A specialist energy consultancy

Constrained Renewables and Green Hydrogen Production Study

Final Report

Scottish Enterprise

12659-01-R4
26 November 2018

COMMERCIAL IN CONFIDENCE

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This report investigates current commercial conditions regarding the production of green hydrogen from onshore wind power in Scotland. The intention of the report is to inform Scottish Enterprise's (SE) understanding of alternative business models that may facilitate the wider deployment of renewable energy, and to identify the challenges to the viability of said models. The production price of hydrogen cited in the report is not fully costed and the simple cost comparisons between the price of hydrogen and diesel may not be fully representative of the expected hydrogen price per kg, given the early stage of maturity of the hydrogen economy and sensitivity to current subsidy regimes, which are likely to change over time. SE's Foresighting Team therefore invites discussion from all interested parties regarding the interpretation of this report and its findings.

Document Control

Revision	Status	Prepared by	Checked by	Approved by	Date
R0	DRAFT	LM/SH/ RG/VO/DR/EJ	SH/DA	SH/DA	21/06/2018
R1	CLIENT COMMENTS			SH/DA	09/08/2018
R3	FINAL ISSUE			SH/DA	18/09/2018
R4	FINAL ISSUE			SH/DA	26/11/2018

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Executive Summary

TNEI Services Ltd (TNEI) and Pure Energy Centre (PEC) have been commissioned by Scottish Enterprise to undertake an initial knowledge gathering exercise regarding the nature of constrained renewables in Scotland. This is being investigated with a view to understanding the opportunities and the feasibility of utilising this constrained renewable power in the production of green hydrogen. Several recent developments have prompted this study, including the classification of hydrogen as a development fuel by the Department for Transport, meaning it is now eligible for Renewable Transport Fuel Certificates (RTFC). The Scottish Government's Energy Strategy (Dec, 2017) and the UK Government's Clean Growth Strategy (Oct, 2017) have also both cited hydrogen as playing an important role in the future GB energy system. This has prompted the drive to create and maximise any benefits and opportunities for synergetic working within the energy sector. This study encompasses a review of the nature of constrained renewables in Scotland, including constraints and curtailment levels around the country, and the cost of curtailment actions and services e.g. system balancing. The study investigates the possibility of diverting some of this constrained renewable energy to produce green hydrogen, the different ways this could be achieved and the estimated cost benefits of this potential revenue stream.

Green hydrogen is understood to be hydrogen produced using a renewable energy source, such as wind, to power a water electrolyser system, thus providing a zero-emission fuel or feedstock. Hydrogen is considered as one of the key enablers to the low carbon energy landscape of the future by Scottish, UK and international policy makers and so there is considerable work ongoing in this sector to understand the extent of hydrogen's role. Coupled with National Grid's undertaking to reduce curtailment payments and other ancillary service expenditure, there is a strong case to investigate the potential of a complementary solution that promotes both the reduction of curtailment payments and the production of green hydrogen. The objectives of this study were therefore to perform an early scoping exercise to better understand the nature and strength of any technical and economic correlations between constrained renewable and green hydrogen production.

The study provides an initial indication of the feasibility of such an application, and identifies in what scenarios a favourable business case could be made for combining constrained renewable generation with the production of green hydrogen. The approach to the study was two-fold, examining the electricity network and wind farm connection aspects, as well as the hydrogen production aspects. An overview of the constraint issues currently facing Scottish electrical networks sets the scene for why hydrogen could be relevant to future decarbonisation efforts; and a list of technical, regulatory and other barriers are presented to highlight the challenges that still need to be overcome, even with a positive business case. A review of the grid connection process for transmission and distribution networks has been performed to understand how co-location (and potentially other options) with a hydrogen production site could impact wind farm developments in terms of agreements, costs and revenues. A cost modelling exercise was also undertaken to assess potential scenarios where this application of combining constrained wind with the production of hydrogen could prove cost-effective.

<u>Opportunities for Scotland</u>

The potential benefits of utilising constrained renewable energy to produce hydrogen are clear; however, at this early stage it is difficult to fully quantify them within the scope of this project. These benefits include:

- Maximising the use of renewable energy resource;
- Reducing constraint payments for the system operator;

- Providing additional revenue streams to wind farm developers in a post-subsidy environment; and
- Producing hydrogen for use as a fuel or feedstock from renewable sources i.e. green hydrogen.

Large areas of the electrical transmission and distribution networks across Scotland are facing constraints, primarily as a result of the unprecedented increase in distributed generation connections over the past decade. The following figures from the TEC Register, National Grid's database of connected generation, illustrate the scale of onshore wind on Scottish networks:

- 4.7 GW connected
- 180 MW under construction
- 2.4 GW with consents approved
- 1.4 GW awaiting consents
- 1.9 GW in the scoping phase of development

These figures do not include the 3.2 GW of onshore wind projects connected to the distribution networks that do not have transmission entry capacity (TEC), meaning they do not participate in the Balancing Mechanism (BM) and so are not eligible for curtailment payments.

There is no specific pattern to the areas of constraint; however, those more rural areas with plenty of land for development and abundant wind resource have been more susceptible. These areas include Ayrshire, Lothian & Borders, Dumfries & Galloway and the Highlands & Islands. Of the 145 Grid Supply Point (GSP) substations in Scotland (across both distribution network operator (DNO) areas), 89 are constrained.

The DNOs are already trialling new solutions to managing network constraints through the implementation of Active Network Management (ANM) and other technologies, to provide a cost-effective connection option to generation developers and avoid or defer costly wider network reinforcements. Therefore, there is clearly an appetite for innovative solutions to manage constraints; the deployment of green hydrogen production for this purpose could prove valuable under the right regulatory conditions, which are currently not as flexible at lower voltages in terms of market participation, however, the transition of DNOs to a distribution system operator (DSO) model could enable more flexibility.

<u>Feasible Scenarios for Green Hydrogen Production</u>

In order to ascertain the viability of green hydrogen production as a mechanism for managing constraint, cost modelling was carried out to examine six potential scenarios. The cost modelling conducted for this study was performed using real operational constraint data from existing wind farms and real hydrogen system installation costs. From the analysis, two main conclusions can be derived:

1. Hydrogen production can be financially viable today under the appropriate conditions. The cost for producing hydrogen can be below £6 per kilogram even if the Power Purchase Agreement (PPA) is up to £60 per MWh. Note that this is for a hydrogen installation located at a wind farm.
2. A constrained wind farm that experiences curtailment of less than 15% will not be financially viable for hydrogen production. Even at 15%, substantial public sector financial support intervention would be required to make a project economically viable.

To this end, six hydrogen production scenarios have been investigated to assess if the production of hydrogen fuel from constrained renewable energy can be financially viable. Three scenarios, Scenarios 4, 5 and 6, have shown real promise for being financially viable. These are:

- Scenario 4 'An electrolysis facility that produces hydrogen from electricity supplied by a cluster of Scottish onshore wind farms that sell a large proportion of their electricity to the facility via a long-term PPA.'
- Scenario 5 'An electrolysis facility built as part of a new onshore wind project that incorporates the sale of green hydrogen as a core constituent of its business model.'
- Scenario 6 'An electrolysis facility that is powered by onshore wind and able to sell the by-products of electrolysis (i.e. heat and oxygen) in addition to green hydrogen.'

Generic Production of Green Hydrogen from Constrained Wind

In Scenario 4, the cost of electricity is assumed to be between £20 and £60 per MWh (the average wholesale price of electricity at the end of 2017 was £42/MWh). For a cost of electricity of £20 per MWh, the hydrogen can be produced for as low as £3.30 per kilogram. At £60 per MWh, the hydrogen will still cost less than £6 per kilogram to produce.

This is a significant finding, as hydrogen is currently being sold at a higher price per kilogram to a number of projects, such as the Aberdeen Hydrogen Bus Project, where the price of hydrogen is £7.50 per kilogram. It is also being sold (at a loss) at £7 per kilogram in some cases.

From the analysis, it is clear that the cost of producing green hydrogen from constrained renewables is affected by two main factors:

1. The price of electricity.
2. CAPEX and OPEX of the hydrogen system.

Scenario 4 demonstrates that the production of green hydrogen fuel is currently financially viable if the hydrogen system is operating close to continuously and at its rated production output. Also, there could be economies of scale for larger systems that can use the constrained energy from a number of wind farm sites.

There is a need to have a high utilisation of the hydrogen system in order to lower the unit cost of hydrogen production. As a rule of thumb, any system that is reliant on curtailed power from a wind farm subject to curtailment below 15% is unlikely to be viable at today's hydrogen system CAPEX and OPEX levels. Therefore, there would need to be a public sector intervention to make this type of project viable.

It is important to note that while three of the six scenarios analysed are not financially viable today, when hydrogen system costs fall as they are expected to in the future, there will be need to revisit them. For instance, in Scenario 3 it is possible to produce hydrogen at £20 per kilogram when power was purchased at £60 per MWh. In this case, all of the power was provided by 9 MW wind farm. This is a significant finding as it shows that even a small wind farm of 9 MW could benefit through intervention e.g. the provision of public funding, coupled with as assumed decrease in the price of hydrogen systems, could stimulate growth in the sector resulting in the price per kg of hydrogen falling to a price point that would enable it to be sold on a commercial basis.

When the level of curtailment or constraint reaches anything above 25%, then there is a significant potential for a hydrogen project to be viable. The nature of the curtailment a given wind farm is subject to, in terms of magnitude and frequency is, however, an important consideration. A wind farm that undergoes long periods of sustained constraint will have more success in producing hydrogen than one that is curtailed frequently but for shorter time periods due to utilisation inefficiencies. And as stated previously, curtailment levels of less than 15% would have to be considered carefully for this application and a business case cannot be presently proven, even at an electricity purchase price of £0.

Specific Hydrogen Demand Applications

Building hydrogen facilities with specific demand applications in mind can prove cost effective as the system can be sized accordingly, as illustrated by Scenarios 5 and 6.

In Scenario 5, the ferry application, the price of hydrogen was calculated as £6.10 per kilogram for a 20 MW electrolyser and 30 tonne storage system when supplying one sailing route on the Western Isles (Stornoway to Ullapool). Incremental requirements and costs of supplying hydrogen to all ferry routes around the Western Isles were calculated as £6.20 per kilogram. A cost of £6 per kilogram for all public transport routes (ferries and buses) was calculated considering a 20% discount in CAPEX due to economy of scale. However, selling hydrogen fuel at around £6 per kilograms is uneconomical for ferries applications while economical for road transport. The price of road diesel at £1.50 per litre is equivalent to £6 per kg for hydrogen (similar energy density) and as such at these prices hydrogen is competitive for road transport. The price of diesel used in ferries is three times cheaper than road diesel at about £0.50 per litre (and cheaper at times). As such, £6 per kilograms of hydrogen makes the fuel cost for marine application not viable. 1kg of hydrogen must be sold at around £2 to be deemed financially viable in the marine sector (≈£0.50 per diesel litre equivalent).

Scenario 6, the hospital application business model, was based around the hospital purchasing a combination of oxygen, waste heat and electricity from the development. Assuming certain commercial arrangements were available and in place, the wind farm developer, the hydrogen system developer and the hospital all benefited financially and the hospital stood to save up to £10,000 per annum on energy costs through a joint price for heat and electricity.

Transporting Hydrogen

The transportation of hydrogen can be achieved in a variety of forms, primarily: gaseous; liquid; and liquid organic hydrogen compound (LOHC). A positive business case for each form is dependent on the distance of travel where:

- Transporting hydrogen in gaseous form is achievable and can be done for £1.15 per km (assumed 800km daily distance covered by truck trailers and 100km between point of supply and demand). As distances from point of supply to point of demand increase, the amount of hydrogen that can be transported decreases linearly.
- Liquid hydrogen can be transported in larger quantities, however, there is much more energy required to liquify the hydrogen and this increases the costs so much so that it is difficult to prove a positive business case.
- The combining of hydrogen with another element resulting in a liquid compound that is less hazardous than pure hydrogen can allow large quantities of hydrogen to be transported under less stringent safety conditions which, under the right conditions, can reduce cost. This method of transportation has a UK optimum distance range of between 270km and 600km where there is a favourable business case and it is able to maximise multiple processes e.g. driver's time. In this case, the hydrogen can be transported for between £1.03 and £1.05 per km. There is the need to factor in the cost of hydrogenation and dehydrogenation at either end of the transportation process, which has not been considered by this study.

Recommendations

Based on the findings of this study, a number of recommendations can be made:

1. The undertaking of a detailed analysis of all wind farms in Scotland to determine specific wind farms, or clusters of wind farms, that meet the minimum viable curtailment levels identified in this study.

2. For existing onshore wind projects that are eligible for ROCs, investigate whether the electricity that would be redirected to a hydrogen electrolyser would still be eligible to receive ROCs despite not being exported to the electrical grid.
3. Initiate a pilot scheme with a large wind farm, consistent with Scenario 4, to demonstrate that continuous production of hydrogen is possible and that this can be achieved economically. The benefits of this approach should be assessed in terms of curtailment and also environmental benefits.
4. An investigation into the maximum size of an electrolyser when compared to the size of a wind farm to determine optimal economic viable could be of interest to developers.
5. A study into whether the production of green hydrogen would be feasible for the marine energy sector is recommended to understand if and where there are potential benefits. Hydrogen energy storage could be a useful addition to marine energy projects, particularly tidal, where there are more consistent energy resource patterns that could be capitalised upon.
6. A feasibility study, potentially leading to a pilot scheme, which looks in more detail at the specific aspects of building a business case for the transport sector on an island network is recommended. Lessons learned from other hydrogen transport pilots and trials can be taken on board while challenges/opportunities unique to island networks can be identified and disseminated for the benefit of all Scottish islands (and beyond).
7. The sale of by-products (of the hydrogen production process) such as oxygen and heat can be viable in certain circumstances. More detailed modelling of this particular application could identify a potentially large demand base (hospitals). This could be achieved through a feasibility study to outline business case development, and where assessment of the commercial aspects of trading hydrogen, electricity, heat and oxygen between various stakeholders could be included. Identification of a candidate hospital to participate in a trial would be a logical next step to a feasibility study if a favourable business case(s) is/are identified.
8. Different modes of transportation for hydrogen are suited to different distances. It would be helpful to developers to understand the costs involved for the transportation element of their system depending on location. A set of guidelines and/or specifications for each method of transportation should be produced for developers to reference.

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1 Introduction

Since the closure of the Renewables Obligation (RO) and exclusion of onshore wind from the UK Contracts for Difference (CfD) regime, gigawatts (GW) of onshore wind projects with planning consent have been deemed non-financeable. In response to this, the energy industry has been investigating various ways to make these projects bankable in the absence of a subsidy e.g. the provision of ancillary/grid services to the system operator as an additional revenue stream.

Recently, hydrogen was classified as a development fuel by the Department for Transport and is now eligible for Renewable Transport Fuel Certificates (RTFC). It has also been identified in the Scottish Government's Energy Strategy (Dec, 2017) and the UK Government's Clean Growth Strategy (Oct, 2017) as having an important role in the future GB energy system.

Separately, National Grid Electricity Transmission (NGET), the GB transmission system operator is spending around £1bn annually on ancillary grid services, and expects this to rise to around £2bn by 2022. Part of this £1bn currently paid out is made up of constraint payments where generators are compensated for not generating electricity in order to balance the system.

An opportunity to address each of these situations with one overarching solution has been recognised, where wind generation that would otherwise be constrained is diverted and used to produce hydrogen. This in turn would provide a route to market for dormant wind projects, while also supporting the development of the hydrogen sector and also helping to reduce NGET expenditure (and ultimately household bills).

Scottish Enterprise, in their role as an economic development agency, is keen to understand the opportunities for Scotland and Scottish companies in this particular application: the utilisation of renewable generation that would otherwise be constrained, being diverted for use in the production of hydrogen. Combining a reduction in renewable energy constraints with increased production of green hydrogen would have benefits across both the electricity and hydrogen sectors for a large number of stakeholders and provide crucial development and expansion of the hydrogen sector. It is therefore important for Scottish Enterprise to understand the scope of the potential opportunities to provide the necessary support and targeted interventions.

The report presents the findings and results from some early indicative assessments on both the electricity and the hydrogen side of this application:

- Section 2 provides a description of the nature of constrained renewables in Scotland at present and highlights some key areas of interest where constraint and curtailment are a particular issue.
- Section 3 describes the potential benefits and remaining barriers to this application, highlighting specific feedback from relevant stakeholders.
- Section 4 summarises the current grid connection processes for the transmission and distribution networks in Scotland and outlines how the hydrogen application being studied could influence future connections and the overall costs and revenues.
- Section 5 presents the cost modelling performed utilising wind farm constraint data to assess the cost implications and opportunities of utilising constrained wind power to produce hydrogen in six different scenarios.
- Section 6 presents the results of an assessment into the cost of transporting hydrogen, where a number of different transportation modes are considered.

2 Nature of Constrained Renewables

Networks are constrained when they are operating close to or in excess of specific safety and operational limits e.g. thermal capacity, voltage bandwidth, fault level. Areas of network can be constrained at any point and by multiple parameters. Curtailment is an action undertaken to either instruct a generator to reduce their output below the maximum output capacity in response to an unbalance in the generation-demand relationship, or it is an action taken to restrict generation output to manage a network constraint. In the context of this study, the term "constrained renewables" is used and refers to all wind generation that is curtailed either as part of the balancing mechanism or to manage a constrained area of network.

It is necessary to understand the nature of constrained renewables on the electrical network as this will ultimately determine how feasible it would be to re-direct this energy into the production of hydrogen.

The easiest way to manage thermal constraints on an electrical network is to manage generation through curtailment. Extremely low curtailment levels and/or short curtailment periods would not likely be conducive to successful and sustained production of hydrogen. The threshold of curtailment level is explored in more detail in Section 5 while this section describes what is known about the current situation regarding constraints and curtailment in Scotland. At the time of writing, there is over 4.7 GW of onshore wind projects connected to the Scottish networks that are eligible to participate in the balancing mechanism i.e. they have a TEC and impact the transmission network in some way. In addition to this, there is over 3.2 GW of onshore wind projects connected across the two DNO licence areas which are embedded and do not have a TEC. The Scottish transmission and distribution networks have over 8 GW of wind generation connected to them, and this has led to many areas experiencing some kind of operational constraint. Of the 145 Grid Supply Point (GSP) substations in Scotland (across both distribution network operator (DNO) areas), 89 are constrained. This not only impacts the distribution networks, but also the transmission networks as excess generation is being exported up into the higher voltage transmission network.

2.1 Distribution Networks (33 kV, 11 kV and below)

There are two distribution network operator (DNO) licence areas in Scotland. Both of these DNOs — SSE Power Distribution (SSEPD) in the North, Highlands and Islands and Scottish Power Distribution (SPD) in the Central Belt and Borders — provide information on the level of constraint across their licence network area to aid developers when planning their generation project. This information is provided on their respective websites in the form of heat maps, which detail the substations on the network that are constrained. These heat maps are shown in Figure 2.1 and Figure 2.2.

Figure 2.1 Scottish Power Distribution Heat Map [Source: SPEN Website]

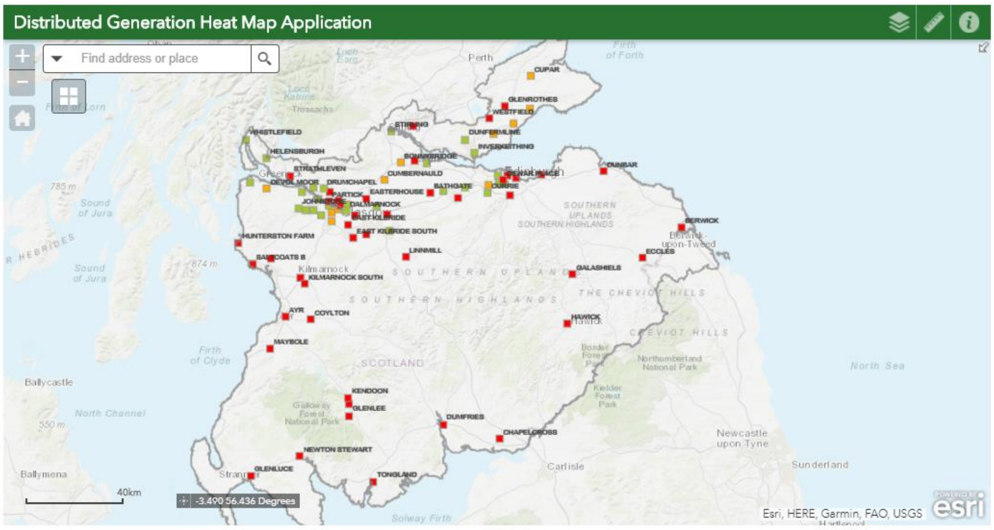


Figure 2.2 SSE Power Distribution Heat Map [Source: SSEPD Website]

The nature of the constraints on the Scottish distribution networks can be summarised as follows:

- The SSE Power Distribution (SSEPD) Long Term Development Statement, correct as of November 2017, details a total of 63 Grid Supply Points (GSP), of which 45 are constrained.
- The Scottish Power Distribution (SPD) LTDS shows they have 82 GSPs across their network, of which 44 are constrained.
- The majority of the substations highlighted as constrained (red) in Figure 2.1 and Figure 2.2 above are **constrained due to generation** (rather than demand) since demand growth over

the past few years has been steady but is a fraction of the growth of generation connections.

The GSPs are identified as constrained when one or more of their operational limits is close to or already being exceeded. Common reasons for this are:

- **Substation transformers** are restricted by their **reverse-power flow capability**, whereby once local demand is met, any excess generation will be fed back through transformers into the higher voltage network. Many older transformers do not have this capability or are restricted to a percentage of the standard capacity. Networks are getting so congested that even those with full reverse-power flow capability are no longer adequate.
- **Fault levels** are also becoming a major issue for DNOs as more and more generation is added to the system and switchgear must be replaced to ensure the safety of the network and its equipment. These reinforcements are expensive, and increasingly so as voltage levels increase.

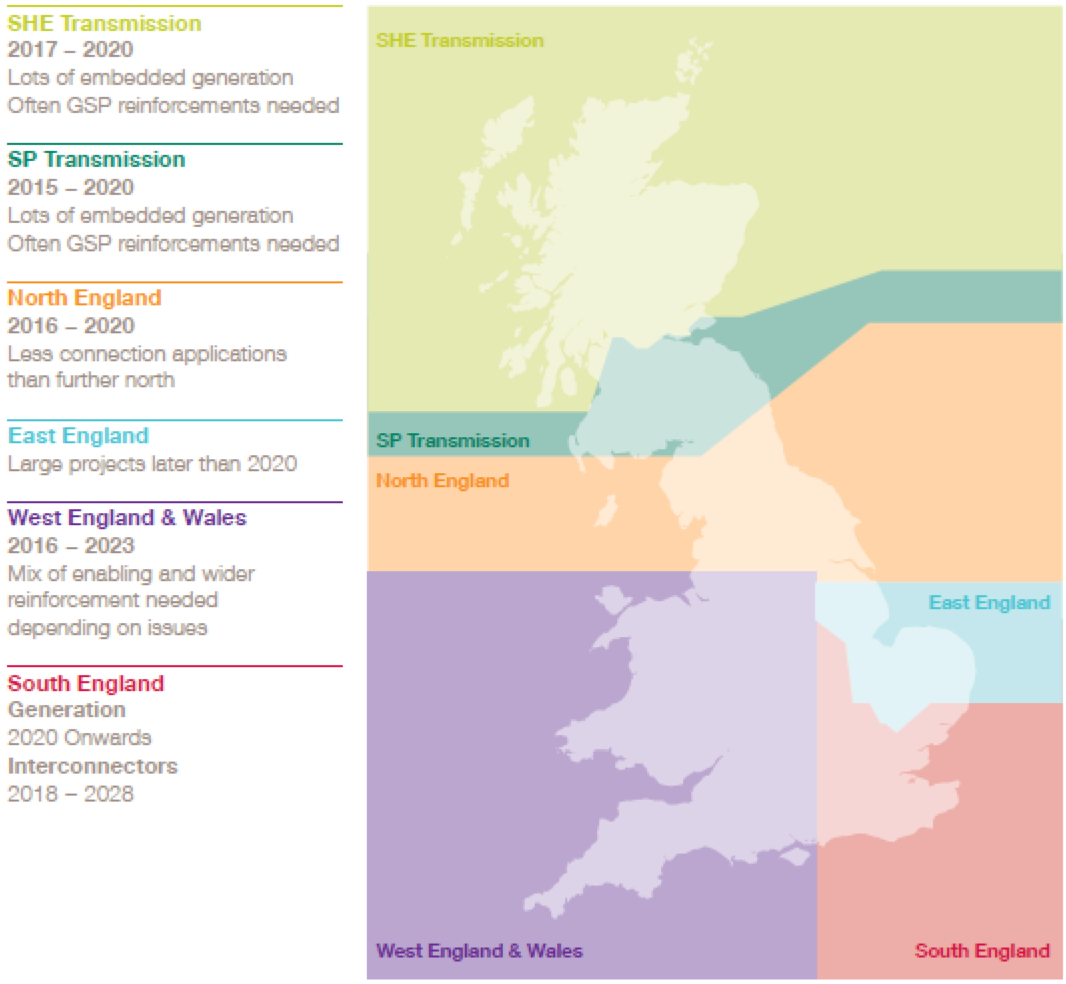
2.2 Transmission Network Constraints (132 kV up to 400 kV)

The transmission network in Scotland is owned by two parties: Scottish Hydro Electric Transmission (SHE-T) and Scottish Power Transmission (SPT), split over the same general geographic areas as the SSEPD and SPD distribution network areas. The transmission system is operated by National Grid Electricity Transmission (NGET), who is responsible for the operation and balancing of the whole GB network, including Scotland. Of the 4.7 GW of onshore wind projects connected to Scottish networks which have a TEC:

- 1.75 GW are connected to or directly impacts the SHE Transmission network; and
- 2.95 GW are connected to or directly impacts the SP Transmission network.

Less information is readily available regarding the constraints on the transmission system in Scotland and there are no available heat maps, however, a high-level overview of each area is provided by NGET as shown in Figure 2.3 below.

Figure 2.3 Transmission System Overview [Source: How to Connect to the National Electricity Transmission System – National Grid 2015]



2.3 Curtailment Levels in Scotland

To determine the potential role of curtailed wind energy in producing hydrogen in Scotland, the volume of curtailed wind must first be identified. Since this is the energy that could be produced if wind farms were not subject to curtailment, it is important to understand the value and resultant scale of resource for hydrogen production.

The department for Business, Energy & Industrial Strategy (BEIS) maintain a renewable generation database[1] detailing the volume of generation produced by each renewable source on an annual basis. From this database, the total wind generation for the UK and Scotland can be identified.

Using 2015 as a base case, the total wind generation in Scotland as a percentage of the total UK wind generation was found to be 59%. The volume of constrained wind energy in the UK for the same year was approximately 1,276.24 GWh[2] with the curtailment volume in Scotland totalling

[1] https://www.gov.uk/government/statistics/regional-renewable-statistics
[2] http://www.ref.org.uk/constraints/indextotals.php

1,217.85 GWh (UK curtailment levels were reported to have increased to 1.5 TWh[3]). The table below highlights the wind generation and curtailment for both the UK and Scotland in 2015.

Table 2.1 Wind Generation and Curtailment Levels

	Total Wind Generation in 2015 (GWh)[1]	Volume of Wind Constraint 2015 (GWh)
UK	22,713.40	1,276.26
Scotland	13,295.50	1,217.85

It can be seen from Table 2.1 that despite only having 59% of the total UK installed capacity of wind generation, Scottish wind accounted for over 95% of the curtailment in 2015. In both 2015 and 2016, the 31 wind farms with the highest curtailment levels were located in Scotland. These are listed in Table 2.2 below.

Table 2.2 Wind Farms with Highest Curtailment Levels[4]

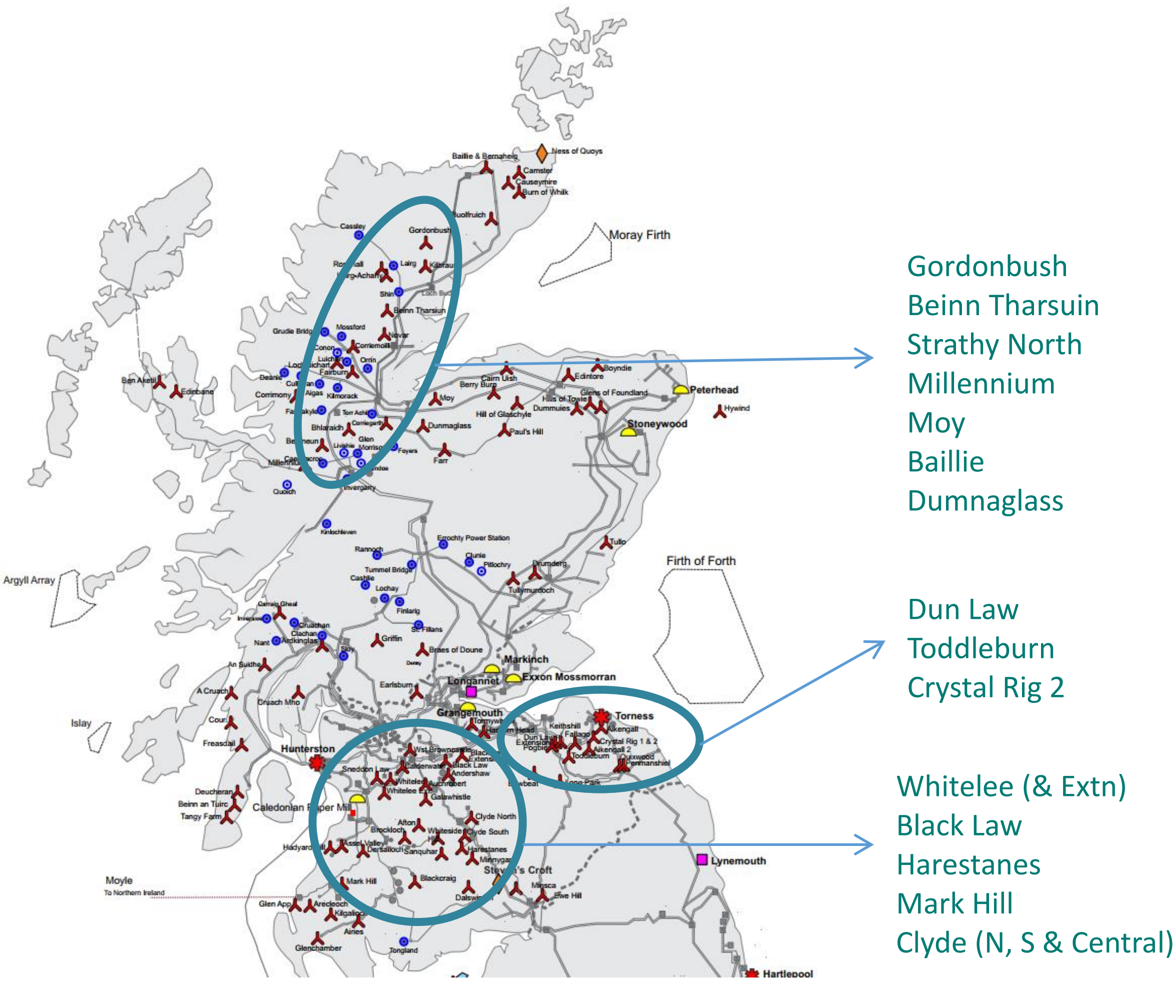
Wind Farm	Curtailment (%)			DNO	Geographical Area
	2015	2016	2015-2016		
Whitelee	32%	31%	32%	SPEN	South Lanarkshire
Beinn an Tuirc	24%	28%	26%	SSEPD	West of Scotland & Islands
Black Law	23%	27%	25%	SPEN	South Lanarkshire
Whitelee Ext	25%	23%	24%	SPEN	South Lanarkshire
Harestanes	20%	26%	23%	SPEN	Dumfries & Galloway
Strathy North	25%	20%	22%	SSEPD	Highlands
Griffin	23%	19%	21%	SSEPD	Highlands
Arecleoch	20%	23%	21%	SPEN	Ayrshire
Beinn Tharsuin	21%	20%	21%	SSEPD	Highlands
Fallago	20%	17%	19%	SPEN	Lothian
Mark Hill	16%	21%	18%	SPEN	Ayrshire
Gordonbush	22%	12%	18%	SSEPD	Highlands
Dun Law	19%	15%	17%	SPEN	Lothian

[3] http://www.telegraph.co.uk/news/2018/01/08/wind-farms-paid-100m-switch-power/
[4] Joos & Staffell, 2017 – Wind Power Curtailment and Balancing.xlsx

Wind Farm	Curtailment (%) 2015	2016	2015-2016	DNO	Geographical Area
Hadyard Hill	16%	17%	16%	SPEN	Ayrshire
Clyde South	16%	17%	16%	SPEN	Borders
Clyde Central	14%	15%	14%	SPEN	Borders
Clyde North	13%	14%	14%	SPEN	Borders
Toddleburn	16%	10%	13%	SPEN	Lothian
Millennium	13%	9%	12%	SSEPD	West of Scotland & Islands
Edinbane	10%	12%	11%	SSEPD	West of Scotland & Islands
Farr	11%	10%	10%	SSEPD	Highlands
Kilbraur	8%	10%	9%	SSEPD	Highlands
Clachan Flats	7%	11%	9%	SSEPD	West of Scotland & Islands
Crystal Rig 2	8%	9%	8%	SPEN	Lothian
Moy		8%	8%	SSEPD	Highlands
An Suidhe	7%	7%	7%	SSEPD	West of Scotland & Islands
Lochluichart	4%	6%	6%	SSEPD	West of Scotland & Islands
A'Chruach		4%	4%	SSEPD	West of Scotland & Islands
Baillie	2%	4%	3%	SSEPD	Highlands
Dunmaglass		3%	3%	SSEPD	Highlands
Dalswinton	2%	4%	3%	SPEN	Dumfries & Galloway

Table 2.2 also shows the geographical areas where these wind farms are located, which allows for an assessment of specific areas of focus when considering diverting curtailed wind energy to produce green hydrogen. Figure 2.4 below highlights three areas across the country where the majority of these 31 wind farms are located. The characteristics of the constraint, and ongoing work in these areas, are explored further in Section 2.4.

Figure 2.4 Areas with Highest Wind Curtailment Levels in Scotland



2.3.1 Constraint Payments

From 2002 to March 2017, a qualifying UK onshore wind farm would have been eligible for a subsidy in the form of Renewable Obligation Certificates (ROCs). The ROC subsidy works as a mechanism to top up the price of electricity generated by renewable energy assets, including onshore wind farms. For each MWh of electricity generated by an RO accredited onshore wind farm, the operator will receive 0.9 ROCs that can then be sold alongside the electricity to electricity suppliers. The ROCs are sold via auction rounds and their price varies; the average price for a ROC in the November 2017 auction was £49.41. The average electricity price in this same period was £51.45 per MWh. Using these figures, the electricity price and ROC value combine to give £100.86.

For wind farms built and operating within this time frame, any curtailment due to balancing requirements, and in some cases, congestion on the transmission network, would likely be compensated by NGET (see Section 4 for more information on connection agreements and how to be eligible for compensation). The Transmission Constraint Licence Condition (TCLC), introduced by the electricity regulator Ofgem, prohibits manipulation and exploitation of market conditions to profit from curtailment, essentially ensuring that those bidding into the balancing mechanism to be curtailed cannot make any more money than is reasonable to cover the cost of not generating. As such, a constraint payment would be priced to cover lost revenue from both the wholesale of the electricity and also the loss of a subsidy payment (i.e. a ROC), both of which are priced per MWh.

According to the Renewable Energy Foundation[5] the average price per MWh for a wind farm constraint payment in 2015 was £71. So, with the volume of constraint in Scotland in 2015 being over 1.2 GWh from Table 2.1, the total constraint payments for the year to Scottish wind farms is estimated to amount to around £85.2m.

As of the 31st March 2017, the ROC subsidy was withdrawn and replaced with the Contracts for Difference (CfD) mechanism, from which UK mainland onshore wind projects have been excluded; however, projects located on remote Scottish islands (e.g. Orkney, Shetland and the Western Isles), will be eligible to participate in the forthcoming CfD auction in 2019.

Should any onshore wind projects be built in the post-subsidy environment, the process for bidding into the balancing mechanism to be curtailed could become complex. One impact could be advantage wind farms connecting post-March 2017, as their bids into the balancing mechanism would be cheaper (reflective only of lost wholesale electricity price) than bids from wind farms in receipt of subsidies.

2.4 Particular Areas of Interest

As noted in Section 2.1, many areas of the Scottish electricity are constrained in some way. Areas that are particularly affected by constraint are described in the following subsections. In each of these areas, the DNO has intervened to manage these constraints more effectively and create capacity for more generation to connect.

