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CCS Sector Development Scenarios in the UK

Final report

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elementenergy

PÖYRY

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Disclaimer

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Glossary

CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbines
CCR	Carbon capture ready
CCS	Carbon capture and storage
CCSA	Carbon Capture and Storage Association
CNS	Central North Sea
CO_2-EOR	CO_2-enhanced oil recovery
DECC	Department of Energy & Climate Change
EIS	East Irish Sea
EMR	Electricity Market Reform
EOR	Enhanced oil recovery
ESME	Energy Systems Modelling Environment
ETI	Energy Technologies Institute
FID	Final investment decision
FiT CfD	Feed-in Tariff with Contracts for Difference
FOAK	First of a kind
GDP	Gross Domestic Product
GW	Gigawatt
IED	Industrial Emissions Directive
IGCC	Integrated gasification combined cycle
kWh	kilowatt hour
LCF	Levy Control Framework
Mt	Million tonnes
MWh	Megawatt hour
NGO	Non-governmental organization
NNS	Northern North Sea
NOAK	Nth of a kind
SNS	Southern North Sea
T&S	Transport and storage
TPA	Third part access
UKCS	United Kingdom Continental Shelf
ZOAK	Zero-th of a kind (i.e. the first plant built in the UK with a particular capture technology)

Preface

This report aims to extend the Energy Technology Institute's (ETI) modelling analysis of the role of carbon capture and storage (CCS) in enabling the UK to meet its carbon budgets efficiently. ETI's energy system modelling uses robust engineering analysis and cost evidence within its Energy System Modelling Environment (ESME). ESME analysis suggests that without CCS, the cost of reaching UK Climate Change targets will double from a minimum of around £30bn per year in 2050[1]. Apart from its role in power generation, CCS enables flexible low carbon energy by capturing industrial emissions, through gasification applications and by delivering negative emissions in combination with bio-energy.

Enabling CCS to realise its potential and play this key role will require substantial investment in building the sector over the period to 2030. ESME scenarios suggest that a cost-optimal 2050 energy system would require building a sector storing ca. 100 million tonnes of CO_2 by 2050. To reach this target requires that the CCS sector and associated infrastructure will need to be extensively developed by 2030, storing ca. 50 million tonnes of CO_2 with ~10 Gigawatts (GW) of power CCS and contribution from industrial sources. Delaying development of this capacity beyond 2030 would expose the UK to substantial cost and deployment risks in meeting carbon budgets.

If delays were to permanently stunt the growth of CCS in the UK the likely impact is a substantial increase in the economic burden of meeting carbon targets, arising from the need to deploy higher cost technologies to cut emissions, particularly in heat and transport. As suggested above, a complete failure to deploy CCS would imply close to a doubling of the cost of carbon abatement to the UK economy from circa 1% to 2% of GDP.

To date the development of CCS sector in the UK has been subject to many delays – although now the White Rose and Peterhead/Goldeneye projects look likely to proceed with support under the Department of Energy and Climate Change's (DECC) Commercialisation Programme. Nevertheless the question of how the CCS sector might develop beyond these first Commercialisation Programme projects towards the longer term levels anticipated in the ETI's ESME modelling remain open. Growing CCS will require parallel development of both the storage and transport infrastructure, and sources from the power sector and industrial processes: this gives rise to many important choices and decisions that could affect the speed of implementation and the cost of projects as envisaged by the CCS Cost Reduction Task Force in 2013.

ETI commissioned Element Energy and Pöyry to explore alternative ambitious but deliverable scenarios for the UK CCS sector to 2030 in the context of real geographies and dependencies, plausible potential projects, existing and potential power generation and industrial sources of CO_2, realistic decision timelines and project economics. The identification of challenges and the steps required to overcome these is informative for policymakers and industry participants alike.

We are grateful for the valuable insights and input to this project from The Crown Estate, DECC, the Carbon Capture and Storage Association (CCSA) and many other stakeholders in the CCS industry.

[1] Based on ESME v3.1

Executive summary

The context

The UK has an opportunity to build a CCS sector capable of reducing the costs of meeting its carbon targets by tens of £billions, while exploiting the UK's unique offshore engineering capabilities and safeguarding the future of key energy-intensive industries.

This report identifies the practical steps needed over the period to 2030 to build a UK CCS sector that can:

- move rapidly towards cost competitive low carbon electricity generation during the 2020s
- deliver low cost emissions reductions to efficiently meet the 4th and 5th carbon budgets, and
- put the broader UK energy system on a trajectory towards its long term objectives of affordable and secure low carbon energy

The analysis uses three ambitious but deliverable sector scenarios for the UK CCS sector to 2030. The sector scenarios are tools to identify challenges and the steps required to overcome these in the context of real geographies and dependencies, plausible potential projects, existing and potential power generation and industrial sources of CO_2, realistic decision timelines and developing project economics.

Over a period of six months, and with significant input from many stakeholders, the project has developed three realistic sector scenarios to 2030. This both extends previous modelling-based analysis of the potential role of CCS (based for example on ETI's energy system modelling, analysis of the UKCS geological storage resource and modelling of transport and storage infrastructure) and builds on the Government's outcome for the CCS Commercialisation Programme that:

> *"private sector electricity companies can take investment decisions to build CCS equipped fossil fuel power stations, in the early 2020s, without Government capital subsidy, at an agreed CfD Strike Price that is competitive with the strike prices for other low carbon generation technologies."*

The project team does not seek to recommend a particular scenario – indeed the specific development path of the CCS sector could mix elements of all three scenarios presented. However the outcomes of the analysis and identified actions are intended to inform policy makers and industry participants alike.

Why develop CCS at scale in the UK?

ETI's analysis of the UK energy system points to the central importance of CCS in enabling the UK to meet its carbon budgets efficiently. ETI's energy system modelling is based on robust engineering analysis and cost evidence and suggests that successfully deploying CCS would save tens of billions of pounds (up to circa 1% of GDP by 2050) from the annual cost of meeting UK Climate Change targets, compared with alternative approaches to reducing emissions which do not deploy CCS. Apart from its role in power generation, CCS can capture industrial emissions at low cost; provide flexible low carbon energy for industry, transport and heat through gasification; and deliver high value negative emissions (in combination with bio-energy).

Enabling CCS to realise its potential and play this key role in UK decarbonisation will require developing around 10 GW of capacity by 2030. This level of ambition is consistent with DECC's EMR delivery Plan (which included up to 13 GW of CCS by 2030)[2], and with the Committee on Climate Change's (CCC)[3] scenarios for curbing power sector emissions to 50g CO_2/kWh by 2030. Capital investment required would be around £21 – £31 billion to build the sector over the period to 2030, equivalent to around 10 to 14% of total power sector investment estimated by the Committee on Climate Change. Delaying development of this level of capacity beyond 2030 would expose the UK to substantial cost and deployment risks in meeting carbon budgets.

Overview of 2030 Sector Scenarios

On this basis the three scenarios summarised below represent distinct and plausible pathways to developing a 'close to optimal' 10 GW of CCS capacity by 2030.

Scenario	Costs	Strike prices	Benefits / issues
Concentrated			
Geographic concentration around two competition projects to reduce T&S costs and barriers; dominant role for gas CCS with SNS storage.	CfD payments total around £14bn to 2030, rising to £2.1bn per annum in 2030 Cumulative capex in 2030 is £21.4bn	Fall quickly from early Phase 2 projects to < £100/MWh by 2025, falling below £90/MWh for new gas fired projects in 2030 (close to prevailing wholesale price)	Achieves fastest cost reduction, but geographic concentration limits future optionality & leaves cost of developing further T&S hubs to 2030s.
CO_2-EOR			
Scenario dominated by EOR in CNS under a Wood report-style push to maximise UKCS oil production. Market pull for CO_2 for EOR supported by policy (e.g. tax incentives).	CfD payments total around £14bn to 2030 CfD payments rise to £2.2bn per annum in 2030 reflecting the benefits of EOR via lower strike prices Cumulative capex in 2030 is £27.2bn	Strike prices for both coal and gas plants fall below £90/MWh by 2030 as EOR benefits feed through. Assumes £20/t CO_2 sale price at the oil field for flows that go to EOR	Could help to safeguard jobs and tax revenues from North Sea oil & gas, with costs partly offset by oil and gas revenue. Clearly at risk of oil price volatility affecting viability of EOR.
Balanced			
Push "on all fronts" to create a flexible base of deployment and win support from diverse stakeholders. A variety of regional clusters, with multiple fuels and capture technologies.	CfD payments total around £18bn to 2030, rising to £3.2bn per annum in 2030, reflecting the cost of developing two further hubs Cumulative capex in 2030 is £31.2bn	Strike prices remain comparatively high as multiple technologies are deployed and new infrastructure hubs are developed Strike prices for both coal and gas plants drop below £100/MWh by 2030	This approach delivers valuable optionality for lower cost CCS roll out in the 2030s, location of low carbon industry and potentially lower risks (through diversity of storage & technology)
Notes: The CCC projections suggest that annual LCF spend could be around £10bn per annum by 2030 (CCC projections in Energy prices and bills – impacts of meeting carbon budgets, Dec 2014)			

[2] DECC, 2013, Electricity Market Reform Delivery Plan
[3] The CCC, 2013, Fourth Carbon Budget Review

Key conclusions emerging from the scenarios

- Developing a 10 GW scale CCS sector by 2030 is feasible and affordable through a number of different pathways, based on co-ordinated cluster / hub development
- Early phase 2 projects can make use of the stores and transport infrastructure developed under the Commercialisation Programme, delivering strike prices at or below £100 per MWh by 2025, with potential further cost reductions by 2030.
- A 10 GW scale CCS sector would be affordable in terms of the demand on levy control framework funds (an annual support cost of around £1.1 to £1.3 billion by 2025) and efficient in terms of cost per tonne of CO_2 reduction.
- This scale of CCS deployment could capture and store around 50 million tonnes of CO_2 emissions per annum from power and industry by 2030, enabling CCS to develop in the 2030s to the optimal scale suggested by longer term analysis of the UK energy system.
- This outcome can be delivered by creating a supportive policy environment with early action on critical issues to bring forward timely investment.

Key requirements for CCS sector development

1. **Timely implementation of <u>both</u> CCS Commercialisation Programme projects:**
   The scenarios point clearly to the value of both Commercialisation Programme projects in developing vital transport and storage infrastructure which unlock later unit cost reductions and strategic build out options. Failure to develop two projects to open up two CCS hubs would constrain options and increase the risk of failure to develop a CCS sector at scale by 2030.

2. **Early investment in physical appraisal to expand the promising 5/42 and Captain aquifer stores and appraise further sites:**
   All scenarios require suitable sinks for subsequent phases of project to be developed early, given long lead times for developing storage sites, and the need for clarity to underpin investment decisions. This means that, in addition to the vital storage development under the Commercialisation Programme, immediate investment to expand capacity is needed, either tax payer funded or by creating sufficiently strong incentives to bring forward private investment.

3. **Enable early investment decisions by phase 2 projects by awarding a further 3 appropriately designed CfDs by 2020:**
   All three scenarios depend on enabling at least three early phase 2 projects to reach FID by 2020, in effect requiring the award of three further power sector CfDs ahead of commissioning of the Commercialisation Programme projects.

   This is a key challenge for the current policy framework, requiring early commitment of levy control framework resources, and potentially bespoke contractual design to bring forward sufficient private sector investment while maintaining incentives for cost-efficiency.

4. **Stimulate a robust project development pipeline by delivering clear signals to investors and project developers about the scale and strength of policy (levy control framework support) commitment to developing CCS:**

All of the scenarios require a robust pipeline of developing projects throughout the 2020s. Stimulating a sufficiently project pipeline will require significant strengthening of current policy and market signals, and resolution of uncertainties for investors.

The scenarios point clearly to the need to achieve 5 or 6 CfD awards by 2020, committing around £1.1 - £1.3 billion annually of the LCF to CCS by 2025. A consistent pipeline of projects will be needed through the 2020s, resulting in support costs around £2-3bn per annum by 2030 (or around 20-30% of expected annual low carbon support costs) Investors and project developers will require clearer signals about this scale and strength of commitment.

Other issues to be resolved

The scenario analysis also suggests that a range of other issues will need to be resolved to support the rapid development of the sector during the 2020s, including

- **Governance for infrastructure sharing:** Efficient sharing of infrastructure is central to the strategic value and cost reductions achievable in all scenarios, but the most effective associated arrangements for governance or regulation, and for charging will need to be clarified. A purely negotiated incremental cost approach would have very different strike price and risk management implications to a more regulated network charging framework.
- **Strategy for capture readiness:** Developing a more robust strategy for capture readiness, the location of new thermal plant and retro-fitting needs greater attention if, as seems likely, a wave of investment in unabated gas-fired capacity is required early in the 2020s (ahead of CCS sector development) to bolster energy security / supply margins.
- **Financial incentives for industrial CCS:** All scenarios demonstrate the clear potential for CO_2 capture from major industrial sites before 2030; but realising this will require early resolution of financial incentives to support capture of industrial process-related emissions with CCS.
- **Management of load factor risk for CCS power projects:** The potential load factors achievable by CCS power plants in the medium and long term will depend on the broader generation mix. Given the lifetime of CCS projects investors may well require greater clarity on this or a move away from a reward structure entirely dependent on delivered output.
- **Risk management and governance for CO_2-EOR:** The degree of reliance on EOR (and associated incentives) in financing and leading the development of the sector and its infrastructure will need to clarified, as it will be an important influence on the pipeline of projects. Investments in northern / Scottish capture and CO_2 infrastructure would become more attractive along with coal-based capture projects to provide CO_2 volumes. However, an EOR-led approach would also need to manage oil-price risks, address greater complexity in cross-sector co-ordination and clearly demonstrate how it delivers value in ultimately reducing emissions.
- **Reflecting strategic value in CfD allocation decisions:** The scenario modelling showed that developing a range of capture technology options and more diversity in geographic location can deliver reduced risk and increase optionality for future CCS development. But this looks likely to come at some added financial cost. While there is no clear case for government to pick technologies, policy on CfD allocation will need to clarify how these issues will be taken into account.

What if CCS sector development is delayed?

- Delay to developing a UK CCS sector of around 10 GW scale by 2030 will increase the risks of higher costs in meeting carbon budgets, both before and after 2030.

- Slower development of CCS (e.g. a 5 year delay) would require advancing other technologies (e.g. a substantial move away from gas heating in the 2020s) and/or risk increasing the costs of power sector decarbonisation.

If delay were to permanently stunt the growth of CCS in the UK, ETI's analysis points to a substantial increase in the economic burden of meeting carbon targets, arising from the need to deploy higher cost technologies to cut emissions, particularly in heat and transport. A complete failure to deploy CCS would imply close to a doubling of the annual cost of carbon abatement to the UK economy from circa 1% to 2% of GDP by 2050 (or roughly an extra £1,000 per household). ETI's analysis suggests that success or otherwise in deploying CCS determines key aspects of the UK's energy infrastructure architecture (e.g. the extent of decarbonisation of heat and transport required to meet carbon budgets).

Scenario analysis and historical experience suggests that creating momentum in the sector to stimulate a robust project development pipeline will be important to deployment and realising cost reductions in practice. So delay in building the sector will increase the risk that CCS fails to deliver a significant contribution to either power sector or broader decarbonisation, in turn creating broader risks of higher costs, heavy reliance on other technologies or potential failure to meet carbon budgets

A shorter 5 or 10 year delay in developing the CCS sector would still be likely to increase costs and risks across the UK energy system. There is an argument that delay would enable the UK to take advantage of technology cost reductions delivered by CCS investment elsewhere globally. But many of the costs and risks of early CCS deployment are UK-specific and early cost reduction opportunities depend on early infrastructure investments, achieving scale and capacity utilisation in the UK sector.

Containing the cost impacts of a 5 year delay would require *both* rapid (and risky) 'catch up' development of CCS during the 2030s *and* accelerated early uptake of a range of other low carbon technologies during the 2020s to fill the gap left by CCS (e.g. rapid replacement of gas heating during the 2020s as well as very rapid growth of biomass value chains to serve both heat and industrial energy needs).

More realistically, if broad strategy remains focused on early decarbonisation of the power sector, delay to CCS would lead to greater reliance on nuclear and offshore wind. Even with successful unit cost reductions, this would increase system risk and costs both before and after 2030.

Further details of the scenarios, investment timelines and economic modelling are set out, analysed and explored in the chapters and appendices to this report.

The ETI welcomes both feedback on this report and further engagement with stakeholders around actions to enable efficient CCS sector development.

1 Introduction

1.1 Context

Analysis of the UK energy system by the Energy Technologies Institute (ETI) points to the central importance of Carbon Capture and Storage (CCS) in enabling the UK to meet its carbon budgets efficiently. ETI's modelling of the UK energy system shows that without CCS, the cost of reaching the UK's climate change targets will increase by over £30bn per year in 2050[4].

In addition to its role in power generation, CCS enables a flexible low carbon energy system by capturing industrial emissions, through gasification applications and by delivering negative emissions in combination with bio-energy. Due to its unique position the value proposition for CCS is therefore much greater than the ability to deliver cost-competitive low carbon power. The additional benefits of system security, power generation flexibility and cross-sector decarbonisation are not well captured in simple metrics such as a £/MWh Levelised Cost of Energy (LCOE). Throughout the project, we present £/MWh figures where appropriate, as they allow a simple cost comparison of CCS with other low carbon options, and correspond to current proposals for CCS funding mechanisms. It should be borne in mind, however, that a complete representation of the value that CCS can deliver to UK decarbonisation goals would require an assessment of its full impact on the costs and performance of the broader energy system.

ETI's ESME scenarios suggest that a cost-optimal 2050 energy system would require building a sector storing ca. 100 million tonnes of CO_2 per year by 2050. Modelling also suggests that to reach this target requires the development of the CCS sector and associated infrastructure by 2030, storing ca. 50 million tonnes of CO_2 with ~10 GW of power CCS and contribution from industrial sources.

Currently, the most important driver for CCS in the UK in the short term is DECC's CCS Commercialisation Programme, which is making available £1 billion capital funding, together with additional revenue support through the Contract-for-Difference Feed-in-Tariff (Fit CfD). DECC announced its two preferred projects in 2013 as:

- **Peterhead Project:** A 340 MW post-combustion capture plant retrofitted to part of the existing Peterhead gas power station (ca. 1 Mt/yr CO_2) with transport using an existing offshore pipeline for permanent storage in the Goldeneye gas condensate field.
- **"White Rose" Project:** Oxyfuel capture at a new 304 MW coal power station at the Drax site (ca. 2 Mt/yr CO_2), with an over-sized pipeline transport to an aquifer in the Southern North Sea.

Under the existing Electricity Market Reform arrangements, follow-on or 'phase 2' power CCS projects in the UK will be supported mainly through FiT CfDs. Many bodies of work, including the Cost Reduction Task Force project, have established that CCS power generation costs could fall considerably following the initial projects. Key drivers for cost reduction were identified as greater technical learning, economies of scale and reduced financing risk premiums.

While there has been a great deal of policy attention on the CO_2 source (e.g. capture at power stations), it is well understood in the CCS industry that development of the transport and storage infrastructure may well be even more important as developing a mature CCS industry will entail simultaneous growth of the sources and of the transport and storage infrastructure. Cost optimal development of the sector will require co-ordination in rollout

[4] ESME version 3.1

across the complete CCS chain and over short term and longer term (strategic) timescales.

1.2 Project objectives

The aim of this project is to explore the symbiosis across the CCS chain and between short term and longer term rollout in a practical sense to develop a range of realistic and deliverable scenarios for development of the CCS sector at scale by 2030. This report identifies the practical steps that are required to support the building of the UK CCS sector over the period to 2030, such that it:

- moves rapidly towards cost competitive low carbon electricity generation during the 2020s building on the two commercialisation projects,
- delivers low cost emissions reductions to efficiently meet the 4^{th} and 5^{th} carbon budgets, and
- places the broader UK energy system on a trajectory towards its long term objectives of affordable and secure low carbon energy.

The analysis identifies and explores the key issues using three ambitious but deliverable scenarios for the UK CCS sector to 2030 considering real geographies and dependencies, plausible potential projects, existing and potential power generation and industrial sources of CO_2, realistic decision timelines and developing project economics.

The three scenarios were developed over a period of six months, with significant input from many stakeholders. The outputs from this work are informative for policymakers and industry participants alike.

1.3 Project methodology

The project methodology, summarised in Figure 1, consists of four key steps:

1) Development of the CCS sector development scenarios based on the key drivers for CCS deployment, which are identified by reviewing recent CCS studies and considering the 2050 deployment goals;
2) Creation of detailed onshore and offshore configurations taking account of scale, siting, sequencing/timing and inter-dependencies of capture projects, clusters, storage hubs and infrastructure to realise an integrated CCS sector by 2030;
3) Economic modelling using existing and new bespoke Element Energy and Pöyry models to estimate total investment in capture projects and T&S infrastructure, and CfD strike price requirements using alternative approaches to charging for shared transport and storage infrastructure;
4) Stakeholder engagement to review the sector scenarios and identify key requirements for CCS roll-out in each scenario.

Process	Key aspects
Development of the outline CCS scenarios based on key drivers	• Identify key CCS drivers by reviewing recent CCS studies • Develop three CCS sector development scenarios achieving 10GW of CCS by 2030, which represents credible point on achievement of 2050 deployment goals based on ETI's energy system modelling
Detailed onshore and offshore configurations	• Potential power CCS and industrial CCS projects based on previous studies by Element Energy and Pöyry, and CCS proposals • Offshore T&S network design using CO_2Nomica (ETI's T&S network analysis tool developed by Element Energy), CO_2Stored database and potential EOR fields identified in the previous Element Energy studies
Economic modelling	• Strike price, power plant and onshore pipeline costs using Pöyry models • Offshore T&S infrastructure sizing and cost estimation using CO_2Nomica • Industrial CCS costs based on previous Element Energy studies • CO_2-EOR modelling using Element Energy's in-house CO_2-EOR model
Stakeholder engagement	• Steering Board input throughout the project from ETI, The Crown Estate, DECC and CCSA • A facilitated workshop with more than 20 key CCS stakeholders and a number of bilaterals to review the deployment scenarios and identify key requirements

Figure 1: Key aspects of project methodology

2 Approach to sector scenario development

This chapter summarises the process that has been followed to develop the outline CCS sector development scenarios. It is important to note that these sector scenarios are not forecasts or recommendations, but are designed to represent viable alternative pathways for a significant level of CCS deployment in the UK. Scenario analysis is insightful as it bridges the "top-down" understanding of what would be most beneficial in the period to 2050, with a "bottom-up" perspective of what is most realistic in the 2010s and early 2020s, given current awareness, interest, existing project proposals and technology priorities.

