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ENERGY RESEARCH

Out of gas?

The role and potential business models for CCS and hydrogen conversions in Net Zero

For press - **CONFIDENTIAL**

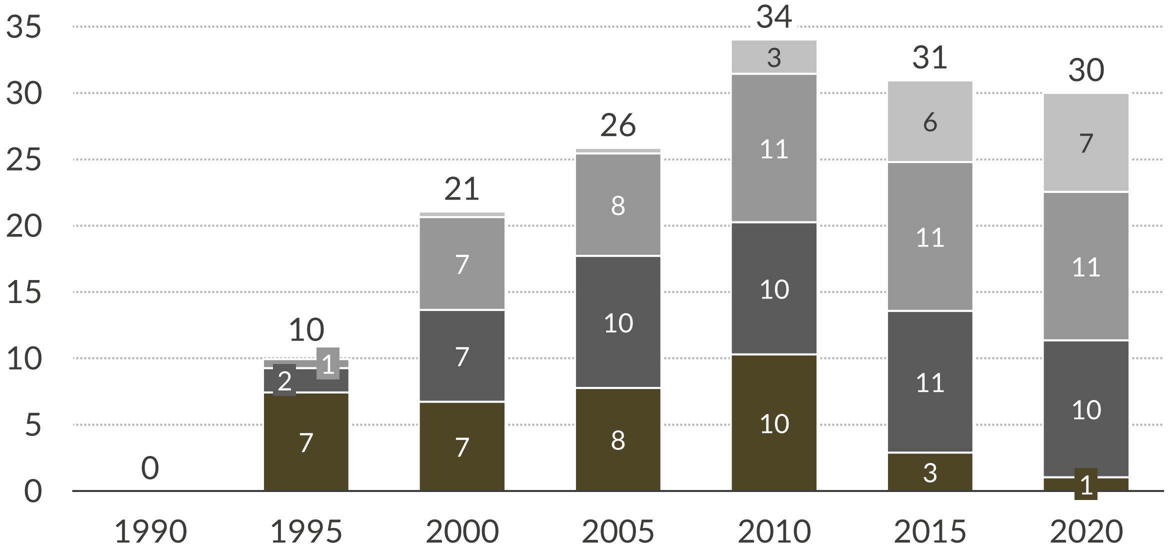
Agenda

Transforming the GB power sector, the “dash for gas” saw over 30 GW of CCGTs installed, resulting in a coal to gas switch between 1990 – 2010

1 From zero installed CCGT capacity in 1990, over 30 GW of capacity was deployed by 2010 in the “dash for gas”…

Installed CCGT capacity[1]

GW



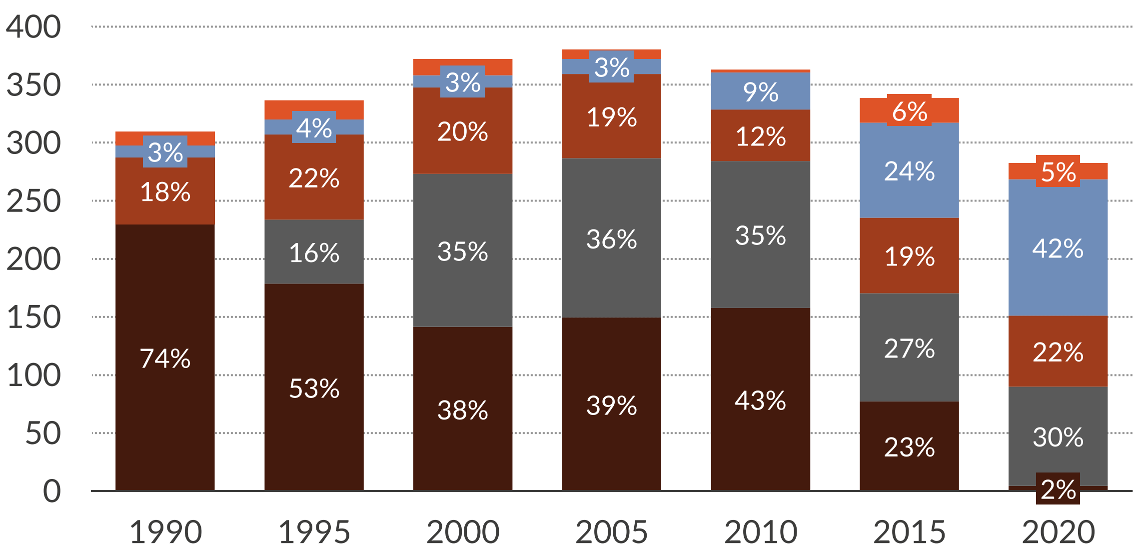
- Started by the legalisation of gas a fuel for power generation, the 1990s and early 2000s saw newly privatised utilities deploy over 30GW of CCGTs.
- By 2010, over 20 GW of CCGTs were deployed with the majority falling below 52% HHV, followed by a further 15 GW between 2000-2010 at efficiencies above 52% HHV
- The last CCGT commissioned in this period was Carrington in 2016, which had obtained financial close prior to the introduction of the Capacity Market in 2014.

High-merit[2] Mid-merit[3] Low-merit[4] Unknown merit

2 … resulting in CCGT generation reaching 137 TWh (36% of total) in 2005 mostly at the expense of coal, while generation has declined in recent years

Electricity supplied

TWh



- Coal was the backbone of the GB electricity system producing 74% of total GB electricity in 1990.
- The deployment of CCGTs largely displaced coal with the gas share of generation peaking at 36% in 2005.
- Driven by the Government’s decarbonisation agenda, the introduction of the CPS and EU ETS largely wiped out coal generation, whilst subsidised renewable deployment since 2010 has taken a significant share off both gas and coal.

Net Imports Renewables Nuclear Gas Coal

1) Also includes CHP plants. 2) High-merit is >52.5% HHV efficiency. 3) Mid-merit is 50-52.5% HHV efficiency. 4) Low-merit is <50% HHV efficiency.

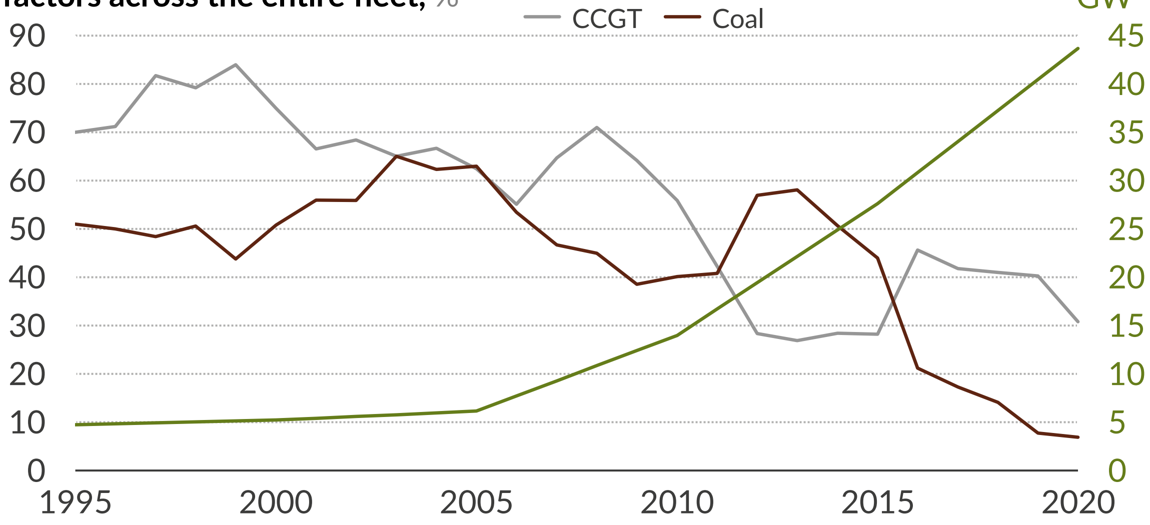
Sources: Aurora Energy Research, BEIS

CCGT load factors and spreads remained favourable throughout the 1990s and 2000s, but have declined in the last decade due to the growth in RES

1 **CCGT load factors remained between 60-80% in the 1990s and 2000s, and have been increasingly pushed out of merit by renewables since 2010**

Average annual CCGT and Coal load factors across the entire fleet, %

Installed renewable capacity, GW



2 **Clean spark spreads averaged between £10-20/MWh until 2010 (although lower than dark spreads), but have fallen to below £10/MWh in recent years**

Average annual clean spark and dark spreads
£/MWh

- CCGT economics were favourable for the first two decades after 1990 with load factors remaining above those of coal at between 60-80%, while spreads remained high but lower than coal's
- Before the introduction of the Carbon Price Support in 2013, gas economics were less competitive than that of coal, with gas profitability seeing a significant deterioration between 2010 – 2015
- The introduction of the CPS favoured more efficient CCGTs to less efficient coal assets. Consequently, the CCGT fleet saw an improvement in economics post 2013, although this was in part mitigated by the rise in renewables
- CCGT economics look challenging moving forward with the growth in RES set to continue in the coming decades while at the same time CCGTs will see competition grow from other forms of flexible technologies such as gas-peakers and batteries

1) Spark spreads calculated assuming HHV thermal efficiency of 49.13%. 2) Dark spreads calculated assuming HHV thermal efficiency of 35%. 3) In 2012, a 35% HHV coal plant variable costs where £8/MWh below those of a typical 49.13% HHV CCGT. However, with the introduction of the CPS in 2013 carbon prices increased from £6/tCO_2 to £22/tCO_2, and by 2016 gas generation was ~£10/MWh cheaper than coal.

Sources: Aurora Energy Research, BEIS, National Grid.

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I. Historical performance of gas assets in GB and future outlook

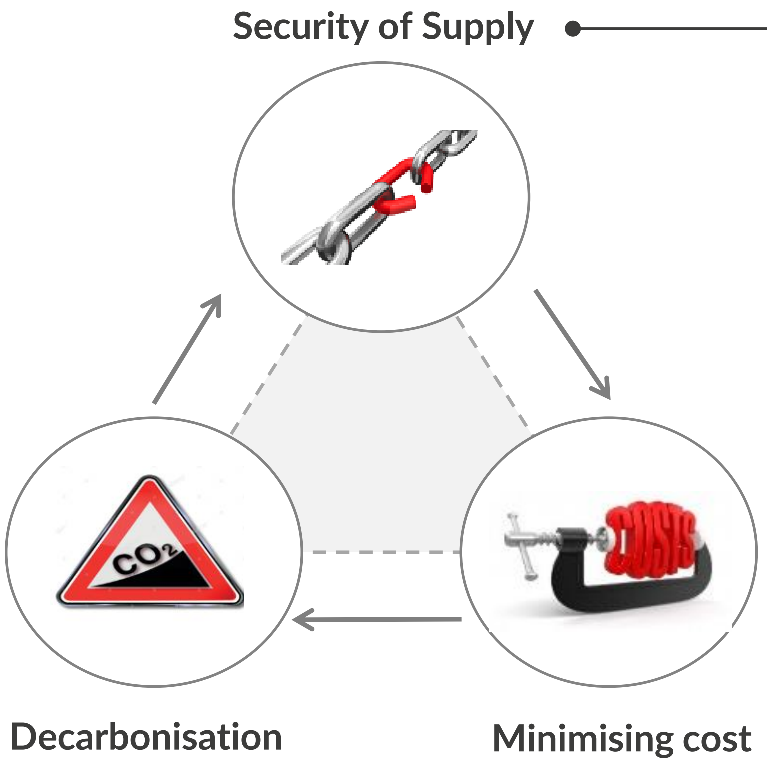
II. Ensuring security of supply in a Net Zero power system

III. Potential business models for gas assets in Net Zero

IV. Considerations for policymakers and investors

Whilst there are clear answers to decarbonising our energy mix, maintaining security of supply will become increasingly challenging

UK energy policy aims to meet three overarching objectives, often referred to as the 'energy trilemma'. Of the three, ensuring energy security is expected to be most challenging in a Net Zero world and will have several key requirements.



1 Firm Capacity

- Energy security is guaranteed by ensuring adequate power capacity is available during peak times from a variety of technologies.

2 Flexible Capacity

- Capacities that are able to ramp up rapidly will also be required to guarantee energy security as more intermittent renewable capacity comes on the system. This could see output vary significantly between settlement periods necessitating fast ramping capacities and increasing the need for balancing actions.

