Net Zero Teesside

OGCI CLIMATE INVESTMENTS
OIL AND GAS CLIMATE INITIATIVE

System Value to the UK Power Market of Carbon Capture and Storage

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Overview of analysis

The analysis undertaken by Baringa provides insight into the GB 'system value' of Gas with CCS in power in terms of low carbon energy, flexibility and dispatchability under a 2050 Net Zero target

- The United Kingdom (UK) Net-Zero Teesside (NZT) was announced by the Oil and Gas Climate Initiative (OGCI) in 2017. The OGCI would like to understand the value and services that a CCGT (Combined Cycle Gas Turbine) with CCS (Carbon Capture and Storage) plant can provide to the future UK power market and create an evidence base to support future interactions between the NZT project and key stakeholders. The project represents a first-of-a-kind (FOAK) CCGT with CCS plant in Teesside which is in early stages of evaluation.
- Baringa has been commissioned on behalf of the OGCI, to undertake economic modelling to quantify the value associated with low carbon energy, flexibility and dispatchability of the CCGT with CCS technology in meeting the 2050 Net Zero emissions target in the UK within the power sector. This is for both the FOAK plant and the broader role for gas CCS to 2050. A key aspect is to explore how robust this value is under different market assumptions (e.g. future gas prices or the costs of competing sources energy and flexibility) and how they can impact the deployment and role of CCGT with CCS on the system. The overview of the work undertaken is provided below:

Scenario framing

- **A Base Case scenario**, for the pathway of the power system from now to 2050, has been formed as the first step by agreeing the key assumptions with the OGCI
- Eight **additional scenarios** around the Base Case have been formed after identifying three key factors that can impact the scale and pace of cost-effective deployment of Gas with CCS in the power sector
- An additional three **spot sensitivities** have been analysed, considering specific further questions that could impact the value of Gas with CCS

Electricity market modelling of future pathways with and without Gas CCS

- The core scenarios and spot sensitivities have been run using the Baringa GB PLEXOS model which assesses the **cost optimal capacity expansion *and* operation** of the power sector over the pathway to 2050, taking into account the key input assumptions and constraints.
- The counterfactual scenarios - *where Gas with CCS for power is unavailable, but the system still has to achieve the same decarbonisation and demand outcomes* - have also been run in order to calculate the benefit that Gas with CCS provides to the system

Assessment of the system value of Gas CCS

- The system value of gas with CCS is assessed using an opportunity cost based metric, named the Adjusted Levelised Cost Of Electricity (ALCOE), that has been calculated for each scenario based on the delta in total system costs (capital, operating and resource) with their counterfactual
- This metric shows how the underlying system fundamentals change the 'all-in' value of having Gas CCS, given different implications for what a least cost power sector pathway would look like (e.g. where future gas prices are higher or lower).

Approach - key input assumptions

The modelling approach undertakes least-cost optimisation of the capacity mix and operation of the power sector from now to 2050 considering a range of key inputs assumptions and constraints

- The Baringa GB PLEXOS Long Term Planning (LT) model has been used to run the scenarios and sensitivities. PLEXOS is a commercially available program used for power system optimisation that is widely used within the energy industry.
- The model assesses the annual **cost optimal capacity expansion *and* operation** (with 16 sample weeks of hourly operation in each year) of the power sector over the pathway to 2050, taking into account the key input assumptions and constraints.
- The key input assumtions to the model include:

Key assumptions	Description
GB Capacity Mix to 2028	GB electricity sector installed capacity to 2028 is based on Baringa's most decarbonized reference scenario, reflecting near term policy and 'momentum' effects driving new build. Capacity build beyond this year is then optimized.
Commodity prices to 2050	Including natural gas, hydrogen, coal, oil and biomass.
Demand to 2050	Annual and peak demand to 2050 accounting for increased electrification of other sectors. The hourly shape of demand shape is split into two components: a fixed demand profile element and a flexible component that can be optimised in line with wider system conditions (e.g. overnight electric vehicle charging).
Technology parameters	Operational and economic lifetimes, Weighted Average Cost of Capital (WACC), build costs, fixed and operating variable and maintenance costs, availability, efficiencies, maximum capacity
Additional renewable technology parameters	Renewable technology load factors and hourly generation profiles.
De-rating factors	Factors for technologies and interconnection, used to calculate the technologies' contribution to security of supply constraints within the model (see next slide)
CCS Transport and Storage (T&S) costs	To account for the costs for the transport and storage of abated carbon emissions
Interconnection capacity and the European market prices	From the Baringa Pan European model: only the expansion of GB domestic generation is considered in this study and expansion of cross-border capacity is an exogenous assumption

Approach – key constraints

The choices within the future electricity system pathway over which technologies to build, when to build them, and how to operate them must be consistent with a set of overarching constraints

- The key constraints that the Baringa GB LT model considers include:

Key constraints	Description
Emission intensity of GB power generation	Defines an upper limit on the emissions from GB power generation divided by the total domestic generation, starting from 2030 CCC mid-range of 75 g/kWh and linearly decreasing to 0 g/kWh by 2050 (assuming the power sector will have to decarbonise completely to reach an economy wide Net Zero target).
Availability of Bioenergy with CCS (BECCS) for power generation	Linked closely to the above, the negative emissions rate and maximum availability of BECCS deployed in the power sector equates to a circa 20g/kWh headroom for residual emissions from Gas with CCS and other fossil power technologies, such as gas peaking plant.
Technology maximum build rates and quantities	Based on technical and resource constraints, for example, the ability of the underlying supply chain to deploy new offshore wind is limited to X GW/year. This also includes an overarching group build rate constraint for 'large' plant such as CCS, biomass, nuclear and H2 CCGT capacity
Maximum renewable generation	Constraint ensures that the maximum level of generation from renewables (if chosen on economic grounds) is no more than that seen in the Committee on Climate Change's core net-zero scenario by 2050
Peak security of supply	Defines the minimum level of firm capacity required on the system calculated from the peak demand and the targeted capacity margin required above this. This is broadly analogous to the Capacity Market requirements.
Operational reserve requirement	This requires the system to maintain enough dispatchable reserve (or "holding volume") to respond to near term fluctuations in intermittent renewables output on the system (e.g. from wind and solar) on an hour-to-hour or multi-hour basis. This is particularly important given the significant increases in renewables on the system to reach net zero emissions by 2050 and is broadly analogous to tertiary ancillary services (e.g. Short Term Operating Reserve) managed by the System Operator).
Net zero annual imports in GB	This constraint ensures that whilst interconnectors can provide hour-by-hour flexibility they are not a source of bulk energy imports or exports on an annual level. This reflects the significant uncertainty around the decarbonisation levels in GB's interconnected markets and their corresponding prices to 2050

- It should be noted the **carbon price is an output of the GB LT model** in response to the first constraint, represented by the marginal cost of carbon for the last/next unit of emission production to the emission target in each year, given all other inputs and constraints considered above.

Key scenarios and sensitivities explored

Exploring a Base Case and scenarios that vary 3 key dimensions with a significant impact on CCS deployment and its system value, in power sector pathways that are ***all*** net-zero compliant

- The Base Case represents a central view of the key modelling inputs and constraints such as future technology costs and build limits, electricity demand, commodity prices and system security constraints. In addition to the Base Case, we have run eight core scenarios and three spot sensitivities to explore the solution space around the Base Case in more detail. We have established the assumptions that are likely to have the greatest impact on Gas CCS deployment in power **(*both more and less favourable for CCS*)** and assumed credible ranges for these assumptions to assess the potential impact on the Gas CCS system value **(*i.e. whilst always reflecting net-zero compliant pathways for power*)**

- The eight core scenarios are based on the 2x2x2 permutations of the three key dimensions that we have established with each dimension defined by a lower and upper bound. The three further spot sensitivities are aimed to explore specific *additional* questions.

Three key dimensions	Description
Gas Price (High / Low)	The marginal cost of operating a gas powered plant is directly proportional to the price of gas. A lower gas price will therefore make gas plant, including Gas with CCS, more competitive in the market.
Nuclear Favourability (High / Low)	Given that increasing renewable capacity is expected under almost all scenarios, the main low carbon technology in competition with Gas with CCS is nuclear power. Lower nuclear capex will make nuclear more favourable, potentially displacing Gas with CCS.
Level of Flexibility (High / Low)	Increasing levels of flexibility in the wider system will reduce the need for dispatchable low carbon generation and thus the deployment of Gas with CCS. These scenarios consider changing demand side-flexibility (from electric vehicles and heat pumps), changing grid scale battery costs and peak de-rating factors and different rates of interconnector deployment.

Additional sensitivities	Description
Stress test	A 1-in-20 year cold weather event could lead to a significantly higher peak demand level than during an Average Cold Spell given the level of electrified heat (potentially 30-40 GW or more by 2050). This combined with lower wind output and unavailability of interconnection will lead to increased requirement for firm and dispatchable capacity where Gas CCS could play a key role.
Slower renewable cost reduction	Slower future cost reductions for renewables will make them less cost-competitive and can impact both the timing and scale of Gas with CCS deployment given the need to meet the same underlying CO2 intensity pathway to 2050.
Super high gas price	This considers a world where gas prices might turn out to be even higher than those explored at the upper end of the core scenarios.

Rationale for other factors not varied by scenario

There remain other dimensions which could impact the role of Gas with CCS in the power sector, which have not been explored in this project due to their secondary effect or complexity

Dimension	Description
Rate of decarbonisation	There is considerable uncertainty around the rate of decarbonisation required to meet a net-zero emission target by 2050. Government policy will have a significant impact on this though little information is currently available. It is considered that a linear reduction from 75 g of CO2/kWh in 2030 to 0 g/kWh in 2050 is a reasonable approximation of the pathway required and therefore variations in the rate have not been explored in this project.
Decarbonisation of other sectors	The net-zero emissions by 2050 target is applicable to all sectors in the UK, not just the power sector, and therefore the decarbonisation of other sectors will impact the power sector in multiple ways. For example as electrification presents a route to decarbonisation in many sectors (e.g. transport and domestic heating) the rate of decarbonisation of these sectors will have a large impact on the demand for electricity. Similarly, the role of hydrogen and its production costs as well as was as the costs of transport and storage infrastructure to support CCS across multiple sectors are key “whole energy system” questions. Given that the main aim of this project is to understand the role of Gas with CCS in the power sector, a detailed model of the power system (the Baringa GB PLEXOS LT Plan model) has been used which requires the power sector to be modelled in isolation. Central benchmarked assumptions have therefore be made for the impact of other sectors on the power sector by 2050, drawing on separate whole-energy systems net-zero analysis.
Demand levels	The level of flexible demand has been varied though the flexibility dimension, but all scenarios assume the same total annual demand level. Varying the total annual demand could impact the load factors and deployment of Gas with CCS though it is more likely that increases in peak demand would have a greater impact on Gas with CCS capacity. Given the uncertainty around demand levels under a net-zero target the demand assumptions made have been benchmarked against other net-zero reports.
Interconnected market prices	The modelling approach taken isolates the GB power system from interconnected European markets, and replaces European markets with fixed price series based on Baringa’s Pan European model, assuming consistent gas and a carbon price broadly consistent with that needed to achieve net-zero in the UK. While interconnector flows are likely to have a significant impact on the GB power system in future, there is considerable uncertainty around the rate of decarbonisation of interconnected markets. In addition, modelling the LT expansion of connected markets would add significant complexity. Therefore in order to manage the uncertainty and maintain the focus on the role of interconnectors in providing flexibility, the net zero interconnector flow constraint has been implemented. The net zero flow constraint applied to interconnectors itself was tested in multiple forms and it was found that varying the period from a week to a year had a limited impact on the results and therefore the constraint was applied on an annual basis for computational simplicity.

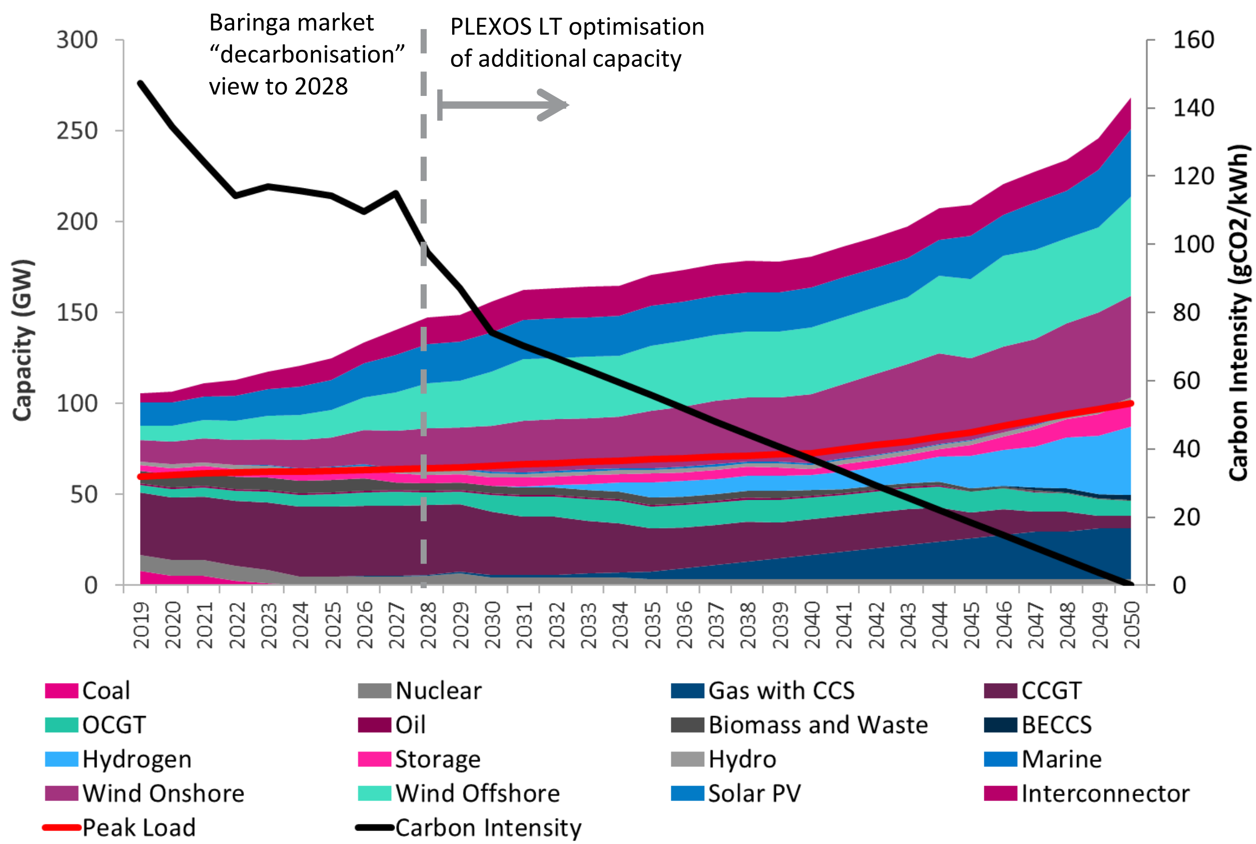
Evolution of the capacity mix in the Net-Zero Base Case

A significant increase in renewable capacity is seen, with retiring flexible plant replaced predominantly by Gas with CCS, hydrogen turbines and battery storage capacity

Description

- An increasing level of peak demand, rising to around 100 GW by 2050, results in an increase in the total installed capacity on the system, reaching around 250 GW by 2050. The majority of this capacity is from renewable technologies as they present the cheapest source of low carbon generation
- As the aging existing gas and nuclear fleet retire, the dispatchable capacity is replaced by Gas with CCS*, hydrogen turbines and battery storage, as well as a moderate build of peaking OCGT plant
- The optimal level of dispatchable capacity on the system is a result of the increased need for dispatchable generation to cope with increased level of intermittent renewables, the increased need for firm capacity on the system for Security of Supply reasons and increasing operational reserve requirement
- There is no new build of nuclear, excluding Hinckley C which is assumed to become operational in the late 2020s
- In the late 2040s a small capacity of BECCS is built in order to offset the residual emissions of the Gas with CCS and OCGT plant and achieve net-zero emissions

Capacity Mix Evolution, Base Case Scenario



OGCI CCGT with CCS plant assumed to come online in 2026

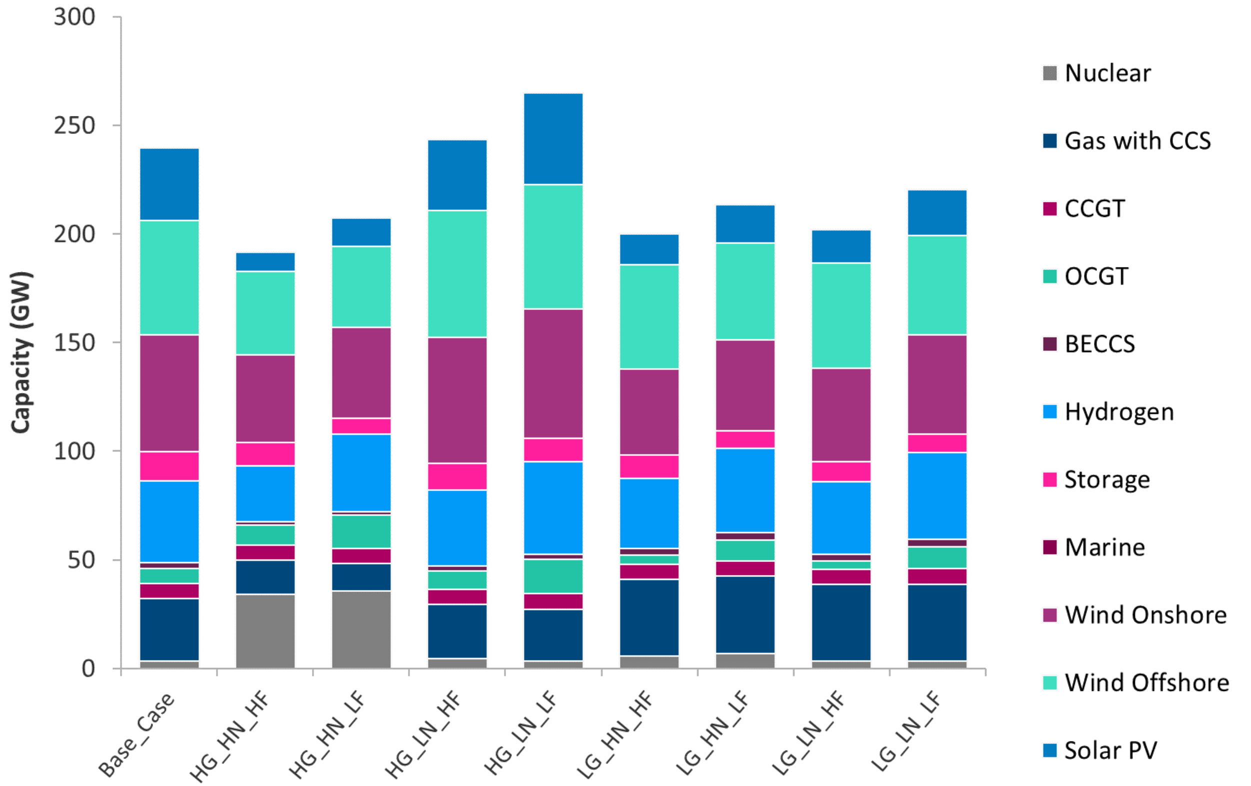
Comparison of capacity mix across core scenarios

Significant renewable capacity seen in all scenarios, with a sizeable capacity of Gas CCS in even the most unfavourable scenario for the technology, while new nuclear built in a small number of cases

Description

- The chart displays the capacity mix in 2050 under the Base Case scenario and the eight core .scenarios
- The LG_LN_LF scenario represents the most favourable combination of assumptions for Gas with CCS deployment. Lower gas prices, together with lower nuclear favourability, makes Gas with CCS a more competitive technology and it subsequently displaces new renewable build. As hydrogen prices are assumed to be linked to gas prices, and are thus lower in this scenario, hydrogen generation becomes more competitive thereby resulting in a greater capacity.
- The HG_HN_LF scenario represents the least favourable assumptions for Gas with CCS deployment. High nuclear favourability, together with higher gas prices, makes nuclear a more competitive technology and results in higher nuclear capacity, displacing about half of the Gas with CCS capacity in comparison to the Base Case. The significant volume of low carbon generation due to new nuclear capacity also displaces the need for new renewable generation, and the renewable capacity is consequently lower.

Capacity Mix in 2050

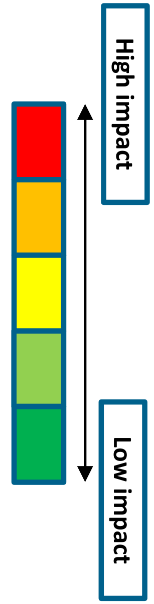


Dimension	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

Materiality of key drivers for gas with CCS deployment

Analysis across the scenarios and sensitivities shows that the most material drivers for the deployment of Gas with CCS capacity are the price of gas and the evolution of nuclear power costs

Key factors	Description of impact based the results of core scenarios and spot sensitivities	Materiality of impact* (Red = High)
Evolution and level of flexibility on the system	Reduced flexibility (e.g. interconnection and storage) results in a higher pace of deployment of 1-2 GW Gas CCS per year, but with a similar overall level of deployment by 2050 compared to the base and high flexibility cases.	
Evolution and level of gas prices	Lower gas prices result in significantly higher CCGT CCS deployment of about 10-20 GW by 2050 (depending on the competing nuclear costs) and also 5-10 GW higher capacity in the early to mid-2030s.	
Evolution of nuclear costs	A reduction in nuclear costs has more impact in a world which also has high gas prices, resulting in 10-20 GW higher deployment of Gas with CCS by 2050 (depending on the level of flexibility on the system) and also a significantly increased pace of deployment from 2040. In cases with low gas prices and low nuclear costs, Gas CCS remains more cost competitive.	
Cost reduction pathway for renewable technologies	A slower future cost reduction for renewables brings the build of Gas with CCS slightly earlier in the horizon and also leads to slightly higher deployment in 2050, of about 5 GW. Given that renewable costs are already relatively low and present the one of the cheapest source of low carbon generation, a slower cost reduction in future has a limited impact on Gas with CCS deployment.	
Stress test	Stress conditions created by 1-in-20 cold weather event, unavailability of interconnection and higher operational reserve requirement (due to lower wind output) increases the pace of deployment of Gas with CCS in the 2030s, in particular due to increased requirement for firm capacity. The deployment level by 2050 remains similar compared to Base Case.	
Super high gas price	A "super high gas price" reduces and delays the deployment of Gas with CCS plant. Deployment is ca. 10 GW lower by 2050 compared to the Base Case and also 5-10 GW lower in late 2030s to 2040. However, the overall deployment level in this case remains similar to the core scenario with high gas prices, high nuclear favourability and high level of flexibility.	



* Materiality in this context refers to a significant deviation (either positive or negative) in Gas CCS capacity relative to the Base Case

Approach to calculating Adjusted Levelised Cost of Electricity

This is an opportunity-cost based metric, which represents the LCOE of a technology adjusted by the amount which that technology impacts overarching system costs when it is introduced

- The levelised cost of electricity (LCOE) is a common metric for comparing the cost of power generation technologies. It considers the full life-cycle costs of a new power generation project, and assuming a load factor over the project life-time, calculates the long-term average cost of power production.
- However, the **Adjusted LCOE** also considers how broader system costs change when you introduce a technology into the power system, which replaces the marginal competing alternatives that would otherwise have been used.
  - For example, if CCS is not available the system may need to build and/or run a more expensive set of alternative technologies to provide the same services for consumers, i.e. the same level of decarbonisation, meet the same underling level of demand and same security of supply requirements.
- For this analysis we are primarily concerned with how **underlying system fundamentals change the value of having Gas with CCS in and of itself** rather than providing a comparison across specific individual technologies.
- *If the system value of Gas with CCS is material, robust to a sizeable volume of Gas with CCS capacity and robust to changes in the underlying system fundamentals then this provides strong evidence that Gas with CCS has a valuable and important role to play in the power system*
- The adjusted LCOE is calculated as follows for a given scenario:
  1) Calculate the total system costs (capital, operating and resource costs) for a given scenario (same services for consumers) *both with and without* Gas with CCS as a possible technology.
     - If the total system costs are higher in the case where CCS is *not* available this indicates CCS has a positive system benefit.
  2) Calculate the total system cost savings per year associated with a given installed capacity Gas with CCS by taking the difference between the total system costs in the runs from 1) with and without Gas with CCS runs (in £/year),
  3) Convert the cost savings (2) into a saving for the vintage of plant built in year Y over its operating life in the pathway (in £/MWh) and
  4) Take the difference between the LCOE of that vintage and the cost savings over the operating life (3) to calculate the **opportunity cost based metric: adjusted LCOE.**
     - For example, in the Base Case the LCOE for a new Gas CCS plant built in 2035 over its lifetime is circa £80/MWh and the calculated system benefit is circa £15/MWh over the same time horizon, therefore the adjusted LCOE is £65/MWh.

Summary of key Gas with CCS results

The results demonstrate a robust and valuable role for Gas with CCS in the power sector across the core scenarios and spot sensitivities, with some key areas and uncertainties to consider for future

- Over the long-term the scale of cost-optimal deployment ranges from 13-36 GW level by 2050. Even in the most unfavourable cases for Gas with CCS (i.e. high gas prices and high nuclear favourability) the scale of Gas with CCS capacity is still significant at around 13-16 GW.
- In terms of the pace of deployment of CCS, further capacity beyond the OGCI plant (which is assumed to come online in 2026 in all cases) occurs around 2030, with only a few cases of this being delayed until 2040. This means that CCS plays a key and valuable role early in the electricity pathway.
- Similar to the pace and scale of deployment, the range for the *system value* of Gas with CCS by 2050 is robust across all cases, varying in the range 16-20 £/MWh (i.e. this is the value by which the underlying LCOE would be reduced to infer the Adjusted LCOE). The system value is also shown to be a net benefit by 2030 and 2040 in the *majority* of cases and gives an indication of the additional benefit CCS can provide in meeting overarching carbon targets, which should be considered when considering support for this technology.
- The OGCI plant is a FOAK unit due to be commissioned in 2026 and will play a crucial role in accelerating the broader development of CCS as a technology. This analysis helps demonstrate both the long-term- and *importantly also* the nearer term- value of new CCS in low carbon energy provision, and providing dispatchability and flexibility as part of the GB power sector's transition to meeting net zero targets.