As explained in the previous section, the key objective of this study is to build a range of scenarios for the development of CCS by 2030 at a scale commensurate with realising the full potential of CCS in the UK's strategy to meet 2050 carbon targets (as suggested by ETI's ESME scenario analysis). In outline, this means scenarios for a 2030 UK CCS sector which:

- entails the storage of ca. 50 million tonnes of CO_2 with ~10 GW of power CCS and contribution from industrial sources (consistent with the ETI's ESME scenarios) in 2030;
- starts with the development of the Goldeneye/Peterhead project in North East Scotland and the White Rose in Yorkshire; and
- recognises that there might be many pathways between these two points.

The literature review of recent CCS studies by Element Energy, Pöyry, the ETI and other organisations is described further in Appendix 1. This review quickly identified that the degrees of freedom for scenarios which reach the level of roll-out required for consistency with ESME scenarios are limited by practical deployment restrictions. However, some choices still remain, and the following key drivers for CCS sector development scenarios have formed the basis of our scenario development:

1. **CCS location:** Sector scenarios at scale could include different onshore clusters (e.g. Scotland, Yorkshire, Teesside, Thames/Bacton and Liverpool) and offshore storage regions (e.g. Southern North Sea, Central North Sea and East Irish Sea). Among the wide range of possible CCS locations, we examined two different options:
   - Maximising economies of scale and spare infrastructure capacity from the initial projects;
   - Developing more storage basins and onshore hubs, which give more options for the longer term growth.

2. **Generating additional revenues from CO_2-Enhanced Oil Recovery**: Similarly, a high CCS roll-out could be achieved in the UK with different levels of CO_2-EOR (ranging from no CO_2-EOR to high CO_2-EOR). The level of CO_2 demand from CO_2-EOR projects would have implications for network configurations and cost profiles in the scenarios.

Using these two key drivers, we have developed three CCS sector development scenarios for the pathways to 2030, which are presented in the figure below[5].

[5] It was assumed that there is no great interaction with other countries before 2030; power system developments are based on current policy trends (i.e. CfD payments for the follow-on projects); and broadly efficient decisions are taken around the oversizing and sharing of pipes and stores.

Although we have limited our key scenario drivers to two dimensions that develop divergent CCS sector development scenarios, other scenario elements vary between scenarios such as capture technology, fuel source and storage type depending on the scenario narrative. This approach ensures we capture the diversity of outcomes of for the future development of the sector, but retain a consistent story-line for each scenario narrative. Also it should be noted that, in this report, we present three plausible scenarios, which aim to push the feasible boundaries of the key drivers and to be distinct enough to be insightful. Other scenarios, with different combinations of those same drivers, would also be plausible.

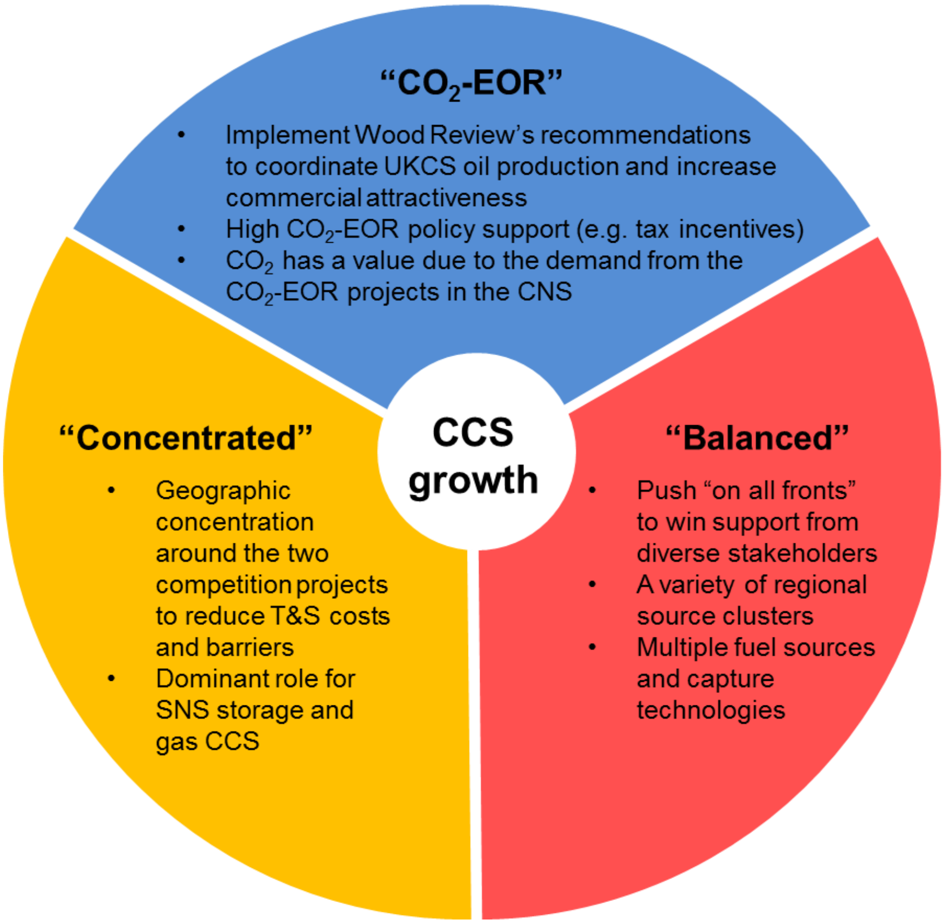


Figure 2: Three CCS sector development scenarios

The sector scenarios are tools to identify challenges and the steps required to overcome these in the context of real geographies and dependencies, plausible potential projects, existing and potential power generation and industrial sources of CO_2, realistic decision timelines and project economics.

In the following chapter we describe each of the three scenarios in more detail, including realistic timelines for capture and storage development, CO_2 flows, investment requirements, strike prices, T&S costs and CfD costs in each scenario. Further economic modelling and timeline assumptions are explained in Appendix 2.

3 CCS sector development scenarios

In the following three sections we describe each of the three CCS sector development scenarios in more detail. It is important to note that these are not forecasts or recommendations; however, they are designed to represent deliverable and realistic alternative pathways for CCS deployment in the UK over the period to 2030.

3.1 Concentrated scenario

The main driver underpinning the Concentrated scenario is the focus on building successive CCS projects out from the initial Commercialisation Programme projects to reduce transport and storage (T&S) costs and barriers. The follow-on projects are therefore geographically concentrated around the two competition projects (i.e. Yorkshire and Scotland). In this scenario, we see a more dominant role for Southern North Sea (SNS) storage.

As the key driver of this scenario is to achieve cost reductions in the short-term, it is assumed that one of the lower cost capture technologies currently available (e.g. post combustion gas) becomes the technology of choice, and improves quickly to maximise cost reductions from learning by doing.

3.1.1 Description

Implementation of the concentrated scenario can be framed in three distinct phases:

- The first phase is the connection to the offshore stores of the initial Commercialisation Programme projects, White Rose (2 Mt/yr) and Peterhead (1 Mt/yr), by 2020/2021. The existing Goldeneye pipeline will be used for storage in the Goldeneye gas field, and a new trunk pipeline (with a capacity of ca. 17 Mt/yr) for storage in aquifer 5/42 (a saline aquifer 70 km off the coast of Yorkshire) will be developed. Both pipelines will be oversized compared to initial project requirements in order to accommodate future growth.

- The second phase is characterised by utilisation of the available transport and storage capacity to connect additional projects around Yorkshire (total 8 Mt/yr) and in Scotland (total 5 Mt/yr). The subsequent capture projects that are developed between 2020 and 2025 will connect to the same shoreline terminals, and the CO_2 will be transported utilising the phase 1 offshore pipelines. An existing onshore pipeline (i.e. Feeder 10) will be re-used to transport captured CO_2 from the Forth of Firth to the Fergus shoreline terminal. The 5/42 aquifer storage capacity is assumed to be sufficient for the additional projects around Yorkshire in this phase. Storage starts at the Captain aquifer (which is connected to the Goldeneye field) in 2022 to accommodate storage for additional projects in Scotland.

- The third phase realises the development of additional T&S infrastructure in the same two locations to accommodate further capture projects, with a total of 29 Mt/yr around Yorkshire and 11 Mt/yr in NE Scotland. By 2030, storage for projects in Scotland is extended to Central North Sea (CNS) aquifer 2. It should be noted that CO_2 captured in Scotland can be injected into a potential EOR field in the CNS; however, this has not been modelled explicitly. CO_2-EOR potential in the CNS is examined in more detail in the “CO_2-EOR” scenario. Storage for the projects close to Yorkshire is extended to a further storage site ‘SNS aquifer 2’, which requires development of a new trunkline from the shoreline terminal.

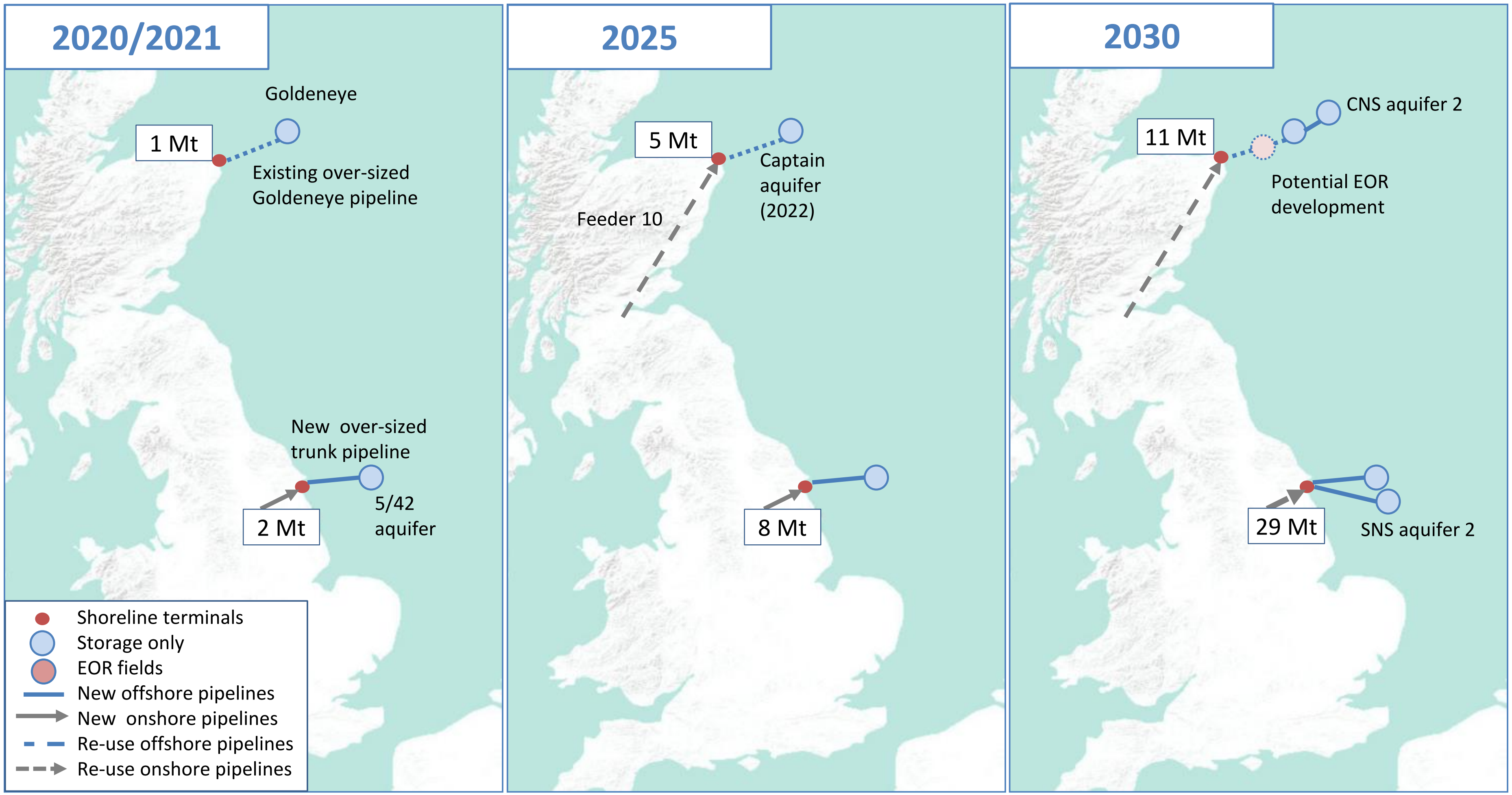


Figure 3: Transport and storage network development in the Concentrated scenario

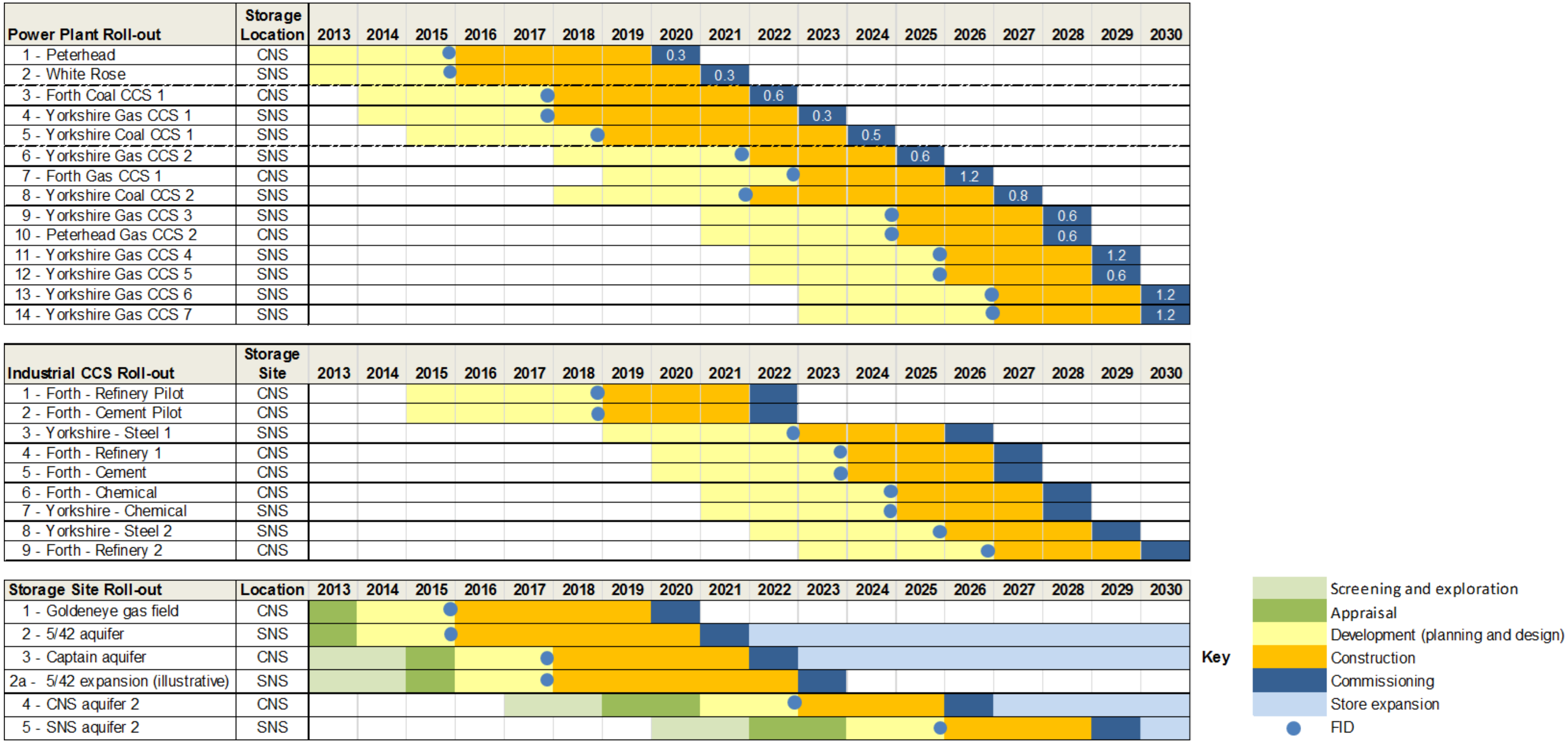


Figure 4: Timelines for capture and storage development in the Concentrated scenario

3.1.2 Timelines and CO_2 flows for capture and storage[6]

Power plant capture roll out

- In the Concentrated scenario one or more power plant projects are connected to the onshore terminals each year, as is the case in the other two scenarios. The average size of projects increases as more projects are connected.
- In each phase, the number of projects connecting to the onshore terminal and the total capture capacity are both higher for the Yorkshire area, compared to NE Scotland.
- Both the development period and the construction period for capture projects vary depending on the technology type and maturity[6]. All power plants with CCS are assumed to be 'new build' in this scenario.
- In this scenario, the Commercialisation Programme projects become operational by 2020-2021.
- The next three projects that are currently in the early stages of planning need to have progressed to Final Investment Decision (FID) before 2020. The next three projects are assumed to start development around the same time, and reach FID around 2021/2022.
- The next six projects need to reach FID between 2025 and 2027, by which time significantly more operational experience has been developed.
- At the start of the roll out, a mix of coal and gas power plants are connected. Gas post combustion capture is one of the lower cost options and uptake increases quickly to become the technology of choice. Beyond 2027 only gas power plant and industrial projects are connected. Total installed capacity of gas and coal CCS plants under the Concentrated scenario are ca. 8 GW and 2 GW, respectively.

Industrial capture roll out

- By 2030, around 6 Mt/yr from industrial sources are captured in Yorkshire and Forth.
- CO_2 is captured in the refinery, cement, steel and chemical sectors.
- Compared to the power sector, industrial plants (especially in larger refineries, chemicals and steel facilities) can be more heterogeneous. In addition, the impact that capture plants could have on core processes is perceived as an additional risk. Implementation may require more extensive and iterative build-up of pilot and demonstration projects at individual plants, and may also result in a lower ability to learn from other international projects, compared to power plant projects. Two pilot scale industrial CCS projects are therefore developed around 2020, leading to commercial scale industrial CCS in the late 2020s in the scenario.

[6] Timeline assumptions are based on previous work including "Cost Reduction Task Force (2014)", "Infrastructure in a low-carbon energy system to 2030 for the CCC (2014)", and the project team's experience. See Appendix 2 for further information on the timeline assumptions.

Storage roll out

- Timelines show that the FID for storage development at the Goldeneye gas field and the 5/42 aquifer needs to be taken by 2016 for these to be operational in 2020/2021.
- By 2018 FID needs to be taken for development of the Captain aquifer, and extension of the 5/42 aquifer, in order for them to be operational in the early 2020s. In order to meet that deadline, appraisal of these aquifers should be completed by 2016.
- FIDs for CNS aquifer 2 and SNS aquifer 2 are taken after the first Commercialisation Programme projects are operational.
- The cumulative stored CO_2 from 2015 to 2030 is highest for the 5/42 aquifer with ca. 100 Mt, and next highest for the Captain aquifer with 40 Mt. The Goldeneye gas field is only utilised for CO_2 storage from the Peterhead project.
- Total CO_2 storage in 2030 is around 40 Mt/yr annually and more than 180 Mt cumulatively. This is lower than other scenarios, due to the predominance of gas-fired power in this scenario.

Implications of the timeline analysis

- The Concentrated scenario requires the first two Commercialisation Programme projects to be operational by 2020-2021.
- FID for the early phase 2 projects needs to be taken before the two initial Commercialisation Programme projects have been commissioned and operational experience is gained.
- As explained in the box on retrofitting and carbon capture readiness (CCR) below, the potential timing mismatch between potential requirements for new thermal generation capacity and CCS roll-out suggests that retrofitting “carbon capture ready” (CCR) gas plants, which might be built initially without CCS units in the period to 2023, could be an important option. In this scenario, potential CCR ready gas power plants should be developed and located around the Yorkshire area and in NE Scotland so they can cost-effectively link into a cluster when CCS is fitted.
- Pilot scale industrial CCS projects are required in the early 2020s.
- Appraisal of the Captain aquifer, and the 5/42 aquifer expansion should start in 2015 or as soon as possible.

