Green hydrogen in Scotland

A report for Scottish Futures Trust

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Report summary

The development of green hydrogen production in Scotland is an important tool in delivering an efficient and effective energy system for both GB and Scotland. Pairing electrolysis with new Scottish wind generation will ensure that the benefits of low cost, zero carbon electricity generation support decarbonisation across the whole energy system including industrial energy demand, energy storage, and some elements of heat decarbonisation, as well as providing new tools for balancing the supply and demand of electricity itself.

Over the past few years, UK government has introduced mechanisms to support hydrogen, with a particular focus on the development of electrolytic or 'green' hydrogen. The Low Carbon Hydrogen Standard (LCHS) has been introduced to ensure a clear definition of what constitutes appropriately decarbonised hydrogen and links this to the Hydrogen Production Business Model (HPBM) through Low Carbon Hydrogen Agreements (LCHA). The first round of LCHA contracts have been identified through Hydrogen Allocation Round 1 (HAR1) with 125 MW capacity successful, and HAR2 is well underway. However, as significant consumers of electricity, electrolysers are subject to electricity system regulations and market frameworks which were largely designed for a pre net-zero system.

Beyond HAR2 it is critical that we continue to scale up production, bring down costs, increase flexibility and locate plant in the most effective places. This will benefit Scotland and GB as a whole. It will support a more efficient *electricity* system and will share benefits across the wider *energy* system. By investigating four business and operational models for green hydrogen, this report highlights some key barriers to achieving these outcomes under current arrangements and suggests routes to overcome them. The recommendations include:

- Review the allocation of electricity system charges which currently contribute up to 45% of the levelised cost of hydrogen (LCoH) from network charges, balancing charges and electricity system policy levies. In particular, electricity system charges are highest in the most flexible and versatile business and operating model: separate, optimally placed grid-connected electrolysers and wind farms, trading via Power Purchase Agreements (PPAs).

- Index future LCHA strike prices against wholesale electricity prices to encourage greater flexibility and competition in PPAs and to reduce the substantial risk premiums, potentially several tens of pounds per megawatt hour, that electrolysers need to pay to PPA providers.

- Adjust the LCHS and HPBM to reflect the additional benefits that Scottish green hydrogen delivers to the Scottish and GB electricity system in comparison to projects located elsewhere in the country.

- Simplify arrangements for green hydrogen projects by basing the LCHS on an 'assumption of success' for decarbonising the GB electricity system by 2035.

Issues and recommendations

Issue 1: electricity system costs can represent up to 45% of the levelised cost of hydrogen

- Consider ways to reduce the burden of system charges on both a national and locational basis, particularly where these don't align with the fundamental impact that green hydrogen production has on the electricity system.
- DESNZ should explore the potential to either reduce locational generation TNUoS or remove the floor on locational demand TNUoS. They should also review arrangements for demand residual charges to ensure they don't introduce unintended consequences for green hydrogen development.

Issue 2: indexing arrangements under the current LCHA significantly increase electricity costs

- For future allocation rounds, index link strike prices to wholesale electricity costs. This reduces the need to take out very long-term fixed price PPA contracts and can reduce the associated risk premiums, which can be significant.

Issue 3: complex definitions of low carbon hydrogen don't align with plans for a net zero power system by 2035

- Commission analysis to understand the potential to allow lower time-granularity and to allow electrolysers to account for carbon at regional grid intensity values when importing without a PPA to a specific generator.

Issue 4: operation of electrolysers for active curtailment reduction is disincentivised and involves an invalid carbon penalty

- Prioritise new longer-term constraint management approaches which improve volume and price confidence for reducing renewable curtailment, such as those being considered by ESO in its Thermal Constraint Collaboration Project.
- Change the LCHS rules to allow electrolysers engaged in curtailment reduction to account for their electricity at zero carbon intensity.

Issue 5: interaction between constraints, wholesale PPA arrangements, and balancing actions

- Explore the interaction between constraints and PPA contracts in greater detail. Identify the extent to which Scottish electrolysers deliver additional benefits and consider ways to ensure they are appropriately rewarded for the value they create by locating behind the same constraint as the generator.

Issue 6: arrangements for behind-the-meter electrolysers may limit their size

- Review rules around electricity system costs, particularly demand TNUoS, when applied to behind-the-meter electrolysers and wind farm projects.

Issue 7: avoiding electricity system costs could encourage islanded systems, but these face higher risks and lack flexibility

- DESNZ should commission analysis of the optimal scale of islanded systems, taking account of avoided system costs and the likely scale of additional risk relative to alternative models. The rules around electricity system charges should be reviewed to ensure this model isn't over-incentivised relative to alternatives.

Introduction

Organisations relevant to this report:

DESNZ: the UK government department responsible for setting overall energy policy and designing and delivering the LCHS and HPBM.

ESO / NESO: The electricity system operator has several roles. It operates the electricity system in real time, maintains security of supply, runs the Balancing Mechanism (BM) and resolves network constraints. It also plans the electricity transmission network. The ESO will soon become the National Energy System Operator (NESO) and, in addition to its existing duties, will take on a range of whole-energy-system responsibilities including some related to the development of a hydrogen system.

Ofgem: the GB energy system regulator. Ofgem makes determinations on network investment, regulates the ESO (although the relationship with the NESO will be different). Ofgem also makes regulatory decisions on some elements of market design.

Locating green hydrogen production in Scotland has the potential to deliver benefits across the GB energy system, not just for electricity, and not just for Scotland.

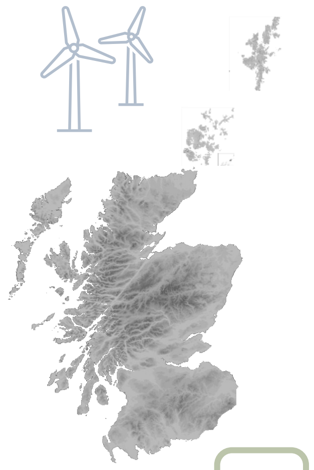
Scottish green hydrogen production can be low cost because it partners with some of the inherently lowest cost renewable generation in GB: wind generation in the windiest part of the country. By connecting in areas of excess generation it can actively reduce the need for both transmission network capacity or renewable curtailment.

Scottish green hydrogen production can be low carbon because the average intensity of Scottish electricity generation is already very low, well under the level needed to meet the LCHS (approximately 50g CO_2 / $KWh_{electric}$), and because, where it acts to reduce the curtailment of Scottish wind generation, it creates direct additionality by using zero carbon electricity generation that is otherwise wasted.

Significant growth in Scottish wind generation is required to deliver net zero. For example, all the ESO's 2023 FES [1] net zero compliant scenarios show Scottish wind capacity in excess of 50 GW by 2035 and to accommodate this the transmission capacity across some of the major transmission boundaries needs to double or even triple in some cases by the early part of the next decade [2]. Flexible hydrogen electrolysis represents one of the most effective ways of harnessing the zero carbon electricity we can produce in Scotland. It can reduce curtailment by ensuring that it operates at any time that a transmission constraint is binding and can complement transmission build to help deliver an appropriate balance of wind capacity, transmission network, curtailment and flexibility investment. Scotland also has the potential to capture economies of scales from gigawatt sized electrolysis projects linked to large offshore wind farms.

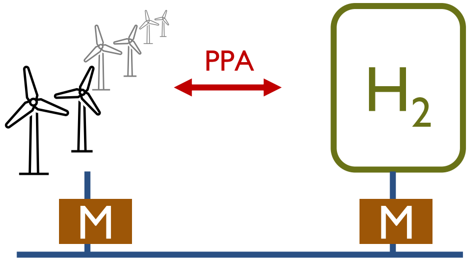
Whilst the Low Carbon Hydrogen Standard (LCHS) [3] and Hydrogen Production Business Model (HPBM) [4] represent significant steps forward in standardising and developing our nascent hydrogen system, some of the design choices are creating barriers for the development of Scottish green hydrogen. Some of these barriers apply to electrolysis wherever it is in GB, whilst others specifically limit the value that Scottish projects can deliver.

By exploring the interaction of four green hydrogen business and operational models with the LCHS, HPBM and wider electricity market arrangements, this report explores the need for electrolysers to work effectively with the electricity system to produce hydrogen certified to the LCHS and supported by the HPBM.



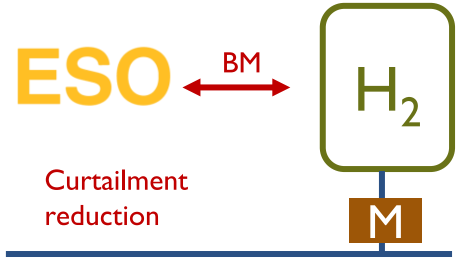
Four ways that green hydrogen production can interact with the electricity system

There are different models for the connection and operation of electrolysers which allow them to produce low carbon hydrogen. Each model will interact with the electricity market, regulations and infrastructure in different ways. Differences between models include whether generators and electrolysers are co-located or developed in separate locations, whether the link between the two is purely contractual or distinctly physical and even whether the project is connected to the wider electricity system at all. It may be possible to combine some models with others, whilst other combinations will be mutually exclusive. For example, Model 2 may be developed in combination with Model 1 because limiting operation to only curtailed electricity would result in a very low load factor. In this report we use four models, which have the potential to play a part in the evolution of a Scottish green hydrogen industry over the coming decades, to explore the interaction between electricity market regulation, the LCHS, and the design of the HPBM.



