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Contract Incentives for Industrial Carbon Capture

A review of design options

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Summary

- Contracts giving incentives for reducing emissions by carbon capture have a valuable role to play in stimulating deployment of early CCS. Contracts may be Contracts for Difference (CfDs) on the market carbon price, but will not necessarily be so. The form of the contract will depend on how changes in carbon prices affect project income.

- Other mechanisms can also play a valuable role, include creating low carbon markets, procurement mandates, robust carbon pricing, and capital grants or other direct subsidies. In the long term is it expected that some combination of carbon prices and product standards will mean that dedicated support for CCS projects is no longer required.

- Contract incentives should be based on the amount by which CO_2 emissions are reduced compared with continued operation without capture. They should not be based on amount of CO_2 captured, which distorts incentives for efficiency and potentially distorts project choice. It is important to not incentivise CO_2 production by making it a driver of remuneration.

- Project eligibility should require meeting basic quality thresholds. For example, minimum capture rates should be specified. Carbon Capture and Use (CCU) projects should be excluded unless the use results in the CO_2 being permanently removed from the atmosphere, which will rarely be the case.

- Early projects should be chosen on the basis of strategic demonstration value as well as on cost of abatement. In particular this should favour projects where there are few if any alternative decarbonisation options, and that will be an important part of a net zero economy. In the UK context this may require enabling CCS at sites remote from project clusters.

- Contract duration should be a minimum of 10 years, with the full capital investment requiring at least this long for full remuneration. There should also be incentives to continue operation into the medium and longer term.

- A risk sharing mechanism should be included in contracts to take account of unexpectedly high or low out-turn costs or rate of returns.

- Separating support into components, for example including a proportion of fixed payments, should be considered to reduce risks and therefore costs.

- There are various options for managing risks around free allocation of emissions allowances under an ETS. If free allowances are not allocated to the project, then mechanisms need to be put in place to ensure the allowances are issued and retained by government for auction.

1 Introduction

1.1 Scope of this briefing

This briefing looks at incentives for carbon capture at industrial sites using contractual payments to cover the additional costs due to carbon capture. It looks at specific issues of contract design, rather than looking more broadly at risks, incentives and support mechanisms for CCS.

Contracts provide payment for an environmental service (reduced emissions). They are analogous to contracts for renewable electricity, such as feed in tariffs or contracts for differences. Because contracts are legally binding they can provide certainty to investors, and thus can be a powerful mechanism for stimulating deployment. The counterparty will usually be government or a government supported entity such as a government backed company.

Contracts may take a variety of forms, including contracts for difference on the carbon price (CfDs or Carbon CfDs, CCfDs), with the amount of support paid to a carbon capture project decreasing as the carbon price rises. However, they are not restricted to that – for example they may simply pay a specified level of support irrespective of the carbon price.

This briefing sets out a **range of contract design choices**, and some of their implications. It does not seek to define best practice, which will in any case vary with circumstances.

This briefing seeks to build on previous work such as the report of the CCUS advisory group from 2019[1] . It considers capture projects only, and does not consider incentives or risk sharing across the chain - for example what happens if transport or storage is unavailable - although such issues will be important in realising projects. It also necessarily summarises possible approaches. There will often be alternative ways of reaching similar outcomes.

This briefing covers industrial carbon capture. Many of the same issues will arise in other sectors. However there will sometimes be additional issues to be addressed in other sectors, such despatch of power generators, which are not addressed here.

It takes the pricing of the transport and storage elements of the CCS chain as given. This is the subject of a separate briefing.

This briefing also excludes consideration of other possible mechanisms for incentivising CCS, such as the creation of markets for low carbon products and carbon pricing, which can also play a valuable role either on their own or in conjunction with contracts.

The main elements most likely to be part of contract design are summarised in the table below, and considered further in the remainder of this report.

1 https://carbontakeback.files.wordpress.com/2020/11/ccus_advisory_group_final_report_22_july_2019-1.pdf

The design or contracts and mix of support mechanisms is likely to change over time. Support for early CCS projects is necessary as the technology is immature and costs are high. However later projects may become economic based on avoiding costs due to carbon pricing, or obtaining a premium for low carbon production, for example low carbon cement. They are likely at least to require reduced levels of contractual support.

It is mainly intended to inform the current debate on these issues in the UK. However, many of the points are relevant to similar approaches in other jurisdictions. It focusses on principles of design, as there are few instances of industrial carbon capture projects to date. However, reference is made to mechanisms in other jurisdictions including Norway, the Netherlands and the USA.

1.2 Elements of the payment

Revenue under a contract to support CCS may have a single component, most usually a payment per tonne of CO_2. Alternatively, it may have several components, each usually chosen to reflect a different type of cost. The inclusion of different elements can reduce risks, and so make the contract more attractive to project developers and better value for money for governments. These advantages need to be balanced against the costs of greater complexity.

Table 1: Possible components of a support contract

Contract component	Parameters	Rationale
Payment per tonne of reduction in CO_2 emissions	£ per tCO_2 (strike price) * tCO_2 emissions reduced	Matches non-energy opex plus other elements
Fixed payment p.a.	£ million p.a. (may depend on availability)	Matches capex and other fixed costs
Payment indexed to energy prices	£ per tCO_2 (strike price) * tCO_2 emissions reduced Energy prices in future versus energy prices at contract start	Manages risks of varying energy costs of capture
Transport and storage costs (T+S)	T+S price per tonne * amount transported	Matches T+S regulated prices
Variation in payments to reflect carbon pricing	carbon price * tCO_2 emissions reduced	Manages the benefits and risks from carbon pricing

Payment per tonne of CO_2. Such a payment is likely to be part of any contract, because it incentivises operation of the capture plant. The price per tonne of CO_2 is often referred to as the strike price in the contract, because it is usually set by negotiation, competitive tender or auction.