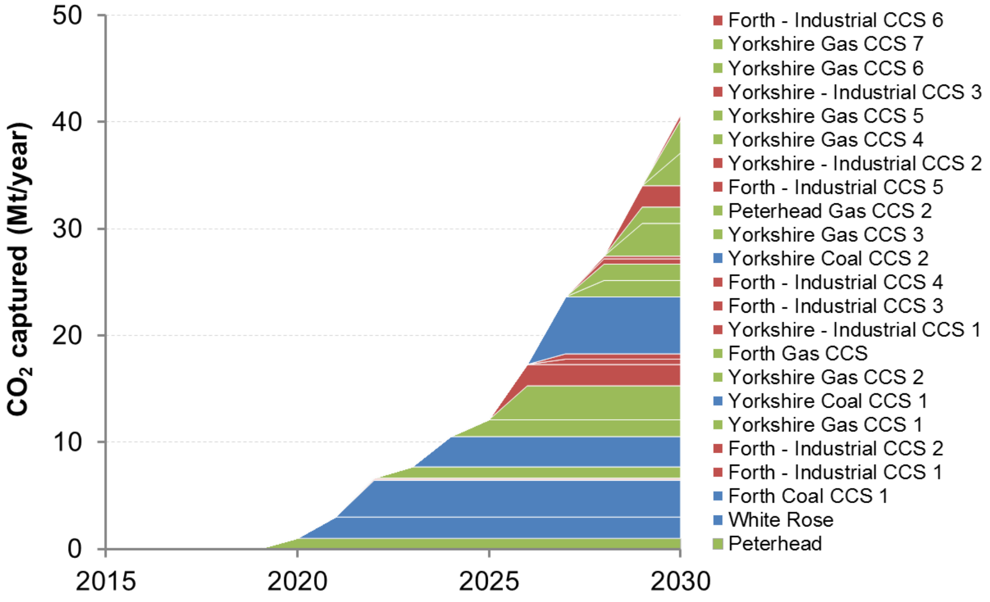


Figure 5: Annual CO_2 capture in the Concentrated scenario

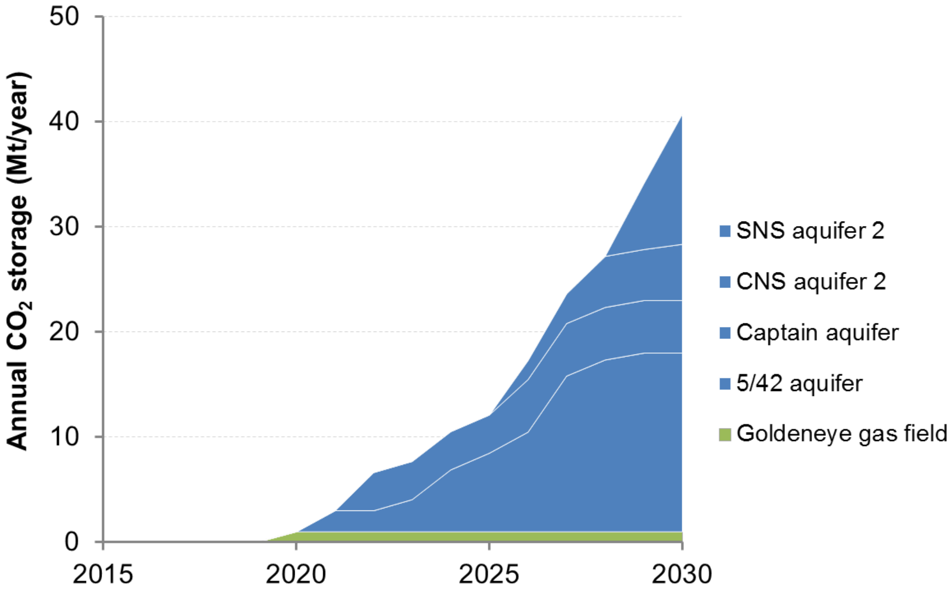


Figure 6: Annual CO_2 storage in the Concentrated scenario

Note on retrofitting and carbon capture readiness (CCR)

As presented previously, the first projects supported under the DECC commercialisation programme are expected to be operational by 2020/21. These could be followed by a limited number of follow-on projects in the early 2020s, with a total of 10 GW of power CCS deployed by 2030 in the three CCS sector development scenarios. Similarly, around 10 GW of new conventional thermal capacity is required by the late 2020s due to the slow but positive demand growth in the long-term combined with expected capacity decommissioning (led by Industrial Emissions Directive requirements). However, it is expected that much of the new-build capacity will be required in the period to 2023, which is earlier than the expected commissioning of the majority of CCS units. The potential timing mismatch between the new build requirements and potential CCS roll-out is illustrated in the figure below. This timing mismatch would be even more of an issue if we saw lower overall build requirements in the 2020s resulting from falling demand.

If new gas capacity is built before the early 2020s to meet the new build thermal capacity requirements, the total need for new thermal capacity in the late 2020s may be lower than the implied rate of CCS roll-out to reach 10GW by 2030. This potential timing mismatch suggests that retrofitting "carbon capture ready" (CCR) gas plants, which will be built initially without CCS units in the period to 2023, could be an important option. However, this will only be a viable option if the new unabated gas plants are located close to potential CCS clusters and T&S networks.

The potential need for CCS retrofit tends to favour gas-based CCS technology as it is not possible to build new unabated coal plants (even if they are 'carbon capture ready') under a number of current policy and planning rules.

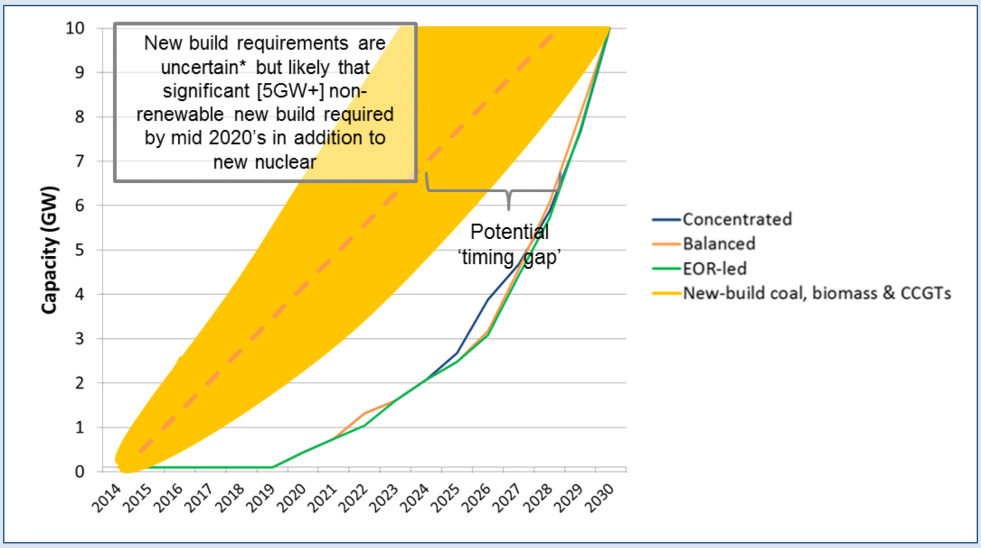


Figure 7: New build thermal capacity requirements compared to CCS roll-out

It should be noted that indicative requirements for new build coal, biomass and CCGT capacity are based on the 2014 Pöyry view. A large number of assumptions around demand growth and plant retirement go into such projections and so requirements are inherently uncertain – the figures are provided for illustration purposes only.

3.1.3 CCS economics

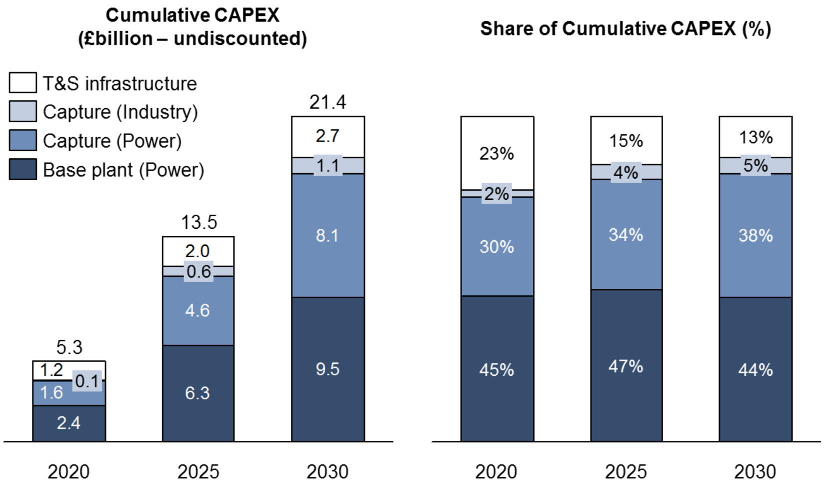


Figure 8: Cumulative CAPEX in the Concentrated scenario (undiscounted)

Figure 8 presents the cumulative investment in CCS over time for the Concentrated scenario. During the early years a relatively large investment is needed in transport and storage infrastructure (i.e. more than £1bn). The relative cost for transport and storage (T&S) however comes down over time from 23% of the cumulative capex in 2020 to only 13% by 2030, as future projects utilise spare capacity in the pipelines and infrastructure built during the early years. Total T&S investment is less than £3bn, as significant economies of scale are realised for T&S in this scenario.

A significant investment will also need to be made in base plants for the power projects. Based on our estimates, cumulative investment in base power plants will be almost £10 billion (undiscounted) by 2030, which corresponds to more than 40% of the cumulative CAPEX by 2030. Cumulative investment required is around £5bn and £21bn in 2020 and 2030, respectively. To put this in context, cumulative capital expenditure on nuclear in the CCC's 'Higher Energy Efficiency' scenario is estimated to be almost £70bn for similar levels of capacity (i.e. around 12 GW)[7].

The strike price for each project has been modelled based on two different T&S charging methods (see the note on different transport and storage charging methods). Figure 10 shows the potential range for the required strike price for CCS Commercialisation Programme projects and the development of the required strike prices over time under the marginal T&S charging method. Strike prices are calculated assuming that each power plant pays all the T&S fees with respect to the captured CO_2 volume, and that each CCS project meets its hurdle rate through electricity revenues and Contract for Difference (CfD) subsidies. Further economic modelling assumptions are explained in Appendix 2.

In this scenario, the strike price for gas CCS comes down to less than £100/MWh by 2025, compared to ca. £120/MWh for coal CCS (see Figure 10). The main drivers for the reduction in the gas CCS strike price by 2025 are economies of scale in the T&S costs, with multiple power plants sharing the same infrastructure, and the change from Zero-th of a Kind (ZOAK) to First of a Kind (FOAK) capture technology applications. Cost of Nth of a Kind (NOAK) gas CCS plants drops to less than £90/MWh in the late 2020s.[8]

[7] CCC, 2013, Fourth Carbon Budget Review – technical report – sectoral analysis of the cost-effective path to the 2050 target
[8] DECC September 2014 fossil fuel price projections (real and expressed in 2014 prices) are used

Note on different transport and storage charging methods

The diagram below illustrates the wide range of possible options for CO_2 transport and storage business models

Charging regime	Postage stamp £/tCO_2 charged to feed into any point on network	...	Variable 'average cost' charging Variable fee charged based on allowed revenue over part of network	...	Strictly marginal cost charging New user pays only for additional connection (first user funds all initial costs)
Regulatory landscape	Price control regulated national monopoly provider	...	Revenue control regulated local monopoly provider	...	TPA to all pipes/stores, with only shallow operational cost recovery allowed
Active government intervention	Very Little involvement once regulator is set up				Each new hub/pipe/store would require active involvement

Figure 9: Wide range of possible options for T&S cost charging

The diagram represents three points on a very diverse curve of potential future regulatory and charging regimes ranging from regulated monopoly uniform pricing approaches to competitive provision of infrastructure with third party access (TPA) regimes. On the far left of the diagram we see a regulated regime for a national monopoly infrastructure provider (a good example here would be National Grid's electricity and gas transmission networks). The most extreme charging regime here is 'postage stamp' where the same fee (on a £/tCO_2) basis would be charged to any customer wishing to feed into any point on the system. Active government involvement in the industry would be minimal after the initial setting up of the regulatory structure as CfD auctions could be conducted 'independently' of decisions regarding transport and storage (with all CCS projects expected to feed their CO_2 into the national network, and costs generally socialised across all projects).

In the centre we see a situation with regulated local monopoly infrastructure providers (such as the electricity and gas distribution networks in GB). Fees are variable by user rather than postage stamp but are set such that the infrastructure provider is only allowed to recover a given total revenue for all or part of its network. Under this scenario, if a part of the network (e.g. a pipeline) is more highly utilised, the fee charged to each user of that part of the network would be expected to fall.

On the far right of the diagram we see a regulatory landscape of privately owned pipes and stores, subject to strict third party access arrangements. Under this model, the first user of T&S infrastructure pays the full capital costs and future users only pay for incremental costs such as additional injection wells and compression at shoreline terminal. In this scenario we could see a situation where each new hub, pipe or store may need direct government involvement as it would lead to a 'spike' in CfD strike prices each time a new over-sized infrastructure was required.

We have modelled two transport and storage business models in this study to show the impact that the charging methods could have on strike prices:

1) *Strictly marginal cost charging is used in the main section of the report.*
2) *Results for variable 'average cost' charging (i.e. shared T&S cost charging model) are shown in Appendix 3: Results for shared business model". Based on our modelling, the charging method might have significant impact on the strike price requirements when a new over-sized infrastructure is required.*

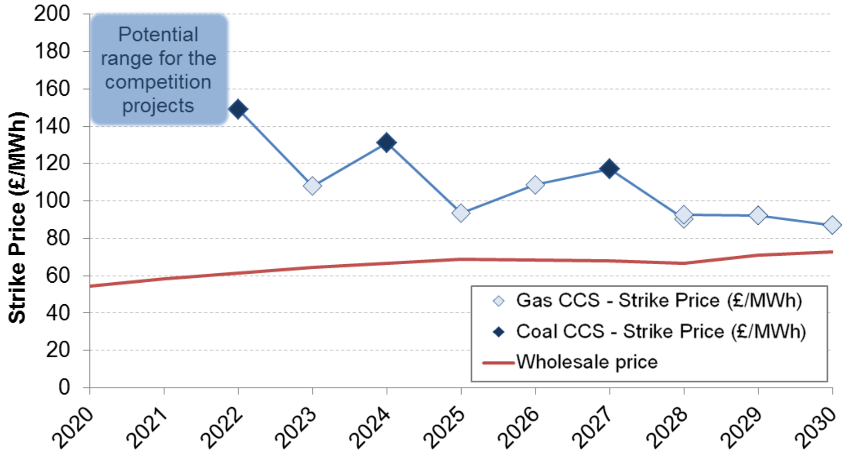


Figure 10: Strike price requirements in the Concentrated scenario[9]

Figure 11 shows the T&S costs of all power CCS projects in terms of the impact on strike price requirements (£/MWh) under the fully marginal T&S cost charging method. The early T&S costs are expected to be high as large pipes and stores are developed and paid for by the Commercialisation Programme projects. The costs at all hubs fall quickly as economies of scale are realised. The analysis suggests that the T&S costs of the initial projects vary depending on the business model; however, T&S costs for the follow-on projects are typically less than £10/MWh. The transport and storage costs in Scotland are higher, due to the higher storage and pipeline investments in the CNS.[10]

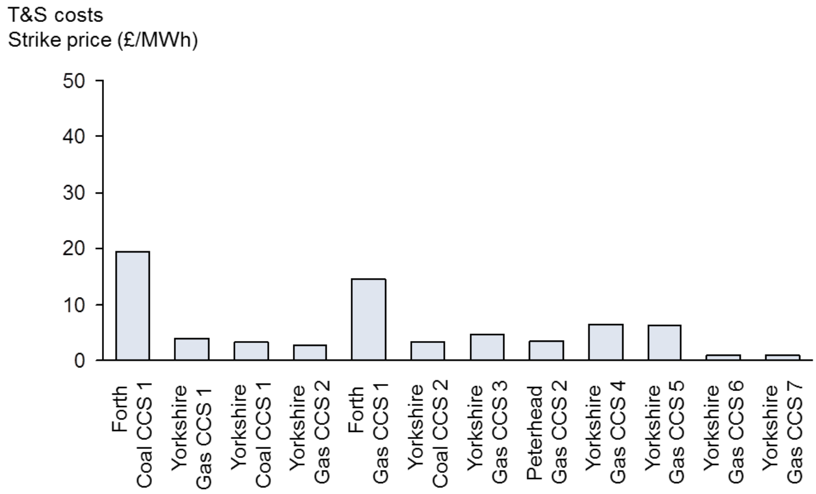


Figure 11: Transport and storage costs in the Concentrated scenario (marginal T&S cost charging)

The annual support cost for CCS in 2030 is around £2.1bn in this scenario (in terms of the average annual value of CfD ‘top up’ payments), and the cumulative payments under the CfD mechanism total approximately £13.9bn over the period to 2030 (Figure 12).

[9] It should be noted that the strike price for the first follow-on gas project in Yorkshire in 2023 is lower here compared to the other scenarios due to the technology choice. In this scenario, one of the cheapest capture technologies (i.e. post combustion gas) is assumed to become the technology of choice in the early 2020s, which does not apply to the other two scenarios. A spike in CfD strike prices is observed in 2026 for gas CCS, as a new aquifer is developed in the CNS.

[10] Based on the CO_2 Stored data, storage costs are generally higher in the CNS compared to SNS as CNS aquifers are deeper and have relatively lower injectivity. Also, “Forth Coal CCS 1” has higher transport costs due to the additional investment required for reusing the Feeder 10 pipeline.

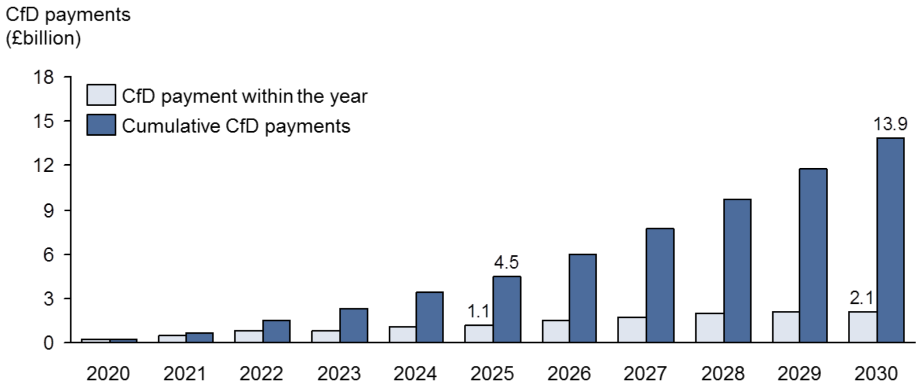


Figure 12: Annual and cumulative CfD payments in the Concentrated scenario

3.1.4 Key messages and requirements

In this scenario, we see the benefits of cost reductions in the near term arising from economies of scale, as T&S networks from each "hub" are fully utilised. The cost of gas CCS comes down to less than £100/MWh by 2025 and becomes competitive with other low carbon technologies in the 2020s. However, coal CCS is projected to have a higher cost (i.e. around £120/MWh) as a NOAK coal CCS plant is not built in this scenario.

The assumed strong geographical bias for new sources in Humberside and Scotland is feasible, but limits wider participation. This would have particular implications on industrial CCS in other regions such as Teesside. Also, preparation for post 2030 CCS development is less well-developed, as only two hubs are initiated in this scenario.

As the storage in this scenario is dominated by aquifers in the SNS and CNS, early investment in appraisal is required. For the early phase 2 projects, expansion is needed in the 5/42 and Captain aquifers. Around 700 Mt of bankable/proven storage capacity is needed by 2025 in this scenario assuming 20 years' worth of proven storage capacity is required at project FID, which is around 3-5 years before the project commissioning date. In order to deliver this, further storage capacity sites should be appraised in the near term, as some of these sites may fail suitability tests (see the box on appraisal requirements for further information on the next page).

Based on the analysis and wider stakeholder engagement we identify the following key requirements to deliver the Concentrated scenario:

- Successfully deliver 2 Commercialisation Programme projects on time
- Enable FIDs for 3 additional power CCS projects by 2020
- New CCR gas plants should be located near the two hubs (i.e. Scotland and Yorkshire) so that there is a practical option for them to fit CCS at a later date
- Implement pilot scale industrial CCS projects in the early 2020s
- Design and implement reward mechanism to support decarbonisation of process-related industrial emissions with CCS
- Aquifer expansion for the phase 2 projects: Captain in the CNS and 5/42 expansion in the SNS. Appraisal for both needs to start in 2015
- Sufficient Government support for power CCS (i.e. CfD and/or other funding)
- Creation of an environment which supports a business case to bring forward investment in appraisal of the significant long-term storage requirement
- Transparent and predictable business models and governance for T&S (i.e. charging regimes and Third Party Access) ensuring that transport and storage infrastructure is efficiently over-sized and shared

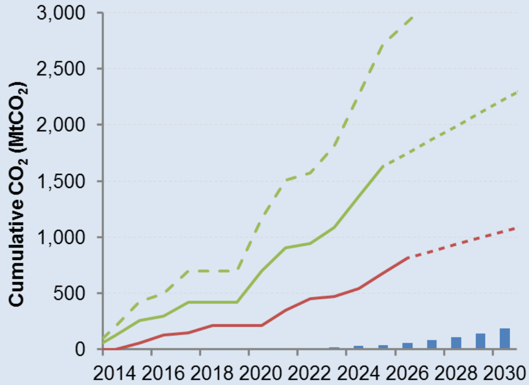
Note on storage appraisal requirements

Storage appraisal is required to "prove" and de-risk storage capacity ahead of final investment decisions by capture projects. This is because capture projects are not investible without a degree of assurance around a secure storage option for the captured CO_2. The storage appraisal process involves obtaining seismic data, drilling appraisal wells, and analysing results for the aquifers (for hydrocarbon fields, data regarding the field characteristics might already be available due to several years of hydrocarbon production). Although storage appraisal costs correspond to a small fraction of the overall CCS costs (i.e. around £10s of millions per project), appraisal requirements are identified as one of the key barriers of CCS deployment in the UK because appraisal costs are incurred several years before a capture plant takes FID.

If power based CCS projects are to compete effectively for CfDs, leading to an efficient allocation and cost discovery process, the expectation is that bankable storage would be required ahead of the CfD auction process. Due to the lead times of storage appraisal, this will need to form a priority if more CCS projects are to come online in the early 2020s.

The level of "proven" storage capacity needed at project FID is currently uncertain. Up to 40 years' worth of proven storage might be required for coal power CCS projects with long lifetimes. On the other hand, one possibility is that proven storage capacity requirements for project FID might decrease to 5-10 years for follow-on projects as banks become more confident in the CO_2 storage development process once CCS has been demonstrated in the UK.

The graph below shows the requirements for bankable/proven capacity in the "Concentrated" scenario, assuming 20 years' worth of proven storage capacity is required at project FID, around 3-5 years before the project commissioning date. In order to deliver the bankable capacity, much more storage capacity should be appraised, assuming several of these storage sites may fail; however, the ratio of bankable capacity to appraised storage capacity is highly uncertain. As the graph below illustrates, storage appraisal requirements by the mid-2020s could be as high as several billion tonnes. It should be noted that appraisal requirements might be lower for hydrocarbon fields (depleted and/or for EOR) and the success rate might be higher for aquifers, which are well known through previous hydrocarbon exploration and production activity (e.g. some of the aquifers in the CNS).



