

# Decarbonising hydrogen in a net zero economy

27 September 2021



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# Report context

Prepared by  
Anna MacDonald, Senior Associate

Felix Chow-Kambitsch, Head of  
Commissioned Projects Western Europe  
[felix.chow@auroraer.com](mailto:felix.chow@auroraer.com)

## ① Executive summary

AURORA

Aurora Energy Research has been commissioned by Urenco to investigate the benefits of the deployment of both Renewable Energy Sources (RES) and nuclear to support decarbonisation and reduce reliance on fossil fuels as a transitional fuel source in GB.

The scenarios presented in this report are not Aurora forecasts but exploratory scenarios to assess a wider range of technology mixes.

In addition to integrated modelling of power and hydrogen markets, this report also discusses potential risks to the transition and policy implications of modelled technology pathways.

Additional input has been provided by LucidCatalyst, the International Atomic Energy Agency (IAEA), and EDF.

Authored by:



Commissioned by:



Additional inputs from:



# What's new?

The majority of studies on the future of the hydrogen sector in GB focus electrolytic H<sub>2</sub> from RES and fossil based H<sub>2</sub> with CCS. The potential for nuclear to participate in the H<sub>2</sub> economy is often not considered due to high costs of recent assets and lack of clear policy direction leading to planned projects being put on hold. This study investigates how policy support for new nuclear technologies and business models to provide low carbon electrolytic H<sub>2</sub> could reduce nuclear and system costs whilst reducing reliance on fossil fuels when deployed alongside RES on the path to net-zero.

## Research questions

- 1 Routes to decarbonise**  
Can total system costs and emissions be reduced by including nuclear in a net-zero strategy?
- 2 The hydrogen economy**  
How could renewables and new nuclear technologies influence the hydrogen economy?
- 3 The role of nuclear**  
Can new nuclear business models and technologies with co-located H<sub>2</sub> production provide flexibility to the grid, displace reliance on fossil fuels and improve nuclear economics?

## Modelling approach

- 1 Integrated in-house modelling simultaneously solves for supply mixes in power and hydrogen markets**
- 2 Use of a capacity market with a high carbon price to incentivise economic entry of low carbon capacity**
- 3 Modelling new nuclear technologies and business models in the power sector**
- 4 Economic entry of hydrogen supply from nuclear**
- 5 Discussion of the implications of each modelled scenario for policy and consumers in addition to the risks associated with achieving net-zero**

# Key insights

**1 Deploying renewables and nuclear for power and hydrogen is required to ensure rapid decarbonisation and reduced reliance on fossil fuels**  
Cumulative emissions from 2021-2050 can be reduced by 80 MtCO<sub>2</sub>e and gas usage in power and H<sub>2</sub> by 8k TWh<sub>th</sub> in our core scenarios.

**2 Achieving H<sub>2</sub> volumes required for net-zero without fossil fuels will be challenging without support for electrolytic H<sub>2</sub> from RES and nuclear**  
The high share of virtually baseload H<sub>2</sub> demand from transport and industry results in a high dependence on fossil based blue H<sub>2</sub>, comprising over 35% of demand in 2050 in all scenarios that exclude a “Gigafactory” for nuclear derived H<sub>2</sub>. Clear support for electrolytic H<sub>2</sub> is required to reduce costs relative to fossil based blue H<sub>2</sub>.

**3 Including nuclear with co-located electrolysers alongside high RES is economically efficient, reducing total system spending by 6-9% (NPV from 2021 – 2050)**  
Co-locating electrolysers with nuclear enables nuclear plants to provide additional flexibility to the power grid to match fluctuations in RES supply by diverting electricity output to or away from electrolysers for H<sub>2</sub> production.

**4 Novel business models for nuclear energy can provide cost competitive and scalable sources of zero carbon electricity and hydrogen**  
There are opportunities for existing and new nuclear co-located with H<sub>2</sub> electrolysers to produce cost competitive electricity and H<sub>2</sub>. In addition, a new generation of nuclear reactors (i.e. small modular reactors and Gen IV reactors) can potentially speed up decarbonisation and reduce use of fossil fuels. Utilising new high temperature nuclear as a source of heat can further increase efficiency of hydrogen production.

**5 Careful market design and policy support structures are required to get to net-zero**  
Systems with large volumes of RES and nuclear but limited fossil fuels result in many hours of very low power prices. This leads to an increased need for either support payments or new market designs to bring forward low carbon supply. The continuation of direct support for RES and nuclear (i.e. via CfDs or RABs) and changes to the Capacity Market (CM) are key tools to ensure sufficient low carbon capacity is built. Nuclear can play a key role in decarbonising power and H<sub>2</sub> but clear policy intention is required to lower the financing cost of nuclear and deploy a pipeline of identical projects at low cost.

**6 Broader potential benefits of technology mixes should be considered**  
Deploying RES alongside nuclear can facilitate low carbon systems and those with minimal reliance on fossil fuels are found to have the lowest costs. However, the ability of technologies to drive deeper decarbonisation should be considered such as the potential for nuclear gigafactories for H<sub>2</sub> production to decarbonise hard to abate sectors like aviation and shipping via H<sub>2</sub> directly or H<sub>2</sub> derived synthetic fuels.

# Hydrogen has the potential to decarbonise multiple sectors

## Sectors considered in report

|  |   |   |   |   |   |
|--|---|---|---|---|---|
| <p>Power</p>  | <p>Heat</p>  | <p>Road transport</p>  | <p>Aviation</p>  | <p>Shipping</p>  | <p>Industry</p>  |
|--|---|---|---|---|---|

## Ease of abatement

|   |   |   |   |   |   |
|---|---|---|---|---|---|
| ● | ◐ | ◑ | ◒ | ◓ | ◔ |
|---|---|---|---|---|---|

## The challenge

|  |   |  |   |   |  |
|--|---|--|---|---|--|
| <p>Many low carbon technologies are available; the key challenge is coping with variable RES output without relying on fossil fuels.</p> | <p>The majority of UK homes are fitted with gas boilers, with many too inefficient to be compatible with electric heat pumps.</p> | <p>Costs of electric cars have plunged but uncertainties remain for road freight. H<sub>2</sub> fuel cells/or H<sub>2</sub> derived synfuels are an alternative but yet to be deployed at scale.</p> | <p>Orders for current models until the mid 2020s, combined with aircraft lifetimes of 20-30 years could lock-in reliance on fossil fuels for decades.</p> | <p>Electric vessels could decarbonise short-haul routes but sustainable alternative fuels (SAF) are needed for long-haul routes. Long vessel lifetimes require entry by 2030.</p> | <p>Many industrial processes (i.e. steel, cement, chemicals and synfuel manufacture) rely on fossil feedstock with complete overhaul of systems and processes required to decarbonise.</p> |
|--|---|--|---|---|--|

## Low carbon solutions available

|   |   |   |   |  |  |
|---|---|---|---|--|--|
| <ul style="list-style-type: none"> <li>▪ <b>H<sub>2</sub> combustion plants</b></li> <li>▪ RES, Nuclear</li> <li>▪ Gas-CCS</li> <li>▪ Batteries, DSR</li> </ul> | <ul style="list-style-type: none"> <li>▪ <b>H<sub>2</sub> boilers</b></li> <li>▪ District heating (incl. nuclear waste heat)<sup>1</sup></li> <li>▪ Electricity (via heat pumps)</li> <li>▪ Alternative thermal energy storage</li> </ul> | <ul style="list-style-type: none"> <li>▪ <b>H<sub>2</sub> fuel cell vehicles</b></li> <li>▪ <b>Synfuels (via H<sub>2</sub>)</b></li> <li>▪ Electric vehicles</li> </ul> | <ul style="list-style-type: none"> <li>▪ <b>H<sub>2</sub></b></li> <li>▪ <b>Synfuels (via H<sub>2</sub>)</b></li> </ul> | <ul style="list-style-type: none"> <li>▪ <b>H<sub>2</sub></b></li> <li>▪ <b>Synfuels (via H<sub>2</sub>)</b></li> <li>▪ Electricity (batteries)</li> </ul> | <ul style="list-style-type: none"> <li>▪ <b>H<sub>2</sub></b></li> <li>▪ <b>Synfuels (via H<sub>2</sub>)</b></li> <li>▪ Electricity (batteries)</li> </ul> |
|---|---|---|---|--|--|

1) District heating using waste heat from nuclear has not been considered in this report.

# The majority of hydrogen is currently derived from fossil fuels but can be produced by a range of low carbon methods



|  |                                 |  |   |   |   |
|--|---------------------------------|--|---|---|---|
| Standard nomenclature                                    | Grey                            | Blue   | Pink  | Yellow <sup>1</sup>   | Yellow  |
| Nomenclature in report                                   | Grey                            | Blue   | Green   | Green   | Yellow  |
| Conversion method  | Steam reformation               | Steam/autothermal reformation  | Electrolysis                                    | Electrolysis  | Electrolysis  |
| Primary energy source                                    | Natural gas                     | Natural gas  | Nuclear electricity and waste heat              | Zero carbon grid electricity from RES and nuclear                         | Non-zero carbon grid electricity  |
| Technologies modelled in report                          | Steam methane reformation (SMR) | Steam methane reformation with CCS (SMR+CCS)<br>Autothermal reformation with CCS (ATR+CCS) | High temperature solid oxide electrolysis (SOE) | Alkaline electrolyte membrane (ALK)<br>Polymer electrolyte membrane (PEM) | Alkaline electrolyte membrane (ALK)<br>Polymer electrolyte membrane (PEM) |
| Emissions intensity, kgCO <sub>2</sub> /kgH <sub>2</sub> | 8 - 12                          | 0.6 - 1  | 0   | 0   | 0 - 9   |

1) Note that the current European Commission definition of green H<sub>2</sub> differs to that used in this report. The EU states that H<sub>2</sub> can only be considered green if created using electricity from new, H<sub>2</sub> production dedicated RES assets that do not provide electricity to the grid 2) No "yellow" electrolysis is seen in the core scenarios and electrolyzers only produce when power prices are low.

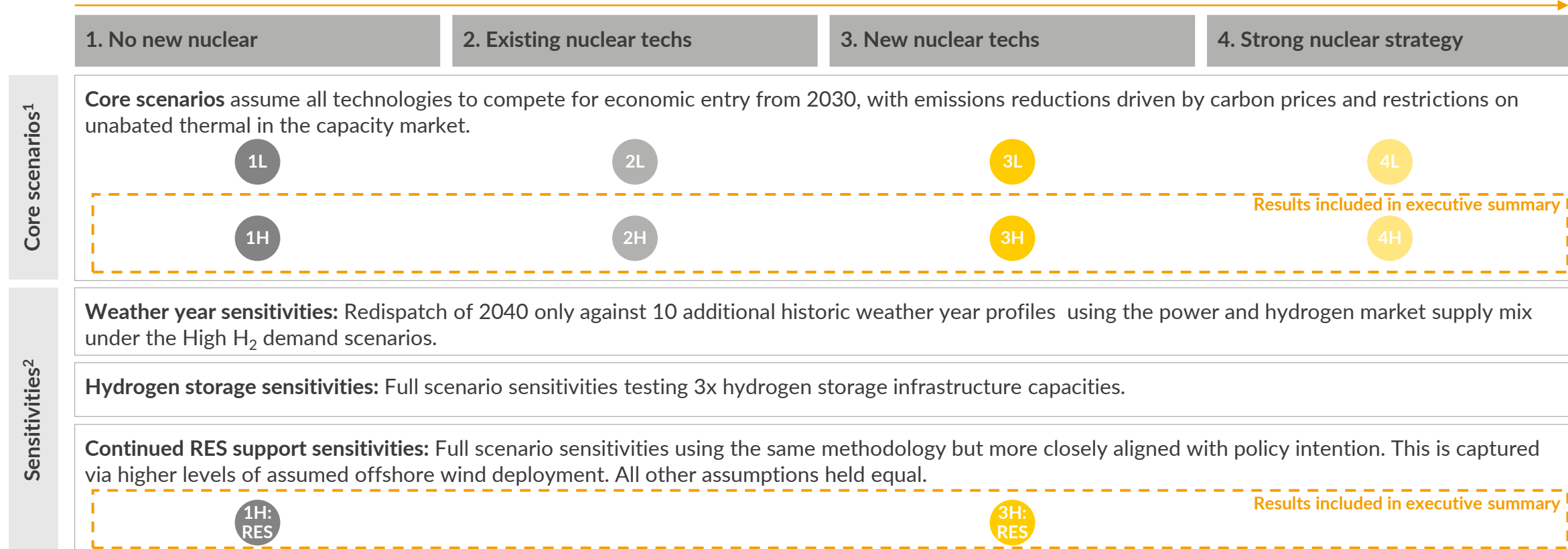
Sources: Aurora Energy Research, IEA, CE Delft, NREL, NETL, EC JRC-IE

# A range of scenarios have been modelled to investigate the impacts of differing levels of nuclear advancement on achieving net-zero

## Modelled GB market scenarios

#L Low H<sub>2</sub> demand    #H High H<sub>2</sub> demand

Increasing nuclear ambition 




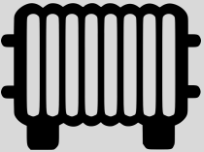
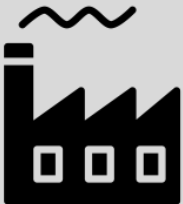
The scenarios that follow are exploratory scenarios to investigate the role of nuclear and H<sub>2</sub> in reaching net-zero and are not forecasts.

1) Core scenario modelling results are explored in detail in Section V; 2) Sensitivity analysis is presented in Section VI.









# Two hydrogen demand scenarios reflecting differing levels of ambition are modelled in this report

Overview of Aurora’s GB H<sub>2</sub> demand scenarios – scrutinised by over 18 market participants

|   | Low Hydrogen   | High Hydrogen  |
|---|--|--|
| <p>Transport</p>   | <p>Low penetration of FCEVs for private transport with moderate use of Hydrogen for in freight and public transport, where use of natural gas prevails.</p> <p><b>18 TWh H<sub>2</sub> in 2050</b></p> | <p>Moderate presence of H<sub>2</sub> in private transport, with higher uptake in public transport and freight. Adoption of H<sub>2</sub> for maritime and rail transport.</p> <p><b>162 TWh H<sub>2</sub> in 2050</b></p> |
| <p>Heating</p>     | <p>H<sub>2</sub> serves certain areas in the country with advantageous conditions, but use is not widespread.</p> <p><b>110 TWh H<sub>2</sub> in 2050</b></p>  | <p>Gas networks are converted to hydrogen with 14 million H<sub>2</sub> boilers present in 2050.</p> <p><b>230 TWh in 2050</b></p>   |
| <p>Industry</p>  | <p>H<sub>2</sub> use for high-grade heat applications along with CCS, electricity serving with low-grade heat requirements. Use as feedstock remains.</p> <p><b>82 TWh by 2050</b></p>                 | <p>H<sub>2</sub> used for both high and low-grade heat applications, as well as for industrial feedstock.</p> <p><b>114 TWh by 2050</b></p>  |

# Other transport segments were considered only in our High H<sub>2</sub> scenario, but likelihood of uptake is still uncertain

|  | GB outlook for H <sub>2</sub> Adoption  | Likelihood  | GB High H <sub>2</sub> Scenario Assumption <sup>3</sup>  |
|--|---|---|--|
| <b>Railway</b><br>    | <ul style="list-style-type: none"> <li>Most promising options for rail decarbonisation include electrification and fuel switching to biofuels or H<sub>2</sub>.</li> <li>There are concerns on supply limitations for biofuels and, in some areas, cost and infrastructure disruption could make electrification prohibitive, making a case for H<sub>2</sub> adoption.</li> </ul>  |    | <p><b>29 TWh by 2050</b><br/>                     Equivalent to a third of all trains in the UK switching fuel use to H<sub>2</sub></p>                              |
| <b>Aviation</b><br>   | <ul style="list-style-type: none"> <li>Prospective measures include increasing efficiency, reducing allowed cargo and using alternative fuels.</li> <li>Even with all these measures, the sector will likely face disruption or high abatement needs in order to reach Net Zero.</li> <li>Although small demonstration projects seek to prove feasibility, H<sub>2</sub> uptake in the sector is highly uncertain.</li> </ul>   |    | <p><b>No demand</b> was assumed for this sector in the high H<sub>2</sub> scenario, however higher H<sub>2</sub> demand scenarios could see adoption in aviation</p> |
| <b>Shipping</b><br> | <ul style="list-style-type: none"> <li>International Maritime Organisation has enacted a mandate to cut the sector's CO<sub>2</sub> emissions by 50% (relative to 2008 levels) by 2050.</li> <li>Organisations have stated that without the use of alternative fuels this is likely to be missed.</li> <li>Despite technical and financial challenges, potential for H<sub>2</sub> uptake in the sector is considered high, either through direct use or as ammonia.<sup>1</sup></li> </ul> |  | <p><b>11 TWh by 2050</b><br/>                     Equivalent to the forecasted fuel demand for the sector<sup>2</sup></p>  |

1) ICCT; 2) BEIS' forecast extrapolated to 2050; 3) None of these segments were considered in our Low H<sub>2</sub> scenarios.

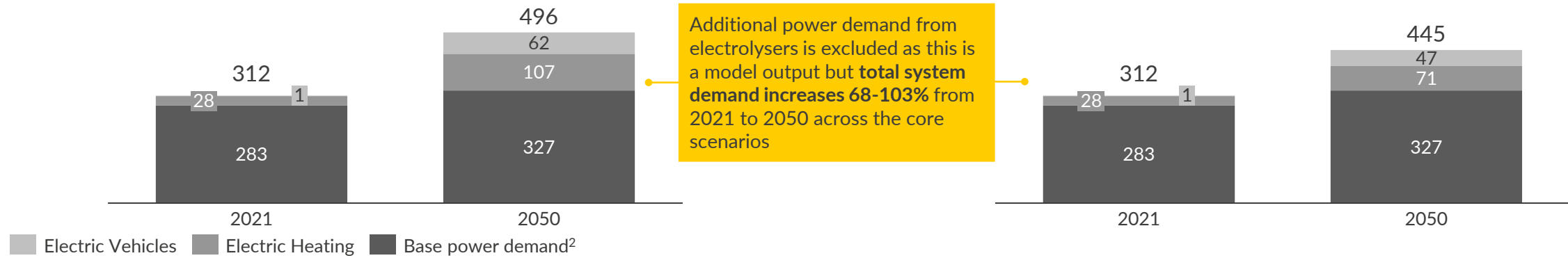
# Final energy demand across scenarios is held constant, with deviations in system size driven by electrification and electrolysers

Low H<sub>2</sub> demand

High H<sub>2</sub> demand

## GB annual power demand by sector<sup>1</sup>

TWh electricity



## GB annual hydrogen demand by Sector

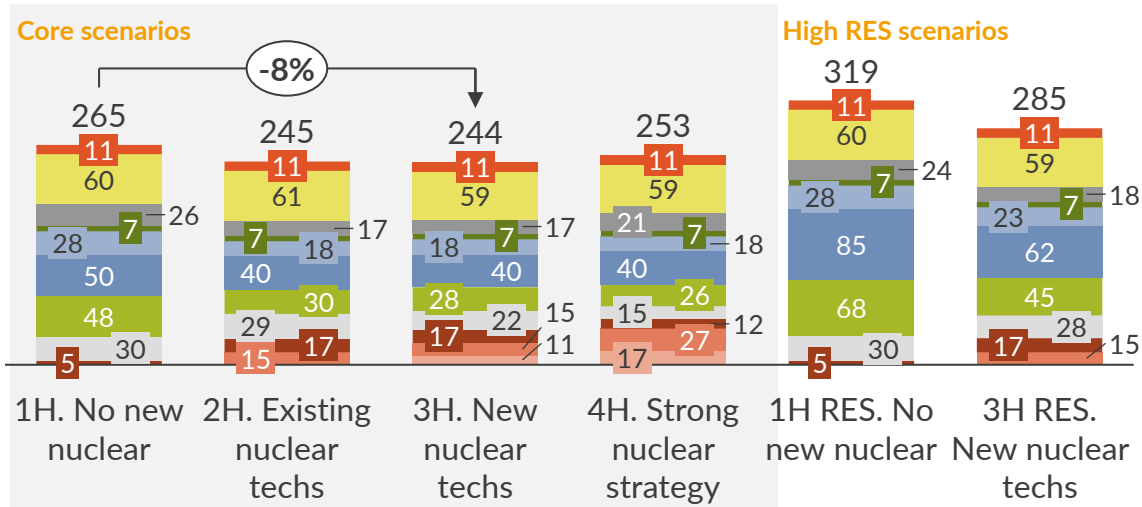
TWh H<sub>2</sub>



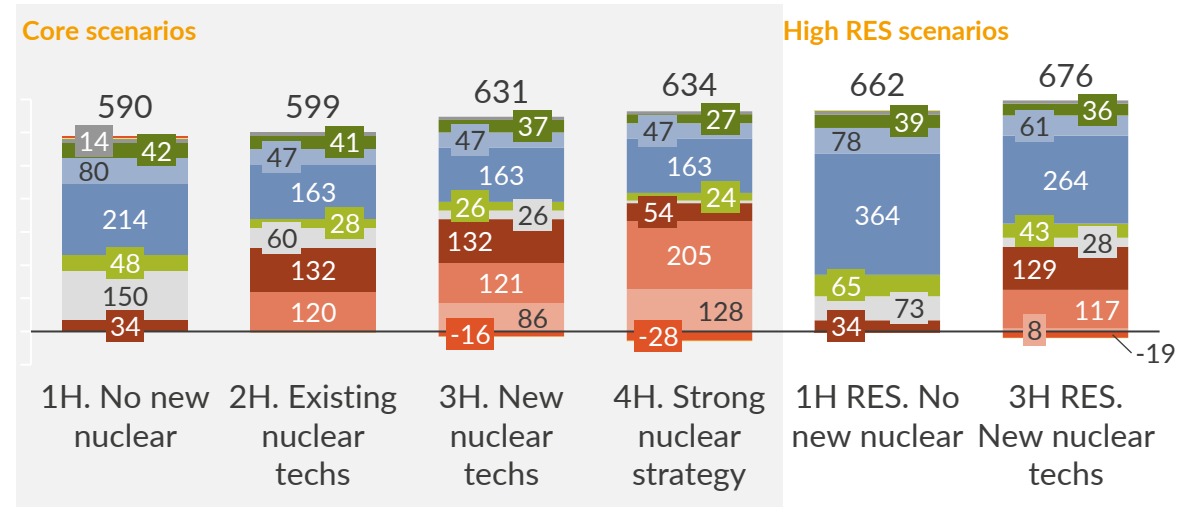
1) Excludes power demand from electrolysers for H<sub>2</sub> production as this is a model output. Total power demand therefore varies in each market scenario.

# Adopting a strong nuclear strategy could reduce power system reliance on fossil fuels to just 3% of generation

GB installed capacity in 2050  
GW



GB electricity production and net imports in 2050  
TWh



- The four core scenarios show an increasing prevalence of nuclear power, with most of the demand in 4H met by nuclear sources by 2050 facilitated by low nuclear costs. The bulk of this generation comes from small modular and Gen IV reactors, which are expected to come online from the 2030s onwards. 4H sees less economic deployment of large nuclear reactors as they are displaced by small and Gen IV reactors which see lower costs in this scenario.
- Higher levels of cheap electricity from RES and nuclear lead to greater overall electricity demand, due to increased demand for electrolytic H<sub>2</sub> which benefits from low electricity prices.
- The 1H RES and 3H RES sensitivities assume more support for renewables than their core scenario counterparts. This leads to a RES-dominated supply mix and lower levels of nuclear buildout. It also creates a larger system in terms of installed capacity, due to the lower load factors of RES relative to nuclear.

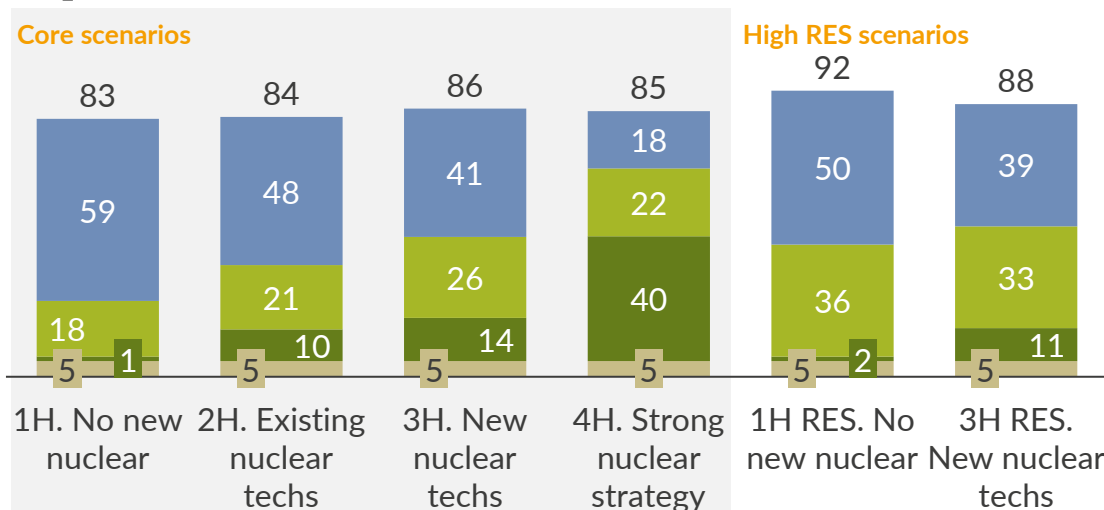


1) Low carbon flex includes DSR, battery storage, hydrogen peakers, hydrogen CCGT, pumped storage 2) Other RES includes biomass, BECCS, EfW and marine; 3) Unabated thermal includes CCGTs, gas peaking, embedded CHP.

# Low nuclear costs and economic entry of a hydrogen Gigafactory enable reliance on fossil H<sub>2</sub> to drop to 6% by 2050

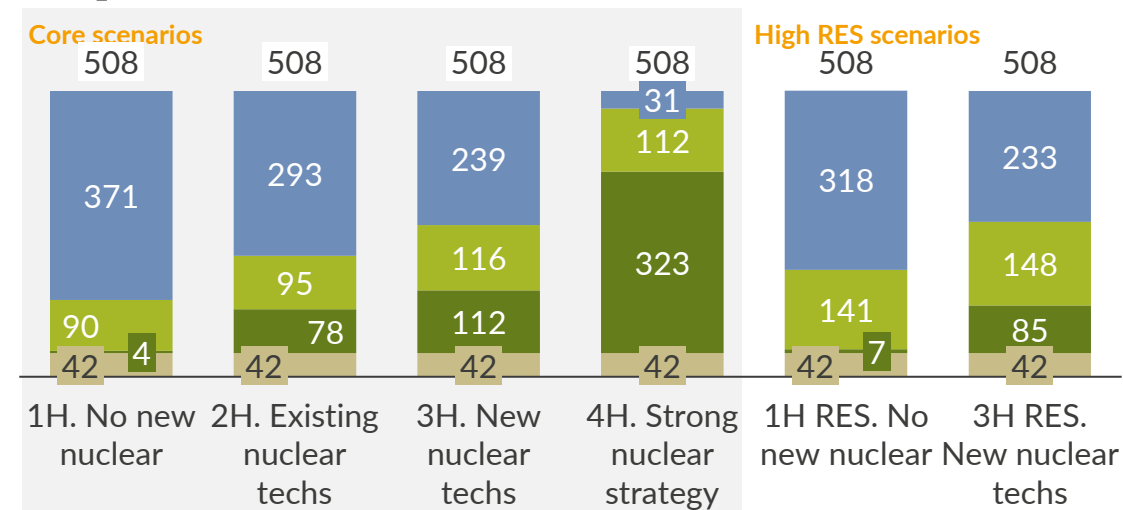
GB installed capacity in 2050

GW H<sub>2</sub>



GB gross H<sub>2</sub> production in 2050

TWh H<sub>2</sub>



- All scenarios with the exception of 4H have a high reliance on blue H<sub>2</sub> made from fossil gas with CCS. This is responsible for 73% of supply in 2050 in 1H and remains a significant source of H<sub>2</sub> in 2H and 3H. Variability in RES output, combined with low levels of excess RES lead to unfavourable economics for non-nuclear derived green H<sub>2</sub> relative to fossil based blue H<sub>2</sub>.
- Indeed, in 1H RES and 3H RES, the greater levels of intermittent, cheap renewable generation create more periods of low power prices, enabling more grid connected electrolysers to enter profitably.
- Scenario 4H outlines that strong support for a nuclear construction pipeline could establish a nuclear gigafactory consisting of many small nuclear reactors dedicated to H<sub>2</sub> production via SOEs. This enables almost all 2050 H<sub>2</sub> demand to be met via zero-carbon electrolysis and reduces reliance on fossil fuels for H<sub>2</sub> production to just 6%.
- The “negative carbon emissions” associated with BECCS are expected to be highly valuable and attributed to hard to abate sectors. This capacity is therefore assumed in model as it is likely to be driven by policy or valuable carbon credits.

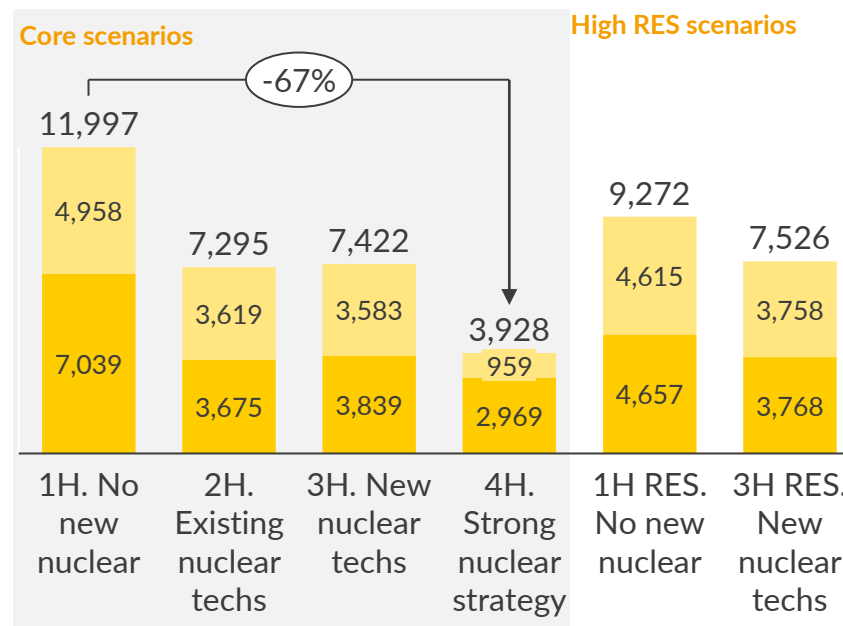
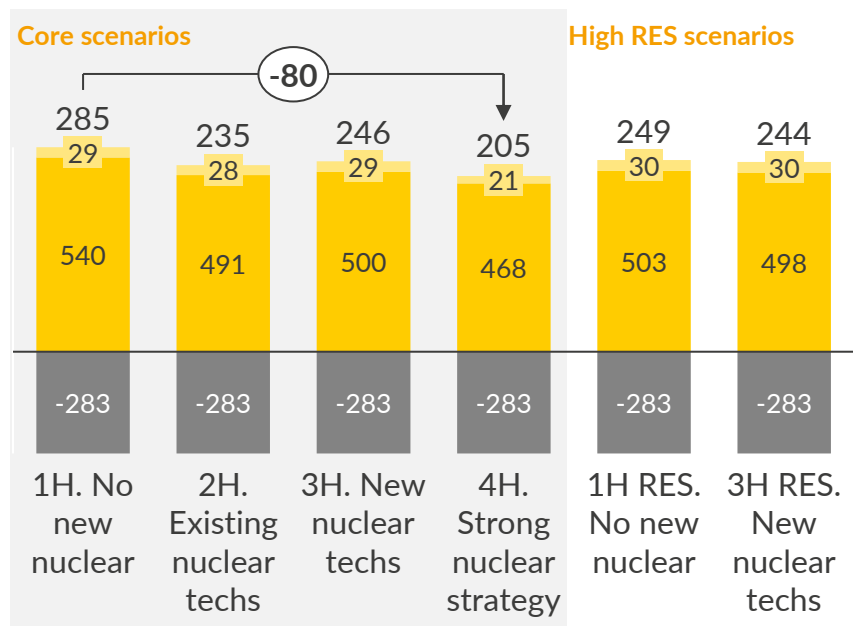
BECCS Green: nuclear derived Green: grid connected Blue Grey

1) Majority of PEM electrolyser capacity and generation shown here correspond to re-fuelling stations providing pure H<sub>2</sub> for hydrogen-powered vehicles. These are treated separately and do not contribute to market dynamics shown in the following slides.

# Systems with higher levels of nuclear deployment lead to lower emissions from the power and hydrogen sectors

GB cumulative emissions from electricity and H<sub>2</sub> production (2021-50)  
MtCO<sub>2</sub>

GB cumulative natural gas usage from electricity and H<sub>2</sub> production (2021-50)  
TWhth HHV



GB emissions from electricity and H<sub>2</sub> production in 2050 excluding BECCs  
MtCO<sub>2</sub>

GB natural gas usage from electricity and H<sub>2</sub> production in 2050  
TWhth HHV



■ Power production ■ Hydrogen production ■ BECCs<sup>1</sup>

■ Power sector ■ Hydrogen sector

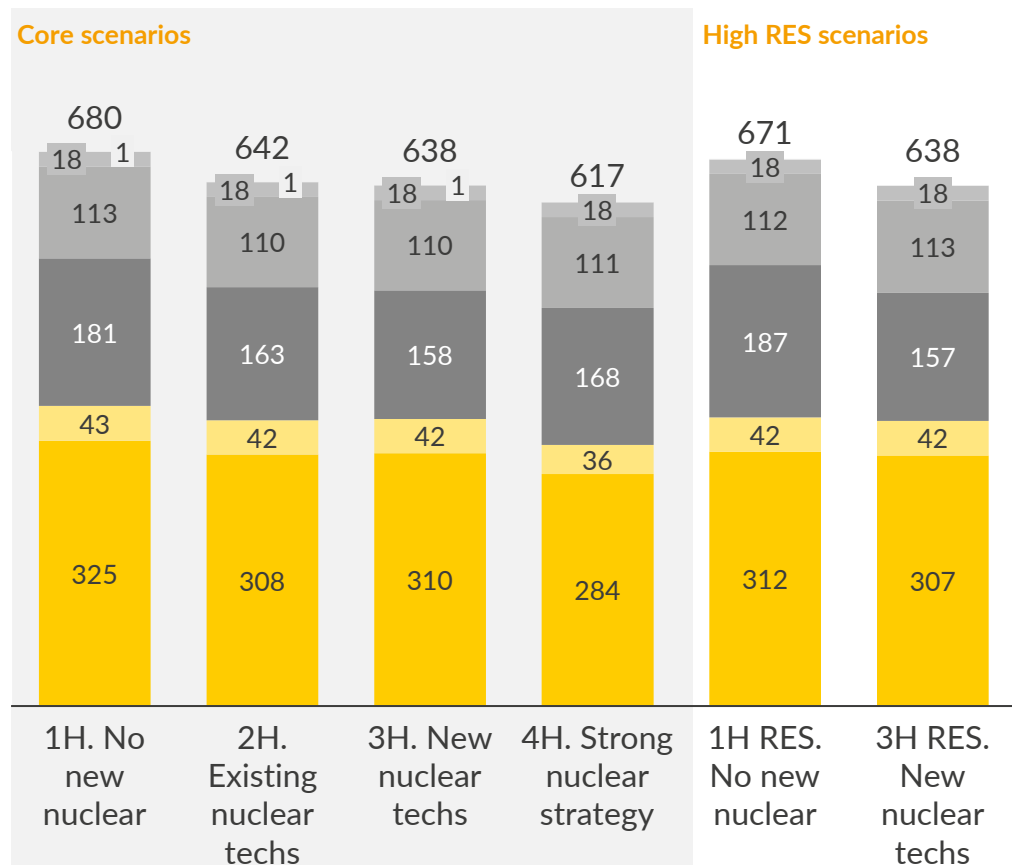
- Support for a pipeline of nuclear projects leading to low nuclear costs can lead to:
  - 80 MtCO<sub>2</sub>e avoided emissions from 2021-2050
  - 67% reduction in fossil gas usage from 2021-2050.
- 1H, 1H RES and 3H RES have the highest fossil fuel use due to the variability in RES output requiring flexible gas plants to ramp up and down to meet demand.
- Comparing 1H and 3H to their high RES counterparts highlights that while supporting renewables buildout can help reduce fuel use and emissions, the benefits of doing so are less stark in a high nuclear system (3H) as emissions are already very low.

1) Potential to cancel out up to 36 MtCO<sub>2</sub> annually by considering negative emissions from sustainable biomass paired with CCS.

# Net-zero pathways that adopt RES and nuclear in power and hydrogen markets can reduce total system spending by 6-9% (NPV)

GB NPV total system spend from 2021 - 2050<sup>1</sup>

£bn



- **Electricity market spending** is the key driver of total system spend across scenarios and is directly linked to the supply mix. Scenarios with a high share of RES and nuclear dampen electricity prices, whereas scenarios that rely on more expensive fossil based sources for baseload and flexibility see higher electricity prices.
- **Hydrogen market spending** is similar across scenarios as prices are typically set by blue H<sub>2</sub> and strongly correlated with gas prices. Lower costs in 4H are driven by nuclear derived electrolytic H<sub>2</sub> meeting demand in summer.
- **Support costs** are strongly linked to electricity market prices as low wholesale market revenues lead to higher top-ups for existing contracts (CfDs) and higher CM payments for new capacity to break even. The need for higher support costs in 4H due to low electricity prices is counteracted by lower costs for nuclear and a smaller system overall.
- **Infrastructure costs** are similar across all core scenarios as systems are of a similar size and H<sub>2</sub> and CO<sub>2</sub> costs are volumetric. H<sub>2</sub> and CO<sub>2</sub> costs could vary much more depending on proximity of supply to demand.

■ Electricity market   
 ■ Support Costs   
 ■ Hydrogen Infrastructure  
■ Hydrogen market   
 ■ Electricity Infrastructure   
 ■ CO2 Infrastructure

1) Costs are discounted using a rate of 5%.

# A series of least regret options can be pursued to minimise risks to the transition towards net-zero

- 1 Continued revenue support for low carbon technologies**  
To incentivise deployment of low-carbon capacity despite low wholesale market revenues as a result of high penetrations of low marginal cost supply. A level playing field for all technologies is required.
- 2 Limit participation of unabated thermal in the CM**  
To prevent locking in reliance on new unabated thermal assets, that will remain online for 25 years, by only procuring low carbon alternatives.
- 3 Studies on the role of green H<sub>2</sub> from RES and nuclear to displace fossil fuels**  
Further investigations of H<sub>2</sub> only business models for RES and nuclear to create low cost H<sub>2</sub> without fossil fuels.
- 4 Conduct in depth siting and feasibility studies for nuclear and RES deployment**  
To ensure target deployment can be met.
- 5 Assess infrastructure requirements of decarbonisation pathways**  
To assess need, cost, development time and ecological impact for required infrastructure to be deployed in time for assets to online.
- 6 Examine the role existing nuclear can play in green H<sub>2</sub> production**  
Co-location of electrolysers with existing nuclear can unlock additional revenue streams whilst providing additional power system flexibility.
- 7 Explore support for a construction pipeline of small modular reactors**  
To enable deployment, costs reductions and assess feasibility of large scale deployment.
- 8 Explore support options for nuclear business models for power + H<sub>2</sub>**  
To compare against other low carbon technologies.
- 9 Further investigate the benefits of high temperature nuclear (Gen IV)**  
High temperature reactors could unlock very high H<sub>2</sub> conversion efficiencies using waste heat, with potential for cost reductions.
- 10 Development of clear business models for H<sub>2</sub> and CO<sub>2</sub> infrastructure**  
To assess costs and incentivise investment.