Dimension	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

Results for the pace and scale of deployment of Gas CCS

Core scenarios and spot sensitivities	Year of the first capacity build after the OGCI plant	Scale of deployment by 2050 (GW)
Base_Case	2030	29
HG_HN_HF	2041	16
HG_HN_LF	2028	13
HG_LN_HF	2035	25
HG_LN_LF	2028	24
LG_HN_HF	2028	35
LG_HN_LF	2028	36
LG_LN_HF	2028	35
LG_LN_LF	2028	36
Super_high_gas_price_(BEIS high)	2040	19
Slower_Renewable_CAPEX	2030	34
Stress_Test	2028	29

Results for system value of Gas with CCS

Core scenarios and spot sensitivities	System value in 2030 (£/MWh)	System value in 2040 (£/MWh)	System value in 2050 (£/MWh)
Base_Case	-9	-17	-20
HG_HN_HF	37	1	-16
HG_HN_LF	8	-7	-20
HG_LN_HF	-4	-15	-20
HG_LN_LF	11	-14	-20
LG_HN_HF	-13	-18	-18
LG_HN_LF	-14	-17	-17
LG_LN_HF	-14	-19	-20
LG_LN_LF	-16	-19	-19

Negative value indicates a benefit to the system from CCS

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Introduction

Background to the Net-Zero Teesside Project and purpose of this analysis

- The UK Net-Zero Teesside (NZT) was announced by the Oil and Gas Climate Initiative (OGCI) in 2017 and is one of the first OGCI projects. The Project concept was acquired by the OGCI from the Energies Technology Institute. The Project's current development concept consists of a gas-fired power generation facility with a carbon capture plant to be located in Teesside, United Kingdom, and an offshore transportation and geological storage facility to be in the Southern North Sea region of the UK continental shelf. The Project is in early stages of evaluation (including technical and financial feasibility) by the OGCI.
- Six OGCI members (BP, Eni, Equinor, Oxy, Shell and Total) have agreed an MoU to form a strategic partnership capable of supporting the commercial and technical progression of the NZT, and a project team has been set up to deliver this.
- The purpose of this analysis is to provide commercial analytical and modelling capability to support the development of a first-of-a-kind (FOAK) CCGT with CCS plant in the UK, by helping to understand the value of low carbon power, flexibility and dispatchability of CCGT CCS and how robust this is likely to be to different market scenarios under the economy wide net zero emissions target by 2050.
- The OGCI would like to understand the value and services that a CCGT with CCS plant can provide to the future UK power market and create an evidence base to support future interactions between the NZT project and key stakeholders. The analysis performed aims to address the following key questions, also considering the development of additional CCGT with CCS plants beyond the FOAK NZT project:
  - What is the system value CCGT with CCS plant (energy + flexibility + peak capacity provision) to the UK power market and how can this be quantified?
  - Is the value of CCGT with CCS plants to the UK power system resilient to different power system configurations, for example:
    - How do costs / performance / availability of other technologies affect the deployment of CCGT with CCS?
    - How do policy / resource assumptions affect the deployment and operation of CCGT with CCS?
  - What is the capacity and timing requirement of CCGT with CCS in the UK power market?
- To address these questions, we have developed a number of core scenarios and spot sensitivities, translating the economy wide net zero target to the target for the power sector to analyse the detailed electricity decarbonisation pathways under varying key fundamentals. This involves modelling the optimal capacity expansion and operation and the overall electricity system costs, with focus on the role of Gas with CCS in power, in particular the pace and scale of deployment and its associated system value.

Overview of analytical framework

Use of PLEXOS tool to simulate annual capacity expansion and hourly operational dispatch

- For this work, we have used the Long-Term (LT) planning functionality within PLEXOS (a commercial power sector modelling tool https://energyexemplar.com/software/plexos-desktop-edition). PLEXOS is used globally by power market participants, regulators, and analysts for modelling power systems of all characteristics
- PLEXOS allows the detailed modelling of electrical systems: it receives inputs such as existing and future generators with their characteristics, fuel prices and hourly demand. It optimises the generator dispatch in a way that the total costs are minimised. Typical outputs are generation dispatch and hourly power prices. The engine can optimise several electrical nodes with different supply and demand balance that can be connected with lines providing different prices for each. It also allows complex constraints to be modelled
- PLEXOS LT module can optimise capacity and transmission line and expansion decisions (we have not included transmission builddecisions in this study). More details on the PLEXOS modelling framework is provided in the Annex. The overview of the analytical framework used for this work is illustrated below with the key inputs, modelling framework and key outputs

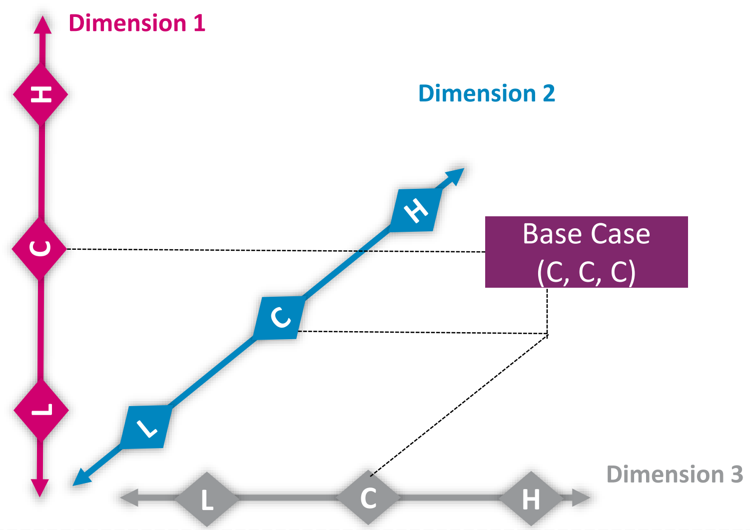
Key inputs and constraints	GB Long Term Planning (LT) model in PLEXOS	Key modelling outputs
▪ **Key inputs** include technology cost trends, technology parameters (e.g. efficiencies, max capacity and min stable level, start costs) max build limits and parameters, demand, commodity prices, interconnection capacity and interconnected market prices) ▪ **Key constraints** include emission constraints, security of supply constraints and maximum deployment constraints for technologies	▪ The Baringa GB LT PLEXOS model computes the optimal capacity with the objective to minimise the total system costs to 2050, taking into account the key input assumptions and constraints	▪ Optimal capacity and generation mix to 2050 ▪ Total system costs to 2050 ▪ Load factor by generation type ▪ Hourly dispatch outputs, constructed from 16 sample weeks ▪ Interconnector flows ▪ Shadow carbon prices

Overview of approach (1)

Understanding the ‘system value’ of Gas CCS in the GB power sector

- The overview of the approach for assessing the system value of Gas with CCS in the power sector is illustrated below. It consists of two parts:
  - **Scenario framing** involves structuring a set of market scenarios which frame the set of key drivers of system value of CCS from low carbon power, dispatchability and flexibility points of view. Three key dimensions have been identified as explained later in this section and we have assumed high and low ranges for these dimensions. The Base Case represents a central view on these dimensions. Scenarios are then framed around the Base Case with different permutations of these ranges across the three dimensions as illustrated below
  - The objective of scenario framing is to explore a credible solution space around the Base Case for which CCS is more or less valuable. The system value of Gas with CCS in power is assessed using the scenarios constructed as shown below and explained in the next slide in more detail.

Scenario framing



Dimension 1	Dimension 2	Dimension 3
H	H	H
H	H	L
H	L	H
H	L	L
L	L	L
L	L	H
L	H	L
L	L	H

C: Central, H: High, L: Low

Assessment of system value of Gas with CCS

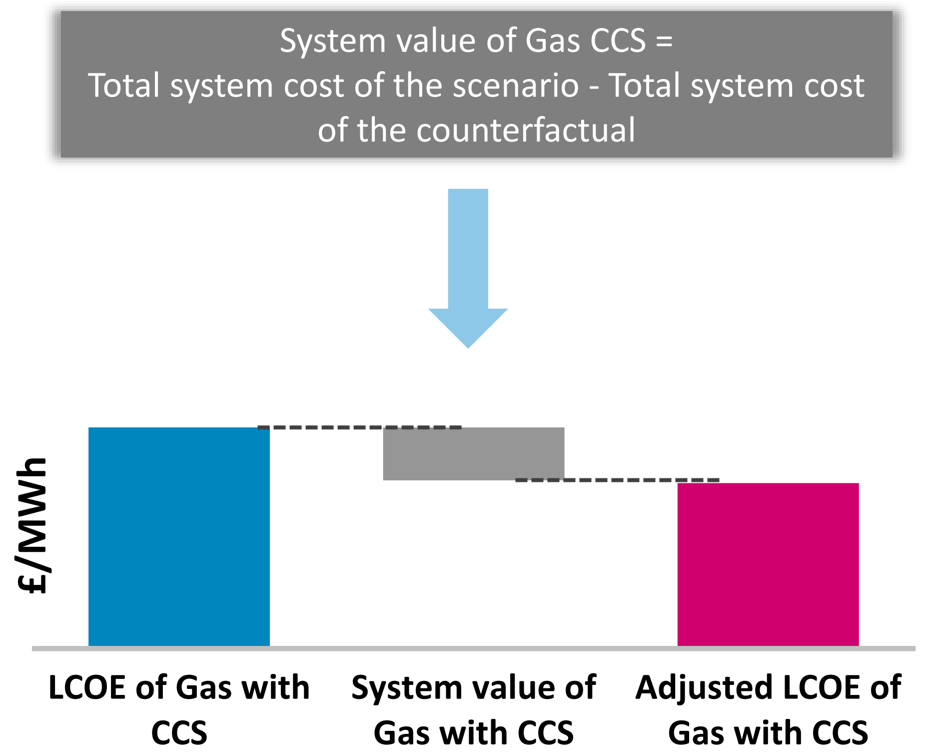
1. Scenario with Gas CCS deployment based on optimal capacity mix
2. Counterfactual with the optimal mix when no is Gas CCS available
3. System value of Gas CCS= Total system cost (1)- Total system cost (2)

Overview of approach (2)

Understanding the 'system value' of Gas CCS in the GB power sector

- For the assessment of system value of Gas CCS, each scenario is first run using the Baringa GB Long Term Planning (LT) PLEXOS model which results in an optimal capacity mix (that may or may not include Gas CCS in the optimal mix) resulting from the underlying assumptions
- The counterfactual of each scenario is then run considering no Gas CCS deployment in power and letting the LT model optimise the capacity mix. The difference between the total system costs of the scenario and its counterfactual is then used for the evaluation of the system value of Gas CCS under each scenario (as shown on the right)
- The counterfactual case with No CCS does not represent a world with failure of CCS, but rather is a world where blue (i.e. gas-based) hydrogen with CCS is the focus and whilst Gas CCS is not available in the power sector
- The system value is quantified using an "**opportunity cost metric**" which represents the fact that if CCS is part of the cost optimal solution then removing it will increase system costs and the delta in costs is taken as proxy for "system value"
- We use the opportunity cost metric to create a "system adjusted Levelised Cost Of Electricity (LCOE)" for Gas CCS as shown on the right. The system adjusted LCOE is a measure of how the LCOE of Gas with CCS changes when system value is taken into account
- The system value is not static and changes over time and is dependent on the underlying energy system configuration, which is why a broad solution space is explored by considering a number of scenarios and sensitivities

Calculation of Gas CCS system value and adjusted LCOE



Key drivers influencing role and system value of CCS (1)

Understanding the key electricity system factors in a Net Zero world is the first step to identify key drivers for the system value of Gas CCS

- Understanding the key electricity system factors in a Net Zero world is the first step to identify key drivers for the system value of Gas CCS
- A Net Zero target will accelerate transformation in the power sector, potentially pushing the system and market structures into a new paradigm. As the Committee on Climate Change's (CCC) Net Zero technical report[1] suggests, this means increasing interactions of the power system with the sectors of the wider economy influencing and framing boundary of power sector. The key electricity system factors that will influence the evolution of the power sector under an economy wide net zero target are summarised below:
- **Wider system decarbonisation and pace of decarbonisation of the power sector through 2030 and to 2050:**
  - 'Net zero' means that any emissions are balanced by absorbing an equivalent amount from the atmosphere. The target means all parts of the whole energy system including power, heat, transport and industry will together need to result in no emissions by 2050.
  - In many sectors of the economy, technologies exist that can bring emissions to zero. However, in some industries, aviation and agriculture residual emissions are likely to remain due to limited abatement options. Therefore in order to offset these, an equivalent amount of CO2 will need to be taken out of the atmosphere through so called 'negative emissions'
  - Today, the negative emission technology with the biggest potential is bioenergy with carbon capture and storage (BECCS). Plant material is burned to generate electricity. The CO2 is captured and stored underground. More plants are then grown, absorbing CO2 from the air – this is burned, taking more CO2 underground; and so on.
  - Overall, the role of negative emissions either within power directly (e.g. biomass + CCS) or indirectly (bio + CCS to hydrogen to hydrogen turbines) and the wider system decarbonisation will be a key factor on the implied emissions target for the power sector
- **Implied annual and peak demand for power due to electrification in other sectors:**
  - Net zero target will drive significant electrification in sectors such as heating and transport resulting from the increasing use of electric vehicles and heat pumps. Power demand is projected reach ~500-600 TWh by 2050 – almost doubling from the current level of 325 TWh as evidenced by the CCC Net Zero report
  - Similar to the annual demand, peak demand is also projected to increase significantly, exceeding 100 GW level by 2050 compared to the current level of 59 GW. The exact level of peak demand will be driven by the level of demand side flexibility such as the ability of electric vehicles and heat pumps to shift some demand to outside peak demand hours

[1] https://www.theccc.org.uk/publication/net-zero-the-uks-contribution-to-stopping-global-warming/

Key drivers influencing role and system value of CCS (2)

Understanding the key electricity system factors in a Net Zero world is the first step to identify key drivers for the system value of Gas CCS

- **Commodity prices (mainly gas and hydrogen prices and coal and oil prices to a less extent):**
  - The increasing levels of annual and peak demand requires increase in deployment of baseload and variable low-carbon power such as renewables, Gas with CCS, nuclear and hydrogen turbines
  - The evolution of gas prices will impact the operational costs of Gas with CCS plant and the production costs of blue hydrogen. Therefore, this will impact the scale of deployment of key low carbon technologies such CCGT with CCS and hydrogen turbines as the operational costs
- **Technology costs, maximum build limits and other parameters:**
  - Significant reductions in the cost of renewable technologies have been observed in recent years as evidenced by auction clearing prices globally. Both wind and solar technologies are already quite far down learning curve and there is less uncertainty around scope for further improvements compared to other technologies
  - The evolution of costs and maximum pace of deployment for the key technologies providing baseload/mid-merit/peaking low carbon power including nuclear/CCGT with CCS/ hydrogen turbines will impact their future role
  - The deployment levels for all technologies will be impacted by the maximum build limits due to technical and resource constraints
- **Security of supply (SoS) constraints and level of demand and supply side flexibility:**
  - With significantly increased levels of demand and renewable generation, the system must be designed to have sufficient levels of firm capacity to meet the minimum level of SoS standard defined by targeted capacity margin levels: ~4-5% in the long term based on National Grid projections and to avoid unserved energy at times of peak demand
  - In addition, the system must maintain enough dispatchable reserve to respond to hour-to-hour fluctuations in intermittent renewables output, particularly in future worlds such as the CCC's where ~2/3 of total electricity supply is from wind and solar by 2050. There should also be consideration of how such a system is designed to cope with extended low wind/other output periods
- It is important to note that it is not possible to explore all possible combinations of the power system factors mentioned above, therefore we have reviewed and assessed the most material ones for Gas with CCS to explore a credible solution space for favourable and less favourable CCS outcomes, as shown in the next slide.

Key drivers influencing role and system value of CCS (3)

Level of flexibility, nuclear favourability and gas prices have been identified as the three key drivers for the system value of CCS

- Among the key electricity factors to consider in a net zero world outlined in the previous slide, we have identified three key dimensions that are likely to impact the deployment and system value of CCS significantly. These three dimensions that are used for framing the core scenarios around the Base Case are outlined below:

Level of flexibility	Nuclear favourability	Gas prices
▪ ***Increasing levels of supply and demand side flexibility as well as interconnection*** will impact the need for other dispatchable generation including Gas with CCS. Demand side flexibility provided by demand side response, flexible EV and heat pump demand will enable demand to shift to low price periods which coincide with high renewable generation. Similarly, supply side flexibility such as batteries will help manage the increasing levels of renewable generation on the system to 2050. Increasing interconnection with the neighbouring markets will provide flexibility by allowing imports to GB at times of system stress and exporting excess renewable generation in other times, impacting the deployment of CCGT with CCS.	▪ The projected significant increase in renewable generation to 2050 to meet a net zero target will increase the need for the low carbon energy providing technologies including ***nuclear and Gas with CCS as two direct competitors***. The reduction in nuclear capex will increase its potential to displace Gas with CCS capacity. It is considered that further cost reductions can be achieved for nuclear technologies by moving towards more standardized designs and improving the conditions for manufacturing components. The availability of government subsidies is also another enabler for the deployment of nuclear. As a result, the possibility of cost reductions for nuclear must be considered within the scenario framing.	▪ The ***cost-competitiveness of CCGT with CCS*** will be directly ***impacted by the level of gas prices*** and lower gas prices will help the deployment of Gas CCS. The evolution of future gas prices will depend on the supply and demand dynamics of the global gas markets. The level of gas prices will also indirectly drive hydrogen prices as blue hydrogen production using Gas with CCS is projected to be significant by 2050. Some hydrogen will then be used as fuel in hydrogen turbines for power generation. Considering the likely scenarios that might prevail, the range of uncertainty in future gas price levels and its impact on hydrogen prices must be captured within the scenario framing for assessing the system value of Gas CCS.

Framing of scenario analysis

Eight core scenarios and three spot sensitivities in addition to the Base Case are studied to explore the solution space around the Base Case and the resulting Gas CCS system value

- A total number of eight core scenarios have been created using the different permutations of the three key dimensions and considering the lower and upper boundaries for each one as shown below. In addition to these scenarios, three spot sensitivities have been studied to explore the solution space around the Base Case in more detail

Level of flexibility:
- Storage costs and de-rating factors
- Demand side flexibility (EV and HP demand)
- Interconnection

Nuclear favourability:
- Nuclear Gen III Capex
- Nuclear SMR availability

Gas prices:
- Gas and hydrogen prices

Core scenario	Level of flexibility	Nuclear favourability	Gas prices
HF_HN_HG	High	High	High
HF_HN_LG	High	High	Low
HL_LN_HG	High	Low	High
H:_LN_LG	High	Low	Low
LF_LN_LG	Low	Low	Low
LF_LN_HG	Low	Low	High
LF_HN_LG	Low	High	Low
LF_LN_HG	Low	Low	High

Eight core scenarios around the Base Case

- In addition to the eight core scenarios above which are used to understand broad solution space for Gas with CCS around the Base Case, we also consider separately three "spot sensitivities“ which aim to explore more specific questions as outlined below. Relative to the Base Case, these sensitivities cover:
  - **Stress security of supply test:** considering a 1-in-20 cold weather peak day demand (as opposed to an average cold spell), increased operational reserve requirements due to lower wind output and the unavailability of interconnection
  - **Slower future cost reduction for renewable technologi**es: assuming that costs of solar and wind technologies will decrease more slowly to 2050 with the end point costs being higher than the Base Case
  - **Super high gas prices:** higher than the top range of the gas prices used in the scenarios above

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Purpose of this section

Key assumptions and constraints to optimise the GB capacity mix to 2050

- The purpose of this section is to present the key input assumptions and constraints for the Base Case and associated scenarios/sensitivities in more detail. These assumptions have been agreed through discussions with the OGCI and come from a mix of sources including the OGCI, Baringa and third party views. These assumptions have been also validated through a benchmarking exercise with other external views where possible
- The overview of key assumptions and constraints is given below. The key assumptions that are varied across the eight core scenarios and the three spot sensitivities are explained in the following slides

Key assumptions	Key constraints
GB annual and peak electricity demand to 2050	Emission intensity constraint (this is an explicit outcome that is optimised and as a result an input carbon price is not needed)
GB electricity sector installed capacity to 2028, reflecting near term policy and 'momentum' effects driving new build.	Cap on availability of BECCS for power generation
Interconnection capacity and wholesale prices for the interconnected markets	Security of supply (SoS) constraint
Commodity prices to 2050 (gas, hydrogen, coal, oil and others)	Operational reserve requirement constraint
Technology parameters (operational and economic lifetime, Weighted Average Cost of Capital (WACC), build costs, fixed and operating variable and maintenance costs, availability considering forced and planned outages, efficiencies, maximum capacity)	Technology maximum build rates and quantities
Renewable technology load factors and generation profiles	Net zero annual imports between GB and interconnected markets
CCS Transport and Storage (T&S) costs	Large plant maximum build constraint
De-rating factors for technologies and interconnection	Maximum renewable generation constraint 2050

Summary of core scenario and spot sensitivity assumptions

Defining a Base Case and varying three key dimensions that will have the greatest impact on CCS deployment and system value

- The Base Case represents a central view of the key modelling inputs and constraints such as the future technology costs and build limits, electricity demand, commodity prices and system security constraints. In addition to the Base Case, we have run eight core scenarios and three spot sensitivities to explore the solution space around the Base Case in more detail. We have established the assumptions that are likely to have the greatest impact on the Gas CCS deployment in power and assumed credible ranges for these assumptions to assess the potential range of their impact on the Gas CCS system value

- The eight core scenarios are based on the 2x2x2 permutations of the three key dimensions that we have established with each dimension defined by a lower and upper bound. The additional three spot sensitivities are aimed to explore specific additional questions.

Three key dimensions	Description
Gas Price	The marginal cost of operating a gas powered plant is directly proportional to the price of gas. A lower gas price will therefore make gas plant, including Gas with CCS, more competitive in the market.
Nuclear Favourability	Given that increasing renewable capacity is expected under all scenarios, the main low carbon technology in competition with Gas with CCS is nuclear power. Lower nuclear capex will make nuclear more favourable and potentially displace Gas with CCS capacity.
Level of Flexibility	Increasing levels of flexibility will reduce the need for dispatchable low carbon generation and thus the deployment of Gas with CCS. These scenarios consider changing demand side-flexibility (from electric vehicles and heat pumps), changing grid scale battery costs and peak de-rating factors and different rates of interconnector deployment.

Additional sensitivities	Description
Stress test	1-in-20 peak demand could lead to significantly higher peak demand level than ACS demand (30-40 GW more). This combined with lower wind output and unavailability of interconnection will lead to increased requirement for firm and dispatchable capacity where Gas CCS could play a role
Slower renewable cost reduction	Slower cost reduction of renewables will make them less cost-competitive and can impact the timing and scale of Gas with CCS deployment
Super high gas price	Considering a world where gas prices might turn out to be very high will impact Gas with CCS deployment

Key overarching assumptions

Emission intensity, SoS and operational reserve constraints must be considered simultaneously to design an operable system with net zero emissions and avoiding unserved energy by 2050

- The emission intensity constraint defines an upper bound on the emissions from GB domestic power generation to 2050
- The security of supply constraint requires a minimum amount of firm capacity on the system as a proportion of the peak demand to avoid unserved energy at times of peak. In addition, as imposed by the operational reserve constraint, the system must maintain enough dispatchable reserve to respond to hour-to-hour fluctuations in intermittent renewables output and designed to cope with extended low wind/other output periods.