	2020	2025
Cumulative CO2 stored in the Concentrated scenario	1 Mt	40 Mt
Bankable capacity needed at FID	210 Mt	680 Mt
Appraisal requirement assuming 50% success rate	700 Mt	1,600 Mt
Appraisal requirement assuming 30% success rate	1,200 Mt	2,700 Mt

Figure 13: Storage capacity requirements in the "Concentrated" scenario

3.2 CO_2-EOR scenario

In this scenario, Government implements the Wood Review's recommendations[11] to coordinate UKCS oil production and increase commercial attractiveness of CO_2-EOR (e.g. through providing tax incentives). Due to demand from CO_2-EOR operations in the CNS, CO_2 is assumed to command a value of £20/tCO_2 at platform (under favourable conditions such as high oil price and Government support for CO_2-EOR).

A key driver underpinning this scenario is the coupling of a major portion of CCS deployment with CO_2-Enhanced Oil Recovery. The scenario explores how the window of opportunity for CO_2-EOR in the UKCS, which is limited by diminishing access to existing infrastructure, could support CCS projects by providing a high value application for captured CO_2, as well as supporting the UK to recover more of its hydrocarbon reserves. CO_2-EOR projects would have wider economic benefits due to the additional oil produced (either directly or through taxation), which are not quantified further in this report.

3.2.1 Description

The CO_2-EOR scenario implementation can be framed in three distinct phases.

- Common to all three scenarios, the first phase encompasses the connection to the offshore stores of the initial Commercialisation Programme projects, White Rose (2 Mt/yr) and Peterhead (1 Mt/yr), by 2020/2021. The existing Goldeneye pipeline is used for storage in the Goldeneye gas field, and a new over-sized trunk pipeline for storage in aquifer 5/42 will be developed. Both the Goldeneye pipeline and the White Rose pipeline are over-sized compared to the initial project requirements.
- The second phase is characterised by the development of EOR in NE Scotland, with one EOR project operational in 2022 and a second in 2025. The Captain aquifer is also developed for storage in NE Scotland, mainly as a back-up storage option. Additional capture projects are developed in Scotland (total 3 MtCO_2/yr), and the onshore Feeder 10 pipeline (National Grid's existing natural gas pipeline) is re-used to transport captured CO_2 from Forth to the Fergus shoreline terminal. In this scenario, unlike the Concentrated and Balanced scenarios, a new offshore trunkline is developed from Teesside to the shoreline terminal in Fergus, to transport CO_2 captured in Teesside for the EOR projects in the CNS. This trunkline delivers a further 5 MtCO_2/yr in 2025, and is oversized to accommodate future projects. In Yorkshire additional capture projects are developed (total 6 MtCO_2/yr), storing the CO_2 in the SNS utilising the existing T&S infrastructure. The overall capture capacity in this scenario is 15 MtCO_2/yr by 2025.
- In the third phase, CO_2 storage is focused even more on NE Scotland. A further three EOR projects are developed, as well as the CNS aquifer 2. The total storage capacity in NE Scotland is increased to a total of 36 Mt/yr. Further capture projects are developed in Teesside and a total of 17 Mt/yr is delivered to the NE Scotland shoreline terminal through increasing utilisation of the Teesside-Fergus offshore trunkline (created in 2025). This scenario also sees further expansion of capture projects in south Scotland, which requires the development of a second onshore pipeline from Forth to the shoreline terminal in Fergus. In Yorkshire additional capture projects are developed, reaching a total of 16 Mt/yr, which can be accommodated by existing offshore pipeline and storage capacity (according to existing storage capacity estimates). The overall capture capacity in 2030 is 52 MtCO_2/y, the highest of the three scenarios.

[11] UKCS Maximising Recovery Review: Final report, 2014

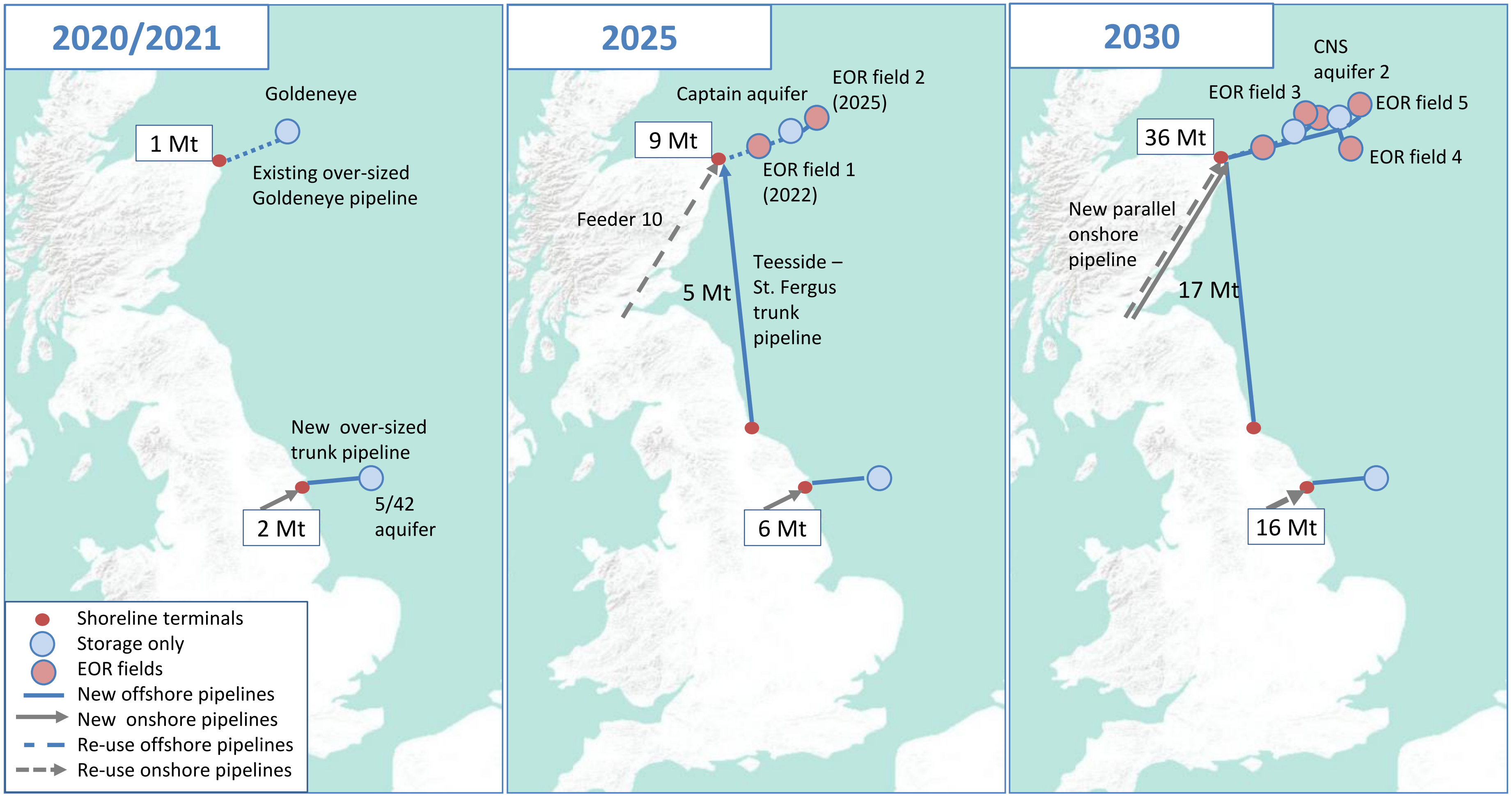


Figure 14: Transport and storage network development in the CO_2-EOR scenario

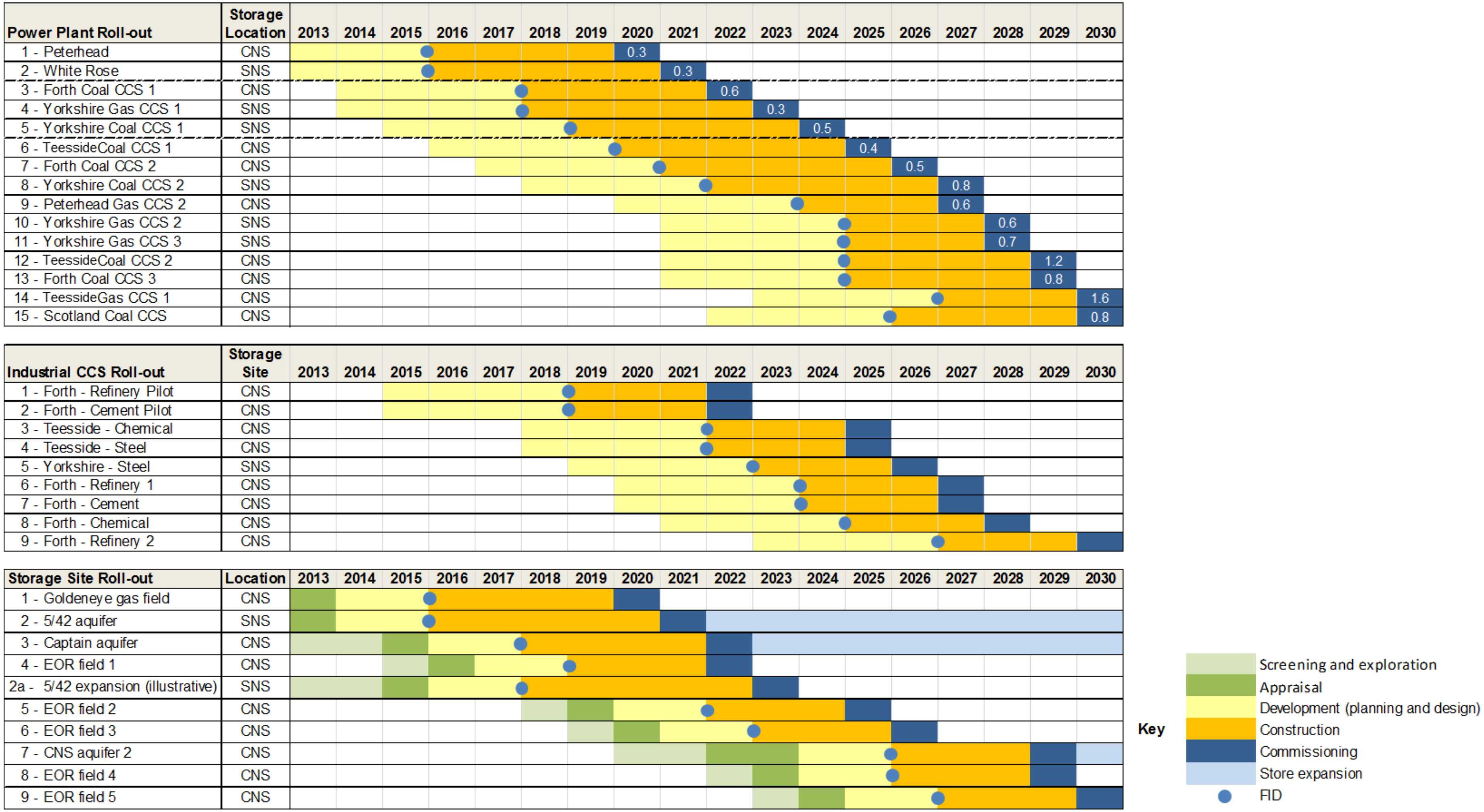


Figure 15: Timelines for capture and storage development in the CO_2-EOR scenario

3.2.2 Timelines and CO_2 flows for capture and storage

Power plant capture roll out

- In the CO_2-EOR scenario, one or more power plant projects are connected to the onshore terminals each year from 2020 to 2030, as is the case in the other two scenarios.
- The average size of these projects increases as more projects are connected. Throughout the period from 2015 to 2030 a mix of gas (ca. 4 GW total) and coal CCS (ca. 6 GW total) projects are developed. However, compared to the concentrated and the balanced scenario, coal power plants are a more dominant source of CO_2. This is especially the case for the projects in Teesside and Scotland, which supply captured CO_2 to EOR fields.
- As in the Concentrated scenario, the Commercialisation Programme projects become operational by 2020-2021.
- Following FID for these two projects around 2016, three early phase 2 projects need to take FID before 2020.
- Around 2020, development for a further four to six projects should start, with FID around 2025.
- New gas plants (these might include CCR plants) are mainly located in Yorkshire, whereas coal CCS plants are closer to the EOR fields (i.e. Scotland and Teesside).

Industrial capture roll out

- Two pilot scale industrial CCS projects (refinery and cement) are developed around 2020, leading to commercial scale industrial CCS projects by 2027.
- Similar to the Concentred scenario, around 6 Mt/yr is captured from industrial sources by 2030. CO_2 is captured in the refinery, cement, steel and chemical sectors in Teesside, Yorkshire and Forth by 2030.

Storage roll out

- FID for storage development at the Goldeneye gas field and the 5/42 aquifer needs to be taken by 2016 for these to be operational in 2020/2021.
- By 2018, FID needs to be taken for development of the Captain aquifer and 5/42 store expansion.
- The first CNS EOR field is likely to take FID by 2019 (i.e. after the capture plant and back up storage in the CNS take FID).
- By 2023, FID for a further two EOR fields needs to be taken. Around the same time development of the next two EOR fields needs to start. FID for these two should be taken by 2026.
- The cumulative storage in EOR fields is more than 100 Mt by 2030. A significant fraction of the CO_2 captured in this scenario is stored in aquifer 5/42 (ca. 80 Mt by 2030), while total storage in the Goldeneye field and the Captain aquifer is

significantly smaller as most of the CO_2 in the CNS is used for EOR. Figure 17 shows the net storage in EOR fields.[12]

Implications of the timeline analysis

- This scenario requires the first two Commercialisation Programme projects to be operational by 2020-2021.
- FID for the early phase 2 projects needs to be taken before 2020. This is before operational experience has been obtained from the Commercialisation Programme projects, as these are then only just being commissioned.
- In the CO_2-EOR scenario, new CCS plants need to be developed and located near the onshore hubs developed in the scenario, which are Teesside, Scotland and Yorkshire.
- Pilot scale industrial CCS projects are required in the early 2020s.
- This scenario has more flexibility for the location of potential industrial CCS projects compared to the Concentrated scenario, due to the higher number of onshore clusters.
- Appraisal of the Captain aquifer and the 5/42 aquifer expansion should start in 2015.
- The storage appraisal requirements in this scenario may be less challenging compared to the Concentrated scenario, due to the dominant role of EOR fields, which are better characterised through previous hydrocarbon exploration and production activity.

[12] In Element Energy's in-house CO_2-EOR model, the CO_2 produced from the oil field throughout the CO_2-EOR operations is recycled back into the field again. The total CO_2 injection into the field therefore increases as more CO_2 is recycled over time. In the model, 100% of the initially purchased CO_2 is permanently stored at the end of the CO_2-EOR operations.

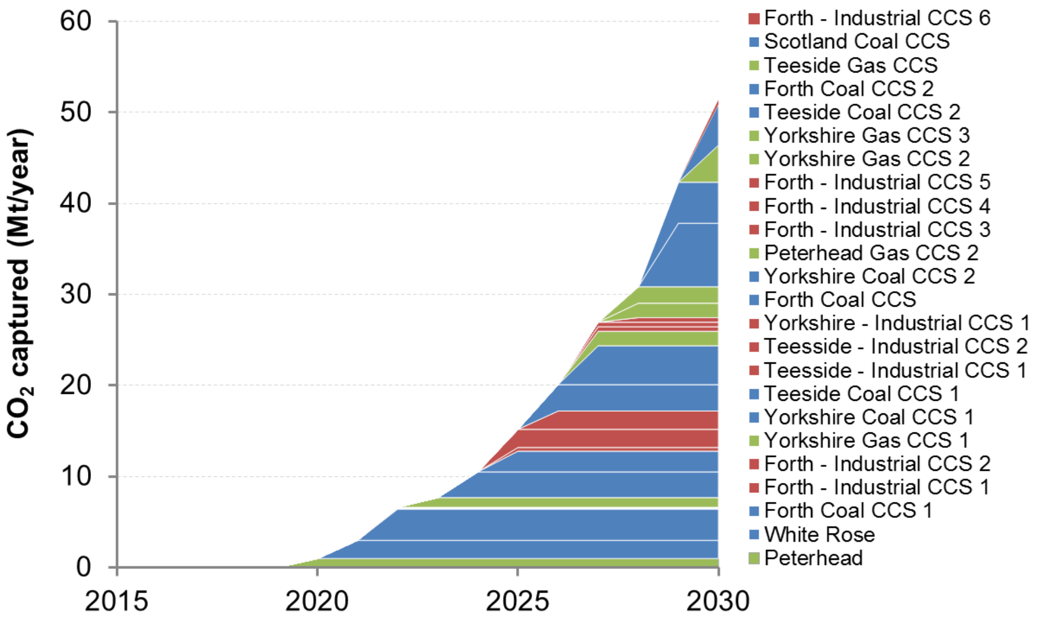


Figure 16: Annual CO_2 capture in the CO_2-EOR scenario

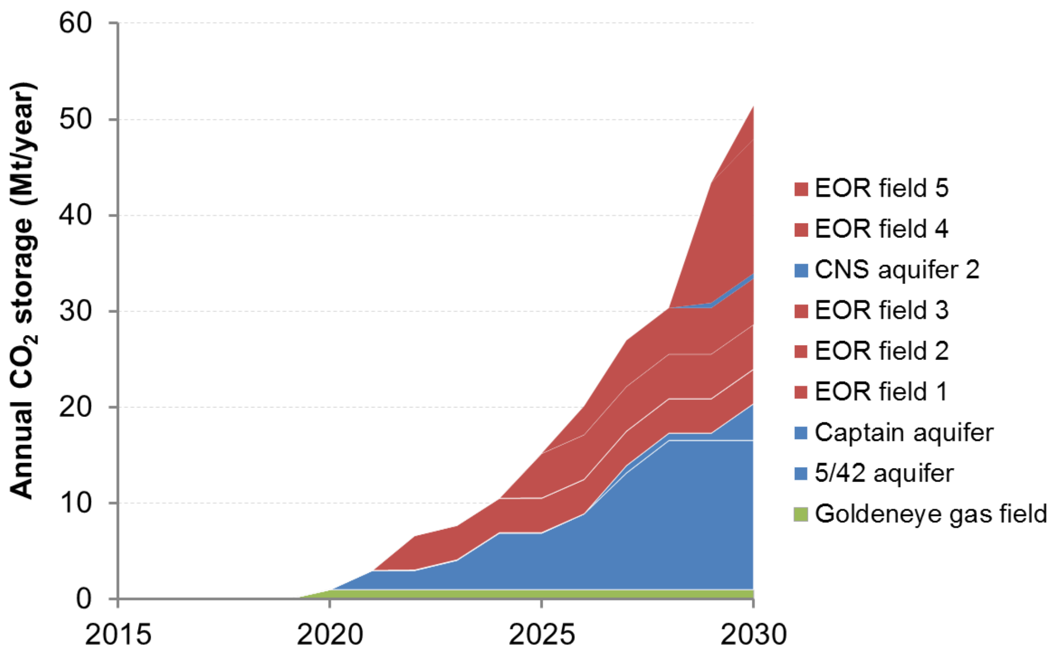


Figure 17: Annual CO_2 storage in the CO_2-EOR scenario

3.2.3 CCS economics

In the EOR scenario, cumulative CAPEX is around £27bn, of which around £9bn is for power capture plants. Around £12.5bn of capital investment in base generation plants is also needed, which corresponds to more than 45% of the cumulative CAPEX by 2030. The relative capex of transport and storage comes down from 22% in 2020 to 15% in 2030 as future projects utilise the oversized infrastructure built during the early years. Total T&S investment is more than £4bn. This is £1bn more than the Concentrated scenario, but similar to the Balanced scenario, mainly due to the additional offshore pipeline costs from Teesside to St Fergus and a number of offshore pipelines connected to the five EOR projects. It should be noted that T&S infrastructure costs exclude EOR infrastructure (on the assumption that this investment is remunerated through oil and gas revenues).

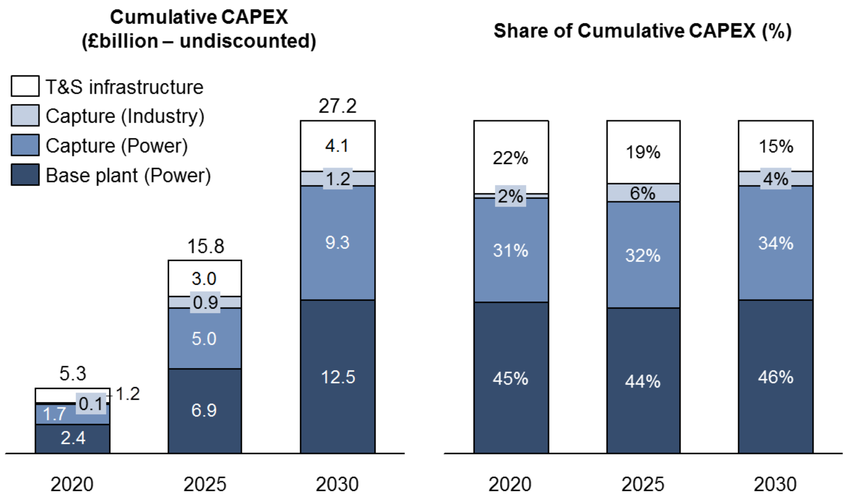


Figure 18: Cumulative CAPEX in the CO_2-EOR scenario (undiscounted)

Both coal and gas CCS achieve significant cost reductions and strike price requirements drop below £100/MWh by 2026 (Figure 19). For coal plants, the cost reduction is driven by the additional benefits of EOR, and through learning by doing for coal capture technology. For gas CCS, the key drivers are T&S economies of scale in Yorkshire and learning by doing for gas capture technology.

