INVESTMENT FRAMEWORKS FOR DEVELOPMENT OF CCUS IN THE UK

CCUS ADVISORY GROUP (CAG)
FINAL REPORT

July 2019
DISCLAIMER

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They cannot and should not be taken to represent the views of each or all members of the CAG.

They do, however, aim to reflect a general consensus within the CAG.

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Foreword

Following the CCUS Cost Challenge Taskforce and the publication of the Department of Business, Energy and Industrial Strategy (BEIS) CCUS Action Plan in 2018, the CCUS Advisory Group (“CAG”) was established at the beginning of 2019 as an industry body, including wide representation of industry, BEIS and HM Treasury. Its scope of work for the first half of this year has been to develop the business models needed to support the growth of CCUS – for transportation and storage, power, industrial capture, hydrogen and BECCS in particular – as well as to consider the role of competition and collaboration in the market to drive down costs and reduce risks.

The CAG’s formation was timely. The Committee on Climate Change, in their recent ‘Net Zero’ report, have described CCUS as “a necessity, not an option”, while, since its inception, the BEIS Select Committee has recommended the acceleration of CCUS, advocating a number of cluster developments. Perhaps most critically, Government has now legislated its commitment to the UK having net zero greenhouse gas emissions by 2050. This target can only be achieved through material investment in CCUS.

These reports recognised the need for sound commercial models to underpin the rollout of CCUS, to make those investments both deliverable and affordable. This has been the main focus of the CAG. We have developed a suite of business models in detail, having considered a wide set of alternatives which were discussed and analysed at length.

The key results of the CAG’s work over these six months have been summarised in this report, which has been produced to be published alongside BEIS’ business models consultation. It is designed to be read in conjunction with the BEIS consultation document, setting out the detailed business models that have been proposed by the CAG and the alternative models that have also been considered. It reflects the collective views of the CAG rather than the precise views of any individual member.

We hope that the work done by CAG will be seen as a significant step forward for the industry, giving a commercial framework from which the CCUS industry can be developed. It is, of course, work in progress; there is much more to do, both centrally but also at the project and cluster level.

Our current intention is that the work of the CAG will continue. There is substantial work needed to develop this market, engage financiers and help develop options for the rollout of integrated and affordable clusters. We believe that delivering this report has been an important milestone for an industry where collaboration and integration is essential.

In that spirit, this has been a highly collaborative effort, involving detailed hard work from all of our members, from both the public and private sector, demonstrating their commitment to developing this industry. We would like to thank everyone for their contribution.

Particular thanks go to all the members from BEIS for their help in guiding and participating in the CAG’s work. We would also especially like to thank Linklaters LLP, as well as Shell International Limited and Equinor UK Limited, for their generosity in hosting CAG meetings.

We hope that the report is seen as a valuable contribution to the development of the industry and to Government’s ambitious target of net zero emissions by 2050. We also hope that the CAG output is useful to consultees and we encourage them to review this document and provide their perspectives back to BEIS.

Paul Davies
Chair of the CCUS Advisory Group

Patrick Dixon
Leader of the CCUS Advisory Group
Guide to the Report

Guide to the structure of this report.

- This report is more akin to a manual than a narrative.
- It is intended that each chapter in this report will largely “stand alone”, so that readers can choose to read the chapters and parts of the report that best suit their needs. There is therefore considerable (intentional) repetition throughout the document.
- Reading this guide to the structure and contents of the report - and studying the table of contents - will help the reader find what they seek.

This report contains a series of business models, and options for business models, that could be used in developing CCUS projects in the UK.

- A one-page Executive Summary appears immediately after the table of contents.
- Those looking for a high-level view should then read chapters 1, 2 and 3.
- Those looking for detail on the options considered and the business models themselves should look at chapters 4 to 12. These are arranged to cover each business model separately.
- CHAPTER 1 - INTRODUCTION - is just that - an introduction to the work of the CAG.
- CHAPTER 2 - BUSINESS MODEL VARIANTS - gives a summary of the variants of business models considered by the CAG. The CAG is recommending that Variants 1 to 6 be considered for use in early CCUS projects in the UK. Variant 1 is the Base Case. (The detail is in Chapter 20.)
- CHAPTER 3 - RECOMMENDATIONS FOR THE VARIANT 1 BUSINESS MODELS - the Base Case. This chapter contains a summary of all work done and all the recommendations made by the CAG.
- CHAPTERS 4 to 16 contain the detailed work done by the CAG on the Variant 1 Base Case.
  - In each of chapters 4, 7 and 10 there are Options Papers which describe the options considered by the CAG when recommending the business models.
  - Then, in chapters 5, 8 and 11 there are three detailed business models; covering CO₂ Transport and Storage, Electricity Generation with CO₂ Capture and Industrial Production with CO₂ Capture respectively.
  - Finally, chapters 6, 9 and 12 cover detailed descriptions of the Residual Risks and their allocation and possible mitigations, for each of those three business models.
  - CHAPTERS 13 and 14 contain Options Papers for Hydrogen and Bioenergy with CCS (BECCS). Detailed business models have not been produced for these technologies.
  - CHAPTERS 15 and 16 contains Options Papers for common business model issues across all clusters and projects.
- CHAPTERS 17 to 19 cover separate papers (not directly related to the Business Models) on CCUS Metrics, Delivery Capability, and Competitive Tension respectively.
- Finally, CHAPTER 20 describes in more detail the Variants of Business Models that the CAG has considered, and which were summarised in Chapter 2.
Executive Summary

- The CCUS Action Plan\(^1\) announced that HMG will consult on the emerging findings of a “Review of Delivery and Investment Frameworks” for CCUS in the UK in 2019. This report has been produced by the CCUS Advisory Group (CAG) in support of that consultation.

- The bulk of this report describes in detail possible Business Models that may be used to deploy CCUS in the UK.

- The CAG has considered a range of 13 high-level business models for CCUS (called Variants). The Base Case - Variant 1 - was based on the recommendations made by the UK CCUS Cost Challenge Taskforce in 2018\(^2\), though changes have been made in a number of respects.

- Variant 1 comprises a private sector owned, regulated CO\(_2\) Transport and Storage (T&S) business; privately owned Electricity projects with CO\(_2\) capture with revenue support provided by a new “Dispatchable CfD”; and Industrial CCUS projects with CO\(_2\) capture supported by an “Industrial CCUS Contract” between industrial producers and HMG. The CAG recommends Variant 1 as a suitable basis for developing CCUS projects in the UK.

- Under this Variant, T&S would be privately owned, and regulated under a RAB\(^2\) structure. T&S would be designed to achieve a low, “utility” rate of return and risk. To achieve this, the costs of some low-probability risks would be borne - if they materialise - either by insurance, or by end-consumers or tax revenues.

- The CAG also endorses another six Variants as suitable alternatives that should also be considered. These include:
  - providing a grant to cover the initial capital cost of T&S in a new CCUS cluster;
  - initial ownership of T&S by HMG, prior to privatisation;
  - extending the T&S company to cover the whole of the UK under either private ownership; or alternatively under HMG ownership;
  - public-private ownership of T&S, and;
  - the use of RAB structures for other parts of the CCUS chain.

- The CAG recommends the introduction of a “Dispatchable CfD”. This would include fixed and variable payments, and it would be designed to bring forward investment in dispatchable low-carbon power generation capacity, including electricity generation with CCUS. The design of the “dispatchable CfD” is intended to ensure that electricity plants with CCUS would dispatch ahead of unabated gas-fired plants, but behind renewables and nuclear generation. It would be funded by electricity consumers through the LCCC.

- The CAG recommends the introduction of an “Industrial CCUS Contract” to deliver decarbonisation of industrial production. This could be delivered either through direct contracts between HMG and industrial producers, or through a private sector “Decarbonisation Service Company”.

- The contract would comprise a “Hybrid Grant plus CO\(_2\) CfD” model. Capital costs of investment would be financed by the private sector, supported for early projects by a grant. Operating costs would be recovered through a “contract for difference”, which would cover the difference between the revenue received for unused ETS certificates\(^3\) and either budget or actual operating costs.

- Given its future importance in decarbonising the UK energy system, the CAG recommends that low carbon hydrogen production forms part of the CCUS cluster developments during the 2020s.

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\(^2\) Regulated Asset Base - see Glossary

\(^3\) This report refers throughout to EU ETS certificates as the key means of carbon pricing. This should also be taken to refer to any future system of carbon pricing that may replace EU ETS certificates in the future.
HMG should consult on options for developing a low carbon hydrogen market or markets; including on possible market structures, commercial structures, financing options and funding sources to support low-carbon hydrogen production with CCUS.

- BECCS$^4$ will probably be important in providing negative emissions that offset those parts of the economy that would be very difficult to decarbonise otherwise. A new framework must be developed for providing income to projects delivering negative emissions through BECCS. In the meantime, biomass may be treated commercially in a way similar to other fuels used for electricity generation or hydrogen production, albeit without the carbon penalty.

- All but one of the business model Variants are based on “splitting the chain” commercially and contractually between CO$_2$ capture and CO$_2$ T&S. Proposals have been developed in this report to address the resulting “Cross Chain Issues” that represent a significant source of risk to the individual parts of the chain. This risk is highest during the development of the initial projects within a cluster but are expected to diminish rapidly and eventually to disappear as further projects are added to a cluster, and transport links to other clusters are created.

- An exhaustive detailed design for the allocation and mitigation of “residual risks” has been included in the business models. Within these, there is a small group of “irreducible” residual risks which are related to highly unlikely events of large consequence. These are very difficult for the private sector to price effectively, they cannot therefore be borne by the private sector at reasonable cost.

- The potential to mitigate most of these “irreducible residual risks” will increase rapidly once CCUS is operating in a CCUS cluster, and once further projects join the cluster CCUS network. However, for early CCUS projects, and for a limited period, HMG will need to facilitate the management of these irreducible residual risks; and if any costs do materialise, they will need to be borne by either tax revenue or by consumers.

- The CAG believes that the proposed management of residual risks gives a suitable balance between reducing costs of CCUS deployment and placing risk outside the private sector.

- This report also addresses the issues of:
  - The role of a “Programme Development Consortium” in each cluster to work with HMG, local government and other stakeholders to ensure that the first developments in a cluster succeed;
  - the appropriate sizing of assets of early CCUS projects, and;
  - potential sharing between the private sector and HMG of funding of the development costs for early CCUS projects.

- Finally, this report contains discussion papers on:
  - Metrics that might be used to assess and compare CCUS projects which may assist in prioritisation and schedule of CCUS role out;
  - the Delivery Capability required across government and industry to develop CCUS in the UK at scale, including the organisation types and bodies best suited to optimise strategy and execution, and;
  - the role of Competitive Tension in reducing CCUS project costs to ensure best value is derived from costs carried from tax revenue and by consumers.

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$^4$ Bioenergy with CCS.
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CHAPTER 1 - INTRODUCTION

The UK CCUS Action Plan

The UK Government (HMG) published the “CCUS Deployment Pathway - An Action Plan” in November 2018. This plan “is designed to enable the development of the first CCUS facility in the UK, commissioning from the mid-2020s”; in order to “realise the ambition for the UK having the option to deploy CCUS at scale during the 2030s, subject to the costs coming down sufficiently”.

The CCUS Action Plan announced that “in 2019 we will commence detailed engagement with industry on the critical challenges to delivering CCUS in the UK, in particular the cost structures, risk sharing arrangements and the necessary market-based frameworks.” The CAG was established as part of providing that engagement.

The CCUS Action Plan also announced that a Review of Delivery and Investment Frameworks was underway, committing to “consult on our findings in 2019, announcing the outcome of the review by the end of 2019”. This report has been produced by the CCUS Advisory Group (CAG) to support that consultation.

Net Zero

Since publication of the CCUS Action Plan and agreement of the CAG Terms of Reference (see below), there has been a substantial change in UK policy. The new commitment is to meet a target of 100% reduction (i.e. “Net Zero”) in CO₂ emissions by 2050, rather than the previous 80% target.

In their advice to HMG on what achieving “Net Zero” might mean, the Committee on Climate Change issued a report which includes the following:6

- “Our assessment is that delivery of CCS requires action on CO₂ infrastructure, development of the hydrogen option and policy frameworks across energy generation, industry and greenhouse gas removals:
  - **CO₂ infrastructure.** An approach to CO₂ infrastructure development and funding is needed that is separate from that for individual projects. CO₂ infrastructure roll-out and initial projects should lead to multiple CCS clusters being operational by the mid-2020s, and all major clusters having CO₂ infrastructure by around 2030.
  - **Development of the hydrogen option.** Given the importance of hydrogen in our net-zero scenarios, especially in industry, and the importance of CCS to its production at large scale, hydrogen production should start at scale by 2030 at each of the industrial CCS clusters.
  - **Policy Frameworks.** Delivery of CCS projects across the range of applications requires a policy framework that covers energy generation, industry and greenhouse gas removals...... Given the scale of BECCS that might be required by 2050, the Government should aim to have an initial BECCS project at scale early on (e.g. by around 2030).”

The UK CCUS Advisory Group (CAG)

The CAG is an industry-led joint collaboration, including both industry and HMG members, that has worked in partnership with HMG to advise on the critical challenges that face CCUS as defined in the Action Plan.

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5 “The UK carbon capture, usage and storage (CCUS) deployment pathway: an action plan”. BEIS. November 2018.
6 “Net Zero - The UK’s contribution to stopping global warming”. CCC May 2019 pp 198
CHAPTER 1: Introduction

The core membership of the CAG consisted of 19 corporate bodies actively involved in CCUS project development in the UK, as well as Department of Business, Energy and Industrial Strategy (BEIS), Scottish Government and HM Treasury (HMT). Participation is voluntary, and non-exclusive. Principles of working include transparency, and inclusive governance. Papers and recommendations are to be made public.

The CAG’s role is not advocacy. The case for whether, when and what CCUS projects should be developed in the UK has and continues to be made elsewhere. The CAG’s role is to advise on “How” CCUS could be deployed in the UK.

However, the CAG has recently been mindful of the change in UK policy, and has kept in mind that the chosen options need to be robust to an accelerated ambition - if it materialises - compared to that stated in the CCUS Action Plan.

The CAG was established in March 2019 and issued its final report on 22nd July 2019.

The CAG Terms of Reference (TORs) are shown in Appendix 2. Most of the deliverables in the TORs were delivered in July 2019.

A key part of the CAG’s work was to consider OPTIONS. The Options Papers, which form a key part of this report, document the wide range of options considered for all aspects of the CCUS business models, and the reasons for choosing the preferred options. The intention is to provide policy makers with an understanding of the options they have, to allow them to make informed choices.

The Options Papers, business models and commercial papers were developed by the CAG in numerous workshops and sub-groups. They therefore reflect the collective synthesis of views of the CAG derived through that process rather than purport to be the precise views of any individual member. It is expected that alternative views may be aired through the forthcoming consultation or expressed in private to HMG.

Key CAG Deliverables - Delivered in this Report

The CAG Terms of Reference, as shown in Appendix 2, asked the CAG to focus on the following areas.

Market frameworks

- The CAG has considered a range of high-level business models - called Variants - that cover the credible ways in which CCUS projects could be established in the UK in the future.
- The CAG has developed detailed business models for Variant 1 (the Base Case) for each of CO₂ transport and storage, power production with CCUS and industrial CCUS. In doing so, the CAG considered how these business models interact with each other to minimise issues such as cross-chain risks that arise from adopting a “split chain” structure.
- The CAG has identified both potential sources of revenue support and delivery mechanisms for delivering that revenue support; and identified the sources of that revenue support (including groups of consumers, and tax revenue).
- The CAG has recommended ownership and capital financing structures, including considering development costs. The CAG has recommended models in which we assume all or most CCUS cluster developments will be off HMG’s balance sheet. The CAG has, however, made no formal assessment of whether that will be the case.
- The CAG has considered ranges for the likely costs of capital that might flow from each model, and the overall cost of capital for CCUS developments as a whole.

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7 The CAG Terms of Reference envisaged Industrial CCUS and Hydrogen Production with CCUS would be considered together. However, it became clear early in the work that the issues concerning business models for hydrogen production with CCUS and industrial production with CCUS differed substantially. The work on these was therefore separated.

8 The meaning of the terms Variants, and CCUS business models, as well as the components of a business model, are described in Chapter 2 on page 14.
The CAG has identified in a number of areas the “enduring regimes” that may be needed to deliver CCUS at scale, and how the business models recommended might evolve to those enduring regimes.

**Risk allocation, mitigation and management**

- We have identified detailed risk allocation and mitigation options across the recommended business models. In doing so we have considered how these might affect price, contingent liabilities and balance sheet treatment.
- In some areas we have referred to how risks may evolve over time, and how the risk allocations and mitigations may be updated as a result.
- We have modelled and considered the impact of each option on overall WACC and capital structures of developers but have not reported on that work in detail in this report.

**Delivery Capability**

- We have provided a discussion paper that considers the delivery capabilities needed in the UK to support deployment of CCUS, how these capabilities can be created, and the actions needed to create them.

**Costings**

- We have modelled the ranges of estimated costs of prospective CCUS projects, using public domain information, in order to test the likely impact of business model structure on costs. We have used these to inform our recommendations on the business model structures.

**Metrics**

- We have provided a discussion paper on the metrics that could be used to assess CCUS projects.

**Competitive Tension**

- We have provided a discussion paper on the constraints and benefits of competition. This describes where competitive pressure can drive cost reduction, and where other approaches, particularly collaboration, might prove more productive. It also describes how competitive pressures can be maintained in CCUS in a framework which does not use standard competitive government procurement processes.

**Key CAG Deliverables - Possible Future Work**

Some issues in the TORs have not been fully addressed in this report. These may be covered by future work.

- We have done limited modelling of sensitivities of costs to features of the business model choices. The work done in economic modelling has informed a number of the recommendations.
- Legislative, Regulatory and State Aid implications of the business model choices have not been reviewed in detail, though CAG member’s experience of these issues has been taken into account when considering the recommendations.
- We have not given detailed consideration to BECCS, and the mechanisms by which negative emissions can be monetised.
- We have not tested the recommended business models with the financial community. Given the recommendations made, and the need for both equity and debt financing of T&S, this would now appear to be important.
CHAPTER 1: Introduction

Key Issues, Challenges and Trade-offs

One goal of the CCUS Advisory Group has been to identify the actions required by the private sector and government alike that will together deliver a successful CCUS industry for the UK by the 2030s and at low cost. Achieving this involves overcoming the challenges to CCUS of conventional private sector business models, and finding the best balance between many competing issues.

Some significant examples are listed below.

- Despite the UK having higher carbon prices than many other countries, at current and foreseeable carbon prices, there is no economic incentive to develop CCUS in the UK. Low carbon products cannot displace incumbent equivalents that do not pay for their impact on the climate. CCUS-related premia may not be recoverable from customers, and there are no widely accepted standards for ‘low carbon’ products today.
- There is a tension between actually “getting the first projects done” and the need to establish an “optimal” path to an enduring regime.
- First of a kind projects (FOAK) are usually more expensive than and may therefore require more financial support than those that follow.
- Some risks in a single project can have a major impact on the entire chain. The ability to manage and finance these risks becomes easier as more projects are developed, and risks and mitigations are shared across a network with more sites and stakeholders.
- Transport and storage (T&S) can raise finance at low cost if it can be set up with low risk. T&S for the first CCUS project in a cluster could however be - initially at least - a relatively high-risk activity.
- It may be challenging to coordinate separate final investment decisions (FID) taken by separate projects (CO₂ capture projects and T&S projects).
- The cost of “right-sizing” infrastructure for growth in demand needs to be borne by someone.
- Because CO₂ capture assets and T&S assets are interdependent, there are “cross-chain risks” that parts of the chain may be late, constrained, or unavailable.
- Companies may not be able to commit to the costs of CCUS ahead of their global competitors. Unilateral imposition of low carbon standards without carbon border adjustments or revenue support will cause UK manufacturing to move “offshore”.
- In new regulated markets it may be desirable to provide significant discretion to the regulator, although this creates significant regulatory risk for market participants.
- Collaboration between developers of infrastructure in a new CCUS industry will create significant value and reduce risk. However, this may sit in tension with a general philosophy of reducing costs through competition.
- CCUS offers the opportunity to create valuable negative emissions (for example using BECCS⁹ and DAC¹⁰). To meet emissions reductions targets it may in fact be better to reward the capture and storage of CO₂ rather than the production of low-carbon energy or products.

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⁹ Bioenergy with Carbon Capture and Storage.
¹⁰ Direct Air Capture.


CHAPTER 2 - BUSINESS MODEL VARIANTS

Introduction to CCUS Business Models

In the context of deploying CCUS in the UK, the term “business model” refers to the commercial, legal, regulatory, financial and risk structures that HMG and investors in CCUS projects will agree on.

Broadly speaking, the business model will include, amongst other things, the following:

i. Commercial Model - the commercial structures that will be used by CCUS projects, including ownership, financing and any regulatory features;

ii. Source of Funding - the source and mechanisms by which revenue support will be delivered from either consumers or tax revenue to the projects;

iii. Risk Management - the risk allocation and mitigation structures.

These are jointly referred to in this paper as comprising the “Business Model”.

This report uses the following terminology:

- “Financing” is the money raised to invest in projects (capital expenditure, working capital etc).
- “Funding” is the money used to pay for capital repayment, a return on capital and operating costs.
- “Revenue Funding” is the money required to be economically viable, over and above that provided by customers in the marketplace. (This use of the term is specific to this report, and it may have other connotations in other circumstances.)
- “Funders of CO2 Capturers” are the sources of the “Revenue Funding”. The CAG’s recommendation is that for the first CCUS projects:
  - for Electricity Generation projects with CCS this should be the LCCC;
  - for Industrial projects with CCS this should be HMG providing funds from tax revenue.

The CCTF recommended business models

In 2018 the UK CCUS Cost Challenge Task Force (CCTF) was set up by HMG to inform and propose a strategic plan for supporting the development of CCUS in the UK. It reported in July 2018.11

The CAG started with the three business models that were proposed by the CCTF. These were:

1. CO2 Transport and Storage would be owned, financed and operated by the private sector, and regulated under a RAB (Regulated Asset Base) system. Its revenues would come from customers who capture CO2 and deliver it for transport and then permanent sequestration or storage by the T&S RAB holder/operator;

2. Electricity Generation with CO2 Capture would be privately owned, financed and operated, and unregulated. Its revenues would come from the wholesale electricity market in the UK, and be supplemented by a modified Contract for Difference (CfD) funded by UK electricity consumers;

3. Industrial Production with CO2 Capture would be privately owned, financed and operated. They would be funded from tax credits provided by HMG for each tonne of CO2 captured and stored.

The CCTF recommended that, in the main, risks would be managed by each project; and that “cross chain risks” would be dealt with through contractual relationship between the projects. However, there would also be an “irreducible core of risks - those which the private sector, at least initially, could not price or take” which should “be initially shared by Government and industry and transferred to the private sector as the CCUS sector matures.”12

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The Business Model Variants

The CAG has considered a range of high-level business model structures that could be adopted for developing CCUS in the UK. These have been described in thirteen Business Model “Variants”. A high-level description of each is given below, and further detail on each is provided in Chapter 20.

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<td><strong>CORE VARIANTS</strong></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>T&amp;S receives a Grant for initial capex in a cluster</td>
</tr>
<tr>
<td>3</td>
<td>HMG owns T&amp;S (prior to privatisation)</td>
</tr>
<tr>
<td>4</td>
<td>Single privately-owned UK-wide T&amp;S RAB</td>
</tr>
<tr>
<td>5</td>
<td>HMG owns UK-wide T&amp;S RAB (prior to privatisation)</td>
</tr>
<tr>
<td>6</td>
<td>Public-private ownership of T&amp;S</td>
</tr>
<tr>
<td>7</td>
<td>Regulated capture - separate RABs for individual parts of the CCUS chain</td>
</tr>
<tr>
<td><strong>OTHER VARIANTS</strong></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>A single RAB covers a “condominium” capture plant(s) and T&amp;S assets</td>
</tr>
<tr>
<td>9</td>
<td>Separate onshore CO₂ transport and CO₂ storage businesses(^\text{13})</td>
</tr>
<tr>
<td>10</td>
<td>A single RAB structure for most of CCUS</td>
</tr>
<tr>
<td>11</td>
<td>HMG initially own Electricity and T&amp;S assets, prior to privatisation (“Oxburgh”)</td>
</tr>
<tr>
<td>12</td>
<td>Private sector full chain CCUS development, with some HMG risk-share</td>
</tr>
<tr>
<td>13</td>
<td>“Fixed Price, Project Finance” structure for T&amp;S - HMG share some risks</td>
</tr>
</tbody>
</table>

- The Base Case - known as Variant 1 - is based directly on the recommendations of the CCTF. It has however evolved from that structure in some aspects of the model, as described below.
- The specific structures of the Variant 1 Business Models have been developed in considerable detail, roughly at a conceptual or “Memorandum of Understanding” level. Detailed commercial and legal drafting would be required to resolve the many detailed issues not addressed at this level. These detailed models are shown in Chapters 5, 8 and 11.
- All the other Variants can be compared to this Base Case (Variant 1).
- Variant 2 and Variants 3 to 7 are the Core Variants to consider alongside the Base Case i.e. Variant 1. Summaries of the differences between Variant 1 and these models have been included in the detailed Business Model documents.
- Variants 8 to 12 are other variants which - for a variety of reasons explained below and in Chapter 20 - are less likely to be suitable for the UK. They do, however, contain elements which may be worth considering in the future as the CCUS industry evolves in the UK.
- The following is a short description of each Variant. A more detailed description, plus a diagram representing each Variant, is contained in Chapter 20.
- The CAG recommends Variant 1 as a suitable basis for developing the first CCUS projects in a cluster in the UK, and Variants 2 to 7 as suitable alternatives that should also be considered.

---

\(^{13}\) Onshore pipelines and CO₂ Shipping are grouped together as they both usually use onshore facilities at each end of their delivery.
### Variant 1 – Base Case

**Private/Unregulated**
- **Electricity**
- **Industrial**
- *Grants?*

**Regulated/RAB**
- **Hydrogen***

**T&S**
- **CO₂ Shipping**

**Gov’t**

<table>
<thead>
<tr>
<th>Production/Generation</th>
<th>CO₂ Capture</th>
<th>Onshore Pipelines/CO₂ Shipping</th>
<th>Offshore Transport</th>
<th>Offshore Storage</th>
</tr>
</thead>
</table>

- This Base Case is described pictorially in this diagram:
- This case is based broadly on the structure recommended by the CCTF report in 2018, but with some significant changes. In the CAG’s view this could represent a long-term enduring model, which perhaps fits best with current HMG policy on energy markets and infrastructure ownership.
- This is seen as the most suitable model against which other Variants can most usefully be judged.
- Key aspects of the asset ownership and financing within Variant 1 are:
  - T&S assets for a cluster would be privately owned and financed, regulated through a RAB structure, and funded through T&S fees charged to their customers;
  - If CO₂ shipping is required, it would probably be sub-contracted to private companies by the T&S company;
  - Electricity generation would be privately owned and financed, and funded through a “Dispatchable CfD contract” held with the LCCC;
  - Industrial CCUS projects would be privately owned, financed privately (but possibly with HMG grants as well), and funded by HMG.
  - Hydrogen production would be privately owned and financed. A low-carbon hydrogen industry could develop without commercial regulation; or as a regulated industry operating in regulated markets, perhaps using RAB structures.

- Similar diagrams for the other Variants are shown in Chapter 14.

### Variant 2 – T&S receives a Grant for initial capex in a cluster

- T&S would receive a grant to cover all or most of the capital investment in the first T&S assets in a cluster.
- This model would have advantages if the structures described in Variant 1 to allocate and mitigate cross-chain risk are deemed by HMG to be unacceptable.

---

15 The CCTF suggested that the existing “CfD model could be adapted to incentivise flexible generation through allowing targeted revenues”. CCTF report p52.
A grant could also be considered to support the oversizing of a T&S asset to allow for tie-in of future emissions.

**Variant 3 – HMG owns T&S (prior to privatisation)**

- HMG ownership of T&S would probably allow CCUS development with the lowest cost of capital for T&S, and would simplify the initial cross chain risk allocation and management. These risks will also decline as the T&S network expands, but any remaining cross chain risk issues would need resolution ahead of any privatisation. The arguments for and against HMG ownership of T&S are discussed in Options Paper 4A: T&S Co Commercial Model and Returns (p.37)

**Variant 4 – Single privately owned UK-wide T&S RAB**

- Rather than each cluster having a separate T&S RAB, a single privately-owned T&S RAB could be developed for the whole of the UK, holding the T&S assets of all UK clusters.
- This gives advantages of scale, perhaps speed of execution, and possibly better inter-connectivity. However, it may add complexity, and possibly risks fragmentation of project development.

**Variant 5 – HMG owns UK-wide T&S RAB (prior to privatisation)**

- In this case, HMG would own a single T&S RAB for the whole of the UK, holding the T&S assets of all UK clusters. In addition to the arguments for Variant 4, this could reduce T&S costs, and simplify cross-chain risks further. Again, these arguments are discussed in Options Paper 4A: T&S Co Commercial Model and Returns.

**Variant 6 - Public-private ownership of T&S**

- The private sector owns a majority share in T&S and HMG owns a minority share. HMG could contribute both equity and debt. This would demonstrate a joint HMG-industry commitment to deliver and provide aligned incentives when addressing risks.

**Variant 7 – Regulated capture - separate RABs for individual parts of the CCUS chain**

- If, in the future, the profit of electricity generation is regulated, or if a RAB model is implemented for nuclear power generation, then a RAB model could be adapted to cover power generation with CCUS as well. A similar model could also be developed for separate RABs for hydrogen generation. A RAB model could also be used to govern a new company charged with financing and delivering industrial CCUS projects.

**OTHER VARIANTS: 8 TO 13**

**Variant 8 – A single RAB covers a “condominium” capture plant(s) and T&S assets**

- A “condominium” CO₂ capture plant would be a post-combustion capture plant that serves a number of investors who jointly own the plant, and who each send their flue-gas or process gas to the capture plant to have the CO₂ extracted and sent for storage.

This is a credible option though it may perhaps be somewhat project and location specific. It requires commitment to CO₂ separation from flue gases as the technology of choice.

**Variant 9 – Separate onshore CO₂ transport and CO₂ T&S businesses**

- Once clusters are well established it may sometimes make sense to separate Onshore Transport from Offshore T&S to create three (or even four) parts to the CCUS “chain”. The additional interface could create significant cross-chain complexity, and in the shorter term it is most likely to be more effective if Onshore Transport is sub-contracted by either the T&S assets or the Capture assets.
CHAPTER 2: Business Model Variants

Variant 10 – A single RAB structure for most of CCUS

- This model is included for completeness. It currently seems unlikely that a single RAB containing all CCUS assets would add value. The benefits of separating the CCUS “chain” to allow “logical” owners and developers of each part of the chain may be lost, although cross-chain issues might be easier to handle.

Variant 11 – HMG initially own Electricity and T&S assets, prior to privatisation (“Oxburgh”)

- This may accelerate development, allow strong management of CCUS risks, and minimise cost of capital of initial CCUS developments. All assets would initially appear on HMG’s balance sheet.

Variant 12 – Private sector full chain CCUS development, with some HMG risk-share

- If HMG do not wish to take on all of the “irreducible risks” required in the models above, CCUS could be developed using the Business Model used in the 2012-15 UK CCUS Commercialisation Programme. This would place higher risks and returns with the private sector developers and would increase CCUS costs considerably. The project scope, procurement process and risk allocation process would need to change substantially from that used previously if the projects were to be financeable.


- This is a sub-case of Variant 12. The characteristics of “project finance” structures are described in Appendix 1.
- T&S would receive a fixed price T&S fee structure with no change depending on demand changes or cost changes. T&S would be financed using project finance (i.e. usually equity plus debt in a “special purpose vehicle” company (an SPV) which isolates the performance of the project inside that company.) HMG would share some risk in T&S, but not in Capture. Again, this would place higher risks and returns with the private sector developers and would increase CCUS costs, as risk premia would be added for risks that may not transpire.
- Under this arrangement, T&S would be receiving a “capacity reservation” fee for making T&S available. It would not be taking demand risk, nor risk on the performance of CO₂ suppliers (as it could not provide a fixed price for elements and risks it would not control), but would take fixed price T&S risks, such as the cost of store management, necessary wells and operating costs.
CHAPTER 3 - RECOMMENDATIONS FOR THE VARIANT 1 BUSINESS MODELS

Introduction

- The CAG has considered in detail the design of specific Business Models for three businesses:
  - CO₂ Transport and Storage;
  - Electricity Generation with CO₂ Capture, and
  - Industrial Production with CO₂ Capture.
- The CAG’s discussion on Hydrogen business models have not advanced to the point where a detailed business model could be developed for Hydrogen. The position on BECCS is the same. However, the principles for both Hydrogen and BECCS business models are discussed in this report, and in this chapter.
- The specific structures for each of the Business Models of the Base Case (Variant 1) have been developed in detail, at a conceptual or “Memorandum of Understanding” level. Detailed commercial and legal drafting would be required to resolve the many detailed issues not addressed at this level.
- This report also discusses the issues that might lead to adopting one of the other business model Variants described in Chapter 20.
- Some of these issues are specific to the individual business. Others, however, are common to all the business models. These common features fall into two groups:
  - Cross chain issues. These relate to the impact on a business when the business in the other part of the chain fails to perform - whether partially, temporarily or completely.
  - Development issues. These relate to the way in which businesses in separate parts of the chain will need to work together to synchronise, coordinate, define and then develop their projects. It also covers the issue of funding project development activities.
- The CAG has developed recommendations for how all these issues (both business-specific and common) could be managed as clusters to develop their first projects.
- These are described in the sections below. The business specific issues are tackled first, followed by the common issues.
- The fundamental idea is that the recommendations for all the business model issues in Variant 1 form a coherent package, within which “split chain” projects in a cluster are bankable and deliverable.
- These business models are a potential starting point for future negotiations between clusters, projects and HMG. Not all issues are fully resolved, and not all projects will have the same requirements.
- There will be some optionality in how HMG may choose to facilitate some risks. HMG may be able to resolve some of that optionality independently. However, some of those choices may only be made when more detailed proposals come forward from the clusters and projects, and when negotiations commence.

Residual Risk Management in the Variant 1 Business Models

A core consideration in the design of these business models is the way that risks are managed. This includes where the risks fall under the terms of the model, and most importantly, how they can be mitigated. This is spelled out in detail in each of the three business models in Chapters 4 to 12 of this report.
It is usual, and therefore assumed, that all key stakeholders in a major project will run effective risk management processes that manage and mitigate the “Business as Usual” risks they face arising through their involvement in the project.

However, once these “Business as Usual” risks have been mitigated using “Business as Usual” processes, a number of important “Residual Risks” will remain to be managed and mitigated. The key Residual Risks for the stakeholders in the development of early projects in a new CCUS cluster are shown below for each of the three business models. (“Business as Usual” risks are not listed - that is for stakeholders to do themselves.)

The following tables show how these residual risks are allocated in these business models. The specific means by which each of these risks can be mitigated are shown in Chapters 6, 9 and 12 respectively.

### T&S Business Model - Variant 1 - Residual Risk Allocation

<table>
<thead>
<tr>
<th>Risk Sits With:</th>
<th>T&amp;S Co Equity Shareholders</th>
<th>Funders of CO₂ Capturers</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>RAB Incentives and Penalties Regime</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RAB Regulatory Risk</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RAB “Non-Allowable Costs”</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Third Party Access</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uncertain Calls on Cash</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Financial Security - EU Directive</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shareholder Exit</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ delivered off-specification (borne by capture plant)</td>
<td>n/a</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Costs and Timetable</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>T&amp;S Performance and Costs</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Cross Chain Failure - T&amp;S Assets Not Available</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Cross Chain Failure - Capture Plant does not Deliver CO₂</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cost of Contingency Funds</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Permanent Store Closure</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>CO₂ Leakage from Store</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Project Fails post-FEED - Loss of Development Funding</td>
<td>✓</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>“State Aid”</td>
<td>✓</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>HMG acts as “Insurer of Last Resort”</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Pre-commissioning Stranded Asset Risk - no Capture Plant</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Change in Law, Policy</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>

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16 This would be LCCC for Electricity Generation projects with CO₂ capture; and tax revenue (via HMG) for Industrial production with CO₂ capture.
## ELECTRICITY BUSINESS MODEL - VARIANT 1 - RESIDUAL RISK ALLOCATION

<table>
<thead>
<tr>
<th>Risk sits with:</th>
<th>EG&amp;Co Equity Shareholders</th>
<th>Electricity Consumers (via LCCC)</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction - Costs and Timetable</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>EG&amp;Co Plant Performance and Costs</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>CO₂ delivered off-specification</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Uncertain Calls on Cash</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Cross Chain Failure - T&amp;S Assets Not Available - Temporarily or Permanently</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Cross Chain Risk - Capture Plant Does Not Deliver CO₂ to T&amp;S Co</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Fuel Price Indexation</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Project fails post-FEED - Loss of Development Funding</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>State Aid</td>
<td>✓</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Pre-commissioning Stranded Asset Risk - no T&amp;S System</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Change in Law, Change in Policy</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>

## INDUSTRIAL CCUS BUSINESS MODEL - VARIANT 1 - RESIDUAL RISK ALLOCATION

<table>
<thead>
<tr>
<th>Risk sits with:</th>
<th>Equity Funders</th>
<th>Tax Revenue (via HMG)</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction - Costs and Timetable</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>IP&amp;Co Plant Performance and Costs</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>CO₂ delivered off-specification</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uncertain Calls on Cash</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cross Chain Failure - T&amp;S Assets Not Available - Temporarily or Permanently</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Cross Chain Risk - Capture Plant Does Not Deliver CO₂ to T&amp;S Co</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Loss of Development Funding</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Project fails post-FEED - Loss of Development Funding</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>State Aid</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Pre-commissioning Stranded Asset Risk - no T&amp;S System</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Change in Law, Change in Policy</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>
Recommendations - Specific Business Models

**CO₂ TRANSPORT AND STORAGE**

**Opportunity**

- The CCTF recommended that the T&S assets for a cluster should be privately owned and financed, regulated through a low-risk (i.e. high revenue certainty) albeit low-reward RAB structure, and funded through T&S fees charged to their customers.

- This CCTF recommendation was based on two competing pressures:
  - The drive to reduce costs of CCUS, and T&S within it, as far as possible by establishing T&S as a low-risk, low return business earning “infrastructure” rates of returns;
  - Using a model that keeps the T&S assets off HMG balance sheet.

- T&S for the first CCUS projects could be - initially at least - a relatively high-risk activity until the store is well established and a network of interlinked capture and T&S assets has been created and experience with store performance reduces the perception of potential risks. The risks, whether perceived or real, will then drop substantially.

- The T&S RAB structure allows much of the early risk to be passed to a wide base of either consumers or tax revenue, with ample capacity to absorb the risk. This allows the private sector to accept a lower risk profile, and therefore a lower return.

- And beyond that, this structure then allows HMG (through the taxpayer) to take the responsibility for addressing - often at no or low cost to the taxpayer - those irreducible risks that simply cannot be left with the private sector nor passed to consumers.

**Recommendations**

- Two main types of business models for T&S are therefore available:
  - Variant 1 - the Base Case - which follows the CCTF recommendation to create one or more T&S RAB structures with utility rates of return and risk, which keeps costs low, and;
  - Variant 3 which envisages initial HMG ownership of T&S infrastructure followed by privatisation when the T&S system has sufficient experience to price in the remaining risks properly.

- Putting aside the issue of the “HMG balance sheet”, there is a balance of advantages and disadvantages to HMG T&S ownership. At its heart is the fact that HMG clearly has the capacity to absorb the costs, risks and uncertainties of a first T&S investment; while on the other hand if privatisation is the clear end-goal then little may be gained from HMG ownership rather than HMG simply facilitating the management of those irreducible risks that it need to facilitate in either case.

- The choice between these main Variants will depend on HMG’s attitude to the “irreducible risks” that HMG will need to facilitate under each model. These risks reduce with greater direct involvement by HMG in the models.

- The key challenge to delivering Variant 1 is whether the T&S RAB offers the right investors sufficient incentive to invest in the business; whether HMG will accept that significant risks can be passed to consumers or tax revenue; and whether HMG will agree to facilitate mitigation of (and in extremis for tax revenue to absorb) the residual risk that neither consumers nor investors can accept.

- Variant 2 provides a further alternative, which would be to mitigate some cross-chain risk by supporting all of (or most of) the initial capital expenditure for T&S in a cluster using an HMG grant. A grant could also support the oversizing of a T&S asset to allow for growth.

- In this case, the need for cross-chain risk protection for T&Sco is removed **both** in the case where CO₂ capturers do not deliver CO₂ to T&Sco; **and** in the case where T&Sco is not functioning for
CHAPTER 3: Recommendations for Variant 1 Business Models

whatever reason. T&S Co would then not need to receive the fixed “capacity reservation payments” in these cases, because it would not need to service or repay equity and debt used for the initial capital expenditure in a cluster.

- Depending on the nature of the proposed project, and circumstances at the time, this may prove a suitable way forward. This device would only be needed for the first T&S investment in any CCUS cluster.
- The CAG endorses the choice of any of these three options. All three are credible - the choice revolves around ease of implementation, timing and ambition.
- The CAG believes that Variants 1 and 2 are both likely to prove acceptable to some equity and debt investors in a T&S project using these models.

ELECTRICITY GENERATION WITH CO₂ CAPTURE

Opportunity

- Electricity Generation with CO₂ Capture can provide economical low-carbon dispatchable (or “flexible”) electricity generation capacity which can replace the unabated dispatchable electricity generating capacity currently provided by gas-fired CCGTs. This will represent a very significant role in the future UK energy system.
- The increase in deployment of intermittent renewable capacity means that the system value of dispatchable generation is likely to increase.
- The existing CfD structure features a single strike price, paid on dispatch only, which does not incentivise dispatchable (or “flexible”) generation capacity.
- The Business Model for Electricity with CCUS needs to be designed to allow such plants to deliver this role.

Recommendations

- The CCTF recommends that Electricity Generation with CCUS be privately owned and financed and funded through a CfD. It also suggested that “…the CfD model could be adapted to incentivise flexible generation through allowing targeted revenues.”
- Following from this, the CAG recommends that Electricity Generation with CO₂ Capture be privately owned and financed.
- The CAG recommends that funding comes from the LCCC, which is in turn funded by electricity consumers (as with existing CfD contracts in the UK). This would be consistent with other low-carbon electricity generation.
- The CAG is recommending the introduction of a “dispatchable CfD”, which would include fixed and variable payments. This would be designed to bring forward investment in dispatchable low-carbon generation capacity, including electricity generation with CCUS.
- The design of the “dispatchable CfD” is intended to ensure that electricity plants with CCUS would dispatch ahead of unabated gas-fired plants, but behind renewables and nuclear generation, thereby acting as a key source of low-carbon flexibility.
- The regular fixed payments from LCCC would broadly cover capital expenditure and fixed costs, including a direct pass-through of the T&S capacity reservation fees. It may be subject to additional incentive mechanisms relating to performance targets.
- The majority of variable revenue will come from the wholesale market. There will also be a net CfD payment which may be either positive or negative, comprising of:
  - A cap on margin, with excess paid by the plant to LCCC
  - A start-up support payment from LCCC to the plant for each start-up

CHAPTER 3: Recommendations for Variant 1 Business Models

- A dispatch incentive payment from LCCC to the plant to ensure dispatch ahead of unabated gas plants, given prevailing gas and carbon prices. It will be indexed to take into account both fuel price and carbon price.

- The proportion of fixed to variable payments will be based on further evaluation by HMG and discussions with individual projects.

- The CAG is recommending that the first such modified CfDs include an initial period allowing for baseload generation to establish stable operations (a ‘proving’ period) or additional support to allow the plant to develop experience in dispatchable generation.

- The contract length needs to recognise the expected long life of new CCUS plant. It is recommended that the “Dispatchable CfD” contracts run for at least 20 years. This would reduce the annual level of revenue support required, incentivise unabated operation for a longer period, underpin the investment in the initial T&S infrastructure, and make project financing more manageable.

- Analysis of the levels of revenue support justified for “dispatchable” electricity will need to pay careful attention to the correct metrics for judging such an investment. These should specifically cover the system value of dispatchable low-carbon electricity - and not just the levelized cost of electricity (LCOE) metrics that apply to intermittent or baseload plant. They should also value the total integrated energy system value of low carbon dispatchable generating capacity, as both the energy sector and other sectors of the economy are decarbonised. The CAG was unable to analyse this issue in depth, and more work is needed on this issue. This is discussed in further in Chapter 17.

INDUSTRIAL PRODUCTION WITH CO₂ CAPTURE

Opportunity

- Industrial decarbonisation is challenging, and Industrial CCUS provides one of the few routes to cut emissions from industrial processes. It provides an opportunity for investments in low carbon manufacturing and process industries, and will be essential if the UK is to meet its Net Zero target cost effectively.

- There are currently a number of industrial point sources in the proposed CCUS clusters where significant CO₂ emissions CO₂ can be captured - either as a by-product from industrial production process (ammonia for fertiliser, steel, cement) or through post-production capture of CO₂ from waste and flue gases which are currently emitted to atmosphere (refineries, chemical plants, and others).

- Some of these emissions can be captured in quantities and at costs which compare favourably to other carbon abatement opportunities faced by the UK.

- Amongst others, the CAG considered the six possible options previously identified by Element Energy18 and Poyry19 for supporting the development of CCUS projects of industrial producers.

Recommendations

- The CAG recommends that an “Industrial CCUS Contract” be developed to deliver such projects.

- Two commercial models are recommended by the CAG as credible options for early development of projects for industrial production with CO₂ capture.

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19 Some of these options had also been described and evaluated earlier by Poyry. “A Business Case for a UK Industrial CCS Support Mechanism.” A report produced in partnership with the Teesside Collective. February 2017.
CHAPTER 3: Recommendations for Variant 1 Business Models

1) HYBRID GRANT PLUS CO₂ “CONTRACT FOR DIFFERENCE” MODEL.

- This is based on the Element Energy “CfD+ abatement strike price” proposal20; however, as suggested by Element Energy, it also includes an HMG grant to support capital expenditure.
- In this model the “Industrial CCUS Contract” would be between the industrial producer and HMG. The contract will have three elements:
  
  i. Capital Cost Recovery

  - The capital cost recovery element of the “Industrial CCUS Contract” will allow IP&CCo to earn a return on their capital investment.
  - Plant owners will invest in plant to capture CO₂, and HMG will support this with a grant towards part of the capital cost. A grant of at least 50% of the capex involved for the first capture sources in a cluster should be considered.
  - Once the plant is operational HMG will make a periodic fixed payment to the industrial producer to cover repayment of the capital invested, plus an agreed return on the capital investment. This would be set at a level which takes into account the fact that the capital is not at risk, and that the capital invested is repaid over a relatively short period of 3-5 years for retrofit plant, and potentially longer for new plant. It would stop once the capital had been repaid with the agreed rate of return.
  - Project developers will be expected to explain their requested rates of return through an “open book” approach with HMG, including comparing their proposals to their other project opportunities.

  ii. Operating Cost Recovery

  - There will also be a further “contract for difference” periodic payment between IP&CCo and HMG.
  - The “Industrial CCUS Contract” will provide for cost recovery of the operating costs based on a CO₂ contract for difference. This will be structured using one of the two following models:
    - The difference between the actual sales proceeds from the sale of surplus ETS allowances, and the actual fixed and variable operating costs of the capture plant, using “open book” principles. Contracts will be based on absolute rather than unit costs.
    - The difference between the CO₂ ETS income and an agreed “strike price” which will be agreed in advance, based on forecasts of fixed and variable operating costs and capture volumes. Costs will be normalized on a unit basis (i.e. on a £/t CO₂ contract basis) and may be reset periodically.
  - In order to incentivise operating cost reduction, if EU ETS income exceeds costs the excess will be shared between IP&CCo and HMG, perhaps in proportion to the percentage of the capex funded by the HMG grant.

  i. T&S Capacity Reservation Fee

- Finally, HMG will make periodic payments to IP&CCo to cover the agreed T&S capacity reservation fees. These would then be paid directly by IP&CCo to T&SCo.

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2) REGULATED “DECARBONISATION SERVICE COMPANY” (DSC) WITH A RAB

- In this case the “Industrial CCUS Contract” would be between the industrial producer and the “Decarbonised Service Company” as follows:
  
  o A new company - possibly regulated under a RAB model - would raise private sector finance to invest in CO$_2$ capture projects on industrial sites and provide a “decarbonisation service” to industrial emitters. This finance may also include HMG grants.
  
  o In some cases it may be appropriate for the individual industrial producer to be responsible for CO$_2$ capture plant construction and installation so as to avoid any complications regarding site interfaces and conflicts.
  
  o Revenue support would flow from HMG to the service company. This eliminates the need for industrial producers to invest directly in capture plant, or to require any revenue support mechanism for the IP&CCo.
  
  o The plant could be operated either by the DSC, or by their customers on the DSC company’s behalf.
  
  o HMG would make payments to this DSC to cover the operating costs, repayment of capital, and an agreed return for the company.
  
  o It is possible that the returns required by the DSC may be somewhat lower than for individual industrial producers, as the DSC may be able to spread their risks across a portfolio of projects.
  
  o It is possible, though not necessary, that this company could undertake other activities in the CCUS industry as well.
  
  o This will work well for “post-combustion” capture. Where capture is integrated into the process plant this may be more challenging; but an analogue of “plant leasing” may possibly make this workable for those plants as well.

- Whilst some form of auction for awarding the “Industrial CCUS Contracts” may be desirable, the drawbacks of auctions may be significant. Early potential projects are limited in number, and vary widely in their size, characteristics and potential level of revenue support required. The “depth of the market” needed to create a competitive process seems limited. The CAG recommends that - if possible, and subject to State Aid considerations - a system of bilateral negotiations for awarding Industrial CCUS Contracts is considered.

- There is no “logical” group of consumers or customers of the companies producing these industrial manufacturing emissions that could provide funding for these projects. The CAG therefore recommends that funding for such industrial projects is provided directly by HMG, from tax revenue.

- However, it is recognised that this can only be regarded as an interim source of funding, and a more suitable “enduring source of funding” will be needed for the future. The CAG recommends that alternative sources of funding for CCUS be considered for the future.

- A CCUS Obligation System using CCUS Certificates, supported initially by a CCUS Obligation Fund, is a future option for funding CCUS in the UK. This would be self-funding, would automatically introduce competition into the allocation of funds, and would avoid the need for any further CCUS revenue support from tax revenue or other customer groups in the future.

- The CAG is therefore recommending that for early projects direct payments are made between HMG and either the industrial producer or the “Decarbonised Service Company”, depending on the commercial model chosen.

- “Industrial CCUS Contracts” should have a two-phase structure, with early capital repayment and continued revenue support thereafter. Early projects may also need to include an “proving” period to gain experience of their process operations.
Opportunity

- The CAG agrees with the CCC that low carbon hydrogen has a key role to play in decarbonising the UK’s energy infrastructure.
- Bulk production of low-carbon hydrogen from natural gas (or other hydrocarbons) with CO₂ capture provides a wide range of opportunities to reduce CO₂ emissions.
- Around half of UK industrial emissions come from combustion of fossil fuel, mainly natural gas and process gases. Substitution by low-carbon hydrogen may represent a practical option to reduce these emissions across all industrial sectors.
- Other applications may include power generation, both small scale to “private wire” industrial installations, and large scale for supply to the grid transmission system; and supply of hydrogen in bulk for transport use (trains, HGVs, buses and some ships).
- Natural gas is widely used in domestic and commercial heating. Hydrogen use in existing and new gas networks provides a potential means to reduce these emissions.
- Initial deployments are likely to be for supply to industrial customers, power production, and injection in the gas network, through new pipeline distribution systems; with the addition of hydrogen storage as hydrogen networks expand.
- The first hydrogen projects may act as anchor projects for the creation of CCUS infrastructure as well as for hydrogen distribution infrastructure. Producing hydrogen from natural gas with CCUS (“blue hydrogen”) may establish a robust hydrogen infrastructure that “green hydrogen” (produced from electrolysis with renewable power) may then use.

Market

- The nature and possible evolution of any future hydrogen markets needs to be established so that support mechanisms can be defined.
- The CAG recommends consultation on the possible options for the development of a market or markets for hydrogen.

Support for Production of Hydrogen

- Hydrogen production assets could be built, owned and financed by the private sector. A low-carbon hydrogen industry could develop without commercial regulation; or as regulated industry operating in regulated markets, perhaps using RAB structures.
- Revenue support for low-carbon hydrogen production is best provided by the beneficiaries of the end-use of the energy delivered using low-carbon hydrogen. These are primarily users of gas (domestic, commercial, industrial and electricity producers). The costs could be socialised across these gas users generally, or more specifically funded by electricity consumers for those volumes used to generate electricity, tax revenue where it is used in industry, and gas consumers for the remaining volumes which would be used to generate heat via the gas networks.
- Potential mechanisms for delivering funding for low-carbon hydrogen production include:
  - funding revenue collection through a RAB structure;
  - premium payments from specific users;
  - a low-carbon Hydrogen CfD;
  - an Obligations-based system;
  - an incentive scheme like the Renewable Heat Incentive scheme; or

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21 “Net Zero - The UK’s contribution to stopping global warming”. CCC May 2019 pp 137
CHAPTER 3: Recommendations for Variant 1 Business Models

- HMG grants.
- The CAG supports consultation on the possible commercial structures and funding sources that may be used to support hydrogen production with CCUS.

Recommendations

- Given its future importance in decarbonising the UK energy system, the CAG recommends that low carbon hydrogen is part of the low carbon CCUS cluster developments during the 2020s.
- The CAG recommends that HMG consults urgently on options for developing a low carbon hydrogen market or markets.
- The consultation should seek views on possible market structures, commercial structures, financing options and funding sources to support low-carbon hydrogen production with CCUS.
- The consultation should consider whether the additional cost of low carbon hydrogen production, storage and distribution should be borne by electricity consumers, energy (gas) consumers or tax revenue, depending on the end-use of the energy delivered by low-carbon hydrogen.
- The consultation should consider potential options for mechanisms to provide revenue support. The CAG has identified a number of possible options.
- The CAG recommends that provision for the sources of funding and funding mechanisms for low-carbon hydrogen is included in the forthcoming White Paper.

BIOENERGY WITH CO₂ CAPTURE AND STORAGE - BECCS

Opportunity

- CCUS provides the opportunity not just to decarbonise energy or products, but also to create negative CO₂ emissions through Bioenergy with CCS (BECCS):
- Bioenergy with CCS (BECCS) represents one of the few technologies that can deliver negative emissions at scale, by removing carbon from the biosphere for permanent sequestration. As such, it is expected to play an important role in meeting the UK’s 2050 emissions targets. The CCC’s Further Ambition scenario (which identifies measures that “will definitely be needed for a net-zero emissions target”) states that up to 51 million tonnes of BECCS will need to be stored per year by 2050. This is based on an assumed overall biomass available to the UK for BECCS of around 173TWh.
- The CCC’s Further Ambition scenario estimates that bioenergy could account for up to 10% of primary energy in 2050. Of this, 6% of UK electricity in 2050 could be generated by BECCS, with the remaining bioenergy resources used to achieve decarbonisation in other sectors.
- The supply and availability of sustainable biomass globally, and in the UK, is not unlimited. It is therefore very important to prioritise its use to maximise carbon savings. As noted by the CCC in their Net Zero report, this means combining BECCS, “whether for power generation, hydrogen production or production of biofuels”.
- As outlined in the CCC’s 2018 Bioenergy in a Low Carbon Economy report, the UK should continue to take a global leadership role in ensuring strong sustainability governance of both domestic and international bioenergy feedstocks.
- As the CCC notes, in addition to BECCS and hydrogen production, bioenergy could also be deployed for biofuels. A combination of all of these approaches will play a role in achieving a ‘net zero’ economy by 2050.

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22 “Net Zero - The UK’s contribution to stopping global warming”. CCC May 2019 p149
23 “Net Zero - The UK’s contribution to stopping global warming”. CCC May 2019 p148
• Market mechanisms should be developed to encourage BECCS to operate with a high load factor to maximise the generation of negative emissions, in addition to low-carbon energy.

Monetising negative emissions

• A key issue for BECCS business models is that there is currently no framework in place for valuing negative emissions and providing a commercial return on them. Bioenergy is rewarded as renewable, but the value of capturing and storing CO\textsubscript{2} from that use cannot currently be monetised.
• The issue covers both the ultimate source of funding (e.g. tax revenue or consumers, and which consumers); and also, the mechanism for delivering such revenue support. (The limited work done so far (by CAG) indicates a potential role for EU ETS certificates (or equivalent) in proving such a mechanism, but this needs much more analysis.)

Recommendations - BECCS in electricity generation

• In the meantime, biomass may be treated commercially in a way similar to other fuels used for electricity generation or hydrogen production, albeit without the carbon penalty.
• It is recommended that BECCS electricity generation projects be supported with at least a 20-year CfD using the existing CfD structure, but without the discrimination between retrofit of existing plant and new build. This would however need to pay a fixed element for CO\textsubscript{2} T&S costs. However, this leaves the negative emissions unvalued and unrewarded.
• It is recommended that a framework is developed for providing income to those delivering negative emissions through BECCS using one of the following:
  o Inclusion of a negative emission value in the CfD strike price, or;
  o Integration of negative emissions value into the EU ETS or a linked/stand-alone UK ETS, or;
  o Standalone instrument which recognises and values negative emissions.

Recommendations - BECCS in hydrogen production

• Commercially, biomass may be treated similarly to other fuels in hydrogen production, albeit without the carbon penalty;
• It is recommended that BECCS is incorporated into the mechanisms for supporting hydrogen production;
• It is noted that integration of negative emissions value into the EU ETS (or a linked/stand-alone UK ETS system) are likely to require no or minimal change between bioenergy applications.

Recommendations - Common Issues

CROSS CHAIN ISSUES

Context

• Previous UK CCUS business models were based on the private sector developing “full-chain” projects for the first capture and T&S elements of the CCUS “chain” in a CCUS cluster. Two changes are proposed by the CAG (based on the CCTF recommendations).
• First, the CCUS business models proposed by the CAG are based on the CCTF recommendation of splitting the CCUS “chain” into part-chain elements - i.e. separating the ownership and operatorship of capture from T&S. This allows “natural investors” to invest in each part of the chain.
• With private sector investors in each part of the split chain, each needs protection against failure of the other part of the chain to perform. This is particularly so for the first projects in each part of the chain in a new cluster.

• However, in each cluster this risk will decline significantly when new capture and T&S assets (or CO₂ shipping options) are added to the network, or when the original assets are expanded to create multiple options for capture and storage in the cluster CCUS network. Additionally, as the assets are expanded even further beyond that, these risks should largely disappear.

• Second, the recommendation of the CCTF was to reduce project risks and returns by accepting that “an irreducible set core of risks” would be better managed outside the projects\textsuperscript{24}. This “would reduce the cost of CCUS projects”.

• Inevitably, the combination of these two strategies exposes cross-chain performance risk as a major set of risks that needs to be mitigated and managed “outside the projects”.

• This is one of the “irreducible risks” identified by the CCTF for which HMG needs to help facilitate the risk mitigation and management in some way.

• The issue is how these risks can be mitigated for the first projects in a cluster.

• The CAG is proposing a set of measures that HMG can facilitate which will do this.

Duration

• The potential to mitigate cross-chain risks will increase over time. They are most acute with the first investments in new CCUS cluster. Once the first assets are operating in a cluster confidence in managing these risks will increase rapidly, firstly as the first projects demonstrate sound performance; and secondly as new capture and T&S elements are added to the cluster network.

• Once several options for CO₂ supply and disposal are created in a cluster then the risk is largely removed. For example, with two stores in a network, possibly a shipping terminal and several capture projects the risk will be all but gone.

• Once several clusters are operating, and provided that they have made investments in the necessary storage and port facilities, the cross-chain risk for a new cluster can be lower if both the new cluster and other clusters can be connected by CO₂ shipping and possibly pipelines, to provide access to alternative T&S systems if needed.

Proposals - T&S Assets Temporarily not operating

The current CAG proposal is that when T&S is not operating:

• “CO₂ producers”\textsuperscript{25} will still be able to operate, but in unabated mode. (This means they will not waste energy capturing CO₂ which is then simply emitted).

• CO₂ producers will continue to receive some revenue support and the fixed T&S capacity reservation fee. This will be set to keep them economically neutral versus their normal abated operating mode. (A grant would reduce or eliminate this need).

• It may be necessary to provide “free allowances” to Industrial Production with CO₂ Capture projects to permit CO₂ emissions without penalty

• It should not be necessary to provide such allowances to Electricity Generators if they have a dispatchable CfD contract which provides a fixed payment regardless of generation, nor to Hydrogen Production if it operates under a RAB.

• Subject to the provisions of the incentives and penalties regime under the RAB, T&S will receive a portion of their fee. They will be able to make up lost fees in arrears under the RAB structure when they are operating again. (There are precedents in other industries for this).

\textsuperscript{24} “Delivering clean growth: CCUS Cost Challenge Taskforce report”. BEIS. July 2018. pp35,40

\textsuperscript{25} “CO₂ producers” means plants receiving revenue support (e.g. from LCCC for electricity projects or from HMG for Industrial projects) for capturing CO₂ for delivery to T&S.
The appropriate level of reduction of the T&S fee will need to be developed between T&SCo and the regulator, balancing the desire to incentivise T&SCo to restore services, but recognising that in most instances unavailability will result from circumstances which could not be predicted nor controlled by T&SCo.

Proposals - Capture Assets not operating

- The CAG proposes that when Capture is not operating:
  - Capture assets will not receive revenue support.
  - However, either LCCC or HMG will continue to pay the fixed part of the revenue support to cover the fixed T&S capacity fee (which will continue to be paid). This will keep T&S whole financially.
  - Alternatively, if the T&S investment capex is paid for by an HMG grant then this payment of the fixed T&S capacity fee in these circumstances would not be necessary. (Variant 2).

Proposals - Permanent or Prolonged shut-in of T&S

- This risk is low and will reduce further as the T&S network is expanded. Appropriate store selection and appraisal, choice of developer and operator, and care in the project design and execution by experienced companies with the right capability makes this a manageable risk.
- T&SCo would be contractually bound to honour its T&S contract if possible, with additional costs allowable under the RAB.
- In the event of permanent closure or a prolonged shutdown of the store, T&SCo will continue to receive the reduced T&S fee until operations are restored or an alternative regulatory settlement is reached.
- If after an agreed period injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as an “insurer of last resort”.

Proposals - Cross Chain Failure - Pre-Commissioning Stranded Asset Risk - No T&S

- This possibility is extremely remote if capture developers and T&S developers are properly chosen, and if they coordinate, develop and execute their projects with due care.
- This risk drops away completely when the network is expanded.
- For capture plant, a decision would need to be made as to whether to run the new assets unabated, adapt the new assets to an alternative service, or close and abandon the new assets.
- Thereafter, HMG would act as “insurer of last resort” and cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

Proposals - Cross Chain Failure - Pre-Commissioning Stranded Asset Risk - No CO₂ Capturers

- Again, this possibility is extremely remote if capture developers and T&S developers are properly chosen, and if they coordinate, develop and execute their projects with due care.
- Once T&S assets are ready to accept delivery of CO₂ from the capturers, the “Funders of the CO₂ Capturers” will be obliged to start paying the “capacity reservation” portion of the agreed T&S fee. There will be no contractual limit to how long this will continue.
- It is possible (though again extremely unlikely) that, if no capture plants are built to use the T&S assets, that these should be abandoned.
- In that event HMG would act as “insurer of last resort”. HMG would then cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.
COORDINATION BETWEEN CO₂ CAPTURE AND T&S ASSETS

• It is recommended that a Programme Development Consortium is created in each cluster to coordinate the development of the first CCUS projects (both the capture and T&S) in the cluster. This consortium should appoint a “Programme Development Coordinator” to lead the Consortium.

• The Consortium should work with HMG, with local authorities, and with other organisations in the region.

• The Coordinator will produce a plan, covering a range of scenarios, for integration of the first projects in a cluster and also further capture sources in the cluster, into the T&S system. This will be crucial for making judgements on the sizing of assets in the cluster (see below).

• The role should be sponsored by the capture, transport and storage projects involved in the cluster, and may include cost sharing arrangements with government.

• Contractual arrangements between each project in the programme covering the development phase are likely to be used.

• Project development should be synchronized, using coordinated stage-gate decision points. The first “anchor” projects in a cluster will look to pass i) into FEED, and ii) through FID simultaneously. Project development funding provided by HMG prior to FEED should be coordinated across each programme element.

• All parties should be bound contractually to manage risks and deliver an operating project; with terms depending on the nature of the projects involved, risk allocations and arrangements put in place by HMG to allow the projects to proceed.

ASSET SIZE AND CAPACITY

• Decisions on sizing initial and subsequent investments in CCUS assets will entail a series of significant trade-offs.

• The issue of assets sizing is faced in all large infrastructure developments and is not unusual. The objective of this section is to make it explicit that these trade-offs exist, and that they have to be addressed transparently.

• These trade-offs will need to be worked through on a case by case basis, using cost-benefit analysis, and risk analysis.

• Judgements on asset sizing will be made on the basis of the “cluster plans” produced by the Programme Development Coordinator” (see above).

