Department for
Business, Energy
& Industrial Strategy

Low Carbon Hydrogen Business Model: consultation on a business model for low carbon hydrogen

Closing date: 25 October 2021

August 2021

Any enquiries regarding this publication should be sent to us at:
Hydrogen.BusinessModels@beis.gov.uk

Introduction

In our response to the consultation on business models for Carbon Capture, Utilisation and Storage (CCUS) in August 2020 we confirmed our intention to develop a business model to incentivise the production and use of low carbon hydrogen in the UK. Alongside the consultation response, we published a BEIS-commissioned report from Frontier Economics into possible support mechanisms for large-scale hydrogen producers. In December 2020, we provided an update on hydrogen business model policy development as part of a wider update on CCUS business models, where we said we would “aim to consult on a ‘preferred’ hydrogen business model, or models, in Q2 2021”.

Working with stakeholders via the Hydrogen Advisory Council, the Hydrogen Business Model Expert Group, and directly with specific projects and interested parties, we have been building on the work set out in those documents to identify a preferred way forward for low carbon hydrogen business model policy development. The aim of the business model is to overcome one of the key barriers preventing the deployment of low carbon hydrogen projects, namely the cost gap between low carbon hydrogen and higher carbon counterfactual fuels. This consultation sets out our approach to the business model design, proposed positions on key design features, and other considerations. This consultation affects stakeholders involved in low carbon hydrogen project development, and wider energy and net zero policy.

Contents

General information

Why we are consulting

The purpose of this consultation is to set out our proposed business model that is intended to support deployment of low carbon hydrogen projects. We are seeking views from stakeholders on the design choices that make up the main elements of the business model.

Consultation details

Issued: 17/08/2021

Respond by: 25/10/2021

Enquiries to: Hydrogen.BusinessModels@beis.gov.uk

Consultation reference: Consultation on a business model for low carbon hydrogen

Audiences:

We are seeking views from stakeholders with an interest in low carbon hydrogen. This includes (but is not limited to) project developers, financial investors and trade associations.

Territorial extent:

The scope of this consultation is UK-wide. Our preferred approach is for the business model to be funded and delivered on a UK-wide basis to support decarbonisation across the UK. We will continue to work with the devolved administrations as we develop and finalise the business model.

How to respond

Respond online at: https://beisgovuk.citizenspace.com/clean-growth/hydrogen-business-models

or

Email to: Hydrogen.BusinessModels@beis.gov.uk

Write to: Please do not send responses by post to the department at the moment as we may not be able to access them.

When responding, please state whether you are responding as an individual or representing the views of an organisation.

Your response will be most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

Confidentiality and data protection

Information you provide in response to this consultation, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018 and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential please tell us, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not individuals' names, addresses or other contact details.

Quality assurance

This consultation has been carried out in accordance with the government's consultation principles.

If you have any complaints about the way this consultation has been conducted, please email: beis.bru@beis.gov.uk.

Executive summary

The Prime Minister's *Ten Point Plan for a Green Industrial Revolution*, published last November, set out an ambition to deploy 5GW of low carbon hydrogen production capacity by 2030. As outlined in the Hydrogen Strategy published alongside this consultation, a range of market barriers are currently inhibiting the development of the low carbon hydrogen economy. The business model design we set out in this consultation aims to overcome one of these barriers, namely the higher cost of low carbon hydrogen compared to high carbon counterfactual fuels. The business model should be seen as one of a range of government interventions intended to facilitate the deployment of low carbon hydrogen projects that will be necessary to meet Carbon Budget 6 and net zero targets.

In section 1, we set out our overall strategic objectives, re-state the need for revenue support and identify the key contextual issues relevant for business model design. In section 2, we establish the proposed overarching parameters of the business model design and our rationale for directing support towards the production of hydrogen. We propose that its scope covers a range of hydrogen production technologies and possible end users, in line with the position set out in the Hydrogen Strategy. We propose the delivery mechanism to be private law contracts between hydrogen producers and a government counterparty.

In section 3, we set out our objectives of the business model, building on those outlined in previous publications, and describe our approach to the design of the model by focusing on the two key risks faced by investors in hydrogen production facilities. These are market price risk – the risk that the price received by hydrogen producers for their product is lower than their cost of production; and volume risk – the risk that volume of sales falls below a level that allows producers to recover their production cost.

In section 4, we set out options for addressing price risk and propose proceeding with a 'variable premium' price support mechanism. This involves setting a 'strike price', which is intended to represent the price that the hydrogen producer needs to achieve to cover their production costs, and a 'reference price', which is intended to represent the market value of hydrogen. This mechanism better achieves our overall objectives than the alternatives considered, namely fixed price and fixed premium mechanisms.

The key challenge with a variable premium mechanism is setting the reference price in the absence of an observable market benchmark price for low carbon hydrogen. We set out seven options for identifying a 'proxy' value that can be used as a reference price. We put forward our position that, for initial projects, a mechanism deploying the highest of two proxies – natural gas price and achieved sales price – would best meet our overall policy objectives, combined with additional contractual measures to incentivise producers to seek higher priced sales. For future projects, we propose to integrate a market benchmark price into the reference price at the earliest opportunity.

The final feature of the price support mechanism is indexation of the strike price. Hydrogen production requires an input fuel, such as natural gas or electricity, and the price of those input fuels will, in many circumstances, vary across time. This variation will affect the cost of production and therefore investability of a production plant. We set out options for indexation.

Section 5 sets out options for addressing volume risk. We propose a 'sliding scale' mechanism. This works by managing volume risk through the price received by a producer for different volumes of hydrogen. It would pay a higher level of price support on initial volumes, allowing the producer to recover fixed costs at relatively low offtake volumes. The level of price support would taper off as volumes increase, with last volumes recovering only marginal costs and equity returns. We consider this best meets our overall objectives in comparison to the alternatives considered, namely availability-based and ‘take or pay’ mechanisms.

Section 6 summarises our proposal for the business model to incorporate different production technologies, as opposed to separate mechanisms for different technologies. We also set out our reasoning behind proposing not to bring forward a separate business model for smaller scale hydrogen projects.

In section 7, we set out our current thinking with respect to other important business model design features including contract length, volume scaling, treatment of other key risks, and compatibility with other revenue support policies. In section 8, we propose a near-term allocation process for initial projects not part of the CCUS cluster sequencing process. Section 9 considers the issue of funding of the business model. Finally, section 10 outlines our proposed approach to interactions between the business model and the near- and medium-term needs relating to hydrogen distribution and storage.

We intend to provide a response to this consultation, details on the allocation process for initial projects not part of the CCUS sequencing process, and indicative Heads of Terms in Q1 2022.

The consultation is supported by an ‘Analytical Annex’ which provides further supporting evidence for this and other consultations being published alongside this one.

Section 1: Background and rationale for the hydrogen business model

Section 1 outlines the strategic context for introducing a hydrogen business model, re-states the need for revenue support and sets out the key contextual issues and challenges that need to be considered in the design of the hydrogen business model.

1.1 Strategic objectives and context

Low carbon hydrogen will be critical for meeting the UK's legally binding commitment to achieving net zero by 2050. It has the potential to play a role in decarbonising vital UK industry sectors and provide flexible deployment across heat, power and transport. There are uncertainties around the exact role of hydrogen in 2030 and out to 2050, including the likely split of production methods and scale of demand and deployment in different sectors. However, it is likely that significant volumes of low carbon hydrogen will be needed to support our net zero target. Analysis by BEIS on Carbon Budget 6 (CB6) suggests 250 – 460 TWh of hydrogen could be needed in 2050[1], meeting 20-35% of total energy demand.[2]

As set out in the Prime Minister's *Ten Point Plan for a Green Industrial Revolution*, working with industry the UK is aiming for 5GW of low carbon hydrogen production capacity by 2030. One of the measures noted by the plan for achieving this is the introduction of a hydrogen business model, which is the subject of this consultation. The objective of the business model is to incentivise the production and use of low carbon hydrogen through the provision of ongoing revenue support.

Alongside this consultation, the government has published further documents (the Strategy Package) building on the Ten Point Plan.

- **Hydrogen Strategy**: this sets out a series of commitments and actions which show how government, in partnership with industry, the innovation community, and wider civil society, will deliver our vision for a UK hydrogen economy in 2030 and beyond.[3]
- **Net Zero Hydrogen Fund (NZHF) consultation**: this sets out the proposed scope, design and delivery of the £240 million NZHF, which intends to make grant funding available to support the capital costs of developing and building low carbon hydrogen production projects.[4]
- **Low Carbon Hydrogen Standard consultation**: this sets out options for an emissions standard that could underpin the deployment of low carbon hydrogen for use across the

[1] Based on pathways to cut emissions by 78% by 2035, as agreed under CB6. More information can be found at: https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
[2] Hydrogen as a proportion of final energy consumption in 2050 in agriculture, industry, residential, services and transport sectors. Excludes energy demand for resources, processing and electricity generation.
[3] For more information, see the Hydrogen Strategy, which can be found at: https://www.gov.uk/government/publications/uk-hydrogen-strategy
[4] For more information, see the NZHF consultation, which can be found at: https://www.gov.uk/government/consultations/designing-the-net-zero-hydrogen-fund

economy. One of the objectives of the standard will be to ensure that hydrogen projects supported by government are consistent with our net zero ambitions.[5]

To grow from a very low base of low carbon hydrogen production and use at present to meeting our ambition of 5GW by 2030 will require rapid and significant scale up. As detailed in the Hydrogen Strategy, the UK is well positioned to take advantages of the opportunities presented by low carbon hydrogen, delivering clean growth opportunities across the UK. We can realise these opportunities if we put in place the necessary policy environment and support to facilitate investment in hydrogen projects, develop robust supply chains, upskill our people, and secure high-quality jobs.

The above Strategy Package aims to provide investors with greater confidence in long-term policy and details the actions required to bring forward investments in hydrogen projects. Our overall approach is to ensure optionality to deliver a range of credible pathways to 2050, bringing forward multiple hydrogen technologies and end use applications that could support our 2030 5GW ambition as well as CB6 and net zero targets.

1.2 The need for a hydrogen business model

1.2.1 Market barriers across the value chain

We recognise that significant barriers across the value chain are inhibiting the widespread deployment of low carbon hydrogen. The main barriers relevant for hydrogen adoption include:

- high cost of low carbon hydrogen relative to high-carbon alternatives
- high technological and commercial risks for investment in 'First-of-a-Kind' projects
- demand uncertainty due to current limited use of low carbon hydrogen
- lack of market structure and long-term policy and regulatory framework
- distribution and storage barriers, reflecting the current lack of hydrogen distribution infrastructure and sufficient carbon capture and storage
- policy and regulatory uncertainty, including the lack of established standards to define low carbon hydrogen

These barriers are linked to market failures, where the free market results in outcomes that are not optimal at a societal level, including the presence of a negative externality linked to carbon (due to the social cost of carbon emissions not being captured in the market for high carbon fuels) and the lack of coordinated investment across the supply chain.

A range of policy interventions across the value chain will be necessary in the 2020s to help overcome these barriers and market failures, enable projects to get off the ground, and support the growth of a sustainable and resilient UK hydrogen market. Acting now will stimulate hydrogen supply chains to help us meet our 5GW ambition and put us on a credible trajectory that aligns with a pathway to our carbon reduction targets. Further details on the key barriers

[5] For more information, see the Low Carbon Hydrogen Standard consultation, which can be found at: https://www.gov.uk/government/consultations/designing-a-uk-low-carbon-hydrogen-standard

and failures to hydrogen deployment, and how they affect different parts of the value chain can be found in Chapter 2 of the Analytical Annex.[6]

1.2.2 Revenue support to overcome hydrogen cost competitiveness barriers

In our response to the consultation on business models for CCUS published in August 2020[7], we committed to progressing the development of a business model to support the at-scale deployment of low carbon hydrogen in the 2020s. We also confirmed that the cost gap between low carbon hydrogen and cheaper high-carbon counterfactual fuels – which is one of the most significant barriers to the adoption of low carbon hydrogen – will be the key focus of the business model.

As such, low carbon hydrogen can only be considered as a decarbonisation option if it is affordable. Producing and selling hydrogen is currently more expensive than most high-carbon fuel alternatives, which deters widespread hydrogen adoption. This means that in the absence of government intervention it is unlikely that hydrogen producers would choose to invest in new low carbon production facilities as the high costs they face mean that it is not possible to make a return on their investment. While this lack of cost competitiveness might fall away over time, in the short term not only will low carbon hydrogen need to compete against cheaper alternatives for end users such as electricity, natural gas or biomass, but it will also rely on them for production inputs.

We have considered how to best overcome this cost barrier by focusing on the design of ongoing revenue support provided through the business model. The objective of revenue support is to help make hydrogen a price competitive decarbonisation option to encourage users to switch to low carbon hydrogen. The following sections of this consultation set out our proposed revenue support approach and preferred commercial design.

1.2.3 Need for a bespoke hydrogen business model

We consider that a bespoke hydrogen-specific business model is required to meet our strategic objectives. This is because existing policies that could have a bearing on low carbon hydrogen (outlined below) are neither expected to provide sufficient investment signals in the near term, nor are designed to bring forward a diverse range of low carbon hydrogen projects in line with our strategic deployment objectives.

- **Carbon pricing**: higher carbon prices and an extension of the UK Emissions Trading Scheme (ETS) to the transport and domestic heat sectors of the economy could help address the cost gaps and send clear investment signals. However, the carbon price is unlikely to be sufficient in the near term to close the cost gap and incentivise end users to replace fossil fuels, nor to address the other risks and barriers associated with early hydrogen production projects. Decisions are yet to be taken regarding the future scope of the UK ETS and the adoption of carbon pricing across wider end uses.[8]

[6] For more information, see the Analytical Annex, which can be found at: https://www.gov.uk/government/publications/uk-hydrogen-strategy
[7] For more information, see the government response: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/909706/CCUS-government-response-business-models.pdf
[8] In the Industrial Decarbonisation Strategy published in March 2021, we have committed to carry out a review of the UK ETS in 2021. This will include consulting on a net zero consistent emissions cap; reviewing the long-term role of free allowances; exploring expanding the scope of the scheme to cover more sectors of the economy and linking with other schemes internationally; and considering the case for a supply adjustment mechanism.

- **Renewable Transport Fuel Obligation (RTFO)**: this scheme provides revenue support to promote biofuels and renewable fuels, including low carbon hydrogen. However, support is limited to renewable hydrogen for supply into the transport sector.

- **Industrial Carbon Capture (ICC) Business Model**: this policy is being developed with the aim of making it commercially viable for existing and future industrial facilities to decarbonise, including those currently producing carbon intensive hydrogen, where carbon capture may be the preferred route to decarbonisation.[9] However, the ICC business model is not well suited to support new-build CCUS-enabled hydrogen production plants. This is because the ICC business model is focused on supporting investment in carbon capture retrofits and is not designed to compensate for the additional costs of hydrogen production or to incentivise hydrogen use.

- **Capital support**: 'one-off' capital support to hydrogen producers, such as through the NZHF, and/or to hydrogen end users[10] can be beneficial to encourage and accelerate hydrogen deployment and uptake. Capital support is, however, unlikely on its own to incentivise supply and use of hydrogen without support to overcome the high ongoing costs of producing and using hydrogen, with some exceptions.[11] Many projects are still likely to require ongoing revenue support as they face the risk that the price at which they sell or buy their hydrogen on the market is less competitive than counterfactual fuels, which will deter investment.

Therefore, a new revenue support model is needed to bring forward a diverse range of low carbon hydrogen projects by making projects an investable proposition.

1.2.4 Complementary interventions across the value chain

By bringing down the costs of supplying and using hydrogen relative to high carbon alternatives, the revenue support will help to address one of the major barriers preventing hydrogen uptake. Although the focus of this consultation is on the design of revenue support, we recognise that cost-effective scaling up of hydrogen deployment will also require concerted action to address other market barriers across the entire hydrogen value chain. As set out in the UK Hydrogen Strategy, government is progressing a range of actions in parallel to the hydrogen business model to ensure that the broader enabling environment, including regulation, policies and incentive mechanisms, is put in place to kickstart the hydrogen economy.

1.3 Key contextual issues relevant to business model design

The business model design outlined in this consultation has considered the complexities of the hydrogen value chain and the technical and economic characteristics of projects in order to maximise the effectiveness of the proposed policy. The following key features are described in more detail below:

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[9] For more information see the ICC business model update from May 2021, which can be found at: https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models

[10] For example, end user grants are offered under the Industrial Energy Transformation Fund (IETF) and Zero Emission Bus Regional Area (ZEBRA) scheme.

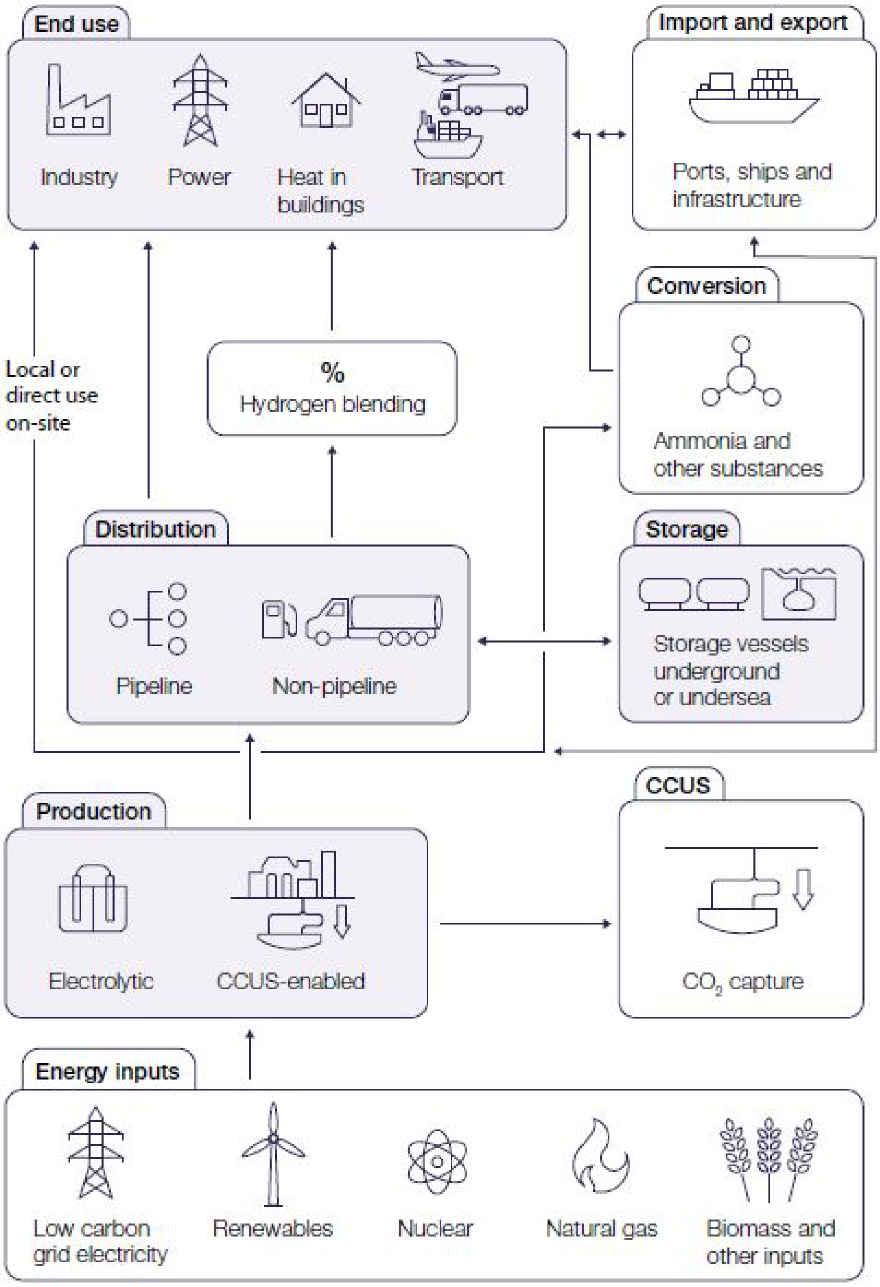
[11] For example, there might be cases in which end users are prepared and able to pay a price premium to switch to low carbon hydrogen, or cases where low carbon hydrogen may be cost-competitive with high-cost fuels (e.g. diesel) and where switching costs are minimal.

- the nascent and complex low carbon hydrogen value chain
- the different market values of hydrogen depending on its use
- the different hydrogen production characteristics

1.3.1 The nascent and complex low carbon hydrogen value chain

The low carbon hydrogen value chain is both nascent, in that hydrogen use today is limited mostly to existing feedstock applications, and complex, in part due to the versatile nature and many possible end uses of hydrogen. The value chain is also long, stretching across input fuels, production technologies, distribution and storage, end uses, and links with related economic activities (e.g. natural gas and electricity markets and networks).

Figure 1: The hydrogen value chain



The Hydrogen Strategy and Analytical Annex describe in detail the different components of the value chain. For business model design, the most important points to note are:

- Hydrogen must be produced from an input energy source. As we scale up low carbon hydrogen through the 2020s, we expect the main production methods to be methane reformation with carbon capture using natural gas, and electrolytic hydrogen using low carbon electricity. These production methods create system dependencies, for example with CCUS networks and natural gas markets for CCUS-enabled hydrogen and with electricity systems for electrolytic hydrogen.
- Production technologies are at varying levels of technological maturity. In addition, a single project can vary in capacity, from sub-1MW electrolysers to gas reformers at 500MW and above. Electrolytic technologies are modular, allowing for flexible sizing to meet demand.[12]
- Limited physical infrastructure exists for hydrogen distribution and storage.
- Very little low carbon hydrogen is produced and consumed in the UK today. Low carbon hydrogen is not therefore a traded commodity with an observable wholesale market price.
- Hydrogen is mostly used as a chemical feedstock. However, hydrogen as an energy vector has a wide range of potential applications in industry, transport, electricity generation, heating, each at varying levels of technical maturity. Users' ability to pay, and how much, varies widely (discussed further below).
- Many of the technologies necessary for end users to switch to hydrogen (e.g. furnaces) are not yet commercially available or still need to be demonstrated at scale, while some hydrogen equipment (e.g. domestic hydrogen boilers) must be proven safe to allow switching.

While we can draw on lessons from the development of other low carbon energy technologies, the complex nature of the hydrogen value chain means that different solutions will be required to stimulate the hydrogen market. In particular, one of the key consequences of the immaturity of the hydrogen market is that many potential users cannot readily switch to hydrogen and that hydrogen cannot currently easily be 'fed' into established distribution networks, as was the case with early renewable electricity deployment. In contrast to renewable electricity, we also expect that the hydrogen market will be characterised initially by few buyers and sellers and largely localised, with the first projects likely to need to match together production, distribution and end use.

1.3.2 The different market values of hydrogen depending on its use

Various factors will influence the decision of end users to switch to hydrogen, such as costs, resilience of hydrogen supply, technological readiness, safety risks, and the availability of distribution infrastructure.

The primary incentive for end users to switch to low carbon hydrogen is financial. Financial considerations influencing the decision to switch include the cost of buying hydrogen compared to competing higher carbon alternatives and to other decarbonisation options, for example

[12] For more information, see the 2021 BEIS analytical report on Hydrogen Production Costs, which can be found at: https://www.gov.uk/government/publications/hydrogen-production-costs-2021

electrification, CCUS and biofuels; the cost of converting existing equipment, for example upfront capital investment in new hydrogen-ready equipment and the need to develop new processes; and the cost of distribution and storage.

The business model is primarily focused on making low carbon hydrogen cost competitive with higher carbon counterfactual fuels. If hydrogen can be price competitive with counterfactual fuels and if carbon cost savings can be realised, end users are more likely to switch. The counterfactual fuel and carbon price exposure differ depending on the end use application, as shown in Table 1. In many cases hydrogen would be a replacement for natural gas, but it could also replace a range of other fuels, for example petrol or diesel in transport applications.

