POLICY MECHANISMS FOR FIRST OF A KIND DIRECT AIR CARBON CAPTURE AND STORAGE (DACCS) AND OTHER ENGINEERED GREENHOUSE GAS REMOVALS

A report for the

Department for Business, Energy & Industrial Strategy

Department for
Business, Energy
& Industrial Strategy

Element Energy, E4tech and Cambridge Econometrics

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Executive Summary

Importance and current state of engineered GGRs

Greenhouse gas removal (GGR) technologies are deemed essential by the UK Government to achieve the UK's medium and long-term decarbonisation targets. Modelling for the Net Zero Strategy suggests that by 2050, between 75 and 81 $MtCO_2$/year of negative emissions from engineered GGRs might be required to meet the UK's 2050 net zero target[1]. However, to date there are no large-scale active and operational engineered GGR projects within the UK.

Bioenergy with carbon capture and storage (BECCS) and direct air carbon capture and storage (DACCS) are two of the most promising engineered GGR approaches for deployment over the next decade, with numerous other innovative GGR technologies at earlier research and development stages. Despite their relative importance for decarbonising economies, engineered GGRs have not been deployed at commercial scales, with extremely few exceptions.

So far, the major barriers to large-scale rollout of GGRs have been their relatively high and uncertain costs, as well as lack of a substantial negative emissions (NE) market. In the absence of government support to bridge the gap between technology demonstration and commercialisation, these issues will persist and stifle the GGR sector. Therefore, to establish a GGR sector which enables the UK to reach its carbon budget commitments and net zero targets, the government must develop policies to provide revenue certainty to engineered GGRs with a specific view to support first-of-a-kind (FOAK) deployment in the short term.

This study explores how GGR policies may be designed to deliver the UK's NE targets with a specific focus on supporting FOAK DACCS projects. The general GGR policies are designed to be compatible with the wider decarbonisation policies of the UK and prioritise national technology deployment. An emphasis on FOAK DACCS technologies is provided to complement BEIS' previous work on FOAK BECCS power commercial frameworks and to address some of the unique challenges of this emerging technology type.

Policies to support engineered GGR deployment

A longlist of potential GGR policies is compiled based on literature review and discussions with a diverse set of stakeholders. These policies, listed in Table 1, can be broadly grouped as those establishing a market for NE credits, those that award contracts for production of NE and other policies requiring government involvement at various degrees.

Table 1: Longlist of potential GGR policies considered

Category	Name	Description
Market-based	**UK ETS**	Inclusion of NE credits in the UK Emissions Trading System (ETS) which, depending on market design, could allow participants to offset a portion of their emissions through purchasing allowances from GGR developers that meet market participation criteria.
	Obligation Schemes	A requirement placed on certain emitters or fossil fuel suppliers to offset an increasing portion of their emissions through NE credits.
Contracted	**Carbon CfDs**	Carbon contracts for difference (CfDs) where the government pays the developers the difference between an agreed strike price and a reference price on a £ per tonne of CO_2 removed basis.
	Payment Schemes	Procuring NE through paying developers a specified £ per of tonne of CO_2 removed, determined through bilateral negotiations or reverse auctions.
Government Intervention	**Cost Plus Subsidy**	Open book contracts where the government pays all the eligible costs and an additional margin as a profit to selected projects.

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[1] Net zero strategy: build back greener. BEIS, 2021 [Link].

	Competitions	Direct government grants to GGR projects which can demonstrate value for money or are strategically important in other ways.
	Tax Incentives	Awarding investment tax credits equivalent to a specific % of total capital investment and/or production tax credits on a £ per tonne CO_2 removed basis.

To identify the policies with the highest likelihood of success, a set of assessment criteria was developed in consultation with BEIS and a cross-government Steering Group, which is presented in Table 2. Each of the longlisted policy mechanisms were then ranked against the criteria in a RAG (red, amber, green) rating with the results summarised in Figure 5 in section 4.3. The final shortlisting was carried qualitatively based on the scores and feedback from the stakeholders.

Table 2: Criteria used for the assessment of the long list of GGR policy mechanisms

Category	Name	Description
Economic Viability	**Revenue stability**	The policy should create a stable source of demand/revenue for negative emissions to instil confidence among project developers and incentivise private investment.
	Proportionality	The policy should ensure that policy support does not lead to excessive rewards or over-subsidisation.
	Transition	Over time the policy should enable a transition to a competitive and mature GGR market with reduced government support, allowing market-led growth of the sector.
Ethics and Equality	**Cost reduction**	The policy should promote cost reductions over time through innovation, learning by doing and competition as appropriate. This is both within a specific deployed project and within the industry as a whole.
	Applicability across scales	The policy is appropriate across different scales of companies and can benefit smaller and larger companies in the same or similar manner and level. Additional administrative burdens to smaller projects (~10s $ktCO_2$/year) are also considered under this criterion.
	Fair cost distribution	The policy enables costs to be distributed in an equitable way (emitters, fuel producers, consumers, etc.), minimising burden on government and the taxpayer and leveraging private sector investment as far as possible.
Feasibility	**Deliverability**	The policy should be feasible to implement in the 2020s to facilitate FOAK deployment, and should aim to minimise administrative and policy complexity.
	Compatibility	The policy should be compatible with business models under development in sectors such as CCUS and hydrogen production. It should not misalign with or require redesign of wider policy frameworks.
	Track record	The policy has been implemented in other applicable industries for a suitable period and has demonstrated that the policy is likely to achieve what it set out to achieve. In order of preference, applicable industries are engineered GGRs, other CCUS technologies, and energy-related sectors.
	Reaching GGR targets	The policy should enable the government to reach target levels of GGR deployment in the UK.
	Policy flexibility	The policy should be flexible, allowing the level of deployment and incentives to be modulated over time allowing the government to potentially pay less and phase out the policy if needed.

The obligation schemes, carbon CfDs, and payment schemes were shortlisted for further investigation for the following reasons:

- **Obligation schemes** are shortlisted as a GGR policy mechanism because they can help create demand for negative emissions credits. Compared to contracted mechanisms, obligations help establish a market price for NE, which can be used as a reference price for carbon CfD, and allow private sector to directly fund GGRs, in line with the polluter pays principle. The main drawback of obligations is lack of revenue certainty for project developers, which is likely to require the introduction of additional support mechanisms in early years.
- **Carbon CfDs** are shortlisted because of their multiple strengths such as revenue certainty, ability to transition to market-based systems and the successful track record of power CfD. Applicability of CfDs to small scale projects may be challenging, since engaging with the scheme has significant administrative costs, however, most commercial engineered GGRs are likely to be large enough to justify engaging with CfDs. Carbon CfDs are also compatible with many existing policies and offer a relatively fair risk sharing between the developers and the government, although they must be funded by the taxpayer (unless a levy were introduced to cover the costs).
- **Payment schemes** are shortlisted because they share most of the strengths and weaknesses of carbon CfDs. Direct NE procurement has less of a track record compared to CfDs but is likely to be more favourable for smaller developers. Since they lack a reference price, payment schemes perform slightly worse in enabling transitioning to market-based systems and proportionality; however, these can be mitigated to an extent by gain sharing mechanisms.

Detailed design considerations of shortlisted policies

The shortlisted policy mechanisms are **considered in terms of their primary design features** and how each mechanism can best satisfy the **key design principles** of **achieving NE targets, developing a portfolio of GGRs, rewarding NEs equally, providing revenue certainty, encouraging innovation and competition, and offering value for money**. Natural tensions exist between some of these design principles and so they are each discussed in terms of the short-medium term and potential evolution to the medium-long term.

Detailed consideration of an **obligation scheme design finds that while this policy mechanism has many merits**, including setting a market price for NE credits and following the polluter pays principle, it **does not sufficiently satisfy the key design principles in the short-medium term.** Specifically, it does not provide revenue certainty, may not enable the development of a portfolio of GGRs, and may fail to support innovation or competition.

As **payment and CfD schemes are both contract-based mechanisms and share many similarities**, their common design features are considered together. Unique design features, such as the strike price for the CfD schemes are considered at length separately. The policy mechanisms' similarities mean that **they both tend to satisfy the key design principles to the same extent**. They both provide revenue certainty, encourage innovation, and aid competition, which helps to develop a portfolio of GGRs and makes achieving NE targets more achievable over the long run.

Advanced market commitments (AMCs) are considered as an alternative to a standard payment scheme. Though they are found to **have many merits, they do not satisfy the key design principles to the same extent as a typical payment scheme design**. AMCs will reward those technologies that are able to compete on price, which is desirable in a mature market but will not provide support to nascent technologies who have higher costs initially.

Key findings

The **GGR methods that could be supported by the policy mechanism vary widely** in terms of potential scale, cost, and other considerations. Combined with the variable policy support already available in some of the sectors where GGR options sit (some of which will have a bearing on NE), this creates a very varied landscape over which the overarching policy mechanism should sit. Overall, shortlisted policy mechanisms explored through this study were mostly considered by stakeholders to be potentially viable, with early clarity on what support will be available important in the near term.

A **contracted mechanism is likely the most appropriate for incentivising the development of a portfolio of GGRs in the short-medium term**. While it is desirable to allocate funding via reverse auctions wherever possible, for FOAK projects, where there may be insufficient competition, bilateral negotiations may be a more appropriate way to agree terms. In the medium term it should become more feasible to establish separate pots[2] for projects/technologies in combination with reverse auctions. In the long term, this can evolve into a market-based option, fitting with the principles of equal reward for each unit of negative emissions and value for money.

A carbon CfD for rewarding negative emissions has some advantages over a Payment Scheme, partially due to its explicit inclusion of market revenues and clearer evolution (as the reference price changes together with the market landscape). The UK low carbon policy environment is familiar with the concept of CfDs, mitigating potential additional complexities. Initially the reference price should likely be linked to the voluntary market (ideally a new regulated version of a market). This should transition to either the UK ETS price or the price of a separate obligated market once issues surrounding the early integration of GGRs into the UK ETS[3] or around the setup of a new obligation can be addressed.

DACCS technologies have unique challenges, such as exposure to heat and electricity price volatility and lack of a co-product revenue, compared to GGRs using biomass. Furthermore, DACCS technologies are currently at lower development levels and FOAK plants could be deployed at smaller capacities than early BECCS plants.

FOAK DACCS can be supported within the general GGR policy mechanism, as the mechanism must already be flexible in the level of reward granted to the different GGR technologies (given the varied level of support needed for different GGRs in the short-medium term). FOAK DACCS would potentially benefit from some capital support as well, bridging the gap from innovation grants to large-scale rollout, however this is not viewed as essential and is secondary to a bankable revenue stream. As the general GGR policy mechanism needs to be flexible in the level of support which can be provided, this approach could be replicated for other innovative FOAK GGRs and fits well with potential commercial frameworks suggested for FOAK BECCS power deployment.

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[2] The term pots refers to the process of grouping comparable technologies, allowing them to compete with one-another at auction.

[3] The government is consulting on the role of UK ETS as a potential long-term market for negative emissions. Developing the UK ETS – a consultation by the UK ETS Authority [Link]

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This report has been prepared by **Element Energy**, **E4tech** and **Cambridge Econometrics** for the UK Department for Business, Energy and Industrial Strategy (BEIS).

Element Energy (an ERM Group Company) is a strategic energy consultancy, specialising in the intelligent analysis of low carbon energy. The team of over 80 specialists provides consultancy services across a wide range of sectors, including the built environment, carbon capture and storage, industrial decarbonisation, smart electricity and gas networks, energy storage, renewable energy systems and low carbon transport. Element Energy provides insights on both technical and strategic issues, believing that the technical and engineering understanding of the real-world challenges support the strategic work.

E4tech (an ERM Group Company) is a strategic energy consulting firm working at the interface of business, sustainability, and policy. We are well known for our work in renewable fuels, chemicals, and hydrogen across many end-use sectors and markets. The E4tech team has significant experience in the carbon removals sector and in-depth knowledge of biomass value chains.

Cambridge Econometrics is an economics consultancy that works globally from offices in Cambridge (UK), Brussels, Budapest and Northampton, Massachusetts. We specialise in economic research and the application of economic modelling and data analysis techniques for policy assessment and scenario planning. We have particular expertise in the application of whole-economy macro-sectoral models, notably our global E3ME model.

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Acronyms

AD	Anaerobic Digestion
AMC	Advanced Market Commitment
BiCRS	Biomass Carbon Removal and Storage
BECCS	Bioenergy with Carbon Capture and Storage
BEIS	UK Government Department for Business, Energy, and Industrial Strategy
Capex	Capital Expenditure
CCC	Climate Change Committee
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CCUS	Carbon Capture, Utilisation, and Storage
CfD	Contract for Difference
CO_2	Carbon Dioxide
CTBO	Carbon Takeback Obligation
DAC(CS)	Direct air (carbon) capture (and storage)
DACCU	Direct air capture with utilisation
DPA	Dispatchable Power Agreement
EfW	Energy from Waste
EOR	Enhanced Oil Recovery
ETS	Emissions Trading Scheme
FOAK	First of a Kind
GGR	Greenhouse Gas Removal
GGSS	Green Gas Support Scheme
GHG	Greenhouse Gas
H_2	Hydrogen
ICC	Industrial Carbon Capture
IRR	Internal Rate of Return
LCA	Lifecycle analysis
LCFS	Low Carbon Fuel Standard
LCOD	Levelised Cost of DACCS
Mt	Mega tonne
MRV	Monitoring, Reporting and Verification
NDC	Nationally Determined Contributions
NE	Negative Emissions
NOAK	N^{th} of a Kind
Opex	Operational Expenditure
R&D	Research and Development
RAG	Red-Amber-Green
REGO	Renewable Energy Guarantees of Origin
RHI	Renewable Heat Incentive
RO	Renewable Obligation
RTFO	Renewable Transport Fuel Obligation
SAF	Sustainable Aviation Fuel
SEG	Smart Export Guarantee
T&S	Transport and Storage
TRL	Technology Readiness Level
UK ETS	United Kingdom Emissions Trading Scheme
UKIB	UK Infrastructure Bank

Contents

1 Introduction

1.1 Context

Greenhouse gas removal (GGR) technologies and techniques directly remove greenhouse gasses (GHGs) (primarily CO_2) from the atmosphere by storing them in geological formations, products with long lifetimes (e.g., construction materials), or the natural environment (e.g. forests). In addition to reducing legacy CO_2 emissions, **GGRs offer a unique decarbonisation solution to compensate for emissions from certain sectors in which mitigation options are less viable, such as agriculture and aviation.**

GGRs have been recognised by the Intergovernmental Panel on Climate Change as vital to achieving the 1.5ºC global climate target, with deployment envisioned from the mid to late 2020s[4]. Modelling for the UK Net Zero Strategy suggests that by 2050, between 75 and 81 $MtCO_2$/year of negative emissions from engineered GGRs might be required to meet the UK's 2050 net zero target[5]. However, to date there are no large-scale active and operational engineered GGR projects within the UK.

GGRs are a diverse mix of **nature-based** (e.g., afforestation, soil sequestration, habitat/ecosystem restoration, etc.) and **engineered solutions**. Currently, the government is developing policy frameworks for nature-based solutions and this study is exclusively concerned with engineered GGRs. Two of the most prominent engineered GGR technologies are direct air carbon capture and storage (DACCS) and bioenergy with carbon capture and storage (BECCS) with multiple configurations (see Section 2).

However, neither BECCS nor DACCS currently have financially viable business models due to the immaturity of negative emissions (NE) markets and lack of reliable revenue streams for removing GHGs. Recognising the importance of bridging these technologies towards viable long-term business models, the UK Government has already provided assistance in the form of innovation programmes and a variety of illustrative GGR deployment scenarios have been developed[6]. However, a more integrated and comprehensive government incentive scheme is required to further encourage investment, development, and wider deployment of GGR technologies to deliver on the magnitude of GGR volumes required to reach net zero.

Previously, GGR policy development has been suggested to occur within 2020-2025, with rollout of the most viable policies occurring between 2025-2030, reaching full maturity between 2030-2045[7]. The UK Government has published several reports to meet these timelines. A review of first-of-a-kind (FOAK) BECCS power plants was conducted in 2021 which outlined the key factors impacting investability and policy frameworks to overcome current commercial challenges[8]. Furthermore, immediate action to bring forward a portfolio of GGR technologies was recommended in the same year by the National Infrastructure Commission, after reviewing a diverse set of potential policies for NE[9].

In light of the above findings, in late 2021 HM Government released a summary of its call for evidence on GGR development within the country[10] and outlined a need for a diverse GGR portfolio approach to meet its net zero targets. In doing so, **the government announced its intention to deploy at least 5 $MtCO_2$/year of**

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[4] Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. IPCC, 2018 [Link]
[5] Net zero strategy: build back greener. BEIS, 2021 [Link].
[6] Greenhouse gas removal methods and their potential UK deployment. A report by Element Energy for BEIS, 2021 [Link].
[7] Greenhouse Gas Removal (GGR) policy options – Final Report. A report by Vivid Economics for BEIS, 2019 [Link].
[8] Investable commercial frameworks for Power BECCS. A report by Element Energy and Vivid Economics for BEIS, 2021 [Link].
[9] Policy Mechanisms for Supporting Deployment of Engineered Greenhouse Gas Removal Technologies. A report by Element Energy for NIC, 2021 [Link].
[10] Greenhouse Gas Removals Summary of Responses to the Call for Evidence. HM Government, 2021 [Link].

engineered removals by 2030 – which may need to increase to 23 $MtCO_2$/year by 2035 to meet the 6th Carbon Budget[5] – **and consult on preferred policy mechanisms to incentivise early investment in GGRs in 2022**. These were in addition to an earlier commitment of the government to **deliver £100m of innovation funding for DACCS and other GGRs.**

1.2 Objectives & scope

The UK aims to develop an engineered GGR sector to:

- **Hit climate targets** – net zero and the 6th carbon budget will not be feasible without at-scale deployment of a range of engineered GGRs in the UK (the Net Zero Strategy committed to seek an amendment to the Climate Change Act to enable engineered removals to contribute to emissions reduction targets).
- **Position the UK as a global leader in clean technologies** – GGRs represent a new opportunity to capitalise on emerging technologies by exporting expertise, technology, and equipment as well as creating high-quality green jobs.

However, there are **market barriers** associated with developing a GGR sector:

- The fundamental barrier to GGR deployment is the **lack of an established market or customer demand** for engineered removals.
- The high capital and operational costs make engineered GGRs unattractive with the current revenue streams for NE, which are low and unstable.

Given this current situation, reaching the aims stated above without further intervention is highly unlikely. Therefore, **a policy intervention is needed**.

The overarching aim of this project is to **deepen the UK Government's understanding of policies which could enable deployment of DACCS and other engineered GGRs at commercial scales**. This analysis is intended to improve the current evidence base around the relative merits of different potential GGR policy mechanisms in the UK and provide additional recommendations to enable deployment of FOAK DACCS. This project aims to inform the government through evidence-based analysis and discussions with a wide range of stakeholders, contributing towards BEIS's consultation on a preferred policy mechanism to incentivise the development of a portfolio of GGR projects in the UK.

Within this project, there were a number of scope constraints:

- **Engineered GGRs** – the project was restricted to engineering-based GGR approaches. While the project focuses primarily on DACCS and BECCS, the policy mechanism is intended to be sufficiently general to support the deployment of other GGR approaches which might emerge in the future. Previous work has taken place looking at commercial frameworks for FOAK BECCS power plants[8].
- **UK based** - The scope of this project focuses on the incentivisation of GGR projects that are in the UK. This is core to assessment and analysis of policies and reflects the two main aims lying behind the intention of incentivising the development of a GGR sector.
- **Short – medium term –** The project focuses on policy mechanisms which can incentivise the development of engineered GGRs (and a portfolio of different engineered GGRs) over the short to medium term, approximately the 2025-2035 period. This is crucial, as the policy mechanisms considered need to be applicable in the current policy environment and be consistent with the government's expectation of an evolution towards market-based frameworks, closer to 2050, where direct government support would be significantly reduced.

1.3 Report structure

The report is structured into the following sections:

Section 2 begins with a review of GGR technologies, examining the techno-economic characteristics of DACCS, a variety of BECCS configurations, and other emerging GGRs at lower TRLs. This contextualises why policy support is needed to enable large-scale GGR deployment.

Section 3 outlines the international policy landscape for DACCS, lists wider decarbonisation policies in the UK which may interact with potential policy mechanisms to support GGR, and identifies remaining gaps/barriers to be addressed.

Section 4 presents the longlist of GGR policy mechanisms considered in this study, the criteria against which the policies were assessed, and the reasoning for shortlisting the promising policy mechanisms.

Section 5 provides further detail on how these policies may be designed and feasibly implemented in the UK, considering their pros and cons from a wide variety of market, cost distribution, and societal considerations.

Section 6 evaluates how the shortlisted policy mechanisms for engineered GGRs could be optimally designed to support FOAK DACCS projects, as well as presenting additional capital cost support mechanisms which may be beneficial to enable deployment.

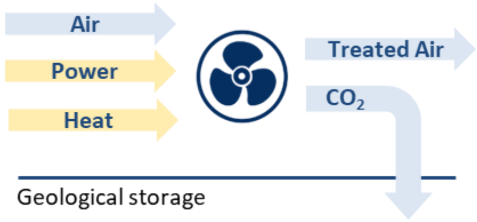
Section 7 summarises the key findings and conclusions of the work.

2 GGR Technology Review

This section provides an overview of engineered GGR technologies that are in the scope of this study, including their technological readiness levels (TRLs), techno-economic characteristics and key risks/barriers to their deployment. A special emphasis is given to costs and siting factors for leading DACCS technologies.

2.1 Description of engineered GGR technologies

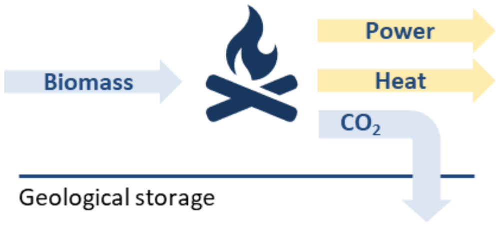
Direct Air Capture with Storage (DACCS)



Process: Direct air capture (DAC) refers to technologies that remove and isolate CO_2 from ambient air using different chemicals. Currently, solid adsorbents and liquid solvents represent the most advanced approaches. The process requires heat and electricity input, but novel approaches using only electricity are being developed. The captured CO_2 may be used in various processes or permanently stored (DACCS) to result in negative emissions. Air contactors which capture the CO_2 are mostly modular, but the downstream processes of releasing and transporting the CO_2 typically require a level of centralization to improve efficiency.

Constraints: Operation of DACCS plants result in minor emissions associated with the heat and electricity used in the process. It is estimated that even when low-carbon energy sources are utilised these emissions may be in the range of 5%-15% of CO_2 captured from air[11], highlighting the importance of having access to low-carbon heat and electricity. DACCS plants should ideally be located close to CO_2 transport and storage (T&S) infrastructures and water sources. Plants' land footprints are usually low, but the renewable energy needed to power the plants may take up more space.

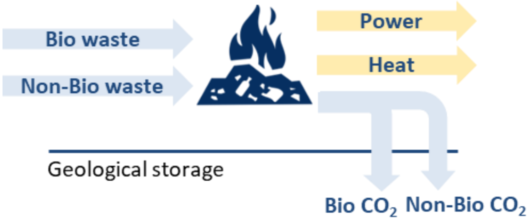
BECCS Power



Process: BECCS power refers to technologies that convert bioenergy to electricity while capturing and storing the resultant biogenic emissions, with heat potentially being generated as a by-product. Power may be produced via biomass incineration with post-combustion CO_2 capture or though gasification of biomass and subsequent combustion of syngas (with pre-combustion CO_2 capture). It is possible to convert coal power plants to biomass plants and/or retrofit carbon capture units to existing biomass power plants.

Constraints: The volume of negative emissions achieved depends on emissions relating to sourcing and transport of biomass to plants. The plants themselves are not likely to have large environmental impacts, but land use may become a constraint depending on the type of biomass. Plants benefit from proximity to CO_2 T&S infrastructures and local biomass sources.

BECCS Energy from Waste (EfW)



Process: BECCS EfW plants are like BECCS power plants in the sense that they also use incineration (with post-combustion CO_2 capture) or gasification (with pre-combustion capture) to generate power and heat. The process typically uses household and commercial waste where recyclable content may be removed prior to incineration. These wastes are generally composed of equal parts of waste from biogenic (e.g., food, wood) and non-biogenic (e.g., metals, plastics) origin. Permanent storage of CO_2 from biogenic waste

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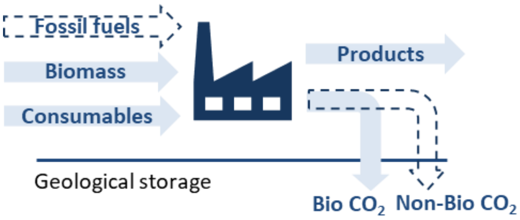
[11] Global Assessment of Direct Air Capture Costs. A report by Element Energy for IEAGHG, 2022 [Link]

results in negative emissions. EfW plants are usually smaller than biomass plants, since they serve local municipalities, and some existing plants may be retrofitted with carbon capture.

Constraints: EfW plants prevent waste being sent to landfills. However, based on UK Waste Hierarchy guidelines, it is environmentally beneficial to reduce, reuse, and recycle waste before recovering energy[12]. BECCS EfW plants require a sustained supply of waste, hence they are best located near both population centres and CO_2 T&S infrastructures, which may not always be an option.

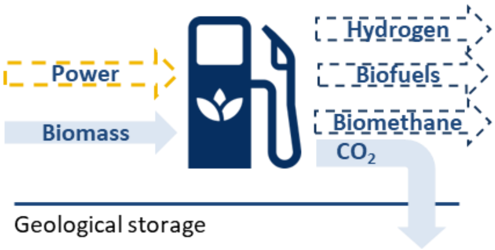
BECCS Industry



Process: BECCS industry refers to CCS installation at industrial facilities which use biomass (or have a potential to switch to using biomass) as a feedstock or source of energy. BECCS may be achieved within a wide variety of sectors such as cement, steel, pulp and paper, each with very different properties and costs. Although some industries (like pulp and paper) already use biomass, BECCS in other sectors (e.g., cement) requires development of new technologies or processes to increase bioenergy use[13].

Constraints: BECCS in industry is mostly constrained to locations with existing plants. Cement plants are usually smaller and distributed, making conversion to BECCS more difficult. Increasing bioenergy use in industry would create competition for these resources and in some cases could have land use impacts. Since the primary aim of the plants is to produce goods, they are likely to operate continually. Proximity to CO_2 T&S infrastructure is another constraint, which may be less impactful for facilities in CCS clusters.

BECCS Hydrogen & Biofuels



Process: Various conversion technologies may be used to produce hydrogen and other fuels from biomass. For example, thermochemical conversion through gasification can produce syngas, which can be converted to hydrogen, methanol, or hydrocarbons. Alcohols may also be produced through fermentation and hydrogen, or biogas (and biomethane) may be generated via anaerobic digestion (AD). Some processes may need external energy. Each configuration results in varying concentrations of CO_2 in exhaust streams, determining costs of capture. Some carbon is left uncaptured if products other than hydrogen are produced, assuming that they are consumed at some point.

Constraints: These BECCS plants have minimal environmental impact besides increased bioenergy demand. In addition to CO_2 T&S infrastructure and biomass supply, siting plants need to consider demand for final products. Small sizes and distribution of some existing plants (i.e., AD plants) may make BECCS retrofits unfeasible.

Other GGRs

Although this study predominantly focusses on DACCS and BECCS technologies, GGR policies investigated may potentially be applicable to other engineered GGR technologies, including:

- **Biochar:** Pyrolysis of biomass or wastes containing biomass results in syngas, oils and biochar. Syngas and oils can be used to produce power, heat, or various fuels. Biochar is a relatively stable solid substance containing carbon, so permanent storage of biochar results in negative emissions. Pyrolysis plants may

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[12] Guidance on applying the Waste Hierarchy, Defra, 2011 [Link]

[13] Barriers and opportunities for industrial fuel switching in the UK have been explored in market studies [Link] and a study on deep decarbonisation pathways for UK industry [Link]. Industrial fuel switching is being explored through BEIS's Industrial Fuel switching programme, with outcomes becoming available on the .gov.uk website [Link to 2019-2022 competition, Link to 2022 – 2024 competition].

also install traditional CCS modules to capture CO_2 resulting from processing of syngas. Such plants would be biochar/BECCS hybrids and would at least partially be engineered GGRs.

- **Marine carbon removal:** Marine carbon removal refers to technologies that remove CO_2 from oceans or seawater, in a process very similar to DACCS. These technologies are currently at low development levels and further RD&D is needed to understand their real potential and environmental impacts. The plants would need to be on shorelines or on offshore platforms. Significant renewable electricity is needed for the process, which produces a gaseous stream of CO_2, much like other GGR technologies. There may be synergies between offshore wind energy and hydrogen production, considering siting requirements and energy needs.
- **Biomass carbon removal and storage (BiCRS):** BiCRS refers to a simple set of techniques involving burying biomass in underground formations which prevent the decomposition of biomass. This does not produce any co-products.
- **Enhanced weathering:** Pulverised silicate rocks or other cation-rich minerals may be spread over large areas of agricultural land or beaches to speed up the natural process of removing CO_2 from the air through the formation of carbonate minerals via chemical reactions with water and air.
- **Passive liming:** In a process similar to enhanced weathering, lime can be spread over large areas to capture CO_2 from air, forming calcium carbonate in a process called passive liming. The CO_2 can then be released and captured, with the benefit of lime regeneration to repeat the process. Alternatively, zero carbon lime produced in a process that captures all CO_2 may be used in construction materials and result in permanent NE.

2.2 Deep dive into DACCS technologies

There are numerous DACCS technologies employing different chemical processes, reactants, and energy sources to remove CO_2 from air. Two of the more established DACCS methodologies are processes utilising liquid absorbents and solid adsorbents.

One of the companies developing the liquid absorbent technology is Carbon Engineering. In this process, CO_2 in ambient air comes into contact with a basic liquid solution where it dissolves to form carbonate ions, which are then deposited to form $CaCO_3$ pellets (Figure 1). In a separate desorption unit, these pellets are heated to 900°C to release pure CO_2 gas. Reaching these high temperatures currently requires combustion of natural gas, where the CO_2 from combustion is fully co-captured and stored with CO_2 from air. In the future, hydrogen or electricity may replace natural gas.

Beneficially, most of the required process equipment is already widely used within industry. The front-end capture process has a modular design, and the CO_2 release process benefits from economies of scale where higher capacity plants experience significant cost reduction. The process consumes some capture chemicals and water and requires on site oxygen generation.

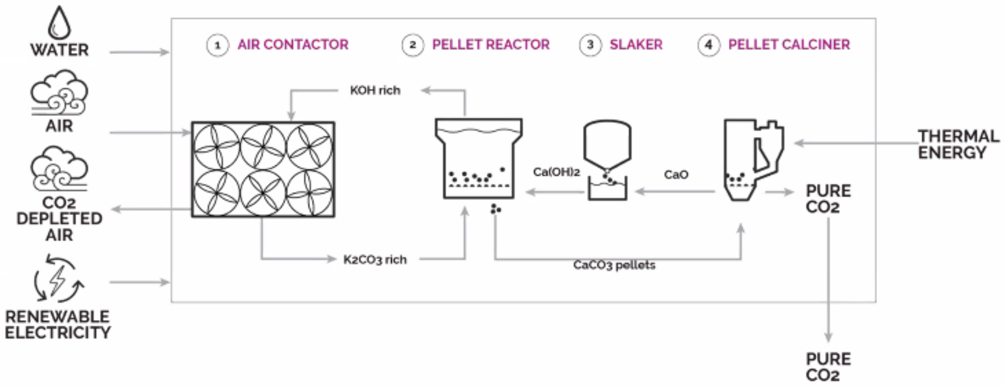

Figure 1: Schematic representation of Carbon Engineering's liquid absorbent DAC process[14]

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[14] Presented in Climeworks' 2nd DAC Conference, 2021. [Link]

Another major DAC technology is using solid adsorbents to separate CO_2 molecules in air. Climeworks and Global Thermostat are two major developers working with solid adsorbent DAC.

The process involves cyclical operation of individual units, which capture CO_2 in one phase and are heated to release it in the other phase. This allows for a more modular design, but the plant still benefits from economies of scale. Temperatures around 80-120 ºC are usually enough for desorption so low temperature heat sources, such as waste heat from industrial and power plants, may be used for solid DACCS operations. The process currently requires frequent replacement of adsorbents, which are relatively expensive. Future R&D aims to improve adsorbent performance and reduce costs.

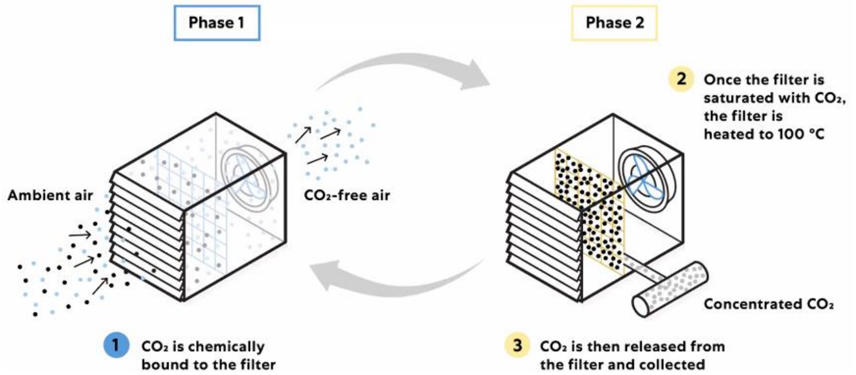

Figure 2: Schematic representation of Climeworks' solid adsorbent DAC process[14]

For the purposes of policy analysis, this study focusses on solid and liquid DACCS technologies. However, given the low maturity of DACCS, there are other designs currently in the R&D or demonstration stages which may prove to be more viable than the current options presented above. Some of these designs are featured in the BEIS GGR Innovation Competition[15] and aim to:

- Replicate the current technologies by only using waste heat so that DACCS can easily run at baseload without needing renewable power
- Run on electricity only, so plants do not need to be restricted to sites with waste heat availability
- Replace natural gas with renewable hydrogen as the heating source, allowing the plant to run continuously regardless of intermittent renewables
- Develop novel capture mechanisms using membranes, electrochemistry, or moisture swing, which are currently not as efficient as solid or liquid DACCS options
- Design processes which leverage wind or other natural flows of air to reduce the energy required by fans to increase contact

Current DACCS cost estimates span a wide range and have inherent uncertainties due to lack of publicly available information and significant assumptions around cost reduction for larger scale and NOAK plants. Element Energy has recently developed a high-level techno-economic model[16] to estimate global DACCS costs of solid and liquid plants using data from the literature and some technology developers. Figure 3 below represents the key results of this study for the base case conditions studied with key assumptions[17].