As explained previously, two different charging methods were studied. Under the marginal cost charging method, the first coal CCS project developed in Teesside is assumed to invest in an expensive over-sized pipeline from Teesside to St Fergus. Follow-on CCS projects in Teesside only pay for the incremental costs while benefiting from additional EOR revenues. A spike in CfD strike prices is therefore observed in 2025 for coal CCS (Figure 19). On the other hand, under the shared T&S charging method, strike price requirements for both coal and gas come down over time (see Appendix 3).

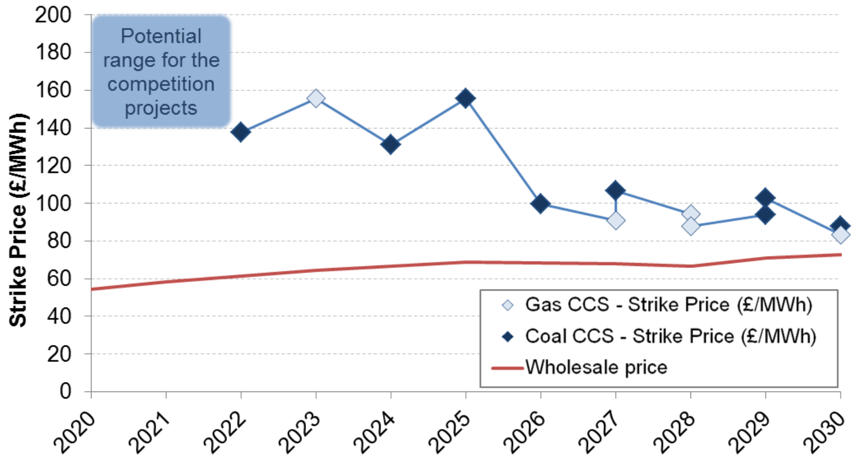


Figure 19: Strike price requirements in the CO_2-EOR scenario

A similar impact can also be seen in Figure 20. T&S costs are very low and even negative for some projects, due to the additional revenue reflecting the value of CO_2 for EOR. However, the T&S cost of Teesside Coal CCS 1 project is very high due to the investment in the trunk-pipeline from Teesside to St Fergus under the marginal cost charging method (i.e. almost £50/MWh). If the additional investment can be shared with the follow-on CCS projects including the industrial CCS projects, T&S costs become less than £10/MWh for all of the CCS projects in Teesside (see Appendix).

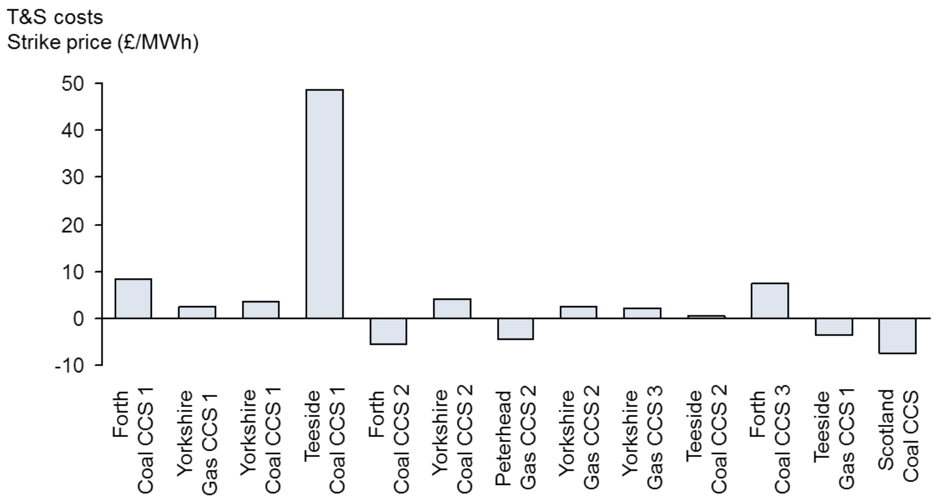


Figure 20: Transport and storage costs in the CO_2-EOR scenario (marginal T&S cost charging)

Finally, the lower strike prices are also reflected in the CfD top-up payments. The annual CfD payments for CCS in 2030 are approximately £2.2bn, while the cumulative payments under the CfD mechanism are around £14bn over the period to 2030 (Figure 21).

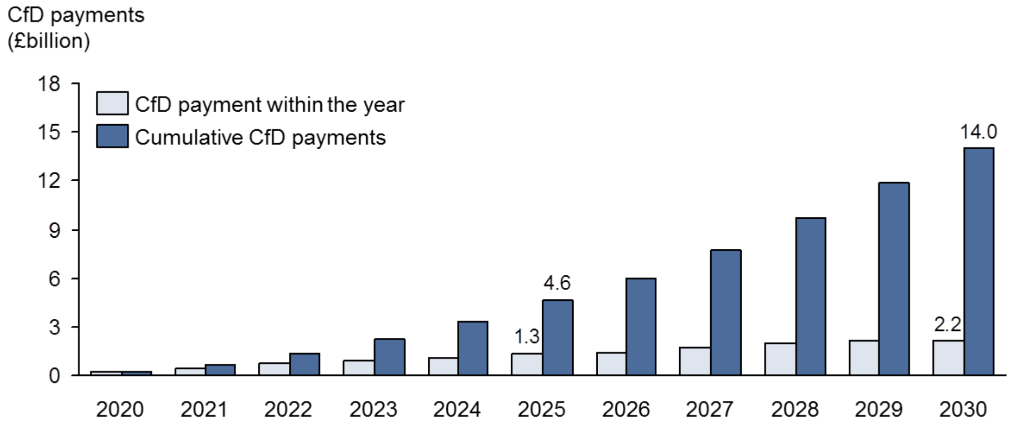


Figure 21: Annual and cumulative CfD payments in the CO_2-EOR scenario

3.2.4 Key messages and requirements

In this scenario, both coal and gas CCS projects achieve cost reductions, falling below £100/MWh by the late 2020s. This limits the costs of the CfD payments, which are lowest of the three scenarios by 2030.

In order to maximise CO_2-EOR potential in the UKCS, significant volumes of CO_2 should be transported to the Central North Sea (regardless of whether these are gas or coal fired power projects). This requires an offshore trunk pipeline from Teesside to NE Scotland. The capex for this pipeline is likely to be more than £700m. Although the cost of this trunk pipeline is very high for a single point-to-point project, based on our analysis this investment could be covered by the CO_2 transfer payments from a cluster of oil fields, assuming a value of £20/tonne CO_2 at platform (which may be taken to reflect favourable commercial conditions for CO_2-EOR, such as high oil price and/or favourable tax environment).[13]

The EOR scenario may also provide benefits in achieving the required timelines for the development of CO_2 stores, because appraisal requirements could be lower for hydrocarbon fields (depleted and/or for EOR) and for the aquifers, which are well known through previous hydrocarbon exploration and production activity (e.g. some of the aquifers in the CNS).

Compared to the other scenarios, the EOR scenario introduces a risk through the dependency of CCS project business cases on oil prices and on the commercial viability of EOR investments.

The CO_2-EOR scenario also represents greater complexity, with greater requirements for coordination between potential onshore capture clusters in NE England and CO_2-EOR candidate oil fields in the CNS (and Northern North Sea in the post-2030 period). We also note that there are likely to be challenges around public acceptance and political support.

[13] Some of the recent studies on CO_2-EOR in the UKCS assumed a £0/tCO_2 cost for CO_2 supplied at platform. A recent analysis by Element Energy showed that oil fields could be capable of paying for the fresh CO_2 with a sufficiently high level of fiscal incentives (Element Energy et al., 2014, CO_2-EOR in the UK: Analysis of fiscal incentives). With value of £0/tCO_2, strike price requirements in this scenario would be higher but more importantly, it might not be possible to justify the additional investment needed in a new pipeline from Teesside to the CNS.

Based on the analysis we have identified the following key requirements for this scenario:

- Successfully delivery of 2 Commercialisation Programme projects on time
- Enable FIDs for 3 additional power CCS projects by 2020
- New CCR gas plants located near one of the onshore hubs developed in the scenario (Yorkshire, Teesside and Scotland) so that there is a practical option for them to fit CCS at a later date
- Implement pilot scale industrial CCS projects in the early 2020s
- Design and implement reward mechanism to support decarbonisation of process-related industrial emissions with CCS
- Aquifer expansion for the early phase 2 projects: Captain in the CNS as back-up capacity for the EOR fields and 5/42 in the SNS for the follow-on projects in Yorkshire. Appraisal for both needs to start in 2015
- Sufficient Government support for power CCS (i.e. CfD and/or other funding)
- Creation of an environment which supports a business case to bring forward investment in appraisal of the significant long-term storage requirement. Long-term appraisal requirements until 2030 might be lower due to the EOR operations
- Transparent and predictable business models and governance for T&S (i.e. charging regimes and TPA) ensuring that transport and storage infrastructure is efficiently over-sized and shared
- Strong inter-regional coordination for the additional trunk pipeline from NE England to St Fergus or CNS
- Favourable conditions for CO_2-EOR – i.e. high oil price and Government support for CO_2-EOR through fiscal incentives and regulatory support
- Increased public acceptance and support from influential stakeholders (e.g. environmental NGOs)

3.3 Balanced Scenario

The defining theme of this Scenario is a broader geographic spread of CCS development, commanding support from a broader spectrum of regional stakeholders, as well as offering a more diverse infrastructure as a foundation for developments post 2030.

This scenario provides increased optionality for post-2030 CCS deployment with several onshore and offshore hubs, different capture technologies and fuel sources. However this results in higher infrastructure costs and fewer savings from 'learning by doing'.

3.3.1 Description

The development of the Balanced scenario can be framed in three distinct phases.

- The first phase is the same as for the Concentrated and Balanced scenarios. This encompasses the connection to the offshore stores of the initial DECC Commercialisation Programme projects, White Rose (2 Mt/yr) and Peterhead (1 Mt/yr), by 2020/2021. The existing Goldeneye pipeline will be used for storage in the Goldeneye gas field, and a new trunk pipeline for storage in aquifer 5/42 will be developed. Both pipelines will be oversized compared to initial project requirements in order to accommodate future growth.

- The second phase is characterised by additional projects close to the areas where the initial projects were developed, in addition to the development of the Teesside cluster. In NE Scotland, additional projects are connected (total 5 $MtCO_2$/yr) to the existing shoreline terminal and offshore pipeline and the onshore Feeder 10 pipeline is re-used to transport captured CO_2 from Forth to the Fergus shoreline terminal. The Captain aquifer is also developed for further storage capacity. Around Yorkshire, additional projects are developed, connecting to the 5/42 aquifer through the existing trunk pipeline (total 6 $MtCO_2$/yr). In Teesside, CO_2 captured at coal and industrial capture projects (total 5 $MtCO_2$/yr) are transported through new onshore and offshore pipelines to the SNS aquifer 2, close to the initially developed 5/42 aquifer. The overall capture capacity in this scenario is 16 $MtCO_2$/yr by 2025.

- In the third phase, further storage projects are developed in various regions around the UK, and additional T&S infrastructure is developed in parallel. Notably the East Irish Sea (EIS) hydrocarbon field is developed for storage from capture projects in North East England, and further to this, SNS aquifer 3 is developed for storage from capture projects in the Thames estuary area and Bacton. Capture in Teesside and Yorkshire is further expanded, utilising the same offshore pipeline and storage sites; however, further investment is required in onshore compression and incremental storage infrastructure (i.e. additional wells and appraisal). The combined storage utilisation for the 5/42 aquifer and SNS aquifer 2 is some 22 Mt/yr, compared to 29 Mt/yr in the concentrated scenario. Capture in NE Scotland is also expanded. Similar to the concentrated scenario, the CNS aquifer 2 is developed for further storage; total storage in the area is 9 Mt in 2030, compared to 11 Mt in the concentrated scenario. It should be noted that CO_2 captured in Scotland could be injected into a potential EOR field in the CNS; however, this has not been modelled explicitly. (CO_2-EOR potential in the CNS is examined in more detail in the "CO_2-EOR" scenario). The overall capture capacity in the Balanced scenario is 50 $MtCO_2$/yr by 2030, compared to 40 $MtCO_2$/yr in the concentrated scenario.

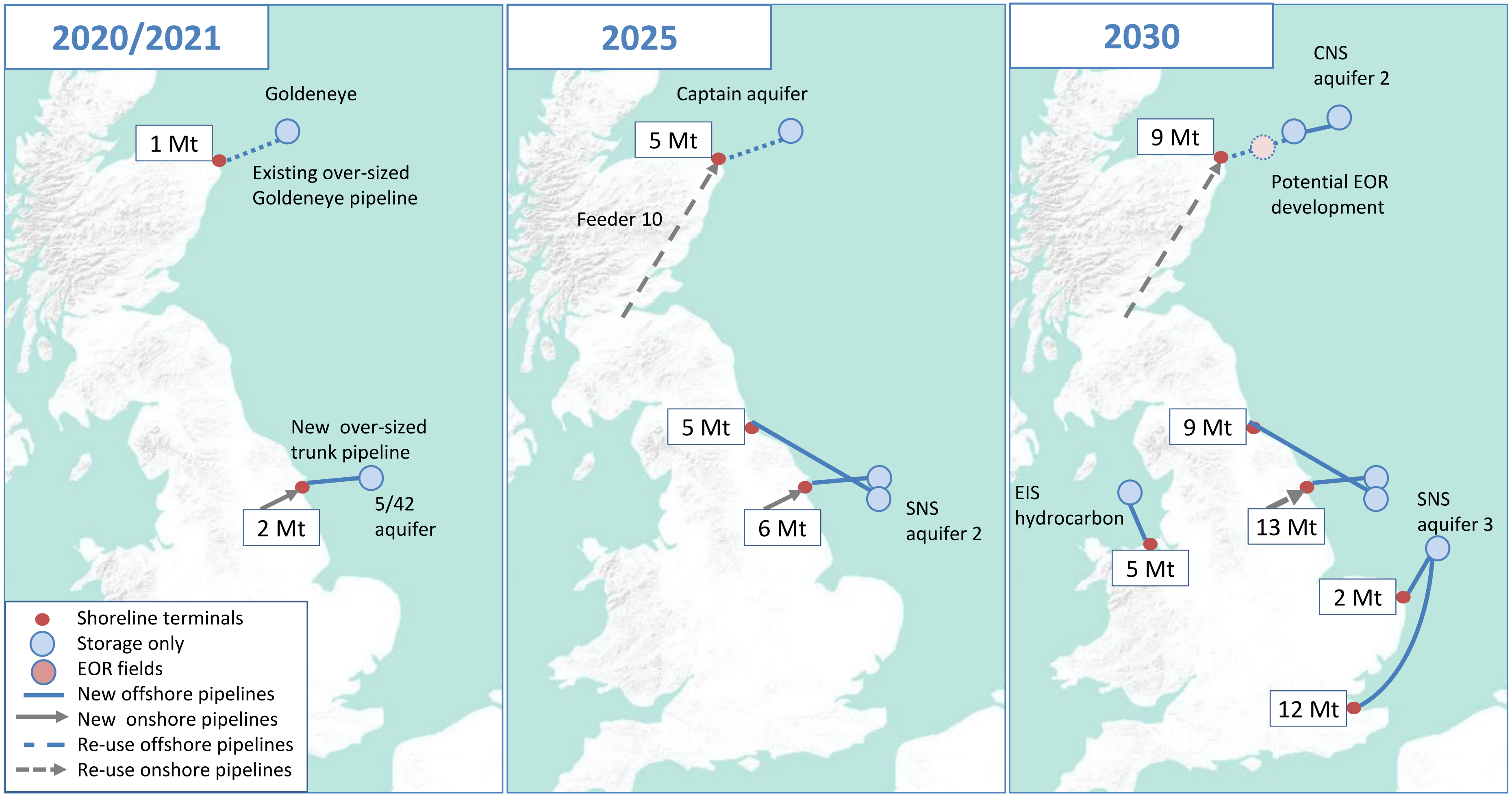


Figure 22: Transport and storage network development in the Balanced scenario

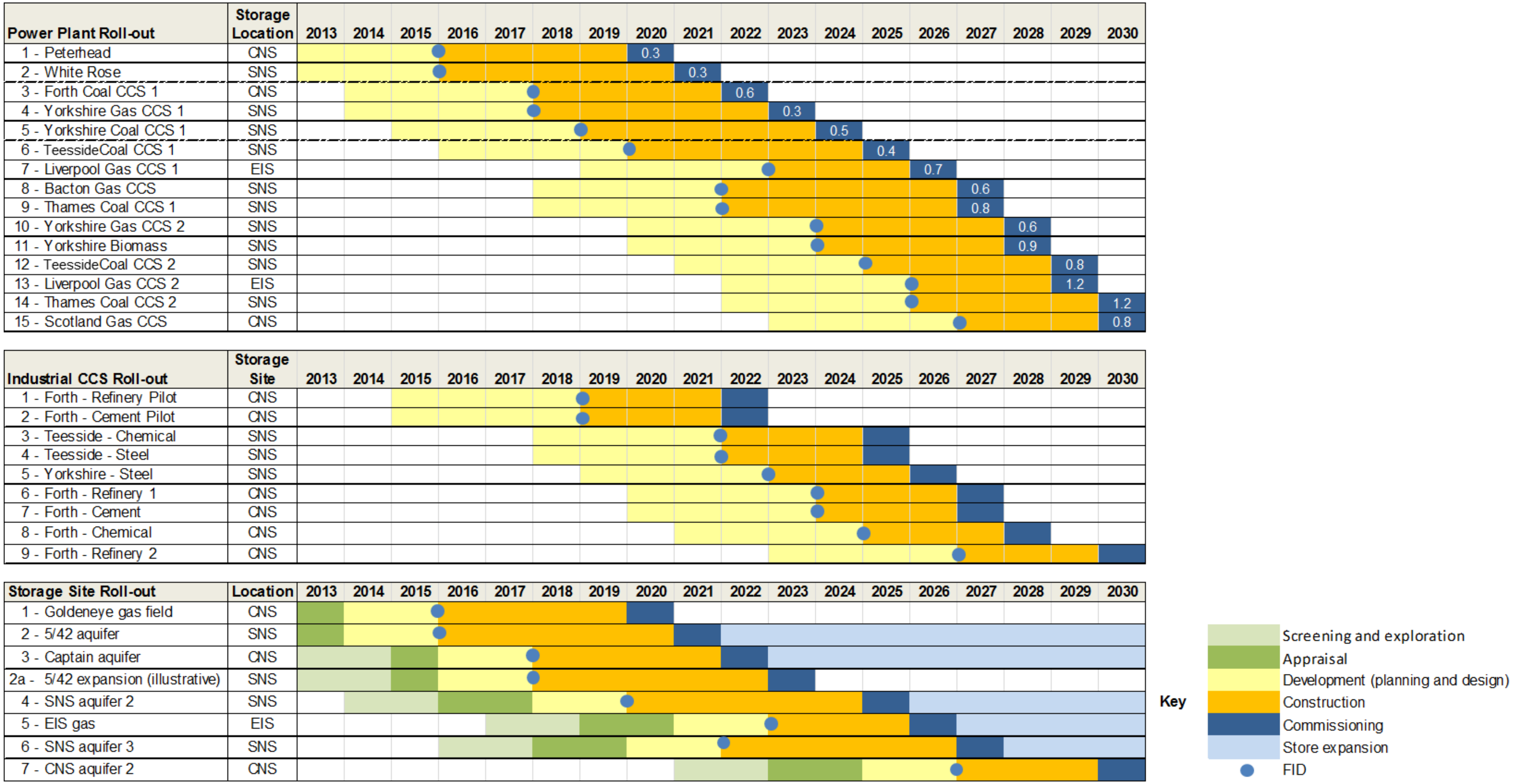


Figure 23: Timelines for capture and storage development in the Balanced scenario

3.3.2 Timelines and CO_2 flows for capture and storage[6]

Power plant capture roll out

- In the Balanced scenario, one or more power plant projects are connected to the onshore terminals each year, as is the case in the other two scenarios.
- The average generating capacity of these projects increases as more projects are connected. Throughout the period from 2015 to 2030 a mix of gas (4.5 GW total) and coal CCS (4.5 GW total) projects are developed.
- No "technology of choice" develops, in contrast to the Concentrated scenario. In 2027, the first biomass CCS project is also developed, opening up the potential for a 'negative emissions' pathway.
- As with the other scenarios, the Commercialisation Programme projects become operational by 2020-2021.
- Following FID for the two Commercialisation Programme projects (around 2016), development of three new projects should start. FIDs for three capture projects need to be taken by 2020.
- Around 2020 the development for a further four to six projects should start, with FID around 2025.

Industrial capture roll out

- Two pilot scale industrial CCS projects (refinery and cement) are developed around 2020, leading to commercial scale industrial CCS projects by 2027.
- Around 6 Mt/yr from industrial sources are captured as with all scenarios. CO_2 is captured in the refinery, cement, steel and chemical sectors in Teesside, Yorkshire and Forth by 2030.

Storage roll out

- The FID for storage development at the Goldeneye gas field and the 5/42 aquifer needs to be taken by 2016 for these to be operational in 2020/2021.
- To meet the storage requirements of early phase 2 CCS projects in Scotland and Yorkshire, FIDs for development of the Captain aquifer and extension of the 5/42 aquifer need to be taken by 2018. In order to meet that deadline, appraisal of these aquifers should be completed by 2016.
- The cumulative stored CO_2 from 2015 to 2030 is highest for the 5/42 aquifer, with more than 70 Mt, and around 35 Mt each for the Captain aquifer and SNS aquifer 2. Total CO_2 storage in 2030 is around 50 Mt/yr annually and more than 200 Mt cumulatively.

Implications of the timeline analysis

- The scenario requires the first two DECC Commercialisation Programme projects to be operational by 2020-2021.
- FIDs for three early phase 2 capture projects need to be taken by 2020. This is before operational experience has been obtained from the Commercialisation Programme projects, as these are expected to be commissioned in 2020/21.
- Appraisal of the Captain and the 5/42 aquifer expansion should start in 2015.

