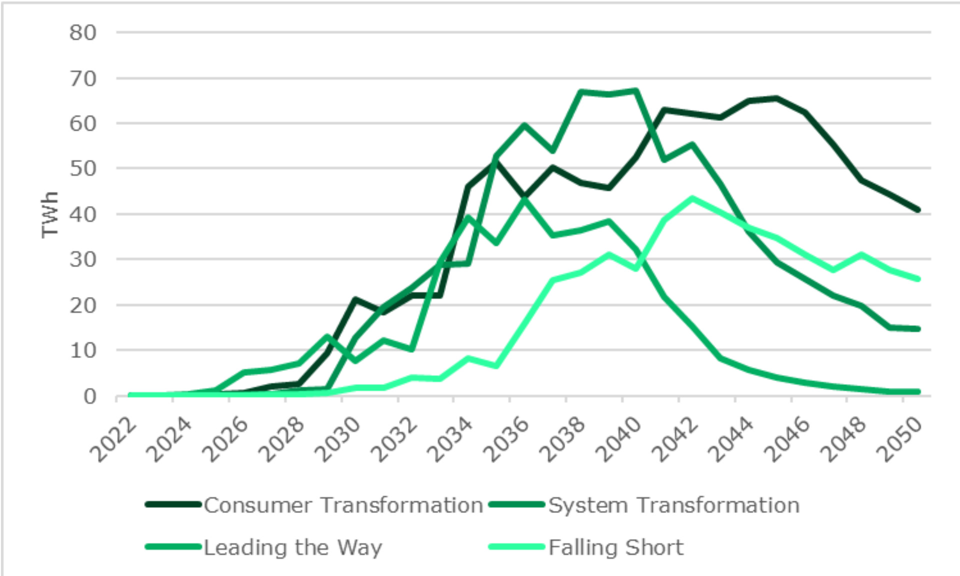
This puts pressure on the system in a number of ways.

- Thermal overload of transmission and distribution circuits
- Voltage disruption
- More challenging power restoration

Thermal overload of the grid

Overloading of the grid as too much distributed generation tries to get exported down lower capacity grid connections is likely to be exhibited in the grid breaching thermal limits creating thermal constraints. When this happens the system operator, National Grid ESO, will try to reduce generation or increase demand behind the constraint and increase generation or reduce demand in front of the constraint. Controlling demand is generally more challenging so the norm is for upstream generation to be curtailed and replaced with downstream generation. The impact of this is likely to be seen in growing curtailment and this can be seen in the FES forecasts for curtailment out to the mid 2030s. Beyond this point, the FES forecasts assume that curtailed energy will be used for local hydrogen production and so the curtailment figures start to show slower growth. However, there is still energy lost to the electricity system and the peak curtailment at 43TWh to 67TWh is more indicative of the issue.

Curtailment forecasts



Source: National Grid

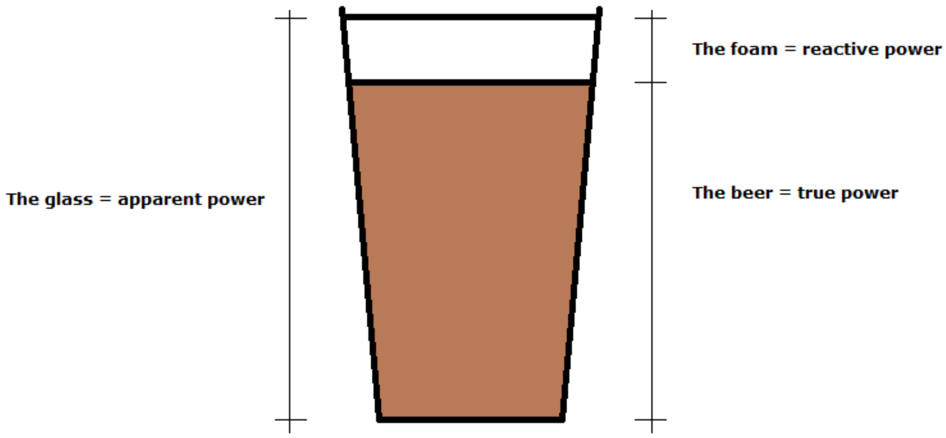
Voltage

Location also has an impact on voltage and voltage stability. As more generation is delivered at the end of the distribution system as opposed to centrally on the gird, the need for voltage management is increased.

Most electricity systems including the UK grid use an alternating current which reduces losses on the grid. Here voltage and current alternate between positive and negative. If they do this together then power is always positive and useful or active power is transferred to the load. However, certain types of load result in voltage and current being out of phase which results in a certain amount of power transfer that is not useful. This is known as reactive power. While it may appear wasteful, generators still need to provide reactive power as insufficient reactive power on the system can lead to voltage reductions and even to network collapse.

Useful power is referred to as true power. Apparent power is the total power needed by the system to deliver both true power and reactive power. A well-known analogy is to compare power to beer in a glass. Most beer will have a head of foam which is relatively useless but difficult to avoid. This is the reactive power. The beer is the true power, but you need a beer glass big enough for both, which is the apparent power. The exact relationship is that of a right-angled triangle with apparent power as the hypotenuse. The power factor is the ratio of true power to apparent power. While a lower power factor means more losses, it is driven by the nature of the load and therefore the uses of the power. It can be reduced by better design of connected appliances but is almost impossible to avoid.

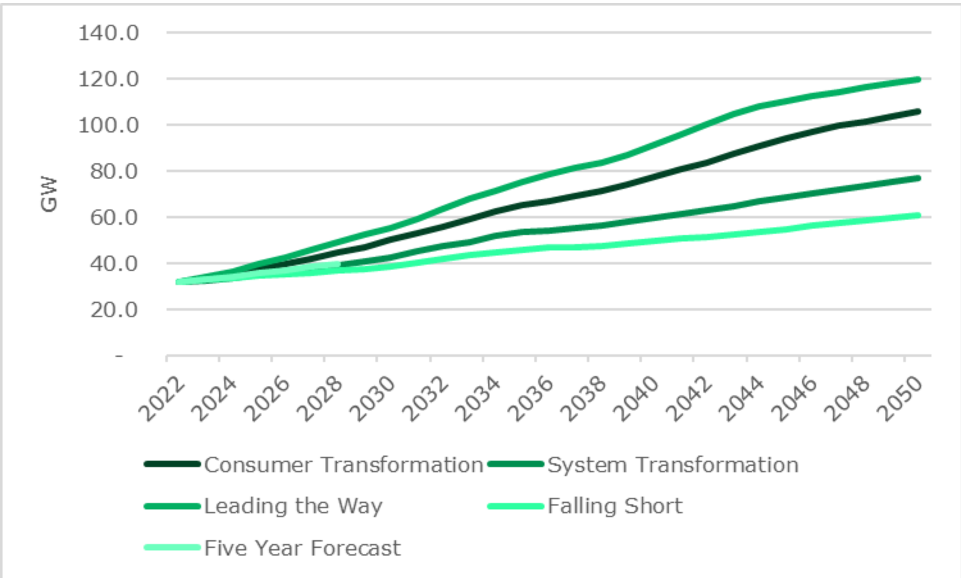
Reactive power beer glass analogy



Source: Longspur Research

As the system becomes more distributed the need for reactive power increases and additionally the overall stability of voltage reduces. This increases demand for reactive power which is met as part of ESO's acquisition of ancillary services. Even the lowest of the FES forecasts expects a doubling in distributed generation.

Distribution connection generation forecasts



Source: National Grid

Restoration

The restoration of power after a major outage includes black start which is the requirement for generation plant to be available to restart the system in the event of a system wide or regional shut down. Most generation equipment needs power itself to restart but a few are capable of starting on their own and then restarting the system. Restoration is more easily provided by large well located generators and in this regard Drax has a key advantage with both Cruachan and Drax power station located centrally within their grid regions and in the case of Drax power station even able to send power north to provide cover.

All these problems of location have an obvious solution in the form of additional expenditure on transmission and distribution grids. This creates opportunities for grid and distribution companies, although most of these companies are fully regulated and returns may be limited. But it is also a major undertaking and with grid connection dates for some new assets out as far as 2037, it is unlikely to solve all of the problems and certainly not quickly.

Wrong Time – Issues With Balancing The System

Timing issues vary from the seasonal down to the micro second level. At the micro level, frequency is the biggest issue with the 50 Hz system in the UK representing a period of 20ms between cycles. At longer time periods the biggest problem results from the intermittency of wind and solar generation.

Frequency – The Problem Of Inertia

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

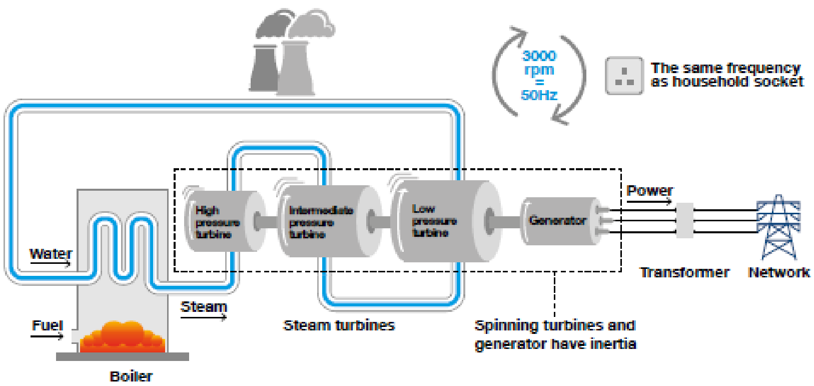
In the UK, as in other markets, there is a statutory requirement for National Grid ESO to keep the frequency of the electricity system within a narrowly defined range. The nominal frequency is set at 50Hz and the SO must keep actual frequency to +/- 1% of the 50Hz standard.

Frequency trigger points

Source: National Grid

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

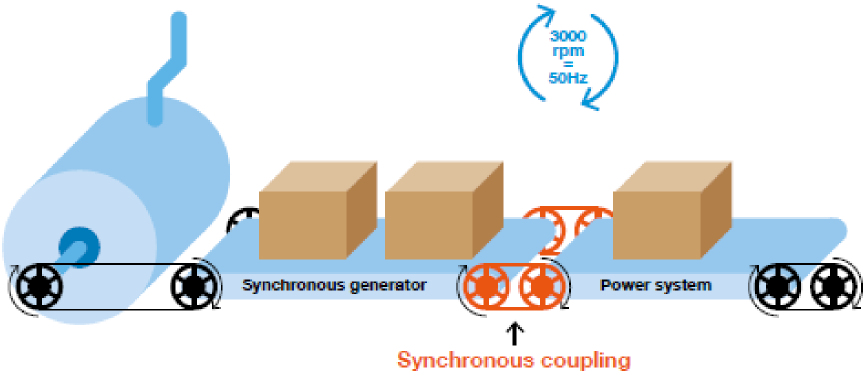
Synchronous Generation Creates Inertia



Source: National Grid

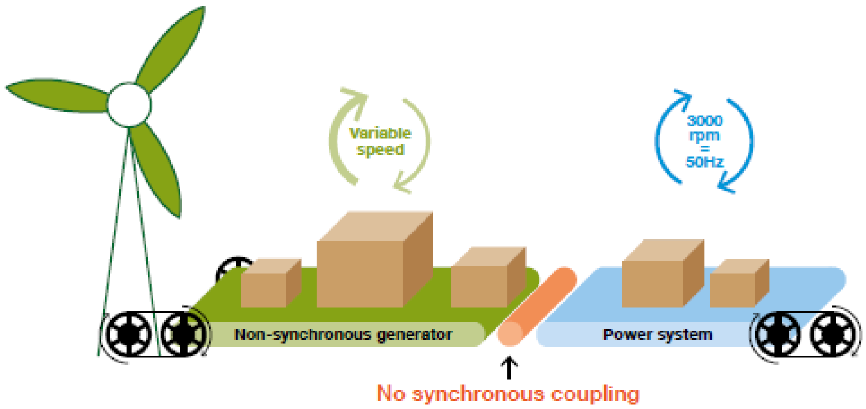
This worked reasonably well when most of the system's generators were synchronous. Unfortunately, the main forms of renewable generation, wind and solar PV, do not provide inertia to the system. Their generation output varies continuously as wind rises and falls and as cloud cover materialises and disperses.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

