MAKING EARLY HYDROGEN PROJECTS INVESTABLE

Contractual and regulatory infrastructure for early hydrogen projects

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INTRODUCTION

Low carbon hydrogen has assumed a central role in the net zero plans of the UK, the EU, an ever-increasing number of EU member states, and others. It appears that this star commodity is set to play a key role in decarbonising key manufacturing sectors, road freight, shipping and aviation; balancing renewables-heavy power grids; and heating homes and other buildings within our carbon budgets.

The world's current, relatively modest hydrogen demands are almost all met by processing fossil fuel feedstocks with technologies that result in considerable carbon emissions (so-called "grey hydrogen"). At the heart of hydrogen's new-found prominence is the possibility of producing it cost-effectively without these – in particular by:

- adding carbon capture, usage and storage (CCUS) to fossil-fuel based techniques such as steam methane reforming (SMR) or auto thermal reforming (ATR) to reduce or eliminate their emissions ("blue hydrogen"); or
- using electricity generated from renewable sources to electrolyse water ("green hydrogen").

Blue hydrogen is currently closer to being cost-competitive with grey hydrogen than green hydrogen is. Even if green hydrogen comes to dominate, the shorter term deployment of blue hydrogen in areas where there are existing clusters of heavy industry offers the prospect of growing the demand for low carbon hydrogen, reducing emissions, and helping to support the scaling up of CCUS. This last in itself is seen as playing a long-term role in securing net zero target through biomass with CCS (BECCS) and other "negative emissions" technologies.

Increasing carbon prices will help to incentivise demand for both blue and green hydrogen in some sectors. But, like renewable electricity generation technologies before them, they will need elements of public financial support in order to make them

EXEC SUMMARY

We explore the contractual and regulatory infrastructure that would support a first wave of blue hydrogen projects.

Like any project, early hydrogen projects will be exposed to a variety of risks. Allocating these risks effectively will be an important part of ensuring the investability and affordability of early projects. We reach the following general conclusions for the next steps for investors and policymakers:

- there are significant cross-value chain risks to manage, and in many cases there are several ways in which risks could be allocated;
- projects will need the active involvement of government at a relatively detailed level to get off the ground, and government may have to provide protection to one link in the chain against the failure of another link;
- securing "value for money" for the government will require an integrated view across conversion support for customers and support to hydrogen production;
- pinning down an early view of an acceptable allocation of risk will be absolutely critical – and government support contract(s) will be an important part of this risk allocation; and
- potential hydrogen investors and customers will need to form an early view as to their preferences in terms of risk allocation.

investable propositions at scale in the near term. Alongside rising carbon prices, this should in turn enable production costs to be reduced and their product eventually to compete with grey hydrogen, fossil methane and other energy vectors on price.[1]

UK government policy is to encourage a range of low carbon hydrogen technologies[2]. However, the different technologies raise different issues. This paper explores the contractual and regulatory infrastructure that would support a first wave of blue hydrogen projects in the UK's CCUS clusters. It looks at the commercial relationships between producers, suppliers, infrastructure providers and customers, and, given these, considers the role of public support in making projects more investable (including in relation to limited recourse financing). We draw some early conclusions on the process which is likely to be required to ensure the right mix of commercial relationships and public support is in place.

STYLISED PROJECT AND ITS KEY RELATIONSHIPS

It is expected that policy makers may push for the early schemes to focus on industrial users: they are likely to have fewer alternative practical and cost-effective decarbonisation options than other end user groups. They also tend to be geographically clustered and can provide large baseload demand for early projects without the need for large-scale hydrogen transport infrastructure.

Throughout this paper, we consider a stylised example of an early-mover project – a methane reformation project, located in or near one of the CCUS clusters, with plant installed to capture its CO2 emissions.

We assume that the project operates on a merchant basis, selling hydrogen (and taking commodity risk in its inputs and outputs) rather than under a tolling model. In our example, the project:

- will sell hydrogen to industrial customers (such as steel or cement plants), located nearby, allowing those customers to convert to run on blue hydrogen instead of fossil methane (we assume some public subsidy of customer conversion costs);[3] and

- may also sell hydrogen for blending with natural gas in the gas grid.[4]

We assume that the project will supply its output over a local hydrogen pipeline network. The project may include or have access to hydrogen storage.

The project's key commercial and regulatory relationships are reflected in the diagram below.