• The initial capture and T&S projects in any cluster or region should be sized to meet two goals:

  1. Meet a common set of metrics for “economically efficient” costs (e.g. cost of carbon abatement, unit cost of low carbon electricity or other output), as well as “economically efficient” use of capital and capital efficiency.

  2. Demonstration of how development of further cluster capture projects and the expansion of T&S assets provides a clear pathway to allowing CCUS to “operate at scale in the 2030s”.

• Critical T&S assets (pipelines, and available well slots, perhaps terminals) should be “right sized” on the basis that further capture projects will join the network once the anchor projects are operating.
CHAPTER 3: Recommendations for Variant 1 Business Models

PROJECT DEVELOPMENT FUNDING

- The developers of early CCUS assets are unlikely to be prepared to invest the significant sums required to take their project development through to FID without significant commitment by HMG that provides some degree of comfort that FID will be reached and CCUS development will go ahead.
- This commitment could take different forms, either via a signal of commitment (e.g. HMG sharing in the project development costs of CCUS project development), or actual contractual commitment, e.g. a commitment to support a ‘basis for proceeding’ to enable developers to proceed with confidence that a CfD contract (or other similar revenue support) will be available.
- The CAG recommends that for early projects, the developers of CCUS projects and HMG share the costs of project development through to FID - covering both pre-FEED and FEED costs.
- In addition, a range of other sources of development funding (e.g. EIB) should also contribute to development funding.
- This development cost sharing is likely to be needed until developers have sufficient confidence that they will be able to secure revenue support funding for their projects if they commit substantial development funding to the projects.
CHAPTER 4 - CO₂ TRANSPORT & STORAGE - OPTIONS PAPERS

Summary

CCTF RECOMMENDATION

The CCTF recommended that the T&S assets for a cluster should be privately owned and financed, regulated through a regulated asset base (RAB) structure, and funded through T&S fees charged to their customers (i.e., CO₂ capture projects).

That recommendation was based on two competing pressures:

- The drive to reduce costs of CCUS, and in particular T&S within it, as far as possible by establishing T&S as a low-risk, low return business earning "utility" rates of returns;

- Using a model that keeps the T&S assets off HMG balance sheet, and hence out of HMG ownership.

T&S for the first CCUS projects could be - initially at least - a relatively high-risk activity until the store is well established and a network of interlinked capture and T&S assets has been created. The risks will then drop significantly. The T&S RAB structure allows much of the early risk to be passed to a wider base of consumers which has greater capacity to absorb the risk. This structure then allows HMG to take the responsibility for addressing - often at no or low cost to the taxpayer - those irreducible risks that simply cannot be left with the private sector nor passed to consumers.

THE CAG VARIANTS

Several business models for T&S, including the CCTF recommended model, have been reviewed and these options are described in Options Paper 4A this chapter. Three of these business models for T&S are endorsed by the CAG as suitable for development of CCUS in the UK. These are:

- Variant 1 - the Base Case - which follows the CCTF recommendation to create one or more T&S RAB businesses with utility rates of return and risk, which keeps costs low, and;

- Variant 2, which is largely the same as Variant 1, but in which the capital expenditure on the first T&S assets in a cluster are funded through an HMG grant (but not HMG ownership).

- Variant 3, which envisages initial HMG ownership of T&S infrastructure followed by privatisation when the T&S system has sufficient experience to price the remaining risks properly.

Putting aside the issue of the HMG balance sheet, there is a balance of advantages and disadvantages to HMG ownership of the first T&S assets in a cluster. At its heart is the fact that HMG clearly has the capacity to absorb the costs, risks and uncertainties of a first T&S investment. On the other hand, if privatisation is the clear end-goal then little may be gained from HMG ownership rather than HMG simply accepting the obligation to facilitate the management of those irreducible risks for the first T&S projects in a cluster.

Indeed, private ownership (Variants 1, and perhaps 2) delivers the lowest cost of capital available without T&S being in HMG ownership, or the assets of T&S appearing on the HMG balance sheet. It represents a logical structure in an enduring regime for large scale infrastructure. However, the key challenges to delivering Variant 1 are:

- whether the T&S RAB offers investors sufficient incentive to invest in the business;

- whether HMG will accept that significant risks can be passed to consumers or tax revenue (albeit, at very low cost per single consumer or taxpayer); and
• whether HMG will accept the obligation to facilitate mitigation of (and in extremis to absorb) the “irreducible residual” risk that investors cannot price properly.

The most acute issue is whether HMG will accept the “cross-chain failure” provisions being proposed by the CAG. These provisions are discussed in Options Papers 15 A to 15C in Chapter 15. This question will need to be resolved as part of the assessment to be made through the forthcoming Consultation on CCUS.

If this proves too difficult, the problem can largely be removed if the initial capital expenditure for T&S in a cluster is funded by an HMG grant. This is described as Variant 2. Depending on the nature of the proposed project, and circumstances at the time, this may prove a suitable way forward. The provision of a grant would only be necessary for the first T&S investment in any CCUS cluster - thereafter the cross-chain risks will have declined substantially and would no longer warrant use of a grant. A grant could also be considered to support the oversizing of a T&S asset to allow for tie-in of future emissions.

Finally, there is some debate as to the appropriate level of return that will be required by equity investors in such a company, regulated through a RAB.

CAG RECOMMENDATION

The CAG endorses the choice of any of these three options: Variant 1, Variant 2 or Variant 3.

The CAG believes that Variants 1 and 2 are both likely to prove acceptable to equity and debt investors in a T&S project using these models; and that if HMG owns the T&S assets under Variant 3, it will be possible to privatise such an investment without loss once the assets are running normally.
Options Paper 4A: T&SCo Commercial Model and Returns

CONTEXT

Over time, several possible business models for T&S within CCUS in the UK have been proposed. Amongst these, the CCUS CCTF\textsuperscript{26} proposed a “RAB structure”, the Oxburgh report\textsuperscript{27} proposed regulated structures within HMG ownership, and the UK Commercialisation Programme (2012-15) proposed private sector ownership with some risk share with HMG\textsuperscript{28}.

The following first lists and describes the options considered, then discusses the pros and cons of each option, and finally concludes with the recommendation to consider three of them.

PREFERRED OPTIONS (VARIANTS 1, 2 AND 3)

VARIANT 1: PRIVATE SECTOR OWNERSHIP; REGULATED UNDER RAB STRUCTURE

This is based on the model proposed by the CCUS CCTF.

As a private sector company, T&SCo will operate under a new “Regulated Asset Base” (RAB) regime - designed for the CO\textsubscript{2} T&S business. T&SCo’s investments and operations are designed to achieve a utility rate of return and risk. Including debt financing will help further to keep post-tax costs down.

When regulated under a Regulated Asset Base (RAB) system, a company is permitted by a regulator to charge fees which allow it to make a return commensurate with the risk it is incurring. All costs can be recovered, provided they are properly incurred, and a return made on the capital invested.

The basis and key mechanics for regulation will work as follows:

- T&SCo will be a “private sector regulated company”, with a regulator appointed by HMG.
- T&SCo will operate under a system of periodic reviews and “settlements”. T&SCo will agree a plan for T&SCo’s expenditure and operations with the regulator. This will be reviewed and updated periodically - typically every five years.
- As under any regulatory regime, the regulator will determine the target regulated return of T&SCo at the start of each regulatory review period. This will give certainty to investors and will be predicated on the risks of the T&SCo, its regulatory structure, its protections and the prevailing market appetite and conditions. Actual returns earned within review periods will be dependent on performance.
- Normally, capital expenditure outside the plan will be absorbed into the RAB from the time of the next settlement. However, if exceptional events occur, requiring exceptional expenditure or loss of income, the regulator may agree to additional expenditure, before the next review is due.
- There will a system of appeal against decisions of the Regulator, after which the decisions of the Regulator will be binding.

T&SCo will be entitled to charge fees that enable it to operate, make required future investments and make a regulated return on its investment for shareholders, subject to performance.

T&SCo will be expected to make a “utility rate of return” based on market precedents, adjusted for industry and project specific risks and contractual protections the T&SCo regulatory structure offers.

\textsuperscript{26} “Delivering clean growth: CCUS Cost Challenge Taskforce report”. BEIS. July 2018.
\textsuperscript{28} “Carbon Capture and Storage Knowledge Sharing: Commercial, Project Management and Lessons Learned”. BEIS Knowledge Sharing. 2015-16.
In the longer term, some or all of the finance required may be put out to competition in the market. It is not the presumption that the original sponsors and owners of T&S Co will wish to retain ownership indefinitely.

As with other regulated sectors, there will be a concept of “allowable costs”, which are deemed to be properly, economically and efficiently incurred. Both foreseeable as well as unforeseeable, exceptional costs can fall within the definition of “allowable costs”. Only “allowable costs” will be chargeable as costs to the RAB. Under a RAB structure, many costs that might more traditionally fall on a project developer (e.g. the need to drill unexpected wells to maintain CO₂ store integrity) would be allowable costs. Should they occur, they therefore are costs that would be passed through the RAB to end consumers.

**Justification for choosing this option**

**Pros**

In reviewing the alternatives for delivering T&S assets, the CCUS Advisory Group has determined that a RAB model is the best approach for T&S, for a variety of reasons. These include size and scale, the ability to become UK wide, its proven precedents and attractiveness to a wide investor base and the likely consequent low cost of capital; but principally because of the ability to accommodate risk, both to the investors in RABs and to end consumers.

**Cons**

RAB structures usually operate and succeed in circumstances where risks are low and can be managed effectively. CCUS T&S may approach that state in the future, but for the first projects it may have a higher risk profile than would be considered normal for other, RAB-based regulated utilities.

RABs are also effective where returns to investors are low - socialising risk across a wide consumer base is an effective means of spreading risk. However, the investors likely to be most capable and interested in making the first investments in T&S, typically oil and gas companies, do not normally invest under RAB models.

**Discussion**

CCUS is an emerging technology. Consequently, there are risks associated with T&S that are inherently unforeseeable, and it would both be difficult and represent poor value for money to pass these to a privately-owned T&S Co and its sub-contractors; it would be difficult for a private company to sensibly price risks it cannot quantify nor control, and they would have to price on the assumption that those risks do actually occur to avoid loss should they occur. Under a RAB structure, these risks, should they occur, are ultimately passed to the end consumers of lower-carbon products, or to tax revenue, through an increase in RAB charges, but are not priced in at the outset and never will be should the risks not arise.

A regulator is an independent party that on the one hand protects RAB-supported companies and investors by allowing the RAB business to accommodate such risks by passing on allowable costs; but also protects the end consumer, who needs assurance that any increased costs have been reasonably incurred.

Inherent in T&S operations are some low probability but high impact risks that might occur that could lead to temporary or indefinite store closure, through no fault of the T&S Co. Options Paper 15C gives some examples of the risks envisaged. The business model adopted for T&S needs to recognise the existence of such risks, and any regulator would need to strike a balance between creating the correct incentives for T&S Co to remedy such issues, whilst at the same time not overly penalizing the company for risks it cannot control. To do so would not be compatible with the cost of capital and risk provisions which a RAB should normally attract, and which are in the consumers’ interest as they keep the cost of capital low.
CHAPTER 4: CO₂ Transport and Storage – Options Papers

The RAB structure needs to recognise the possibility of those risks and have a suite of protections to address them. The primary protection is always to determine whether problems can be solved economically through expenditure, for which the regulator would allow additions to the RAB cost base at a cost of capital that would allow T&SCo to finance that additional expenditure.

There is no presumption that either the original or the existing shareholders of T&SCo would at any time nor under any circumstances be obliged to inject further finance (above any pre-agreed levels). The regulator must therefore ensure that the T&S company is capable of maintaining a high investment grade rating and that it can finance itself from the market.

It is in the nature of RAB-supported companies that they are incentivised to build and maintain the relevant assets. The T&SCo should therefore have incentives and a duty to build its stores and plan for the renewal or replacement of existing stores over a long-term planning horizon. Regular long-term plans should be submitted to the regulator. Sources of finance for detailed technical reviews and geological surveys will need to be agreed between T&SCo, HMG and contractors looking to provide new, competitive sources of storage.

VARIANT 2: T&S RECEIVES A GRANT FOR INITIAL CAPEX IN A CLUSTER

This is largely the same as Variant 1, except the capital expenditure on the first T&S assets in a cluster are funded through an HMG grant.

A grant could also be considered to support the oversizing of a T&S asset to allow for tie-in of future emissions.

This would not result in any HMG ownership of the T&S company or assets.

It is also likely that this will not lead to the T&S assets appearing on the HMG balance sheet, though care will be needed with the rest of the business model structure to ensure this. (Classification of companies with levels of government support is ultimately the role of the Office of National Statistics; the CAG has not looked to carry out any preliminary balance sheet treatment review within its scope)

Justification for choosing this option

One key issue in the variant 1 structure is that of cross-chain failure when T&S assets are available to accept CO₂, but the CO₂ capturers are not able to deliver CO₂ to T&SCo. With utility returns T&SCo cannot realistically provide a return on and repay its capital invested if the T&S fees stop when the CO₂ flow stops. The T&S fees will therefore need to be paid, whether or not CO₂ is being delivered to T&SCo.

Also, at least part of the T&S fees will still need to be paid, even if T&S assets are not operating.

One way to overcome these issues would be if HMG provided a grant to T&SCo to cover the capital investment in the first T&SCo assets in a cluster. An HMG grant would only be needed for the first T&S investment in any cluster, and not thereafter.

Pro

T&SCo would no longer need to service its capital investment and could probably absorb the fluctuations in its income when CO₂ was not being delivered, or the T&S assets were not operating, without further assistance. Cross chain payments would then not be needed if CO₂ was not delivered to T&SCo. This would save cost to consumers through lower T&S fees.

A grant could also be considered to support the oversizing of a T&S asset to allow for tie-in of future emissions.

Con

This would require a direct payment from tax revenue.
CHAPTER 4: CO₂ Transport and Storage – Options Papers

VARIANT 3: HMG OWNS T&SCO (PRIOR TO PRIVATISATION)

HMG ownership of T&SCO is a realistic option. The assumption is that T&SCO would be set up with the full apparatus of the RAB structure, to ensure the company can be privatised once the assets of T&SCO are operating effectively and the business is deemed viable.

HMG would aim to privatise T&SCO as early as practicable after its assets and business are operating normally.

Justification for choosing this option

Pros

• Low cost of capital (subject to State Aid approvals);
• T&SCO can be charged with delivering government policy through encouraging new entrants;
• With no external capital to service, the impact of cross chain risk is mitigated; unavailable upstream assets do not lead to un-serviced capital;
• No government insurer of last resort required;
• Time – in theory a Government funded option can be delivered faster;
• Scale – smaller T&S schemes may not be deemed of sufficient scale to warrant the implementation of a complex regulatory structure;
• Ability to absorb start up risks – a government T&SCO could absorb late delivery of upstream projects and First-of-a-Kind risks;
• Flexibility – with less contractual rigidity, it can be more flexible in early years as the industry develops.

Cons

• Privatisation preparation – structure needs to be put in place that will satisfy long term investors, so limited time advantage. The contractual interfaces with the upstream CCUS companies will have to be resolved to make those financeable;
• Lack of market interface – in practice it is only through market negotiations that detailed, financeable provisions are agreed. This will be delivered faster by private sector negotiations;
• Lack of delivery capability – Government currently has no such delivery capability; neither commercial nor technical;
• Scale – for CCUS to be introduced at scale requires long term investment from the private sector. A Government option does not develop that capability nor the commercial structure to incentivize investment;
• Non-repeatable – unless Government intends to fund all future T&SCos, the model would not meet its objectives of developing the industry in a way that can be rolled out at scale;
• Lack of ownership – Government does not currently own the assets under consideration. Would it purchase those assets, at what cost? Or get the incumbents to operate? But if the latter, would it not be better for those companies to have investment in the T&SCO and be taking risk on assets they know best?

Whether a Government-funded T&SCO is desirable is therefore a balance of the above benefits and drawbacks, which may be different for different projects of different sizes.
ALTERNATIVE VARIANTS

VARIANT 4: SINGLE PRIVATELY OWNER UK-WIDE T&S CO RAB

Rather than each cluster having a separate T&S RAB, a single T&S RAB could be developed for the whole of the UK, holding the T&S assets of all UK clusters.

This gives advantages of scale, perhaps speed of execution, and possibly better inter-connectivity. However, it may add complexity, and possibly risks fragmentation of project development.

Justification for not choosing this option

Pros

This gives advantages of scale, perhaps speed of execution, and possibly better inter-connectivity.

The main features and benefits of a UK T&S Co might include:

- Ownership of all T&S Co assets – spreads the risk and offers alternative stores during potential periods of unavailability;
- Large RAB – greater risk to absorb T&S risks without the need for Government support e.g. the cost of early review of competing store capabilities; exploratory wells, surveys, FID work;
- With a number of stores on the RAB, the financial impact of unavailability would be less material relative to the RAB, making revenues less volatile and reducing or removing the need for Government backstops (or decreasing the probability they might ever be called upon);
- Introduction of the RAB structure for a single development may be costly and complex, and would be more appropriately spread across a number of schemes;
- Public ethos governance – as a national enabler of CCUS, its governance and regulatory duties would be to enable CCUS and work across the economy to promote decarbonisation; heat, power, hydrogen, industrial, BECCS;
- Government could take a minority position as a result, with the UK T&S Co assuming many of the roles of a CCUS Delivery Body alternative;
- Acting across the UK and being the focal point for development plans, it could have competence to recommend and implement rollout plans approved by the regulator within Government funding/support envelope;
- Duty to recommend investment, prioritised through pre-agreed criteria; suitability to RAB, leverage, employment – prioritising projects with the greatest impact and commercial deliverability;
- If established as a private sector initiative, it should be off Government’s balance sheet and investment focused; driven by incentives to add further T&S assets to the RAB and hence grow and accelerate the deployment of CCUS;
- Independent – seen as a strong regulated counterparty, with regulated revenues and investment grade credit-ratings enables the UK T&S Co to efficiently execute transactions with proposed new projects on consistent and standardised terms.

Cons

- Establishing a UK T&S Co may add complexity, and possibly risks fragmentation of project development
- It may be difficult for one T&S Co company to interact with and invest several capture clusters with different priorities and project characteristics.
- It may detract from the cluster focus which is a key driver of CCUS development.
- It may slow projects by taking time to establish a UK-wide T&S Co.
CHAPTER 4: CO\textsubscript{2} Transport and Storage – Options Papers

A key uncertainty that will impact the attractiveness of this model is how in practice investment in CCUS will be rolled out across the UK. If, for instance, only one T&S project was carried forward at the outset, then it is more likely that a single project RAB company would be formed, with a very project specific risk share and the initial ownership likely to be with the project sponsors. A UK wide T&SCO might possibly evolve from that initial entity. In contrast, if more than one T&S project were promoted from the outset, then this might be through an integrated UK T&SCO, which would be more able to absorb risks, have a lower volatility in earnings and returns and a wider appeal to third party investors rather than just project sponsors.

**VARIANT 5: HMG OWNS UK-WIDE T&SCO RAB (PRIOR TO PRIVATISATION)**

Again, rather than each cluster having a separate T&S RAB under HMG ownership, a single T&S RAB could be developed for the whole of the UK, holding the T&S assets of all UK clusters.

Again, this gives advantages of scale, perhaps speed of execution, and possibly better inter-connectivity. However, it may add complexity, and possibly risks fragmentation of project development.

Under this arrangement, Government would not only fund the first RAB (with all the benefits and drawbacks described above) but would commit to roll in subsequent T&S assets as they come on stream.

**Justification for not choosing this option**

**Pros**

- Government would clearly be seen to underpin the development of CCUS and provide the enabling infrastructure for a competitive, growing CCUS market.
- HMG would have the choice of funding the structure through the charging mechanisms envisaged under Variant 1, in preparation for subsequent privatisation, or the option for all or part of its costs to be funded directly by the taxpayer. This means HMG could determine where the burden of payment for T&S services best lies (e.g. the LCCC or the taxpayer).

**Cons**

- Under a privately-owned RAB, there will be clear incentives on the T&SCO to maintain and replace stores. The role of the independent regulator would be to allow charges to end users to include those costs. The risk of a public-owned entity is that it would be reliant on periodic funding from Government to maintain that expenditure, which might be subject to future budget cuts in times of austerity.
- The structure seems most suited to fund ‘one-off’ projects. But a major benefit of a UK T&SCO is to develop it as a business; one capable of competing and procuring additional assets, stores and storage capability, and one with the ability to widen its scope and encourage the use of CCUS across the wider economy. Typically, that type of major corporate capability has not been established within government.
VARIANT 6: PUBLIC-PRIVATE OWNERSHIP OF T&SCO

T&SCO has majority private sector ownership, with a minority share owned by HMG. HMG may provide both equity and debt to T&SCO.

The main perceived disbenefit of this structure is uncertainty on balance sheet classification. Nevertheless, the CAG felt that joint ownership could be attractive to both the public and private sector.

Justification for not choosing this option

Pros

• Joint ownership of T&SCO would be the best demonstration of the collaborative relationship needed between the public and private sectors to make widespread rollout of CCUS a success;
• CAG is recommending that T&SCos have clear ‘public ethos’ governance, for instance with a clear focus on long term growth, a resistance to ‘financial engineering’ and aggressive refinancing and a clear focus on value to the end consumer (see under ‘Governance’ in Chapter 5). A minority HMG stake, with board representation would emphasise this public approach to end investors, appealing to long term investors rather than those looking to make short term gains from a new industry;
• Particularly at the early stage, when a T&SCO may be relying on funding from its sponsors which may have limited balance sheet capacity to finance schemes, a significant public participation in the companies’ funding (equity and debt as appropriate) would both lessen the burden on private investors and demonstrate aligned incentives. Joint investment in T&SCO would change the nature of the relationship from negotiating and transactional to a partnership approach with shared incentives when addressing risks.

Cons

• Depending on the size of HMG’s stake, they may have a ‘significant interest’ in T&SCO. When considering the likely balance sheet treatment of the structure of T&SCO, this will be one consideration that would weigh in favour of classification on Government’s balance sheet.

VARIANT 9: SEPARATE CO₂ TRANSPORT (PIPELINES AND SHIPPING) AND CO₂ STORAGE BUSINESSES.

This structure would be the same as in Variant 1, except that the CO₂ Transport and the CO₂ Storage activities would be separate businesses.

The current working assumption of the CAG is that in this model either the main T&S project or the Capture projects will “sub-contract” these separated services from third party private sector providers, on terms to be agreed between them. These terms would have to respect the provisions of any Third-Party Access Regulations, and any other appropriate constraints.

It has been assumed that the sub-contracted activities would not form a separate “third leg” in the CCUS chain that HMG would need to deal with. Any revenue or revenue support provided to the sub-contractors would flow to them via either the T&S or the Capture projects.

Currently the CAG is not considering proposing any alternative to these assumptions.

Arrangements for provision of separate CO₂ transportation or CO₂ shipping services would be left to the project developers as and when any opportunities arise.
CHAPTER 4: CO₂ Transport and Storage – Options Papers

Justification for not choosing this option

Pros

- Onshore pipeline CO₂ transport and CO₂ shipping are activities which are naturally distinct from offshore CO₂ transport and storage.
- Different investors therefore might find these businesses more attractive and might have better capabilities to deliver these activities.

Cons

- Creating another full interface along the chain would also create significant further complexity.
- Significant complexity would also arise if a “third leg” in the chain created another contractual relationship with HMG.

For these reasons sub-contracting of these activities is recommended.

VARIANT 12: PRIVATE SECTOR FULL-CHAIN DEVELOPMENT - HMG SHARE SOME RISKS

If HMG do not wish to take on the “irreducible risks” required in the models above, CCUS could be developed using the Business Model used in the 2012-15 UK CCUS Commercialisation Programme²⁹. This would place higher risks and returns with the private sector developers and would increase CCUS costs. The project scope and allocation process need to change substantially from that used previously.

CO₂ Capture and T&S would be owned by the same shareholders; creating a de facto “full chain” project. This provides mitigation against some cross-chain risks. They can be split apart when they are operating effectively.

Justification for not choosing this option

Pros

- This provides mitigation against some cross-chain risks. They can be split apart when they are operating effectively.

Cons

- This would place higher risks and returns with the private sector developers and would increase CCUS costs.
- The previous competition suggests there will be significant market reluctance to finance a full-chain CCUS development. At the point that the competition was stopped, the banking market had not become comfortable that the combination of these risks in one entity was financeable. This was not a question of pricing but of financeability in total. In practice financiers would look to introduce a suite of protections akin to those envisaged in CAG’s recommended structures.

VARIANT 13: “FIXED PRICE, PROJECT FINANCE” STRUCTURE FOR T&S - HMG SHARE SOME RISKS.

This is a sub-case of Variant 12. T&S would receive a fixed price T&S fee structure with no change depending on demand changes or cost changes. T&S is likely to be financed using project finance (i.e. usually equity plus debt in a “special purpose vehicle” company - an SPV - which isolates the performance of the project inside that company.) HMG would share some risk in T&S, but not in capture. Again, this would place higher risks and returns with the private sector developers and would

increase CCUS costs. Under this arrangement, T&S would be receiving an “capacity reservation” fee for making T&S available. It would not be taking demand risk, nor risk on the performance of CO₂ capturers (as it could not provide a fixed price for elements and risks it would not control), but would take fixed price T&S risks, such as the cost of store management, necessary wells and operating costs.

**Justification for not choosing this option**

The CAG’s recommended structure of a RAB based model assumes that there are some risks inherent in T&S that it would be difficult for the private sector to price; either at all or only with a material price premium to cover risks that might not occur. The RAB structure allows those risks to be absorbed by the T&SCo and the cost of those risks added to the RAB only if they occur.

An alternative would be a fixed-price structure; one that can be financed by a corporate, but more typically by a special purpose company using project finance (i.e. finance raised specifically for that project company).

Appendix 1 to this report gives a more detailed contrast between the RAB model and fixed price structures.

**Pros**

- The LCCC or HMG (and hence end consumers or tax revenue) would pay a fixed, predictable price for T&S;
- Risk transfer to the private sector would be clear and unambiguous;
- Incentives to deliver available services would be incentivised; typically, fees to the SPV are not paid if the assets are unavailable.

**Cons**

- This would place higher risks and returns with the private sector developers and would increase CCUS costs;
- It assumes the private sector will be willing to price T&S delivery risk where in practice some operational risks could only be priced at a premium and more extreme risks may not be capable of being priced on a fixed price basis.
Options Paper 4B: T&S Dividend Policy

CONTEXT

Under a RAB structure which provides utility rates of returns in exchange for commensurate risks, shareholders will wish to see dividends maintained, regardless of whether additional expenditure is being allowed by the regulator to cater for unforeseen circumstances.

PREFERRED OPTION

Dividends allowed irrespective of cash reserves position

In order to keep the costs of capital low, T&SCo will always be allowed to make dividend payments, assuming satisfactory performance under the incentives and penalties regime. The implication is that contingency reserves may have to be topped up from new financing at the same time as dividends are being paid.

ALTERNATIVE OPTIONS

Dividends restricted if cash reserves are low

T&SCo will only be able to pay dividends when it has sufficient cash reserves and is able to justify forecasting a healthy future cash position.

Dividends restricted if cash reserves are unsustainable

T&SCo will only be able to pay dividends if the outlook for paying dividends for the next [3 or 5] years is sustainable. T&SCo’s 3 [or 5] year plan should be able to illustrate that any budget deficit from any years’ dividend payment is a short-term impact and that no further annual budget deficits are foreseen over the planning period.

PROS AND CONS OF THE OPTIONS

Pros

• As a base case assumption, paying a level of dividends during periods of capital expenditure is more likely to attract low cost institutional funders and is preceded

Cons

• There are also precedents of a more ‘project finance’ approach where dividends are paid only from the start of operations; this may be more suitable for early industry investors more used to this approach and who will be looking to reduce the overall finance requirement
• Utility industry precedents also have examples of dividend suspension for extreme events or periods of major expansion.

While the payment of dividends is recommended by CAG as the working assumption, in practice the approach should be optimised for each development.
Options Paper 4C: CO₂ Storage Leakage

This paper describes the options for dealing with the risk of CO₂ leakage from the store post injection and explains why the “chosen option” has been selected.

CONTEXT

The T&S assets that comprise the storage complex, namely the geological formation used for geological storage of CO₂, the surrounding geological domain and associated surface and injection facilities, will fall under the terms and conditions of the EU CCS Directive.³⁰ Leakage of stored CO₂ is extremely unlikely. No leakage of any significance has been reported in any of the eighteen³¹ projects that are currently in operation - and no reported leakage of any significance has occurred of any of the 250³² million tonnes of CO₂ that has been stored underground in the last 47³³ years.

This paper covers the following issues:

- The definition, detection and quantification of CO₂ leakage;
- Decisions to intervene to stop the leak or reduce the leakage rate, and;
- Options for satisfying requirement to surrender EU ETS allowances equivalent to volume leaked.

DEFINITION, DETECTION AND QUANTIFICATION OF CO₂ LEAKAGE

It is the responsibility of T&SCo as storage site operator to develop and execute a monitoring and surveillance plan as agreed with the competent authority (UK OGA). Given the nature of geological uncertainty, it is possible that CO₂ may migrate in a way not originally predicted. Should this raise the risk of leakage, the directive terms it a ‘significant irregularity’. However, only leakage, defined as an escape to the seabed or atmosphere is dealt with here.

Leakage via a well, or via a geological conduit (fault, fracture, permeable formation outcrop) may be readily detected but be difficult to quantify precisely.

Should a leak be detected, the options for quantifying it are:

1) PREFERRED OPTION - OGA ENDORSES LEAKAGE ESTIMATES

   T&SCo shall assess and provide an estimate of leakage rate, with the evidence used to determine it, to the OGA for endorsement.

2) ALTERNATIVE OPTION - T&S CO PROVIDES ITS OWN LEAKAGE ESTIMATES

   The OGA shall make its own estimate based on data provided by T&SCo and any supplementary data required.

DECISION TO INTERVENE

- Should a leak be detected, any decision to intervene to stop the leak or reduce the rate of leakage should be agreed between the regulator, the competent authority (OGA) and T&SCo.

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³¹ Based on large-scale projects currently operating. (Source: Global CCS Institute)

³² Anthropogenic CO₂ only. Naturally occurring CO₂ is also extensively used for CO₂ EOR (Source: Global CCS Institute)

³³ The first commercial CO₂ EOR injection project was initiated in January 1972 at the Kelly Snyder Field in West Texas. (Source: Global CCS Institute)
In some foreseeable situations the impact of a leak may be deemed insignificant, and no intervention would be justified. However, the surrender of EU ETS allowances would still be required.

In other circumstances, no adequate intervention may be possible.

Finally, should the risk of an intervention worsening leakage be considered too high, the parties may agree not to intervene. In all cases, the requirements of the Environmental Liability Directive as well as the CCS Directive should be upheld.

If intervention is required options for funding this are:

**Preferred option**

3) **T&SCO ADDS COST TO THE RAB**

T&SCo adds the cost to the RAB as an allowable cost (subject to the provisions of the incentives and penalties regime).

To address the possibility that at the time of leakage the store may close or have already closed, a mechanism for ongoing cost recovery under the RAB would be required. Options for distribution of cost to the “Funders of CO₂ Capturers” may include a predetermined formula for allocation to consumers or tax revenue based on prior contribution of stored CO₂ volumes.

**Argument for Chosen Option**

Should a CO₂ leak occur, the T&SCo operator is best positioned to estimate the leakage rate. It is incentivised to be entirely transparent on its data and methods with both the regulator and the OGA in its capacity as competent authority. Should there be disagreement, evidence-based cooperation between the parties should enable satisfactory resolution, as no party benefit from a poor assessment.

By deeming the cost of an intervention to stop a leak an ‘allowable cost’ (and therefore eligible for addition to the RAB) enables the management of activity for leak prevention and leak remediation to occur under the same process, simplifying efforts while keeping all intervention decisions transparent to the regulator.

**Alternative Options**

4) **BUILD A REMEDIATION FUND**

Draw down on an intervention or remediation fund built up over time by predefined contributions, with HMG providing additional funding should the established fund be fully depleted.

5) **RELY ON INSURANCE**

Use of insurance instruments, with HMG providing additional funding should the policy payout cap be exceeded.
CHAPTER 4: CO₂ Transport and Storage – Options Papers

REQUIREMENT TO SURRENDER EU ETS ALLOWANCES EQUIVALENT TO VOLUME LEAKED

Under the conditions of the EU CCS Directive, leakage from a storage complex requires the surrender of EU ETS allowances equivalent to the volume leaked. The options for addressing this requirement are:

Preferred option

1) ETS RESERVE

Whilst T&SCo is storing CO₂, it will concurrently contribute to a National Contingency Reserve of ETS allowances (ETS Reserve). These will be purchased in the market by T&SCo but held centrally in escrow by the regulator or OGA on behalf of all T&SCos and designated for offsetting any future emissions arising from CO₂ that leaks from any UK store. (As with any insurance, it is likely to be better to hold such a reserve centrally rather than at an individual project level).

The rate of building the ETS certificates contingency reserve to cover future storage leaks will be agreed with the regulator and set at a small percentage (for example 2%) of the total CO₂ stored. The costs of these allowances will be an allowable cost.

If CO₂ leaks from the store, certificates will be drawn from the National Contingency Reserve of ETS allowances to cover the resulting obligation under the EU CCS Directive.

If, should a leak occur, the ETS Reserve contains insufficient allowances to cover the volume of CO₂ leaked, then HMG will act as insurer of last resort. HMG would have several options for doing this, potentially without incurring direct cost.

Argument for Chosen Option

Building up a National Contingency Reserve of EU allowances removes all but the very unlikely possibility that leakage will lead to a loss that cannot be covered by the ETS Reserve.

Consistent with the spirit of the EU CCS Directive, the final tranche of risk imposed by the Directive once Contingency Reserves are exhausted is of a nature (extremely low probability - indeterminate consequence) that only governments can absorb. It will not be possible to develop projects which include debt finance if HMG does not do so and would also be unattractive to equity investors.

Alternative Options

2) T&SCO PROVIDED WITH ETS CERTIFICATES:

T&SCo is given ETS allowances when needed to cover the leaked volume. This would be arranged in some way by HMG - i.e. the risk is removed from T&SCo.

3) ADD ETS CERTIFICATE COSTS TO THE RAB:

T&SCo pays for and surrenders allowances to cover volumes leaked at the time of escape but adds the cost to the RAB. To address the possibility that at the time of leakage the store may close or have already closed, a mechanism for ongoing cost recovery under the RAB would be required. Options may include a predetermined formula for ongoing allocation to consumers based on prior contribution of stored CO₂ volumes.
4) **HOLD CONTINGENCY RESERVE AT PROJECT LEVEL**

As in a), except that instead of a National Contingency Reserve, there is a Project Contingency Reserve held by T&ScO or in escrow by the regulator or OGA. However, this increases HMG exposure as insurer of last resort.

5) **T&SCO HOLD FINANCIAL RESERVE TO BUY CERTIFICATES**

T&ScO builds up a financial reserve to buy certificates to be used in the event of a leak. (This leaves T&ScO exposed to the uncertain future the price of certificates).

6) **T&SCO CARRIES THE COST OF ETS CERTIFICATES**

T&ScO pays for the certificates and is not allowed to charge the costs of these certificates to the RAB costs. (This option is un-investable).

7) **MODIFY UK REGULATIONS**

Once the UK leaves the EU, the UK could choose to withdraw from the EU CCS Directive and modify UK law governing storage. Subject to having acted diligently an in good faith, T&ScO may be exempted from the requirement to surrender allowances in the event of a leak. Such a move may limit the opportunity for the UK to store CO₂ on behalf of EU member states.
CHAPTER 5 - CO₂ TRANSPORT & STORAGE - DETAILED BUSINESS MODELS

Summary of Variant 1 Business Model:

PART 1 – COMMERCIAL ARRANGEMENTS

Ownership, Commercial Structure and Governance. The transport and storage assets will be privately owned, financed, developed, built and operated. They will be owned by T&SCo. None of the T&S assets, liabilities, nor contingent liabilities will appear on HMG’s balance sheet. T&SCo will have a governance structure that ensures its commitment to cost reduction, industry development and looking to benefit the end user.

T&S RAB model. T&S will operate under a RAB model structure. It will earn a “utility rate of return”. All costs that are “properly incurred” will be “allowable costs” eligible for inclusion as costs in the RAB. There will be an incentive and penalty regime to incentivize cost effective development and operation of the T&S assets, which ensures that actual returns earned by T&SCo depend on performance.

Insurance. Insurance will be an allowable cost, and will operate within a three tier regime: i) T&SCo carries the risks below the agreed insurance “excess”; ii) above this the insurance market covers risks up to the maximum economical insurance cover available; iii) HMG acts as the “insurer of last resort” for a closed list of specific, defined risks whose costs exceed the maximum economical insurance cover available.

Third Party Access rights. The assets of T&SCo will operate under the UK Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011, which provide “open access” to CCUS T&S infrastructure; and also under any protocol or treaty under which the UK agrees to store CO₂ from other countries.

Coordination between CO₂ Capture and T&S assets. A “Programme Development Consortium” will be created for a cluster / region. The Consortium will appoint a “Programme Development Coordinator”. Project development will be synchronized, using coordinated stage-gate decision points. Project development funding provided by HMG prior to FEED will be coordinated across the CO₂ Capture and T&S projects.

A contractually agreed system of penalties will operate between the projects if “first CO₂” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

Asset size. The critical T&S assets (pipelines, and perhaps terminals) should be “right sized”. This should be judged against measures of “reasonable” unit cost and of capital efficiency; and also against the need to provide a clear pathway to allowing CCUS to “operate at scale by 2030”.

Development Funding. For early projects, the developers of T&SCo and HMG will share the costs of project development of T&SCo assets through to FID - both pre-FEED and FEED costs.

Financing. T&SCo will be financed by private sector equity and debt; including all required working capital; and considerable, prudent contingency funding, which will be restored promptly if used. A ring-fenced Decommissioning Reserve fund will be built up from T&SCo’s funds during the active life of the store.

Construction. Given the nature of new sub-sea CO₂ stores, some uncertainty in the projected costs of construction is unavoidable. Subject to the provisions of the regime of incentives and penalties, the

34 “UK Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011.”
costs or financial consequences to T&SCo from foreseeable as well as exceptional and unforeseeable construction events or commissioning delay will all be included as “allowable costs” under the RAB structure.

**Operating Performance and Costs.** Similarly, and subject to the provisions of the RAB regime of incentives and penalties, the costs or financial consequences to T&SCo from foreseeable as well as exceptional and unforeseeable operating performance or events will all be included as “allowable costs” under the RAB structure.

**Decommissioning and Monitoring.** T&SCo will be obliged to decommission and monitor the T&S assets once either the store is full, or no further T&SCo Customers have contracted to use it. The store will be handed to HMG after decommissioning and monitoring are complete.  

**T&S Fees.** T&SCo will charge fees to “T&SCo Customers” (i.e. those who are capturing CO₂ and delivering it to T&SCo for transport and storage) that allow T&SCo to cover its allowable operating and maintenance costs; to build the Decommissioning Reserve; to repay its debt; and to provide a regulated return to shareholders, where the actual return will depend on performance.

T&S fees will be made up of a “capacity reservation” element and a “variable” element.

T&SCo will able to increase its fees to make up any forecast shortage in required cash reserves caused by “allowable” expenditure; and will be obliged to reduce its fees if cash reserves are forecast to grow excessively.

If only one CO₂ Capture project is being built initially, T&SCo will charge that project a fee that covers all T&SCo’s costs. If more than one project is being built initially then the costs will be spread across all these projects.

Funding for the T&S fees will come from the “Funders of CO₂ Capturers” (i.e. the source of revenue support that is being provided to T&SCo Customers. This will be the LCCC for electricity generating projects with CCS, and HMG for Industrial Production and CO₂ capture projects). T&SCo Customers will be obliged to pass these fees through directly to T&SCo.

**Follow-on Projects.** T&S fees charged will spread the costs of the T&S assets equitably across all T&SCo Customers. If new CO₂ Capturers join the network, their “capacity reservation” fee may be set to zero if they do not receive a fixed payment from their “Funders of CO₂ Capturers”.

**Expansion of the T&S Assets.** T&SCo may choose to expand their assets to cater for new customers. Subject to agreement with the Regulator, the costs of doing so will be included in the RAB. The UK Third Party Access regulations (see above) will govern whether T&SCo can be obliged by the Secretary of State to expand their assets to accommodate new customers.

**Dividend policy.** T&SCo will always be able to make pre-agreed dividend payments, assuming satisfactory performance under the incentives and penalties regime.

**Cross chain failure - T&S temporarily not available.** If, after “first CO₂”, the T&S assets are not available, the following will apply:

- Capture plants will be entitled to continue to run, either wholly or partially unabated. They will continue to receive a portion of their revenue support. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage. (Under the CAG recommended structures for revenue support, it may be necessary to provide “free allowances” to Industrial CCUS projects to enable them to continue to operate unabated, though not for Electricity Generators nor Hydrogen Producers.)

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The CCS Directive is implemented in the UK mainly through the [Energy Act 2008](https://www.legislation.gov.uk/ukpga/2008/4) (Chapter 3), which introduces a new regulatory framework to facilitate the offshore storage of carbon dioxide.
CHAPTER 5: CO2 Transport and Storage – Detailed Business Model

T&SCo will continue to receive a portion of their T&S fees, at a level set in advance by agreement between the regulators and T&SCo.

**Cross chain failure - Permanent of prolonged shut-in of CO2 store**

This is a remote possibility and as T&SCo expands, adding stores and perhaps the capacity to ship CO₂, the need for the HMG “last resort” roles described below will fall away.

In the unlikely event of permanent closure or a prolonged shutdown of the store, T&SCo will continue to receive the reduced T&S fee until operations are restored or an alternative regulatory settlement is reached. T&SCo would be contractually bound to honour its T&S contract if possible. The regulator could require T&SCo to incur costs as necessary to do so, which would be allowable under the RAB. T&SCo’s shareholders would not be obliged to provide any finance to cover these costs, and the regulator would be obliged to set an allowable rate of return on such costs that would attract alternative funding if it is needed.

If after an agreed period injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as an “insurer of last resort”. HMG would cover the remaining exposure of any debt providers and equity of equity shareholders. HMG would also become the “funder of last resort” for a new CO₂ T&S service to be provided to those with contracts with T&SCo.

**Cross chain failure - Capture plant does not deliver CO₂ to T&SCo.** The capture plants are not obliged to deliver CO₂ to T&SCo. However, regardless of the volume of CO₂ delivered, from the start date of the T&S Services Contract the Funders of CO₂ Capturers will still be required to pay the “capacity reservation” portion of the T&S fees to the T&SCo Customers, for pass-through directly to T&SCo.

**CO₂ Leakage from CO₂ store.** Whilst T&SCo is storing CO₂, it will concurrently build up a “Project Contingency Reserve of ETS Certificates” (ETS Reserve). These will be purchased in the market. The costs of these certificates will be an “allowable” cost. If the ETS Reserve contains insufficient certificates to cover the volume of any CO₂ leakage, then HMG will act as insurer of last resort.

Part 2 – Other Elements

These elements are described in the detailed section later in this chapter, and are listed here for completeness only.

**Storage Lease, Storage License, Consents, Permits and Land Rights.**

**CO₂ Delivery Certification, Ownership, and Sale.**

**Rights to use of storage; allocation of storage capacity.**

**Timing of planned maintenance.**

**Capture plant delivers off-spec CO₂ to T&SCo.**

**T&SCo Bankruptcy.**

**Change of Control, Equity Dilution, and Refinancing.**

**Change in Law, Change in Policy.**

“State Aid”.
Comparison of Variant 1 with Other Variants

CO\textsubscript{2} TRANSPORT AND STORAGE - COMPARISON WITH OTHER VARIANTS

VARIANT 2: T&SCo RECEIVES A GRANT

Summary. T&SCo receives a grant for the capital investment in T&SCo’s first assets in the cluster.

Financing. The whole cost of capital investment in T&SCo’s first assets in the cluster will be financed by an HMG grant. T&SCo will raise finance for all required working capital; and considerable, prudent contingency funding, which will be restored promptly if used.

Expansion of the T&S Assets. T&SCo may choose raise finance to expand their assets to cater for new customers. Subject to agreement with the Regulator, the costs of doing so will be included in the RAB.

Cross chain failure - Capture plant does not deliver CO\textsubscript{2} to T&SCo. Because the whole capital cost is covered by a grant no payment for return on the capital investment is required. The other costs of ongoing operation are relatively small. It is therefore not necessary for the “Funders of CO\textsubscript{2} Capturers” to pay the T&S fee when CO\textsubscript{2} is not delivered. T&SCo can simply roll those losses into the RAB.

VARIANT 3: HMG OWNS AND FINANCES T&SCo

Summary. HMG owns and finances T&SCo.

Ownership, Commercial Structure and Governance. The transport and storage assets will be owned and financed by HMG. HMG will contract out development (to a degree), construction and operation. All the T&S assets, liabilities, and contingent liabilities will appear on HMG’s balance sheet.

T&SCo will be set up in the same way as if it were owned by a private sector owner, in preparation for eventual privatisation.

Development Funding. HMG will finance all development costs.

Financing. T&SCo will be financed by both HMG equity and HMG debt; including all required working capital.

Expansion of the T&S Assets. Before privatisation any expansion would be financed by HMG.

Cross chain failure - T&S temporarily not available. It will probably not be necessary for T&SCo to continue to receive T&S fees when the store is not operating.

Cross chain failure - Permanent of prolonged shut-in of CO\textsubscript{2} store. HMG would automatically carry the losses incurred in the (very unlikely) event of a permanent shut-in of the store.

Cross chain failure - Capture plant does not deliver CO\textsubscript{2} to T&SCo. It will probably not be necessary for the Funders of CO\textsubscript{2} Capturers to pay the “capacity reservation” portion of the T&S fees to T&SCo.

CO\textsubscript{2} Leakage from CO\textsubscript{2} store. HMG would automatically carry the consequences (which may not be significant) if the ETS Reserve contains insufficient certificates to cover the volume of any CO\textsubscript{2} leakage.
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VARIANT 4: SINGLE PRIVATELY OWNER UK-WIDE T&SCO RAB

Summary. T&SCo - a private sector company - will own and operate all UK T&S assets. There is almost no difference in the detailed Business Model from Variant 1. All the advantages come in the ability of T&SCo to operate at scale in a coherent way across the UK.

VARIANT 5: HMG OWNS AND OPERATES ALL UK T&S ASSETS

Summary. In this case, HMG will own T&SCo, and T&SCo will own and operate all UK T&S assets. Again, there is almost no difference in the detailed Business Model from Variant 4. All the advantages come in the ability of T&SCo to operate at scale in a coherent way across the UK.

VARIANT 6: PUBLIC-PRIVATE OWNERSHIP OF T&SCO

Summary. The private sector owns a majority share in T&SCo; HMG owns a minority share. HMG could contribute both equity and debt. Again, there is almost no difference in the detailed Business Model from Variant 1. The advantages come a demonstration of collaboration to develop critical UK infrastructure. It would change the relationship between HMG and industry from transactional to collaborative, with joint incentives to deliver and alignment when addressing risks.
Detailed Business Model - Variant 1: CO₂ Transport and Storage

INTRODUCTION

This is the Business Model for CCUS T&S in the UK. It is part of the suite of four models which collectively are known as Variant 1.

Variant 1 is based on the CCTF recommendation to use a RAB-based model for T&S, and private sector ownership for Capture.

PART 1 – COMMERCIAL ARRANGEMENTS

1) SCOPE OF T&SCO

A private sector company, known as T&SCo, will contract to supply a CO₂ T&S service to CO₂ Capture projects.

This service may include onshore CO₂ transport, offshore CO₂ transport, CO₂ shipping, and offshore CO₂ storage.

T&SCo may choose to sub-contract the provision of CO₂ shipping, and of onshore CO₂ transport.

2) OWNERSHIP AND COMMERCIAL STRUCTURE

As a private sector company, T&SCo will own, finance, develop, build and operate the T&S assets.

Neither the T&S assets, nor any liabilities or contingent liabilities associated with them, will appear on HMG’s balance sheet.

3) GOVERNANCE

From its inception, T&SCo will operate under governance that demonstrates commitment to cost reduction, industry development and looking to benefit the end user. Its Constitution or Articles will and governance will reflect this.

The public sector ethos and governance of T&SCo should aim to prevent some of the behaviours that are currently creating difficulties between regulators and utilities in the UK. T&SCo will be subject to standard regulatory scrutiny as to its performance and behaviour, and its regulated returns should reflect this.

4) T&SCO REGULATORY ASSET BASE (RAB) MODEL

As a private sector company, T&SCo will operate under a new “Regulated Asset Base” (RAB) regime - designed for the CO₂ T&S business. T&SCo’s investments and operations are intended to be low risk and earn a low return. Including debt financing will help further to keep post-tax costs down.

When regulated under a Regulated Asset Base (RAB) system a company is permitted by a regulator to charge fees which allow it to make a return commensurate with the risk it is incurring. All costs can be recovered, provided they are properly incurred, and a return made on the capital invested.

The basis and key mechanics for regulation will work as follows:

- T&SCo will be a “private sector regulated company”, with a regulator appointed by HMG.
- T&SCo will operate under a system of periodic reviews and “settlements”. T&SCo will agree a plan for T&SCo’s expenditure and operations with the regulator. This will be reviewed and updated periodically, typically every five years.
As under any regulatory regime, the regulator will determine the target regulated return of T&SCo at the start of each regulatory review period and returns within review periods will be dependent on performance. This will give certainty to investors and will be predicated on the risks of the T&SCo, its regulatory structure, its protections and the prevailing market appetite and conditions.

Normally, capital expenditure outside the plan will be absorbed into the RAB from the time of the next settlement. However, if exceptional events occur, requiring exceptional expenditure or loss of income, the regulator may agree to additional expenditure, before the next review is due.

There will be a system of appeal against decisions of the Regulator, after which the decisions of the Regulator will be binding.

**Risks - see Equity Shareholder Risk - Regulatory Risk**

T&SCo will be entitled to charge fees that enable it to operate, make required future investments and make a regulated return on its investment for shareholders, subject to performance.

T&SCo will be expected to make a “utility rate of return” based on market precedents, adjusted for industry and project specific risks and contractual protections the T&SCo regulatory structure offers.

In the longer term, some or all of finance required may be put out to competition in the market; it is not the presumption that the original sponsors and owners of T&SCo will wish to retain ownership longer term.

As with other regulated sectors, there will be a concept of “allowable costs”, which are deemed to be properly, economically and efficiently incurred. Both foreseeable as well as unforeseeable, exceptional costs can fall within the definition of “allowable costs”. Only “allowable costs” will be chargeable as costs to the RAB. Under a RAB structure, many costs that might more traditionally fall on a project developer (e.g. the need to drill unexpected wells to maintain CO₂ store integrity) would be allowable costs. Should they occur, they therefore are costs that would be passed through the RAB to end consumers.

**Risks - see Equity Shareholder Risk - “Non-allowable costs”**

The CAG has not determined whether new legislation or regulation would be required to implement a RAB-based model for CO₂ Transport and Storage.

5) **INCENTIVES AND PENALTIES REGIME**

T&SCo will be subject to regulated incentives to deliver and operate projects economically and efficiently. There will be a regime of incentives and penalties to ensure alignment of T&SCo’s objectives to those of HMG, CO₂ Capturers[^36]^[37] and those ultimately carrying the costs of T&S (consumers, taxpayers). T&SCo will therefore have exposure to its own performance and cost control.

The RAB regime of incentives and penalties will work as follows:

- The concept will be that T&SCo will be incentivized to operate properly, efficiently and economically.
- The system will be intended to align the interests of T&SCo, and its shareholders, with those of customers of T&SCo, HMG and those ultimately carrying the costs of T&SCo (consumers, tax revenue etc).
- The regime of incentives and penalties will include construction costs and schedule, operating costs and performance, and storage monitoring and decommissioning.

**Risks - see Equity Shareholder Risk - Incentives and Penalties Regime**

[^36]: “CO₂ Capturers” will be those who are capturing CO₂ and delivering it to T&SCo for transport and storage.
[^37]: The “Funders of CO₂ Capturers” are the source of revenue support that is being provided to CO₂ Capturers. This will be the LCCC for electricity generating projects with CCS, and HMG for Industrial production with CO₂ Capture projects.
6) INSURANCE

Insurance will be a key risk mitigation measure - where it is commercially available at economical rates. The cost of insurance will be an “allowable cost”.

*Risks - see HMG risks - “Insurer of Last Resort”*

Insurance will sit within a three-tier regime:

i. T&SCo carries the costs of risks below the insurance product “excess”. Subject to the incentives and penalties regime these will be “allowable costs”;

ii. The insurance market carries the costs of risks above the “excess” up to the available insurable maximum;

iii. HMG acts as the “insurer of last resort” for a closed list of specific, defined risks falling outside the available insurable maximum. This list currently includes and is limited to:

   o Failure or prolonged shut-in of the store, with no alternative route to storing CO₂;
   o T&SCo building the T&S assets, but no CO₂ Capture plant is ever built in the cluster, leaving T&SCo with “stranded assets”;
   o Insufficient ETS certificates available in the Contingency Reserve of ETS Certificates to cover the volume of any CO₂ leakage from the store;
   o The Decommissioning Reserve proves insufficient to meet the costs of decommissioning and monitoring in the post closure period of the store.

These issues are expanded on in the sections below.

7) STORAGE LEASE, STORAGE LICENSE, CONSENTS, PERMITS AND LAND RIGHTS

T&SCo will obtain and hold the store license (from OGA) and the store lease (from Crown Estate). T&SCo will be responsible for securing all Consents, Permits and Land Rights required for development of the project.

8) CO₂ DELIVERY CERTIFICATION, OWNERSHIP, AND SALE

When CO₂ has been received from CO₂ Capturers and delivered to the specified T&SCo delivery point, T&SCo will certify that delivery of CO₂ has been made.

T&SCo will take title to and own the CO₂ once delivery is made and it enters the T&S assets. T&SCo will account for the CO₂ “delivered for storage”, the CO₂ injected into the storage wells and the CO₂ held as working inventory in its assets.

Income to T&SCo from sale of CO₂ owned by T&SCo will be included as income in the RAB.

9) RIGHTS TO USE OF STORAGE; ALLOCATION OF STORAGE CAPACITY

Subject to the Crown Estate lease, T&SCo will hold all the rights to the injection and storage capacity, which will be held in the first instance for the use of customers nominated by HMG receiving “revenue support” contracts.

Subject only to capacity limits, T&SCo will have an obligation to take on new CO₂ Capturers at a pre-published price (being T&SCo’s costs shared between the existing and new CO₂ Capturers). (See Third Party Access below).

(The intention is to give both Government and future new entrants (CO₂ Capturers) certainty that their chosen projects will be allowed on to the network; and to give clarity over the cost of doing so).

In general, T&SCo will enter into contracts with its customers that reserve an annual CO₂ T&S capacity for the term of the contract, within a specified minimum (probably zero) and maximum range.
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10) THIRD PARTY ACCESS

The assets of T&SCo will be operated and governed in accordance with The Storage of Carbon Dioxide (Access to Infrastructure) Regulations 2011. (These Regulations provide a “back-stop” in cases where companies are unable to reach agreement “on a voluntary basis” on terms of access, including tariff levels).

They will also operate under any protocol or treaty under which the UK agrees to store CO₂ from other countries.

Risks - see Equity Shareholder Risk - Third Party Access.

11) CO-ORDINATION BETWEEN CO₂ CAPTURE AND T&S ASSETS

It is anticipated that for the development of the first projects in a cluster a “Programme Development Consortium” would be created involving one or more potential capture sources and prospective owners of key CO₂ transport and storage facilities. The Consortium will appoint a “Programme Development Coordinator” to lead the Consortium.

The Consortium will work with regional authorities and other organisations in the region, noting that any T&S infrastructure developed will have third party access arrangements. The Coordinator will produce a plan for integration of further capture sources into the system. The Coordinator could be one of the possible anchor projects, an external organization appointed by the projects, the regional government authority, or possibly an organization appointed by HMG that works to a scope defined by HMG.

In general, it is likely that the anchor T&S project developer will be appointed as Coordinator, as they will often have the best opportunity to create a coherent picture of the status of possible capture projects that may be developed in a cluster/region.

The role will be sponsored by the capture, transport and storage projects involved, and may include cost sharing arrangements with government (see “Development Funding” below). Contractual arrangements between each element of the total project are expected to be used.

Project development would be synchronized, using coordinated stage-gate decision points. The first anchor projects in a cluster/region will look to pass i) into FEED, and ii) through FID simultaneously. Project development funding provided by HMG prior to FEED will be coordinated across each programme element. All parties will be bound contractually to manage risks and deliver an operating project; with terms depending on the nature of the projects involved, risk allocations and arrangements put in place by HMG to allow the projects to proceed.

A contractually agreed system of penalties will operate between the projects if “first CO₂” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

Risks - see Equity Shareholder Risk - Stranded Assets

12) ASSETS SIZE/ CAPACITY

The initial cluster capture and T&S projects in any cluster or region should be sized to meet two criteria:

i. Meet a common set of metrics for “reasonable” unit cost (e.g. cost of carbon abatement, unit cost of low carbon electricity or other output), as well as “reasonable” use of capital and capital efficiency.

ii. Demonstration of how development of further cluster capture projects provides a clear pathway to allowing CCUS to “operate at scale by 2030”.

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The critical T&S assets (pipelines, and available well slots, perhaps terminals) should be “right sized” on the basis that further capture project will join the network once the anchor projects are operating. State Aid clearance may be required.

T&SCo will charge T&S fees to recover the full cost of the “right sized” assets, even if they are not fully utilised to start with. (Section 20 describes two options which may be considered to reduce these initial fees.)

A clear cost reduction pathway for future build out and follow on projects will need to be provided to Government and other stakeholders for all initial projects, noting that the cost of carbon abatement from the initial projects could already be the lowest available.

13) DEVELOPMENT FUNDING

For early projects, the developers of the project and HMG share the costs of project development of T&SCo assets through to FID - both pre-FEED and FEED costs.

*Risks - see Equity Shareholder Risks - Political Risks (1) - Project fails post-FEED.*

*Risks - see HMG Risks - Loss of development funding.*

14) FINANCING

T&SCo will be financed by private sector equity, and most probably debt, at least in the longer term. The finance raised will include all required working capital.

T&SCo will create and maintain considerable, prudent contingency funding from its financiers at all times. As is typical in RAB structures, they will be able to claim the costs of doing so as an allowable cost.

These funds need to be sufficient to cover reasonable unplanned costs of the T&S assets, and particularly the store, throughout their lives; including the costs of any reasonable unplanned storage liabilities that arise, and the costs of decommissioning and monitoring the store.

The levels of funding required, and the means of restoring the required levels of contingency funding if unexpected expenditure is needed, will form part of the initial regulatory settlement put in place by the regulator, whose duties will include ensuring that T&SCo can finance its operations prudently.

One further possibility raised by the CAG is that the existing system of “Decommissioning Tax Allowances” could be restructured to allow some of the tax allowances to be used to facilitate and partially finance conversion of suitable existing oil and gas assets to CCS service.

*Risks - see “Funders of CO2 Capturers” Risks - Cost of Contingency Funds.*

*Risks - see Equity Shareholder risks - Uncertain calls on cash.*

*Risks - see Equity Shareholder risks - Financial Security (EU Directive)*

15) DECOMMISSIONING RESERVE

A ring-fenced “Decommissioning Reserve” to cover forecast decommissioning and monitoring costs of the store post closure (including a significant contingency) will be built up from T&SCo’s funds over the life of the store, as CO2 is injected into the store. The cost of this reserve will be included in the T&S fee charged to the CO2 Capturers.

The regulator may require that an initial tranche of funding for this fund be put in place when the T&S assets are first commissioned, but it is otherwise envisaged this will be built up over a period commensurate with the projected life of the plants it is servicing. As new plants are added with longer life, the build-up period of this fund can be lengthened, lessening the burden on all projects.
Any surplus funds in this reserve will be redistributed appropriately when the store is finally handed to HMG after monitoring is complete.

16) CONSTRUCTION - COSTS AND TIMETABLE

Given the nature of new offshore CO₂ stores, some uncertainty in the projected costs of and schedule for construction is unavoidable.

Subject to the provisions of the regime of incentives and penalties, the costs or financial consequences to T&SCo from both foreseeable as well as exceptional and unforeseeable construction events or commissioning delays, will be all be included as “allowable costs” under the RAB structure.

T&SCo will use best practice from other regulatory sectors in their contracting policy where such experience could be helpful to ensure economic and efficient delivery of the project. If appropriate T&SCo will put in place a number of risk mitigation measures to address this unavoidable risk, including some or all of the following:

- Fixed price contracts with contractors for those parts of the project where such contracts can be provided economically;
- Pain share/ gain share arrangements with contractors where such arrangements can be provided economically;
- Delivery and performance contractor “full EPC wrap” provisions, including performance guarantees, to be provided by contractors for those elements of the contracts where these can be provided economically;
- Building prudent contingency into cost estimates, funding availability and schedule plans to cater for significant unforeseen events.

T&SCo will be obliged to agree with the regulator how much of the construction and operating costs it is economic and efficient to let on fixed cost contracts. Finding the optimal balance between risk transfer to contractors (who will have to build contingency into the project cost to cover these risks in a new and inherently uncertain industry), total construction price and cost of capital of T&SCo, can minimize the cost to CO₂ Capturers, but it will leave some risk that costs might escalate.

Risks - see Equity Shareholder risks - Construction Costs and Timetable
Risks - see Funders of CO₂ Capturers’ risks - Construction Costs and Timetable

17) T&S PERFORMANCE AND COSTS

Given the nature of new offshore CO₂ stores, some uncertainty in the projected performance and costs is unavoidable.

Subject to the provisions of the RAB regime of incentives and penalties, the costs and financial consequences to T&SCo from both foreseeable as well as exceptional and unforeseeable problems in operating performance or events will be all be included as “allowable costs” under the RAB structure.

Risks - see Equity Shareholder risk - T&S Performance and Costs
Risks - see “Funders of CO₂ Capturers” risks - T&S Performance and Costs

18) DECOMMISSIONING AND MONITORING

T&SCo will decommission and monitor the T&S assets once either the store is full, or no further CO₂ Capturers have contracted to use it.

The Decommissioning Reserve (see above) will be used to cover the costs of both decommissioning and monitoring.
Should the Decommissioning Reserve prove insufficient in the post-closure period, HMG will act as “insurer of last resort”.

The store will be handed to HMG after decommissioning and monitoring are complete.\(^{38}\)

Provisions should be included in the agreements between HMG and T&Sco which, following cessation of \(\text{CO}_2\) storage, allow T&Sco to crystallise their obligations in the store and hand the store back to HMG earlier than envisaged in the EU CCS Directive.

\section*{19) T&S FEES}

T&Sco will charge each customer T&S fees under a “T&S Services Contract”.

Funding for the T&S fees will come from the “Funders of \(\text{CO}_2\) Capturers” (i.e. the source of revenue support that is being provided to \(\text{CO}_2\) Capturers). For early projects this will, for example, be the LCCC for electricity generating projects with CCS, and HMG for Industrial Production with \(\text{CO}_2\) capture projects. The ultimate ‘funder’ is therefore the consumer or taxpayer. \(\text{CO}_2\) Capturers will be obliged to pass these fees through directly to T&Sco. Some form of protection for T&Sco will be required if a \(\text{CO}_2\) Capturer fails to pass these fees through.

Under the plan agreed with the regulator T&Sco will be allowed to charge to its customer(s) fees that are pre-agreed with the regulator.

On instruction of the T&S regulator, the T&S fees may change from time to time, depending on new plant being commissioned, and on other factors.

These fees will allow T&Sco to cover its “allowable” operating and maintenance, to build the Decommissioning Reserve, to repay its debt, and to provide a regulated return to shareholders within the expected life of its contracts. The life of the assets may be extended as capture projects are added, which will lower payments to the original users.

Under the RAB incentives and penalties regime, only “allowable costs”\(^ {39}\) will be recoverable, and these will be subject to the regime of incentives and penalties.

The T&S fees will be charged partly as a fixed “capacity reservation” fee i.e. a fixed annual/monthly fee, and partly as a “variable” element i.e. per tonne of \(\text{CO}_2\) delivered to T&Sco’s delivery point. The “capacity reservation” fee will comprise most of the T&S fee - to provide stable, non-volatile income required by investors in low risk, low return RAB structures.

If only one \(\text{CO}_2\) Capture project is being built initially, T&Sco will charge that project a fee that covers all T&Sco’s costs (including debt serving and repayment, and dividends to shareholders), and any required accumulation of reserves for future store decommissioning and monitoring costs.

If more than one project is being built initially then these costs will be spread across all these projects.

Consideration may also be given to two options to reduce the T&S fee charged to the first project:

- Allowing a portion of the early costs of T&Sco to “wrap up” on the RAB before further capture projects are commissioned. This will require T&Sco to raise enough finance to cover the shortfall in operating costs and capital servicing requirements of their investors until further capture projects are commissioned.
- Providing an HMG grant to cover a portion of the capital cost of T&Sco, so that the first project does not have to carry the costs of remunerating the whole of the initial capital investment in the first T&S system in a cluster.


\(^{39}\) “Allowable costs” include “business as usual costs” and “exceptional costs”. See the earlier definition of “allowable costs” in the section on “Ownership and Commercial Structure”.

