Department for Energy Security & Net Zero

The Need for Government Intervention to Support Hydrogen to Power

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Department for Energy Security & Net Zero

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Contents

Executive Summary

Introduction to work

The UK Government has committed to reaching Net Zero by 2050, and to decarbonising the power sector, subject to security of supply, by 2035. Achieving these commitments alongside delivering reductions required for the Sixth Carbon Budget will require low carbon flexible electricity generation capacity to complement the deployment of intermittent renewables[1].

Several technologies can potentially provide this flexibility, including grid storage technologies, interconnectors, Demand Side Response (DSR), gas turbines with carbon capture and storage technology (gas CCS) and hydrogen-fuelled thermal generation which is referred to as hydrogen-to-power (H2P).

This report focusses on H2P. Frontier Economics and LCP Delta were commissioned by DESNZ to assess the need for financial support to enable H2P and to describe options for business models that could incentivise investment. We assess the need for support in the context of existing business models and support packages, including the Capacity Market (CM)[2], which provides a payment for reliable sources of electricity generation capacity, and the Hydrogen Production Business model (HPBM)[3], which will provide revenue support to low carbon hydrogen producers.

Our assessment has two parts.

- In Work Package 1 (WP1), we set out the results of quantitative modelling alongside stakeholder engagement and secondary research to understand:
    - The overall need for H2P in a low carbon electricity system;
    - The need for a financial incentive to deliver investment in H2P; and
    - The need for an incentive to ensure appropriate dispatch of H2P.
- In Work Package 2 (WP2), we draw on the insights developed in WP1 to develop and assess options for unlocking investment in H2P plants, were DESNZ to decide to provide additional financial support. Our qualitative assessment uses criteria agreed with DESNZ along with additional stakeholder engagement and quantitative illustrations.

[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1148252/powering-up-britain-energy-security-plan.pdf
[2] https://www.gov.uk/government/collections/electricity-market-reform-capacity-market
[3] https://www.gov.uk/government/publications/hydrogen-production-business-model

WP1: Needs case for support for H2P

The overall needs case for H2P

The stakeholders we consulted expressed a view that H2P generation is currently one of the most promising technology to provide the low-carbon, firm, flexible generation required in a high-renewables future grid mix world.

Analysis[4] carried out using LCP Delta's EnVision modelling framework is consistent with this view[5]. A large amount of flexible capacity will be required to ensure security of supply in a low carbon system. These plants are likely to be dispatched infrequently. Under the scenarios modelled for this project, projected load factors for combined cycle turbines fall from between 5-20% prior to 2030 to below 5% in all scenarios examined post 2040, and projected load factors for reciprocating engines remain below 5% in all scenarios in all years. In one scenario, the capacity required for fewer than 10% of hours per annum rises from 50GW in 2035 to 110GW in 2050.

Given its lower capital-intensity, H2P is more suited to operate at these low load factors than gas CCS. Its greater degree of dispatch flexibility will also support the needs of a high renewable system, alongside other technologies such as storage and interconnection.

H2P also provides a useful decarbonisation strategy for assets that cannot decarbonise through CCS, for example due to space or infrastructure requirements. This could enable a decarbonised power system to better utilise existing assets and delay additional capital expenditure.

The need for a financial incentive to deliver investment in H2P

The stakeholders we consulted confirmed their appetite to invest in H2P solutions. However, they noted that to commit further significant expenditure to feasibility studies and beyond they would require the Government to commit to a supportive framework for H2P as part of its long-term decarbonisation strategy. While H2P is seen by existing generators as an option to decarbonise the existing generation fleet, there is currently little stated appetite to bring forward new-build H2P generation in the absence of further policy intervention.

To assess the needs case for H2P support to deliver investment, LCP Delta used its EnVision modelling framework to simulate the dispatch and projected returns of a H2P plant under different hydrogen price and availability scenarios. The modelling examined the level of CM payments that would be required for mid-merit and peaking technology archetypes to break-even.

- New build peaking plant, such as c. 300MW Open Cycle Hydrogen Turbines (OCHT) and 20MW reciprocating engines ('recips'), exhibited low load factors under all price

[4] LCP Delta analysis for National Grid ESO and DESNZ as part of the "Case for Change" for REMA, using DESNZ Net Zero High Electrification scenario.
[5] Generation capacity was an exogenous input to this modelling, based on DESNZ scenarios.

sensitivities and hydrogen availability scenarios explored. However, with lower CAPEX requirements, average CM payments between £40-80/kW per annum ('pa') may be sufficient to allow build in line with the DESNZ reference case, under the medium hydrogen price scenario.

- New build Combined Cycle Hydrogen Turbines (CCHT) running on 100% hydrogen required average CM clearing prices of £50-100/kW pa to break even, under the medium hydrogen price scenario.
- Refurbished H2P plants across all of the plant types looked at (CCHT[6], Combined Heat and Power (CHP), OCHT and recips) required CM clearing prices in the range of £20-70/kW to break even in the medium price scenario (more details of the breakdown of the range between plant types can be found in Section 4).
- CCHT, OCHT and recips that operate on a blend of fuel (the modelling looked at plants with a 30% blend of hydrogen volume) required CM clearing prices in the range £20-80/kW.

Recent CM clearing prices have been in the range £20-65/kW[7]. If H2P plants require CM prices significantly above this (i.e., at the top end of those modelled for new build CCHTs or refurbished H2P plants), absent further intervention there would be a risk of other participants in the CM earning significant inframarginal rents.[8] The potential for H2P plants to require very high CM prices therefore provides a rationale for considering other specific forms of support.

The need for an incentive to ensure appropriate dispatch of H2P

We assessed the extent to which there is a need for support to deliver efficient dispatch with reference to the social cost of generation across technologies. This social cost is the short-run marginal cost of generation using unsubsidised fuel prices plus the appraisal price of carbon (which reflects economy-wide abatement costs). To minimise costs to society[9], H2P technologies, gas CCS and unabated gas should dispatch in order of their social cost.

The modelling suggests that dispatch order under market prices would generally already align to the socially optimal order.

- Without any further dispatch incentives, the modelling showed H2P generally dispatches behind CCS. This is an efficient order, given H2P's has higher social short run marginal costs if carbon is priced at the appraisal value.
- Where hydrogen fuel is not subsidised, unabated gas plant often dispatches ahead of H2P, especially in the early period. However, this is in line with the fact that unabated gas has lower social short run marginal costs until 2040.

[6] Combined Cycle Hydrogen Turbine
[7] We understand that current CM clearing prices are not a perfect proxy for future clearing prices, but it was out of scope of this report to predict future clearing prices of other technologies.
[8] Inframarginal rents refer to the difference between the clearing price in the CM auction and a plant's costs of committing to remain available.
[9] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent/the-green-book-2020#valuation-of-costs-and-benefits

Therefore, under the assumptions used in the modelling, additional interventions to incentivise the dispatch of H2P would not reduce costs to society.

However, in practice, their actual outturn order of dispatch will depend on factors including market carbon and fuel prices. It is possible that the outturn carbon price will be lower than that assumed in the modelling. Under these conditions an additional dispatch incentive could reduce social costs (depending on the level of the outturn carbon price).

In addition, if deliberately ensuring H2P dispatches ahead of unabated gas plant is a policy aim, the modelling suggests that a further intervention would be required if hydrogen fuel is unsubsidised or where limits on the level of subsidised hydrogen prevent further H2P generation.

Key conclusions

The key conclusions of WP1 can be summarised as follows.

- **The need for H2P**. Modelling suggests many flexible plants will be required for system security purposes, but that they are likely to be running at relatively low load factors. Given its lower capital-intensity, H2P is likely to be more cost-effective in this role than gas CCS.
- **The need for financial support for H2P investment.** Peaking H2P generators such as OCHT and recips may be sufficiently supported through existing policy mechanisms (CM) despite low load factor operation. There may be a justification for additional support to higher capital cost technologies such as CCHT in some scenarios.
- **The need for a dispatch incentive for H2P**. Modelling suggests that an additional dispatch incentive for H2P plants would not reduce costs to society. Under the market prices assumed in the modelling, flexible plants already dispatch in order of their social costs.

WP2: Potential business model design

Having established that H2P could play an important role in a decarbonised power sector and that the current CM may not be able to support all types of H2P, in WP2 we qualitatively assess six short-listed business models[10] that could provide financial support.

The six business model options we consider in detail are:

- **Capacity Market ('CM').** The CM is an auction process. Investors bid to receive a Capacity Agreement, which provides them with a fixed monthly payment per kW of capacity, independent of their level of dispatch (except during stress events). All successful bidders receive the auction clearing price in a given year. Investors can receive a contract for a period of up to 15 years for a new plant, and up to three years

[10] The six business models were filtered from a longlist which covered the business models considered in the REMA consultation, as well as wider business models and policies employed in the UK and other jurisdictions.

for refurbished plants. Under this option, H2P would bid into the existing CM, assuming changes to the CM price cap such that it could support the higher clearing prices potentially required for H2P. This could set a high clearing price in the CM, resulting in high payments to non-H2P plants. We use the CM as the counterfactual in our analysis of alternative business models.

- **Split CM with a separate auction for low-carbon dispatchable power technologies (‘CM+’).** This alternative business model (outlined in the REMA consultation[11]) represents changes to the current CM that could reduce the problem of excessive inframarginal rents. It involves splitting out a separate auction to cover less mature low-carbon dispatchable power technologies. As with the counterfactual CM, successful bidders would receive a Capacity Agreement for up to 15 years, which provides them with a fixed monthly payment per kW of capacity that is available, regardless of how the asset dispatches (except in system stress events).
- **Deemed Generation CfD.** This option (also outlined in the REMA consultation[12]), builds on the current contract for differences (‘CfD’) in place for renewable generation. It involves support paid per unit of ‘deemed output’[13] rather than per unit of metered output, alongside the similar concepts of strike price and reference price. This means that operators are exposed to market prices when making dispatch decisions and are incentivised to dispatch efficiently (when market prices are above their marginal costs), because the level of actual dispatch does not affect the support payment they receive. The level of support per unit of deemed output is similar to a regular CfD, and is based on the difference between a strike price which is fixed for the length of the contract, and a reference price which changes over time.
- **Dispatchable Power Agreement (‘DPA’).** The DPA is being put in place to support gas CCS projects and could be extended to also cover H2P investments. It includes two possible payment streams. First, an availability payment is paid per unit of capacity that is available over time, regardless of dispatch. This is similar in form to a CM payment but without the strict conditions related to security of supply which feature in the Capacity Agreement. Second, a variable payment could also be paid per unit of output. For a CCS plant, this has the objective of reducing marginal costs such that it dispatches just ahead of unabated gas in the merit order.
- **Revenue Cap and Floor.** This intervention would provide increased certainty on the revenue received by the H2P investor, within a defined range. The operator receives market revenue and if this market revenue is below a minimum (floor), then the operator receives a top-up support payment to the level of the floor at the end of a defined reconciliation period. Similarly, if market revenue is above a maximum (cap) defined by the regulator, then the operator pays back the ‘excess’ at the end of the reconciliation period. This builds on the regime in place for interconnectors.

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[11] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
[12] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
[13] In this case, a plant’s deemed output is the output that the model thinks the plant could have produced given market assumptions, rather than the output it actually produces (‘metered output’). Deemed output is determined administratively based on factors such as the generation technology, location, and market conditions.

- **Fossil Fuel Ban.** This intervention would define the maximum level of unabated gas to be used in power generation over a specified time period. The maximum level could be set at zero from a certain date or could reduce to zero over a specified time horizon. We assume that the current CM is still in place under this business model.

To assess the business models, we first consider the risks and barriers that H2P developers would be likely to face, and which ones the business model should aim to mitigate. While exposing H2P developers to risks increases their cost of capital (in the extreme, potentially making H2P plants uninvestible), risk exposure also incentivises developers to adjust their behaviour to manage risks efficiently. Therefore, not every risk H2P plants face should be mitigated by a business model. Instead, we focus only on the risks that developers are unable to efficiently manage because they relate to factors beyond their control, such as policy.

Based on the evidence from the stakeholder engagement and WP1 modelling results, we start with a long-list of risks and barriers across the development, construction and operation of H2P plants. We identify a short-list that should be covered by the business model to make H2P plants investible:

- Policy-driven electricity price risk;
- Policy-driven electricity demand risk;
- Policy-driven hydrogen fuel price risk; and
- Policy-driven hydrogen fuel availability risk.

Having derived this short-list, we assess the business models against a number of criteria, covering both risk mitigation and other factors. We assess whether each business model:

- Mitigates the key risks and barriers that investors are not well placed to manage, reducing the cost of capital and making an H2P plant more investible;
- Maximises the decarbonisation of the power sector;
- Minimises costs to society by not distorting dispatch or encouraging over-/under-investment in H2P;
- Provides value for money to the funders of the business model (e.g. taxpayers or energy customers);
- Is practical in terms of transparency, deliverability and administrative burden – especially when other relevant policies are considered; and
- Allows for flexibility and adaptability to expected and unexpected changes in the sector.

In doing so, with the exception of the Fossil Fuel Ban, we assume that business models provide support for 15 years, during which time supported plant cannot participate in the current CM, due to concerns around the cumulation of aid. We assume that operators would be able to bid into the annual CM after the 15 year support period.

Assessment results

We find that the CM could support H2P relatively efficiently (without further H2P-specific intervention) but only under specific circumstances which are unlikely to hold for early investments.

WP1 modelling suggests that new build CCHTs would require a CM payment from £50/kW to £100/kW per year[14], depending on the availability of hydrogen, and levels of capex and hurdle rate.

For H2P bids to be at the lower end of the range, and therefore for CM clearing prices to be closer to today's levels, very specific conditions would need to be in place:

- The capital costs of H2P plants would need to be similar to those of unabated gas;
- The hurdle rates of H2P plants would need to be similar to those of unabated gas;
- There would need to be sufficient subsidised hydrogen available, such that the fuel costs of H2P were similar or lower than that of unabated gas;
- Investors would need to believe that there were not significantly higher fuel availability risks associated with hydrogen as compared to gas[15].

WP1 modelling finds that under the above conditions a new-build CCHT could be supported by a clearing price of £70/kW per year. This is closer to clearing price levels seen today, and more likely to be similar to that of an unabated Combined Cycle Hydrogen Turbine (CCGT) going forwards. Therefore, the impact on inframarginal rents (relative to those present in the CM today) would likely be low.

However, these conditions are unlikely to hold for the first investments in H2P:

- It is not likely that early H2P will be able to achieve the capex and hurdle rates of unabated gas, given the risks and additional costs associated with first-of-a-kind investments;
- Focussing on subsidising low carbon hydrogen (via an expansion of the HPBM) rather than targeting a support mechanism at H2P may increase societal costs (for example, if a large amount of subsidised hydrogen available means that consumers in other sectors choose to decarbonise with subsidised hydrogen, when an alternative decarbonisation option with lower societal costs is available); and
- In the early hydrogen market, fuel availability risk that results from cross-chain and policy-related risks is likely to represent a key risk to investors, and one that an H2P business model should ideally mitigate.

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[14] These modelling results are for new-build CCHTs in 2026 operating on 100% hydrogen fuel in the medium hydrogen price scenario. The equivalent modelling results from WP1 for OCHTs are £41-70/kW, £73-205/kW for CHPs, and £41-82/kW for recips.

[15] Given the strict security of supply conditions associated with the CM, investors would be penalised if they were not available to generate during a stress event. Relying on the CM alone exacerbates fuel availability risk for investors.

The required conditions may hold in the medium to long term. Over the long term, including H2P in the CM could provide a valuable incentive for H2P plants to contribute to security of supply.

The CM+ has the potential to provide support to H2P but has some drawbacks.

The CM+ would involve an auction only open to a narrow range of low carbon technologies[16]. This would reduce the risk of high inframarginal rents even if H2P clearing prices remained high (i.e., if the conditions above did not hold)[17].

However, because a narrower set of technologies would be eligible, the auction may be less competitive[18]. This could in turn result in uncompetitively high auction clearing prices, and excess inframarginal rents for participants in the CM+ auction. This trade-off between reducing the number of players in an auction that could receive inframarginal rents and increasing the number of players in an auction to ensure competitiveness is less important for other business models that can be allocated via bilateral negotiations in the years before there are enough potential investors to rely on a competitive allocation process.

Furthermore, plants clearing in the CM+ auction would still be penalised in the situation of non-availability during a stress event, exposing investors to fuel availability risk. Our understanding from current investors views is that this could make H2P uninvestible, given perceptions of cross-chain and policy-related risks.

Finally, we note that delivering the CM+ via changes to the legal and regulatory framework currently used for the CM could be administratively difficult.

The DPA performs well against the assessment criteria

While the DPA delivers a fixed monthly payment (in common with the CM and the CM+), it has four advantages over these mechanisms.

- First, the DPA could be given directly to H2P operators without altering the clearing price in the CM for other technologies, and therefore the level of support received by these other operators (either low carbon or otherwise). Therefore, the DPA should not lead to high inframarginal rents for other operators;
- Second, for early investments, the DPA could be designed to mitigate fuel availability and cross chain risks for investors. For example, the availability payment could still be paid when fuel is unavailable due to cross-chain outages, rather than penalising plant operators when they cannot meet the security of supply conditions inherent to the CM and the CM+;

[16] These low carbon technologies could in theory include new pumped hydro storage, Power CCUS (if it no longer receives a DPA), and H2P. However, it was beyond the scope of this work to think about business models that would be appropriate for other technologies.
[17] Given the combination of the need for substantial derating of H2P to take into account fuel availability risk with the high costs of H2P, issues of inframarginal rents for some technologies may remain, especially if it is not possible to exclude batteries from the CM+.
[18] Liquidity would not be an issue for the CM, because the full range of flexible plants could bid in.

- Third, the DPA could be allocated by bilateral negotiation in the near term and an auction in the longer term (to the extent that support beyond the CM is required in the longer term). This would reduce risks associated with lack of competition in an auction; and
- Fourth, the DPA may have a lower administrative burden than other business models, as it is already being introduced for Power CCUS but does not rely on changes to the CM legal and regulatory framework.

While there is an option in the DPA to include a variable payment to shift H2P ahead of unabated gas in the merit order, our analysis suggests that incentivising additional dispatch of H2P would not increase whole system efficiency (and it would add significant complexity to the electricity market[19]). If applied without the variable payment, the DPA would not distort dispatch.

There are significant issues with the other three options considered.

- The Deemed Generation CfD is designed for intermittent renewables rather than dispatchable technologies. The concept of providing support based on deemed output is designed to incentivise investors in renewables to locate efficiently, for example, in areas of high wind. However, this type of locational incentive is not relevant to non-renewable power. It would also be very difficult to appropriately estimate deemed output (as outlined in the REMA consultation). In addition, the fact that the levels of support change with the reference price would bring in additional risks for dispatchable power operators;
- The Revenue Cap and Floor is more suited to technologies with high capex, low and stable operating costs, and where significant barriers to entry exist. For dispatchable power technologies with non-negligible operating costs, the revenue cap and floor could distort dispatch incentives, increasing costs to society. There are a number of adjustments that could be made to a traditional Revenue Cap and Floor to mitigate this distortion. However these are unlikely to fully remove it, and would add complexity to the business model; and
- The Fossil Fuel Ban would not help to the issue of inframarginal rents that we expect to be present in the CM. Moreover, it may be difficult to ensure that the ban is credible to investors, and if it is not, it will not deliver H2P investment.

Overall conclusions

Given it is likely we will require significant dispatchable capacity, albeit operating at lower load factors, the lower capex requirements of H2P compared to Power CCUS means it could play a helpful role in a decarbonised power sector.

Some H2P plants - peaking plants (OCHTs and recips), refurbished plants (of all plant types looked at) and plant utilising a 30% blend of hydrogen and methane - may not need support

[19] Especially as such a payment would interact with the payment already in place for Power CCUS.

beyond the current CM depending on the scenario used. However, other plant types are likely to need additional support to avoid issues associated with inframarginal rents.

If the decision were made to give H2P additional support, then the most suitable business model is likely to be a DPA (with an availability payment only). This would mitigate the key risks that investors are not best placed to manage, avoid distorting dispatch incentives, allow a negotiated allocation process in the near-term, and build on a mechanism already being introduced for Power CCUS. Competitive allocation could be foreseen in the longer-term to encourage cost reductions, increasing value for money to those funding the business model (e.g., taxpayers or energy customers).

1- Introduction

Aims of the project

The UK Government has committed to reaching Net Zero by 2050, and to decarbonising the power sector (subject to security of supply) by 2035. Achieving these commitments alongside delivering reductions required for the Sixth Carbon Budget will require low carbon flexible electricity generation capacity to complement the deployment of intermittent renewables[20].

Several technologies can potentially provide this flexibility, including grid storage, interconnectors, Power CCUS and H2P.

This report focuses specifically on H2P. LCP Delta and Frontier Economics were appointed to undertake analysis for DESNZ to assess the financial need case for market intervention in H2P, and to assess potential business model design options. The aim of this research is to inform policy development to support the Government's commitment to assess the need and case for market intervention to support the deployment of H2P.

The analysis is split into two work packages. WP1 looks at whether there is a need for intervention to deliver H2P. WP2 assesses different business models that could be used to support H2P.

Is there a need for intervention to deliver H2P?

In WP1 we consider whether there is a need for intervention in the hydrogen to power (H2P) sector. This involves:

- Stakeholder engagement (interviews with eleven developers, two original equipment manufacturers (OEMs), and four investors, to understand the current market conditions and stakeholder concerns)[21];
- Modelling the costs and dispatch of a range of hydrogen to power (H2P) technologies;
- Examining the returns under a range of hydrogen fuel availability and cost levels; and
- Assessing the required levels of subsidy (in the CM) under different scenarios.

We look at eight different H2P fuel and technology combinations: CCHT, CHP, OCHT and recips; looking at both a full-hydrogen and 30% blend for each. We use DESNZ assumptions on capacity requirements, fuel and carbon prices, and fuel availability throughout.

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20 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1148252/powering-up-britain-energy-security-plan.pdf

21 We incorporate feedback from these interviews into the assumptions and operating models examined as part of this analysis.

As part of this analysis, we examine whether:

- There is an overall need for H2P in decarbonising the power sector;
- There is a financial needs case for intervention to ensure sufficient investment in H2P; and
- There is a need to ensure H2P dispatches appropriately to minimise costs to society and to maximise carbon reductions.

LCP Delta used its EnVision modelling framework to simulate the dispatch and projected returns of H2P plant under different hydrogen price and availability scenarios. The modelling estimates the level of the CM clearing price required for each case plant type and blending level to break even. This level represents the required level of subsidy, which we compare to recent CM payments to determine whether further intervention is needed.

Assessment of potential business model design

In WP2 we consider potential designs for business models that could be used to support H2P, were Government to decide to provide additional support to this technology.

We select a short-list of business models using two hurdle criteria to remove a business model where it is clear that it would significantly distort dispatch, or where a simpler version of the business model already in the long-list could potentially deliver the same outcomes. This short-list consists of six business models that are either already in place or that have been suggested under REMA.

We then define a set of six criteria to qualitatively assess the business models, including the extent to which the business model is investible[22], efficient, and practical.

We bring together the six business models and six assessment criteria in a qualitative assessment, that also draws on stakeholder engagement and quantitative illustrations where relevant. This assessment outlines which business models are likely to be more and less suitable to promote investment in H2P.

The remainder of this report is set out as follows:

- Section 2 ‘The need for intervention to support H2P’ analyses the needs case for intervention to support H2P;
- Section 3 ‘Assessment of potential business models for H2P’ sets out our assessment of business models.

[22] Understanding the investibility of H2P plants in particular involves a detailed understanding of the risks and barriers facing investors. Since it would not be efficient for developers to be protected from all risks, we also assess which of the risks and barriers should be covered by the H2P business model (rather than left with the developer).

Further detail on the stakeholder engagement, the modelling and the qualitative assessment is provided in the annexes.

2- The need for intervention to support H2P

This section sets out the WP1 analysis, and addresses the following questions, based on EnVision modelling and stakeholder engagement:

- Is there an overall need for H2P?
- Is there a need for a financial incentive to deliver investment in H2P? and
- Is there a need for an incentive to ensure appropriate dispatch of H2P?

Key assumptions used in modelling H2P revenue streams

We first set out the key assumptions used in the modelling. Further details are provided in 'Annex B: Modelling assumptions and approach'.

H2P capacity

DESNZ provided their Net Zero High Electrification reference case scenario for this analysis. This scenario includes high electricity demand and a high level of hydrogen generation capacity. The amount and composition of H2P technologies is key, due to the volume of H2P capacity assumed, the impact of revenue cannibalisation from a plant with similar technological characteristics is significant.

The DESNZ reference case assumptions provided assume all H2P generation to take the form of CCHT capacity. LCP Delta has reviewed the reference case and made three modifications to the capacity mix:

- **Battery storage** – the DESNZ reference case assumption for storage remains far below the committed levels of build in the capacity auctions that have taken place to date and as such are not credible. The assumptions for battery storage capacity have been increased based upon LCP Delta's internal modelling.
- **H2P** – H2P in the DESNZ reference case is assumed to be wholly CCHT, we refined this to include additional H2P technology archetypes.
- **Open Cycle Gas Turbine (OCGT)** – the DESNZ reference case assumes significant build-out of unabated OCGT capacity through to 2050 to meet security of supply requirements. Based on the proposals set out in the January 2023 CM consultation (to strengthen CM emission limits from 1 October 2034) we have assumed that no new unabated gas fired generation will be built from 2035 onwards. Instead, we have added OCHT build to ensure security of supply requirements are met.

These changes have been made to ensure that the results for the technology archetypes are not biased by a lack of competition from similar units.

Further details on the background scenario and capacity mix can be found in ‘Annex B: Modelling assumptions and approach’.

Hydrogen price

The hydrogen price is key in determining the dispatch of H2P and its ability to run ahead of or behind, an unabated natural gas plant.

The price of hydrogen available for electricity production is uncertain and will depend upon:

- The underlying price of natural gas utilised to produce hydrogen via the steam methane reformation process;
- The cost of producing green hydrogen and whether this cost reflects the long-run marginal cost or short-run marginal cost of production;
- The split of green and blue hydrogen assumed in future years; and
- Any subsidies applied.

In this analysis, we assume that limited quantities of both subsidised and unsubsidised hydrogen are made available to H2P generators. Subsidised hydrogen is that supplied from hydrogen production supported by the Hydrogen Production Business Mode (HPBM)[23] and is cheaper than unsubsidised hydrogen, which is assumed to receive no support.

DESNZ has provided low, medium and high scenarios for the price of both subsidised and unsubsidised hydrogen. We assess the levels of subsidy for the technology archetypes under each of these cases.

Transport and Storage Costs

We also account for Hydrogen Transport and Storage (T&S) costs in addition to the hydrogen price in the running costs of hydrogen to power generators. There is uncertainty in the level of T&S costs and these were reflected in the illustrative assumptions provided by DESNZ to represent the range of potential costs.

Hydrogen availability

The volume of hydrogen available to be used for electricity production is uncertain. DESNZ has provided a high case and low case under which the levels of subsidy required for each technology archetype will be assessed.

The modelling did not take into account the locational availability of hydrogen as this was out of scope for this piece of analysis.

[23] https://www.gov.uk/government/publications/hydrogen-production-business-model

H2P Technologies

We consider four technology archetypes. Key assumptions for these technologies are shown below. The DESNZ 2020 report on Electricity Generation Costs[24] is the main source for technology characteristics and costs of H2P plants which, in the low case, are assumed to be in line with those of a gas plant. High capex (an increase of 34% representing the increase to 2023 levels in real terms) and high hurdle rates (increase of 2%) scenarios are also explored in this analysis.

Table 1: Plant characteristics

Tech[25]	Hydrogen utilisation (volume %)	HHV Efficiency (%)	CAPEX (£/kW) – Low (DESNZ 2020 report)	CAPEX (£/kW) – High (2023 estimate)	Hurdle rate, pre-tax real (DESNZ 2020 report[26])
CCHT	30%, 100%	53%	New Build: 640 Refurb: 320	New Build: 857 Refurb: 429	7.5%
CHP	30%, 100%	60%[27]	New Build: 981 Refurb: 491	New Build: 1,315 Refurb: 657	9.0%
OCHT	30%, 100%	34%	New Build: 489 Refurb: 245	New Build: 655 Refurb: 328	6.8%
Recip	30%, 100%	32%[28]	New Build: 508 Refurb: 254	New Build: 681 Refurb: 340	7.1%

Source: LCP Delta

For each technology, we assess subsidy levels, assuming fully hydrogen-fired operation as well as operation on a blend of hydrogen and natural gas (30% hydrogen, 70% natural gas by volume with blending occurring locally onsite). Due to the low energy density of hydrogen, the

[24] https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020
[25] Reference technologies from DESNZ 2020 report are as follows: CCHT (CCGT H Class), CHP (CCGT CHP mode), OCHT (OCGT 299MW 500hr), Recip (Recip Gas 500 hrs)
[26] High hurdle rate sensitivity (increase of 2%) is also tested.
[27] Electrical efficiency, assuming operating in CHP mode and supplying useful heat (33% electrical efficiency and 45% of fuel use being associated with heat production).
[28] Sourced from DESNZ assumptions, however this efficiency is lower than that achievable by newer gas reciprocating engine plant.

30% co-firing (by volume) assumption equates to a c.12% co-firing with hydrogen on an energy basis.

The blended fuel assumption represents a less capital-intensive operating model using existing assets under a limited retrofit. In contrast, the fully hydrogen-fired assumption represents a more capital-intensive route in which a new build hydrogen-ready asset is constructed or a full re-plant of an existing unit is made.

We assume that plants which utilise a blended hydrogen fuel also retain the ability to run wholly on natural gas and are able to switch between the two fuels.

The CHP and CCHT archetypes represent a high efficiency thermal plant, with CHP being the more capital-intensive option with a higher hurdle rate. The OCHT and recip are less capital-intensive, lower efficiency peaking thermal plant, which present one option of securing dispatchable power to ensure security of supply in the transition to Net Zero.

It is important to note that the differing efficiencies assumed impact not only where plants sit in the merit order but also the amount of subsidised and unsubsidised hydrogen allocated to each plant. High efficiency hydrogen units are prioritised in the modelling to ensure that carbon emissions are minimised.

Is there an overall need for H2P?

It is clear that dispatchable low-carbon power will be required on a path to Net Zero. H2P can play an important role in fulfilling this need at lower cost in the few extreme periods in which backup power is required. Box 1 sets out stakeholder views on this issue, and we discuss the results of the modelling below.

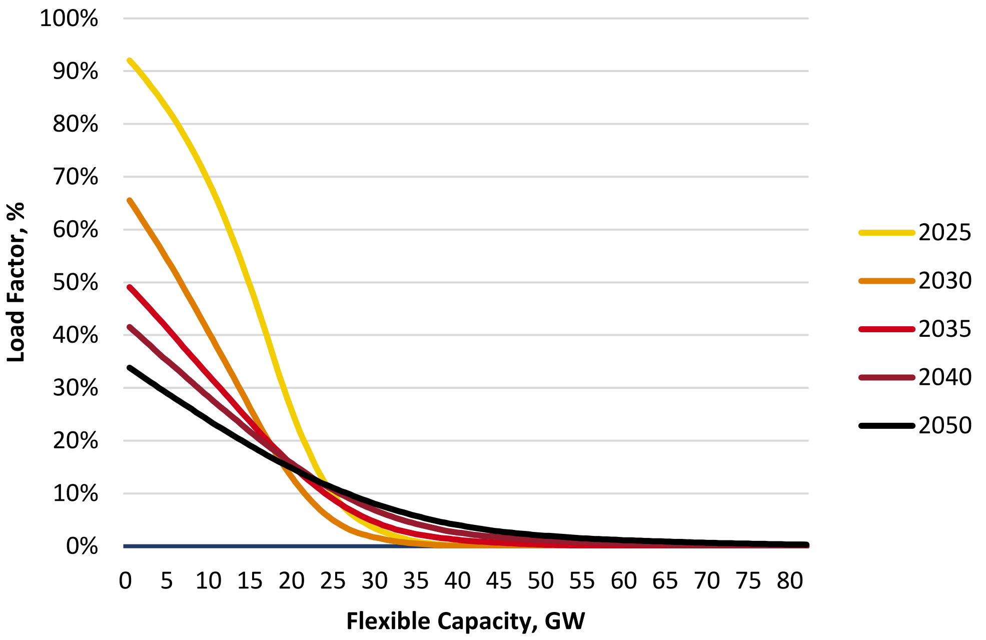
Box 1: Stakeholder views on the need for H2P

> The stakeholders we interviewed see a role for hydrogen to power, predominately to provide flexibility to the system on a path to net zero.
>
> In particular, the stakeholders we interviewed believe that H2P can respond more flexibly than Power CCUS. There is an expectation that OEMS will allow turbines and recips to ramp up and down from full load quickly and repeatedly. Compared to Power CCUS, their superior ramping times will make them the preferred option in terms of flexibility.
>
> Some stakeholders also see a role for H2P in providing zero carbon baseload generation. Ultimately the future role for hydrogen will depend upon a number of factors, including but not limited to the future generation mix and the amount of renewable, extent of DSR and deployment of storage and interconnection in the electricity system.

We did not directly assess the need for H2P in the energy system as part of the modelling in this project. In the modelling, H2P capacity is an exogenous input taken from the DESNZ Net

Zero High reference case. However, the modelling demonstrates a need for a large amount of low carbon generation capacity with low utilisation to ensure security of supply (Figure 1).

Figure 1: Implied load factor of flexible capacity (DESZN Net Zero High Electrification scenario)[29]



Source: LCP Delta

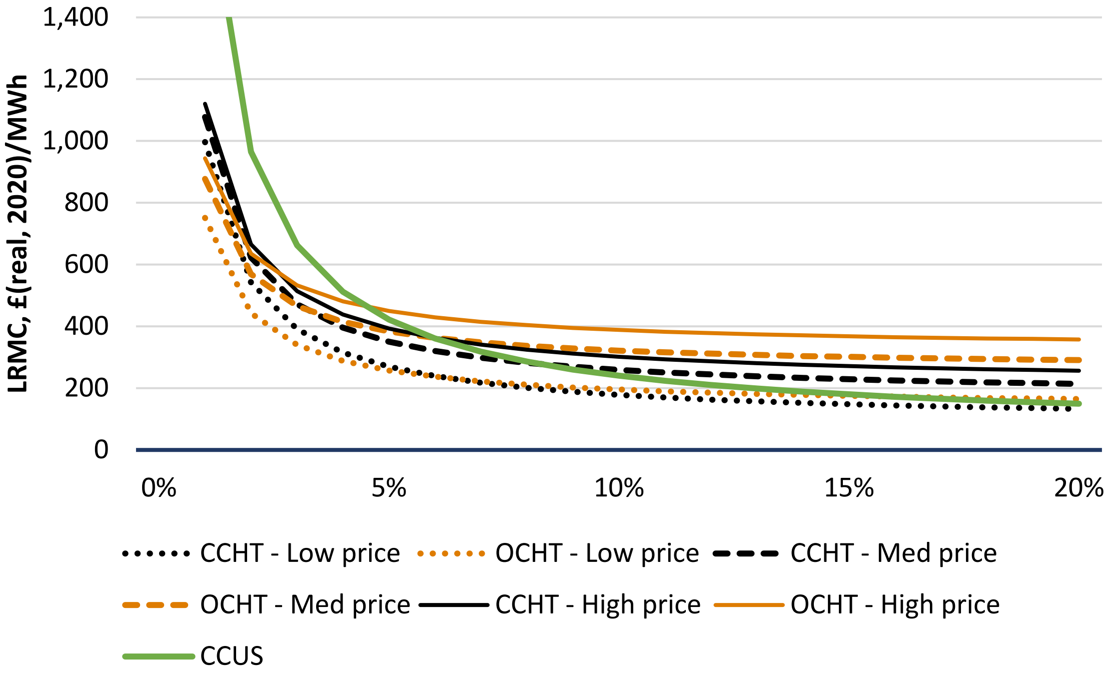
To ensure security of supply as the electricity system decarbonises, there is a need for firm flexible capacity that is dispatched in a small number of extreme periods. While battery storage has a role to play, often the need in the future is driven by these limited duration assets having run out of charge.

The load factors for small amounts of firm flexible capacity can be significant (left hand side of (Figure 5). However, they begin to decrease for each additional GW added, falling below 10% when the amount of firm flexible capacity reaches 25-30GW. Large amounts of firm flexible capacity are required to cover extreme periods reaching 83GW in 2035 rising to 140GW in 2050.

Given the lower load factors of these plant it may not make sense for abated generators (Power CCUS) with their higher capital costs to be used in this role. Our analysis shows H2P can provide firm capacity more cost-effectively (i.e., for lower LRMC) than Power CCUS at low load factors (Figure 6).

[29] From LCP Delta analysis for National Grid ESO and DESNZ as part of the “Case for Change” for REMA.

Figure 2: LRMC of low carbon thermal generation at low load factors, under different hydrogen price scenarios (assuming unsubsidised hydrogen prices in 2035)



Source: LCP Delta

The long run marginal cost (LRMC) is made up of the plant's Short Run Marginal Costs (SRMCs) plus the capex and fixed opex spread across its total generation.

Figure 2 shows that:

- At very low load factors OCHT has a lower LRMC than CCHT;
- The LRMC of H2P is lower than that of Power CCUS at low load factors (c. 9% in the medium price sensitivity);
    - In the low hydrogen price sensitivity, the LRMC of CCHT remains lower than that of Power CCUS up to load factors of 30%; and
    - In the high price sensitivity, it is lower up to load factors of 5%.

This illustrates that H2P is more cost effective than Power CCUS at the low load factors expected for a large proportion of the future flexible fleet.

Is there a financial need for a business model to ensure sufficient investment in H2P?

We now examine whether there is a need for intervention to ensure that sufficient capacity is deployed to achieve Net Zero targets. We discussed this with stakeholders (Box 2) and assessed the question in the modelling.

Box 2: Stakeholder views on the need for a business model

The majority of stakeholders that we interviewed support a policy intervention to support H2P.

However, we found a wide range of views around the level and nature of the support required – predominantly due to the lack of certainty and confidence around hydrogen availability (when it becomes available and in what volumes).

- Most stakeholders argued that there is a need for H2P within GB to support the decarbonisation of the electricity sector. Due to the costs and uncertainties in investment involved there is a need for a specific H2P framework. A hydrogen specific business model should be seen as a sensible way to reduce risk for merchant investment – which is currently challenging. One counterargument given from a large developer was that Government should not give continuous support to H2P. It should do this for hydrogen production instead, and non-continuous support is a better option e.g. grants for changing equipment to enable transition from gas to hydrogen.
- Some investors currently favour the tax credit framework of the IRA in the USA due to the simplicity of the mechanism.
- A small number of stakeholders expressed a view that a greater policy emphasis should be placed in hydrogen transportation and storage to enable large volumes, rather than developing application-specific interventions including H2P Business Model.
- Most stakeholders agreed that policy intervention should not be complicated. For example the CM is a well understood example of a support mechanism that can enable investment.

In our modelling, the ‘need’ is assessed as whether the CM could support H2P deployment without resulting in exceedingly high clearing prices leading to excess inframarginal rents, where required CM prices are high in comparison to CM prices we see today (in the range of £20-65/kW pa), and do not exceed the current CM price cap of £75/kW pa.

The modelling suggests that:

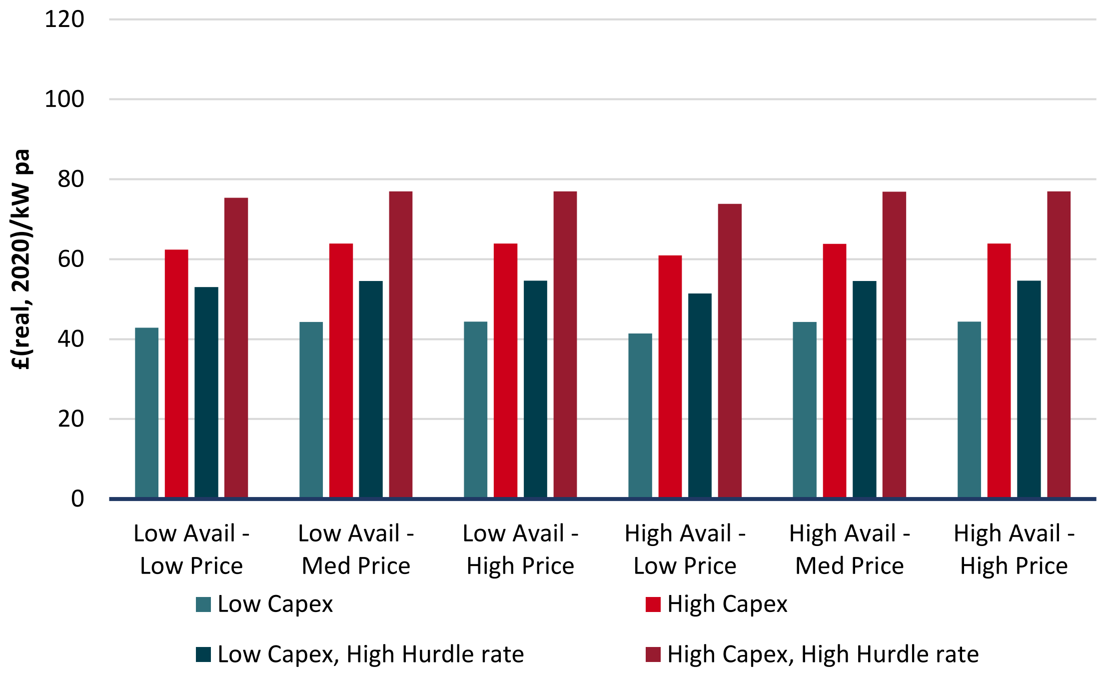
- New build peaking plants (OCHT and recip) may not need financial support beyond the CM due to their lower capital requirements under all hydrogen price sensitivity and availability scenarios. Limited intervention may be required under high capex and high hurdle rate assumptions;
- New build CCHT and CHP would need support to cover higher costs, given low expected load factors; and
- Retrofit or blending CCHTs may also be investible without additional intervention (beyond the CM) assuming capital costs are significantly lower than new build.

Peaking (OCHT and recip) plant

OCHT and recip plant potentially do not need support beyond the CM. Our modelling finds that clearing prices of £40-80/kW are generally required for new build OCHT and recip to break even (Figure 3). These clearing prices are similar to those seen in recent auctions; this is because:

- The additional capex of a OCHT relative to a OCGT is small;
- They very rarely run so there is no significant opex difference; and
- Given their low load factors, H2P peakers would operate similarly to current unabated gas peakers, relying heavily on CM payments for revenue.

Figure 3: CM support required for new build 100% hydrogen fired OCHT commissioning in 2026

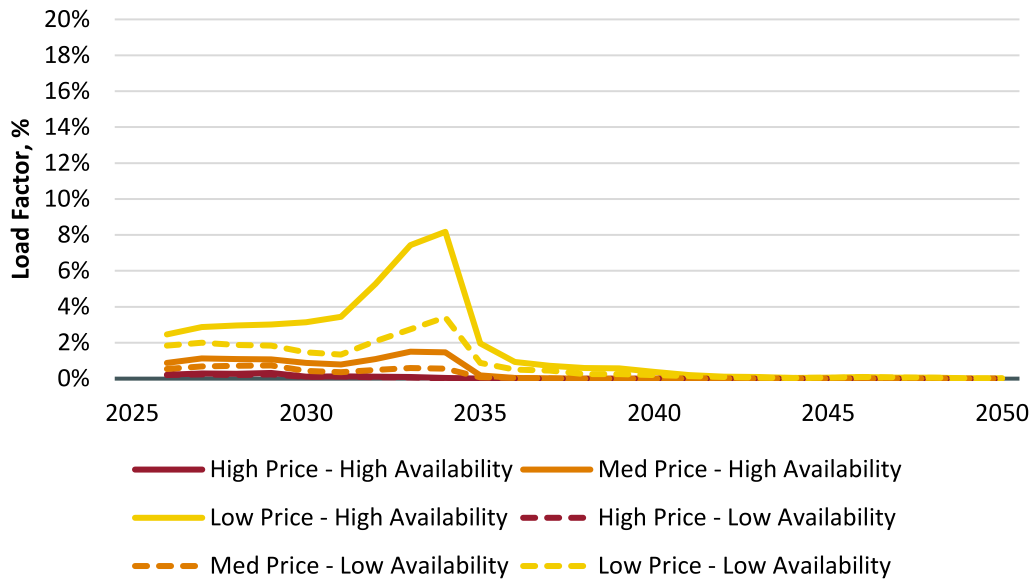


Source: LCP Delta

The load factors of OCHT are much lower than those of CCHT (up to 15%) and CHP (up to 25%). Prior to 2035 when competition from other H2P units is low, load factors average around 4%. Due to their lower efficiency, OCHT are allocated lower volumes of hydrogen in the modelling (as to maximise carbon savings plant with higher efficiencies are allocated greater volumes of hydrogen) which limits their ability to generate.

