Hydrogen Production from Thermal Electricity Constraint Management

National Grid ESO & National Gas Transmission

A Network Innovation Allowance funded project

Contents

Executive summary

Arup, in partnership with National Grid Electricity System Operator (ESO) and National Gas Transmission (NGT), has investigated the technical, commercial, and economic case for electrolytic hydrogen production facilities to help manage thermal constraints on the electricity transmission system.

As the electricity system has decarbonised over the last decade, large-scale renewables have connected onto the electricity transmission network and significant further renewables are expected to connect, to achieve a net zero electricity system by 2035. A substantial amount of renewable generation is expected to come online in the north of the UK whereas the bulk of energy demand is likely to continue to be in the South. The electricity transmission network needs to be substantially reinforced to enable these power flows, with delivery taking at least 5-10 years for large transmission infrastructure upgrades given consenting and construction timeframes.

In the interim, when there is significant renewable generation, regional power flows can sometimes exceed the thermal capacity of electricity transmission assets, requiring the ESO to take action to maintain safe system operation. At present, the ESO will pay to turn down (constrain) renewable generation and to dispatch alternative (mostly fossil fuel) generation closer to the demand. The cost of these thermal constraint actions, which are passed onto consumers through energy bills, have increased significantly and in 2022/23 totalled £1.5 billion. With thermal constraints on the transmission network expected to increase further over the next decade or more before being eased by network reinforcement, there is a strong case for alternative solutions to thermal constraint management in the next 10-20 years.

Hydrogen production facilities could reduce regional thermal constraints by utilising electricity from renewables that would otherwise need to be constrained. The low carbon hydrogen generated can then be used as an alternative to fossil fuels in industry, heating or transport to help decarbonise the UK economy.

The technical and commercial viability of using hydrogen production to manage thermal constraints on the electricity network

This innovation project has determined that it is technically viable to operate a hydrogen production facility in a manner that allows it to support management of thermal constraints on the electricity network. Electrolysers, which use electricity to derive hydrogen (and oxygen) are able to react fast enough with response times varying between 10 seconds and 20 minutes, depending on the type of electrolysis technology. Electrolysis facilities in a hot or 'warm' state can respond more rapidly than facilities that are completely 'cold' i.e. restarting.

However, from a commercial perspective, electrolysers are high capital cost equipment. Therefore, a hydrogen production facility would normally seek to maximise utilisation to recover initial investment costs i.e. running at or near to full capacity as much as possible. Thermal constraints will not be present on the electricity network for much of the time, even in very constrained areas reflecting the intermittent nature of renewable generation. This makes the commercial case for a hydrogen facility seeking to manage constraints challenging, even if the cost electricity during the times of constraints was very low or zero (or even negative prices). This project has found that under current market arrangements there is not a sufficiently strong commercial incentive for hydrogen production facilities to play an active role in thermal constraints management without additional support.

An additional challenge is that currently most hydrogen customers, industrial and transport offtakers, require a steady or predictable hydrogen output profile. A hydrogen production facility that supports thermal constraints management will have a more variable production profile as it maps its production up and down. Such a facility therefore either needs access to hydrogen storage (likely to be prohibitively expensive for more than small quantities) or an offtaker that can accept a varying production profile.

This is most likely to be a connection to a gas network. Although some 100% hydrogen networks are planned, during the timeframe when a facility such as this is likely to be required to manage thermal constraints (the next 10-15 years), blending into the existing gas network is likely to be the most feasible option. The case for a facility blending hydrogen into the gas network will depend on network location and will need to be worked out on a case-by-case basis.

Through our investigations, we have found that there is a viable commercial case for hydrogen production facilities to help manage thermal constraints providing:

- There is an alternative electricity supply to draw upon when constraints are not available, to firstly increase utilisation and thus revenue generated from the electrolysers and secondly ensure electrolysers are 'warm' enough to ramp up rapidly when required. This may mean hydrogen production facilities drawing energy from the grid during non-constrained times;
- There is access to a flexible offtaker. The most likely available flexible offtake option is blending into the gas network either as a sole or secondary offtaker; and
- A support mechanism is in place that will incentivise hydrogen production facilities to connect in the right locations and maintain operational profiles that will contribute to the management of thermal constraints in the electricity network. The design of this mechanism is critical to the commercial case and our proposed solution to a support mechanism is summarised below.

The proposed commercial solution: contract mechanisms

Today, decisions over the location of hydrogen projects are a triangulation between multiple factors. This includes the location of the demand offtake, available water resources and an available electricity network grid connection that is able to provide low carbon electricity and/or availability of renewable generation that can be directly connected to the facility.

Current electricity market arrangements, which are based on a single national power price, do not provide strong incentives to hydrogen production facilities to locate in areas where the electricity network is thermally constrained. Whilst a hydrogen production facility could provide demand response services during periods of constraints potentially via participation in the Balancing Mechanism and through bidding for existing ancillary services, this presents considerable commercial uncertainty.

Further, a hydrogen production facility needs to ensure that during periods where there are no thermal constraints on the electricity network, they do not expose themselves to additional price risk compared to if they were in a long-term Purchase Power Agreement (PPA). Under current arrangements, the investment risk lies with the hydrogen production facility and creates challenges for the competitiveness of the hydrogen produced in this way compared to alternative business model approaches.

This project has looked at four potential contract mechanisms that would aim to limit the market risk exposure of hydrogen production facilities and ensure they are remunerated fairly for the whole system benefits they can provide to the electricity system.

The four contract options that have been considered are:

1. Option 1: a utilisation payment (£/MWh) which is received for every 30-minute settlement period that a facility provides a demand turn up in response to thermal constraints.

2a. Option 2a: an availability payment (£kW), similar to the capacity market, whereby a facility is paid to be available for a defined period and then a utilisation payment (£/MWh) for every 30-minute settlement period that a facility provides a demand turn up in response to thermal constraints. The utilisation payment would be lower than option 1 to reflect that the facility also receives an availability payment. Under this option the availability and utilisation payments are higher in Autumn/Winter than Spring/Summer to reflect that constraint costs are likely to be more impactful in terms of system cost in Autumn/Winter than Spring/Summer.

2b. Option 2b: this option is as per 2a however the payment does not vary seasonally between Autumn/Winter and Spring/Summer

3. Option 3: a fixed payment (£m) to be available and provide a response during periods of thermal constraints.

For the business model to be viable, a production facility would utilise this contract mechanism as a secured revenue stream and would otherwise participate as normal in the market to secure low-cost electricity during periods in which thermal constraints are not forecast to occur, for example participation in the balancing mechanism and procurement of electricity purchased in the spot power market and/or via a PPA.

Each of the options provide a different allocation of risk and reward between the ESO (and consumers) and a production facility. Option 1 provides certainty over the price that will be received however does not provide certainty over the volume and the ESO will only be required to pay during periods of constraints. Whereas under options 2a and 2b there is certainty over the price and some volume certainty, however, there remains some volume uncertainty as the utilisation payment will only be paid during periods of constraints. This results in a more balanced allocation of risk between the ESO and the facility. Under Option 3, depending on the actual constraints, the risk allocation may see the ESO over pay if constraints are much lower than forecasted or the facility incurring additional costs to run for more periods than expected if constraints are higher than forecasted. Under all options, the value of the contract(s) will be lower than the cost of constraining the renewables to ensure that the contract(s) delivers value for consumers and a wider whole system benefit.

For all contract options the expectation is that, to create an investable business model, the contract would need to be secured ahead of a Financial Investment Decision (FID) on the hydrogen production plant which is likely to be three to four years ahead of commercial operations. It will also be critical for the production facility to receive a transmission or distribution connection that aligns with these timelines.

Recommendations and next steps

This project has found that with the right commercial arrangements in place hydrogen production facilities could support thermal constraints management.

More work will be required to understand what these arrangements may look like, to explore this further the following next steps are recommended:

- As part of the Constraints Collaboration Project, the ESO should further develop the contract details and engage with Ofgem on whether this could be delivered within the existing regulations.
- A full cost benefit analysis and socio-economic welfare should be undertaken to understand the range and the scale of benefits that can be delivered through the contract and the impact on consumer bills. As part of this, an assessment should be undertaken of how competitive a hydrogen production facility would be compared to other technology types based on the detailed contract elements.
- Engagement with the Department for Energy Security and Net Zero (DESNZ) to consider whether the hydrogen production business models can be allocated in line with a constraints contract from the ESO.
- The whole system benefits that a facility that can contribute to management of thermal constraints should also be recognised in the hydrogen blending arrangements. As the blending arrangements are developed further steps could be taken to favour a hydrogen production facility that is providing genuine whole system benefits when blending capacity is allocated.
- A decision on blending on the transmission network should be taken as soon as possible, for larger facilities the higher pressure network offers higher injection capacity and flexibility.

Introduction and approach

The ESO manages the flow of electricity across the GB transmission network from where electricity is generated to where it is consumed 24 hours a day, 365 days a year. Whilst balancing the system, they are required to maintain the system within defined limits for safety purposes.

The transmission assets that carry this electricity around the network have physical limitations on how much electricity can be carried. To safely operate the system, these limits must be prevented from being reached, or even exceeded, to prevent a loss of supply across the network. In these circumstances, the ESO will take action to reduce (curtail) generation and then redispatch alternative generation in areas where the network limits have not been reached or exceeded. The costs associated with these actions are recovered within consumer bills as thermal constraint costs and results in a significant carbon system operability impact.

Electricity transmission constraints are increasing year on year and are predicted to continue increasing. This is driven by the increase in new renewable generation, particularly offshore wind, connecting onto the network to achieve the UK Government's policy ambitions of 50GW of offshore wind by 2030 and a net zero electricity system by 2035. The majority of the offshore wind is expected to connect in the North of the country, whereas the majority of demand is in the South. By 2030 some areas of the network will see peak electricity flows which are 400% greater than the current boundary capacity. The costs of managing thermal electricity constraint, by paying renewable generators in constrained areas to turn down, is expected to be between £500m and £3bn annually.[1]

Constraints can be addressed through transmission network reinforcement. The transmission network operators, National Grid Electricity Transmission (NGET), SP Energy Networks and SSEN Transmission, have been investing in their networks in line with the Holistic Network Design (HND)[2]. This investment is supported by Ofgem's Accelerating Strategic Transmission Investment (ASTI), which is driving the delivery of a programme of network reinforcement projects by 2030. However, delivering network investment can be a lengthy process, given consenting and construction timeframes.

As a result, there are limited near term levers to manage these increasing constraint costs and, with the volume of constraints currently on the grid, the ESO is looking for shorter term solutions to help manage the costs of constraints on behalf of consumers.

The proposed solution

In April 2023, Arup, working alongside the ESO and NGT, began an investigation into the possible role that electrolytic hydrogen production could play in reducing the impact of thermal constraints on the electricity transmission network.

Electrolytic hydrogen is produced through a chemical process, known as electrolysis, that uses an electrical current to separate the hydrogen from the oxygen in water. To be considered 'green', or low carbon, the electricity needs to be from a renewable source. Green or low carbon hydrogen has been identified as a key opportunity for decarbonising the UK Economy. The UK Government's 'Powering Up Britain'[3] policy included low carbon hydrogen at its core.

This Network Innovation Allowance project has investigated the technical, commercial, regulatory and economic case for electrolytic Hydrogen Production Facilities (HPFs) providing constraint management services to an electricity system operator.

Scope

In exploring the role that electrolytic hydrogen production could have on reducing the impact of thermal constraints, Arup completed multiple workstreams, each exploring the feasibility of an HPF in managing thermal constraints from different perspectives.

Energy modelling – a energy system model was produced to examine the potential size of constraints in the most constrained boundaries between 2023 – 2040. The model took into consideration the impact of changing boundary capabilities over time as network reinforcements are delivered and the subsequent impact on power flows and operating profiles of generators, to provide a view of future constraint profiles and costs.

Commercial analysis – the commercial viability of an HPF utilising constrained electricity was explored by outlining the commercial model of an HPF that uses thermal constraints energy and calculating the Levelised Cost of Hydrogen (LcoH) that a plant using thermal constraints energy could achieve.

Technical analysis – the ability of an electrolysis facility to respond to thermal constraints was examined. This included exploring some modular HPF design concepts to assist in determining the characteristics and constraints of archetype plant designs.

Offtakers – the feasibility of hydrogen produced from the hydrogen production facilities being blended into the gas grid as well as any other alternative off-takers for the hydrogen produced. This took into consideration technical blending requirements as well as commercial and regulatory considerations.

Location – the potential location of production facilities was considered using a mapping tool. This looked at multiple factors, for example, the electricity system boundaries, location of electricity and gas grid and availability of water resources.

What are thermal constraints?

Electricity system constraints

The GB electricity transmission system is used to transport electricity from where it is generated at scale to where demand users are located. As shown in Figure 1, the transmission system comprises of 400kV and 275kV levels in England and Wales (whereas in Scotland it comprises of 400kV, 275kV and 132kV levels) and spans the breath of Great Britain. Currently, power flows are typically from the North (where there is significant generation) to the South (where large demand centres are located).

As the electricity transmission system operator, it is the ESO's responsibility to ensure that the transmission system is balanced on a minute by minute, second by second basis, taking actions as a residual balancer if supply and demand are imbalanced.

The GB electricity transmission system is used to transport electricity from where it is generated at scale to where demand users are located.

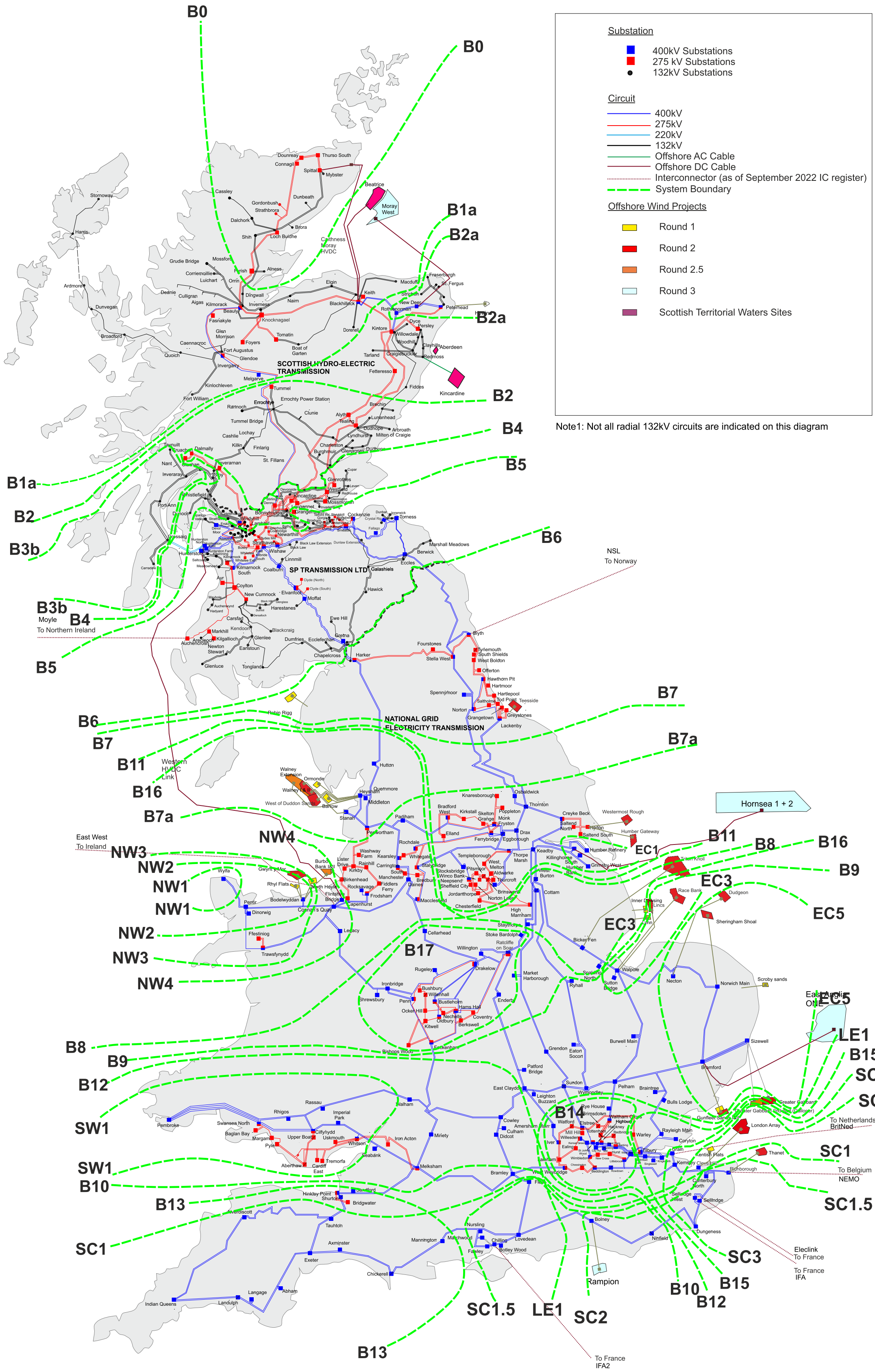


Figure 1 – GB electricity transmission system boundaries

The electricity transmission system is broken into different zones, separated by boundaries where power flow limitations may be encountered. The GB transmission system boundaries are shown in Figure 1. Electricity system constraints occur when the required electricity flow is greater than the capacity of a transmission line across the boundary. To manage these constraints, the ESO will curtail and re-dispatch generation. As greater renewable generation connects to the network, these constraint costs increase to a point whereby the generation connecting, for example in Scotland, is requested to turn down their generating output, as the power cannot flow across the boundary. This results in system costs, which are passed onto consumers, and in many instances fossil fuel generation is required south of the boundary.

The costs of managing thermal constraints have grown significantly over the last 6 years, rising from £309m in FY2017/2018 to £1.5bn in FY2022/23 as shown within Figure 2. This has been driven by the increase in renewable generation, mainly in Scotland and Northern England, which the network was unable to then flow to demand centres in other areas of Great Britain. As identified within Figure 3, there were significant constraints throughout 2022/23 across all boundaries. On days where there were constraints, on average, the cost of thermal constraints was £4.6m per day, with a maximum constraint cost of £62.1m experienced on 20th July 2022.

By 2030, some areas of the network will see peak power flows that are 400% greater than current boundary capability. As a result, the GB's thermal constraint costs are forecasted to reach between £500m to £3bn annually by 2030[4]. These costs will be passed onto consumers through their energy bills. Therefore, there is a requirement to find alternative solutions, whilst network reinforcements are delivered, to minimise the cost of managing constraints on behalf of consumers.

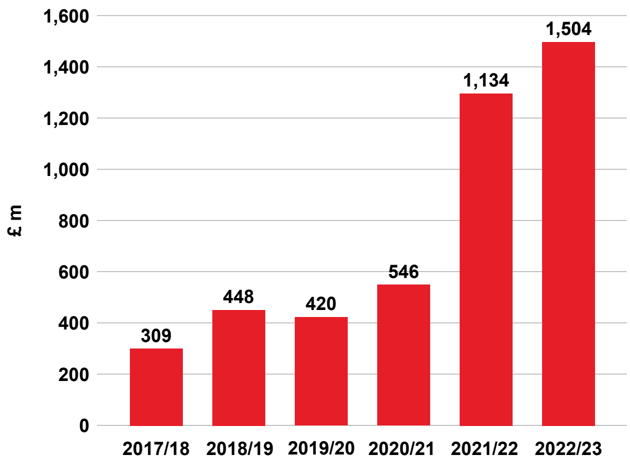


Figure 2 – Annual thermal constraints costs from FY18 to FY23

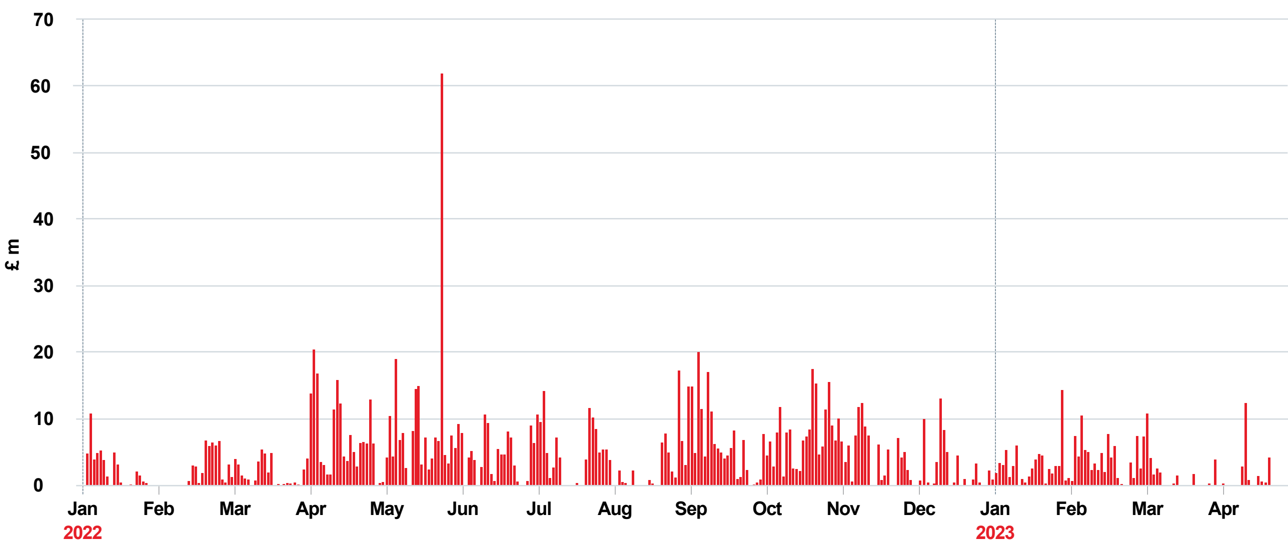


Figure 3 – Daily thermal constraints costs for FY23 (all boundaries)

Future constraints modelling

As part of this project, Arup have modelled future network constraint costs using PLEXOS Energy Modelling Software. Arup developed a model of the GB electricity system, which took into consideration the known network developments considered within the HND and the latest Electricity Ten Year Statement (ETYS) on future power flows and the operating profiles of generators.

The cost of thermal constraints includes two components: the cost of curtailing electricity generators due to thermal constraints behind the boundary and the cost of re-dispatching electricity generators to balance the resulting energy imbalance in front of the boundary.

Based on our analysis of the ETYS 2022 and discussions undertaken with the ESO, Arup's analysis focused on the flows across Scotland and Northern England. Arup has modelled the constraint profile and cost of thermal constraints across boundaries B4, B5, B6, B7 and B8 between 2030 and 2040. These are the boundaries where the majority of constraints are expected going forward, as the planned network reinforcements would not be adequate to completely offset the steep increase in renewable generation deployment (mostly offshore wind).

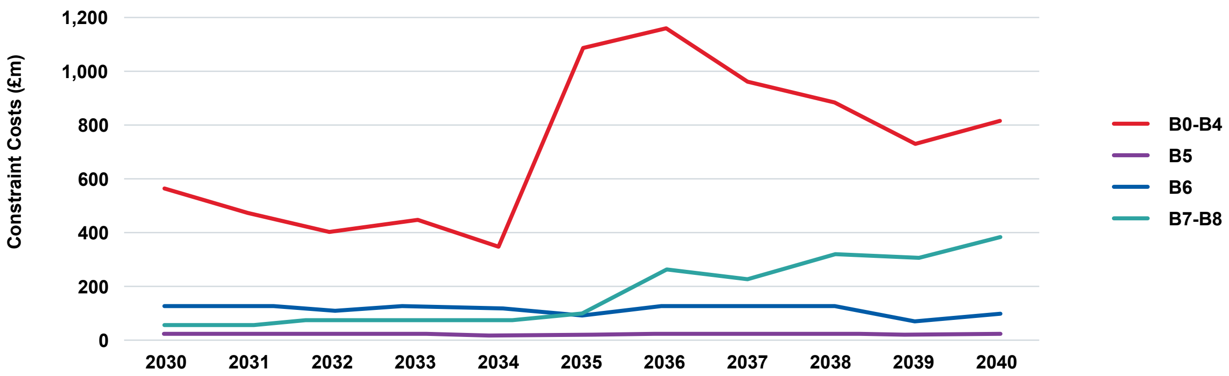


Figure 4 – Total constraint cost between 2030 and 2040 for boundaries B0 to B8

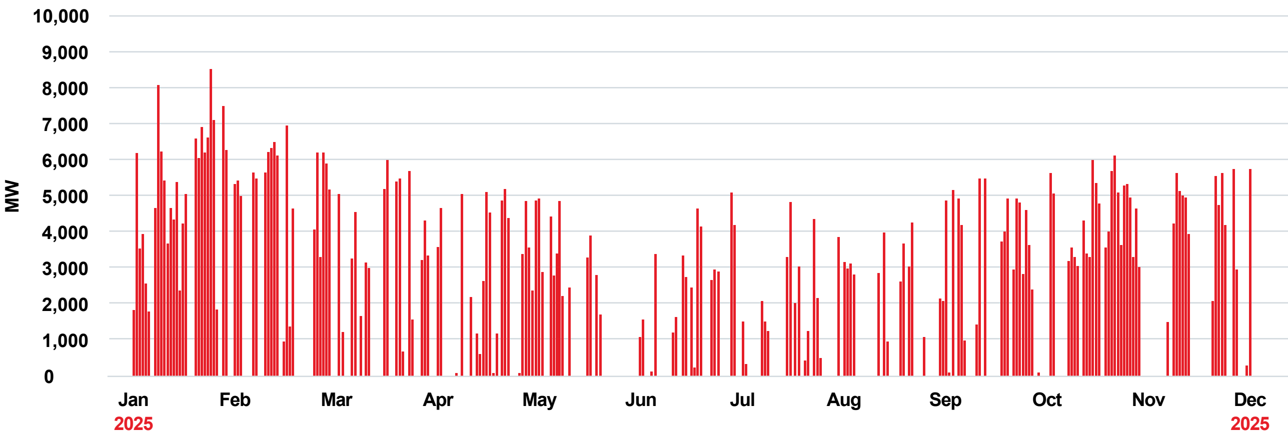


Figure 5 – B0-B4 constrained volume profile 2035

As seen in Figure 4, the highest constraint costs and volumes are observed in B4 across the modelling horizon. B6 is the second highest until 2035. Post 2035, B7 and B8 costs surpass B6 costs. Following network reinforcements, driven by the HND and the ASTI framework, there is a slight dip in costs between 2030 and 2035. However, a significant increase in renewable generation connected above B4 leads to a jump in costs post 2035, mainly driven by an increase in offshore wind capacity.