Generator with synchronous coupling



Source: National Grid

Generator with non-synchronous coupling



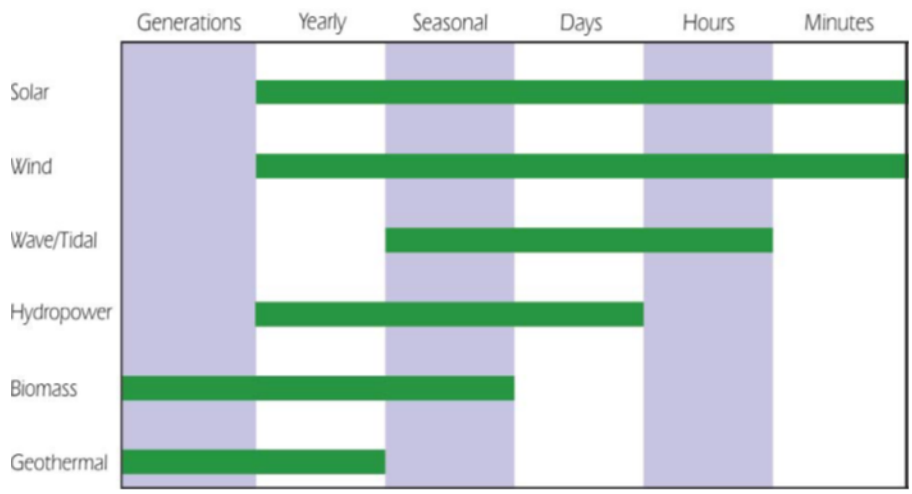
Source: National Grid

As a result, the ESO is becoming more reliant on a smaller group of synchronous generators including Drax. As we shall see this makes it more likely that non-synchronous wind and solar assets will be constrained off the system at times of stress and more likely that Drax assets will be constrained on to replace them.

INTERMITTENCY AND VOLATILITY

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

Timing Impact of Intermittency



Source: IEA

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

Long periods of low wind when combined with cloudy weather reducing solar output are known as dunkelflaute or dark doldrums. On average there are 50 to 100 hours of such periods occurring in Northern Europe in each of the months of November, December and January when such events are defined as those lasting 24 hours or longer.

Storage required to meet lost wind output at an offshore wind farm

	Lost hours	Missing power	Missing power (MWh)*	Storage (MWh)*
Largest gap	82	100%	1,005	1,124
Average gap	13	69.40%	145	162
Smallest gap	1	7.70%	16	18

Source: Project Neos Public Report, * assumes peak demand at 16.4MW

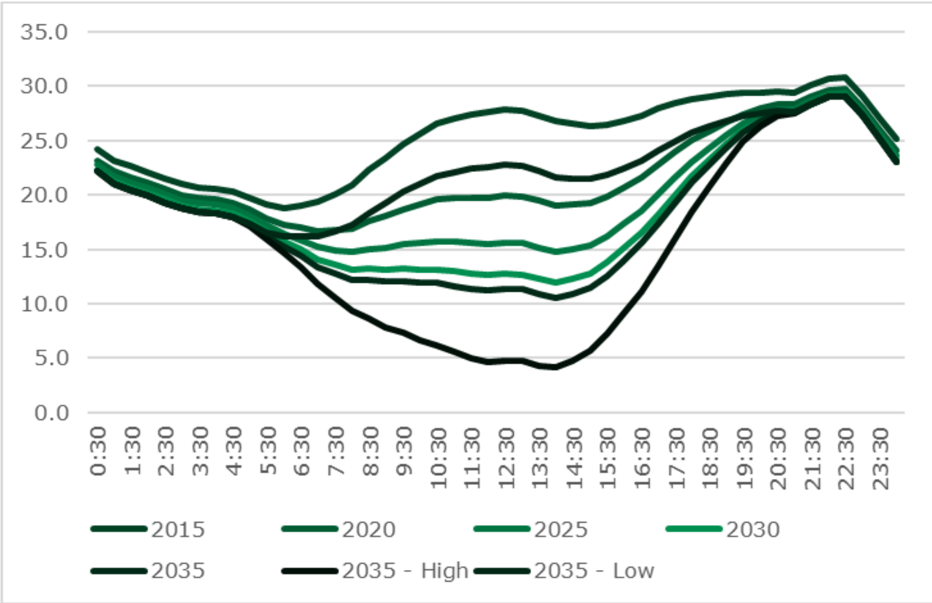
The intermittency problems created by renewable generation are well known in terms of the longer duration issues of daytime versus nighttime for solar and windy days and calm days for wind. However, short term volatility is less generally understood outside the industry. In terms of value it is potentially 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.

Within day timing issues – The Duck Curve

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

The graph shown is for the GB grid based on embedded renewables and shows that the issue is just as relevant here as in California.

Duck Curve



Source: National Grid

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

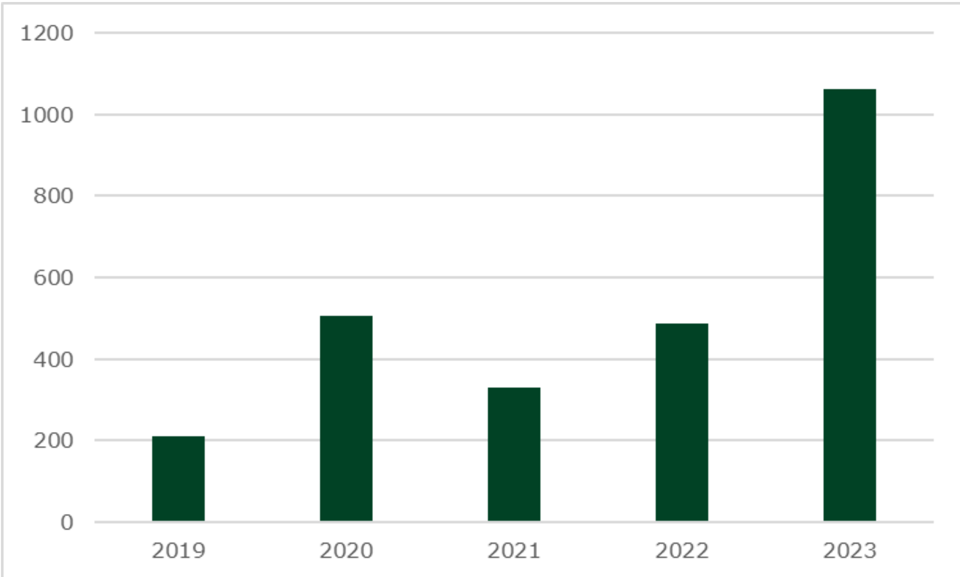
Short Circuit Level

Another issue also exists in the provision of the Short Circuit Level (SCL). SCL is the current that flows in the system when there is a fault. It is essential to maintaining system voltage during a fault. However, renewables only provide about a fifth of the required SCL compared with large rotating generation such as the biomass units at Drax Power Station.

WRONG PRICE - MARKET STRUCTURE ISSUES

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

Negative pricing periods



Source: Elexon

When enough low marginal cost assets are present in a market, low or negative prices result in uneconomic returns (missing money) for generators. As a result, this puts pressure on incumbent generators who suffer from low prices. It is also likely to lead to low investment, exacerbating security of supply issues in the medium and longer terms. While the capacity market attempts to address this, it is not necessarily sufficient to forestall many of the problems.

However, we think the other side of this argument is that storage and other flexible capacity picks up the “missing money” by being able to buy low or negatively priced electricity when renewable generation output is strong (on windy, sunny days) and then sell it when renewable output is low (calm evenings).

WHAT ARE THE SOLUTIONS?

The problems of place mean that some plant is curtailed out of the system because of its location. More well located plant must be able to be dispatched to make up for this loss. Timing issues require plant that is flexible and for the specific issues of frequency, spinning reserve is the main solution. Pricing issues are really about economic curtailment and again flexible generation is the main solution. So the main solution to all these issues is to have flexible, dispatchable power sources that can make power available when you want it and where it is most useful.

Key generation technologies in the UK

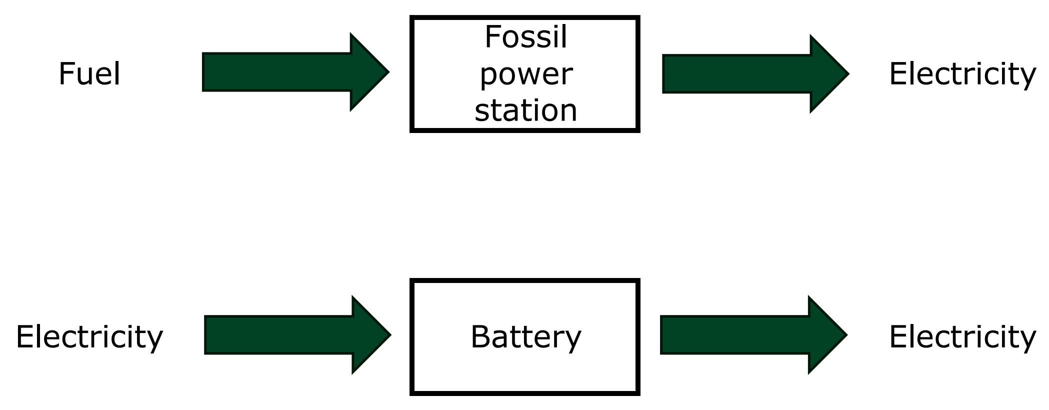
Generation technology	Dispatchable?	Ramp rate (%/min)	Inertial constant (MW)
CCGT	Yes	2.2	6.0
Wind	No	1.0	0.0
Solar PV	No	0.4	0.0
Nuclear	No	1.5	6.0
Biomass	Yes	1.6	6.0
Pumped hydro	Yes	360.0	4.5
OCGT	Yes	21.0	5.0
Natural flow hydro	Yes	360.0	4.5

Source: Longspur Research, Central Power Research Institute (India), IEA

Flexible generation and storage

Storage can be looked at as a type of power station. A traditional power station takes fuel and converts it into electricity. Storage also does this but in the case of storage the fuel is also electricity.

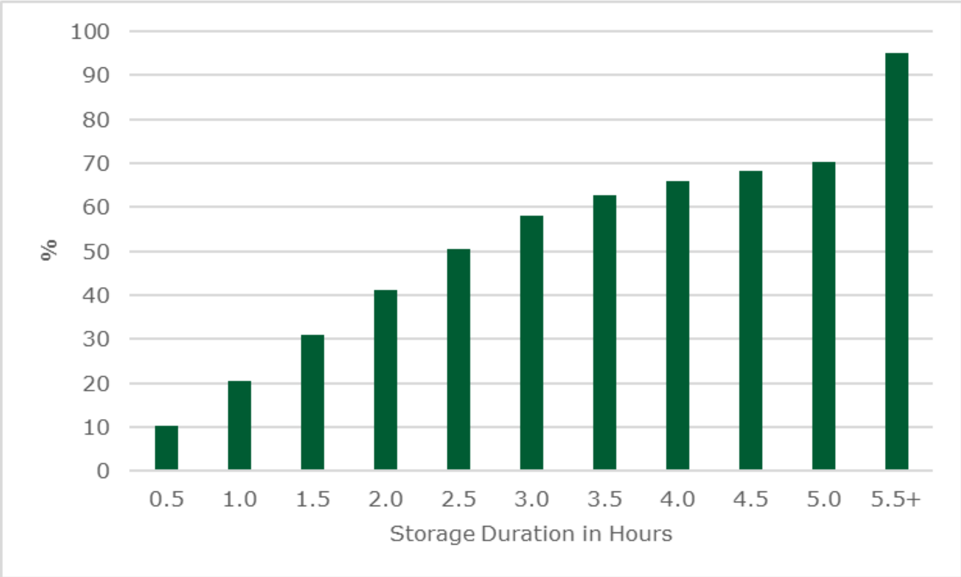
Power stations and storage



Source: Longspur Research

Unfortunately, battery storage is only dispatchable for the duration of storage it has available and this limits its use for addressing the growing issues in managing the grid. In fact the Capacity Market penalises short duration storage for this reason. With a typical duration of two hours, most batteries in the Capacity Market are derated to just over 40% of their nominal capacity.