Beyond 2035, due to the influx of competition from H2P peaking and mid-merit plant load factors reduce to almost zero. There is a peak in load factors in the early 2030s as the OCHT is able to access subsidised hydrogen fuel and displace natural gas fired units in this period (when the carbon price is rising significantly to reach the appraisal value by 2040). This is illustrated in Figure 4.

Figure 4: Load factors for 100% hydrogen fired OCHT commissioning in 2026



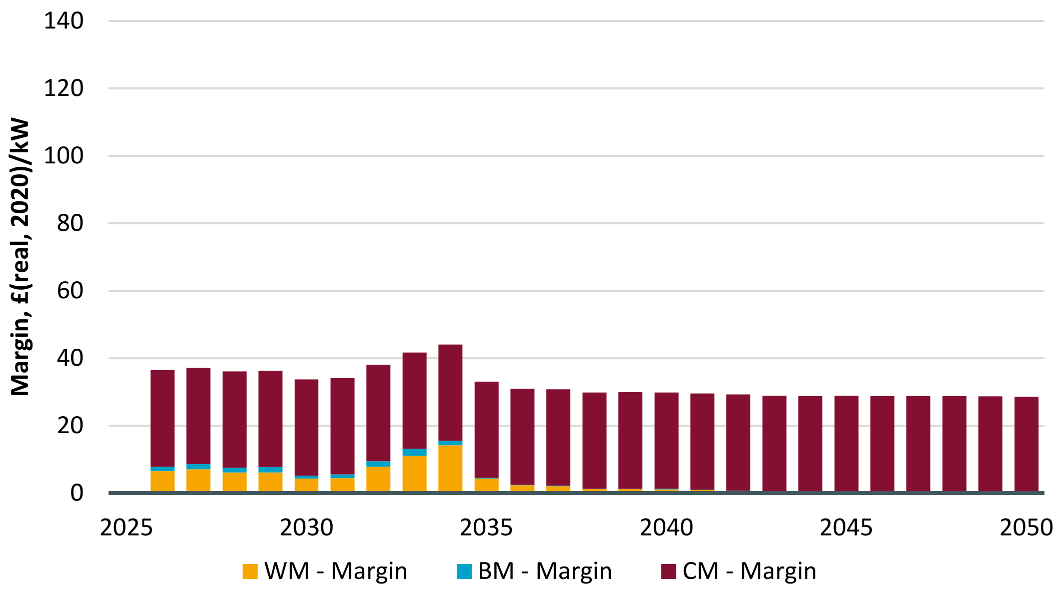
Source: LCP Delta

Due to their low load factors, margins from energy markets only make up a small proportion of overall revenues for these plants. OCHT plants rely on CM payments to make a return, otherwise only dispatching during times of high demand/low renewable output (Figure 5).

This is because:

- Wholesale Market (WM) margins decline as the deployment of hydrogen capacity begins in earnest post 2035;
- Balancing Mechanism (BM) payments are similarly affected by the deployment of newer H2P capacity; and
- CM payments make up the majority of revenues received over the lifetime of the plant.

Figure 5: Margin for new build 100% hydrogen fired OCHT commissioning in 2026 (low hydrogen price, low hydrogen availability scenario)



Source: LCP Delta

Mid-merit (CCHT/CHP) plant

Our modelling finds that new build CCHTs and CHPs are likely to need support beyond the CM to cover their higher capex and opex requirements.

CHP

CHP plant in addition to providing power is also capable of providing heat, for example to local district heating networks. In 'dunkelflaute' periods (periods of low wind and solar generation) these plants can act to both generate electricity and lower demand for electricity (lower electrical demand from ground/water source heat pumps). However, examining these additional use cases for heat was out of scope for this piece of analysis.

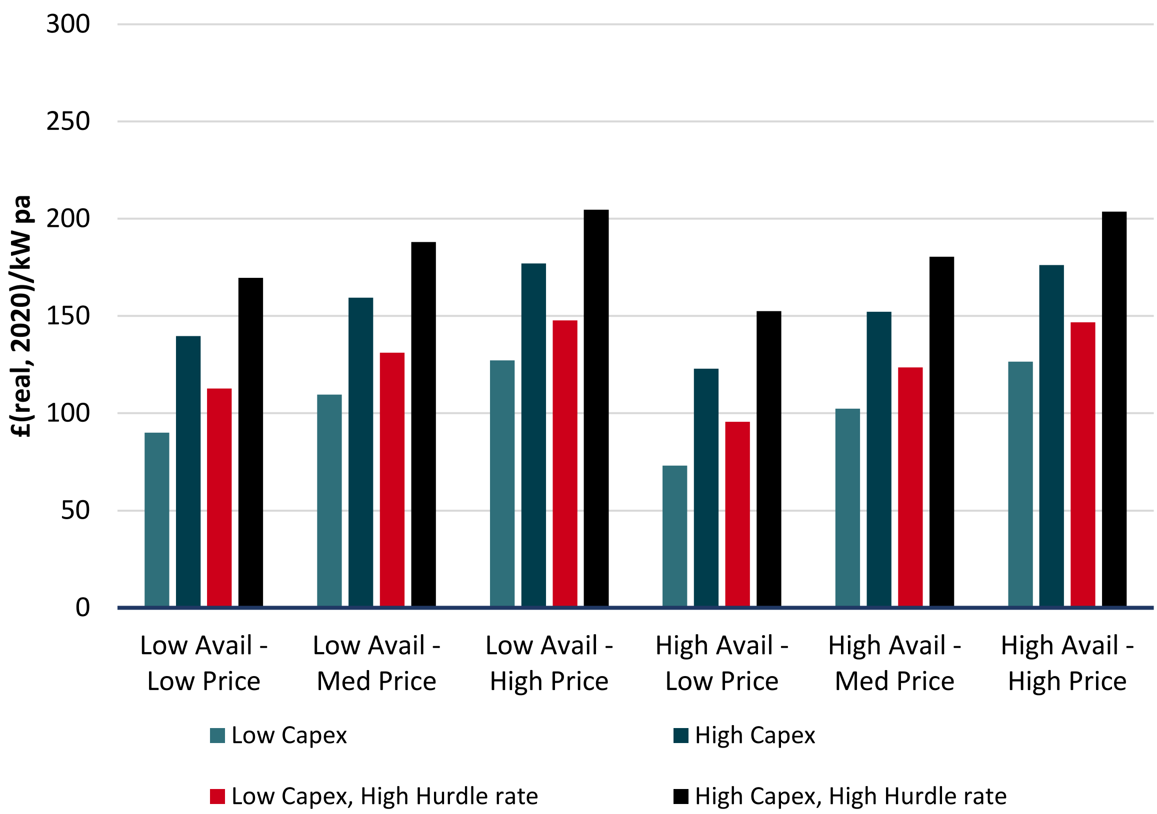
Figure 6 shows that, under many combinations of fuel price and capex, CHPs would need support from government in addition to supporting fuel costs (via subsidised volumes of hydrogen) through a higher CM price (or similar).

- CHP plants are found to need support payments, ranging from £100-190/kW pa. These exceed the support payments required for CCHT due to the higher capex and hurdle rate requirements of CHP.
- The need for support increases over time, with the required CM payments across different scenarios for CHPs built in 2035 ranging from £130-210/kW pa[30].

[30] These figures represent ranges for anew-build CHP operating on 100% hydrogen in the medium hydrogen price scenario, as does the bullet above.

Wholesale revenues for CHP decline over time with load factors, and they are found to be increasingly reliant on CM or other forms of revenue support over time.

Figure 6: CM support required for new build 100% hydrogen fired CHP commissioning in 2026



Source: LCP Delta

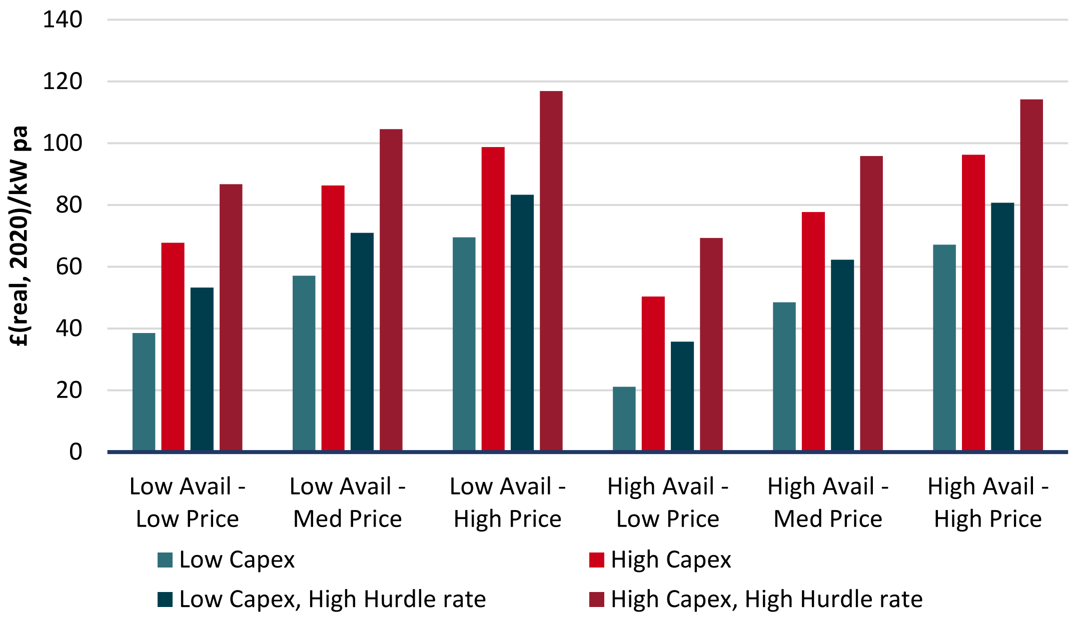
CCHT

We estimate that support levels for new build CCHT range from £20-120/kW pa. Hence in a number of scenarios, additional intervention could be needed to support new build CCHTs, as using the CM alone could entail a high risk of inframarginal rents were CCHTs to be price setting. The high clearing prices required in a number of scenarios could limit the deployment of CCHT plant and may therefore delay efforts to decarbonise generation.

Figure 7 shows that, under many combinations of fuel price and capex, CCHTs would need support from government in addition to supporting fuel costs (via subsidised volumes of hydrogen) through a higher CM price (or similar).

- The need for support increases over time, with the required CM payments across different scenarios for CCHTs built in 2035 ranging from £60-120/kW pa.
- Wholesale revenues for CCHT decline over time with load factors, and they are found to be increasingly reliant on CM or other forms of revenue support over time.

Figure 7: CM support required for new build 100% hydrogen fired CCHT commissioning in 2026

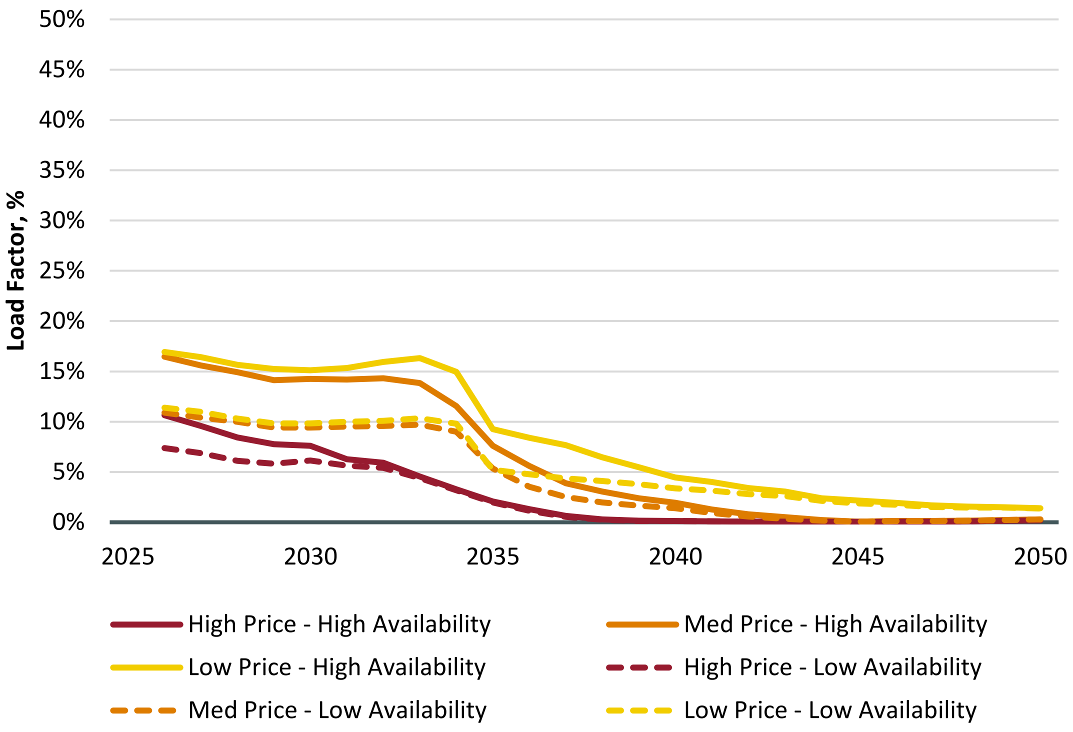


Source: LCP Delta

Load factors for CCHT remains low, under 20%, in all scenarios and years modelled. Prior to 2035, in a scenario with low hydrogen prices and high hydrogen availability, load factors remain above 15%, they then decline to below 5% by 2050 (Figure 8).

- The higher load factors pre-2035 are due to the availability of subsidised hydrogen and lack of other competing hydrogen plant. In this period availability of hydrogen is a limiting factor in the low and medium price scenarios; and
- The decline in load factors beyond 2035 is a result of the decrease in availability of subsidised hydrogen and build-out of newer CCHT.

Figure 8: Load factors for 100% hydrogen fired CCHT commissioning in 2026



Source: LCP Delta

Given the exogenous H2P capacity assumptions used as an input to the modelling and provided by DESNZ, very low load factors are expected across all types of H2P plant post-2035. This is for three reasons:

- High renewable penetration (with significant growth from 2025 to 2035) means the need for generation from the flexible fleet reduces, despite this fleet growing due to an increasing need for firm capacity (due to demand growth).
- H2P capacity increases, cannibalising load factors until they are very low for each individual plant. This especially happens after 2035; and
- Subsidies for hydrogen decrease, meaning the cost of fuel increases.

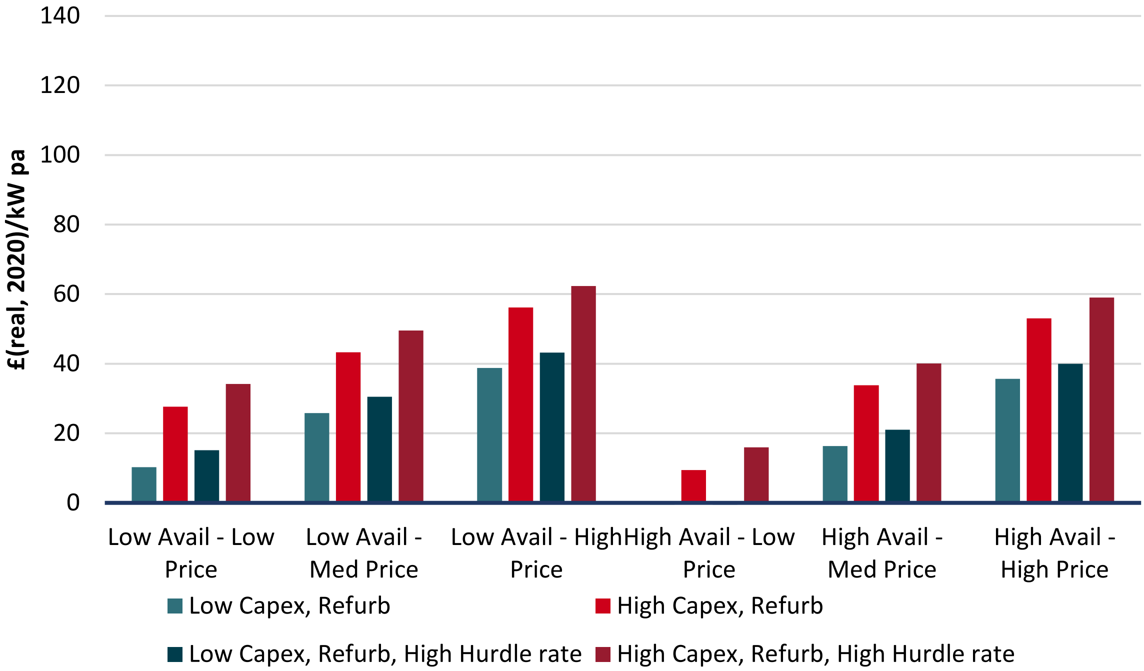
Subsequently the financial needs case for investment for CCHT plants increases over time because of these declining load factors.

Refurbishing assets

The deployment of H2P generation can also be achieved through the refurbishment of existing generation assets. Based upon industry feedback it is assumed that the refurbishing capex is half that of new build. It is conservatively assumed that refurbishment extends life by 10 years (relative to the 25-year life for new build). In the modelling these 10-years occur during the highest load factor years.

As a result, the support levels required for refurbishing assets are significantly lower than those for new build (Figure 9).

Figure 9: CM support required for refurbishing 100% hydrogen fired CCHT re-commissioning in 2026



Source: LCP Delta

Hydrogen blend

In general, assets making use of blended hydrogen fuel require lower levels of support of between £20-80/kW pa in all scenarios. Blending occurs at the point of combustion with a 30% hydrogen and 70% natural gas mix by volume assumed. These plant are less likely to require support beyond the level of clearing prices seen in recent CM auctions.

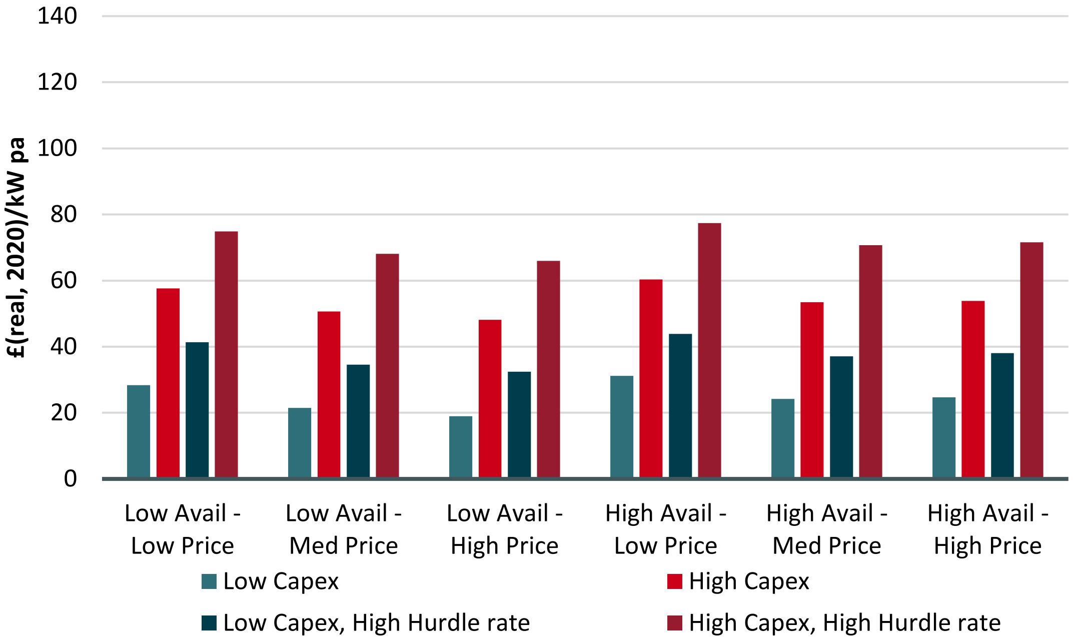
This is not the case for CHP which would still need £100-180/kW pa due to their higher capex and hurdle rate requirements[31].

Blended fuel assets are capable of running wholly on natural gas when economic to do so and so the limited availability of hydrogen presents less of a restriction to their dispatch. This increased flexibility allows blended assets to capture greater revenues in energy markets.

The high hydrogen availability, low hydrogen price scenario is an exception in which lower levels of support are required by wholly hydrogen-fired plants. In this instance being able to access large quantities of subsidised hydrogen fuel (resulting in SRMCs well below those of unabated gas plant) allows these assets to capture higher energy market revenues than their blended fuel counterparts.

[31] These figures, as do the ones above, come from the medium hydrogen price scenario, and the range reflects the availability of hydrogen as well as the levels of capex and hurdle rates.

Figure 10: CM support required for new build 30% (by volume) hydrogen fired CCHT commissioning in 2026



Source: LCP Delta

Is there a need to ensure appropriate dispatch of H2P?

Given the financial needs case to provide support for H2P we next examine whether there is a need for a business model to:

- Ensure H2P dispatches in a way that reduces societal costs; or
- Ensure H2P dispatches ahead of unabated gas.

Stakeholders generally did not make a case for a dispatch incentive. The modelling also suggests that in most cases a dispatch incentive would not reduce costs to society, at least where the outturn market carbon price is in line with our assumptions.

To minimise costs to society[32], plants should dispatch in order of their social SRMCs. Social SRMCs include the resource cost of the fuel and other operating costs, as well as the social value of the emissions (based on the economy-wide marginal greenhouse abatement cost in the Green Book appraisal values).

When the full appraisal value of carbon has been incorporated and when hydrogen is not subsidised (so the resulting SRMCs represent the resource costs to society from the dispatch of each plant):

[32] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent/the-green-book-2020#valuation-of-costs-and-benefits

- Power CCUS should always dispatch ahead of H2P;
- Before 2040, CCHT should dispatch behind unabated CCGT, except in the low hydrogen price scenario;
- Where hydrogen prices are high, CCHT should always dispatch behind unabated gas;
- OCHT should always dispatch behind unabated CCGT, except in the low hydrogen price scenario (after 2028); and
- OCHT should always dispatch behind unabated OCGT, except in the low hydrogen price scenario and in the medium price scenario (after 2042).

Using a market price of carbon and subsidised hydrogen price (so that the implied SMRCs represent how plants may dispatch in the absence of an additional dispatch incentive) the dispatch order is close to the order that would minimise costs to society. The SRMCs then show that:

- Except in the low hydrogen cost scenario, Power CCUS always dispatches ahead of H2P;
- Before 2040, H2P dispatches ahead of unabated gas in the medium scenario (which may be more than optimal);
- Where hydrogen prices are high, CCHT sometimes dispatches with unabated gas (which may be more than optimal); and
- OCHT will generally dispatch behind or alongside unabated gas, except in the low hydrogen cost scenario.

When the market price of carbon and unsubsidised hydrogen price (so that the implied SRMCs represent how plants may dispatch in the absence of an additional dispatch incentive and when hydrogen is no longer subsidised) the dispatch order is close to the order that would minimise costs to society. Though H2P in some scenarios is dispatching less than may be optimal before 2040 (under the price assumptions made in the analysis):

- Power CCUS always dispatches ahead of H2P (which is optimal);
- Where hydrogen prices are high, CCHT dispatches behind unabated CCGT (which is cost optimal) and where hydrogen prices are medium CCHT dispatches behind unabated CCGT until 2040 (which is also cost optimal). However, we note that these outcomes do not minimise emissions;
- Where hydrogen prices are low, CCHT dispatches behind unabated gas before 2032 (which may be suboptimal based on social SRMC); and
- OCHT will generally dispatch behind unabated CCGT, except in the low hydrogen cost scenario after 2038. This may be suboptimal as social SRMC suggests OCHT should dispatch ahead in the 2028-2038 period.

This analysis suggests that overall, intervention is not necessary to have H2P using subsidised hydrogen dispatch ahead of unabated gas in the low and medium hydrogen price scenarios, provided the outturn market carbon price is at the level we assume in the modelling.

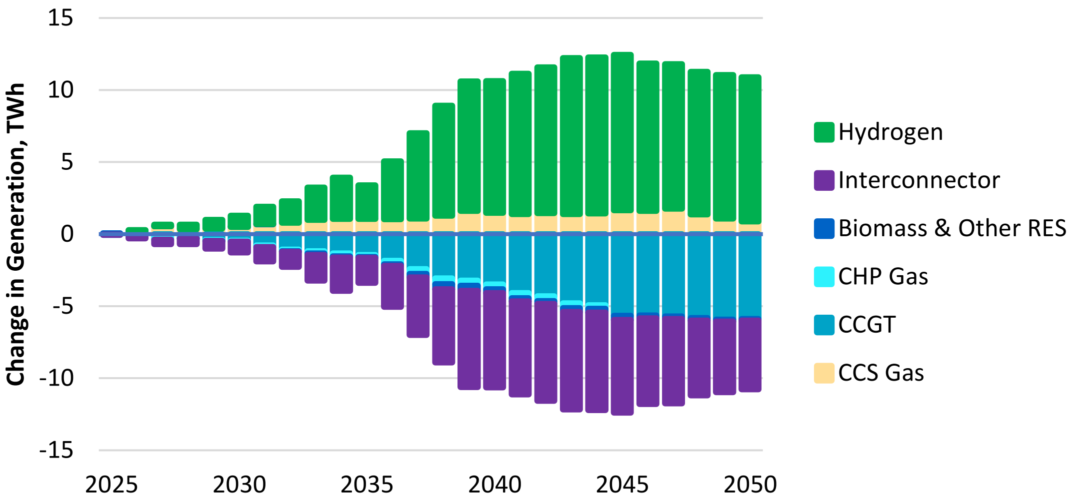
The modelling shows that H2P dispatches efficiently but not always ahead of unabated gas in all cases. Under the assumed market carbon price, regardless of whether hydrogen is subsidised, moving H2P up the merit order could lead to an increase in societal costs.

- H2P generally dispatches behind Power CCUS (without a further dispatch incentive). This is an efficient order, given H2P's higher social short run marginal costs; and
- Where hydrogen fuel is not subsidised, unabated gas plant often dispatches ahead of H2P, especially in the early period.

If dispatching H2P ahead of unabated gas plants is a policy aim, the modelling suggests that a dispatch incentive would be required, where hydrogen is unsubsidised, or in the high hydrogen price subsidised scenario.

Figure 11 shows that increasing hydrogen generation reduces generation from unabated gas and the use of interconnector imports. This displacement of unabated gas continues until 2050, implying that there is still significant use of unabated gas generation over that period if the price of hydrogen is high.

Figure 11: Difference in generation mix between low and high price scenarios assuming low hydrogen availability



Source LCP Delta

- H2P using subsidised hydrogen generally dispatches ahead of unabated gas except in the high subsidised hydrogen price scenario where its SRMC is similar to that of unabated gas, and it sometimes dispatches behind unabated gas due to limited volumes of subsidised hydrogen available;
- In the low and medium subsidised hydrogen price scenarios, further intervention on dispatch would not incentivise greater use of subsidised hydrogen because it is capped by the availability of subsidised hydrogen;
- Unabated gas often dispatches ahead of H2P using unsubsidised hydrogen except in the low hydrogen price scenario and the late years of the medium price scenario. To

shift H2P using unsubsidised hydrogen ahead of unabated gas in the merit order some form of dispatch intervention would be required; and

- This would incentivise greater hydrogen generation and reduced unabated gas generation.

Intervening would increase the use of hydrogen, and reduce the use of unabated gas for:

- H2P using subsidised hydrogen in the high hydrogen price scenario; and
- H2P using unsubsidised hydrogen.

Conclusions

The purpose of WP1 is to explore three main questions:

- **Is there an overall need for H2P?** Dispatchable low carbon power will be required in a low carbon energy system. While both Power CCUS and H2P could play this role, modelling suggests many flexible plants will be required for system security purposes but be running at relatively low load factors. Given its lower capital-intensity, H2P is likely to be more cost-effective in this role than Power CCUS.
- **Is there a need for a financial incentive to deliver investment in H2P?** Peaking plants, with their low load factors and lower capex requirements, may be able to receive sufficient payment through the CM to be built in line with the DESNZ capacity assumptions. The same may also be true for some refurbished plants and some plants using a blend of hydrogen and methane as fuel. New CCHT and CHP running on 100% hydrogen would be likely to need additional support. In the absence of additional intervention, it would require CM clearing prices of up to £120/kW, depending on the price and availability of hydrogen. If CCHT were to clear at this price, it would lead to a risk of other participants in the CM earning inframarginal rents.
- **Is there a need for an incentive to ensure appropriate dispatch of H2P?**

  Modelling suggests that a dispatch incentive would not reduce cost to society. Under the assumed market carbon price, moving H2P up the merit order could lead to an increase in societal costs. H2P generally dispatches behind Power CCUS, without a further dispatch incentive, which is an efficient order, given H2P's higher social short run marginal costs. Where hydrogen fuel is not subsidised, unabated gas often dispatches ahead of H2P, especially in the early period. However, this is in line with the fact that unabated gas has lower social short run marginal costs until 2040[33].

  The modelling also suggests that if dispatching H2P ahead of unabated gas plant is a policy aim, a dispatch incentive would be required, where hydrogen fuel is unsubsidised, or where the price for subsidised hydrogen fuel is high.

[33] These have been calculated including the appraisal carbon price, reflecting the economy-wide marginal abatement cost.

3- Assessment of potential business models for H2P

Introduction to business model assessment

The WP1 modelling demonstrates that some H2P generators may need support beyond that which is likely be provided in the CM. We therefore now turn to a consideration of how support could best be designed to meet the needs of H2P, were DESNZ to decide that it wanted to support these plants.

For our business model assessment, we assume that business models provide support for the first 15 years. After that period, operators are still able to bid into the annual CM but will receive no additional support. Further, we generally assume that the business models are not combined with the current CM, due to concerns around the cumulation of aid. The exception to this is the Fossil Fuel Ban.

This first stage of this assessment involves determining the business models we assess as well as the criteria we use to assess them.

We start the assessment with a long-list of business models to deliver support, with the aim of including a broad mix of options covering a variety of support mechanisms. We select a short-list using two hurdle criteria to remove business models where it is clear that it would significantly distort dispatch, or where a simpler version of the business model already in the long-list could potentially deliver the same outcomes[34]. The details of the long-list of business models as well as the filtering process using the two hurdle criteria can be found in Annex E.

Six business models passed these hurdle criteria and are assessed in more detail below. They are:

- CM;
- CM+ (split CM for low-carbon dispatchable technologies);
- Deemed Generation CfD;
- DPA;
- Revenue cap and floor; and
- Fossil Fuel Ban.

We agreed the criteria to assess these short-listed models with DESNZ. These criteria come from three main sources: the REMA consultation summary, the CCS update on business models, and the UK Hydrogen Strategy. Combining the criteria from these three sources and removing any duplication or criteria inappropriate for the H2P context leaves us with a list of six

[34] For example, while an upfront grant could incentivise appropriate dispatch, the counterfactual CM could achieve the same outcome of a lump-sum payment more simply.

assessment criteria. These, along with the sub-criteria, are set out in Figure 12. More details can be found in Annex F.

Figure 12: Assessment criteria

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?
Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?
Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)?[1] ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?
Cost distribution	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?
Practicality	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?
Adaptability and flexibility	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

Source: Frontier Economics

To apply the first assessment criteria, we undertake detailed analysis to assess specifically the risks and barriers that H2P developers face, and which should be most efficiently covered by the H2P business model (rather than left with the developer). This analysis takes into account the fact that there are trade-offs to consider:

- Leaving risks with the developer can incentivise developers to efficiently manage risk where they have some degree of control through their behaviour; but
- Leaving risks with developers increases their cost of capital.

Generally, policy-driven risks should be covered by the H2P business model, whereas risks that unabated gas plants currently face, such as construction delays or overspend, are most efficiently managed by the H2P developer. Therefore, the risks that should be covered by the business model relate to the policy-driven elements of whether a H2P developer will be able to access hydrogen when needed, how much it will have to pay for that hydrogen, and how much revenue it will receive in the market. These are outlined in Figure 13 and described in more detail in Annex D.

One other thing to note relates to the third sub-question within the cost distribution criteria. All business models, if funded via a levy on consumers, could affect energy prices and therefore impact international competitiveness. As this is common to all business models, we do not include this in the individual assessments.

Figure 13: Short-list of risks and barriers to be addressed by the H2P business model

Short-list of risks and barriers to be addressed by the H2P business model			
Developm.	▪ Policy support for hydrogen production ▪ Policy support for H2P as hydrogen use case ▪ Policy support for storage and network development		
Constr.	▪ Delays in cross-chain (hydrogen) infrastructure ▪ Higher construction costs for FOAK technology		
Operation	**Price risk**	**Volume risk**	**Cost risk**
	▪ Policy driven electricity price risk (incl. carbon price)	▪ Policy driven demand risk ▪ Fuel availability from outages (incl. cross-chain)	▪ Fuel price

Source: Frontier Economics

The remainder of this chapter sets out our qualitative assessment of each of the six business models. This assessment includes stakeholder views and quantitative illustrations where relevant.

Assessment of business models

CM

Description of the mechanism

The CM is the business model currently used to ensure that there is enough capacity on the system. All generation, demand side and storage technologies that do not have a separate business model can operate in the CM (alongside interconnectors).

The CM provides a fixed, regular payment to asset operators, per kW of capacity. This payment is made regardless of the level of dispatch (outside stress events). Because the support payment is independent from the level of output, this means that it does not distort the dispatch incentive, as generators will still have the incentive to dispatch if the market price is greater than their marginal cost. The dispatch incentive is reinforced at times of system stress, as generators receive a penalty if they do not generate.

The level of the payment is determined in an auction (the main auction is held four years ahead in order to allow new plant to go to final investment decision and be built). All asset operators bid their required need for support, and are paid the auction clearing price. Hence while total capacity required is determined centrally, the capacity of any given technology clearing in the auction is determined by the market.

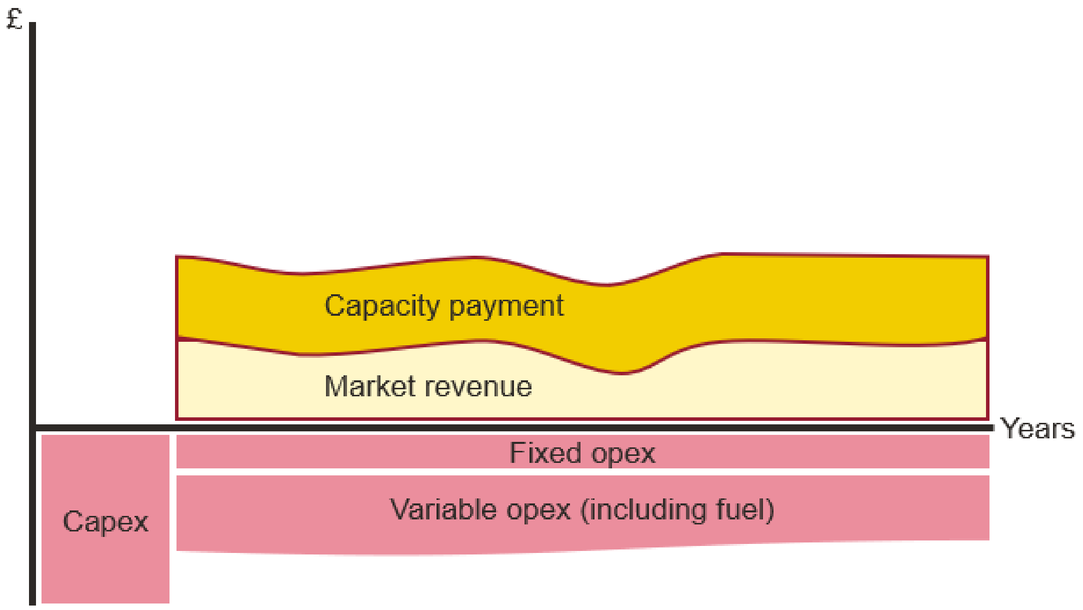
New-build plants can receive a contract of up to 15 years, and refurbished assets can receive a contract of up to three years. Other assets must bid into the auction annually.

Cheaper technologies will bid in a lower price for support and are hence more likely to clear than more expensive technologies. As a more expensive technology (i.e. one with higher long run marginal costs) policy, H2P could be outcompeted by other technologies. This could result in an efficient quantity of investment if other technologies represent a lower long term cost option to society, but it may mean that the mechanism does not deliver any H2P.

Currently the CM price cap is £75/kW and WP1 modelling shows that this would not be high enough for some H2P plants to secure agreements under different scenarios. Therefore, we assume in this assessment that the CM is adapted in such a way that it is viable for H2P (e.g. by increasing the price cap).

These elements are summarised in Table 2, and an illustrative diagram of costs and revenues is included in Figure 14.

Figure 14: CM – illustrative diagram



Source: Frontier Economics

Note: This and all other business model diagrams are illustrative of how a business model could work, and not meant to be reflective of expected cost or revenue streams to H2P generators over time.

Table 2: CM – description

Key elements	Description
Fixed payments	Regular payment per kW of capacity. Capacity is derated according to reliability of energy production
Variable payments	None
Duration of payment	Initial contract for new builds is 15 years, then bid into auction annually. Retrofits would have a 3-year contract and then bid into auction annually.
Basis	Providers who are successful in the auction are awarded Capacity Agreements, which confirm their CM Obligation and the level of payments that they will be entitled to receive
Impact on dispatch	No impact – payment is received for capacity, and hence generator still has incentive to dispatch if marginal revenue is greater than marginal cost. Incentive is reinforced at times of system stress as generators receive a penalty if they do not generate

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated.

Qualitative assessment

We summarise our qualitative assessment of the CM in Table 3, and provide more detail on each element below.

Table 3: CM – Qualitative assessment

Criteria	Assessment
Investibility	The CM could not cover the significant investor fuel availability risk.
Decarbonisation of the power sector	The CM will not maximise the decarbonisation potential of the sector.
Cost efficiency	The CM will does not distort dispatch or incentivise over-investment.
Cost distribution	The CM risks significant inframarginal rents.
Practicality	The CM is a deliverable business model that is well understood and would not cause difficulties interacting with other relevant government policies.
Adaptability and flexibility	The CM could be adaptable for subsequent investments to changes in the sector.

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated.

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

The CM could not cover the significant investor fuel availability risk.

The risks that a business model should mitigate for investors can broadly be categorised into:

- Policy-driven electricity price risk;
- Policy-driven electricity demand risk; and
- Hydrogen fuel price and availability risk (as outlined in Annex D).

We assume that under the CM, investors will seek to cover most of their capital and fixed costs with CM payments (support revenue), and then will dispatch when the marginal revenue of doing so exceeds the marginal costs[35].

- For the CM, support revenue is independent of electricity price and demand risks, and therefore this business model partially mitigates these risks for investors (though they are still exposed to changes in market revenue).
- However, investors remain significantly exposed to fuel price and availability risk (driven by cross chain issues or policy risk under the CM. The CM is designed to provide security of supply, which means support payments reflect the reliability of supply associated with each plant or technology. Paying a plant when the plant could not actually dispatch would affect the mechanism's primary objective. This is the case even if a plant's inability to dispatch is as a result of cross-chain risks and through no fault of its own. Hence the CM cannot mitigate H2P developers from fuel availability risk.

Whether through the derating factor[36] or simply the risk of not being able to produce in a stress event as a result of fuel security issues, investors would be penalised for being 'unavailable' when outage in hydrogen production or infrastructure. This would mean that significant risks remain with the investor.

H2P plants that rely less on cross-chain infrastructure, such as blended plants and prosumers, are less exposed to fuel availability risk due to cross-chain risk. Therefore these types of plants may still be investible if CM payments do not cover fuel availability risk.

Decarbonisation of the power sector

Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?

The CM will not maximise the decarbonisation potential of the sector.

As the CM does not impact dispatch, the dispatch order outlined in Section 5.3 would remain under this business model. Therefore, if the outturn carbon price is lower than modelled, if hydrogen is not subsidised, or the hydrogen price is in line with that assumed in the high subsidised hydrogen price scenario (see Section 2) there is a risk that unabated gas will dispatch at or ahead of H2P plants[37] and the decarbonisation potential of the power sector is not maximised.

[35] WP1 modelling results show that market revenue is likely to be a smaller proportion of total revenue for most H2P plants.

[36] Currently the derating factors used in the CM assume that fuel is always available and therefore do not themselves incentivise operators to have back-up fuel supply. Operators are partially incentivised to have a back-up (e.g., distillate fuel onsite) since this would allow them to avoid penalty payment in the event of a fuel supply interruption. Fuel availability could become a bigger issue with H2P as there is a less resilient supply and network.

[37] WP1 modelling found that where hydrogen fuel is not subsidised, unabated gas plant often dispatches ahead of H2P. H2P sometimes also dispatches behind unabated gas in the high subsidised hydrogen price scenario.

Cost efficiency

Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

The CM will does not distort dispatch or incentivise over-investment.

The CM does not affect the dispatch order. WP1 modelling shows that if the outturn carbon price is at or above the assumed carbon price used in the modelling, then H2P will already dispatch at least as much as its efficient level. Under these conditions, an additional dispatch signal could be distorting. However, since the CM doesn't provide a dispatch signal, this risk is avoided.

The CM does not risk incentivising over-investment in a particular technology (such as H2P), because the level of investment in each technology is determined by the market. Moreover, the auction mechanism promotes competition to bring down the bids of H2P investors to an efficient level.

Cost distribution

Cost distribution	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

The CM risks significant inframarginal rents.

If high CM clearing prices are needed to make H2P plants investible, this is likely to lead to significant inframarginal rents[38] to other technologies. This may not provide value for money to those funding the CM.

The WP1 modelling shows that a range of clearing prices (up to £120/kW for CCHTs) could be needed to support H2P plants, depending on the plant type, price and availability of hydrogen fuel, as well as levels of capex and hurdle rates. Table 4 demonstrates how this range can be broken down by plant type.

[38] Inframarginal rents are the difference between the clearing price and the marginal cost of an operator. If an operator has very low marginal costs, then it could receive high inframarginal rents if the CM clearing price is very high.

Table 4: Range of CM clearing prices required for different plant types (medium price scenario)

£/kW	CCHT	OCHT	CHP	Recip
New-build	49 - 105	44 - 77	102 - 188	49 - 82
Blended asset	21 - 71	36 - 69	96 - 176	46 - 78
Commissioned in 2035	69 - 119	44 - 77	130 - 210	51 - 83
Retrofit	16 - 50	33 - 50	31 - 71	36 - 55

Source: LCP Delta analysis (WP1)

Note: The first row represents a new-build plant commissioned in 2026 and operating on 100% hydrogen fuel. The following three rows deviate from that base case in each of three ways.

Lower clearing prices – similar to those seen today of £40-80/kW – may be able to support peaking plants (OCHT and reciprocating plants), as well as blended plants and retrofit plants. However higher clearing prices could be needed for new-build CCHTs and CHPs. These higher clearing prices could lead to significant inframarginal rents if H2P were price setting in the CM.

The WP1 modelling finds that if capex and hurdle rates for H2P are at similar levels to unabated gas and there is enough subsidised hydrogen available for it to be the predominantly fuel, then a new-build CCHT in 2026 operating on 100% hydrogen could be supported by CM clearing prices between £20/kW to £70/kW[39] – the variation depends on the price and availability of hydrogen. Hence, if these conditions are met, H2P could be supported by the CM without significant inframarginal rents.