It is multiplied by a number of tonnes of CO_2 to define the amount of the contract payment. How these tonnes of CO_2 are defined can have an important effect on the incentives created by the contract. The amount by which CO_2 emissions are reduced is preferable, for reasons set out later in this briefing.

An annual fixed payment. This does not depend on volumes of CO_2, but is paid anyway, for example as a fixed monthly or annual amount. It may be made unconditionally, provided only that the plant remains open, or may be based on availability of the capture plant. This type of payment is usually intended allow repayment of a portion of capital costs irrespective of the utilisation of the capture plant. It has some potential benefits similar to a capital grant, which may also be part of a support package.

Costs of energy used in capture. Some proportion of the per tonne payment, most likely corresponding to the energy costs of running the capture plant, may be indexed to energy prices. This can reduce financial risks to the capture plant, because energy costs may have quite different trends from other operating costs, and from general inflation. Energy costs may in practice include separate electricity and fuel components. These may be indexed separately. The proportion of energy costs indexed in this way may depend in part on the extent to which waste heat from existing operations can be used to run the capture process.

Transport and storage costs. These will normally be set by regulation, and most likely be remunerated on a pass-through or similar basis.

The carbon price. While the other components of the contract all correspond to different types of costs, the carbon price component corresponds to potential revenue. A CfD reduces payment as the carbon price rises because it is assumed that revenue will increase with the carbon price. As the carbon price rises, so should market product prices as they include carbon costs. For example steel prices should include the cost of carbon incurred by marginal producers. The value of any free allocation of allowances should also rise. However there are a number of potential complications. In particular, carbon prices may not be fully reflected in product prices, so the CCS plant owner may see little or no benefit from higher carbon prices. Under some variants, if the carbon price rises above a certain level projects may be required to make payments to government (a two-way CfD), but this is not a necessary feature of a CfD.

1.2 Changes to contract parameters

Contract parameters may change in various ways.

Changes over time. For example, payments may reduce over time to reflect expected learning both within and outside the project.

Changes in market conditions or regulation. For example, payments may change if market CO_2 prices under a carbon tax or emissions trading system go outside certain ranges. Similarly, contract provisions may change if there is a change in the form of carbon pricing, for example the introduction of carbon border adjustments.

Risk sharing. For example, there may be reduced payments if rates of return exceed a given level or outturn costs are lower than expected. Similarly, there may be an increase in payments if returns fall below a specified level, or costs are higher than expected. There may also be risk sharing through changes being passed through only in part. For example, only a portion of CO_2 prices may be passed through.

Changes may be written into the contract, or subject to re-negotiation in certain conditions (re-openers).

1.3 Contract duration

To ensure value for money for tax-payers (assumed to be the ultimate provider of funds for the contract payments), contracts should run for long enough to gain the value from operation of the plant, including benefits of reducing emissions and technological learning.

There is some convergence of length of support amongst existing or proposed arrangements, even though the type of support varies.

Table 2: Duration of support in different jurisdictions

Project location and support mechanism	Form of support	Support duration (years of operation)
Norway's Longship project	Capex and opex subsidy	10
The Netherlands SDE++	Support contract	15
UK's current proposals	Support contract	10-15, but with capital recovered in 5 years
USA 45Q	Tax credits for storage	12

Different elements of the contract may have different durations. For example, a fixed payment to remunerate capital may be of a shorter duration than a per tonne of CO_2 payment intended to cover continuing operating expenses.

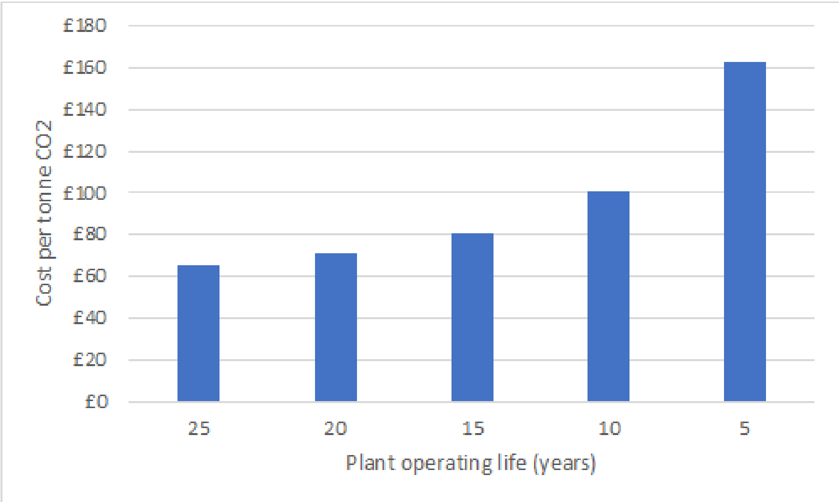
The problems with shorter duration support
Some industrial investors look for shorter paybacks on investment. Shorter paybacks may be achieved either if:

- the contract as a whole is short duration with higher payments; or
- capital costs are entirely recovered in the first few years, with only operating costs supported thereafter, in which case capture operations can cease and investment will still have been recovered.