Table 1: Fuel cost, non-fuel cost and carbon cost exposure for a range of counterfactual fuels

Sector	Counterfactual fuel	Subject to carbon price[13]	Wholesale fuel cost[14] (£/MWh)	Non-fuel costs[15] (Ex. VAT) (£/MWh)	Carbon costs[16] (£/MWh) @ £25/tCO2e
Industry:					
	Natural gas	ETS, CCL	13.70	4.40	4.60
	Carbon intensive hydrogen	ETS, CCL	17.90 - 41.00	-	6.40
Heat for buildings:					
Commercial	Natural gas	ETS, CCL	13.70	9.60	4.60
Domestic	Natural gas	No	13.70	29.00	-
Power:					
	Coal	ETS, CPS	12.00	-	13.70
	Natural gas	ETS, CPS	13.70	4.40	7.90
Transport:					
	Road Diesel	No	47.10	52.90	-
	Petrol	No	48.00	60.30	-

The diversity of counterfactual fuel prices and potential carbon cost savings means that the 'market value' end users assign to low carbon hydrogen – and therefore their willingness to pay a higher or lower price for it – is likely to differ across end use applications.

For example, the relative value of hydrogen is expected to be higher in applications where relatively more expensive fuels are displaced (e.g. road diesel), reflecting end users' ability to

[13] Heat for domestic buildings and transport are not currently within scope of the UK ETS and are therefore not considered in the 'carbon costs' column of the table. Other policy costs (e.g. fuel duty) may be viewed as 'implicit carbon prices' and influence end users' incentives to switch to low-carbon alternative fuels such as hydrogen, however these are instead accounted for in the 'non-fuel costs' column.
[14] Wholesale gas prices are based on Eurostat (2019) data available at: https://ec.europa.eu/eurostat/web/main/data/database. Carbon intensive hydrogen price is a levelised cost range from the International Energy Agency available at: https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050.
[15] Non-fuel costs are based on BEIS (2019) data excluding VAT. They represent network costs, supplier margins, and other policy costs such as fuel duty in the case of road fuels. Data available at: https://www.gov.uk/government/collections/quarterly-energy-prices.
[16] Carbon costs represent the cost of ETS (Emissions Trading Scheme) allowances per MWh and CPS (Carbon Price Support) costs for power generators. CCL (Climate Change Levy) costs are not included as different users benefit from reductions and exemptions.

pay a higher price for low carbon hydrogen. Where end users are exposed to carbon pricing, the potential to avoid carbon costs is likely to positively impact the relative value of low carbon hydrogen – this relative value is likely to increase over time in line with an anticipated increase in the price of carbon. Conversely, users of relatively less expensive fuels which are not subject to carbon pricing (e.g. domestic heat users) are likely to assign a relatively lower value to hydrogen owing in particular to the absence of a carbon cost saving incentive to switch.

Business model design – including the process through which the business model is allocated – can take into account the different 'values' of hydrogen and their impact on switching incentives in different market segments. Policies outside of the business model could potentially impact non-fuel costs (e.g. policy costs) and the end users' incentive to switch.

1.3.3 The different hydrogen production characteristics

Our design principles outlined in section 3 include the business model being applicable to a range of production technologies. This means taking account of the characteristics of different technologies and their optimal operating modes, which in some cases impact wider energy systems. By way of illustration, we have set out below some of the characteristics of natural gas reformation with CCUS and electrolytic hydrogen that can have implications for policy design.

Natural gas reformation with CCUS

- **Operational characteristics**: gas reformers running off primarily natural gas have relatively long start up and shutdown times and are generally more suited to baseload hydrogen production.[17]
- **Main drivers of costs**: fuel cost (natural gas) is the main cost driver. The price of natural gas does not tend to change significantly over short periods of time (i.e. within a 24-hour period). Cost reduction potential is driven by economies of scale and reduction in operational costs through technological learning, however the overall potential is limited given the scope to reduce fuel cost.
- **Emissions**: Hydrogen produced from natural gas reformation can be considered low carbon if the captured CO2 is stored (such as through permanent underground storage). This means the availability of CO2 transport infrastructure and access to a CO2 store is needed to enable low carbon natural gas reformation projects to come forward. The low carbon hydrogen standard will clarify how CCUS emissions should be accounted for, including whether CCU (carbon capture and utilisation) should be included as an allowable benefit in GHG calculation.

Electrolytic hydrogen

- **Operational characteristics:** electrolysers can operate in baseload or in flexible, dispatchable modes.[18] As electrolysers can cycle up and down rapidly, they may offer opportunities for synergy with the electricity system by responding to the electricity output of variable renewables and helping to balance electricity supply with demand. Rapid dispatchability can make electrolysers well suited for co-locating, for example, with dedicated wind farms.

[17] Further information on hydrogen production technologies can be found at: https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base.
[18] Ibid. See also p.79, 'Solving the Integration Challenge', https://ore.catapult.org.uk/wp-content/uploads/2020/09/Solving-the-Integration-Challenge-ORE-Catapultr.pdf.

- **Main driver(s) of cost:** energy input cost (electricity) is the main driver, but this differs across different configurations of electrolytic projects. We anticipate that accessing grid electricity (and therefore paying the retail price for it) will be more expensive than using dedicated low carbon electricity sources or electricity that would otherwise be curtailed, although these latter options are limited by the availability of electricity supply and may result in lower electrolyser load factors. Where electrolysers import grid electricity, a further consideration is how electrolysers are exposed to electricity market signals so that electricity is used when wholesale market prices are low.

- **Emissions:** hydrogen produced from electricity is only as low carbon as the electricity used to produce it. We have made good progress in decarbonising our electricity generation in recent years. But there is more to do, as to date electricity generation still remains a large source of carbon emissions – cutting emissions further in the power sector will be needed to achieve our net zero targets.[19] The low carbon hydrogen standard is intended to determine how the use of low carbon electricity should be accounted for and the evidence that is required to prove the electricity is low carbon. The standard could play a role in influencing the operating mode of electrolysers, noting for grid connected electrolysers the positive correlation between wholesale electricity market prices and the carbon intensity of grid electricity. The exact interplay between electricity market signals, the business model, and the low carbon hydrogen standard is to be determined.

While energy input and capital costs are likely to vary across projects, hydrogen producers might also face further project-specific costs associated with different routes to market and policy considerations (e.g. costs of accessing and using CO2 and hydrogen transport and storage infrastructure), meaning that the level of revenue support required to cover fixed and variable costs and make a reasonable return on investment is likely to differ across projects.

[19] The UK has dramatically reduced greenhouse gas emissions from electricity generation, achieving a 72% reduction between 1990 and 2019. This will need to fall further, and, as we progress towards net zero, we will deliver an overwhelmingly decarbonised power system in the 2030s, with over 75% of electricity projected to be from low carbon sources by 2030. See https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2020; CCC (2020) The Sixth Carbon Budget; https://www.theccc.org.uk/publication/sixth-carbon-budget/

Section 2: Rationale for a production-focused business model and key design parameters

This section outlines the intended scope of the business model, the rationale for directing the business model subsidy towards hydrogen producers, and the delivery mechanism.

2.1 Intended scope of the hydrogen business model

We have set out below the intended scope of our hydrogen business model, which seeks to be applicable to a range of hydrogen production technologies and possible end users, in line with the position set out in the UK Hydrogen Strategy.

Our preferred approach is for the business model to be funded and delivered on a UK-wide basis to support decarbonisation across the UK. We will work with the devolved administrations as we develop and finalise the business model design.

2.1.1 Types of hydrogen production technology covered

Hydrogen production technologies

The business model is intended to support multiple hydrogen production routes to enable us to bring forward the broad range of projects needed to ensure a rapid and cost-effective build out of the hydrogen economy, with greater competition spurring innovation and cost reductions. We intend for the business model to be applicable across different production technologies, including the main types of production (natural gas reforming with CCUS, and electrolytic hydrogen) as well as other potential production technologies, such as hydrogen from biomass gasification with CCUS.

UK low carbon hydrogen standard

To ensure that our business model delivers carbon savings and that investment in hydrogen projects is consistent with our net zero commitments, we intend to require the volumes of hydrogen produced to meet a future UK low carbon hydrogen standard to qualify for and receive business model support. The standard is intended to provide clear criteria to define what is meant by 'low carbon hydrogen' and set out maximum acceptable levels of greenhouse gas emissions associated with different production technologies. The standard is being consulted on alongside this consultation and government expects to finalise the design elements of the standard in early 2022. Wider environmental standards and regulations are not in scope of our work on the standard, though we are not excluding the potential for further work on this later. We expect hydrogen producers to comply with current and future regulations on air pollutants including nitrogen oxides (NOx).

Existing hydrogen production plants

Existing hydrogen production plants would not be eligible to apply for revenue support via the business model. This is because the hydrogen business model seeks to stimulate investment in new production capacity to help us achieve our hydrogen deployment ambition. We also expect that support towards the cost of hydrogen production would not be needed for existing plants. Much of the existing volumes manufacturers in the UK use are for own consumption, where they are already able to pay the higher costs of using hydrogen. Existing hydrogen producers and industrial facilities looking to retrofit using CCUS technology may be eligible to apply for the ICC business model, which aims to support the cost of carbon abatement to help decarbonise existing industrial processes, including the production of carbon intensive hydrogen. We will consider further the risk of perverse outcomes arising from subsidy arbitrage between retrofitting CCUS to existing plants through the ICC business model and building new low carbon production plants supported by the hydrogen business model.

2.1.2 Types of hydrogen end use applications covered

End user applications

The current low carbon hydrogen project landscape suggests there are a variety of end users across diverse market segments, including refinery process heating, transport, industrial heating, hydrogen blends used in Combined Cycle Gas Turbines (CCGTs), and ammonia production.

We are aiming for the business model to facilitate hydrogen use in a broad range of sectors, reflecting the role that hydrogen is expected to play in decarbonising our energy system, with potential to help decarbonise heavy industry, and provide greener, flexible energy across power, heat and transport. This approach would help unlock the deployment of hydrogen in various sectors in line with the UK Hydrogen Strategy and help to stimulate the build out of a diverse hydrogen supply chain. We also recognise that restrictions on end use applications could be challenging to manage for projects that want to supply multiple different end users, and that need multiple end users to achieve economies of scale.

Exports

The business model is intended to support domestic production and consumption of hydrogen. Subject to further consideration, exports of hydrogen could be permitted for projects benefiting from business model support, although the specific volumes exported would not be eligible for support payments. In addition, export proposals would need to be in line with relevant national and international laws and regulations.

2.2 Producer-led business model

As committed to in our August 2020 consultation response, we have considered how best to provide ongoing revenue support to overcome the cost challenge of producing and selling low carbon hydrogen against cheaper higher-carbon counterfactual fuels. Two broad approaches are available to government to provide revenue support.

- **Producer-led revenue support**: Ongoing support payments directly to hydrogen producers to enable them to price hydrogen competitively against alternative fuels while recovering production costs.
- **End user-led revenue suppor**t: Ongoing support payments directly to end users informed by the price of the displaced fuel, with this support flowing up the value chain to indirectly compensate producers for the additional costs of production.

In the table below, we have summarised the main advantages and disadvantages of targeting our business model to hydrogen producers or end users. Chapter 3 of the Analytical Annex has a more detailed assessment.

Table 2: Advantages and disadvantages of producer or user revenue support

	Advantages	Disadvantages
Producer model	- Single policy can be applicable to all eligible producers - Producer support can be applicable to the supply of hydrogen into all eligible end use sectors - Fewer interfaces between government and private sector, facilitating quicker implementation and easier compliance monitoring - Can be designed to directly address barriers to hydrogen supply including investor risk aversion	- Does not guarantee demand, although helps address significant barriers to adoption
End user model	- Can be designed to target the needs and specific characteristics of individual sectors - Can directly incentivise the use of hydrogen - Sector specific support can be designed to be compatible with existing policies more easily	- Higher number of interfaces/counterparties and multiple subsidy models would likely be required given diversity of end use sectors and users, resulting in more complexity and slower implementation - May not stimulate hydrogen specifically where policies are technology neutral. - Unlikely to give sufficient certainty over demand to unlock investment in larger-scale production projects, and could create policy dependencies between end user models

While both approaches could enable investment in hydrogen projects, our minded to position is to provide revenue support through a producer-led incentive model which can work across a range of different production technologies and end use sectors. We consider this is the most effective approach to provide reasonable surety of returns for investors and achieve our strategic objectives. This is for two main reasons:

- **Relatively faster and less complex**: noting the UK project landscape and the variety of proposed hydrogen end use applications, a producer subsidy would be simpler and relatively faster to implement (by having one scheme and fewer counterparties) compared to introducing multiple targeted end user revenue support schemes, allowing us to take the swift action needed in the 2020s to deliver our 2030 ambition and set us on the path to CB6 and net zero.
- **More effective at stimulating investment in production**: a producer subsidy would be better suited at providing the certainty and revenue visibility necessary to facilitate

investment. This is particularly relevant for larger-scale production projects which are looking to supply multiple end users in different sectors. Different end use subsidies with distinct implementation timelines could create dependencies that might be difficult to manage in a way that provides sufficient confidence for timely investment. Furthermore, end use subsidies typically do not provide protection to producers if demand volumes reduce or if end users are no longer eligible for end use support. This means that end use subsidies could be unattractive if there is a risk that producers cannot recover subsidy payments indirectly via individual end users, including if end users' financial circumstances change.

2.3 Delivery mechanism

There are three possible mechanisms through which the revenue support could be delivered to hydrogen producers: policy-based approach, economic regulation, and private law contract.

In a policy-based approach, the level of subsidy is set out in rules and guidance, which government is able to change, sometimes retrospectively. Such mechanisms are likely to be less effective at giving confidence to investors, particularly in larger-scale assets requiring significant upfront capital investments. This is due to the uncertainty these mechanisms can entail such as potential for future policy change. Any resulting investment may come at a relatively high cost of capital and therefore higher costs to government compared to the two alternative approaches. As such we do not propose a policy-based approach for the business model.

Economic regulation involves an economic regulator periodically setting prices that infrastructure asset owners can charge end consumers. It is typically used in privately owned monopoly assets as a way of protecting consumers. A private law contract mechanism involves a bilateral contract between a project and a counterparty. Detailed terms and conditions, usually signed prior to the construction of an asset, can provide investor certainty at a relatively low cost of capital. Both models are used in the UK energy sector, particularly for large projects. Either model could be applied to hydrogen production. However, of the two we favour a contractual approach for the following reasons:

- **Compatibility with our long-term vision**. Economically regulated assets tend to be monopoly assets like electricity and gas transmission and distribution networks for which it is assumed there will always be a need. They are therefore subject to ongoing regulation to protect users and to ensure continuous service provision. Our ultimate ambition for hydrogen production plants is for them to compete with other low carbon alternatives subsidy free, with support provided through the business model being time limited. Support provided via a contract, where support is limited to the length of the contract, is therefore more appropriate than ongoing economic regulation.

- **Suitability for initial investors**. Assets that are subject to economic regulation are usually a natural fit for 'low risk - low return' infrastructure investors. Hydrogen production plants are most likely to attract, in particular in the early stage of market development, 'strategic' investors, meaning those more closely associated with the energy sector. Based on stakeholder feedback, strategic investors would be more familiar with a contractual instrument.

- **Consistency with other policy interventions**. Contractual funding mechanisms are proposed for power and industrial carbon capture, with an economic regulatory framework proposed for carbon Transport & Storage (CO2 T&S) network. The low carbon Contract for Difference (CfD) is used to support electricity production assets, with economic regulation used for electricity transmission and generation. A consistent approach across a broadly similar set of assets is potentially helpful in terms of learning benefits and exploiting synergies.

The contractual model would require a counterparty to manage the contracts. We are currently assessing options as to the most appropriate organisation to perform that function and intend to provide an update in response to this consultation.

Notwithstanding the above position, we recognise a contractual mechanism is not necessarily as suitable for some smaller scale projects, and address this point further in section 6.

2.4 Long-term vision for role of revenue support

While revenue support is needed in the near-term, we expect reliance on it to reduce as the hydrogen market matures.

Our longer-term ambition is a liquid, competitive, and transparent market for low carbon hydrogen where it competes on an equal footing against other technologies, without the need for financial support. Competition between technologies will drive down costs and allow us to meet our decarbonisation objectives in the most cost-effective way.

As detailed in the Hydrogen Strategy, a combination of market developments is expected to underpin this longer-term vision and allow hydrogen to be economically viable without subsidy. They include the following:

- Revising the design of the UK Emissions Trading Scheme (UK ETS) and a sustainable increase in the price of carbon to be consistent with our net zero commitment, providing an incentive to decarbonise and making low carbon energy sources progressively more cost competitive
- Cost reductions and scale increases in hydrogen production technologies, in particular electrolytic hydrogen
- The development of hydrogen distribution and storage infrastructure to underpin the expansion of the hydrogen economy, as well as investments in CO2 transport and storage infrastructure (for CCUS-enabled hydrogen) and low carbon power generation (for electrolytic hydrogen)
- The roll-out of sector-specific decarbonisation policies driving self-sustaining demand for low carbon hydrogen and a potential price premium for green products
- The establishment of a regulatory and market framework that supports the deployment of hydrogen at scale

1. **Do you agree with our overall approach to introduce a contractual, producer-focused business model covering the proposed scope?**

Section 3: Our approach to design of the business model

In this chapter we set out our approach to design a producer-led private law contract business model. We consider respectively the needs of the main parties involved in a hydrogen project, government's objectives, and the two key risks - price risk and volume risk - faced by investors that we consider form the basis of the business model design.

3.1 Needs of the three main parties

To design a business model we have considered the needs of the main parties involved in hydrogen projects: producers, government and end users.

Producers need:

- Sufficient visibility and predictability over returns on capital invested and operational costs to justify making the investment now
- To demonstrate to investors that revenues will be sufficient to pay a return on any capital provided to the producer
- To be able to price competitively in comparison to counterfactual fuels to attract end users
- To be able to supply hydrogen in the market regardless of the technology they have used to produce hydrogen or the size of their operations

Government needs:

- To achieve strategic objectives as set out in section 1, including the CB6 and net zero targets, as well as the 5GW hydrogen production capacity ambition
- To keep the subsidy to a minimum to reduce distortions created by government intervening in the market, and the right duration necessary to trigger investment and establish a self-sustaining market
- To be comfortable that projects represent value for money. Funding is limited – if it has been allocated to one project to achieve a particular objective, it will not be available to another if the first project does not deliver on that objective
- To ensure all subsidy control requirements have been met and be comfortable with any balance sheet implications

End users need:

- Sufficient visibility of costs and availability of hydrogen to justify switching
- The cost of hydrogen to be no more than the cost of the counterfactual fuel that it is replacing to justify switching to hydrogen (adjusted for the lower volumetric energy density of hydrogen and carbon cost) or any additional cost to be matched by achieving a higher value for a low carbon product

- To be able to secure long-term supplies of hydrogen and find alternative sources of low carbon hydrogen should producers cease production. Early end users may retain access to their existing energy source(s), where possible, as secondary fuels in case of limited hydrogen supply (e.g. natural gas connection)

Taking into account these perspectives, the implications for the design of the business model are that it:

- Must enable hydrogen to be price competitive with counterfactual fuels if there is to be significant demand for it
- Will need to incentivise the producer to produce, rather than simply to build production capacity, for net zero to be achieved
- Needs to mitigate volume (offtaker) risk for the producer, though does not need to remove it entirely

3.2 What does 'good' look like?

Our objectives for a low carbon hydrogen business model are as below:

A 'good' business model should provide a stable contractual framework, that avoids both unnecessary complexity and excessive simplicity.

It should incentivise the private sector to allocate capital to the construction of hydrogen production plants, incentivise that plant to produce hydrogen only when there is demand for it, incentivise the producer to promote and develop end use markets, and incentivise them to sell that production at a price that fairly reflects its intrinsic value in various applications.

It should protect the plant from bearing the full uncertainties of an immature market but reduce/remove those protections as they cease to be necessary.

It should ensure that returns to the producer are not excessive, and tightly control overall cost to the government by enabling subsidy to reduce both within the contract life and across different rounds of contract awards. It should effectively reduce the subsidy to zero when the market has sufficiently developed to a point that the value of hydrogen reflects the cost of producing it.

It should enable investment in projects based on low carbon hydrogen production technologies, and for progression from 'first of a kind' (FOAK) to 'Nth of a Kind' (NOAK) to be supported with only minor adjustment (e.g. removal/addition/modification of individual clauses) to the model rather than a more fundamental redesign.

In future it should be able to function in a competitive allocation process.

3.3 Key design principles for assessment of options

Following on from our objectives for a 'good' business model, we have set out our key design principles which we have used to consider the advantages and disadvantages of each option, with more detailed analysis set out in the Analytical Annex. We have built on the design principles we proposed previously and as set out by Frontier Economics in their 2020 report.

Table 3: Business model design principles

Principle	Description
Promotes market development	Model should incentivise producers to seek and develop sources of demand for hydrogen and promote its use
Promotes market competition	Model should not create barriers to market entry, enable abuse of market power, or provide an enduring competitive advantage to first movers compared to later market entrants
Investable	Model should provide sufficient predictability over revenues and returns to investors and mitigate risks which investors are not best able to bear
Value for money	Model should be effective in achieving its intended purpose at the lowest possible cost to government and prevent excessive returns to developers
Reduces support over time	Model should allow for revenue support to producers to reduce over time (within and between contracts) by being responsive to evolving market conditions and encouraging learning, innovation, and cost reductions over time
Suitable for future pipeline	Model should be fit for purpose for FOAK projects as well as nth of a kind projects with minor or reasonable adjustments
Compatible	Model should be compatible with other policies across the value chain and should not result in double subsidisation of the same units
Technology agnostic	Model should be applicable to a range of production technologies (provided they meet the low carbon hydrogen standard and do not create an enduring competitive advantage for one technology over another)
Size agnostic	Model should be applicable to a range of project sizes and should not incentivise inefficient sizing of production plants
Avoids unnecessary complexity	Model should avoid unnecessary complexity in its design, implementation and administration, and be transparent for producers to comply with

3.4 Key risks that the business model will need to address

The key design principles will help us to evaluate whether different model design options meet government objectives. To build those different options we have considered the key risks that hydrogen producers face as a foundation for design. Achieving the appropriate allocation of these key risks between investors in production facilities and government will make hydrogen production bankable for investors and value for money for government.

Given the very early stage of market development, we have considered risks primarily in relation to initial projects which entail greater risk and uncertainty than future projects are likely to. In the absence of high demand for low carbon hydrogen, shared distribution and storage infrastructure and a market price for hydrogen, we recognise there is a role for government to manage some of these risks for early projects. Specifically, we identify the following two risks requiring significant government support to effectively manage:

- **Market price risk**: This is the risk that the price the producer is able to achieve for selling hydrogen does not cover the cost of producing it, as it is unable to compete against counterfactual fuels, such as natural gas or diesel. This makes it uneconomical to produce low carbon hydrogen and attract the necessary investment in a production plant
- **Volume risk**: This is the risk that a hydrogen production facility is unable to sell enough volumes of hydrogen to cover costs with reasonable confidence. Scenarios where this may happen include, but are not limited to:
    - inconsistent demand for hydrogen by offtakers
    - offtakers are slow to adopt and use contracted hydrogen
    - unforeseen outage or unplanned closure of offtaker
    - an offtaker's market conditions or financial circumstances unexpectedly change
    - a sole demand user no longer requires low carbon hydrogen, leading to stranded production assets

Towards the end of the decade and beyond, we see the nature and balance of risks between hydrogen production facilities and government evolving. With the scale up of capacity from the first hydrogen producers, we are likely to see higher adoption of hydrogen in the area around those producers. An increase in demand would improve volume certainty for existing and new hydrogen producers and would likely lead to the development of shared hydrogen networks and storage, further reducing the reliance on localised offtakers. A changing risk profile would therefore require an evolution of the risk allocation between investors and government which would need to be reflected in future allocations of a hydrogen business model contract.