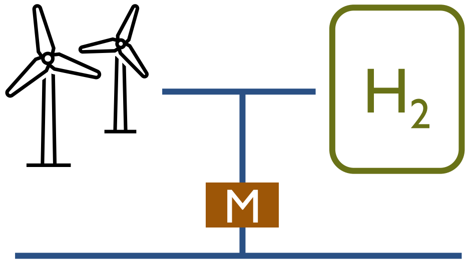
Electrolysers are developed separately from renewable generation and are linked contractually through Power Purchase Agreements (PPAs).

Model 1: Grid connected electrolyser and renewable PPA



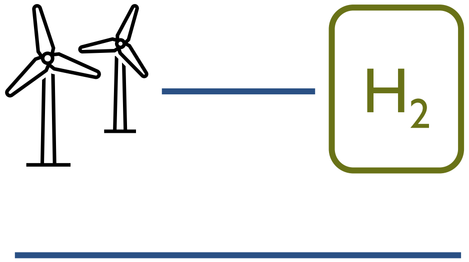
Electrolysers developed separately from generation which acts flexibly to reduce renewables curtailment driven by network constraints and increasingly by an excess of generation over demand across GB.

Model 2: Grid connected electrolyser using curtailed wind



Electrolysers and renewable generators co-locate with a single connection to the grid.

Model 3: Behind-the-meter electrolyser and generator



Electrolysers and renewable generators developed as co-dependent stand-alone projects with no connection to the wider electricity system.

Model 4: Islanded electrolyser and generator

The design of the LCHS removes the potential of a fifth model – one where import from the Scottish network is able to meet the LCHS by virtue of the low carbon intensity of the Scottish electricity generation fleet. This is discussed further on page 15.

TEL the energy landscape

Electrolysers and the low carbon hydrogen standard

The UK LCHS [3] was introduced in 2022 and sets a maximum threshold for the quantity of greenhouse gases that are emitted when producing hydrogen. The standard can be applied to any method of producing hydrogen including electrolysis, reformation of natural gas, and gasification of biomass. The standard has been set to ensure new low carbon hydrogen production makes a direct contribution to our carbon reduction targets.

Overall low carbon standard: the heart of the LCHS is that in order to be considered 'low carbon' the total carbon intensity, including all inputs, needs to be less than 20g CO_2 equivalent per megajoule of energy stored in the hydrogen, calculated using the hydrogen's Lower Heating Value (20 g $CO_{2\ equivalent}$ / $MJ_{hydrogen,\ LHV}$) [3]. The carbon intensity is calculated from the total carbon footprint of the inputs used. For electrolysis the main source of carbon comes from the electricity used to run the electrolyser. The amount of electricity – and hence embedded carbon – depends on the efficiency of the process. Assuming a 70% efficiency, the carbon intensity of the electricity used to create the hydrogen must be less than approximately 50g $CO_{2\ equivalent}$/ $KWh_{electric}$. This must be achieved separately during each half hour settlement period.

H_2 Low carbon hydrogen standard 20g $CO_{2\ equivalent}$ / $MJ_{hydrogen,\ LHV}$

Assuming 70% efficiency → Implies

Likely to need electricity of less than approximately 50g $CO_{2\ equivalent}$/ $KWh_{electric}$

Rules for calculating the carbon intensity of electrical inputs: the standard also defines how producers need to account for the carbon intensity of the inputs they use. For electricity there are three methodologies, depending on how the electricity has been sourced:

Sourced from a specific generator: where electricity is sourced from a specific, identifiable, generator the carbon intensity is set by a generic intensity for that specific technology. For example, renewables have a generic intensity of 0, Nuclear of 14g CO_2 / kWh electric; and natural gas via Closed Cycle Gas Turbines (CCGT) of 471.6g CO_2 / kWh electric [5]. This applies if the sourcing is contractual, e.g. through a PPA, or if it is physical through siting of the electrolyser behind-the-meter with a specific generator.

Sourced from the GB grid: where electricity is purchased from the GB electricity market and physically imported from the grid, the carbon used is calculated from the average carbon intensity of the GB grid during the specific half hour settlement period during which it was consumed. Data is published by the ESO [6].

ESO Balancing mechanism

Sourced from the ESO via the balancing mechanism: the electrolyser can use the prevailing regional average grid intensity for that half hour settlement period [6]. GB is divided into 14 regions of which 'North Scotland' and 'South Scotland' are individual regions.

Electrolysers and the hydrogen production business model

The HPBM is designed to support hydrogen production that meets the LCHS. It is designed for a range of pathways, electrolysis (green hydrogen) is one along with reformation of natural gas with carbon capture and storage, and biomass gasification.

LCHS contracts will be awarded through allocation rounds. To date, two allocation rounds are underway – HAR 1 and HAR 2. HAR 1 focused only on electrolytic projects whilst HAR 2 invited applications from a range of eligible production technologies.

There are three components to the support awarded in a HPBM contract, with commercial operation dates being set in 2026:

- **A hydrogen CfD** which pays the producer the difference between a reference price and a strike price. In the case of electrolysis, the reference price is likely to be the 'achieved sale price'.
- **A 'price discovery incentive'** which aims to correct for the fact that the CfD removes the incentive to maximise the sale price of hydrogen.
- **A volume risk mitigation 'sliding scale'** which provides a small top-up payment if sales of hydrogen fall due to the current illiquidity of the nascent market.

In addition, for HAR1 and HAR 2, CAPEX support can be provided through the Net Zero Hydrogen Fund (NZHF).

Above: Successful projects in HAR 1
(Source: [7] and TEL analysis**)**

Hydrogen Allocation Round 1 (HAR 1) concluded in late 2023 and awarded contracts to 11 electrolytic hydrogen projects with a total production capacity of 125 $MW_{hydrogen}$. The average strike prices for the CfD component was £241 / $MWh_{hydrogen, LHV}$ in 2023 prices (£175 / MWh in 2012 prices). In addition to the 11 successful projects, four projects were unsuccessful and a further 2 withdrew before the final assessment [7].

Of the successful projects, two are in Scotland: the Cromarty Hydrogen project being developed by Scottish Power and Storegga, and the Whitelee Green Hydrogen project being developed by Scottish Power. Two of the projects that entered final negotiations, but which were ultimately unsuccessful, were also located in Scotland.

The map to the left shows the location and capacity of the 11 successful HAR 1 projects.

Projects that have been offered HPBM support are now required to reach final investment decision (FID) and sign the low carbon hydrogen agreements in the next few months.

Applications for the second allocation round – HAR 2 – closed in April 2024. This round has an objective to significantly increase the scale of low carbon hydrogen production to help meet the ambition of up to 1 GW of electrolytic hydrogen.