# Glossary of terms

| Term               | Description                            | Term                 | Description  |
|--------------------|--|----------------------|--|
| UK-ETS             | United Kingdom Emission Trading Scheme | CCGT                 | Combined Cycle Gas Turbine   |
| gCO <sub>2</sub>   | Gram of carbon dioxide                 | CCS                  | Carbon capture and storage   |
| GWe                | Gigawatt Electricity                   | RES                  | Renewable Energy Sources   |
| HHV                | Higher Heating value                   | SOE                  | Solid oxide electrolyser   |
| kWhe               | Kilowatt-hour Electricity              | Blue H <sub>2</sub>  | H <sub>2</sub> derived from natural gas with CCS   |
| Mt CO <sub>2</sub> | Megatonne carbon dioxide               | Green H <sub>2</sub> | H <sub>2</sub> derived from electrolyzers  |
| MWhe               | Megawatt-hour Electricity              | Hydrogen Gigafactory | Nuclear and electrolyzers for dedicated H <sub>2</sub> production with no connection to the electricity grid               |
| TWhe               | Terawatt-hour Electricity              | Low-marginal cost    | Supply sources with low costs of producing an additional unit of output (i.e. RES and nuclear as they face low fuel costs) |
| GW H <sub>2</sub>  | Gigawatt Hydrogen                      | Capture price        | The production weighted average market price achieved  |
| kWh H <sub>2</sub> | Kilowatt-hour Hydrogen                 | Merchant             | Refers to assets that build without subsidies  |
| MWh H <sub>2</sub> | Megawatt-hour Hydrogen                 |                      |  |
| TWh H <sub>2</sub> | Terawatt-hour Hydrogen                 |                      |  |

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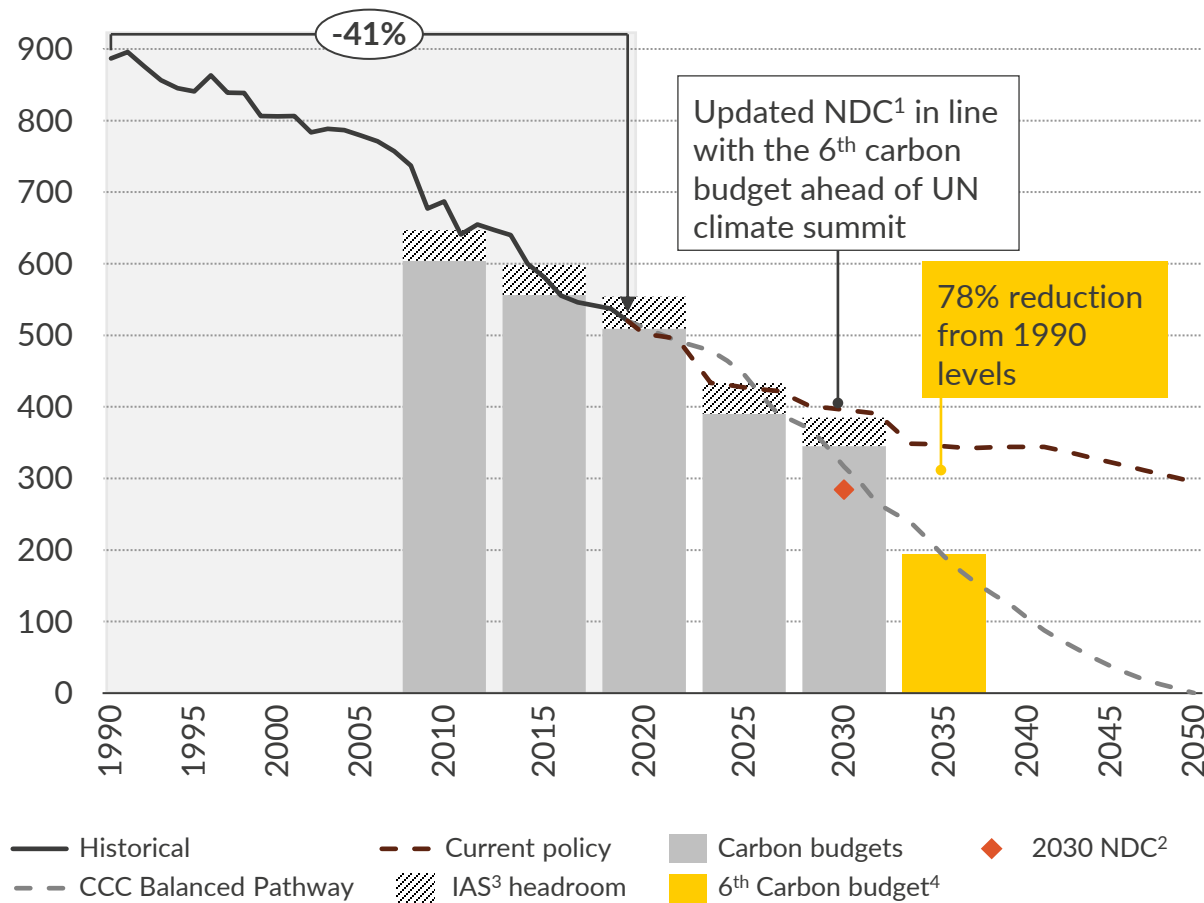
VIII. Appendix

# The UK is almost half way to net-zero but additional policies are required to meet current targets

GB has been a world leader in reducing emissions, and the first country to introduce a legally binding target of net-zero emissions by 2050 however significant challenges must be overcome to reach net-zero emissions

## Total UK Greenhouse Gas Emissions and carbon budgets

MtCO<sub>2</sub>e



- The Climate Change act (2008) committed the UK to 80% emissions reductions below 1990 levels by 2050 through setting legally binding 5-year carbon budgets advised by the Committee on Climate Change (CCC).
- The UK has seen a 41% decline in emissions since 1990 and has beaten all of its carbon budgets to date.
- This has mainly been driven by decarbonisation in the power sector, initially linked to the switch from coal to gas, and later due to the introduction of the Carbon Price Support, and growth in renewables through subsidies (see next slide).
- Further abatement efforts across the economy are expected to be increasingly challenging, especially outside of the power sector.
- The previous 5 carbon budgets, which covers the period to 2032, were based on the old 80% target for 2050. The 6<sup>th</sup> carbon budget, published in December 2020, which covers the time period between 2033 – 2037, seeks to align the UK's trajectory with its recently legislated 2050 net zero target in June 2019.
- The CCC recommend a **78% reduction from 1990 levels** across greenhouse gas emissions by 2035 (including international aviation and shipping). This new target essentially brings forward the previous 80% emission reduction target for 2050 forward by 15 years.

1) Nationally Determined Contributions; 2) NDCs excludes international aviation and shipping as per UN convention; 3) International aviation and shipping; 4) CCC's 6<sup>th</sup> Carbon budget includes IAS emissions.

# Technologies for power sector decarbonisation are plentiful; hydrogen can participate in all sectors even when options are limited

## Sectors considered in report

|  |   |   |   |   |   |
|--|---|---|---|---|---|
|  <p>Power</p> |  <p>Heat</p> |  <p>Road transport</p> |  <p>Aviation</p> |  <p>Shipping</p> |  <p>Industry</p> |
|--|---|---|---|---|---|

## Ease of abatement

|   |   |   |   |   |   |
|---|---|---|---|---|---|
|  |  |  |  |  |  |
|---|---|---|---|---|---|

## The challenge

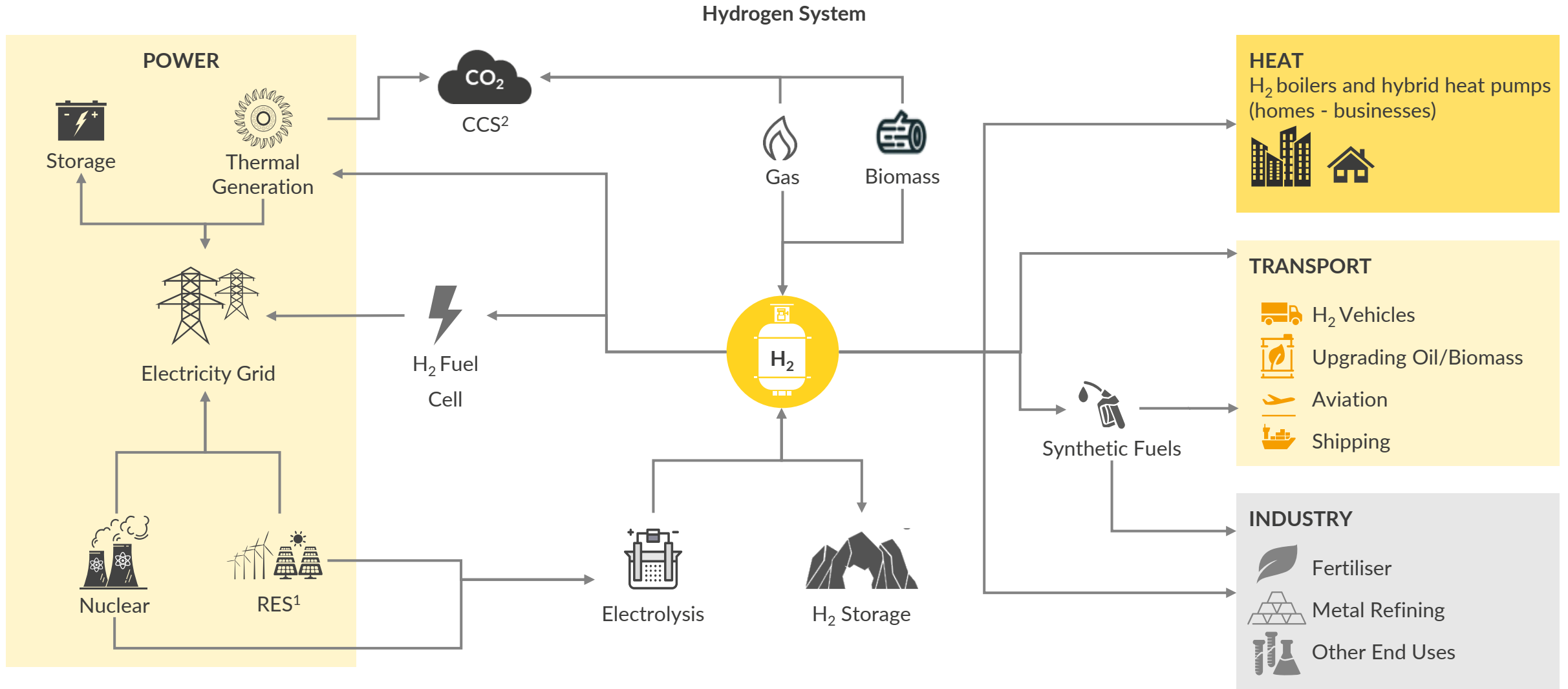
|  |   |  |   |   |  |
|--|---|--|---|---|--|
| <p>Many low carbon technologies are available; the key challenge is coping with variable RES output without relying on fossil fuels.</p> | <p>The majority of UK homes are fitted with gas boilers, with many too inefficient to be compatible with electric heat pumps.</p> | <p>Costs of electric cars have plunged but uncertainties remain for road freight. H<sub>2</sub> fuel cells/or H<sub>2</sub> derived synfuels are an alternative but yet to be deployed at scale.</p> | <p>Orders for current models until the mid 2020s, combined with aircraft lifetimes of 20-30 years could lock-in reliance on fossil fuels for decades.</p> | <p>Electric vessels could decarbonise short-haul routes but sustainable alternative fuels (SAF) are needed for long-haul routes. Long vessel lifetimes require entry by 2030.</p> | <p>Many industrial processes (i.e. steel, cement, chemicals and synfuel manufacture) rely on fossil feedstock with complete overhaul of systems and processes required to decarbonise.</p> |
|--|---|--|---|---|--|

## Low carbon solutions available

|   |   |   |   |  |  |
|---|---|---|---|--|--|
| <ul style="list-style-type: none"> <li>RES, Nuclear</li> <li>Gas-CCS</li> <li><b>H<sub>2</sub> combustion plants</b></li> <li>Batteries, DSR</li> </ul> | <ul style="list-style-type: none"> <li>Electricity (via heat pumps)</li> <li>District heating (incl. nuclear waste heat)<sup>1</sup></li> <li><b>H<sub>2</sub> boilers</b></li> <li>Alternative thermal energy storage</li> </ul> | <ul style="list-style-type: none"> <li>Electric vehicles</li> <li><b>H<sub>2</sub> fuel cell vehicles</b></li> <li><b>Synfuels (via H<sub>2</sub>)</b></li> </ul> | <ul style="list-style-type: none"> <li><b>H<sub>2</sub></b></li> <li><b>Synfuels (via H<sub>2</sub>)</b></li> </ul> | <ul style="list-style-type: none"> <li>Electricity (batteries)</li> <li><b>H<sub>2</sub></b></li> <li><b>Synfuels (via H<sub>2</sub>)</b></li> </ul> | <ul style="list-style-type: none"> <li>Electricity (batteries)</li> <li><b>H<sub>2</sub></b></li> <li><b>Synfuels (via H<sub>2</sub>)</b></li> </ul> |
|---|---|---|---|--|--|

1) District heating using waste heat from nuclear has not been considered in this report.

# Hydrogen is emerging as a potential key player to decarbonise multiple hard to abate sectors



1) Renewable Energy Sources; 2) Carbon Capture and Storage.

# Hydrogen can be produced by a range of low carbon methods, however most H<sub>2</sub> today is currently derived from fossil fuels



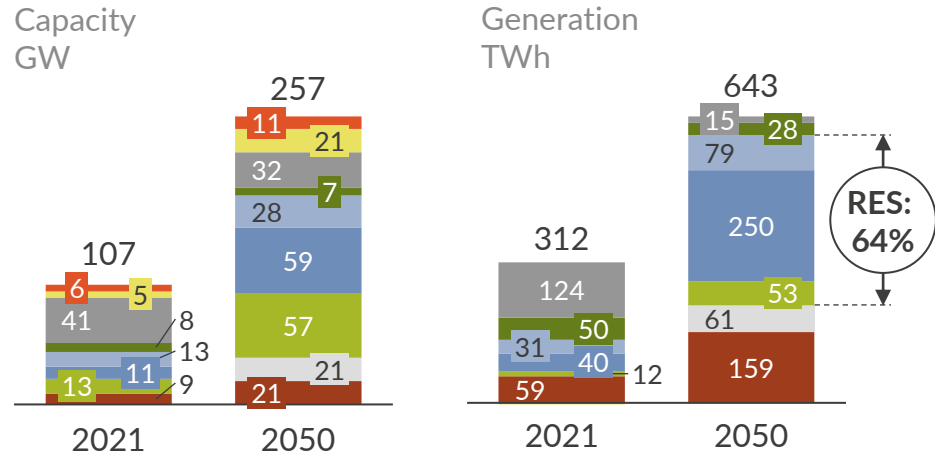
|  |                                 |  |   |   |   |
|--|---------------------------------|--|---|---|---|
| Standard nomenclature                                    | Grey                            | Blue   | Pink  | Yellow <sup>1</sup>   | Yellow  |
| Nomenclature in report                                   | Grey                            | Blue   | Green   | Green   | Yellow  |
| Conversion method  | Steam reformation               | Steam/autothermal reformation  | Electrolysis                                    | Electrolysis  | Electrolysis  |
| Primary energy source                                    | Natural gas                     | Natural gas  | Nuclear electricity and waste heat              | Zero carbon grid electricity from RES and nuclear                         | Non-zero carbon grid electricity  |
| Technologies modelled in report                          | Steam methane reformation (SMR) | Steam methane reformation with CCS (SMR+CCS)<br>Autothermal reformation with CCS (ATR+CCS) | High temperature solid oxide electrolysis (SOE) | Alkaline electrolyte membrane (ALK)<br>Polymer electrolyte membrane (PEM) | Alkaline electrolyte membrane (ALK)<br>Polymer electrolyte membrane (PEM) |
| Emissions intensity, kgCO <sub>2</sub> /kgH <sub>2</sub> | 8 - 12                          | 0.6 - 1  | 0   | 0   | 0 - 9   |

1) Note that the current European Commission definition of green H<sub>2</sub> differs to that used in this report. The EU states that H<sub>2</sub> can only be considered green if created using electricity from new, H<sub>2</sub> production dedicated RES assets that do not provide electricity to the grid 2) No "yellow" electrolysis is seen in the core scenarios and electrolyzers only produce when power prices are low.

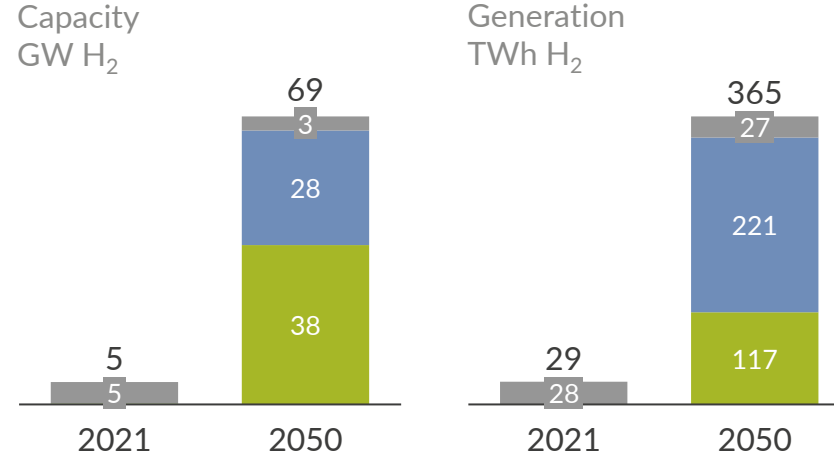
- I. Executive summary
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- VIII. Appendix

# Aurora's in-house Net Zero view sees strong deployment of RES capacity, with wind making up >50% of generation in 2050

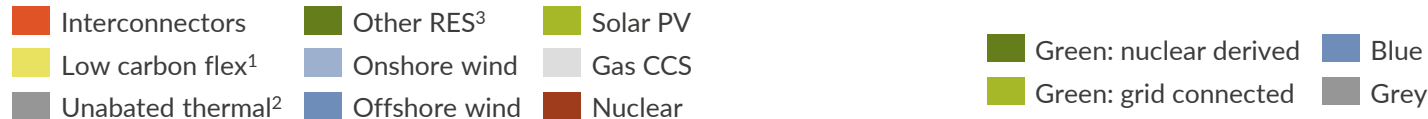
GB power Production in 2050 – Aurora Net Zero



GB hydrogen Production in 2050 – Aurora Net Zero



- Aurora forecasts demand to more than double by 2050 to meet rising electricity demand, driven by the decarbonisation of sectors including heat and transport via electrification and hydrogen via electrolysis. The core scenarios modelled in this report see a 68% - 103% increase in electricity demand.
- Power capacities are similarly required to increase due to the replacement of unabated thermal plants which run at high capacity factors of over 80% with RES, which run at comparatively lower load factors and require additional battery storage and peaking capacities.
- GB does not match the specific support for electrolytic H<sub>2</sub> seen in other European countries like Germany and 60% H<sub>2</sub> supply in 2050 is forecast to come from fossil based blue H<sub>2</sub>.



- Our in-house Net Zero scenario reflects all recent government targets, including the Energy White Paper's 40GW of offshore wind and capture of 10 MtCO<sub>2</sub> via CCS by 2030.
- Installed power capacity increases by 150 GW across the horizon, driven by rapid growth of renewable and peaking capacity.
- Hydrogen capacity increases by almost 20x across the horizon, with electrolysers and ATR+CCS being key contributors to hydrogen production in the long-term.
- The scenarios modelled in this report do not represent Aurora's forecasts but instead explore the implications of high nuclear systems.

1) Low carbon flex includes DSR, battery storage, hydrogen peakers, hydrogen CCGT, pumped storage 2) Other RES includes biomass, BECCS, EfW and marine; 3) Unabated thermal includes CCGTs, gas peaking, embedded CHP.



# What's new?

The majority of studies on the future of the hydrogen sector in GB focus electrolytic H<sub>2</sub> from RES and fossil based H<sub>2</sub> with CCS. The potential for nuclear to participate in the H<sub>2</sub> economy is often not considered due to high costs of recent assets and lack of clear policy direction leading to planned projects being put on hold. This study investigates how policy support for new nuclear technologies and business models to provide low carbon electrolytic H<sub>2</sub> could reduce nuclear and system costs whilst reducing reliance on fossil fuels when deployed alongside RES on the path to net-zero.

## Research questions

- 1 Routes to decarbonise**  
Can total system costs and emissions be reduced by including nuclear in a net-zero strategy?
- 2 The hydrogen economy**  
How could renewables and new nuclear technologies influence the hydrogen economy?
- 3 The role of nuclear**  
Can new nuclear business models and technologies with co-located H<sub>2</sub> production provide flexibility to the grid, displace reliance on fossil fuels and improve nuclear economics?

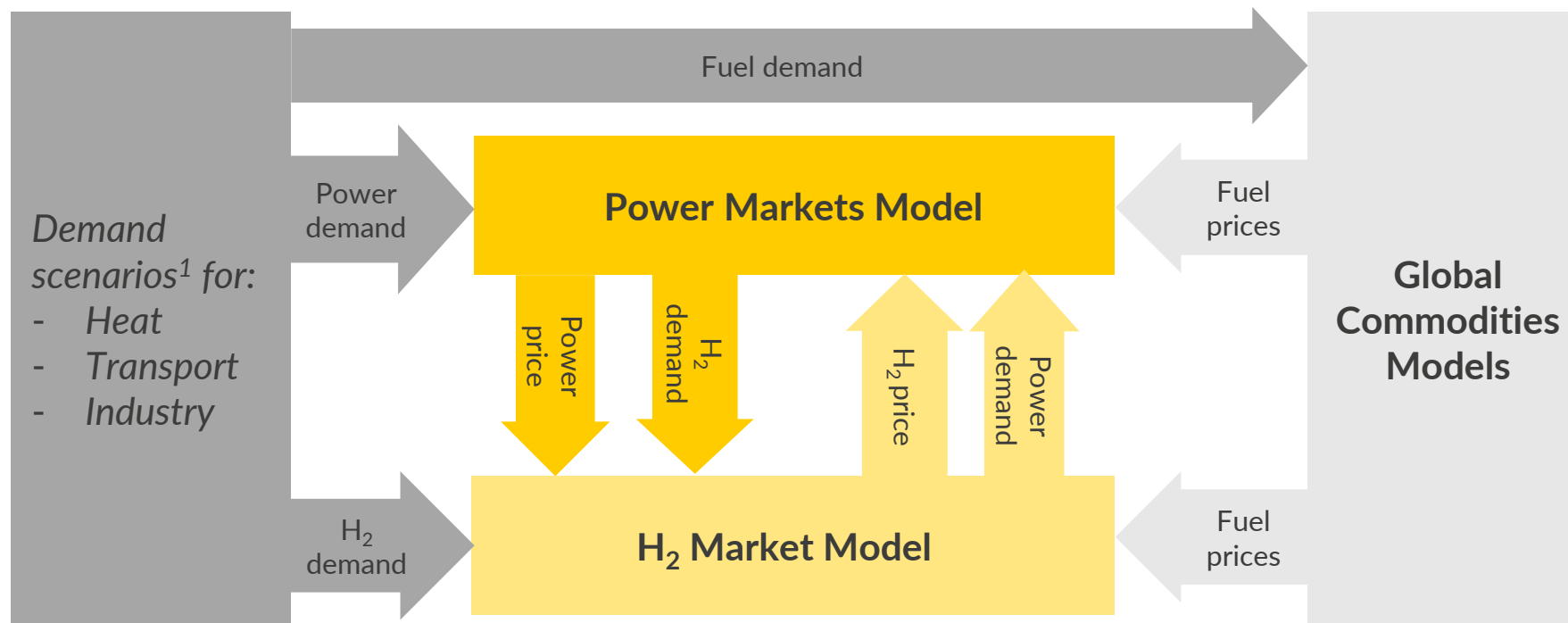
## Modelling approach

- 1 Integrated in-house modelling simultaneously solves for supply mixes in power and hydrogen markets**
- 2 Use of a capacity market with a high carbon price to incentivise economic entry of low carbon capacity**
- 3 Modelling new nuclear technologies and business models in the power sector**
- 4 Economic entry of hydrogen supply from nuclear**
- 5 Discussion of the implications of each modelled scenario for policy and consumers in addition to the risks associated with achieving net-zero**

# This study utilises our integrated modelling suite to capture market interactions and impacts of deploying RES and nuclear

## 1 Integrated in-house modelling and economic entry of capacity in power and hydrogen markets

Overview of Aurora's modelling suite



Aurora's analytical approach is based on an integrated framework that covers the entire energy system, using:

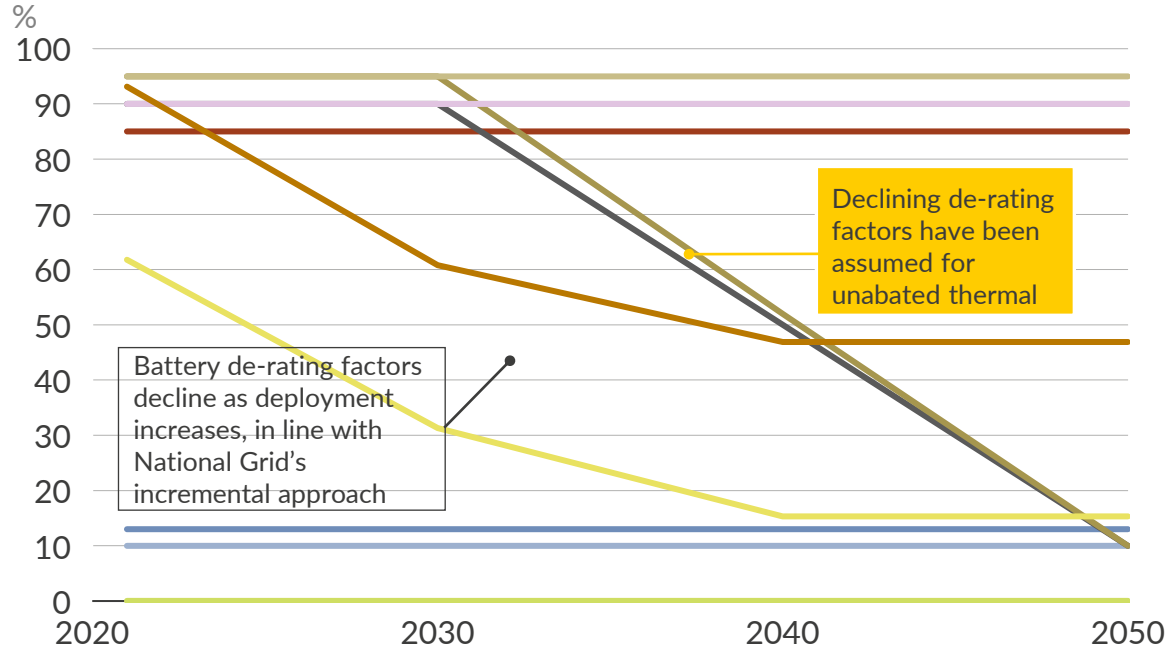
- internally consistent gas, power and H<sub>2</sub> demand scenarios for heat, transport and industry
- commodity price forecasts that reflect a Net Zero outlook for Europe
- a modelling suite that highlights feedback loops across H<sub>2</sub> and power markets.

By integrating H<sub>2</sub> and power market modelling, Aurora's approach captures the interactions of power and H<sub>2</sub>.

# A revised Capacity Market is used to deploy low carbon capacity but has limited effectiveness in fully merchant low marginal cost systems

## 2 Use of a capacity market to incentivise economic entry of low carbon capacity

Capacity market de-rating factor (i.e. contribution to security of supply)



$$\text{Annual CM payment, } \pounds = \text{Auction clearing price, } \pounds/\text{MW} \times \text{De-rating factor, } \% \times \text{Nameplate capacity, MW}$$

- Nuclear
- Offshore Wind
- CCGT
- Reciprocating gas engine
- Hydrogen OCGT
- Battery storage (4h)
- Onshore Wind
- Solar PV
- CCGT + CCS
- Hydrogen CCGT
- Battery storage (2h)

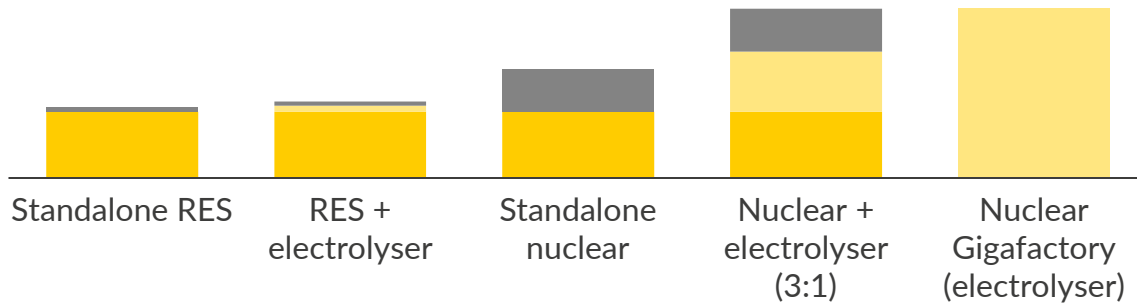
- The Capacity Market (CM) awards contracts, paid to existing (1yr) and new-build (15yr, 1yr) assets on a £/kW basis in a pay-as-clear auction, to ensure there is sufficient capacity to meet demand.
- De-rating factors are applied to each technology to reflect their contribution to security of supply and influence the size of the payment received and the volume of capacity procured each year.
- Typically, the CM payment covers any shortfall in forecast revenue from wholesale and balancing markets, and ancillary services required to keep existing capacity online or enable entry of new capacity.
- In this modelling exercise, all capacity entering post-2030 in the core market scenarios is assumed to enter economically on a merchant basis (i.e. without direct subsidy support) based on returns available in model and the use of the CM has been expanded to procure low-carbon capacity by assuming declining de-rating factors for unabated thermal assets.
- As the CM is the only tool providing contracted revenues to top-up any shortfalls in wholesale and balancing markets, this modelling approach favours the build of firm dispatchable capacity to meet supply targets (i.e. nuclear, gas-CCS) over RES that contributes less to security of supply.
- Merchant RES build-out in systems with high shares of low-marginal cost supply and a low carbon CM will inherently be low.

Note that the current administrative CM price cap of £75/kW has been removed for this exercise.

# Economic entry of RES and nuclear under a range of business models have been considered in this report

## 3 Modelling new nuclear technologies and business models in the power sector

Revenue streams for new capacity (illustrative)  
£/kW



- Most RES capacity in GB has been deployed via direct support i.e. CfDs<sup>1</sup>, however merchant business models, especially with PPA<sup>2</sup> contracts are increasing.
- Dedicated RES for H<sub>2</sub> co-located with electrolyzers do not deploy in this modelling without very high RES deployment but mechanisms could be introduced to facilitate these business models.
- New nuclear in GB has recently been supported with a CfD but other options are being explored (i.e. RAB model).
- The majority of new nuclear in this modelling builds with a co-located electrolyser for H<sub>2</sub> as this enables nuclear to secure higher value for power output in H<sub>2</sub> markets when electricity prices are low.
- Colocation of RES or nuclear with electrolyzers could reduce market risk and therefore discount rates, however this has not been modelled in this report.

■ Wholesale electricity ■ Wholesale hydrogen ■ Capacity market

### Overview of modelled nuclear business models

|   | Unit size (MW <sub>e</sub> ) | Electrolyser pairing | H <sub>2</sub> conversion efficiency (% HHV) <sup>3</sup> | Description   |
|---|------------------------------|----------------------|---|---|
| Existing nuclear: large scale (gen III) | c.1500                       | PEM/ Alkaline        | 75%   | Hinkley Point C and Sizewell B are assumed to install onsite electrolyzers in 2030.                           |
| Large scale (gen III)                   | c.1500                       | Solid oxide          | 107%  | Same underlying technology but smaller unit sizes facilitate siting closer to demand centres.                 |
| Small scale (gen III)                   | <300                         | Solid oxide          | 107%  |   |
| Large/small scale (gen IV)              | c.1500 / <300                | Solid oxide          | 114%  | High temp. reactors allow greater efficiency of electrolysis using high grade heat.                           |
| Gigafactory (gen IV)                    | Min. 1000                    | Solid oxide          | 114%  | Dedicated H <sub>2</sub> production facility with nuclear & electrolyzers near H <sub>2</sub> demand sources. |

1) Contract for Difference 2) Power Purchase Agreement (PPA) 3) MWh electric to MWh H<sub>2</sub> conversion, values greater than 100% achieved for solid oxide electrolyzers due to the added energy input from heat.

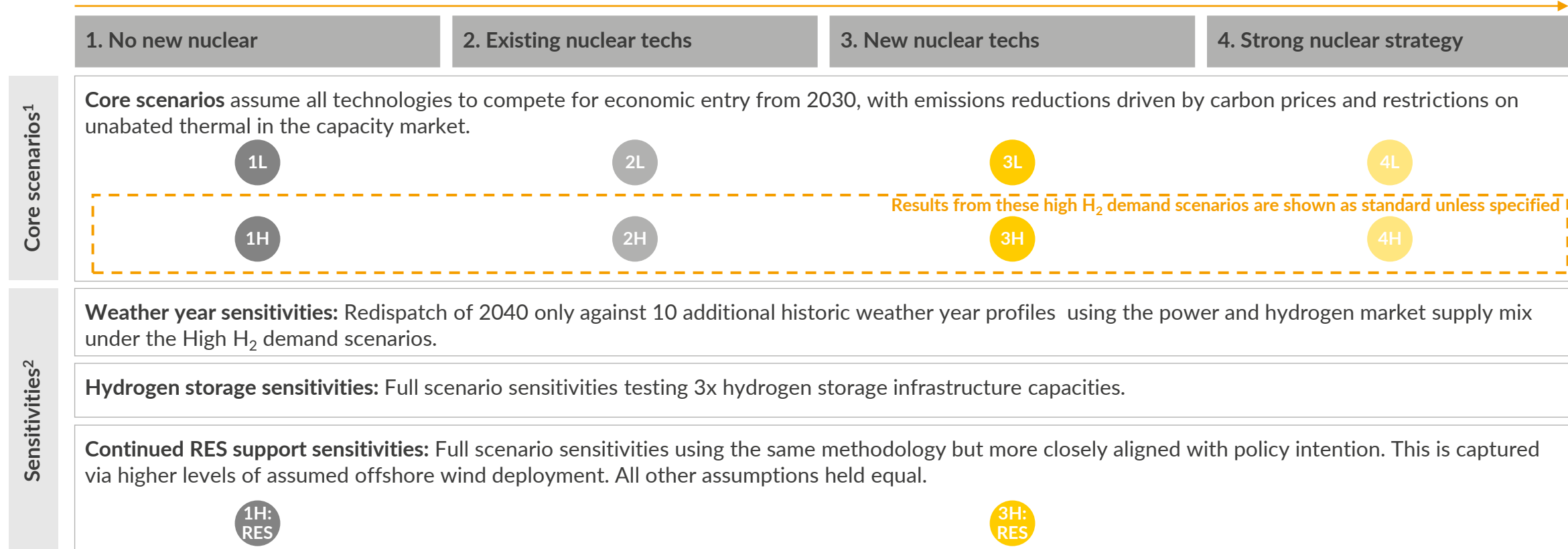
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# 8 core market scenarios explore 4 alternative nuclear supply pathways under two H<sub>2</sub> demand outlooks

Modelled GB market scenarios

#L Low H<sub>2</sub> demand #H High H<sub>2</sub> demand

Increasing nuclear ambition →



The scenarios that follow are exploratory scenarios to investigate the role of nuclear and H<sub>2</sub> in reaching net-zero and are not forecasts.

1) Core scenario modelling results are explored in detail in Section V; 2) Sensitivity analysis is presented in Section VI.

# Overview of core market scenario assumptions

| Key assumptions                 | 1. No new nuclear   | 2. Existing nuclear techs   | 3. New nuclear techs | 4. Strong nuclear strategy |
|---------------------------------|---|---|----------------------|----------------------------|
| Electricity demand <sup>1</sup> | 2021: 312 TWh rising to 2050: 445 TWh (High H <sub>2</sub> ), 496 TWh (Low H <sub>2</sub> )   |   |                      |                            |
| H <sub>2</sub> demand           | 2021: 28 TWh H <sub>2</sub> rising to 2050: 508 TWh H <sub>2</sub> (High H <sub>2</sub> ), 210 TWh H <sub>2</sub> (Low H <sub>2</sub> )   |   |                      |                            |
| H <sub>2</sub> storage          | 2050: 26 TWh H <sub>2</sub> (High H <sub>2</sub> ), 18 TWh H <sub>2</sub> (Low H <sub>2</sub> ), Includes salt caverns and pipelines  |   |                      |                            |
| Commodities                     | Gas: Base case, Carbon price: Base case   |   |                      |                            |
| Nuclear business models         | Hinkley Point C and Sizewell B are co-located with PEM electrolyzers  |   |                      |                            |
|                                 |   | <ul style="list-style-type: none"> <li>LWSMR co-located with SOE electrolyzers</li> <li>New large nuclear co-located with SOE electrolyzers</li> </ul>  |                      |                            |
|                                 |   | <ul style="list-style-type: none"> <li>Gen IV co-located with SOE electrolyzers</li> <li>Gigafactory of gen IV reactors and SOE electrolyzers exclusively for H<sub>2</sub> production</li> </ul> |                      |                            |
| Nuclear costs                   | Base  |   |                      | Low                        |
| Policy support                  | <p><b>Capacity Market:</b> All technologies are allowed to participate with de-rating factors reflecting contribution to security of supply. Unabated thermal can only secure 1yr contracts post-2030 and their de-rating factors decline from 90% in 2030 to 10% by 2050.</p> <p><b>Other:</b> Existing subsidies applied, and a further 9.3 GW offshore wind supported by CfDs to reach 40GW deployment by 2030. Unabated CCGTs are not allowed to build post-2030.</p> |   |                      |                            |
| Build decisions                 | Economic entry of capacity assuming 5% discount rates for low carbon technologies (incl. nuclear, RES, gas-CCS, all H <sub>2</sub> production technologies, hydrogen CCGTs and hydrogen OCGTs) and 11% for other technologies.  |   |                      |                            |

Note that the high H<sub>2</sub> demand scenarios are shown as default in the main body of the report unless specified. Please see Appendix for detailed assumptions.

1) Excluding demand from electrolyzers for H<sub>2</sub>.

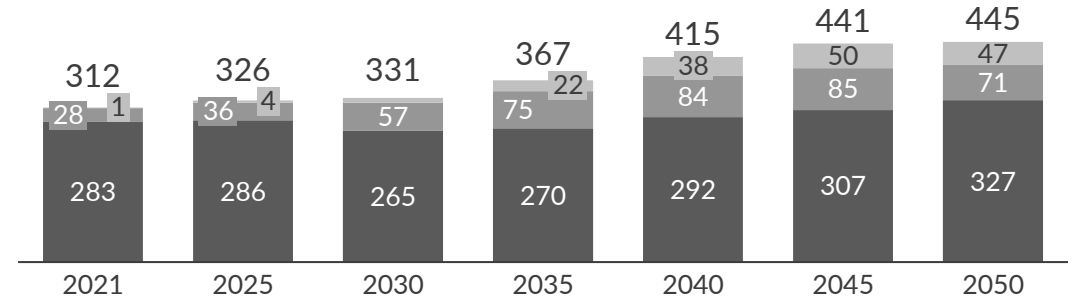
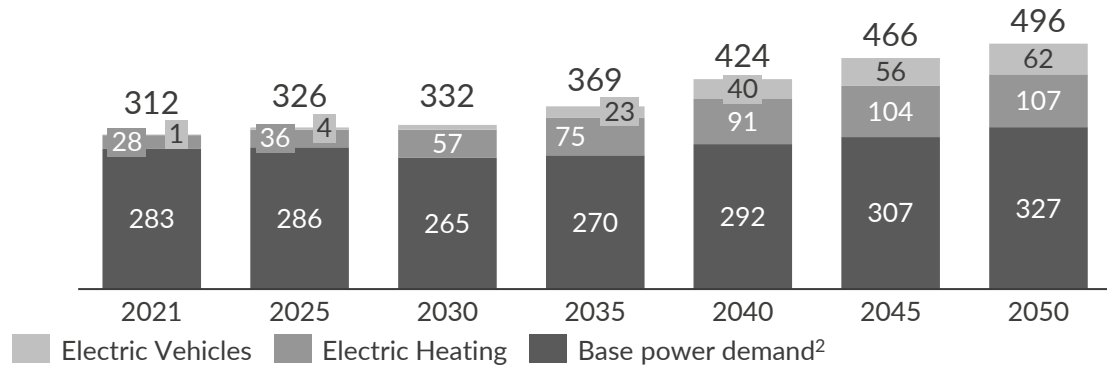
# Two internally consistent hydrogen demand scenarios are modelled, with implications for power demand

Low H<sub>2</sub> demand

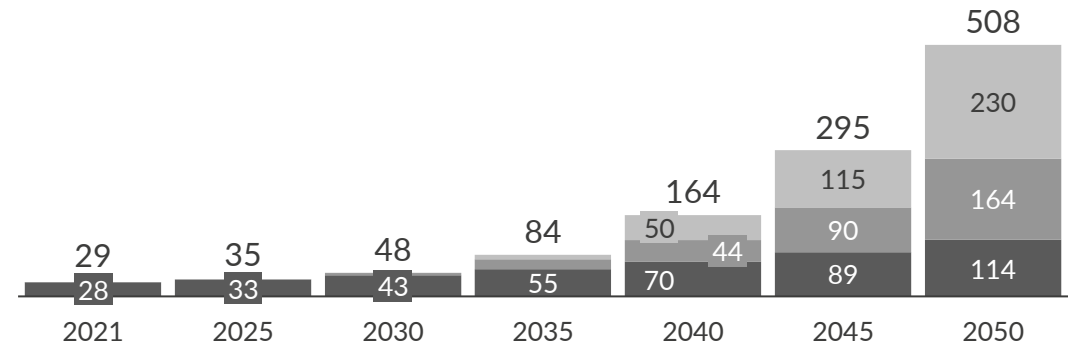
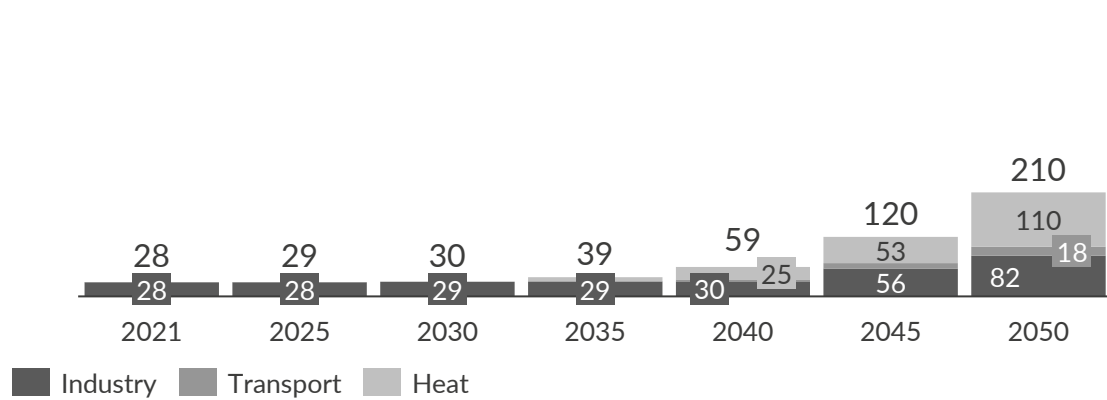
High H<sub>2</sub> demand

GB annual power demand by sector<sup>1</sup>  
TWh electricity

Additional power demand from electrolyzers is excluded as this is a model output but total system demand increases 68-103% from 2021 to 2050 across the core scenarios



GB annual hydrogen demand by Sector  
TWh H<sub>2</sub>

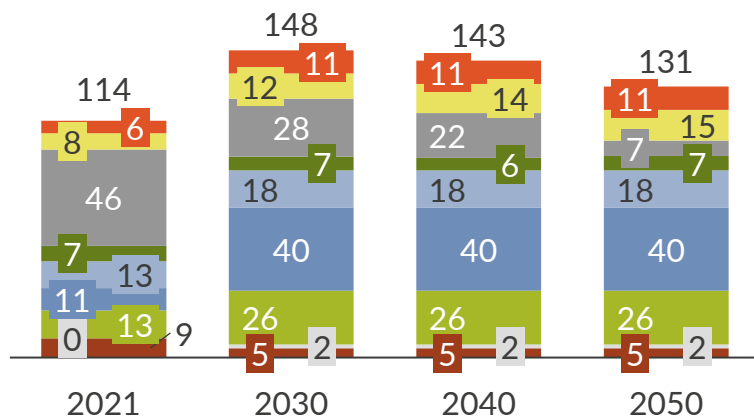


1) Excludes power demand from electrolyzers for H<sub>2</sub> production as this is a model output. Total power demand therefore varies in each market scenario.