Similar to the observations presented on cost, 2035 and 2036 are the years with both the highest number of hours and the highest volume of constrained renewable generation in B0-B4. The increase in B7-B8 costs is mostly affected by increased renewable generation in Scotland, combined with additional generation added in the North of England.

As a result, there is an opportunity to explore how thermal electricity constraints could be used to produce low carbon hydrogen, rather than paying generators to turn down. Using hydrogen production to manage thermal constraints could have a positive impact on consumer bills, as well as provide a whole system benefit.

Benefit of using demand to manage constraints

This analysis has found that there is a benefit in using renewable electricity that would have otherwise been curtailed to deliver green hydrogen. Assets that are called by the ESO to resolve thermal constraints usually add a premium on prices when called upon at relative short notice in the balancing mechanism (BM). The main system benefit identified for a hydrogen production facility is the saving achieved by removing the premium on prices that can be achieved by generators in the Balancing Mechanism.

The analysis indicates that this ‘premium’ for CCGT assets (which is the predominate technology currently used by the ESO to provide flexibility) is around 30%. This was derived by analysing historical system offer prices of CCGTs. For wind assets this is quite varied, and it is based on the assumptions listed in the “Market Power” scenario (see appendix 2). Adding a hydrogen facility (or any other demand asset) acts to increase demand in a constrained region, meaning that this demand could be removed from the balancing mechanism and moved into the open market, such as the day-ahead market, because it is known upfront. With sufficient competition, generators should come forward and offer to meet this known increase in demand, again bringing forward generation from the balancing market to the open market. Bringing forward demand and supply to the open market and away from the balancing market creates savings by reducing the added price premium that generators would otherwise add when offering their units in the balancing market.

Benefits of managing constraints through demand management – worked example

The following provides a theoretical explanation of the benefits of managing constraints through demand management would work in practice. Please note that this is only an indicative scenario with illustrative numbers, and it should not be used as a quantification of savings but rather as a simulated example of how savings would be achieved in a single half hour. Further details of our analysis on avoided premium in the context of proposed contract mechanism designs is detailed in the Support Mechanisms section.

For the basis of this theoretical explanation, the following assumptions are made:

In the example scenario where there is no Hydrogen facility present, the following occurs:

- CCGT A and Wind Farm are successful in the Day-Ahead (DA) auction which clears at £90/MWh. This means both assets will receive £90/MWh to deliver 500MWh. CCGT-B is not successful as the clearing price is above its Short Marginal Cost (SRMC). This means that only CCGT-A and Wind Farm sell energy in the Day-Ahead auction.
- In real time the ESO has to instruct the wind farm to not generate due to a thermal constraint. The wind farm is eligible for support which is equal to £54/MWh, which they receive only if they generate. In reducing its output, the wind farm would theoretically need to recover the money of the lost subsidy and therefore bid in the BM at a price equal to the lost subsidy of £54/MWh.
- As the Wind Farm is being constrained off behind the thermal constraint an energy imbalance results in front of the constraint. To resolve the imbalance, the ESO calls on CCGT-B in the Balancing Mechanism to generate 500MWh. CCGT-B offers its output in the BM at £130/MWh including a premium of 30% on its actual SRMC.
- The actions above results in a total cost of £182,000 for this half hour for the consumer in this example.

In the case where the Hydrogen facility or any other flexible asset is present, the following occurs:

- An additional 500MWh of flexible demand coming from the hydrogen facility will participate in the DA auction. As a result, CCGT-A, Wind Farm and CCGT-B will all be successful in the auction. CCGT-B will now be the marginal unit clearing the auction at £100/MWh.
- The ESO does not need to take any action as the flexible demand facility will use the electricity that in the event of a thermal constraint would have otherwise needed to be curtailed whilst the dispatch of CCGT-B has already been secured at DA stage to meet the additional demand.
- However, in this scenario the Wind Farm will still be paid £54/MWh as based on their subsidy scheme , the wind farm is paid a fixed amount of £54 for every MWh it generates and exports to the grid.
- The total cost of the actions described above would be £177,000 resulting in a saving of £5,000 for the half-hour. In essence this saving comes from the avoided premium that CCGT-B would charge if it had to be dispatched with short notice in real time.

The charts below show the actions taken by the ESO in this example:

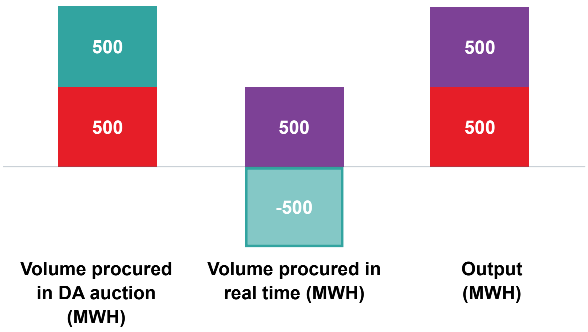


Figure 6 – Actions without H_2 Facility[5]

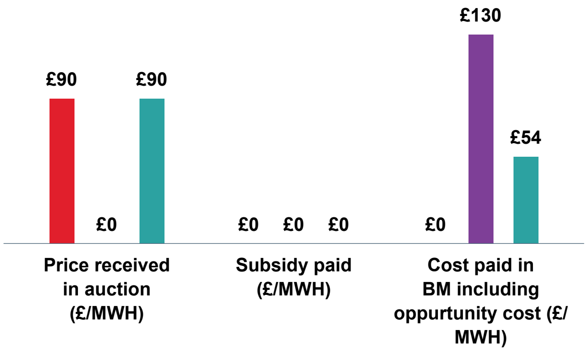


Figure 7 – Price per MWh without H_2 facility

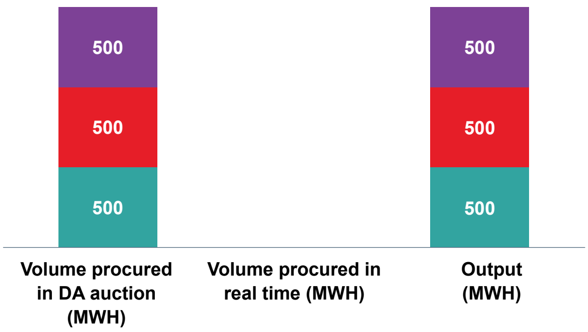


Figure 8 – Actions with H_2 facility

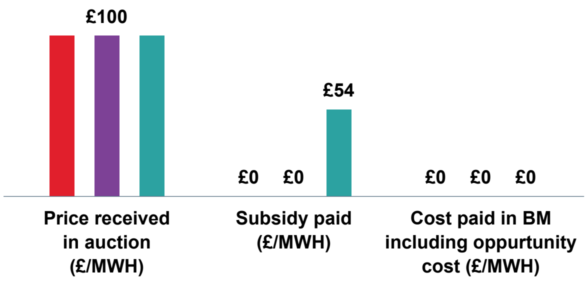


Figure 9 – Price per MWh with H_2 facility

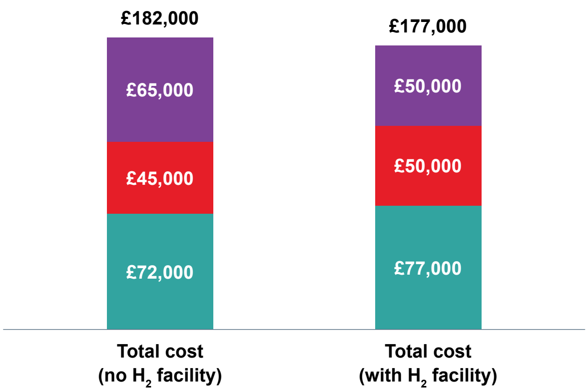
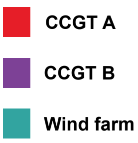


Figure 10 – Total system cost with and without the H_2 facility single half hour (illustrative)



Use of hydrogen to manage thermal constraints

Low carbon hydrogen production

Electrolytic hydrogen is produced by using electricity to separate water (H_2O) into hydrogen (H_2). For this hydrogen to be low carbon, the electricity used must come from renewable sources such as wind and solar. As shown in Figure 11, this hydrogen can then be used in multiple sectors:

- In industrial processes, as a feedstock, or, in industrial heating, as a low carbon alternative to natural gas;
- In transport, in hydrogen fuel cell electric vehicles (FCEV) or hydrogen combustion vehicles. In theory, hydrogen can be used in all road vehicles, in practice however it is more likely to be used in larger vehicles that need to travel long distances such as HGVs, heavy industrial equipment buses, trains (where lines are not electrified);
- In shipping and aviation, either as hydrogen or as a key component in the manufacture of sustainable fuels;
- In domestic and commercial heating, as an alternative to natural gas; and
- In power generation, hydrogen could be used to generate electricity during peak times, effectively acting as a large battery, generated at times of high renewable production, then used to provide power during periods of low renewable electricity production and high demand.

Hydrogen can be transported either through pipelines or tube trailers from the production location to the end user. Pipelines provide the most cost-effective way of transporting hydrogen at scale. In the shorter-term, up to 20% hydrogen volume can be blended into the existing natural gas network, with minimal changes to the network or gas appliances. An advantage of hydrogen is, like natural gas, that it can be stored in large quantities in geological storage helping to balance the energy system.

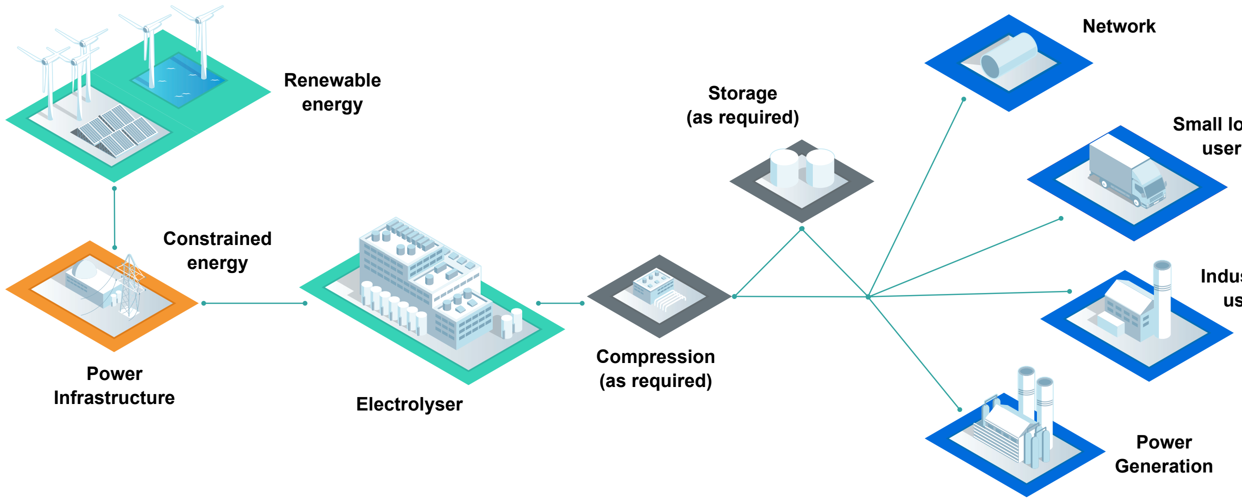


Figure 11 – Hydrogen value chain

The UK Government sees hydrogen as an important decarbonisation option, as the UK delivers upon its net zero commitment by 2050. The Government has set an ambition to have 10GW of low carbon hydrogen by 2030.[6] To support this ambition, the Government have introduced the hydrogen production business model (HPBM) to support the development of hydrogen as a clean and low-cost energy technology. The HPBM provides ongoing revenue support to projects by covering the difference between the cost of making hydrogen and the price they can receive for the hydrogen, known as a strike price, over a 15-year period.

To date, 11 projects have been awarded CapEx and OpEx funding in the first Hydrogen Allocation Round (HAR1)[7] and the Government is currently running the process for HAR2[8]. As part of HAR2, the assessment criteria for awarding support considers the impact on the electricity system, with projects encouraged to be located optimally to reduce system constraint costs and to utilise excess renewable generation (thus providing a whole system benefit to consumers). In the assessment criteria, DESNZ highlighted that projects located in Northern areas would be considered to have the most positive impact on the electricity system, as shown in Figure 12.

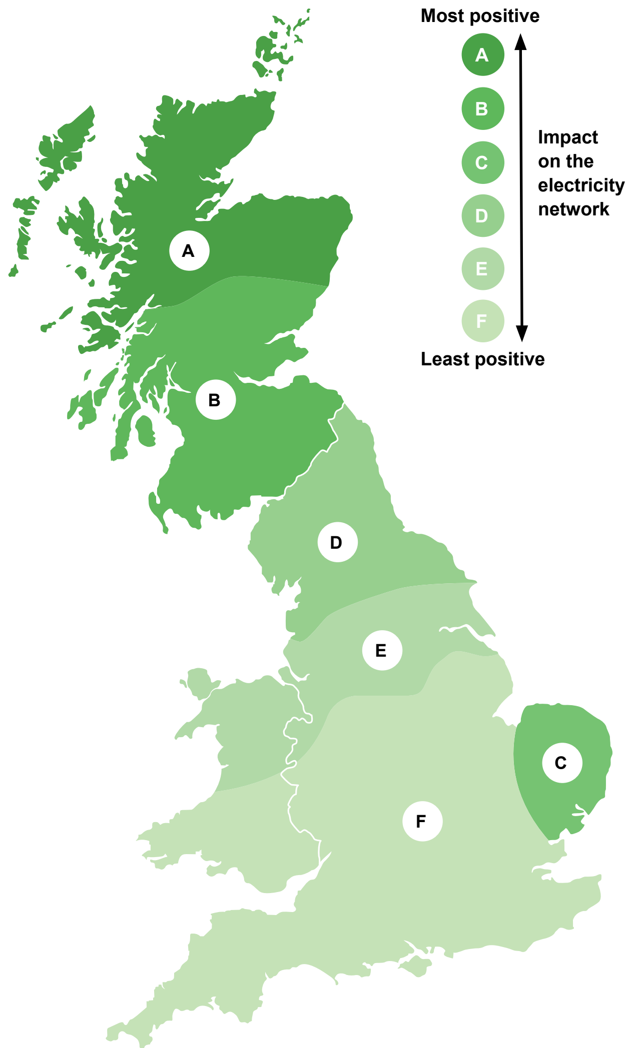


Figure 12 – Impact of the location of low carbon hydrogen on the electricity system

Source: DESNZ

Hydrogen production using thermal constraints

A hydrogen production facility could use electricity from excess renewables to produce hydrogen by locating near to a constrained boundary and increasing generation at times of constraints.

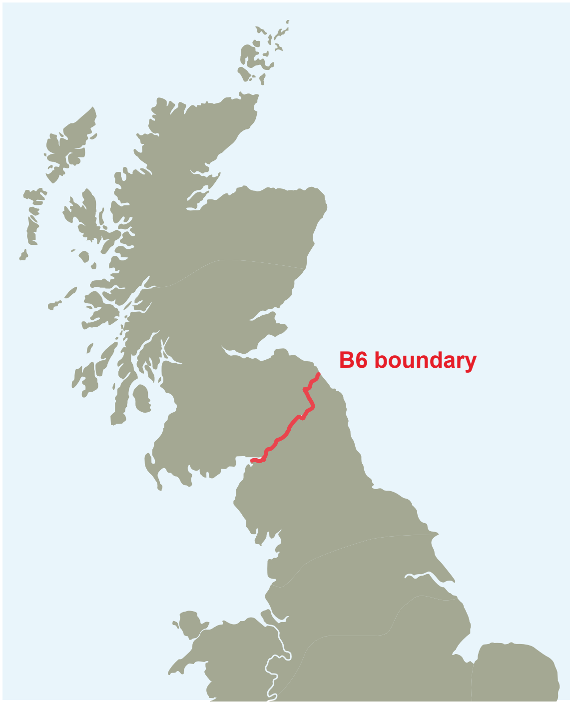
Case Study

B6 boundary

Currently, the B6 boundary, which geographically spans the border between England and Scotland, is constrained as the offshore wind north of the B6 boundary, at times, can produce greater electricity than can flow down to the large demand centres in Southern England.

To support constraints within this area, a hydrogen production facility could be located anywhere north of the B6 boundary to provide demand when there is a system imbalance. When there are periods of network constraints, the production facility would increase its use of electricity and therefore its hydrogen production. This would support the ESO in managing the imbalance between supply and demand and reduce the need for the ESO to instruct and pay renewable generators that connect north of the boundary to turn down.

As the ESO balances the system on a half hourly basis, there are 48 half hourly periods within a day that the production facility may be able to turn up its demand to use the excess renewable generation (that would otherwise have been constrained). For example, if there were constraints during half hourly periods 1-6 and then 24-48, the production facility would be able to increase their demand during periods 1-6, turn down during periods 7-23 (as there are no constraints) and then turn back up during periods 24-48.



The amount by which the production facility would increase its demand would depend on the volume of constrained electricity. For example, it may be that the constraint is greater than the size of the facility and the hydrogen production facilities' demand could increase to full capacity (100%). Alternatively, it could be that the size of the constraint is equal to 50% of the hydrogen production facility's capacity and demand would only increase to 50%, with 50% of capacity unused if only using thermally constrained electricity as the electricity source. The number of constraints would vary within every half hour.

Today, decisions over the location and operation of hydrogen projects are a triangulation between multiple factors. This includes the location of the demand offtake, available water resources and an available electricity network grid connection (or the availability of renewable generation through a direct private wire connection).

In considering the feasibility of a hydrogen production facility utilising thermally constrained electricity, this investigation has looked at whether it is:

- technically feasible for the production facility to ramp up to provide a response during periods of constraints; and
- commercially viable to operate a hydrogen production facility in this manner, and what the offtake route for the hydrogen produced could be.

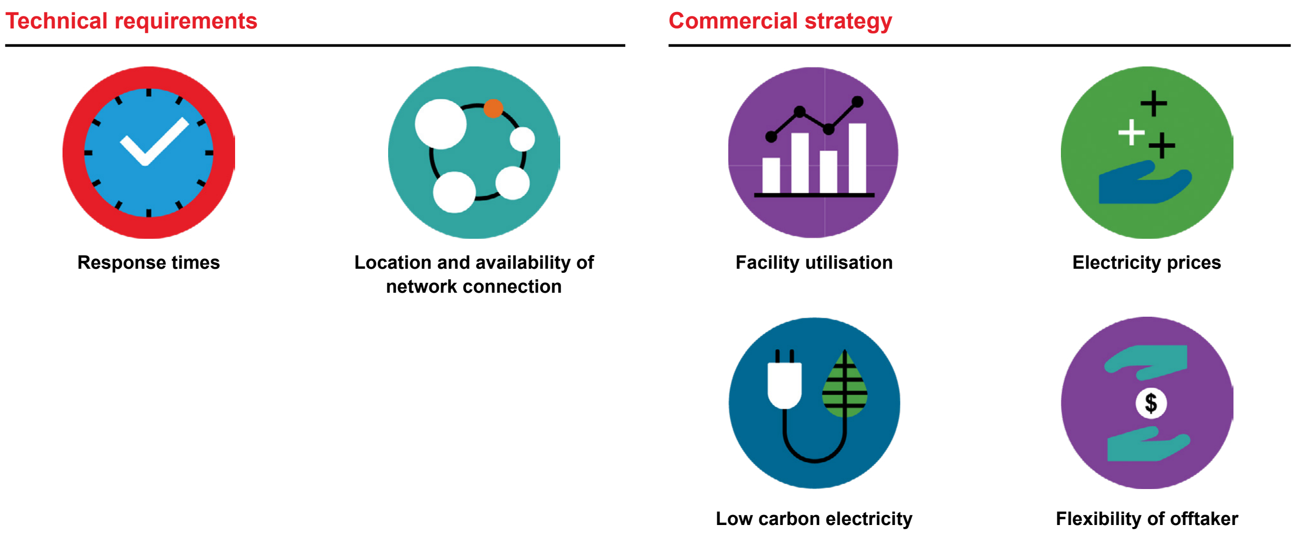


Figure 13 – Factors influencing an HPF responding to thermal constraints

The technical feasibility of the production facility to ramp up

For the facility to be able to respond to thermal constraints, the facility will need to turn up and down quickly in line with signals from the ESO. There are three main technologies for producing hydrogen via electricity: Alkaline, Proton Exchange Membrane (PEM) and Solid Oxide Electrolyser Cell (SOEC). Currently, most projects use either Alkaline or PEM as an electrolyser technology, as these are more mature than SOEC technology. Table 1 presents the response times of hydrogen electrolysers in different states. In both a hot and warm state, the production facility would be able to respond reasonably quickly to a signal from the ESO to increase demand in the event of a constraint of the electricity network. The ESO acts as the residual balancer after the market closure, one hour ahead of real time. It is during this hour that the ESO would provide signals to providers to turn up demand.

Whilst it is technically feasible to respond quickly, there are wider impact considerations on the production facility itself. Constantly adjusting the settings of an electrolyser, whether it's being turned up and down (or subjected to frequent cold starts to manage constraints), can have significant technical impacts. Such fluctuations can lead to increased wear and tear on the equipment, potentially reducing its operational lifespan. Moreover, abrupt changes in operation can affect the stability and efficiency of electrolysis processes, resulting in fluctuations in gas purity and output. Additionally, frequent cold starts can impose thermal stress on the system, potentially causing thermal expansion and contraction issues that may compromise the integrity of components over time.