However, there are two things to note:

- Given H2P is still at first-of-a-kind stage, and it may not be realistic to assume that capex and hurdle rates for H2P would be at similar levels to unabated gas;
- Subsidised hydrogen will be demanded by multiple sectors. This means that by increasing the supply of subsidised hydrogen fuel for H2P, the Government would also be increasing the supply to other sectors. This increases the risk that another sector

[39] These numbers differ to the ranges seen in Table 4, because this range looks at the low capex – low hurdle rate case under multiple hydrogen price and availability scenarios. Whereas the ranges in the Table 4 depict different capex, hurdle rate, and hydrogen availability cases in the medium hydrogen price scenario.

could decarbonise with subsidised hydrogen when it would have been more efficient from a societal perspective for the sector to choose another decarbonisation option[40].

Given the likely higher costs, and the risks associated with focussing on increasing the supply of subsidised hydrogen, it may not be likely or optimal for all of these conditions to be met. Therefore, relying on the CM for H2P could lead to significant inframarginal rents.

Practicality

Practicality	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

The CM is a deliverable business model that is well understood and would not cause difficulties interacting with other relevant government policies.

The CM is already up and running, and investors as well as regulatory bodies are used to it, so the understanding of the model is high. Therefore, the CM approach is likely to be deliverable, and additional administrative burdens should be low. Moreover, the CM would not cause difficulties when interacting with the hydrogen production business model (HPBM), and could be modified given any changes that are made to the sector by the Review of Electricity Market Arrangements (REMA).

However, the CM may need to be adapted to accommodate fuel switching plants. To prevent an H2P plant receiving support and then using natural gas, CM support payments may need to come with conditions. These could include annual emissions limits, a maximum number of hours of generation that can be fuelled by unabated gas, or specific force majeure conditions that allow unabated gas use only when the hydrogen network goes down for reasons that could not be anticipated. These conditions could add to the complexity of its application.

Adaptability and flexibility

Adaptability and flexibility	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

The CM could be adaptable for subsequent investments to changes in the sector.

The CM would be robust to changes in key variables, such as technology costs, carbon prices and fuel costs.

Overall

While the current CM could be a fast solution to implement, it has two major disadvantages:

[40] For example, it could cost a manufacturer £100m to electrify, £120m to decarbonise using unsubsidised hydrogen, and £80m to decarbonise with subsidised hydrogen. Hence the manufacturer would choose to decarbonise with subsidised hydrogen, but from a societal perspective it would be most efficient for the manufacturer to electrify. The more that hydrogen is subsidised, the more sectors we would expect to inefficiently choose hydrogen.

- The high price of H2P is likely to result in significant inframarginal rents for other participants in the CM (and therefore higher than necessary costs to consumers); and
- Investors remain exposed to hydrogen price and availability risk- via the risk of outages in hydrogen production or infrastructure. This may have a significant impact on investibility.

CM+

Description of the mechanism

We now consider variations on the existing CM that aim to accommodate higher cost, low carbon options. Building on the three CM+ options covered in REMA (Box 3), we focus on a combined split auction – a split auction for low-carbon dispatchable technologies – including technologies that would not clear in the current CM[41].

CM+ options contained in REMA

The CM+ outlined in REMA included three different options. These were:

- Split auction for low-carbon technologies
- Split auction for dispatchable technologies
- Multipliers to clearing prices for either low-carbon technologies or dispatchable technologies.

Split auction for low-carbon technologies

This option would involve creating a second CM auction – effectively splitting the current CM into two auctions – one for low-carbon technologies and one for all other technologies. This could allow higher clearing prices in the second auction without inframarginal rents going to all technologies. The low-carbon technology auction could potentially include: wind, solar, hydro, biomass, batteries, pumped storage, nuclear, H2P, DSR, and energy from waste. Splitting the auction does not remove inframarginal rents completely, but it reduces the number of technologies that will receive the high clearing prices and therefore reduces inframarginal rents. Hence if H2P is to be successful in the CM+ auction, including it with technologies that are already successful in current CM would increase the inframarginal rents that these technologies receive in the split low-carbon technologies auction, compared to if they were in the ‘other technologies’ auction instead.

Split auction for dispatchable technologies

This option would also involve splitting the current CM into two auctions, one for dispatchable technologies and one for all other technologies. This could allow higher clearing prices in the second auction without inframarginal rents going to all technologies. The dispatchable technology auction could potentially include: unabated gas, H2P, batteries, pumped storage,

[41] Box 3 sets out the potential advantages and disadvantages of the CM+ REMA options for H2P. We have aimed to combine the best features of these options in the CM+ that we take forward to assessment.

interconnectors, DSR, and potentially, nuclear technologies. Dispatchable technologies represent the majority of current capacity in CM. However, if H2P were to participate successfully, then there would be potentially significant inframarginal rents. Moreover, if this were achieved then levels of inframarginal rents similar to CM without further intervention.

Multipliers on either low-carbon technologies or dispatchable technologies

The principle of the design of the current CM auction is to be market-led, hence reducing inefficiency and lowering costs to society as much as possible. Adding appropriate multipliers could allow selected technologies to compete in the CM without leading to significant inframarginal rents for a number of technologies. However, estimating appropriate multipliers would be a very difficult exercise, particularly given the likely volatility of clearing prices. This could increase societal costs to a greater degree than splitting the auction[42].

CM+ option considered here

This CM+ could include H2P, and other long-term duration storage such as new pumped hydro[43]. As large-scale batteries are already successful in the current CM, including them in this smaller auction (which is likely to have higher clearing prices) could increase the marginal rents for their operators, without adding additional benefit.

There may be liquidity issues in the near-term if there are only a small number of bidders into the CM+ auction. As the competitive auction is a core design component of the model, an alternative allocation mechanism could not be used in the near-term (i.e., CM+ support cannot be agreed by bilateral negotiation).

Key elements to the CM+ design are summarised in Table 5, and then an illustrative diagram of costs and revenues is included in Figure 15.

Table 5: CM+ – Description

Key elements	Description
Fixed payments	Regular payment per kW of capacity. Capacity is derated according to the reliability of energy production.
Variable payments	None

[42] Setting the multipliers to a level that gives confidence that some H2P would be delivered could risk high costs to consumers. The CM+ clearing price can be quite volatile, and if the multiplier is set a level which gives confidence that H2P is delivered and the outturn clearing price is higher than expected, there is the risk that too much support is given to investors.

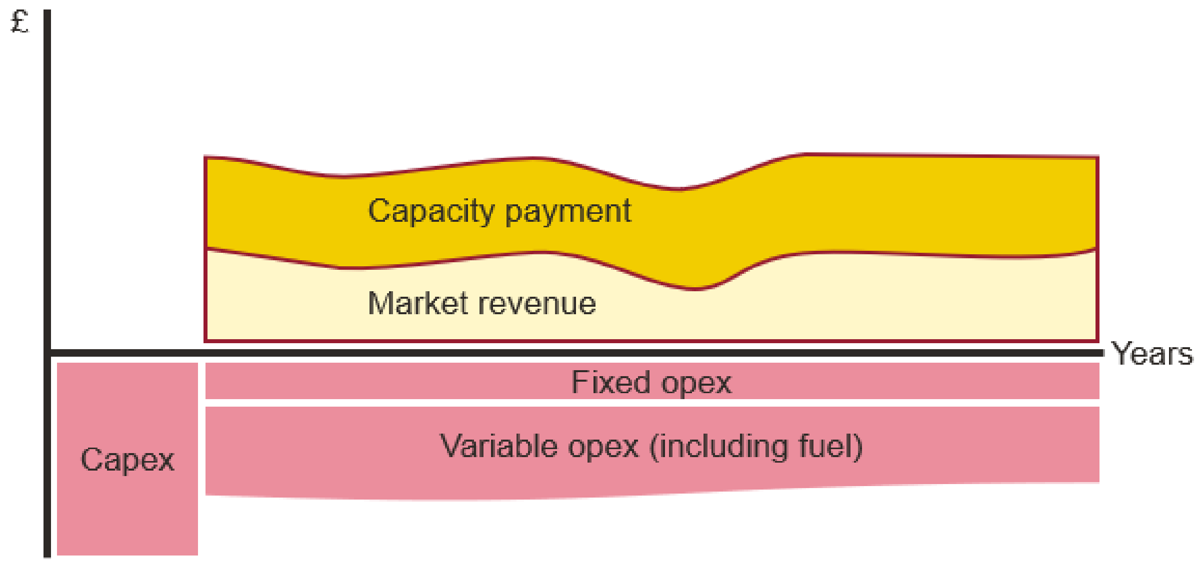
[43] In theory this auction could also include Power CCUS (if it no longer receives a DPA), however it was beyond the scope of this work to think about business models that would be appropriate for other technologies.

Duration of payment	Initial contract for new build is 15 years, then could join the CM auction. Retrofits would have a 3-year contract and then bid into auction annually.
Basis	Providers who are successful in the auction are awarded Capacity Agreements, which confirm their CM Obligation and the level of payments that they will be entitled to receive
Impact on dispatch	No impact – payment is received for capacity, and hence generator still has incentive to dispatch if marginal revenue is greater than marginal cost

Source: Frontier Economics

Note: The assumed design of the CM+ is based on the current CM design. Variable payments refer to payments per kWh of electricity generated.

Figure 15: CM+ - illustrative diagram



Source: Frontier Economics

Note: This and all other business model diagrams are illustrative of how a business model could work, and not meant to be reflective of expected cost or revenue streams to H2P generators over time.

Qualitative assessment

We summarise our qualitative assessment of the CM+ in Table 6, and provide more detail on each element below.

Table 6: CM+ – Qualitative assessment

Criteria	Assessment
Investibility	The CM+ could not cover the significant investor fuel availability risk.
Decarbonisation of the power sector	The CM+ would not maximise the decarbonisation potential of the sector.
Cost efficiency	The CM+ will does not distort dispatch or incentivise over-investment.
Cost distribution	The CM+ reduces the risk of inframarginal rents relative to the CM.
Practicality	The CM+ would be well understood by operators, but changing the CM may be administratively difficult
Adaptability and flexibility	The CM+ could be adaptable for subsequent investments to changes in the sector.

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated.

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

The CM+ could not cover the significant investor risk related to fuel availability.

The CM+ would perform similarly to the CM on investibility: it would mitigate the electricity price and electricity demand risks faced by investors, but would leave them exposed to fuel availability and price risks.

As with the CM, H2P could be outcompeted by other technologies, if other technologies represent a lower cost option to society in the short term.

Decarbonisation of the power sector

Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?

The CM+ may not maximise the decarbonisation potential of the sector.

As with the CM, the CM+ does not impact dispatch, Therefore, if the outturn carbon price is lower than modelled, if hydrogen is not subsidised, or the hydrogen price is in line with that assumed in the high subsidised hydrogen price scenario (see Section 3.1.2) there is a risk that unabated gas will dispatch at or ahead of H2P plants[44] and the decarbonisation potential of the power sector is not maximised.

Cost efficiency

Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

The CM+ will not distort dispatch, but may incentivise over- or under-investment in H2P.

The CM+ does not affect the dispatch order. As with the CM, assuming the outturn market carbon price is at or above the level assumed in the WP1 modelling, the CM+ avoids the risk of distorting dispatch.

The CM+ could risk incentivising over-investment or underinvestment in H2P if too much or too little capacity is allocated to the low-carbon dispatchable technologies auction. This risk is potentially greater than in the CM, given the need to specifically allocate capacity to this category of plants (rather than just to allocate capacity overall to the CM)[45]. This issue will arise in all of the mechanisms that are not wholly technology neutral. We also note that supporting dispatchable plants outside the CM will also make it more difficult to determine the quantity of capacity that should be supported within the CM for security of supply purposes. This issue applies to all mechanisms other than the CM.

Auctioning in the CM+ has the potential to drive innovation and downward pressure on costs over time, but this will depend on the extent of competition from H2P plants and the costs of other low carbon technologies participating in the CM+. To the extent that other low carbon technologies such as new pumped hydro storage have much lower costs, the efficiency (and distributional) benefits of including them in an auction with H2P would be limited.

[44] WP1 modelling found that where hydrogen fuel is not subsidised, unabated gas plant often dispatches ahead of H2P. H2P sometimes also dispatches behind unabated gas in the high subsidised hydrogen price scenario.
[45] A fundamental feature of CM+ (whether it includes H2P or not) is that there would need to be co-ordination between the demand curves in multiple auctions, in order to ensure that there was not over- or under-procurement of reliable capacity.

Cost distribution

Cost distribution	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

The CM+ reduces the risk of inframarginal rents.

The CM+ has some risk of inframarginal rents within the low-carbon dispatchable auction, but these are likely to be much lower than under the CM because the auction will be limited to less mature technologies with higher costs, with lower cost technologies remaining in the separate CM auction.

To illustrate this, we calculated the potential distributional consequences of the CM+ compared to the CM. Under our illustrative assumptions[46], we estimate that the cost to funders[47] of funding H2P under the CM could be almost twice as much as the cost to funders of funding H2P under the CM+. However, as noted above, the distributional benefits of the CM+ will depend on the extent to which the other low carbon technologies included in the auction have similar costs.

Practicality

Practicality	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

The CM+ would be well understood by operators, but changing the CM may be administratively difficult.

A separate low-carbon dispatchable auction would still make use of the well-understood Capacity Agreements, as well as the auction. However, changes to the CM can be administratively difficult, and stakeholders expressed an interest for a support [mechanism?] that could be delivered soon.

As with the CM, adaptations would be needed to accommodate plants that can fuel switch.

The CM+ can be combined with the existing CM and would not interfere with HPBM, however it would need to be considered alongside other changes to take place under REMA.

[46] We assume: DESNZ capacity assumptions used in the WP1 modelling; H2P and Power CCUS would be in the low-carbon dispatchable CM+ auction; average value of the CM clearing price required for a FOAK new-build CCHTs in 2026 under the medium hydrogen price scenario – £100/kW; and an illustrative CM clearing price of £50/kW for other technologies.
[47] By 'cost to funders' we mean the cost to whoever is providing the subsidy funding for the business model, for example taxpayers or energy consumers.

Adaptability and flexibility

Adaptability and flexibility	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

The CM+ could be adaptable for subsequent investments to changes in the sector.

As with the CM, the CM+ could be flexible to unforeseen changes in technology and commodity prices.

Overall

The CM+ reduces the problem of inframarginal rents that would occur under the CM, but like the CM, it does not reduce fuel availability risk. This risk may be driven by policy and cross-chain issues in the early market, and may be difficult for investors to manage.

The extent to which there are benefits from using the auction mechanism in the CM+ will depend partly on the extent to which there are other low carbon technologies with similar costs that could increase competitiveness in the auction.

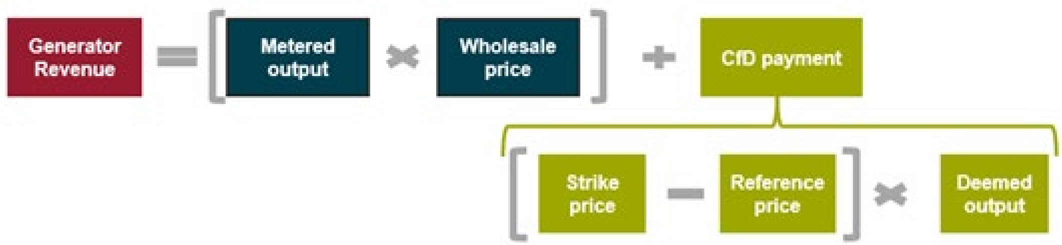
Deemed Generation CfD

Description of the mechanism

The Deemed Generation CfD would provide asset operators support each reference period – for example, one year – that is decoupled from their metered output. This means that the level of support is independent from the amount of electricity that an operator generates, and therefore there is no impact on dispatch.

The level of the support is calculated based on a strike price and a ‘deemed output’ that is fixed for the length of the contract (likely 15 years), as well as a reference price that is set within a reference period but can vary between reference periods. This is outlined in Figure 16, which demonstrates that as the reference price varies over time, the amount of support that operators receive – or pay if the reference price exceeds the strike price – may vary each reference period.

Figure 16: Deemed Generation CFD – illustrative diagram



Source: Frontier Economics

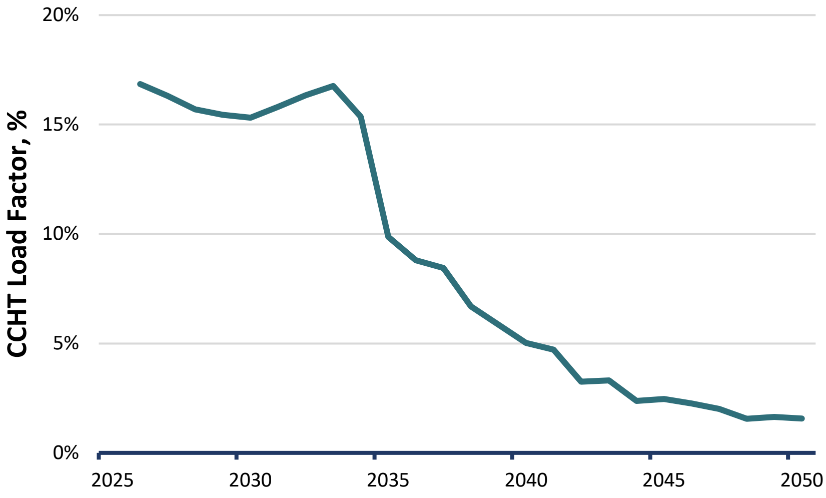
The reference price is likely to be closely linked to the wholesale electricity price that operators would expect to receive. This means that as an operator’s market revenue increases, their support revenue decreases, and vice versa. This protects developers from market price risk. However, as with all CfDs, operators are exposed to the risk that the electricity capture price and the reference price diverge.

It is likely that a plant's deemed output would be estimated administratively based on factors such as location and generation technology, and might not vary over the length of the contract. This means that the business model is likely to be less appropriate for dispatchable power compared to intermittent renewables:

- Deemed output makes sense for intermittent renewables such as offshore wind, as it incentivises investors to choose location efficiently, for example in areas with high wind resources. Locating in these areas would result in higher levels of deemed generation. Location does also have an impact on the societal benefits that an H2P plant can offer. For example, it would be efficient from a societal perspective for an H2P plant to locate near underground hydrogen storage. However, despite the Deemed Generation CfD offering locational incentives to intermittent renewables, it does not provide H2P with an incentive to locate efficiently. This is because while locating near the storage would reduce the costs of an H2P plant, it would not affect deemed output. Therefore, as H2P generation is not likely to vary by location, the locational price signal offered by the Deemed Generation CfD would not lead to significant benefits for H2P.
- Deemed output for a dispatchable plant introduces a new risk. This is the risk that a plant's metered and deemed output diverge, and changes in the electricity capture price could reduce support revenue without leading to corresponding increases in market revenue[48]. The output of intermittent renewables is not expected to vary much over time (for a wind plant, the average level of wind is unlikely to change and the average efficiency of the turbine is unlikely to degrade significantly). Hence using the same deemed output forecast over time may be considered appropriate. However, policy decisions mean that, for reasons not directly within the investor's control, the level of output from each low-carbon dispatchable plant is likely to decline over time (Figure 21). Therefore assuming a constant deemed output is not appropriate.

[48] This could happen for two reasons. (i) Estimates of deemed output could be inaccurate, as it would be very difficult to accurately estimate an appropriate deemed output. This was pointed out in REMA. This difficulty in estimating deemed output is particularly the case for a dispatchable plant, given all of the variables that determine any one dispatchable plant's load factor. (ii) Metered output follows a trend over time, while deemed output is fixed. Results from WP1 modelling (Figure 25) show that load factors for a CCHT can vary considerably over time – from 1.1% to 17.3% – and that there could be a strong decline in load factors from 2030 to 2050. Hence if an average output over the whole period were used as the deemed output, then there would be many periods where metered output were below deemed output.

Figure 17: CCHT load factors



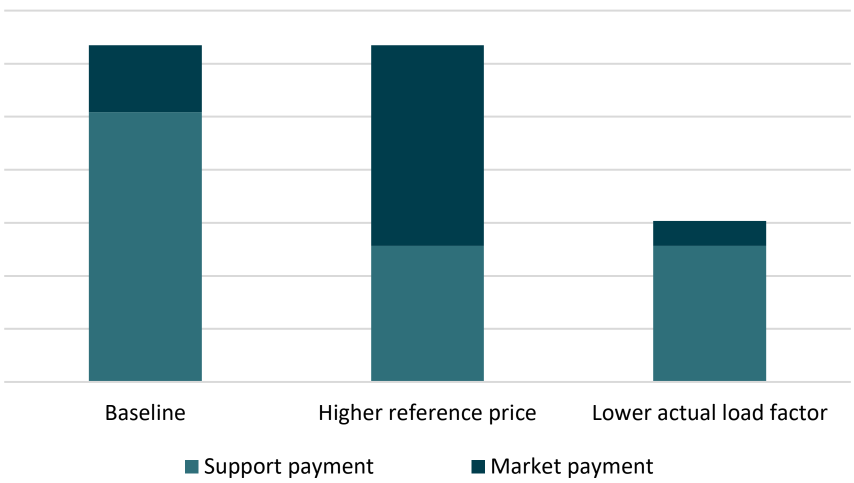
Source: LCP Delta

Note: Low availability, high hydrogen price scenario

Figure 18 demonstrates the potential additional risk that the Deemed Generation CfD brings to developers. The baseline is an illustration of what developers may be expecting to receive, and what funders may be expecting to pay. The second column represents what would happen if the electricity capture price increases, but deemed output and metered output were the same. The developer receives the same revenue under both scenarios and it is only the mix of payments that changes. This shows that if metered and deemed output are the same, then the Deemed Generation CfD can provide greater revenue certainty to developers than a fixed payment support like the CM.

However, if metered output is less than deemed output, as in the third column, then support revenue decreases if there is an increase in the electricity capture price, but market revenue cannot increase enough to compensate developers for the loss of support revenue. Figure 18 demonstrates the risk if metered output is below deemed output, and Figure 17 above shows the WP1 modelling finding that this situation could be likely to occur.

Figure 18: Additional risk of Deemed Generation CfD – illustrative diagram

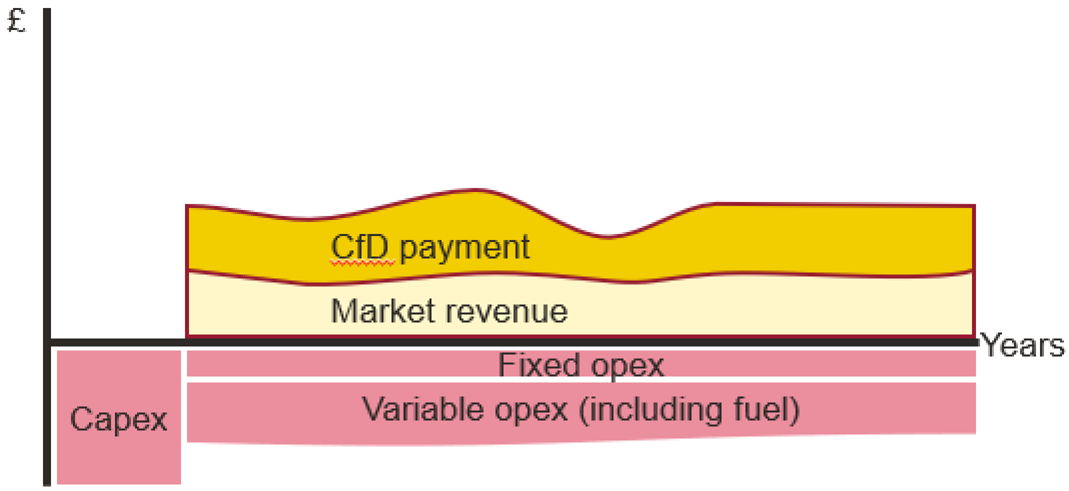


Source: Frontier Economics

Note: These calculations assume that deemed output is forecasted using the average load factor over 2025-2050 which is 8.5%. The right-hand column uses a metered output of the lowest P5 value over the period, which is 1.1%.

As with the other business models, some of the key features of the Deemed Generation CfD are laid out in Table 7 and an illustrative diagram is in Figure 19.

Figure 19: Deemed Generation CfD – illustrative diagram



Source: Frontier Economics

Note: This and all other business model diagrams are illustrative of how a business model could work, and not meant to be reflective of expected cost or revenue streams to H2P generators over time

Table 7: Deemed Generation CfD – Description

Key elements	Description
Fixed payments	Periodic payment per MWh of deemed output, referred to as 'fixed' because it is unrelated to actual level of output, however it could vary between reference periods.
Variable payments	None
Duration of payment	15 years to reflect other CfD contracts
Basis	Contractual (with LCCC as the counterparty) – given that this would be a H2P-specific support mechanism, allocation could be through bilateral negotiation at the beginning until there were enough operators to create a competitive auction without risking competition issues.
Impact on dispatch	No impact – payment is received for level of output that is deemed possible, rather than on actual output. Hence generator still has incentive to dispatch if marginal revenue is greater than marginal cost.

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated.

Qualitative assessment

We summarise our qualitative assessment of the Deemed Generation CfD in Table 8 and provide more detail on each element below.

Table 8: Deemed Generation CfD – Qualitative assessment

Criteria	Assessment
Investibility	Could be designed to protect H2P investors from some risks, but because it is not designed for dispatchable power, it exposes investors to additional risks
Decarbonisation of the power sector	Will not maximise the decarbonisation potential of the sector.
Cost efficiency	Will not distort dispatch but may incentivise over- or under-investment.
Cost distribution	Mitigates the risk of inframarginal rents but exposes funders to risks in terms of changing support payments that CM-like business models do not.
Practicality	The administrative burden is likely to be high
Adaptability and flexibility	Could be adaptable for subsequent investments to changes in the sector.

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated.

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

The Deemed Generation CfD could be designed to protect H2P investors from some risks, but because it is not designed for dispatchable power, it exposes investors to additional risks.

As with the CM and CM+, market price and demand risk do not impact support revenue in the Deemed Generation CfD, and hence are likely to be lower priority risks. Higher priority risks that could impact an operator's level of support include:

- Fuel availability risk (particularly where caused by cross-chain and policy issues);
- The risk that electricity capture price and the reference price diverge;
- The risk that an operator's deemed output and metered output could diverge (described above); and
- The risk that fuel costs could increase when H2P plants are price setting.

Fuel availability risk

If an unexpected outage in hydrogen production or infrastructure does not impact deemed output, i.e., the Deemed Generation CfD is paid in this case, then the Deemed Generation CfD could mitigate the impact of fuel availability risk on support payments (though fuel availability risk will still affect market revenues). If investors are penalised for being 'unavailable' when there is an unexpected outage in hydrogen production or infrastructure (i.e., their deemed output is reduced and lower levels of support are paid), then significant risks remain with the investor.

As outlined for the CM and CM+, risks around fuel availability are less likely to affect plants that rely less on cross-chain infrastructure (blended plants and prosumers).

Support price risk

In general, the Deemed Generation CfD protects developers from market price risk more than a fixed CM-type payment would, because if market prices, and hence market revenue, go down, then support payments increase. This is outlined in the description section above. However, the Deemed Generation CfD does expose investors to the risk that the electricity capture price and the reference price diverge. This means that an operator's support revenue could change without a corresponding change in market revenue.

Output risk

As explained above, output and deemed output could diverge. If metered output is less than deemed output when the electricity capture price rises, then operators could lose support revenue without a corresponding gain in market revenue. This is outlined in Figure 22.

Fuel cost risk

If H2P is price setting in the wholesale electricity market, then this could expose developers to fuel cost risk. If the price of hydrogen fuel increases then the market electricity price would increase accordingly. This means that developers would be making the same amount of market profit as before the price increase. However, if the market price – and hence the reference price – increases, then H2P developers are earning less support revenue than previously. Lower support revenue combined with constant profit from market revenue would reduce the total profitability of the plant. Whereas under the CM or a similar mechanism, support revenue and hence total plant profitability would stay constant in this scenario.

Decarbonisation of the power sector

Decarbonisation of the power sector	- Does the BM encourage H2P to dispatch ahead of unabated gas?

The Deemed Generation CfD will not maximise the decarbonisation potential of the sector.

As with the CM and the CM+, the Deemed Generation CfD does not impact dispatch, Therefore, if the outturn carbon price is lower than modelled, if hydrogen is not subsidised, or the hydrogen price is in line with that assumed in the high subsidised hydrogen price scenario (see Section 2) there is a risk that unabated gas will dispatch at or ahead of H2P plants[49] and the decarbonisation potential of the power sector is not maximised.

Cost efficiency

Cost efficiency	
	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

The Deemed Generation CfD will not distort dispatch, but may incentivise over- or under-investment.

The Deemed Generation CfD does not affect the dispatch order. As with the CM and CM+, assuming the outturn market carbon price is at or above the level assumed in the WP1 modelling, the CM+ avoids the risk of distorting dispatch.

As with the CM+, the Deemed Generation CfD could risk incentivising over-investment or underinvestment in H2P if too much or too little capacity is allocated to the mechanism. This risk is potentially greater than in the CM, given the need to specifically allocate capacity to this category of plants (rather than just to allocate capacity overall to the CM).

Assuming a Deemed Generation CfD is eventually allocated via auctions, competition between plants would incentivise reductions in costs to a certain degree. But again, this will depend on the extent of competition from H2P plants and the costs of other low carbon technologies.

Cost distribution

Cost distribution	
	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

The Deemed Generation CfD mitigates the risk of inframarginal rents.

The allocation under the Deemed Generation CfD could change over time.

- In the early years, where a small number of plants are being developed, allocation could be via bilateral negotiation. This would limit any risk of either (i) competition issues in an auction (because of a small number of participants) or (ii) high inframarginal rents because other, cheaper technologies have also been included in the auction.
- In later years, an auction mechanism could be used. This would have the advantage of price discovery using a mechanism familiar to investors.

[49] WP1 modelling found that where hydrogen fuel is not subsidised, unabated gas plant often dispatches ahead of H2P. H2P sometimes also dispatches behind unabated gas in the high subsidised hydrogen price scenario.

Once an auction is in place, the Deemed Generation CfD could lead to lower inframarginal rents than under the CM, assuming the auction is limited to low carbon plant.

While the CM and CM+ payment provide a constant cost to funders[50], if the optional variable payment is included, the Deemed Generation CfD payments could vary over time with changes in the prices of hydrogen, natural gas and carbon, as well as changes in plant dispatch and availability.

Practicality

Practicality	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

The administrative burden of the Deemed Generation CfD is likely to be high.

As stated in the REMA consultation, the administrative burden of the Deemed Generation CfD for government may be large. It is potentially very difficult to forecast accurately the deemed output of an asset, and its calculation for a dispatchable asset is not likely to be simple or transparent. Given this is a new type of business model, it is not likely to be deliverable in a short space of time. Stakeholders also had a preference for using an existing business model for H2P, rather than something new.

We assume that asset operators with this support do not participate in the CM (following precedent in relation to cumulation of support). However, the Deemed Generation CfD could operate alongside HPBM.

Adaptability and flexibility

Adaptability and flexibility	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

The Deemed Generation CfD would not be adaptable to changing market conditions.

The Deemed Generation CfD cannot be adjusted within contract. This could be a significant difficulty, given the risk to which operators are exposed, if metered output declines over time compared to deemed output. Results from the WP1 modelling demonstrate load factors could fall by up to 16 percentage points from 2025-2050.

Overall

While the Deemed Generation CfD would mitigate issues of inframarginal rents, it bring additional complexity and risks to developers, when compared to other means of providing a fixed payment.

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[50] By 'cost to funders' we mean the cost to whoever is providing the funds for the business model, for example taxpayers or energy consumers.

DPA

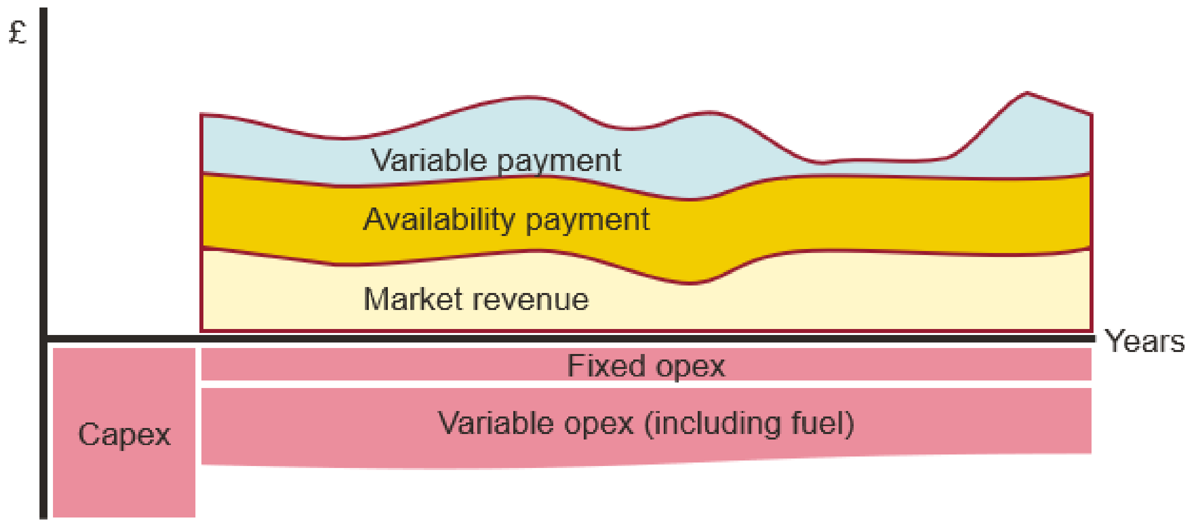
Description of the mechanism

The dispatchable power agreement (DPA) is due to be introduced for Power CCUS In an H2P context, it could potentially consist of two types of payments:

- An availability payment which would be similar to the CM or CM+ but without strict conditions aimed to incentivise security of supply.
- The option to include a variable payment that shifts H2P ahead of unabated gas in the merit order. Any variable payment would not replace the HPBM support provided to hydrogen producers[51];

These two payments are illustrated in Figure 20.

Figure 20: DPA – illustrative diagram



Source: Frontier Economics

Note: This and all other business model diagrams are illustrative of how a business model could work, and not meant to be reflective of expected cost or revenue streams to H2P generators over time

As with the Deemed Generation CfD, under the DPA, the decision around the appropriate level of H2P capacity would be determined centrally, rather than by the market. Stakeholders agreed that it may be appropriate to start by allocating DPA support under bilateral negotiations, until operator numbers are significant, mimicking the current approach for the Power CCUS DPA. This is due to the potential risk in early years of lack of competition in any DPA auctions as the number of H2P operators is expected to be low[52].

Key elements of the DPA are also summarised in Table 9.

[51] Under the assumptions used in the WP1 modelling, the variable payment would not be required for H2P plants using subsidised hydrogen, as the marginal cost is already below the marginal cost of natural gas plus carbon. However, it may be required to ensure that plants using unsubsidised hydrogen dispatch ahead of unabated gas.
[52] DESNZ assumptions are for 5GW in 2030s.

Table 9: DPA – Description

Key elements	Description
Fixed payments	Fixed payment paid on availability regardless of output.
Variable payments	Optional variable payment covers any additional cost of H2P generation compared to reference unabated gas plant.
Duration of payment	Generators can choose a term length between 10-15 years.
Basis	Contractual (with Low Carbon Contracts Company (LCCC) as the counterparty) – given that this would be a H2P-specific support mechanism, allocation could be through bilateral negotiation at the beginning until there were enough operators to create a competitive auction without risking competition issues.
Impact on dispatch	Only if optional variable payment is included. A variable payment would ensure H2P dispatches ahead of unabated gas, but careful consideration would be required to ensure efficient dispatch compared to Power CCUS, and within the H2 fleet.

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated

Qualitative assessment

We summarise our qualitative assessment of the DPA in Table 10, and provide more detail on each element below.

Table 10: DPA – Qualitative assessment

Criteria	Assessment
Investibility	The DPA could mitigate key investor risks.
Decarbonisation of the power sector	The DPA could maximise sector decarbonisation by shifting H2P ahead of unabated gas in the merit order, if an optional payment is introduced.
Cost efficiency	If an optional payment is introduced, whether the optional variable payment component of the DPA makes the dispatch order more or less efficient depends on the level of the carbon price, and whether hydrogen is subsidised.
Cost distribution	The DPA is likely to provide value for money to funders, however if the optional variable payment is included, it could expose funders to risks in terms of changing support payments that CM-like business models do not.
Practicality	Applying the DPA without a variable payment is likely to be a practical option. With an optional variable payment, however the interaction with Power CCUS needs to be carefully considered, and the implementation may be complex.
Adaptability and flexibility	The scheme could be adapted to changes in the sector for subsequent investments.

Source: Frontier Economics

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

The DPA could mitigate key investor risks.

Like the CM and the CM+, DPA support revenue (via the availability payment) is independent of electricity price and demand risks, and therefore this business model mitigates these risks for investors.

Unlike the CM and CM+, the DPA also mitigates fuel price and availability risk (driven by cross chain issues or policy risk). If the DPA availability payment is paid in the case of an unexpected outage in hydrogen production or infrastructure, then the DPA reduces operators' fuel availability risk (though they would still be exposed to reductions in market revenue at times when fuel is not available).

Decarbonisation of the power sector

Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?

The DPA could maximise sector decarbonisation by shifting H2P ahead of unabated gas in the merit order.

If a variable payment is included in the DPA, it could be used to incentivise additional dispatch of H2P. This could increase power sector decarbonisation. It could be effective , where for example, the outturn carbon price is lower than that assumed in the WP1 modelling, where hydrogen is not subsidised, or the hydrogen price is in line with that assumed in the high subsidised hydrogen price scenario[53] (see Annex B).

Cost efficiency

Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

Whether the optional variable payment within the DPA makes the dispatch order more or less efficient depends on the level of the carbon price, and whether hydrogen is subsidised.

As with the CM+ and the Deemed Generation CfD, the DPA could risk incentivising over-investment or underinvestment in H2P if too much or too little capacity is allocated to the mechanism.

Assuming a DPA is eventually allocated via auctions, competition between plants would incentivise reductions in costs to a certain degree. But again, this will depend on the extent of competition from H2P plants and the costs of other low carbon technologies.

If applied only with an availability payment, the DPA does not affect the dispatch order. If the optional variable payment is included, the DPA could increase the dispatch of H2P. Whether or not this increases efficiency, and reduces costs to society, will depend on whether the combination of the market carbon price and support to hydrogen is already incentivising dispatch at or above its socially optimal level. WP1 modelling suggests that an additional dispatch incentive may not increase efficiency if outturn carbon prices are at assumed levels and hydrogen is subsidised. However, outturn conditions could be different to those assumed

[53] WP1 modelling found that where hydrogen fuel is not subsidised, unabated gas plant often dispatches ahead of H2P. H2P sometimes also dispatches behind unabated gas in the high subsidised hydrogen price scenario.

in the modelling. For example, the outturn market carbon price could be lower than that assumed. Under these conditions there could be a case for a dispatch incentive.

As the reference plant would be centrally determined, this means the high-level dispatch order of technologies – Power CCUS H2P, unabated gas – would need to be centrally determined. This brings in potential inefficiency (due to the risk of policy / forecast errors) as it could lead to H2P plants dispatching too much or too little compared to what is socially optimal, hence leading to increased costs to society.

Cost distribution

Cost distribution	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

The DPA is likely to provide value for money to funders (taxpayers or energy consumers), however if the optional variable payment is included, it could expose funders to risks in terms of changing support payments that CM-like business models do not.

As with the Deemed Generation CfD, the DPA allows flexibility over allocation, with bilateral negotiation in the early years, and an auction mechanism in later years.

The DPA could provide value for money for funders as it mitigates the issue of infra-marginal rents, and allocation would ensure operators are not making excessive profits.

However, while the CM and CM+ payment means a constant cost to funders[54], if the optional variable payment is included, the DPA payments could vary over time with changes in the prices of hydrogen, natural gas and carbon, as well as changes in plant dispatch and availability (as would be the case in the Deemed Generation CfD also).

Practicality

Practicality	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

Applying the DPA without a variable payment is likely to be a practical option. With an optional variable payment, however the interaction with Power CCUS needs to be carefully considered, and the implementation may be complex.

The DPA is proposed for Power CCUS, so it is more likely to be understood by investors than a totally new business model. If it is applied just as an availability payment, its implementation could be relatively simple.

Including the variable payment would add complexity.

[54] By 'cost to funders' we mean the cost to whoever is providing the funds for the business model, for example taxpayers or energy consumers.

- The calculation of the variable payment must change for an H2P DPA compared to a Power CCUS DPA as an H2P plant will use a different fuel to the unabated reference plant, which is not the case for Power CCUS.
- If the optional variable payment is included, the interaction between the Power CCUS DPA and the H2P DPA must be considered carefully, so efficient dispatch could be maintained. As outlined in Section 3.4, modelling suggests that Power CCUS should dispatch ahead of H2P as it has lower social SRMC. If both DPA contracts use the same reference plant, then this could lead to some H2P plants dispatching ahead of some Power CCUS plants. As an alternative, the H2P DPA contract could use a slightly less efficient reference plant, that is still more efficient than the majority of the current unabated gas stock. However, then it is possible that some unabated gas would dispatch ahead of some H2P (depending on system parameters).

The variable payment portion of the DPA would partially be subsidising the cost of operating, providing support to H2P operators in a similar way to the HPBM. However, this should not be considered as a double subsidy. The variable payment would be calculated on a plant-specific basis, which means that different variable payments could be paid to H2P plants fuelled by subsidised hydrogen compared to those fuelled by unsubsidised hydrogen – plants using subsidised hydrogen as fuel would receive a lower variable payment than plants using unsubsidised hydrogen as fuel. Therefore, if an H2P plant were using more subsidised hydrogen, receiving greater support through the HPBM, it would receive a lower variable payment and hence less support through the H2P business model. However, it may add complexity if a single H2P plant uses both types of hydrogen as fuel.

We assume that asset operators with this support do not participate in the CM (following precedent in relation to cumulation of support). An H2P DPA may need to be considered in any changes made to the wider electricity market as a result of REMA.

Adaptability and flexibility

Adaptability and flexibility	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

The variable payment is flexible to market conditions and could balance out the support received by H2P plants fuelled by subsidised and by unsubsidised hydrogen.

The optional variable payment portion of the DPA adjusts to changes in gas and carbon prices, so is adaptable to expected trends over time as well as unexpected shocks.

The availability payment portion of the DPA cannot be adjusted within contract, however it could be adjusted for subsequent investments to take into account expected future changes to the market, and unexpected past changes to the market where the effects are still being felt.

As with other business models, a competitive auction process could reduce support required over time as the market developed.

Overall

A fixed payment to deliver investment could be delivered under the DPA, without the practical implications of relying on a CM-type mechanism. There is also the option to include a variable payment to increase dispatch, though this would bring complexity.

Revenue cap and floor

Description of the mechanism

A revenue cap and floor regime is currently in place for interconnectors (interconnectors are still eligible to receive CM support). The business model design means that an operator's market revenue over a certain period – for example 15 years – is assigned a maximum (the cap) and a minimum (the floor). The contract period is divided into 'reconciliation periods' (e.g. 1-5 years). Revenue above the cap in a given reconciliation period is returned to funders (e.g. tax payers or energy consumers), and revenue below the floor in a given reconciliation period is topped up by funders to the floor level. For H2P, market revenue would be likely to include wholesale electricity revenue as well as balancing and ancillary services. However, we assume that they would not be eligible to join the CM, given the difficulties in meeting the security of supply standards (due to cross chain risks) described above.

Revenue cap and floors can be helpful where there is a capital-intense asset with low or predicable running costs, as well as the possibility of very high revenues that are unlikely to be quickly eroded by competition. For example, this option has been used to drive investment in electricity interconnectors.

However, a revenue cap and floor may be less appropriate for a generator, because of the difficulty in capping revenue where opex fluctuates, and the risk of distorting the dispatch incentive. Stakeholders generally agreed with this view during the stakeholder engagement.

In particular, if an operator expects to end the reconciliation period between the cap and the floor, then there is no impact on dispatch. However, if the operator expects to end the reconciliation period either above the cap or below the floor, then dispatch is impacted because marginal revenue is effectively zero and therefore will never be above marginal cost.