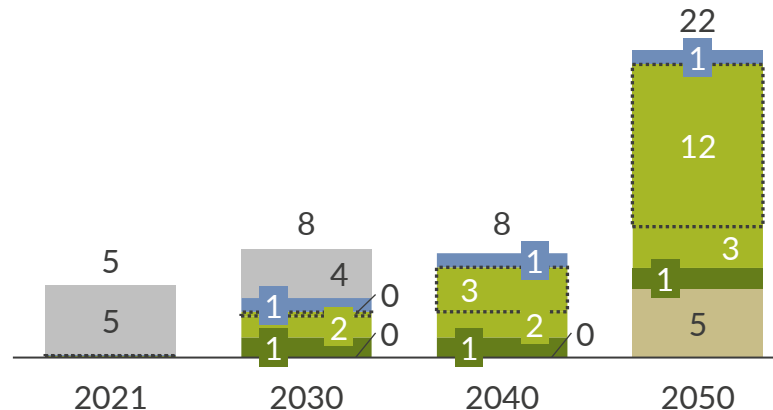


# Assumed capacity deployment in the power and H<sub>2</sub> is consistent across scenarios; all other capacity decisions are solved in model

GB assumed power capacity timelines across all scenarios<sup>1</sup>  
GW



GB assumed hydrogen capacity timeline across all scenarios<sup>1</sup>  
GW



- RES – assumed capacity is constant from 2030 in all scenarios
- Nuclear – existing capacity retires by 2030 except Sizewell B (2055). Hinkley Point C (HPC) enters from 2028.
- Thermal - Existing thermal assets may retire if insufficient revenues are secured in model. Coal assets must retire by 2024.
- BECCS – capacity is assumed to enter to secure “negative emissions”.

- Current H<sub>2</sub> supply is sourced from SMRs.
- 50% of H<sub>2</sub> transport demand is met by PEM electrolyzers at fuel cell charging stations that do not interact with the market.
- Known blue H<sub>2</sub> pilot plants are assumed for entry by 2030
- H<sub>2</sub> storage in the form of pipelines and salt caverns is assumed.
- BECCS for H<sub>2</sub> production is also assumed to secure “negative emissions”.

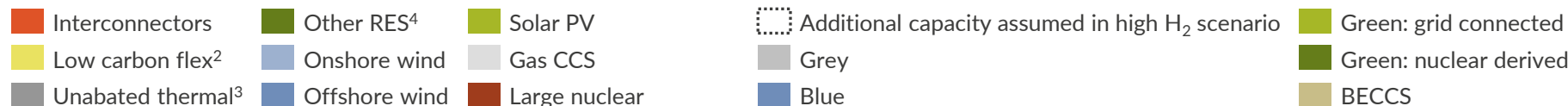
The majority of capacity until 2030 in both the power and hydrogen markets is assumed as a model input.

This assumption reflects:

- currently installed capacity
- known additions including contracted capacity, and
- some forecast additions reflecting current policy (i.e. 40GW offshore wind deployment by 2030).

Any additional capacity required to meet demand is built within model based on profitability of individual plants under each scenario.

All assumed capacity is incorporated in total system cost calculations.

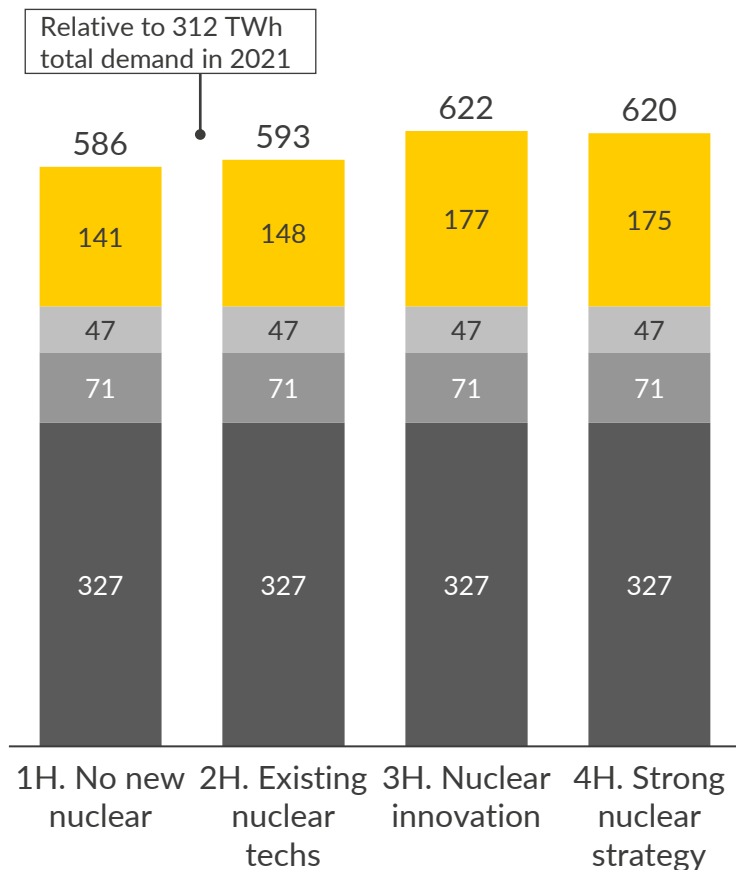


1) Capacity can retire if uneconomic so assumed capacity, particularly thermal may be lower in the model outputs; 2) Low carbon flex includes DSR, battery storage, hydrogen peakers, hydrogen CCGT, pumped storage 3) Other RES includes biomass, BECCS, EfW and marine; 4) Unabated thermal includes CCGTs, gas peaking, embedded CHP.

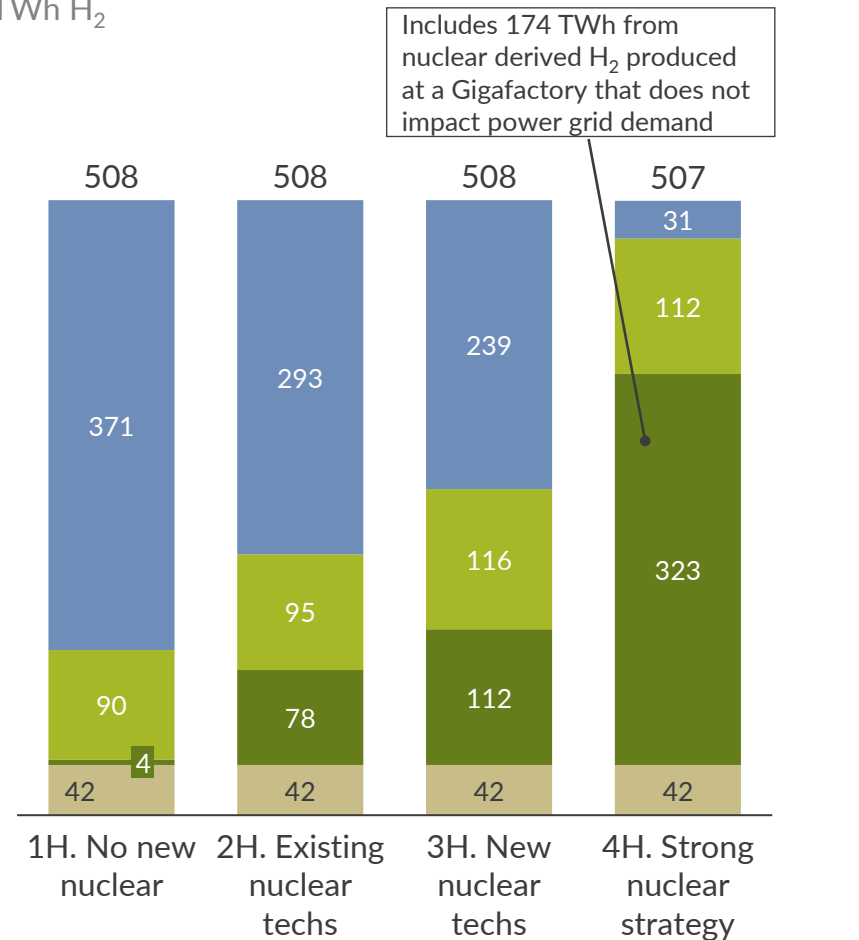
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  - 1. System level impacts
  - 2. Power market impacts
  - 3. H<sub>2</sub> market impacts
- VI. Risks to the transition
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# High nuclear scenarios lead to higher power demand than low H<sub>2</sub> scenarios, driven by increased demand from electrolytic H<sub>2</sub>

GB 2050 Power Demand  
TWh



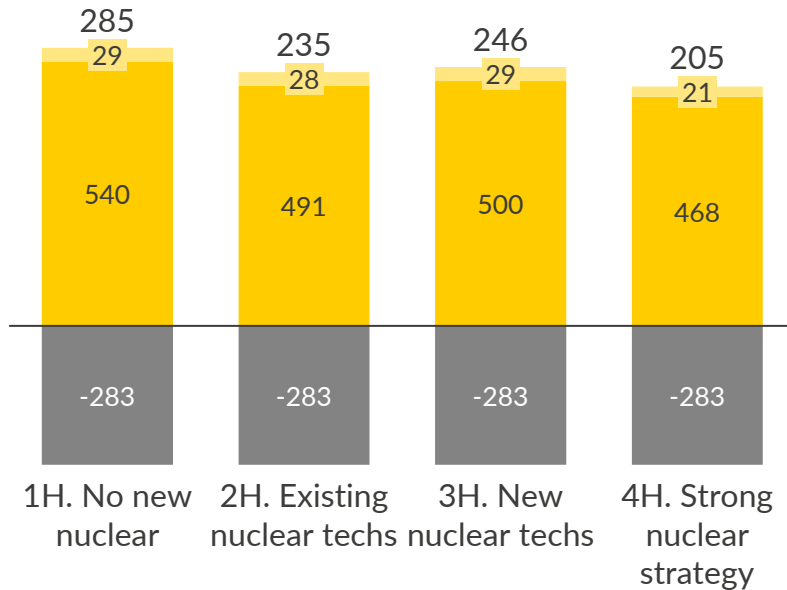
GB gross H<sub>2</sub> production in 2050  
TWh H<sub>2</sub>



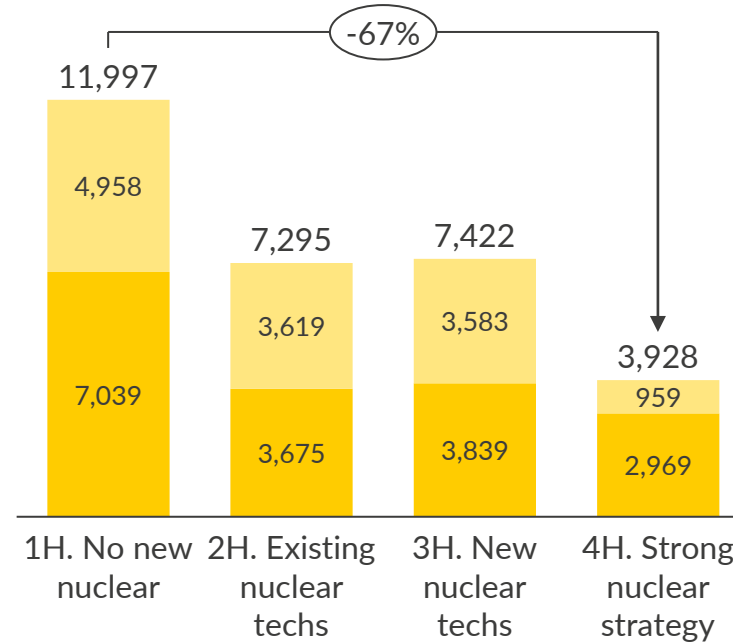
- High nuclear penetration not only enables stable production of H<sub>2</sub> from collocated electrolyzers, it also increases hydrogen production via standalone electrolyzers by providing cheap power to the grid at high load factors.
- Despite resulting in higher energy demand, high levels of nuclear open up pathways to Net Zero with lower systems costs and emissions.

# Systems with higher levels of nuclear deployment lead to lower emissions from the power and hydrogen sectors

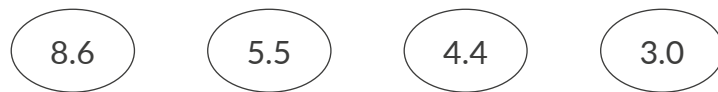
GB cumulative power and H<sub>2</sub> emissions from 2021-50  
MtCO<sub>2</sub>



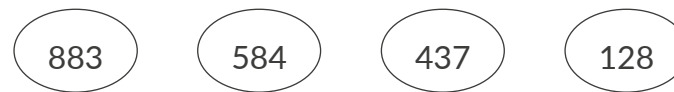
GB cumulative power and H<sub>2</sub> gas usage from 2021-50  
TWhth HHV



GB power and H<sub>2</sub> sector emissions in 2050 excluding BECCs  
MtCO<sub>2</sub>



GB total power and H<sub>2</sub> gas usage in 2050  
TWhth HHV



Power production Hydrogen production BECCs

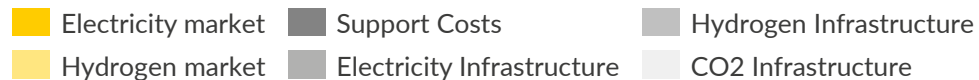
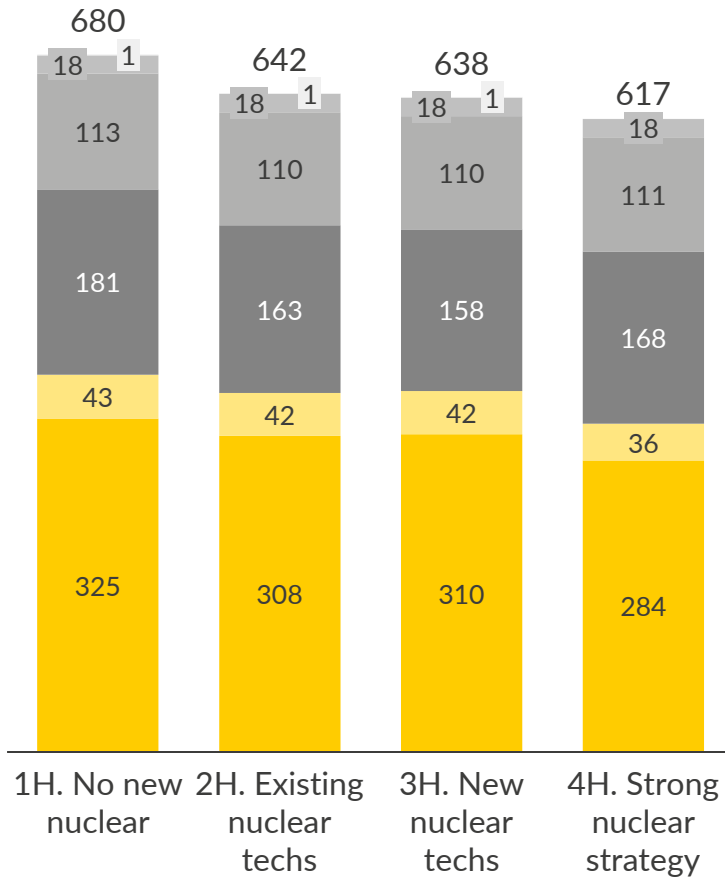
Power sector Hydrogen sector

- Scenario 4H achieves net zero with the lowest emissions and fuel use.
- 1H has the highest fuel use due to high RES intermittency.
- Potential to cancel out up to 36 MtCO<sub>2</sub> annually by considering negative emissions from sustainable biomass paired with CCS.
- Fossil fuel usage is reduced dramatically as nuclear is added to the mix, with 4H having one third the reliance on gas of scenario 1H.

# Electricity prices are the single biggest driver of deltas in system costs and outweigh deltas in infrastructure and support costs

GB NPV total system spend from 2021 – 2050<sup>1</sup>

£bn



## Key drivers

- **Electricity market spending** is the key driver of total system spend across scenarios and is directly linked to the supply mix. Scenarios with a high share of RES and nuclear dampen electricity prices, whereas scenarios that rely on more expensive fossil based sources for baseload and flexibility see higher electricity prices.
- **Hydrogen market spending** is similar across scenarios as prices are typically set by blue H<sub>2</sub> and strongly correlated with gas prices. Lower costs in 4H are driven by nuclear derived electrolytic H<sub>2</sub> meeting demand in summer.
- **Support costs** are strongly linked to electricity market prices as low wholesale market revenues lead to higher top-ups for existing contracts (CfDs) and higher CM payments for new capacity to break even. The need for higher support costs in 4H due to low electricity prices is counteracted by lower costs for nuclear and a smaller system overall.
- **Infrastructure costs** are similar across all core scenarios as systems are of a similar size and H<sub>2</sub> and CO<sub>2</sub> costs are volumetric. H<sub>2</sub> and CO<sub>2</sub> costs could vary much more depending on proximity of supply to demand.

## Overview of cost items<sup>2</sup>

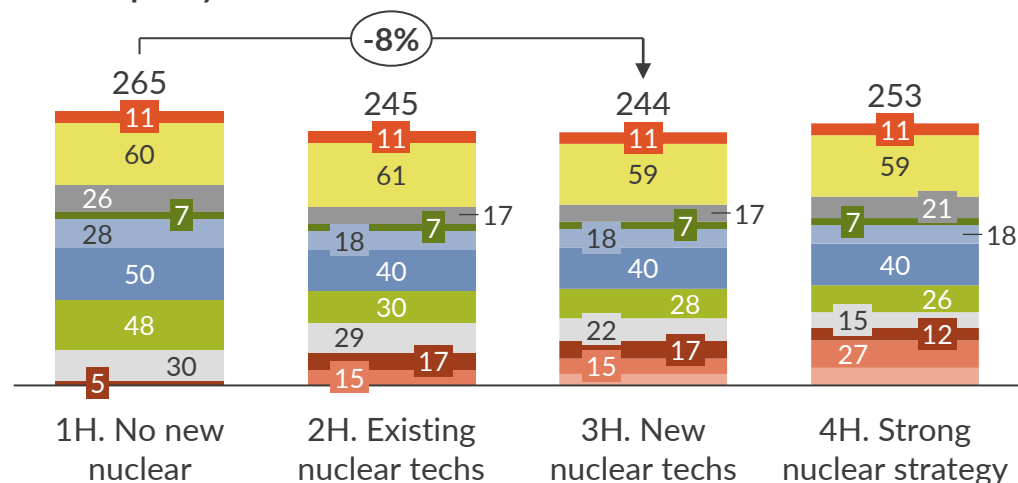
- **Electricity market:** wholesale and balancing market price multiplied by volume.
- **Hydrogen market:** hydrogen market price multiplied by volume.
- **Support costs:** Capacity Market (CM), existing schemes (i.e. CfD) and any top-ups required for assumed capacity to break even.
- **Electricity network:** investment required to maintain and expand the transmission and distribution grids as new capacity is added.
- **H<sub>2</sub> and CO<sub>2</sub> infrastructure:** the capital investment required to transport and store the H<sub>2</sub> and captured CO<sub>2</sub> respectively from power and H<sub>2</sub> generation only.

1) Costs are discounted using a rate of 5% 2) See appendix for further details on methodology.

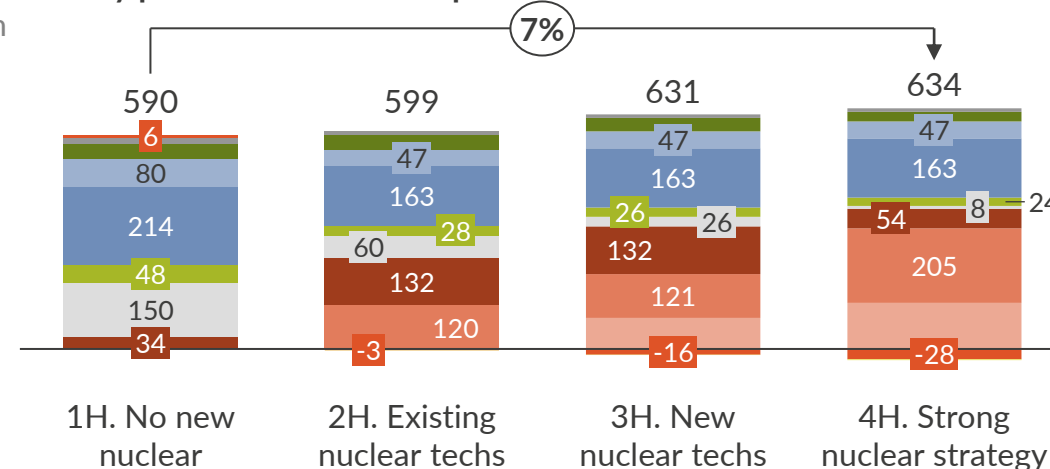
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# Deploying RES alongside nuclear could reduce power system reliance on fossil fuels to just 3% of supply in the strong nuclear strategy case

GB installed capacity in 2050  
GW



GB electricity production and net imports in 2050  
TWh



- 1H with no new nuclear sees just 66% supply met by RES and nuclear and relies on fossil fuels for 28% of supply. Enabling new nuclear to co-locate with electrolyzers for H<sub>2</sub> production could drastically reduce reliance on fossil fuels. By comparison, 3H enables 90% generation to be met by nuclear (53%) and RES (37%) and just 6% provided by fossil fuels. Low nuclear costs assumed in 4H enable 95% generation to be met via nuclear and RES with just 3% from fossil fuels.
- The low nuclear costs in 4H enable small modular and gen IV reactors to be cost competitive with large reactors, displacing 5 GW large reactors and 18 GW small and gen IV reactors.
- Limited RES build out is observed in all new nuclear scenarios due to low capture prices and higher returns for dispatchable capacity.
- Enabling substantial nuclear deployment can reduce overall system size by 8% in 3H relative to 1H as less overall capacity is required to meet demand. This is offset slightly in 4H where the increased levels of low marginal cost generation facilitate greater utilisation of electrolyzers for H<sub>2</sub> and a resulting 6% increase in power demand, resulting in a larger system size. This has implications on land use and network costs.

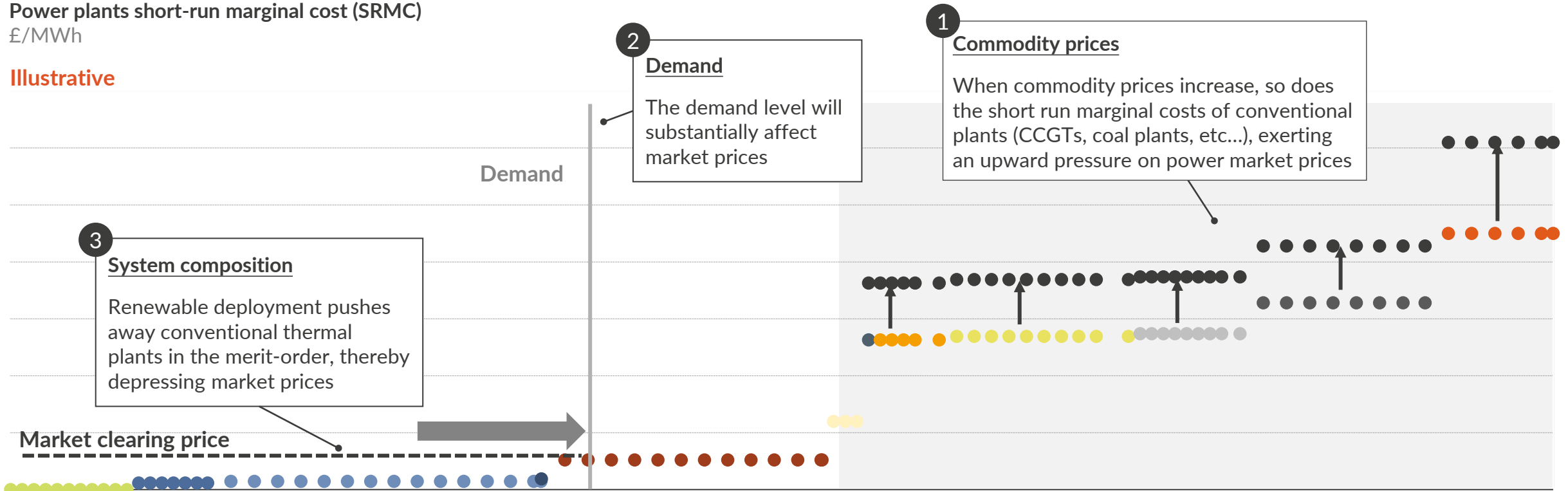


1) Low carbon flex includes DSR, battery storage, hydrogen peakers, hydrogen CCGT, pumped storage 2) Other RES includes biomass, BECCS, EfW and marine; 3) Unabated thermal includes CCGTs, gas peaking, embedded CHP.

# Three key factors determine power prices, with high penetration of RES and nuclear leading to lower prices

Power plants short-run marginal cost (SRMC)  
£/MWh

Illustrative



RES and nuclear are “low marginal cost” technologies due to zero or low fuel costs

The marginal cost of storage varies depending on the price paid to store energy, due to the need to capture sufficient spreads between charge and discharge costs

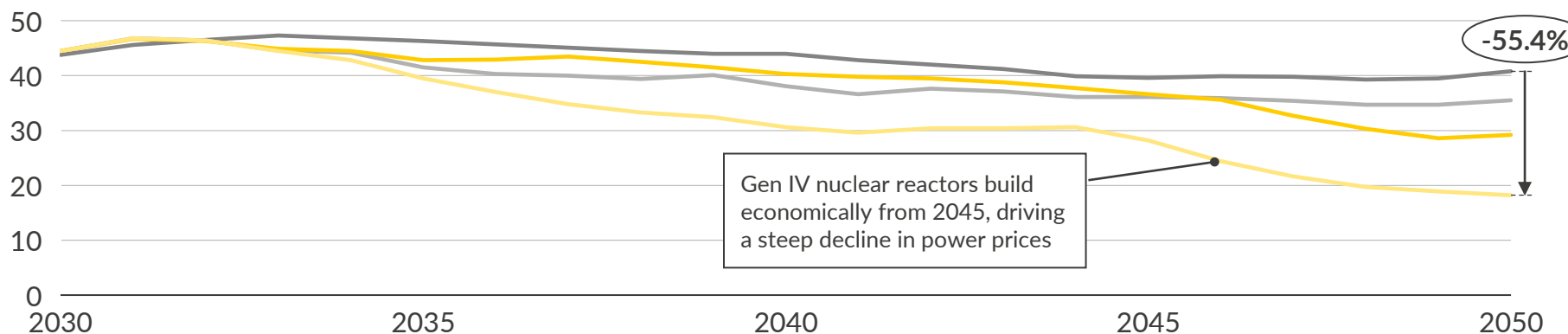
Thermal assets have the highest SRMC driven by fuel and carbon costs

- Solar
- Wind
- Biomass
- Battery storage
- CCGT
- Higher carbon price SRMC
- Hydro run-of-river
- Nuclear
- Pumped storage
- CCGT+CCS
- Gas peakers

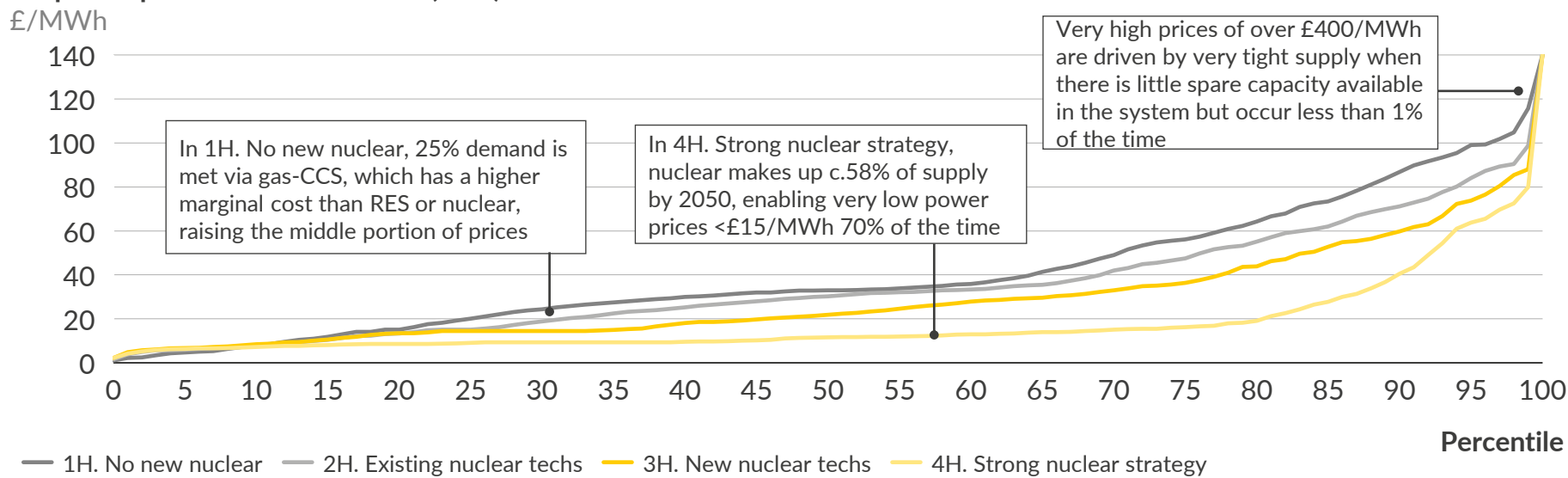


# Higher levels of nuclear generation lead to a greater frequency of low price periods

GB wholesale electricity price  
£/MWh (real 2019)



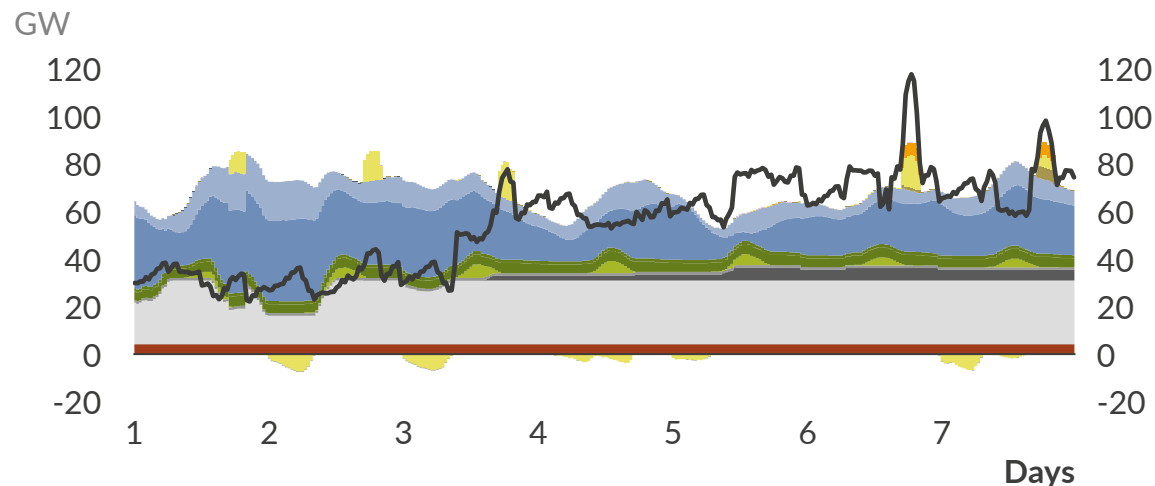
GB power price distribution curve (PDC) in 2045



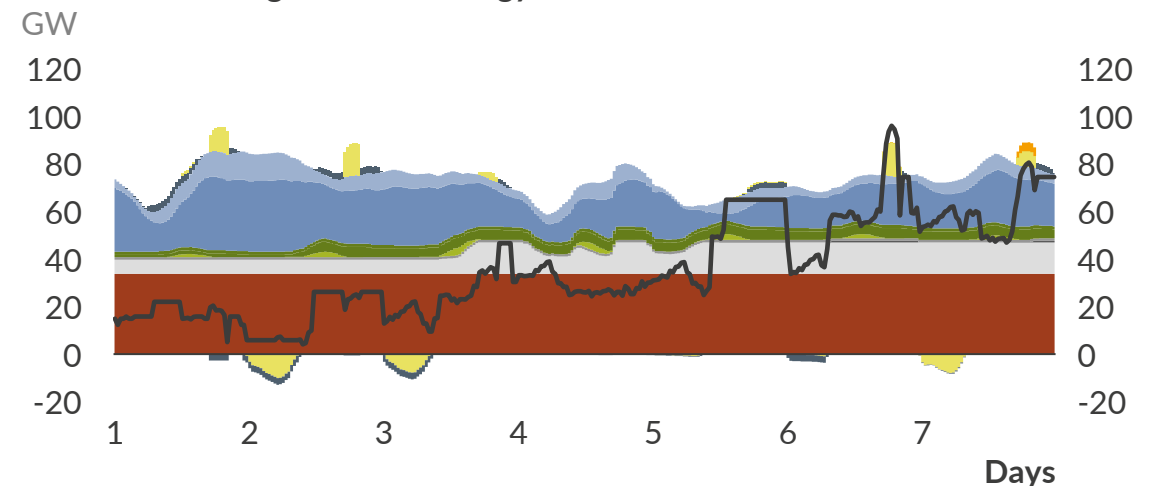
- The low marginal cost of nuclear generation keeps it almost always in merit.
- Large volumes of nuclear generation push more expensive thermal generation out of merit, allowing a cheaper technology to set the price.
- This leads to the wholesale baseload price in 2050 in Scenario 4H to be half of that in Scenario 1H.
- Scenario 4H sees prices below £20/MWh for more than half the settlement periods in 2045.
- None of the scenarios see negative prices by 2045 due to the lack of remaining RES assets with high subsidy payments or thermal that doesn't ramp down in face of low prices.

# Nuclear can meet baseload requirements, reducing the reliance on fossil fuelled gas-CCS by 3 TWh in one sample winter week alone

GB power supply sample winter week in 2045: 1H – No new nuclear



GB power supply sample winter week in 2045: 4H – Strong Nuclear Strategy



- During the winter solar generation in GB is minimal, so wind is the dominant source of renewable power generation, but it is not dispatchable.
- The sample winter week which sees a high price point corresponding to system tightness/ strain due to somewhat low instantaneous wind output during a period of high demand.
- Due to large amounts of cheap baseload low carbon generation, Scenario 4H is able to cope with system stress without gas peakers, keeping prices and emissions lower than in 1H. The contribution of nuclear to system resilience will be explored further in future weather sensitivity analysis.
- The many nuclear plants in 4H displace gas ccs as the dominant baseload supply, and are a more reliable source of clean power, as they are less likely to be pushed out of merit due to their low marginal cost.

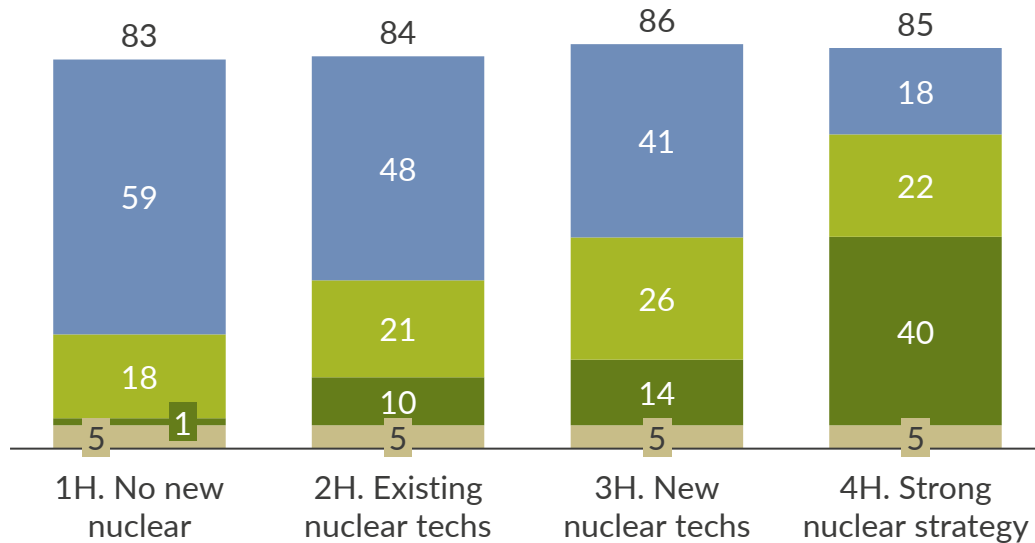


1) Peaking includes gas recipis, OCGTs 2) Other RES includes biomass, BECCS, EfW and marine; 3) Other thermal includes embedded CHP.

