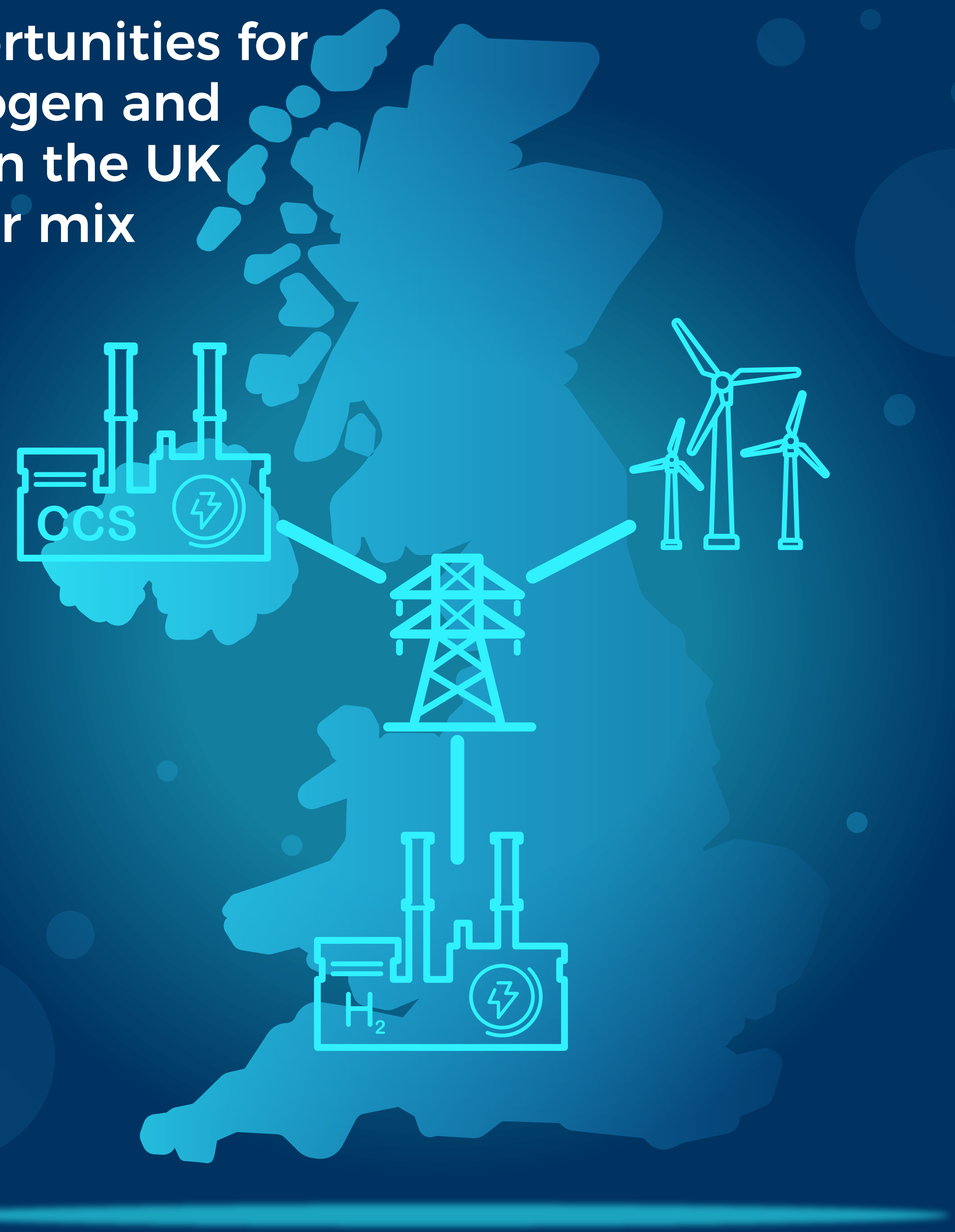
Hy-Impact Series

Study 3: Hydrogen for Power Generation

Opportunities for hydrogen and CCS in the UK power mix



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A report for

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This report has been prepared by Element Energy.

Element Energy is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. Since its inception in 2003, Element Energy provides consultancy services across a wide range of sectors, including carbon capture and storage and industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon vehicles. With a team of over 50 specialists, Element Energy provides consultancy on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work and vice versa.

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Final report date: **November 2019**

Executive Summary

Motivation and project overview

The UK Government recently announced its commitment to achieving net-zero carbon emissions by 2050, in response to the Net Zero report recently published by the Committee on Climate Change.[1] In order to reach this goal cost effectively, the Committee suggests that the first carbon capture and storage (CCS) cluster in the UK must be deployed by the mid-2020s and at least one cluster must produce large scale hydrogen (H_2) and utilise bioenergy with CCS (BECCS) by 2030.

Hydrogen is an energy carrier that can enable the decarbonisation of many industrial sectors, including power generation. Hydrogen-fuelled combined cycle gas turbines (H2GTs) can provide flexible generation as well as baseload generation. Hydrogen is produced most efficiently on a large scale from the reforming of natural gas in centralised autothermal reforming (ATR) plants. When ATR is performed in combination with CCS using a blend of natural gas and biogas as feedstock to the ATR plant, hydrogen production can result in net zero or negative emissions.

The aim of this report is to identify the economic and technical feasibility of low-carbon gas turbine technologies in the UK power sector for a timeframe of up to 2035. Two main technologies were investigated: H2GTs fuelled by negative emission hydrogen and natural gas CCGTs with post combustion CCS, here collectively defined as “Power CCS” technologies. The study was structured as follows:

- Assessment of power generation capacity added between 2019 and 2035, based on the Energy and Emissions Projections by BEIS, that could be replaced by Power CCS technologies;[2]
- Economic comparison of new build and retrofit Power CCS technologies and their alternatives;
- Identification of technical limitations to deployment, such as locations of power plants and gas storage sites;
- Development of three achievable deployment scenarios for Power CCS technologies and assessment of resulting emissions and cost reduction potentials;
- Assessment of additional system benefits of Power CCS technologies, such as supporting a higher penetration of variable renewable energy sources (VRES) and reducing electricity imports.

Overview of BEIS 2035 electricity projections

Power CCS technologies can replace up to 12.3 GW of nuclear and up to 3.5 GW of CCGT by 2035.[3,4] As displayed in Table 1, BEIS projections include 3.5 GW new natural gas CCGT and 12.3 GW new nuclear plants in 2026-2035, which would be prime targets for replacement with Power CCS technologies. Additionally, a total of 15.2 GW interconnector capacity is expected to be commissioned before 2026, but this timeframe would be too early for 1st-of-a-kind Power CCS technologies. BEIS projections include a 1.1 GW CCS CCGT plant commissioning in 2035.

1 CCC 2019, Net Zero – The UK's contribution to stopping global warming

2 BEIS 2019, Energy and emissions projections

3 Unless stated otherwise, all power units (e.g. GW) and energy units (e.g. GWh) refer to electricity.

4 Throughout this report CCGT refers to unabated CCGT, unless explicitly stated to be CCS CCGT.

Table 1 also shows the evolution of the average load factors of power fleets in the BEIS mix.[5] By 2035 CCGTs increasingly fill the role of a flexible peaking plant, mostly operating during high demand. On the other hand, load factors for nuclear plants will increase, indicating their role as continuously operating baseload plants.

Diversification of the generation portfolio would be beneficial as the UK nuclear industry struggles with delays and unfavourable market conditions. Recently many nuclear projects in the UK have been frozen and currently only one project, Hinkley Point C, is under construction. Technical difficulties of a new generation of nuclear reactors in Europe causing financial and time budget overruns by multiples of the original estimate as well as the high dependence on policy support make the level of nuclear deployment forecasted by BEIS uncertain. Further diversification of the power mix through the development of available low carbon technologies would therefore be beneficial to increase the resilience of the future power sector.

Table 1: Breakdown of new build capacity as projected by BEIS

Technologies	Replaceable by Power CCS?	Load factors	New build capacity in BEIS projections (GW)		
		2018 → 2035	2019-25	2026-29	2030-35
Natural gas	✔	35% → 15%	3.9	too small	3.5
Nuclear	✔	73% → 90%	-	6.3	6.0
Interconnectors	✘	85% → 20%	15.2	-	-
Natural gas CCS	✔[6]	None → 70%	-	-	1.1
Potential Power CCS capacity (GW)			3.9	6.3	10.6
Power CCS replacement type			Retrofit	New build early phase	New build late phase

Cost-effectiveness of Power CCS technologies

The majority of new nuclear plants and CCGTs can be cost effectively replaced by hydrogen and CCS. The levelised cost of electricity (LCOE)of Power CCS technologies in 2035 was compared to that of CCGTs in flexible operation (15% load factor) and to nuclear in baseload operation (90% load factor), see Figure 1.[7] H2GTs with 10% biogas blending are more cost effective than both CCGTs in flexible operation and nuclear plants in baseload operation under future BEIS carbon price projections.[8] While CCS CCGTs are more cost effective than both nuclear and H2GTs at high load factors, they are more expensive than both CCGTs and H2GTs at low load factors. As the CCGT fleet will show a range of load factors, a small share of the fleet, operating at a sufficiently high load factor, can also be cost effectively replaced by CCS CCGT. In 2035, CCS CCGTs become cheaper than CCGTs above a load factor of 35% and cheaper than H2GTs above a load factor of 41%, under the carbon price assumptions.[8]

5 The load factor is a metric of plant utilisation and is calculated as the proportion of the actual power produced over the maximum power that could be produced by a plant

6 The CCGT CCS plant included in the BEIS forecast is replaced by an H2GT plant in two of our scenarios.

7 LCOE is a common metric used in power plant analysis which allows to compare plants of different characteristics such as fuel, lifetime and plant utilisation in terms of total costs per MWh of generation.

8 Carbon price estimates are taken from the 2016 BEIS Electricity Generation Costs document. They represent the sum of EU-wide prices of the EU-Emissions Trading Scheme (ETS) and UK specific Carbon Price Leavy. The carbon price estimations for 2019, 2035 and 2050 are £19/tonne, £79/tonne and £206/tonne, respectively. More information can be found in Appendix 2.

Hydrogen-ready CCGTs can blend different ratios of hydrogen in the 2030s cost effectively. It is possible to run CCGTs with a fuel blend of different ratios of hydrogen and natural gas. Many turbine manufacturers are committed to R&D work for developing turbines that will be able to use blends with 30% to 90% hydrogen by volume without further capital investment.[9] For "hydrogen ready" plants located close to potential hydrogen production sites and equipped with the latest turbine technologies, blending is found to be cost effective starting from the early 2030s, when carbon cost savings start to exceed increased fuel prices.

Retrofit of CCGT plants to either H2GT (using 100% hydrogen) or to CCS without turbine replacement is not found to be cost-effective. As shown in Figure 2, carbon prices are expected to be too low in the lifetime of the plants to compensate the extra capital investment required for retrofits, especially considering the lower remaining lifetimes compared to new plants. If a retrofit is accompanied by lifetime extension through turbine replacement, it has the potential to be cost-effective, however this was not considered in this study.

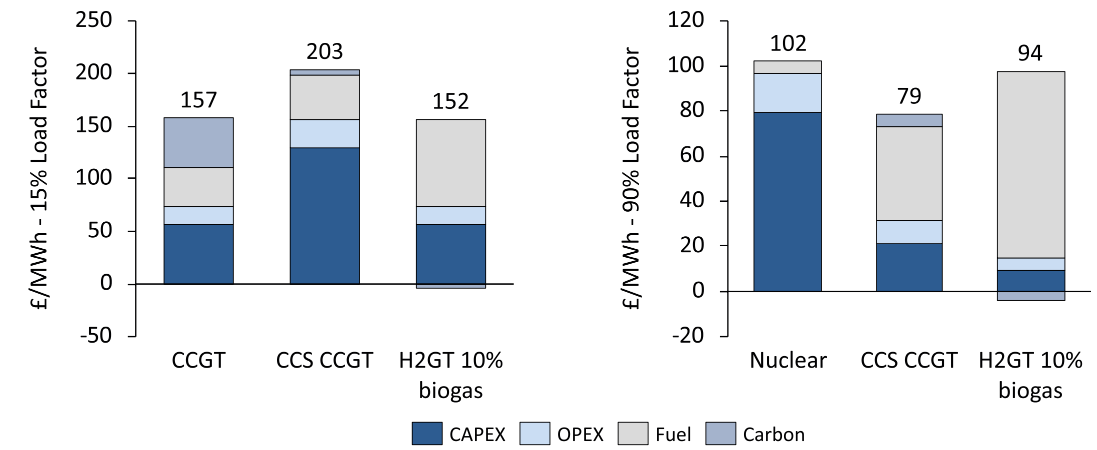


Figure 1: LCOE breakdown of technologies at low and high load factors (NOAK in 2035)

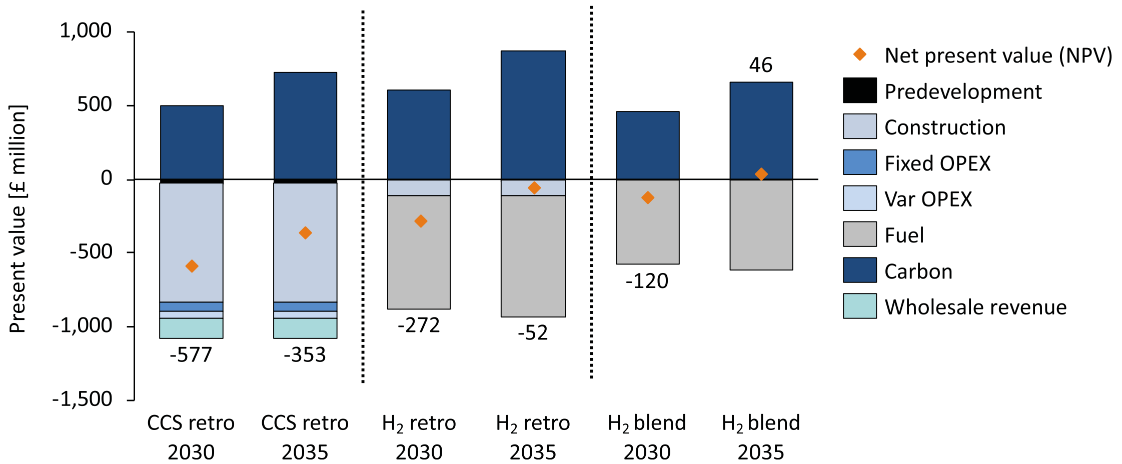


Figure 2: Economic assessment of CCS and hydrogen retrofits as well as hydrogen blending compared to continued operation as CCGT for a plant of 1,200 MW capacity

9 https://www.ge.com/reports/hydrogen-generation-gas-turbines-can-run-abundant-element-universe/

Scenarios for roll out of Power CCS technologies up to 2035

To assess the deployment potential of Power CCS technologies, three ambitious but achievable scenarios were created, using BEIS projections as a baseline. 10% biogas is assumed to be used for hydrogen production, allowing H2GTs to reach net negative emissions with a carbon intensity of -29 gCO_2/kWh_e. The three scenarios were built as follows:

Central hydrogen scenario:

- Partial replacement of nuclear and CCGT capacity to be built after **2029** by new build H2GT, powered by 100% hydrogen.

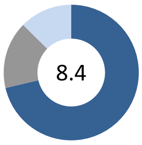
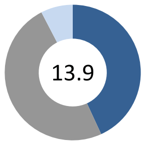
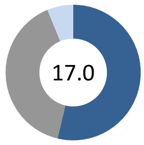
High hydrogen scenario:

- Identical replacement of new built nuclear and CCGT by new built H2GT, powered by 100% hydrogen, as in Central hydrogen scenario.
- Gradual conversion, starting in 2032, of remaining CCGTs built between **2020** and **2035** to CCGTs using hydrogen blending. Blending rates are increased from 30% in 2032 to 90% in 2034.

High hydrogen & CCS scenario:

- Partial replacement of nuclear and CCGT capacity to be built after **2026** by CCS CCGTs and new built H2GT powered by 100% hydrogen.
- Gradual conversion, starting in 2032, of remaining CCGTs built between **2020** and **2035** to CCGTs using hydrogen blending. Blending rates are increased from 30% in 2032 to 90% in 2034.

Table 2: Summary of the key parameters of the Power CCS scenarios

Year 2035	Central H_2 Scenario	High H_2 Scenario	High H_2 & CCS Scenario
Replaced BEIS capacity (GW) Nuclear, CCS CCGT, CCGT			
H_2 demand ($TWh_{H2, HHV}$/year) 15 $TWh_{H2, HHV}$/year	108	116	77
Biomass use (TWh_{HHV}/year) 2 TWh_{HHV}/year	12.7	13.6	9.1
Cost savings (£ million/year) £100 million	450	460	1,210
Emissions savings ($MtCO_2$/year)	2.5	3.9	1.8
Grid CO_2 intensity reduction	6 gCO_2/kWh_e ↓ -15%	10 gCO_2/kWh_e ↓ -24%	5 gCO_2/kWh_e ↓ -12%

The scenarios provide annual cost savings of £450 million - £1,210 million and emission savings of 1.8 – 3.9 $MtCO_2$/year by 2035, totalling to £9-25 billion and 28-68 $MtCO_2$ (cumulatively) respectively for the 2025-2050 period. The "high hydrogen & CCS" scenario provides by the highest cost savings, while the "High hydrogen" scenario offers the highest emission savings reducing total power sector emissions by 24% in 2035. These results reflect the trade-off between higher cost effectiveness of CCS CCGT to replace nuclear (compared to H2GT) and the higher emission savings obtained by H2GT (compared to CCS CCGT).

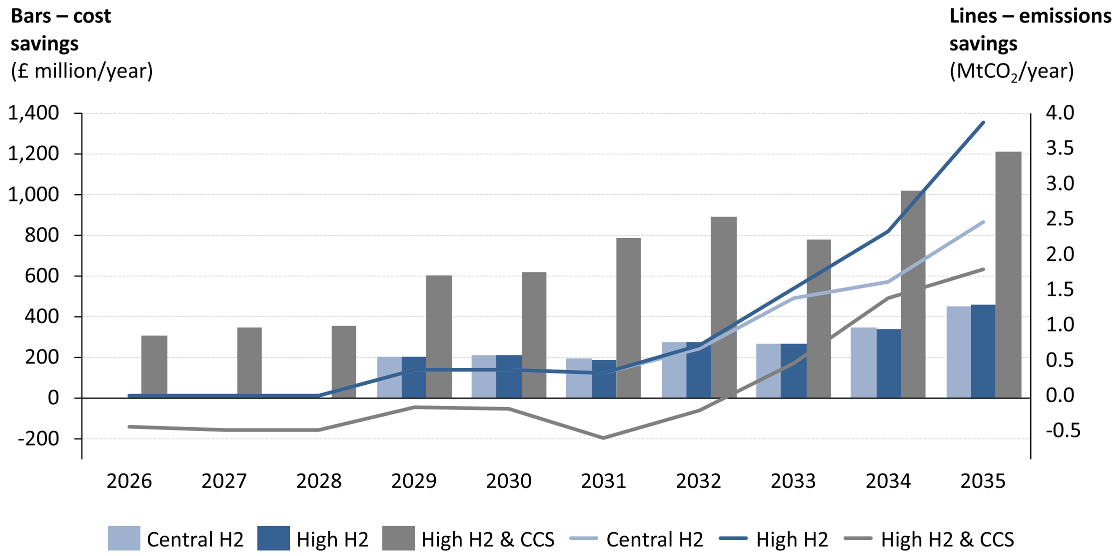


Figure 3: Annual emission and cost savings in the 3 Power CCS scenarios compared to the baseline BEIS forecast

Level of biogas blend

Using a biogas blend to produce hydrogen is crucial for achieving emission reductions. To assess the impact of using different levels of biogas blend in the hydrogen production on cost and emission savings, a sensitivity study was carried out, using a 0% biogas blend as well as a 20% biogas blend instead of 10%. Using a 20% biogas blend increased emission savings significantly but lead to much lower cost savings (even negative cost savings in two scenarios) due to the increasing cost of biogas resource used in hydrogen production at high consumption levels. Using a 0% biogas blend allowed slightly higher cost savings but reduced emission savings drastically (almost eliminating them in two scenarios). The 10% biogas blend is therefore found to be the best balance of cost and emission savings.

The Power CCS scenarios require significant but achievable levels of bioenergy resource. The scenarios require 77-116 TWh/year of hydrogen by 2035, while UK non-power related hydrogen demand is expected to be around 140 TWh/year in the same year.[10] The biomass supply of the UK is estimated to be able to support the production of 243 TWh/year (central case) to 565 TWh/year (high case) of hydrogen, produced from 10% biogas.[11]

10 H21 NoE XL scenario and Element Energy's work for the CCC and LowCVP hydrogen Infrastructure Roadmap

11 Net-zero hydrogen: Hydrogen production with CCS and bioenergy, Element Energy for Equinor, 2019

Additional system benefits

H2GTs are cost competitive compared to CCGTs in a future power system with even higher penetration of renewables. It is possible that the UK opts for a higher-than-expected renewables future, which would reduce the load factors of non-renewable technologies and thus render Power CCS options less cost-effective. To investigate this possibility, a case study has been conducted with 30% higher wind energy capacity in 2035 compared to the BEIS projections, resulting in an average load factor of 10.7% of CCGTs instead of 15% in the BEIS projections. At this low load factor, H2GTs (£179/MWh) stay cost competitive compared to CCGTs (£185/MWh), due to projected future carbon prices, whereas CCS CCGTs (£261/MWh) become prohibitively expensive.[8]

Deploying a large capacity of hydrogen fuelled power plants in the UK could reduce imports of electricity generated from fossil fuel while reducing costs. By 2035 interconnectors are expected to be mainly used to provide flexibility to the system. Reducing imports generated by flexible CCGTs abroad by hydrogen fuelled generation in the UK could reduce import related emissions by up to 68% and increase the utilisation of hydrogen fuelled power plants, thereby reducing their cost of generation.