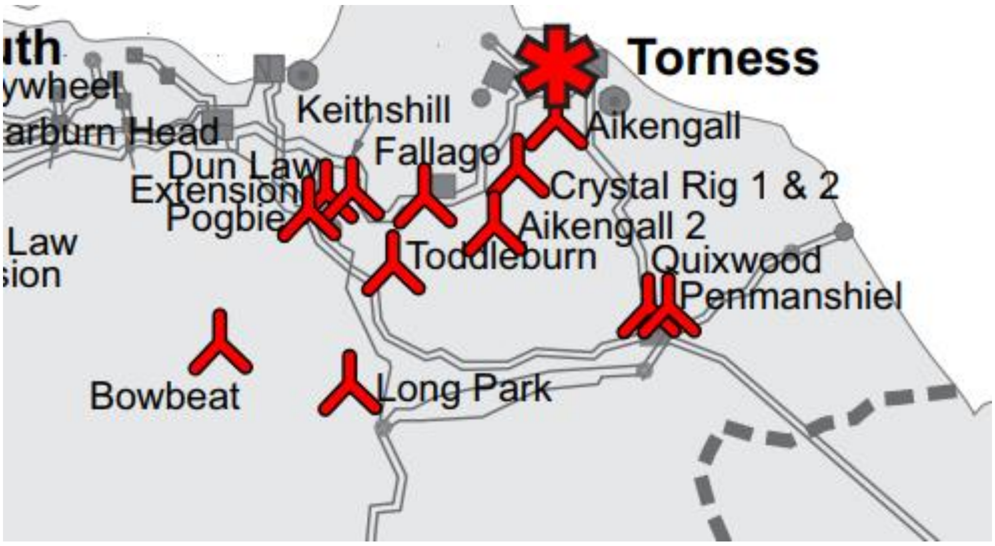
2.4.1 Lothian & Borders

In the SPD DNO licence area and the overlying SP Transmission region, the network in and around Lothian & Borders was identified as close to its operational limits owing to a large increase in the volume of distributed generation connections. Across the transmission and distribution networks there is:

- In excess of 500 MW of onshore wind connected,
- A further 164 MW known to be contracted to connect to the distribution network.

A map of TEC-connected wind farms is shown in Figure 2.5.

Figure 2.5 Lothian & Borders Connected Onshore Wind with TEC



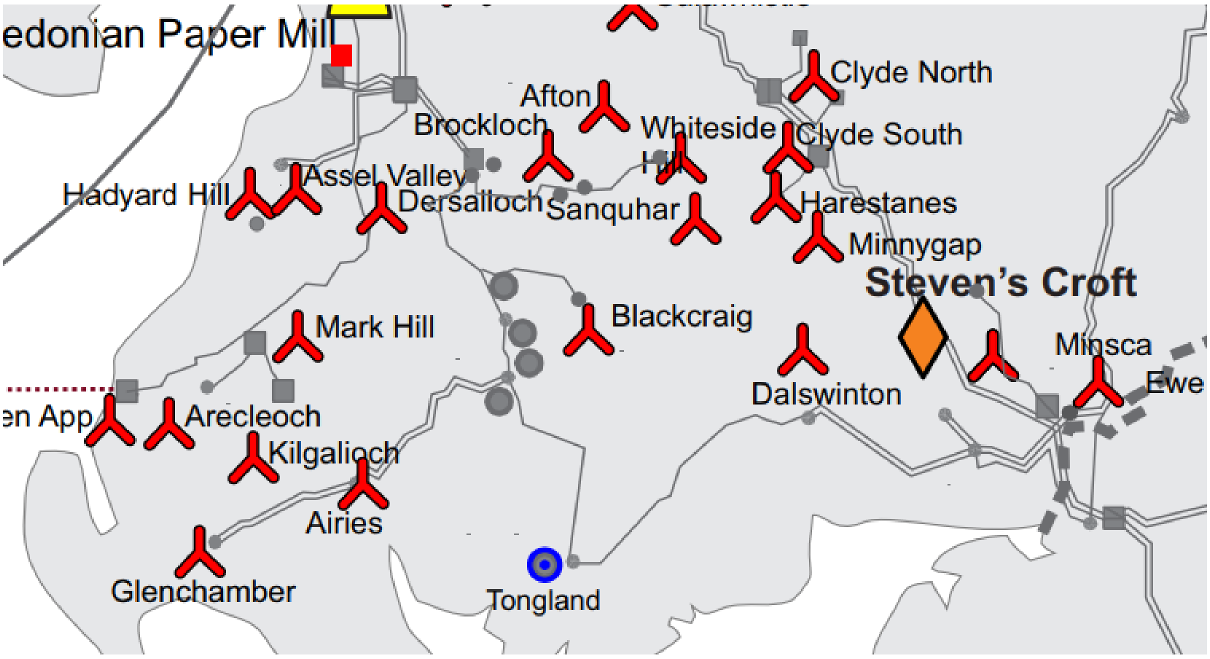
5 The Renewable Energy Foundation is a registered charity promoting energy conservation and renewables however there have been cases in the past where they have been critical wind power.

Conventional reinforcement solutions at one of the GSPs were quoted as costing circa £20m with a completion date of 2021. SPD received Ofgem funding in 2012 for their "Accelerating Renewable Connections" project[6], which would allow more distributed generation to connect by managing transmission and distribution network constraints while transmission network reinforcements were in progress. Active Network Management (ANM) schemes to accelerate more flexible connection solutions have been deployed and generation connected under the schemes is curtailed according to requirements to maintain the system within operational limits.

2.4.2 Dumfries and Galloway

The transmission network in the Dumfries and Galloway area is operating at full capacity. The area is popular with wind generation developments, with around 2.9 GW of generation contracted and/or connected. TEC-connected wind farms in this area are highlighted in Figure 2.6.

Figure 2.6 Dumfries & Galloway Connected Onshore Wind with TEC



The DNO is struggling to accommodate the level of generation and connection applications as the network is fully utilised with no spare capacity. SP Transmission is rolling out reinforcement projects to upgrade the network, most of which are expected to be completed by 2023. These reinforcement works will significantly improve the network; however, the additional capacity created will once again be fully used as these upgrades will only accommodate the currently contracted generation.

Following the network upgrades, any new connection applications applying for a connection into Dumfries and Galloway will most likely be subjected to an ANM scheme. As with those connected through the ARC project, these connections will experience periods of curtailment when the network has high levels of generation. The terms of the curtailment will be defined in the connection offer but it is suspected that this curtailment will be uncompensated since the developer will be avoiding reinforcement costs.

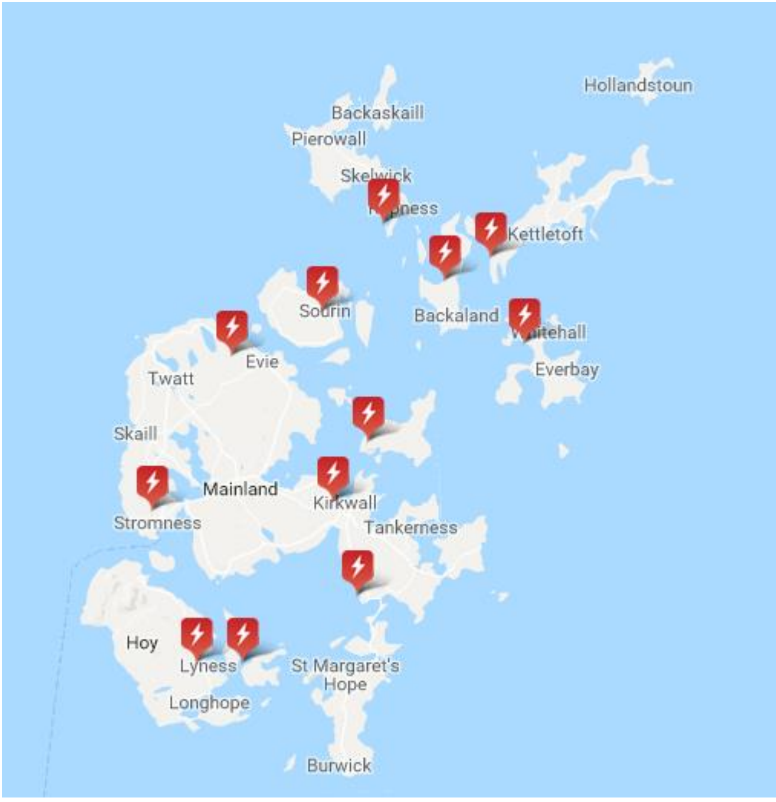
2.4.3 Highlands & Islands

In the SSEPD license area, there are several areas of network that are heavily constrained, including areas in the Highlands & Islands. One particular area of interest is the Orkney Isles, which were

[6] https://www.spenergynetworks.co.uk/pages/arc_accelerating_renewable_connections.aspx

constrained by their 33 kV connection to the Scottish mainland as well as local thermal issues as shown in Figure 2.7.

Figure 2.7 Constraints on the Orkney Distribution Network



An ANM scheme was introduced to manage these constraints and allow additional generation to connect and utilise the vast renewable resource available in the area. The reinforcements necessary to upgrade the network would have cost approximately £30m, but were avoided via the implementation of an ANM scheme costing £500k[7], which allowed an additional 20 MW of generation to connect. The area is now known as the Orkney smart grid, within which storage and other technologies, such as tidal, are being trialled. The tidal scheme, operated by EMEC, made headlines in 2017 for being the first in the world to be used to generate hydrogen gas.

2.4.4 Solutions to Manage Constrained Networks

It is evident that network operators are researching, developing and investing in new approaches to manage constraints on their network, recognising the need for alternatives to the traditional network upgrade route. ANM has been trialled in Orkney, Lothian & Borders as well as on several distribution networks in England & Wales. Its success is bringing it into the "business as usual" domain and it is being adopted more readily as confidence grows in the technology.

ANM is not the only solution to solve network constraint issues, however, and vast amounts of R&D have gone into methods such as demand side response, energy storage (including co-location with renewables) and even the implementation of DC networks.

It is in this light that there is a real appetite for new and innovative ways to improve the operation and management of networks, while also promoting decarbonisation. It is possible that, given the

[7] https://www.ssepd.co.uk/OrkneySmartGrid/

right regulatory environment and support, the production of hydrogen from renewables, constrained or otherwise, could thrive.

It should be noted that network operators are also implementing upgrades where necessary to reinforce their networks. One such example is the Western HVDC Link[8], which was commissioned in late 2017. This link connects Hunterston in Scotland to Deeside in Wales, as shown in Figure 2.8.

Figure 2.8 Western HVDC Link Route

The 2200 MW link will provide several benefits including strengthening the transmission network. Most relevant to this study is its expected effect in alleviating constraints on the Scottish network by transporting large amounts of energy from the Central Belt down to demand centres in England & Wales.

[8] http://www.westernhvdclink.co.uk/

3 Feasibility of Green Hydrogen Production from Constrained Renewables

The feasibility of producing green hydrogen from constrained renewables must be assessed on both a technical and a commercial level. From a technical standpoint, the feasibility of producing green hydrogen itself is not in question; rather the practical aspects, such as diverting constrained energy to a facility specifically for this purpose or transportation of the fuel end-product. In order to gather greater insight into how this could be achieved in practice, wind farm developer and network operator stakeholders were consulted. Since this is a novel idea, using specifically constrained energy, opinions vary on what the key challenges are and how they should be addressed.

According to the TEC Register[9], there are 4.7 GW of onshore wind farms connected to the Scottish electricity networks (transmission and distribution) that can participate in the balancing mechanism, and are therefore eligible for constraint payments if and when they enter the process.

There are a further:

- 180 MW under construction;
- 2.4 GW with consenting approved;
- 1.4 GW awaiting consents; and
- 1.9 GW in the scoping phase.

There is also 3.2 GW of onshore wind farms connected to the distribution networks (which are not currently eligible to participate in the BM), with:

- 1.67 GW connected to the SPD network;
- 1.53 GW connected to the SSEN network;

And a further:

- 860 MW contracted to connect to the SPD network; and
- 311 MW contracted to connect to the SSEN network.

These figures represent a massive potential for decarbonisation of the GB electricity system. However, loss of subsidy support for onshore wind has made many of these projects financially unviable, no onshore wind projects <5 MW having reached financial close in the post-subsidy environment. This study examines the production of green hydrogen as one possible method of making some of these projects bankable through the provision of different revenue streams.

3.1 Potential Benefits

The potential benefits of utilising constrained renewables to produce green hydrogen can be easily recognised. These include:

- Maximising the use of renewable energy resource;
- Reducing constraint payments for the system operator;
- Providing additional revenue streams to wind farm developers in a post-subsidy environment; and
- Producing hydrogen as a fuel or feedstock from renewable sources i.e. green hydrogen.

Maximising the deployment and use of renewable resource would support the decarbonisation aims of the Scottish and UK Governments, as well as overall global climate change goals. Reducing

[9] The TEC Register is a log of all of the generation in GB which has Transmission Entry Capacity from National Grid

constraint payments for the system operator would bring economic benefits to National Grid, distribution network owners and operators, other parties connecting to these networks and eventually end-users through an overall reduction in costs to operate and manage the system. The provision of additional revenue streams to wind farm developers would help to make previously non-bankable projects financially viable where traditional renewable energy subsidies are not available, thus providing support for around 2.4 GW of projects in Scotland that already have planning permission, and up to 4.5 GW of other projects in the earlier stages of development.

Development of the hydrogen sector would also be a major benefit, and this particular application of producing green hydrogen from constrained renewables could be supported by the Renewable Transport Fuel Certificate (RTFC) incentive, which recently classified hydrogen as a development fuel.

The Renewable Transport Fuel Obligation (RTFO) was introduced in the UK in 2008 and encompasses transportation elements of the EU Renewable Energy Directive. It obligates suppliers of road transport fuels to ensure a certain potion is supplied from sustainable fuels (predominantly biofuels but now hydrogen is included). RTFCs are administered by the Department of Transport and companies proven to have sold more than their obligation will be able to trade their certificates to others who have sold less.

At this early market stage, it is difficult to fully quantify the benefits of green hydrogen production from constrained renewables within the scope of this study due to uncertainty and lack of available data; however, some analysis presented in the following sections provides preliminary indications and the potential scale of the benefits are discussed.

3.2 Remaining Challenges

Despite the potential benefits that could be gained from such a development, there are still substantial challenges to be overcome. These are summarised in Table 3.1 below.

Table 3.1 Barriers to Hydrogen Production from Constrained Renewables

Barrier	Description	Type/ Severity/ Difficulty	Proposed Action(s)
Value of Renewable Transport Fuel Certificate (RTFC)	In a new subsidy environment, there are serious financial constraints on developers. As such, the value of the RTFC would have to be substantial enough to support funding of a Hydrogen electrolyser and associated equipment.	Regulatory High Low	Further study into production levels of Hydrogen from constrained renewables is required to provide realistic estimates on the suitable amount of subsidy to support this.

Barrier	Description	Type/ Severity/ Difficulty	Proposed Action(s)
Location of Hydrogen electrolyser with respect to wind farm and end-user demand	There are different costs associated with Hydrogen site placement. Location behind the meter at the wind farm site will reduce grid costs (DUoS, TNUoS) but will have increased transportation costs to a Hydrogen demand centre (presently mainly used in commercial scale vehicles e.g. Aberdeen Hydrogen Bus Project or in chemical feedstock manufacture at Grangemouth) due (most likely) to remote geography. Meanwhile locating the site near a demand centre would incur grid costs but minimise transportation costs. There is also the consideration of network constraints at remote wind farm locations vs. busier urban demand centres.	Commercial Low Low	Cost benefit analysis assessments should be carried out on a case by case basis to determine best placement of the Hydrogen site. Locating a Hydrogen site remote from the wind farm will require a PPA and some regulatory changes are required to facilitate this (see below).
Supply and Demand	At the moment, there is no guarantee of a supply or a demand for Hydrogen and so there is hesitation on either side to develop. Building an expensive Hydrogen production and storage sites without a demand is too high risk. Similarly, there would be no investment in Hydrogen production if the resource was not guaranteed.	Commercial High Medium	For development projects it would be practical for developers to be proactive and line up supply/demand partnerships in advance of any funding applications.
Characteristics of Constraint	Hydrogen production not intended for use in the transport or chemical feedstock sectors could be utilised as a means of storage. However, Hydrogen is not efficient enough to be considered as a means of temporary storage (conversion efficiency), while battery storage is not an efficient means of bulk storage (modular increase in size).	Technical Medium Medium	The characteristics of the network constraint a particular wind farm would face would have to be determined in advance to assess suitability of Hydrogen vs. battery storage where this was the main driver. A demonstration of hydrogen storage technology would be useful.

Barrier	Description	Type/ Severity/ Difficulty	Proposed Action(s)
Refuelling Station Infrastructure	Refuelling is an issue in some cases. Hydrogen has a reasonably long range so buses and refuse trucks who return to a common base would face no problem. HGVs and Haulers who are on the road for longer periods however, would require refuelling infrastructure.	Technical Medium Low	Clustering e.g. Aberdeen Hydrogen Bus Project, could be a solution for long-haul vehicle refuelling. More investigation would be necessary.
Interaction of market mechanisms	The interaction of market mechanisms from the electricity and transport sectors e.g. ROCs (or similar) and RTFCs, would have to be carefully designed so as to ensure fairness among participants.	Regulatory High Medium	Assessment of the market mechanisms available to each sector and how they interact is required once the scale of the opportunity is known.
User acceptance of Hydrogen as a transport fuel	There is always the challenge of user acceptance of new technologies. Transport is particularly sensitive to change where Hydrogen will be compared against petrol and diesel. This is especially true for private transport. Electric vehicles have also undergone this challenge relating to cost, range, recharging etc. Hydrogen cars would also be in competition with EVs.	Social High High	Utilise information from all Hydrogen trials where vehicles have been used to build up a demonstration track record to bolster public opinion. Incentivise private transport trials.
Network grid connection policies including the queuing system	Networks generally operate on a first come first served basis regarding connection applications and so new developments will be constrained simply by not having an existing grid connection agreement.	Technical High High	Changing the grid connection application process would be a long and complex undertaking. A strong justification for evolving network needs would be required. The same is true for all other existing policies; changes would have to go through extensive consultation and rigorous testing.
Quantification of constraints (prediction)	More accurate modelling and assessment of constraint predictions is required. Investors are risk averse and require as much certainty as possible else they will not invest.	Technical High High	Development of new and existing constraint modelling tools, with collaboration from the network operators.

4 Green Hydrogen as a Route to Market for Renewable Projects

To establish a route to market for green hydrogen projects utilising constrained renewables in the context of the UK electricity sector, it is necessary to understand the current framework for connection and operation. This section explores the types of grid connections available to developers across Scotland and highlights potential ways in which green hydrogen production could be integrated. Possible future connection options are also discussed. The full grid connection application process for distribution and transmission connections is provided in Appendix D.

4.1.1 Types of Distribution Connection Agreement

Traditionally, there was one type of connection offered by DNOs:

- **Firm** – connections are guaranteed to be allowed to export their full capacity, even in N-1 operating conditions. Very few generators install more than a single circuit connection from their site to the point of connection, so this section of the connection would be considered non-firm.

Owing to increases in distributed generation and generally "fuller" networks, the DNOs have expanded the types of connections they offer, known as *Flexible* or *Alternative* connections. These promote continued connection of renewable generation and also better utilisation of existing assets.

SPD offer the following types of connection:

- **Non-Firm** – full export capacity is not guaranteed in abnormal/N-1 operating conditions and may be curtailed/removed
- **Export Restricted** – pre-determined export capacity where the generator can either self-balance or be curtailed
- **Active Network Management** – dynamic limit on export capacity in accordance with network requirements, generator will be placed in a LIFO (last in, first off) priority stack

SSEPD offer the following types of connection:

- **Timed** – generation is curtailed within specific time periods
- **Intertrip** – generation can export when constrained assets are operating within normal parameters, otherwise they will be curtailed
- **Active Network Management** – dynamic limit on export capacity in accordance with network requirements, generator will be placed in a LIFO (last in, first off) priority stack
- **Export Limited** - pre-determined export capacity where the generator can either self-balance or be curtailed
- **3rd Party Active Network Management** – generator(s) self-manage but SSEPD have an intertrip in place in case of system failure

In all of these flexible or alternative connections, the generation developer has voluntarily agreed to some level of constraint and/or curtailment, for which there would be no compensation offered by the DNO. Should any of these generators have a BEGA in place, however, they could participate in the balancing mechanism and earn constraint payments that way.

The types of connection offered by DNOs that are most applicable to this study and the production of green hydrogen are the Non-Firm and Export Restricted options from SPD and the Intertrip and Export Limited options from SSEN. Developers with Non-Firm and Intertrip connections would benefit from their requirements to curtail generation in times of constraint, such that this energy is diverted instead of lost, and additional revenue can be gained.

Similarly, the Export Restricted and Export Limited connections would gain additional revenue from being able to fully utilise their installed capacity. This option would also offer more consistent operation, and therefore revenue, as it would not be dependent on network constraints (but still on wind resource).

4.2 Grid Connection Options for Green Hydrogen Production

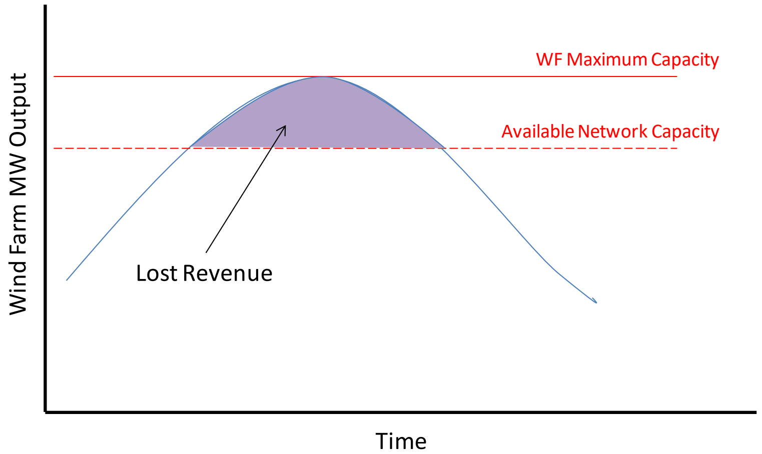
Based on the grid connection processes highlighted in the previous sections, a high-level assessment has been carried out to understand how diverting constrained wind energy to produce green hydrogen could affect connection CAPEX costs and overall revenues. The analysis has been performed on only distribution connections at this stage, due to these being more affordable to developers in a post-subsidy environment. Two base cases have been configured to outline the current ways in which a constrained connection would be handled by the DNOs:

1. An onshore wind farm that is shown to cause constraint on the network and so is offered a constrained connection offer to avoid network reinforcement costs
2. An onshore wind farm that is shown to cause constraint on the network and so must pay for network reinforcements to accommodate the additional capacity

4.2.1 Constraint Case

The Constraint Case considers the scenario where a developer is unable to export the full capacity of the generation site, as the connection of the onshore wind farm has been shown to cause constraints in the local network (up to the Grid Supply Point substation). In this scenario, the DNO has issued a connection offer whereby the wind farm will be permanently constrained to a value lower than the total installed capacity. The terms of this constraint will be defined in the connection offer. The developer will not have to pay reinforcement CAPEX costs as the curtailment of the site will forgo any reinforcement works. This will, however, result in lost revenue proportional to the level of curtailment experienced from the capped MW output of the site. This lost revenue will be equal to the price of a subsidy (if available) plus the price of wholesale electricity over the lifetime of the wind farm. Figure 4.1 below illustrates this operation.

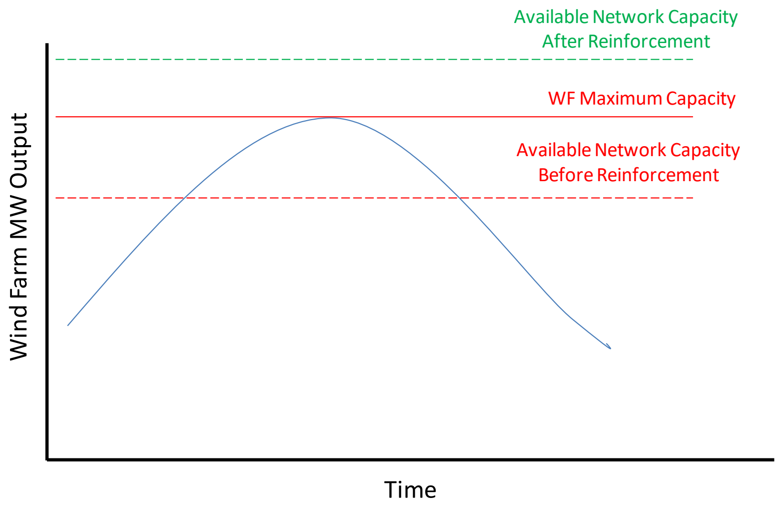
Figure 4.1 Constraint Case Operation



4.2.2 Reinforcement Case

The Reinforcement Case is reflective of the scenario where the wind farm connection will cause the firm capacity of the substation to be exceeded. This will lead to the requirement of transmission system upgrades to accommodate the connection. Following the network upgrades the developer will be able to export the full installed capacity of the site, however, in this case the developer will be required to contribute towards the costs incurred for the transmission system upgrades. A typical range for the cost of these upgrades would be between £5million and £15million, depending on local and wider works. In this scenario, the developer will experience up front capital costs, however, no revenue will be lost due to curtailment as the site will be able to export the full capacity. This is illustrated in Figure 4.2 below.

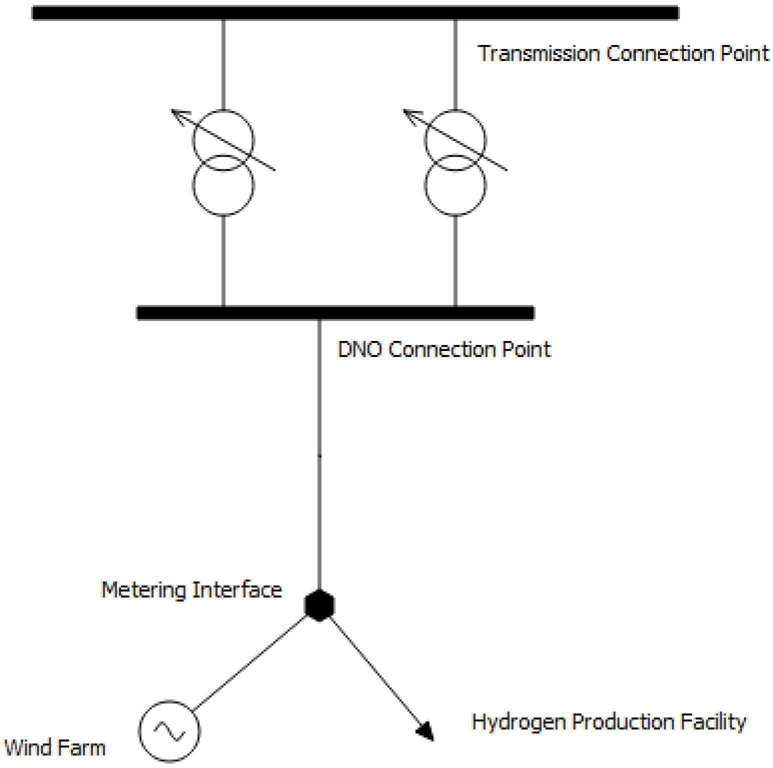
Figure 4.2 Reinforcement Case Operation



4.2.3 Green Hydrogen Production Case

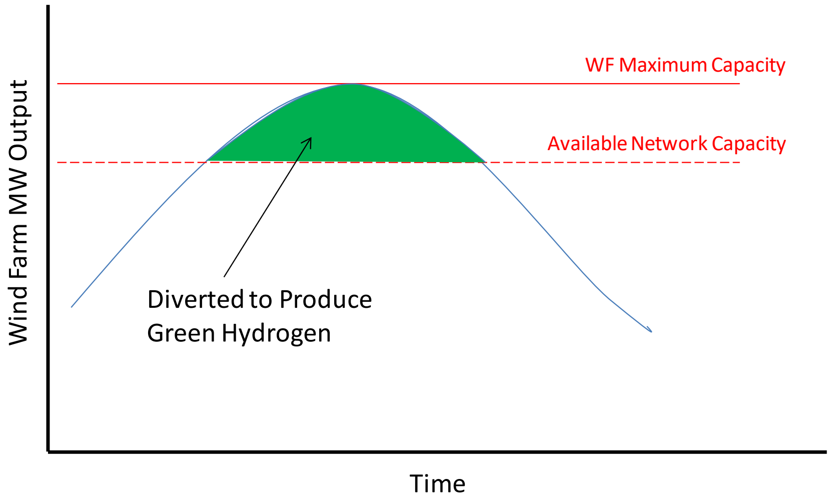
Both the Constraint Case and Reinforcement Case are compared to a plausible arrangement where green hydrogen production can be utilised to aid both connection cases. The most feasible solution for green hydrogen production within the current connection processes is to have a production facility co-located at the wind farm metering interface, where the facility will be viewed as behind the meter. This arrangement is shown in Figure 4.3 below.

Figure 4.3 Behind the Meter Green Hydrogen Production



Locating the hydrogen facility behind the meter will enable the facility to utilise the constrained capacity directly for green hydrogen production as shown in Figure 4.4. In this instance the wind farm will avoid paying high CAPEX costs for network reinforcements and can also substitute lost revenue costs for export to the network with gained revenue from the production of green hydrogen. There will be a CAPEX cost associated with the hydrogen facility and so the level of constraint must be high enough to justify this additional cost; this is discussed in more detail in Section 5. The wind farm developer would not be liable for the costs associated with the hydrogen facility itself if this was a separate development, so an agreement would be in place between the two parties.

Figure 4.4 Behind the Meter Green Hydrogen Production Operation



4.2.4 Comparison of Grid Connection Options

Table 4.1 highlights the three comparison cases and the likely cost implications they will face.

Table 4.1 Comparison of Grid Connection Option Cost Requirements

Comparison Scheme	CAPEX	OPEX	Revenue
Constraint Case	No network reinforcements	DUoS	Lost revenue from constrained capacity
Reinforcement Case	Network reinforcement works	DUoS	No lost revenue
Hydrogen production facility located behind the meter	None in relation to the wind farm (Hydrogen facility equipment)	DUoS (Hydrogen operating costs)	Lost revenue from wholesale electricity market Additional revenue from electricity sold to hydrogen facility

The financial elements of each scheme, discussed the preceding sections, is summarised in Table 4.2.

Table 4.2 Cost Comparison of Grid Connection Options

Comparison Scheme	CAPEX	OPEX	Revenue
Base Case 1		DUoS	Lost revenue from constrained capacity
Base Case 2	Network reinforcement works – usually in the order of £millions	DUoS	
Hydrogen production facility located behind the meter		DUoS	Lost revenue from wholesale electricity market Additional revenue from electricity sold to hydrogen facility OR from sale of hydrogen as a revenue generator for wind farm owner directly Difference over the lifetime of the wind farm

Further study would be required with appropriate data to quantify these costs. A like for like comparison would be location specific and have to be carried out on a case by case basis to understand the most economical solution. It is clear, however, that the larger the constraint/curtailment, the more potential energy resource for the production of hydrogen and thus larger potential revenue stream from that application.

4.2.5 Future Connection Options to be Considered

Initially, a further two options for the connection of green hydrogen were proposed for comparison against a typical wind farm connection that experiences constraint issues:

1. An onshore wind farm with a PPA to sell a portion of its electricity to an offsite hydrogen electrolysis facility.
2. An onshore wind farm connecting to an ANM scheme where constraint payment is not recoverable. In this case the constrained generation is diverted to an offsite hydrogen facility via a specific PPA.

A review of these connection arrangements highlighted some issues:

- For the first case, an offsite hydrogen facility would cause concern for the DNO and the transmission system operator.
- In this scenario it cannot be guaranteed the allotted generation contracted to the offsite facility will be delivered to said facility due to current market arrangements, and thus it could feed onto the distribution network and, subsequently, the transmission network.
- A connection offer would have to be provided for the maximum capacity that could be exported onto the grid leading to curtailment or triggering reinforcement works.
- The hydrogen facility would therefore make no difference to a typical wind farm connection.

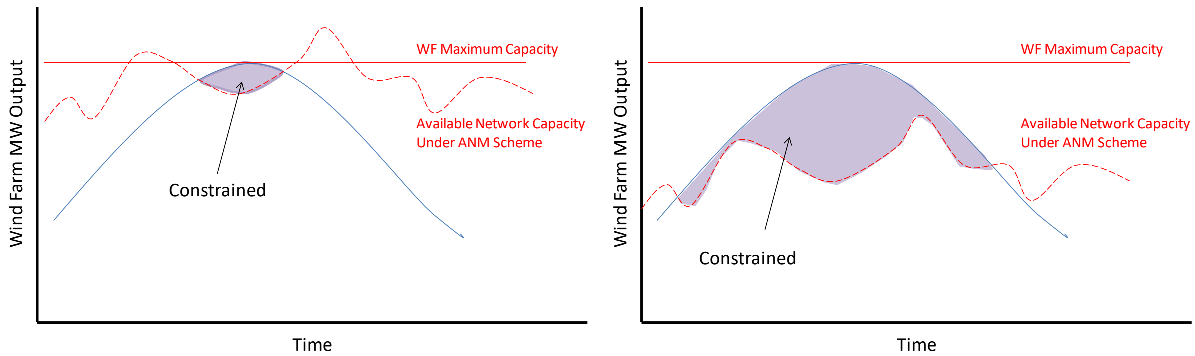
This arrangement could be possible in the future as the distribution network operator adopts a distribution system operator (DSO) role. As a DSO, the network operator may become more flexible and pragmatic in its operation, which would provide a suitable environment for this connection arrangement enabling a market to be implemented at this local level. As it stands, this connection option is not a feasible comparison, however, it is one of the scenarios that has undergone cost modelling in Section 5, which calculates and quantifies different volumes of electricity and hydrogen to assess economic feasibility rather than the practicalities of implementation under the current electricity market framework.

In the case of a wind farm connecting under an ANM scheme:

- A wind farm connecting as part of an ANM scheme will be subject to the varying level of constraint depending on the requirements of the network at any time.
- The ANM connection arrangement is synonymous with the current practice of permanently curtailing a wind farm i.e. the full installed capacity of a site cannot be exported. In this case instead of the level of constraint fluctuating, the level of network capacity will be the variable.
- As the curtailment will fluctuate in real time, it is difficult to assess the impact the ANM scheme will have on the cost and revenue of wind farm, and in turn how this would impact a hydrogen production facility.

This is highlighted Figure 4.5 below, where two very different outcomes could occur. Better forecasting tools and visibility of the network would improve the predictability of this type of connection.

Figure 4.5 Different Levels of Curtailment for an ANM Connected Wind Farm



The priority stack of an ANM scheme would also play a role in determining levels of constraint, where in a last in first off (LIFO) stack, the generation connecting later would be more frequently constrained and so could benefit more from the hydrogen application than earlier connections.

4.3 Opportunities across Scottish Networks

The extent of the constraint problems being faced by the Scottish DNOs and TNOs means there is a real opportunity for innovative solutions such as green hydrogen production. In areas like Dumfries and Galloway, where even large-scale strategic reinforcement works will prove insufficient to accommodate additional generation beyond that already contracted, the combination of ANM with green hydrogen production could enable further generation capacity. This could be extended to other areas where ANM is being deployed to manage constraint due to capacity restrictions including, but not limited to, the East Lothian and Borders areas, which are operating under ANM from the ARC project.

On the Orkney Isles, there is already an operational smart grid and an appetite for innovation that could provide an ideal site for trialling and demonstration of a hydrogen application. It would also introduce a local hydrogen supply to the islands, thus solving some location vs. transportation issues, providing hydrogen as a fuel for commercial vehicles and potentially even private vehicles. There are also lessons that could be learned from the EMEC tidal/hydrogen venture. An additional benefit to this could be the provision of a refuelling base for hydrogen vehicles that travel frequently to and from the Scottish mainland. This could be replicated in Shetland and any of the other remote islands in the Inner and Outer Hebrides.

5 Cost Modelling of Green Hydrogen Production Scenarios

From a technical standpoint, there are a number of scenarios that could support the production of hydrogen from constrained renewable energy. This section explores the economic feasibility of some of these scenarios and examines how hydrogen could best be exploited to maximise the benefits to both wind farm and hydrogen developers.

5.1 Understanding Cost Assumptions

One of the most critical factors in determining the economic viability of hydrogen production using constrained electricity is establishing the true installed cost of large electrolysis units, including the cost of compression and storage. This section explains the basis of a costing methodology that can be applied to a typical hydrogen system. The work presented is based on publicly documented installation costs, serving to expand current industry knowledge of hydrogen production from curtailed turbines. This information could be used to support wind developers in determining the most viable wind hydrogen configuration to invest in.

Hydrogen equipment costs vary widely depending on manufacturer. Over the last few years a significant effort has been made to establish realistic costs and future trends; in particular, the Fuel Cell and Hydrogen – Joint Undertaking (FCH-JU) has funded several schemes aimed at providing figures that can inform future hydrogen project development.

The typical cost of a large electrolyser is £1.5 million per MW for alkaline electrolysers, which is predicted to fall to £1 million per MW by 2020[10]. The cost of a large PEM (Polymer Electrolyte Membrane) electrolyser is generally accepted to be £2.5 million per MW, which is expected to fall to £1.5 million per MW by 2020[11]. In addition, installation costs of £0.5 million per MW, and £0.5 million per MW for compression and storage, need to be included in any cost estimate. These additional costs apply to both Alkaline and PEM electrolysers.