Costs are represented as **levelised cost of DACCS (LCOD), which measures the cost of capturing a tonne of CO_2 over the lifetime of the plant**. Columns show the cost breakdown per tonne of CO_2 captured by the plant. The net costs (shown as red diamonds) are calculated by taking into account various emissions

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[15] Projects selected for Phase 1 of the direct air capture and greenhouse gas removal programme [Link]

[16] Global Assessment of Direct Air Capture Costs. A report by Element Energy for IEAGHG, 2022 [Link]

[17] Key assumptions: Cost of finance - 10% for FOAK and 5% for NOAK; Electricity - Global solar PV with additional flexibility requirements. FOAK: £53.0/MWh with 50.9 $kgCO_2/MWh$ and NOAK: £39.0/MWh with 24.8 $kgCO_2/MWh$; Heat - Natural gas for liquids: £14.8/MWh gas for FOAK and £6.6/MWh gas for NOAK, nuclear waste heat for solids: £15.1/MWh_{th}; CO_2 transport - £6.4/tCO_2; CO_2 storage - £11.1/tCO_2. See the main report for more detail.

associated with the process, including construction, energy use, chemical use, solvent replacement and upstream methane leakage. Hybrid plants use both heat and power, whereas electric plants only use power.

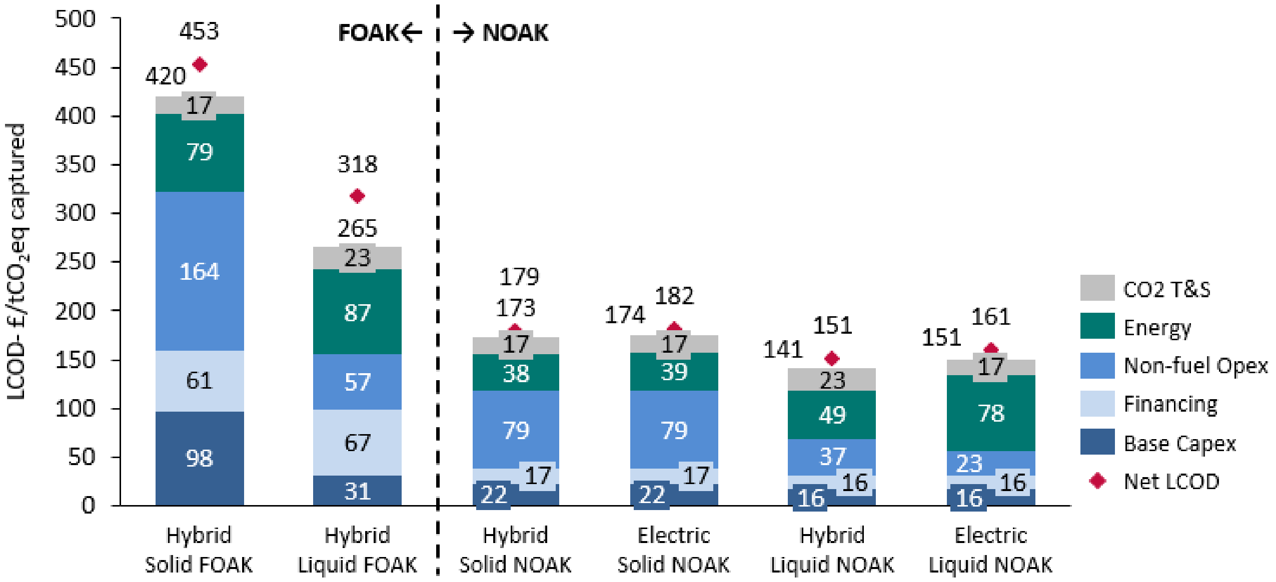

Figure 3: Levelised cost of DACCS (LCOD)[16] of 1 $MtCO_2$/year capacity FOAK and NOAK[18] solid and liquid plants - £/tCO_2

Costs of FOAK DACCS plants were found to be relatively high compared to many other GGR technologies or emissions mitigations measures. Significant cost reduction can be realised by NOAK plants, but for the baseline case **costs are found to stay over the long-term target of £78/tCO_2** ($100/$tCO_2$), which is commonly quoted by technology developers. Costs below this target were achieved when several favourable conditions and ambitious performance assumptions were explored (e.g., low T&S costs, solar prices, and cost of capital). Costs were found to have **high sensitivity to Capex, plant lifetimes, electricity prices and solid adsorbent prices**.

Energy prices and carbon-intensities are found to be two of the most influential parameters on DACCS costs. Generally, for a given source of power, DACCS costs increase linearly with electricity prices. Costs around the £100-150/tCO_2 range were achievable with some of the lowest cost solar energy in the world. On the other hand, utilising unabated natural gas as a heat source significantly increased costs to above £300/tCO_2, which highlights the need to secure low-cost low carbon energy sources to make DACCS affordable. This requirement to have access to affordable low-cost energy separates DACCS from BECCS, which generates its own energy and is affected by biomass prices instead.

DAC with utilisation

In addition to generating negative emissions (NE) through DACCS, Direct Air Capture can also be used in a DACCU (DAC with utilisation) configuration. This can involve CO_2 use in products with

- longer lifetimes (e.g., cement) which may be classified as NE depending on permanence of storage.
- shorter lifetimes (e.g., synthetic fuels or carbonated drinks).

This utilisation configuration allows for a revenue[19] from the sale of CO_2 generated through DAC, and potentially allows for either a voluntary green premium for low carbon products or through defined schemes

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[18] In the context of this analysis NOAK refers to around 5-7 doublings of an initial total capacity of 1 $MtCO_2$/year which is assumed to be the first large scale DACCS plant.

[19] The price of CO_2 for DACCU configurations is difficult to predict as this is likely to depend on complex supply and demand interactions and the specific industries in which CO_2 is utilised. As a reference, in

(e.g., Renewable Transport Fuel Obligation – RTFO). DACCU also avoids additional costs for CO_2 transport and storage.

The GGR policies developed in this report are not intended to support CO_2 utilisation which do not result in long duration NE, however, DACCS and DACCU may directly compete or on some occasions complement each other.

Synthetic fuel production configuration can use a similar DAC plant as DACCS. Plants are not expected to flexibly shift between DACCS and synthetic fuel production modes due to the large investments needed for CO_2 T&S or hydrogen and fuel production facilities. Synthetic fuel production cost is expected to be largely governed by the renewable electricity cost, leading to a potential advantage for plants located outside of the UK where renewable power costs are likely to be lower.

In the medium-term DAC deployment may be limited by supply chains such as rates of supplying equipment, chemicals, and engineering, procurement, and construction. If this is the case, deployment of DACCU facilities might limit the corresponding deployment of DACCS. However, some technologies, like liquid absorbents, might have fewer constraints on supply chains due to the more established equipment and processes they employ.

Some technology developers feel that DACCS offers a simpler business model than DACCU based synthetic fuels or other products. Other technology developers however have business models focused on CCU, and many are engaged with emerging CCU projects. This interest is driven by the current demands for DAC based products and the existence of policies like the RTFO.

Since base DAC plants for DACCS and DACCU are the same, deployment of both dedicated storage and synthetic fuel production can drive down each other's costs. A policy mechanism supporting DACCS needs to consider this possible alternative use for DAC plants, as it influences the UK's targets for GGR deployment. For example, deployment of DAC could be unexpectedly utilisation, or synthetic fuels, focused, potentially leading the UK to miss its targets for GGRs (although DACCU can bring climate benefits in other ways). Alternatively, in the absence of supply-chain restrictions, deployment of DACCU may bring down the cost of DACCS and help establish a wider DAC technology base.

2.3 Techno-economic characteristics of GGRs

As shown in Table 3 below, near and long-term costs of engineered GGR technologies in the UK show a large range, indicating current uncertainties and variation in costs depending on the unique circumstances of individual projects. Most GGRs are around TRL 6-7 as they have only been deployed at modest volumes and occasionally not as a fully integrated system from capture to storage[20]. However, there are many larger scale GGR projects planned internationally, and most technologies may be fully demonstrated at climate relevant scales by 2030 if these projects are delivered.

September 2021 British Soft Drinks Association indicated that the price of CO_2 soared to above £1,000/tCO_2 which was ten times the normal price (£100/tCO_2) for the industry due to the sudden increase in global natural gas prices. [Link]

[20] For instance, the Mikawa power plant in Japan uses biomass and captures its CO_2 but does not store the CO_2 permanently as storage infrastructure is not yet developed.

Table 3: Costs, estimated TRLs and current deployment levels of engineered GGR technologies[21,22]

Sector	2030 Costs	2050 Costs	Estimated TRL	Technology Deployment Levels
DACCS	£150-700 /tCO_2	£70-250 /tCO_2	6[23]	• 15 DAC plants are operational with a combined capacity of 11.3 ktCO_2/year[24] • Most plants are at demonstration scale and utilise the captured CO_2 rather than storing it permanently • The largest DACCS plant is Climeworks' 4 ktCO_2/year Orca plant which commissioned in Iceland in 2021, storing CO_2 in underground basalt formations and pursuing rapid mineralisation • The first large-scale (1 MtCO_2/year) DAC plant is planned to be deployed by mid-2020s in the USA by Carbon Engineering
BECCS Power[25]	£70-150 /tCO_2	£30-170 /tCO_2	7	• The first large-scale plant is now operational in Mikawa, Japan (2020) with a capacity of 180 ktCO_2/year, however, currently captured CO_2 is not permanently stored • In the UK, Drax is planning for large scale deployment by 2027.
BECCS EfW[26]	£60-140 /tCO_2	£50-110 /tCO_2	7	• Currently there are no large-scale EfW plants providing negative emissions • Fortum Oslo Varme is planning to deploy full scale CCS and capture 400 ktCO_2/year at its Klemetsrud plant in Norway by 2026/27 • AVR's EfW plant at Duiven in the Netherlands is capturing 15% of its emissions for use at a local greenhouse or in aggregates • Multiple other BECCS EfW projects are being planned in the UK and the rest of the world
BECCS Industry[27]	£50-270 /tCO_2	£40-300 /tCO_2	7	• Currently there are no operational BECCS industry plants • Norcem cement plant in Norway is planning to install CCS by 2024 • Resolute's Pulp Mill in Quebec is capturing 11 ktCO_2/year for use in a greenhouse

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[21] Technology costs are based on: Greenhouse Gas Removal Methods and Their Potential UK Deployment, Element Energy, 2021 [Link]. The costs are inclusive of CO_2 transport and storage costs of £17/tCO_2 in 2030 and £10/tCO_2 in 2050.

[22] TRL stands for Technology Readiness Levels and are consistent with the guidance note for the UK's SBRI DAC and GGR demonstration programme (Annex 3, pg. 45-6).

[23] TRL 6 is the estimated highest TRL for DACCS technologies. There are many emerging DACCS technologies at lower TRLs, which are at R&D or earlier demonstration stages.

[24] Carbon 180's The DAC MAPP [Link]

[25] The costs provided for BECCS power represent a range of technologies and efficiencies by taking revenues from electricity sales into consideration. New build plants are estimated at the higher end of this range.

[26] Costs provided for BECCS EfW represent retrofitting existing plants with CCS. Costs include Capex and Opex of CCS as well as loss of revenue from powering the CCS units.

[27] BECCS industry costs represent retrofitting CCS units to plants in a wide range of applications, heat and electricity prices. Costs are split equally between capture of fossil and biogenic emissions.

BECCS Hydrogen & Other[28]	£50-120 /tCO_2	£30-100 /tCO_2	5 (9)	• Current deployment consists of 1 MtCO_2/year of a large-scale ethanol BECCS plant in Illinois, USA and ~1 MtCO_2/year of smaller bioethanol plants mostly with CO_2 utilisation • In the UK, some companies are exploring options for BECCS with biomethane production via AD and hydrogen production via gasification or AD in combination with steam methane reforming • BECCS ethanol is currently at high TRLs, and other applications are closer to TRL 5.

For each of the main GGR technologies focussed on in this study, Table 4 below summarises any co-products they produce, main revenue streams and key risks/barriers to their potential business models, not accounting for any current or future policies. Risks/policies common to all technologies are provided at the top. This table is built for technologies delivering negative emissions, so some utilisation routes (such as DAC to fuels) are not considered. The revenues, risks, and barriers of some emerging GGR technologies – such as ocean removals, enhanced weathering, and passive liming – are expected to be very similar to those of DACCS.

Table 4: Co-products, revenue streams and key risks or barriers of GGR businesses

Sector	Co-Product(s)	Revenue (or similar)	Key Risks and Barriers
			All sectors: • CO_2 T&S availability • CO_2 T&S costs for dispersed sites • High capital costs for deployment of carbon capture • Lack of reliable revenues from NE
DACCS	None	• NE credits	• Fuel prices (heat and electricity) • Permitting processes, requirements • Public acceptability
BECCS Power	Electricity (sometimes heat)	• Electricity sales • Capacity payments • Heat sales • NE credits	• Biomass prices • Uncertain plant dispatch • Electricity revenue • Public acceptability
BECCS EfW	Electricity (sometimes heat)	• Electricity sales • Capacity payments • Heat sales • Gate fees • NE credits	• Feedstock availability and variability – long term uncertainty of gate fees • Public acceptability (e.g., air pollution) • Permitting processes, requirements
BECCS Industry	Low-carbon goods (e.g., cement, steel, paper)	• Commodity markets • Avoidance of UK ETS prices or selling allowances • NE credits	• Carbon leakage • Difficulty financing / short payback periods required • Cost of fuel switching (for some sectors)
BECCS Hydrogen & Other	Low carbon fuels (e.g., hydrogen, biomethane, bioethanol)	• Low-carbon fuel sales • Gate fees • Avoidance of UK ETS prices (non-bio waste feedstocks) • NE credits	• Hydrogen/fuel market demand and sale price • Hydrogen T&S availability • Feedstock availability/price • Permitting processes, requirements

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[28] Costs presented for BECCS fuels are based on hydrogen production via gasification, which produces a relatively pure stream of CO_2. Only additional costs for installing CCS are considered and base costs of producing the fuel is not accounted for. Cost ranges include a margin to account for high technical uncertainties.

Currently all engineered GGR options face various risks and barriers preventing deployment at large-scales. Some of these barriers are addressed at different levels via new or proposed policies in the UK, which are important to understand how new GGR policies can address the problem of lack of revenue streams for NE.

3 Policy Landscape Review

This section identifies existing and proposed UK policies that interact with engineered GGR technologies and makes a case for further financial support (i.e., a negative emissions incentive) by the government. It also provides a brief overview of the global state of voluntary NE credits markets and DACCS specific policies adapted in different countries, which inform the detailed policy mechanism design in later sections.

3.1 UK policy landscape impacting GGR technologies

Table 5 below provides an overview of existing and planned policies in the UK that can directly or indirectly support engineered GGR businesses through providing revenue streams or other incentives. Only policies which are likely to affect future policies and business models for negative emissions are reviewed in detail. Innovation programmes such as the BEIS DAC and GGRs Innovation Competition are excluded.

Table 5: Summary of existing UK policies which may interact with policy mechanisms to support engineered GGRs

Policy	Description	Affected GGRs
Power Contracts for Difference (CfD)	The Contracts for Differences (CfD) scheme is run by BEIS and the National Grid. It provides price certainty to clean energy generators by ensuring a fixed amount of payment per MWh of power generated for 15 years, which is determined through auctions. Three rounds of auctions have taken place to date and the fourth round is expected to be finalised by Summer 2022. Strike prices agreed in the last round were around ~£40/MWh.	BECCS – Power, EfW
Renewable Energy Guarantees of Origin (REGO)	This is a scheme administered by Ofgem to certify production of renewable electricity. Any generator in the UK can acquire credits per MWh of renewable output and sell credits to power suppliers, who need to demonstrate their fuel mixture to their customers. Biomass power is eligible for credits; however, current credit prices are too low to justify any investment on its own.	BECCS – Power, EfW
UK Emissions Trading Scheme (UK ETS)	The UK ETS is a cap-and-trade system covering power generators, heavy industry (excluding EfW plants), and aviation. Participants in the UK ETS are required to obtain allowances equivalent to their annual emissions under the scheme. These can be bought in regular auctions or by trading on the secondary market; some participants at risk of carbon leakage receive some allowances for free. Currently negative emissions are not included in the ETS, therefore plants installing CCS would only benefit from emissions reduction. The Government has recently consulted on proposals to expand the UK ETS to waste incineration and domestic maritime, and has called for evidence on the role of the UK ETS as a potential long-term market for GGRs.	BECCS – Industry, potentially EfW
Green Gas Support Scheme (GGSS)	GGSS replaced the RHI in November 2021. It provides payments to AD biomethane injections to the grid for small producers. Payments follow a tiered approach and are financed through a levy charged to gas suppliers. Contracts run for 15 years and inclusion of other types of gases will be considered in the future. At least 50% of the energy must be produced using waste or residue feedstocks.	BECCS -biogas, biomethane

Renewable Transport Fuel Obligation (RTFO)	RTFO requires producers of land transportation fuels to source Renewable Transport Fuel Certificates (RTFCs) to cover an increasing portion of their production. These certificates are awarded to biomass-based fuels on a per litre basis and gases on a mass basis, considering energy densities. A sub-set of fuels called development fuels have a separate sub-target. Development fuels are hydrogen, drop in road or aviation fuel or methane substitutes made from wastes or renewable fuels of non-biogenic origin (e.g., CO_2 from DAC).	BECCS – hydrogen, biofuels, biogas, biomethane
Capacity Market	National Grid provides fixed payments to generators to maintain power generation capacity. There are 1-year and 15-year contracts awarded through auctions. These can provide additional revenues to power generators.	BECCS – Power, EfW
Smart Export Guarantee (SEG)	SEG is a scheme launched in January 2020 replacing the Feed-in-tariffs. It requires large power suppliers and voluntary entities to pay for power generation by small generators, with a capacity of up to 5MW. Eligible technologies include solar PV, wind, micro-CHP, hydro, and AD. Tariffs are paid only on the net exports to the grid and prices differ for each company offering tariffs.	BECCS – power
Renewable Heat Incentive (RHI)	The non-domestic RHI has been closed to new applicants since 2016, however, there are previous applicants still receiving funding from the programme. RHI provides fixed payments per MWh of heat provided via installations running on solid biomass, biogas, and energy from waste.	BECCS – power, EfW, biogas

Apart from the established policies currently in effect, there are a few key policies and business models that the government is currently developing to enable deployment of initial CCUS-related projects (along with electrolysis-based hydrogen) in the UK. These policies (Table 6), are very important because they may have significant implications for and interactions with future potential GGR policy mechanisms.

Table 6: Policies and business models that are currently being developed

Policy	Description	Affected GGRs
UK CO_2 T&S Business Model[29]	The government expects to set up a regulated asset-based model for T&S businesses where capture plants are charged a fixed capacity fee and a volumetric fee per tonne of CO_2 processed. In the future separate connection fees may be charged for onboarding new customers. These costs will be determined by a regulator, allowing a return on investment.	All
BECCS Power Business Model	This policy is still under development, and possible mechanisms were outlined in the “Investable commercial frameworks for 'power-BECCS'” report which was published in October 2021.[30]	BECCS – power

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[29] BEIS updates and proposals for business models for CO_2 transport and storage and industrial carbon capture [Link]

[30] Investible commercial frameworks for Power BECCS. By Element Energy and Vivid Economics for BEIS, 2021 [Link].

Industrial Carbon Capture (ICC) Business Model[29]	ICC business models will be used to help industries and EfW plants install CCS units as part of Phase 2 of the CCS Cluster Sequencing. The model will cover some of the initial costs through grants in a last spend approach. A separate ongoing revenue support will be provided on a per tonne of CO_2 stored basis for a period of 10-15 years. Strike prices will initially be negotiated bilaterally, and later through auctions. Remaining Capex will be recovered through increased payments in early years. CO_2 T&S fees will also be covered by the contract. Finally, businesses will forfeit a portion of their free UK ETS allowances but will be compensated for their financial value.	BECCS – industry, EfW
Low Carbon Hydrogen Business Model[31]	BEIS is developing a hydrogen business model which is intended to provide revenue support to hydrogen producers to overcome the operating cost gap between low carbon hydrogen and high carbon counterfactual fuels. The consultation proposed that revenue support will be provided through a contractual, CfD-style variable payment model, where the subsidy is the difference between a 'strike price' reflecting the cost of producing hydrogen and a 'reference price' reflecting the market value of hydrogen. Furthermore, the government proposes to use a sliding scale approach to manage volume risk in which the strike price (and therefore subsidy) is higher on a per unit basis if hydrogen offtake falls. Business model support will be awarded competitively. Hydrogen production supported through the business model will need to meet the UK Low Carbon Hydrogen Standard developed by BEIS. NE from the hydrogen plants may be used to meet this standard.	BECCS – hydrogen
Sustainable Aviation Fuel (SAF) Mandate[32]	The Department for Transport recently consulted on a mandate which would require aviation fuel suppliers to meet GHG targets by sourcing an increasing portion of their fuels from sustainable aviation fuels (SAFs). The proposed scheme could start in 2025 and is expected to replace SAF's inclusion in the RTFO. Unlike RTFO, it would be based on lifecycle GHG emissions reduction, not fuel volumes. SAF from wastes, residues, and DAC may be eligible for credits.	BECCS - biofuels

These policies are at varying stages of development and the Government is progressing work on their design. The government intends to finalise these models in the next couple of years, particularly with a view to supporting low-carbon projects to deploy through the CCUS clusters in the second half of this decade.

The GGR policies investigated in this study should be compatible with the existing and proposed policies listed above and provide proportionate financial support only if individual GGR technologies are not viable without them. The tables below summarise the inherent barriers to deployment of GGR technologies and how the aforementioned policies are likely to address these barriers, as well as a brief rationale to why additional GGR policies are needed to overcome these remaining barriers.

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[31] BEIS – Low carbon hydrogen business model consultation (25 October 2021) [Link]

[32] DfT – Sustainable aviation fuels mandate consultation (July 2021) [Link]

DACCS

<table>
<tr><th>Inherent Risks/Barriers</th><th>Policy Support</th><th>Remaining Risks/Barriers</th></tr>
<tr><td>• High capital costs
• Availability of CO_2 T&S infrastructure
• High/uncertain energy prices
• Permitting processes, requirements
• Lack of reliable revenues from NE</td><td>• CO_2 T&S Business Model</td><td>• High capital costs
• CO_2 T&S costs
• High/uncertain energy prices
• Permitting processes, requirements
• Lack of reliable revenues from NE</td></tr>
<tr><th colspan="3">Case for Additional Support</th></tr>
<tr><td colspan="3">DACCS would potentially require the most support from the government as it is currently an expensive technology with no reliable revenue streams and almost none of its risks are addressed by the current policy landscape.</td></tr>
</table>

BECCS Power

<table>
<tr><th>Inherent Risks/Barriers</th><th>Policy Support</th><th>Remaining Risks/Barriers</th></tr>
<tr><td>• High capital costs
• Availability of CO_2 T&S infrastructure
• High CO_2 T&S costs for dispersed sites
• Future biomass price uncertainty
• Uncertainty on plant load factors (how much it can be dispatched)
• Electricity price uncertainty
• Lack of reliable revenues from NE</td><td>• CO_2 T&S Business Model
• Power Contracts for Difference (CfD)
• Renewable Energy Guarantees of Origin (REGO)
• Capacity Market
• Smart Export Guarantee (SEG)
• BECCS Power Business Model
• Renewable Heat Incentive (RHI)</td><td>• High CO_2 T&S costs for dispersed sites
• Future biomass price uncertainty
Addressed by FOAK BECCS power commercial framework:
• High capital costs
• CO_2 T&S costs
• Lack of reliable revenues from NE</td></tr>
<tr><th colspan="3">Case for Additional Support</th></tr>
<tr><td colspan="3">The FOAK BECCS power commercial framework currently under development is seeking to address all vital risks of the technology for plants in CCUS clusters. However, this support is targeted towards early plants, therefore creation of a negative emissions market can reduce the burden on the taxpayer.</td></tr>
</table>

BECCS EfW

<table>
<tr><th>Inherent Risks/Barriers</th><th>Policy Support</th><th>Remaining Risks/Barriers</th></tr>
<tr><td>• High capital costs
• Availability of CO_2 T&S infrastructure
• High CO_2 T&S costs for dispersed sites
• Lack of reliable revenues from NE
• Feedstock availability and variability</td><td>• CO_2 T&S Business Model
• Power Contracts for Difference (CfD)
• Renewable Energy Guarantees of Origin (REGO)
• Capacity Market
• Industrial Carbon Capture (ICC) Business Model
• Renewable Heat Incentive (RHI)</td><td>• High CO_2 T&S costs for dispersed sites
• Lack of reliable revenues from NE
• Feedstock availability and variability</td></tr>
<tr><th colspan="3">Case for Additional Support</th></tr>
<tr><td colspan="3">The Government is exploring how the ICC could be adapted for the waste management sector to enable initial waste CCS projects to deploy through the CCUS Clusters Sequencing process in the mid-2020s. BECCS EfW plants eligible for the ICC business model support will receive payments for biogenic and non-biogenic CO_2 and will therefore be fully viable without any additional GGR specific support. In the short/medium term participation in market-based carbon removal may be sufficient for BECCS EfW, however, in the long-term waste feedstock availability may be a concern.</td></tr>
</table>

BECCS Industry

Inherent Risks/Barriers	Policy Support	Remaining Risks/Barriers
• High capital costs • Availability of CO_2 T&S infrastructure • High CO_2 T&S costs for dispersed sites • Lack of reliable revenues from NE • Carbon leakage • Short payback periods required • Future biomass price uncertainty • Cost of fuel switching (for some sectors)	• CO_2 T&S Business Model • UK Emissions Trading Scheme (UK ETS) • Industrial Carbon Capture (ICC) Business Model	• High CO_2 T&S costs for dispersed sites • Lack of reliable revenues from NE • Future biomass price uncertainty • Cost of fuel switching (for some sectors)
Case for Additional Support		
ICC business model allows for recovery of the Capex over 5-years and ongoing operating costs of a CCS unit for 10-15 years. However, it provides no incentive for fuel switching to biomass. Plants that already use biomass would receive sufficient support under the ICC business model to deliver negative emissions by covering the costs of carbon capture., but most sectors will likely require additional policy support to justify fuel switching.		

BECCS Hydrogen

Inherent Risks/Barriers	Policy Support	Remaining Risks/Barriers
• High capital costs • Availability of CO_2 T&S infrastructure • Lack of reliable revenues from NE • Hydrogen price/demand • Hydrogen T&S infrastructure • Future biomass price uncertainty	• CO_2 T&S Business Model • Renewable Transport Fuel Obligation (RTFO) • Hydrogen Business Model • Net Zero Hydrogen Fund	• Lack of reliable revenues from NE • Hydrogen T&S infrastructure • Future biomass price uncertainty
Case for Additional Support		
The proposed business model for hydrogen covers costs associated with operating a CCS unit, however, is not designed to expressly incentivise negative emissions, so marginal support proportional to negative emissions may be needed if voluntary markets are not sufficient to cover the cost differential between BECCS hydrogen and other low carbon hydrogen production methods.		

BECCS Biofuels

Inherent Risks/Barriers	Policy Support	Remaining Risks/Barriers
• High capital costs • Availability of CO_2 T&S infrastructure • Lack of reliable revenues from NE • Future biomass price uncertainty • Biofuel's price/demand	• CO_2 T&S Business Model • Renewable Transport Fuel Obligation (RTFO) • Sustainable Aviation Fuel (SAF) Mandate	• High capital costs • CO_2 T&S costs • Lack of reliable revenues from NE • Future biomass price uncertainty
Case for Additional Support		
Low-carbon fuels are awarded to an extent by RTFO, but this policy does not reward NE explicitly. On the other hand, the new SAF mandate will likely be based on net carbon intensity of fuels, which may recognize fuels with negative footprints. Future GGR policies may be needed to cover the additional expenses of operating a CCS unit, compared to the core biofuels business models, unless the SAF mandate provides sufficient revenues for SAF-based plants.		

BECCS Biogas

<table>
<tr><th>Inherent Risks/Barriers</th><th>Policy Support</th><th>Remaining Risks/Barriers</th></tr>
<tr><td>• High capital costs
• Availability of CO_2 T&S infrastructure
• High CO_2 T&S costs for dispersed sites
• Lack of reliable revenues from NE
• Future biomass price uncertainty
• Biogas/biomethane price/demand</td><td>• CO_2 T&S Business Model
• Green Gas Support Scheme (GGSS)
• Renewable Transport Fuel Obligation (RTFO)
• Renewable Heat Incentive (RHI)</td><td>• High capital costs
• High CO_2 T&S costs for dispersed sites
• Lack of reliable revenues from NE
• Future biomass price uncertainty</td></tr>
<tr><th colspan="3">Case for Additional Support</th></tr>
<tr><td colspan="3">Existing revenue streams for biogas/biomethane businesses are sufficient to cover the core expenses of the process, however, currently there are no additional incentives to install a CCS unit to generate NE. Future GGR support may be needed to cover the CCS related expenses of BECCS biogas.</td></tr>
</table>

3.2 Voluntary negative emissions markets

The current state of the voluntary market

Currently there are no sufficient, reliable financial incentives to deploy and operate large-scale engineered GGRs. However, some voluntary corporate purchases through bilateral agreements have allowed start-ups to fund early projects:

- In 2021 **Microsoft** purchased[33] a total of 1.3 $MtCO_2$ of carbon removal from 15 organisations, including 1,400 tCO_2 from Climeworks (DACCS) and 2,000 tCO_2 from Charm Industrial[34] (biomass storage).
- Over 2020-2021 **Stripe** has added three DACCS projects to their portfolio[35] of promising carbon removal providers. Furthermore, it announced a partnership with non-profit Activate to support its fellows pioneering early-stage carbon removal technologies[36].
- **Shopify** is another advocate of corporate carbon removal purchases and has bought 15,560 tCO_2 removal via DACCS (Carbon Engineering and Climeworks) and 1,000 tCO_2 via BECCS (Charm Industrial) in 2020[37].
- The longest term and highest value corporate purchase in the voluntary market to date belongs to **Swiss Re**, a re-insurance company, which made a 10-year purchase agreement with Climeworks for $10 million[38].

In addition to the high-profile negative emissions purchases discussed above, some GGR companies are directly selling credits to businesses and individuals.

- **Climeworks** established a subscription programme for individuals and is offering DACCS removal credits publicly[39] for £900/tCO_2. Currently they have received orders from more than 13,000 unique customers, including individuals.
- **Carbon Engineering** is partnering with BeZero Carbon, a carbon credit ratings company for the voluntary carbon market, to pre-sell credits from its future plants. Prices are not publicly available, and customers are encouraged to get a quote online.

Furthermore, several marketplaces specialising in negative emissions credits are emerging:

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[33] Microsoft carbon removal: lessons from an early corporate purchase [Link]
[34] Charm Industrial produces bio-oil through pyrolysis and stores it permanently in geologic formations.
[35] Stripe's carbon removal web page [Link]
[36] Activate's web page [Link]
[37] How to kick-start the carbon removal market: Shopify's playbook [Link]
[38] News article [Link]
[39] Climeworks' website, accessed 07.03.2021 [Link]

- **Puro Earth** is the world's first business-to-business carbon removal market which currently sells credits for biochar, soil enhancement, and net-negative construction materials. As of March 2022, credits for wood in construction were trading at €20 - €25/tCO_2, whereas biochar credits were at €95 - €200/tCO_2. Puro has sold 123 ktCO_2 credits to date and established a scheme for offtake agreements for early-stage projects. Carbon removal providers are audited by third party verifiers and must adhere to Puro's protocols, which includes a cradle to gate lifecycle analysis.
- **Nori** is a marketplace using blockchain technology to issue carbon removal credits. Currently only soil carbon storage projects are included and credits trade for $15 + a 15% fee to maintain the platform. Suppliers are audited by third party verifiers. To date 64 ktCO_2 credits have been sold. Nori only guarantees removals for up to 10 years.

These platforms or future marketplaces may develop frameworks to include DACCS and BECCS credits to expand the reach of engineered GGRs to the public.

Voluntary support for GGRs can also take the form of philanthropic carbon removal competitions. In 2021 Elon Musk launched a $100 million carbon removal competition[40] through XPRIZE, for companies with innovative and scalable negative emissions technologies. The competition will last for 4 years, and the majority of the funding will be awarded to 4 promising start-ups.

In the absence of sufficient government funding beyond innovation support, such philanthropic contributions and voluntary corporate NE purchase are currently driving the wider global NETs industry.

The future and implications of voluntary markets

Voluntary carbon removal markets are still very immature in many ways. Trading of non-afforestation removal credits only started in 2019 and current marketplaces do not include credits from existing engineered removal projects, except for small amounts of biochar. **Inclusion of DACCS and BECCS in these markets requires developing robust accounting frameworks** to ensure that customers are paying for genuine removals. Prices paid by corporations and credits traded at Puro Earth clearly attract premiums above the market value of other types of offset credits, however, the volumes purchased are still very low.

Future scale and **prices in voluntary markets are very difficult to predict**, but Figure 4 illustrates one possible way prices may evolve as the voluntary market matures. Currently, the lower end of prices is for nature-based removal options whereas the highest prices are for very small volumes of DACCS credits. Engagement with technology developers reveals that securing corporate interest in removals at MtCO_2 scales is challenging due to high costs. It is likely that **if high volumes of permanent removals were available, they would attract prices only marginally higher than current offsets markets,** because customers are unlikely to pay more for credits at high volumes. On the other hand, as economies decarbonise, demand for carbon removal will increase, pushing up the lower end of the credit price range.