Recommendations

Realising the opportunities illustrated in the report requires:

- promptly starting to construct the UK's first CCS cluster(s),
- developing an efficient 100% hydrogen gas turbine by the late 2020s,
- ensuring that all CCGT capacity built in the meantime are fully hydrogen ready, and
- deploying best efforts to secure sufficient bioenergy resources to achieve net negative emissions.

To further assess the role and value of Power CCS projects, the following future work is recommended:

- Expansion of the analysis to include **BECCS, industrial CCS** and other **hydrogen** applications.
- Assessment of **dynamic daily and seasonal hydrogen** demand, with respect to variable renewable generation to reveal synergies between different components of the energy system.
- Projecting **the role of Power CCS beyond 2035** under various long-term scenarios.
- An analysis of viable business models for H2GTs with net-zero/negative-emissions hydrogen.
- Investigating the **interaction with neighbouring electricity markets** in more detail to assess the system benefits of Power CCS plants in the UK on a European level.

Contents

Acronyms

ATR	Autothermal Reforming
BECCS	Bioenergy with carbon capture & storage
BEIS	Department for Business, Energy & Industrial Strategy
Capex	Capital expenditure
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbines
CCR	Carbon capture ready
CC(U)S	Carbon capture (utilization) and storage
CCSA	Carbon Capture and Storage Association
CNS	Central North Sea
CO_2-EOR	CO_2-enhanced oil recovery
DCO	Development consent order
EIS	East Irish Sea
EOR	Enhanced oil recovery
EPR	European pressure reactor
ETI	Energy Technologies Institute
FID	Final investment decision
FOAK	First of a kind
GDP	Gross Domestic Product
GW	Gigawatt
H2GT	Hydrogen gas turbine
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
LCOE	Levelised cost of electricity
LF	Load factor
kWh	kilowatt hour
Mt	Million tonnes
MWh	Megawatt hour
NNS	Northern North Sea
NOAK	Nth of a kind
Opex	Operational expenditure
SCR	Selective catalytic reduction
SNS	Southern North Sea
SOAK	Second of a kind
T&S	Transport and storage
VRES	Variable renewable energy share

Introduction

1

Introduction

1.1 Background

Many international studies, including the IPCC's Assessment Reports and International Energy Agency (IEA) scenarios have shown that the deployment of Carbon Capture and Storage (CCS) is essential for meeting climate targets. According to these models, the exclusion of CCS from the future energy portfolio has the greatest economic impact in a 2°C scenario compared with any other technology. The IEA projects that CO_2 emissions from electricity generation in 2060 must be reduced by 46% in order to reach global climate targets and CCS applications in the power industry could play a significant role in achieving these goals.

Similarly, CCS is a vital technology for the UK power sector for two main reasons:

- As the variable renewable energy share (VRES) increases, there is greater need for low-carbon, flexible generation technologies. Regions with highly seasonal availability of renewables, like the UK, especially need this flexibility, since solar energy with storage would not be enough for matching demand in winter and large renewables curtailment would be economically damaging.
- The UK's current power market depends heavily on nuclear power running as baseload. Despite inclusion of new nuclear plants in many electricity projections, the future role of nuclear in the UK is highly uncertain as financial problems has recently led to the cancellation or freezing of many projects (see section 2.2 for more detail). Power CCS applications, on the other hand, have the potential to cost effectively replace nuclear as low-carbon baseload generators.

A recent report by the Energy Technologies Institute (ETI) investigates the role of CCS in the UK and warns that delaying CCS deployment until after 2030 would increase CO_2 abatement costs by ~£1 billion/year and this figure may double if CCS deployment is delayed until 2050.[12] The higher abatement costs associated with the alternatives to CCS would be caused by the intermittency of renewables, a heavier dependence on nuclear and delayed deployment of hydrogen for power generation. As a consequence, although the cost of renewable power technologies and storage has been substantially decreasing in the recent years, there is a strong business case also for the deployment of CCS in the power sector. The report also underlines the potential of CCS to support hydrogen production before 2030 and achieve negative emissions through bioenergy with CCS (BECCS) in the medium term.

These findings are further reaffirmed through the Committee on Climate Change's (CCC) advice on pathways to reaching net zero emissions in the UK by 2050.[13] The report identifies the following key actions for low-cost, efficient emission reductions:

- Initial CO_2 infrastructure must be developed through at least one industrial CCS cluster in the mid-2020s, ideally with a second one deployed by 2030.
- Large scale hydrogen production must start in at least one CCS cluster by 2030, supporting applications that are relatively easy to convert, such as power, gas grid injection and industry.
- Initial BECCS capacities must be deployed sufficiently early (by 2030) to allow for rapid scale-up in the long term. Bioenergy resources must be used sparingly and for technologies that can maximize their emission reduction impact, such as BECCS.

12 ETI, 2018, Still in the mix? Understanding the system role of CCUS

13 CCC, 2019, Net Zero: UK's contribution to stopping global warming

The CCC's work includes an analysis of the future role of hydrogen in the UK and expects Hydrogen production from natural gas with CCS (blue hydrogen) to play a major role, due to the higher costs and lower availability of hydrogen produced from electrolysis (green hydrogen) and hydrogen imports.[14] Research suggests that in a highly electrified future hydrogen would be essential for ambitious long-term targets and hydrogen for power generation (combined with CCS and bioenergy could serve as a strong initial deployment strategy. A key requirement for unlocking this opportunity is building future gas plants "hydrogen ready", by positioning them in favourable locations to easily receive hydrogen supply and leaving enough space on site for additional equipment that may be required to convert to hydrogen.

1.2 Objectives and scope

The role of Power CCS technologies in the future UK electricity industry is clear, however unlocking the necessary early investment will require demonstrating the technical and economic feasibility of these technologies in the short to medium term. This report aims to determine the potential for power with hydrogen and CCS to be competitive in providing decarbonised power to the UK power system in a 2035 timeframe, with the specific objectives of:

- Identifying required targets and realistic hydrogen fuelled combined cycle gas turbine (H2GT) deployment pathways which are equal or below nuclear and CCGTs in terms of cost and CO_2 emission factors, when based on the BEIS 2035 energy and emissions forecast.
- Developing a set of high level scenarios that represent ambitious but deliverable deployment strategies to investigate the system benefits.
- Exploring the extent to which Power CCS technologies can displace or reduce power import via interconnectors.
- Exploring the extent to which the technology can support an increased share of VRES in the UK power system.

1.3 Methodology overview and s tructure of the report

The project methodology, as outlined in Figure 4, consists of five main steps:

1. Analysis of the BEIS power projections to establish a baseline for the project.
2. Economic analysis to determine the new-build capacity that can be replaced cost-effectively.
3. Assessment of technical requirements that may limit deployment.
4. Development of 3 plausible scenarios based on BEIS forecasts that can deliver meaningful H2GT and CCS CCGT capacities by 2035.
5. Assessment of additional system benefits of Power CCS technologies, such as their potential to reduce electricity imports and support a higher VRES.

14 CCC, 2018, Hydrogen in a low-carbon economy

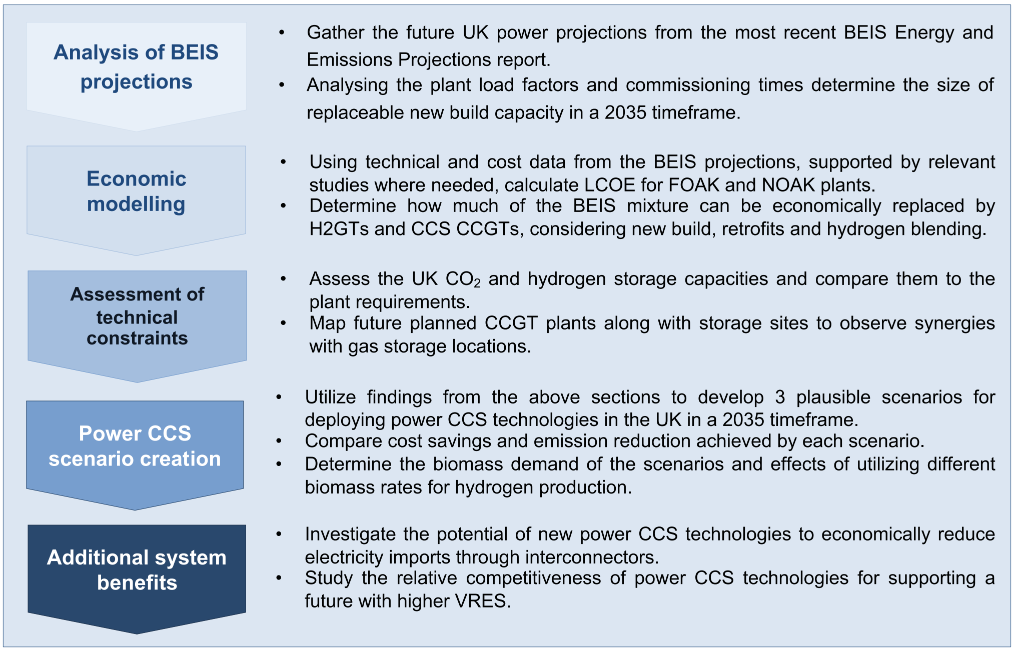


Figure 4: Key aspects of project methodology

The rest of this report is structured into 6 sections as follows:

Section 2 introduces the BEIS 2018 energy projections and identifies the target technologies for replacement with Power CCS options.

Section 3 presents the key findings of the economic analysis for new build and retrofit plants, as well as the option of blending hydrogen with natural gas as an alternative to retrofits.

Section 4 describes the three Power CCS deployment scenarios and their respective economic and environmental benefits, as well as a sensitivity study around bioenergy usage.

Section 5 examines the potential of the three scenarios to reduce net electricity imports and support a future with high VRES.

Lastly section 6 summarizes the key conclusions and recommendations while section 7 serves as an appendix containing detailed assumptions, results and data acquired for this project.

BEIS energy and emissions projections

2 BEIS energy and emissions projections

2.1 Overview of future power generation

The 2018 BEIS Energy & Emissions Projections forms the starting point and baseline case of this project. The report forecasts the UK new build capacity, electricity generation and associated emissions in the timeframe up to 2035. The key takeaways from the future power mix of the UK (as shown in Figure 5) are:

- As the UK is moving towards meeting its climate goals, coal will be phased out by 2023, with the decommissioning of the last plants.
- Share of renewables will steadily rise from around 36% in 2018 to 54% by 2035.
- Despite an early reduction in nuclear generation, new nuclear capacity in 2030s will be deployed to meet low carbon electricity demand.
- There will be a sustained dependence on net electricity import via interconnectors.
- Natural gas will shrink from around 36% of the electricity mix in 2018 to 8.6% in 2035, however it will still play a vital role by providing peak-load, flexible generation.
- A single 1.1 GW natural gas CCS plant is added in 2035, operating at a 70% load factor.

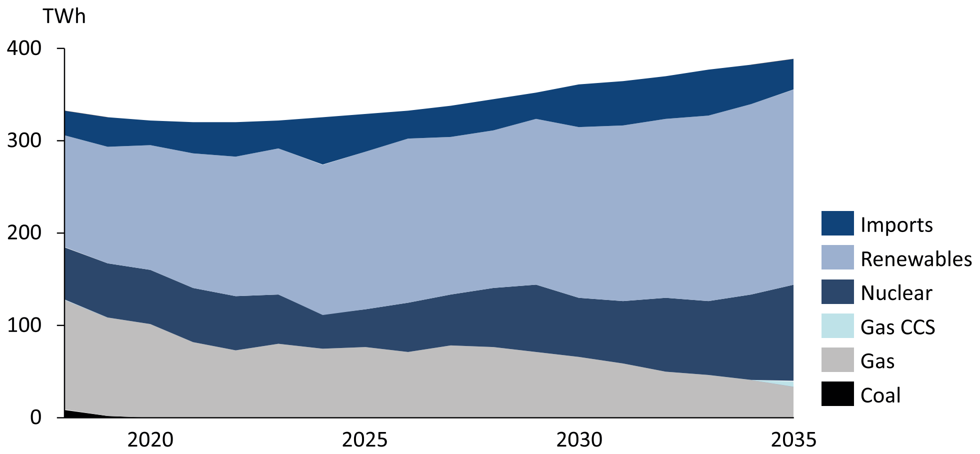


Figure 5: BEIS electricity production projections

Load factors for these technologies, shown in Figure 6, are dynamic and provide key insights to the technologies' roles in the power mix. Interconnectors that run almost as a base-load source today will experience much lower load factors starting from mid 2020s and provide flexibility to the system. Natural gas plants will have a similar transition to mostly running as peaking plants by 2035 with a 15% load factor. Contrastingly, nuclear load factors are projected to increase because as older plants shut down less downtime for maintenance will be needed.

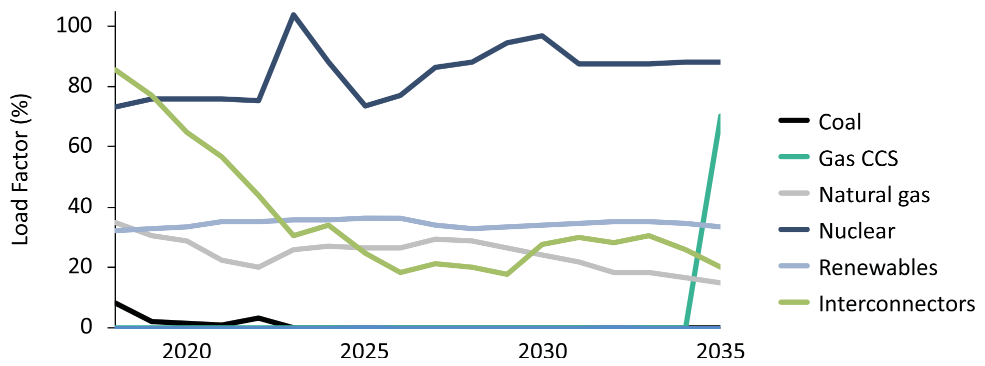


Figure 6: Load factors of selected technologies in the BEIS projections

2.2 Constraints for hydrogen and CCS deployment in the BEIS mix

The range of load factors and the role of the technologies in the power mix pose a constraint towards the feasible capacity replacement investigated in this project, as summarized in Table 3 below. Renewables are left out of the scope because they provide the base of low carbon generation, and CCS and hydrogen are not expected to restrict their deployment in the UK. Oil plants are also out of the scope because they only operate as backup generators and have close to zero load factors. Lastly, coal plants will not be considered since they will phase out by 2023 and no new coal plants are predicted in the BEIS mix. Nuclear, interconnectors and natural gas can be replaced by CCS CCGTs and H2GTs that operate as baseload or flexibly.

Table 3: BEIS load factors and suitability for replacement per technology

Technologies	Load factors 2018 → 2035	Can be replaced by CCS/H_2?
Interconnector	86% → 20%	✔
Renewables	32% → 34%	✘
Nuclear	73% → 88%	✔
Gas	35% → 15%	✔
Oil	0.0%	✘
Coal	diminishes in the 2020s	✘

In order to determine the potential nuclear, interconnector and gas capacity that can be replaced, the annual new capacity of the BEIS projections are shown in Figure 7.

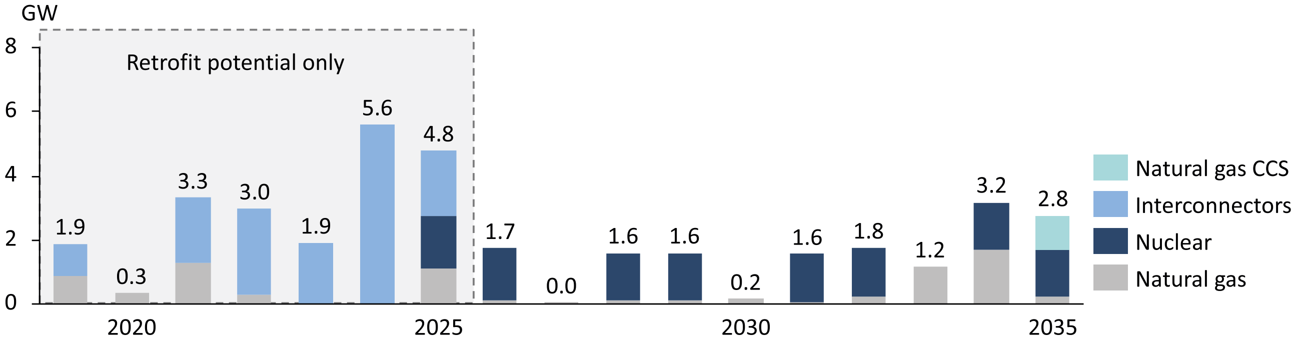


Figure 7: Annually added power capacity in the BEIS projection

Table 4 breaks down the newly added capacities into broad periods of first-of-a-kind (FOAK), second-of-a-kind (SOAK) and Nth-of-a-kind (NOAK) availability of Power CCS technologies. Since all new interconnector capacity will be built in the early 2020s, their replacement by Power CCS technologies is highly unlikely and will not be considered in this study. However, in section 5.1, a case study is presented examining the import reduction potential of the Power CCS technologies.

Between 2026-2035 a total of 12.3 GW nuclear capacity will be added which can be targeted by both FOAK and NOAK type plants. A further 3.5 GW of natural gas CCGTs added in 2030-35 could be replaced by SOAK/NOAK plants. Finally, BEIS includes a 1.1 GW CCS CCGT plant commissioning in 2035; in this study, this plant is assumed to be replaceable by a H2GT, if more cost effective.

Table 4: Breakdown of BEIS projected new build capacity into Power CCS technology development stages

Technologies	New build capacity in BEIS projections (GW)			
	2019-25	2026-29	2030-35	2026-2035
Natural gas	3.9	too small	3.5	3.5
Nuclear	-	6.3	6.0	12.3
Interconnectors	15.2	-	-	-
Natural gas CCS	-	-	1.1	1.1
Replaceable by Power CCS	3.9	6.3	10.6	16.9
Replacement type	Retrofit	New build FOAK	New build SOAK/NOAK	Total new build

Note on the uncertain future of nuclear in the UK

Although BEIS estimates that the share of nuclear energy in the UK power mix is expected to increase from 17% to 27% in the 2018-2035 timeframe with 12.3 GW new build capacity, there is little confidence that these levels of nuclear deployment are deliverable in the current market environment.

Table 5 below summarizes the progress of future nuclear plants in the UK (source: Nuclear electricity in the UK, BEIS, 28.03.2019). Two phases of Hinkley Point C represent the 1.65GW additions in the BEIS projections for years 2025 and 2026. However, EDF Energy suggests that Hinkley Point C is expected to be £2.2 billion over budget and electricity generation may be delayed for up to 15 months.

In January 2019, citing financial reasons, GE-Hitachi announced that they have frozen two nuclear projects (Wylfa Newydd and Oldbury B) which were in the planning stage. The Sizewell C project has not applied for a Development Consent Order (DCO) yet and may be operational in 2030s at the earliest. Bradwell B, on the other hand, is at a very early concept stage with little material development.

The EPR plant at Hinkley Point C, and the HPR1000 in Bradwell B, will be FOAK designs, increasing their costs and construction periods. Even if the UK government lends further support to realise these new nuclear projects, it is unlikely that new capacity will come online in 1.5 GW batches as projected in the BEIS forecast in years 2028-2035 (1.5GW addition in 2028,2029, 2031,2032,2034 and 2035).

For the sake of consistency, this project continues to work with the BEIS projections for nuclear deployment. However, any nuclear capacity replaced by power CCS technologies may be viewed as having the additional benefit of alleviating government's requirement to rapidly provide additional policy incentives for these projects.

Table 5: Future UK nuclear plants

Power Station	Opening Date	Capacity (MW)	Status	Reactor Type
Hinkley Point C 1	2025	1630	In construction	EPR
Hinkley Point C 2	2026	1630	In construction	EPR
Sizewell C	2030-2035	3340	Proposed	EPR
Bradwell B	2030-3035	2300	Proposed	HPR1000

Economic assessment of replaceable capacity

3 Economic assessment of replaceable capacity

3.1 Potential of new build plants

In order to compare the economic performance of CCGT & nuclear plants to Power CCS technologies, the levelised cost of electricity (LCOE) over the whole lifetime of new build plants is calculated for each option.