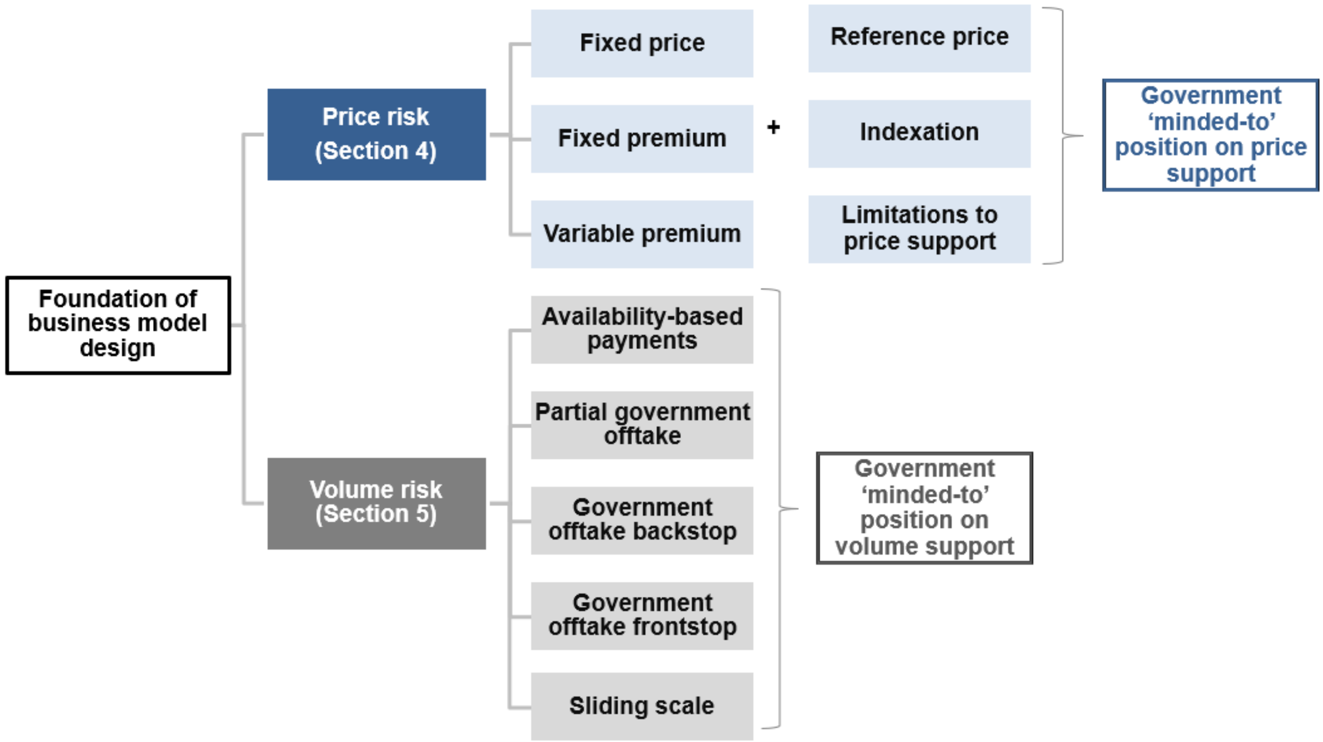
While market price risk and volume risk are the most important risks to address, we have also outlined a position on allocation of other key risks in section 7.3.

3.5 Approach to allocation of price and volume risks

Market price risk and volume risk are different in nature, as outlined above, and therefore our approach to the business model design is to consider them individually.

The allocation of these two risks forms the foundation of the business model design, as shown in figure 2 below. Each of the options presented below are discussed in the following two sections.

Figure 2: Approach to business model design



2. Do you agree with our approach to the business model design?

Section 4: Price support

In this section we consider three options for managing the type of price support payment the model can provide to address market price risk: fixed price, fixed premium and variable premium, and assess each of them against the key design principles set out in section 3. For the last option, we set out options for setting a reference price as it is the fundamental feature of a variable premium model. We have also set out the circumstances where we are considering limits to price support.

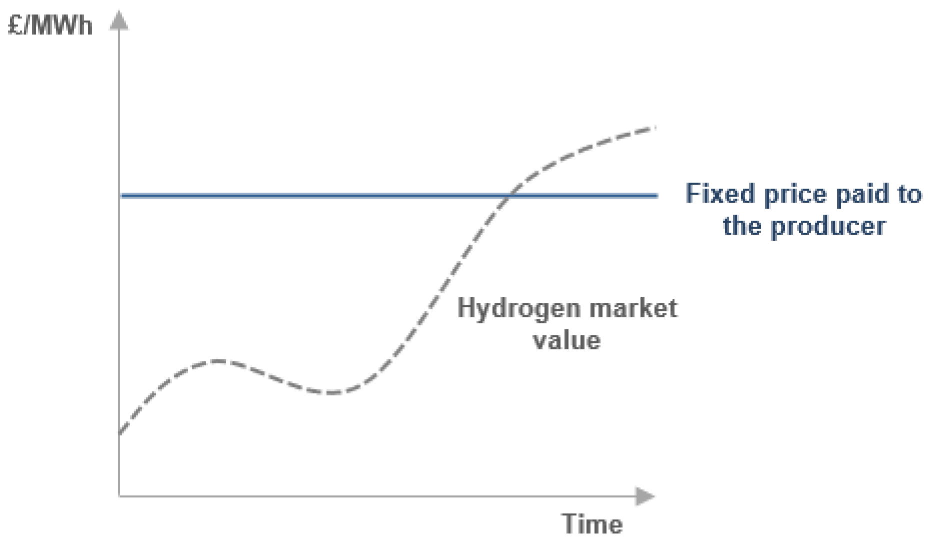
4.1 Price support options

Price support option 1: Fixed price

Description of option

Each producer is paid a fixed price for every unit of hydrogen produced, with this price reflecting their anticipated cost of production, irrespective of the value of hydrogen – see figure 3. Examples of fixed price support include Feed-in Tariffs (FiTs) for small-scale renewable electricity generation and early North Sea natural gas contracts. This option would likely require a government body to facilitate the market and pay producers the fixed price, rather than producers having flexibility to sell hydrogen direct to offtakers at the price they are able to achieve.

Figure 3: Fixed price



Advantages

The main advantage with this approach is that a fixed price removes uncertainty for producers over what unit price might be commanded by hydrogen in the market. This approach is also simple. The price does not need to be adjusted over time and can be set on the producer's expected levelised cost of hydrogen production.

Disadvantages:

There are however significant challenges with a fixed price approach for hydrogen production:

- **A fixed price support mechanism requires a relatively high level of government intervention.** A government body would need to be set up to facilitate transactions in the market. The body would pay for each unit of hydrogen produced as well as offer offtake agreements at the fixed price (with price support now required for the end user) or at a negotiated price (with the counterparty absorbing the difference).

- **Setting the fixed price at the right level to attract investment while also achieving value for money is difficult.** It needs to be set sufficiently high to attract investment but if it is set too high it would be at greater cost than government needs to have paid. A high fixed price is therefore open to windfall profits if the costs of production fall in future, although a competitive allocation mechanism could mitigate some of this risk. A fixed price which is too low might not attract sufficient investment in hydrogen as producers will need a fixed price high enough to compensate for the risk of rising input costs (particularly energy costs) to prevent producers' equity return being reduced or potentially eliminated. Indexation could help with ensuring that changes in the producers' costs are matched. If adjustments are made however, the support mechanism would no longer be a fixed price.

- **A fixed price has implications for which end users can afford to switch to hydrogen.** Depending on the level at which the fixed price is set, only users who have a higher priced counterfactual fuel than the fixed price would be able to afford to fuel switch. It is more likely that these would be end users who are currently using relatively expensive fuels such as diesel and kerosene. Those who are currently using lower priced counterfactual fuels such as natural gas and coal would likely be less able to justify fuel switching. A separate demand side intervention would be needed to bring the fixed price down to less than or equal to lower price counterfactual fuels.

- **Government support through the business model does not have the potential to reduce over the contract length and does not facilitate price discovery and convergence to a market price for hydrogen.** With a fixed price the support per unit of hydrogen does not fall over time (as illustrated in figure 3) even if production costs decrease, unless periodic price reviews are included in the contract. Including price reviews would undermine investability if producers do not have visibility over the revenues over the duration of the contract.

Summary

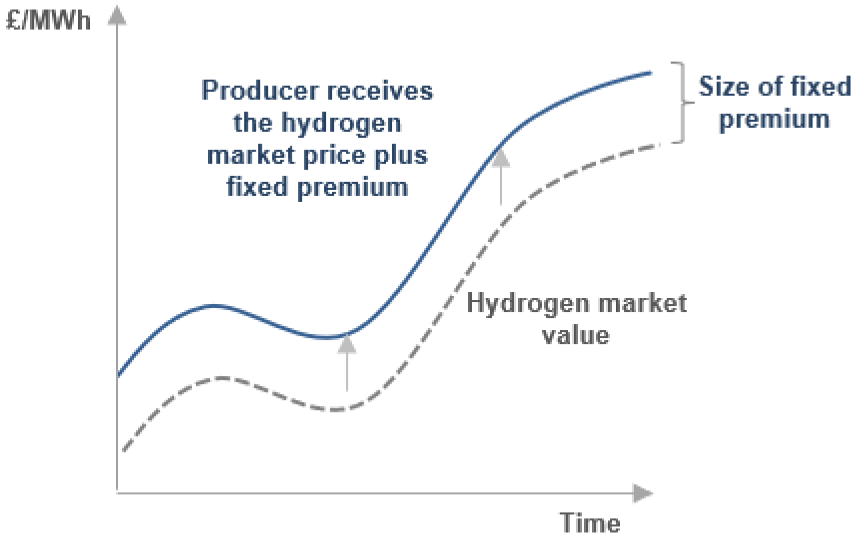
While the support mechanism would incentivise production so long as input prices remained low, it would not necessarily support demand formation to the level required to support the government's ambition of 5GW of capacity by 2030. The model could be adjusted to enable the government body to sell the hydrogen at different prices for different end users, to mitigate some of the above issues associated with fixed prices. However, this approach would require the creation of a loss absorbing market making entity – either the government body would need to play that role or government would need to create an additional intervention to incentivise a third party to take on that role – or a supplemental demand side intervention to enable end users to pay the fixed price. In doing so we would be introducing complexities that might undermine the formation of a genuine market for hydrogen.

Price support option 2: Fixed premium

Description of option

The producer is paid a fixed payment (a 'premium') for every unit of hydrogen sold in addition to whatever price the producer is able to achieve from the market itself – see figure 4. The size of the fixed premium can be calculated in a range of ways – for example on the basis of production costs, or the cost of counterfactual fuels, at the outset of the contract. The fixed premium can also be expressed as a percentage uplift.

Figure 4: Fixed premium



Advantages

Compared to the fixed price option, the fixed premium provides higher confidence in terms of profitability for the producer, as it has greater potential to maintain a differential over the input energy cost that is not possible in a fixed price model, assuming that changes in input energy prices are reflected in sales prices. Although the considerations underpinning the setting of the premium at the start of the contract are likely to be complex, the premium would not be adjusted over the course of the contract so is relatively simple to implement.

Disadvantages

- **The fixed premium mechanism is not flexible to changes in market conditions.** The level of the premium, although paid on top of the price which the producer can sell the hydrogen for, does not bear any relation to any changes in the market value of hydrogen from the start of the contract. The unit premium does not vary as the market value of hydrogen changes, so could potentially lead to excessive subsidy if the market value of hydrogen rises (and the unit subsidy remains fixed). The level of subsidy therefore would not reduce over time as the market value of hydrogen rises.
- **Given the inflexible nature of the fixed premium there are risks of overcompensation of sales into certain end use sectors.** For example, a fixed premium designed to help hydrogen penetrate the domestic heat market could significantly overcompensate sales into the transport sector – either for the producer or the end user. This is because the prices of the counterfactual fuels differ significantly, and a fixed premium reflecting parity with natural gas would be inappropriate for sales to

diesel users – either through excessively discounted hydrogen to the end user, or excessive revenue to the producer.

Summary

While this option addresses some of the key risks with the fixed price approach, we consider it is unlikely to represent value for money. The risk of over/under-subsidisation could be addressed by allowing the premium to adjust in response to market conditions – either automatically or via price reviews. To do so, however, would change the nature of the price support intervention and it would cease to be a fixed premium.

Price support option 3: Variable premium

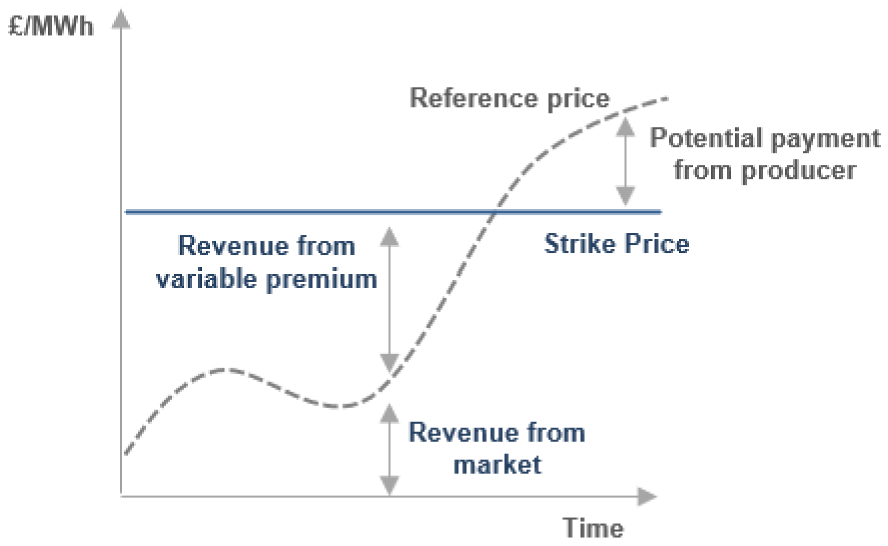
Description of option

The producer is paid a premium for the hydrogen produced. The premium is calculated as the difference between a 'strike price' and a 'reference price' for each unit of hydrogen sold – see figure 5:

- **The strike price is intended to reflect the overall value of a unit of hydrogen that the producer needs** to achieve to cover their fixed and variable costs of production (including any associated costs such as carbon transport and storage for CCUS-enabled projects), financing costs and equity return.

- **The reference price is intended to represent the market price received by the producer for each unit of hydrogen.** The payment to the producer is the difference between this reference price and the strike price, enabling the producer to achieve the necessary return for each unit of hydrogen over the lifetime of the contract (although the level of subsidy from the government will fluctuate). There is also the potential for the producer to pay the government counterparty the difference if the reference price rises above the strike price.

Figure 5: Variable premium



Examples of variable premiums include the CfD for low carbon electricity generation[20] and the Dutch SDE++ which supports a range of low carbon applications including electrolytic hydrogen.[21]

There is flexibility in determining the strike price at the outset. It can be bilaterally negotiated between producers and government or it can be set using a competitive allocation process, such as an auction. It can also be adjusted in line with indexation to account for the variability of input costs over time. This enables the strike price to respond to any rises in the cost of production and avoid pressure on the producer's margins, and equally any falls to avoid it leading to greater margins. Options for indexation are covered in more detail in section 4.3.

The reference price in the case of CfD-supported low carbon electricity generation is the wholesale market price for electricity (so it reflects the market value of the output that is being supported by the variable premium support intervention). There is not an observable wholesale hydrogen market price, and it will take time for one to develop, so this approach cannot be directly replicated. We could instead use a proxy for the market value of hydrogen until a market price emerges - a range of options are considered in section 4.2.

Advantages

A variable premium mechanism overcomes some of the key challenges of the previous options.

- **The subsidy adjusts as the market evolves, which is likely to deliver greater value for money for government.** The amount of the subsidy can increase or decrease in line with wider market conditions (adjusted through the reference price). If the reference price rises, reflecting a rise in the market price for hydrogen, the level of government support reduces. There is the potential for the payment to flow in the other direction if the reference price rises above the strike price over the course of the contract. This does however depend on how the reference price is set – we consider reference price options in the next section.

- **The variable premium is adaptable to different end use cases** as there is flexibility in setting the reference price. The reference price is key for how producers and end users interact with the variable premium mechanism, as well as playing a role in supporting sales into a range of end use sectors and avoiding over- or under-subsidisation of certain sectors.

Disadvantages

The main disadvantage of this option in comparison to others is that it may be regarded as more complex. The methodology for determining the variable premium (particularly identification of the reference price) would need to account for how the hydrogen market is expected to evolve over time, to ensure the variable premium also evolves with it.

Summary

We consider this option is the most advantageous with clear benefits over the alternatives. In particular, it provides the opportunity for the level of subsidy to adjust to the evolution of the hydrogen market. If the producer is able to sell hydrogen for a higher price as the value of

[20] Information on the CfD variable premium can be found at: https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference
[21] Information on the Dutch SDE++ variable premium mechanism can be found at: https://english.rvo.nl/subsidies-programmes/sde/features-sde

hydrogen increases (for example as the carbon price increases and it becomes more expensive to use higher carbon fuels), then the subsidy paid through the business model can reduce. We consider this has the potential to provide better value for money, but requires careful selection of the reference price to be effective. Options for the reference price are considered in the next section.

4.2 Reference price

4.2.1 Approach to reference price

In a liquid market with established regional and national hydrogen distribution networks, the logical choice for the reference price would be the market benchmark – a reflection of the price which end users are willing to pay for it. As outlined above, it is unlikely that initial hydrogen production projects would be taking investment decisions solely based on conditions where a hydrogen market price has emerged, as the market is likely to still be immature and regional distribution networks would not have been developed. Instead, in the early stages, we expect the hydrogen market to be localised, characterised by few buyers and sellers, and rather than a prevailing market price, multiple localised prices to emerge which are linked to a counterfactual fuel.

How we set the reference price is likely to influence price formation, meaning the process by which information on the price at which hydrogen is bought and sold emerges and determines the market price over time. If a producer sells their hydrogen below the reference price, the combination of their support payment (strike price minus reference price multiplied by sales volume) and their market revenue (sales price multiplied by sales volume) would be lower than their expected revenue (strike price multiplied by sales volume), impacting their return on investment. Producers would likely be incentivised to sell their hydrogen above the reference price to maximise their revenues but their ability to do so would depend on how the reference price is set and how closely it reflects the value of hydrogen to end users.

The reference price will influence the incentive for end users to switch to hydrogen, and potentially the price which they are willing to pay for hydrogen over time. We have assumed that the value that end users place on hydrogen is influenced by the cost of the counterfactual fuel they are currently using and carbon pricing. If they can make a sufficient cost saving to justify their demand side investment they will have a financial incentive to switch to hydrogen. We acknowledge there may be other barriers to end users switching to low carbon hydrogen.

If the reference price is set at a level which is at parity with relatively less expensive fuels (e.g. natural gas), end users using relatively expensive fuels (e.g. diesel) would potentially have a strong financial incentive to switch, which could drive faster take up in this end use sector. This incentive is higher still for end users who are currently included within the UK ETS. If, however, the price of hydrogen is more at parity with diesel, then instead this makes it more expensive for those using cheaper fuels and would not incentivise them to switch as they would be worse off in cost terms. The reference price is therefore crucial for determining whether end users are likely to switch.

There are a broader set of incentives both within and outside of the business model design, which could also play a role in driving where hydrogen is used, in addition to the reference price. This includes the allocation process through which hydrogen projects receiving business model support will be selected, as well as sectoral decarbonisation policies which might influence hydrogen roll-out in various market segments (e.g. sector-specific capital support towards end user switching costs). The assessment of reference price options has been carried out in the absence of any other assumed government intervention, to understand the impact of the reference price specifically.

4.2.2 What does 'good' look like?

As outlined above, we aim to structure a reference price around a proxy which as far as possible reflects the market value of hydrogen. We have considered more widely what a 'good' reference price looks like, taking account of the key design principles outlined in section 3.

A 'good' reference price should be reflective of the value of low carbon hydrogen in the market. It should promote the development of the hydrogen market by providing sufficient flexibility to producers to allow them to sell their output at a price that supports fuel switching by end users, while also enabling government support payments to reduce over time as the intrinsic value of hydrogen increases versus counterfactual high-carbon fuels. It should represent overall value for money for government while also preventing excessive returns to producers. It should enable price discovery and not undermine competition.

It should also aim to be applicable across all technology types and operating archetypes to reduce monitoring and administration costs, and minimise possible market distortions.

Given the many possible end uses of hydrogen and counterfactual fuels displaced, any reference price option should require an appropriate degree of transaction reporting from the producer to ensure that the system is not being gamed, and to provide government, delivery and regulatory bodies with the data needed to iterate future versions of the support regime, as well as to help develop a market benchmark.

4.2.3 Reference price options

We have considered seven options for the reference price: input energy price, natural gas price, counterfactual fuel price, achieved sales price, market benchmark price, carbon price and natural gas plus carbon price.

Taking 'what good looks like' into account, each reference price option has been defined and split into how well aspects of it perform against the relevant design principles. The assessment includes how well each option serves as a proxy for the value of hydrogen in the market; for promoting the development of the hydrogen market (both from a producer perspective to provide sufficient confidence over their revenues, and also for end users' price incentives for switching); and for government from a value for money perspective as well as whether the subsidy support evolves and reduces over time. Broader implications for the development of the market are also considered.

Reference price option 1: Input energy price

Description of option

Hydrogen plants will always use a primary input energy for which there will be either an observable market benchmark or observable contract price. Input energy is a key driver of the producer's cost of production and therefore this makes input energy prices a potential starting point for a reference price. The reference price could vary depending on the source of the producer's primary energy input. For example, it could be set based on the natural gas price (the primary input fuel for reformation-based production technologies) or wholesale electricity price (for electrolytic production technologies). In practice this would mean different reference prices for each hydrogen production technology.

Advantages

- **Input energy prices are transparent and simple to understand.** Market benchmarks exist for energy prices to which all parties have access. Subject to disclosure by producers, the same would apply to specific contract prices.
- **Distortions in the hydrogen market and wider energy markets may be avoided** by linking to the input energy price. The hydrogen plant is not subsidised for sales below that input energy price (i.e. hydrogen sold by a reformation-based or electrolytic plant for less than the input energy price would not attract additional government support). This avoids distorting energy markets through the subsidisation of input energy in the hydrogen business model.

Disadvantages

- **Input energy prices are not necessarily positively correlated to the value of hydrogen** as fluctuations in benchmark natural gas and electricity prices reflect supply and demand conditions for those products rather than reflecting the supply and demand for hydrogen. The extent to which the input fuel is correlated to the value of hydrogen is also likely to vary for each input fuel. Contract prices may be entirely uncorrelated.
- **Different production technologies may not be able to compete in the same markets.** For example, a continuously operating grid linked electrolyser and a methane reformer may not be able to consistently compete in the same markets if their reference prices were different. This is because, while both prices fluctuate, wholesale electricity prices are on average higher than natural gas prices, which may make it harder for them to achieve the same level of overall revenue in the same market. As a result, certain technologies may then be favoured in certain end use applications due to the influence of the support mechanism rather than their fundamental suitability to the application.
- **Although producers have an incentive to sell for higher than the reference price, i.e. input energy costs, this risks over-compensation to the producer.** The producer could sell at any price above that level and still claim the full subsidy offer as there is no positive link between the market value of hydrogen and subsidy payments.
- **There is no guarantee that the level of subsidy reduces over time within a contract.** For the subsidy to reduce over time, the reference price needs to rise over time. Given the reference price is linked to input energy costs, the level of the subsidy would be determined by the trajectory of electricity prices and natural gas prices. As such, in the absence of other contractual mechanisms, the level of subsidy could increase if input energy prices fall.
- **Linking the reference price to input energy costs may encourage transfer pricing.** Transfer pricing is a means of pricing transactions between connected parties to alter where profits and losses are incurred. Transfer pricing might happen if the project is integrated with the input energy source, and the price that the hydrogen plant is charged for that energy is used to move profits from one part of the value chain to another. This could potentially lead to the business model indirectly subsidising the producer’s other operations.