State	Definition	PEM Response time	Alkaline Response time
Hot	A hot start refers to when the production facility is already producing hydrogen.	10% per second and therefore can reach full capacity within a maximum of 10 seconds	0.2%/s (atmospheric) to 10%/s (pressurised) (8.3min-10sec startup)
Warm	A warm start refers to when the electrolyser is already consuming power to maintain specific temperatures and pressures within the electrolyser but there is not necessarily any hydrogen production.	10% per second and therefore can reach full capacity within a maximum of 10 seconds	8 minutes
Cold	A cold start refers to when the starting from no power to the electrolyser or any balance of plant components.	5 minutes as it can ramp 20% per minute	20 minutes (5% per minute)

Table 1 – Electrolyser response times

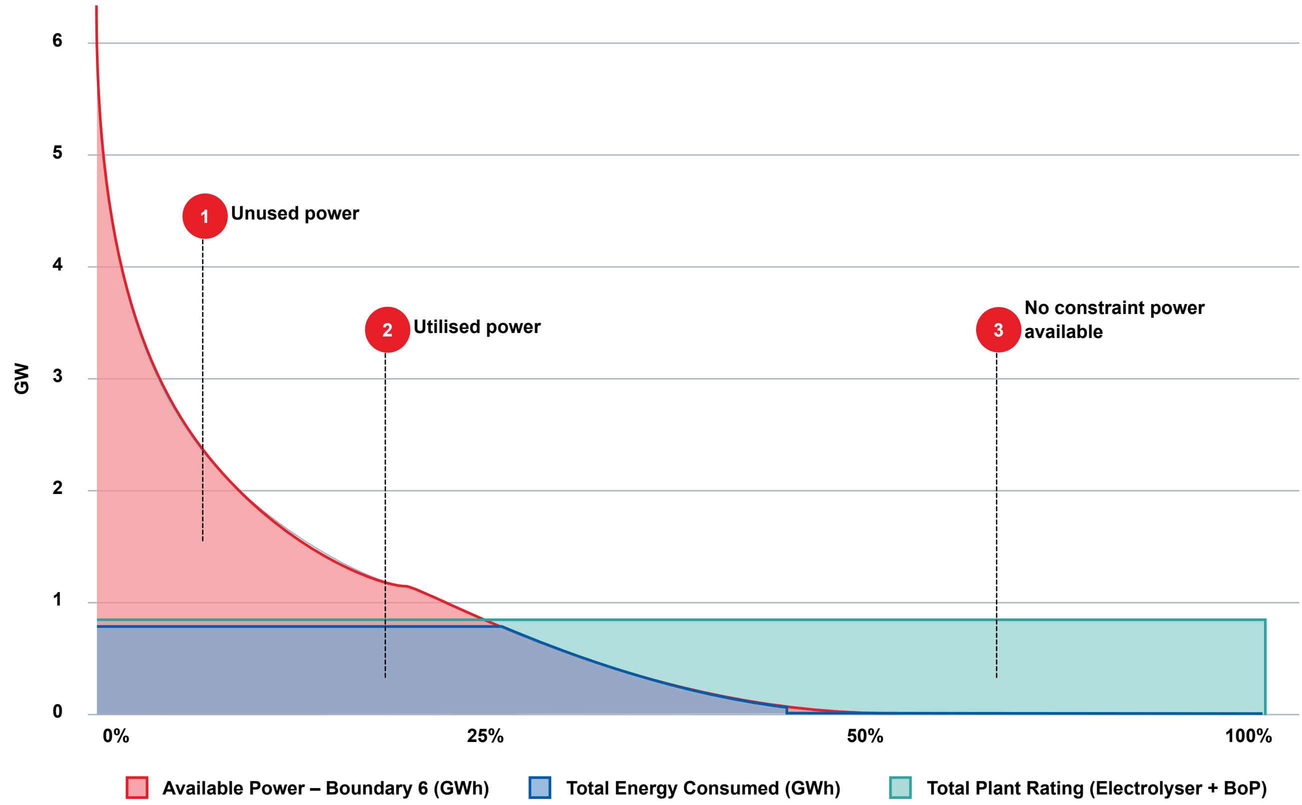


Figure 14 – Indicative load duration curve for one year (data within the graph is illustrative)

The commercial viability of operating a hydrogen production facility using thermal electricity constraints

To be able to operate the hydrogen production facility in the flexible manner required to utilise thermally constrained electricity, a robust business model is needed that allows the investor to recover the high capital costs of an electrolyser facility.

Utilisation of the facility

In terms of the frequency and number of constraints, this will be determined by the profile of thermal constraint electricity on the boundary that the production facility is located above. Figure 14 provides an illustration of the constraints experienced (GW) within a year on any one boundary, as indicated by the curve, and the subsequent load factor, hours of the year, that the production facility would operate.

Area 2 indicates the periods during which an example 750MW production facility would be operating. In over 36% of the hours within the year, the production facility would be operating at full capacity utilising thermal constraints and, for a further 20% of the hours, the production facility would be operating but at a lower capacity. Overall, for around 60% of the hours in the year, the production facility would utilise thermally constrained, either at full capacity or to a lower capacity.

Area 1 represents periods when there are constraints, however, the constraints are greater than the size of the production facility and therefore not resolved, assuming no other facilities or other mechanisms are used. Area 3 represents the periods where there are no thermal constraints and therefore it is not operating or using alternative power sources.

Commercial Strategy

A significant driver of the operating costs of a hydrogen production facility are the electricity costs. A production facility will look to optimise their electricity costs to allow for their hydrogen to be competitive compared to other projects. The production facility can secure their electricity prices through several routes including the wholesale market, Balancing Mechanism (BM), a PPA or Over the Counter (OTC) contracts. Currently, most current or planned electrolytic hydrogen projects are securing their electricity prices through renewable PPAs.

Through a PPA, OTC contract or spot wholesale price, the HPF will pay positive prices for the electricity and look to secure the most competitive price available to provide stability for their business model. Through the BM, there is the opportunity for the facility to bid successfully at zero or negative prices. This would allow the hydrogen production facility to earn revenue by using electricity for hydrogen during periods of where electricity is constrained. However, the BM can be volatile and reflects real time fluctuations in demand and supply. As such, it does not guarantee any certainty on prices, nor that the hydrogen production facility would always be successful with their bidding strategy. For example, a hydrogen facility may expect zero or negative prices if forecasts indicate high amounts of wind generation but closer to real time, wind suddenly drops and prices become positive.

Optimising between a PPA or OTC contracts and the BM provides the opportunity for the production facility to reduce its overall electricity costs. However, to recover the overarching investment cost, an HPF may target a higher utilisation factor and may need to make last minute optimisation decisions, which may be more expensive had the facility procured a fixed electricity price through an alternative approach. This then leaves the investment risk with the facility, as the balance of revenues and costs from participating in the balancing market will depend on how well a hydrogen production facility can optimise across different revenue streams.

As a result, current arrangements do not provide sufficient incentive for a hydrogen production facility to locate in areas of constraints and provide a demand response during periods of constraints as there is too much risk with the investor when recovering the costs of the production facility.

A significant driver of the operating costs of a hydrogen production facility are the electricity costs. A production facility will look to optimise their electricity costs to allow for their hydrogen to be competitive.

Electricity sourcing and the low carbon hydrogen standard

For the hydrogen produced to meet the Low Carbon Hydrogen Standard (LCHS),[9] the hydrogen developer will need to evidence that the electricity source mix used will need to be sufficiently low carbon. The LCHS allows for hydrogen projects to record electricity consumption as 'electricity curtailment avoidance'. This lets the emissions of the electricity source during times where electricity is thermally constrained to be claimed at the regional or national GHG emissions figure (in CO2/KWh) during the relevant time period. For example, a hydrogen production facility using constrained electricity in the North of Scotland[10] area can claim the North of Scotland regional system emissions figure published by National Grid ESO[11] or Elexon[12] as its electricity consumption during that time period. The emissions figure is likely to be at or near to zero during times of thermal constraints in areas with excess renewable generation. A hydrogen project that is located in constrained areas will want to claim regional rather than national emissions figures as the regional figure will reflect the (very low) emissions intensity of the electricity used much better than the national figure. The LCHS requires evidence of Bid Offer Acceptance within the Balancing Mechanism and metered electricity consumption data for each time period claimed.

Required flexibility of offtaker

A hydrogen production facility that uses thermally constrained electricity as described in this report is likely to have a varying hydrogen production profile, producing more hydrogen during times when the constrained electricity is available. To date, most hydrogen production facilities are being developed to supply a single or a small number of clustered offtakers either for industrial process or for use in transport refuelling. These offtakers typically require a stable or predictable profile of hydrogen.

An option to manage the flow of hydrogen to offtakers would be to use hydrogen storage facilities which are sized to be filled during periods of high production and emptied during low/no production. However, above ground hydrogen storage tanks can only offer limited storage, and larger geological storage facilities (such as in salt caverns) are limited. New geological underground hydrogen storage in salt caverns and other geological formations potentially offer a low unit cost solution for large scale storage, but the capital costs are likely to be too high for an individual project to absorb. Large scale underground storage is more likely to be part of a wider hydrogen network where costs can shared by a number of projects and customers.

A more viable option for a hydrogen production facility with a varying production profile is a connection to a gas network. The ideal offtake solution would be a 100% hydrogen network which could take all the hydrogen a facility produced (within the limits of the pipeline' capacity), these are currently planned near and within the industrial clusters and through National Gas Transmissions' Project Union. However, 100% hydrogen networks are likely to be limited in the next 10-15 years, therefore, in the short-to-medium term, blending into the existing gas network is likely to be the most likely flexible offtake option.

Using the gas network as a flexible offtaker

GB has a comprehensive gas network delivering (near) 100% natural gas to around 80% of residential homes and thousands of industrial and commercial customers. A hydrogen blend of up to 20% could be injected into the existing gas networks with limited alterations to the network. The vast majority of current gas appliances could accept a blend of up to 20% hydrogen (by volume) without needing to be amended or replaced. A major advantage of blending as an offtaker is its flexibility. Hydrogen can be blended into the network when it is produced. Periods of no or reduced hydrogen production are not an issue as there is no specific off-taker reliant on the hydrogen from the facility.

The volume of hydrogen you can blend at any particular point in the gas network will depend on a number of factors, including:

- the size and pressure of the pipeline, generally the larger size and pressure offers more injection capacity;
- the location, with network entry points generally offering greater capacity; and
- the distance to other blending facilities, if other blending facilities are close the blending limit would need to be managed.

This is further explored in appendix 4.

In December 2023, the UK Government published a strategic decision on blending, where it announced that it intends to proceed with blending into the gas distribution networks subject to a safety assessment and subsequent finalisation of the economic assessment. In its decision, the UK Government stated that it saw two strategic roles for hydrogen blending;

1. An ‘offtaker of last resort’ - being able to accept hydrogen when there is excess production that is not required by the primary offtaker; and
2. As a ‘strategic enabler’ where hydrogen production facilities are able to support the wider energy system by locating in areas where there is excess constrained electricity.

The decision stated that the HPBM would be the most appropriate mechanism to support hydrogen blending. In the first two rounds of HPBM, hydrogen blending has not been allowed as an offtaker. The UK government’s future rounds will allow for blending to be considered as a qualifying offtake, as long as a projects use of blending as an offtaker aligns with the strategic roles outlined above. A hydrogen production facility that uses thermal constraints will be ideally placed to play a role as a strategic enabler.

It is important to note that the UK Government’s decision has been at distribution network level and there remains uncertainty about whether blending will be allowed at transmission level.

The appropriateness of using hydrogen to manage thermal constraints

The analysis conducted for this project has confirmed that is it technically possible for the electrolyser to turn up their demand quickly when there are periods of thermally constrained electricity. For this to be feasible, the production facility would need to have a flexible offtaker who can take the hydrogen when its produced but does not need a constant supply of hydrogen. Of the offtakers considered, blending into the gas grid provides the flexibility that a facility turning up and down production will need and in the locations and time frame when its likely to be needed.

Irrespective of the technical feasibility and offtaker viability, the challenge remains that, if the production facility locates in an area of where there is constrained electricity available and is only operating during periods of constraints, this is most likely to result in a low utilisation of the production facility. This would prevent the production facility owner from sufficiently recovering the cost of investment and results in a higher cost of hydrogen produced compared to other business model approaches.

However, by providing this capacity to the system operator, the production facility could provide significant benefits in managing constraint costs. Therefore, for this business model to be viable, a support mechanism is necessary to incentive hydrogen production facilities to locate in areas of constraints and be actively involved in managing electricity transmission system constraints.

The production facility would need to have a flexible offtaker who can take the hydrogen when its produced but does not need a constant supply of hydrogen. Blending into the gas grid provides the flexibility that a facility turning up and down production will need.

Support mechanism

To incentivise HPFs to locate in areas of system constraints and to use the excess renewable generation, this project has identified and assessed potential support mechanisms that could be introduced.

In considering the options, several factors were reviewed, including: the ESO's system balancing responsibilities, hydrogen production facility requirements and the need to deliver value for money when managing constraints.

ESO's system balancing responsibilities

The design of any potential support mechanisms is bound by the ESO licence, where the ESO is required to:

- ensure the efficient, economic, and coordinated operation of the electricity transmission system; and
- promote effective competition in the generation and supply of electricity, and promote efficiency in the implementation and administration of the balancing and settlement arrangements.

Therefore, the ESO will need to demonstrate that any potential contract mechanism meets these requirements. The incoming National Energy System Operator (NESO) will have a broader licence and responsibilities, specifically to ensure that the system is economic, efficient, secure, and reliable, as well as achieving net zero. This will result in the NESO taking a more strategic and whole system approach to electricity and gas system operation.

Hydrogen production facility requirements

To be able to make an investment in the production facility to utilise the constrained electricity, a production facility will need a long-term contract that provides revenue certainty, alongside other revenue streams, to enable a hydrogen production developer to reach a FID.

In the short to medium term, there is likely to remain a cost gap between hydrogen and carbon based fuels. The UK Government has introduced the Hydrogen Production Business Model[13] (HPBM) to incentivise low carbon hydrogen production, by providing revenue support to hydrogen producers. It is expected that a hydrogen production facility that uses constrained energy will still require support through the HPBM.

Delivers value in managing constraints

In developing the mechanism, historic constraint costs were reviewed, and future constraint costs were modelled. Historically, the costs of thermal constraints management have been highest in terms of frequency and impact during the winter months, however, whilst less frequent in summer months, they can have a significant impact. A similar result is seen in the future constraint modelling results, with B4 experiencing significant constraint costs post 2030 across the years.

The value of a support mechanism

Under the support mechanism, the hydrogen production facility would be incentivised and paid to turn up its demand during periods of constraints, as presented in Figure 15.

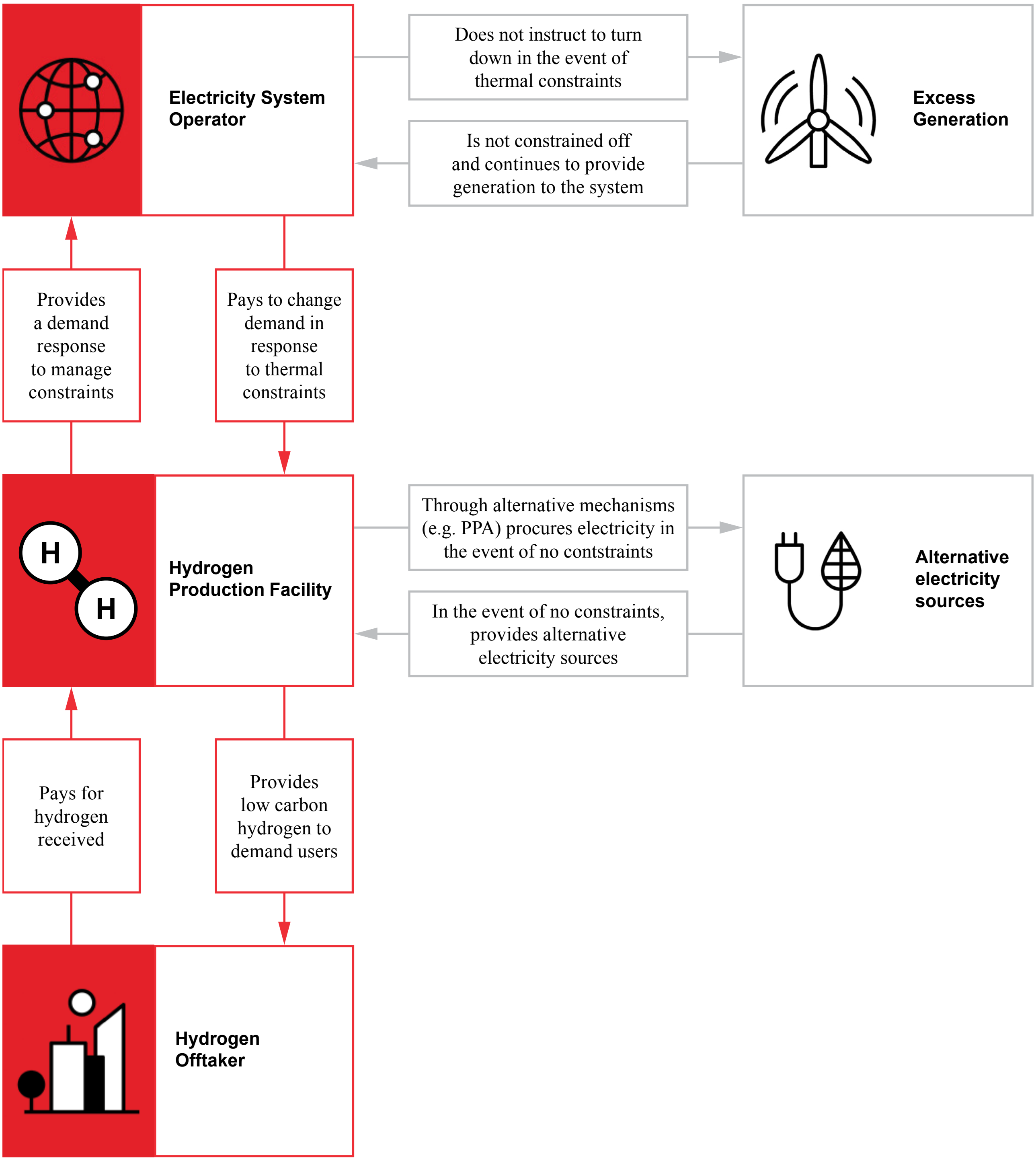


Figure 15 – How the mechanism would work

Underpinning considerations for all mechanisms

Implicit in the design of the mechanism is that:

- There will be a ceiling price for all options to ensure that the value secured through the mechanism will be lower than that of the constraint costs payments made by the ESO that would otherwise be incurred through the balancing mechanism. This is to ensure that the overall benefit to the electricity system delivered through the mechanism is greater than in the 'do nothing' scenario of paying renewable generators to turn down.
- In securing support through the mechanism, all demand units would need to meet prequalification requirements (specifically technical requirements) and a competitive process would be facilitated to allocate contracts. Contracts would be awarded based on best value for consumers considering the whole system.
- The mechanism would be aligned, where possible, to the new planning processes that are being developed, specifically the Centralised Strategic Network Plan (CSNP), which would consider alternative solutions.
- This contract could be utilised either by new facilities or by existing facilities as long as these are located in the right locations to support thermal constraints management.

The options

This project has identified four contract mechanism designs:

1 Utilisation payments

2a Seasonally varying utilisation and availability payments

2b Utilisation and availability payments that do not vary seasonally

3 Fixed payment (either yearly or half-year)

In assessing these options, the 'do-nothing option' for comparison is the production facility participating in and being called upon through the Balancing Mechanism.

The following provides an overview of how each of these options would work and the balance of risk and reward between the ESO/GB consumers and the hydrogen production facility (the demand 'provider').

1 Option 1 Utilisation payment

Overview

Under this option, demand assets connected to the network that can respond during periods of constraints are paid an agreed utilisation payment (£/MWh) for the duration of the constraints. The provider would inform the ESO ahead of time of their availability and the associated utilisation fee they would expect for the duration. Tenders will be paid on a 'pay as bid' tender process, with bids accepted from the lowest to the highest price until sufficient capacity has been secured.

Contract length

The duration of the contract could vary in duration between 1 – 10 years. The length will be driven by the forecasted constraints profile certainty, this will take into consideration wider decisions regarding network investment, specifically expected network investment within the 10-year period that is likely to be impactful in reducing constraints. This contract would most likely be procured at T-1 years but could potentially be procured up to T-4 years. The contract would also be available for facilities that relocate, that can demonstrate that their relocation does not have a material negative impact elsewhere on the system. For relocated facilities, the contract duration could be shorter depending on the ESO's assessment of future network infrastructure and constraint costs.

Dispatch periods

This would have two instruction windows: 21:00 (day-ahead) for the period of 07:00 – 06:59 and 13:00 (within day) for the period of 19:00 – 06:59. For instruction window 1, providers will have up to 10 hours to prepare for dispatch post instruct time, and 6 hours for window 2.

Other design features

- To incentivise providers to respond through this rather than the Balancing Mechanism, these responses will be prioritised ahead of BM units. This prioritisation would not include a financial incentive.
- If providers confirm availability, they will be required to meet a minimum level of availability to receive full utilisation payment.
- A penalty could be applied if the provider has committed to being available during periods of constraints but then utilises the Balancing Mechanism instead. This penalty would not be applied to factors outside of the control of the responder.

2a

Option 2a
Seasonally varying utilisation payment and availability payment

Overview

In addition to the utilisation payment discussed within option 1, the demand user would receive an availability payment similar to the existing Capacity Market mechanism whereby the provider is paid a £/MW to be available for defined periods. The availability payment (against an associated MW) would be defined and agreed ahead of the service period and in line with the contract duration. The utilisation rate (£/MWh) would be scaled to consider the size of the availability payment.

Under this option, the availability payment and utilisation payment would vary during autumn/winter and spring/summer periods to reflect the difference in impact and frequency of constraints during these periods. This seasonality reflects that the historic constraints and the future modelled constraints are generally most impactful in terms of volume and costs during the autumn/winter period, and the provision of a demand response from the production facility during the autumn/winter period is likely to deliver greater value to consumers. Therefore, the total value of response in the autumn/winter period is higher than the spring/summer period.

Contract length

For new facilities, the contract length would be 10 years, aligning with the timescales of known electricity network development as per the ETYS/CSNP network upgrades. The procurement of this contract would be 4 years ahead of need (T-4 years), which would likely be in line with the hydrogen production facilities FID timelines.

The contract would also be available for facilities that relocate, that can demonstrate that their relocation does not have a material negative impact elsewhere on the system. For relocated facilities, the contract duration could be shorter depending on the ESO's assessment of future network infrastructure and constraint costs.

Dispatch periods

This would have two instruction windows: 21:00 (day-ahead) for the period of 07:00 – 06:59 and 13:00 (within day) for the period of 19:00 – 06:59. For instruction window 1, providers will have up to 10 hours to prepare for dispatch post instruct time, and 6 hours for window 2.

Other design features

- The utilisation element of the contract could be capped and/or an expected utilisation profile could be provided within the technical specification document.
- A penalty is applied during periods where the demand provider (the hydrogen production facility) is expected to be available but subsequently provides short notice that they are unavailable.
- As part of the contract terms, if providers confirm availability for a period, they will be required to meet a minimum level of availability to receive the full utilisation payment.

2b Option 2b Availability payment and utilisation payment (year-round)

Overview

This option would be similar to option 2a, however, the utilisation and availability would not vary seasonally, but would be fixed at the same level throughout the year. This would mean that the same amount of kWs is effectively secured for the year.

Contract length

For new facilities, the contract length would be 10 years, aligning with the timescales of known electricity network development as per the ETYS/CSNP network upgrades. The procurement of this contract would be 4 years ahead of need (T-4 years), which would likely be in line with the hydrogen production facilities FID timelines.

The contract would also be available for facilities that relocate, that can demonstrate that their relocation does not have a material negative impact elsewhere on the system. For relocated facilities, the contract duration could be shorter depending on the ESO's assessment of future network infrastructure and constraint costs.

Dispatch periods

This would have two instruction windows: 21:00 (day-ahead) for the period of 07:00 – 06:59 and 13:00 (within day) for the period of 19:00 – 06:59. For instruction window 1, providers will have up to 10 hours to prepare for dispatch post instruct time, and 6 hours for window 2.

Other design features

- The utilisation element of the contract could be capped and/or an expected utilisation profile could be provided within the technical specification document.
- A penalty is applied during periods where the demand provider (the hydrogen production facility) is expected to be available but subsequently provides short notice that they are unavailable.
- As part of the contract terms, if providers confirm availability for a period, they will be required to meet a minimum level of availability to receive the full utilisation payment.

3 Option 3 Fixed payment

Overview

This option would see the provider receive a fixed £ value for a defined period for the level of response (in MW) they could make available to the ESO. The value received through the contract would be predetermined by the avoided premium in section 3.

Contract length

This contract would be procured for 1 year period only.

Dispatch periods

This would have two instruction windows: 21:00 (day-ahead) for the period of 07:00 – 06:59 and 13:00 (within day) for the period of 19:00 – 06:59. For instruction window 1, providers will have up to 10 hours to prepare for dispatch post instruct time, and 6 hours for window 2.

Other design features

- A penalty is applied during periods where the demand provider (the hydrogen production facility) is expected to be available but subsequently provides short notice that they are unavailable.
- As part of the contract terms, if providers confirm availability for a period, they will be required to meet a minimum level of availability to receive the full utilisation payment, or would be subject to a penalty payment.

Utilisation payment calculation

Based on the avoided constraint cost that was derived by Arup's modelling, the project has calculated the average utilisation payment (£/MWh) between 2030 and 2040 for the constrained boundaries.

The utilisation payment is the volume weighted average of the avoided premium involved in curtailing renewable electricity and ramping up flexible generation (CCGT in our analysis). This results in a volume weighted average of £22.40/MWh for the utilisation payment for the period between 2030 and 2040. This is the Base Case minus market power to incorporate the premium applied (plus CCGT ramp up cost), see appendix A2.

This is the maximum figure and is also an indicative figure and further modelling will be required to derive a more accurate figure; Arup expects that the actual number would be lower to take into consideration firstly that the contract should deliver a value below the cost of the 'do nothing' scenario of just paying the constraints and liquidity within the market should drive competitiveness in bid responses when securing the contract. Arup has assumed that the HPF would receive a 50% discount on the BSUoS costs to reflect the positive impact that they provide to the system.

Availability payment calculation

For each asset, the total expected benefit between 2030 and 2040 has been calculated. This was based on the volume of constraints avoided across the 10-year period, multiplied by the utilisation payment described above. The total volume was then divided by the asset capacity and the number of years to derive the maximum availability payment per annum. For option 2b, Arup assumed that the asset would recover 70% of its revenue via the availability payment (i.e. multiply by 70% the total availability payment) and the rest via a reduced utilisation payment. For option 2a, Arup defined seasonal utilisation and availability payments by calculating the winter and summer volume weighted average of the total renewable curtailment cost (utilisation payment). The values for the contract options are set out in Figure 16 for the three different electrolyser sizes Arup modelled: 300MW, 750MW and 1500MW.