Capacity market derating of storage according to duration



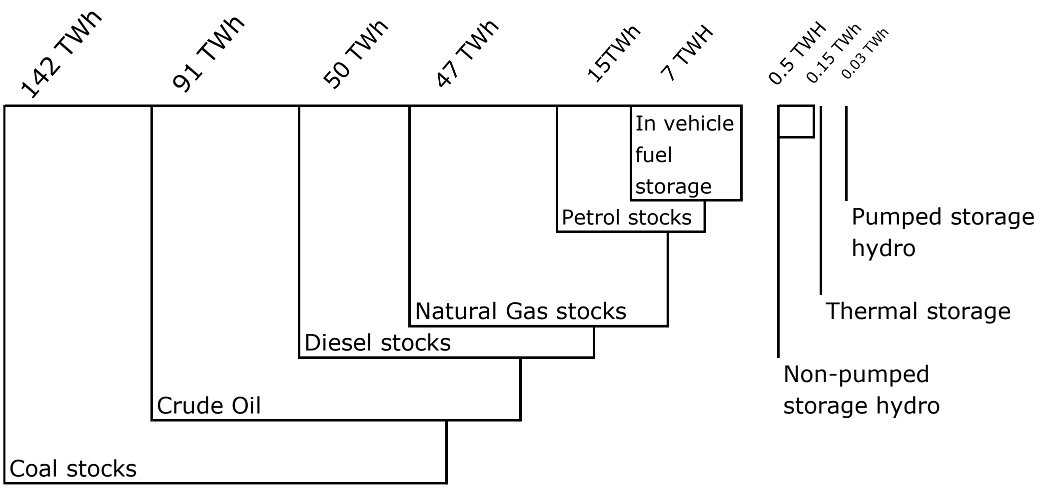
Source: National Grid

Battery storage can have longer durations but this gets expensive. Batteries also degrade if cycled too often, limiting their usefulness. Long duration storage is a key solution and we see demand growing as renewable penetration increases. The key form of long duration storage in the GB market is currently pumped hydro with Drax owning 440MW out of a total of 2,900MW at its Cruachan power station, with an additional upgrade of 40MW now funded from the Capacity Market and planning secured for a major 600MW expansion.

Thermal generation as storage

Looked at the other way round, thermal generation is a form of storage with the storage medium being the fuel which locks up energy through chemical storage. In fact, the old fossil fuel energy world stored enormous amounts of energy in its fuel stores.

Energy Storage in the UK, 2015



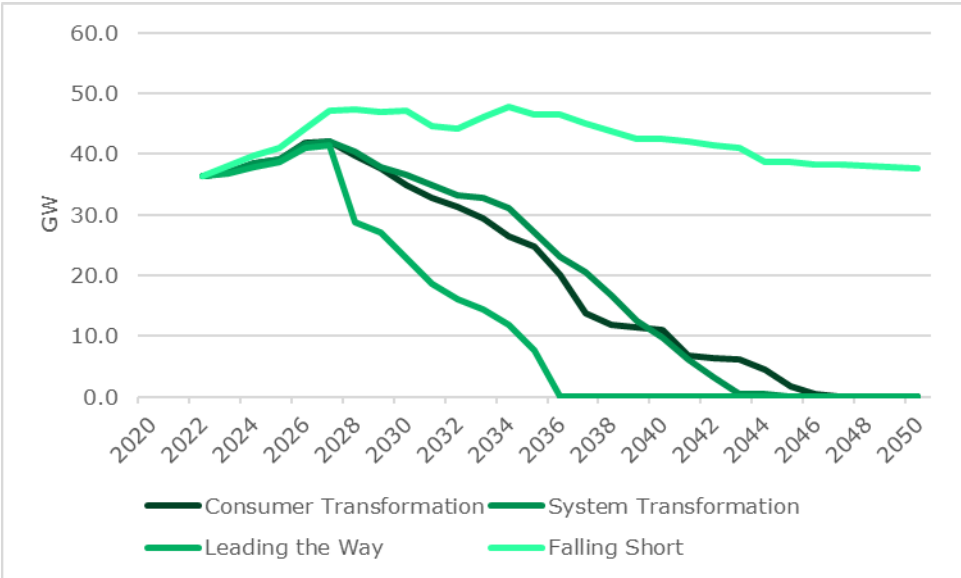
Source: Simon Gill, University of Strathclyde, 2015

In the case of Drax, the Drax biomass units represent significant storage assets. Drax Power Station has 300,000 tonnes of biomass storage capacity. The chemical energy contained in this biomass represents 650,000MWh of dispatchable energy.

Gas generation

Gas generation also represents storage with gas stored in pipelines acting as a large battery that can be dispatched via both combined cycle and open cycle gas power stations. Gas generation is currently the main provider of flexibility in the GB market but it will not be so forever because it is a fossil fuel with emissions of between 365 gCO_2e/kWh and 488 gCO_2e/kWh. Existing gas plant are beginning to come to the end of their useful lives. New build stations have been announced but are limited and have not sufficiently responding to capacity market incentives. Uncertainty over the cost of carbon which impacts gas plant through the UK Emissions Trading Scheme make investment decisions risky. The FES forecasts all show a reduction in unabated gas generation from 2028 onwards.

Unabated gas capacity forecast



Source: National Grid

Nuclear

Nuclear is not flexible and not really dispatchable. It is always on so is less useful in managing the system although it does provide inertia as synchronous generation. Perhaps the biggest issue with nuclear is that while it does serve some of the needs of the system, existing capacity is closing down and new capacity takes a long time to build, normally longer than expected.

Grid reinforcement

Grid investment in network reinforcement will help and National Grid investment plans include spend of £42bn by 2026. However new transmission and distribution lines can only remove some of the issues. Specifically, frequency and voltage issues are mainly a function of the move to asynchronous distributed renewables and not mitigated by new connections.

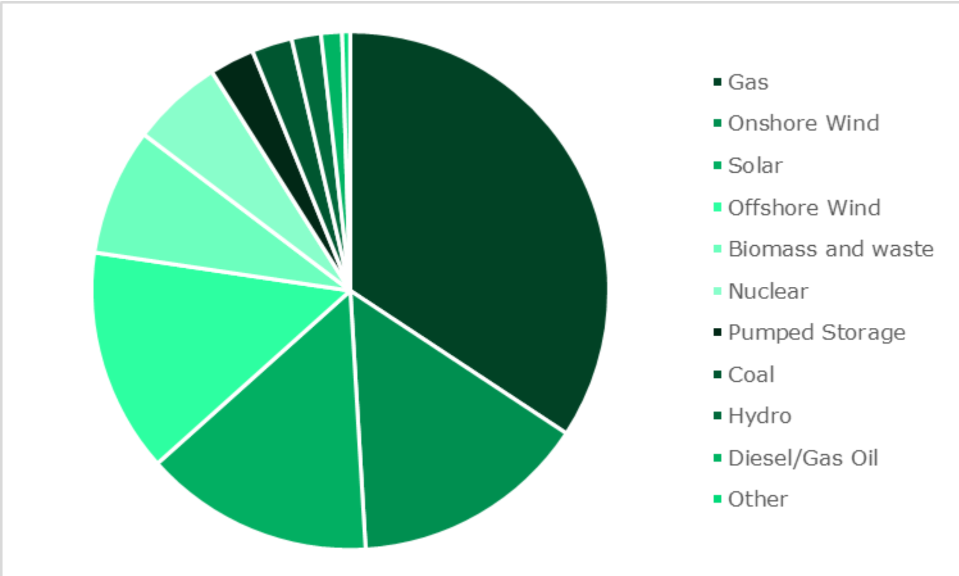
Demand side flexibility

Demand side actions are an important part of the armoury and this can provide additional flexibility with the Demand Flexibility Service launched in 2022. However while the ESO has paid for an average of 251MW of demand reduction this winter, the actual demand flexibility delivered was only 70% of that contracted. This reflects changes in consumer behaviour with initial enthusiasm starting to wane. It makes predicting demand side response more difficult making alternative solutions more attractive.

Loss Of Flexibility In The System

The GB market is dominated by intermittent renewables and combined cycle gas turbines, together accounting for 75% of capacity as of May 2023. CCGTs provide both flexibility and spinning reserve. Further flexibility is provided by biomass generation, mainly Drax, and by pumped storage and smaller diesel and open cycle gas generation. Nuclear provides additional spinning reserve.

GB generation capacity (May 2023)

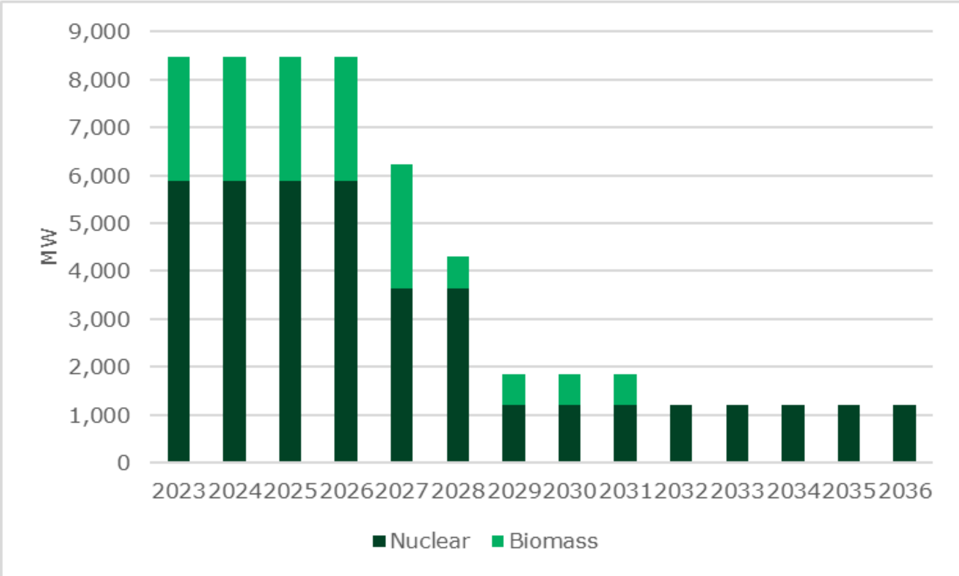


Source: National Grid

Closures and lack of replacement

The problem is that nuclear is closing with most plant shut by 2028 taking out 4,685MW of spinning reserve. If the current Government consultation fails to fund the ROC supported biomass from 2027 a further 1,935MW is removed.