Summary

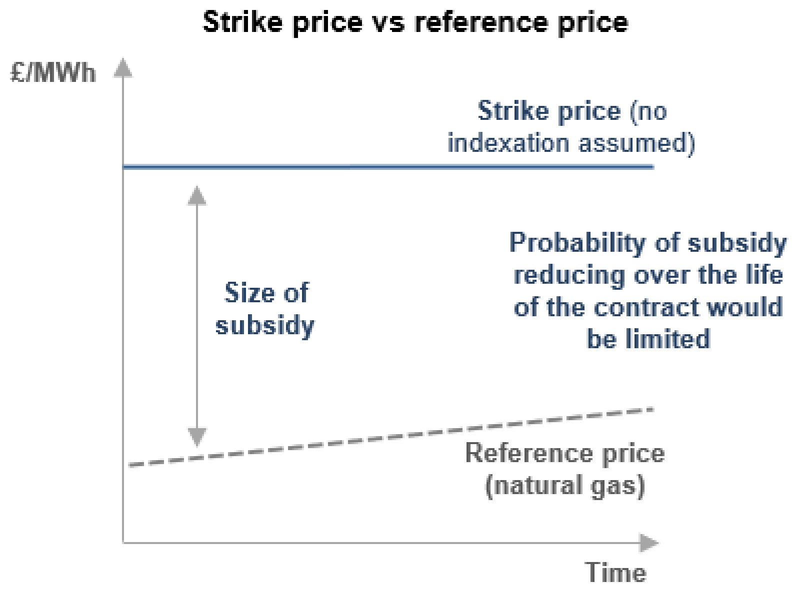
Using the input energy price has the advantage of being relatively simple to understand and transparent given the link to liquid energy markets or contract prices. The main drawbacks are that producers of different production technologies may not be able to compete in the same markets due to the reference price that they are subject to, and that support payments would not be linked to the price that the producer receives for their hydrogen.

Reference price option 2: Natural gas price

Description of option

One of the main drawbacks with the previous option is that with multiple reference prices linked to different input energy prices, it may be difficult for different production technologies to compete in the same end use markets. An alternative would be to use natural gas, which is likely to be the fuel most end users would be switching from, as the reference price across all production technologies – see figure 6. We note that the outline revenue support mechanism in Portugal's Hydrogen Strategy is based upon closing the gap between the cost of electrolytic hydrogen and the local natural gas benchmark.

Figure 6: Natural gas as a reference price



Advantages

- **Natural gas is a liquid market and therefore using it as a benchmark has transparency benefits,** as with option 1.
- **The value of hydrogen to the market can be expected to be strongly correlated to the natural gas price in end user sectors where natural gas is the counterfactual fuel being replaced.** Natural gas, an input for reformation-based projects, is likely to be the main counterfactual fuel being displaced by hydrogen in industry, power generation and domestic heating markets so is directly linked. This correlation however can be expected to weaken over time as carbon prices begin to place a more significant burden upon unabated natural gas users.
- **As with option 1, distortions in the hydrogen market and wider energy markets may be avoided as the hydrogen plant is not subsidised for sales below the**

natural gas price. The natural gas price acts as a floor beneath which further support payments are not provided, therefore incentivising the hydrogen plant to achieve at least the natural gas price for their sales. As with option 1 this avoids the distortion of energy and related product markets that could arise from subsidising input energy.

- **A floor price at the natural gas price provides incentives for certain end users to switch to low carbon hydrogen.** End users subject to carbon pricing have an incentive to switch to hydrogen as they would save on carbon costs, including those using natural gas as a counterfactual fuel. Those using non-natural gas products where counterfactual fuels are more expensive, such as gas oil or diesel, would also have an incentive to switch and save on fuel costs. Over time this price incentive is likely to increase as carbon prices rise.

Disadvantages

- **Linking to natural gas could potentially lead to excessive subsidy for sales to certain end users.** Those using fuels which are more expensive than natural gas may be able to access hydrogen at a cost which is far lower than the prices they are currently paying for their counterfactual fuels, and therefore may make higher savings than are necessary to incentivise them to switch. Alternatively, these higher savings may be at least partially captured by the producer without leading to any reduction in subsidy payments.

- **There are fewer incentives to switch to hydrogen in non-ETS markets where natural gas is the primary input fuel.** This is because carbon pricing is not a factor, and so the ongoing fuel cost saving for existing natural gas users in these markets (e.g. smaller industrial installations, domestic heating), may be minimal or zero.

- **As with option 1 (input energy price) there is a risk this option overcompensates the producer.** Producers have an incentive to sell for higher than the reference price but this does not reduce the subsidy. The producer could sell at any price above that level and still claim the full subsidy offer.

- **The level of subsidy may not reduce over time** as the gap between the strike price and the reference price may not necessarily close. This is because the reference price is based on natural gas, an input cost, and not the market value of hydrogen.

Summary

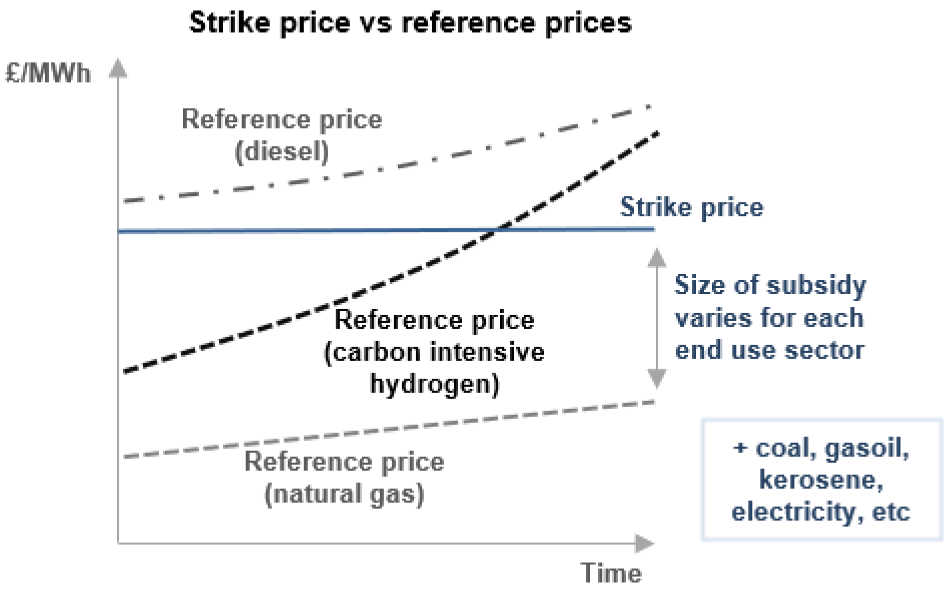
Natural gas as a reference price is simple to apply but the probability of the subsidy reducing over time is likely to be limited and could lead to excessive subsidy to certain end users and/or the producer. This approach is also likely to incentivise producers to sell hydrogen in end user sectors where the market value of hydrogen is the highest (due to the lack of impact on support payments), potentially to the detriment of supplying other markets.

Reference price option 3: Counterfactual fuel prices

Description of option

Instead of looking at just one counterfactual fuel, such as natural gas, the reference price could instead be constructed around the counterfactual fuel price for every sale that the hydrogen plant makes. If hydrogen is sold to a diesel customer, then diesel could be the reference price, and so on for each different counterfactual fuel used by end users – see figure 7.

Figure 7: Counterfactual fuels as a reference price



Advantages

- **Using counterfactual fuel prices in theory enables each end user to pay the same for hydrogen as the fuel they have switched from.** End users would continue to pay the same price as before switching (but with a carbon cost saving if they are subject to carbon prices) and hydrogen producers would be able to extract the majority of the theoretical market value from each end user. However, the positive correlation of each counterfactual fuel with the value of hydrogen may weaken or reverse over time as the carbon price rises.

Disadvantages

- **The main challenge is that there are a lot of different fuels, which introduces complexity to this mechanism**. Figure 7 shows only three fuels but the contract would need to reference all possible fuels, as well as iterations of different fuel mixes, many of which may not have easily observable prices. The complexity of this mechanism extends to the administrative burden of delivering the contract as well as the monitoring requirement. The reference price would vary from end user to end user which could become onerous to administer as the number of end users and projects increase. Government would also need a mechanism through which it is ensured that customers are not obtaining hydrogen with a more beneficial reference price than that to which they are entitled (i.e. to ensure diesel customers are not getting a natural gas reference price). There is also the question of what the reference price would be for entirely new energy end users under such a model. A simpler alternative would be to reduce the number of counterfactual fuels down to those which have a correlation with the end market. For example, adopting diesel for all transport applications and natural gas for non-transport applications. This is likely to have similar advantages and disadvantages as the natural gas price as a reference price (option 2).

- **Difficulties arise from charging different prices to different customers for a chemically identical product.** While there may be some specific applications that require higher purity hydrogen (fuel cells, semiconductor manufacturing), the hydrogen that could be used for domestic heating, industrial heating, combustion engines, power stations and chemical feedstock would be uniform.

- **This approach diminishes the incentive to sell into higher value markets for the producer**. Due to the reference price always reflecting the counterfactual fuel, sales into higher value markets would be no more profitable to the producer than sales into lower value markets, and so may encourage sales into the markets (regardless of financial value) that can absorb the highest volumes with the least effort.
- **This reference price option eliminates the price incentive to switch for many end users.** The choice to switch from one fuel to another is at least partly driven by price so if there is little or no cost saving, it will be harder for end users to justify the investment to switch. This approach also makes it harder to get hydrogen into higher value markets compared to other approaches because the hydrogen is priced at the exact price that the end users are already paying for their counterfactual fuels. The incentive to switch is then narrowed to any carbon cost savings, and thus would only apply to end users subject to carbon pricing. Greater support for end users may then be needed to stimulate take up of hydrogen to avoid the slow development of the market.
- **The ability for the producer to use pricing to build volumes would be limited.** This might slow fuel switching in all sectors and also might deter producers from investing or could result in higher strike prices to give producers more pricing flexibility.

Summary

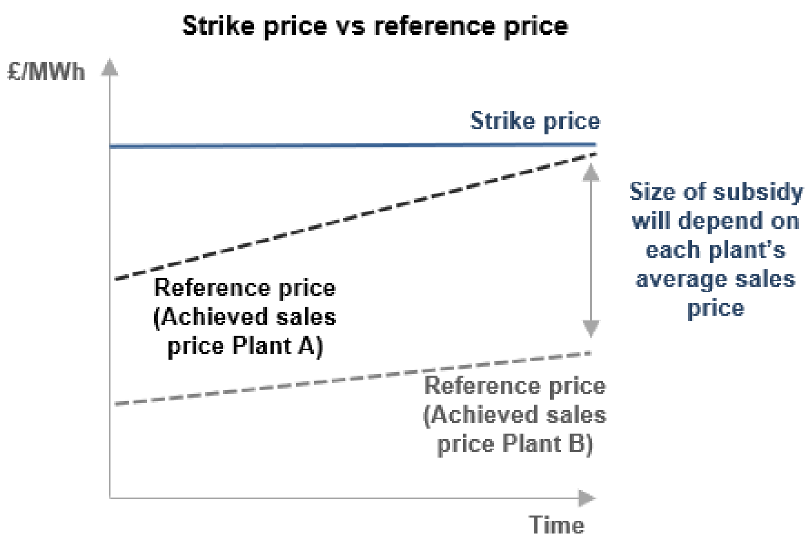
The counterfactual fuel option eliminates the price incentive to switch for many users who are not subject to carbon pricing. This is likely to hamper market development as well as adding significant complexity to administration of the contract. It is likely to be unworkable unless it is applied simplistically. With multiple reference prices focused on end uses, it may also be challenging for a market benchmark price to develop.

Reference price option 4. Achieved sales price

Description of option

The previous option attempts to have a counterfactual fuel price for every offtake contract that the producer signs. This complexity can instead be left for the producer to manage themselves (i.e. the producer can decide the price at which they sell to end users) and their achieved sales price at their individual plant can be used as the reference price (i.e. as a proxy for market value) – see figure 8.

Figure 8: Achieved sales price as a reference price



Advantages

- **The approach is relatively simple.** It avoids the need for an end user specific reference price. Unlike previous options the achieved sales price is a measure of what the market is actually paying for hydrogen across all sales rather than a proxy for sales price. It also recognises some plants will receive higher or lower subsidies depending on the price they have sold hydrogen at – as illustrated in figure 8. How closely the sales price is correlated with the market value of hydrogen will depend on how other incentives to producer behaviour are managed, which we consider below.
- **Pricing flexibility ought to lead to a faster rate of market penetration.** Allowing the producer the flexibility to alter pricing in order to deliver a more targeted incentive to end users to switch will enable it to build volumes more quickly, giving momentum to hydrogen take up and therefore its decarbonisation benefits.

Disadvantages

- **There is no reward for price discovery and subsequently the level of subsidy is not likely to reduce over time.** The sales price is asymmetrically influenced by the producer in the sense that they can easily reduce prices, but it requires much more effort to increase them. By setting the sales price as the reference price, the reward for that effort to generate higher prices for hydrogen is almost entirely removed (beyond the need to avoid a cliff edge at contract end) as it reduces the subsidy. This is illustrated in figure 8 where Plant A is unrewarded for outperforming Plant B on market sales. As such, other contractual mechanisms would be needed to ensure that development of higher value sales is rewarded in order to discourage reliance solely on subsidy.
- **The lower incentive for producers to generate higher market prices for hydrogen may result in overcompensation.** If the producer prices the hydrogen at a relatively low sales price to intermediaries this may enable intermediaries to sell the hydrogen onto end users at a higher price. This could also happen if intermediaries were able to sell to higher value markets which the producer may not be able to.
- **Producers may be incentivised to focus on generating revenue by focusing on sales volume instead of the sales price.** A commercial operator seeking to build a long-term business would attempt to extract as much market revenue as possible from their offtakers. If the sales price is the reference price, they are not strongly incentivised to increase the sales price as this results in a lower subsidy from government, yielding no improvement in revenue. Instead, there may be an incentive for producers to concentrate on generating revenue by focusing on sales volume and not the sales price. This perverse incentive to not maximise the sales price is a bigger problem where hydrogen is being manufactured for own consumption – there would be no incentive to charge a market price for such a sale.
- **There is a potential for energy rather than hydrogen to be subsidised, leading to market distortions.** If end users are able to secure hydrogen from producers for a price which is lower than their counterfactual energy input, it may change their competitive positioning. For example, it may allow end users (e.g. a manufacturer) to cut the price of their product in order to boost market share without diminishing their own margins, which may be to the detriment of other end users who have decarbonised via other pathways or those who have not yet been able to decarbonise.

- **Information is required from producers on their achieved sales price.** Producers would need to provide their achieved sales prices across all projects. We would need to consider the calculation period to determine how often information is requested.

Summary

While actual sales prices are a proxy for market value, they may have a distortional effect if used as a reference price by discouraging the producer from seeking higher prices, and encouraging the building of volume through discounting prices. Other contractual mechanisms would be needed to avoid the hydrogen subsidy becoming an energy subsidy, and to ensure that producers are rewarded for achieving higher value sales.

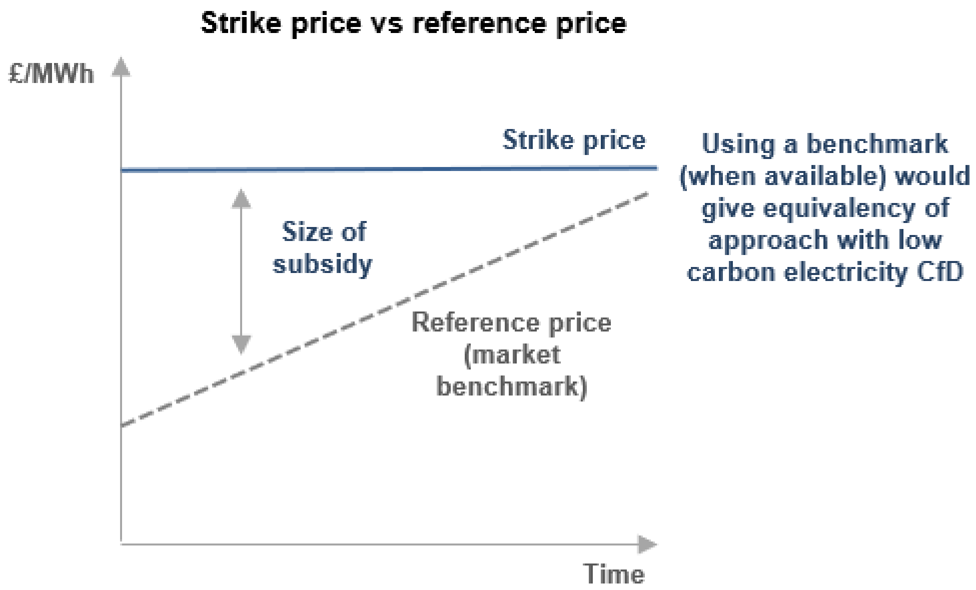
Reference price option 5. Market benchmark price

Description of option

Price benchmarks are used in energy markets in a variety of ways. Independent parties assess the value that the market places on an energy commodity and these are then used as reference points for contracts. A market benchmark for the hydrogen price, equivalent to Brent crude or the National Balancing Point for gas, does not currently exist.

We propose to work with price reporting agencies to consider how to enable the development of a market benchmark price. This is likely to involve collecting data from hydrogen producers on sales and playing a role in assisting and facilitating the early development of a benchmark, which might otherwise struggle to establish itself, in the absence of intervention, due to the private nature of contracts. Figure 9 illustrates a variable premium using the hydrogen market benchmark when it becomes available.

Figure 9: Market benchmark as a reference price



Advantages

- **A liquid market benchmark price would provide the clearest indication of the market value of hydrogen** and would be positively correlated to the value of hydrogen in the market.

- **Using the market benchmark as a reference price incentivises plants to maximise their market revenues**. A market benchmark is influenced by the hydrogen plant's activity but lies outside of its direct control. This results in basis risk i.e. the possibility that individual projects are either selling above or below that benchmark – see figure 9; and it is this basis risk which incentivises the producer to sell above the market benchmark. This basis risk arises due either to the nature of the market that they have been targeting or the way in which their contract has been structured. Producers selling below the market benchmark are likely to lose out as the subsidy would not support sales of hydrogen below the benchmark price. On the other hand, producers selling above the market benchmark are likely to earn a higher return as they would be receiving subsidy payment in addition to the market revenue from finding higher value end users. Producers would effectively be incentivised to reference the market benchmark in their offtake contracts which would help avoid contracts getting anchored at very low prices that do not reflect the market value.
- **Basis risk enables the hydrogen plant to potentially create a competitive advantage over other plants by developing and selling into higher value market segments**. For example, displacing carbon intensive hydrogen and diesel usage, rather than non-ETS natural gas usage, would enable plants to "beat the market benchmark". For plants that continue to sell only into lower value market segments, it encourages them to either undertake actions, such as assisting domestic heat customers to invest in energy efficiency, to enable them to charge the true cost of producing hydrogen to their customers.
- **The level of subsidy should reduce relatively quickly over time** in comparison to the other options given the incentive for producers to focus on developing higher value sales channels and being disadvantaged for failing to do so.

Disadvantages

- **We do not have certainty over when a benchmark for hydrogen would become available.** It is likely that it will emerge as the number of producers and end users increases, and the demand for a benchmark increases. At that point it would be the most logical reference price for a hydrogen business model contract.
- **This option may disincentivise sales into the lowest value markets.** For example, domestic heating end users are only paying the cost of natural gas without carbon priced in and therefore the price that they would be willing to pay is likely to be lower than the market benchmark (unless effort is made to enable such users to pay a higher price through efficiency savings). This may in turn impact decarbonisation in those markets over time. Projects seeking sales into those markets may raise their strike prices to manage the risk that they may receive too low a subsidy compared to their achieved sales price, although this risk may be lower with a competitive allocation process in place.

Summary

The market benchmark is currently not available for early projects and is therefore not suitable as a standalone reference price for projects seeking to take final investment decisions in the near term. Once available, it offers simplicity and brings an external and independent view on hydrogen prices. It would be the logical choice for a reference price as it is a reflection of the price which end users are willing to pay for hydrogen and is what we are seeking to proxy in the absence of a market benchmark. It would also introduce an equivalency of approach with

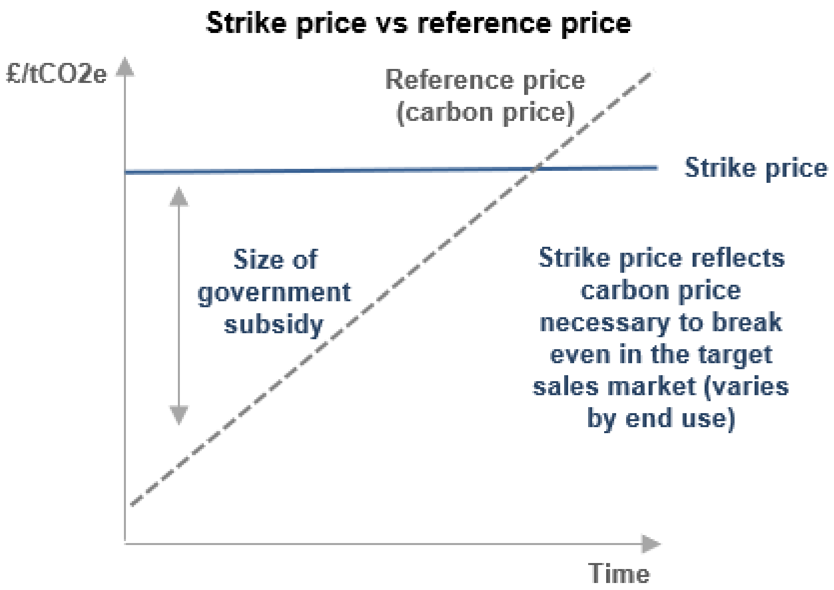
CfDs in the power sector. We would therefore expect the market benchmark price to be the reference price for NOAK projects.

Reference price option 6. Carbon price

Description of option

Another option is to use the carbon price as a reference price. In contrast to other options, the strike price under this option would no longer be defined in terms of the costs of producing hydrogen, i.e. £/MWh, and instead as a carbon value in £/tCO2 that would be necessary to allow low carbon hydrogen to compete with the counterfactual fuel – see figure 10. For example, a project focused on supplying natural gas end users would require a higher strike price than a project focused on the displacement of carbon intensive hydrogen, as it would be displacing less carbon and a lower value counterfactual. The strike price would thus reflect the carbon price it would take to sell into a particular end use market, and would vary between end uses.

Figure 10: Carbon price as the reference price



There is precedent for this approach already, as the Dutch SDE++ scheme[22] uses the EU ETS price, and in its first allocation round both reformation and electrolytic projects came forward for support. It would also be consistent with the reference price approach being used in the ICC business model.

Advantages

- **It is likely the market value of hydrogen and the carbon price in the initial stages of development will be correlated.** The primary benefit of using hydrogen is that it is carbon free at the point of consumption. This is in contrast to counterfactual fuels where carbon is emitted at the point of use. For end users currently using counterfactual fuels which are subject to carbon prices, the value of hydrogen will be closely linked to carbon prices which they would avoid paying when switching to hydrogen.
- **Carbon prices are likely to rise over time and therefore the subsidy is likely to reduce over time**. The costs of continuing to use the counterfactual fuel which is

[22] Key features of the SDE++ can be found at: https://english.rvo.nl/subsidies-programmes/sde/features-sde

subject to carbon prices will therefore rise over time. This is likely to be the primary driver of fuel switching for many end users.

Disadvantages

- **The carbon price may not perfectly reflect the market value of hydrogen.** The carbon price is only one of the drivers for the market value of hydrogen but not the only one. Other drivers of value include end users' willingness to pay as covered in section 1. It is therefore possible that the market value of hydrogen could be rising either faster or slower than the carbon price, in which case the producer would be respectively over or under subsidised.

- **The correlation between carbon price and market value of hydrogen will weaken over time.** Once carbon prices have risen and/or hydrogen production costs have fallen to the point where hydrogen is cost competitive on a carbon adjusted basis with the counterfactual fuel, the carbon price may no longer drive the value of hydrogen. The ability for the producer to pass on further increases in the cost of carbon to hydrogen end users would be limited by the ability of new entrants to enter the market without subsidy and compete on cost of production directly.