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[40] Competition webpage [Link]

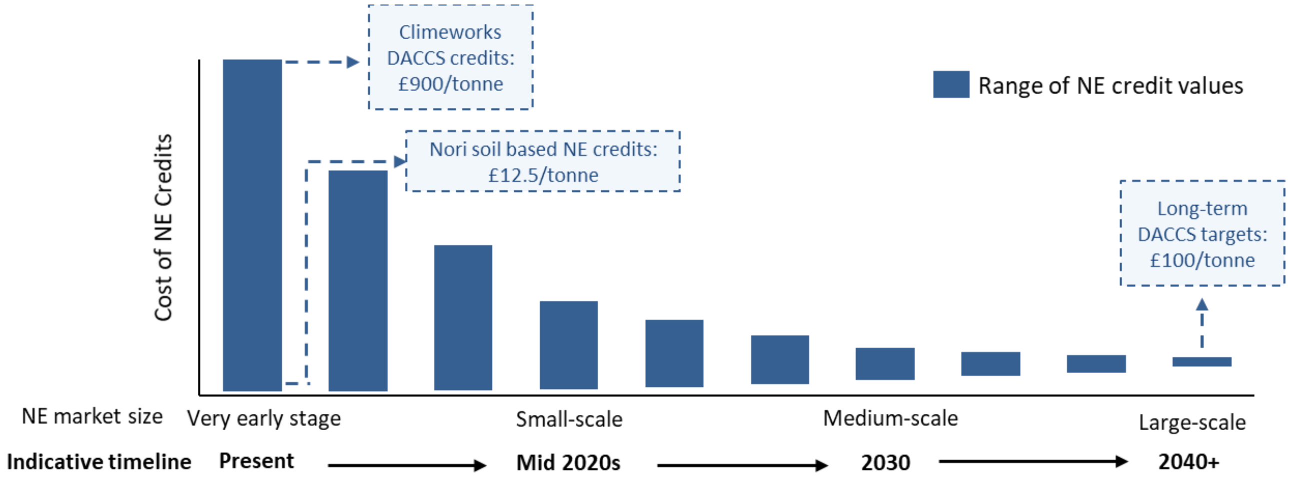

Figure 4: Schematic representation of a possible evolution of voluntary NE credit costs with time and market size. The bars represent the range of costs for the cost of credits.

Article 6 of the Paris Agreement, as agreed at COP26, allows countries to trade carbon credits internationally. However, full Article 6 trades of UK-based removals credits would require a 'corresponding adjustment' to stop the removal from being reported towards both the UK's UN climate target (Nationally Determined Contribution) and the buyer's target. This accounting is not required under voluntary markets, which could make them a more viable income stream for UK-based GGR projects.

Since voluntary markets provide revenue streams from private companies, they should be considered as the baseline incentive for engineered GGRs. **The government should seek to capitalise on voluntary carbon markets, while recognising that voluntary corporate purchases are unlikely to be sufficient for most engineered GGRs, hence requiring additional intervention.** Consequently, new GGR policies should encourage participation in voluntary markets through incentives such as allowing developers to keep a portion of revenues from credit sales. Understanding the exact nature of these interactions will take time as sufficient liquidity is achieved in carbon removal markets.

3.3 Global policies supporting DACCS

Although no large-scale DACCS plant is currently operational or under construction, several policies that directly or indirectly incentivise DACCS are emerging globally. The most common type of support is R&D funding through national or regional research programmes, with some dedicated funding emerging recently:

- **US Energy Act 2020:** A total of $447 million was authorised to be used in 2021-2024, for RD&D of GGRs, including DACCS, BECCS and agricultural options[41].
- **US FY22 Appropriations:** Discussions around an additional funding of at least $175 million for R&D on DAC, CO_2 mineralization, storage, and monitoring[42].
- **UK's** £8.6 million GHG Research and Development Programme (2017-2021), co-funded by NERC, BEIS, EPSRC and ESRC. It supports a host of GGRs, including DACCS.
- **China – Zhejiang University's** DAC R&D programme involves utilisation of captured gas as a fertiliser for crop growth in a greenhouse[43].
- **EU RD&D Programmes:** Horizon Europe is the EU's main R&I programme for funding GGRs research, among many other technologies. Further funding is available for supporting innovative low-carbon companies through the European Institute of Innovation and Technology and the European Innovation Council, although historically funding directed at NETs has been very low.

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[41] Article [Link]
[42] Article [Link]
[43] The programme is listed in Carbon 180's map of activities [Link]

Some policies provide support for early-stage deployment and demonstration of emerging DACCS technologies. Notable examples of recent demonstration support are:

- **The US Energy Act of 2020**
    - Grants for FEED studies and large-scale pilot demonstrations through the $447 million fund.
    - DAC prizes for pre-commercial ($15 million) and commercial ($100 million) technologies.
- **The UK's GHG Removal Innovation Competition** which provides £70 million by BEIS and £30 million by a UKRI programme to fund development of multiple GGRs feasibility studies and a few demonstration plants[44].
- **The Canadian government's direct investment** of CAD$25 million into Carbon Engineering to demonstrate their emerging technologies[45].
- **Australian CCUS Development Fund** which will provide AUS $50 million to CCS and CCU pilot and demonstration projects in the next 3 years[46].
- **Germany's CO_2 avoidance and use funding directive** will mobilise €585 million until 2025 for CO_2 T&S infrastructure around North Sea, CCS, CCU, DACCS and BECCS projects[47].
- **Germany's support for a pilot synthetic liquid fuels plant,** commissioned by Federal Ministry of Transport, will supply at least 10,000 tonnes of fuel per year and may use CO_2 from air[48].
- **Several other EU funds**, such as the Innovation Fund and Connecting Europe Facility, offer financial support for deploying CCS projects and infrastructure.

Currently there are no dedicated, structured financial incentives for deployment of DACCS globally, however significant commitments are made in the US, which will support FOAK DACCS plants, along with other CCS technologies:

- The recent **Infrastructure Investment and Jobs Act** allocates $3.5 billion for **creation of 4 DAC hubs,** each with a capacity of at least $1MtCO_2$/year. This will help the US DOE deliver its target of reducing carbon removal costs to $100/$tCO_2$ announced as part of the Carbon Negative Shot.
- **The 45Q tax credits** award tax alleviation worth $35/$tCO_2$ for enhanced oil recovery (EOR) or $50/$tCO_2$ for dedicated geological storage CCS (including DAC). DAC can directly use this incentive in conjunction with other US incentives. Recently, several amendments have been submitted to the Congress to increase 45Q credits substantially and offer higher incentives to DACCS, and the credit is open to be adjusted in the future to keep up with inflation[49].
- **California's Low Carbon Fuel Standards (LCFS)** require fuel suppliers in the state to reduce their carbon intensity over time or purchase credits to make up the difference. LCFS allows DAC facilities producing synthetic fuels to sell into this market or sell carbon removal credits to fuel suppliers if DAC is used for permanent storage. LCFS credits were worth $135-140/$tCO_2$ in early March 2022[50].

Furthermore, Sweden has introduced a new reverse auction-based system[51] to procure annual BECCS capacities around 200 – 400 $ktCO_2$/year, starting from 2025/26. This model may be adopted for DACCS projects in the future. Another promising global GGR policy is a feed-in-tariff for purchasing permanent NE (including DACCS and BECCS), which is currently being developed by a group of GGR advocates for the Luxemburg government[52].

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[44] Details of the UKRI programme [Link]
[45] Article [Link]
[46] News [Link]
[47] News [Link]
[48] Article [Link]
[49] Article [Link]
[50] Neste California LCFS prices (accessed 08.03.2022) [Link]
[51] Article [Link]
[52] Video of OpenAir Collective's recent work on the Luxemburg feed-in-tariff [Link]

Lastly, some support for CO_2 utilisation technologies indirectly helps improve DACCS technologies by encouraging research or deployment of direct air capture for producing sustainable CO_2. Some notable examples of such support are:

- Most current CCU research is supported by general RD&D (research, development and demonstration) programmes, however:
    - **The US Energy Act of 2020** allocates $280 million specifically for CCU research and establishes a carbon utilisation research centre
    - The State of New York's new $10 million **Carbontech Development Initiative** will carry research, technology transfer and commercialization work for carbon-to-value processes[53].
- **Buy Clean California Act** will require state agencies to purchase construction materials below a threshold of carbon intensity. CCUS and DAC can be used to reduce embedded emissions of these materials, providing a procurement policy support.
- Other CCU policy support includes mechanisms to reduce carbon intensities of fuels, some of which are discussed previously, such as:
    - **California's Low Carbon Fuel Standard**
    - **Swedish GHG reduction mandate in aviation**
    - **Swiss aviation carbon tax**, which is an incentive for carbon intensity reduction of aviation fuels, which may benefit synthetic fuel production from DAC[54].

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[53] Article [Link]
[54] Article [Link]

4 Selection of Viable GGR Policy Mechanisms

Given the case for additional dedicated GGR policy support explored above, a long list of candidate policies was assessed against numerous criteria to determine a shortlist of policy mechanisms with a high likelihood of enabling the UK to reach its GGR targets.

The longlist of GGR policies and the assessment criteria were developed based on Element Energy's recent reports exploring policy mechanisms to support GGRs[55], interactions with various policymakers at BEIS and the cross-government project Steering Group, and engagement with numerous technology developers, academics, and financial sector experts.

Several principles were prioritised when selecting and defining the longlist of policy options:

- Deliver negative emissions on the scale needed to reach interim carbon budgets (and to de-risk this by initially developing a portfolio of different GGRs)
- Reward negative emissions equally (and explicitly)
- Provide a reliable revenue stream for NE providers
- Encourage innovation
- Encourage competition
- Offer value for money and leverage private investment

Some of these principles are inherently desirable – such as rewarding each unit of NE equally, allowing innovation etc. Others are imposed by the circumstances of the sector – for example, the need to achieve and de-risk hitting GGR targets by initially developing a portfolio of different GGR technologies is a result of the uncertainty in the sector. These circumstances might change over time, having an important influence on policy design.

The two sets of principles listed below are somewhat at odds with each other regarding the level of support different technologies should receive:

Initial Development Portfolio of Different GGRs & Value for Money

vs.

Equal Reward & Competition & Innovation

The principles on the left favour rewarding technologies in a way that is specific to their circumstances (e.g., BECCS industry being compensated at a different level from DACCS), and the principles on the right favour equal rewards for each technology. In the future, the scales should tip towards equal reward, however initially, principles on the left are needed to ensure that less developed GGRs that could play a key future role are not prematurely discarded on the grounds of current high costs.

This is reflected in the importance of an initially flexible policy mechanism, where there are practical ways of awarding different levels of incentives to each GGR technology. Flexibility is also needed to consider the varied other forms of existing and proposed policy support across the different GGR technologies. However, an ideal GGR policy must also be able to transition into an appropriately market led approach in the medium- to long-term when uncertainty is reduced.

The rest of this section briefly introduces the longlist of GGR policies considered, the specific assessment criteria against which the policies were ranked, and the reasoning for shortlisting or eliminating each of the policies.

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[55] Policy mechanisms for supporting deployment of engineered GGR technologies. By Element Energy for NIC (July 2021) [Link] and Investable commercial frameworks for power BECCS. By Element Energy and Vivid Economics for BEIS (June 2021) [Link]

4.1 Mechanisms considered

In light of the above discussion, seven GGR policies – which were broadly classified as market-based policies, contract-based policies, and government interventions – were chosen to be in the longlist of options. A brief description of these policies is provided below with more detail on potential design features, strengths, weaknesses, and current examples provided in Appendix 8.2.

Market-based policies

- **UK ETS:** GGR projects may be awarded NE credits that can be traded in the UK ETS. Introduction of new allowances could increase gross emissions, but depending on the market design the cap on total emissions could be adjusted downward to ensure that CO_2 reduction efforts are not slowed. UK ETS credit prices are likely to be too low to incentivise most engineered GGR technologies in the short to medium term, but awarding multiple credits to emerging technologies may make them competitive at the expense of breaking the 1 credit = 1 tCO_2 relationship.
    - In the context of assessing the longlist of GGR policies, only a simple integration of GGR credits into the UK ETS is considered under this policy option. ETS integration may be more viable if it is combined with an obligation scheme requiring participants to source a portion of their credits from GGRs or if the government buys GGR-based credits through an intermediatory agency and sells the credits in the ETS for a lower price. These options are considered under the obligation and payment schemes respectively. Possible ways to integrate GGRs with the UK ETS are explored further in section 5.
- **Obligation schemes:** Fossil fuel suppliers or certain emitters may be required to purchase NE credits equivalent to an increasing percentage of their emissions. Specific GGR technologies may be incentivised through sub-targets. Obligations may be embedded in the UK ETS system, if the obligated parties are participants in the ETS. Alternatively, a carbon takeback obligation may be imposed on fossil fuel suppliers requiring them to secure carbon storage credits.

Contract-based policies

- **Carbon contracts for difference (CfDs):** Carbon CfDs may be used to provide a stable negative emissions revenue stream to GGR projects. The government would pay the difference between a strike price and a reference price on a £ per tonne basis. The reference price may be NE prices in EU ETS, voluntary markets, or the achieved sale price. Contracts for FOAK projects may be bilaterally negotiated and competitive auctions can be held for mature sectors. Technology specific incentives may be provided through dedicated pots. Carbon CfDs would be funded by the government unless new levies are introduced to the private sector.

- **Payment schemes:** The government may directly procure NE through specified £ per tonne payments to GGR developers. Contracts may be bilaterally negotiated or awarded through reverse auctions if there is competition. Alternatively, the government may announce advanced purchase agreements for increasing NE volumes with lower prices. Payment schemes may also be integrated into UK ETS, where the government may commit to purchase the credits at higher prices and sell to the emitters at market rates. Similar to carbon CfDs, payment schemes may be funded by the private sector if new levies are introduced.

Government interventions

- **Cost plus subsidy:** GGR projects may be awarded open book contracts where the government pays all the eligible costs and an additional margin as a profit. Risk management could include build-in of pain-gain sharing mechanisms to incentivise improvements, but the government bears most of the risks. Either the government or the project developer may sell NE credits in voluntary or regulated markets to recuperate some of the costs.

- **Competitions:** Competitions are direct government grants to GGR projects which can demonstrate value for money or are strategically important in other ways. They are traditionally used for innovation purposes and to commercialise emerging technologies. They are not likely to be useful for mature GGR markets due to the administrative burden of evaluating proposals and the very high upfront payments required.

- **Tax incentives:** GGR developers may be awarded investment tax credits equivalent to a specific percentage of total capital investment and/or production tax credits on a £ per tonne CO_2 removed basis. Rates may be set differently for each technology and reduce over time to reflect cost reduction. Since tax incentives do not require the government to directly spend money, they are relatively scalable and not bound by pre-determined budgets. Credits only benefit large companies with high tax liabilities though, so tax credit trading markets may need to be established to deliver GGR roll-out.

4.2 Evaluation Criteria

A total of 11 criteria were chosen for the assessment of the longlist of GGR options. The criteria were thematically divided into three groups: economic viability, ethics/equality, and feasibility. Brief descriptions of the criteria are provided in Table 7 below. More detailed descriptions including high level commentary about the performance of different types of policies against these criteria are provided in Appendix 8.3.

Table 7: Criteria used for the assessment of the long list of GGR policy mechanisms

Category	Name	Description
Economic Viability	**Revenue stability**	The policy should create a stable source of demand/revenue for negative emissions to instil confidence among project developers and incentivise private investment.
	Proportionality	The policy should ensure that policy support does not lead to excessive rewards or over-subsidisation.
	Transition	Over time the policy should enable a transition to a competitive and mature GGR market with reduced government support, allowing market-led growth of the sector.
Ethics and Equality	**Cost reduction**	The policy should promote cost reductions over time through innovation, learning by doing and competition as appropriate. This is both within a specific deployed project and within the industry as a whole.
	Applicability across scales	The policy is appropriate across different scales of companies and can benefit smaller and larger companies in the same or similar manner and level. Additional administrative burdens to smaller projects (~10s $ktCO_2$/year) are also considered under this criterion.
	Fair cost distribution	The policy enables costs to be distributed in an equitable way (emitters, fuel producers, consumers, etc.), minimising burden on government and the taxpayer and leveraging private sector investment as far as possible.
Feasibility	**Deliverability**	The policy should be feasible to implement in the 2020s to facilitate FOAK deployment, and should aim to minimise administrative and policy complexity.
	Compatibility	The policy should be compatible with business models under development in sectors such as CCUS and hydrogen production. It should not misalign with or require redesign of wider policy frameworks.
	Track record	The policy has been implemented in other applicable industries for a suitable period and has demonstrated that the policy is likely to achieve what it set out to achieve. In order of preference, applicable industries are engineered GGRs, other CCUS technologies, and energy-related sectors.
	Reaching GGR targets	The policy should enable the government to reach target levels of GGR deployment in the UK.

	Policy flexibility	The policy should be flexible, allowing the level of deployment and incentives to be modulated over time allowing the government to potentially pay less and phase out the policy if needed.

4.3 Assessment Results

Each of the longlist policies were scored against the assessment criteria in a RAG (red, amber, green) methodology:

- Red – indicates that the policy struggles to meet the criteria
- Amber – indicates that the policy partially meets the criteria
- Green – indicates that the policy successfully meets the criteria

Partial scoring was occasionally used to provide further granularity and capture nuanced implications. The summary of the assessment is provided visually in Figure 5 below. Appendix 8.4 includes detailed reasoning behind individual scores.

The RAG based scores were not quantified or weighted when shortlisting policies. These rankings were used as qualitative indicators of policies' performances and they were used as guidance when the shortlisted policies were selected in consultation with BEIS. The specific reasons for shortlisting the obligation schemes, payment schemes and carbon CfDs, while considering UK ETS and competitions as complementary mechanisms are provided in Table 8.

Key: 🟢 Successfully meets criteria 🟡 Partially meets criteria 🔴 Struggles to meet criteria

Split scoring used to provide greater granularity between ratings (if necessary)

Criteria	UK ETS	Obligation schemes	Carbon CfDs	Payment schemes	Costs plus subsidy	Competitions	Tax incentives
Revenue stability	🟡🔴	🔴	🟢	🟢	🟢	🔴	🟡
Proportionality	🟢	🟢	🟢	🟡	🟡	🟡	🟡
Transition	🟢	🟢	🟢	🟡	🔴	🔴	🟡
Cost reduction	🟢	🟢	🟢🟡	🟢	🟡🔴	🟡	🟢
Applicability across scales	🟢🟡	🟢🟡	🟡🔴	🟢🟡	🔴	🟢🟡	🟡🔴
Fair cost distribution	🟢	🟢	🟡	🟡	🟡🔴	🟡	🟡
Deliverability	🟡🔴	🟡🔴	🟢	🟢	🟢🟡	🟢	🟡
Compatibility	🟢	🟢🟡	🟡	🟡	🔴	🟡	🟡
Track record	🟡🔴	🟢🟡	🟢🟡	🟡🔴	🟡🔴	🟢	🟡🔴
Reaching GGR Targets	🔴	🟢🟡	🟡	🟡	🟡	🟡🔴	🟡
Policy flexibility	🟡🔴	🟢🟡	🟡	🟡	🟡🔴	🟢🟡	🟢🟡
Selected for detailed design short list?	**Considered as complementary policy**	✓	✓	✓	✗	**Considered as complementary policy**	✗

Figure 5: Results of RAG based assessment of GGR policies considered

Table 8: Rationale for final decision on long listed policies

Policy	Decision	Reasoning
UK ETS	Considered as a complementary policy	Integration of GGRs into UK ETS is not chosen as a core policy due to the complexities of early inclusion of engineered GGRs into the ETS, insufficient revenue certainty to investors (due to currently low and dynamic prices) and an insufficient guarantee of supporting required NE volumes. However, as it would establish a market price for CO_2 removal, it can complement other policies by forming a reference price and create a source of private sector demand for GGRs. Therefore, options for ETS inclusion are considered in the context of detailed design of shortlisted mechanisms.
Obligation schemes	Shortlisted	Obligation schemes are shortlisted because they share most of the strengths of the UK ETS and help provide greater assurance that specific GGR volumes are reached. Furthermore, obligation schemes are likely to be more flexible. Compared to contracted mechanisms, obligations help establish a market price for NE and fund GGRs directly through the private sector. The main drawback of obligations is lack of revenue certainty, which may be overcome by additional support mechanisms in early years.
Carbon CfDs	Shortlisted	Carbon CfDs have multiple strengths such as revenue certainty, ability to transition to market-based systems and the track record of power CfDs. Applicability of CfDs to small scale projects may be challenging, since engaging with the scheme has administrative burdens. Carbon CfDs are also compatible with many existing policies and offer a relatively fair risk sharing between the developers and the government, although it must be funded by the taxpayer.
Payment schemes	Shortlisted	Payment schemes, like carbon CfDs, provide good revenue certainty to GGR developers. Direct NE procurement has less of a track-record compared to CfDs at large-scale but are likely to be more favourable for smaller developers. Since payments are not linked to carbon markets through a reference price, they score slightly worse in terms of transitioning to market-based systems and proportionality, but these can be mitigated partially by gain sharing mechanisms.
Cost plus subsidy	Not considered	Although this policy offers high revenue stability, it has multiple weaknesses due to increased administrative costs, difficulty of scale up, incompatibility with some of the other existing policy mechanisms and not transitioning naturally to a market-based system. Another concern is value for money for the government since plants may not be properly encouraged to minimise their costs.
Competitions	Considered as a complementary policy	Competitions awarding grant funding are well understood, flexible and deliverable policy mechanisms, however, they fail to provide revenue certainty over time and do not guarantee required GGR levels are reached. Furthermore, securing sufficient public funding to run such a scheme may be challenging and it does not naturally allow for transitioning to a market-based mechanism. However, grant funding may be valuable as an additional capital support scheme for some early GGR projects, so it is considered as a complementary policy.
Tax incentives	Not considered	Tax incentives score averagely across the criteria. They offer a level of revenue certainty, flexibility, and proportionality, but are disadvantaged in terms of a lack of a UK-sector track record. Deliverability may also struggle if additional mechanisms are not put in place to transfer credits from small businesses (e.g., start-ups) to companies with existing tax liabilities. Other shortlisted policies are likely to achieve the same results more efficiently. For example, contract-based mechanisms offer greater revenue certainty due to longer contract commitments and will also be more familiar to UK investors.

5 Analysis of Shortlisted GGR Policy Mechanisms

This section provides a more comprehensive discussion of some of the key features of the shortlisted policies. This includes a discussion of some of the key questions underpinning the setup of the policies how each policy could feasibly be implemented in the UK, and the pros and cons from a wide variety of market, cost distribution, and societal considerations. The design features explored and recommended below take into account the policy principles outlined in the beginning of section 4.

5.1 Policy Questions

International vs domestic removals

The scope of this project focuses on the incentivisation of GGR projects that are located in the UK. This is core to the project, and reflects the domestic focus of the policy mechanism and the key aims which the policy mechanism is looking to address:

1. A GGR sector is developed in the UK
2. The necessary GGR volumes are provided for the UK to hit its climate targets

However, one key facet of GGRs is that it does not generally matter where the GHG removal takes place for the climate benefits to be realised. The UK has some comparative advantages, such as availability (and maturity) of CO_2 storage at scale, however it is likely that there are other places in the world where engineered GGRs might be less expensive compared to deployment in the UK.

In the Glasgow Climate Pact, key agreements were made around corresponding adjustments and Article 6 of the Paris Climate Accord, however how these will play out in practice is currently unclear. This could mean in the future, GGRs elsewhere in the world could contribute towards the UK’s carbon budgets, which would decouple the aim of the UK to develop GGRs for contributing to carbon budgets from the need for the GGR projects to be in the UK[56].

While not within the scope of the project, some potential implications of extending the GGR policy mechanisms proposed in this study to projects outside the UK are highlighted below:

- Restricting UK companies to purchase removals credits from UK based GGR projects within **an obligation or UK ETS based scheme could be viewed by participants as overly restrictive** to the growth of a global carbon market.
- If UK GGR policies are extended to international projects, any **certification mechanism used for the credits would need to be applicable globally** and be compatible with global standards. UK standards would need to match with global standards (ideally playing a significant role in shaping them for the better) to improve compatibility for project developers in other parts of the world who might not be familiar with any UK specific parts of any standards or certification mechanisms.
- **It may be easier for market-based mechanisms to be expanded to worldwide projects**, compared to contract-based policies, because they involve the private sector directly purchasing NE credits. On the other hand, awarding international projects with carbon CfDs or payment contracts may politically be undesirable as this would involve spending taxpayer money on other countries. Expansion of the UK GGR scheme to international projects could be a natural evolution step for a market-based policy or be part of transitioning from a contract-based policy to a market driven mechanism.

Net vs gross removals

One crucial question when discussing the incentivisation of GGRs is ensuring that they result in net removals of GHGs from the atmosphere when their supply chains are taken into account. The total atmospheric CO_2

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[56] There are a few emerging international GGR policies which reward or aim to reward projects abroad, such as the California LCFS credits that can be awarded to DACCS plants anywhere in the world [Link] and the Luxembourg feed-in-tariff, which proposes to allow international participation capped at a certain portion of the overall budget [Link].

stored away permanently by a GGR process is called gross carbon removals. However, GGR processes have associated scope 1, 2, and 3 emissions from their main processes, construction of plant equipment, feedstock supply chain, and use of energy in the plant. The net amount of NE created when all these scope 1-3 emissions are taken into account is called net carbon removal, as shown in Figure 6 below. For GGRs to be feasible or sometimes desirable, they must have high net removals.

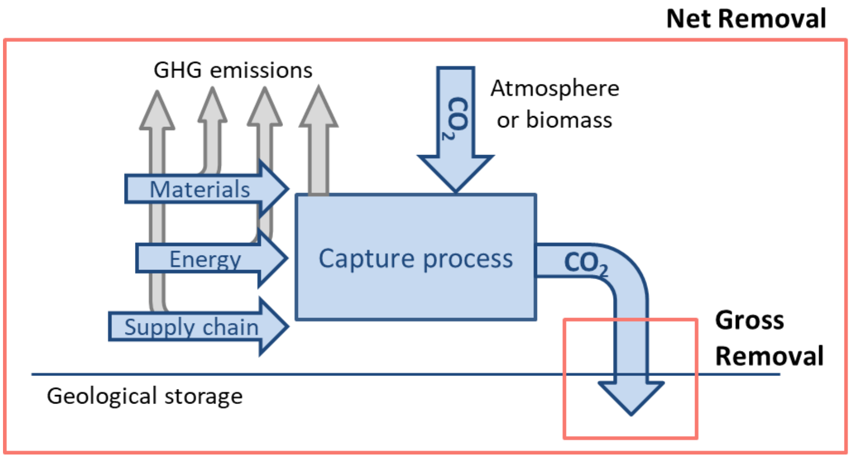

Figure 6: Schematic representation of gross and net removals for a generic GGR process

The discussion of net vs gross removals becomes very important especially in the context of biomass sustainability. Previous work for UK Government on commercial frameworks for FOAK Power BECCS projects stated that 'incentives should be designed in such a way that BECCS developers are incentivised to source from more sustainable sources, rather than the cheapest source that meets the minimum requirements'[57]. This holds for general BECCS and GGR policy mechanisms as well, and the ways to achieve this are similar - setting upstream emission standards and imposing penalties if these are exceeded, and/or linking framework payments to net GHG removed.

There are advantages and disadvantages of using either net removals or gross removals for the calculation of subsidy intensities or market prices. While this was not the focus of this work, a range of these factors are outlined below, as well as a tentative recommendation that **net removals** be used as the basis for a general GGR policy mechanism.

Advantages of using net removals rather than gross removals include:

- Net removals represent the **impact of the new economic activity that is induced by the policy mechanism on global emissions**, including not only the GHG removal, but also the increased emissions in the GGR supply chain, for example from fossil fuel extraction and use, biomass sourcing and transport, and materials synthesis.
- Using net removals approach ensures that **the mechanism can be applicable and balanced across the varied GGR technologies** which have different supply chains and associated supply chain emissions. Using gross removals would mean that ensuring 'a level playing field' as the sector matures (and potentially moves towards a market-based mechanism) could be fraught with difficulties. 'For certificates to be traded, the market needs to be confident that the certificate equivalence holds[58].'
- **Voluntary markets currently use a net-removal based approach**, generally with detailed lifecycle analysis (LCAs) required (depending on the quality of assurance). If a GGR policy mechanism is looking to link to the voluntary carbon market, using accounting based on net removals would improve compatibility and enable easier integration.

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[57] Investable commercial frameworks for power BECCS. By Element Energy and Vivid Economics for BEIS (June 2021) [Link]

[58] GGR policy options. Vivid Economics (June 2019) [Link]

- If gross removals are used and the overall sustainability of GGR processes are ensured through various environmental criteria that the projects must abide by, **novel and innovative GGR technologies in the future may not fit within these frameworks**. This could be a barrier to innovation as it would require new sustainability criteria to be developed for each technology. Using net removals instead may enable a less risky approach to incorporating novel GGR approaches into GGR policies.
- Using net emissions avoids the possibility of NE suppliers **only hitting the minimum standards** associated with supply chain emissions and not making further progress on reducing them. Reductions in supply chain emissions are directly incentivised by using a net removals approach, rather than providing a maximum limit on emissions which could artificially limit progress. This also avoids potentially tricky negotiations around where these standards should be set.
- Using an incentive framework based on gross removals could **risk a public backlash** against the scheme, even if every effort is used to put standards in place robustly. For example, there are risks around inappropriate application of potentially complex guidance or loopholes/grey areas allowing companies to act in a way which might be perceived negatively. Given some of the potential for negative public reaction (especially around the best use of bioresources), using net removals might provide a simple touch point to avoid this.

Disadvantages of using net removals rather than gross removals include:

- Using **net removals could cause reductions in supply chain emissions to be indirectly 'double subsidised'**, potentially causing an uneven playing field, or even perverse incentives. For instance, if the government provides financial incentives to renewables projects through power CfDs to decarbonise the grid, this will also increase the net removals of a DACCS plant using grid electricity. If GGR policy mechanisms are based on net removals, the government would then be double subsidising the same activity (new renewable power), under both the power CfD and the GGR policy.
- Using **net removals could cause some extra administrative burden for NE developers**. Using net removals for incentivisation cannot substitute for sustainability frameworks, and this potentially could provide some extra accounting burden, which would be particularly impactful for smaller developers. However, given that robust calculation of supply chain emissions would need to be included in these frameworks anyway, the additional burden is likely to be low.
- For GGRs needing CO_2 T&S, using **gross emissions for the overall incentivisation would match better with the payments needing to be made to a CO_2 T&S operator**, which will need to be on a gross basis.
- Using a net approach can **create inconsistencies between methodologies for quantifying GGR and non-GGR emissions eligible for government support.** For example, gas fired power or industrial plants are not required to internalise upstream emissions associated with fuel production. Different incentive frameworks for the installation of CCS in these industries compared to GGR support applicable for the same industries could result in inconsistencies.

Given the balance of these advantages and disadvantages, **we recommend that net removals should be used as the unit of choice for incentivisation of negative emissions**. The advantages of better integration, future proofing, and balance, for a net removal based approach likely outweigh the disadvantages, which are largely around the potential administrative complexity and can likely be overcome.

Fair cost distribution

One highly debated issue in setting decarbonisation policies, including GGRs, is determining who pays for the policies. Discussions with stakeholders and literature review revealed two main approaches to answering this question.

- **Option 1 – policies should ideally be funded by the private sector:** This is in line with the polluter pays principle and emitters are best placed to change their processes to reduce their emissions (although they are usually not best positioned to deploy GGRs themselves). This would also alleviate the financial burden on the taxpayer. If the private sector increases their prices to accommodate for these policies, customers would be encouraged to choose the most sustainable products.

- **Option 2 – policies should be funded through general taxation:** Most of the financial burden placed on the private sector will be passed on to the customers through increased prices. Although some of these prices (such as aviation costs) will mostly impact higher income households, other costs (like increased food prices) are expected to disproportionately impact lower income households. This effect can clearly be observed in early distributional impact analysis of GGR costs[59], as shown in Figure 7 below. When sectors with remaining emissions in 2050 are asked to pay for abatement through GGRs, pass through costs amount to greater percentages of total household income for people in lower income percentiles. Therefore, according to this view, funding GGRs through general taxation would be more appropriate since taxes are broadly proportional to income levels.

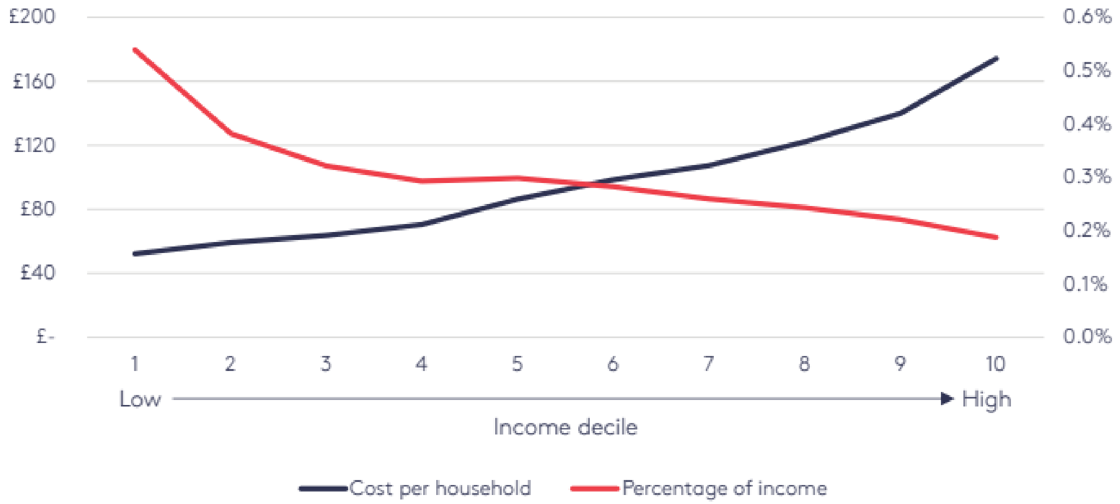

Figure 7: Annual impact of a GGR cost of £100/tCO₂ on equivalised households, by income decile in 2050. It is assumed that GGRs are used to offset all residual emissions according to Climate Change Committee modelling (Owen et al., 2021)[59].

Each GGR policy considered in this study lends itself to one of these two options naturally. For instance, market-based options like obligation schemes and UK ETS are compatible with option 1, whereas contracted mechanisms, like carbon CfDs and payments, can easily be set up as in option 2, since the government directly funds GGR projects under these policies. However, it is possible to shift the financial burden to the private sector under contract-based policies if a special levy is introduced to fund these schemes. Currently, power CfDs awarded to low carbon electricity generators are funded through a levy applied to electricity suppliers, therefore the financial burden is passed on to customers directly.