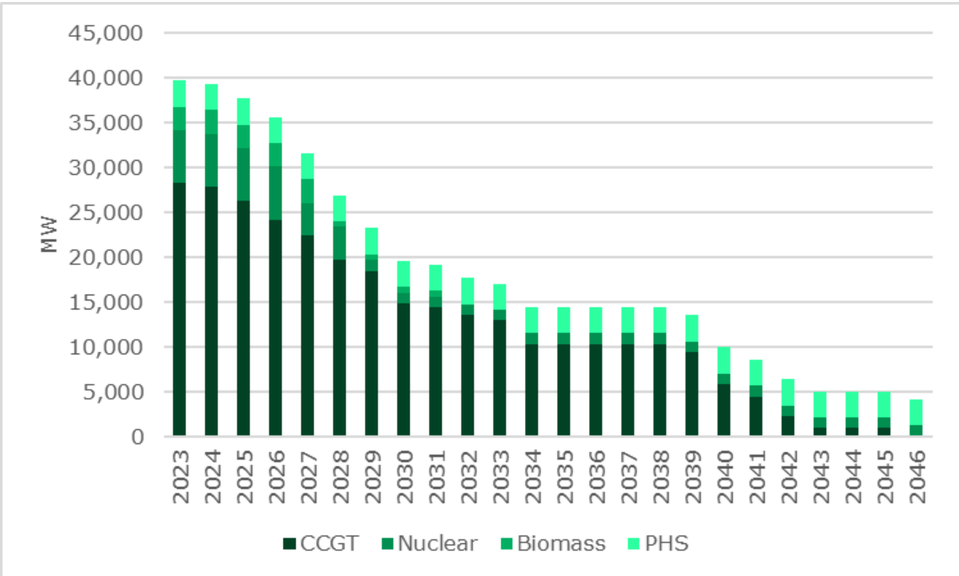
Closures of nuclear and biomass



Source: National Grid, Longspur Research

Additionally, the current fleet of gas generation is starting to get quite aged. Roosecote, the first CCGT in the UK, was commissioned in 1991, mothballed in 2012 and finally demolished in 2015 giving 21 years of useful life. If we were to assume a 30 year life for the existing fleet it can be seen that more than half of the UK's total spinning reserve is closed by 2030.

All spinning reserve



Source: National Grid, Longspur Research

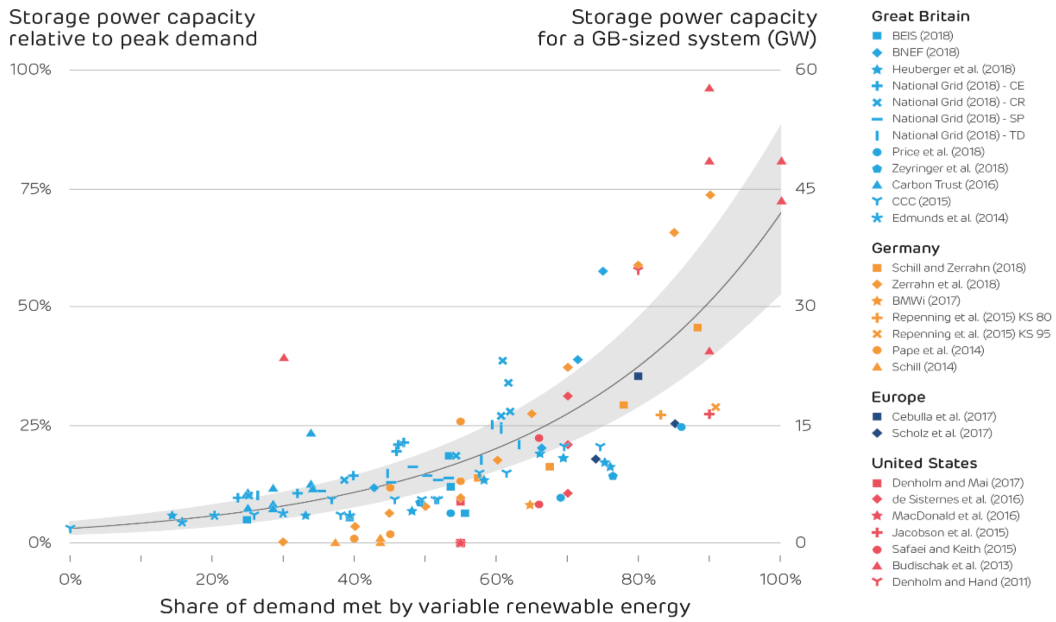
In straight generation terms this capacity loss is overshadowed by the growth in wind and solar. But that does not deliver spinning reserve nor flexibility. It was hoped that the Capacity Market would provide sufficient incentive for new CCGTs to be built. So far only four CCGTs have cleared the market auctions one of which has subsequently withdrawn. Eggborough, Kings Lynn A and Keadby II will deliver 2.7 GW of new capacity when completed. Additionally new gas capacity may emerge but with consenting and build times of around five years, a capacity crunch is looming. New nuclear is also hoped to replace the decline in spinning reserve but with the 3.2GW Hinkley Point C reactor again pushed back to at least 2029 there is a definite reduction in the second half of the current decade. Hinkley Point C was originally due to come online in 2017.

But it is not simply about replacing lost capacity. As the system becomes more dominated by intermittent renewable energy, the need for matching flexibility increases meaning we need to go beyond simple replacement.

THE NEED FOR FLEXIBILITY

Much academic work has been done on the need for storage and by extension flexible generation as renewable penetration increases. As we add more intermittent renewable energy, the demand for storage and long-duration storage in particular increases. The following meta study of research by Imperial College London shows this fairly clearly.

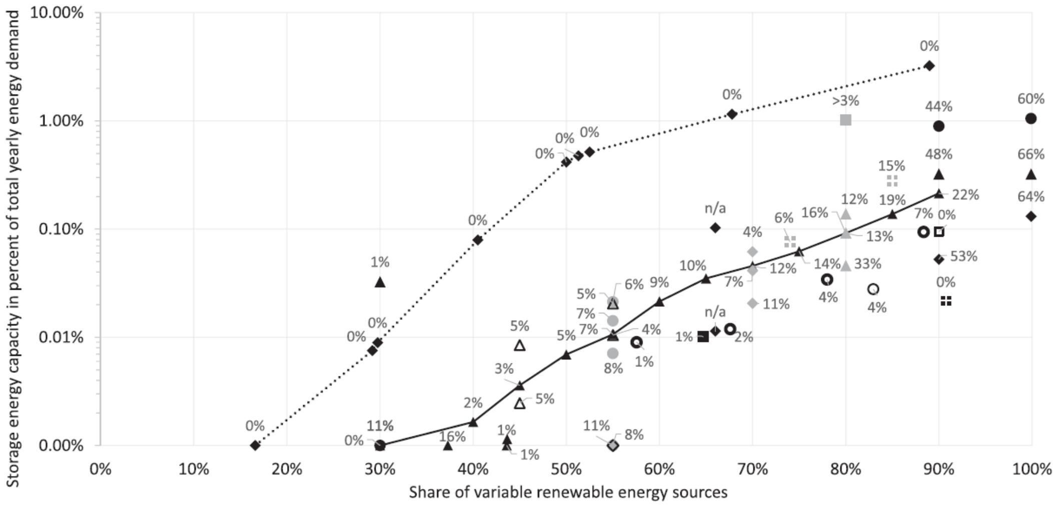
Storage capacity relative to renewable penetration



Source: Imperial College based on Zerrahn et al., 2018.

The Imperial work shows storage expressed as storage power capacity as a percent of peak demand. However, to really work out storage demand we need to know how much storage energy capacity is needed rather than power. The Imperial study draws heavily on another meta study; Zerrahn, A, Schill, W, Kemfert, C, On the economics of electrical storage for variable renewable energy sources, European Economic Review 108 (2018) 259–279. This shows the storage energy capacity as a percentage of total annual energy demand.

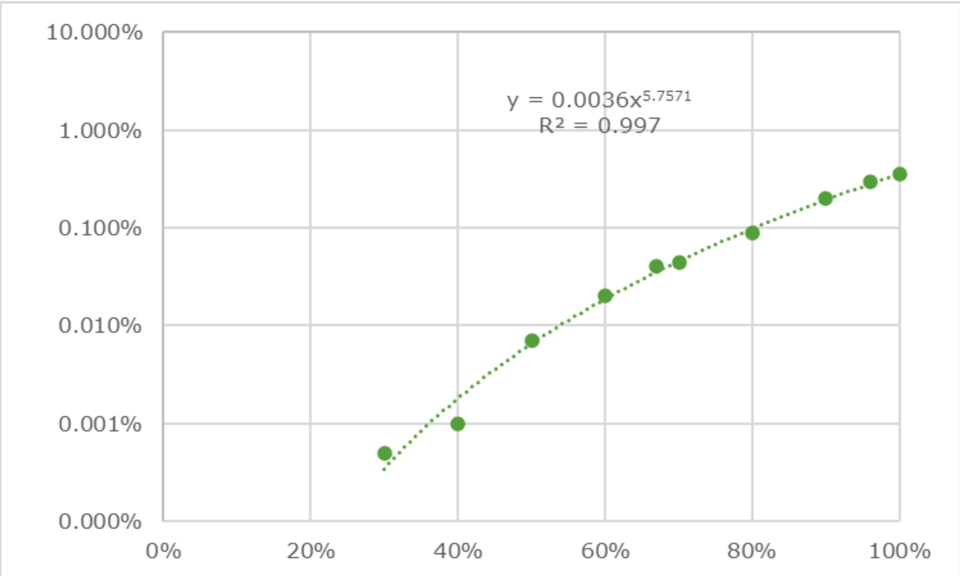
Storage energy requirements in recent research literature



Source: Zerrahn et al., 2018. Percentages show curtailment. Upper line assumes no curtailment.

We have plotted a trendline to this data to derive a relationship between variable renewable energy penetration and the required storage energy capacity demanded to minimise curtailment. Note that this does not eliminate curtailment but represents the least cost outcome. Even with significant energy storage, curtailment varies from 2% at 40% renewable penetration to 22% at 90% with 66% if there is 100% variable renewable energy supply. Our trendline has the equation S = $0.036P^{5.7571}$ where S = storage as a percent of annual energy demand and P = variable renewable energy penetration.

Best fit line to Zerrhan et al.



Source: Zerrahn et al., 2018, Longspur Research

We can use this with the FES forecasts for renewable penetration to estimate demand for storage. This suggests that even the least ambitious FES forecast with 75% renewable penetration would mean storage of 0.3% of yearly electricity demand. It also represents storage demand of more than double the current storage operating, with planning and in planning including existing and planned pumped hydro.

Storage required in UK for peak renewable penetration

	Max penetration	Year	Storage required (GWh)
Consumer transformation	82%	2035	623
System transformation	82%	2037	591
Leading the way	86%	2034	869
Falling short	77%	2037	375
Current operational storage in GB			32
Add storage with planning			99
Add storage in planning			163

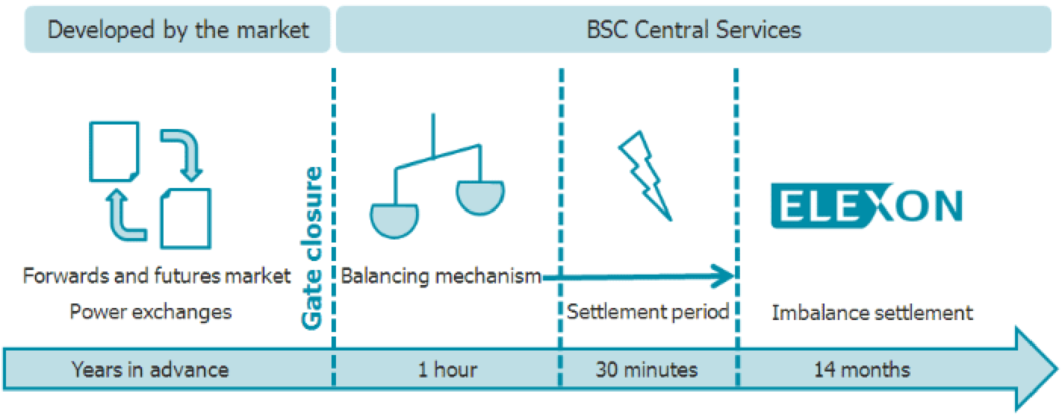
Source: Longspur Research, Department of Energy Security and Net Zero

Clearly to solve curtailment the amount of storage required is very high indeed. Other solutions are required as part of the solution.