- Similar to the Concentrated scenario, due to the potential timing mismatch between new build thermal capacity requirements and CCS roll-out, retrofitting "carbon capture ready" (CCR) gas plants could be an important option. The larger number of geographically spread shoreline terminals results in more flexibility for the location of new CCR gas plants, compared to the Concentrated scenario.
- Pilot scale industrial CCS projects are required in the early 2020s.
- This scenario has more flexibility for the location of potential industrial CCS projects compared to the Concentrated scenario due to the higher number of onshore clusters.

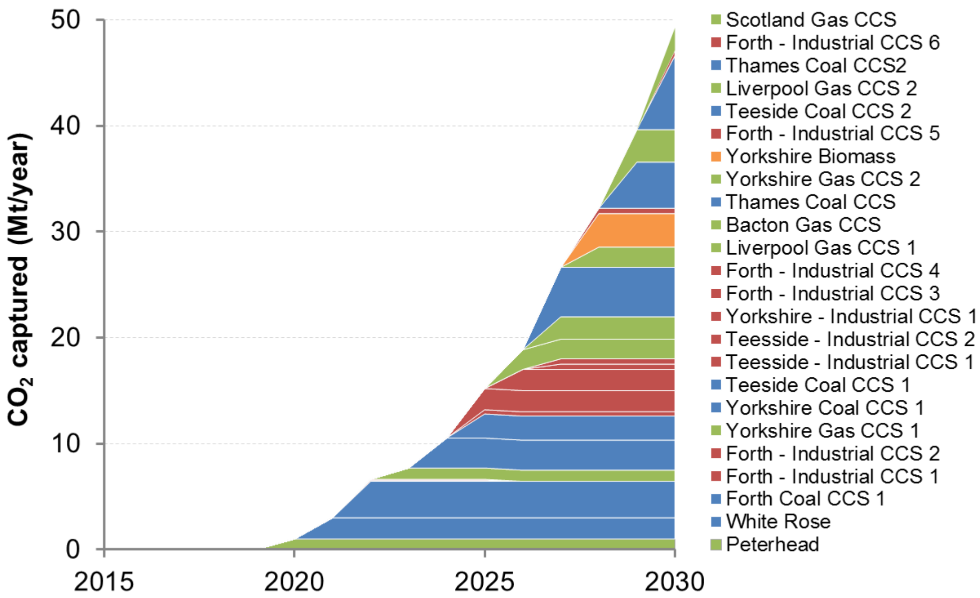


Figure 24: Annual CO_2 capture in the Balanced scenario

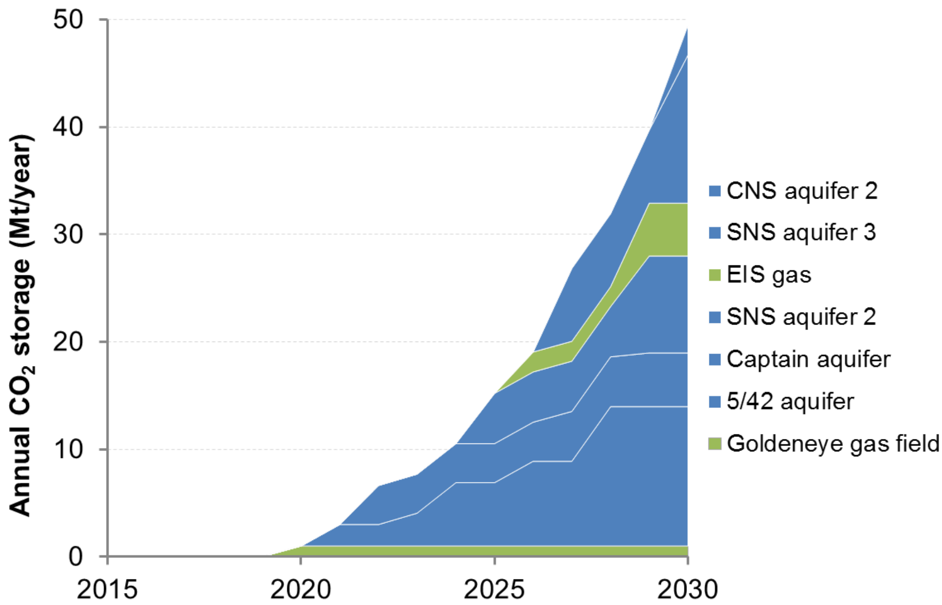


Figure 25: Annual CO_2 storage in the Balanced scenario

3.3.3 CCS economics

Figure 26 presents cumulative CAPEX of CCS over time for the Balanced scenario. The graph shows that cumulative investment in CCS (including T&S infrastructure and capture plants) is more than £15bn, of which more than £10bn is for power capture plants. In addition to the CCS investment, around £15bn of capital investment in base plants is needed, which corresponds to 50% of the cumulative CAPEX by 2030. The relative capex of transport and storage comes down from 23% in 2020 to 14% in 2030 as future projects utilise the oversized infrastructure built during the early years. Total T&S investment is more than £4bn (i.e. £1bn more than the Concentrated scenario) as several onshore and offshore hubs are built in this scenario.

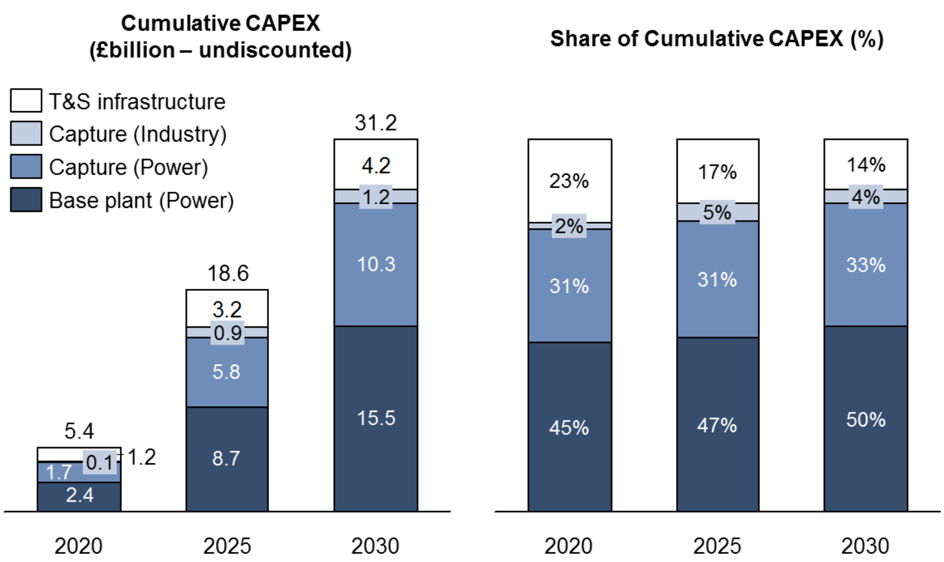


Figure 26: Cumulative CAPEX in the Balanced scenario (undiscounted)

In the Balanced scenario, the strike prices for individual projects reduce more gradually throughout the 2020s as multiple technologies are utilised and new transport and storage hubs are developed. This limits cost efficiencies from replicability and economies of scale. More importantly, more expensive capture technologies are also built to maintain optionality in this scenario, which is the reason that gas CCS costs peak in 2027. Whilst some low cost options are developed, the average cost of CCS technologies remains relatively higher. The required strike prices for both coal and gas CCS projects drop below £100 around 2030 as third generation plants are developed.

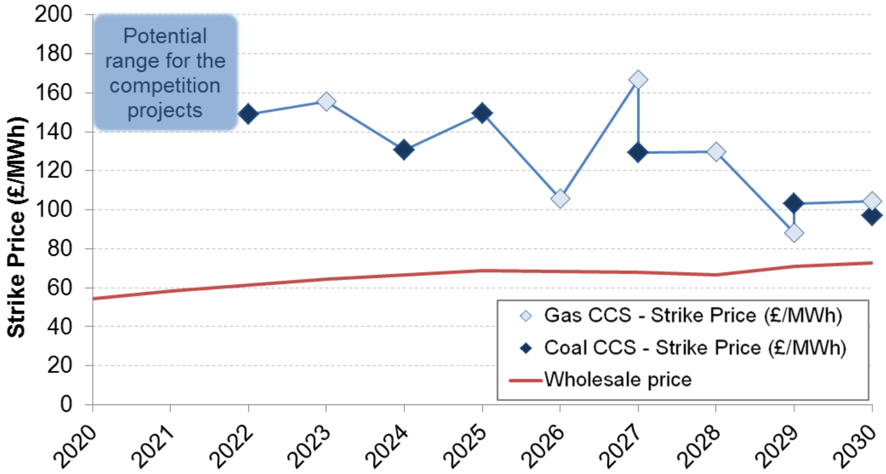


Figure 27: Strike price requirements in the Balanced scenario

As explained in Section 3.1.3 (Concentrated scenario CCS economics), two different charging methods have been studied in this report. Under the marginal cost charging method, the first user of a pipe pays the full capital costs and that future users only pay for additional operational cost recovery. With this charging method, each new hub, pipe or store leads to a 'spike' in CfD strike prices. In Figure 28 we see the effect of this business model, with particular impacts in Teesside and Thames. The T&S costs in the Balanced scenario are highly variable, as many trunklines and storage hubs are developed in different regions (Figure 28). Under the shared T&S charging method, T&S costs in the Balanced scenario are typically less than £20/MWh for all CCS projects (see Appendix 3).

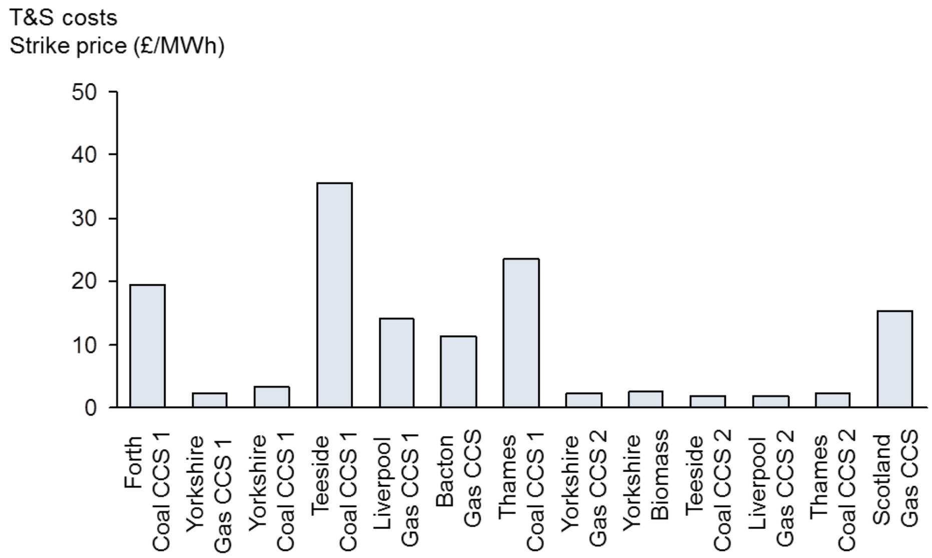


Figure 28: Transport and storage costs in the Balanced scenario (marginal T&S cost charging)

Finally, the annual support cost for CCS in 2030 is more than £3bn in this scenario, and the cumulative payments under the CfD mechanism over the period to 2030 total approximately £18bn. This is higher than in the other two scenarios (Figure 29).

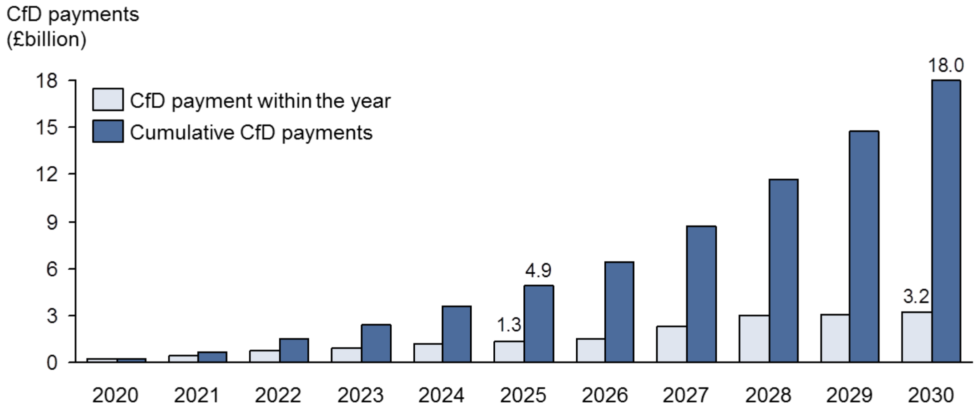


Figure 29: Annual and cumulative CfD payments in the Balanced scenario

3.3.4 Key messages and requirements

The Balanced scenario provides increased optionality for post-2030 with several onshore and offshore hubs, different capture technologies and fuel types. Also, this scenario offers a lower risk of picking the wrong technology (i.e. if one technology fails, there are other options that are tested and matured), as more technology and fuel options are developed through the initial stages.

Each scenario provides a T&S infrastructure roll-out option out to 2030; however for each scenario the T&S infrastructure will be utilised beyond the 2030 time frame to support growth towards the CCS 2050 target. In order to realise the full potential of CCS it is likely that a similar spread of hubs to those built before 2030 in the Balanced scenario would be needed in the period from 2030 to 2050, if the sector had followed either of the other scenarios up to 2030.

In the Balanced scenario, the strike price for individual projects comes down more slowly throughout the 2020s as multiple technologies are tested and new transport and storage hubs are developed. The projects have different characteristics and whilst some CCS projects are low cost, others are expensive and the average cost of the CCS technologies remains high. In this scenario there is a larger opportunity for the UK to benefit from advances elsewhere in the world (e.g. IGCC and post-combustion coal projects that are being developed in North America), as several capture technologies and fuel types are developed in this scenario.

The T&S costs are highly variable in this scenario as many storage hubs and trunk lines are developed in several regions. The greater amount of infrastructure also requires higher capex spending in the period up to 2030, compared to the other scenarios. However, there is also an opportunity for projects beyond 2030 to benefit from this infrastructure.

The Balanced scenario includes wider involvement of industrial sources in several regions, including Teesside, Yorkshire and Forth (similar to the CO_2-EOR scenario). Pilot scale industrial CCS projects need to be developed in the early 2020s based on the timelines of this scenario.

A further upside of this scenario is a potentially lower portfolio risk, as storage is developed in more formations and different locations, rather than concentrated in a few stores.

Based on the analysis we identify the following key requirements for the Balanced scenario:

- Successfully deliver 2 Commercialisation Programme projects on time
- Enable FIDs for 3 additional power CCS projects by 2020
- New CCR gas plants should be located near the hubs developed in this scenario so that there is a practical option for them to fit CCS at a later date. This scenario has more flexibility compared to the other two scenarios
- Implement pilot scale industrial CCS projects in the early 2020s
- Design and implement reward mechanism to support decarbonisation of process-related industrial emissions with CCS
- Aquifer expansion for the phase 2 projects: Captain in the CNS and 5/42 expansion in the SNS. Appraisal for both needs to start in 2015
- Sufficient Government support for power CCS (i.e. CfD and/or other funding)
- Creation of an environment which supports a business case to bring forward investment in appraisal of the significant long-term storage requirement in the CNS, SNS and EIS
- Transparent and predictable business models and governance for T&S (i.e. charging regimes and Third Party Access) ensuring that transport and storage infrastructure is efficiently over-sized and shared
- Active “bottom-up” regional action and support to develop more onshore hubs

3.4 Delayed CCS sensitivities

In all three CCS sector development scenarios, the two preferred DECC Commercialisation Programme projects, namely the White Rose Project and the Peterhead Project, form the first phase of CCS deployment in the UK. Successful delivery of both Commercialisation Programme projects is required under realistic timelines to achieve 10 GW of CCS by 2030. The analysis of timelines for CCS deployment suggests that around three additional CCS projects will need to take FID before the first Commercialisation Programme project is operational, if the levels of CCS deployment in the three scenarios are to be realised. Project developers of the early phase 2 projects might therefore face many of the same challenges as the competition projects; however, they will benefit from the over-sized T&S infrastructure that will be provided by the two competition projects.

In recognition of the tension between the deployment of 10GW CCS by 2030, and project lead times, we also examined the potential implications of a lower level of CCS deployment by 2030. For example, if FIDs on the phase 2 projects occur after the first Commercialisation Programme projects are operational, then developing 10 GW of power CCS would be very challenging in the short period of time to 2030. In such a case, meeting the 10 GW of power CCS ambition looks likely to be delayed by around five years. CCS deployment scenarios including the "delayed" CCS roll-out sensitivities are shown in Figure 30. For these sensitivities, a second wave of CCS projects take a FID after the first Commercialisation Programme project is operational and CCS capacity reaches 10GW by 2035.

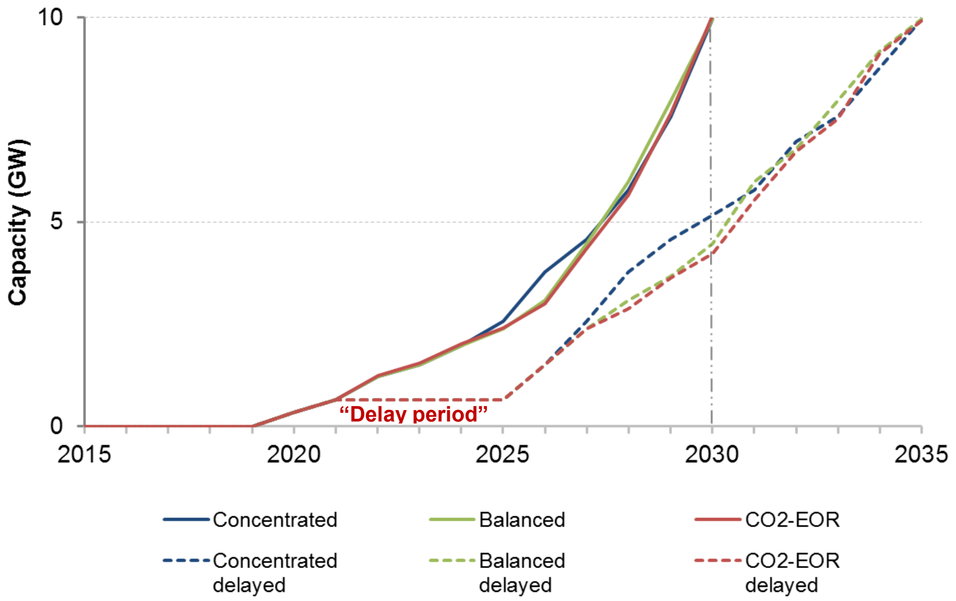


Figure 30: CCS deployment under delayed CCS sensitivities

Such a delay would have several negative consequences, including:

- If CCS deployment is delayed further, investors (CCS and CO_2-EOR), project developers and researchers might lose interest in CCS altogether, potentially removing it as a decarbonisation option in currently considered timescales.
- There is a strong risk that the CCS supply chain currently being created through the competition projects would be lost, and would take some time to become re-established.

- The window of opportunity for CO_2-EOR in the UKCS is limited by diminishing access to existing infrastructure, as the CO_2-EOR candidate oil fields will be decommissioned over time. In the "CO_2-EOR" scenario, delayed CO_2 supply will lead to a loss of benefits/revenues from some of the candidate CO_2-EOR fields.

- Finally, given the UK status as a leading proponent of CCS, the loss of momentum for CCS in the UK could have large knock-on impacts in the prospects for CCS in the rest of the world, with implications for global CO_2 emissions.

ETI's analysis of sensitivities around potential energy system transitions also points to the following implications arising from a delay or failure to develop a UK CCS sector of circa 10GW scale (with associated industrial capture projects) by 2030:

- If a delay were to permanently stunt the growth of CCS in the UK, the likely impact would be a substantial increase in the economic burden of meeting carbon targets, arising from the need to deploy higher cost technologies to cut emissions, particularly in heat and transport. A complete failure to deploy CCS would imply close to a doubling of the annual cost of carbon abatement to the UK economy from circa 1% to 2% of GDP by 2050. ETI's analysis also suggests that success or otherwise in deploying CCS determines key aspects of the UK's energy infrastructure architecture (e.g. the extent of decarbonisation of heat and transport required to meet carbon budgets).

- Scenario analysis and historical experience suggests that creating momentum in the sector to stimulate a robust project development pipeline will be important to deployment and realising cost reductions in practice. As such, delay in building the sector will increase the risk that CCS fails to deliver a significant contribution to either the power sector or broader decarbonisation, in turn creating broader risks of higher costs, heavy reliance on other technologies or potential failure to meet carbon budgets

- A shorter 5 or 10 year delay in developing the CCS sector would still be likely to increase costs and risks across the UK energy system. There is an argument that suggests that a delay would enable the UK to take advantage of technology cost reductions delivered by CCS investment elsewhere globally. However, many of the costs and risks of early CCS deployment are UK-specific and early cost reduction opportunities depend on early infrastructure investments in the UK to achieve scale and capacity utilisation in the UK sector.

- Containing the cost impacts of a 5 year delay would require both rapid (and risky) 'catch up' development of CCS during the 2030s, and accelerated early uptake of a range of other low carbon technologies during the 2020s to fill the decarbonisation gap. This would be a highly challenging strategy to implement, requiring at least the following:
  - Comparatively greater deployment of onshore and/or offshore wind capacity before 2030 (6 to 10 GW), within a broader context of successful cost reduction for these technologies;
  - A substantial programme of retrofitting of CCGTs with CCS during the 2030s;
  - A significantly faster transformation of domestic heating during the 2020s, with faster uptake of biomass heat, district heating and heat pump technologies to replace gas boilers;
  - Accelerated development of hydrogen production during the 2020s and use for low carbon energy.