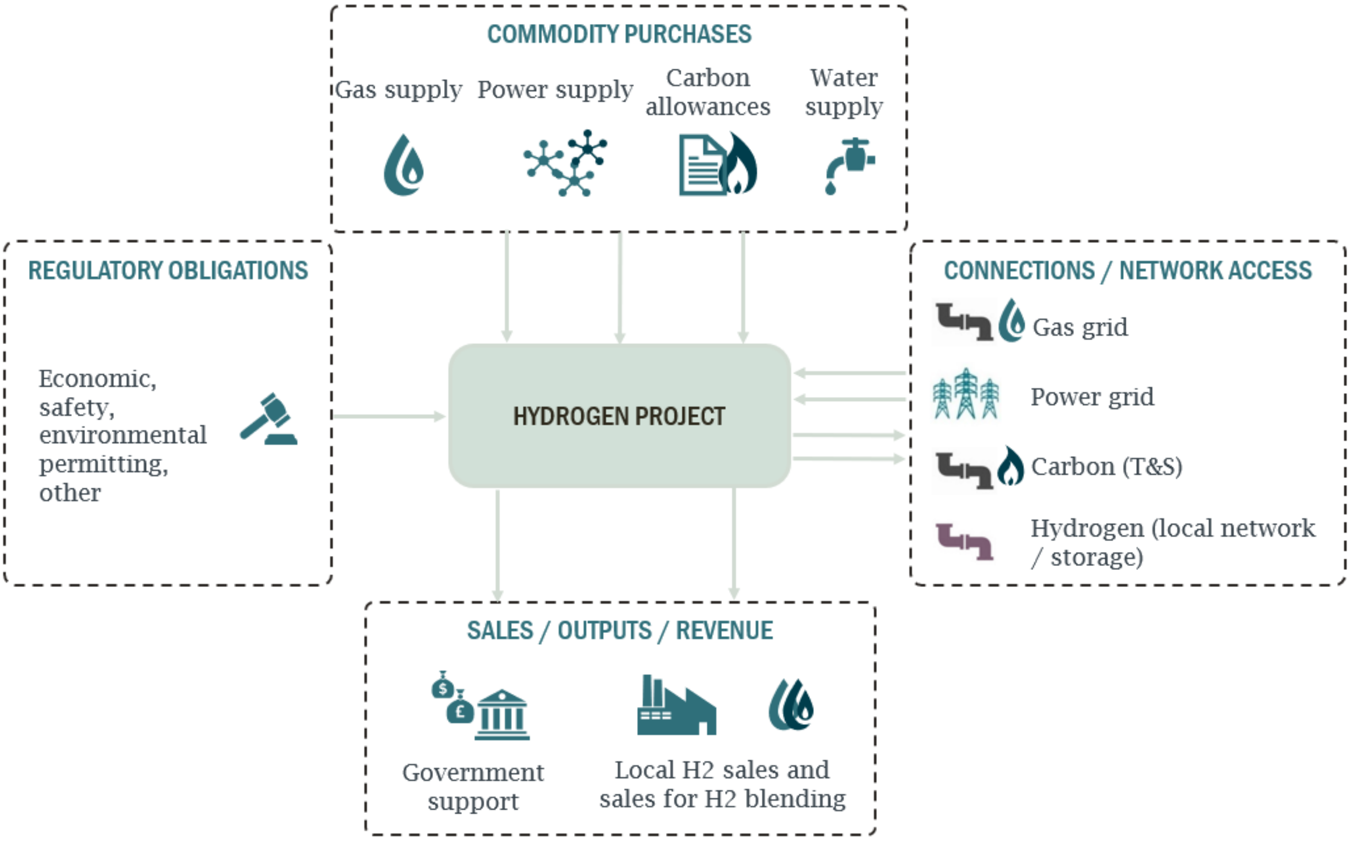
[1] Frontier Economics (August 2020) Business Models for Low Carbon Hydrogen Production: a report for BEIS, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/910382/Business_models_for_low_carbon_hydrogen_production.pdf. We note that, following government confirmation on 21 December 2020, a UK Emissions Trading System (which may in future be linked to other emissions trading systems) replaced the EU Emissions Trading System as the primary carbon pricing mechanism in GB as of 1 January 2021.

[2] See the December 2020 Energy White Paper, Powering our net zero future, https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future.

[3] Other markets (customers with a specific process need for hydrogen, or use as a transport fuel) are assumed to be secondary for the project.