However, very short contract durations, for example five years, are unlikely to be optimal. The project can close after the contract ends having recovered their capex, including a rate of return, and other costs, with no loss. Such an out-turn would present the following difficulties.

- The cost per tonne of CO_2 becomes very high. This is shown in the chart below using illustrative cost assumptions. Costs increase from £80/tCO_2 for a 15 years contract to £160/tCO_2 for a five year contract, assuming all capex and opex over the period is fully remunerated. This may be difficult to sustain politically, as well as being economically costly abatement.
- There will be a corresponding loss of environmental benefits if the capture plant closes after only a few years.
- Similarly, a short period of operation will lead to a loss of learning benefits that would come from more prolonged operation.
- It risks leaving transport and storage infrastructure investment stranded if capture plants cease operation early.

Chart 1: Costs of emissions reductions per tonne of CO_2 with different operating lives



Assumptions: Capex £610/ tCO_2, opex £22/tCO_2 p.a. Discount rate 5% real terms.

1.4 Broader conditionality

There may be limits on the type of project eligible for contractual support. For example, there should be a requirement that any CO_2 captured is permanently stored. Projects where carbon captured is used but not stored should not be eligible. There are strong rationales for such limitations. For example, many CCU projects result in carbon dioxide eventually returning to the atmosphere. Government will want to ensure that the project it is paying for is actually solving the problem it seeks to address, that is preventing emissions from entering the atmosphere.

There may also be basic thresholds for performance, for example maintaining a capture rate of at least 90%, and higher capture rates may be favoured in the project selection process.

Provisions in the case of factory closure will also be required.

1.5 Process and transition to a more mature market

It will usually be important to keep competitive tension between projects from the start of any CCS programme to ensure value for money and consistency with strategic objectives.

Tender processes and bilateral negotiations, rather than auctions, are likely to be required for early projects, as many considerations other than price will play a role in project selection. For example, support can be targeted at projects which meet certain strategic objectives, including demonstration in a particular sector, even where they are not the lowest cost per tonne of emissions reduction.

Under a tender process, different contract features may be tested against multiple projects, revealing which are most valued by projects. The market can thus reveal information about the perceived value of contract terms, for example whether support payments can be reduced with different indexation terms, or different payment profiles.

Contract design may also be influenced by the need to scale up to the extent required for CCS to make a substantial contribution to achieving net-zero emissions targets. In principle, the use of contracts can clearly scale-up, as demonstrated by the success of CfDs in the UK power sector. Nevertheless, it may be helpful to establish contractual arrangements that can readily be adapted to later contracts. Such features give a route to transition into a more mature market, sometimes refered to as a transition from first of a kind (FOAK) to Nth of a kind (NOAK) projects.

Auctions are also possible, and may become more appropriate as the market matures. The Dutch SDE++ approach, which is based on a competitive bidding, gives an example of an auction process. Auction processes have also become widely used for renewables. For example, in 2015 the UK replaced the previous renewables obligations with auctions for CfDs, and auctions for renewables were introduced in Germany in 2016.

2 Payments per tonne of CO_2

2.1 The need for payment per tonne of CO_2

Payment per tonne of CO_2 will likely form part of any contract because it provides incentives to operate the capture plant. Without such incentives capture plant would risk remaining idle. This would, in turn fail to maximise the environmental benefits of the project. Learning would also be reduced.

An example of what can happen in the absence of such payment is given by the Petra Nova coal fuelled power plant in the USA[1] . The capture unit operated on the basis of revenues from enhanced oil recovery (EOR). When EOR became uneconomic because of falls in the oil price during 2020 the plant temporarily stopped capturing. It had not applied for incentives under the 45Q programme, which provides a credit of $35 per tonne stored for EOR projects (the payment is $50 per tonne stored for non-EOR projects). Had these payments been in place, the capture unit would have likely continued operating.

A carbon price on emissions can also provide an incentive to operate, because the cost of these emissions can be avoided by running the capture plant. However, there remains a risk that the incentive from carbon price will be below the operating costs of capture, especially for early capture plants which are likely to have higher costs. There may therefore need to be an additional incentive to operate. The potential for over-recovery of operating costs - if carbon prices are high and there is an additional incentive payment under the contract - is reviewed later under the section on contracts for difference.

2.2 The need to base payment on emissions reductions rather than tonnes captured

Some systems base payments on tonnes of CO_2 captured or stored. For example, the 45Q tax credits in the USA are based on tonnes stored. The SDE++ support payments in the Netherlands are based on tonnes captured.

However, this creates inefficient incentives, because it provides incentives for production of additional CO_2. The undesirability of these types of incentive is recognised in the UK Government's update document of December 2020[2]. This assumes the primary objective is to avoid emissions. If the main objective is to produce CO_2, for example for EOR, then incentives to maximise volumes of CO_2 might be more appropriate. However, this is not (and should not be) the goal of CCS in Europe.

1 https://www.catf.us/2020/08/petra-nova-de-risking-carbon-capture-business-models-with-saline-storage/
2 See page 9 of: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/946561/ccus-business-models-commercial-update.pdf

A better approach is to use the reduction in emissions due to the operation of the CCS plant. This represents much more closely the actual environmental benefit of the project. It gives better incentives and a better basis for comparing projects.

These differences are now examined.