LCOE is a useful metric given by the present value of lifetime costs of a power station (capital and operating expenses) divided by present value of lifetime electricity generation, discounted by a predefined rate. Using the present value weighs short-term costs and generation higher than future expenses and generation. Using LCOEs allows for the comparison of different technologies of unequal lifespans, project size, costs, risks, returns and capacities. LCOE is also heavily influenced by load factors, as these regulate the amount of total electricity produced by a power station and thus also capital expenditures per kWh generated.

The main assumptions and references used in the LCOE calculations are listed below. More detail can be found in Appendix 2.

- As stated in the introduction section, the major source of hydrogen is expected to be natural gas because the hydrogen import potential is highly uncertain and electrolysis is significantly more expensive. Also, availability of excess renewable electricity that can be diverted to electrolysis is projected to be small. Therefore, this study assumes that hydrogen production will be through centralised ATR plants. Furthermore, bioenergy is expected to play a vital role in combination with CCS to provide negative emissions, thus this study investigates using different biomass blends in hydrogen production. hydrogen production parameters are taken from a recent Element Energy study exploring net zero hydrogen production in the UK and assumptions used for these calculations can be found in appendix 1. For instance, a 10% biogas blend used in hydrogen production results in -17 gCO2/kWh$_{H2, LHV}$ at an average hydrogen price of £46.2/MWh$_{H2, LHV}$ for demand levels defined in the central hydrogen scenario of section 4.

- Economic data used in this section are gathered primarily from the 2016 BEIS Electricity Generation Costs document, which forms the basis of the BEIS Energy and Emission Projections. A recent technical update to the BEIS Dynamic Dispatch Model is also used to supplement data on H2GT and CCS technologies.

- Nuclear plants are assumed to have a 60-year lifetime, while others have a 25-year lifetime. A uniform 10% discount rate is applied for all technologies. Load factors are assumed to be the same as in BEIS projections until 2035 and stay constant thereafter. CO_2 transport and storage (T&S) infrastructure is provided by a 3rd party company and a 90% CO_2 capture rate is used for CCS CCGTs.

Figure 8 compares the LCOEs for FOAK plants commissioning in 2025 for two different load factors. CCGT plants as well as plants replacing CCGTs would be operating at a 27% load factor. At such low load factors, CCGTs offer the lowest cost and there is no replacement potential for either Power CCS option. On the other hand, nuclear plants and any plant replacing them would be operating at a very high (90%) load factor. Both CCS CCGTs and H2GTs can cost effectively replace nuclear, which is helped by the fact that these nuclear plants would also be the FOAK European Pressurized Reactors in the UK. At 90% load factor, CCS CCGT would be a better nuclear replacement than H2GT due to its lower LCOE.

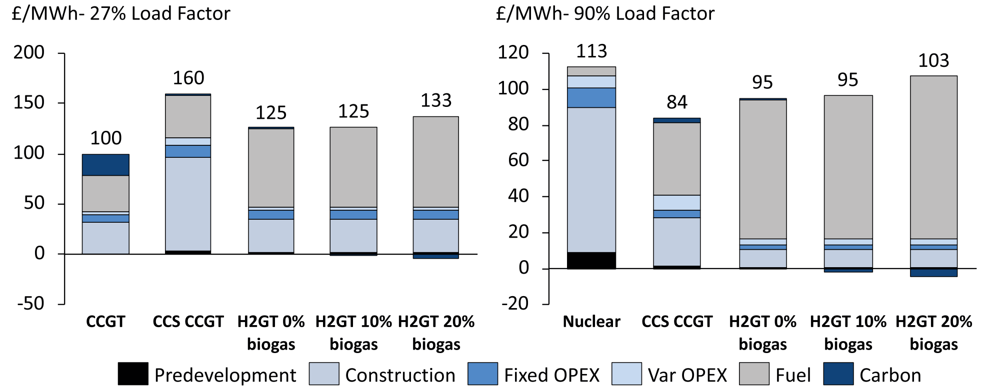


Figure 8: LCOE breakdown of FOAK technologies in 2025 at 27% and 90% load factors

Figure 9 compares LCOEs for NOAK plants commissioning in 2035. The load factor of CCGTs are down to 15% according to BEIS projections, increasing LCOEs of all plants compared to Figure 8. Although H2GTs have higher fuel prices and similar capital and operational expenses to CCGTs, they are found to be more cost competitive than CCGTs because of higher levels of projected carbon prices, compared to earlier years.[15] On the other hand, CCS CCGTs are still more expensive than CCGTs. The conclusions around nuclear plants do not change as much, as both Power CCS technologies are cost effective. CCS CCGTs still perform much better than H2GTs at these high load factors.

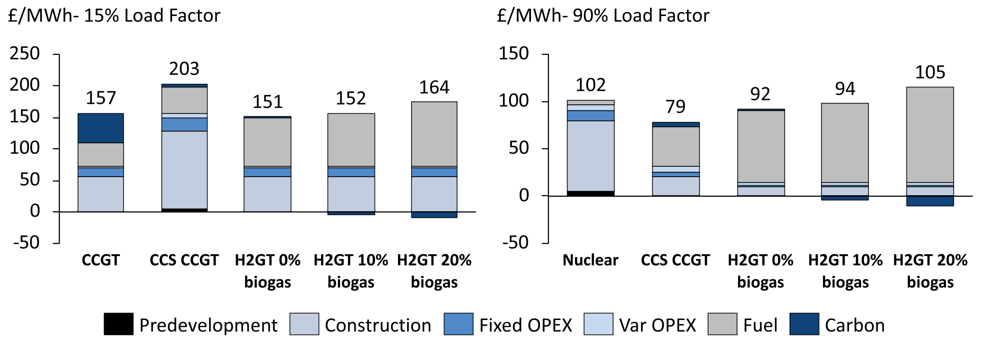


Figure 9: LCOE breakdown of NOAK technologies in 2035 at 15% and 90% load factors

Analysis at a range of load factors indicates that CCS CCGTs become more cost effective than H2GTs above load factors of 44%, 41% and 29% for 0%, 10% and 20% biogas blends, respectively. This is due to the higher Capex and lower Opex of CCS CCGTs compared to H2GTs. At high load factors, the effect of Capex diminishes and Opex becomes the dominant contributor to LCOE. Therefore, CCS CCGTs would be better replacements for baseload plants.

15 Carbon price estimates are taken from the 2016 BEIS Electricity Generation Costs document. They represent the sum of EU-wide prices of the EU-Emissions Trading Scheme (ETS) and UK specific Carbon Price Leavy. The carbon price estimations for 2019, 2035 and 2050 are £19/tonne, £79/tonne and £206/tonne, respectively. More information can be found in Appendix 2.

Throughout 2025-2035 the LCOE of H2GTs with blue hydrogen (0% biogas blend) and net negative hydrogen (10% biogas blend) are almost the same. Therefore, it would be preferable to opt for utilizing 10% biogas to achieve much better emissions savings for almost the same price. A 20% biogas blend would provide better emissions savings but significantly increase the cost of generation, as explained in section 4.6 in more detail. Therefore, in the rest of this study, it will be assumed that hydrogen production includes a 10% biogas blend, resulting in net negative emissions of -17 $gCO_2/kWh_{H2,\ LHV}$.

Figure 9 shows the LCOEs of plants running at the average BEIS load factor of 15%. However, in reality, CCGTs in a fleet operate on a wide range of load factors depending on their specific economic structure, efficiency, contracts and supply-demand balance at that time of the day. Even though CCS CCGTs at the average 15% load factor are 30% more expensive than CCGTs, some of the plants in the fleet may be operating at high enough load factors to justify replacement with CCS CCGTs. To investigate this, the distribution of load factors across the whole gas fleet capacity in 2035 as projected by BEIS (25.7GW) has been calculated. The distribution was derived from a simulation of plant dispatch and power consumption in the British electricity system in each hour of the year 2035, using historic power consumption and wind and solar power generation profiles, adjusted for the future power capacity mix as projected by BEIS. Details of this calculation are included in appendix 2 and the resulting replaceable capacities are shown in Figure 10.

Total UK **natural gas capacity** is forecasted to be 25.7 GW in 2035, according to BEIS projections. CCS CCGT plants could replace the portion of plants operating at load factors above 35%, accounting for 4.1 GW. Ideal target for replacement with CCS CCGT are the newest plants built in the 2020s, as these provide the highest generation efficiencies and are therefore typically operated at high load factors (due to low running costs). On the other hand, H2GTs could replace the entire CCGT fleet, excluding only 4.6GW, projected to be idle at 0% load factor.

Total UK **nuclear capacity** is forecasted to be 13.5 GW in 2035, according to BEIS projections. The entirety of this capacity can be replaced by either technology, since nuclear constantly runs at high load factors, where its LCOE is higher than the alternatives.

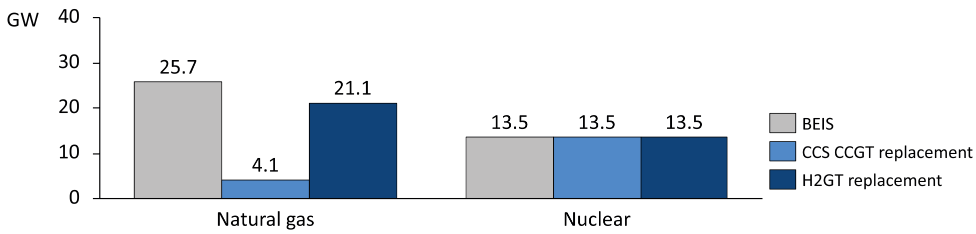


Figure 10: Total BEIS capacity in 2035 that can be replaced by H2GTs and CCS CCGTs

Note on 100% hydrogen burning, next generation gas turbine availability

Most current natural gas turbines can operate by burning a small fraction of hydrogen blended with methane. However, increasing the hydrogen content leads to high NOx emissions which violate environmental standards. Therefore, if a plant desires to operate purely on hydrogen today, it would either use diluted fuels (with N_2) or install a NOx capture facility. These additions are estimated to cost around 10-15% more Capex for new build plants and 15-20% for retrofits.

However, a recent ETI report (Salt Cavern Appraisal for Hydrogen and Gas Storage, 2018) estimates that large scale H2GTs, without any such problems, will be available by 2029-2030. Major turbine manufacturers already pledge support to developing new H2GTs capable of burning 100% hydrogen at similar efficiencies to current CCGTs and very low NOx emissions, which would not require additional capture plants. Some examples of recent developments and pledges are:

- **EUTurbines**, an association of the EU steam and gas turbine sector, committed to provide turbines capable of burning 20% hydrogen by 2020 and 100% hydrogen by 2030.
- **GE** developed the DLN 2.6e combustion system, available on 9HA turbines, that can operate with 50% hydrogen blend. Their smaller turbines, such as the 6B.03, have been working on 70% (reaching 90% at times) hydrogen for 20 years.
- **MHPS** have completed dry combustion tests with 30% blending and are targeting to develop full hydrogen turbines by 2024. They are also undertaking the Magnum project in the Netherlands, which aims to retrofit a 440 MW gas turbine, by 2025, to run on hydrogen with water injection and N_2 dilution.
- **Ansaldo** has proved the possibility of 100% hydrogen in combustion tests and are offering GT26 F-class and GT36 H-class turbines which are claimed to have an unrivalled ability to burn the widest range of hydrogen-methane mixes. They are also offering retrofit solutions to existing F-class turbines from GE, Siemens-Westinghouse and MHPS.
- **Siemens** successfully run a turbine prototype in Germany with 100% hydrogen and estimates that it can unveil 25 MW and 50 MW hydrogen burning turbines within two years.

Considering the above information, this study assumes that FOAK 100% H2GTs will be ready to be commissioned in 2029, at the earliest. It also assumes that if new CCGT plants are built hydrogen ready in 2020s using the newest available technology and in locations close to potential hydrogen production sites, they will be able to operate on blend of hydrogen in the future without any significant Capex investment. We assume the hydrogen blend is increased from 30% (by volume) initially to 90%, once more learning and experience has been gathered and blending starts to make economic sense due to higher carbon prices. H2GT availability is paramount for a future with hydrogen and requires continued R&D support of the turbine manufacturers to overcome current technical barriers.

3.2 Retrofits and Blending

BEIS projections include several natural gas plants being built in 2019-2025, before Power CCS technologies can be deployed. These plants have the potential to be retrofitted in later years, given they are built to be carbon capture and hydrogen ready. This section investigates the possible economic benefits of retrofitting CCGTs or converting them to use a blended fuel.

As explained in the note on 100% H2GT availability above, retrofitting early CCGTs with H2GT would cost 15-20% of the initial Capex. An additional cost of 15% is assumed in this section to determine the best-case situation. Furthermore, it is assumed that CCS CCGT retrofits would cost the same as the CCS-related components (e.g. capture facility Capex, T&S infrastructure system use charges) of the new built CCS CCGTs. Plants are not expected to get a life extension from retrofits since this process will not be replacing their turbines; thus a 20-year remaining lifetime (as opposed to 25 years for new build) is assumed. All the other assumptions are the same as in the previous section.

Figure 11 shows the net present (NPV) value of retrofits in 2030 and 2035 compared to continued unabated operation of the CCGT. Neither technology can be cost effectively retrofitted in 2030 or 2035 given the used cost assumptions. In general, H2GT retrofits are more cost effective than CCS retrofits. The Capex requirement for CCS retrofits is significantly higher than that for the H2GTs. Furthermore, CCS retrofits result in efficiency losses for the plant, since some of the electricity must be consumed by the capture plant. This is quantified by the negative "wholesale revenue" component in the diagram below. On the other hand, additional costs of H2GT retrofits are dominated by the higher fuel price of hydrogen compared to natural gas.

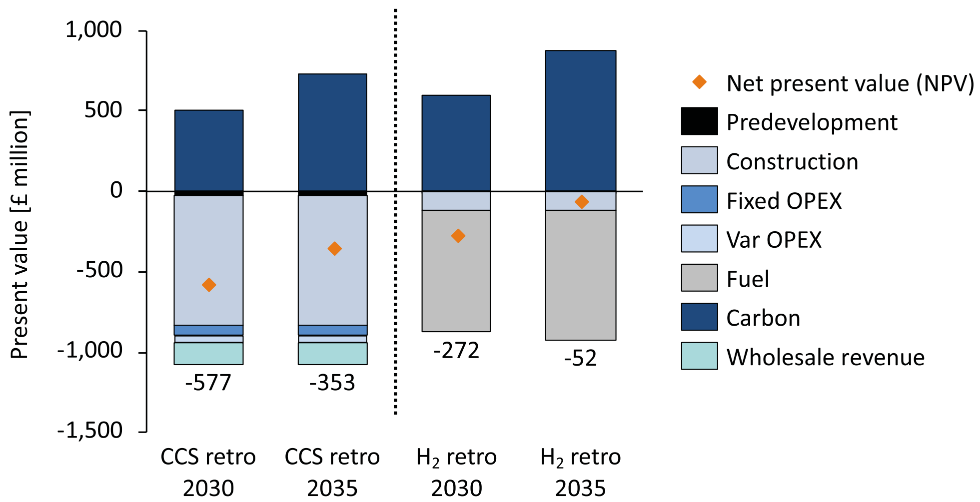


Figure 11: Net present value (NPV) of retrofitting CCGTs in 2030 and 2035, compared to continued operation as CCGT for a plant of 1,200 MW capacity

Retrofits introduce a trade-off between minimising Capex and Opex. In terms of Opex it is preferable to introduce the retrofit at a later date, when carbon prices are sufficiently high such that carbon cost savings exceed increased fuel and variable costs. However, the later the retrofit is conducted, the lower the remaining lifetime of the plant will be. Subsequently the Capex of the retrofit will have to be spread among fewer and fewer MWhs. Replacing the turbine during retrofits may extend the lifetime but would add significantly more Capex. Retrofitting will not be considered further in this report due to the lack of economic justification.

Instead of an outright retrofit, many plants can run on a blend of hydrogen and natural gas. Blending a specific ratio of hydrogen with natural gas is expected to be a lower cost option if future plants are built "hydrogen ready". This would require future plants to be located in the proximity of potential hydrogen production sites and be equipped with the latest turbine technologies capable of burning high hydrogen blends without requiring new Capex investments. As explained in the "Note on 100% hydrogen availability" in the previous section, current gas turbines can use 30% (by volume) blending and the newer gas turbines that would be built in mid 2020s can be expected to be able to run on 90% blending.

Figure 12 below compares the net present value of fuel switching in 2030 and 2035 at 30% and 90% blend rates. In the absence of Capex costs, the investment decision ultimately depends on the trade-off between higher fuel costs and new carbon cost savings that hydrogen provides. Carbon prices in the 2030-2045 timeframe are too low to justify switching in 2030, however, blending becomes economically feasible for plants converting in early 2030s as the carbon price rises to a sufficient level.

The ratio of blending does not impact whether it is cost effective or not because both the fuel costs and carbon prices vary in proportion to the blending ratio. Therefore, even if only small blending ratios can be reached, it would still be economically feasible to blend in early 2030s. However, the magnitude of financial gain/loss increases proportionally with the blending ratio.

Hydrogen produced from a blend of natural gas and 10% biogas is associated with net negative emissions of -17 $gCO_2/kWh_{H2, LHV}$. The carbon footprint of CCGTs can be reduced from 341 gCO_2/kWh_e to 62 gCO_2/kWh_e (82% emissions reduction) when blending 90% hydrogen by volume (75% by energy). The emissions reduction achieved through hydrogen blending is therefore ~92% of the emissions reduction achieved through CCS (capture rate 90%), considering the efficiency penalty of carbon capture. More detail on the carbon intensity of the various Power CCS options is given in section 4.6.2.

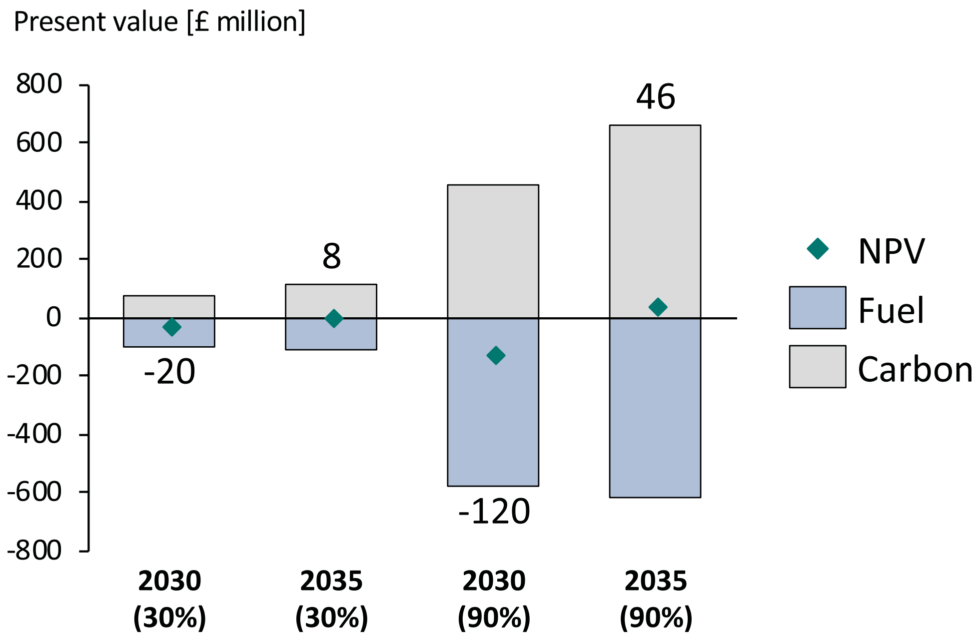


Figure 12: NPV of blending 30% and 90% (by volume) hydrogen for CCGTs in 2030/35, compared to continued operation as CCGT for a plant of 1,200 MW capacity

Note on CO_2 and hydrogen storage potential of the UK and likely future plant locations

Figure 13 below shows the locations and capacities of the proposed new CCGT projects in the UK along with potential CO_2 and hydrogen storage locations. The figure also specifies for each CO_2 and hydrogen storage location the CCGT CCS and H2GT capacity respectively for which it could supply sufficient storage. As of 2019 Q2, there are 4 CCGT projects (green dots) that recently received DCOs (Development Consent Order) according to the National Infrastructure Planning website. Of these, only the 0.84 GW Keadby 2 plant received final investment decision (FID) and is expected to start operation by the end of 2022.

While the total capacity of these plants alone is almost equivalent to the new CCGTs in the BEIS projections, building many small scale (<0.5GW) plants commissioned over many years, as BEIS suggests, is highly unlikely since fewer high capacity plants would be much more feasible. However, as in the case of nuclear new build, this project continues to use the BEIS projections as the baseline scenario.

There is a total of 8 CO_2 storage sites in the UK with full project appraisal (source: ETI, Strategic UK CCS storage appraisal project, 2016) and many more sites at various levels of development. Figure 13 presents the CCS CCGT capacities that they can support at maximum CO_2 injection rates, assuming a 1GW plant injects 2.92 $MtCO_2$/year at full load. Red values are the total capacities of storage clusters and higher numbers represent a 33% load factor assumption. Clearly these sites alone could accommodate the captured CO_2 if all new CCGTs of the BEIS forecast in 2020-2035 (7GW) were fitted with CCS.