3 Frequency Response and Inertia

- Deviations in system frequency can be detrimental to the grid resulting in blackouts. Inertia is critical to prevent sharp movements in system frequency, making the grid resilient to energy imbalances.
- Frequency response is equally essential to counteract sharp deviations if they occur. This is mitigated by generators that are able to react instantaneously to changes in system frequency by ramping generation up or down.

4 Voltage

- It is essential to keep the voltage on the grid stable to prevent damage to grid infrastructure and blackouts. Maintaining grid voltage is dependent on reactive power and Short Circuit Levels which can come from a variety of assets and technologies.

Sources: Aurora Energy Research

As demand increases from higher levels of electrification, the need for firm capacity to maintain system security will increase

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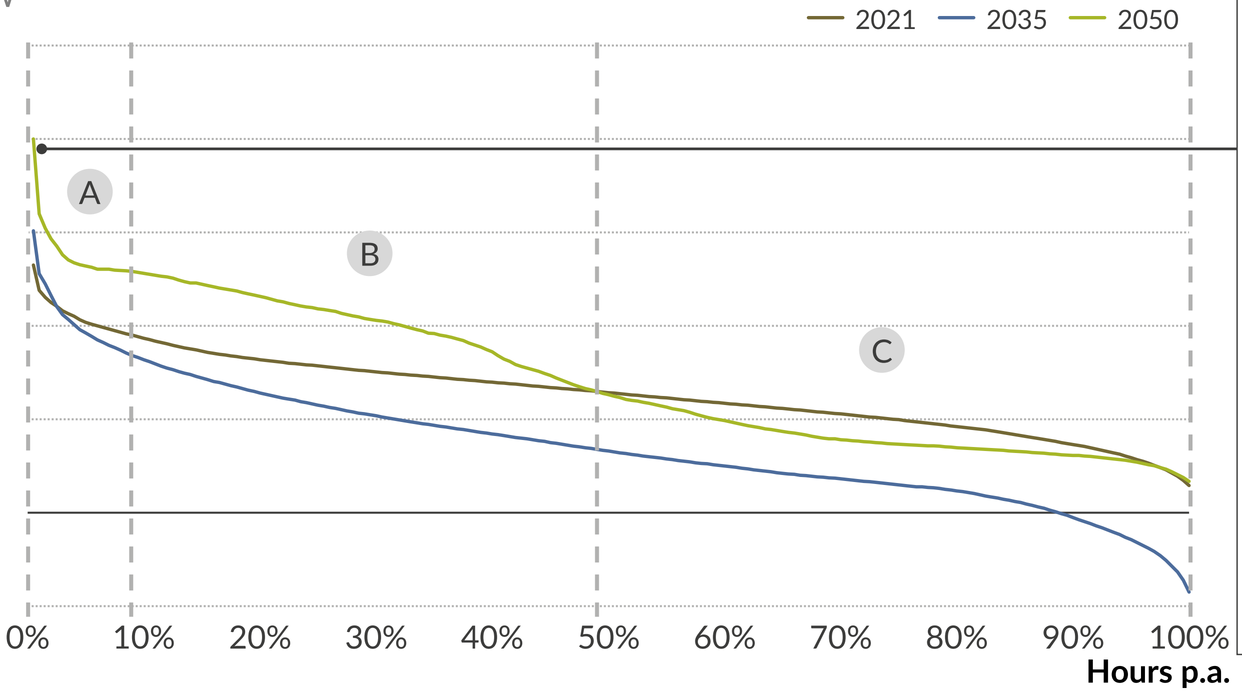
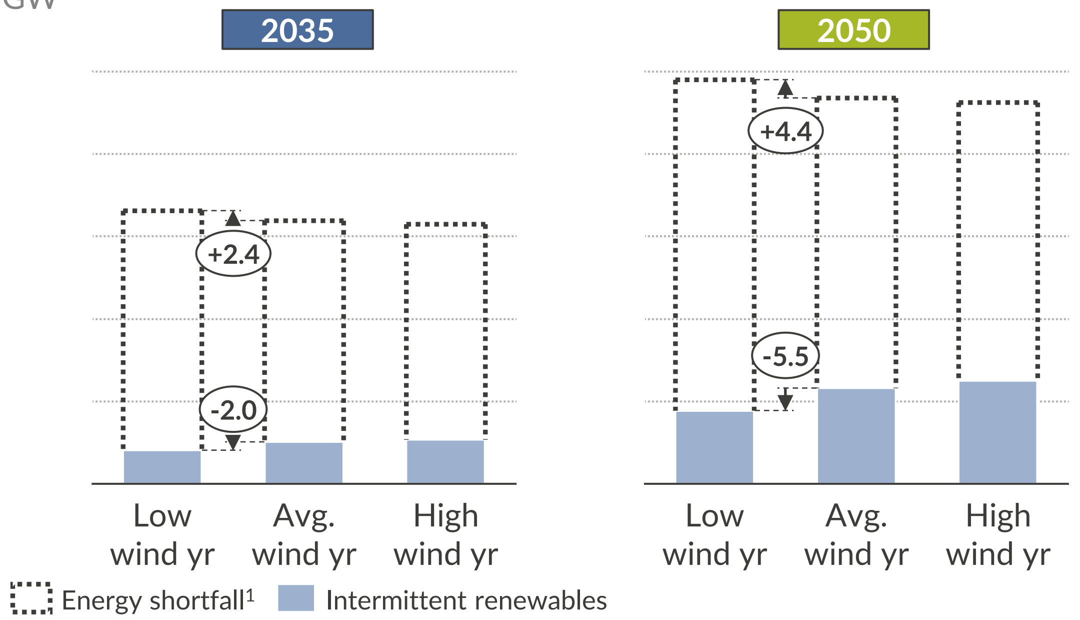
Energy shortfall from renewables in Aurora Net Zero[1]
GW



Average hourly demand and renewables generation in 20 tightest periods
GW



- The growth in renewable capacity lowers the need for thermal generation, while the need for firm capacity remains high for security of supply due to increased levels of electrification. Relative to 2021, the following is observed on the residual load curve (energy shortfall from renewables) towards 2050:
  - A **Increased need for peaking capacities** (<10% load factor) as increased electrification increases demand the most during the average cold spell periods
  - B **Increased need for low-mid merit baseload assets** (with load factors between 15-50%) also due to higher demand[2]
  - C **Reduced need for high merit assets** (with load factors in excess of 50%) as surplus low carbon power becomes available
- Procuring security of supply requirements will become increasingly challenging due to varying weather outcomes which affects both demand (due to temperature) and renewables output. Relative to an average year, a low wind year in 2050 would see the requirements for residual load increase by 9.9 GW, due to a dip in wind output during peak periods of 5.5 GW and an increase in demand of 4.4 GW

1) Shown as the difference between demand and generation from intermittent renewables, i.e. solar PV and wind. 2) However, in 2035 relative to 2021 the need for low-mid merit baseload assets is lower due to higher availability of low carbon power relative to demand.

Sources: Aurora Energy Research

Firm capacity will need to be flexible to supplement the intermittency of renewables, however current storage technologies cannot fulfil this alone

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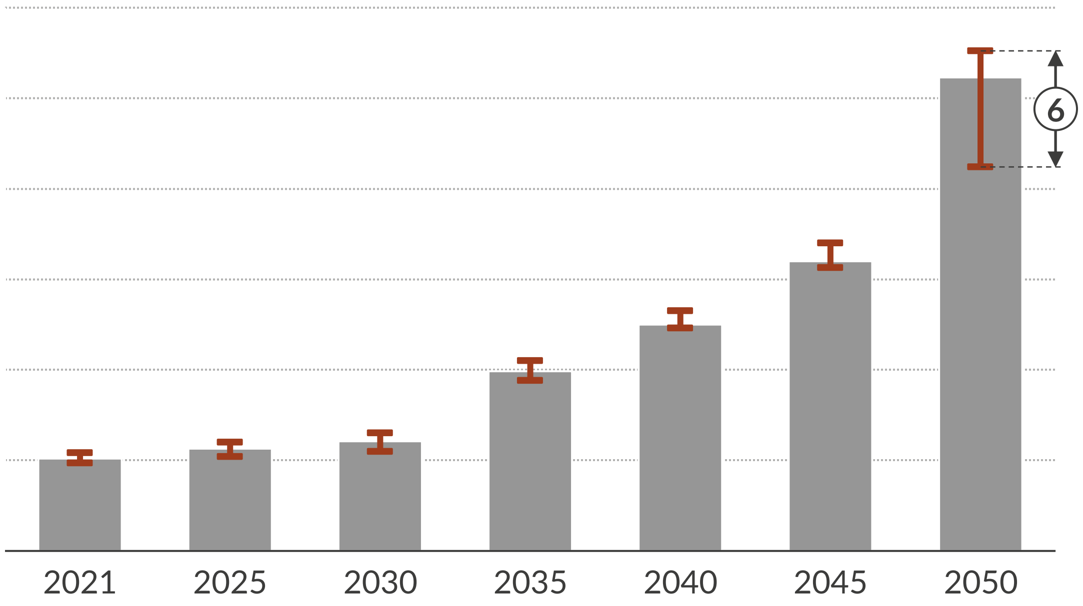
1 **The need for fast-ramping generation increases by over 20 GW from now until 2050 as supply volatility increases with the buildout of renewables …**

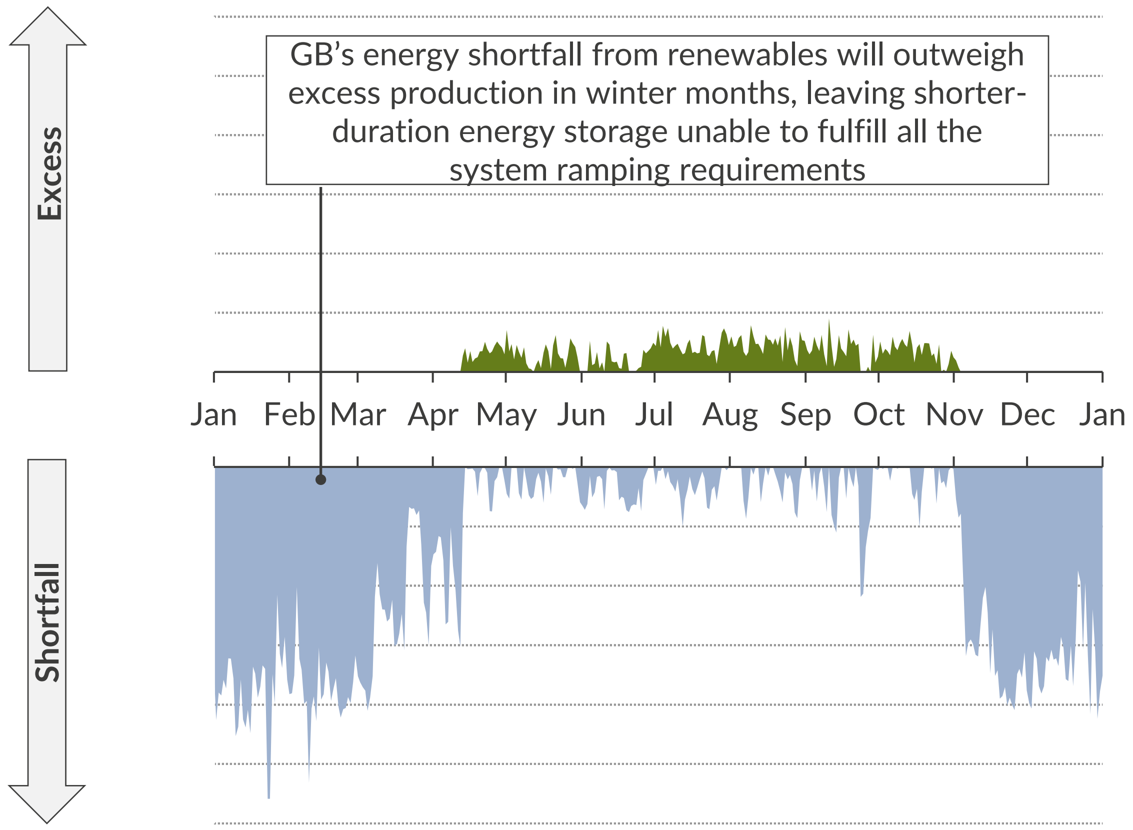
System maximum ramping requirements[1,2]
GW/hour



- The growth of renewables will necessitate a higher buildout of faster-ramping generation as intermittent renewables can experience sudden shifts in output between consecutive hours
- By 2050, renewable output between two consecutive hours can fluctuate by up to 26 GW (up from 5 GW in 2021). However, this can also depend on weather outturns, where deviations in wind profiles could result in differences in requirements of ~6 GW