The overall efficiency of a hydrogen electrolyser will be between 65% and 70%. This corresponds to 60 kWh per kg. Electrolysis efficiency will typically decline by 2% or more each year. Common practice calculates the effect of CAPEX (Capital Expenditure) on the cost of hydrogen production by applying a 20 year amortisation. It should be noted that CAPEX price reductions predicted over the last 20 years have in almost all cases being significantly overestimated[12].

As a reference point, the bulk price of hydrogen produced by steam methane reforming for industrial use is typically around £2 per kilogram[13]. The current market-acceptable price for hydrogen produced from renewables - to be used in buses for example - is around £6 kg^{-1}. Typical OPEX (Operational Expenditure) costs for producing green hydrogen are £0.50 per kg[14]. This OPEX cost is adopted here - it excludes the cost of electricity and reflects only the O&M (Operation & Maintenance) costs of the production facility.

[10] 'MEGASTACK: Stack Design for a Megawatt Scale PEM Electrolyser', JU FCH project in the 7th Framework Programme.
[11] The basic cost includes power and system control and gas drying, not external compression, purification and storage.
[12] http://www.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf
[13] Potential Role of Hydrogen in the UK Energy System - October 2016 Energy Research Partnership.
[14] http://www.fch.europa.eu/sites/default/files/5%20APPENDIX%202B%20FCHJUElectrolysisStudy%20(ID%201329459).pdf

Currently, there are no significant bulk savings achieved by moving to multi-MW electrolysis cell stacks: the rational being that existing, reliable electrolysers have a capacity of around 1 MW or lower. In most cases, capacities larger than 1MW are achieved by installing multiple 1 MW electrolyser cell stacks within a single machine.

In the short term, the size of the largest individual cell stack modules will not increase beyond 1 MW. This is due to economies of scale resulting from increased production of 1MW cell stacks and the inherent redundancy of larger machines composed of multiple 1 MW cell stacks. There are a number of installations that use larger scale stacks, but no independently verified financial and technical studies have been published. Consequently, larger scale stacks have not been considered in this study.

5.2 Brief Example of Hydrogen Financial Viability

This section provides a brief case study illustrating the challenges that have to be overcome to ensure a hydrogen project is economically viable. This is especially true when investigating the production of hydrogen from renewable sources, i.e. green hydrogen.

Looking at this case in comparison to the more typical reformation method, it would appear that hydrogen produced from renewables is not a competitive option. The reasoning underlying this assertion is outlined below.

It is assumed that a 3 MW Alkaline Electrolyser with Storage and Compression is installed at a given location. The actual costs of an installation are dependent on specific application and location. For example, if the facility is built close to a wind farm in a remote location, the capital costs for a hydrogen system will be higher. Transportation costs for the gas would also be a significant consideration. Were the plant located in a more accessible location, but at a distance from the wind turbine, green energy would have to be purchased and costs incurred from transmission over the existing network.

It is assumed that the hydrogen system is installed at a wind farm site and there is no need to transport the gas - a 'best-case' scenario. A 33% load factor (input power), a 3% interest 10-year capital payback, and a 2% annual performance degradation on the hydrogen system (efficiency decline) defines the wind to hydrogen system. From this, the following figures are derived:

- Installed cost for a 3MW hydrogen system: £7.5 m
- Total Hydrogen Production (for 10 years): 1,200 tonnes
- Total OPEX (10 years): £600,000
- Capital Repayment Total: £9.25 m[15]

The minimum price for hydrogen per kilogram to make the above system financially viable is £8.21.

The above calculation does not include the cost of electricity which would add to the operational costs. The £8.21/kg price for hydrogen is effectively the best case scenario. As the best case scenario is not conducive financially, the cost for electricity has not been investigated further.

This is helpful in understanding why industry and developers have not invested in hydrogen installations to date. This basic calculation shows the challenge facing an electrolyser with a low capacity factor to meet the aforementioned target price point of £6 per kilograms.

[15] Based on FCH-JU installed prices http://newbusfuel.eu/wp-content/uploads/2015/09/NBF_GuidanceDoc_download.pdf

This section is based on publicly documented state of the art installation costs from 2017.

The aim is to demonstrate whether the six scenarios described below are financially viable based on today's known cost structures. Where a scenario is found to be viable, the market conditions required to support this are described.

5.3 Methodology for Calculating the Price of Hydrogen per kilogram

The method used to calculate the price of hydrogen per kilogram is outlined below. This is applied within the six scenarios, with any local variations being described and justified as part of the specific scenario.

a. Available annual energy is calculated
    a. The cumulative total energy for the data provided by wind farm operators is computed.
b. Electrolyser size is selected
    a. The size of the electrolyser is selected. The size is scenario dependent. The rationale behind the size of the electrolyser is described in each scenario.
c. Cost of hardware including their OPEX is taken into account
    a. The costs have been taken from publicly published and available information. This includes housing (containers), installation, commissioning, hardware (electrolyser, compressor, storage, water treatment, and control & monitoring), shipment costs and maintenance costs.
d. Cost of electricity purchase added to the above costs
    a. This is the price of electricity only where it is investigated in the described scenarios. The best case scenario, where electricity is free, is investigated to define if hydrogen can be produced economically. If the case it is not economical, then no further analysis is conducted. Otherwise, the impact of the price of electricity on a kilogram of hydrogen is investigated and provided.
    b. No cost for Distribution Use of System (DUoS) fees is assumed. This is to determine if the best case scenario can be financially viable.
    c. Only one scenario includes private wire costs (Scenario 6). All other scenarios do not include this. The rational is that costs associated with a private wire are site dependent. As all of the scenarios, apart from scenario 6, are not associated with a specific site location, these costs cannot be estimated for the deployment of a hydrogen system, and as such have not been taken into account. Also, the aim is to identify if hydrogen is financially viable with the best possible conditions. If it is not viable in the best conditions, then there is no need to further investigate the need for a private wire. If Hydrogen is proven to be viable, then future case by case studies can be investigated.
e. Selection of a sensible hydrogen system efficiency assumed
    a. The efficiency of the overall system is assumed to be 60%. This includes all balance of plants, electrolyser, compressor and remote control and monitoring systems.
f. Quantity of hydrogen over lifetime calculated (assuming annual drop in electrolyser efficiency)
    a. A minimum of 12 months wind data were used for each scenario. For example, the wind turbines used in the wind farm described in Scenarios 1 and 2 were manufactured by Enercon. For both, three years data was available and by plotting and comparing the power curves each year, no decline in performance was found. Therefore, no degradation was assumed when extrapolating the data.

g. Total cost over lifetime (CAPEX + OPEX) divided by total amount of hydrogen produced in kg provides the price of H2 per kg. Note that scenarios 1 to 4 are based on a 10 year lifetime / payback period and scenarios 5 and 6 investigate a 20 year lifetime.

The end price is the price of hydrogen compressed and stored at the production site and not the delivered to end-user price.

5.4 Other Considerations for Hydrogen Systems

Manufacturers were asked to provide information detailing potential future reductions in equipment costs. The aim was to determine if a reduction in CAPEX would improve a scenario's cost estimate by including equipment price projections for 2020 and 2025.

Cost reduction data supplied by manufacturers stipulated that the projections were based on realising mass production and mass deployment. As mass deployment is not seen as currently achievable by any of the manufacturers, future price reductions have not been taken into account.

Electrolyser manufacturers advertise their equipment as being 70% to 80% efficient. However, in practice, electrolysers have been monitored as having a maximum efficiency of 65%[16]. This identifies a potential 35% heat loss issue. As electrolysers age, their efficiency also decreases. A more appropriate, practically justifiable value for the efficiency of a hydrogen system over the lifetime of the asset is taken to be 60%.

In all of the six scenarios discussed below, none have investigated how efficiency varies with electrolyser loading - the efficiency of the electrolyser varies. The efficiency of the electrolyser is low at start up - from a cold position and starting to warm up. Efficiency also changes when the electrolyser does not operate at its optimal point. This 'operating sweet point' varies from technology to technology and from manufacturer to manufacturer. As electrolysers get bigger in size, the effect of electrolyser loading will increase. Through time, the production of hydrogen can be negatively affected by this. Assuming an optimal, 'best-case' analysis across all scenarios, a hydrogen system efficiency of 60% has been used unless otherwise stated.

Stakeholder discussions highlight the lack of clarity as to whether wind farm operators will still be able to claim subsidy payments when the electricity is used for electrolysis rather than exported to the grid. If electricity is directed to the electrolyser instead of the grid, the Regulator (Ofgem) is under no obligation to award ROCs. The electrolysis facility must then buy the electricity at market rate, paying an additional 'make up' cost for the lost ROC. This could be as much as £100 / MWh total, which may compromise the economic viability of hydrogen systems.

[16] https://www.sciencedirect.com/science/article/pii/S0360319909001244

5.5 Scenario 1 – Curtailed Power Only

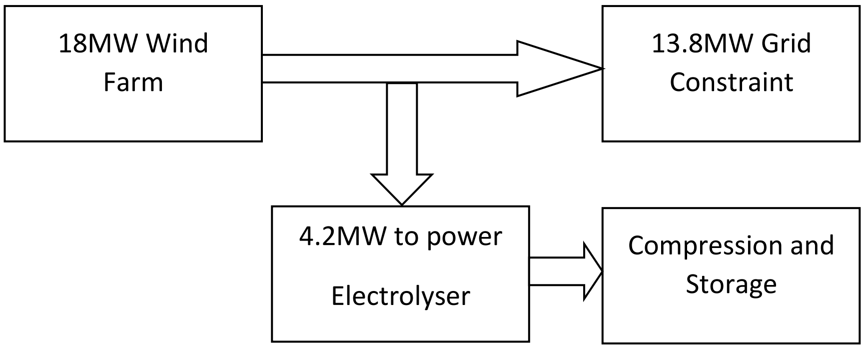
Scenario 1 investigates the following:

'An electrolysis facility that produces hydrogen from electricity supplied by a single Scottish onshore wind farm asset that is subject to high levels of curtailment, using only the electricity that would otherwise be curtailed.'

Data were acquired for an 18 MW wind farm that has a grid connection agreement limited to 13.8 MW. In this scenario, it can be seen that the level of constraint is significant. The wind farm is made up of six 3 MW turbines and the wind resource is considered excellent.

This scenario can be scaled to relate to the wind sector in Scotland as a whole where there is a production ceiling based on maximum demand and maximum export capability. Figure 5.1 illustrates the scenario, where the electrolyser is connected 'behind the meter' to the wind farm directly.

Figure 5.1 Scenario 1 - An 18 MW wind farm constrained to 13.8MW



The impact of paying for the electricity on economic viability is investigated. A 4.2 MW electrolyser capacity is considered to be installed on site and is evaluated using the data from a typical year (2014).

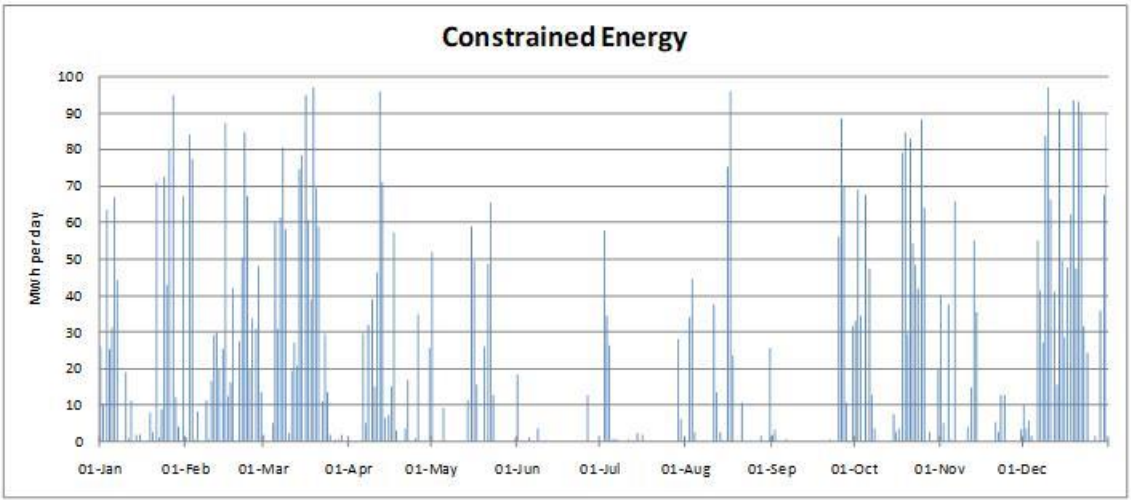
The electrolyser is scaled to utilise the full capacity of the existing connection constraint. It is, therefore, 30% of the size of the 13.8 MW grid connection agreements and not the full installed capacity of the wind farm. For the avoidance of doubt, the size of the electrolyser is calculated as follows:

Size of electrolyser system = 13.8 MW grid connection x 30% = 4.14 MW.

A 4.2 MW electrolyser size is selected.

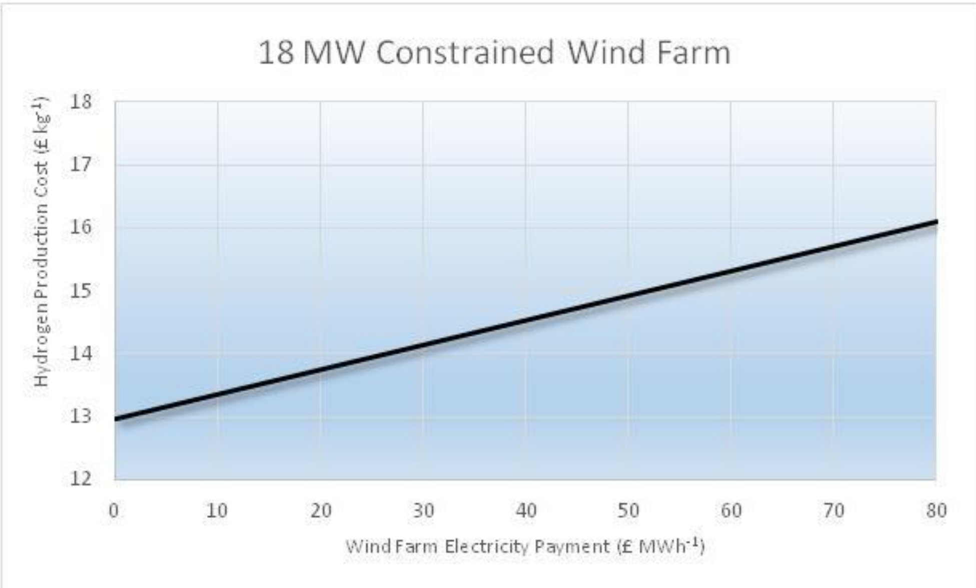
Figure 5.2 below highlights the constrained energy from the 18 MW wind farm (13.8 MW export agreement) throughout the year 2014.

Figure 5.2 Constrained energy spread over the year 2014 for an 18 MW wind farm with curtailment being 11%



From the above available energy, it is now possible to define the price of hydrogen per kilogram. Note that the wind farm produced 58,099 MWh of electricity in 2014. Without curtailment, an additional 6,767 MWh would have been produced. This is the amount of energy available to the electrolyser. The hydrogen production cost is shown below in Figure 5.3. Although it is assumed that the price of electricity is nil at first, the impact that paying for electricity will have on the cost of hydrogen needs to be defined. This is also shown in Figure 5.3.

Figure 5.3 Hydrogen production cost in £ per kg versus cost of electricity



5.5.1 Scenario 1 Conclusion

It can be seen from Figure 5.3 that the hydrogen production cost is high. This is true even when constrained electricity is available at no cost. The reason is that the electrolyser has a low capacity factor.

In this particular scenario, the electrolyser is used only about 10% of the time. Again, this is why the capital payback time is so long as the principal equipment, the electrolyser, is only used a small fraction of the year with all of the associated consequential financial issues. For instance, the electrolyser will still need to be maintained once a year, thus OPEX will be high in comparison to the usage of the electrolyser.

In summary, the basic production cost for hydrogen is £13 kg^{-1}. That is only true when electrical energy is supplied with no cost attached.

Under the condition that the electricity has to be paid for, the costs of hydrogen production per kilogram will increase. If the cost of electricity is taken as the value of the national constraint payment (in the order of £70 MWh^{-1}), the cost of H2 rises to £15.7 kg^{-1}. This can be seen in the above Figure 5.3.

Overall, in the case that the available amount of energy is low in comparison to the size of the equipment, then a hydrogen energy storage system may not be viable.

5.6 Scenario 2 – Cluster with Curtailed Power Only

Scenario 2 investigates the following:

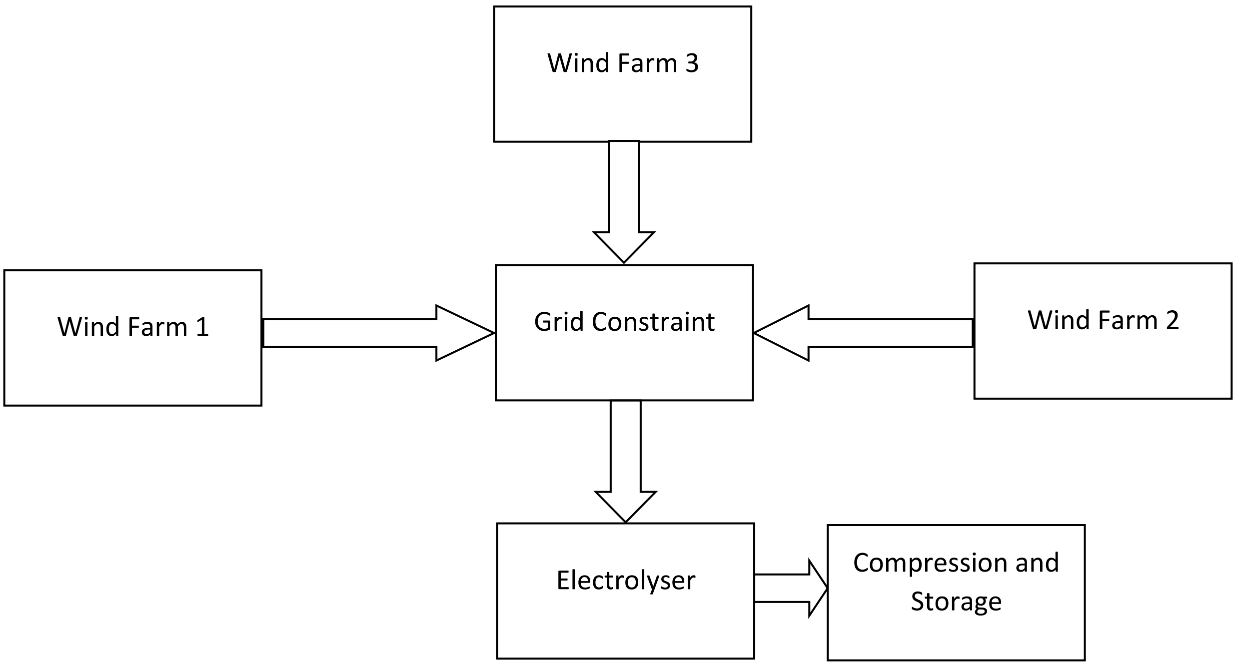
'An electrolysis facility that produces hydrogen from electricity supplied by a cluster of Scottish onshore wind farms that are subject to high levels of curtailment, using only the electricity that would otherwise be curtailed.'

Data were acquired for a 200 MW cluster of wind farms that are subjected to approximately 4% grid constraint. In this scenario, the level of constraint is not significant, and is consistent with the national level of 3% on UK wind farms.

However, for the size of the wind farm and considering that the site has an excellent wind resource, there is substantial amount of energy lost throughout the year due to constraint. Figure 5.4 illustrates the system that has been investigated.

Note that the selected cluster had a 20 km radius and it is assumed that private wire connection(s) to the electrolyser is utilised. Also note that the cost of a private wire is not factored in. The aim is to define if the hydrogen system proposed in this scenario is financially viable with the best conditions. If it is, then the cost of the private wire can be added. If the price of hydrogen is not viable in the best possible conditions, then it will not be viable with the addition of the private wire cost.

Figure 5.4 Scenario 2 - A 200 MW wind farm cluster constrained

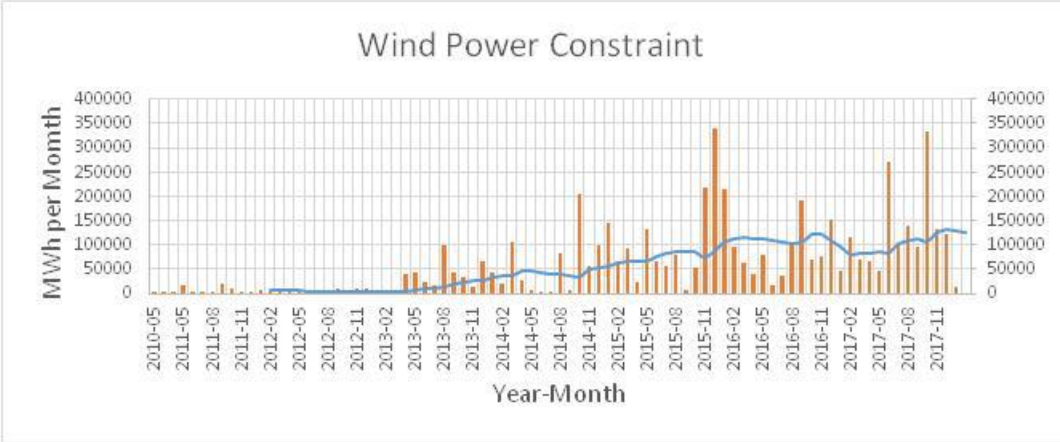


5.6.1 Why is the constraint 'low'?

Based on the location of the wind farm, each has a different curtailment pattern. One of the wind farms had only 2% curtailment, while others had 4% and 6% respectively. As such, the average curtailment of the cluster was 4% in the data period.

The above number is quite important as it can be related to the UK curtailment trend as shown Figure 5.5.

Figure 5.5 The constraint payment is currently just under £70 MWh^{-1}. The blue line shows the one-year running average



Note that the amount of electricity generated from wind turbines is increasing each year. As such the above graph shows that the fraction that is constrained is actually decreasing in comparison to the overall increase in wind generation capacity.

There are a number of reasons for this. The first reason is that the technology has improved and therefore better weather predictions are available and better understanding of energy consumption too. As such, the network operator and the generation supplier can better plan in advance the electrical energy needs and how to fit the wind generation within the energy supply realm.

Additionally, many grid connection infrastructure upgrades and improvements have been implemented too. These are some of the reasons why the level of curtailment for a given cluster may not be high (specifically for the wind farm investigated). Further to this, the above graph illustrates the UK wide scenario for curtailment and not Scotland specifically (which is higher). In 2017, 3% of the available energy was constrained 'off' in the whole of the UK (i.e. the energy available for capture was lost due to operational constraints).

5.6.2 How to interconnect the electrolyser(s) to the wind farms?

There are two different methods that can be used to select the appropriate electrolysis installation for a cluster of wind farms being curtailed.

The first method is to install a hydrogen system at each wind farm. In this case, one electrolyser will be located at each wind farm that makes up the cluster. For the avoidance of doubt, if the cluster consists of four wind farms, then four electrolysers will be installed, one at each wind farm.

The second method is to have one single electrolyser installed at one of the wind farms that makes up the cluster. In this case, there are benefits in using a single electrolysis facility to handle the excess production of a number of wind farms that makes up the cluster. The reason is that costs will reduce in terms of civil works as there is no need to have hydrogen systems being despatched around the different wind farms. However, there will be costs associated with the installation of a private wire. Therefore, this option should be investigated on a case by case basis.

A third option exists in addition to the above two methods. This option is associated with the use of the grid network. Again, one single electrolyser could be installed at a given location provided that the grid is strong enough to transport the power from the wind farms to the electrolyser installation.

The only issue in this case will be associated with Distribution Use of System charges. And this is true even for a few kilometres distance, where charges could be significant.

5.6.3 Curtailment versus price of electricity for a cluster of wind farm

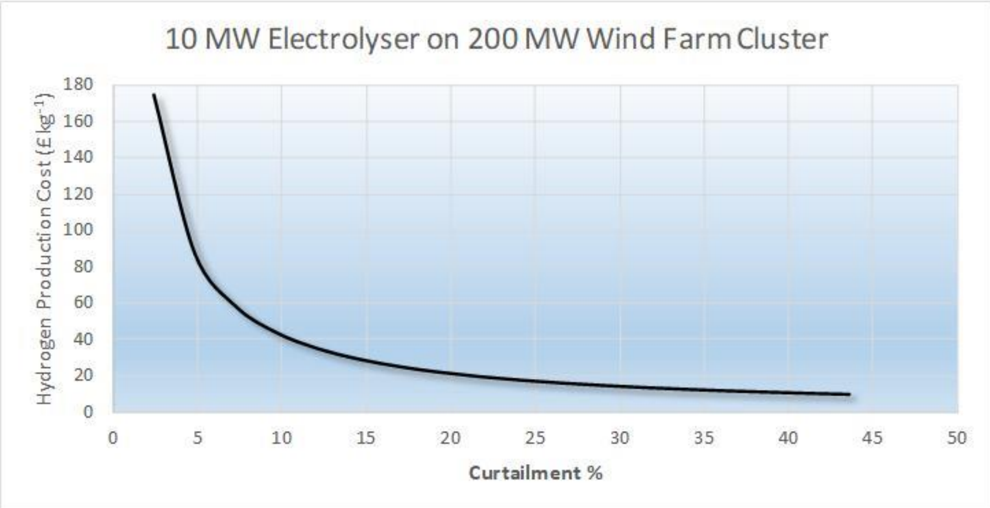
For this particular scenario, it is important to understand how the hydrogen price varies with curtailment fraction. For the purposes of this scenario, it is assumed that the wind farm operators will continue to receive the normal constraint payments, however, this should not necessarily be assumed for a 'real life' project. Such a scenario could be used as a pilot project in Scotland to test the financial and technical condition of a hydrogen scheme. Under this condition, there is no electricity cost to the electrolyser facility.

It is assumed that a pilot scheme of a 10 MW electrolysis and storage facility is installed at a single location within the cluster of wind farms. The 10 MW system has been selected as being a good balance between making a significant effect on recovering energy (that would otherwise be lost), and reasonable cost.

Note that 10 MW hydrogen systems are now possible and seen as being a routine installation by the industry[17]. However, a 10 MW installation working alongside a 200 MW wind farm is new territory.

Using the 4% curtailment described previously, the electrolyser will only reach full power 1.5% of the time. The utilisation of the electrolysis unit is therefore extremely low. This will result in high production cost as shown in Figure 5.6. The reason for such low electrolyser operation is due to wind distribution. Curtailment takes place at high wind generation output, which is the case for only a relatively small fraction of the year.

Figure 5.6 Hydrogen production cost in £ per kg versus cost of electricity



The cost of electrolysis is extremely high for low curtailment. For example, a 10 MW electrolyser operating at full power for 1.5% of the time uses 1300 MWh of electrical energy a year. This is enough to make 20,000 kg of pressurised hydrogen (assuming 65% electrolyser efficiency and 60% for the overall hydrogen system) a year.

The "curtailed" electrolyser would have produced 200,000 kg of hydrogen in total over the 10-year lifetime of the unit. The CAPEX and OPEX together of the electrolyser for the 10 year installation

[17] http://www.itm-power.com/news-item/worlds-largest-hydrogen-electrolysis-in-shells-rhineland-refinery

(plus interest payments) will come to about £29,000,000[18]. This will result in a hydrogen cost of £145 per kg (H2 cost = £29,000,000/200,000 kg of H2 = £145/kg).

5.6.4 Scenario 2 Conclusion

As can be seen in Figure 5.6, hydrogen production cost is extremely high for a cluster of wind farms with low overall curtailment.

In common with Scenario 1, even when the electricity used by the electrolyser is available at no cost, the cost of hydrogen per kilogram produced by the system will remain high. The reason being that the overall curtailment is typically very low at the wind farm cluster considered by this scenario.

In addition, considering that the curtailment is low, the overall operation of the electrolyser will be even lower. In the above example, a curtailment of 3% will lead to the hydrogen system operating for only 1.5% of the time. In parallel to this, there is an extremely high CAPEX and OPEX for such a small time of electrolyser operation.

In summary, the current levels of curtailment on large-scale wind farms (3% curtailed energy, 1.5% electrolyser runtime) do not justify the use of electrolysis to address curtailed energy loss. Moreover, even with a small electrolyser size of 10 MW, this scenario does not work out as a viable option.

However, the price for hydrogen falls below £20 per kilogram when average annual curtailment reaches 20%. Overall, the higher the curtailment is, the lower the hydrogen price will be. In turn, the higher the curtailment, the more hydrogen production. Thus, there will be a higher utilisation of CAPEX and therefore a higher income.

This scenario assumes that the constrained electricity is available at no cost. It also considers that there are no transmission system charges. This is again a best case scenario that does not include all of the costs of a 'real life' system. As this scenario did not work out to be viable, it will not become viable under even less favourable, more fully costed conditions (i.e., when there are transmission charges, or when electricity must be paid for).

In essence, the main finding from this scenario is that it will be very difficult to develop a viable case for a cluster of wind farm and using only the curtailed power. However, special cases can be considered for investigation where there is a high curtailment associated with a cluster of wind farms.

Similarly, the cost for a private wire has not been considered in this scenario. However, if there is a potential for the installation of a private wire instead of the use of the grid to alleviate grid charges, then this needs to be investigated.

A cost comparison between the installation of the private wire and the use of the transmission charges could provide the best way forward for a given location and cluster of wind farms.

Lastly, the size of the electrolyser and its annual production are the two main key factors that can lead to economic success.

[18] Based on FCH-JU installed prices http://newbusfuel.eu/wp-content/uploads/2015/09/NBF_GuidanceDoc_download.pdf

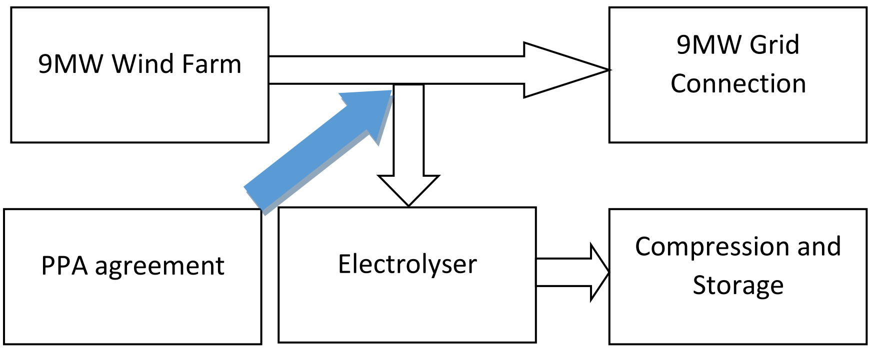
5.7 Scenario 3 – Long Term PPA

Scenario 3 investigates the following:

'An electrolysis facility that produces hydrogen from electricity supplied by a single Scottish onshore wind farm that sells a large proportion of its electricity to the facility via a long-term PPA.'

Data were acquired for a 9 MW wind farm. The wind farm is made up of three 3 MW turbines and the wind resource is considered excellent. In this scenario, a Power Purchase Agreement (PPA) is negotiated between a wind farm owner and the hydrogen facility owner. Note: the sale price of electricity is dependent on factors such as the duration of agreement, facility capacity and the variability of the electricity. Figure 5.7 illustrates the system that has been investigated.

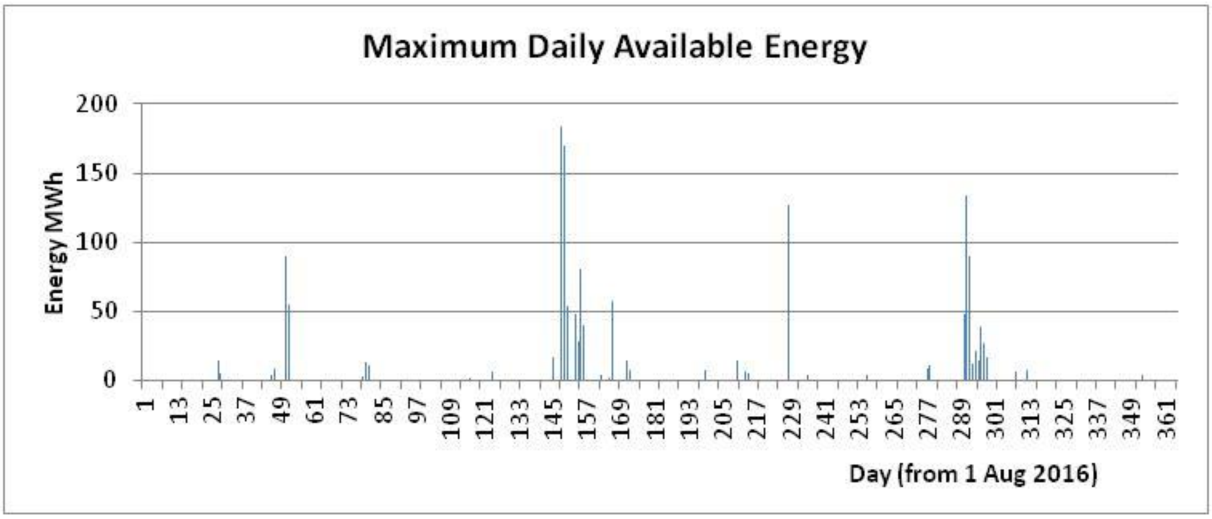
Figure 5.7 Scenario 3 - A 9 MW wind farm with a PPA agreement with a hydrogen production facility owner



The aim of this scenario is to investigate if the purchase of electricity from a 9 MW wind farm with moderate constraint at their existing PPA price of £33 MWh^{-1} is financially viable for a hydrogen system.

In comparison with Scenario 1, the curtailment is related to a weak grid and is not absolutely dependent on output power. From the data acquired, the wind farm produced 29,500 MWh of electricity in 2016. Of this, 1,535 MWh was lost because of curtailment. This is a loss of 5.2%, which is about half the loss in Scenario 1. The constrained energy profile is shown in Figure 5.8.

Figure 5.8 A 9 MW community wind farm with 3 turbines. Maximum energy is recovered by installing a 9 MW electrolyser



There are three possible approaches to addressing curtailment under this scenario: only the curtailed energy is purchased; all the energy is purchased; or purchase some of the energy from the wind farm, with an agreement to take all of the curtailed energy and some of the other available energy (this can only be achieved on a case by case basis).

From the previous two scenarios (Scenario 1 and 2), it was clear that when the electrolyser used only curtailed power, then the financial case for hydrogen is difficult to attain. Nevertheless, this is potentially achievable if an appropriate subsidy was available (CAPEX or production type subsidy similar to the Feed-In-Tariff).

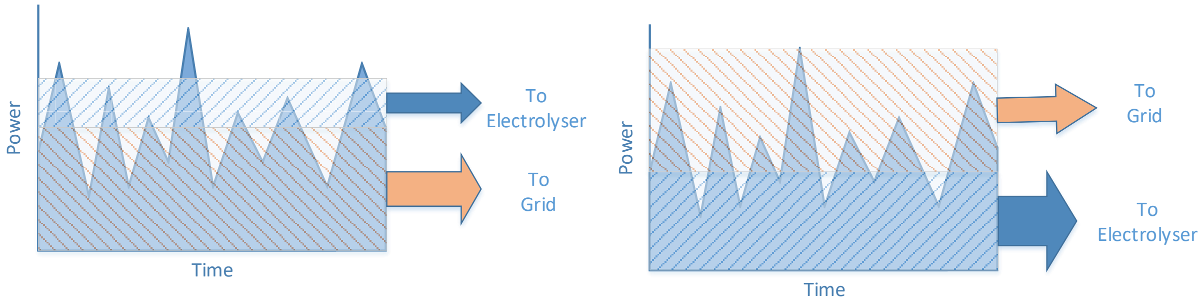
In this scenario, it is important to address the issue of low electrolyser capacity factor. The difficulty in this particular scenario is the design of the PPA. Recent discussions with wind farm owners indicate that they would prefer to sell all of the power to a single entity, with the aim of reducing the amount of paperwork (and costs) associated with selling to multiple entities. Furthermore, the wind farm owners do not believe that they could justify the need for civil works and power connection cost for the electrolyser just to take a fraction of the available power (the curtailed power).

Note that an agreement to purchase only part of the electricity generated would help electrolysis economics considerably so long as the electrolyser has ‘priority despatch’, i.e. the electrolyser will always receive any energy available up to its rated power.

However, the electricity that is left will be highly variable and of low value (see Figure 5.9). As aforementioned, it is unlikely that wind farm operators would be able to enter into an agreement to sell this residual electricity to a distributer. Therefore, the option of a shared PPA cannot be considered further[19].

[19] It is not the aim of this study of dealing with curtailment to transfer the problem onto the grid operator using the method described in figure 5.9 (see graph on the right).