the energy landscape

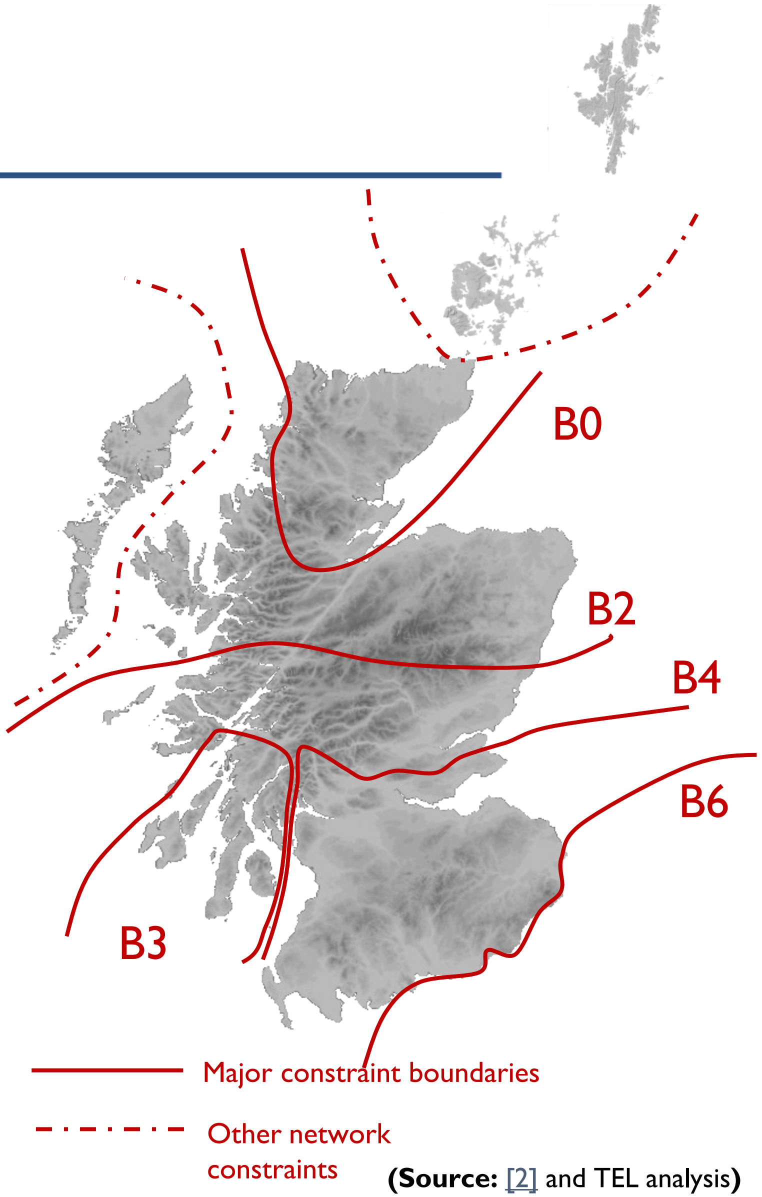
The value of electrolysis in Scotland

Electrolysis located in Scotland offers the opportunity to expand the benefit of renewable generation from the electricity system to the wider energy system. Scotland has a well-developed wind industry including a significant pipeline of projects in development. Renewable generation already exceeds demand on an annual basis and the carbon intensity associated with the Scottish generation fleet is already lower, on average, than that required to meet the LCHS. In addition, for a significant fraction of the year wind output needs to be constrained due to limited transmission network capacity with its output typically replaced by gas power stations in England. This creates a pool of unused renewable generation which can be captured and turned into hydrogen.

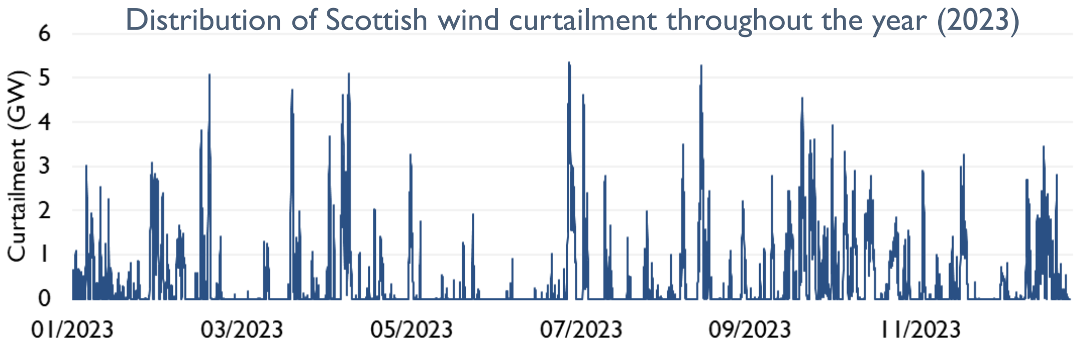
The length of many curtailment events is likely to exceed the typical duration of batteries and even pumped storage. In 2023, whilst average curtailment events were relatively short, at around 4 hours, longer events already contribute significantly, with 13% of events lasting longer than 24 hours. The typical length of curtailment events is likely to increase significantly over the coming years.

Key metrics for the Scottish electricity system:

- Average carbon intensity for North Scotland was 35g CO_2 / kWh across all hours of the year, for South Scotland the value was 30g CO_2 / kWh. This compares with 153g CO_2 / kWh for GB. The upper limit for electricity used to hydrogen which meets the LCHS is approximately 50g CO_2 / kWh (see page 6).
- In 2022 Scotland produced more renewable electricity than it consumed, the equivalent of 113% of overall consumption. This is expected to grow over the coming decades, with renewable generation potentially four times the electricity consumed in 2035.
- 4.1 TWh of wind generation was curtailed in 2023 through the balancing mechanism at a cost of £226 million.
- Curtailment lasted for 3160 hours or 36% of the year in 2023 – the distribution of curtailment throughout the year is shown in the graph below.
- Curtailment events were on average around 4 hours - whilst the longest was 104 hours.



(Source: [2] and TEL analysis**)**



Source: Analysis is based on BM data published by Exelon [8] and Scottish Government [9] and analysis by TEL. It is based on all 'Bid Offer Acceptance Volumes', that is the volume of actions taken by the ESO in the BM aggregated by unit and by settlement period.

Understanding the cost of green hydrogen

The costs of hydrogen production include the cost of developing and maintaining the electrolyser and the cost of the electricity used to operate it. The cost of the electricity itself can be broken down into two components: the cost of producing the energy, a component that is wrapped up in the 'wholesale price of power', and the costs associated with the wider electricity system. When combined, the wholesale costs and electricity system costs are sometimes referred to as the 'merchant price' or 'retail price' of power. This reflects the fact that, for most electricity consumers, wholesale and system costs are bundled together in a single electricity bill. The costs associated with the electricity system are usually larger than the wholesale cost of generation.

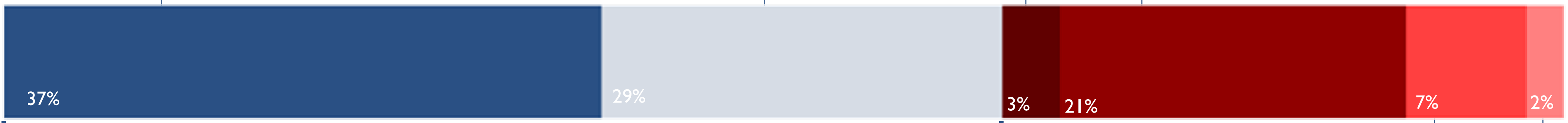
The illustration below shows the contribution of different components of project costs to the Levelised Cost of Hydrogen (LCoH) (see box on page 11)as calculated as part of this report for operational Model M1. This includes a number of assumptions on how the electrolyser would be operated and includes the return on investment modeled as a hurdle rate, these are based on the UK Government Hydrogen Production Cost Report 2021 [10][11]. For details of the methodology and assumptions used see page 21.

Wholesale electricity costs: the cost associated with producing the electrical energy used to create the hydrogen. For wind and solar generated electricity this is largely the capital investment, operation and maintenance.

Electricity system costs: these include the cost of the electricity network, of keeping the electricity system in balance and the cost of policies to support low carbon generation and deliver energy efficiency. The costs are recovered through regulated charges including network charges and policy levies.

Grid connection costs: electrolysers, and all users of the electricity system have to pay the cost associated with connecting them to the network.

CAPEX: The initial capital investment in an electrolyser, including the initial upfront investment and also covering the cost of the electrolyser itself, the balance of plant and civil works.



(source: TEL analysis**)**

Merchant or retail price of power
The combination of wholesale and system electricity costs is sometimes referred to as the merchant price or retail price. This is the total cost of purchasing electricity from the grid. Some electrolysis operators may purchase this directly from a supplier or other third party, others may deal with the individual components (wholesale, TNUoS, BSUoS etc.) themselves.

Fixed OPEX: Ongoing operational costs that don't depend on utilisation. For example, general maintenance costs or costs associated with keeping maintenance teams on standby.

Variable OPEX including stack replacement costs: operational expenditure which depends on the level of utilisation of the electrolysers. This includes the cost of replacing the stack – the active component of the electrolyser where the chemical reaction occurs.

The impact of electricity system costs

Electricity system costs can constitute a significant fraction of the total cost of hydrogen. Because electricity network and electricity system operation are regulated monopoly activities, and because low carbon and energy efficiency support schemes are designed by government, their costs are recovered not by market mechanisms but by regulated charges. The key charges considered here are:

- **Transmission Network Use of System (TNUoS) charges:** these are levied on all users of the transmission system including both demand and generation, although the charging methodology differs for each. TNUoS aims to be cost reflective and the size of charges varies by location.
- **Balancing System Use of System (BSUoS) charges:** these cover the cost of keeping the system in balance. They are recovered via a charge on demand only (not on generation), are calculated separately for each half hour settlement period and are levied on each MWh consumed.
- **Policy Levies:** there are a range of policies levies charged on demand only (not on generation) which cover the cost of the CfD, Renewable Obligation Certificates (ROCs), Feed in Tariffs (FITS), Capacity Market, Energy Company Obligation (ECO) and several others. Policy levies are sometimes called Final Consumption Levies (FCLs).

The discussion in this report focuses on transmission connected projects, for distribution connected projects Distribution Use of System Charges (DUoS) adds a further regulated charge.

The system charges faced by electrolysers can be adjusted to reflect the fact that hydrogen production is an Energy Intensive Industry (EII). Currently, there is an EII exemption of 85% of the cost of policy levies related to the cost of low carbon generation (CfDs, FITS and ROCs) [12].

A further adjustment that is likely to be introduced in the next year is the British Energy Supercharger (BES) scheme which will extend the current EII exemption to 100% of the cost of some policy levies and provide a 60% refund on TNUoS and BSUoS costs [13].