2.2.1 Payment based on tonnes captured

The incentive to produce more CO_2 is seen in its clearest form when energy is cheap. This may be, for example, due to a fall in market energy prices, or access to low costs energy, for example at a refinery. If a factory reduces output of its main product, it may continue to burn fuel and run it through the capture process, because it's profitable. It will essentially get into the CO_2 production and capture business – a "CO_2 factory".

Similarly, energy efficiency projects can become less profitable, because increased efficiency reduces energy use, and so leads to a loss of capture payments.

Stylised examples of these effects are shown in an Annex.

These incentives will not apply to payments that are not linked to tonnes of CO_2, such as a capacity or availability payment.

2.2.2 Improved incentives by estimating tonnes avoided

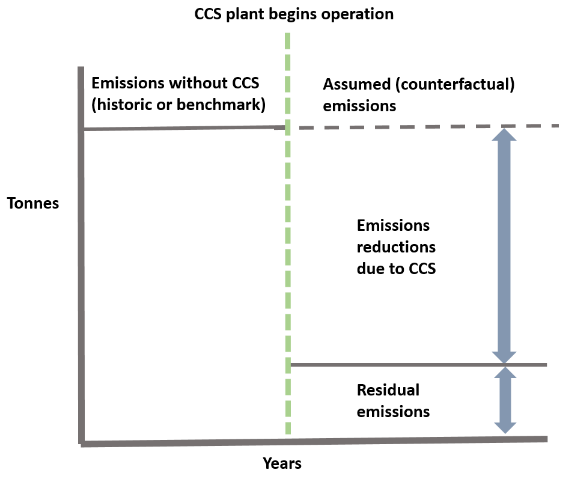
Better incentives can be created by making payments on the basis of emissions reductions due to the capture project, that is the difference between:

- what would have been efficiently emitted without the capture plant operating; and
- what is emitted with the plant operating.

That is:
Emissions without capture (tonnes) – emissions with capture (tonnes).

This represents more closely the environmental benefit from the project's emissions reductions (excluding some lifecycle emissions). This is illustrated in the chart below.

Chart 2: Schematic illustration of payment by emission reductions



Payments are not dependent directly on tonnes captured, so give no incentives for additional CO_2 to be produced. However, they do give incentives for increased capture rates, increased energy efficiency or other changes that reduce residual emissions (the 5-10% or so typically not captured).

This incentive extends to choosing the appropriate size of capture unit and efficiently operating the plant, including optimising capture rate.

The need for a counterfactual

This approach requires the emissions that would have happened without the capture plant to be estimated (the counterfactual). For example, it can be based on the following.

- Benchmark emissions per tonne of product. This could be based on benchmarks under the ETS, which already exist for most producers at risk of carbon leakage.
- Historical emissions per tonne of product from that particular plant.
- Some other metric fixed in advance.

This approach solves the problems of the examples given above as follows:

There is no incentive to burn energy to generate capture revenues. No extra revenue is earned under this approach, because the payment does not vary with tonnes captured. It is only affected by the benchmark. However, the costs are still incurred, so it becomes highly unprofitable.

No net revenue is lost by an energy efficiency project. Indeed, some may be gained due to reductions in residual emissions. Incentives are thus maintained or strengthened.

The principle of using output-based measures extends to other sectors. For example, there are proposals in the UK and discussions in the USA about awarding support per MWh for capture at power plants. This would, for example, avoid disadvantaging gas against coal plant, which has higher emissions due to its lower thermal efficiency and higher carbon content of the fuel.

Lifecycle emissions and CCU

Neither approach recognises total lifecycle emissions. In particular it does not address the problems of CCU projects where the product may be eventually returned to the atmosphere, for example by burning synthetic fuels. CCU projects of this type should be excluded from qualifying contractual support of the type described here.

2.2.3 What is the effective carbon price on residual emissions under this approach?

There is the risk of double penalty for additional emissions if payments under the CfD contract are reduced and a carbon price is also payable on residual emissions. This can be addressed simply by paying only the difference between the carbon price and the strike price on the residual emissions. Payment would be:

Benchmark emissions * strike price
– residual emissions * (strike price – carbon price)
– residual emissions * carbon price   this is the payment under carbon pricing system

This would effectively charge a higher carbon price for residual emissions. This would give stronger incentives, which may be appropriate for early demonstration projects. An alternative would be to price any residual emissions at the carbon price only. Payment would be:

Benchmark emissions * strike price
– residual emissions * carbon price this is the payment under carbon pricing system

3 Payments per tonne of CO_2

If carbon prices rise projects may benefit from:

- Higher carbon prices being reflected in higher product prices, because marginal price setting production faces a carbon price.
- Retaining free allocation of allowances under an emissions trading system, which become more valuable as their price rises