2 **… however, batteries alone cannot fulfil total energy requirements, particularly in winter months when solar output is low**

Daily excess and shortfall from renewables in 2050[1,3]
GWh



1) Shown for Aurora Net Zero. 2) Difference in residual demand from one half-hour to the next. Residual demand is calculated as the difference between demand and generation from intermittent renewables. 3) Excess and shortfall are calculated as the difference between demand and production from low carbon sources including solar, offshore- & onshore wind, and nuclear.
Sources: Aurora Energy Research

A low-wind week in 2050 requires 45 GW firm capacity to fill a 3,900 GWh energy gap; short duration storage is not a cost-effective solution

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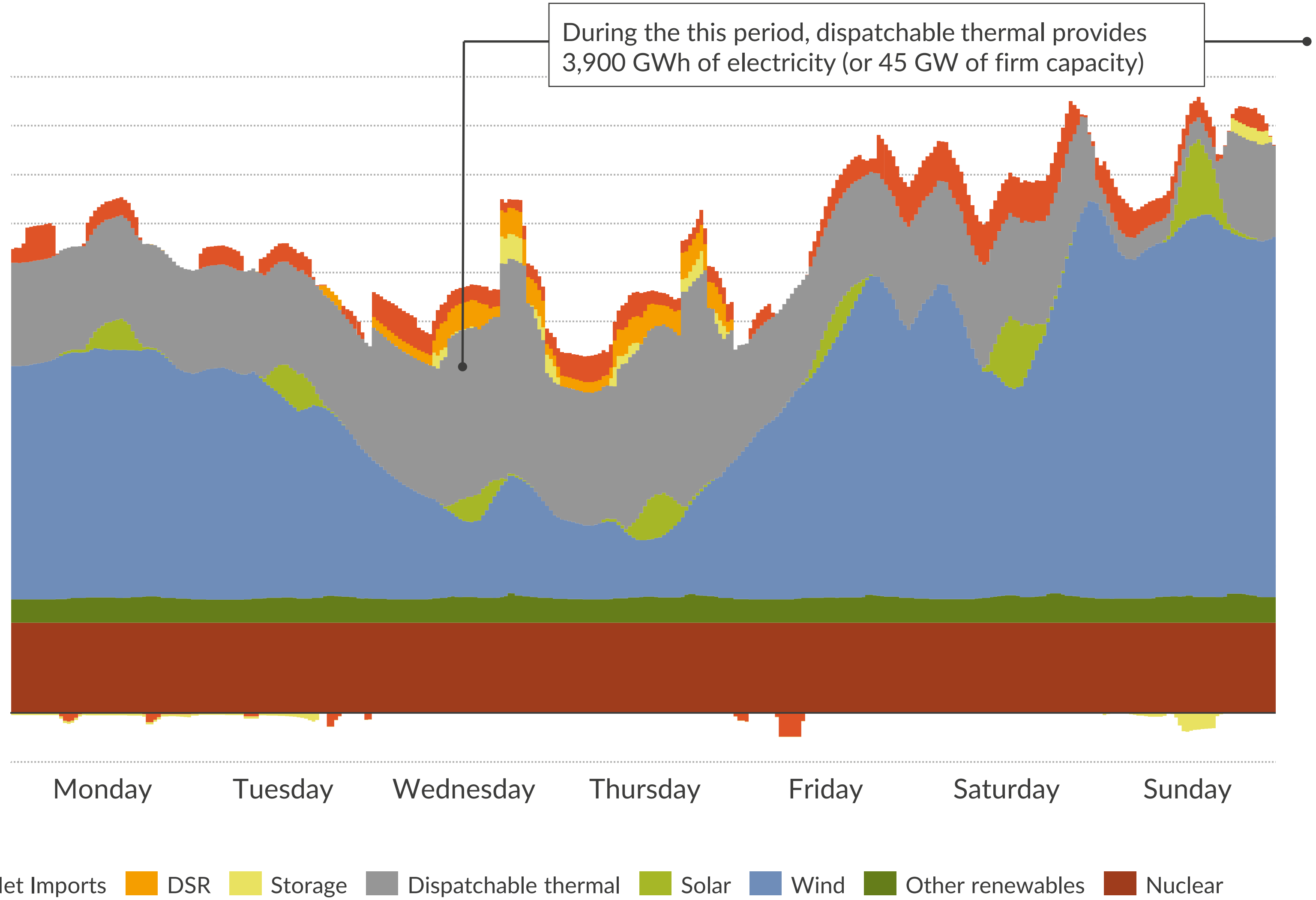
Generation over a tight week in winter in 2050
GW



1 To fill this gap of energy the following amount of storage would be required[1]:

Storage duration	GW	Plant CAPEX[2]
2-hour	1,951	£747bn
4-hour	976	£546bn

2 Alternative options to fill the energy gap and the firm capacity needs include[3]:

Wind	250	£240bn
Nuclear	44	£175bn
Combination of the following		
Wind	60	£56bn
Nuclear	5	£20bn
4-hour storage[4]	175	£98bn
Total	*240*	*£174bn*

3 While using low carbon dispatchable thermal generation requires investment below £40bn

Low-carbon dispatchable[5]	45	£38bn

1) Assumes that the storage capacity would be fully charged at the beginning of the week as during the week there are few opportunities to charge energy. 2) Only assuming the plant CAPEX and not any other associated costs needed to develop infrastructure to accommodate the additional capacities or any other costs. 3) Additional to what is already installed if non of the dispatchable thermal was installed. 4) In this example the storage would not need to be fully charged at the beginning of the week. 5) Assumes a mix of 20 GW of baseload generation such as CCS and H_2 CCGTs and 25 GW of fast ramping H_2 peakers. Sources: Aurora Energy Research

Gas assets currently provide 59% of inertia on the GB grid which keeps the system frequency stable as required

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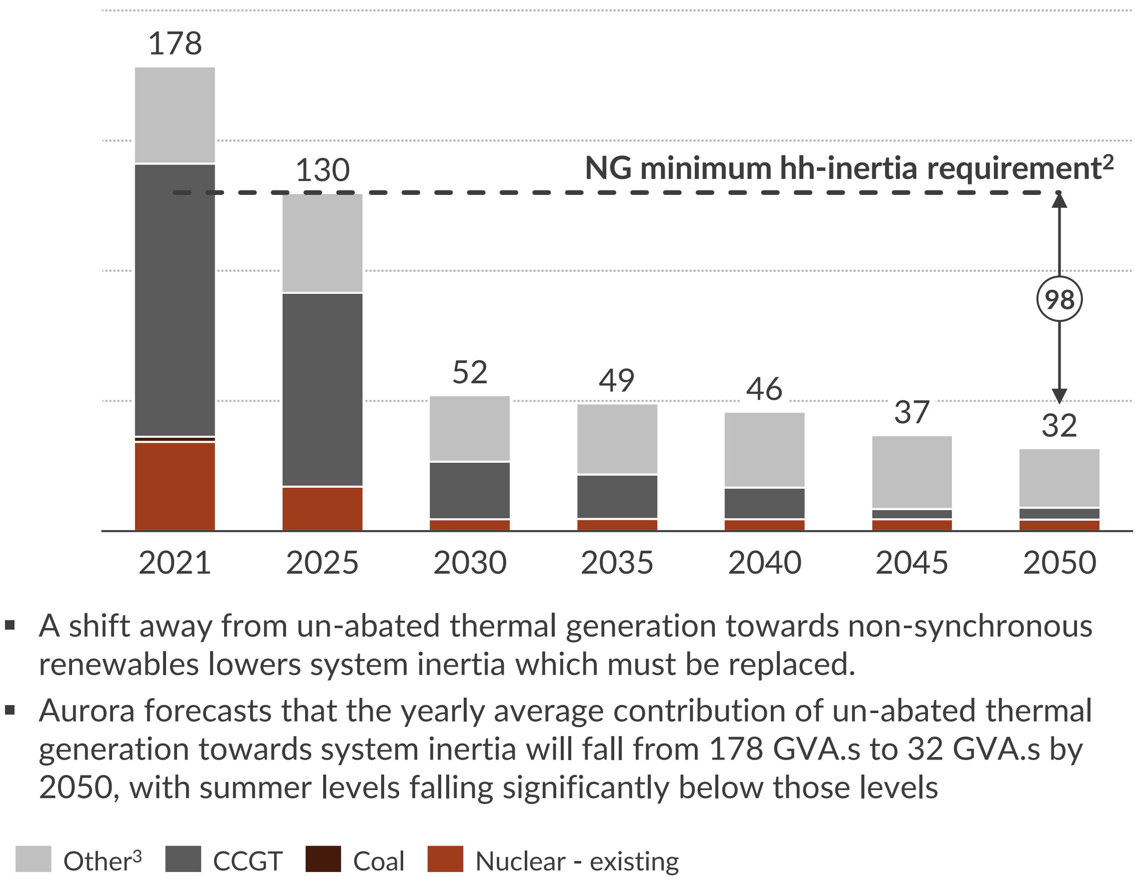
1 Inertia contribution from conventional assets is set to fall from today's level of 178 GVA.s to only 32 GVA.s by 2050, or below NG requirements

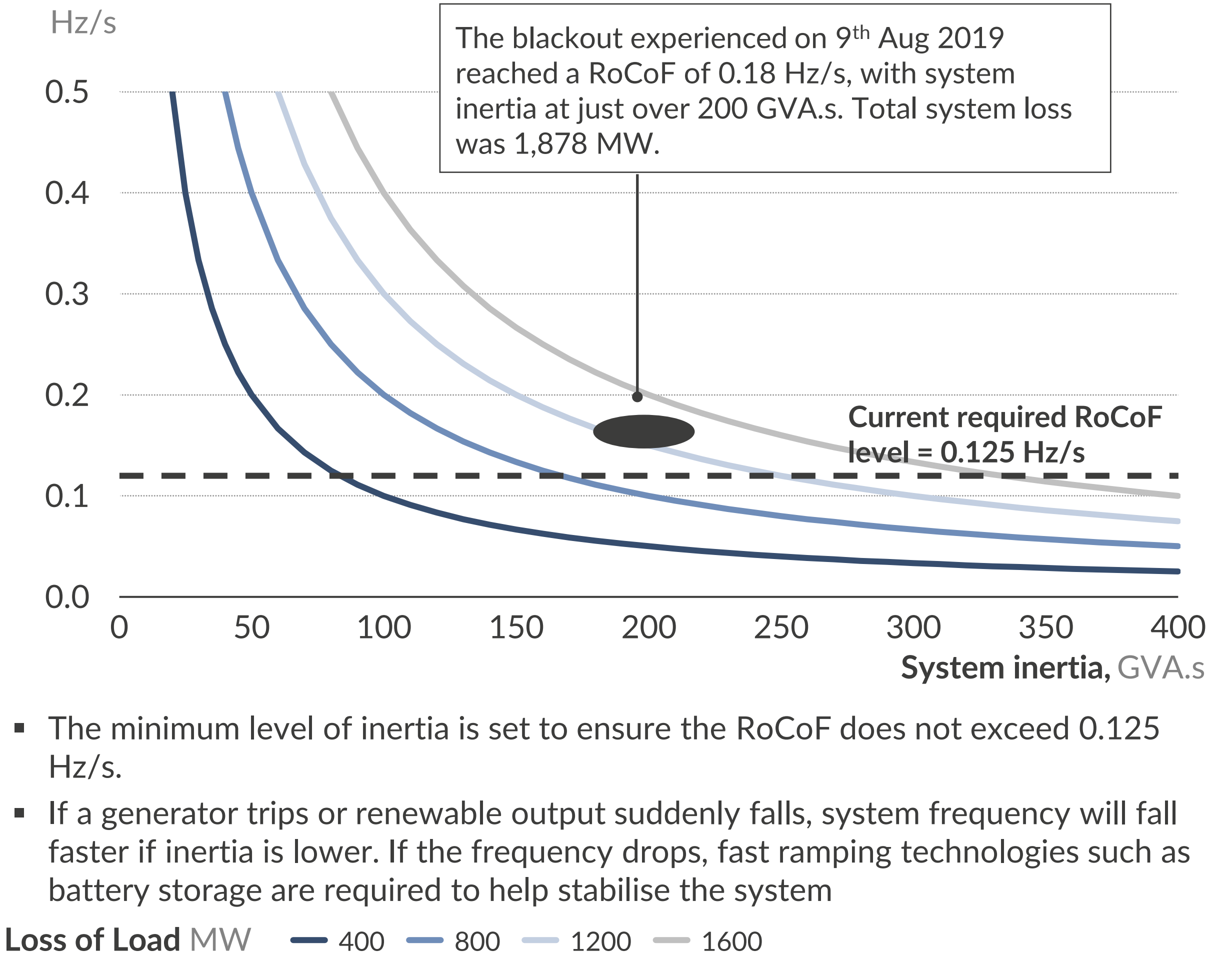
Yearly average inertia contribution from today's unabated thermal and nuclear, GVA.s[1]



- A shift away from un-abated thermal generation towards non-synchronous renewables lowers system inertia which must be replaced.
- Aurora forecasts that the yearly average contribution of un-abated thermal generation towards system inertia will fall from 178 GVA.s to 32 GVA.s by 2050, with summer levels falling significantly below those levels

2 Declining inertia results in greater rate of change of frequency (RoCoF) for a given loss size making it more difficult to manage the system

Instantaneous RoCoF
Hz/s



- The minimum level of inertia is set to ensure the RoCoF does not exceed 0.125 Hz/s.
- If a generator trips or renewable output suddenly falls, system frequency will fall faster if inertia is lower. If the frequency drops, fast ramping technologies such as battery storage are required to help stabilise the system

1) Giga Volt amp seconds. 2) National Grid has previously published that the lowest amount of inertia the system can manage at any given half-hour is 130 GVA.s. However, the system has on a few occasions already seen system inertia fall below this level. 3) Includes biomass, hydro (both pumped storage and run-of-river), and OCGTs.