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By agreement with the regulator, T&SCo will make up any forecast shortage in required cash reserves by being allowed to increase its fees; and will reduce its fees if cash reserves are forecast to grow excessively.

20) CONTRACT START DATE

For each “T&S Services Contract”, payments of the “capacity reservation” portion of the T&S fees will start from the Contract Start Date, which will be the latest of:

- a pre-agreed start date;
- the date when T&SCo is ready to accept delivery of the first CO₂ from the customer (whether or not the customer is ready to deliver it).

21) FOLLOW-ON CAPTURE PROJECTS

If future capture projects join the network and are provided with T&S services by T&SCo, then the T&S fees charged to existing customers will be reduced to spread the costs of the T&S assets proportionately across all CO₂ Capturers.

When capture projects stop using T&SCo’s assets the T&S fees to the remaining customers will be adjusted upwards accordingly to allow T&SCo to recover all its costs.

T&S fees charged will spread the costs of the T&S assets equitably across all CO₂ Capturers.

However, if new CO₂ Capturers join the network, their “capacity reservation” fee may be set to zero if they do not receive a fixed payment from their “Funders of CO₂ Capturers”.

22) EXPANSION OF THE T&S ASSETS

T&SCo may choose to expand their assets to cater for new customers. Subject to agreement with the Regulator, the costs of doing so will be included in the RAB.

The UK Third Party Access regulations (see above) will govern whether T&SCo can be obliged by the Secretary of State to expand their assets to accommodate new customers.

23) DIVIDEND POLICY

T&SCo will agree a dividend policy with regulators, allowing it to provide a pre-agreed return to its shareholders.

In order to keep the costs of capital low, T&SCo will always be allowed to make pre-agreed dividend payments, assuming satisfactory performance under the incentives and penalties regime.

24) TIMING OF PLANNED MAINTENANCE

All capture plants and T&S assets in a cluster will agree a rolling 5-year forward programme of planned major maintenance. All asset operators will cooperate to ensure that as far as possible planned maintenance occurs simultaneously across all assets in the cluster.

A pre-agreed contractual regime will allow for an agreed duration of shutdown for planned maintenance without penalty across the cluster.

(Unplanned maintenance will be covered by the “Cross-chain failure” provisions below.)

25) CROSS-CHAIN FAILURE - DELAY IN COMMISSIONING T&S ASSETS

As described in sections 14 and 15 above (covering Construction - Costs and Timetable, and T&S Performance and Costs), subject to the provisions of the RAB regime of incentives and penalties, the
costs and financial consequences to T&SCo from both foreseeable as well as exceptional and unforeseeable problems will be all be included as “allowable costs” under the RAB structure.

This covers delay in commissioning the T&S assets.

T&SCo will be entitled to accumulate these costs on to the RAB. However, T&SCo will need to have access to contingency reserve funds sufficient to cover the cash flow requirements of dealing with such events.

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26) CROSS CHAIN FAILURE - T&S ASSETS TEMPORARILY NOT AVAILABLE

If, after the Contract Start Date for the first “T&S Services Contract”, and for whatever reason, T&S assets are not available to accept CO₂ delivered to the point of receipt, the following will apply:

This includes circumstances where:

- T&S assets are temporarily completely unavailable;
- T&S assets are available but are capacity constrained for any reason and cannot accept the full contracted quantity of CO₂ being delivered.

**CO₂ Capturers**

CO₂ Capturers will be entitled to continue to run, either wholly or partly unabated. They will continue to receive a portion of their revenue support from the “Funders of CO₂ Capturers”. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage. The definition of this level of support will be set case by case.

In the case of Industrial Production with CO₂ Capture projects, it may be necessary to provide the CO₂ Capture projects with “free allowances” for CO₂ emissions as well as continued revenue support to enable them to continue to operate unabated.

In the case of Electricity Generators with a “Dispatchable CfD Contract”, it may not be necessary to provide additional ETS certificates when they are running unabated. When running unabated, the “Dispatchable CfD Contract” will provide a fixed payment and take CO₂ emissions into account through the variable payment.

In the case of Hydrogen Production in a RAB structure it will be logical for any emissions certificates required to be included in the costs charged to the RAB.

**T&SCo**

If T&SCo’s assets are not available, T&SCo would be contractually bound to honour its T&S contract if possible. This could include using alternative assets, or shipping to other T&S assets.

Costs incurred in doing so would be recoverable through the RAB (subject to the incentives and penalties mechanism).

During the period of unavailability or reduced availability, T&SCo will be entitled to receive a portion of their T&S fees. Payments by the “Funders of CO₂ Capturers” will be adjusted accordingly.

The level of appropriate reduction will need to be developed between T&SCo and the regulator, balancing the desire to incentivise T&SCo to restore services, but recognising that in most instances unavailability will result from circumstances which could not be predicted nor controlled by T&SCo.

T&SCo therefore carries the risk that it loses a portion of its cash flow when it cannot accept delivery of CO₂. However, provided it performs to the requirements of the incentives and penalties regime, T&SCo will be permitted to carry forward and recover these cash-flow losses through resetting the fees at the next periodic review.

*Risk - HMG risk - Cross chain failure - T&S assets temporarily not available.*
CHAPTER 5: CO2 Transport and Storage – Detailed Business Model

27) CROSS CHAIN FAILURE - PERMANENT CLOSURE OR PROLONGED SHUT-IN OF CO2 STORE

T&SCo would be contractually bound to honour its T&S contract if possible. This could include replacing onshore or offshore pipelines or facilities or developing new wells or an alternative store. The regulator could require T&SCo to incur costs as necessary to do so, which would be allowable under the RAB. However, T&SCo’s shareholders would not be obliged to provide any finance to cover these costs, and the regulator would be obliged to set an allowable rate of return on such costs that would attract alternative funding if it is needed.

In the event of permanent closure or a prolonged shutdown of the store, T&SCo will continue to receive the reduced T&S fee until operations are restored or an alternative regulatory settlement is reached.

If after an agreed period injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as an “insurer of last resort”. HMG would cover the remaining exposure of any debt providers and equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies, as well as returns to date.

HMG will have step-in rights to any remaining assets and contracts (should they wish to exercise them). They would become the “funder of last resort” for a new CO2 T&S service to be provided to those with contracts with T&SCo. There may be a need to create a special administration regime to protect consumers against the possibility of T&SCo insolvency.

28) CROSS CHAIN FAILURE - CAPTURE PLANT DOES NOT DELIVER CO2 TO T&SCO

If for whatever reason the CO2 Capture plant does not deliver the contracted volume of CO2 to the T&S assets, options are:

a) Capture plants are not obliged to operate or deliver CO2 to T&SCo.

   EG&CCo will not receive revenue support when they are not operating.

   However, regardless of the volume of CO2 delivered, the “Funders of CO2 Capturers” will still be required to pay the “capacity reservation” portion of the T&S fees to CO2 Capturers, and CO2 Capturers will still be obliged to pass these fees through directly to T&SCo. (The alternative of passing these fees directly to T&SCo has also been proposed but is not recommended.)

   This obligation should start from the Contract Start Date of the “T&S Services Contract”.

b) If the T&S investment capex is paid for by an HMG grant, then this payment of the T&S fee in these circumstances would not be necessary. (This is Variant 2)

29) CROSS CHAIN FAILURE - PRECOMMISSIONING STRANDED ASSET RISK - NO CO2 CAPTURE

The event that T&SCo builds a CO2 T&S system, and that no prospect then appears of a CO2 capture plant being built to supply CO2 to it, seems extremely unlikely.
However, in that event HMG would need to act as “insurer of last resort”. The store would need to be permanently closed and decommissioned in the most financially effective way possible. HMG would then cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

30) CAPTURE PLANT DELIVERS OFF-SPEC CO₂ TO T&SCO

T&SCO will be entitled to reject delivery of CO₂ which is not in specification. This will be treated as a case where CO₂ Capture plants are failing to deliver CO₂ to T&SCO.

A regime for compensation to be paid by suppliers of off-spec CO₂ to T&SCO will cover losses incurred by T&SCO if they inadvertently accept off-spec CO₂.

Risk - Equity Shareholder risk - off-spec CO₂

31) CO₂ LEAKAGE FROM CO₂ STORE

Whilst T&SCO is storing CO₂, it will concurrently build up a “Project Contingency Reserve of EU ETS Certificates” (‘ETS Reserve’). These will be purchased over a period commensurate with the RAB duration in the emissions traded market, held in a Contingency/Reserve account by T&SCO and designated for offsetting any future emissions arising from CO₂ that may leak from any CO₂ storage reservoir.

The rate of building the ETS certificates contingency reserve to cover possible future storage leaks will be agreed with the regulator and set at a small percentage (say 2%) of the total CO₂ stored annually. The costs of these certificates will be an “allowable” cost recovered through the RAB structure.

If CO₂ leaks from the T&SCO store, certificates will be drawn from the Project Contingency Reserve of ETS certificates to cover the resulting obligation under the EU CCS Directive.

If, should a leak occur, the Contingency Reserve of ETS Certificates contains insufficient certificates to cover the volume of CO₂ leaked then HMG will act as “insurer of last resort”. HMG would have several options for managing this event without incurring excessive direct cost.

The resulting costs of resolving any CO₂ leaks or mitigating their direct effects will also (subject to the provisions of the incentives and penalties regime within the RAB) be “allowable” costs for T&SCO within the RAB.

Risk - HMG risk - CO₂ Leakage from CO₂ Store
Risk - “Funders of CO₂ Capturers” risk - CO₂ Leakage from CO₂ Store

PART 2 - OTHER ISSUES

32) T&SCO BANKRUPTCY

Where discretion exists, the order of claims post-bankruptcy is to be defined. HMG will have the first step-in rights to T&SCO’s assets in the event of T&SCO bankruptcy.

A Special Administration Regime may be required, similar to other regulated industries.

33) REFINANCING

Appropriate regimes covering and Refinancing of and Equity Dilution in T&SCO will be defined. Whilst T&SCO should have a duty to examine the efficiency of its capital structure, any refinancing will largely be to the benefit of end users and/or for investing in growth in the industry.
34) CHANGE OF CONTROL AND T&SCO SHAREHOLDERS EXIT

Applicable regimes covering Change in Control of T&SCO will be defined.

Risk - Equity Shareholder risk - Shareholder Exit

35) CHANGE IN LAW, CHANGE IN POLICY.

If applicable, provisions covering Change in Law will be defined.

Provisions covering Change in Policy will be defined. These will provide “grandfathering” protections to T&SCO.

Risk - HMG Risk - Change in Law, Change in Policy

36) [FORCE MAJEURE]

T&S owners should be relieved of their obligations under Force Majeure circumstances.

37) “STATE AID”

Some form of “State Aid” approval may be needed for the project, and for the protections envisaged under this business model. Whilst after Brexit the form of “State Aid” rules may change the principles probably will not.

Risk - HMG risk - State Aid Approval
Risk - Equity Shareholders risk - State Aid Approval
CHAPTER 6 - CO₂ TRANSPORT AND STORAGE - RESIDUAL RISKS

It is usual, and therefore assumed, that all key stakeholders in a major project will run effective risk management processes that manage and mitigate the “Business as Usual” risks they face arising through their involvement in the project.

However, once these “Business as Usual” risks have been mitigated using “Business as Usual” processes, a number of key “Residual Risks” will remain to be managed and mitigated. The key Residual Risks for key stakeholders in the development of early projects in a new CCUS cluster are listed in this section. (“Business as Usual” risks are not listed - that is for stakeholders to do themselves.)

The effect of this Business Model is to allocate those Residual Risks to one or more key stakeholders. This section shows how the Business Model drives the allocation of these Residual Risks. They are categorized into three main sections - HMG Risks; “Electricity Consumers via LCCC” risks; EG&CCo Equity Shareholder Risks. A high-level listing of these risks is shown in the following table.

Finally, there are a number of ways in which these Residual Risks can be mitigated by those who hold them. These are also shown in this section.

**T&S BUSINESS MODEL - VARIANT 1 - RESIDUAL RISK ALLOCATION**

<table>
<thead>
<tr>
<th>Risk sits with:</th>
<th>T&amp;S Co Equity Shareholders</th>
<th>“Funders of CO₂ Capturers”</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>RAB Incentives and Penalties Regime</td>
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<td></td>
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<tr>
<td>RAB Regulatory Risk</td>
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</tr>
<tr>
<td>RAB “Non-Allowable Costs”</td>
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<td></td>
</tr>
<tr>
<td>Third Party Access</td>
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<td></td>
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<tr>
<td>Uncertain Calls on Cash</td>
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</tr>
<tr>
<td>Financial Security - EU Directive</td>
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<td></td>
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<tr>
<td>Shareholder Exit</td>
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<td></td>
</tr>
<tr>
<td>CO₂ delivered off-specification (borne by capture plant)</td>
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</tr>
<tr>
<td>Construction Costs and Timetable</td>
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<td></td>
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<tr>
<td>T&amp;S Performance and Costs</td>
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<td>✓</td>
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</tr>
<tr>
<td>Cross Chain Failure - T&amp;S Assets Not Available</td>
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<td>✓</td>
<td></td>
</tr>
<tr>
<td>Cross Chain Failure - Capture Plant does not Deliver CO₂</td>
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<tr>
<td>Cost of Contingency Funds</td>
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<td>✓</td>
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<td>Permanent Store Closure</td>
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<tr>
<td>CO₂ Leakage from Store</td>
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<td>✓</td>
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<tr>
<td>Project Fails post-FEED - Loss of Development Funding</td>
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</table>
CHAPTER 6: CO₂ Transport and Storage – Residual Risks

<table>
<thead>
<tr>
<th>Risk sits with:</th>
<th>T&amp;S Co Equity Shareholders</th>
<th>“Funders of CO₂ Capturers”</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>“State Aid”</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
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<tr>
<td>HMG acts as “Insurer of Last Resort”</td>
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<td>✓</td>
</tr>
<tr>
<td>Stranded Assets Prior to Commissioning</td>
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<td></td>
<td>✓</td>
</tr>
<tr>
<td>Change in Law, Policy</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>

“Irreducible” Residual Risks to be facilitated by HMG

This section describes those risks where HMG acts in the capacity of facilitating those “irreducible risks” that industry cannot properly price, and therefore cannot accept at reasonable cost.

1) HMG RISK - HMG ACTS AS “INSURER OF LAST RESORT”.

Residual Risk:
- Insurance will sit within a three-tier regime - a) T&S Co self-insurance - events within this layer will be allowable costs; b) Commercial insurance; c) HMG acts as “Insurer of Last Resort”.

Residual Risk Allocation. HMG will carry a closed list of the following, as “Insurers of Last Resort” (these are expanded on in the sections below):
- In the event of complete failure of the store, with no alternative route to storing CO₂:
  - HMG would cover the remaining debt exposure of any debt providers and equity of the equity shareholders;
  - HMG would become the funder of last resort for a new CO₂ T&S service to be provided to those with contracts with T&S Co.
- In the event of no CO₂ capture plant ever being commissioned and operational, T&S assets would need to be permanently closed and decommissioned in the most financially effective way possible. HMG would then cover any remaining exposure of any T&S Co debt providers and the equity of T&S Co equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.
- If there were insufficient ETS certificates available in the Contingency Reserve of ETS Certificates to cover the volume of CO₂ leaked from the store, the HMG would need to arrange for further “free allowances” to be provided to cover the shortfall.
- In the event that in the post-closure period the Decommissioning Reserve proves to be insufficient, HMG will provide funds to fill the shortfall.

Risk Mitigation:
- These are covered in the sections below.

2) HMG RISK - CROSS CHAIN FAILURE - T&S ASSETS TEMPORARILY NOT AVAILABLE.

Residual Risk - Cross Chain Risk T&S Performance Risk
- T&S Co assets are not available to accept and store CO₂; or they are constrained and can accept and store only a portion of the contracted CO₂ volumes.

Residual Risk Allocation:
- HMG may need to facilitate the provision of “free allowances” to Industrial Producers with CO₂ Capture, to offset the incremental cost of emissions they will incur when running unabated.
However, the bulk of this risk will sit with the “Funders of CO₂ Capture”.

They will continue to pay CO₂ Capturers a portion of their revenue, set at a level to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage.

They will also continue to pay T&Sco a portion of their normal T&S fee.

Residual Risk Mitigation:

The risk of T&S not being available cannot be entirely avoided. It can and must be mitigated by:

- Good construction management processes and contracts;
- Good operational performance management processes.
- T&Sco can be incentivized to mitigate this risk through the incentive and penalty regime in the RAB structure.
- HMG can minimize this risk through the vetting and acceptance (or otherwise) of the T&Sco shareholders, developer and operator, by ensuring they have sufficient capability to minimize these risks and through the due diligence that will be carried out by debt providers on all of these issues.

3) HMG Risk - Cross Chain Failure - Permanent closure or prolonged shut-in of CO₂ Store.

Residual Risk - Permanent unplanned closure of a CO₂ store

- It is possible - though very unlikely - that, after commissioning, an event occurs which causes permanent closure or prolonged shut-in of the CO₂ store.

Residual Risk Allocation:

- T&Sco would be expected to provide an alternative CO₂ T&S service to honour their T&S contract if possible. The costs of doing so would be allowable under the RAB. This risk associated with these costs therefore falls on the “Funders of CO₂ Capturers”.
- T&Sco will continue to receive a reduced T&S fee until operations are restored or an alternative regulatory settlement is reached. This risk therefore falls on T&Sco and Funders of CO₂ Capturers.
  - Note: Provisions or time periods will be required to determine the transition from temporary to permanent closure.
- If injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as “insurer of last resort” after an agreed period.
  - HMG would cover the remaining debt exposure of any debt providers and the equity of the equity shareholders. (This role may reduce over time, once the store is proven, more storage is added to the cluster, or further operating experience is gained)
  - HMG would carry the risk of acting as a funder of last resort for constructing a new store.

Residual Risk Mitigation:

- T&Sco need to choose their first store very carefully, to reduce the risk of failure of the store or existing legacy wells.
- T&Sco will also need to build sufficient redundancy in the asset (e.g. spare wells) to cater for potential performance problems.
- The possibility of appraising and preparing for investment in an alternative store at short notice should be considered - though this will not always be a feasible option.
- The contingency funds available to T&Sco to cover this scenario need to be substantial.
- HMG will need significant informed due diligence to ensure that these risks are all but eliminated.
4) **HMG RISK - PROJECT FAILS POST-FEED - LOSS OF DEVELOPMENT FUNDING.**

**Risk - Loss of the HMG share development funding**
- If the project does not proceed, HMG and developers will each lose their share of the development funding provided.

**Risk Allocation:**
- This risk is shared between the project developers and HMG.

**Risk Mitigation:**
- Development funding expenditure by the developers of T&SCo provides tangible evidence to HMG that the developers intend to secure investment in T&SCo assets.

5) **HMG RISK - CO₂ LEAKAGE FROM CO₂ STORE.**

**Residual Risk - CO₂ leaks from CO₂ to the atmosphere:**
- There is very small probability but potentially medium to high consequence risk that CO₂ may leak from offshore CO₂ stores in the future. The consequences of such a leak are indeterminate, possibly (though not probably) large and the possible timing is of very long duration (well beyond the revenue generating life of the store).
- Such leaks will give rise to two costs:
  - Under the EU CCS Directive T&SCo will be liable for the cost of ETS certificates required to offset the deemed emissions from these leaks.
  - T&SCo will also be liable for the costs of preventing such leaks and mitigating the non-climate effects (if any) (e.g. sea-bed damage due to increased acidity).
- The nature of these risks makes it extremely unlikely that a project could be financed with debt if it had to accept these risks and similarly equity appetite is untested.

**Residual Risk Allocation:**
- As part of the incentives and penalties regime, T&SCo will be incentivized (and will therefore carry some limited risk) to ensure that CO₂ is stored properly, that the store is properly monitored, and that sufficient preventative action is taken well before any CO₂ leakage occurs.
- ETS certificates:
  - T&SCo will build up a “Project Contingency Reserve of ETS Certificates (ETS Reserve)” to cover potential future storage leaks.
  - Up to agreed level of the “Project Contingency Reserve of ETS Certificates (ETS Reserve)” the costs of ETS certificates will be allocated to T&SCo’s Customers, through passing on the cost of purchasing the certificates for the ETS Reserve.
  - Above the agreed level of the ETS Reserve this risk will be borne by HMG as the “insurer of last resort”. HMG have several means to deal with this risk without incurring cost.
- Costs of stopping the leakage and remediating any effects:
  - These costs will be allowable under the RAB (if properly incurred), and therefore borne by the “Funders of CO₂ Capturers”.

**Residual Risk Mitigation:**
- As part of the incentives and penalties regime negotiated by HMG with T&SCo will be incentivized (and will therefore carry some limited risk) to ensure that CO₂ is stored properly, that the store is properly monitored, and that sufficient preventative action is taken well before any CO₂ leakage occurs.
6) HMG RISK - CHANGE IN LAW, CHANGE IN POLICY.

Risk - Change in Law, Policy
- T&SCo are exposed to future adverse changes in Law and Policy.

Risk Allocation
- This risk will be retained by HMG through suitable “change in law” and “change in policy” provisions in contracts held with T&SCo.

Mitigation:
- HMG is well placed to decide how best to deal with such issues should they arise.

7) HMG RISK - “STATE AID”:

Risk - “State Aid”
- Some form of “State Aid” approval may be needed for the project.

Risk Allocation:
- This risk is shared. All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

Mitigation:
- HMG will seek to obtain “State Aid” clearances where appropriate before excessive time and money has been spent on developing the project.
CHAPTER 6: CO₂ Transport and Storage – Residual Risks

Risks Sitting with “Funders of CO₂ Capturers” ⁴⁰

This section describes those risks that will be covered either by the LCCC for Electricity generation with CO₂ capture; or by tax revenue, where HMG is providing revenue funding for Industrial production with CO₂ capture projects.

8) COST OF CONTINGENCY FUNDS:

Risk - Cost of increased contingency funds:
• New contingency funds will be required and remunerated if the original contingency funding is used.

Risk Allocation:
• The T&S Co Equity Shareholders are obliged to secure and hold access to additional contingency funds if they are required.
• The costs and required returns on these funds will be allowable costs in the RAB, and therefore the “Funders of CO₂ Capturers” carry the cost of servicing the contingency fund, and any increase to it.

Risk Mitigation:
With the agreement of the T&S regulator:
• T&S Co will maintain sufficient contingency funding to deal with uncertain cash calls;
• T&S Co will secure and maintain significant contingency in the construction project (both cost and schedule) to cater for the remaining uncertainties;
• T&S Co will include contract provisions (e.g. fixed price contract elements, gain/ pain share arrangements, performance guarantees and other mitigation provisions) to minimize this risk to the degree that these are economical. It should be noted that in many cases it is better to cover this risk through holding contingencies at the project level rather than attempting to pass these risks on to contractors, who will then increase their own contingencies at the contract and sub-contract level.
• T&S Co will build considerable spare capacity into critical assets (particularly the number of wells, and well injection capacity) to provide operating contingency against unforeseen performance problems;
• T&S Co will build in and hold significant contingency into both cost and schedule estimates to cater for significant unforeseen operational and performance events.

9) “FUNDERS OF CO₂ CAPTURERS” RISK - CONSTRUCTION COSTS AND TIMETABLE

Residual Risk - T&S Co Construction Costs and Timetable Risk.
• Given the nature of offshore CO₂ storage assets, some uncertainty in the cost and schedule for construction and commissioning of the T&S assets is unavoidable.
This includes possible overruns in capital cost (for example driven by scope changes), pre-start-up operating costs, and delay in start-up. Residual Risk Allocation:
• The risk of uncertain construction cost and schedule sits ultimately with equity shareholders to raise sufficient capital to finance construction; and with the Funders of CO₂ Capturers to absorb the resulting increases in T&S Fees, and the consequences of commissioning delay.

Residual Risk Mitigation:
• T&S Co will hold prudent contingency in the construction project (both cost and schedule) to cater for the remaining uncertainties and a prudent capital structure that allows raising further funds to meet unforeseen cost escalations;

⁴⁰ The “Funders of CO₂ Capturers” are the source of revenue support that is being provided to CO₂ Capturers. For electricity generation with CO₂ capture this is LCCC; for Industrial production with CO₂ capture this is tax revenue.
• T&SCo will include contract provisions (e.g. fixed price contract elements, gain/ pain share arrangements, performance guarantees and other mitigation provisions) to minimize this risk, to the degree that this is judged to represent value for money. It should be noted that in many cases it is better to cover this risk through holding contingencies at the project level rather than attempting to pass these risks on to contractors, who will then add contingencies at the contract and sub-contract level.

10) “FUNDERS OF CO2 CAPTURERS” RISK - T&S PERFORMANCE AND COSTS

Residual Risk - T&SCo Performance Risk.
• Given the nature of offshore CO2 storage assets, some initial uncertainty in the performance the T&S assets is unavoidable.
• Where the costs vs benefits appear favourable, and where they can be provided economically, T&SCo will put in place a number of risk mitigation measures to address this unavoidable risk.
• This includes, amongst other things, operating costs (after start-up) and monitoring costs (after injection ends).
• This includes the risk of “minor failure of injectivity” into the store.

Residual Risk Allocation:
• The risk of uncertain performance sits ultimately with equity shareholders to raise sufficient contingency funding; and with “Funders of CO2 Capturers” to absorb the resulting increases in T&S Fees.

Residual Risk Mitigation:
• T&SCo will build considerable spare capacity into critical assets (particularly the number of wells, and well injection capacity) to provide operating contingency against unforeseen performance problems;
• T&SCo will build in and hold significant contingency into both cost and schedule estimates to cater for significant unforeseen events following construction.

11) “FUNDERS OF CO2 CAPTURERS” RISK - CROSS CHAIN FAILURE - T&S ASSETS TEMPORARILY NOT AVAILABLE.

Residual Risk - Cross Chain Risk T&S Performance Risk
• T&SCo assets are not available to accept and store CO2; or they are constrained and can accept and store only a portion of the contracted CO2 volumes.

Residual Risk Allocation:
• The bulk of this risk will sit with the “Funders of CO2 Capture”.
• They will continue to pay CO2 Capturers a portion of their revenue, set at a level to hold them economically neutral versus the situation where they run abated and are able to deliver CO2 for transport and storage.
• They will also continue to pay T&SCo a portion of their normal T&S fee.
• HMG may also need to facilitate the provision of “free allowances” to Industrial Producers with CO2 Capture, to offset the incremental cost of emissions they will incur when running unabated.

Residual Risk Mitigation:
• The risk of T&S not being available cannot be entirely avoided. It can and must be mitigated by:
  o Good construction management processes and contracts;
  o Good operational performance management processes.
  o T&SCo can be incentivized to mitigate this risk through the incentive and penalty regime in the RAB structure.
  o HMG can minimize this risk through the vetting and acceptance (or otherwise) of the T&SCo shareholders, developer and operator, by ensuring they have
sufficient capability to minimize these risks and through the due diligence that will be carried out by debt providers on all of these issues.

12) “FUNDERS OF CO₂ CAPTURERS” RISK - CROSS CHAIN RISK - PERMANENT CLOSURE OR PROLONGED SHUT-IN OF STORE.

Residual Risk - Permanent unplanned closure of a CO₂ store
- It is possible - though very unlikely - that, after commissioning, an event occurs which causes permanent closure or prolonged shut-in of the CO₂ store.

Residual Risk Allocation:
- T&SCo would be expected to provide an alternative CO₂ T&S service to honour their T&S contract if possible. The costs of doing so would be allowable under the RAB. This risk associated with these costs therefore falls on the “Funders of CO₂ Capturers”.
- T&SCo will continue to receive a reduced T&S fee until operations are restored or an alternative regulatory settlement is reached. A portion of this risk therefore falls on Funders of CO₂ Capturers.
  - Note: Provisions or time periods will be required to determine the transition from temporary to permanent closure.
- If injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as “insurer of last resort” after an agreed period.
  - HMG would cover the remaining debt exposure of any debt providers and the equity of the equity shareholders. (This role may reduce over time, once the store is proven, more storage is added to the cluster, or further operating experience is gained)
  - HMG would carry the risk of acting as a funder of last resort for constructing a new store.

Residual Risk Mitigation:
- T&SCo need to choose their first store very carefully, to reduce the risk of failure of the store or existing legacy wells.
- T&SCo will also need to build sufficient redundancy in the asset (e.g. spare wells) to cater for potential performance problems.
- The possibility of appraising and preparing for investment in an alternative store at short notice should be considered - though this will not always be a feasible option.
- The contingency funds available to T&SCo to cover this scenario need to be substantial.
- HMG will need significant informed due diligence to ensure that these risks are all but eliminated.

13) “FUNDERS OF CO₂ CAPTURERS” RISK - CROSS CHAIN FAILURE - CAPTURE PLANT DOES NOT DELIVER CO₂ TO T&SCO.

Residual Risk - T&S Demand Risk:
- Capture plants may choose to or may have to deliver less CO₂ than contracted because of operational problems, variability in demand for their products, and change in their production processes.
- Regardless of whether CO₂ Capturers deliver any or sufficient CO₂ to T&SCo, the “Funders of CO₂ Capturers” will still be required to pay the full “capacity reservation” portion of the T&S fees to the CO₂ Capturers, who will be obliged to pass it through to T&SCo. This obligation will start from the date of “first CO₂”.
- This is a potential problem with all CO₂ Capturers, but especially with industrial CO₂ Capturers whose plant/factory and product life can be quite short.

Residual Risk Allocation:
- After “first CO₂” the “Funders of CO₂ Capturers” carry this risk. They will be obliged to pay the “capacity reservation” fee, irrespective of the volume of CO₂ delivered.
**Residual Risk Mitigation:**

- *It is in the hands of the capture plants shareholders and operators to mitigate this risk through good project development, construction project management, and plant operational management.*
- *This risk can be minimized through vetting and acceptance (or otherwise) of T&SCO shareholders, developers and operators, including ensuring they have sufficient capability to minimize these risks.*

14) “FUNDERS OF CO₂ CAPTURERS” RISK - CO₂ LEAKAGE FROM CO₂ STORE.

**Residual Risk - CO₂ leaks from CO₂ to the atmosphere:**

- *There is very small probability but potentially medium to high consequence risk that CO₂ may leak from offshore CO₂ stores in the future. The consequences of such a leak are indeterminate, possibly (though not probably) large and the possible timing is of very long duration (well beyond the revenue generating life of the store).*
- *Such leaks will give rise to two costs:*
  - *Under the EU CCS Directive T&SCO will be liable for the cost of ETS certificates required to offset the deemed emissions from these leaks.*
  - *T&SCO will also be liable for the costs of preventing such leaks and mitigating the non-climate effects (if any) (e.g. sea-bed damage due to increased acidity).*
- *The nature of these risks makes it extremely unlikely that a project could be financed with debt if it had to accept these risks and equity appetite is also untested.*

**Residual Risk Allocation:**

- *ETS certificates:*
  - *T&SCO will build up a “Project Contingency Reserve of ETS Certificates (ETS Reserve)” to cover potential future storage leaks.*
  - *Up to agreed level of the “Project Contingency Reserve of ETS Certificates (ETS Reserve)” the costs of ETS certificates will be allocated to T&SCO’s Customers, through passing on the cost of purchasing the certificates for the ETS Reserve.*
  - *Above the agreed level of the ETS Reserve this risk will be borne by HMG as the “insurer of last resort”. HMG have several means to deal with this risk without incurring cost.*
- *Costs of stopping the leakage and remediating any effects:*
  - *These costs will be allowable under the RAB (if properly incurred), and therefore borne by the “Funders of CO₂ Capturers”.*

**Residual Risk Mitigation:**

- *As part of the incentives and penalties regime, T&SCO will be incentivized to ensure that CO₂ is stored properly, that the store is properly monitored, and that sufficient preventative action is taken well before any CO₂ leakage occurs.*
Risks Sitting with Equity Shareholders

This section describes those risks that will be covered by equity shareholders in T&SCo.

15) EQUITY SHAREHOLDER RISK - REGULATORY RISK

Residual Risk: T&S “regulatory risk”.
- There is a risk that the T&S regulator may make decisions which T&SCo does not expect (or like).

Residual Risk Allocation:
- T&SCo equity shareholders will be expected to accept this “regulatory risk”.

Residual Risk Mitigation:
- The regulatory regime will be defined, including under existing or amended legislation before investors in T&SCo make their investment decisions.
- There is long experience of “regulatory risk” in the UK. Equity and debt investors are likely to be able to “price” this into their financing decisions.

16) EQUITY SHAREHOLDER RISK - “NON-ALLOWABLE” COSTS

Residual Risk: T&SCo incurs “non-allowable” costs.
- T&SCo incurs excessive costs, outside those allowed by the incentives and penalties regime. Caused, by poor T&SCo operation and cost control, this leads the Regulator to declare that some costs are not “allowable costs”.

Residual Risk Allocation:
- T&SCo equity shareholders will carry excessive or unjustifiable costs.

Residual Risk Mitigation:
- T&SCo will need to install processes of control and governance that ensure that non-allowable costs are not incurred.

17) EQUITY SHAREHOLDER RISK - INCENTIVES AND PENALTIES REGIME

Residual Risk: Incentives and Penalties Regime.
- T&SCo makes a return lower (or higher) than targeted regulated rate of return, due to operation of the incentives and penalties regime.

Residual Risk Allocation:
- T&SCo equity shareholders will carry the impacts of the incentives and penalties regime.

Residual Risk Mitigation:
- T&SCo will need to install processes of delivery, management control and governance that delivers performance which meets or exceeds that envisaged in the incentives and penalties regime.

18) EQUITY SHAREHOLDER RISK - THIRD PARTY ACCESS

Risk - Third Party Access:
- The UK TPA regulations, and any new treaty or protocol with other countries, may require T&SCo to provide a T&S service that it would otherwise choose not to provide.

Risk Allocation:
- This risk sits with the equity shareholders of T&SCo.

Risk Mitigation:
- The equity shareholders of T&SCo should be aware of the requirements of the UK regulations, and act to protect their interests accordingly.
- The equity shareholders of T&SCo should seek to influence the contents of any future protocol or treaty with other countries that may require access to its assets.
19) EQUITY SHAREHOLDER RISK - PRE-COMMISSIONING STRANDED ASSETS - NO CAPTURE

Residual Risk - T&S “stranded asset risk” prior to commissioning:

- It is possible that once the T&S assets pass through FID and construction begins and perhaps reaches commissioning, the construction of the assets of the CO₂ Capture either does not start or is stopped before completion and commissioning. This would leave the T&S assets unable to get to “first CO₂”, thereby leaving T&Sco “stranded” without any CO₂ Capturers and hence no income stream.

Residual Risk Allocation

- This risk will be carried by T&Sco shareholders.

Residual Risk Mitigation:

- The process of co-ordination, and the contractual commitments and penalties between the T&Sco project and the CO₂ capture project should ensure that the projects take FID at the same time; and commit to construction and commissioning according to synchronized timetables.

- Capture project contractor guarantee: The first capture project(s) will be obliged to enter into a Contractor “full EPC wrap”, including vendor’s guarantees. This should provide considerable (though not total) assurance that the CO₂ Capture facilities will be built; will be built and commissioned to an agreed schedule; and will operate as designed.

20) EQUITY SHAREHOLDER RISK - PROJECT FAILS POST-FEED - LOSS OF DEVELOPMENT FUNDING

- Residual Risk: Political risk (1) - political decisions during or after the project development phase mean projects do not proceed.

- There is a risk that projects do not proceed after T&S development funding is spent, and that the “sunk” development funding is not remunerated or recovered.

Residual Risk Allocation

- This risk is carried by the shareholders of T&Sco, by HMG and by any other providers of development funding according to the level of their funding.

Risk Mitigation

- Investment by HMG in a share of development funding provides tangible evidence to developers of T&Sco that HMG intends to support the development of CCUS projects through provision of revenue support as required, subject to the HMG strategy on CCUS at the time.

- Similarly, investment by the developers of T&Sco provides tangible evidence to HMG that the developers intend to secure investment in T&Sco assets.

- Both HMG and T&Sco could limit their development funding expenditure if they believe that the risk of the other side not developing a project is significant.

- HMG could signal that it is willing to commit to developing the CCUS industry through measures such as visibly creating the required delivery capability within HMG, passing required legislation, and empowering and clarifying the role of the designated regulator.

21) EQUITY SHAREHOLDER RISK - UNCERTAIN CALLS ON CASH

Residual Risk: Uncertain calls on cash.

- For any new CO₂ store, the costs that may be incurred by T&Sco during construction, commissioning and early years of operation will be uncertain, and may be difficult to predict. Until the store has been operating for some time there will be some unavoidable uncertainty around performance of the store, and the expenditure needed to maintain performance. (For example, it may be necessary to install an additional
well if original well injection performance is not adequate, and spare well capacity is not sufficient.)

Residual Risk Allocation:

- The risk of uncertain calls on cash sits with equity shareholders to raise sufficient capital and contingency funding.

Risk Mitigation. With the agreement of the regulator:

- T&SCo will maintain sufficient available contingency funds to cover significant unexpected problems;
- T&SCo will maintain the means of accessing further funding to rebuild contingency reserves if they have to be drawn down at any stage.
- T&SCo will invest in sufficient spare well capacity and other asset capacity to mitigate this risk.

22) EQUITY SHAREHOLDER RISK - FINANCIAL SECURITY (EU DIRECTIVE)

Residual Risk - Establishing Financial Security

- There is a risk that establishing the financial security under the EU Directive and other similar requirements may be delayed; or that the security put in place may be insufficient.

Residual Risk Allocation:

- The risk of both delay and the need to raise sufficient security sits with the equity shareholders.

Residual Risk Mitigation

- Equity shareholders should ensure the process for establishing financial security is properly established, resourced and managed.

23) EQUITY SHAREHOLDER RISKS - CONSTRUCTION COSTS AND TIMETABLE

Residual Risk - T&SCo Construction Costs and Timetable Risk.

- Given the nature of offshore CO₂ storage assets, some uncertainty in the cost and schedule for construction and commissioning of the T&S assets is unavoidable.
- This includes possible overruns in capital cost (for example driven by scope changes), pre-start-up operating costs, and delay in start-up.

Residual Risk Allocation:

- The risk of uncertain construction cost and schedule sits ultimately with equity shareholders to raise sufficient capital to finance construction; and with the Funders of CO₂ Capturers to absorb the resulting increases in T&S Fees, and the consequences of commissioning delay.

Residual Risk Mitigation:

- T&SCo will hold prudent contingency in the construction project (both cost and schedule) to cater for the remaining uncertainties and a prudent capital structure that allows raising further funds to meet unforeseen cost escalations;
- T&SCo will include contract provisions (e.g. fixed price contract elements, gain/ pain share arrangements, performance guarantees and other mitigation provisions) to minimize this risk to the degree that this is economical. It should be noted that in many cases it is better to cover this risk through holding contingencies at the project level rather than attempting to pass these risks on to contractors, who may then hold larger contingencies at the contract and sub-contract level.
24) EQUITY SHAREHOLDER RISK - T&S PERFORMANCE AND COSTS

**Residual Risk - T&SCo Performance Risk.**
- Given the nature of offshore CO₂ storage assets, some initial uncertainty in the performance the T&S assets is unavoidable.
- Where the costs vs benefits appear favourable, and where they can be provided economically, T&SCo will put in place a number risk mitigation measures to address this unavoidable risk.
- This includes, amongst other things, operating costs (after start-up) and monitoring costs (after injection ends).
- This includes the risk of “minor failure of injectivity” into the store.

**Residual Risk Allocation:**
- The risk of uncertain performance sits ultimately with equity shareholders to raise sufficient contingency funding; and with “Funders of CO₂ Capturers” to absorb the resulting increases in T&S Fees.

**Residual Risk Mitigation:**
- T&SCo will build considerable spare capacity into critical assets (particularly the number of wells, and well injection capacity) to provide operating contingency against unforeseen performance problems;
- T&SCo will build in and hold significant contingency into both cost and schedule estimates to cater for significant unforeseen events following construction.

25) EQUITY SHAREHOLDER RISK - CROSS CHAIN FAILURE - T&S NOT AVAILABLE

**Residual Risk - Cross Chain Risk T&S Performance Risk**
- T&SCo assets are not available to accept and store CO₂; or they are constrained and can accept and store only a portion of the contracted CO₂ volumes.

**Residual Risk Allocation:**
- This key residual risk will sit with the “Funders of CO₂ Capturers”. They will need to continue to provide a portion of the revenue support to CO₂ Capturers, even though their assets are running unabated, in order to keep the CO₂ Capturers economically neutral versus their normal abated operation. This will need to include both the cash needed to cover the costs and return required to keep the CO₂ Capturer neutral, and the costs of ETS certificates needed to cover the CO₂ emissions caused by unabated operation.
- T&SCo carries the risk that it loses cash flow when it cannot accept delivery of CO₂. However, subject to T&SCo performance under the terms of the incentives and penalties regime, T&SCo will be able to make up these cash flow losses later when the T&S assets resume operation (as part of the next periodic regulatory review).

**Residual Risk Mitigation:**
- The risk of T&S not being available cannot be entirely avoided. It can and must be mitigated by:
  - Good construction management processes and contracts;
  - Good operational performance management processes.
  - T&SCo can be incentivized to mitigate this risk through the incentive and penalty regime in the RAB structure.
  - This risk can be minimised through the vetting and acceptance (or otherwise) of the T&SCo shareholders, developer and operator, by ensuring they have sufficient capability to minimize these risks and through the due diligence that will be carried out by debt providers on all of these issues.
26) EQUITY SHAREHOLDER RISK - CLOSURE OR PROLONGED SHUT-IN OF STORE.

Residual Risk - Permanent unplanned closure of a CO₂ store
- It is possible - though very unlikely - that, after commissioning, an event occurs which causes permanent closure or prolonged shut-in of the CO₂ store.

Residual Risk Allocation:
- T&SCo would be expected to provide an alternative CO₂ T&S service to honour their T&S contract if possible. The costs of doing so would be allowable under the RAB. This risk associated with these costs therefore falls on the “Funders of CO₂ Capturers”.
- In the event of permanent closure or a prolonged shutdown of the store, T&SCo will continue to receive the reduced T&S fee until operations are restored or an alternative regulatory settlement is reached. A portion of the risk therefore falls on T&SCo.
- If injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as “insurer of last resort” after an agreed period.
  o HMG would cover the remaining debt exposure of any debt providers and the equity of the equity shareholders. (This role may reduce over time, once the store is proven, more storage is added to the cluster, or further operating experience is gained)
  o HMG would carry the risk of acting as a funder of last resort for constructing a new store.

Residual Risk Mitigation:
- T&SCo need to choose their first store very carefully, to reduce the risk of failure of the store or existing legacy wells.
- T&SCo will also need to build sufficient redundancy in the asset (e.g. spare wells) to cater for potential performance problems.
- The possibility of appraising and preparing for investment in an alternative store at short notice should be considered - though this will not always be a feasible option.
- The contingency funds available to T&SCo to cover this scenario need to be substantial.
- HMG will need significant informed due diligence to ensure that these risks are all but eliminated.

27) EQUITY SHAREHOLDERS RISK - CO₂ SPECIFICATION

Risk - CO₂ fails to meet specification.
- There is a risk that capture plants produce and deliver off-spec CO₂ to the T&S assets.

Risk allocation:
- The risk of producing off-spec CO₂ lies with the owners of the capture plants. T&SCo can reject delivery of off-spec CO₂. A regime for compensation to be paid by suppliers of off-spec CO₂ to T&SCo will cover losses incurred by T&SCo if they inadvertently accept off-spec CO₂.

Risk Mitigation:
- T&SCo should have in place a rigorous process for monitoring CO₂ delivered against specification and preventing delivery of off-spec CO₂.

28) EQUITY SHAREHOLDER RISK - SHAREHOLDER EXIT

Risk - Exit possibilities.
- Investors and technical service provider may have limited exit options. (The responsibility and liability for CO₂ is transferred to the storage provider at the point of delivery and not transferred to the authorities before 30-80 years (sic) after receipt of the CO₂).
CHAPTER 6: CO₂ Transport and Storage – Residual Risks

- This may be aggravated by a combination of Third Party Access requirements which require that the T&S assets remain operating (with increasing liability as more CO₂ is stored) and restrictive Change in Control provisions and options which “trap” shareholders and provide no way to liquidate their shareholdings, liabilities or obligations.

**Risk Allocation:**
- The equity shareholders hold the risk of limited options for exit.

**Risk Mitigation:**
- Equity shareholders should negotiate provisions with HMG (perhaps through the Regulator) which allow them to crystallise their obligations and hand the store back to HMG earlier than envisaged in the EU CCS Directive.

29) EQUITY SHAREHOLDER RISK - CHANGE IN LAW, CHANGE IN POLICY

**Residual Risk - Political Risk (2) - Change in Law, Change in Policy**
- There could be a risk that a change in HMG policy, and hence UK law, could jeopardise the interests of T&SCo shareholders.

**Residual Risk Allocation**
- This risk will be transferred to HMG through a suitable “change in law” provision in contracts held by T&SCo.

**Residual Risk Mitigation**
- HMG is well placed to decide how best to deal with such issues should they arise.

30) EQUITY SHAREHOLDER RISK - STATE AID APPROVAL

**Residual Risk - “State Aid” Approval:**
- “State Aid” approval may not be received. HMG is not prepared to carry cost or other liability if this happens.

**Residual Risk Allocation:**
- All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

**Residual Risk Mitigation**
- HMG will seek to obtain “State Aid” clearance before excessive time and money has been spent on developing the project.
CHAPTER 7 - ELECTRICITY GENERATION WITH CO₂ CAPTURE - OPTIONS PAPERS

Discussion of Options

The growth in intermittent generation in the UK has led to a change in modus operandi of fossil fuel generation which must increasingly operate as mid-merit or peaking capacity. Dispatchable power provides the TSO (Transmission System Operator), the ‘market operator’ an ability to:

- call for flexible generation during periods of low wind/solar output and can assist with maintaining frequency stability of the network;
- whilst having the ability to reduce output to avoid curtailment of renewables at times of high wind or insolation.

Analysis of the UK’s electricity generation market in 2018 shows that on average fossil fuelled generation is now already operating at around 45% load factor. Whilst it is acknowledged that electricity storage has a part to play, it is unlikely to provide the cost-effective volumes required at a network level for the foreseeable future.

Fossil fuel generation provides the electricity network with the necessary flexibility and reliability, functionality required, but it is not sustainable in delivering a low carbon system, and therefore needs to be decarbonised, i.e. through CCUS. In its Net Zero report, the CCC recognises this, with 55 million tonnes per annum of CO₂ sequestration from 148TWh dispatchable generation in 2050. The CCC refers to this as ‘gas with CCS plants.’ This gas-fired power generation could potentially be either post-combustion capture, or pre-combustion capture, via hydrogen.

In considering the introduction of power plants utilising CCS at scale, the preferred contractual model is one which incentivises generation that delivers the maximum total value to consumers (including system impacts). As the proportion of low or zero marginal-cost, intermittent renewable electricity in the UK market rises, there will be an increasing demand for flexible, reliable and dispatchable generating capacity.

From an overall efficiency perspective, this capacity should generally be dispatched behind renewables, but ahead of unabated gas in the merit order, subject to constraints around efficiency, start costs, ramp rates and other plant parameters. The actual merit order outcome will be driven by the incentives created by the CfD structure, the prevailing gas and carbon prices, and flexibility of individual plants. This will be discussed in more detail later.

The first power plants with CCUS are likely to face higher costs, lower capture efficiency, less flexible operability and higher financing costs than subsequent CCUS power plant and will therefore require greater support. Baseload generation could therefore be justified to encourage investment in early plants at an ‘acceptable’ strike price. However, dispatchable generation would provide greater overall value to the system. There are several challenges to the implementation of a framework for dispatchable generation:

- Technical constraints on flexibility of the power plant, capture plant and T&S system;
- The perception of high cost based on the required strike price;
- Additional legislation required to introduce a new CfD model.

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41 “A significant low-carbon hydrogen economy will be needed to help tackle the challenges of industry, peak power, peak heating, heavy goods vehicles, and shipping emissions” Net Zero - The UK’s contribution to stopping global warming, CCC May 2019 (https://www.theccc.org.uk/publication/net-zero-the-uk-s-contribution-to-stopping-global-warming/)
TECHNICAL CONSTRAINTS ON FLEXIBILITY

In order to replace the role of existing mid-merit unabated thermal plants in the market, power plants with CCUS would be expected to operate on at least a two-shift basis, i.e. generating during the day and early evening but not during the night.

For a standalone system incorporating a CCGT power plant, post-combustion capture plant, CO₂ compression, onshore and offshore pipelines, offshore facilities and CO₂ injection wells, the cost of starting up and shutting down this infrastructure across this entire chain within the necessary system balancing timeline is prohibitive with existing technology.

However, there are a number of technical and commercial solutions to this, for example:

- Where the power plant is part of a broader CO₂ transportation and storage system with multiple CO₂ suppliers, the ‘baseload’ CO₂ produced (& supplied) by from industrial emitters can minimise the time required to ramp up or ramp down the CO₂ system.
- If alternative sources of steam are available, the capture plant may be able to ramp up more quickly than if it were relying on the power plant alone. The plant may also be able to operate at a minimum turndown level for short periods in order to enable a quicker ramp up when required.

Further technical work should be carried out on a project-by-project basis to understand the potential for flexibility. The dispatchable CfD should be flexible enough to incentivise the appropriate level of flexibility for different projects.

Significant improvements in flexibility are expected, given operating experience and improvements in technology.

Alternatively, hydrogen-fired generation utilises pre-combustion carbon capture. When combined with hydrogen storage, it allows for the hydrogen production plant and CO₂ capture plant to operate at high load factors, while the hydrogen-fuelled electricity generation (CCGT) plant operates flexibly.

PERCEPTION OF HIGH COST

Comparison of CfDs across different asset types is typically based on a comparison of strike prices or levelised cost of electricity. This is misleading, because average unit costs (e.g. LCOE) do not capture the broader system benefits and value of flexibility.

Intermittent sources such as wind and solar cannot dispatch electricity in line with market demand and require significant additional investments in alternative sources of flexibility.

Dispatchable CCUS capacity provides this flexibility to the system, adding significant value that will increase as the proportion of intermittent generation on the system increases.

It is important that this value is clearly demonstrated; for example, by including an explicit assumption for system costs in any comparison between technologies.

ADDITIONAL LEGISLATION

A dispatchable CfD mechanism would be materially different from the existing CfD model and is likely to require new legislation. It is important that potential projects understand the timeline for implementing the required legislation, and that projects and government consider appropriate interim contractual mechanisms to enable project progression.
Options Paper 7A: Electricity CCUS – Commercial Model

CONTEXT

The context for investors in electricity generation in the UK is currently framed by the four principles laid out by the Secretary of State, Greg Clarke, in November 2018. These are:

i. use of market mechanisms wherever possible;
ii. government intervenes to provide insurance and preserve optionality;
iii. regulation to be “agile”, and;
iv. consumers pay a fair share of all market costs.

Since the 1980s electricity generation in the UK has been largely owned by the private sector. These principles indicate that policy is likely to continue.

There has nevertheless been discussion about the degree to which parts of the electricity generation industry - particularly the nuclear industry - might become more regulated. Whether this might become an option for the Electricity CCUS generators remains to be seen.

The report entitled ‘Lowest Cost Decarbonisation for the UK: The Critical Role of CCS’ recommended in 2016 that early electricity generation plant with CO₂ capture should be owned by HMG, and subsequently privatised when operating.

In following the market principle, investors in electricity CCUS projects are likely to be fully exposed to two of the three main market risk categories, namely: market demand risk (including through inability to dispatch ahead of renewables and nuclear generation), and performance risk (including capital and operating costs, and operating performance). Moreover, they may be exposed to price risk as well, depending on the structure of any revenue support mechanism provided to such projects.

As a private sector company, EG&CCo will therefore expect to earn a return on its equity investment commensurate with the business risk it is taking. A projected rate of return would need to be agreed between HMG and any electricity CCUS projects, which would then be used in setting the level of revenue support EG&CCo will receive.

PREFERRED OPTION

VARIANT 1: PRIVATE SECTOR OWNERSHIP, WITH “DISPATCHABLE CF D” CONTRACT

EG&CCo (the company owning the electricity CCUS project) will be a private sector, licensed UK electricity generating company. It will earn an unregulated, “commercial” rate of return on its equity (and therefore its project investments) commensurate with the business risk it is taking.

For early projects, EG&CCo will secure the revenue support contract (a “Dispatchable CfD contract) through bilateral negotiation between HMG and EG&CCo. The risks to be taken on by EG&CCo will be as described in this business model.

The expected return on EG&CCo’s project investments will be a key consideration when the level is set for the revenue support received by EG&CCo (see below).

Justification for choosing this option

In a market where all electricity generation is currently owned, financed and operated by the private sector, it seems logical that Electricity CCUS projects should be as well.

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42 “After the trilemma - 4 principles for the power sector”. Speech by Greg Clarke on the future of the energy market. November 2018.


The benefits of these being private sectors projects (access to capital, expertise, innovation, competition) would seem to outweigh the potential cost reductions available through the lower costs of capital of other models - though this judgement is not clear-cut, and the case can be made for using other models too.

**ALTERNATIVE OPTIONS**

**VARIANT 7: REGULATED GENERATION - SEPARATE RABS FOR PARTS OF THE CCUS CHAIN**

Electricity generation with CCUS operates under a RAB (separate from the T&SCo RAB). The regulator instructs LCCC to adjust the CfD payment to EG&CCo when required.

**Justification for not choosing this option**

Regulating generating investments does not just imply imposing a cap on profits. It also implies that investors will be assured (provided they run their businesses according to the regulator’s standards and requirements) of a relatively more reliable (albeit lower) return than unregulated business would be. In doing so, investors will be able to pass on to their customers all those costs that are deemed by the regulators to have been efficiently and properly incurred in running the business.

This is an attractive business model for many investors and for HMG as they aim to keep costs to consumers and tax revenue as low as they can. If it is endorsed for use in the nuclear industry, then it could also be considered for CCUS investments.

It must be noted that for dispatchable generation, some type of dispatchable CfD or equivalent incentive system would still be required in addition to a RAB.

Therefore, the CAG recommends that this option is not explored further at this stage.

**VARIANT 11: HMG INITIALLY OWN ELECTRICITY AND T&S ASSETS, PRIOR TO PRIVATISATION (“OXBURGH”)**

HMG owns EG&CCo and T&SCo, with a view to privatisation as soon as feasible. (Oxburgh model).

**Justification for not choosing this option**

The Oxburgh report proposed that HMG should own the first electricity CCUS projects. This was to ensure that such projects were delivered at the lowest cost possible. This would be achieved by HMG absorbing the early risks during project delivery. As soon as the project was operating effectively, and these risks had been either reduced substantially or largely overcome, the projects would be privatised.

The calls on HMG tax revenues are always very heavy, and the “four principles” (see above) imply a reluctance for HMG to own and pay for operating assets unless there is a need to provide “insurance” or “optionality”.

**VARIANT 12: PRIVATE SECTOR FULL-CHAIN CCUS DEVELOPMENT - HMG SHARES SOME RISKS**

EG&CCo and T&SCo are owned by the same shareholders; creating a de facto “full chain” project. This provides mitigation against some cross-chain risks. They can be split apart when they are operating effectively.

CHAPTER 7: Electricity Generation with CO₂ Capture – Options Papers

Justification for not choosing this option

This model was applied in the UK CCS Commercialisation programme which ran from 2012 to 2015. The argument for this model rests on the possible need to integrate the capture and T&S parts of the chain very tightly together, in order to ensure projects are delivered and cross-chain risks are managed effectively by a single owner.

This model does not represent a probable “enduring” business model for the future, where the T&S business is expected to operate separately as an infrastructure utility providing T&S services to a wide range of customers.

It is the view of the CAG that both project development coordination and cross chain performance risks can be managed satisfactorily under a “split chain” structure using contractual obligations.

The weaknesses of this model were exposed in the “Commercialisation Programme”, and it the CAG considers it better to manage those weaknesses through a split chain model, rather than use this model again.

VARIANT 8: A SINGLE RAB COVERS A “CONDOMINIUM” JOINT INVESTMENT IN CAPTURE PLANT(S) AND T&S ASSETS (EXCLUDING GENERATION).

CO₂ Capture (but not generation) is combined with T&S.

This could include a local “Decarbonisation Service Company”, which could develop and possibly operate post-combustion capture plants for a number of electricity generators and industrial producers. Common capture facilities could be economic for emitters that are very close geographically (as flue gas volumes are typically very large).

This may be a credible option for clusters in the future when there is an existing T&S system in place.

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46 A “condominium” CO₂ capture plant would be a post-combustion capture plant that serves a number of investors who jointly own the plant, and who each send their flue-gas to the plant to have the CO₂ extracted and sent for storage.
Options Paper 7B: Electricity CCUS - Source of Revenue Support

CONTEXT

The existing CfD contracts for renewables and nuclear are funded by the LCCC, and this is expected to continue. This is in turn funded by UK electricity consumers.

In the future it may make sense for all CCUS contracts to funded by a single fund, which it itself funded by all consumers of CO₂ producing fuels and materials (specifically all hydrocarbons, and calcium carbonate used in cement manufacture).

PREFERRED OPTION

1) ELECTRICITY CCUS FUNDED BY THE LCCC

As is the case for all low carbon electricity contracts in the UK, revenue support for gas-fired electricity generation with CCUS will be funded by the LCCC, which is itself funded by UK electricity consumers.

Justification for choosing this option

As a source of low-carbon electricity, it is appropriate for electricity generated using CCUS be funded in the same way as other low-carbon electricity generation.

The mechanisms for collecting and allocating funds from electricity consumers to low-carbon electricity generation are in place and work effectively.

ALTERNATIVE OPTIONS

2) CCUS OBLIGATION SYSTEM; WITH A CCUS OBLIGATION FUND:

All revenue support for CCUS projects could be provided by a new CCUS Obligation Fund. This would in turn be funded through a CCUS Obligation System.

When either hydrocarbons or calcium carbonate enter the market in the UK, they would attract an obligation to sequester a small but rising proportion of their “contained CO₂” using CCUS. These obligations would be tradeable. They would also be redeemable by HMG; and HMG would inject the funds raised when obligations were redeemed directly into a CCUS Obligation Fund.

The CCUS Obligation Fund would then provide revenue support funding to CCUS projects.

Justification for not choosing this option

The cost of electricity generation from renewables may fall, and in some cases perhaps has fallen, below the cost of unabated generation from gas. However, by definition the cost of low-carbon electricity generated from gas can never fall below that of unabated electricity generation from gas. An enduring source of funding for CCUS low-carbon generation will be needed for as long as the carbon price is insufficient to incentivise low-carbon electricity production over unabated generation.

The fundamental assumption that the carbon price will rise this far remains in doubt. Firstly, there is political pressure from some quarters to keep the carbon price down to “acceptable” levels. Secondly, international carbon prices will set an informal ceiling above which it will be very unlikely that UK carbon prices will rise.

As a result, a CCUS Obligations System remains a logical solution for replacing funding by electricity consumers as the source of funding for electricity CCUS projects in due course (as well as all other CCUS activities). Introducing a CCUS Obligation Fund could accelerate implementation of such a system dramatically.
However, these options may not be ready for the earliest CCUS projects. Introducing a CCUS Obligation Fund in the very short term may be challenging, but it remains a logical option and potentially compelling for and enduring funding regime for CCUS.

3) **CCUS OBLIGATION SYSTEM - TRADED WITHOUT A FUND:**

As above, but obligations would be traded between those incurring them and those operating CCUS assets and infrastructure. No separate fund or revenue support system would be provided. This option can only work once a mature CCUS industry is established. However, once it is established it would be entirely self-funding.

**Justification for not choosing this option**

Introducing a CCUS Obligation System without a CCUS Obligation Fund requires a developed CCUS industry to be in place, which is likely to take some time.

It is expected that a CCUS Obligation Fund would migrate to a CCUS Obligation System. The Fund would then be closed. And no other further revenue support (or subsidy) would then be needed, as the CCUS Obligation System would be self-funding.

4) **ETS CERTIFICATE SALES BY HMG:**

All UK CCUS could be funded by the proceeds raised by HMG from selling ETS certificates. This is essentially form of tax revenue controlled by HMG.

While it may appear logical to allocate any revenues from selling emissions certificates to revenue support for low-carbon production, this may well not be attractive for HMG.

It is unlikely that this option will outweigh the ease of using the LCCC as the funding source for electricity generation, so it not considered a viable option at this stage.

5) **CCS LEVY:**

All UK CCUS could be funded by the proceeds raised by HMG from the various carbon and non-carbon taxes that are imposed by HMG, including fuel duty and other similar taxes. (A CCS levy was legislated for in The Energy Act of 2010, but this was specifically focused on electricity supply and was subsequently abandoned).

Again, these are all forms of taxation, and so are not considered preferable options at this stage.
Options Paper 7C: Electricity CCUS - Mechanisms for Delivering Revenue Support:

CONTEXT

Under the existing UK energy market framework, the decision to generate electricity is taken by individual assets in response to price signals and their respective cost structures. Assets are not directed to generate on a baseload or flexible basis; rather, the contractual framework is designed to incentivise the required behaviour.

The existing CfD contracts are structured to support electricity generation from intermittent technologies (such as solar and wind), and baseload technologies (such as nuclear). These feature a single strike price to provide a return on all capex and opex, such that a generator earns their long-run marginal cost (LRMC) – which is significantly higher than their short-run marginal cost (SRMC).

This is an effective model for intermittent and baseload technologies that would not normally be competitive (high LRMC) in the wholesale market (i.e. requiring subsidy), ensuring that:
- assets are incentivised to generate whenever available;
- lifetime utilisation, and hence return on capital, is predictable and attractive to debt and equity investors.

For a dispatchable technology, however, assets facing a single strike price may be incentivised to generate at a higher utilisation level than desirable for the overall economic optimisation of the system.

In addition, uncertainty in future pricing of electricity, gas and CO₂ means that return on capital is highly uncertain for mid-merit dispatchable technology; this is a particular issue for high-capex CCS plants.

For these reasons, flexible generation would require an amended CfD pricing mechanism, which would be likely to require new legislation.

PREFERRED OPTION

1) “DISPATCHABLE CFD”

The first power plant with CCUS will use a modified CfD structure incentivising dispatchable generation.

Proposed CfD mechanism

- The proposed CfD mechanism aims to incentivise the appropriate dispatchable operation of the plant whilst ensuring a reasonable and proportionate level of risk and return:

  Initial Baseload Period

  - The first such modified CfDs would include an initial period of baseload operation to establish stable operations and/or additional support to allow the plant to develop experience in dispatchable generation.

  Fixed fee from LCCC

  - A fixed fee (indexed to inflation) would be payable on a monthly basis for the lifetime of the contract with the LCCC. This would be paid on the basis of installed generation and capture capacity (i.e. based on the CCUS power plant’s gross capacity).
  - The fixed fee would be designed to cover:
    - Capex: Payment of debt and equity service for power and capture plant and other financing costs along with provision for a basic investor return
CHAPTER 7: Electricity Generation with CO₂ Capture – Options Papers

- Opex: Payment of fixed opex for the power and capture plants
- T&S fees: Payment of associated fixed transport and storage fees; aligned with allocation of cross-chain risk - e.g. in circumstances when T&S is unavailable

- This Fixed Fee may be subject to additional incentive mechanisms relating to availability, efficiency and other key performance targets both during construction and (possibly) operations.
- The fee would be fixed for the contract duration subject to appropriate mechanism to allow for required changes (e.g. change in law, T&S fee changes, increased capacity etc.).

**Variable payment from/to LCCC**

- The majority of variable revenue will come from the wholesale market. There will also be a net CfD payment which may be either positive or negative, comprising of:
  - A price cap: the plant repays any cash above an agreed margin above its variable cost;
  - Start-up support: the plant receives a support payment equal to the incremental cost of starting up a CCS plant versus an unabated plant;
  - Dispatch incentive payment: the plant receives an incentive payment to ensure it dispatches ahead of equivalent unabated plants, subject to the price cap.
- These calculations are likely to be based on the day-ahead market, in line with current intermittent CfD contracts.

**Fixed and variable returns**

- The proportion of fixed to variable payments will be based on further evaluation by HMG and discussions with individual projects. This will require careful consideration of the impacts on incentives to dispatch, as well as investor risk appetite, and considerations around balance sheet reporting.

**Alternative mechanism**

- An alternative mechanism could be for the plant to receive the market price for electricity, with a monthly or annual payment to top-up or reduce returns to a target level. This would reduce the complexity in the payment mechanism but would require further work to ensure that the plant is appropriately incentivised to dispatch in line with the desired merit order.

**Justification for choosing this option**

This mechanism would deliver greater value to the system and consumers and deliver an enduring mechanism for power with CCS.

The fixed fee provides investors a basic return, subject to performance, that is not affected by dispatch risk. It ensures that the T&S fee can be paid, underpinning debt and equity investment in the T&S JV. Project investors will have to manage construction overspend risk based on agreed capex.

The price cap (variable cost + agreed margin) ensures that the plant does not earn excessive returns if the market price or dispatch requirement is higher than expected. The agreed margin should be set at a level that ensures the plant can earn sufficient margin to cover start-up costs over the course of a typical shift (e.g. daytime + early evening ‘extended peaks’ generation).