This study does not have a preference for either option and further evidence is likely needed for the government to make a better-informed decision when designing the funding of these policy mechanisms. For the assessment of the longlist of GGR policies, policies which were flexible to enable option 1 (private sector funding) were favoured under the “fair cost distribution” criterion, because they would enable the polluter pays principle to be satisfied. However, for the detailed design stage of this report market-based mechanisms are assumed to be funded by the private sector and contract-based mechanisms are assumed to be funded by the taxpayer since these are the natural or default ways these policies are set up. However, as explained above, the burden of the contracted policy mechanisms may be passed to the private sector through a levy if

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[59] University of Leeds and Grantham Research Institute on Climate Change and the Environment (2021) Distributional impacts analysis of engineered greenhouse gas removal technologies in the UK: Report Prepared for the National Infrastructure Commission. [Link]

desired, or GGR support may follow option 2 in the beginning and later transition into option 1. The assumption around who pays for the contracted policies has minimal impact on the design principles explored.

5.2 Establishing a GGR market in the UK

This section explores two ways to establish a functioning GGR market in the UK, which are not likely to be able to enable GGR rollout on their own but can complement the three shortlisted policies.

5.2.1 A regulated voluntary GGR market

As discussed in Section 3.2, current voluntary markets for NE are in their infancies and future prices are very difficult to predict. However, voluntary markets represent private sector's willingness to pay for GGRs, therefore future government policy should aim to capture the potential in these markets and provide additional financial incentives if private funding is not enough.

One way for the government to enhance the voluntary GGR markets is to create **a national regulated market overseen by a regulatory body**. A similar option is alluded to by the EU in its recent Communication on Sustainable Carbon Cycles[60]. This regulatory body would be responsible for determining monitoring, reporting and verification (MRV) standards for all GGR technologies, as well as registering carbon removal projects and awarding NE credits. It may keep a small percentage of credit costs as administrative changes to fund its operations.

In 2021, the UK government established a GGR MRV Task and Finish Group to investigate best approaches to setting MRV standards. Its findings are being taken forward by the government, which may form the basis of any future regulatory framework. The standards used in this market may be linked to future EU or other global GGR markets to increase international collaboration.

This new regulated GGR market can increase the trust of NE customers and simplify their due diligence processes, ensuring that the credits they purchase are of high quality. Such a regulated market would also help establish a clear GGR market price and potentially be linked to future GGR policies such as obligation schemes, the UK ETS, and carbon CfDs.

Although the government operating a single regulated market would have the above advantages, it may be administratively costly and may place this new regulated market in direct competition with the private (voluntary) carbon credits markets. An alternative setup may be setting common MRV standards and requiring voluntary markets to adhere to them. One example of this working in practice is the sustainability requirements for renewable fuels within the EU Renewable Energy Directive. These are set by the EU, with companies demonstrating compliance through verification by voluntary schemes. These schemes are international, and typically offer verification for compliance in multiple jurisdictions.

5.2.2 Integration of GGRs into the UK ETS

Inclusion of GGRs in the UK ETS is not shortlisted as a viable standalone policy to enable NE in the UK (see Section 4). However, establishment of a market price for NE through inclusion in the UK ETS could aid and complement the shortlisted GGR policies investigated in this study in the following ways:

- A future **GGR obligation may be implemented via the UK ETS** where the obligated parties would be ETS participants. Even if non-ETS industries were also obligated, the MRV standards and the regulatory body certifying credits for both policies could be the same.
- **UK ETS may serve as the reference price for a carbon CfD** through the sale of credits on the ETS market. Since the UK ETS is a relatively large market, linking these two policies may increase investor confidence and signal government commitment to GGR support.

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[60] Communication by the European Commission on Sustainable Carbon Cycles (December 2021) [Link]

- Similarly, enabling sales of NE credits in UK ETS may provide a straightforward revenue stream for projects signed up to **a payment scheme, allowing the government to reduce its contributions proportionally.**

Therefore, it is valuable to understand how GGRs may be included in UK ETS and how some potential conflicts or challenges may be resolved. The points that follow are theoretical considerations on some of the most pertinent issues. The government launched a call for evidence[61] in March 2022 on the UK ETS as a potential long-term market for GGRs.

A simple GGR integration in UK ETS would see **a regulatory body issuing NE credits** for each **tonne of net CO_2 removed** to project developers. **BECCS and DACCS are ideal technologies** to be included as provisions are already in place relating to CO_2 leakage risk from geological formations, and measurement, reporting, and verification (MRV) of engineered GGRs are simpler.

The annual cap for the UK ETS was 155.7 $MtCO_2$ in 2021, and it is set to reduce by 4.2 $MtCO_2$ per year[62]. The Government has also set out its intention to consult on aligning this cap with net zero in future[61]. **A GGR capacity of 5 $MtCO_2$ in 2030 represents 4.2% of the emissions allowed in the current cap**. If new sectors are not brought into the ETS, GGR volumes may represent a much more significant portion of emissions in the system by 2035.

As shown in Figure 8 below, UK ETS prices have steadily increased since its inception due to a combination of macroeconomic factors (until the Russian invasion of Ukraine in March 2022). However, the UK ETS prices are still not high enough to finance many GGR technologies alone and **under a simple integration only projects closer to commercial viability would be incentivised**, which is unlikely to bring forward a portfolio of GGR technologies.

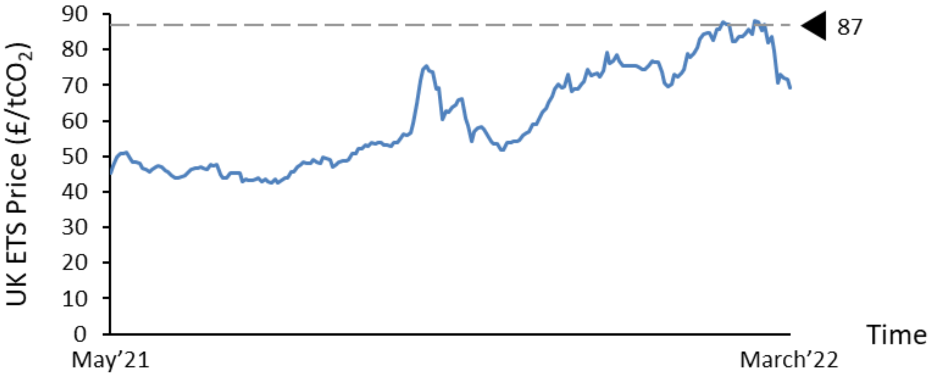

Figure 8: The price of UK ETS credits since its separation from the EU ETS[63]

An increase of total emissions allowances due to newly introduced NE credits would likely **reduce credit prices** without any intervention (assuming all other factors remain unchanged). Moreover, if the overall cap is not adjusted, **each tonne of NE introduced to the system would likely directly prevent avoidance of another tonne of emissions** elsewhere in the economy, causing mitigation deterrence. Both of these issues could be prevented if **the overall emissions cap is adjusted downward by the volume of NE credits sold,** although the exact adjustment needed would require careful analysis. NE volumes can be very dynamic so a regulatory body may have to predict deployment rates and adjust auctioned allowances at regular intervals.

The historic prices observed in the ETS market would not be able to support expensive GGR technologies like DACCS, which currently require prices above several hundreds of pounds per tonne. A potential solution to this would be awarding multiple credits to technologies needing additional support. For example, a DACCS project may receive four credits per tonne of net CO_2 removed, rather than one. **Providing additional credits**

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[61] Developing the UK ETS – a consultation by the UK ETS Authority [Link]
[62] International Carbon Action Partnership – ETS Detailed Information (17 November 2021) [Link]
[63] Ember daily carbon prices [Link]. The fall of UK ETS prices in March 2022 coincides with the beginning of the Russian – Ukrainian conflict.

like this would damage the fungibility of NE credits and regular ETS allowances and would very likely increase mitigation deterrence since removing one tonne of CO_2 would be worth reducing multiple tonnes of emissions. Therefore, awarding multiple credits per tonne of CO_2 removed is not recommended.

Practically, including NE in the ETS would present some challenges and require new legislation and provisions. **One method to integrate BECCS emissions would be to stop treating biogenic emissions as zero** and turning plants with purely biogenic emissions into ETS participants. These plants may then be given free allowances equal to their biogenic emissions to protect them from increased carbon costs. If these plants deploy CCS units and generate NE through BECCS, they can sell their unused free allowances in the ETS providing them a new revenue stream. However, such a change to the UK ETS accounting system would not work for DACCS or other non-biogenic removals and would create a disconnect with the EU ETS (if the two systems are to be linked in the future). Such a shortcut to include BECCS credits in the ETS may have far-reaching implications for carbon accounting and should be studied in greater detail before any action is taken.

EfW plants may similarly be encouraged to deploy CCS if they are included as a mandatory participant in the system. This would encourage them to reduce their fossil-based emissions. Retrofitting CCS would have an additional benefit of producing NE credits, even if biogenic emissions are continued to be treated as zero. The ETS Authority has recently called for evidence on expanding the ETS to waste incineration including EfW.

Regardless, expansion of the ETS to other sectors would increase the overall emissions cap and the ability of the system to accommodate higher GGR volumes, since the maximum amount of NE credits permitted in an ETS would be equal to the total positive emissions. Such an expansion may see introduction of new free allowances to sectors deemed at risk of carbon leakage.

Future of the UK ETS

As the economy decarbonises and GGR technologies are deployed at higher rates, **there will be a point where the total emissions cap will equal the NE volumes traded in the ETS** if GGRs are included in the ETS. This will see all marginal emitters offsetting through NE and **net zero being reached** among participants, assuming all free allocation is phased out.

Inclusion of GGRs in the ETS may be viable in the medium term **but supporting GGRs beyond 2050 would require the ETS to be recalibrated to achieving net-negativity**. This may involve the government purchasing NE credits or certain companies being required to be net-negative to account for their historic emissions. An alternative could be UK companies selling credits in international markets, if NE are not needed in the UK's national balance sheets. Further work is needed to better understand such long-term options.

5.3 Obligation Scheme – Overview and Primary Design Features

An obligation scheme for GGRs consists of establishing a compliance market for negative emissions (NE), which foresees the inclusion of three main actors: GGR developers, obligated parties, and a regulator.

The regulator is typically an external party or a government body which allocates negative emission credits to GGR developers for each net negative tonne of CO_2 captured and stored. The regulator then **obligates emitters from certain sectors to purchase negative emission credits**, hence covering a portion of their emissions. Depending on the obligation scheme's design, the obligated emitters could include a range of different sectors. For example, obligations could be placed on hard-to-abate sectors, such as agriculture, aviation, shipping, cement, steel, aluminium, ammonia, plastics, and fossil fuel producers. Alternatively, obligations could be set on fossil fuel producers, so that the additional imposed costs may automatically be passed on to the biggest emitters.

Within the obligation scheme, the regulator also defines a **buyout price**, which obligated parties must pay if they do not meet their obligation, on a per negative emission credit basis. The buyout price is typically set above the prevailing market price. Therefore, the obligation scheme establishes a negative emission market with a variable price point. This allows the **polluter-pays principle** to be enforced, as the polluting sectors would pay a price (market price of carbon) for capturing and storing their emissions or else they would pay a penalty (buyout price). The price paid for negative emissions represents a source of revenue for GGR developers.

Examples of this type of scheme in the UK include the now retired Renewables Obligation (RO), and the Renewable Transport Fuel Obligation (RTFO), which had varied levels of success. Figure 8 shows the cash flow of an illustrative DACCS developer which receives revenues from an obligation scheme. This illustrates how, for more expensive GGR technologies like DACCS, the market price may not be sufficient to cover the costs of producing negative emission credits. Figure 10 shows how, where supply of NE credits is short, compared to the demand created by the obligation targets, the market price will rise to the buyout price.

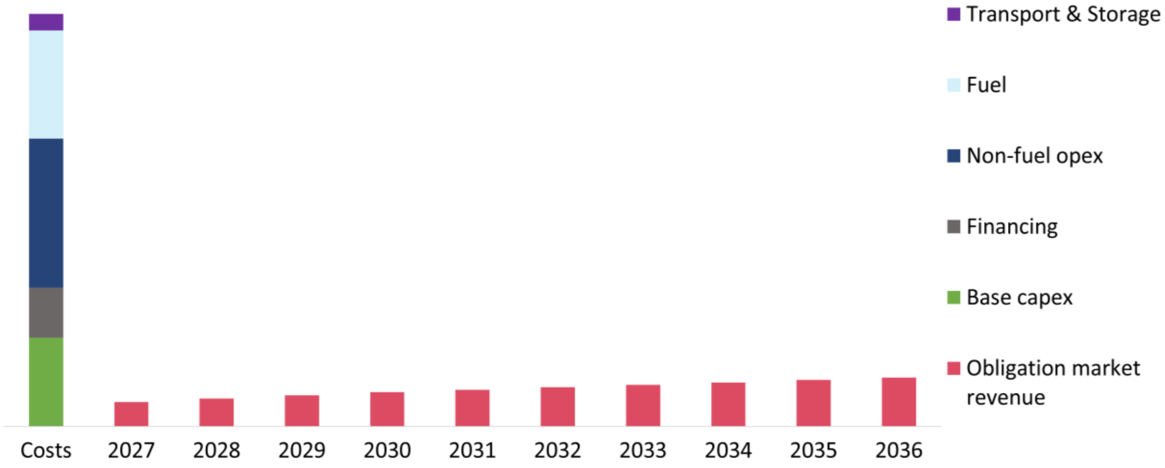

Figure 9: DACCS cash flow under an obligation scheme where supply outstrips demand (£/tCO_2)

Figure 10: DACCS cash flow under an obligation scheme where demand outstrips supply (£/tCO_2) Note: For illustration, the buyout price here is set at the marginal cost of running a BECCS Power plant. As the supply of NE credits is lower than the demand created by obligation, the market price rises to the buyout price.

Establishing an obligation market for NE as described above would need to be underpinned by legislation, much like that which created the RTFO. It would require the creation of a regulator, design of clear monitoring, reporting, and verification (MRV) standards, determining annual targets, identifying and obligating emitters, and setting a buyout price. These aspects of the scheme design are each discussed below. Following this, the dynamics of the supply and demand of NE credits and the resulting NE credit price are discussed. Finally, we discuss the limitations of an obligation scheme for NE credits, with reference to the key design principles outlined above.

5.3.1 Establishing a market regulator

As noted above, a key role in the establishment of a market for negative emissions is that of a regulator. The regulator has several responsibilities:

- Creating **clear MRV standards** to ensure that NE credits are of a commonly understood and reliable standard, allowing a single price to emerge and facilitating trade of high-integrity credits between participants.
- Determining **annual negative emission targets, in line with those outlined in the Net Zero Strategy**. These targets should be published long in advance of an obligation market's creation, to allow sufficient time for emitters and GGR developers to prepare. In the earlier years, special consideration should be given to the supply pipeline of GGR projects, as targets without the means to meet them will be ineffectual.
- Identifying **which emitters would be obligated to purchase NE credits**. This involves determining which sectors and which firms within those sectors would be obligated – which itself involves setting criteria on which firms are targeted.
- Determining the **extent of emitter obligations, for example, as a share of their total emissions**. Another consideration is whether all emitters would be obligated from the start or would the obligation apply only to the largest emitters initially, with the roll-out being extended as NE targets increase.
- **Setting a buyout price**, which emitters will be obligated to pay in lieu of NE credits they do not purchase.

Each of these points are explored in more detailed below.

5.3.2 Creating MRV standards for NE credits

A regulator will be responsible for determining MRV standards for all GGR technologies, as well as registering carbon removal projects and awarding NE credits for each tonne of CO_2 captured and stored. A single market price for NE credits relies on NE credits being of the same quality regardless of their source. This quality is underpinned by MRV standards, which requires transparency and inspection. In registering projects, a regulator also ensures that **only NE credits purchased from GGR developers that satisfy the MRV standards count towards an emitter's obligation**. A GGR MRV Task and Finish Group has already been established by the UK Government to investigate best approaches to setting MRV standards. The findings could form the basis of a new regulatory framework.

5.3.3 Sizing the market for negative emissions

The overall target for negative emissions from engineered GGRs is set out in the Net Zero Strategy (5 $MtCO_2e$/year by 2030, potentially rising to 23 $MtCO_2e$/year by 2035). While these figures are useful in terms of setting a path for GGR development, they do not necessarily provide sufficient information to emitters and developers to allow them to quantify their potential exposure and opportunities respectively, were an obligation market to be established.

There is significant benefit in the regulator **producing forward guidance on annual NE targets in advance of the market being established**. This guidance could be provided along with scenarios to show what might happen if overall targets are adjusted, to allow for uncertainty over the long term. Such guidance allows developers to plan for expected demand for NE credits over time and provides some certainty to those providing finance.

This information is also important to emitters. Learning of the targets that they will face, and how these will increase year-on-year, emitters will be incentivised to decarbonise as much as possible – reducing their NE obligation. It will also allow them to prepare for the cost of purchasing NE credits for any residual emissions.

Overall, **NE targets must broadly reflect the capacity to produce NE credits**. It may take considerable time for capacity to increase to a meaningful level and in the early years each additional GGR plant is bound to have a significant marginal effect on capacity. The lumpy nature of this supply pipeline may be problematic for emitters. One possible way to reduce this effect is to allow emitters to be over-compliant in the early years, by purchasing NE credits before their supply becomes available so that they can be used against obligation targets in later years.

Nonetheless, while an obligation scheme would effectively create demand for NE credits by setting a clear target and obligating emitters, it does not directly guarantee the supply of NE credits, as obligated parties can buy out.

5.3.4 Identifying market participants

Once overall annual targets have been determined, it falls to a regulator to identify how those targets should be translated into obligations on individual sectors and firms. This is a complex task with each solution having potentially far-reaching consequences. Broadly, there **are three ways to apply targets to emitters: (i) obligating all sectors, (ii) obligating hard-to-abate sectors only, or (iii) obligating fossil fuel producers and importers, and large emitters.** Each of these solutions ensures that the polluter pays but the way in which costs are passed on to consumers may vary. A further consideration is the treatment of emissions in the UK versus emissions by UK firms globally. The costs of running the scheme may also vary considerably depending on which emitters are obligated.

In obligating all sectors, every firm is obligated to purchase NE credits as a share of their emissions. This has the effect of spreading the cost widely and ensuring that there is a large customer base for GGR developers. This would also see the pass-through to consumers diluted across a wide range of goods and services. While obligations desirably increase the cost of some high-emitting products, they may also disproportionately affect lower incomes. The degree of **pass-through to consumers is difficult to determine and depends on the elasticity of demand for products/services**. Applying obligations so widely would be a considerable challenge, given the sheer number of entities affected, the fact that many of these may not measure their emissions today, and particularly given the international nature of supply chains feeding into final goods and services. It may also lead to some emitters who could otherwise decarbonise their business activities purchasing NE credits instead. Given the likely short supply of NE credits, at least in the short-medium term, this could lead to significant challenges for firms in hard-to-abate sectors who cannot readily decarbonise to reach net zero.

Targeting hard-to-abate sectors, such as agriculture, aviation, and shipping, directly has the advantage of ensuring that the supply of NE credits is preserved for those firms who cannot readily decarbonise. It also reduces the number of entities affected, leaving the scheme somewhat easier to administer. As many hard-to-abate sectors are found in the early stages of the supply chain, reliably estimating cost pass-through to consumers in complex supply chains is difficult. However, for the same reason, it would be relatively easier to quantify the emissions produced by these sectors within the UK.

The simplest of the three alternatives to implement is to obligate fossil fuel producers and importers, and large emitters. In this way emissions from hard-to-abate sectors that rely on fossil fuels will be accounted for at the start of the supply chain. Similarly, by-product emissions from large emitting industries (i.e., cement and steel) are also accounted throughout the manufacturing processes. As this will increase the cost of fossil fuels and end products, these costs will then pass through the supply chain to increase the cost of intermediate and final goods and services. Again, it is difficult to quantify the degree of pass-through and its ultimate distribution, given varying elasticities and consumption profiles. However, as an indication, **CarbonTakeback.org have calculated that sequestering 10% of the emissions from fossil fuels adds £0.7-£1.8 to the cost of a barrel of oil, less than current carbon prices.**[64] With oil at c. £81 per barrel, for example, this equates to an increase of 0.9-2.2%. While this is the simplest way to target emitters, it has several weaknesses. For example, the production of cement releases significant quantities of CO_2 as a by-product of the chemical processes in its manufacture and these emissions would not be covered by an obligation on fossil fuels. To account for all of the emissions of cement production, it would be required to obligate the cement industry for the share of non-fuel related emissions released during the manufacturing process. However, separating out emissions from different sources can be very challenging, and may represent a major obstacle in the design of the obligation scheme. Moreover, this alternative does not take account of non-fuel related emissions which may be hard to abate, such as methane and N_2O emissions from agriculture.

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[64] About section of the carbontakeback.org (accessed 25 March 2022) [Link]

In future, a further alternative would be to integrate an obligation scheme into the UK ETS, with GGR developers given tradable credits and emitters obligated to source a minimum portion of their allowances from NE credits. This could be designed so that only hard-to-abate sectors must purchase NE credits and would have the effect of increasing compliance costs for those emitters. One potential drawback with such an integration is that introducing new sectors to the scheme might be difficult.

5.3.5 Determining how emitters will be obligated

Having identified the emitters that will be obligated under the scheme, the manner in which they will be obligated must be determined. There are two main parts to this: (i) setting targets at the firm level, and (ii) determining the phasing of the imposition of obligations on firms.

In relation to setting targets at the firm level, the most obvious approach is to **base the target on a firm's emissions**. This will ensure that firms are targeted in proportion to the level of emissions that they produce. This approach requires individual firms to measure their emissions in line with a standard methodology. Another consideration is what is meant by emissions in this context – for example **does the target apply to direct emissions only (scope 1) or extend to indirect emissions also (scope 2 and 3)?** If applied to fossil fuel producers and importers, it seems sensible that all three scopes would be included in the definition of emissions under the obligation. These are significant barriers, given the complexity of measuring, reporting, and verifying these emissions for so many firms. However, the alternative – setting targets independent of output or emissions - would place very large burdens on businesses and/or sectors that are not trading at full capacity.

The phasing of the scheme's rollout is another important consideration. Regardless of which of the three options is chosen above, there will be significant diversity of firms within the obligated group. This raises important questions. Should large, established firms be obligated first, leaving smaller or newer firms some time to improve their business practices before obligations bind on them, for example. In such a scenario, as overall NE targets are increased, the threshold could be reduced, bringing new firms into the scheme. This would spread the cost across emitters but still leave the biggest emitters paying the most.

5.3.6 Setting a buyout price

A critical feature of the design of an obligation scheme is the buyout price, which is determined by the regulator. **Where obligated parties do not purchase sufficient NE credits to cover their entire obligation, they are required to pay the buyout price for each remaining tonne of CO_2 to the regulator.** The buyout price sets a cap on the NE credit price – once the price of an NE credit rises to the buyout price, the emitter's incentive to avoid the buyout price penalty no longer exists. By acting as price ceiling, the buyout price protects obligated parties from exposure to soaring market prices for NE credits, which could be caused by an increase in demand or a shortfall in supply. For this reason, the setting of the buyout price is very important.

Clear guidance on the buyout price is important to both developers and emitters. Existing obligation schemes, such as the RTFO, have increased the buyout price after consultation with stakeholders. In the case of the RTFO the buyout price was set at 30p/l of fuel until this price was overtaken by the market price for renewable fuels, meaning that the buyout price no longer served as an effective penalty for non-compliant parties. After consultation the RTFO buyout price was increased and now stands at 50p/l[65]. A consultative process such as this has the benefit of bringing industry on board with proposed changes.

It should be expected **that the market price for NE credits would lie above the ETS price because of the greater costs associated with capturing and storing carbon using engineered GGRs compared to conventional abatement**. However, the cost of producing an NE credit will vary greatly across carbon capture technologies, as more established GGR processes have relatively lower costs. Conversely, producing NE credits from more innovative, early-stage technologies, such as DACCS, is significantly more expensive. When the market is short (i.e., supply of NE credits is below demand for them), NE credits will trade at the buyout

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[65] Increasing the RTFO buyout price to ensure continued greenhouse gas savings – outcome, summary of responses and cost-benefit analysis – DfT [Link]

price. If this is set to a price which covers the cost of expensive technologies, developers operating with much lower costs will achieve large margins, and new technologies will be incentivised, but the costs to obligated suppliers will be very high. If the buyout price is set at lower levels developers of more expensive technologies would not achieve a market price that would cover their cost of production.

One way to reflect different costs of carbon capture in the market price is to implement a system of sub-obligations. **A sub-obligation market would obligate emitters to purchase a specific share of their overall NE credit obligation from a specific source.** For example, an emitter may be required to source 40% of their NE credits from DACCS operators. This creates a separate market for DACCS NE credits, and this market would have its own buyout price and market price, distinct from the overall GGR obligation scheme prices. This approach, its benefits and drawbacks are discussed in more detail in chapter 6.

5.3.7 Supply, demand, and price volatility

In an obligation scheme, revenue is achieved through the sale of NE credits on the compliance market. **Demand is created by the obligation target, but the price is determined by the relationship between the total obligation (demand for NE credits) and the total supply of NE credits.** With GGR developer revenues dependent on the NE price, revenue volatility could be driven by changes in supply or demand, or both simultaneously.

As the initial number of GGR plants will be very low, each additional plant will have a significant effect on the total supply of NEs. These step changes in supply may, unless matched by equivalent changes in demand, cause a sudden fall in the price of NE credits. Conversely, if a GGR plant is withdrawn from service in the early years, it may cause a sudden shortage of NE credits, driving the price up. These step changes may be larger in the GGR market than for other examples of obligations, as a result of the link to CO_2 transport and storage projects for many GGRs, with several GGR projects linked to the same T&S project coming online at similar times. For example, as development of GGR plants may be contingent on a piece of T&S infrastructure, the deployment of GGR plants could be stalled for years until the T&S network is ready. Then, once the network expands, the number operational GGR plants could jump suddenly. Equally, the shutdown of a section of the T&S network could force several GGR plants offline.

Demand will be affected by the obligation targets set, innovation in decarbonisation, and the performance of the wider economy. As obligation targets increase, so will demand. These increases should be predictable and well signposted but are unlikely to perfectly match the profile of supply over time. Innovation that allows for decarbonisation of some hard-to-abate sectors would lead to a fall in demand for NE credits and is difficult to foresee. Changes in the macro-economy will influence industrial output and consumption, which will affect demand for NE credits if targets are mechanically linked to emissions.

5.3.8 A negative emissions obligation scheme and the key design principles

Under an initial assessment, an **obligation scheme has many advantages when considered against the key design principles**. It would reward NE credits equally, by establishing a single market price. It would provide value for money for taxpayers by pushing the costs on to polluters. The market would encourage competition and drive efficiency. It would leverage in private investment in GGR technologies by creating demand.

Despite this, **an obligation scheme has limitations in terms of satisfying other key design principles**. An obligation scheme may not ensure that NE targets are met. By setting annual obligation targets, the regulator will create demand for NE credits. This will act as a clear signal to GGR developers that there will be growing demand in each year and that there is a potential business opportunity in supplying NE credits to the market. However, this does not guarantee that supply will increase to meet demand. The decision to invest remains with developers and investment will only be possible if they can raise the required finance. The outcome of that investment decision will be based on projected future cash-flows, which will depend on costs and the market price, which is influenced by the buyout price. Setting a buyout price too low will mean that more costly projects would be inviable. In such a scenario there remains the risk that an obligation scheme alone will not ensure that UK GGR deployment targets are met.

Developers face considerable uncertainty about their costs, due to volatility in the cost of inputs such as energy. **Under an obligation scheme, developers would also face significant uncertainty over their revenues due to volatility in the market price for NE credits.** Whilst in early years it may be possible to expect credits to trade at the buyout price, there could be significant volatility once projects start to come online. This overall high level of uncertainty would greatly increase the cost of finance, making some projects inviable. The knock-on effect of this may be reduced innovation and competition, with nascent technologies unable to get backing. Price volatility may be reduced in a number of ways. A pilot programme could provide a learning opportunity to assist with the coordination of supply and demand, which should reduce volatility. Developers and emitters could enter long-term bilateral contracts to secure certainty of price. This could have the effect of forcing some emitters to pay the penalty buyout price for their entire obligation if the NE supply is insufficient. Another way in which volatility might be reduced is by the regulator stepping in to smooth supply through the purchase of surplus NE credits (creating a price floor). These credits could then be sold in times of deficit (when supply does not meet demand). This would represent a risk to the taxpayer and there are limits to the effect it could have on price volatility.

While an obligation scheme may enable competition among comparable technologies, it alone **may not be suitable for enabling nascent technologies to be commercialised, if the market price is not high enough to support their deployment.** Even if the price is high in early years, when supply is low and so the price is near to a buyout price set high enough to encourage new technologies, the market price will fall once supply increases. If this happens rapidly, it could make it impossible to meet NE targets over the long term, where technologies such as DACCS may be essential. Sub-obligations could provide a means of increasing the market price for DACCS technologies, but they also increase complexity and may reduce market liquidity, increasing price volatility.

Other challenges remain, including the complexity around determining which sectors should be obligated, how large the obligations should be, and how regularly they should be reviewed. In particular, setting targets based on emissions requires all obligated parties to have their emissions measured and verified in a comparable way, which is not necessarily the case today depending on which companies and emissions are in scope. This is compounded by the issue around cost-pass-through to vulnerable consumers.

In short, an obligation scheme would be difficult to implement and **would not satisfy the key design principles in the short-medium term**. There are some advantages to an obligation scheme, including the polluter pays principle, reduced government intervention, and establishing a market price for NEs. These advantages make it **worthy of consideration in the medium-long term, where a portfolio of viable technologies have developed sufficiently to compete with one another on the market**.

5.4 Contract-based mechanisms – Overview

Payment schemes and CfD schemes are both contract-based mechanisms and as such share many common design features. Unlike in market-based mechanisms such as an obligation scheme, **in a contract-based mechanism, revenues are guaranteed by the contract.** This is not to say that the market is entirely ignored. NE credits can be sold on voluntary or regulated markets and how the revenues from those credits are treated will depend on the terms of the contract. However, **unlike an obligation scheme, a contract-based scheme does not directly influence demand for NE credits.** Instead, the **contract-based policy mechanism influences the supply of NE credits by guaranteeing revenues and reducing developers' financing costs** - creating attractive terms for investors and developers. These guarantees transfer significant risks from developers and investors to government. This section provides a more detailed overview of how typical payment and CfD schemes work.

5.4.1 Payment Scheme

Payment schemes are contracted mechanisms which can either consist of government directly purchasing negative emission credits from GGR developers on a £ per tonne basis or making payments directly to GGR developers to cover their costs. In either case negative emissions are considered by the government as a public good, which needs to be supported directly, providing a guaranteed revenue stream for GGR developers. Contracts can be bilaterally negotiated or awarded through reverse auctions. The latter would typically be implemented when the market for GGRs has become highly competitive. Then, GGR developers would sell negative emission credits in the voluntary market or in any other regulated market and the revenues would be shared between the government and the GGR developers. This reduces the burden on the taxpayer and means that private investors can be leveraged. An alternative to a standard payment scheme is advance market commitments (AMC) where government commits to purchasing credits in the future (future price reductions commit government to procuring increasing amounts of credits).

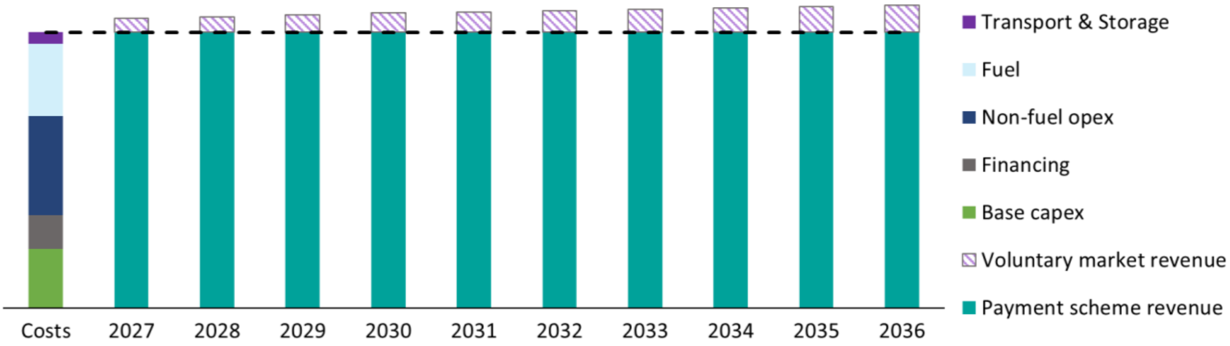

Figure 11: DACCS cash flow under a payment scheme (£/tCO_2)

5.4.2 CfD Scheme

A carbon contract for difference (CfD) is a contracted mechanism between the government (or a counterparty company) and the GGR developer. The contract stipulates that the government pays the GGR developer an amount that equals the difference between the reference market price of an NE credit and its value at contract time. This requires the counterparty to hold a competitive auction for contracts with the aim to incentivise GGR investments. GGR developers would then bid to provide negative emissions for a fixed strike price. The latter is a price for NE credits reflecting the cost of capturing and storing emissions and the required return on investment.

Successful bidders secure a guaranteed revenue stream for carbon removal and storage for the duration of the contract. GGR developers then sell their negative emission credits on the open market, at the floating reference price, which is a measure of the average market price for negative emission credits. Where the reference price is below the strike price, the difference is paid to the GGR developer by the counterparty, and that represents a source of revenue for GGR plants. Conversely, where the reference price overtakes the strike price, the difference is paid to the counterparty by the GGR developer. As the market matures, and the price of negative emission credits increases, it is expected that the burden on government would be reduced (Figure 12).

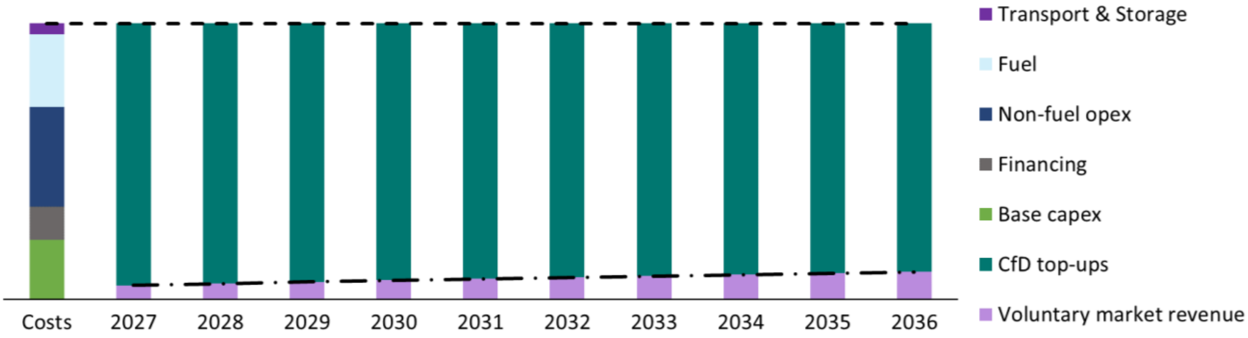

Figure 12: DACCS cash flow under a payment scheme (£/tCO$_2$)

CfD schemes incentivise investments in GGRs by providing developers with greater revenue than available from NE markets today, and protection from volatile prices of NE emissions. Indeed, the revenue certainty that a CfD scheme provides to developers results in an increased pool of investors, a lower average cost of capital, and a potential for greater debt leverage. This increases the likelihood of the delivery of required GGR projects, to meet NE targets, at the lowest unit cost per NE credit. There are several examples of CfD schemes working successfully in the power sector, with the Low Carbon Contracts Company acting as counterparty to renewable power CfDs. However, given the unique nature of the GGR sector, some adaptations to the CfD framework may be required, especially in the early years.