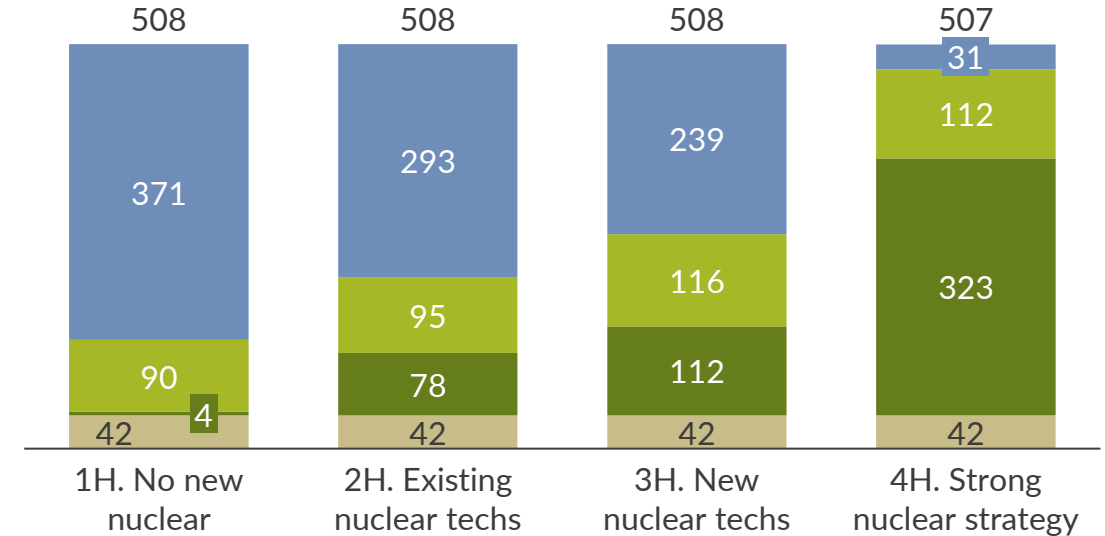
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# Low nuclear costs and economic entry of a hydrogen Gigafactory enable reliance on fossil H<sub>2</sub> to drop to 6% by 2050

GB installed capacity in 2050  
GW H<sub>2</sub>



GB gross H<sub>2</sub> production in 2050  
TWh H<sub>2</sub>



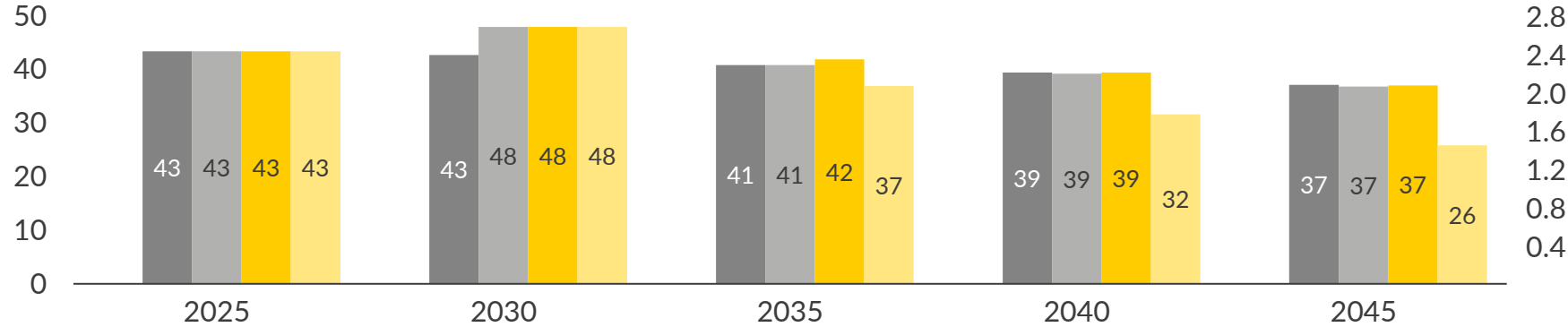
- All scenarios with the exception of 4H have a high reliance on blue H<sub>2</sub> made from fossil gas with CCS. This is responsible for 73% of supply in 2050 in 1H and remains a significant source of H<sub>2</sub> in 2H and 3H. Variability in RES output, combined with low levels of excess RES lead to unfavourable economics for non-nuclear derived green H<sub>2</sub> relative to fossil based blue H<sub>2</sub>.
- In contrast, strong support for a nuclear pipeline could enable the construction of a nuclear gigafactory consisting of many small nuclear reactors dedicated to H<sub>2</sub> production via SOEs can reduce reliance on fossil fuels for H<sub>2</sub> production to just 6% by 2050.
- The “negative carbon emissions” associated with BECCS are expected to be highly valuable and attributed to hard to abate sectors. This capacity is therefore assumed in model as it is likely to be driven by policy or valuable carbon credits.

Blue Green: grid connected Green: nuclear derived BECCS

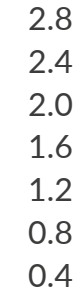
1) Majority of PEM electrolyser capacity and generation shown here correspond to re-fuelling stations providing pure H<sub>2</sub> for hydrogen-powered vehicles. These are treated separately and do not contribute to market dynamics shown in the following slides.

# High levels of nuclear H<sub>2</sub> deployment facilitate cheaper and lower carbon intensity H<sub>2</sub>

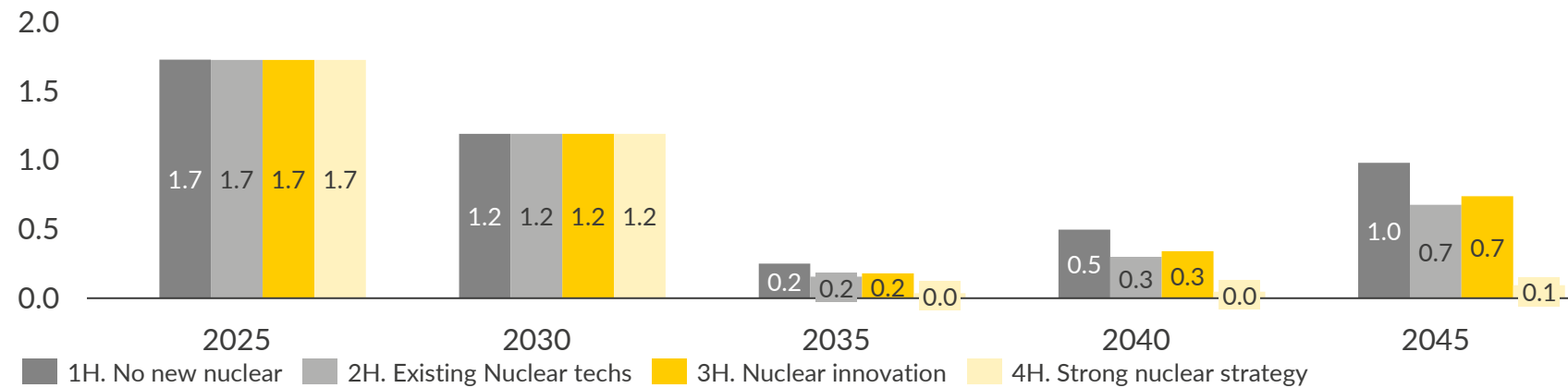
GB wholesale H<sub>2</sub> price  
£/MWh H<sub>2</sub> (real 2019)



GB wholesale H<sub>2</sub> price  
£/kg H<sub>2</sub> (real 2019)



GB annual emissions from H<sub>2</sub> production<sup>1</sup>  
MtCO<sub>2</sub>e



The availability of large volumes of low cost nuclear derived enable H<sub>2</sub> price reductions of c.1/3 due to the low costs of input heat and electricity relative to:

- Fossil gas for blue H<sub>2</sub> production
- Grid electricity prices for green/yellow H<sub>2</sub>, particularly in winter.

The low marginal cost of nuclear derived H<sub>2</sub> displaces blue and yellow H<sub>2</sub> from the supply mix, enabling the rapid growth in H<sub>2</sub> demand being met with fewer cumulative emissions.

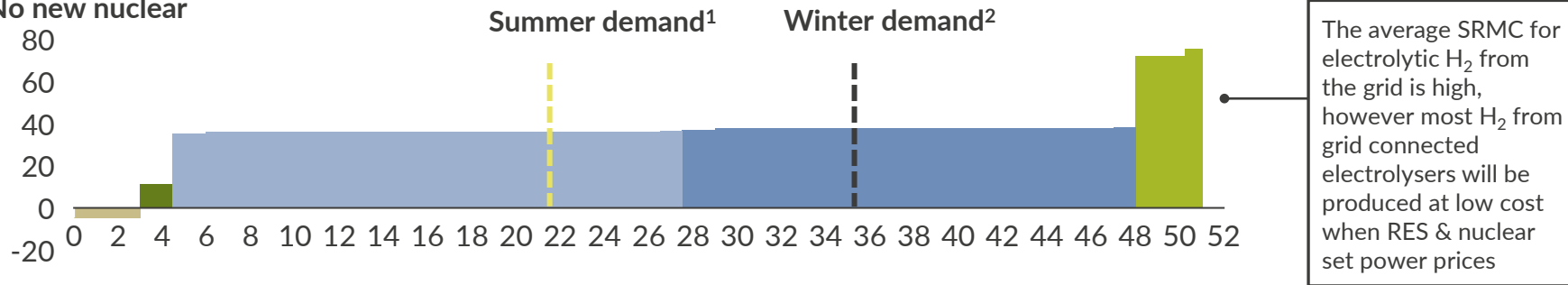
Emissions rise in all scenarios in the 2040s due to substantial increases in forecasted hydrogen demand and residual emissions from blue hydrogen, with the notable exception of 4H.

# Nuclear H<sub>2</sub> has the potential to meet demand at low prices throughout the summer, with marginal blue H<sub>2</sub> used in winter

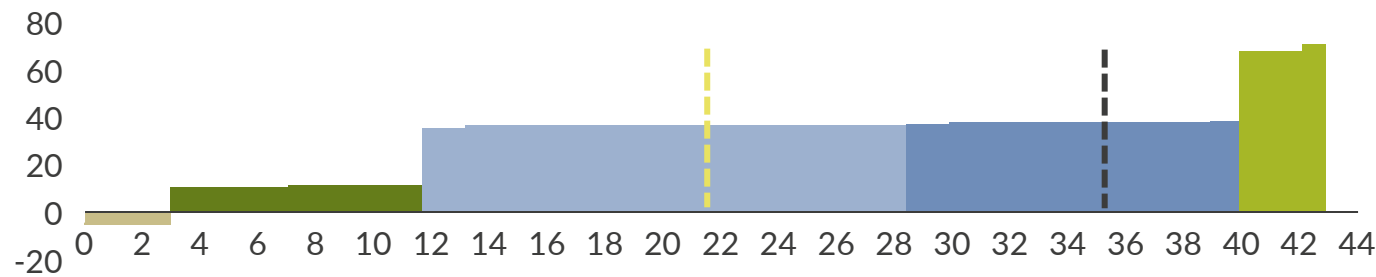
## GB average merit order of H<sub>2</sub> supply in 2045

£/MWh H<sub>2</sub> (real 2019)

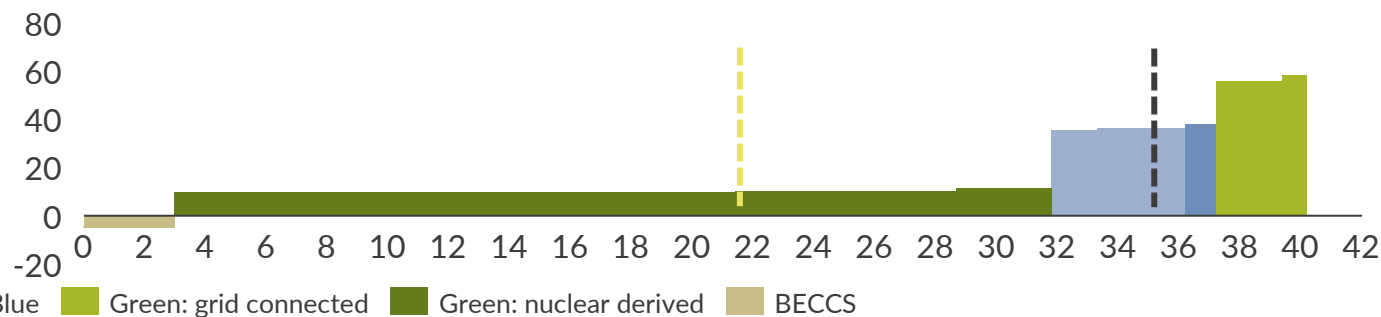
### 1H. No new nuclear



### 3H. New nuclear techs



### 4H. Strong nuclear strategy

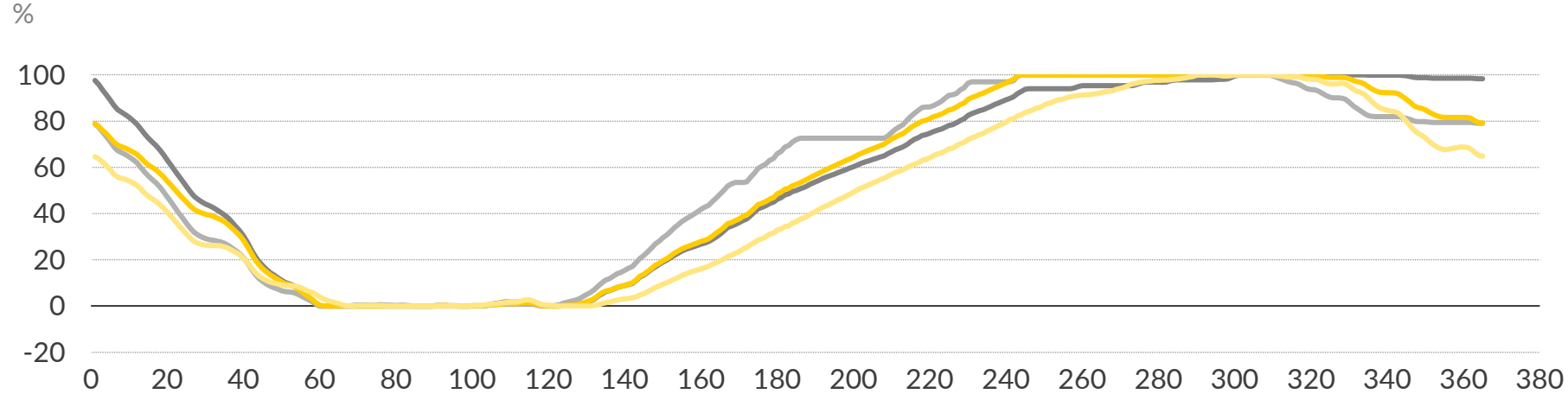


1) Average hydrogen demand from April to September 2045; 2) Average hydrogen demand from January to March and October to December 2045.

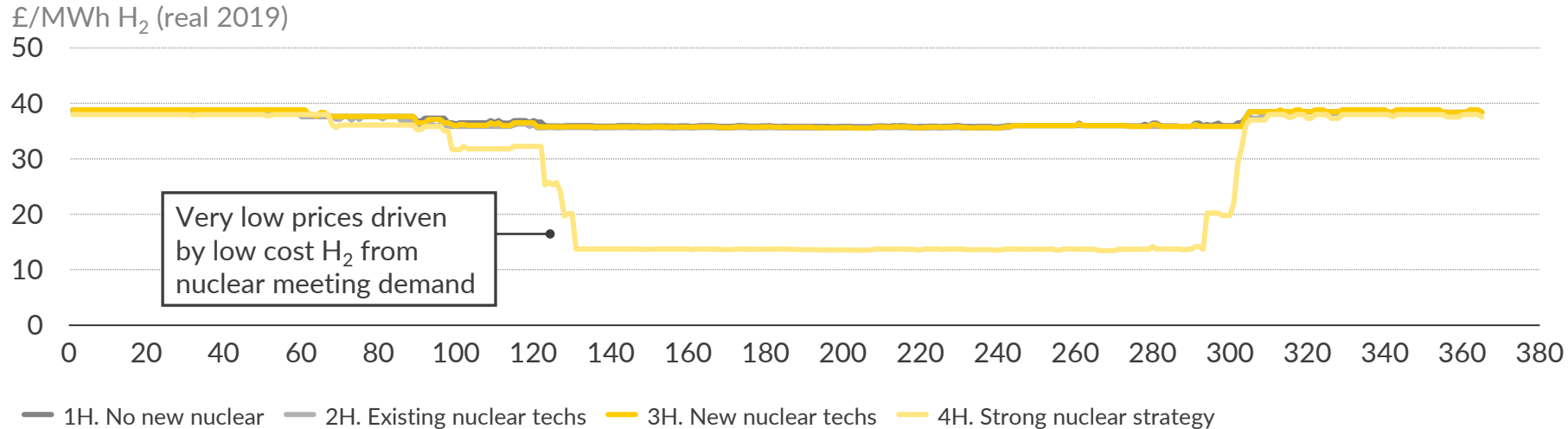
- In 1H the supply stack in 2045 is dominated by blue hydrogen. This sets the price around the £40/MWh H<sub>2</sub> in both summer and winter.
- As more nuclear comes onto the system the blue hydrogen production technologies are shifted up the merit order.
- In 4H, nuclear derived H<sub>2</sub> sets the very low prices in summer with blue H<sub>2</sub> setting prices in winter.
- Storage is not included in the merit order as it does not capture how and when storage would decide to discharge, with other factors like opportunity costs and recovering the cost of charging requiring consideration.

# H<sub>2</sub> storage consistently discharges in winter when demand is high and charges in summer months when demand and prices are low

GB salt cavern H<sub>2</sub> storage state of charge in 2045



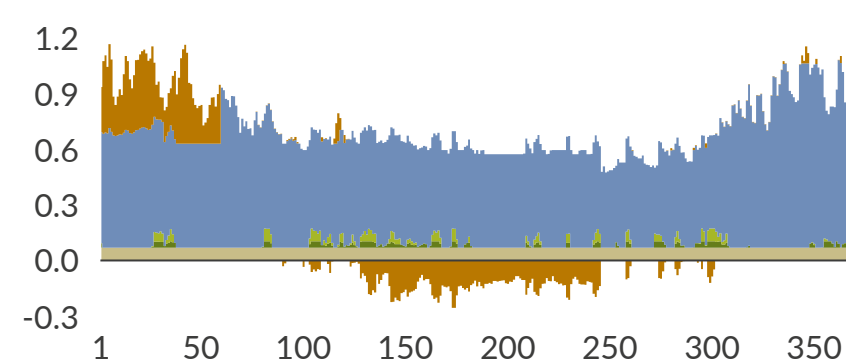
GB H<sub>2</sub> price in 2045



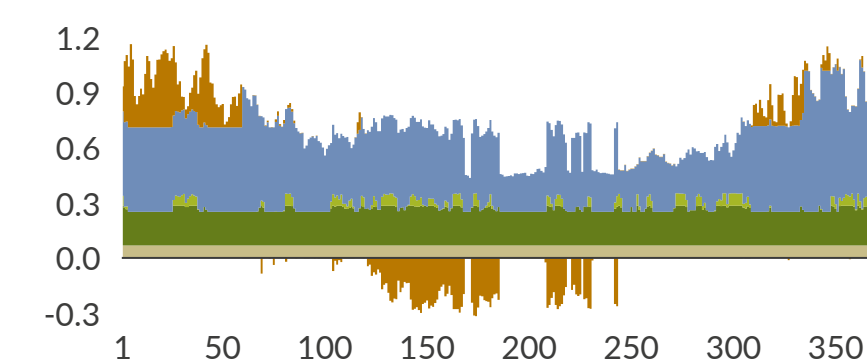
- Seasonality in H<sub>2</sub> storage levels is driven by selling H<sub>2</sub> to meet high winter demand for heating, followed by stockpiling during summer months, when hydrogen demand is lower.
- Storage utilisation is similar across all scenarios.
- In scenarios 1-3, blue hydrogen technologies set the price throughout the year.
- The very high penetration of nuclear derived H<sub>2</sub> in 4,H enabled by hydrogen gigafactories, allows all demand in summer months to be met by nuclear derived H<sub>2</sub>, resulting in very low prices of c.£14/MWh H<sub>2</sub>.

# The majority of demand is met by blue H<sub>2</sub>, with most dynamic use of storage in 4L where the share of green H<sub>2</sub> is greatest

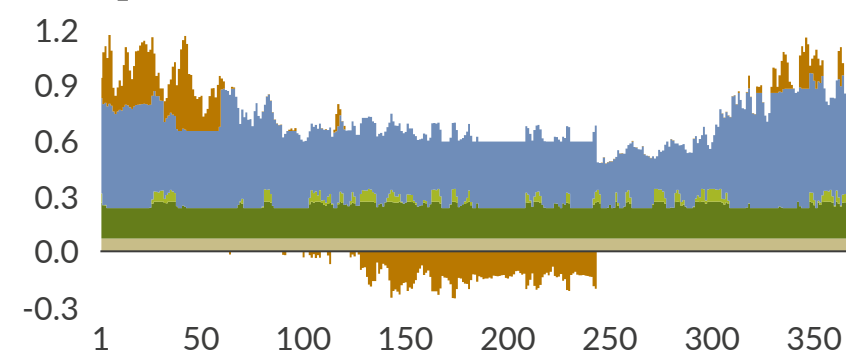
GB daily H<sub>2</sub> production in 2045: 1H. No new nuclear



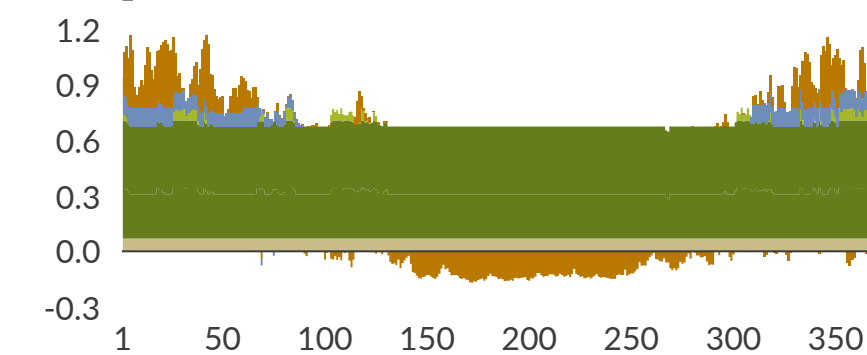
GB daily H<sub>2</sub> production in 2045: 2H. Existing nuclear techs



GB daily H<sub>2</sub> production in 2045: 3H. New nuclear techs



GB daily H<sub>2</sub> production in 2045: 4H. Strong nuclear strategy



Blue Green: grid connected Green: nuclear derived BECCS Storage

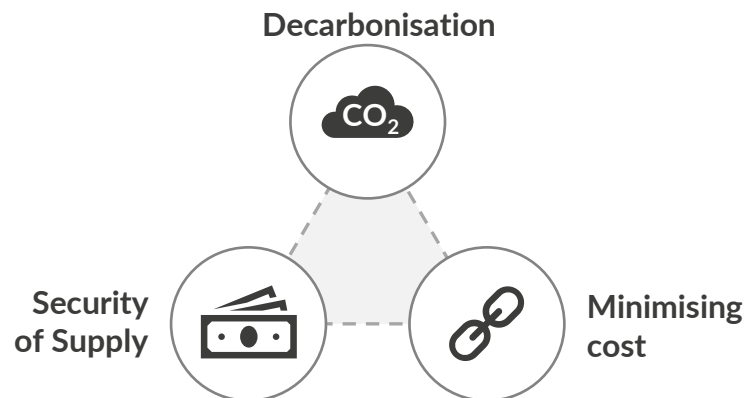
- Fossil based blue H<sub>2</sub> plays an important role in achieving the volume of H<sub>2</sub> required in all scenarios bar 4H, ramping up in the winter to meet peak heating demand along with storage
- Nuclear derived electrolytic H<sub>2</sub> is a cheaper alternative that is able to displace blue H<sub>2</sub>, providing a stable supply of Hydrogen throughout the year.
- This is most evident in scenario 4H, due to the deployment of nuclear H<sub>2</sub> gigafactories.
- RES and grid derived electrolytic H<sub>2</sub> are not able to consistently meet fluctuating H<sub>2</sub> demand throughout the year when competing with blue H<sub>2</sub>.



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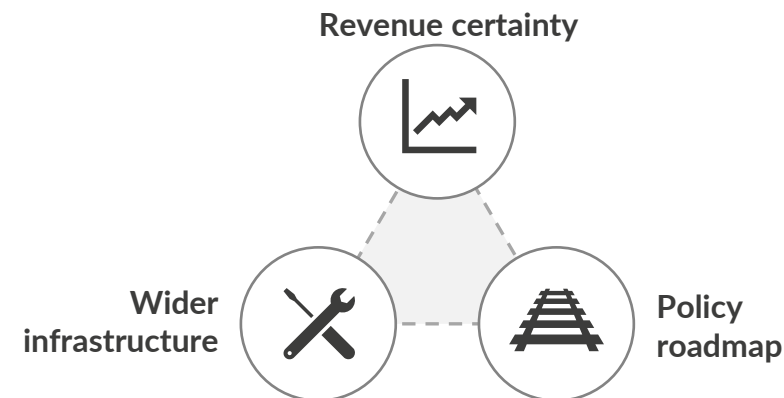
# Policy objectives and investment requirements must be met in order to deploy low carbon supply and limit risks to the transition

## Government objectives



- 1 **Decarbonisation:** Mitigate climate change and decrease emissions via policies that increase low carbon supply i.e. rising carbon prices that increase revenues for low carbon techs, direct support for low carbon techs, wider facilitation of low carbon systems.
- 2 **Security of Supply:** Objective to deliver energy security by ensuring adequate power capacity is available during peak times from a variety of technologies. The Capacity Market was created as the primary mechanism to achieve this.
- 3 **Minimising cost:** Objective to minimise cost to consumers through efficient markets and low-carbon support measures, household energy efficiency, and encouraging competition among suppliers.

## Investment requirements



- 4 **Revenue certainty:** Meet required returns via markets designed to support low carbon techs and additional value streams with long term contracts (i.e. CM, ancillary services, CfD) to account for market shortfalls. This reduces investor risk and therefore financing costs.
- 5 **Policy roadmap:** Required for clarity on future market developments, planning approval, development of a project pipeline and supply chains.
- 6 **Wider infrastructure:** High level planning for system infrastructure to ensure requisite infrastructure is in place in time for assets to be deployed.

# An assessment of risks in not achieving net-zero must be undertaken

## Policy & market design



- Low marginal cost systems yield low revenues and low carbon techs won't deploy without support under current market design.
- This led to low RES deployment in the core scenarios however introducing additional supported RES did not increase system costs.
- Unclear policy increases uncertainty, investor risk and the likelihood of projects not being delivered due to insufficient project pipelines.
- Inefficient market design may lead to suboptimal supply mixes being locked in for decades due to asset lifetimes.

## System resilience & emissions



- Capacity is needed to meet demand during prolonged periods of low RES output.
- Without direct limitations on emissions intensive technologies.
- Climate change leads to increasingly unpredictable weather, potentially exacerbating risk of unexpected high emissions and fossil fuel use in high RES systems.
- Weather year sensitivities, using 10 years of historic weather data, found that systems with low nuclear penetration were more likely to see higher fossil fuel usage than high nuclear scenarios due to the reliance on fossil fuels for flexibility.

## Infrastructure requirements



- Insufficient assessment of the requirements for very large systems at an early stage may result in unforeseen limits on deployment of low carbon techs in future.
- The H<sub>2</sub> and CO<sub>2</sub> transport and storage infrastructure is dependent on demand, with short haul transport of pure H<sub>2</sub> for transport and industry vs a large pipeline network for H<sub>2</sub> use in heating with decisions on infrastructure pathways required well in advance of deployable need.
- Infrastructure must be built before new supply can be connected, however large infrastructure projects often take a long time to deploy and are subject to cost and time overruns.

## Costs

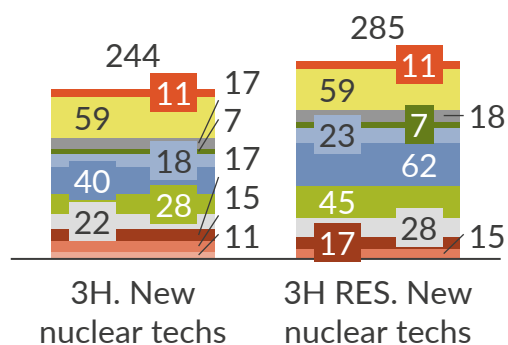


- An uncoordinated approach to decarbonisation may limit the scale of cost reductions or even increase project costs.
- Although technology cost declines have historically been underestimated, costs associated with deploying very high levels of low carbon tech may rise due to limited resource and site availability.
- The full infrastructure costs of decarbonisation pathways should be assessed to determine lowest cost pathways to net-zero and prevent unexpectedly high infrastructure investment costs in future when alternative options are limited.

# High RES net-zero systems in line with government ambition can be achieved at no additional cost with direct support for RES capacity

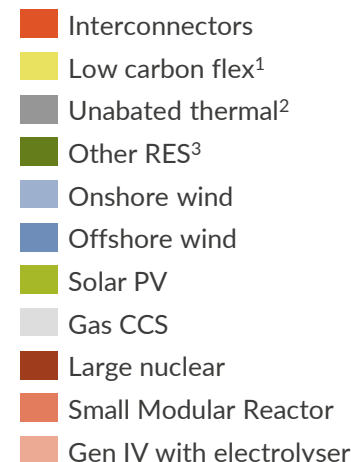
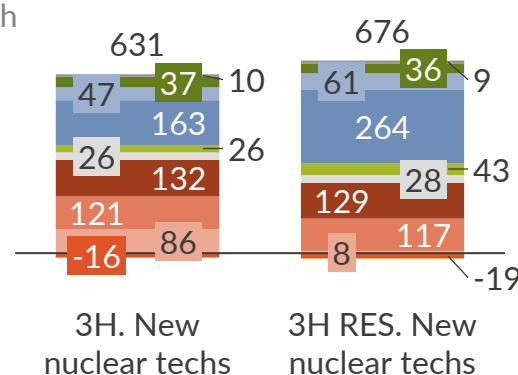
GB installed capacity in 2050

GW



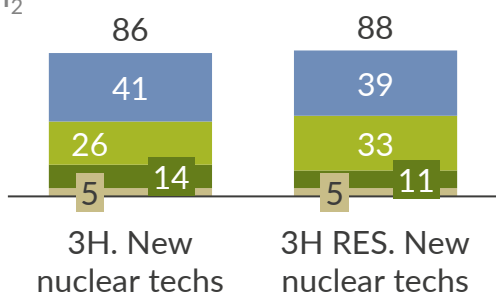
GB electricity production in 2050

TWh



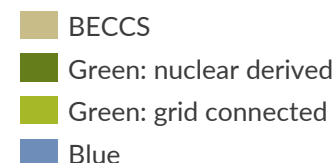
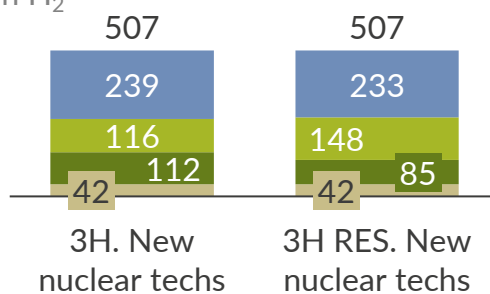
GB installed capacity in 2050

GW H<sub>2</sub>



GB gross H<sub>2</sub> production in 2050

TWh H<sub>2</sub>



- To reflect government ambition for high RES systems, 3H RES assumes additional subsidised RES deployment beyond 2030. All other assumptions are equal to 3H.
- Despite resulting in a larger system capacity, 3H RES still reaches net-zero with similar system costs relative to 3H.
- This is driven by the very high share of low marginal cost supply on the system remaining relatively consistent between scenarios as electricity prices are the biggest driver for differences in total system costs.
- The large amounts of offshore wind generation on the system improve the economics of alkaline electrolysers in 3H RES reducing the total share of blue hydrogen.

NPV System costs 2021-50, £bn

638

638

H<sub>2</sub> and Power sector emissions 2050, MtCO<sub>2</sub>

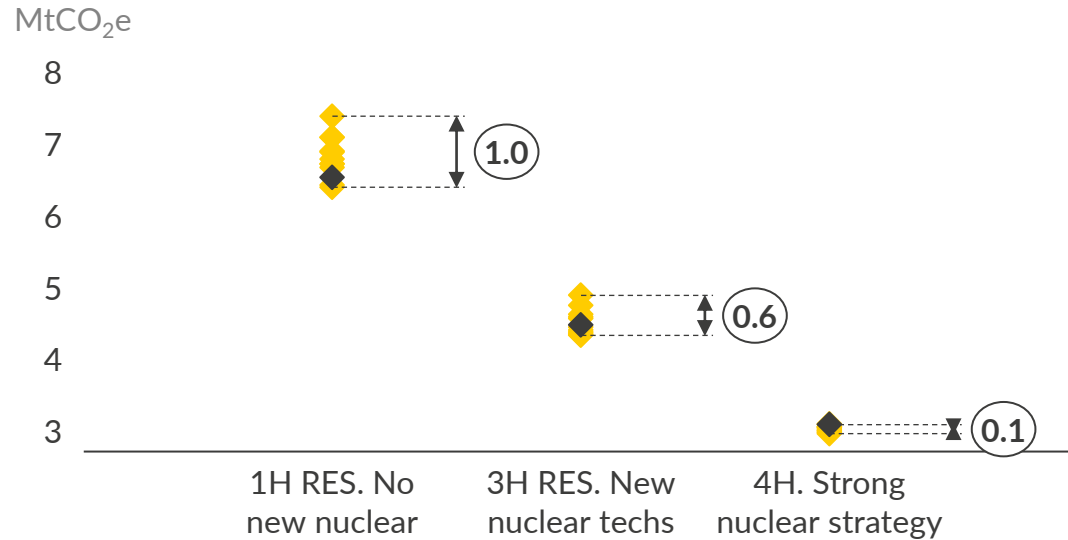
4.4

4.5

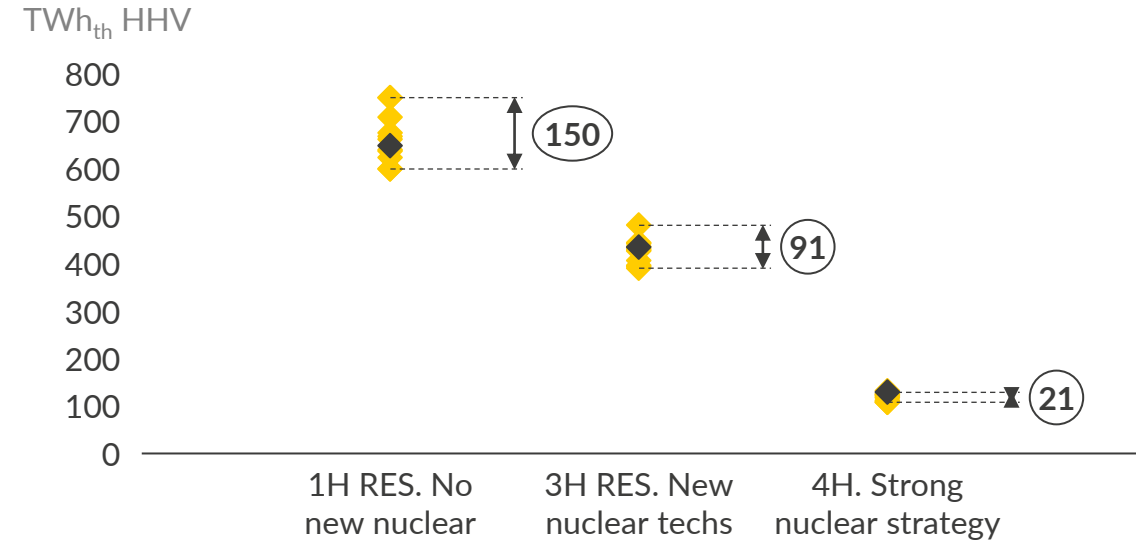
1) Low carbon flex includes DSR, battery storage, hydrogen peakers, hydrogen CCGT, pumped storage 2) Other RES includes biomass, BECCS, EfW and marine; 3) Unabated thermal includes CCGTs, gas peaking, embedded CHP.

# High nuclear scenarios are more resilient to higher than expected emissions and fossil fuel usage under different weather patterns

GB power and hydrogen market emissions 2050 (2006-2016 weather patterns)<sup>1</sup>



GB power and hydrogen market natural gas use in 2050 (2006-2016 weather patterns)



- The core scenarios modelled in this report use historic weather patterns from 2013 to inform the profiles of RES generation and demand in the model and single year sensitivities using GB weather patterns from 2006- 2016 were applied to test resilience to emissions and fuel use.
- Variations in fuel use and emissions are lowest in 4H, where a high penetration of nuclear capacity co-located with electrolysers provides flexibility to the system to meet changing RES output. The variation is higher in the high RES scenarios, 1H RES and 3H RES, due to greater reliance on fossil fuels via gas-CCS or gas peaking plants to provide flexibility.
- Whilst the variations are modest, at <1 MtCO<sub>2</sub>e, using historic weather patterns does not simulate the effects of extreme weather events such as wind droughts that are more likely in future as a result of climate change.
- A supply mix that combines RES and nuclear with limited reliance on fossil fuels for flexibility is key to minimising the risk of unexpected emissions on the path to net-zero.

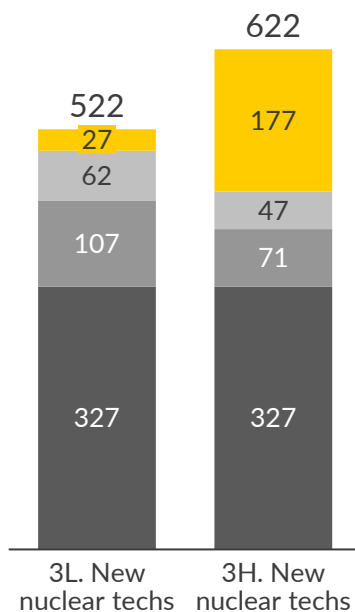
◆ Sensitivity ◆ Original

1) Note negative emissions from BECCS are not included.

# A high H<sub>2</sub> strategy leads to increased system size and therefore greater system costs due to electricity to H<sub>2</sub> conversion losses

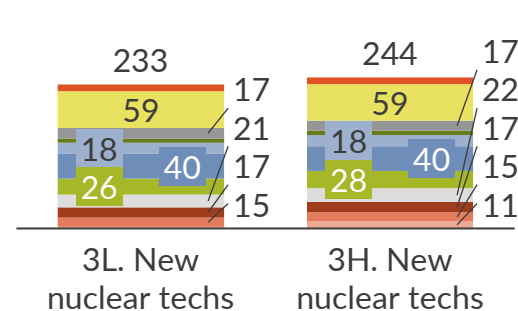
The high H<sub>2</sub> demand scenarios assume the same degree of decarbonisation as low H<sub>2</sub> but with less electrification. Increased power demand in high H<sub>2</sub> scenarios is slightly counterintuitive but highlights the need for greater deployment of power and H<sub>2</sub> supplies and infrastructure.