The start-up support and dispatch incentive payments are designed to ensure that the CCS plant runs ahead of unabated plants. This is not required when the carbon price is relatively high and the gas price is relatively low, i.e.:

\[
\text{Savings in CO₂ emissions cost} > (\text{incremental gas cost of CCS} + \text{incremental start-up cost of CCS})
\]

However, there may be periods when the carbon price is too low to overcome the incremental marginal costs of CCS, such that unabated power plants dispatch ahead of plants with CCS. Furthermore, the longer start-up time of plants with CCS may cause them to dispatch behind unabated plants even when the marginal cost is lower.
The start-up support payment covers the incremental start-up costs of the CCS plant versus an unabated plant. The dispatch incentive payment provides a top-up payment equivalent to the incremental costs of CCS versus an unabated plant, plus a minimum margin. In combination, these ensure that the CCS plant can dispatch ahead of an equivalent unabated plant. Overall, the price cap is likely to apply for significant periods, while the start-up support and incentive payments are likely to be lower, such that the overall net variable payment is likely to be from the plant to the LCCC.

**ALTERNATIVE OPTIONS**

2) **BASELOAD CfD**

The first power plant with CCS will use an existing CfD structure incentivising baseload generation with a season-ahead reference price.

**Justification for not choosing this option**

The increased deployment of intermittent renewable energy will inevitably change the role of traditional baseload electricity generating plant. It will probably always make sense to ensure that renewable capacity with low variable costs always dispatches ahead of fossil-fuel based low-carbon energy. It is likely that whatever nuclear generating capacity is available will run in baseload mode, as their variable costs are also very low.

Electricity generation with CCUS is therefore likely to be required to fill the role of producing mid-merit (and in the longer term perhaps even peaking) plant that is currently filled by unabated generation from gas.

A baseload CfD contract will not achieve that. With such a contract there could be situations (possible many situations) when the CCUs would be incentivised to dispatch ahead of renewable generation.
CHAPTER 7: Electricity Generation with CO\textsubscript{2} Capture – Options Papers

Options Paper 7D: Electricity CCUS – Revenue Support: Contract Duration

**CONTEXT**

CfD contracts currently being awarded for renewable electricity generation typically have a term of 15 years.

Prior to BEIS, DECC established a framework to analyse the effect of varying the term of the CfD for renewable projects and concluded that a 15-year CfD term provided the best value for consumers. The same framework could be used to carry out a similar assessment for CCUS projects.

However, there may be technology specific characteristics that justify a different contract term e.g. Hinkley Point C nuclear power station has a 35-year CfD term.

**PREFERRED OPTION**

1) **20-YEAR MINIMUM CONTRACT DURATION**

EG&CCo will receive a CfD with at least 20 years’ duration.

**Justification for choosing this option**

The characteristics of CCUS projects that support the case for a longer contract term are:

*Operation of the plant after the end of the Contract.*

The asset life of a CCUS plant is likely to be over 25 years, and it may not be competitive with unabated fossil plant after the contract has ended. This could result in the CCUS plant load factor reducing, being closed or switching to unabated operation. A longer-term contract could be justified to ensure that the plant continues delivering low carbon electricity for a longer period.

*Carbon Dioxide Transport & Storage*

A longer-term contract could be needed to support the high capital cost in establishing the T&S network for the CO\textsubscript{2} expected to be captured, particularly if there are no other users committed to using the infrastructure.

*Project Financing*

The duration of the CfD contract and certainty of revenues (CCUS at large-scale is still relatively unproven) will influence the equity and debt financing that is available for a project. The same term that is used for the renewable CfD (a 15-year CfD term) may be too short to make the investment viable for the initial CCUS projects.

**ALTERNATIVE OPTIONS**

2) **15-YEAR CONTACT DURATION**

EG&CCo will receive a revenue support contract of 15 years.

**Justification for not choosing this option**

If investors are to recoup their investment over a shorter period, the level of annual revenue support will have to be significantly higher. A longer contract allows a lower annual cost, and therefore a lower unit cost.
CHAPTER 8 - ELECTRICITY GENERATION WITH CO₂ CAPTURE - DETAILED BUSINESS MODELS

Summary of Variant 1 Business Model

PART 1 - COMMERCIAL ARRANGEMENTS

Ownership and finance. The electricity generation and CO₂ capture (EG&C) assets will be privately owned, financed, developed, built and operated. They will be owned by EG&CCo.

EG&CCo commercial model. EG&CCo will be a private sector, licensed UK electricity generating company. It will earn a “commercial” rate of return on its equity, commensurate with the risk taken.

Insurance. Insurance will operate within a three-tier regime: i) EG&CCo carries the risks below the agreed insurance “excess”; ii) above this the insurance market covers risks up to the maximum economical insurance cover available; iii) HMG acts as the “insurer of last resort” for a closed list of one specific, defined risks whose costs exceed the maximum economical insurance cover available. One such risk has been identified: the “Pre-Commissioning Stranded Asset Risk” that no T&S assets are built to store the CO₂ captured by the first capture plant in a cluster.

Coordination between CO₂ Capture and T&S assets. A “Programme Development Consortium” will be created for a cluster / region. The Consortium will appoint a “Programme Development Coordinator”. Project development will be synchronized, using coordinated stage-gate decision points. Project development funding provided by HMG prior to FEED will be coordinated across the CO₂ Capture and T&S projects.

A contractually agreed system of penalties will operate between the projects if “first CO₂” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

Asset size. Asset size should be judged against measures of “reasonable” unit cost and of capital efficiency; and also, against the need to provide a clear pathway to allowing CCUS to “operate at scale by 2030”.

Development Funding. For early projects, the developers of T&SCo and HMG will share the costs of project development of T&SCo assets through to FID - both pre-FEED and FEED costs.

Financing. EG&CCo will be financed by private sector equity and debt. The finance raised will include all required working capital; and prudent contingency funding.

Construction. EG&CCo will carry the costs and consequences of exceeding the capital budget for construction, and commissioning delays. EG&CCo will put in place significant contingency funding, as well contractual arrangement with contractors, to mitigate against these risks.

Operating Performance and Costs. EG&CCo will carry the costs and the consequences of risks associated with operating performance and costs. EG&CCo will put in place significant contingency funding, as well performance guarantees from contractors (if deemed economic), to mitigate against these risks.

T&S Fees. T&SCo will charge T&S fees to EG&CCo set by agreement between T&SCo and the T&S regulator. T&S fees will be made up of a “capacity reservation” element and a “variable” element. The T&S regulator may instruct that these fees should change from time to time.

Funding for the T&S fees will come from the LCCC to EG&CCo; and EG&CCo will be obliged to pass these fees directly through to T&SCo.

Follow-on Projects. T&S fees charged will spread the costs of the T&S assets equitably across all T&SCo Customers. If other CO₂ Capturers join the T&S network after EG&CCo’s project is running, their
“capacity reservation” fee may be set to zero if they do not receive a fixed payment from their “Funders of CO₂ Capturers”.

**Cross chain failure - T&S not available.** If, after “first CO₂”, the T&S assets are not available, the following will apply:

Capture plants will be entitled to continue to run, either wholly or partially unabated. They will continue to receive a portion of their revenue support. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage.

T&SCo will continue to receive a portion of their T&S fees, at a level set in advance by agreement between the regulators and T&SCo.

**Cross chain failure - Capture plant does not deliver CO₂ to T&SCo.** The capture plants are not obliged to deliver CO₂ to T&SCo. However, regardless of the volume of CO₂ delivered, from the start date of the T&S Services Contract the Funders of CO₂ Capturers will still be required to pay the “capacity reservation” portion of the T&S fees to the T&SCo Customers, for pass-through directly to T&SCo.

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**PART 2 - REVENUE SUPPORT**

As an electricity generator, EG&CCo will receive a “Dispatchable CfD Contract” under a policy framework set up by HMG.

**Source of revenue support.** Revenue support for electricity generation with CCUS will be funded by the LCCC, which is itself funded by UK electricity consumers.

**Mechanism for delivering revenue support.** Revenue support for electricity generation will be delivered from LCCC to EG&CCo through the “Dispatchable CfD Contract”, which would include fixed and variable payments.

- The regular fixed payments from LCCC would broadly cover capital expenditure and fixed costs, including a direct pass-through of the T&S capacity reservation fees.
- The majority of variable revenue will come from the wholesale market. There will also be a net CfD payment which may be either positive or negative, comprising of:
  - A cap on margin, with excess paid by the plant to LCCC
  - A start-up support payment from LCCC to the plant for each start-up
  - A dispatch incentive payment from LCCC to the plant to ensure dispatch ahead of unabated gas plants, given prevailing gas and carbon prices.
- The proportion of fixed to variable payments will be based on further evaluation by HMG and discussions with individual projects.

**CfD contract duration.** EG&CCo will receive a CfD contract of at least 20 years.

**Definition of “Clean Electricity”.** The CfD will pay out on the dispatch of “Clean Electricity”. A new definition of “Clean Electricity” will be created.

**Fuel price indexation.** The CfD will be indexed to the price of fuel (as well as to CPI).
Comparison of Variant 1 with Other Variants

**ELECTRICITY GENERATION AND CO₂ CAPTURE - COMPARISON WITH OTHER VARIANTS**

**VARIANTS 2 TO 6**

**Summary.** There would be no impact on the Electricity Generation and CO₂ Capture Business Model in these Variants.

**VARIANT 7: REGULATED ELECTRICITY GENERATION AND CO₂ CAPTURE - OPERATING UNDER A RAB MODEL**

**Summary.** If, in the future, the profit of electricity generation is regulated, or if a RAB model is implemented for nuclear power generation, then this model could be adapted to cover power generation with CCUS as well.

**EG&CCo commercial model.** EG&CCo would operate under a RAB model structure. It will earn a “utility rate of return”. All costs that are “properly incurred” would be “allowable costs” eligible for inclusion as costs in the RAB. There would be an incentive and penalty regime to incentivize cost effective development and operation of the T&S assets, which ensured that actual returns earned by T&SCo depend on performance.

**Financing.** EG&CCo would be financed by private sector equity and debt; including all required working capital; and considerable, prudent contingency funding, which would be restored promptly if used.

**Construction.** Subject to the provisions of the regime of incentives and penalties, the costs or financial consequences to EG&CCo from construction events or commissioning delays might be included as “allowable costs” under the RAB structure.

**Operating Performance and Costs.** Similarly, and subject to the provisions of the RAB regime of incentives and penalties, the costs or financial consequences to T&SCo from operating performance or events might all be included as “allowable costs” under the RAB structure.

**Mechanism for delivering revenue support.** A variety of mechanisms for providing revenue support, including either an existing CfD contract, or a new “Dispatchable CfD Contract” might be considered.
Detailed Business Model - Variant 1: Electricity Generation with CO₂ Capture

INTRODUCTION

This is the Business Model for Electricity generation and CO₂ Capture in the UK. It is part of the suite of four models which collectively are known as Variant 1.

Variant 1 is based on the CCTF recommendation to use a RAB-based model for T&S, and private sector ownership for Capture.

PART 1 - COMMERCIAL ARRANGEMENTS

1) SCOPE OF EG&CCo

A private sector company (EG&CCo) will own, finance, develop, build and operate the electricity generation and CO₂ capture assets.

EG&CCo will contract with T&SCo, who will supply a CO₂ T&S service.

Neither the EG&CCo assets, nor any liabilities/contingent liabilities associated with them, will appear on HMG’s balance sheet.

2) EG&CCo COMMERCIAL MODEL

EG&CCo will be a private sector, licensed UK electricity generating company.

It will earn an unregulated, “commercial” rate of return on its equity (and therefore its project investments) commensurate with the business risk it is taking.

For early projects EG&CCo will secure a “Dispatchable CfD Contract” with the LCCC through bilateral negotiation between HMG and EG&CCo. This is described in “Part 2 - Revenue Support” below.

EG&CCo will expect to make a return on the project investment in line with the risk profile of the project. The risks to be taken on by EG&CCo will be as described in this business model.

The expected return on EG&CCo’s project investments will be a key consideration when the level is set for the revenue support received by EG&CCo.

3) DISPATCHABLE CfD CONTRACT START DATE

Payments from the LCCC will start from the Contract Start Date, which will be the latest of:

- a pre-agreed start date;
- the date when EG&CCo is ready to deliver the first CO₂ to T&SCo (whether or not T&SCo is ready to receive it).

4) INSURANCE

EG&CCo will be responsible for carrying insurance appropriate to its business. Insurance will be a key risk mitigation measure - where it is commercially available at economical rates.

Insurance will sit within a three-tier regime:

i. T&SCo carries the costs of risks below the insurance “excess”. Subject to the incentives and penalties regime these will be “allowable costs”;

ii. The insurance market carries the costs of risks above the “excess” up to the available insurable maximum;
iii. HMG acts as the “insurer of last resort” for a closed list of specific, defined risks falling outside the available insurable maximum. One such risk has been identified:

   - Pre-Commissioning Stranded Asset Risk. In the event of no T&S system ever being commissioned and operational, it is likely that EG&CCo’s plant would be reconfigured for some other purpose. Thereafter, HMG would cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

*Risks - see HMG Risk - HMG acts as Insurer of Last resort*

Co-ordination between CO₂ Capture and T&S assets

It is anticipated that for the development of the first projects in a cluster a “Programme Development Consortium” would be created involving one or more potential capture sources and prospective owners of key CO₂ transport and storage facilities. The Consortium will appoint a “Programme Development Coordinator” to lead the Consortium.

The Consortium will work with regional authorities and other organisations in the region, noting that any T&S infrastructure developed will have third party access arrangements. The Coordinator will produce a plan for integration of further capture sources into the system.

The Coordinator could be one of the possible anchor projects, an external organization appointed by the projects, the regional government authority, or possibly an organization appointed by HMG that works to a scope defined by HMG.

In general, it is likely that the anchor T&S project developer will be appointed as Coordinator, as they will often have the best opportunity to create a coherent picture of the status of possible capture projects that may be developed in a cluster/region.

The role will be sponsored by the capture, transport and storage projects involved, and may include cost sharing arrangements with government. Contractual arrangements between each element of the total project are expected to be used.

Project development would be synchronized, using coordinated stage-gate decision points. The first anchor projects in a cluster will look to pass i) into FEED, and ii) through FID simultaneously. Project development funding provided by HMG prior to FEED will be coordinated across each programme element. All parties will be bound contractually to manage risks and deliver an operating project; with terms depending on the nature of the projects involved, risk allocations and arrangements put in place by HMG to allow the projects to proceed.

5) ASSETS SIZE/ CAPACITY

The initial cluster Capture and T&S projects in any cluster or region should be sized to meet two criteria:

1. Meet a common set of metrics for “reasonable” unit cost (e.g. cost of carbon abatement, unit cost of low carbon electricity or other output), as well as “reasonable” use of capital and capital efficiency.
2. Demonstration of how development of further cluster capture projects provides a clear pathway to allowing CCUS to “operate at scale by 2030”.

6) DEVELOPMENT FUNDING

For early projects, the developers of the project and HMG share the costs of project development of EG&CCo assets through to FID - both pre-FEED and FEED costs.

*Risks - see Equity Shareholder Risks - Political Risks (1) - Project fails post-FEED.*
*Risks - see HMG Risks - Loss of development funding.*
7) **FINANCING**

EG&CCo will be financed by private sector equity and debt. The finance raised will include all required working capital.

EG&CCo will create and maintain considerable, prudent contingency funding from its financiers at all times.

Sufficient flexibility will need to be included in debt finance servicing arrangements to ensure that EG&CCo can weather a considerable period of uncertain plant performance and cost during commissioning and early years of operation.

*Risk - see: Equity Shareholder risk - Uncertain calls on cash*

8) **CONSTRUCTION - COSTS AND TIMETABLE**

Given the nature of the new CO$_2$ capture technologies, some uncertainty in the projected costs and schedule for construction is unavoidable.

EG&CCo will carry the costs and consequences of exceeding the capital budget for construction, and commissioning delays.

In addition, EG&CCo will, in agreement with HMG, where it is economically justified, put in place risk mitigation measures to address this unavoidable risk, including some or all of the following:

i. Fixed price contracts with contractors for those parts of the project where such contracts can be provided economically;

ii. Pain share/gain share arrangements with contractors where such arrangements can be provided economically;

iii. Delivery and performance contractor “full EPC wrap” provisions, including performance guarantees, to be provided by contractors for those elements of the contracts where these can be provided economically;

iv. Building considerable contingency into cost estimates, funding availability and schedule plans to cater for significant unforeseen events or circumstances.

9) **EG&CCO PERFORMANCE AND COSTS**

Given the nature of the new CO$_2$ capture technologies, some uncertainty in the performance of the plant is unavoidable.

EG&CCo will carry the costs and consequences of underperformance of the plant.

EG&CCo will obtain performance guarantees, provided it is deemed economic to do so, from technology providers to mitigate against these risks.

10) **T&S FEES**

Under the plan agreed with the regulator T&SCo will be allowed to charge to its customer(s) T&S fees that are pre-agreed with the regulator.

On instruction of the T&S regulator the T&S fees may change from time to time, depending on new plant being commissioned, and on other factors.

The T&S fees will be charged partly as a fixed “capacity reservation” fee i.e. a fixed annual/monthly fee, and partly as a “variable” element i.e. per tonne of CO$_2$ delivered to T&SCo’s delivery point. The “capacity reservation” fee will comprise most of the T&S fee - to provide stable, non-volatile income required by investors in low risk, low return RAB structures.
If only one CO₂ Capture project is being built initially, T&SCo will charge that project a fee that covers all T&SCo’s costs. If more than one project is being built initially then these costs will be spread across all these projects.

Funding for the T&S fees will come from the LCCC. EG&CCo will be obliged to pass these payments directly through to T&SCo. The ultimate ‘funder’ is therefore the consumer or taxpayer. CO₂ Capturers will be obliged to pass these fees through directly to T&SCo. Some form of protection for T&SCo will be required if a CO₂ Capturer fails to pass these fees through.

11) FOLLOW-ON CAPTURE PROJECTS.

If future capture projects join the network and are provided with T&S services by T&SCo then the T&S fees charged to existing customers will be reduced to spread the costs of the T&S assets proportionately across all CO₂ Capturers.

When capture projects stop using T&SCo’s assets the T&S fees to the remaining customers will be adjusted upwards accordingly to allow T&SCo to recover all its costs.

T&S fees charged will spread the costs of the T&S assets equitably across all CO₂ Capturers.

However, if new CO₂ Capturers join the network, their “capacity reservation” fee may be set to zero if they do not receive a fixed payment from their “Funders of CO₂ Capturers”.

12) TIMING OF PLANNED MAINTENANCE

All capture plants and T&S assets in a cluster will agree a rolling forward programme of planned major maintenance. All asset operators will cooperate to ensure that as far as possible planned maintenance occurs simultaneously across all assets in the cluster.

A pre-agreed contractual regime will allow for an agreed duration of shutdown for planned maintenance without penalty across the cluster.

(Unplanned maintenance will be covered by the “Cross-chain failure” provisions below.)

13) CROSS CHAIN FAILURE - T&S ASSETS NOT AVAILABLE - TEMPORARILY OR PERMANENTLY

Before the Contract Start Date of the Dispatchable CfD Contract, EG&CCo will be able to operate unabated, provided they obtain ETS certificates to cover their emissions.

If, after the Contract Start Date of the Dispatchable CfD Contract, and for whatever reason, T&S assets are not available to accept CO₂ delivered to the point of receipt, the following will apply.

This includes circumstances where:
- T&S assets are temporarily completely unavailable;
- T&S assets are available but are capacity constrained for any reason and cannot accept the full contracted quantity of CO₂ being delivered.

It will also include circumstances where:
- T&S assets have not yet started operation for the first time;
- T&S assets are suffering a prolonged shut-in or are permanently closed.

EG&CCo will be entitled to continue to run, either wholly or partly unabated. They will continue to receive revenue support from the LCCC. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage. The definition of this level of support will be set case by case.

If, as proposed by the CAG, the Electricity Generators have a “Dispatchable CfD Contract”, it may not be necessary to provide additional ETS certificates when they are running unabated. When running
unabated, the “Dispatchable CfD Contract” will provide a fixed payment and take CO₂ emissions into account through the variable payment.

*Risk - see: LCCC Risk - Cross Chain Failure - T&S Assets Not Available - Temporarily or Permanently*

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14) CROSS CHAIN FAILURE - DEMAND RISK - CAPTURE PLANT NOT AVAILABLE

EG&CCo is not obliged to operate or deliver CO₂ to T&SCo.

EG&CCo will not receive revenue support when the capture plant is not available, except under exceptional circumstances that may be defined under the CfD.

However, regardless of the volume of CO₂ delivered, the LCCC will still be required to pay the “capacity reservation” portion of the T&S fees to EG&CCo, and EG&CCo will still be obliged to pass these fees through directly to T&SCo.

This obligation should start from the Contract Start Date of the “T&S Services Contract”.

*Risk - see: LCCC Risk - Cross Chain Failure - Capture plant does not deliver CO₂ to T&SCo*

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15) CROSS CHAIN FAILURE - PRE-COMMISSIONING STRANDED ASSET RISK - NO T&S

The likelihood that EG&CCo builds a CO₂ capture plant and that no prospect then appears of a CO₂ T&S system being built to store the captured CO₂ seems extremely low.

However, in that event HMG would need to act as “insurer of last resort”. It is likely that the plant would be reconfigured for some other purpose. Thereafter, HMG would cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

*Risk - see: HMG Risk - Pre-Commissioning Stranded Asset Risk - CO₂ Capture Plant but no T&S System*
PART 2 - REVENUE SUPPORT

As an electricity generator, EG&CCo will receive a “Dispatchable CfD2 Contract” under a policy framework set up by HMG.

16) ELECTRICITY WITH CCUS - SOURCE OF REVENUE SUPPORT.

As will be the case for future low carbon electricity contracts in the UK, revenue support for electricity generation will be funded by the LCCC, which is itself funded by UK electricity consumers.

17) MECHANISM FOR DELIVERING REVENUE SUPPORT

The first power plant with CCUS will use a modified CfD structure incentivising dispatchable generation.

Proposed CfD mechanism

- The proposed CfD mechanism aims to incentivise the appropriate dispatchable operation of the plant whilst ensuring a reasonable and proportionate level of risk and return:

Initial Baseload Period

- The first such modified CfDs would include an initial period of baseload operation to establish stable operations and/or additional support to allow the plant to develop experience in dispatchable generation.

Fixed fee from LCCC

- A fixed fee (indexed to inflation) would be payable on a monthly basis for the lifetime of the contract with the LCCC. This would be paid on the basis of installed generation and capture capacity (i.e. based on the CCUS power plant’s gross capacity).
- The fixed fee would be designed to cover:
  - Capex: Payment of debt and equity service for power and capture plant and other financing costs along with provision for a basic investor return
  - Opex: Payment of fixed opex for the power and capture plants
  - T&S fees: Payment of associated fixed transport and storage fees; aligned with allocation of cross-chain risk - e.g. in circumstances when T&S is unavailable
- This Fixed Fee may be subject to additional incentive mechanisms relating to availability, efficiency and other key performance targets both during construction and (possibly) operations.

- The fee would be fixed for the contract duration subject to appropriate mechanism to allow for required changes (e.g. change in law, T&S fee changes, increased capacity etc.).

Variable payment from/to LCCC

- The majority of variable revenue will come from the wholesale market. There will also be a net CfD payment which may be either positive or negative, comprising of:
  - A price cap: the plant repays any cash above an agreed margin above its variable cost;
  - Start-up support: the plant receives a support payment equal to the incremental cost of starting up a CCS plant versus an unabated plant;
  - Dispatch incentive payment: the plant receives an incentive payment to ensure it dispatches ahead of equivalent unabated plants, subject to the price cap.
- These calculations are likely to be based on the day-ahead market, in line with current intermittent CfD contracts.

Fixed and variable returns

- The proportion of fixed to variable payments will be based on further evaluation by HMG and discussions with individual projects. This will require careful consideration of the impacts on
incentives to dispatch, as well as investor risk appetite, and considerations around balance sheet reporting.

**Alternative mechanism**

- An alternative mechanism could be for the plant to receive the market price for electricity, with a monthly or annual payment to top-up or reduce returns to a target level. This would reduce the complexity in the payment mechanism but would require further work to ensure that the plant is appropriately incentivised to dispatch in line with the desired merit order.

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**CFD CONTRACT DURATION.**

EG&CCo will receive a CfD of at least 20 years. This will reduce the annual level of revenue support required, incentivise unabated operation for a longer period, underpin the investment in the initial T&S infrastructure, and make project financing more manageable.

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**PART 3 - OTHER ELEMENTS**

**19) BANKRUPTCY**

Where discretion exists, the order of claims post-bankruptcy is to be defined.

**20) CHANGE IN LAW, CHANGE IN POLICY.**

If applicable, provisions covering Change in Law will be defined.

*Residual Risk - Political Risk (2)*

- *There could be a risk that a change in HMG policy, and hence UK law, could jeopardize the interests of EG&CCo’s shareholders.*

*Residual Risk Allocation*

- *This risk will be transferred to HMG through a suitable “change in law” provision in contracts held by EG&CCo.*

*Residual Risk Mitigation*

- *HMG is well placed to decide how best to deal with such issues should they arise.*

If applicable, provisions covering Change in Policy will be defined. These will provide “grandfathering” protections to EG&CCo.

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**21) “STATE AID”**

Some form of “State Aid” approval may be needed for the project. Whilst after Brexit the form of “State Aid” rules may change the principles probably will not.
CHAPTER 9 - ELECTRICITY GENERATION WITH CO$_2$ CAPTURE - RESIDUAL RISKS

It is usual, and therefore assumed, that all key stakeholders in a major project will run effective risk management processes that manage and mitigate the “Business as Usual” risks they face arising through their involvement in the project.

However, once these “Business as Usual” risks have been mitigated using “Business as Usual” processes, a number of key “Residual Risks” will remain to be managed and mitigated. The key Residual Risks for key stakeholders in the development of early projects in a new CCUS cluster are listed here. (“Business as Usual” risks are not listed - that is for stakeholders to do themselves.)

The effect of this Business Model is to allocate those Residual Risks to one or more key stakeholders. This section shows how the Business Model drives the allocation of these Residual Risks. They are categorized into three main sections - HMG Risks; “Electricity Consumers via LCCC” risks; EG&CCo Equity Shareholder Risks. A high-level listing of these risks is shown in the following table.

Finally, there are a number of ways in which these Residual Risks can be mitigated by those who hold them. These are also shown in this section.

ELECTRICITY BUSINESS MODEL - VARIANT
RESIDUAL RISK ALLOCATION

<table>
<thead>
<tr>
<th>Risk sits with:</th>
<th>EG&amp;CCo Equity Shareholders</th>
<th>Electricity Consumers</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction - Costs and Timetable</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EG&amp;CCo Plant Performance and Costs</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>CO$_2$ delivered off-specification</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uncertain Calls on Cash</td>
<td>✓</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cross Chain Failure - T&amp;S Assets Not Available - Temporarily or Permanently</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Cross Chain Risk - Capture Plant Does Not Deliver CO$_2$ to T&amp;S Co</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Fuel Price Indexation</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Project fails post-FEED - Loss of Development Funding</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>State Aid</td>
<td>✓</td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Pre-Commissioning Stranded Asset Risk - No T&amp;S System</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
<tr>
<td>Change in Law, Change in Policy</td>
<td></td>
<td></td>
<td>✓</td>
</tr>
</tbody>
</table>
“Irreducible” Residual Risks to be facilitated by HMG

This section describes those risks where HMG acts in the capacity of facilitating those “irreducible risks” that industry cannot properly price, and therefore cannot accept at reasonable cost.

1) **HMG RISK - PRE-COMMISSIONING STRANDED ASSET RISK - NO T&S SYSTEM**

   **Residual Risk:**
   - It is conceivable - though extremely unlikely - that EG&CCo builds a CO₂ capture plant and that no prospect then appears of a CO₂ T&S system being built to store the captured CO₂.

   **Residual Risk Allocation:**
   - In the event of no T&S system ever being commissioned and operational, “it is likely that EG&CCo’s plant would be reconfigured for some other purpose. Thereafter, HMG would cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

   **Risk Mitigation:**
   - HMG will seek to ensure that:
     - The process of co-ordination, and the contractual commitments and penalties between EG&CCo and T&SCo, should ensure that the two projects take FID at the same time; and commit to construction and commissioning according to synchronized timetables.
     - The project developers of these projects have the capability and commitment to deliver such projects.

2) **HMG RISK - HMG LOSS OF DEVELOPMENT FUNDING.**

   **Residual Risk - Loss of the HMG share development funding**
   - If the project does not proceed, HMG and developers will each lose their share of the development funding provided.

   **Residual Risk Allocation:**
   - This risk is shared between the project developers and HMG.

   **Residual Risk Mitigation:**
   - Development funding expenditure by the developers of EG&CCo provides tangible evidence to HMG that the developers intend to secure investment in EG&CCo assets.

3) **HMG RISK - CHANGE IN LAW, CHANGE IN POLICY.**

   **Residual Risk - Political Risk (2)**
   - There could be a risk that a change in HMG policy, and hence UK law, could jeopardize the interests of EG&CCo’s shareholders.

   **Residual Risk Allocation**
   - This risk will be transferred to HMG through a suitable “change in law” provision in contracts held by EG&CCo.
• HMG is well placed to decide how best to deal with such issues should they arise.

4) HMG RISK - STATE AID RISK

Residual Risk - “State Aid” Approval:

• “State Aid” approval may not be received. HMG is not prepared to carry cost or other liability if this happens.

Residual Risk Allocation:

• All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

Residual Risk Mitigation

• HMG will seek to obtain “State Aid” clearance before excessive time and money has been spent on developing the project.
Residual Risks carried by electricity consumers via the LCCC

This section describes those risks that will be covered by electricity consumers, via funding provided by the LCCC.

5) LCCC RISK - CROS S CHAIN RISK T&S ASSETS NOT AVAILABLE

- T&SCo assets not available to accept and store CO₂

Residual Risk Allocation:

- LCCC will continue to support EG&C Co revenue. This will be set to hold EG&C Co economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage.

Residual Risk Mitigation:

- The risk of T&S not being available cannot be entirely avoided. It can and must be mitigated by:
  - Good construction management processes and contracts;
  - Good operational performance management processes.
- T&SCo can be incentivized to mitigate this risk through the incentive and penalty regime in the RAB structure.
- HMG can minimise this risk through the vetting and acceptance (or otherwise) of the T&S Co shareholders, developer and operator by ensuring they have the capability to minimize these risks; and through the financier due diligence that will be carried out on these issues.

6) LCCC RISK - CROSS CHAIN FAILURE - CAPTURE PLANT DOES NOT DELIVER CO₂ TO T&S CO.

Residual Risk - T&S Demand Risk:

- Capture plants may choose to or may have to deliver less CO₂ than contracted because of operational problems, variability in demand for their products, and change in their production processes.

Residual Risk Allocation:

- After the Contract Start date of the T&S Services Contract the LCCC carries this risk. It is obliged to pay the T&S Co “capacity reservation” fee, irrespective of the volume of CO₂ delivered.

Residual Risk Mitigation:

- It is in the hands of the capture plants shareholders and operators to mitigate this risk through good project development, construction project management, and plant operational management.
- This risk can be minimized by HMG through vetting T&S Co shareholders, developers and operators, ensuring they have the capability to minimize these risks.
Residual Risks carried by Equity Shareholders of EG&CCo

This section describes those risks that will be covered by equity shareholders in IP&CCo.

7) EQUITY SHAREHOLDER RISK - PROJECT FAILS POST-FEED - LOSS OF DEVELOPMENT FUNDING

Residual Risk: Political risk (1) - political decisions during or after the project development phase mean projects do not proceed.

- There is a risk that projects do not proceed after CO₂ Capture development funding is spent, and that the “sunk” development funding is not remunerated or recovered.

Residual Risk Allocation:

- This risk is carried by the shareholders of EG&CCo, by HMG and by any other providers of development funding according to the level of their funding.

Risk Mitigation:

- Investment by HMG in a share of development funding provides tangible evidence to developers of EG&CCo that HMG intends to support the development of CCUS projects through eventual provision of revenue support as required, subject to the HMG strategy on CCUS at the time.
- Similarly, investment by the developers of EG&CCo provides tangible evidence to HMG that the developers intend to secure investment in EG&CCo assets.
- Both HMG and EG&CCo could limit their development funding expenditure if they believe that the risk of the other side not developing a project is significant.
- HMG could signal that it is willing to commit to developing the CCUS industry through measures such as visibly creating the required delivery capability within HMG, passing required legislation, and empowering and clarifying the role of the designated regulator.

8) EQUITY SHAREHOLDER RISK - UNCERTAIN CALLS ON CASH

Residual Risk: Uncertain calls on cash.

- For any new CO₂ capture plant, the costs that may be incurred by EG&CCo during construction, commissioning and early years of operation will be uncertain and may be difficult to predict. Until the plant has been operating for some time there will be some unavoidable uncertainty around its performance and costs.

Residual Risk Allocation:

- The risk of uncertain calls on cash sits with equity shareholders to raise sufficient capital.

Risk Mitigation:

- EG&CCo will maintain sufficient available contingency funds to cover significant unexpected problems;
- EG&CCo will maintain the means of accessing further funding to rebuild contingency reserves if they have to be drawn down at any stage.
- EG&CCo need to ensure that debt servicing obligations are sufficiently flexible to weather a considerable period of uncertain performance during commissioning and early years of operation.
9) EQUITY SHAREHOLDER RISKS - CONSTRUCTION COSTS AND TIMETABLE

Residual Risk - EG&CCo Construction Costs and Timetable Risk.

- Given the nature of new CO₂ capture technologies, some uncertainty in the cost and schedule for construction and commissioning of the CO₂ capture assets is unavoidable.

Residual Risk Allocation:

- The risk of uncertain construction cost and schedule sits ultimately with equity shareholders to raise sufficient capital to finance construction.

Residual Risk Mitigation:

- EG&CCo will hold significant contingency in the construction project (both cost and schedule) to cater for the remaining uncertainties and a prudent capital structure that allows raising further funds to meet unforeseen cost escalations;
- EG&CCo will include contract provisions (e.g. fixed price contract elements, gain/ pain share arrangements, performance guarantees and other mitigation provisions) to minimize this risk to the degree that this is economical. It should be noted that in many cases it is better to cover this risk through holding contingencies at the project level rather than attempting to pass these risks on to contractors, who may then hold larger contingencies at the contract and sub-contract level.

10) EQUITY SHAREHOLDER RISK - PLANT PERFORMANCE AND COSTS

Residual Risk - EG&CCo Performance Risk.

- Given the nature of new CO₂ capture technologies, some uncertainty in the performance the capture plant is unavoidable.

Residual Risk Allocation:

- The risk of uncertain performance sits ultimately with equity shareholders to raise sufficient contingency funding.

Residual Risk Mitigation:

- EG&CCo will secure and hold significant contingency funds to cater for significant performance problems.
- EG&CCo will obtain performance guarantees from the technology providers and EPC contractors to mitigate against performance risks, provided it is deemed economic to do so.

11) EQUITY SHAREHOLDER RISK - STATE AID RISK

Residual Risk - “State Aid” Approval:

- “State Aid” approval may not be received. HMG is not prepared to carry cost or other liability if this happens.

Residual Risk Allocation:

- All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

Residual Risk Mitigation

- HMG will seek to obtain “State Aid” clearance before excessive time and money has been spent on developing the project.
CHAPTER 10 - INDUSTRIAL PRODUCTION WITH CO₂ CAPTURE - OPTIONS PAPERS

Options Paper 10A: Industrial CCUS – Commercial Models

CONTEXT

IP&CCo will be an existing private sector company producing industrial products at scale and not subject to commercial regulation. IP&CCo may own and operate CO₂ capture plant, or it may use other models based on third party ownership and operation, and it is anticipated that the plant will be located within or adjacent to its existing plant boundaries. The first capture plants may well be retrofitted on to an existing process. Alternatively, capture plant may be integrated into new industrial process plant.

Example processes to be considered in this model include chemical production, steel production, hydrocarbon refining, cement manufacture and fertiliser manufacture. (Note: Hydrogen production either for use in producing heat and power in factories, or for industrial use e.g. as a chemical intermediate or for refining, is covered separately in the Hydrogen Options Papers in Chapter 13.)

IP&CCo will expect to earn a return on its investment commensurate with other investment opportunities, adjusted for risk. This will depend on the structure and profitability of its UK assets, its wider risk appetite, and on other opportunities for investment both in the UK and elsewhere.

IP&CCo will either be an ‘anchor’ project for a CCUS cluster or joining an existing cluster to share T&S infrastructure with other capture projects. This paper covers both scenarios.

KEY PRINCIPLES

Most UK industrial enterprises with significant CO₂ emissions receive “free” emissions allowances up to a declining benchmark initially set at the level of the “best performing 10% of the installations producing that product in the EU”\. They are ‘price-takers’ in a global market and, if they were exposed to the carbon price, would be unable to pass decarbonisation costs to customers unless all plants in all other global jurisdictions face identical, or closely similar regimes.

Key principles build on those set out in previous work in this area, namely the 2018 report for BEIS by Element Energy\.  

- Costs incurred due to implementation of CCUS (either operational or capital) cannot be passed onto customers without some sort of compensation being in place. Costs for initial industrial capture projects must therefore be covered by alternative sources of revenue support.
- Risks and returns on any investment will need to be in line with their shareholder’s other investment opportunities. Plant construction and operational risks will need to be broadly similar to those for existing process plant owned and operated by IP&CCo, to satisfy shareholder risk and financing requirements. We note that many UK industrial producers are global companies that compete in and have opportunities in international markets.
- Cluster development plans should support the participation of as many emitters as possible sharing as much infrastructure as possible (e.g. amine conditioning/ compression / onshore pipelines) to ensure lowest capture costs. An approach which simply focuses on lowest individual project capture costs will lead to lower volumes, fail to exploit economies of scale and fail to support multiple industrial sectors.

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47 Emissions Trading System (EU ETS)” Allocation to Industrial Installations”.
PREFERRED OPTIONS

Two models are recommended as credible options for early development of industrial production with CO\textsubscript{2} Capture projects.

1) HYBRID GRANT PLUS CO\textsubscript{2} “CONTRACT FOR DIFFERENCE” MODEL:

Grant; Capital Repayment with project-specific rate of return; Contract for Difference for operating costs

As an industrial producer with a CO\textsubscript{2} capture project, IP&CCo will receive an “Industrial CCUS Contract”. This will be based on the following principles:

- co-financing between plant owners and HMG to build a CO\textsubscript{2} capture plant;
- short payback of IP&CCo’s investment with a project-specific rate of return reflecting the risk taken by IP&CCo;
- a “Contract for Difference” structure for paying the difference between sales of surplus ETS allowances and the fixed and variable operating costs of the CO\textsubscript{2} capture plant.
- Early project contracts would be secured through bilateral negotiations between the industrial producer and HMG. Funding for the “Industrial CCUS Contract” will be directly from tax revenues.

The “Hybrid Grant plus CO\textsubscript{2} CfD” contract between the industrial producer and HMG will have three elements as follows:

**Capital cost recovery**

The capital cost recovery element of the “Industrial CCUS Contract” will allow IP&CCo to earn a return on their capital investment.

- Plant owners will invest in plant to capture CO\textsubscript{2}, and HMG will support this with a grant towards part of the capital cost. A grant of at least 50% of the capex involved for the first capture sources in a cluster should be considered.
- Once the plant is operational HMG will make a periodic fixed payment to the industrial producer to cover repayment of the capital invested, plus an agreed return on the capital investment. This would be set at a level which takes into account the fact that the capital is not at risk, and that the capital invested is repaid over a relatively short payback period of 3-5 years for retrofit plant, and potentially longer for new plant. It would stop once the capital has been repaid with the agreed rate of return.
- Project developers will be expected to explain their requested rates of return through an “open book” approach with HMG, including comparing their proposals to their other project opportunities.

**Operating Cost Recovery**

There will also be a further “contract for difference” periodic payment between IP&CCo and HMG. IP&CCo will pay, or be paid if the amount is negative, the difference between the income generated from sale of surplus free ETS allowances associated with the industrial production, and the costs of operation (fixed and variable) of the CO\textsubscript{2} capture plant. This will be calculated in one of two ways - either:

- The difference between the actual sales proceeds from the sale of surplus ETS allowances\textsuperscript{49}, and the actual fixed and variable operating costs of the capture plant, using “open book” principles. Contracts will be based on absolute costs rather than unit costs.

\textsuperscript{49} Surplus allowances means the difference between the allocation of free allowances and the allowances needed to meet ETS compliance after CCUS has been fitted.
The difference between the CO₂ ETS income and an agreed “strike price” (index linked as required) which will be agreed in advance on a per-project basis, based on forecasts of fixed and variable operating costs and capture volumes. Costs will be normalized on a unit basis (i.e. on a £/t CO₂ contract basis). Due to technological or operational uncertainty on early projects this strike price will need to ‘price-in’ a wide range of operational risks but could, over time, be progressively reduced as operational certainty increased leading to an enduring contract basis. Reopeners could be considered to ensure fair but not excessive returns.

In order to incentivise operating cost reduction, if EU ETS income exceeds costs the excess will be shared between IP&CCo and HMG, perhaps in proportion to the percentage of the capex funded by the HMG grant.

**T&S Capacity Reservation Fee**

Finally, HMG will make periodic payments to IP&CCo to cover the agreed T&S capacity reservation fees. These would then be paid directly by IP&CCo to T&SCo.
Construction

IP&CCo will manage the construction activity. The actual cost of construction will be recoverable under the contract. Efficient delivery will be incentivised as follows.

- The return on capital invested will be paid by HMG on the pre-agreed target cost. If there are cost over-runs these would be repaid at cost, but no shareholder return will be payable on any cost overruns above that target cost.
- A gain share mechanism could also be put in place to incentivise cost efficiency, such that any savings versus target cost are shared between IP&CCo and HMG.

In addition, IP&CCo will, in agreement with HMG, where it is economically justified, put in place risk mitigation measures to address this unavoidable risk, including some or all of the following:

- Fixed price contracts with contractors for those parts of the project where such contracts can be provided economically;
- Pain share/gain share arrangements with contractors where such arrangements can be provided economically;
- Delivery and performance contractor “full EPC wrap” provisions including performance guarantees, to be provided by contractors for those elements of the contracts where these can be provided economically;
- Building considerable contingency into cost estimates, funding availability and schedule plans to cater for significant unforeseen events or circumstances.

Justification for choosing this option

This model allows IP&CCo to earn a return on their investment commensurate with their other investment opportunities, therefore making it attractive for shareholders.

It provides a mechanism for funding operational costs for industrial CO₂ capture while accommodating variations in CO₂ price. The link to the carbon price also ensures that the level of support is proportionate to that required to support investment and is expected to decline over time as the price of carbon increases to the point where this complementary funding mechanism is no longer required.

IP&CCo will bear a level of construction cost risk, which manifests itself as a lack of return on costs beyond target cost – though capital recovery itself is not at risk. They will also be incentivised by the gain share to manage capital costs.

The “Open Book” approach provides an efficient delivery model, meaning that HMG does not overpay and is the most attractive option to Industry as it minimises their risk exposure. An accountancy ‘rule book’ would be established by HMG which would set out allowable expenditure, to be verified by an independent audit process. The “open book” approach provides transparency to HMG.

The objective of sharing any net proceeds of surplus income less costs between HMG and IP&CCo is to align objectives by incentivising reductions in operating costs. (It is suggested that these are shared in proportion to the percentage of HMG grant funding in the capital investment).

Early projects are likely to need relatively low levels of revenue support, compared to other abatement programmes being pursued by HMG. The contracts do require ongoing administration, as each project needs to be evaluated annually, and so may better suited for projects of significant size.

Other Criteria to Evaluate ‘Value for Money’

The ‘Value for money’ for industrial CCUS includes how much each project at a Cluster helps:

a) the Cluster or region to transition to a low carbon economy

b) tackling hard to decarbonise but critical national assets that enable decarbonisation of vital national supply chains key to a low carbon economy. Ammonia is a good example. Ammonia has no
Economically viable alternative decarbonisation options but is relatively cost efficient for CCS. It will benefit the carbon footprint of agriculture through reduction of UK fertiliser carbon footprint, reduce emissions associated with the production of building insulation and carbon fibre. Finally, it has the potential to provide a low carbon energy vector (for HGVs or Ships) or act as a storage or transport medium for hydrogen, within a hydrogen economy.

c) encourage “circular economy” behaviour and sharing of infrastructure (further reducing emissions).

Value for money is increased if emitters share as much infrastructure as possible e.g. amine conditioning/compression/onshore pipelines, in order to lower overall capture costs. On the other hand, an approach which simply focuses on lowest individual capture costs will lead to lower volumes, fail to exploit industrial economies of scale and fail to support a wide range of industrial sectors.

**Common rate of return**

As an alternative within option a), setting an industry-wide or sector-specific rate of return might be attractive if there were the opportunity to roll out “Industrial CCUS Contracts” across many industries and projects. This level of return for early projects could either be maintained by HMG for later (follow-on) projects at a Cluster or revised to reflect changes in CCUS costs and prevailing economic and industrial circumstances.

In practice, it is expected that for early projects there will be relatively few material capture projects available, each with significantly different characteristics. This will probably make it difficult to set either a single or an industry-specific rate of return for these contracts. (Too high a rate leaves a lot of “money on the table”; too low a rate will attract too few investors).

When considering participation in such a system, industrial producers emitting CO\(_2\) would need to consider the prospects for the future award of ETS allowances, future ETS prices and the likely terms of future decarbonisation schemes.

**Using reverse auctions for setting rate of return**

This would be a further alternative for setting returns. An auction process could be introduced by HMG to procure the lowest cost capture opportunities (in a similar process to current power CfD auctions).

This would require multiple prospective projects being available at the same time to participate in an auction process, and each requiring access to a CO\(_2\) T&S network. For early projects, there are unlikely to be enough projects available for an auction to succeed.

Later, if and when a significant range of potential projects emerges, then auctions may well be more successful at allocating contracts to projects which provide value for money to HMG.

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**2) REGULATED “DECARBONISATION SERVICE COMPANY” WITH A RAB:**

A new private sector commercially regulated company would be established to invest in and install CO\(_2\) capture facilities next to industrial production plant. This option delivers the new company a regulated return. The returns of the company would be regulated under a regulated asset base (RAB) system. The company’s investments would be financed by the private sector. The new company would be funded through revenue provided by HMG, paid for by UK tax revenue.

Any surplus revenues generated within the IP&CCo against its EU ETS benchmarks as a consequence of this structure would need to be taken into account i.e. shared or netted off.
For an IP&CCo where capture is relatively straightforward and can be retrofitted with minimal intervention in the existing process flow (e.g. Ammonia plants and some chemical plants), a RAB model could work well, as it largely insulates the industrial producer from any commercial transaction and allows them to focus on their core business of competitive product manufacture.

Where capture is directly integrated into the process flow (e.g. oil refining), a third-party design and construction activity by a third-party provider under a RAB model is harder to envisage. However, industrial producers could choose to construct the capture plants themselves, and then use arrangements similar to the “Dry Lease” model used in the airline industry, or “Finance Leases” used in other industries.

**Justification for choosing this option**

This model may have several attractions:

- It would allow industrial producers to maintain their competitiveness and would mitigate their exposure to future carbon prices, tariffs and regulation.
- It overcomes the lack of incentives of many industrial emitters to invest as they have no opportunity cost, and no expertise in CO₂ capture. They avoid having to negotiate a complex deal and will be more willing to participate because they can decarbonise and be held economically neutral.
- Capture assets will be on the balance sheet of the regulated company, with low cost of capital, rather than the cost of capital necessary to incentivise industries to carry out the expenditure.
- It avoids the need for HMG to negotiate “Industrial CCUS Contracts” with a wide range of individual CCUS projects;
- Repositioning industrials producers as low-carbon producers will extend their competitiveness and significantly reduce their exposure to future carbon prices;
- Expertise in CCUS can be centred in the regulated company. Industrial producers will not have to develop capability in a non-core activity;
- The regulated company can be incentivised to drive the deployment of CO₂ capture from industrial producers at a rate that HMG choose to be desirable and affordable.
- It could be the conduit for grant allocation, within an HMG budget allocation, to the companies with the greatest value of abatement, job retention and creation, and contribution to the decarbonisation economy.

Over time, it may make sense in the future for a regulated “Decarbonisation Service Company” to link up with, or even combine with, a regulated T&S company. This may have several advantages.

- The linked companies could procure the delivery of both capture assets for installation at each site and the required T&S assets. It can be incentivised to optimise the sharing of CCUS assets, including pipes, compression and shipping. This would enhance system flexibility. They could become the catalyst and focal point for a new industrial capture industry, both small and large scale, fostering competition between installers and different technologies.
- They will be exposed to a large number of potential schemes and can help prioritise deployment investment. Co-ordinating T&S and Industrial capture investment may help optimise “value for money”.

Nevertheless, there will be challenges to overcome in adopting this option. The business case for many IP&CCo’s is not purely related to the emissions reduction benefit, making it difficult to design a suitable mechanism for “leasing” the new plant to the “Decarbonisation Service Company”. Changes in process efficiency, replacement of time expired (end-of-life) equipment, reduction in other emissions required
from a regulatory perspective, may all be significant, indeed the primary motivations, of such investments. Control of capture assets may also be highly problematic, particularly where they are absolutely integral within the production process in a high hazard facility.

### ALTERNATIVE OPTIONS

#### 3) PAYMENT PER TONNE CO₂ CAPTURED THROUGH TAX CREDITS

This option delivers to an industrial producer a fixed level of revenue support per tonne of CO₂ stored, by providing tax credits that be offset against UK pre-tax corporation tax profits.

This system leaves all demand risk with the industrial producer.

The mechanisms for delivering either a tax credits system or a CO₂ CfD system are described in Options Paper 10C.

**Justification for not choosing this option**

Providing a payment per tonne of CO₂ captured through a tax-credit system would appear potentially attractive to HMG, as this represents a transparent system, providing apparent clarity to all observers.

However, this would leave all demand risk with the industrial producer. This will almost certainly not work for retrofitting existing plant, where both plant life and utilisation rates are somewhat uncertain.

In addition, inherent difficulties for projects that retrofit CO₂ capture to existing industrial production plant for tax credits are described in Options Paper 10C.

#### 4) UNREGULATED THIRD-PARTY PROVISION

A third party is selected, probably through a competitive process, to finance, own and operate the capture plant (or potentially multiple capture plants), at a lower cost of capital than IP&CCo. This would be similar to option 2. above, but the provider would be unregulated.

This could only work if there were enough potential and actual providers to establish competition between them to keeps costs down. This is unlikely to be the case for some time.

#### 5) INCREASING EXPOSURE TO THE CARBON PRICE

Industrial emitters would receive progressively fewer “free” allowances, thereby increasing their exposure to the carbon price. When the carbon price is sufficiently high decarbonisation investments on industrial production processes could then be justified.

If this business model is adopted by HMG, it is very likely that significant parts of energy intensive industrial production in the UK would cease, thereby increasing “imported emissions”, along with the resultant job losses and fall in GDP.
Options Paper 10B: Industrial CCUS - Source of Revenue Support

CONTEXT

There is no natural ‘pool’ of consumers or tax revenue in the UK who can be said to be the logical funders of the revenue support for industrial CCUS. In electricity production, passing costs of decarbonization to consumers was a logical step which is already well advanced in the UK. Similar arguments can be made for the decarbonization of domestic gas through hydrogen production and distribution.

It is unlikely that in the short to medium term UK consumers will be prepared to pay substantially increased prices for decarbonized products produced in the UK if they have the alternative of buying non-decarbonized products produced elsewhere.

As the industrial sector contributes significantly to the UK economy, and decarbonization is a pillar of the government’s industrial strategy, it is not unreasonable to assume that UK tax revenue are the most logical initial source of funding for industrial CCUS in the short term.

However, funding industrial production from tax revenue is not a sustainable option. Given the pressures on government funding, an alternative source of funding decarbonisation of industrial production will have to be found in the relatively near future.

PREFERRED OPTION

1) FUNDING FROM TAX REVENUE:

This is proposed both for the direct co-financing between plant owners and HMG, and also for funding a regulated “Decarbonisation Service Company”. This would cover both ongoing revenue support and also grant funding.

Justification for choosing this option

Given that industrial CCUS projects, particularly when viewed through the lens of a cluster, cover a wide range of

When either hydrocarbons or calcium carbonate enter the market in the UK, they would attract an obligation to sequester a small but rising proportion of their “contained CO₂” using CCUS. These obligations would be tradeable. They would also be redeemable by HMG; and HMG would inject the funds raised when obligations were redeemed directly into a CCUS Obligation Fund. The CCUS Obligation Fund would then provide revenue support funding to CCUS projects.

Justification for not choosing this option

A CCUS Obligations System remains a logical solution for replacing tax revenues as the source of funding for CCUS projects in due course. Introducing a CCUS Obligation Fund could accelerate implementation of such a system dramatically.

However, this option may not be ready for the earliest CCUS projects. Introducing a CCUS Obligation Fund in the very short term may be challenging, but it remains a logical and potentially compelling option for an enduring funding regime for CCUS.

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CHAPTER 10: Industrial Production with CO₂ Capture – Options Papers

2) **US OBLIGATION SYSTEM - TRADED WITHOUT A FUND:**

As above, but obligations would be traded between those incurring them and those operating CCUS assets and infrastructure. No separate fund or revenue support system would be provided. This option can only work once a mature CCUS industry is established. However, once it is established it would be entirely self-funding.

**Justification for not choosing this option**

Introducing a CCUS Obligation System without a CCUS Obligation Fund requires a developed CCUS industry to be in place, which is likely to take some time.

It is expected that a CCUS Obligation Fund would migrate to a CCUS Obligation System. The Fund would then be closed. And no other further revenue support (or subsidy) would then be needed, as the CCUS Obligation System would be self-funding.

3) **ETS CERTIFICATE SALES BY HMG:**

All UK CCUS could be funded by the proceeds raised by HMG from selling ETS certificates. This is essentially a form of tax revenue controlled by HMG, and therefore is really a sub-set of option 1. above.

4) **CCS LEVY:**

All UK CCUS could be funded by the proceeds raised by HMG from the various carbon and non-carbon taxes that are imposed by HMG, including fuel duty and other similar taxes. (A CCS levy was legislated for in The Energy Act of 2010, but this was specifically focused on electricity supply and was subsequently abandoned). Again, these are all forms of taxation, and therefore a sub-set of option 1.

5) **DIRECT FUNDING BY CUSTOMERS, ALONGSIDE AN IMPORT TAX:**

CCUS costs could be funded directly by customers of industrial products (chemicals, industrial hydrogen, steel, cement, glass, ceramics, fertiliser etc.) through carbon taxes levies on these products. However, to be viable an import tax framework would need to be introduced in parallel to ensure that cheaper, non-decarbonised products produced elsewhere did not displace decarbonised products produced in the UK causing carbon leakage. There would also need to be adjustments to allow exporters to compete abroad.

6) **TRANSITION TO ENDURING REGIME**

Looking ahead, it is recommended that a move away from general tax-payer funding is developed to create an enduring regime.

A CCUS Obligation System using CCUS Certificates preceded, if necessary, by a CCUS Obligation Fund, is an option for funding CCUS in the UK. This would be self-funding, would automatically introduce competition into the allocation of funds, and require no further CCUS revenue support from the taxpayer or other customer groups.
Options Paper 10C: Industrial CCUS - Mechanisms for Delivering Revenue Support

CONTEXT

Several mechanisms have been used globally to provide revenue support for industrial CCUS. These include 45Q Tax Credits in the US (although these remain at an early stage, and no projects have yet reached FID using this mechanism) and various carbon pricing schemes in other jurisdictions.

At present, there is no statutory instrument or mechanism to transfer funds from the funding source to industrial CCUS projects. Such an instrument exists for Electricity Generation projects in the form of a CfD (Contract for Difference), but no equivalent exists for industrial CCUS.

The CAG has considered all six possible options previously identified by Element Energy\(^{51}\), as well as other options.

PREFERRED OPTIONS

1) DIRECT PAYMENTS FROM HMG - USING “INDUSTRIAL CCUS CONTRACT”:

Options Paper 10A describes the concept of a “Hybrid Grant plus CO\(_2\) CfD” Industrial CCUS Contract. This structure would be underpinned by direct payments made from HMG to the industrial producer to cover repayment of capital plus a return.

Justification for choosing this option

If as recommended early Industrial CCUS Contracts are to be funded from tax revenue, and the “Industrial CCUS Contract” structure set out in Options Paper 10A is chosen, then no additional payment body or mechanism is needed.

2) HMG FUNDING OF “DECARBONISED SERVICE COMPANY”:

Having been financed by the private sector, the Decarbonised Service Company would be funded directly by HMG, to cover its operating costs, repayment of capital and return.

Justification for choosing this option

If as recommended the source of funds for early Industrial CCUS Contracts is to be funded from tax revenue, and the “Decarbonised Service Company” commercial model is chosen, then again, no additional payment body or mechanism is needed.

ALTERNATIVE OPTIONS

3) TRADEABLE CO\(_2\) TAX CREDIT SYSTEM:

The revenue support for IP&CCo could be delivered through a new “CCUS Tax Credit” system. This would need to differ significantly from the 45Q system used in the USA.

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This scheme would reward the industrial producer with tax credits based on each tonne of CO₂ captured, probably in parallel with a capital grant to part-fund a level of initial capital outlay. Key features of this scheme could include:

- A tax credit would be provided to IP&CCo by HMG for each tonne of CO₂ captured.
- The tax credits could be offset against any UK tax liability.
- To be ‘bankable’ the tax credit will need to be contractually guaranteed by HMG for the duration of the project. Any award of tax credit should be “grandfathered” i.e. there will a guarantee that any contract awarded will continue the agreed contract period, even if the original CCUS Tax Credit scheme is discontinued or its terms are amended significantly.
- These tax credits would need to be transferable - perhaps to other group companies, or to other participants in the CCUS chain, so that if the industrial producer does not have sufficient tax liabilities to offset against the tax credit, they can still be monetised.
- Any economic impact on IP&CCo under any carbon price schemes would be adjusted to ensure that IP&CCo neither profits nor loses from surrendered allocations of tax credits.

The value of tax credits could be fixed across all industries, be subsector specific, have value varying by factors such as CO₂ purity and the carbon price, be negotiated for each site, or be awarded under a competitive bidding process.

**Justification for not choosing this option**

Fixed tax credits are simple, may appear not to represent a direct payment by HMG, and promote low cost project selection if there is active competition for them.

However, the proposed tax credit system suffers from a number of drawbacks.

First, as with the CO₂ CfD, demand risk (i.e. the uncertainty around the volume of CO₂ that will be produced) sits with the industrial producer. This risk will have to be priced in. This might just be acceptable (albeit expensive) for a new plant which is expected to have a long life, and which is expected to run (for a foreseeable period) at high utilisation rates. However, this will almost certainly not work for retrofitting existing plant, where both plant life and utilisation rates are uncertain.

The one way to avoid the effects of this demand risk would be for HMG to provide a grant to cover 100% of the capital investment cost of the plant.

Second, the taxable profit of many industrial producers, and therefore their capacity to use tax credits themselves could be heavily outweighed by the value of the tax credits being earned. There would therefore have to be a risk-free route for the industrial producer to monetise the tax credits they received. This underlies the proposed design features of the tax credit system described above. It is this that makes the features of the US 45Q system unsuited for retrofitting to existing plant in the UK.

The system may well overcompensate some emitters and fail to incentivise others. Given the relatively limited depth of the market for early projects, it may be difficult to set suitable industry-wide or sector specific values for tax credits that would attract the right projects at the right price.

4) **ACCELERATED DEPRECIATION:**

Accelerated depreciation is a well-used alternative means of incentivising investment, and it could be used to reduce an industrial producer’s tax burden. However, to fully realise the funding value required by industrial producers with CCUS projects (i.e. to cover both the capital cost and the operational costs), it is likely that depreciation of over 100% of the original asset value will be required.

5) **CCUS OBLIGATION FUND**

This is discussed in Options Paper 10C. Industrial producers would receive revenue support - in any of the ways described above - from a CCUS Obligation Fund rather than directly from HMG.
6) **CCUS OBLIGATION SYSTEM - WITHOUT A CCUS OBLIGATION FUND:**

This is discussed in Options Paper 10C. Industrial producers would be paid by the holders of CCUS Obligations to take those Obligations on, and to capture CO\(_2\) (and deliver if for storage).

7) **CREATION OF LOW-CARBON MARKET:**

Industrial producers might achieve a price premium, through creating markets for their low-carbon products through certification, public procurement and end-use regulations.

This may well prove an effective mechanism for funding the costs of decarbonisation of industrial production in the future, but it is extremely unlikely that this can happen quickly enough or deliver sufficient value to be considered a viable means of funding production of low-carbon products in the near term.

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**FURTHER ISSUE - PAYMENT ROUTE FOR T&SCO FEES**

**Context**

The common model assumed for remunerating T&Sco is through T&S fees charged to its customers, analogous to most pipeline infrastructure systems.

This is the model being assumed for Electricity with CCUS and Hydrogen with CCUS.

In both cases it is expected that the T&S fee will be funded through some source of revenue support. They would be paid to the company capturing CO\(_2\), who would pass the fee on to the T&S company. Legal and contractual provisions would be put in place to ensure that the fees would pass to the T&S company if the capture company experienced financial difficulties.

In both cases the capturers are expected to have the financial capacity to handle the pass-through of the T&S fees.

However, some industrial producers have expressed concern that the payments due to the T&S company could be significantly larger than their normal operating cash flows, and this could cause complications in the finances of their companies.

**Option**

The T&S fees would be passed by the providers of the revenue support to the industrial producer, who would then pass it on to the T&S company.

The provider of the revenue support could pay the T&S fee directly to the T&S company. This is illustrated in the diagram below:
Arguments for the option

If the “Co-investment with HMG” model is used, then it is arguable that either option could be used. However, it is possible that if HMG paid the T&S company directly this may influence the balance sheet treatment of the T&S company. If this consideration is correct, then contractual provisions should be used to deal with the concerns of some industrial producers. If this consideration is not correct, then payment of the T&S fee directly from HMG to industrial producer should be considered.

If a “Decarbonisation Service Company” is established than it may be an option that this company should receive the revenue support related to the T&S fees and pay it directly to the T&S company. Again, balance sheet treatment needs to be considered.

As a final option, it may be worth considering waiving T&S fees for industrial producers completely in some circumstances. If their volumes are small, and the T&S costs have been covered by previous projects, it may make sense to treat these projects as purely incremental. This could help encourage new investments by low-carbon producers.
Options Paper 10D: Industrial CCUS – Contract Duration & Accelerated Capital Repayment

HYBRID GRANT PLUS CO₂ “CONTRACT FOR DIFFERENCE”

Context

We note that many UK industrial enterprises are global companies that are headquartered overseas. Risks and returns on any investment will need to be in line with their shareholder’s other investment opportunities.

Typically, these investors will have short investment payback requirements.

Because CO₂ capture produces no profit, investors will need to be confident of recouping their investment, and return, during the life of the contract. (CAG has assumed that there are no regulatory/legislative obligations placed on industrial companies that would mean investment in capture avoids payment of such obligations).

Industrial producers are exposed to changes to their obligations during each phase of the Emission Trading Scheme. It may therefore be sensible to consider alignment between the contractual terms across each phase of this scheme.

Preferred options

The ‘Industrial CCUS Contract’ is split into two elements, with contract durations as follows:

Capital Cost Recovery

- For retrofitting capture plant, the contract would be split over two periods. The repayment of capital invested in capture plant would be accelerated and repaid with return over an agreed, relatively short payback period of 3-5 years. Thereafter, the contract would continue to operate, with a lower level of revenue support sufficient to cover the capture plant operating costs.

- For new industrial plant with carbon capture, capital investment could be repaid over a longer period, potentially up to the full expected economic lifetime of the plant. (Note: a relatively short payback time does have the advantage of lowering the lifetime costs of Industrial CCS).

Operating Cost Recovery

- The Operating Cost recovery contract would run for the duration of the operating life of the plant. If the ‘actual cost’ CfD option is utilised, no contract revision would be required, as annual payments of actual costs less actual income from sale of surplus EU-ETS (or UK equivalent) allowances would be paid. If the ‘strike price’ CfD option is utilised, periodic price re-setting will be required. This could be aligned with EU-ETS phasing.

Justification of the Preferred Options

Industrial producers have significantly shorter payback period expectations than infrastructure funds – typically 3-5 years on plant upgrades. (New plant payback periods may be longer).

Recovering actual costs would minimise risk to the industrial producer, and reduce the return required.

DECARBONISATION SERVICE COMPANY

The lifetime of the assets of a decarbonisation service company would depend very much on the nature of the plant in which it was investing.

If it was to capture CO₂ from a wide range of customers, it may well be able to accept a repayment of capital and return over the full economic life of the plant.
If the investment is more bespoke, and for example is capturing the CO₂ from a single emitter, the capital repayment will have to be tailored to allow for the demand risk and other uncertainties that the emitter may face.

**ALTERNATIVE OPTIONS CONSIDERED**

- Basing cost recovery on target costs, or benchmark costs. This would minimise administration and incentivise performance but would increase risk and therefore return required.
- Recovering all costs through fully variable payments. This would increase risk to the industrial producer, and the return required.
- Possible options include actual costs (minimises risk to the industrial producer) or benchmarks or targets (minimises administration and incentivises performance).
- Extending the capital repayment period. Pricing in demand risk is difficult, and so this is likely to increase risk, and hence return requirements, very substantially.
CHAPTER 11 – INDUSTRIAL PRODUCTION WITH CO2 CAPTURE – DETAILED BUSINESS MODEL

Summary of Variant 1 Business Model

VARIANT 1: THE ‘HYBRID GRANT CO2 PLUS CFD MODEL’

Grant; Capital repayment with project-specific rate of return; and CfD Model for operating costs.