Sources: Aurora Energy Research, National Grid

With renewables eroding the load factors of thermal capacities, new sources of voltage control will need to be found

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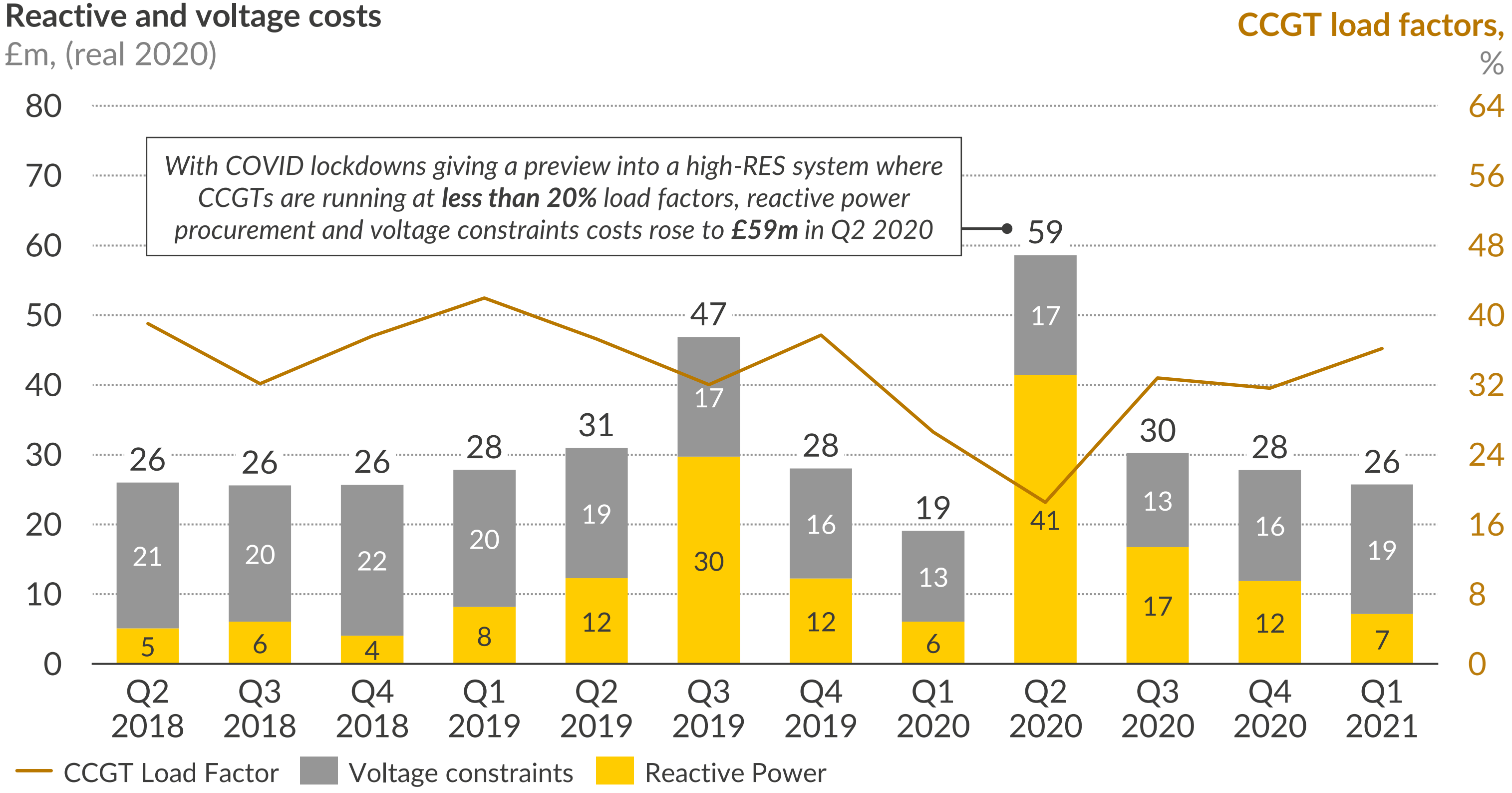
- Short Circuit Level (SCL) and reactive power are two requirements for keeping GB's voltage levels at 400 kV or 275 kV.
- This is achieved through having sufficient SCL (measured in MVA) being produced on the network which prevents voltage from fluctuating, whilst reactive power injection and absorption (measured in MVAr) are used to increase and decrease voltage levels in real-time.
- SCL and reactive power have been traditionally provided by synchronous thermal assets, however, with renewables eroding the thermal load factors and no other sources for voltage control, National grid are forced to turn up out-of-merit thermal assets via the Balancing Mechanism.
- As a result, alternative markets for voltage are currently being developed through the NOA Voltage Pathfinder.

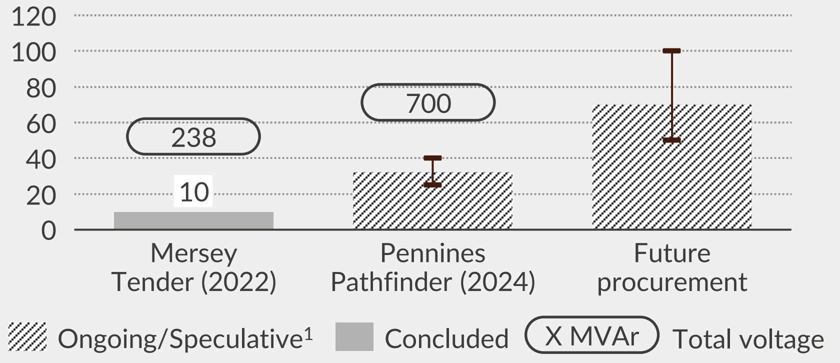
Reactive and voltage costs
£m, (real 2020)



Future System Outlook

- With CCGT load factors expected to average less than 20% towards 2050, reactive power and voltage constraint costs are expected to rise over time.
- National Grid has introduced the **NOA Voltage Pathfinder** to address system voltage issues
- This has cost £10m so far on the first Mersey Tender and is expected to cost more over the years as more thermal capacity comes offline.

Total cost of procurement, £m



1) Cost ranges estimated based on Mersey Tender trends and volumes to be procured and potential bids

Sources: Aurora Energy Research, National Grid

Gas assets remain an effective technology to maintain security of supply, however they will need to adapt to a decarbonised world

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	Nuclear		Storage		Interconnectors	Synchronous condensers	Unabated thermal gas	
	Conventional	*SMR*	*Short-duration (0.5-8hr)*	*Longer-duration (>8hr)*	*EU-wide*	*Rotating stabilisers*	*Large-scale CCGTs/CHP*	*Peakers*
Commercial readiness	**Mature**	**Nascent**	**Mature**	**Intermediate**	**Mature**	**Nascent**	**Mature**	**Mature**
Asset availability[1]	81%	Unknown	12 – 74%	95%	49 – 90%	No active power	90%	95%
Start-up time	12hr >	30 – 60 min	<0.1 min	0.1 – 10 min	<30 min	N/A	30 – 60 min	0.5 – 15 min
Synchronous generation and inertia contribution[2]	✓	✓	✗	✓	✗	✓	✓	✓
CAPEX	£4,000-5,000/kW	£3,600-4,500/kW	£250-950/kW	£600-5,500/kW	£600-700/kW	N/A	£500-600/kW	£300-450/kW
Carbon intensity	**Zero**	**Zero**	**Zero**	**Zero**	**Low**	**Zero**	**High**	**High**
Other comments	Only 20 GW of suitable sites available	Potentially large pipeline as land is not a limiting factor		Technologies can include Liquid/Compressed Air Energy Storage, Molten Salt Thermal, and Pumped storage[3]	19 GW potential capacity but limited reliability due to RES correlation in EU	Do not produce energy and will be powered by the grid	**Abatement potential exists for these assets through CCS or H_2 conversion. See Section 3 for analysis on abated thermal assets**	

1) Quantified by the de-rating factors set in the Capacity Market auctions. 2) Synchronous generation also provides reactive power and short-circuit alongside with inertia. 3) Pumped Storage is a mature technology unlike other longer duration technologies. However, pumped storage is limited by suitable sites and costs can be very site specific. Overall, GB has the potential for roughly 10 GW of pumped storage.

Sources: Aurora Energy Research, EMR, BEIS

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Thermal assets have several pathways to adapt to a Net Zero world

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Unabated gas CCGT	H_2 blend CCGT	Power CCS plant	Hydrogen CCGT	Unabated gas peakers	Hydrogen peakers
CH_4 CH_4	CH_4 H_2	CH_4 CH_4	H_2 H_2		H
Conventional gas-powered turbines	*CCGTs with hydrogen blends*	*CCGTs with carbon capture and storage*	*Hydrogen powered turbines (100%)*	*Conventional gas-powered peakers*	*Hydrogen powered OCGTs/recips*
CAPEX:	*CAPEX:*	*CAPEX[2]:*	*CAPEX:*	*CAPEX:*	*CAPEX:*
£500 - 600/kW	**£170 - 250/kW**	**£500-1,800/kW**	**£550-700/kW**	**£300-600 /kW**	**£350-600/kW**
Efficiency:	*Efficiency:*	*Efficiency[2]:*	*Efficiency:*	*Efficiency:*	*Efficiency:*
57% HHV	**57% HHV**	**44-50% HHV**	**57% HHV**	**38% HHV**	**38% HHV**
Carbon intensity:	*Carbon intensity[1]:*	*Carbon intensity[3]:*	*Carbon intensity[4]:*	*Carbon intensity:*	*Carbon intensity[4]:*
320 gCO_2/kWh	**160 - 185 gCO_2/kWh**	**20 - 25 gCO_2/kWh**	**0 - 55 gCO_2/kWh**	**480 gCO_2/kWh**	**0 - 80 gCO_2/kWh**
UK installed capacity:	*UK projects:*	*UK projects:*	*UK projects:*	*UK installed capacity:*	*UK projects:*
30 GW	**Saltend (400 MW)**	**Keadby 3 (910 MW)**	**Saltend (400 MW)**	**6 GW**	**N/A**
	Rocksavage (800 MW)	**Peterhead (900 MW)**	**Immingham (1.2 GW)**		

1) Assuming a 50% H_2 blend and reflecting range for Green to Blue H_2. 2) Range shown considers retrofits (lower end) and new builds (upper end). Assumes CCS efficiency penalty of 7 p.p. 3) Assumes capture efficiency of 95% and reflects range for retrofits (upper end) and new builds (lower end). 4) Reflects carbon intensity of production and range for Green to Blue H_2. Hydrogen is a zero emissions fuel at point of use.