- Marginal revenue is effectively zero for an operator once it has exceeded the cap, because at the end of the reconciliation period the operator will pay back all revenue above the cap. Therefore, if the operator dispatches an extra unit of electricity and earns this revenue, this will only increase the amount of revenue that the operator pays back at the end of the reconciliation period. It will not be able to keep any of that extra revenue; and
- Marginal revenue is effectively zero for an operator who expects to end the reconciliation period below the floor because at the end of the reconciliation period the operator will receive a top-up subsidy to the level of the floor. Therefore if the operator dispatches an extra unit of electricity and earns this revenue, this will only reduce the top-up support that it receives at the end of the period, and will not increase overall revenue for the operator.

We illustrate this in Table 11. This shows that where the operator expects revenue to be greater than the cap, it will not dispatch, even though it would be beneficial for society if it did (assuming the market price and the marginal cost are in line with social benefits and costs).

Table 11: Revenue Cap and Floor – Quantitative illustration of dispatch distortion

			Floor > Revenue	**Cap > Revenue > Floor**	**Revenue > cap**
Regime	Floor	£	15,000	15,000	15,000
	Cap	£	150,000	150,000	150,000
Before	Market revenue	£	2,000	20,000	200,000
	Support	£	13,000	0	-50,000
	Total revenue	£	15,000	20,000	150,000
Societal dispatch decision	Market price	£/MWh	100	100	100
	Marginal cost	£/MWh	75	75	75
	Profit (MR-MC)	£/MWh	25	25	25
	Dispatch?		Yes	Yes	Yes
Market dispatch decision	Market revenue	£	2,100	20,100	200,100
	Support	£	12,900	0	-50,100
	Total revenue	£	15,000	20,100	150,000
	Marginal revenue	£/MWh	0	100	0
	Marginal cost	£/MWh	75	75	75

	Profit (MR-MC)	£/MWh	-75	25	-75
	Dispatch?		No	Yes	No

Source: Frontier Economics

Note: The marginal cost comes from the WP1 modelling, as the average SRMC over time for a new-build CCHT fuelled 100% by subsidised hydrogen in the medium hydrogen price scenario. The level of the cap and the floor, as well as the market price and overall market revenue of operators is purely illustrative.

The narrower the gap between the cap and the floor, the worse the potential distortion, because operators are more likely to be confident that they will end the reconciliation period either above the cap or below the floor. In contrast, the longer the reconciliation period, the greater the uncertainty faced by operators regarding when they will end the reconciliation period. This uncertainty means the mechanism is less likely to distort dispatch, and more likely to follow market signals. This means a longer reconciliation period reduces but does not remove these dispatch distortions. However, a long reconciliation period would also reduce investibility as investors will have to wait longer for top ups to support debt finance. A ‘soft’ cap or floor (i.e., where there is a gain share mechanism included) could also reduce (but not remove) the dispatch distortions. We discuss this further in Annex H.

In practice, distortions driven by an expectation of being below the floor are likely to be important. WP1 modelling suggests that a significant CM payment could be required for H2P operators to break even. Therefore, funders are very likely to need to top-up an operator to the level of the floor at the end of every reconciliation period, with the associated risk of dispatch distortions.

We also note that a cap is less likely to be needed for H2P than for highly capital-intense assets such as interconnectors. For example, there may be lower barriers to entry if H2P plants can be built more quickly, and there are a wider range of potential sites available. This means that if a plant were earning excessive profits then it is likely that others would enter the market until profits were reduced to a normal level, providing the support mechanism is allocated on a regular basis.

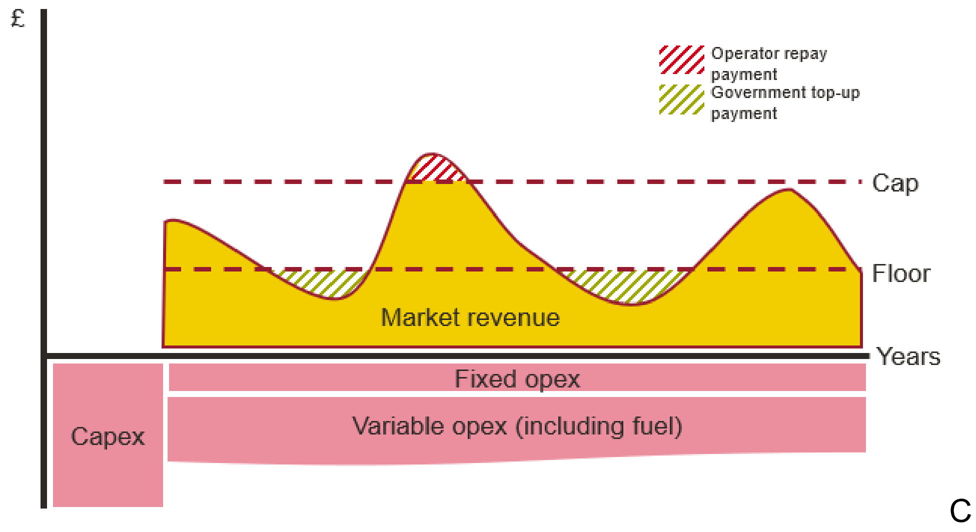
The key features of a revenue cap and floor are outlined in Table 12 with an illustrative diagram in Figure 21.

Table 12: Revenue Cap and Floor – Description

Key elements	Description
Fixed payments	Periodic payment (positive or negative) depending on how far revenue is below the floor or above the cap.
Variable payments	None (payments are not the same every period, but do not vary directly with output, unless there is a 'soft' cap or floor).
Duration of payment	Periodically over a period of years (potentially 15).
Basis	Regulated returns - it could be most appropriate to allocate support under bilateral negotiations. While in theory a Revenue Cap and Floor could be allocated via an auction, this would be complex (due to the number of parameters requiring specification) and therefore may be impractical.
Impact on dispatch	An operator experiences dispatch distortions if they expect to end the reconciliation period either below the cap or above the floor.

Source: Frontier Economics

Figure 21: Revenue Cap and Floor – illustrative diagram



Source: Frontier Economics

Note: This and all other business model diagrams are illustrative of how a business model could work, and not meant to be reflective of expected cost or revenue streams to H2P generators over time

Qualitative assessment

We summarise our qualitative assessment of the Revenue Cap and Floor in Table 13 and provide more detail on each element below.

Table 13: Revenue Cap and Floor – Qualitative assessment

Criteria	Assessment
Investibility	Depending on the design of the floor and the length of the reconciliation period, a revenue cap and floor could mitigate significant investor risks.
Decarbonisation of the power sector	Would not incentivise H2P to dispatch ahead of unabated gas, and may even incentivise reduced dispatch.
Cost efficiency	Could significantly distort dispatch.
Cost distribution	Unlikely to provide significant value for money over other business models in practice, and dispatch distortions could have an indirect impact increasing market prices.
Practicality	While a Revenue Cap and Floor is familiar to investors from interconnectors, establishing the regime for H2P is likely to be lengthy, costly, and complex.
Adaptability and flexibility	Could be adaptable for subsequent investments to changes in the sector.

Source: Frontier Economics

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

Depending on the design of the floor and the length of the reconciliation period, a revenue cap and floor could mitigate significant investor risks.

An operator's revenue over a period is fixed within a certain range. This has the potential to mitigate the key risks identified in Annex D.

The extent to which these risks are covered depends on definition of the floor and reconciliation period. The higher the level of the floor or the shorter the reconciliation period, the more risks are covered. However, a high floor would increase the likelihood that operators would end the reconciliation period below the floor, and hence experience dispatch distortions, and a shorter reconciliation period also exacerbates this issue. Therefore, there is a trade-off between increasing investibility and reducing dispatch distortions.

Decarbonisation of the power sector

Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?

The revenue cap and floor would not incentivise H2P to dispatch ahead of unabated gas, and may even incentivise reduced dispatch. This is not maximising the decarbonisation of the sector.

The revenue cap and floor will not incentivise increased dispatch of H2P beyond the order determined by its SRMC, and in fact may actually limit dispatch of H2P below this level when the expectation is that revenue will be below the floor or above the cap at the end of the reconciliation period. This impact would reduce the incentive to dispatch, and hence mean unabated gas more likely to dispatch ahead of H2P. This is outlined in more detail above.

Cost efficiency

Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

The revenue cap and floor could significantly distort dispatch.

As described above, the Revenue Cap and Floor incentivises efficient dispatch when revenue is between the cap and floor, but distorts dispatch if revenue is above the cap or below the floor, hence increasing costs to society. This can be seen across the three columns in Table 11. This dispatch distortion is reduced the lower the level of the floor and the longer the reconciliation period. There are a number of alternative cap and floor models discussed further in Annex H. However, our overall finding is that while these alternatives can partially mitigate some of the dispatch distortions described below, they increase the complexity of the business model. It would therefore be better to choose a business model that did not distort dispatch in the first place.

As with the Deemed Generation CfD and the DPA, the Revenue Cap and Floor may incentivise over-investment or under-investment in H2P. This is because H2P capacity is centrally determined based on the number of Revenue Cap and Floor contracts signed.

As with the other models, the allocation for contracts could incentivise cost reduction over time, if it is possible to introduce a competitive auction mechanism[55].

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[55] The design of such a mechanism for the Cap and Floor would require further thought. Given the number of parameters to be agreed, it could be complex.

Cost distribution

Cost distribution	
	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

The model is unlikely to provide significant value for money over other business models in practice, and dispatch distortions could have an indirect impact increasing market prices.

Government payment could be anything from zero if the asset operator ends the reconciliation period between the cap and the floor to potentially very large sums – up to the total value of the floor. Given the WP1 modelling that finds H2P asset operators need support beyond market revenue to breakeven, it is unlikely that H2P operators will earn market revenue above the floor.

The cap and floor may significantly impact market prices through dispatch distortions. If a H2P would have been the marginal plant, but did not dispatch due to distortions from the business model, then the next marginal plant would be more expensive, and hence could increase market prices.

Practicality

Practicality	
	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

While a Revenue Cap and Floor is familiar to investors from interconnectors, establishing the regime for H2P is likely to be lengthy, costly, and complex.

In principle, the Revenue Cap and Floor is already known from interconnectors and is hence understood by investors. However, the implementation of a Revenue Cap and Floor could be complex.

For example, this could require establishing: the basis for a cap, the basis for a floor, agreeing the term, agreeing the approach to unpredictable opex, designing a mechanism aiming to 'soften' the cap and floor, and establishing any further detailed conditions around availability and dispatch requirements.

A Revenue Cap and Floor regime would need to take into account any changes due to REMA, and be compatible with the HPBM.

Adaptability and flexibility

Adaptability and flexibility	
	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

A Revenue Cap and Floor could be adjusted for subsequent investments but adding in additional flexibility could lead to complexity.

A Revenue Cap and Floor could be adjusted for subsequent H2P investments to take into account expected future changes to the market, and unexpected past changes to the market where the effects are still being felt. The wider the gap between the cap and the floor, the less intervention and hence the more adaptable the BM is to unexpected shocks.

Support in standard cap and floor does not fluctuate with costs and therefore would not be flexible to changes to input fuel cost. However, the level of the cap and floor could be indexed to take these into account to some degree. Given volume produced also fluctuates, indexing could lead to a lot of complexity.

Overall

A Revenue Cap and Floor is not likely to be appropriate for dispatchable power generation as it distorts dispatch if the operator does not expect the end the reconciliation period between the cap and the floor. We cover potential alternative cap and floor models in Annex G.

Fossil Fuel Ban

Description of the mechanism

A Fossil Fuel Ban differs from the other business model options. Unabated gas would be limited in power generation[56]. This could be via an emissions performance standard – similar to coal – such that a maximum gCO2/kWh is set that effectively eliminates generation from unabated gas. This is a technology neutral option, as it does not provide support to H2P over that which is provided to other low-carbon technologies.

We assume that the rest of the market stays the same, and hence that the CM is still in place with a Fossil Fuel Ban. The Fossil Fuel Ban should therefore be seen as an addition to the CM (building on the existing emissions performance standard within the CM), rather than an independent business model.

As the CM is still in place, the market determines H2P capacity. However, the removal of unabated gas from the CM auction means that H2P is more likely to get support through the CM. H2P would also likely have higher load factors than if unabated gas plants were also dispatching, given the WP1 modelling results that in some scenarios unabated gas dispatches with or ahead of H2P.

For comparison with the other business models, key elements of a Fossil Fuel Ban are outlined in Table 14, and an illustrative diagram – the same as under the CM – is in Figure 22.

[56] For example, under the Large Combustion Plant Directive, where after a certain date, plants without desulphurisation equipment could only run 20,000 hours and then had to close.

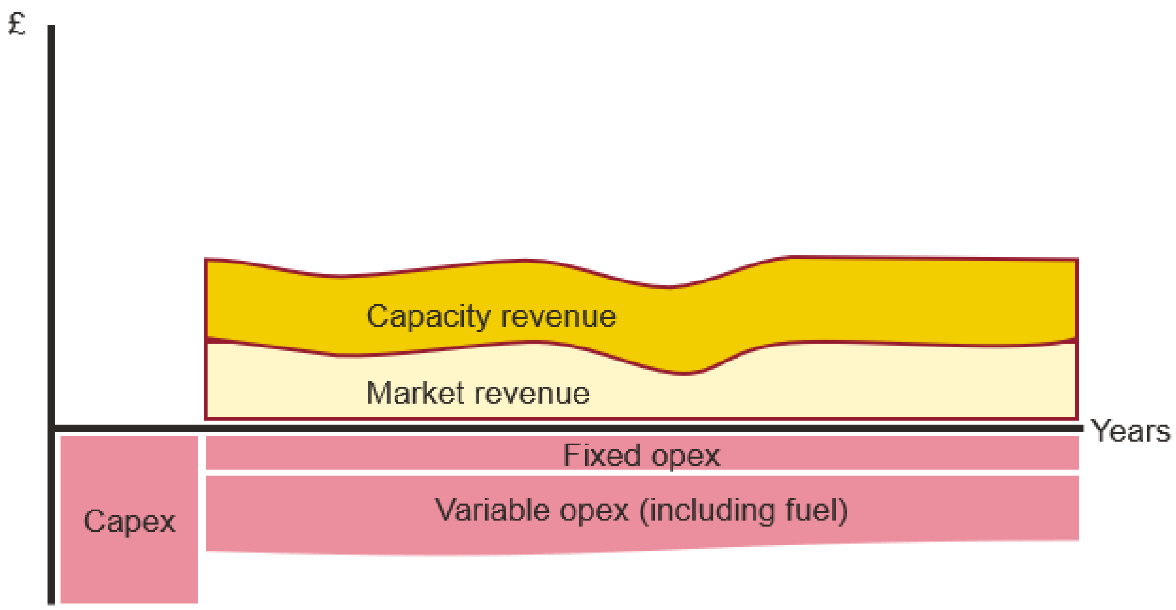
Table 14 : Fossil Fuel Ban – Description

Criteria	Assessment
Key elements	Description
Fixed payments	No additional payments beyond the CM
Variable payments	None
Duration of payment	As per CM
Basis	Obligation
Impact on dispatch	H2P higher in merit order as unabated gas (previously likely to be ahead of H2P) is removed. Otherwise, no impact on dispatch as generator still has incentive to dispatch if marginal revenue is greater than marginal cost

Source: Frontier Economics

Note: Variable payments refer to payments per kWh of electricity generated

Figure 22: Fossil Fuel Ban – illustrative diagram



Source: Frontier Economics

Note: This and all other business model diagrams are illustrative of how a business model could work, and not meant to be reflective of expected cost or revenue streams to H2P generators over time

Qualitative assessment

We summarise our qualitative assessment of the Fossil Fuel Ban in Table 15, and provide more detail on each element below

Table 15: Fossil Fuel Ban – Qualitative assessment

Criteria	Assessment
Investibility	Does not remove significant investor risks.
Decarbonisation of the power sector	Allows H2P to dispatch ahead of unabated gas, and hence maximise the decarbonisation of the sector.
Cost efficiency	Banning unabated gas distorts efficient dispatch, as some unabated gas dispatch is required to minimise social costs (under the assumptions used in the WP1 modelling).
Cost distribution	Could lead to significant inframarginal rents, and could increase market electricity prices, negatively impacting competitiveness.
Practicality	Simple and transparent, however it may not be credible if prices of low-carbon dispatchable power remain high.
Adaptability and flexibility	Could be relatively flexible to market conditions.

Source: Frontier Economics

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

As with the CM, the Fossil Fuel Ban does not remove significant investor risks.

As with the CM, the main risk that could affect support revenue is fuel availability risk (driven by cross chain and policy risk), and this could not be mitigated for developers under the current CM.

Decarbonisation of the power sector

Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?

A Fossil Fuel Ban allows H2P to dispatch ahead of unabated gas, and hence maximise the decarbonisation of the sector.

H2P always dispatches ahead of unabated gas (as it is limited).

Cost efficiency

Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

Banning unabated gas distorts efficient dispatch, as some unabated gas dispatch is required to minimise social costs (under the assumptions used in the WP1 modelling).

WP1 modelling results show that it is socially optimal for some unabated gas to dispatch in the market. Under the assumption that the carbon price accurately reflects the societal costs of carbon, then banning unabated gas is distorting efficient dispatch and could increase costs to society.

WP1 demonstrates that the SRMC for unabated gas is lower than for H2P in the early years under some scenarios. Given that H2P will be likely to have higher capex as a first-of-a-kind technology, the LRMC may be lower for unabated gas than for H2P in the early years, assuming the carbon price appropriately reflects the cost to society. Therefore, a Fossil Fuel Ban may incentivise over-investment in H2P and too much H2P may be built, further increasing costs to society.

Incentives to bring down H2P deployment costs are maintained in the CM while H2P is competing against other low-carbon options.

Cost distribution

Cost distribution	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

A Fossil Fuel Ban likely leads to significant inframarginal rents, and could increase market electricity prices, negatively impacting competitiveness.

Given that a Fossil Fuel Ban would need to be accompanied by the current CM, this business model also is likely to lead to high clearing price in CM (though inframarginal rents are likely to be lower than with a CM alone). This would lead to significant infra-marginal rents and relatively poor value for money for funders (taxpayers or consumers). Banning fossil fuels is likely to increase market prices by increasing the cost of the marginal plant in cases where previously unabated gas would have been the marginal plant. This could reduce UK competitiveness.[57]

[57] This impact on UK competitiveness would be over and above the impact caused by the CM being funded by energy consumers, which is common to all business models and outlined at the beginning of this chapter.

Practicality

Practicality	
	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

A Fossil Fuel Ban is simple and transparent, however it may not be credible if prices of low-carbon dispatchable power remain high.

A Fossil Fuel Ban is simple and transparent and easy to implement. Legal issues would need to be considered, but there may be little administrative burden for government, beyond the ruling of which fuels are banned, and a Fossil Fuel Ban would prevent fuel switching between natural gas and hydrogen that could cause complexity under other business models. The ban could run alongside the CM, HPBM and any changes made under REMA.

However, the ban would need to be announced in advance, and stakeholders had a preference model for a business model that would be delivered soon. Moreover, there may be issues with making the ban credible with investors, if H2P continues to be expensive and there is not another mature alternative.

Adaptability and flexibility

Adaptability and flexibility	
	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

A Fossil Fuel Ban could be relatively flexible to market conditions.

Because the Fossil Fuel Ban would leave is technology neutral (in terms of the low carbon plants that it incentivises), it could be relatively adaptable to changing market conditions.

Overall

While a Fossil Fuel Ban is a simple business model that ensures decarbonisation of the power sector it does not necessarily support the investibility of H2P and could lead to low value for money for funders. It may also be practically difficult to implement, given challenges in setting it credibly.

Conclusion of business model assessment

Our key takeaways are:

We find that the CM could support H2P relatively efficiently (without further H2P-specific intervention), but only under specific circumstances which are unlikely to hold for early investments.

WP1 modelling suggests that new build CCHTs could require a CM payment from £50/kW to £100/kW per year[58], depending on the availability of hydrogen, and levels of capex and hurdle rate.

For H2P bids to be at the lower end of the range, and therefore for CM clearing prices to be closer to today's levels, very specific conditions would need to be in place:

- The capital costs of H2P plants would need to be similar to those of unabated gas;
- The hurdle rates of H2P plants would need to be similar to those of unabated gas;
- There would need to be sufficient subsidised hydrogen available, such that the fuel costs of H2P were similar or lower than that of unabated gas;
- Investors would need to believe that there were not significantly higher fuel availability risks associated with hydrogen as compared to gas[59].

WP1 modelling finds that under the above conditions, a new-build CCHT could be supported by a clearing price of £70/kW per year. This is closer to clearing price levels seen today, and more likely to be similar to that of an unabated CCGT going forwards. Therefore the impact on inframarginal rents (relative to those present in the CM today) would likely be low.

However, these conditions are unlikely to hold for the first investments in H2P:

- It is not likely that early H2P will be able to achieve the capex and hurdle rates of unabated gas, given the risks and additional costs associated with first-of-a-kind investments;
- Focussing on subsidising low carbon hydrogen (via an expansion of the HPBM) rather than targeting a support mechanism at H2P may increase societal costs (for example, if a large amount of subsidised hydrogen in the market means that consumers in other sectors choose to decarbonise with subsidised hydrogen, when a decarbonisation option with lower societal costs is available); and
- In the early hydrogen market, fuel availability risk that results from cross-chain and policy-related risks is likely to represent a key risk to investors, and one that an H2P business model should ideally mitigate.

The required conditions may hold in the medium to long term. Over the long term, including H2P in CM could provide a valuable incentive for H2P plants to contribute to security of supply.

The CM+ has the potential to provide support to H2P but has some drawbacks.

[58] These modelling results are for new-build CCHTs in 2026 operating on 100% hydrogen fuel in the medium hydrogen price scenario. The equivalent modelling results from WP1 for OCHTs are £41-70/kW, £73-205/kW for CHPs, and £41-82/kW for recips.
[59] Given the strict security of supply conditions associated with the CM, investors would be penalised if they were not available to generate during a stress event. Relying on the CM alone exacerbates fuel availability risk for investors.

The CM+ would involve an auction only open to a narrow range of low carbon technologies[60]. This would reduce the risk of high inframarginal rents even if H2P clearing prices remained high (i.e. if the conditions above did not hold)[61].

However, because a narrower set of technologies would be eligible, the auction may be less competitive[62]. This could in turn result in uncompetitively high auction clearing prices, and excess inframarginal rents for participants in the CM+ auction. This trade-off is less important for other business models that can be allocated via bilateral negotiations in the years before there are enough potential investors to rely on a competitive allocation process.

Furthermore, plants clearing in the CM+ auction would still be penalised in the situation of non-availability during a stress event, exposing investors to fuel availability risk. Our understanding from current investors views is that this could make H2P uninvestible, given perceptions of cross-chain and policy-related risks.

Finally, we note that delivering the CM+ via changes to the legal and regulatory framework currently used for the CM could be administratively difficult.

The DPA performs well against the assessment criteria.

While the DPA delivers a fixed monthly payment (in common with the CM and the CM+), it has four advantages over these mechanisms.

- First, the DPA could be given directly to H2P operators without altering the clearing price in the CM and therefore the level of support received by other operators (either low carbon or otherwise). Therefore, the DPA should not lead to high inframarginal rents for other operators;
- Second, for early investments, the DPA could be designed to mitigate fuel availability and cross chain risks for investors. For example, the availability payment could still be paid when fuel is unavailable due to cross-chain outages, rather than penalising plant operators when they cannot meet the security of supply conditions inherent to the CM and the CM+;
- Third, the DPA could be allocated by bilateral negotiation in the near term and an auction in the longer term (to the extent that support beyond the CM is required in the longer term). This would reduce risks associated with lack of competition in an auction; and
- Fourth, the DPA may have a lower administrative burden than most other business models, as it is already being introduced for Power CCUS but does not rely on changes to the CM legal and regulatory framework.

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[60] These low carbon technologies could in theory include new pumped hydro storage, Power CCUS (if it no longer receives a DPA), and H2P. However, it was beyond the scope of this work to think about business models that would be appropriate for other technologies.
[61] Given the combination of the need for substantial derating of H2P to take into account fuel availability risk with the high costs of H2P, issues of inframarginal rents for some technologies may remain, especially if it is not possible to exclude batteries from the CM+.
[62] Liquidity would not be an issue for the CM, because the full range of flexible plants could bid in.

While there is an option in the DPA to include a variable payment to shift H2P ahead of unabated gas in the merit order, our analysis suggests that incentivising additional dispatch of H2P would not increase whole system efficiency (and it would add significant complexity to the electricity market[63]). If applied without the variable payment, the DPA would not distort dispatch.

There are significant issues with the other three options considered.

- The Deemed Generation CfD is designed for intermittent renewables rather than dispatchable technologies. The concept of providing support based on deemed output is designed to incentivise investors in renewables to locate efficiently, for example, in areas of high wind. However, this type of locational incentive is not relevant to non-renewable power. It would be very difficult to appropriately estimate deemed output (as outlined in the REMA consultation). In addition, the fact that the levels of support change with the reference price would bring in additional risks for dispatchable power operators.
- The Revenue Cap and Floor is more suited to technologies with high capex, low and stable operating costs, and where significant barriers to entry exist. For dispatchable power technologies with non-negligible operating costs, the revenue cap and floor could distort dispatch incentives, increasing costs to society. There are a number of adjustments that could be made to a traditional Revenue Cap and Floor to mitigate this distortion. However, these are unlikely to fully remove it, and would add complexity to the business model.
- The Fossil Fuel Ban would not help to the issue of inframarginal rents that we expect to be present in the CM. Moreover, it may be difficult to ensure that the ban is credible to investors, and if it is not, it will not deliver H2P investment.

[63] Especially as such a payment would interact with the payment already in place for Power CCUS.

Annex A: Stakeholder interviews

Summary of stakeholder engagement

Approach to stakeholder engagement in WP1

LCP Delta conducted seventeen stakeholder interviews (eleven developers, two OEMs, and four investors). We used a semi-formal and semi-structured interview structure, allowing interviewees the space to provide a level of detail they were comfortable with and to add or bring additional detail (outside of the scope of the interview guidance) to the discussion. Stakeholders provided information on the basis of organisational anonymity to encourage interviewees to share sensitive and project information, and to help gather critical insights from industry.

The stakeholder interviews had three objectives:

- To gather views from three key stakeholder groups (project developers, investors, and OEMs) on the suitability and merit of hydrogen for power production, relative to alternatives;
- To establish a qualitative evidence base to inform the modelling approach and assumptions for the detailed modelling work on the H2P archetypes; and
- To identify key risks and issues impacting the H2P market and gather industry views on solutions.

Stakeholder overarching views on H2P

Stakeholders agreed that there is a clear need for flexible generation to provide services to the system and operate in the market to meet residual demand.

Those interviewed considered hydrogen-fuelled power generation to be the most promising technology to provide low-carbon, firm, flexible generation. The majority of interviewees expressed a view that H2P is a particularly suitable decarbonisation option for assets that cannot meet the physical space requirements needed for retrofitting Power CCUS equipment.

Stakeholders also believe that H2P can respond more flexibly than Power CCUS. In particular, H2P is the preferred option in terms of flexibility due to the superior ramping up and down times when compared to Power CCUS.

Stakeholders also argued that barriers to investment remain.

We interviewed project developers that expressed support for investing in retrofitting and converting their assets from natural gas to hydrogen. They are currently in advanced stages of preparatory work to assess the financial and technical feasibility of H2P. However, some explained that they were waiting to obtain more policy clarity regarding the Government's commitment to H2P before committing additional and substantial expenditure on technical feasibility studies with OEMs. The capex and requirements associated with this retrofitting investment provided by interviewees fed into our cost assumptions and modelling. There was already a view from operators of smaller assets (such as reciprocating engines and OCGTs) that existing assets may already be able to accommodate significant volumes of hydrogen, but further feasibility studies are required.

In addition, of particular concern to smaller generators is the requirement for NOx abatement technologies (such as Selective Catalytic Reduction (SCR)) which can be costly and would reduce the units de-rated capacity.

There is currently little appetite expressed to bring forward new-build H2P generation as the business case for firm power generation is perceived to be more favourable for post-combustion Power CCUS (however, Power CCUS is not suitable for all plant due to the increased site footprint requirement). Stakeholder views on their preferred option was unsurprisingly influenced by the location, size and age of their respective asset(s).

Stakeholders shared cost and operating assumptions.

Most viable case studies discussed (where an H2P project could be completed) were retrofitting and fuel conversion - with a range of modest blends expected in the near to future to test technical performance and owing to a potential short supply of hydrogen, before extending to around 30% by the end of this decade.

For a CCGT to be capable of burning 30% hydrogen, one stakeholder provided a capex range from around £90m for a hydrogen pipeline, and blending package, and compressor package. A figure of up to ~£200m was given for more extensive retrofitting and full conversion. These figures are indicative and based upon early pre-feasibility work that the stakeholder has commissioned.

It is likely that in the event of a conversion of a gas turbine to accept increasing quantities of hydrogen fuel, a more significant repowering would also be undertaken to guarantee the extended life of the asset to allow hydrogen burn (and should be factored into any H2P support).

Stakeholder views on the financial needs case for investment in H2P

The majority of H2P project developers interviewed considered that there is a need for a specific H2P support framework from Government.

However, one large H2P stakeholder expressed the view that the Government should not give continuous support to H2P. Their view was that hydrogen production should be incentivised instead (i.e. the H2 production business model), and more significant non-continuous support should be provided in the short e.g. grants for changing equipment to enable transition from gas to H2.

Overall, all stakeholders agreed that if Government did introduce a H2P business model that it should be a simple and easily understood as possible. The current tax credit framework of the

US Inflation Reduction Act was provided as an example given by the investor interviewees of this. It is understood that this type of policy mechanism is not suitable or preferred in the UK, however the key point being made by stakeholders is in regard to policy certainty and risk-reduction i.e. the greater the complexity and number of interventions, the greater the risk of unintended policy outcomes and increased policy and regulatory risk.

Another key policy area that stakeholders encouraged government to address urgently is around the need to incentivise hydrogen transportation and storage to enable large volumes of fuel to be available to the market. One stakeholder expressed a view that a storage policy intervention is more important than a power policy on the grounds that without enough hydrogen fuel available power generators will not be able to operate, rather than developing application-specific interventions including H2P BM.

Approach

Stakeholder Interviews – approach to gathering data: Qualitative data gathered from project developers, OEMs, and investors

To kick off WP1, LCP Delta conducted a number of stakeholder interviews. The purpose of these was to set the scene for the H2P project and establish a qualitative evidence base to inform the modelling approach and assumptions for the detailed modelling work on the hydrogen power archetypes. Three key stakeholder groups were included within the scope of the project:

- H2 project developers (power generation operators) – eleven interviews completed
- Investors and lenders – four interviews completed
- H2 technology OEMs – two interviews completed

Overall, 29 organisations were invited to participate.

An interview guide was developed and agreed with DESNZ to define the scope and specific data points to explored, and interview data to be collected from stakeholders. Specific sets of questions were developed for each stakeholder group, based on that group’s requirements and the type of data being sought for the project.

The interviews were conducted in a semi-formal and semi-structed manner, allowing interviewees the space provide a level of detail they were comfortable with and to add/bring additional detail (outside of the scope of the interview guide) to the discussion. This approach supported an open discussion where interviewees were comfortable to share commercially sensitive information.

This information was shared with us on the basis of anonymity on the understanding that it is valuable and worth including for the benefit of providing insights for the development of policy in this space.

Key themes and takeaways from developers

Hydrogen availability

There was consensus amongst interviewees that uncertainty around readily available hydrogen for power generators is the most significant risk for developers. Tied up in this risk is the challenge of developing the hydrogen transportation and storage sector sufficiently to create a liquid and diverse marketplace for hydrogen.

Several specific fuel availability risks exist which require policy intervention to overcome, in the absence of a mature hydrogen economy. These are explored in more detail in WP2.

A number of power generation operators were in favour of exploring the option of a 'ring-fencing' policy on the grounds of securing supply of electricity, in the absence of a deep and liquid hydrogen supply market.

Alongside this a number of project developers considered that it would be worthwhile exploring regulatory options to utilise low-cost renewable otherwise-curtailed power to capture the lost opportunity to produce clean hydrogen.

Transportation and Storage

A small number of developers consider that the Government should urgently prioritise a high-quality gas network or existing storage which can be repurposed for hydrogen as H2P projects logically make most commercial and operational sense when co-located or located near hydrogen storage.

Without a policy that values large volumes of long-duration hydrogen storage, all applications for hydrogen will be significantly held back and prevented from developing.

Retrofitting existing or new-build assets – technology readiness

The certainty around technical feasibility for H2P turbines is limited to a ~30% blend of hydrogen to natural gas. At this blend limit there is sufficient technical compatibility to require modest retrofitting/upgrading to an OCGT or CCGT. Only one interviewee shared specific capex figures and details, amounting to £50-90m for 2-3 front-end upgrades (pipeline, compressor and blending packages). These upgrades do not involve internal changes to the gas turbines. It was estimated that pushing the blending beyond 30% and towards 70-90% including new turbines would well exceed £200m (see note 1 below). These figures represent the capex outlay for a typical CCGT.

It should also be noted that the UK GT fleet is generally split evenly between newer (~5yr old) and older (~20yr old) plant. Operators of older plant are unlikely to commit significant capital expenditure to old plant and are more likely to fully rebuild.

Note 1: It should be noted that the figure of £200m is an estimate based on best endeavours. This figure has not been substantiated by technical or commercial studies for the reason outlined in Note 2 below.

Note 2: It should be noted that a number of OEMs are progressing on their technology readiness pathways for fully hydrogen-fired turbines but have indicated to the market that they will not provide operational and technical assurances to operators, to the sufficient level required for an operators insurance/indemnity requirements, until entering into commercial arrangement to supply equipment. Meanwhile, operators are unwilling to commit to orders until they have more certainty around the support mechanism from Government. OEMs are expecting equipment for 50-80% H2 to be available by 2025, and 100% H2 by 2027.

Key themes and takeaways from OEMs

Policy goals vs. market development reality:

- H2P is a more straightforward application for hydrogen, e.g., industry, mobility and heat are more complex problems to solve. Electricity demand is established and significant and will just get bigger with the broader electrification of the economy, demand could get up to 500-1000 TWh/pa – nuclear and renewables will not meet this demand without low carbon thermal generation.
- Current renewables policies have created a surplus of power which should be captured by LDES solutions, for which hydrogen should be the key technology.
- Net zero target to 2035 is very challenging, making H2P very important. Decarbonization of separate industries are not going to make big change. The urgency for power sector to lean towards H2 is high.
- Limited knowledge, resources and time to achieve the 2035 grid decarbonisation target is a major concern - E.g. switchgears and electrical equipment supply are limited (according to data from a Japanese manufacturer). Lead times to develop the technology are quite significant. UK developers needs to secure EPC services in next 1-2 years to do H2P, CO2, hydrogen storage, or hydrogen production projects and meet policy goals.

Key themes and takeaways from investors

Maturity of hydrogen assets:

- All investors (infrastructure fund managers, lenders/banks) interviewed agreed that hydrogen to power investments in the UK are not yet de-risked sufficiently to be considered at the present time but expect this to improve over the next two years. Two-year timeframe is linked to the timeframes for executed LCHAs and the visibility of hydrogen volumes and prices that these will bring to the market.

- Currently the majority of the investor interviewees favoured the tax credit framework of IRA in the USA due to the simplicity of the mechanism. However, the UK is expected to become increasingly as investable in the near to medium term.
- Residual power supply cannot depend on storage alone, e.g. batteries/pumped hydro, since the capex is too large. Storing hydrogen is much cheaper on unit energy basis (price/kJ).

Risk sharing:

- A large international lender considered that the creating the opportunity to lend to hydrogen project developers should not be difficult to complete if the risk sharing was fairer between the project developers and offtakers. NEOM project in Saudi Arabia sets an example of risk sharing between developers and offtakers.
- An investor and a significant global financial institution confirmed that the majority of projects under consideration are in pre-construction phase and based on equity funding. The risk profile of these are project-specific and complex – maybe similar to O&G's LNG model.

Policy risk:

- Key to unlocking investment in hydrogen to power assets will be coherent policies covering the hydrogen value chain e.g., production, transportation, storage and application. Other policies could have knock-on effects as well e.g., REMA. Government should very carefully consider these impacts.
- Govt. shouldn't worry about creating new mechanisms. New mechanisms may also inadvertently overlap the existing CM. Government should signal policy support for the shift to hydrogen clearly so investors have confidence of its place in the future energy system. Investors are trying to get as much info as possible regarding strategy and business model. Need signals that the Government is genuinely behind this transition/tech as solution.

Financing of projects:

- The risk profiling for hydrogen projects is project-specific, not homogenous, more complex/varied than lots of parties have seen in the last decade. Probably closer to the O&G's LNG model. Therefore, projects are going for equity rather than debt for project financing.

Annex B: Modelling assumptions and approach

Market background scenarios and capacity mix

DESNZ have provided two market background scenarios in which outlooks of demand and capacity mix differ:

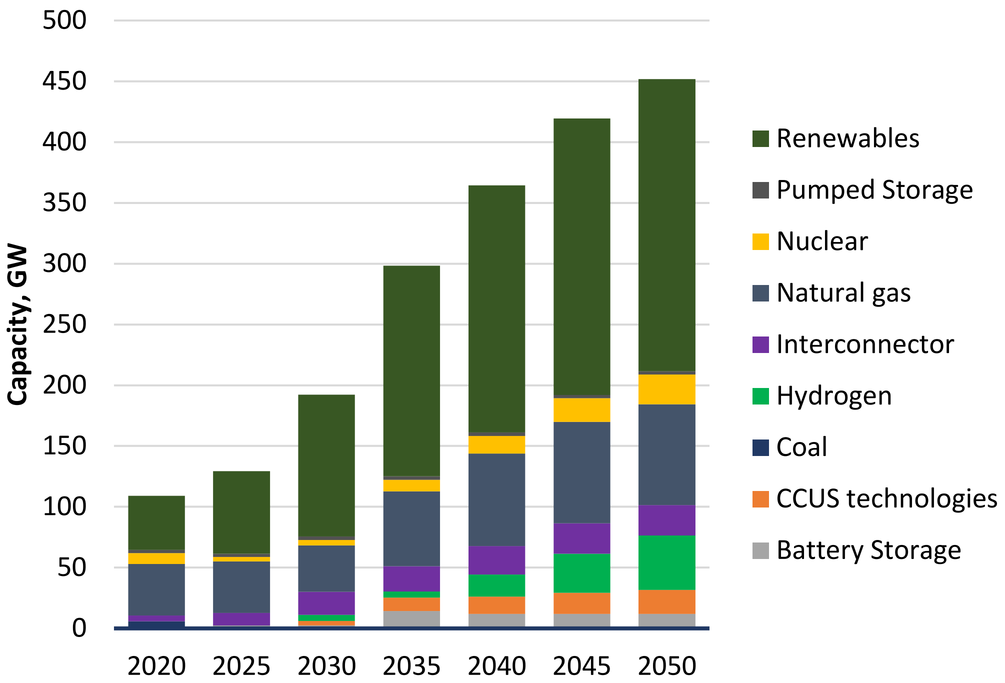
- Net Zero High Electrification
- Net Zero Low Electrification

Hydrogen generation capacity under both scenarios remains similar until the 2040s with capacity reaching 45GW by 2050 in the high electrification case and 35GW in the low case. The greater levels of hydrogen generation capacity will mean there is increased competition and therefore cannibalisation of revenues which could lead to higher levels of support being implied by the modelling.

DESNZ, separately to the reference case, provided assumptions for electrolyser capacity.

The DESNZ Net Zero High Electrification reference case is utilised in this analysis (high hydrogen generation capacity, low electrolysis capacity, high electricity demand scenario).

Figure 23: DESNZ Net Zero High Electrification reference case capacity mix



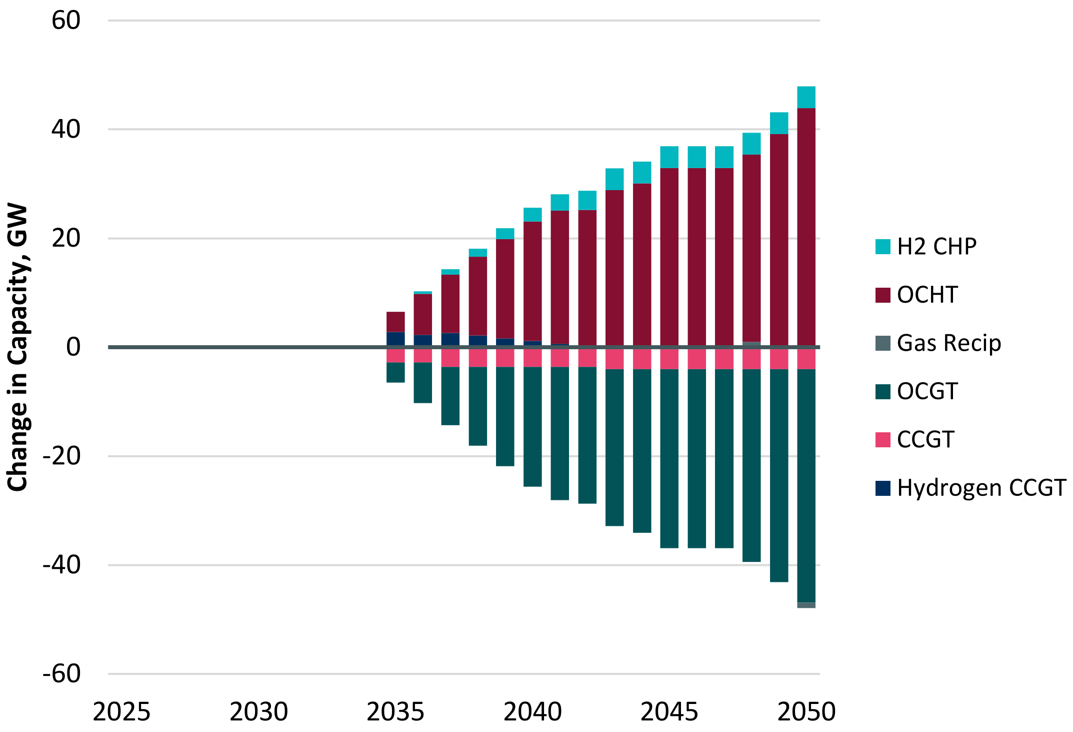
Source: DESNZ

LCP Delta have reviewed the reference case and made three modifications to this capacity mix:

- **Battery Storage** – the DESNZ reference case assumption for storage remains far below the committed levels of build in the capacity auctions that have taken place to date and as such are not credible. The assumptions for battery storage capacity have been increased based upon LCP Delta's internal modelling.
- **Hydrogen** – H2P generation in the reference case is assumed to be wholly CCHT, this has been refined to include additional H2P technology archetypes.
- **OCGT** – the DESNZ reference case assumes significant build-out of unabated OCGT capacity through to 2050 to meet security of supply requirements. Based upon the proposals sets out in the January 2023 CM consultation to strengthen CM emission limits from 1 October 2034 it has been assumed that no new unabated gas fired generation will be built from 2035 onwards. Additional OCHT build has been added to ensure security of supply requirements are met.

These changes have been made to ensure that the results for the technology archetypes are not biased by a lack of competition from similar units.

Figure 24: LCP Delta revisions to DESNZ Net Zero High Electrification reference case capacity mix



Source: LCP Delta

Technological assumptions

The subsidy levels, and (?) the required Capacity Market support payment for each archetype to break even, for the following four technology archetypes are examined:

- CCGT
- CHP
- OCGT
- Recip

These support levels are calculated assuming that each archetype run either wholly on hydrogen otherwise on a blend of hydrogen and natural gas. The hydrogen blend is defined as a 30% mix of hydrogen to 70% natural gas by volume.

The 30% hydrogen utilisation by volume assumption has been chosen to represent the less capital intensive operating model whereby existing assets undergo a limited retrofit to allow co-firing of natural gas with hydrogen. Due to the low energy density of hydrogen the 30% co-firing (by volume) assumption equates to a c.12% co-firing with hydrogen on an energy basis.

It is assumed that plant which utilise a blended hydrogen fuel retain the ability to run wholly on natural gas and are able to switch between the two fuels.

This 30% hydrogen by volume assumption aligns with the hydrogen readiness of existing large duty gas turbines[64].

The 100% hydrogen utilisation by volume assumption represents the more capital intensive route of either constructing a new build fully hydrogen ready generation asset or re-planting an existing asset.