PART 1 – COMMERCIAL ARRANGEMENTS

Ownership and finance. The CO2 capture (IP&CCo) assets applied to industrial production plant will be privately owned, financed, developed, built and operated. The CO2 capture assets will be owned by IP&CCo supported by an HMG grant. It is the intention that none of the IP&CCo assets, liabilities, nor contingent liabilities will appear on HMG’s balance sheet.

IP&CCo commercial model. IP&CCo will be a private sector company producing industrial products at scale. It will receive an “Industrial CCUS Contract” from HMG. IP&CCo will invest in the CCUS project, together with a supporting grant from HMG, on the basis that they will achieve a project return on their investment in line with their shareholder’s other investment opportunities, adjusted for risk.

Insurance. IP&CCo will be responsible for carrying insurance appropriate to its business. Insurance will be a key risk mitigation measure - where it is commercially available at economical rates. If commercial insurance is not available, HMG will act as the “insurer of last resort” for only one specific, defined risk; namely, the “Pre-Commissioning Stranded Asset Risk” that no T&S assets are built to store the CO2 captured by the first capture plant in a cluster.

Coordination between CO2 Capture and T&S assets. A “Programme Development Consortium” will be created for a cluster. The Consortium will appoint a “Programme Development Coordinator”. Project development will be synchronized, using coordinated stage-gate decision points. Any project development funding provided by HMG prior to FEED will be coordinated across the CO2 Capture and T&S projects.

A contractually agreed system of penalties may operate between the projects if “first CO2” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

Asset size. Asset size should be judged against measures of “reasonable” unit cost and of capital efficiency; and also against the need to provide a clear pathway to allowing CCUS to “operate at scale by 2030”.

Development Funding. For early projects, the developers of CO2 capture assets on industrial production plant (IP&CCo) and HMG will share the costs of project development of the CO2 capture assets through to FID - both pre-FEED and FEED costs.

Financing. CO2 capture plant assets will be financed by IP&CCo. It will also be supported by a grant from HMG. The finance provided by IP&CCo will include all required working capital; and prudent contingency funding.

Construction. The actual cost of construction will be recoverable under the contract. To incentivise efficient delivery the return on capital invested will be paid by HMG on a pre-agreed target cost. If there are cost over-runs these would be repaid at cost, but no shareholder return will be payable on any cost overruns above that target cost. A gain share mechanism could also be put in place to incentivise cost efficiency, such that any savings versus target cost are shared between IP&CCo and HMG.
Operating Performance and Costs. Given the nature of CO₂ capture technologies, some uncertainty in the performance of the plant is unavoidable. IP&CCo will obtain performance guarantees, provided it is deemed economic to do so, from technology providers to mitigate against these risks.

T&S Fees. T&SCo will charge T&S fees to IP&CCo set by agreement between T&SCo and the T&S regulator. T&S fees may be made up of a “capacity reservation” element and a “variable” element for as many years as the industrial plant is running, updated annually. These fees may change from time to time and are expected to reduce as more capture projects are added into the T&S network. Revenue support for the T&S fees will be paid from HMG to IP&CCo.

Follow-on Projects. Industry may be expected to increase their share of capital investment in future projects as the CCUS industry develops. T&S fees charged will spread the costs of the T&S assets equitably across T&SCo Customers.

Cross chain failure - T&S not available. If, after “first CO₂”, the T&S assets are not available, the following will apply:

- IP&CCo will be entitled to continue to run unabated until a suitable T&S solution is available and will continue to receive a portion of their revenue support. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage.
- T&SCo will continue to receive a portion of their T&S fees, from HMG, paid via IP&CCo at a level set in advance by agreement between the regulators and T&SCo.

Cross chain failure - Capture plant does not deliver CO₂ to T&SCo. IP&CCo is not obliged to deliver CO₂ to T&SCo. However, regardless of the volume of CO₂ delivered, from the start date of the T&S Services Contract, HMG will still be required to pay the revenue support related to the “capacity reservation” portion of the T&S fees to IP&CCo for pass-through directly to T&SCo.

PART 2 - REVENUE SUPPORT

As an Industrial Producer with CO₂ capture, IP&CCo will receive revenue support through a new “Industrial CCUS Contract” with HMG.

Source of revenue support. Revenue support for early Industrial CO₂ capture will be funded by HMG, which is itself funded by UK tax revenue.

Mechanism for delivering revenue support. Payments from HMG under the “Hybrid Grant plus CO₂ Cfd model” will cover the following:

- Repayment of the capital invested, plus an agreed return on the capital investment. Capital will be repaid over a relatively short payback period of 3-5 years for retrofit plant, and potentially longer for new plant.
- Recovery of the operating costs, based on a CO₂ “contract for difference”, which will one of the two following models:
  - The difference between the actual sales proceeds from the sale of surplus ETS allowances, and the actual fixed and variable operating costs of the capture plant, using “open book” principles. Contracts will be based on absolute costs rather than on a unit basis.
  - The difference between the CO₂ ETS income and an agreed “strike price” which will be agreed in advance, based on forecasts of fixed and variable operating costs and capture volumes. Costs will be normalized on a unit basis (i.e. on a £/t CO₂ contract basis) and may be reset periodically.
- The agreed T&S capacity reservation fees. These would then be paid by IP&CCo to T&SCo.
Industrial CCUS Contract duration. The two elements of the Industrial CCUS Contract will have different contract durations as follows:

- Capital Cost Recovery: For retrofit plant the repayment of capital invested in capture plant will be repaid over an agreed, relatively short payback period of 3-5 years. This could potentially be longer for new plant.

- Operating Cost Recovery: The Operating Cost recovery contract would run for the duration of the operating life of the plant. (If the ‘strike price’ CfD option is utilised, periodic price re-setting will be required. This could be aligned with EU-ETS phasing.)
Comparison of Variant 1 with Other Variants

INDUSTRIAL PRODUCTION AND CO$_2$ CAPTURE - COMPARISON WITH OTHER VARIANTS

VARIANTS 2 TO 4

Summary. There would be no impact on the Industrial Production and CO$_2$ Capture Business Model in these Variants.

VARIANT 7: “DECARBONISED SERVICE COMPANY” REGULATED UNDER A RAB

(Regulated capture. Separate RABs for parts of the CCUS chain.)

Ownership and finance. The “Decarbonisation Service Company”, a new private sector company - regulated under a RAB model - will raise funds to invest in CO$_2$ capture plant on industrial processes and provide a “decarbonisation service” to industrial emitters. These funds may include HMG grants. The objective would be that none of the IP&CCo assets, liabilities, nor contingent liabilities will appear on HMG’s balance sheet.

“Decarbonisation Service Company” commercial model. This company will develop CO$_2$ capture projects together with industrial producers on their manufacturing plant to the point of FID, and finance them. Either the service company or the industrial producer will then build and operate them. (In the second case, some form of “plant leasing” or “build and transfer” arrangements might be used.) The “Decarbonisation Service Company” will enter into an “Industrial CCUS Contract” with the industrial producer. The length and terms of these contracts will depend on the commitments the service company needed in order to be viable, and the commitments that industrial producers were able to make without jeopardising their businesses.

The industrial producers will pay the service company an amount equal to their savings on carbon taxes - leaving the industrial company economically neutral. In addition, revenue support would flow from HMG to the service company.

It is possible, though not necessary, that the service company could undertake other activities in the CCUS industry as wellCO$_2$.

Financing. The “Decarbonisation Service Company” will be financed by private sector equity and debt. It may be supported by a grant from HMG. The finance raised will include all required working capital; and prudent contingency funding.

Construction. The “Decarbonisation Service Company” will carry the costs and consequences of exceeding the capital budget for construction, and commissioning delays. These may be shared with the industrial producer if the industrial producer chooses to build and operate the plant. The service company will put in place significant contingency funding, as well contractual arrangement with contractors and the industrial producer, to mitigate against these risks.

Operating Performance and Costs. The “Decarbonisation Service Company” will carry the costs and the consequences of risks associated with operating performance and costs. These may be shared with the industrial producer if the industrial producer chooses to build and operate the plant. The service company will put in place significant contingency funding, as well as performance guarantees from contractors (if deemed economic) and the industrial producer, to mitigate against these risks.

T&S Fees. T&SCo will charge T&S fees to the “Decarbonisation Service Company”, set by agreement between T&SCo and the T&S regulator. T&S fees may be made up of a “capacity reservation” element and a “variable” element. The T&S regulator may instruct that either of these fees start at zero for industrial emissions, or that they should change from time to time, as contractually agreed beforehand. Funding for the T&S fees will come from HMG to the service company and the service company will be obliged to pass these fees directly through to T&SCo.
Detailed Business Model - Variant 1: Industrial Production with CO₂ Capture

INTRODUCTION

This is the Business Model for Industrial Production with CO₂ Capture in the UK. It is part of the suite of four models which collectively are known as Variant 1.

Variant 1 is based on the CCTF recommendation to use a RAB-based model for T&S, and private sector ownership for Capture.

This model uses the Industrial CCUS Contract model for providing funding to Industrial producers with CO₂ capture projects. This is made up of two parts; the first of which provides for recovery of the capital investment with an agreed rate of return, and the second which provides ongoing revenue support based on a CO₂ CfD.

PART 1 – COMMERCIAL ARRANGEMENTS

1) SCOPE OF IP&CCO

A private sector company (IP&CCo) will own, finance, develop, build and operate industrial production assets, and CO₂ capture assets.

IP&CCo will contract with T&SCo, who will supply a CO₂ T&S service.

Neither the IP&CCo assets, nor any liabilities/ contingent liabilities associated with them, will appear on HMG’s balance sheet.

2) IP&CCO COMMERCIAL MODEL

IP&CCo will be a private sector UK company, producing industrial products at industrial scale.

It will earn an unregulated, “commercial” rate of return on its equity, commensurate with the business risk it is taking.

The expected return on IP&CCo’s investment in the production of industrial products and in the associated CO₂ capture will be a key consideration when the level is set for the revenue support received by IP&CCo (see below).

IP&CCo will expect to make a return on their project investment in CO₂ capture in line with their shareholder’s other investment opportunities.⁵²

3) INDUSTRIAL CCUS CONTRACT START DATE

Payments from HMG will start from the Contract Start Date, which will be the latest of:

- a pre-agreed start date;
- the date when IP&CCo is ready to deliver the first CO₂ to T&SCo (whether or not T&SCo is ready to receive it).

4) INSURANCE

IP&CCo will be responsible for carrying insurance appropriate to its business. Insurance will be a key risk mitigation measure - where it is commercially available at economical rates.

⁵² Purple text indicates key difference between the “Electricity Generation with CO₂ Capture” model and the “Industrial Production with CO₂ Capture” model.
If commercial insurance is not available, HMG will act as the “insurer of last resort” for only one specific, defined risk; namely, the “Pre-Commissioning Stranded Asset Risk” that no T&S assets are built to store the CO₂ captured by the first capture plant in a cluster.

Residual Risks - see HMG Risk - HMG acts as Insurer of Last resort

5) CO-ORDINATION BETWEEN CO₂ CAPTURE ASSETS AND T&S ASSETS

It is anticipated that for the development of the first projects in a cluster a “Programme Development Consortium” will be created involving one or more potential capture sources and prospective owners of key CO₂ transport and storage facilities. The Consortium will appoint a “Programme Development Coordinator” to lead the Consortium.

The Consortium will work with regional authorities and other organisations in the region, noting that any T&S infrastructure developed will have third party access arrangements. The Coordinator will produce a plan for integration of further capture sources into the system.

The Coordinator could be one of the possible anchor projects, an external organization appointed by the projects, the regional government authority, or possibly an organization appointed by HMG that works to a scope defined by HMG.

In general, it is likely that the anchor T&S project developer will be appointed as Coordinator, as they will often have the best opportunity to create a coherent picture of the status of possible capture projects that may be developed in a cluster/ region.

The role will be sponsored by the capture, transport and storage projects involved, and may include cost sharing arrangements with government. Contractual arrangements between each element of the total project are expected to be used.

Project development will be synchronized, using coordinated stage-gate decision points. The first anchor projects in a cluster will look to pass i) into FEED, and ii) through FID simultaneously. Project development funding provided by HMG prior to FEED will be coordinated across each programme element. All parties will be bound contractually to manage risks and deliver an operating project; with terms depending on the nature of the projects involved, risk allocations and arrangements put in place by HMG to allow the projects to proceed.

6) ASSETS SIZE/ CAPACITY

The initial cluster Capture and T&S projects in any cluster or region should be sized to meet two criteria:

- Meet a common set of metrics for “reasonable” unit cost (e.g. cost of carbon abatement, unit cost of low carbon electricity or other output), as well as “reasonable” use of capital and capital efficiency.
- Demonstration of how development of further cluster capture projects provides a clear pathway to allowing CCUS to “operate at scale by 2030”.

7) DEVELOPMENT FUNDING

For early projects, the developers of the project and HMG share the costs of project development of T&S assets through to FID - both pre-FEED and FEED costs.

In the event projects fail then neither side compensates the other.

Residual Risks - see Equity Shareholder Risks - Political Risks (1) - Project fails post-FEED.
Residual Risks - see HMG Risks - Loss of development funding.
8) **FINANCING**

IP&CCo investment in the CO₂ capture plant will be financed by the private sector, which is funded by equity and debt as required by IP&CCo’s financial structure.

It will also be supported by an HMG grant.

The finance raised will include all required working capital.

IP&CCo will create and maintain considerable, prudent contingency funding from its financiers at all times.

*Residual Risk - see: Equity Shareholder risk - Uncertain calls on cash*

9) **CONSTRUCTION**

Given the nature of CO₂ capture technologies, some uncertainty in the projected costs and schedule for construction is unavoidable.

IP&CCo will manage the construction activity.

The actual cost of construction will be recoverable under the “Industrial CCUS Contract”. Efficient delivery will be incentivised as follows.

- The return on capital invested will be paid by HMG on a pre-agreed target cost. If there are cost over-runs these would be repaid at cost, but no shareholder return will be payable on any cost overruns above that target cost.
- A gain share mechanism could also be put in place to incentivise cost efficiency, such that any savings versus target cost are shared between IP&CCo and HMG.

In addition, IP&CCo will, in agreement with HMG, where it is economically justified, put in place risk mitigation measures to address this unavoidable risk, including some or all of the following:

- Fixed price contracts with contractors for those parts of the project where such contracts can be provided economically;
- Pain share/gain share arrangements with contractors where such arrangements can be provided economically;
- Delivery and performance contractor “full EPC wrap” provisions including performance guarantees, to be provided by contractors for those elements of the contracts where these can be provided economically;
- Building considerable contingency into cost estimates, funding availability and schedule plans to cater for significant unforeseen events or circumstances.


10) **OPERATING PERFORMANCE AND COSTS**

Given the nature of CO₂ capture technologies, some uncertainty in the performance of the plant is unavoidable. IP&CCo will obtain performance guarantees, provided it is deemed economic to do so, from technology providers to mitigate against these risks.

In order to incentivise operating cost reduction, if EU ETS income exceeds costs the excess will be shared between IP&CCo and HMG, perhaps in proportion to the percentage of the capex funded by the HMG grant (see section 18 below).

*Residual Risk - see: IP&CCo Shareholder Risk - Performance and Costs.*
11) T&S FEES

Under the plan agreed with the regulator, T&SCo will be allowed to charge to its customer(s) T&S fees that are pre-agreed with the regulator.

On instruction of the T&S regulator/HMG, the T&S fees may change from time to time, depending on new plant being commissioned, and on other factors.

The T&S fees will be charged partly as a fixed “capacity reservation” fee i.e. a fixed annual/monthly fee, and partly as a “variable” element i.e. per tonne of CO₂ delivered to T&SCo’s delivery point. The “capacity reservation” fee will comprise most of the T&S fee - to provide stable, non-volatile income required by investors in low risk, low return RAB structures.

If only one CO₂ Capture project is being built initially, T&SCo will charge that project a fee that covers all T&SCo’s costs. If more than one project is being built initially then these costs will be spread across all these projects.

Funding for the T&S fees will come from HMG to IP&CCo under the contract. IP&CCo will be obliged to pass these payments directly through to T&SCo. The ultimate ‘funder’ is therefore the taxpayer. Legal protection for T&SCo will be required if IP&CCo fails to pass these fees through.

12) FOLLOW-ON PROJECTS

On instruction of the T&S regulator, the T&S fees may change from time to time, depending on new plant being commissioned, and on other factors.

If future capture projects join the network and are provided with T&S services by T&SCo, then the T&S fees charged to existing customers will be reduced to spread the costs of the T&S assets proportionately across all CO₂ Capturers.

When capture projects stop using T&SCo’s assets—the T&S fees to the remaining customers will be adjusted accordingly to allow T&SCo to recover all its costs.

T&S fees charged will spread the costs of the T&S assets equitably across all CO₂ Capturers.

However, if new CO₂ Capturers join the network, their “capacity reservation” fee may be set to zero if they do not receive a fixed payment from their “Funders of CO₂ Capturers”.

13) TIMING OF PLANNED MAINTENANCE

All capture plants and T&S assets in a cluster will agree a rolling 5-year forward programme of planned major maintenance. All asset operators will cooperate to ensure that as far as possible planned maintenance occurs simultaneously across all assets in the cluster.

A pre-agreed contractual regime will allow for an agreed duration of shutdown for planned maintenance without penalty across the cluster.

(Unplanned maintenance will be covered by the temporary “Cross-chain failure” provisions below.)

14) CROSS CHAIN FAILURE - T&S ASSETS NOT AVAILABLE - TEMPORARILY OR PERMANENTLY

If, after the Contract Start Date for the first “T&S Services Contract”, and for whatever reason, T&S assets are not available to accept CO₂ delivered to the point of receipt, the following will apply.

This includes circumstances where:

- T&S assets are temporarily completely unavailable;
- T&S assets are available but are capacity constrained for any reason and cannot accept the full contracted quantity of CO₂ being delivered.
CHAPTER 11: Industrial Production with CO₂ Capture – Business Model

IP&CCo will be entitled to continue to run, either wholly or partly unabated. They will continue to receive a portion of their revenue support from HMG. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO₂ for transport and storage. The definition of this level of support will be set case by case.

It may be necessary to provide IP&CCo with “free allowances” for CO₂ emissions as well as continued, albeit perhaps reduced, revenue support to enable them to continue to operate unabated.

\[ Risk - see: HMG Risk - Cross Chain Failure - T&S Assets Not Available - Temporarily or Permanently \]

15) CROSS CHAIN FAILURE - DEMAND RISK - CAPTURE PLANT DOES NOT DELIVER CO₂ TO T&SCO

IP&CCo is not obliged to operate or deliver CO₂ to T&SCO.

IP&CCo will not receive the variable element of revenue support when they are not operating.

However, regardless of the volume of CO₂ delivered, HMG will still be required to pay the “capacity reservation” portion of the T&S fees to IP&CCo, and IP&CCo will still be obliged to pass these fees through directly to T&SCO.

This obligation should start from the Contract Start Date of the “T&S Services Contract”.

\[ Risk - see: HMG Risk - Cross Chain Failure - Capture plant does not deliver CO₂ to T&SCO \]

16) CROSS CHAIN FAILURE - PRE-COMMISSIONING STRANDED ASSET RISK - NO T&S

The likelihood that IP&CCo builds a CO₂ capture plant and that no prospect then appears of a CO₂ T&S system being built to store the captured CO₂ is extremely low, as a contract for grant funding of a capture plant will be contingent on the T&S system reaching a particular threshold, such as FID.

However, in that event HMG ill need to act as “insurer of last resort”. The CO₂ capture plant will, if possible, be converted to some other use to mitigate the losses incurred. Thereafter, HMG will cover any remaining IP&CCo financial exposure.

\[ Risk - see: HMG Risk - Pre-Commissioning Stranded Asset Risk - no T&S System \]

PART 2 – REVENUE SUPPORT

As an industrial producer with a CO₂ capture project, IP&CCo will receive an “Industrial CCUS Contract”. This will be based on the following principles:

- co-financing between plant owners and HMG to build a CO₂ capture plant;
- short payback of IP&CCo’s investment with a project-specific rate of return reflecting the risk taken by IP&CCo;
- a “contract for difference” structure for paying the difference between sales of surplus ETS allowances and the fixed and variable operating costs of the CO₂ capture plant.

Early project contracts will be secured through bilateral negotiations between the industrial producer and HMG.

\[ 17) SOURCE OF REVENUE SUPPORT - INDUSTRIAL CCUS. \]

Revenue support for Industrial CO₂ capture will be funded by HMG, which is itself funded by UK tax revenue.

This would cover both ongoing revenue support and also grant funding.
18) **MECHANISM FOR DELIVERING REVENUE SUPPORT.**

The “Hybrid Grant plus CO₂ CfD” contract between the industrial producer and HMG will have three elements as follows:

**Capital Cost Recovery**

The capital cost recovery element of the “Industrial CCUS Contract” will allow IP&CCo to earn a return on their capital investment.

- Plant owners will invest in plant to capture CO₂, and HMG will support this with a grant towards part of the capital cost. A grant of at least 50% of the capex involved for the first capture sources in a cluster should be considered.
- Once the plant is operational HMG will make a periodic fixed payment to the industrial producer to cover repayment of the capital invested, plus an agreed return on the capital investment. This would be set at a level which takes into account that the capital is not at risk, and that capital invested is repaid over a relatively short payback period of 3-5 years for retrofit plant, and potentially longer for new plant. It would stop once the capital has been repaid with the agreed rate of return.
- Project developers will be expected to explain their requested rates of return through an “open book” approach with HMG, including comparing their proposals to their other project opportunities.

**Operating Cost Recovery**

There will also be a further “contract for difference” periodic payment between IP&CCo and HMG. IP&CCo will pay, or be paid if the amount is negative, the difference between the income generated from sale of surplus free ETS allowances associated with the industrial production, and the costs of operation (fixed and variable) of the CO₂ capture plant. This will be calculated in one of two ways:

- The difference between the actual sales proceeds from the sale of surplus ETS allowances, and the actual fixed and variable operating costs of the capture plant, using “open book” principles. Contracts will be based on absolute costs rather than unit costs.
- The difference between the CO₂ ETS income and an agreed “strike price” (index linked as required) which will be agreed in advance on a per-project basis, based on forecasts of fixed and variable operating costs and capture volumes. Costs will be normalized on a unit basis (i.e. on a £/t CO₂ contract basis). Due to technological or operational uncertainty on early projects this strike price will need to ‘price-in’ a wide range of operational risks but could, over time, be progressively reduced as operational certainty increased leading to an enduring contract basis. Reopeners could be considered to ensure fair but not excessive returns.

In order to incentivise operating cost reduction, if EU ETS income exceeds costs the excess will be shared between IP&CCo and HMG, perhaps in proportion to the percentage of the capex funded by the HMG grant.

**T&S Capacity Reservation Fee**

Finally, HMG will make periodic payments to IP&CCo to cover the agreed T&S capacity reservation fees. These would then be paid directly by IP&CCo to T&SCo.

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53 Surplus allowances means the difference between the allocation of free allowances and the allowances needed to meet ETS compliance after CCUS has been fitted.
19) “INDUSTRIAL CCUS CONTRACT” DURATION.

The ‘Industrial CCUS Contract’ is split into two elements, with contract durations as follows:

- **Capital Cost Recovery**
  - For retrofitting capture plant, the contract would be split over two periods. The repayment of capital invested in capture plant would be accelerated and repaid with return over an agreed, relatively short payback period of 3-5 years. Thereafter, the contract would continue to operate, with a lower level of revenue support sufficient to cover the capture plant operating costs.
  - For new industrial plant with carbon capture, capital investment could be repaid over a longer period, potentially up to the full expected economic lifetime of the plant. (Note: a relatively short payback time does have the advantage of lowering the lifetime costs of Industrial CCS).

- **Operating Cost Recovery**
  - The Operating Cost recovery contract would run for the duration of the operating life of the plant. If the ‘actual cost’ CfD option is utilised, no contract revision would be required, as payments of actual costs less actual income from sale of surplus EU-ETS (or UK equivalent) allowances would be made. If the ‘strike price’ CfD option is utilised, periodic price re-setting will be required. This could be aligned with EU-ETS phasing.

PART 3 – OTHER ELEMENTS

20) BANKRUPTCY

[The order of claims post-bankruptcy is to be defined.]

21) CHANGE IN LAW, CHANGE IN POLICY.

If applicable, provisions covering Change in Law will be defined.

If applicable, provisions covering Change in Policy will be defined. These will provide “grandfathering” protections to IP&CCo.

*Residual Risk - see: HMG Risk - Change in Law, Change in Policy.*

22) “STATE AID”

Some form of “State Aid” approval may be needed for the project.

“State Aid” approval may not be received. HMG is not prepared to carry cost or other liability if this happens.

All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

*Residual Risk - see: IP&CCo Risk - “State Aid” Approval*
*Residual Risk - see: HMG Risk - “State Aid” Approvals*
CHAPTER 12 - INDUSTRIAL PRODUCTION WITH CO₂ CAPTURE - RESIDUAL RISKS

It is usual, and therefore assumed, that all key stakeholders in a major project will run effective risk management processes that manage and mitigate the “Business as Usual” risks they face arising through their involvement in the project.

However, once these “Business as Usual” risks have been mitigated using “Business as Usual” processes, a number of key “Residual Risks” will remain to be managed and mitigated. The key Residual Risks for key stakeholders in the development of early projects in a new CCUS cluster are listed here. (“Business as Usual” risks are not listed - that is for stakeholders to do themselves.)

The effect of this Business Model is to allocate those Residual Risks to one or more key stakeholders. This section shows how the Business Model drives the allocation of these Residual Risks. They are categorized into three main sections - HMG Risks; “Tax Revenue (via HMG)” risks; IP&CCo Equity Shareholder Risks. A high-level listing of these risks is shown in the following table.

Note: The distinction between HMG Risks and “Tax Revenue (via) HMG” Risks is potentially confusing. Both are ultimately borne by taxpayers. But the role of HMG in each case is different:
- The HMG risks are similar to those borne by HMG for Electricity Generation;
- The “Tax Revenue (via HMG)” Risks are similar to those borne by the LCCC for Electricity Generation (i.e. acting as “Funders of CO₂ Capturers”).

Finally, there are a number of ways in which these Residual Risks can be mitigated by those who hold them. These are also shown in this section.

INDUSTRIAL PRODUCTION BUSINESS MODEL
RESIDUAL RISK ALLOCATION

<table>
<thead>
<tr>
<th>Risk sits with:</th>
<th>Equity Funders</th>
<th>“Tax Revenue (via HMG)”</th>
<th>HMG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction - Costs and Timetable</td>
<td>✔️</td>
<td>✔️</td>
<td></td>
</tr>
<tr>
<td>IP&amp;CCo Plant Performance and Costs</td>
<td>✔️</td>
<td>✔️</td>
<td></td>
</tr>
<tr>
<td>CO₂ delivered off-specification</td>
<td>✔️</td>
<td></td>
<td></td>
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<tr>
<td>Uncertain Calls on Cash</td>
<td>✔️</td>
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<tr>
<td>Cross Chain Failure - T&amp;S Assets Not Available - Temporarily or Permanently</td>
<td>✔️</td>
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<tr>
<td>Cross Chain Risk - Capture Plant Does Not Deliver CO₂ to T&amp;SCo</td>
<td></td>
<td>✔️</td>
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<tr>
<td>Loss of Development Funding</td>
<td>✔️</td>
<td>✔️</td>
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<tr>
<td>Project fails post-FeED - Loss of Development Funding</td>
<td>✔️</td>
<td>✔️</td>
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<tr>
<td>State Aid</td>
<td>✔️</td>
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<tr>
<td>Pre-Commissioning Stranded Asset Risk - No T&amp;S System</td>
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<td>Change in Law, Change in Policy</td>
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</table>
“Irreducible” Residual Risks to be facilitated by HMG

This section describes those risks where HMG acts in the capacity of facilitating those “irreducible risks” that industry cannot properly price, and therefore cannot accept at reasonable cost.

1)  **HMG RISK - PRE-COMMISSIONING STRANDED ASSET RISK - NO T&S SYSTEM**

   **Residual Risk:**
   - It is conceivable - though extremely unlikely - that IP&CCo builds a CO₂ capture plant and that no prospect then appears of a CO₂ T&S system being built to store the captured CO₂.

   **Residual Risk Allocation:**
   - In the event of no T&S system ever being commissioned and operational, it is likely that IP&CCo’s plant would be reconfigured for some other purpose or owner. Thereafter, HMG would cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

   **Risk Mitigation:**
   - HMG will seek to ensure that:
     - The process of co-ordination, and the contractual commitments and penalties between IP&CCo and T&SCo, should ensure that the two projects take FID at the same time; and commit to construction and commissioning according to synchronized timetables.
     - The project developers of these projects have the capability and commitment to deliver such projects.

2)  **HMG RISK - HMG LOSS OF DEVELOPMENT FUNDING**

   **Residual Risk - Loss of the HMG share development funding**
   - If the project does not proceed, HMG and developers will each lose their share of the development funding provided.

   **Residual Risk Allocation:**
   - This risk is shared between the project developers and HMG.

   **Residual Risk Mitigation:**
   - Development funding expenditure by the developers of IP&CCo provides tangible evidence to HMG that the developers intend to secure investment in IP&CCo assets.

3)  **HMG RISK - CHANGE IN LAW, CHANGE IN POLICY**

   **Residual Risk - Political Risk (2)**
   - There could be a risk that a change in HMG policy, and hence UK law, could jeopardize the interests of IP&CCo’s shareholders.

   **Residual Risk Allocation:**
   - This risk will be transferred to HMG through a suitable “change in law” provision in contracts held by IP&CCo.
HMG is well placed to decide how best to deal with such issues should they arise.

4) HMG RISK - STATE AID RISK

Residual Risk - “State Aid” Approval:
- “State Aid” approval may not be received. HMG is not prepared to carry cost or other liability if this happens.

Residual Risk Allocation:
- All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

Residual Risk Mitigation
- HMG will seek to obtain “State Aid” clearance before excessive time and money has been spent on developing the project.
CHAPTER 12: Industrial Production with CO\textsubscript{2} Capture – Residual Risks

Residual Risks underwritten by Tax Revenue (via HMG)

This section describes those risks that will be covered by tax revenue, where HMG is acting as the “Funder of the CO\textsubscript{2} Capturers”.

5) TAX REVENUE RISK - CROSS CHAIN FAILURE - T&S ASSETS NOT AVAILABLE - TEMPORARILY OR PERMANENTLY

Residual Risk - Cross Chain Risk T&S Assets NOT Available

- T&SCo assets not available to accept and store CO\textsubscript{2}

Residual Risk Allocation:

- HMG will be obliged to pay a portion of the normal revenue support to IP&CCo. This will be set to hold IP&CCo economically neutral versus the situation where they run abated and are able to deliver CO\textsubscript{2} for transport and storage.

Residual Risk Mitigation:

- The risk of T&S not being available cannot be entirely avoided. It can and must be mitigated by:
  
  a. Good construction management processes and contracts;
  
  b. Good operational performance management processes.

- T&SCo can be incentivized to mitigate this risk through the incentive and penalty regime in the RAB structure.

- HMG can minimise this risk through the vetting and acceptance (or otherwise) of the T&SCo shareholders, developer and operator by ensuring they have the capability to minimize these risks; and through the financier due diligence that will be carried out on these issues.

6) TAX REVENUE RISK - CROSS CHAIN FAILURE - CAPTURE PLANT DOES NOT DELIVER CO\textsubscript{2} TO T&SCo.

Residual Risk - T&S Demand Risk:

- IP&CCo may choose to, or may have to, deliver less CO\textsubscript{2} than contracted because of operational problems, variability in demand for their products, and change in their production processes. IP&CCo is not obliged to operate or deliver CO\textsubscript{2} to T&SCo. IP&CCo will not receive revenue support when they are not operating.

- However, regardless of the volume of CO\textsubscript{2} delivered, the HMG will still be required to pay the “capacity reservation” portion of the T&S fees to IP&CCo, and IP&CCo will still be obliged to pass these fees through directly to T&SCo. This obligation should start from the Contract Start Date of the “T&S Services Contract”.

Residual Risk Allocation:

- After the Contract Start date of the T&S Services Contract HMG carries this risk. It is obliged to pay the T&SCo “capacity reservation” fee, irrespective of the volume of CO\textsubscript{2} delivered.

Residual Risk Mitigation:

- It is in the hands of the capture plants shareholders and operators to mitigate this risk through good project development, construction project management, and plant operational management.
• This risk can be minimized by HMG through vetting T&SCo shareholders, developers and operators, ensuring they have the capability to minimize these risks.

7) **TAX REVENUE RISKS - CONSTRUCTION COSTS AND TIMETABLE**

**Residual Risk - IP&CCo Construction Costs and Timetable Risk.**

- Given the nature of new CO₂ capture technologies, some uncertainty in the cost and schedule for construction and commissioning of the CO₂ capture assets is unavoidable.

**Residual Risk Allocation:**

- The risk of uncertain construction costs will be shared between HMG and IP&CCo.
- IP&CCo will not make a return on any capital cost overruns against target cost, although the actual capital expenditure itself will be recovered.
- A gain share mechanism may be put in place to incentivise cost efficiency, such that any savings below target cost are shared between IP&CCo and HMG.

**Residual Risk Mitigation:**

- IP&CCo will hold significant contingency in the construction project (both cost and schedule) to cater for the remaining uncertainties and a prudent capital structure that allows raising further funds to meet unforeseen cost escalations;
- IP&CCo will include contract provisions (e.g. fixed price contract elements, gain/ pain share arrangements, performance guarantees and other mitigation provisions) to minimize this risk to the degree that this is economical. It should be noted that in many cases it is better to cover this risk through holding contingencies at the project level rather than attempting to pass these risks on to contractors, who may then hold larger contingencies at the contract and sub-contract level.

8) **TAX REVENUE RISK - PLANT PERFORMANCE AND COSTS**

**Residual Risk - IP&CCo Performance Risk.**

- Given the nature of new CO₂ capture technologies, some initial uncertainty in the performance the capture plant is unavoidable.

**Residual Risk Allocation:**

- The risk of uncertain plant performance and costs will be shared between HMG and IP&CCo.
- In order to incentivise operating cost reduction, if EU ETS income exceeds costs the excess will be shared between IP&CCo and HMG, perhaps in proportion to the percentage of the capex funded by the HMG grant.
- If the “contract for difference” calculation is based on actual costs, then the exposure to uncertain operating costs lies more with HMG. If a unit price system is used, then the exposure lies more with IP&CCo.

**Residual Risk Mitigation:**

- IP&CCo will obtain performance guarantees from the technology providers and EPC contractors to mitigate against performance risks, provided it is deemed economic to do so.
- IP&CCo will secure and hold significant contingency funds to cater for significant performance problems.
Residual Risks carried by Equity Shareholders of IP&CCo

This section describes those risks that will be covered by equity shareholders in IP&CCo.

9) **EQUITY SHAREHOLDER RISK - PROJECT FAILS POST-FEED - LOSS OF DEVELOPMENT FUNDING**

*Residual Risk - Loss of the HMG share development funding*

- If the project does not proceed, HMG and developers will each lose their share of the development funding provided.

*Residual Risk Allocation:*

- This risk is shared between the project developers and HMG.

*Residual Risk Mitigation:*

- Development funding expenditure by the developers of IP&CCo provides tangible evidence to HMG that the developers intend to secure investment in IP&CCo assets.

10) **EQUITY SHAREHOLDER RISK - UNCERTAIN CALLS ON CASH**

*Residual Risk: Uncertain calls on cash.*

- For any new CO₂ capture plant, the costs that may be incurred by IP&CCo during construction, commissioning and early years of operation will be uncertain and may be difficult to predict. Until the plant has been operating for some time there will be some unavoidable uncertainty around its performance and costs.

*Residual Risk Allocation:*

- The risk of uncertain calls on cash sits with equity shareholders to raise sufficient capital.

*Risk Mitigation:*

- IP&CCo will maintain sufficient available contingency funds to cover significant unexpected problems;
- IP&CCo will maintain the means of accessing further funding to rebuild contingency reserves if they have to be drawn down at any stage.
- IP&CCo need to ensure that debt servicing obligations are sufficiently flexible to weather a considerable period of uncertain performance during commissioning and early years of operation.

11) **EQUITY SHAREHOLDER RISKS - CONSTRUCTION COSTS AND TIMETABLE**

*Residual Risk - IP&CCo Construction Costs and Timetable Risk.*

- Given the nature of new CO₂ capture technologies, some uncertainty in the cost and schedule for construction and commissioning of the CO₂ capture assets is unavoidable.

*Residual Risk Allocation:*

- The risk of uncertain construction costs will be shared between HMG and IP&CCo.
- IP&CCo will not make a return on any capital cost overruns against target cost, although the actual capital expenditure itself will be recovered.
- A gain share mechanism may be put in place to incentivise cost efficiency, such that any savings below target cost are shared between IP&CCo and HMG.
CHAPTER 12: Industrial Production with CO₂ Capture – Residual Risks

Residual Risk Mitigation:

- **IP&CCo** will hold significant contingency in the construction project (both cost and schedule) to cater for the remaining uncertainties and a prudent capital structure that allows raising further funds to meet unforeseen cost escalations;

- **IP&CCo** will include contract provisions (e.g. fixed price contract elements, gain/ pain share arrangements, performance guarantees and other mitigation provisions) to minimize this risk to the degree that this is economical. It should be noted that in many cases it is better to cover this risk through holding contingencies at the project level rather than attempting to pass these risks on to contractors, who may then hold larger contingencies at the contract and sub-contract level.

12) **EQUITY SHAREHOLDER RISK - PLANT PERFORMANCE AND COSTS**

Residual Risk - **IP&CCo Performance Risk**.

- Given the nature of new CO₂ capture technologies, some initial uncertainty in the performance of the capture plant is unavoidable.

Residual Risk Allocation:

- The risk of uncertain plant performance and costs will be shared between HMG and IP&CCo.

- In order to incentivise operating cost reduction, if EU ETS income exceeds costs the excess will be shared between IP&CCo and HMG, perhaps in proportion to the percentage of the capex funded by the HMG grant.

- If the “contract for difference” calculation is based on actual costs, then the exposure to uncertain operating costs lies more with HMG. If a unit price system is used, then the exposure lies more with IP&CCo.

Residual Risk Mitigation:

- **IP&CCo** will obtain performance guarantees from the technology providers and EPC contractors to mitigate against performance risks, provided it is deemed economic to do so.

- **IP&CCo** will secure and hold significant contingency funds to cater for significant performance problems.

13) **EQUITY SHAREHOLDER RISK - STATE AID RISK**

Residual Risk - “State Aid” Approval:

- “State Aid” approval may not be received. HMG is not prepared to carry cost or other liability if this happens.

Residual Risk Allocation:

- All parties accept that they will not have a claim against HMG if “State Aid” approval is not received.

Residual Risk Mitigation

- HMG will seek to obtain “State Aid” clearance before excessive time and money has been spent on developing the project.
CHAPTER 13 - HYDROGEN PRODUCTION WITH CO2 CAPTURE – OPTIONS PAPERS

Summary

The Terms of Reference of the CAG envisaged that hydrogen production with CCUS and industrial production with CCUS would be considered together, and would be treated in the same way. It quickly became apparent that the hydrogen market and the economic and commercial requirements of hydrogen production with CCUS will differ significantly from those for industrial production. The two streams of work were therefore separated.

This Chapter therefore describes the options identified for business models for hydrogen production, and these can be considered in the HMG consultation. However, the work of the CAG on hydrogen production has not progressed sufficiently to allow the identification and development of specific business models in detail, and these have therefore not been developed for this report.

It is proposed that further work including the detailed development of the hydrogen model be carried out in the future, informed by the results of the HMG consultation.

Opportunity

- The CAG agrees with the CCC that low carbon hydrogen has a key role to play in decarbonising the UK’s energy infrastructure.
- Bulk production of low-carbon hydrogen from natural gas (or other hydrocarbons) with CO₂ capture provides a wide range of opportunities to reduce CO₂ emissions.
- Around half of UK industrial emissions come from combustion of fossil fuel, mainly natural gas and process gases. Substitution by low-carbon hydrogen may represent a practical option to reduce these emissions across all industrial sectors.
- Other applications may include power generation, both small scale to “private wire” industrial installations, and large scale for supply to the grid transmission system; and supply of hydrogen in bulk for transport use (trains, HGVs, buses and some ships).
- Natural gas is widely used in domestic and commercial heating. Hydrogen use in existing and new gas networks provides a potential means to reduce these emissions.
- Initial deployments are likely to be for supply to industrial customers, power production, and injection in the gas network, through new pipeline distribution systems; with the addition of hydrogen storage as hydrogen networks expand.
- The first hydrogen projects may act as anchor projects for the creation of CCUS infrastructure as well as for hydrogen distribution infrastructure. Producing hydrogen from natural gas with CCUS (“blue hydrogen”) may establish a robust hydrogen infrastructure that “green hydrogen” (produced from electrolysis with renewable power) may then use.

Market

- The nature and possible evolution of any future hydrogen markets needs to be established so that support mechanisms can be defined.
- The CAG recommends consultation on the possible options for the development of a market or markets for hydrogen.

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54 Net Zero - The UK's contribution to stopping global warming, CCC May 2019 pp 137
Support for Production of Hydrogen

- Hydrogen production assets could be built, owned and financed by the private sector. A low-carbon hydrogen industry could develop without commercial regulation; or as regulated industry operating in regulated markets, perhaps using RAB structures.
- Revenue support for low-carbon hydrogen production is best provided by the beneficiaries of the end-use of the energy delivered using low-carbon hydrogen. These are primarily users of gas (domestic, commercial, industrial and electricity producers). The costs could be socialised across these gas users generally, or more specifically funded by electricity consumers for those volumes used to generate electricity, for example tax revenue where it is used in industry, and gas consumers for the remaining volumes which would be used to generate heat.
- Potential mechanisms for delivering funding for low-carbon hydrogen production include: funding revenue collection through a RAB structure; premium payments from specific users; a low-carbon Hydrogen CfD; an Obligations-based system; an incentive scheme like the RHI scheme; or HMG grants.
- The CAG support consultation on the possible commercial structures and funding sources that may be used to support hydrogen production with CCUS.

Recommendations

- Given its future importance in decarbonising the UK energy system, the CAG recommends that low carbon hydrogen is part of the low carbon CCUS cluster developments during the 2020s.
- The CAG recommends that HMG consults urgently on options for developing a low carbon hydrogen market or markets.
- The consultation should seek views on possible market structures, commercial structures, financing options and funding sources to support low-carbon hydrogen production with CCUS.
- The consultation should consider whether the additional cost of low carbon hydrogen production, storage and distribution should be borne by electricity consumers, energy (gas) consumers or tax revenue, depending on the end-use of the energy delivered by low-carbon hydrogen.
- The consultation should consider potential options for mechanism to provide revenue support. The CAG has identified a number of possible options.
- The CAG recommends that provision for the sources of funding and funding mechanisms for low-carbon hydrogen is included in the forthcoming White Paper.
Options Paper 13A: The Uses and Sources of Hydrogen (Now and Future)

1) BACKGROUND

Hydrogen is a vector which delivers energy without carrying carbon and therefore with no carbon dioxide emissions at point of use.

Hydrogen is not itself an energy source, and must be produced from other sources, such as conversion of low carbon electricity (eg wind generated electricity used to split water via electrolysis) or conversion of hydrocarbon sources (eg reforming of natural gas, or potentially conversion of renewable biomass). Where the source is from fossil resources, then no carbon benefit is conferred unless the carbon is captured such that CO₂ is not released to the atmosphere (CCUS). Where the source is biogenic, then conversion to hydrogen with CCUS is also a mechanism to remove carbon from the biosphere, known as BECCS; a form of geoengineering.

Conversion of fossil resources to hydrogen with CCUS is a practical means of bulk production. In the context of CCUS, hydrogen as a vector allows the centralised capture of CO₂ for sequestration via transport and storage (T&S) infrastructure, whilst providing distributed low carbon energy to multiple users. Hydrogen can be used to supply many parts of the energy system, often advantageously, for example: high temperature heat for industrial applications; rapid fill and range benefits for mobility; as well as the potential for low cost diurnal or seasonal energy storage. Hydrogen is recognised as playing an important role in industrial transformation and delivering clean growth, and therefore has a role in the UK’s industrial strategy. Hydrogen should be pursued where it offers the potential for economic advantages compared with other low carbon solutions, or where it unlocks benefits that cannot readily be delivered through alternatives.

The Committee on Climate Change has recognised the important role that hydrogen plays in decarbonising the energy system in its Net Zero report. For the UK to deliver a net zero carbon energy system, it has explicitly identified the requirement for 225TWh of low carbon hydrogen production with CCUS. The CCC also identifies 148TWh electricty from ‘gas with CCS plants.’ This gas generation could potentially be gas fired generation with post-combustion capture, or pre-combustion capture, via hydrogen. The supporting work by Imperial indicates that their modelling preferentially selects the hydrogen route over post combustion capture. This equates to a further ~300TWh of hydrogen production demand. Similarly, the CCC assumes that there will be a significant tranche of BECCS but is not explicit about the vector produced. The supporting work by Imperial indicates that their model chose to use BECCS to produce hydrogen in all cases. The CCC identifies 200TWh of primary biomass, which at the 69% conversion efficiency identified the Imperial report suggests 138TWh of bio-hydrogen. In aggregate this is a full potential of over 650TWh of hydrogen. The CCC concludes that:

‘In order to develop the hydrogen option, which is vital in our scenarios, significant volumes of low-carbon hydrogen must be produced at one or more CCS clusters by 2030, for use in industry and in applications that would not require initially major infrastructure changes (e.g. power generation, injection into the gas network and depot-based transport).’

Hydrogen is recognised as a key element in the development of a CCUS market, forming an element of all the publicly known emerging UK CCUS clusters and therefore establishing the business models

55 “A significant low-carbon hydrogen economy will be needed to help tackle the challenges of industry, peak power, peak heating, heavy goods vehicles, and shipping emissions”
“Net Zero - The UK’s contribution to stopping global warming”. CCC May 2019 pp 137
56 Ibid pp 150
57 Analysis of Alternative UK Heat Decarbonisation Pathways, Imperial College August 2018, pp18
58 Ibid pp14, 87
to support its deployment will form an important part of the CCUS Advisory Group scope at the next stage.

2) HYDROGEN USES

Hydrogen as a low carbon vector has the potential to enable carbon reductions for industrials, dispatchable power, injection into the gas network and mobility. The following provides a brief overview of each of these sectors, including level of readiness and timelines as well as potential capacity. For reference, it also includes an overview of the current UK hydrogen market.

Industrial

This is a key hydrogen market identified by the Committee on Climate Change\(^{59}\). This is line with a growing recognition of the importance of this sector by BEIS as well as the wider low carbon industry. For many applications there are limited alternative choices to deliver low carbon solutions, particularly high heat industrial requirements. Manufacturing industry is exposed to increasing carbon prices and decreasing protections from ‘free allowances’ threatening the continued viability of industrials.

The work by Imperial\(^{60}\) supporting the CCC’s Net Zero report indicates industrial fuel switching to hydrogen of up to 135TWh. Work undertaken for BEIS\(^{61}\) indicates a potential for just under 100TWh of industrial fuel switching to hydrogen. Work commissioned by BEIS under the Hy4Heat programme, WP6, and shared as an industrial workshop\(^{62}\), identifies 115TWh of gas consumption by industry on both the transmission and distribution networks.

In terms of timescales to deployment, the Hy4Heat programme indicates that many applications will be commercially ready for deployment during the early 2020s, with boilers, indirect users, heaters, kilns and many furnaces all able to be deployed 2023-2025. By-product hydrogen is already used as a substitute fuel for firing boilers in a number of plants. The third phase of the BEIS Fuel Switching programme\(^{63}\) sets out to provide the necessary demonstration across a range of applications by March 2021 in order expedite deployment.

Dispatchable Power

The UK is making good progress in decarbonising its electricity generation. This is in part due to closure of coal stations, but a significant contribution is from increased capacity of wind and solar. This growth in intermittent generation has led to a change in modus operandi of fossil fuel generation which must increasingly operate as mid-merit or peaking capacity. Dispatchable power provides generation during periods of low wind/solar output and can assist in maintaining frequency stability whilst having the ability to reduce output to avoid curtailment of renewables at times of high wind or insolation.

Analysis of the UK’s fossil generation in 2018 shows that on average this is now already operating at around 45% load factor. Whilst electricity storage has a part to play, it is unlikely to provide the cost-effective volumes required at a network level for the foreseeable future.

Fossil generation provides the electricity network functionality required, but it is not sustainable in delivering a low carbon system, and therefore needs to be decarbonised, ie through CCUS. The CCC identifies this, with 55 million tonnes per annum of CO\(_2\) sequestration from 148TWh dispatchable generation. This type of duty requires that power plant is able to operate flexibly from technical, efficiency and economic perspectives with both low load factors and appropriate ramp rates, Hydrogen fired generation when combined with hydrogen storage allows hydrogen production and CO\(_2\) capture to operate a high load factors, with hydrogen-fuelled electricity generation plant

\(^{59}\) Hydrogen in a low-carbon economy, CCC November 2018

\(^{60}\) Analysis of Alternative UK Heat Decarbonisation Pathways, Imperial College August 2018, pp53

\(^{61}\) Industrial Fuel Switching Market Engagement Study, Element Energy December 2018, pp6


\(^{63}\) https://www.gov.uk/guidance/funding-for-low-carbon-industry
operating flexibly. The CCC requirement for 148TWh dispatchable generation from gas would equate to around 300TWh of hydrogen.

In terms of technology readiness, hydrogen fuelled gas turbines are currently available commercially. Both the Teesside Low Carbon and Caledonia Clean Energy projects in the DECC Commercialisation programme in 2011 were predicated on hydrogen fuelled CCGTs, for which OEM solutions were provided on commercial terms with financeable performance guarantees. More recently, the Nuon Magnum project in Holland is currently part of a programme to convert one of the units to hydrogen production by 2023. The work by Jacobs and Cardiff University supporting Element Energy in the Hy4Heat programme focused on industrial scale CHP facilities also supports the feasibility of hydrogen operation at smaller scales. Gas turbine manufacturers recognise the growing market for hydrogen enabled gas turbines, with commitments by European Manufacturers to provide such machines.

**Mobility (Transport)**

The transport sector is particularly challenging to decarbonise. The incumbent high carbon solutions benefit from the energy density benefits of liquid hydrocarbon fuels and therefore range, ability to refuel rapidly and over a century of technology and infrastructure development.

Electrification is increasingly seen to be the solution for passenger vehicles, particularly since it also confers significant local quality benefits. This is likely to be the case, although will require extensive development of charging point infrastructure, electricity network and generation capacity as well as battery developments to deliver range, charging rate and ensure availability of materials of construction required for extensive displacement of petrol and diesel vehicles. Over time, hydrogen fuel cell passenger vehicles could have a part to play in this sector, particularly given international developments of fuel cell vehicles.

However, for heavy transport applications, it is recognised that alternative solutions are likely to be necessary to achieve the volumetric/gravimetric energy storage capacity and fill rates that the market requires. The CCC’s Net Zero report identifies that hydrogen is particularly important for the HGV sector, as well as for shipping. DfT data indicates that HGVs currently consume around 80TWh per annum. There are also opportunities in the train sector. Alstom has already deployed its Coradia iLint hydrogen hybrid trains in Germany and is currently working with Eversholt Rail to deploy its Breeze trains in the UK.

**Gas networks**

Over 23.5 million homes (83%) are connected to the gas network and are heated by natural gas fuelled central heating. Gas boilers are low cost and particularly well suited to the fabric of the UK housing stock as they deliver high heat rapidly and efficiently for the periods of time that users require it. An objective to reduce dependence on gas heating was announced by the Chancellor in March 2019, by proposing that new build properties are not heated by natural gas. Even if this were to be enacted, it is projected that 80% of the homes in 2050 have already been built with their inherent fabric of construction. The existing gas network provides very high levels of resilience, capacity and flexibility (meeting 20-year 6 minute peak as well as summer lows).

It is widely recognised that an alternative to gas-based heating is electrification through heat pumps. Providing that the electricity supplied is low carbon, this provides a potential low carbon solution and

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66 [Net Zero - The UK’s contribution to stopping global warming](https://www.ukenvironmentalpolicy.com/), CCC May 2019 pp162
67 The age of the UK housing stock, combined with a relatively benign climate, means that dwellings are typically not well insulated. Whilst this is a vital area to address, it has proven challenging to deliver the necessary improvements to this aging housing stock from both technical and behavioural perspectives.
68 [Institution of Engineering and Technology (IET) and Nottingham Trent University](https://www.iet.org/), October 2018
relatively high penetration of heat pumps has been assumed by the CCC, National Grid’s Future Energy Scenarios and others.

To deliver this requires that heat pumps are able to provide the same level of comfort required by customers within their existing homes. They need to deliver heat effectively and efficiently in different operating modes (lower heat intensity over longer periods, rather than high heat for shorter periods). Widespread roll out requires customers to make disruptive and high capital cost changes to their heating systems and relies on the electricity network being able to deliver resiliently the peak capacity required (low carbon), in parallel with the demands of an increasingly electrified passenger vehicle transport market. Currently heat pumps are well supported under the RHI with over £100/MWh of support for air source heat pumps and £200/MWh for grounds source heat pumps (equating to £500-£1000/te CO\textsubscript{2} depending on electricity carbon intensities). Despite this support, uptake has been relatively low (around 45,000 installations since April 2014). In recognition of these challenges, the CCC has identified hybrid gas-heat pumps as a potential solution. Analysis and experience of hybrid heat pumps is developing. In reality both gas and electricity are likely to play a role in UK domestic heating in the future.

For gas to play a role, the carbon intensity must be reduced. This can be achieved either by replacing the fossil carbon molecule with renewable biogenic carbon, biomethane, or by removing the carbon molecule entirely ie using hydrogen. Over 80 biomethane plants have been constructed in the UK over the last 5 years, with BioSNG offering the potential to increase volumes significantly\textsuperscript{69}.

Hydrogen has the potential to make a major contribution provided it can be delivered cost effectively to each user and modifications to or replacement gas appliances if necessary are available at reasonable cost. Two strategies, which are complementary rather than alternatives, are being progressed to make maximum use of the existing gas network: blending of hydrogen into the gas at a level which can be safely transported in the existing gas networks and requires no changes to existing appliances, and full conversion of selected networks to 100% hydrogen - facilitated by the Gas Distribution Network operators’ programme of replacing 91,000km of old iron mains.

Blending hydrogen into the gas network reduces the carbon intensity of gas without requiring the users to make disruptive changes. In parts of continental Europe up to 12% hydrogen is permissible but, in the UK, the current allowable level is 0.1%. Work is being undertaken internationally (for Example Engie’s project at Dunkirk\textsuperscript{70}. In the UK, the HyDeploy project\textsuperscript{71} is demonstrating that levels of 20% by volume (7% by energy) can be achieved in the UK gas distribution network without requiring changes to the network or appliances. If rolled out across the UK gas distribution network this equates to 29TWh of hydrogen. Having successfully established the safety case, the HyDeploy programme will be injecting hydrogen in a closed private network at Keele University in 2019, with a managed programme of public trials designed to allow widespread deployment from 2023, akin to biomethane injection today. National Grid Transmission is also commencing work on assessing the feasibility of blending into the transmission network\textsuperscript{72}. Given the wider users, duty of the network and materials of construction, this is currently expected to be at 2-3% by volume. Blending could assist in establishing bulk hydrogen production with CCUS, developing hydrogen distribution pipeline infrastructure, building associated supply chains, and addressing regulatory hurdles and importantly consumer perceptions of hydrogen.

In light of the merits of using a gas-based vector for consumer heating, including the opportunity provided by its mature gas network, consideration is being given to the conversion of the gas network to full hydrogen. This was initiated by the original H21 programme in 2016 which considered the issues involved in supplying consumers in Leeds with 100% hydrogen rather than natural gas, followed by

\textsuperscript{69} Review of Bioenergy Potential, Anthesis & E4Tech, June 2017
\textsuperscript{70} https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project/
\textsuperscript{71} https://hydeploy.co.uk/
\textsuperscript{72} https://www.hsl.gov.uk/media/1298380/09.%20antony%20green.pdf
the H21 North of England programme in 2018\textsuperscript{73}. BEIS is funding the Hy4Heat\textsuperscript{74} programme to establish the developments required for gas users connected to the low-pressure gas distribution network to use full hydrogen and includes the specification of demonstration tests and definition of the programme necessary to secure regulatory approval for deployment. The current programme completes in March 2021 and is expected to be followed by demonstration testing in public networks and any other work necessary to secure the required regulatory approvals. Boiler manufacturers, such as Worcester Bosch, are actively developing ‘hydrogen-ready’ appliances. The H21 North of England programme has considered the deployment potential suggesting the potential to ramp up hydrogen demand through conversion of existing networks to 194TWh\textsuperscript{75} by 2050.

BEIS is undergoing a strategic review of heat options, which will be informed by all of these programmes to define policy on the role of hydrogen in reducing emissions from heating.

3) **EXISTING HYDROGEN MARKET**

Currently, the use of bulk hydrogen is primarily for chemical uses or for adventitious heat where it is produced as a co-product in existing processes. There is as yet no market for low carbon hydrogen and it is not primarily produced with the low carbon benefits in mind. The following assessment draws on European public domain data\textsuperscript{76}.

The UK hydrogen market is dominated by the conversion of natural gas to hydrogen as part of the ammonia production process (~5TWh pa). However, the optimised flowsheet provides a blend of hydrogen and nitrogen for the Harber Bosch process, and in that sense does not produce a pure hydrogen stream.

Refineries use hydrogen as part of upgrading of petroleum-based products (2.3TWh) and are also producers of certain hydrogen-rich streams in the form of Refinery offgases (RoG). These latter sources are also not pure hydrogen sources and would require significant upgrading so are typically used as fuel gases in their raw state for heat or power generation.

Electrolytic Chlorine manufacture produces hydrogen as a by-product. The remaining UK facility produces around 0.4TWh per annum and has already converted one of its boilers to operate on the by-product hydrogen. The recent changes to Sabic’s Wilton facility is reported to produce hydrogen as a co-product, which is used as a fuel gas following conversion of some of their units to hydrogen firing, although the hydrogen volumes are not in the public domain.

A variety of users require hydrogen as a chemical feedstock for the processing industry or as a reductant such as in glass making. These are typically supplied from Steam Methane Reformation plants, the biggest of which is BOC’s facility at Teesside(1.2TWh). 11 further merchant BOC and Air Product plants have a combined capacity of ~0.3TWh.

Together these plants indicate a hydrogen capacity of ~10TWh\textsuperscript{77}, although less than half of this is ‘pure’ hydrogen’

\textsuperscript{73} https://www.northerngasnetworks.co.uk/
\textsuperscript{74} https://www.hy4heat.info
\textsuperscript{75} H21 North of England, November 2018 pp23
\textsuperscript{76} https://h2tools.org/hyarc/hydrogen-production
\textsuperscript{77} The Energy Research Partnership report “Potential Role of Hydrogen in the UK Energy System” October 2016 indicates 27TWh, but no references are provided.
The application of CCUS to the largest of these plants would reduce the carbon intensity of the products being manufactured with low capture costs. This is especially true of the two ammonia plants where 1Mt CO₂/yr is already separated.

Summary of overall hydrogen demand volumes

From the foregoing, the potential hydrogen usage is seen to range from the 225TWh quoted by the CCC to potentially in excess of 650TWh, with a diverse range of potential users from industrials, power generation, transport as well as network blending or potentially full conversion. Together this is a many fold expansion of the existing hydrogen market. It is the diversity of users that makes hydrogen attractive as a vector.

4) HYDROGEN SOURCES

Low Carbon hydrogen can be produced via three primary routes; electrolytic splitting of water using renewable electricity, reforming of fossil resources with CCUS, or conversion of renewable biomass with or without CCUS. Hydrogen produced from renewable resources is commonly referred to as ‘Green Hydrogen’, and from fossil resources with CCUS as ‘Blue Hydrogen’.

Electrolysis

Production of hydrogen by electrolysis is a mature technology and is widely deployed internationally at scales of 100sKWth capacity. In the UK there are examples of operational hydrogen filling stations at this capacity78, and ITM is supplying a similar electrolyser for the HyDeploy hydrogen project79. Projects are underway to scale up production such as Project Centurion80 which is targeting around 75MWth of installed hydrogen capacity.

The carbon intensity of hydrogen produced by electrolysis is a function of the electricity supplied. Current grid carbon intensities are around 200kg/MWh81 and with projected efficiencies of 75%82, this is a hydrogen carbon intensity of 267kg/MWh which is higher than natural gas. However, with high levels of renewable penetration (electricity grid intensity of ~80kg/MWh in 203083) this falls to around 105kg/MWh around half that of natural gas, and with private wire connection to a renewable source this is zero.

The use of electrolysis is not only seen as a means to produce hydrogen, but also a means to address capacity constraints for renewable electricity production. The economic feasibility of this depends on a) the utilisation of the conversion assets at the specific location, b) the efficiency of conversion to

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78 http://www.itm-power.com/h2-stations
79 www.hydeploy.co.uk
80 https://www.itm-power.com/news-item/100mw-power-to-gas-p2g-energy-storage-feasibility-study
81 https://carbonintensity.org.uk/
82 Fuel Cell & H2 joint undertaking (FCH JU), Multi - Annual Work Plan (2014 – 2020)
83 Updated energy and emissions projections 2019, BEIS April 2019
hydrogen c) the value of the hydrogen or the efficiency/cost of conversion back to power and d) the capital cost.

The cost of electrolytic hydrogen depends on the capital cost of the equipment and crucially the cost of electricity and utilisation of the plant. Operating at high load factor reduces the capital cost element of the levelised cost, but means that electricity will need to be purchased at market prices, meaning that the electricity cost alone is in excess of £100/MWh of hydrogen. Using constrained renewable resources will lower the cost of electricity and the carbon intensity, but the capital cost element rises with low utilisation. For example, offshore wind has a load factor of around 40%, but it is unlikely it could deliver economically with >10% constraint, which is a utilisation of the electrolysis plant of <4%.

In summary, electrolytic production of hydrogen is a mature technology and is likely to have adventitious opportunities for relatively small-scale production in the short term, but would require substantially large excess renewable generation capacity, associated reductions in costs and benefits from economies of scales on the electrolysis plant. This could potentially include international imports of hydrogen.

Fossil fuel reformation

Conversion of natural gas to hydrogen is a mature technology deployed internationally. Typically, hydrogen is produced using Steam Methane Reformation (SMR), and this was the basis of the early H21 assessments. However, this process gives rise to two separate CO₂ streams, one of which is at low pressure and low CO₂ concentration. Therefore, where there is a requirement to capture CO₂, then it is increasingly recognised that Autothermal Reformation (ATR) is a more appropriate technology. Auto-reformation is deployed across the chemical processing industry, although less frequently for hydrogen production than SMR.

Hydrogen production via this route is at scale with a typical reference design being 300-500MWth for a single line with a compact design suitable for multiple lines. A single unit will capture around 0.6-1.0 million tonnes of CO₂ per annum. The technology can be supplied commercially by large reputable vendors from the UK and Internationally.

Using publicly available data, the CAG modelling group has assessed the cost of bulk hydrogen produced via SMR as £43/MWh and ATR as £39/MWh with costs per tonne of carbon stored of £98/tonne and £89/tonne respectively. The Autothermal reformation route is assumed to have a capture rate of 94%. Development work is underway in the industry to further improve the flowsheet design, optimised for hydrogen production with capture to further improve efficiencies and improve capture rates towards 97% and above.

In the future, there may also be opportunities to produce hydrogen from industrial by-product gases such as from refineries or steelworks or other fossil fuel sources for which CCS infrastructure is available.

It is widely recognised that bulk hydrogen production will be dominated by reformation of gas with CCUS for the foreseeable future, although there is likely to be a pathway to renewable solutions over the following decades.

Conversion of biomass

Bioenergy with CCS (BECCS) is widely recognised as playing an important role in meeting our 2050 obligations. It is one of few options for the removal of carbon from the biosphere for permanent sequestration. As identified by the CCC in its Net Zero report, this means combining bioenergy with CCS, “whether for power generation, hydrogen production or production of biofuels”.

The CCC identifies the requirement for around 50 million tonnes of bio-CO₂ storage. This is based on an assumed overall bioresource available to the UK of around 200TWh. The CCC assumes that the

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84 Net Zero - The UK's contribution to stopping global warming, CCC May 2019 pp148
majority of this is directed towards electricity production with a small proportion going to biofuels for aviation. This is similar to Drax’s ambitions to fit post combustion capture on its existing facilities for power generation\textsuperscript{85}. This generally assumes that such operation is baseload.

The Imperial work supporting the CCC report takes a different view. Their model chose to use BECCS \textit{to produce hydrogen in all cases}. The CCC identifies 200TWh of primary biomass, which at the (conservative) 69\% conversion efficiency identified the Imperial report suggests 138TWh of bio-hydrogen.