4 Key implications and conclusions

The scenario analysis has demonstrated that there are a number of feasible pathways to developing a large-scale CCS sector by 2030, and showed in each case the demand on levy control framework funds. All of the scenarios suggest that substantial and rapid cost reductions are achievable after the early phase of projects with strike prices falling to £100/MWh or lower by the mid or late 2020s. Early phase 2 projects are likely to be able to make use of the same stores and transport infrastructure as phase 1 projects, enabling a dividend of early strike price reductions arising from infrastructure investments under the Commercialisation Programme.

The scenarios also suggest that deployment of CCS capacity at scale (i.e. ~10 GW) and infrastructure capable of capturing circa 50 $MtCO_2$/year from power and industry by 2030 is challenging but feasible, provided that a supportive environment can be created. This will require sufficient policy commitment and urgency to bring forward timely investment leading to early actions on critical issues.

While the scenarios are distinct, with the issues unique to each providing important insights, they also have certain common requirements. In this chapter, we explore the primary requirements for CCS deployment in the UK as well as the additional issues that should be resolved to support rapid development of the sector during the 2020s.

4.1 The primary requirements for CCS deployment in the UK

Timely implementation of both CCS Commercialisation Programme projects

In the three CCS sector development scenarios, the two preferred Commercialisation Programme projects, namely the White Rose Project and the Peterhead Project, form the first phase of CCS deployment in the UK. These projects are expected to:[14]

- drive down the costs of CCS through knowledge transfer;
- build familiarity with the CCS regulatory framework;
- act as anchor projects for the development of early infrastructure for CO_2 transport and storage.

The scenarios point clearly to the value of both Commercialisation Programme projects in developing vital transport and storage infrastructure which unlock later unit cost reductions and strategic build out options. Failure to develop two projects (which catalyse two CCS hubs) would constrain options and substantially increase the risk of failure to develop a CCS sector at scale by 2030.

Early investment in storage appraisal to expand the promising 5/42 and Captain aquifer stores and appraise further sites

Given the long lead times for developing storage sites, all scenarios require imminent action to mature and de-risk storage sites. This means that, in addition to the vital storage development under the Commercialisation Programme, immediate action is needed to expand the promising 5/42 and Captain aquifers for the early phase 2 projects.

[14] UK CCS: government funding and support, Available at: https://www.gov.uk/uk-carbon-capture-and-storage-government-funding-and-support

As presented above, more than 500 Mt of bankable storage capacity is likely to be needed by 2025 to meet the storage demand in the three scenarios. In order to deliver the bankable capacity, much more storage capacity should be appraised assuming that several of these storage sites may fail. Appraisal requirement by the mid-2020s could be as high as several billion tonnes. Further storage sites in addition to Captain and 5/42 should also be physically appraised. Scenarios illustrate potential storage sites and regions that need to be appraised under potential CCS development pathways.

Currently there is no business case to bring forward private sector investment in either the urgent storage appraisal requirements for early phase 2 projects (i.e. 5/42 and Captain expansion) or the significant long-term storage appraisal requirements. Therefore, additional support mechanisms for storage appraisal or other measures such as spatial planning are likely to be needed, as suggested by the UK Transport and Storage Development Group.[15]

Delays in investment in storage appraisal would have significant consequences for other parts of the CCS chain, as bankable storage will be required ahead of the CfD auction process. Without bankable storage capacity, project FID is likely to be delayed, with knock on impacts on the overall CCS roll-out.

Enabling early investment decisions by phase 2 projects by awarding a further 3 appropriately designed CfDs by 2020

All three scenarios depend on enabling at least three early phase 2 projects to reach FID by 2020, in effect requiring the award of three further power sector CfDs ahead of commissioning of the Commercialisation Programme projects. This is a key challenge for the current policy framework, requiring early commitment of levy control framework resources, and potentially bespoke contractual design to bring forward sufficient private sector investment and create incentives for cost-efficiency.

Key requirements for the early phase 2 projects include the following:

- These early follow-on projects are likely to make use of the T&S infrastructure that will be delivered through the Commercialisation Programme projects. Clarity on business models for T&S (i.e. charging regimes and Third Party Access) is therefore required. The impact of different business models on the strike price requirements of the follow-on projects were presented in the “CCS sector development scenarios” chapter.
- As explained above, storage development timelines clearly demonstrate that expansion of 5/42 and Captain aquifers are required in all three scenarios. Timelines also indicate clearly that appraisal of these aquifers is needed immediately.
- Three further power sector CfDs should be awarded ahead of commissioning of the Commercialisation Programme projects so that the first phase 2 projects can take FID by 2017/2018.

[15] UK Transport and Storage Development Group, 2014, Delivering CO_2 storage at the lowest cost in time to support the UK decarbonisation goals

Stimulate a robust project development pipeline by delivering clear signals to investors and project developers about the scale and strength of policy (levy control framework support) commitment to developing CCS

All of the scenarios require a robust pipeline of developing projects throughout the 2020s. The chart below illustrates this point by assuming that for each successful CCS project we see two more in development which fail to reach FID given typical power sector project attrition rates.[16] In a scenario where 10GW of CCS power capacity is developed by 2030, we would therefore expect a multiple of that to have reached the development stage (and therefore have incurred significant development costs). Stimulating a sufficiently robust project pipeline will require significant strengthening of current policy and market signals, and resolution of uncertainties for investors.

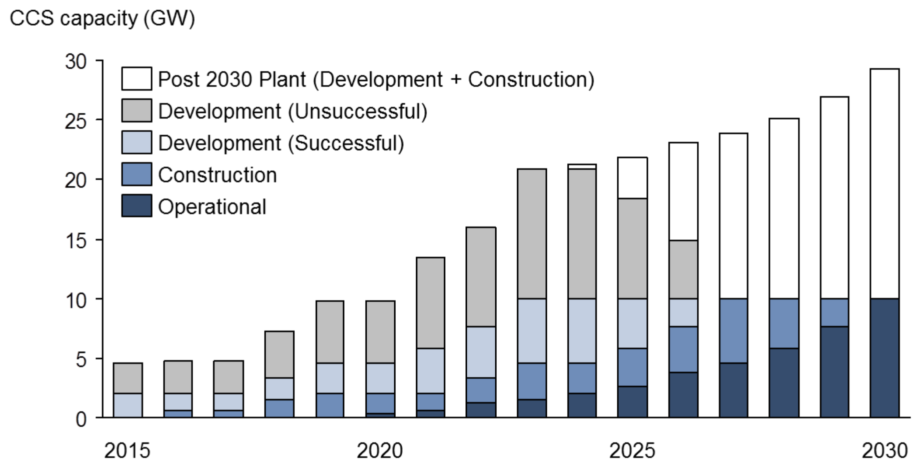


Figure 31: Capacity of CCS plant in the development phase by 2030

The modelling in this report indicates the CfD strike prices required to support projects in each of the three CCS sector development scenarios. We project that the LCOE of CCS power projects by the late 2020s will be in the range £80-£100/MWh. In the EOR and Balanced scenarios, both gas and coal CCS achieve cost reductions, whereas in the Concentrated scenario, only gas CCS achieves some cost reductions but these come down to less than £100/MWh as early as 2025. These figures look competitive compared to the strike price requirements for onshore and offshore wind as forecast by Pöyry for the CCC.[17]

The analysis also indicates that the difference in the total cost of CCS deployment to 2030 between scenarios is relatively small compared to the overall decarbonisation bill. We have estimated that the total annual support cost for CCS in 2030 varies from around £2bn (Concentrated and CO_2-EOR scenarios) to around £3bn (Balanced scenario). By comparison, total annual support costs for all low-carbon technologies are projected to be around £7bn in 2020 and £10bn in 2030 in the "Energy prices and bills - impacts of meeting carbon budgets" report by the CCC.[18]

Although the overall costs of CCS are not high compared to the overall decarbonisation bill, the lack of clarity around the CfD terms and Levy Control Framework (LCF) for CCS projects is creating uncertainty for the phase 2 projects. In the case of nuclear projects,

16 Pöyry assumption (based on historical experience)
17 Pöyry for the CCC, 2013, Technology Supply Curves for Low-carbon Power Generation http://www.theccc.org.uk/wp-content/uploads/2013/05/325_Technology-supply-curves-v5.pdf
18 CCC, December 2014, Energy prices and bills - impacts of meeting carbon budgets

CfD commitments have already been made beyond 2020/2021 (i.e. Hinckley Point C). Development of a bankable CfD for CCS projects through an appropriate CfD allocation methodology and visibility for LCF budgets (available for CCS beyond 2020/21) are vital to stimulate the development of a strong competition for early phase 2 CCS projects. Due to the lead time for electricity sector projects such as CCS, the contracts for post-2020 plants will need to be available in the period 2016-2020 to allow for final investment decisions to be taken. Investors and project developers are likely to require clearer signals about this scale and strength of commitment.

4.2 Additional issues that should be resolved to support rapid development of the sector during the 2020s

Governance for infrastructure sharing

Efficient sharing of infrastructure is central to the cost reductions and the longer term strategic value available in all scenarios, but the most effective arrangements for governance, regulation and for charging will need to be clarified. A purely negotiated incremental cost approach would have very different strike price and risk management implications for a more regulated network charging framework.

Different T&S charging methods were explained in the previous section. Under the fully marginal charging method, which may be interpreted as a business-as-usual model[19], the first user of a pipe pays the full capital costs, with future users paying only for additional operational cost recovery. Under this model, we see significant cost reductions arising from the increased utilisation of existing hubs. However, where there is a new hub or large-scale infrastructure, there is a consequential ‘spike’ in CfD strike prices. For instance, in the EOR and Balanced scenarios, T&S cost of the first project in Teesside is very high compared to the other follow-on projects because of this.

In order for the phase 2 CCS projects to come forward in a timely manner it is important for all potential CCS project developers to have clarity on T&S charging methods (including Third Party Access conditions), and how the Government will support pre-investment in over-sizing (or right-sizing) of new trunk-lines in addition to the two Commercialisation Programme projects. In the absence of such clarity, there remains significant risk of non-optimal development of infrastructure and, moreover, the systemic uncertainty may lead to reduced or restricted activity in the CCS sector.

Strategy for capture readiness

As presented previously, if new gas capacity is built before the early 2020s to meet potential new build thermal capacity requirements[20], there is a potential that the remaining need for new thermal capacity delivered during the 2020s may be lower than level of new CCS capacity required in the same period by the scenarios developed in this report.

[19] See DECC, 2014, Guidance on Disputes over Third Party Access to CO_2 Transport and Storage Infrastructure – The Storage of CO_2 (Access to Infrastructure) Regulations 2011

[20] For instance, in the DECC Reference scenario, 13 GW of new gas capacity is built by 2024 and only 4 GW of new gas capacity is built between 2025 and 2030. (DECC Updated Energy & Emissions Projections - September 2014)

This potential timing mismatch suggests that retrofitting "carbon capture ready" (CCR) gas plants, which would be expected to be built initially without CCS units in the period to 2023, could be an important requirement. However, this report has shown that the location of potential CCS clusters and associated T&S networks should also be considered as part of these "capture ready" requirements for new-build thermal plants. The three scenarios presented in this report illustrate potential onshore hubs and T&S infrastructure in NW England, NE England, SE England and East of England. Developing a more robust strategy for capture readiness, the location of new thermal plant and retro-fitting could resolve this tension – and send a strategic signal to project developers and investors..

Accessing industrial sources of CO_2

To meet the UK's longer term decarbonisation goals, UK industrial CO_2 emissions, which are currently around 112 Mt/yr[21], should be reduced. Although some CO_2 savings are possible through energy efficiency measures and fuel substitution, CCS technology is recognised as a key option for substantially decarbonising the energy intensive industries, namely the cement, chemicals, oil refining, and iron and steel sectors. Achieving significant cost effective carbon savings in these sectors in the medium to long term looks very challenging without using CCS.[22] In all of the three CCS sector development scenarios, CO_2 is captured from a number of industrial sites before 2030.

A recent techno-economic evaluation by Element Energy et al. for BIS and DECC[23] identified both the main barriers and key enablers related to the deployment of industrial CCS. The study suggested that some of the site level barriers (including increased operational complexity and risks, plant integration risks, high cost uncertainty and lack of applications proven at scale) could be addressed by providing funding support for detailed engineering studies, pilots and demonstrations in industry applications. In all of the three scenarios, pilot scale industrial CCS projects are developed around 2020.

Another key system level barrier is the lack of business case due to the weak and uncertain CO_2 prices. Power plants and onsite electricity generation at industrial sites with CCS will be eligible for CfD payments; however, there is currently no financial incentive in place to support decarbonisation of process-related emissions with CCS. In the short to medium term, additional incentives will be needed to kick-start industrial CCS applications.

The lack of available transport and storage infrastructure was identified as another over-arching systematic barrier for industrial CCS. Individual industrial facilities typically produce lower volumes of CO_2 compared to the power sector. Consequently, unit transport and storage costs (£/tCO_2) for industrial sites are higher unless industry clusters (such as Teesside) are developed, which can provide economies of scale and efficient utilisation of infrastructure. A "bottom-up" regional approach for onshore clusters should therefore be more actively supported. Finally, CCS commercialisation in the power sector should also include T&S infrastructure that can be utilised by industrial CCS applications. Higher CO_2 prices alone may not be sufficient to incentivise industrial CCS, and instead could risk an unintended displacement of industrial activity to outside of the UK.

[21] DECC CO_2 emission data tables, available at: https://www.gov.uk/government/organisations/department-of-energy-climate-change/about/statistics
[22] DECC, 2014, Next steps in CCS: Policy Scoping Document
[23] Element Energy et al. for BIS and DECC, 2014, Demonstrating CO_2 capture in the UK cement, chemicals, iron and steel and oil refining sectors by 2025: A Techno-economic Study

Management of load factor risk for CCS power projects

The potential load factors achievable by CCS power plants in the medium and long term will depend on the broader generation mix. Current renewables and industrial/energy efficiency policy suggests a considerable increase in renewable capacity over next decade, compared with a smaller increase in thermal capacity. In time, the increase in intermittent generation will put downward pressure on the amount of base-load running capacity required in the system.

It is likely that while CCS plants will need to be able to flex in system response to wind intermittency, the load factors of CCS projects developed up to the late 2020s can be close to base-load[24], and that the cost of power production is not affected significantly by lower load factors. While the scenarios are based on reasonable expectations of renewables deployment, there is significant uncertainty around the deployment of wind, and far higher amounts of wind on the system would be expected to impact the load factor of CCS project, with cost implications.

Given the lifetime of CCS projects, and the potential for impact on future revenues, investors may require greater clarity on this or a move away from the CfD reward structure, which is entirely dependent on delivered output.

Risk management and governance for CO_2-EOR

CO_2-enhanced oil recovery is one of many EOR technologies that can be used to maximise recovery from the UK's oil and gas reserves. CO_2-EOR offers the highest theoretical potential for the UKCS, compared to alternative EOR technologies such as low-salinity and polymer flooding.[25] The Wood Review also recognised the potential of CO_2-EOR in their recent review.[26]

Recent techno-economic studies by Element Energy et al. for Scottish Enterprise[27] and CO_2-EOR Joint Industry Project[28] identified several CO_2-EOR candidate oil fields in the UK Continental Shelf, which would be economic under a wide range of conditions (i.e. would have positive net present value from oil revenues). However, the CO_2-EOR projects would be unlikely to meet commercial post-tax investment criteria without further incentives in part at least due to the high marginal tax rate on UKCS fields. The recent study by Element Energy et al. on potential fiscal incentives for CO_2-EOR[28] suggested that CO_2-EOR in the UKCS could also be kick-started through fiscal incentives. CO_2-EOR projects could offer free or negative cost storage if sufficient fiscal incentives were provided.

In all of the three scenarios, CO_2 captured in Scotland could be used for a limited number of EOR projects with relatively lower T&S costs. As illustrated in the CO_2-EOR scenario, in order to maximise CO_2-EOR potential in the UKCS, significant volumes of CO_2 should be transported to Central North Sea, which would require a trunk pipeline (capex is likely to be more than £700m) from East of England. The cost of this trunk pipeline is too high for a single capture project to cover through CfD payments (i.e. strike price requirement would increase by around £50/MWh). However, based on our analysis, the impact of this potential trunk pipeline on the strike price requirements would be low if the cost can be

[24] It is estimated that the marginal load factor of the 10th GW of plant in 2015 would be 89%, falling to 85% in 2025 and 82% by 2030 (New build/load factor based on 2014 Pöyry view)
[25] T. Garlick, DECC/Pilot EOR Workstream Update - Presentation delivered 23rd May 2012
[26] Sir Ian Wood, 2014, UKCS Maximising Recovery Review: Final Report
[27] Element Energy et al. for Scottish Enterprise, 2012, Economic impacts of CO_2-EOR for Scotland
[28] Element Energy et al. for CO_2-EOR JIP, 2014, CO_2-EOR in the UK: Analysis of fiscal incentives.

shared between a number of capture projects, which would all receive CO_2 transfer payments from a cluster of oil fields.

Our analysis also suggests that unless CO_2 has a positive value 'at platform' due to the CO_2-EOR projects, it might not be possible to justify the additional investment required for this potential trunk pipeline. In such a case, CO_2 from NE England is likely to be stored in the SNS storage sites. The value of CO_2 'at platform' depends on a number of factors including oil price and potential Government support for CO_2-EOR.

In order to create a CO_2-EOR cluster in the CNS, coordination is required between potential onshore capture clusters and CO_2-EOR candidate oil fields in the CNS (and Northern North Sea in the post-2030 period). The Wood Review also suggested that a new arms' length regulatory body should be created to maximise collaboration and co-ordination in exploration, development and production.[26] This regulator could play a role in CO_2-EOR co-ordination.

Finally, lack of public acceptance is one of the key barriers of CO_2-EOR in the UK. Public acceptance/support can be increased through communicating the societal benefits of CO_2-EOR to public. Similarly, sufficient evidence should be provided for the 'carbon balance' of CCS projects including CO_2-EOR.

Reflecting strategic value in CfD allocation decisions

Each scenario provides a T&S infrastructure roll-out option out to 2030; however each scenario depends on projects which develop the T&S infrastructure which is utilised by other subsequent projects and which will be utilised beyond the 2030 time frame to support growth towards the CCS 2050 target. The economic analysis shows clearly that the cost of T&S infrastructure impacts on strike prices at project level. Development of new hubs and over-sized T&S infrastructure in the three scenarios would not be possible if CfDs were allocated simply on the basis of lowest strike prices or LCOE.

Under the fully marginal charging method, the first user of a new hub pays the full capital costs of the T&S infrastructure. Although the Commercialisation Programme projects can recover some of these costs through Government funding in addition to CfDs, follow-on CCS projects in the UK will need to recover T&S costs mainly through CfDs. Follow-on CCS projects, which are creating new hubs and/or building new over-sized infrastructure, will not be able to compete on a level playing field against projects that are only paying incremental cost to access pre-existing infrastructure. The strategic value of the project to the development of the sector needs to be reflected in CfD allocation decisions.

In addition, the Balanced scenario showed that developing a range of capture technology options and more diversity in geographic location can increase optionality for future CCS development. But this looks likely to come at some added financial cost. While there is no clear case for government to pick technologies, policy on CfD allocation will need to clarify how these issues will be taken into account.

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Appendix:

Appendix 1: Themes/drivers for scenario development

The key themes identified have been categorised based on:

- Whether the driver is an input or output of the analysis;
- Whether the theme can be varied or it is fixed.