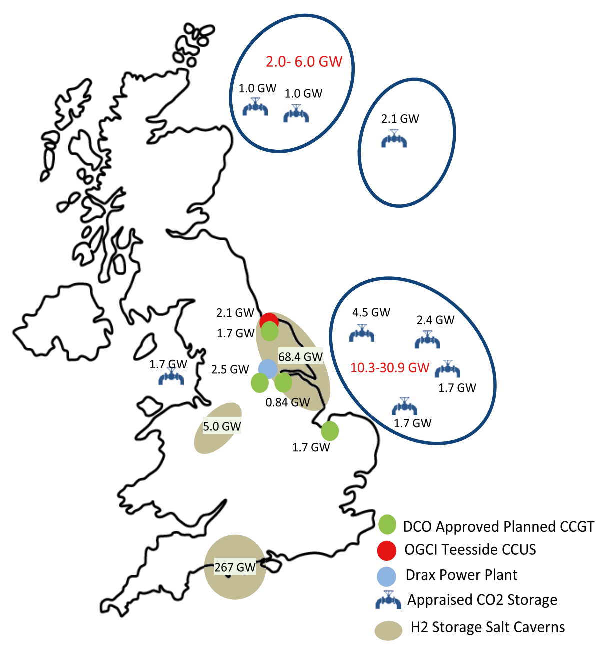


Figure 13: UK gas storage potential and locations of proposed CCGTs

Similarly, hydrogen storage capacity in salt caverns in the Humber-Teesside region can sustain operations of a total of 68 GW H2GT plant (refer to appendix 4 for details), which would be enough for a deep hydrogen transition going beyond the power and heating industries. The coexistence of hydrogen and CO_2 storage sites makes this region an ideal candidate for early CCS clusters, where any new CCGT plants built in the next 6-7 years can have easy access to hydrogen for blending in the future. The Teesside CCUS cluster project by OGCI Climate Investments (red dot on the map) may serve as an initial anchor from as early as 2025.

Drax, shown as the blue dot on the map, is also investigating options for converting its remaining coal turbines to CCGTs with CCS, which may serve as the perfect anchor for a Humber low carbon cluster.

Deployment of H2GTs and Power CCS in the UK

4

4. Deployment of H2GTs and Power CCS in the UK

4.1 Technology availability and deployment timelines

The economic assessment presented in the previous chapter showed that it would be cost-effective to replace most of the CCGTs and nuclear with H2GTs and CCS CCGTs between 2020 and 2035. The key barrier to deployment of these technologies in the UK is expected to be technology availability and long lead times. FOAK projects are not operational in the UK yet; however, several project development activities are taking place in the UK and elsewhere in the world, with potential implications on the UK's Power CCS and hydrogen deployment. An overview of these projects and their key significance to this study are provided below:

- **Hydrogen to Magnum**: Equinor, Vattenfall and Gasunie signed a memorandum of understanding to convert one of the 440 MW gas turbines of the Magnum power plant in Eemshaven in the Netherlands to run on 100% hydrogen by 2025. Even though this project is not in the UK, it has the potential to contribute to the learning curve of H2GTs and large scale hydrogen production through ATR, reducing costs potentially faster than at the rate considered in this report.

- **H21 North of England (NoE)**: As a detailed engineering solution to converting 3.7 million UK homes to hydrogen, H21 NoE is the largest clean energy project in the world. It hopes to decarbonize heating in a wide region containing Leeds, Bradford, Wakefield, York, Huddersfield, Hull, Liverpool, Manchester, Teesside and Newcastle. The project estimates that large scale hydrogen production through ATR in the Humber region may start as early as 2028, which aligns with the assumption of full H2GT availability by 2029. Furthermore, the H21 XL scenario presented in the report identifies significant cost saving opportunities if the excess hydrogen not required for heat in the summer is re-directed to power generation. Such an integrated system could alleviate some storage requirements and increase ATR operation hours, thus reducing hydrogen production costs.

- **OGCI Clean Gas Power Project in Teesside**: OGCI Climate Investments proposed a 2100 MW CCS CCGT facility in Teesside, expected to apply for a development consent order (DCO) by Q2 2020 and potentially commission in 2026 after a 5-year construction period. This plant may form an anchor for an early cluster at Teesside. While our study does not assume success or failure of the OGCI CCS plant, 2026 is chosen as an achievable target for FOAK CCS CCGT availability.

- **Drax, Equinor, National Grid Ventures - Humber CCS Project**: Three key stakeholders in the energy industry recently announced their partnership in exploring opportunities to create the world's first negative emission power plant in Yorkshire and the Humber. They aim to investigate scaling-up the pilot BECCS project of Drax and building a large scale hydrogen demonstrator at the site by the mid-2020s. This project may establish the Humber region as the prime location for a future hydrogen economy and, if successful, attract H2GT plants by providing essential T&S infrastructure.

In light of the projects listed above, Figure 14 shows the earliest availabilities of FOAK to NOAK Power CCS technologies in the UK. FOAK, SOAK and NOAK pre-development and construction times for Power CCS technologies are taken from the BEIS electricity generation costs data and are listed in appendix 5 in detail. The periods shown in Figure 14 form the basis of technology availability in scenario creation, presented in the rest of this section.

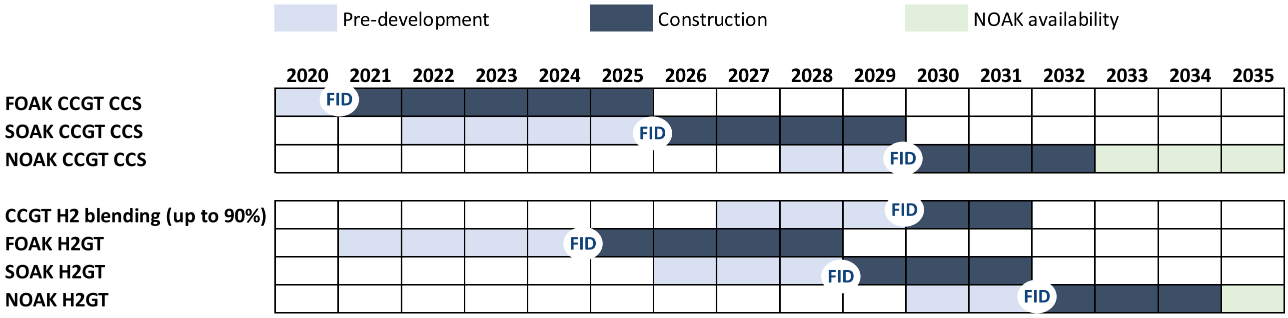


Figure 14: Representative deployment timetables for FOAK to NOAK stages

A total of 3 Power CCS scenarios (see Figure 15) were developed examining different levels of ambition and technology diversity:

- **Central hydrogen Scenario:** New build H2GTs replace some of the planned nuclear and CCGT plants starting from 2029.
- **High hydrogen Scenario:** In addition to the H2GT plants in the central scenario, early CCGTs convert to burning a blend of hydrogen and natural gas starting from 2032.
- **High hydrogen & CCS Scenario:** Both CCS CCGTs and H2GTs replace a portion of the planned BEIS plants and both technologies reach NOAK status as soon as possible. Blending is used for the leftover new build CCGTs starting from 2032.

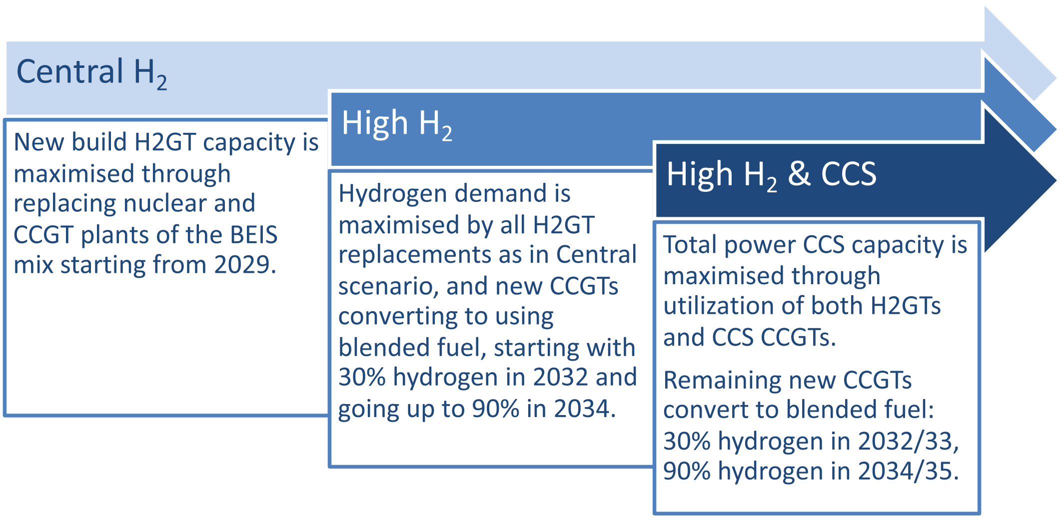


Figure 15: Three Power CCS deployment scenarios in order of increasing ambition

Key scenario assumptions are the following:

- Nuclear and CCGT plants in the BEIS projections will be replaced by Power CCS technologies, keeping the new capacity added each year constant.
- Power CCS plants will operate at the same load factor as the technologies they replace (nuclear or CCGT). These are dynamic until 2035 and are assumed to stay constant afterwards.
- Plants of capacity smaller than 200MW are not replaced as they don't offer sufficient economies of scale.
- New CCGT plants are assumed to be hydrogen ready: they are situated close to future hydrogen sources (i.e. industrial clusters) and utilizing state of the art turbines with high blending capabilities.

The next sections will explain the details of these scenarios and their key improvements compared to the technologies deployed in the BEIS forecast.

4.2 Central hydrogen scenario

In the central scenario, deployment of new built H2GTs is maximized starting from 2029 onwards. As shown in Figure 16, a total of 8.4 GW H2GTs are built in form of 1 FOAK, 3 SOAK and 2 NOAK plants. They replace a total of 6 GW of nuclear, 1.4 GW of CCGT and 1.1 GW of CCS CCGT.[16] 6.3 GW of nuclear in the BEIS mix could not be replaced because they are commissioned before 2032, when SOAK H2GTs are not yet available.

In 2034, BEIS projections include a 1.5 GW nuclear and a 1.68 GW CCGT plant, both of which could be replaced by H2GTs. It was chosen to replace the nuclear plant instead of the CCGT, even though CCGT replacement saves more emissions per MWh generated, as nuclear operates at significantly higher load factors and therefore provides higher total cost savings.

16 The nuclear, CCGT and CCS CCGT capacities do not add up to 8.4GW due to rounding

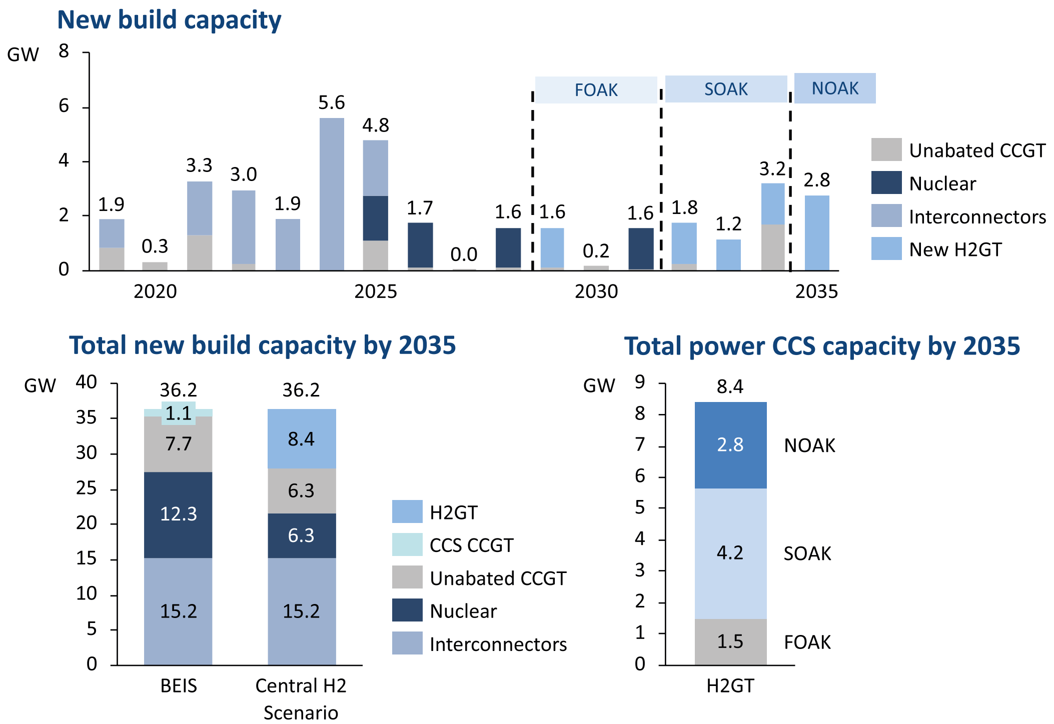


Figure 16: Summary of the added capacity in the Central Scenario

The electricity generation mix of the central scenario is shown in Figure 17. Compared to the BEIS forecast (Figure 5), the share of nuclear is almost halved (reduced from around 27% to 15%) in 2035, while the share of natural gas only marginally decreases from 8.6% to 8.2%. New built H2GTs contribute to 14% of the power mix.

The central scenario achieves emission savings of 2.5 $MtCO_2$/year and annual system level cost reductions of £450 million by 2035 compared to BEIS projections.[17] Furthermore, the grid carbon intensity (given by the total emissions by all power plants divided by the total power generation) in the central scenario in 2035 would be 35 gCO_2/kWh_e, 6 gCO_2/kWh_e lower than in the BEIS projections.

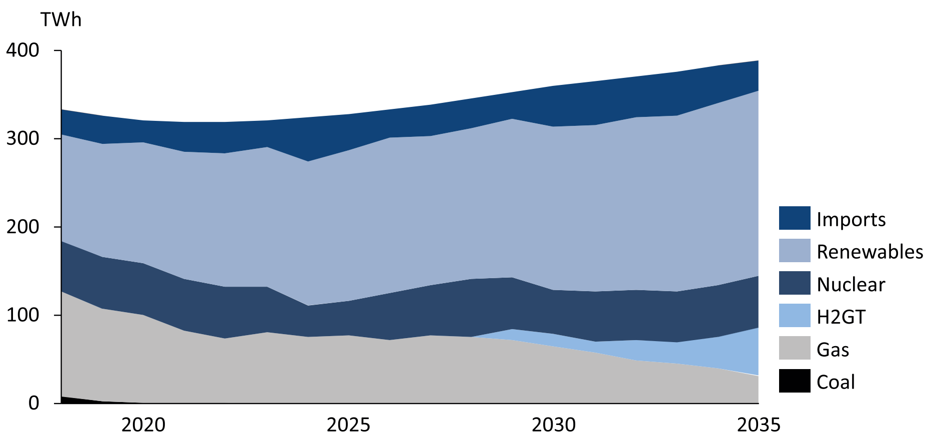


Figure 17: Electricity generation in the central scenario

17 Annual system cost savings are calculated based on the LCOE of various power plants. Compare Appendix 2 for more details on the methodology used to calculate system cost and emission savings.

4.3 High hydrogen scenario

The high hydrogen scenario is identical to the central case in terms of H2GT deployments but adds hydrogen blending to the CCGT plants built after 2020, which are all considered to be hydrogen ready. Blending would start in 2032 on small scale (0.60 GW) and is gradually deployed to reach a total of 5.5 GW by 2035. Blending starts in 2032/33 with 30% hydrogen by volume and progresses to 90% blending (75% by energy) in 2034/35 as technology learning happens. Figure 18 summarizes the high hydrogen scenario deployment. CCGT capacities after 2032 represent added capacity net of plants converting to blending in the same year.

In more detail, the assumptions on the capacity using a hydrogen blend are the following:

- 2032: CCGT capacity added (in High hydrogen scenario) in 2020 and 2022 starts blending.
- 2033: CCGT capacity added (in High hydrogen scenario) in 2021 starts blending.
- 2034: CCGT capacity added (in High hydrogen scenario) in 2023-2029 starts blending.
- 2035: CCGT capacity added (in High hydrogen scenario) in 2030-2034 starts blending.

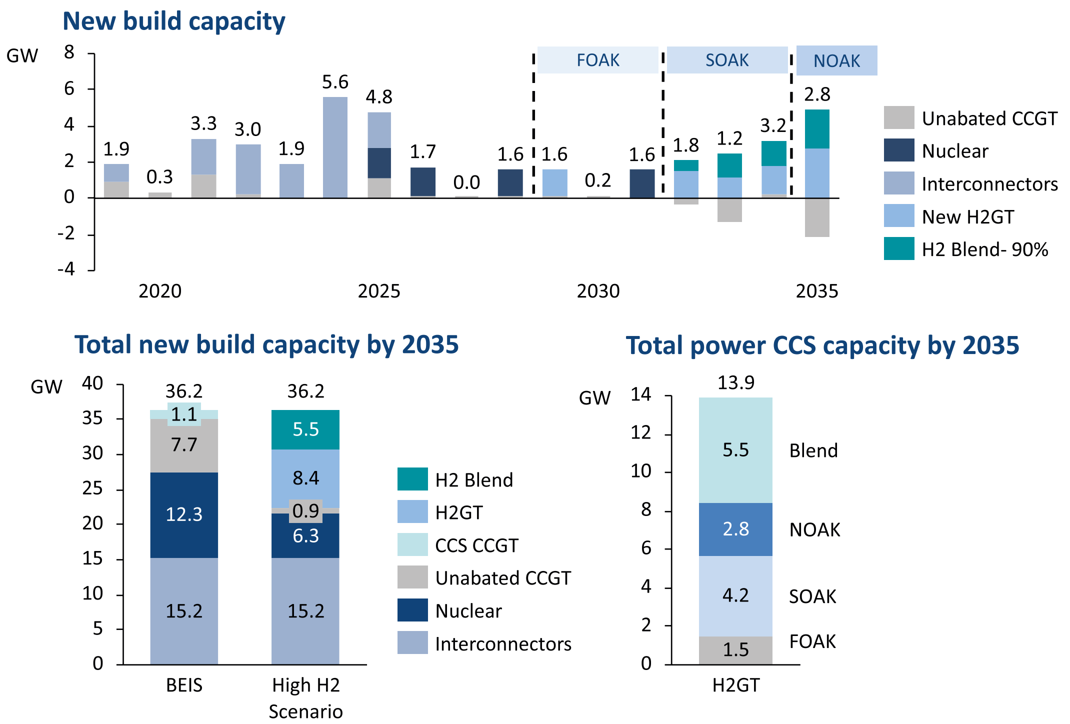


Figure 18: Summary of the added capacity in the high hydrogen scenario

The electricity generation mix is shown in Figure 19. The share of total natural gas-based generation (including CCGTs and natural gas used in blending) is further reduced to 6.8% compared to 8.6% in the BEIS mix and 8.2% in the central scenario. Total generation from blending is relatively low, at 7.12 TWh/year in 2035, due to low load factors.

The high hydrogen scenario achieves emission savings of 3.9 $MtCO_2$/year and annual system level cost reductions of £460 million by 2035 compared to BEIS projections. Furthermore, the grid carbon intensity in the high hydrogen scenario in 2035 would be 31 gCO_2/kWh_e, 10 gCO_2/kWh_e lower than in the BEIS projections.

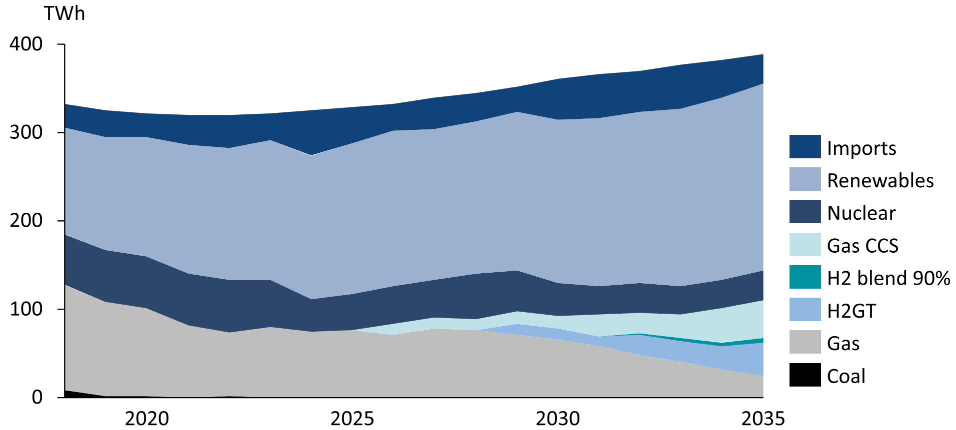


Figure 19: Electricity generation in the high hydrogen scenario

4.4 High hydrogen & CCS scenario

The high hydrogen & CCS scenario replaces BEIS capacities by both H2GTs and CCS CCGTs. As shown in Figure 20, this scenario is able to cover a wider timescale and therefore replace more capacity, since CCS CCGTs will be available as FOAK by 2026. A total of 6.2 GW H2GT and 7.1 GW CCS CCGT is built until 2035, in addition to 3.8 GW CCGTs converting to 30% (2032/33) and 90% (2034/35) hydrogen blend. The total capacity converting to blending is smaller than in the High hydrogen scenario, because CCGTs are mostly replaced rather than converted to blending. The detailed assumptions on the timing of the conversion to blending are the same as in the High hydrogen scenario, i.e.