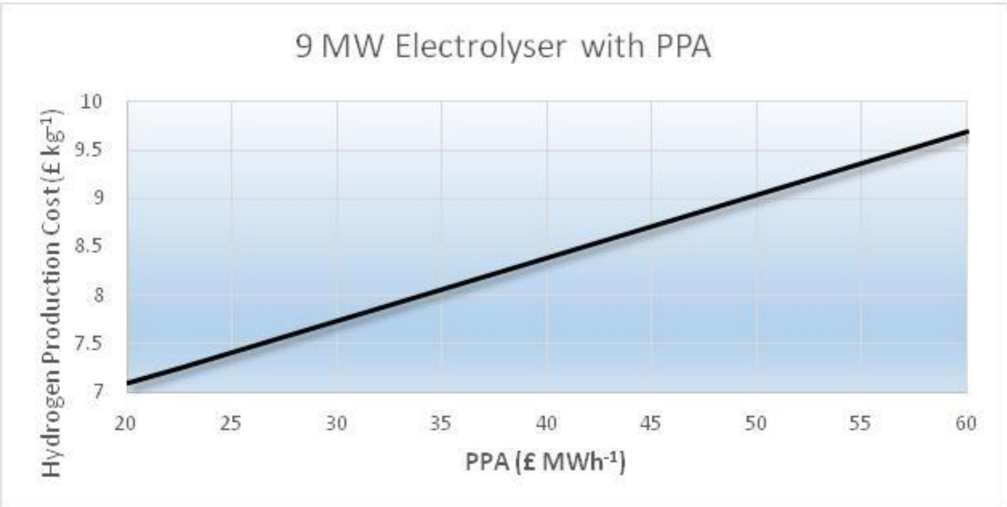
Figure 5.9 Two methods of dividing electricity between electrolysis and grid



On the left of figure 5.9, the electrolyser only takes the curtailed and highly variable power. On the right, the electrolyser has a priority despatch contract, meaning it takes the cleanest and most available power off the wind farm.

In line with the aforementioned preferences of wind farm owners, this scenario focusses on the possibility of buying all of the electricity from the 9 MW wind farm through a PPA (ranging from £20 MWh^{-1} to £60 MWh^{-1}). This includes the curtailed power too. As such, the proposed system ensures that all the energy from the wind farm is consumed (i.e. none spilled / curtailed). The findings are shown in Figure 5.10.

Figure 5.10 Cost of hydrogen versus the cost of purchasing all the electricity produced by the wind farm at different rates per MWh



The graph illustrated in Figure 5.10 is effectively an off-grid system, although the wind farm would retain its existing connection to the grid. The possible use for the energy lost through heat production (40% in this case) has not been considered, however, the potential income from the sale of the heat could potentially determine the financial viability of the system considered in this scenario. Further information about the heat financial effect can be found in Appendix B.

5.7.1 Scenario 3 Conclusion

From Figure 5.10, it can be seen that hydrogen production cost is dictated by the PPA. The curtailed energy is not a hindrance in this case, in fact, the hydrogen system could ensure an optimum use of green energy.

The cost of hydrogen in Scenario 3 has dropped considerably in comparison to Scenarios 1 and 2. The reason being that the hardware is used for longer period of times, hence the CAPEX and OPEX of the system do not inflict such a large proportion of cost on the price of the hydrogen per kilogram. Therefore, the potential high CAPEX and OPEX of hydrogen systems can be better distributed against the price of hydrogen.

In terms of the financials, if the price for purchasing electricity is around £40 per MWh, the price for a kilogram of hydrogen will be just under £8.50. Similarly, if the price of the electrical power is as high as £60 per MWh, then the cost of one kilogram of hydrogen will still be less than £10 at around £9.70 per kilogram. Note that the payback period for this scenario is 10 years.

It is possible to conclude that if there were a legal and financial mechanism available for buying all of the electricity from a wind farm (or most of it with a priority despatch agreement), then hydrogen produced using renewable electricity could become competitive. Similarly, this scenario could be viable if the owner of the hydrogen system could access a market support mechanism (such as the Renewable Transport Fuel Obligation (RTFO)). Such market support mechanism would allow hydrogen to be sold at a competitive price, potentially leading to market uptake of hydrogen as a fuel.

Scenario 3 considers that the electricity is not free of charge and has an associated cost per MWh. Note, Scenario 3 does not consider DUoS charges to be applicable. This is effectively the case as all the power is purchased at the source i.e. the wind farm 'behind the meter'.

The main finding from Scenario 3 is that it is possible to make a viable project with an electrolyser that uses all the power from a given wind farm. In addition, it is possible to foresee that utilising energy storage in the form of hydrogen technology will potentially lead to unviable wind farm projects becoming viable. In other words, there are times where wind farm projects cannot be developed because it does not make financial sense. Adding to this project a hydrogen system could mean that a wind farm scheme becomes financially viable and is taken to the deployment stage.

This could potentially not have been the case because at some locations there could be no load demand, lack of grid connection, too high curtailment imposed on the wind farm, etc. In those scenarios, the addition of an electrolyser could see a renewable project materialise. In essence, hydrogen system could potentially support the installation of more renewables.

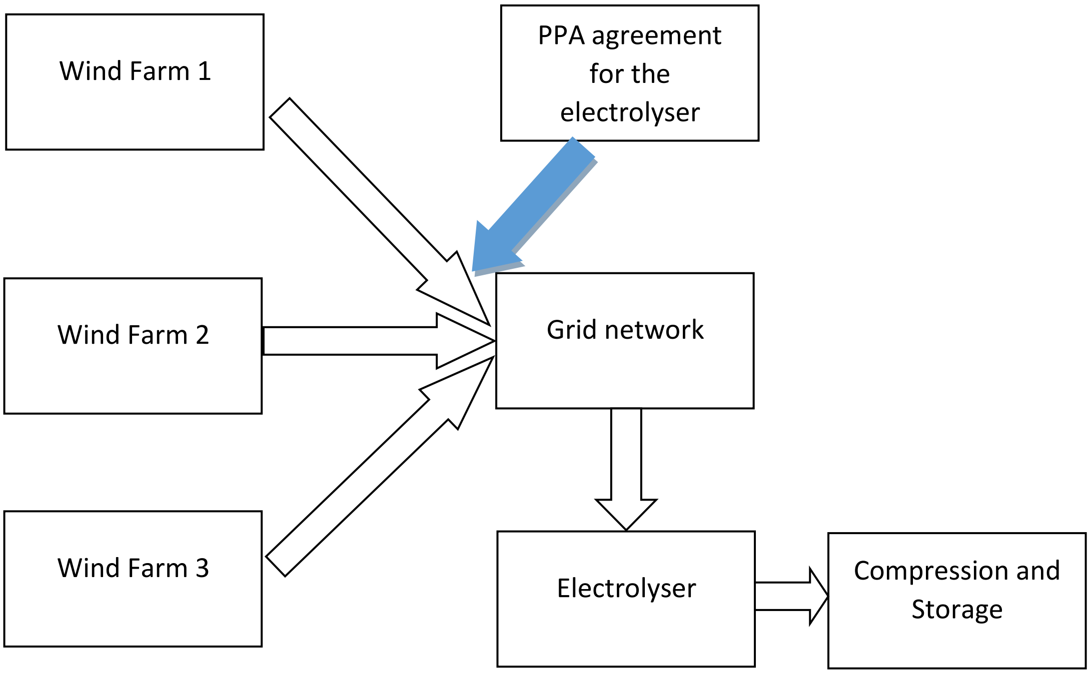
5.8 Scenario 4 – Cluster with Long Term PPA

Scenario 4 investigates the following:

'An electrolysis facility that produces hydrogen from electricity supplied by a cluster of Scottish onshore wind farms that sell a large proportion of their electricity to the facility via a long-term PPA.'

The data used for this particular scenario is the same as the one used for Scenario 2. Figure 5.11 illustrates the system that is investigated.

Figure 5.11 Scenario 4 - A 200 MW wind farm cluster with a PPA agreement for supplying electricity to the electrolyser



The aim of this scenario is to investigate the possibility of purchasing electricity in order to run the electrolyser for most of the time during the year. The scenario must not be confused with Scenario 3 where the selected electrolyser was scaled to match the size of a single wind farm.

In this case, the electrolyser size is a fraction of the size of a cluster of wind farms. As such, the electrolyser will operate most of the time. Therefore it is anticipated that the CAPEX and OPEX cost should not have a significant impact on the cost of hydrogen per kilogram.

In common with Scenario 2, the electrolysis system is scaled to maximise production and maintain a high electrolyser utilisation. The difference between the two scenarios is that in Scenario 2 only curtailment power was used to power the hydrogen system.

In Scenario 4, the aim is to have the size of the electrolyser small in comparison to the wind farm, but large enough to produce significant amount of hydrogen so that CAPEX and OPEX are manageable within the overall project budget.

Therefore, with this approach, a 10 MW electrolyser installation is considered. This electrolyser is large in comparison to units currently available on the market, however, 10MW hydrogen systems are now possible and seen as being a routine installation by the industry.

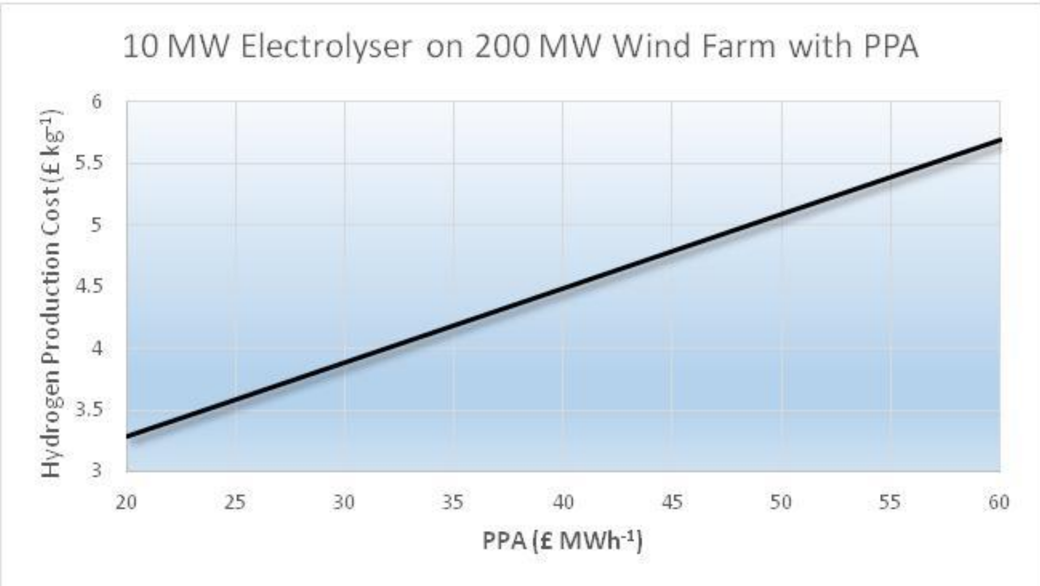
However, when associated with a large wind farm or a cluster of wind farms (in this case a 200 MW cluster), the electrolyser is relatively small. As mentioned above, the small size of the electrolyser in comparison with the wind farm means that the electrolyser will operate most of the year (as long as there is some wind, even at low yield, the combination of the wind turbines would easily be able to provide 10MW of power).

Therefore, the electrolyser will be taking electricity whenever it is available, which will be paid for through a long-term PPA.

Using the data collected from a cluster of turbines (same data as Scenario 2), the energy available to the electrolyser is 83,695 MWh per annum. This means that the capacity factor of the electrolyser is 95.5% (almost 100% production throughout the year), which is due to the electrolyser having priority despatch. The only times the electrolyser would be shut down is when the wind speed at hub height is below cut-in speed. This is equivalent to 2.5 m/s or less at ground level. It should be noted that in Scotland this occurs on average less than 5% of the time[20].

Using the wind data, the cost of electrolyser (CAPEX and OPEX) and the cost of electricity, the hydrogen cost per kilogram can be derived and is shown in Figure 5.12. Note that the payback period for this scenario is 10 years.

Figure 5.12 Cost of hydrogen versus the cost of purchasing all the electricity produced by the wind farm at different rates per MWh



5.8.1 Scenario 4 Conclusion

From Figure 5.12, it can be concluded that this scenario is the most effective way to generate green hydrogen of all the scenarios considered thus far. **Most importantly, it demonstrates that hydrogen produced from onshore wind can be economically viable.** Even when buying electricity at £60 per MWh, the price per kilogram of hydrogen is below £6. This price is based on today's hydrogen installation costs and not potential future costs. Therefore, as the cost of hydrogen installations falls in the future, the cost for producing hydrogen per kilogram will also drop.

[20] https://www.metoffice.gov.uk/services/data-provision

The cost of producing hydrogen as found under this scenario is in line with what the market is prepared to pay for hydrogen per kilogram. However, it should be noted that Scenario 4 does not consider costs associated with grid network charges that may be needed to support the connection of a large-scale electrolysis unit. It has been assumed that hydrogen is produced through either a private wire connection or directly connected behind the meter, but these costs have not been factored into the model. As previously stated, the aim of these scenarios is to ascertain whether hydrogen production would be viable under the best conditions, rather than to calculate a fully costed £/kg price.

As the cost of hydrogen has been proven as viable here, it is required to further investigate both the cost of a private wire and the charges if the grid network is used to transport the electricity to the hydrogen system.

It should be highlighted that the proposed solution does not really address intermittency, although it would allow some electricity to be used for hydrogen production even when the wind farm is subject to is curtailment. Nevertheless, because the size of the wind farm is large (200MW) relative to the size of the electrolyser (10MW), the effect on curtailment is relatively limited.

Also, the impact of taking away the most reliable electricity for use by the electrolyser would need to be assessed, as it will affect the value of the remaining (highly variable – see Figure 5.9 right) electricity for export to the grid. However, it is anticipated the impacts would be very minimal for this scenario as the size of the wind farm is very large relative to the electrolysis plant.

The additional cost in moving electricity from the wind farms to a single central site also has to be considered (as per the above comment on private wire). However, if the geographical distances between the wind farm's cluster are manageable, then this should not have a substantial cost impact over the lifetime of the system. If these distances are high, then a study must be completed to define the best option for the electrolyser location and if the private wire is the most cost-effective solution.

5.9 Scenario 5 – Ferry Application

Scenario 5 investigates the following:

'An electrolysis facility built as part of a new onshore wind project that incorporates the sale of green hydrogen as a core constituent of its business model'

The scenario examines a scheme for producing green hydrogen that has a reasonable likelihood of being commercially viable. It has already been noted in Scenario 4 that, by linking an electrolyser to a large wind farm and giving priority to hydrogen production, hydrogen can be produced at a competitive price.

To this end, a large consented wind farm cluster in the Western Isles of Scotland is investigated. This farm cluster has been selected because:

- Construction is dependent on CfD success in round 3 (2019).
- If the CfD is not successful, there is a need to identify other innovative means of financing the projects. Hydrogen could provide such a solution by purchasing the electricity generated by the wind farms through a long-term purchase contract. Hydrogen fuel could then be sold to a third end-user party.
- There is a grid connection available to the mainland UK, but the connection is already saturated. As such, there is a need for a new sea cable to be laid.
- There is no guarantee that a new subsea cable will be installed for the transmission of power from the Western Isles to the mainland UK. As per point 2 above, there is a need to investigate other means to use the wind electricity generation. Hydrogen is considered as a potential energy storage mechanism for the wind generation.
- A number of potential uses of hydrogen are available. For instance, it may be possible to link up with a project that is investigating the addition of a hydrogen ferry to the Stornoway-Ullapool route[21]. The Leverburgh-Berneray route is also viable.
- There are hydrogen skills available in the Western Isles both at the Council (hydrogen development and permitting skills) and College level (hydrogen teaching, training, designing). In addition, hydrogen production systems have been installed and are available for hydrogen testing and development.

The wind farm cluster modelled under Scenario 5 comprises EDF's 180 MW Stornoway Wind Farm[22] and 162 MW Uisenis Wind Farm[23] projects. Data for this scenario were acquired from a nearby site as the selected wind farms have not yet been built. The wind resource in the region is excellent and excluding unscheduled down time (curtailment/faults) a capacity factor in excess of 45% is achievable.

Figure 5.13 illustrates the system that is investigated.

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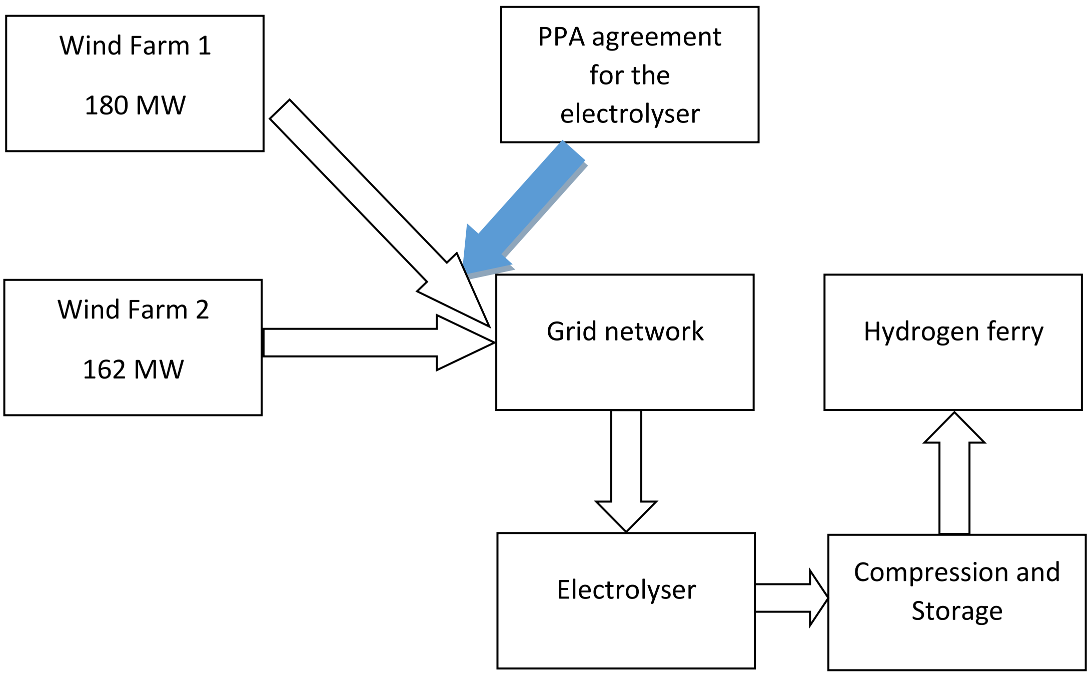
[21] http://www.bbc.co.uk/news/uk-scotland-highlands-islands-43140326
[22] http://www.stornowaywind.co.uk/
[23] http://www.stornowaywind.co.uk/2016/09/lewis-wind-power-buys-uisenis-wind-farm/

Figure 5.13 Scenario 5 - A 342 MW wind farm cluster with a PPA agreement for supplying electricity to the electrolyser and a hydrogen ferry that will use hydrogen as fuel



There are two main aims within this scenario:

1- To investigate whether the wind farm cluster is large enough to produce sufficient fuel for the hydrogen ferry.
2- To define if the hydrogen fuel can be produced at an affordable price without jeopardising the financial viability of the wind farm.

In summary, this scenario aims to define an acceptable size of wind farm to supply a hydrogen ferry, rather than fitting the scale of the electrolyser to the size of the wind farm (as studied in previous scenarios). The questions that will be addressed are:

(1) What size a wind farm should be to supply a ferry with ample fuel?
(2) What would be the price of hydrogen per kg in order to make the project viable?
(3) How does the price of electricity impact on the end price of hydrogen?

As per the previous scenarios, a key requirement is that hydrogen is available at low production cost and is also available for a high percentage of the time. It is assumed that the electrolysis unit will be located close to the electrical grid network transmission / distribution lines that will form part of the wind farm project costs. It is also assumed that hydrogen transportation costs to the chosen ferry terminal will be minimal as the electrical infrastructure where the hydrogen system will be connecting to exists near the pier (in this case, it is assumed that the cost for transporting hydrogen is negligible). Excluding the cost of transporting hydrogen will allow the model to determine whether hydrogen fuel production on its own is economically viable. If found economical, then the cost for transporting hydrogen can be included in the model and optimal distances investigated.

In addition, it is assumed that the ferry's engine technology is a hydrogen-powered Internal Combustion Engine (ICE) rather than a fuel cell with an electric motor drive train.

ICE technology can also be converted to run on hydrogen at an affordable price[24].

Complete fuel consumption data for Scottish ferries were acquired from the Scottish Government[25] official figures. The Ullapool to Stornoway ferry route was selected for investigation using the data from the MV Loch Seaforth, which travels the route twice daily and consumes a total of 20,000 litres of diesel per day.

Equal energy conversion efficiency between the diesel and hydrogen is assumed. In energy terms, this means that 1 kg of hydrogen is equivalent to 4 litres of diesel[26]. As such, considering 20,000 litres of diesel required per day for the ferry journeys between Ullapool and Stornoway, there is a need to produce 5 tonnes of hydrogen per day for an equivalent hydrogen powered craft.

To answer the first question posed above — ***'What size a wind farm should be to supply a ferry with ample fuel?'* —** there is a need to size the electrolyser facility to match the production requirement. i.e. the electrolyser must be able to produce 5 tonnes of hydrogen per day.

Initial calculations indicated that an electrolyser of 15 MW in size is sufficient to produce the fuel needed by the ferry. From this, a model was produced to simulate whether the selected size of electrolyser unit could produce the required quantity of fuel all year around.

The model was run over a one year period. It showed that there is a significant variation in hourly hydrogen production, but by employing a 15 MW electrolyser and 5 days of storage capacity, it is possible to supply all the energy required. The graph shown below (Figure 5.14) illustrates these findings and the following table (Table 5.1) summarises the key assumptions made in the model.

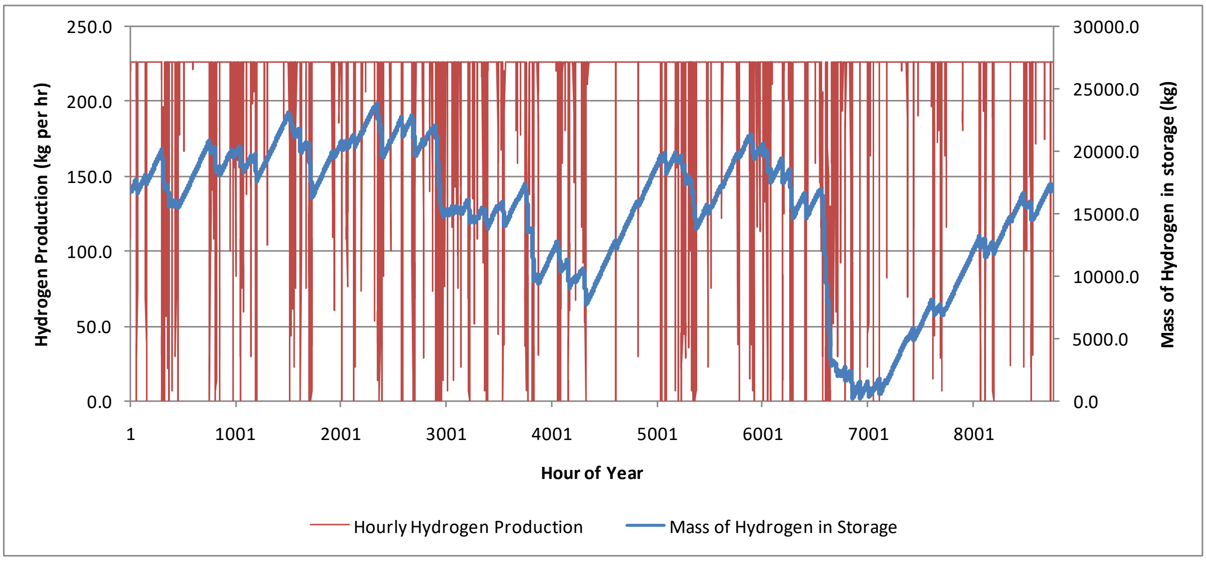
Table 5.1 – Key assumptions for the hydrogen fuelled ferry model

Electrolyser Capacity	15.0	MW
Conversion Efficiency	60	%
Average Daily Hydrogen Production	5000.3	Kg
Daily Demand	5000.0	Kg
Maximum Storage Capacity	24000.0	Kg
Initial Quantity in Storage	17000.0	Kg

Other assumptions include borrowing rate (nominal 6%), payback time (nominal 20 years), OPEX as a function of hydrogen production (nominal £0.50 kg^{-1} for a large-scale system as per above scenarios) and £2.5 m per MW electrolysis system total installed cost (including compression and small-scale storage).

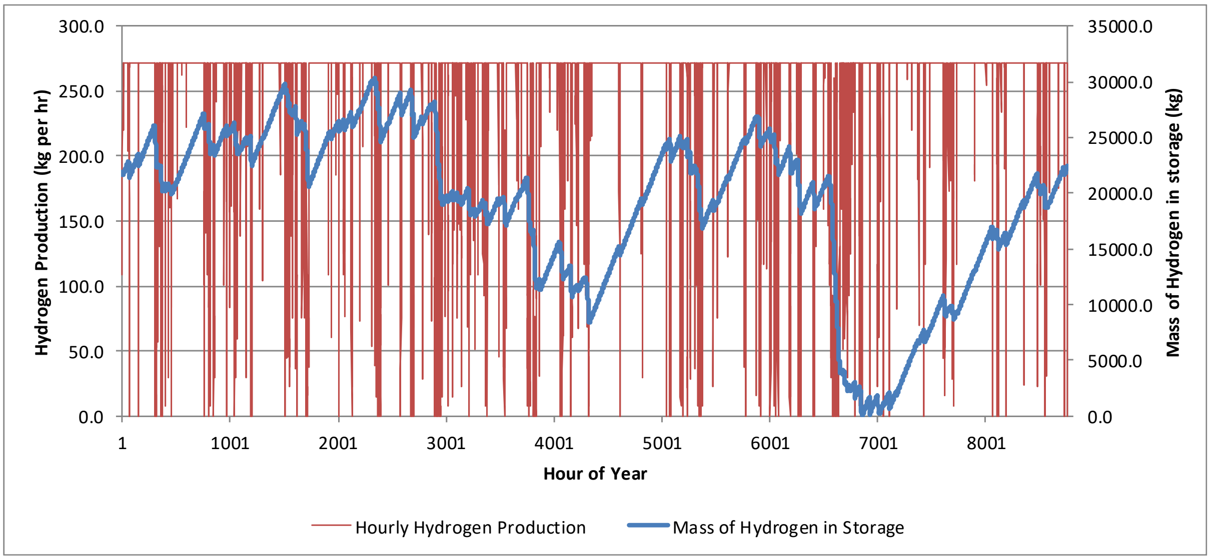
[24] See http://www.fch.europa.eu/sites/default/files/FCH%20Docs/171121_FCH2JU_Application-Package_WG3_Ferries%20%28ID%202910573%29%20%28ID%202911659%29.pdf for up-to-date information about FCH hydrogen ferries.
[25] http://www.gov.scot/resource/doc/935/0105733.pdf
[26] The energy content of hydrogen is 143 MJ/kg and diesel is 36-42 MJ / kg. The ratio is about 4.

Figure 5.14 Scenario 5 - A 15 MW electrolyser operating from a 342 MW wind farm with a 24 tonne storage system



For a real, on the ground, practical installation to be deemed viable, there is a need to take into account year by year variations in wind regimes. As such, there is a need to include a contingency for both production and storage. For these reasons, the electrolyser facility has been increased and rated at 20 MW. The storage system now has the ability to store 30 tonnes of hydrogen. The model results are shown in Figure 5.15 below.

Figure 5.15 Scenario 5 - A 20 MW electrolyser operating at the back of a 342 MW wind farm with a 30 tonnes storage capacity



The above figure shows that by increasing the electrolyser size to 20 MW and the storage to 30 tonnes, the system can meet demand and account for seasonal variations. The model assumes that the hydrogen system has been operating for some time prior to filling the ferry. The initial amount in the storage is, therefore, not relevant as the above figure illustrates that the storage depletes for only a short time within the 12 months of operation and replenishes to a level that is acceptable faster than the previous electrolyser and storage system. As such, the above graphs (Figure 5.14 and

Figure 5.15) illustrate that some level of contingency is required during planning of the hydrogen installation.

Note that storing fuel on a ferry vessel for two daily return crossings could prove to be challenging from a design perspective. For instance, to store 5 tonnes of hydrogen for one day, even at a pressure of 700 bar takes up a lot of space[27] (approximately 80 m^3). This would need to be considered in the design and construction of a hydrogen ship (ferry, fishing boat, outboard, inboard vessels, etc.).

On the other hand, it is possible to anticipate building a ferry with a fuel tank capacity of 1.25 tonnes of hydrogen rather than a 5 tonne capacity. In this case, it is assumed that the ferry can be refuelled at both Stornoway and Ullapool (4 times a day). However, fast filling such an amount of hydrogen would require a large amount of cooling, a production site, a filling station, safety systems and logistics (transport of hydrogen) at both ends. This would increase the CAPEX and OPEX of the installations and may lead to the non-economical viability of the hydrogen ferry, unless the production sites are part of other local hydrogen requirements.

In addition, for safety reasons and reduction on cooling requirements, it would be better to refuel at night time when there are no passengers in the area, and to fill with all the fuel required for 24 hours. Finally, there is a need to have some spare hydrogen capacity on the ferry – there have been times when the ferry has had to turn back because of adverse weather conditions. This needs to be considered in the design.

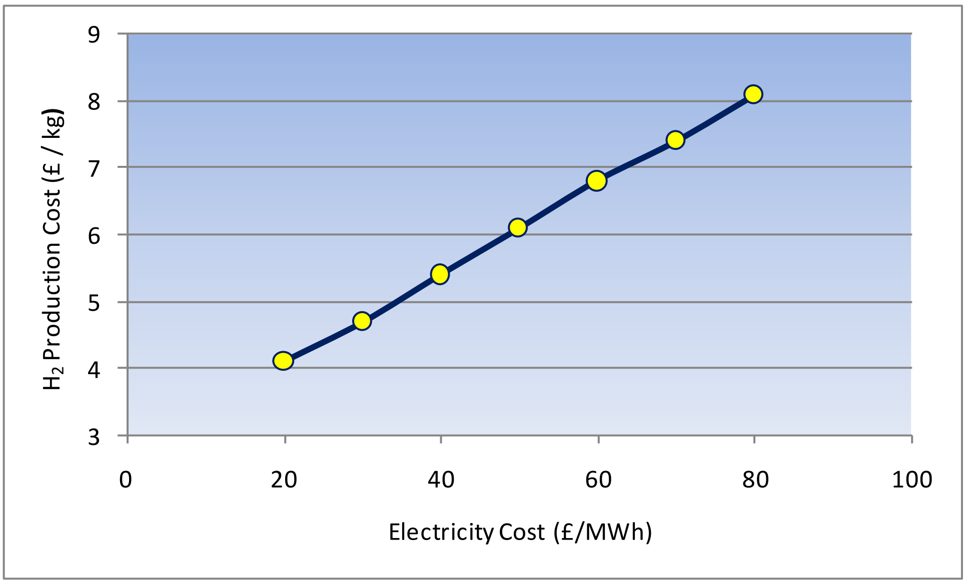
Practical issues with space on a ferry and the cost for a storage system may mean that hydrogen fuelled ferries are initially focused on shorter routes and smaller vessels for pilot projects. For instance, the storage cost is estimated at £400[28] kg^{-1} or £12 m for the stationary hydrogen 30 tonne storage. This storage cost is included in the model that answers the remaining two questions posed for this scenario: '***What would be the price of hydrogen per kg in order to make the project viable?';*** and ***'How does the price of electricity impact on the end price of hydrogen?'***.

Using the aforementioned assumptions, the graph below (Figure 5.16), shows how the hydrogen price varies with electricity costs:

[27] If 1 kg of hydrogen occupies about 11 m^3, then 5 tonnes @ 700 bar will occupy approximately 11 x 5000 / 700 = 78.5 m^3 (the product PV is constant for isothermal compression).

[28] https://www.hydrogen.energy.gov/pdfs/review16/st100_james_2016_o.pdf

Figure 5.16 Scenario 5 – Price of hydrogen per kg from a 20 MW electrolyser operating at the back of a 342 MW wind farm with a 30 tonnes storage system and electricity cost variation from £20 MWh^{-1} to £80 MWh^{-1}



5.9.1 Scenario 5 Conclusion

In this scenario, the electrolyser has been sized to fit the fuel requirements of a hydrogen ferry serving the route between Ullapool and Stornoway. This route is currently served by the *MV Loch Seaforth*, which is Caledonian MacBrayne's largest ferry in terms of length (117.9m) and one of the largest in terms of capacity, able to accommodate up to 700 passengers and 143 cars or 20 commercial vehicles. The electrolyser size is a fraction of the size of the 342 MW wind farm. In fact, the electrolyser size can be defined as **"a small electrolyser"** - 20 MW in size when compared to the wind farm size. Therefore, it is possible to conclude that there is no need for a medium to large scale electrolyser to supply the largest of Caledonian MacBrayne's ferries.

Similarly, there is no need to build a large-scale wind farm to fuel a hydrogen ferry that uses the equivalent of 20,000 litres of diesel a day (5,000 kg H_2), however, there is a need for the electrolyser to have priority access to the wind farm's power output[29]. In this scenario, as the electrolyser is small in comparison to the wind farm, it will operate most of the time. Therefore, the CAPEX and OPEX cost of the hydrogen system does not have a significant impact on the cost of hydrogen per kilogram.

In other words, Scenario 5 is similar to Scenario 4, where the size of the electrolyser is small in comparison to the wind farm, but large enough to produce a significant quantity of hydrogen. The system is able to supply fuel to the ferry and at the same time the hydrogen system's CAPEX and OPEX are manageable within the overall project budget (considering that the cost of constructing Stornoway and Uisenis wind farms is likely to be in the order of £400m). Like Scenario 4, the 20 MW electrolyser is large in comparison to units currently available on the market, but small in size when compared to the wind farm.

[29] This will slightly reduce the reliability of the remaining electricity generated by the wind farm, but this is not a serious issue as price is not presently associated with (or dependent on) how variable the supply is.

From Figure 5.14 and Figure 5.15, it can be seen that the storage system depletes towards the end of the year due to lack of wind, but recovers quickly thereafter when there is more wind resource. This is why the size of the electrolyser selected for this scenario was increased from 15 MW to 20 MW, and the storage capacity from 24 tonnes to 30 tonnes. This provides a good contingency at times of low wind, but also during times of substantial wind generation throughout the year. The 20 MW electrolyser will allow replenishing the storage system to be achieved much more quickly and the 30 tonne storage capacity will improve energy security, providing an extra day of fuel available to the ferry thus reducing the risk of no fuel availability and all the potential detriments this incurs for passengers and freight.

From the data collected, the capacity factor of the 20 MW electrolyser is calculated to be 90.1%. This is due to the electrolyser having priority despatch, and the size of the electrolyser being relatively small compared to the wind farm. The only time the electrolyser would be shut down is when the wind speed at hub height is below cut-in speed. Note: The wind speed in the Western Isles is lower than 2.5 m/s for less than 5% of the time. The 342 MW wind farm will only produce 20 MW in total when the wind speed has reached almost 4 m/s. Up to that point the electrolyser is running at less than 100% capacity, hence the 90.1% figure provided.

Figure 5.16 has been produced using the available wind data, the cost of electrolyser (CAPEX and OPEX) and the cost of electricity. From this Figure 5.12, it can be concluded that if the wind farm operators are paid £50 per MWh, the hydrogen price per kg will be £6.10. This is equivalent to a road diesel fuel cost at the pump of £1.50 per litre (1 litre of diesel ~ 36 MJ. 1 kg of hydrogen when burnt is 143 MJ. 1 kg is equivalent to 4 litres diesel hence equivalent diesel cost is £6.10 / 4 = £1.50).

The CAPEX for this scenario is high and requires an initial investment of £62 million. The OPEX is also high, although given the scale of the installation and its CAPEX cost, it can be considered moderate at around £1.2 million per year. Using these costs and an electricity price of £50 MWh^{-1}, the payback period is just over 19 years. While the cost of producing hydrogen under this scenario is in line with what the market could be prepared to pay for as an initial price for green hydrogen per kilogram, at £6.10 kg^{-1}, it will be difficult to deploy such a system due to the long payback time. This is also due to the fact that marine diesel is three times cheaper (£0.50 per litre) than road diesel (£1.50 per litre). To be competitive in the marine sector, hydrogen must be sold at around £2 per kilogram (this corresponds to the price of £0.50 for 1 litre of diesel equivalent as sold to ferry operators). Therefore, there could be a need for public sector intervention to reduce the financial risk and support the uptake of the hydrogen fuel within the maritime sector.

In this scenario, the costs for water treatment and payment for water supply to the electrolyser have been taken into account. The cost of grid network charges for connecting the electrolysis unit to the wind farm are not applicable in this instance, as it assumed the system would be installed behind the meter of the wind farm. The private wire connection costs have not been included – the distance is small and a precise cost depends on location. In any case, the effect of the private wire on calculations is negligible because the distances are short.

Finally, this model shows that there is no need for a large-scale electrolyser to fuel the Ullapool to Stornoway ferry in the Western Isles. As discussed, a 20 MW electrolyser is fairly small in comparison to the 342 MW wind farm cluster selected for this scenario. As such, the remaining power from the wind farm has been modelled to see if it is enough to supply all of the Western Isles ferries, which is explored in Scenario 5-1.