The conversion efficiency of biomass to hydrogen is around double that of power production with post combustion capture. Hydrogen can then be delivered to a range of markets. This could potentially include dispatchable power production when combined with hydrogen storage. This route allows the biomass conversion and capture plant to operate baseload which matches the requirements of the biomass supply chain, plant operation and economic utilisation of equipment, whilst enabling dispatchable generation.

The Wood group assessed hydrogen production from biomass in its study for BEIS\textsuperscript{86}, based on Shell technology. Based on these figures the CAG modelling group assessed the cost of hydrogen production via this route which indicated a cost of £65/MWh or £111/tonne stored.

However, the carbon benefit extends beyond this. Given that the production of hydrogen from biomass \textit{without capture} is considered to be zero carbon, without capture it is functionally equivalent to hydrogen production from gas \textit{with capture}, i.e. it is saving 0.23tCO\textsubscript{2}/MWh of hydrogen produced. Additionally, storage of the bio carbon (0.40tCO\textsubscript{2}/MWh) is carbon removed from the biosphere, so the effective carbon outcome is 0.63tCO\textsubscript{2}/MWh which is 157\% of that stored. Such an assessment indicates that the cost of the effective carbon benefit is £71/tonne, i.e. lower cost per tonne than hydrogen produced from gas.

5) \textbf{HYDROGEN INFRASTRUCTURE ELEMENTS TO DELIVER TO MARKETS}

To deliver hydrogen to the various markets identified requires additional infrastructure alongside bulk hydrogen production.

\textbf{Hydrogen distribution}

Whilst a large direct user such as a big industrial customer or dispatchable power plant may be directly connected, a key benefit of hydrogen is that it can be delivered to multiple users. This requires some form of public distribution network. The extent of this will depend on specific context and the spatial density of users.

The CCUS clusters are generally in various proportions at centres of industry with substantial populations which also have a need for clean transport. Frequently large power stations are in the area as well as a number of CHP stations. Locations in close proximity to large industrial users, high levels of population density, demand for dispatchable power generation and hydrogen storage potential are well suited for cluster development. It is expected that in the first instance hydrogen distribution systems will develop regionally accessing the user set in those areas. This initial distribution system could extend over time to become a national hydrogen transmission system ultimately joining up clusters and delivering to major dedicated hydrogen users and consumer nodes on the gas distribution network.


\textsuperscript{86} \textit{Assessing the Cost Reduction Potential and Competitiveness of Novel (Next Generation) UK Carbon Capture Technology}, Wood Group July 2018
Storage

To maximise the benefit of hydrogen production to accommodate variable demand, particularly to meet the requirements of flexible dispatchable power plant, hydrogen storage will become an important part of the system. This allows hydrogen production facilities to operate at high load factor which is both economically and technically desirable. If large numbers of domestic consumers receive 100% hydrogen, then the seasonal variations in demand that must be accommodated are large. Hydrogen storage in salt caverns is a known technology with examples already at Teesside. There is a large potential for storage in salt formations in the North West, in the Humber region and at Teesside.

Individual user modifications/equipment

End users may also need to make modifications to use hydrogen. The equipment used by industry and other consumers taking 100% or close to 100% hydrogen will typically require some changes. The primary tranche for this is expected to be industrial users. This has been assessed in BEIS’ Hy4Heat programme and phase 1 the Fuel Switching Programme where the level of intervention varies by application but is generally recognised as being technically feasible and cost effective compared with alternative decarbonisation strategies in many applications. Domestic and commercial consumers would require new or modified appliances if their network is converted to 100% hydrogen. Adoption of a hydrogen blend is at a level that does not require any change or modification to users appliances.

Large scale dispatchable power plant is generally expected to be new build generation, although some prime movers may be suitable for modification for hydrogen use.

Transport applications will use entirely new equipment with fuel cell HGVs, buses, trains and marine applications. They will also require appropriate refuelling infrastructure. Such refuelling stations may be served most cost effectively from the hydrogen distribution system. The CCC identifies that the early tranche will be HGV ‘back to base’ fleets.

6) DEPLOYMENT TIMELINE

The scale of ambition identified is 100sTWh of hydrogen across multiple market segments. This represents a significant fraction of overall UK energy flows and given that currently only a small merchant market for hydrogen exists, a major transformation in the gas market and infrastructure is required. Such major changes take time. The Oxford Institute for Energy Studies has described the transformation required in a recent paper. The study highlights the scale of transformation needed to decarbonise gas supply suggesting that deploying a combination of biomethane, and hydrogen from fossil fuel with CCS and from electrolysis in the European context will require longer than a decade to restructure the regulatory framework and investment market to enable the necessary changes in infrastructure. In the UK the Energy Networks Association has been facilitating the development of a gas decarbonisation pathway with the Gas Network operators. The work describes a pathway involving incremental steps starting from the industrial regions at which CCUS clusters are being developed. The need for a supportive regulatory framework is key to deployment.

The above actions are against a background of increasing recognition that to avoid catastrophic impacts of climate change requires more urgent action than current trajectories. Each year that action is not taken, increases the global inventory of CO₂ by 40 billion tonnes. The CCC has indicated that hydrogen deployment is an area where progress has been too slow.

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88 All Gas network operators are involved in this work which is well advanced. It is expected to complete in Q3 2019
89 “What we do over the next 10 years will determine the future of humanity for the next 10,000 years.” former British government chief scientist David King, November 2018
90 “In this report, we highlight particular priorities where progress has been too slow: low-carbon heating, hydrogen, CCS and agriculture and land use. As well as driving deployment, Government must ensure that the necessary infrastructure is delivered.” Net Zero - The UK’s contribution to stopping global warming, CCC May 2019
Early progress on low cost no-regrets applications allows ‘learning by doing’ across technical, societal financial and regulatory dimensions. The CCC identifies early roll out this as being important for this purpose. This provides the basis to establish the real scope for cost effective carbon reductions through hydrogen as well as to unlock cost savings as exemplified by the offshore wind sector. It also provides the opportunity for a material contribution towards 4th and 5th carbon budget targets.

In the context of CCUS, hydrogen production can provide an anchor for the development of CO\textsubscript{2} transport and storage infrastructure. The diversity of applications for the hydrogen with near term deployment readiness, provides commercial resilience for projects. Hence there is a strong incentive to consider CCUS deployment policy and Hydrogen deployment together on the same timescale.

The CCC identified this principle: ‘In order to develop the hydrogen option, which is vital in our scenarios, significant volumes of low-carbon hydrogen must be produced at one or more CCS clusters by 2030, for use in industry and in applications that would not require initially major infrastructure changes (e.g. power generation, injection into the gas network and depot-based transport).’

Industry advocates a more ambitious timeframe, particular given the integral role hydrogen production provides in all the CCuS clusters. In many cases it provides a key element of the first phases of cluster development, i.e. by the mid-2020s, which requires the implementation of an appropriate support framework by the early 2020s to enable delivery.

Given the opportunities it provides to assist in decarbonisation of industry, it forms a key part of the UK’s Industrial Strategy, enabling green growth. In light of the economic importance of this for the UK against the current outlook, the jobs it can safeguard and grow, inward investment it can attract and export opportunities it can develop, are strategically important. This also supports a more ambitious approach.

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91 “Even an imperfect roll-out is likely to be better in the long term than a ‘wait-and-see’ approach that fails to develop the option properly.” CCC Hydrogen in a low-carbon economy, November 2018
Options Paper 13B: The ‘Blue Hydrogen’ Commercial Market Framework

CONTEXT

- Hydrogen is a vector which delivers energy without carrying carbon and therefore with no carbon dioxide emissions at point of use. Hydrogen is not itself a primary energy source. Conversion of fossil resources to hydrogen with CCUS is a practical and low cost means of bulk production of low carbon ‘Blue hydrogen’. Blue Hydrogen as a vector allows the centralised capture of CO₂ for sequestration via transport and storage (T&S) infrastructure, whilst providing distributed low carbon energy to multiple users.

- The Committee on Climate Change has recognised the important role that hydrogen plays in decarbonising the energy system in its Net Zero report:\(^92\) ‘A significant low-carbon hydrogen economy will be needed to help tackle the challenges of industry, peak power, peak heating, heavy goods vehicles, and shipping emissions’

- For the UK to deliver a net zero carbon energy system, the CCC has explicitly identified the requirement for 225TWh of low carbon hydrogen production with CCUS\(^93\), although, it is recognised in the supporting work by Imperial this figure could be higher, with additional use of hydrogen for dispatchable generation and/or hydrogen production from biomass with CCUS. The CCC concludes\(^94\) that: ‘In order to develop the hydrogen option, which is vital in our scenarios, significant volumes of low-carbon hydrogen must be produced at one or more CCS clusters by 2030, for use in industry and in applications that would not require initially major infrastructure changes (e.g. power generation, injection into the gas network and depot-based transport).’

- There is no ‘blue hydrogen’ market today. Some ‘brown hydrogen’ is produced for use by the producers. Other production is sold commercially. The existing brown hydrogen commercial market is purely a ‘private-pipe’ market, in which producers and customers (who are all industrial customers) create their own infrastructure and enter into commercial arrangements for sale and purchase on a private, unregulated basis. No licences are needed to make, sell and buy hydrogen at present. There is no profit regulation. And there is no form of protection for market participants. Participants are all deemed to be large enough, informed, capable and able to look after their own interests without regulatory assistance.

- Future production of blue hydrogen will require either some form of revenue support, or some form of economic protection through carbon prices. The implication is that HMG will have a direct interest in the nature of the low carbon hydrogen market because:

- They will have to facilitate the provision of revenue support to the participants in it, and therefore will want to know on behalf of those who are providing this revenue support that it is being well spent.

- The requirement to reduce carbon emissions is a national interest and creating the market which delivers this most effectively is important.

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\(^93\) Ibid pp 150

\(^94\) Ibid pp 178
POSSIBLE OPTIONS

1) REGULATED MARKET OPTION
- Provide a regulatory framework, similar to that which is used for regulated gas, electricity and water assets to enable the establishment of new infrastructure. In this option, a licenced entity is permitted to make a regulated return on the investment and operation of assets which could include blue hydrogen production, distribution and storage. Based on the permitted regulated return they are licenced to collect funds, accounting for all the revenue streams they are receiving. (Example – regulated gas, electricity, water infrastructure)

2) PRIVATE MARKET SUPPORT OPTION
- Provide some form of market-based revenue support. This could be direct support for the production of blue hydrogen (for example a CfD or obligation on gas) or support provided to users of hydrogen which flows as a premium value to the producer (for example a low carbon electricity CfD, or direct support to industrials which funds purchase of blue hydrogen).
- Without separate support for distribution and storage infrastructure, this premium would also have to fund these elements, which would develop organically.

3) FREE MARKET OPTION
- Expect blue hydrogen to compete in the open market with existing energy vectors and build out the required infrastructure without any form of revenue support.

DISCUSSION OF OPTIONS
- A regulated model allows a structured approach for the development of a nascent market. A free market approach is likely to lead to a more organic development. Like existing energy markets both regulated and free market elements can work together.
- In these models, the value of the underlying hydrogen will need to be considered; whether it is at party with natural gas, or a value which accounts in some way for its lower carbon intensity.
- An entire free market approach with no form of support relies on the price of carbon being sufficiently high to enable adoption of low carbon solution and establish appropriate infrastructure. This is not the case, and so a blue hydrogen market would not develop. Over time, once infrastructure is developed, and the price of carbon is more fully internalised in energy markets, this may be the case.
- The most appropriate models: regulated or private market support options, or combinations of the two, depend on:
  - Whether it incentivises delivery of blue hydrogen to the markets which benefit most.
  - Whether the approach leads to the development of appropriate robust infrastructure to allow blue hydrogen to benefit the all appropriate energy sectors, which green hydrogen, produced from renewable sources, can also use.
  - The sources of funds and how those revenue streams are physically delivered to the owners of the elements in the supply chain.
  - The routes which deliver the most cost-effective solution, minimising the quantum of revenue support.
  - The requirement to successfully finance and deliver early projects in a nascent market.
  - The timeframes over which the market is being sought to be established.
- Suitability to establish an enduring regime, with the objective of reducing revenue support as the price of carbon increases
- These factors are addressed in more detail in Options Papers 13C and 13D.

**RECOMMENDATION**

- Given its future importance in decarbonising the UK energy system, the CAG recommends that low carbon hydrogen is part of the low carbon CCUS cluster developments during the 2020s.
- The CAG recommends that HMG consults urgently on options for developing a low carbon hydrogen market or markets.
- The consultation should seek views on possible market structures, commercial structures, financing options and funding sources to support low-carbon hydrogen production with CCUS.
- Development of business models and funding sources for hydrogen should be a future priority.
Options Paper 13C: Blue Hydrogen Supply: Sources of Revenue Support

**CONTEXT**

- Unless or until the cost of carbon is fully internalised in energy markets, revenue support will be required for blue hydrogen, to fund its production, distribution and storage.
- There are two sources of revenue available; from energy consumers or tax revenue.
- There is a strong economic argument for the costs where possible to be borne by the beneficiaries. In general, this is energy consumers. However, there may be specific cases where there are wider economic benefits and so tax revenue may be more appropriate.
- The principle of socialisation of costs is established in the energy sector. This is embodied under Electricity Market Reform (EMR) and through the funding of energy distribution infrastructure. Under EMR the costs of new low carbon electricity generation is socialised across all electricity consumers rather than those local to the facility paying a higher price. This is because: a) it is fair b) it allows markets to operate efficiently, and generation to occur in the geographies that deliver lowest cost, c) it provides deliverability and price certainty to generators backed by the wider market, reducing cost of capital.

**POSSIBLE OPTIONS**

1) **GAS CONSUMERS**

- The UK’s largest flows of energy are via the gas grid. The majority of the potential beneficiaries of hydrogen currently consume gas.
- The UK currently consumes approximately 800TWh (excluding losses) of natural gas per annum, of which approximately 300TWh pa is used by domestic and commercial customers, around 200TWh pa used by industrials, and around 300TWh for dispatchable power generation. The consumers of gas in these sectors would provide the funds flowing from the beneficiaries (domestic consumers of heat, industrial consumers of heat and ultimately the consumers of gas-fired power generation)
- The exception is transport, which is currently delivered via liquid fuel infrastructure, but is increasingly expected to receive energy via the electricity network. Some HGV and bus fleets do operate on gas and are fuelled via the gas grid.

2) **INDIVIDUAL MARKET SECTOR CONSUMERS**

- Individual Market sectors could pay a specific premium for the hydrogen that they consume. For example:
  - Low Carbon electricity. If the increased costs of generating low carbon electricity were socialised across electricity users, this would allow a premium payment for the low carbon hydrogen to flow back to the producer.
  - Industrial Users. If revenue support were provided to Industrial Users to make carbon reductions, this could allow them to fit post combustion capture or pay a premium to use low carbon hydrogen.
  - Transport users. A support mechanism for transport applications could be established which flows back to the value of the hydrogen.
- In these cases, the socialisation depends on the structure of these mechanisms.
- For some industrials, hydrogen is used for its chemical value rather than energy value. These users are currently prepared to pay a premium for brown hydrogen. They may seek to use blue hydrogen and may also be able to pay some premium.
3) **TAX REVENUE**

- Support could be provided directly from tax revenue, for example through an incentive similar to the Renewable Heat Incentive.
- Support could be provided indirectly from tax revenue. There may be cases where there is individual sector support from the tax revenue (for example industrials) which flows back as a premium value for the fuel consumed.

**DISCUSSION OF OPTIONS**

- Energy flows are dominated by the gas market. The use across consumers (domestic, commercial, industrial, power) is relatively evenly split.
  - In this case all domestic, commercial, industrial, power gas consumers contribute to the cost of hydrogen production. For consumers of gas from the existing gas network this could mean that low carbon hydrogen and natural gas are delivered at parity in cost terms. This would currently be necessary for domestic and commercial consumers who do not pay for carbon burned.
  - Similarly, larger commercial and industrial entities that receive full hydrogen could be supplied at price parity with natural gas. As gas users they would be contributing to the socialised costs of hydrogen. Although these entities fall with the carbon emissions trading scheme, many industrials are not able to pass on the cost of carbon in a global environment, therefore this would provide a means to enable them to decarbonise and be competitive, addressing an objective laid out by the CCC.
  - Similarly, hydrogen could be supplied at parity with natural gas with costs of hydrogen production socialised across all gas users. Electricity generators are UK’s largest gas consumers and therefore contribute accordingly. In this regime, it would be expected that no further support might be required for the generator, and so dispatchable generation could potentially be delivered ‘in the market’.

- Where Individual Market sectors can pay a specific premium for the hydrogen that they consume, the costs could be socialised more directly. For example:
  - If a low carbon electricity support regime were established for blue hydrogen fuelled generation, then generators could pay a premium for the blue hydrogen.
  - If industrial users received revenue support to reduce carbon, (for example from tax revenue) they could pay a premium for blue hydrogen.

- There may be benefits to being able to combine these factors to deliver best value for money to those providing the revenue support. The specific approach depends on the ability of individual support mechanisms to address these issues. This is discussed in more detail in Options Paper 13D.

- In general, it is considered more appropriate for costs to be socialised across energy consumers rather than tax revenue, unless there is a particular economic argument to do so.

**RECOMMENDATIONS**

- The consultation should consider whether the additional cost of low carbon hydrogen production, storage and distribution should be borne by electricity consumers, energy (gas) consumers or tax revenue, depending on the end-use of the energy of low-carbon hydrogen.

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95 On the basis of eg three initial projects of 3x3TWh per annum of hydrogen requiring a support requirement for bulk production of £18/MWh (CAG modelling), assuming UK assumed gas consumption of 800TWh this equates to a socialised increase of £0.20/MWh. This is well within the recent fluctuations in wholesale gas price (over 15p/therm = £5/MWh over the last 18 months). And equates to an increase of around £2.60 per annum on a consumer’s bill. Typical delivered price of gas per annum is £550 pa, so this equates to ~0.5% increase, and well within the fluctuations in gas bills due to wholesale price fluctuations (up to £65 pa, based on the £5/MWh variation).

96 “Government must implement an approach to incentivise industries to reduce their emissions through energy and resource efficiency, electrification, hydrogen and CCS in ways that do not adversely affect their competitiveness.” Net Zero, CCC 2019
Options Paper 13D: Hydrogen Supply - Mechanisms for Delivering Revenue Support

**CONTEXT**

Without the cost of carbon fully internalised in our energy markets, delivering low carbon solutions will require some form of revenue support, which should be minimised. The mechanism by which support is delivered has a significant impact on this, and on the benefits to the energy system.

**Functional Requirements**

Appropriate revenue mechanisms should:

- **Enable multi-use**: A key benefit of low carbon hydrogen is that it can deliver to multiple energy sectors. Any support regime should enable this and not artificially constrain the opportunities for other parts of the energy system, particularly where hydrogen can deliver cost-effective decarbonisation compared with alternatives.

- **Establish new infrastructure**: Low carbon hydrogen is a new vector. The revenue mechanism should enable bulk production of low carbon hydrogen and enable the establishment of infrastructure to enable the market to develop.

- **Be cost effective**: The business model should provide the necessary support efficiently to be cost effective: a) the mechanism should efficiently deliver the revenues to the actors requiring it, and b) given the capital-intensive nature of production and infrastructure, models which allocate risk appropriately to minimise cost of capital are important.

- **Be financeable in a nascent market**: The use of low carbon hydrogen is an emerging market, dependent on early adopters. Like any nascent market, the low carbon hydrogen supplier faces higher volume and price risk than a fully established market. The appropriate actors must have the appetite to participate, and the commercial risk profile must be suitable for financing.

- **Avoid unintended consequences**: It should not create perverse incentives nor encourage actors to develop projects which are not aligned with policy objectives or undermine cost-effectiveness.

- **Be deliverable on an appropriate timeframe**: Avoiding catastrophic impacts of climate change requires urgent action\(^\text{97}\). Each year that action is not taken, increases the global inventory of CO\(_2\) by 40 billion tonnes. The CCC states that hydrogen is an area where progress has been too slow.\(^\text{98}\) Early progress on low cost no-regrets applications allows ‘learning by doing’, which the CCC identifies as important\(^\text{99}\). The support regime should be deliverable on an appropriate timeframe to deliver initial projects by the mid-2020s. Given construction, financial investment decisions (FID) would be needed 2-3 years beforehand. Financing actors must also have sufficient confidence a new regime following its implementation before they will make an FID decision; this takes time. It is unlikely that new primary legislation could be delivered in this timeframe, so a regime which is able to use existing frameworks is an important factor for timely delivery.

- **Be suitable for an enduring regime**: The business model should be at best suitable for an enduring regime, or at least compatible with likely future developments. Changes to the

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\(^{97}\) “What we do over the next 10 years will determine the future of humanity for the next 10,000 years.” former British government chief scientist David King, November 2018

\(^{98}\) “In this report, we highlight particular priorities where progress has been too slow: low-carbon heating, hydrogen, CCS and agriculture and land use. As well as driving deployment, Government must ensure that the necessary infrastructure is delivered.” Net Zero - The UK’s contribution to stopping global warming, CCC May 2019

\(^{99}\) “Even an imperfect roll-out is likely to be better in the long term than a ‘wait-and-see’ approach that fails to develop the option properly.” CCC Hydrogen in a low-carbon economy, November 2018
landscape may be general, or specific. Given the range of potential opportunities hydrogen offers and wider developments in the user sectors, the balance of uses will change over time. Any regime should be able to accommodate the implications of such changes, at a minimum for the projects already funded, even if new projects are supported differently.

- **Accommodate the price of carbon.** This will change over time, and the regime should be consistent with this. As carbon prices rise, the quantum of additional revenue support for low carbon solutions relative to fossil counterparts should reduce.

**Assumptions**

Reference assumptions taken by the CCUS working group are:

- **CO₂ Transport and Storage.** It is assumed that the funding regime for CO₂ transport and storage is addressed more widely by the CCUS Advisory Group. For the purposes of the hydrogen business model, it is assumed that this is a separate or passed through service.

- **Hydrogen production approach.** The focus is on bulk hydrogen with CCUS, consistent with work of the CAG and the primary hydrogen production approach identified by the CCC. It is not primarily tailored for the production of electrolytic hydrogen, although ideally is not incompatible with a regime to support it.

- **Early hydrogen markets.** Consistent with the CCC report it is assumed that early hydrogen markets are ‘for use in industry and in applications that would not require initially major infrastructure changes (e.g. power generation, injection into the gas network and depot-based transport)’. Given that hydrogen production facilities are expected to have a lifetime of at least 20 years, the mechanism should be compatible with further hydrogen market developments.

- **Treatment of carbon.** Most larger emitters fall within the emissions trading scheme; this includes power plants and medium to large industrial facilities. However, domestic and many commercial and smaller industrial facilities are outside of the regime and therefore do not currently incur carbon costs. The mechanism should operate in this framework.

- **Reference UK gas demand.** Whilst the mechanism should not depend on a specific gas demand, it is helpful to understand it. The UK currently consumes approximately 800TWh (excluding losses) of natural gas per annum, of which approximately 300TWh pa is used by domestic and commercial customers on the gas distribution system, around 200TWh pa used by industrials (primary on the distribution system, but with a few of the largest on the transmission system) and around 300TWh for power generation, primarily on the transmission system, but increasingly more connected at the distribution level as distributed peaking plant.

- **Reference bulk hydrogen production scale and costs.** Whilst the mechanism should not depend on a specific development pathway or costs, it is helpful for evaluation purposes to understand typical hydrogen plant scales and costs. The levelized cost of bulk hydrogen production are as assumed in the CAG Archetype model for Auto Thermal Reformation. This is a levelized cost of £38.60/MWh (HHV basis) comprising £9.20/MWh of capital cost, £4.80/MWh of operational costs and £24.60/MWh of feedstock on the basis of natural gas at a price of £20.50/MWh. Single production lines would typically produce 3-5TWh pa at baseload; early projects might be expected to be smaller single lines, with larger units and more lines over time with market confidence. These costs and size may vary over time, particularly with technology development.

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100 For example, this has been addressed under EMR in terms of the electricity CfD regime, where the cost of carbon and change in energy mix flows through to the wholesale electricity price. The out-turn level of subsidy varies accordingly to maintain the agreed strike price

101 Net Zero - The UK's contribution to stopping global warming, CCC May 2019 pp178
The above figure summarises the potential elements in the low carbon hydrogen supply chain alongside potential users. This includes low carbon hydrogen production, distribution and storage. The treatment of ‘distribution’ and ‘storage’ are discussed briefly below.

**Hydrogen distribution:**
- For delivery to multiple users a hydrogen distribution system will be required. In the early stages of development this is expected to be new dedicated pipeline assets; in the future this could include repurposing of existing gas pipeline assets.
- Where distribution is a ‘public’ asset, it is a natural extension to the existing gas network RAB. It is proposed that provision is made to include this within the RIIO-GD2 period which runs from 2021.
- Other delivery modes (eg private or direction connection and/or liquid deliveries) may not naturally fall under the existing RAB and, if required, would need to be supported under the hydrogen production revenue support mechanism.

**Hydrogen Storage:**
- A key benefit of low carbon hydrogen as a vector is the ability to store low carbon energy cost-effectively. Heat demand is highly variable diurnally and seasonally and increasing penetration of intermittent renewables requires balancing with demand.
- Storage of hydrogen allows the optimisation of production with ability to supply dispatchable energy to match demand. System Operation of a hydrogen distribution system is likely to depend on access to storage. There is logic for this also to be included with the existing gas network RAB, if possible. It is proposed that provision is made to include this within the RIIO-GD2 period which runs from 2021.
- Where this is not the case (noting that only limited gas storage is provided by GDNs under the existing RAB, or in the case of private storage), then storage would need to be supported under the hydrogen production revenue support mechanism.

**Hydrogen production**
- This is the primary focus of the rest of this paper, recognising that where the distribution and storage elements are not covered under existing regimes, their costs would need to be covered under this hydrogen revenue support mechanism.

**POSSIBLE OPTIONS**

Six revenue support mechanisms are summarised here. More detailed descriptions and assessment of benefits and issues are summarised at the end of this paper.

1) **A HYDROGEN RAB MODEL**

- A licenced entity is permitted to make a regulated return on the investment and operation of the assets. Based on the permitted regulated return, they are licenced to collect socialised funds from the supply/shipping of commodities, accounting for all the revenue streams they are receiving. (Example - regulated gas, electricity, water infrastructure) The largest, and most
relevant energy flow in the UK is gas which is supplying domestic, commercial, industrial and power users.

- This could be a new hydrogen licence or potentially an extension of the existing gas distribution/transmission licence.
- The RAB model is capable of accommodating higher value revenues from individual users or end market sectors\(^{102}\), reducing the socialised cost to all gas users.

**2) INDIVIDUAL REVENUE SUPPORT TO INDIVIDUAL END MARKET SECTORS (INDIVIDUAL SECTOR SUPPORT)**

- This assumes that revenue support mechanisms are set up for specific end user sectors. This allows these users to pay a premium value for the low carbon fuel, hydrogen. Examples could be a low carbon Electricity CfD which supports hydrogen fuelled power generation, or Industrial user support for use of low carbon hydrogen.
- This premium value would need to be set to enable the hydrogen producer to make its return from the end users it sells to, and to be financeable.

**3) LOW CARBON GAS (HYDROGEN) CfD**

- A body is set up by HMG to run an auction process for supply of low carbon gas (hydrogen) to use the market to find the private sector pricing and provide a contract at a Strike price. The body would be authorised to collect the necessary socialised funds from gas shippers/suppliers and would be the counterparty to the contract with the private entities providing the low carbon hydrogen. (Analogous to EMR CfDs in the electricity sector).
- Under contract, the producer would receive a payment for each unit of low carbon hydrogen produced. It would receive revenue support based on the difference between the Strike price and the ‘Reference Price’ the assumed value of the underlying commodity.

**4) LOW CARBON GAS (HYDROGEN) OBLIGATION**

- An obligation is imposed by HMG on gas suppliers to secure low carbon gas (hydrogen); This incentives them to buy a specified proportion of low carbon gas, but to secure this at lowest cost compared with competitors, with the ability to trade or buy out if they are unable to meet their obligation. This is the basis of the former electricity Renewable Obligation, and the current Renewable Transport Fuel Obligation.

**5) DIRECT TAX REVENUE SUPPORT: INCENTIVE**

- A direct revenue premium made to the producer from the Exchequer funded from the tax revenue. This would supplement the commodity price secured for the hydrogen. It is analogous to the Renewable Heat Incentive.
- This premium value would need to be set to enable the hydrogen producer to make its return from this plus the sum of the individual market revenues streams secured by the user, and be financeable.

**6) DIRECT TAX REVENUE SUPPORT: GRANT**

- A grant payment made to the producer from the exchequer funded from tax revenue. This could cover a proportion of the capital cost of the facility.

\(^{102}\) A “Single Till” mechanism. For Example, under the Heathrow RAB, Single Till parking revenues are accounted for in the revenue base and therefore reduce the regulated landing fee charges.
DISCUSSION OF OPTIONS

Further detail is provided on each of the options at the end of this paper. The following provides a high-level assessment of the mechanisms against the functional requirements

Appropriate socialisation of costs

- The RAB, Gas CfD and Gas Obligation mechanisms socialise the costs across all gas users, which is currently relatively evenly split between domestic and commercial customers (300TWh), industrial users (200TWh) and Power users (300TWh).
- Individual Sector Support mechanisms for end users more specifically allocate costs to the specific beneficiaries.
- The RAB structure benefits from being able to accommodate revenues from Individual Sector Support mechanisms, reducing the residual socialised costs to all gas consumers. This enables further rebalancing and reducing of the socialised costs compared with a Gas CfD or Gas Obligation.
- Direct Tax Revenue support, either Incentive or Grant doesn’t place the cost on the beneficiaries. Whilst this may be a potential route for early adoption it is unlikely to be an appropriate long-term solution.

Enable Multi-Use & Establish new infrastructure

- The RAB, Gas CfD, Gas Obligation and Tax Revenue Incentive mechanisms are designed to support low carbon hydrogen at source, such that in theory it could flow to any end user, enabling producers to delivery to any market.
- In practice for the Gas CfD or Gas Obligation, the producer will need to be confident in securing a market price for the commodity, commensurate with that which has determined the revenue support, which may limit the markets.
- The RAB allows delivery into multiple markets and works effectively with support for public-access delivery and storage infrastructure.
- Relying only on Individual Sector Support mechanisms will lead to build out focused on the specific individual markets being supported. Low carbon hydrogen will be delivered preferentially to sectors with the highest support regime. This would require co-ordination to ensure enduring policy objectives are being met. There is a risk of driving point to point development rather than establishing appropriate infrastructure for market development.

Cost Effective

- The RAB structure is designed to allocate risk appropriately in order to reduce the cost of capital and therefore cost to the consumer.
- The CfD, Gas Obligation and Tax Revenue Incentives are market mechanisms with higher risks and costs of capital. This is particularly the case for an Obligation in a nascent market due to higher uncertainty. An Obligation also delivers the support via a market intermediary, which is likely to lead to some revenue ‘leakage’ on route to the producer.
- Individual Sector Support mechanisms mean that the revenue to the producer is via an individual user, which is likely to lead to some revenue ‘leakage’ on route to the producer. There may be additional counterparty risks for the producer which increase the cost of capital.

Financeable in a Nascent Market

- The RAB structure is suited to financing in a nascent market as the inherent risks associated with limited users are reduced by the design of the mechanism. It is also possible that the production of hydrogen could be added to a larger RAB (T&S or industrial capture) more able to absorb rollout risk because of its size and stable income base.
• Individual Sector Support mechanisms, if well-structured allow individual projects to be financed based on supply to specific users. The counterparty risk may be higher due to lack of market diversity.
• A Gas CfD or a Tax Revenue Incentive provide direct revenue to the producer. The ability to finance relies on the producer being confident that the underlying commodity price secured matches the Reference price (CfD) or assumed price when the Incentive was developed\textsuperscript{103}.
• A Gas Obligation is expected to be more challenging for a nascent market due to the revenue uncertainty. An Obligation works more effectively when there is a widespread market for the commodity.
• Grant funding alone does not deliver a financeable project as revenue support is also required. Well-structured revenue support allows capital markets to provide the funds.

Avoiding unintended consequences

• All mechanisms need to be carefully designed to avoid unintended consequences.
• Relying only on Individual Sector Support mechanisms would require careful co-ordination to ensure enduring policy objectives are being met, given that the market will follow the highest revenue support\textsuperscript{104}.
• Under a RAB, there is the opportunity for more control over outcomes through the structure, provided that the licence terms are appropriately defined for the Regulator to manage effectively.

Deliverable on an appropriate timeframe

• For a RAB an existing regulator and framework could be sued which could allow a licensing regime in a timely manner, potentially extending the existing licence or establishing a new licence. Under the existing licence, it would need to be included in the current RIIO-GD2 scope for the period commencing 2021. A new licence regime could potentially be delivered within 3 years from concept to delivery with action by government.
• A new Gas CfD, or Gas Obligation would require development of a wider gas policy framework, policy commitment, development of the mechanism and appropriate primary legislation. For a CfD, a contracts body would be required, and in both cases, the market would need to be confident in a new regime.
• Individual Sector Support mechanisms depend on the timeframes for individual sectors. For example, the structure for a low carbon electricity CfD is already in place. A range of Individual Sector Support mechanisms across relevant users is expected to take more time.
• If the current RHI could be extended to cover low carbon heat, then potentially an initial Direct Tax Revenue Incentive could be established, although this would still require legislative change and State Aid Approval. A more enduring Incentive would take time.

Suitable for an Enduring Regime

• CfDs or Obligation are generally considered to be appropriate enduring regimes.
• A RAB is expected to be an enduring regime for delivery infrastructure and could be for production. If other market mechanisms are preferred longer term, then the scope of the RAB can be limited.
• Direct Tax Revenue Support is not expected to be suitable for an enduring regime.
• Individual Sector Support mechanisms would need to be evaluated on their own merits.

\textsuperscript{103} The method of Digression under the RHI has led to a challenging (stop-start) market development profile for the supply chain and therefore financing. This would need to be addressed.
\textsuperscript{104} Consider for example, the care required in managing the cross departmental the support regimes relating to waste materials, for transport, heat and power.
Accommodating the cost of carbon

- This is linked with an enduring regime; as the price of carbon increases, low carbon solutions should require lower revenue support compared with fossil alternatives.
- A Gas CfD and or RAB are designed to accommodate changes to the price of carbon
- A Gas Obligation may be able to do so but would need to be structured differently from Renewables Obligation.
- Direct Tax Revenue Support does not naturally achieve this and would need to be structured differently from the Renewable Heat Incentive.
- Individual Sector Support mechanisms would need to be evaluated on their own merits.

SUMMARY

- Hydrogen production assets could be built, owned and financed by the private sector. A low-carbon hydrogen industry could develop without commercial regulation; or as regulated industry operating in regulated markets, perhaps using RAB structures.
- Revenue support for low-carbon hydrogen production is best provided by the beneficiaries of the end-use of the energy delivered using low-carbon hydrogen. These are primarily users of gas (domestic, commercial, industrial and electricity producers). The costs could be socialised across these gas users generally, or more specifically funded by electricity consumers for those volumes used to generate electricity, for example tax revenue where it is used in industry, and gas consumers for the remaining volumes which would be used to generate heat.
- Potential mechanisms for delivering funding for low-carbon hydrogen production include: funding revenue collection through a RAB structure; premium payments from specific users; a low-carbon Hydrogen CfD; an Obligations-based system; an incentive scheme like the RHI scheme; or HMG grants.
- The CAG support consultation on the possible commercial structures and funding sources that may be used to support hydrogen production with CCUS.

RECOMMENDATIONS

- Given its future importance in decarbonising the UK energy system, the CAG recommends that low carbon hydrogen is part of the low carbon CCUS cluster developments during the 2020s.
- The CAG recommends that HMG consults urgently on options for developing a low carbon hydrogen market or markets.
- The consultation should seek views on possible market structures, commercial structures, financing options and funding sources to support low-carbon hydrogen production with CCUS.
- The consultation should consider whether the additional cost of low carbon hydrogen production, storage and distribution should be borne by electricity consumers, energy (gas) consumers or tax revenue, depending on the end-use of the energy delivered by low-carbon hydrogen.
- The consultation should consider potential options for mechanism to provide revenue support. The CAG has identified a number of possible options.
- The CAG recommends that provision for the sources of funding and funding mechanisms for low-carbon hydrogen is included in the forthcoming White Paper.
CHAPTER 13: Hydrogen Production with CO₂ Capture – Options Papers

Options Paper 13E: Specific Mechanism Descriptions

1) RAB MECHANISM

Overview

- Under a RAB, a regulator grants a licence to an entity, which gives it the right to collect revenues to achieve an agreed regulated return on the assets which it delivers and operates. This underpins the existing funding regime for the gas distribution and transmission networks.
- In some cases, it is the regulated entity which delivers and operates the assets, in others, such as the case of Thames Tideway in the water sector, the investment, ownership and operation of the specific assets is undertaken by a third party, with the required revenues collected by the regulated entity.
- The principle of the RAB regime is that the entity is permitted to make an agreed return through collection of socialised funds from the relevant energy market, in this case, gas.
- A RAB can accommodate individual and changing revenue streams over time, using Single Till arrangement.
- A RAB system has the following attributes:
  - It provides the opportunity to reduce the cost of capital through appropriate risk allocation in the structure. With capital intensive assets, this reduces the cost to the consumer.
  - It provides revenue certainty for investors. The licence regime provides confidence to the investors in the revenue streams, providing that the plant is constructed and operated appropriately\(^\text{105}\). Addressing risks relating to revenue certainty is particularly important in developing markets with limited early users.
  - It is resilient to market developments. To maximise the benefit of low carbon hydrogen as vector, it is ideally used across the range of sectors it is able to service. Given the stage of market development, the balance of demands between different sectors will inevitably change over time. A RAB structure is able to accommodate this and deal with changing sources of revenues, whilst minimising the costs for the consumer.
- This is a regulated approach to the market. This offers benefits to establishment of a nascent low carbon hydrogen sector given the risk profile and enables establishment of infrastructure. Once established, a more market-based mechanism may be more appropriate.

Socialisation of costs

- Additional cost of low carbon hydrogen, relative to natural gas would be socialised across all gas consumers. The current gas market is split between domestic and commercial customers (300TWh), industrial users (200TWh) and Power users (300TWh).
- Revenues would be collected from these users via shippers/suppliers in the same way that the gas distribution and transmission infrastructure is funded today.
- For users of low carbon hydrogen via the existing gas network (either as a blend or 100% conversion) this means that hydrogen and natural gas are delivered at parity in cost terms.
- Where low carbon hydrogen is delivered to specific users (taking for example power production or industrial users), various approaches could be taken:
  - Low carbon hydrogen could be delivered at parity with natural gas. This would mean that such a user (power generator, or an industrial) would be receiving a low carbon fuel at the cost of natural gas, which is a benefit. Such users would then need limited or no further direct support.

\(^{105}\) This can be managed through established regulated asset incentivisation mechanisms.
Where there is a revenue support regime for individual users (such as a electricity CfD for low carbon power or and industrial support regime) then these users would be able to pay a premium for low carbon hydrogen, including recognising carbon benefits. This additional revenue could be accounted for by a RAB Single Till Mechanism, which would reduce the socialised costs to all consumers. This delivers rebalancing of the socialised costs. This is a particular benefit of the RAB structure.

- A similar Single Till approach could be taken for the transport and chemical hydrogen sectors.

### Licenced Entity & the Role of Regulator

- The logical regulator would be OFGEM. It would need to provide a licence which grants the right to collect the revenues necessary to deliver and operate the assets.
- The license could either be a) the current gas licences and therefore the regulated entities being one of the existing GDNs/NGT, or b) a new licence. In either case, the actual investment, ownership and/or operation could be undertaken by a third party as a service to the regulated entity.
- Delivery under the current gas license regime
  - The existing licensees are already collecting revenues from gas users. This is may be an expeditious approach requiring least regulatory and legislative intervention for delivery. Provision could be made during the current RIIO-GD2 round of business plans, to enable delivery during the period 2021 onwards.
  - Hydrogen distribution is a logical extension of their existing activities\(^{106}\). In this case, the GDN in a particular region where the hydrogen is being distributed would be the logical licensee. Including hydrogen production within the existing licence scope would provide integration of the operation of the full chain.
  - Current unbundling rules preclude the gas distribution and transmission companies from gas production. A view could be taken that the gas is being ‘processed’ to remove the carbon, akin to the service provided when the gas is odorised, rather than ‘produced’. Careful legal consideration would need to be considered to establish the exact position.
- Delivery under a new license regime
  - Alternatively, a new license regime could be established. This is expected to be more time consuming, although it has been indicated this could be delivered within 3 years from concept to full implementation.
  - Such licences would need to grant the licensees the ability to collect revenues via gas shippers/suppliers from gas users. In the event of a new licence, hydrogen distribution and storage could either be retained within the existing GDN/NGT regime, or potentially included in the new licence.
  - The focus here is on bulk production of low carbon hydrogen necessary to establish infrastructure. The licencing regime could support all forms of low carbon hydrogen, providing they deliver value for money to the consumer, or other individual routes could be supported separately.
- It is important for the Regulator to have good benchmarking to deliver best value for the gas consumer. This could be delivered by a number of licenced entities, using the existing GDNs as a model. A single RAB entity would not provide this. However, it would be important that the licence provides for the collection of revenues on a national basis to ensure that the costs are fully socialised.
- These licencing requirements would require the Regulator to be given the necessary policy direction. It would also need to have the capacity to deliver it.

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\(^{106}\) As noted above, storage would also logically fit within this framework, particularly as it will be important for operation of nascent infrastructure.
Transferring to an enduring regime

- A RAB structure is currently the enduring framework which is used to deliver much of the energy transmission and distribution infrastructure in the UK. This could be the case for the hydrogen distribution and storage elements, and potentially hydrogen production.
- Over time, government policy could move to a more market-based mechanism for hydrogen production. In this scenario, existing facilities would continue to be funded under the RAB licence, but new plants could be constructed under any new regime, with clear licence provisions that preclude the regulated entities from receiving support under both the RAB and market mechanisms.

Benefits and issues

<table>
<thead>
<tr>
<th>Potential benefits of mechanism</th>
<th>Potential issues of mechanism</th>
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</thead>
<tbody>
<tr>
<td>• Configurable to encourage multi-users of hydrogen.</td>
<td>• Long term there may be merits to a market-based mechanism. Is the regulated approach appropriate to start the market?</td>
</tr>
<tr>
<td>• Provides revenue certainty for providers, and therefore low cost of capital.</td>
<td>• Does the Regulator have the capability/capacity to manage this function?</td>
</tr>
<tr>
<td>• To enable a nascent market development, it provides revenue risk management</td>
<td>• Risk of too few or too many RAB entities for efficient delivery.</td>
</tr>
<tr>
<td>• Already in use for distribution infrastructure</td>
<td>• Any regulatory hurdles to deliver the licence regime</td>
</tr>
<tr>
<td>• Uses established mechanisms to socialise costs across energy consumers</td>
<td>• Is socialisation across all gas consumers considered to be fair (mitigated by single till mechanism)</td>
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<tr>
<td>• Is a flexible system to accommodate higher value streams (Single Till) to reduce the socialised costs?</td>
<td>• Lack of familiarity of the mechanism by some actors</td>
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<tr>
<td>• It doesn’t require a major gas policy decision</td>
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<tr>
<td>• Is suitable for an enduring regime, but could be managed so future facilities could be built under new (market based) regimes</td>
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2) INDIVIDUAL MECHANISMS PER END USER

Overview

- This assumes that revenue support mechanisms are set up for specific end user sectors. This allows these users to pay a premium value for the low carbon fuel, hydrogen. Examples could be a low carbon Electricity CfD which supports hydrogen fuelled power generation, or industrial user support for use of low carbon hydrogen.
- This premium value would need to be set to enable the hydrogen producer to make its return from the end users it sells to, and to be financeable.

Socialisation of costs

- This relies on individual end user sectors receiving support which can flow through a premium value of the low carbon hydrogen
- This means that the sectors for which support is provided receive the hydrogen and so are paying the support revenue costs
- End user support mechanisms could include:
  - Low Carbon electricity. A low carbon electricity CfD could include production from low carbon hydrogen. This would allow a premium payment for the low carbon hydrogen to flow back to the producer
Industrial Users. Revenue support could be provided to Industrial Users which could allow them to fit post combustion capture or pay a premium to use low carbon hydrogen.

o Gas network users. This would require a separate support mechanism to support use of hydrogen by gas users. Logically this would be at the injection into the gas network (although in the case of a RAB structure this is already included)

o Transport users. A support mechanism for transport applications could be established which flows back to the value of the hydrogen. This could include fuel duty adjustments and/or a new regime

Delivery

• Financing hydrogen production facilities based on this approach, relies on individual mechanisms with their associated need to be established.

• It means that hydrogen infrastructure will develop to match the individual sectors policy regimes. This requires careful policy coordination across these sectors to avoid unintended consequences.

• This may incentivise point to point production, rather than establishing infrastructure which can allow low carbon hydrogen to deliver opportunities across the whole energy sector

• Financing depends on individual counterparties, with potentially different revenue streams and values, with implications for cost of capital

Benefits and issues

<table>
<thead>
<tr>
<th>Potential benefits of mechanism</th>
<th>Potential issues of mechanism</th>
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<tbody>
<tr>
<td>• Costs are transparently borne by the individual users receiving the benefit</td>
<td>• Relies on individual sector revenue support regimes to be put in place</td>
</tr>
<tr>
<td>• Uses specific markets to establish early production</td>
<td>• Individual revenue support regimes (heating, power, industrial, transport) would need to be</td>
</tr>
<tr>
<td>• It is a “market-based” regime from a hydrogen perspective</td>
<td>co-ordinated to ensure that policy objectives are met.</td>
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<tr>
<td>• It can work in tandem with a RAB. In that case, as the support from specific market increases,</td>
<td>• Low carbon hydrogen will be delivered preferentially to sector with highest support regime.</td>
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<tr>
<td>then RAB socialised costs could reduce.</td>
<td>Policy co-ordination required to ensure this is best value for consumers.</td>
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<td></td>
<td>• Risk of driving drive point to point development rather than incentivising establishment of</td>
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<td></td>
<td>appropriate infrastructure for market development</td>
</tr>
<tr>
<td></td>
<td>• Financing risks. Producers will either be dependent on single offtaker (counterparty risk)</td>
</tr>
<tr>
<td></td>
<td>or multiple support regimes. This increases risk and cost of capital for hydrogen producer.</td>
</tr>
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<td></td>
<td>Consequently, increased cost to consumer</td>
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<td></td>
<td>• There may be some revenue leakage from end user to low carbon hydrogen producer</td>
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</table>
3) **LOW CARBON GAS (HYDROGEN) CFD**

### Overview

- A body is set up by HMG to run an auction process for supply of low carbon gas (hydrogen) to use the market to find the private sector pricing and provide a contract at a Strike price. The body would be authorised to collect the necessary socialised funds from gas shippers/suppliers and would be the counterparty to the contract with the private entities providing the low carbon hydrogen. (Analogous to EMR CFDs in the electricity sector)

- Under contract, the producer would receive a payment for each unit of low carbon hydrogen produced. It would receive revenue support based on the difference between the Strike price and the ‘Reference Price’ the assumed value of the underlying commodity.

### Socialisation of costs

- The producer would bid a strike price and be awarded a contract by the Contracts Body. Under contract it would receive revenue support based on the difference between the Strike price and the ‘Reference Price’ the assumed value of the underlying commodity.

- The revenue support costs would be socialised across all gas consumers. The current gas market is split between domestic and commercial customers (300TWh), industrial users (200TWh) and Power users (300TWh). Revenues would be collected from these users via shippers/suppliers by the new contracts body.

- For domestic and small commercial consumers who don’t have to pay for carbon, the underlying commodity price is the wholesale price of gas. However, for larger industrial, power and transport markets, it is possible that the value of the underlying commodity could be higher.

- Under a CfD scheme, care is required in pre-determining the basis of the underlying Reference price, given it could vary by sector, and over time the proportion being used by different sectors could also vary.

- The risk is either a) that an individual plant owner is able to sell the commodity at a higher price than the Reference Price and so the socialised cost is higher than it should be, offering poor value to the consumer, or b) that the assumed Reference Price by the CfD Body is higher than an individual producer is able to secure in practice from the particular set of users being supplied, which is a significant risk for financing and operating the plant.

- This is more challenging for a nascent commodity which can supply a variety of markets. Over time it is possible that a market reference price could develop, although in the presence of CfDs themselves would influence this (in the same way that wholesale electricity price is influenced by the market behaviour induced by the CfDs today).

- Alternatively, it could be managed by defining more narrowly the permitted markets/uses that hydrogen supported by the CfD can be sold into. However, this limits the multi-user opportunities that hydrogen can provide, and would also be likely to open to gaming.

### New Contracts entity

- The delivery body would need to be set up with the necessary legislative rights to enter into contracts on behalf of the government with hydrogen producers, and the necessary rights to collect revenues from gas consumers.

- To establish this would require commitment to the principle (along with treatment of other low carbon gases), agreement to approach along with appropriate consultation, primary and secondary legislation to establish the delivery body (or empowering an existing one). The market would then need confidence in the regime to start investing.

- There is a risk this would take a considerable length of time, and would require significant commitment to long term and wider regime.
During this time, there would be no bulk hydrogen delivery, so no ability to establish infrastructure, nor benefit from ‘learning by doing’.

**Policy commitment to principle of a gas CfD**
- Early days policy-wise, especially dependency on hydrogen. FOAK projects provide the evidence needed to

**Agreement of CfD approach**
- Principle established from electricity sector, but concerns from (a) domestic consumers (Fuel Poverty) and (b) industrial competitiveness. Needs common HMG view &

**Primary Legislation**
- Does Energy Act have sufficient basis? Unlikely to be achievable without some changes

**Secondary Instrument**
- Would require new secondary instrument and implementation of Management body (EMR Delivery, OFGEM, Other?)

**Market Confidence**
- Market confidence in a new regime typically takes time, especially for large capital investment

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**Enduring regime**
- In a mature market, this may be an appropriate enduring regime if the price of carbon is insufficient to support low carbon hydrogen

**Benefits and issues**

<table>
<thead>
<tr>
<th>Potential benefits of mechanism</th>
<th>Potential Issues of mechanism</th>
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</thead>
<tbody>
<tr>
<td>• It is a “market-based” regime. It uses an auction basis to establish strike price</td>
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<tr>
<td>• Uses the model which has led to the reduction in cost of renewable electricity such as offshore wind</td>
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<tr>
<td>• It is likely to depend on a wider policy framework for gas</td>
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<tr>
<td>• It requires new legislation and the establishment/empowering of a Contracts body</td>
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</tr>
<tr>
<td>• Complexity to administrate given the range of potential markets and values for low carbon hydrogen</td>
<td></td>
</tr>
<tr>
<td>• A market mechanism particularly at a nascent stage carries risks to the producer entails a higher cost of capital and requires a higher level of return to encourage new entrants</td>
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<tr>
<td>• Risk that producers could deliver hydrogen to markets of higher value than the Reference price, and so the socialised cost is higher than it should be, offering poor value to the consumer</td>
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<tr>
<td>• Risk that the Reference Price is higher than an individual producer is able to secure in practice. This concern could hinder the ability to finance a plant.</td>
<td></td>
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<tr>
<td>• Risk that in addressing these concerns producers are constrained in the markets to which they can supply hydrogen, limiting the potential benefits of hydrogen, and risking gaming.</td>
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4) LOW CARBON GAS (HYDROGEN) OBLIGATION

Overview

- An obligation is imposed by HMG on gas suppliers to secure low carbon gas (hydrogen); This incentivises them to buy a specified proportion of low carbon gas, but to secure this at lowest cost compared with competitors, with the ability to trade or buy out if they are unable to meet their obligation. This is the basis of the former electricity Renewable Obligation, and the current Renewable Transport Fuel Obligation.

Socialisation of costs

- The level of obligation on suppliers (the proportion of gas they supply that must be low carbon - or hydrogen) would be set by HMG. This sets a headroom of low carbon supply required above that which is available, and therefore value.
- Supplier can either discharge their obligation by buying certificated low carbon fuel, trade certificates with other suppliers or potentially buy out. This creates a market value for the certificates for the low carbon hydrogen. The producer receives the commodity price as well as the certificate value.
- The cost of these certificates is socialised by the suppliers across all gas consumers. The current gas market is split between domestic and commercial customers (300TWh), industrial users (200TWh) and Power users (300TWh).
- The objective of this socialisation methodology is to allow the market to set the price of the revenue support required.
- At the nascent stages of a market the lack of price certainty for producers is a particular challenge in financing.

Mechanism for delivery

- A benefit of an Obligation is that it relies on existing suppliers, rather than setting up a new delivery body.

Experience

- In the electricity sector a move was deliberately made away from an Obligation to CFDs in order to a) to avoid over rewarding (when the underlying commodity price moved upwards) and b) to provide better revenue certainty and therefore lower costs of capital.
- The RTFO has delivered a proportion of renewable transport fuel, but this is largely imported. Very few new plants were constructed in the UK on the basis of the RTFO, and the majority of those that defaulted on debt. They now only operate because the new owners were able to purchase the plants heavily written down and can now operate on a marginal cost basis.

Enduring regime

- In a mature market, this may be an appropriate enduring regime if the price of carbon is insufficient to support low carbon hydrogen.

Benefits and issues

<table>
<thead>
<tr>
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<th>Potential Issues of mechanism</th>
</tr>
</thead>
<tbody>
<tr>
<td>• It is a “market-based” regime. It uses an obligation to drive</td>
<td>• Financing risk. An obligation does not readily provide a secure income stream and is dependent on the headroom between the obligation and delivery.</td>
</tr>
<tr>
<td>• It is a mechanism that is understood by the market for production of low carbon energy</td>
<td>• Given the range of potential markets and values for low carbon hydrogen as a commodity, setting</td>
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| the headroom and buyout certificate price could be challenging |
| • The value of an obligation will always be discounted in financing. To achieve the required level of build out will require a higher premium and socialised cost on consumers, than if the income stream were guaranteed. |
| • A market mechanism inevitably entails a higher cost of capital and requires a higher level of return to encourage new entrants |
| • Length of time to establish a new, wider regime including the legislative process |

5) DIRECT TAX REVENUE SUPPORT: INCENTIVE

Overview

• A direct revenue premium made to the producer from the Exchequer funded from tax revenue. This would supplement the commodity price secured for the hydrogen. It is analogous to the Renewable Heat Incentive
• This premium value would need to be set to enable the hydrogen producer to make its return from this plus the sum of the individual market revenues streams secured by the user, and be financeable

Socialisation of the Costs

• The costs in this case are borne from tax revenue rather than energy users.
• This may be appropriate for a nascent market. However, it is recognised that longer term this may not be tenable, with a general policy preference for the revenue support to be provided by the beneficiaries.
• Care will be required setting the price of the incentive. The RHI is based on set support levels with a mechanism of digression. This does rely on effectively determining the appropriate level of support, that is most cost effective for consumers, whilst providing sufficient revenue for producers to finance delivery.
• A fixed price incentive means that as the value of the underlying commodity varies over time, there is a risk that producers are over or under rewarded. The consequence is either poor value to the tax payer, or risk and cost of financing the facility.

Benefits and Issues

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<thead>
<tr>
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<tbody>
<tr>
<td>• It provides a fixed revenue stream to the producer backed by a government contract</td>
<td>• The additional costs are paid by the tax payer rather than energy users</td>
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<td></td>
<td>• It would require legislation for delivery and may be more challenging from a state aid perspective and take time.</td>
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<td></td>
<td>• Risk that producers could deliver hydrogen to markets of higher value than the assumed in fixing the Incentive and so the cost is higher than it should be, offering poor value to the tax payer</td>
</tr>
<tr>
<td></td>
<td>• Risk that the commodity price paid to an individual producer is lower than assumed in setting the incentive. This concern could hinder</td>
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</table>
the ability to finance a plant, and/or increase the cost of capital

6) DIRECT TAX REVENUE SUPPORT: GRANT

Overview

- A grant payment made to the producer from the exchequer funded from tax revenue. This could cover a proportion of the capital cost of the facility

Socialisation of the Costs

- The costs in this case are borne from tax revenue rather than energy users.
- For a nascent market this may be an appropriate element of support to support early plants. However, it is recognised that longer term this may not be tenable, with a general policy preference for the revenue support to be provided by the beneficiaries.
- The fundamental issue is that the capital cost is only one element of the cost of low carbon hydrogen production. On its own this would not be sufficient to deliver production; revenue support is also required.

Benefits and Issues

<table>
<thead>
<tr>
<th>Potential benefits of mechanism</th>
<th>Potential Issues of mechanism</th>
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<tbody>
<tr>
<td>It provides a fixed revenue stream to the producer backed by a government contract</td>
<td>The support is paid by the tax payer rather than energy users</td>
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<td>It is not sufficient on its own to deliver new plants</td>
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<td></td>
<td>In general, market capital is available, providing a bankable revenue support regime is provided</td>
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CHAPTER 14 - OPTIONS PAPER - BIOENERGY WITH CCS (BECCS)

CONTEXT

- Biomass\(^{107}\) absorbs CO\(_2\) (through photosynthesis) as it grows. If, when the biomass is burnt the resulting CO\(_2\) from combustion is captured and stored permanently, the effect is to remove CO\(_2\) from the atmosphere. This is one route to creating so-called “negative emissions”. CCUS therefore provides the opportunity not just to decarbonise energy or products, but also to create negative CO\(_2\) emissions through BECCS.
- BECCS represents one of the few technologies that can deliver negative emissions at scale, by removing carbon from the biosphere for permanent sequestration. BECCS projects have two outputs: renewable energy and negative emissions of CO\(_2\).
- It is this capability to deliver negative emissions that has led the Committee on Climate Change to identify BECCS as an essential technology if the UK is to achieve a ‘net zero’ carbon economy by 2050. As such, BECCS is expected to play an important role in meeting the UK’s 2050 emissions targets.

THE BEST USE OF A LIMITED BIOMASS RESOURCE

- It is critical that any biomass used in BECCS must be, and must be seen to be, a sustainable resource; and the supply of sustainable biomass globally is, and will remain, limited. It will therefore important to prioritise its use to maximise carbon savings.
- As noted by the CCC in their Net Zero report, this means combining bioenergy with CCS, “whether for power generation, hydrogen production or production of biofuels”.\(^{108}\)
- The CCC ‘Further Ambition’ scenario identifies a potential overall bio resource available to the UK of around 200 TWh of which 173 TWh is assumed for BECCS in 2050. This implies a potential requirement in the UK for around 50 million tonnes of bio-CO\(_2\) storage by 2050.
- As the CCC notes, in addition to BECCS and hydrogen production, bioenergy could also be deployed for biofuels. A combination of all of these approaches will play a role in achieving a ‘net zero’ economy by 2050.

ELECTRICITY

- The CCC’s Further Ambition scenario estimates that bioenergy could account for up to 10% of primary energy in 2050. Of this, 6% of UK electricity in 2050 could be generated by BECCS, with the remaining bioenergy resources used to achieve decarbonisation in other sectors.
- Like CCS-enabled gas plant, BECCS power stations have the capability to operate as both baseload and flexible plant, and thereby contribute to system flexibility and stability.
- However, the volume of negative emissions generated by a BECCS project will be a function of its running regime. It may make most sense if market mechanisms are put in place to encourage BECCS to operate with a high load factor to maximise the generation of negative emissions, in addition to low-carbon energy.

HYDROGEN

- Another route for BECCS would be through production of hydrogen, as an alternative vector for energy transmission. The primary conversion efficiency of biomass to hydrogen is around double that of electricity production with post combustion capture, although the hydrogen may of

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\(^{107}\) For this report, and in this context, “biomass” generally refers to wood pellets or other fuels grown specifically for use as a renewable resource. “Bioenergy” also encompasses other sources such as biogenic waste or crop fermentation, which also have BECCS applications.

\(^{108}\) Net Zero - The UK’s contribution to stopping global warming, CCC May 2019 p148
course then need further conversion downstream from the initial conversion process. Hydrogen can then be delivered to a range of markets.

- Analysis by Imperial College suggests this may be an appropriate use of a finite feedstock\(^{109}\); their modelling pointed towards the use of BECCS to produce hydrogen in all cases. In that scenario use of 200TWh of primary biomass, at a (conservative) conversion efficiency of 69% would produce some 138TWh of bio-hydrogen.

- When combined with hydrogen storage, hydrogen use could include dispatchable power production. This route would allow a biomass conversion and capture plant to operate in a baseload mode, which matches the requirements of the biomass supply chain, plant operation and economic utilisation of equipment; whilst enabling dispatchable generation.

### MONETISING NEGATIVE EMISSIONS

- In either case, BECCS projects will generate negative emissions as they operate. Over time, these negative emissions will become increasingly valuable as a lower cost solution to offset emissions in other hard-to-decarbonise sectors, such as aviation or agriculture.

- A key issue for BECCS business models is that there is currently no framework in place for valuing negative emissions and providing a commercial return on them. Bioenergy use is rewarded as renewable, but the value of capturing and storing CO\(_2\) from that use cannot currently be monetised.

- At present, there is no domestic (UK) or regional (European) mechanism that values or incentivises negative emissions. This policy gap needs to be addressed by HMG if BECCS is going to deploy in the UK at the scale required to meet long-term carbon targets. As stated within the CCC net zero report, “Bioenergy when paired with CCS, can provide negative emissions. Investment mechanisms will need to be developed that recognise and reward the value of negative emissions across a range of Greenhouse Gas Removal (GGR) technologies, whilst also incentivising energy production”\(^{110}\).

- The issue covers both the ultimate source of funding (e.g. tax revenue or consumers, and which consumers); and also, the mechanism for delivering such revenue support. (The limited work done so far by the CAG indicates a potential role for EU ETS certificates (or equivalent) in proving such a mechanism, but this needs much more analysis.)

- Negative emissions could be supported through:
  - Inclusion of a negative emission value in the CfD strike price awarded to BECCS developers, which could reduce as a secondary market for negative emissions emerges over time;
  - Integration of negative emissions into a stand-alone UK ETS or new UK emissions system;
  - A stand-alone mechanism or traded marketplace designed to incentivise investment in not just BECCS but other Greenhouse Gas Removal technologies.

### BECCS IN ELECTRICITY GENERATION - CONTRACTS FOR DIFFERENCE (CFD)

- Commercially, biomass can be treated similarly to other fuels in electricity generation, although there is no carbon price penalty when it is used as fuel. The Contracts for Difference (CfD) regime is a well-established mechanism for supporting bioenergy power projects, both conversions and new builds.

- It is recommended that BECCS electricity generation projects be supported with at least a 20-year CfD through modifications to the existing CfD structure, but without the discrimination between retrofit of existing plant and new build. This would however need to pay a fixed element for CO\(_2\) T&S costs. However, this leaves the negative emissions unvalued and unrewarded.

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\(^{110}\) Net Zero - The UK’s contribution to stopping global warming, CCC May 2019 p53
• As noted by the CCC, in the future there will clearly be a value to negative emissions and Greenhouse Gas Removal (GGR) technologies. This will probably increase over time as international markets develop and hard-to-decarbonise sectors look to ‘procure’ negative emissions if alternative decarbonisation options are more expensive (or indeed are proven to be technically challenging). In the absence of a clear price signal through a specific policy mechanism, GGR developers will not be able to realise this value.

• Like other CCS power projects, the existing CfD structure would need to be amended to be suitable for supporting BECCS projects. In line with the recommendations of the CAG electricity WG, amendments should include at least a 20-year CfD term and the integration of a fixed T&S capacity fee in the strike price. To maximise negative emissions generation, BECCS should operate at a high load factor, more akin to a traditional baseload profile.
CHAPTER 15 – CROSS-CHAIN ISSUES

Summary

CONTEXT

• Previous UK CCUS business models were based on the private sector developing full-chain projects for the first capture and T&S elements of the CCUS “chain” in a CCUS cluster. Two changes are proposed by the CAG (based on the CCTF recommendations).

• First, the CCUS business models proposed by the CAG are based on the CCTF recommendation of separating the CCUS “chain” into part-chain elements - i.e. Capture and T&S. This allows “natural investors” to invest in each part of the chain.

• But it does introduce the issue of how the part chain elements operate together.

• With private sector investors in each part of the split chain, each needs protection against failure of the other part of the chain to perform. This is particularly so for the first projects in each part of the chain in a new cluster.

• However, in each cluster this risk will decline significantly when new capture and T&S assets (or even shipping options) are added to the network, or the original assets are expanded to create multiple options for capture and storage in the cluster CCUS network. And as the assets are expanded even further beyond that these risks should largely disappear.

• Second, previous models also allowed for “private sector” levels of risk and reward in the projects. The recommendation of the CCTF, adopted by the CAG, is to keep costs of capital as low as possible by ensuring that only modest risk (commensurate with say an 8-12% real pre-tax return) remains with the Capture projects, and minimal risk (commensurate with say an 4-7% real pre-tax return) remains with the T&S projects.

• Inevitably, the combination of these two strategies exposes cross-chain performance risk as a major set of risks that needs to be mitigated and managed “outside the projects”.

• This is one of the “irreducible risks” identified by the CCTF for which HMG needs to help facilitate the risk mitigation and management in some way.

• The issue is how these risks can be mitigated for the first projects in a cluster.

• The CAG is proposing a set of measures that HMG can facilitate which will do this.

DURATION

• Cross chain risks will not last indefinitely - nor even very long!

• They are most acute with the first investments in new CCUS clusters.