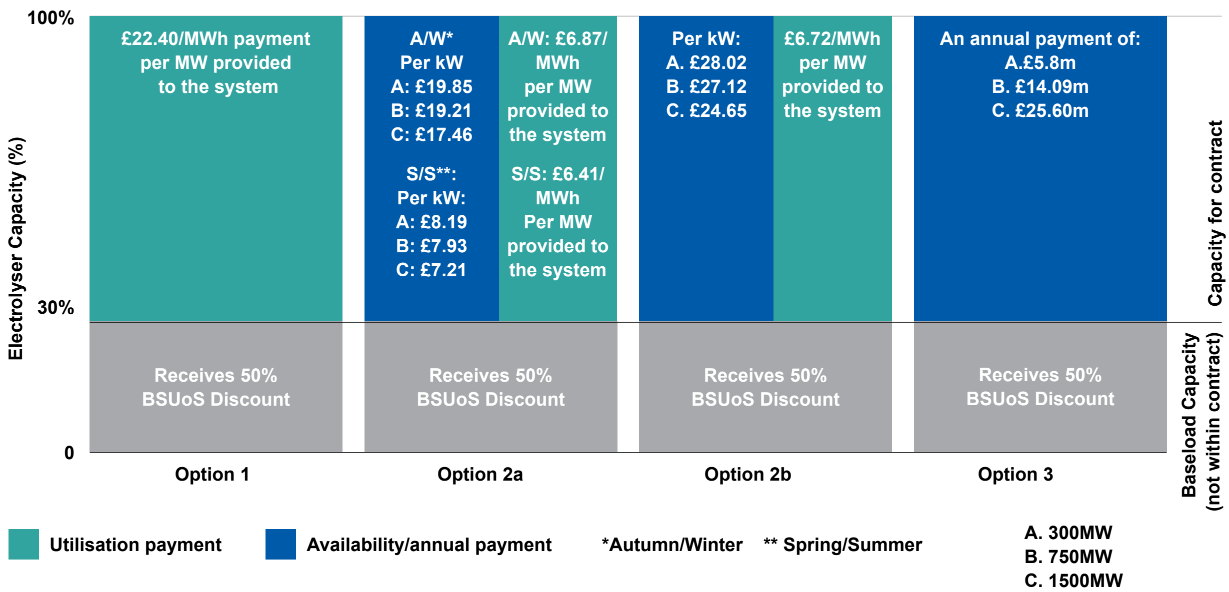


Figure 16 – Estimated prices secured under the contract mechanism options

The following provides a theoretical explanation of how the mechanisms would work in practice across multiple scenarios. For the basis of this theoretical explanation, the following assumptions are made:

- A hydrogen production facility has secured a contract with the ESO to make available up to 750MW of its capacity to support management of the thermal constraints. These 750MW are only utilised for constrained circumstances and do not have any other electricity input.
- Under options 2a and 2b, the production facility has received an availability contract for the full capacity of 750MW.
- At contract signing, the ESO would confirm the merit order for the assets that have secured a contract. For all scenarios, except scenario 4, the hydrogen production facility is assumed to be first in the merit order.

Scenario	Option 1 **Utilisation payment**	Option 2a **Seasonally varying utilisation payment and availability payment**	Option 2b **Availability payment and utilisation payment (year-round)**	Option 3 **Fixed payment**
1. There is a constraint of 750MW in autumn/winter	The production facility would receive a utilisation payment for the capacity supplied of 750MW.	The production facility would receive a utilisation payment for the 750MW and the winter/autumn availability payment for the 750MW.	The production facility would receive a utilisation payment for the 750MW and an availability payment for the 750MW.	The facility would receive the payment irrespective of the constraints that materialise. During this period, it would provide the capacity of 750MW.
2. There is a constraint of 300MW in autumn/winter	The production facility would receive a utilisation payment for the 300MW.	The production facility would receive a utilisation payment for the 300MW and the winter/ autumn availability payment for the 750MW.	The production facility would receive a utilisation payment for the 300MW and an availability payment for the 750MW.	As per scenario 1, the facility would receive the fixed payment irrespective of constraints. In this scenario, it would provide 300MW of demand.
3. There is a constraint of 300MW in spring/summer	As per scenario 2	As per scenario 2, however they receive the spring/summer availability payment.	As per scenario 2.	As per scenario 2.
4. There is a constraint of 750MW; The HPF is second in the merit order after another 500MW asset	The production facility would receive a utilisation payment for the 250MW.	The production facility would receive a utilisation payment for the 250MW and the winter/ autumn availability payment for the 750MW.	The production facility would receive a utilisation payment for the 250MW and an availability payment for the 750MW.	As per scenario 1. In this scenario it would provide 3MW of demand.
5. There is a constraint of 2GW	The production facility would receive a utilisation payment for the 750MW. The ESO also calls upon other assets within the merit order to manage the constraint.	The production facility would receive a utilisation payment for the 750MW and the winter/ autumn availability payment for the 750MW. The ESO may then also call upon other demand providing assets within the merit order.	The production facility would receive a utilisation payment for the 750MW and an availability payment for the 750MW. Then, the ESO would also call upon other demand providing assets within the merit order.	The facility would provide its full capacity of 750MW. The ESO may then also call upon other demand providing assets within the merit order.
6 A period of no constraints in autumn/ winter	The production facility would receive no utilisation payment as it is not providing any demand.	As scenario 1 except no utilisation payment.	As scenario 1 except no utilisation payment.	As with all other scenarios, the provider would receive the fixed payment but only this time it would not provide any demand.

Table 3 – How the contract options would work in practice

As the contract is for periods of thermal constraints, it is expected that hydrogen production facilities would take actions to optimise their utilisation, and therefore their business model, during periods of no constraints. This optimisation is likely to only occur when the HPF is confident that it will not be called upon through the contract, to ensure it avoids any penalties for non-response. This optimisation will be driven by the wider business model of the HPF but could include a PPA and/or providing responses through the BM. This wider optimisation is likely to increase the viability of the business model as it results in higher utilisation of electrolyser capacity.

Contract allocation approach

To offer this contract mechanism to the market, an auction and an allocation window approach could be utilised. The approach that is most suitable varies depending on the timing of when the contract mechanism needs to be secured and the likely liquidity of the market.

The viability of the auction approach will depend on whether there is sufficient liquidity within the market to encourage competition between bidders when determining their £/MW and £/MWh. In the event of limited or no competition, bidders could be incentivised to provide a higher bid price than they would have in the event of strong competition. This higher price would ultimately mean that consumers would be faced with higher costs had competition incentivised bidders to provide a more competitive price.

Depending on the boundary, it may be that there are less technologies located (or are planning to locate) in proximity to the boundary, and are able to meet the requirements to result in a competitive auction. Thus, an auction approach may not deliver the best value for consumers. An alternative approach could be to utilise allocation windows and a whole system approach to the allocation of contract mechanism.

Under the allocation approach, windows would be used to invite providers to meet a defined system need. This approach is similar to the Cap and Floor Windows and the Network Options Assessment (NOA) Stability Pathfinder. The approach could be aligned with the new Centralised Strategic Network Plan (CSNP)[14] process, which is expected to be introduced in 2026, as per Figure 17.

Model Future Supply & Demand

Future Energy Scenarios development to provide a view on supply and demand out to 2050.

↓

Need identified

Through the NESO planning process (transition or final CSNP) future supply and demand are modelled to provide a view on system needs, including thermal constraints. The outputs of the system needs identification would be published to the market.

↓

Tender process to identify solutions

Based on the identified needs, the NESO would provide a tender to the market that invites non-network solutions. Based on the CSNP, this would provide a view for <=12 years.

↓

Cost benefit analysis of solutions

A technical, economic, social and environmental assessment would be undertaken. This would need to provide a view of the whole system benefits, specifically the socio-economic benefits of, for example, the downstream benefits of use of the hydrogen e.g. displaced gas.

↓

Contract awards

A confirmed solution would be awarded a MW capacity and a £ /MW / hr. Similar to the Cap and Floor, mechanisms would be included for this to be revised based on agreed market conditions including indexation to ensure it delivers best value for consumers and is investable.

Figure 17 – New CSNP process including proposed allocation window

The ESO/NESO would identify a need via the Future Energy Scenarios (FES) and detailed network planning, which would then be put out to market via tender windows. As part of the tender process, the NESO would provide:

- the specific system need that is being resolved through the window, including the required MW;
- the duration of the need, including an indicative benefit saving that the NESO are trying to achieve; and
- the tender assessment process and the criteria that will be used to assess tender responses.

Tender responses would detail non-network solutions and would provide detail on:

- technical information, including likely performance and capability and capacity;
- deliverability information, including evidence that the project will be commissioned on time;
- commercial proposition of the asset (for the availability and/or utilisation element) and the time duration this can be provided for (if it is less than the proposed tender duration); and
- the whole system benefits that would be delivered by the HPF, specifically: how is the output of the constrained electricity going to be used, and whether will it be displacing carbon usage in other areas of the economy.

NESO would then assess the providers responses based on the assessment criteria. The criteria would likely combine technical, deliverability and commercial. This approach is likely to be more effective where there is less liquidity (i.e. few solutions that are able to meet the needs of the tender) and where a rigorous project-by-project assessment needs to be undertaken to consider the full benefits that are being delivered to bring forward the necessary investment.

As the NESO becomes a technical advisor to DESNZ and Ofgem, there is the opportunity to consider the alignment between the allocation of this contract with the hydrogen production business models. Project applications for HPBM funding and the thermal constraints contract could be assessed jointly, allowing for a strategic whole system decision to be made that provides benefits to the electricity system, meets the demands of the hydrogen market, ensures deliverability of the projects, and has credible offtakers in line with wider GB decarbonisation ambitions. This could result in an overall reduced cost to the consumer/taxpayer whereby the amount of funding allocated through the hydrogen business model accounts for the revenue received through the contract.

As the NESO becomes a technical advisor to DESNZ and Ofgem, there is the opportunity to consider the alignment between the allocation of this contract with the hydrogen production business models.

Allocation of risk and reward across the contract options

The overarching purpose of the contract is to secure optimal consumer benefit for consumers during periods of constraints. In unlocking this value, the allocation of risk between the ESO, acting on behalf of all electricity consumers, and the HPF, has been considered. This is summarised in Table 4 below.

Risk Allocation	ESO		Hydrogen Production Facility	
	Price Risk	Volume Risk	Price Risk	Volume Risk
Option 1. Utilisation payment	High	Low	Low	High
Option 2a. Seasonally varying utilisation payment and availability payment	Medium	Medium	Medium	Medium
Option 2b. Availability payment and utilisation payment	Medium	Medium	Medium	Medium
Option 3. Fixed payment (either yearly or half-year)	High	High	Low	Low

Table 4 – Allocation of risk in the contract mechanisms

In Option 1, the ESO is taking the price risk by providing a guaranteed price (£/MWh) for the duration of the contract, but is not committed to call upon the HPF unless there are thermal constraints. This means the volume risk for the ESO is low. As a result, whilst the HPF understands the price it will receive, it bears the volume risk as it does not have any certainty on the amount of MWs that will be called upon during the contract. Also, hydrogen production developers have indicated that, under this option, the duration of the contract may not provide sufficient revenue certainty to a HPF developer to allow them to operate in the flexible manner that would be required. HPF developers indicated that the contract length would need to be closer to the contract length under the HPBMs of 15 years.

Options 2a and 2b provide a more balanced risk allocation between the ESO and the HPF. These options transfer some of the volume risk to the ESO through the availability payment linked to the capacity, which means that the hydrogen producer has some revenue certainty over what will be received during the contract.

This means that the ESO still bears part of the price risk as they are committed to an availability payment but also have committed capacity that will, in the event of constraints, provide a demand response delivering value for consumers. However, the ESO's price risk is more limited because of the utilisation payment, which would only be paid during periods of constraints. As a result, the hydrogen producer still carries some volume risk as the revenue it receives through the utilisation payment will be dependent on the actual constraints profile (although this is a lower risk than under option 1).

In Option 3, the ESO bears both the volume and the price risk in the event of lower constraints than forecasted. as they offer a fixed price to the facility. The hydrogen producer has lower price risk, as it understands the full revenue it will receive for the duration of the contract, and has low volume risk. However, in the event that the outturn constraint costs were higher than forecasted at the point of the contract agreement, the HPF would be required to provide a demand response.

Levelised cost of hydrogen (LCOH)

LCOH considers the total costs (including capital, operating, replacement CAPEX) of hydrogen production over the life of the asset and divides it by the total volume of hydrogen produced over the same period. The costs and volume of hydrogen produced are discounted at a rate of 7% using the following formula:

LCOH (£kg) = Sum of costs over lifetime (£) x discount rate (%) / Sum of hydrogen produced over lifetime (kg) x discount rate (%)

It is used as a measure to compare the competitiveness of hydrogen produced from different projects. For producing hydrogen from thermal constraints to be a viable commercial opportunity, the cost of producing hydrogen will need to be competitive with other hydrogen production routes. For example, using renewables generation via a PPA to produce hydrogen. To be able to compare the hydrogen production viability using thermal constraints compared to other routes, LCOH modelling was undertaken for the scenario of producing hydrogen to inject (blend) into the natural gas grid. This was modelled across three different hydrogen production facility sizes – 300MW, 750MW and 1500MW.

Note that there are many factors that will influence the levelised cost. The LCOH figures used here are illustrative based on assumptions, and actual LCOH of individual projects can vary significantly. The assumptions and detailed modelling results are included within A.1.

Modelling results and sensitivities

The LCOH modelling results concluded that all contract options improve the LCOH compared to a scenario of no contract using electricity via a PPA rather than constrained electricity, as shown in Figure 18. Based on the expected constraint profiles in 2030, the LCOH modelling indicated an approximate levelised cost range of £4.7/kg to £5.0/kg. See A1 for more details on LCOH assumptions and figures. According to a range of sources, including BNEF, ClimateXChange and Hydrogen Insight, the LCOH for hydrogen production plants in the UK can range between[15] £3.90-£9.50/kg.

In the UK Government's hydrogen business model first allocation round (HAR1), the strike price agreed with projects was £241MWh[16], which is £9.50/kg. This is a strike price negotiated in order for a production facility to cover early projects risks and make a commercial return so it would be expected to be above the levelised cost.

The differences between contracts though are relatively small in the year modelled. The larger difference between the contract options is the allocation of risk between the ESO and the hydrogen producers.

Due to the changing constraint profile, the LCOH changes year on year. In years where there are greater constraints, the facility is able to respond more and receive greater revenues through the contract, compared to years when the actual constraints are lower.

The future constraints modelling estimated that 2036 could be most prevalent. Based on the 2036 constraints profile, the modelling estimated a LCOH of between £3.6/kg to £3.9/kg.

In terms of contract sensitivities, changing the contract assumptions (e.g. the received contract value or contract length) had less of an impact than changing the technical assumptions (e.g. electrolyser capex or amount of storage).

Utilisation is a major driver of the LCOH, lower utilisation would lead to higher LCoH due to the underutilised capex. The contracts effectively act as compensation for the hydrogen production facility utilise its assets in a less optimal way that it would otherwise do in order to respond to constraints.

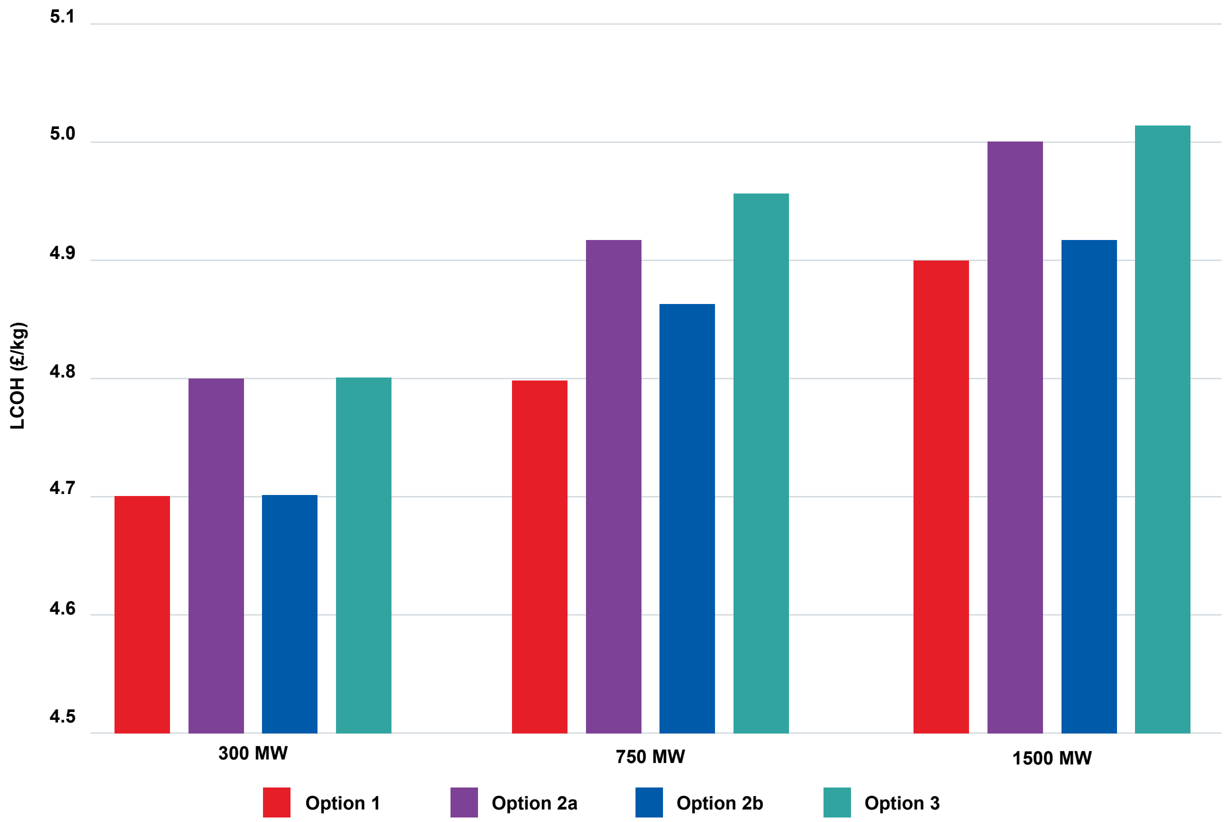


Figure 18 – LCOH range for contract options using 2030 modelled constraints profile

Stakeholder engagement

Following the development of outline contract mechanisms options, Arup, National Grid ESO and National Gas Transmission engaged with several potential HPF developers to capture feedback on the concept of hydrogen production in thermal electricity constraint management and the proposed contract options. During the discussions, feedback was sought on the detailed elements on the contract design and whether the contract mechanisms would provide sufficient incentives to firstly locate in areas of constraints and secondly provide demand turn up during periods of contracts.

Feedback on hydrogen production using thermal constraints and contract options

Hydrogen developer stakeholders generally agreed that an ESO contract to respond to thermal constraints on the electricity network would benefit the business model of an HPF. There were varying views on the extent to which a contract would encourage a HPF to locate in the most beneficial areas for thermal electricity constraints management. Some developers felt that hydrogen demand was likely to remain the strongest factor as to where HPF would locate today, and that this demand was likely to be from industrial or transport users.

Most developers are not currently looking at hydrogen blending as an offtake option, in line with the Government's position to date on hydrogen blending. Those that were looking at hydrogen blending as an offtake did feel that a contract such as this would be of major benefit to their project and help projects achieve FID. Developers emphasised the importance of having sight of a reasonably developed contract prior to reaching a FID.

The December 2023 Government decision on blending at the distribution networks was welcomed as a positive step. However, developers expressed some frustration over the uncertainty of whether blending could go ahead at transmission level. It was also raised that a facility, such as the one described in this report, that provides genuine whole system benefits should be prioritised when it comes to allocating hydrogen blending rights.

It was felt that some of the blending arrangements proposed such as the 'free market' approach to blending allocation and the restrictions around trading of green gas certificates may inadvertently hinder facilities that do provide whole system benefits.

All hydrogen developers stated that it was critical for the HPF to take wider optimisation actions, securing electricity through other means (PPAs, directly connected renewable generation) outside of constrained times. Most developers would not want to be restricted from pursuing their own electricity sourcing strategies outside of the times when they were needed by the ESO. Linked to this, developers stressed that sufficient notice would need to be provided by the ESO as to when the HPF would be expected to provide a demand response under any contract. It was suggested that ideally this would be much greater notice that the design dispatch periods of day-ahead, though it was recognised that this would need to be a negotiation between developers and the ESO.

Generally, developers felt that any ESO contract should be closely aligned with the HPBM with developers favouring the idea that the contract is allocated in conjunction with future allocation rounds of the hydrogen business model. Specifically, developers felt that the contract would ideally need to be closely aligned in duration with the contract length under the HPBM of 15 years. Some developers felt that 10 years could be sufficient recognising the risks to the ESO of longer contracts.

Overall, it was the allocation of risk that was regarded as the most important factor to developers, with the main risk being the facility underutilisation, and, therefore, its potential inability to pay back the initial investment. The lower the price and volume risk to a HPF, the more likely to be incentivised by a contract. Clearly, there is an acceptance that a hydrogen production developer should take some level of risk in return for the payments it is receiving from the ESO. The balance of risk between the parties will need to be explored further. Ultimately, a one size fits all contract may not be possible. Rather, it may come down to individual contract negotiations reflecting the HPF size, who their offtakers are, and the hydrogen developers risk appetite.

Stakeholder feedback on specific models' options

1 Option 1. Utilisation payment: it was felt that this option was risky for hydrogen production developers and would be unlikely to provide sufficient certainty (which would be required if developers were to commit to providing some of their capacity towards managing thermal constraints). Hydrogen developers thought they would need some certainty over the number of hours per year that they would be required if they were to base their business model around these terms.

3 Option 3. Fixed payment: developers found Option 3 an attractive option given the certainty of the payment. However, the proposal to limit the contract length to just a year at a time would be a significant barrier and would make it very difficult for a project that would rely on this length to achieve FID.

2a 2b Option 2a) and 2b). Utilisation and availability payments: developers recognised that option 2 provides a more optimal balance of risk between HPFs and the ESO. In general, developers thought it could work as a contract option if the right risk balance can be struck – this would depend on the contract details and terms. Similarly with option 1, the need for some certainty over the amount of time they would be required and as much prior notice as possible, was stressed.

Some developers raised the risk that the availability payment would not be sufficient to cover the lost opportunity to produce hydrogen, if available, but were not in the end required by the ESO to manage constraints. Developers were also wary that penalty payments (for not being available to ESO when needed) would add additional risk that would make the business model more difficult.

Wider points raised

Developers were supportive of the proposed mechanisms to support hydrogen production from thermal electricity constraints, but raised a number of wider challenges that could impact the viability of a HPF using thermal electricity constraints (as well as hydrogen production projects generally).

- Electricity network connection timelines – Developers expressed some frustration with waiting times for a grid electricity connection. Almost half of transmission connection projects have an offered connection date of at least five year wait, and more than one in five will wait over ten years[17]. Thermal electricity constraints management is likely to be most needed in the next 10-15 years (prior to network reinforcement). If an electricity transmission network connection takes a decade more, then much of the opportunity of a HPF to benefit constraints management will be lost.
- Indexation – as things stand, electrolytic ('green') hydrogen is indexed against the Consumer Price Index (CPI), which potentially provides no protection against volatile input electricity prices. This encourages electrolytic hydrogen producers to contract on long term PPAs (often with temporal correlation to a specific windfarm). This would not offer the flexibility needed in order to play a role in thermal constraints management. Some developers felt that that a more appropriate indexation mechanism was needed for electrolytic hydrogen producers to encourage a more flexible dispatch.

Mapping tool

The final aspect of the project assessed where is best to locate any potential HPF that will support in the management of thermal constraints.

Utilising GIS technology, a map has been created that compares a number of different factors and overlays each of them, to provide a scale of preferable locations for a HPF that could contribute to thermal constraint management. To be able to contribute to constraint management, a facility needs to be above (north of) constrained boundaries. For the purpose of this mapping exercise, boundary B8 acts as the furthest south point a facility would be needed. Areas north of B4 (the north of Scotland) have the highest weighting. Other factors that have been used to map potential areas for a facility were (in order of weighting):

- proximity to substations on the electricity transmission network;
- proximity to the gas transmission network – as the offtake route that would be required;
- proximity to water sources, as water will be required in the electrolysis process;
- proximity to the major industrial demand locations; and
- proximity to the motorway network.

Areas that are known to be restricted by environmental and planning rules were also ruled out. Further detail as to the variables and weightings applied to the mapping tool can be found in appendix 5.

Output

Figure 19 shows the north of England and the whole of Scotland highlighting areas that are scoring more than 50% compatibility, based on the weighted variables. The map shows a number of locations in the North of England and Scotland would suitable to locate an HPF that can contribute to management of thermal constraints.

However, when the tool criteria are updated to show areas with a 80% compatibility, based on the same weightings, the map shows a smaller number of suitable areas in Scotland.