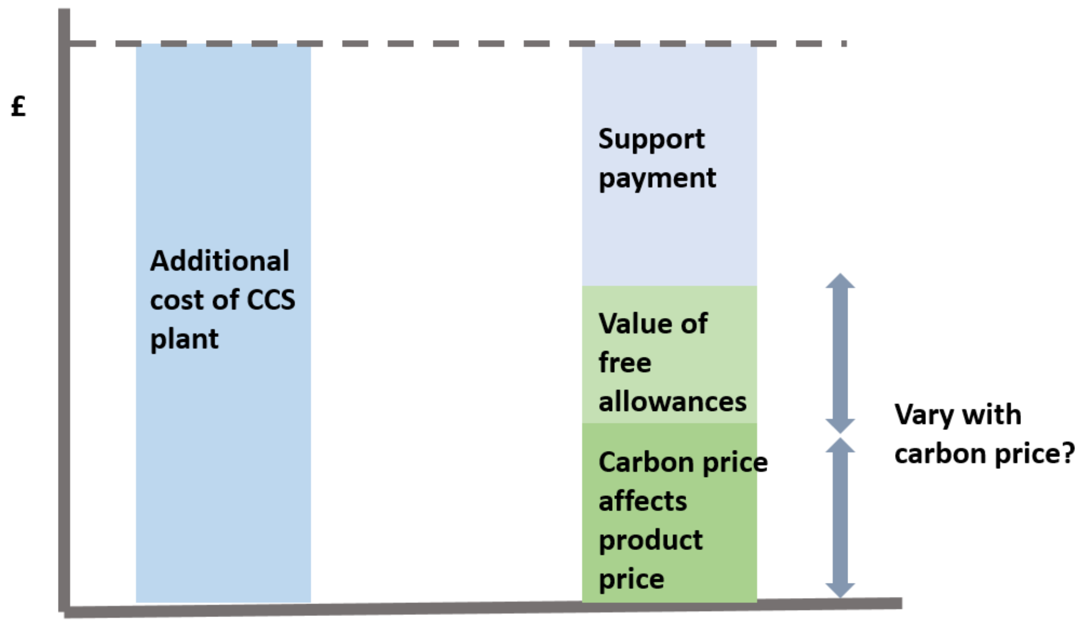
If the project benefits in this way then the required additional support is reduced (see chart).

Keeping contract payments constant while the carbon price increases risks excess profits for capture projects if the support level is set without recognising the additional value. Using a contract for difference to reduce contract payments as carbon prices increase is intended to avoid over-rewarding projects with excessive subsidy. Similarly, it is intended to avoid projects receiving too little support if carbon prices fall.

Contracts for Difference are being introduced or planned in a number of jurisdictions. They are part of the Netherlands SDE++ system, the planned UK system (though with modifications – see below) in Portugal (for electrolytic hydrogen) and elsewhere in the EU. Because the contracts are written on the carbon price they are sometimes referred to as Carbon Contracts for Difference (CCfDs).

However, if the carbon price does not affect product prices and no free allowances are retained there may be no need for a CfD in the carbon price, because the carbon price has little effect on project profitability.

Chart 3: Possible need to vary support payments with the carbon price



The circumstances in which projects may benefit from higher carbon prices are summarised in the table, and described further below.

In some cases, the effect of the carbon price will result from regulatory change and so will best be addressed by a contract re-opener, which may include introducing terms for a CfD.

Table 3: Cases in which carbon price changes may affect the need for support

Market prices for product	Value of assets
Non trade-exposed product allows carbon prices to be passed through	Allocation of free allowances is retained by project (perhaps with volume guarantees)
Carbon Border Adjustments may increase commodity prices	
Carbon regulation in other countries may price carbon to marginal production	
Low carbon product markets, including procurement rules, may allow a price premium for low carbon product to be realised	

3.1 Carbon cost in the product price

Carbon costs may become part of prices in product markets, such as steel. The producer with CCS may then benefit from higher carbon prices through higher product prices with few additional costs. Carbon costs may form part of product prices in a number of circumstances, which are now outlined

Non-trade exposed product. In non-emissions intensive trade exposed sectors, carbon prices may be passed through because international competition is not enough to prevent this, and so the threat of carbon leakage is much lower. Electricity prices in Europe currently include costs from carbon prices because the electricity price is set by local competition among producers, which are all subject to a carbon price. Other producers not subject to international competition may similarly see a carbon price in product prices. This is why the free allocation regime for emissions intensive trade exposed industry in the ETS (sectors at the risk of carbon leakage) differs greatly from that for other sectors.

However, electricity intensive products will not see the benefit of carbon pricing in their product unless price setting producers in other jurisdictions also face carbon pricing. This has been recognised in the provision of financial support to electricity intensive industry.

Carbon border adjustment mechanisms (CBAMs) may lead to the carbon price being reflected in product prices because all producers – importers and local producers - will pay a carbon price. CBAMs remain under discussion in the EU and UK. It is unlikely that they will apply to most products, at least at first, being restricted to commodities, perhaps including electricity, iron and steel, cement, fertilisers and aluminium, as well as power generation. However, these may be sectors with CCS projects, so the CBAM will be relevant.

Carbon regulation in other countries may increase the prices for a commodity. This may not necessarily be in the form of carbon pricing in other jurisdictions. Other mechanisms, for example product standards, may increase costs.

Markets for low carbon products. There may be a market premium from regulations which limit the carbon content of product. For example, building regulations may require the use of low carbon steel. Such measures are in their early stages, but may be in place within the duration of a support contract.

In principle, as carbon prices rise over time and the costs of new-build CCS decrease, avoiding paying carbon prices will be sufficient in itself to incentivise the installation of CCS at industrial facilities; provided a CO_2 infrastructure is in place. This could avoid the need for subsidy entirely, although regulatory involvement in the CCS chain will still be required and allocation of risks will remain an important issue.

However, it is not clear at the moment that carbon pricing will be reflected in the prices of products as a result of the circumstances outlined above. Prices might continue to be set in international markets in ways that do not include a carbon price, for example because carbon may not be priced in the jurisdiction where marginal production is located. Producers within the EU have long received free allocation of allowances under the EU ETS to recognise this, and the corresponding risk of carbon leakage. If product prices are not higher due to the carbon price, then higher carbon prices do not necessarily benefit the industrial emitter with CCS.