• Once the first assets are operating in a cluster they will fall away very rapidly as i) the first projects demonstrate performance; and ii) new capture and T&S elements are added to the cluster network.

• Once more than one option for CO₂ supply and disposal is created in a cluster then the risk is largely removed. For example, with two stores in a network, possibly a shipping terminal and several capture projects the risk will be all but gone.

• Once other clusters are operating the cross-chain risk for a new cluster can be lower if clusters both the new cluster and other clusters can be connected by CO₂ shipping, to provide a “safety valve”.

• However, maturity of the technology and experience operating it provide little relief. It is not a question of waiting until others have the experience - there have to be other assets to provide the “safety valve”.
CHAPTER 15: Cross-Chain Issues

Options Paper 15A: Cross Chain Failure - T&S Assets Temporarily Not Available.

CONTEXT

T&S assets are designed to comply with high levels of reliability, availability, maintainability (RAM). Experience of existing facilities suggest typical availability rate in excess of 97%, system failure probability around 1%, and downtime due to planned maintenance activities around 2%.\(^{111}\)

Possible causes of T&S assets unavailability can arise in the transport segment of the chain (compression system, pipeline, offshore platform, liquefaction plant, loading/offloading facilities, etc.) as well as in storage (wellheads, well completion, reservoir, etc.). T&S chain is exposed to risks that could affect the T&S assets availability for a short-medium term (less than cumulative 6 months over a period of 15 calendar years) or long term (cumulative six months or more over a period of 15 years).

Consequences of different magnitude are expected for CO\(_2\) capturers, whether T&S assets are unavailable for a short, medium or long term. The capacity of capture projects to carry consequences depends on the duration of the T&S assets non-availability. Short- and medium-term non-availability can be carried by the CO\(_2\) capturing project.

OPTIONS

All options below assume that before “first CO\(_2\)”, CO\(_2\) capture assets will be entitled to operate unabated, provided they obtain sufficient ETS certificates to cover their emissions.

PREFERRED OPTION

1) HMG FACILITATES ARRANGEMENTS TO HOLD CAPTURERS ECONOMICALLY NEUTRAL

If, after the Contract Start Date for the first “T&S Services Contract”, and for whatever reason, T&S assets are not available to accept CO\(_2\) delivered to the point of receipt, the following will apply:

This includes circumstances where:

- T&S assets are temporarily completely unavailable;
- T&S assets are available but are capacity constrained for any reason and cannot accept the full contracted quantity of CO\(_2\) being delivered.

CO\(_2\) Capturers

CO\(_2\) Capturers will be entitled to continue to run, either wholly or partly unabated. They will continue to receive a portion of their revenue support from the “Funders of CO\(_2\) Capturers”. This will be set to hold them economically neutral versus the situation where they run abated and are able to deliver CO\(_2\) for transport and storage. The definition of this level of support will be set case by case.\(^{112}\)

In the case of Industrial Production with CO\(_2\) Capture projects, it may be necessary to provide the CO\(_2\) Capture projects with “free allowances” for CO\(_2\) emissions as well as continued revenue support to enable them to continue to operate unabated.

In the case where Electricity Generators have a “Dispatchable CfD Contract”, as proposed by CAG, it may not be necessary to provide ETS certificates when they are running unabated. When running unabated, the “Dispatchable CfD Contract” will provide a fixed payment and take vented CO\(_2\)

\(^{111}\) Equinor confirmed that both the Sleipner and Snohvit stores in the Norwegian North Sea operate to a level of 98% availability. This has been achieved intentionally through both design and project execution. Actual load factors are therefore determined primarily by the rate of capture of CO\(_2\). Source: Private correspondence between CAG members.

\(^{112}\) Note: The level of support needed will be very dependent on the design of the revenue support provided to each technology. Changing support mechanisms will change the level of support needed.
emissions into account through the variable payment. In addition, the cost of purchasing the necessary ETS certificates for running unabated should be taken into account when the Electricity Generator decides to operate in unabated mode for economic reasons.

In the case of Hydrogen Production in a RAB structure it will be logical for any emissions certificates required to be included in the costs charged to the RAB.

If T&S assets are not available, it should be possible for HMG to arrange to provide ETS certificates to Industrial Producers with CO₂ Capture at no cost to HMG if necessary. The easiest way to do this may be through providing free certificates under the rules covering possible “leakage” to other countries caused by the EU ETS.

An alternative is for T&SCO or HMG to build up a contingency reserve of ETS certificates, purchase in advanced and held for use when needed.

**T&SCO**

If T&SCO’s assets are not available, T&SCO would be contractually bound to honour its T&S contract if possible. This could include using alternative assets, or shipping to other T&S assets.

Costs incurred in doing so would be recoverable through the RAB (subject to the incentives and penalties mechanism).

During the period of unavailability or reduced availability, T&SCO will be entitled to receive a portion of their T&S fees. Payments by the “Funders of CO₂ Capturers” will be adjusted accordingly.

The level of appropriate reduction will need to be developed between T&SCO and the regulator, balancing the desire to incentivise T&SCO to restore services, but recognising that in most instances unavailability will result from circumstances which could not be predicted nor controlled by T&SCO.

T&SCO therefore carries the risk that it loses a portion of its cash flow when it cannot accept delivery of CO₂. However, provided it performs to the requirements of the incentives and penalties regime, T&SCO will be permitted to carry forward and recover these cash-flow losses through resetting the fees at the next periodic review.

If the initial capex for T&SCO was provided by a grant, then this payment would not be needed.

**Justification for choosing this option**

There is a strong economic imperative to allow CO₂ Capturers to continue to run unabated when T&S cannot accept CO₂ temporarily. The cost of having to cease production would increase the cost of production, and therefore the required revenue support, dramatically.

Precedents exist in other regulated industries (e.g. the OFTOs in Offshore Wind) whereby payments continue but are reduced in periods of unavailability.

Clearly the incentives and penalties regime trumps all! This will contain measures that provide both incentives and penalties - and the principles laid out throughout this document will be subject to T&SCO performing satisfactorily.

As a network of capturers and T&S assets develops in a region/cluster the requirements for this cross-chain protection will diminish significantly and in due course disappear.

The returns being offered in our model are low. T&SCO therefore need to be confident of an income stream - subject of course to incentives and penalties. Therefore T&SCO with the store down would be able to make up the losses through their RAB.

The exact design of these features under the RAB will need scrutiny to ensure there is no over-compensation.
CHAPTER 15: Cross-Chain Issues

ALTERNATIVE OPTIONS

2) **T&SCO Buy ETS Certificates; Treated as an Allowable Cost**

CO₂ Capturers will run unabated.

T&SCO will be obliged to purchase sufficient ETS certificates to cover any incremental CO₂ that has to be emitted by Industrial producers with CO₂ Capture. The cost of these certificates will be treated as an “allowable cost” under the RAB model.

3) **T&SCO Dispose of CO₂ Elsewhere; Treated as an Allowable Cost**

T&SCO will seek alternative routes for disposing of the CO₂ - in particular, shipping to another T&S facility. If this proves possible then the extra costs of shipping (and storage) will be allowable costs (subject to the provisions of the incentives and penalties regime). (By definition, this is not an option for the very first T&S network, as it obviously presupposes the development and existence of more than one T&S network both of which can accept CO₂ shipping. However, over time and once several networks are developed, this option will of course help reduce the consequences of cross chain failure at each network.)

4) **T&SCO Carry the Cost of ETS Certificates Resulting from Unavailability**

CO₂ will be vented, and T&SCO will be obliged to purchase sufficient ETS certificates to cover any CO₂ that has to be vented. T&SCO will still be paid their T&S fee in order to cover the cost associated to ETS certificates purchase and will have to pay liquidated damages equal to £ XXX to the CO₂ capturing project in case T&S assets are not available for cumulative six months or more over a period of 15 years.
Options Paper 15B: Cross Chain Failure - Capture plant does not deliver CO₂ to T&SCo

CONTEXT

The failure of a Capture plant to deliver CO₂ to a T&S could arise for several reasons:

- Delays in the construction programme, resulting in the Capture plant commissioning later than envisaged;
- An unexpected outage in the Capture plant;
- An unexpected technical issue with the capture technology.

In the first instance, the Capture plant developer/operator (assumed here to be one and the same) will take all reasonable steps to mitigate the risk of non-delivery of CO₂ through conventional commercial and legal remedies, such as agreeing performance guarantees and securing performance security with its EPC contractors.

However, despite these best efforts, the Capture plant may i) not be commissioned in time to meet the first delivery milestone for CO₂ to the T&S, or ii) once operational may fail to supply CO₂ to the T&S for a period of time due to the failure of the Capture plant or the capture technology. During this period, it is vital that T&S receives enough revenue to ensure its commercial viability.

In the event of a failure of the Capture technology rather than the Capture plant itself, it may be preferable for the Capture plant to continue to operate unabated whilst the capture technology is being repaired. This would however expose the Capture plant operator to additional costs (i.e. carbon pricing), undermining the commercial viability of the project itself and creating additional uncertainty for investors prior to any FID.

PREFERRED OPTIONS

If for whatever reason the CO₂ Capture plant does not deliver the contracted volume of CO₂ to the T&S assets, options are:

1) T&S “CAPACITY RESERVATION FEE” STILL PAID

Capture plants are not obliged to operate or deliver CO₂ to T&S. Capture plants will not receive revenue support when they are unable to operate, except under exceptional circumstances that may be defined under the CfD.

However, regardless of the volume of CO₂ delivered, the “Funders of CO₂ Capturers” will still be required to pay the “capacity reservation” portion of the T&S fees to CO₂ Capturers, and CO₂ Capturers will still be obliged to pass these fees through directly to T&S. (The alternative of passing these fees directly to T&S has also been proposed but is not recommended.)

This obligation should start from the Contract Start Date of the “T&S Services Contract”.

2) VARIANT 2: T&S CAPEX PAID BY GRANT FOR FIRST T&S ASSETS IN A CLUSTER

If the T&S investment capex is paid for by an HMG grant, then this payment of the T&S fee in these circumstances would not be necessary. (This is Variant 2)

Justification for choosing these options

The expected return from investments in the T&S assets under the RAB is low, commensurate with accepting low risk. T&S will not have the income in times of normal operation, nor the liquidity in times of disruption, sufficient to absorb the impact of a loss of income when if their customer’s deliveries of CO₂ stop. It is unrealistic to expect investment in a low-risk, low-return infrastructure
asset operating under a RAB if they face volatility of income caused by factors outside their own control.

The alternative option (Variant 2) should also be considered carefully. This would remove the need for payments of the T&S fees to be made when the capture plants were not delivering CO₂.

### ALTERNATIVE OPTIONS

3) **DEFER “CAPACITY RESERVATION FEE” PAYMENTS**

Allowing the capturers to defer payment of T&S fees until they start or restore operations and increasing the fees T&SCo charges to them when they do so to recover any backlog.

4) **WAIVE “CAPACITY RESERVATION FEE” PAYMENTS – INCREASE OTHER CUSTOMER FEES**

Requiring T&SCo to waive the capturer’s fees and allowing T&SCo to recoup the lost fees in the future or from other customers through the RAB calculations.

5) **WAIVE “CAPACITY RESERVATION FEE” PAYMENTS – COMPENSATE THROUGH OTHER FUNDING**

Requiring T&SCo to waive the capturer’s fees and arranging further funding of T&SCo to compensate for the loss of income from the capturer.

### PROS AND CONS OF OPTIONS

Continued payment of the T&S fee when CO₂ is not delivered provides much more certainty of income for investors in T&SCo.

This would not be necessary if the capital investment in the first T&S assets in a cluster were paid for through an HMG capital grant.

Requiring T&SCo to hold contingency reserves which are large enough to allow loss of income to be recovered only either when the capture plant returns to operation, or through in future regulatory settlements, will increase the cost of T&S very significantly.

Passing lost fees on to other customers would be an option, though this would probably be seen as an unattractive solution.

Raising further funding, and “rolling these losses up into the RAB” would also be an option but would require very significant levels of contingency funding for T&SCo, and would increase costs substantially.
CHAPTER 15: Cross-Chain Issues

Options Paper 15C: Permanent Closure or Prolonged Shut-In of Store

CONTEXT

There is a remote possibility - albeit extremely unlikely - that, after commissioning, an event occurs which causes permanent closure or prolonged or repeated shut-in of the CO₂ store. This could include a decision by the operator, regulator or other relevant authority to stop injection permanently, for a prolonged period, or repeatedly, due to issues such as:

- Ship collision, wave or weather event causing significant damage to offshore facilities;
- Corrosion/failure of legacy wells causing leakage of hydrocarbons or CO₂ to the surface;
- Failure of development wells causing leakage of hydrocarbons or CO₂ to the surface;
- Loss of store integrity due to unpredicted CO₂ migration, caprock failure or overpressure, leading to CO₂ migration to surface;
- Reduced reservoir capacity due to unexpected reservoir characteristics.

Individual risks will vary across projects, and projects will need to agree risk and mitigation registers and allocation of risks with government at relevant stage gates.

PREFERRED OPTION

1) HMG ACTS AS INSURER OF LAST RESORT

Despite these setbacks, T&SCo would be contractually bound to honour its T&S contract if possible. This could include replacing onshore or offshore pipelines or facilities or developing new wells or an alternative store. The regulator could require T&SCo to incur costs as necessary to do so, which would be allowable under the RAB. However, T&SCo’s shareholders would not be obliged to provide any finance to cover these costs, and the regulator would be obliged to set an allowable rate of return on such costs that would attract alternative funding if it is needed.

In the event of permanent closure or a prolonged shutdown of the store, T&SCo will continue to receive a reduced T&S fee until operations are restored or an alternative regulatory settlement is reached.

If after an agreed period injection could not be resumed, or was not permitted by relevant authorities, then HMG would act as an “insurer of last resort”. HMG would cover the remaining exposure of any debt providers and equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies, as well as returns to date.

HMG will have step-in rights to any remaining assets and contracts (should they wish to exercise them). They would become the “funder of last resort” for a new CO₂ T&S service to be provided to those with contracts with T&SCo. There may be a need to create a special administration regime to protect consumers against the possibility of T&SCo insolvency.

Justification for choosing these options

Given that the likelihood of this risk materializing is extremely low, this option would seem to present good value for money for the UK Taxpayer. It should reduce the cost of projects materially and represent an extremely small contingent liability to HMG.

Whilst the regulator will have the power to require new expenditure by T&SCo, the regulator cannot force shareholders to inject new finance into T&SCo. In practice therefore, this power will be constrained by the ability to find finance at economic rates and affordability, so the regulator’s choice
as to which course of action should be followed will be based more on mutual agreement with T&SCo than the regulations might imply.

The need for the “insurer of last resort” is required at the outset as T&SCo may have only the one T&S asset, with no readily available alternatives. As T&SCo expands, adding several stores and perhaps the capacity to ship CO₂, the need for this insurer of last resort role, and the probability it would ever be called upon, will fall away rapidly.

**ALTERNATIVE OPTIONS**

2) **NO INSURER OF LAST RESORT**

The investment in the first T&S assets in a cluster using a RAB model are made using equity shareholder finance only, provided by equity investors who believe that they can assess the likelihood of store “failure” and mitigate it effectively. No HMG “insurer of last resort” option would be required.

3) **HMG ACTS AS INSURER OF LAST RESORT FOR DEBT PROVIDERS ONLY**

HMG act as “insurer of last resort” for debt providers, but not for shareholder equity investments.

**PROS AND CONS OF OPTIONS**

It is very unlikely that debt providers will invest in the first T&S assets in a cluster without some form of HMG “insurer of last resort” role. There is no other form of insurance or protection available that would provide suitable reassurance that they would be protected from the consequences of store “failure” or similar events.

Equity investors could invest in the first T&S assets in a cluster with equity only and no debt, and then refinance their projects to include debt once they are running successfully. However, this will increase the cost of such investments substantially.

T&S investors could accept that they will not receive the protection of HMG as an “insurer of last resort” against a store “failure” or other similar scenario. Again, this will increase the cost of these projects significantly.
Options Paper 15D: Cross Chain Failure - Pre-Commissioning Stranded Asset Risk - No T&S

**CONTEXT**

It seems extremely unlikely that CO₂ Capturers will build a CO₂ T&S system, and that for whatever reasons no prospect then appears of a T&S system being available to store the CO₂.

The preponderance of advice is that CCUS will be critical in the UK to enable meeting the Carbon Budgets set under the Climate Change Act. T&S assets will therefore almost definitely be built and made to work. This so-called “stranded asset” risk therefore seems very remote.

This is a sub-case of Options Papers 15A and 15C.

The situation where a T&S system is delayed is covered in Options Paper 15A. CO₂ Capturers will be able to operate unabated until the store is available.

The situation where a T&S system fails is covered in Options Paper 15C. T&SCo will be obliged to seek to deliver alternative options for CO₂ T&S. If they are unable to, then HMG would act as “insurers of last resort” for T&SCo.

**PREFERRED OPTION**

1) **HMG ACT AS INSURER OF LAST RESORT**

For Capture, a decision would need to be made as to whether to:

- Run the new assets unabated;
- Adapt the new assets to an alternative service, or;
- Close and abandon the new assets.

Thereafter, HMG would act as “insurer of last resort” and cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

**Justification for choosing this option**

Given that the likelihood of this risk materializing is extremely low, the preferred option would seem to present good value for money for the UK Taxpayer. It should reduce the cost of projects materially and represent an extremely small contingent liability to HMG.

**ALTERNATIVE OPTIONS**

2) **HMG ACTS AS INSURER OF LAST RESRT FOR DEBT PROVIDERS BUT NOT EQUITY INVESTORS**

HMG act as “insurer of last resort” for debt providers, but not for shareholder equity investments. This is a credible alternative, though it will increase the cost of the projects significantly.

3) **HMG DO NOT ACT AS INSURERS OF LAST RESORT**

HMG do not provide any protection for the “stranded asset” scenario for the first investors in a CCUS cluster.
4) EQUITY INVESTORS ACCEPT PRE-COMMISSIONING STRANDED ASSET RISK

The first capture plants in a cluster are made using equity shareholder finance only, provided by equity investors who believe that they can assess and price the pre-commissioning stranded asset risk and mitigate it effectively - principally through programme development coordination, and through sound choices in and management of the T&S project.

PROS AND CONS OF OPTIONS

It is very unlikely that debt providers will invest in a capture project before it commissions without some form of HMG “insurer of last resort” role. There is no other form of insurance or protection available that would provide suitable reassurance that they would be protected from the consequences of such an event.

Capture projects could invest with equity only, and then refinance their projects to include debt once they are running successfully. However, this will increase the cost of such investments substantially.

Capture projects could accept that they will not receive the protection of HMG as an “insurer of last resort” against a pre-commissioning stranded asset risk. Again, this will increase the cost of their projects.
Options Paper 15E: Cross Chain Failure - Pre-Commissioning Stranded Asset Risk - No CO₂ Capturers

**CONTEXT**

It seems extremely unlikely that T&SCo will build a CO₂ T&S system, and that for whatever reasons no prospect then appears of any CO₂ capture plants being built to use it.

The preponderance of advice is that CCUS will be critical in the UK to enable meeting the Carbon Budgets set under the Climate Change Act. CO₂ capture plants will therefore almost definitely be built and made to work. This so-called “stranded asset” risk therefore seems extremely unlikely.

This is a sub-case of Options Paper 15B.

Once T&S assets are ready to accept delivery of CO₂ from the capturers, the “Funders of the CO₂ Capturers” will be obliged to start paying the “capacity reservation” portion of the agreed T&S fee. There will be no contractual limit to how long this will continue.

It is possible (though again extremely unlikely) that HMG could decide that the T&S assets should be abandoned.

**PREFERRED OPTION**

1) **HMG ACTS AS INSURER OF LAST RESORT**

In that event HMG would act as “insurer of last resort”. The T&S assets would need to be permanently closed and decommissioned in the most financially effective way possible. HMG would cover any remaining exposure of any debt providers and the equity of equity shareholders at an agreed repayment rate reflecting the reduction in risk that repayment implies.

**Justification for choosing this option**

Given that the likelihood of this risk materializing are extremely low, this would seem to present good value for money for the UK Taxpayer. It should reduce the cost of projects materially and represent an extremely small contingent liability to HMG.

**ALTERNATIVE OPTIONS**

2) **HMG ACTS AS INSURER OF LAST RESRT FOR DEBT PROVIDERS BUT NOT EQUITY INVESTORS**

HMG act as “insurer of last resort” for debt providers, but not for shareholder equity investments. This is a credible alternative, though it will increase the cost of the projects significantly.

3) **HMG DO NOT ACT AS INSURERS OF LAST RESORT**

The first capture plants in a cluster are made using equity shareholder finance only, provided by equity investors who believe that they can assess and price the pre-commissioning stranded asset risk and mitigate it effectively - principally through programme development coordination, and through sound choices in and management of the capture project.

**PROS AND CONS OF OPTIONS**

It is very unlikely that debt providers will invest in a T&S project before it commissions without some form of HMG “insurer of last resort” role. There is no other form of insurance or protection available that would provide suitable reassurance that they would be protected from the consequences of such an event.
T&S projects might invest with equity only, and then refinance their projects to include debt once they are running successfully. However, this will increase the cost of such investments substantially.

T&S projects might accept that they will not receive the protection of HMG as an “insurer of last resort” against a pre-commissioning stranded asset risk. Again, this will increase the cost of their projects.
CHAPTER 16 - PROJECT AND CLUSTER DEVELOPMENT

Option Paper 16A: Coordination between CO₂ Capture and T&S assets

CONTEXT/BACKGROUND/INTRODUCTION

To deliver CCUS coordination between capture and T&S projects

- It is expected that that the first Capture and T&S projects in a Cluster will be developed together, reaching FID at the same time and then built and commissioned in a coordinated way to create a functioning integrated CCUS chain;
- Whilst Capture & T&S projects are designed to ensure that they “fit” together, there must be sufficient points to allow for expansion of both the T&S infrastructure in an economically sensible way as more captured CO₂ requires storage;
- Business models will need to be developed and put in place ahead of FID for the project which sets up the CCUS network to accommodate production (industrial, hydrogen or electricity) and to allow this to continue economically when the T&S infrastructure is temporarily unavailable due to expansion or maintenance.

PREFERRED OPTION

1) PROGRAMME DEVELOPMENT CONSORTIUM.

It is anticipated that for the development of the first projects in a cluster a “Programme Development Consortium” would be created involving one or more potential capture sources and prospective owners of key CO₂ transport and storage facilities. The Consortium will appoint a “Programme Development Coordinator” to lead the Consortium.

The Consortium will work with regional authorities and other organisations in the region, noting that any T&S infrastructure developed will have third party access arrangements. The Coordinator will produce a plan for integration of further capture sources into the system.

The Coordinator could be one of the possible anchor projects, an external organization appointed by the projects, the regional government authority, or possibly an organization appointed by HMG that works to a scope defined by HMG.

In general, it is likely that the anchor T&S project developer will be appointed as Coordinator, as they will often have the best opportunity to create a coherent picture of the status of possible capture projects that may be developed in a cluster/region.

The role will be sponsored by the capture, transport and storage projects involved, and may include cost sharing arrangements with government (see option Options Paper 16C). Contractual arrangements between each element of the total project are expected to be used.

Project development would be synchronized, using coordinated stage-gate decision points. The first anchor projects in a cluster will look to pass i) into FEED, and ii) through FID simultaneously. Project development funding provided by HMG prior to FEED will be coordinated across each programme element. All parties will be bound contractually to manage risks and deliver an operating project; with terms depending on the nature of the projects involved, risk allocations and arrangements put in place by HMG to allow the projects to proceed.
ALTERNATIVE OPTIONS

2) **INFORMAL COORDINATION.**

Capture and T&S projects arrange informal coordination between themselves. A contractually agreed system of penalties will operate between the projects if “first CO₂” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

3) **CONTRACTUAL COORDINATION BETWEEN PROJECTS.**

Capture and T&S projects arrange bespoke coordination between themselves, using contractual arrangements to bind the projects to an agreed scope and timetable. A contractually agreed system of penalties will operate between the projects if “first CO₂” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

4) **HMG COORDINATE**

CCUS development through a central organization. A contractually agreed system of penalties will operate between the projects if “first CO₂” does not flow between them by a pre-agreed date, or if one of the projects does not start or complete construction.

5) **CROSS-CHAIN HOLDINGS BINDS PROJECTS TOGETHER.**

Development projects may choose to acquire cross chain holding or ownership to manage cross chain risks, but this cannot be enforced or depended on.

In all cases:

i. Project development would be synchronized, using coordinated stage-gate decision points;

ii. All projects would look to pass i) into FEED, and ii) through FID simultaneously;

iii. Project development funding provided by HMG prior to FEED will be coordinated across projects by the “project development co-ordinator”.

DISCUSSION OF OPTIONS

Past experience has shown that when projects have acted independently in one part of the chain, or where projects have carried significant cross chain risks, these projects have not succeeded. Given that the government desire to enable CCS in clusters, and the intention to deploy T&S infrastructure that can be available to follow on projects to allow CCUS to eventually operate at scale from 2030, project co-ordination in each cluster is key. This naturally leads to the development of a lead or “project development co-ordinator” (also likely to be the anchor project participant in each cluster).

ARGUMENT FOR CHOSEN OPTION

- Government deployment pathway is to enable CCUS in clusters;
- CCUS in any given cluster will need to build to operate ‘at scale’ by 2030;
- Mix of power, industrial CO₂ and hydrogen potential pathways mean that a central anchor project, or natural project development co-ordinator will be necessary to interface with Government for any given deployment project in a cluster.
Options Paper 16B: Asset Size/Capacity - CO₂ Capture and T&S

CONTEXT

Decisions on sizing initial and subsequent investments in CCUS assets will entail a series of significant trade-offs.

Electricity generating assets come naturally in “turbine” units; and investing in more than one unit brings substantial economies of scale. Biomass electricity plants and hydrogen fueled electricity plants follow a similar pattern. However, in specific circumstances a single unit of each of these may be of sufficient size to act as an “anchor” project for a region or cluster.

Projects involving hydrogen production from fossil fuel for use in industry may be sized to match the market need which may involve supply to a number of users or into the gas network more widely.

Industrial on-site capture projects are very varied. Projects have been envisaged for which comparatively small industrial capture projects can act as anchor projects for a regional cluster.

The historical evidence from new build power CCUS projects and the construction of new CO₂ pipelines is that the project economics benefit enormously from scale. This is not the case if existing infrastructure is use or to some extent if ship transport is used.

For new pipelines it is highly economic to “over size” pipelines as the intent is to put in place infrastructure able to transport CO₂ from further capture projects, and it will make sense to do so. Storage costs are less sensitive to scale, but economies of scale do exist.

Choices on T&S infrastructure may also be driven by the availability of existing assets - of whatever size - which can be repurposed for CCUS use, rather than being decommissioned. If available such assets may well be preferred. However suitable reusable assets may not always be available, or available on the timescales envisaged, and the trade-off between keeping overall investment costs low at the expense of incurring high unit costs per tonne of CO₂ abated through CCUS, versus achieving low unit costs through economies of scale may arise in some possible cluster projects. Any such choice would need to be made in conjunction with HMG, and in the context of proposed future CCUS investment policy in the UK.

PREFERRED OPTIONS

1) SIZE SENSIBLY FOR THE FUTURE

The initial cluster capture and T&S projects in any cluster or region should be sized to meet two criteria:

1) Meet a common set of metrics for “reasonable” unit cost (e.g. cost of carbon abatement, unit cost of low carbon electricity or other output), as well as “reasonable” use of capital and capital efficiency.

2) Demonstration of how development of further cluster capture projects provides a clear pathway to allowing CCUS to “operate at scale by 2030”.

The critical T&S assets (pipelines, and available well slots, perhaps terminals) should be “right sized” on the basis that further capture projects will join the network once the anchor projects are operating.

T&SCo will charge T&S fees to recover the full cost of the “right sized” assets, even if they are not fully utilised to start with.

A clear cost reduction pathway for future build out and follow on projects will need to be provided to government and other stakeholders for all initial projects, noting that the cost of carbon abatement from the initial projects could already be the lowest available.
CHAPTER 16: Project & Cluster Development

ALTERNATIVE OPTIONS

2) LARGE SCALE

With sufficient confidence gained elsewhere in specific technologies through operating track record, if HMG decides to exercise the option to deploy CCUS at scale before the 2030s, it may make sense to invest at large scale in the first anchor projects in a cluster.

3) USE CO₂ SHIPPING FOR INITIAL PROJECTS

If the initial T&S investments in a region are likely to be high, it may make sense to use CO₂ shipping to other existing stores for the initial anchor projects in that region.

DISCUSSION OF OPTIONS

Industry, or the developer of the deployment cluster project, does not have the incentive mechanism to build anything other than right size assets, including those for T&S. Without this, an important means to cost reduction for future CCUS projects would be lost.

ARGUMENT FOR CHOSEN OPTION

- Government deployment pathway is to enable CCUS in clusters.
- CCUS in any given cluster will need to build to operate ‘at scale’ by 2030.
- Deploying an offshore T&S asset that has sufficient capacity to accommodate follow on and future projects (from all possible pathways – hydrogen, industry) is a critical component of the cost reduction pathway.
- Government will need to support the means to pay for the additional capacity beyond the anchor project via the T&S business model, whether this is incurred up front, or added incrementally.
- Government is the natural owner of this decision to support paying for additional T&S capacity as it has the only means to manage this risk, via enabling policy to encourage others to fill the T&S network.
Options Paper 16C: Project Development Funding

**CONTEXT**

The developers of CCUS assets are unlikely to be prepared to invest the significant sums required to take their project development through to FID without significant commitment by HMG that provides some degree of comfort that FID will be reached and CCUS development will go ahead.

This commitment could take different forms, either via a signal of commitment (e.g. HMG sharing in the project development costs of CCUS project development), or actual contractual commitment (e.g. a firm commitment to a CfD contract or other similar revenue support contracts to capture projects.)

**PREFERRED OPTION**

1) **DEVELOPERS AND HMG SHARE DEVELOPMENT COSTS OF EARLY PROJECTS**

For early projects, the developers of CCUS projects and HMG share the costs of project development through to FID - both pre-FEED and FEED costs.

2) **ADD EXTERNAL DEVELOPMENT SUPPORT FUNDING**

As in 1) above, but other sources of development funding (e.g. EIB, EU, etc) also contribute to development funding.

**ALTERNATIVE OPTIONS**

3) **DEVELOPER FUNDING ONLY**

The developers of CCUS projects carry the full cost of project development up to FID.

4) **HMG COMMIT EARLY TO REVENUE FUNDING**

HMG provides firm contractual commitment to providing revenue support contracts to CCUS projects before project developers enter FEED studies.

5) **BOTH 1) AND 4)**

The developers of CCUS projects and HMG share the costs of project development through to FID and HMG (or their “agent”) provides firm contractual commitment to providing revenue support contracts to CCUS projects before project developers enter FEED studies.

**DISCUSSION OF OPTIONS**

- Industry is unlikely to want to incur significant cost ahead of FID given past failures of the CCUS commercialisation programmes.
- Non-UK governmental or agency funding may be a possible option to provide non-industry match funding in the future, but the current climate is too uncertain to count on these as realistic to challenge the base case.

**ARGUMENT FOR CHOSEN OPTION**

- HMG controls the principal means to enable successful FID for any CCUS project, through:
  - establishing an appropriate policy framework (CfD, RAB structure etc) across the chain;
  - facilitating provision of revenue support contracts.
- Major projects continue to carry significant development risk, and the UK has a poor track record of taking CCUS projects through to a point of successful FID.
There are significant differences in the methods employed by various organisations to estimate the cost of CCUS. Consequently, this leads to misunderstanding, confusion, and misrepresentation of CCUS cost information, especially among audiences not familiar with the details of CCUS costing. Given the international importance of CCUS for climate change mitigation, efforts to improve the estimation and communication of CCUS costs and value to society are especially urgent and timely.

The UK Government has published guidance on project appraisal and evaluation, “Valuation of Energy Use and Greenhouse Gas”\textsuperscript{113}. This provides industry with the key parameters for measuring and evaluating their projects seeking Government support – some key points from this:

- NPV of CO\textsubscript{2} saved, based on valuing emissions reductions in each year based on traded and non-traded ETS CO\textsubscript{2} price curves is a key metric (see flowchart).
- Cost of CO\textsubscript{2} emissions reductions (abated) is a key metric of the evaluation.
- More qualitative benefits of the project as part of the evaluation process can be factored in. These are discussed in the “Metrics that Address Wider Economic Impacts” section of this paper.
- A simpler metric of “Cost (£/tonne of CO\textsubscript{2} stored” is useful for a first cut evaluation: (this has been used for CAG modelling). There is no need to define an appropriate counterfactual - it is measurable, and gives useful indicative evaluations, especially considering the usual cost uncertainties.

This paper introduces and describes the options available for measuring and evaluating on a consistent basis CCUS costs and value to the wider economy and society either from power plant and/or a variety of different industrial applications, including production of decarbonised hydrogen for the heating sector, maritime, transport, electricity production etc.

The purpose of this paper is therefore to present to the UK Government a broader list of metrics and considerations needed in their effort to target and prioritise CCUS investments.

CCUS Metrics should be able to be used for evaluating CCUS investments including but not limited to ranking by HMG but with a full understanding that ranking was not the sole purpose and that both ‘cost’ and ‘value’ metrics should be consistently used to evaluate CCUS investments.

It is not within CAG’s mandate to recommend specific metrics or considerations.

Some of these metrics may represent measurable quantitative values; while others may be challenging to quantify; nevertheless, the latter may be well as important as more quantitative values.

Given the international importance of CCUS for climate change mitigation, and the recent Committee on Climate Change report on net-zero emissions by 2050 stating that “CCUS is a necessity, not an option”, efforts to improve the estimation and communication of CCUS costs and value to society are especially urgent and timely\textsuperscript{114}.

CCUS is such a broad set of technologies and applications that it is impossible to calculate the costs and benefits of it with a single metric. The value of CCUS on power cannot be easily compared with the value of CCUS on cement manufacture, or with the value of having hydrogen available for use in

\textsuperscript{113} Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal, BEIS, April 2019

\textsuperscript{114} “Policy priorities to incentivise large scale deployment of CCS”, Global CCS Institute, April 2019
the gas network, or with the value of negative emissions from capture of CO₂ emissions from biogenic sources, or with having none of those things.

Furthermore, all the costs of CCUS are internal to the project, and all the benefits are external to the project. These benefits include an increase in inward investment (carbon intensive industry attracted to areas with CCS infrastructure), retention and creation of new jobs, improved air quality plus, in the future, income from storing CO₂ from other countries.

The benefits/value of reducing emissions are much higher than the cost of doing so. However, the benefits don’t accrue to the business that would normally spend the money. This, therefore, justifies public investment, as it means the government can avoid the costs to society of job losses, healthcare for air-quality related illnesses and support for people affected by extreme weather.

The main value of CCUS is in its ability to provide us with the products, services and jobs that we have come to expect, in a way that is consistent with a low-or zero-carbon economy. Rather than providing a good or service (e.g. cement or electricity) that can be valued in a straightforward way, CCUS generally modifies existing production methods to internalise the environmental costs, and address the adverse environmental impacts, of the original manufacturing process.\(^{115}\)

However, in some cases CCUS does provide a good that can be valued: where CCUS is applied to biogenic sources of CO₂ to provide negative emissions, the CO₂ removed from the atmosphere could be priced as a public good.

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**DECARBONISING THE ECONOMY**

The underlying assumption of this report is that the UK is serious about meeting the greenhouse gas emissions targets proposed by the Committee on Climate Change (CCC) – that is, net-zero greenhouse gas emissions by 2050 – and is prepared to invest in meeting the targets. This implies that metrics should help government find the least cost way of meeting the emissions targets. If not meeting the targets is not an option, then the costs and benefits of decarbonising the economy using CCUS must be compared to the costs and benefits of decarbonising the economy using other methods: business as usual is not an option, so should not be used as a counterfactual.

LCOE is found to be relied upon by Governments and Inter-Governmental agencies (e.g. OECD, IEA) for evaluating policy decisions in relation to differential support between carbon-based, low-carbon and renewable electricity generation.

However, there is a lack of transparency in the UK around the £/tonne CO₂ avoided for various technologies to reduce UK emissions i.e. new nuclear, offshore wind, solar, tidal etc. Assessment of costs of CCUS, should be compared with the £/tonne of the alternative forms of permanent emissions reduction across the entire economy:

**Electricity generation:** comparing the costs and benefits of CCGT with CCUS to alternative low-carbon technologies, such as renewable or nuclear energy. This needs to consider the value of providing power on demand against the costs of intermittent renewables\(^{16}\) or inflexible nuclear including the recently estimated back up capacity charges, development of battery or other storage for renewable energy and upgrades to grid and other infrastructure.

The focus for CCUS should be on the value to the system it provides, rather than assessing its costs against renewable or nuclear power.

**Industrial production with a high heat demand:** comparing the costs and benefits of production using fossil fuels and CCUS with production where heat demand is met with hydrogen (which, for large

\(^{115}\) It has been assumed within this paper (Chapter 17) that the Government wishes to maintain or increase current industrial output, and the jobs associated with it, and does not intend to make any judgements on whether some sectors are more desirable or worthy of being maintained than others. There may be additional questions that could be asked about whether all manufacturing output is desirable, or whether the UK economy should be structured differently, but these are beyond the scope of this paper.
volumes and lower cost, initially at least, will have been produced from methane using CCUS) or electrification.

**Industrial production with process CO\(_2\) emissions:** comparing the costs and benefits of industrial manufacture of products with retrofit post-combustion with new technology and processes. New processes may result in transfer of manufacturing jobs overseas while the UK continues with increasing CO\(_2\) emissions.

**Hydrogen production:** comparing the costs and benefits of having the option of hydrogen for heating and transport with the costs and benefits of increased nuclear plus intermittent renewable power, supported by gas plus CCS power for electrification, and comparing the costs with hydrogen manufacture from electrolysis or natural gas reforming or even importing hydrogen.

**Negative emissions:** comparing the costs and benefits of biogenic emissions captured and permanently stored, with continued afforestation for timber production, weathering and peatland restoration. These considerations need to include the timescale over which the CO\(_2\) can be securely stored.

**TARGETING CCUS INVESTMENT**

In addition to economy-wide considerations, metrics are needed to understand where to target CCUS investment to best effect. As above, no single metric will adequately lead decision-makers to the right course of action. Decision-makers will need to articulate their desired policy outcomes – e.g. job retention, negative emissions, provision of particular goods, avoidance of costs elsewhere – and apply a weighting to each, which would then allow a suite of metrics to be compared between projects or clusters of projects.

These metrics may in many cases be similar to those for understanding economy-wide impacts, but at a more detailed scale.

This paper introduces and describes the options available for measuring and evaluating on a consistent basis CCUS costs and value to the wider economy and society. This includes CCUS on power plant; a variety of industrial applications, including production of decarbonised hydrogen for the heating sector, maritime, transport, electricity production etc., and bioenergy with CCUS (BECCS).

It is acknowledged, on a general level, that some metrics (e.g. LCOE\(^{116}\)) can imply negative or adverse measures (costs) for CCUS without communicating its true or full ‘value’:

- It is likely that for a first (‘anchor’) project within a cluster, as a stand-alone project, the unit will not reflect that the cost element in the metrics includes cost for infrastructure with spare capacity while ignoring the value that the anchor project delivers in facilitating further decarbonisation of the region and the protection of jobs, improved air quality and wider national/regional economic benefits (GVA, Balance of Trade etc).
- For some metrics the difference in CO\(_2\) volumes being abated are not reflected adequately – they do not take into account the comparison of small versus large projects, e.g. two projects with the same IRRs or unit costs can have drastically different impacts based on their scale.

There is now an opportunity to address this ‘weakness’ while the UK focuses on the development and deployment of CCUS clusters.

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\(^{116}\) See the section on “Metrics that Compare the Costs of Different Low-Carbon Power Generation Technologies” below.
WHAT CAN WE MEASURE?

The purpose of developing metrics is to be able to answer questions about the costs and value of CCUS to the UK: this includes economic, social and environmental impacts of deploying CCUS, and requires a comparison with the impacts of not deploying it.

The choice of metric(s) used will depend on the objectives of the user and the question(s) they are trying to answer.

The key comparison metric is to compare the cost of the various ways of reducing UK emissions in line with targets and budgets of the Climate Change Act and now, also with the Net Zero Carbon Emissions Legislation. Since it is desirable to maintain a level of output – of power or materials – that meets the UK’s needs, and to retain or increase employment, metrics must also demonstrate impact on these objectives.

CAPTURING, STORING & ABATING CO₂ EMISSIONS

Cost of revenue support per unit of CO₂ abated

This metric gives an overview of project/cluster economics, including a quantification of the cost of revenue support based on the quantity of CO₂ abated. It thus takes into account residual emissions and is useful to compare emissions reduction through CCS with emissions reduction through other technologies: nuclear, offshore wind.

How is it measured?

The “cost of CO₂ abated” is the overall cost measure most commonly reported in CCUS cost studies and cost-abatement curves. It compares a plant with CCUS to a “reference plant” without CCUS and quantifies the average cost of avoiding a unit of atmospheric CO₂ emissions (in tonnes) while still providing a unit of useful product (i.e. MWh in the case of a power plant).

What are we comparing it to?

To compare CCUS schemes with renewable generators, carbon abatement cost should be applied. If you are comparing a whole system cost for CCUS then you need to include whole system costs for renewables i.e. grid strengthening, additional transmission lines e.g. Beauly-Denny, and the costs of compensating for the days when there is no wind (storage and/or capacity market), etc. This can be the beginning of a Value for Money comparison, to which is added labour retention, air quality improvements etc.

The reference plant to which the plant with CCUS is being compared is the same ‘base’ plant i.e. usually a Combined Cycle Gas Turbine (CCGT). The cost of CO₂ abated (obviously) includes the full chain of CCUS processes (capture, transport and storage) that leads to the captured CO₂ being permanently sequestered. (See also later section on ‘Permanence’).

Pros and cons

If whole system costs are used for all technologies, this metric provides a good starting point for making comparisons between them.

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When comparing clusters to their counterfactuals using the metric £/t CO₂ abated it provides a comparison of the unit cost of different CCUS technologies but what is not measured is the overall decarbonization impact that each technology can achieve. For example, capturing only 50% of the emissions from a hydrogen production plant might provide a very low £/t CO₂ abated whereas achieving 95% would have a might higher unit cost but have a much larger overall impact and benefit. Marginal Abatement Cost (MACC) curves, such as the example below, with the reference being the counterfactual can communicate the differences between unit cost of CO₂ abated and the potential CO₂ reduction of different projects and clusters.

Cost of revenue support per unit of CO₂ stored

This metric gives a simpler overview of project/cluster economics, including a simple quantification of the cost of revenue support based on the quantity of CO₂ permanently stored.

How is it measured?

£/tCO₂ stored, based on the amount of CO₂ transferred down the CCUS chain through capture, transport and storage. It can be related to metered quantities of CO₂ in the project.

What are we comparing it to?

This metric is useful for comparing one project, application or cluster with another.

Pros and cons

It can provide a simple economic comparison between projects/clusters, without having to understand the more complex assumptions that are frequently associated with the assessment of the cost of CO₂ abated.

This metric is not trying to be precise: it does not account for residual CO₂ emissions that result from either the additional energy needed for processing the CO₂ capture, or from capture systems that are less than 100% efficient.

In what circumstances is it useful?

It can be a useful metric to use in cross-chain CCUS commercial contracts within clusters, based on metered quantities of CO₂.
CHAPTER 17: Metrics

METRICS THAT ADDRESS CO₂ EMISSIONS

**CO₂ emitted per unit of product**

**CO₂ emitted per unit of electricity**

For the first planned CCUS projects in the UK, that were within the electricity sector, this was an unhelpful metric that arguably led to those projects not progressing. This is because First of a Kind (FOAK) costs were compared with costs associated with mature technologies, ‘Nth of a Kind’ (NOAK) and because full grid costs had not been considered before making those comparisons. However, if these shortcomings are taken into account, this metric could potentially be used to enable the CCUS project to be compared with the emissions associated with other forms of electricity generation, particularly unabated fossil fuelled generation — coal (especially lignite), oil or natural gas — as well as wind and solar.¹¹⁸,¹¹⁹

In assessing any reduction in emissions associated with a power-CCUS project, it is necessary to define the emissions associated with an appropriate counterfactual. In the UK, all utilities are obliged to share this information on their consumer bills, i.e. as at August 2018¹²⁰, the carbon intensity of all power generating sources was:

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>Carbon Intensity (g/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>918</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>357</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
</tr>
<tr>
<td>Renewables</td>
<td>0</td>
</tr>
<tr>
<td>Other</td>
<td>691</td>
</tr>
<tr>
<td>Overall Average</td>
<td>225</td>
</tr>
</tbody>
</table>

The application of CCUS significantly improves, by about 90%, the carbon intensity metric for gas-fired power generation when compared to the unabated natural gas plant. CO₂ emitted per unit of industrial product

For industrial CCUS projects/clusters this is a potentially useful metric to enable assessment of the impact of the CCUS plant on the emissions usually associated with the production of the relevant end-product, e.g. cement, fertiliser or steel. This could be either for the actual plant prior to implementation of CCUS, or for a counterfactual industrial plant that represents “best practice”.

METRICS THAT COMPARE THE COSTS OF DIFFERENT LOW-CARBON POWER GENERATION TECHNOLOGIES

**Levelised cost of energy (LCOE)**¹²¹

The LCOE metric generates a figure equal to the constant real energy price required by a project to return the rate of return on capital invested equivalent to the discount rate and therefore equivalent to the energy price required by the project in an inflation-free world.

The calculation of the unit cost of energy, LCOE is an established metric can provide a comparative measure between projects and technologies. LCOE is relied upon by Governments and Inter-

Governmental agencies (e.g. OECD, IEA) for evaluating policy decisions in relation to differential support between carbon-based, low-carbon and renewable electricity generation.

However, the CAG believes that this metric is incomplete for CCUS as it fails to account for several factors that are only applicable to CCUS plant and not to other generation technologies such as renewables, and also fails in its accounting for the added value/benefits of CCUS to the wider economy. If LCOE is used, then the calculation should include the grid carbon intensity for the intermittent periods (i.e. when the wind is not blowing) and when capacity market diesel plant or alternative, that are required to provide electricity (and the cost of that capacity market).

It is the view of the CAG that LCOE is inadequate to assess the merits and evaluation of CCUS investments. It should be acknowledged that there are pros and cons of using LCOE.

How is it measured?

In general terms, this metric sums the lifetime costs of the energy system under consideration (such as a wind farm, or CCGT power plant), and divides this by the lifetime energy production to deliver an output in cost per unit of energy. Conventionally, LCOE includes only “plant-level costs” and does not take account of “effects at the system level in the sense that specific technologies demand additional investments in transmission and distribution grids or demand specific additional reconfigurations of the electricity systems”\(^\text{122}\) (OECD/IEA, 2015).

Pros and cons

It is acknowledged that the LCOE metric is an established measure and relied upon by Governments and other international agencies.

Notwithstanding the robustness of this metric, there are two important weaknesses of LCOE as a metric for non-renewable power generating technologies (CCGT with or without CCUS). Firstly, the LCOE does not consider the impact of changes in the value of electricity through the day or the higher value of dispatchable (CCGT with/without CCUS) compared to intermittent generation (renewable technologies).

The second key weakness in the application of the LCOE metric is in the handling of inflation. The incorporation of inflation can generate divergent results between different technologies from their inherently different time-based patterns of expenditure. As CCGT schemes (with or without CCUS) incur higher operating costs (fuel) throughout the schemes’ lifetime compared with renewables’ zero fuel costs – this difference means that as cost inflation increases, this yields an increase in LCOE for CCGT (and CCUS) plant compared with renewables.

One of the challenges of the LCOE metric is that it does not measure the ‘value’ that a dispatchable electricity generator such as CCGT with CCUS (or battery storage, hydroelectric) provides the grid, and the suggestion to compare the LCOE of power generation using CCUS with the LCOE of renewables + LCOE of storage does seem more reasonable. However, calculating how much storage to add to renewables is not simple because the true amount of storage required will depend on the electricity system and how closely electricity demand matches the generation profile of that renewable energy source. Is sizing the storage asset to 30-40% of renewable generation sufficient for the combined plant to avoid the need for additional balancing reserve? The amount of storage required would also be dependent on how much flexibility already exists in the system. As the proportion of renewables increases, assuming that it displaces flexible fossil power generation, then it should follow that the backup storage requirement increases. Other electricity system considerations such as how much demand side response exists could also influence how much backup storage is necessary.

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\(^{122}\) OECD/IEA, 2015. Projected Costs of Generating Electricity; 30th September 2015
In what circumstances is it useful?

If the calculation of the unit cost of energy, LCOE is improved as discussed above, then it can provide a comparative measure between projects and technologies. This improvement is critical, since LCOE is found to be relied upon by Governments and Inter-Governmental agencies (e.g. OECD, IEA) for evaluating policy decisions in relation to differential support between carbon-based, low-carbon and renewable electricity generation.

METRICS THAT ADDRESS WIDER ECONOMIC IMPACTS

Gross value added

This estimates the benefit to the economy of a course of action, such as retaining jobs in high-emitting industries through deployment of CCUS.

How is it measured?

Gross value added (GVA) is defined as output (at basic prices) minus ‘intermediate consumption’\(^\text{123}\) (at purchaser prices); it is the balancing item of the national accounts production’ account. GVA can be broken down by industry and institutional sector. The sum of GVA over all industries or sectors plus tax revenues on products minus subsidies distributed on products gives gross domestic product.

Summit Power\(^\text{11}\) estimated GVA using ONS statistical data on output per job, applying it to the direct and indirect jobs created and retained from deploying CCUS. In the report, all GVA from jobs retained was credited to CCUS.

The study\(^\text{11}\) showed that CCUS represents a unique solution with multiple economic and societal benefits that provide a compelling case to start a steady deployment of CCUS in the UK, delivering £54bn in GVA to the UK economy cumulatively to 2060 (with £5bn in GVA positively delivered to the UK economy even as a result of the very first CCS projects to 2032).

Employment Security

This estimates the jobs that are created or retained resulting from deploying CCUS.

How is it measured?

The Summit Power\(^\text{124}\) led report “East Coast UK CCS Investment Study” in 2017 estimated the number of direct jobs in CCUS development using generic sector-specific assumptions on domestic content, for both CCUS project investment and operation phases; and the number of direct jobs retained based on an estimate of the jobs that would be lost without CCUS. The number of indirect jobs was also calculated using economic multipliers on the numbers of direct jobs.

Cost per job

This estimates the cost of intervention per job retained in direct, indirect or increased employment as a result of deploying CCUS.

How is it measured?

Turner \textit{et al} (2019)\(^\text{125}\) have proposed using economic multiplier methods to understand the potential impacts of retaining jobs in key industries using CCUS, expressed as a ‘cost per job’. With CCUS, this

\(^{123}\) Intermediate consumption is a national economics concept which measures the value of the goods and services consumed as inputs by a process of production. It excludes fixed assets whose consumption is recorded as consumption of fixed capital. The goods and services may be either transformed or used up by the production process. Intermediate consumption is valued (recorded) at purchaser prices.


could be used to assess the relative benefits of deploying CCUS to retain jobs in key industries; presumably with further work this could also apply to clusters of industry in a particular geographical area.

A methodology for this has yet not been developed, although Turner et al explores the use of input-output (IO) multipliers for selected industries in Scotland. Turner et al conclude that “IO multiplier analysis provides a first step in generating these metrics”, but more work needs to be done on development and modelling of scenarios.

**ISSUES TO BE CONSIDERED IN MODELLING**

**Value of carbon dioxide**

The Summit Power\(^\text{11}\) led report “East Coast UK CCS Investment Study” in 2017 used the central case of the traded price of carbon covered by HMT in the Green Book. Shadow cost of carbon and social cost of carbon are no longer used by HMT, but might they still have a value?

**Discount rate**

The discount rate used in modelling impact and costs will have an impact on the outputs and a bigger impact the longer the period the modelling covers and vary widely, e.g.:

- HMT Green Book\(^\text{126}\) recommends 3.5% for the first 30 years, then a progressively lower discount rate thereafter.
- The Stern Review used 0.1%\(^\text{127}\).
- The Committee on Climate Change uses 3.5% for social costs and 7.5% for private costs.

**How many years should economic modelling cover?**

The “East Coast UK CCS Investment Study” led by Summit Power\(^\text{11}\) modelled impacts to 2060. The recent CCC Report proposed targeting net-zero emissions by 2050 in the UK as a whole and by 2045 in Scotland.

**OBSERVATIONS AND REMARKS**

Near-term investment in CCUS (including CCUS applied to energy intensive industries) can be a cost-effective, attractive proposition for Government as part of the energy transition. Total costs, including access to a transportation and storage network, have been estimated for a group of energy intensive industry applications at approximately £58/\(\text{tCO}_2\)\(^\text{13}\) – making Industrial CCUS as a lower cost form of carbon abatement than offshore wind (£200/\(\text{tCO}_2\)) and new nuclear power (£128/\(\text{tCO}_2\)). For Government to meet its carbon reduction obligations, Industrial CCUS needs to be implemented alongside low carbon energy sources. On a £/\(\text{tCO}_2\) basis therefore the business case for CCUS is very strong.\(^\text{128}\)

However, this paper has shown that there are significant differences in the methods currently used by different organisations and government agencies to estimate the cost (and value the benefits) of carbon capture and storage (CCUS) schemes. Many of these differences are not clear in publicly reported CCUS cost estimates, and the existence of such differences hampers rather than helps efforts to properly assess CCUS investments and their relationship to other greenhouse gas control measures.


\(^{127}\)https://www.nytimes.com/2006/12/14/business/14scene.html

\(^{128}\)http://www.teessidecollective.co.uk/teesside-collective-report-a-business-case-for-a-uk-industrial-ccs-support-mechanism/
Given the international importance of CCUS for climate change mitigation, efforts to systemise and improve the estimation and communication of CCUS costs are therefore especially urgent.

As discussed in this paper, the costs of CCUS are internal to the project, and the benefits are external, so even though the benefits/value of reducing emissions are much higher than the cost of doing so, the benefits don’t accrue to the business spending the money. This therefore justifies public investment, as it means the government can avoid the costs to society of job losses, increased healthcare costs (for air-quality related ailments) and support for people affected by extreme weather etc. Those external (avoided) costs and benefits are a) hard to value b) hard to quantify (which is why more work is required) and c) take place over different timescales (so the discount rate makes a big difference). This also justifies our assertion that LCOE is a dangerously misleading metric (on its own) in transitioning to a net-zero emissions future.

From the above, useful CCUS Metrics need to harmonize the various costing methods now in use, beginning with a common nomenclature (terminology) for CCUS cost elements and the method of aggregating them to arrive at the total cost and value of a project. The value of CCUS can best be measured through a combination of:

- £/tonne CO₂ abated;
- £/tonne CO₂ stored:
  - A simple metric and is useful for a first cut evaluation: this has been used for CAG modelling, there is no need to define an appropriate counterfactual - it is measurable, and gives useful indicative evaluations, especially in light of the usual cost uncertainties.
- £M per annum, consumer exposure;
- £ per unit of product:
  - £/MWh (LCOE, with recognition of its limitations), or LACE (subject to further work), and
  - £/tonne of (industrial) product, e.g. cement etc.
- Wider economic benefits, e.g.:
  - GVA (It is acknowledged that there can be concerns about the robustness of GVA assessments for projects).
  - Employment security/protection etc

The choice of metric(s) used will depend on the objectives of the user and the question(s) they are trying to answer. For example, and as discussed in this report, comparing projects on a £/tonne CO₂ stored basis alone could lead to misleading results – in this case the total quantity and cost of CO₂ stored could also be reviewed in order to paint the full picture. This essentially highlights one of the risks of only using a single metric. It is likely that metrics are only useful in combination, and to answer particular questions for different audiences. Some examples are given below.

**What is the economic benefit of deploying CCUS in high-emitting industries?**

The East Coast study showed that CCUS represents a unique solution with multiple economic and societal benefits that provide a compelling case to start a steady deployment of CCUS in the UK:

<table>
<thead>
<tr>
<th>Year</th>
<th>GVA¹ (£bn)</th>
<th>Job Creation</th>
<th>Overall Jobs</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Direct</td>
<td>Indirect</td>
<td>Total</td>
</tr>
<tr>
<td>2032</td>
<td>3,050</td>
<td>4,550</td>
<td>7,600</td>
</tr>
<tr>
<td>2060</td>
<td>38,800</td>
<td>28,200</td>
<td>47,000</td>
</tr>
</tbody>
</table>

The CCUS Investments envisaged in the Study would lead to the creation/retention of 225,600 jobs and £54bn in GVA cumulatively to 2060. The asset life of infrastructure was conservatively assumed to end in 2060 for the purposes of the Study.
A positive impact on the balance of trade (BoT) of £9bn has been estimated through to 2060 considering the provision of CO₂ storage services for imported CO₂ (up to 5 MtCO₂ pa by 2060) and the expected benefit from import and export of CCUS related goods and services.

How might potential clusters be evaluated?

There are a number of competing objectives and constraints that an evaluation of the merits of investing in a cluster might consider, including:

- Level of regional support;
- Commercial viability – store size, total cost, potential for further projects;
- Leverage – potential to build upon anchor projects and share the T&S costs;
- Attraction to new investors and ability to foster competition;
- Job creation/preservation;
- Speed of implementation;
- Ability to foster alternative CCUS technologies and innovation; projects with highest system value and that extend the reach of CCUS into the economy;
- Affordability to customers or tax revenue;
- Avoided costs (e.g. decommissioning) and maximising use/longevity of existing infrastructure and industry;
- Ability to mitigate risks (e.g. not relying on one CO₂ supplier or one CO₂ store);
- Ability to fairly allocate (and share) risks across different stakeholders – utilities, industry, shareholders, consumers and tax revenue;
- Affordability – ability to deliver decarbonisation objectives cost effectively and within funding limits;
- Demonstration of competitiveness – use of competition in procurement, assets, operations – showing competitive margins, contingencies and risk absorption;
- Income to UK from storing CO₂ for Europe.

This demonstrates the difficulty of evaluating CCUS projects and prospective clusters through a single metric. It makes direct comparison between technologies (even between clusters) extremely difficult.

The Government’s recent approach to facilitating investment in renewable electricity has been to support certain technologies through competitive auctions (offshore wind, solar, biomass combined heat and power) and others on a bilaterally negotiated basis (new nuclear). With intermittent wind and solar now accounting for an increasingly significant part of the electricity mix, it is clear that to maintain the stability of the system, the future electricity grid will need a portfolio of solutions and flexible sources of generation that can dispatch at short notice or for multiple days during high demand, low wind, cold snaps. A recent report from Imperial College London for Ofgem estimated that having a more flexible power sector could save consumers between £6.6bn and £13.6bn per year129.

Finally, it is acknowledged on a general level, that several metrics can imply negative or adverse measures (costs) for CCUS without communicating its true or full ‘value’:

- It is likely that for a first (‘anchor’) project within a cluster, as a stand-alone project, the unit will not reflect that the cost element in the metrics includes cost for infrastructure with spare capacity while ignoring the value that the anchor project delivers in facilitating further decarbonisation of the region and the protection of jobs, improved air quality and wider national/regional economic benefits (GVA, Balance of Trade etc).
- For some metrics the difference in CO₂ volumes being abated are not reflected adequately – they do not take into account the comparison of small versus large projects, e.g. two projects with the same IRRs or unit costs can have drastically different impacts based on their scale.

129 “Value of baseload capacity in low-carbon GB electricity system”. Imperial College London. 2018
There is now an opportunity to address this ‘weakness’ while the UK focuses on the development and deployment of CCUS clusters.

**ISSUES TO BE CONSIDERED FURTHER**

It is clear that measuring the value of CCUS schemes highlights the existence of several specific and broader measures of the impacts of a full-chain CCUS project on both the power, the industrial and wider regional and national economy.

Several additional measures were brought to the attention of the Working Group during the CCUS Advisory Group deliberations. It is the view of the working group that these metrics are worthy of consideration for wider utilisation and application, but further work is required for use of:

- Levelized avoided cost of energy (LACE),
- Permanence of CO₂ storage,
- Maintenance of CO₂ stored,
- Balance of Trade (BoT), and
- Health Benefits

**Levelized avoided cost of energy (LACE)**

The US Energy Information Agency publishes a metric called the Levelized Avoided Cost of Electricity (LACE) in its Annual Energy Outlook¹³⁰, which compares projects while taking into account electricity system considerations. A generator’s avoided cost is a measure of what it would cost to generate the electricity that would be displaced by a new generation project. To put it simply, it is a measure of how much revenue a project can generate combined with the value of how much backup generation it can displace which can be assumed to be the cost of a backup natural gas CCGT or whatever the cost of the marginal unit of generation needed to balance the system. Comparing a project’s LACE to its LCOE can determine which project provides the most system value (LACE) compared to its cost (LCOE).

However, the metric LACE is not widely recognised, particularly by governments or international agencies and so does not have the ‘profile’ of LCOE and hence the need for further work.

**Permanence of CO₂ storage**

This calculates the permanence of CO₂ abatement.

Geological injection of CO₂ into saline formation or depleted gas reservoirs is permanently stored/sequestered. However, the ‘permanence’ of CO₂ storage through Enhanced Oil Recovery (EOR) is discussed. Although ‘working’ CO₂ is recycled i.e. not emitted, EOR process contributes to CO₂ emissions from the enhanced oil produced. But the site will remain permanently as a CO₂ store after cessation of production can thus have an overall and large net positive benefit¹³¹. Storage of CO₂ in wood occurs in nature during growth. But CO₂ is released as the wood decays after death - say 40 years in a temperate cycle. And first fire can release multiple percent carbon stock during growth. Utilisation of captured CO₂ for foodstuffs (tomatoes etc) and/or drinks industry – these ‘store’ CO₂ only for weeks or hours.

This is useful for comparing secure geological CO₂ storage with other forms of storage such as sequestration in forest growth or peatland; or comparing CO₂ storage with CO₂ utilisation.

**Maintenance**

This metric tells us how much effort is needed to keep CO₂ stored, e.g.

- for a forest – this is high maintenance as trees need replanting every 50 years and need protection from fire, and the previous wood needs to be utilised via BECCS or Anaerobic Digestion schemes with CCUS etc

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- For permanent geological storage as liquid CO\(_2\) – maintenance during the CO\(_2\) injection phase, and eventually permanent abandonment of the injection wells is required. In order to learn from the first projects e.g. in Norway, monitoring has been carried out using time lapsed seismic surveys every 10 years and may well be continued for some decades. This is useful for comparing secure geological CO\(_2\) storage with other forms of storage such as sequestration in forest growth or peatland.

**Balance of trade**

The Summit Power\(^{132}\) led report “East Coast UK CCS Investment Study” in 2017 calculated balance of trade (BoT) impacts considering import and export of CCUS equipment, machinery, materials and services. The provision or purchase of CO\(_2\) storage services yielded positive results.

**Health benefits**

The co-benefits of CO\(_2\) emissions reductions in Europe have been estimated to be around €24/tCO\(_2\) by a WHO led study “Health Risks of Air Pollution in Europe (HRAPIE)”. The Royal College of Physicians has referenced this in their working party report in 2016. Implementation of CCUS Project Investments would undoubtedly contribute to improvements in levels of health and well-being in the UK.

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CHAPTER 18 – DISCUSSION PAPER - DELIVERY CAPABILITY

BACKGROUND

The CAG was requested to consider what delivery capabilities the UK would require to be able to deliver CCUS at scale (See Terms of Reference in text box below).

To address the ToR questions this paper will identify the key capabilities needed in the UK to deliver on its ambitions for CCUS deployment. These capabilities should be sufficient to enable the UK to move to a higher level of CCUS ambition, e.g. in the event that the CCC advice on a Net-Zero GHG target results in a higher level of CCUS ambition. The capabilities are considered generic capabilities in that they will be required regardless of the final business model that is selected to support delivery of CCUS.

For each of the capabilities, this paper will describe how it can be created and will also identify the actions required by the public and private sector entities needed to deliver the capability.

“Delivery capability:

• Describe the delivery capabilities needed in the UK to support deployment of CCUS (including Government, industry, projects and finance).
• Describe how these delivery capabilities can be created, and recommend the actions needed to create them.”

The following key capabilities have been identified and these are considered in further details below.

1. CCUS Deployment Framework
2. CCUS Delivery Body
3. National T&S infrastructure assessment
4. CCUS Project pipeline
5. UK skills and supply chain
6. Coordination of cluster developments
7. Public acceptance
8. Research and Development requirements
9. Finance

CAPABILITIES REQUIRED TO DELIVER CCUS AT SCALE

1) CCUS DEPLOYMENT FRAMEWORK

Capability

A CCUS Deployment Framework that provides clarity and confidence on the UK CCUS market opportunity is an important signal that enables the private sector and other key stakeholders to respond and organise themselves in order to support delivery of the sector.

Visibility provided by the Deployment Framework should be provided for a period of time that is sufficient to enable stakeholders to take the required actions, e.g. ten years, to allow the development of projects. This forward visibility will need to be updated on a rolling basis so that there is sufficient forward confidence in the market to underpin private sector investment. These medium-term goals should be consistent with the wider decarbonisation objectives, e.g. 2050 goals and Net-Zero targets.
CHAPTER 18: Delivery Capability

The Deployment Framework should retain sufficient flexibility to ensure that the CCUS sector can respond to wider changes in the market or decarbonisation ambition to create an industry that has the capability to scale at pace.