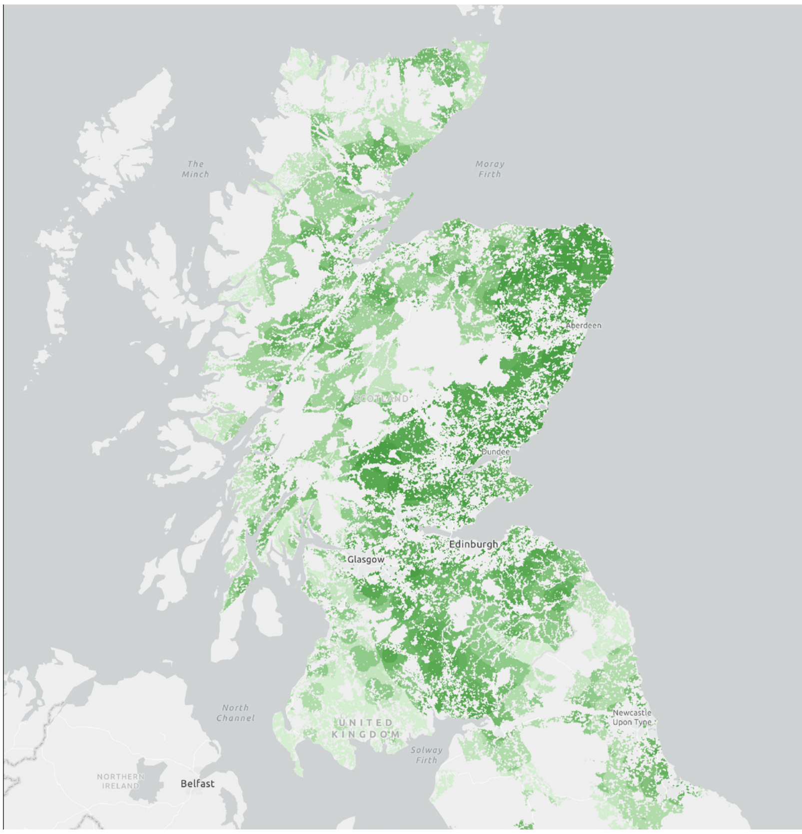


Figure 19 – GIS mapping tool with 50% compatibility measure

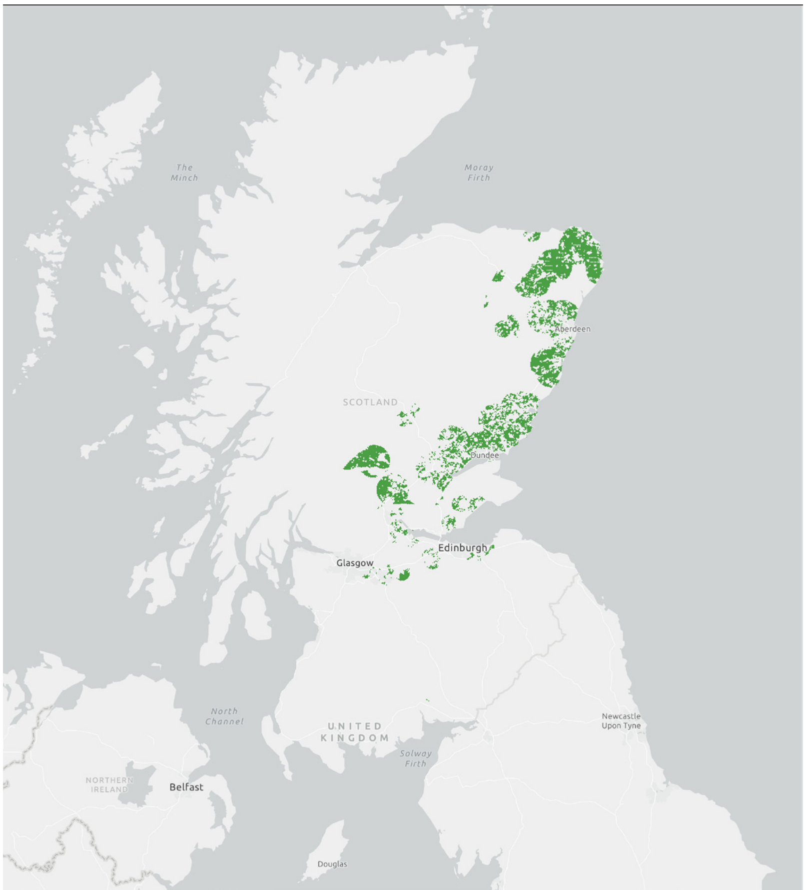


Figure 20 – GIS mapping tool with 80% compatibility measure

Conclusions and next steps

Over the next 10-20 years, the cost of managing thermal constraints during times of high renewable generation output is expected to increase on a number of transmission network boundaries, primarily in Scotland, and the North of England.

Planned network reinforcement will reduce or remove constraints, but this will take a significant time to deliver.

HPFs could provide an alternative way of managing constraints by connecting to the transmission network in areas where there are constraints, and utilising electricity that would otherwise require to be constrained to generate low carbon ('green') hydrogen.

This investigation has found that there is a viable technical and commercial pathway for hydrogen production to play an impactful role in managing thermal constraints.

The assessment indicates that:

- It is technically viable to operate an HPF in a manner that allows it to support constraints management. Electrolysers are able to turn up to respond to periods of thermal constraints on the transmission network.
- An HPF will need an offtaker that is sufficiently flexible to consume hydrogen output varying in line with the variability of thermal constraints. The gas network offers this flexibility. Given that constraints management will be needed in the next 10-20 years, blending hydrogen into the existing network is the most likely route.
- The current regulatory and market arrangements do not currently provide sufficient signals to incentivise locating hydrogen production in areas where there will be thermal constraints, or to use electricity during constrained periods. To be commercially viable and to have a meaningful impact on thermal constraints, an HPF will need additional support. This could be facilitated via a contractual arrangement with the ESO. However, it would be important to ensure net benefits for consumers (from avoided costs of not having to constrain renewable generation) and/or taxpayers (through reducing the revenue support for hydrogen projects) are present.

The use of hydrogen production to manage thermal constraints through a contract could have a number of benefits:

- Lower the cost to the ESO and therefore of electricity consumers of managing thermal constraints, as it is proposed that the funding made available to hydrogen producers through the contract is lower than the cost of turning down renewable generation;
- Decarbonising the GB energy system by using 'excess' renewable generation that would otherwise not be able to be used via the production of hydrogen; and
- Potentially lower the cost of producing low carbon hydrogen and therefore lowering the costs to the Government of supporting hydrogen production.

While a hydrogen production facility could play a role in managing thermal constraints, on its own it is unlikely to be the 'silver bullet' for managing constraints. Rather, it is one solution among other demand response options.

Further, it cannot be concluded that all HPFs could or should play the active role in the management of thermal constraints as described in this report. For many HPFs, the role of responding to constraints will not suit their business model. Potentially, only a limited number of HPFs will be able to play a role in constraint management and have a contract with the ESO.

Finally, there is likely going to be a limited window (i.e. the next 15-20 years) when a demand provider (such as hydrogen from a thermal constraint facility) is likely to be required before network reinforcement may reduce or remove the need for such a facility. A hydrogen production facility could be built where it is needed to play a role during this window of time, assuming a development and construction timeframe for a facility of around 4-5-years (noting some existing or currently planned projects could play a role sooner). However, this limited time window does mean there is a need to develop a support mechanism soon if we are to see hydrogen production playing a role in thermal constraints management.

The contract options

Four potential contract options have been identified:

1 Option 1: utilisation payment

2a Option 2a: seasonal utilisation payment and availability payment

2b Option 2b: utilisation payment and availability payment

3 Option 3: fixed payment

Across the options, there are different balances of risk for the ESO, consumers, and HPFs. To provide the most benefits, this risk should be balanced as much as possible across all parties.

Option 1 provides production facilities with price certainty. However, volume risk remains as there is no certainty over the periods that the facilities would be called upon to provide a demand response. For this option, the ESO (and consumers) are only required to pay during periods of constraints when the facility is providing a demand response. Options 2a and 2b are likely to provide a more balanced price and volume risk between parties, as production facilities have certainty over the price for the availability and utilisation elements and some certainty over volume through the availability payment. Option 3 provides price certainty for the production facility, however, may overexpose the ESO, and consumers, if constraints do not materialise as forecasted (as opposed to the current situation, where wind generation is only constrained when required).

For an investable business model, the production facility would need to secure the contract ahead of FID. This means that for an HPF to be delivering benefits to the electricity system, the contract would need to be allocated in the next 1 to 2 years based on current development and construction timelines for am HPF of approximately 3 to 5 years.

Feedback from stakeholders indicates that the allocation of risk was the most important factor to developers, with the main risk being that the facility is underutilised and therefore less able to pay back the initial investment. The balance of risk between the parties will need to be explored further. Ultimately, a ‘one size fits all’ contract may not be possible. Rather, it may come down to individual contract negotiations reflecting the HPFs: size (and capacity they are willing to offer ‘at risk’), who their offtakers are, and the hydrogen developers’ risk appetite.

Recommended next steps

This project has investigated and confirmed the technical and commercial viability of using HPFs to manage thermal constraints on the transmission network.

In order to take this forward, the following key actions are recommended:

- As part of the Constraints Collaboration Project, the ESO should further develop the contract details and engage with Ofgem on whether this could be delivered within the existing regulations.
- A full cost benefit analysis and socio-economic welfare study should be undertaken, to understand the range and the scale of benefits that can be delivered through any potential contract and the impact on consumer bills. The impact a contract could have on reducing the cost of hydrogen production (and thereby reducing the amount of funding that the Government would need to allocate to hydrogen projects through the hydrogen business model) should be explored further. As part of this, an assessment should be undertaken as to how competitive an HPF would be compared to other technology types, based on the detailed contract elements.
- The contract options should be further tested with stakeholders, particularly demand providers, with a particular focus on balancing risks between parties. This could be wider than HPFs and also encompass other demand providers.
- There should be engagement with the Government (DESNZ) on how there can be alignment between a contract offered by the ESO and the hydrogen business model. This should include examining how the contract could be included within future hydrogen allocation rounds.
- A decision on blending on the transmission network should be taken as soon as possible, for larger facilities the higher-pressure network offers higher injection capacity.
- The whole system benefits that a facility that can contribute to management of thermal constraints should also be recognised in the hydrogen blending arrangements. In their December 2023 consultation response the Government recognised blending role as strategic enabler which is important for this type of facility. As the blending arrangements are developed further steps could be taken to favour a hydrogen production facility that is providing genuine whole system benefits. This could include taking a strategic approach, prioritising this type of production facility over others when it to allocating blending rights. It could also include allowing onward trading of green gas certificates from such a facility to enable a hydrogen producer contributing to constraints management to earn more of a premium on the hydrogen it generates.

Appendices

Appendix 1
Commercial model

Levelised cost model methodology

To understand the costs that an HPF using thermally constrained electricity may be able to achieve, the Levelised Cost of Hydrogen (LCOH) for each of the contract options was modelled. Specifically, the LCOH was modelled for three years: 2030, 2036 and 2040. It considered the total costs (capital, operating, replacement CAPEX) of production over the project life, divided by the total volume of hydrogen produced. The costs and volume of hydrogen produced are discounted at a rate of 7% using the following formula:

LCOH (£kg) = Sum of costs over lifetime (£) x discount rate (%) / Sum of hydrogen produced over lifetime (kg) x discount rate (%)

The building blocks of the model are broken down into electricity generation, electrolyser (hydrogen production), compression, transport (where required) and offtake. For each part of the supply chain, the inputs are used to determine an annual cost split between these categories:

1. Project development costs;
2. Capital costs of infrastructure;
3. Replacement costs of infrastructure;
4. Fixed operational costs; and
5. Variable operational costs.

The building block costs are based on both constant and variable input assumptions, gathered from publicly available data and Arup benchmarks. The total discounted costs of production are then summed over the project life and divided by the total discounted volume of hydrogen produced.

Initial analysis

Findings

At the outset of the project, Arup used historical data for the most constrained network boundary, B6, to model hydrogen production profiles and the potential LCOH. Arup conducted LCOH analysis for electrolyser plant sizes (300MW, 750MW and 1,500MW). By current standards these are large to very large electrolyser projects (most electrolysis facilities are less than 100MWs) however these facility sizes were chosen as this was the size of demand response that could make an impact on thermal constraint management. Over three production ‘pathways’, which reflect different offtake scenarios for the hydrogen that is produced:

- Pathway 1 – electricity balancing: using the hydrogen produced to generate electricity at peak times;
- Pathway 2 – hydrogen to grid: using the hydrogen produced to supply the gas network; and
- Pathway 3 – hydrogen refuelling: using the hydrogen produced for transport applications.

These interim results showed that:

- The cost of production for 'Pathway 2- hydrogen to grid' is lower relative to the other pathways. This is primarily driven by a reduced need for storage.
- The constrained electricity profile at network boundary B6 is highly intermittent, resulting in an intermittent supply of hydrogen production. To provide a steadier supply of hydrogen, Arup considered the use of additional non-constrained electricity from the grid or storage. Results showed that the additional storage required to offset the intermittency increased the overall cost of production significantly due, in part, to the high capital costs of hydrogen storage (E.g. £800/ kg H_2).
- The cost of production for the relatively smaller electrolysers (E.g. 300 MW) was lower relative to the larger electrolysers, due to the higher levels of production resulting in a better use of capital.

Methodology

Arup conducted LCOH analysis on each of the Contract options for the hydrogen production facility.

Assumptions

Arup used the expected electricity constraint profile for years 2030, 2036 and 2040, from the B4 boundary. This is because the modelling undertaken (see section A2) showed that B4 boundary has the most frequent constraints. To reflect that a HPF would not want to be at zero production (both for technical and commercial reasons), for the purposes of the LCOH calculation, it was assumed that the HPF would source power from the grid via a PPA to allow for a minimum operating load of 30% to be achieved. It was then assumed the remaining 70% of capacity was available as part of the contract, only used during periods when there are constraints. The £/kW values that we derived from the modelled constraint costs (see section 5 and section A2) were used as the electricity cost during constrained times. Arup assumed the ESO would pay the hydrogen production facility for using the constrained electricity and using the modelling results (see section 5) and considering current market arrangements Arup assessed the potential values that would be awarded through four contract options available to the hydrogen production facility as set out in Table 5. Please note that the numbers below are only indicative and not intended to inform the actual value of any contract that may be offered.

Option	Contract mechanism inputs into the LCOH
Option 1: Utilisation payment	Hydrogen producer is a paid a utilisation fee of £22.40/MWh for every MWh of constraint power that is consumed. Arup defined this by looking at the volume weighted average of the avoided premium between 2030 and 2040.
Option 2a: Seasonally varying utilisation payment and availability payment	Hydrogen producer is a paid a utilisation fee of £6.87/MWh for every MWh of constraint power that is consumed in autumn/winter and £6.41/MWh for every MWh of constraint power that is consumed in the spring/summer. In addition to the utilisation payment, this contract considers an additional availability payment that compensates the hydrogen producer for reserving capacity at the hydrogen plant that is prioritised for thermal constraints. Given that the electrolyser assumes that 30% of the facility will be supplied by grid PPAs, this effectively relates to 70% of the available capacity. In this contract, it varies between spring/summer (£7.21-8.19/kW) and autumn/winter (£17.46-19.85/kW) in terms of value. To define the utilisation and availability payments Arup looked at the volume weighted average of constraints in the summer and in the winter. Arup's analysis indicated that 69% of the total volume of constraints in boundary B4 occur between October and March (Winter) and 31% between April and September (Summer). Essentially the numbers indicate that an asset should be receiving higher remuneration to be available in the winter and a lower utilisation rate but for a significantly higher volume. The opposite is true for the summer when the constraint volume is significantly reduced which is reflected in the numbers above.
Option 2b: Availability payment and utilisation payment (year-round)	This contract is identical to the optional 2a other than that the availability payment is available for the full year at a constant rate.
Option 3: Grant payment	This contract assumes that fixed grant payment of £5.8m/yr to £25.6m/yr (depending on the plant size) is paid to the electrolyser operator to ensure a competitive price of hydrogen can be achieved.

Table 5 – Contract mechanism inputs into the LCOH model

To reflect the contract payments in the overall LCOH, Arup calculated the total annual amount the ESO would pay the HPF under the relevant contract option and subtracted this from the total annual expenditure the HPF will have incurred.

The analysis was focused on the hydrogen to grid pathway (pathway 2) as in its interim findings Arup found it was the most likely pathway primarily due to the fact that the grid could act as a flexible off-taker meaning that storage costs were avoided. It also assumed the HPF will be located in close proximity to both the electricity network and the gas grid and that the gas grid, as an offtake type, could accept whatever hydrogen was produced. For comparison a 'no contract' option was also run, this assumes that all the electricity is procured via a wind PPA at steady cost. Below, Arup set out the key technical and economic assumptions used in the LCOH analysis.

Factor	Input
PPA electricity cost (with contract and BSUoS discount)	£77/MWh
PPA electricity cost (without contract and no BSUoS discount)	£84/MWh
Electrolyser Efficiency (including Balance of Plant)	57.5 kWh/ kg H_2
Average Electrolyser Utilisation (without contract, no constrained electricity)	85%
Average Electrolyser Utilisation (with contract) (2030)	43%
Average Electrolyser Utilisation (with contract) (2036)	51%
Average Electrolyser Utilisation (with contract) (2040)	45%
Electrolyser Capex	£730,000/ MW
Electrolyser Stack Life	80,000 hours
Electrolyser Water Consumption	12 litre/ kg H_2
bWater Pipeline Capex	£140,000/ kg H_2
Water Variable Opex	£0.0003/ litre
Hydrogen Storage Capex	£800/ kg
Compressor Unit Capex	£1,300,000/ MWe
Pipeline to Gas Grid Capex	£1,500,000/ km

Table 6 – LCOH analysis key assumptions

Plant utilisation

As discussed earlier in the assumptions section, hourly thermal constraint electricity data was used for years 2030, 2036 and 2040 to estimate the overall plant utilisation per year analysed.

The electrolyser utilisation, which is defined as the hydrogen produced in a period (e.g., one year) divided by the hydrogen it could have produced if it had operated at 100% output for that period, varies in years 2030, 2036 and 2040. In 2030, the average utilisation across electrolyser sizes was estimated to be 43%, increasing to 51% by 2036, and decreasing to 45% by 2040. Generally, higher utilisation rates result in a better use of capital, therefore leading to lower LCOH. Given this result, producing hydrogen in 2036 is most cost effective on a levelised basis relative to the other years. It should be noted that these overall plant utilisation rates are inclusive of electricity that comes from the grid via PPA for 30% of its capacity.

In the no contract option shown in Figure 21, Arup have assumed the HPF exclusively procures electricity via a wind PPA, resulting in a higher electrolyser capacity factor of 85% as it does not rely on the intermittent thermally constrained electricity. This scenario is chosen to represent how a more 'typical' HPF connected to the grid aiming for a steadier production profile may operate. It should be noted that such a facility would likely need another offtaker other than the gas grid, as it may not be able to prove wider electricity system benefits.

Results

The LCOH results vary depending on the year of analysis, the contract option, the electrolyser size, and the sensitivities applied. The results in Figure 21 are for year 2030. The results show that the LCOH ranges between £4.7/kg to £5.0kg. Contracting option 1 results in the lowest LCOH across all electrolyser sizes, while contracting options 2a and 3 result in the highest LCOH. However, Arup notes the results are very similar.

The LCOH is higher in the 'no contract' option, where a facility only uses a PPA due to the relatively higher electricity costs. Note thought that if utilisation can be pushed higher than the 85% assumed than the facilities LCOH could be pushed lower.

Further, sensitivities affect the overall LCOH. For example, the exclusion of a minimum operating load of 30% sourced from a grid PPA increases the overall LCOH, while, in contrast, increasing the minimum operating load from 30% to 50% decreases the LCOH. Increased storage capacity to manage intermittent hydrogen production significantly increases the LCOH due to the high capex associated with storage

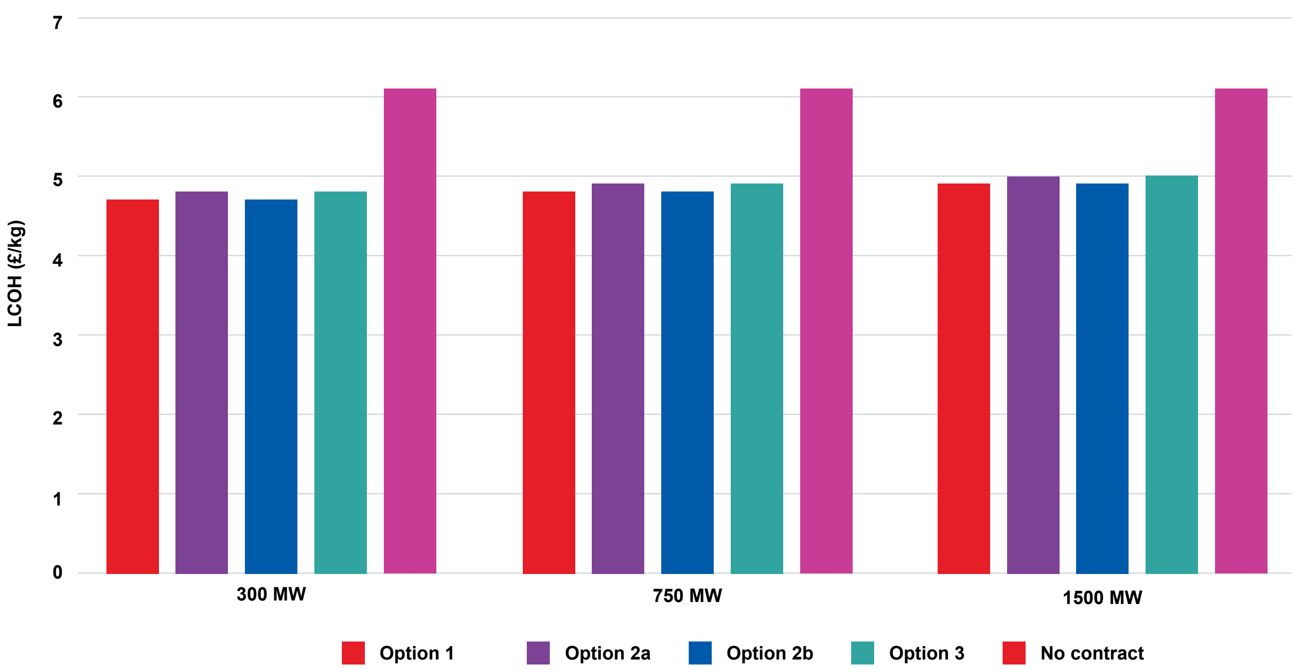


Figure 21 – LCOH range for contract options using 2030 modelled constraints profile

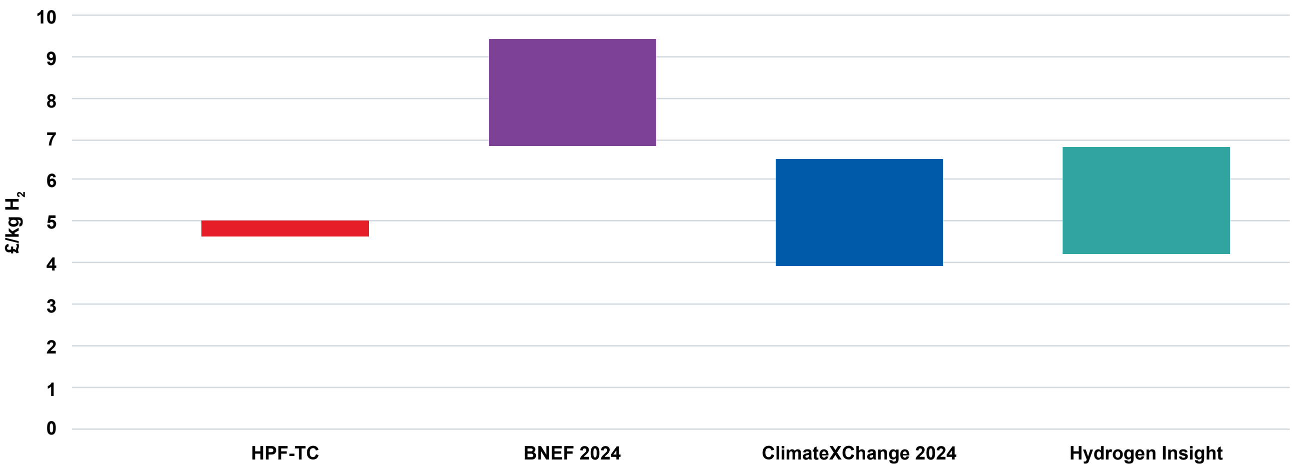


Figure 22 – High level LCOH comparison

LCOH in a wider context

The LCOH across all contract options for all years is expected to be competitive. Arup have compared the LCOH range that can be achieved by the HPF (i.e. the range driven by contract options, year of analysis and electrolyser sizes) against the LCOH outputs that are quoted in literature from Bloomberg New Energy Finance, ClimateXChange and Hydrogen Insight. As shown below, the HPF LCOH may be in line with other real projects and so commercially competitive. In the UK Government's hydrogen business model first allocation round (HAR1), the strike price agreed with projects was £241MWh[18], which is £9.50/kg. This is a strike price negotiated in order for a production facility to cover risks and make a commercial return, thus it would be expected to be slightly above the LCOH.