[4] Hydrogen blending in the grid poses a number of challenges, not discussed in detail here. See A commercial framework to facilitate hydrogen blending, http://www.frontier-economics.com/uk/en/news-and-articles/news/news-article-i7704-a-commercial-framework-to-facilitate-hydrogen-blending/, and Hydrogen blending in the GB grid,.https://www.dentons.com/en/insights/articles/2020/october/21/hydrogen-blending-in-the-gb-grid.

FIGURE 1



The project's commercial contracts include (working clockwise from the top):

- gas supply agreement with a licensed gas shipper / supplier – for gas as feedstock for the reformation, at the GB wholesale (NBP) price[5];
- power supply agreement with a licensed supplier – for power consumed in methane reformation and CO2 capture, at the GB wholesale power price[6];
- purchase of carbon allowances for the proportion of its emissions which are not captured;
- water supply for the reformation process;
- Network Exit Agreement (under the Uniform Network Code) governing gas offtake connection to the gas grid;

[5] The project could alternatively receive gas (direct from offshore fields or a LNG import terminal) upstream of the gas transportation system.

[6] The project might alternatively self-supply from the grid (becoming a party to the BSC, and holding a supply licence); or it could have a captive power supply, potentially avoiding some green levies.

- Connection Agreement (under the CUSC or DCUSA) to the electricity grid;
- agreement for transportation and storage of CO2 (CO2T&S) with the entity providing this service at the cluster;
- local hydrogen network connection and use agreement (if applicable), and possibly connection and use of hydrogen storage.[7] If the project sells hydrogen for blending, Network Entry Agreement (under the UNC), for hydrogen delivery to the gas grid;
- hydrogen sale agreements for sale of hydrogen to industrial customer(s) in the cluster, and/or for hydrogen injected to the gas grid for blending. There may also be a small revenue stream from the sale of higher hydrocarbons (than CH4) stripped out of its natural gas feedstock;
- agreement(s) for public financial support of blue hydrogen production, reflecting its contribution to decarbonisation.

The project would also be subject to regulatory requirements:

- There is no visibility of any future Gas Act (or equivalent) regime for a hydrogen market. The existing Gas Act applies to hydrogen; but it would not regulate the project as a hydrogen producer; and it allows exemptions which make it unlikely any licence (transporter, shipper or supplier) would be needed for supply to local industrial customers;
- The hydrogen production project will also be subject to significant health and safety and (non-carbon) environmental regulation and permitting. There is no reason in principle for this to differ from the current framework;
- Sale of gas for blending in the gas system would require the project or its customer to hold a shipper licence;
- At a future time, regulation of a local hydrogen distribution network might be appropriate (for example, if competing hydrogen projects needed access);
- Before the development of interconnected delivery infrastructure (or conversion of the gas grid to hydrogen), early hydrogen projects will have a degree of market power, at least for their near-site customers. While they will be subject to general competition law, these issues may also be addressed directly under the government support agreement and/or customer contracts.

MANAGING RISKS IN THE H2 PROJECT

Like any other project, early hydrogen projects will be exposed to a variety of risks. As a general principle, risk should be allocated to the party that is best placed to manage it. It may be reasonable to afford early projects some additional protections, since there is likely to be 'learning by doing' for first movers, and with relatively limited prior demonstration it may be difficult for investors to estimate the scale of some risks.

[7] Not needed if this infrastructure is owned and operated by the project itself.

As with the rollout of less mature renewable electricity projects, allocating risks effectively and hence reducing developer cost of capital is likely to be an important part of ensuring the investability and affordability of early hydrogen projects. The ability of projects to support debt is critical in this regard. Project finance lenders (to any industry) almost always require long-term volume offtake commitments from creditworthy buyers (or an acceptable substitute for such commitments) to support the debt under a range of sensitivities.

Below we consider a range of risks which investors will be keen to see managed effectively if the project is to be bankable. We consider in turn:

- Development phase risks:
  - Co-ordinating commitment;
  - Co-ordinating operational start;
- Operational risks:
  - Commodity risk;
  - Demand risk;
  - Network cost risk; and
  - Infrastructure availability risk.

A recurrent theme is whether the project can secure long-term take-or-pay type H2 sale contracts, or whether industrial customers (facing volatility in their product markets) will only contract short-term.

DEVELOPMENT PHASE RISK

The development of the hydrogen project must be coordinated with (i) the development of the CO2 T&S service, (ii) the customers' converting to hydrogen use, and (iii) if blending from day one is intended, with the development of the blending regime. This coordination is needed in terms both of when commitments are made and when operations start.