GETTING PAID

National Grid Electricity System Operator (ESO) undertake management of the system. ESO has the job of balancing the system. It uses a variety of techniques to do this including the purchase of generation, paying for the wrong types to stand down, and procuring specific services, normally from generators with the characteristics to provide these services. Much of this activity is undertaken through the Balancing Mechanism, a short-term market that operates up to half an hour prior to the dispatch of electricity.

Wholesale markets summary



Source: Elexon

However, ESO also procures generation directly, normally by auction, for a range of services which together are known as ancillary services.

PRICING OF BM TRADES

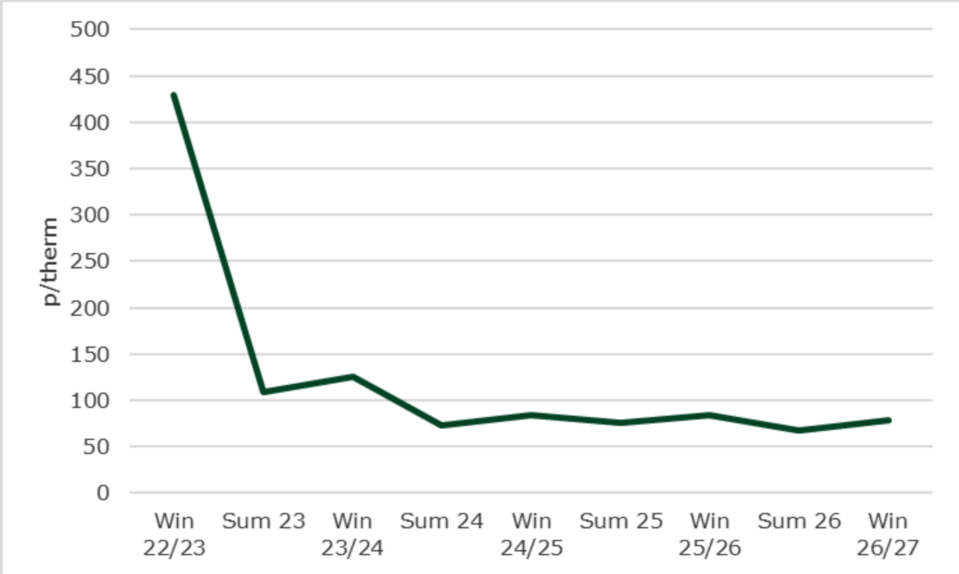
Power trading is just one element of the revenue stack of a typical power project or storage installation but can deliver a high proportion of the value. For Cruahan the ability to buy power and pump water uphill when prices are low and to sell power by discharging when prices are high is key. Our analysis of the past four years suggests that the average spread between high and low prices can be significant and make power trading a key part of the revenue stack.

Cruachan will operate in both the normal power markets including the day ahead market as well as in the balancing mechanism. For analysis we have used the balancing mechanism to examine pricing. The day ahead market on an annual average basis will see slightly higher prices but specific balancing mechanism trades are likely to be available to Cruahan resulting in better economics for this asset.

Balancing mechanism prices in 2022, and storage spreads in particular, were clearly exceptional. We also see them as an example of the way in which power markets are likely to develop going forward with relatively high gas prices determining peak and peak load prices and higher renewables penetration keeping "off peak" prices low. Low off peak prices will occur more often as renewable penetration increases.

Power markets are seeing growing penetration of intermittent renewable energy in the form of wind and solar PV. At the same time gas prices have been rising and were already doing so before the Russian invasion of Ukraine. They have fallen back in 2023 and may fall further, but forward curves at least suggest stabilisation around an average annual price of c.75p per therm.

Gas forward curve (seasonal NBP)

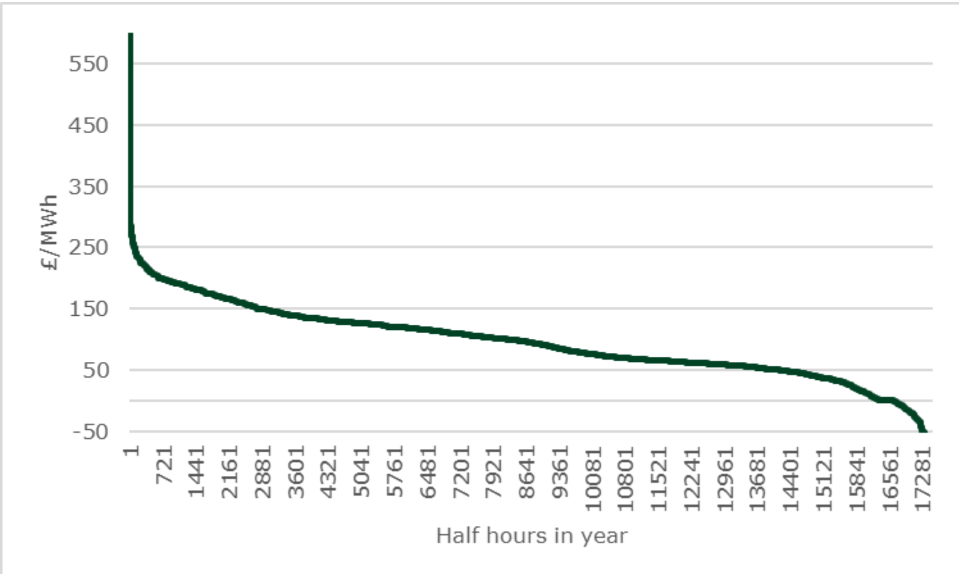


Source:Bloomberg

Broadly speaking, generators in electricity markets compete on the basis of their short run marginal costs. When renewables are running, they have a very low short run marginal cost. As renewables take up more of the system, low price periods become more frequent. However, when there are not enough renewables to meet demand, more expensive fossil fuelled generation becomes price setting. With high fossil fuel prices this makes these periods very expensive. Even when fossil fuel prices normalise, these periods are expected to remain expensive as fossil fuel generators will increasingly have to cover costs and margin over a shrinking number of operating hours.

We can look at the distribution of balancing mechanism prices in what the power industry has historically termed a price duration curve with highest prices shown first at the left hand end and low prices at the right hand end.

Price duartion curve 2020

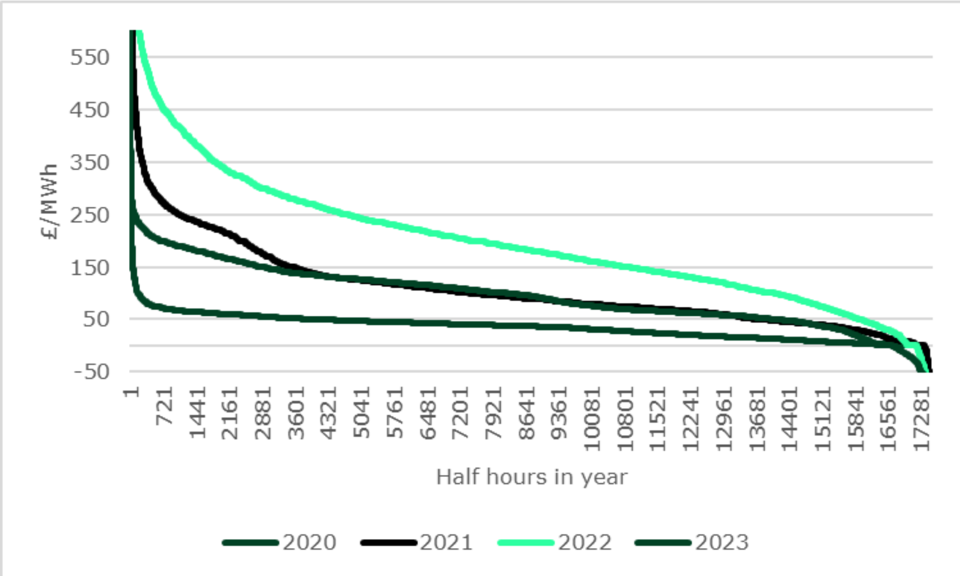


Source: Longspur Research, Elexon

The experience in 2020 was unusual with exceptionally low demand due to COVID lockdowns. While this meant that there were relatively more periods when renewables were price setting, penetration rates remained low so these periods were still not particularly frequent. With lower overall demand pricing was weak across all periods.

2021 was a more normal year with renewable penetration as a percent of demand growing but gas prices also starting to rise leading to higher peak prices. 2022 saw high gas prices but demand had grown so renewables set prices less of the time. 2023 has seen gas prices fall back but renewable penetration has continued to grow. This means that the curve is similar to 2021 but the very high prices seen towards the end of that year are not apparent.

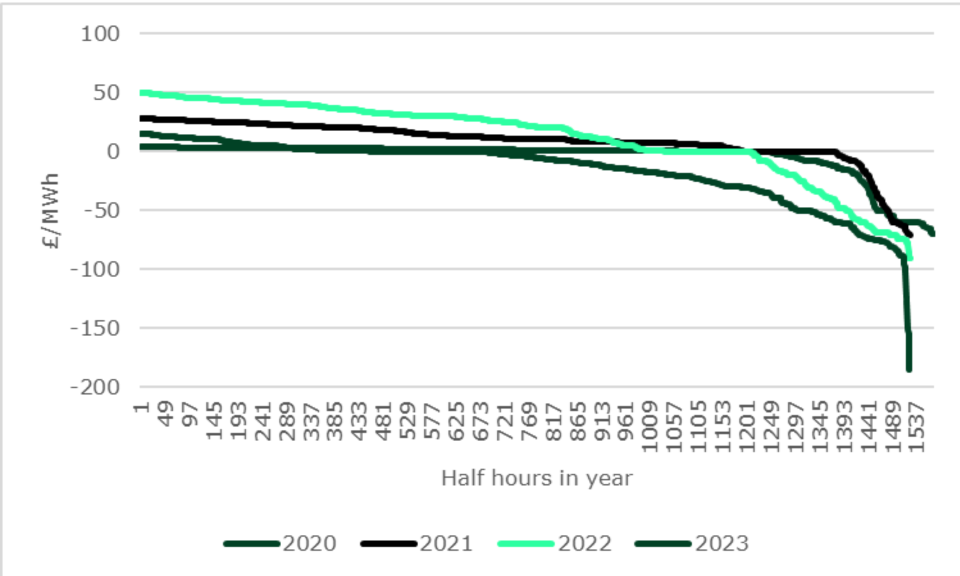
Price duration curves for 2020, 2021, 2022 and 2023



Source: Longspur Research, Elexon

At the low end of the price curve there are now many more periods of zero or negative pricing.

Price duration curves for 2020, 2021, 2022 and 2023

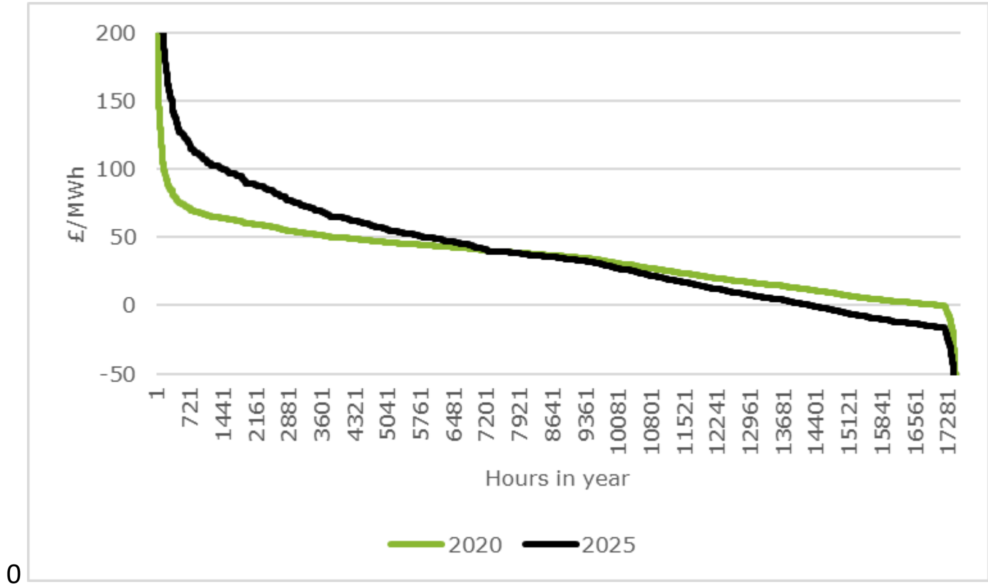


Source: Longspur Research, Elexon

In fact, there were over 1,000 pricing periods with prices at zero or less in 2023, representing 6% of all trading periods.