- **There is potential for gaming (either deliberate or inadvertent) by producers to maximise their revenues.** By linking to the carbon price, the strike price for the variable premium would be defined in terms of £/tCO2 rather than related to the price of hydrogen, and so as a result, the level of subsidy received would be independent of the price that the plant is actually achieving for its sales. The potential for gaming stems from hydrogen plants bidding strike prices on the basis of selling into one market, but could end up selling into other higher carbon value markets in reality. For example, if the strike price is set on the basis of selling into the natural gas market and the producer starts to sell into the transport market the producer receives too much subsidy as the strike price will be static.

- **The carbon price is not expected to be strongly correlated with costs of producing and therefore having a strike price as the carbon price may not reflect the right level of subsidy needed by producers**. Reformation-based producers are expected to capture a large proportion of emissions so avoid carbon pricing on the majority, although they would still be exposed to the carbon price for the proportion not captured. Electrolytic projects linked to dedicated renewables have no direct carbon emissions, and emissions from grid-linked electrolysers would be determined by the broader mix of electricity generation. There is the risk therefore that production cost increases or decreases would lead to under or over subsidy.

Summary

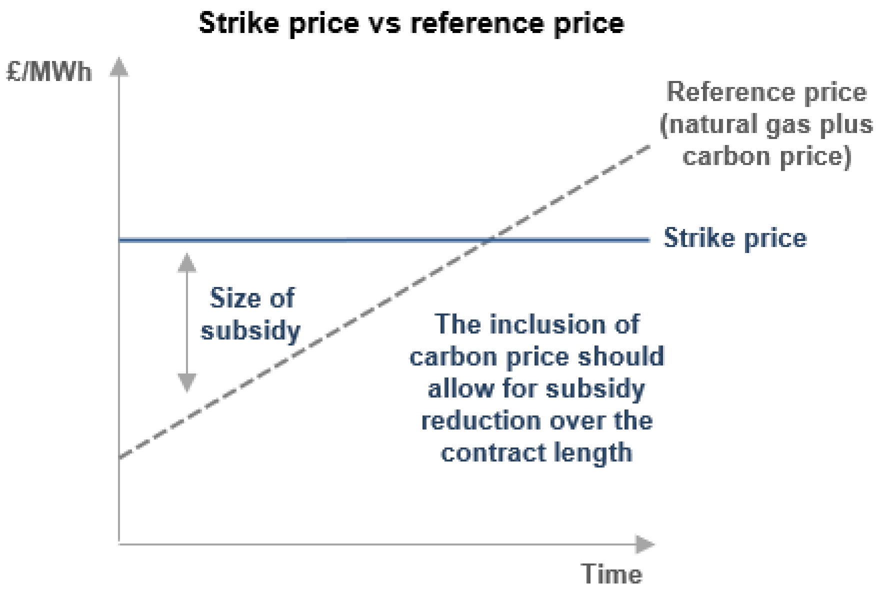
The carbon price approach may appear to be relatively simple but there is potential for overcompensation to the producer if the target market changes – from this perspective, it is easier to apply to the consumption side. The carbon price as a reference price also gives significant pricing freedom to the producer, with the subsidy reflecting their target market rather than actual costs of production or market value of hydrogen. As such, long duration, bilaterally negotiated contracts would bear higher risk of over subsidy, whereas shorter duration, competitively allocated contracts would likely offer a higher probability of avoiding excessive subsidy.

Reference price option 7: Natural gas plus carbon price

Description of option

The reference price could be expressed as the natural gas price plus the carbon cost associated with it – see figure 11. This approach combines previous options: natural gas (option 2) as the most common fuel which end users are likely to be switching from, with carbon prices (option 6) which are likely to rise over time.

Figure 11: Natural gas plus carbon price as reference price



Advantages

- **This is potentially the closest proxy to how the market might value low carbon hydrogen as a fuel.** For the industrial user this encapsulates the value of hydrogen to them on an ongoing basis as natural gas is the main counterfactual fuel and the primary benefit of switching to hydrogen is the carbon cost saving that it provides. A reference price that aggregates both natural gas and carbon price would be positively correlated with the value of hydrogen.

- **Producers would be encouraged to seek sales into higher value areas**. The level of subsidy payments would be driven by the value of low carbon hydrogen to a relatively low value market (i.e. natural gas). It would therefore incentivise producers to seek to maximise their market revenues and seek sales into higher value end use sectors such as transport or displacement of carbon intensive hydrogen to benefit from the higher revenue they would receive in those areas.

Disadvantages

- **The price incentive to switch is removed for end users in the industrial sector**. Fuel switching is dependent on upfront investment made by the end user to then enable them to use hydrogen. If the price at which they can buy hydrogen is the same as their existing fuel (i.e. natural gas plus the carbon price) then there are no ongoing cost savings to justify switching to hydrogen. The price incentive to fuel switch for various end users, as implied by the counterfactual fuel price minus the reference price, disappears or reduces for some fuels, slowing the rate at which the market develops.

- **This approach reduces the flexibility for producers to price into certain markets.** For end users currently using natural gas and subject to ETS the cost saving that they achieve by no longer emitting carbon has been taken away. For those not subject to ETS this approach makes it more costly to use hydrogen on an ongoing basis. Both of these remove the incentive of end users to switch fuels unless supplementary measures are implemented (such as grants for end users to switch). The producer may as a result seek higher strike prices to facilitate sales to natural gas users. This is to counteract the lack of flexibility to price at a lower level to these end use sectors.
- **As with Option 6, there may be a limit to the duration of how useful this reference price would be.** Once carbon prices have risen and/or hydrogen production costs have fallen to the point where hydrogen is cost competitive on a carbon adjusted basis with the counterfactual fuel, the carbon price may no longer drive the value of hydrogen. The ability for the producer to pass on further increases in the cost of carbon to hydrogen end users would be limited by the ability of new entrants to enter the market without subsidy and compete on cost of production directly.

Summary

Although this option is potentially the closest proxy for the value of hydrogen to end users, it may be less useful as a reference price as it removes incentives for end users in the industrial sector to switch and reduces producers' flexibility to sell into lower value markets. It might also result in the producer seeking higher strike prices to compensate for the lack of flexibility in pricing hydrogen to end users.

Government minded to position on reference price

All of the above options individually have drawbacks which could undermine their effectiveness as a reference price for a contract that is negotiated or signed in the 2020s, given how nascent the hydrogen market is. Natural gas as a reference price does not respond to the changing market value of hydrogen; counterfactual fuels introduce administrative complexity; achieved sales price could lead to market distortions; there is uncertainty around when a market benchmark will emerge; the carbon price may not be suitable beyond the point where hydrogen is cost competitive with counterfactual fuels; while a combination of natural gas plus carbon price largely eliminates or reduces the price incentive to switch for natural gas users, in particular in the industrial, power and residential heat sectors.

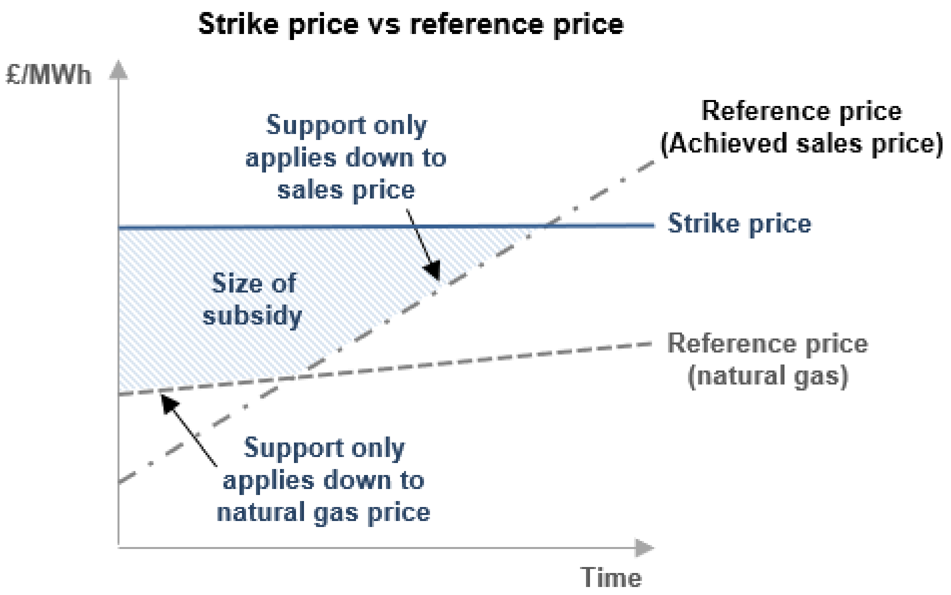
Our view is that, in time, the market benchmark price will best represent the value of low carbon hydrogen in the market. The point at which the hydrogen market is sufficiently liquid to have a representative benchmark price may be some time away, so this approach would be adopted for future contracts once we consider that the market benchmark will be sufficiently robust to be used as the reference price.

In the near term, for initial projects, the closest to a market benchmark would be the achieved sales price. This option gives pricing power to the hydrogen producer to incentivise end users to switch, but on its own it does not reward the producer for any effort in developing higher value sales, features no floor, and may encourage over reliance on government subsidy. It also could create wider distortions in other energy markets. We therefore propose to also include natural gas as a price floor given it is the most common fuel from which end users would switch so are likely to be willing to pay at least that price for hydrogen. The natural gas price floor would prevent the producer from receiving additional support for sales below that price, improving value for money for government.

In addition, we would like to incentivise producers to increase the achieved sales price and avoid sales remaining at the natural gas price floor for the duration of the contract, enabling the subsidy from government to reduce over time in line with the value of hydrogen increasing over time. To incentivise this, we are therefore minded to include additional contractual measures, such as a gainshare mechanism or a periodic payment linked to achieving or exceeding a defined pricing threshold or benchmark. This approach would require appropriate reporting and monitoring processes to ensure transparency, as well as careful design to avoid perverse outcomes. Further work on these additional contractual measures will be discussed with stakeholders.

In summary, our minded to position is that, for initial projects, the reference price would comprise the higher of the natural gas price and the achieved sales price – see figure 12. We expect that this would be combined with additional contractual measures to incentivise producers to seek higher priced sales. Under this model, the plant would not receive additional subsidy for sales below the natural gas price, to deliver value for money for government and to avoid distorting energy markets, but when sales occur above the natural gas price, the sales price would prevail. We are minded to take this approach for initial projects and integrate a market benchmark into this approach at the earliest opportunity for future projects.

Figure 12: Minded to position on reference price - highest of two inputs



While this approach uses more than one reference price in the reference price calculation, it is still a single rather than multiple reference price approach. This means that, at any one point, only one reference price would apply.

Any variable reference price gives rise to a correlation risk between the value of sales of low carbon hydrogen and the level of support payment received. This might occur if the reference price is not also reflected in the sales agreements between low carbon hydrogen producers and end users (such as would typically be seen in contracts for other manufactured fuels). A variable reference price may limit the ability of producers to offer fixed price sales agreements for low carbon hydrogen to end users in the absence of pathways to manage the resulting basis risk. Nonetheless, our view is that the use of a variable reference price, and therefore the incentive for sales agreements to reflect that same variable reference price, is more likely to both facilitate the price discovery process for the market value of low carbon hydrogen and prevent downstream distortions that might arise from high levels of government support being locked in by early end users through fixed price sales agreements.

There are interdependencies of our minded to position on the reference price with indexation which are considered in detail in the next section.

3. **Do you agree with our minded to position for a variable premium for price support? Please provide arguments to support your view.**

4. **Do you agree with our minded to position for setting the reference price? Please provide arguments to support your view.**

5. **Does our minded to position create any other specific risks, incentives or disincentives which we have not already stated above? If so, what are they and how could the related risks be addressed – either within the model or outside of the model?**

4.3 Indexation

Production costs can increase or decrease over time as a result of rising or falling input costs (such as fuel costs). If the strike price remains fixed while production costs increase or decrease this could lead to under or over subsidy to producers through its impact on producers' equity returns.

Indexation is a method to link the value of payments to changes in production costs which are outside of the producer's control. Indexing the strike price protects the producer from having their margins impacted from input costs being higher than expected, while also protecting government against the possibility of the producer making higher-than-expected profits due to falling input costs.

Leaving strike prices fixed would mean the producer would have to manage their input price risk. Producers would have to rely on being able to obtain long-term supply contracts at fixed prices without variability and there is no guarantee that these would be commonly available. Without indexation of the strike price, it is likely that producers will bid for higher strike prices to manage their exposure to future changes in input costs. We therefore consider there is a case for the strike price, or elements of it, to be indexed and have considered the possible approaches to this, as well as which approaches might be most suitable for different production types.

4.3.1 Indexation options

We have considered four options for indexing of the strike price: inflation-linked, natural gas benchmark, electricity price benchmark and actual input energy cost.

Indexation option 1: Inflation-linked

Advantages

It is simple and reflects the increase in cost of some components of production. It is also supported by precedent as it is a mirror of the approach used for electricity CfDs where the strike prices are indexed to Consumer Price Index (CPI) inflation.

Disadvantages

- **Inflation may not reflect the input cost changes faced by hydrogen producers.** For renewable electricity generation the majority of total project costs are fixed (and cover elements such as staff and maintenance). In the case of a hydrogen plant, the primary component of project cost is input energy costs[23], which are driven by supply and demand for the input energy rather than inflation more generally. Electrolysers combined with dedicated renewable sources of energy may have a similar cost structure to renewable electricity generation. This might make inflation a better measure of ongoing cost changes for electrolysers linked to dedicated renewables.

- **Inflation always has a positive average value (based on historical evidence).** Taking CPI inflation, the Bank of England has a mandate to target 2% inflation, and since CPI was introduced the lowest recorded monthly annual figure is +0.2%.[24] Over the duration of a long contract, it would be potentially expensive for government in nominal contract value terms to provide this type of indexation. In real terms however, the cost would not have changed.

Indexation option 2: Actual input energy cost

Advantages

- Each producer faces a unique set of energy costs. Indexing to input energy costs would therefore reflect the actual energy costs faced by a producer (e.g. for a methane-reformation plant mostly natural gas with some electricity costs), protecting each individual producer in full from any changes in the energy costs faced.

Disadvantages

- **As the costs faced by producers are unique, they are not easily observed.** This would put a much higher administrative and monitoring burden on the delivery body to ensure that the producer is reporting the right input energy costs.

- **There is a risk of transfer pricing distortions.** As outlined in the reference price section, transfer pricing might happen if the project is integrated with the input energy source, and the price that the hydrogen plant is charged for that energy is used to move profits from one part of the value chain to another**.**

- **A producer might be less diligent in controlling their input energy costs** as they are not liable for any changes to future input energy costs.

Indexation option 3: Natural gas benchmark

Advantages

- **There are relatively strong links between hydrogen activity and natural gas.** End users currently using natural gas, such as industrials, are likely to be the largest group switching to hydrogen, and CCUS-enabled producers use natural gas as an input fuel so it will likely be the primary input fuel for large-scale hydrogen producers in the near

[23] More detail on cost structures across technologies can be found at: https://www.frontier-economics.com/media/4157/business-models-for-low-carbon-hydrogen-production.pdf
[24] Historical data on the Consumer Price Index can be found at: https://www.ons.gov.uk/economy/inflationandpriceindices/datasets/consumerpriceinflation

term. There is therefore a strong correlation between the value of hydrogen, the cost of producing CCUS-enabled hydrogen and natural gas prices.

- **Natural gas prices and wholesale electricity prices are partially correlated.** Natural gas is still an important fuel for power generation so there is a relationship with electricity prices. The energy sector is familiar with spark spreads (i.e. divergence between natural gas and electricity prices), and there is a wide array of physical and financial tools available to manage the differences between them.

- **Natural gas prices are fairly stable.** They are also less volatile than electricity prices because natural gas is easier to store and therefore **the natural gas market** does not have the same challenges as the electricity market.

Disadvantages

- **The link between electricity and gas prices will alter.** Over time, the correlation will become weaker by the move to net zero, as more renewable energy sources comprise the fuel mix supplying the electricity grid. Electricity storage, Liquefied Natural Gas (LNG) import dependency and hydrogen will all have an impact. This may over- or under-reward electrolytic projects as the costs of input energy are not necessarily tied to natural gas prices.

- **There may be a tension between this approach and wider policy.** Wider security of supply considerations might have an impact on natural gas prices and potentially make them less stable which could make this a less favourable option for indexation.

Indexation option 4: Electricity price benchmark

Advantages

- This option may be a reasonable proxy for input energy costs for grid-linked electrolyser plants. With a greater proportion of electricity from renewable energy sources in future, we may see the wholesale price of electricity fall, contributing to potentially lower strike prices in due course.

Disadvantages

- This option would enable grid-connected electrolysers to run continuously, even at times when electricity prices are very high. Short-term electricity prices can be very high and therefore could result in a large subsidy payment. We would want to incentivise grid-connected electrolysers to operate at times of low electricity prices to ensure electrolysers work in tandem with the power grid and do not place extra stress on the power grid at times of low variable renewable generation and high electricity demand.

- Depending on how low carbon hydrogen standards are formulated, it could enable electrolysers to run at times when grid carbon intensity is high. This would increase the strain on the electricity grid, whereas it would be ideal for electrolysers to act as a source of variable demand, switching off at times of high power prices / low renewable generation.

Summary of options

Input energy cost is the largest component for all technologies, apart from for electrolysers combined with dedicated renewables where the largest costs are capital expenditure. General inflation changes therefore would not fully protect most hydrogen producers from input cost changes.

Actual input energy prices might best reflect the variation of costs for each producer. However, they are unique to each producer so indexing to these introduces complexity through the monitoring required to assess the input fuel mix used.

Electricity prices best reflect costs faced by grid-linked electrolysers but indexing the strike price to an electricity price benchmark would likely place extra strain on the power system grid as it would not disincentivise electrolysers from running at times of high electricity demand.

The natural gas price index is likely to be strongly linked with future hydrogen activity and the cost of producing CCUS-enabled hydrogen. Natural gas prices have the potential to fall as well as to rise so we could see a reduction in strike prices over time, and not just a strike price on an upwards trajectory that we would get (based on historical evidence) with general inflation indexation. Although natural gas is also an input to producing electricity, and there is a well understood relationship between natural gas and electricity prices, the link between natural gas and electricity prices is likely to weaken over time.

We propose to carry out more analysis to consider how the indexation options work across different archetypes of projects, the impact on producers' incentives to invest in hydrogen production and whether different approaches are appropriate for different production technologies. We will consider whether to apply indexation for input fuel costs and whether there are other cost elements which also need consideration.

We welcome stakeholder views to support our thinking on this.

6. **What do you think is the most appropriate option (or options) for indexation of the strike price? Please explain your rationale.**

4.4 Limitations to price support for users of hydrogen as a feedstock

While our preferred reference price mechanism is intended to accommodate all end use sectors, we are considering the risk of overcompensation where hydrogen is used as a feedstock. Existing users of carbon intensive hydrogen as a feedstock (e.g. chemical sector, ammonia production) already place a relatively high value on hydrogen and pay a higher price associated with using carbon intensive hydrogen (see section 1).

If users of hydrogen as a feedstock were to receive hydrogen benefiting from the same level of subsidy as end users switching from counterfactual fuels, it could lead to over-reward and create distortions in the downstream markets they compete in. For example, hydrogen subsidised at the price of natural gas would allow an ammonia producer to cut the price of its products without diminishing its margins and gain a competitive advantage compared to other ammonia producers using unsubsidised hydrogen. This could include competing producers decarbonising their existing carbon intensive hydrogen via CCUS with support from the ICC business model, which supports the cost of carbon abatement but does not subsidise the production of hydrogen.

Support to hydrogen producers via the business model should provide a proportionate subsidy to incentivise users to switch to low carbon hydrogen. We are therefore interested to hear views from stakeholders on the potential need to limit the proposed price support for uses of hydrogen as a feedstock. We also welcome views from stakeholders on potential measures which could be considered to counteract any risk of over-reward, including capping support to the equivalent of the additional costs needed for retrofitting CCUS on ‘carbon intensive’ hydrogen plants (e.g. through the ICC business model as an alternative decarbonisation route) and potential mechanisms to recoup any excess subsidies.

7. **What are your views on whether price support for low carbon hydrogen should be constrained for applications using hydrogen as a feedstock to mitigate potential risks of market distortions? Please explain your rationale, including any suggestions both within and outside the business model to mitigate these risks.**

Government’s ‘minded to’ position on price support

Our preferred option for price support is a variable premium. It gives the price support intervention flexibility and adaptability that the fixed price and fixed premium approaches do not provide. In particular, it enables the possibility that the level of subsidy can reduce over the length of the contract as the market evolves, rather than only across allocation rounds.

The key for ensuring this mechanism realises the benefits is finding a workable solution for setting the reference price. We have considered a range of options for the reference price, all with their own advantages and drawbacks. Our preferred option, for initial projects, is the approach that comprises the highest of two inputs: the natural gas price and the achieved sales price. We expect that this would be combined with additional contractual measures to incentivise producers to seek higher priced sales. We aim to integrate a market benchmark price into the reference price at the earliest opportunity for future projects.

We have considered options for indexation of the strike price to address the risk to producers from changes in input costs. We recognise the need to carry out more detailed design work on how each of the indexation options we have set out might work across project archetypes and producer incentives, as well as interaction with other features of the design. We are planning further work on the appropriate approach to indexation.

We are considering the risk of overcompensation where hydrogen is used as a feedstock and the potential need to limit price support for feedstock applications. We are planning further work on the potential measures to address this.

8. **Do you agree with our overall minded to position on price support? Please provide arguments to support your view.**

Section 5: Volume support

We are designing a revenue support contract in the early stages of the creation of the low carbon hydrogen economy where volume risk (i.e. the risk that the producer is unable to sell enough volumes of hydrogen to cover costs with reasonable confidence) is at its highest. As noted earlier, various measures that sit outside the scope of the business model contract could reduce volume risk for hydrogen producers, such as the availability of hydrogen distribution and storage infrastructure, ability to blend hydrogen into the existing gas grid, as well as a wide pool of end users ready and able to use hydrogen. Our assumption is that such measures will not be available when initial projects are making their final investment decisions but may be available once these projects are operational and for projects coming online later this decade. Therefore, we expect the level of volume risk faced by producers to reduce over time.

We have reviewed five volume support options, assessed each one against the key principles for business model design, and considered how well they support our objectives. The options are: availability payments, partial government offtake, government offtake backstop, government offtake frontstop and sliding scale.

We have considered how well the volume support options perform across project archetypes (generally defined by operating characteristics, project size and technology type). We believe all options potentially work equally well across different project sizes and technology types, and therefore have focused the assessment on type of operations: continuous operations (characteristic of reformation-based technologies and potentially grid-linked electrolysers) and intermittent operations (more characteristic of electrolytic projects linked to dedicated or curtailed renewable electricity sources).

All volume support options have been assessed on the basis of a variable premium being provided as the price support mechanism.

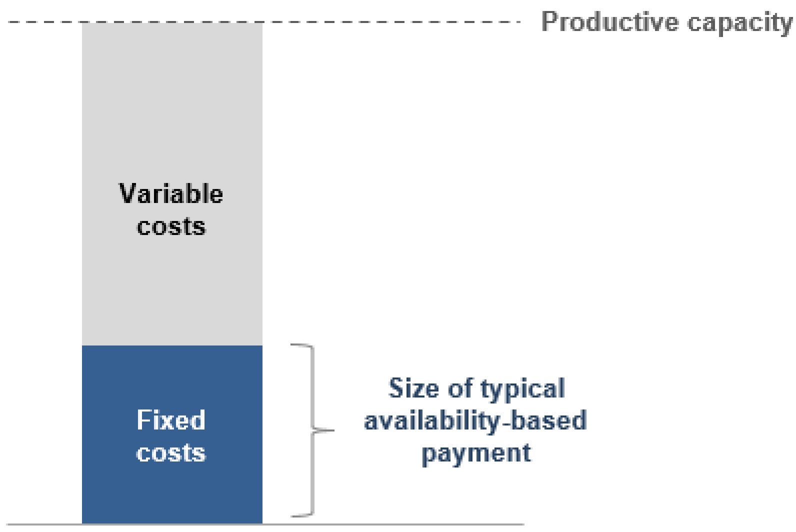
5.1 Volume support options

Volume support option 1: Availability-based payments

Description of option

Availability payments are neither linked to production nor to profitability, but to physical productive capacity. The plant owner is compensated for making the plant’s capacity available to the market, and this therefore ensures that construction can proceed even if market demand is not sufficiently robust to otherwise justify the investment (or continued operation). Availability-based payments are typically sized to cover the fixed costs (including maintenance) of the plant – see figure 13.