5.10 Scenario 5-1 – Fuelling all ferries

This scenario extends the Scenario 5 model to include the powering of all ferries in the Western Isles with green hydrogen. This results in higher CAPEX and OPEX and also adds costs associated with the need to transport hydrogen[30] to the points of use. However, it is assumed that there will be a reduction in the hydrogen system CAPEX costs because of the savings associated with scaling up. It is assumed that mass manufacture will reduce by 10% the cost of hydrogen systems per MW of installed capacity.

For instance, in previous scenarios it was assumed that the cost for a 1 MW electrolyser was £2.5 million. Under this scenario the cost for a 1 MW electrolyser is £2.25 million (2.5 million – (10% x 2.5 million)). The same discount is used across all hydrogen equipment considered for this scenario.

There are four Western Isles ferry routes in addition to the Stornoway to Ullapool route, as shown below in Table 5.2.

Table 5.2 – Other ferry routes in the Western Isles

Route	Kg H_2 per Day
Uig to Tarbert/Lochmaddy	4,100
Barra to Eriskay	520
Berneray to Leverburgh	1,450
Oban to Castlebay/Lochboisdale	4,800
Total	**10,870**

The above total is added to the Stornoway to Ullapool route, which results in a total requirement of almost 16 tonnes of hydrogen per day to operate all Western Isles ferry routes using hydrogen powered vessels. To produce this quantity of hydrogen, the size of the electrolyser must be a minimum of 40 MW, assuming an ideal 5 kWh per Nm^3 of hydrogen production.

Taking into consideration electrolyser losses (in real life the efficiency is likely to be 5.5 kWh per Nm^3) and providing some contingency, the size of the electrolyser system required to produce enough hydrogen per day is actually 55 MW. Each day, the electrolyser system will be required to produce around 192,000 Nm^3 of hydrogen. To do so, the capacity of the electrolyser should produce about 8,000 Nm^3 per hour.

This electrolyser can be defined as a **'large scale system'** as only a few of these currently exist around the world. One disadvantage of increasing the size of the electrolyser and using the same 342 MW wind farm cluster is a drop in capacity factor from 90.1% (for the 20 MW electrolyser system) to 80.1% (for the 55 MW electrolyser system). The reason for this drop is the reduction in the availability of wind generated electricity for electrolysis, which reduces relative to the average capacity factor of the wind farm as the electrolyser size increases.

Another issue is the quantity of storage needed to ensure a continuity of supply, which results in basic storage costs increasing from £12 m to £48 m. The key assumptions and results from the model are shown below in Table 5.3:

[30] Ideally it should be moved by trucks that are themselves powered by hydrogen.

Table 5.3 – Model results summary for fuelling all Western Isles ferries

Electrolyser Capacity	55.0	MW
Conversion Efficiency	60	%
Average Daily Hydrogen Production	15988.2	kg
Daily Demand	15870.0	kg
Maximum Storage Capacity	120000.0	kg
Initial Quantity in Storage	77500.0	kg
Electrolyser Capacity Factor	80.1	%

Other assumptions factored into the model include borrowing rate (nominal 5.5%), payback time (nominal 20 years), OPEX as a function of hydrogen production (nominal £0.45 kg^{-1} for a large-scale system as per above scenarios) and £2.25 m per MW electrolysis system total installed cost (including compression and small-scale storage). The large size of the hydrogen system — both in technical and financial terms —opens up the potential for discussions and negotiations on the cost of project finance. Therefore, a 5.5% interest rate is reflected in the model rather than the 6% rate applied to the other scenarios.

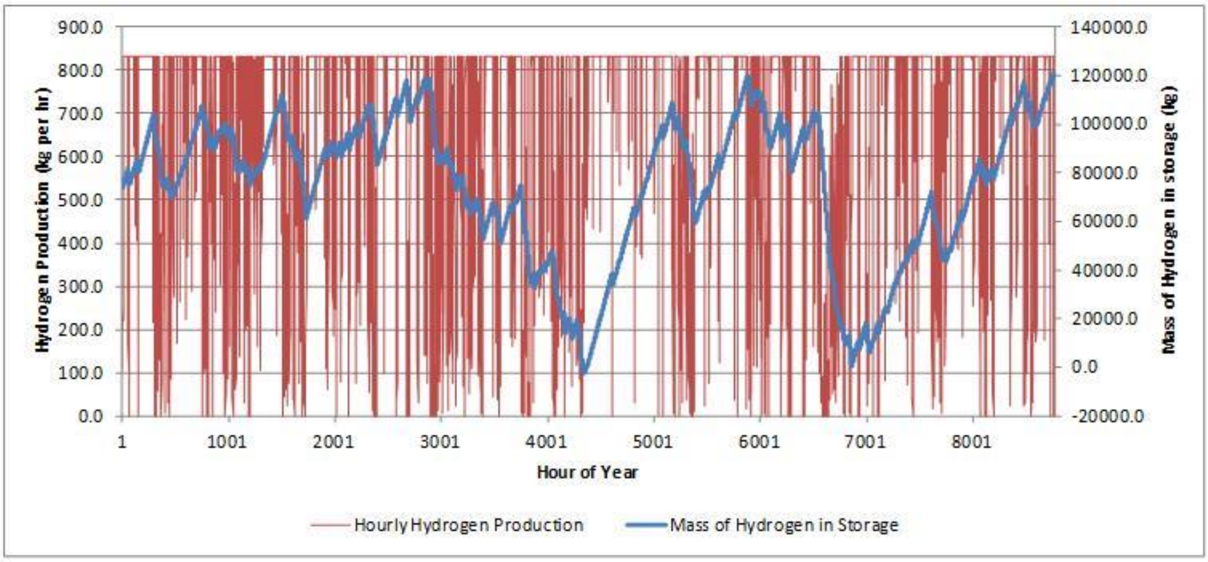
This scenario also introduced a need to transport hydrogen to the points of use by the ferries. To do so, a £500,000 budget has been added for a trailer truck with £100,000 annual running costs. These are nominal costs are explored in detail in Section 6 of the report[31].

The Scenario 5-1 model was run over a one year period. It showed a significant variation in hourly hydrogen production, but found that a 55 MW electrolyser and 8 days of storage capacity (120 tonnes) was adequate to supply the energy requirements of the Western Isle ferry routes throughout the year.

The graph shown below in Figure 5.17 illustrates these variations where hydrogen stored drops to near zero kilograms twice in a year (just after the half a year mark and about three quarters of the way through the year). The graph also shows that the hydrogen storage system only fills up once to its maximum capacity (and twice it is near full capacity). This means that it is desirable to further increase the size of the electrolyser to allow for more contingency. The alternative is to potentially import hydrogen when the store falls to a low level.

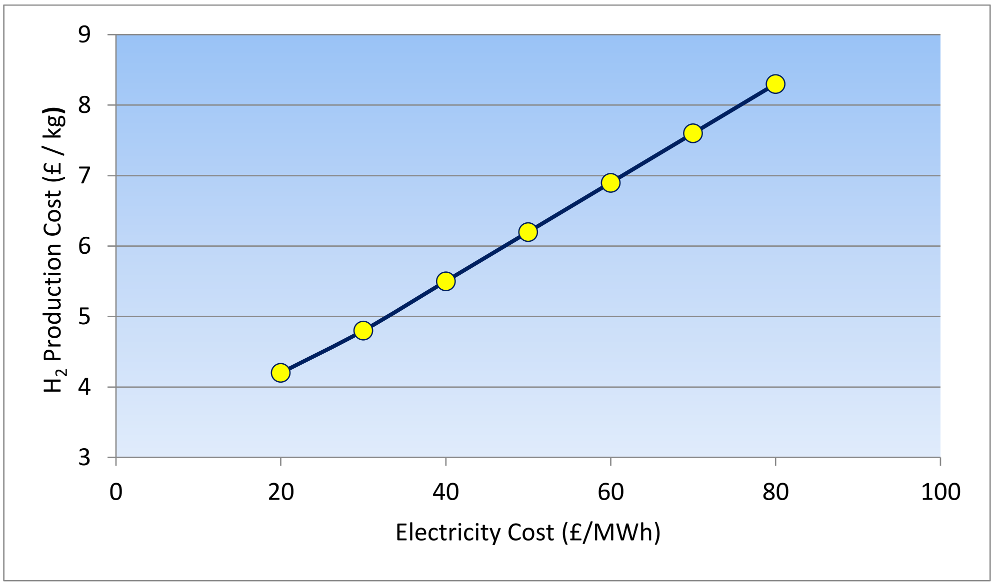
[31] It may be that distributed hydrogen production may be cheaper and easier than transporting hydrogen by road, but this presupposes the existence of an appropriate electricity transmission infrastructure between ports. This would require detailed investigations on a case by case basis.

Figure 5.17 Scenario 5.1 - A 55 MW electrolyser operating at the back of a 342 MW wind farm with a 120 tonnes storage system



With the above assumptions, it is possible to define the price of hydrogen per kilogram to supply all of the Western Isles ferries. This is shown in Figure 5.18

Figure 5.18 Scenario 5.1 – Price of hydrogen per kg from a 55 MW electrolyser operating at the back of a 342 MW wind farm with a 120 tonnes storage system and electricity price varying from £20 MWh^{-1} to £80 MWh^{-1}



5.10.1 Scenario 5-1 Conclusion

In this scenario, the electrolyser has been sized to fit the fuel requirement for all of the Western Isles ferry routes. The electrolyser size is 55 MW, which is 2.75 times larger than the one sized for fuelling the Ullapool to Stornoway ferry.

Similarly, the price for hydrogen per kilogram is higher at £6.20 per kilogram for an electricity payment of £50 per MWh, where it was £6.10 per kg for the single ferry scenario (from Ullapool to Stornoway). This is true even though the interest rates considered for Scenario 5-1 are lower and 10% economy of scale was taken into account. The reason for this is the requirement for a much larger storage system and the lower capacity factor of the electrolyser, which decreases from 90.1% to 80.1%.

The total CAPEX for the project is over £162 million and the OPEX is £2.6 million per year. Assuming these CAPEX and OPEX costs and electricity price of £50MWh^{-1}, the payback period is just over 19 years.

Although the cost of producing hydrogen under this scenario is in line with the price the market may be willing to pay for green hydrogen, at £6.20 kg^{-1} from buying electricity a 50 per MWh, it will be difficult to deploy such system due to the long payback time.

A cost of £6.20 per kilogram of H2 is almost equivalent to the price of £1.50 per litre of road diesel fuel at the pump. Again, and as per the Stornoway-Ullapool ferry, this scenario will be challenging to set up due to the fact that marine diesel is three times cheaper (£0.50 per litre) than road diesel (£1.50 per litre). Hydrogen would need to be priced at around £2 per kilogram if it is to compete with marine diesel prices as paid by ferry operators (currently marine diesel is sold at £0.50 per litre and at times it is cheaper). Therefore, fuelling a ferry with green hydrogen would require public sector intervention to reduce the financial risk or subsidise the sale price of the hydrogen. At £6.20 per kg, the hydrogen revenue reaches £36.18 million per year. If sold at marine diesel equivalent prices, then the revenue will only be £12.06 million per year (1/3rd of the price for road diesel equivalent).

From Figure 5.17, it can be seen that the storage system depletes twice during the year, but recovers quickly thereafter. This is why there may need to increase the size of the storage system, thereby increasing costs and resulting in a longer payback period.

The costs for a water treatment and payment for supplying deionised water to the electrolyser have been taken into account. The costs associated with the grid network charges have not been considered and it was assumed the hydrogen system is to be installed behind the meter of the wind farm.

Finally, this scenario shows that all of the ferries can be fuelled from the 342MW wind farm electricity. However, there is still renewable power available that could be used for more hydrogen fuelled applications. For instance, it is possible to consider fuelling all of the Western Isles buses and investigating the size of the electrolyser required for this purpose (all of the ferries and buses on the islands). This is described in the following section.

5.11 Scenario 5-2 – Fuelling all ferries and all buses

As shown in the previous section, there is a possibility that an electrolyser can be sized up behind the meter of the 342 MW wind farm to supply all of the Western Isles ferries and buses with green hydrogen.

In essence, if this is developed, most of the ‘large’ fuel consuming applications within the public transport sector in the Western Isles would be fuelled using green fuel, thereby reducing emissions, increasing energy security, supporting the deployment of renewables and potentially increasing the financial viability of the transport sector in remote locations.

In effect, if there is no need to import hydrocarbon fuel, and it is possible to produce it locally, this may mean that every pound generated in the community is potentially re-invested in the community, thus making the community wealthier in the long run.

To investigate this scenario, the number of bus journey miles per day is estimated from the Western Isles timetables to be 9,000 miles. From this, it is possible to define the hydrogen requirements to fill the buses. The Aberdeen Hydrogen Bus Project is used as a reference point to define the hydrogen consumption needs.

Table 5.4 shows the performance up to January 2017 of part of the European hydrogen bus fleet[32].

Table 5.4 – European hydrogen bus fleet performance

STATUS january 2017						
Location	Project	# buses	# km driven	# kg H2 fuelled	# tons of CO2 emission avoided	# litres of Diesel saved
Aargau**	CHIC	5	1 308 601	115 792	1398	523 440
Bolzano	CHIC	5	680 146	59 627	726	272 058
Cologne***	CHIC	4	1 579 485	39 987	1687	631 794
Hamburg	CHIC	6	500 889	43 721	535	200 356
London	CHIC	8	1 439 682	133 949	1538	575 873
Milan	CHIC	5	199 875	20 709	213	79 950
Oslo	CHIC	5	589 554	78 278	630	235 822
Berlin*	CHIC	4	898 477	205 188	960	359 391
Aberdeen (First)	HighVLOCity	4	311 188	27 053	332	124 475
Antwerp	HighVLOCity	5	163 866	10 929	175	65 546
Aberdeen (Stagecoach)	HyTransit	6	576 332	45 203	616	230 533
Karlsruhe	KIT	2	199 762	14 499	213	79 905

The above results in Table 5.4 suggest that 78 kg per 1,000 km is required (using the figures for the 6 Aberdeen Stagecoach buses). As such, for the Western Isles buses, an additional 1,100 kg of hydrogen would be required each day. This has been incorporated into the model.

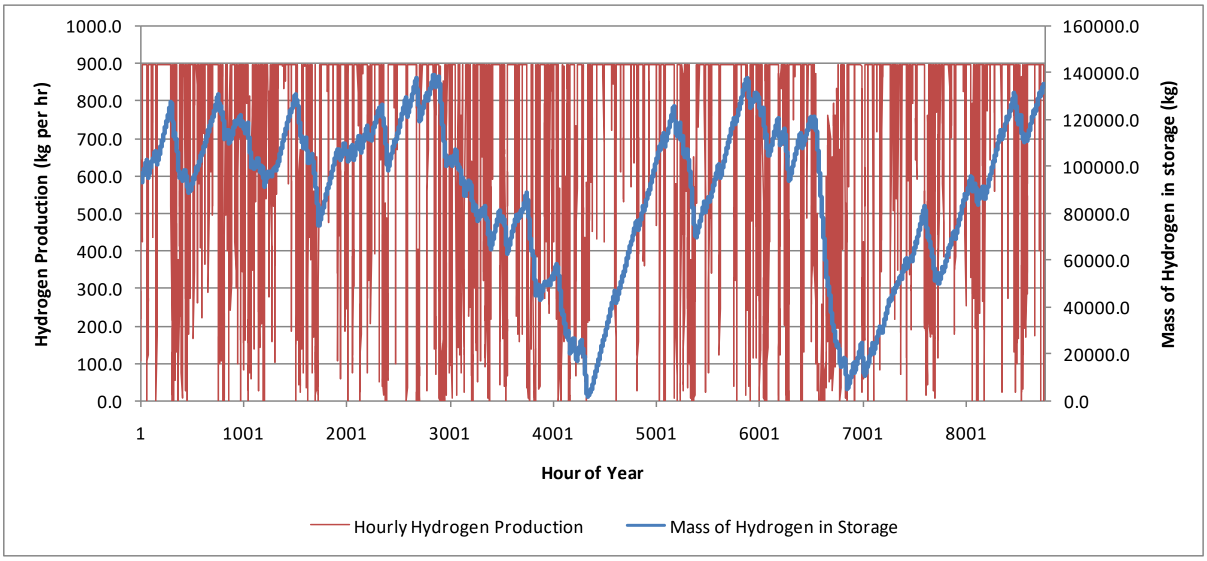
The size of the electrolyser is now almost 60 MW. The electrolysis system will then take 31.9% of the energy produced by the 342 MW wind farm, equivalent to diverting 109 MW of installed capacity.

In summary, the 342 MW wind farm has an average power output of 147 MW, and the electrolyser has an average power input of 47 MW. The electrolyser draws on the equivalent of 109 MW of the total wind farm capacity.

The model shows the effect of a 20% CAPEX and OPEX reduction accompanying the larger scale of the project (20% reduction in CAPEX and OPEX is due to economy of scale). The model suggests a 60 MW electrolyser and 140 tonnes of storage is required. The below graph illustrates the storage capacity and the hydrogen production on a daily basis for a one year period.

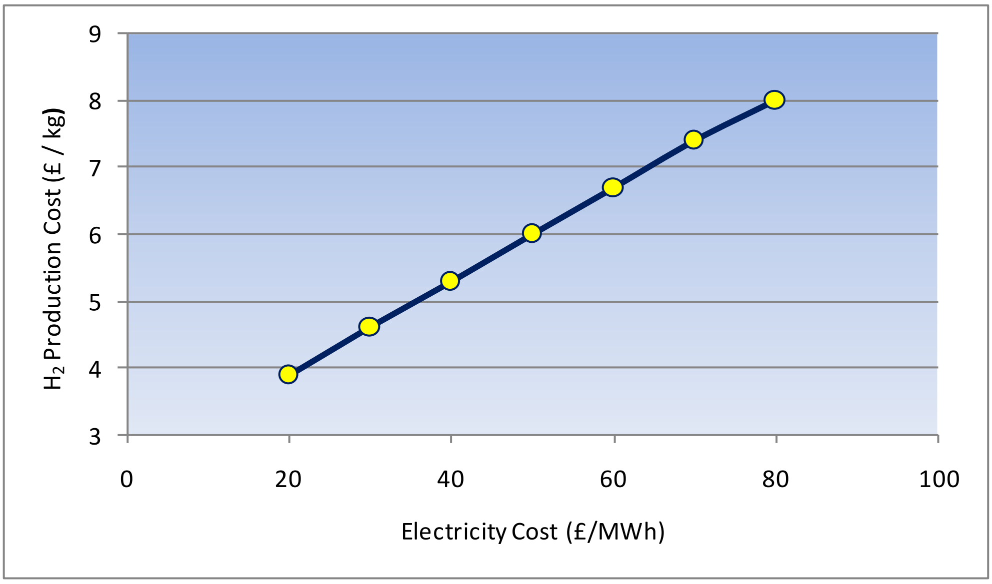
[32] http://www.fuelcellbuses.eu/category/performance-data-0

Figure 5.19 Scenario 5.2 - A 60 MW electrolyser operating at the back of a 342 MW wind farm with a 140 tonnes storage system



The graph below illustrates the financial impact.

Figure 5.20 Scenario 5.2 – Price of hydrogen per kg from a 60 MW electrolyser operating at the back of a 342 MW wind farm with a 140 tonnes storage system and electricity variation from £20 MWh^{-1} to £80 MWh^{-1}



5.11.1 Scenario 5-2 Conclusion

In this scenario, the electrolyser has been sized to fit the fuel requirement for all of the Western Isles ferry and buses routes. The electrolyser size is 60 MW and it is 3 times larger than the one sized for the Ullapool - Stornoway ferry.

This shows that the hydrogen required to satisfy the terrestrial transport is low when compared to the fuel requirements for the maritime sector. As such, adding a land transport solution – as a potential 'bolt on' – to a ferry maritime project has very little effect in the size of a hydrogen system. This is true for a remote community bus service, but may not be the case for a large community (i.e. a city with a large fleet of buses).

For instance, using the Ullapool to Stornoway ferry example, where the electrolyser is 20 MW in size, the addition of a 5MW electrolyser would be enough to supply all of the buses in the Western Isles. This would total a 25 MW electrolyser. However, the size of the electrolyser would need to be much larger to supply all of the Glasgow or Edinburgh buses.

In terms of the finance for the project, the price for hydrogen per kilogram is lower than the previous two ferry scenarios, at £6.00 per kilograms (instead of £6.10 for the Ullapool to Stornoway ferry and £6.20 per kilograms for Scenario 5-1).

This is due to a 20% economy of scale reduction in cost for both CAPEX and OPEX. It is also due to the fact that there is not a big difference in the electrolyser capacity factor, 79.1% in this model (compared to Scenario 5-1).

The interest rates are similar to the previous model sitting at 5.5%. Coincidentally, the total CAPEX for the project is just over £162 million with £2.5 million OPEX expenditures per year. This is almost the same as the figures in Scenario 5-1 (due to lowering CAPEX and OPEX by 20% when compared to Scenario 5).

Assuming the above CAPEX and OPEX costs and an electricity price of £50MWh^{-1}, the payback period is just over 19 years. As per the previous scenarios, the cost of producing hydrogen under this scenario is in line with what the market could be prepared to pay for green hydrogen at £6.00 per kg^{-1}. However, it could be difficult to deploy such system due to the long payback time without public sector support. As per the main scenario 5 and sub-scenario 5-1, the price of £6 per kilograms is well suited for road transport but not suited to marine fuel (as marine fuel is much cheaper than road fuel). As such, strategies would need to be developed to reduce the financial risk or supplement the sale price of the hydrogen. At £6.00 per kg, the hydrogen revenue reaches £37.4 million per year. However, if the sale price of marine diesel is considered (£0.50 per litre ≈ £2 per kg), then the equivalent revenue will drop to about £12.4 million per year.

The costs for water treatment and payment for supplying deionised water to the electrolyser have been taken into account and are low when compared to the overall project costs. The costs associated with the grid network charges have not been considered and it was assumed the hydrogen system is to be installed behind the meter of the wind farm.

Costs for transporting hydrogen from the production site to the end user site have been considered. These are minimal costs at £500,000 CAPEX, £100,000 OPEX. Once more, there is a need to develop a much more detailed model for transporting and delivering hydrogen to the point of use.

As per Scenario 5, there is still power available from the wind farm to supply other applications in the Western Isles. This leads to the overall conclusion that a large-scale island wind farm (or other form of large scale renewables, such as marine energy), could potentially supply an island's entire transport sector with renewably produced fuel, as well as additional power to meet local electricity demand.

5.12 Scenario 6 – Hospital Application

Scenario 6 investigates the following:

"An electrolysis facility that is powered by onshore wind and able to sell the by-products of electrolysis (i.e. heat and oxygen) in addition to green hydrogen".

This scenario investigates a wind farm site that requires extra local load demand to allow the deployment of onshore wind turbines. At the present time, the electrical network cannot accommodate any additional renewable generation due to stability constraints. The local electrical distribution network (which is on an island) is only connected to the mainland UK grid by a very small interconnector that is already operating close to its maximum capacity.

The selected site is near a hospital. This site aligns with Scenario 6 requirements for the sale of heat and oxygen by-products of the electrolyser to the hospital. This will bring extra income in addition to the sale of hydrogen, which this scenario assumes could be sold for use in transport applications such as buses, commercial and/or private vehicles.

The site for the onshore wind farm is located a couple of miles from the hospital. Two solutions have been modelled to supply the electrolyser with power from the 'semi-remote' wind site. The first model uses the utility electrical grid network to transport and deliver power to the electrolyser. The second model incorporates the cost of installing a private wire and transmitting the power via this link. Each of these proposed solutions adds an extra economical dimension to the modelling tool that was not taken into account for Scenarios 1 - 5.

As mentioned, the hospital is located on an island where there is a grid constraint and where the cost of importing oxygen is prohibitive and subjected to high emissions. The cost of fuel and energy in general is also high on the island when compared to other non-remote locations around Scotland and the UK.

In addition, there are a limited number of local jobs and industries, a small and fairly limited gas grid is used to supply a few inhabitants / businesses, and the islanders are heavily dependent on imports (some of which are subsidised). All of these factors accumulate to a higher cost of living and an increase in fuel poverty levels on the island in particular, and across Scotland in general.

Data for this scenario were acquired from the hospital for heat, electricity and oxygen. Figure 5.21 illustrates the system that is investigated.

Other points to be considered in this scenario are:

In the past decade, there has been a significant demand increase in the community to provide relief for those with lung diseases. Long-Term Oxygen Therapy[33, 34] (LTOT) improves survival, ability to function, and quality of life in hypoxemic chronic lung disease patients. The Nocturnal Oxygen Therapy Trial[35] (NOTT) and the British Medical Research Council[36] (MRC) trials together demonstrated greater survival directly relating to the number of daily hours of usage.

Note that a 1 kg of oxygen is equivalent to a volume of 700 litres at Standard Temperature and Pressure[37] (STP). The equivalent price of oxygen in bulk (6,800 litre cylinders) is £1.71 per kg[38]. A low

[33] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2629963/
[34] https://www.guysandstthomas.nhs.uk/news-and-events/2016-news/september/New-hope-for-patients-with-severe-lung-disease.aspx
[35] http://cochranelibrary-wiley.com/o/cochrane/clcentral/articles/319/CN-01262319/frame.html
[36] https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2676407/
[37] https://en.wikipedia.org/wiki/Standard_conditions_for_temperature_and_pressure
[38] https://www.boconlineshop.com/shop/en/uk/oxygen-cylinder-medical-grade-compressed-gas

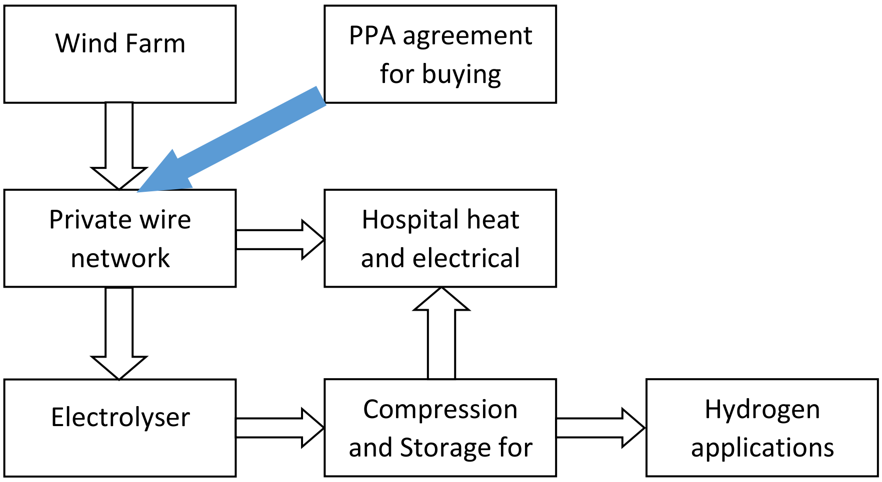
production and bottling price (£0.50 per kg) is considered in this scenario. This low cost means the gas can potentially be exported to other health regions. It would however be necessary to develop the distribution chain. Similarly, other oxygen applications should be investigated as green oxygen could be of value to a number of organisations.

Only 70% of the waste heat from the electrolyser is usable because the output temperature is low (~ 70 to 80ºC). Though the temperature is low, the excess electricity from the wind turbine can be used to increase the temperature to the required hospital heat levels. In this case, there will be no need for modifying the hospital current heating infrastructure, reducing technical and financial risks.

This scenario does not consider other applications for hydrogen at the hospital site. However, having hydrogen fuel on site could also lead to financial and CO_2 savings on a number of areas. For instance, a backup power supply based on a fuel cell or hydrogen internal combustion engine generator set could be installed. Such an addition would remove the current set up for diesel backup generators at the hospital, leading to an even higher decrease in import of fuel (and emissions).

Finally, the proposed hospital scenario may reduce (if not remove) the need for importing oil for heat, increase the use and deployment of renewables (wind and potentially on-roof solar on the hospital), decrease the need for importing fuel for transport (for buses, cars, trucks, etc.), reduce the need for brown / black grid electricity, allow the supply of green oxygen to the communities around the hospital and further afield at a competitive price, and support the potential use of rain water to produce hydrogen.

Figure 5.21 Scenario 6 - A wind farm cluster with a PPA agreement for supplying electricity to the electrolyser located at a hospital



The aim of this scenario is to identify whether selling the by-products, specifically oxygen and heat, from a hydrogen facility can lead to better financial returns. The rationale behind this analysis is to investigate niche hydrogen applications (i.e. hospitals) where both oxygen and heat can be used. For those niches, it is helpful to determine how selling the by-product heat and oxygen impacts on the financial viability of a green hydrogen installation.

Therefore, Scenario 6 investigates a situation where a single wind turbine that would not otherwise be constructed is matched to a specific (and potentially technically challenging) end user load application. This would allow the deployment of a new wind renewable solution in a location where there is no grid connection availability nearby.

The proposed turbine can be erected by a community group in the Western Isles as an addition to their existing farm. Grid constraints mean that other expansion opportunities for the group are limited and outwith their control. The above concept and proposed model can be scaled up and replicated in other areas where there is demand of a similar nature.

The strategy is to prioritise hydrogen production and also to ensure that waste heat and oxygen are supplied to the hospital to generate income for the project. Surplus electricity that occurs when the hydrogen storage is full will be used by the hospital to displace grid electricity and heat.

In this application there are three parties involved: (1) the wind farm operator; (2) the hospital; (3) the hydrogen system installer (supplying H_2, O_2 and electrolyser heat to the hospital). All of the parties must benefit from the project.

Average energy demand figures have been acquired from the hospital. These include daily energy demand cycles produced by using the BEIS templates of average electrical demand data (Energy Trends)[39].

The hourly data matched the granularity of the wind turbine data. Generation was estimated using wind data from an anemometer fitted to a turbine on the selected site (with adjustments for hub height). The below table provides the key assumptions for the hydrogen, oxygen, heat and power model.

Table 5.5 – Key assumptions for the hospital hydrogen model

Wind Turbine	3 MW
Annual Electricity Demand	2,203,000 kWh[40]
Annual Heat Demand	6,863,000 kWh[41]
Current cost of Electricity	£0.11 / kWh[42]
Current cost of Heat (Oil)	£0.04 / kWh[43]
Hospital Payment for WT Electricity (proposed)	£0.06 / kWh
Hospital Payment for WT Heat (proposed)	£0.047 / kWh
Payment to WT Operators (proposed)	£0.05 / kWh
Electrolyser Rated Capacity	1 MW
Electrolyser and Storage Efficiency (as per previous scenarios)	60%
Conversion of Waste Heat to Useful Heat	70%
Sale Price of Hydrogen	£6 / kg
Sale Price of Medical Oxygen	£0.5 / kg
Hydrogen end user needs	250 kg per day

As aforementioned, a single turbine of 3 MW in size is proposed. The site for the wind turbine is a distance of 4 km from the hospital. Currently, the community wind farm operators are unable to extend their existing grid connection, and projects of this type where they are able to sell their electricity privately are the only way the wind farm (which already has three turbines) can grow.

[39] Energy Trends: Electricity. Department for Business, Energy & Industrial Strategy, BEIS. Available at – https://www.gov.uk/government/statistics/electricity-section-5-energy-trends
[40] Greenspace Live, (2011). Western Isles Hospital Assessment of Energy Reduction and Carbon Dioxide Emission Saving Opportunities, Stornoway
[41] Greenspace Live, (2011). Western Isles Hospital Assessment of Energy Reduction and Carbon Dioxide Emission Saving Opportunities, Stornoway
[42] Mackenzie D, (2015). NHS Western Isles Hospital Property and Asset Management Strategy, Stornoway.
[43] Mackenzie D, (2015). NHS Western Isles Hospital Property and Asset Management Strategy, Stornoway.

The electricity can be fed to the hospital by constructing a private wire connection. However, it is preferable to using the existing electrical grid connection if a transmission charge of £10 per MWh or less can be negotiated (with the project paying for all connection equipment). Both the grid connection and private wire solutions are discussed below.

Note that the hospital must be in a position to consume all of the electricity produced by the turbine and that there is no curtailment.

Waste heat from the electrolyser will be supplied to the hospital at a price of £0.047 per kWh. This is a higher price than the £0.04 currently being paid for oil heat. In effect, the price reflects the greater value of this 'new green heat', which could potentially become accredited under the Renewable Heat Incentive[44] (RHI) in the future. This would provide the hospital (or supplier to the hospital) with an extra income, thereby making green hydrogen a much more economically viable proposition.

In addition, it could be possible to negotiate and supply the hospital with a **'green energy package'**. Such a package would combine both renewable heat and electricity. The renewably produced electricity would be cheaper (£0.06 per kWh) than the current price (£0.11 per kWh). This would, therefore, provide a good balance between the higher price for green heat and lower price of green electricity.

Note that the hospital requires much more heat than electricity, but as the hospital reduces greenhouse gas emissions associated with heat by using energy from the wind turbine, it also reduces its potential for current and future emission related outgoings[45].

The hospital solution would also align with the Scottish Government Energy Strategy, in so far as it makes '**efficient use of the available resources'** through the use of green energy for heat, electricity and transport through hydrogen energy storage technologies[46]. It also fits with the Scottish Government's aspirations to reduce the carbon footprint associated with heating Scotland's buildings, as set out in the Energy Efficient Scotland: Route Map[47].

It is proposed that the hospital pay £0.06 per kWh of wind electricity. It is assumed that the charge for using the electrical grid network is £0.01 per kWh (this is fairly low, but is considered as this is a demonstration site).

It is further assumed that the wind farm operator receives £0.05 per kWh of generated wind electricity. The hydrogen system owner takes no part in the deals between the hospital, the electrical grid operator and the wind turbine owner. It is only given priority access to the wind energy and buys it at the above prices.

For this scenario, an electrolyser capacity of 1 MW has been selected. This is because it was determined in previous scenarios that matching wind power with an electrolyser of one third of the wind farm capacity is a good 'rule of thumb'. This ensures the electrolyser capacity factor (i.e. usage) is sufficiently high to allow for a good trade-off between CAPEX/OPEX and optimises the use of the electrolyser at its rated power.

In addition, this enables a manageable amount of hydrogen to be produced and used (around 250 kg a day). In other words, the aim is to capture as much of the power available from the wind turbine, but not to oversize the electrolyser, thereby optimising CAPEX and OPEX of the installation. In these

[44] https://www.ofgem.gov.uk/environmental-programmes/non-domestic-rhi
[45] https://www.gov.uk/government/collections/crc-energy-efficiency-scheme
[46] http://www.gov.scot/Publications/2017/12/5661
[47] http://www.gov.scot/Publications/2018/05/1462

operational conditions, the electrolyser is given priority access to the wind generation (unless the store is full or close to full).

The 250 kg of hydrogen to be used per day by the end users may seem a fairly large amount of fuel. However, this amount would only supply 6 buses per day at 40 kg each, totalling 240 kg per day.

It would otherwise be able to supply 2 hydrogen-diesel converted refuse trucks (currently converter hydrogen-diesel trucks need 5 kg of H2 per day - the two trucks will require a total of 10 kg per day), 10 cars (at 40 kg a day, each car supplied with 4 kg per day) and 5 buses (at 200 kg a day, each bus fuelled with 40 kg a day). As this shows, the 250 kg a day would only supply about 17 vehicles and potentially fewer if the cars were to be filled at 7 kg a day (which is the current trend[48]).

The by-product oxygen produced from the electrolyser is also 'green'. The sale price is set very low in order to stimulate demand, as production could potentially exceed demand from the local Health Boards when hydrogen system installations grow in a small island community (although demand has been rapidly increasing over the past few years).

The conversion of waste heat to useful heat is taken to be 70% because the temperature of the waste heat is considered to be low. The electrolyser will operate at about 80°C and, dependant on the system design, the cooling water may run several hundred metres to the hospital via a heat exchanger for isolation. Therefore, significant heat losses are, in this case, unavoidable.

Using the above assumptions, the following table has been derived from the model:

Table 5.6 – Financial and technical summary for the hospital scenario

Item	Figures	Unit	Item	Figures	Unit
Total WT Electricity Transmitted (per year)	11,348,473	kWh			
Total Heat to Hospital (per year)[49]	5,949,426	kWh	Hospital Heat Demand	6,863,00 0	kWh
Total Electricity to Hospital (per year)	1,044,226	kWh	Hospital Electricity Demand	2,203,00 0	kWh
Financial Benefit to Hospital (per year)	10,565	£			
Oil not Burnt by Hospital (per year)	595	tonnes			
Annual CO2 Emission Reduction (oil) (per year)	1,606	tonnes			
Annual CO2 Emission Reduction (heat and electricity) (per year)	3,405	tonnes			
WT Capacity Factor	43.2	%			
Payment to Community Energy Group (per year)	567,424	£	Payment to Community Energy Group	£0.05	/ kWh
Daily Oxygen Production (Average)	2,003.5	kg			
Daily Hydrogen Production (Average)	250.4	kg			
Electrolyser Water Requirement (per year)	823	tonnes	Water Purifier Water Use Efficiency	20	%
Mains Water Requirement (per year)	4,113	tonnes			

[48] UK car usage information is available here: https://www.licencebureau.co.uk/wp-content/uploads/road-use-statistics.pdf
[49] Total heat to hospital is the sum of the heat from electrolyser and the wind turbine electricity used to produce heat. Total heat = 5,949,426 kWh = 4,255,884 direct wind to heat + 1,693,542 heat captured from the electrolyser for one year

Item	Figures	Unit	Item	Figures	Unit
Electrolyser Capacity Factor (per year)	69.0	%			
Income: Electricity Sale (per year)	62,654	£	Hospital Electricity Charged at	£0.06	/ kWh
Income: Heat Sale (per year)	279,623	£	Hospital Heat Charged at	£0.047	/ kWh
Income: Hydrogen Sale (per year)	457,055	£	Hydrogen Price	£6.00	/ kg
Income: Oxygen Sale (per year)	365,644	£	Oxygen Price	£0.50	/ kg
Total Income (per year)	1,164,976	£			
Annual Profit	**597,552**	£			

The carbon emissions reduction calculation is based on the official UK Parliament published data[50].