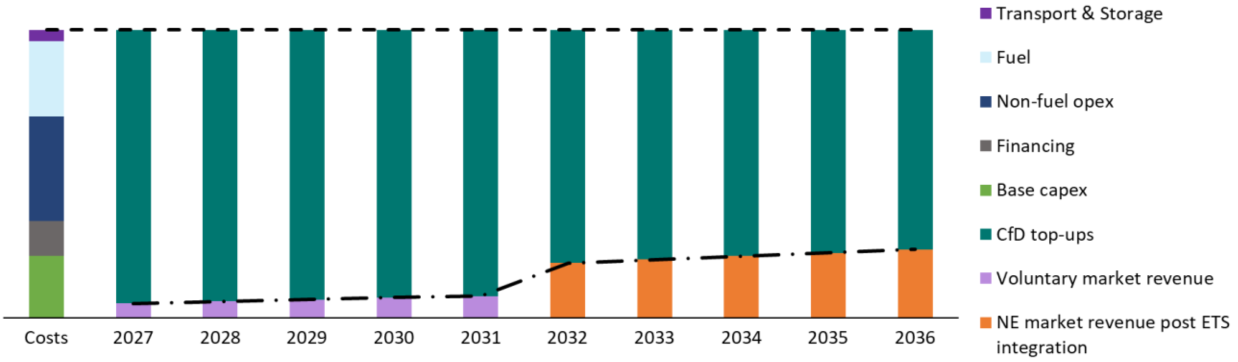

Figure 13: DACCS cash flow under a CfD scheme with ETS integration (£/tCO$_2$)

5.5 Common Design Features of Contract Mechanisms

Being contract-based mechanisms, payment and CfD schemes share many common design features. This section discusses each of the primary common design features in turn. Where there are subtle differences between contract mechanisms these are identified explicitly. Primary design features that are unique to payment and CfD schemes are discussed in sections 5.6 and 5.7, respectively.

5.5.1 Establishing a counterparty company

While the ultimate counterparty to a contract with GGR developers is the state, there is benefit in **establishing a counterparty company to act on behalf of the government in the administration of the contract-based scheme.** This approach has been taken in implementing the renewable CfD scheme, with the Low Carbon Contracts Company, for example.[66] Once the broad parameters are set by the government, in line with its objectives and the Net Zero Strategy, the counterparty company could manage and maintain the contract mechanism day-to-day, reducing the administrative burden on the government. Another benefit of such an approach is that it develops a level of independence within which the counterparty can operate. This, along

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[66] Who we are | Low Carbon Contracts Company

with the private-law nature of contracts may help attract investment by **insulating developers and investors from political risk**, providing additional certainty.

Government could set overall NE targets, maximum contract lengths, outline the balance between supporting innovation and value for money today, and set rules governing revenue generation through the sale of NE credits. The duties of the counterparty company would then fall within that framework and would include determining the appropriate pipeline of GGR projects to satisfy future annual NE targets, specifying optimal contract lengths and terms, consideration of costs and risks, how to allocate funding, and how to support innovation and competition.

5.5.2 Setting annual NE targets and the amount of support available

The Government's near-term ambition for negative emissions from engineered GGRs is set out in the Net Zero Strategy (5 $MtCO_2e$/year by 2030, potentially rising to 23 $MtCO_2e$/year by 2035). These figures are useful, but more information would be required by GGR developers and their financiers before deciding to invest. Government would need to produce forward guidance on annual NE targets and the overall amount of funding available to support GGR development in advance of the scheme opening. This guidance should include scenarios to show what might happen if overall targets are adjusted, to allow for uncertainty over the long term. Such guidance allows developers to plan to ramp up NE capacity over time and provides some certainty to those providing finance to such projects.

A contract-based scheme allows for considerable control of NE volumes, if developers can bring plants online in line with the NE targets set out by government. The overall support that a plant receives is based on their NE volumes. Once a pathway for NE targets is determined by government, funding can be put in place to achieve those NE volumes by supporting the required number of projects.

Some discovery will be required to establish how much funding may be needed overall to reach NE targets. This will depend on the mix of technologies supported, and their relative share of the mix. Given uncertainty about costs and revenues, and how this uncertainty varies by technology, there is a risk that targets would not be met if funding is insufficient. Shorter contracts would be one way to give more control over NE volumes, allowing the government to tune supply. However, this is only possible to a point – short contracts will be unattractive to developers and investors who want certainty before investing to expand supply. Contract length, along with other contract terms are discussed in the next section.

5.5.3 Discussion on optimum contract length

Finding the optimum contract length for a contract mechanism is one key consideration. **If a contract is too long, the government may end up supporting a technology long after it makes financial sense to do so. If a contract is too short, it may not provide sufficient certainty to attract developers and projects may never go ahead.** A complicating factor is that the optimal contract length may vary by technology but also by whether a technology is first of a kind (FOAK), second of a kind or nth of a kind (NOAK).

The remainder of this section uses a CfD scheme as an example to discuss some issues around optimal contract lengths and proposes several options for contract-based mechanisms.

Traditionally CfDs have been used in the UK to incentivise renewables, such as offshore wind. These renewable projects are Capex dominated, with minimal ongoing operational and maintenance costs. This means that the revenues a renewable energy project need to receive from a CfD to breakeven mostly consists of the upfront Capex investment and interest payments. Therefore, cumulative revenue needed to breakeven would only reduce by a small amount if a short contract is awarded to the plant (as opposed to Opex heavy projects which have very low costs if they cease operating). With such a cost structure the government benefits from awarding longer contracts (e.g., 15 years) because:

- Reference price may increase in the future, reducing government's burden
- Payments spread over more units of products generated (which is MWh of electricity for power CfDs), reducing government's total payments

GGR projects have a much higher Opex component compared to renewable power projects, therefore a large portion of costs are avoidable if a project is abandoned early.

Figure 14 presents illustrative graphs showing how strike prices (£/tCO_2) required by a project change with different contract lengths and for different Capex/Opex splits. The numbers on the graphs are only illustrative and are not based on data for any specific technology. The base case is assumed to be a project with a 15-year CfD contract requiring a strike price of 100 £/tCO_2. All other figures were calculated relative to the base case assuming an annual interest rate of 9%. Opex payments per tonne of CO_2 do not change over time.

As expected, **strike prices increase with shorter contract lengths** since the project must recover its Capex in a shorter operational period. However, the increase in strike prices is significantly smaller for projects with a lower percentage of Capex costs because Opex costs are not affected by contract length.

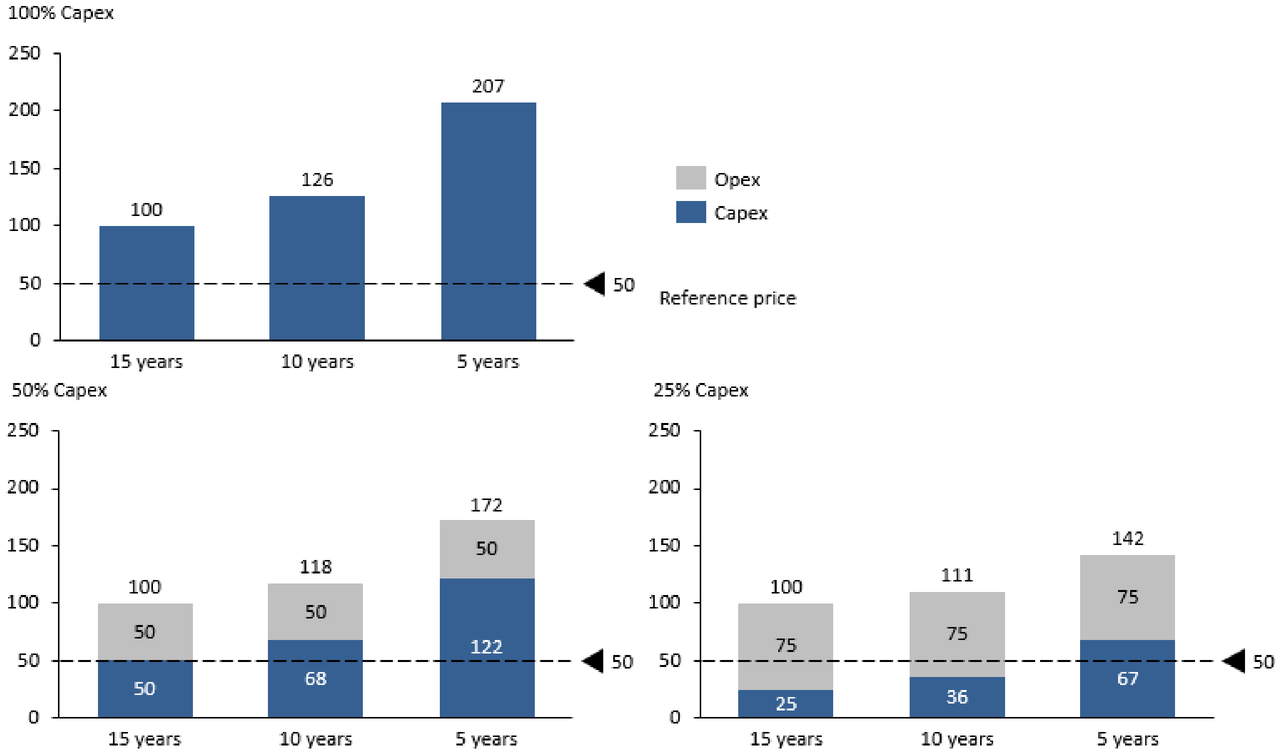

Figure 14: Strike prices of projects with different Capex/Opex splits under different contract lengths. Figures are illustrative and relative to a base case of a 15-year project requiring a strike price of 100. It is assumed that Opex per tonne of CO_2 stays constant over time and the interest rate for Capex repayments is 9%.

Another angle to view the burden on the taxpayer is understanding cumulative payments to projects under different contract lengths. Table 9 shows the cumulative government payments needed for each of the scenarios considered in Figure 14. Payments are calculated by multiplying contract length by the difference between the strike and reference prices. For the sake of this calculation, it is assumed that the reference price stays constant at 50 throughout the contract period[67].

Table 9: Cumulative government payments for the scenarios explored in Figure 14

% of costs that is Capex	15 years	10 years	5 years
100% Capex	£750	£756	£786
50% Capex	£750	£679	£612
25% Capex	£750	£606	£462

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[67] Sample calculation for a 15-year project: (£100 – £50) * (15 years) = 750. These figures are meant to be only illustrative and should be viewed as relative to each other.

Clearly total policy costs for the government increase with reducing contract lengths for Capex dominated technologies (e.g., renewables). However, **shorter contract periods for Opex heavy projects (including most GGRs) reduce the burden on the government significantly**. This introduces **an incentive for the government to terminate contracts early** if a project receiving CfD support is deemed not to be offering value for money due to changing circumstances (e.g., cheaper technologies emerging). The only disadvantage of shorter contract lengths would be losing GGR capacity, since many GGR technologies would not be able to operate without government support.

One approach to protect the government from locking itself into expensive technologies is having a shorter contract period (e.g., 10 years as opposed to 15) and **allowing plants with expired contracts to compete for new contracts directly against newly proposed projects**. Older generation plants reapplying for CfDs would have an advantage by not having Capex costs (since it would have been paid back under the initial contract), however, they would potentially have higher Opex costs.

Figure 15 illustrates the strike prices of an old (FOAK) plant in its first and second application to the CfD scheme, along with a new generation plant with lower Capex and Opex costs. It is assumed that both the Capex and Opex costs of the new generation plant are reduced by the indicated learning rates. In case 1, the Capex component is high, and the new plant ends up being more expensive than the older plant even with a 40% cost reduction. In case 2, Capex is a much smaller factor, so a more modest 25% cost reduction allows the new plant to out compete the older plant re-applying for funding.

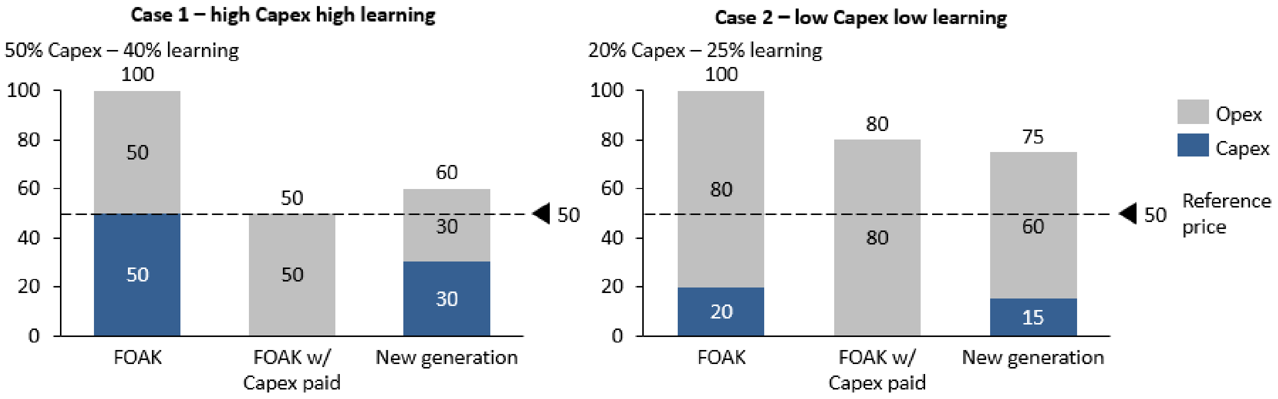

Figure 15: Strike prices of older and newer generation projects with different Capex/Opex splits and learning rates. Capex of older plants is assumed to have been paid.

This example illustrates that **Opex heavy technologies are likely to be outcompeted by the new generation of plants**, allowing the government to cut its costs if the contract length is restricted. If the older plant ends up being more cost effective (as in case 1), the government still pays the lowest price per tonne of negative emissions.

Reducing contract length can be a form of insurance – protecting the government against locking itself into backing expensive technologies, in exchange for paying slightly higher prices per tonne of CO_2 removed. The choice of having such an insurance depends on current and future expected costs of GGR technologies, which have many uncertainties. Nonetheless, a contract reduction from 15 to 10 years may be beneficial because it results in relatively lower unit cost hikes (an increase of 11% for a 25% Capex project in the above example) and GGRs are expected to experience significant cost reduction after the FOAK stage.

The discussion presented above is broadly applicable to payment schemes in addition to carbon CfDs, if the GGR projects are allowed to sell their credits in the voluntary markets and share a portion of their revenues with the government.

Given the uncertainties discussed above, a preferred approach may be to **determine contract lengths using indicative bids from developers**. Minimum and maximum terms could be set, with developers invited to bid for a term they deem sufficient to provide certainty to their investors, reduce their finance costs, and enable development. As contract length patterns emerge across technologies, these could then be standardised across technology pots for subsequent rounds of funding.

Alternatively, the government may find that determining the term through the bidding process represents the best way to achieve value for money and continue the practice indefinitely. A hybrid system could also be envisaged, where more mature and certain technologies graduate from the bid process to enter standardised technology pots while less mature technologies remain within the more flexible framework and less promising technologies are not supported.

5.5.4 Contract review mechanism

While it is important that, once agreed, contract periods are fixed and contracts cannot end unless through breach of terms, there may be **a benefit to both parties in building a review mechanism into contracts, at least in the initial round(s).** The great uncertainty in terms of costs and revenues, combined with lead-in time of up to five years on some projects, mean that by the time a plant is fully operational, the originally agreed terms may be overly or insufficiently supportive. A review mechanism that is triggered one year after the first day of operation could be beneficial. It is essential that the boundaries of such reviews, and their ability to modify terms within contracts be clearly set out. Contracts with unlimited scope to review terms would become de-facto short-term agreements and so would provide not revenue certainty or long term guarantees of NE emissions production. **An example of a well bounded review mechanism is to allow the strike price to be reviewed downward (or upward) within a strictly defined range (say +/- 10%) after one year of operation if costs are lower (higher) than originally expected.** There is potential to include a similar review after five years, for example, particularly for contracts that last for 10-15 years.

Another way to modify the risk profile and who bears the risk over time is to consider the treatment of Capex. Specifically, to **consider whether Capex support is frontloaded or spread over the entire contract period.**[68] With frontloaded Capex support, the support received would be revised downward once the Capex is paid off. The optimal configuration here may depend on the Capex/Opex profile of each technology.

5.5.5 Who bears the costs and risk?

Contract-based schemes will involve administrative overheads for both parties. These costs may be greater initially if contracts are to be bilaterally negotiated and reviewed periodically but also due to the learning required by both parties. Establishing a counterparty company may be one way to maximise administrative efficiency. The costs of running the scheme could be recouped through the sale of NE credits or levies on emitters. These options are explored in subsequent sections.

One significant difference between a basic contract-based mechanisms and market-based mechanisms is the link between the polluter and who pays for NEs. NEs are produced with a mix of funding from the sale of NE credits and the state. This means that compared to an obligation scheme, the **pass-through of costs to consumers is likely to be lower as some of the costs would be passed on to taxpayers through taxation.** If it is desired to pass more of the cost on to polluters there is the possibility of raising revenue through levies on hard-to-abate sectors or linking funding to the carbon tax. How much of the total cost is passed through to consumers, some of whom may be particularly vulnerable, would depend on the share of the costs covered by taxation versus the share covered through the sale of credits and/or a levy on emitters.

Along with the treatment of Capex within the terms of a contract discussed previously, the treatment of Opex is equally worthy of consideration. Specifically, transport and storage costs must be considered. Transport and storage costs are a major source of uncertainty for GGR developers, as they are dependent on large infrastructure projects and other government policy decisions. Therefore, they should be covered explicitly by the contract mechanism initially, if sufficient investment in GGR technologies is to be achieved[69]. As the

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[68] The ICC business models propose a similar approach with Capex recovery in 5-years and a contract length of 10-years with a 5-year extension option. [Link]

[69] The draft industrial carbon capture business models and CCUS dispatchable power agreement propose to explicitly cover all CO_2 T&S fees of plants. These may be used as a template for GGR policies as well. [Link]

transport and storage network develops, uncertainty around availability and cost should reduce, allowing for subsequent contracts to exclude or reduce support for these costs. This unwinding of transport and storage support may be important over the long run, to place downward pressure on costs and deliver value for money for taxpayers.

Overall, the certainty offered to developers and investors by a contract-based scheme administered by a counterparty company significantly reduces or eliminates financing, inflation, regulatory, legal, political, and market price risk. **Incentives should be built into contracts to ensure value for money without undermining the certainty that GGR developers require.** This, combined with well-designed contracts and carefully selected developers should incentivise innovation across the sector while limiting the exposure of the taxpayer.

5.5.6 How to fund a contract-based mechanism

At its most basic, the funding for a contract-based scheme is provided by central government through general taxation. Initially, this may be the best approach due to simplicity and speed of implementation. This will allow some NE credit supply to come on stream quickly and encourage the maturation of the market for NE credits. In parallel, while NE credit supply ramps up, a mechanism to pass the costs on to emitters could be developed and ready to deploy for subsequent rounds of support. A further benefit of passing costs on to emitters is that it may influence their actions and further decarbonisation.

5.5.7 How to allocate funding to projects

As has been stressed throughout, the uncertainty that prevails in terms of costs, revenues, and the viability of various GGR technologies means that both parties face a significant learning curve. Established contract-based mechanisms typically use reverse auctions to allocate funding efficiently. However, this may not be feasible where there are a small number of projects and in such cases it may make sense to allocate funding via bilateral negotiation. Bilateral negotiations could be operated within a framework that ensures that short-term NE targets are met through the support of currently viable technologies, while also keeping an eye on longer-term targets through the support of a portfolio of technologies.

As the market matures in the medium-term, funding should be allocated to technology pots. These pots should reflect the varying cost profiles of bidding technologies and the policy environment and existing support across different GGR technologies. To enable competition, pots should contain comparable technologies. For example, if only two pots are created, technologies with very different cost profiles would be expected to bid against one another. The more expensive technology would be incapable of attracting the support required to proceed. In an established market, this outcome makes sense, but as this policy mechanism aims to support nascent technologies, this could limit competition over the long run. Conversely, a proliferation of pots could see a situation where each pot contains a very low number of bidders – perhaps as low as one – and this would also limit competition. This could be counteracted by a rule where any pot with only one bidder is either closed or else merged into its next closest pot.

Given the uncertainty around technology development and the evolution of costs and revenues, it is impossible to be prescriptive about technology pot design at this stage. A call for evidence should be used to guide technology pot design once the initial stage of bilaterally negotiated contracts is underway. Much will be learned through the initial stage and as GGR technologies develop, and this will inform the call for evidence.

For very small GGR projects, a feed-in tariff, which provides fixed payments per tonne removed without any contractual arrangement may reduce administrative complexity. However, this may represent poor value for money, if the cost of producing a single NE credit is greater in small GGR projects than in large GGR projects. Most engineered GGR technologies would benefit from large-scale so a feed-in-tariff may not be necessary unless significant demand for small applications emerge.

5.6 Design Features Unique to Payment Schemes

This section first discusses how payment schemes can generate revenue through the sale of NE credits, including internationally. It then explores how a payment scheme can be reconfigured to achieve theoretically infinite volumes of NEs using advanced market commitments.

5.6.1 Revenue generation under a payment scheme

Beyond placing a levy on emitters, **another way in which government can reduce its exposure within a payment scheme is to allow developers to sell NE credits on the market.** A share of the revenue from these sales (for example 50% - 80%) could be passed back to the government under the terms of the contract. This would have the effect of reducing the net support provided by the taxpayer while maintaining revenue certainty for the developer and preserving their incentive to achieve the best market price for their NE credits.

The NE credits could be sold in voluntary NE markets, a regulated voluntary market (see section 5.2.1), the ETS, or an obligation market. If a suitably mature market has not yet developed, the Government could buy and hold these credits to be released onto the market in due course, or simply take the NE credits in exchange for the payment support provided. However, this may be a less efficient outcome than letting the NE developer sell the NE credits directly and may also further expose the Government. **This strengthens the case for developing a regulated voluntary market to underpin these policy mechanisms.**

If taxpayers are supporting developers, it may be important to ensure that credits are sold, at least primarily, within UK markets. However, there may be a benefit in allowing some sale into international voluntary markets internationally, where the UK could become an exporter of NEs. One way to facilitate this would be to implement a quota system, whereby developers are expected to sell, for example, 70% of their NE credits within the UK. The government may prevent international sales which would also transfer the credit to another country’s NDC under Article 6.

5.6.2 A variation on a payment scheme – advanced market commitments

As noted previously, a payment scheme typically purchases a fixed volume of NE credits, with payments assured to cover the costs of producing those NE credits. **An advanced market commitment (AMC) is a variation on a payment scheme where the price is fixed rather than the quantity.** They are a type of pull incentive and are also known as advanced purchase agreements. AMCs have been used successfully in the roll-out of vaccines, recently in the case of COVID-19 vaccines. AMCs work by de-risking a company’s investment in R&D through the promise to purchase products when they come to market. In the context of NEs, the government would attempt to de-risk investment by developers in GGR technologies by agreeing in advance to purchase NE credits at an agreed price if those credits are delivered by an agreed date.

The agreement can be tailored to incentivise developers to push down costs. **For example, the government can agree to buy X NE credits at £300 per credit if those credits are available by 2027 but also commit to buying 2X NE credits if developers can sell them for £200 per credit,** and so on. This creates a clear incentive for companies to drive development through to become operational, and then reduce costs as they compete to sell more and more credits. With sufficient investment, this could lead to NE targets being hit and even overtaken. Theoretically, the commitment may achieve near infinite volumes of NE credits if the budget is high enough. **A number of developers with the cheapest bids would get a contract proportional to their costs, while those unable to compete would receive nothing.**

However, despite AMCs’ theoretical potential to achieve scale at low cost, there are some considerations which may make them unsuitable for GGR development in the short-medium term. **As the price is fixed, and that price may not be sufficient to allow a portfolio of developers to compete**, this could reduce the potential for innovation and competition over the long term. This may lead to market dominance and so less potential to drive down costs over the long term because innovators would be unable to secure funding to compete with more established technologies. With only relatively viable projects being able to compete, it may not be possible to meet NE targets over the long run. For example, a currently expensive DACCS technology with expectation of falling costs and great potential to scale might be priced out of competing and may never develop further. Meeting long run NE targets may depend on the development of DACCS technologies, however, because of the potential limits to growth of BECCS development.

In short, AMCs are a high risk, high reward strategy. If they work well, they will deliver value for money and a large quantity of NEs. But if they do not work well, they may deliver only up to the scale that the cheapest initial bidders can offer, and as a result, nascent, but promising technologies may never develop.

5.7 Design Features Unique to CfD Schemes

This section showcases the design of two features unique to CfD schemes: the strike price and the reference price. Setting these prices, in an uncertain and immature market is a significant challenge. Inappropriate price setting may leave the developer and/or the counterparty over-exposed for the duration of the agreed contract.

5.7.1 Setting the strike price

Finding the appropriate strike price for an NE CfD scheme is a significant challenge given the uncertainty around costs and revenues across GGR technologies and over time. **Setting the strike price too high would see overly generous top-up payments provided to developers at the expense of the taxpayer. Setting the strike price too low would at best leave projects vulnerable to shocks and at worst incapable of being developed in the first place** due to an inability to attract funding from investors. Given this uncertainty, and the steep learning curve presented to both parties, the strike price could initially be negotiated bilaterally on a case-by-case basis. The strike price would be set to reflect the marginal cost of negative emissions, with full transparency required between developers and the counterparty. This will require strict criteria by the counterparty, so that the inherent flexibility of a bilaterally negotiated strike price does not lead to clearly unsuitable projects being backed. The counterparty must protect against the risk of cost inflation by developers through the comparison of costs across similar technologies/developers.

Once feasible, some or all technologies could be transitioned over to a reverse-auction process, where the strike price would be determined through competitive bidding within each technology's respective technology pots. If the cost profile of a technology changes over time, it could move from one pot to another, so that its strike price bid is competing with comparable technologies. Over the medium-long term, more mature pots, consisting of comparable technologies could operate on what is known as a pay-as-clear basis. Pay-as-clear is where once a strike price is determined via reverse auction, all successful bidders within that technology pot are paid the same strike price. This differs from the pay-as-bid basis, which would be in operation in the early years, where each successful bidder would be paid the strike price that they specifically bid for. A key reason for not using a pay-as-clear basis from the beginning is that it may lead to excessive over-subsidisation of some bidders (e.g. before the market price of biomass has settled to a new equilibrium).

5.7.2 Setting the reference price

By design, a CfD scheme will secure guaranteed revenues for NE providers, which will support investment by transferring risk and the reducing cost of finance. This guarantee creates an exposure for the taxpayer and so it is important that the level of support provided is sufficient but not overly generous. Just as setting an appropriate strike price is important, so is determining an appropriate basis for its counterpart – the reference price. The **reference price will rely on an underlying market price, which must be chosen at the beginning of a contract and potentially stand for the contract period**. In a new market such as that for NEs, this is a difficult choice to make. A number of options exist, including voluntary markets, regulated voluntary market, the UK ETS, or an obligation market.

Currently, no regulated or obligation market for NEs exists. Instead, relatively small quantities of NEs are traded across a selection of voluntary NE markets. The quality of NE credits on these markets is not assured by government, access to the markets may be limited, and credits from one market may not be directly comparable with those of another. The UK ETS carbon price relates to carbon reduction rather than removal. Integration with the UK ETS is discussed in section 5.2.2.

Volatility may greatly affect the reference price, which can be influenced by several factors, as outlined below. This volatility may make it difficult to estimate the exposure of government throughout the lifetime of a CfD. When the reference price is relatively high (low), the top-up payment provided by government falls (increases).

- Increased demand for NE credits from hard-to-abate sectors will push the NE price up
- Increased expectation by consumers that emitters will reduce their net emissions will push the NE price up
- Increased concern by shareholders may force emitters to improve their business practices. Where they cannot readily decarbonise, they will increase demand for NE credits, pushing the price up
- If emitters can purchase international NE credits more cheaply, this could drive the UK NE price down
- Technological breakthroughs making decarbonisation more affordable will reduce demand for NE credits
- The lower cost and growing supply of nature-based solutions could have the effect of reducing demand and reference prices for negative emissions.

Furthermore, in the early years, the market reference price could be driven down by the success of the CfD scheme, as the supply of NE credits increases rapidly, without the guarantee of a corresponding increase in demand for NEs. As the strike price would be fixed for a number of years, this would mean that GGR providers would receive greater top-up payments from the counterparty than originally forecast. However, if the market is dominated by non-engineered removals this effect is likely to be small.

Additional incentives could be put in place to encourage NE providers to achieve the maximum possible sale price, such as gainsharing or periodic bonuses based on sale price performance. A study to establish a market benchmark price for NE credits, based on data from NE providers, may be beneficial. The organic occurrence of this is unlikely because of the private contractual nature of the interactions between GGR developers and emitters, and so government's intervention may be valuable.

The preferred basis for a reference price initially is a regulated voluntary market carbon price, which is an indicator of what price for NE is achievable on the market. In the longer term, UK ETS or an obligation market price may be used instead if integration with such options are pursued. In the short term, while the regulated voluntary market will be immature and illiquid, the achieved sale price would serve as the reference price. This could be supported by a pain/gain sharing system to ensure that developers achieve the best possible price for NE credits, reducing the requirement for taxpayer support. Such a system would require a benchmark price such as the international voluntary offset market price. As typically configured, achieving the best price offers no reward to the developer as the top-up payment falls by an equivalent amount. Under this system, the top-up payment would not fall on a one-for-one basis, allowing the developer to increase their revenues somewhat. Using the international voluntary offset market prices as a benchmark can help protect the government from very low sales prices. This is based on the principle that NE credits should at least cost as much as average offset market credits.

Building a regulated market is an essential step in ensuring that all NE credits are priced in accordance with their quality, which will be important to GGR developers as they project their costs and revenues when bidding for contracts. A regulated market also helps to ensure that if any government support is provided, it is allocated to producing NEs of verifiable quality. Furthermore, establishing a regulated market is a sensible first step in developing a market-based solution for the future. **A regulated market would provide the necessary infrastructure and establish a clear market price for NEs, which would ease the transition to either ETS integration or an obligation market.**

5.8 Contract-based Mechanisms and the Key Design Principles

As with an obligation scheme, a contract-based mechanism will satisfy some key design principles well but may struggle with others. A key consideration when making this assessment is the short-medium versus the medium-long term perspective. A contract-based scheme will not necessarily reward all negative emissions equally as the payments received will reflect the varying costs of producing NEs across technologies. However, revenues from the sale of NE credits should be comparable across technologies if a single market prevails. **A contract-based scheme will also provide core revenue certainty, which will in turn encourage innovation and enable competition over the long run.** In the short term, if taxpayers are assumed to fund these mechanisms, a contract-based scheme represents a significant cost to taxpayers but, if it enables NE targets to be met in a sustainable way and allows for scaling, it may offer value for money over the long run. Furthermore, by passing some of the cost onto emitters via the sale of NE credits, the burden on taxpayers is reduced and as the market price is expected to increase over time, this burden should continue to fall.

In short, a contract-based scheme, if well designed, could broadly satisfy the key design principles and provide enough support to industry to drive the investment required to achieve NE targets. The sale of NE credits will not only reduce the net burden on taxpayers but also help to drive NE market activity which may assist in the eventual transition to market-based solution for GGR technologies over the long run.

5.9 Interactions of the shortlisted policies with the wider policy landscape

An aim of this study is to ensure that the three shortlisted policies developed are applicable to all GGR technologies and are compatible with the wider decarbonisation policies which could interact with a policy mechanism to support GGRs. These wider policies are briefly introduced in Table 6 in section 3.1.

Table 10 describes how GGR obligations may interact with these wider policies and how potential conflicts may be resolved, considering the core principle of rewarding each product separately and ideally equally between different technologies. Table 11 below then investigates these interactions for contract-based mechanisms (carbon CfDs and payment schemes).

Table 10: Interactions of **obligation schemes** with key wider decarbonisation policies and recommendations for addressing potential conflicts

<table>
<tr><th>Wider Policy</th><th>Description of Policy Interactions with a GGR Obligation Mechanism</th><th>No Conflict</th><th>Potential Conflict</th></tr>
<tr><td>Industrial plants emitting fossil-based CO₂ benefiting from ICC business models</td><td colspan="3">These plants are not compensated for fuel switching to biomass to generate NE, so an obligation market on top of ICC support could provide this additional incentive. Furthermore, the revenues made from an obligation scheme would be functionally the same as voluntary market revenues.</td></tr>
<tr><td>EfW and industrial plants with biogenic emissions benefiting from ICC business models</td><td colspan="3">Through the capture of biogenic CO_2, these plants will produce negative emissions as a result of retrofitting a CCS unit through ICC business models. As BEIS' latest update on the ICC model suggests, any future negative emissions revenues are likely to require adjustments to subsidy payments to reduce the risk of over-subsidy. These adjustments could account for revenues from an obligation scheme; therefore, the introduction of an obligation scheme is not expected to create a significant conflict with this model.</td></tr>
<tr><td>BECCS H_2 plants benefiting from low carbon H_2 business model.</td><td colspan="3">If the future hydrogen business model support allocates funding to different production technologies through separate pots, an obligation scheme would be compatible because it would simply replace the NE revenue from the voluntary market and NE related revenue would be accounted for by the level of support awarded in this pot. If all H_2 technologies compete in the same pot, NE credits would provide an advantage over other options. This may be acceptable if BECCS H_2 prices are estimated to be higher than other options, or the CfD payments may be adjusted to take into account additional revenue.</td></tr>
<tr><td>BECCS power plants included in the new BECCS power business models</td><td colspan="3">Currently the BECCS power business model is under development, with potential models outlined in the "Investable commercial frameworks for 'power-BECCS'" report. NE credit prices in an obligation market can easily be used as a reference price for a carbon CfD, hence no conflicts are expected in this model.</td></tr>
</table>

BECCS biofuels plants participating in the RTFO	BECCS biofuels plants in GGR obligation schemes would have revenues from two different streams. This does not introduce any conflicts or additional burdens. Income from GGR obligations may even reduce the compliance costs in the RTFO markets.
BECCS biofuels plants participating in the SAF mandate	The proposed SAF mandate is a GHG based obligation. If the proposed approach is extended to NE, the SAF output from BECCS biofuels plants would benefit from higher value under the SAF mandate (i.e., the plant would be financially compensated for generating NE). Excluding BECCS SAF plants from the GGR obligation would not be preferred, as many of these plants will produce other non SAF fuels that cannot valorise their associated negative emissions. Not allowing these plants to claim net negative emissions intensities under the SAF mandate would be an option, though changes to the SAF mandate are not desirable. A viable option may be allowing plants to benefit from both the SAF mandate and GGR obligations, with only negative emissions not already claimed in the SAF mandate to be eligible for the GGR obligation.