[64] Siemens 'Hydrogen gas turbine readiness' whitepaper, https://www.siemens-energy.com/global/en/offerings/technical-papers/download-hydrogen-gas-turbine-readiness-white-paper.html

Table 16: Plant characteristics

Tech[65]	Hydrogen utilisation (volume %)	HHV Efficiency (%)	CAPEX (£/kW) – Low (DESNZ 2020 report)	CAPEX (£/kW) – High (2023 estimate)	Hurdle rate, pre-tax real (DESNZ 2020 report[66])
CCHT	30%, 100%	53%	New Build: 640 Refurb: 320	New Build: 857 Refurb: 429	7.5%
CHP	30%, 100%	60%[67]	New Build: 981 Refurb: 491	New Build: 1,315 Refurb: 657	9.0%
OCHT	30%, 100%	34%	New Build: 489 Refurb: 245	New Build: 655 Refurb: 328	6.8%
Recip	30%, 100%	32%[68]	New Build: 508 Refurb: 254	New Build: 681 Refurb: 340	7.1%

Source: LCP Delta

The Capex, Opex and hurdle rate assumptions outlined above are sourced from the 2020 DESNZ Generation costs publication[69].

Due to this report being released in 2020 the Capex estimates have become dated, to address this a high Capex estimate is also tested. The high Capex estimate is based upon the DESNZ assumptions increased by the change in US and EU materials indices between 2020 and 2023

[65] Reference technologies from DESNZ 2020 report are as follows: CCHT (CCGT H Class), CHP (CCGT CHP mode), OCHT (OCGT 299MW 500hr), Recip (Recip Gas 500 hrs)
[66] High hurdle rate sensitivity (increase of 2%) is also tested.
[67] Electrical efficiency, assuming operating in CHP mode and supplying useful heat
[68] Sourced from DESNZ assumptions, however this efficiency is lower than that achievable by newer gas reciprocating engine plant.
[69] DESNZ Generation Cost Report 2020, https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

Hydrogen availability

The volumes of hydrogen available to be used for electricity production is uncertain. DESNZ have provided a high and low case under which the levels of subsidy required for each technology archetype will be assessed.

Given the small number of plant capable of producing hydrogen, envisaged low capacity of available storage and issues with the development of a first of a kind technology, the occasional interruption of hydrogen flows will need to be accounted for. This will be reflected in the outage rates assumed for hydrogen generation plant which will change over time as the hydrogen market develops and sources of hydrogen production diversify.

Plant which are able to run wholly on hydrogen or a blend of hydrogen and natural gas will therefore be able to access hydrogen fuels with differing price and availability levels.

To model the dispatch of these plant the following algorithm is applied:

- Calculate the profitability of hydrogen and hydrogen blend plant based upon the subsidised hydrogen fuel price;
- Firstly, the limited quantity of subsidised hydrogen is assigned to the most profitable plant in the most profitable periods across each year;
- Secondly, the above process is then repeated layering in the available quantity of unsubsidised hydrogen; and
- Lastly dispatch plant capable of running on blended hydrogen in any remaining periods based upon its short-run marginal cost of running wholly on natural gas (if able to do so).

Early hydrogen plant will be able to access the two hydrogen price tiers mentioned above. Later plant, due to subsidised hydrogen volumes being fully subscribed, will only be able to access the unsubsidised hydrogen price otherwise run wholly on natural gas.

Locational hydrogen fuel availability constraints

The modelling did not take into account the local availability of hydrogen as was not in scope for this piece of work.

Hydrogen price

The price of hydrogen available for electricity production is uncertain and will depend upon:

- The underlying price of natural gas utilised to produce hydrogen via the steam methane reformation process;
- The cost of producing green hydrogen and whether this cost reflects the long-run marginal cost or short-run marginal cost of production; and

- The split of green and blue hydrogen assumed in future years.

DESNZ have provided low, medium and high cases for the price of both subsidised and unsubsidised hydrogen under which the levels of subsidy for the four technology archetypes will be assessed.

Transport and Storage Costs

Transportation and Storage (T&S) costs are accounted for in addition to the hydrogen price in the running costs of hydrogen to power generators. DESNZ have provided assumptions for T&S costs based upon their internal modelling with three price sensitivities utilised.

Carbon price

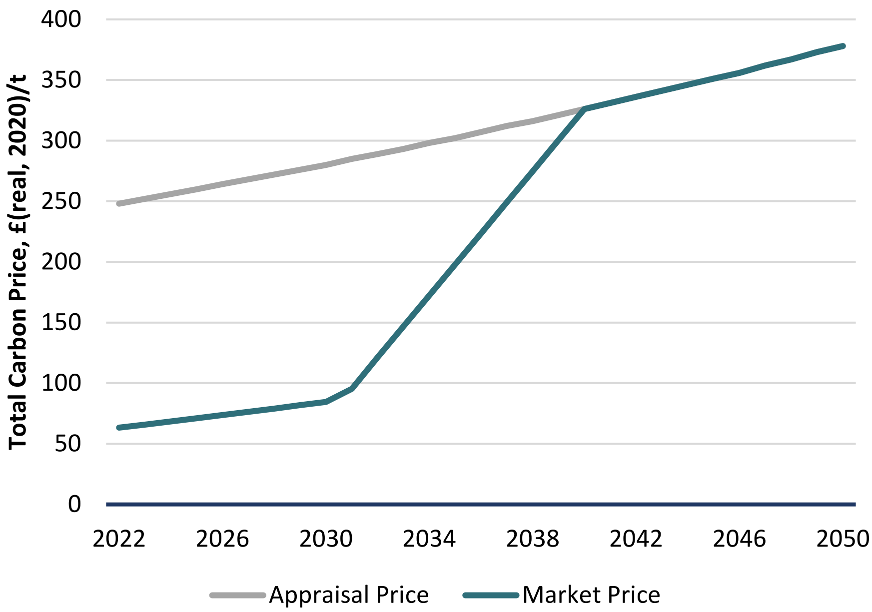
In this analysis the total carbon price is set to equal the DESNZ Net Zero High Electrification reference case market price of carbon.

In the early 2020s it represents the traded price of carbon before increasing from 2030 to equal the appraisal price of carbon from 2040 onwards.

It should be noted that:

- Prior to 2040 the full externalities of carbon emissions are not accounted for in the dispatch of fossil fuelled plant. Societal costs are not minimised prior to this;
- In the DESNZ reference case scenario the availability of subsidised hydrogen fuel is at its maximum between 2030 and 2040. In this period the carbon price assumption transitions between the traded price of carbon to the appraisal value (which represents the cost to society of emitting one tonne of carbon dioxide); and
- From 2040 onwards the full externalities of emitting hydrogen are accounted for in the dispatch of gas fired plant, in this period H2P generation using unsubsidised hydrogen will help to reduce wider societal costs.

Figure 25: Comparison of the market price of carbon to the appraisal value



Source: LCP Delta

Short-run Marginal Cost

The relative short-run marginal costs (SRMC) of CCGT, Power CCUS (CCS) and H2P plant vary depending on the hydrogen price scenarios.

The SRMC of CCHT plant running on subsidised hydrogen is either equivalent or lower than those of equivalent unabated CCGT plant in all scenarios.

Subsidised Hydrogen Price

Under the low subsidised hydrogen price scenario, the SRMC of CCHT becomes low enough to also displace Power CCUS (assuming 90% CO2 capture rate and a 6% reduction in efficiency due to the CCS process). Otherwise, the SRMC of a Power CCUS plant remains below that of CCHT in the medium and high subsidised hydrogen price scenarios.

The SRMC of OCHT remains above that of Power CCUS under all subsidised hydrogen price scenarios.

Unsubsidised Hydrogen Price

The SRMC of CCHT plant running on unsubsidised hydrogen are generally higher in the medium and high price scenarios than those of Power CCUS and CCGT plant.

In 2033 under the low hydrogen price scenario CCHT begins to displace CCGT plant, this crossover occurs later in 2043 for the medium price scenario whereas under the high price scenario CCHT remains above CCGT plant.

The SRMC of OCHT remains above that of Power CCUS under all unsubsidised hydrogen price scenarios.

Scenarios overview

In this analysis subsidy levels for wholly hydrogen-fired and blended hydrogen plant are examined under the following three scenarios:

- Low scenario – encompasses the 'low' views of subsidised, unsubsidised and T&S costs.
- Medium scenario – encompasses the 'medium' views of subsidised, unsubsidised and T&S costs.
- High scenario – encompasses the 'high' views of subsidised, unsubsidised and T&S costs.

T&S costs are added to both subsidised and unsubsidised hydrogen prices.

Table 17: Scenario overview

Scenario	Unsubsidised hydrogen price	Subsidised hydrogen price	Transport and Storage costs
Low	Low	Natural Gas price (Scenario B)	'lower'
Central	Medium	'central' (mid point of low and high)	'central'
High	High	Natural Gas Price (Scenario B) + carbon emissions cost	'higher'

Source: LCP Delta

Annex C: Modelling results

Given the exogenous H2P capacity assumptions used as an input to the modelling and provided by DESNZ, very low load factors are expected across all types of H2P plant post-2035. This is for three reasons:

- High renewable penetration (with significant growth from 2025 to 2035) means the need for generation from the flexible fleet reduces, despite this fleet growing due to an increasing need for firm capacity (due to demand growth);
- H2P capacity increases, cannibalising load factors until they are very low for each individual plant. This especially happens after 2035; and
- Subsidies for hydrogen decrease, meaning the cost of fuel increases.

Subsequently the financial needs case for investment for CCHT plants increases over time because of these declining load factors.

Note: the source for all charts in this section is LCP Delta modelling analysis.

Additional system-level results

Utilisation of subsidised hydrogen

The utilisation of subsidised hydrogen varies between the high and low availability scenarios.

Higher availability of subsidised hydrogen fuel results in greater utilisation in the low and medium price scenarios. In these scenarios the hydrogen price remains below the equivalent natural gas and carbon costs.

In the high price scenario there is no additional incentive to burn hydrogen relative to natural gas, so hydrogen use remains well below the level available, because it is not economic to run more.

Utilisation of unsubsidised hydrogen

The utilisation of unsubsidised hydrogen does not differ greatly between the high and low availability scenarios.

Apart from the period between 2035 and 2040 for the low availability scenario the limitations on the amounts of unsubsidised hydrogen available are not binding. Hence increasing the amount of available unsubsidised fuel has no impact to the dispatch of H2P plant.

In the low availability scenario between 2035 and 2040 there is a small increase in unsubsidised hydrogen fuel use in the low price scenario, in 2038 fuel use increased from 10TWh gas to 14.4TWh gas.

This aligns with a period of tightness in which demand is increasing rapidly and the deployment of hydrogen plant is beginning to accelerate. Beyond this point the increase in renewable capacity acts to limit the load factors of thermal generators which have higher short-run marginal costs and therefore restricts the usage of unsubsidised hydrogen.

Figure 26: Unsubsidised hydrogen utilisation in high availability scenarios

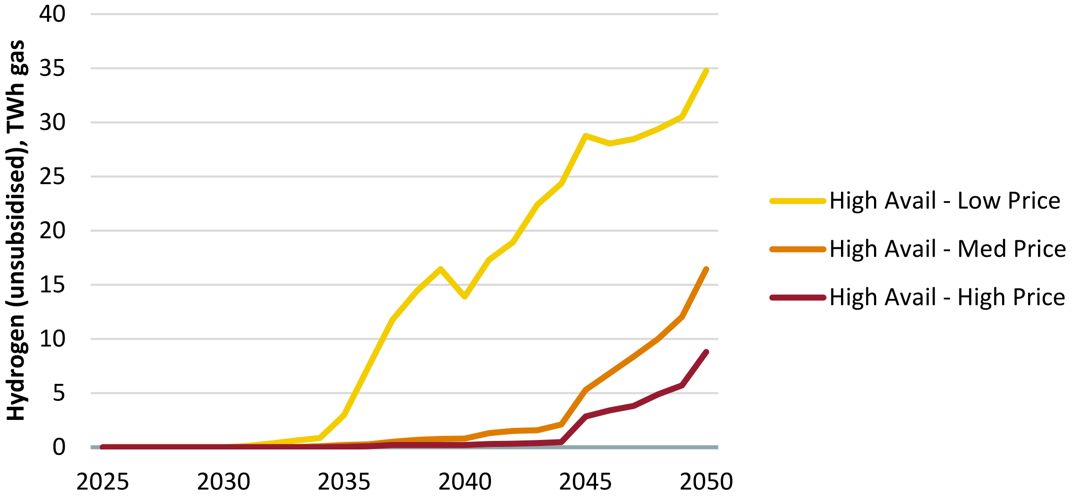
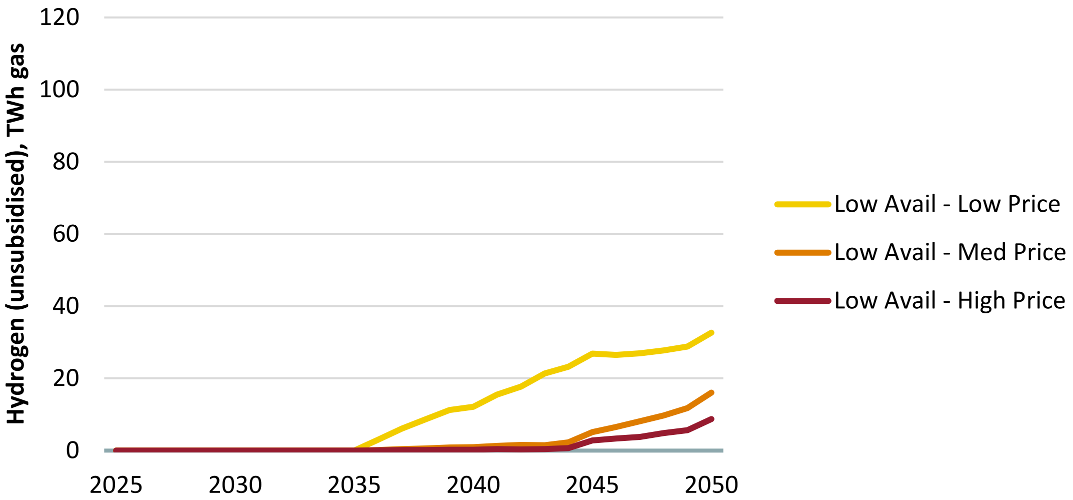


Figure 27: Unsubsidised hydrogen utilisation in low availability scenarios



Difference in generation mix

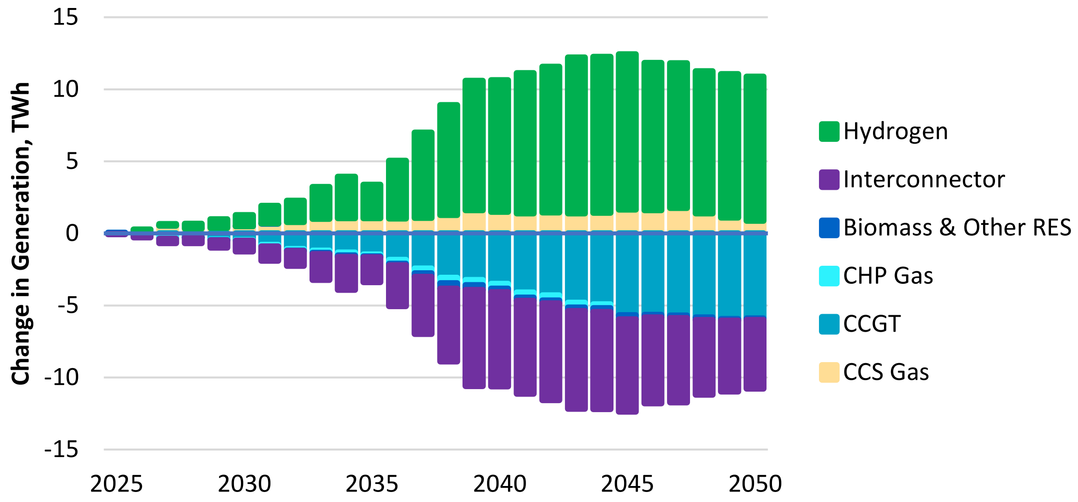
Contrasting the generation mix assuming low and high hydrogen prices under the low hydrogen availability scenario shows that:

- With lower hydrogen prices output from H2P plant increases as these units are able to displace other forms of thermal generation, particularly CCGT;
- Interconnector net imports decrease, facilitated by the increase in hydrogen-fuelled generation;
- Unabated CCGT generation is displaced in all years, suggesting significant CCGT generation under the high hydrogen price scenario through to 2050; and

- Power CCUS generation increases slightly, displacing generation from inflexible CCGTs that were incentivised to run by high hydrogen prices.

Note, to avoid unintended interactions we have assumed a low price for electrolyser dispatch, meaning it is not affected by changes in hydrogen price assumptions.

Figure 28: Difference in generation mix between low and high price scenarios assuming low hydrogen availability



Additional asset-level results

Load factors and revenues – CCHT (100% hydrogen)

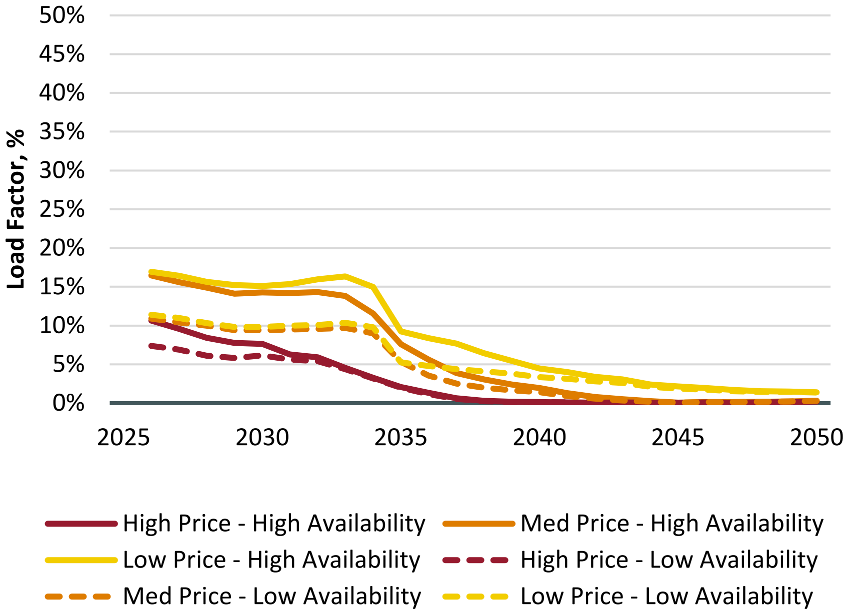
Load factors for CCHT remains low, under 20%, in all scenarios and years modelled. Prior to 2035 in the low hydrogen price high hydrogen availability scenario load factors remain above 15%, they then decline to below 5% by 2050.

The higher load factors pre-2035 are due to the availability of subsidised hydrogen and lack of other competing hydrogen plant. In this period availability of hydrogen is a limiting factor in the low and medium price scenarios.

The decline in load factors beyond 2035 is a result of:

- The increase in renewable capacity pushing thermal capacity further to the margins;
- The decrease in availability of subsidised hydrogen; and
- Build-out of newer CCHT.

Figure 29: Load factors for wholly hydrogen-fired CCHT

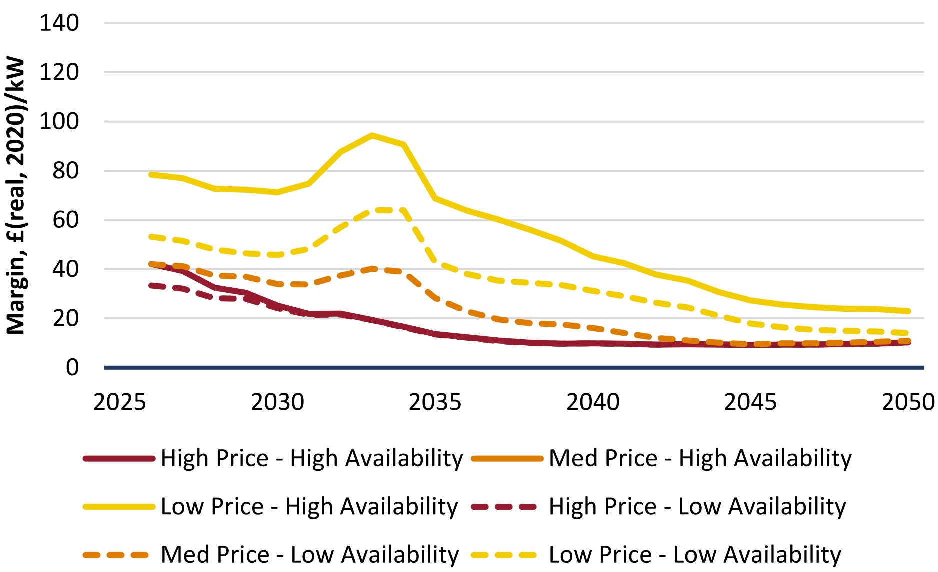


Revenues for CCHT mirror the load factors shown:

- Prior to 2035 whilst there is limited competition from other hydrogen plant (both in terms of revenue and for the limited amount of subsidised hydrogen fuel) revenues for the CCHT reach c. £80/kW pa in the low price scenario;
- Beyond 2035 due to the amount of competing new hydrogen plant coming online revenues decline to c. £20/kW pa in the low price scenario.

CCHT does not tend to be the marginal unit, as the most efficient H2P technology it is first to utilise the limited amount of subsidised hydrogen fuel available, as a result its level of participation and revenues in the balancing mechanism tends to be limited.

Figure 30: Margin for wholly hydrogen-fired CCHT (excludes CM payments)



Load factors and revenues – CCHT (hydrogen blend)

The load factors for CCHT utilising blended hydrogen fuel exceed those of their wholly hydrogen fuelled equivalents in the early years. This is because wholly hydrogen fuelled plant are restricted by the availability of hydrogen whereas hydrogen blend plant can run wholly on natural gas when economic to do so.

As the prices of both subsidised and unsubsidised hydrogen decrease so too do the load factors of CCHT utilising blended fuel. The decrease in hydrogen (subsidised) prices results in H2P plants displacing natural gas units in the merit order. Plants utilising a hydrogen blend fuel are mostly fuelled by natural gas (hydrogen component is c. 12% in terms of energy content)..

Figure 31: Load factors for CCHT utilising hydrogen blend

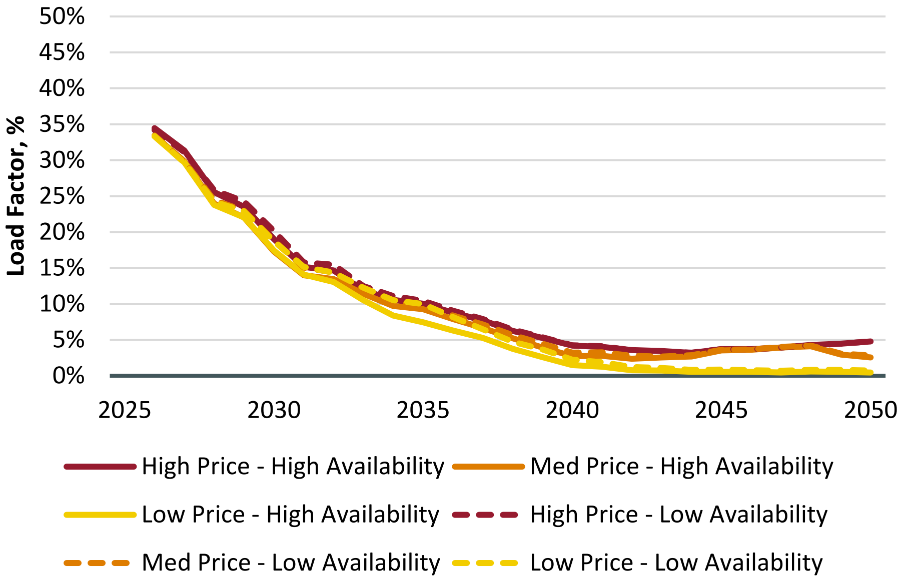
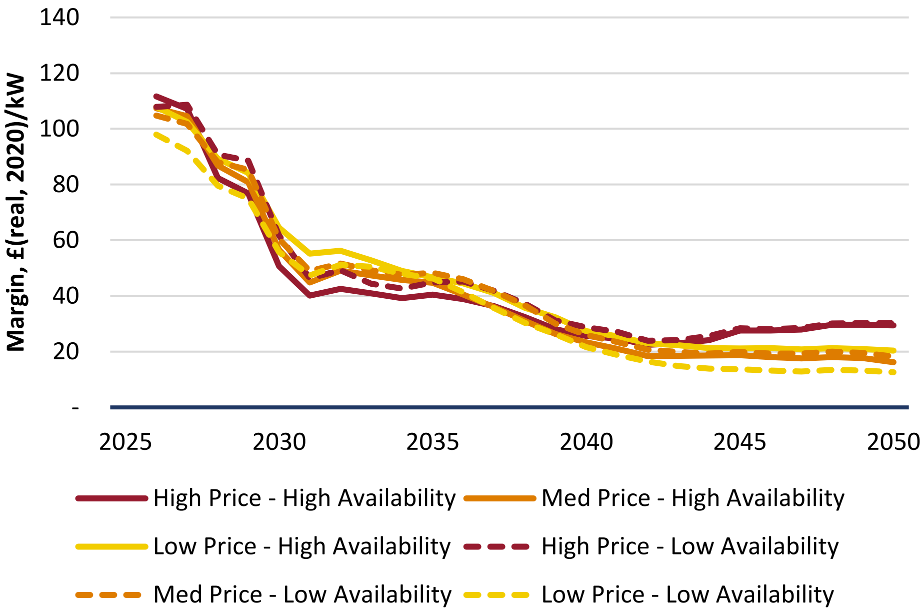


Figure 32: Margin for CCHT utilising hydrogen blend (excludes CM payments)



Load factors and revenues – CHP (100% hydrogen)

The load factors for the wholly hydrogen-fired CHP are higher than that for wholly hydrogen-fired CCHT because:

- Their higher efficiency means more generation from the same amount of hydrogen; and
- The asset is allocated more subsidised hydrogen as it is assumed that the most efficient plants are allocated higher volumes to maximise carbon displacement.

Figure 33: Load factors for wholly hydrogen-fired CHP

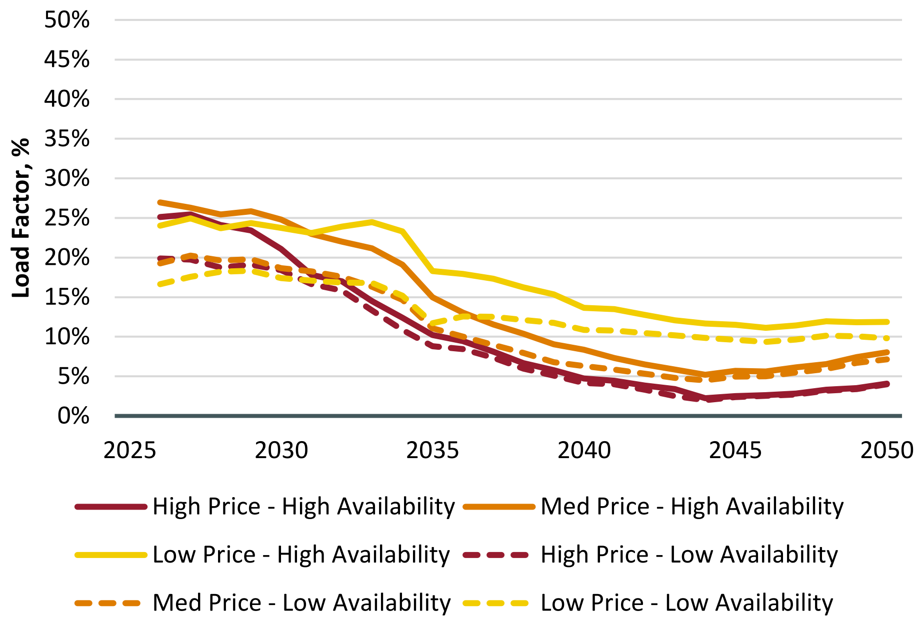
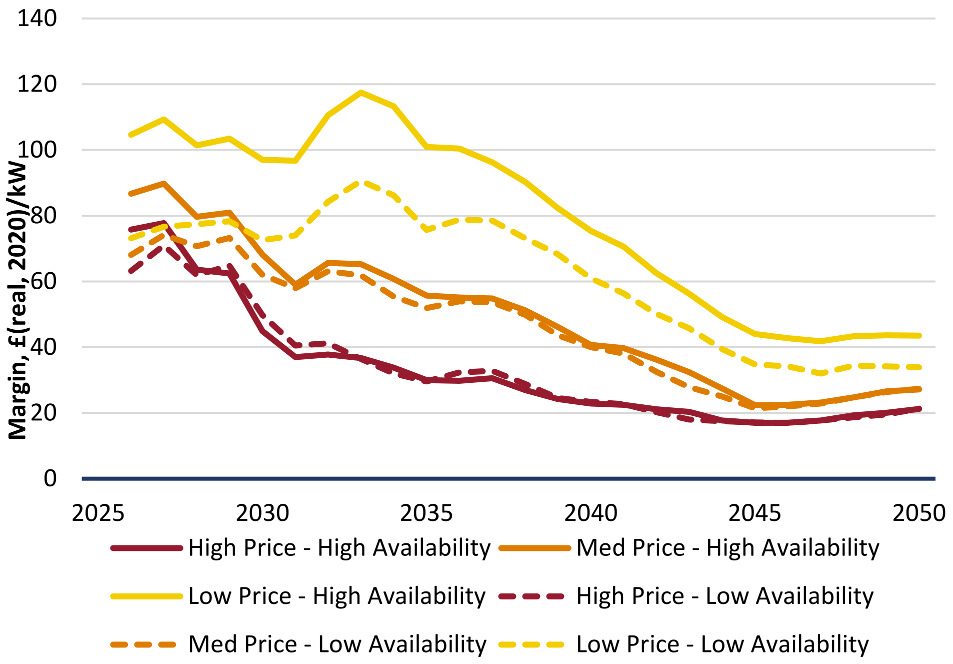


Figure 34: Margin for wholly hydrogen-fired CHP (excludes CM payments)



Load factors and revenues – CHP (hydrogen blend)

Similarly to CCHT, the load factors for CHP utilising blended hydrogen fuel exceed those of their wholly hydrogen fuelled equivalents in the early years. This is because wholly hydrogen fuelled plants are restricted by the availability of hydrogen whereas hydrogen blend plant can run wholly on natural gas when economic to do so.

As the prices of both subsidised and unsubsidised hydrogen decrease so too do the load factors of CHP utilising blended fuel. The decrease in hydrogen (subsidised) prices results in H2P plants displacing natural gas units in the merit order. Plants utilising a hydrogen blend fuel are mostly fuelled by natural gas (hydrogen component is c. 12% in terms of energy content).

Figure 35: Load factors for CHP utilising hydrogen blend

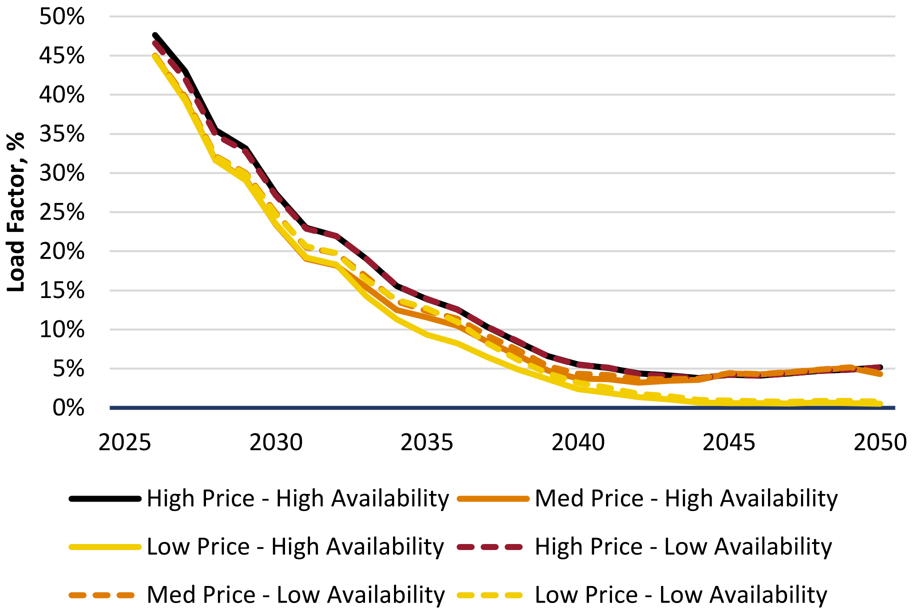
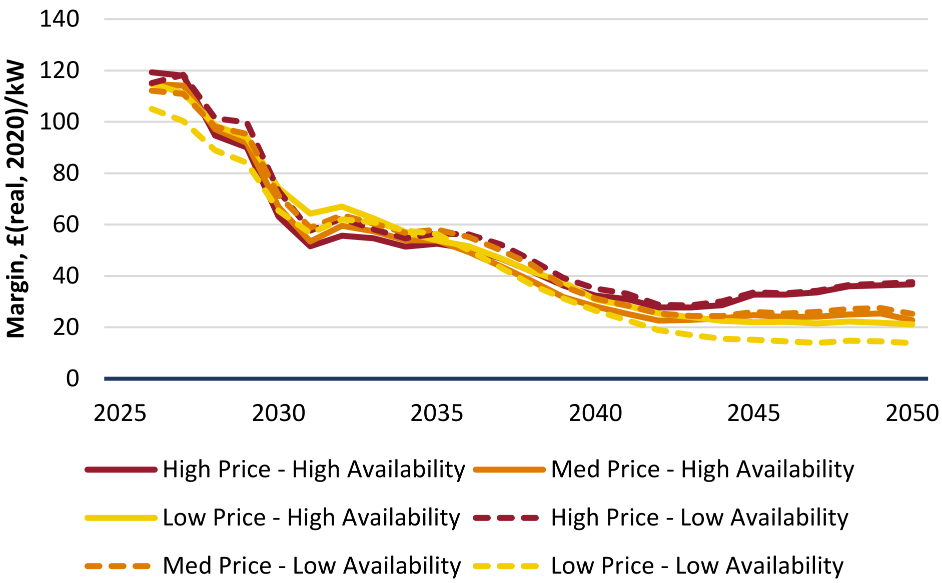


Figure 36: Margin for CHP utilising hydrogen blend (excludes CM payments)



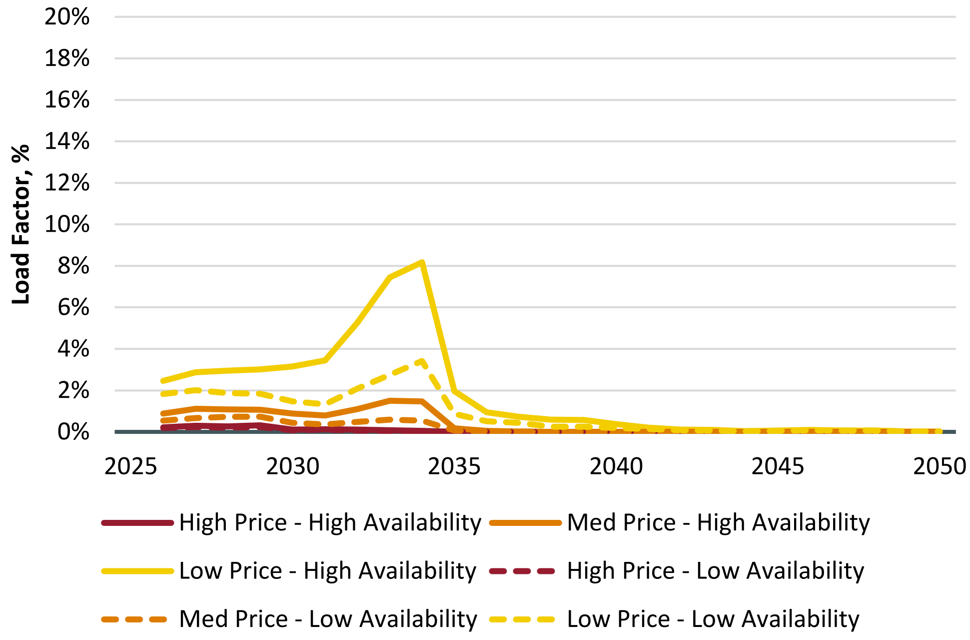
Load factors and revenues – OCHT (100% hydrogen)

The load factors of OCHT are much lower than the those of CCHT and CHP, prior to 2035 when competition from other H2P units is low load factors average around 4%. Due to their lower efficiency OCHT are allocated lower volumes of hydrogen (as to maximise carbon savings plant with higher efficiencies are allocated greater volumes of hydrogen) which limits their ability to generate.

Beyond 2035 due to the influx of competition from H2P peaking and mid-merit plant load factors reduce to almost zero.

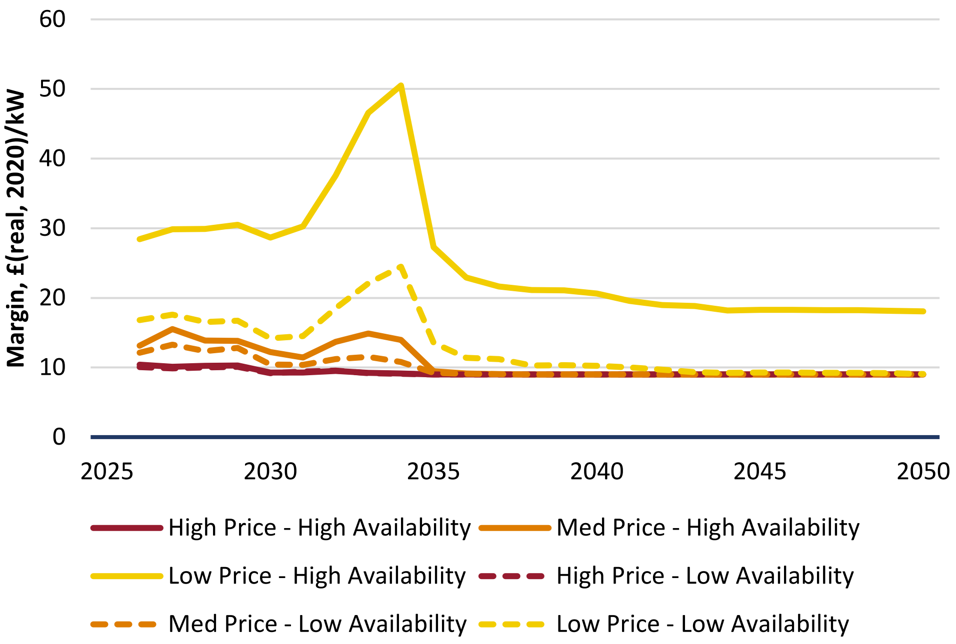
There is a peak in load factors in the early 2030s as the OCHT is able to access subsidised hydrogen fuel and displace natural gas fired units in this period (when the carbon price is rising significantly to reach the appraisal value by 2040).

Figure 37: Load factors for OCHT utilising hydrogen blend



Due to their low load factors margins for OCHT remain low in all years and in all scenarios. This in turn means that the level of subsidy required for OCHT plant is mostly set by the assumed levels of capex and hurdle rates required.

Figure 38: Margin for wholly hydrogen-fired OCHT (excludes CM payments)



Load factors and revenues – OCHT (30% by volume hydrogen blend)

The load factors of OCHT fuelled by blended hydrogen are slightly higher than those of their wholly hydrogen fuelled equivalents in the early years. This results from the assumption of blended plant being able to run wholly on natural gas and so are not restricted by the limited availability of hydrogen initially.

Figure 39: Load factors for OCHT utilising hydrogen blend

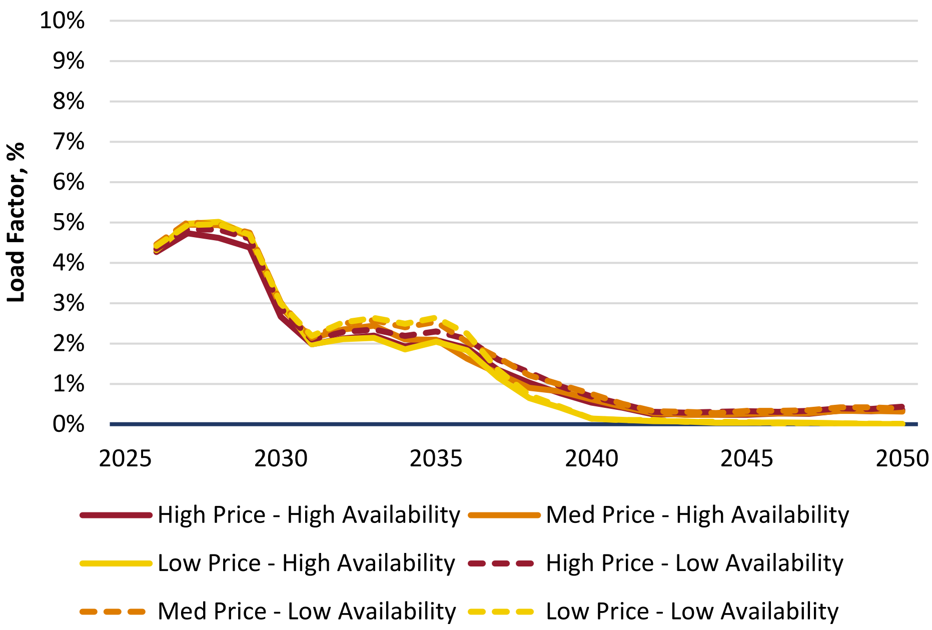
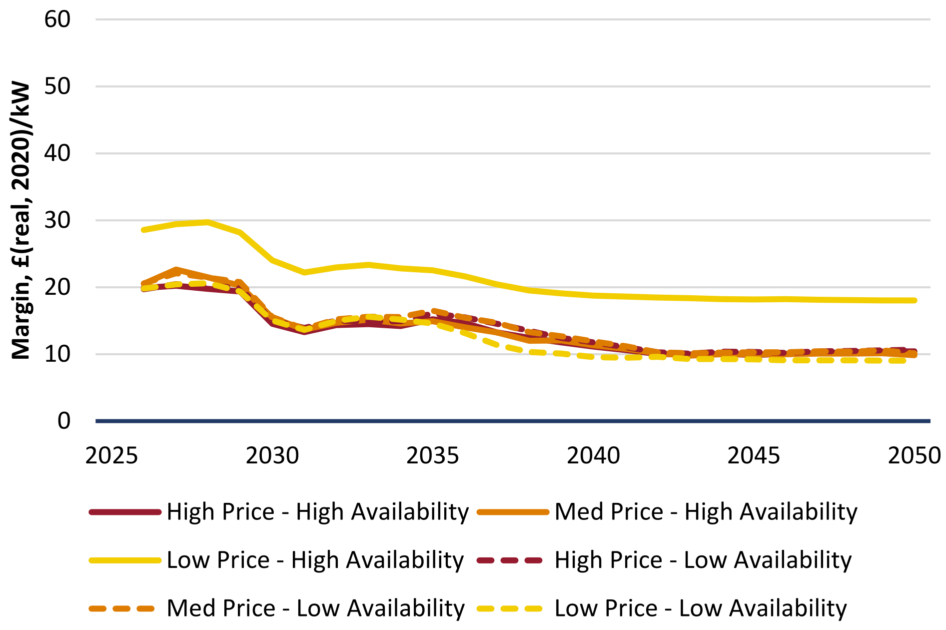


Figure 40: Margin for OCHT utilising hydrogen blend (excludes CM payments)



Load factors and revenues – Recip (100% hydrogen)

The load factors for wholly hydrogen fuelled recips are similar to those for OCHT (with the assumed efficiency of recip units being close to but slightly lower than that of OCHT). In all years and for all scenarios the load factors for recips remain low, there is a slight peak in the early 2030s as the access to subsidised hydrogen allows these peaking units to displace natural gas fired plants (as in this period the carbon price climbs rapidly to meet the appraisal value in 2040).

The influx of competition from other hydrogen peaking assets post 2035 reduces load factors to near zero.