**GB power demand in 2050**  
TWh



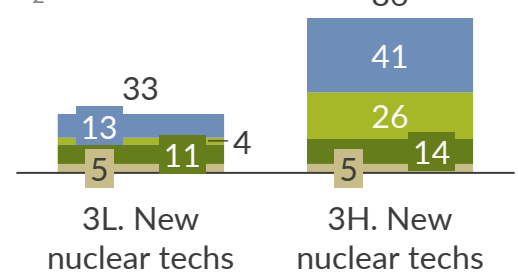
- Electrolyser demand
- Electric Vehicles
- Electric Heating
- Base power demand<sup>2</sup>

**GB installed capacity in 2050**  
GW



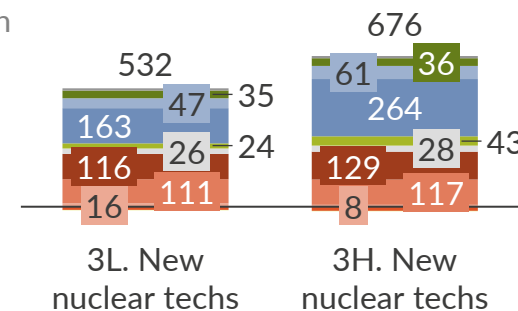
- Interconnectors
- Other RES
- Solar PV
- Small Modular Reactor
- Low carbon flex
- Onshore wind
- Gas CCS
- Gen IV with electrolyser
- Unabated thermal
- Offshore wind
- Large nuclear

**GB installed capacity in 2050**  
GW H<sub>2</sub>

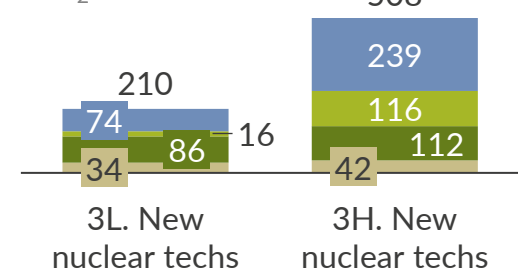


- Blue
- Green: grid connected
- Green: nuclear derived
- BECCS

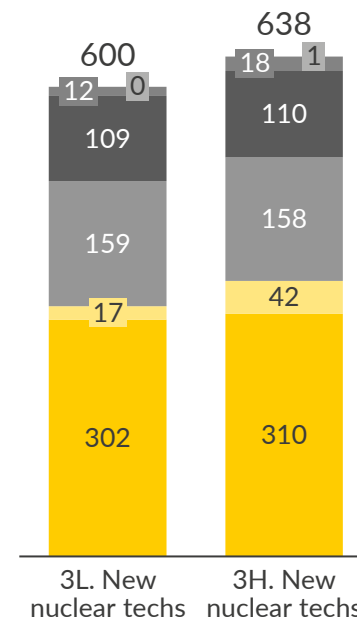
**GB electricity production and net imports in 2050**  
TWh



**GB gross H<sub>2</sub> production in 2050**  
TWh H<sub>2</sub>



**GB NPV system spend (2021-2050)**  
£bn

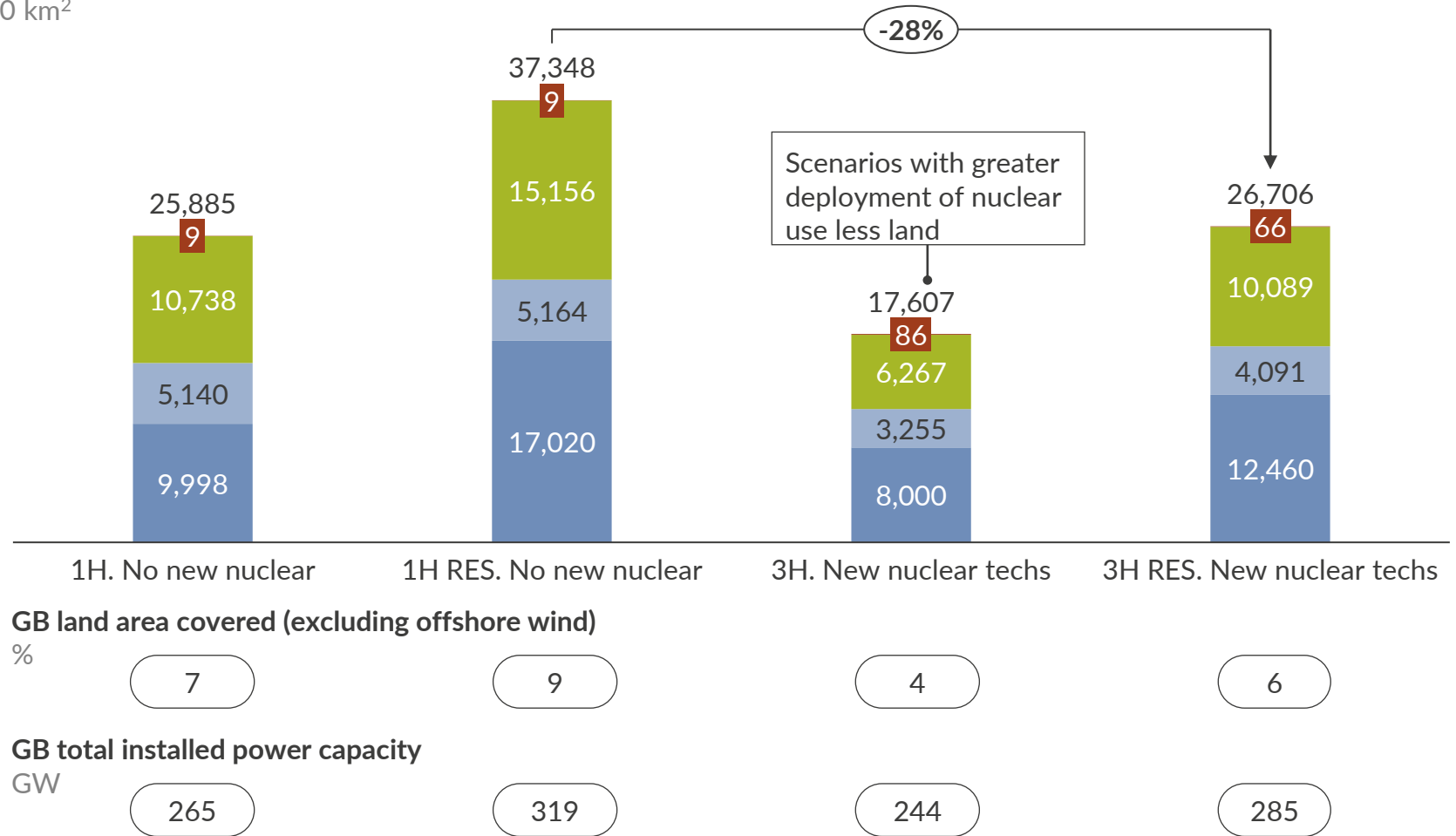
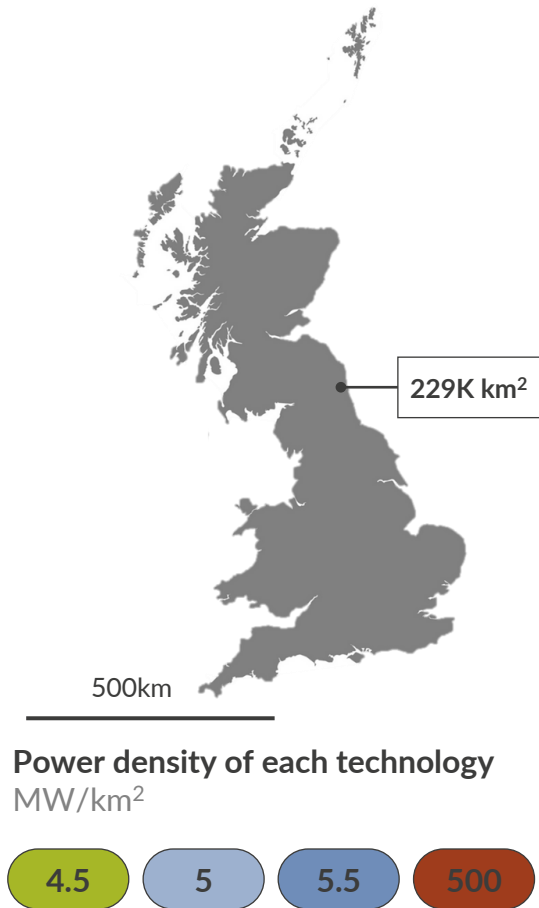


- Electricity market
- Hydrogen market
- Support Costs
- Electricity Infrastructure
- Hydrogen Infrastructure
- CO2 Infrastructure

1) Low carbon flex includes DSR, battery storage, hydrogen peakers, hydrogen CCGT, pumped storage 2) Other RES includes biomass, BECCS, EfW and marine; 3) Unabated thermal includes CCGTs, gas peaking, embedded CHP.

# Full feasibility assessments on the land use of different supply mixes are needed to assess ecological, environmental and deployment program risks

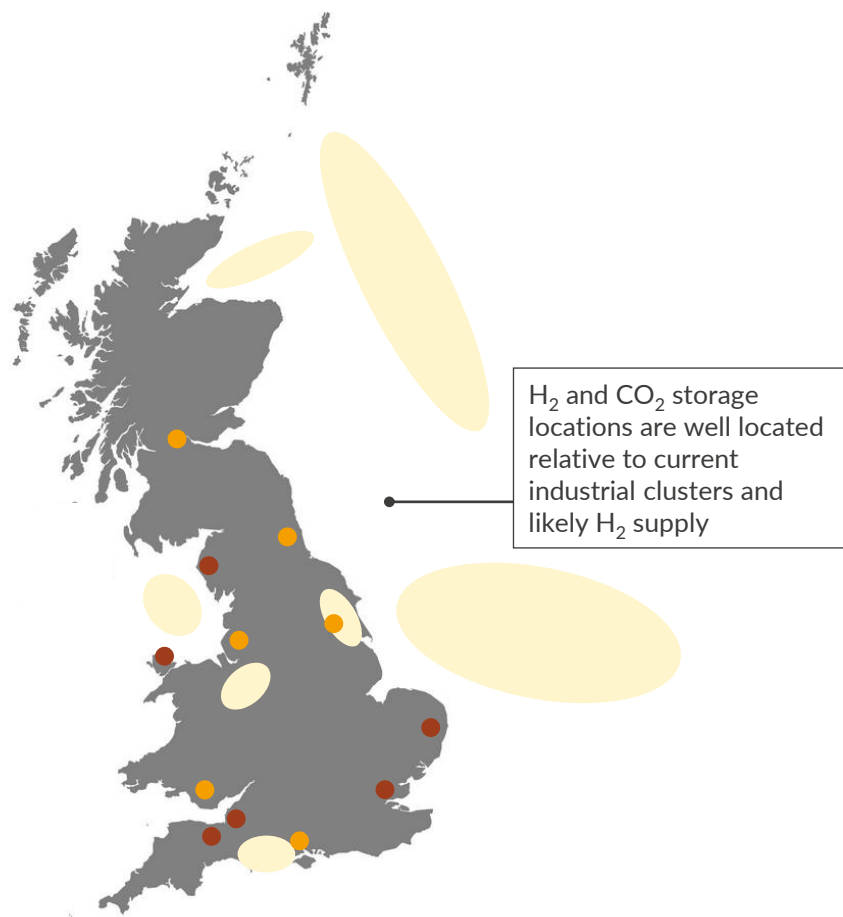
Area covered by technology in 2050<sup>1</sup>  
'000 km<sup>2</sup>



Offshore wind Onshore wind Solar PV Nuclear

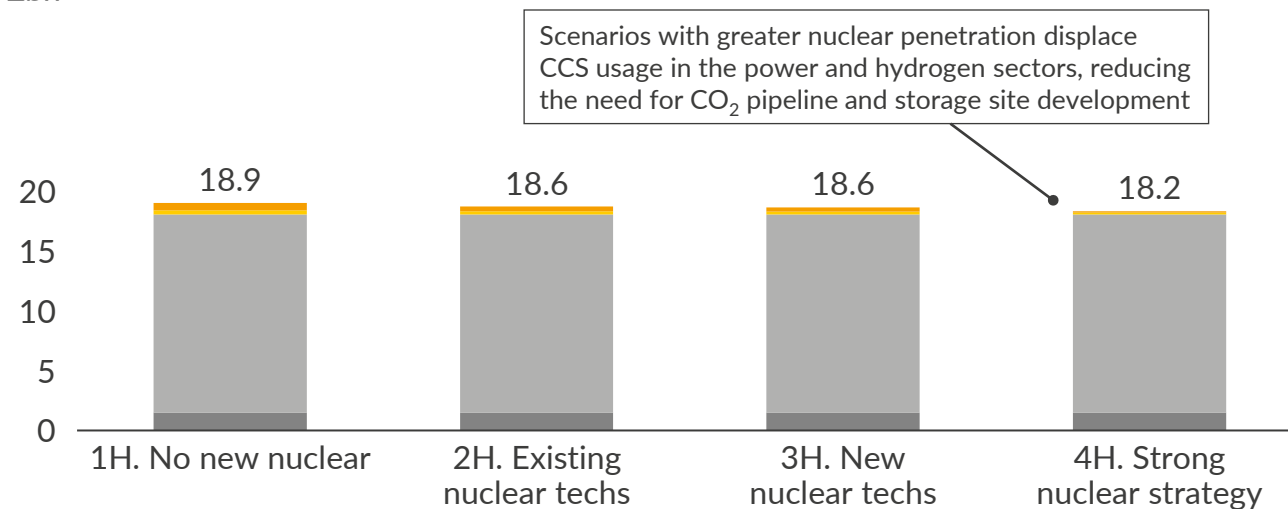
# Hydrogen storage will take up ~90% of infrastructure investment in scenarios with high levels of hydrogen demand

Map of GB



● Industrial cluster ● Planned new nuclear site ● H<sub>2</sub> / CO<sub>2</sub> storage sites

NPV GB H<sub>2</sub> and CO<sub>2</sub> infrastructure spending  
£bn



- Infrastructure spending quantifies the capital investment needed to build the gas pipeline and storage infrastructure required to cope with the volumes of H<sub>2</sub> and captured CO<sub>2</sub> in each scenario.
- In the core scenarios, we see at most 1.08 Gt CO<sub>2</sub> being captured and stored from 2021-50, utilizing a mere 1.5% of the UK's overall CO<sub>2</sub> storage potential.<sup>1</sup>
- CO<sub>2</sub> infrastructure spending will be higher than what is presented in this report due to significant volumes of CO<sub>2</sub> being captured outside the power and hydrogen sectors i.e. from industrial processes, which are not accounted for in these calculations.

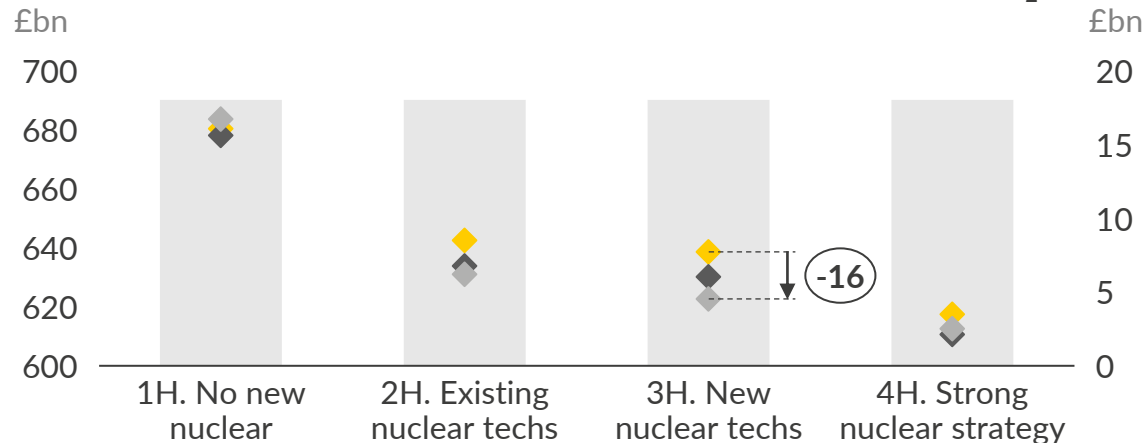
■ CO<sub>2</sub> storage<sup>2</sup> ■ CO<sub>2</sub> Transport<sup>2</sup> ■ H<sub>2</sub> Storage<sup>3</sup> ■ H<sub>2</sub> Transport<sup>3</sup>

1) This assumes an emission intensity of 7kg/MWh of biomass combusted. Supply chain emissions not included. 2) Costs for CO<sub>2</sub> transport include onshore and offshore pipelines from key industrial centres to offshore storage sites, most of which are saline aquifers 3) Costs for H<sub>2</sub> transport include transmission pipelines and repurposed natural gas distribution networks, while H<sub>2</sub> storage refers to long-term salt cavern storage.



# NPV savings of up to £16bn with minimal changes to emissions could be realised by lowering reliance on hydrogen storage

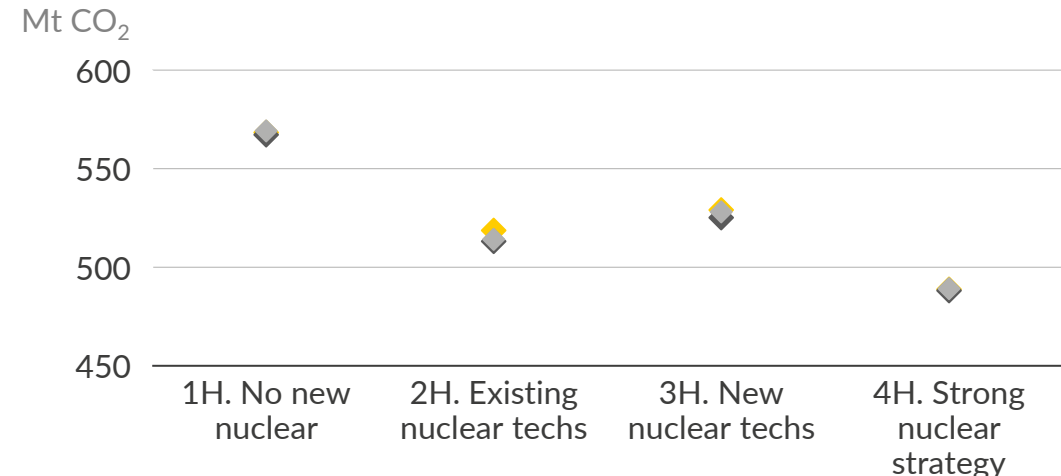
GB NPV total system spending<sup>1</sup>



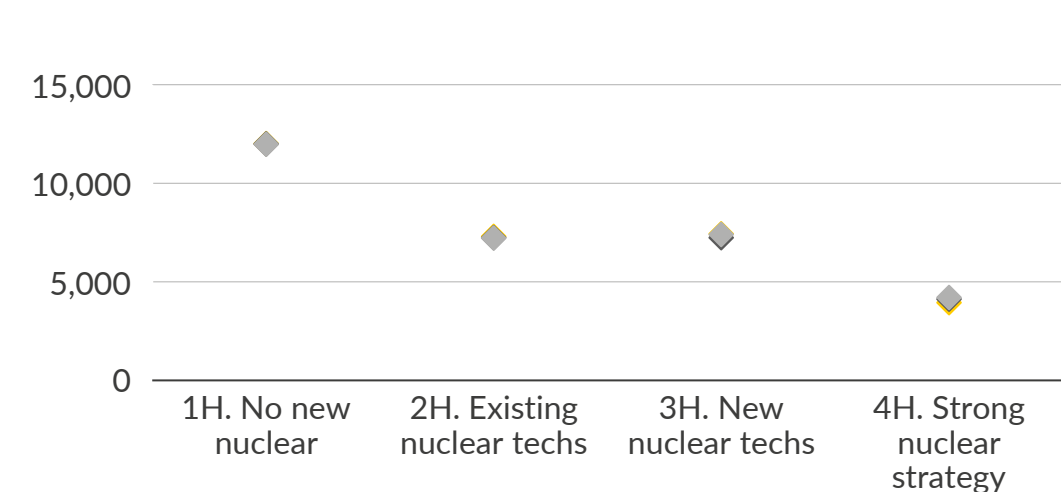
GB NPV H<sub>2</sub> spend<sup>1</sup>



GB cumulative emissions from power and hydrogen production, 2021-50



GB cumulative natural gas use for power and hydrogen production, 2021-50



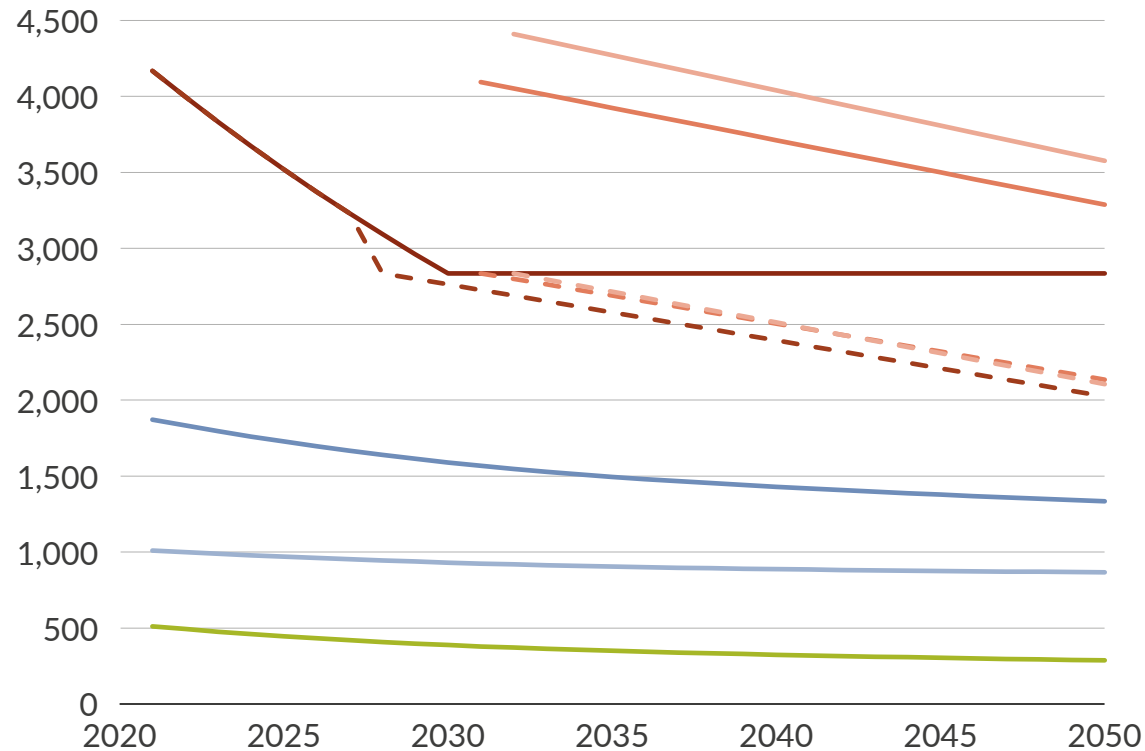
- System costs can be reduced on net by lowering the hydrogen storage capacity on the system.
- Scenario 3H demonstrates NPV savings of £16bn when lowering the 2050 hydrogen storage capacity from 26TWh to 10TWh. This is driven by a combination of reduced hydrogen infrastructure spend, support costs and electricity infrastructure spend.
- In a system with little power and hydrogen production from nuclear (1H), savings from reduced storage are not realised.
- Reducing the levels of hydrogen storage has limited risks in terms of increasing unabated emissions and reliance on fossil fuels.

■ H<sub>2</sub> infrastructure    ◆ 26TWh H<sub>2</sub> storage    ◆ 18 TWh H<sub>2</sub> storage    ◆ 10 TWh H<sub>2</sub> storage

1) Using 5% discount rates on spending from 2021 - 2050.

# Technology costs could fall slower or faster than expected but historic reductions have largely been achieved by clear policy

GB CAPEX  
£/kW



- Technology cost reductions are assumed for RES, and new nuclear technologies, however these forecasts are uncertain and could increase due to:
  - Lower than expected learning rates although these have historically been underestimated
  - Deploying capacity on worse sites as capacity will first be deployed on sites with the lowest costs and therefore highest returns
  - Tight supply chains and high demand for key materials due to high levels of global demand and the pace of delivery required to reach net-zero.
- The most recent new build nuclear plant in GB, Hinkley Point C, has faced high costs driven by a number of factors including being a first of a kind (FOAK) plant and commencement of construction before completion of the plant design. Support for a pipeline of nuclear projects, particularly small reactors less exposed to delays and cost overruns, could lead to decreased costs for nuclear plants.
- If the low costs for nuclear in the 4H. Strong nuclear strategy scenarios are not realised, system spending could increase by £21bn (NPV 2021-2050), when comparing against 3H. New nuclear techs.

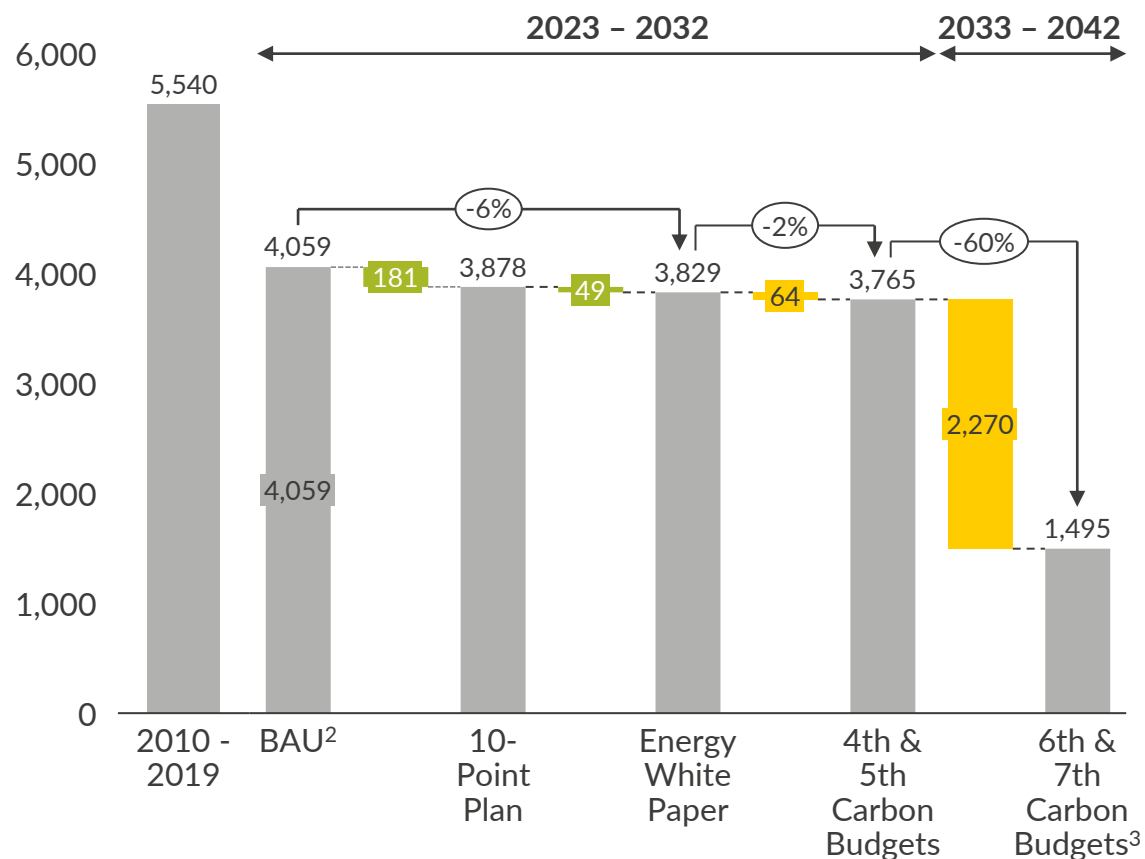
— Large Scale Nuclear (Scen 1-3)  
 — LWSMR (Scen 1-3)  
 - - - LWSMR (Scen 4)  
 — Onshore Wind  
 — Solar PV  
- - - Large Scale Nuclear (Scen 4)  
 — Gen IV (Scen 1-3)  
 - - - Gen IV (Scen 4)  
 — Offshore Wind

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# New policies for low carbon solutions beyond recently announced ambitious policies are needed to reach net-zero

GB estimated reduction in annual GHG emissions from quantifiable policies announced in the 10-Point Plan and Energy White Paper (EWP)<sup>1</sup>

MtCO<sub>2</sub>e



■ Cumulative emissions ■ Policy driven emissions reductions ■ Emissions gap left by current policy

- GB has been a world leader in reducing emissions, and the first country to introduce a legally binding target of net-zero emissions by 2050.
- The 10-Point Plan, published in 2020, includes targets for:
  - **Energy:** 40 GW offshore wind by 2030
  - **Transport:** Ban on combustion engines from 2030 and hybrid vehicles from 2035
  - **Hydrogen:** 5 GW ‘low-carbon’ H2 production capacity by 2030
  - **CCS:** Removal of 10 MtCO<sub>2</sub>e per year by 2030
  - **Buildings:** 600k heat pumps installed annually from 2028
  - **Nature:** 30k hectares of trees planted each year.
- Combined with the Energy White Paper, these initiatives are expected to deliver a 6% reduction in emissions on top of existing policies.
- The recent ratification of the 6th carbon budget (78% 1990 levels) in April 2021 will require a much more comprehensive decarbonization plan to be developed to align UK’s carbon emission trajectory.
- Despite these ambitions and policies, the UK is on track to exceed its 4th & 5th carbon budgets.
- Careful consideration of technology pathways and the additional policies required to support them is needed to ensure these targets are met.

1) As laid out in The Ten Point Plan for a Green Industrial Revolution. Cumulative numbers shown; 2) Emissions under existing policies, based on estimated net carbon account as published in CCC’s 2020 Progress Report; 3) 7<sup>th</sup> Carbon budget predicted based on a trajectory consistent with the balanced pathway.

Sources: Aurora Energy Research, BEIS, CCC

# Considerable UK commitments on H<sub>2</sub> are colour agnostic but lack incentives for consumption and greater clarity is needed

## The United Kingdom's Energy White Paper

- The UK published its Energy White Paper in December 2020, which was informed by the 10 point plan released in November 2020, both documents contained hydrogen based targets and incentives.
- The announcements within the UK so far are production method agnostic – with mention of electrolysis, gas reformation and even use of runoff nuclear heat being used to improve efficiency of processes.

## Policies and targets

- 5 GW of electrolyser capacity built by 2030, requiring about GBP4bn of private investment.
- Saving of 41 Mt of CO<sub>2</sub> between 2023 and 2032
  - Capturing 10 MT of CO<sub>2</sub> annually by 2030 using CCUS.
- Seeking to blend 20% hydrogen in the natural gas network by 2023.
- 60,000 jobs in hydrogen production and CCS.
- Release of hydrogen strategy document in spring 2021.

Thematic and incentive focus in the UK is spread throughout all three areas of hydrogen demand – focusing on pilot and demonstration projects, and development of a hydrogen ecosystem on a local scale.

The UK has announced many funds but support is combined across green and blue hydrogen, and actual production and consumption support mechanisms are not realised aside from some grid blending and home use pilot programs.

## Incentives cover several business models

- Hydrogen technology development is included as able to participate in the GBP1bn energy innovation program.
- GBP20m in 2021 in zero emission hydrogen freight trials.
- Funding for 4,000 zero emissions buses (both battery and hydrogen fuelled).

If hydrogen fuel cell buses dominate this allocation, this will be by far the biggest hydrogen bus fleet in Europe.

- Plan to fund the expansion of hydrogen neighbourhood to hydrogen village by 2025.
- Investing GBP1bn in CCS deployment in two industrial clusters.
- GBP240m of investment in a “net zero hydrogen fund” until 2025.
- GBP315m of investment in the “Industrial Energy Transformation Fund” until 2024.

# Future policy direction should consider the decarbonisation routes facilitated by different supply mixes in addition to fossil fuel usage

## 1 Enabling deeper emissions reductions

### 2

- industrial processes, with nuclear H<sub>2</sub> particularly suited to production of synfuels to be used as drop-in replacement for fossil fuels in aviation and shipping, which are very hard to abate
  - A key advantage is the ability to locate supply near demand with nuclear H<sub>2</sub> gigafactories and offshore wind plants near ports and industrial clusters and refueling stations.
- Waste heat from nuclear can also provide low carbon district heating applications and increase efficiency of Direct Air Capture (DAC) of CO<sub>2</sub>.<sup>1</sup>
- Impure H<sub>2</sub> from fossil based blue H<sub>2</sub> is only suitable for heating and H<sub>2</sub> combustion plants so uses are limited and may be associated with continued methane leaks from gas pipelines and undesirable combustion byproducts.

### System resilience and reliance on fossil fuels

- Low carbon dispatchable capacity is required to manage short- and long-term fluctuations in variable RES output, particularly during consecutive days of low wind output when battery storage is unlikely to meet demand.
- Gas CCS is a useful transitional technology on the path to net-zero however it extends reliance on fossil gas and uncertainties remain on long term storage of CO<sub>2</sub>.
- Large scale nuclear can provide flexibility but co-location with electrolyzers enables plants to provide more flexibility to the grid by diverting electricity output to H<sub>2</sub> production, thereby displacing the role of gas CCS and fossil fuels.
- Small nuclear reactors have the added benefit of providing local flexibility in addition to reducing the risk of in-feed losses and reliance on back-up gas.

## 3 Mechanisms required to support low carbon supply

### 4 Broader economic benefits of RES and nuclear based H<sub>2</sub>

- 1) Funding awarded for Sizewell C to explore designs to use waste heat for DAC.
    - provide sufficient economic incentives for low carbon capacity, particularly in low marginal cost systems with high shares of RES and/or nuclear and low wholesale market prices.
- The capacity mechanism is not an effective tool for decarbonization when used in isolation, as in the core scenarios, and may lead to inefficient spending. This is demonstrated by the lack of RES build in the core scenarios.
  - Hybrid business models of RES or nuclear with H<sub>2</sub> production can boost project revenues and potential revenue support payments.
  - Adopting a suite of mechanisms that provide either direct support for low carbon capacity or add value to grid services can lead to more efficient deployment of low carbon capacity and system spending.
  - Hydrogen exports** to neighboring countries could enable GB to become a world leader in low carbon hydrogen supply due to very high resource availability enabling even high levels of H<sub>2</sub> supply than modelled in this report.
  - Creation of jobs** due to the development of the offshore wind, electrolyser and nuclear industries.
  - Retention of industry** due to the abundance of low cost, low carbon H<sub>2</sub> preventing relocation to cheaper areas.

# A range of mechanisms are available to encourage deployment of low carbon supply

|                                     | Description   | Benefits   | Limitations  | Solutions it supports  |
|-------------------------------------|---|--|--|--|
| <b>Contract for Different (CfD)</b> | <ul style="list-style-type: none"> <li>Long term contracts awarded in a competitive auction that guarantee a fixed price for generation.</li> </ul> | <ul style="list-style-type: none"> <li>High degree of revenue certainty, reduces cost of capital, clear pipeline of auctions, auctions across different technology buckets.</li> </ul> | <ul style="list-style-type: none"> <li>Not market led, reduces market dispatch signals.</li> </ul>   | <ul style="list-style-type: none"> <li>RES (offshore wind, onshore wind, solar) and emerging techs (floating offshore wind).</li> </ul>                          |
| <b>Capacity Market (CM)</b>         | <ul style="list-style-type: none"> <li>Long &amp; short term contracts to procure sufficient firm capacity to meet demand.</li> </ul>               | <ul style="list-style-type: none"> <li>Competitive auction.</li> </ul>   | <ul style="list-style-type: none"> <li>Procures cheapest capacity resulting in deployment of unabated gas peaking plants.</li> </ul>                 | <ul style="list-style-type: none"> <li>All with payments reflecting contribution to security of supply.</li> </ul>   |
| <b>Carbon price</b>                 | <ul style="list-style-type: none"> <li>Market based tool to increase costs associated with emissions.</li> </ul>                                    | <ul style="list-style-type: none"> <li>Increases SRMC for emitters and revenues for non-emitters.</li> </ul>   | <ul style="list-style-type: none"> <li>Trajectory highly uncertain, of limited use in low carbon systems.</li> </ul>                                 | <ul style="list-style-type: none"> <li>All non-emitting technologies.</li> </ul>   |
| <b>Carbon CfD</b>                   | <ul style="list-style-type: none"> <li>Payments to low carbon solutions relative to their carbon emissions savings.</li> </ul>                      | <ul style="list-style-type: none"> <li>Reduces costs for low carbon solutions below emissions intensive alternatives, multi-sector applicability.</li> </ul>                           | <ul style="list-style-type: none"> <li>Some complexity associated with new policy design.</li> </ul>   | <ul style="list-style-type: none"> <li>All low-carbon solutions.</li> </ul>  |
| <b>Dispatchable CfD</b>             | <ul style="list-style-type: none"> <li>Guarantees payments to ensure low carbon assets dispatch ahead of unabated thermal.</li> </ul>               | <ul style="list-style-type: none"> <li>Ensures low carbon solutions displace unabated solutions in the merit order, guaranteeing higher output volumes.</li> </ul>                     | <ul style="list-style-type: none"> <li>Reduces revenues for existing assets, potentially increasing costs elsewhere.</li> </ul>                      | <ul style="list-style-type: none"> <li>Low carbon dispatchable (i.e. gas CCS, H<sub>2</sub> turbines for power).</li> </ul>                                      |
| <b>Regulated Asset Base (RAB)</b>   | <ul style="list-style-type: none"> <li>Guarantees a fixed rate of return on investment, despite costs.</li> </ul>                                   | <ul style="list-style-type: none"> <li>Guaranteed return lowers financing costs and increases private investment where otherwise considered too risky.</li> </ul>                      | <ul style="list-style-type: none"> <li>Consumers bear the significant risk of cost and time overruns as well as potential monopolisation.</li> </ul> | <ul style="list-style-type: none"> <li>Capital intensive (i.e. large nuclear, CO<sub>2</sub> and H<sub>2</sub> transport and storage infrastructure).</li> </ul> |
| <b>Ancillary services (AS)</b>      | <ul style="list-style-type: none"> <li>Contracts for targeted grid services (i.e. STOR, Black Start, Dynamic Containment, FFR).</li> </ul>          | <ul style="list-style-type: none"> <li>Able to meet specific grid needs.</li> </ul>  | <ul style="list-style-type: none"> <li>Occasionally opaque process for awarding contracts.</li> </ul>  | <ul style="list-style-type: none"> <li>Dependent on each ancillary service.</li> </ul>   |

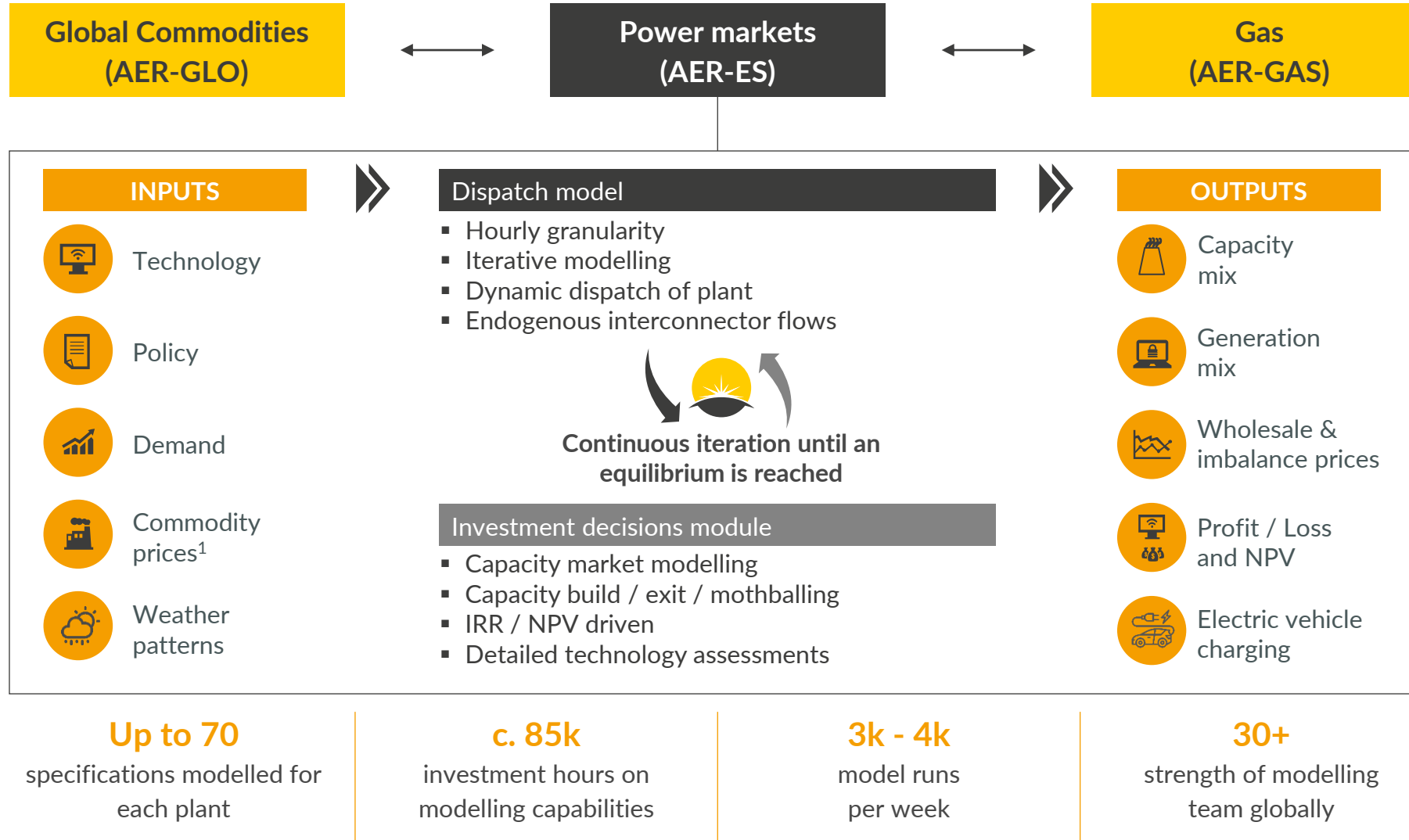
# A series of least regret options can be pursued to minimise risks to the transition towards net-zero

- 1 Continued revenue support for low carbon technologies**  
To incentivise deployment of low-carbon capacity despite low wholesale market revenues as a result of high penetrations of low marginal cost supply. A level playing field for all technologies is required.
- 2 Limit participation of unabated thermal in the CM**  
To prevent locking in reliance on new unabated thermal assets, that will remain online for 25 years, by only procuring low carbon alternatives.
- 3 Studies on the role of green H<sub>2</sub> from RES and nuclear to displace fossil fuels**  
Further investigations of H<sub>2</sub> only business models for RES and nuclear to create low cost H<sub>2</sub> without fossil fuels.
- 4 Conduct in depth siting and feasibility studies for nuclear and RES deployment**  
To ensure target deployment can be met.
- 5 Assess infrastructure requirements of decarbonisation pathways**  
To assess need, cost, development time and ecological impact for required infrastructure to be deployed in time for assets to online.
- 6 Examine the role existing nuclear can play in green H<sub>2</sub> production**  
Co-location of electrolysers with existing nuclear can unlock additional revenue streams whilst providing additional power system flexibility.
- 7 Explore support for a construction pipeline of small modular reactors**  
To enable deployment, costs reductions and assess feasibility of large scale deployment.
- 8 Explore support options for nuclear business models for power + H<sub>2</sub>**  
To compare against other low carbon technologies.
- 9 Further investigate the benefits of high temperature nuclear (Gen IV)**  
High temperature reactors could unlock very high H<sub>2</sub> conversion efficiencies using waste heat, with potential for cost reductions.
- 10 Development of clear business models for H<sub>2</sub> and CO<sub>2</sub> infrastructure**  
To assess costs and incentivise investment.