It is likely to be necessary to recognise these uncertainties at least in the design of early subsidy contracts. In the medium to longer term product prices may reflect more fully the cost of carbon, and therefore low carbon producers such as those with CCS see the benefits of investing in low carbon production. The Dutch SDE++ regulations already make an adjustment for higher carbon prices.

3.2 Free allocation under a UKETS

Free allocation under the UK emissions trading system (UKETS) is expected to closely resemble that under the EUETS. Whether or not the free allocation of allowances is retained affects the required level of contract support for a carbon capture project. There are various options, which are set out in the table and discussed further below. These have different implications for:

- Whether the value of free allowances is retained by project or government (or neither)
- The exposure to allowance price risk
- Exposure to risks of a varying volume of free allowances. Volume can vary over time as allocation changes under an ETS. Changes in volume may be predictable in the short term while rules remain defined, but unpredictable in the longer term as regulations change.

Table 4: Options for allocation of free allowances to a capture project

	Project retains free allocation		No free allocation of allowances to project	
	No CfD	CfD	Allowances are issued and retained (or clawed back) by government	Allowances are not issued
Revenue to project from sale of free allowances?	Yes	Yes	No	No
Carbon price risk for project?	Yes	No (small residual risk)	No (small residual risk)	No (small residual risk)
Free allocation volume risk due to ETS rules?	Yes	Yes	No	No
Revenue for government to reduce net support costs for taxpayer?	No	No	Yes	No

Retention of free allocation – no CfD
In this case, subsidy meets part of the costs of the capture project, with the remainder being absorbed by the project owner (or met by revenue from the sale of those free allowances that are no longer needed because the CCS plant is operating). Carbon price risk remains with the project, because the revenue from sale of free allowanced depends on the carbon price. The net cost of subsidy to government is reduced by the expected value of the free allowances for the project.

Under this approach, contract terms may need to address the volume risk from free allocation, because if the allocation of allowances changes the profitability of the capture project will also change.

Something like this approach is applied in the Norcem capture project, part of the Norwegian Longship project. The project is subsidised by government (though not by a contractual payment per tonne), with subsidy covering 75-80% of costs. The project retains free allowances, which can be sold to cover remaining costs. (The site will also need allowances to cover other emissions from the site, as only about half are part of the capture project.) As there is no CfD on the carbon price the project retains carbon price risk.

One important consideration is that implementing CCS should result in no reduction of benchmarks for free allocation, unless that loss is compensated for by additional support. If the benchmark were to reduce, support based on the assumption of continuing free allocation of allowances would not provide sufficient funding.

Free allocation is retained along with a CfD
Under this option, like the previous option, a subsidy meets a part of the cost of CCS with the remainder met by the sale of free allowances. However, in this case a CfD fixes the price of freely allocated allowances removing carbon price risk from the project. The net cost of the subsidy to government is reduced by the expected value of the free allowances to the project and again contract terms need to address free allocation volume risks.

In any case there is some residual carbon price risk due to the small residual amount of emissions (typically 5-10% of the total) will remain. For those projects where only a proportion of emissions from the site go into the capture unit (the rest being emitted), the carbon price risk is greater. If a project currently has net carbon costs, because free allocation covers less than 100% of its emissions, there is also an additional carbon price risk without CCS.

Any CfD will need to be robust to regulatory changes affecting the carbon price, for example, if other taxes are implemented.

This is similar to the approach used in the SDE++ programme in the Netherlands. Projects retain free allowances.

Removal of free allocation and allowances aren't issued
If free allowances are removed from the project owner the subsidy will need to meet the cost of CCS in full. This removes carbon price risk from the project because there are no free allowances to vary in price.

If allowances are never issued they are not available for government or others to auction. This increases the net cost to the taxpayer compared with the case where allowances are issued and can be auctioned (assuming no significant effects on the market price).

Removal of free allocation and allowances are issued and auctioned by government
The net cost of the subsidy to government is potentially reduced by auction revenue from selling allowances not allocated to projects. However, to secure this there is a need to ensure that the allowances are issued, and that they return to government, and can subsequently be sold.

Proposals in the UK include a provision that payments will be given to the project to represent the value of the free allowances removed at an assumed carbon price path, and perhaps with volume guarantees. However, because this payment is determined in advance it becomes rather like any other form of fixed contractual payment.