Figure 13: Availability-based payments[25]



Availability-based payments are used in the GB Capacity Market in that capacity providers are paid regardless of whether the assets are generating or not, and aim to ensure reliable sources of electricity capacity are available when needed. These payments are intended to address the risk that potential revenues from energy-only markets may not incentivise sufficient investment in new capacity to deliver an adequate level of security of electricity supply.[26]

Availability-based payments are also proposed under the Dispatchable Power Agreement ("DPA") for power CCUS. Availability payments typically provide a premium to resources that might otherwise be unavailable to the market due to the relative infrequency with which they might be called upon (e.g. peaking power plants and battery storage). Actual electricity generation is then stimulated by wholesale market price signals and instructions from market operators.

Advantages

Volume risk is eliminated for producers as they are primarily compensated for availability rather than production. This ensures the plant is investable even if offtake volumes are not secured, enabling producers to build plants in advance of the market developing, and offers at least some protection of their investment in the event that end users are lost.

Disadvantages

There are however significant challenges with using availability-based payments to provide volume support:

- **Significant budget is used with no guarantee of any decarbonisation** because payments only ensure availability of productive capacity rather than incentivising actual production of hydrogen so this approach does not help government achieve value for money.

[25] Fixed costs include the upfront investment costs of the plant plus fixed operating costs, which include for example debt repayment and personnel costs, amortised over the duration of the contract
[26] A presentation on the design of the GB Capacity Market can be found at: https://www.gov.uk/government/publications/final-capacity-market-design-presentation

- **Lack of physical production support may be insufficient for some hydrogen production technologies where there is a minimum safe operating level** so availability-based payments may to some extent be counterproductive. While it is possible for some electricity generators to operate at very low utilisation rates and to respond to calls from the market within a specific, typically short timeframe[27], the same is not necessarily true of hydrogen plants. Methane reformation-based technologies are particularly sensitive to utilisation levels, with a minimum operating capacity of c.70% and a turn up/down rate of no more than 10% in 24 hours.[28] Simply having a financial payment to be available may not work as well for such plants as having physical offtake of the same value given the minimum load factors.

- **Approach is more suited to supporting intermittent operations and not continuous operations**. Availability payments are typically used for markets where there is high variability in demand, the end product from producers is fully fungible and where there is limited ability to store the product. In the electricity market these payments are designed to encourage investment in resources needed to maintain security of supply but which might otherwise be uneconomic due to the relative infrequency with which they might be called upon. This type of payment would appear less appropriate at this stage of the hydrogen market development, where end users and producers have a more closely tied relationship, than in future when there is a more liquid market.

- **Approach would not mature with the market.** Availability-based payments have the potential to become an enduring competitive advantage for the recipient as the market develops. The payment typically would be calculated as the upfront investment costs of the plant plus fixed operating costs, amortised over the duration of the contract. For this reason, the size of the payment would remain fixed and the producer would continue to benefit for the whole contract term. As the market develops, these payments could end up over-subsidising the producer, as they would still be due even when the market price of hydrogen is sufficient to support fixed costs without availability payments.

- **Once the plant is operational it is derisked and can be refinanced at a lower interest rate** which the availability payment may not account for. The interest rate at which projects attract debt financing is higher the greater the risk being taken by the lenders. This risk will be higher during construction (given risks of cost overruns, and lack of positive cashflows) and will reduce as the plant becomes operational. If this future lower rate is not accounted for in the availability payment at the start, it may dilute some of the incentive for producers to seek offtakers and reduce value for money for government.

- **Availability payments are an enduring model feature so may be difficult to reduce or remove entirely.** By starting with availability payments, it may create an ongoing demand from project developers and capital providers to continue with them into the future, to avoid the risk of NOAK projects being disadvantaged with respect to profitability or access to low cost capital in comparison to legacy plants. Removing them may therefore be difficult without reducing investment demand. They also provide little future optionality to government as they are an obligation to make payments for which

[27] Services range from calls to respond in sub-second to 30-45 min depending on the technology. A list of National Grid balancing services can be found at: https://www.nationalgrideso.com/balancing-services/list-all-balancing-services
[28] Taken from a BEIS commissioned report led by Element Energy, which can be found at: https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base

nothing monetizable is received (i.e. it does not secure any volumes of hydrogen, only an obligation to remain available to produce).

Summary

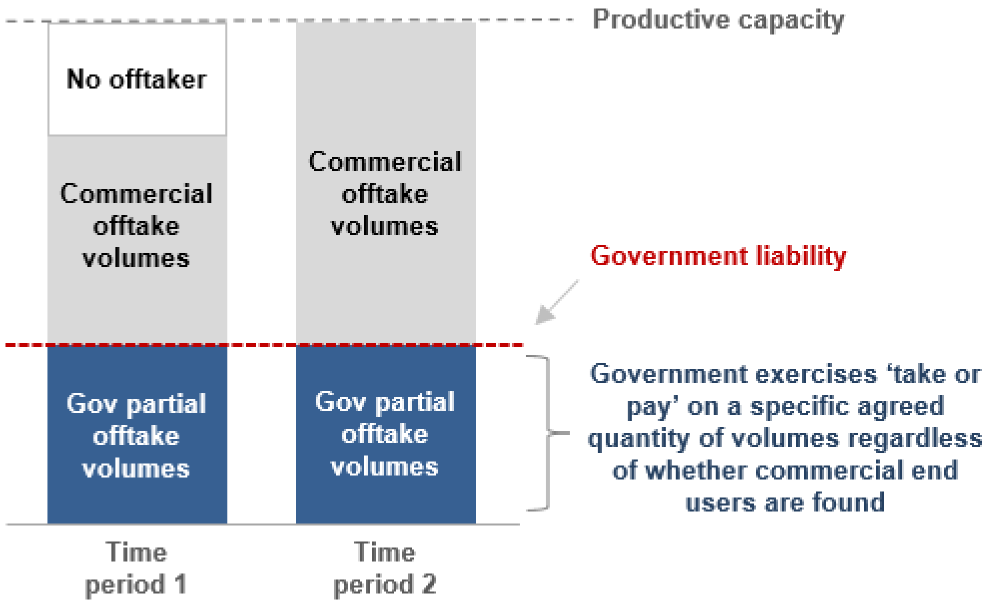
Although volume risk is removed for producers, which would make it easier to obtain financing for construction, the main disadvantage of availability-based payments is they do not incentivise production of hydrogen so there is no guarantee of decarbonisation benefits. This approach also does not evolve over time and therefore is not our preferred volume support option for aiding the roll out of hydrogen projects and the development of the hydrogen economy.

Volume support option 2: Partial government offtake

Description of option

As noted, a key weakness of the availability payment approach is its (by definition) lack of link to actual production. The partial government offtake option seeks to address this with an obligation on government to offtake a specific quantity of volumes for a specific duration to mitigate potential volume risk for the producer over the duration of the contract. This would be irrespective of whether the producer secured commercial offtakers – see figure 14.

Figure 14: Partial government offtake



The volumes are purchased at a price which allows the producer to cover fixed costs, maintenance, debt servicing and a portion of equity return - a 'minimum economic return' (MER). The MER is important as it represents the 'downside case' which investors in production plants would look for to make an investment. It is unlikely that a bank or financial investor would provide funding to a project where the reasonable downside case provides zero return to producers as this would raise questions about how committed that sponsor would be to the safe, reliable and continued operation of the project.

Government would have the option to 'take-or-pay' – this means volumes could either be settled physically (i.e. government takes the volumes produced and uses or remarkets them) or financially (i.e. government does not take volumes but pays the producer for their value). The latter would be similar to an availability payment; the difference being under this option the government would be able to choose whether to invoke it, rather than it being inherent to the model design.

Advantages

- **Volume risk is removed for the volumes government has agreed to purchase, making this option investable.** It gives producers certainty that they have some offtake volumes secured, with the price at which the volumes are settled enabling the producer to cover the MER required for the project to be investable. The producer takes all the risk over remaining volumes.

- **Government has certainty over physical volumes it will be receiving at all times and/or its financial liability for volume support.** As a result, government can make plans for how it will use any hydrogen bought as the size of the liability to manage it is known. It could potentially sell the hydrogen via offtake contracts which government could secure with another party, although this may not be viable in practice if producers have themselves not been able to secure end users.

- **The government offtake contract is suitable for supporting NOAK projects as the offtake can be reduced or removed if no longer needed.** Supporting projects to create a new market through offtake is more akin to a standard private sector structure for project development – for example, in many countries around the world liquified natural gas projects and fossil fuel-fired power plants are typically developed on the back of offtake contracts between private parties. As a result of echoing a more commercial structure, the approach becomes more responsive to the development of the market – as prices increase and liquidity improves, the government offtake contract becomes a valuable asset rather than just an obligation to buy volumes from the producer. If pricing is particularly favourable to government, the plant itself may wish to buy themselves out of the support. The government offtake contract can also be structured as a side agreement rather than forming an enduring feature of the business model. It can then be removed for future contracts if it is no longer needed.

Disadvantages

- **The level of government intervention necessary with this option may create distortionary effects in the market.** Commercial sources of offtake demand may be crowded out by government buying physical volumes or settling financially and may undermine market competition. There is also the critical issue of what government does with the volumes of hydrogen which are purchased. If it does not have a use for these volumes, government is unlikely to be as effective as private producers at remarketing any physical volumes purchased, and may find itself in competition with the plant that it is supporting, to the detriment of both parties.

- **This approach is more suited to continuous operations**, where the offtake volume could be expected to reflect a fairly constant proportion of overall plant output. When applied to plants producing hydrogen intermittently, this support becomes difficult to size. If the plant is not producing then government cannot provide any support but there could also be times when the government offtake comprises the plant’s entire output. Either of these outcomes are not ideal in mitigating volume risk for producers.

- **Significant complexity for government as delivery, institutional and potentially regulatory architecture is needed** for government to successfully carry out its obligation to settle volumes. This includes introducing a body to make certain decisions: whether to ‘take or pay’ hydrogen; what government does with volumes if purchased;

setting out the conditions under which government would take hydrogen and when it would settle volumes financially instead; how these conditions might evolve over time as the market develops and how frequently these decisions need to be taken. In the event government settles volumes physically instead of settling financially, there would be substantial decisions to be made for what government does with the volumes. There are four options: for the hydrogen to be sold, stored, vented or flared. Government could remarket the hydrogen and sell onto third party buyers but as mentioned above this may not be viable in practice if producers have themselves not been able to secure end users. It is also not a core competence of government to be performing this type of role in commercial contracts. Storing hydrogen would be dependent on the infrastructure being available so is not an option for FOAK projects. Without end users willing to buy the hydrogen, storing hydrogen delays decisions which government would still have to take in the future. If hydrogen is disposed of (i.e. vented or flared) the benefits of using hydrogen are not realised and therefore this represents extremely poor value for money for government compared to utilising the pay option.

Summary

Government could seek to mitigate some of the disadvantages described above by reducing the offtake volumes purchased but this may trade off with having to offer higher unit prices for volumes to enable producers to still cover the MER they need for investment. Government could also limit the duration over which this support applies. On balance however the level of intervention required with this option is significant with substantial risks of crowding out commercial end users. As such, it is not our preferred approach to providing volume support.

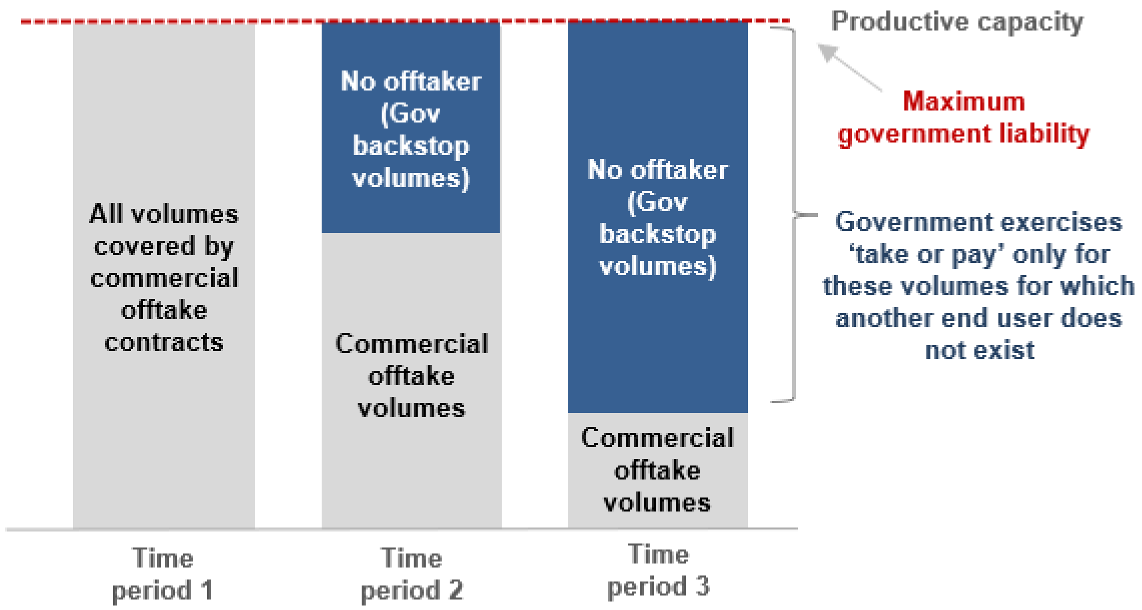
Volume support option 3: Government offtake backstop

Description of option

The key concern with the previous model, i.e. government intervening in the market and buying volumes, is the distortionary effect in the market and the potential for crowding out commercial end users.

The government offtake backstop, as presented here, seeks to address this point by acting as a buyer of last resort only for those volumes for which another end user does not exist, either at the outset of the contract or during it (or both). In the previous option government purchases a set volume of hydrogen with certainty in each time period regardless of whether alternative commercial end users are found by the producer. In option 3, however, the backstop is triggered only when market demand is lower than that set out in the contract, i.e. government steps in on a contingent basis, and purchases the first volumes that cannot be otherwise sold. Figure 15 sets out how government backstop volumes would vary based on offtake scenarios across time periods.

Figure 15: Government offtake backstop



The price paid by government to the producer under the backstop would be sufficiently unattractive to discourage reliance upon the backstop, but attractive enough to enable the plant to cover the MER required and therefore enable the plant to be built in the first place. As with the partial offtake option, government could choose to settle these volumes physically or financially.

A similar mechanism was developed as part of Electricity Market Reform, with a Backstop Power Purchase Agreement (BPPA) introduced in order to act as an Offtaker of Last Resort (OLR) for renewable electricity.[29] The OLR for holders of a CfD is a private sector entity (the largest energy suppliers). The BPPA only lasts for 12 months, and the auction through which the buyer offtakes starts at a discount of £25/MWh to the prevailing market price. Since its implementation in 2014, there have been no applications to use the scheme.[30] It is not difficult for the largest energy suppliers to find willing end users of electricity at a discount. However, such a mechanism with a private sector OLR would be difficult to apply to the hydrogen market given how nascent it is and in particular where 'demand sinks' such as grid blending do not exist in the same way as for electricity.

Advantages

By agreeing to purchase any volumes produced for which a commercial end user has not been found, government eliminates the producer's volume risk entirely, and therefore enables both initial investment and ongoing operations. As the market develops the backstop may be triggered less frequently, or in decreasing volumes, but this is not certain.

[29] The Backstop Power Purchase Agreement Contract can be found at: https://www.ofgem.gov.uk/publications-and-updates/backstop-power-purchase-agreement-bppa-contract
[30] The 2018-2019 Annual Report on the Offtaker of Last Resort can be found at: https://www.ofgem.gov.uk/publications-and-updates/offtaker-last-resort-annual-report-2018-19

Disadvantages

- **Incentives are weakened for producers to seek market demand for their hydrogen** as government will purchase any remaining volumes required for the producer to cover the MER. The producer knows they can always sell their hydrogen and may therefore be less selective about which customers they agree a contract with – placing a much greater onus on government to adequately assess the risk of individual end users, especially for FOAK projects.

- **Market formation may be undermined**. If the backstop is physical (i.e. 'take' rather than 'pay'), further distortions may arise if commercial end users choose to wait for government to sell at a low enough price (which producers may not have been able to offer due to the price support model) instead of buying from the producer directly.

- **Government buying volumes on a contingent basis gives rise to budgeting difficulties.** Having no certainty as to what the volumes will be in each time period requires larger headroom to accommodate for higher spending, or otherwise there is a risk of budgetary overspend. Even if the plant has secured commercial offtakers for its full productive capacity and government offtake in that period is zero (a 'good outcome'), government's contingent budget has been tied up which could impact the overall number of projects being supported.

- **The backstop is more suited to continuous operations.** With intermittent operations there would be a need to ensure the backstop is only drawn upon when the plant could and would have actually produced, rather than when input energy would not have been available or would have been available but at prices that would have been uneconomic. For the backstop to work for intermittent operations, significant reporting and monitoring would be required to prevent gaming.

- **Significant complexity for government** as delivery, institutional and potentially regulatory architecture is needed for government to successfully carry out its obligation to settle volumes as with the partial offtake option. This detail is set out in option 2.

Summary

The level of intervention required with this option is significant and it risks undermining market formation and weakening incentives for producers to seek market demand for their hydrogen. Some of the above issues could be mitigated partially by paying the producer not to produce instead of settling volumes physically, which would be the less costly option if government has no offtake or storage alternative. This option comes with the risk that the backstop pays for non-production in a similar way to availability-based payments, effectively acting as a minimum revenue guarantee. We have outlined above our view that these are not our preferred starting points.

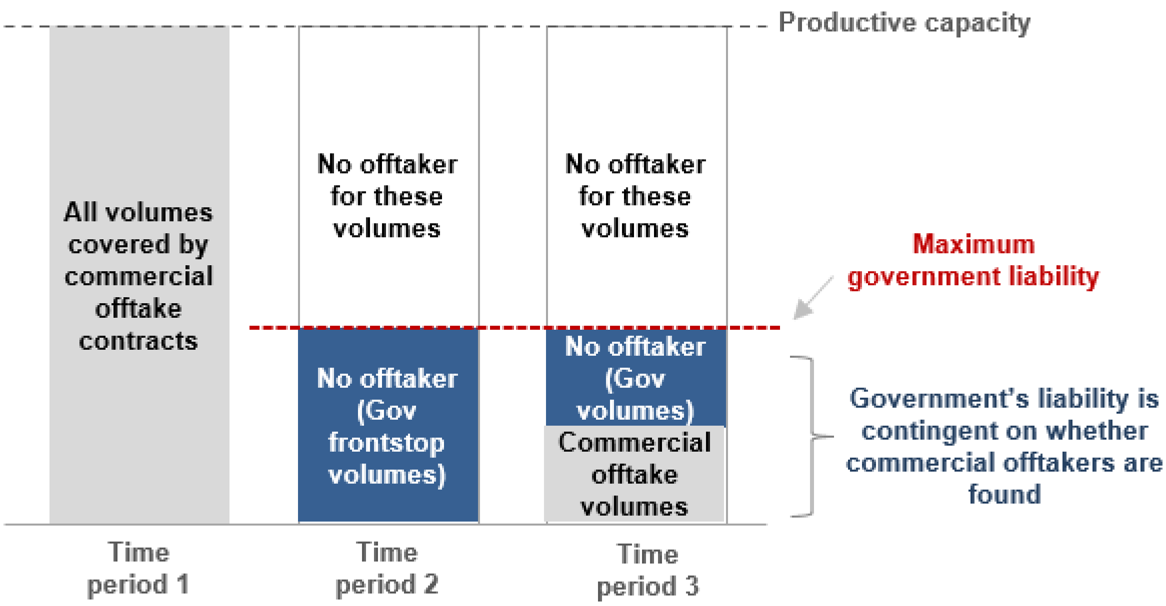
Volume support option 4: Government offtake frontstop

Description of option

An alternative approach is an option which combines the benefits from the contingent nature of the backstop with the smaller volumetric commitment of the partial offtake.

The government offtake frontstop is equivalent to the government offtake option but with an obligation on the producer to re-sell the government's volumes before selling any other volumes. A safety net similar to a backstop is created through this approach, but government support is triggered on the last volumes that cannot be sold rather than the first volumes (i.e. offtake volumes need to drop to below the point at which the plant cannot cover the MER before the frontstop is triggered). The support given by the frontstop is also across lower volumes than with those covered by the backstop. Figure 16 sets out how government support through the frontstop option would vary with different offtake scenarios across time periods.

Figure 16: Government offtake frontstop



Compared to the backstop, the frontstop leaves volume risk with the producer to a greater extent, as it would be triggered at relatively low levels of market demand rather than at below full capacity as in the backstop approach. However, the level of financial support on a unit basis would need to be higher to support the producer in covering their MER across a narrower 'slice' of volumes.

There is an additional layer of complexity under this option. In the frontstop, if the producer cannot sell the frontstop volumes at the price agreed with government, then government would have to pay the producer the difference. This is the frictional cost of making the mechanism work as otherwise the producer would lose out. If, however, the producer is able to achieve a higher market price then the producer returns the difference to the government so the payments work in both directions and give certainty to government on budget and producers on revenues.

Advantages

This approach reduces volume risk for the producer by ensuring they are able to cover the MER in the event offtake volumes fall away. Producers are incentivised to find commercial end users as only a narrow 'slice' of volumes are covered by the front stop. The contract could be structured in a way that reduces over time, in a similar way to the partial offtake option, and be suitable for future pipeline projects.

From a government perspective there is a reduced probability (compared with the backstop) that volumes would either have to be fully paid for or taken (i.e. take-or-pay basis), as the circumstances under which it would be triggered are more remote (assuming projects have been adequately assessed prior to contract award) and government can clawback some of the support from volumes sold on behalf of government.

Disadvantages

As with the partial offtake option there is some potential for the frontstop to undermine market competition as government volumes would have to be sold in the market but this effect would depend on the price the producer is able to achieve for government volumes. If the volumes are not sold then there is a risk that government achieves poor value for money. The contingent nature of this option ties up government budget in a similar way as described under the backstop option, and including ‘take-or-pay’ requires government delivery, institutional and potentially regulatory architecture. The frontstop is also more suitable for supporting continuous operations than intermittent, similar to the options from which it is derived (details are noted under the partial offtake and the backstop options).

Summary

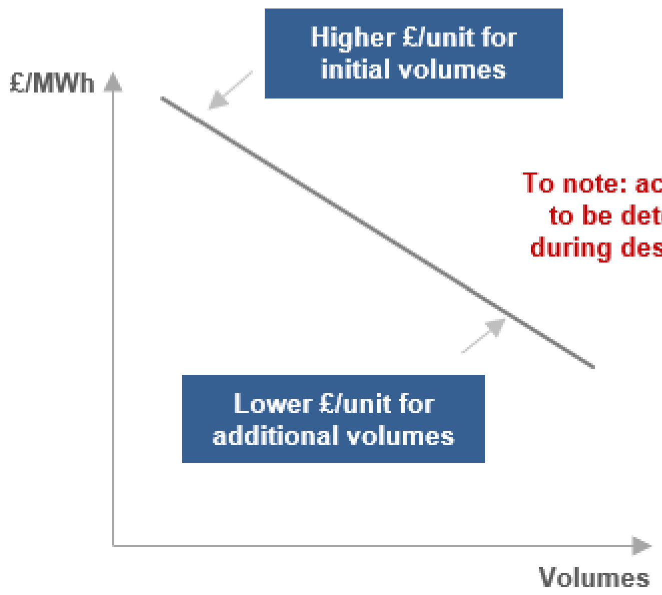
This option combines the advantages of the partial offtake and backstop options and also works to mitigate some of the disadvantages. Putting limits on the duration of the frontstop may further mitigate some of the disadvantages of this option. It might however mean that government would need to offer a higher per unit price to make this option investable. One of the key drawbacks is that the frontstop is less suitable for intermittent operations. In addition, the potential for the frontstop to undermine market development remains, as well as the need for complex government delivery architecture. For these reasons, the frontstop is not our preferred option.