COORDINATING COMMITMENTS

The table below illustrates progressive milestones which (variously) the hydrogen project sponsors, industrial customers, the CO2 T&S project developers (if the hydrogen project is an anchor T&S customer), and Government would expect to see met before being committed under the various contracts they will sign. It illustrates the relative importance of the different milestones to each stakeholder group and illustrates mutual dependencies up and down the chain - most conditions impact two or more of these stakeholders.

In granting public financial support (both to hydrogen production and for customer conversion), as well as wanting a value for money approach to defining and allocating support to reduce emissions, Government would want to minimise the risk of support being provided to a link in the chain out of step with the overall planned programme.

Reaching these milestones will require sponsors to incur, at risk, development costs which may be substantial and involve 'chicken-and-egg' issues. Government may need to provide some early-development grants to kick-start the process. Stakeholders may need to agree interim project development arrangements (heads of agreement, MOUs, etc) to provide mutual assurances of intent.

TABLE 1

DEVELOPMENT RISK	HYDROGEN PROJECT	INDUSTRIAL CUSTOMER	CO2 T&S	HMG
H2 project sufficiently developed that it can be costed and shown to be technically and commercially viable	High	High	High	High
H2 customers identified, who are technically and financially credible and willing to convert	High		Medium	High
If the project depends on blending, the blending regime is in place, and the project has secured blending capacity	High		Medium	High
CO2 T&S arrangements defined and project developed; T&S contract is in place, and target operational start-up known	High	Low	High	High
Government support arrangements for H2 production in place; award processes completed; support contract signed	High	Low	High	High
Other hydrogen project development risks (planning, land rights, permits, connections) managed	High	Low	Low	High
Customers have evaluated all aspects (including cost) of conversion to and running on hydrogen	Medium	High		Medium
Customer conversion subsidy arrangements in place, and subsidy awarded to identified customers	Medium	High		High
H2 sale contracts signed with customers (and customers released from any existing fuel commitments)	High	High	Medium	High
H2 project has construction contracts and construction finance in place	High	Low	Low	High

This coordination of investment commitments would typically be managed through conditions precedent to the effectiveness of contracts, leading to a final investment decision (FID) by the sponsors of each project. That assumes that customers will (some years ahead of first supply) sign long term hydrogen sale contracts with take-or-pay volume commitments. If they will not, and assuming sales contracts for blending do not provide an adequate alternative, then Government support will need to manage some of the risk that, after the project takes FID, sufficient customer demand does not materialise. This situation is discussed further below, in relation to managing operational demand risk.

COORDINATING OPERATIONAL START

Customers will not want to complete conversion of their processes and then find the hydrogen supply is not yet available.[8] The hydrogen project will want both its customers and the CO2 T&S service ready to start by the time it starts.[9] The CO2 T&S project has similar issues if the hydrogen project is an anchor customer.

These risks are typically managed by 'narrowing window' mechanisms allowing the project with the longest (or possibly the most uncertain) construction programme to fine tune the target start date. Those timing decisions are passed on in the other contracts to the other component projects.

Beyond that flexibility, the contracts will need to address (through liquidated damages or other remedies) delay in achieving operational start by any link in the chain. For example, the support contract may need to limit exposure of the hydrogen project to the risk of delay in CO2 T&S start-up. The issues are essentially the same as the infrastructure availability risks discussed below.

OPERATIONAL PHASE

COMMODITY RISK

Absent a support contract, the project would be exposed to power, gas and carbon prices.

In terms of commodity costs, the project will need to purchase fossil methane and power as input products, and hence will be exposed to fluctuating wholesale prices. Given the nature of these product markets, it is unlikely that it would be attractive to contract to fix prices for a long period. The project will also need to purchase CO2 permits in relation to any residual emissions, which would result in some CO2 price exposure, which again is likely to be difficult to fix via contract.

In terms of revenues, the project will be selling hydrogen to one or more industrial customers whose alternative fuel is likely to be fossil methane. The hydrogen sale price is therefore likely to be linked to the methane price (i.e. the NBP gas price), although there are a number of potential adjustments to consider.

First, there may be avoided gas network exit costs for the customer. These may allow an uplift to the methane price.

Second, even after a conversion cost subsidy from the government, customers may need to be incentivised to convert to hydrogen, meaning there is a need for a discount to the NBP.

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[8] This risk may be mitigated if the customer retains the ability to use natural gas as a back-up.