Obligation schemes are generally compatible with the wider policies because they are market-based mechanisms which replace the revenues NE would generate in the voluntary market with higher revenues from the obligation market. This allows NE revenues to easily stack up with revenues from other policies. Furthermore, some business models, like ICC, are working on provisions to account for additional NE revenues when determining compensation levels. Obligations would fit well with these policies and require minimal adaptation.

On the other hand, integration of a GGR obligation with the SAF mandate is likely to be more challenging because the proposed structure of the SAF mandate is likely to reward NE already. Since the SAF mandate is an obligation and is well received by the industry, we would not suggest any changes to its structure. However, there is no guarantee that plants producing SAF from biogenic sources will be incentivised sufficiently to install CCS and become BECCS plants under this scheme. Therefore, SAF plants should ideally be able to access additional support so that they are incentivised to create net negative emissions at the same level as other GGRs.

One challenge with such a dual support is the link between financial incentives and physical NE credits. The SAF mandate operates by calculating the GHG content of the fuel, therefore producing fuel with lower carbon footprint, reduces the emissions of its customers. This emission reduction will most probably be accounted for in the UK's national carbon budgets. So, if SAF plants are allowed to sell credits in an obligation scheme, these credits may be double counted – appearing as emissions reductions in the aviation industry as well as NE in the obligation market. If SAF plants indeed need additional GGR support, corresponding accounting adjustments must be made to avoid this double counting.

Table 11: Interactions of **contract based GGR policies** (carbon CfD and payment schemes) with key wider decarbonisation policies and recommendations for addressing potential conflicts

Wider Policy	Description of Policy Interactions with a Contract Based GGR Policy	No Conflict	Potential Conflict
Industrial plants emitting fossil-based CO_2 benefiting from ICC business models	These plants are expected to require smaller financial incentives on top of ICC support to convert to biomass use. If voluntary markets or sales into UK ETS does not provide the desired guaranteed income stream, they could be allowed to participate in carbon CfD or payment schemes in a special lot. Their business case would be similar to recent offshore wind power CfD winners which secure strike prices very close to power market costs but want a constant income level.		

EfW and industrial plants with biogenic emissions benefiting from ICC business models	These plants will already be viable with the ICC business model support and their incentives will have to be reduced by any revenues they receive from NE credit sales. Therefore, it is likely that plants receiving this support should be excluded from a wider carbon CfD or payment mechanism.
BECCS H_2 plants benefiting from low carbon H_2 business models.	A key challenge with BECCS H_2 is its uncertain cost compared to other low-carbon H_2 options. If costs of biomass-based hydrogen and operating a CCS unit is comparable to other hydrogen production methods plus NE revenues from the voluntary market, BECCS H_2 may be excluded from additional GGR support. If BECCS H_2 is more expensive, a second contract should be awarded for NE. This may initially be bilaterally negotiated and later through auctions in a special lot.
BECCS power plants included in the new BECCS power business models	The BECCS power business model is under development, with potential models outlined in the "Investable commercial frameworks for 'power-BECCS'" report. These models do not present a conflict with the contract-based GGR policies considered.
BECCS biofuels plants participating in the RTFO	Since the RTFO values fuel volume, not GHG saving, it presents no technical challenges for integration with carbon CfDs or payment schemes, however, having a unique revenue stream may require consideration of BECCS biofuels in a separate lot for funding purposes.
BECCS biofuels plants participating in the SAF mandate	The proposed SAF mandate is a GHG based obligation: as such the SAF output from BECCS biofuels plants (i.e., NE) will benefit from higher value under the SAF mandate. Excluding BECCS SAF plants from the GGR mechanism would not be preferred, as many of these plants will produce other non SAF fuels that cannot valorise their associated negative emissions. A solution may be not rewarding net-negativity under SAF and allowing BECCS SAF plants to benefit from GGR policies in a special lot similar to the plants contributing to the RTFO. However, this option would change the structure of the SAF mandate, which is not desirable. Another alternative could be running both schemes as proposed and setting the CfD reference price of SAF plants to net-negative based SAF payments (or treat these payments as NE credit revenue under a payment mechanism).

Interactions of carbon CfDs and payment schemes with the wider policy landscape are very similar and covered together because both policies have a very similar contract-based mechanism.

Currently, there are uncertainties around the financial viability of BECCS industry and BECCS hydrogen plants under the ICC and low carbon hydrogen business model, and additional revenues from the voluntary NE market. If these are not enough to encourage the deployment of GGR technologies so as to bring them forward as part of a portfolio of GGR technologies, dedicated GGR support may need to be offered with a second contract for negative emissions. Discussions with stakeholders suggested that such a dual contract mechanism would be generally workable for project developers, however more evidence is potentially needed around whether this would be workable for GGR options or developers with smaller plant sizes. However, in this case BECCS industry and hydrogen projects should be considered in special pots, if the costs of CCS are covered by the ICC and Hydrogen business models.

Contract-based mechanisms should not be offered to plants that receive ICC business model support and currently use biomass. Carbon CfDs and payment schemes are likely to be compatible with biofuel production under RTFO and BECCS power business models.

Interactions of contract-based mechanisms with the SAF mandate are less complicated than the obligation schemes because inclusion of SAF plants in carbon CfDs or payment schemes do not result in double counting of credits. As described above, the SAF mandate is well received by the industry so, it is not recommended to change its structure. NEs are already awarded to a degree in the SAF mandate, so this can replace the NE credit prices used in the contract-based mechanisms. Specifically, once the effective compensations received by the SAF plant per tonne of NE is calculated, it can be used as the reference price in a carbon CfD or it can be treated as additional revenue from credit sales under a payment scheme (e.g., a portion is shared with the government).

5.10 Evolution of the policy mechanism in the long term

There is **significant uncertainty** associated with how the technology landscape associated with engineered GGRs will evolve (costs, potential capacities) in the future. Given this, specifying how policies should evolve from this early vantage point is not recommended, however looking at some of the possibilities and considering potential evolutions is useful to understand the viability of the short-term options.

It is assumed that the short-medium term policy options considered in this study would evolve further in the long term, allowing technologies to compete (and when the future circumstances become clearer, for some options to be competed out of the market). For this long-term evolution, **it is important that the policy mechanism can transition to an appropriately market led state**, which is one of the policy assessment criteria used in this study.

A **CfD based framework provides a clear path to this market led state**, as it incorporates a market into the initial mechanism. Once this market has matured and evolved, this can become the primary method for supporting GGR development. A payment scheme framework has reduced natural links with markets as it does not depend on a reference price. This gives increased flexibility to define the appropriate market at a later stage, however, does not contribute actively towards the evolution of a market.

Many of the emissions pathways limited to 1.5°C of warming involve emissions eventually becoming **net negative**. This has implications in the very long term (post 2050) if a long-term market-based mechanism where the polluter pays principle is in place. For example, there are questions around who should pay for removal of historical emissions and going net negative – should this be current emitters, historical emitters, or the taxpayer. Among the many potential challenges associated with each of these, some of these options could be **challenging to integrate with the ongoing long-term market-based mechanism**. However, this is a very long-term consideration, and likely can be overcome with considered policy design.

5.11 Complementary and Enabling Policies

Complementary policies

This section briefly discusses three complementary policies which may be integrated with the wider GGR policies discussed in the report, to improve the viability of projects and reduce their risks even further.

Capital Cost Support

To aid reaching a final investment decision of GGR projects, especially at early stages, and crowd in additional private investment, different capital support mechanisms can be used to reduce the capital or financial costs:

- Grant funding with competitions: The government may award capital grants to certain projects through competitions to directly reduce the upfront investment needed.
- Co-investment: The government (potentially through the UK Infrastructure Bank - UKIB) may make equity investments up to a certain percentage of total costs to encourage private equity.
- Loan guarantees: UKIB may provide loan (or bond) guarantees by agreeing to pay back the loans of GGR companies in case of default, which would reduce the cost of capital for the projects.
- Low interest loans: The government (potentially through UKIB) may directly provide low interest loans.

These capital support mechanisms may be introduced if the deployment of GGRs without them is not quite financially sound in the early stages, however, once initial plants are rolled out, the main GGR policies explored above should be sufficient to incentivise deployment. The four capital support options listed above are explored in more detail in section 6.4.

Availability Payments

Cross-chain risk[70] is a significant concern for GGR developers and is likely to stall deployment if provisions are not put in place to protect the projects from failures outside their control. Two recommended actions to prevent this are:

- Alignment of final investment decisions of projects forming CCUS clusters/chains to prevent a situation where GGR plants are built without any CO_2 T&S infrastructure in place.
- Full availability payments to project developers if the CO_2 T&S infrastructure fails. These payments would be lower than the ordinary payments plants receive under a contract-based mechanism, considering their reduced Opex and revenues from co-products.

Further information on how availability payments may be setup for GGR projects is provided in section 4.3 of a previous report for BEIS on FOAK BECCS power commercial frameworks[71]. Additionally, the proposed approach to cross-chain risk sharing in the industrial carbon capture business models[72], which includes shifting contractual periods in case of a commissioning mismatch and reimbursing qualified costs in case of T&S outage, may form the basis of the approach for GGR policies.

Care must be taken when awarding availability payments to ensure that GGR projects with lower cross-chain risks, such as enhanced weathering or projects with certain CO_2 utilisation routes, are not disadvantaged. These projects may not need or benefit from availability payments so de-risking GGRs with geological storage may result in unfair competition in the long term. Until confidence in CO_2 T&S systems is gained, however, the government is best positioned to assume these risks.

Price Indexing

Although payment schemes and carbon CfDs address the market risk for NE credit prices by providing revenue certainty, GGR projects are left facing several other risks, such as dynamic and sometimes unpredictable fuel/energy prices. If the government wants to de-risk projects further by mitigating these risks, payments to the projects under contract-based mechanisms may be indexed to these prices. For example:

- International biomass market prices – for BECCS companies relying on such markets to source biomass. As economies decarbonise, demand for sustainably sources of biomass is likely to increase, which is a risk for BECCS companies.
- National electricity and/or natural gas prices – for DACCS companies using various energy sources, which are at risk of price volatility.

Price indexing can improve the investability of GGRs substantially, however, energy and biomass price risks have been successfully handled by the private sector for a long time. Furthermore, the government assuming these risks may turn payment schemes or carbon CfDs into risk-free investments, which do not offer a fair distribution of risk sharing between the taxpayers and the private sector. Therefore, careful consideration should be given to determine which technologies or types of input (if any) should receive price indexing support.

Enabling policies

Establishing a flourishing and successful GGR sector in the UK requires significant effort that goes beyond the immediate financial support provided to projects. Table 12 presents seven key enabling policies or actions,

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[70] Cross-chain risk refers to the risk of parts of a CCS chain not being able to perform normally when another component fails to work properly. For example, if the CO_2 T&S infrastructure fails, the upstream capture plants cannot continue operating, unless they can divert the CO_2 for another utilisation route.
[71] Investable commercial frameworks for power BECCS. By Element Energy and Vivid Economics for BEIS (June 2021) [Link]
[72] BEIS update on ICC business models (October 2021) [Link]

which are not components of the shortlisted GGR policies explored in this study but would accelerate development of a GGR industry. The table provides a brief description of each of the policies and their status in the UK. Future development of these policies/actions are recommended to increase the success chances of the shortlisted wider GGR policies.

Table 12: Enabling policies that can aide GGR deployment

Enabling Policy	Description	Current Status in the UK
NE Accounting Standards	Developing, publishing and regularly updating monitoring, reporting and verification (MRV) standards for each GGR technology.	No current MRV standards exist, however BEIS established an MRV taskforce in 2021 to advise the government on best practices to tackle this challenge[73].
R&D Support	Continued funding for R&D of key GGR technology components to enable cost reduction and UK technology export.	Some funding is earmarked for GGRs for pure research and the government is investing £100 million in demonstration of lower TRL engineered GGR technologies[74].
CO_2 Transport & Storage Infrastructure	Taking steps to construct effective CO_2 T&S infrastructures in favourable locations which can suit GGR deployment.	CO_2 T&S regulatory investment business model under development by BEIS[75].
CCUS Industrial Clusters	Forming industrial CCUS clusters and incentivising them to deploy GGRs through using common CO_2 T&S infrastructures and setting net zero/negative targets.	Two clusters are chosen for phase 1 funding through CCUS Infrastructure Fund, and more clusters are in the pipeline[76].
Biomass Sustainability & Environmental Impact	Regulatory frameworks or financial incentives to ensure sustainable biomass sourcing and meeting other environmental criteria (i.e., biodiversity, etc.).	The Environmental Agency has existing regulations and will work with future GGR plants to develop new standards as needed. Minimum biomass sustainability standards can be included in GGR policies or MRV. HMG has committed to publishing a new Biomass Strategy in 2022.
Workforce and Supply Chains	Identifying skills gaps and training local workforces to fill in the demand from GGR technologies. Determining potential supply chain bottlenecks and developing strategies to resolve them.	UK Government launched a taskforce in 2020 to drive the transition towards a net zero workforce[77].
National and Regional GGR Targets	Public announcement of specific long-term NE targets for the UK and specific regions (e.g., Scotland) to increase investor confidence regarding commitment levels.	The Net Zero Strategy[78] sets out an ambition to deploy at least 5 $MtCO_2$/year for 2030 for the UK, while Scotland has a target[79] of 5.7 $MtCO_2$/year for 2032. No longer term commitments are made.

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[73] Monitoring, reporting and verification of GGRs: Task and Finish Group report [Link]
[74] BEIS DAC and other GGR technologies competition [Link]
[75] CCUS: an update on the business model for transport and storage (BEIS, 2022) [Link]
[76] BEIS - Cluster sequencing for CCUS deployment: phase 1 [Link]
[77] Press release: "UK government launches taskforce to support drive for 2 million green jobs by 2030" (BEIS, 2020) [Link]
[78] Net zero strategy: build back greener. BEIS, 2021 [Link]
[79] Scottish Government – climate change plan 2018–2032 – update [Link]

6 Policy applicability to FOAK DACCS

6.1 The potential need for additional support for FOAK DACCS

In order to reach its decarbonisation targets, the UK economy needs a diverse portfolio of GGR technologies. Since the GGR industry is in its infancy and all technologies present unique opportunities, co-benefits, risks, and limitations – supporting all GGR options (even the currently financially less viable ones) is desired.

As discussed in section 2, DACCS technologies have unique challenges, such as exposure to heat and electricity price volatility and lack of a co-product revenue, compared to GGRs using biomass. Furthermore, DACCS technologies are currently at lower TRLs and are deployed at much more smaller capacities than early BECCS plants. Even BECCS applications which are not demonstrated at full commercial scales yet (e.g., BECCS industry and BECCS hydrogen) potentially carry less technology risk than DACCS, because parts of their value chains have been well demonstrated. On the other hand, most DACCS technologies are not part of other processes, therefore carry higher risks for investment.

These challenges are exacerbated for FOAK (first of a kind) plants, which are expected to have the highest technology risks, as well as capital and operational expenses. Due to their unique processes and risk profiles, FOAK DACCS technologies require specific support potentially going beyond the level of support provided by generic GGR policies.

In the context of this study, FOAK refers to the first few large-scale plants that receive government support. Most of the risks mentioned above are expected to reduce significantly even after a single large-scale plant is successfully operated for several years, however, many novel DACCS concepts are still at RD&D stages. Furthermore, other GGR technologies, like engineered capture of CO_2 from seawater, could have very similar value chains and challenges to DACCS. Therefore, even after the first DACCS plant is deployed, dedicated FOAK DACCS support will be needed for a period to enable commercial demonstration of these novel technologies.

Providing additional support for FOAK plants is a common practice BEIS employs for supporting early stage decarbonisation technologies. As presented in section 3.1, BEIS is currently developing commercial frameworks for FOAK BECCS power technologies and some of the other business models it is currently finalising (e.g., the industrial carbon capture business model) have provisions for offering limited capital grants to early applicants if needed. Designing additional support for FOAK DACCS would therefore be consistent with this approach.

In this report, the additional support for FOAK is defined as an investible framework that goes beyond a generic GGR policy to address unique challenges of a DACCS or similar technology. Figure 16 below illustrates the three building blocks used to create this:

- First, a NE market is enabled or created for the projects to sell its credits into. This may be the voluntary or a regulated market in early years, potentially transitioning to become the UK ETS.
- Second, ongoing operational support is provided to top-up revenues from NE markets. This support would be in the form of the two contracted policy mechanisms shortlisted in this report, with some minor modifications to better accommodate FOAK DACCS technologies.
- Third, additional capital cost support could be provided, as needed, to close any investment gaps, crowd in private investment, and reduce financing costs.

The rest of this section discusses the second and third building blocks in greater detail and explores how an investible case for FOAK DACCS may be set up.

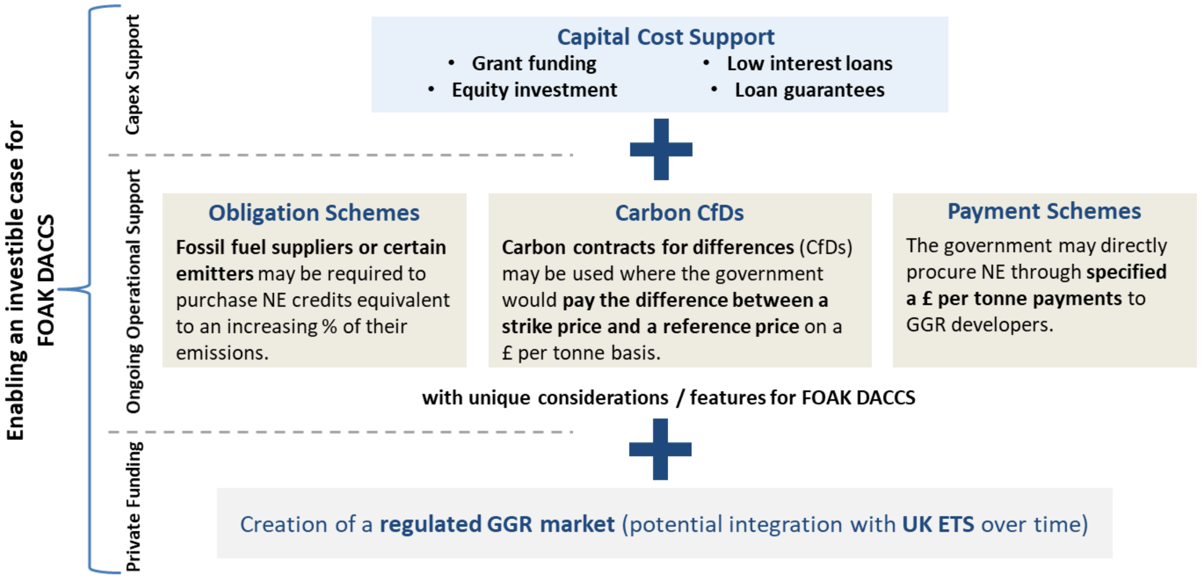

Figure 16: Schematic representation of key building blocks to enable an investible case for FOAK DACCS

6.2 How the additional support could fit within the policy mechanisms

Within the category of engineered GGRs there is a diverse range of solutions, with very different degrees of market readiness, cost profiles, and abilities to generate revenues. Over time, some of these differences may reduce in significance. For example, the cost of carbon capture by DACCS may fall appreciably to levels similar to that of BECCS, as the sector matures. However, **as DACCS produces no co-products, some of the revenue generating opportunities that help to make BECCS viable are not open to DACCS developers.** This is illustrated in Figure 17 below, where the cost of DACCS is currently significantly higher than that of BECCS, and the potential for revenues is considerably lower for DACCS on account of the lack of co-products to sell.

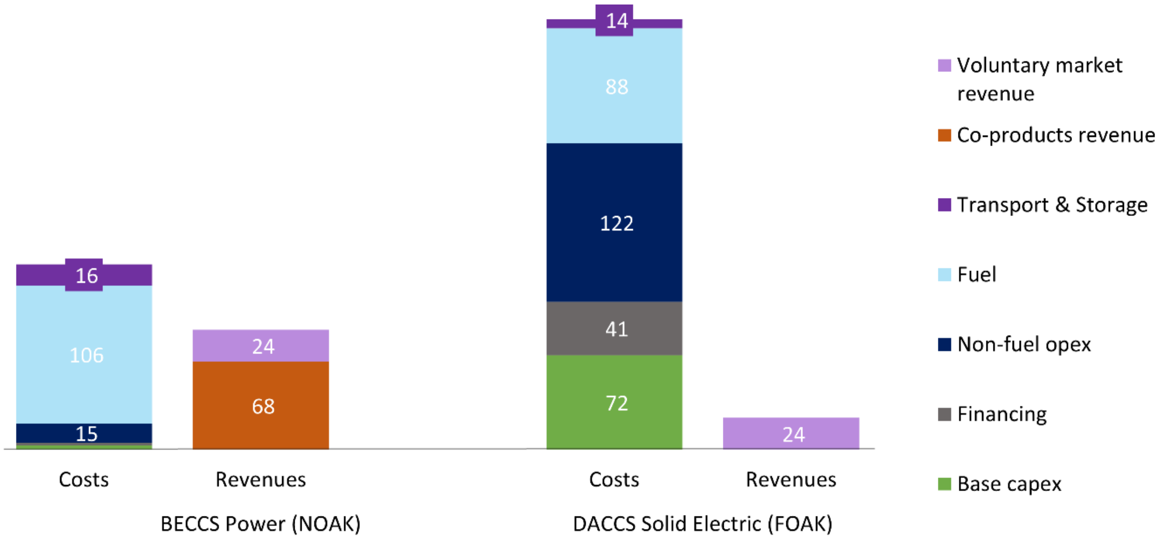

Figure 17: Illustrative comparison between BECCS and DACCS (£/tCO$_2$)

The three policy mechanisms discussed in detail in chapter 5 are designed to provide a general supportive framework for engineered GGR technologies. Throughout that chapter, consideration was given to how this framework can provide the required support to all GGR technologies despite the different technology cost profiles that exist. This section gives more specific consideration to peculiarities of DACCS technologies and how their fundamentally different nature may warrant additional support through supplementary policy support and/or changes to policy design.

By design, **contract-based mechanisms allow for adaptive levels of support** within a common GGR framework. This means that **the contractually agreed (top-up) payment will always be set at a level sufficient to meet the strike price or cover the marginal cost**. This is not the case for a general GGR obligation scheme, as the market price that supports cheaper GGR technologies will not necessarily cover the cost of producing NE credits by currently more expensive means such as DACCS. The next section reviews how the creation of a sub-obligation scheme could provide additional support to DACCS development. A section reviewing the use of CfD scheme to supplement an obligation scheme follows. Finally, the modification of design features of contract-based mechanisms to support DACCS is discussed.

6.2.1 Creating sub-obligations within an overall GGR obligation scheme

A single GGR obligation market sets a single NE credit price, regardless of technology cost. This **does not allow for targeted interventions to support a range of technologies – all technologies receive the same unit revenue regardless of their unit cost**. This means, for example, that a NE credit produced by a DACCS plant will achieve the same price as an NE credit that is produced far more cheaply by a BECCS plant. It also means that cheaper forms of non-engineered GGRs may benefit greatly from a NE credit price that is higher than their costs.

Sub-obligation schemes provide a way to **establish more than one NE credit price by obligating emitters to procure a specific share of the NE credits from a specific source**. For example, an emitter may be required to buy half of their total NE credit obligation from DACCS sources. **This would increase the costs of compliance for emitters and would establish a separate market price for DACCS NE credits.** Where this price would sit relative to the general NE credits price would depend on the relative supply and demand of DACCS NE credits, with a higher price leading to higher revenues as illustrated in Figure 18.[80]

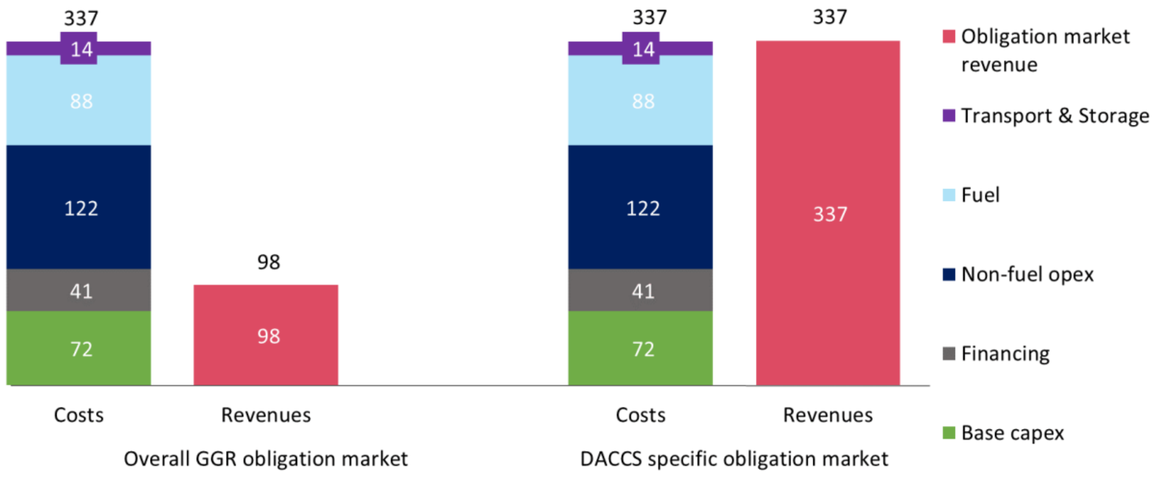

Figure 18: A sub-obligation scheme for DACCS (£/tCO$_2$)

However, creating a sub-obligation scheme may considerably increase complexity. Where sub-obligations exist, separate NE targets, obligations, and buyout prices would be required for each market. This complexity would increase with any attempt to provide specific NE credit price support to a technology with a different cost profile. For example, establishing an obligation market for GGRs generally with a single sub-obligation market for DACCS may provide sufficient support to the cheapest DACCS technology but this would not be sufficient to support the remaining DACCS technologies. An additional sub-obligation market would need to be created for each DACCS technology that government wished to support. This would become even more complex over time, as adding new sub-obligations for new technologies would have knock-on effects on the size of the

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[80] For details on assumptions used in creation of charts in this chapter, see the appendix section 8.5.

already existing sub-obligation markets and their market prices. A proliferation of markets would also reduce liquidity and increase volatility, meaning that while on average a technology could achieve the required price to cover their costs, they may face periods of boom and bust. There is therefore a limit to how many sub-obligations could be practically implemented.

Despite this increase in complexity, the obligation scheme would face many of the same shortcomings discussed in chapter 5. This reinforces the finding that an obligation scheme has merit over the long run, for a well-established market, but that implemented alone it is not suitable to promote the development of a portfolio of GGR technologies.

6.2.2 Using a CfD to top-up obligation scheme revenue

As an overall GGR obligation scheme establishes a market for NE credits but does not provide any direct revenue support, there is no transfer of risk. This means that **while the scheme will create demand for NE credits and set a market price for them, it will not guarantee sufficient revenue for DACCS developers**. Not only would this make it more difficult, if not impossible for DACCS developers to attract investment, it would also leave successful developers particularly exposed to changes in costs and revenues, even if the market price for NE credits is relatively high. There are several factors that could cause shocks to costs or revenues.

- The opening of a new GGR plant would increase the supply of NE credits and, all else equal, cause the market price for NE credits to fall.
- A technological breakthrough in a hard-to-abate sector would cause demand for NE credits to fall, driving the market price down.
- Transport and storage costs represent another risk to plants operating under an obligation scheme. Transport and storage provision is a particular consideration for DACCS plants, where utilisation of captured carbon is considered, such as in industrial processes. Providers can try to pass changes in transport and storage costs through to emitters as part of the market price for NE credits, but this will depend on a range of factors within the market and still leaves the developer exposed.
- The failure of a transport and storage network would be a major shock to those GGR plants affected, who would face greater transport and storage costs if seeking temporary alternatives or a loss in revenue if no alternative can be found.

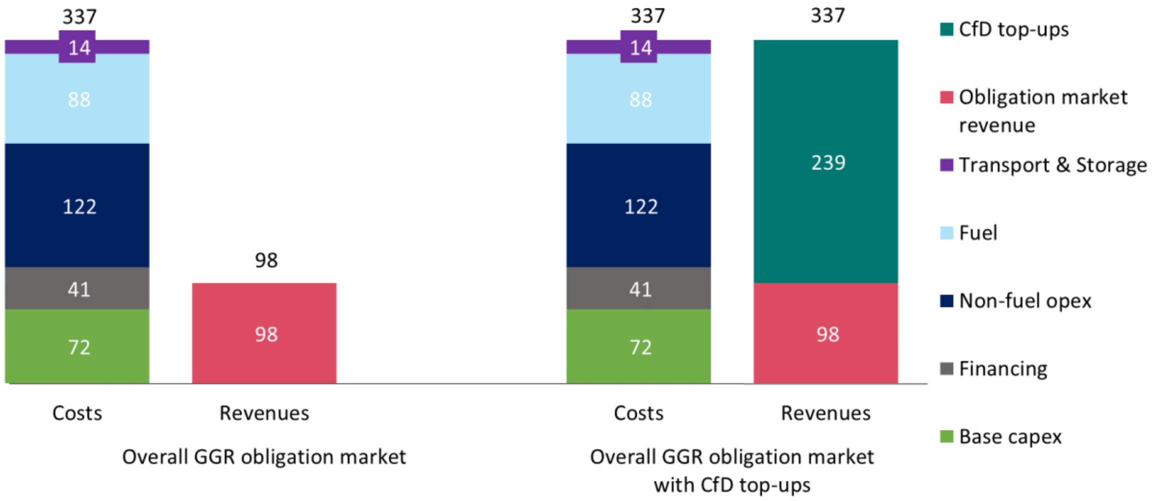

Figure 19: FOAK DACCS plant with different obligation schemes (£/tCO_2)

Combining an obligation market with a CfD scheme could help DACCS developers to overcome volatility, cover costs, and achieve revenue certainty while also creating a clear market price for NE credits. Under such a combined scheme **NE credits are traded within the wider GGR obligation market and a CfD pays the difference between the strike price and the obligation market price**. This would ensure that only the required support is provided by the taxpayer, with polluters covering part of the cost through the purchase of NE credits.

Using a CfD scheme to top-up any revenue shortfalls under an obligation scheme solves some of the underlying issues but adds complexity to the design. The time required to implement an obligation scheme, given the challenges outlined in chapter 5, and then to implement a supplementary CfD scheme could delay and limit the required level of development and deployment. However, it is worth **noting this bears significant similarity to the CfD mechanisms integrated with the obligated market at a later stage, being a reversal of whether the CfD or the obligation is put into place first.**

6.2.3 Contract-based mechanisms and DACCS technologies

By their nature contact-based mechanisms can provide an adaptive level of support to DACCS developers. In the case of a CfD, the strike price would be sufficiently high to account for the greater costs associated with producing NEs through DACCS. Alternatively, under a payment scheme the size of the payment would increase to meet the cost of producing a NE credit. However, there are other ways in which these contracts can be modified to support the specific differences of a DACCS project, where the technology readiness level and revenues are lower, and costs and uncertainty are higher. **Two examples of modifications are explored below: (i) modifications to contract length, and (ii) treatment of Capex.**

As discussed in section 5.5.3, there may be a benefit to maintaining flexibility over contract lengths by letting developers make indicative bids, specifying the contract length that they believe is required to make a project viable. Possible contract lengths should be within a range stipulated by the counterparty. In the case of DACCS specifically, there may be a benefit to shorter contracts than in the case of more established technologies. **Shorter contracts may lead to more efficient use of taxpayers' money by allowing funds to be redeployed more readily.** If, as is expected DACCS costs fall substantially over the coming years, this would protect against the risk of over-subsidisation. **However, there is a trade-off, as shorter contracts would increase developer risk and increase the cost of finance.** Making contracts too short could make projects inviable. The central point here is to maintain flexibility in scheme design.

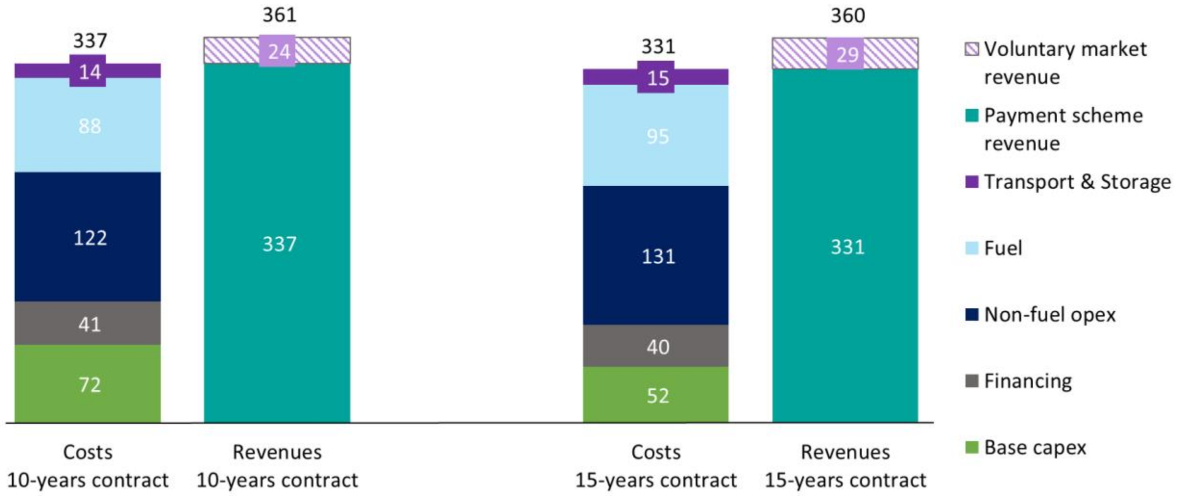

Figure 20: FOAK DACCS plant with different contract lengths (£/tCO_2)

Another possible modification that may make sense in certain situations and given the different nature of DACCS projects is to allow for support for Capex to be frontloaded within a contract.[68] **For example, the contract could be designed so that all Capex costs are paid off within the first five years, after which time a review takes place and the level of support is reduced to cover Opex only.** In the case of a payment scheme, this would mean a reduction of the payment received by the developer, while in the case of a CfD scheme the strike price would be reduced, resulting in a reduction in the top-up payments received by the developer. This may also leave open the possibility of retiring inviable technologies, after providing adequate compensation, and reallocating the unspent funds to support new projects. This flexibility reflects the deep uncertainty around some of these technologies while also being cognisant of the exposure of developers and their investors. Frontloading Capex support may have the added benefit of lowering the overall cost of finance by reducing risk.