Sources: Aurora Energy Research, SSE, Equinor, BEIS

Carbon Capture & Storage (CCS) systems have the potential to reduce gas plant emissions by up to 95%, however at lower efficiencies

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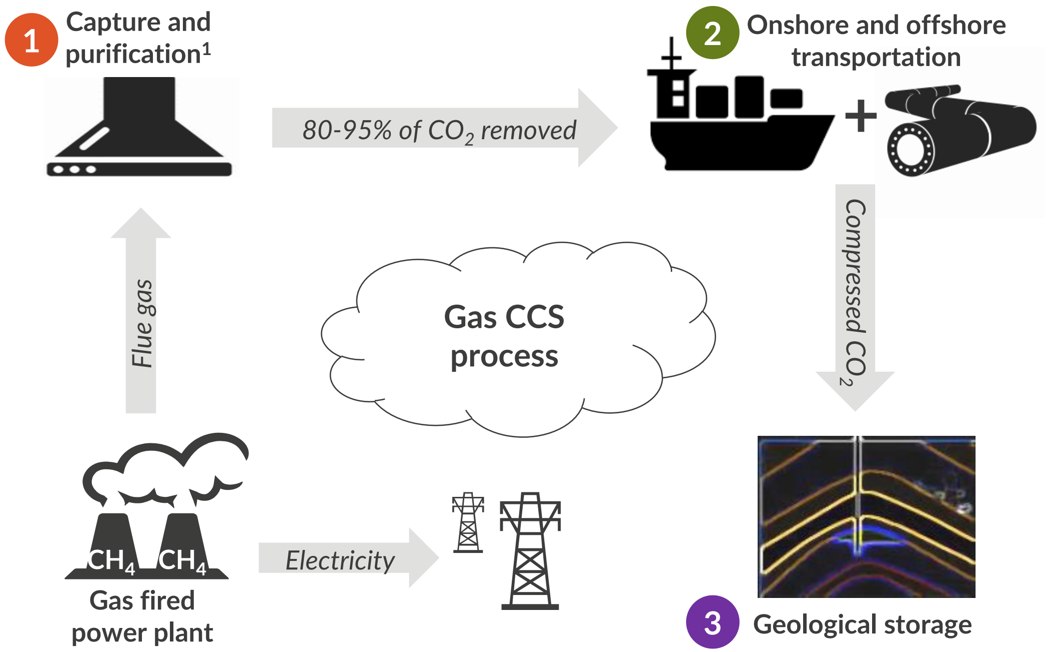
What is gas CCS?

- Power CCS plants are conventional CCGTs fitted with carbon capture and storage equipment that capture post combustion emissions which are then transported and stored in geological formations
- They provide a viable pathway for conventional thermal plants to significantly reduce their carbon emissions. However, this process has multiple steps with various downstream costs and requirements

How does it work?



1 Installation, capture and purification

- CCS can be fitted to both new or existing CCGT plants but requires additional land
- Capex ranges between **£1,100 -1,800/kW** for new builds (2-3x higher than un-abated plants at ~£550/kW) and **£500-1,000/kW**[2] for retrofitting existing plants
- CCS can capture up to **95%** of carbon emissions but with efficiency penalties[3] on CCGTs between **6-9 p.p.** and parasitic load capacity penalties[4] of about **10%.**
- The energy intensive and parasitic nature of the capture and purification process creates an efficiency and capacity penalty on unabated plant

2 CO_2 transport

- Captured and purified CO_2 needs to be compressed for transport
- With most storage sites located offshore, there are 2 phases to CO_2 transport:
  - i. Onshore: CO_2 is transported by onshore pipelines to a buffer storage location. Trucks and Rail could be used for transporting small quantities
  - ii. Offshore: CO_2 is transported either by offshore pipelines or by ship to final storage locations
- Total CO_2 transport costs vary between **£7-25/tCO_2**

3 CO_2 storage

- Compressed CO_2 is injected into geological formations for permanent storage
- A variety of geological storage options exist including deep saline aquifers and depleted oil and gas fields.
- CO_2 injection and storage could cost up to **£20/tCO_2**

1) The captured flue gas is first cooled using water then fed into an absorber where the CO_2 is bound with amines then fed into a separation unit where it is heated, and the pure CO_2 is stripped out. 2) Includes repowering costs. 3) Defined as the drop in the thermal efficiency (ratio of net electric energy output to total heat input) from the addition of a CCS unit. 4) The energy intensive nature of carbon capture technology requires a lot of extra energy limiting the plant's capacity output known as "parasitic load."
Sources: Aurora Energy Research, BEIS, Zero Emissions Platform, Global CCS Institute

For both existing and new build CCS plants to be commercially viable, proximity to CCS infrastructure is paramount

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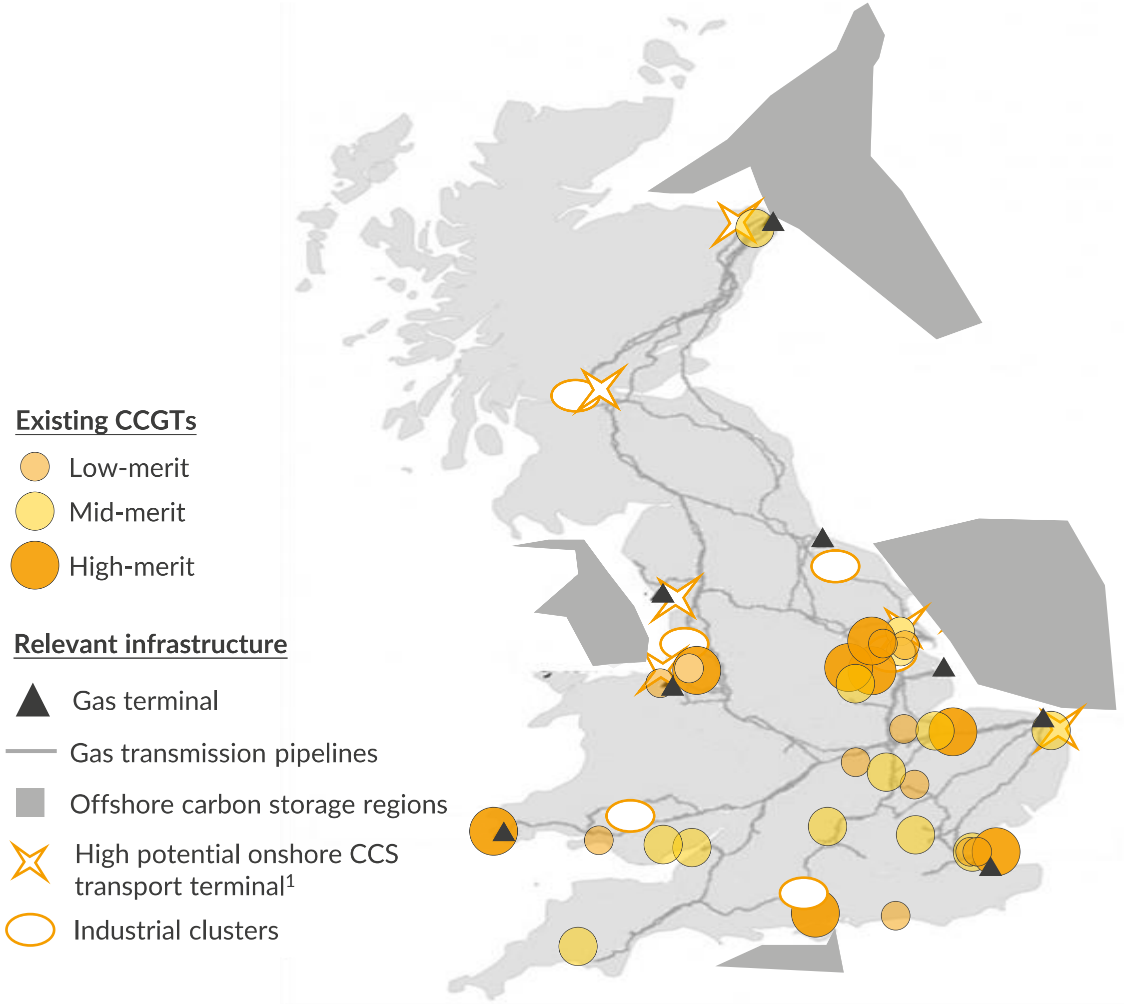
Existing CCGT and relevant infrastructure locations in UK



Developers will need to consider several key elements including:

1. **Business model and policy support** - high capital costs would be incurred to convert and deploy gas CCS, early projects will require direct support.
2. **Location** – key locational considerations exist for both new and existing plants:
   - *Proximity to potential offshore carbon storage sites* – this is key for CCS plants, as distance will determine transport and storage requirements and costs. Alternatively, proximity to ports could be beneficial due to potential development CO_2 shipping hubs.
   - *Proximity to industrial clusters* – with policy currently focused on deployment of CCS in industrial clusters, CCS plants in close proximity may benefit from potentially useful infrastructure in these clusters.
3. **Efficiency** - with CCS causing efficiency penalties between 6 - 9 p.p. on CCGTs, only high-merit plants will remain with reasonable efficiencies and new build plants will also require very high efficiencies to account for the efficiency loss.

Potential capacity for retrofitting existing CCGTs
MW

Efficiency[3] \ Location[2]	Poor location	OK location	Good location
Low-merit	930	2,220	7,990
Mid-merit	2,960	5,840	1,600
High-merit	0	3,500	5,620

The range for reasonable existing CCGT conversions lies between 8 GW to 18 GW

Rating scale Low potential – High potential

1) Hydrogen Supply Chain Evidence Base – Element Energy. 2) Locations are ranked as: Good – close proximity to offshore storage, OK – bit further inland but within 50 km of suitable storage, Poor – greater than 100km away from suitable storage. 3) Efficiencies of gas assets are ranked as: Low-merit – ≤50% HHV CCGTs, Mid-merit – 52.5% HHV CCGTs, High-merit – ≥54% HHV CCGTs.

Sources: Aurora Energy Research, Element Energy

The Government has proposed a Dispatchable Power Agreement business model for Power CCS plants

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The Government has proposed a Dispatchable Power Agreement (DPA) business model for Power CCS plants which is intended to incentivise power CCS to operate flexibly, dispatching after renewables and nuclear, but ahead of other unabated power plants. The DPA will consist of two payments:

1. **Availability payment** – to subsidise upfront capital costs
   - This payment is intended to provide investors with a regular payment based on the availability of low carbon generation capacity
   - The payment will be based on a fixed monthly Availability Payment Rate (APR), with settlement adjusted to reflect the availability of generation and availability of capture that the plant is able to achieve
   - The APR will be set through either a negotiated or competitive allocation process and contracts will be awarded for 15 years to new builds and 10 years to retrofitted plants

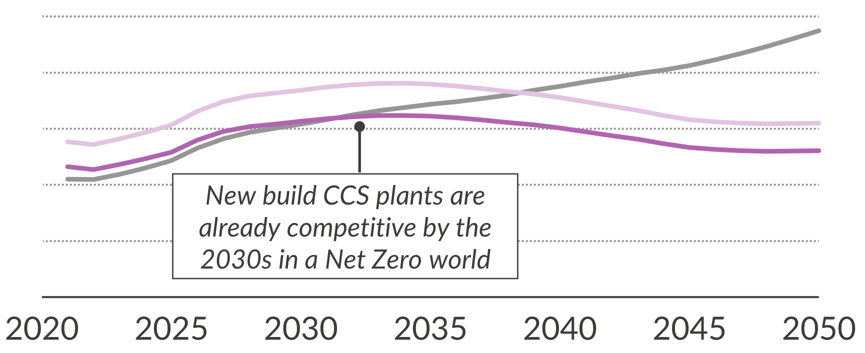
Availability payment = **Availability of generation** × **Availability of capture** × **Plant capacity** × **Availability payment rate**

2. **Variable payment** – to incentivise dispatch
   - This payment will be given as an incentive for power CCS plants to generate ahead of unabated plant when demand cannot be met by renewables and nuclear
   - The variable payment will be calculated by considering the difference in short run marginal cost between the power CCS plant as agreed in the DPA contract and a reference unabated plant
   - The payment will however only be made at times where the market conditions are not sufficient to incentivise CCS dispatch ahead of unabated plants

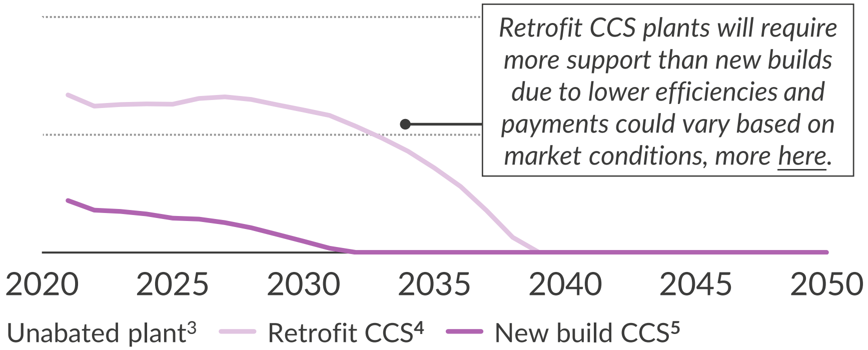
Variable payment = **Gas cost differential** + **Carbon cost differential** + **T&S volumetric payment rate** + **Additional variable cost**

While the majority of payments is expected through availability, variable payments are expected to differ in duration and amount between new build and retrofit plants.