Generally, LCOH of electrolytic hydrogen can vary depending on more factors than just electricity input costs. There may also be additional costs that hydrogen projects have included in their levelised cost calculations that have not been included in the levelised cost for this report, such as additional transport costs, storage and water treatment, amongst others. Comparisons of LCOH should therefore be treated with caution. The analysis has shown the most important factor for driving costs is utilisation of the electrolyser asset and electricity cost.

Appendix 2
Modelling constraints

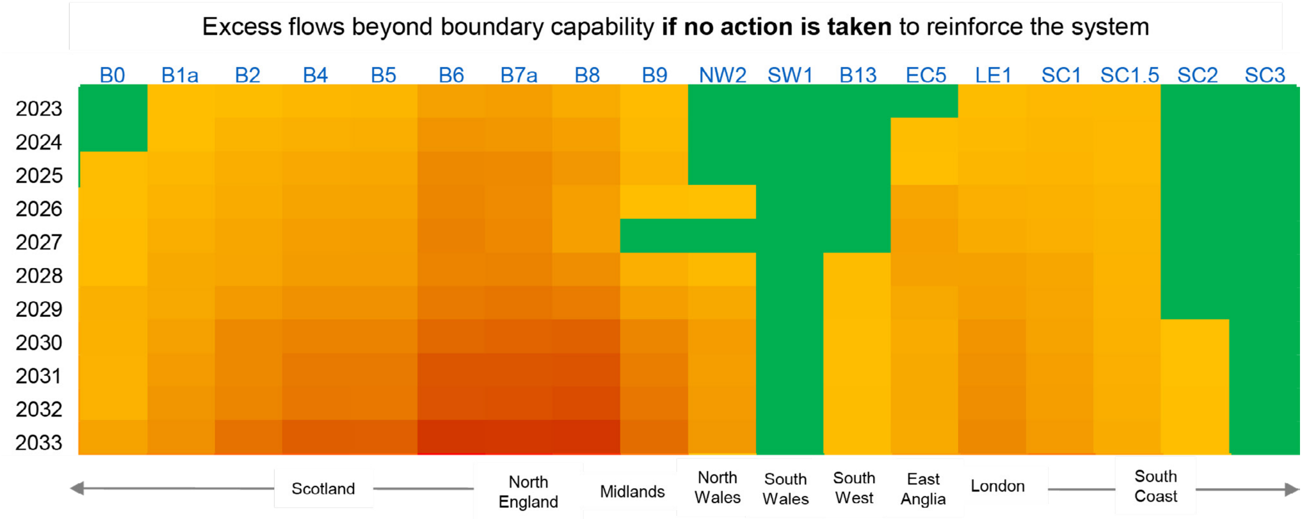
To identify the locations facing the most significant thermal constraint challenges, analysis was undertaken to define the boundaries of focus for an HPF using thermal constraints. The analysis considered both historical and future thermal constraint costs and profiles.

Location of thermally constrained electricity

Arup undertook an assessment of the location of thermal constraints using the latest NGESO Electricity Ten Year Statement (EYTS), the Network Option Assessment (NOA) and Holistic Network Design (HND). This analysis took into consideration the planned or proposed network reinforcements and constraint management strategies to provide the latest view of potential locations. The heatmap in shows boundaries and regions where thermal constraints are expected to persist with and without network reinforcement.

The analysis found that Scotland, the North of England and the South of England are expected to continue facing constraint challenges towards 2030. This is mainly due to increased renewable penetration and interconnection capacity mostly in the South of England. In Scotland and the North, development of wind generation is already creating constraint management challenges. Flows of electricity across Scottish boundaries are expected to triple between 2022 and 2030, due to further development of wind generation according to the EYTS; the B6 boundary is particularly affected. The ESO currently manages thermal constraints costs in B6 through a commercial solution, known as Constraint Management Intertrip Service (CMIS). Network reinforcements are planned but constraint issues are expected to persist. The problem is similar in the North of England.

In the South of England, the transmission network is heavily meshed around the London boundary B14 and the Thames Estuary. Future connections in the South may lead to various challenges. If interconnectors export power to Europe during periods of high demand in London, the network could become thermally overloaded. It is expected that problems could persist, even after reinforcement and constraint management solutions.



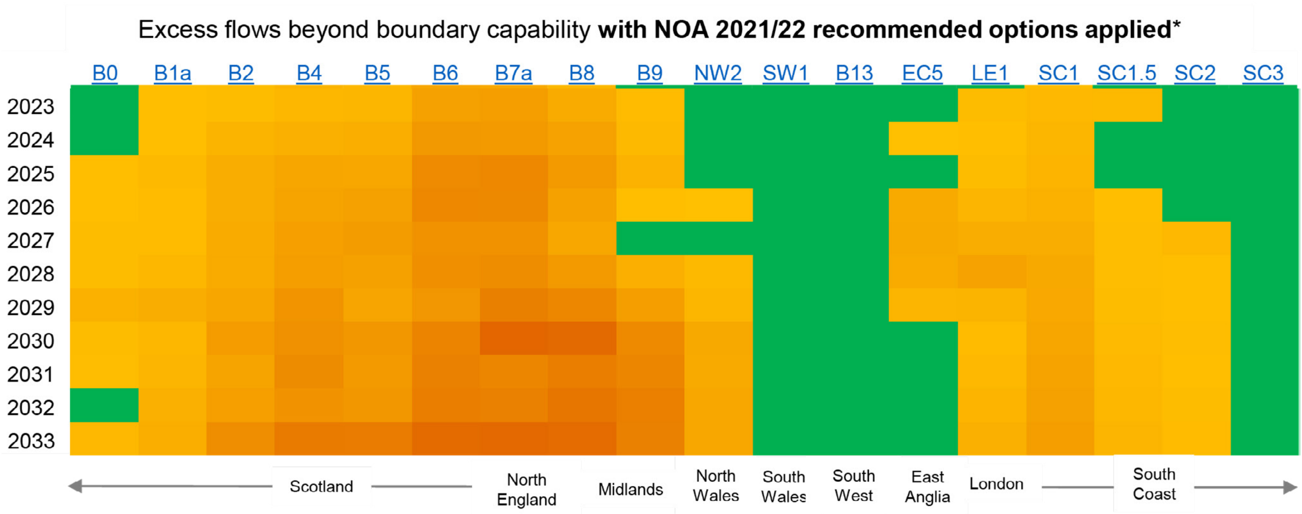


*Chart uses the 2021/22 NOA recommendations against *Leading the Way* scenario in 2022 FES flows

Figure 23 – Excess flows behind boundaries if no action is taken and if NOA 2021/2022 recommend options are implemented

Source: NGESO, ETYS

Future constraints methodology

Arup carried out a modelling exercise to understand the impact of changing boundary capabilities over time as network reinforcements are carried out, and the subsequent impact on power flows and the operating profiles of generators. Arup used PLEXOS Energy Modelling Software to build a model of the GB electricity system[19].

Figure 24 summarises the model of the GB electricity system. Several 'Nodes' shown in red have been created to represent areas of GB behind or between certain boundaries. These nodes comprise of demand and generation sources reflective of the area behind (or between) the applicable boundary (or boundaries) and are linked to a "Region", which is GB.

'Lines' in PLEXOS represent transmission lines in the network and are represented by arrows in Figure 25. Lines have been used to represent the flows along transmission lines possible across the boundaries studied. A max flow capacity (and where applicable reverse flow capacity) has been defined for each line, representing the maximum boundary capability, these have been based on 2022 EYTS. This capacity changes over time as network reinforcements are deployed.

A 'stack' approach has been taken for generation, whereby each applicable 'source' of generation is assigned to each node as a single PLEXOS generator - these are represented by the boxes outlined in blue in Figure 24. This is opposed to individual units representing each individual generator. Each generation source comprises of several units reflecting the capacity growth trajectory assumed. As a simplified assumption, the techno-economic parameters of each unit are assumed to be identical.

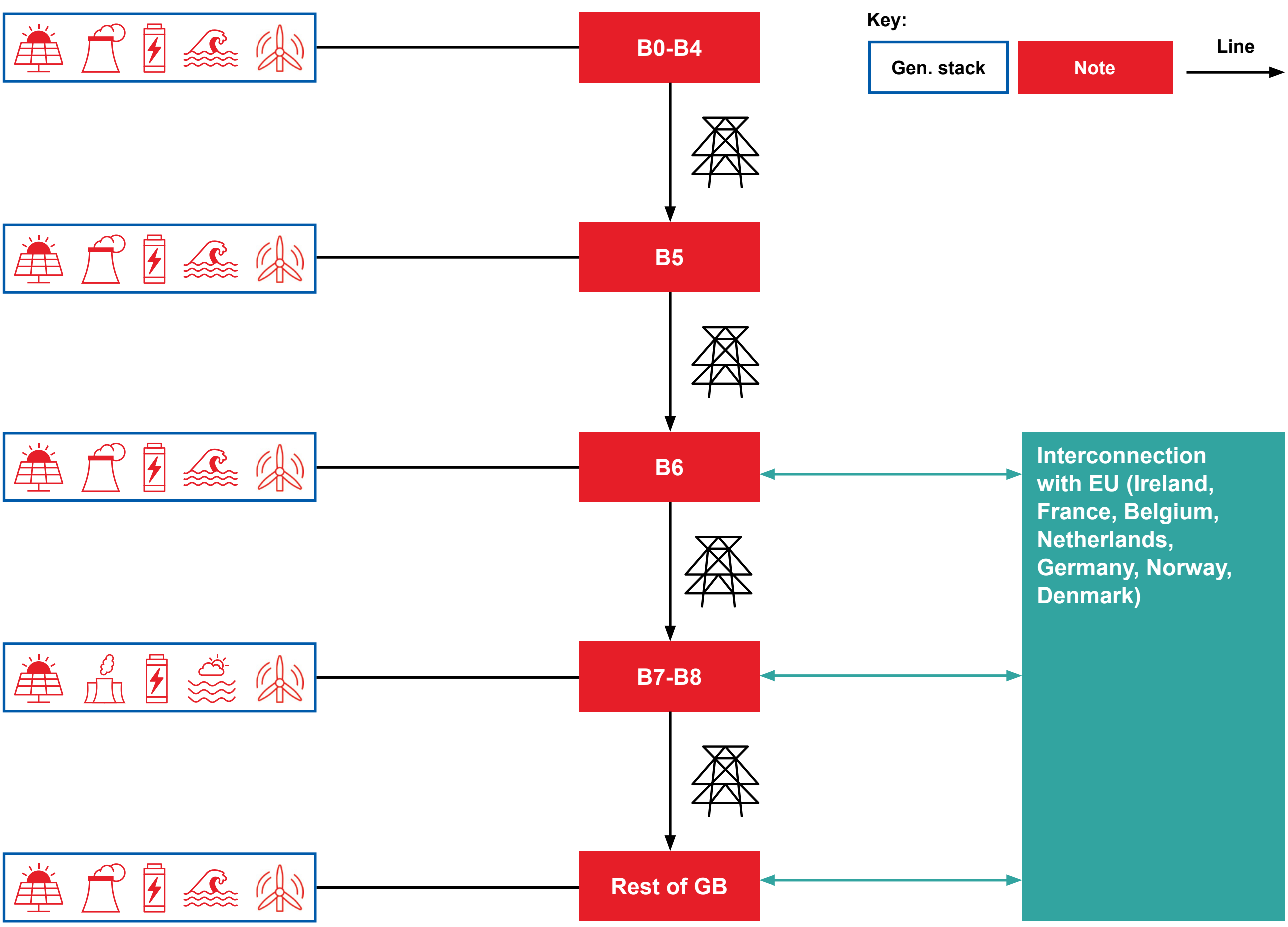


Figure 24 – PLEXOS model topography

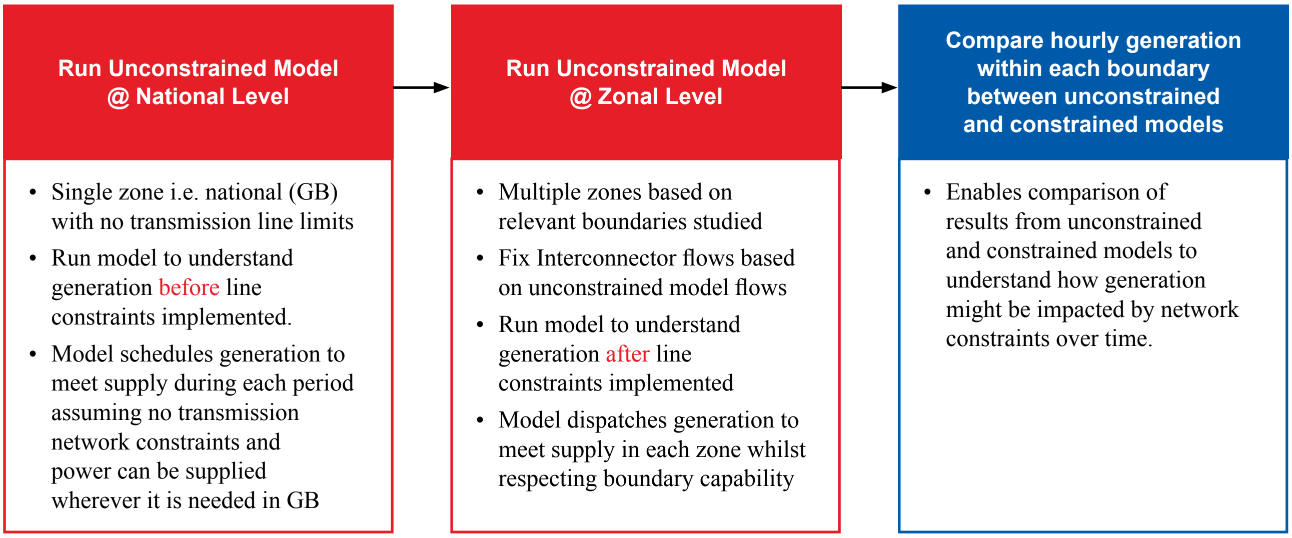


Figure 25 – Defining the profile of future constraints

To define the profile of constrained electricity, two model runs were performed. The first was an unconstrained run that assumes no limitations on the network, and the second was a constrained run, also known as the ‘redispatch’ model run, which considers the physical constraints of the transmission network. The unconstrained model topology is the same as above, except there are no line limitations i.e. a single node model.

As outlined in Figure 25 the two model runs were used to generate the total wind and solar curtailed volumes and their hourly profile. Arup’s analysis focused on renewable constraint volume, to understand the ability to use curtailed renewable energy to produce green hydrogen.

The total constraint costs avoided from 2030-2040 are the total cost to the ESO to constraint off (biding cost), renewable generation, plus the cost to turn up combined cycle gas turbine (CCGT) generation to balance the resulting demand shortfall.

To derive the potential system benefit by the use of electrolyser in constrained locations, Arup looked at the avoided renewable curtailment cost resulting from the operation of the electrolyser. In practice, Arup applied a cap equal to the total available capacity of the electrolyser to ensure the constraint volume avoided could not exceed the HPF capacity used to alleviate thermal constraints. This benefit was used to define the availability and utilisation payments in £/kW discussed in 5.2.

Overview of assumptions

Inputs and assumptions were mostly based on publicly available datasets from the ESO, the European Network of Transmission System Operators for Electricity (ENTEO-E) and Ofgem, and supplemented with information from Arup. These are summarised in Table 7.

Assumption	Source	Description
Demand	NGESO	FES 2022 demand projects under the System Transformation (ST) scenario and broken down by individual boundaries using data from ESO.
Generation capacity	NGESO	FES 2022 generation capacity projections under ST scenario. Arup subsequently mapped generation to boundaries studied using information provided by the ESO.
Commodity prices	NGESO	Current forward/futures curves for carbon and fuels used in power generation for 2023-2027 and longer term projections for commodities from FES 2022 for 2030-2050.
Network Reinforcements	NGESO and Ofgem	Boundary capability data from ETYS 2022 reflecting NOA 2021/22 Refresh and Ofgem's 2022 Accelerated Strategic Transmission Investment (ASTI) decision.
Techno-economic parameters	DESNZ and Arup	Arup's European Power Market Model assumptions based on DESNZ Electricity Generation Costs publication and Arup's internal insight.
Interconnector Assumptions	NGESO and Arup	Existing and planned interconnector projects as per ESO Interconnector Register.

Table 7 – Table of assumptions

Bidding behaviour

Assumptions were made around generators' bidding behaviour, based on analysis of historical data, considering factors such as the subsidy scheme for low carbon generation and market dynamics. It is expected that different technologies will have different bidding strategies as summarised in Table 8.

Technology	Constraint Cost (£/MWh)
Merchant Renewable	£0/MWh
CfD supported renewable	Base Case scenario: Wholesale price - CfD strike price. Imperfect Competition: Base case if strike price above wholesale price 50% of the difference the Day-Ahead price and strike price. Market Power: Base case if strike price above wholesale price £0 if not.
ROC renewable	ROC Buy-out price
CCGT Offer up	Offer Uplift × SRMC

Table 8 – Bidding strategies

The generator curtailment cost is the product of the thermal constraint profile and the system bid price of the curtailed generation. The system bid price is the price generators are willing to pay in the balancing mechanism to reduce their output when the ESO needs them to manage a system constraint. On the contrary, a system offer price is the price generators are asking to receive in the balancing mechanism to increase their output when the ESO needs them to manage a system constraint. Bidding down for assets that are supported by government schemes (e.g. Contracts for Difference, Renewable Obligation Certificates (ROC) etc.) would come at a cost to the ESO. This is because renewable generators aim to recover lost subsidy revenue, which in many cases leads to negative bidding (turn down costs) as opposed to conventional fuelled assets that pay the ESO at a discount to their fuel and carbon cost.

The system bid price is based on the generator bidding behaviour. Therefore, understanding and defining the curtailment cost relies heavily on the bidding behaviour of generators. The reasonable approach would be for these generators' bidding price to be equal to the difference between the wholesale price and the CfD strike price. To investigate bidding behaviour, historical data was analysed, considering factors such as the subsidy scheme for low carbon generation and market dynamics.

Arup's analysis indicates that bidding behaviour may vary depending on the subsidy scheme under which a low carbon generator operates. The focus of the historical analysis was on the Scottish region where there is strong wind generation.

Assets operating under the CfD scheme demonstrated more sophisticated bidding patterns when prices became volatile. As day-ahead prices experienced spikes in the past year, certain CfD generators began incorporating market premiums into their bidding behaviour, resulting in increased sophistication.

For renewable generators under the ROC scheme, Arup's analysis assumes a simple bidding strategy. Conversely, more vsophisticated bidding behaviour is assumed for CfD generators.

The cost of the resulting energy imbalance was based on unabated CCGTs. Even though the technology mix will be changing, and a different mix of technologies will be used going forward, we used this cost as a basis for our analysis, as it is currently a key balancing technology (and enough data was available to derive an assumption on the energy imbalance cost). Based on our historical analysis the cost of offering up CCGT generation was assumed to be the cost to run the asset (i.e. the fuel and emissions cost), including an uplift of 129%.

To calculate the utilisation payment, Arup estimated the maximum potential benefit delivered to the consumer. The benefit is based on the saving achieved by removing the cost premium incurred when generators participate in the BM vs the day ahead market. This cost is the result of both renewable and flexible generators exercising market power (i.e. charging significantly above their marginal or subsidy cost) when asked to change their output by the ESO in order to manage thermal constraints. This is largely due to the balancing market design and the fact that the ESO has a short window to resolve system constraints. Adding a hydrogen facility on the constrained side of the boundary would enable renewable electricity to be used and would remove the need for these actions in real time.

Practically, the avoided constraint cost benefit is equal to the sum of the avoided uplift cost charged by CCGT generators when instructed to ramp up their output and the uplift cost included in the bid price of renewable generators when instructed to reduce their output. The total CCGT uplift is 29% of the CCGT Short Run Marginal Cost (SRMC). This figure was derived by calculating the average historical uplift of CCGT in the BM during system offer actions.

The avoided premium of renewable generators is the difference between the base case and the market power scenario as described above.

Modelling outputs

As seen in the figures below, the highest constraint costs and volumes are observed in B4 across the modelling horizon. B6 is the second highest until 2035. Post 2035, B7 and B8 costs surpass B6 costs. Following network reinforcements driven by the HND and the ASTI framework, we see a slight dip in costs between 2030 and 2035. However, a significant increase in renewable generation connected above B4 leads to a jump in costs post 2035, mainly driven by an increase in offshore wind capacity.

Similar to the observations on cost, 2035 and 2036 are the years with both the highest number of hours and the highest volume of constrained renewable generation in B0-B4. The increase in B7-B8 costs is mostly affected by increased renewable generation in Scotland, combined with additional generation added in the North of England.

As noted by Figure 26, in 2035 (for the B0-B4 boundaries) there is seasonable variation in the constraints profile, with constraints more frequent during autumn/winter period. Constraints are still high during summer; however, they are less frequent.

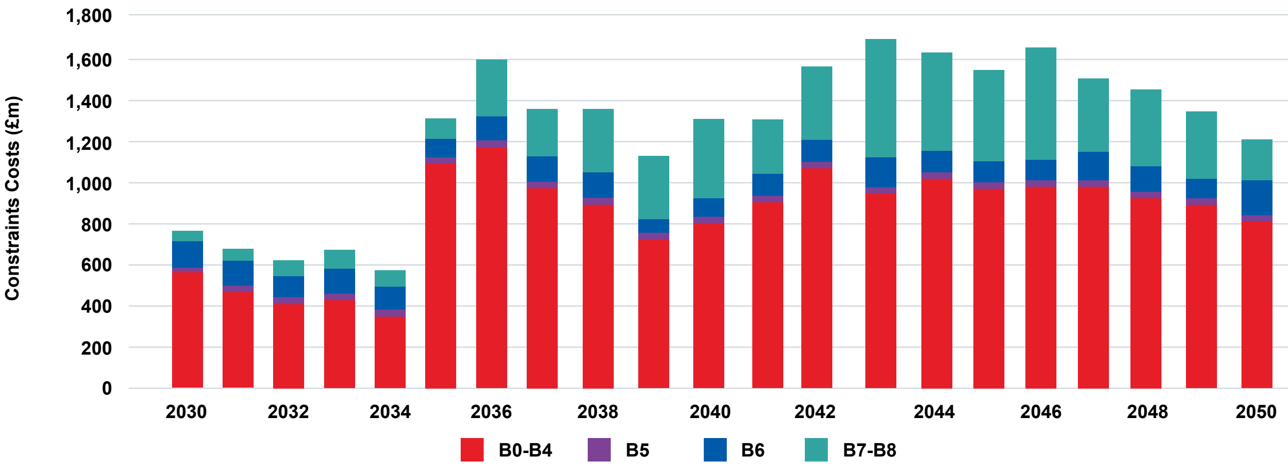


Figure 26 – Total constraint cost between 2030 and 2050 for boundaries B0 to B8

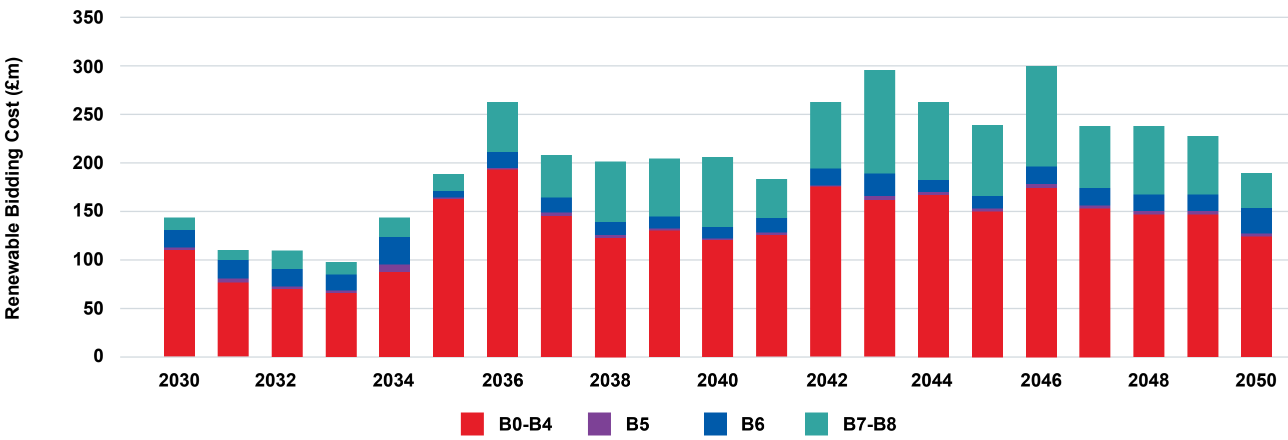


Figure 27 – Cost to constraint off renewables

The total constraint cost refers to the total cost to the ESO to constraint off (bidding cost) renewable generation (solar, offshore and onshore wind) plus the cost to turn up CCGT generation in the south to balance the resulting demand shortfall. The total costs shown in the charts below assume renewable generators do not exercise any market power (£0/MWh premium).