[9] If there are multiple customers they may have different target start dates, implying some over-capacity in the project in the early stages

Third, the customers' avoided cost of CO_2 permits (a cost which it would have faced if it continuing use of fossil methane) needs to be taken into account.[10] There is therefore a question as to which party secures the benefits of avoided CO_2 costs. This could be:

- left with the customer and used to offset some of the customer's conversion costs; or
- captured by the project and used to offset its ongoing support costs.

Under the first option, the customer would need to form a view of the NPV of this stream of benefits. However, there is a risk that customers discount this uncertain value stream. It may therefore be the case that support costs (in aggregate across the value chain) would be minimised by allocating the avoided CO_2 benefits to the hydrogen project, by setting the hydrogen sale price at a level which reflect these benefits. The actual carbon price could then be taken into account in the operating support provided, and investors would not have to form a view of the NPV of avoided CO_2 costs at the point of the investment decision.

In addition to direct customer sales, the project may be selling hydrogen for blending in the grid, again being paid a price per MWh based on the NBP price (but without uplift for avoided CO_2 costs).

It is not likely to be easy to fix long term the sale price from either direct sales to industrial customers, or from blending in the grid.

The project's overall exposure to commodity price volatility is therefore likely to be complex:

- due to conversion losses, the project will need to purchase more MWh of gas than it produces;
- the project will be exposed to CO_2 prices on the net of its own emissions and potential avoided emissions from the customer; and
- the project will be exposed to power prices, which today are highly correlated to gas prices, but in the future may be less so as more low marginal cost renewables are connected to the electricity grid.

At least for early projects, in order to secure financing, it is likely that a CfD support contract will need to hedge investors against commodity exposure. This might entail a contract which aims to achieve a target operating margin per MWh by providing a variable support level, which itself is calculated with reference to:

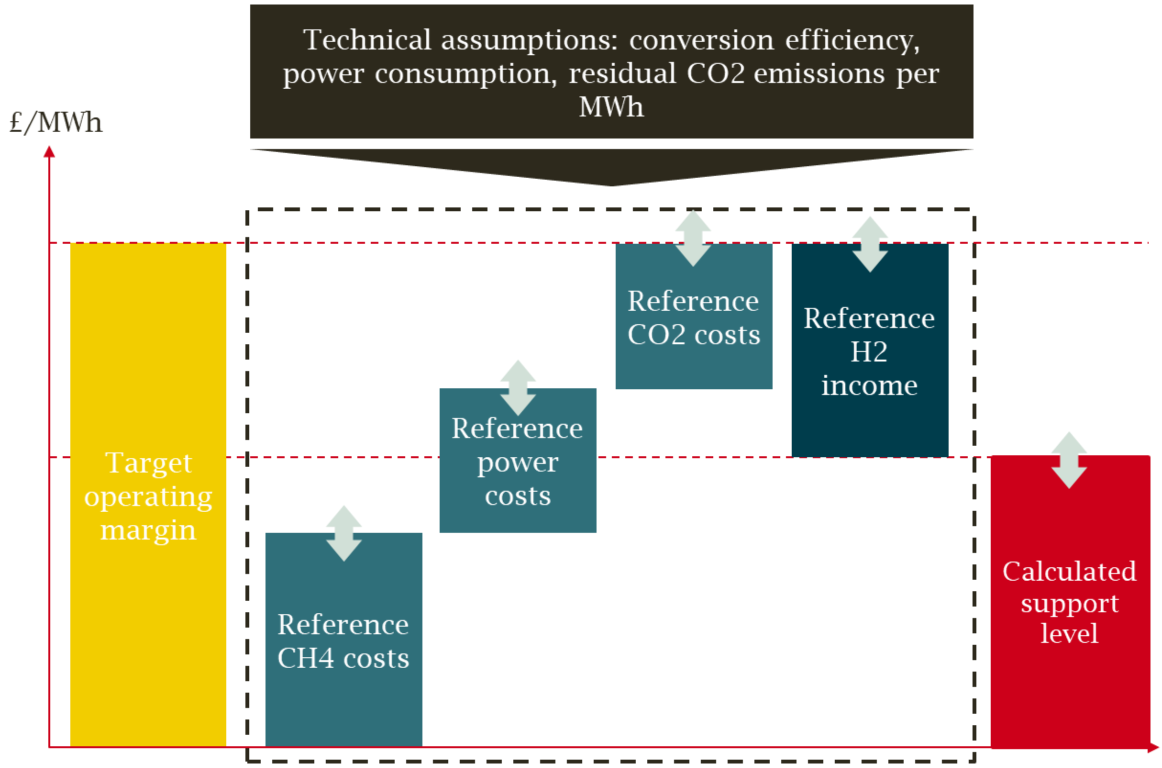
- pre-determined reference products[11] for the purchase and sale of commodities; and
- predefined technical characteristics for the plant. The CfD would specify process efficiency factors (for methane, power and CO_2 emissions) with upside and downside either shared or allocated 100% to the project.