Average SRMC of gas plants[1], £/MWh



Variable payment required to incentivise CCS dispatch, £/MWh



1) Based on Aurora's Net Zero scenario (see appendix) which assumes a carbon price of £128/tCO_2 by 2050 and a gas price of £14/MWh. 3) Assumes 57% HHV efficiency. 4) Assumes 44% HHV efficiency. 5) Assumes 50% HHV efficiency

Sources: Aurora Energy Research, BEIS

Hydrogen can serve as an alternative low carbon fuel for gas assets and will depend on the availability of low carbon hydrogen

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1 Hydrogen CCGTs

- Hydrogen CCGTs are standard gas powered plants that can run either on hydrogen blends or on pure hydrogen
- Existing CCGTs can already burn up to ~20% hydrogen without major conversions but full hydrogen turbines are still in development
- Capex for H_2 CCGT conversions range between **£170 – 250/kW**
- New builds have an estimated capex of **£550 - £700/kW**, similar to standard CCGTs
- New builds will have high efficiencies of **55% - 57%** while conversions of older assets will be lower

2 Hydrogen peakers

- Hydrogen peakers are standard Open cycle gas turbines (OCGTs) or reciprocating engines that are instead powered by hydrogen
- They offer a solution for decarbonising flexible power generation but the technology is still in exploratory phase
- Blending is not economically viable for this asset class due to combination of high fuel costs, residual emissions and very low load factors
- Capex costs are expected to be marginally higher than the conventional options, ranging between **£350 - £600/kW**
- Efficiencies are expected around **38 – 40%,** similar to gas peakers

… however the commercial viability of these technologies could however be limited by a few key factors

Hydrogen availability

- ***Production*** - Hydrogen can be produced through various methods that have different carbon intensities, but only low carbon hydrogen would achieve a Net Zero world
- ***Transport & Storage (T&S)*** - A fully functional GB hydrogen network will likely only materialise in the 2040s[1] and as such, hydrogen powered assets will need to consider alternate decentralised means of hydrogen T&S

Hydrogen properties

- Despite hydrogen's higher energy content per kg than natural gas, its lower mass results in a lower energy content by volume
- Hydrogen powered assets will thus need higher volumes to deliver similar energy levels as conventional assets, resulting in higher operational costs
- Additionally, hydrogen as a fuel costs significantly more than gas – up to 500% more in the 2020s and decreasing to ~ 70% more by 2050

1) As outlined in 'Britain's Hydrogen Network Plan' published by ENA

Sources: Aurora Energy Research, BEIS, Energy Networks Association, Goldman Sachs Global Investment Research

Blue hydrogen can reduce gas-fired emissions by up to 93% whilst Green hydrogen has the potential to reach zero emissions…

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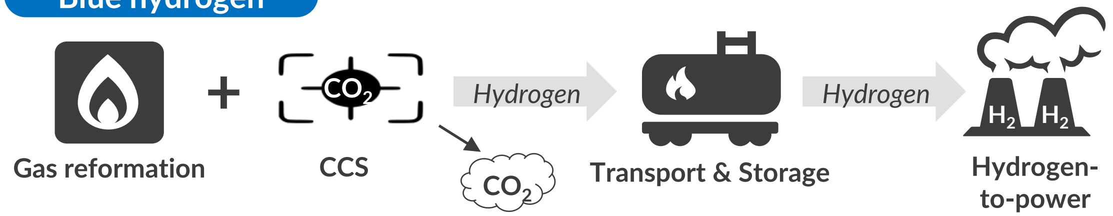
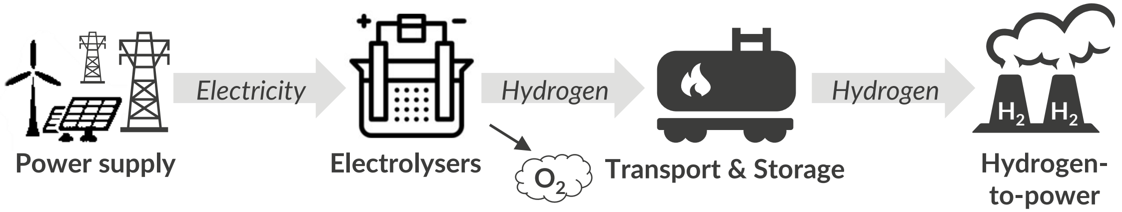
Low carbon hydrogen can be produced through two main processes which are classified as blue and green hydrogen…

Blue hydrogen



- Reformation of gas coupled with CCS produces **low carbon** hydrogen with **5-15%** residual emissions
- Can be produced through either steam methane reforming (SMR) or auto thermal reforming (ATR) processes coupled with CCS
- Blue hydrogen has potential for large scale production

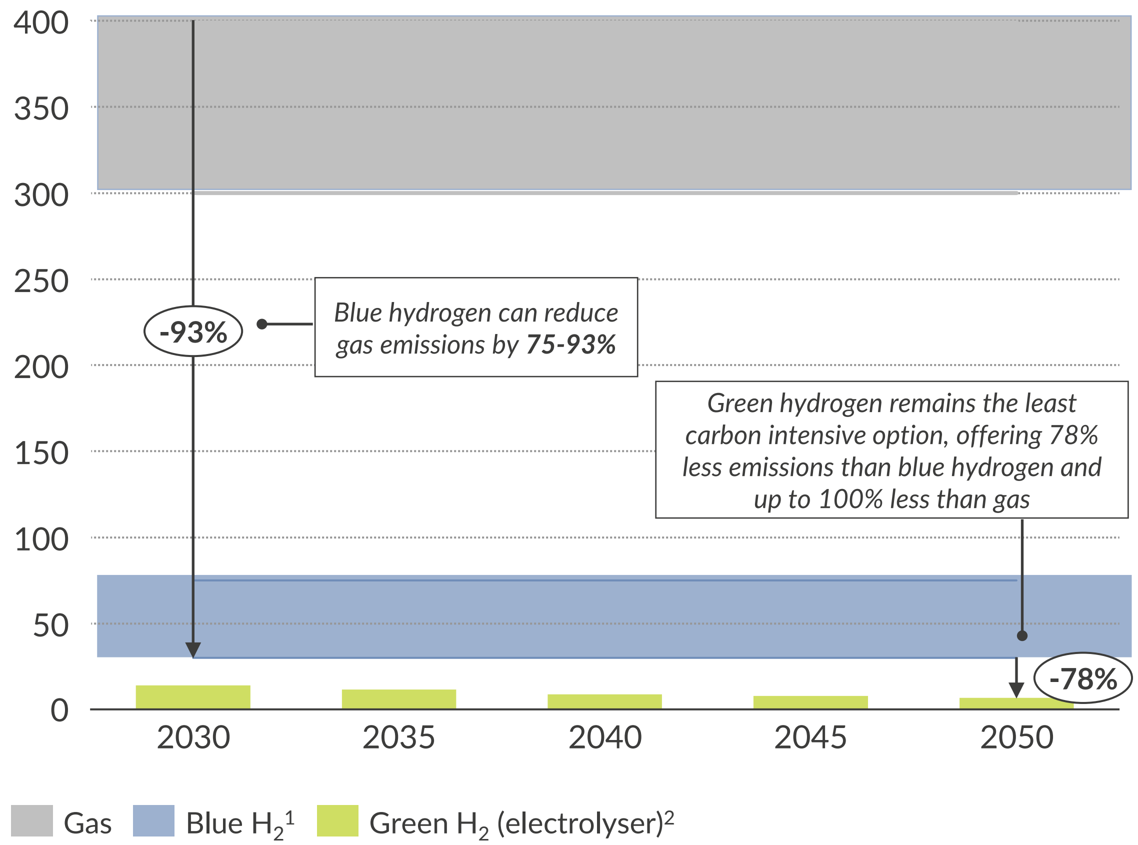
Green hydrogen



- Electrolysis produces hydrogen with oxygen as the only by product
- It has the potential to produce **zero carbon** hydrogen depending on the power source – can either be dedicated renewables or grid connected
- The carbon intensity of the end-end process will also be dependent on business models used

…The carbon intensity of these processes determines the carbon intensity of hydrogen, as a fuel with only green hydrogen can fully be zero carbon

Average carbon intensity of gas and hydrogen
($gCO_2/kWhH_2$)



1) Depending on process efficiency and CCS rates, blue H_2 will have carbon intensity between 30-75 gCO_2/kWh. 2) Average power system intensity when grid-connected electrolysers are producing more than 1 kWh. Shown for a grid-connected electrolyser with 80% efficiency and 20% average load factors.

Sources: Aurora Energy Research

…however, this comes at significantly higher costs with both blue and green hydrogen remaining uncompetitive against gas

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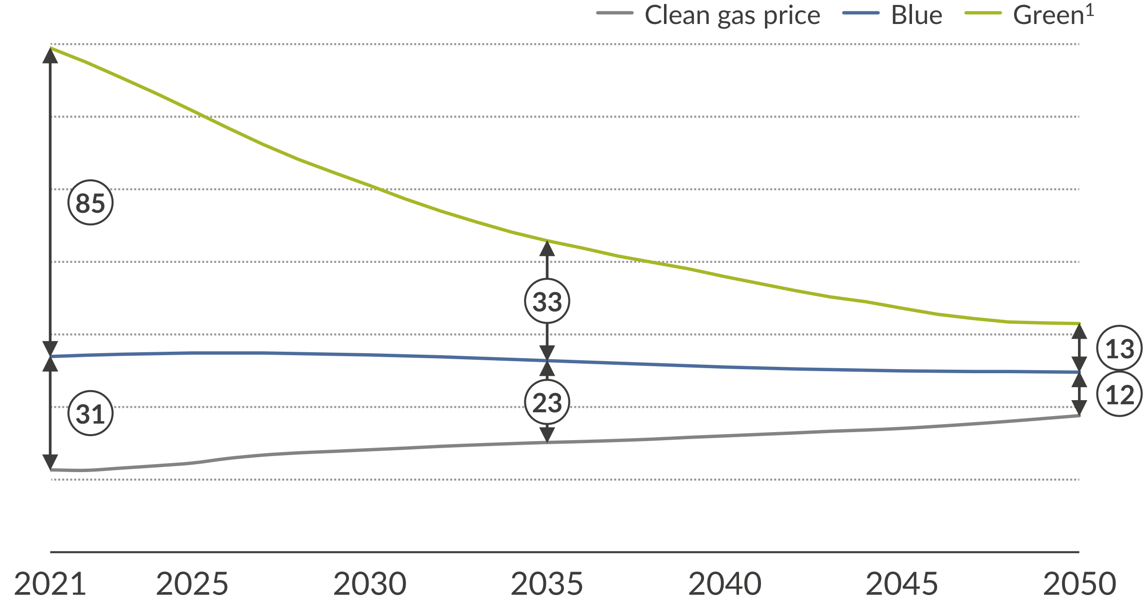
1 **Hydrogen fuel remains uncompetitive against gas, with its costs expected to remain above those of gas throughout the whole forecast horizon…**