Key assumptions for the Base Case (modelling constraints)	Source of assumption	Notes on benchmarking
▪ Emission intensity constraint	▪ 75gCO2/kWh by 2030 following a linear pathway to get to 0g/kWh by 2050	▪ CCC decarbonisation levels by 2030 and 2050
▪ Availability of BECCS for power generation	▪ 45TWh per annum ▪ Negative emissions from BECCCS provide a 20g/KWh headroom to allow for residual emissions	▪ CCC Net Zero report
▪ Security of supply constraint (SoS)	▪ Minimum capacity reserve requirements based on National Grid capacity margin target	
▪ Operational reserve constraints	▪ Baringa modelling based on National Grid requirements	

Key demand assumptions (1)

Electricity demand is projected to increase significantly to 2050 under an economy wide Net Zero target

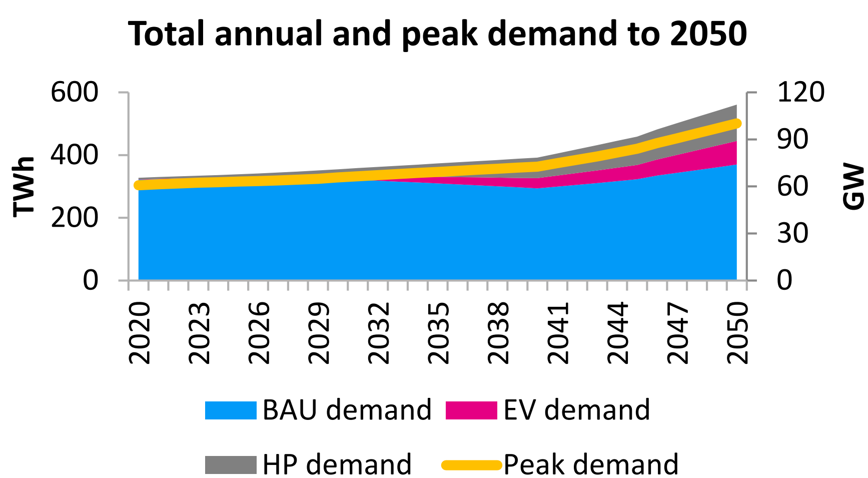
- Reflecting the need for significantly increased electrification in other sectors to meet an economy wide net zero target by 2050, the sources and benchmarking exercise have been outlined below for the forecasted GB electricity demand in the Base Case. In addition to the level of annual demand, hourly demand shape also changes as the penetration of flexible Electric Vehicle (EV) and Heat Pump (HP) load increases on the system as explained more in the next slide

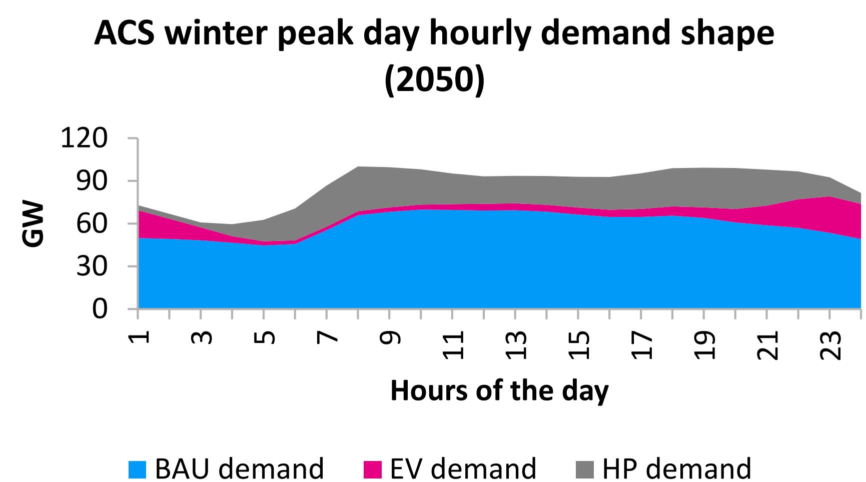
Key assumptions for the Base Case	Source of assumption	Notes on benchmarking
▪ GB annual and peak electricity demand to 2050	**Annual demand:** ▪ Consisting of business as usual (BAU), EV and HP demand components ▪ Near to medium term demand informed by Baringa Reference Case/ Decarbonisation scenarios ▪ Longer term demand trending towards a level consistent with net zero target **Peak demand:** ▪ The projected peak demand resulting from the evolution of BAU hourly demand, flexible vs inflexible portions of the EV and HP demand (source as above)	▪ The total demand level for 2050 compared to CCC Net Zero Report and National Grid FES sensitivity studies (annual demand reaching ~500-600 TWh levels by 2050) ▪ External studies do not provide a pathway for the electricity demand to 2050 to meet a net zero target, rather they present a view for 2050 only

Key demand assumptions (2)

Both annual and peak demand are projected to nearly double to 2050 compared to current levels, driven by increasing electrification of heat and transport

- The near to medium term power demand in the Base Case is a blend of Baringa's power sector Reference Case (central market view) and Baringa Decarbonisation scenarios, which indirectly reflect a mix of National Grid near-term forecasts and accelerated demand growth driven by a more decarbonized world as shown in the chart on the left below
- In the longer term, electricity demand picks up further and grows to a level that is consistent with the economy wide net zero target by 2050, as a result of the significant electrification in other sectors (reaching a similar level to the CCC forecasted demand of ~600 TWh/year by 2050). In addition, the Baringa Decarbonisation scenario assumes 1.2 GW of DSR load shedding capacity (e.g. I&C) from 2021 onwards
- Similar to the annual demand, the peak demand grows to 100 GW by 2050, as a result of the evolution of the BAU, EV and HP demand segments and the associated flexible and inflexible demand portions (the resulting hourly demand shape in 2050 is shown in the chart on the right below). It is assumed that:
  - EV home and depot-charging for cars and depot charging for vans reflects broad Time of Use (ToU) shifting and EV charging at other locations is assumed to be unmanaged (further detail provided in the Annex), similarly HP demand is also broadly assumed to reflect ToU shifting given interaction with hot water storage or use of gas boilers within hybrid heat pump systems at times of peak demand.
  - The assumed demand shifting for EVs and HPs in the Base Case is effectively a fixed assumption in the GB PLEXOS LT model. An overview of the demand side flexibility assumptions for the other core scenarios is provided in the next slide.





Key demand assumptions (3)

Demand side flexibility is varied in the core scenarios, represented through demand shifting assumptions for EVs and HPs

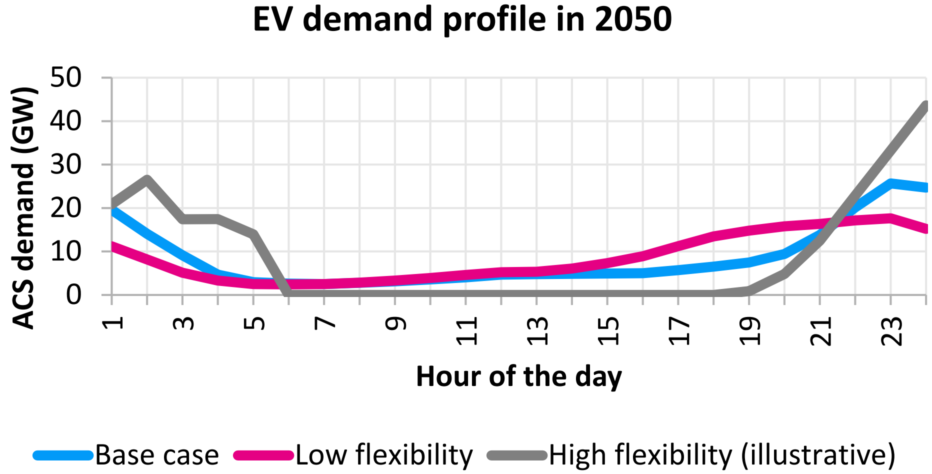
- The total annual demand is kept the same as the Base case with demand side flexibility from EVs and HPs varied for the high and low flexibility assumptions fed into the eight core scenarios. The I&C load shedding capacity has been kept the same across all cases as per the Base Case (1.2 GW from 2021 onwards)
- We assume some portion of demand shifting from EVs and HPs across all cases outside the model (based on time of use shifting for EVs and , interaction with hot water storage for HPs), which is then fed as a fixed input into the GB PLEOXS LT model in most cases as shown below. One exception is that flexible EV demand is hourly optimised in the model in the case of the high flexibility

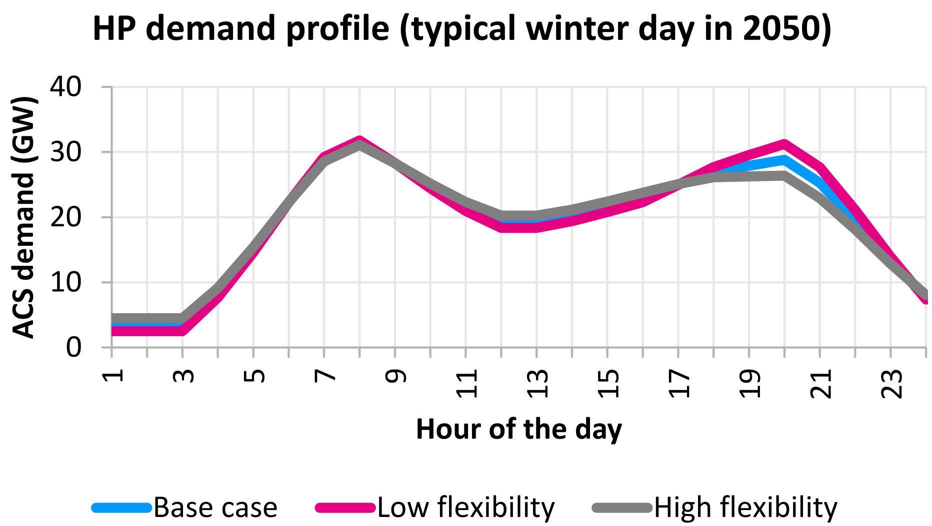
Scenario	ACS Peak demand in 2050 (GW)	EV demand 2020	EV demand 2050	HP demand 2020	HP demand 2050	Source
Base Case	100	Home/depot charging is ToU shifted. Non-home charging is unmanaged.	Home/depot charging is ToU shifted. Non-home charging is unmanaged.	HP demand profile represents 75% customers responding to broad ToU incentives and 25% load-following profile		Baringa Reference Case / OGCI
High flexibility	97	As above.	Fully hourly optimized charging for home/depot charging which can take place overnight. As per base case for other EV charging.	HP demand profile represents 100% customers responding to broad ToU incentives		
Low flexibility	108	Home/depot charging has ca. half of the ToU shifting seen in the base case. Non-home charging is unmanaged.	Home/depot charging has ca. half of the ToU shifting seen in the base case. Non-home charging is unmanaged.	HP demand profile represents 50% customers responding to broad ToU incentives and 50% load-following profile		

Key demand assumptions (4)

Peak electricity demand in 2050 ranges from 97 GW to 108 GW between the high and low flexibility assumptions for the core scenarios

- The resulting hourly electricity demand profile for EVs and HPs in 2050 is shown on the right, driven by the demand side flexibility assumptions shown in the previous slide
- The EV home/depot charging, which occurs overnight is fully optimised by the GB LT model in the high flexibility case and other non-home charging is unmanaged (similar to the Base Case and low flexibility)
- The resulting hourly EV demand from the optimised and fixed portions is therefore illustrative for the high flexibility case on the right
- For other cases, the demand that can be shifted for EVs and heat pumps due to ToU shifting in the case of EVs and interaction with hot water storage in the case of HPs is a fixed input into the model as mentioned in the previous slide





Implicit capacity assumptions (1)

The GB capacity mix is fixed to 2028 as per Baringa's "Decarbonisation" scenario. The prices in the interconnected EU markets are as reflect the Base Case commodity and carbon prices

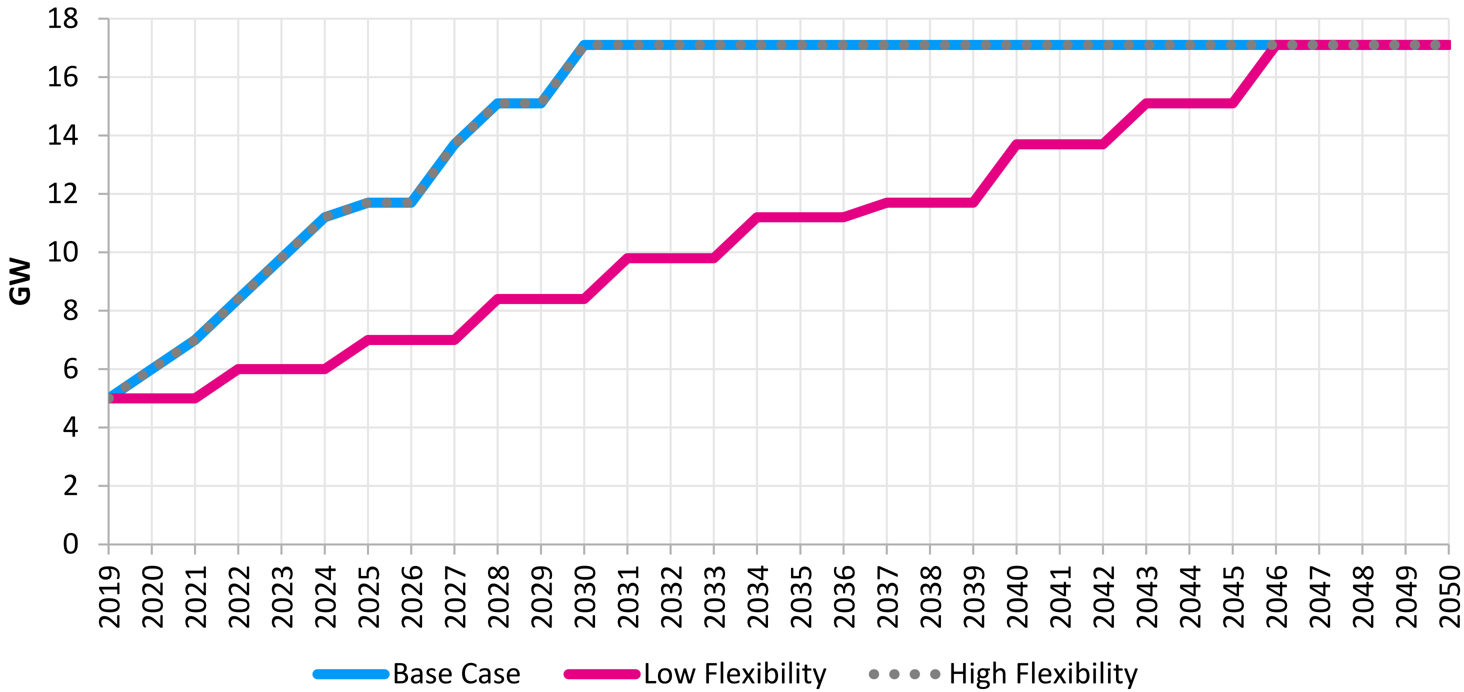
- The GB power sector installed capacity has been fixed from now to 2028, as per the Baringa decarbonisation scenario due to the fact that the near to medium term capacity will be based on the latest construction pipeline and policies. The capacity mix beyond 2028 to 2050 is the outcome of the GB PLEXOS LT modelling
- For the interconnected markets, we have run the Baringa Pan European model (using Baringa's decarbonisation scenario) with the commodity and carbon prices in the Base Case and the outturn hourly interconnected market prices are fed as input to the GB PLEXOS LT model
- Interconnection capacity is based on Baringa Decarbonisation scenario and is varied between the high and low flexibility assumptions for the core scenarios as shown in the next slide

Key assumptions for the Base Case	Source of assumption	Notes on benchmarking
GB electricity sector installed capacity to 2028	Baringa decarbonisation scenario taking into the latest information on the capacity pipeline, policy announcements, capacity market news and renewable auctions etc.	Compared to National Grid FES scenarios for benchmarking
Interconnection capacity and wholesale prices for the interconnected markets to GB to 2050 (France, Belgium, Netherlands, Norway and Denmark)	Baringa decarbonisation scenario (pan EU wide), reflecting the gas and carbon prices in the Base Case	

Implicit capacity assumptions (2)

Interconnection capacity is varied between the high and low flexibility assumptions for the core scenarios

- Interconnection serves as a source of flexibility on the system, in particular in the timeframe to 2050 with the expected significant expansion of renewables to 2050
- Interconnection capacity is varied between the high and low flexibility cases as shown below, with low flexibility case assuming delayed interconnection compared to Base Case and High flexibility cases which assume the same interconnection assumptions



Key commodity price assumptions (1)

Coal, oil and gas prices are based on the latest views from credible third party providers. Hydrogen prices reflect the cost of blue hydrogen production from the underlying gas prices.

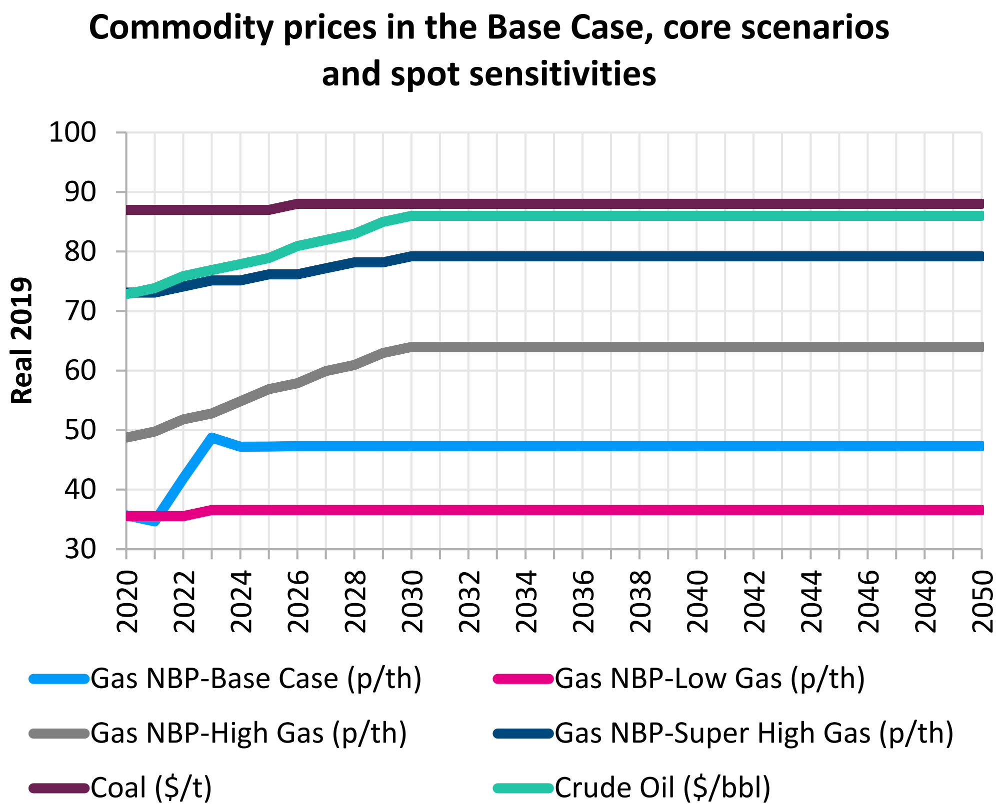
- Coal, gas and oil prices are based on the latest projections available from credible external providers including the Department for Business, Energy & Industrial Strategy (BEIS) and other service providers. Gas prices have been compared with other third party views shown below as part of the benchmarking. Hydrogen prices reflect the cost of blue hydrogen production, resulting from the underlying gas prices. Differently from the commodity prices below, carbon shadow prices are an outcome of the modelling as mentioned previously.

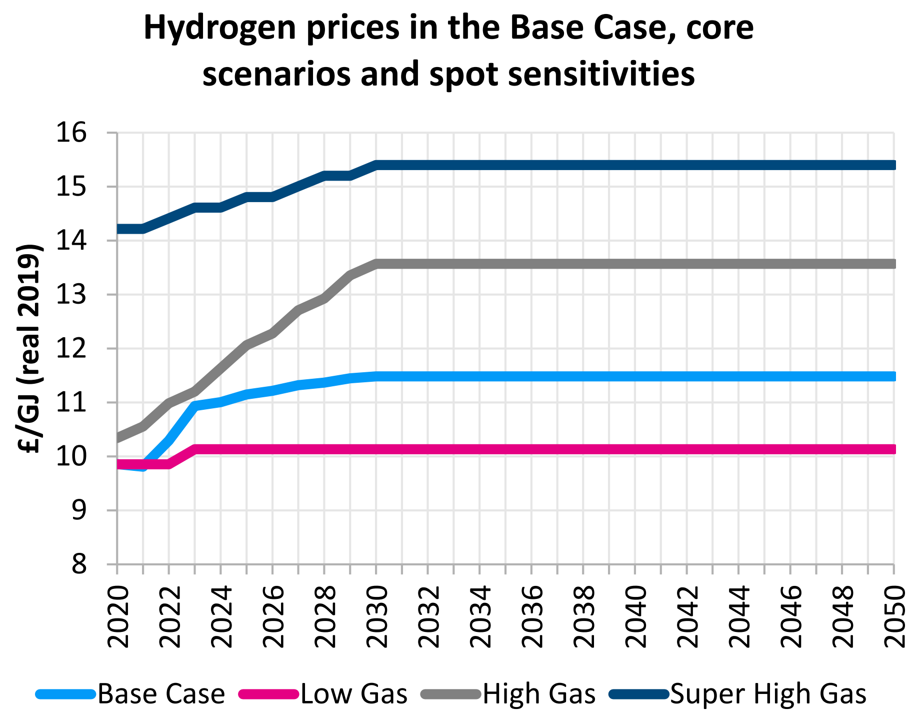
Key assumptions for the Base Case	Source of assumption	Notes on benchmarking
Gas NBP prices to 2050	Oct'19 Price Forecast	Compared to other external views including BEIS, IEA, EIA, National Grid FES and Baringa projections
Hydrogen prices to 2050	OGCI projections	UK H2 prices based off 'Blue H2' technology assumptions, therefore intrinsically linked to long term gas price assumptions
Coal and oil prices to 2050	BEIS 2018 Updated Energy & Emissions Projections (assumed flat from 2035)	Compared to other external views such as IEA and EIA
Other commodity prices to 2050 (biomass, waste and uranium prices)	Baringa decarbonisation scenario	

Key commodity price assumptions (2)

Range of gas, oil and coal prices

- The projections for gas, coal and oil prices in the Base Case, core scenarios and spot sensitivities are shown below. Gas prices include the Base Case projections, high and low gas prices used in the core scenarios and the 'super high gas prices' in the super high gas price spot sensitivity
- The range of hydrogen prices reflecting the costs of blue hydrogen from the underlying gas prices are also shown below





Key technology assumptions (1)

Technology assumptions benchmarked against external views as possible

- Technology assumptions have been discussed and agreed in detail with the OGCI. External views have been used where needed and supported through benchmarking as possible.
- Renewable technology parameters are based on Baringa assumptions, reflecting the latest market intelligence

Key assumptions for the Base Case	Source of assumption	Notes on benchmarking
▪ Operational and economic lifetimes ▪ WACC	▪ Baringa and OGCI assumptions ▪ Flat rate of 8% used for WACC for all technologies	▪ All technology operational and economic lifetimes based on latest market data
▪ Build costs, fixed and variable operating and maintenance costs (FOM and VOM)	▪ Baringa assumptions for renewable costs, a mix of OGCI, UKERC and BEIS assumptions for others	▪ Baringa views reflecting the latest market intelligence and benchmarked against recent auction data
▪ Availability of generation (planned and unplanned outages)	▪ Baringa assumptions	▪ Baringa assumptions calibrated to market data
▪ Efficiencies at min stable level (MSL) and maximum export limit (MEL)	▪ Baringa and OGCI assumptions	▪ Efficiencies reflect the latest market intelligence of operational and planned plant

Key technology assumptions (2)

Technology assumptions benchmarked against external views as possible

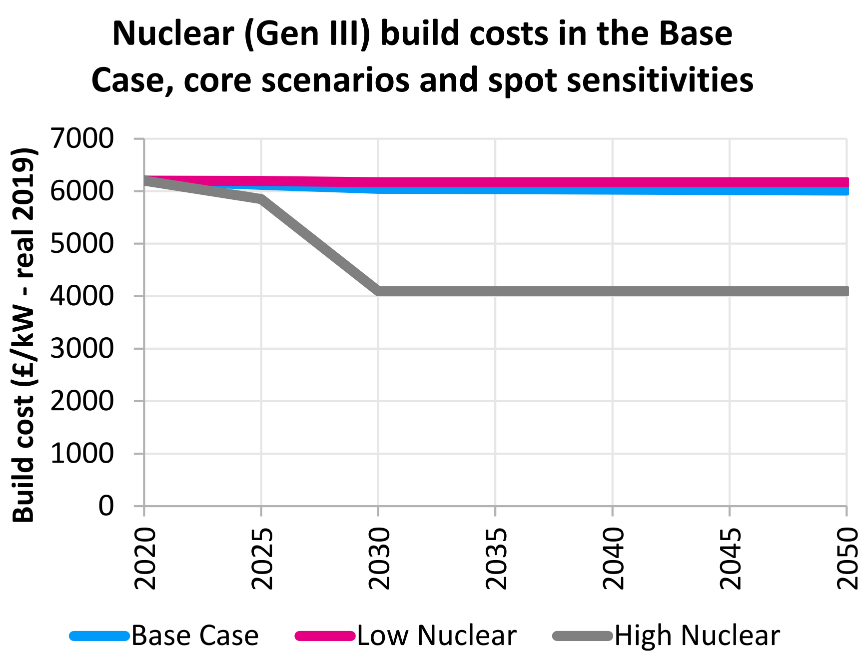
- Technology assumptions have been discussed and agreed in detail with OGCI. External views have been used where needed and supported through benchmarking as possible.
- De-rating factors are in line with the latest capacity market parameters set by National Grid

Key assumptions for the Base Case	Source of assumption	Notes on benchmarking
Renewable technology load factors and generation profiles	Baringa assumptions consistent with the cost data	Compared to other external views including BEIS, IEA, EIA, National Grid FES and Baringa projections
Maximum build rates and quantities	Mix of OGCI, Baringa. Max build quantity for offshore wind floating and tidal are from BVG and ETI, respectively.	Benchmarked against CCC Net Zero report, historical build rates,
CCS T&S costs	BEIS	BEIS costs created through benchmarking against various reports from AMEC, ROAD project and Zero Emission Platform. BEIS costs inline with current NZT projected costs.
De-rating factors	In-line with latest CM de-rating factors set by National Grid	

Key technology assumptions (3)

Nuclear build costs are varied for the nuclear favourability assumptions in the core scenarios. Nuclear SMR deployment assumptions are also varied

- Nuclear build costs are varied across the low and high nuclear favourability assumptions for the core scenarios as below. Nudear (Gen III) costs are shown as it is projected to be cost competitive compared to SMR technology in all cases
- Another assumption varied for the nuclear favourability dimension is the availability of SMR technology which is assumed to be deployable from 2035 in the high nuclear favourability case and unavailable in other cases as shown in the table below

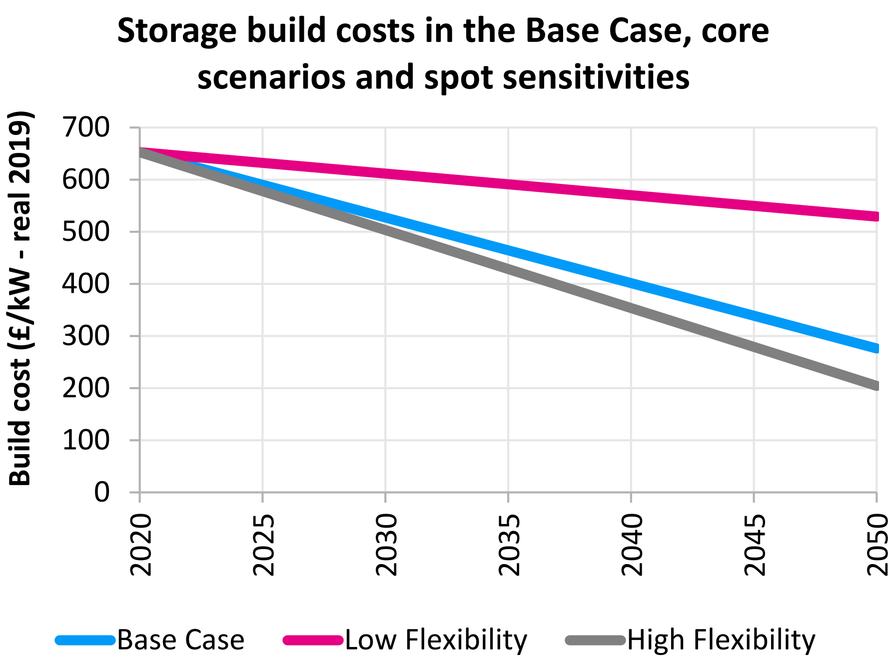


Dimension	Parameter	High	Base Case	Low
Nuclear Favourability	Large Nuclear CAPEX	Low Scenario, BEIS 2016 Generation Costs Report	Marginal reduction to High Scenario, BEIS 2016 Generation Costs Report	High Scenario, BEIS 2016 Generation Costs Report
	Nuclear SMR	Deployable from 2035	Unavailable	Unavailable