- 2032: CCGT capacity added (in the High hydrogen & CCS scenario) in 2020 & 2022 starts blending.
- 2033: CCGT capacity added (in the High hydrogen & CCS scenario) in 2021 starts blending.
- 2034: CCGT capacity added (in the High hydrogen & CCS scenario) in 2023-2029 starts blending.
- 2035: CCGT capacity added (in the High hydrogen & CCS scenario) in 2030-2034 starts blending.

There is a trade-off between nuclear replacement via H2GTs and CCS CCGTs. When nuclear plants are replaced by CCS CCGTs, cost savings are higher (as suggested by LCOEs, Figure 9). However, H2GTs provide better emission reduction due to being carbon negative. In fact, replacement of nuclear with CCS CCGT increases CO_2 emissions, because it requires combustion of natural gas with only 90% of emissions captured, whereas nuclear generation produces zero emissions. As a consequence, this scenario opts for a middle ground that balances cost and emissions savings: in 2032-33 one nuclear plant is replaced by an H2GT and one CCGT is replaced by CCS CCGT, while in 2034 the opposite is chosen.

This scenario includes a total of 3.15GW of CCGTs with CCS by 2030, which is in line with the recommendation of investing into 3 GW Power CCS by 2030 in ETI's recent CCS report.[18]

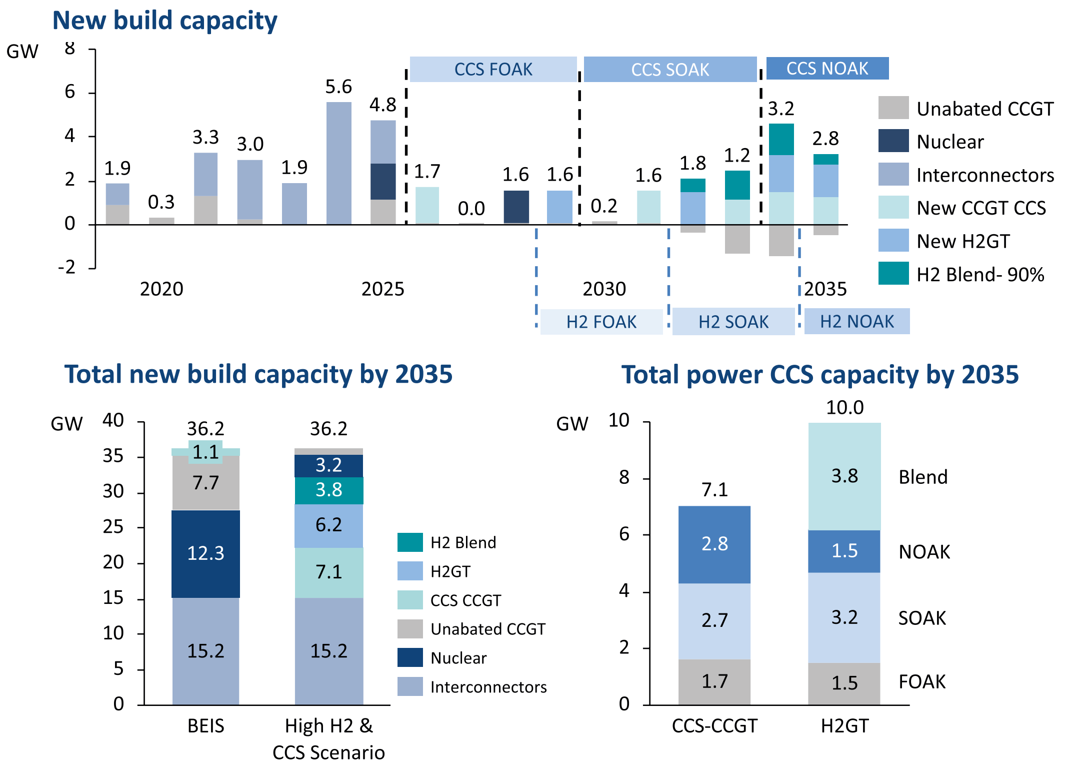


Figure 20: Summary of the added capacity in the high hydrogen & CCS scenario

Figure 21 shows the power generation mix of the high hydrogen & CCS scenario. Compared to the BEIS projections the share of nuclear generation decreases from 27% to 8.6% and the share of unabated gas is 6.3% instead of 8.6%. H2GTs comprise 9.5% of the total generation, while CCS CCGT accounts for 11.4%.

18 ETI, 2018,Still in the mix? Understanding the system role of CCUS

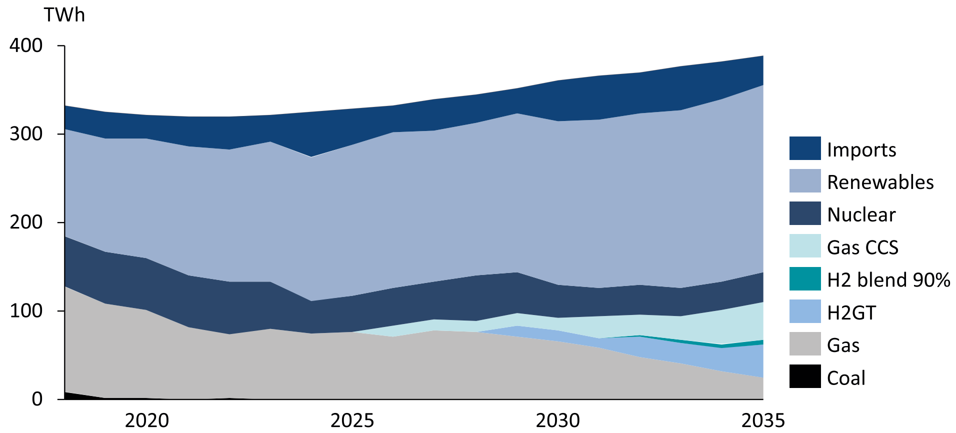


Figure 21: Electricity generation in the high hydrogen & CCS scenario

The high hydrogen & CCS scenario achieves emission savings of 1.8 $MtCO_2$/year and annual system level cost reductions of £1,210 million by 2035 compared to BEIS projections. Furthermore, the grid carbon intensity in the high hydrogen & CCS scenario in 2035 would be 36 gCO_2/kWh_e, 5 gCO_2/kWh_e lower than the BEIS projections.

4.5 Comparison of system level benefits

Figure 22 compares the projected capacity mix of the three scenarios with the original BEIS estimation. It can be noticed that scenarios progressively replace more capacity, to the point that only 3.2 GW nuclear capacity is retained in the high hydrogen & CCS scenario. Individual power plant rollout timetables of all scenarios can be found in Appendix 6.

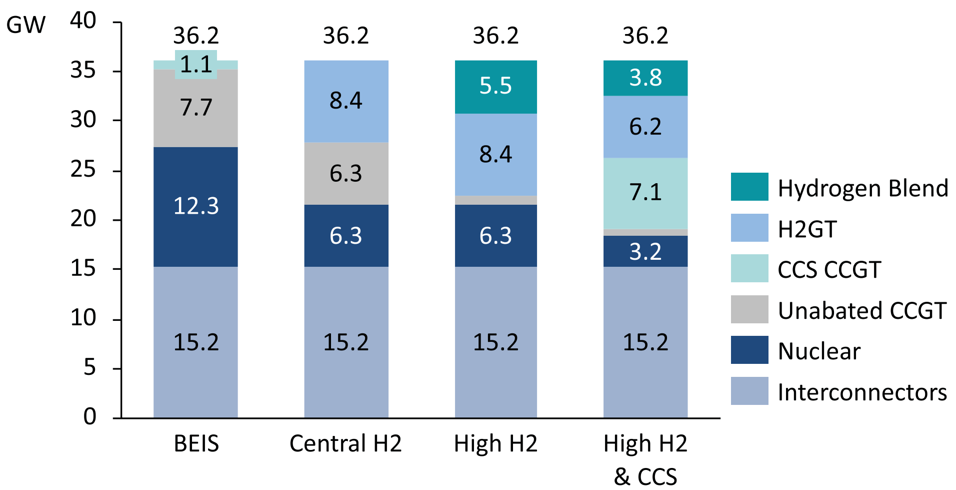


Figure 22: Comparison of cumulative added capacity in all scenarios

Figure 23 compares the capacities of the replaced technologies in the three scenarios. The majority of generation capacity being replaced in all scenarios is baseload nuclear, operating at high load factors. However, all three scenarios also include the replacement of one flexible CCGT plant, operating at low load factors. Therefore, Power CCS technologies substituting conventional generation technologies would need to be capable of competitive operation at both high and low load factors.

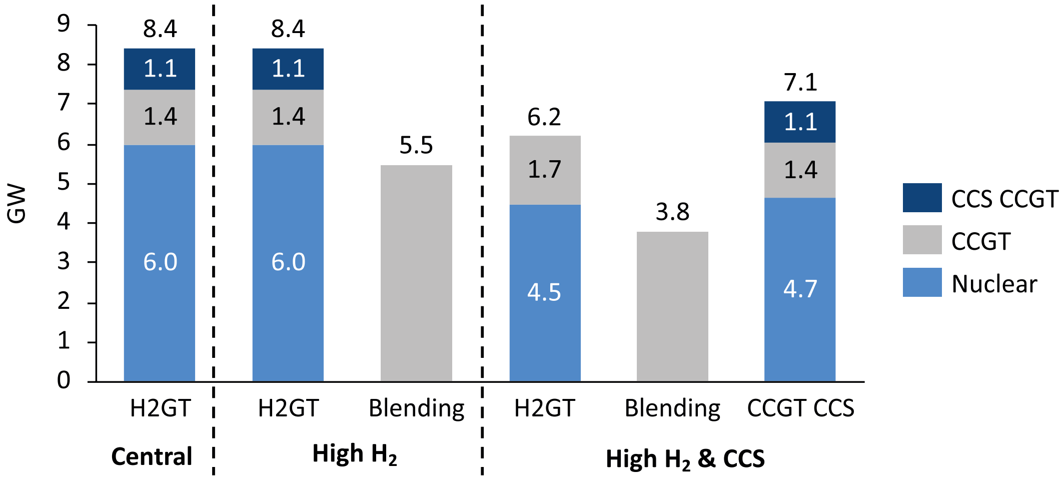


Figure 23: Replaced capacities per replaced and replacing technologies in each scenario

Annual emission savings of all scenarios are compared in Figure 24. The early emissions increase observed with the high hydrogen & CCS scenario is due to the replacement of one nuclear plant with a CCS CCGT. High hydrogen scenario provides the highest emission savings, through maximization of net negative hydrogen deployment.

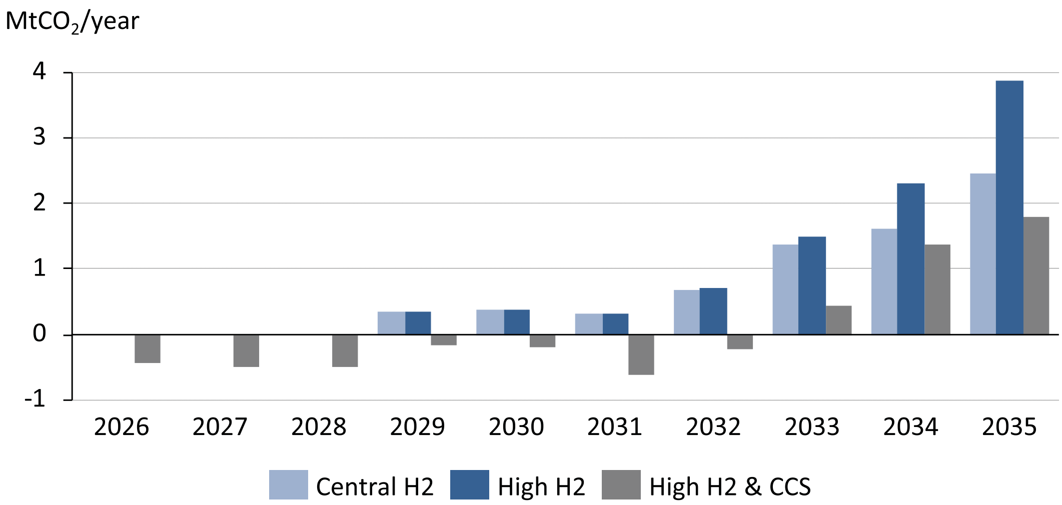


Figure 24: Annual emission savings of the 3 scenarios

Figure 25 puts the emissions savings in context by comparing the annual emissions from electricity generation in the whole UK in a 2026-2035 timeframe. The BEIS emissions are calculated considering all types of generation technologies in the BEIS projections.[19] The high hydrogen scenario leads to the best savings in 2035, amounting to a reduction of 24% compared to the BEIS projections. The Central hydrogen scenario saves 15% and the High hydrogen & CCS scenario saves only 11% in the same year.

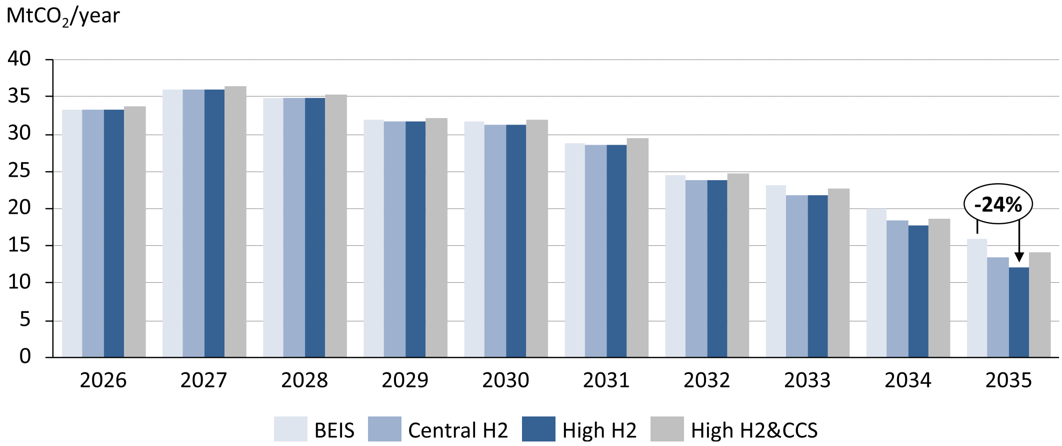


Figure 25: Annual emissions of the BEIS and 3 Power CCS scenarios compared

Figure 26 compares the annual cost savings of all scenarios relative to BEIS between 2026-2035. In 2017 the market value of inland electricity consumption was £36 billion, implying that the three Power CCS scenarios would reduce the total national electricity generation cost between 1.2% to 3.4%.[20]

The High hydrogen scenario results in similar cost savings as the Central hydrogen scenario. This is due to the trade-off introduced by adding hydrogen blending: while carbon costs decrease, higher hydrogen consumption leads to increased biomass use and subsequently to higher hydrogen prices.

On the other hand, the high hydrogen & CCS scenario provides 2.6 times the savings of the other options. This significant improvement is explained by (a) more of the BEIS capacity being replaced with the addition of early CCS availability and (b) CCS CCGTs being much more economic than H2GTs for replacing baseload nuclear plants (Figure 9).

19 Compare Appendix 2 for the assumptions on carbon intensities of older CCGT, coal and imports. Renewables and nuclear are assumed to have no emissions.

20 Digest of United Kingdom Energy Statistics (DUKES) 2018, page 33

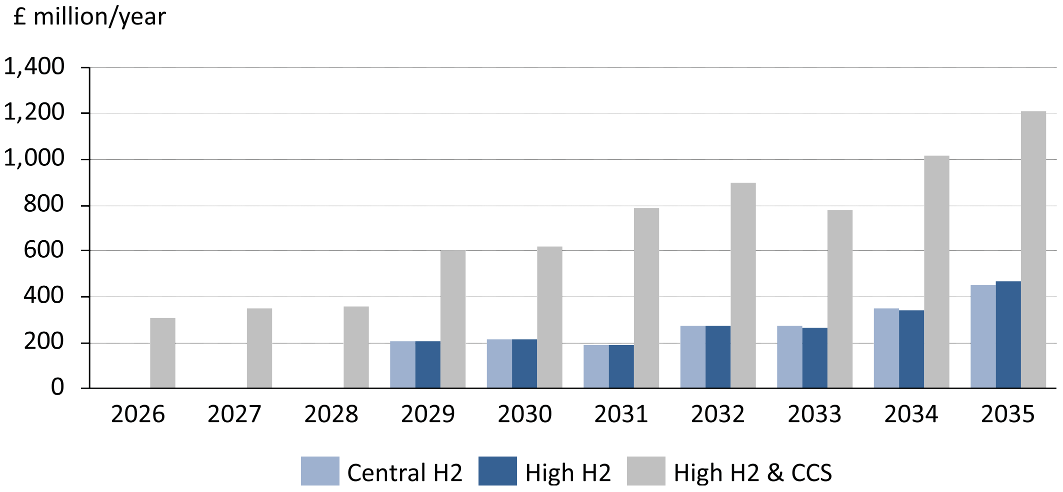


Figure 26: Annual cost savings of 3 scenarios compared with BEIS scenario

Table 6 summarizes the key performance parameters of the three scenarios, for hydrogen production from a 10% blend of biogas. The addition of CCS CCGTs in the third scenario provides a trade-off between lower emissions savings and significantly higher cost reduction. The scenarios are also able to decrease the grid carbon intensity by 5-10 gCO_2/kWh_e, which is a significant contribution considering BEIS projections of 41 gCO_2/kWh_e by 2035.

Parameter	Units	Central	High H_2	High hydrogen & CCS
Annual cost saving in 2035	£ million/year	450	460	1,210
Total cost saving (2025 – 2050)	£ billion	8.7	8.9	25.1
Annual emission savings in 2035	$MtCO_2$/year	2.5	3.9	1.8
Total emission savings (2025-2050)	$MtCO_2$	44	68	28
Grid intensity reduction in 2035	gCO_2/kWh_e	6	10	5
Annual hydrogen demand in 2035	$TWh_{H2, HHV}$/year	108	116	77
Annual bioenergy demand in 2035	$TWh_{H2, HHV}$/year	12.7	13.6	9.1

Table 6: Key performance parameters of the CCS power scenarios compared to BEIS forecast

4.6 Impact of biogas blending rates

Using a blend of natural gas and biogas is necessary to make hydrogen produced by ATRs carbon neutral or net negative. A 10% biogas blend was chosen for the scenarios of this study as presented in the previous sections. However, to assess the impact of the level of biogas used in hydrogen production on emissions and costs, a sensitivity study with 0% and 20% biogas blend was conducted. Furthermore, the availability of the biomass volumes required to supply demand in hydrogen production at different biogas blending percentages was assessed.

4.6.1 Biomass availability

Large volumes of hydrogen production using a 10% biogas blend for ATR would also result in large utilisation of biogas. It is therefore necessary to assess the availability of biogas from biomass in the UK and determine its impact in the Power CCS scenarios. Element Energy previously estimated biogas availability in the UK for 2035 to be able to support 243-556 $TWh_{H2, HHV}$/year hydrogen with 10% biogas blend and 122-275 $TWh_{H2, HHV}$/year hydrogen with 20% biogas blend between the central and high availability cases of the study ***Net zero hydrogen production and deployment in the UK*** by Element Energy for Equinor.[21]

The three Power CCS scenarios developed in this study lead to a hydrogen demand of 77 – 116 $TWh_{H2, HHV}$/year in 2035 for power generation. Additionally, hydrogen demand from industry, heat and transport in the UK was estimated to be 140 $TWh_{H2, HHV}$/year in 2035, based on the H21 NoE XL scenario and EE's work for the CCC and LowCVP hydrogen Infrastructure roadmap. As a result, total maximum hydrogen demand from all sectors considered is estimated to be 256 $TWh_{H2, HHV}$/year in 2035.

Total hydrogen demand in all three Power CCS scenarios of this study is therefore compatible with the estimated future availability of biomass supply in the UK - both in the cased of 10% and 20% biogas blending in hydrogen production. However, while biomass demand for 10% blending of biogas aligns well with the central projections of biomass availability, 20% biogas blending would require a high availability of UK bioenergy resource.

21 Note that the report does not explicitly mention the different volumes of hydrogen that could be produced under different biomass availability scenarios and different biogas blends. Instead the levels of hydrogen demand are set and the biogas blend is varied based on how much bioenergy is available (cp. Table 4.3 of the report). The volumes mentioned here have been calculated using the same model and assumptions as the report.

4.6.2 Carbon intensities of generation technologies

To understand the impact of replacing CCGT and nuclear with CCS and hydrogen fuelled power plants on electricity system emissions, the carbon intensities (emissions per kWh of electricity generated) of the technologies considered must be compared. These carbon intensities are shown in Figure 27 below.