[10] In switching from fossil methane to a low carbon hydrogen source, there is an avoided cost accruing initially to the customer resulting from avoided CO_2 emissions.

[11] As is the case for non-intermittent CfDs for low carbon electricity generation projects, or as proposed by BEIS as part of a Dispatchable Power Agreement for power CCUS (in its December 2020 update on business models for CCUS).

This target operating margin could be set to cover operating and investment costs or, under a split CfD (see below), simply to ensure operating costs are covered.

FIGURE 2 ILLUSTRATIVE CALCULATION OF VARIABLE SUPPORT LEVEL



If the support contract is structured in this way, then while there may be incentives to trade to beat the pricing on the reference products in the contract (and the reference conversion losses, CO_2 emissions etc), there will also be a "low risk" trading strategy of just replicating the trades the support contract assumes. Once the contract terminates, assuming it is shorter than the asset's technical life, the trading strategy will need to evolve to a fully merchant position.

The above description assumes that the project's commercial position is fixed at least over the lifetime of the support arrangement. The hydrogen price for sales to industrial customers is different (as it reflects avoided CO_2 emissions costs) from the blending sales price; and so the support arrangement must be designed to assume a given mix of these sales, and/or include a true-up mechanism to reflect changes in the mix.[12]

It is also possible that the market for hydrogen develops during this period (for example as a result of new policy developments), and it is subsequently possible for the project to sell hydrogen at a price higher than the (uplifted) fossil methane price. One of the questions for the design of the support contract is whether the project would be able to benefit from such an upside.

[12] Assuming that the scope of the UK ETS remains as at present. However, it may expand over time.

Equally, while this structure of support contract may be appropriate for early projects, by "insulating" investors against movements in prices, it may distort the signals which wholesale prices provide to investors. The nature of the distortion will depend on the overall structure of support. As has been seen in relation to RES-E support, CfDs which ensure investors receive a constant achieved price for output in all market conditions mean that plant do not respond to wholesale market despatch signals (e.g. negative prices). Even with a split CfD, where variable payments are intended to ensure the investor covers variable costs and do not have to provide a return on investment costs, it is difficult to protect investors while still allowing wholesale prices to provide signals as to when production is valuable from the point of view of the market as a whole. For example, in a period of gas shortage, very high short term gas prices should act as a signal for gas demand to reduce. If projects are insulated against the impact of such movements, they will not respond appropriately.

As with RES-E, the nature of the support arrangements may therefore need to evolve beyond the early projects in order to ensure that hydrogen producers act to minimise overall system costs.

DEMAND / VOLUME RISK

While there are obvious attractions to policy makers for industrial customers to form the core of demand, there is equally significant uncertainty around demand for low carbon hydrogen from this source. The level of demand from any given industrial customer could vary, and indeed the customer could go out of business. This means that even if customers were willing to sign a long term take or pay contract (with price indexed to the NBP), this may not be sufficient for investors. While diversifying across multiple customers may be possible, this clearly increases complexity in the development stage. It also relies on demand being stimulated: in almost all cases, hydrogen will not be a direct substitute for the incumbent fuel of these customers.

This demand risk could be managed through some sort of "buyer of last resort" backstop scheme, where producers are paid regardless of demand levels. However, this could lead to inefficient over-production and high per unit support costs. An alternate solution would be a split CfD, involving separate support payments: one stream related to fixed and capital costs regardless of demand, and a second related to variable costs where low carbon hydrogen is being produced.

Whether this is required will depend in part on the role that selling low carbon hydrogen for grid blending could play in providing a reliable source of baseload demand. This in turn will depend on the following.

- Hard limits on blend mix: The level of hydrogen in the mix will need to stay below the allowed maximum at all times and in all locations. This may require constraints to be placed on hydrogen injection. While early investment could be promoted by providing initial projects with long term rights to inject, this might come at the expense of more efficient decisions about grid access in future.

- The role of storage: The emergence of hydrogen storage facilities to provide a way of matching a constant supply profile to a seasonal demand profile, as well as providing a way to deal with temporary constraints placed on injection to maintain blending limits, will help producers manage risk to demand.