Key technology assumptions (4)

Assumptions for storage costs and contribution to SoS are varied for the level of flexibility dimension in the core scenarios

- Storage build costs and de-rating factors are varied across the different cases as below, meaning both the cost competitiveness and contribution to SoS are changing

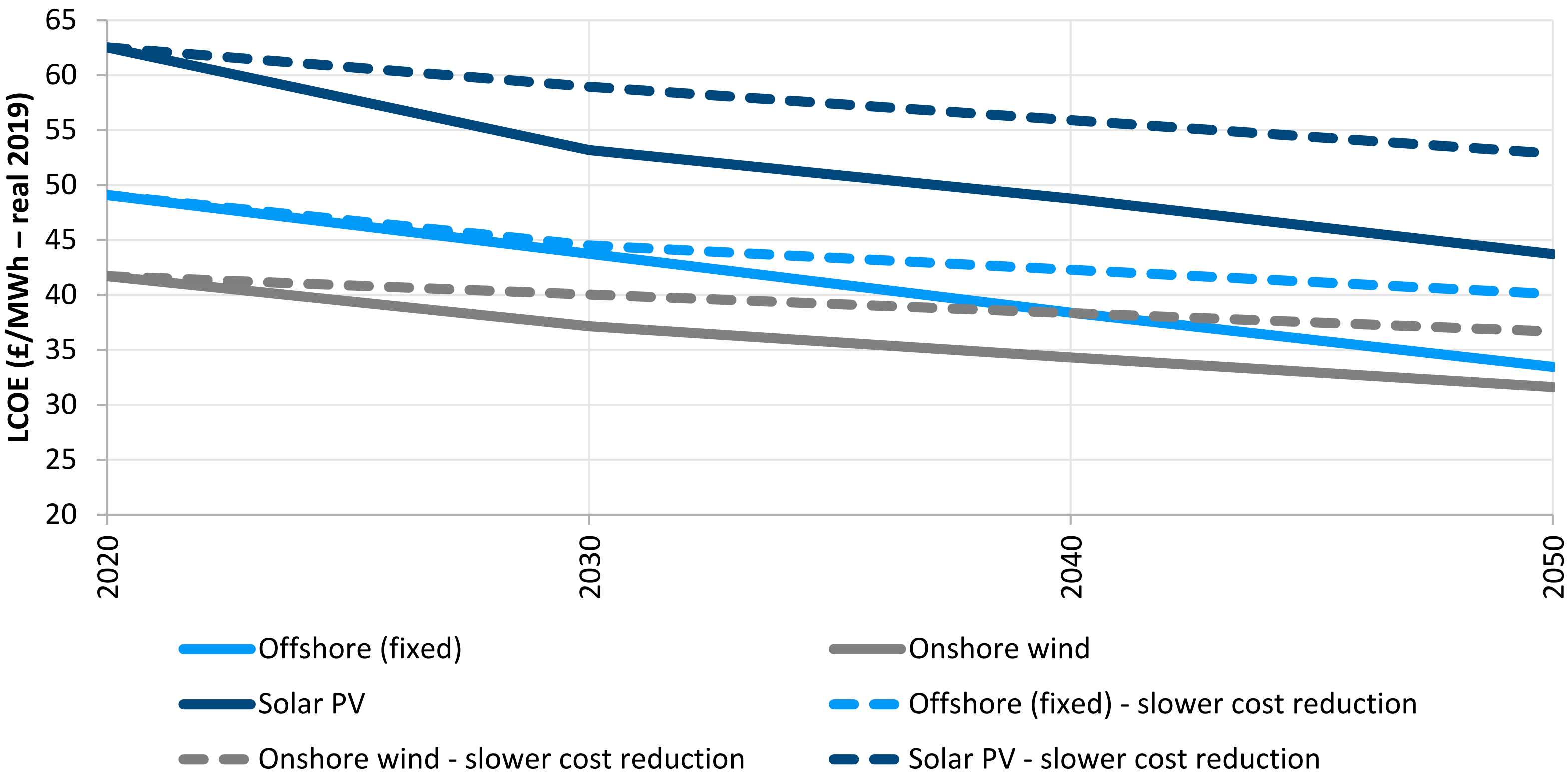


Scenario	Battery de-rating factor (2 hour battery)	Source
Base case	41%	Latest Capacity Market (De-Rating factor (DRF) for 2 hour battery
High flex	61%	Higher end of historical CM DRF for batteries
Low Flex	21%	Lower end of historical CM DRF for batteries

Key technology assumptions (5)

Onshore and offshore wind levelised costs converge to 2050 with solar PV remaining at a premium

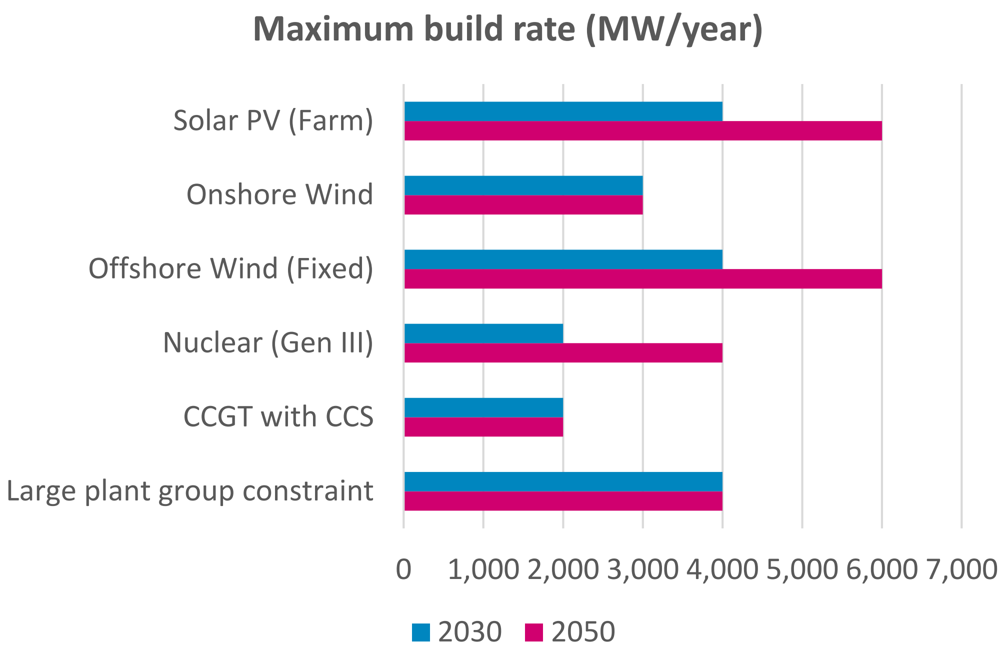
- The levelised costs of the renewable technologies are shown below (solid lines representing the Base Case trajectory). Costs of onshore and offshore wind almost converge by 2050 with solar remaining at a premium. The levelised costs shown below account for construction time for each technology, representing investors’ perspective. However, it is worth noting that our modelling compares cost-competitiveness of these technologies from a central planning perspective, so do not account for construction times
- The slower renewable cost reduction spot sensitivity assumes that the CAPEX for renewables will end up at the mid point of the starting and final build costs in the Base Case, resulting in the higher LCOEs throughout the pathway as below (dotted lines)

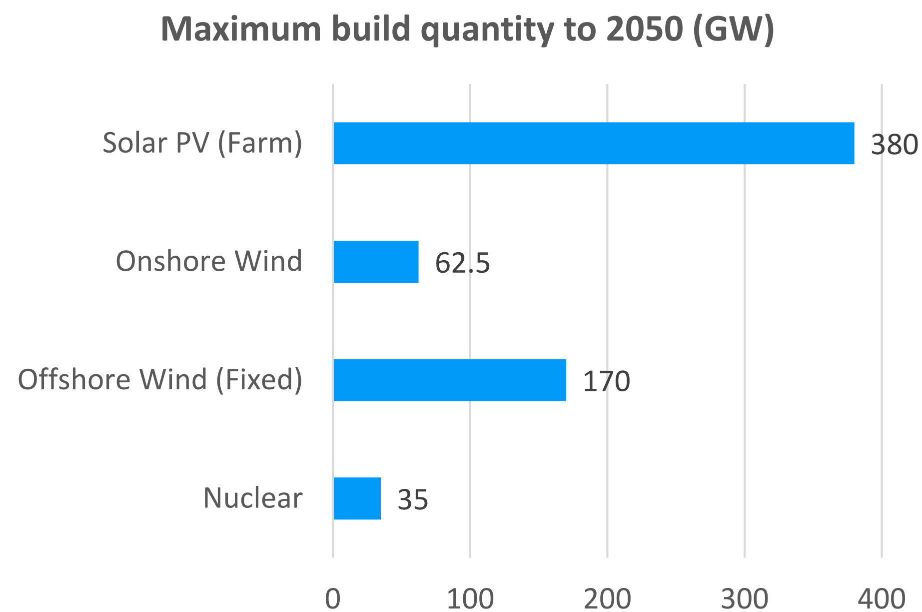


Key technology assumptions (6)

There are maximum annual build and maximum build quantity limits on the deployment of the key technologies to represent resource and technical limits

- The maximum annual build rates and maximum build quantities (total capacity that can be present in any year to 2050) are shown below for the solar, wind, nuclear and CCGT CCS technologies, representing the combined impact of technical and resource limits
- There is a constraint on the maximum annual build rate for large plant including CCGT with CCS, biomass with CCS, H2 CCGT and CCGT, representing a plausible and sustained build out based on the CCC Net Zero report (large plant group constraint as shown below)





Key additional constraints

Additional constrains have been imposed to design a system that represents a sustainable and plausible evolution of GB generation mix to 2050

- Additional constraints on the net annual energy flow through interconnectors, larger plant maximum build rate and maximum renewable generation have been considered as explained below.

Key assumptions for the Base Case (modelling constraints)	Source of assumption	Notes on benchmarking
Net zero annual imports between GB and interconnected markets	Baringa – the constraint allow interconnectors to provide flexibility across the year but prevents GB being a net importer or exporter. This is to reflect the uncertainty around the decarbonisation levels in the interconnected markets and their prices to 2050	
Large plant maximum build constaint	CCC – to represent a sustained and plausible build out rate for large plant including CCS, biomass, nuclear and H2 CCGT	
Maximum renewable generation constraint 2050	CCC - to get to similar level of renewable generation in 2050 with CCC	

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Key Base Case Results

The key results of the Base Case scenario, which represent a central view of the GB power system evolution, are presented in this section

- This section presents the key results of the Base Case scenario, which represents a central view of the future GB power system evolution under a net-zero emissions target by 2050
- The key results include:
  - The evolution of the capacity mix, broken down by technology type
  - The evolution of the carbon price
  - The evolution of the generation mix, broken down by technology type
  - A benchmarking of the results against other studies of a 2050 net-zero power system
  - Load factors of key flexible technologies
  - Sample weekly generation and demand profiles in 2030 and 2050
  - The system benefit provided by Gas with CCS
- These results have been chosen to illustrate the role of Gas with CCS in a net-zero power system

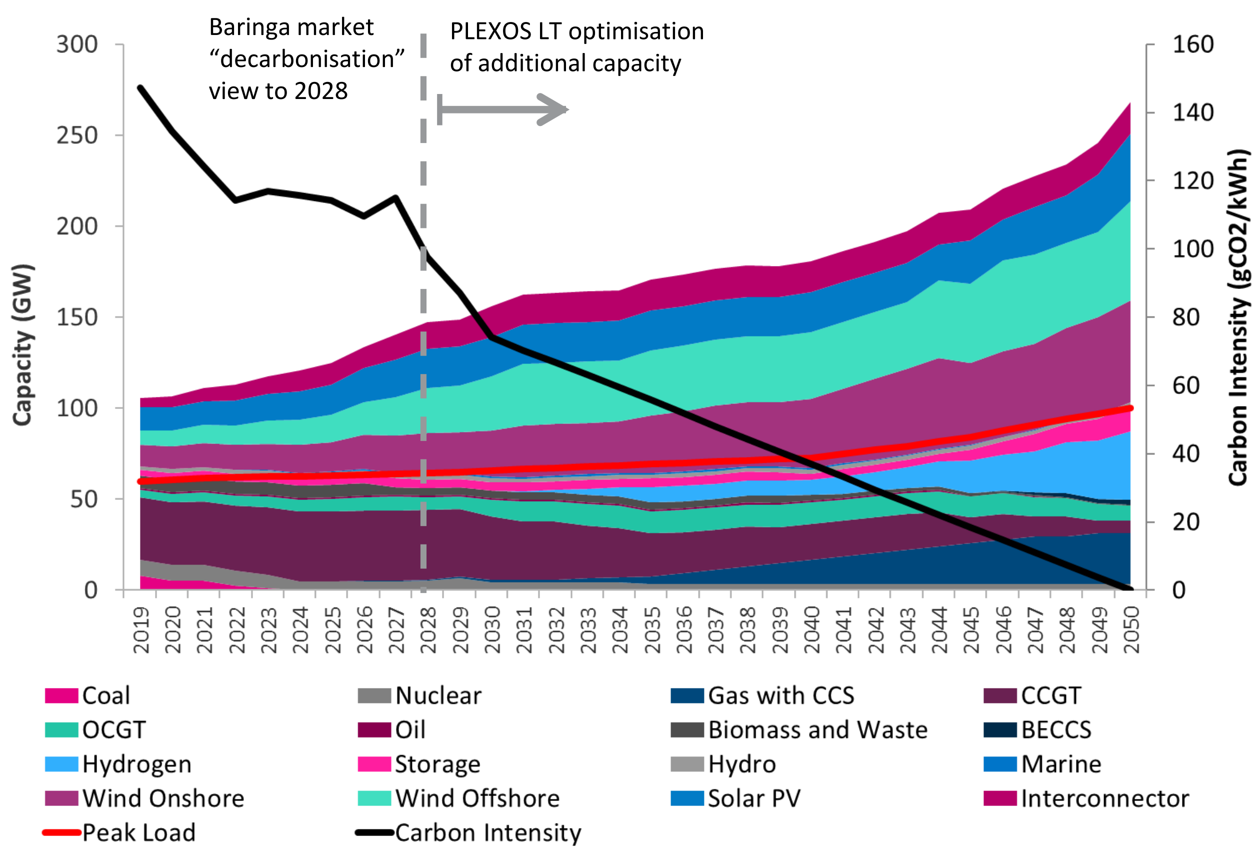
Evolution of the capacity mix

Significant increase in renewable capacity, and retiring flexible plant replaced predominantly by Gas with CCS, hydrogen turbine and battery storage capacity

Description

- An increasing level of peak demand, rising to around 100 GW by 2050, results in an increase in the total installed capacity on the system, reaching around 250 GW by 2050. The majority of this capacity is from renewable technologies as they present the cheapest source of low carbon generation
- As the aging existing gas and nuclear fleet retire, the dispatchable capacity is replaced by Gas with CCS*, hydrogen turbines and battery storage, as well as a moderate build of peaking OCGT plant
- The optimal level of dispatchable capacity on the system is a result of the increased need for dispatchable generation to cope with increased level of intermittent renewables, the increased need for firm capacity on the system for SoS reasons and increasing operational reserve requirement
- There is no new build of nuclear, excluding Hinckley C which is assumed to become operational in the late 2020s
- In the late 2040s a small capacity of BECCS is built in order to offset the residual emissions of the Gas with CCS and OCGT plant and achieve net-zero emissions

Capacity Mix Evolution, Base Case Scenario



**OGCI CCGT with CCS plant assumed to come online in 2026*

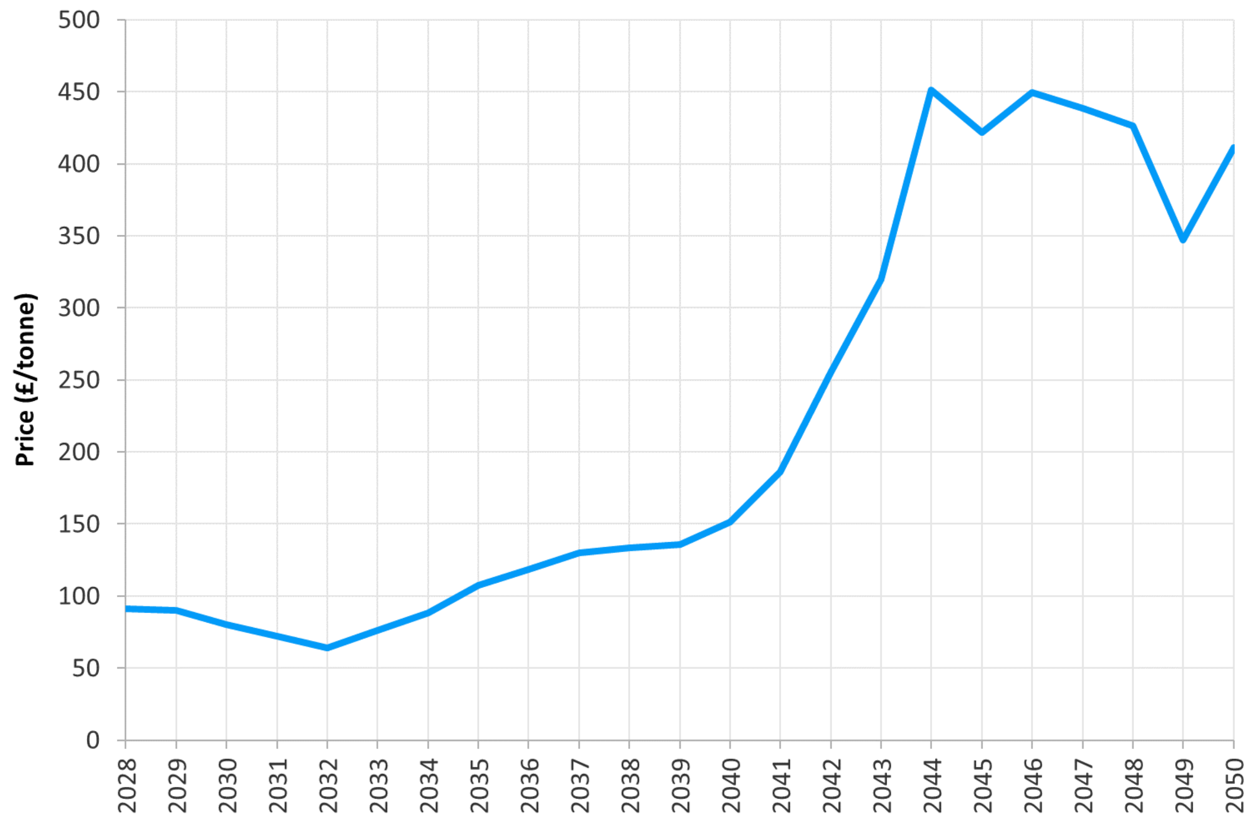
Evolution of the shadow cost of carbon

The shadow cost of carbon rises from £90/tonne in 2028 to over £400/tonne by the mid 2040s, significantly above the current GB carbon price of around £40/tonne

Description

- The RHS chart displays the evolution of the shadow cost of carbon across the horizon
- The shadow cost of carbon reflects the shadow cost of the carbon emissions constraint i.e. it is the ***marginal*** carbon price that ensures that the capacity mix is built and dispatched in such a manner that it satisfies the carbon emissions constraint
- As the shadow cost of carbon is a function of the constraint the value is volatile and as such we present a rolling average to illustrate the general trend
- The shadow cost of carbon rises from around £90/tonne in 2028 to more than £400/tonne by the mid 2040s
- The carbon price in GB is currently around £40/tonne and therefore the shadow cost of carbon to drive an electricity system outcome consistent with a net-zero target is significantly above current the carbon price
- However carbon price projections produced by BEIS reach around £100/tonne by 2035 in the reference scenario[1], and in longer term projections fall between £130/tonne and £370/tonne by 2050[2]

5-year Rolling Average Shadow Cost of Carbon , Base Case Scenario



[1] https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2018

[2] https://www.gov.uk/government/collections/carbon-valuation--2#guidance-on-estimating-carbon-values-beyond-2050

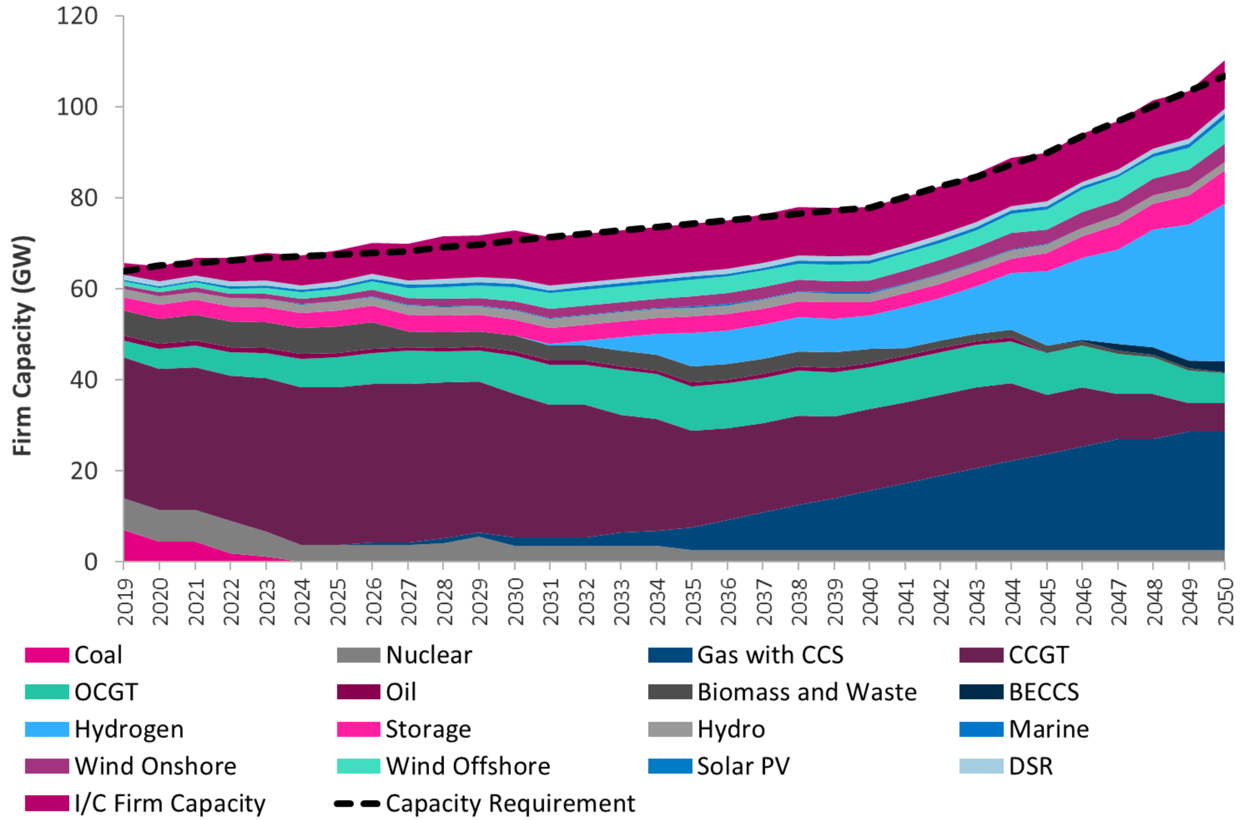
Evolution of the firm capacity mix

Rising peak demand, alongside significant retirements of the existing nuclear and CCGT fleets, requires significant levels of new flexible capacity to satisfy firm capacity requirements

Description

- The RHS chart displays the de-rated or 'firm' capacity mix, calculated using the latest GB Capacity Market de-rating factors
- Those technologies that are deemed less likely to be able to generate during periods of peak demand are given low de-rating factors and thereby contribute less to the firm capacity requirement
- The firm capacity requirement is a function of the peak demand, to ensure that peak demand can be served in the face of a number of plant outages
- In the near term the firm capacity lost due to the retirement of the remaining coal fleet, followed by the retirement of existing nuclear plant and later by retiring CCGTs is replaced by increased interconnection and OCGT build
- In the 2030s more significant CCGT retirements occur and Gas with CCS and hydrogen turbines are built to replace the shortfall in firm capacity
- In the 2040s a significant increase in peak demand further drivers the need for further Gas with CCS and Hydrogen Turbine deployment