The water purifier will consume more water than it delivers and a worst case of 20% water use efficiency is assumed. The total water consumption for such a low efficiency water purifier is 4,113 tonnes per year. This will produce 823 tonnes of high grade deionised water that is required by the electrolyser to produce hydrogen.

Using the assumptions described previously, an electrolyser capacity factor of 69% is achieved. Any surplus electricity not used for electrolysis is directly supplied to the hospital, being the selected sink for excess energy either as heat or electricity.

It is assumed that there is no need to transport hydrogen in this scenario; the hospital grounds where the electrolyser is located will be accessible to end users. All of the hydrogen is sold at £6 per kilogram.

The 1 MW electrolyser can produce a maximum of 362 kg of hydrogen per day if operated at maximum capacity (on a windy day for example). The data in Figure 5.22 (hydrogen delivery) shows how much hydrogen is delivered by the electrolyser to the storage system every day from 27/04/2017 for one year. It also assumes that the hydrogen storage is 2.9 tonnes at the start of the production (27/04/2017) and that the model is run for a period of one 1 year (8,868 hours on the x-axis)[51].

The mass of H_2 in storage (see Figure 5.22 below - right) shows that there is good hydrogen production from September to March with few gaps. However, this is not the case in summer where there are significant gaps in the production of hydrogen due to lower wind speed.

The results from the model show that there is a need for a 3.4 tonne storage system. This size of storage is required in order to supply the average 250 kg of hydrogen fuel per day to the local end users, and to ensure the supply is secure all year around. This is a medium to large storage scheme[52] and the cost for such system could potentially jeopardise the development of the project.

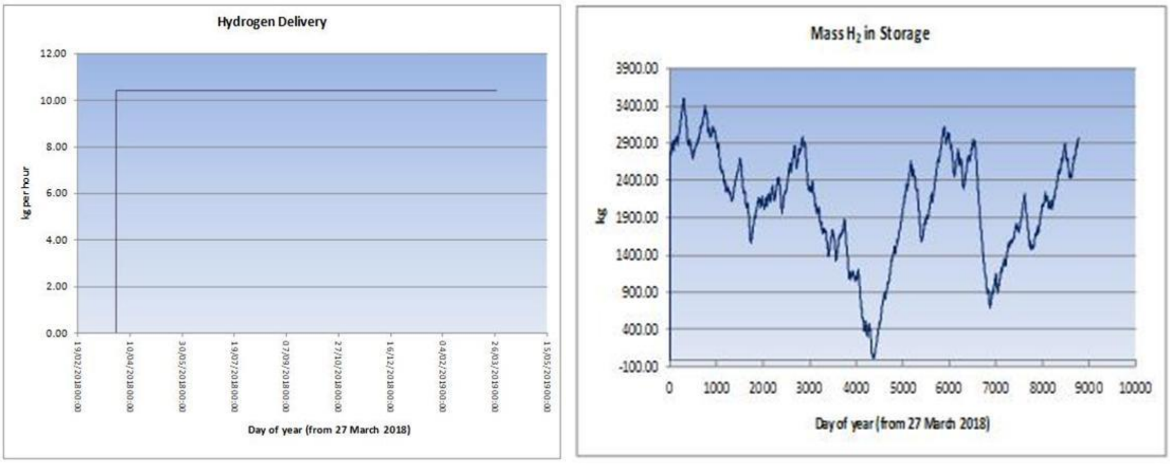
The 3.4 tonne storage system is the absolute minimum solution for supplying all loads all year round with 250 kg of hydrogen. Effectively, this is a storage system that stores some of the winter excess energy for later summer use. It is also an alternative solution to importing hydrogen in the summer for days where there is lack of available wind energy.

[50] https://www.parliament.uk/documents/post/postpn_383-carbon-footprint-electricity-generation.pdf

[51] It is assumed that the system is running continuously and the high value in storage at the start is of no consequence: it merely reflects the start point.

[52] This is about 180,000 litres of H_2 at a pressure of 200 bar. The cost for stationary storage is £300 k a tonne, a little lower than in Scenario 5 because storing smaller volumes is less challenging in terms of safety regulations. This is consistent with https://www.hydrogen.energy.gov/pdfs/review15/st100_james_2015_o.pdf

Figure 5.22 Scenario 6 – Hydrogen produced and delivered by the electrolyser (kg/hour) to the storage system for a one year period (left). Mass of hydrogen in the storage system in kg for a one year period (right) for Scenario 6 with a wind turbine of 3MW and a rated storage system of 3.4 tonnes



As mentioned, if there is a need to reduce the cost of the storage system, so importing hydrogen could potentially provide a tangible solution. Another alternative would be to produce hydrogen by drawing power from the electrical grid network when the price of electricity is lowest (e.g. at night time). This may not be the best solution, as the fuel could become brown / black hydrogen (rather than "green") for a limited amount of time during the year. However, this solution has potential to be more environmentally friendly than importing the hydrogen fuel from mainland Scotland (which may also be brown / black hydrogen) due to the emissions associated with its transportation).

By using the electrical grid network to compensate for periods of low generation from the wind turbine, a more realistic quantity of storage can be used for this scenario. Having a smaller storage capacity will reduce project CAPEX and could potentially provide other opportunities for the use of the electrolyser if backup grid operation is available (not investigated in this scenario).

By reducing the size of the storage system, it is possible to envisage the system becoming full quite often at various in the year. As such, there could be excess hydrogen generated and a requirement for a sink to absorb this excess. For example, the gas network could take the excess green hydrogen when the storage system becomes full. Generally, this an undesirable solution – at the moment hydrogen is considered as too valuable a molecule to be disposed of in this way as the price for producing it is still high when compared to the price of gas with which it is mixed. Nevertheless, other applications could be identified for the fuel.

Considering that the CAPEX available to the project does not allow the installation of a 3.4 tonne storage system, the question is how 'small' or 'large' the hydrogen storage system must be to permit; (a) optimum use of the wind turbine; and (b) optimum hydrogen storage solution that provides a good compromise between the availability of hydrogen to the end user and a minimal requirement for importing / grid hydrogen production. Essentially the challenge lies in understanding the optimum size of the hydrogen system where CAPEX is a constraint.

To illustrate this, a further scenario is considered, Scenario 6-1, which assumes that storage is reduced to 1600 kg (just under half of the 3.4 tonnes of storage considered in Scenario 6 above). The hydrogen gaps that have to be addressed can be modelled and are shown in

Figure 5.23**.**

Figure 5.23 Scenario 6-1 – Hydrogen produced and delivered by the electrolyser (kg/hour) to the storage system for a one year period (left). Mass of hydrogen in the storage system in kg for a one year period (right) for scenario 6 with a wind turbine of 3MW and a rated storage system of 1.6 tonnes

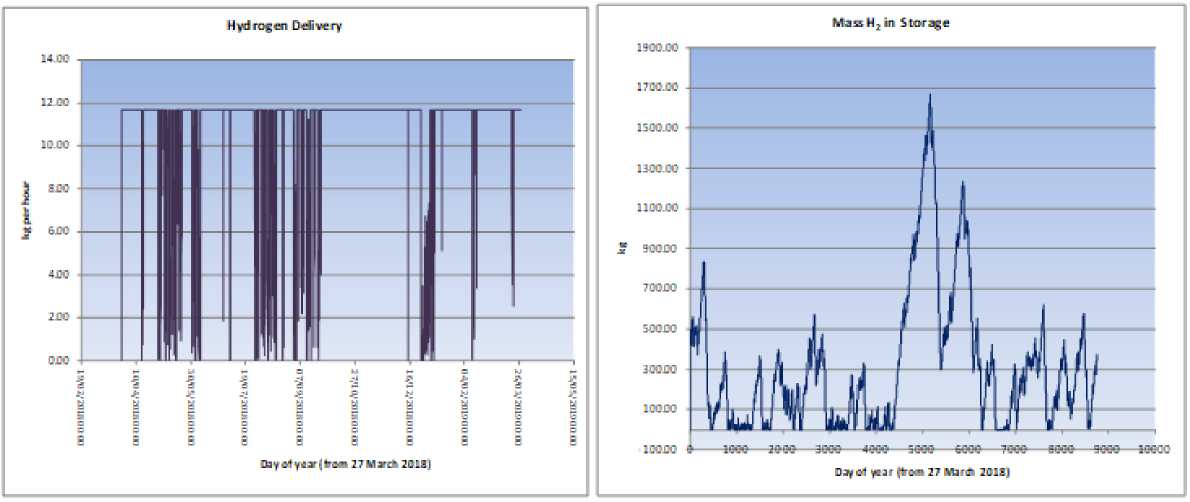
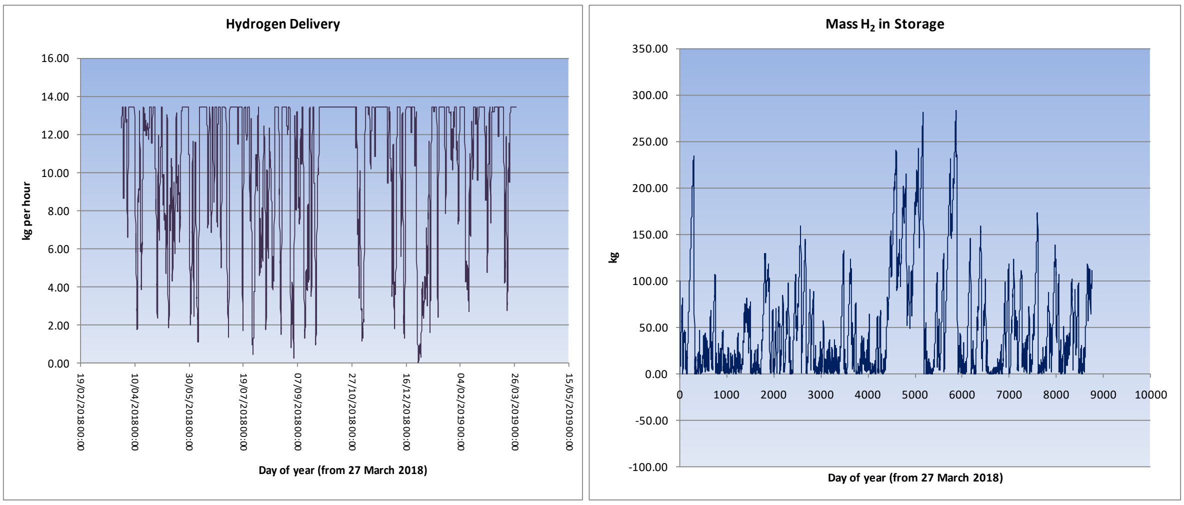


Figure 5.23 shows that there is a shortage of hydrogen in the summer. It also shows that the tank has storage capacity not used over a long period of time during the year. The graph on the left illustrates the quantity of hydrogen that is delivered to the end user and that without large scale hydrogen storage; the ability to meet the end demand is compromised.

The graph on the right suggests that the size of the tank could potentially be oversized when compared to its yearly usage, hence increasing CAPEX.

This leads to a third scenario, Scenario 6-2, where a storage system of 300 kg is installed. The system would provide about 1 day of storage. This is shown in Figure 5.24.

Figure 5.24 Scenario 6-2 – Hydrogen produced and delivered by the electrolyser (kg/hour) to the storage system for a one year period (left). Mass of hydrogen in the storage system in kg for a one year period (right) for Scenario 6 with a wind turbine of 3MW and a rated storage system of 300 kg



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In this case, there are several periods when there is insufficient hydrogen (see Figure 5.24- right).

Figure 5.23What the above three scenarios illustrate is that there is a need for a careful trade-off between the capacity (and cost) of storage and the reliability of supply. The actual decision of the best solution depends on the end use of the hydrogen produced. This further suggests that selecting the appropriate size of the storage is as important as choosing the size of the electrolyser.

"Too big a storage system means high CAPEX and low utilisation of the available storage resources. Too small a storage system means reduction in the abilities to supply the end user with fuel."

Scenario 6-1, with 1.6 tonnes of storage capability is therefore used for the financial calculations. This storage capacity offers the best balance of CAPEX and capacity in supplying the end user with hydrogen. In addition, there is still the potential for importing electricity from the grid to produce hydrogen when there is no wind generation.

Furthermore, if grid import is not acceptable by the hospital, then it is also possible to consider mixing in other renewable sources such as solar photovoltaic (hospitals usually have large roof areas).

Mixing renewable sources could therefore address the gaps in hydrogen supply. Note that rainwater could also be collected from the large roof area, deionised and used for electrolysis. This strategy would comply with the Scottish Government efficient use of available resources and save on OPEX spent on buying water from the mains supply.

The total cost of the above installation is just under £4.8 million. This includes the electrolyser at £2.5 million plus the oxygen system, storage, compression and grid connection. The project assumes a 5% rate of interest. The lower interest rate is related to the assumption that the project is less risky than a project built for transportation applications.

5.12.1 Scenario 6 Conclusion

This scenario illustrates that selling the by-products oxygen and heat from a hydrogen facility can lead to better financial returns than a system that is only selling hydrogen. It illustrates that it is possible to produce hydrogen at a price point of £6/kg by selling the by-products of the production process to a local hospital. It also highlights that by using hydrogen energy storage technologies, it is possible to erect a financially viable wind turbine in a situation and location where this would not have been possible due to a constrained grid connection. Furthermore, it shows that the three parties involved in the scenario: (1) the wind farm operator; (2) the hospital; (3) and the hydrogen system installer are all financially independent and profitable from the project.

The wind turbine is of 3 MW in size and the electrolyser of 1 MW. These sizes have been selected because the system is only cost effective if a capacity factor for the electrolyser of 50% or more is achieved. This requirement was demonstrated in the previous scenario analysis. By selecting an electrolyser of 1 MW, a capacity factor of 69% has been obtained.

The wind turbine will satisfy 86% of the hospital's heat demand and 47% of the electricity demand. What these figures illustrate is that there is potential scope for a second turbine and a larger electrolyser to supply 100% of the heat and electricity to the hospital (and some of the transport sector). A much more integrated solution would be required if an extra turbine is to be installed, but the project could in future be extended in this way.

Two models were produced for transporting / distributing wind electricity to the hospital's electrolyser. The first model assumed that the electricity can be moved from the turbine to the hospital via the existing 33 kV line. This is for a distance of 4 km. In this case, it is assumed that a transmission charge of £0.01/kWh is negotiated. The total cost over the lifetime of the project would be £310,000 for the initial capital cost of the connection equipment and £2 m in transmission charges.

The second model assumes the construction of a private line as an alternative to using the grid. This has the particularity to have higher CAPEX, but reduced OPEX. The total cost of the grid connection (including interest) is £3.3 m, which is equivalent to a cost of £1.80 per kg of hydrogen produced by the project over a 20 year timeframe. Options such as private overhead line or underground cable could be considered if these could be implemented for a capital cost of less than £1.7 m (so that the total paid back with interest is less that £3.3 m)[53].

For the two models explored, the payback time is just under 20 years for the entire system assuming 5% interest on CAPEX loans and a 0.2% decline in system performance each year. The O&M costs have been based on £0.50 per kg of hydrogen as in previous scenarios.

On average, about 250 kg of renewable hydrogen can be produced each day. The model shows that 90% of the deficit days (days where there is not enough hydrogen production) can be covered using 300 kg of storage. The model also shows that a storage system of 1.6 tonnes provides the best balance of CAPEX and capacity in supplying the end user with hydrogen. However, as the cost of storage is a major factor in deciding the financial viability of a hydrogen system, it may be best to adopt the 300 kg storage option (one fourth of the original 1.6 tonnes system). The 10% shortfall in hydrogen production due to lack of wind could be compensated by the installation of a solar system or importing grid electricity.

In this scenario, the green oxygen price is set to be lower than that of the production of 87% concentration oxygen from a portable concentrator/ generator[54]. The price for green oxygen produced at the hospital grounds is set at £0.50 per kilogram. The current equivalent price of oxygen

[53] The voltage from the wind turbine will only be 690 V. For such a short distance a low-voltage cable could be installed.
[54] https://www.nhs.uk/conditions/home-oxygen-treatment/

in bulk (6,800 litre cylinders) is £1.71 per kg[55]. The low production and bottling price (£0.50 per kg) means the green O_2 gas produced at the hospital can potentially be exported to other health regions. It would however be necessary to develop the green O_2 distribution chain.

In terms of the heat, the price charged for renewable heat is higher than the cost of the hospital's existing fuel oil heating system (£0.047 per kWh for green heat compared with £0.04 per kWh for CO2 intensive oil heat). In contrast, the renewable electricity is purchased at a lower price (£0.06 per kWh of wind energy compared with £0.11 per kWh for grid supplied electricity). As such, the hospital could be presented with a combined deal for 'green heat' and 'green electricity' where the higher price for the heat is compensated by the lower cost of electricity. Between both electricity and heat, the hospital saves over £10,000 a year on total energy costs.

It was shown that about 4,113 m^3 of water is required to produce 823 tonnes of high grade deionised water for the electrolyser. The costs for the water deioniser system has been included[56] and the OPEX cost @ £0.61 per m^3 of mains water have also been factored in. The water price contributes to less than 1% of the hydrogen cost and is not significant. There is, however, an opportunity to use the 1% water financial contribution to the overall project by installing a water collection system and deionising it. Such system would fit within the Scottish Government latest strategy for efficient use of resources.

In summary, the hydrogen, oxygen and heat scenario still requires a 20 year return on investment. This is due to the cost of private wire (or grid connection plus 'electricity transport' charges), extra CAPEX / OPEX, low sell price of oxygen (to ensure market uptake), and low income from the sale of renewable electricity and heat.

If the project were implemented, it would lead to a decrease in emissions from the hospital of 3,405 tonnes per year (a total of 68,100 tonnes over the 20 year project lifetime). This figure does not include emission savings from the use of hydrogen by the local transport sector, or emissions saved by negating the need to ship oxygen and fuel oil to the hospital.

The cost of the system, at £4.8 million, is a significant factor in the deployment of what could be seen as an innovative use of a wind, hydrogen, heat and power installation, which could deter the Health Board and any investor from initiating such a project.

However, by developing a "green energy supplied hospital", the NHS could potentially reduce its outgoings under the CRC scheme, which has had a negative financial impact on the organisation in the last couple of years[57].

In addition, if the green heat produced from the electrolyser and the wind turbine was certified through the RHI scheme, then it is possible to envisage selling it at a lower price. This would lead to a better return on investment and spearhead other similar initiatives in Scotland and beyond.

If CRC costs and RHI income are factored in the above scenario, these could change the rate of return to the project.

Finally, though the CAPEX / OPEX are high, the project is a good fit with the Scottish Government aspirations for sustainable local energy solutions and efficient use of energy resources, as expressed in the Scottish Energy Strategy and Climate Change Plan it has the potential to reduce and close the

[55] https://www.boconlineshop.com/shop/en/uk/oxygen-cylinder-medical-grade-compressed-gas
[56] https://www.brightwater.com/wp-content/uploads/2018/02/Brightwater-BSL-Tar-BWS-2018.19-v.2.55.190218.pdf
[57] https://www.sduhealth.org.uk/policy-strategy/legal-policy-framework/carbon-reduction-commitment.aspx

gaps in fuel poverty between remote and urban inhabitants, increase energy efficiency, improve energy security, reduce the cost of energy to the NHS, decrease emissions at all levels (heat, electricity, oxygen, shipping, transport), and create the opportunity for new highly skilled local jobs, thereby reducing 'brain drain'. All of these could potentially be achievable through the installation of a hydrogen energy storage system within a grid constrained remote location.

6 Cost Modelling of Hydrogen Transportation Scenarios

This section investigates the following:

"Modelling the costs of transporting hydrogen within Scotland from point of generation to point of supply."

With the latest developments in hydrogen refuelling stations and many other anticipated large-scale H_2 related applications, there is a need to find methods for transporting bulk hydrogen by road, rail or sea. These methods are required to be safe, energy efficient and cost effective to support the wide deployment of hydrogen technologies. Whilst it could be convenient to install pipelines[58], this is not always possible. Therefore, initially, it is expected that hydrogen will be moved by road.

In the UK, there are regulations that govern the movement of flammable and explosive substances by road, which differ for liquids and pressurised gases. Hydrogen can be moved either way (i.e. in gaseous or liquid form), and each has its own challenges.

However, transporting hydrogen from the point of production to the point of use is not a new problem. For instance, hydrogen derived from fossil fuels has been used for decades in industry, and specifically designed gaseous truck trailers have been produced for this purpose.

In the USA (and in other countries), the gas is usually loaded into large cylinders with the most common configuration being four tubes attached onto a truck trailer (also called a tube trailer). The extreme weight of the individual tubes means that only 250 kg to 500 kg of hydrogen can be transported by a single truck[59,60].

One issue associated with transporting hydrogen is the energy used to move the energy stored in the tube trailer. For a typical lorry or truck, the energy equivalent[61] of 6 kg of hydrogen is used to travel 100 km[62]. Considering the price per kg of hydrogen at around £6 (as per Scenario 6), the cost for transporting 250 kg of hydrogen 100 km would be £36. This means the cost per km to transport hydrogen over a 1 km distance is £0.36 (or £0.18 per km for a 500 kg trailer). This is only the price to be paid per km, that is OPEX (only fuel costs – no other costs included such as compression, etc.). It does not include the CAPEX costs (e.g. purchase of the tube trailer) or any other OPEX costs (e.g. driver salary, cost for maintenance of the trailer and truck, etc.).

The requirement for a more holistic understanding of hydrogen transportation options and costs has prompted several studies via FCH-JU funded projects. Some of these investigate future potential

[58] 'Piping hydrogen is also problematic due to the energy required for pumping and the low volumetric energy density of hydrogen, demanding higher flow rates which in turn lead to greater flow resistance. Consequently about 4.6 times more energy is required to move hydrogen through a pipeline than for natural gas and 10% of the energy is lost every 1000 km, the additional problem that hydrogen is not compatible with the current piping infrastructure due to brittleness of material, seals and the incompatibility of pump lubrication poses further problems.' *O. Sylvester-Bradley, 'Is Hydrogen Sustainable? A critical review of the sustainability of a hydrogen economy', EV World 2003.* He adds: 'Ironically, petrol is the most concentrated form of hydrogen available for human consumption containing more hydrogen by volume than pure hydrogen itself, since the structure of the atoms in hydrocarbons use less space.'
[59] Amos, W. A.. Costs of Storing and Transporting Hydrogen. United States: N. p., 1999. Web. doi:10.2172/6574 https://www.energy.gov/sites/prod/files/2014/03/f12/25106.pdf.
[60] The following ISO standard is relevant: ISO/DIS 19884 Gaseous hydrogen -- Cylinders and tubes for stationary storage
[61] A 500 km journey would represent a significant energy loss (30kg of H2), though it is only of the same order of magnitude as losses along medium voltage grid lines.
[62] *ETSAP - Technology Brief T09 – January 2011*

trends in hydrogen transport and based on future financial predictions[63]. There are also substantial academic research in this area[64,65,66,67,68]. Therefore, there is clearly a need to understand the different costs associated with transporting hydrogen within Scotland as these could comprise a significant (or non-significant) portion of the whole system cost of a hydrogen energy project.

As such, the availability of a hydrogen transport model will allow these costs to be factored into financial considerations for hydrogen developers so that it is possible to anticipate the viability of a full cycle hydrogen energy system. Such a model could help determine the viability of a project before any investment and development works start.

6.1 Scenario A - Transporting H2 in Gaseous Form

Scenario A investigates the following:

"Modelling the costs of transporting hydrogen within Scotland from point of generation to point of supply in gaseous form."

In the UK, hydrogen is classified as transport category 2 (flammable gas, Figure 6.1)[69]. The UK guidelines suggest the number of litres per cylinder times the number of cylinders cannot exceed 333 litres. For example, only six 700 bar 50 litre cylinders would be allowed (6 tanks x 50 litres = 300 litres).

Figure 6.1 Scenario A – Symbol that must be shown on trucks when transporting hydrogen. The words "Hydrogen, Compressed, UN 1049" must also be included

The UK guidelines can be exceeded (700 bar times 333 litres is only 20 kg of hydrogen), but the *European Agreement Concerning the International Carriage of Dangerous Goods by Road* (ADR)[70] rules need to be strictly applied and a detailed risk assessment is required. These regulations apply

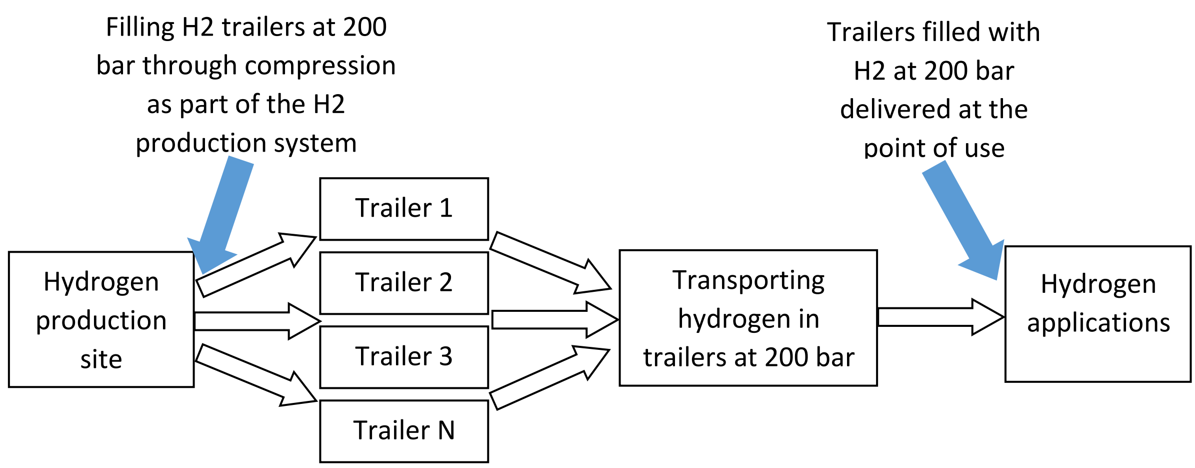
[63]http://www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf Page 155 investigates curtailment in the UK (and is relevant to the earlier parts of the study). The calculations for 2017 are not convincing and the 2025 predictions are not sufficiently justified. Refer also to FCH-JU HYSTOC project.
[64]Amin Lahnaoui, Christina Wulf and Didier Dalmazzone, 'Building an optimal hydrogen transportation system for mobility, focus on minimizing the cost of transportation via truck', Energy Procedia, Volume 142, December 2017, Pages 2072-2079
[65]Krishna Reddi, AmgadElgowainy, Neha Rustagi and Erika Gupta, 'Techno-economic analysis of conventional and advanced high-pressure tube trailer configurations for compressed hydrogen gas transportation and refueling', International Journal of Hydrogen Energy, Volume 43, Issue 9, 1 March 2018, Pages 4428-4438
[66]ShahanaBano, Praveen Siluvai Antony, VivekJangde and Rajesh B. Biniwale, 'Hydrogen transportation using liquid organic hydrides: A comprehensive life cycle assessment', Journal of Cleaner Production, Volume 183, 10 May 2018, Pages 988-997.
[67]R. Gerboni, 'Ch11: Introduction to hydrogen transportation', in Compendium of Hydrogen Energy, 2016, Pages 283-299.
[68]KasparLasn and Andreas T. Echtermeyer , 'Safety approach for composite pressure vessels for road transport of hydrogen. Part 1: Acceptable probability of failure and hydrogen mass', International Journal of Hydrogen Energy, Volume 39, Issue 26, 3 September 2014, Pages 14132-14141.
[69]http://www.bcga.co.uk/assets/publications/GN27.pdf
[70] https://www.unece.org/trans/danger/publi/adr/adr_e.html

even in the case of the movement of small quantities of hydrogen in pilot projects, but include a proviso that allows the transport of small quantities of hydrogen in Manifold-Cylinder Packs (also known as MCPs[71]) without the need for ADR certification.

However, the five different hydrogen production scenarios considered by this report (Scenarios 1 to 5) would generate large quantities of hydrogen and require larger transportation systems. Therefore, transporting hydrogen via MCPs is not investigated in this report as it only allows limited amount of hydrogen to be distributed.

As such, for large scale applications, dedicated ADR compliant trailers are required. These are produced globally as an essential part of the hydrogen economy supply chain. Most standard trailers transport the gas at 200 bar. Figure 6.2 illustrates the system that is investigated.

Figure 6.2 Scenario A – Transport of hydrogen through an ADR certified trailer at 200 bar pressure



The aim of this scenario is to identify the cost for transporting hydrogen from the point of production to the point of use.

For high pressure hydrogen gas, the cost of a typical hydrogen trailer ranges from £270 - £450 per kg of carrying capacity[72] (truck and load weight of about 40 tonnes).

It is possible to model the cost by distance for one truck, taking the median £360 per kg with a capacity of 500 kg. It is assumed that trucks will need 1 hour to load (or swapping one empty trailer for another fully loaded hydrogen trailer) and 1 hour to unload (or swapping) time. The staff requirement would be 4 drivers per truck (for 24/7 hour operation) with 0.1 persons for maintenance and 2 x 0.5 person's equivalent to assist with loading and unloading.

The salary costs for the staff are based on typical haulage company wages for drivers of ADR compliant vehicles and are included in the calculations. Fuel costs have been taken into account with other costs, including insurance, training and maintenance. A conservative average vehicle speed has been chosen. Although the lorry travels back to the production site empty, a faster journey time on the return journey is not assumed.

[71] https://pureenergycentre.com/hydrogen-storage/
[72]http://www.fch.europa.eu/sites/default/files/project_results_and_deliverables/Recommendations%20to%20industry%20%28ID%202849587%29.pdf

Table 6.1 summarises the different costs associated with a hydrogen truck and trailer. It also summarises the different assumptions made for the model.

Table 6.1 – Assumptions for transporting hydrogen in gaseous form with a hydrogen truck trailer

Cost per truck (£)	**180000**
Number of Trucks	**1**
Payback Time (y)	**10**
Staff Required	**5.1**
Salary per Person - inclusive (£)	**35000**
Fuel Cost per km (£)	**0.18**
Other Running Costs per km (£)	**0.3**
Load/Unload Time (hr each way)	**1**
Av. Speed (km/h)	**50**
Mass H_2 per Trip (kg)	**500**

The model investigates the cost effect of transporting hydrogen for a given distance. Figure 6.3 below illustrates the cost of transporting a given mass of hydrogen versus distance travelled per day and

Figure 6.4 illustrates the cost of transporting a given mass of hydrogen versus a distance from the site of production to the end user.

Figure 6.3 Scenario A – Transport cost of hydrogen in £ per kg

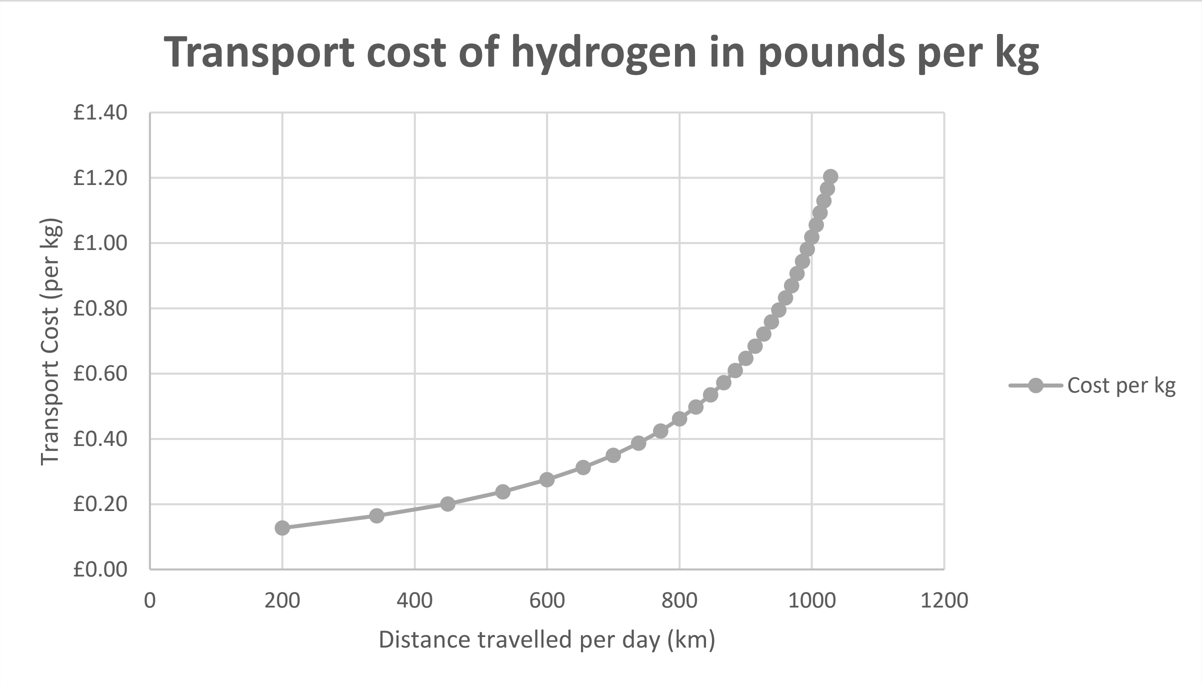


Figure 6.4 Scenario A – Transport cost of hydrogen in pound per km

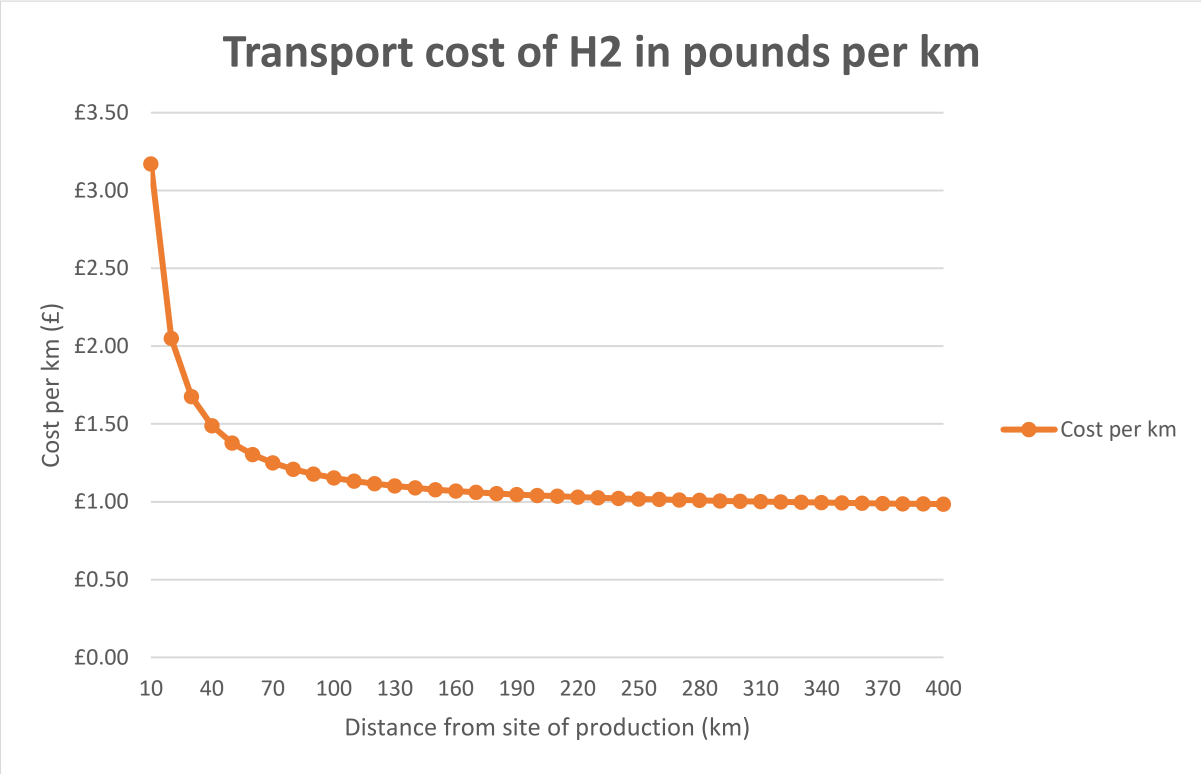


Figure 6.5 Scenario A – Mass of H2 transported per day

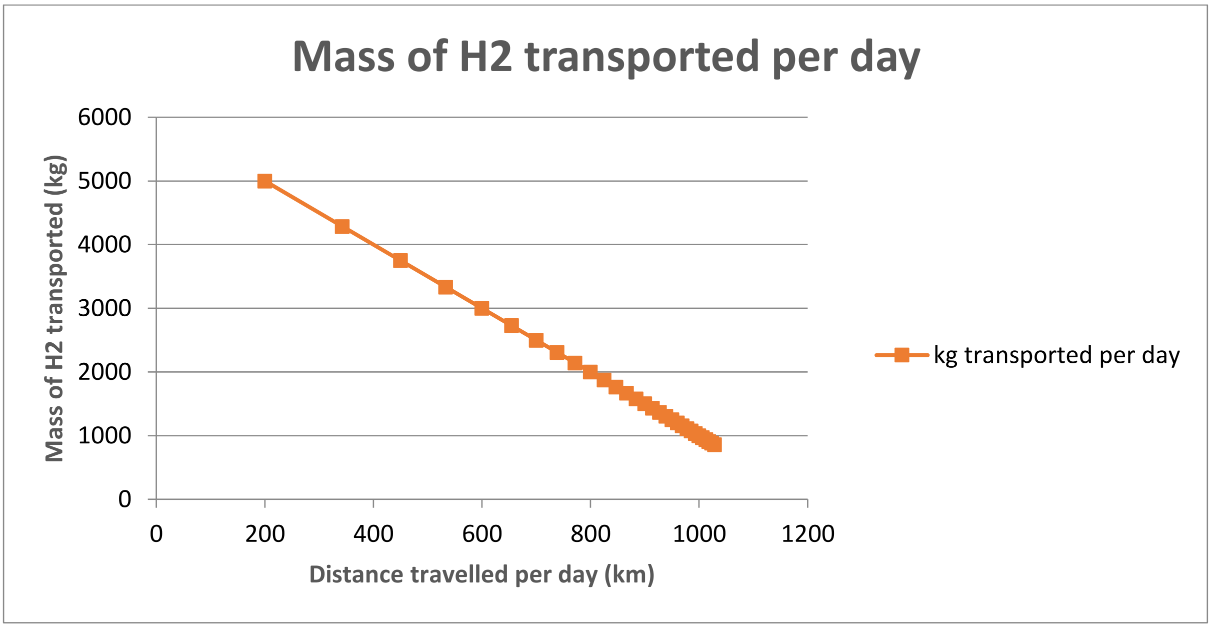


Table 6.2 - Cost per km and cost of delivery per kg of H2 for different distances

Distance, km	Cost per km, £	Cost of delivery per kg of H2
10	£3.17	£0.13
30	£1.68	£0.20
50	£1.38	£0.28
70	£1.25	£0.35
90	£1.18	£0.42
110	£1.13	£0.50
130	£1.10	£0.57
150	£1.08	£0.65
170	£1.06	£0.72
190	£1.05	£0.80
210	**£1.04**	**£0.87**
230	£1.03	£0.94
250	£1.02	£1.02
270	£1.01	£1.09
290	£1.01	£1.17
310	£1.00	£1.24
330	£1.00	£1.32
350	£0.99	£1.39
370	£0.99	£1.46
390	£0.99	£1.54
400	£0.98	£1.58

6.2 Scenario A Conclusion

This scenario illustrates that the cost of transporting hydrogen in gaseous form to the point of use is not to be neglected when developing hydrogen projects. Even for small distances, the cost of transportation can increase the total cost of supplying hydrogen to an end-user beyond the price point at which a project could operate on a commercial basis

Assuming a distance between hydrogen production sites and end-user sites of 100 km, which would represent a typical distance for Scotland, a single lorry capable of transporting 500 kg of hydrogen per trip can move 2 tonnes of H_2 gas in 24 hours (assuming 4 trips in a 24 hour period). For this particular scenario, the transport cost will be £0.46 per kg[73] of hydrogen. This is the equivalent of £1.15 per km for an 800 km travelled distance (see Figure 6.3).