Themes	Input/Output	Fixed/Variable	Comments
CCS location	Input	Variable	Capture and storage locations can vary (i.e. concentrated vs. balanced)
CO_2-EOR	Input	Variable	CCS scenarios can be plausible with or without EOR
Industrial CCS	Input	Fixed	Contribution from industrial CCS will be important in all CCS scenarios
Regulatory framework	Input	Fixed	Required to achieve large-scale CCS deployment to 2030
Coordinated development	Input	Fixed	Required to achieve large-scale CCS deployment to 2030
Sufficient supply chain	Input	Fixed	Required to achieve large-scale CCS deployment to 2030
Funding availability	Input	Fixed	Required to achieve large-scale CCS deployment to 2030
Financeable projects	Input and Output	Fixed	Required to achieve large-scale CCS / viability of projects will be assessed
Vision for CCS	Input and Output	Fixed	Key output will be a number of CCS scenarios consistent with the ESME vision
CfD FiT requirements	Output		CfD requirements will be estimated through economic modelling
Policy support for T&S	Output		Key requirements for T&S development will be identified

Figure 32: Remaining degrees of freedom for scenario development

Themes identified through a literature review

Theme	Key actions to support large-scale CCS development	Report
CCS location	Ensure optimal UK CCS transport and storage network configuration	EE & Poyry for NSBTF (2007) CRTF final report
	Promote characterisation of CO_2 storage locations to create maximum benefit from the UK storage resource	ETI – Insights from UKSAP CRTF final report
	identify optimum networks for the UK CCS transport and storage system for both early CCS projects and future CCS projects, in order to minimise costs.	EE Insights from CO_2NomicA Element Energy study for the CCC
CO_2-EOR	Incentivise CO_2-EOR to limit emissions and maximise UK hydrocarbon production	EE Economic Impacts from CO_2-EOR (2010) CRTF final report
	Consider opportunities to develop low/negative cost storage sites, such as through tax-based incentives for early deployment of CO_2-enhanced oil recovery with CCS projects.	Element Energy CCC study
Industrial CCS	Create policy and financing regimes for CCS from industrial CO_2	EE (2014) Industrial CCS CRTF final report
	Explore how to create reward mechanisms for non-power sector applications of CCS	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
	Create necessary policy and financing regimes for	Element Energy study for the

	industrial CCS	CCC
	Consider incentivising the development of early industrial CCS projects	

Theme	Key actions to support large-scale CCS development	Report
Regulatory framework	The regulatory framework for CCS in the UK needs to be finalised following the review of the EU CCS Directive in 2015.	Element Energy study for the CCC
	Ensure contracts, licences and leases are structured to allow CO_2 to be injected into alternative stores, where this can be done safely	EE for ETI Business & Regulatory Models
	Appropriate regulations and business models should be in place for shared pipelines and storage sites/hubs. At a minimum, ensure rights of way are in place to allow several parallel pipelines to use similar routes if pipeline "over-sizing" cannot be adopted.	Poyry for TCE
	Consider case for regulatory or market frameworks to underpin business structures	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
Coordinated CCS development	Explore the role and scope for public private sector coordination mechanisms	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
Sufficient supply chain	Ensure effective supply chain planning (people, materials, equipment, capital)	Element Energy study for the CCC
Funding availability	Funding mechanisms and the cap on the Levy Control Framework should reflect immature market conditions of CCS for the commercial CCS projects.	Element Energy study for the CCC
Financeable projects	Focus on reducing, managing and sharing risks for early follow on projects	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
	Explore risk sharing structures and mechanisms	
	Consider GIB role in facilitating sourcing of capital	
	Increase depth of policy makers' engagement with potential financiers (as per Ofgem/Ofwat)	
	Consider strategies for addressing private sector concerns around storage liabilities	
Vision for UK CCS development	Improve the CCS roadmap through engagement with key stakeholders, including investors	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
	Consider stronger policy signals on electricity decarbonisation or capture readiness	
	Create a vision for development of CCS Projects in the UK from follow-on projects through to widespread adoption	EE & Poyry for NSBTF (2007) EE & Poyry for NSBTF (2010) CRTF
	A clear vision for CCS, with credible location, time and capacity signals, is required	Element Energy study for the CCC
	Develop business models and vision for development of CCS projects in the UK from demo projects to widespread adoption.	
CfD FiT requirements	Right pricing of CCS contracts for difference	EE & Redpoint for DECC
	Evaluate risks and develop strategy for risk sharing in projects supported by contracts for difference	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
	Examine scope to build certainty of a market for CCS through EMR delivery plans	
	Clarify revenue support and ensure timescale is sufficiently long	
	Ensure funding mechanisms and policy support for post-demonstration CCS projects are fit-for-purpose and sufficient for the projects that will mainly be supported by CfD contracts.	Element Energy CCC study
	Encourage and guide developers of the follow-on UK CCS projects as to the incentive mechanisms in place that support transport and storage infrastructure, potentially ahead of the agreement of a Contract for Difference (CfD) Strike Price with individual sources.	
	Ensure funding mechanisms are fit-for-purpose	CRTF
Policy support for T&S	Consider public funding for strategic R&D, e.g. proving of North Sea storage or enabling infrastructure	ETI and Ecofin, Mobilising private sector finance for CCS in the UK
	Consider targeted public support for derisking (e.g. storage)	

Appendix 2: Economic modelling assumptions

Capture plant cost data sources

Capture plant types	Data sources
Post-comb gas CCS: CRTF	Cost reduction task force[29]
Post-comb coal CCS: CRTF	
Oxyfuel-comb coal CCS	
IGCC coal CCS	
Pre-comb gas CCS	Based on ETI data on pre-comb gas CCS and biomass CCS but indexed to be consistent with IGCC coal CCS data from CRTF
Biomass CCS	

Capture units cost development are categorised into three representative phases:

- ZOAK (Zeroth of a kind):
    - The first plant with a particular technology. However,
    - Regarding the proximity of project development and design periods, the first five projects are all accepted as ZOAK regardless of the technology.
- FOAK (First of a kind):
    - 2nd and 3rd plants of a particular technology (regarding the time/experience required to improve a technology, it is assumed that there will be 2 FOAK projects, with considerable risks/costs, before the NOAK stage)
- NOAK (Nth of a kind):
    - All projects after the two FOAK projects for a particular technology

Costs and technical specifications (i.e. efficiency and availability of the power plants) are determined based on CRTF cost assumptions, which are based on the FID date of the project. It is assumed that

- ZOAK projects have the costs equivalent to those having FID date at 2013;
- FOAK projects have the costs equivalent to those having FID date at 2020; and
- NOAK projects have the costs equivalent to those having FID date at 2028 in the CRTF cost assumptions

[29] CCS Cost Reduction Taskforce Final Report, 2013, Available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/201021/CCS_Cost_Reduction_Taskforce_-_Final_Report_-_May_2013.pdf

Scale, revenue and fee allocations

- Main drivers of the system sizing (thus the model) will be:
  - installed capacity of CCS on power and industrial sites;
  - the CO_2 volume captured at power and industrial CCS and sent to the transport network & storage sites;
  - the electricity volume generated by the power capture units; and
  - opportunities for the CO_2 to be utilised for EOR purposes

- Capture units will pay all the onshore/offshore transport fees and the storage fees with respect to the CO2 volume they capture/send. There will be no additional cash flow between the transport and storage companies.

- Capture units' revenues are assumed to be only electricity revenues, which will include the CfD subsidies (industrial CCS revenue is not in the scope of revenue calculations)

- It is currently unclear whether CfDs for CCS (and strike prices) will be allocated based on a multi-sector pot, sector-specific (i.e. all CCS), technology type-specific, or on a plant basis. The model calculates the CfD for each plant

CfD assumptions

- Period over which CfD payments are offered would change the level of strike price required (e.g. 15 years for most technologies and 35 years for Nuclear)

- Assuming that each CCS plant should 'just' meet its hurdle rate is the starting point. However, it should be recognised that some plants would be expected to receive returns above their hurdle rates if the CfD is determined on technology-neutral basis.

- Current DECC wholesale, gas, coal and carbon price assumptions are used as reference prices against which the LCF costs are assessed.

Onshore network design assumptions

- Each region has at least one trunk-line

- Each plant has a branch-line connected to the trunk-line

- Feeder-10 pipeline (~10 $mtCO_2$ capacity) and Yorkshire trunkline (~17 $mtCO_2$ capacity) are developed in Scotland and Yorkshire regions

- In Scotland region, Peterhead Power Plant has its own line to the terminal due to its proximity to the terminal

- Each trunk and branch pipe is sized to cover the required max CO_2 flow with costs calculated based on pipe size

- Onshore costs are based on CRTF

Offshore network design and cost assumptions

Offshore and storage network designed to flow, inject and store all CO_2 volumes in each scenario using the following models:

- CO_2NomicA, CO_2 transport and storage network model developed in partnership with ETI
- CO_2EOR KickStart, Element Energy's CO_2-EOR model

All CO_2 emitters are connected to the nearest shoreline terminals (i.e. St Fergus, Teesside, Easington Yorkshire, Bacton, Thames and Wirral).

Storage sites are chosen:

- Based on the previous CO_2Nomica runs for ETI and the CCC (potential sinks identified in UKSAP)
- Sites having sufficient theoretical injection capacity to meet the storage demand, and sufficient storage capacity to meet at least ten years of demand.
- From the potential sinks, choose those that were nearest to the shoreline terminals and had least costs (on a £/t basis).

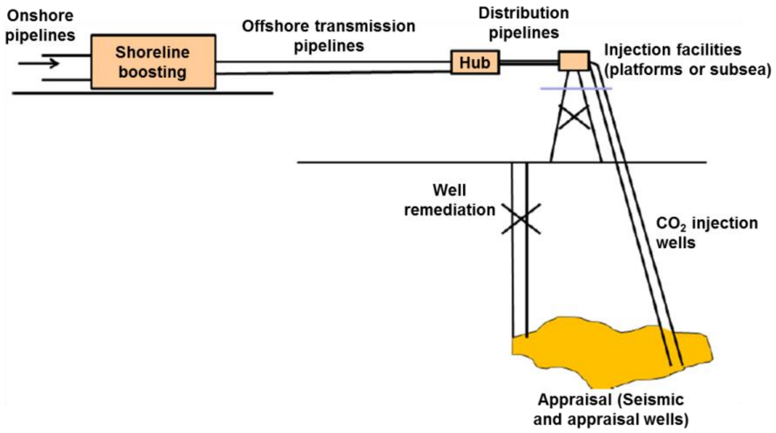
EOR fields are based on previous EE studies on CO_2-EOR considering COP dates, candidate oil fields, storage capacity and CO_2 requirements for EOR.

Fuel price assumptions

- DECC September 2014 fuel prices[30] are used.
- All prices are real and are expressed in 2014 prices.

[30] DECC, 2014, Fossil fuel price projections: 2014, Available at: https://www.gov.uk/government/publications/fossil-fuel-price-projections-2014

CO_2 transport and storage infrastructure elements included in this study



Infrastructure	Definition
Onshore pipelines	CO_2 transport from CO_2 capture to shoreline terminals
Shoreline boosting	Onshore sites are assumed to be connected to a shoreline hub, where it is assumed that the CO_2 is delivered at 10 MPa at the required purity for pipeline transport and geological storage.
Offshore transmission pipelines	CO_2 transport from shoreline terminals to storage sites - pipeline diameter depends on limiting pressure drops
Hub	Where offshore boosting is required, hubs are added to the network
Distribution pipelines	CO_2 transport from hub to CO_2 injection facilities
Injection facilities	CO_2 injection facilities might include platforms or sub-sea injection facilities
CO_2 injection wells	The number of injection wells depends on CO_2 flow rates and pressure limits associated with injection
Appraisal	Appraisal costs include the cost of seismic assessment and appraisal wells
Well remediation	Existing wells drilled primarily for hydrocarbon production could provide a pathway for CO_2 to escape from a designated storage site, potentially to the seabed or atmosphere; therefore, they might be resealed.

Timeline assumptions

Infrastructure		Duration	Data source
Power plant (gas and coal)	**Development phase**	4 years	CRTF modelling by Pöyry
	Construction phase	Varies between 3 and 5 years depending on the capture technology and maturity of the CCS unit (i.e. ZOAK to NOAK)	CRTF modelling by Pöyry
Industrial sites	**Development phase**	4 years	Same as power plant development phase
	Construction phase	3 years	Element Energy for the CCC, 2013, Infrastructure in a low-carbon energy system to 2030: CCS
Storage sites	**Screening, exploration, appraisal and development phase**	5 to 6 years	Element Energy for the CCC, 2013, Infrastructure in a low-carbon energy system to 2030: CCS and the project team's experience
	Construction phase	Varies between 3 and 5 years consistent with the capture plant development	Storage sites and the first capture plants (that will be connected to the storage site) take FID in the same year
EOR fields	**Screening, exploration, appraisal and development phase**	4 years	Element Energy for the CCC, 2013, Infrastructure in a low-carbon energy system to 2030: CCS (using hydrocarbon storage development timeline)
	Construction phase	3 years	

Appendix 3: Results for shared business model

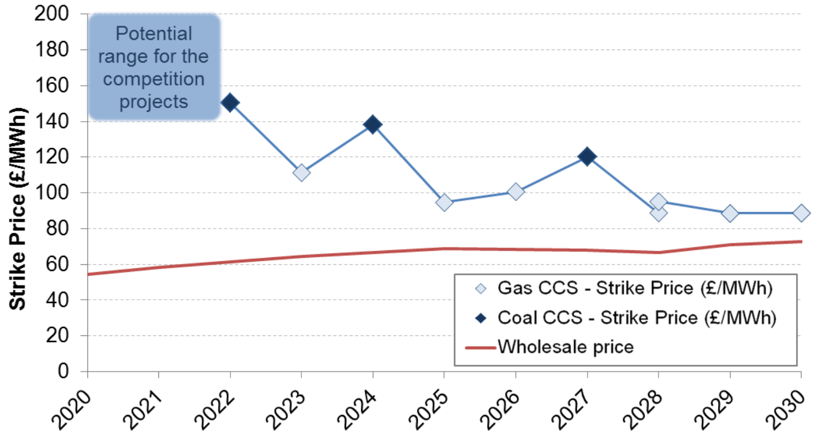


Figure 33: Strike price requirements in the Concentrated scenario (Shared T&S cost charging)

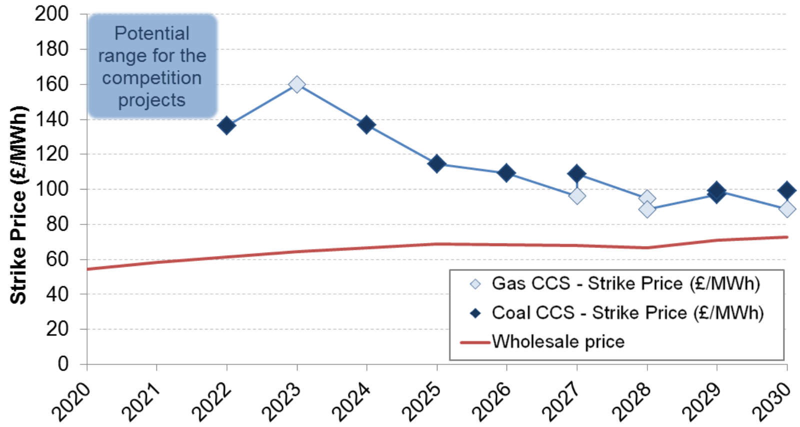


Figure 34: Strike price requirements in the CO_2-EOR scenario (Shared T&S cost charging)

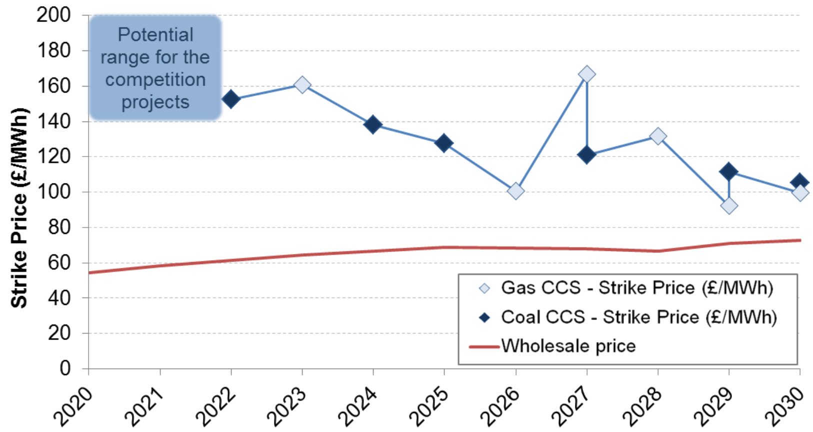


Figure 35: Strike price requirements in the Balanced scenario (Shared T&S cost charging)

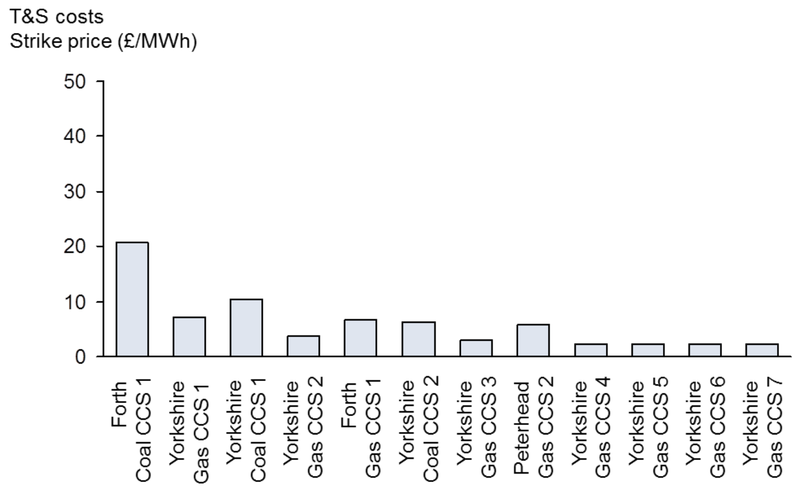


Figure 36: T&S costs in the Concentrated scenario (Shared T&S cost charging)

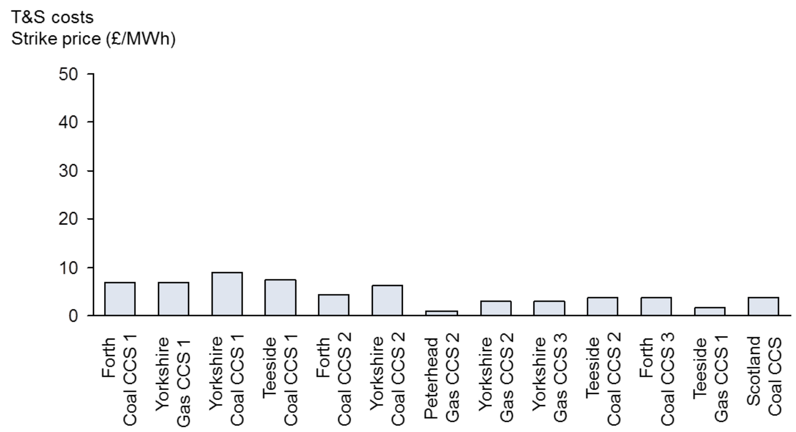


Figure 37: T&S costs in the CO_2-EOR scenario (Shared T&S cost charging)

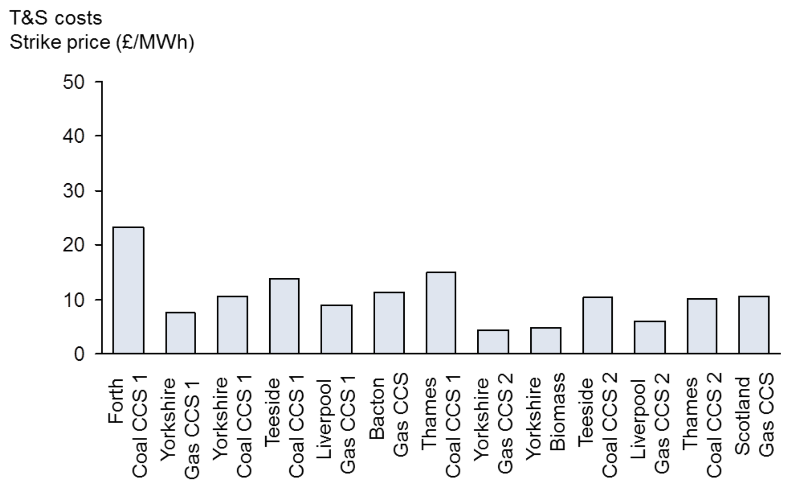


Figure 38: T&S costs in the Balanced scenario (Shared T&S cost charging)

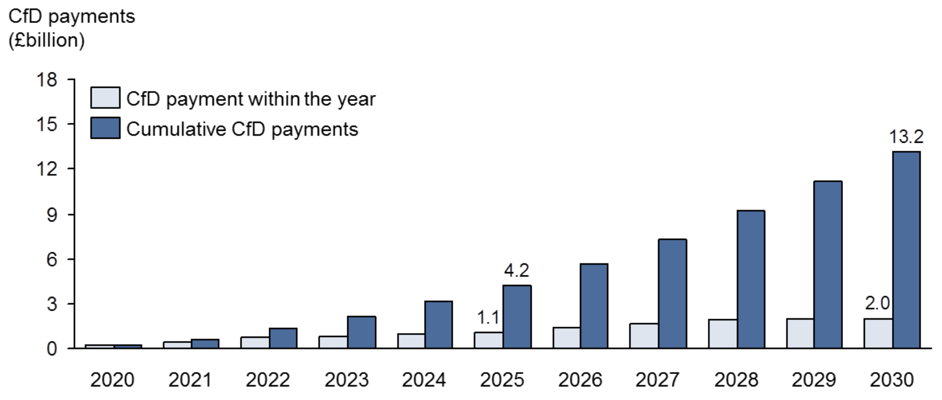


Figure 39: Cumulative CfD payments in the Concentrated scenario (Shared T&S cost charging)

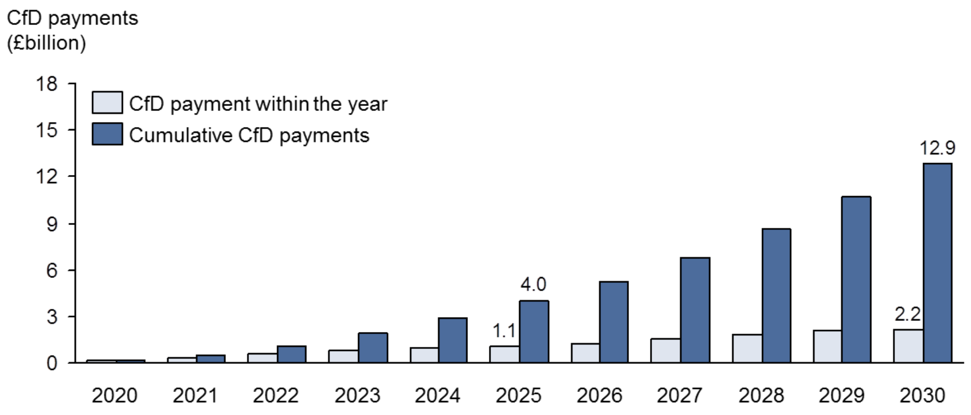


Figure 40: Cumulative CfD payments in the CO_2-EOR scenario (Shared T&S cost charging)

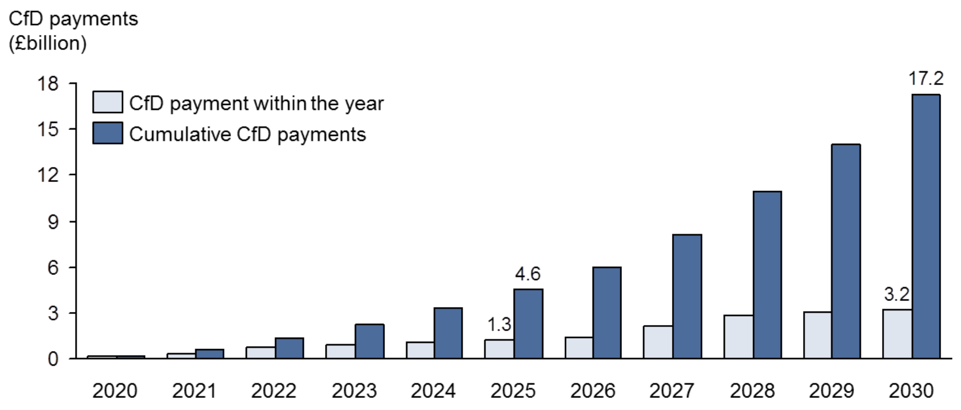


Figure 41: Cumulative CfD payments in the Balanced scenario (Shared T&S cost charging)

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