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# Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis of the power system



## Advantages of Aurora approach

- Flexible and nimble because we own the code.
- Transparent results.
- State-of-the-art infrastructure.
- Zero dependence on black-box third-party software (e.g. Plexos).
- Constantly up to date through subscription research.
- Ability to model complex policy changes very quickly.

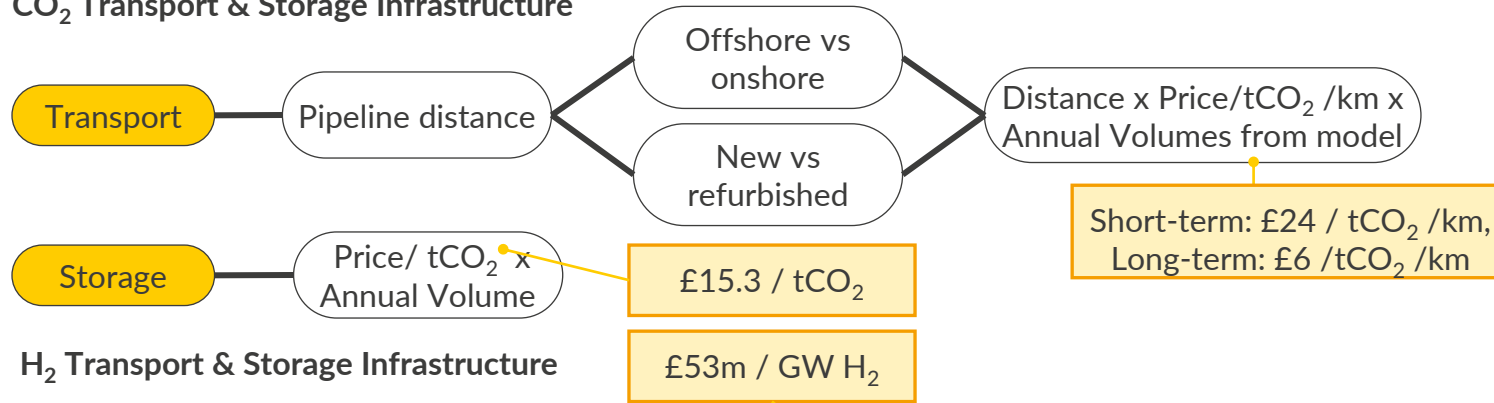
1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model.

# Methodology for calculating total system spending across scenarios

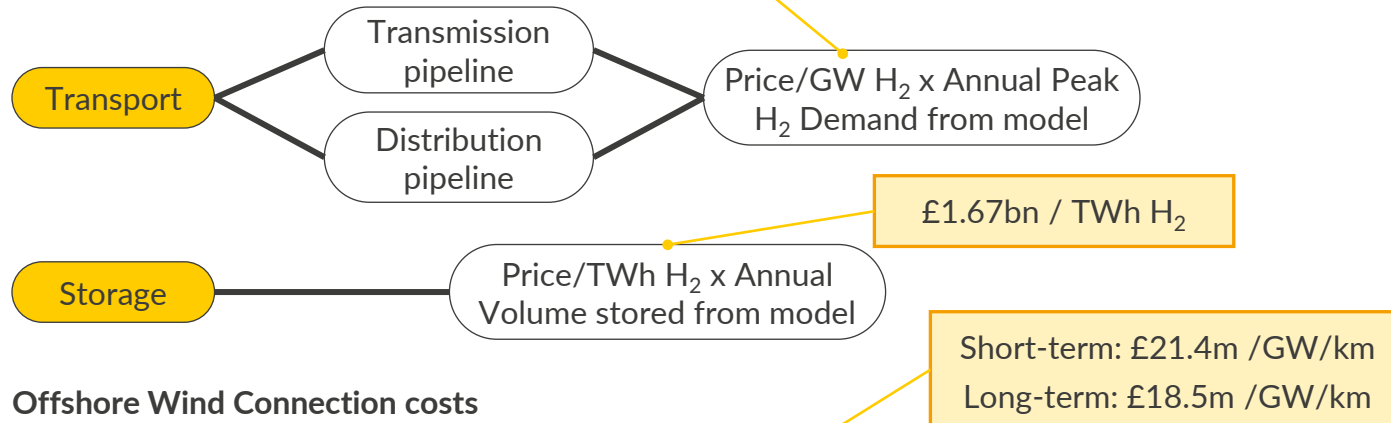
| System cost component                                 | Approach   |
|---|--|
| Electricity market                                    | Includes the total spend in the wholesale electricity market (i.e. wholesale price x demand, assuming 8% transmission losses) and the electricity balancing market to match outturn supply and demand.   |
| Electricity market support payments                   | <ul style="list-style-type: none"> <li>▪ Subsidy payments to plants with existing support contracts (e.g. ROC, FiT, CfD).</li> <li>▪ Capacity Market payments to ensure acceptable returns are met for sufficient capacity to build to meet security of supply targets.</li> <li>▪ Additional top-up payments required for assumed capacity additions to breakeven.</li> </ul> |
| Network costs (TNUoS, DUoS)                           | Estimate of the costs required to expand the network to connect new capacity (accounting for retirements), and the costs to operate and maintain the existing network (underestimates the cost of connecting offshore wind).   |
| Hydrogen market costs                                 | Includes the total spend in the hydrogen market (i.e. wholesale hydrogen market price x demand, hydrogen price achieved by PEM electrolyzers at vehicle charging points x demand).   |
| Additional infrastructure costs (see following slide) | <ul style="list-style-type: none"> <li>▪ Estimate of additional costs of connecting offshore wind to the transmission network not accounted for in network costs.</li> <li>▪ Estimate of the costs of hydrogen storage and pipeline infrastructure.</li> <li>▪ Estimate of the costs of CO<sub>2</sub> storage and pipeline infrastructure.</li> </ul>                         |

# Methodology for estimating additional infrastructure costs

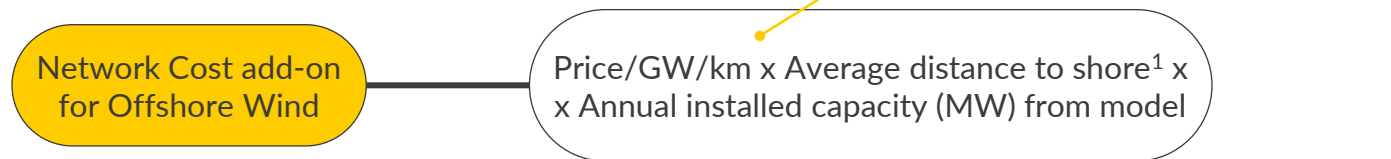
## CO<sub>2</sub> Transport & Storage Infrastructure



## H<sub>2</sub> Transport & Storage Infrastructure



## Offshore Wind Connection costs



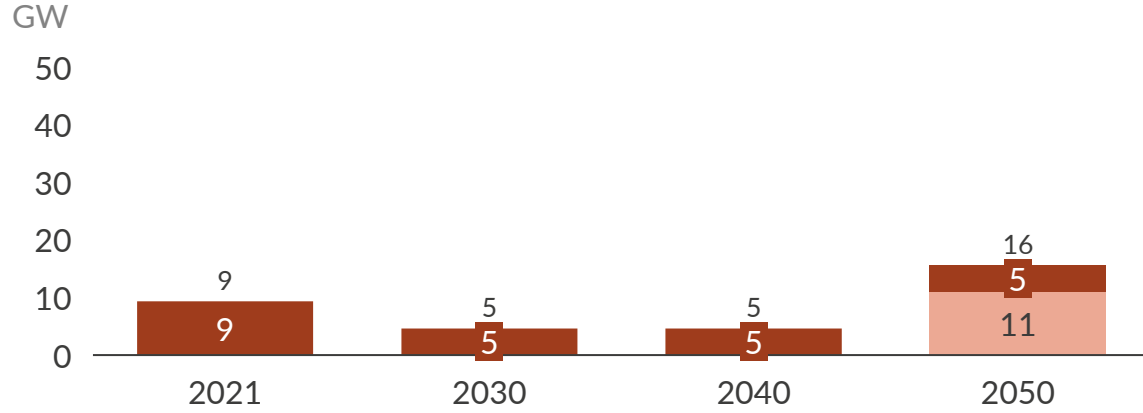
- Our proposed methodology is influenced by the IEA 2020 Special Report on CCUS.
- We propose to ignore shipping as a means of transport as it is competitive with pipelines only for long-haul transport of small CO<sub>2</sub> volumes.
- Infrastructure cost estimates for the Hydrogen system are based on the assumption that large parts of existing gas network infrastructure can be refitted to carry H<sub>2</sub>.
- Price points are averaged from project cost estimates spanning multiple reports and were agreed upon by the consortium behind Aurora’s 2020 Hydrogen Study.
- Price/ km estimate will be based on recent greenfield and brownfield transactions for offshore transmission infrastructure.
- Average distance to shore and Number of offshore sites per MW will be calculated by analysing the existing fleet.

1) Average distance to shore increases over time to reflect future sites building far away from present ones. It also reflects increasing penetration of floating offshore wind.

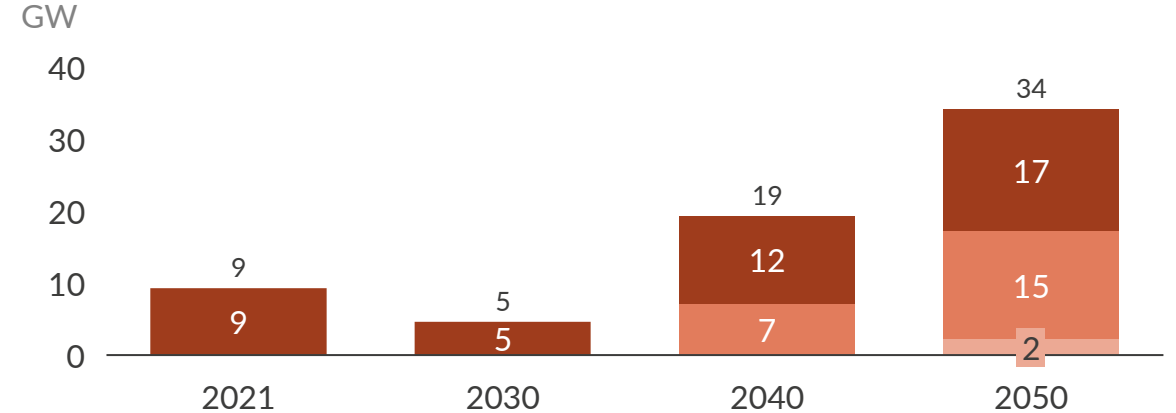
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# Nuclear capacity forecast by scenario

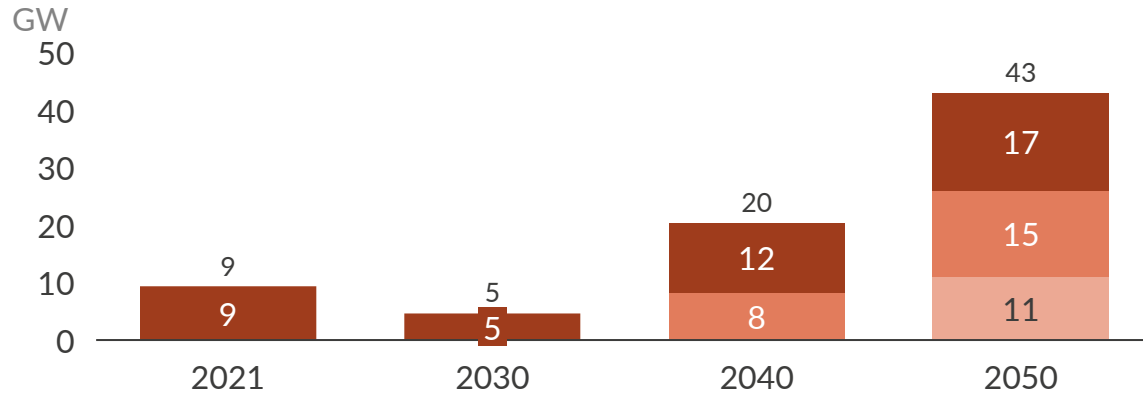
GB installed nuclear capacity: 1L. No new nuclear



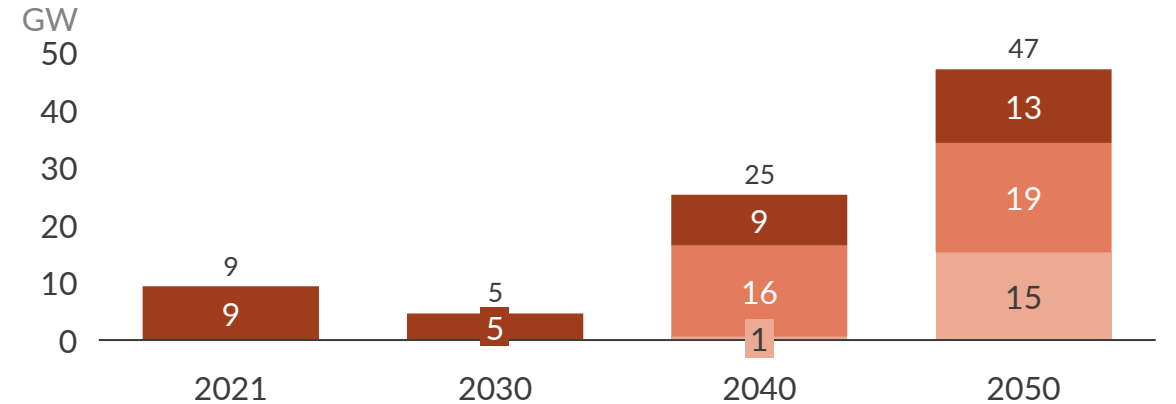
GB installed nuclear capacity: 2L. Existing nuclear techs



GB installed nuclear capacity: 3L. New nuclear techs



GB installed nuclear capacity: 4L. Strong nuclear strategy

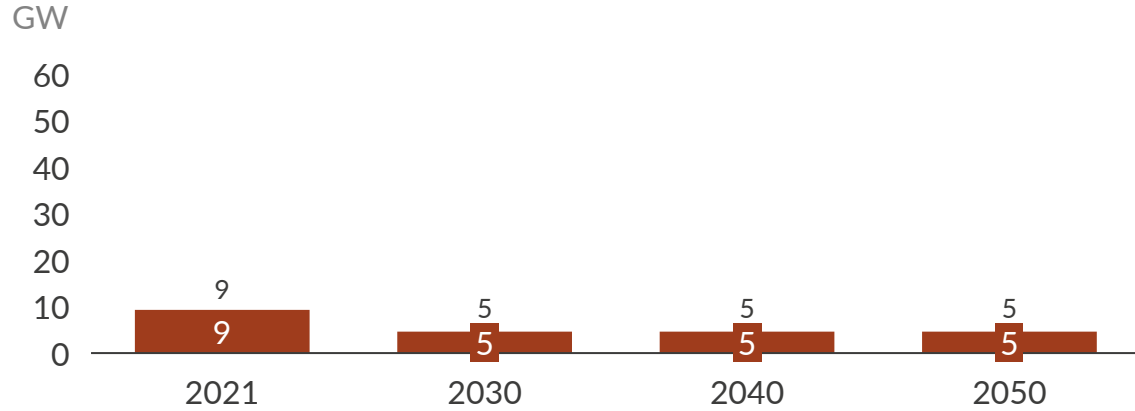


■ Nuclear ■ Small Modular Reactor ■ Gen IV with electrolyser

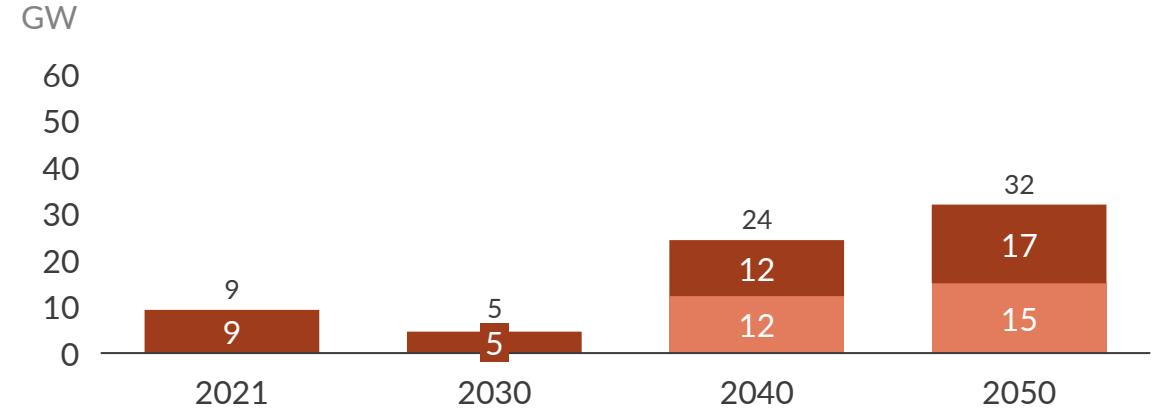
1) Other RES includes EfW and marine; 2) Other thermal includes embedded CHP; 3) Gas CCGT includes abated and unabated plants.

# Power market capacity forecast by scenario

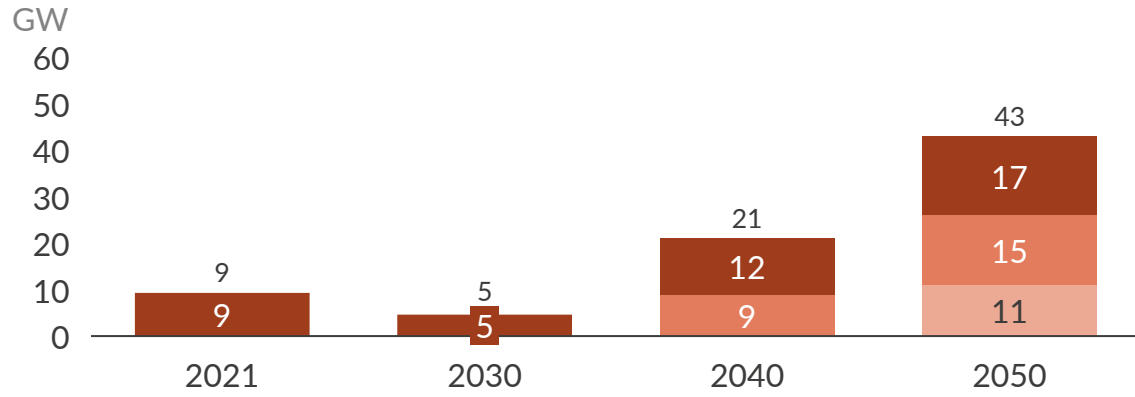
GB installed nuclear capacity: 1H. No new nuclear



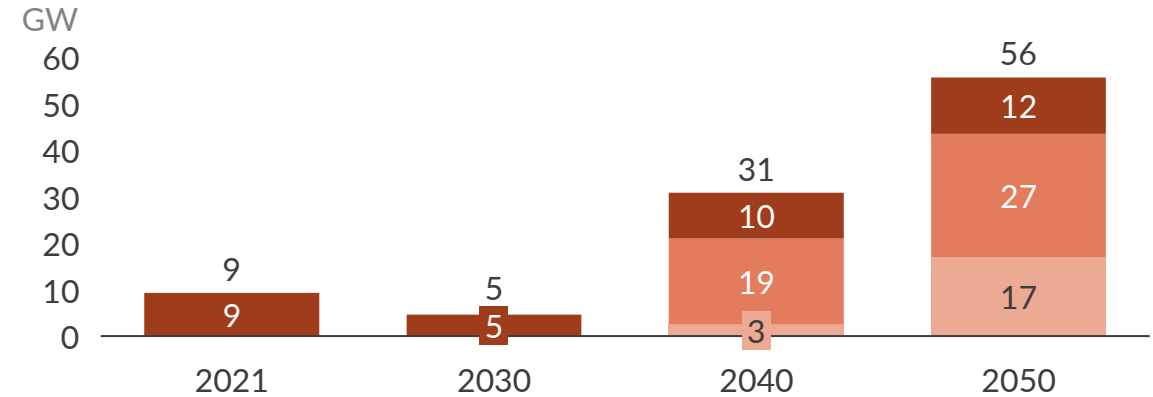
GB installed nuclear capacity: 2H. Existing nuclear techs



GB installed nuclear capacity: 3H. New nuclear techs



GB installed nuclear capacity: 4H. Strong nuclear strategy

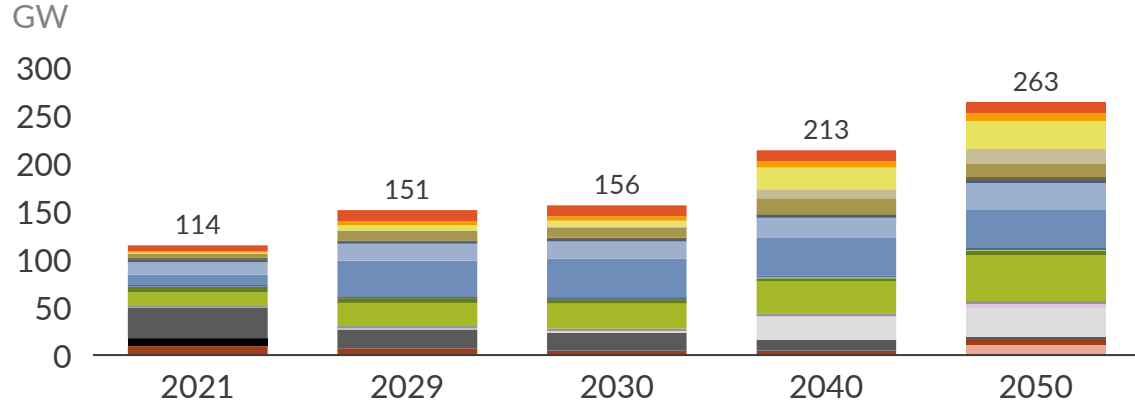


■ Nuclear ■ Small Modular Reactor ■ Gen IV with electrolyser

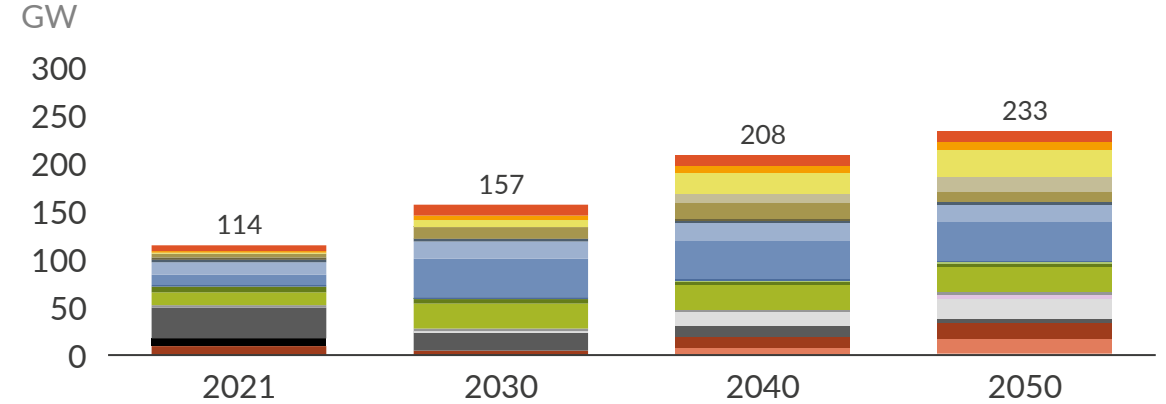
1) Other RES includes EfW and marine; 2) Other thermal includes embedded CHP; 3) Gas CCGT includes abated and unabated plants.

# Power market capacity forecast by scenario

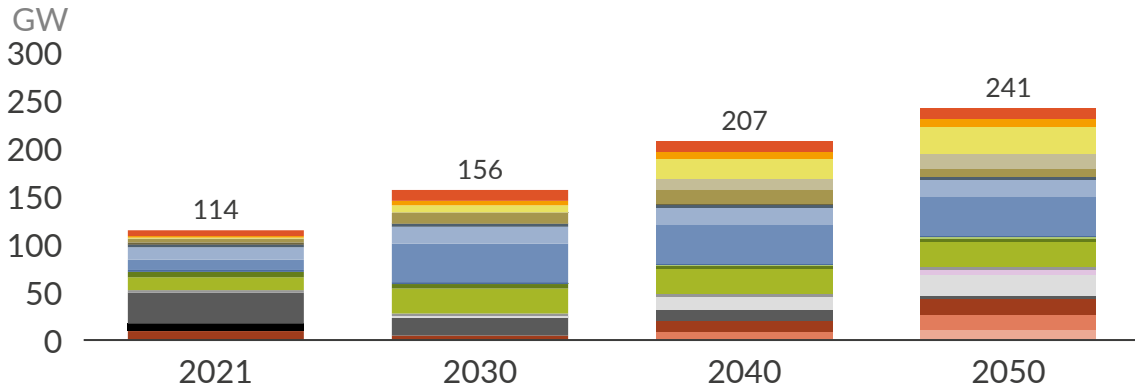
GB installed capacity: 1L. No new nuclear



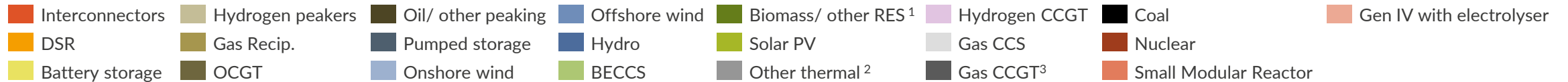
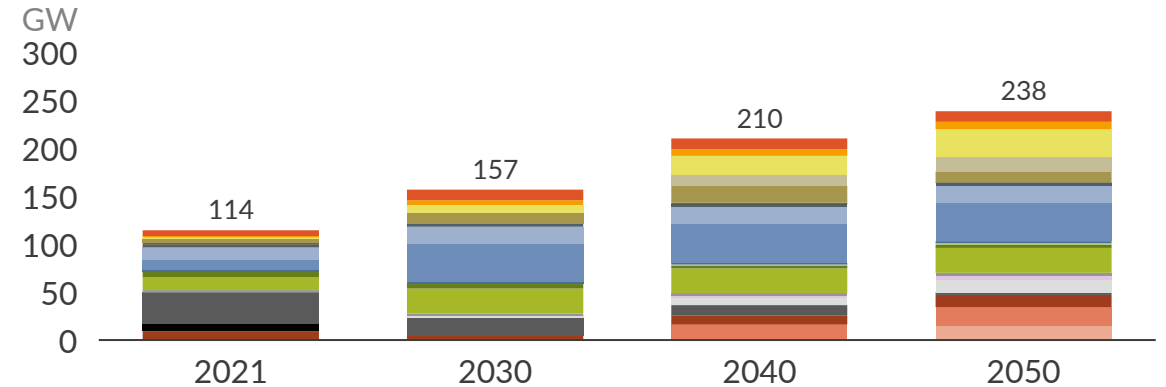
GB installed capacity: 2L. Existing nuclear techs



GB installed capacity: 3L. New nuclear techs



GB installed capacity: 4L. Strong nuclear strategy

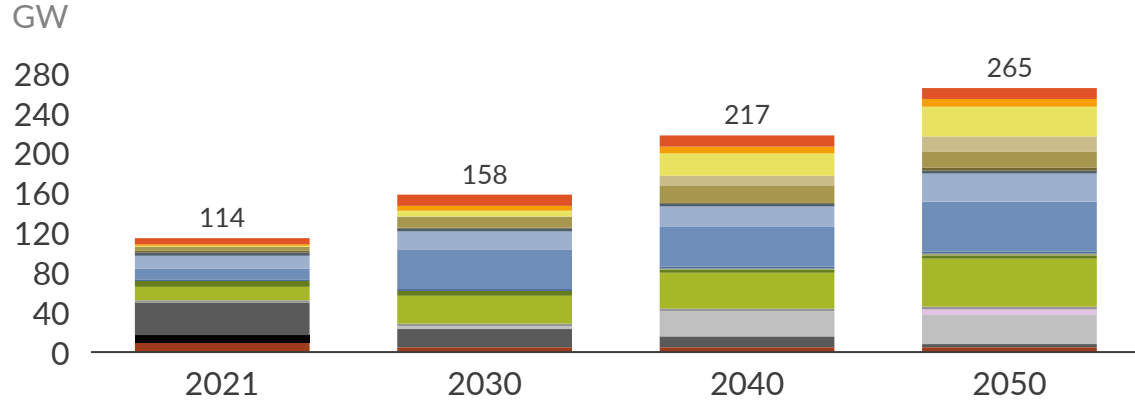


1) Other RES includes EfW and marine; 2) Other thermal includes embedded CHP; 3) Gas CCGT includes abated and unabated plants.

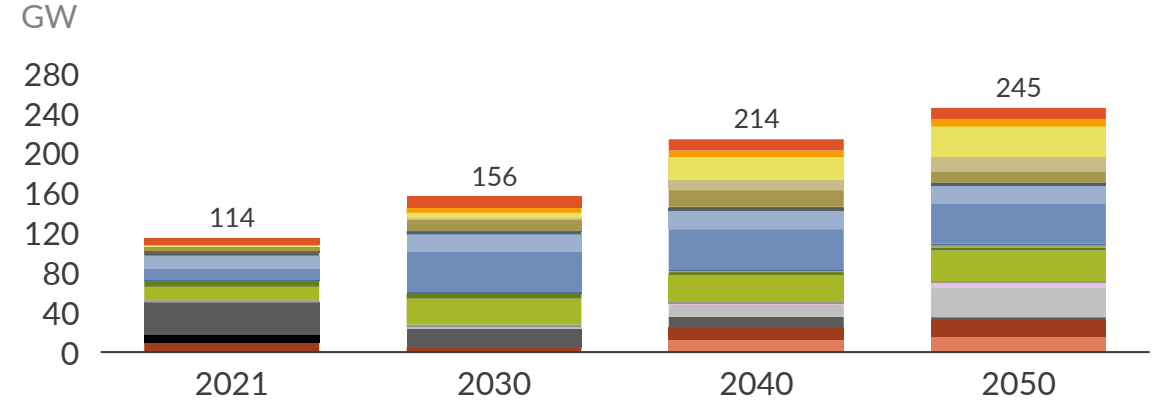


# Power market capacity forecast by scenario

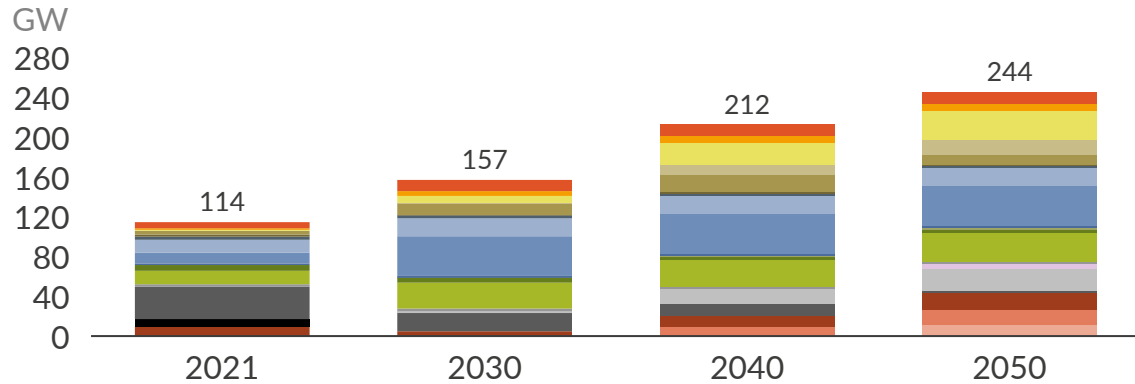
**GB installed capacity: 1H. No new nuclear**



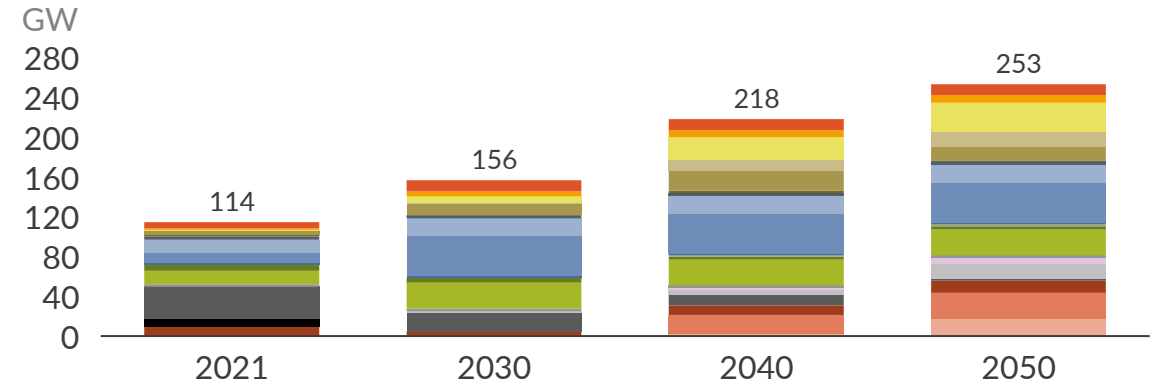
**GB installed capacity: 2H. Existing nuclear techs**



**GB installed capacity: 3H. New nuclear techs**



**GB installed capacity: 4H. Strong nuclear strategy**

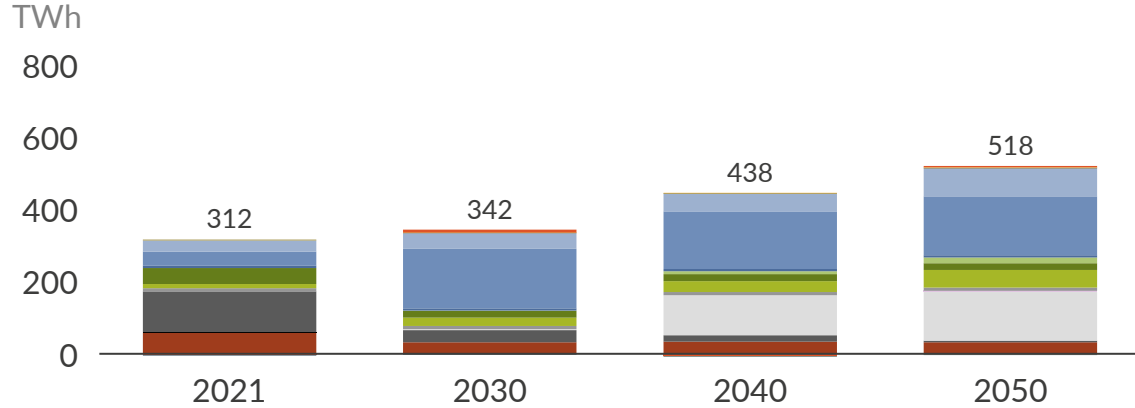


- Interconnectors
- Hydrogen peakers
- Oil/ other peaking
- Offshore wind
- Biomass/ other RES<sup>1</sup>
- Hydrogen CCGT
- Coal
- Gen IV with electrolyser
- DSR
- Gas Recip.
- Pumped storage
- Hydro
- Solar PV
- Gas CCS
- Nuclear
- Battery storage
- OCGT
- Onshore wind
- BECCS
- Other thermal<sup>2</sup>
- Gas CCGT<sup>3</sup>
- Small Modular Reactor

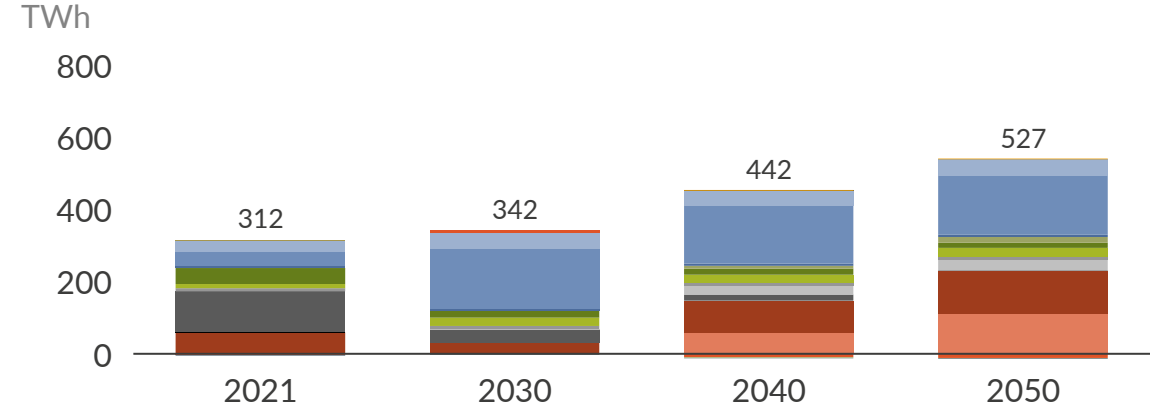
1) Other RES includes EfW and marine; 2) Other thermal includes embedded CHP; 3) Gas CCGT includes abated and unabated plants.

# Power market generation forecast by scenario

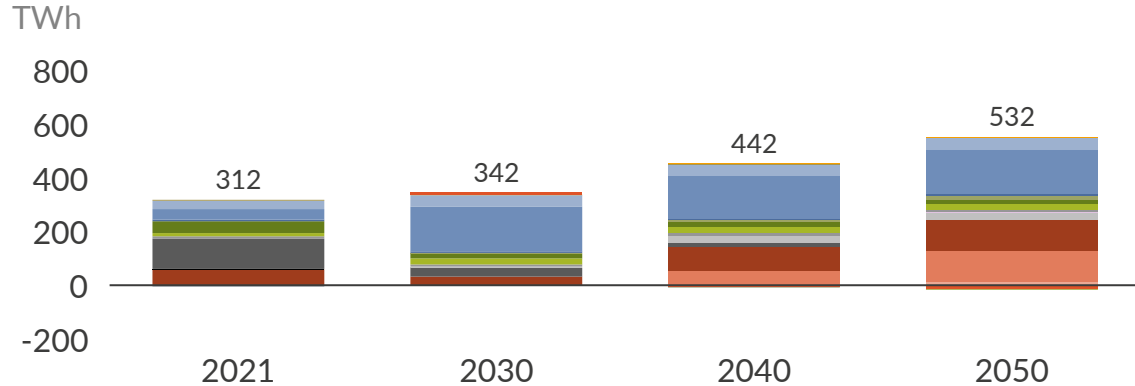
Electricity production and net imports: 1L. No new nuclear



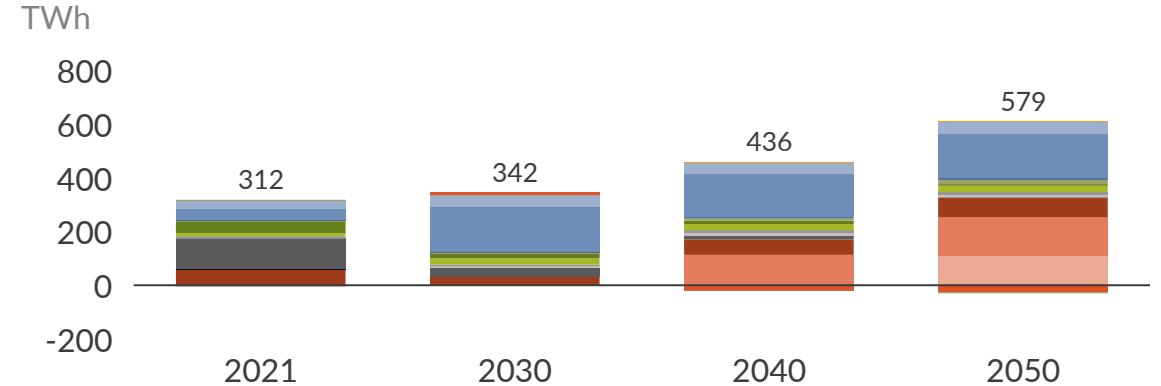
Electricity production and net imports: 2L. Existing nuclear techs



Electricity production and net imports: 3L. New nuclear techs



Electricity production and net imports: 4L. Strong nuclear strategy

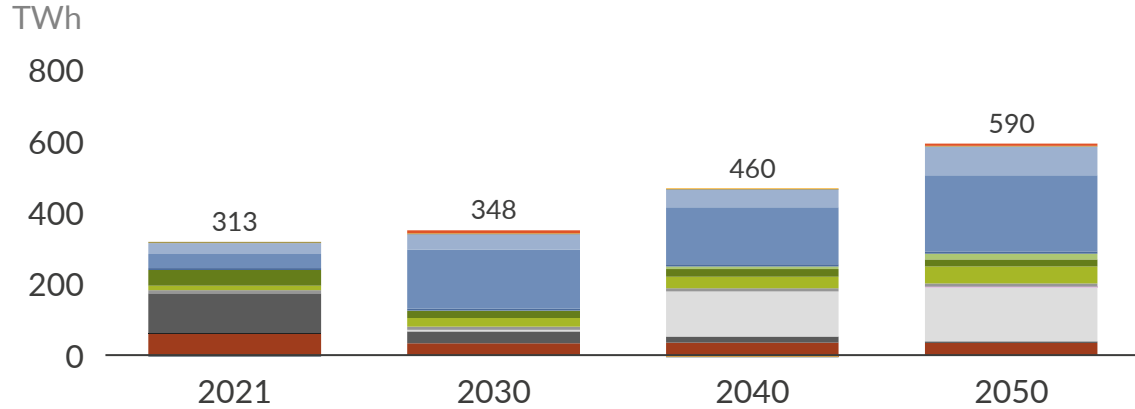


- Interconnectors
- Hydrogen peakers
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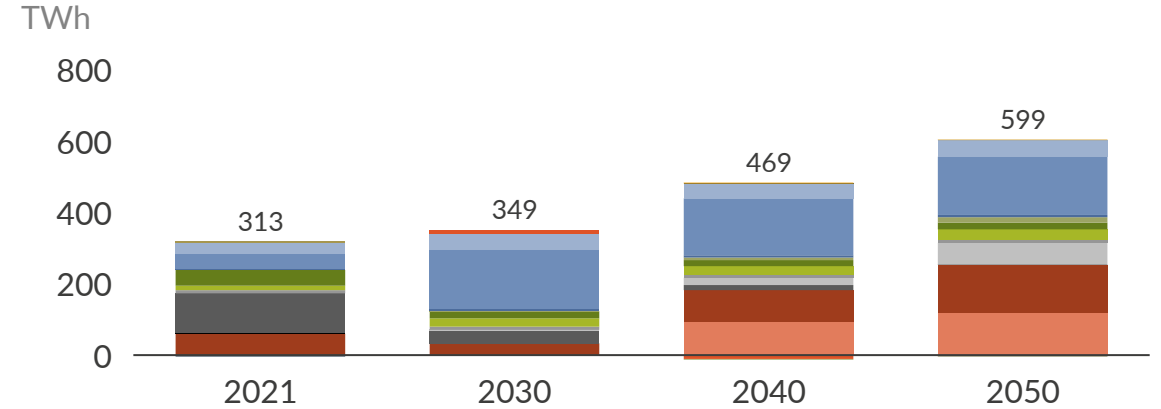
1) Other RES includes EfW and marine; 2) Other thermal includes embedded CHP; 3) Gas CCGT includes abated and unabated plants.