To allow the CCUS market to respond efficiently it is expected that visibility is required across a number of dimensions:

- Clear statement on the policy mechanisms that will be available to support development of the sector.
- Clarity on the respective roles of government and the private sector in supporting delivery of projects.
- Volume of CO₂ abatement required from CCUS over a ‘reasonable’ timeframe.
- Sectors where CCUS is required to contribute to CO₂ emission reductions.
- Regional distribution of CCUS clusters
- Establish key Government objectives that CCUS projects are expected to deliver or adhere to.
- The potential to provide CCUS services to third countries, e.g. CO₂ storage or BECCS.

Creating capability

A range of approaches have been adopted to provide signals on the market opportunity for different low carbon technologies and these could be adapted for use in CCUS. It may also be the case that different instruments may also be appropriate for the different parts of the CCUS value chain, e.g. regional T&S infrastructure, BECCS, hydrogen, industry or power.

- Examples of different approaches include;
  - A ‘commit and review’ CCUS policy, similar to the approach used successfully for offshore wind. This can provide clarity and confidence on the market over the near to medium term for industry and its supply chain whilst also not over committing Government to more uncertain long-term targets. The Government can establish goals for wider development of the sector (e.g. UK content of supply chain, etc) upon which future support will be judged.
  - National Policy Statements, similar to those used to identify sites for new nuclear investment, could identify the regions where the Government would support investment in CCUS and the key requirements for any new investment.
  - The use of standards/obligations have been used successfully to drive investment in low carbon fuels, e.g. renewable electricity, transport fuels and heat and could be adapted for CCUS.
  - Development of Local Industrial Strategies that identify those regions with the clear potential and opportunities to develop CCUS infrastructure and how these can be aligned with national CCUS ambitions and goals.

Actions

*Government* – to consult with industry and other key stakeholders on the most effective approach to establish a CCUS Deployment Framework.

This should consider whether differentiated approaches are required across the different market segments of the CCUS value chain. It is likely that the approaches used will be influenced by the investment framework selected for each part of the value chain.
CHAPTER 18: Delivery Capability

2) CCUS DELIVERY BODY

Capability

HMG will require organisational capacity and capability to realise its CCUS Deployment Framework policy and oversee the deployment of CCUS at scale in a strategically sound and economically effective way.

The Delivery Body will be required to;

- Provide periodic reports to HMG on delivery of CCUS projects
- Assess expected development of the CCUS market to meet UK decarbonisation objectives and report to HMG.
- Administer the UK CCUS deployment policy, e.g. allocation of contracts to projects.
- Facilitate the signing of contracts with CCUS developers to deliver projects. These could be signed directly by the Delivery Body or they may partner with an existing contracting body that have these powers, e.g. the Low Carbon Contracts Company.

Creating capability

A Delivery Body will need to be established either inside HMG, in an external organisation already existing or created by HMG for this purpose, or in a new private sector entity.

The options include:

- Create an organisation within HMG capable of delivering CCUS. This could be analogous to the DECC Office for Carbon Capture and Storage (OCCS) and the current BEIS Office for Nuclear Development.
- Create an organisation outside of HMG – either a company, a non-departmental public body (NDPB) or a similar body – to deliver CCUS. This could be similar to the role that Gassnova plays in supporting the Norwegian state to develop CCUS.
- Vest an existing organisation with the responsibilities of the CCUS Delivery Body, e.g. expand the remit of the EMR Delivery Body which has responsibility for Contracts for Difference and the Capacity Market.
- Establish a new body in the private sector that could deliver all or some of these functions. For example, this could be similar to some of Network Rail’s functions which advise Government on the investment options available in the rail sector with the Government then ultimately deciding which investments to progress based on their priorities and constraints.

It is important to recognise that the best approach to delivering the required capacity and capability may change over time as the CCUS market evolves.

- Initially a key priority will be to ensure that momentum is maintained, and the early projects can be delivered from the mid-2020s. This may necessitate the establishment of a Delivery Body within HMG or an existing organisation.
- In the medium to longer term – as it is assumed that CCUS has to be scaled up dramatically to deliver on UK carbon budgets – then there may be a strong case for establishing a specialist CCUS Delivery Body, potentially outside of HMG, that has the capacity and capability to support an industry of this scale.

Actions

- Government – to consult on most appropriate structure(s) to establish a CCUS Delivery Body.
- The consultation should consider how this capability should be established in the near-term in order to ensure that its objective of delivering the first project from the mid-2020s is realised as well as the longer-term arrangements that are required for an industry of the size and with the deployment rates that are expected from CCUS.
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3) NATIONAL T&S INFRASTRUCTURE ASSESSMENT

Capability

Appropriate volumes of transport and storage infrastructure need to be available ahead of demand over the period to 2050 and beyond in order to service the CO$_2$ supply from a range of sectors.

Expected storage capabilities;

- Industry and the regulator require the ability to effectively and efficiently licence and operate storage sites.
- Facilitate the timely availability of the required regional storage capacity. This is expected to require the development of capability that;
  - Ensures that clarity on the required volumes of storage capacity (including both annual and total CO$_2$ injection requirements) is provided ahead of demand (e.g. 10 years or more) in order that there is sufficient time for capacity to be appraised ahead of need.
  - Provides CO$_2$ capturers with confidence that adequate storage will be available in their region to accept their volumes of CO$_2$ over the lifetime of the project.
  - Identifies storage assets of national significance, e.g. highly prospective geological storage sites or opportunities for O&G infrastructure reuse.
  - Develop policies and organisational capability to ensure that nationally important geological and infrastructure assets are managed so that they can be retained for CCUS.

Expected transport capabilities;

- The development of a CO$_2$ transport network planning function that ensures the development of a transport network that is capable of transporting CO$_2$ from industrial regions to geological storage sites.
- Assessments are required for how emitters outside of industrial clusters can also access and benefit from the storage infrastructure.
- Assessments on transport needs should also consider long-term demand scenarios so that opportunities to cost-effectively right-size infrastructure can reduce future costs to the system.

Creating capability

- A Coordinated National Assessment on the expected demand for CO$_2$ storage (and associated transport) over a future time period (at least ten years) in order to provide sufficient lead time to appraise storage and develop transport networks.
- The resources used to service the existing regulatory framework related to the licensing of geological storage sites will need to be increased to provide the capacity that can support delivery CCUS at scale.
- Development of best practice related to the appraisal, operation and decommissioning of geological storage sites is required to ensure that the framework is implemented in a predictable and efficient manner.
- Capacity is required to identify geological and infrastructure assets of national significance. New policies and powers, e.g. governing decommissioning, interim responsibility of existing assets between decommissioning and use for CCUS, etc are required to ensure that these assets of national significance are retained for CCUS.
- A process is required to undertake CO$_2$ transport network planning onshore. A similar function is needed offshore including the effective management of competing uses of the seabed.

Actions

- *Industry / storage operators* – should be incentivised to identify additional volumes of CO$_2$ that can utilise transport and storage infrastructure.
In the event that the Government pursues a Regulated Asset Base model for the development of CO₂ transport and storage infrastructure then there should be a licence duty for the operator to undertake a periodic assessment of future demand and develop a forward business plan that can meet this demand profile.

- **CCUS Delivery Body and/or regulator** – forecast expected CO₂ demand and provide guidance to entities responsible for transport and storage development on the required capacity that should be brought forward.
- **OGA** – ensure that sufficient resources available to license CO₂ storage sites.
- **Government/OGA/Ofgem** – develop powers to identify key pieces of O&G infrastructure or geological formations of national significance and ensure that steps taken to retain these for UK PLC (e.g. appropriate decommissioning, access to data, etc).
- **Government/OGA/industry** – establish knowledge sharing activities in order to develop best practice in the appraisal, operation and decommissioning of CO₂ storage assets.
- **The Crown Estate/Ofgem/DEFRA/OGA** – develop powers to undertake CO₂ transport network planning both on and offshore. Ensure that competing uses of the seabed do not unduly hinder the deployment of CCUS.

4) **CCUS PROJECT PIPELINE**

**Capability**

Sufficient numbers of CO₂ capture projects must be developed that deliver the required levels of CO₂ mitigation for meeting Carbon Budgets.

CCUS project development timescales requires that projects are initiated substantially ahead of the period when the emission reductions are required.

CO₂ mitigation needs to be delivered across all of the key sectors, e.g. power, industry, hydrogen, Bio-CCUS. However, the respective contribution of different sectors may vary over time as decarbonisation efforts progress and the project pipeline should flex to meet these changes in demand.

The development of robust and visible project pipeline is an important enabler for the development of a strong supply chain that can meet wider government objectives, e.g. UK content targets.

**Creating capability**

- Capability to ensure continuity of a CCUS programme over a multi-year period, to ensure follow on projects are delivered to meet long term targets and thus avoid deployment of only a few initial projects.
- Rolling periodic reviews required on the expected CCUS deployment needs across different sectors. These assessments need to be synthesised into forward CCUS policy objectives, communicated to the market and supported by policies to deliver.

**Actions**

- **Committee on Climate Change** – provide periodic assessments and recommendations to Government on the volumes of CCUS that need to be delivered by sector to deliver on legislated Carbon Budgets.
- **Regulators/Delivery Bodies (EMR Delivery Body, Ofgem, others?)** – provide periodic assessments on the decarbonisation options available to their respective sectors and the expected demand for CCUS.
- **Industry** – provide periodic assessments on future deployment capabilities by sector with an assessment of the scale of mitigation that can be achieved and a forward assessment of material
CHAPTER 18: Delivery Capability

CCUS developments, e.g. forecast costs, development of CCUS-enabled markets, supply chain developments, etc.

- **Government** – Review above third party assessments on the forecast role of CCUS to supporting decarbonisation of the UK economy. Report on conclusions and integrate into the CCUS Deployment Framework to provide visibility on the future CCUS market and enable industry to progress projects to deliver on these goals.

5) **UK SKILLS AND SUPPLY CHAIN**

**Capability**

UK will require an appropriately sized CCUS supply chain to deliver the scale of CCUS required. The supply chain and skills base for the CCUS industry are likely to come from the existing UK oil and gas, power and chemicals industries.

The Supply Chain may also need to contribute to wider UK Government policy objectives, e.g. UK content, development of export opportunities, etc.

The UK will need access to appropriate skills to deploy CCUS at the required scale. These may come from both the diversification of existing supply chains, e.g. O&G into CCUS as well as the development of appropriately trained graduates from UK universities.

The development of CCUS at scale in the UK, as well as globally, is likely to create novel opportunities for both existing and new supply chains. UK companies should ensure they are well placed to access these new markets.

**Creating capability**

- These supply chains already exist but will need to be re-oriented to supporting a growing CCUS industry.
- To meet the Government’s wider low carbon policy goals then project developers and their supply chain partners should ensure that they have appropriate supply chain development plans established. HMG should articulate its expectations / requirements for the CCUS supply chain.
- Identify and support UK companies with strengths in emerging CCUS market opportunities.

**Actions**

- **Government** – develop a CCUS Deployment Framework to provide visibility to the supply chain on the scale of the CCUS market.
- **Industry** – to ensure that the supply chain capabilities, and industry skills, are retained and available in the UK, and that they can be and are transferred to CCUS deployment.
- **Government** – publishes requirements for supply chain content and characteristics that they require from UK projects.
- **Government / Industry / research community** – identify opportunities for emerging CCUS markets where UK is advantaged.
- **Regional partners** – identify opportunities to host and support the CCUS supply chain in Local Industrial Strategies.

6) **COORDINATION OF CLUSTER DEVELOPMENTS**

**Capability**

CCUS should be developed in clusters and industry, Government and regional partners work together to support the development of business plans that promote the development of CCUS clusters.

The development of clusters is expected to change over time. Initial projects will need to be highly synchronised so that the capture plant and T&S infrastructure is developed in parallel.
Once clusters are established there may still be a requirement for investments in capture and T&S to be highly coordinated, e.g. if a large new source of CO₂ is captured and brought into a cluster. However, there may also be times where incremental investments are made in capture or transport that do not require a concomitant investment in the rest of the cluster, albeit there still needs to be a high degree of coordination.

Creating capability

The processes for developing T&S infrastructure and capture projects will be separate and distinct but will need to be highly coordinated. The informal co-ordination between the project developers will be crucial, but not sufficient. Industry will need to work with the CCUS Delivery Body to create processes to provide co-ordination between projects developers (on both sides) and the government.

Possible approaches that could underlie this cluster coordination include:

- Criteria are developed which establish the characteristics that CCUS clusters will be expected to deliver. These will be aligned with both national priorities but also regional priorities, e.g. those established in Regional Industrial Strategies.
- T&S developers, capture developers (these may be the same organisation) and local partners (including local and regional government and others), work together in each regional cluster to create and then deliver a Cluster CCUS Business Plan that address these criteria.
- Assessment of the cluster business plans, and the project plans for projects within those clusters, is undertaken against the pre-agreed criteria. Those assessments would guide which clusters, and which projects in those clusters, would receive funding arranged by HMG - either for project development prior to FID or for a revenue contract after construction.
- CCUS Cluster Business Plans will be dynamic and will need to evolve over time. At minimum they would probably be updated every time a project within a cluster seeks funding which is arranged by HMG.
- Development of the T&S infrastructure project and capture project(s) are likely to be synchronised within a cluster. Commercial / institutional structures will need to be established to enable the activities to be presented as a cluster.
- Cluster CCUS Business Plans and projects will not be synchronized across clusters. Each cluster can - and probably will - run to a different timetable.
- Different clusters may cooperate to share or link their T&S infrastructure.

Actions

- **Government** – publish criteria against which CCUS clusters will be assessed.
- **CCUS Delivery Body** – develop capacity to assess CCUS cluster plans.
- **Local partners / industry** – develop capability to contribute to and develop cluster plans and ensure that they are aligned with local / regional / national priorities.
- **Industry** – develop projects that are aligned with national and local priorities.

7) **PUBLIC ACCEPTANCE**

**Capability**

There is a need for broad and sustained support for CCUS across society if the sector is to be developed at the scale required to meet UK climate goals. This will require a much larger and wider set of stakeholders to understand and agree with the need for widespread deployment of CCUS.

Creating capability

- Local communities will need to feel that the development of CCUS projects in their region is aligned with their interests and brings value to the local community.
• At the national level key influencers that help shape the discourse on national and regional policies will need to also recognise and understand the value that developing a CCUS sector can bring to the UK.
• The realisation of both local and national support for CCUS is a prerequisite for securing the sustained cross-party political support needed to ensure consistent and support for the deployment of CCUS infrastructure.
• The local, national and political support needs to be underpinned by compelling set of socio-economic arguments that draw out the benefits that CCUS can bring. These arguments need to be supported by actions and behaviours from the main CCUS players that show the benefits ascribed to the deployment of CCUS are authentic and consistent with wider UK policy and social values.

Actions

• Government – clearly articulate the value proposition that the development of a CCUS sector can bring to the UK.
• Local partners – should develop a narrative/guidance on how CCUS developments could be developed in a way that maximises local opportunities. Ensure that this is communicated to national level key influencers and politicians.
• Project developers – develop projects that deliver tangible and material benefits. Manage the planning process and ensure that the concerns of local communities are addressed.
• Industry (through both representative bodies and individual companies) – ensure that the benefits of developing CCUS are clearly articulated to national influencers and politicians.

8) RESEARCH AND DEVELOPMENT REQUIREMENTS

Capability

• Develop a strategic approach to research and development recognising where the UK has particular strengths and avoiding those areas where other regions are leading.
• Strong links between academia, industry, commercial, and policy sectors should be fostered to ensure that research and development activities are supporting wider CCUS deployment efforts.

Creating capability

• Adequate funding for CCS and GGR from UKRI in both standard and responsive mode. This should include funding for PhD students. This funding should include engineering, physical, and natural science research, as well as economic and social science research.
• The UK has a particular strength in multi-disciplinary work and systems thinking/engineering, which should continue to be supported.
• Particular consideration should be given to research and development activities which may be stranded somewhere between conventional academic and purely commercial activities. Sufficient resources are likely to be required in these areas if CCUS is to be deployed at the scales required, for example;
  o Making support available for moving technologies from lower TRL levels to pilot scale and through to market.
  o Ensuring that insights developed by the academic community can be effectively analysed, synthesised and used to support policy development.
  o Enabling the timely targeting of research capacity to address the technical and scientific challenges that will arise during a large scale CCUS deployment programme across multiple sectors.

Actions

• Research Councils - extend and support the existing “CCS Fellowship” scheme
• **UKRI** – Ensure that a commercial CCS programme has a material research block associated with it to rapidly address fundamental science or technical challenges arising from the programme.

• Extend and refund the UK CCS Research Centre (UKCCSRC)

9) **FINANCE**

**Capability**

• The development of finance and insurance sectors that are comfortable with CCUS technologies and the funding mechanisms used to support investment.

• Positive changes in the perception of CCUS commercial and technical risks resulting in a deepening of the pool of finance and insurance companies engaged in CCUS, leading to greater competition and improving the financing conditions for the sector.

• Greater involvement of the insurance sector leads to the development of a wider range of products that can help to manage the regulatory and commercial risks associated with CCUS.

• Creating a world leading CCUS-literate finance and insurance sector that can support delivery of CCUS projects globally.

**Creating capability**

• Building understanding in the financial and insurance sectors on the role that CCUS must play in delivering on national and international climate goals as well as helping industries to transition to a low carbon economy.

• Ensure that the finance and insurance sectors understand and are comfortable with the policy and investment framework that will support delivery of CCUS clusters. This will include engagement with Government, regulators and industry on their respective roles in delivering CCUS and familiarisation with the business models recommended by CAG as updated following consultation.

**Actions**

• **Government** – Develop a Deployment Framework that provides clarity on the role of CCUS, the size of the CCUS market and the investment framework that will be used to support projects.

• **Project developers and Industry** – Engage with the finance and insurance sectors both as individual companies but also through representative bodies.

• **Finance and Insurance** – build understanding in their sectors on the role of CCUS including through the use of their representative bodies, e.g. Association of British Insurers, Institutional Investors Group on Climate Change.
CHAPTER 19 – DISCUSSIONS PAPER - COMPETITIVE TENSION

The Constraints on and Benefits of Competition in Deploying CCUS in the UK

CONTEXT

The CAG is considering business models for potential use in deploying the first CCUS projects in the UK.

In general HMG seek wherever possible to use competitive processes when allocating funding to projects to gain, and to be seen to be gaining, best value for money. But this may not always be appropriate.

The Terms of Reference of the CAG addressed two issues:

i. Describe how competitive pressure can drive cost reduction and where and when other approaches, e.g. collaboration might prove more productive;

ii. Describe how productive competitive pressures can be maintained in CCUS in a framework which does not use a standard competitive government procurement process.

The UK has twice used competitive HMG procurement processes to procure highly specified outcomes; which aimed to secure the first CCS projects in the UK. Neither of these were successful - perhaps in part because the procurement process focussed on “procuring assets on the ground” rather than delivering outcomes. The USA used somewhat similar approaches under the “Industrial Carbon Capture and Sequestration Programm (ICCS)” and the Clean Coal Power Initiative (CCPI), with mixed results. The USA has now deployed a system of fixed price tax credits without competition which is attracting significant interest. The Government of Alberta, Canada used a standard process of expressions of interest which appeared more “outcome focussed”; and this then evolved into bilateral negotiations across a wide range of types of projects; leading to two successful commercially sized projects. (This last example is discussed further later in this paper).

In the light of those and many other experiences, this chapter discusses the constraints on and benefits of competition. It covers where and how competition can and should (and should not) be best used, to gain and to be seen to be gaining, best value for money; and where competitive processes should or should not be built into the process of developing cluster and project proposals.

Clusters

The CCTF recommended developing clusters as the key approach to delivering CCUS as this provided the greatest opportunities to maximise the value of CCUS to the UK.

The HMG CCUS Action Plan also recognised the benefits that clusters could bring (pp29,30):

“… a successful proposition for a CCUS facility and carbon dioxide infrastructure network could enable innovation, bring economies of scale and provide an integrated decarbonisation solution for a diverse range of industries, including the potential of using carbon dioxide to create new products and services, stimulating clean growth within a defined place.”

And it continued:

“We will examine in detail the scope of the opportunity for maximising economies of scale by developing a shared carbon dioxide infrastructure centre and will report by the end of 2019.”

133 Funding Opportunity Announcement for Carbon Capture and Sequestration from Industrial Sources and Innovative Concepts for Beneficial Use (June 2009)
134 Clean Coal Power Initiative
And on page 61:

“... we will also work with industry to examine the delivery implications of deploying CCUS at scale in the UK during the 2020s.”

One of these implications is on the timing of when clusters will proceed with CCUS developments. Whilst developers will propose CCUS development plans, the decisions on when individual clusters proceed will ultimately sit with HMG, as they will have to arrange the revenue support that will underpin the economics of every CCUS development. In addition, the characteristics of each cluster will vary significantly, including the infrastructure required, the sources of CO\textsubscript{2} available to capture, and so on. And HMG will need a basis on which to make those decisions.

Whatever the chosen scale and pace, CCUS deployment is more likely to proceed in a phased manner, rather than with a single big development across all clusters simultaneously.

In practice it is therefore likely that CCUS clusters will be initiated at different times and progress through development on varying schedules. The development of CCUS is unlikely to proceed in a single big development across all clusters simultaneously and this has implications on the ability to use competitive processes to progress CCUS.

HOW COMPETITION CAN DRIVE COST REDUCTION

The HMG drive for competition is in search of value for money. And it can be a powerful force in delivering it.

Where the desired outcomes can be clearly specified in a consistent way across different projects and where there is considerable interest and capacity in the private sector to deliver those outcomes, then competitive processes can succeed. The renewables electricity generation sector provides clear examples of this. The costs of wind, solar and biomass projects have come down as technology has improved, scale has increased, and experience has grown. Competition has clearly been a driver in this process.

And in many other sectors of the economy, the government procurement process has been used, often successfully, to procure infrastructure for the UK economy.

The question is whether competition, and in particular competition between initial clusters, is the best way forward in all circumstances.

IS COMPETITION ALWAYS APPROPRIATE?

No.

Care is needed to ensure that introducing competition for its own sake does not cause unintended and negative consequences which run counter to the objective - in this case the objective of developing CCUS.

The following are examples of when Competitive procurement processes are less suitable:

- If the scope and nature of the assets being procured is difficult to specify at the start of the procurement, e.g. different project permutations could be progressed according to relative priorities of HMG;
- if early projects could vary considerably in scope and scale;
- if the depth of interest and capability in developing projects is limited, for example when only one infrastructure development is needed in a region;
- if projects risks are significant.
In those circumstances, it may be better to evaluate clusters on their own merits rather than in competition. Cluster’s individual business cases should be considered in the light of HMG priorities more generally (including the commitment to achieve zero GHGs by 2050).

Under these circumstances cost reduction may be better delivered through other means (see the later sections of this paper). This applies particularly when trade-offs around infrastructure development, pace and economies of scale are in play.

Nonetheless, competition can be introduced “lower down” in the projects between contractors who bid to execute the project once it has been specified. “Value engineering” processes are well understood and - if properly exercised - can drive very significant value creation and cost savings through collaboration. Additionally, projects can be assessed on their intrinsic merits, against agreed criteria, rather than against each other.

The distinction between “doing the right project” and “doing the project right” needs to be kept very clearly in focus. Successful processes for the former i.e. defining the right project scope, can look very different from the latter i.e. choosing who should execute the project and with what budget.

How competition should feature in the development of the CCUS industry therefore requires careful consideration, as it needs to balance two factors:

- On the one hand, a competitive market, underpinned by a clear contractual framework, can lead to significant investment and cost reductions over time, as has been seen in the solar and wind markets for instance.
- On the other, most initial clusters are likely to be developed around some pre-existing assets and industrial conurbations that can be made more efficient and substantially de-risked through the integration of and collaboration between schemes.

Given the need to balance these factors, competition and collaboration are likely to play different roles in different parts of, and at different times in, the development of the industry.

Given this context, this discussion paper considers:

- The difficulties of having competitions between clusters;
- A process by which clusters can be assessed in parallel (though not synchronised) and awarded revenue support without being in direct competition;
- The importance of having competitive elements within clusters, anchor capture projects and as part of T&S projects;
- The use of competition outside the first projects.

It concludes that whilst direct competition between clusters is not recommended, competition and competition proxies have to be embedded throughout CCUS cluster and projects to demonstrate the value for money of their approach against alternatives. Clusters can be appraised in parallel (though not synchronised) and awarded revenue support without being in direct competition.

**THE DIFFICULTIES OF HAVING COMPETITIONS BETWEEN CLUSTERS - HOW POTENTIAL MIGHT CLUSTERS BE EVALUATED.**

There are a number of competing objectives and constraints that an evaluation of the merits of investing in a cluster might consider, including:

- Level of regional support;
- Commercial viability – store size, total cost, potential for further projects;
- Leverage – potential to build upon anchor projects and share the T&S costs;
- Attraction to new investors and ability to foster competition;
- Job creation and preservation;
- Speed of implementation;
CHAPTER 19: Competitive Tension

- Ability to foster alternative CCUS technologies and innovation; projects with highest system value and that extend the reach of CCUS into the economy;
- Affordability to customers or tax revenue;
- Avoided costs (e.g. decommissioning) and maximising use/longevity of existing infrastructure and industry;
- Ability to mitigate risks (e.g. not relying on one CO₂ suppliers or one CO₂ store);
- Ability to fairly allocate risks amongst industry, shareholder, consumers and tax revenue;
- Affordability – ability to deliver objectives cost effectively and within funding limits, mindful of other potential CCUS projects;
- Compatibility with business models – could it fit with the T&S RAB for instance;
- Demonstration of competitiveness – use of competition in procurement, assets, operations – showing competitive margins, contingencies and risk absorption.

This breadth and diversity of these issues demonstrates the difficulty of evaluating clusters competitively in any “mechanistic” way. It makes formal direct competition between clusters extremely difficult, because:

- These objectives cannot be ranked formulaically in a way which allows bidders to know how to respond;
- HMG will be unable to give firm affordability guidance until detailed costs are received according to agreed business models;
- Clusters may develop sequentially with varying levels of support; an evaluation at a point in time would simply emphasise their differing level of development, rather than encourage investment at each cluster at the appropriate time;
- Evaluating clusters formulaically could easily introduce unintended consequences, and skew development plans to “meet the test, beat the rest” rather than finding the best deployment pathways over time.

Further considerations also suggest competition between clusters would be difficult:

- Even if there is a renewed policy commitment to deploy CCUS, given past experience the appetite of developers to participate in an HMG procurement competition (perhaps for a third time) within an (understandably) complex set of competing policy objectives and unknown level of policy commitment may be limited. Confidence that policy commitments will result in actual projects needs to be improved.
- CCUS developments may be developed more efficiently – potentially with lower overall cost and definitely with lower risk – if developed on a coordinated basis, which competition between clusters would discourage. For instance:
  - sharing onshore pipeline networks, large scale hydrogen production and salt cavern inter-seasonal storage (for domestic heat applications), amine conditioning pipeline networks and multi-stage compression, T&S pipes, wellheads and injection wells, cross country new and disused natural gas and other pipelines, port facilities, CO₂ storage terminals and CO₂ ships; or;
  - through proposals to jointly invest in shipping technology and assets, agree CO₂ capture engineering standards, offer industrial capture processes across regions and most critically the possible link of clusters and T&S facilities all offer the opportunity to lower both costs and risks.
- The industry should therefore be looking for ways to cooperate at the cluster level.

Combining these difficulties with the fact that projects at each location may have a narrow “incumbent-focussed” outcome in mind, suggests the need for a more collaborative and open-book approach as described later in this chapter.
A possible approach:

*Assess clusters - and the initial capture and T&S projects that comprise them - on their intrinsic qualities, not by comparison with other clusters.*

- It is probably valid to assume that only one proposal for a T&S network will be developed by each cluster. Competition in those projects can therefore only be generated “within” the project (i.e. between potential suppliers and contractors).
- It is probably fairly unlikely (though not out of the question) that competing capture projects will vie for the role as an anchor project in a cluster. Competition “within” these projects is probably therefore again key.
- The easy conclusion to then draw is that competition between clusters is an inevitable requirement. As discussed above, it is not.
- The objective is value for money - not competition per se’.
- The focus should therefore be on the intrinsic value of the cluster development pathway.
- There is direct precedent for such an approach for CCUS - which has been successful. This is how it worked:

**The process for developing CCUS in Alberta, Canada**

- In 2008 the government of Alberta, Canada asked for submissions of expressions of interest in developing CCUS projects. They received 50 such “EOIs”, which they reduced to 20 on the basis their high-level objective, which was stated as being those “proposals having the greatest chance of being built quickly and providing the best opportunities to significantly reduce GHG emissions”. Those were invited to submit full proposals.
- That is a fairly standard process in the early stages of a procurement competition. But thereafter the process took a less normal path.
- The projects were so different in type and scope that each was judged on its own merits against the stated high-level objective. As each project was developed it was expected to pass through predefined stages, and to meet the criteria set for those stages. Those projects that met the criteria proceeded to the next stage; those that did not could recycle and try again or drop out.
- The projects were developed in parallel, and soon moved on to very different timetables. They were assessed on their individual merits, rather than against each other.
- In the end two projects have been built. The Quest project commissioned in 2015 and the Alberta Carbon Trunk Line project is being built and is scheduled to commission in 2020.

Building on and adapting this example, a process for developing CCUS clusters in the UK could work as follows:

- Clusters could enter a process with HMG - at any time, not just at the start of the process - through an expression of interest, followed by a detailed project proposal.
- Clusters would run through this process in parallel, but not synchronised. At any stage they would be judged on the merits of their proposal against a set of objectives for the development of CCUS clusters set by HMG, rather than against each other.
- Projects would pass through a staged process. At each stage projects would be assessed against high level objectives, not against other clusters. If they met the criteria they could proceed to the next stage; otherwise they could recycle and try again or withdraw.

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135 "OGCC following CCS initiatives, rulemaking". Oil and Gas Journal 24th Nov 2008.
136 "The pipeline we do not know". BIV. 9th April 2019.
• HMG would not be obliged to continue the process with any cluster and could withdraw from appraisal of any project at any time.
• If HMG so wish, and subject to HMG policy at the time and availability of funds, at various stages HMG may make development funding available, and at the final stage may award contracts for revenue support to those developing the cluster.
• There would be no fixed competitive timetable. Assessments would be made at the right time for each cluster and project.
• Competition would be built into the procurement processes inside the cluster and projects. This would be a key mean of keeping the price of each part of the project down. This is covered in the next section of the paper.
• The cost of the whole programme would be optimised not through competition with other clusters, but through techniques like “value engineering”, which are commonly used when the overall objective of a project or programme scope has already been set, and the required scope and support for the programme is to be decided (e.g. Heathrow Terminal 5 or HS2).

Recommendations:

A new competition between alternative clusters is not recommended
The business case for investing and supporting developments at clusters should be justified against the high-level objectives set by industry and HMG for the deployment of CCUS in the UK.

The industry should develop a methodology for fully appraising and describing the benefits of their cluster proposals against those objectives, on a consistent basis, that would allow each cluster to be evaluated and promoted on a stand-alone basis, and at a time suitable to HMG and the cluster.

Industry should work together at the cluster level to develop a range of rollout options for one or more clusters according to a suite of alternative affordability ranges and policy objectives, recognising the different levels of project readiness and the need to reduce risks and support levels. This should consider not only alternative numbers of cluster developments but also possible timelines for rollout, highlighting alternative rollout scenarios, ranked by the fulfilment of competing objectives and affordability. (From these strategies clusters may form different views as to when they might deliver an EOI under the above structure or request earlier funding support to develop proposals to that EOI level of readiness)

It will be incumbent on the industry to articulate the business case for investment in all clusters in the best light and for Government to determine which of a series of rollout strategies presented are most aligned to fulfilling its objectives for CCUS, affordability constraints and ambition for meeting the zero GHG commitment.

It is recognised this may be a difficult decision for Government, as unless it were to promote all major clusters simultaneously, then some clusters will initially be disappointed. However, CAG recommendation is that it is better to rollout CCUS within a clearly articulated strategy which probably would lead to the acceleration of projects overall, than through an unclear competitive process against a limited budget allocation. Projects not initially selected would still have a framework to express interest to proceed and may have greater clarity of how their project may fit within a longer-term rollout strategy.
THE IMPORTANCE OF HAVING COMPETITIVE ELEMENTS WITHIN CLUSTERS, CAPTURE PROJECTS AND T&S PROJECTS

While it would be challenging to have direct competitions between competing clusters for the reasons described above, competition should be an essential element within the development plans of individual clusters.

Whatever processes and criteria are used to ensure that the cost and fees of the T&SCo and anchor project(s) represent good value for money, they must, as an absolutely critical element in that decision, consider the inherent competitiveness of the schemes.

This competitiveness can be demonstrated in a number of ways:

**Extensive competition between sub-contracts** – individual elements of particular projects can be competed to demonstrate competition, such as operation, well provision, pipeline laying and construction, power plant components, and CO₂ capture equipment.

**Open book accounting and transparency of pricing elements** – the greater the use of open book accounting and detailed disclosure, the easier it is for the regulator/CCUS Delivery Body to understand and determine whether the proposed projects are good value for money. Bidders will need to show a willingness to engage and either accept authority’s views on prices or demonstrate openly why their pricing is competitive. This can be a controversial subject in public procurement, where different companies have markedly different views on the level of disclosure that is appropriate. Industry and Government should develop a detailed description of the level of price disclosure appropriate in non-competitive situations.

**Disclosed profit margins** – bidders should expect to have to show these in a format that is comparable between schemes, owners, operators and sub-contractors.

**Competition for operational contracts** – T&S operations are likely to be outsourced by the T&SCo and should be competed.

**Explicit rates of return embedded within contracts** – contractors will be expected to show explicitly the margins included within prices to cater for risk and reward.

**Finance competitions** – use of finance competition for both debt and equity – as was the case at Thames Tideway – will demonstrate competitive finance.

**Competitive cost of capital** – where bidders will be financing a scheme – RAB or project finance – is the cost competitive; benchmarked to other schemes with allowance for the risk package at that location. A T&SCo regulator will ultimately have to sanction the return on capital as part of the regulatory settlement. Substantial precedents exist for the general cost of capital determination, but detailed work will be required to determine the appropriate risk premia for CCS, which will require extensive industry cooperation.

**Ability to absorb risks** – different owners and operators may have different risk appetites rather than or as well as return requirements. This may feed into a competitive evaluation of competing proposals; which schemes can absorb more risk with sensible risk premia.

**Level of contractual underpinning required** – the level of Government support that may be requested may well differ between bidders at different locations, which would be an important consideration as to which scheme is preferred and the prioritisation of projects.

**Cost of storage** – A key consideration when prioritising schemes will be the comparable cost of storage per tonne of CO₂, including transportation costs and servicing requirements

**Cost of capture and the efficiency of capture (abatement rate)** - comparable between schemes, this will differentiate industrial schemes, for instance, as to which will be prioritised. For anchor power projects, this will influence which schemes get priority.
Economic and efficient contracting process – in other regulatory settlements, the regulator and utility may agree a procurement process that describes how the utility will proceed on the occurrence of certain adverse events, for instance the use of competition to price additional capex required. More generally the contracting strategy – what is the best balance of fixed and firm priced contracts – may be agreed beforehand to ensure it produces the most competitive bids and outcomes. This approach will be appropriate for T&SCo.

Profit sharing and refinancing benefits retained within projects – as projects complete and are de-risked, they can be refinanced, raising a larger amount of lower cost debt finance. The benefits of refinancing may be largely retained within the company so that the consumer (whose support has allowed a low risk project from the outset) enjoys the benefits of such finance competitions.

Incentives to introduce new CO₂ capturers – the regulatory structure adopted by T&SCo should clearly include incentives to introduce new CO₂ capturers, possibly through competition, reducing the cost to existing customers.

Ability to absorb and encourage new users – the structure of the original anchor projects and T&S should involve oversizing and incentives to foster competition rather than barriers to entry for new businesses.

Recommendations:

The CCUS industry should ensure competitiveness is embedded through cluster proposals;

For projects where competition is not possible, project sponsors should introduce a suite of measures to demonstrate the value for money of their proposals.

Industry and Government should jointly develop a detailed description of the level of open book disclosure that is appropriate in non-competitive situations to demonstrate the value for money of the projects.

DRIVING COMPETITION INTO CCUS

It is also important that initial projects are also structured in a way that encourages wider competition over time at the cluster level and across the CCUS industry, given the proven impact this has on long term costs. If correctly structured and incentivised, we expect the CCUS market to increasingly competitive in a number of ways:

New power producers – open access to T&S networks will in the future allow competition - either formal or informal - to build new CCS power plants. The development of dispatchable CfDs by CAG and their subsequent introduction could create a stable framework for power competitions, similar to the CfD framework for wind power.

From local industrial users - looking to de-risk their business through decarbonisation, and investors looking to make inward investments in low-carbon production in the UK.

With T&SCo as capturer - as an alternative approach, T&SCo could provide industrial capture facilities and add it to the RAB (this is described in more detail in a CAG paper on the potential scope of RABs). In such an arrangement, there could then be strong competition between industrials looking to offset, measured through their relative cost of CO₂ abatement, and between companies bidding to T&SCo to deliver those CO₂ capture facilities.

Hydrogen producers - competing to use the T&SCo network. The consequent readily available hydrogen will in turn stimulate (and will be incentivised to actively encourage) the development of competing users of hydrogen; HGVs and transport, local heating, and industrial.

New providers of stores – in the longer term, the T&SCo will need to extend its store network both to extend capacity or replace stores as they fill to capacity. CO₂ storage capacity in the UK offshore waters is plentiful, and in most cases this will be about simply extending into formations nearby. T&SCo may
need to run competitions between alternative providers to determine the most economic method and locations to introduce new stores at the lowest prices.

**Recommendation:**

At each cluster, careful consideration needs to be given from the outset as to how the cluster is established to stimulate ongoing competition and incentives to widen the use of CCUS.

### AN ENDURING FUNDING REGIME THAT EMBEDS COMPETITION

In the future funding regimes can be put in place that embed competition in the funding process itself.

A. **Carbon Price**

   If the Carbon Price were to rise sufficiently to incentivise CCUS deployment, then no revenue support would be needed, and no choices would need to be made centrally between clusters or projects.

B. **Obligation System.**

   If, as seems much more likely, carbon prices do not rise to these levels, then creating a CCUS Obligation System would also introduce and embed competition into the funding process. This would automatically allocate revenue support to the most competitive bidders amongst those capturing and storing CO₂ in order to discharge those Obligations.

**Recommendation:**

Analysis should be undertaken of the options for creating an enduring funding regime in the future that embeds competition.

### Summary

Competition between clusters is not recommended.

Instead, the business case for investing and supporting developments at clusters should be justified against the high-level objectives set by HMG for the deployment of CCUS in the UK. Assessment of project developments should not be synchronised. The industry should develop a methodology for fully appraising and describing the benefits of their cluster proposals against those objectives, on a consistent basis, that would allow each cluster to be evaluated and promoted on a stand-alone basis, and at a time suitable to HMG and the cluster.

Whilst direct competition between clusters is not recommended, competition and competition proxies have to be embedded throughout CCUS to demonstrate the value for money of the approach against alternatives. This will be particularly important at the outset when CCUS is likely to be dominated by a small number of strong incumbent players.

For anchor capture projects and the first T&S facilities, a range of measures needs to be introduced to demonstrate the competitiveness and value for money of the proposals.

When developing the business plans for rollouts at particular clusters, a key consideration must be how competition can be introduced at each location. Do the incentives and technical configuration actively encourage new entrants and competitors who will collectively share the cost of T&S, lowering its collective cost across the economy?

And finally, consideration is needed of an enduring funding regime that embeds competition.
CHAPTER 20 – BUSINESS MODEL VARIANTS – DETAILED DESCRIPTION

The following is the CAG’s assessment of the thirteen Business Model Variants identified for development of CCUS in the UK. The CAG recommends that six of these Variants be considered for development of CCUS in the UK.

**CORE VARIANTS:**

**VARIANT 1: BASE CASE - PRIVATE ELECTRICITY & INDUSTRIAL / H2 RAB / T&S RAB**

\(*hydrogen could also be private/ unregulated*

This case is based broadly on the structure recommended by the CCTF report in 2018, but with some significant changes. In the CAG’s view this could represent a long-term enduring model, which perhaps fits best with current HMG policy on energy markets and infrastructure ownership.

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<tr>
<th>Private/ Unregulated</th>
<th>Electricity</th>
<th>Industrial</th>
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<tr>
<td>Regulated/RAB</td>
<td>Hydrogen*</td>
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- *Alternatively, hydrogen production might also be private owned and unregulated*.

This is seen as the most suitable model against which other Variants can most usefully be judged.

- Key aspects of the asset ownership and financing within Variant 1 are:
  - T&S assets for a cluster would be privately owned and financed, regulated through a RAB structure, and funded through T&S fees charged to their customers;
  - If CO₂ shipping is required, it would probably be sub-contracted to private companies by the T&S company;
  - Electricity generation would be privately owned and financed, and funded through a “Dispatchable CfD contract” held with the LCCC137;
  - Industrial CCUS project would be privately owned, financed privately (but possibly with HMG grants as well), and funded by HMG.
  - Hydrogen production would be privately owned and financed. A low-carbon hydrogen industry could develop without commercial regulation; or as regulated industry operating in regulated markets, perhaps using RAB structures.

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137 The CCTF suggested that the existing “CfD model could be adapted to incentivise flexible generation through allowing targeted revenues”. CCTF page S2. [get proper reference].
VARIANT 2: T&S RECEIVES A GRANT FOR INITIAL CAPEX IN A CLUSTER

This is the same as Variant 1, except that T&S would receive a grant to cover the capital investment in the first T&S assets in a cluster. This model would have advantages if the structures in Variant 1 to allocate and mitigate cross-chain risk are deemed by HMG to be unacceptable.

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<th>Private/Unregulated</th>
<th>Electricity</th>
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<tbody>
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<td>Grants?</td>
<td>Industrial</td>
<td>Regulated/RAB</td>
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<td>Gov’t</td>
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<td>Hydrogen*</td>
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<td></td>
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<td>Production/Generation</td>
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This would:

- reduce the risks to be borne by the private sector in T&S;
- would reduce the “irreducible risks” to be carried by HMG;
- and would have the benefit of avoiding continued payment of fixed T&S fees by the “Funders of CO₂ Captures” (i.e. LCCC for electricity generation, and HMG for Industrial CO₂ capture) when Capture plants are not operating.
- A grant could also be considered to support the oversizing of a T&S asset to allow for tie-in of future emissions.

VARIANTS 3: HMG OWNS T&S (PRIOR TO PRIVATISATION)
HMG ownership of T&S would probably allow CCUS development with the lowest cost of capital for T&S, and would simplify cross chain risk allocation and management, though any remaining cross chain risk issues would need resolution ahead of any privatisation.

The T&S assets would appear on HMG’s balance sheet.

The arguments for and against HMG ownership of T&S are discussed in Options Paper 4A.

**VARIANT 4: SINGLE PRIVATELY-OWNED UK-WIDE T&S RAB**

Rather than each cluster having a separate T&S RAB, a single T&S RAB could be developed for the whole of the UK, holding the T&S assets of all UK clusters. This would be regulated as a single entity.

This gives advantages of scale, perhaps speed of execution, and possibly better inter-connectivity. However, it may add complexity, and possibly risks fragmentation of project development.

**VARIANT 5: HMG OWNS UK-WIDE T&S RAB (PRIOR TO PRIVATISATION)**
In this case, HMG would own a single T&S RAB for the whole of the UK, holding the T&S assets of all UK clusters. In addition to the arguments for Variant 4, this would reduce T&S costs, and simplify cross-chain risks further. Again, these arguments are discussed in Options Paper 4A.

### Variant 6: Public-Private Ownership of T&S

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<th>Private/Unregulated</th>
<th>Electricity</th>
<th>Industrial</th>
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<tbody>
<tr>
<td>Regulated/RAB</td>
<td>Hydrogen</td>
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The private sector owns a majority share in T&SCo; HMG owns a minority share. HMG could contribute both equity and debt. This would demonstrate a joint HMG-industry commitment to deliver and provide aligned incentives when addressing risks.

### Variant 7: Regulated Capture - RABs for Separate Parts of the CCUS Chain

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<th>Private/Unregulated</th>
<th>Electricity</th>
<th>Industrial</th>
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<tbody>
<tr>
<td>Regulated/RAB</td>
<td>Hydrogen</td>
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</table>

If, in the future, the profit of electricity generation is regulated, or if a RAB model is implemented for nuclear power generation, then this model could be adapted to cover power generation with CCUS as well. A similar model could also be developed for separate RABs for hydrogen generation. A RAB model
could also be used to govern a new company charged with financing and delivering industrial CCUS projects.

- Electricity generation, Hydrogen generation, and T&S would each sit in separate RAB structures.
- Industrial production with CCUS would remain in the private sector.

OTHER VARIANTS:

**VARIANT 8: “CONDOMINIUM” POST-PRODUCTION CAPTURE AND T&S, SINGLE RAB**

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<tr>
<th>Private/Unregulated</th>
<th>Electricity</th>
<th>Industrial</th>
<th>Grants?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulated/RAB</td>
<td>Hydrogen*</td>
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This is a credible option, though it may perhaps be somewhat project and location specific. It requires commitment to CO₂ separation from flue gases as the technology of choice.

- A single “post-combustion” CO₂ capture plant captures CO₂ from the “flue gas” (and other similar CO₂-bearing gases”) of several CO₂ producers in a cluster.
  - the capture plant may be owned by several of its customers, or by a separate “service provider” (e.g. the local infrastructure provider).
- The same owner provides a full CO₂ “T&S service”
  - including sub-contracting CO₂ shipping if necessary.
- This would require significant commitment to CO₂ separation from flue gases as the technology of choice for Industrial production and Electricity generation (though not for hydrogen production).

**VARIANT 9: SEPARATE ONSHORE CO₂ TRANSPORT AND CO₂ STORAGE BUSINESSES**

Once clusters are well established it may sometimes make sense to separate Onshore Transport from Offshore T&S to create three parts to the CCUS “chain”. The additional interface could create significant cross-chain complexity, and in the shorter term it is most likely to be more effective if Onshore Transport is sub-contracted by either the T&S assets or the Capture assets.

- Under this Variant, once clusters are well established it may sometimes make sense to separate Onshore Transport from Offshore T&S to create a “third leg” of the CCUS chain.

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138 A “condominium” CO₂ capture plant would be a post-combustion capture plant that serves a number of investors who jointly own the plant, and who each send their flue-gas to the plant to have the CO₂ extracted and sent for storage.
- Onshore T&S could be provided by a separate company from Offshore T&S.
- Such a “three-part” chain might play a role in future “enduring regimes”.
- However, in the shorter term a “three-part” chain could create significant cross-chain complexity, as it would introduce a new contractual interface, and require more complex cross-chain “contract machinery”.
- In the shorter term it is most likely to be more effective if Onshore Transport is:
  - either be sub-contracted for by the T&S provider, whose total service offer would still fall under the RAB structure (as shown in the diagram);
  - or it could sub-contracted for by all of, or any of, the Capture projects (not shown).

**VARIANT 10: A SINGLE RAB STRUCTURE FOR MOST OF CCUS**
This model is included for completeness. It currently seems unlikely that a single RAB containing all CCUS assets would add value. The benefits of separating the CCUS “chain” to allow “logical” owners and developers of each part of the chain may be lost, although cross-chain issues might be easier to handle.

- Electricity generation, Hydrogen production and T&S in a single RAB.
  - (perhaps T&S has a grant)
- That RAB may invest in some equipment in the factories of Industrial producers.
- CO₂ shipping – Private sub-contracted by either Capture or T&S
- The benefits of separating the CCUS “chain” to allow “logical” owners and developers of each part of the chain may be lost, although cross-chain issues might be easier to handle.
- This model is included for completeness. It currently seems unlikely that a single RAB containing all CCUS assets would add value.

**VARIANT 11: HMG INITIALLY OWN ELECTRICITY AND T&S ASSETS, (“OXBURGH”)**

<table>
<thead>
<tr>
<th>Private/Unregulated</th>
<th>Regulated/RAB</th>
<th>Gov’t</th>
<th>Production/Generation</th>
<th>CO₂ Capture</th>
<th>Offshore Pipelines/CO₂ Shipping</th>
<th>Offshore Transport</th>
<th>Offshore Storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td></td>
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<tr>
<td>(Regulated contracts see Oxburgh – para 307)</td>
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This may accelerate development, allow strong management of CCUS risks, and minimise cost of capital of initial CCUS developments. All assets would initially appear on HMG’s balance sheet.

- The Oxburgh report recommended that HMG initially develop and own both electricity generation with CCUS and T&S.
- Both would be set up with a view to future privatisation – with electricity CCUS likely to be privatised earlier than T&S.
- Electricity generation with CCUS and T&S would both be subject to economic regulation following privatisation.
- Industrial customers would be provided with regulated contracts for capturing and storing CO₂ by the UK taxpayer (i.e. ultimately by the taxpayer).
- This may accelerate development, allow strong management of CCUS risks, and minimise cost of capital of initial CCUS developments. All assets would initially appear on HMG’s balance sheet.

**VARIANT 12: “2012 COMMERCIALISATION PROGRAMME” – PRIVATE, FULL CHAIN**

If HMG do not wish to take on the “irreducible risks” required in the models above, CCUS could be developed using the Business Model used in the 2012-15 UK CCUS Commercialisation Programme.
This would place higher risks and returns with the private sector developers and would increase CCUS costs. The project scope and allocation process need to change substantially from that used previously.

- This is an ownership and funding structure similar to that used in the “Commercialisation Programme” in 2012-15.
- All CCUS activities are privately funded.

**VARIANT 13: “FIXED PRICE, PROJECT FINANCE” FOR T&S - HMG SHARE SOME RISKS.**

- This is a sub-case of Variant 12. The characteristics of “project finance” structures are described in Appendix 1.
- T&S would receive a fixed price T&S fee structure with no change depending on demand changes or cost changes. T&S would be financed using project finance (i.e. usually equity plus debt in a “special purpose vehicle” company (an SPV) which isolates the performance of the project inside that company.) HMG would share some risk in T&S, but not in Capture. Again, this would place higher risks and returns with the private sector developers and would increase CCUS costs.
- Under this arrangement, T&S would be receiving a “capacity reservation” fee for making T&S available. It would not be taking demand risk, nor risk on the performance of CO₂ suppliers (as it could not provide a fixed price for elements and risks it would not control), but would take fixed price T&S risks, such as the cost of store management, necessary wells and operating costs.
Appendix 1 - Comparison of RAB vs Fixed Price Models using Project Finance.

In a RAB structure, certain (eligible) costs of managing long term risks are passed to the consumer should they occur, and charges are updated periodically by the regulator.

Under a fixed-price model (CfD, PPA, FIT, PFI) the price is set under a long-term contract (likely with inflation indices) and the risks are absorbed by the private sector. How it is then financed is secondary. For instance, Shell was proposing to finance its Peterhead CCUS Project (in 2015) on balance sheet whereas White Rose (within the same CCUS Commercialisation Programme) was going to use project finance, setting up and financing a special project vehicle. But the risk transfer was similar for both; fixed price via the CfD model.

A key question is whether fixed price risk transfer is either possible or good value for money (VfM) for CCUS. Given it involves risk that the private sector cannot control, can the private sector price it economically, or at all. While either model can import elements of the other, there are key differences:

<table>
<thead>
<tr>
<th>RAB</th>
<th>Project Finance</th>
</tr>
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<tbody>
<tr>
<td>Revenues periodically reviewed by a regulator to protect both investors and customers</td>
<td>Revenues contractually fixed for entire concession (with flex for particular risks, e.g. CPI inflation)</td>
</tr>
<tr>
<td>(Efficient) cost overruns passed on to customer through the RAB – i.e. financed by RABCo and added to long term charges</td>
<td>Cost overruns absorbed by PFCo (and sub-contractors)</td>
</tr>
<tr>
<td>Regulator sets return for review period and updates RAB for actual capital expenditure</td>
<td>Returns fixed at the outset at a level necessary to absorb risk</td>
</tr>
<tr>
<td>Cost risk within RABCo relatively involatile relative to total RAB</td>
<td>Significant delivery risk to be absorbed within long term high cost of capital</td>
</tr>
<tr>
<td>Negotiated review settlement with open book accounting</td>
<td>Price determined through competition, of which cost of capital is only one element</td>
</tr>
<tr>
<td>Low cost of capital with substantial investment grade debt and highly competitive equity</td>
<td>High cost of capital necessary to absorb risk; lower levels of debt, high risk transfer to sub-contractors</td>
</tr>
<tr>
<td>Relatively known scope of work with clear incentives to expand the RAB</td>
<td>Model used for project specific purposes, where technologies and companies compete and where returns are a strong incentive to invest</td>
</tr>
<tr>
<td>Size, scale and duration of projects make it difficult to sub-contract at a fixed price or retain risks in the company; in the end funding comes from the consumer through return on the RAB</td>
<td>Size means risks can be sub-contracted or absorbed within PFCo for the duration of the project</td>
</tr>
<tr>
<td>Used when there is an incumbent/regional oligopoly</td>
<td>Used as part of a competitive process, where the benefits of competition outweigh the higher cost of capital</td>
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A key difference is that with RABs the cost of capital is an important part of the total cost, so needs to be low and many key risks could be passed through to the consumer over time, should they occur. Conversely, for project finance, much more of the risk remains within the (private sector) company and its sub-contractors. The company will have a higher cost of capital to be able to absorb those risks.
within the company. This higher cost of capital is a necessary evil to incentivise risk transfer, innovation and competition.

For example, contrast the RAB of the privatised UK water companies – stable, regional monopolies - to the project finance approach that has been used in the wind and solar markets as part of a competitive process.

Different parts of the CCUS industry exhibit different elements of the above:

- T&SCo and anchor projects – there is an incumbent operator/owner, known assets, but T&S has inherent uncertainty where the RAB structure can absorb project uncertainties (particularly for the early-movers, FOAK projects) avoiding uncertain risks from being priced into a fixed price contract
- New ‘upstream’ users (CO₂ Capture projects) such as power plants:
  - Competing to deliver more CO₂
  - Need incentives to invest
  - CO₂ capture project proponent understands and can quantify the costs and risks

This suggests RABs are more appropriate for T&S in particular, but that to encourage competition and innovation longer-term, a more project finance approach may be appropriate elsewhere as part of a competitive market.
Appendix 2 – CAG Terms of Reference

1. Context

1.1 The Government’s CCUS Deployment Pathway: An Action Plan (“Action Plan”) is designed to enable the UK’s first CCUS facility to be commissioned from the mid-2020s in order to meet its commitment for the UK to have the option to deploy CCUS at scale during the 2030s subject to the costs coming down sufficiently. The Action Plan sets out a number of actions designed to enable this.

1.2 Central to this is Government’s commitment to commence detailed engagement with industry on the critical challenges to delivering CCUS in the UK, focusing (at least initially) on: CCUS for industry (this can include hydrogen for industry or transport); CCUS for power; and carbon dioxide transport and storage infrastructure. It can include “full and part chain” projects as appropriate.

1.3 This reflects a desire of the Government and industry for detailed engagement to develop the cost structures, risk sharing arrangements and the necessary market mechanisms which create the stable investment framework necessary to deliver projects. Both the Government and industry see this as a necessary priority action to build mutual confidence that CCUS can play an affordable and potentially critical role in decarbonising the UK economy and support the Industrial Strategy.

1.4 This engagement will support and shape the Government’s Review of Delivery and Investment Frameworks which will be consulted on in 2019 and the outcome published by the end of 2019. It will also be an important step in developing the analysis in relation to the Government’s CCUS ambition set out in the Clean Growth Strategy and Action Plan.

1.5 To enable and progress this engagement and address these critical challenges, BEIS and industry will jointly establish a CCUS Advisory Group (the “Advisory Group”)

2. The CCUS Advisory Group

2.1 The Advisory Group is designed to be an industry led group working in partnership with Government to advise on the critical challenges that face CCUS as identified in the Government’s CCUS Deployment Pathway.

2.2 The work of the Advisory Group will be problem solving and solutions focused, bringing in specific expertise from across the CCUS industry and finance, combined with a public sector view of policy constraints and objectives. It will also include, where relevant, updates from other work BEIS may have commissioned to ensure consistency and integration, to make recommendations on developing the CCUS market in the UK, focusing initially on the market frameworks for CCUS.

2.3 For example, BEIS has committed to a review of the delivery and investment frameworks for CCUS to develop market-based frameworks that can best support investment in, and deployment of, CCUS. As such, a key role of the Advisory Group will be to support and shape the Review with clear recommendations to BEIS that command market support.

2.4 The outputs from the Advisory Group will be short, targeted summaries on the critical challenges facing CCUS and the Advisory Group’s analysis and recommendations on how these challenges can be met and at what cost and to whom. The outputs will be supported by clear and robust evidence, including the use of modelling and detailed costings where appropriate.

2.5 The Advisory Group will focus on the following areas:

Market frameworks for CCUS

- Develop, exemplify and advise on the business models proposed for CCUS investments principally focusing on industrial CCUS, power production and CO₂ transport and storage.
- Consideration should also be given to how the proposed business models interact with each other to minimise issues such as cross-chain risk.
- For each business model tested, the Advisory Group will identify and outline:
a) Revenue support mechanisms and who pays including consideration of the implications on tax revenue or consumers\textsuperscript{139}. This should also consider the issue of balance sheet funding from Government and any contingent liabilities;

b) Risk allocation and risk management options (covered in more detail in the next section);

c) Ownership structures;

d) Capital financing structures (including development costs);

e) The likely cost of capital that will flow from each model and how each business model is likely to affect the overall cost of capital. Consideration of financiers’ views on this would be welcome;

f) The legislative requirements for each business model (with the starting point to minimise or avoid primary legislation);

g) Advise on whether and how the business model, Government exposure and balance sheet treatment might evolve as the CCUS industry matures.

The Advisory Group will recommend initial business models and risk allocations for each sector, evaluated against a suite of public and private objectives, which although non-binding can then form the basis of subsequent costing by the Group and wider industry.

Risk allocation and risk management solutions

- For each business model tested for CCUS investments for industrial CCUS, power production and CO\textsubscript{2} transport and storage, the issue of risk allocation and risk management should be described in detail:
  a) The options for risk allocation of CCUS clusters and how the options may impact price, contingent liabilities and balance sheet treatment.
  b) Identify options for different risk allocations and risk management solutions for different types of CCUS clusters.
  c) Describe how the options for risk allocation framework can be flexible, and how they can evolve, this should include how this can be assessed and managed over time.
  d) Show the impact of each option on overall WACC and capital structures of developers and the impact of each option on tax revenue or consumers.

This detailed analysis will, inter alia, allow Government to understand the balance sheet treatment of each of the models, with the objective that all or most clusters will be off Government’s balance sheet.

Delivery capability:

- Describe the delivery capabilities needed in the UK to support deployment of CCUS (including Government, industry, projects and finance).
- Describe how these delivery capabilities can be created, and recommend the actions needed to create them.

Costings:

- Provide ranges for the estimated costs (capex and opex) of prospective CCUS projects using the business models tested and related costs of capital. This can include engagement with potential industrial clusters which CCUS projects may be a key component of.
- Consider a suite of metrics that should be used to assess the possible range of CCUS projects, e.g. compare power with industry and then industry sub-sectors (including hydrogen); compare BECCS with gas CCUS.
- Provide quantified estimates of cost reduction trajectory from initial CCUS projects (including the range of possible projects).

\textsuperscript{139} If a RAB model is recommended for CO\textsubscript{2} transport and storage, this should include how it will be funded for example, any balance sheet implications and contingent liabilities.
Process

- Describe how competitive pressure can drive cost reduction and where and when other approaches, e.g. collaboration might prove more productive.
- Describe how productive competitive pressures can be maintained in CCUS in a framework which does not use a standard competitive government procurement process.

3. Ways of working and resources

3.1 The Advisory Group will be chaired by an industry representative and supported by industry the CCS Association and BEIS.

3.2 It will be established and run for an initial 7 months (to 31 July 2019). BEIS and industry will review the Advisory Group’s Terms of Reference and role in July 2019 to decide on the role of the Advisory Group after this point.

3.3 The Advisory Group’s membership will be from industry and the finance sector and BEIS (proposed membership is at Annex A). Additional industry members willing to contribute resources to the group may be able to join.

3.4 The Advisory Group will meet fortnightly with sub-groups meeting on alternative weeks to progress actions. The fortnightly meetings will be held in compliance with Competition Law and attendees reminded of their Competition Law obligations at the start of each meeting.

3.5 The Advisory Group will be resourced from in-kind contributions from its Members, with some funding from members to cover independent costs, advice, accommodation and admin.

3.6 The papers, findings and recommendations from the Advisory Group will be made available and will be based on wider industry engagement.
## MEMBERSHIP OF THE CCUS ADVISORY GROUP

<table>
<thead>
<tr>
<th>Company</th>
<th>Name</th>
<th>Affiliation</th>
<th>Notes</th>
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<tr>
<td>BP</td>
<td>Ben Hanson</td>
<td>Pale Blue Dot</td>
<td>Alan James</td>
</tr>
<tr>
<td>BP</td>
<td>Ian Hunter</td>
<td>Pale Blue Dot</td>
<td>Luke Robertson</td>
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<td>BP</td>
<td>Martin Towns</td>
<td>SCCS</td>
<td>Philippa Parmiter</td>
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<td>Cadent</td>
<td>Andy Lewis</td>
<td>SCCS</td>
<td>Rebecca Bell</td>
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<td>Cadent</td>
<td>Damien Hawke</td>
<td>Scottish Futures Trust</td>
<td>Paul Moseley</td>
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<td>CCSA</td>
<td>Chris Gent</td>
<td>Scottish Govt</td>
<td>Kate Chalmers-Deacon</td>
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<td>Judith Shapiro</td>
<td>Scottish Govt</td>
<td>Stuart Mackay</td>
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<td>CCSA</td>
<td>Marine D’Elloy</td>
<td>Shell International UK Ltd</td>
<td>Angus Lochhead</td>
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<td>CCUS Council Chair</td>
<td>James Smith</td>
<td>Shell UK Limited</td>
<td>Matthew Livingston</td>
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<tr>
<td>CF Fertilisers</td>
<td>Debbie Baker</td>
<td>Siemens</td>
<td>Matthew Knight</td>
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<td>Paul Davies</td>
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<td>Renato De Filippo</td>
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<td>Kristofer Hetland</td>
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<td>Stanislas Van den Berg</td>
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## Disclaimer

The views expressed in this report do not reflect UK Government policy.

They cannot and should not be taken to represent the views of each or all members of the CAG.

They do, however, aim to reflect a general consensus within the CAG.
GLOSSARY

BEIS: the UK Government’s Department for Business, Energy and Industrial Strategy

CAG: CCUS Advisory Group

Capex: capital expenditure or investment

Catalyst Project: first capture projects in a regional cluster that will anchor the T&S enabler to that regional cluster

CCC: Committee on Climate Change – an independent, statutory body established under the Climate Change Act 2008 to advise the Government on emissions targets and progress made in reducing greenhouse gas emissions

CCS: Carbon Capture and Storage

CCUS: Carbon Capture Usage and Storage

CGR Zone: clean growth regeneration zone

CFD: Contract for Difference established under Energy Act 2013

CO2: Carbon Dioxide

DSC: Decarbonised Service Company

EG&CCo.: Electricity Generator and (CO2) Capture Company

EOR: Enhanced Oil Recovery

EU ETS: European Union Emissions Trading Scheme. Launched in 2005, was the first greenhouse gas emissions trading scheme in the world.

FEED: Front End Engineering Design

Feeder Project: follow on capture projects in a regional cluster that will feed into the T&S enabler at that cluster

FID: Final Investment Decision

GGR: greenhouse gas removal – technologies that remove greenhouse gases from the atmosphere

GHG: Greenhouse Gas

HMG: HM Government

HMT: HM Treasury

IP&CCo.: Industrial Products and (CO2) Capture Company

IPCC: Intergovernmental Panel on Climate Change

LCCC: Low Carbon Contracts Company, the counterparty to the CFD contracts and manager of those contracts

LCOE: levelised cost of electricity

Mt: million tonnes (or megatonnes)

MTPA: million tonnes per annum

MWh: megawatt hour

NPV: net present value

Opex: Operational expenditure or investment
OGA: The Oil and Gas Authority, a government company that works with Government and industry to regulate, influence and promote the UK oil and gas industry

NPS: National Policy Statement, as may be applicable to planning policy for England and Wales R&D – research and development

RAB (Regulated Asset Base): is a system of long-term tariff design aimed primarily at encouraging investment in the expansion and modernisation of infrastructure. The allowed revenue for provision of regulated services includes the operating cost, depreciation and return on regulated assets. The return, if calculated as the allowed rate of return (cost of capital) is charged on the regulated assets.

RIIO-2: Revenue = Incentives + Innovation + Outputs (RIIO) is the price control for the network companies running the gas and electricity transmission and distribution networks. The RIIO-2 period is due to start on 1 April 2021

T&S: transportation and storage parts of CCUS infrastructure

T&SCO: a company established to operate the T&S infrastructure

T&S Enabler: first CO₂ transportation pipes and CO₂ stores in a CCUS transportation and storage hub into which future projects can connect

WACC: weighted average cost of capital
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