The 800 km distance based on multiple trips to and from a site and represents total distance travelled in a day. As the site for production is located 100 km away from the site of consumption (end-user site), the truck trailer will be required to travel a distance of 200 km to deliver the hydrogen to the end-user and return to base (i.e. a 200 km round trip). Assuming there are 4 round trips a day, this will total a daily travel distance of up to 800 km (i.e. 4 x 200 km).

[73]The above costs are significantly higher than those in scenario 6 because it is assumed the electrolyser in scenario 6 is located in such a way as to minimise transportation requirements. Scenario 7 assumes all hydrogen has to be moved a significant distance.

In essence, the shorter the distance between the production and the consumption site, the more gaseous hydrogen can be transported per day per truck trailer. As shown in Figure 6.35, if 200 km total distance is to be travelled in a day, then 5 tonnes of hydrogen can be moved from the production to the consumption site per day. In this case, the production site is only located 10 km away from the consumption site.

However, if the site of consumption is located about 300 km away from the electrolysis unit, then only 1 tonne of hydrogen can be transported per truck in a day. In this case, the truck will only be able to perform two return trips in a day, totalling just over 1000 km.

This means that increasing the distance between the production site to the end-user site leads to a linear decrease in the quantity of hydrogen that can be transported in any given period of time (see Figure 6.35).

The total quantity of H2 that can be transported in a day is reduced as the distance between the point of production and point of consumption is increased i.e. less round trips are possible. This, in turn, leads to an overall decrease in the daily cosy of transporting hydrogen (Fig 6.4) due to less load/unload time per day. These costs can potentially be decreased under the following conditions:

- If the load/unload time is reduced.
- The mass that can be carried is increased.
- The CAPEX costs for the trailers are reduced. Note that the industry belief is that this cost will halve over the next 10 years[74].

From the above, there is an argument for comparing the cost of transporting hydrogen via road in a gaseous form and producing hydrogen at the point of consumption using the electrical grid network. The comparison could illustrate a breakeven point and highlight the distance at which a developer should use the electrical grid network instead of transporting hydrogen via a truck trailer.

6.3 Scenario B -Transporting H2 in Liquid Form

Scenario B investigates the following:

"Modelling the costs of transporting hydrogen within Scotland from point of generation to point of supply in liquid form."

It is possible to transport hydrogen in a liquid form (known as liquefied hydrogen) by cooling it to the point where it becomes a liquid. The advantages are the high density (70.8 kg per m^3, equivalent to a pressure of 100 bar) and low pressure (hence a reduced mass of tank is required). In essence, more hydrogen can be transported in liquid form than gaseous form for the same tank void volume.

The disadvantage is that hydrogen can only exist in liquefied form at a temperature of 20 K or below (-253°C). Therefore, if liquefied H_2 is transported via a truck trailer, the trailer must be super-insulated and journey time must be carefully controlled (the truck will not actively manage the temperature of the load).

[74]FCH-JU: '*Compressed gas truck distribution will initially be the most common way to transport hydrogen from central production sites to consuming facilities. Significant introduction of hydrogen vehicles requires a scale up of two orders of magnitude hydrogen truck distribution. At the same time developing and deploying a high volume trailer is necessary to address both the H2 Mobility market but also the industrial market to increase the volume transported so as to decrease transportation cost and CO2 emissions in a context of increasing fuel cost; to increase customer autonomy and storage footprint and to reduce the HRS investments and ease the ramp up of first stations. Current standards, regulations and safety codes have been developed for a relatively small market volume and deliveries mostly to industrial sites. These standards need to be reviewed, and adapted if needed, to ensure safe, efficient and low-cost hydrogen delivery at larger scales and in residential areas. These regulations and standards need to be harmonised across Europe.*' 'Harmonisation of hydrogen gas trailers' http://ec.europa.eu/research/participants/portal/desktop/en/opportunities/h2020/topics/fch-04-2-2017.html

Liquid hydrogen truck trailers can transport up to 10 times more hydrogen than tube trailers[75], which equates to a typical transport volume[76] of around 50-85 m^3.

One disadvantage of liquid H_2 is the energy cost to convert from gaseous H_2 to liquid H_2. Usually, medium pressure storage requires only 5% of energy for compressing the H_2 to a 200 bar tank. For liquefaction, the energy required to convert and store the hydrogen can exceed 30%[77].

A detailed economic analysis by U Cardella et al (2017) suggests[78] that at a production level of 5 tonnes per day, the energy associated with production is equivalent to 10 kWh of energy to store 1 kg of liquid hydrogen (divided equally between CAPEX and OPEX). The cost for converting hydrogen into liquid is higher than the cost for transporting pressurised H_2 gas. Note that other work suggests[79] a lower energy cost of 6.5 kWh per kg of liquid H_2, but the facility is much larger.

The cost of transporting liquid H_2 produced by a wind farm has also been analysed by Argonne National Laboratory in a report for the US Department of Energy and a summary of the findings is provided below[80]:

'Hydrogen liquefaction accounts for nearly half of liquid truck delivery cost. Liquefaction includes gas compression, cooling with water, and pre-cooling with liquid nitrogen to drop the hydrogen below its inversion temperature. For a 40 tonne/day market demand with 10% additional capacity to satisfy peak summer demand, the liquefier must deliver 44 tonnes/day. For such an installation, the installed capital cost of the liquefier is approximately $100 million. The corresponding liquefaction electric energy requirement is 10 kWh per kg of hydrogen. Assuming 5¢/kWh electricity, the contribution of the liquefier to the levelized cost of delivered hydrogen is $2.40/kg. The levelized cost contribution of the Liquid H_2 is $0.20/kg.

The typical L H_2 tanker truck has a tank capacity of approximately 17,000 gallons (65 m3), with a nominal holding capacity of 4,600 kg of hydrogen. The truck fill time is approximately 2 to 3 hours. Upon arrival at the fuel station, the truck is assumed to unload the Liquid H_2 into storage tanks. The boiloff during this transfer process is assumed to be recovered and re-liquefied at the terminal. The truck is assumed to make one 1,600-mile round trip every two days and to drop the entire load at a single station every trip. A station dispensing 1,200 kg/day, is assumed to receive a shipment every 4 days. To achieve this, there is a need for 32 trucks in order to deliver 40 tonnes of Liquid H_2 every day from the production plant to the end-user market. With a capital cost of $800,000 per vehicle, cryogenic tanker trucks contribute $1.20/kg to the levelized cost of delivered hydrogen.'

6.4 Scenario B - Conclusion

As illustrated by the above summary, liquefying hydrogen for transporting can be deemed to be expensive. However, the quantities of hydrogen that can be transported as a liquid are high. In essence, 40 tonnes per day of liquid hydrogen is sufficient to supply 80,000 H_2 fuel cell vehicles. The

[75]http://www.fch.europa.eu/sites/default/files/project_results_and_deliverables/D2.1_HyResponse_DescriptionOfSelectedFCHSystemsAndInfrastructureRelevantSafetyFeaturesAndConcepts_V6_20150615.pdf
[76] https://www.netinform.de/GW/files/pdf/Hydrogen_energy.pdf
[77] https://www.sciencedirect.com/science/article/pii/S0306261917305457
[78] U. Cardella, L. Decker and H. Klein, 'Economically viable large-scale hydrogen liquefaction', IOP Conf. Series: Materials Science and Engineering 171 (2017) 012013 doi:10.1088/1757-899X/171/1/012013 - http://iopscience.iop.org/article/10.1088/1757-899X/171/1/012013
[79] Integrated design for demonstration of efficient liquefaction of hydrogen (IDEALHY) http://www.fch.europa.eu/sites/default/files/project_results_and_deliverables/IDEALHY_D4-20_Journal%20article_Task3-3%20%28ID%202849533%29.pdf
[80] Liquid hydrogen production and delivery from a dedicated wind power plant - https://www.energy.gov/sites/prod/files/2014/07/f17/fcto_liquid_h2_wind_power_may2012.pdf

wind to liquid hydrogen report for the US Department of Energy concludes that for liquid hydrogen to be financially viable, a gallon of gasoline should reach $6.

On the other hand, the above referenced wind to liquid hydrogen volume is much larger than the six scenarios considered by this report, and already benefits from economy of scale at all levels. Although liquid hydrogen may play a role in the hydrogen economy, there is still a need for efficiency improvements in terms of energy required to liquefy hydrogen before such system is deemed economically viable. Liquid hydrogen is also dependent on the price of hydrocarbon fuel increasing to $6 USD for it to break-even (considering a 40 tonne per day of liquid H_2 production and transportation system). As such, the price of liquid H_2 is currently high for the smaller scale hydrogen projects considered in this report, and would not be a cost effective or solution for any of the six scenarios.

6.5 Scenario C – Liquid Organic Hydrogen Compound

Scenario C investigates the following:

"Modelling the costs of transporting hydrogen within Scotland from point of generation to point of supply with LOHC."

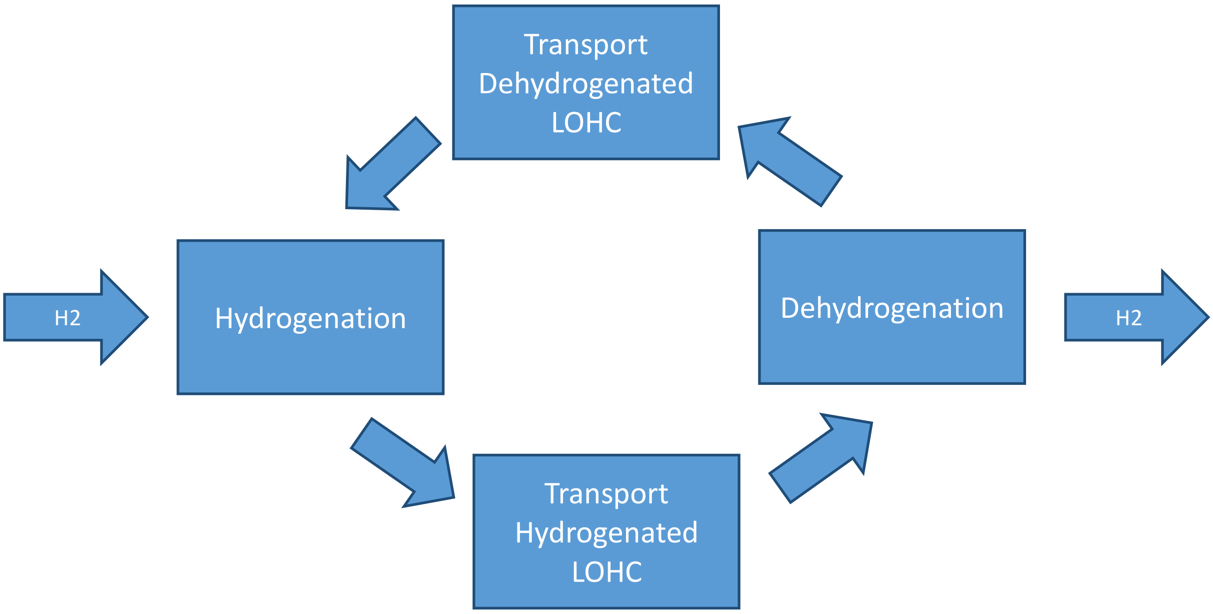
There are many other technologies that can be used to transport hydrogen instead of the above mentioned high pressure gaseous and liquefied hydrogen methods. Such technologies are based on transforming hydrogen into a liquid form (not liquefying hydrogen) by bonding the H_2 to another chemical called a carrier. The main rationale behind these technologies is that large quantities of hydrogen can be transported over long distances when compared to compressed gas. In many cases, hydrogen stored as a compound induces a non-flammable and non-hazardous form, thus negating the need for stringent safety requirements (note that the safety is dependent on the hydrogen storage technology being used).

6.5.1 What is Liquid Organic Hydrogen Carrier?

Liquid organic hydrogen carriers (LOHC) are compounds that enable chemical energy storage through reversible hydrogenation. The concept is shown in

Figure 6.6.

Figure 6.6 – Liquid Organic Hydrogen Carrier



In this concept, aromatic compounds 'absorb' hydrogen in a catalytic hydrogenation reaction. The output compound is saturated with hydrogen and stored at ambient conditions. It is this saturated compound that is transported to the site where the hydrogen is to be used.

In order to release hydrogen, a dehydrogenation process is used. When the hydrogen is separated from the compound, it can be compressed or utilised to directly fuel H_2 applications.

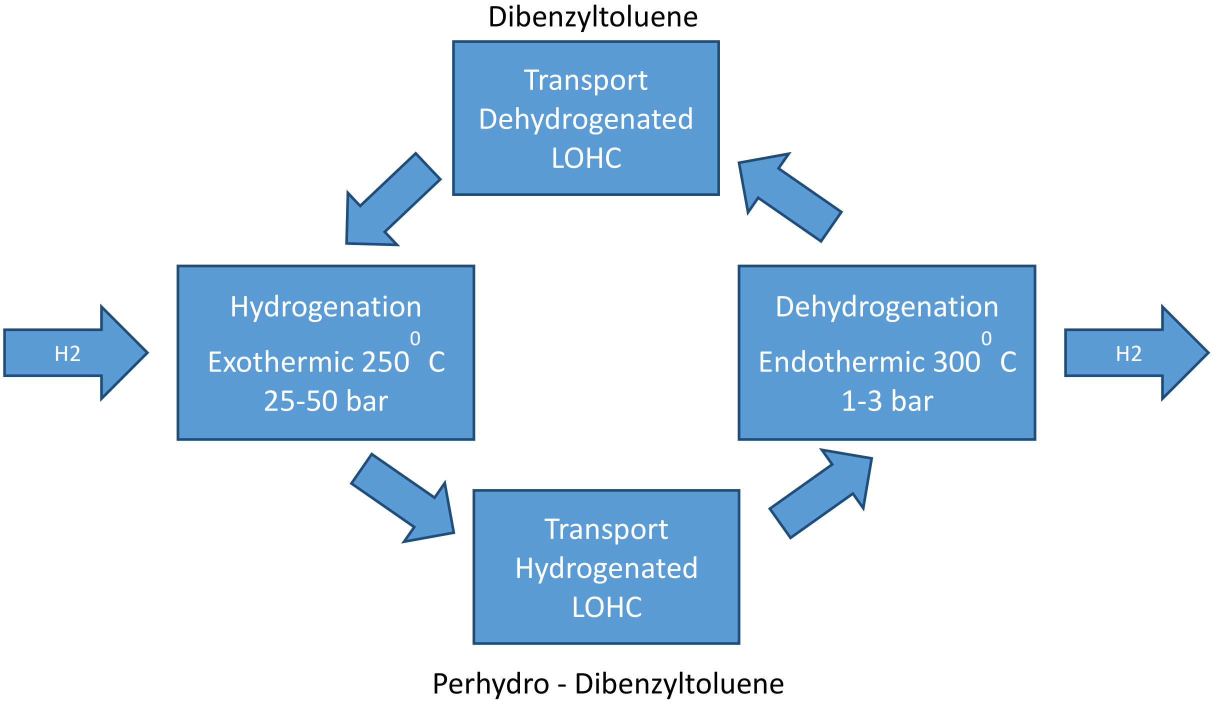
The original compound (also called carrier as it essentially carries the hydrogen) is recovered during the dehydrogenation process. The compound is then reused to again store and transport hydrogen completing a full transport of hydrogen cycle (from storing to releasing hydrogen back to storing and releasing hydrogen until the compound is no longer useable and needs replacement).

There are different carrier materials that can be used to develop an LOHC transport system. These include toluene, N-ethyl carbazole, and dibenzyltoluene amongst others[81]. Each of these carriers has different absorbing properties and the hydrogenation/dehydrogenation happens at different pressures and temperatures.

Figure 6.7 illustrates the characteristics and properties for producing a transportable dibenzyltoluene LOHC[82] complete cycle to transport and release hydrogen at ambient conditions.

Figure 6.7 – Dibenzyltoluene LOHC characteristics

[81] https://onlinelibrary.wiley.com/doi/full/10.1002/ente.201700376#ente201700376-bib-0002
[82] http://www.hydrogenious.net/en/home/



Only a few steps are required to store and release hydrogen using the LOHC technologies. First, when hydrogen is produced, it needs to be pressurised up to 50 bar (lower pressures are also possible depending on the technology being used).

Second, the hydrogen is injected into a reactor, where a chemical reaction occurs using the hydrogenation process. The reaction leads to the hydrogen 'bounding' with the carrier (in this case, the carrier is dibenzyltoluene).

The reaction is exothermic in nature, producing heat at around 250 degree Celsius. The heat can be flared or used for other local heating purposes at the hydrogen production and storage site.

When the reaction is completed, the Perhydro-dibenzyltoluene chemical is produced, which is saturated with hydrogen. It is this chemical that is used to transport the hydrogen and called LOHC.

At the other end, the site where hydrogen is consumed (or dispensed), there is a dehydrogenation process. This process is the opposite of the hydrogenation. It is endothermic in nature, meaning that there is a need for heat to release the hydrogen from the carrier.

When 300 degree Celsius is applied to the Perhydro-dibenzyltoluene carrier, hydrogen is released at pressure between 1 to 3 bar. The hydrogen can then be pressurised or used directly to fuel local stationary applications.

The advantage of LOHC when compared to gaseous and liquefied hydrogen transportation is its ability to carry a substantial amount of hydrogen within a limited volume. For instance, for the above mentioned Perhydro-dibenzyltoluene example, 630 Nm^3/m^3 LOHC can be stored. This is equivalent to a 6.23 percentage by weight (wt%) or about 57 kg of H_2 per m^3 of LOHC.

This means that a standard truck trailer can transport a maximum of just over 2500 kg of hydrogen (depending on the truck trailer length and void volume). This is higher than the gaseous trailer, which can transport up to 350 kg at 250 bar (depending on the truck trailer length). It is lower than the liquefied hydrogen trailer, which can transport up to 3,300 kg (again depending on the truck trailer length).

However, the strength of the LOHC option comes from the fact that it is usually non-explosive and is not classified as dangerous. As such, it does not need to carry special certification including ADR. The carrier is reusable, can operate at ambient conditions and can be handled in the same way as any other liquid. In addition, there is no boil-off of hydrogen, where 1 to 3% of hydrogen is lost per day when using the liquefied storage technology.

In common with the other H_2 transport systems, LOHC can be transported in trailer trucks, trains and boats. It can do so easily as it is in liquid form. Therefore, the LOHC liquid is of interest to hydrogen logistic companies to ship large quantities of hydrogen from the point of production to the site where hydrogen is consumed.

Currently there are many companies developing LOHC carriers, some of which use water as a catalyst to release the hydrogen[83]. Each technology has associated pros and cons and is only viable for a specific range of distances. Wang, Zhou and Ouyang[84] have looked at a number of organic materials capable of acting as carriers and concluded the overall efficiency is 69.1% (i.e. 30.9% loss), though this becomes 88.7% with heat recovery.

Note that the concept is attracting attention with a number of EU projects being financed such as LOHCNESS (completion 2019) and HYSTOC (completion 2020). Also note that transport scenarios are discussed by Teichmann, Arlt and Wasserscheid[85], who considered that even in 2012 the technology was broadly competitive[86].

6.5.2 What is the cost of transporting H2 through LOHC?

Figure 6.8 illustrates the LOHC system that is investigated.

Only the cost for transporting hydrogen is investigated; the costs of producing and pressurizing hydrogen are not included as it is assumed that these are similar to the costs of pressurizing hydrogen in the gaseous transport scenario. However, the added heating cost at the dispensing end (consumption end) needs to be taken into account when using LOHC (see Figure 6.8). This cost is not factored into the scenario below as it does not form part of the cost to transport hydrogen from the point of production to the point of consumption.

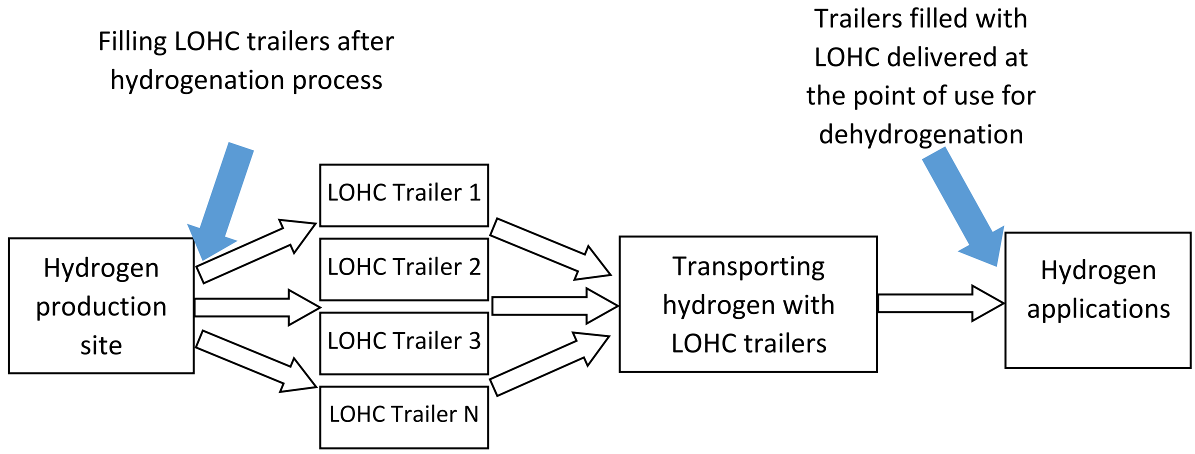
[83] http://hysilabs.com/

[84] H. Wang, X. Zhou and M. Ouyang, 'Efficiency analysis of novel Liquid Organic Hydrogen Carrier technology and comparison with high pressure storage pathway', International Journal of Hydrogen Energy 41(40) pp 18062-18071 26 October 2016

[85] D. Teichmann, W. Arlt and P. Wasserscheid , 'Liquid Organic Hydrogen Carriers as an efficient vector for the transport and storage of renewable energy', International Journal of Hydrogen Energy 37(23) pp 8118–18132 December 2012

[86] However, in light of the analysis here, that conclusion should be disputed.

Figure 6.8 Scenario 7 – Transport of hydrogen through LOHC trailer at ambient conditions



The aim of this scenario is to identify the cost for transporting hydrogen using the LOHC storage medium from the point of production to the point of use. This will be expressed in £s per km, and calculated a £s per km cost over distances of 25 km, 50 km, 100 km, and 200 km and above.

For transporting a liquid, the cost of a typical trailer is £200,000. It is assumed that a trailer truck will need 0.5 hours load (or swapping one empty trailer for another fully loaded hydrogen trailer) and 0.5 hours unload (or swapping) time. The staff requirement would be 2 drivers per truck for a maximum distance of 270 km per day (2 truck trailer deliveries over 24 hour period). There is a need for 4 drivers for a maximum distance of 600 km. The section below describes the drivers and distances assumptions.

The UK's Department for Transport and Driver and Vehicle Standards Agency, "Drivers' hours: rules and guidance[87]" sets the rules (and legislation) for lorry, bus and coach drivers on the number of hours a driver can drive, exemptions from the rules, and when the rules can be relaxed temporarily. These rules state:

- A 9 hour daily driving limit, which can be increased to 10 hours twice a week
- After a period of no more than 4.5 hours of driving, drivers must immediately take a break of at least 45 minutes unless a rest period is taken instead
- A regular daily rest period should be of 11 hours uninterrupted

Based on these rules, and considering the average speed of 60km/h, the following assumptions are made:

1. For distances from 0km to 270km, only 2 drivers are required per week. The maximum distance one driver can cover without needing a break over a 4.5 hour period is 270 km. A full shift for one driver will comprise of 0.5h-loading, 4.5h-driving, 45min-rest, 0.5h-unloading, 4.5h-driving.
2. For longer distances, e.g. 280 km to 600 km, there is a need for 2 drivers. One driver will drive for 9 hours (or 600 km) to the end-user site. The other driver will drive 600km back to the production site.

[87] https://www.gov.uk/government/collections/drivers-hours-rules-and-guidance#working-time-and-drivers'-hours

3. Distances above 600 km require the introduction of an additional truck, trailer and 4 members of staff.

The salary costs for the staff are based on typical haulage company wages for drivers and are included in the calculations. Fuel costs have been taken into account with other costs, including insurance, training and maintenance. A conservative average vehicle speed is chosen and although the lorry travels back 'empty of hydrogen' (but not empty of the LOHC carrier), a faster journey time on the return journey is not assumed.

Table 6.3 and Table 6.4 below summarise the different costs associated with a truck and trailer. They also summarise the different assumptions made for the model.

Table 6.3 – Fixed cost assumptions for the model

Fixed Costs		
Purchase Price of Vehicle	200000	£
Monthly Interest	-	£
Insurance	4000	£
Licenses, Taxes & Compliance	2000	£
Office overheads	1000	£
Total fixed costs per km	**0.295714**	**£**

Table 6.4 – Variable costs assumptions for the model

Variable Costs		
Fuel	375000	£
Long-Term Maintenance (10% of total price)	20000	£
Regular maintenance (tyres, brakes, oil etc)	10000	£
Tolls	N/A	£
		£
Total variable costs per km	**0.578571**	**£**

Table 6.5– Other costs assumptions for the model

Other Costs		
Drivers wages per annum per driver	35000	£

To calculate the transportation costs per kilometre, the below formula is used:

$$Cost\ per\ km = \frac{Fixed\ Costs}{Expected\ Kilometrage} + \frac{Variable\ Costs(Including\ wages)}{Actual\ km\ driven}\text{, Eq.1}$$

Figure 6.9 and Figure 6.10**Figure 6.3** below illustrate the transport cost of hydrogen for a given mass versus distance travelled per day.

Figure 6.9 - Transportation cost per km

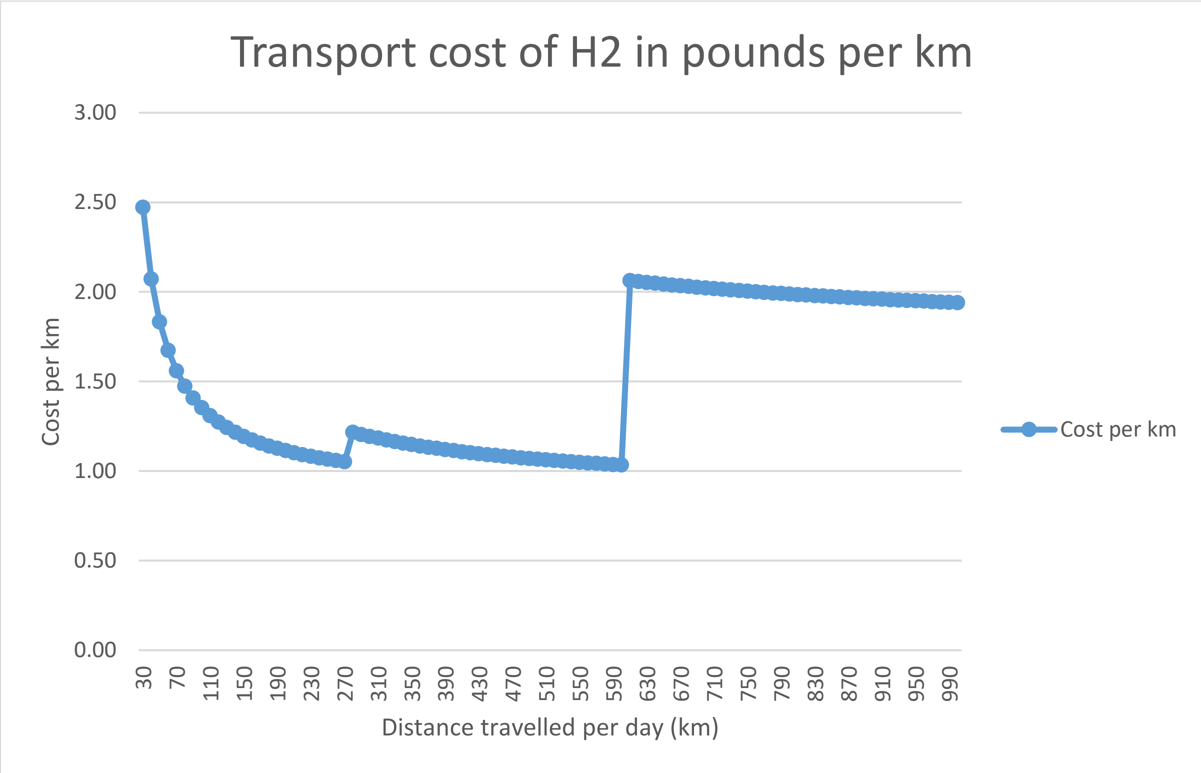


Figure 6.10 - Transportation cost per kg

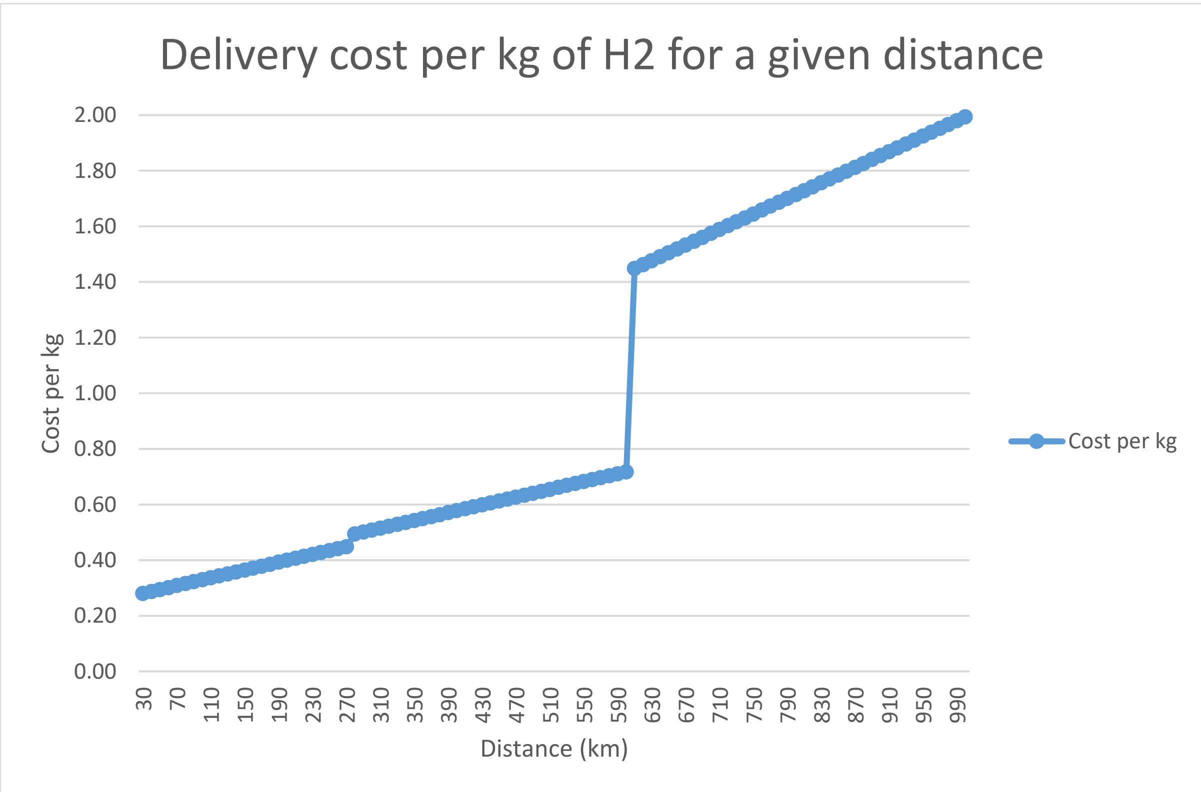


Table 6.6 - Cost per km and cost of delivery per kg of H2 for different distances

Distance, km	Cost per km, £	Total cost of delivery per kg of H2 including cost of LOHC, £
25	2.79	0.29
50	1.83	0.29
100	1.35	0.33
150	1.19	0.36
200	1.11	0.4
250	1.07	0.43
270	1.05	0.45
300	1.19	0.51
350	1.15	0.54
400	1.11	0.58
450	1.09	0.61
500	1.07	0.65
550	1.05	0.68
600	1.03	0.72
650	2.06	1.5
700	2.02	1.57
750	2	1.64
800	1.99	1.71
850	1.97	1.78
900	1.96	1.85
950	1.95	1.92
1000	1.94	1.99

6.5.3 Scenario C Conclusion

This scenario illustrates that the cost of transporting hydrogen using LOHC technology to the point of use could be of interest in a number of production scenarios, while in others this mode of transport would not be not viable.

For instance, at distances below 25km, the cost of transporting/delivering hydrogen at £2.50 per km for 5 tonnes of hydrogen a day is high. This is due to an inefficient use of the available resources (such as minimum use of the truck on the road, driver's low driving range with high income, etc.). The cost per km in this scenario can be improved if a driver is employed part-time.

The most efficient scenario is the one that optimises the use of the assets including drivers' time. Using the LOHC carrier, the optimum use of the assets is achieved at distances between 270 km and 600 km. This is where the cost of transporting hydrogen is at its lowest. These distances are usually considered as fairly long by the hydrogen industry and the cost of transporting hydrogen in forms other than LOHC over these distances is high.

As such, LOHC can be a potential alternative to transporting H_2 in a liquid form. For this particular scenario, the transport cost will be £1.05 per km for a 270 km distance and £1.03 per km for a distance of 600 km. These costs are lower than the cost per km for transporting hydrogen in gaseous form.