When CCGTs and nuclear are replaced with H2GTs, the **carbon saving per replaced kWh** of electricity will depend on the percentage of biogas blended in the production of the hydrogen utilised:

- When using a 10% biogas blend, power from H2GTs (-29 gCO_2/kWh) **replacing CCGTs** (-341 gCO_2/kWh) delivers an emission saving of 370 gCO_2/kWh. This saving is 12% higher when a 20% biogas blend is used and 12% lower when a 0% biogas blend is used.
- When using a 10% biogas blend, power from H2GTs (-29 gCO_2/kWh) **replacing nuclear** (0 gCO_2/kWh) delivers an emission saving of 29 gCO_2/kWh. This savings is more than doubled (74 gCO_2/kWh), when a 20% biogas blend is used, whereas the use of 0% biofuel results in an increase in emissions (15 gCO_2/kWh).

When H2GTs (with a 10% biogas blend) replace CCGTs, the emission saving per kWh (370 gCO_2/kWh) is about 13 times as high as when H2GTs replace nuclear (29 gCO_2/kWh). But the load factor of nuclear power plants is about 6 times as high as that of CCGTs, i.e. each year nuclear plants produce 6 times as many kWh per GW of installed capacity as CCGTs. The resulting yearly **emission saving per unit** of replaced **capacity** is therefore roughly **twice as high** for H2GTs **replacing CCGT** as for H2GTs replacing nuclear.

Additionally, the **conversion of CCGTs** to using a fuel blend of 90% hydrogen (produced with a 10% biofuel blend) delivers emissions savings of 279 gCO_2/kWh, which is about 10 times as high as the emission savings resulting from the replacement of nuclear with H2GTs (29 gCO_2/kWh). Similarly, to above, due to the higher load factor of nuclear, this means the resulting emission savings per replaced capacity is roughly twice as high when CCGTs switch to a 90% hydrogen blend as when nuclear is replaced by H2GTs.

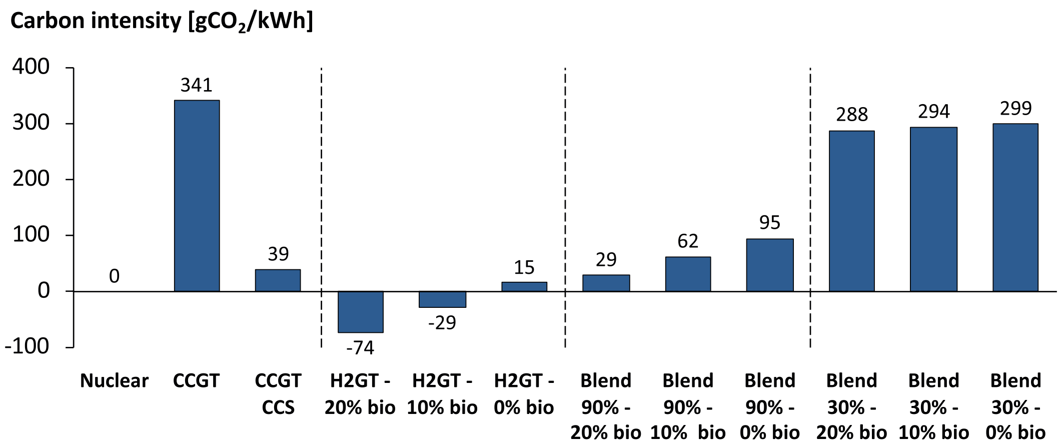


Figure 27: Carbon intensity of electricity generation for the technologies considered in the scenarios

4.6.3 Comparison of cost & emission savings for different biogas blends

The total cost savings and emission savings compared to the BEIS mix were calculated for the case of using a 20% biogas blend as well as for the case of using 0% biogas for hydrogen production. Savings for 0%, 10% and 20% biogas blends in 2035 are shown in Figure 28 below.

Compared to the emission savings of the 10% blending case, emissions savings in both Central and High hydrogen & CCS scenarios are almost doubled when using the 20% biogas blend and almost completely eliminated when using the 0% biogas blend. In the High hydrogen scenario, emission savings are increased by 67% when using the 20% biogas blend and reduced by 67% when using 0% biogas. This is because a larger proportion of emission savings in the High hydrogen scenario stems from the replacement of CCGTs by H2GTs (or hydrogen blending CCGTs) compared to the other scenarios. The emission savings due to this replacement are less sensitive to the biogas blend than the replacement of nuclear generation, as shown in the previous section.

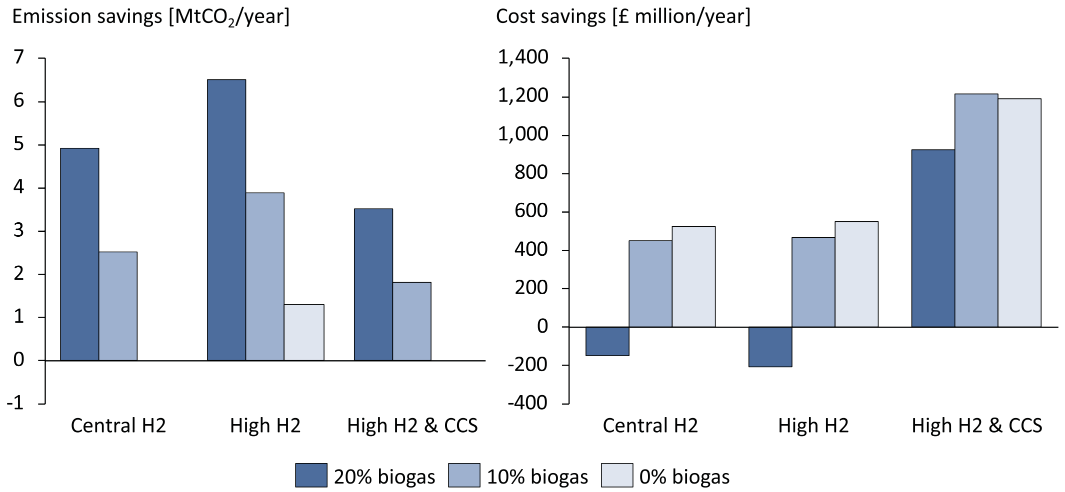


Figure 28: Annual emission and cost savings in 2035 relative to the BEIS scenario for different biogas blending rates and CCS scenarios

Using a 0% biogas blend achieves similar cost savings as using a 10% biogas blend, whereas using a 20% biogas blend leads to significantly lower cost savings and even to an increase in costs for the Central hydrogen and High hydrogen scenarios. This is due to the difference in fuel and carbon costs for hydrogen fuelled CCGTs when using different biogas blends.

As shown previously (Figure 8 and Figure 9), the LCOE of H2GTs using 0% biogas are minimally lower than those of H2GTs using 10% biogas, while those of H2GTs using 20% biogas are significantly higher. This is in line with the comparison of total annual cost savings for different blending rates in the Central hydrogen and High hydrogen scenario shown in Figure 28 above. The LCOEs discussed previously were based on the Central hydrogen scenario. LCOEs estimated for different biogas blends compare similarly in the High hydrogen scenario, but the differences are slightly amplified, as hydrogen consumption is higher than in the Central hydrogen scenario, leading to higher hydrogen prices in the case of the biogas blending (see Appendix 1 for details on hydrogen price calculations).

However, the situation is slightly different in the High hydrogen & CCS scenario, where lower hydrogen consumption than in the Central hydrogen consumption leads to lower prices of hydrogen using biogas blending. This in turn leads to minimally lower LCOE of H2GTs when using 10% biogas blending than when using 0% biogas (for a comparison of the LCOEs in the different scenarios and for the different biogas blends, compare Appendix 2). Consequently, the 10% biogas blend shows slightly higher cost savings than the 0% biogas blend in this scenario.

In conclusion, a 10% biogas blend appears to offer the best combination of cost and emission savings: a 20% biogas blend achieves higher emission reductions but at significantly higher cost. A 0% biogas blend does hardly achieve any emission reduction compared to the BEIS scenario and it only leads to marginally higher cost savings than the 10% blend. Therefore, a moderate level of bioenergy utilization is paramount to optimize the Power CCS technologies for both cost and emissions savings.

Additional system benefits

5. Additional system benefits

5.1 Potential to reduce future power imports

This section investigates the contribution of interconnectors to security of supply in the BEIS forecast and the potential of Power CCS technologies to displace imports at lower costs and emissions. The analysis focuses on the High hydrogen scenario as a case study.

Contribution of interconnectors to security of supply and emissions

The BEIS projections expect around 10% of electricity demand to be supplied by imports by 2035. Current interconnections include countries with low (France, Belgium) as well as high (Netherlands, Republic of Ireland) carbon intensities of electricity. Future interconnections are expected to include countries who currently have higher (Germany) and lower (Norway) carbon intensities than the UK.

Currently interconnectors are used at a high load factors reflecting price differentials e.g. to the French electricity market dominated by low marginal cost generation from nuclear power. In the future they are however expected to be used as a source of flexibility complementing domestic supply by variable renewable energy sources (VRES), such as wind and solar. This is reflected in the increasing interconnector capacity but decreasing load factors of this capacity in the BEIS projections up to 2035.

To assess the carbon intensities of imports, the generation mix in the exporting countries at the time of import must be considered. Furthermore, to assess the interconnectors' contribution to security of supply, the number of hours when the net demand, i.e. the demand after subtracting non-dispatchable generation (wind, solar, run-off hydro and nuclear), exceeds the domestic flexible capacity, needs to be quantified.

Dispatch simulation

It is assumed that exporting countries will deploy electricity decarbonisation efforts similar to the UK and will reach similar VRES penetration levels in the electricity sector. As the interconnections will be to geographically close markets, the VRES feed-in in these markets will be governed by weather regimes very closely related to those in the UK. Demand profiles are also expected to show high correlation due to similar diurnal patterns as well as similar impacts of weather on demand. The hourly carbon intensity of electricity in the neighbouring countries can thus be approximated by using the carbon intensity of UK based generation.

An hourly simulation of electricity demand, non-flexible generation (wind, solar, run-off hydro and nuclear) and flexible generation (domestic CCGTs and interconnectors) is carried out, based on fleet capacities projected by BEIS, and historic hourly demand and VRES generation profiles. The simulation is calibrated to match the total annual generation of the different technologies in the BEIS mix.

The simulation suggests that net demand exceeds the domestic flexible generation capacity for only 650 hours in a year, or 8% of the time. The domestic flexible capacity in the BEIS projections consists of 25.7 GW CCGTs, whereas in the high hydrogen scenario 1.4 GW new built H2GT and 5.5 GW of hydrogen blending plants partially replace CCGTs (compare Figure 23). The net demand that cannot be supplied by the domestic capacity only amounts to 4.4 TWh/year or 7% of total annual positive net demand, or 13% of projected annual electricity imports.

The model estimates that during times of interconnector usage, the average UK grid intensity would be 89 gCO_2/kWh in 2035, which is significantly higher than the average grid intensity of 41 gCO_2/kWh as projected by BEIS. Assuming that the import carbon intensity would be the same as the UK intensity at the time of import, this suggests that there is great potential for reducing emissions from imports.

This leads to two conclusions:

1. The domestic flexible capacity could replace significant amounts of imports.
2. Doing so could lead to emission and cost savings.

Potential cost and emission reductions from replacing imported CCGT generation

Nonzero carbon electricity generation in the UK as well as connected markets is expected to be dominated by natural gas. Therefore, any emissions of imports can be assumed to come from natural gas fuelled electricity generation. The share of imports generated by CCGTs can thus be estimated by dividing the average carbon intensity of imports (88 gCO_2/kWh) by the intensity of CCGTs (341 gCO_2/kWh). This leads to a share of 26%, or 8.6 TWh/year in 2035.

Replacing 8.6 TWh/year of imports generated by CCGTs by domestic flexible generation would increase utilisation of domestic flexible capacity and lead to lower LCOEs. Figure 29 left shows the impact of increased utilisation on the cost of generation of H2GTs.

If the imported generation from CCGTs is replaced by generation across the whole domestic flexible capacity (25.7 GW in total), their average load factor would increase from 15% in the BEIS projection to 19%. If the imported generation from CCGTs is only replaced by H2GTs and CCGTs using hydrogen blends (6.8 GW in total), their load factor would need to increase from 15% to 29%. A higher utilisation of the new technologies would also increase their profitability, reducing the LCOE of H2GTs built in 2035 by up to 23%.

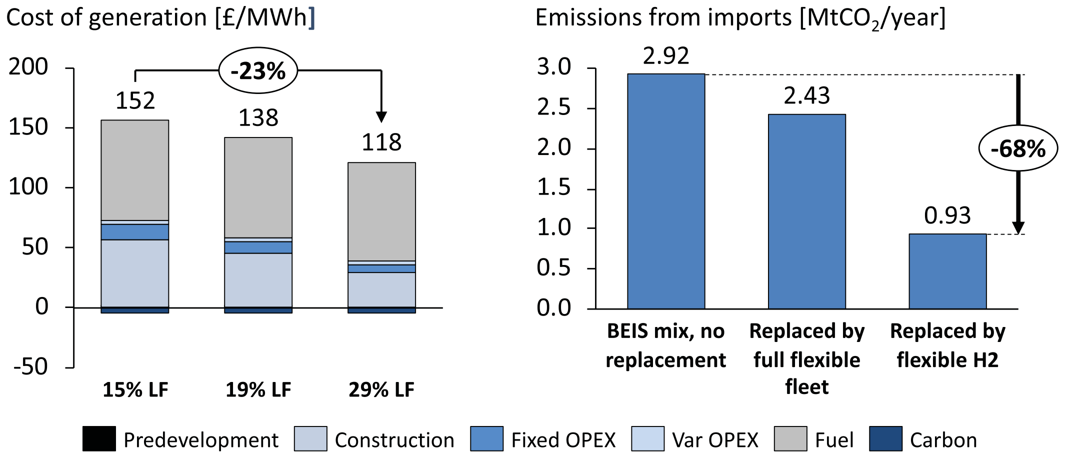


Figure 29: 2035 LCOEs of H2GTs for different load factors (left) and emissions from electricity imports under different replacement options (right)

Figure 29 (previous page) shows the emission savings which could be achieved if imported CCGT generation is replaced by domestic flexible generation in the High hydrogen scenario. The graph shows the emissions of 8.6 TWh/year of imported CCGT generation, as well as the emissions from providing this generation by either the full domestic flexible capacity or by the H2GT and hydrogen blending capacity only (assuming 10% biogas blend for hydrogen).

If extra generation is spread over the whole flexible generation fleet, a 17% reduction of import emissions may be achieved, whereas if only the hydrogen fleet is utilised, up to 68% of import emissions can be eliminated. This second option would provide further cost reductions too, since hydrogen options are expected to be cheaper than CCGTs in 2035.

5.2 Potential to support a higher penetration of variable renewable energy

The current study uses BEIS forecasts as a baseline for the future UK electricity mix, however, the UK may choose to adopt a power strategy with significantly higher VRES (mainly wind and solar) deployment. Increased wind and solar capacities would inevitably reduce the load factors of other technologies (most likely flexible generation plants) in the system.

In order to assess the effects of higher VRES deployment, a case study is developed with 30% higher wind capacity compared to the BEIS mix in 2035. This is equivalent to 61.4 GW of installed wind capacity, which is slightly lower than the wind capacity of the CCC's High Renewables scenario in 2030 and thus clearly within the range discussed in current debates.[22] The corresponding renewables electricity generation would be expected to increase from 211 TWh/year (BEIS forecast) to 238 TWh/year, after curtailment is considered.

Figure 30 illustrates the resulting load factors of flexible generation plants compared to the original BEIS forecast assuming extra wind generation would equally lower interconnector and CCGT utilization. The distribution is gained from an hourly dispatch simulation of the electricity system as described in the previous section (and in more detail in Appendix 2) and adjusted for the modified VRES capacity and generation. A 44% load factor marks the threshold below which H2GTs become more cost effective compared to CCS CCGTs in replacing CCGTs. The higher wind capacity reduces the total CCGT capacity operating above a 44% load factor from ~2GW to zero, thereby eliminating CCS CCGT's ability to compete with H2GTs for replacing unabated gas plants.

22 CCC progress report to parliament, 2018, p.70

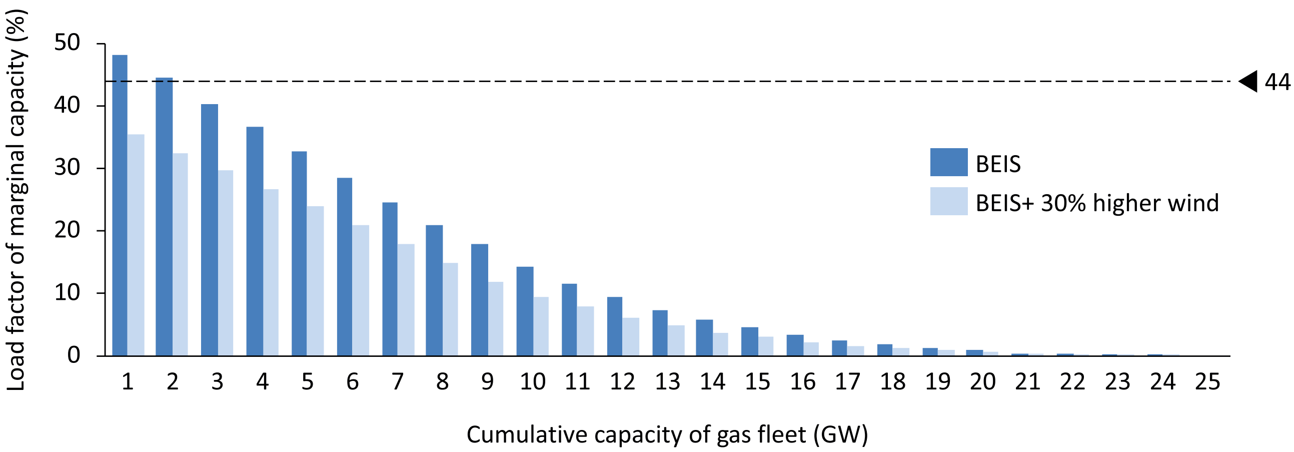


Figure 30: Load factor distribution of CCGT plants in the BEIS and high VRES scenarios

Furthermore, even at low load factors, H2GTs are found to be always cost effective compared to CCGTs, unlike CCS CCGTs, under future BEIS carbon price projections.[15] Figure 31 below compares the LCOE's of these technologies at a 15% LF, corresponding to the CCGT average load factor in the BEIS projections in 2035, and at a 10.7% load factor, corresponding to the new average load factor with 30% more wind capacity. Although all the technologies become more expensive at lower load factors, H2GTs using 0% and 10% biogas blend are still as cost effective (compared to CCGTs) as before, because they have the same Capex but lower Opex (due to carbon cost savings) compared to CCGTs. On the other hand, higher Capex of the CCS CCGTs dominate their LCOE at low load factors.

In summary, in a high variable renewable energy future, H2GTs are expected to be a more resilient alternative to provide low carbon flexible generation compared to CCS CCGTs due to their ability to provide cost savings under a wide range of load factors.

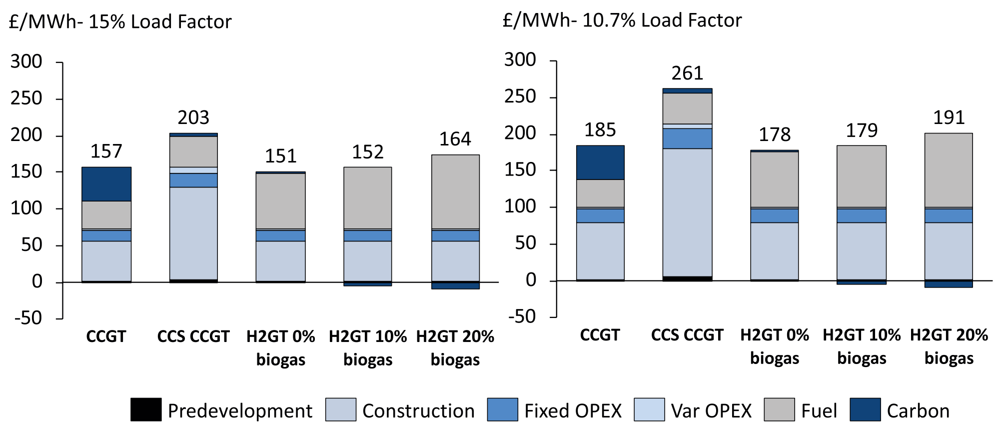


Figure 31: LCOE of NOAK technologies (2035) at lower load factors

Conclusions and recommendations

6

6. Conclusions and recommendations

6.1 Key implications and conclusions

BEIS 2035 power industry forecast

- **Prime targets for replacement by Power CCS technologies are the ~12.3 GW baseload nuclear and ~3.5 GW peaking CCGT plants, forecast to be built after 2025 according to BEIS projections**. Interconnectors are expected to be commissioned before Power CCS becomes available. While BEIS projections include substantial nuclear deployment starting from 2025, recent delays and cancellations of nuclear projects in the UK must also be considered. The increased uncertainties associated with a strategy that heavily relies on nuclear represent, therefore, another driver for the diversification of the UK power technology portfolio.