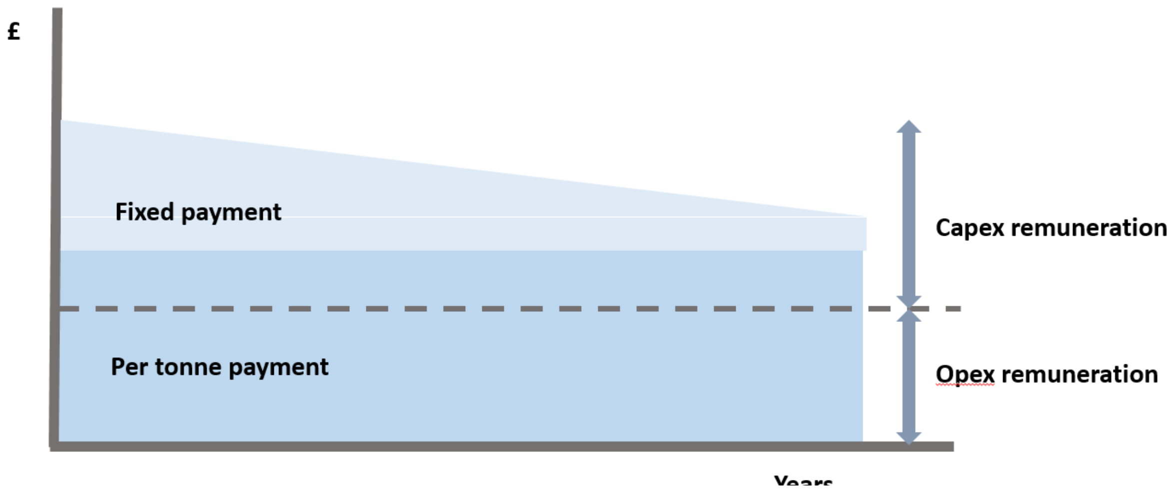
4 Fixed payments

Some payments may not depend on the quantity of CO_2 avoided or captured. Instead payments may be fixed and either:

- made automatically on an annual basis; or
- subject to the test of plant availability.

This type of mechanism enables recovery of some of capital costs (and any long term fixed operating costs) from a fixed annual payment. The per tonne payment continues to cover variable operating costs and some proportion of fixed costs. This is illustrated in simplified form in the chart. In practice payment per tonne would likely vary as production and other conditions changed.

Chart 4: Schematic representation of different components of payment



Note: not to scale

This potentially reduces the risks for the project investor because payments are not subject to fluctuations in CO_2 volumes. These may due to, for example variations in factory output arising from changes in market demand or production scheduling, and thus the amount of CO_2 produced by the factory process.

Any fixed payment is likely to give better outcomes if it covers at most only a proportion of fixed costs, as illustrated in the schematic diagram above. Covering all of its fixed costs would reduce incentives to complete, maintain and operate the plant, potentially leading to closure when the fixed payments expire. Continued operation produces environmental benefits from capturing additional CO_2, and value from learning. There may also be political challenges to expensive plants not running.

The value of fixed payments to projects is likely to be particularly high if these can be front loaded, as this increases rates of return and reduces payback periods for commercial investors. This can potentially provide better value for money for the government, provided there is sufficient competitive tension between projects applying for support to ensure that the value of additional upfront payments to projects is recognised.

However, there is a countervailing risk of very early repayment of capex, which may reduce incentives for continuing operation (even though capital costs are already sunk), as the plant operator will already have recovered costs and future incentives will be lower. Capex recovery periods need to be at least 10 years to keep unit costs to acceptable levels (see Section 1).

Reductions in fixed payments over time may be stepped, for example reducing every five years, or more continuous, for example an annual reduction.

Front loading can be applied to fixed payments per tonne of CO_2, but is most clearly relevant for fixed payments, as it has the greatest value in increasing return to capital.

Closure provisions analogous those to those under the EU ETS may be necessary to deal with what happens in the event of plant closure.

A hybrid of fixed and per tonne payments
The current UK proposals include a variant where payment per tonne of CO_2 is used to remunerate capital, but only up to the fixed amount of the capital invested (including some allowance for rate of return). Further CO_2 capture in that year does not increase payment. If capital costs are not recovered in one year, because CO_2 volumes are low for some reason, they can be made up in subsequent years.

This has elements of both fixed and per tonne payments. It has properties intermediate between the two.

4.1 Capital grants

Fixed payments have some characteristics in common with capital payments to the project during construction. Both can provide valuable upfront cash and are independent of the throughput of the capture plant (and therefore the tonnes of CO_2 produced and captured). As fixed payments and capital payments provide similar benefits, they can to some extent substitute for each other. Consequently, a decision to provide capital payments for a project may reduce or eliminate the need for fixed payments.

Capital payments can take several forms. These include grants, loans or lower cost equity. Each has potential benefits, but also associated risks. The benefits arise because higher private sector discount rates mean that upfront cash is more valuable to private investors than costly to the State. Savings can be large for long-lived projects, depending on the relative cost of capital.

However, there are also associated risks the project may fail to deliver, or deliver late, or cost may overrun. Depending on the structure of the support these can create a substantial financial exposure for the funder. An extreme version of these risks can be seen in the Kemper County CCS project in Mississippi in the USA. In this project $7.5 billion was spent on a CCS project based on gasification of low quality coal. In the event the project was never completed and instead a gas plant without CCS was built. The $7.5 billion was essentially wasted. The gas plant had similar emissions to the planned coal plant with CCS, due to the relatively low capture rates and high carbon content of the coal.

These risks can be reduced by choice of terms on which capital is provided, for example, by giving repayment of low-cost loans first priority from any cash flows, or recourse to investor balance sheets.

5 Risk sharing and avoiding overcompensation

5.1 Risks of over or under rewarding projects

The capture project may be financially under-rewarded or over-rewarded (on a risk adjusted basis) if contract payments are out of line with market conditions. For example:

- Costs may turn out differently than expected. CCS is a relatively immature technology and not currently deployed in Europe, with little deployment in industry globally, so uncertainties in costs are inevitably large.
- There may be unanticipated regulatory changes. For example, there may be changes to carbon pricing which affect the cost of residual emissions, or market price for products.
- There may be changes to end markets for the product. For example, a chemicals plant may experience reduced demand for its product that may affect the profitability of the capture plant.