- Blending can only ever be a transitional option: Given the concentration of methane in the blended mix, it will need to be phased out in sufficient time to ensure the path to net zero is met. Whether this will provide investors with a sufficient window to manage demand risk depends in part on when blending will become available as an option, which in turn requires a set of activities to happen to prove the safety case and make ready the commercial arrangements.[13]

NETWORK COST RISK

The project will face a number of network costs:

- charges for use of the gas grid, captured in the price of methane used in the hydrogen production process (and potentially a grid entry charge for hydrogen supplied for blending);
- charges for use of the electricity system, captured in the price of electricity used in the hydrogen production process;
- charges for use of a local hydrogen-specific network to transport hydrogen to customers, or for use of a local hydrogen storage facility; and
- charges for use of CO2 T&S infrastructure.

The first two – the cost of gas and electricity networks – do not pose obvious challenges. Charges are fairly stable and charging methodologies are well-established.[14] The hydrogen project is similar to any other industrial gas or electricity consumer so should be able to bear these costs and manage the associated risk.

The local hydrogen network may be repurposed natural gas pipes or newly installed. It could be owned and operated by one of: (a) the project; (b) the hydrogen customers; (c) the regional gas network; or (d) an outside party, potentially selected through a tendering process. As noted above, existing Gas Act exemptions may need to be reviewed to allow regulation of charging under options (c) or (d).

If it is not owned by the project or regulated separately, contractual protection against changes in the terms and conditions of access to the pipeline are likely to be required. These protections may also need to address what happens with the connection of further hydrogen producers.

The costs of using CO2 T&S networks raise more questions. These networks need to be built before production and use of low carbon hydrogen can begin; however they are likely to involve significant infrastructure costs and the basis for recovering those costs from early vs. future users is currently subject to some uncertainty. The model used to fund these networks will have important implications for a hydrogen project looking to be an early user of carbon storage infrastructure.

In its December 2020 update on business models for carbon capture, usage and storage,[15] BEIS set out its proposal for a "User Pays" revenue model for CO2 T&S networks. This model would involve:

- setting allowed revenue using a framework set out in the licence, based on efficient and economic costs of operating the T&S infrastructure;

[13] See Frontier's report for Cadent Gas: https://cadentgas.com/nggdwsdev/media/FRoG/Hydrogen-Blending-Commercial-Framework-Frontier-report-FINAL.pdf.

[14] Further work is needed to define grid entry charges for hydrogen blending - see the Frontier report for Cadent Gas.

[15] BEIS (December 2020) An update on business models for Carbon Capture, Usage and Storage, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/946561/ccus-business-models-commercial-update.pdf, p19-27.

- the T&S operator collecting revenues through T&S fees paid by users of the network. These fees would be set using a methodology initially developed by the government and the Regulator; and
- the T&S operator recovering any shortfall between 1 and 2 through consumer and/or taxpayer support to ensure a predictable and robust revenue stream.

The availability of contingent recourse to consumer and/or taxpayer support overcomes the challenge that T&S infrastructure is likely to have a small user base initially. Without this additional support, in the near term a single hydrogen project with relatively limited use could face the full cost of funding the network. Which in turn could result in very high per-unit support costs.

Network costs will form a part of the expected cost base of any project, and so will need to be taken into account in ensuring the project is viable. It may be reasonable for projects to be exposed to variations in more well-established network charges. To the extent that hydrogen and CO2 network costs may be particularly variable, some form of protection against such variations might be needed in early hydrogen support arrangements. In the longer term however, once use of the networks has increased to a sustainable level (and potentially a track record of charge setting is established), hydrogen projects could be exposed to these (ideally cost-reflective) charges in order to encourage efficient use of the networks.

INFRASTRUCTURE AVAILABILITY RISK

Some of the unavailability risk for a hydrogen project will arise from infrastructure built, owned and controlled by the project itself – e.g. the hydrogen production plant, the CO_2 capture equipment, or the hydrogen network (if owned by the investor). The risk of outages on these assets should (within limits) rest with the project (through liquidated damages or ship-or-pay liabilities upstream and downstream).

However, unavailability risk associated with other parts of the value chain are less directly manageable by the project – e.g. the risk of outages of CO_2 T&S assets, the hydrogen network (if not owned by the investor), and/or curtailment of blending in the gas grid.