Volume support option 5: Sliding scale

Description of option

In contrast to the preceding options, a sliding scale approach provides volume support indirectly through price variation. The government does not purchase any hydrogen under this option and therefore does not guarantee volumes or a MER to the producer. Instead, this option reduces the volumes that need to be sold for the producer to cover their MER. It allows the producer to earn higher unit prices where offtake volumes are low to help recover fixed and marginal costs. This support declines as the offtake volumes the producer secures increase, such that while revenues would continue to rise with volumes, it would be at a declining rate – see figure 17. These later volumes would enable the producer to earn their target equity returns. In the event offtake volumes fall to zero after the contract is in place there is no support provided to producers.

Figure 17: Sliding scale



The application of a sliding scale approach is commonplace already in various policy areas. For example, a progressive sliding scale is adopted for how much income tax is paid by UK workers. The amount of income tax paid depends on how much income falls into each tax band – income in the first band is not taxed, while income in the last band is taxed at a marginal rate of 45%, such that the amount of tax paid increases progressively rather than proportionally with increases in income.[31]

Advantages

- **Producers have an incentive to find and build offtake volumes as the producer needs to be producing hydrogen to benefit from volume support.** The sliding scale therefore supports market development and competition. Although this option does not fully protect the producer from volume risk, it provides producers reasonable certainty that they will be able to cover their MER over lower volumes while seeking further sales. Consequently the volume risk left with the producer is reduced substantially.

- **Potential negative distortions that may result from government acting as an offtaker are avoided.** Other options considered previously (with the exception of availability-based payments) all have an element of government participating in the market whereas the sliding scale requires less government intervention. The burden of marketing and managing end user risk also remains with the producer.

- **The sliding scale is suitable across all operating archetypes** – the sliding scale would be based on total volumes sold in a specific time period so even if volumes are produced on an intermittent basis those producers would still be able to cover their MER. The design would need careful consideration to avoid incentivising the inefficient sizing or operation of plants in order to benefit from the highest paying parts of the sliding scale.

- **Avoids complexity of delivery architecture needed for options where government is an offtaker** – government does not need to pay for volumes that are not produced, nor does it need to take physical delivery of volumes. Although there is no need to set

[31] Details on how UK income tax is calculated can be found at: https://www.gov.uk/income-tax-rates

up delivery architecture to either take physical delivery or make payment for non-production, there may still be a need for government to review volumes for each project over the contract duration.

Disadvantages

- **The main disadvantage of this option is that the plant has to be producing to benefit from the support** as the sliding scale does not provide protection to the hydrogen plant in the event that volumes fall to zero. It relies on producers managing this risk themselves, for example through their commercial decisions around diversifying offtake and use of funds earned under the support.

- **Similar to the availability payment, the sliding scale is a fundamental feature of the business model**, unlike the partial offtake option which can be structured as a side agreement, and so may become an enduring feature of future contracts if developers and capital providers become acclimated to its presence. This being said, it provides a means of changing the balance of risk between government and the producer for future rounds of contract allocation.

Summary

This approach addresses many of the disadvantages of the other volume support options as it does not require government to either take volumes or pay for non-production of hydrogen. It therefore avoids market distortions and complexity of delivery architecture resulting from government acting as an offtaker. Managing offtake risk also remains with the producer, which is the best party to manage this risk, rather than government. Compared with the other support options, we consider the sliding scale has the advantage of being more readily applied across both continuous and intermittent operations.

For the sliding scale to be successful, careful consideration would need to be given to the design details as well as integration with the variable premium as the price support. The design would need to avoid creating any perverse incentives around plant sizing. For example, the design would need to avoid fixed price support for tranches of volumes irrespective of overall plant size, as that might incentivise the construction of plants designed to fit in the most generous tranche or the choice of production technologies to suit that scale rather than the most efficient plant size and technology pathway.

Additionally, the period over which the sliding scale is applied would have a bearing. For example, calculating it on an annual basis would incentivise slightly different behaviour to calculating it on a monthly basis. The former would significantly weight payments towards the early part of the year, whereas the latter would offer a better match to when the producer actually incurs costs.

Government's 'minded to' position on volume support

Based on the assessment of the volume support options against the key principles the sliding scale is our preferred option to provide volume support. This manages volume risk through paying a higher level of price support on initial volumes, allowing the producer to recover fixed costs at relatively low offtake volumes. The level of price support would taper off as volumes increase, with last volumes recovering only marginal costs and equity returns. We consider this option best balances investability from the perspective of producers and value for money from the perspective of government. In comparison to other options, we consider the sliding scale minimises the risk of distortions and unintended consequences.

The sliding scale would provide volume support via the variable premium to producers and although it is compatible across operating conditions, the design would need to be carefully considered for the benefits to be realised.

We want to understand if any volume risk that remains with the producer would be a barrier for investment decisions to be taken once market price risk and volume risk are mitigated through the variable premium and sliding scale support mechanisms respectively. If there are outstanding volume risks that are not sufficiently mitigated by the proposed sliding scale mechanism to enable investment, we want to understand what these are, the circumstances under which they might occur and what further support may as a result be necessary.

9. **Do you agree with our minded to position of sliding scale for volume support? Please explain your rationale.**

10. **Do hydrogen plants need any further volume support in addition to the sliding scale? Please explain your response, including what kind of additional volume support and under what circumstances it would be needed.**

Section 6: Applicability of the business model across different types of projects

We have noted throughout the previous chapters that what constitutes a hydrogen project can vary substantially in terms of production technology, operating mode and size (or capacity). As part of our assessment, we have considered how the key components of the business model design could accommodate different types of projects. This is to help answer the question of whether or not a fundamentally different approach to that set out here would be required or appropriate for certain project 'archetypes'. In particular, we have considered whether different business models would be required for CCUS enabled and electrolytic projects, and/or for larger and smaller scale projects.

Regarding the production technologies, their differing characteristics will mean they have different support requirements. For the following reasons, our view is that it is possible to accommodate these different requirements within the business model approach set out in the previous sections:

- It is possible to incorporate different design features into the basic model, in particular relating to indexation, rather than requiring an entirely separate support mechanism. The low carbon electricity CfDs support a range of technologies with different characteristics, such as offshore wind, anaerobic digestion, and others. We consider that similar design flexibility could be built into the design of the hydrogen business model.
- Different support requirements can be reflected in strike prices and managed via a separate allocation process and/or separate funding pots.

With respect to smaller scale projects, we acknowledge that the private law contract with variable payment mechanism we are proposing will not necessarily be as suitable for some projects at the lower end of the capacity scale. This may be where the administrative costs of negotiating and/or applying for the contract make up a substantial proportion of the overall project costs, or where the project sponsor and/or proposed owner of the project has limited experience or capacity to manage such a contract.

An alternative approach would be to design and implement a separate revenue support scheme along the lines of historical schemes developed more specifically for smaller scale technologies, such as the small-scale Feed in Tariff for sub 5MW distributed electricity generation projects. Such schemes have typically had relatively lower barriers to entry given the support payment is fixed and the allocation process is on a "First Come First Serve" basis and awarded subject to meeting scheme requirements.

For the following reasons, our view is that the majority of potential smaller scale projects would have the opportunity to proceed without a separate revenue support scheme:

- Many (but by no means all) smaller scale projects we are aware of, based on stakeholder engagement and a survey of electrolytic projects, are intending to supply hydrogen to transport applications. They are therefore potentially eligible to apply to the existing RTFO revenue support scheme. More generally, some smaller scale projects may, depending on their specific circumstances, be able to make a business case with support via other policy mechanisms including grant funding.

- The low carbon electricity CfD scheme has demonstrated that private law contracts enable investment in a wide range of technologies and capacities, including relatively smaller scale projects. There is no reason in principle why the contract mechanism could not work for smaller scale projects.

- Designing, implementing and administering more than one scheme would create its own problems. It would be more challenging for government to deliver, with a consequent impact on delivery timeframes. It would increase the complexity of the policy landscape. It could also distort competition and create perverse incentives (if one scheme provided a more generous subsidy than another) that might alter the shape and pace of hydrogen market development (i.e. through biasing developers' choices around production technology, scale of projects or offtake contracting strategies). Considering the disadvantages of introducing more than one scheme, alongside our assessment that a majority of potential projects would be able to proceed either through the business model proposed here or through other policies, we are minded to develop a single scheme that can accommodate different types of project.

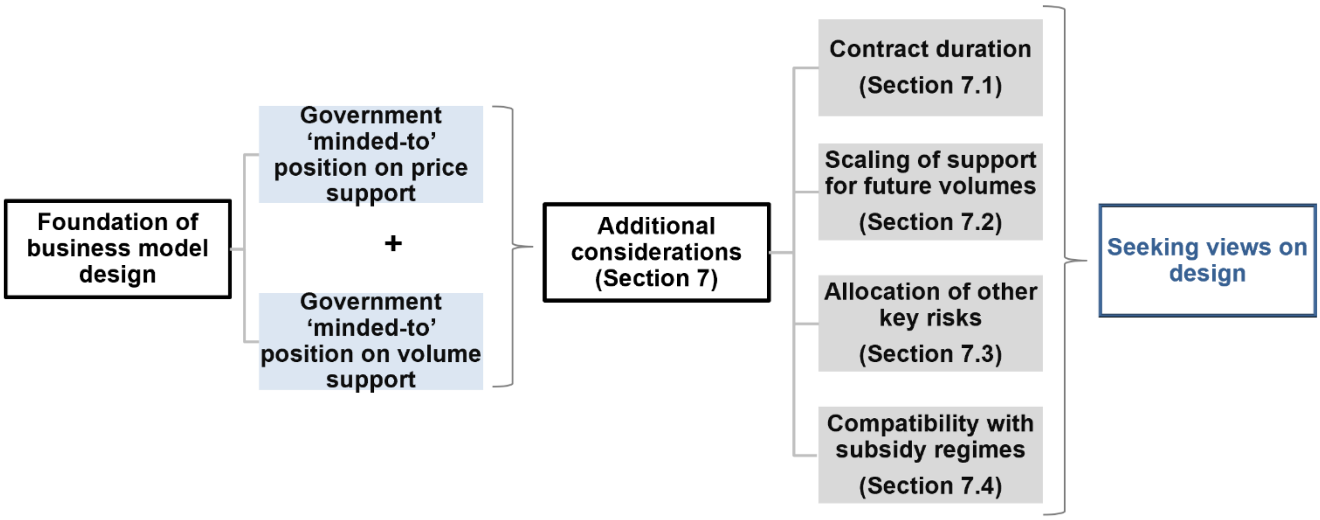
11. **Do you consider our preferred options on price and volume support outlined in sections 4 and 5 can work across different production technologies and operating patterns? If not, what difference in payment mechanisms might be required between different technologies and how should any downsides associated with that be managed?**

12. **Do you agree with our proposal not to introduce a separate revenue support scheme for projects of a smaller scale? Please give arguments to support your response.**

Section 7: Additional considerations for preferred model

We have considered business model foundations in the previous sections – namely options for price support and volume support. This section outlines some of the key additional considerations pertinent to the design of the business model. The right-hand side of figure 18 sets out the features we have considered to date. These are: contract duration, scaling of support for future production volumes, allocation of other key risks and compatibility with existing subsidy regimes. This list is not exhaustive and further work will be required on other design elements as well as a position on each of the elements listed below.

Figure 18: Approach to business model design



7.1 Contract duration

A key feature of the business model will be the duration over which revenue support is provided. Defining contract length is important for producers as it will determine the period for which there is revenue certainty and predictability while the hydrogen market develops. It is also important for government in determining the value for money proposition of the scheme as a whole and for individual projects.

To determine the length of the contract there are some key factors to account for – some of these imply a shorter or longer contract length and have been considered in turn.

- **Lifetime of the asset** – the operational lifetime of some CCUS-enabled hydrogen production plants may be greater than 30 years, while those of electrolytic technologies are shorter.[32] While the useful life of the asset may be shorter (determined by factors

[32] Taken from BEIS Hydrogen Production Cost Analysis (2021) and a report by Element Energy which can be found at: https://www.gov.uk/government/publications/hydrogen-supply-chain-evidence-base

other than the physical condition of the plant), it may be relevant to take operating life into account.

- **Financing of the capital asset** – the contract must be long enough to allow for capital repayment. Debt providers are more likely to invest if they expect to be repaid during the lifetime of the support contract, and for debt payments to tail off sufficiently before the end of this period. A longer contract length may therefore be more attractive from the perspective of lowering the cost of capital.

- **Net present value of support** – there is a difference between the discount rate investors use to appraise projects and that used by government. Investors are more likely to discount future costs and revenues at a higher rate (in line with their real cost of capital and project risks) than the government social discount rate (more reflective of wider societal time preference and wealth effects).[33] As a result of the difference, investors value future revenue streams at a lower rate than society values the cost of paying them. Over time, each additional year of support may eventually add a cost to society at a value that outweighs the benefit perceived by investors. This would suggest a shorter contract duration may be preferable from a government perspective.

- **Evolution of market conditions** – as the low carbon hydrogen market becomes more liquid, and the market value of hydrogen increases and the cost of production decreases (compared to alternative fuels), the need for revenue support diminishes. At this point, government support could potentially achieve greater value for money if budget is allocated to other areas. It is difficult to predict how market conditions will evolve – for a liquid market to emerge, overcoming large-scale distribution and storage barriers is likely necessary, however this is not expected in the near term. There may be a case for considering longer contract lengths to allow the market to develop.

Precedents for contract duration have already been created in the energy sector.

- The CfD for renewable electricity has a standard contract duration of 15 years, with capital recovery across the duration of the contract.[34]

- The proposed ICC business model is a 10-year contract with a possible additional five years available.[35] The capital repayment period is over five years, meaning a shorter period than the length of the contract. The main drivers for introducing a shorter capital repayment period are to reflect investors' expectations for such projects and to enable investors to recoup capital payments in later years of the contract. This is in the event of low product demand, which is an inherent uncertainty for such industries (and the ICC model does not specifically offer coverage of demand risk). [36] A shorter repayment period also helps to reduce total costs to government.

We are seeking views on the appropriate contract length, taking account of government's minded to position on price and volume support as well as the factors listed above.

[33] Details of the components of the social discount rate can be found in Chapter 5 of the Green Book: https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent
[34] Information on the latest allocation round for CfDs can be found at: https://www.cfdallocationround.uk/about
[35] The May 2021 update on the ICC business model can be found at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/984119/industrial-carbon-capture-icc.pdf
[36] See pg.22 on "Capex repayment terms" of the May 2021 update on the ICC business model here: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/984119/industrial-carbon-capture-icc.pdf

13. **What do you think is an appropriate length of contract? Please explain your rationale.**

14. **Should the length of contract vary for different technologies? Please explain your rationale.**

7.2 Scaling of support for future production volumes

Hydrogen producers, including both CCUS-enabled and electrolytic, may wish to have the ability to increase the volume of hydrogen produced at a plant[37] above the capacity defined in their contract to respond to increased demand. We are assessing several options for this scaling up of volumes and are considering them against our key design principles.

The options for volume scaling and our initial assessment of them are outlined below.

- **No volume scaling allowed**. The volumes of hydrogen produced above the capacity in a contract would not qualify for revenue support. Given the infancy of the hydrogen economy, this option could limit market development as any increase in supply could be largely determined by the timing of future allocation rounds of business model support contracts. This could also create uncertainty for producers over whether they will be successful in future rounds, potentially incentivising perverse behaviour, such as capacity overbuild at a plant.
- **'Grandfathering'**. This is where a producer is able to apply to government on an ad hoc basis to increase the capacity at a plant and receive the same terms as under their existing contract. While being transparent and providing flexibility to government and producers, keeping existing terms for new volumes could lead to over subsidy as government is unable to negotiate new terms that reflect developments in the hydrogen economy. The option would also tie up government budget to provide for an event where a producer applies for a capacity increase, place a large administrative burden on government and may restrict competition as an increase in capacity would be allocated outside of a competitive allocation process.
- **'Accordion'**. This is where a producer is able to increase capacity of a plant up to a pre-agreed maximum level (e.g. 10% or 20% above the capacity defined in the contract). It is anticipated that these incremental volumes would receive reduced support payments compared to earlier volumes as fixed costs and capital returns would already have been recovered from the volumes produced against the capacity. Where a producer would like to go above this capacity at a plant, they would need to participate in a competitive allocation process and would receive new contractual terms for the additional capacity. This option provides a degree of flexibility to producers and an incentive to seek sales, allows supply to flexibly respond to incremental (but not material) increases in demand, and enables a stronger level of budgetary control for government than the grandfathering option.

15. **What are your views on the most appropriate option for scaling up volumes?**

[37] In this sub-section, 'a plant' refers to the hydrogen producer's project that is allocated a business model support contract. We have referred to 'a plant' as hydrogen producers, including both CCUS-enabled and electrolytic, may build up a roster of plants in the future, all potentially under different contract terms.

7.3 Allocation of other key risks

While the approach to market price risk and volume risk has been considered already, a number of other risks would need to be allocated to ensure an investable and value for money proposition. We have considered these risks with the central aim of achieving the right incentives for initial projects, while ensuring that both the private sector and the government are not allocated risks that they cannot manage or price for.

Our initial view reflects the risks faced by initial hydrogen production facilities, and is likely to evolve as the hydrogen market develops and with it the necessary commercial frameworks. The following table details other key risks relating to hydrogen production projects and where applicable our 'minded to' position on allocation of these risks.

Table 4: Risks relating to hydrogen production projects

Risk	Description	Allocation
Change in law, policy or regulatory framework risk	Risk that any change in law, policy or regulation impacts hydrogen production or hydrogen consumption. This could be where a change impacts on the cost of producing and/or using hydrogen, the uptake of hydrogen, or on the feasibility of delivering the necessary infrastructure for carbon capture and/or future hydrogen infrastructure development	The business model contract would set out appropriate provisions to protect the hydrogen producer from certain unforeseeable and material changes
Qualifying hydrogen risk	Risk that hydrogen produced does not meet the low carbon hydrogen standards and therefore may not qualify for support payments. This could happen in a number of situations. One example would be where the CO2 T&S network is unavailable due to a temporary outage and CCUS-enabled producers are unable to inject CO2 into the network	We are considering the most appropriate way of managing this risk across a number of different scenarios However, in principle, where the producer is at fault for producing hydrogen that does not meet the standard, we are minded to not provide support On the other hand, where the producer is not at fault, we are considering the most appropriate way of managing the risk with further work on this to be undertaken in 2021
Construction risk	The risk of construction overruns and, as a result, an increase in capital costs	The developer of the hydrogen production plant is best placed to manage construction risk through effective risk and financial management, including sufficient allocation of contingency within their budget Where hydrogen producers may apply and be successful for capex support

Risk	Description	Allocation
		through the NZHF, government may cover a fixed percentage of a project's initial cost estimate, including contingency costs, where this represents value for money
Technology risk	Risk that technology related to low carbon hydrogen production fails or does not behave predictably	The hydrogen producer is responsible for procuring technology with a high level of confidence, and ensuring there are contingency plans if it were to fail
Decommissio-ning risk	Risk that decommissioning costs are higher or lower than originally forecasted, or where the hydrogen producer is unable to carry out the decommissioning process	The hydrogen producer is responsible for decommissioning the hydrogen plant in line with the relevant industry standards
Input fuel supply disruption risk	Risk that an energy network supply mismatch, unplanned outage or inconsistent input fuel supply means that hydrogen producers are unable to fulfil offtaker contracts	The hydrogen producer is responsible for managing this risk to ensure they have a supply of input fuel to produce low carbon hydrogen

16. **Do you agree with our minded to allocation of the risks presented? Please explain your arguments, including if any other key risks have not been identified and how they should be allocated.**

7.4 Compatibility with existing subsidy regimes

A key design principle for our business model is that the subsidy should be compatible with other existing support policies across the hydrogen value chain. Hydrogen's versatility as an energy carrier and the multiple possible end uses means there may be interaction between the hydrogen business model and existing subsidy schemes. These schemes include:

- The RTFO which provides revenue support for qualifying hydrogen supplied to the transport sector
- The CfD for low carbon electricity generation, where electricity supported by the CfD could be used as input energy for electrolytic hydrogen production
- Schemes available to hydrogen end users, such as the Industrial Energy Transformation Fund (IETF) for industrial end users and the GB Capacity Market for hydrogen-fired power generators

In the future, new schemes to further facilitate the growth of hydrogen production and expand the hydrogen economy could also interact with the business model.

As explained in section 1, the cost-effective scaling up of hydrogen production will also need concerted action and targeted support across the hydrogen value chain. We are minded to accommodate a combination of different sources of support across the value chain to help drive demand for hydrogen in different sectors and reduce the costs of production. We are keen to explore the benefits of 'revenue stacking' – allowing hydrogen producers to combine support under the business model with revenue streams from other subsidies for hydrogen production, such as from the RTFO, subject to projects meeting the schemes' respective eligibility requirements and business model support not being cumulated with the RTFO for the same costs.

We will consider the following principles to ensure the business model interacts effectively and is compatible with other sources of support across the value chain:

- maximising the benefits of government intervention, while avoiding the risk of preserve outcomes
- avoiding double subsidisation and/or over-compensation, including by ensuring support is only received once for the same costs
- mitigating the risk of introducing policy complexity and dependencies
- minimising additional administrative complexity
- being adaptable to the potential future introduction of complementary subsidies across the value chain

We will also consider how schemes might interact in practice, how the business model design remains adaptable to potential future subsidy schemes, and how to meet the above principles, including through appropriate metering, monitoring, and reporting arrangements.

We welcome views from stakeholders on ways hydrogen producers could benefit from interactions between subsidy schemes, on revenue stacking, and on how to mitigate the risk of perverse outcomes.

17. **Do you agree with our approach to seek to accommodate different sources of support? Please explain your arguments, including any views on the risk of perverse outcomes linked to revenue stacking and how they might be mitigated.**

Section 8: Allocation

An important feature of the business model policy is determining which types of projects are eligible for the support contract and the basis on which they are allocated.

Eligibility criteria serve several functions. They ensure financial support is aligned with government's objectives, provide clarity to market participants on what projects could potentially receive support, and can also be used to seek initial evidence regarding project credibility and discourage speculative applications.

We expect to set out specific eligibility criteria each time we open an opportunity to allocate business model support. For example, we set out eligibility criteria for CCUS-enabled hydrogen projects seeking hydrogen business model support as part of the CCUS cluster sequencing process published in May 2021.[38] The cluster sequencing process is not the subject of this consultation.

There are two mechanisms through which the proposed business model could be allocated.

- **Bilateral negotiation**: Government and a project, or projects, enter into a negotiation to agree a contract. The terms and conditions could be fixed from the outset with the main negotiation around price, or the negotiation could be extended to include key terms and conditions. This negotiation could be with one or a limited number of potential recipients. An assessment of project applications against defined evaluation criteria could be used to select the projects who will enter into negotiations with government. Government affordability considerations could be used to determine the number of contracts and the subsidy amount awarded to projects. A bilateral process is being considered for the awards of the first power CCUS 'DPA' and the ICC business model contract.

- **Auction**: A competitive process with terms and conditions being standardised across all bidders and allocation of support determined by the lowest strike price bid. Pots can be used for technologies with different cost bases to ensure a diversity of projects are awarded support and not just the lowest cost technology at a point in time. The clearing price of each auction could be set at a level that fits within government's affordability envelope or ensures a predetermined target capacity is allocated support. Competitive auctions have been a key driver of reductions in the capital cost of offshore windfarms.