Firm Capacity Mix Evolution, Base Case Scenario



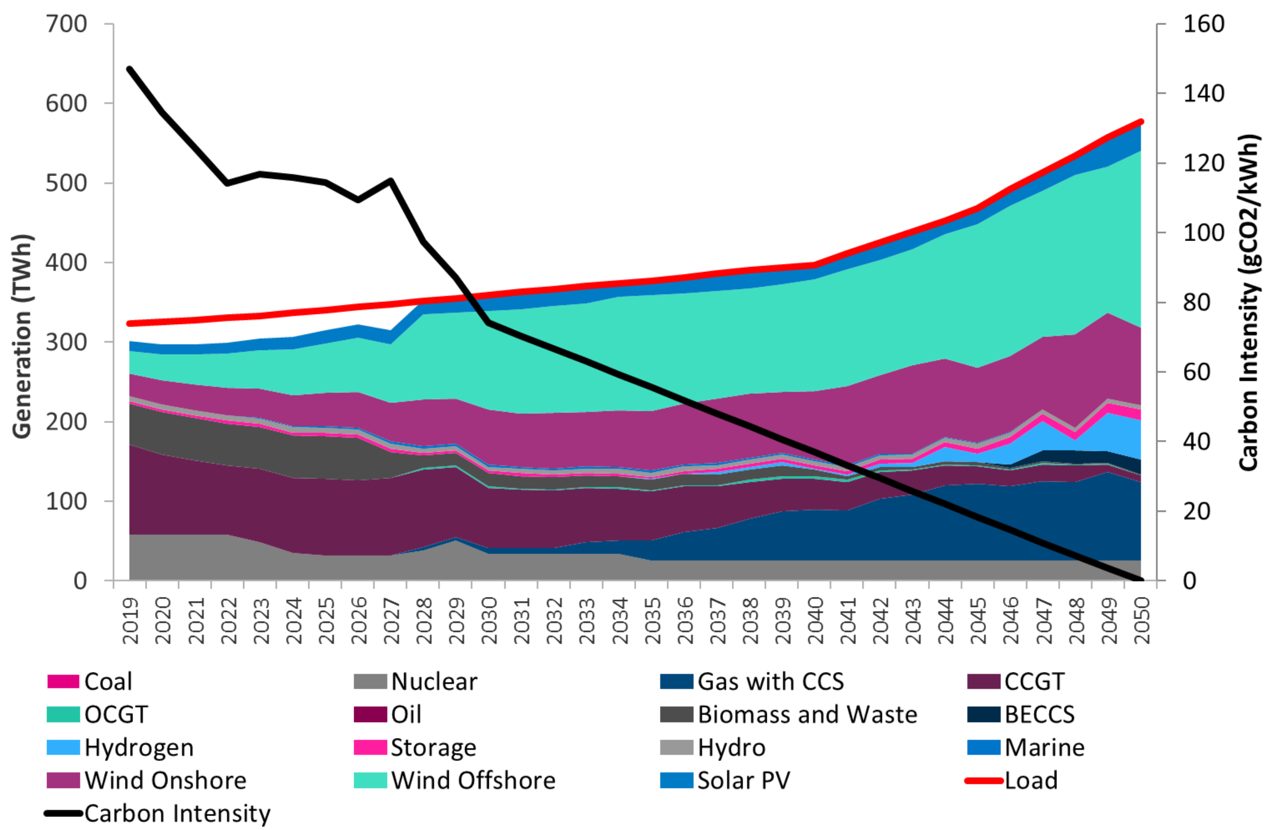
Evolution of the generation mix

Renewables meet an increasing share of the demand whilst Gas with CCS generation replaces retiring mid-merit plant and Hydrogen turbines operate on a peaking basis

Description

- The RHS chart illustrates the changes in the generation mix out to 2030
- The total generation matches the total annual demand from 2028 as interconnector flows are enforced to be net zero on an annual basis. Before this date the GB power system is a net importer of power, shown by the annual generation being lower than the annual demand/
- The share of renewable generation increases from around 25% in 2029 to around 65% in the 2040's
- This increase displaces and replaces generation from thermal plant, including nuclear, gas and biomass due to competitiveness on a marginal basis and retirement of thermal plant
- Gas with CCS contributes an increasing share from the early 2030s, displacing existing unabated gas plant as the carbon emissions constraint tightens
- In the late 2040's Hydrogen plant are operating on a peaking basis while a modest BECCS generation offsets the residual emissions of Gas with CCS, due to it's negative emission rate

Generation Mix Evolution, Base Case Scenario

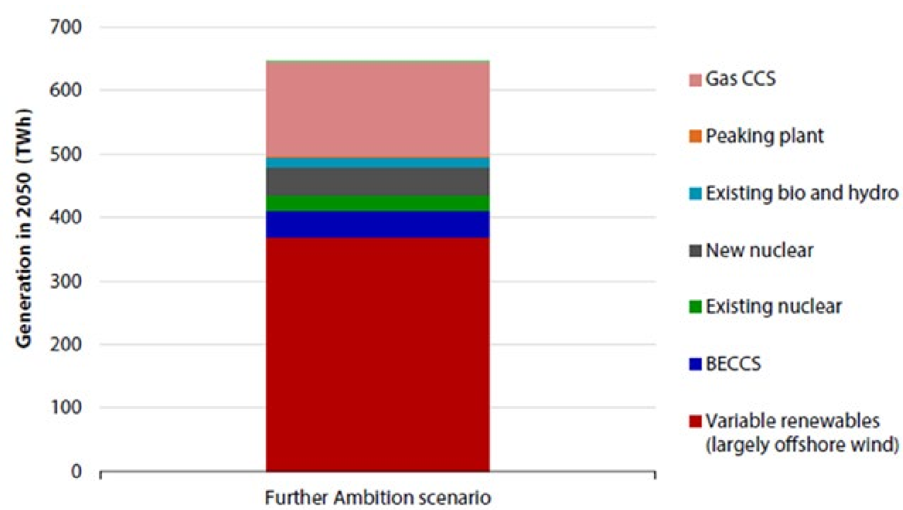


Benchmarking against the CCC Net-zero report

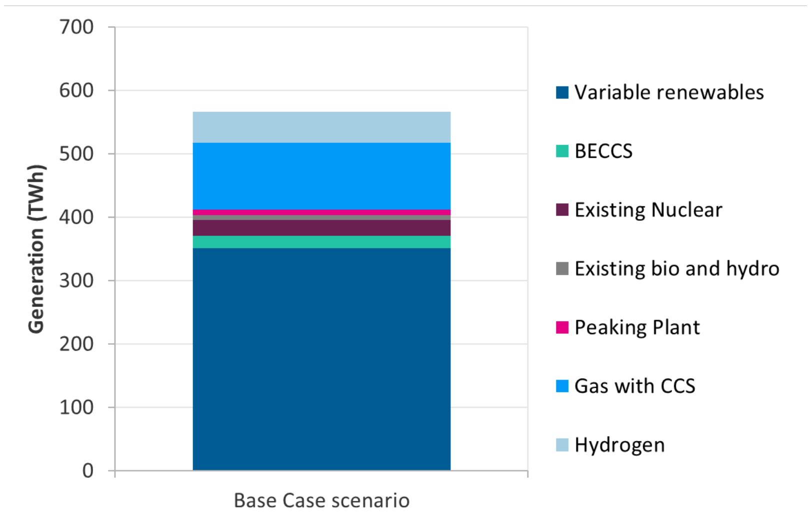
Renewables hold the largest share of generation by 2050 with significant volume of Gas with CCS generation in both sets of results

- The charts below compare the generation mixes in 2050 from the Base Case scenario with the Further Ambition scenario from the Committee on Climate Change (CCC) Net Zero report, published in May 2019. They present a reasonably similar generation mix though the total generation level is greater in the CCC results due to a higher demand assumption
- Both sets of results have similar levels of renewable generation, with 369TWh in the CCC results compared to 350TWh in the Base Case scenario. The role of Gas with CCC appears to be broadly similar in both cases, providing dispatchable generation to complement the significant variable renewable generation. No new nuclear is built in the Base Case scenario, unlike in the CCC results. There is no hydrogen turbine generation in the CCC results, unlike in the Base case scenario where hydrogen generation reaches almost 50TWh in 2050

CCC Net-zero Report



Base Case Scenario



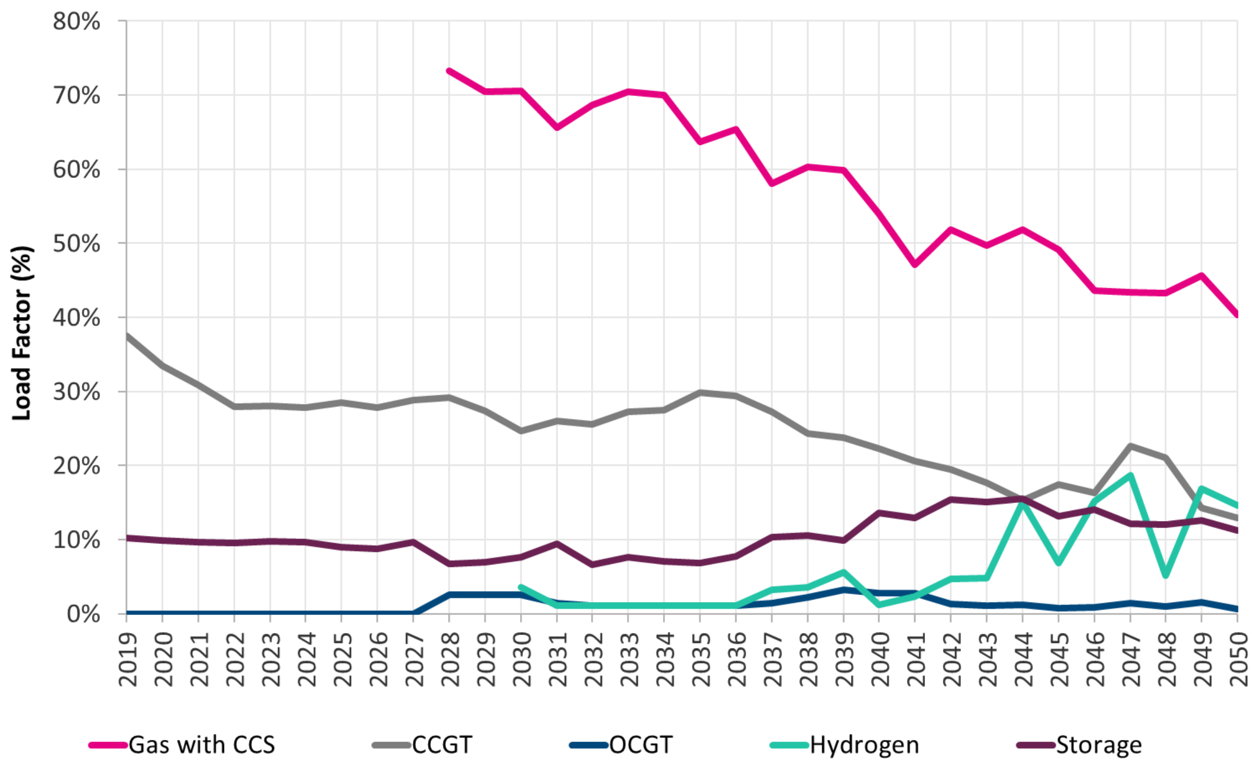
Dispatchable technology load factors

Gas with CCS load factors fall as renewable generation rises, existing CCGT load factors fall as the carbon emissions constraint binds, and Hydrogen turbines and Storage provide a peaking role

Description

- The RHS chart displays the annual load factors of the dispatchable technology types out to 2050
- The average load factor of Gas with CCS plant falls from around 70% in 2028 to around 40% in 2050 as the technology becomes displaced by more competitive renewable generation
- The average load factor of existing CCGT plant falls from around 40% in 2028 to around 15% in 2050 as the carbon emission constraint increasingly restricts its competitiveness, resulting in the reaming CCGT operating on a peaking basis
- Hydrogen plant and battery storage provide a peaking role throughout the horizon with average load factors remaining under 20%

Technology Load Factors, Base Case Scenario



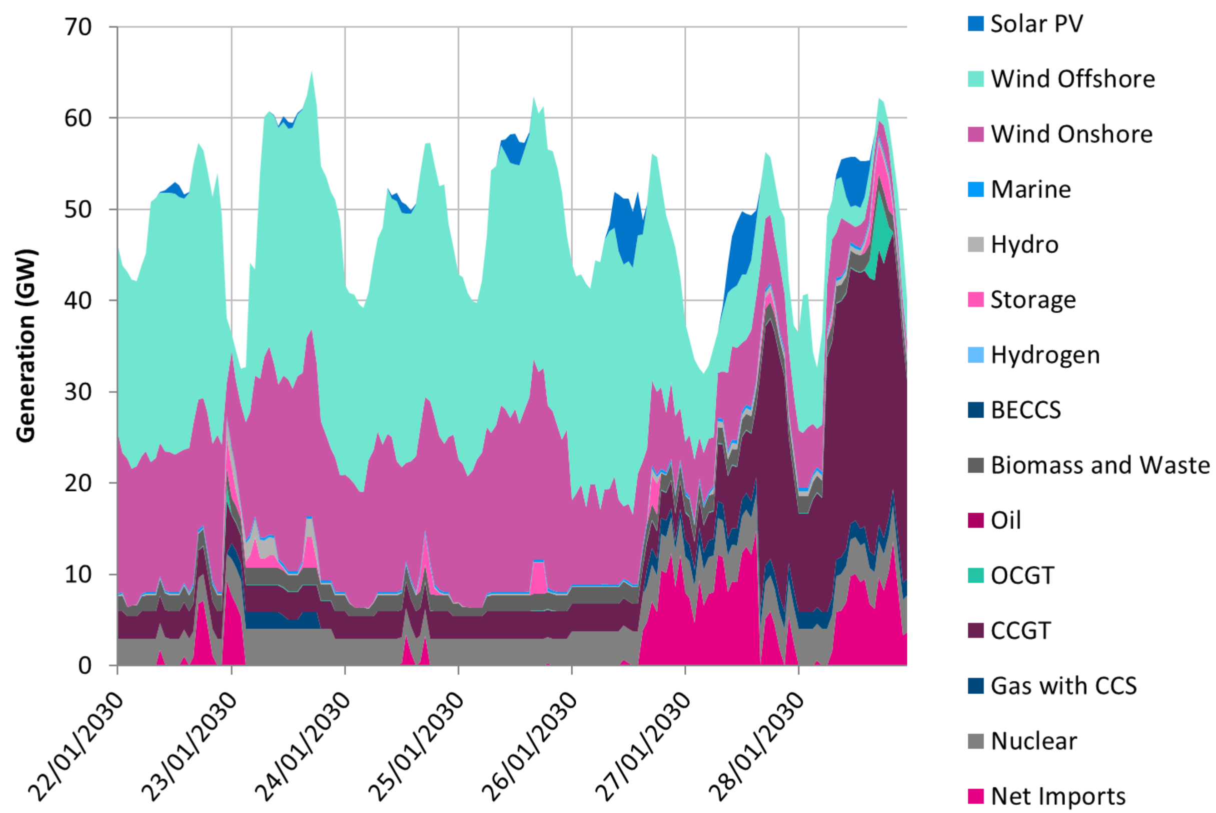
Sample dispatch week

In 2030 flexibility is predominantly provided by existing CCGTs with interconnection imports helping to meet demand during peak hours

Description

- In 2030, during periods of low renewable generation, interconnectors and the existing CCGT fleet are able to provide the day to day flexibility required to satisfy demand
- The existing nuclear fleet provides baseload power
- Both existing biomass plant and the small capacity of Gas with CCS are run at near baseload levels throughout the week
- Pumped and battery storage is dispatched to meet peak demand and at times of tight capacity margins, OCGT plant are dispatched

Sample Dispatch Week, Winter 2030, Base Case Scenario



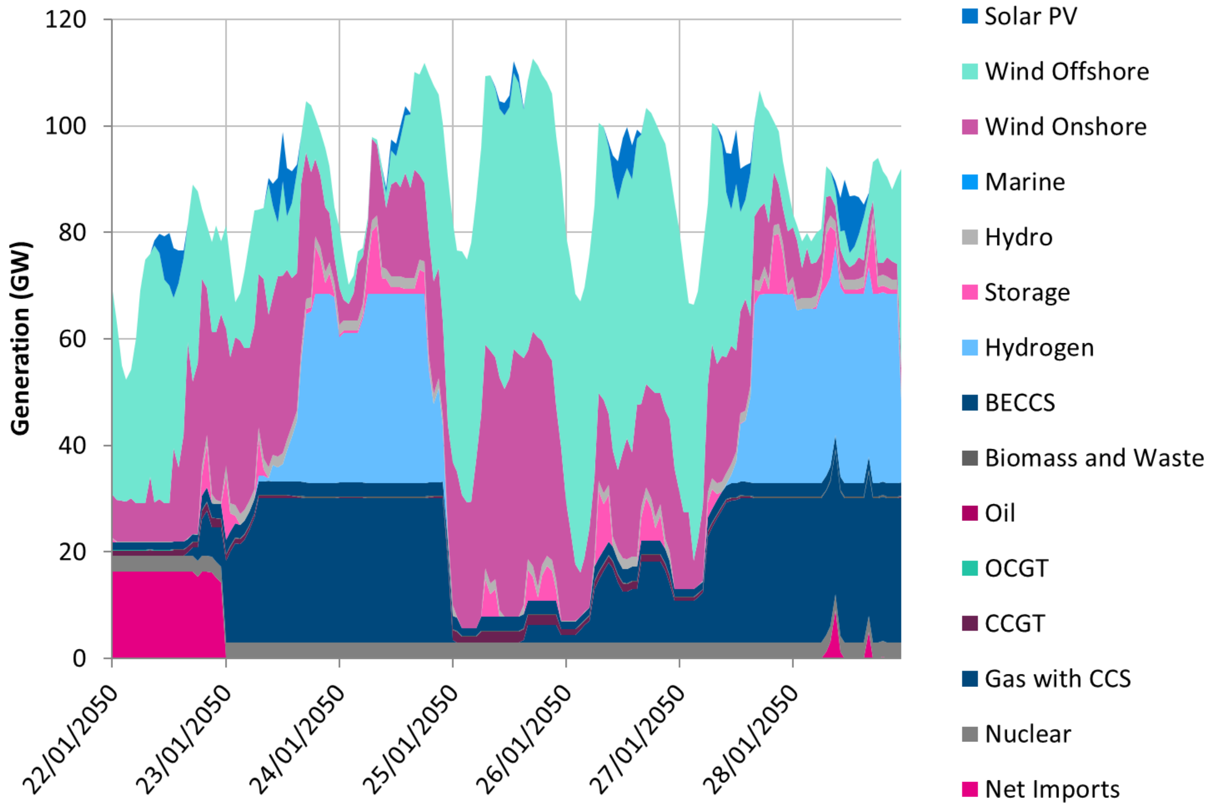
Sample dispatch week

In 2050 Gas with CCS and Interconnectors provide the majority of flexibility on the system, with hydrogen and battery storage contributing when renewable generation falls to low levels

Description

- In 2050, interconnectors and Gas with CCS provides the day to day flexibility required to satisfy demand
- At times renewable generation is able to satisfy all demand, with only must run constraints or inflexibility of online plant preventing it from doing so
- During periods of low renewable generation, the full gas with CCS fleet is dispatched, with hydrogen turbines being dispatched flexibly to meet shortfalls in demand
- Pumped and Battery storage plays a more significant role with significantly greater levels of generation during peak hours in comparison to 2030
- The operational reserve constraint implemented in the model is used to reflect the reserve that the system operator must withhold to cover any unexpected shortfalls in generation, particularly from wind/solar. The required volume is proportional to the demand level and renewable generation level, based on their average forecast errors. This ensures there is sufficient dispatchable capacity available to cover an unexpected period of low renewable output.

Sample Dispatch Week, Winter 2050, Base Case Scenario



Determining the system value of Gas with CCS

An opportunity-cost based metric, the adjusted LCOE, represents the LCOE of a technology adjusted by the amount which that technology impacts system costs when introduced

- The levelised cost of electricity (LCOE) is a common metric for comparing the cost of power generation technologies. It considers the full life-cycle costs of a new power generation project, and assuming a load factor over the project life-time, calculates the long-term average cost of power production.
- However, the **adjusted LCOE** also considers how system costs change when you introduce a technology into the power system, which replaces the marginal competing alternatives that would otherwise have been used
- For this analysis we are primarily concerned with how **underlying system fundamentals change the value of having Gas with CCS in and of itself** rather than providing a comparison across specific individual technologies.
- If the system value of Gas with CCS is material, robust to a sizeable volume of Gas with CCS capacity and robust to changes in the underlying system fundamentals then this provides strong evidence that Gas with CCS has a valuable and important role to play in the power system
- The adjusted LCOE is calculated as follows for a given scenario:
    1) Calculate the total system cost savings per year associated with a given installed capacity Gas with CCS by taking the difference between the total system costs in a power system with and without Gas with CCS runs (in £/year),
    2) Convert the cost savings (1) into a saving for the vintage of plant built in year Y over its operating life in the pathway (in £/MWh) and
    3) Take the difference between the LCOE of that vintage and the cost savings over the operating life (2) to calculate the **opportunity cost based metric: adjusted LCOE**
- To calculate the system cost savings associated with Gas with CCS in the power system we consider the counterfactual case with no Gas with CCS availability for power generation. In this counterfactual scenario all assumptions are held constant, but the LT optimisation of future generation capacity cannot build Gas with CCS capacity, and therefore must replace any capacity with the next most economical option.

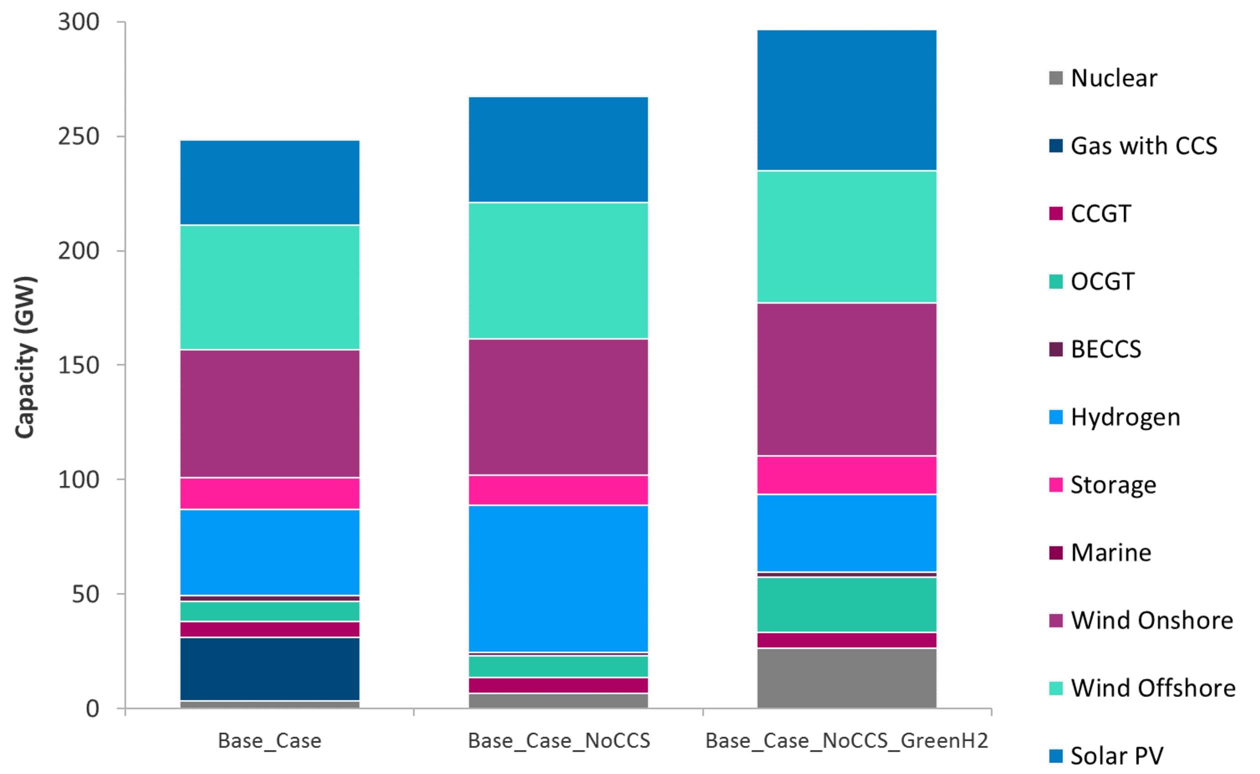
Determining system value of Gas with CCS

Defining a counterfactual scenario where Gas with CCS is not deployed can allow the opportunity cost of Gas with CCS to be quantified

Description

- The Base Case scenario model was re-run with Gas with CCS unavailable to be deployed in order to determine the optimal capacity mix in the absence of the technology
- When the Gas with CCS technology is removed, a significantly greater capacity of hydrogen plant and renewables are built to replace the firm capacity and mid-merit generation that Gas with CCS provides
- When both Gas with CCS and blue hydrogen are made unavailable then significant nuclear capacity is built out to provide baseload generation with green hydrogen turbines providing flexibility
- The electrolysis required to produce green hydrogen significantly increases the demand and thus a far greater total capacity is built in comparison to the Base Case scenario, with around 40 GW of further renewable capacity built by 2050

Capacity Mix in 2050, Base Case and Counterfactual Scenarios



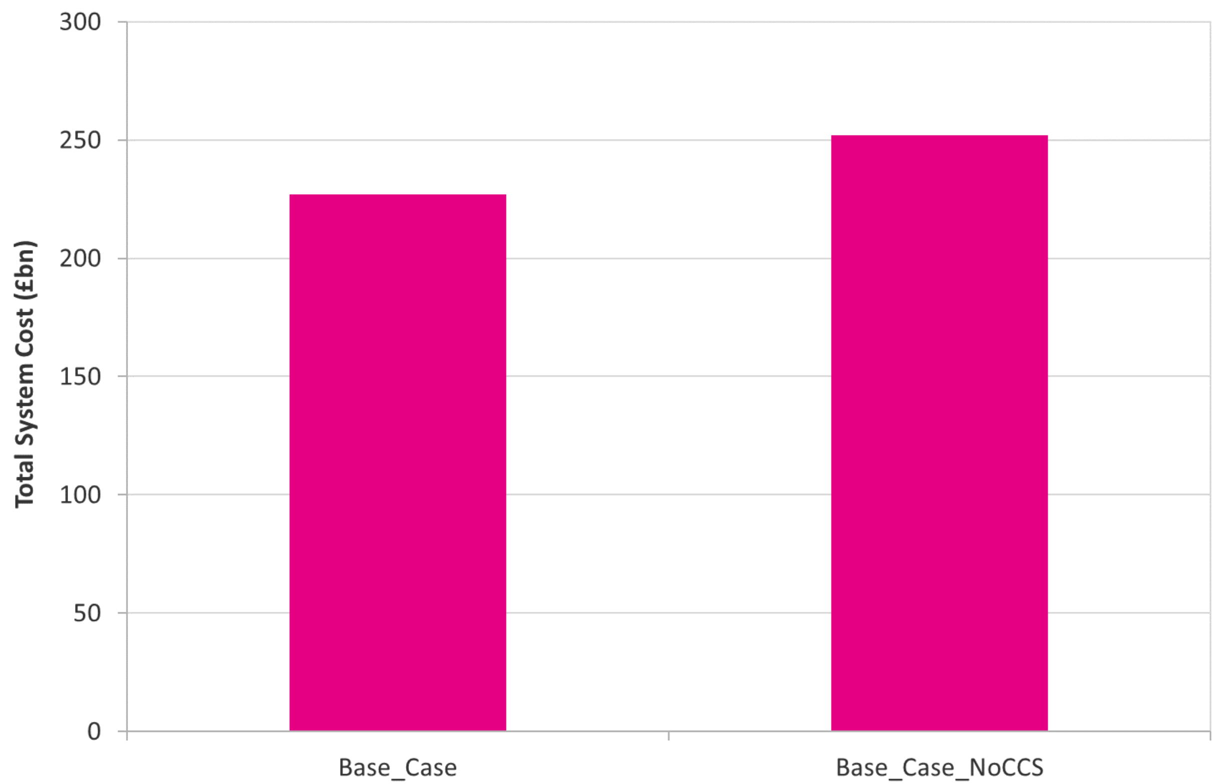
Determining system value of Gas with CCS