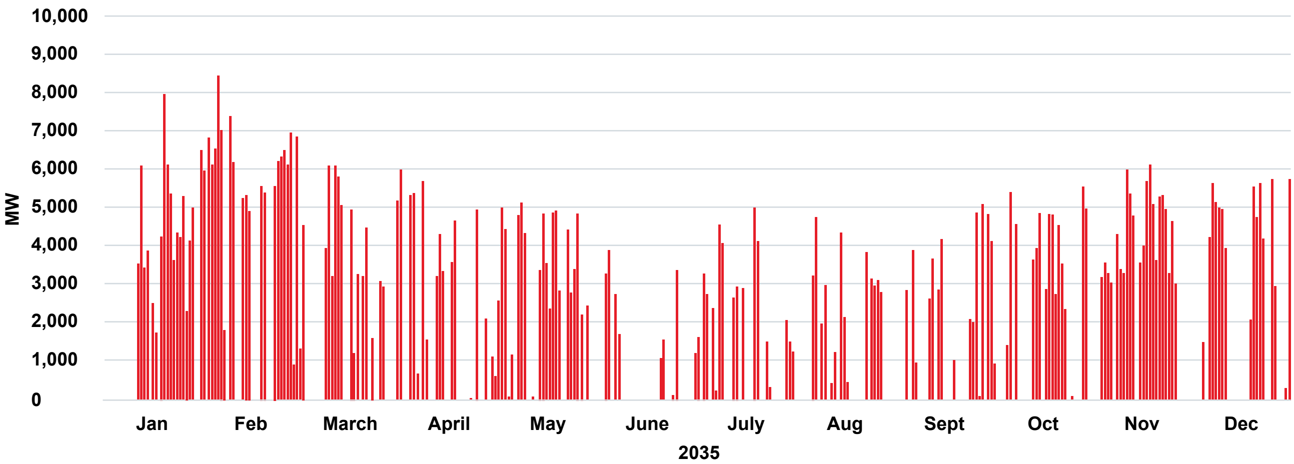


Figure 28 – B0-B4 constrained volume profile 2035

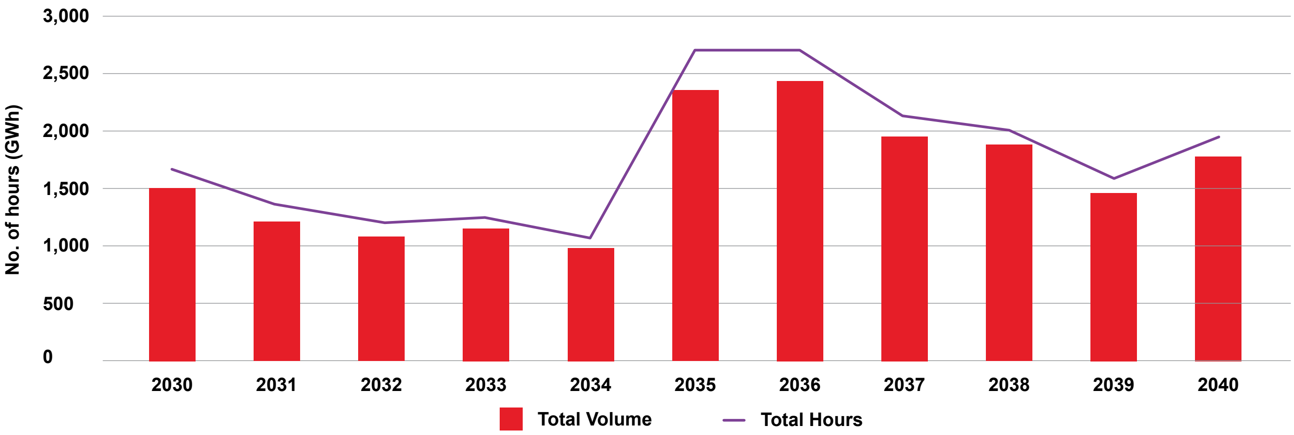


Figure 29 – Total volume and no of hours constrained B0-B4 boundary

Appendix 3
Modular design

Arup undertook analysis of potential hydrogen production technologies to determine whether production facilities were able to provide a demand response during periods of thermal constraints.

Arup also undertook an assessment of the design basis and hydrogen production summary for three plant sizes: 300MW, 750MW and 1500MW. These were chosen as facilities that were large enough to make a real impact on thermal constraint management.

HPF technology review

The technology review investigates four technical areas behind a green hydrogen plant design:

- Electrolyser and Integration Technology;
- Hydrogen Storage and Carriers;
- Hydrogen Dispensing; and
- Bulk Transportation

The report details each of the different technologies available to each of the technical processes and concludes which form of technology and process would be most suitable for a HPF using thermal constraints.

Note that, during the course of conducting this innovation project, it became clear it is unlikely that a facility would be designed and built purely to manage thermal constraints. More likely, participating in thermal constraints management would be part of an HPF business model. Therefore, the focus of the technical work was on how a suited hydrogen technology was to responding to constraints in the timescale that the ESO would require for the proposed contract.

Electrolyser and integration technology

An overview of both PEM and alkaline electrolyser types has indicated that, for an HPF supporting management of thermal constraints, the most appropriate technology is PEM. This is predominately down to the flexibility of a PEM electrolyser (with a ramp up from a hot standby to maximum capacity in 10 seconds, compared to 8 minutes for an alkaline facility). However, this does not necessarily rule out alkaline electrolyser technology, which could still potentially respond in time. Nevertheless, a PEM electrolyser is likely to be a better fit.

Parameter	PEM	Alkaline
Efficiency	56-60%	63-70%
Stack lifetime	30,000-90,000 hrs (3-10 years)	60,000-90,000 hrs (6-10 years)
Pressure	30-80 bar	30-80 bar
Temperature	50-90°C	50-90°C
Minimum to maximum load	10-120%	15-100%
Ramp rate from hot standby	10%/s (10sec startup)	0.2%/s (atmospheric) to 10%/s (pressurised) (8.3min-10sec startup)
Ramp rate from cold standby	20%/m (5min startup)	5%/m (20min startup)
Water Consumption	Potable: 20-25 L/kgH_2	
Maximum Stack Size	2.5MW/stack	5MW/stack
Catalyst	Platinum and Iridium	Nickel
Operational History	Decade	Century
Purity	99.9-99.9999%	99.8%
Lead time	1-2 years	1-1.5 years
Positives	Compact size, highest purity hydrogen, more flexible operation.	Non-precious metal, stable, high purity hydrogen, long stack lifetime and reasonable efficiency.
Negatives	Expensive/uncommon material requirements, can be highly sensitive to impurities.	Requires additional compression, can be sensitive to impurities and slow ramp up rate.

Table 9 – A comparison of the PEM & Alkaline electrolyser technologies

Another key characteristic for a facility managing thermal constraints is a large operating range (turndown). In order to allow the plant to continue to operate when there is a low power supply, a low large turndown ratio is required. This can be achieved by using a design comprised of a number of electrolyser modules. For example, if an electrolyser's lowest operating capacity is 20%, a single 10MW electrolyser's lower operating bound is 2MW; however, an electrolyser system comprised of ten 1MW electrolysers have a lower operating bound of 0.2MW (by placing 9 electrolysers in cold standby and operating one at its' lowest capacity). Therefore, a modular electrolyser system approach is more optimal.

Hydrogen storage and carriers

The options that were explored were compressed hydrogen gas, geological storage hydrogen gas, cryogenic hydrogen liquid and hydrogen carriers: ammonia, methanol, liquid organic hydrogen carriers (LOHCs) or metal hydride. In each instance, the economic viability of the individual option depends on the scale of the storage required, which in turn is linked to the potential offtaker.

It was concluded that compressed gas would be the most viable storage option for this project. Compressed gas storage is a mature technology and can provide local balancing for supply and demand. However, due to the low density of hydrogen, the viability of compressed gas storage is dependent on: site footprint constraints, commercial aspects, and end-user pressure profile requirements.

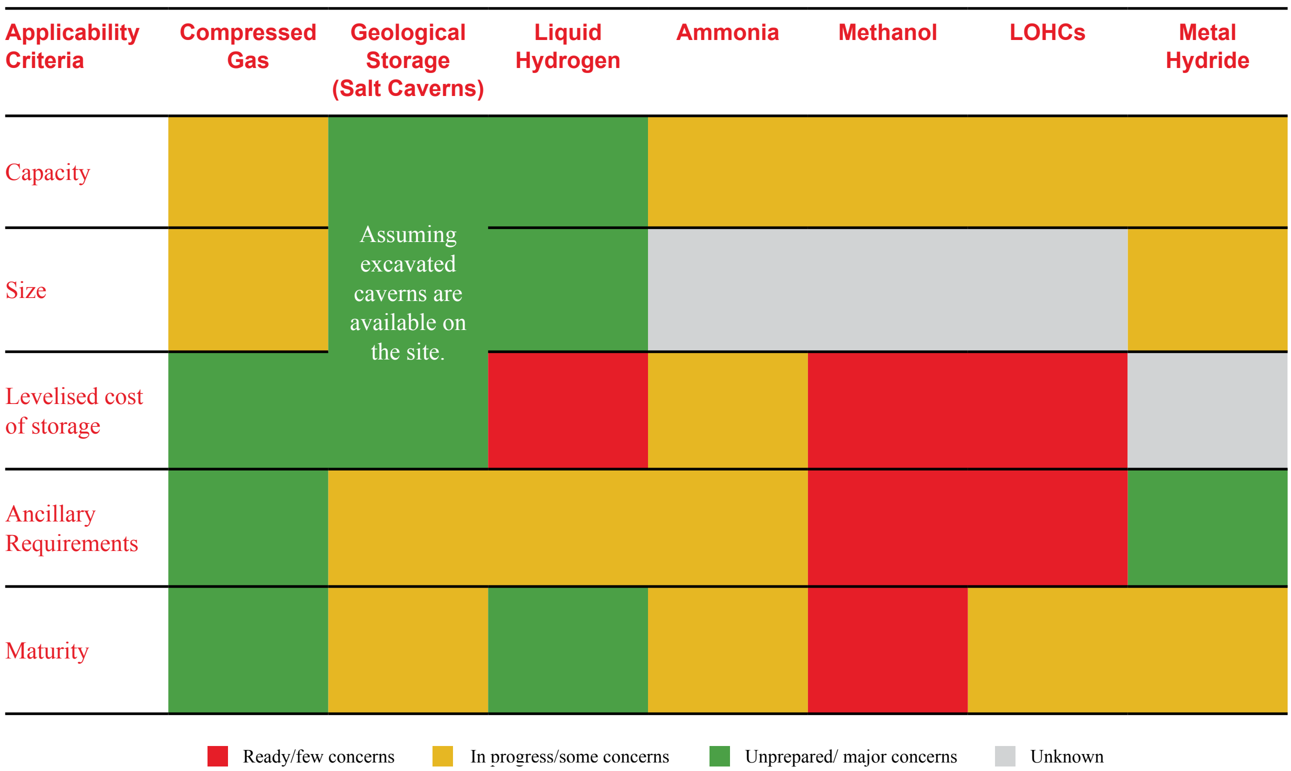


Table 10 – A summary of the different hydrogen storage options investigated within the report

Bulk transportation

The options that were explored were, tube trailers, pipelines, and export shipping. As with hydrogen storage, the economic viability of each option will be dependent on the volume of demand as well as the travel distance. For short distances and small volumes, tube trailers transporting compressed gaseous hydrogen are the expected preferred option. As transport distances increase, tube trailers transporting LOHCs are expected to become a more feasible option; however, consideration should be given to the conversion requirements at the point of use. Transmission and distribution pipelines are considered to the be a cost-effective, long-term solution for distribution for a network with sufficient capacity and sustained demand.

The most efficient transport option is dependent on the potential offtaker and, therefore, until that is confirmed, no one option can be decided. However, for this project, a working assumption is that there would be a transmission and/or distribution gas network from which a facility could connect to.

Applicability Criteria	Tube Trailer	Pipelines	Export Shipping
Capacity			
Size			
Capex			
Ancillary Requirements			
Maturity			

Ready/few concerns   In progress/some concerns   Unprepared/ major concerns   Unknown

Table 11 – Summary comparing three different hydrogen transport options

Basis of design

Description of facilities

An HPF will comprise of three main components:

1. Electrolyser
   - The model is based on a PEM electrolyser as this is the only technology type that can cope with the highly variable power supply associated with a facility managing thermal constraints.
   - 10MW electrolyser modular units composed of 15 stacks per module.
2. Balance of Plant (BOP)
   - Compressor – required for hydrogen storage / distribution unless stored at Low Pressure (LP).
   - Electrical Systems – this includes the transformers for DC electrolysis and AC generators.
   - Water Treatment Systems – the system design includes a reverse osmosis (RO) process for treating supply water for feed. The current designs have been based on a portable water feedstock.
   - Control Systems – ensuring a safe and efficient facility operation.
   - Dryer/Water Separation – purifying the hydrogen produced.
   - Cooling System – maintaining the electrolyser operating temperature.
3. Hydrogen Storage Tanks
   - Designs offer storage options at Low Pressure, LP (30barg). or High Pressure, HP, (300barg), in a number of storage containers.
   - The hours' worth of hydrogen storage can be modified to give the required hydrogen storage footprint at both LP and HP condition.

Design parameters

Capacity

The electrolyser capacity results in the hydrogen production capacity shown in Table 12 below. The hydrogen production capacity is calculated by using the hydrogen production rate given by ITM of 36kg/h, which equates to 57.5kWh/kg[20].

Parameters	Modular Electrolyser Size Options		
Electrolyser Capacity (MW)	300	750	1500
Total Hydrogen Production Capacity (t/d)	125	313	626
Total Hydrogen Production Capacity (kt/yr)	46	114	229

Table 12 – A summary of the maximum hydrogen produced at different electrolyser capacities

Feedstock – water

The feedstock of water, either seawater, river water or portable water, has to be treated using a RO operation. The pressure and recovery rates depend on the water source. Table 13 explains the requirements by water source.

Water Source	RO Pressure Required	Water Recovery Through RO
Potable Water	10barg	75%
River Water	10barg	75%
Seawater	55barg	45%

Table 13 – A summary of how the water source affects reverse osmosis

Feedstock – power

There are four main sources of consumption:

- Pump power consumption – for pumping the feedstock water to the required pressure for RO.
- BOP power consumption – for cooling the electrolyser. The power required for the BOP is 2.5kWh/kgh$_2$.
- Electrolyser power consumption – the power required for the electrolysis process. When the electrolyser is operating at maximum capacity, this is equivalent to a hydrogen production rate of 57.5kWh/kgH$_2$. For example, a 50MW electrolyser requires 50MW of power at maximum capacity.
- Compressor power consumption – compressing the hydrogen product to the required distribution/ storage pressure. The power required will depend on the offtaker. For this work, it has been assumed that the hydrogen product is compressed to 75barg to allow blending into the NTS.

Therefore, the total power feedstock required for production hydrogen via this design is 62.1kWh/ kgh$_2$.

Products

Hydrogen would be produced at 57.5kWh/kg, at 30barg and 30C and then compressed to 75barg for transmission.

Civils design

Hydrogen storage footprint

LP or HP storage options with safety considerations with the model assuming 24hr storage currently.

General plant footprint

Scaled to electrolyser capacity, including the different modules, auxiliaries and grid connection facilities, the facility would have a total surface area of 1,125m2/100MW.

Initial Pressure	Final Pressure	Initial Temperature	Final Temperature	Power Consumption Rate
barg	barg	ºC	ºC	kWh/t
30	75	30	30	567.99

Table 14 – An explanation of the power required for compression under the current model conditions

Pressure	Vessel Length	Vessel Diameter	Safety Spacing	Total Surface Area	H_2 Storage Mass
LP (30barg)	25m (From Wefco Conversation)	4m	2.5m	178.75m2	700kg
HP (300barg)	8.5m (From Chesterfield Special Cylinders Conversation)	1.5m	2.5m	44m2	246kg

Table 15 – A description of the pressure vessel sizing information used for the design footprint calculation.

Appendix 4
Injecting Hydrogen into the Gas Networks

This project has investigated whether and how hydrogen production facilities can use constrained electricity. A hydrogen production facility support thermal constraint management will have a varying production profile.

Direct hydrogen offtakers such as industrial users or transport refuelling stations would require a steady and/or predictable supply of hydrogen. A hydrogen production facility with varying production profile would struggle to supply these users without expensive storage.

A connection to the gas network could offer a more flexible offtake route for a hydrogen production facility with a varying profile. A network could accept all the hydrogen produced at peak production times (when there are high thermal constraints). Equally there would not be an issue during periods of low or no hydrogen production.

A 100% hydrogen network would be the ideal off-taker providing the ability for a hydrogen production facility to inject and sell whatever it produces. However, given that there is likely to be limited 100% hydrogen networks in GB in the short-term (next 10 – 20 years) blending hydrogen into the existing network is likely to be the most commonly available route for hydrogen production facilities.

Therefore Arup, together with National Grid Gas Transmission, explored potential opportunities and challenges for a production facility using thermally constrained energy to blend some or all of its hydrogen into the gas network. The focus of this review is on the highest-pressure parts of the gas networks, the National Transmission System (NTS) and Local Transmission System (LTS) which are part of the Gas Distribution Networks. These networks have the highest flow and therefore the most capacity for hydrogen injection without breaking the blending limits, which will be a challenge at lower pressures.

This work has found that:

- Network injection is a good option for an HPF using thermally constrained energy from an operational standpoint A HPF utilising thermal constraint energy will have a varying production profile. A network connection which can accept varying levels of hydrogen injection is an ideal option for HPF using thermally constrained energy. Direct off-takers such as industrial users or transport refuelling stations would require a steady and/or predictable supply of hydrogen which an facility with a varying production profile would struggle to supply (without expensive storage)
- Blending hydrogen into the existing grid is a technically feasible option. Blending is technically possible anywhere along the NTS and LTS network. The feasibility of any particular facility and the amount that facility can inject will depend on the location and will need to be assessed on a case by case basis.
- Billing methodology will restrict blending rates initially to ~5% which could be restrictive for larger HPF. This may be sufficient for smaller facilities but could be restrictive for larger ones (>500MW).
- The requirement to vary the blend volume poses a challenge but it is expected to be manageable. The benefit of grid injection for a HPF-TC is the ability to vary the volume injected to match the varying production profile. For this key benefit to be realised there needs to be an ability to vary the blend percentage. Given the size of the gas flows at NTS level vs the size of likely HPF facilities, the percentage variance is likely to be relatively small (a few percent) and could be managed by the network. Deblending offers a way of managing the blends of more ‘hydrogen sensitive’ customers.

- The capex of a blending facility and grid connection is expected to be a relatively small part of overall project capex. Indicative analysis shows that blending and connection costs will be relatively small compared to the capex of the HPF itself. Connection and blending facility costs may represent around 4% of capex for a 50 MW electrolyser and this percentage falls as the facility size increases. These costs will have a very small impact on the LCoH.
- Need to recognise the strategic role a hydrogen facility using constrained electricity could play in the wider electricity system. The role hydrogen production facility using constrained energy could plays in managing the electricity network brings strategic value over and above other hydrogen production facilities seeking to inject. This should be recognised and taken into when account when blending capacity is allocated. This value should also be recognised within the HPBM and in how hydrogen blending capacity is allocated.
- Blended hydrogen should be certified so that it can be traded at a premium to natural gas, Hydrogen that is created from thermal constrained energy could potentially be treated as a more premium product than other forms of hydrogen to reflect its wider energy system benefits. Hydrogen developers will need evidence that the thermally constrained electricity it uses will be classed as low carbon in order to be traded as a green gas.
- Need a way for a Gas system operator to communicate to potential HPFs where they can inject hydrogen. There is set to be a 'free-market' approach to hydrogen connections in theory allowing for hydrogen injection anywhere along the network. Although this opens up a number of locations it could unintentionally 'crowd out' hydrogen production facilities that offer wider benefits as there may be other hydrogen blending facilities connecting nearby, preventing or restricting their hydrogen injection.

UK Government decision on blending

During the course of this innovation project, in December 2023, the UK Government published a strategic decision on blending, where it announced that it intends to proceed with blending into the gas distribution networks subject to a safety assessment and subsequent finalisation of the economic assessment. In its decision, the UK Government stated that it saw two strategic roles for hydrogen blending;

1. An 'offtaker of last resort' - being able to accept hydrogen when there is excess production that is not required by the primary offtaker; and
2. As a 'strategic enabler' where hydrogen production facilities are able to support the wider energy system by locating in areas where there is excess constrained electricity.

The decision stated that the HPBM would be the most appropriate mechanism to support hydrogen blending. In the first two rounds of HPBM, hydrogen blending has not been allowed as an offtaker. The UK government's future rounds will allow for blending to be considered as a qualifying offtake, as long as a projects use of blending as an offtaker aligns with the strategic roles outlined above. A hydrogen production facility that uses thermal constraints should be ideally placed to demonstrate that it aligns with these strategic aims and provides wider system benefits.

It is important to note that the UK Government's decision has been at distribution network level and there remains uncertainty about whether blending will be allowed at transmission level. Larger hydrogen production facilities that can make the biggest impact on thermal constraints are more likely to need a connection at the higher pressure transmission network, which offers a higher hydrogen offtake capacity. Though the higher pressure systems (LTS) within the distribution network can also provide this higher offtake.

Technical implications of blending

The main limitation on hydrogen injection volumes is the volume blend percentage of hydrogen, which cannot exceed the 20% maximum, and, in practice, this percentage is likely to be even lower in the short term (closer to 5%) due to the need to work within existing billing methodology frameworks.

In theory, hydrogen could be blended anywhere along the gas network. However, in practice, for larger scale projects (more than 100MW) blending is more likely at higher pressures either into the NTS or the highest-pressure tiers of the distribution networks, the LTS. This is because the flow of gas at these pressures allows for significant volumes of hydrogen to be injected before the volume blend limit is breached. A simplified case study was carried out to estimate the amount of hydrogen that could be injected into the gas network based on three sizes of electrolyser: 300MW, 750MW and 1500MW these sizes were chosen for consistency with other parts of the study. Various assumptions were made around the configuration of the gas network and the electrolyser. The inputs and assumptions are summarised in Table 16.

Figure 30 shows the hydrogen blend percentages for the different sizes electrolyser facilities studied, these were chosen with different amounts of electricity 'topped-up' from the wholesale electricity market. This is the amount of electricity needed to meet a minimum operating load of either 20%, 40% or 60% of the electrolyser's total capacity. Note at 0% top up the facility is in effect only operating during constrained times and therefore has the biggest variance between minimum (0) and maximum capacity. The length of the bars represents the range in blend percentage at the point of injection resulting from variation in the hydrogen injection rate.

The results show that the hydrogen blend range does not exceed 20 vol.% for any of the electrolyser ratings considered. However if the blend percentage is set lower, e.g. at 5% to manage customer billing arrangements the blend range could impact that threshold for the larger facilities.

Inputs	Assumption
Proximity of injection point to other injection points	There is no blending upstream affecting the assumptions below.
Feeder diameter (NB)	36 inch which is representative of a typical NTS gas pipeline with a diameter of 24-36".
Operating pressure	70 barg which is representative of a typical NTS gas pipeline.
Natural gas velocity	20 m/s which is representative of a typical NTS gas pipeline.[21]
Natural gas Wobbe Index (WI)	50.9 MJ/Sm³ (WI is measured in mega joules per standard metre cubed based on GS(M)R standard conditions of 15 degrees and 1 atmosphere pressure. Note that WI depends on source of gas).[22]
Assumed natural gas temperature	10°C
Size of electrolyser	300MW, 750MW and 1500 MW with no top up from the grid, 20% top up, 40% top up and 60% top up from the grid.
Electrolyser Power Consumption	57.5 kWh/kg
Blend limit on LTS and NTS (%)	20% by volume

Table 16 – Inputs and assumptions in the case study

The variability of blending increases for larger electrolysers, the higher the baseload capacity (i.e. the 'top-up') the lower the variation. A large variation in blend could have implications for any sensitive customers connected to the network who may struggle with variations in blend.

For this exercise a constant flow rate is assumed but in practice, the flowrate is likely to vary seasonally and will be lower in summer which would increase the percentage blend for the same rate of hydrogen injection. The pipeline size also varies around the network which would impact the flow rate and therefore the maximum hydrogen injection that can be accommodated.