Looking forward, as renewable penetration increases, there will be more periods of extremely low or negative prices, extending the low end of the curve towards the centre. While gas units will mainly price on a marginal basis, these power stations will try to recover as much income as possible but will have fewer hours of operation in a year to do so. Where there is scarcity pricing gas generators will therefore push for higher pricing and we think this will increase prices at the left hand end of the price duration curve.

Expected price evolution

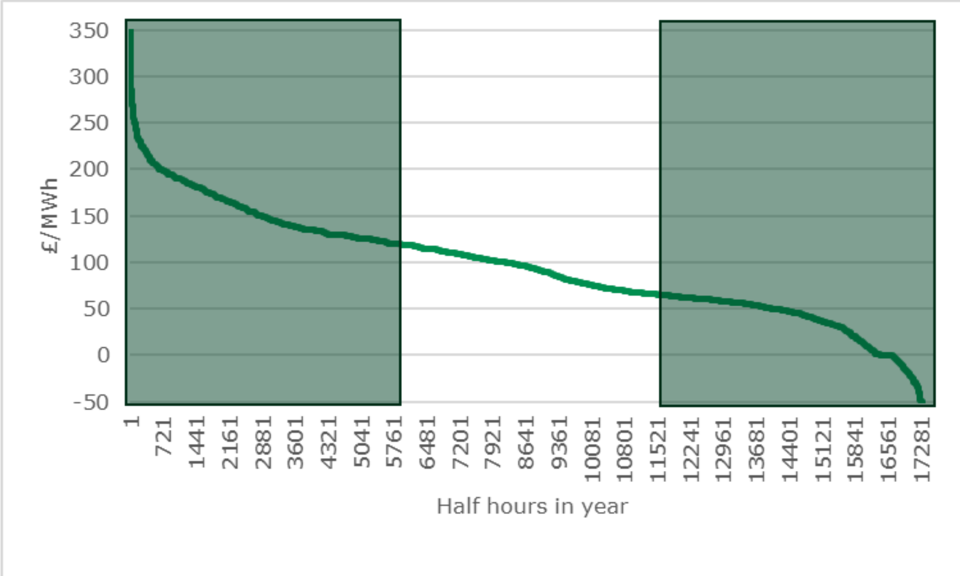


Source: Longspur Research, Elexon

IMPACT FOR CRUACHAN

Looking at the price duration curves we can estimate the average charging cost and discharging price assuming utilisation of 33% based on eight hours of storage duration with one cycle a day (8/24=0.333). The resulting average spread will then be the difference between the average prices in the two green boxes below.

Calculating the storage spread



Source: Longspur Research, Elexon

Calculating the storage spread

We have shown the top and bottom third of prices in the table below. 2020 shows low spreads based on low gas prices. 2021 starts to reflect higher gas prices to deliver a spread of £171/MWh, with a charging cost of £40/MWh and a discharging price of £210/MWh. 2022 sees the spread rise to £264/MWh as high gas prices drive peak power prices. The spread then falls back in 2023 to below that of 2021 at £128/MWh but still offering an attractive revenue proposition.

Storage spreads for Cruachan

£/MWh	High 33.3%	Low 33.3%	Spread	Est. revenue (£m)	Actual EBITDA (£m)
2020	62	8	53	52	73
2021	210	40	171	168	68
2022	341	77	264	259	171
2023	160	32	128	126	230

Source: Longspur Research, Elexon,

We have estimated the revenue assuming a 90% availability, 85% round trip efficiency and compared against the reported EBITDA that Drax shows for the combination of Cruachan and the hydro projects. Operating costs will not be overly significant but there is still a large gap in 2022 between estimated revenue and EBTIDA. We think this is because Cruachan was not necessarily available to participate in some of the exceptionally high periods available in that year. In 2023 the estimated revenue is lower than the achieved EBITIDA in part because Drax was able to lock in some forward pricing based on the high prices at the end of 2022.

Both 2020 with its low demand and 2022 with high gas prices were exceptional but 2023 could represent a sensible base case going forward. Given our expectations of how the market will evolve, 2023 could even look quite conservative given it assumes that charging costs stay on the high side when they are likely to fall as renewable penetration grows.

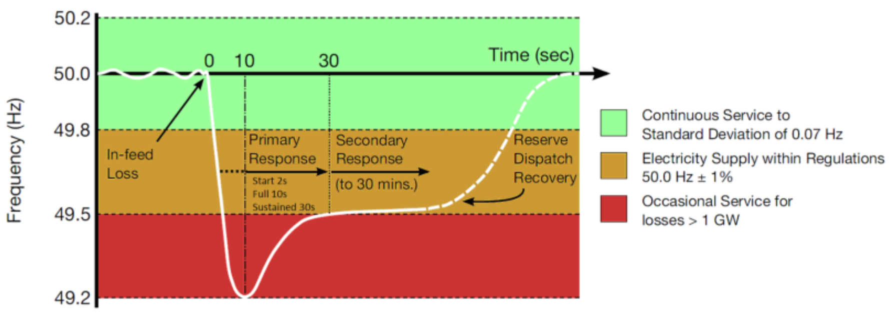
GETTING PAID FOR INERTIA AND ANCILLARY SERVICES

Inertia

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

While inertia is the key to maintaining frequency, when there is any significant change in the market such as the sudden tripping of a major power station, frequency can move significantly. Restoring it to normal is undertaken by a number of services starting with a group of services known as response and then followed by slower reacting reserve services. These are part of the large group of services provided under the heading of ancillary services. Notably Cruachan has a pathfiner contract for one of its units to provide inertia with up to £5m in revenue over the 6 year contract.

Frequency response – a matter of timing



Source: National Grid

Most are secured through auctions run by the ESO and some are subject to confidential arrangements on which there is limited disclosure. However the ESO Monthly Balancing Services Summary (MBSS) gives a lot of cost information. These are the total costs including both balancing mechanism actions and ancillary services payments. We summarise the 2023 payments below.

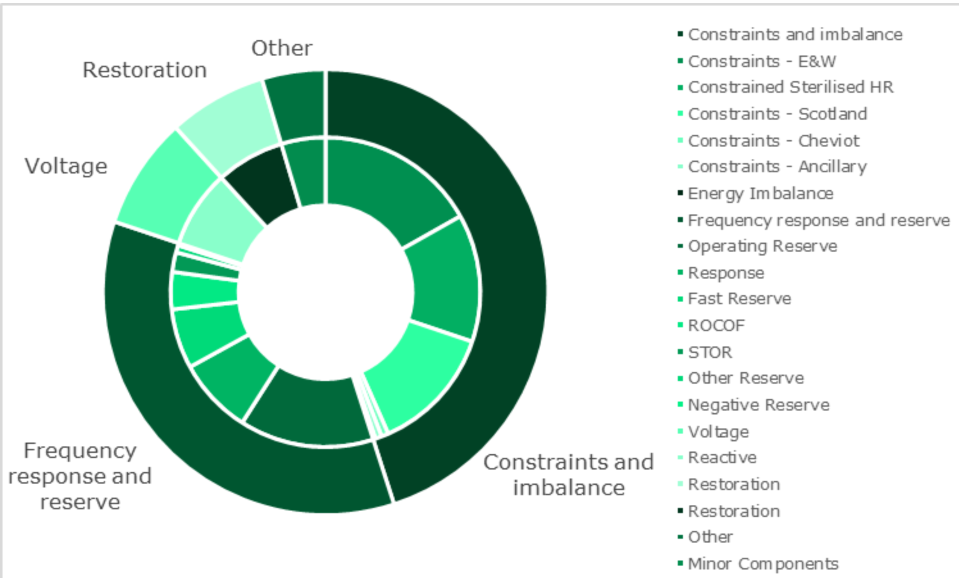
Balancing costs breakdown (2023)

Service	£m	%
Constraints and imbalance		
Constraints - E&W	476	17%
Constrained Sterilised HR	377	13%
Constraints - Scotland	373	13%
Constraints - Cheviot	21	1%
Constraints - Ancillary	19	1%
Energy Imbalance	7	0%
Frequency response and reserve		
Operating Reserve	397	14%
Response	224	8%
Fast Reserve	176	6%
ROCOF	110	4%
STOR	58	2%
Other Reserve	21	1%
Negative Reserve	7	0%
Voltage		
Reactive	229	8%
Restoration		
Restoration	202	7%
Other		
Minor Components	130	5%
Total	2,826	100%

Source: Longspur Research, National Grid

We can group these into services primarily aimed at balancing and curtailment, direct frequency services, voltage services, restoration and other. This shows that curtailment and frequency dominate with other ancillary services a smaller part of the market

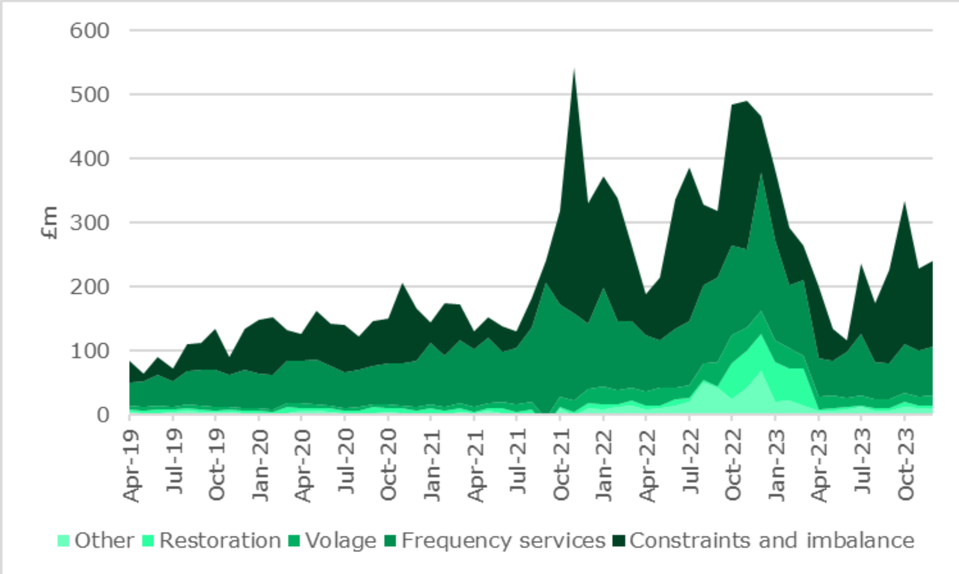
System balancing cost breakdown (2023)



Source: National Grid

Over time we can see that spend has increased dramatically from late 2021. While it is volatile, the long term trend is clearly up and we expect spend to increase as more renewables are added this will continue to show growth.