Defining a counterfactual scenario where Gas with CCS is not deployed can allow the opportunity cost of Gas with CCS to be quantified

Description

- Given that the LT expansion mode of PLEXOS seeks to minimise the total system cost, if a technology is present in a solution then re-running that scenario with the technology removed will incur an increase in total system costs
- The RHS chart displays the difference in total system costs and its components across the Base Case and it's counterfactual*
- The removal of Gas with CCS increases the total system cost predominantly due to the greater total generation cost, driven by higher fuel cost due to a greater hydrogen capacity

Total System Cost in 2050, Base Case and Counterfactual Scenarios



The cost of emissions has been excluded in the total system costs shown as the cost of meeting the emissions constraint is already reflected in the cost of building such a system and accounting for cost of emissions on top would mean double-counting

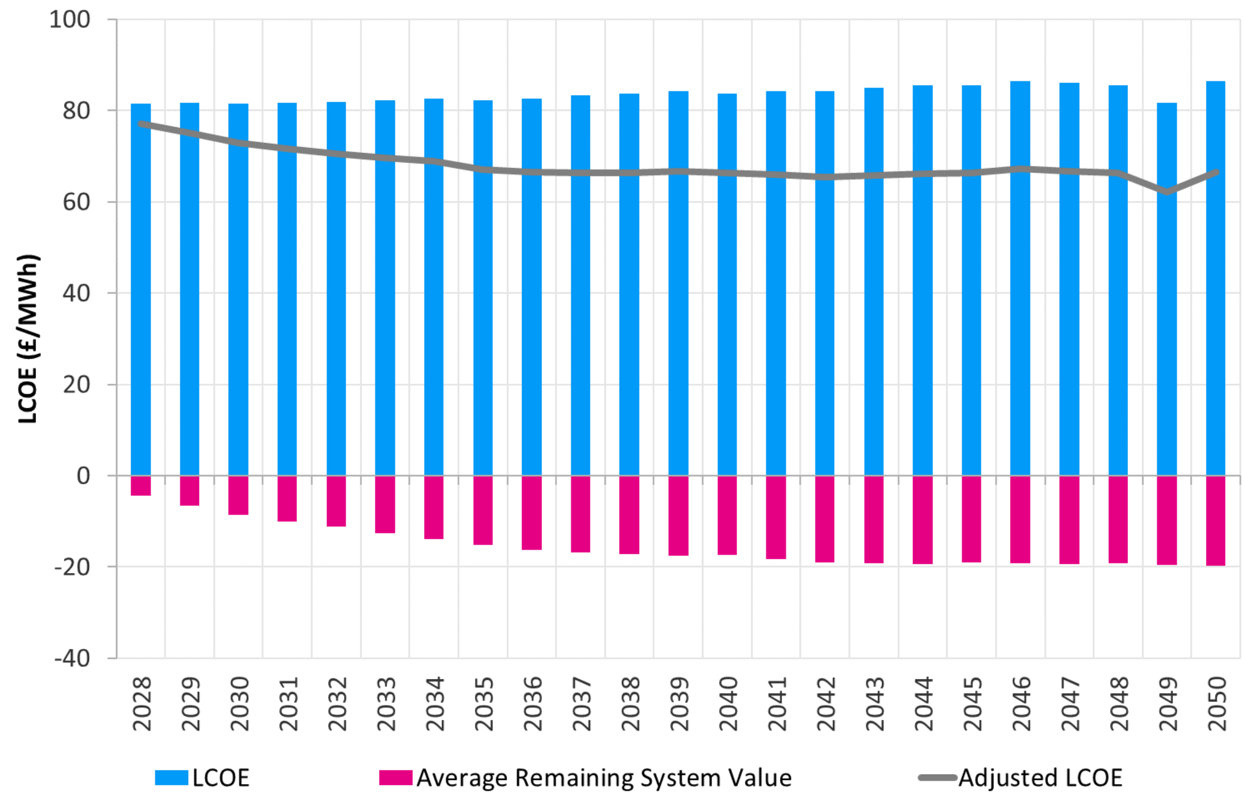
The Adjusted LCOE of Gas with CCS

Gas with CCS provides a long-term benefit to the system as it reduces the total system costs required to meet a net zero power system by 2050 and as a result reduces the costs to consumers

Description

- In the Base Case scenario the availability of **Gas with CCS reduces the total system cost by around £10bn** on a discounted basis over the pathway
- The calculated LCOE of Gas with CCS rises slightly from around £80/MWh to £86/MWh across the horizon. This occurs due to falling build costs being offset by falling load factors.
- The chart shows that for a new vintage of CCGT with CCS in 2035 the adjusted LCOE over all years of operation in the pathway from this point will be £65/MWh. Similarly the system value for this new plant when operating across the pathway from this point onwards equates to £15/MWh.
- By 2050 the system value of a new vintage of Gas with CCS increases to £20/MWh, with the adjusted LCOE remaining around £65/MWh
- These results assume that the NZT CCS project is operational from 2026, and the cost of this plant is accounted for in the calculations

Adjusted LCOE of Gas with CCS, Base Case (counterfactual: Base Case_No CCS)



Summary of key insights from base case

The results of the Base Case scenario, which represents a central view of the GB power system evolution, show an increasingly important role for Gas with CCS by 2050

- Gas with CCS capacity, in addition to the NZT plant assumed online from 2026, is constructed in 2030 with significant subsequent build occurring from 2033 onwards, culminating in 28 GW of installed Gas with CCS plant capacity by 2050
- This is alongside a significant build out of renewable capacity, mainly driven by onshore and offshore wind, which provides the cheapest source of low carbon generation
- However, Gas with CCS also provides the low-carbon flexibility required in the system given the variability of renewable generation
- Gas with CCS is favoured over other low carbon generation technologies such as nuclear, given that technology's relatively higher build costs and inflexible operation, and hydrogen turbines, which play more of a peaking role given the relatively low build costs but higher fuel costs
- The benefit that Gas with CCS provides to the power system, measured by the difference in total system costs between a powersystem with and without Gas with CCS available, is shown to increase over time. This reaches the equivalent of a £20 benefit for every MWh of Gas with CCS generation in the 2040s, in the case of the counterfactual where Gas with CCS is available for blue hydrogen production but not for power generation

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Key scenarios and sensitivity results

We have varied the fundamentals that will most impact the deployment of gas with CCS in order to understand the range and robustness of the value of the technology

- This section presents a comparison of the key results across all the modelled scenarios and sensitivities
- As discussed earlier in the document, the scenarios were defined according to the fundamentals that are most likely to impact the potential deployment of Gas with CCS plant on the system. These include:
  - **Gas Price**: The marginal cost of operating a gas powered plant is directly proportional to the price of gas. A lower gas price will therefore make gas plant, including Gas with CCS, more competitive in the market.
  - **Nuclear Favourability**: Given that increasing renewable capacity is expected under all scenarios, the main low carbon technology in competition with Gas with CCS is nuclear power. Lower nuclear capex will make nuclear more favourable and potentially displace Gas with CCS capacity.
  - **System Flexibility**: Increasing levels of demand flexibility will allow demand to shift to low price periods which coincide with high renewable generation. This will in turn reduce the need for dispatchable low carbon generation and thus the deployment of Gas with CCS.
- A high and low view of these three fundamentals was defined in order to construct 8 scenarios, which explore the full set ofhigh/low combinations of fundamental drivers
- A further 3 scenarios were constructed to understand the robustness of Gas with CCS deployment under more extreme assumptions
  - **Stress Test:** A combination of a 1-in-20 cold weather peak day demand, lower wind output and unavailability of interconnection. Results in an increasing the need for firm and dispatchable capacity on the system including Gas with CCS.
  - **Slower Renewable Cost Reduction:** Solar and wind technologies are less cost competitive as build cost fall at a slower rate in comparison to the Base Case scenario. This can impact the timing and scale of Gas with CCS deployment across the pathway.
  - **Super High Gas Price:** Considers a world with a very high gas price compared to current levels, negatively impacting the cost competitiveness of Gas with CCS.

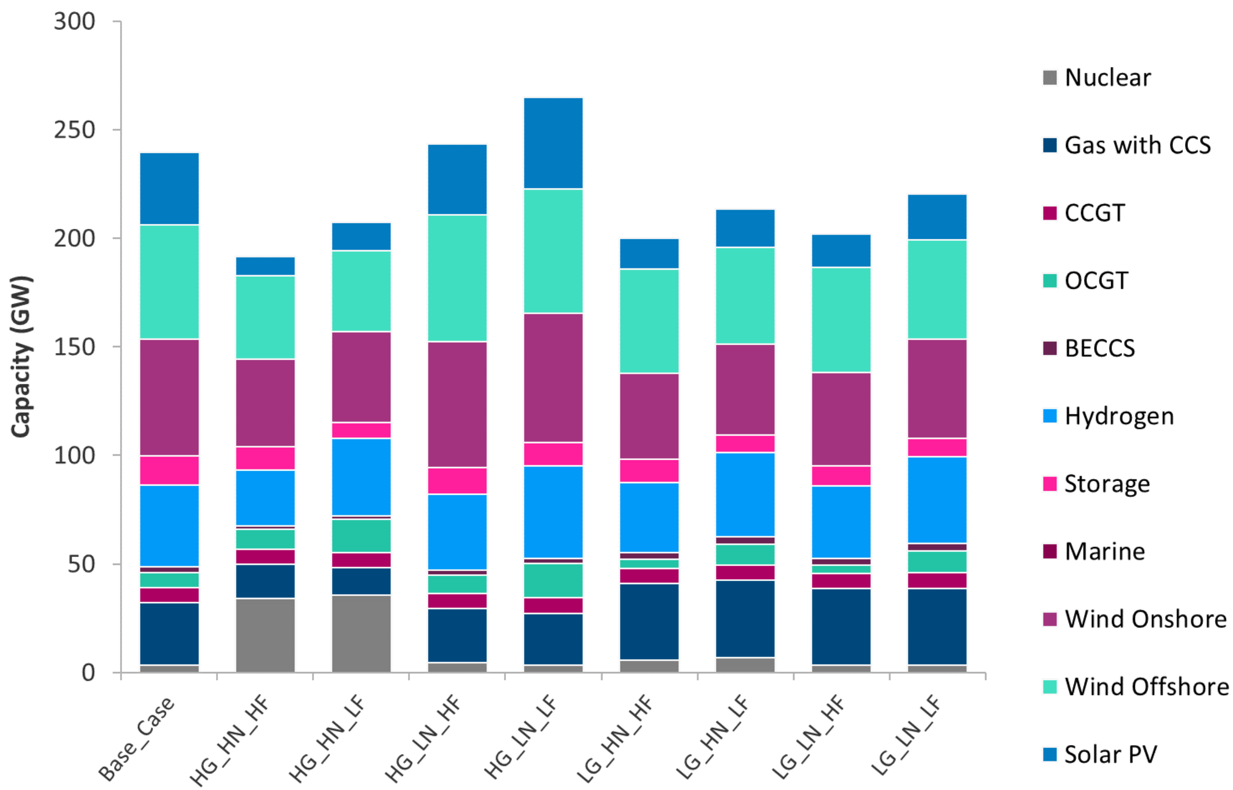
Comparison of capacity mix across scenarios

Significant renewable capacity in all scenarios, with a sizeable capacity of Gas with CCS in even the most unfavourable scenario for the technology, while new nuclear built in a small number of cases

Description

- The chart displays the capacity mix in 2050 under the Base Case scenario and the eight scenarios
- The LG_LN_LF scenario represents the most favourable combination of assumptions for Gas with CCS deployment. Lower gas prices, together with lower nuclear favourability, makes Gas with CCS a more competitive technology and it subsequently displaces new renewable build. As hydrogen prices are assumed to be linked to gas prices, and are thus lower in this scenario, hydrogen generation becomes more competitive thereby resulting in a greater capacity.
- The HG_HN_LF scenario represents the least favourable assumptions for Gas with CCS deployment. High nuclear favourability, together with higher gas prices, makes nuclear a more competitive technology and results in higher nuclear capacity, displacing about half of the Gas with CCS capacity in comparison to the Base Case. The significant volume of low carbon generation due to new nuclear capacity also displaces the need for new renewable generation, and the renewable capacity is consequently lower.

Capacity Mix in 2050



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

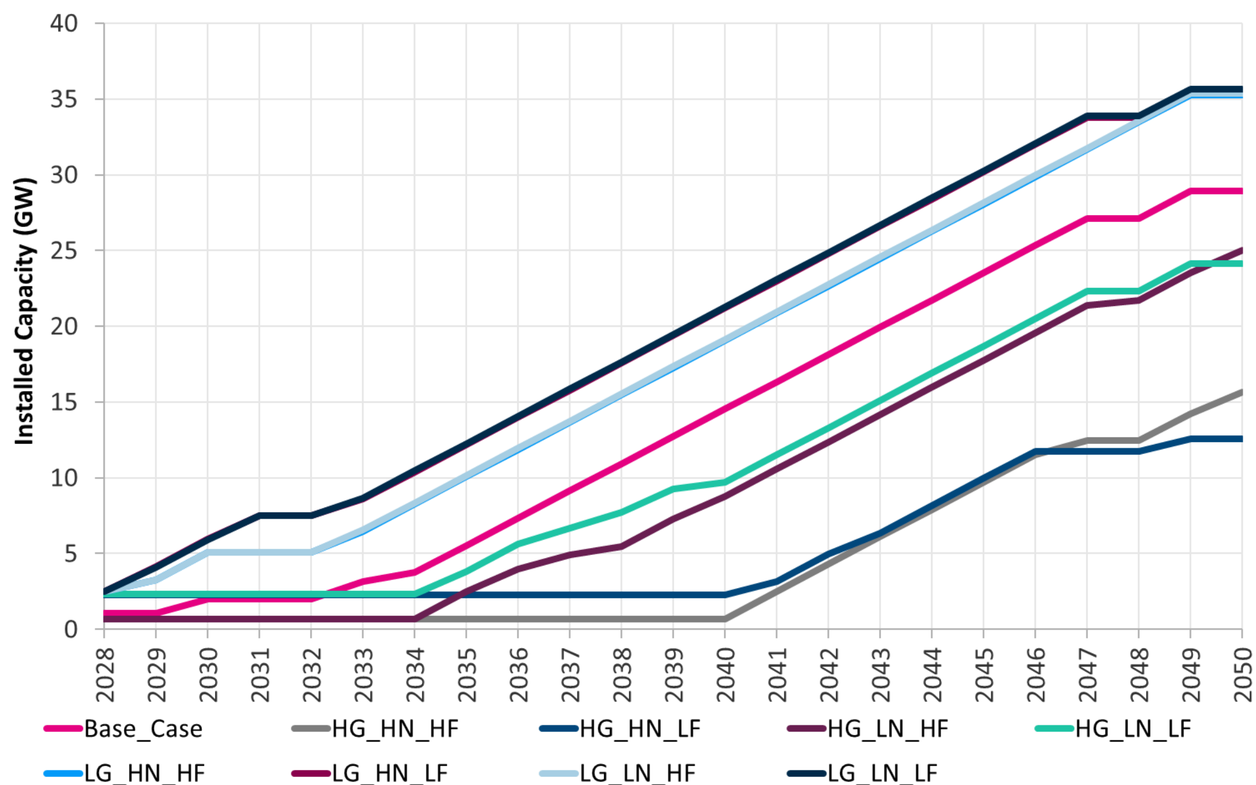
Evolution of Gas with CCS capacity across scenarios

Lower gas prices results in a greater deployment of Gas with CCS, while under a high gas price scenario a similar total capacity is deployed unless nuclear favourability is high

Description

- Under the Base Case scenario a total of 27GW of Gas with CCS capacity is installed by 2050, with the deployment of additional plant occurring from the early 2030's
- Under the LG_LN_LF scenario the combination of assumptions drives an earlier and greater overall build out of Gas with CCS capacity. This is in part due to lower gas prices making the technology more competitive in the market, with the capacity reaching 35GW by 2050.
- Another factor driving the earlier deployment is the retirement of existing gas and nuclear plant and a subsequent need for extra firm capacity. This is exacerbated under the low flexibility scenario due to lower de-rating factors for battery storage and a slower deployment of new interconnector capacity.
- Under the HG_HN_LF scenario the higher gas price and low nuclear CAPEX makes Gas with CCS less competitive in the market and results in 13GW of capacity by 2050. While a lower level of flexibility may be expected to result in a greater build out of Gas with CCS, a marginally greater build out of nuclear capacity and other forms of peaking capacity offsets this.

Capacity Mix in 2050



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

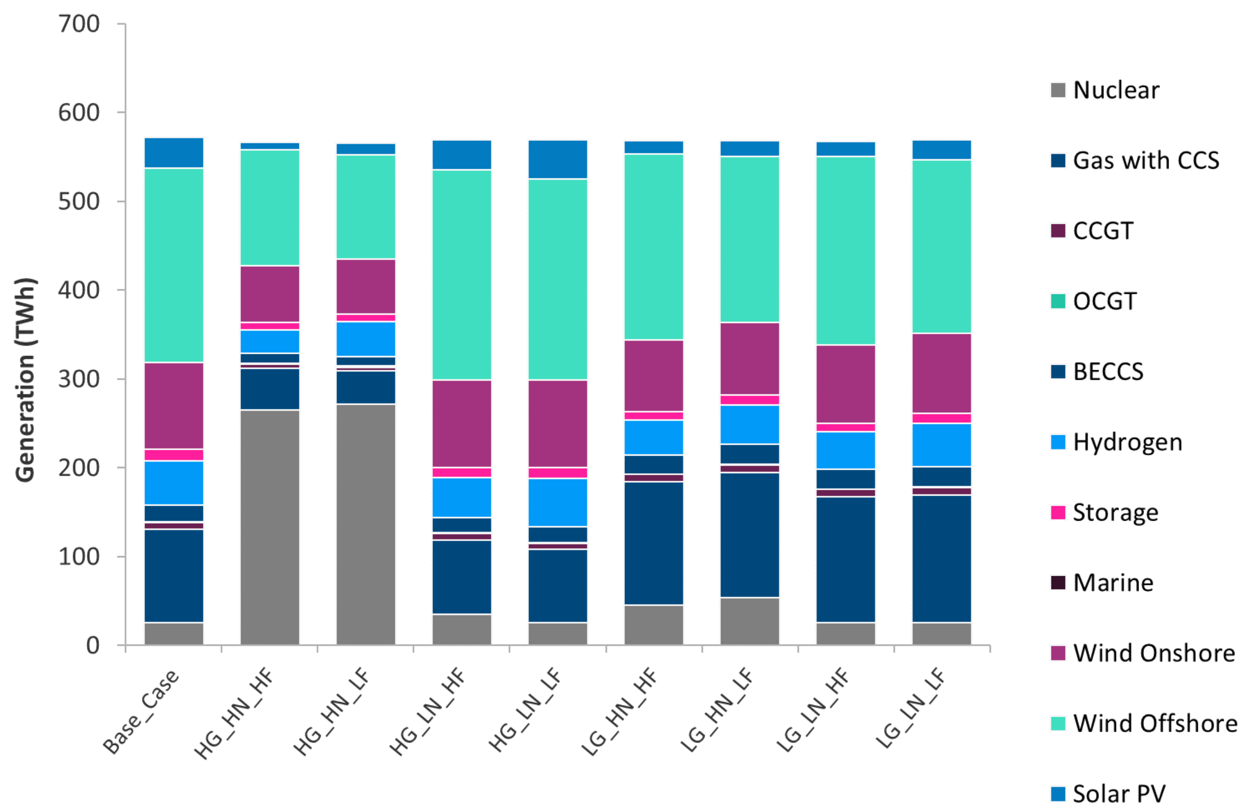
Comparison of generation mix across scenarios

Majority of the generation share is held by renewables other than when there is significant new build of nuclear, with the share of Gas with CCS varying with the gas price

Description

- The RHS chart displays the generation mix in 2050 across all scenarios
- Gas with CCS maintains a share of the generation volume of between 35TWh and 150TWh with the lowest levels coinciding with high gas prices and new nuclear capacity. The higher level is maintained across all scenarios with low gas prices.
- In the high gas and high nuclear favourability scenarios nuclear capacity displaces Gas with CCS generation which offsets the need for some BECCS generation, due to lower emission levels

Capacity Mix in 2050



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

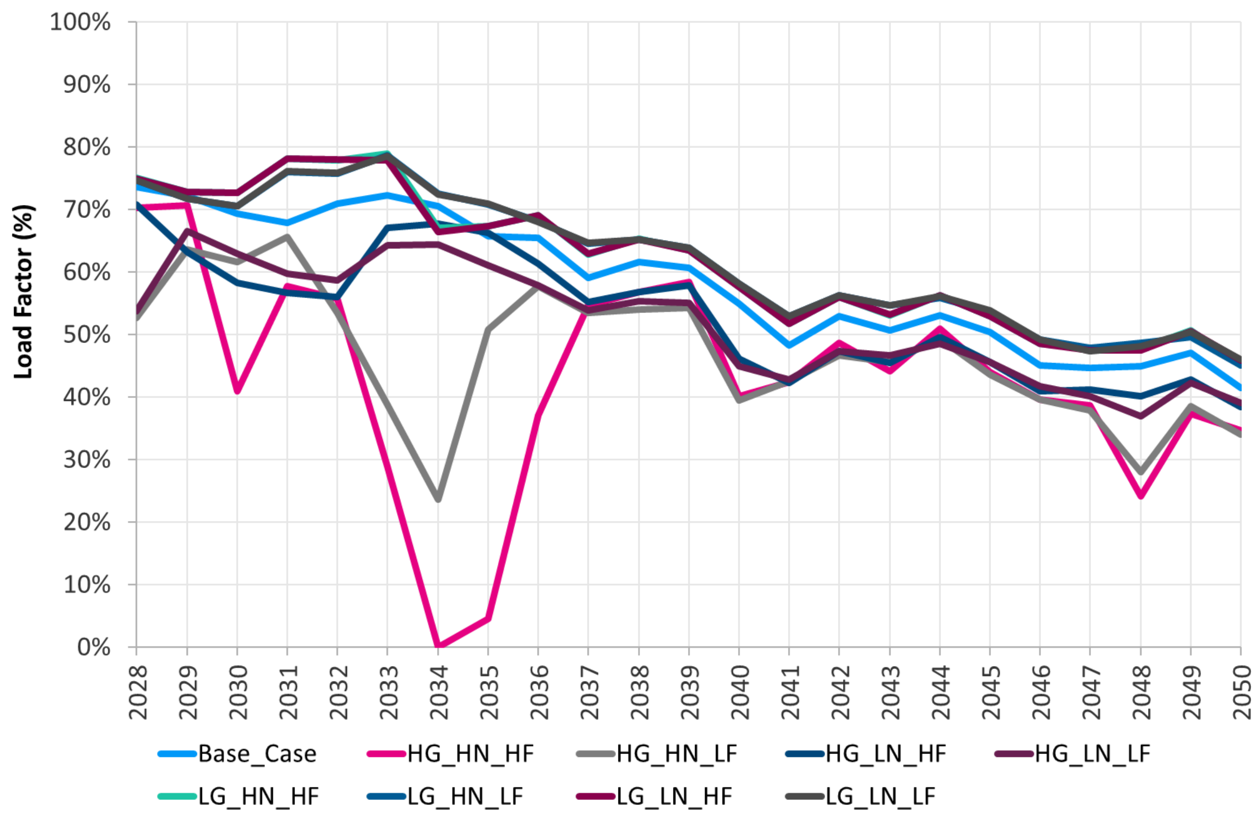
Evolution of Gas with CCS load factors across scenarios

Average load factors of Gas with CCS fall from around 70% to 40% across the horizon as the carbon emissions constraint tightens and renewable capacity increases

Description

- The RHS displays the average annual load factor of Gas with CCS plant under all scenarios
- The load factors of Gas with CCS in the majority of scenarios follow a similar trajectory to the Base Case scenario
- However, higher gas prices result in Gas with CCS capacity being built more for peaking operation and therefore with lower load factors, with the converse true under lower gas price scenarios
- In the HG_HN_HF and HG_HN_LF scenarios the load factors fall to significantly lower levels in comparison to other scenarios in 2034/35. This is a modelling artefact due to a surplus of low carbon generation on the system, which itself is a function of the carbon emissions constraint, build rate constraints and the lumpy build profile of large plant.