Figure 41: Load factors for Recip utilising hydrogen blend

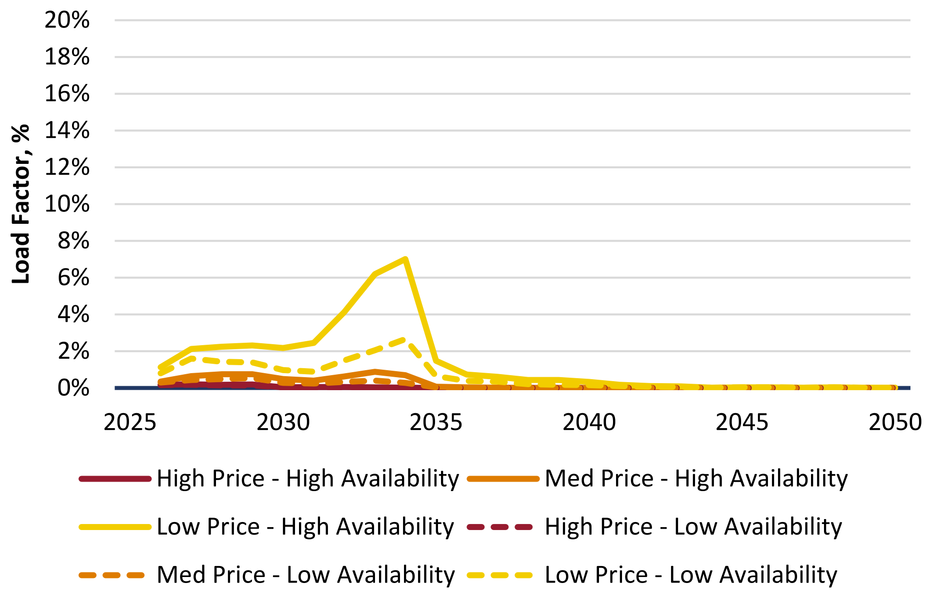
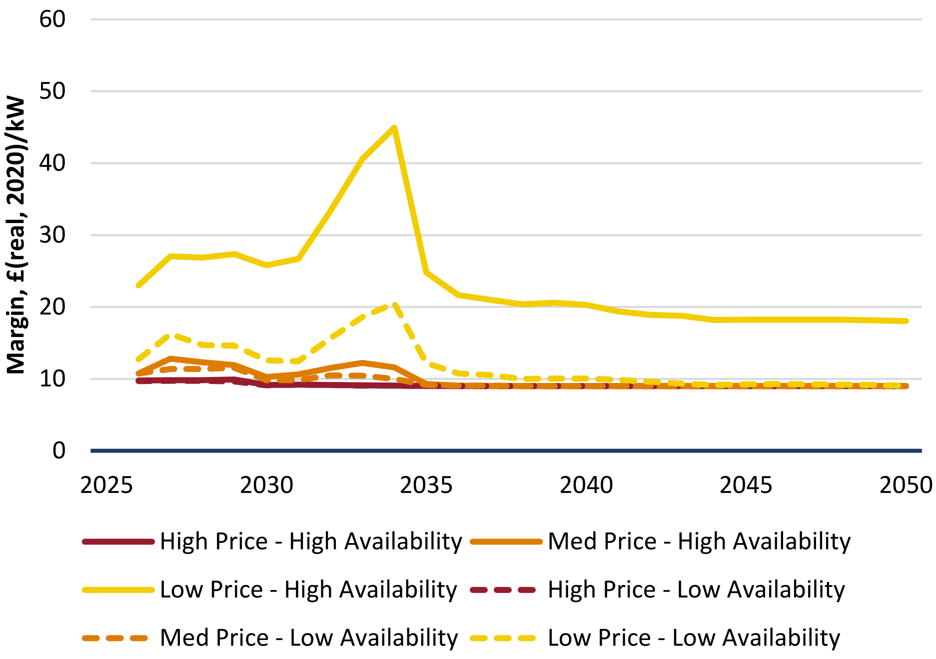


Figure 42: Margin for wholly hydrogen-fired Recip (excludes CM payments)



Load factors and revenues – Recip (30% by volume hydrogen blend)

The load factors of recips fuelled by blended hydrogen are slightly higher than those of their wholly hydrogen fuelled equivalents in the early years. This results from the assumption of blended plants being able to run wholly on natural gas and so are not restricted by the limited availability of hydrogen initially.

Figure 43: Load factors for Recip utilising hydrogen blend

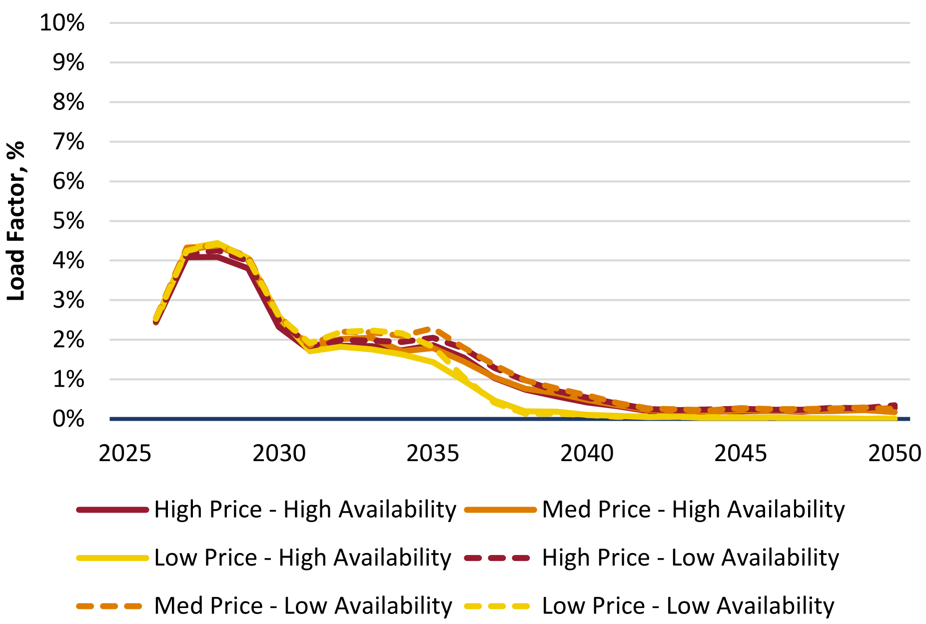
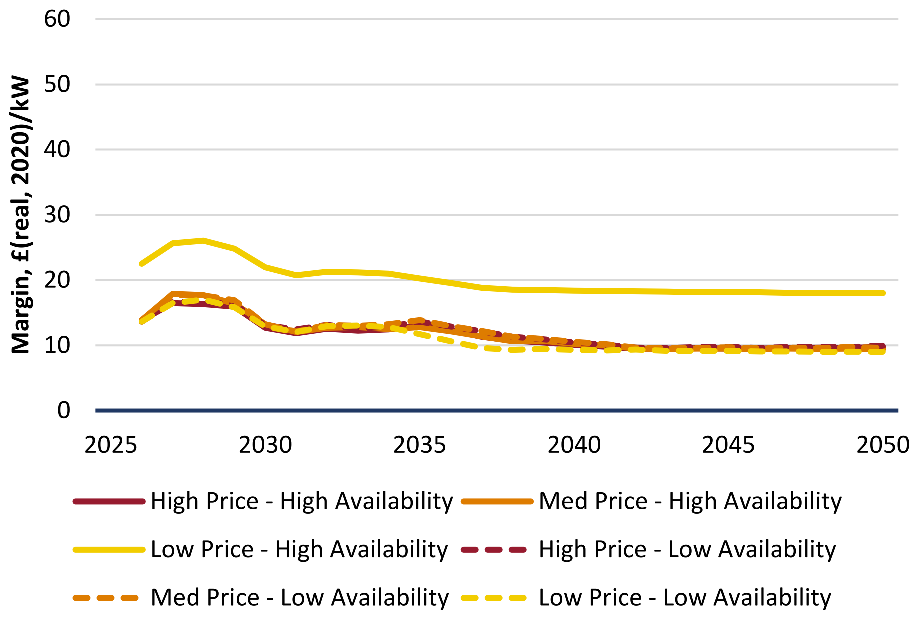


Figure 44: Margin for CHP utilising hydrogen blend (excludes CM payments)



CM Support – CCHT

The support levels calculated, based upon the modelled gross margin results, under differing capex and hurdle rate assumptions are shown below. The support takes the form of a £/kW pa 15-year contract (i.e. in line with the form of existing new build capacity market contracts).

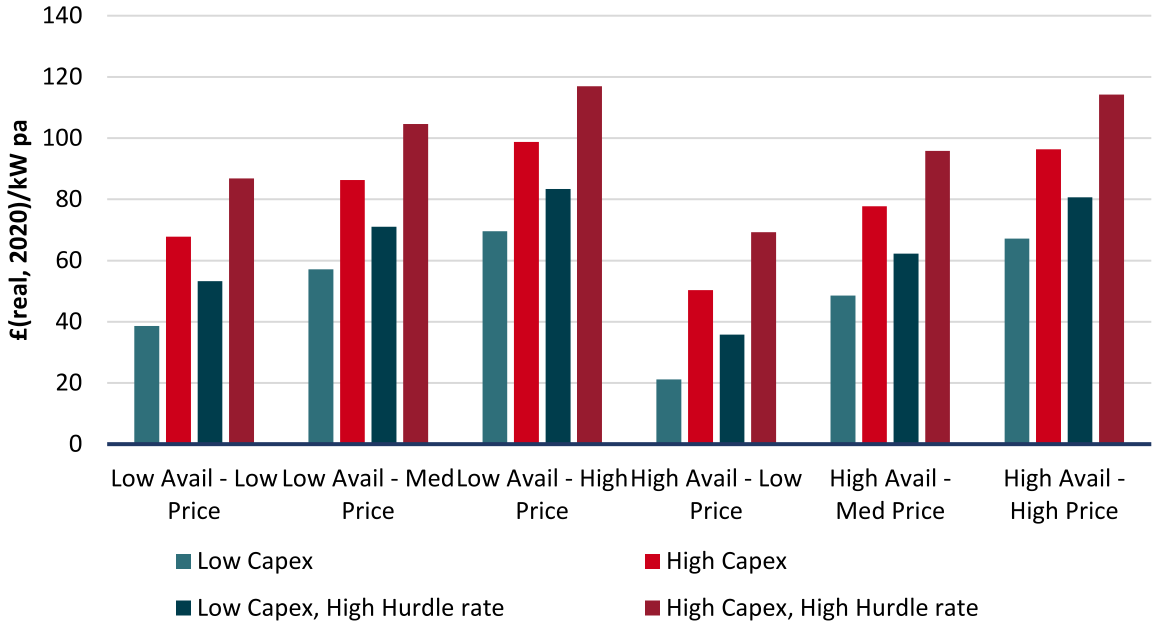
It should be noted that in addition to this support, payment hydrogen plants also receive additional support through the subsidised price of hydrogen.

In terms of capital assumptions for CCHT:

- The low capex assumption of £640/kW is based on medium level from DESNZ's 2020 generation cost report. The central hurdle rate of 7.5% is also sourced from this report;
- The high capex assumes a 34% increase to 2023 levels (in real terms) to reflect significant recent rises in material costs; and
- A further sensitivity increasing hurdle rates by 2% is also included (i.e. 9.5% for CCHT)

The support levels for new build CCHT range from £21/kW pa (low capex in the high availability, low price scenario) through to £117/kW pa (high capex and high hurdle rate in the low availability, high price scenario).

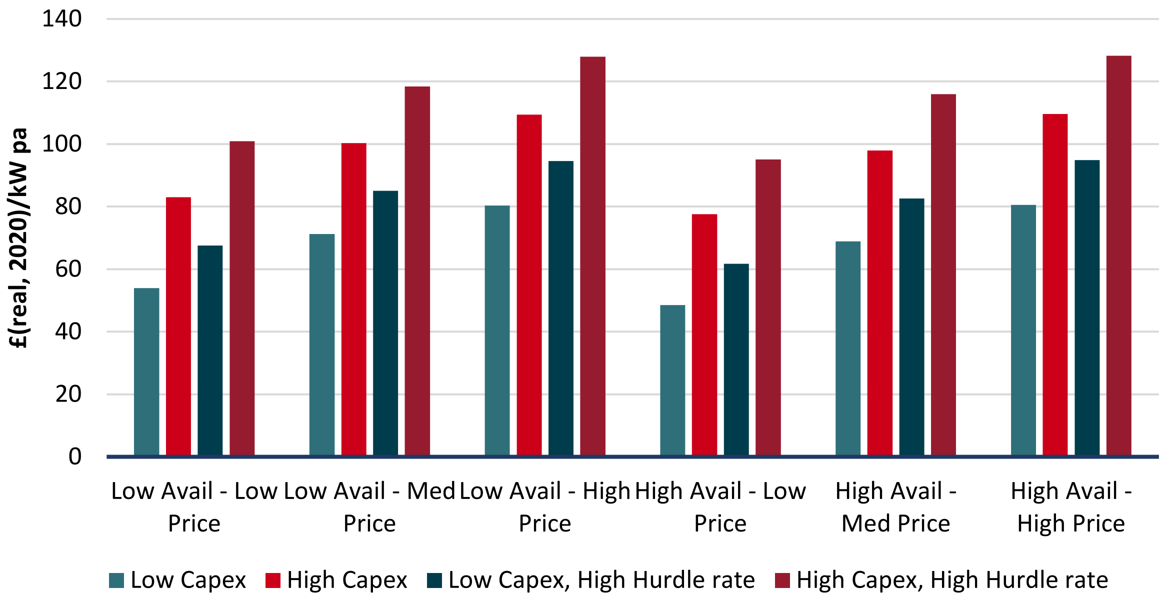
Figure 45: CM support required for new build CCHT commissioning in 2026 assuming 100% hydrogen-fired



CCHT assets which commission later in 2035 require higher levels of support than their 2026 counterparts (both 100% H2 and 30% blend).

Prior to 2035 the total amount of H2P capacity remains low, beyond 2035 the deployment of hydrogen generation increases significantly. Due to the increasing levels of competition from newer H2P capacity, hydrogen plants commissioning in 2035 capture lower energy market revenues and therefore require higher levels of support.

Figure 46: CM support required for new build CCHT commissioning in 2035 assuming 100% hydrogen-fired



In general, assets making use of blended hydrogen fuel require lower levels of support. These assets can choose to run wholly on natural gas when economic to do so and so the limited availability of hydrogen presents less of a restriction to their dispatch. This increased flexibility allows blended assets to capture greater revenues in energy markets.

The high hydrogen availability, low hydrogen price scenario is an exception in which lower levels of support are required by wholly hydrogen-fired plants. In this instance being able to access large quantities of subsidised hydrogen fuel (resulting in SRMCs well below those of unabated gas plant) allows these assets to capture higher energy market revenues than their blended fuel counterparts.

Figure 47: CM support required for new build CCHT commissioning in 2026 assuming hydrogen blend

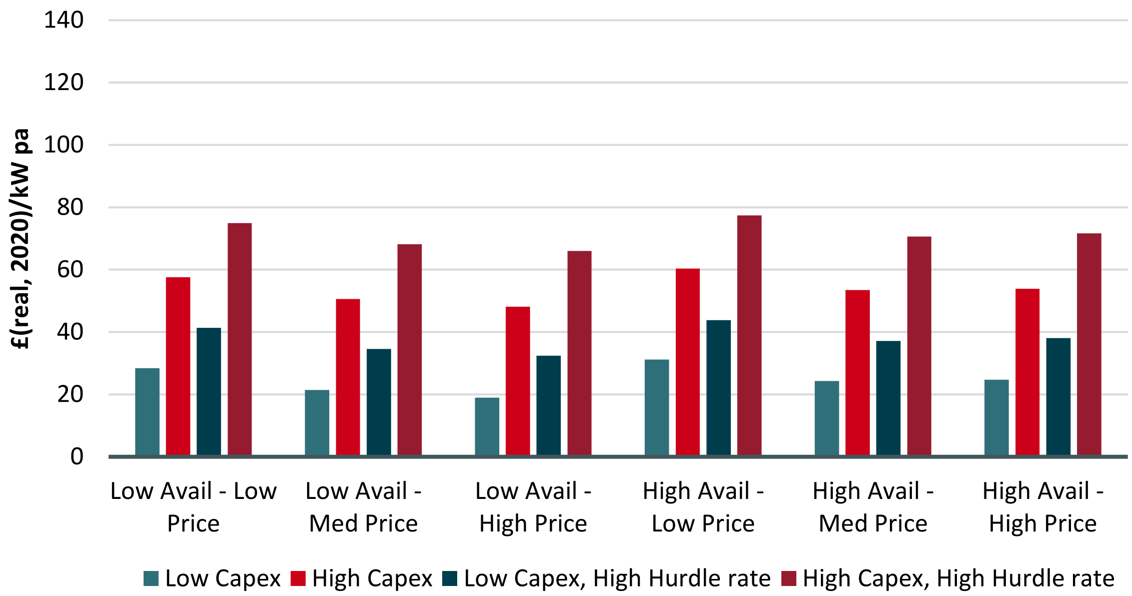
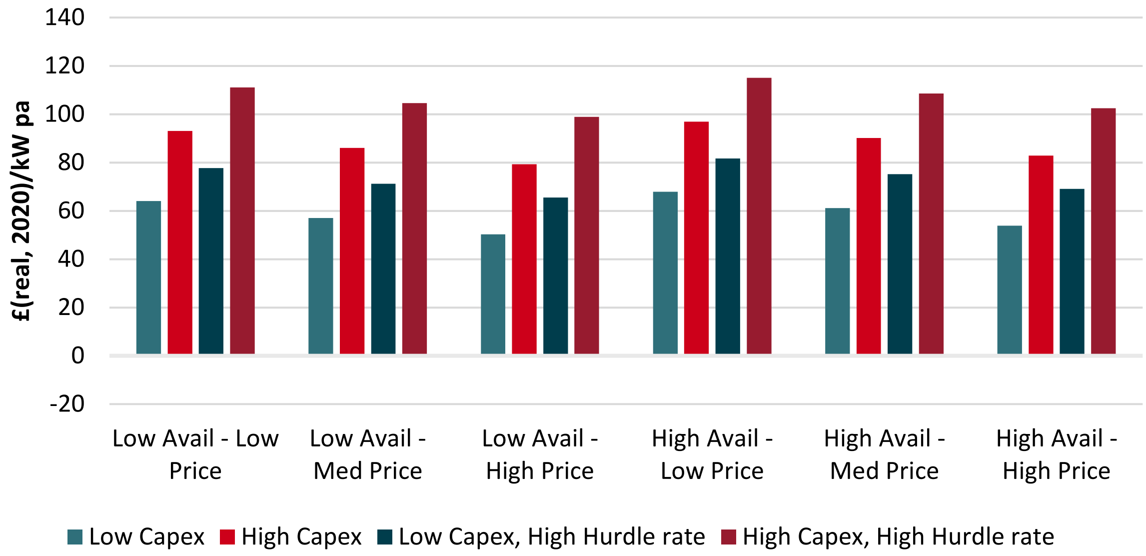


Figure 48: CM support required for new build CCHT commissioning in 2035 assuming hydrogen blend



The deployment of H2P generation can also be achieved through the refurbishment of existing generation assets. Based upon industry feedback, it is assumed that the refurbishing capex is half that of new build. It is conservatively assumed that refurbishment extends life by 10 years (relative to the 25-year life for new build).

As a result, the support levels required for refurbishing assets are significantly lower than those for new build.

Figure 49: CM support required for refurbishing CCHT commissioning in 2026 assuming 100% hydrogen-fired

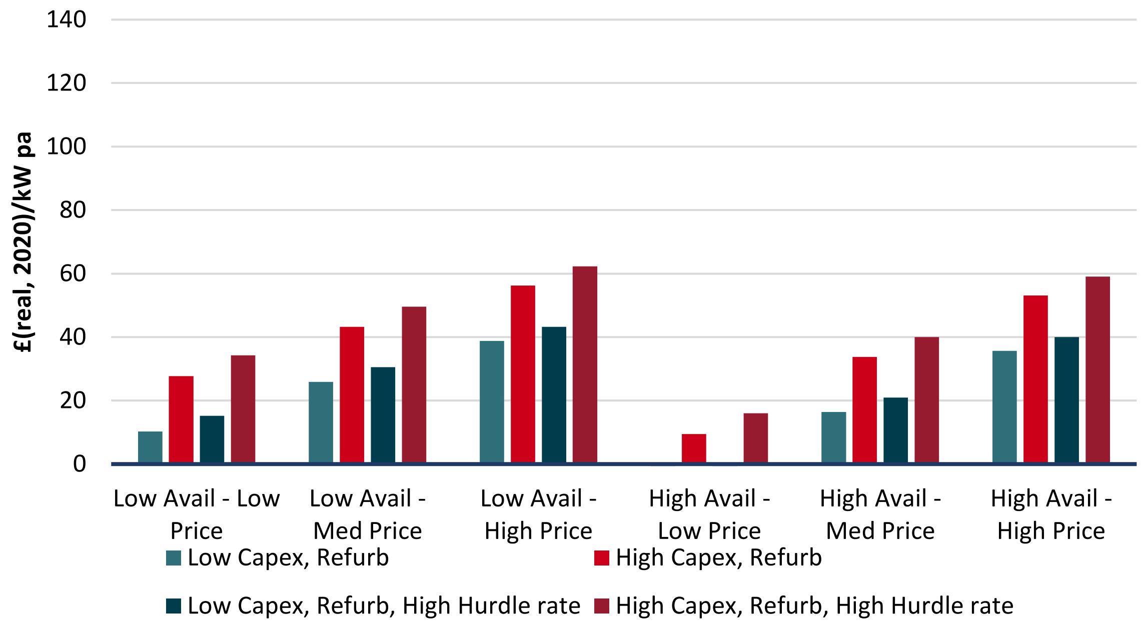
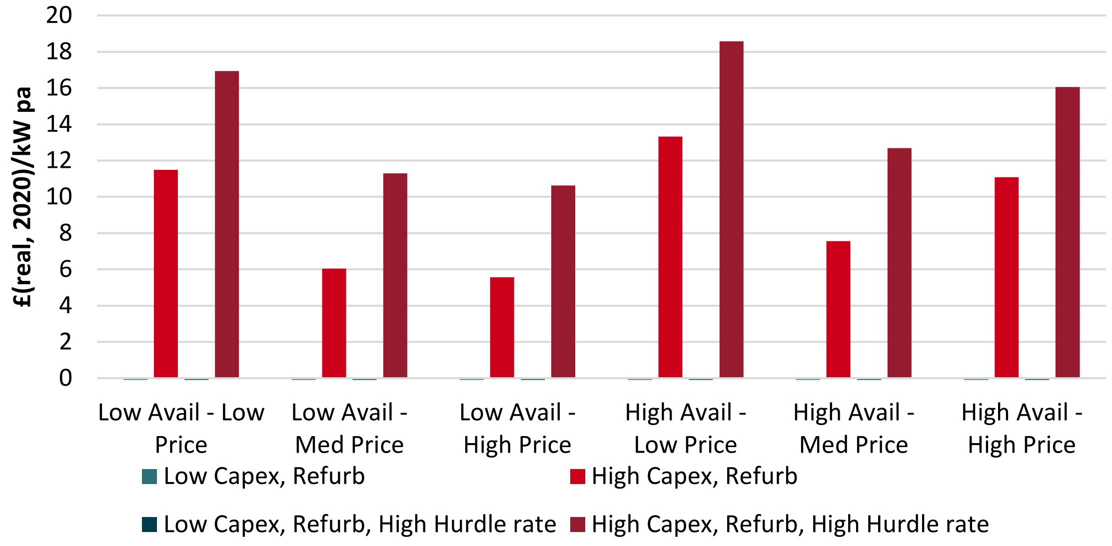


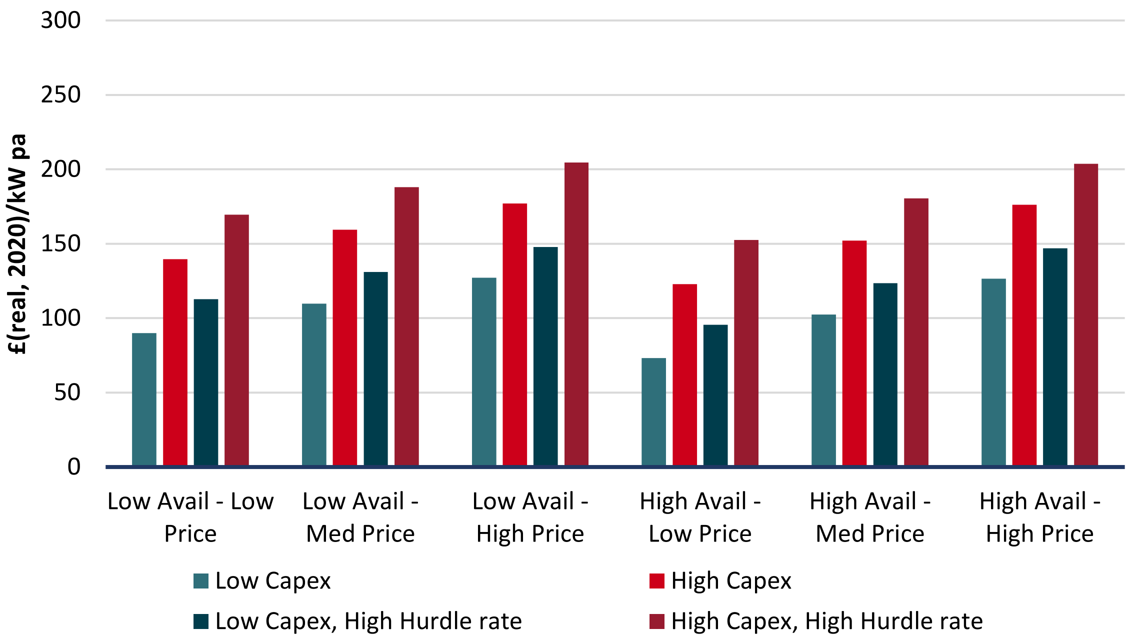
Figure 50: CM support required for refurbishing CCHT commissioning in 2026 assuming hydrogen blend



CM Support – CHP

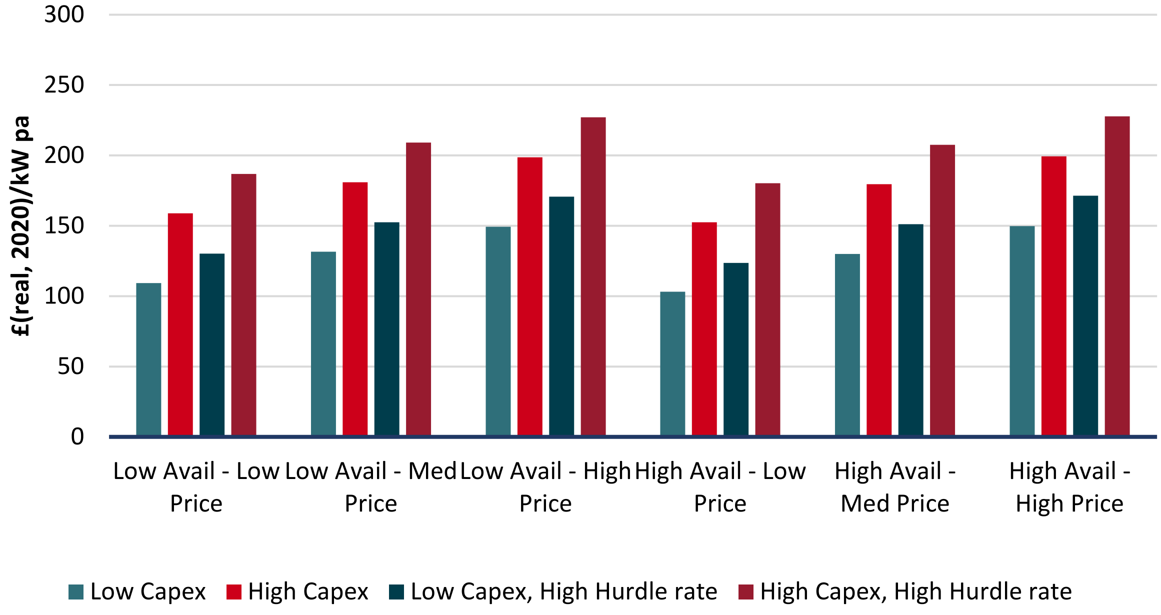
Required support levels for Hydrogen CHP assets are much higher than those for CCHT, despite higher energy market revenues and load factors. This is due to much higher capex levels (£981/kW low, £1315/kW high), and higher hurdle rate assumptions (9% and 11%).

Figure 51: CM support required for new build CHP commissioning in 2026 assuming 100% hydrogen-fired



Hydrogen CHP assets commissioned in 2035 require higher levels of support than their 2026 counterparts (both 100% hydrogen and 30% hydrogen blend).

Figure 52: CM support required for new build CHP commissioning in 2035 assuming 100% hydrogen-fired



Results show that prices for CHPs between blended and 100% hydrogen-fired are similar. (In comparison, there's a large difference in required price between blended CCHTs and 100% hydrogen-fired CCHTs). Slightly higher support levels are required for the blended asset in the low-price scenarios and some of the medium price scenarios. This reflects the advantages of a more efficient unit which can make use of low-cost subsidised hydrogen.

Figure 53: CM support required for new build CHP commissioning in 2026 assuming hydrogen blend

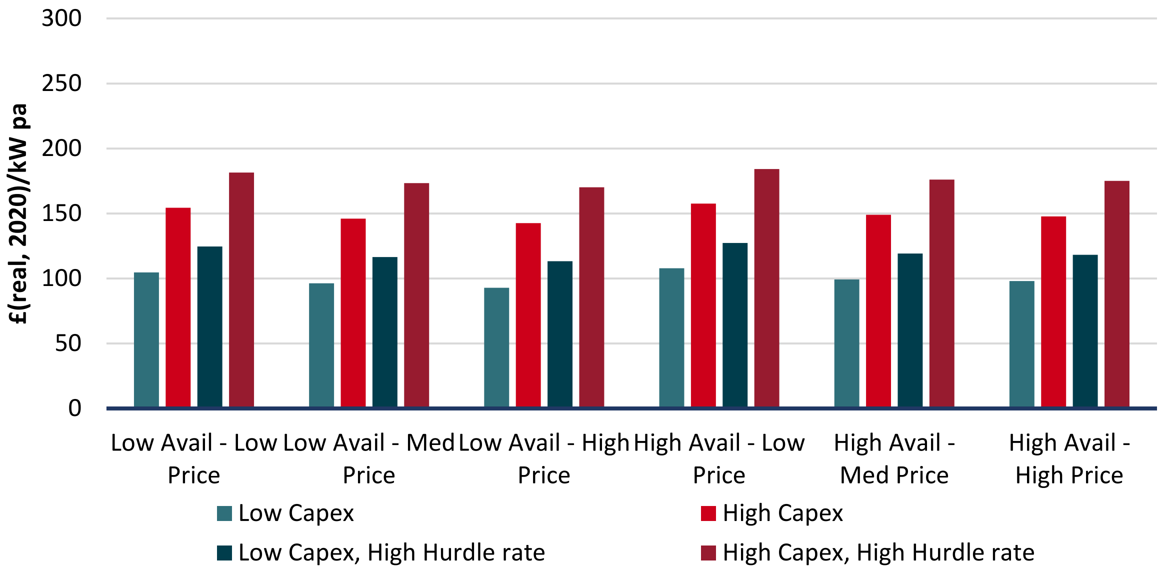
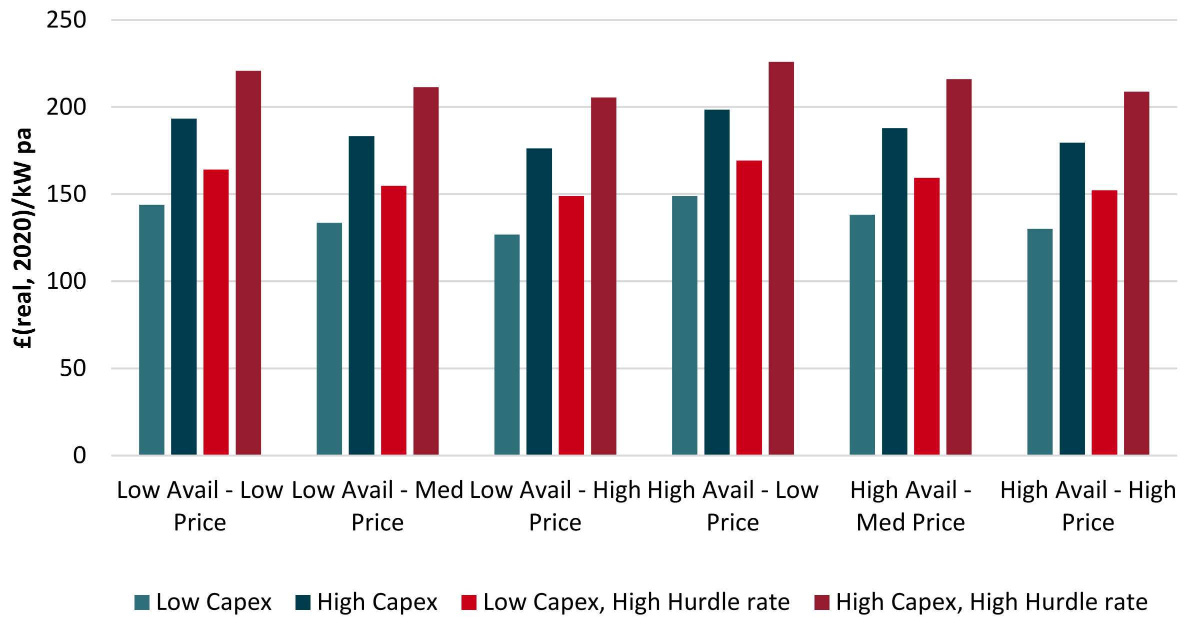


Figure 54: CM support required for new build CHP commissioning in 2035 assuming hydrogen blend



The deployment of H2P generation can also be achieved through the refurbishment of existing generation assets. Based upon industry feedback it is assumed that the refurbishing capex is half that of new build. It is conservatively assumed that refurbishment extends life by 10 years (relative to the 25-year life for new build). As a result, the support levels required for refurbishing assets are significantly lower than those for new build.

Figure 55: CM support required for refurbishing CHP commissioning in 2026 assuming 100% hydrogen-fired

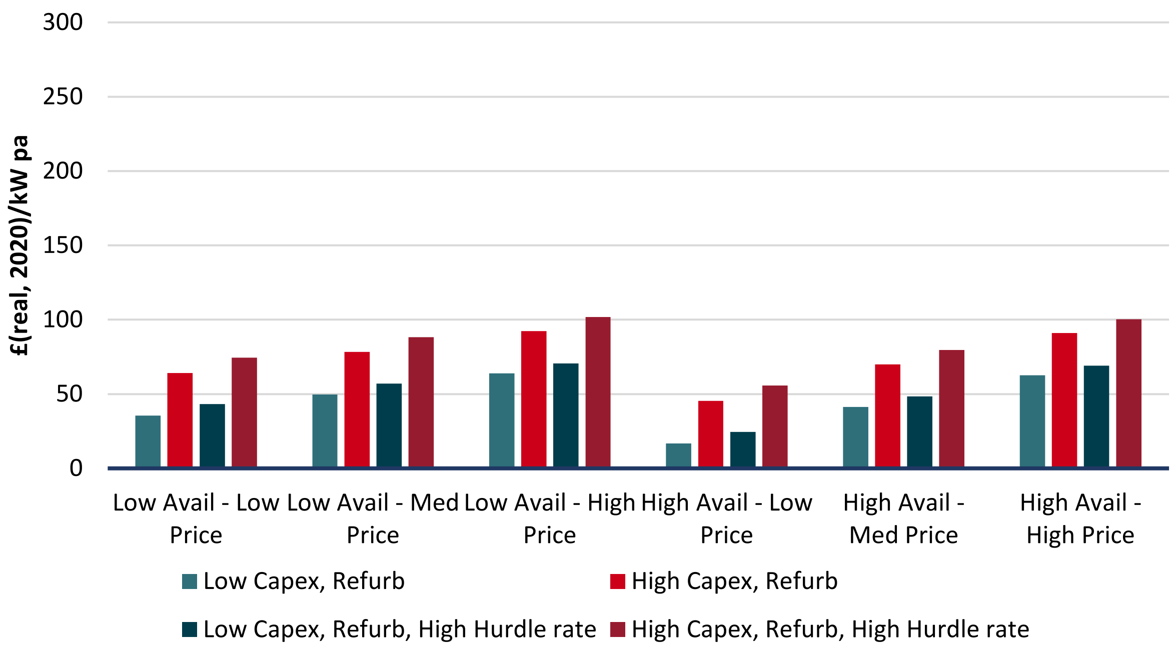
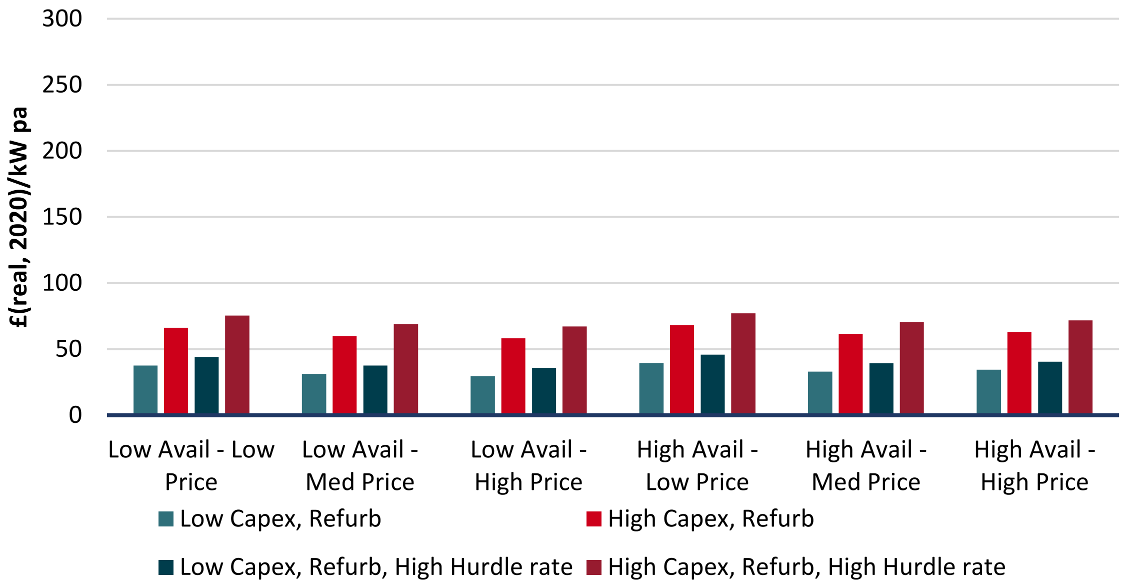


Figure 56: CM support required for refurbishing CHP commissioning in 2026 assuming hydrogen blend



CM Support – OCHT

New build OCHT require levels of support ranging from £40/kW to £77/kW. At the lower end of this range (low capex and hurdle rate assumptions) these compare favourably with the 2026/27 CM T-4 clearing price of £63/kW pa.

The level of support required by a new build OCHT commissioning later in 2035 is similar to that for plant building in 2026. This is as a result of their low load factors; the CM payments are mainly utilised to cover the capex costs incurred.

Figure 57: CM support required for new build OCHT commissioning in 2026 assuming 100% hydrogen-fired

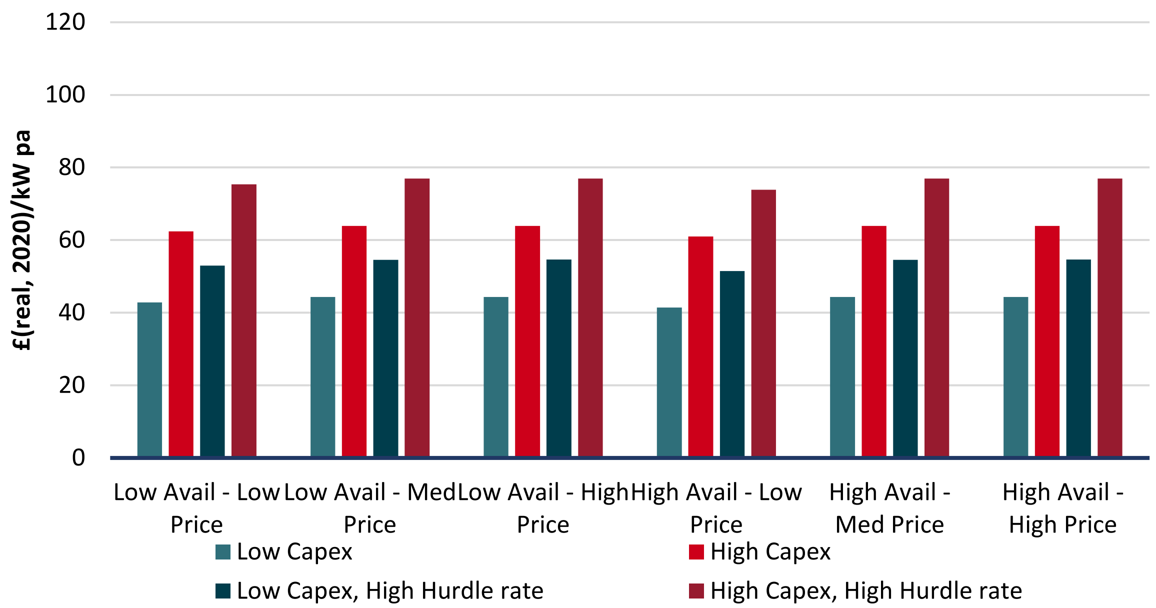
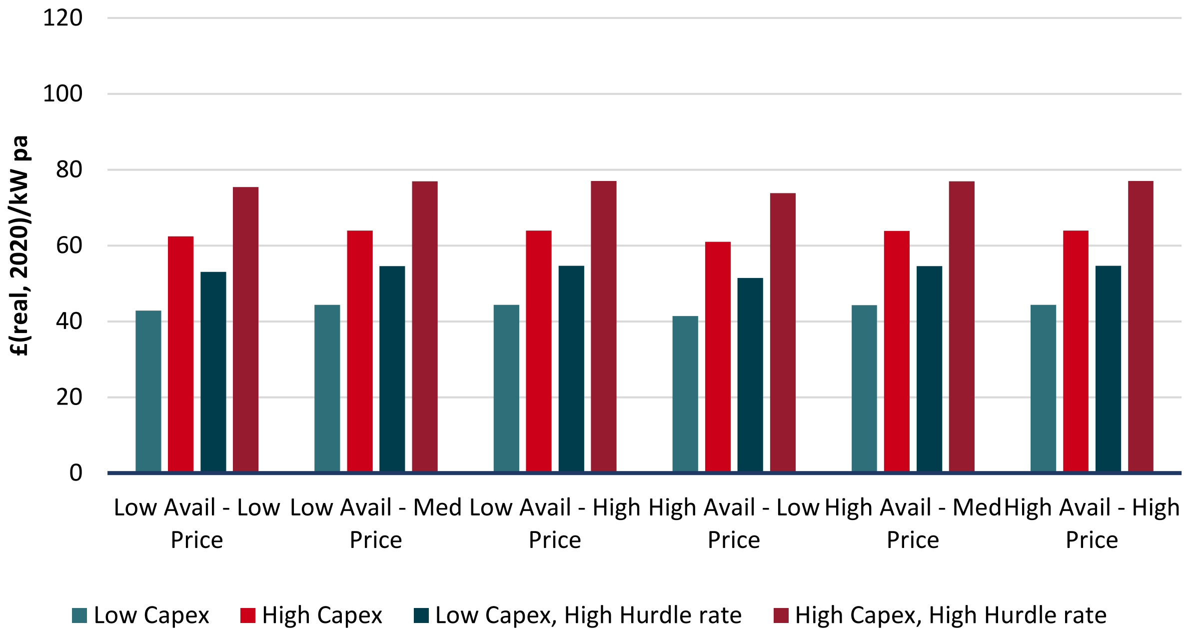


Figure 58: CM support required for new build OCHT commissioning in 2035 assuming 100% hydrogen-fired



The 30% blended assets' lower fuel restrictions (that is, their ability to run on 100% natural gas when opportune) result in slightly lower levels of required support in all scenarios.