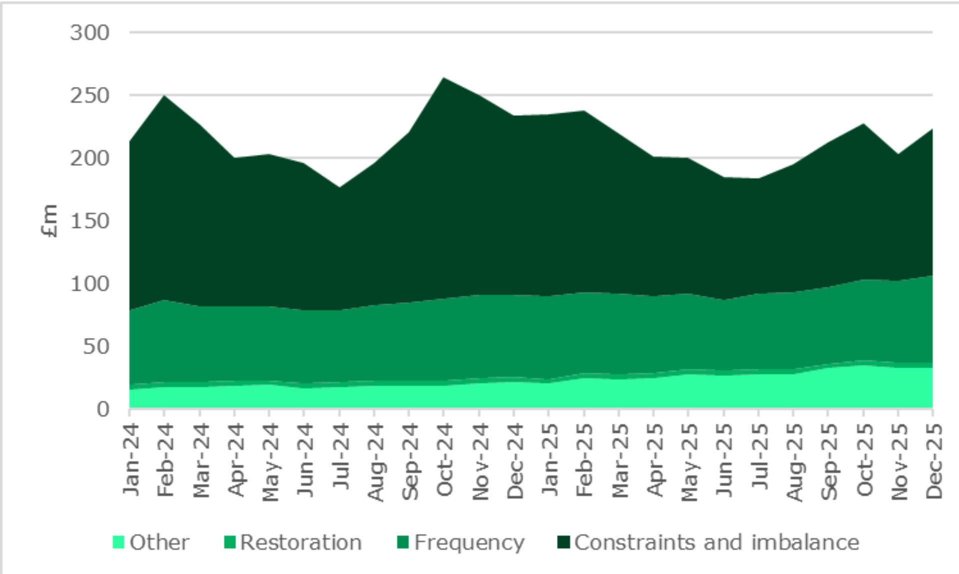
System balancing cost history



Source: National Grid

ESO forecasts its spend on these services two years ahead and these show relatively flat balancing costs but growing cost levels in all other areas.

System balancing cost forecasts



Source: National Grid

CAPACITY MARKET LOOKING ATTRACTIVE

Also available in the revenue stack for Drax is the Capacity Market. The capacity market is a Government scheme administered by ESO which runs auctions for capacity to be available in four years' time (T-4 auctions). Additionally, top up capacity needs are met through auctions for delivery in a year's time (T-1 auctions). Auction winners must be available to operate if called in times of system stress. Failure to respond when called results in penalties worth 1/24th of the clearing price applied per MW for under-delivery in each settlement period with a cap of 200% monthly contract value and 100% annual contract value. Existing plant can get contracts for one year, or three for plant that carries out upgrades. New generation capacity can get 15 year contracts via T-4 auctions. Auctions pay as clear (i.e everyone gets the clearing price).

The most recent auctions have seen a strong rise in pricing and battery projects are taking advantage of this with 107 battery units with 1.1GW of derated capacity winning contracts in the T-4 auction, the majority of which were new projects. While 2.7GW of new CCGTs have been added this is below what might have been expected.

Capacity market auction results

Auction	Start	End	Price	Capacity
2014 T-4	Oct-18	Sep-19	19.40	49,258.94
2015 T-4	Oct-19	Sep-20	18.00	46,353.57
2016 T-4	Oct-20	Sep-21	22.50	52,425.30
2017 T-4	Oct-21	Sep-22	8.40	50,415.40
2019 T-3	Oct-22	Sep-23	6.44	45,058.83
2020 T-4	Oct-23	Sep-24	15.97	43,748.99
2021 T-4	Oct-24	Sep-25	18.00	51,981.69
2022 T-4	Oct-25	Sep-26	30.59	48,581.33
2023 T-4	Oct-26	Sep-27	63.00	43,000.96
2024 T-4	Oct-27	Sep-28	65.00	42,830.83

Source: Longspur Research, National Grid

Drax has won Capacity Market agreements for existing assets at Cruachan, the Galloway hydro and the OCGTs at Drax and for new assets for three of the OCGT projects. Compared to other storage assets, Cruachan is only minimally derated so has more availability to discharge during potential stress events.

Drax capacity contracts

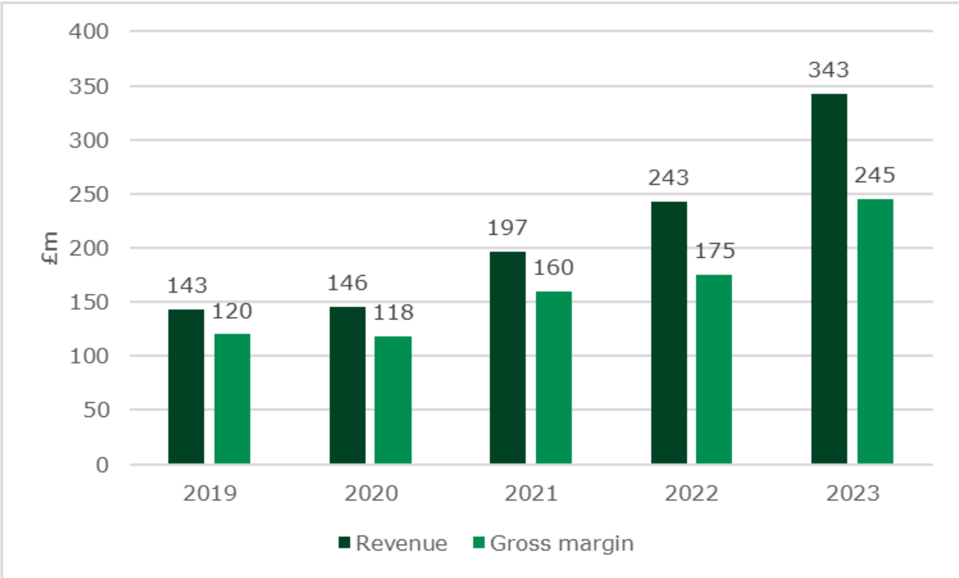
Asset	Payment period	Value £m
Pumped storage	1 year contracts (2024-2028)	68
Pumped storage	15-year contracts (2027-2042)	221
Hydro	1 year contracts (2024-2028)	17
OCGTs	15-year contract (2024-2039)	275
Total existing capacity agreements		580
Potential future agreements at £35/KW		c.270
Illustrative Capacity Market Income 2024 to 2042		c.850

Source: Drax Group

HOW DRAX BENEFITS

Drax reports combined income from the balancing mechanism, ancillary services and portfolio optimisation. This shows that it is making good money from the provision of system support with FY 2023 revenue rising 41% compared to FY 2022.

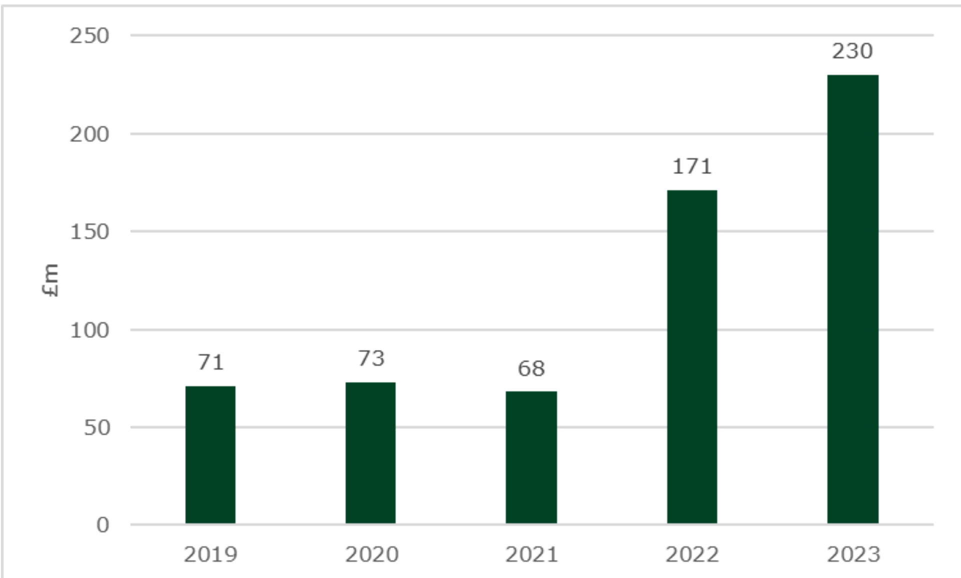
Drax system support and optimisation revenue and gross margin



Source: Drax Group

Drax also reports adjusted EBITDA for Cruachan and the hydro assets as a group and the results for 2023 are strong. We have already seen that theoretical storage spread for Cruachan falling back from the exceptional levels of 2022. But with strong ancillary services income and some hedging the company has reported FY 23 adjusted EBITDA of £230m. We see this as a signal that these assets benefit from more than just the straight trading spread and in particular are benefiting from the location of Cruachan within the GB grid.

Drax hydro adjusted EBITDA

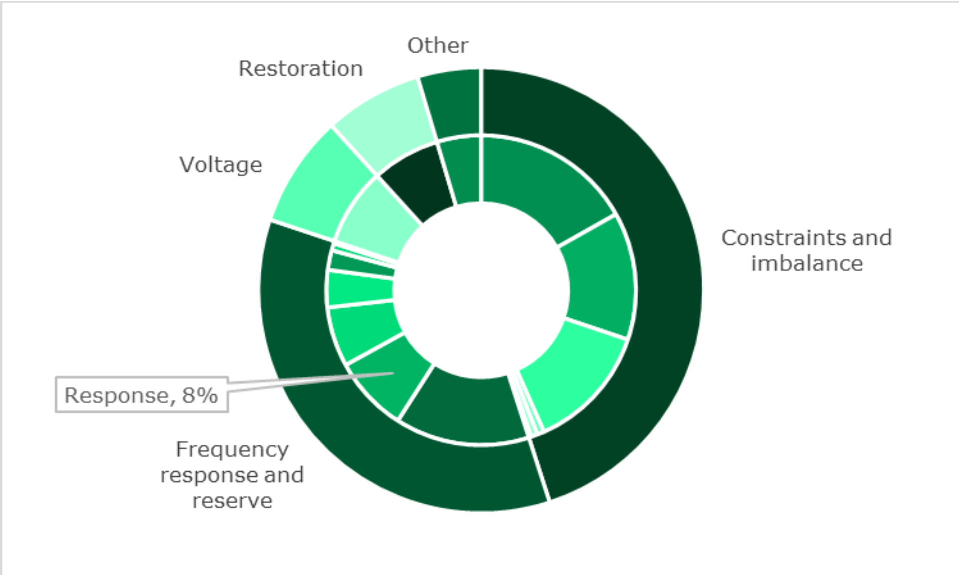


Source: Drax Group

Short duration storage issues not affecting Drax

The storage and by extension the flexibility market feels weak given the very public poor performance of some of the battery investment trusts active in the UK market. Both Gresham House Energy Storage Fund (GRID LN) and Harmony Energy (HEIT LN) have postponed dividend payments. This is as a result of lower income from BM and power trading but mainly from lower pricing in certain ancillary services markets. This latter is from pricing in the three Dynamic Services markets for frequency response. These represent a small part of the overall ancillary services market and one where lithium ion batteries have dominated. They are a small part of the response range of services which itself only represents 8% of balancing spend. We think that batteries are not as much of a threat in other areas of the ancillary services market due to limitations such as asynchronous supply. Additionally, the weakness in trading is really only weak in comparison to 2022. We still see good pricing in the spreads in 2023 and expect these to improve going forward.