# Power market generation forecast by scenario

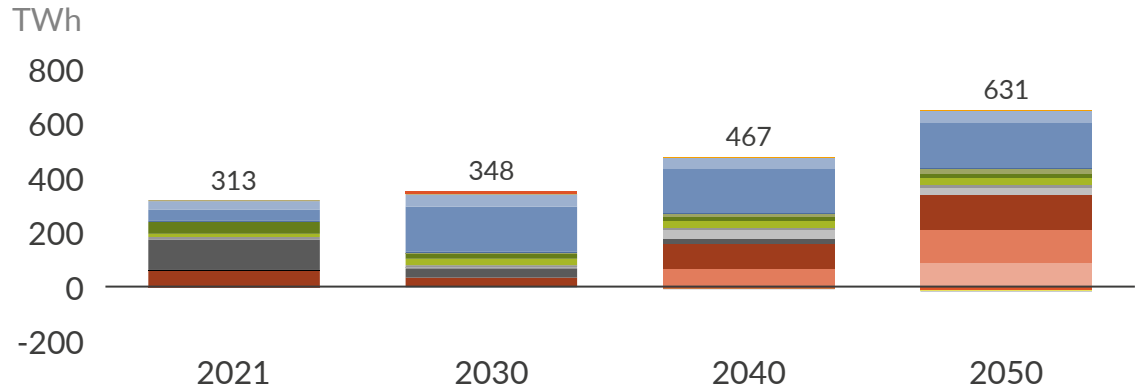
Electricity production and net imports: 1H. No new nuclear



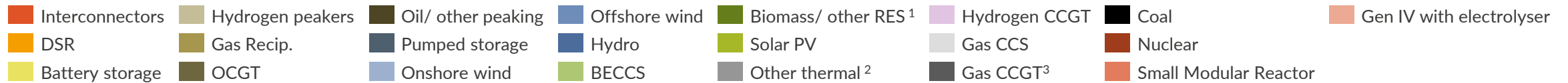
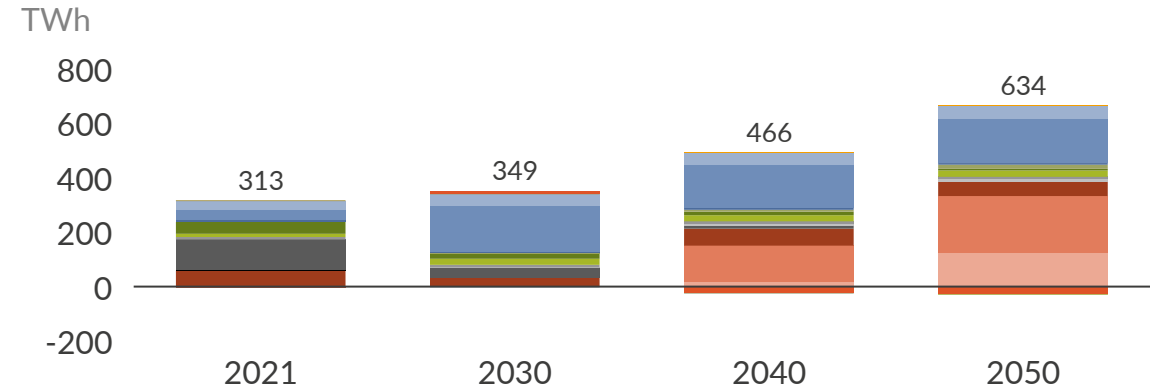
Electricity production and net imports: 2H. Existing nuclear techs



Electricity production and net imports: 3H. New nuclear techs



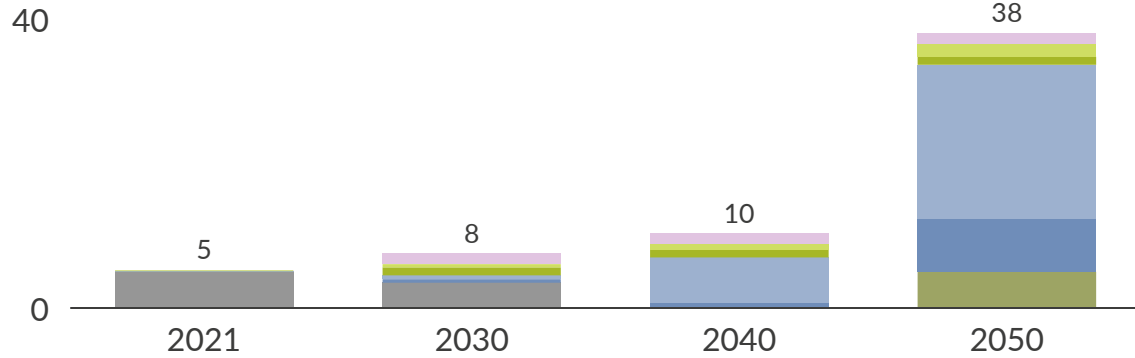
Electricity production and net imports: 4H. Strong nuclear strategy



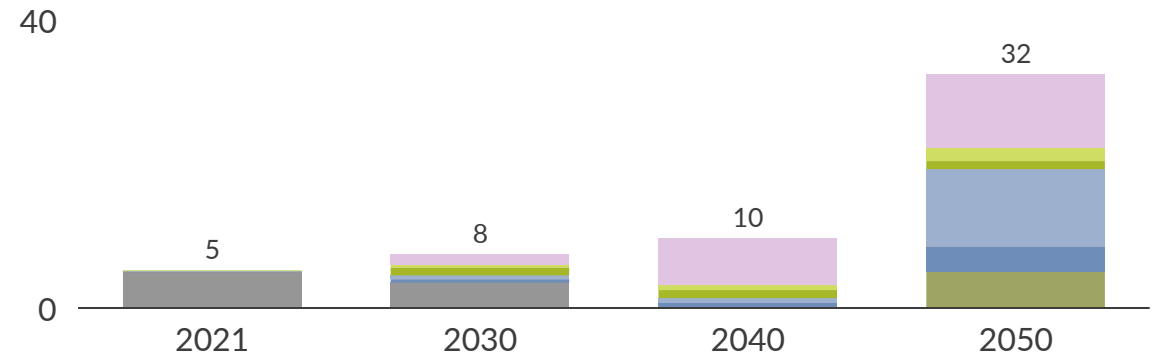
1) Other RES includes EfW and marine; 2) Other thermal includes embedded CHP; 3) Gas CCGT includes abated and unabated plants.

# Hydrogen market capacity forecast by scenario

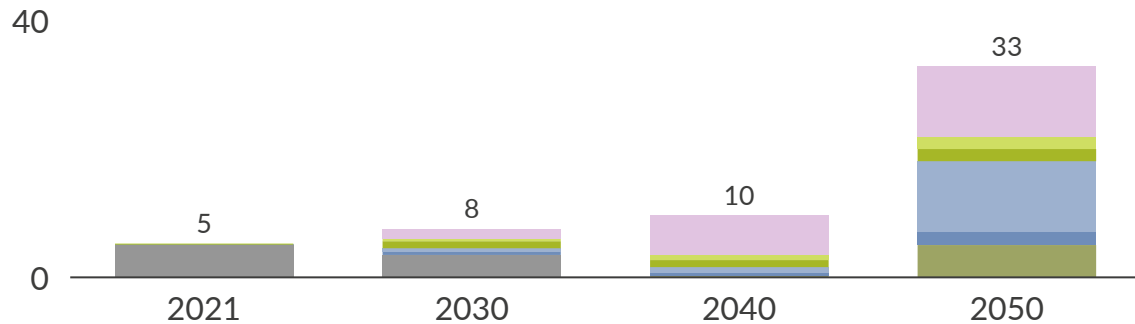
**GB H<sub>2</sub> installed capacity: 1L. No new nuclear**  
GW H<sub>2</sub>



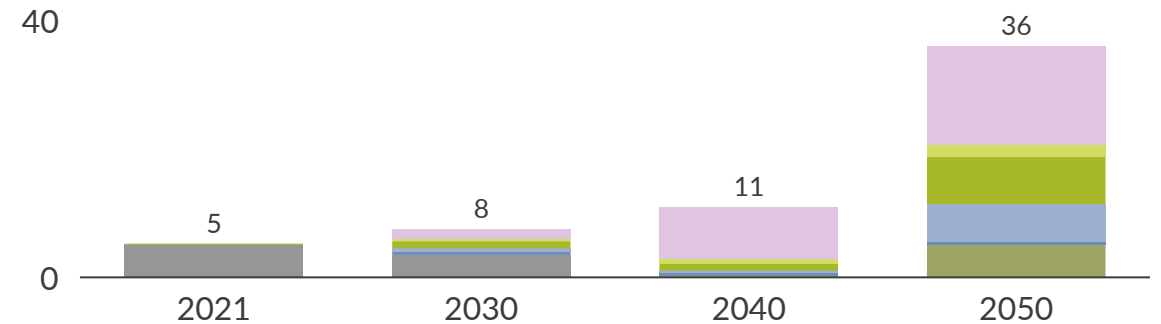
**GB H<sub>2</sub> installed capacity: 2L. Existing nuclear techs**  
GW H<sub>2</sub>



**GB H<sub>2</sub> installed capacity: 3L. New nuclear techs**  
GW H<sub>2</sub>



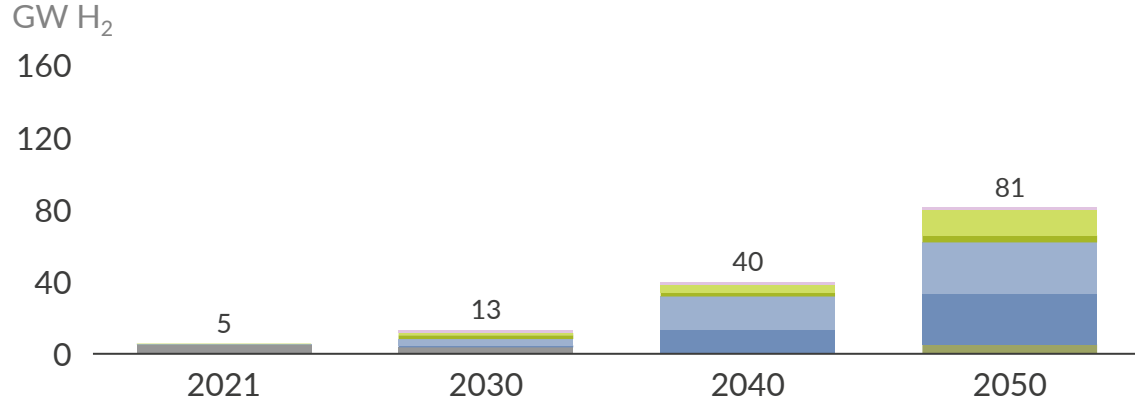
**GB H<sub>2</sub> installed capacity: 4L. Strong nuclear strategy**  
GW H<sub>2</sub>



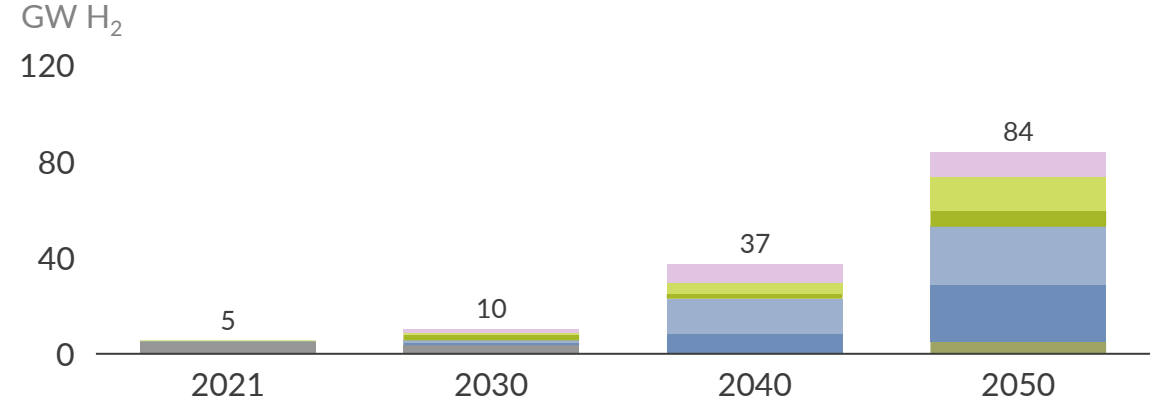
SMR
  H<sub>2</sub> BECCS
  SMR+CCS
  ATR+CCS
  Alkaline
  PEM
  SOE
  Gigafactory

# Hydrogen market capacity forecast by scenario

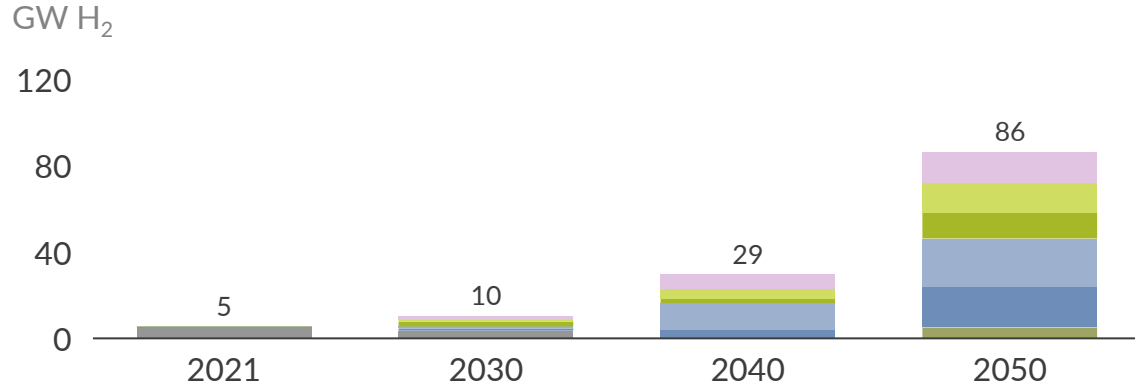
GB H<sub>2</sub> installed capacity: 1H. No new nuclear



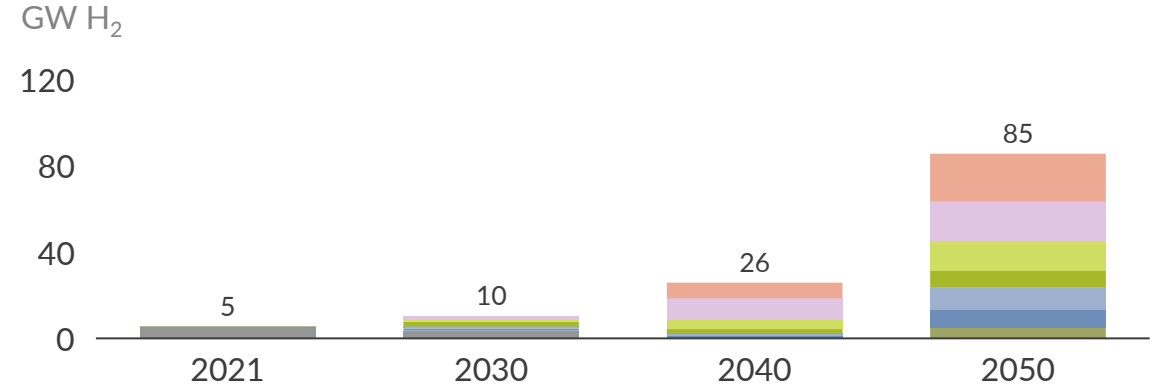
GB H<sub>2</sub> installed capacity: 2H. Existing nuclear techs



GB H<sub>2</sub> installed capacity: 3H. New nuclear techs



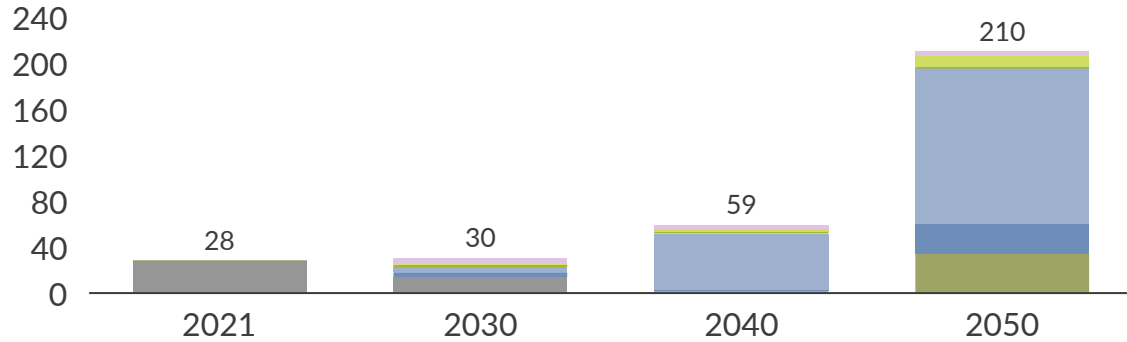
GB H<sub>2</sub> installed capacity: 4H. Strong nuclear strategy



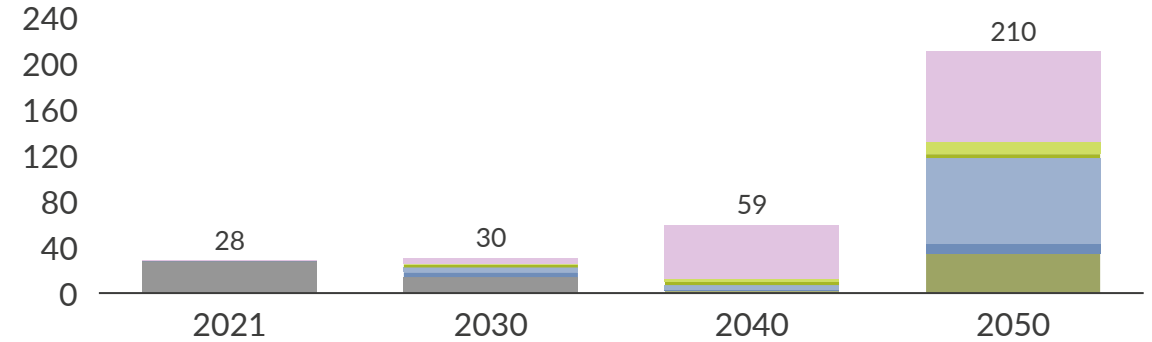
SMR H<sub>2</sub> BECCS SMR+CCS ATR+CCS Alkaline PEM SOE Gigafactory

# Hydrogen market generation forecast by scenario

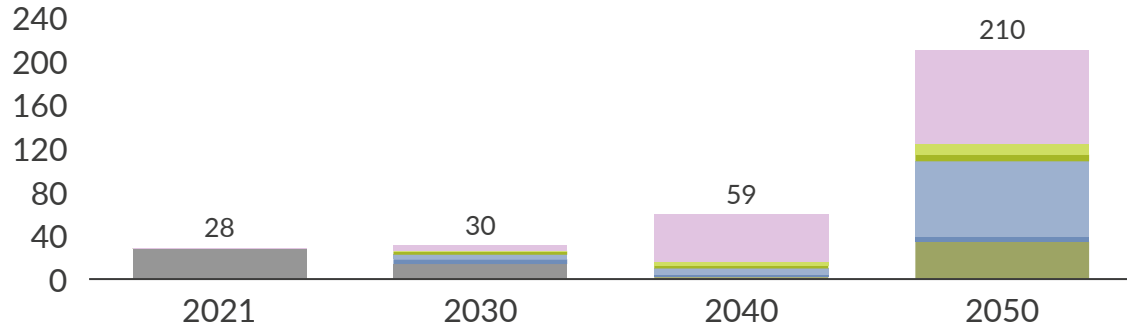
**GB gross H<sub>2</sub> production : 1L. No new nuclear**  
TWh H<sub>2</sub>



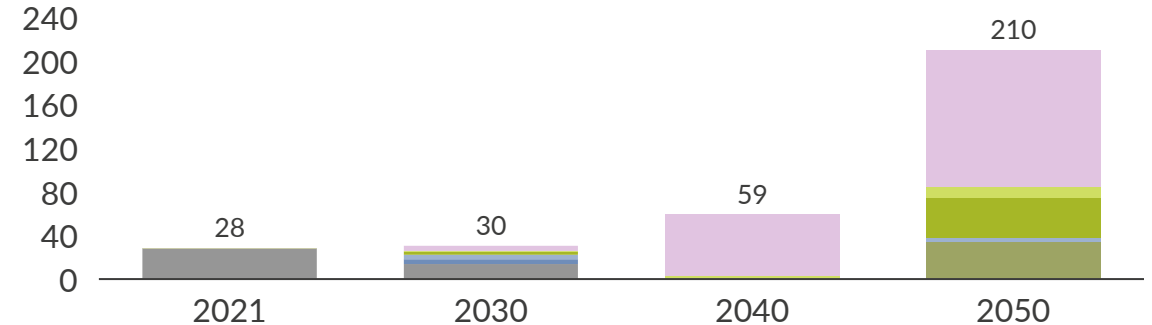
**GB gross H<sub>2</sub> production : 2L. Existing nuclear techs**  
TWh H<sub>2</sub>



**GB gross H<sub>2</sub> production : 3L. New nuclear techs**  
TWh H<sub>2</sub>



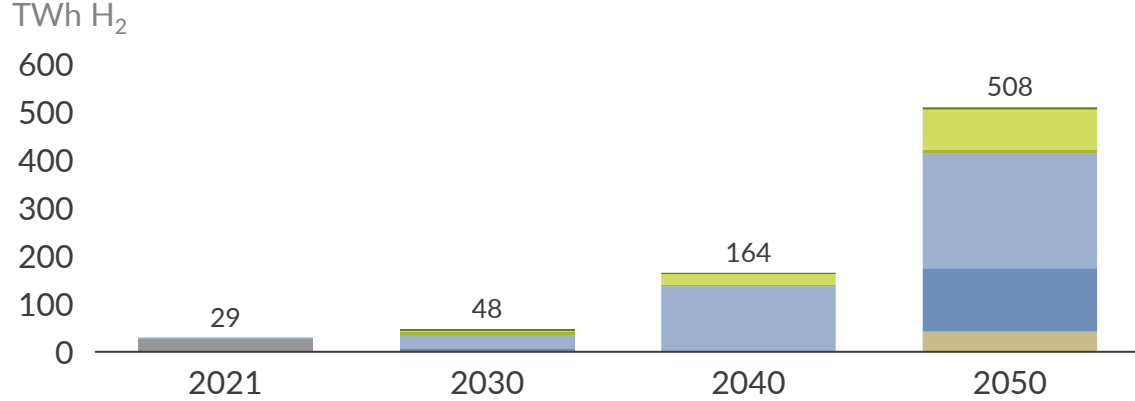
**gross H<sub>2</sub> production : 4L. Strong nuclear strategy**  
TWh H<sub>2</sub>



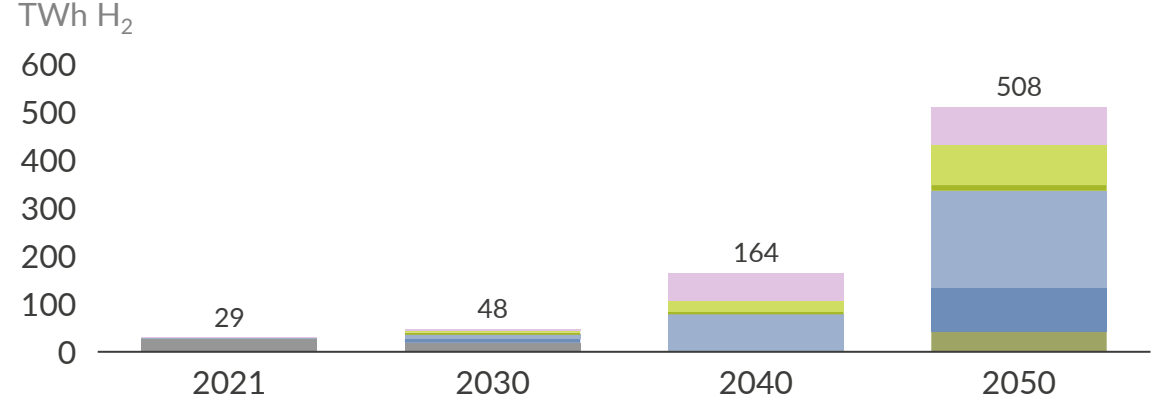
SMR
  H<sub>2</sub> BECCS
  SMR+CCS
  ATR+CCS
  Alkaline
  PEM
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  Gigafactory

# Hydrogen market generation forecast by scenario

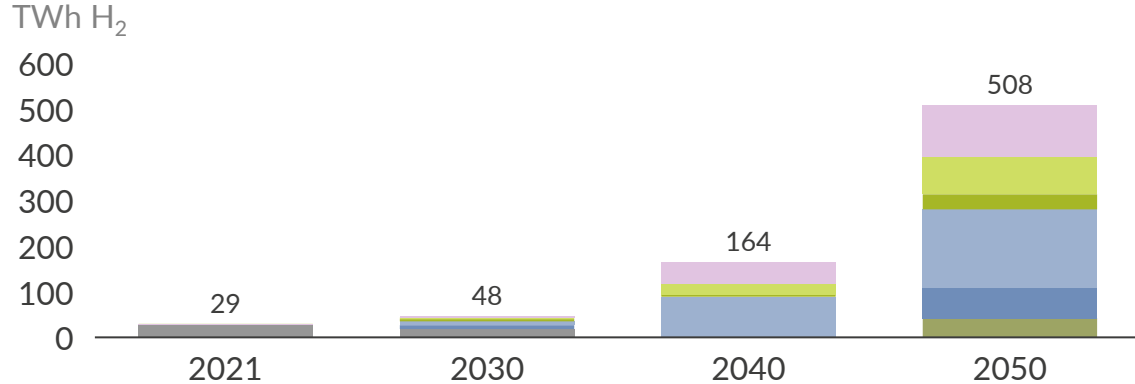
GB gross H<sub>2</sub> production : 1H. No new nuclear



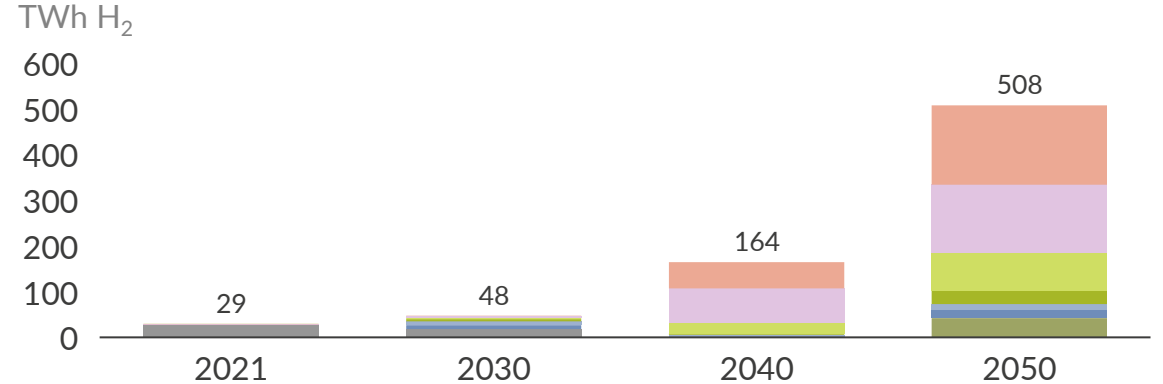
GB gross H<sub>2</sub> production : 2H. Existing nuclear techs



GB gross H<sub>2</sub> production : 3H. New nuclear techs



GB gross H<sub>2</sub> production : 4H. Strong nuclear strategy

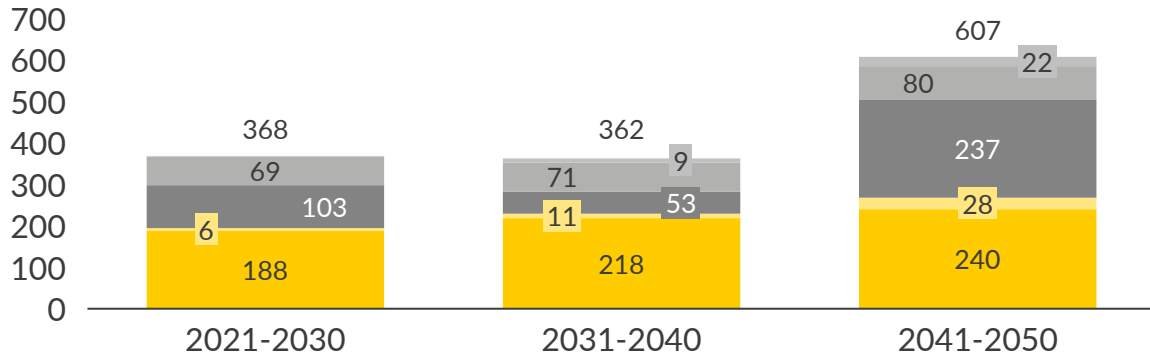


SMR H<sub>2</sub> BECCS SMR+CCS ATR+CCS Alkaline PEM SOE Gigafactory

# Total system costs by scenario

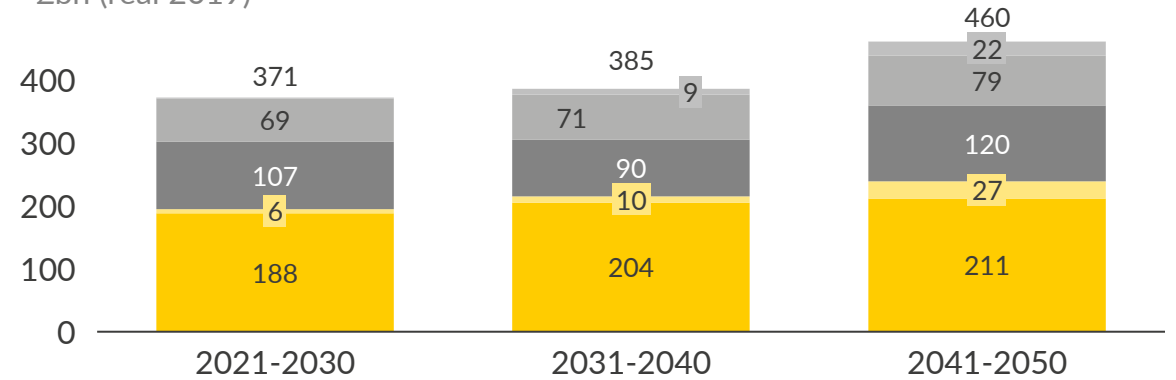
**GB total system spend: 1L. No new nuclear**

£bn (real 2019)



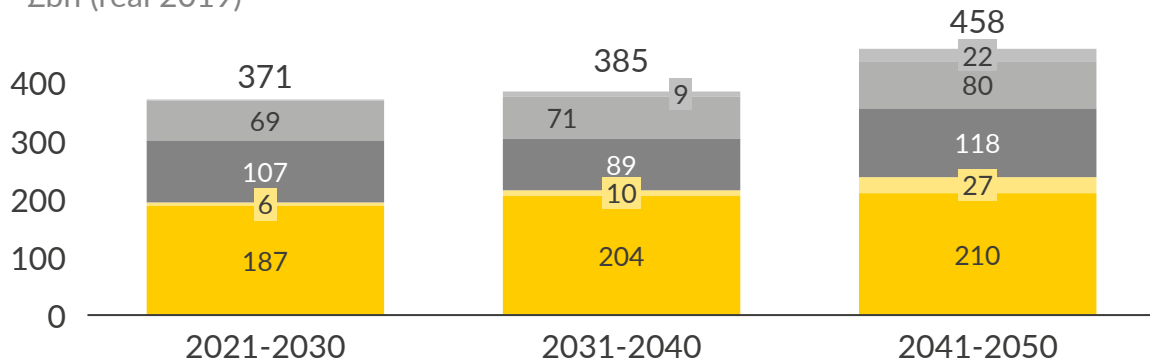
**GB total system spend: 2L. Existing nuclear techs**

£bn (real 2019)



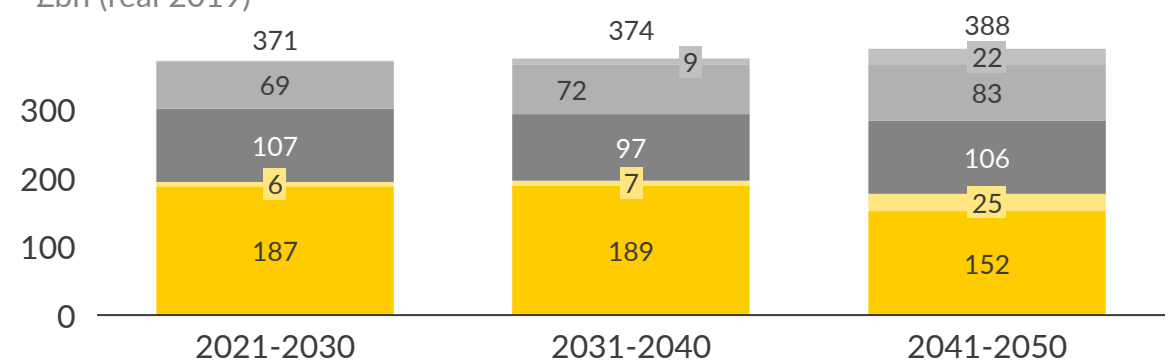
**GB total system spend: 3L. New nuclear techs**

£bn (real 2019)



**GB total system spend: 4L. Strong nuclear strategy**

£bn (real 2019)



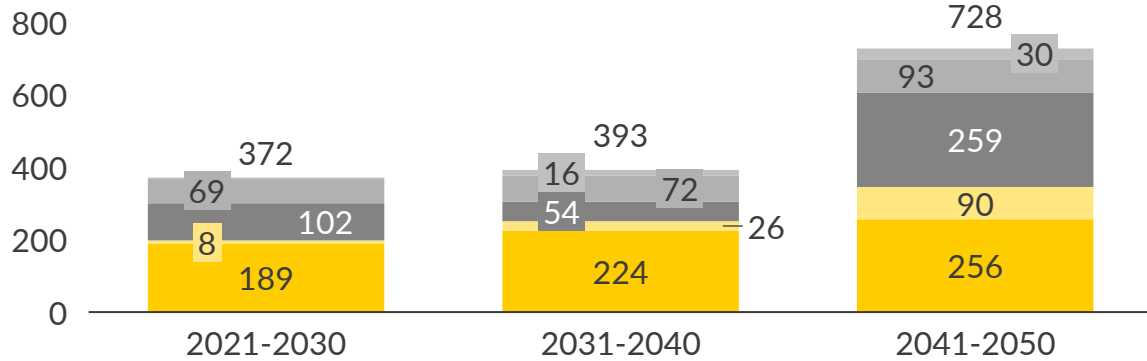
Wholesale electricity Wholesale hydrogen Support costs (incl. CM & subsidies) Electricity infrastructure Hydrogen infrastructure CO2 infrastructure



# Total system costs by scenario

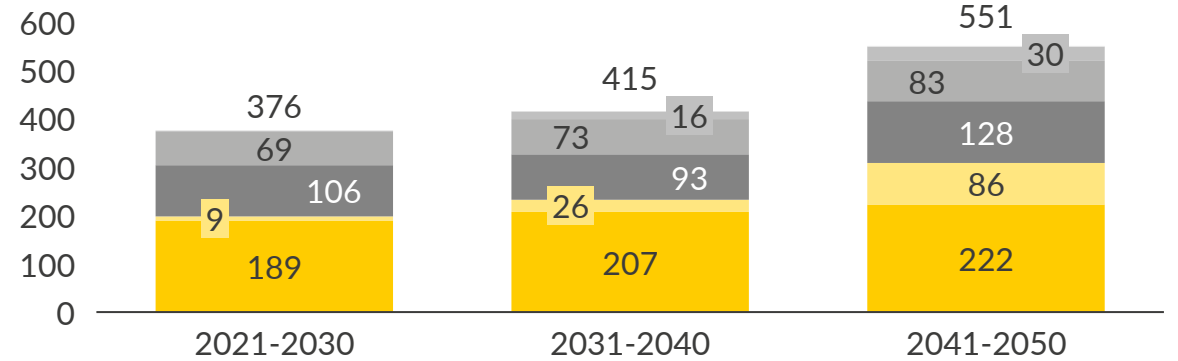
**GB total system spend: 1H. No new nuclear**

£bn (real 2019)



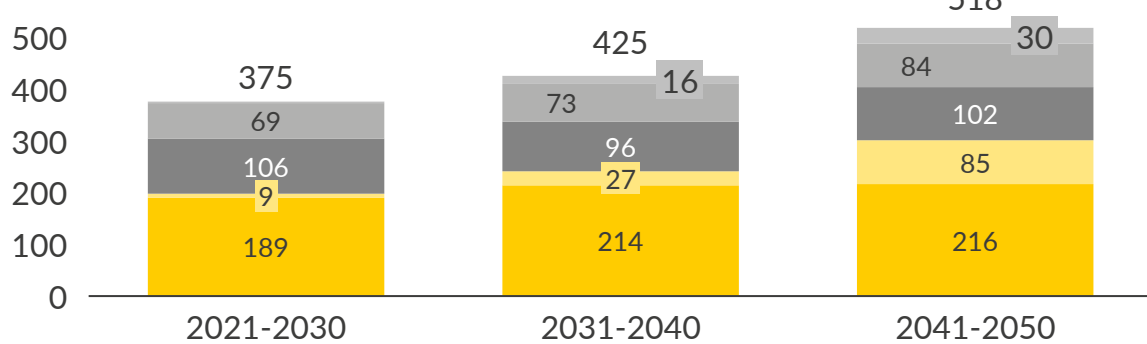
**GB total system spend: 2H. Existing nuclear techs**

£bn (real 2019)



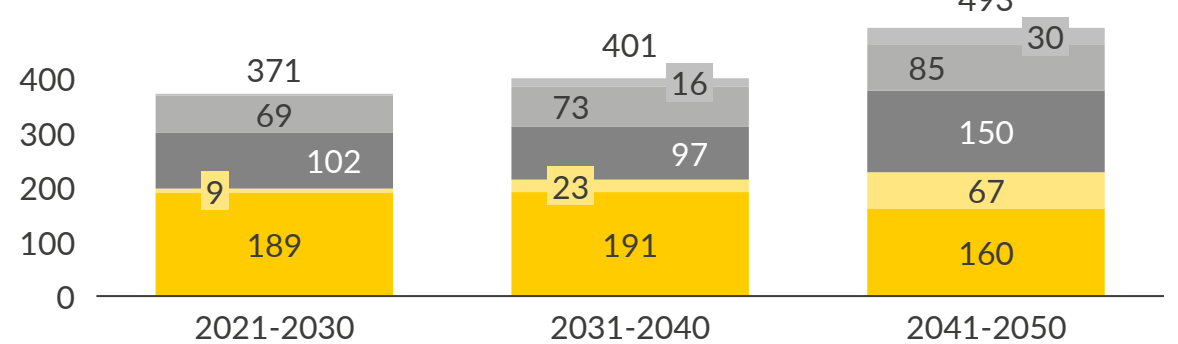
**GB total system spend: 3H. New nuclear techs**