Figure 59: CM support required for new build OCHT commissioning in 2026 assuming hydrogen blend

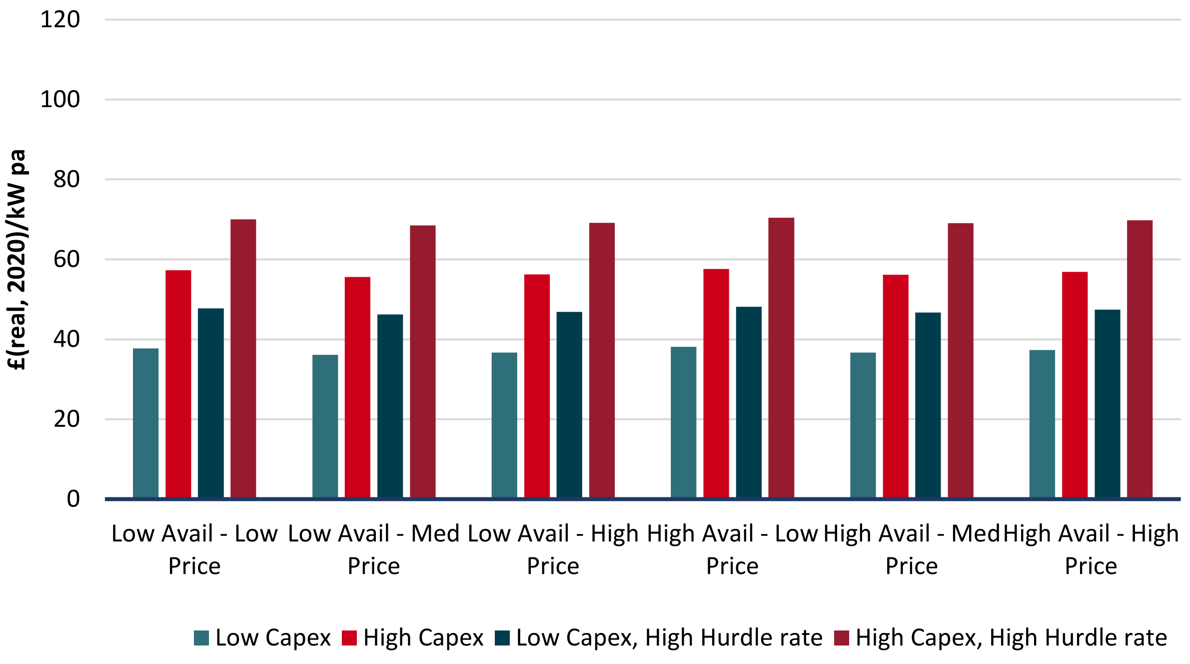
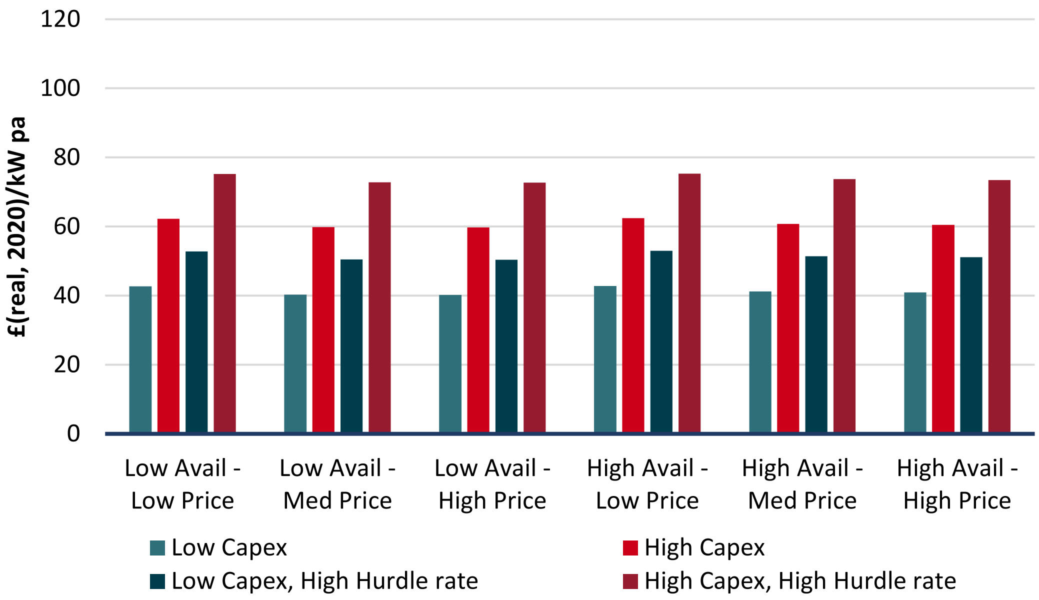


Figure 60: CM support required for new build OCHT commissioning in 2035 assuming hydrogen blend



The deployment of H2P generation can also be achieved through the refurbishment of existing generation assets. Based upon industry feedback, it is assumed that the refurbishing capex is half that of new build. It is conservatively assumed that refurbishment extends life by 10 years (relative to the 25-year life for new build).

As a result, the support levels required for refurbishing assets are significantly lower than those for new build.

Figure 61: CM support required for refurbishing OCHT commissioning in 2026 assuming 100% hydrogen-fired

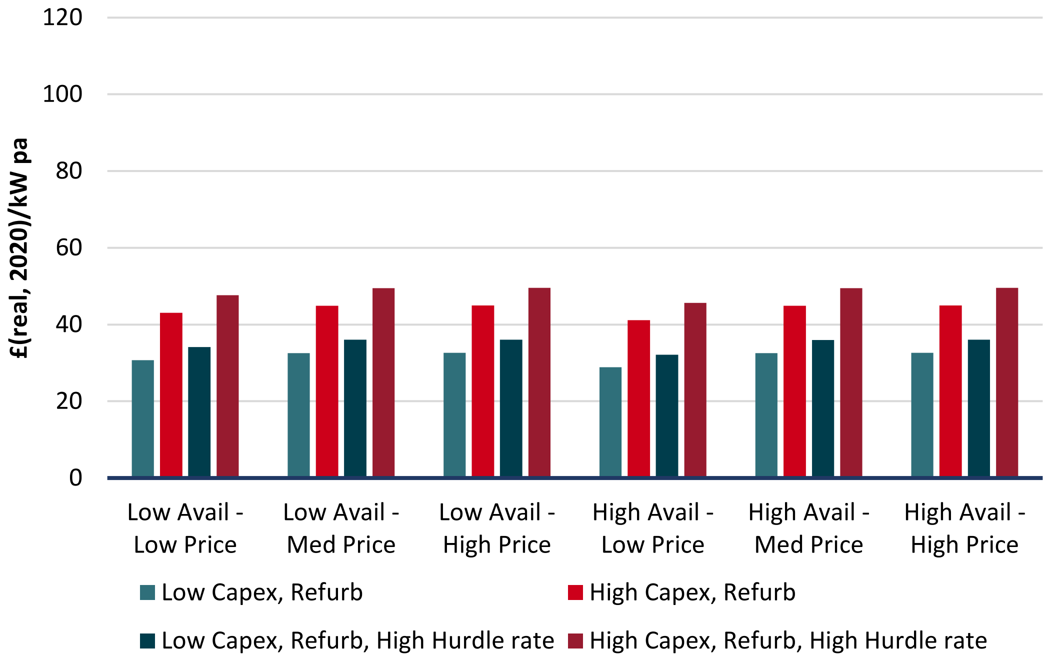
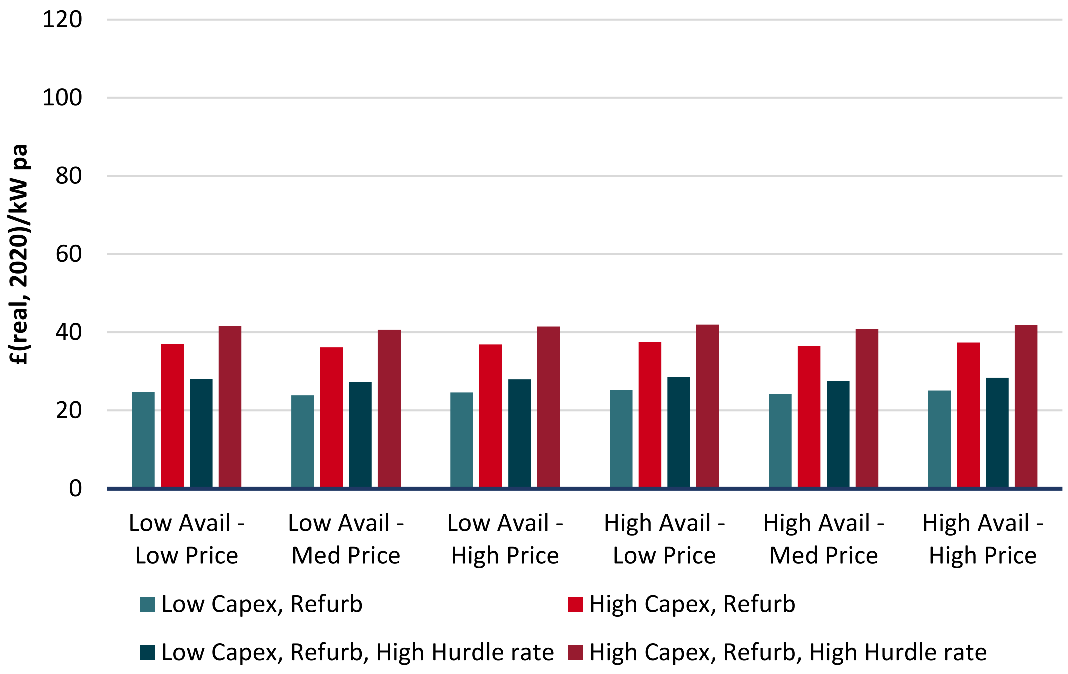


Figure 62: CM support required for refurbishing OCHT commissioning in 2026 assuming hydrogen blend



CM Support – Recip

Required support for new build recips are similar to that for new build OCHT, but slightly higher. This is due to:

- The assumption of a slightly lower efficiency of 32%;
- Higher capex requirement; and
- Slightly higher hurdle rate (7.1% vs 6.8%)

Figure 63: CM support required for new build recip commissioning in 2026 assuming 100% hydrogen-fired

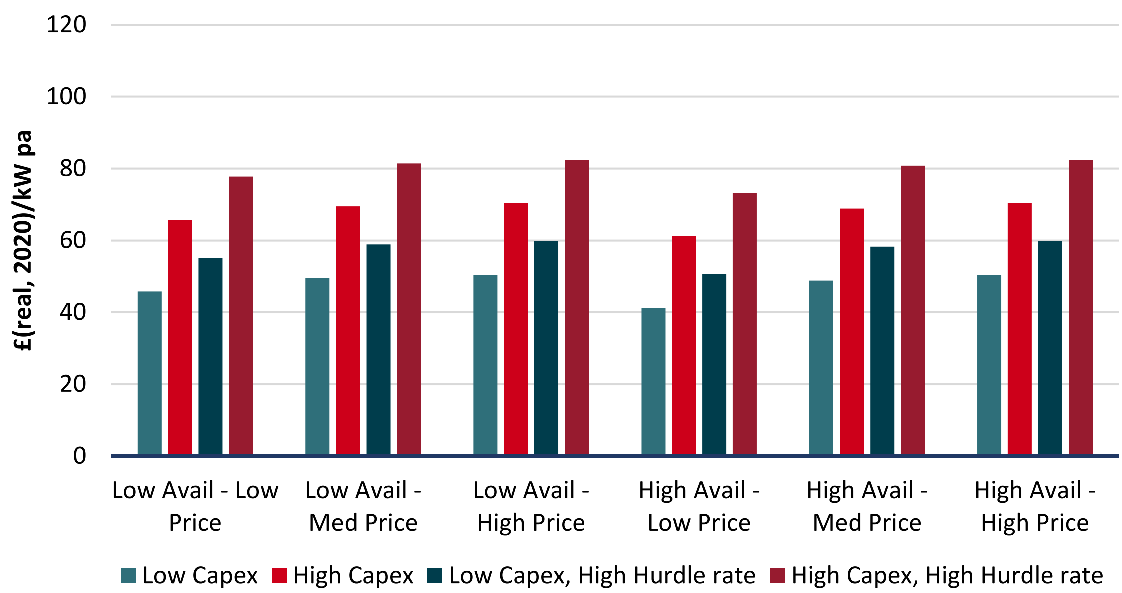
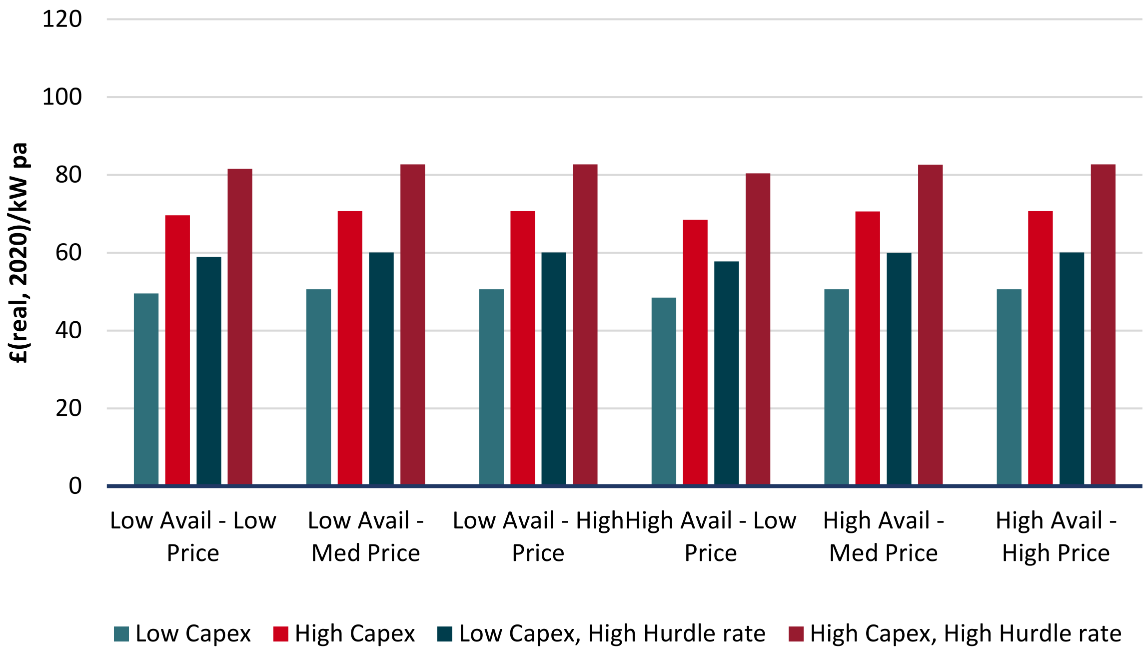


Figure 64: CM support required for new build recip commissioning in 2035 assuming 100% hydrogen-fired



New build hydrogen recips using a 30% gas blend require similar support levels to new build OCHT. Their low running hours means that the biggest sensitivity is around the capex and hurdle rate assumed.

Figure 65: CM support required for new build recip commissioning in 2026 assuming hydrogen blend

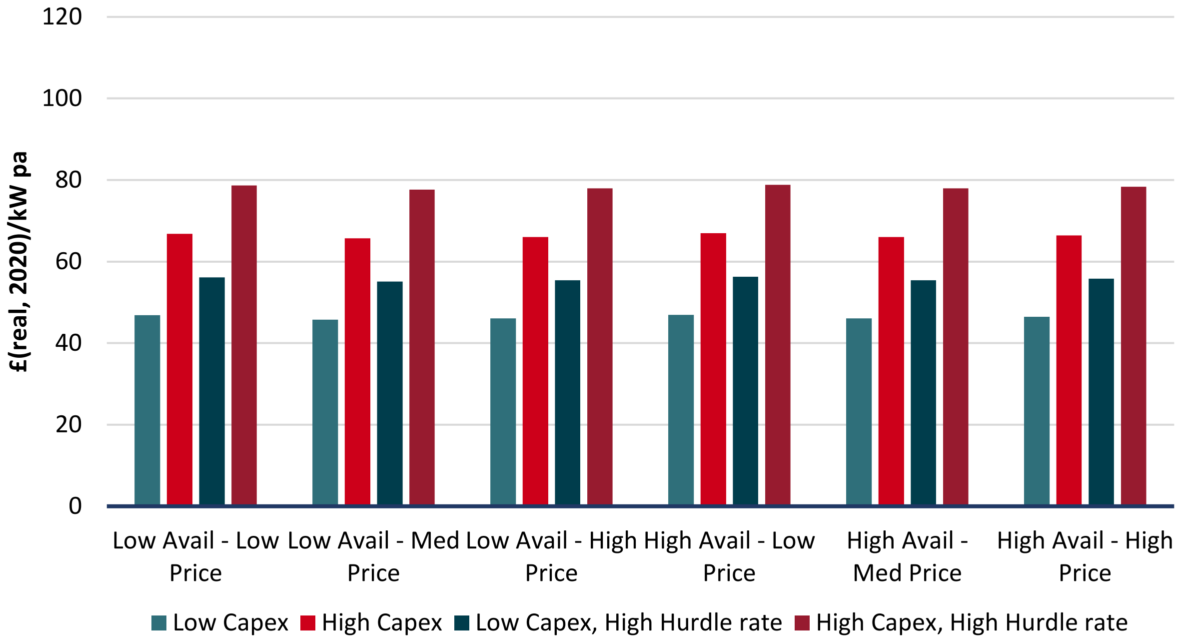
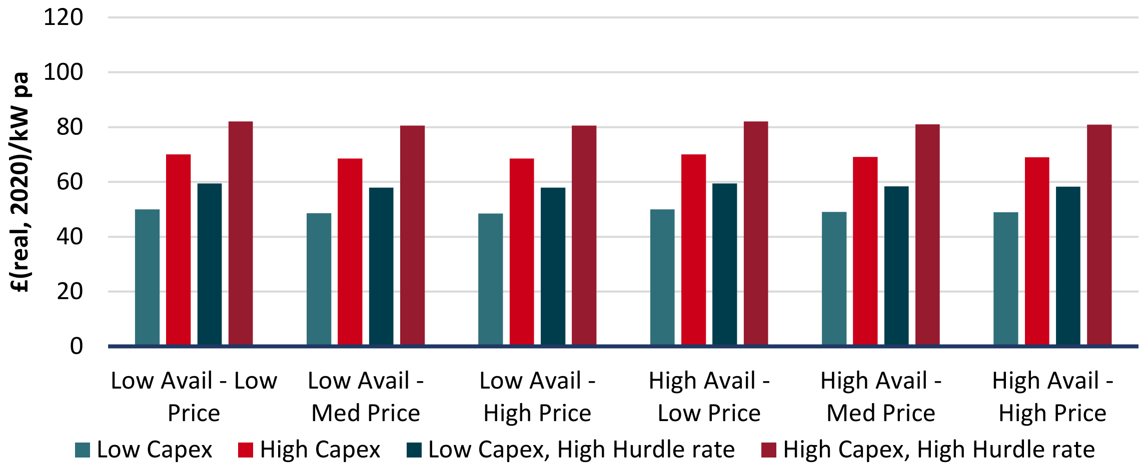


Figure 66: CM support required for new build recip commissioning in 2035 assuming hydrogen blend



The deployment of H2P generation can also be achieved through the refurbishment of existing generation assets. Based upon industry feedback, it is assumed that the refurbishing capex is half that of new build. It is conservatively assumed that refurbishment extends life by 10 years (relative to the 25-year life for new build).

As a result, the support levels required for refurbishing assets are significantly lower than those for new build, requiring levels of support ranging from £27/kW to £56/kW. Again, these compare favourably with the 2026/27 CM T-4 clearing price of £63/kW pa.

It is worth noting that the costs of refurbishing are very uncertain, and 100% H2 may not be feasible.

Figure 67: CM support required for refurbishing recip commissioning in 2026 assuming 100% hydrogen-fired

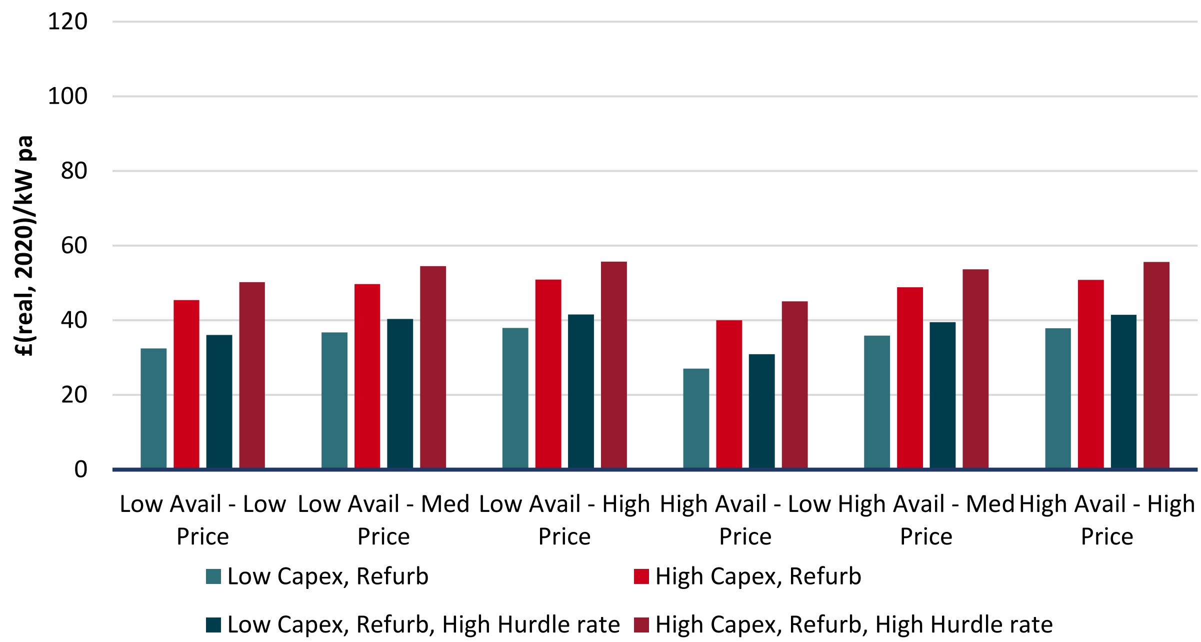
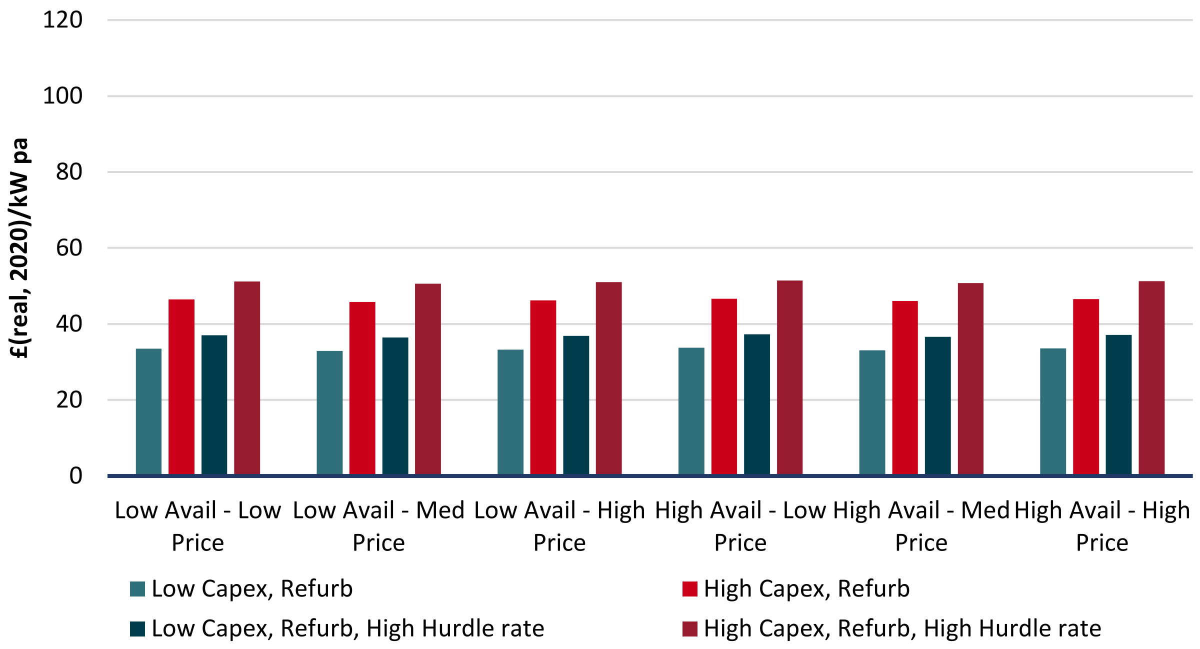


Figure 68: CM support required for refurbishing recip commissioning in 2026 assuming hydrogen blend



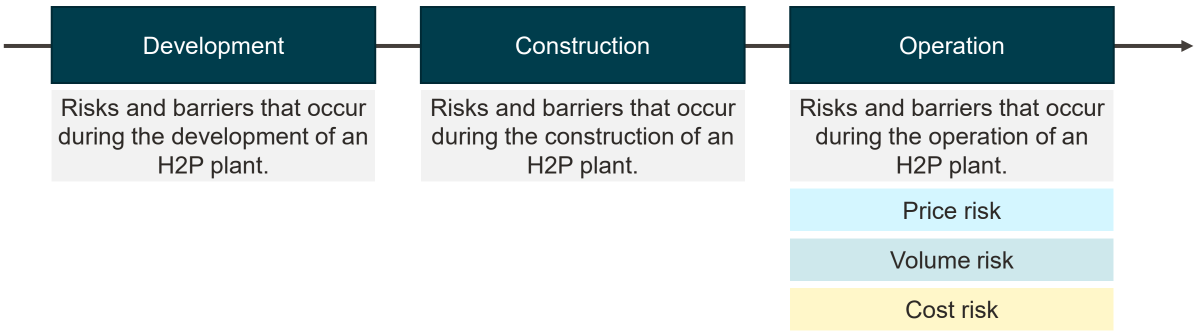
Annex D: Analysis of risks and barriers

Introduction and aims

To ensure that H2P plants are investible, it is necessary for us to understand the risks and barriers that are faced by developers and investors. This annex aims to set out information on the key risks and barriers faced by developers and investors of H2P plants.

We collected evidence primarily from the WP1 stakeholder engagement and from WP1. Combining these inputs, we set out a long-list of 24 risks and barriers. We then categorise these risks and barriers into the development, construction or operation phases of an H2P plant. For risks and barriers relevant during the operation, we differentiate these further between price risks, volume risks and cost risks. Figure 69 summarises this categorisation.

Figure 69: Framework for splitting risks and barriers into different buckets



Source: Frontier Economics illustration

While exposing H2P developers to risks may increase their cost of capital, risk exposure also incentivises developers to adjust their behaviour to efficiently manage risks. Therefore, not every risk should be covered by an H2P business model.

To reflect this, we narrow the long-list down to a shorter list of nine risks and barriers which we suggest should be covered by an H2P business model. The subsequent sections of this annex outline the details of this filtering process and our rationale for short-listing some risks.

Long-list of risks and barriers

Based on the framework outlined in the previous section and using the evidence collected as part of the stakeholder engagement in WP1, we identified 24 risks and barriers[70] as relevant for the long-list of risks and barriers that H2P developers could face. Figure 70 sets out these risks and their definitions are given below.

[70] While risks can generally go in both directions (i.e. there may be upside as well as downside risk), for simplicity, our subsequent descriptions give examples of the downside risk for developers.

Figure 70: Long-list of risks and barriers

Long-list of risks and barriers faced by developers

Developm.

- Allocation risk
- Policy support for hydrogen production
- Policy support for H2P as hydrogen use case
- Policy support for storage and network development
- Planning risk
- Technology risk

Constr.

- Delays in cross-chain (hydrogen) infrastructure
- Power connection
- Construction costs (incl. supply chain)
- Construction delay (incl. supply chain)
- Decommissioning
- Higher construction costs for FOAK technology

Operation

Price risk

- Policy driven electricity price risk (incl. carbon price)
- Other electricity price risk (wholesale / non-wholesale)

Volume risk

- Non-power demand risk
- Volume risk from power network outage
- Commercial demand risk
- Policy driven demand risk
- Fuel availability as a result of insufficient supply
- Fuel availability as a result of securing insufficient fuel contracts
- Fuel availability from outages (incl. cross-chain)

Cost risk

- Fuel price
- Operational outages
- Non-fuel opex

Source: Frontier Economics illustration

Development

- **Allocation risk**. Risk that developers are not among the investors that receive funding through the H2P business model.
- **Policy support for hydrogen production.** Risk that the hydrogen business model for production is removed or amended in the near term, or that the level of funding provided through it is insufficient to deliver the required amount of production.
- **Policy support for H2P as hydrogen use case.** Risk that the policy support for hydrogen use cases (financial or other) does not involve support for H2P technologies or that it disproportionately supports other sectors.
- **Policy support for storage and network development**. Risk that the policy support (financial or other) for the development of storage and network capacities is limited and/or reduced in the future.
- **Planning risks.** Risks that developers face in the planning of H2P plants, with respect to required permits / consents.

- **Technology risks.** Risk that the technology for using hydrogen for H2P is not yet developed when needed.

Construction

- **Delay in cross-chain (hydrogen) infrastructure.** Risk that the cross-chain hydrogen infrastructure (production, networks, storage) required by an H2P plant is not in place at the time of construction, for non-policy driven reasons.
- **Power connection**. Risk that the power connection required by an H2P plant is not available at the time of construction, despite a previous agreement with the network operator - for example, due to constraints on the network.
- **Construction costs (incl. supply chain).** Risk that H2P plant construction costs are high than expected / forecasted.
- **Construction delay (incl. supply chain).** Risk that H2P plant construction is delayed (compared to the expected timelines).
- **Decommissioning**. Risk that plant decommissioning costs are higher than expected.
- **High construction costs for first of a kind (FOAK) technology**. Construction costs likely to be higher for FOAK technology compared to the nth of a kind, because of increased technology risks associated with immature technologies. This would be seen as a barrier, rather than a risk.

Operation

Price risks

- Policy driven electricity price risk (incl. carbon price). Risk that a policy change results in a change in electricity prices, balancing or ancillary services (for example as a result of investment in wind energy); and
- Other electricity price risk (wholesale / non-wholesale). Risk that electricity prices are lower than expected/forecasted for market reasons (for example due to lower wholesale input prices).

Volume risks

- **Non-power demand risk.** Risk that the demand for other products produced by the plant, such as steam or heat, is lower than expected/forecasted (for example relevant for CHP or private wire contracts).
- **Volume risk from power network outage**. Risk that the volumes of wholesale electricity, balancing or ancillary services cannot be sold due to a power network outage.
- **Commercial demand risk.** Risk that the demand for electricity is lower than expected due to market factors (for example innovation in consumer end use appliances).

- **Policy driven demand risk**. Risk that the demand for electricity is lower than expected due to policy-driven factors (for example, a tightening of the 2030 energy efficiency target). This relates to a shift in the average demand for electricity.
- **Fuel availability as a result of securing insufficient fuel contracts**. Risk that hydrogen becomes unavailable during the operation of a H2P plant because the developer did not secure sufficiently high volumes of hydrogen.
- **Fuel availability as a result of insufficient supply.** Risk that hydrogen becomes unavailable during the operation of a H2P plant because the developer was not able to secure sufficient hydrogen when renewing a contract. For example, the developer initially secured hydrogen over a five year period, but cannot secure enough hydrogen at the end of the contract due to changes in the supply and demand for hydrogen.
- **Fuel availability from outages (incl. cross-chain).** Risk that hydrogen becomes unavailable during the operation of an H2P plant. This includes the risk of cross-chain elements becoming unavailable (for example an electrolyser).

Cost risks

- **Fuel price.** Risk that the price of hydrogen fuel (subsidised or unsubsidised) is higher than expected/forecasted[71]. This includes T&S costs.
- **Operational outages**. Risk that the operation of an H2P plant is interrupted due to higher than expected operational outages in (parts of) the H2P technology used.
- **Non-fuel opex.** Risk that non-fuel costs of operating an H2P plant are higher than expected/forecasted.

Filtering of risks and barriers

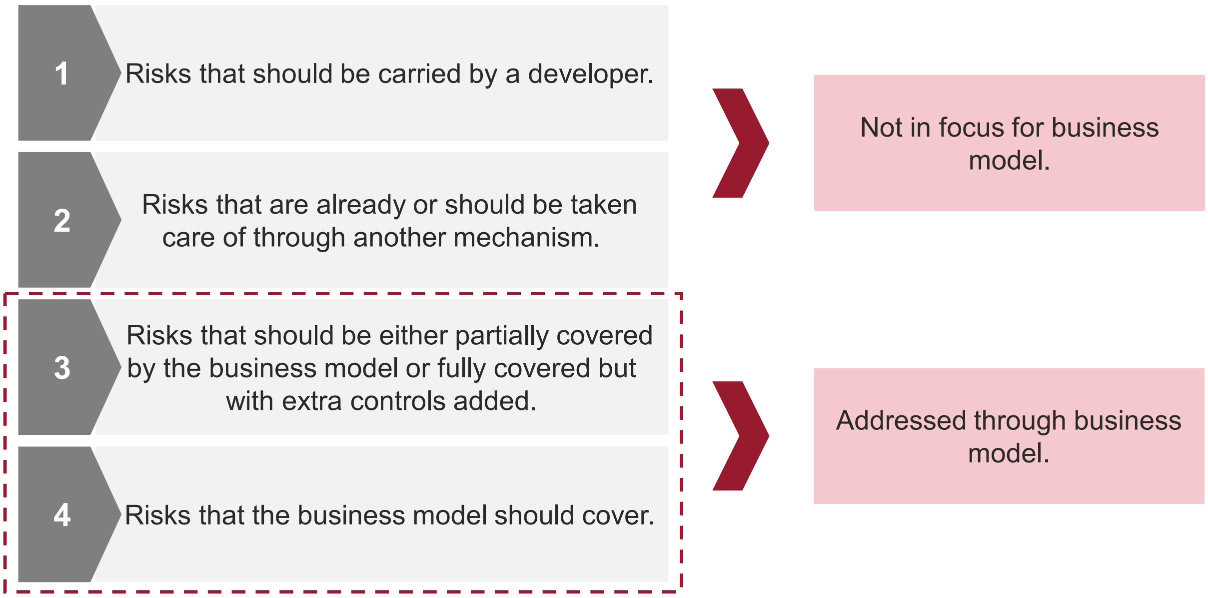
As outlined in the introduction, the presence of risks and barriers can generally have two effects for developers. While they may incentivise developers to efficiently manage risks that they face where possible (i.e., where developers have some degree of control through their behaviour), risks and barriers also increase the cost of capital for developers, making H2P plants less investible. Given this trade-off, a business model should not by default protect investors from all risks. To determine which risks and barriers a business model should address, and hence to balance the two effects, it is generally necessary to assess their costs and benefits from a societal perspective.

It is out of scope for this project to undertake a quantitative assessment of the costs and benefits. However, to determine which risks and barriers should be covered by an H2P business model, we categorise risks into four buckets[72], as displayed in Figure 71. Risks and

[71] If there is enough hydrogen for all customers, as expected by DESNZ, then subsidised hydrogen will remain at the methane price, because there is no competing demand pushing up the hydrogen price. In that case, fuel price risk would be limited to the price of unsubsidised hydrogen.
[72] Only exception is allocation risk (risk that developers are not chosen for the business model) – the business model itself cannot mitigate, but implementation of business model can mitigate or exacerbate.

barriers assigned to category one or two should not be covered by a H2P business model, we think that those in categories three and four should be addressed through a H2P business model.

Figure 71: Categorisation of risks and barriers



Source: Frontier Economics

In the following sections, we briefly explain the rationale for assigning each of the risks and barriers to one of the four categories.

Development

We assign three risks and barriers from the development to category four, therefore short-listing these. These are all related to policy risk, and our rationale for short-listing these is that developers cannot efficiently manage risks that arise from uncertainty about the future design of policies. Therefore, an H2P business model should cover these risks:

- Policy support for hydrogen production;
- Policy support for H2P as hydrogen use case; and
- Policy support for storage and network development.

We assign two risks and barriers to category one. These are not short-listed because we think a H2P developer should bear these risks as these risks to drive efficient decisions. These include planning risks and technology risks, both of which we find should be carried by a developer.

Allocation risk has not been assigned to any of the four buckets, since the business model itself cannot mitigate the risk that developers do not receive the business model. Instead, the implementation of a business model can mitigate or exacerbate the risk.

Figure 72 summarises the filtering process for risks and barriers during the development.

Figure 72: Risks and barriers during the development phase

	Risk / Barrier	Bucket	Explanation
Development	Allocation risk	N/A	While allocation risk is a relevant risk for developers, the business model itself cannot mitigate it. Instead, the implementation of a business model can mitigate or exacerbate the risk.
	Policy support for hydrogen production	4	Policy risk cannot be efficiently managed by investors.
	Policy support for H2P as hydrogen use case	4	Policy risk cannot be efficiently managed by investors.
	Policy support for storage and network development	4	Policy risk cannot be efficiently managed by investors.
	Planning risks	1	Risks from uncertainty around the planning are relevant for developers but should not sit within the H2P BM and are typically managed by developers for other plant types.
	Technology risks	1	H2P developers should make sure that the timing of their investment is aligned with the development of the required technology.

Source: Frontier Economics

Construction

We assign two risks and barriers from the construction to category four, therefore short-listing these. As cross-chain infrastructure is heavily policy dependent, H2P developers cannot efficiently manage these risks, and we do not want higher FOAK costs to be a barrier to H2P development given it is plausible there will be learning spillovers.

We assign one construction risk and barrier to category one, because we believe that decommissioning risk of an H2P plant is no different from that of an unabated gas plant, and that leaving this risk with developers could promote efficient behaviour.

We assign three risks and barriers from the construction to category two, because we believe that these risks and barriers can be covered more efficiently through another mechanism / contract.

- Power connection: risks from an (unexpected) unavailability of the power connection at the time of construction (despite a previous agreement with the network operator), can be covered in a contractual agreement with the network operator.
- Construction costs (incl. supply chain) and construction delay (incl. supply chain): Since these risks can be efficiently managed by the OEM, developers can address these in their contracts with the OEM. Therefore, the risks should not be covered by the H2P business model.

Figure 73 summarises the filtering process for risks and barriers during the construction.

Figure 73: Risks and barriers during the construction phase

	Risk / Barrier	Bucket	Explanation
Construction	Delays in cross-chain (hydrogen) infrastructure	4	H2P developers cannot efficiently manage the risk from delays in cross-chain infrastructure.
	Power connection	2	The risk should be covered in a contractual agreement with the network operator.
	Construction costs (incl. supply chain)	2	The risk is most efficiently managed by the OEM and developers can address this in their contracts with the OEM.
	Construction delay (incl. supply chain)	2	The risk is most efficiently managed by the OEM and developers can address this in their contracts with the OEM.
	Decommissioning	1	Developers should carry this risk to incentivise efficient forecasting of decommissioning costs.
	Higher construction costs for first of a kind (FOAK) technology.	4	Technology risk placed with OEMs through contracts, but a likely increase capex for FOAK technology could be a barrier for H2P developers. Expected learning spillovers justify this being covered by the H2P business models.

Source: Frontier Economics

Operation

Price risks

We assign one risk and barrier related to price risks during operation to category four, therefore short-listing it. This is electricity price risk that is policy driven, and therefore out of the control of developers, who cannot efficiently manage this risk.

We assign other electricity price risks to category one, because we think that developers are well-positioned to efficiently manage this risk, and hence can be incentivised to behave efficiently.

Figure 74 summarises the filtering process for risks and barriers related to price risks during the operation.

Figure 74: Risks and barriers related to price risks during the operation

	Risk / Barrier	Bucket	Explanation
Operation – price risks	Policy driven electricity price risk (incl. carbon price)	4	Policy risk cannot be efficiently managed by investors.
	Other electricity price risk (wholesale / non-wholesale)	1	Developers can efficiently manage the risk and should thus be incentivised to behave efficiently by carrying the risk.

Source: Frontier Economics

Volume risks

We assign two risks and barriers that relate to volume risks during operation to category four (hence short-listing these):

- Policy driven demand risk: Risks that arise from uncertainty about future policy changes are outside of the control of developers and cannot be efficiently managed.

- Fuel availability from outages (incl. cross-chain): While developers cannot efficiently manage the risk that hydrogen becomes unavailable during the operation of an H2P plant (incl. the risk that cross-chain elements become unavailable), this could sit well with the transport and storage operators as well as hydrogen producers, and hence could form part of contracts that H2P developers sign with these parties. However, given the nascent stage of the market, DESNZ prefers to cover the risk through the H2P business model.

We assign non-power demand risk, commercial demand risk, and the other two forms of fuel availability risk to category one, because we believe developers are best placed to efficiently manage this risk. We think that volume risk from power network outages would best be covered in the contracts that H2P developers have with electricity grid operator, as is already in place for current gas generators.

Figure 75 summarises the filtering process for risks and barriers related to volume risks during the operation.

Figure 75: Risks and barriers related to volume risks during the operation

	Risk / Barrier	Bucket	Explanation
Operation – volume risks	Non-power demand risk	**1**	Developers can efficiently manage the risk and should thus be incentivized to behave efficiently by carrying the risk.
	Volume risk from power network outage	**2**	This risk already exists with current gas generators, and is commonly addressed through the actions of the electricity grid operator. This should be dealt with similarly for H2P.
	Commercial demand risk	**1**	Developers can efficiently manage the risk and should thus be incentivised to behave efficiently by carrying the risk.
	Policy driven demand risk	**4**	Policy risk cannot be efficiently managed by investors.
	Fuel availability as a result of insufficient supply	**1**	Developers can mitigate this risk by making accurate forecasts of their required hydrogen, and the business model should incentivise them to do so.
	Fuel availability as a result of securing insufficient fuel contracts	**1**	Developers can mitigate this risk, i.e. by securing longer term contracts, or siting in hydrogen production and storage clusters, and the business model should incentivise them to do so.
	Fuel availability from outages (incl. cross-chain)	**4**	Developers cannot efficiently manage the risk. While this could sit well with the T and S operators and H2 producers, DESNZ prefer to cover it by H2P BM.

Source: Frontier Economics

Cost risks

We think that because the price of hydrogen is heavily policy-driven, fuel price risk should be covered by the business model. However non-fuel opex price risk and the risk of operational outages should not be covered by the business model to drive efficient management of these risks by operators. While operational outages may be higher for H2P developers than unabated gas plant developers because it is a less mature technology, this is best addressed in the contract between the H2P developer and the OEM, rather than the H2P business model.

Figure 76 summarises the filtering process for risks and barriers related to cost risks during the operation.

Figure 76: Risks and barriers related to cost risks during the operation

	Risk / Barrier	Bucket	Explanation
Operation – cost risks	Fuel price	3	Hydrogen price is heavily policy-driven, so should be at least partially covered by business model. However, full coverage means no incentive for developer to get a competitive price.
	Operational outages	2	Developers can address this in their contracts with the OEM.
	Non-fuel opex	1	This is a risk typically borne by plant operators.

Source: Frontier Economics

Figure 77: Short-list of risks and barriers

Short-list of risks and barriers to be addressed by the H2P business model

Developm.

- Policy support for hydrogen production
- Policy support for H2P as hydrogen use case
- Policy support for storage and network development

Constr.

- Delays in cross-chain (hydrogen) infrastructure
- Higher construction costs for FOAK technology

Operation

Price risk	Volume risk	Cost risk
▪ Policy driven electricity price risk (incl. carbon price)	▪ Policy driven demand risk ▪ Fuel availability from outages (incl. cross-chain)	▪ Fuel price

Source: Frontier Economics

Variation across risks and barriers

As the H2P business model would need to cover different types of plants, we also analyse how the short-listed risks and barriers vary across several dimensions:

- Plant type;
- Retrofit / new-build;
- Prosumer / consumer;
- Blend / full hydrogen; and
- Changes over time.