Deciding which allocation process to adopt will depend on a variety of factors. The status of these factors is likely to change over time, meaning a different approach may be required as the market develops. It may also be possible to mix features of the two approaches (e.g. a competitive process to earn the right to enter a bilateral negotiation with government). The factors include:

- **Size of the project pipeline**: where this is large, demand for support may exceed supply, providing the conditions for a competitive auction. Where only a relatively small number of projects are in a position to enter an allocation process, a bilateral process may be the most feasible approach. The more mature the sector, and/or the lower the

[38] The eligibility criteria can be found at: https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest

cost faced by a project in getting to the beginning of the allocation process, the larger the project pipeline is likely to be.

- **Maturity of the revenue support contract**: to enable an auction process, contracts would need to be standardised, and market participants would need prior understanding of the payment mechanism and other contractual features. While we expect to be able to draw on precedents in drafting the support contract, it is possible there may need to be a 'learning by doing' approach where new concepts are being applied for the first time.

- **Interdependencies**: for example, CCUS-enabled hydrogen projects based in CCUS clusters are part of the wider cluster sequencing process. The process for awarding support to these projects is dependent on the CO2 T&S infrastructure and therefore will need to take account of cluster level portfolio considerations. Standalone projects with less or no interdependency on other infrastructure may not have the same constraints.

- **Supporting different technologies**: there is scope to treat different production technologies separately, both through bilateral and competitive allocation. This could ensure a range of technologies are supported and current high-cost technologies do not automatically lose out to lower cost technology. This is important as today's high-cost technologies could have the potential for significant cost reductions and be the lower cost technology in the long-term. This reduction in cost is expected to be achieved, at least partly, through deployment.

- **Implementation requirements**: government will need to consider how to implement an allocation process, including the in-house delivery capability required if negotiating bilaterally or that required to run an auction (e.g. an auction delivery body).

For initial CCUS-enabled hydrogen projects seeking hydrogen business model support and that are planning to be operational by 2027 as part of the CCUS cluster sequencing process, further details on the allocation process will be laid out in the Phase 2 launch document to be published in due course. We expect this will enable final investment decisions to be made from 2023. In addition, we expect to set out further details on the Track 2 process for clusters and projects to be operational between 2027 and 2030 in October 2021.

We are keen to provide a route forward for initial projects not eligible for that process (e.g. electrolytic projects) and are considering the best approach and process for initial contract allocation. We are minded to invite project applications in 2022, for assessment against defined evaluation and eligibility criteria, followed by a bilateral process with selected projects to enable final investment decisions to be made from 2023. Subject to responses received to the question in this section, we aim to set out further detail on process outlined above as part of the government response to this consultation.

Any decision to award support to both initial CCUS-enabled and electrolytic projects would only be made subject to government being comfortable with: the application of subsidy control requirements, any balance sheet implications, the status of any relevant statutory consents and value for money of the project.

In the medium term, we expect competitive allocation (e.g. auctions) to be our preferred approach for awarding support contracts to all types of hydrogen projects. We are mindful of the potential need to create different allocation pots for different types of projects, as referenced above.

18. What are your views on the most appropriate allocation mechanism for the hydrogen business model contract, both in the near term (for projects outside the CCUS cluster sequencing process) and the longer term (for all technologies/projects)?

Section 9: Funding the hydrogen business model

As we move to a net zero economy, a key question for government and society is how we pay for this transition and who should bear the costs. This issue is being considered across many sectors and technologies, and at a strategic level through the Treasury's Net Zero Review.

As discussed in section 3, the design of the business model must enable hydrogen to be price competitive with counterfactual fuels if there is to be significant demand for it. Where producers cannot pass on the additional costs of producing low carbon hydrogen directly, funding must be found elsewhere.

Revenue support for clean electricity has been funded by passing on costs indirectly, for example through supplier obligations and suppliers passing costs onto energy bills. This approach has been used in the electricity sector to support the deployment of renewables through CfDs, Renewables Obligation and FiTs via the Control for Low Carbon Levies, and is being introduced in the gas sector through the Green Gas Support Scheme via the Green Gas Levy. We assume a similar approach would be taken for funding hydrogen production projects, taking into account consumer affordability. A funding mechanism would need to be sensitive to the specifics of the nascent hydrogen market and any potential requirement for new legislation.

Any costs passed onto consumers through energy bills will need to fit into the wider policy landscape. As set out, energy bills already bear various policy costs and we will be considering the overall impact of decarbonisation policies on consumer bills, ahead of the Net Zero Strategy. Decisions about funding for the hydrogen business model will reflect this. A Call for Evidence on energy consumer funding, affordability and fairness is expected to be published soon.

Any projects coming forward in the first half of the 2020s will largely be first of a kind in nature and therefore entail a higher degree of risk. There are also several end-uses for hydrogen, meaning the impacts of a chosen funding mechanism must be considered across a range of different sectors and consumers, including their ability to absorb these costs, and the impact additional costs would have on demand. A further consideration is the time taken to implement a funding mechanism and the need to align with our low carbon deployment ambitions.

As set out in the *Ten Point Plan*, further details of the revenue mechanism that will fund the hydrogen business model will be provided later this year.

19. **What are your views on the possible approaches to funding the proposed hydrogen business model?**

Section 10: Hydrogen distribution and storage

Hydrogen distribution and storage infrastructure is an essential part of facilitating the expansion of the hydrogen economy by helping to connect production facilities to end users, and providing flexibility and resilience to supply and demand. The business model's interaction with hydrogen distribution and storage infrastructure is likely to change over time and vary according to the types of projects. As discussed below, funding considerations will differ depending on distribution and storage infrastructure needs.

10.1 Small-scale infrastructure

To date, hydrogen production in the UK is on a small-scale. Most of the hydrogen tends to be produced and used in the same location, and then directly used in industrial processes, often with one operator overseeing both operations. There is limited hydrogen pipeline and storage infrastructure. Where there is, it is primarily used to supply users located in industrial clusters, as well as some transport of hydrogen by road into these hubs. Existing infrastructure is privately owned and operated.

Similarly, we anticipate that early hydrogen projects supported through the business model will be highly localised, site-specific projects coupling hydrogen producers to one-to-few end users. Given the very early stage of the market, pipeline distribution will likely be via small-scale, dedicated, point-to-point private access infrastructure. Non-pipeline distribution such as tube trailers could also play an important role, particularly for smaller capacity projects. Our engagement with hydrogen project developers to date suggests that the need for large-scale storage, such as salt caverns, remains minimal for early projects, but there is likely to be a role for above ground storage vessels (as already seen at hydrogen refuelling stations).

We recognise that hydrogen producers might face different hydrogen distribution and storage infrastructure costs depending on the location and specificities of their projects, which might impact the overall cost of a unit of hydrogen produced. We propose that the costs (if any) of small-scale hydrogen pipelines and non-pipeline distribution and small-scale storage infrastructure could potentially be factored in as part of projects' overall costs of production when seeking business model support. Factoring in these costs under the business model could help reduce project costs and risks and enable production assets to meet the specific needs of the producers and users in question.

We welcome stakeholder views on how business model support can be effective in ensuring that investment in small-scale infrastructure leads to flexible and resilient supply and demand of hydrogen and supports the future expansion of the hydrogen economy, while remaining proportionate to needs and preventing market distortions.[39] We are also interested in hearing views from stakeholders on the treatment of costs for connecting to and using distribution and storage infrastructure operated by third parties within the business model.

[39] This could be achieved through incentives in the business model to design infrastructure a certain way or through contractual conditions (e.g. to provide for potential future non-discrimination, third-party access and unbundling).

10.2 Large-scale infrastructure

As the production and use of hydrogen increases to meet our 5GW ambition, scaling up hydrogen distribution and storage will be needed to integrate new producers and end users across a wider region.

The expansion phase is likely to occur first in industrial clusters, where pipeline distribution is expected to expand in length and size. Some proposed projects in development are already signalling their intention to go beyond small-scale, point-to-point projects, with plans to roll out a network of new pipelines and large-scale storage facilities in their regions. This may develop alongside non-pipeline distribution, and both could be integrated into shared regional networks serving multiple producers and end users as demand scales up. In the longer term, the hydrogen market may start to look like that of natural gas where non-integrated, third-party actors provide distribution and storage services to a liquid developed market.

Government's view is that the hydrogen business model proposed for initial projects would not be appropriate to support the build-out of new hydrogen pipelines and new storage infrastructure as needs become greater in scale, or where the required hydrogen pipelines become part of a larger, shared network. The main reasons for this are as follows:

- It has not yet been established whether funding for larger, shared distribution and storage infrastructure is needed, and what appropriate funding mechanism(s) might look like. It is also unclear who might own and operate these assets. It is plausible that new assets could be owned and financed by the private sector, much like the existing hydrogen pipelines and storage, driven by growing infrastructure demand, without the need for intervention.

- Hydrogen production, distribution, and storage are substantially different asset classes, providing separate supply chain services and facing different cost structures. Including infrastructure costs within the producer business model is unlikely to stimulate efficient scaling of hydrogen infrastructure, which means there is a risk that investments would be made on a project rather than societal basis. To reflect the higher risk of investing in low carbon hydrogen production activity, the rate of return that would be necessary to unlock investment in production would likely be in excess of what would normally be expected for investment in distribution and storage infrastructure. While the risk of overcompensating relating to distribution and storage costs is likely to be minor in early projects given the small scale of the distribution and storage assets involved, higher returns offered through the producer business model would not be commensurate with the lower risk of the investment undertaken in larger-scale assets, and could give rise to windfall profits via future monetisation of the assets.

- The pace of development and mix of distribution and storage requirements currently remains uncertain. For example, there may be efficiencies in using or repurposing the existing gas network, either fully or in part, which could reduce the need to build new hydrogen pipelines.[40] Furthermore, future decisions on hydrogen heating and on the future of the existing gas network may influence the regulation, financing and ownership structure of hydrogen networks in the long term.

[40] Work is underway to understand the option of blending hydrogen into the existing natural gas grid and converting the existing gas network to enable it to transport 100% hydrogen, including safety, technical feasibility, costs and benefits assessments. See Chapter 2 of the UK Hydrogen Strategy for further details.

Next steps

As committed to in the Hydrogen Strategy, we will undertake a review to further understand hydrogen network requirements in the 2020s. This review will seek to design in optionality to support different infrastructure pathways as the market develops and will consider the need for funding and other incentives; introduction of regulation specific to hydrogen networks; resilience and future-proofing ahead of potential regional and national networks; and interaction with wider networks including CCUS, gas and electricity.

BEIS has also released a Call for Evidence on facilitating the deployment of large-scale and long-duration electricity storage (LLES), seeking views from industry on the barriers that electricity storage technologies face, including hydrogen where it is used in the power system.[41] To build on this evidence beyond the electricity system, we announced in the Hydrogen Strategy that we will undertake a review of likely scenarios for hydrogen storage need up to and beyond 2030, including its potential role as a critical enabler for some end use sectors. The review will consider issues such as funding, whether further government regulation or support might be required to ensure that the necessary storage infrastructure is available when needed, and what form this might take.

To inform and shape our forthcoming reviews, we are interested in gathering stakeholder views in this consultation on the potential need for bespoke funding mechanism(s) to facilitate investment in future larger scale hydrogen distribution and storage assets.

20. **Do you agree with our proposal to allow projects to factor in small-scale hydrogen distribution and storage costs as part of projects' overall costs of production when bidding for business model support? Please explain your arguments, including any considerations relating to avoiding market distortions and facilitating future expansion of the hydrogen economy.**

21. **Do you consider that bespoke funding model(s) might be needed to enable investments in larger-scale, shared hydrogen networks and storage? If so, which model(s) might be best suited to bring forward projects? Evidence provided under this question will be used to inform our forthcoming reviews.**

[41] For more information, see the Call for Evidence on facilitating the deployment of large-scale and long-duration electricity storage, which can be found at: https://www.gov.uk/government/consultations/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence

Section 11: Timing and next steps

The consultation will be open for 10 weeks closing on 25th October 2021. The department will analyse all responses and aim to publish our response to the consultation in Q1 2022. Alongside this, we will publish an indicative Heads of Terms of the business model contract and provide further details on the allocation process for initial projects outside of the CCUS sequencing process.

We aim to finalise the business model in 2022, enabling the first contracts to be allocated from Q1 2023.

On-going engagement will form an important part of our work as we test our emerging business model design. We intend to continue to engage with stakeholders through our hydrogen business model expert group and bilateral meetings.

Consultation questions

Section 2

1. Do you agree with our overall approach to introduce a contractual, producer-focused business model covering the proposed scope?

Section 3

2. Do you agree with our approach to business model design?

Section 4

3. Do you agree with our minded to position for a variable premium for price support? Please provide arguments to support your view.

4. Do you agree with our minded to position for setting the reference price? Please provide arguments to support your view.

5. Does our minded to position create any other specific risks, incentives or disincentives which we have not already stated above? If so, what are they and how could the related risks be addressed – either within the model or outside of the model?

6. What do you think is the most appropriate option (or options) for indexation of the strike price? Please explain your rationale.

7. What are your views on whether price support for low carbon hydrogen should be constrained for applications using hydrogen as a feedstock to mitigate potential risks of market distortions? Please explain your rationale, including any suggestions both within and outside the business model to mitigate these risks.

8. Do you agree with our overall minded to position for price support? Please provide arguments to support your view.

Section 5

9. Do you agree with our minded to position of sliding scale for volume support? Please explain your rationale.

10. Do hydrogen plants need any further volume support in addition to the sliding scale? Please explain your response, including what kind of additional volume support and under what circumstances it would be needed.

Section 6

11. Do you consider our preferred options on price and volume support outlined in sections 4 and 5 can work across different production technologies and operating patterns? If not, what difference in payment mechanisms might be required between different technologies and how should any downsides associated with that be managed?

12. Do you agree with our proposal not to introduce a separate revenue support scheme for projects of a smaller scale? Please give arguments to support your response.

Section 7

13. What do you think is an appropriate length of contract? Please explain your rationale.

14. Should the length of contract vary for different technologies? Please explain your rationale.

15. What are your views on the most appropriate option for scaling up volumes?

16. Do you agree with our minded to allocation of the risks presented? Please explain your arguments, including if any other key risks have not been identified and how they should be allocated.

17. Do you agree with our approach to seek to accommodate different sources of support? Please explain your arguments, including any considerations of unintended consequences linked to revenue stacking, and how might they be mitigated.

Section 8

18. What are your views on the most appropriate allocation mechanism for the hydrogen business model contract, both near term (for projects outside the CCUS cluster sequencing process) and longer term (for all technologies/projects)?

Section 9

19. What are your views on the possible approaches to funding the proposed hydrogen business model?

Section 10

20. Do you agree with our proposal to allow projects to factor in small-scale hydrogen distribution and storage costs as part of projects' overall costs of production when bidding for business model support? Please explain your arguments, including any considerations relating to avoiding market distortions and facilitating future expansion of the hydrogen economy.

21. Do you consider that bespoke funding model(s) might be needed to enable investments in larger-scale, shared hydrogen networks and storage? If so, which model(s) might be best suited to bring forward projects? Evidence provided under this question will be used to inform our forthcoming reviews.

Acronyms and glossary

Acronym	Definition
BPPA	Backstop Power Purchase Agreement
CB6	Carbon Budget 6
CCGT	Combined cycle gas turbine
CCU	Carbon capture and utilisation
CCUS	Carbon capture, usage and storage
CfD	Contract for difference
CPI	Consumer Price Index
DPA	Dispatchable Power Agreement
EU ETS	European Union Emissions Trading System
FiT	Feed in tariff
FOAK	First of a kind
GGSS	Green Gas Support Scheme
GW	Gigawatt
HMG	Her Majesty's Government
ICC	Industrial Carbon Capture
IETF	Industrial Energy Transformation Fund
LCCC	Low Carbon Contracts Company
LCH	Low carbon hydrogen
LLES	Large-scale and Long-duration Electricity Storage
LNG	Liquified natural gas
LPG	Liquified petroleum gas
MER	Minimum economic return
MW	Megawatt
MWh	Megawatt hours
NOAK	Nth of a kind

Acronym	Definition
NZHF	Net Zero Hydrogen Fund
OLR	Off-taker of last resort
RHI	Renewable Heat Incentive
RTFO	Renewable Transport Fuel Obligation
T&S	Transport and storage
tCO2	Tonnes CO2
TWh	Terrawatt hours
UK ETS	UK Emissions Trading Scheme
UKRI	UK Research and Innovation
VLSFO	Very low sulphur fuel oil

Term	Definition
Achieved sales price	The value a hydrogen producer achieves selling hydrogen on the market
Allocation	The process of allocating revenue support through the hydrogen business model
Availability payments	A payment based on a hydrogen production facility's production capacity regardless of sales
Backstop	A financial arrangement where government acts as the buyer of last resort for unsold volumes of hydrogen
Backstop Power Purchase Agreement	A standard form of power purchase agreement under which an offtaker of last resort provides a route to market and a minimum revenue stream for a generator who has been awarded a CfD under the Electricity Market Reform programme
Balance sheet	The national balance sheet shows the market value of the financial and non-financial assets for the UK
Baseload	Operating continuously to meet a minimum level of demand
Brent crude price	Global benchmarking price for crude oil production
Business model	The mechanism which government proposes to establish to support producers of low carbon hydrogen
Capacity Market	A market-based mechanism that incentivises reliable generating capacity to be available to ensure security of electricity supply

Term	Definition
Carbon Budget 6	Limits the volume of greenhouse gases emitted over a 5-year period from 2033 to 2037, taking the UK more than three-quarters of the way to reaching net zero by 2050
Carbon Capture Utilisation and Storage	The process of capturing carbon dioxide from industrial processes, power generation, certain hydrogen production methods. The captured carbon dioxide is then either used or stored permanently
Carbon price	A cost applied to carbon emissions to encourage emitters to reduce the amount of greenhouse gases they emit into the atmosphere
CCUS cluster sequencing process	The process by which CCUS industrial clusters are chosen, with two anticipated by the mid-2020s, and a further two clusters by 2030 as outlined in the 10 Point Plan
CCUS-enabled hydrogen production	Low carbon hydrogen produced from methane reformation with CCUS
Consumer Price Index inflation	The speed at which the prices of the goods and services bought by households rise or fall in the UK. It is estimated by measuring changes in price of a basket of commonly consumed goods and services
Contract for difference	A Contract for Difference, as set out in the Energy Act 2013, is a contract between a generator and the Low Carbon Contracts Company (LCCC), to encourage the generation of low carbon electricity where-by LCCC will pay an electricity generator the difference between the CfD reference price and the CfD strike price
Counterfactual fuel	The main fuel currently used in an end use sector, which a low carbon alternative could replace
Curtailed electricity	Renewable electricity generation that is lost or wasted due to a reduction in output from the power source into the grid due to a variety of issues such as grid capacity
Dispatchable Power Agreement	A mechanism to support power-CCUS projects
Electricity Market Reform	A government policy to incentivise investment in secure, low carbon electricity, improve the security of Great Britain’s electricity supply, and improve affordability for consumers
Electrolysis	A hydrogen production process which involves using electricity to generate hydrogen from water, with no CO2 emissions at the point of production. Low carbon hydrogen is created when low carbon electricity is used as the input fuel
Electrolytic hydrogen production	Hydrogen produced from electrolysis

Term	Definition
Feed-in tariffs	A now closed fixed price support scheme run by government to promote the uptake of small-scale renewable and low carbon electricity generation technologies
First of a kind	The first low carbon hydrogen projects accessing revenue support through the business model, who take on first mover risk by entering an undeveloped low carbon hydrogen market
Fixed premium	When a producer is paid an additional fixed payment for every unit of hydrogen produced, on top of the price the producer achieves in the market
Fixed price	When a producer is paid a fixed price for every unit of hydrogen produced, with this price reflecting the anticipated cost of production
Frontstop	In a scenario where the government acts as the off-taker of last resort, under a frontstop an obligation is placed on the hydrogen producer to re-sell the government's volumes before selling any other volumes
Green Gas Support Scheme	A financial support scheme to increase the proportion of green gas in the grid, through support for biomethane injection by the process of anaerobic digestion
Grey/carbon intensive hydrogen	Hydrogen that is produced from unabated methane-reformation, commonly used in industrial processes
Hydrogen business model	Business models aim to address the key risks and barriers that prevent low carbon hydrogen from developing without policy support
ICC business model	Designed to incentivise the deployment of carbon capture technology for industrial users, the ICC business model is a private law contract, similar to a CfD, that provides the emitter with a payment per tonne of captured CO_2. Projects looking to retrofit carbon intensive hydrogen production will be eligible for support through this scheme
Indexation	Applied to the strike price to account for the varying cost of production inputs over time
Industrial Energy Technology Fund	A grant scheme for industrial businesses to implement energy efficiency and deep decarbonisation solutions. The fund covers feasibility and engineering studies and deployment of projects
Low carbon hydrogen	Hydrogen that is produced with significantly lower greenhouse gas emissions compared to current methods of production – methods include methane reformation with CCUS and electrolysis using renewable electricity
Low carbon hydrogen market	A future fluid market where hydrogen is established in the energy system and moves towards being more competitively priced

Term	Definition
Low carbon hydrogen value chain	The low carbon hydrogen value chain covers; input fuels, production technologies, distribution and storage, end uses, and links with related economic activities
Market price risk	The risk that the price achieved for the selling of hydrogen into the market does not cover the cost of production, as it is unable to compete with the cost of high-carbon counterfactuals
Methane-reformation	A process for hydrogen production in which methane is the input fuel
National Balancing Point for natural gas	UK benchmarking price for natural gas
Net zero	Legislation passed by the government to reduce greenhouse gas emissions to net zero by 2050
Net Zero Hydrogen Fund	A £240m fund to support low carbon hydrogen production
Non-ETS	Includes sectors such as transport, agriculture, waste, certain industrial emissions and the built environment who are not covered by the UK ETS
Nth of a kind	Low carbon hydrogen projects entering into a more developed hydrogen market using mature technologies and processes with less risk
Reference price	Reflects the price that the producer would receive for hydrogen in the market under a variable premium model
Renewable Heat Incentive	A fixed rate tariff designed to incentivise the use of renewable heat for both domestic and non-domestic properties
Renewables Obligation	An obligation on licenced electricity suppliers to source a proportion of the electricity they supply from eligible renewable sources
Renewable Transport Fuel Obligation	A requirement on suppliers of transport and non-road mobile machinery fuel in the UK to show that a percentage of the fuel they supply comes from renewable and sustainable sources
Revenue stacking	Common with battery storage business cases, revenue stacking is the combining of a variety of revenue streams to generate income to help pay for an asset
Revenue support	The funding provided on an ongoing basis, for an agreed term, which would cover a proportion of operating costs and an appropriate rate of return on private sector capital invested
SDE++	A Dutch subsidy scheme that subsidises the operating shortfall of renewable energy generation and other CO2-reducing technologies

Term	Definition
Sliding scale	When volume support is provided through a variation in price, with higher unit prices on initial volumes to help recover fixed and marginal costs
Strike price	Reflects the pre-agreed production cost of low carbon hydrogen under a variable premium model
Take-or-pay	A mechanism where unsold volumes of hydrogen are physically taken by government, or where government pays hydrogen plants not to produce
Ten Point Plan	Sets out the approach government will take to build back better, support green jobs, and accelerate our path to net zero
Transfer pricing	A means of pricing transactions between connected parties to reduce cost burdens and maximise profits
UK Emissions Trading Scheme	Replacing the UK's participation in the EU ETS, the UK Emissions Trading Scheme applies to energy intensive industries, the power generation sector and aviation
Variable premium	A producer is paid a premium for the hydrogen produced. The premium is calculated as the difference between a strike price and a reference price for each unit of hydrogen sold
Volume risk	The risk that a hydrogen production facility is unable to sell enough volumes of hydrogen to cover costs with reasonable confidence

This consultation is available from: www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

If you need a version of this document in a more accessible format, please email enquiries@beis.gov.uk and state in the email what assistive technology you use.