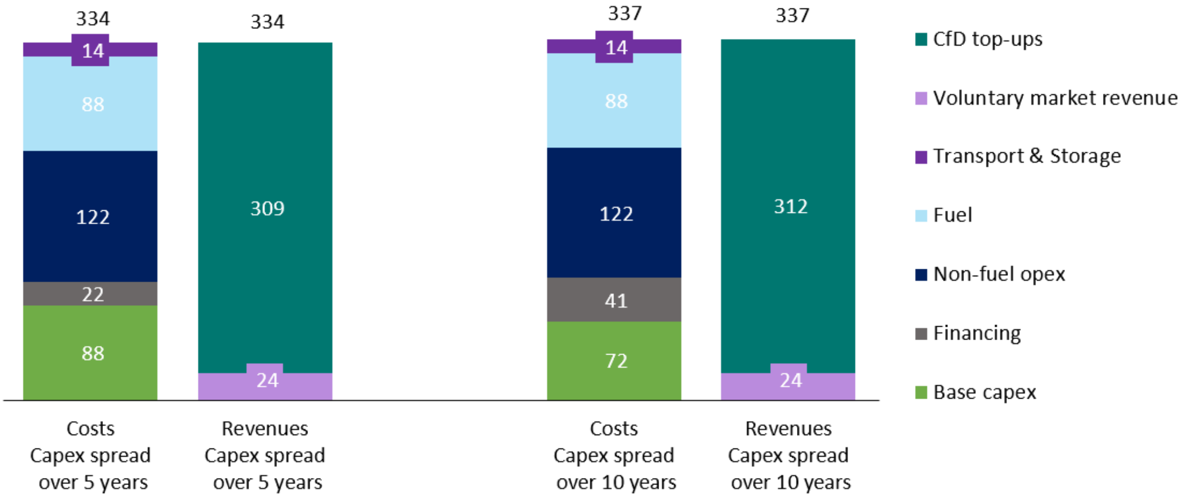

Figure 21: Illustrative FOAK DACCS plant with and without frontloading Capex (£/tCO_2)

Beyond these modifications, it may be necessary to treat DACCS projects differently to other GGR projects in terms of the mechanism for allocating funding. More developed GGR technologies may be able to advance to a system where they compete within technology pots via reverse auction much more quickly than DACCS plants. **Allowing the flexibility to deal with DACCS plants bilaterally into the future may be required to ensure learning by both parties but also to account for greater levels of uncertainty.** One solution to this might be that once a system of technology pots and auctions is implemented, if DACCS plants are unable to secure funding through those processes they can engage bilaterally to explore possible opportunities for support.

6.3 Uncertainty, maturity, and the sensitivity of DACCS projects to changes in costs

Given the considerable uncertainty surrounding the costs of DACCS projects and the transfer of risk from developers to government resulting from a contract-based policy mechanism, it is important to consider how costs might evolve over time and the effect that this may have on the amount of government support required. This section considers three scenarios in turn: (i) the transition of DACCS technologies from FOAK to NOAK, (ii) changes in energy prices, and (iii) increases in operating efficiency. The first scenario involves changes to a range of variables while scenarios ii and iii are considered based on all else being equal, i.e. energy price volatility is considered separately to an increase in energy efficiency.

6.3.1 From first of a kind to market maturity

As the technology transitions from FOAK to NOAK, **it is anticipated that costs will fall**, driven by several factors including process efficiency, cost of inputs, and alternative energy sources. Meanwhile, it is expected that **market revenues will increase with the market price for NE credits**. With these changes the amount of **support required from government for NOAK plants will fall considerably**, as shown below, where the CfD top-up falls by 48%. This may strengthen the case for awarding the shortest viable contracts, with suitable review mechanisms as described in the CfD design features section. In doing so, government reduces the risk of over-subsidisation and frees up funding for reallocation to other projects.

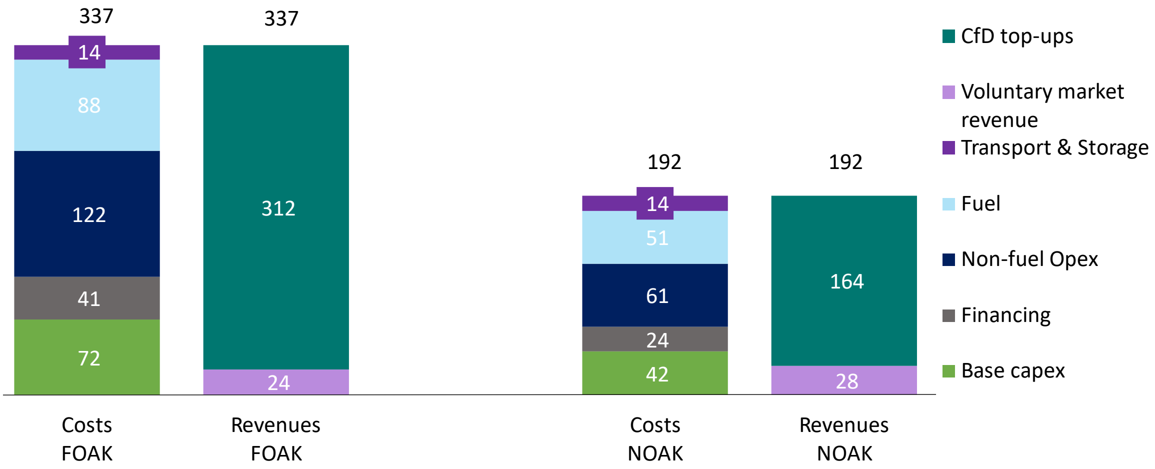

Figure 22: Lower costs after the transition from FOAK to NOAK (£/tCO$_2$)

6.3.2 Energy price volatility

Given the significant share of DACCS costs attributable to energy, changes in energy prices can have very sizeable effects on the cost of producing an NE credit by DACCS. The figure below shows the effect of electricity prices rising from the IEA's low forecast, through to their central forecast and ultimately to their high forecast. It cannot be assumed that these prices could be entirely passed on in the market price for NE credits as energy costs make up varying shares across GGR technologies. Those technologies with lower energy costs would be able to produce NE credits more cheaply than those with higher energy costs, all else being equal. In such a scenario some plants could be forced to shut down operations if additional government support is not available. One way to reduce this risk is to link the contractual strike price to an index, as discussed in the section on complementary policies.

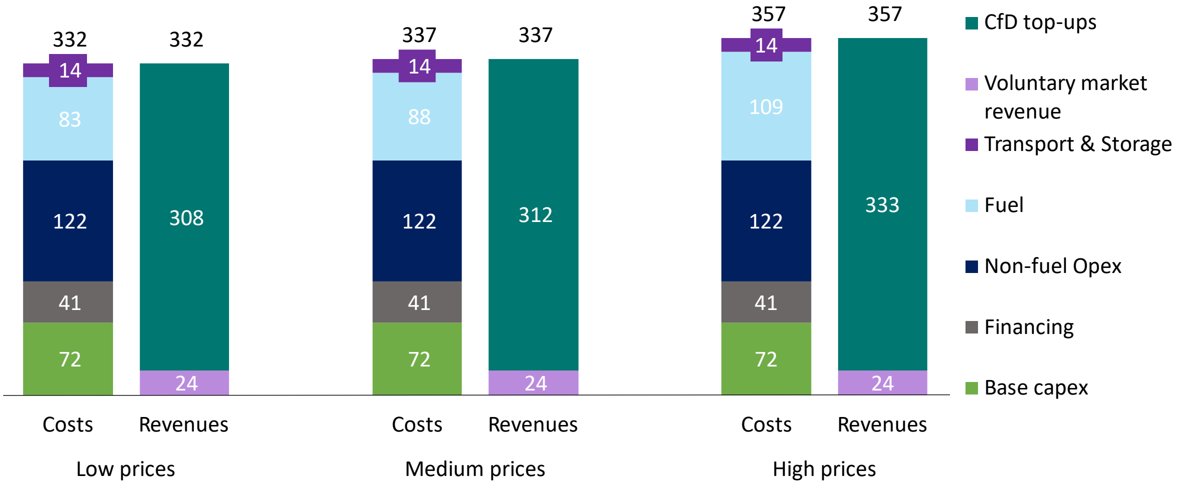

Figure 23: Sensitivity to energy price volatility (£/tCO$_2$)

6.3.3 Increases in efficiency lowering Opex

Over time, a plant may achieve a reduction in Opex through greater efficiency, a fall in input costs, etc. Where government support is provided, and such reductions are achieved, there could be some form of pain/gain sharing written into contractual agreements. **In the example shown below a 20% fall in Opex would result in the top-up needed from government falling by 5%.** However, **in order to incentivise efficiency, there is value in allowing the developer to retain some of the savings through, for example, a bonus system.** Conversely, there may be an argument for pain-sharing, where Opex sees an unexpected increase, but this could have unintended consequences and is probably best resolved through index-linking the contractual strike price.

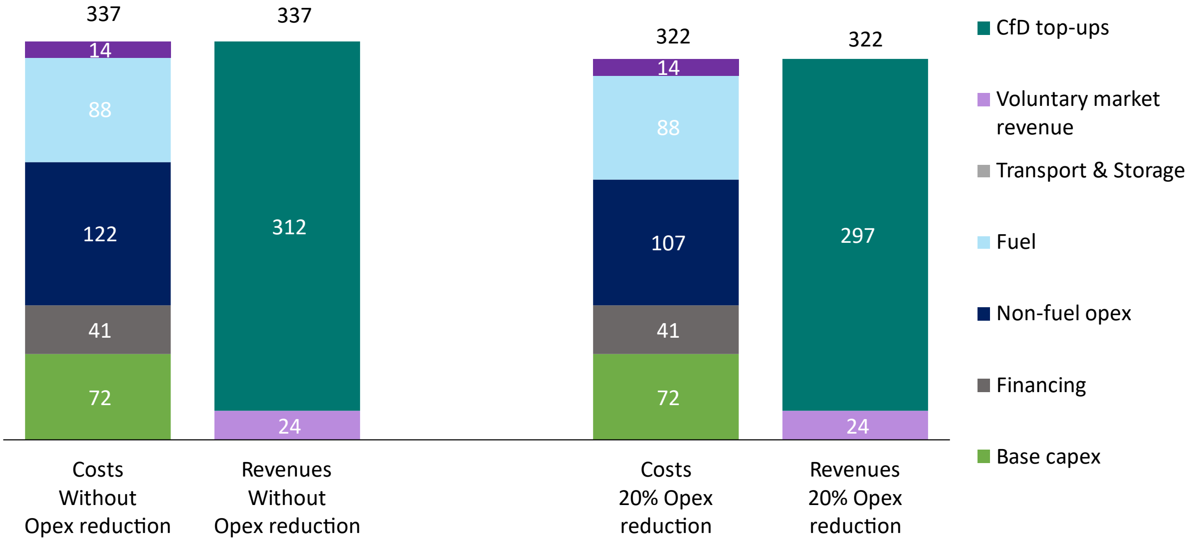

Figure 24: Effects of an increase in operating efficiency (£/tCO$_2$)

The degree of uncertainty with respect to costs and revenues is substantial, and the examples above should not be confused with forecasts. Instead, they serve as an aid to consider the consequences of various scenarios for the policy design. As the market develops, learning occurs for both parties, and uncertainty falls, the scenarios could be tuned to reflect the new information and the policy design tweaked accordingly.

6.4 Capital Support Options

This section describes the four additional capital support options, which were briefly mentioned under complementary policies in section 5.10, in greater detail and discusses their advantages and disadvantages in supporting FOAK DACCS.

Grant funding

The government may offer grants covering a portion of the upfront capital costs of the GGR projects. This would increase investor confidence and reduce the total funding needed, helping reach the final investment decision faster. Figure 25 illustrates the impact of capital grants, where providing 25% and 50% Capex support leads to 9% and 18% fall in CfD top-ups paid by the government, respectively.

Grants must follow the new Subsidy Control Regime[81] which replaces the old EU State Aid Rules. The maximum level of support or conditions for support will have to be determined/set in the future.

The disadvantage of a grant scheme is the direct burden on the taxpayer and the requirement for the government to allocate cash in a short span of time. The advantage is a straightforward method to close the funding gap.

If grant funding is provided for FOAK DACCS plants, we suggest having a "last spend" approach to cover expenses only after the project raises as much capital from the private sector as possible. This mirrors the approach to offering capital support in the ICC business models.

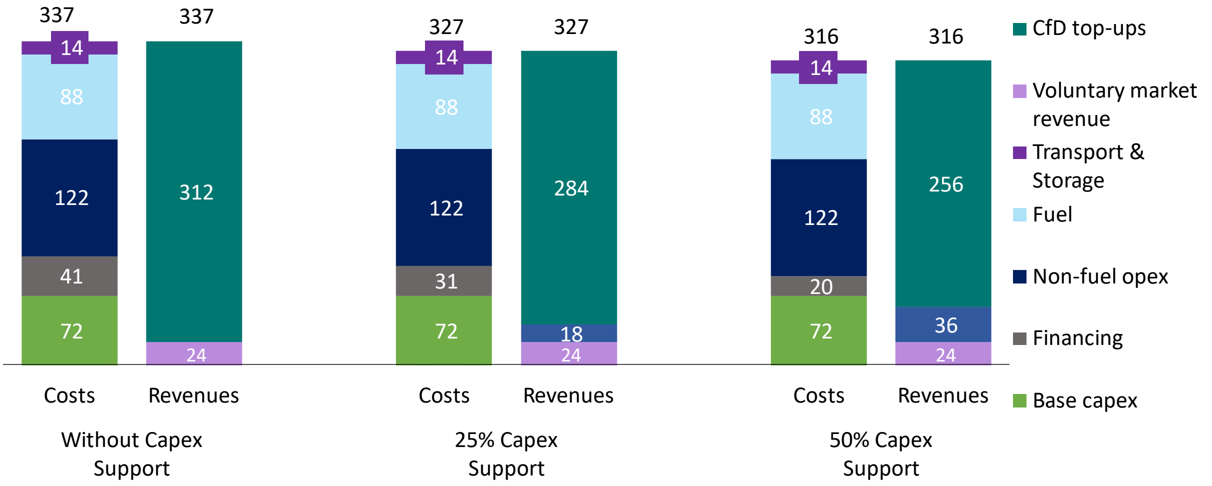

Figure 25: Changes in costs and revenues of a FOAK DACCS plant under different levels of capital grants (£/tCO_2)

Equity investment

An alternative to awarding grants is direct equity investment in FOAK DACCS projects by government backed institutions, such as the UK Infrastructure Bank (UKIB). An equity investment would be similar to a grant in the sense that the project would receive cash upfront to complete the project. However, once the project starts profiting, payments to shareholders (including the government) may be made. The taxpayer may recover all of their costs and may even profit off the success of the company.

Equity investment may help projects through closing the funding gap and crowding in private finance. In exchange, it will reduce the net present value for the developers by forfeiting some portion of ownership.

However, equity investment is a high-risk high reward approach which may lead to significant loses if the project fails, therefore it may not be the most optimum approach for FOAK DACCS projects unless revenue

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[81] BEIS presentation on the Subsidy Control Regime [Link]

certainty risks are sufficiently addressed. Furthermore, the total funding available through equity funding is likely to be limited.

Low interest loans

Debt financing, along with equity finance, is one of the main methods for project finance. Normally, the interest rate the project needs to pay back represent the risk of the project and financial institutions may not offer loans if they perceive the project to be too risky. However, the government, through a publicly owned bank, may directly provide low interest loans, recognising the importance of FOAK DACCS plants.

Compared to grants or equity investment, low interest loans reduce the risk to taxpayers significantly since the bank is able to recover underlying assets in the event of bankruptcy.

A limitation of debt financing is the total available funds a bank may be willing or able to invest into a single asset class and their requirement to still seek profits, which limits how low interest rates may go.

Loan guarantees

Rather than directly awarding low interest loans, the government may provide loan guarantees to projects, which allow them to access low interest loans from the private financial sector.

The task of running the UK Guarantees Scheme was recently given to the UKIB. Under this flexible scheme UKIB would agree to pay back all capital and interest a DACCS company owes to private investors. The DACCS company is then able to benefit from the UK Government's high credit rating to access low interest loans or issue bonds.

The advantage of the guarantee scheme is inclusion of the private financial sector in the DACCS sector to a greater extent and increasing total funding available through accessing a bigger pool. A disadvantage may be lack of control of final interest rates and potentially a smaller overall benefit to individual projects.

Loan guarantees or directly providing low interest loans benefits projects by reducing cost of finance, which in turn benefits the government by reducing financial support needed by plants. This is illustrated in Figure 26 below where a 2 percentage point (pp) and 4pp fall in interest rates bring down the government's CfD top-up payments by 3% and 7%, respectively.

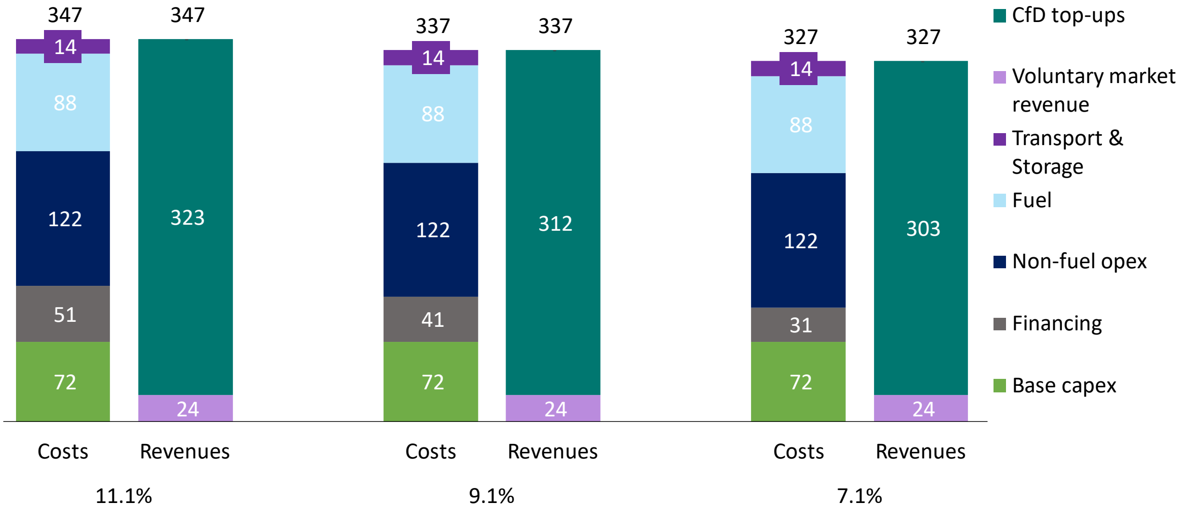

Figure 26: Changes in costs and revenues of a FOAK DACCS plant under different interest rates (£/tCO_2)

In general, all four capital support options explored above may be viable in supporting FOAK DACCS projects. The stakeholders engaged throughout the project did not state a strong preference for a specific support mechanism, although additional capital support was highlighted as a very useful component in creating investable environments for FOAK plants.

Nonetheless, discussions with the technology developers and the financial sector revealed a slight preference for loan guarantees over more direct government funding options, because this would establish an early relationship between the DACCS projects and the private finance industry. It would also transfer learnings and knowledge from technology developers to the financial sector, making them more comfortable with these emerging technologies for financing further project development beyond FOAK.

7 Conclusions

7.1 Key findings of the study

- The **GGRs that could be supported by a new GGR policy mechanism vary widely** in terms of potential scale, cost, and other considerations. Combined with the variable policy support already available in some of the sectors where GGR options sit (some of which are tentatively looking at rewarding GGRs), this creates a very varied landscape over which the overarching policy mechanism should sit. Overall, shortlisted policy mechanisms explored through this study were mostly considered by stakeholders to be potentially viable, with early clarity on what support will be available important in the near term.
- A **contracted mechanism is likely the most appropriate for incentivising the development of a portfolio of GGRs in the short-medium term**. For FOAK projects, bilateral negotiations may be the most appropriate way to agree terms where the number of projects is low. Once feasible, this should progress to reverse auctions across separate pots for projects/technologies, depending on their circumstances. In the long term, this can evolve into a market-based option, fitting with the principles of equal reward for each unit of negative emissions and value for money.
- A **carbon CfD for rewarding negative emissions has some advantages over a payment mechanism**, partially due to its explicit inclusion of market revenues and more clear evolution (as the reference price evolves and changes). The UK low carbon space is familiar with the concept of CfDs, mitigating potential additional complexities. Initially the reference price should likely be linked to the voluntary market (ideally more regulated than the current voluntary market). This should transition to either the UK ETS price or the price of a separate obligated market once issues surrounding the early integration of GGRs into the UK ETS or around the set up of a new obligation can be addressed.
- **DACCS technologies have unique challenges,** such as exposure to heat and electricity price volatility and lack of a co-product revenue, compared to GGRs using biomass. Furthermore, DACCS technologies are currently at lower development levels and FOAK plants could be deployed at smaller capacities than early BECCS plants.
- **FOAK DACCS can be supported within the policy mechanism proposed for GGRs**, as the mechanism has to be flexible in the level of reward granted to the different GGR technologies (given the varied level of support needed for different GGRs in the short-medium term). FOAK DACCS would potentially benefit from some capital support as well, bridging the gap from innovation grants to NOAK, however this is not viewed as essential and is secondary to a bankable revenue stream. As the general GGR policy mechanism needs to be flexible in the level of support which can be provided, this approach could be replicated for other innovative FOAK GGRs and fits well with potential commercial frameworks suggested for FOAK BECCS power deployment.

7.2 Potential policy design

As has been stressed throughout the report, there is great uncertainty surrounding costs, revenues, and market preparedness of the various GGR technologies. The range of technologies and existing support schemes, combined with a desire to satisfy the key design principles adds further complexity to policy design, where the preferred outcome is a single over-arching policy framework applicable to all GGRs. It is the consideration of all of these factors that led to discounting an obligation scheme in the short-medium terms. The analysis finds that an obligation scheme has many merits, and it could be an appropriate policy response in the long run. The success of such an obligation scheme will be greatly influenced by the choice and design of policy framework implemented in the intervening years.

This analysis finds that a contract-based mechanism is best suited to creating the conditions for transitioning to a successful market-based solution in the long run. Based on the considerations discussed in chapters 5 and 6, this section presents outlines of potential designs for CfD and payment schemes in Table 13 and Table 14, respectively. These are not meant to be prescriptive, but rather devices to stimulate discussion and design refinement as new information becomes available. For this reason, a central recommendation of this report is to ensure that the policy design contains enough flexibility to adapt to what will likely be a rapidly changing landscape over the next decade. As an illustration of how such flexibility can be maintained, we outline potential designs for the short term and medium term respectively.

Table 13: Potential design principle for a **carbon CfD** mechanism

Design feature	Initial policy design – Short Term	Evolved policy design – Medium term
Contract length	Determined by indicative bids – may vary by technology.	Informed by outcomes of initial round, tied to technology pots.
Review mechanism	Strictly bounded review after 1 year of operation. For example, allowing the strike price to be reviewed downwards (upwards) if costs are lower (higher) than expected but only under strict conditions and not beyond an agreed price floor. Potential for an additional review after 5 years if there is significant uncertainty in the cost profile.	Strictly bounded review after 1 year. For example, allowing the strike price to be reviewed downwards (upwards) if costs are lower (higher) than expected but only under strict conditions and not beyond an agreed price floor.
Opex explicitly covered	Fuel/energy, T&S, where these are not covered by other incentives available.	
Funding mechanism for top up	Taxpayer	Sector dependent levy on emitters/fuel producers/consumers (if integration into Obligation or UK ETS does not happen) or continued taxpayer funding.
Allocation of funding	Bilateral negotiation if number of projects is low, with use of technology pots and reverse auctions once feasible.	Technology pots reflecting the cost profiles of the various technologies.
Strike price	Set by examination of cost and revenue projections on a one-by-one basis, due to uncertainty, need for learning, and small number of projects. Requires transparency.	Set by reverse auction aligned to technology pots.

Reference price	Regulated voluntary carbon market price or achieved sale price (with some pain gain sharing for higher prices achieved).	Obligation or UK ETS market price.
Capex treatment	There may be value in frontloading Capex support for some projects[68]. The extent to which such a contract makes sense depends on the Capex/Opex profile of each technology, which should be explored within the initial introduction of the scheme.	Depends on success of this in initial trial. Subsequent contracts for the same plant would not have any Capex costs and so would need to be treated differently.

Table 14: Potential design principle for a **payment scheme**

Design feature	Initial policy design – Short term	Evolved policy design – Medium term
Contract length	Determined by indicative bids – may vary by technology.	Informed by outcomes of initial round, tied to technology pots.
Review mechanism	Strictly bounded review after 1 year of operation. For example, allowing the strike price to be reviewed downwards (upwards) if costs are lower (higher) than expected but only under strict conditions and not beyond an agreed price floor. Potential for an additional review after 5 years if there is significant uncertainty in the cost profile.	Strictly bounded review after 1 year. For example, allowing the strike price to be reviewed downwards (upwards) if costs are lower (higher) than expected but only under strict conditions and not beyond an agreed price floor.
Opex explicitly covered	Fuel/energy, T&S, where these are not covered by other incentives available.	
Funding mechanism	Taxpayer	Taxpayer or partially funded through a levy on emitters/fuel producers/consumers (sector dependent).
Allocation of funding	Bilateral negotiation if number of projects is low, with use of technology pots and reverse auctions once feasible.	Technology pots reflecting the cost profiles of the various technologies.
Sale of NE credits	Permitted, with a percentage of revenues being passed back to the taxpayer.	Permitted with a percentage of revenues being passed back to the taxpayer.
Capex treatment	There may be value in frontloading Capex support for some projects[68]. The extent to which such a contract makes sense depends on the Capex/Opex profile of each technology, which should be explored within the initial introduction of the scheme.	Depends on success of this in initial trial. Subsequent contracts for the same plant would not have any Capex costs and so would need to be treated differently.

8 Appendix

8.1 Acknowledgements

We would also like to convey our thanks to the following stakeholders for valuable input to this work. While their input has in some places been reflected in the study, the information expressed in the report **does not** represent the positions of either these individuals or these organisations.

External Stakeholders

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Advanced Biofuels Ltd	Andrew Cornell
Energy Systems Catapult	Danial Sturge
Cambridge Carbon Capture	Michael Evans
Green Finance Institute	Suzanna Hinson Rhian-Mari Thomas
Carbon Removal Centre	Patricia Silva
Clean Air Task Force	Larissa Lee Beck
Climate Principles	Eve Tamme
Climeworks	Christoph Beuttler
The Lapwing Estate	James Brown
Future Biogas	Helen Wyman
Drax	Richard Bass Angela Hepworth Karl Smyth
L&G Capital	John Bromley
Leeds University	Anne Owen

London School of Economics	Josh Burke Esin Serin
Low Carbon Contracts Company	Tahir Majid
Mission Zero Technologies	Shiladitya Ghosh Nicholas Chadwick
Origen Power	Tim Kruger
Ricardo	Josh Dalby
Sizewell C	Fred Chung
Société Générale	Allan Baker
Storegga	Nicola Cocks Sanjay Parekh Raphael Pfaeltzer Ian Phillips
SUEZ	Stuart Hayward-Higham
University of Edinburgh/CCC	Vivian Scott
University of Exeter	Paul Halloran
University of Oxford	Steve Smith

Cross-Whitehall Steering Group:

BEIS	Sam Armstrong James Bishop Hee Ah Cho Tasnim Choudhury Julia Christodoulides Joshua Frame Matt Eden Robbie Duggleby Nina Gill Alicja Hermann John Hunter Helen Martin	Dennis Morgan Scott Mcdade Theresa Redding Georgie Roberjot Emma Robinson Jay Shah Joanna Warner Chris Williams Carly Whittaker Robert Yarlett
Environment Agency	Thomas Glyn-Jones Caitlin Burns	
DEFRA	Andreas Arvanitakis	
DfT	Darryl Abelscroft Giorgio Parolini Ben Baxter	
HMT	Helen Finney Jack Duffy Tim Leunig Tom Smiles	

8.2 Description, strengths, weaknesses, and examples of GGR policies

Integration with UK ETS

Description

- Under this policy option, the government would need to adapt the UK ETS framework to allow for GGRs to generate **NE credits which could be sold on the existing UK ETS**.
- Any such adjustment would likely need to be supported by **robust monitoring, reporting, and verification systems** for the quantities of NEs achieved.
- While NE credits from both engineered and land-based GGRs have the potential to be monitored, reported, and verified, **the relative ease with which NE credits from BECCS or DACCS technologies can be verified** could support their earlier market integration. This is further supported by existing provisions for leakage from CO_2 storage locations.
- Under a competitive ETS scheme emitters would naturally buy the cheapest credits meaning that **without any additional support, few GGR projects can be funded**. For engineered GGRs, these may include BECCS EfW, BECCS biomethane and other projects with business model support (e.g., ICC). Therefore, the ability of UK ETS to support a GGR market by itself is very limited at current prices.
- **GGR technologies may be given multiple credits** to make them competitive. For example, 1 tCO_2e of removal would receive 2 tCO_2e of credits. However, this would break the direct 1:1 relationship between credits and emissions, with implications on total emissions allowed in the system.
- A flexible emissions cap may be implemented where the **cap is reduced by the amount of NE credits generated** in the market, ensuring that CO_2 reduction proceeds according to the original schedule.
- **BECCS credits may be more easily introduced to the system** by changing the accounting framework and treating biogenic emissions as net positive emissions. Biomass plants may then be registered to the ETS and receive free allowances equal to their current emissions. Any plant installing BECCS would then be able to sell their unused credits in the system. These additional allowances may be supplemented by the reserves.

Strengths	Weaknesses	Application and Examples
• Market-based mechanism which incentivises GGR cost efficiencies by inducing competition between GGR developers. • Promotes fair cost distribution by placing the burden of costs on emitters. • Potentially an ideal mechanism to support mature sectors and enable several other policies, like CfDs, by establishing a market price.	• Uncertainty on the impact of NE credits in the UK ETS, potentially leading to price volatility and market disruptions which may lead to lack of confidence from project developers and investors. • Unlikely to be able to support FOAK GGR projects or at least be unable to provide the level of revenue certainty required by more expensive engineered GGRs at current prices. • Potential to lead to mitigation deterrence or difficulty including all hard to abate sectors which may need offsetting in the UK. • Introducing new parties to the ETS may be difficult so not all the big/hard-to-abate emitters may be required to buy negative emissions credits through this mechanism.	• **Mature projects** – A market-based policy would be more likely geared towards mature projects given the likelihood of integration in 2030s. Early technologies are likely to require additional support. • **Examples** – There are no current examples of NE credit trading in existing carbon pricing schemes. However, the EU is similarly considering the role of NE trading in the EU ETS.

Obligations within a new carbon removals market

Description
• Government enforced obligations to purchase carbon removal credits within a compliance market which would require certain parties to offset their emissions (or face penalties). Examples of obligated parties include: ○ **upstream fossil fuel producers** to dispose of a fixed percentage of the CO_2 contained within their fuel sales ○ **large emitters** from other sectors (e.g., cement, aviation, maritime) • GGR obligations will **create a new market-based negative emissions price** (£/tCO_2 abated) separate from the UK ETS which would be driven by supply and demand from GGRs and emitters, respectively. • The quantity of credits could **target specific allocations** of negative emissions which could be aligned with UK carbon budgets. • **Initial entrants selling credits are likely to be engineered removals** (e.g., BECCS, DACCS) which have reliable MRV methods for the amount of CO_2 removed. Over time, the market liquidity could increase with the inclusion of other GGR options or through the expansion of engineered GGRs which become more cost competitive. • **An obligation scheme may be implemented within the UK ETS** where GGR technologies would be given tradable credits and emitters obligated to source a minimum portion of their allowances from NE credits (or specific GGR technologies). This would increase compliance costs. Different sectors under ETS may be given different obligations but introducing new sectors to the scheme would be difficult. • A **Carbon Takeback Obligation (CTBO)** is a specific form of obligation scheme where fossil fuel producers/importers are expected to secure carbon storage credits equivalent to a portion of emissions they cause. CTBO is a blanket mechanism incentivising CCUS in general and does not treat GGRs any differently. **Under a CTBO, DACCS and BECCS may be viable if credit prices increase sufficiently in the future**. Such a mechanism would not be viable for nature based GGRs which do not store CO_2 geologically or in mineral form.

Strengths	Weaknesses	Application and Examples
• Follows the polluter pays principle since costs are borne by the chosen emitters. • Is revenue-neutral for the government. • Incentivises competition between GGR projects, increasing long term value for money. • Applicable to mature markets and can support other policies by establishing a market price for NE. • Has a good chance to result in required levels of GGR volumes.	• Private sector would bear significant risk due to the uncertainty over the stability of the price of obligations credits over time. • High administrative barrier to setup a new compliance market. • Unfamiliarity of a new market may reduce confidence from investors and developers leading to delays in GGR deployment, especially for FOAK projects. • Obligated parties may object to being obliged to purchase GGR in the UK as opposed to in the cheapest locations globally.	• **Mature projects** – While such a market could be developed for FOAK projects, there is unlikely to be sufficient market liquidity until a more mature and competitive GGR sector has developed. • **Examples** – No governments have developed compliance markets to offset emissions via negative emissions. However, shares similarities with Renewables Obligation previously used in the UK electricity market for deploying low-carbon generation and RTFO currently used for road fuels. Carbon takeback obligations are also discussed in the EU, although no such policy currently exists.