Load Factor of Gas with CCS plant



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

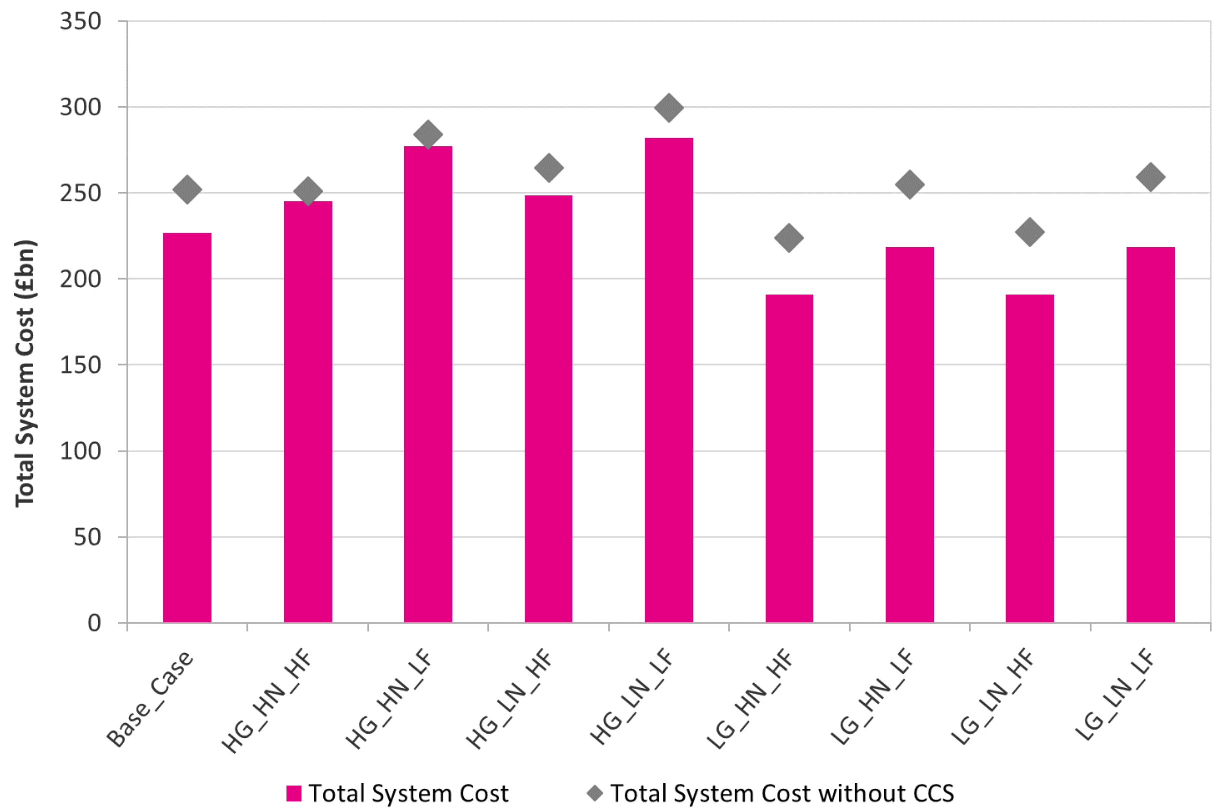
Total system cost across scenarios

Total system costs are sensitive to gas prices, with higher prices driving higher total costs, and to levels of flexibility, with lower flexibility resulting in greater total costs

Description

- The RHS chart compares the breakdown of the total system cost across all scenarios
- Higher gas prices make Gas with CCS less competitive on a marginal basis and result in higher total system costs in all high gas scenarios. When nuclear favourability is also high, new nuclear capacity is built resulting in higher build and fixed costs due to the significantly higher nuclear capex. When nuclear favourability is also low Gas with CCS remains more competitive than nuclear but with higher running costs results in a higher generation cost in comparison to the Base Case.
- Conversely lower gas prices make Gas with CCS more competitive on a marginal basis and result in a lower total system cost in all low gas price scenarios. This is mainly due to the reduction in generation costs of Gas with CCS plant.
- In the counterfactual scenarios with no Gas with CCS the total system costs increase as the LT optimisation must build the next most economic technology. The costs are therefore greater in those scenarios where a greater capacity of Gas with CCS must be replaced.

Undiscounted Total System Cost from 2028 to 2050



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

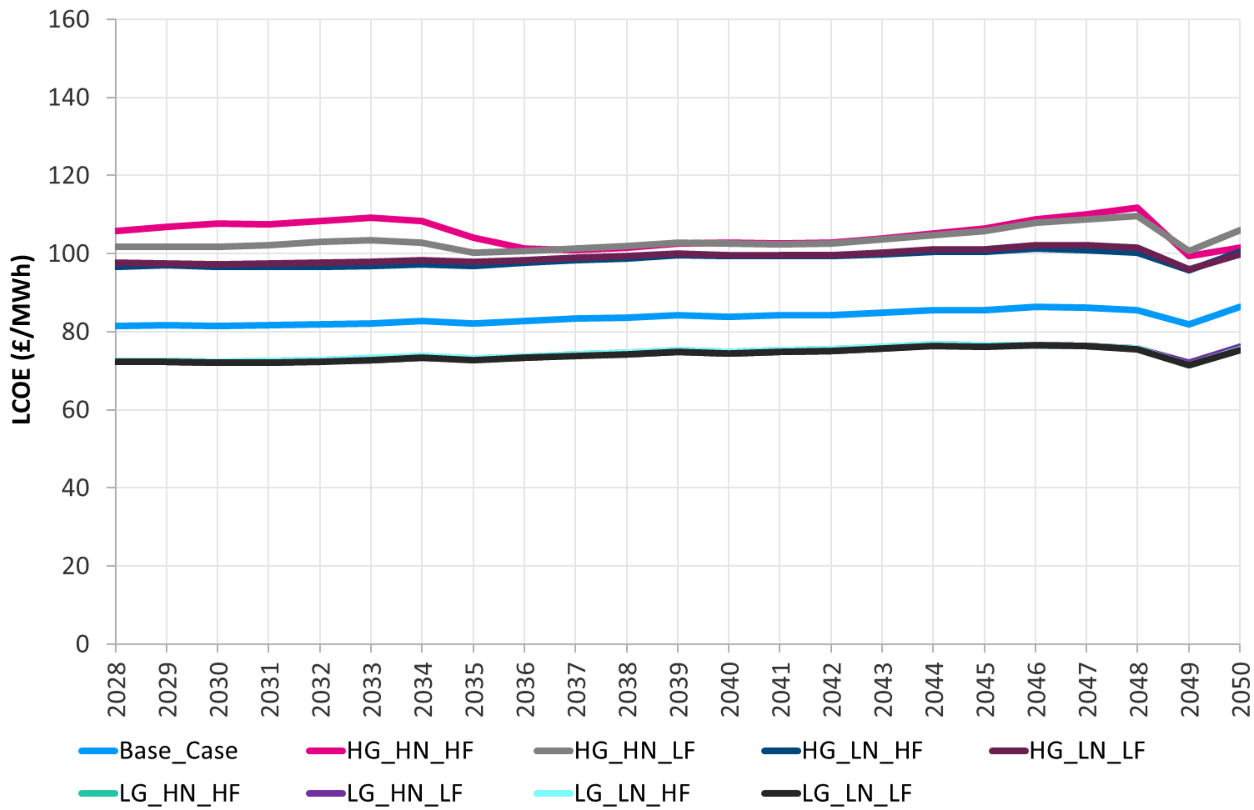
LCOE of Gas with CCS

The LCOE of Gas with CCS is strongly driven by gas prices, with a higher gas price increasing the marginal cost of the technology and thus the LCOE

Description

- The RHS chart displays the evolution of the LCOE of Gas with CCS plant across all scenarios
- As the marginal cost of dispatching the plant is proportional to the gas price an increasing gas price results in a higher LCOE
- The variations in the LCOE across scenarios with the same gas price assumption are driven by variations in the load factor of Gas with CCS plant in those scenarios
- This is most evident in the high gas price scenarios which have the highest variability in Gas with CCS load factors across the horizon
- There is a general trend of an increasing LCOE in all scenarios which is a result of falling load factors. This is due to increases in renewable capacity on the system which displaces generation from Gas with CCS.

LCOE of Gas with CCS



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

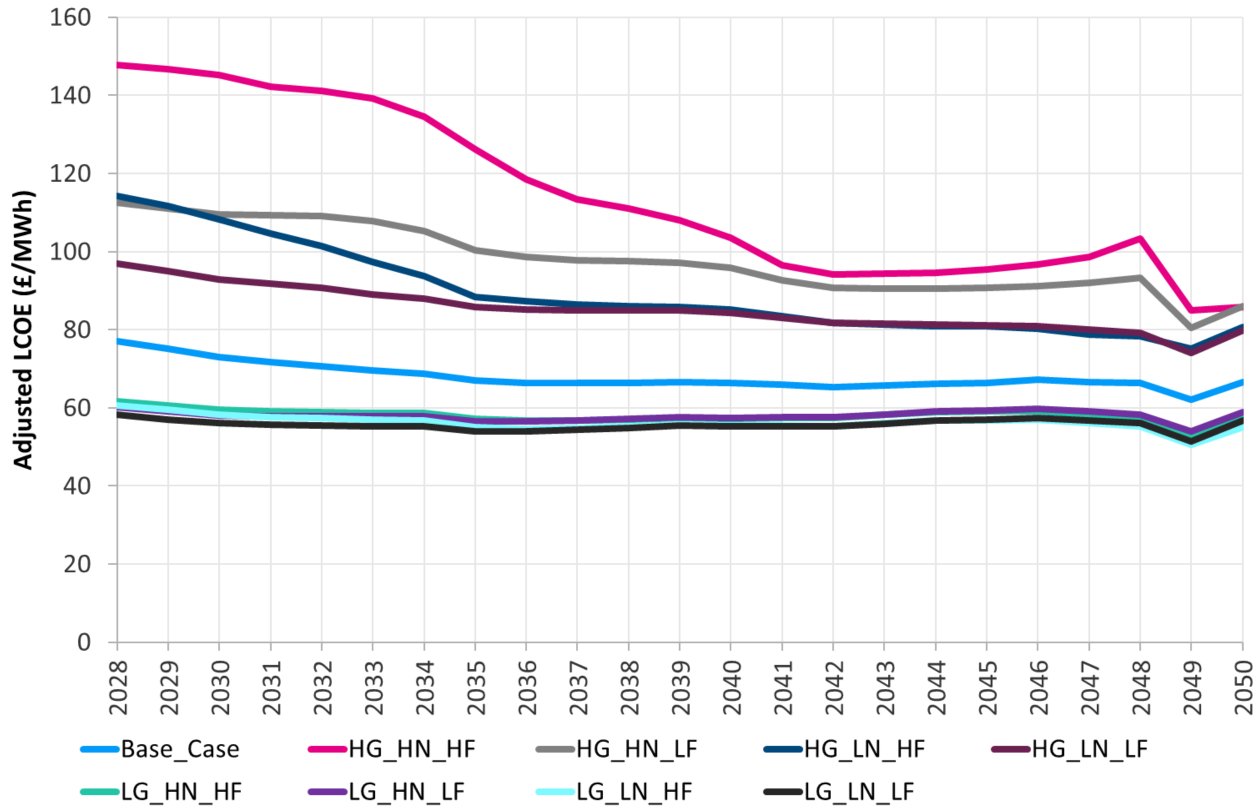
Adjusted LCOE of Gas with CCS

Adjusted LCOEs fall to below £90/MWh in all scenarios by 2050, which represents Gas with CCS providing a benefit to the system in all cases

Description

- The RHS chart displays the evolution of the adjusted LCOE of Gas with CCS plant across all scenarios
- In the early part of the horizon the adjusted LCOE falls within a wide range of values. This is strongly driven by gas prices, which increase the dispatch costs of gas plant, and the decision to include the NZT plant in the capacity mix from the beginning of the horizon.
- In the high gas and high flexibility scenarios the optimal build of Gas with CCS plant occurs later in the horizon in comparison to the Base Case. Therefore under these scenarios the NZT plant presents a dis-benefit to the system in the first part of the horizon, before providing a system benefit in the 2040s.
- By 2050 the range of adjusted LCOE is greatly narrowed to between £60/MWh to £85/MWh as the system benefit of Gas with CCS increases in all scenarios.

Adjusted LCOE of Gas with CCS



Fundamental	High	Low
Gas Price	HG	LG
Nuclear Favourability	HN	LN
Level of Flexibility	HF	LF

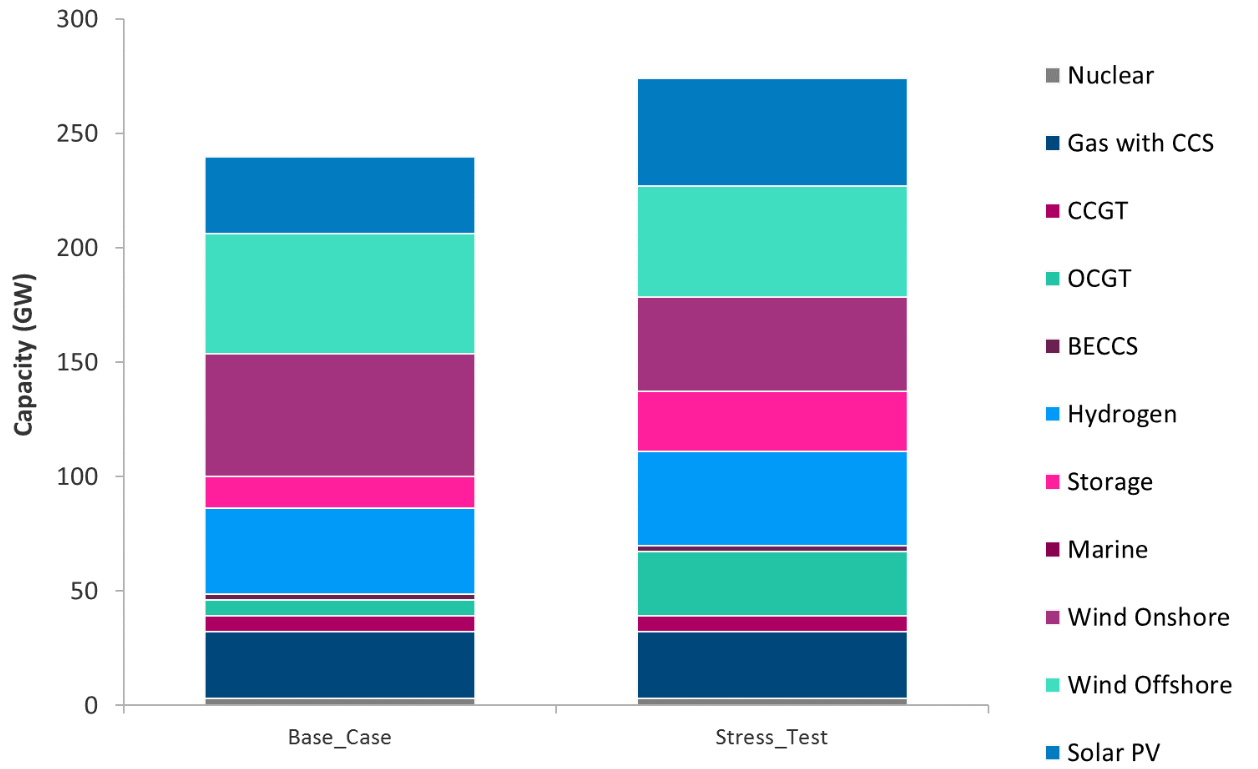
Spot Sensitivity – Stress Test

Under stress conditions a significant volume of extra reserve capacity is constructed with increased solar capacity replacing reduced wind capacity

Description

- The RHS chart compares the capacity mix in 2050 under the Base Case scenario and the Stress Test sensitivity
- Under the stress test the contribution of interconnection to both GB imports/exports and to peak demand is removed, the annual peak demand set to a 1-in-20 year cold-weather level, and the reserve requirement is tightened to cover an extended low wind period across a week, which from historic data implies wind outturn of 1/4 of the output seen across a typical winter week
- This requires the system to build greater capacity in order to meet a higher peak demand and to hold higher operational reserve volumes to account for greater renewable output uncertainty
- However capacity of Gas with CCS remains at a similar level as the Base Case, with the majority of reserve being contributed by OCGT plant. This is due to the low number of hours that the OCGT plant are expected to run in order to meet peak demand, and low plant CAPEX figures in comparison to Gas with CCS.

Comparison of Base Case and Stress Test Capacity Mix in 2050



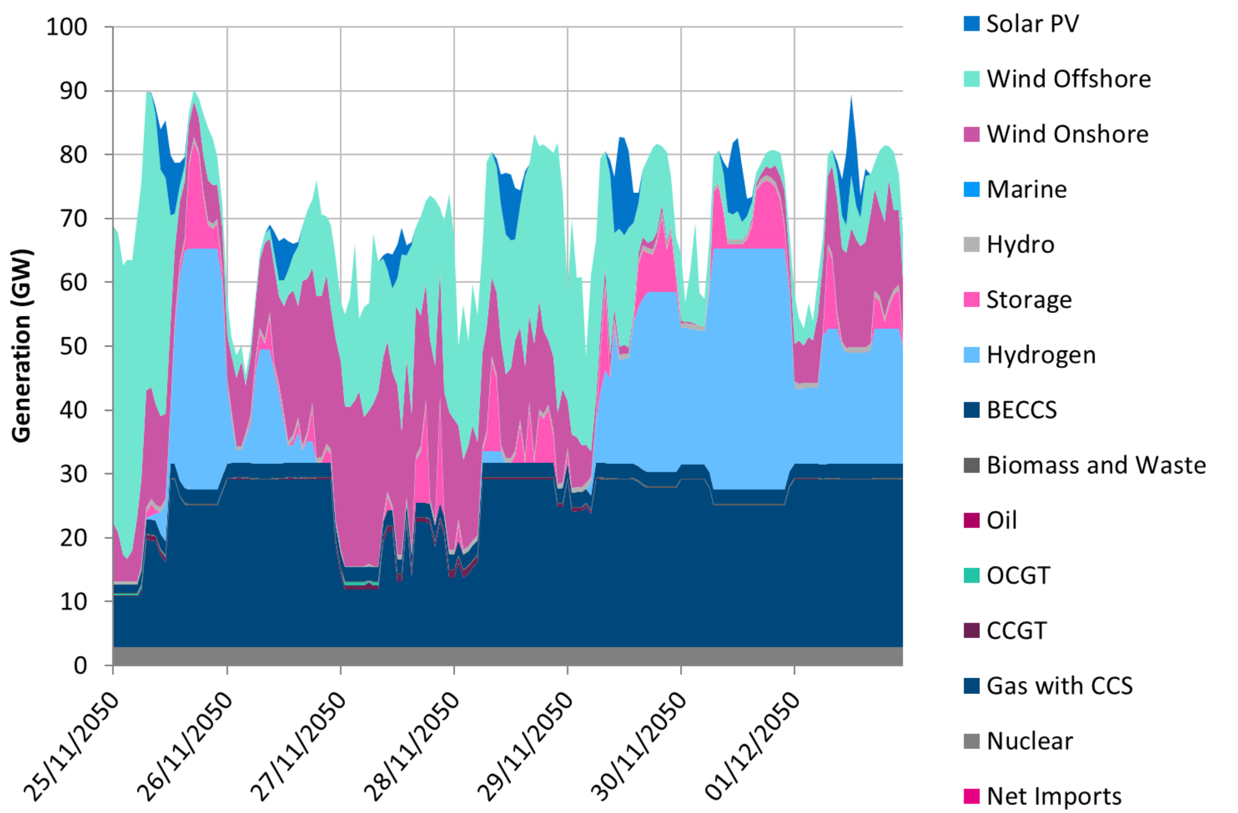
Spot Sensitivity – Stress Test

Under stress conditions the flexibility of Gas with CCS is used to overcome variable renewable production, replacing the role of interconnection in the system

Description

- The RHS chart illustrates the hourly dispatch profile of the GB capacity mix over a week in Autumn 2050 under the Stress Test sensitivity
- In comparison to the Base Case scenario, Gas with CCS provides the day to day flexibility required to satisfy demand rather than a mix of interconnection and Gas with CCS
- At times renewable generation is able to satisfy all demand, with only must run constraints or inflexibility of online plant preventing it from doing so
- During periods of low renewable generation, the full gas with CCS fleet is dispatched, with hydrogen turbines being dispatched flexibly to meet shortfalls in demand

Sample Dispatch Week, Autumn 2050, Stress Test Scenario



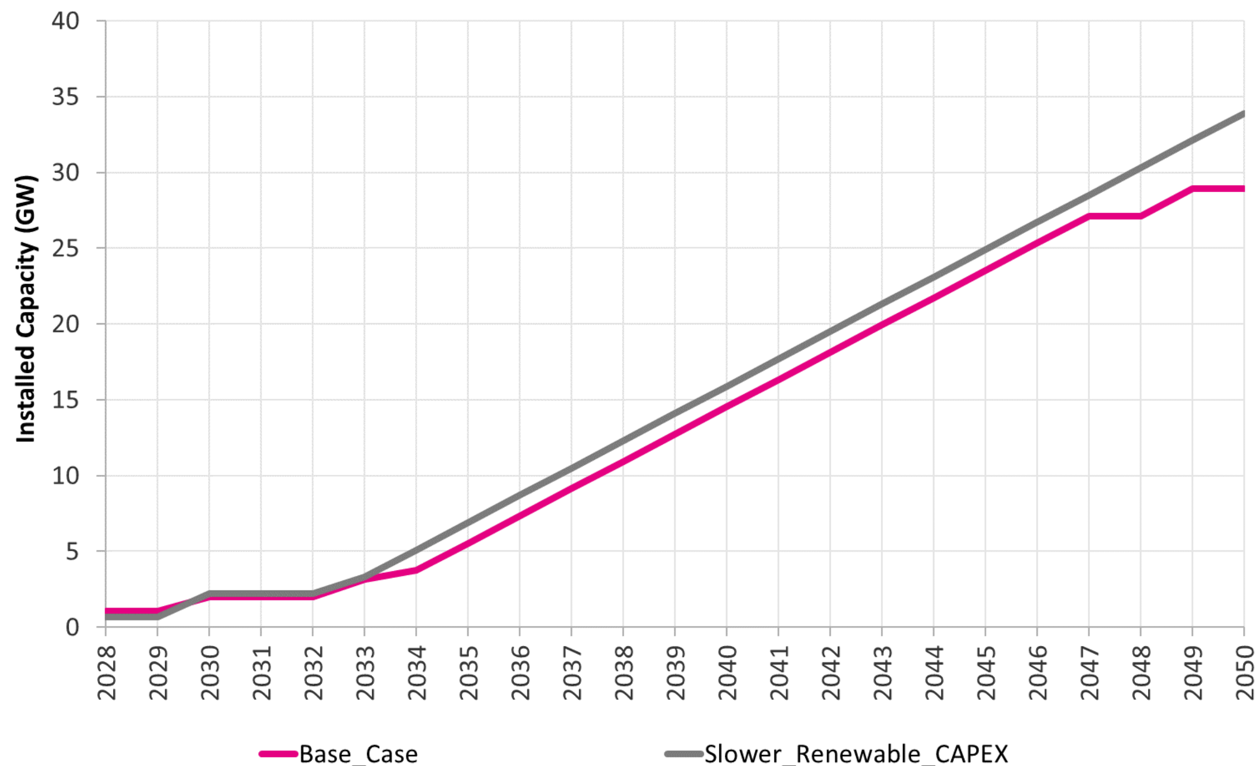
Spot Sensitivity – Slower Renewable Build Cost Fall

A slower reduction in renewable build costs bring forward a modest amount of Gas with CCS new build and results in greater capacity in 2050

Description

- The RHS chart compares the deployment of Gas with CCS capacity under the Base Case scenario and the Slower Renewable Build Cost Fall sensitivity
- The effect of a higher renewable build cost is a greater and earlier deployment of Gas with CCS capacity
- Given the considerably lower build cost of renewables in the near term in comparison to Gas with CCS the slower reduction has a limited impact on Gas with CCS deployment

Comparison of Base Case and Slow Renewable scenario Gas with CCS Deployment



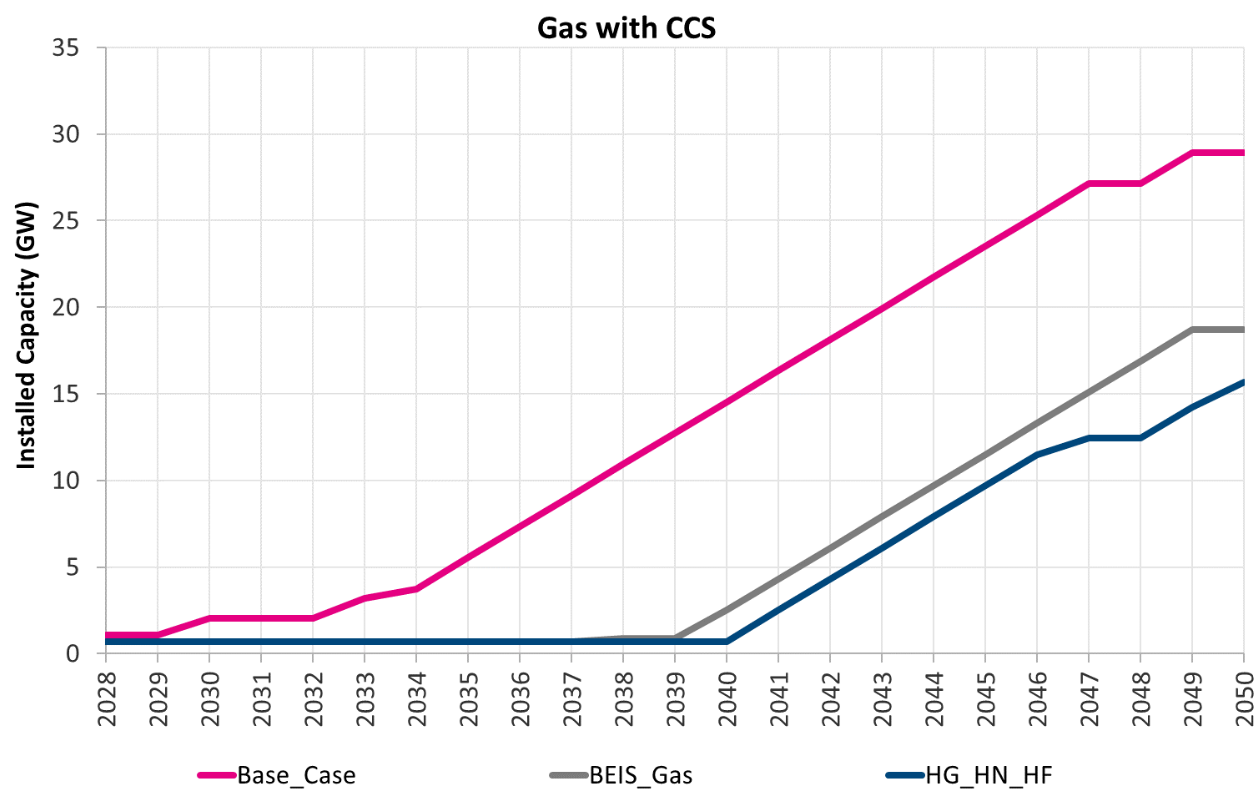
Spot Sensitivity – Super High Gas Price

Increasing the gas price above the high gas price sensitivity assumption has a limited impact on the deployment of Gas with CCS

Description

- The RHS chart compares the deployment of Gas with CCS under the Base Case and HG_HN_HF scenarios with the Super High Gas Price sensitivity
- Under the Super High Gas Price the long term gas price assumption is 79p/therm in comparison to 64p/therm under the High Gas price sensitivity and 47p/therm under the Base Case scenario
- A higher gas prices reduces and delays the deployment of Gas with CCS plant, though the deployment remains similar to the HG_HN_LF scenario which presented the worst case conditions for Gas with CCS of the eight main sensitivities
- Under the Super High Gas Price sensitivity the nuclear build cost assumption remains the same as under the Base Case scenario and thus nuclear remains uncompetitive, with only 4GW of capacity constructed by 2050
- There is a significant increase in the renewable capacity on the system by 2050 as renewable technologies become more economic in comparison to Gas with CCS, hydrogen and nuclear

Comparison of Base Case and Super High Gas Price scenario Gas with CCS Deployment



Summary of key insights (1/2)

Varying the fundamentals that will most impact the deployment of Gas with CCS shows that a significant capacity of Gas with CCS would provide robust system value

- This section presented a comparison of the key results from scenarios which explored a high and low view of gas prices, nuclear favourability and system flexibility and the subsequent impact on the deployment and system benefit of Gas with CCS
- A further 3 spot sensitives were constructed to understand the robustness of Gas with CCS deployment under more extreme assumptions
- It can be inferred from the results that the relative importance of the fundamentals is as follows:
  - **Gas Price:** *The construction of Gas with CCS capacity is sensitive to increases in gas prices though the technology continues to provide a long-term system benefit even in high gas price scenarios*
    - In the low gas price scenarios the gas price is reduced by around 23% in the long term in comparison to the Base Case scenario. This corresponds to a relative increase in Gas with CCS capacity by 2050 of around 23%.
    - In the high gas price scenarios the long term gas price is increased by 35% in comparison to the Base Case scenario. In the scenarios which have a low level of nuclear favourability, this results in a relative decrease in Gas with CCS capacity in 2050 of around 17%, while those scenarios with a high level of nuclear favourability the relative decrease is around 50%.
    - In the Super High Gas Price scenario increasing the long term gas price assumption by 68% of the Base Case scenario reduced the capacity of Gas with CCS installed by 2050 by 35%. Given the relative changes in capacity to gas prices the benefit of Gas with CCS to the system is fairly robust to increasing gas prices.
  - **Nuclear Favourability:** *Gas with CCS capacity is displaced when high nuclear favourability coincides with high gas prices*
    - In scenarios when high gas prices coincide with low nuclear favourability, there is only a marginal impact on Gas with CCS capacity, and little to no new nuclear capacity is seen
    - In scenarios where high gas prices coincide with high nuclear favourability there is a significant reduction in Gas with CCS capacity, with 16GW less capacity built by 2050 in the most extreme case, and a significant increase in new nuclear capacity, with over 30GW added to the system. However even in these scenarios Gas with CCS still provides a significant benefit to the system, with at least 13GW of Gas with CCS capacity online by 2050.