Cost component	M1	M2	M3	M4	M1 (BES)	M2 (BES)
Electrolyser project costs	✓	✓	✓	✓	✓	✓
Wind farm project costs	✓	✓	✓	✓	✓	✓
Demand TNUoS	✓	✓	×	×	Part	Part
BSUoS	✓	✓	×	×	Part	Part
Policy levies	Part	Part	×	×	Part	Part
TNUoS	✓	×	Part	×	✓	×

One consideration when developing an electrolyser project is that each of the operating models introduced on page 5 is exposed to a different set of system costs. The table above shows the breakdown:

- **M1 (grid connected electrolyser with PPA):** the electrolyser is currently exposed to the full suite of system charges with the exception of the 85% exemption on policy levies. Generators supplying the power via a PPA will also be fully exposed to generator TNUoS.
- **M2 (grid connected electrolyser and the BM):** the electrolyser is exposed to the same set of system charges as M1, however because it gains access to cheap – potentially zero price – electricity in the BM, the final cost of hydrogen does include the cost of generator TNUoS.
- **M3 (behind-the-meter electrolyser):** assuming the electrolyser doesn't import power from the grid and only uses electricity directly from its co-located generator, the electrolyser avoids all demand-facing system costs. The generator continues to pay generation TNUoS, the amount can be reduced by minimising the size of the grid connection to reflect the fact that the wind farm will not need to export all its output.
- **M4 (islanded):** as the wind farm and electrolyser are not connected to the electricity system they do not pay any system costs.

- **M1(BES)** and **M2(BES)** are sensitivities that apply the British Energy Supercharger exemptions which will remove some of the TNUoS and BSUoS charges faced by electrolysers if defined as an EII. The BESS will also increase exemptions on some (but not all) policy levies.

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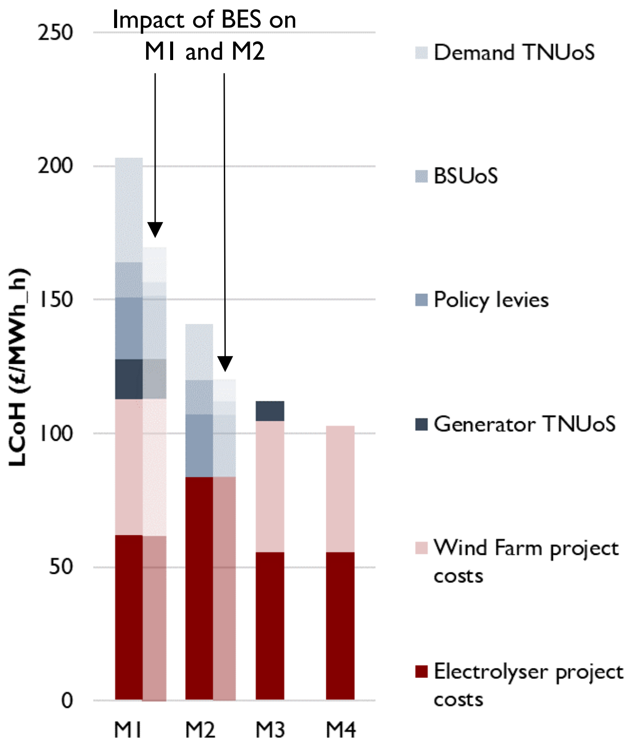
The impact of electricity system cost



(Source: TEL analysis)

The graph on the left gives an indication of the impact of the different system charges faced by the different models on the overall cost of hydrogen. This assumes that all projects face the same hurdle rates and for models M1, M2 and M4 is based on a 51 MW electrolyser (M3 uses a smaller electrolyser to reflect the fact that it needs to be smaller than the wind farm to which it connects in order to achieve a sufficient load factor).

It shows that M1 (grid connected electrolyser with a PPA) is likely to deliver the most expensive hydrogen at a LCoH around £200 / MWh. This is because it faces the largest set of system costs of all the models. Even after the introduction of the BES, this remains the highest.

Model M2 (grid connected with BM) is next – it benefits from avoiding the wholesale cost of electricity which covers both the wind farm project costs and generator TNUoS. The results for this model assume that the electrolyser gets zero price electricity via the BM. Model M3 is cheaper still because it avoids all demand-facing system costs and part of the TNUoS. And model M4 is the cheapest because it faces no system costs.

Whilst this graph gives an indication of the impact of electricity system charges on the cost of hydrogen, it is important to note that there are other effects not modelled but explored later in the report. This includes the variation of risk across the different models, and the potential to optimise the size of the electrolyser relative to generation capacity.

One of the observations this paper makes is that the addition of electricity system costs to M1 means that the most versatile and flexible model, the one that is most likely to support delivery of an efficient and flexible energy system, capable of adapting to different futures, is also inherently the most expensive.

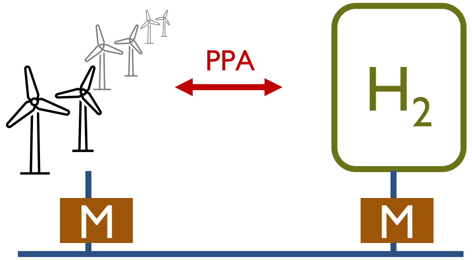
Levelised Cost of Hydrogen (LCoH)

The LCoH is an approach that combines different categories of cost – investment, operation and maintenance costs and system costs – to give an indication of the total cost per MWh of hydrogen produced.

The graph above uses a LCoH calculation to illustrate the contribution of different cost components to the overall cost of hydrogen produced. Details of the LCoH calculation are given on page 21. The calculations use the same set of assumptions, and are broadly consistent with, the UK government's 2021 Hydrogen Production Cost report [10][11].

It is important to note that the LCoH is not the same as a strike price in a LCHA. For example, it does not include any premium added by the PPA provided to manage price risk over the length of the contract. As this report discussed on page 14, this can lead to significant additional costs.

Issue 1: electricity system costs can represent up to 45% of the levelised cost of hydrogen



Model 1: Grid connected electrolyser and renewable PPA

Impact on Scottish green hydrogen: Under current arrangements electricity system charges nearly double the LCoH under M1 and system charges do not always align with the impact that a green hydrogen project has on the electricity system. High system charges under M1 will tend to encourage developers to move to less flexible operating models, particularly M3 and M4 to avoid these costs.

Recommendation: Consider ways to reduce the burden of system charges on both a national and locational basis, particularly where these don't align with the fundamental impact that green hydrogen production has on the electricity system.

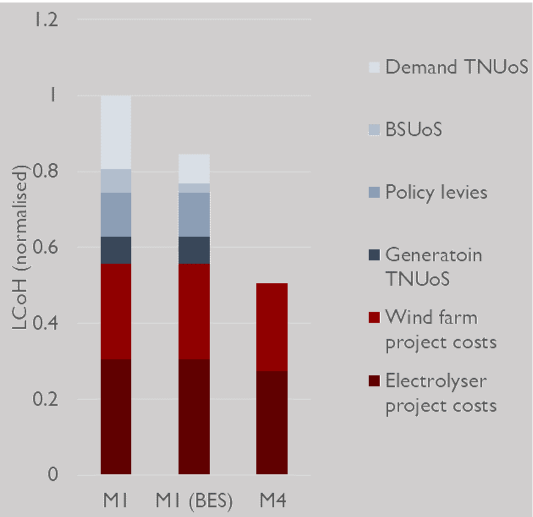
For separately connected renewable generators and electrolysers, and accounting for an Energy Intensive Industry (EII) discount on the cost of policy levies, around 45% of the levelised cost of hydrogen comes from electricity system costs. This compares to zero in the case of islanded generators / electrolyser as in M4. System costs include:

- Generation TNUoS paid by the supplying generator (assuming connected in Central Grampian with generator TNUoS around half-way between north and south of Scotland)
- Demand TNUoS paid by the electrolyser
- BSUoS paid by the electrolyser
- Policy levies paid by the electrolyser.

On the introduction of the BES, the contribution of system costs would fall to 29%. For several of the components there is a mismatch between the system impact of a Scottish green electrolyser project and the system charges that they face:

- **TNUoS:** the design of generation TNUoS is predicated on the assumption that a wind farm's output is transported across the transmission network to demand centres in south and central England. However, if developed in tandem with an electrolyser this assumption does not hold. Generation TNUoS is allowed to go negative for generators connected in the South of GB. If similar principles applied to demand TNUoS, generation and demand charges would largely cancel each other out for co-located project. But a floor imposed on the locational element of demand TNUoS means that the electrolyser does not benefit from locating close to the supply. Across the wind farm and electrolyser there is a clear mismatch between impact and charges. Although the BES could reduce residual demand TNUoS by 60% (see column M1 (BES) in the graph to the right), it does not deal with the locational issue.