£bn (real 2019)



**GB total system spend: 4H. Strong nuclear strategy**

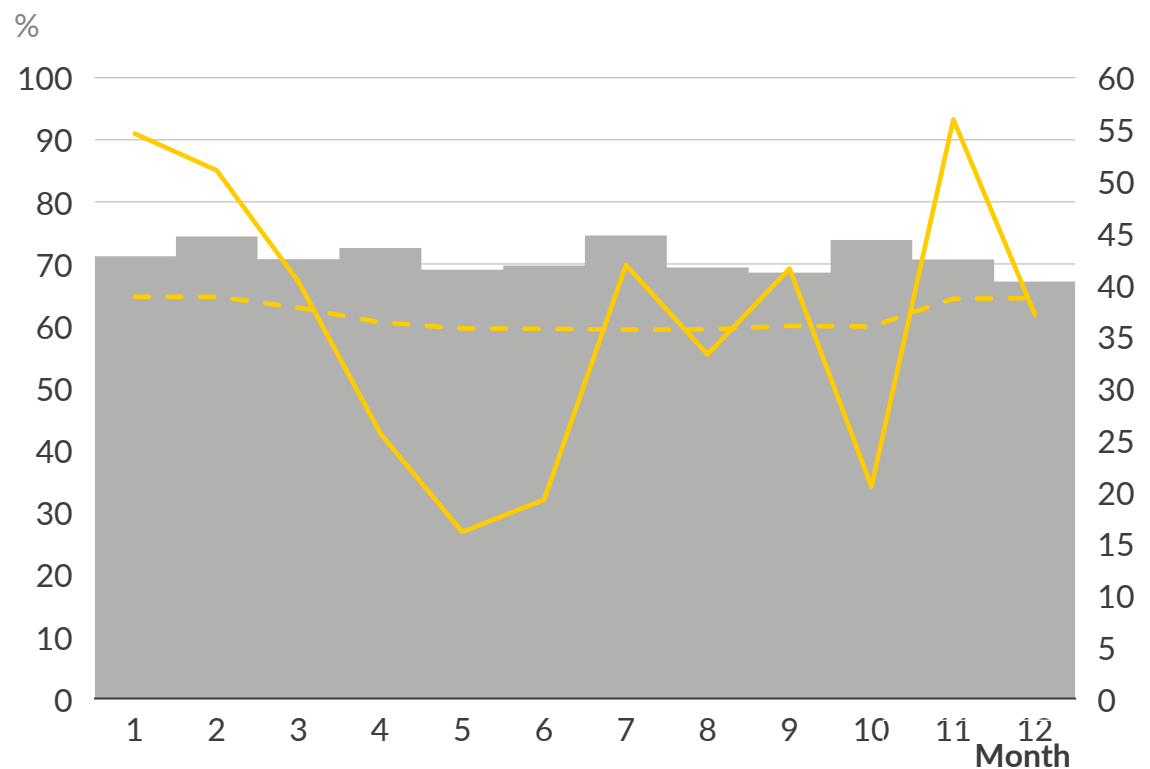
£bn (real 2019)



■ Wholesale electricity 
 ■ Wholesale hydrogen 
 ■ Support costs (incl. CM & subsidies) 
 ■ Electricity infrastructure 
 ■ Hydrogen infrastructure 
 ■ CO2 infrastructure

# Seasonality in H<sub>2</sub> production from electrolyzers paired with nuclear is minimal, with baseload operations preferred

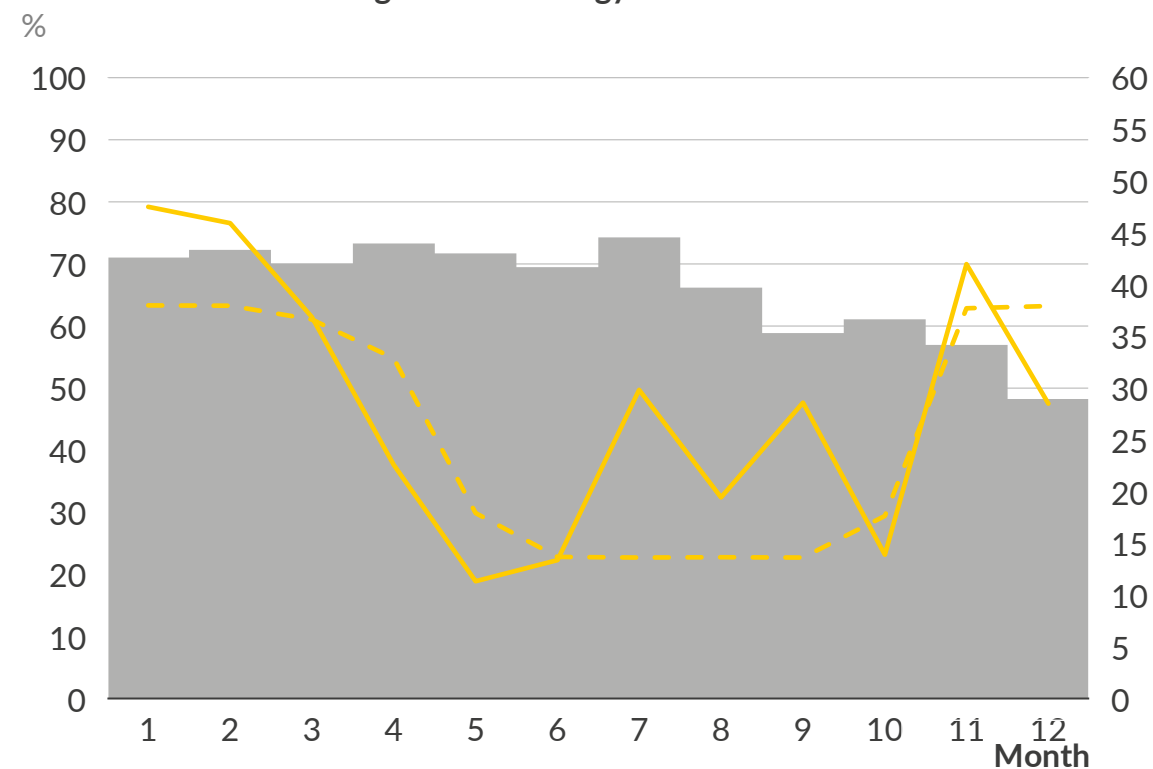
Monthly load factor of SOE co-located with small nuclear 2045: scenario 3H. New nuclear techs



The load factor of the paired electrolyser has a weak relationship with captured power prices for the nuclear asset. Baseload operation at a c.70% load factor ensures maximum revenue in the H<sub>2</sub> market, to account for low overall captured prices in the power sector

■ Load factor — Power price - - H2 price

Monthly load factor of SOE co-located with small nuclear 2045: scenario 4H. Strong nuclear strategy

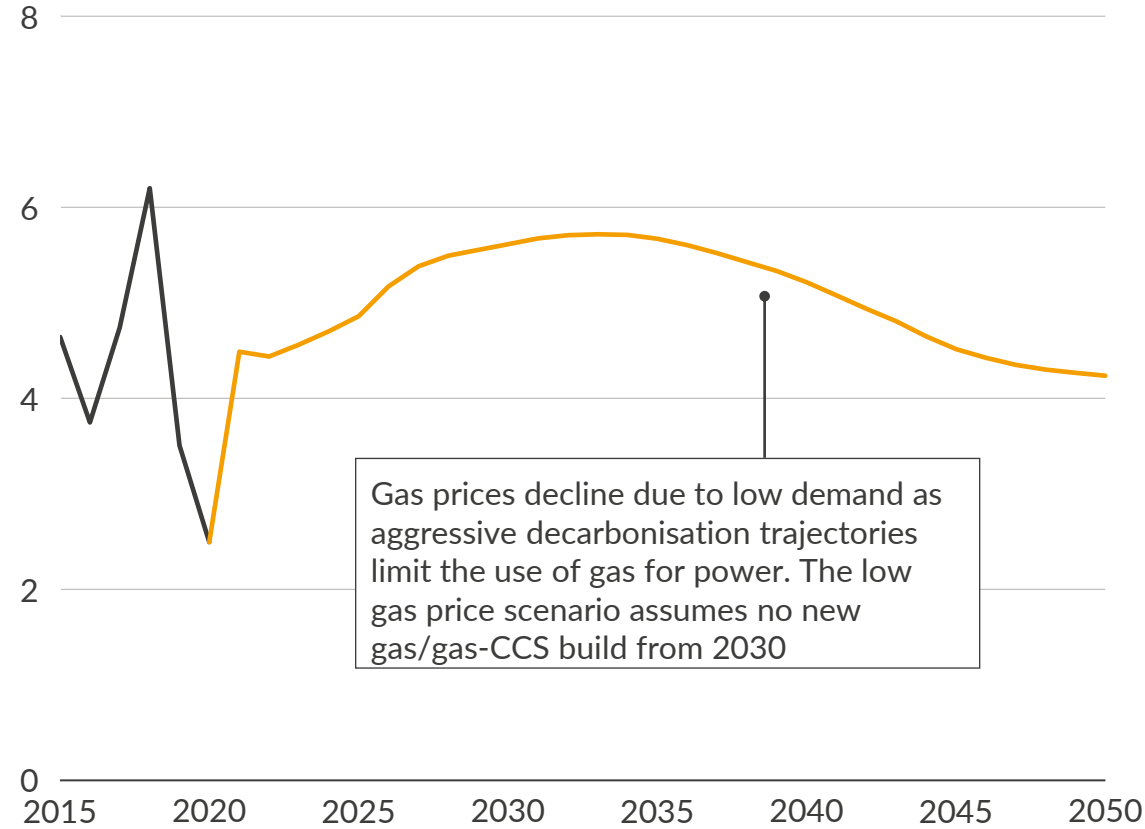


In scenario 4H, electrolyser output declines toward the end of the year in order to capture slightly higher returns in the power sector once storage capacity has been filled over the summer months

- I. Executive summary
- II. The need for H<sub>2</sub> in reaching net-zero
- III. How is this study different?
- IV. Overview of modelled scenarios with H<sub>2</sub>, RES and nuclear
- V. The impact of differing levels of RES and nuclear on power and H<sub>2</sub> markets
- VI. Risks to the transition
- VII. Policy implications
- VIII. Appendix
  - 1. Modelling methodology
  - 2. Additional model results
  - 3. Additional assumptions

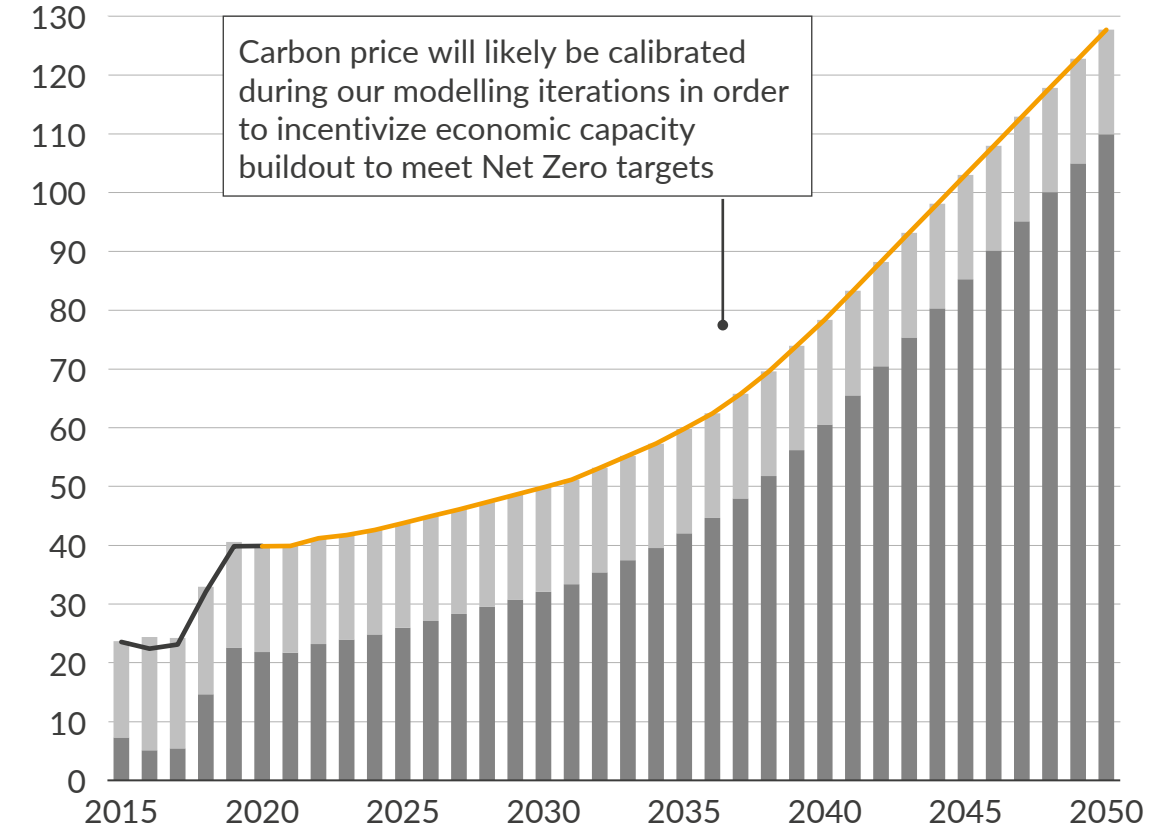
# A Net-Zero scenario is consistent with low gas prices and high carbon prices

**GB gas prices<sup>1</sup>**  
£/MMBtu (real 2019)



— Historical — Base case

**GB carbon prices<sup>1</sup>**  
£/tCO<sub>2</sub> (real2019)


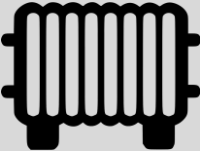
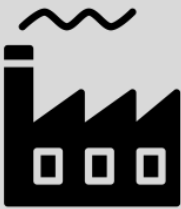


■ CPS ■ UK ETS

1) For years 2021-2025, the prices shown take into account current futures prices for the years in question, with declining weights. Prices are displayed from 2021 onward, reflecting 30-day historical average as of 2 December 2020.

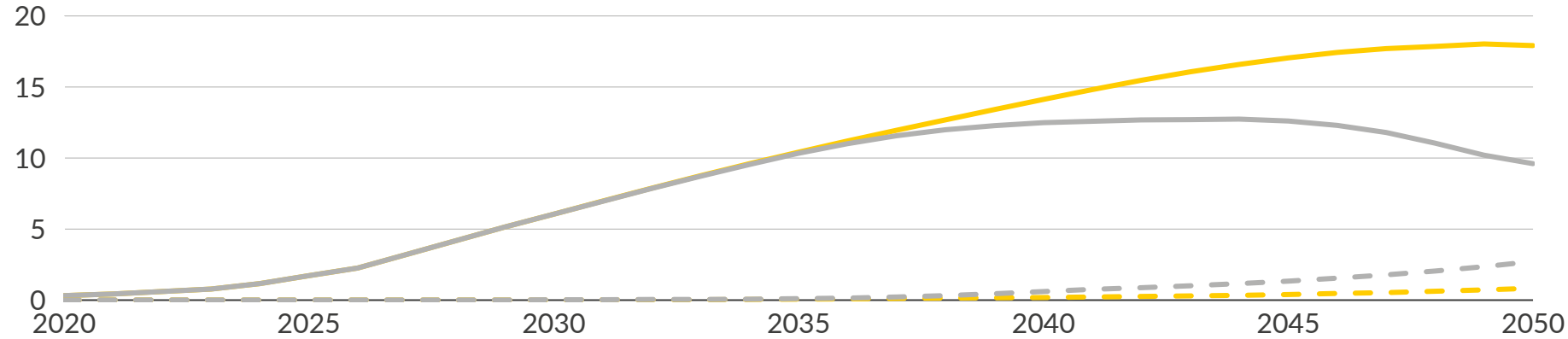
# Aurora's high hydrogen demand scenario sees significant adoption of across transport, heating and industry

Overview of Aurora's GB H<sub>2</sub> demand scenarios – scrutinised by over 18 market participants

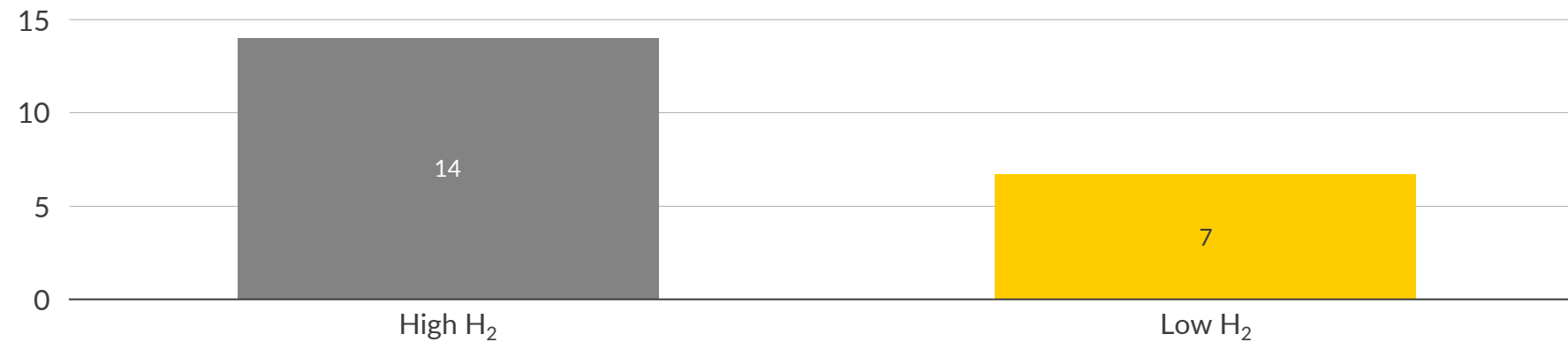
|  | Low Hydrogen   | Central Hydrogen (not modelled in this report)   | High Hydrogen  |
|--|--|--|--|
| <b>Transport</b><br>  | <p>Low penetration of FCEVs for private transport with moderate use of Hydrogen for in freight and public transport, where use of natural gas prevails.</p> <p><b>18 TWh H<sub>2</sub> in 2050</b></p> | <p>Low penetration of FCEVs for private transport with moderate use of Hydrogen for in freight and public transport, where use of natural gas prevails. Adoption of H<sub>2</sub> for maritime and rail transport.</p> <p><b>116 TWh H<sub>2</sub> in 2050</b></p> | <p>Moderate presence of H<sub>2</sub> in private transport, with higher uptake in public transport and freight. Adoption of H<sub>2</sub> for maritime and rail transport.</p> <p><b>162 TWh H<sub>2</sub> in 2050</b></p> |
| <b>Heating</b><br>    | <p>H<sub>2</sub> serves certain areas in the country with advantageous conditions, but use is not widespread.</p> <p><b>110 TWh H<sub>2</sub> in 2050</b></p>  | <p>H<sub>2</sub> serves certain areas in the country with advantageous conditions but is moderately widespread.</p> <p><b>153 TWh H<sub>2</sub> in 2050</b></p>  | <p>Gas networks are converted to hydrogen with 14 million H<sub>2</sub> boilers present in 2050.</p> <p><b>230 TWh in 2050</b></p>   |
| <b>Industry</b><br> | <p>H<sub>2</sub> use for high-grade heat applications along with CCS, electricity serving with low-grade heat requirements. Use as feedstock remains.</p> <p><b>82 TWh by 2050</b></p>                 | <p>Greater H<sub>2</sub> use for high-grade heat applications along with CCS and some low-grade heat requirements. Use as feedstock remains.</p> <p><b>96 TWh by 2050</b></p>  | <p>H<sub>2</sub> used for both high and low-grade heat applications, as well as for industrial feedstock.</p> <p><b>114 TWh by 2050</b></p>  |

# Heating could become the largest demand segment for H<sub>2</sub> but will closely compete with electric heat pumps

GB number of heat pumps  
Millions of units



GB number of H<sub>2</sub> boilers by 2050  
Millions of units



— Low Hydrogen — High Hydrogen — Electric - - Hybrid

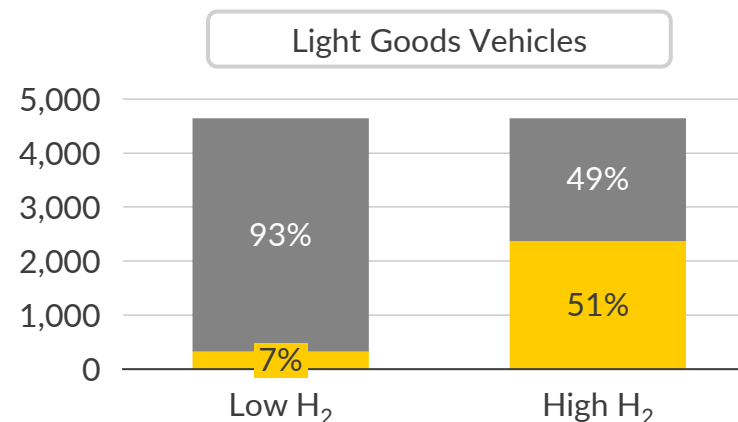
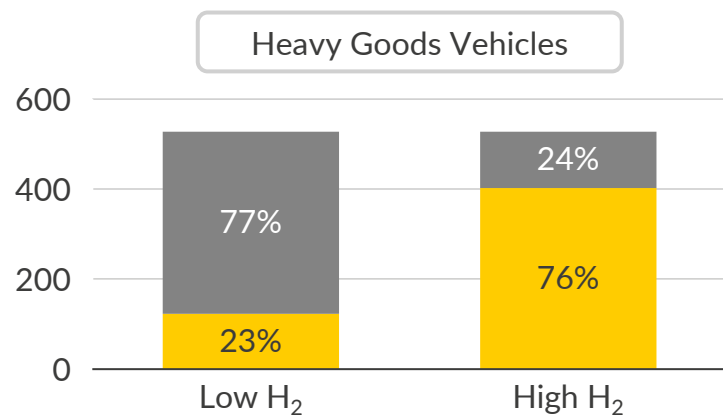
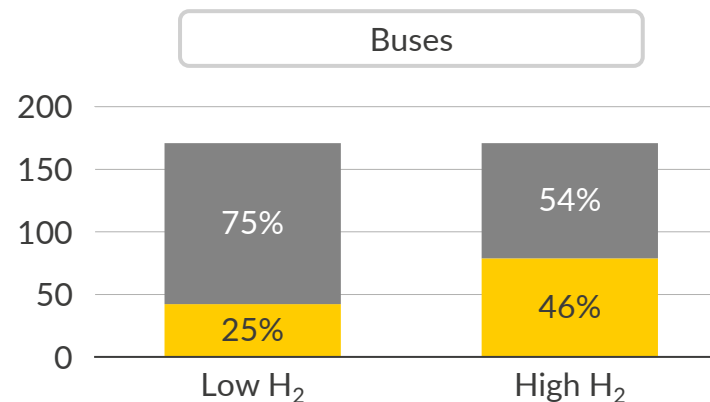
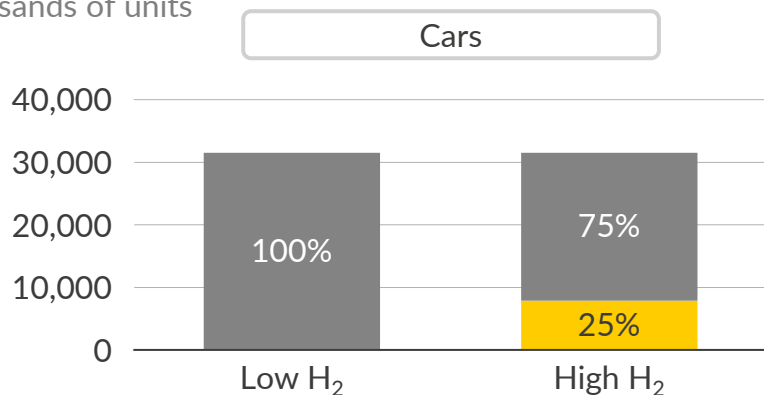
- Significant electrification of heat, despite extensive H<sub>2</sub> penetration will be required to reach net-zero.
- Electrification hurdles could drive H<sub>2</sub> uptake:
  - change in consumer preferences
  - high investment needs for energy efficiency<sup>1</sup>
  - power network upgrades.
- Use of H<sub>2</sub> in residential and commercial heating carries safety concerns and would require infrastructure adequation, and appliance replacement / refurbishment.
- Many projects in the UK and continental Europe show promise for these applications.
- Biogas is likely to play a role at a municipal level.

1) High grades of energy efficiency are required for heat pumps to work at high efficiencies and effectively condition spaces (without the need for heat pump oversizing).

# The entire road fleet is assumed to decarbonise by 2050, with the technology mix depending on the degree of hydrogen penetration

GB number of vehicles in 2050 by type and scenario

Thousands of units









■ BEVs ■ H<sub>2</sub>

- For private cars, customer choice is expected to lean towards BEVs<sup>1</sup>, with higher FCEV<sup>2</sup> uptake for high-mileage and commercial cars.
- The convenient of shorter H<sub>2</sub> refueling times relative to electric charging could drive uptake in light and heavy goods vehicles, as well as buses.
- The HGV segment is expected to be an early adopter of H<sub>2</sub> in the mid-2030s, followed by LGVs and buses in the early-2040s.
- H<sub>2</sub> demand in this sector will be highly dependent on the availability of refuelling infrastructure and is expected to compete with electrification throughout the analysis horizon.

1) Battery-Electric Vehicles; 2) Fuel Cell Electric Vehicles.

# Other transport segments were considered only in our High H<sub>2</sub> scenario, but likelihood of uptake is still uncertain

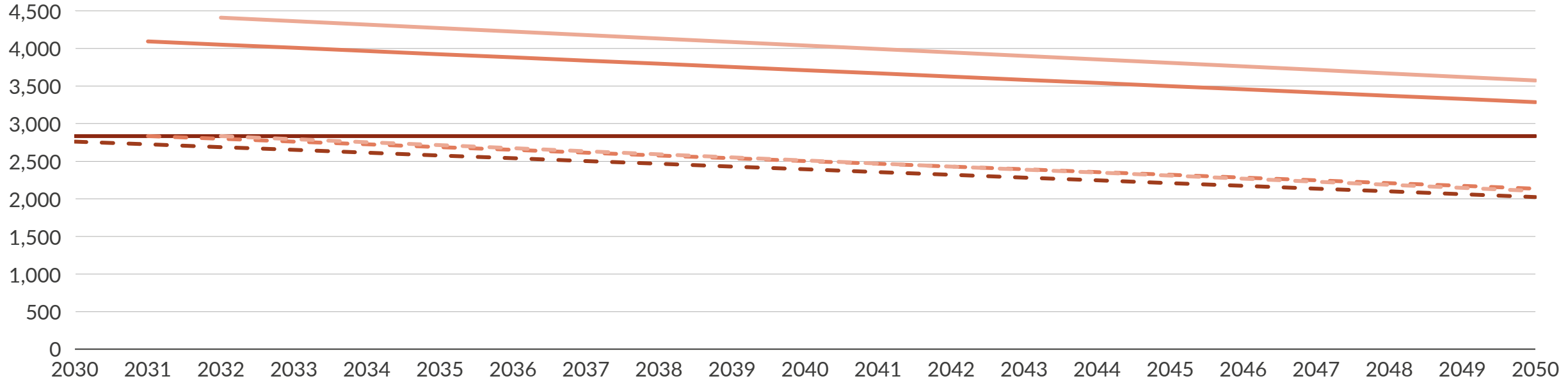
|   | GB outlook for H <sub>2</sub> Adoption  | Likelihood   | GB High H <sub>2</sub> Scenario Assumption <sup>3</sup>  |
|---|---|--|--|
| <b>Railway</b><br>   | <ul style="list-style-type: none"> <li>Most promising options for rail decarbonisation include electrification and fuel switching to biofuels or H<sub>2</sub>.</li> <li>There are concerns on supply limitations for biofuels and, in some areas, cost and infrastructure disruption could make electrification prohibitive, making a case for H<sub>2</sub> adoption.</li> </ul>  |   | <p><b>29 TWh by 2050</b><br/>                     Equivalent to a third of all trains in the UK switching fuel use to H<sub>2</sub></p>                              |
| <b>Aviation</b><br>  | <ul style="list-style-type: none"> <li>Prospective measures include increasing efficiency, reducing allowed cargo and using alternative fuels.</li> <li>Even with all these measures, the sector will likely face disruption or high abatement needs in order to reach Net Zero.</li> <li>Although small demonstration projects seek to prove feasibility, H<sub>2</sub> uptake in the sector is highly uncertain.</li> </ul>   |   | <p><b>No demand</b> was assumed for this sector in the high H<sub>2</sub> scenario, however higher H<sub>2</sub> demand scenarios could see adoption in aviation</p> |
| <b>Shipping</b><br> | <ul style="list-style-type: none"> <li>International Maritime Organisation has enacted a mandate to cut the sector's CO<sub>2</sub> emissions by 50% (relative to 2008 levels) by 2050.</li> <li>Organisations have stated that without the use of alternative fuels this is likely to be missed.</li> <li>Despite technical and financial challenges, potential for H<sub>2</sub> uptake in the sector is considered high, either through direct use or as ammonia.<sup>1</sup></li> </ul> |  | <p><b>11 TWh by 2050</b><br/>                     Equivalent to the forecasted fuel demand for the sector<sup>2</sup></p>  |

1) ICCT; 2) BEIS' forecast extrapolated to 2050; 3) None of these segments were considered in our Low H<sub>2</sub> scenarios.



# Our scenarios explore different plausible trajectories for the development of advanced nuclear technologies

**GB Nuclear – CAPEX**  
£/kW (real, 2019)



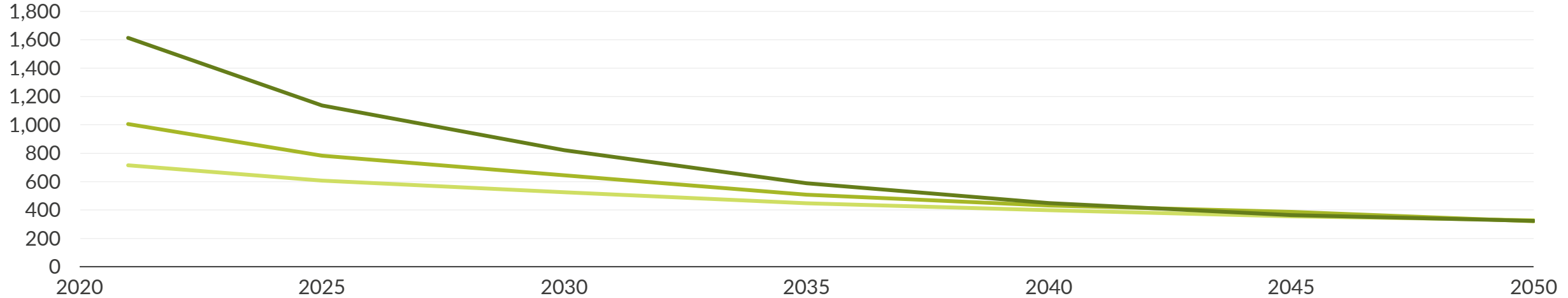
|              |           | Large nuclear | Small nuclear (LWSMR) | Gen IV |
|--------------|-----------|---------------|-----------------------|--------|
| Variable O&M | £/MWh     | 2.4           | 2.4                   | 2.4    |
| Fixed O&M    | £/kW/year | 75.5          | 75.5                  | 75.5   |

- Large Scale Nuclear (Scen 1-3)
 — LWSMR (Scen 1-3)
 - - - LWSMR (Scen 4)
- - - Large Scale Nuclear (Scen 4)
 — Gen IV (Scen 1-3)
 - - - Gen IV (Scen 4)

# Global deployment of electrolysers will drive significant CAPEX, efficiency and lifetime gains

## GB electrolyser – CAPEX

£/kW H<sub>2</sub> (real, 2019)



|                |                      | ALK        |           | PEM        |           | SOEC                                       |  |
|----------------|----------------------|------------|-----------|------------|-----------|--|--|
|                |                      | Short-term | Long-term | Short-term | Long-term | Short-term                                 | Long-term                                  |
| Efficiency     | % LHV (HHV)          | 70%        | 79%       | 68% (74%)  | 77% (82%) | (107%) <sup>1</sup><br>(114%) <sup>2</sup> | (107%) <sup>1</sup><br>(114%) <sup>2</sup> |
| Variable O&M   | £/MWh H <sub>2</sub> | 2.4        | 2.4       | 0.3        | 0.3       | 1.6  | 1.6  |
| Fixed O&M      | £/kW/year            | 22.2       | 22.2      | 31.9       | 31.9      | 22.5                                       | 22.5                                       |
| Stack lifetime | hours                | 75,000     | 125,000   | 72,500     | 150,000   | 34,000                                     | 87,500                                     |

True efficiency does not exceed 100%. These values reflect additional input from waste heat.

— Alkaline — PEM — SOE

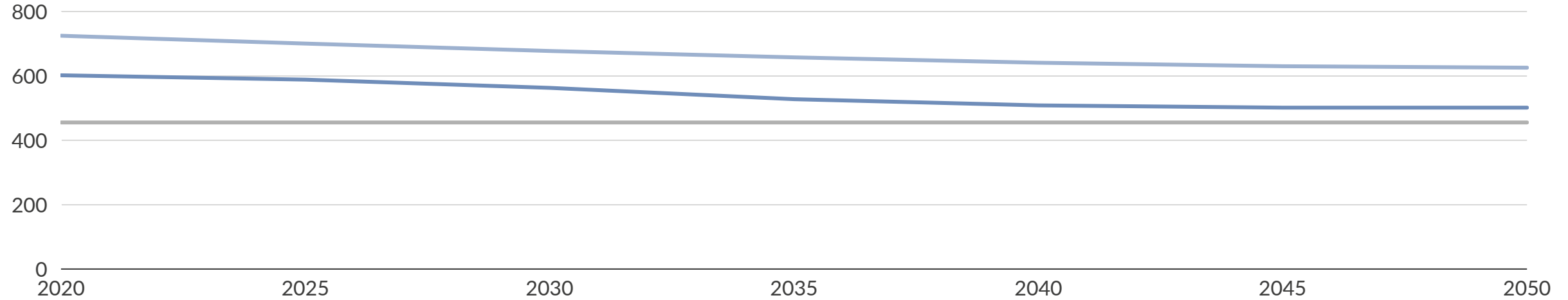
Notes: Variable O&M includes all non-fuel costs; 1) Low temperature heat efficiency; 2) High temperature heat efficiency.

Sources: Aurora Energy Research, IEA, CCC, IRENA, Element Energy, Jacobs Consulting, Equinor, Lucid Catalyst

# Abated gas reforming can also benefit from deployment at scale, albeit to a lesser degree than electrolysers

## GB gas reforming technologies - CAPEX

£/kW H<sub>2</sub> (real, 2019)



|  |                      | SMR           |           | SMR + Carbon capture |           | ATR + Carbon capture |           |
|--|----------------------|---------------|-----------|----------------------|-----------|----------------------|-----------|
|  |                      | Short-term    | Long-term | Short-term           | Long-term | Short-term           | Long-term |
| Efficiency                             | %                    | 80%           | 80%       | 73%                  | 76%       | 74%                  | 80%       |
| Variable O&M                           | £/MWh H <sub>2</sub> | 1.0           | 1.0       | 1.0                  | 1.0       | 1.0                  | 1.0       |
| CO <sub>2</sub> capture                | £/MWh H <sub>2</sub> | -             | -         | 2.4                  | 2.4       | 2.4                  | 2.4       |
| Fixed O&M                              | £/kW/year            | 17.9          | 17.9      | 22.1                 | 18.7      | 17.9                 | 15.3      |
| Reduction in CO <sub>2</sub> footprint | %                    | -             | -         | 90%                  | 90%       | 95%                  | 95%       |
|  |                      | GREY HYDROGEN |           | BLUE HYDROGEN        |           |                      |           |

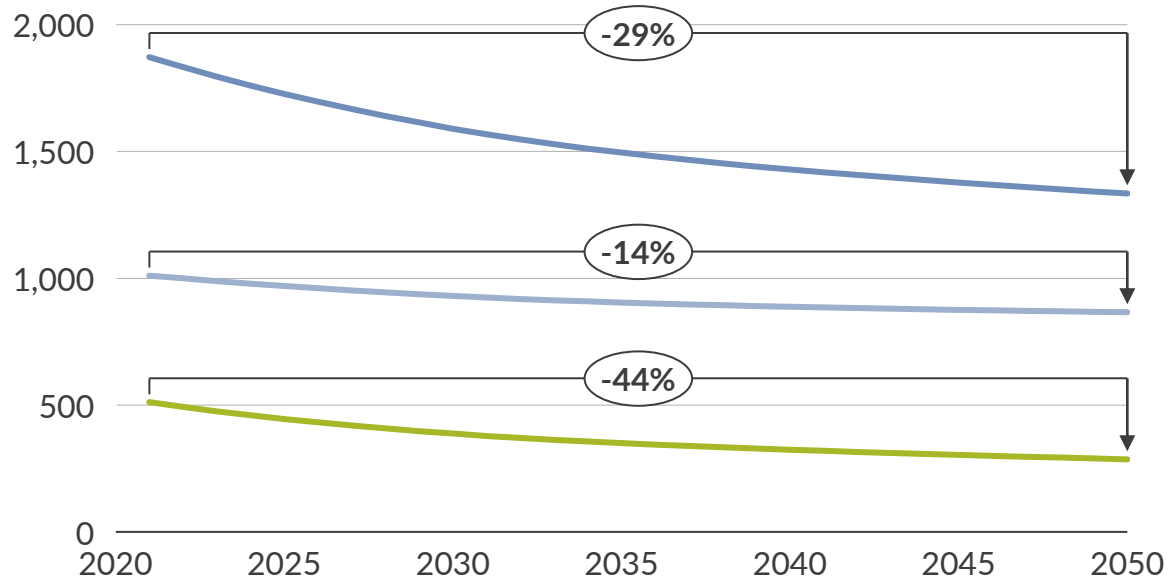
— SMR — SMR with CCS — ATR

Notes: Variable O&M includes all non-fuel costs (neither gas nor oxygen for ATR).

# The continuation of historical learning rates will lead to significant cost declines, particularly for offshore wind and solar PV

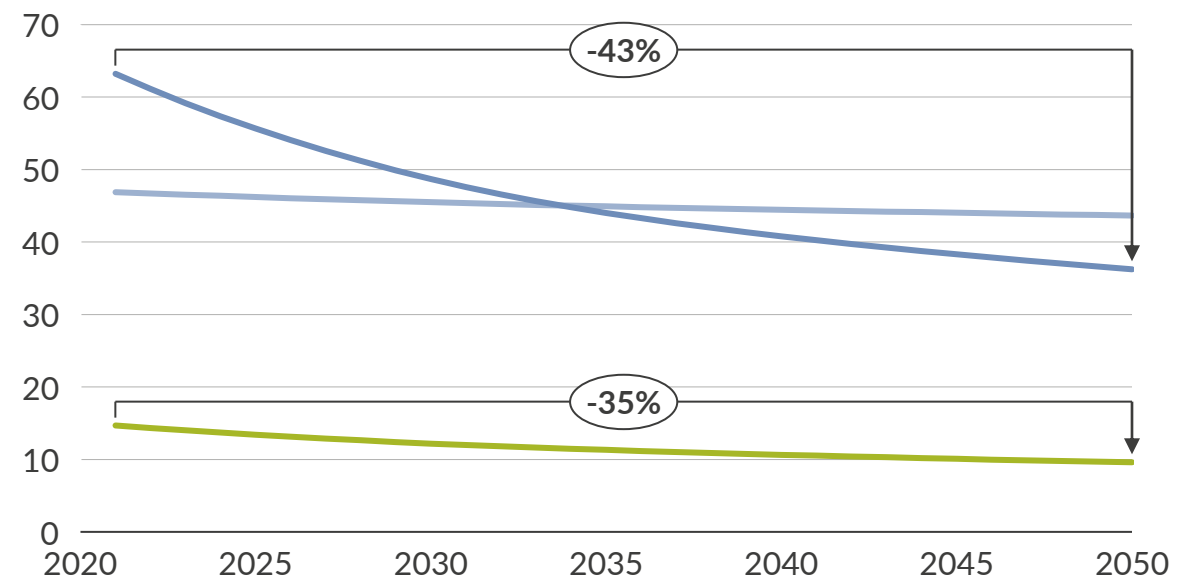
## GB CAPEX

£/kW (real, 2019)



## GB FOM

£/kW (real, 2019)



- Offshore wind benefits from more efficient supply chains and economies of scale as the industry matures, driving strong cost declines for turbines and supporting infrastructure.
- Cost reductions related to onshore wind turbine procurement and development are offset by rising grid connection costs.
- Solar CAPEX declines the most, driven mainly by expected module cost reductions.

— Onshore Wind — Offshore Wind — Solar PV

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