Cost effective replacement of nuclear plants and CCGTs

- **Nuclear plants can be replaced cost-effectively by any of the investigated Power CCS technologies, whereas CCGTs are most economically replaced by NOAK H2GTs**. Both types of Power CCS technologies investigated have lower LCOEs than nuclear. While NOAK CCS CCGTs are more cost effective than H2GTs in baseload operation (above 41% load factor), NOAK H2GTs provide the cheaper alternative when operated at a load factor of 15%, the average load factor of CCGTs in 2035 as projected by BEIS. NOAK CCS CCGTs have therefore the potential to replace ~2GW of CCGTs that would be operating at higher-than-average load factors.

- **While neither hydrogen nor CCS retrofits are cost effective, hydrogen blending becomes a viable option beginning in the early 2030s**. The cost of retrofitting CCGT plants with hydrogen or CCS capabilities is too high and the lifetime of the retrofitted plants too short for the additional investment to be compensated by the savings in carbon costs. However, blending up to 90% by volume hydrogen can be achieved without Capex investment if plants are built “hydgrogen ready”, i.e. install latest turbines capable of burning hydrogen mixes and are deployed close to hydrogen sources. Such a switch to a hydrogen blend would have positive NPV beginning in the early 2030s.

Emission and cost benefits of realistic Power CCS deployment pathways

- **By 2035, the three Power CCS scenarios investigated in this study could result in emissions savings between 1.8 and 3.9 $MtCO_2$/year, reducing power sector emissions by 11-24%**. Most of the emissions savings are achieved by the replacement of CCGTs and nuclear by net negative H2GTs. While the high hydrogen & CCS scenario replaces the largest total capacity of all scenarios, it also provides the least emission reduction, due to a portion of net carbon positive CCS CCGTs replacing emission-free nuclear.

- **By 2035, the three investigated Power CCS scenarios could produce cost savings between £450 milion and £1,210 million per year**. While cost savings are similar for both central and high hydrogen scenarios, savings in the high hydrogen & CCS scenario are significantly higher, due to the replacement of nuclear with CCS CCGTs, which are more cost effective than H2GTs at high load factors. Therefore, CCS CCGTs replacing nuclear present a trade-off between high cost effectiveness and lower emission reductions. Investment decisions between the two Power CCS options may be made based on the priority of future targets, considering this trade-off.

- **Biomass requirements for hydrogen production from a blend of 10% biogas are achievable. Lower or higher biogas utilization would increase net emissions or costs respectively**. In 2035 hydrogen demand in the power sector from the three scenarios is estimated to be 77-116 $TWh_{H2, HHV}$/year whereas hydrogen demand from the UK non-power sectors is expected to be around 140 $TWh_{H2, HHV}$/year, resulting in a total demand of 217-256 $TWh_{H2, HHV}$/year. Biomass supply of the UK is estimated to be capable of supporting the production of 243 $TWh_{H2, HHV}$/year (central case) to 565 $TWh_{H2, HHV}$/year (high case) of hydrogen reformed from 10% biogas and would thus be sufficient to cover hydrogen demand from all sectors. Based on our carbon price assumptions, the utilisation of 10% biofuel in the production of hydrogen balances costs and emissions related to hydrogen production. A higher share of biogas would reduce net emissions but increase costs, while a lower share of biogas would reduce costs but result in higher emissions.

Supporting higher VRES and reducing imports

- **H2GTs are cost competitive compared to CCGTs at reduced load factors and would thus be a resilient technology in a high renewables future**. In a representative case of high VRES penetration in 2035, 30% higher wind capacity is estimated to reduce the load factors of gas fuelled (hydrogen or natural gas) plants to 10.7% from 15% of the BEIS projections. H2GTs have lower LCOEs than CCGTs at all load factors, since they have the same Capex but operate more cost effectively, and therefore provide savings even at reduced load factors. However, CCS CCGTs become much more expensive and are unable to replace any CCGTs at such low load factors.

- **By 2035 up to 26% of imports may be avoided by using the UK domestic hydrogen power fleet, saving costs and emissions simultaneously**. If the portion of the imports estimated to come from fossil fuel plants in other European countries, are replaced by utilization of the UK hydrogen fuelled plants, load factors may increase up to 29% (compared to 15% in the BEIS forecast). LCOEs of these plants are found to decrease by 23% and import related emissions can decrease by up to 68% if all the extra demand is supplied through net negative hydrogen.

6.2 Recommendations for further work

This study has presented an analysis of the economic advantage of Power CCS technologies compared to nuclear and CCGTs in the BEIS projections and showed financial and environmental benefits from deploying CCS at various ambitious but realistic levels in the timeframe leading to 2035. Additional research is needed to better identify system-level opportunities, risks and barriers related to wide scale CCS deployment in the UK. Suggestions for further work include:

- Expansion of the analysis to include **BECCS, industrial CCS and other hydrogen applications** would create a more holistic decarbonization strategy which may lead to cost reduction through economies of scale and shared infrastructure.

- Assessment of **dynamic daily and seasonal hydrogen demand and the potential overlap with generation patterns of VRES** may reveal synergies between different components of the energy system. The H21 NoE study suggests a flexible use of hydrogen depending on the season. In winter, a larger share of electricity is produced from wind and hydrogen could be utilised for heating. Conversely, in summer, when heating demand is lower and wind power less available, hydrogen could be utilised in H2GTs for power generation. This would result in a reduction of hydrogen storage requirements, and thus an overall reduction of costs. A more detailed dynamic dispatch analysis may provide further insight about the interaction of gas Power CCS with other energy system components in an annual or daily time frame.

- Projecting **the role of Power CCS beyond 2035** - with higher NOAK availability, higher carbon prices and potentially lower infrastructure costs - may reveal new opportunities. Inclusion of various long-term scenarios, such as high electrification options, could allow Power CCS technologies to operate at higher load factors and become more pivotal in the UK economy.

- An analysis on possible net-zero/net-negative hydrogen based **H2GT business models** would identify the best financial strategies and policy support for realizing the commercial opportunities identified in this report.

- An in-depth investigation of **interactions with connected electricity markets could help identify opportunities to export low carbon flexible electricity and reduce import related emissions**. Extending the import reduction potential assessment by utilizing power system dispatch models to dynamically simulate the UK's and neighbouring countries' electricity markets would help clarify additional system benefits of Power CCS technologies on a European level.

Appendix

7. Appendix

Appendix 1: Hydrogen production assumptions and data

Hydrogen fuel cost and carbon intensity

The hydrogen fuel costs are taken from the study “Net-zero hydrogen: hydrogen production with CCS and bioenergy” by Element Energy for Equinor. The analysis estimated the cost to produce hydrogen via ATR from pure natural gas as well as from a blend of natural gas and biogas, including the cost of carbon capture and storage. To determine the cost when using a blend of biogas and natural gas, the resource and cost of bioenergy from a range of feedstocks in the UK in the mid-term and long-term future were estimated. Cost curves for the supply of bioenergy showing the cost depending on the cumulative consumption level as well as the resulting cost curves for hydrogen using various blending rates of biogas were produced. It was assumed that the consumption of natural gas for hydrogen production would not have an impact on the price of natural gas. Therefore, the price of hydrogen produced from pure natural gas (0% biogas blend) does not vary with consumption. The price is £37.99/$MWh_{H2,\ HHV}$ based on the assumptions of the mentioned study (in 2014 real terms).

The study also estimated the carbon intensity of hydrogen using various blends of biogas. It quantified the scope 1, 2, and 3 emissions for hydrogen production. This study on which we are reporting here focuses on electricity generation and we consider the scope 1 emissions of hydrogen production as the scope 2 emissions of electricity generation (cp. the BEIS guidance on GHG reporting for the definition of the different emission scopes).[23]

The carbon intensities of hydrogen produced from different blends of biogas and natural gas as well are given in Table 7. The cost curves used in this study are specified in Table 8 (showing costs in £/$MWh_{H2,\ HHV}$). The costs have been converted from 2018 to 2014 real terms, since all costs in this (Power CCS) study are calculated in 2014 real terms. In each of the three Power CCS scenario the hydrogen price for a given biogas blend in a given year is determined by the consumption of hydrogen for power generation in the given year and scenario. A carbon intensity of 184 gCO2/$kWh_{NG,\ HHV}$ is assumed for natural gas, taken from the Treasury Green Book.[24] We refer the reader to the “Net-zero hydrogen: hydrogen production with CCS and bioenergy” study for further assumptions on the availability and cost of biomass as well as the techno-economic assumptions on ATR and CCS.

Natural gas and nuclear fuel and carbon prices

Natural gas prices have been taken from BEIS’ Fossil Fuel Price Assumptions: 2018 and converted to 2014 real terms.[25] For nuclear plants, a fuel cost of £5/MWh_e has been assumed, based on the BEIS 2016 report Electricity Generation Costs.[26]

The carbon price assumptions are also taken from this report.[26] These are as follows (cp. p.10 of the report): “For gas and coal plants, the total carbon price up until 2020/21 is given by the sum of the 2016 EU-ETS carbon price projections and the rate of Carbon Price Support (CPS). This latter is set at £18/tCO_2 until 2019/20 and at £18/tCO_2 uprated with inflation in 2020/21 in line with recent government announcements. For the purposes of modelling we have assumed that the total carbon price after 2020/21 remains constant in real

23 https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2019

24 https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

25 https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2018

26 https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016 terms. However, the projected EU ETS price exceeds the total carbon price from the mid-2020s and reaches around £35/tCO_2 in 2030 (in 2012 prices). As a result, we assume that from the point where the EU ETS price exceeds the total carbon price and till 2030, the carbon price faced by the gas and coal sectors coincides with the EU ETS price. Beyond 2030, the total carbon price increases linearly to reach around £200/tCO_2 in 2050 (in 2012 prices)." The carbon price in the BEIS report has been adjusted to 2014 prices to be in line with the cost assumptions on electricity generation plants, which were given in 2014 prices. After 2050, the carbon price is assumed to stay constant. The assumed carbon prices are shown in Table 9.

Table 7: Carbon intensity of hydrogen for different biogas blends

	0% biogas	10% biogas	20% biogas
Carbon intensity of hydrogen (gCO2/$kWh_{H2, HHV}$)	8	-15	-37

Table 8: Assumed hydrogen costs for 10% and 20% biogas blend and different consumption levels, 2014 real terms

10% biogas		20% biogas	
Demand level ($TWh_{H2, HHV}$/year)	Cumulative mean cost (£/$MWh_{H2, HHV}$)	Demand level ($TWh_{H2, HHV}$/year)	Cumulative mean cost (£/$MWh_{H2, HHV}$)
3.74	36.31	1.87	34.63
7.49	36.31	3.75	34.64
11.23	36.31	5.62	34.64
14.97	36.31	7.49	34.64
18.71	36.31	9.37	34.64
25.70	37.52	12.87	37.05
32.69	38.21	16.37	38.43
39.69	38.66	19.86	39.32
46.68	38.97	23.36	39.95
53.67	39.20	26.86	40.41
65.63	40.12	32.85	42.23
77.60	40.75	38.84	43.49
89.56	41.21	44.83	44.42
101.52	41.56	50.82	45.12
113.49	41.84	56.81	45.68
117.63	41.96	58.88	45.93
121.77	42.08	60.95	46.16
125.91	42.19	63.02	46.37
130.05	42.29	65.10	46.57
134.18	42.38	67.17	46.76
139.02	42.49	69.59	46.98
143.86	42.59	72.01	47.18
148.70	42.69	74.43	47.37
153.54	42.78	76.86	47.55
158.38	42.86	79.28	47.72
163.21	42.95	81.70	47.89
168.05	43.03	84.12	48.06
172.89	43.11	86.54	48.22
177.73	43.18	88.96	48.36
182.57	43.25	91.39	48.50
194.74	43.67	97.48	49.32
206.91	44.03	103.57	50.05
219.08	44.35	109.66	50.69
231.25	44.64	115.76	51.27
243.42	44.90	121.85	51.79

Table 9: Assumed carbon prices

Year	Carbon price (£/tCO_2)
2020	18.6
2021	18.6
2022	18.6
2023	18.6
2024	18.6
2025	21.5
2026	24.4
2027	27.3
2028	30.2
2029	33.2
2030	36.1
2031	44.6
2032	53.1
2033	61.6
2034	70.1
2035	78.6
2036	87.1
2037	95.6
2038	104.1
2039	112.6
2040	121.1
2041	129.6
2042	138.1
2043	146.6
2044	155.2
2045	163.7
2046	172.2
2047	180.7
2048	189.2
2049	197.7
2050	206.2

Appendix 2: Performance and cost data of nuclear, CCGT, CCS CCGT and H2GT

LCOE cost assumptions

The cost assumptions for CCGTs, CCGTs with post combustion CCS as well as H2GTs are taken from the 2018 Uniper report for BEIS, "CCUS TECHNICAL ADVISORY – REPORT ON ASSUMPTIONS". [27] The cost assumptions for Nuclear power plants are taken from the 2016 BEIS report "Electricity Generation Costs" and the report "Electricity Generation Costs and Hurdle Rates, Lot 3: Non-Renewable Technologies" by Leigh Fisher Jacobs.[28, 29] All assumptions are listed in Table 10, Table 11, and Table 12 below. Efficiencies are in terms of lower heating value (LHV). For the calculations in the model, gas and hydrogen fuel prices have been converted from prices in terms of HHV to prices in terms of LHV.[30]

LCOE calculation methodology

The methodology to calculate LCOE as described in the BEIS 2016 report has been used.[28] A discount rate of 10% has been applied for all technologies. LCOEs are calculated individually for each plant being added in the BEIS or the Power CCS scenarios in the period of 2020-2035. The base year in the LCOE calculation for any plant is the commissioning year. For example, for a H2GT commissioning in 2029, the year 2029 is year 1 in the LCOE calculation. A constant load factor over the whole lifetime of the plant has been assumed for the LCOE modelling. The load factor is based on the average load factor of the replaced technology in the BEIS projection during the lifetime of the plant. For example, a H2GT replacing a CCGT in 2033 is assumed to have the average load factor of CCGTs in the BEIS projection in the years from 2033 onwards. Fuel and carbon prices are varied across the lifetime of the plant according to the assumptions described in the previous section.

Calculated LCOEs for replaced and replacing technologies in the Power CCS scenarios are listed in Table 13, Table 14, Table 15, and Table 16 below. The tables show the total LCOE as well as the fuel and carbon component of the LCOE, as these are mainly determining the relative competitiveness of CCS, hydrogen and unabated fossil generation.

27 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/759538/2018_ESD_329.pdf

28 https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

29 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566803/Leigh_Fisher_Non-renewable_Generation_Cost.pdf

30 Gas prices in GB are specified in terms of HHV, cp. p.7 of this document: https://research.birmingham.ac.uk/portal/files/42506031/IMPJ5213_H2FC_Supergen_Energy_Security_032017_WEB.PDF

Table 10: Cost assumptions CCGT with post combustion CCS

Technology	CCS CCGT	CCS CCGT	CCS CCGT
FOAK/NOAK	FOAK	SOAK	NOAK
CAPEX (£/kW)	1,509	1,371	1,232
Fixed OPEX (£/MW/year)	29,792	28,148	26,503
Var OPEX (£/MWh)	8.06	7.39	6.73
Pre-development (%CAPEX)	2%	2%	2%
Construction (%CAPEX)	98%	98%	98%
Reference size (net MW)	1,056	1,063	1,070
Lifetime (years)	25	25	25
Efficiency (LHV)	52.6%	53.0%	53.3%
Capture rate	90%	90%	90%

Table 11: Cost assumptions H2GT

Technology	H2GT	H2GT	H2GT
FOAK/NOAK	FOAK	SOAK	NOAK
CAPEX (£/kW)	559	549	540
Fixed OPEX (£/MW/year)	18,079	17,831	17,584
Var OPEX (£/MWh)	3.45	3.39	3.33
Pre-development (%CAPEX)	2%	2%	2%
Construction (%CAPEX)	98%	98%	98%
Reference size (net MW)	1,160	1,180	1,200
Lifetime (year)	25	25	25
Efficiency (LHV)	57.8%	58.8%	59.8%

Table 12: Cost assumptions CCGT and Nuclear

Technology	CCGT	Nuclear	Nuclear	Nuclear
FOAK/NOAK	NOAK	FOAK	SOAK	NOAK
CAPEX (£/kW)	540	4,343	4,121	3,898
Fixed OPEX (£/MW/year)	17,584	83,400	83,400	83,400
Var OPEX (£/MWh)	3.33	7.00	7.00	7.00
Pre-development (%CAPEX)	2%	6%	4%	3%
Construction (%CAPEX)	98%	94%	96%	97%
Reference size (net MW)	1,200	3,300	3,300	3,300
Lifetime (year)	25	60	60	60
Efficiency	59.8%	100%	100%	100%

Table 13: LCOE of replaced technologies

Technology	FOAK/ NOAK	Commissioning Year	Load Factor	Fuel (£/MWh)	Carbon (£/MWh)	Total (£/MWh)
Nuclear	FOAK	2027	90.0%	5.00	0.00	112.60
Nuclear	NOAK	2030	90.0%	5.00	0.00	101.94
CCGT	NOAK	2020	23.5%	33.48	13.92	95.11
CCGT	NOAK	2021	23.2%	34.08	15.18	97.63
CCGT	NOAK	2022	23.2%	34.67	16.60	99.58
CCGT	NOAK	2023	23.4%	35.20	18.19	101.26
CCGT	NOAK	2024	23.2%	35.71	19.97	103.94
CCGT	NOAK	2025	22.9%	36.14	21.96	107.01
CCGT	NOAK	2026	22.5%	36.49	24.06	110.21
CCGT	NOAK	2027	22.1%	36.80	26.26	113.61
CCGT	NOAK	2028	21.2%	37.02	28.58	118.15
CCGT	NOAK	2029	20.2%	37.19	31.02	123.33
CCGT	NOAK	2030	19.1%	37.25	33.59	128.89
CCGT	NOAK	2031	18.0%	37.25	36.31	134.83
CCGT	NOAK	2032	17.1%	37.25	38.98	140.75
CCGT	NOAK	2033	16.6%	37.25	41.60	144.95
CCGT	NOAK	2034	15.6%	37.25	44.16	151.50
CCGT	NOAK	2035	14.9%	37.25	46.65	157.31
CCS CCGT	FOAK	2035	70.0%	42.35	5.30	97.52
CCS CCGT	FOAK	2026	90%	41.48	2.74	84.79
CCS CCGT	SOAK	2031	90%	42.07	4.10	81.85
CCS CCGT	SOAK	2033	16.6%	42.07	4.70	207.18
CCS CCGT	SOAK	2034	90%	42.07	4.99	82.73
CCS CCGT	NOAK	2035	70.0%	41.79	5.23	85.60

Table 14: LCOE of hydrogen fuelled electricity generation, 0% biogas blend

Technology	FOAK/ NOAK	Comm. Year	Replaced tech.	Load Factor	Fuel (£/MWh)	Carbon (£/MWh)	Total (£/MWh)
H2GT	FOAK	2029	Nuclear	90.0%	77.76	1.42	95.56
H2GT	SOAK	2032	Nuclear	90.0%	76.44	1.75	93.41
H2GT	SOAK	2034	Nuclear	90.0%	76.44	1.98	93.64
H2GT	NOAK	2035	Nuclear	90.0%	75.16	2.06	92.16
H2GT	SOAK	2033	CCGT	16.6%	76.44	1.87	145.69
H2GT	SOAK	2034	CCGT	15.6%	76.44	1.98	149.87
H2GT	NOAK	2035	CCGT CCS	70.0%	75.16	2.06	95.47
H_2 blend 30%	NOAK	2020	CCGT	23.4%	34.69	12.95	95.60
H_2 blend 30%	NOAK	2021	CCGT	23.2%	35.29	14.13	97.79
H_2 blend 90%	NOAK	2026	CCGT	22.2%	48.29	11.95	110.60
H_2 blend 90%	NOAK	2032	CCGT	17.3%	58.03	14.96	136.69