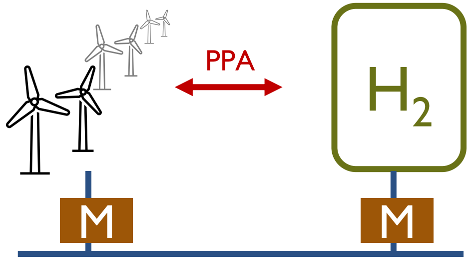
- **BSUoS** is paid by demand to cover the cost faced by the ESO when balancing the system. However, an electrolyser whose investment and operation is predicated on reducing the need for balancing and is likely to operate specifically to reduce balancing need should not then face the same charges as inflexible demand in England and Wales. Although the BES could reduce BSUoS charges by 60%, the remaining charges are still at odds with the benefit that Scottish electrolysis brings.



Above: Comparison of the scale of electricity system costs' contribution to the LCoH for M1 with and without the British Energy Supercharger and compared with M4 which faces no system charges. (**source:** TEL analysis)

the energy landscape

Issue 1: electricity system costs can represent up to 45% of the levelised cost of hydrogen



Model 1: Grid connected electrolyser and renewable PPA

Implications for Scottish green hydrogen:

Locational generation TNUoS combined with the £0 floor on locational demand TNUoS means Scottish projects using model M1 are paying for a network impact that they do not have, and the banding of residual demand TNUoS leads to significant and arbitrary variations in its contribution to the LCoH.

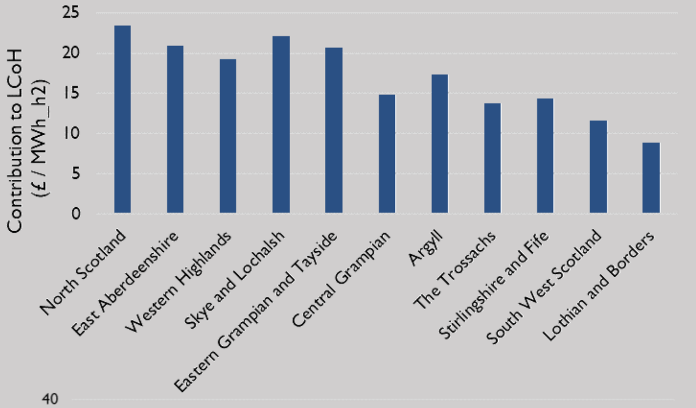
Recommendation: DESNZ should explore the potential to either reduce locational generation TNUoS or remove the floor on locational demand TNUoS. They should also review arrangements for demand residual charges to ensure they don't introduce unintended consequences for green hydrogen development.

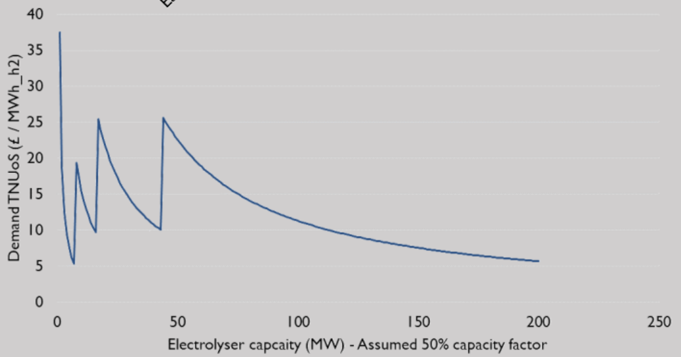
Sensitivity to variation in TNUoS

Generation TNUoS: varies significantly with location. In general, the further north a wind farm is the higher its TNUoS payments will be. In the most southerly GB zones, from approximately Birmingham south, generation TNUoS is negative, with generators receiving a payment to reflect the notional reduction in transmission network they enable. Under current arrangements the locational element of generation TNUoS for Scottish generators is expected to increase significantly from 2030 with the most northerly generators paying potentially £106 / kW more than the most southerly, that equates to £25 / MWh of electricity produced [14].

Demand TNUoS: includes two major components – a locational *demand TNUoS element* and a *residual demand element*. The locational element varies in the opposite direction to generation TNUoS – reducing further north. It would be negative in Scotland but is floored at zero. The residual element has recently been reformed and is applied to demand without consideration of location. For large consumers it is applied on a £ / site / day charge and is banded based on annual energy consumption. For transmission connected demand, there are four bands. Within each band, the contribution of demand TNUoS to the £ / MWh cost will vary significantly, with the lowest contribution coming at the upper end of the band where the fixed cost is spread over the largest number of units of output. For example, within band 3 the contribution of demand TNUoS ranges from £25 / MWh at the bottom of the band to £10 / MWh at the top [15]. Even following the introduction of the BES, a significant difference would remain: a range of £10 / MWh to £4 / MWh impact on LCoH.

Currently demand TNUoS can be recovered through the LCHA strike price, however it impacts on the relative cost-competitiveness of Scottish projects and once the allocation of agreements moves to a competitive basis it will make more northerly projects less likely to win.





Top: Variation in the contribution of generation TNUoS to the LCoH based on generator location within Scotland. **(Source:** [15] and TEL analysis**)**

Bottom: Variation of demand TNUoS per MWh hydrogen produced with the variation in electrolyser capacity (assuming a 50% load factor and transmission connected project). **(Source:** [14] and TEL**)**

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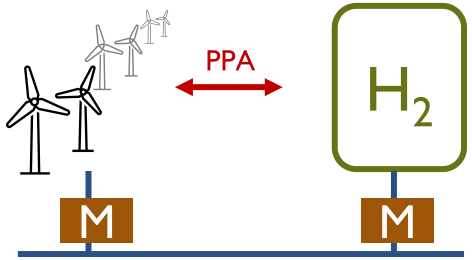
Issue 2: indexing arrangements under the current LCHA significantly increase electricity costs



Model 1: Grid connected electrolyser and renewable PPA

Implications for Scottish green hydrogen:

Indexing future LCHA contracts to reflect typical electricity prices in a similar way to that used to index natural gas production pathways to gas prices could lead to significant cost reduction for Scottish (and wider GB) electrolysers on the order of several tens of pounds per MWh. It would allow electrolysers to use shorter term PPAs and reduce the risk premium that PPA providers need to add to fixed price contracts to manage their own risk.

Recommendation: Consider changing LCHA indexing arrangements to link strike prices to changing electricity costs.

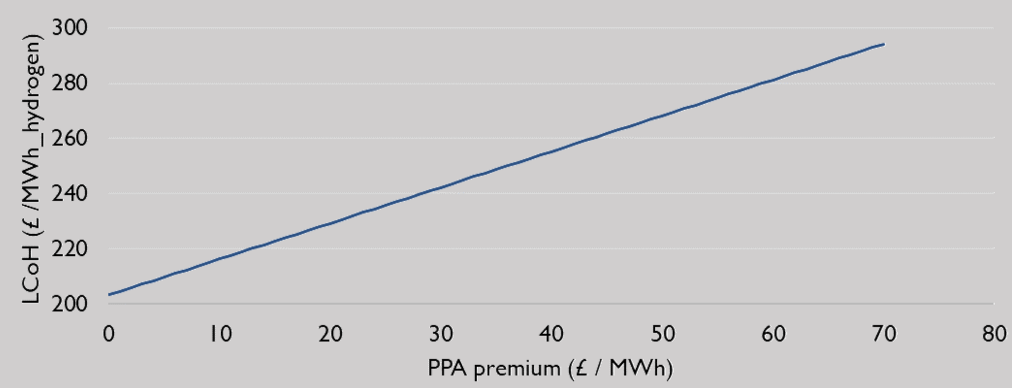
The design of the HPBM includes a 15-year CfD which effectively guarantees a fixed price for the sale of hydrogen subject to an indexation to reflect inflation at the Consumer Price Index (CPI). This has been explicitly designed to build on the success of CfDs for electricity generation at supporting the development of wind and solar.

However, renewable generation has close to zero marginal cost of production – that means that there are very low variable input costs and almost all the costs are in upfront investment and ongoing fixed costs.

By contrast more than half the cost of hydrogen is in the form of variable costs: namely electricity costs. Given that indexing only protects projects from inflation, for the CfD to provide the hedge required to manage project risk, projects will tend to need to fix the electricity price for the duration of the HPBM: 15 years.

By contrast, for projects using natural gas as an input (e.g. steam methane reformation with Carbon Capture and Storage) the strike price is index linked to the gas prices, naturally giving projects protection against market-wide gas price trends and allowing them to source natural gas through shorter term contracts.

The graph below shows the impact of a PPA premium on the LCoH. With zero premium, the assumptions for the LCoH calculation are similar to those used by DESNZ in their 2021 cost of hydrogen report. But LCoH rises as the premium is increased. For comparison, the HAR 1 average weighted strike prices were £241 / MWh $_{hydrogen}$ [7] which also reflected separate capital grants provided by DESNZ to developers through the Net Zero Hydrogen Fund.