So, for example, what is the best way to manage exogenous unavailability risk on CO2 T&S assets? Assuming that the main risk relates to temporary outages of the T&S infrastructure (rather than an unexpected permanent unavailability) there are three potential options:[16]

- mitigate the risk via the CO2 T&S service contract – i.e. when the T&S asset is unavailable, the T&S asset owner will be obliged to compensate the project (and potentially industrial customers);
- mitigate the risk to the hydrogen project via a split CfD (meaning the project does not have to produce to cover fixed costs); or
- provide flexibility for plants with carbon capture to operate unabated for a period of time, if the T&S network is temporarily unavailable. To keep the project whole, the support level would need to increase in this period to cover its increased emissions costs.

[16] If the project has access to hydrogen storage, a buffer stock would allow it to continue to supply customers (and earn output-based CfD support) for a period. The other options would then discount for this.

Under the first two options, the project would cease production until the T&S assets become available. In this case, there is no carbon emitted, but industrial customers will be exposed to the knock-on unavailability of the hydrogen project (unless there are technical solutions that would enable a temporary switch back to methane for the duration of hydrogen supply interruption). These options may be undesirable if, as noted above, they were to dissuade industrial customers from switching to low-carbon hydrogen. The third option avoids significant customer disruption / compensation in the case of T&S unavailability, but carbon will be emitted.

Similarly, there is a risk that blending limits entail some unavailability of access to the local natural gas grid. The extent to which this risk would sit with the project will depend on the commercial framework for blending, which is discussed at length in Frontier's recent study.[17] There are options (within the blending regime) which could give early projects priority, or compensation for curtailment by the grid. Absent those, this is again a risk which might need to be mitigated by a split CfD.

FUTURE-PROOFING

During the life of the government support contract, there may be regulatory or market changes which alter the economic position of the project or otherwise affect the original bargain of the project's contracts. Examples could include:

- gas market changes: for example, impacting the choice of reference prices used in a CfD or the formation of those prices, or their weights;
- hydrogen market changes: competition from lower-cost sources of hydrogen; new sources of hydrogen demand; access to hydrogen storage; evolution of policy on green vs blue hydrogen; the emergence of a true market and market price for hydrogen (on-grid or off-grid, and nationally or internationally); the availability of tradeable low-carbon hydrogen credits;
- changes in the way in which CO2 T&S services are provided and priced (possibly even a short-term market in those services); and
- evolution or revolution in carbon pricing (impacting the project, its feedgas suppliers or its customers).

In considering these, government would seek to avoid windfalls for the project; ensure the project is incentivised to realise efficiencies which these changes allow, and is not shielded from risks which it should manage itself; and avoid 'legacy' situations in which the project can obstruct or distort these developments. Conversely, the project (and its lenders) will wish to avoid stranded costs, ensure the financial support continues to cover its commodity spread, and avoid taking on new risks.

The parties will need to consider the extent to which (in the support contract, and in hydrogen sale contracts if long term) evolution of reference price indices will naturally maintain equilibrium; whether

[17] Frontier Economics (September 2020) Hydrogen blending and the gas commercial framework, Report on conclusions of NIA study commissioned by Cadent, https://cadentgas.com/nggdwsdev/media/FRoG/Hydrogen-Blending-Commercial-Framework-Frontier-report-FINAL.pdf.

'change of law or circumstance' or 'gain-share' clauses can be devised which will restore it; and whether as a last-resort the government should have a right to 'buy-out' the project.

CONCLUSIONS

It is clear that there are a significant number of important issues to be addressed in securing a set of contracts (and resulting allocation of risk) which will make early hydrogen projects an investable prospect. There may not be an efficient one-size-fits-all approach: the preferred contractual relationship may depend on the specific situation of the project in question, and the context of the industrial cluster into which it plans to supply.

However, from the discussion above, we believe it is possible to take away the following general conclusions relevant to the next steps for investors and policymakers:

- there are significant cross-value chain risks to manage, particularly for blue hydrogen projects, and in many cases there are several ways in which risks could be allocated (within the energy sector and outside it);
- projects will need the active involvement of government at a relatively detailed level to get off the ground, and government may have to provide protection to one link in the chain against the failure of another link;
- securing "value for money" for the government will require an integrated view across conversion support for customers and support to hydrogen production;
- pinning down an early view of an acceptable allocation of risk for hydrogen investors, infrastructure investors, customers and government will be absolutely critical – and government support contract(s) with customers and investors will be an important part of this risk allocation; and
- to engage fully with the process, potential hydrogen investors and customers will need to form an early view as to their preferences in terms of risk allocation.

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