Table 15: LCOE of hydrogen fuelled generation, 10% biogas blend

Technology	FOAK/ NOAK	Comm. Year	Replaced tech.	Load Factor	Scenario	Fuel (£/MWh)	Carbon (£/MWh)	Total (£/MWh)
H2GT	FOAK	2029	Nuclear	90.0%	Central	82.28	-2.72	95.94
H2GT	FOAK	2029	Nuclear	90.0%	High & CCS	81.00	-2.72	94.66
H2GT	FOAK	2029	Nuclear	90.0%	High	82.41	-2.72	96.07
H2GT	SOAK	2032	Nuclear	90.0%	Central	82.95	-3.36	94.81
H2GT	SOAK	2032	Nuclear	90.0%	High & CCS	81.20	-3.36	93.06
H2GT	SOAK	2032	Nuclear	90.0%	High	83.13	-3.36	94.99
H2GT	SOAK	2034	Nuclear	90.0%	Central	83.97	-3.80	95.39
H2GT	SOAK	2034	Nuclear	90.0%	High & CCS	81.86	-3.80	93.28
H2GT	SOAK	2034	Nuclear	90.0%	High	84.20	-3.80	95.61
H2GT	NOAK	2035	Nuclear	90.0%	Central	82.78	-3.95	93.77
H2GT	NOAK	2035	Nuclear	90.0%	High & CCS	80.62	-3.95	91.60
H2GT	NOAK	2035	Nuclear	90.0%	High	83.03	-3.95	94.01
H2GT	SOAK	2033	CCGT	16.6%	Central	83.46	-3.58	147.26
H2GT	SOAK	2033	CCGT	16.6%	High & CCS	81.52	-3.58	145.32
H2GT	SOAK	2033	CCGT	16.6%	High	83.66	-3.58	147.46
H2GT	SOAK	2034	CCGT	15.6%	Central	83.97	-3.80	151.61
H2GT	SOAK	2034	CCGT	15.6%	High & CCS	81.86	-3.80	149.50
H2GT	SOAK	2034	CCGT	15.6%	High	84.20	-3.80	151.84
H2GT	NOAK	2035	CCGT CCS	70.0%	Central	82.78	-3.95	97.08
H2GT	NOAK	2035	CCGT CCS	70.0%	High & CCS	80.62	-3.95	94.92
H2GT	NOAK	2035	CCGT CCS	70.0%	High	83.03	-3.95	97.33
H_2 blend 30%	NOAK	2020	CCGT	23.4%	Central	34.88	12.82	95.67
H_2 blend 30%	NOAK	2020	CCGT	23.4%	High & CCS	34.83	12.82	95.61
H_2 blend 30%	NOAK	2020	CCGT	23.4%	High	34.89	12.82	95.67
H_2 blend 30%	NOAK	2021	CCGT	23.2%	Central	35.50	13.99	97.86
H_2 blend 30%	NOAK	2021	CCGT	23.2%	High & CCS	35.44	13.99	97.80
H_2 blend 30%	NOAK	2021	CCGT	23.2%	High	35.51	13.99	97.86
H_2 blend 90%	NOAK	2026	CCGT	22.2%	Central	50.58	10.31	111.27
H_2 blend 90%	NOAK	2026	CCGT	22.2%	High & CCS	49.94	10.31	110.63
H_2 blend 90%	NOAK	2026	CCGT	22.2%	High	50.65	10.31	111.33
H_2 blend 90%	NOAK	2032	CCGT	17.3%	Central	62.21	11.73	137.63
H_2 blend 90%	NOAK	2032	CCGT	17.3%	High & CCS	61.02	11.73	136.44
H_2 blend 90%	NOAK	2032	CCGT	17.3%	High	62.34	11.73	137.77

Table 16: LCOE of hydrogen fuelled generation, 20% biogas blend

Technology	FOAK/ NOAK	Comm. Year	Replaced tech.	Load Factor	Scenario	Fuel (£/MWh)	Carbon (£/MWh)	Total (£/MWh)
H2GT	FOAK	2029	Nuclear	90.0%	Central	95.86	-6.84	104.84
H2GT	FOAK	2029	Nuclear	90.0%	High & CCS	92.52	-6.84	101.49
H2GT	FOAK	2029	Nuclear	90.0%	High	96.54	-6.84	105.52
H2GT	SOAK	2032	Nuclear	90.0%	Central	99.30	-8.45	106.07
H2GT	SOAK	2032	Nuclear	90.0%	High & CCS	94.73	-8.45	101.50
H2GT	SOAK	2032	Nuclear	90.0%	High	100.24	-8.45	107.01
H2GT	SOAK	2034	Nuclear	90.0%	Central	101.33	-9.57	106.97
H2GT	SOAK	2034	Nuclear	90.0%	High & CCS	95.66	-9.57	101.31
H2GT	SOAK	2034	Nuclear	90.0%	High	102.48	-9.57	108.13
H2GT	NOAK	2035	Nuclear	90.0%	Central	100.33	-9.94	105.33
H2GT	NOAK	2035	Nuclear	90.0%	High & CCS	94.48	-9.94	99.47
H2GT	NOAK	2035	Nuclear	90.0%	High	101.51	-9.94	106.50
H2GT	SOAK	2033	CCGT	16.6%	Central	100.27	-9.01	158.63
H2GT	SOAK	2033	CCGT	16.6%	High & CCS	95.17	-9.01	153.54
H2GT	SOAK	2033	CCGT	16.6%	High	101.31	-9.01	159.67
H2GT	SOAK	2034	CCGT	15.6%	Central	101.33	-9.57	163.20
H2GT	SOAK	2034	CCGT	15.6%	High & CCS	95.66	-9.57	157.54
H2GT	SOAK	2034	CCGT	15.6%	High	102.48	-9.57	164.36
H2GT	NOAK	2035	CCGT CCS	70.0%	Central	100.33	-9.94	108.64
H2GT	NOAK	2035	CCGT CCS	70.0%	High & CCS	94.48	-9.94	102.79
H2GT	NOAK	2035	CCGT CCS	70.0%	High	101.51	-9.94	109.81
H_2 blend 30%	NOAK	2020	CCGT	23.4%	Central	35.38	12.69	96.04
H_2 blend 30%	NOAK	2020	CCGT	23.4%	High & CCS	35.25	12.69	95.90
H_2 blend 30%	NOAK	2020	CCGT	23.4%	High	35.41	12.69	96.06
H_2 blend 30%	NOAK	2021	CCGT	23.2%	Central	36.02	13.85	98.24
H_2 blend 30%	NOAK	2021	CCGT	23.2%	High & CCS	35.87	13.85	98.08
H_2 blend 30%	NOAK	2021	CCGT	23.2%	High	36.05	13.85	98.27
H_2 blend 90%	NOAK	2026	CCGT	22.2%	Central	55.87	8.69	114.93
H_2 blend 90%	NOAK	2026	CCGT	22.2%	High & CCS	54.15	8.69	113.21
H_2 blend 90%	NOAK	2026	CCGT	22.2%	High	56.23	8.69	115.28
H_2 blend 90%	NOAK	2032	CCGT	17.3%	Central	71.83	8.50	144.02
H_2 blend 90%	NOAK	2032	CCGT	17.3%	High & CCS	68.62	8.50	140.82
H_2 blend 90%	NOAK	2032	CCGT	17.3%	High	72.47	8.50	144.67

Calculation of total costs and emissions

The total annual generation costs in any year are calculated by adding the generation cost of all plants. The generation cost of any plant in a given year is calculated by multiplying the plant's annual generation with its LCOE (calculated for its average load factor that year). Any plant's annual generation in a given year is calculated by multiplying its capacity with the load factor of the corresponding technology (either the technology of the plant or the technology the plant is replacing) in the BEIS projection in the year.

Analogously the total annual emissions are calculated by adding the emissions of each plant. The emissions of each plant depend on the carbon intensity of its fuel and its efficiency. The carbon intensities of the replacing and replaced generation technologies in the Power CCS scenarios based on the carbon intensity of hydrogen and natural gas as well as the efficiencies of the generation technologies as listed further above are collected in Table 17 below.

Coal fuelled power plants are assumed to have a carbon intensity of 937 gCO_2/kWh, based on historic data on electricity output and fuel consumption.[31] Existing CCGTs are assumed to have an efficiency of 43.4% (HHV, 48% in terms of LHV, as assumed in the ENTSO-E 2018 TYNDP). Imports in 2017 are assumed to have the same carbon intensity as the GB electricity grid (263 gCO_2/kWh) and the carbon intensity as calculated in the import sensitivity of this study (89 gCO_2/kWh, Section 5.1) in 2035 and to decrease linearly between 2017 and 2035.[32]

31 https://electricinsights.co.uk/#/reports/methodology?_k=05rdta

32 CCC, 2018, Progress Report to Parliament, Figure 2.8

Table 17: Carbon intensities of generation technologies

Generation Technology	FOAK/NOAK	Efficiency	Fuel	Carbon intensity (gCO_2/kWh)
Nuclear	FOAK	100%	Uranium	0
Nuclear	NOAK	100%	Uranium	0
CCGT	NOAK	59.8%	Gas	341
H2GT - 20% biogas	FOAK	57.8%	H_2 - 20% biogas	-75
H2GT - 20% biogas	SOAK	58.8%	H_2 - 20% biogas	-74
H2GT - 20% biogas	NOAK	59.8%	H_2 - 20% biogas	-73
H2GT - 10% biogas	FOAK	57.8%	H_2 - 10% biogas	-30
H2GT - 10% biogas	SOAK	58.8%	H_2 - 10% biogas	-29
H2GT - 10% biogas	NOAK	59.8%	H_2 - 10% biogas	-29
H2GT - 0% biogas	FOAK	57.8%	H_2 - 0% biogas	16
H2GT - 0% biogas	SOAK	58.8%	H_2 - 0% biogas	15
H2GT - 0% biogas	NOAK	59.8%	H_2 - 0% biogas	15
CCS CCGT	FOAK	52.6%	Gas	39
CCS CCGT	SOAK	53.0%	Gas	38
CCS CCGT	NOAK	53.3%	Gas	38
H_2 blend 90% - 20% biogas	NOAK	59.8%	90% hydrogen (20% biogas) / 10% Gas	29
H_2 blend 90% - 10% biogas	NOAK	59.8%	90% hydrogen (10% biogas) / 10% Gas	62
H_2 blend 90% - 0% biogas	NOAK	59.8%	90% hydrogen (0% biogas) / 10% Gas	95
H_2 blend 30% - 20% biogas	NOAK	59.8%	30% hydrogen (20% biogas) / 70% Gas	288
H_2 blend 30% - 10% biogas	NOAK	59.8%	30% hydrogen (10% biogas) / 70% Gas	294
H_2 blend 30% - 0% biogas	NOAK	59.8%	30% hydrogen (0% biogas) / 70% Gas	299

Dispatch modelling

The BEIS Energy and Emission Projections (EEP) specify generation (TWh) and the capacity (GW) for different electricity generation technologies. While this delivers an average load factor across the entire fleet of a particular generation technology, it does not specify how load factors might vary across the fleet.

To deduce a distribution of the load factors across the CCGT fleet, the hourly consumption and dispatch of electricity generation has been modelled. For this purpose, historical profiles of electricity demand, wind, solar and hydro generation (2017 data, obtained from https://gridwatch.templar.co.uk/) have been scaled up to match the totals as predicted in the BEIS EEP.

BEIS EEP do not specify a breakdown of renewable generation and capacity, but only the total values for all renewable generation. Therefore, the CCC's power scenarios have been used to guide the modelled capacities.[33] The biomass and hydro capacities are as in the CCC's scenarios (they are the same in all the CCC's scenarios for 2030). Wind and solar capacities have been adjusted in several stages to ensure alignment with the total generation as specified by BEIS EEP.

First the remainder of renewable capacity as projected in BEIS EEP after subtracting biomass and hydro capacity is distributed among wind and solar capacity using the same ratio as in the CCC Central Renewables power scenario. The historic wind and solar hourly load factors are adjusted to match the total renewable generation in EEP (when adding biomass, hydro, wind and solar generation). This required an increase of the load factor of wind compared to the 2017 data, which is in line with the increase of the offshore wind fleet, which achieves higher load factors than the onshore wind fleet.[34]

While the prescribed approach leads to the same total renewable generation as EEP, a significant amount of this renewable generation would need to be curtailed since it exceeds the electricity demand in the several hours of the year. Therefore, the wind capacity was furthermore adjusted such that the renewable generation matches the EEP projection, after such curtailment has been accounted for. As mentioned in the report, for the sensitivity for a higher VRES penetration, the wind capacity has been further increased by 30% (compared to the capacity derived as just described).

The capacities derived by the method described above are within the ranges of capacities in the CCC's power scenarios. For example, the wind capacity in our central case is 47GW, which is still below the wind capacity in the CCC's Central Renewables scenario (56GW), and the wind capacity in the VRES sensitivity is 61GW, which is below the wind capacity in the CCC's High Renewables scenario (63GW).

33 CCC, 2018 Progress Report to Parliament, p. 70

34 Staffell & Pfenninger, 2018, Using bias-corrected reanalysis to simulate current and future wind power output

Appendix 3: Data of recently build CCGTs and plants with recent development consent orders

Table 18 below gives detailed information about large power plants built in the UK after 2009, which are built carbon capture ready. The table also includes some planned power plants that recently received their DCOs. The list of these plants is acquired from the National Infrastructure Planning website.

Special notes: Keadby 2 is the only planned plant on this list to receive final investment decision and started construction. The other plants are generally waiting to secure capacity contracts or favourable market conditions to justify investment.

The Eggborough plant is planned to be 2200 MW CCGT and 299 MW OCGT. King's Lynn B is planned to have two CCGT components or one CCGT and one 299 MW OCGT. In general, all OCGT plants are planned to be 299 MW because the law suggests any plant larger than 300MW to be built carbon capture ready.

Table 18: Data on recently built and DCO granted large power plants

Plant Name	Company	Type	Location	Commission Year	Capacity (MW)	Status
Marchwood	Marchwood Power Limited	CCGT	Southampton	2009	920	Built
Staythorpe C	RWE Generation SE	CCGT	Newark	2010	1772	Built
Langage	EPUKi	CCGT	Plymouth	2010	905	Built
Severn Power	Calon Energy	CCGT	Wales	2010	850	Built
Grain CHP	Uniper UK Limited	CCGT	Isle of Grain	2010	1517	Built
West Burton B	EDF Energy	CCGT	Retford	2012	1332	Built
Pembroke	RWE Generation SE	CCGT	Pembroke	2012	2199	Built
Carrington	ESB	CCGT	Manchester	2016	910	Built
Keadby 2	SSE	CCGT	Scunthorpe	2022	840	DCO Granted
Eggborough CCGT	Eggborough Power Limited	CCGT	North Yorkshire	2022	2500	DCO Granted
King's Lynn B	EPUKi	CCGT	Kings Lynn	2022	1700	DCO Granted
Tees CCPP	Sembcorp Utilities Limited	CCGT	Middlesbrough	2023	1700	DCO Granted
Millbrook Power	Millbrook Power Limited	OCGT	Millbrook	2022	299	DCO Granted

Appendix 4: Detailed data on major CO_2 and hydrogen storage sites

CO_2 Storage Potential

The data on UK's offshore CO_2 storage sites are taken from ETI's 2016 study called "Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource". The report identifies 20 sites (ETI-20) for potential development candidates and performs detailed appraisal work on 5 shortlisted sites (ETI-5). These are joined by 3 other sites (marked FEED) previously appraised for various CCS projects.

Total capacity to support injection is limited by annual injectivity. The study assumes that a CCS CCGT would require 2.92 $MtCO_2$/year, which is used to calculate the total CCGT capacity that can be supported by individual sites. Note that coal plants would require twice as much capacity since they emit significantly more CO_2.

Table 19: UK offshore CO_2 storage sites that are studied in detail

Name	Site Type	Capacity ($MtCO_2$)	Injection Rate ($MtCO_2$/year)	Start Year	CCGT Support (GW)
Bunter Closure 36	ETI- 5	280	7	2027	2.4
Hamilton	ETI- 5	125	5	2026	1.7
Forties 5 Site 1	ETI- 5	300	6	2030	2.1
Captain X	ETI- 5	60	3	2022	1.0
Viking A	ETI- 5	130	5	2031	1.7
Goldeneye	FEED	30	3	2021	1.0
Hewett	FEED	200	5	2029	1.7
Endurance	FEED	520	13	2026	4.5
Bunter Closure 9	ETI- 20	1977	50		17.1
South Morecambe	ETI- 20	855	43	2032	14.7
Bunter Closure 3	ETI- 20	232	12		4.1
Viking Gas Field	ETI- 20	310	15		5.1
Bruce	ETI- 20	188	10		3.4
North Morecambe	ETI- 20	187	10	2032	3.4
Grid Sandstone	ETI- 20	1825	50		17.1
Mey 1	ETI- 20	22			
Maureen	ETI- 20	101			
Captain Aquifer	ETI- 20	49			
Barque	ETI- 20	91			
Captain Oil Field	ETI- 20	95.8			
Bunter Closure 40	ETI- 20	100			
Coracle	ETI- 20	35			
Harding Field	ETI- 20	85			
Forties 5	ETI- 20	1021			
Total		**8818.8**	**237**		**81.3**

Hydrogen Storage Potential

Hydrogen storage potential of selected regions in the UK are provided below, as estimated in a previous Element Energy study for BEIS: Hydrogen supply chain: evidence base (2018). The gas storage potential is converted to hydrogen production capacity via salt cavern sizing parameters used in the H21 North of England project (12.15 $GW_{H2, HHV}$ ATR requiring 56 caverns with 222 $GWh_{H2, HHV}$ gas volume each). These are later converted to H2GT capacities assuming 60% efficiency and 50% load factor.

It should be noted that the storage requirement quoted in the H21 NoE report is primarily for heating, and thus focus on seasonal long-term storage. However, storage for H2GTs may to require less capacity depending on mode of operation. Therefore, capacities shown in the table may be interpreted as lower-end estimations.

Table 20: UK hydrogen salt cavern storage potential

Storage Site	EE estimate of potential storage ($GWh_{H2, HHV}$)	H_2 production capacity supported by caverns ($GW_{H2, HHV}$)	H2GT capacity ($GW_{H2, HHV}$)
Cheshire Basin	4,237	4.14	4.97
East Yorkshire	58,356	57.03	68.44
East Irish Sea (offshore)	32,373	31.64	37.97
Wessex	227,273	222.12	266.54

Appendix 5: Development timelines of CCGTs, nuclear and FOAK/SOAK/NOAK Power CCS technologies

The development times for the CCGT, nuclear and FOAK CCS CCGT plants are taken from the 2016 BEIS Electricity Generation Costs Report. NOAK Power CCS technology timescales are assumed to be the same as CCGTs, considering that additional capture plants can be added within the original construction period of the plant. SOAK timelines are interpolated.

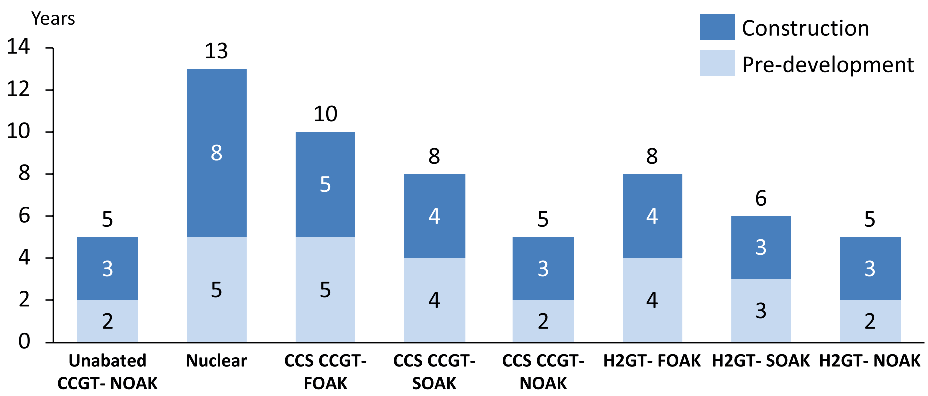


Figure 32: Pre-development and construction times of CCGT, nuclear and Power CCS plants

Appendix 6: Power plant rollout timetable for 3 scenarios

Below are representative timetables for the rollout of Power CCS technologies for the 3 scenarios in a 2020-2035 timeframe. For hydrogen blending, pre-development and construction times are shown only for the first plant.

Central Scenario

Pre-development | Construction | Commissioning (GW) | FID

Power Plant Roll-out	Type	Replacing	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
H2GT- 1	FOAK	Nuclear										1.5						
H2GT- 2	SOAK	Nuclear													1.5			
H2GT- 3	SOAK	CCGT														1.15		
H2GT- 4	SOAK	Nuclear															1.5	
H2GT- 5	NOAK	Nuclear																1.5
H2GT- 6	NOAK	CCS CCGT																1.26

Figure 33: Timelines for power plant rollout in the Central scenario

High hydrogen Scenario

Pre-development | Construction | Commissioning (GW) | FID

Power Plant Roll-out	Type	Replacing	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
H2GT- 1	FOAK	Nuclear										1.5						
H2GT- 2	SOAK	Nuclear													1.5			
H2GT- 3	SOAK	CCGT														1.15		
H2GT- 4	SOAK	Nuclear															1.5	
H2GT- 5	NOAK	Nuclear																1.5
H2GT- 6	NOAK	CCS CCGT																1.26
H2 Blending- 90%		CCGT													0.6	1.3	1.42	2.14

Figure 34: Timelines for power plant rollout in the High hydrogen scenario

High hydrogen & CCS Scenario

Pre-development | Construction | Commissioning (GW) | FID

Power Plant Roll-out	Type	Replacing	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
CCS CCGT- 1	FOAK	Nuclear							1.65									
H2GT- 1	FOAK	Nuclear										1.5						
CCS CCGT- 2	SOAK	Nuclear												1.5				
H2GT- 2	SOAK	Nuclear													1.5			
CCS CCGT- 3	SOAK	CCGT														1.15		
H2GT- 3	SOAK	CCGT															1.68	
CCS CCGT- 4	NOAK	Nuclear															1.5	
H2GT- 4	NOAK	Nuclear																1.5
CCS CCGT- 5	NOAK	CCS CCGT																1.26
H2 Blending- 90%		CCGT													0.6	1.3	1.42	0.46

Figure 35: Timelines for power plant rollout in the High hydrogen & CCS scenario

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Element Energy is a dynamic and growing strategic energy consultancy, specialising in the intelligent analysis of low carbon energy.

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