The graph shows the impact on the LCoH of a premium added by the PPA provider to a 15-year fixed price contract to manage their own risk due to the uncertainty in future electricity prices. Anecdotally, it appears this could be as high as £50 / MWh or more. (**source:** TEL analysis)

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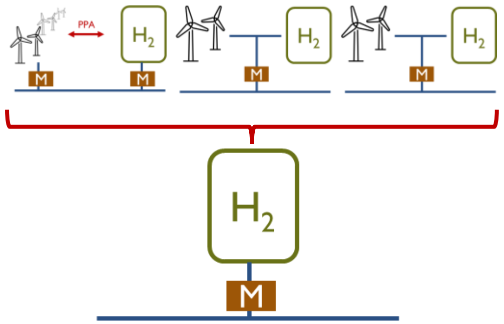
Issue 3: complex definitions of low carbon hydrogen don't align with plans for a net zero power system by 2035



Model 5? Grid connected electrolyser using decarbonised electricity system

Implications for Scottish green hydrogen:

Complex and stringent rules for the LCHS are likely to create barriers to developing Scottish projects despite (a) already largely decarbonised Scottish electricity production and (b) expectation of largely decarbonised GB electricity production by the early 2030s.

Recommendation: Commission analysis to understand the potential to allow lower time granularity and to allow electrolysers to account for carbon at regional grid intensity values when importing without a PPA to a specific generator.

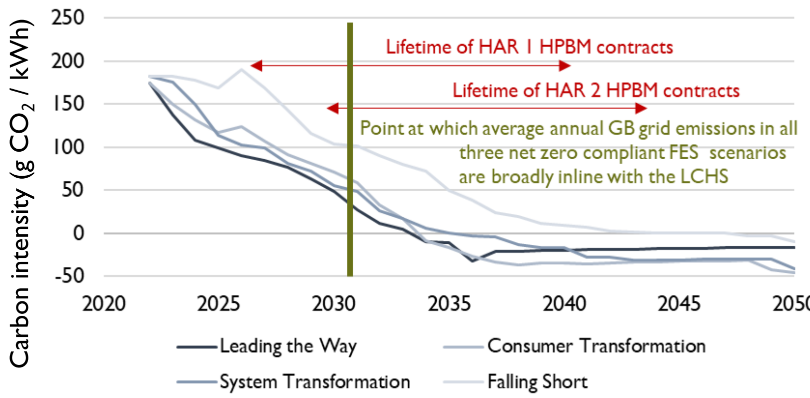
The LCHS runs to 169 pages [3] and, in combination with the HPBM, represents a complex set of definitions which significantly limit the ways in which electrolysers can operate and successfully meet the requirements of the standard.

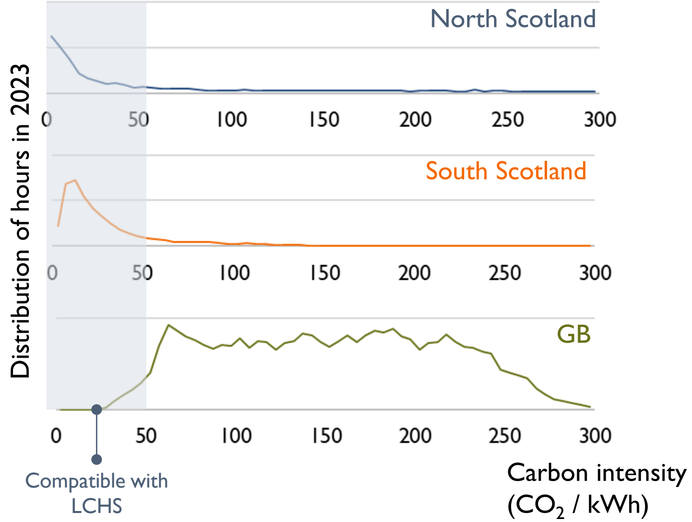
The framing of the requirements can limit the ways in which projects can meet the standard, and in combination with the design of the HPBM, means that projects often need to lock in arrangements for the full 15 years of the contract in order to have the certainty needed for a FID. This is despite the fact that for the majority of their operational lifetime, the whole GB electricity system is expected to be fully decarbonised.

This is particularly true for HAR 2 projects onwards. Using data from the ESO's 2023 Future Energy Scenarios (FES), the estimated average annual GB carbon intensity falls to levels compatible with the LCHS of 20g CO_2 / MJ_{LHV} by 2031 – just two years after the HAR 2 commissioning deadline - in all three net zero compliant scenarios [1].

The standard also rules out the use of regional grid carbon intensity for electricity imported without a link to a specific generator. This is despite Scottish generation already outturning at well below the level needed to meet the LCHS, both in the vast majority of individual settlement periods, and on average across a year.

A simplification of the rules could result in a fifth and significantly simpler model of green hydrogen production involving direct import from the Scottish grid without the need for complex contracting arrangements with potentially high premiums. This would give hydrogen projects the necessary flexibility in procuring their input electricity to lower the cost of the hydrogen produced.





Top: average annual GB carbon intensities for the four FES 2023 scenarios. **(Source:** [1] and TEL analysis**)**
Bottom: distribution of Scottish regional and GB national grid carbon intensity in 2023. **(Source:** [6] and TEL analysis**)**

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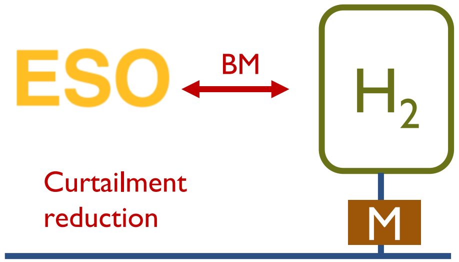
Issue 4: operation of electrolysers for active curtailment reduction is disincentivised and involves an invalid carbon penalty



Model 2: Grid connected electrolyser using curtailed wind

Implications for Scottish green hydrogen:

To support curtailment avoidance new contracting arrangements are needed to provide confidence in volume and cost of curtailed energy and manage the interaction between curtailment avoidance and other electricity purchasing. Electrolysers should also be credited with using zero carbon electricity when reducing curtailment.

Recommendation: Prioritise new longer term constraint management approaches such as those being considered by ESO in its Constraint Collaboration Project.

Recommendation: Change the LCHS rules to allow electrolysers engaged in curtailment reduction to account for their electricity at zero carbon intensity.

For large scale electrolysis, operating in 'electricity curtailment avoidance' configuration, as defined in the LCHS, means participating in the balancing mechanism (BM) to submit bids to increase consumption of electricity at a set price. This can create three barriers: uncertainty over volume and price of available curtailed energy, low load factors, and over-counting carbon intensity.

The BM operates after gate closure of the electricity market, which happens 1 hour before the start of each settlement period. This means that only after that 1-hour point has been passed will an electrolyser be notified if their bid was successful and whether they are required to increase their consumption beyond the level set in the wholesale market.

Scottish electrolysers will regularly be behind the same transmission constraint as wind farms and under the status quo the ESO will need to curtail wind to ensure that transmission limits are not breached.

Where the price to turn up consumption at an electrolyser is cheaper than the price to turn down a wind farm, the ESO should accept the electrolyser's bid, therefore reducing wind curtailment.

The marginal carbon impact of this action is zero: the additional electrolysis demand is entirely met by additional renewable generation.

However, under the current LCHS rules, electrolysers must account for this generation at the regional average carbon intensity as published at carbonintensity.org [6] (which uses data provided and verified by the ESO).

Issue 1: Uncertainty

Electrolysers are likely to be unable to build an investable business case based on BM activity due to the large uncertainty over the price they can achieve in the BM and the prevalence of curtailment across the project's lifetime. This is driven partly by regulatory uncertainty – for example a current Code Modification – P462 – could change the costs that wind farms are allowed to include in their bids, potentially reducing the price against which electrolysers are competing [16]. There are also uncertainties around whether electrolysers might face the equivalent of the Transmission Constraint Licence Condition (TCLC) currently imposed on generators, which limits their ability to make a profit from activities that reduce constraints [17].

Issue 2: Low load factors

Whilst the prevalence of curtailment has grown over the past decade, it is still relatively low, occurring around 36% of the year in 2023 (see page 17). This is likely to be too low a load factor to deliver a strong electrolyser business case, even if the wholesale component of electricity prices are close to zero. This implies that curtailment avoidance is likely to need to be combined with other operational models rather than as a standalone approach.