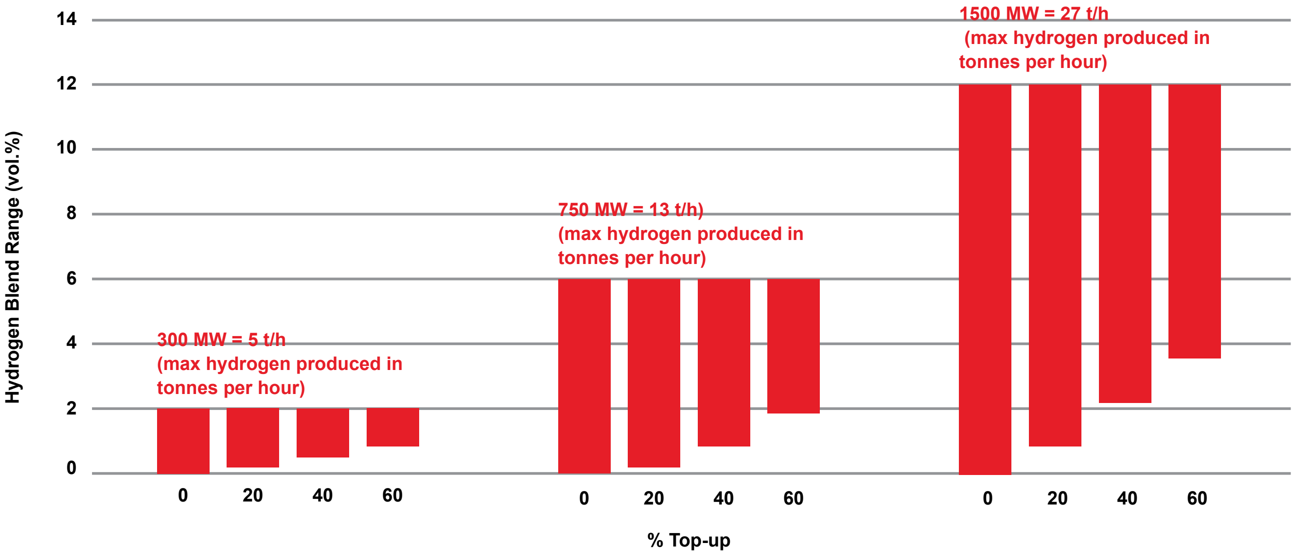


Figure 30 – Expected hydrogen blend range in a 36" pipeline operating at 70 barg when receiving hydrogen produced from electrolysers of different ratings

The rate of hydrogen that can be injected will also depend on where in the network blending is occurring. The factors that will need to be taken into account include:

- The location of other blending facilities – if there are other hydrogen blending facilities injecting hydrogen nearby then the blend rate of both facilities will need to be managed and potentially limited in order to ensure the blend limit is not reached.
- The proximity to more sensitive customers – there may be a small number of customers connected to the network which will either require 100% methane feedstock or will be highly sensitive to gas quality fluctuations. National Grid Gas is exploring deblending as an option for managing this issue[23]. Location is likely to be an important factor for deblending as the gas network will likely want to avoid having a blending facility immediately upstream of a deblending facility.
- The Wobbe Index (WI) of the gas - will also have an impact on the blend rate. In this example a gas with a relatively high WI is used. The WI of the gas will depend on the gas that is being inputted into the system. If the WI of the gas at the point that the hydrogen is blended is lower, than the maximum volume of hydrogen that can be injected would be reduced. This is because hydrogen has a lower WI and the current regulations state that the WI of gas must be between a certain range (47.2 and 51.4 MJ/m ^{3}) though the lower limit is being reduced (to 46.5 MJ/m^3) which should allow for greater levels of hydrogen blending.

Blending at NTS entry points, such as St Fergus or Bacton, are expected allow the greatest amount of hydrogen to be injected. This is because there is a large amount of capacity available at NTS entry points.

In summary blending hydrogen into the gas network is a potential route for a hydrogen production facility that uses thermally constrained energy but the ability to blend and the quantity of hydrogen that can be injected will vary depending on the location. The gas network will treat an application to blend on a case-by-case basis based on the factors outlined above. To support the development of hydrogen projects the networks (national Gas transmission and the distribution networks) should look to communicate where on their network there is likely to be blending capacity. The areas where there is likely to be capacity in the gas network (Scotland/North of England).

Allowed blending limits

At present, a 20% blend is the highest possible blend rate due to technical limits on domestic boilers. However, it is expected that a lower blend cap at around 5% is likely to be set initially due to the nascency of the hydrogen production market, to manage customer billing and support end users' transition to hydrogen. Blending hydrogen into gas networks reduces the Calorific Value (CV) of the gas customers receive. This creates problems for estimating bills, as customers receiving higher blends would pay more per unit of energy than others. The Gas Safety (Management) Regulations, GS(M)R, will need to be amended to accommodate hydrogen blending, beyond case-by-case exemptions.

UK Government has signalled its intention to initially work within existing billing arrangements to enable blending to be rolled out quickly. Based on the analysis presented in the case study above, this may limit larger HPFs' ability to blend hydrogen into gas networks as existing billing arrangements are expected to only accommodate blends of around 5%.[24 25]

Another consideration is that HPFs using thermal constraint energy need to be able to vary the injection rate. The amount of hydrogen that can be injected into the gas network will depend on the flow of gas within the network, which is higher in winter than in summer, driven by seasonal changes in demand. Even if hydrogen production remains steady, the blend percentage could vary during the year. This means that achieving a consistent blend will be extremely difficult. Based on the simple analysis above, the variance of blend percentages is likely to be relatively small and within blend limits for most sizes of electrolyser, except for larger facilities. It would be technically challenging for a HPF to turn production up and down to maintain within blend limits, and commercially challenging to use storage as this would add significantly to project costs.

Regulatory and commercial arrangements

Existing regulations were originally designed for natural gas and, therefore, updates are required to recognise differences in hydrogen e.g. gas quality and safety arrangements. The exact nature of regulatory changes to enable blending is unknown. The UK Government indicates that it may initially prioritise changes that enable blending to be implemented quickly. This includes working within existing billing arrangements and allocating new hydrogen connections on a first come first serve basis – the 'free-market approach'[26].

From the perspective of a hydrogen production facility that is providing electricity system benefits, it would be preferable for NGT and GDNs to take a more strategic approach to allocating blending capacity, with one of the criteria for allocation of capacity being the overall energy system benefits a facility is providing. This would also mitigate the risk under the 'free market approach', where subsequent new connections by other HPFs nearby may limit the amount of hydrogen a HPF using thermally constrained energy could inject which would reduce the benefit such a facility could offer to the electricity system and could even make such a project unviable. This approach requires assessing projects that provide wider energy system benefits as being of greater overall benefit to projects that are only using blending as an offtaker of last resort and not providing any wider system benefits.

Green certificates

Guarantees of Origins[27] and Green Certificates[28] can provide additional revenue streams by allowing hydrogen producers to earn a premium for producing hydrogen that is confirmed to be low carbon or ‘green’. This is likely to be important to the business model for an HPF.

The UK Government has already defined the LCHS and plans to set up a Low Carbon Hydrogen Certification Scheme by 2025. An HPF will need to prove that it meets the LCHS, and it can procure a certificate. It is therefore critical that any electricity procured as part of any contract with the ESO is classified as renewable or low carbon. The commercial viability of an HPF could be further improved if the LCHS recognises wider benefits such as alleviating thermal constrains in addition to the carbon content of hydrogen. The UK Government signalled in its strategic decision in December 2023 that it will aim to take a decision on how certificates should be treated in a blending scenario, ahead of the launch of the LCHS.

The UK Government has also decided to adopt a mass balance system for the LCHCS. This means that certificates can only be bought by consumers if they use green hydrogen it cannot (like the book and claim system) sell the certificates more widely, the government also proposes that on-selling certificates will not be allowed. This is because if hydrogen blended volumes are tradable, this could create a commercial incentive for hydrogen producers to prioritise blending over other off-takers, as they could extract a price premium for green gas certificates issued to gas shippers who could onward trade to suppliers/retail markets. This would go against the Government’s stated aim of blending being a reserve offtaker. These decisions could limit the premium that a hydrogen facility would be able to earn from any hydrogen blended into the gas networks.

There is potentially a case to be made that a hydrogen production facility contributing to constraints management should be allowed to onward trade its certificates as it provides significant benefits to the wider energy system.

Materiality of blending costs

Capex costs are expected to represent the majority of costs associated with building and connecting a blending facility to the gas network It is estimated that the direct capex costs of a blending facility are approximately £1m to £2.5m. The lower bound estimate of £1m is based on direct capex costs: the combined cost of the equipment, piping and infrastructure using the Aspen Capital Cost Estimator Software. The upper bound estimate of £2.5m is based on facility producing around 85,000 tonnes of hydrogen per year and is sourced from DESNZ[29]. In practice, capex costs will vary on a case-by-case basis.

Other costs an HPF can expect are connection offer costs, which are expected to be less than £0.5m. Actual connections costs will depend on whether the connections process and costs will differ for hydrogen connections.

The capex costs of building a blending facility are a relatively small in comparison to estimates of total capex costs of larger hydrogen production facility a 300MW has an estimated capex of ~£200m (excluding storage costs). As a result its estimated that blending facility costs will have a minor impact on the LCOH[30] for all sizes of electrolyser considered in this report. It is important to note that, in practice, actual costs of an electrolyser and the costs of a blending facility will be location specific.

Appendix 5
Mapping tool

The final aspect of the project has been to assess where is best to locate any potential hydrogen production facility that will support the management of thermal constraints. Utilising GIS technology, a map has been created to compare across a number of different datasets and overlays to provide a scale of preferable locations across GB for an HPF.

Methodology

Throughout the development of the GIS mapping tool, there has been a refinement of the different weightings and priority of each when layered onto GB. The weightings applied to the map reflect both the technical requirements of the hydrogen production facility itself to be able to safely run, but also the locational requirements of the of the hydrogen production facility, including where it is best situated to be able to have most impact upon reducing the cost of thermal constraints upon the consumer and within close proximity of the chosen offtaker.

For the mapping tool, 6 'variables' have been agreed alongside the ESO, each given its own weighting, with number 1 given the highest priority descending down to number 6, which was deemed to have the lowest priority.

In addition the map also excludes areas restricted by planning such as national parks and nature reserves etc.

For the Five variables have been agreed alongside the ESO team, and each has been given a weighting from which the mapping tool has been developed against. It should be noted that the 'Fuse app', from which the mapping tool has been developed, allows the user to edit the weighting applied to each variable so it can be used as a dynamic map.

When setting up the variables, the user will have 100 'weighting points' to distribute across the variables. To create the maps shown below (and in the main report) the following points have been assigned:

1. Electricity Distribution Network Boundaries = 35 points;
2. Substation Proximity = 25 points;
3. Gas Network Proximity = 15 points;
4. Water Source Proximity = 10 points;
5. Industrial Users Proximity = 10 points; and
6. Motorway Network = 5 points.

Based on the weightings mentioned above, each of the 1km hex grids are then given a score out of 100 based on their appropriateness, with the darker green the grid, the more appropriate. To aid with the clear distinction between the different areas, the user can adjust the 'threshold' of the hex grid. This allows the user to limit what areas are shown on the map based on their score. Figures 31 and 32 show the differences in the map when the 'threshold' is gradually increased.

Variable	Scoring Methodology	Weighting
Transmission Network Boundaries	North of B6 is the highest scoring; specifically the mapping tool has taken into consideration a more granular view of the boundaries based on the modelling results. The space between B8 and B6 scored slightly less. Due to the constraints being located predominately in the North of England and Scotland, any areas south of the B8 boundary are scored Zero.	V. High
Electricity Substations	Proximity to substations is to be scored based on distance, with grading to be applied in 5km increments. I.e. 0-5km = 'the best', 5-10km = 'second best' etc. This process would be continued up to 50km where any further distance would be scored Zero.	High
Gas Network	The highest score to be given to the area within a 10km proximity of Grid entry points (For example, St Fergus). Forward area to be graded according to distance from the gas transmission or LTS network. < 16km – highest score 16-30km – middle range >30km – lowest score (any facility at this range must require a DCO for development)	Medium
Water Source	Graded system based on distance from the coast or 'Main' rivers, lakes, or lochs on a per KM basis. With each KM further away being scored less than the previous.	Low
Industrial Demand Points	This is continuous grade based on proximity to major carbon dioxide emitters in the UK.	Low
Motorway Network	A 5km of a motorway – potential transport offtaker in the future	Lowest

Table 17 – GIS mapping tool variables and weightings

Future use of the tool

Each of the images shown above have been produced with a consistent weighting (applied to each of the weightings). The tool has been designed so that any user can have the ability to change the weightings, placing greater weight on certain variables compared to others. In each instance, the change in weightings will affect the output of the GIS tool. Currently, the weightings have been aligned with the gas grid being the offtaker of choice, with the motorway network and industrial users weighted lower. These can be updated depending on specific offtaker types and the primary offtaker.

Category	Variable Input Data	Source
Distribution Network Boundaries	High/Low Priority DNB's (Linear)	NGESO
Electricity Substations	Substations (Point)	NGESO
Gas network	Gas Pipes (Linear)	National Gas
Water	Rivers (Linear)	Ordnance Survey, SEPA, DEFRA
Industrial demand points	Source Point Emitters (Point)	DESNZ
Motorway proximity	Open Road Motorways (Linear)	Ordnance Survey

Table 19 – Geospatial datasets inputs and sources

Data preparation and spatial analysis

Data processing for the HPF thermal constraints tool involved a combination of ArcGIS Pro and Feature Manipulation Engine (FME). Initially, ArcGIS Pro was used for constraints mapping to identify relevant areas and exclude hex-grid cells intersecting with spatial constraints. Then, Euclidean distance calculations were performed in ArcGIS Pro to measure straight-line distances from each MCE variable. Next, FME was utilised to spatially filter hex-grid cells based on Euclidean distance measurements. Mean statistics were then applied in FME to calculate the average spatial unit values of the variables within each cell. Finally, the values were remapped to align with the scoring criteria specified in. This integrated approach ensured efficient data processing and accurate determination of suitable locations for the HPF thermal constraints tool.

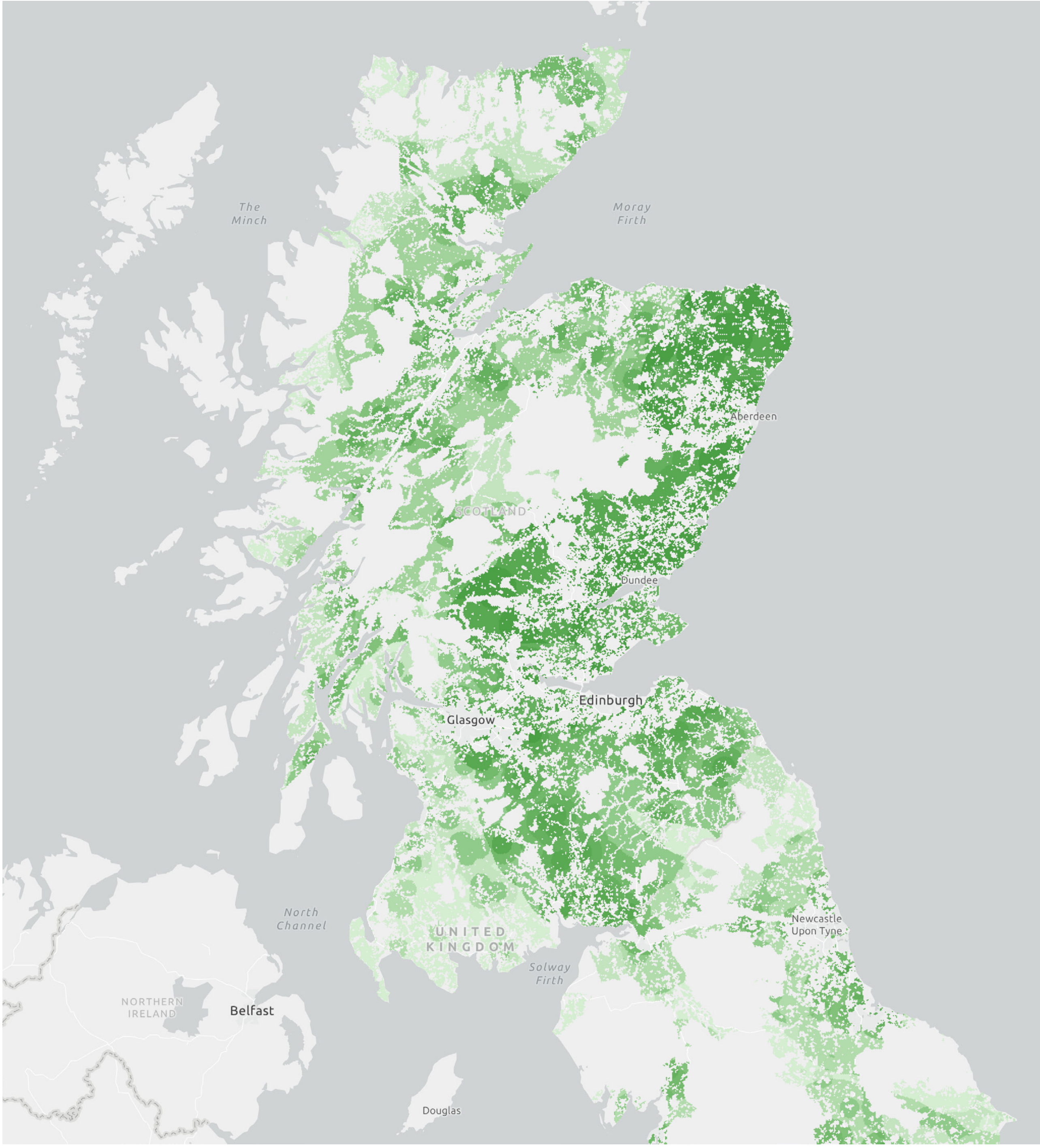


Figure 31 – GIS mapping tool with 50% compatibility measure

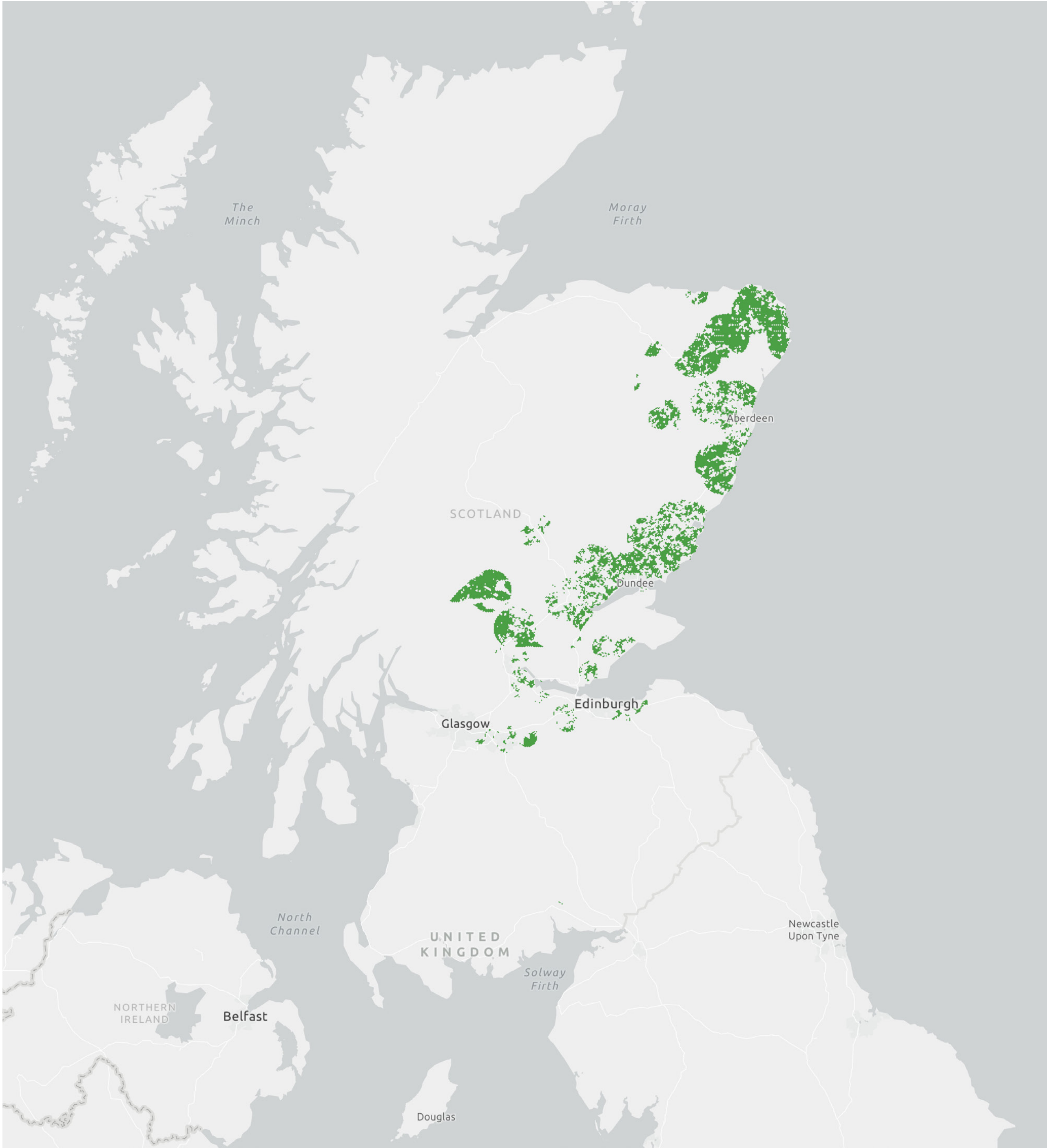


Figure 32 – GIS mapping tool with 80% compatibility measure

References and glossary of terms

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[3] UK Government, the Department for Energy Security and Net Zero: Powering Up Britain 2023 - https://www.gov.uk/government/publications/powering-up-britain

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[22] According to Gas Safety (Management) Regulations, GS(M)R, natural gas in the gas network must have a WI value between 47.2 and 51.4 MJ/m ³ under normal (non emergency) conditions. From 1 April 2025, the GS(M)R will reduce the lower WI limit to 46.5. The upper limit will remain unchanged. Implementation of the Reduced Lower Limit for Wobbe Index

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[24] The Future Billing Methodology project conducted by Xoserve explored a number of billing options and conclude by recommending that billing should initially work within existing frameworks by controlling the rate of low-CV gas into Local Distribution Zones (LDZ) effectively capping the hydrogen blend rate at initially ~5%. Future Billing Methodology, Xoserve https://www.xoserve.com/decarbonisation/decarbonising-gas/future-billing-methodology-project/

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[27] A Guarantee of Origin is a digital document that provides information on where, when, and how an energy product (in this case hydrogen) is produced.

[28] A green certificate is often referred to as a renewable energy certificate (REC). It is a tradable financial instrument that represents the environmental attributes of renewable energy generation. Once certified, the green certificates can be traded in certificate markets, through bilateral agreements, or through other mechanisms.

[29] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1184277/hydrogen-blending-into-gb-gas-distribution-networks-consultation.pdf

[30] The average cost of hydrogen produced over the lifetime of a hydrogen facility

Abbreviation	Term
£/MWh	Pound sterling per Megawatt Hour
£kW	Pound sterling per Kilowatt
AC	Alternating Current
ASTI	Acclerating Strategic Transmission Investment
BM	Balancing Mechanism
BOP	Balance of Power
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Differences
CPI	Consumer Price Index
CSNP	Centralised Strategic Network Plan
DC	Direct Current
DEFRA	The Department for Environment, Food & Rural Affairs
DESNZ	The Department for Energy Security and Net Zero
ENTEO-E	European Network of Transmission System Operators for Electricity
ESO	Electricitiy System Operator
ETYS	Electricity Ten Year Statement
FCEV	Fuel Cell Electric Vehicles
FES	Future Energy Scenarios
FID	Financial Investment Decision
FME	Feature Manipulation Engine
FY	Financial Year
GB	Great Britain
GDN	Gas Distribution Network
GIS	Geographic Information System
GW	Gigawatt
HAR1	Hydrogen Allocation Round 1
HAR2	Hydrogen Allocation Round 2
HND	Holistic Network Design

Abbreviation	Term
HP	High Pressure
HPBM	Hydrogen Production Business Models
HPF	Hydrogen Production Facility
JNCC	Joint Nature Conservation Committee
KM	Kilometer
kV	Kilovolt
LCHS	Low Carbon Hydrogen Standard
LCOE	Levelised Cost of Electricity
LCoH	Levelised Cost of Hydrogen
LOHC	Liquid Organic Hydrogen Carrier
LP	Low Pressure
LTS	Local Transmission Network
MCE	Multi-criteria Evaluation
MW	Megawatt
NESO	National Energy System Operator
NGET	National Grid Electricity Transmission
NGT	National Gas Transmission
NOA	Network Options Assessment
NRW	Natural Resources Wales
NTS	National Transmission Network
NZHF	Net Zero Hydrogen Fund
OPEX	Operating Expense
OTC	Over the Counter
PEM	Proton Exchange Membrane
PPA	Purchasing Power Agreement
RO	Reverse osmosis
ROC	Renewable Obligation Certificates
SOEC	Solid Oxide Electrolyser Cell


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