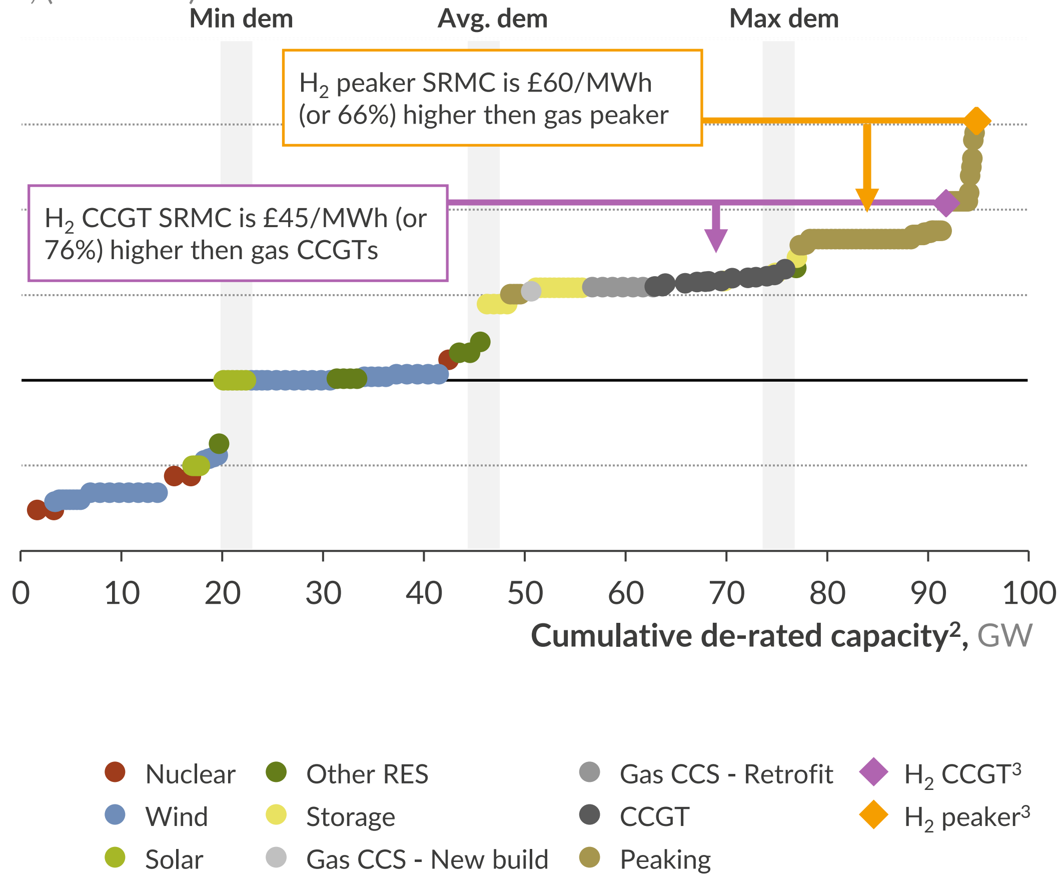
Levelised cost of hydrogen and clean gas price
£/MWh (real 2020)



- Hydrogen remains uncompetitive against the forecast clean gas price to the high capital investment needed in production capacity. The cost of green hydrogen today is estimated to cost £140/MWh, while blue hydrogen remains considerably cheaper or roughly £54/MWh, while the clean cost of gas is £21/MWh
- Technological advancements and economies of scale are expected to drive down the cost of hydrogen, while rising carbon prices increases the cost of clean gas. By 2050 blue and green hydrogen is expected to be only £12/MWh and £25/MWh more expensive than the clean gas price.

2 **… this results in H_2 burning power turbines having significantly higher SRMC relative to other plants which will limit their opportunities to run**

Short run marginal cost 2035
£/MWh, (real 2020)



1) Assuming optimised (or flexible) charging of electrolysers. Inflexible electrolysers LCOH is more than double those of flexible. 2) Wind and solar contribution accounted for by their load factors, not de-rating factors. 3) Assuming they run on blue H_2. If they used green H_2 as fuel the SRMC for the CCGT would be £152/MWh and £229/MWh for the peaker.

Sources: Aurora Energy Research

Depending on load factors, the costs of abated thermal assets differ, with H_2 conversion the lowest cost option at load factors below 20%

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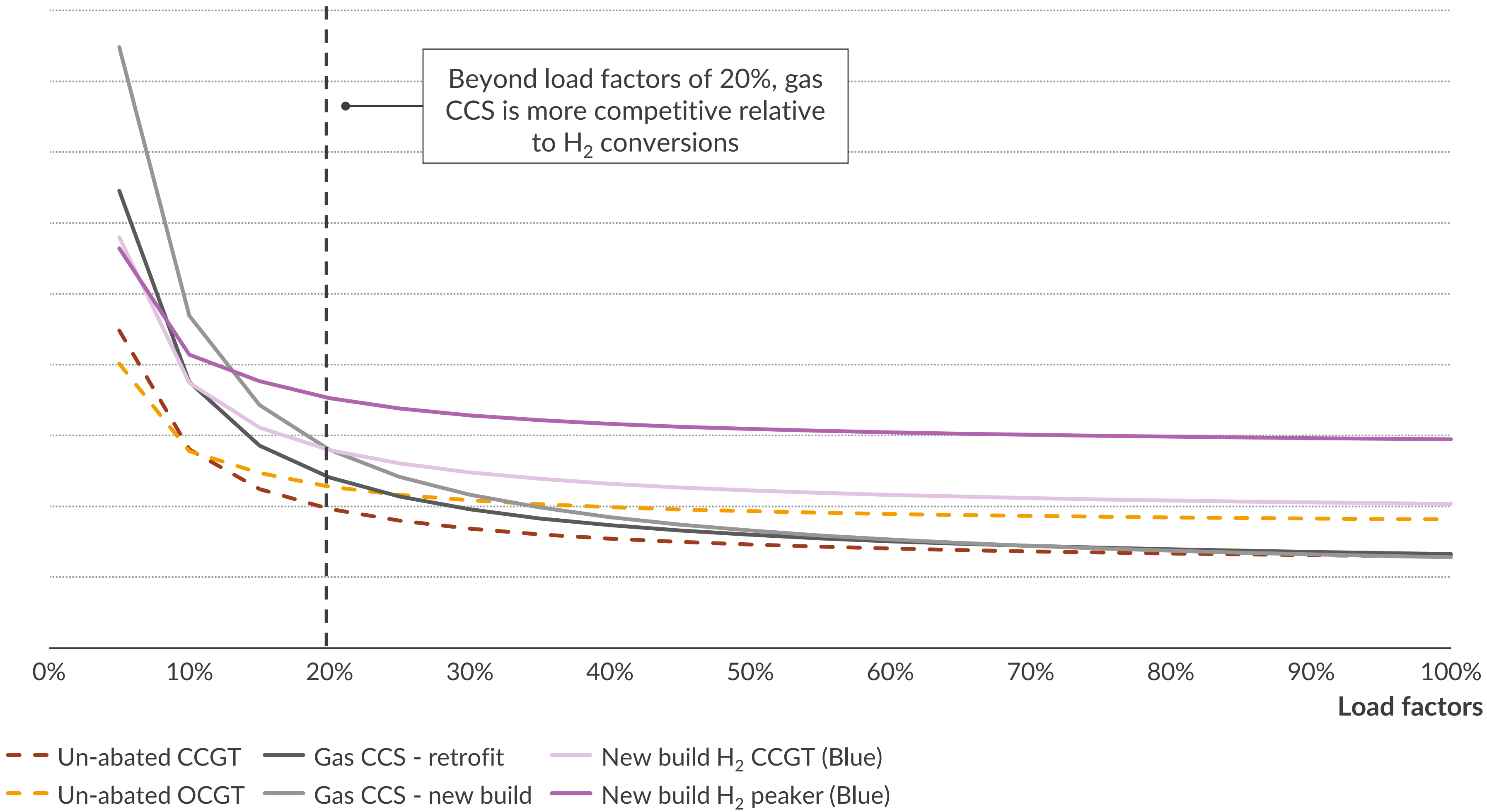
LCOE (assuming entry in 2030)[1,2]
£/MWh, (real 2020)



- Due to the different cost structure, the cost of abated thermal will differ depending on load factors
- With relatively low capex and high fuel costs, H_2 assets remain the most cost effective at annual load factors of 20% or below
- Due to significantly higher capex requirements, CCS does not become competitive on an LCOE basis until annual load factor in excess of 20% with retrofit assets out competing new build CCS until load factors of 50%
- Policy support should therefore focus on the different system needs and applications with CCS assets to focus on baseload operations while H_2 assets should be focused on abating peakload generation

1) Assuming lifetime of 30 years for new build CCGTs and CCS, 20 years for CCS retrofit and 25 years for peakers. 2) Analysis done without assuming any policy support and including carbon prices.
Sources: Aurora Energy Research

Agenda

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I. Historical performance of gas assets in GB and future outlook

II. Ensuring security of supply in a Net Zero power system

III. Potential business models for gas assets in Net Zero

IV. Considerations for policymakers and investors

Decarbonising thermal generation presents several challenges for policymakers

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Infrastructure

A Carbon transport & storage

- Vast carbon transport & storage infrastructure will be required to support the uptake of CCS
- A larger transport & storage network and support system will be vital to unlock the full potential of GB's existing thermal fleet
- Government has proposed a RAB model to incentivise the development of the T&S infrastructure

Hydrogen network

- A fully functional GB hydrogen network is only estimated to be in place in the 2040s, this could slow down the commercialisation of hydrogen-to-power technologies, in particular for H_2 peakers which will need to be distributed around the country and not in industrial clusters
- Hydrogen powered assets will thus likely require on-site storage of hydrogen

Policy support

CCS support structure

- Government has proposed a draft support mechanism for CCS through a DPA which will provide availability and variable payments to ensure that abated generation dispatches before unabated
- With higher residual emissions from retrofit CCS relative to new build should the support mechanism ensure new builds dispatch first?
- Alternative support could also come through higher carbon prices, however this would not help recover capex

Hydrogen support structure

- Government has yet to provide any guidance on a support structure for H_2 assets and how they would be brought to the market
- B Policy options could include:
  1. Carbon Contracts for Difference (CCfD)
  2. Direct hydrogen price support
  3. Capacity Market reforms
  4. Support through higher carbon prices

Cost

Cost of support

- Cost of making CCS and H_2 assets economically viable is expected to be significant due to high capex costs of CCS and high fuel costs for H_2 assets
- C While H_2 assets require less support do they provide the most cost effective way of abating emissions?
- D How much will it cost to abate the last few tonnes out of the power sector? How cost efficient will it be?

Sources: Aurora Energy Research

Development of a carbon T&S network will be crucial to decarbonise thermal assets; RAB based model has been proposed

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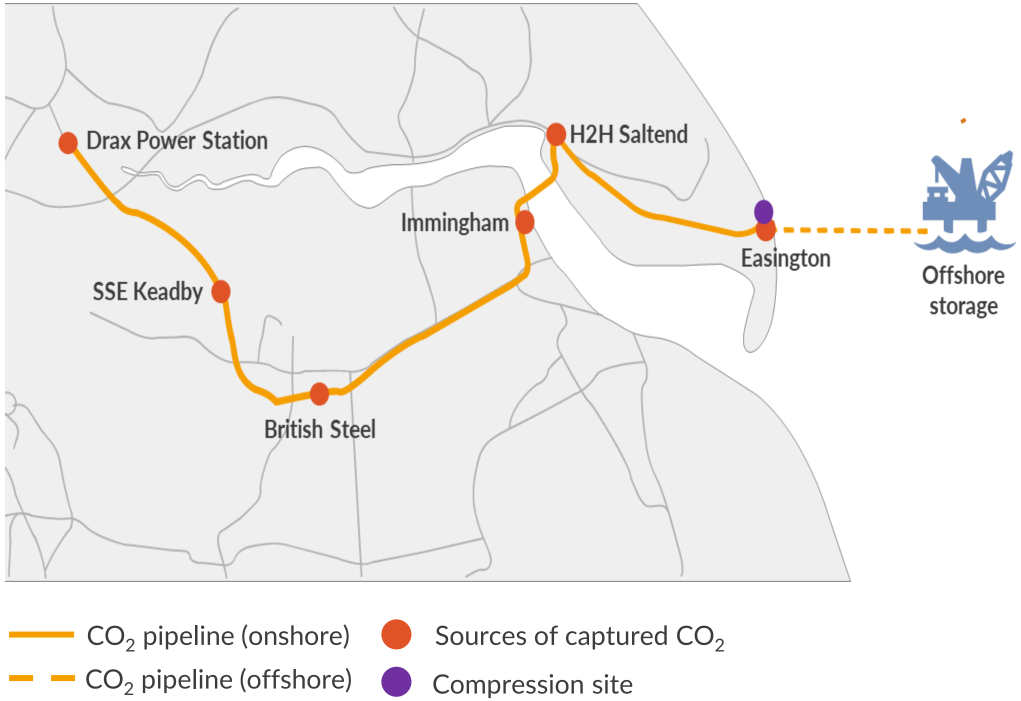
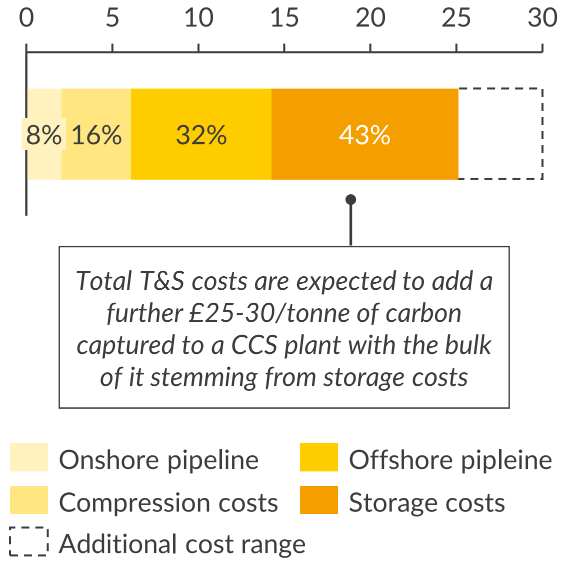
The carbon transport and storage process is complex with multiple requirements across four key stages. Delivery of a fully operational network could take 5-8 years