For example, as noted in Section 3, unanticipated benefits from carbon pricing risk the project earning surplus returns (windfall gains) because it benefits from both the support contract and a rise in product prices. The most prominent example of such windfall gains to date is free allocation to the power sector under the phases one and two of the EUETS, when power generators were allocated EUAs free of charge, and generators also benefited from carbon costs being passed through to electricity prices. This resulted in windfall gains of billions of euros.

A contract for difference is intended to eliminate these risks. However, as noted, there is then the reverse risk that the benefits to the producer do not occur as expected, and the project is disadvantaged by the CfD reducing payments without the project realising benefits.

5.2 Measures to address or share these risks

Risk sharing measures can be included in contracts. For example, there may be varying payments depending on:

- realised rates of return on investment; or
- out turn costs.

Some arrangements of this type are included in the Norwegian Longship project[4] as follows:

Rates of return. Risk sharing is asymmetric. There does not appear to be any clause that declares the State's obligation to cover outcomes with rates of return below defined levels. However there are provisions for returns above a certain level. For capture, when the level of return on investment is initially reached, the operational funding is reduced and eventually stopped entirely. Fifty per cent of net cash flow over and above the agreed “level of return 1” is shared with the state and 75 per cent of net cash flow over and above “level of return 2” is shared with the State. (What levels of return 1 and 2 are is not stated.)

Cost over-runs. For the Norcem capture project investment costs the State will cover costs up to a stipulated level. Above this level, the state will cover 75 per cent of the costs up to the maximum budget. For operating costs, the state will cover 100 per cent of all annual operating costs up to an agreed level. The state will cover 75 per cent of all operating costs above the agreed level, up to the ten-year maximum budget.

The UK's current proposals are considering such arrangements for power projects. They are also looking at the possibility of re-openers for opex payments for industrial capture projects, although this does not at the moment appear to extend to capital.

There may also be price re-openers in contracts that are triggered in specified circumstances, for example regulatory change.

6 Concluding Remarks

Contracts to remunerate the use of low carbon technologies can be a powerful mechanism for stimulating their deployment, because they give a firm revenue stream that enables companies to invest. However, as with many commercial contracts, there is a range of risks that need to be allocated and a variety of incentives that will be created. Careful consideration of contract structures and terms is necessary in designing effective policy in this area.

Annex: Example of incentives due to tonnes captured

If natural gas costs around £10/MWh, it costs just under £60 to make a tonne of CO_2 for capture. If incentive payment for capture are £80/tCO_2 (excluding transport and storage) making CO_2 for capture is profitable even allowing for some non-fuel operating costs. (Historic natural gas wholesale prices have mainly in the range 9-26/MWh over the last decade[5] , although they fell below this range in 2020.) The table below shows this calculation. This does not happen if payments are based on emissions savings (see below).

Table 5: illustrative calculation of incentives to produce more CO_2

Tonnes of CO_2/MWh fuel (GCV)	0.184
Fuel to produce 1 tonne CO_2 (MWh)	1/0.184 = 5.43
Fuel used per tonne CO_2 captured assuming 95% capture efficiency (MWh)	5.43/0.95 = 5.72
Fuel cost (£/MWh GCV)	10
Cost of fuel per tonne CO_2 captured (£/tCO_2)	5.72*10 = 57.2
Non fuel opex per tonne captured (£/tCO_2) including compressor costs	12
Cost of uncaptured emissions at 95% capture and £40/tCO_2 (£/tCO_2)	2
Total costs per tonne captured (£/tCO_2)	57.2 + 12 + 2 = 71.2
Revenue per tonne captured (£/tCO_2)	80 **THIS REVENUE DOES NOT EXIST WITH ALTERNATIVE APPROACHES, SO COSTS ARE NOT RECOVERED**
Profit per tonne captured (£/tCO_2)	8.8

Assumptions: Natural gas cost £10.00 per MWh. No additional costs from producing energy to run the capture process, as equipment is already in place and the energy from the additional fuel burn here is sufficient. There may be some additional electricity costs for running compressors. There are also some incremental non-energy operating costs in running the capture unit. These are assumed £12/tonne including any additional electricity costs. Carbon captured receives a payment of £80 per tonne captured. The 5% not captured pays a carbon price of £40/tonne.

A less extreme form of this type of incentive can be seen by looking at an energy efficiency project. In the illustrative example shown below, improved energy efficiency is economic based on fuel cost savings alone, by £4/MWh. However, there is a loss of revenue from incentive payments due to smaller volumes of CO_2 being captured, which is only partly offset by savings in capture plant operating costs. This loss of revenue leads to a financial loss on the efficiency project of £5/MWh. This makes the project uneconomic. Again, this does not happen if payments are based on emissions saved.

5 Approximately 25-75 p/th. See https://www.ofgem.gov.uk/data-portal/all-charts/policy-area/gas-wholesale-markets

Table 6: Incentive not to improve energy efficiency

Cost of energy efficiency per MWh saved (£/MWh)	6
Fuel cost saving (£/MWh)	10
Profit per MWh saved	**4**
Reduction in tonnes captured per MWh saved	0.175
Loss of incentive payment at £80/tCO_2 (£/t)	14.0 **NO PAYMENTS ARE LOST UNDER ALTERANTIVE APPROACHES SO ENERGY EFFICIENTY REMAINS PROFITABLE**
Savings in capture plant operating costs	5.0
Profit per MWh saved	**4 – 14 + 5 = -5 (now makes a loss)**