Issue 3: Inaccurate accounting for carbon intensity

Whilst the marginal carbon impact of curtailment reduction is zero, the regional carbon intensity for North and South Scotland typically ranges between 0 and 50g CO_2 / kWh $_{electric}$ (analysis based on [6])

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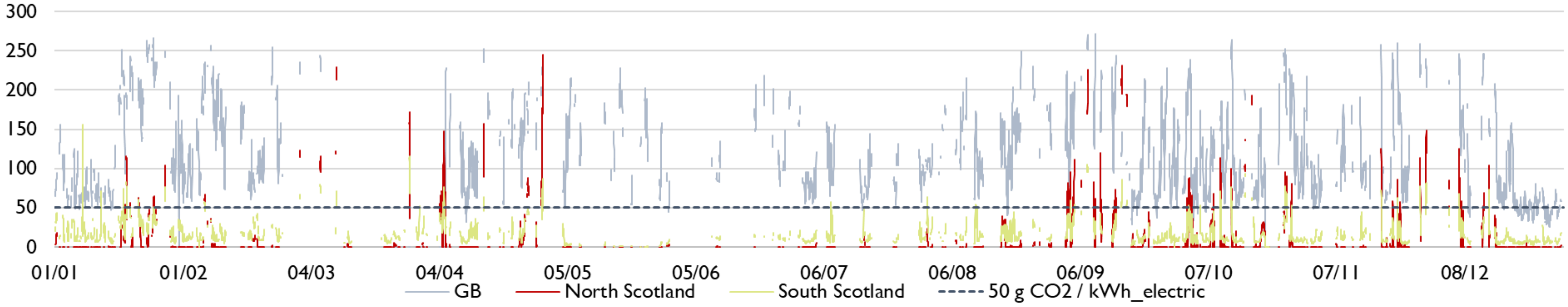
Issue 4: operation of electrolysers for active curtailment reduction is disincentivised and involves an invalid carbon penalty

The LCHS currently requires that when electrolysis operates directly to reduce curtailment or renewables that the electricity is accounted for at the regional average carbon intensity. However, there can be a significant mismatch between the direct carbon impact and the average regional intensity. If electrolysis clearly reduces curtailment, the actual carbon impact is zero, whilst even in the most decarbonised parts of GB (namely the two Scottish regions) regional carbon intensity was well above zero. This means that the LCHS requires electrolysis to significantly over account for the carbon intensity of its inputs. Whilst regional grid intensity for many of the settlement periods would still be compatible with the LCHS if that was the only electricity used, it reduces the opportunity to mix electricity from curtailment reduction with grid sourced electricity, a hybrid operating model which may be well suited to Scottish projects.

Scottish wind curtailment through the balancing mechanism (2023):

- 4.1 GWh
- £226 million curtailment payments
- During 36% of the year – a total of 3160 hours.

g CO2 / kWh	North Scotland	South Scotland	National outturn
All-year average	35	30	153
Curtailment average	8	15	108
All year max	357	223	309
Curtailment max	245	156	271



Above: The graph shows the regional carbon intensity for South Scotland and North Scotland in 2023 during periods of Scottish curtailment and based on data from the source specified by the LCHS and representing the ESO's forecast of grid intensity made just ahead of delivery. Periods without curtailment are left blank. The graph also shows the national outturn carbon intensity. The table summarises the average and maximum values for curtailed periods and compares that against similar calculations for all periods. (**Source** [6], [8], and TEL analysis)

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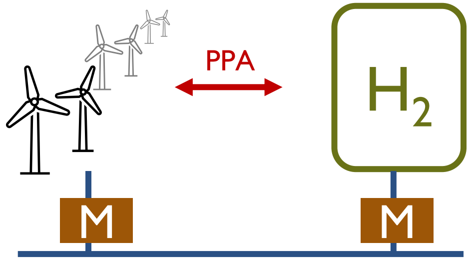
Issue 5: interaction between constraints, wholesale PPA agreements, and balancing actions



Model 1: Grid connected electrolyser and renewable PPA

Implications for Scottish green hydrogen:

Scottish electrolyser projects are not fully rewarded for the additional benefit that they deliver to the wider GB electricity system.

Recommendation: Explore the interaction constraints and PPA contracts in greater detail. Identify the extent to which Scottish electrolysers deliver additional benefit and consider ways to ensure they are appropriately rewarded for the value they create by locating behind the same constraint as the generator.

Whilst the focus on PPAs as a route to delivering green hydrogen that meets the LCHS aligns with the operation of the wholesale electricity market, it can lead to situations where electrolysers located on the opposite side of a transmission constraint are not physically supplied by the renewable generation associated with the PPA.

For example, where a transmission constraint occurs between Scotland and England, generation in Scotland contracted by electrolysers in England cannot be physically transported and those wind farms will be curtailed off and are often replaced by fossil fuel generators in England.

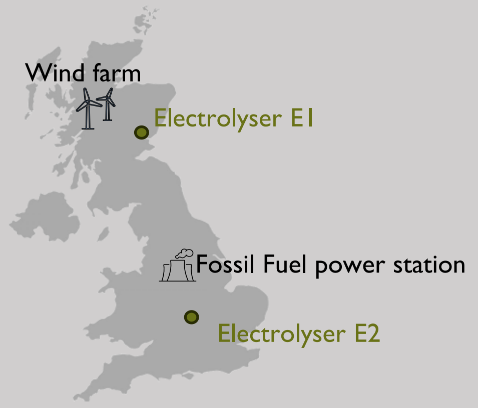
However, the adjustments made in the balancing mechanism are not reflected in the carbon intensity accounting laid out in the LCHS. This is illustrated in the boxes to the right.

Based on 2023 data (see page 17) Scottish wind in was curtailed around 36% (based on analysis of data from [8]) of the year. However, whilst electrolysers in Scotland would be able to access Scottish wind generation the majority of the time (subject to constraints within Scotland) there is little incentive, under the PPA route using model M1, for electrolysers to locate in Scotland behind the same constraint as the contracted generator.

Wholesale market

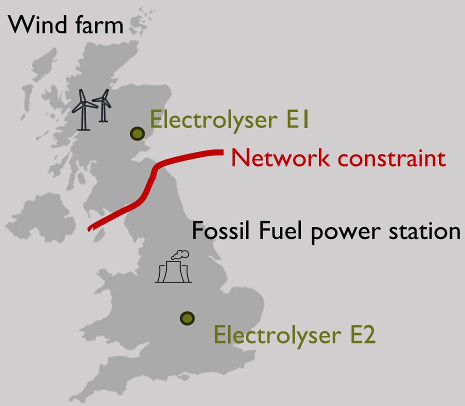
Under PPA agreements, which form part of the wholesale market, both electrolysers are able to contract to use generation from the wind farm located in Scotland.

Both electrolysers will be able to account for the power they use at a carbon intensity of zero. This reflect the principle that The GB wholesale market is agnostic to location.

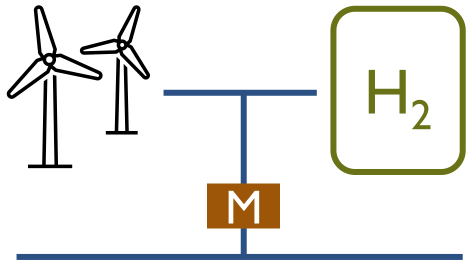


Physical dispatch

Following gate closure of the wholesale market, the ESO will redispatch the system to maintain network constraints. When a network constraint is binding between Scotland and England this means that whilst the demand for electrolyser E1 can continue to use output from the wind farm, demand for electrolyser E2 cannot. The ESO will use the balancing actions to curtail the wind farm and replace its generation with output, typically from a fossil fuel generator.



Issue 6: arrangements for behind-the-meter electrolysers may limit their size



Model 3: Behind-the-meter electrolyser and generator

Model 3 involves locating the electrolyser behind the meter of a wind farm. This can mean co-locating the electrolyser and wind farm on the same physical site, or it can mean the use of a private wire to connect two separate (but geographically relatively close) sites together.

The value of this model is that it can reduce the level of electricity system charges faced by the electrolyser. However, to do so requires that there is no import from the network. If the electrolyser imports at any point during the year it will face demand TNUoS charges, and it will pay BSUoS and policy levies on the volume of imports.

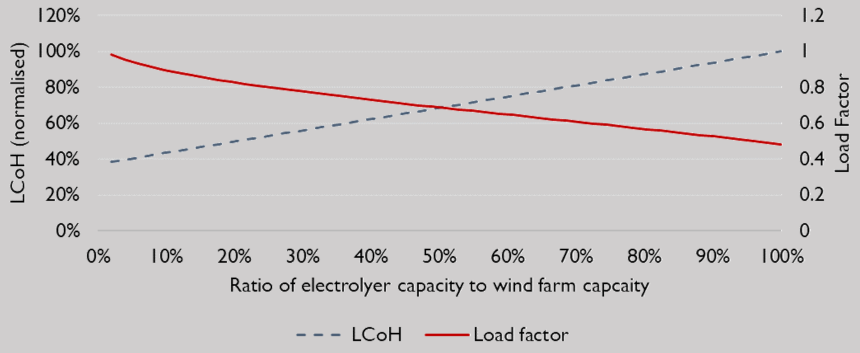
In addition, it allows the wind farm to operate with a smaller network connection than its installed capacity. As such it could support the development of new wind projects. For example, a 100 MW wind farm co-located with a 30 MW electrolyser could operate with a 70 MW connection, reducing the generator connection and generation TNUoS costs. There have been concerns that this model would be difficult to implement with a wind farm that has a CfD contract, recent clarification and consultation suggests that this is not an issue for onshore wind farms, but it could remain an issue for offshore wind where the metering point – the point at which electricity is considered to have entered the GB system – is at the offshore substation.

To achieve a sufficiently high load factor, the electrolyser is likely to need to be significantly smaller than the wind farm (see right). This could create an incentive to undersize electrolysers to maintain shielding from system costs.