Response is just 8% of balancing costs



Source: National Grid

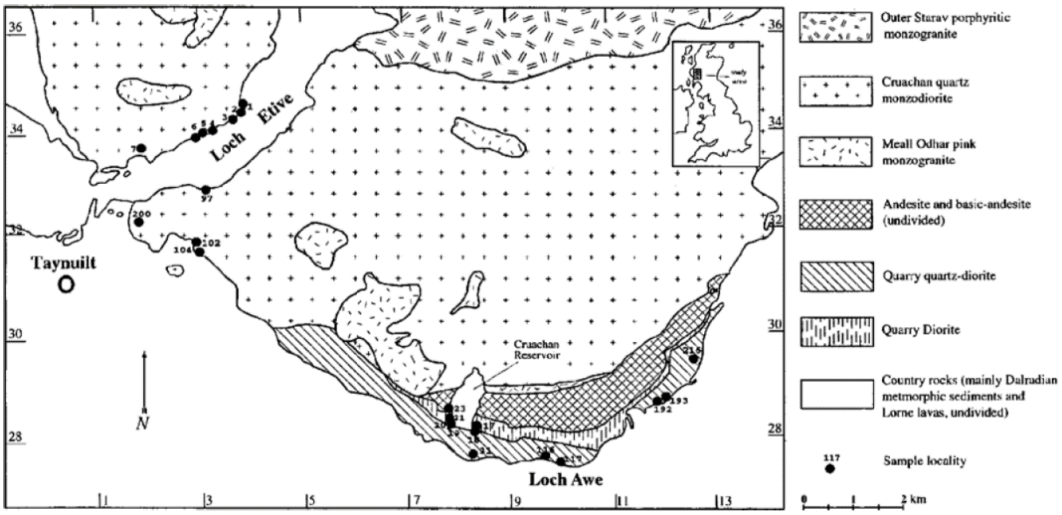
We think it is clear that it is in other less competitive parts of this market where Drax is benefiting, and we think that our analysis of market development means these areas will continue to be strong drivers of income for Drax.

ASSET EXPANSION – CRUACHAN – AND LDES POLICY SUPPORT

Given the opportunities for flexible responsive power it therefore makes sense for Drax to look at investing in expanding Cruachan. By developing here cost can be lower than a greenfield storage asset and the site is more likely to achieve planning giving the existing development. That said planning has been successful for the arguably more challenging Red John project in Inverness-shire, and we see little in the way of planning issues at Cruachan.

One area that could be seen as risky is that of tunnelling. This can be a major source of risk for hydro projects and investors may remember the tunnel collapse experienced by SSE at their Glen Doe PHS project in 2009. However, there are some important distinctions. The Glen Doe tunnel route was through a series of pre-Cambrian, folded and faulted, metamorphosed mudstones and sandstones. It was crossed by a major geological fault, the Conagleann Fault Zone and this is where the collapse occurred. By contrast, Cruachan is situated in the Etive Granite Complex with the tunnel route running through hard igneous quartz-diorite. It runs to well to the north of the Pass of Brander Fault.

Cruachan geology



Source: Tabriz University

Drax's expansion at Cruachan will benefit from policy support currently under consultation. The UK's Department of Energy Security and Net Zero (DESNZ) has issued its consultation paper in January following earlier consultation and this confirms the provision of support on a cap and floor basis. This is largely as expected although there had been some speculation last year that there might be no floor price, potentially limiting the attractiveness of support. The new consultation will look to support existing technologies offering at least 100MW of power and over 6 hours of storage as well as support for novel long duration storage technologies.

The cap and floor support mechanism acts allows projects to trade in the electricity market but where prices fall below the floor a top up subsidy is provided and where prices rise above the cap, a repayment is made. In this case the price will be the gross margin, defined as dispatched revenue less cost of charging. This provides a degree of return certainty helping to overcome barriers to investment such as high upfront capital costs, long lead times and uncertain market signals. The cap and floor approach has already been successfully used to support investment in electricity interconnectors. Notably this consultation supports participation in other markets including the capacity market, balancing mechanism and system support markets.

VALUATION AND FORECASTS

As we have seen Drax has shown growing revenue from balancing services, ancilalary services and portfolio optimisation. While it is difficult to forecast a lot of these revenues we can make a reasonable estimate over the next two years by looking at the ESO forecast for balancing costs.

If we look at the actuals and forecasts for balancing costs we can see that as a proportion of this spend, Drax has increased its share from 8% to 12% with a dip to 6% in between. If we take the average across this period we can see that Drax should be able to maintain a share of 8% with an annual revenue in ancillary services of at least £230m per annum. We would expect this to be a realistic base level going forward and to be improved upon as the market becomes more stressed in the second half of the decade.

Drax system support and optimisation revenue

	2020a	2021a	2022a	2023a	2024e	2025e
System balancing costs	1791	2652	4183	2826	3001	2939
Drax system support revenue	146	197	243	343	234	224
Implied share of revenue	8%	7%	6%	12%	8%	8%

Source: Longspur Research, Drax Group, National Grid

In hydro we note the strong performance at the full year but again see the spread remaining relatively intact going forward as the price duration curve shows more periods with low pricing and peak prices rise with greater scarcity. However, we assume that he introduction of a cap and collar price control will stabilise EBITDA at around the current level and we keep this flat in real terms.

In the near term the share of income from these two sources is in line with our current forecasts which we had already increased in January (Government Consults on Biomass, Longspur Research, 18 January 2024). However, post 2027 we see our assumptions above leading to even higher EBITDA than our current forecasts with hydro and ancillary services making a greater relative contribution against lower income in biomass.

VALUATION IMPACT

Our forecast changes increases our central case valuation to 1,077p from 1,018p. Perhaps more interestingly it sees a higher low case valuation if we assume weak support for biomass. In fact if biomass did not get a sufficient return to continue operating its closure would have the effect of increasing returns at Drax's remaining assets as balancing costs would be likely to rise. While we do not think this would entirely offset the loss of the biomass units it would support a better worst case scenario.

Our valuation cases use a WACC of 8.1% reflecting a continued higher interest rate environment and led by recent regulatory costs of capital considerations as summarised by the UK Regulators' Network.

Valuation Scenarios

p per share	Incremental	Cumulative
Existing assets	926	926
Pellet expansion – central case	89	1015
CCS on two UK units	62	**1077**
Cruachan expansion	75	1152
Global BECCS – high case	131	**1283**

Source:Longspur Research

RISK

The key risks to our valuation are driven by potential policy changes, competition and commodity price risk. Policy risk includes the biomass, BECCS and long duration storage consultations currently underway. We see the signs on these as potentially positive for Drax by creating certainty of income for these activities. Competition always exists but Drax has a strong position both in the UK power market and as a global first mover in BECCS. Commodity price volatility is a big driver of forecasts and there is two-way risk here with positive as well as negative changes possible.

FINANCIAL MODEL

Profit and Loss Account

£,000, Dec	2022a	2023a	2024e	2025e	2026e	2027e
Turnover						
Bioenergy generation	7,074	6,432	4,263	4,153	3,502	3,398
Pumped storage and hydro	284	355	278	224	247	285
B2B Energy Supply	4,143	4,958	3,015	3,229	3,458	3,703
Pellet production	803	822	774	795	898	1,166
Central, int gp and depn	-4,145	-4,725	-2,874	-3,077	-3,295	-3,529
Total turnover	8,159	7,842	5,457	5,324	4,809	5,024
EBITDA						
Bioenergy generation	508	703	670	731	392	478
Pumped storage and hydro	171	230	152	105	132	159
B2B Energy Supply	26	72	41	45	49	53
Pellet production	134	89	105	107	139	246
Central, int gp and depn	-369	-312	-355	-375	-364	-366
Operating profit	469	782	613	613	349	570
P&L Account	**2022a**	**2023a**	**2024e**	**2025e**	**2026e**	**2027e**
Turnover	8,159	7,842	5,457	5,324	4,809	5,024
Operating Profit	469	782	613	613	349	570
Investment income	0	0	0	0	0	0
Net Interest	-64	-116	-88	-69	-57	-56
Pre Tax Profit (UKSIP)	405	665	526	544	292	514
Goodwill amortisation	0	0	0	0	0	0
Exceptional Items	-327	131	0	0	0	0
Pre Tax Profit (IFRS)	78	796	526	544	292	514
Tax	-67	-196	-169	-170	-65	-121
Post tax exceptionals	72	-40	0	0	0	0
Minorities	3	1	0	0	0	0
Net Profit	85	562	356	375	227	394
Dividend	-80	-88	-97	-107	-117	-129
Retained	5	474	259	268	109	265
EBITDA	709	1,009	881	899	641	862
EPS (p) (UKSIP)	85.06	119.56	90.46	95.13	57.60	100.01
EPS (p) (IFRS)	21.25	142.80	90.46	95.13	57.60	100.01
FCFPS (p)	25.20	121.72	72.81	91.41	59.89	157.90
Dividend (p)	21.00	23.10	25.40	27.90	30.70	33.80

Source: Company data, Longspur Research estimates

KEY POINTS

- Pricing drops revenue in FY 24 but profitability remains
- Net interest balanced between cashflow and capex
- Higher tax due to windfall tax in FY 23 and FY 24, lower in FY 25 as pricing starts to normalise
- Dividend remains covered throughout

Balance Sheet

£,000, Dec	2022a	2023a	2024e	2025e	2026e	2027e
Fixed Asset Cost	4,482	5,022	5,402	5,708	6,037	6,140
Fixed Asset Depreciation	-2,094	-2,322	-2,590	-2,876	-3,168	-3,460
Net Fixed Assets	2,388	2,701	2,812	2,832	2,869	2,679
Goodwill	424	417	417	417	417	417
Other intangibles	142	82	82	82	82	82
Investments	145	131	131	131	131	131
Stock	536	621	432	421	381	398
Trade Debtors	1,227	977	680	663	599	626
Other Debtors	1,294	733	783	833	833	833
Trade Creditors	-1,528	-1,540	-1,071	-1,045	-944	-986
Other Creditors <1yr	-1,013	-252	-252	-252	-252	-252
Creditors >1yr	-877	-624	-624	-624	-624	-624
Provisions	-59	-79	-74	-70	-66	-61
Pension	0	0	0	0	0	0
Capital Employed	2,680	3,166	3,315	3,388	3,426	3,242
Cash etc	238	380	477	100	166	615
Borrowing <1yr	67	289	289	289	289	289
Borrowing >1yr	1,527	1,272	1,260	690	683	684
Net Borrowing	1,356	1,183	1,072	878	806	358
Share Capital	48	49	49	49	49	49
Share Premium	433	441	441	441	441	441
Retained Earnings	194	666	925	1,193	1,303	1,567
Other	636	814	814	814	814	814
Minority interest	13	12	12	12	12	12
Capital Employed	2,680	3,166	3,315	3,388	3,426	3,242
Net Assets	1,324	1,983	2,242	2,510	2,619	2,884
Total Equity	1,324	1,983	2,242	2,510	2,619	2,884

Source: Company data, Longspur Research estimates

KEY POINTS

- Working capital remains comfortable across period
- Goodwill increases in FY 21 with pellet acquisition
- Net debt rises with acquisition and then drops with cashflow
- Sale of OCGTs reduces net debt further in FY 26

Cashflow

£,000, Dec	2022a	2023a	2024e	2025e	2026e	2027e
Operating profit	469	782	613	613	349	570
Depreciation	239	228	268	286	292	292
Provisions	-29	-4	-4	-4	-4	-4
Other	14	-6	0	0	0	0
Working capital	-374	112	35	-9	98	-69
Operating cash flow	320	1,111	912	885	735	789
Tax paid	-39	-180	-196	-169	-170	-65
Capex (less disposals)	-173	-430	-429	-356	-329	-103
Investments	-8	-22	0	0	0	0
Net interest	-74	-95	-88	-69	-57	-56
Net dividends	-79	-86	-88	-97	-107	-117
Residual cash flow	-52	298	111	194	72	448
Equity issued	1	-141	0	0	0	0
Change in net borrowing	187	-174	-109	-194	-72	-448
Adjustments	-136	18	0	0	0	0
Total financing	52	-298	-109	-194	-72	-448

Source: Company data, Longspur Research estimates

KEY POINTS

- Working capital negative in FY 23 but some reversal further out
- Capex slightly down in FY 20 as signalled by company
- Sale of OCGTs in FY 26 reflected in capex
- Further capex on pellet business expansion
- Windfall tax outflows in FY 24 and FY 25

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