Purified captured CO_2 → Transported by **onshore pipelines** to a buffer storage location and/or compression site → **Compressed** for offshore transport and injection (*e.g. at Centrica Storage's Easington site*) → Transported by **offshore pipelines** to final storage locations → Compressed CO_2 is injected into **geological formations** (*e.g., in the Southern North Sea*)

Networks are expected to be developed in industrial clusters such as the Humberside region which is expected to submit an application for Low Carbon Pipelines to the Planning Inspectorate in Q3 2022 towards its 2030 target



Breakdown of expected network costs[1],
% of total cost



The Government has proposed a **Transport and Storage Regulatory Investment (TRI)** to:

- Attract investment in the T&S network to establish a new CCUS sector
- Enabling low cost decarbonisation across sectors
- Developing a market for carbon

The model will follow a **Regulated Asset Base (RAB)** structure, establishing a T&S Company (T&SCo) with the following responsibilities:

- Ownership of onshore and offshore network and storage site permits
- Operation of the T&S network
- Regulation of network usage and requirements

The Government indicated a preference for the private sector to develop the network due to greater expected cost efficiency and development speed benefits typical of private sector projects

1) Assumes network capacity of 18 Mtpa with onshore pipeline stints of 180km, offshore pipeline of 500km and storage option of offshore depleted oil and gas fields.

Sources: Aurora Energy Research, Zero Carbon Humber, Global CCS Institute

A number of existing and new policy options which could be used to incentivise gas-to-hydrogen switching

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Assessment criteria ○ Low ● High

	Policy option	Description	*Support upfront costs*	*Incentivise dispatch*	*Ease of implementation*	*Investor confidence*
Existing policies with potential modifications	Carbon pricing	▪ Higher carbon prices to price gas burning assets out of merit and incentivise fuel switching to hydrogen	◔	◕	◕	◔
Existing policies with potential modifications	Contracts for Difference (CfD)	▪ Existing CfD auctions can be expanded to include a new pot for firm low carbon technologies such as hydrogen turbines to enable cost reductions as seen in the renewables sector	◔	◕	◑	◕
Existing policies with potential modifications	Capacity Market (CM)	▪ Design could be modified to a 2-stage auction, with low-carbon technologies able to access higher CM prices in earlier bidding rounds to incentivise low-carbon capacity	◕	◔	◕	◕
Existing policies with potential modifications	Carbon tax exemptions	▪ Policy could incentivise early hydrogen adoption through carbon price exemptions for generators until full conversion	◔	◕	◕	◔
New policies	Carbon Contracts for Difference (CCfD)	▪ A CfD that rewards emissions reduction with a fixed carbon strike price paid for every unit of carbon displaced	◔	◕	◔	◑
New policies	Dispatchable power agreement (DPA)	▪ Provide an availability payment to subsidise upfront costs and a variable payment to incentivise flexible dispatch ahead of unabated plants but after renewables and nuclear	◕	◕	◔	◕
New policies	Hydrogen price support	▪ A subsidy for use of clean hydrogen fuel to outcompete the clean gas price. A supported hydrogen price would incentivise the dispatch of flexible units which respond to price signals	◔	◕	◔	◕

Source: Aurora Energy Research

…However, abatement costs rise with each tonne of carbon removed, raising questions around the value of removing the final tonnes

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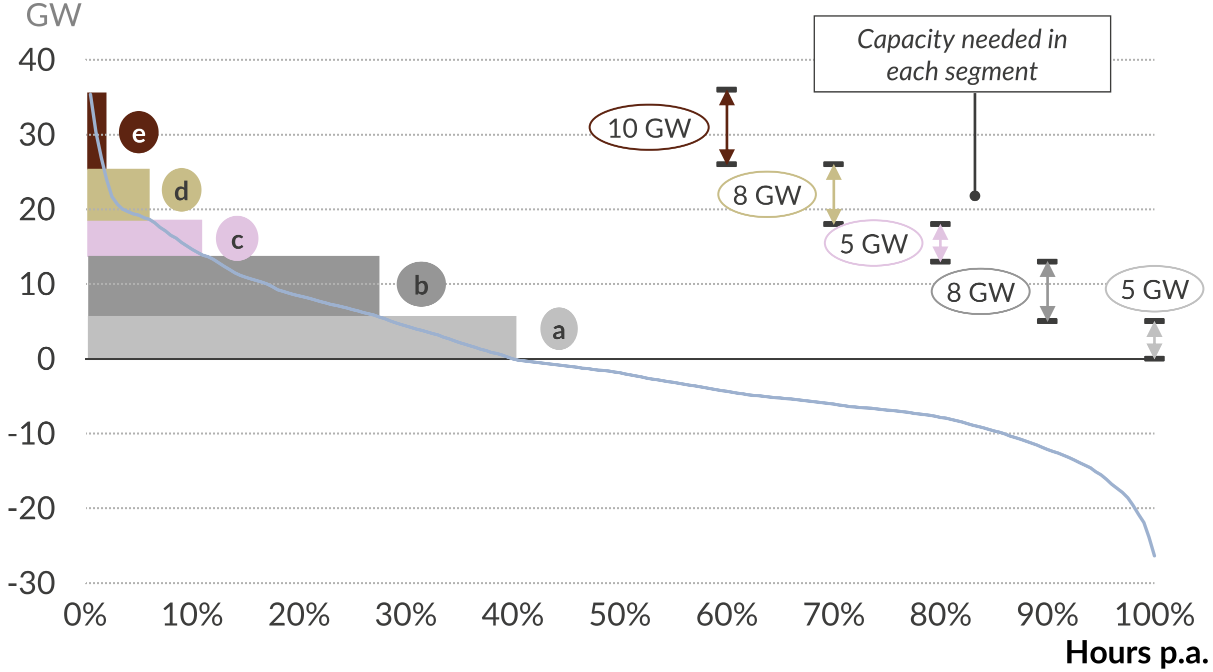
Energy shortfall in 2035 from zero-carbon generation[1]

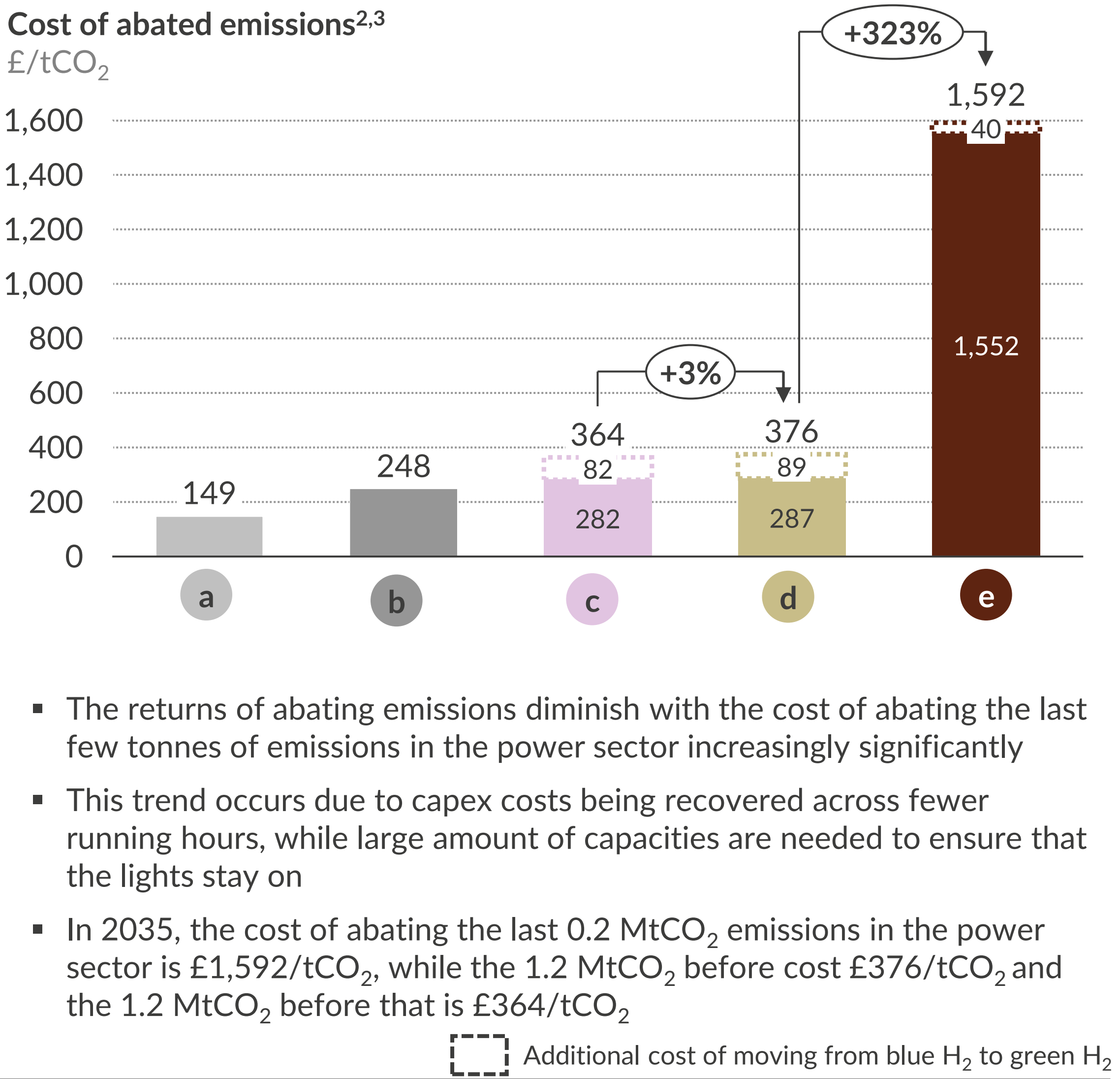
GW



	Capacity required	Load factors	Cheapest technology to operate in area[4]	Total CAPEX	Annual emissions saving
a	5 GW	28-40%	**New build CCS**	£16.8 bn	4.7 $MtCO_2$
b	8 GW	11-28%	**Retrofit CCS**	£6.8 bn	4.7 $MtCO_2$
c	5 GW	6-11%	**H_2 CCGT**	£3.3 bn	1.2 $MtCO_2$
d	8 GW	1-5%	**H_2 peaker**	£2.5bn	1.2 $MtCO_2$
e	10 GW	<1%	**H_2 peaker**	£8.0 bn	0.2 $MtCO_2$

Cost of abated emissions[2,3]

£/tCO_2



- The returns of abating emissions diminish with the cost of abating the last few tonnes of emissions in the power sector increasingly significantly
- This trend occurs due to capex costs being recovered across fewer running hours, while large amount of capacities are needed to ensure that the lights stay on
- In 2035, the cost of abating the last 0.2 $MtCO_2$ emissions in the power sector is £1,592/tCO_2, while the 1.2 $MtCO_2$ before cost £376/tCO_2 and the 1.2 $MtCO_2$ before that is £364/tCO_2

1) Excluding abated thermal assets. Includes renewables, nuclear, interconnectors and batteries. 2) New build CCS assumed to have 30-year lifetime, retrofit CCS 20-year lifetime, H_2 CCGT 30-year lifetime and H_2 peaker 25-year lifetime. 3) Cost of abated emissions calculated by dividing the total abated emissions over the lifetime (from 2035 onwards) with difference in LCOE to the alternative technology (excluding carbon costs), for example moving from new build CCGT to new build CCS. 4) See slide 42 in appendix to see how cost of abating emissions differs between load factors between each technology class. Sources: Aurora Energy Research

Details and disclaimer

Out of gas? The role and potential business models for CCS and hydrogen conversions in Net Zero

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