Carbon CfD

<table>
<tr><th colspan="3">Description</th></tr>
<tr><td colspan="3">• Carbon contracts for difference (CfDc) could be designed to provide a subsidy paid above the prevailing carbon market price for negative emissions or another reference carbon price up to a contractually agreed strike price on CO_2 captured (£/tCO_2).
• For example, the UK's proposed carbon CfDs for industrial CCUS are set to provide a subsidy paid above a prevailing carbon price (referenced to the UK ETS), with contractually agreed strike prices assumed to cover operational capture costs (including fuel), Capex investment and CO_2 T&S costs.
• In the UK's industrial CfDc, the reference price is set to follow a fixed trajectory, whereas the proposed reference price for GGRs in this policy mechanism could follow a market-linked price (e.g., integrated in the UK ETS or a new compliance market for removals).
• Since a reference price does not currently exist for negative emissions, the reference price may be set to the agreed purchase price of credits in the voluntary market, with a minimum level set to current average voluntary market prices. This would mimic the government's proposal for initial hydrogen business model contracts, where setting the reference price would be based on the hydrogen producer's achieved sales price, with a floor at the natural gas price.
• The carbon CfDc could cover the additional costs of the CCS plant and wider integration costs (e.g., for CO_2 transport). Technologies may be funded through different lots, allowing additional support for emerging technologies.
• The policy cost is borne by the government, which bears the risk on carbon market price for both its volatility and implementation timeline.
• Contracts are likely to be bilaterally negotiated first, leading to competitive auctions in the future for scalable technologies.</td></tr>
<tr><th>Strengths</th><th>Weaknesses</th><th>Application and Examples</th></tr>
<tr><td>• CfD contract provides familiarity for investors and is likely to reduce administrative complexity of mechanism implementation.
• Fixed strike price and long-term contract provides revenue certainty to project developers and financiers.
• Linkage with carbon price likely to result in reduced costs borne by government in the long term.
• Cost reduction is incentivized through competitions after the first batch of plants are deployed, ensuring value for money.</td><td>• Uncertainty on whether a prevailing market price for negative emissions would be available for FOAK projects, resulting in delayed implementation or high payments for the full strike price.
• Places the financial burden on the government/taxpayer.
• May not be very viable for smaller scale projects.</td><td>• FOAK or mature projects – This policy could support FOAK projects, although unlikely for reference price to be based on a functioning carbon market price for negative emissions in the 2020s.
• Examples – UK's proposed industrial CfDc for CCUS. However, currently no governments are directly subsiding GGR projects via subsidies linked to market prices for negative emissions.</td></tr>
</table>

Payment schemes

Description
• Service contracts for negative emissions (in £/tCO$_2$) could be administered under three variations: o Direct subsidies o Procurement via reverse auctions o Advanced purchase agreements • As a standalone policy mechanism, it is likely for service contracts **for FOAK GGR projects to be bilaterally negotiated** between government and developers, which could be constructed in similar timeframes as CfD contracts (e.g., up to 15 years) and with different terms or subsidy levels for different GGR technologies. • In a mature GGR market, procurement could be managed through **reverse auctions** with bids submitted for new projects seeking to offer the lowest-cost negative emissions. • Another option to run service contracts are through **advanced purchase agreements**, which were used successfully for vaccination programmes globally. Such a scheme may be designed where the government commits to purchasing increasing amounts of credits for reducing prices. Only projects within a margin of the lowest bidder may be allowed to participate. Such a long-term commitment may encourage investment in the short term with a goal to reduce costs as much as possible. • Projects may be allowed to **sell credits in voluntary or regulated markets**, such as the UK ETS. This would initially reduce the cost-of-service contracts to the government, but lack adjustments for future credit prices. Alternatively, the **government may purchase and re-sell the credits**. • Service contracts would be subject to **revision over time** and assumed to decrease for renewed contracts / NOAK projects as other revenue streams become more prominent (e.g., UK ETS credits or increasing prices in the voluntary market).

Strengths	Weaknesses	Application and Examples
• Procurement mechanisms allows for a tighter control on the exact volumes of CO$_2$ removed from the atmosphere, allowing government to deploy GGRs at more exact quantities for controlling the pathway to net zero and ensure no mitigation deterrence. • Long-term service contracts for negative emissions provide revenue certainty to project developers and financiers. • Cost reduction over time would be incentivised to maximise profits and secure contracts in reverse auctions or advanced purchase agreements.	• Unfair cost distribution as subsidy costs to incentivise GGR projects will likely be high and borne entirely by government / taxpayers. • The policy has very little track record in the energy space, except for the new scheme recently introduced by Sweden.	• **FOAK or mature projects –** Service contracts can be bilaterally negotiated for FOAK GGRs and procurement via reverse auctions could be developed for a wider and more mature GGR sector. • **Examples –** Sweden announced a reverse auctions procurement programme to fund its first BECCS plants[82], which would be operational by 2025-26. The US is also considering direct procurement of carbon removals, although no commitments have been made. Lastly, a feed-in-tariff for procuring permanent NE is being currently being drafted for the Luxemburg government.

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[82] Press release from Swedish Ministry of Finance and Ministry of Environment [Link].

Cost plus subsidy

Description		
• Costs plus subsidy would involve an **open-book contract which includes direct payments from the government** covering all incurred operational costs of the GGR project (fuel costs, CO_2 transport and storage, etc.), plus an agreed margin. The contracts may be set for 15 years, which is the common preferred period used in CfDs in the energy sector. • It is likely that margins on the subsidy would need to be contractually negotiated for bespoke FOAK GGR projects due to expected lack of liquidity and competition at early stages. • GGR developers would need to construct project proposals **outlining the delivery timeframes for their volumes of CO_2 captured** over the operational lifetime of the facility. • **Government would be expected to bear the majority of risks** associated with operational costs and any overall increases in project costs (e.g., due to CCS retrofits and plant-wide integration). • Risk management could include build-in of **pain-gain sharing mechanisms** to incentivise improvements - enabling the contractor to share in the benefits of cost savings, but also to bear some of the cost when there are cost overruns. • **Either the government or the project developer may sell negative emissions credits in voluntary or regulated markets**. The government may recuperate some of its costs through this mechanism, bearing risks of low credit prices. If the developers are allowed to sell credits in various markets, the government may require a large portion of those profits to be paid back to itself.		
Strengths	**Weaknesses**	**Application and Examples**
• Guaranteed payments and long-term contracts provide revenue certainty to project developers and financiers, shielding FOAK GGR projects from market uncertainties and reducing financing costs. • Targeted control of project development could allow for government to select strategically important projects (e.g., baseload power BECCS) or those with maximum co-benefits. • The policy is relatively easy to set-up in the short-term.	• Politically unfavourable cost distribution as all costs and risks are borne by government, with significant annual subsidies required. • Administratively complex, making the policy unfavourable to apply to a wide range of GGR sectors or for projects in mature sectors. • The policy does not naturally incentivise cost reduction once a contract is signed.	• **FOAK projects –** Given the significant government expenditure involved and inability for the policy to transition to a market-based mechanism, it is unlikely for a costs plus subsidy to be used in a maturing GGR market • **Examples –** Policy has not been widely used to support investments in the energy industry, however, has been used for infrastructure and defence projects in the UK (e.g., Heathrow Terminal 5).

Competitions

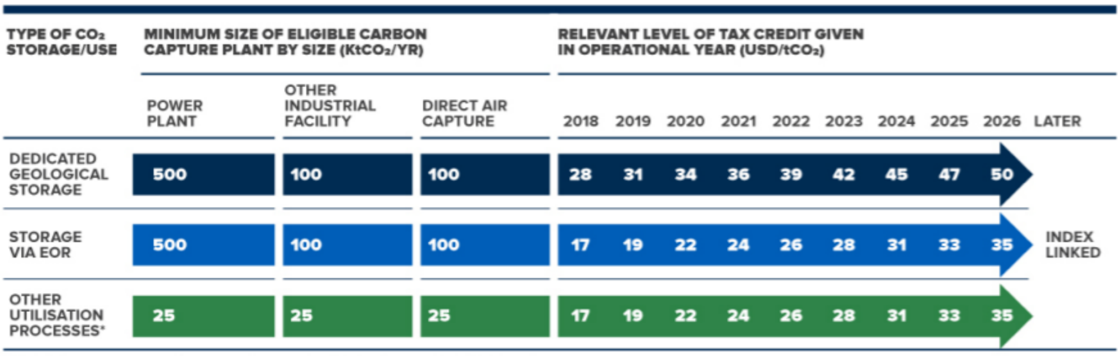
Description
• Competitions are **grant funds** awarded to technology developers to enable project deployment. They are usually used as an intervention to bridge the innovation gap and **pull through low TRL technologies (TRL 4-6)** across the development cycle. This complements private and public R&D efforts by providing a path to commercialise new technologies. • Competitions may also apply to more mature technologies. However, **administrative costs are likely to be prohibitive if demand is high**. • **Specific budgets may be allocated for individual GGR sectors** (e.g., DACCS, BECCS industry, BECCS power, etc.) to incentivise competition between developers for pilot or demonstration projects. This provides flexibility around how much of each technology can be funded and allows more innovative and expensive technologies to be protected from competition with lower cost options. • Projects could be awarded funding based on a range of criteria: o Technology feasibility and applicability o Social metrics (e.g., job growth) o Cost reduction potential o Value for money (to government or consumers) o Scalability potential • Competitions would be government funded; however, they could be designed with **requirements for projects to acquire additional private sector investment** to drive technology commercialisation. Examples for such a provision includes the requirement for more than 50% private finance in the upcoming ICC business models.

Strengths	Weaknesses	Application and Examples
• Incentivises cost-competitiveness between FOAK GGR projects, increasing value for money in the short term. • Able to be adapted to drive commercialisation across a range of GGR sectors or to be focused on specific technologies which deliver additional co-benefits. • Has a good track record in the UK for commercialising emerging technologies. • Is relatively applicable to smaller projects and can easily be delivered in the 2020s with low administrative burden.	• Unlikely to have long-term potential to support NOAK GGR projects, as funding for multiple large-scale projects likely to require significant government expenditure and resourcing. • Unable to be adapted to a market-based mechanism for mature markets. • Does not offer any long-term revenue certainty, since the incentive is paid upfront.	• **FOAK projects –** Competitions would most likely be geared towards supporting FOAK GGR deployment given the inherent structure of the policy to support low TRL technologies. • **Examples –** Competitions are widely used in the UK as well as internationally in the CCUS and GGR spaces. Examples include BEIS's DAC and other GGRs Innovation Competition, BEIS's Industrial Energy Transformation Fund, and the EU Innovation Fund.

Tax incentives

Description

- Tax incentives take the form of credits, where **tax liabilities of developers of certain technologies are alleviated** at a level determined by the government. **Investment credits** may be applied as a percentage of the total capital invested to the project, whereas **production tax credits** (such as the 45Q credits in the US), provide tax benefits in a £/tonne of CO_2 stored/removed format.
- Governments determine the period of credits awarding and may **set different rules/incentives for different technologies**. Credit values may also reduce according to a pre-determined schedule where plants built in the future are eligible for lower credits.
- The policy is **funded by the government/taxpayer** in the form of forfeited tax revenues. Since no immediate payment is made to developers financing becomes relatively easier.
- Small companies with low/zero tax liabilities would not benefit from tax credits, therefore it would be **beneficial to allow these credits to be passed on to larger companies**, which can benefit from them.



TYPE OF CO_2 STORAGE/USE	MINIMUM SIZE OF ELIGIBLE CARBON CAPTURE PLANT BY SIZE ($KtCO_2$/YR)			RELEVANT LEVEL OF TAX CREDIT GIVEN IN OPERATIONAL YEAR (USD/tCO_2)									
	POWER PLANT	OTHER INDUSTRIAL FACILITY	DIRECT AIR CAPTURE	2018	2019	2020	2021	2022	2023	2024	2025	2026	LATER
DEDICATED GEOLOGICAL STORAGE	500	100	100	28	31	34	36	39	42	45	47	50	
STORAGE VIA EOR	500	100	100	17	19	22	24	26	28	31	33	35	INDEX LINKED
OTHER UTILISATION PROCESSES*	25	25	25	17	19	22	24	26	28	31	33	35	

Figure 27: Overview of USA's 45Q tax credit for CCUS[83]

Strengths	Weaknesses	Application and Examples
• Tax incentives covering both operational and capital costs may provide a strong incentive for project developers and financiers by providing revenue certainty, if developers have enough tax liability. • Tax credits do not require a direct funding stream from government making it easier to scale. • The policy can work in a mature market and incentive levels can be changed easily.	• Uncertainty with long-term support of tax credits which could change under different governing political parties and reduce investor confidence (particularly for FOAK GGR projects). • The UK lacks a track record regarding large-scale tax incentives. Successful application of this policy would require setting up markets for credit trading. • Lack of incentive for competition between GGR projects in the same bucket, so risk of overcompensating projects which do not require full credit value. • Taxpayers bear all the financial burden, rather than the emitters.	• **FOAK or mature projects –** Tax incentives could apply to FOAK or mature GGR markets, provided the value of the incentive reflects the appropriate costs (e.g., higher costs / risks for FOAK projects). • **Examples –** Successful track record in developed markets, especially in the USA. 45Q tax credits are awarded to CCUS projects, including DACCS plants. Investment and production credits are also available for other sectors (e.g., renewables).

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[83] GCCSI – The US Section 45Q Tax Credit for Carbon Oxide Sequestration, 2020 [LINK].

8.3 Detailed description of GGR policy assessment criteria

Below are the more detailed descriptions of the criteria used to assess the longlist of general GGR policies:

Economic Viability

- **Revenue stability:** Revenue stability is measured as the predictability of the £/tonne revenue projects will receive under various policies. Policies which do not guarantee any specific revenues score lowest points, since then revenues would only be determined by currently uncertain voluntary markets. Policies with a fixed £/tonne revenue guarantee score the highest.
- **Proportionality:** Refers to the ability of a policy to provide financial incentives proportional to project costs or avoid over-subsidisation considering all sources of revenues and costs associated with a project. Market-based policies are likely to score high in this category since the price of negative emissions are automatically adjusted in line with costs. Competitive auctions are another mechanism which helps with this criterion. Policies which provide a flat revenue for all projects or fail to adjust with NE credit price changes score low since they can lead to over subsidisation.
- **Transition:** One of the main purposes of a GGR policy is to support the technologies in the short and medium terms (e.g. to the mid-2030s) and let the sector transition to a market lead state, not requiring government support indefinitely. This future market-lead state must be competitive with many mature GGR technologies with different scales and applications. Market-based policies and policies which can be naturally integrated to market-based policies, such as a contract for difference using an ETS price as the reference price, score highly in this category. Policies without a natural link to market-based mechanisms score lower since transitioning away from such policies would be more difficult and may require additional intermediate policies.

Ethics and Equality

- **Cost reduction:** This criterion measures the cost reduction promotion of the policy over time through innovation and learning by doing. Cost reduction promotion of both individual projects and the industry as a whole are accounted for. Most policies naturally encourage cost reduction since this would maximise profits of developers, however, policies which provide returns proportional to costs do not have strong incentives for cost cutting and therefore rank poorly.
- **Applicability across scales:** In order to establish a mature GGR market involving many different technologies, small projects, as well as large ones, need to be deployed to maximise capacity and enable learning by doing. It is therefore desirable for GGR policies to be applicable to small projects (~10s ktCO$_2$/year) and present small administrative burdens. None of the policies ranked perfectly in this department since burdens for small developers are always higher than larger projects to a degree. However, policies requiring keeping track of detailed costs or having large tax liabilities ranked low in this criterion.
- **Fair cost distribution:** There are multiple different views as to who should pay for carbon removal, but for the assessment of GGR policies in this project, fair cost distribution is defined as policy costs being borne by the private sector, ideally the industries which require negative emissions in order to offset their remaining emissions. This would reduce the burden on the government and the taxpayer and be in line with the polluter pays principle. Market based policies, such as obligations and the UK ETS, directly force obligated companies to pay for carbon removal, hence rank high in this category. Other policies have lower scores since incentives are paid by the taxpayer, even if some private investment is incentivised. Section 5.1 discusses different approaches to achieving fair cost distribution when designing policies.

Feasibility

- **Deliverability:** The feasibility to be implemented in the 2020s in order to facilitate FOAK deployment and minimise administrative and policy complexity. Market based policies score lower in this criterion since they excel when there are multiple developers in the system. Markets relying on a few FOAK projects can introduce significant risks. Most other policies have relatively high deliverability as the UK government has experience setting up such schemes (except for tax incentives).

- **Compatibility:** The GGR policy should be compatible with business models and other incentives under development in sectors such as CCUS and hydrogen production – it should not misalign with or require redesign of wider policy frameworks. Market based policies generally score higher in the compatibility department since they establish a baseline price for negative emissions, which can then be used by many other policies such as CfDs. Policies based on total project costs may be difficult to set up for projects already receiving multiple incentives. Most other policies can be flexible and provide different incentives levels for different technologies, but this would introduce a level of complexity and may require some schemes currently under development (such as ICC business models) to modify their own incentives.
- **Track record:** This criterion measures if the policy has been implemented previously in applicable industries for a suitable period of time and if the policy is likely to achieve what it set out to achieve. In order of preference, applicable industries are engineered GGRs, other CCUS technologies, and energy-related sectors, including modular technologies such as wind and solar PV. Prior experience in the UK is preferred over experience in other jurisdictions. Some policies, such as UK ETS, existed for a long time as part of EU ETS, but track record is limited as a standalone policy in the UK and integration with GGRs is absent. Some other policies, like government procurement and tax incentives, have been planned/proposed in other countries but have not yet been implemented, resulting in lower scores.
- **Reaching GGR targets:** This criterion measures the ability of a policy to deliver a desired level of GGR deployment, regardless of what that specific target may be in the future. Obligation schemes perform very well in this category since the policy specifically sets a GGR volume target and market price changes to meet demand. Most other policies do not ensure reaching specific GGR volumes, but deployment levels may increase if overall policy budget increases. These policies have an average score because it is not feasible to increase funding levels indefinitely if GGR uptake is low.
- **Policy flexibility:** The policy should allow the level of deployment and incentives to be modulated over time, allowing the government to potentially pay less and phase out the policy if needed. Every policy is naturally flexible to a degree and may be discontinued if needed, but this criterion measures the ease at which this can happen, or adjustments can be made once more experience is gained. Policies which commit to long term financial support for individual projects score lower, since support cannot be modified for eligible projects. However, changes can be made between individual funding rounds. Some policies which can provide Capex support, such as competitions and tax incentives, can have more flexibility as long-term commitment is minimal.

8.4 Reasoning for RAG rating of individual policies

The tables presented in this section provide the brief reasoning behind specific RAG ratings given to each longlisted GGR policy. Partial scoring was occasionally used to provide further granularity and capture nuanced implications.

The RAG based scores were not quantified or weighted when shortlisting policies. These rankings were used as qualitative indicators of policies' performances and they were used as guidance when the shortlisted policies were selected in consultation with BEIS. Information on the reasons for shortlisting the obligation schemes, payment schemes and carbon CfDs, while considering UK ETS and competitions as complementary mechanisms are provided in Table 8.

Please note that the scoring presented here is ultimately subjective and occasionally groups of policies or different ways of setting up a policy are scored under the same umbrella, requiring generalisations to be made. Furthermore, sometimes for a given policy there are tradeoffs between scores for different criteria. For example, if very high funding is allocated to GGRs through competitions, this policy may help reach GGR deployment targets, but deliverability would suffer. Therefore, the rankings below attempt to represent fair assumptions around how such policies may be established within reasonable boundaries.

Integration with UK ETS

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	1.5	The revenues would be tied to the future prices of UK ETS, which may provide certainty if prices are stable and/or on the rise. However, there is no guarantee of a sufficiently high minimum credit value and if the ETS system is expected to undergo significant changes risks would be significant. Near term carbon prices may be too low to support GGRs.
Proportionality	3	Prices are determined in competitive markets and burden on taxpayers is minimal.
Fair cost distribution	3	Private sector funding is prioritised and burden on taxpayers is extremely low. Lowest costing projects are encouraged to deploy in a market setting and costs are borne by the polluters included in the scheme.
Transition	3	This policy already represents an end goal where prices are borne by emitters and government does not provide incentives directly, until at least net zero is reached. The policy is fit for mature sectors where high liquidity enables creation of realistic market prices and competition.
Cost reduction	3	The sector is incentivised to reduce project costs over time to maximise profits.
Applicability across scales	2.5	ETS compliance costs may be significant for small developers, but the system is very flexible and scalable. Plants only need to demonstrate they meet minimum requirements and prove net removals, which needs to be done under any policy.
Deliverability	1.5	The path to integration of NE credits in the ETS is not clear and this policy may take multiple years to properly design and implement. Most FOAK projects would not get sufficient incentives without multipliers based on current prices.
Compatibility	3	UK ETS provides a baseline market price for carbon removal, enabling some other policies, such as carbon contracts for differences. Synergies may exist with BECCS industry technologies and with potential expansion of the ETS coverage.
Track record	1.5	ETS is a relatively stable mechanism in the EU, however, NE credits are not integrated to any ETS in the world and the UK ETS itself has been formed very recently and is under review.
Reaching GGR targets	1	Simple inclusion of engineered GGR in ETS is not likely to result in uptake of engineered GGRs which are more expensive than the current ETS allowance prices. Only few projects near commercialisation may benefit from the policy and it difficult to predict uptake levels.
Policy flexibility	1.5	Certain aspects such as minimum NE uptake requirements or eligibility of different technologies can be adjusted. However, making large changes, such as removal of NE credits from the ETS, is likely to be complicated.

Obligations within a new carbon removals market

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	1	No specific prices are guaranteed and there are no existing markets with a reliable history to provide confidence for future revenues.
Proportionality	3	Prices are determined in competitive markets and burden on taxpayers is minimal.
Fair cost distribution	3	Private sector funding is prioritised and burden on taxpayers is extremely low. Lowest costing projects are encouraged to deploy in a market setting and costs are borne by the polluters included in the scheme.
Transition	3	This policy already represents an end goal where prices are borne by emitters and government does not provide incentives directly, until at least net zero is reached.
Cost reduction	3	The sector is incentivised to reduce project costs over time to maximise profits.
Applicability across scales	2.5	Compliance costs may be significant for small developers, but the system is very flexible and scalable. Plants only need to demonstrate that they meet minimum requirements and prove net removals, which needs to be done under any policy.
Deliverability	1.5	Since this policy has not been implemented before for negative emissions careful planning and piloting will be needed. In the absence of existing GGR projects obligated parties would be exposed to all the technology risks of few projects. Consideration must be given to how the obligations will be handled if GGR projects fail to come online in time (e.g., setting a correct buyout price).
Compatibility	2.5	Obligation would provide a baseline market price for carbon removal, enabling some other policies, such as carbon contracts for differences to use it as a baseline. Additional revenues from this market are not likely to compromise existing policies.
Track record	2.5	Obligation schemes have not been used on GGRs in the world but they have a successful track record in other sectors, like fuels and power, in the UK.
Reaching GGR targets	2.5	The government directly sets the required GGR levels in the policy and the market is forced to provide these volumes. There will be a buyout option which is a last resort for companies not securing NE credits. This protects business from potentially very high costs, but also implies that obligated GGR levels may not be met fully.
Policy flexibility	2.5	The government can adjust the obligation levels according to climate targets, costs, and projects in the pipeline. In the past it was possible for obligation schemes to be ended relatively easily in the UK. It may not be acceptable to discontinue this policy without providing an alternative GGR market, especially for technologies without co-products.

Carbon CfD

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	3	Long-term contracts ensure revenue certainty per tonne of net removals. Some risks remain regarding energy/biomass costs and co-product prices, but these are either covered by other policies, can be addressed within contracts or can be borne by developers.
Proportionality	3	The projects and strike prices are selected through competitions in the future and provisions can be put in place to encourage credit sales in voluntary or other kinds of markets. The reference price ensures that as markets develop, government support reduces over time.
Fair cost distribution	2	A certain level of private funding may be incentivised but the public/taxpayers, not the polluters, bear the direct policy costs.
Transition	3	Policy reduces government dependence over time and naturally leads onto a mature market as reference prices increase. Reference prices are well established and represent real market values in mature sectors.
Cost reduction	2.5	The contracts promote cost reduction to maximise profits. However, FOAK projects may lack competition to encourage cost reduction in the bilateral negotiations phase.
Applicability across scales	1.5	For small scale developers, CfDs would be too complex and have high administrative burdens. Simplifications may be provided for some technologies and scales. Alternative policies would be better suited for small scale applications.
Deliverability	3	Policy is straight forward to implement in the 2020s given previous experience. The policy can be used for FOAK projects and has been under consideration for BECCS power applications.
Compatibility	2	Types of technologies awarded contracts may be chosen to avoid clashes with existing policies. Some existing policies, like ICC business model support, may need to be modified if carbon CfD payments are awarded.
Track record	2.5	CfDs have a good track record in the UK power sector. Similar mechanisms are currently developed for BECCS power, low-carbon hydrogen, and industrial carbon capture businesses. However, no carbon contract for difference is currently operational.
Reaching GGR targets	2	The policy itself does not set GGR uptake requirements. Although higher funding levels will likely lead to higher deployment, there is no guarantee that businesses will invest in GGRs through this policy mechanism.
Policy flexibility	2	Limited flexibility for contracts signed, but the government can easily change the policy between each funding round.

Payment schemes

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	3	The developers would know exactly how much they are getting paid and if payments are set for high enough prices, they should encourage deployment.
Proportionality	2	Reverse auctions or purchase volume adjustments would encourage cost reduction, however, the policy does not allow for payment reductions in case carbon removal credits increase in value and even if gain sharing mechanisms are in place, this only partially compensates the government.
Fair cost distribution	2	A certain level of private funding may be incentivised but the public/taxpayers, not the polluters, bear the direct policy costs.
Transition	2	Payments in successive rounds may be reduced over time to ensure a transition to a market-based system is achieved. However, the policy itself is not market based and requires advancement of voluntary negative emissions markets or creation of a regulated market before it is phased out.
Cost reduction	3	Private sector is incentivised to reduce costs over time to maximise profits.
Applicability across scales	2.5	Small developers can participate in the auctions and are not likely to suffer from caps of available funding, but administrative costs may impact them slightly worse than larger developers.
Deliverability	3	Administrative burden is relatively low and involves setting auction participation rules or price/volume commitments for advanced purchases. Implementable within the timeframes for FOAK projects. Even reverse auctions may be viable for FOAK projects if there are enough developers, as evidenced by Sweden.
Compatibility	2	Types of technologies awarded payments may be chosen to avoid clashes with existing policies. Some existing policies, like ICC business model support, may need to be modified if negative emissions payments are awarded.
Track record	1.5	Government procurement has not been used for negative emissions previously, but some countries are planning or considering this option. In the UK other sectors used payment schemes to various levels of success, but usually at smaller scales.
Reaching GGR targets	2	The policy itself does not set GGR uptake requirements. Although higher funding levels will likely lead to higher deployment, there is no guarantee that businesses will invest in GGRs through this policy mechanism.
Policy flexibility	2	Limited to no flexibility once a project is funded but the scheme may be altered between funding rounds.

Cost plus subsidy

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	3	Guaranteed payments and long-term contracts provide revenue certainty and stability to the investors.
Proportionality	2	By definition the payments are set to slightly higher than actual costs. The government may sell credits in the voluntary market or encourage developers to sell credits to recoup some of the costs. Since the policy does not encourage cost reduction to a great extent, payments may end up being higher than costs that would be achieved in competitive markets.
Fair cost distribution	1.5	A certain level of private funding may be incentivised but the public/taxpayers, not the polluters, bear the direct policy costs. Compared to other policies, the government is likely to cover all the costs, but it is possible for the scheme to cover costs only partially.
Transition	1	The policy does not include a path to transition to a market-based mechanism without government support and is not fit for a mature market due to administrative/funding limitations.
Cost reduction	1.5	The framework does not encourage cost reduction naturally since costs are covered by the government, but pain-gain sharing mechanisms may be put in place to reduce risks of very high costs and encourage some level of cost reduction.
Applicability across scales	1	The policy better suits a smaller number of large-scale projects due to high administrative costs and the requirement to justify and keep track of all expenses.
Deliverability	2.5	Straightforward open-book contract which could be implemented within a relatively short timeframe. The policy may support FOAK GGR projects but the administrative burden on the developers may be significant. Agreeing on eligible costs may lead to objections on both sides.
Compatibility	1	Not compatible with many other policies since the whole project is funded through this mechanism. Additional revenues or support may be difficult to integrate. Having a cost plus subsidy support for GGR retrofits may also prove difficult.
Track record	1.5	In the UK this policy has been used in the defence and infrastructure sectors, but not in the energy industry.
Reaching GGR targets	2	The policy itself does not set GGR uptake requirements. Although higher funding levels will likely lead to higher deployment, there is no guarantee that businesses will invest in GGRs through this policy mechanism.
Policy flexibility	1.5	Flexibility exists in the sense that the scheme can be easily discontinued for new projects, but once a contract is signed very little can change, and the plants will be able to continue to claim all their eligible costs from the government.

Competitions

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	1	Provides no long-term revenue certainty since the incentive is an upfront grant.
Proportionality	2	The competition encourages cost reduction and disclosure of project costs, but only projects submitted to the competition in a specific window compete with each other. Pessimistic scenarios regarding future negative emissions prices may lead to high compensations.
Fair cost distribution	2	A certain level of private funding may be incentivised but the public/taxpayers, not the polluters, bear the direct policy costs.
Transition	1	Does not transition to a market-based system unless costs naturally drop to low enough levels to compete with non-GGR options, which does not apply to GGRs without co-products. The policy is not feasible to create a mature market as administrative costs would be too high.
Cost reduction	2	Cost reduction is promoted in the initial bidding phase but not once the project is chosen for funding. Projects would naturally want to reduce costs to maximise profits, but this is not likely to be priority for FOAK plants.
Applicability across scales	2.5	Smaller projects may also compete, and rules may be adjusted for smaller projects/participants, however, the administrative costs or participation are likely to be too high for smaller developers.
Deliverability	3	Policy can be delivered relatively quickly since multiple competitions are already running for different sectors. Implementable within the timeframes for FOAK projects.
Compatibility	2	Competitions may be designed flexibly to consider current policies, but this would make administration more complicated. It may not be feasible for some projects to compete in multiple schemes.
Track record	3	There are multiple successful examples in the UK and internationally (e.g., EU Innovation Competition) in the CCUS and GGR space.
Reaching GGR targets	1.5	The policy itself does not set GGR uptake requirements. Although higher funding levels will likely lead to higher deployment, there is no guarantee that businesses will invest in GGRs through this policy mechanism. In the past, competitions alone were not enough to achieve large scale technology rollout in similar sectors.
Policy flexibility	2.5	Grant levels and other minimum requirements may be flexibly determined as well as which technologies are getting funding. Once a project is awarded and deployed, there is very little flexibility to modulate future incentives.

Tax incentives

Criteria	Rating (1 to 3)	Rating Notes
Revenue stability	2	Tax credits provide revenue certainty for each tonne of CO_2 removed or captured; however, the payments are subject to policy risk since governments may change incentive levels. Tax credits covering capital investment is less susceptible for this risk since credits are obtained early in the project lifetime. However, without a mature tax credit trading market, companies without tax liabilities cannot fully benefit from them.
Proportionality	2	Incentives are fixed for all technologies or buckets of technologies, and the level will inevitably be fixed at a rate which will be too low or too high for some projects. Policy incentivises deployment of projects under a certain cost threshold, ensuring capping of maximum benefits, but does not necessarily provide preferential incentives to the lowest cost projects.
Fair cost distribution	2	A certain level of private funding may be incentivised but the public/taxpayers, not the polluters, bear the direct policy costs.
Transition	2	Credits may be reduced over time to ensure a transition to a market-based system is achieved, however, the policy itself is not market based and requires advancement of voluntary negative emissions markets or creation of a regulated market before it is phased out.
Cost reduction	3	Projects are incentivised to reduce their costs as much as possible to maximise profits.
Applicability across scales	1.5	Tax credits may easily be awarded to smaller projects, but the credits themselves are not useful for companies which do not have enough tax liability to take advantage of them. Mechanisms allowing transfer of credits to larger corporations need to be implemented and even then, the value of the credits would reduce due to this additional transaction.
Deliverability	2	The UK does not have frameworks for providing production tax credits or for trading tax credits, therefore initial administrative burden is likely to be relatively high. Policy may still be implementable within the timeframes for FOAK projects.
Compatibility	2	Types of technologies awarded tax credits may be chosen to avoid clashes with existing policies. Some existing policies, like ICC business model support for EfW plants, may need to be modified if tax credits are awarded.
Track record	1.5	Tax credits have a proven track record in the US in various sectors, but how well 45Q tax incentivises DACCS and BECCS is currently unclear. Tax credits are not used for similar purposes in the UK and the businesses are less familiar with the mechanism.
Reaching GGR targets	2	The policy itself does not set GGR uptake requirements. Although higher funding levels will likely lead to higher deployment, there is no guarantee that businesses will invest in GGRs through this policy mechanism.
Policy flexibility	2.5	Incentives can easily be changed over time but once the plant starts construction, credits must be provided for the period specified. Investment-based credits are easier to modify with no long-term commitments.

8.5 Default assumptions and data underpinning cashflow modelling

The table below is a non-exhaustive summary of the assumptions and data sources used within the cashflow modelling. The values contained below were those used in the default charts throughout the report. However, as section 6 shows, various scenarios were tested using a range of values around these central defaults.

Item	Description	Default values
Technology maturity	FOAK vs NOAK, where NOAK has lower costs.	FOAK
Technology	Available options included in cashflow model: DACCS Solid Electric, DACCS Solid Hybrid, or DACCS Liquids.	DACCS Solid Electric
Policy timeline	Start and end year of policy intervention.	2027-2036 (10 years)
Plant lifetime	How long plant is assumed to be operational for.	10 years
Gross removals	Capacity of plant in terms of gross emission capture.	9000,000 tCO_2/year [84]
Plant utilization	Capacity utilisation.	90% [84]
Capture rate	Share of carbon captured.	100% [84]
Discount rate	Used to determine present values of future cash flows.	9%
Interest rate	Used to calculate the cost of finance.	9.1%
Gas & Electricity price	The price of gas and electricity.	Central values [85]: • Gas: 24 £/MWh • Electricity: 60 £/MWh
Heat price	The price of heat.	Central values: 11 £/MWh
Carbon price	The price of carbon.	Central values [85]: • 2027: 25 £/tCO_2 • 2036: 50 £/tCO_2

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[84] Global Assessment of Direct Air Capture Costs. A report by Element Energy for IEAGHG, 2022 [Link]

[85] Direct air capture and GGR programme – phase 2 guidance. BEIS (2020) [Link]