Implications for Scottish green hydrogen:

Where system charges – demand TNUoS, BSUoS, policy levies and generation TNUoS – are driving decisions on locating generation behind the meter, the ESO, Ofgem and government need to consider if these decisions drive any material change in the impact on the system.

Recommendation: Review rules around electricity system costs, particularly demand TNUoS, when applied to behind-the-meter electrolysers and wind farm projects.



Above: impact of undersizing the electrolyser relative to the wind farm. **(source:** TEL analysis**)**

The **load factor** decreases as the size of the electrolyser relative to the wind farm increases. This is because the smaller the electrolyser the more time the wind farm is generating at least as much as the electrolyser can use. Therefore, for a wind farm with a load factor of 50%, an electrolyser half the size of the wind farm will have a load factor of around 75% – whereas one the same size as the wind farm will only have a load factor of 50%.

The **LCoH** increases as the size of the electrolyser increases. This is driven by the lower load factor for larger electrolysers (although there will be some economy of scale effects, not modelled in the illustration above, that will act in the other direction).

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Issue 7: islanded system, deliverability and risk

Model 4: Islanded electrolyser and generator

Implications for Scottish green hydrogen:

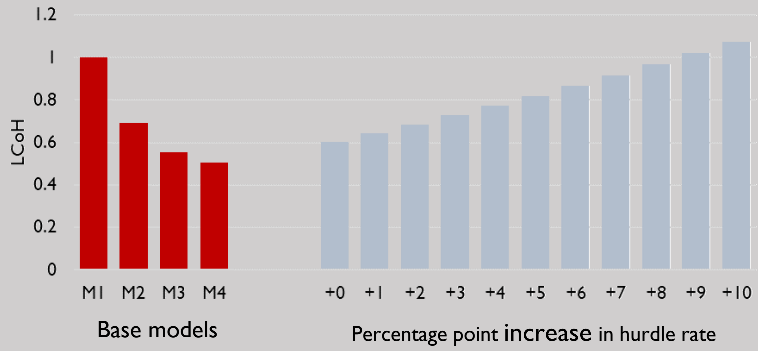
Islanded operation may be suitable for some green hydrogen production in future, particularly linked to very remote offshore wind farms which face significant grid connection costs. However, projects will face risks associated with the inability to access support mechanisms such as CfDs.

Recommendation: DESNZ should commission analysis of the optimal role of islanded systems, taking account of avoided system costs and the likely scale of additional risk relative to alternative models. The rules around electricity system charges should be reviewed in order to ensure this model isn't over-incentivised relative to alternatives.

Islanded generators potentially have the lowest levelised cost of hydrogen because they do not face electricity system costs. However, an islanded system lacks flexibility and could face significantly higher project risk due to the lack of options if there are faults in either the wind farm or electricity: the electrolyser is fully dependent on the wind farm for its source of electricity – there is no option for alternatives. Similarly, the wind farm has a single available user of its output: the electrolyser doesn't have the optionality of moving to an electricity sales with export to grid later in its life. There are also a number of legislative barriers to the islanded model, with the wind farm unable to access CfD support without a grid connection.

Despite these risks, developers may feel pushed towards an islanded system in order to avoid the additional costs – equating to up to 45% of the total LCoH (see page 12). There may also be situations where there is value in using Islanded systems to allow hydrogen production to operate without impact on the grid, particularly for large offshore projects which would involve large costs to integrate into the transmission system. However, it would require careful consideration of risk and is likely to require technology improvements to achieve sufficiently high capacity factors.

The value to the energy system will depend in part on the impact of the cost of capital associated with the more risky approach. The graph below shows that whilst M4 delivers the lowest LCoH based on an assumption of a 10% hurdle rate for the electrolyser component and a 5.2% hurdle rate for the wind farm (assumptions align with those used by DESNZ / BEIS in [10] and [18]). Increasing the hurdle rate of the wind farm to 10% (shown in bar '+0') to give a single project hurdle rate, reflects the full interdependence and lack of optionality for both components increases the LCoH above that of Model 3. Further increasing the hurdle rate by 2 percentage points raises the LCoH above Model 2. It becomes the most expensive model with a nine percentage point increase.



The LCoH for (a) the base models and (b) increased hurdle rate reflecting additional risk associated with an islanded wind farm / electrolyser development. For LCoH assumptions see page 21.

This shows that whilst the LCoH for an islanded system is the lowest of the base models when assumptions about hurdle rates are common to all models, increased hurdle rates for M4 push up the LCoH. (**Source:** TEL analysis)

Annex: assumptions used in LCoH analysis

- The LCoH is calculated from the total lifetime discounted costs of the project divided by the discounted quantity of hydrogen produced.
- There are a variety of different approaches to Levelised Cost analysis which are broadly differentiated by the categories costs that are included.
- The analysis used here largely employs the assumptions laid out in the UK government's 2021 Cost of Hydrogen report [11], and the results are in line with that report.
- Note that the combination of electricity costs and system costs is what is sometimes referred to as the merchant or retail cost of power.
- There are a number of assumptions that could be criticised including:
    - The load factor for electrolysers is relatively low compared with the expectations that some developers have expressed
    - Hurdle rates would likely vary across the different models discussed in this report to reflect the different levels of risk assumed.
- These points should be remembered when considering the absolute values.
- It is also important to remember that LCoH should not be expected to match strike prices agreed under the LCHS. In particular, premiums on various costs to account for risk hedging are not included, and projects may need to consider additional costs not included as part of its negotiation with UK government over final project strike prices. For example, tube trailer transportation costs and insurance.

The LCoH calculation used here is based on the following:

$$LCoH = \sum_{year=1 \ldots y_{max}} \left(\frac{1}{(1+r_e)^{year}} \frac{\text{CAPEX} + \text{OPEX} + \text{electricity costs} + \text{System cost}}{\text{Hydrogen Production } (\text{MWh}_\text{h})} \right)$$

- Y_{max} = project operating lifetime = 25 years
- r_e = discount rate / hurdle rate = 10%
- Size of electrolyser = 51 MW for M1, M2 and M4 and 25 MW for M3. This reflects the need to undersize the electrolyser relative to the size of the wind farm in M3 to increase the load factor.
- Electrolyser efficiency assumed 70%
- Electrolyser Load Factor = 48% in M1 and M4 (matches wind load factor), 36% in M2 reflecting prevalence of curtailment in Scotland in 2023 and 7% in M3 (reflecting undersizing of electrolyser)
- Electrolysis costs = wholesale price which is modelled as the LCoE for a wind farm and uses assumptions based on the 2020 Electricity Generation Cost Report including a hurdle rate of 5.2%, a 25-year lifetime, and generation TNUoS based on the Central Grampians region.
- System costs include:
    - BSUoS based on 2023 values with adjustments to 2035 based on projected curtailment cost trends, then flat at 140% of current levels after that. British Energy Supercharger (BES) sensitivities include a 60% reduction.
    - Demand TNUoS based on residual Transmission Connected Demand Band 4 and zero locational element. BES sensitivities include a 60% reduction.
    - Policy Levies – typical values based on existing levels of £4 / MWh adjusted to account for an 85% reduction in levies to cover CfD, FITs and ROC schemes. BES sensitivities include a 100% reduction in these levies.

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Acronym list

BES	British Energy Supercharger
BM	Balancing Mechanism
BSUoS	Balancing System Use of System
CAPEX	Capital expenditure
CCGT	Closed Cycle Gas Turbine
CfD	Contract for Difference
DESNZ	Department of Energy Security and Net Zero
DEVEX	Development Expenditure
DUoS	Distribution Use of System
ECO	Energy Company Obligation
EII	Energy Intensive industry
ESO	Electricity System Operator
FCL	Final Consumption Levies
FES	Future Energy Scenarios
FID	Final Investment Decision
FIT	Feed In Tariff
HAR 1	Hydrogen Allocation Round 1
HAR 2	Hydrogen Allocation Round 2
HPBM	Hydrogen Production Business Model
LCHA	Low Carbon Hydrogen Agreement
LCHS	Low Carbon Hydrogen Standard
LCoE	Levelised Cost of Energy
LCoH	Levelised Cost of Hydrogen

NESO	National Energy System Operator
NZHF	Net Zero Hydrogen Fund
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
RO	Renewable Obligation
ROC	Renewable Obligation certificate
TEL	The Energy Landscape
TNUoS	Transmission Network Use of System

A note on units:

- The low carbon hydrogen standard is set based on megajoules, lower heating value (MJ_{LHV}) stored within the hydrogen.
- This report converts MJ to kilowatt hours (kWh), megawatt hours (MWh) etc.
- Where required, units are suffixed with either $_{hydrogen}$ or $_{electric}$ to distinguish between energy delivered in electrical form or energy storage in hydrogen form.
- The same approach is used to distinguish megawatts (MW) of installed capacity of hydrogen production from installed capacity of electricity consumption.
- All carbon intensities are listed in terms of CO_2 equivalent.

the energy landscape