Summary of key insights (2/2)

Varying the fundamentals that will most impact the deployment of Gas with CCS shows that a significant capacity of Gas with CCS would provide robust system value

- It can be inferred from the results that the relative importance of the fundamentals is as follows:
  - **Levels of Flexibility:** *Varying the level of flexibility has a limited impact on the capacity of Gas with CCS by 2050 though lower levels of flexibility brings forward the deployment of Gas with CCS capacity*
    - In the majority of scenarios, when varying the level of flexibility on the system, there was a limited impact on the capacity of Gas with CCS by 2050. Only under the high gas and high nuclear favourability scenario did varying the level of flexibility have a noticeable impact on the total Gas with CCS capacity, with a 3GW reduction in capacity in the low flexibility scenario. This reduction was due to the combination of baseload nuclear and additional peaking capacity being the more optimal capacity mix to satisfy demand in 2050
    - However the year of first new build of Gas with CCS capacity, additional to the NZT plant, is highly influenced by the level of flexibility on the system. In all scenarios with low levels of flexibility the first build occurs in 2028 which is as much as 13 years earlier than the corresponding high level of flexibility scenario.
    - The Gas with CCS capacity is deployed earlier in these scenarios due to the delay in additional interconnector capacity which results in a requirement for additional firm capacity and flexibility on the system in the late 2020s/early 2030s
- In addition to the impact of the fundamental drivers on gas with CCS, a range of general insights into the construction and operation of a net-zero GB power system can be garnered from these results:
  - Growth in renewable capacity is likely to remain the greatest across all technology types, with wind capacity maintaining the greatest share of renewable capacity and generation
  - Gas with CCS provides a benefit in the long term to the system under all scenarios and sensitivities, evidenced by the capacity of Gas with CCS deployed on the system ranging from between 13GW to 36GW by 2050. However, in scenarios with high gas prices and high flexibility the technology can provide a dis-benefit to the system in the short term, which is why additional Gas with CCS capacity is delayed to post 2035.
  - Gas with CCS is operated as a mid-merit technology in all sensitivities, with load factors broadly remaining between 30% to 80%, with a decreasing load factor over time being driven by an increasing share of renewable capacity
  - A significant capacity of hydrogen plant is deployed to provide peaking capability in all scenarios and sensitivities given the lower relative build costs, but higher fuel costs in comparison to gas with CCS
  - A slower reduction in the build cost of renewables has a limited impact on Gas with CCS deployment, as renewables remain the source of the lowest cost low carbon generation, and the main drivers behind Gas with CCS deployment are the dispatchability and flexibility of the technology and its contribution to firm capacity requirements

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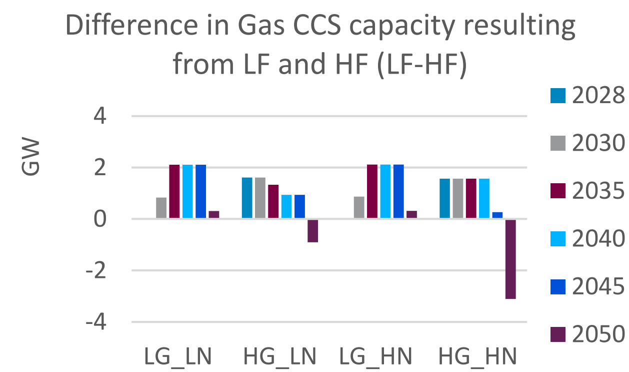
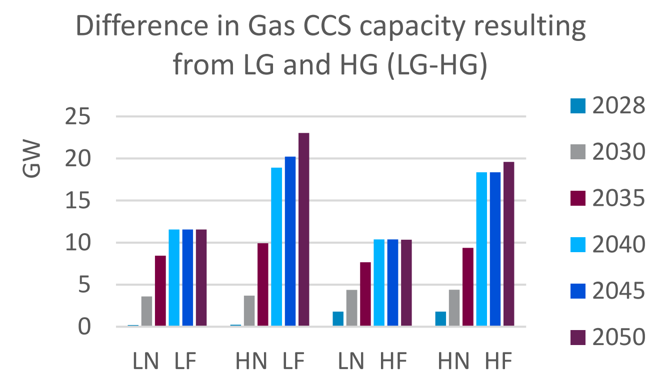
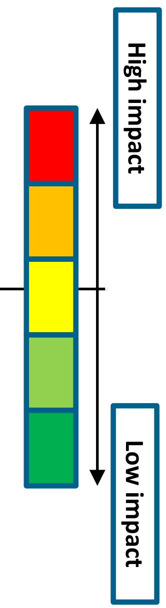
Conclusions (1)

Gas prices, nuclear costs and levels of system flexibility present the highest potential impact on the pace and scale of deployment of Gas with CCS in power based on the results of this analysis

- Based on the key insights from the core scenarios and spot sensitivities presented so far, **key factors** that are expected to impact **the pace and scale of deployment of Gas with CCS** are summarised below with the **materiality of their impact:**

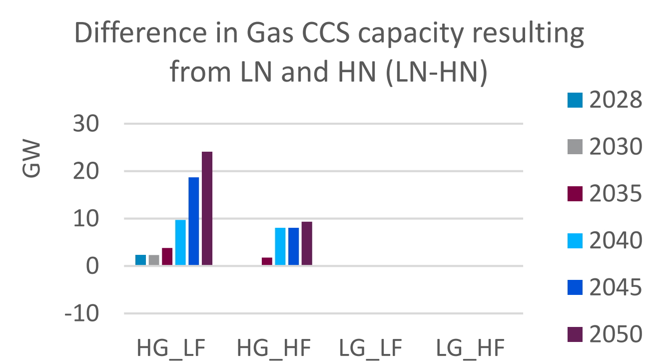
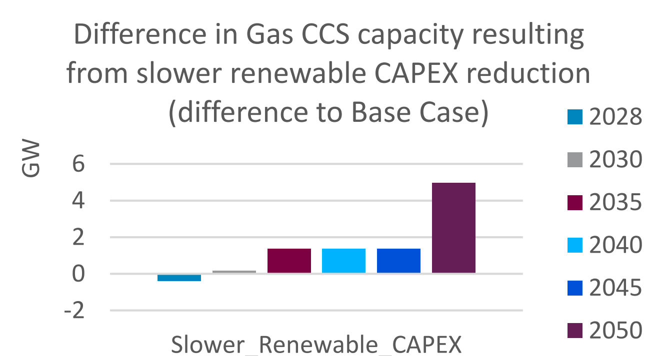
Key factors	Description	Impact on pace and scale of development of Gas with CCS
Evolution and levels of flexibility on the system	• Reduced interconnection and storage capacity and their lower contribution to SoS as a result, brings some 1-2 GW CCGT CCS capacity earlier as can be seen on the right, resulting in a higher pace of deployment • The scale of deployment by 2050 is similar between a high and low flexibility world • The overall impact is not material in terms of long-term capacity but has a significant impact on the year of the first build of additional capacity	
Evolution and level of gas prices in the medium to longer term	• Future evolution and level of gas prices have a material impact in all cases • In scenarios where nuclear costs are projected to decrease significantly in future (HN), gas prices have the greatest impact due to increased competition between nuclear and Gas with CCS capacity • In scenarios with nuclear costs remaining at similar levels into the future (LN), gas prices still have a material impact with higher gas prices making renewables relatively more competitive in comparison to Gas with CCS	

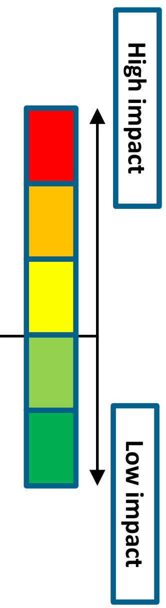


Conclusions (2)

Gas prices, nuclear costs and levels of system flexibility present the highest potential impact on the pace and scale of deployment of Gas with CCS in power based on the results of this analysis

- Based on the key insights from the core scenarios and spot sensitivities presented so far, **key factors** that are expected to impact **the pace and scale of deployment of Gas with CCS** are summarised below with the **materiality of their impact:**

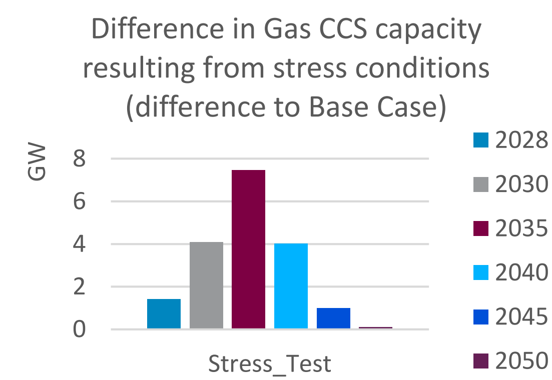
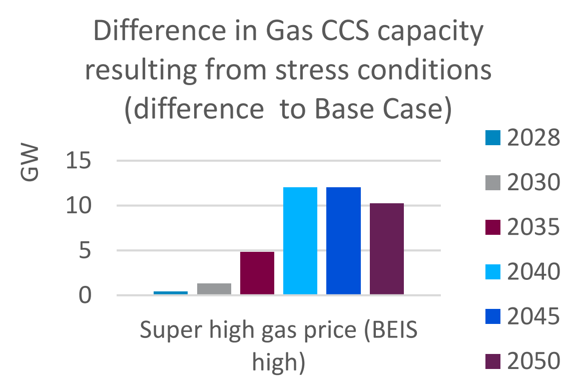
Key factors	Description	Impact on pace and scale of development of Gas with CCS
Evolution of nuclear costs	• Reduction in nuclear costs can have a significant impact on the Gas with CCS pathway when they coincide with higher gas prices. Low nuclear costs and high gas prices make nuclear capacity relatively more competitive resulting in Gas with CCS capacity being displaced by new nuclear capacity. • In scenarios with low gas prices the deployment of Gas with CCS remains robust to reduction in nuclear costs, with little to no Gas with CCS capacity being displaced by new nuclear capacity	
Cost reduction pathway for renewable technologies	• The slower cost reduction of renewables has a limited impact on the deployment of Gas with CCS in the near term as build costs do not deviate significantly from current costs • From the mid 2030s the slower cost reduction of renewables results in a greater rate of deployment of Gas with CCS capacity, leading to higher deployment by 2050 • The overall impact can be considered as medium low compared to other factors	

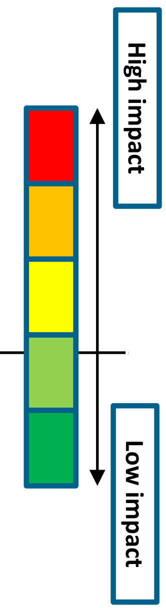


Conclusions (3)

Gas prices, nuclear costs and levels of system flexibility present the highest potential impact on the pace and scale of deployment of Gas with CCS in power based on the results of this analysis

- Based on the key insights from the core scenarios and spot sensitivities presented so far, **key factors** that are expected to impact **the pace and scale of deployment of Gas with CCS** are summarised below with the **materiality of their impact:**

Key factors	Description	Impact on pace and scale of development of Gas with CCS
Stress test	• The stress test, defined as the combination of a 1-in-20 cold weather peak demand, unavailability of interconnection and higher operational reserve requirement, increases the pace of deployment of Gas with CCS in the 2030s. • In particular this is due to the increased requirement for firm capacity and flexibility in the mid 2030s, which interconnectors make a significant contribution to in the Base Case scenario • The deployment level by 2050 remains similar compared to Base Case, with the extra flexibility being provided through a combination of increased solar PV and battery storage, and the extra reserve requirement being satisfied by a increased build of peaking OCGT plant	
Super high gas price	• Super high gas price reduces and delays the deployment of Gas with CCS plant compared to Base Case. • Increasing the long term gas price assumption by 68% in comparison to the Base Case scenario reduces the capacity of Gas with CCS installed by 2050 by 35% • At this gas price nuclear, under Base Case scenario cost assumptions, becomes competitive with 4 GW of new build • In comparison to the Base Case scenario, renewables also become more competitive with a greater deployment of both wind and solar capacity	



Conclusions (4)

Robust role and system value for Gas with CCS in the power sector shown across all core scenarios and spot sensitivities. Scale of deployment remains significant in the range of 13-36 GW by 2050

- The results show a robust role for Gas with CCS in the power system across all the scenarios and sensitivities:
  - The scale of deployment remains around 13-36 GW level by 2050. Even in the most unfavourable cases for Gas with CCS, with high gas prices and high nuclear favourability, the scale of Gas with CCS capacity is significant at around 13-16 GW by 2050.
  - Beyond the OGCI plant that is assumed to come online in 2026 in all cases, additional capacity is built in the period from late 2020s to 2040 depending on the market scenario. In most cases, this capacity is built from 2028-2030, meaning that Gas with CCS starts playing a key role earlier in the pathway to 2050. However, a higher level of system flexibility, driven by greater interconnector capacity can significantly delay Gas with CCS deployment as under the HG_HN_HF scenario. The deployment grows strongly in later years in all cases as the emission intensity constraint becomes more binding.
  - Similar to the pace and scale of deployment, the range for system value of Gas with CCS by 2050 is robust across all cases, varying in the range 16-20 £/MWh. The system value is a net benefit by 2030 and 2040 in most cases and gives an indication of the additional value CCS can provide in meeting overarching carbon targets, which should be considered when considering support for this technology.
- The OGCI plant being the FOAK type unit to be commissioned in 2026 plays a crucial role in demonstrating the low carbon energy provision, dispatchability and flexibility value of Gas with CCS earlier and enable the evolution of the pathway to 2050, leading to more significant deployment levels demonstrated below

Core scenarios and spot sensitivities	Year of the first capacity build after the OGCI plant	Scale of deployment by 2050 (GW)
Base_Case	2030	29
HG_HN_HF	2041	16
HG_HN_LF	2028	13
HG_LN_HF	2035	25
HG_LN_LF	2028	24
LG_HN_HF	2028	35
LG_HN_LF	2028	36
LG_LN_HF	2028	35
LG_LN_LF	2028	36
Super_high_gas_price_(BEIS high)	2040	19
Slower_Renewable_CAPEX	2030	34
Stress_Test	2028	29

Core scenarios and spot sensitivities	System value in 2030 (£/MWh)	System value in 2040 (£/MWh)	System value in 2050 (£/MWh)
Base_Case	-9	-17	-20
HG_HN_HF	37	1	-16
HG_HN_LF	8	-7	-20
HG_LN_HF	-4	-15	-20
HG_LN_LF	11	-14	-20
LG_HN_HF	-13	-18	-18
LG_HN_LF	-14	-17	-17
LG_LN_HF	-14	-19	-20
LG_LN_LF	-16	-19	-19

Negative value indicates a benefit to the system from CCS

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PLEXOS Long-Term (LT) Plan

Inputs, settings and optimization in the LT Plan

LT Plan (Long-Term)

- The LT stage optimises the system in the long-term (across several years)
- It requires inputs related to the capital and fixed costs of assets as well as fuel prices and demand
- It provides solution for capacity, line and storage build and retirement decisions by minimising the investment and production cost for the horizon while respecting constraints

What is the optimal capacity mix?

Inputs used in LT dispatch and capacity optimisation

- Hourly demand profile
- Existing plants
- New plants (committed)
- Fuel and carbon prices
- Import/export prices

Inputs used in LT capacity optimisation

- New plants costs
- New plants characteristics
- New plants build constraints
- Minimum capacity reserve or maximum LOLP
- Carbon/RES target

LT settings

- Planning horizon
- Chronology

LT outputs

- Units build/retired by type and year
- Build, retirement and fixed costs
- Indicative variable costs
- Capacity reserve by region and year
- Indicative capacity factors

PLEXOS LT Plan Stage

Minimisation of the long-term costs of electricity production

- The LT Plan stage takes decisions tominimise the NPV of the total costs in the system across the planning horizon (using a common system discount rate)
- There are four long-term cost components and each of these costs have trade-offs:
  - An increase of the build costs by building an additional high efficient plant will lead to a decrease of the energy costs due to less fuel spent
  - An increase of the build costs by building a peaking plant can lead to a decrease of the energy costs due to lower unmet energy
  - An increase of retirement costs (e.g. retiring an old and expensive to maintain plant) will decrease the fixed operating costs

one-off | annual | interval

Total Costs = **Build Costs** + **Retirement Costs** + **Fixed Operating Costs** + **Energy Costs**

Total Costs

LT minimises the total costs of the system of the horizon taking into account the constraints and trade-offs

Build Costs (one-off)

One-off cost to build new
- Capacity
- Lines
- Storage

Retirement Costs (one-off)

One-off cost to retire existing or new
- Capacity
- Line
- Storage

Fixed Operating Costs (annual)

Annual fixed costs for existing and new assets that are paid since the asset is built until it is retired

Energy Costs (interval)

These are the short-term costs of the system:
- Fuel
- Carbon
- Variable operating
- Start/stops
- Unmet Energy

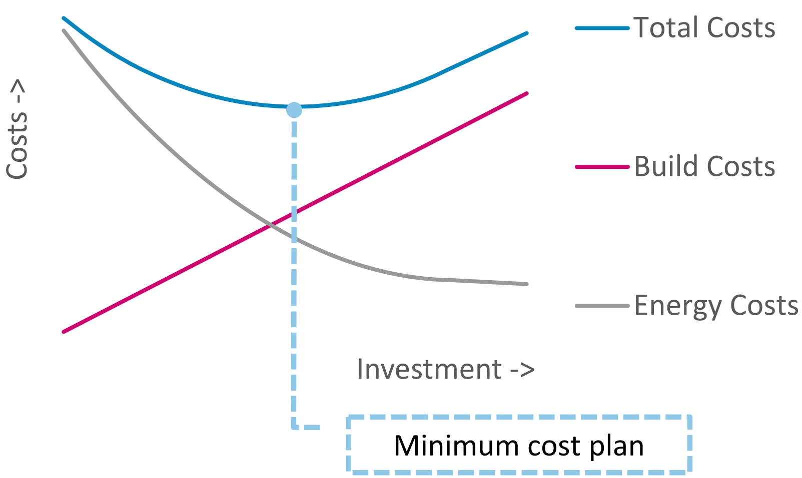
PLEXOS LT Plan Stage

Trade-offs between the cost components

- There are four long-term cost components and each of these costs have trade-offs:
  - An increase of the build costs by building a new high-efficient plant can lead to a decrease of the energy costs due to less fuel spent
  - Also an increase of the build costs by building a peaking plant can lead to a decrease of the energy costs due to lower unserved energy
  - An increase of retirement costs (e.g. retiring an old and expensive to maintain plant) will decrease the fixed operating costs and may increase the energy costs slightly if the old plant had positive load factor

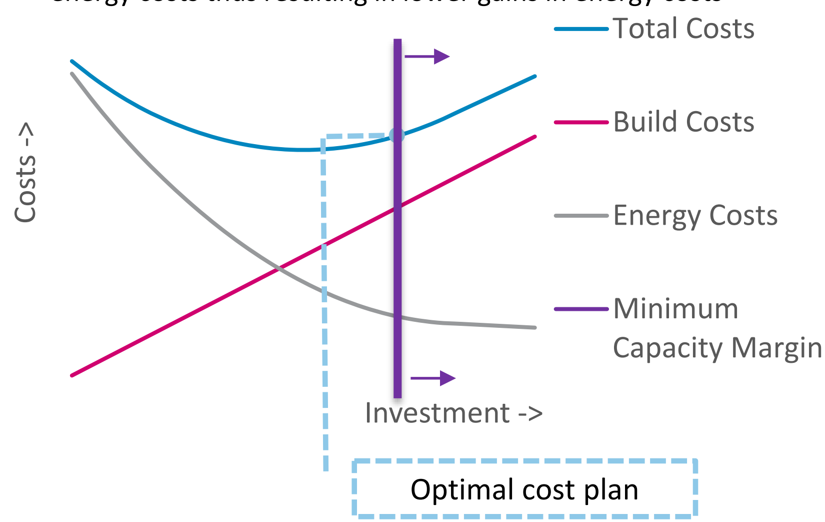
Impact of new asset build - unconstrained

- Retirement option is neglected and fixed costs of new plants are included in the build costs
- Energy costs decrease as more new assets are build. However, the gains are diminishing due to cannibalisation effect



Impact of new asset build - constrained

- If we suppose that the regulator requires a minimum capacity margin, the optimal solution may change: More capacity may be added in the system in order to satisfy the margin requirement or carbon over-arching constraints
- The increase of build may come from cheaper peaking plants with high energy costs thus resulting in lower gains in energy costs



PLEXOS LT Plan Stage

LT Plan Chronology

- The LT Plan takes into account all four cost components to derive an optimal solution. The build costs are oneoff costs and the fixed operating costs are paid on annual basis. The energy costs however are more complicated because they are paid every interval.
- The LT Plan must therefore simulate the dispatch of the system at interval level in order to build a representation of energycosts in the model. Doing so for every interval in the horizon would create a highly complex optimisation problem which is unlikely to be solvable within acceptable time limits. The LT Plan must therefore simplify the analysis.
- In this modelling exercise a sampled chronology has been used to simplify the interval level representation in the model. The sampled chronology preserves full periods of time, by sampling each year of the horizon by a number of specified time windows (e.g. day/week/month). The number of samples is lower in the full chronology (e.g. 365/52/12 respectively).
- The higher the number of samples the more accurate the representation at the cost of greater complexity
- A 16 week sampled chronology has been implemented in the Baringa GB LT Plan model, which gives the model a sufficiently accurate representation of inputs and costs which vary on an hourly basis.
- Sampling is done statistically such that 'like' periods (days/weeks/months) are removed leaving a sample set that is representative of the variation in the original demand series

PLEXOS LT Plan stage

LT Plan capacity build decisions

- The capital costs of the new unit are annualised:

$$AnnualisedCapex = BuildCost \cdot Capacity \cdot \left(\frac{WACC}{1-(1+WACC)^{EconomicLife}}\right)$$

- The annualised build costs added to the annual fixed costs will affect LT Plan's minimisation formula:

$$AnnualisedCost = AnnualisedCapex + FO\&M\ Charge$$

- Constraints can be applied to the specific unit such as maximum number of units built (over full period) and max number of units built per year
- These inputs can be dynamic and change through the planning horizon

Property	Value	Units
Max Capacity	200	MW
FO&M Charge	20	GBP/kW/year
Firm Capacity	190	MW
Build Cost	2000	GBP/kW
Technical Life	40	years
WACC	10	%
Economic Life	25	years
Max Units Built	10	-
Max Units Built in Year	2	-

- The LT Plan allows for constraints on minimum capacity requirements to ensure the system security
- Firm Capacity is the capacity that is assumed to be the capacity available in the peak time or times of high system stress. Firm can be set during the LT Plan set-up.
- Min Capacity Reserve: It can be used to set an absolute level of minimum capacity reserve:

$$\sum_G FirmCapacity + \sum_I FirmCapacity \geq MinCapacityReserve\ *$$