The summary of our analysis is in the following bullets, and in Figure 78. Figures 79, 80, 81 and 82 below show the more detailed analysis of each dimension.

- **Plant type:** CHP / CCHT are more exposed to risks since they have put in more upfront capital and also will be relying on higher load factors.
- **Retrofit vs. new-build**: Assuming efficiencies of retrofit and new-build are similar[73], risk exposure is generally similar, except new-builds (with greater capital outlay) are more exposed to policy-driven development risks.
- **Full hydrogen vs. blend:** Overall, we expect that blended plants are less risk-exposed since the technology is more mature and they are less reliant on the cross-chain.
- **Prosumer / consumer:** Assuming that the hydrogen production business model (HPBM) covers on-site storages, prosumers are less exposed to cross-chain and hydrogen price risk. However, they are more exposed to (policy-driven) demand risk since reduced demand also reduces the support from the HPBM.
- **Over time:** We expect that risks decline over time. This is based on the assumption that the carbon price is going up and that the hydrogen market's depth and liquidity increase over time.

[73] In line with the findings from WP1, older plants are less desirable for retrofit as they need significant upgrades for new equipment to earn enough revenue to pay back a reasonable cost of capital. Hence, only relatively new plants are likely to be used for retrofitting purposes, meaning the efficiencies of retrofit and new-build plants are likely to be similar.

Figure 78: Variation of short-listed risks and barriers

	Risk	Plant type	Retrofit vs. new-build	Hydrogen vs. blend	Prosumer / Consumer	Over time
Development	▪ Policy support for hydrogen production	▪ Although policy support is a risk in several different ways, for H2P developers, it boils down to whether policy support helps with the risk of fuel availability. ▪ Therefore, while the risk of insufficient policy support generally affect all plants, those with higher Capex (i.e. new-built prosumer CHP / CCHT) are most exposed to these risks, as they are tying more capital up in the face of uncertainty in these areas.				Risk decreases over time, with increasing certainty about policy support.
	▪ Policy support for H2P as hydrogen use case					Extent to which risk decreases depends on availability of hydrogen and urgency of other use cases.
	▪ Policy support for storage and network development					Risk decreases over time, but will take a while to get there.
Construction	▪ Delays in cross-chain infrastructure	Limited / no differences.	Limited / no differences.	Less severe for blend scenarios due to lower reliance on x-chain.	Less severe for prosumers due to lower reliance on x-chain.	X-chain risk decreases substantially over time, as H2 infrastructure develops.
	▪ Higher construction costs for FOAK technology	Limited / no differences.	Limited / no differences.	More severe for full hydrogen since technology is less mature.	More significant for prosumers given their greater construction costs of production and storage.	Construction costs reduce over time with learning spillovers.
Operation	▪ Policy driven electricity price risk (incl. carbon price)	Plants with higher load factors affected to a greater degree than plants used for peaking.	Slightly more relevant for retrofits as they're slightly less efficient than new-built.	Limited / no differences.	Limited / no differences.	Expected to decrease over time as carbon price increases.
	▪ Policy driven demand risk	Plants requiring higher load factors more affected from reduction in demand.	Retrofits likely slightly less efficient, thus might be pushed out slightly more often.	Limited / no differences.	Greater for prosumer (with HPBM) as own offtaker, so reduced demand also reduces HPBM support.	Decreases over time due to higher certainty around policy targets.
	▪ Fuel price	Capex-heavy plants are at greater risk of low returns driven by higher fuel costs.	Limited / no differences.	Risk less severe for blend which requires less hydrogen.	Much smaller for prosumer (with HPBM) as dictate own hydrogen fuel price.	Fuel price expected to decrease and stabilise over time as market matures.
	▪ Fuel availability as a result of an outage	Outage more likely to be at times when baseload plant running than peaker.	Limited / no differences.	Smaller for blend as they can likely more easily switch to natural gas.	No risk of cross-chain outage for prosumer.	Reduce with development of T&S, as well as with increasing numbers of hydrogen producers.

Source: Frontier Economics

Figure 79: Factors affecting how investment risk varies across plant technology

	CHP	CCHT	Recips	OCHT
Cost structure	Higher Capex	Higher Capex	Lower Capex	Lower Capex
Place in the merit order	Must-run	Higher in Merit Order	Lower in Merit Order	Lower in Merit Order
Reliance on cross-chain	Limited / no difference between plant types.			
Maturity of technology	Limited / no difference between plant types.			
Fuel switch	Limited / no difference between plant types.			
Range of services offered	Run baseload, with limited flexibility.	Flexibility with mid-merit load factors.	Target short-term / balancing market.	

Source: Frontier Economics

Figure 80: Factors affecting how investment risk varies across retrofit / new-build

	Retrofit	New-build
Cost structure	Relatively lower capex requirement, unless plant is very old (in which case investors would likely prefer new-build).	High capex requirement, but might be easier to secure financing from investors.
Place in the merit order	Less efficient assuming not all equipment replaced - lower in merit order (difference likely to be small)	More efficient, thus higher in merit order (though difference is likely to be small).
Reliance on cross-chain	Limited / no difference between retrofit and new build.	
Maturity of technology	Limited / no difference between retrofit and new build.	
Fuel switch	Limited / no difference between plant types, except new-build are likely more feasible to run on higher levels of H_2. However, it is unclear whether new-build would, in the future, still have a NG connection.	
Range of services offered	Limited / no difference between retrofit and new build.	

Source: Frontier Economics

Figure 81: Factors affecting how investment risk varies across prosumer / consumer

	Prosumer	Consumer
Cost structure	Very Capex-heavy, production and especially on-site storage – depends on coverage of HPBM	Less Capex-intense
Place in the merit order	Lower in the merit order if hydrogen production more expensive (lower economies of scale)	Relatively higher in merit order.
Reliance on cross-chain	Very low reliance on x-chain	Relatively higher reliance on x-chain
Maturity of technology	Technology slightly less mature, especially due to on-site requirements, e.g. for storage.	Technology is more mature.
Fuel switch	Fuel switch likely not feasible.	Fuel switch more likely to be possible.
Range of services offered	Limited / no differences whether a plant is a prosumer or consumer.	

Source: Frontier Economics

Figure 82: Factors affecting how investment risk varies across blend / full hydrogen

	Blend	Full hydrogen
Cost structure	Relatively lower capex costs	Relatively higher capex costs
Place in the merit order	Lower in merit order due to higher carbon costs.	Higher in merit order due to lower carbon costs.
Reliance on cross-chain	Smaller reliance on hydrogen x-chain.	Greater reliance on hydrogen x-chain.
Maturity of technology	Up to 30% feasible now (mature), higher blends not yet sufficiently tested.	Theoretically feasible but not yet at demonstration phase (immature)
Fuel switch	Fuel switch technically feasible.	Fuel switch generally feasible, depending on whether two connections likely to be maintained.
Range of services offered	Not enough evidence that would suggest differences.	

Source: Frontier Economics

Annex E: Development of business model options

Overview

To develop business models options, we first set out a long-list of business models that includes different options delivering support in a variety of ways. To develop the long list, we looked at the business models that are currently in place in the power sector, and combined these with a selection of business models taken from REMA, with the aim of including a broad mix of options. We describe each of the business models from the long-list in more detail later in this annex.

We then filter the longlist of options, based on two 'hurdle criteria', which we describe further in this annex. Based on this, we narrow down the list of options to a short-list of six business models for the assessment.

Long-list of business models

We considered fifteen business models split into four categories (see Figure 83). We now outline the business models in each category in turn.

Figure 83: Long-list of business model options

Contractual payments	1. CM [counterfactual] 2. CM+ (options to overcome IMR problem) 3. CfD 4. CfD+ (average strike price, strike price range, deemed generation CfD) 5. DPA 6. Feed-in-tariff
Regulated returns	7. RAB 8. Revenue cap and floor
Obligations	9. End-user obligation 10. Fossil fuel ban
Other interventions	11. Upfront grant 12. Tax break 13. Changes to UK ETS 14. Government investment 15. Government guarantee

Source: Frontier Economics

Note: IMR problem refers to inframarginal rents, where low-cost technologies are receiving CM payments that are much higher than necessary.

Contractual payments

Contractual payments business models are those where a contract is signed between the H2P developer and a counterparty. These are already used in the energy sector in the UK (for example CfDs, and CM). These could, in principle, be paid for by either taxpayers, energy consumers or even a specific subset of consumers, depending on the setup preferred by the administration. We considered six business models in this category:

- **CM.** The CM is an auction process in which investors bid in to receive a regular fixed payment per kW of capacity that is available, regardless of how the asset dispatches. The amount of capacity auctioned off is centrally determined. All successful plants receive the auction clearing price in a given year. Investors in a new plant can receive a contract with a fixed per kW payment for a period of up to 15 years, providing certainty of support. Under this option, H2P would bid into the existing CM. We use the CM as the counterfactual (base case) in our analysis.
- **CM+.** There is a risk that, under the CM counterfactual, H2P plants set a very high price in the CM, resulting in high payments to non-H2P plants (so-called “inframarginal rents”). This alternative business model therefore represents changes to the current CM that would overcome the problem of inframarginal rents, by splitting out a separate auction to include less mature technologies. Again, capacity would be centrally determined and successful bidders would receive a payment per kW of capacity that is available, regardless of how the asset dispatches.
- **Contracts for difference (CfD).** This business model is currently used extensively in the UK power sector, and has been very successful in funding intermittent renewables such as offshore wind. The business model consists of a strike price that is agreed at the start of a contract, and a market reference price that changes over time. Operators receive the difference between the strike price and the reference price for each unit of electricity that they generate. If plants sell their output at the reference price, then in aggregate they will earn their strike price. Operators receive a varying level of support, but greater revenue certainty.
- **CFD+.** This includes three different options (all outlined in REMA) as adjustments to the current CfD:
- **Average reference price CfD.** A CfD where instead of a continuous reference price being used, the average reference price over a period of time – for example over a week – is used. The idea of this business model is that it exposes operators to greater price risk, such that operators are incentivised to perform efficiently because their actual capture price could outperform or underperform the weekly average.
- **CfD with a strike price range**. Instead of a single pre-agreed strike price, plants are guaranteed a maximum and minimum price per MWh output, with market exposure within this range.

- **Deemed Generation CfD.** Under this business model, the level of support a generator receives is decoupled from output, which differs from all other CfDs considered for assessment. The support is paid per unit of 'deemed output' rather than per unit of metered output. Hence operators are exposed to market prices and are incentivised to dispatch efficiently, while still receiving the security of the support payment. The per unit support is calculated using a pre-agreed strike price which is fixed for the length of the contract, and a reference price which changes over time. Hence the support payment is not fixed over time, but varies every reference period, as the reference price is updated.
- **Dispatchable power agreement (DPA).** This is proposed for Power CCUS projects and includes two payment streams. A variable payment that is paid per unit of output and ensures plant dispatches just ahead of unabated gas in the merit order. An availability payment is paid per unit of capacity that is available over time, regardless of dispatch.
- **Feed-in-tariff.** A feed-in-tariff is a top-up payment per unit of electricity that is generated by the operator. It increases the marginal revenue of the operator.

Regulated returns

Regulated returns business models are those where the business model pre-defines a return, up to which the business model would support developers. Similar to contractual payments, these could, in principle, be paid for by either taxpayers, energy consumers or even a specific subset of consumers, depending on the setup preferred by the administration.

- **Regulated Asset Base (RAB).** This business model is used extensively to fund power and gas networks in the UK, and has been very successful. It is also proposed for new nuclear plants. A RAB provides the plant operator with a regulated return on invested capital (as well as recovery of operating costs), subject to conditions set by the regulator (which are likely to relate to availability, rather than dispatch).
- **Revenue Cap and Floor.** Under this model, an operator receives market revenue and if this market revenue is above a maximum (cap) defined by the regulator, then the operator pays back the 'excess' at the end of the reconciliation period. Similarly, if market revenue is below a minimum (floor), then the operator receives a top-up support payment to the level of the floor at the end of the reconciliation period.

Obligations

Obligations refer to business models which demand or prevent a certain action by a certain group or by society as a whole. These would be paid for through the customers of the obliged parties.

- **End-use Obligation.** An end-user obligation would require consumers (or their suppliers) to purchase a certain amount of electricity from H2P plants over a given time period.
- **Fossil Fuel Ban.** An obligation for power plants to have an emission performance standard below a certain threshold. This would define the maximum level of unabated

gas to be used in power generation over a specified time period. The maximum level could be set at zero from a certain date or ramp down to zero by a certain date.

Other interventions

We also consider other interventions as business models which cannot be assigned to one of the categories above. The business models in this category would be paid for by the Government and, hence, the taxpayer.

- **Upfront Grant.** This would involve one-off support being given to H2P operators, with no ongoing payments.
- **Changes to the UK ETS.** The UK ETS determines the effective carbon price for included sectors in the UK. Changes to the UK ETS could increase the carbon price, which may make H2P plants – and other low-carbon alternatives - more investible.
- **Government Investment.** This would involve one-off support being given to H2P operators, but instead of an upfront grant the government would take an equity stake in the H2P plant.
- **Government Guarantee**. The government would guarantee a minimum level of revenue for H2P plant operators, and if operators did not receive this in market revenue, then the government would provide top-up payments.

Hurdle criteria

As described above, the long-list of business models included about 15 possible business models. This was too many to allow a detailed qualitative assessment to be undertaken. Therefore, we narrowed down this long-list to a more manageable short-list using two simple ‘hurdle criteria’ to eliminate options where it was obvious that the business model did not provide the best answer to the needs case, and hence would definitely perform less well in subsequent detailed qualitative assessment.

The two hurdle criteria we used were:

- **Dispatch** – whether it is clear that the business model would significantly distort the dispatch incentive (this is a crucial factor, given the proposed role of H2P as a means of providing low carbon flexibility); and
- **Simplicity** – whether there is a simpler version of the business model already in the list that could potentially deliver the same outcomes. For example, while an upfront grant could incentivise appropriate dispatch, the counterfactual CM could achieve this more simply.

Filtering business models

Contractual payments

Of the six contractual payment business models on the long-list, four of them pass the filters onto the short-list:

- CM;
- CM+;
- Deemed Generation CfD (part of CfD+); and
- DPA.

Table 18: Business models filtering – contractual payments

Long-list	Dispatch criteria	Simplicity criteria	Short-list
CM	Appropriate dispatch could be incentivised	Could not be achieved with a simpler business model	Yes
CM+	Appropriate dispatch could be incentivised	Could not be achieved with a simpler business model	Yes
CfD	Distorts dispatch incentive as operator typically receives strike price rather than market price	-	No
CfD+ (Average Strike Price)	Distorts dispatch incentive, similar to regular CfD	-	No
CfD+ (Strike Price Range)	Appropriate dispatch could be incentivised	Revenue Cap and Floor is a less distorting version of the strike price range.	No
CfD+ (Deemed Generation CfD)	Appropriate dispatch could be incentivised	Could not be achieved with a simpler business model	Yes
DPA	Appropriate dispatch could be incentivised	Could not be achieved with a simpler business model	Yes
Feed-in-tariff	Distorts dispatch incentive as operator's market price is topped up by tariff	-	No

Regulated returns

Of the two regulated returns business models on the long-list, the Revenue Cap and Floor pass the filters onto the short-list.

Table 19: Business models filtering – regulated returns

Long-list	Dispatch criteria	Simplicity criteria	Short-list
RAB	Appropriate dispatch could be incentivised	Contractual payment could achieve this more simply[74]	No
Revenue Cap and Floor	Appropriate dispatch could be incentivised (assuming revenue often above the floor and below the cap)	Could not be achieved with a simpler business model	Yes

Source: Frontier Economics

Obligation

Of the two obligation business models on the long-list, the fossil fuel ban pass the filters onto the short-list.

Table 20: Business models filtering – obligation

Long-list	Dispatch criteria	Simplicity criteria	Short-list
End-user obligation	Distorts dispatch incentive as operator's market price is topped up by revenue from obligated parties	-	No
Fossil Fuel Ban	Appropriate dispatch could be incentivised	Could not be achieved with a simpler business model	Yes

Source: Frontier Economics

Other interventions

Of the five remaining business models on the long-list, none pass the filters onto the short-list.

[74] The RAB is more suited to technologies where there is greater uncertainty in either the construction or the operation phase. This is because the regulator can then react in the face of that uncertainty. Reacting to uncertainty would not be as simple under a contractual payment, as these are generally fixed at the start of the contract.

Table 21: Business models filtering – other

Long-list	Dispatch criteria	Simplicity criteria	Short-list
Upfront grants	Appropriate dispatch could be incentivised	Counterfactual CM could achieve this more simply	No
Changes to the UK ETS	Appropriate dispatch could be incentivised	Fossil Fuel Ban could achieve this more simply	No
Tax breaks	Appropriate dispatch could be incentivised	Counterfactual CM could achieve this more simply	No
Government investment	Appropriate dispatch could be incentivised	Counterfactual CM could achieve this more simply	No
Government guarantee	Appropriate dispatch could be incentivised	Revenue Cap and Floor could achieve this more simply	No

Source: Frontier Economics

Short-list of business models

Based on the filtering process outlined above, we create a short-list of six business models to be taken to the full qualitative assessment.

- Contractual payments:
    - CM [counterfactual];
    - CM+;
    - Deemed Generation CfD;
    - DPA.
- Regulated returns:
    - Revenue Cap and Floor;
- Obligations:
    - Fossil Fuel Ban.

Annex F: Development of assessment criteria

Introduction and sources

Our approach to identifying the relevant assessment criteria relied primarily on three sources: the REMA consultation summary, DESNZ's CCUS update on business models and the UK Hydrogen Strategy.

Combining inputs from all three sources, we identify a long-list of 17 assessment criteria, summarised in Figure 84.

Figure 84: Long-list of assessment criteria

Objectives outlined in REMA consultation summary

- Least cost
- Deliverability
- Investor confidence
- Whole-system flexibility
- Adaptability

Principles from CCUS business model

- Decarbonisation
- Sustainable financing
- Provide value to UK economy
- Cost reductions
- Market and flexibility
- Value for money
- Fair and reflective costs

Principles outlined in UK Hydrogen strategy

- Long-term value for money (taxpayer / consumer)
- Growing the economy whilst cutting emissions
- Securing strategic advantages for the UK
- Minimising disruption and cost for consumers
- Keeping options open, adapting to developments
- Taking a holistic approach

Source: Frontier Economics

Based on the long-listed assessment criteria, we then identify six assessment criteria for the short-list, mostly through reducing duplication across the three sources. For example, 'least cost' is a criterion in the REMA consultation, while 'value for money' appears in the CCUS update on business models and 'long-term value for money' appears in the UK Hydrogen

Strategy. Hence, to avoid duplication for our H2P assessment, we combine these into the criterion 'cost distribution'. The final assessment criteria have been agreed with DESNZ.

Assessment criteria

Investibility

Investibility	▪ Does the business model (BM) cover the key risks and barriers for project developers identified in WP 2.1? ▪ Would this result in a low cost of capital that is likely to be acceptable to the market, and enable investment from a range of sources (including project finance)?

The criterion of investibility refers to the risks and barriers identified in Annex D of this report.

While we explain in Annex D that a business model should not cover all potential risks (because the presence of certain risks presents an incentive to investors to improve their own performance), Annex D identifies nine short-listed risks and barriers that the H2P business model should cover. A significant number of these risks relate to whether there will be the fuel available for an H2P plant to use. This could either be the risk of an outage or delays in cross-chain infrastructure, or the policy risk around establishing the required production and infrastructure. Mitigating fuel availability risk for developers will therefore be crucial for the business model to allow H2P plants to be investible. Other risks include electricity price and demand risk, to the extent that they are influenced by policy.

Furthermore, WP1 modelling results show that market revenue is likely going to be a smaller proportion of total revenue for most H2P plants (Section 2) compared to support revenue. Hence when thinking about the above risks it is more important to think about how they impact support revenue, rather than how they impact market revenue.

Decarbonisation of the power sector

Decarbonisation of the power sector	▪ Does the BM encourage H2P to dispatch ahead of unabated gas?

The criterion 'Decarbonisation of the power sector' assesses whether a business model is able to provide the incentive for H2P to dispatch ahead of unabated gas.

WP1 modelling results show that H2P plants do not always dispatch ahead of unabated gas, especially when using unsubsidised hydrogen. While the cost efficiency of the precise dispatch order is covered in more detail in the next assessment criterion, the results show that there is potential for reducing the emissions from the power sector by moving H2P (using unsubsidised hydrogen) ahead of unabated gas in the dispatch order.

Cost efficiency

Cost efficiency	▪ Does the BM incentivise an efficient dispatch order (i.e. a merit order in line with the social short run marginal cost of plants)? ▪ Does the BM avoid incentivising over-investment in H2P? ▪ Does the BM promote competition and innovation to bring down H2P deployment costs?

The criterion 'Cost efficiency' assesses whether a business model leads to an efficient dispatch order, while avoiding under- or over-investment in H2P as much as possible (considering the feasibility of a sensible allocation process). In addition, the criterion assesses whether a business model is able to promote competition and innovation, bringing down overall H2P deployment costs.

The criterion of an efficient dispatch order refers to dispatch which is in line with the social short run marginal costs (SRMC) of plants. In particular, we refer to an "efficient dispatch" in the context of the modelling results from WP1 (Section 2). The social SRMC of plants includes the resource cost of the fuel and other operating costs, as well as the social value of the emissions (based on the economy-wide marginal greenhouse abatement cost in the Green Book appraisal values)[75]. This may differ from the market SRMC if fuels are subsidised, or if the market carbon price is different to the social value of the emissions, for example[76].

This analysis suggests that to minimise social costs, Power CCUS should dispatch ahead of H2P (at least until the modelling ends in 2050). However, the socially optimal dispatch order of H2P plants compared to unabated gas plants is more nuanced and depends on the time horizon, as well as the cost of hydrogen. If H2P plant uses unsubsidised hydrogen as a fuel then in all hydrogen price scenarios, it should dispatch after Power CCUS and;

- In the low hydrogen price scenario, it should dispatch behind unabated gas until the early 2030s when it starts to dispatch ahead of unabated gas;
- In the medium hydrogen price scenario, it should dispatch behind unabated gas until the mid-2040s when it starts to dispatch ahead of unabated gas; and
- In the high hydrogen price scenario, it should always dispatch behind unabated gas (up until 2050 when the modelling ends).

[75] https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

[76] When thinking about the carbon cost of hydrogen, we consider the carbon emissions at the point of combustion, rather than using a whole systems perspective and considering the emissions at the point of production (e.g. blue hydrogen compared to green hydrogen with curtailed renewables). Our current treatment of emissions is equivalent to how gas is treated in similar analyses, where emissions at production or during the transport of gas are not considered.

Box 3: Dispatch under an assumed market carbon price

An efficient dispatch order requires a carbon price which accurately reflects the economy-wide marginal abatement cost and hence the social cost of carbon. However, the WP1 dispatch modelling used carbon prices that are lower than the appraisal values up to 2040 (to represent likely market carbon prices). Therefore, the carbon prices for the years before 2040 are below the appraisal values in the Green Book. Under these assumed prices, the modelling found that:

- H2P plants generally dispatch after Power CCUS (without a further dispatch incentive). This is an efficient dispatch order, given that H2P plants have higher social SRMCs than Power CCUS plants.
- Where hydrogen fuel is not subsidised, unabated gas plants often dispatch ahead of H2P plants, especially in the early years of the modelled period. However, this is in line with the fact that unabated gas plants have lower social SRMCs until 2040.

Therefore, the modelling suggests that a dispatch incentive would not increase efficiency as H2P is already dispatching at least as much as is efficient, even though the assumed carbon price is lower than the appraisal value.

However, there is clearly a risk that the outturn carbon price is lower than that used in the WP1 modelling. Under these circumstances, there may be case for a dispatch incentive if the actual carbon price does not result in a dispatch order that is in line with the socially efficient dispatch order. In particular, if carbon prices are significantly below those used in the modelling, unabated gas plants may dispatch ahead of H2P plants.

Cost distribution

Cost distribution	▪ Does the BM offer value for money for those funding it (e.g. tax payers or energy consumers)? ▪ Does the BM have a significant impact on the distribution of energy system costs (e.g. via its impact on market prices)? ▪ Does the BM avoid undermining the UK's international competitiveness?

The criterion 'Cost distribution' assesses whether the business model offers a good value for money for those funding it (e.g., tax payers or energy consumers). For example, one key consideration relates to the inframarginal rents that could be earned by operators of other technologies in the CM[77].

In addition, this criterion evaluates whether the business model would lead to changes in market prices and hence on the UK's international competitiveness. For example, the optional variable payment in the DPA may reduce market prices if H2P is on the margin, because it reduces the marginal costs of H2P to just below those of unabated gas. Hence the electricity

[77] Inframarginal rents are the difference between the clearing price and the marginal cost of an operator. If an operator has very low marginal costs, then it could receive high inframarginal rents if the CM clearing price is very high.

costs to other industries that rely heavily on electricity will reduce, which increases the competitiveness of those industries.

Practicality

Practicality	▪ Is the BM simple and transparent? ▪ Is the BM deliverable and easy to implement? ▪ Is the administrative burden for government low? ▪ Is the BM compatible with other existing and planned mechanisms and policies (HPBM, CM, REMA)?

The 'Practicality' criterion assesses how easily a business model can be implemented, and how well it is likely to be understood by investors. This criterion evaluates whether a business model is simple and transparent as well as the extent to which it can be implemented without adding a high administrative burden for government. The criterion also considers whether the business model is compatible with other existing and planned mechanisms and policies (e.g., DPA, HPBM, CM, REMA).

Adaptability and flexibility

Adaptability and flexibility	▪ Would the BM be adaptable over time (to expected changes)? ▪ Is the BM robust to different outturn scenarios (unexpected shocks)? ▪ Would the BM allow a clear exit route where support is reduced over time (when the sector is mature)?

The criterion 'Adaptability and flexibility' assesses whether the business model is adaptable over time (i.e., to expected changes in market surroundings) and robust to different outturn scenarios than those forecasted (i.e., unexpected shocks to the wider economy or parts of it). In addition, the criterion assesses whether the business model allows a clear exit route where support is reduced over time, when the sector is observed to be mature.

Annex G: Alternative cap and floor designs

Throughout this assessment we have assumed a basic Revenue Cap and Floor without additional features. However, there are a number of tweaks that could be made to the cap and floor. We discuss these features in turn in this section, and their suitability to H2P in particular.

Soft cap

A ‘soft cap’ would reduce the dispatch distortion if the H2P operator expects to end the reconciliation period above the cap, but would not remove it completely. The degree to which the dispatch incentive would be maintained depends on the revenue sharing rate. However as with deciding the level of the cap and floor, deciding the level or profit sharing becomes a trade-off between increasing investibility and reducing the dispatch distortion.

As WP1 modelling shows that operators are more likely to be below the floor if they just receive market revenue, a soft cap is unlikely to reduce dispatch distortions in practice.

Soft floor

Like a soft cap, a ‘soft floor’ would reduce but not remove the dispatch distortion if the H2P operator expects to end the reconciliation period below the floor, depending on the loss sharing rate. The trade-off between increasing investibility and reducing the dispatch distortion is even greater for a soft floor, as reducing the security of the floor may reduce the cost of capital benefits and may reduce the extent to which investors can access debt financing.

An alternative is that the floor is soft but the level of the floor is high (to enable debt financing), increasing investibility but impacting more on dispatch distortions and on costs to funders (tax payers or energy customers).

Revenue multipliers

It would in theory be possible to apply multipliers to the revenue earned on(?) certain units of generation, within the cap and floor model. This could be applied to the first units that an H2P operator generates. This might lead to(?) H2P operators being more likely to end the reconciliation period above the floor, reducing the dispatch distortion.

However, adding these multipliers could increase the dispatch distortion over these early units of generation. If a revenue multiplier is applied, then an operator’s marginal revenue may be above the market price. This may mean that an operator is incentivised to dispatch even when the market price is below its marginal cost, and hence it is inefficient from society’s perspective for that operator to dispatch.

Contractual obligations

It may be possible to add contractual obligations to a Revenue Cap and Floor agreement. This could include performance metrics, obligations, or penalties that require an H2P operator to dispatch when the market price is greater than marginal cost. This could be checked at randomly selected times each reconciliation period, with penalties applied if a plant is not dispatching when the market price is greater than its marginal cost.

If designed efficiently, this reduces the risk of dispatch distortions. However it also increases the complexity and administrative burden of the model, and could impact on investibility. It also opens up the possibility for these features to be designed inefficiently, increasing the costs to society. Therefore while reversing some of the dispatch distortions may be possible, it would add significant complexity and may be preferable to instead use a different business model that does not lead to dispatch distortions that need to be corrected.

Profit cap and floor

A profit cap and floor, with a hard cap and floor, would reduce but not eliminate the dispatch distortion. It would still not necessarily incentivise dispatch if operators are expected to end the reconciliation period above the cap or below the floor.

The impact of dispatch on operators' profits is zero in these regions, whereas under the Revenue Cap and Floor the impact of dispatch is negative on profits for operators. While the distortion is less acute than under a Revenue Cap and Floor, there is still not a positive profit incentive on operators to dispatch, which may distort dispatch behaviour.

Profit cap and floor with soft cap

The profit cap and floor with a soft cap could reduce dispatch distortions when H2P operators are above the cap, depending on the profit sharing rate.

However, WP1 modelling shows that H2P operators are unlikely to be above a cap with just market revenue, and hence this option does not resolve the dispatch incentive that remains when H2P operators are below the floor.

It is possible that additional support revenue could be given to H2P operators so they are more likely to be above the cap, and then a soft cap is applied. This would overcome some of the dispatch distortion, however there are simpler mechanisms available such as the DPA.

Floor linked to fuel price

One possible suggestion is that the level of the floor could be linked to a fuel reference price. Under this mechanism, the level of market revenue that is subject to the cap and the floor is equal to the market revenue earned by the plant minus fuel expenditure.

If an H2P operator is above the cap, the fuel-linked floor does not change dispatch incentives and dispatch is still distorted by the revenue cap. However, WP1 modelling shows that H2P operators are unlikely to be above a cap with just market revenue.

If an H2P operator is below the floor and fuel expenditure (based on a reference price) can be accurately estimated, then this mechanism provides a similar dispatch incentive to the profit cap and floor. The extra unit of dispatch no longer provides a negative impact on profit as under the regular Revenue Cap and Floor, but it does not provide a positive profit incentive either as an H2P operator's profits will be the same whether it dispatches or not.

However, inaccurate forecasting of fuels would also affect the dispatch incentive. Hence, in either circumstance dispatch distortions are likely to remain.

Splitting the H2P operator

The activities of H2P operators could be split into two entities, similar to a gas tolling arrangement, including:

- An infrastructure owner, with high capex and low marginal cost; and
- A risk-taking intermediary, who acts as a shipper, buying the hydrogen and selling the electricity on the wholesale market.

The infrastructure owner could have a Revenue Cap and Floor to cover the increased capex of an H2P plant compared to an unabated gas plant. The H2P infrastructure would have a cost structure suitable for a Revenue Cap and Floor, and there would be no concerns around dispatch distortions.

However the risk-taking intermediary may need to receive another business model to support the use of hydrogen to produce electricity rather than natural gas. If the risk-taking intermediary were using subsidised hydrogen, then it would already be receiving a subsidy through the fuel price and would need no further subsidy. However if the risk-taking intermediary were using unsubsidised hydrogen, then it would need an additional business model to cover the difference in fuel costs. This is likely to significantly increase complexity without offering distinct benefits for H2P ahead of other business models.

Combining a Revenue Cap and Floor with the CM

In theory a Revenue Cap and Floor could be combined the CM. This would mean a multi-year Revenue Cap and Floor contract, where the floor is set at the level of support H2P operators need to break even, and operators bid into the CM on an annual basis. As detailed in Annex D, H2P plants may face difficulty meeting the security of supply requirements of the CM due to cross-chain risks. The rest of this section assumes that security of supply constraints could be met by H2P, and hence a plant would not be penalised during periods of system stress.

The WP1 modelling shows that some H2P plants, such as refurbished assets, blending plants, OCHTs and recips, may not need topping up to the floor if they receive the CM clearing price whereas some H2P assets would need further support beyond the CM.

If operators are topped up to the floor even if they are unsuccessful in receiving CM contracts, then operators would have no incentive to deviate from their true value of support in the CM auction. If H2P assets were then the clearing plant in the CM, then the floor is unnecessary and the model becomes a CM with a gainshare mechanism, and there are the issues of inframarginal rents outlined in our assessment. If asset operators did not receive CM contracts, then this is essentially the Revenue Cap and Floor without the CM, and there are significant dispatch distortions as previously outlined.

If operators are not topped up to the floor if they are unsuccessful in the CM, then this will incentivise H2P operators to underbid into the CM to ensure that they receive a CM contract, as they will have their revenue. This does not reduce the support H2P operators need, but merely splits it between the CM and the Revenue Cap and Floor. WP1 modelling shows that some H2P assets will still need further top-ups to the floor, suggesting that with low CM payments operators could still end each reconciliation period below the floor, meaning dispatch distortions remain. Hence the dispatch distortion remains and the H2P operators provide no liquidity benefits in the CM as they are underestimating their bids.

Annex H: Quantitative comparison of business models

We illustratively compare the cost of funding an H2P plant through different business models, on an asset-level basis. This is in Figure 85 and Figure 86. It was not possible to use the same technique to estimate the level of support that an H2P plant could need under the Revenue Cap and Floor, and generating bottom-up estimates of costs and revenues for an H2P plant was out of scope for this piece of work. Hence the cost comparison is for the other five business models.

Methodology and assumptions

This comparison is from the point of view of 'funders' – for example, taxpayers or electricity consumers - and hence is looking at the social cost of these investments. This is what we refer to as "cost to funders".

The illustrative cost comparison in Figure 85 assumes a start year of 2026 and a common cost of capital of 10%. However, in practice the cost of capital may very across the business models with their relative risk profiles for investors.

The illustration is based on three results from the WP1 modelling:

- CM payment of up to £120/kW could be required to fund a new build CCHT operating on 100% hydrogen. This level of required support would be driven by the total fixed and operating costs expected by the plant (using a dispatch forecast) rather than the market revenue the plant expects to earn from dispatch;
- WP1 results for the wholesale electricity price was used as the reference price in the Deemed Generation CfD calculation;
- WP1 results on the marginal cost differential between a CCGT and CCHT were used to estimate the variable payment.

The private Net Present Value (NPV) for this level of CM support was calculated. The same required private NPV was used to estimate support payments under the other business models. These were then totalled from the societal perspective (the cost to funders) using the 3.5% social discount rate.

Drivers of costs

Differences in cost to funders across these models and for a given H2P investment would generally be driven by three main factors[78]:

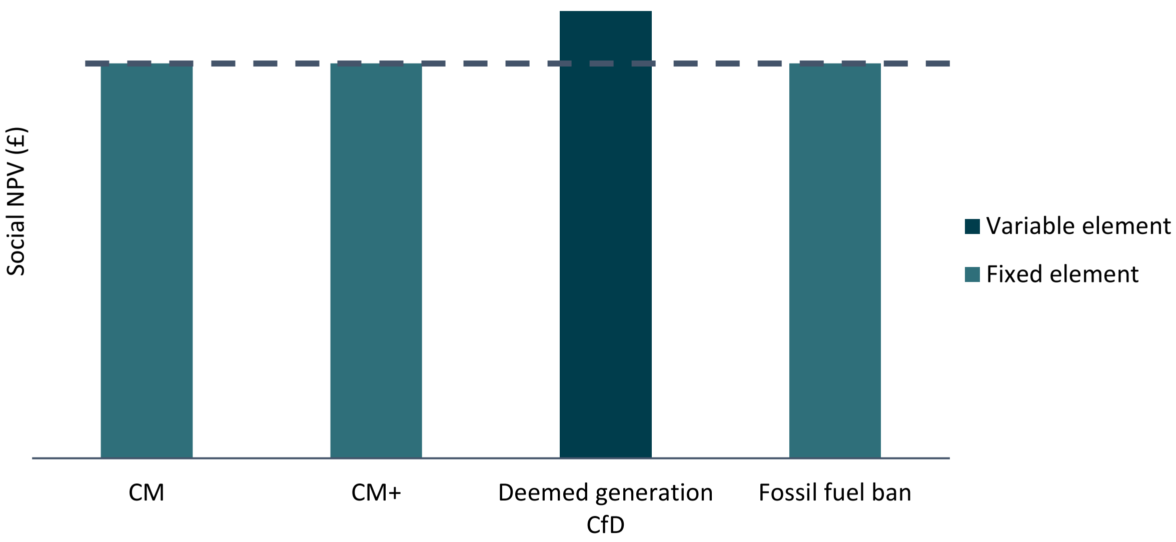
- **Cost of capital.** The illustrative comparison of cost to funders assumes that developer cost of capital is constant across business models. This is likely to vary in practice,

[78] We have not looked at the cost to society of either over- or under-investment in H2P as part of this analysis. This could also be a driver of significant cost to funders.

which could have a significant impact on support. For example, increase in cost of capital from 10% to 12% could increase total support required (in NPV terms) by 12%, and reducing the cost of capital to 8% could save funders 11% (in NPV terms) in support.

- **Cost profile.** The private cost of capital is greater than the social cost of capital, meaning that developers are likely to discount the future to a greater degree than society. Hence for a developer to have a support profile that increases over time, the payment in the future would have to be very large to significantly impact the developer's NPV, because developers discount the future so heavily. However very large payments in the future would be seen as a significant cost to society, who discount the future less. Hence a profile of support payments that increase over time would be more expensive to funders than one that is flat, assuming that developers are indifferent between the two options for support. Equally a profile of support payments that decreases over time would be less expensive to funders than one that is flat, assuming that developers are indifferent between the two options for support.
- **Subsidising dispatch.** While support seems more expensive for developers using unsubsidised hydrogen as fuel instead of subsidised hydrogen, this is because the support is being split across the HPBM and the H2P business model and does not necessarily mean less support is being given to H2P developers overall.

Figure 85: Illustrative comparison of cost to funders – CM, CM+, Deemed Generation CfD and Fossil Fuel Ban



Source: Frontier Economics

Note: As explained above, this analysis assumes a constant cost of capital across business models. This is unlikely to be the case in practice.

Analytical results

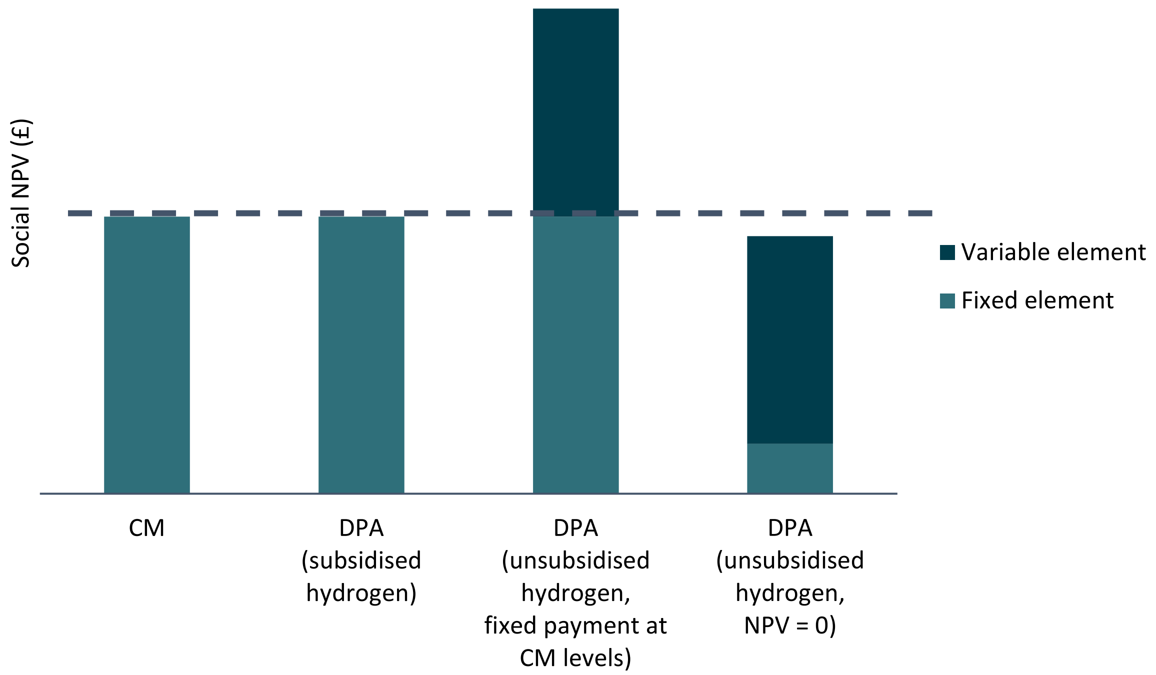
Figure 85 illustrates that, under these assumptions, on an asset-level basis, the CM, CM+ and Fossil Fuel Ban could cost funders a similar amount, whereas the Deemed Generation CfD may be slightly more expensive (measured in terms of the social NPV, assuming constant cost of capital across business models). These represent the likely costs for an H2P plant fuelled by subsidised hydrogen. Costs may differ slightly for H2P plants using unsubsidised hydrogen, but the results from the WP1 modelling do not indicate that this would be large, likely <£10/kW.

As we assume that the CM is still in place with a Fossil Fuel Ban, support payments under the ban are the same as under the CM, if hydrogen is setting the CM clearing price. However, the results of this analysis mask the benefit of the CM+ that this asset-level value of support would need to be paid to fewer assets. Hence on a system-level basis, under these illustrative assumptions, the CM could actually be almost twice as expensive as the CM+.

WP1 modelling suggests that electricity prices are expected to decline over time, and hence support levels would be likely to increase for the Deemed Generation CfD, as the strike price is constant. This profile of support makes the business model more expensive than the CM for funders. Moreover, uncertainty of support is likely to increase developer cost of capital, and hence make the Deemed Generation CfD relatively more expensive than is depicted in Figure 85.

Estimating the cost to funders of supporting an H2P plant through a revenue cap and floor business model would require detailed forecasts of market revenue and was hence out of scope for this work.

Figure 86: Illustrative comparison of cost to funders – CM and various DPA options



Source: Frontier Economics

Note: As explained above, this analysis assumes a constant cost of capital across business models. This is unlikely to be the case in practice.

Figure 86 compares three options for the DPA with the cost to funders of the support required under the CM:

- The DPA for a H2P plant fuelled by subsidised hydrogen;
- The DPA for a H2P plant fuelled by unsubsidised hydrogen, where the availability payment is fixed at the level of the CM. Developers may prefer this business model given that the level of the variable payment is likely to vary over time. This would lead to a private NPV above zero, meaning that developers are earning returns higher than needed to break even; and
- The DPA for a H2P plant fuelled by unsubsidised hydrogen, where the availability payment is calculated such that developers will break even (and hence their NPV is 0).

For H2P plants using subsidised hydrogen, the DPA variable payment is expected to be 0, as the developer's fuel cost is less than or equal to that of unabated gas. Hence support payments on an asset-level are the same as the CM. However, whether an H2P plant is using subsidised or unsubsidised fuel, the same overall subsidy is being provided to H2P developers, it is just being funded across two business models – the HPBM and the H2P business model – instead of one. However, the DPA provides additional support to developers that may reduce cost of capital.

Given uncertainty around outturn dispatch, developers may require an availability payment at a similar level to that required under the CM. This is represented by the second DPA option in Figure 86. This would mean they could gain an IRR greater than their cost of capital, where they are now being subsidised to dispatch, at times when they would have dispatched without the variable payment.

Assuming the DPA is designed so developers are NPV 0 – the thirds DPA option in the list above – the decreasing profile of payments means that the social NPV of support is lower than the CM in expectation. However, there is greater risk for funders of the level of support varying, and a lower availability payment may increase the developer's costs of capital.

This analysis suggests that the CM+ and DPA may be relatively efficient in terms of cost to funders on an asset-level basis and could save funders on a system-level basis compared to the CM and the Fossil Fuel Ban. The profile of payments makes the Deemed Generation CfD likely to be slightly less appealing to funders on an asset-level basis. However, as outlined at the start of this section, investors' cost of capital will make a significant impact to overall costs to funders, so a business model that reduces these is likely to provide greatest value for money to funders.