At 600 km, the cost of transporting hydrogen per kg increases sharply because there is a need for more drivers and more truck trailers, hence higher CAPEX and OPEX. In this particular case, the cost for delivering one kg of hydrogen doubles (see

Figure **6.4**) from £0.72 to £1.50.

Table 6.6 shows that the best cost per km/cost per kg ratio can be achieved at distance of 270 km.

The main differences between LOHC and gaseous transport can be summarised as follows:

- LOHC can transport hydrogen in a condensed form, leading to more hydrogen being transported within a given comparable void volume to gaseous form. Within 57 kg of hydrogen can be stored in 1 m^3 of LOHC. A minimum of 6 MCPs consisting of 12 cylinders each at 175 bar would be needed to match this.
- LOHC does not need specialised ADR certification for transporting hydrogen, reducing the cost of the trailer.
- Transporting LOHC does not need specialised training for the drivers.
- LOHC does not need expensive insurance for the truck.
- LOHC is not explosive.
- Reduced footprint because safety zones around the hydrogen carrier is small.
- Can be used to transport hydrogen in large quantities via truck, boat and train.
- Allow for a large scale hydrogen production system to distribute hydrogen to a multitude end-user (offloading hydrogen at different locations with small and medium quantities). One truck could be used to dispense hydrogen via the LOHC carrier to several different sites.
- There is a need for heat to release the hydrogen at the consumption site. The amount of heat required to release the hydrogen is non-negligible and should be factored in a total cost of ownership scenario.

There is a need to pressurise hydrogen at the point of production to up to 50 bars. Current electrolysers available on the market pressurise hydrogen up to 30 bar and therefore there is a need for a compressor to be installed at the production site, adding to the CAPEX and OPEX at the production site. There is also a need to pressurise hydrogen at the point of the consumption to the end-users required pressure. For instance, if the end-user has a 700 bar application such as a vehicle, then a high pressure compressor would be needed. However, the CAPEX and OPEX for this pressurisation stage at the end user site will be same as the gaseous solution, and therefore does not impact on the costs when both technologies are compared.

However, there is also the need to factor in the cost of the hydrogenation and dehydrogenation when developing an LOHC hydrogen transport solution using the total cost of ownership methodology. The material cost of dibenzyltoluene is £4 per kg and there is scope for the cost to be reduced through large-scale production. It is not a flammable substance in either the charged or uncharged state, hence the quantity that can be carried by lorry is equivalent to as much as 2.5 tonnes of hydrogen under ambient temperature and pressure conditions. Note that there are negligible losses even during long-term storage hence seasonal storage is possible.

Finally, there are other forms of liquid/gaseous hydrogen carriers such as methanol and ammonia which are of interest in other scenarios. The methanol carrier is of interest when there is a large amount of CO_2 available that can be easily captured then mixed with hydrogen to produce methanol. Methanol is a commodity widely used in the chemicals sector that also has applications in the transport and stationary power generation sectors too. The cost of producing methanol using greenly produced hydrogen is being investigated by a number of European projects. With regard to ammonia — this chemical can be used for power generation or fertiliser, and also suitable for transportation over long distances.

7 Conclusions

The potential benefits of utilising constrained renewable energy to produce hydrogen can be clearly understood. These benefits include:

- Maximising the use of renewable energy resource;
- Reducing constraint payments for the system operator;
- Providing additional revenue streams to wind farm developers in a post-subsidy environment; and
- Producing hydrogen as a transport fuel from renewable sources i.e. green hydrogen.

Large areas of the electrical transmission and distribution networks across Scotland are facing constraints, primarily as a result in the unprecedented increase in distributed generation connections over the past decade. There is currently over 8 GW of onshore wind projects connected across the Scottish networks, which has resulted in many areas operating close to, or in extreme cases, in excess of their (N-1) operational limits of thermal capacity, voltage and fault levels. Particularly susceptible areas have been identified as Ayrshire, Lothian & Borders, Dumfries & Galloway and the Highlands & Islands. The majority of the highest curtailed wind farms (for the whole of GB) are located in these areas.

New solutions for managing network constraints are being trialled by the DNOs, including the implementation of Active Network Management (ANM) and other technologies, to provide a cost-effective connection option to generation developers and avoid or defer costly wider network reinforcements. With almost 5.3 GW of onshore wind projects in various stages of planning (but not yet connected) in Scotland alone, there is an urgent need for more innovative solutions to manage these existing and any future constraints.

The deployment of green hydrogen production for this purpose could prove valuable under the right regulatory conditions — which are currently not as flexible at lower voltages in terms of market participation — however the transition of DNOs to a DSO model could enable more flexibility.

In terms of the hydrogen systems themselves, the cost modelling performed in this study has shown that:

1. Hydrogen production can be financially viable today under the appropriate conditions. The cost for producing hydrogen can be below £6 per kilograms even if the Power Purchase Agreement (PPA) is up to £60 per MWh. Note that this is for a hydrogen installation located at a wind farm.
2. A constrained wind farm that experiences curtailment of less than 15% will not be financially viable. Even at 15%, there is a need for substantial public sector financial intervention to allow such a project to be potentially viable.

Scenario 4 has demonstrated that:

- For a cost of electricity of £20 per MWh, the hydrogen can be produced for as low as £3.30 per kilogram. At £60 per MWh, the hydrogen will still cost less than £6 per kilogram to produce.
- The production of green hydrogen fuel is currently financially viable if the hydrogen system is operating close to continuously and at its rated production output. Also, there could be economies of scale for larger systems that can use the constrained energy from a number of wind farm sites.
- High utilisation of the hydrogen system is required in order to lower the unit cost of hydrogen production.

- As a rule of thumb, any system subject to curtailment below 15% may not be viable at today's hydrogen system CAPEX and OPEX levels. When the level of curtailment or constraint reaches anything above 25%, then there is a significant potential for a hydrogen project to be viable.

It is important to note that, despite Scenarios 1, 2 and 3 not being identified as financially viable at present, it will be useful to re-examine these at such times as the costs of hydrogen systems decrease. If the CAPEX/OPEX of a hydrogen installation is reduced to such a degree that green hydrogen is able to compete with other forms of hydrogen production such as gas reformation — due to mass manufacture or even government support — then hydrogen from renewables could have a significant future in Scotland.

From the study results, it could easily be concluded that if the size of an electrolyser is one twentieth of the size of a wind farm, then renewable hydrogen production should be financially viable. This is true for large scale wind farms, however, it is important to further investigate lower capacity systems. The aim is to define the cut off point or the breakeven point where this conclusion cannot be validated.

Specific Hydrogen Demand Applications

Two scenarios were studied with specific hydrogen demand applications in mind: ferries; and a hospital that would buy the hydrogen production by-products (oxygen, heat etc). In the ferry application, the price of hydrogen was calculated as £6.10 per kg for a 20 MW electrolyser and 30 tonne storage system when supplying one sailing route on the Western Isles. Two variations were also studied to understand the incremental requirements and costs for supplying: all ferries on the Western Isles with hydrogen; and all ferries on the Western Isles plus some land transport systems (buses). The cost of hydrogen per kg came out as £6.20 per kg for all ferry routes around the Western Isles and £6.00 for all public transport routes (ferry routes and buses). Both options would require large scale electrolysers. However, the current price of around £6.00 per kilograms is not competitive with the price for 1 litre of marine diesel fuel. Hydrogen must be sold at a £2 per kilogram (≈ £0.50 equivalent for 1 litre of marine diesel) for it to become viable as a marine fuel.

The hospital application business model was based around the hospital purchasing oxygen, waste heat and electricity from the development (green hydrogen is produced from a wind turbine erected specifically for this purpose and sold at a price of £6 per kg). The scenario found that the wind farm developer, the hydrogen system developer and the hospital all benefited financially, with the hospital standing to save up to £10,000 per annum on energy costs through a joint price offered for heat and electricity.

Transporting Hydrogen

There are three main forms in which hydrogen can be transported: gaseous; liquid; and liquid organic hydrogen compound (LOHC). Transporting hydrogen in gaseous form is achievable and can be done for £1.15 per km (assumed 800km distance). As distances from point of supply to point of demand increase, the amount of hydrogen that can be transported decreases linearly. A more detailed analysis would have to be carried out on the breakeven point regarding distance from supply and grid use of system costs to facilitate decision making on a project specific basis.

Liquid hydrogen can be transported in larger quantities, however, the energy required to liquify the hydrogen increases the costs so much that it is difficult to prove a positive business case.

The third main option for transporting hydrogen involves combining it with another element to create a liquid compound that is less hazardous than pure hydrogen. This method allows large quantities of hydrogen to be transported under less stringent safety conditions, which reduces cost. This method of transportation has an optimum distance range of between 270km and 600km where there is a favourable business case and it is able to maximise multiple processes e.g. driver's time. In this case, the hydrogen can be transported for between £1.03 and £1.05 per km. However, there is the need to factor in the cost of hydrogenation and dehydrogenation at either end of the transportation process, which has not been considered by this study.

7.1 Recommendations

A number of recommendations can be made based on the findings of this study:

1. The undertaking of a detailed analysis of all wind farms in Scotland to determine specific wind farms, or clusters of wind farms, that meet the minimum viable curtailment levels identified in this study.
2. For existing onshore wind projects that are eligible for ROCs, investigate whether the electricity that would be redirected to a hydrogen electrolyser would still be eligible to receive ROCs despite not being exported to the electrical grid.
3. Initiate a pilot scheme with a large wind farm, consistent with Scenario 4, to demonstrate that continuous production of hydrogen is possible and that this can be achieved economically. The benefits of this approach should be assessed in terms of curtailment and also environmental benefits.
4. An investigation into the maximum size of an electrolyser when compared to the size of a wind farm to determine optimal economic viable could be of interest to developers.
5. A study into whether the production of green hydrogen would be feasible for the marine energy sector is recommended to understand if and where there are potential benefits. Hydrogen energy storage could be a useful addition to marine energy projects, particularly tidal, where there are more consistent energy resource patterns that could be capitalised upon.
6. A feasibility study, potentially leading to a pilot scheme, which looks in more detail at the specific aspects of building a business case for the transport sector on an island network is recommended. Lessons learned from other hydrogen transport pilots and trials can be taken on board while challenges/opportunities unique to island networks can be identified and disseminated for the benefit of all Scottish islands (and beyond).
7. The sale of by-products (of the hydrogen production process) such as oxygen and heat can be viable in certain circumstances. More detailed modelling of this particular application could identify a potentially large demand base (hospitals). This could be achieved through a feasibility study to outline business case development, and where assessment of the commercial aspects of trading hydrogen, electricity, heat and oxygen between various stakeholders could be included. Identification of a candidate hospital to participate in a trial would be a logical next step to a feasibility study if a favourable business case(s) is/are identified.
8. Different modes of transportation for hydrogen are suited to different distances. It would be helpful to developers to understand the costs involved for the transportation element of their system depending on location. A set of guidelines and/or specifications for each method of transportation should be produced for developers to reference.

Appendix A – Dynamics of Hydrogen Systems

In this report, it was shown that the idea of producing hydrogen to address the problem of curtailment is not at the moment financially viable for a typical small wind farm. It was also shown that there is a need to avoid transmission charges. To do so, a hydrogen system (electrolyser, storage, etc.) would have to be located on site. The hydrogen system would also have to be operating with an appropriate switching mechanism, probably under the control of the grid operator for times when the turbine should be curtailed.

Even with initial capital funding from EU, UK and Scottish Government sources for a pilot to demonstrate the concept, the challenge of developing a market for the electrolysis products (including heat) and moving the products to market would remain. One option is to use hydrogen for public and private transport, following the example of Aberdeen, or for ferries and shipping (as is the case on Orkney).

From the above, if producing hydrogen from a curtailed wind farm is not financially viable, it is evident that it is not economic to use a fuel cell to put electricity back onto the grid – efficiency and storage capacity become significant issues.

There is a potential for hydrogen to be injected into the gas grid network, but this require very special circumstances. For instance, it requires that the wind farm and hydrogen system be near a gas pipeline. Though nowadays the price of natural gas is low, this option could be viable in the future when gas prices will increase.

Nevertheless, for all of the above applications to succeed financially, it is critical to understand the dynamics between the levels of curtailment, the cost of a hydrogen system and the corresponding price of hydrogen per kilograms. Without such an understanding, it is almost impossible to develop a sense where a system could become financially viable.

The below section provides the answer to this issue. It summarises the information needed to quickly define the viability of hydrogen system. It does so by identifying the different dynamics between the above main three criteria (curtailment levels, cost of hydrogen system, and end price of hydrogen per kilogram). Note that the below study is theoretical. However, it forms the basis for understanding of the different issues that hydrogen and wind developers are facing when investigating hydrogen systems deployment at the back of a renewable generation source.

Dynamics between curtailment, equipment cost and H2 price

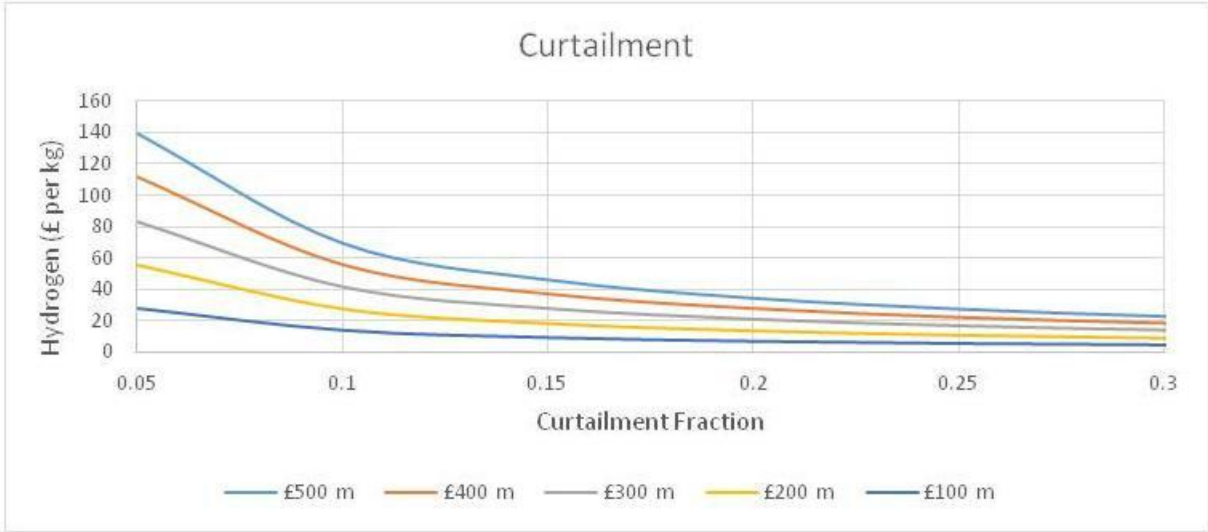
The approach chosen here is to assume that curtailment occurs when the wind farm is operating at its rated power. This is a reasonable assumption because the primary trigger for curtailment is the point of electricity supply exceeding demand.

From the above assumption, the fraction of time the wind farm is on full power and curtailed can be identified. Rather than part-curtailing many wind farms (cluster of wind farms), it is assumed that the curtailment is applied to a single wind farm.

It is also assumed that the size of the electrolyser is of the size of the wind farm rated power. In the present case, the selected wind farm is 100MW in size. As such, the size of the electrolyser is 100MW.

Figure A.1 is produced from the above assumptions. The graph below summarises the cost per kilogram of hydrogen as a function of curtailment fraction and the variation with equipment capital costs.

Figure A.1 Cost per kilogram of hydrogen as a function of curtailment fraction and equipment capital costs



The different coloured curves illustrate the price of hydrogen per kilogram associated with a price of a given hydrogen system (including electrolyser, compressor, storage, etc.). To be more precise, for a 100MW wind farm, the cost of the hydrogen system is taken as:

1- In blue colour: £100 million for a 100MW hydrogen system (this is really an optimistic future price).
2- In yellow colour: £200 million for a 100MW hydrogen system (this is again another optimistic future price, though achievable).
3- In grey colour: £300 million for a 100MW hydrogen system (this is potentially achievable with economy of scale).
4- In orange colour: £400 million for a 100MW hydrogen system (this is achievable nowadays depending on the end application and the location of the system – near or far from end user).
5- In green colour: £500 million for a 100MW hydrogen system (definitely achievable).

From the above figure, it is apparent that to get the hydrogen production cost down to a reasonable level (less than £10 kg^{-1}), there is a need for the hydrogen system cost to be of the £2 million per installed MW. It is also obvious that to maximise income, there is a need for a minimum curtailment fraction to be of the order 15% - 25%.

This is because the capacity of the electrolyser matches the capacity of the wind farm and only uses a fraction of the electrolyser potential (because the electrolyser is only switched on during curtailment).

The above system was also used to define the financial viability for when the electrolyser uses all the electricity (such as in an off-grid system or as per scenario 4). The hydrogen price comes to about £3m per kg for an electrolyser cost of £2m per installed MW (note that in Scenario 4, we used real installation cost for hydrogen system and that is why the numbers differs from the ones found here).

Appendix B - Best Case Scenario for a Curtailed Installation

In this analysis, the impact of installing an electrolysis system to produce pressurised hydrogen at times when a wind farm would otherwise be curtailed is investigated. A best case scenario is foreseen to identify if a curtailed wind farm is financially viable in these particulate conditions.

The best case scenario takes into account the following assumptions:

- All of the products of electrolysis should find their way to market.
- Reasonable initial target for the hydrogen would be £5 kg^{-1} for hydrogen gas at a pressure of 100 bar
- £1 kg^{-1} for oxygen[88]
- £20 MWh^{-1} for waste heat from electrolysis (hot water @ 60°C).

Though the above assumptions are likely to happen in only a few occasions, it is important to identify if a curtailed wind farm associated with a hydrogen system can be financially viable in the best case scenario.

Note that it is also assumed that there is a market for the above three products (hydrogen; oxygen and heat) at the proposed standard market target prices.

Issues with the Best Case Scenario

It is important to note that the status of the existing subsidies in this particular scenario is uncertain. For instance, and when considering ROCs and strike price, only electricity going to the grid is eligible[89], and it is unlikely that the current financial support would carry over to electricity used for electrolysis (unless there is government support for this to happen).

Again, the RHI[90] could apply to the waste heat, but it is likely that a new government policy would be needed to subsidise electricity directed towards electrolysis (at the order of £50 - £100 per MWh).

It is highly feasible to assume that as solar energy and wind power are now becoming cost competitive with traditional power generation, the natural progression would be to move financial support from generation towards energy storage.

The greatest impact of such a scheme, if widely adopted, would be to produce a surplus of green hydrogen. This could kick off the hydrogen economy in Scotland and put Scotland in a world-leading position that would give rise to research and development opportunities and a significant number of jobs in this sector.

Curtailed 9 MW Wind Farm using the Best Case Scenario

This scenario refers to a 9 MW wind farm which is on a weak grid and is constrained in a number of ways. One specific problem is that a heavy oil power station acts as conventional grid back up and if

[88] Note that the production of 1 kg of hydrogen is accompanied by 8 kg of O_2.
[89] http://www.esru.strath.ac.uk/EandE/Web_sites/08-09/Hydrogen_Buffering/Economics%20-%20Renewable%20obligation%20certificates.html
[90] Renewable Heat Incentive

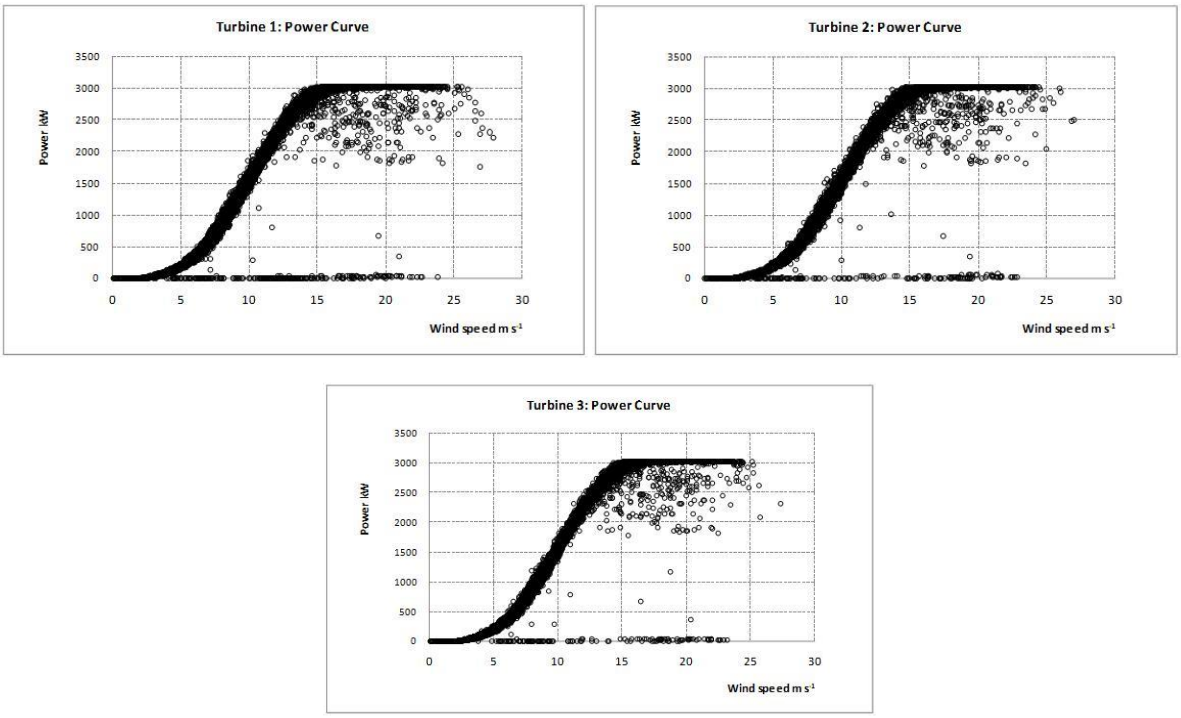
it is operational the wind farm will, unfortunately, automatically be severely curtailed (to prevent grid instability).

Curtailment has been discussed with the wind farm owner. It has been identified from the raw data as occurring when the wind speed exceeds the turbine cut-in speed, but the real power exported is zero. Times when the turbine is faulty or taken offline by the operator have been reported and are excluded from the analysis.

The wind farm is made up of three 3 MW turbines. The power curves below show the response (Figure B.2). The variation at the higher wind speeds is likely the result of the turbines interfering with each other (wake effects[91,92]). Therefore, these have not been included. About 21 months of data has been acquired:

Figure B.2 Curtailed three 3MW wind turbines power curve

Number of turbines	**3**
Start Date	01/12/2015 00:00
End Date	05/09/2017 23:50
Sampling Interval	00:10:00
# Points	278640
# Null data non useful for simulation (offline, maintenance, etc.)	2654
# Curtailed data (lost energy that could have been produced) – these are the number of data points identified as curtailed)	17803



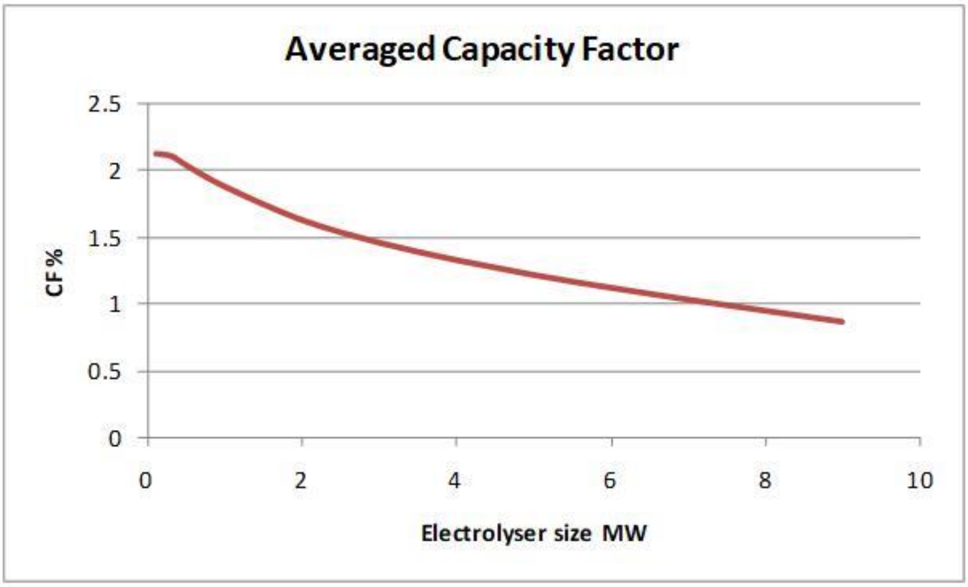
[91] This could be established for certain by correlating deviation with wind direction.
[92] What is the wake effect? - In essence, a wind turbine has two effects on the wind. The first effect occurs when the turbine extracts energy from the wind. In this case, the wind slows down. The second effect occurs as soon as the wind leaves the blade turbines where it creates turbulences in the air. The slowing downs effect and the turbulences created in the wind pattern will therefore affect a wind turbine installed downstream. These two effects are referred to as wake effect. The wake effect is usually causing disturbance for nearby turbines by creating manual vibration from turbulence, increasing wear and causing increased maintenance costs.

From the data, it is possible to estimate the hydrogen production for an electrolyser installation capacity ranging from 0.1 MW to 9 MW.

Income versus electrolyser size

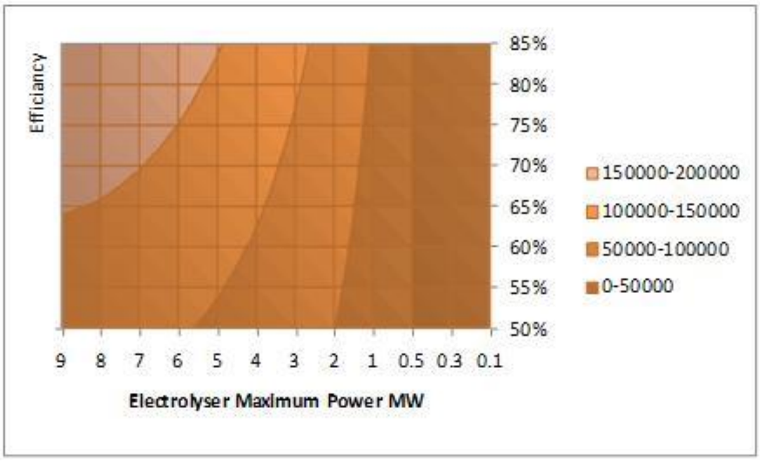
Installing a 9 MW electrolyser would ensure no energy is wasted, but this is not a good solution. Figure B.2 shows the variation of capacity factor with electrolyser size.

Figure B.2 The impact of electrolyser size on hydrogen production (capacity factor)



As Figure B.2 shows, the electrolyser capacity factor for this wind farm is very low. Using the previously stated assumptions (£5 per kg of hydrogen, £1 per kg of oxygen, £20 per MWh of heat) it is possible to calculate the annual income. This is shown in Figure B.3.

Figure B.3 The variation of annual income with electrolyser size and efficiency



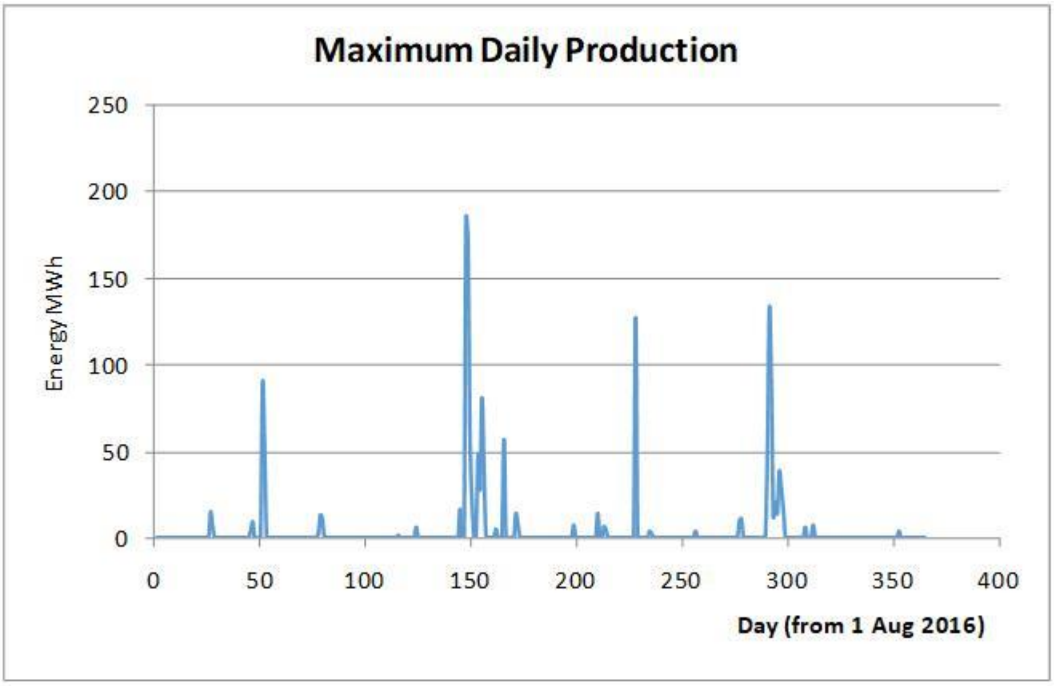
From Figure B.3, it is possible to identify the region where the electrolyser versus income is optimised. In this particular case, a reasonable configuration to take forward into a cost analysis is a 3 MW electrolysis capacity with an efficiency of 75%.

The predicted income in this case is £97,000 a year. The estimated carbon dioxide emissions reduction is[93] 1,500 tonnes.

Having determined the size of the electrolyser that fits the wind farm and the curtailment, it is important to consider the quantity of hydrogen that can be produced. The below figure illustrates when hydrogen production will be operational since August 2016. This clearly shows an extreme variability of hydrogen production due to the fact that there is a small amount of time where the wind farm is curtailed. The wind farm is only curtailed about 6% of the time. This is fairly standard across the wind farm available and therefore this example provides a good case study that can be used for wind farms.

At this point, it is somehow intuitive that this wind farm may not be financially viable, unless the hydrogen system uses more wind generated power.

Figure B.4 Electrolysis operation is extremely variable



From the above, it is now possible to consider if the installation is viable by referring to the purchase, installation and running costs of existing equipment.

Best case scenario financial viability of a 9MW wind farm

As aforementioned, the 9 MW wind farm is curtailed for 6% of the time. With a 75% efficient 3 MW electrolyser, the total income over the lifetime of the wind farm will be just below £2 million (97k income * 20 years = £1,940,000).

Although the above income may suggest that this installation has a good income, it is critical to investigate if this is really the case.

In the below paragraphs and section, it will be shown that this income is not sufficient with current equipment costs. In fact, it will be shown that the income is too small by a factor of 5.

[93] Based on the Defra CO_2 emission factor of 0.527 kg kWh^{-1}.

The curtailed system described above will be compared with existing hydrogen projects in Scotland (already making significant advances in the general progress towards a hydrogen economy). The project that is the most advanced and established is the Aberdeen Hydrogen Bus Project. The rational is to identify the costs for the Aberdeen project and use these to determine if the above best case scenario is viable.

In this case, the initial capital costs were grant funded and the aim was to demonstrate that buses can run effectively by charging a price for hydrogen equal to the production and running cost[94].

Aberdeen is known as the UK energy centre with concentrated expertise in oil and gas, and this is an ambitious development. The project had a budget of £19 million (up to 2018) and supports the current operation of ten hydrogen fuel cell buses.

It included a production facility at Kittybrewser to produce hydrogen by electrolysis using grid electricity. The installed three KOH alkaline electrolysers are capable of producing a total of 360 kg of hydrogen per day[95].

The electricity is purchased at the commercial rate (varying between 8 p – 16 p per kWh over the day). Buses are fuelled on site in 10 minutes. Each bus holds 40 kg of hydrogen at 350 bar in roof tanks and can travel 350 km between refuelling on a typical urban cycle. The fuel cell will deliver 150 kW and has a lifetime of 15,000 hours.

The refuelling station has been installed near member of the public properties as shown in Figure B.5. There is currently an attempt to put a price on the hydrogen produced and used by the buses. This is shown in Figure B.6. The price is £7.50 kg^{-1}.

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[94] One negative aspect is that the hydrogen is not yet green – hydrogen produced using grid electricity is not necessarily from a renewable source.

[95] The three electrolyses can each produce 120 kg a day. Assuming an efficiency of electricity to hydrogen of 65% (including compression), we can calculate the power:

Electrolysing 1 kg of hydrogen requires 130-141 MJ of energy @ 100% efficiency, assume 136
Electrolysing 1 kg of hydrogen requires 136 / 65% MJ of energy @ 65% efficiency = 209 MJ
120 kg requires 120 x 209 MJ = 25,000 MJ.
120 kg requires 25,000 / 3.6 kWh = 6,900 kWh
This is equivalent to 6,900/24 kWh per hour = 288 kW
The total electrolyser capacity is about 800 kW.

Figure B.5 The inside of Kittybrewster refuelling station. Note the houses in the background

Figure B.6 The refuelling station has a price for each kg of hydrogen. In Feb 2017 it was £7.50

This and other bus projects have been assessed by the FCH-JU[96] and the total cost of a complete 7 MW electrolysis and storage system is estimated to be €27.2 million, or £3.4 million per MW (hydrogen only – electrolyser, compressor, storage but no buses).

The 3 MW system proposed for the above best curtailed wind farm scenario would therefore cost more than £10 million (to be exact, it would cost £10.2 million). This is five times the total revenue over the lifetime of the wind farm. From the above, the total revenue from the best case scenario is £1.94 million. When this revenue is multiplied by five, we obtain £9.7 million. This is almost 10 million, hence the factor of 5.

But to this, it is required to add the running costs.

[96] 'New Bus ReFuelling for European Hydrogen Bus Depots: High-Level Techno-Economic Project Summary Report', available at http://newbusfuel.eu/publications/

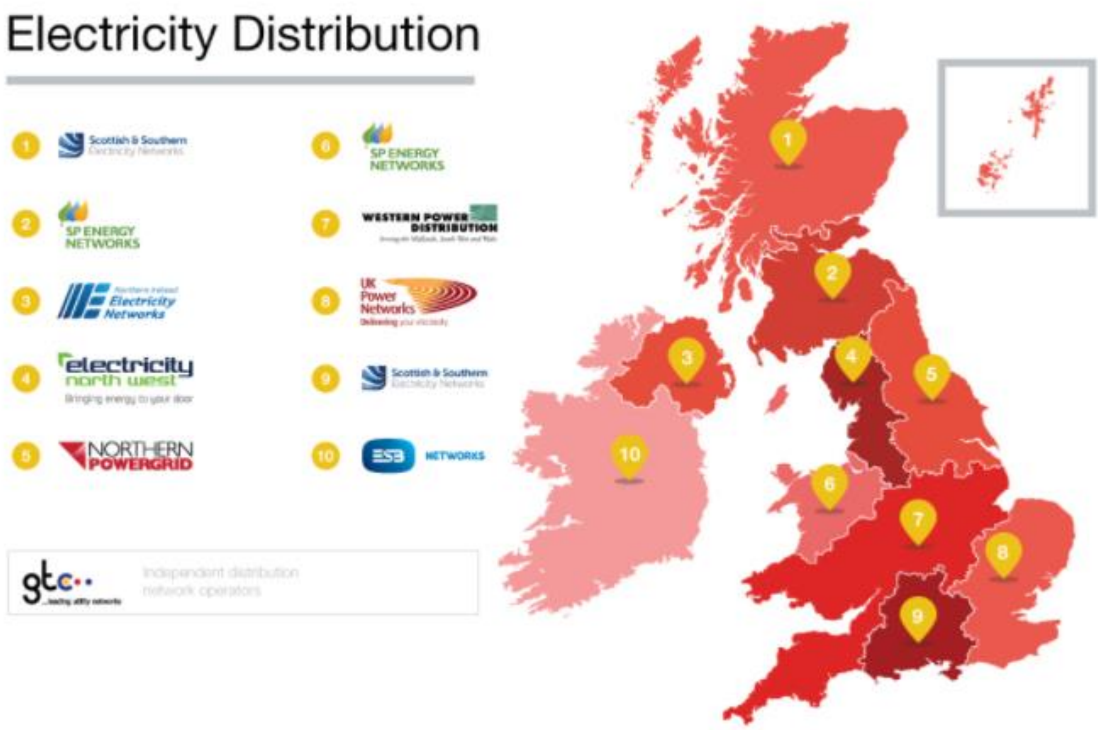
The conclusion from this best case scenario with the sale of hydrogen, oxygen, and heat is that curtailment of the order of 15-30% would be the threshold for making the proposition economically viable (assuming the markets can be created for the hydrogen produced). This confirms the finding of Appendix A with real world figures.

Appendix C – Grid Connection Application Process

Distribution Connection Application Process

Any developer requesting to connect to the distribution network must make a connection application to the relevant DNO. In Scotland this would be either SSEPD in the North, Highlands and Islands and SPD in the Central Belt and Borders. The licence areas for each of these DNOs are shown as areas 1 & 2 on the map in Figure C.1 below.

Figure C.1 UK DNO License Area Map [Source: Energy Networks Association]



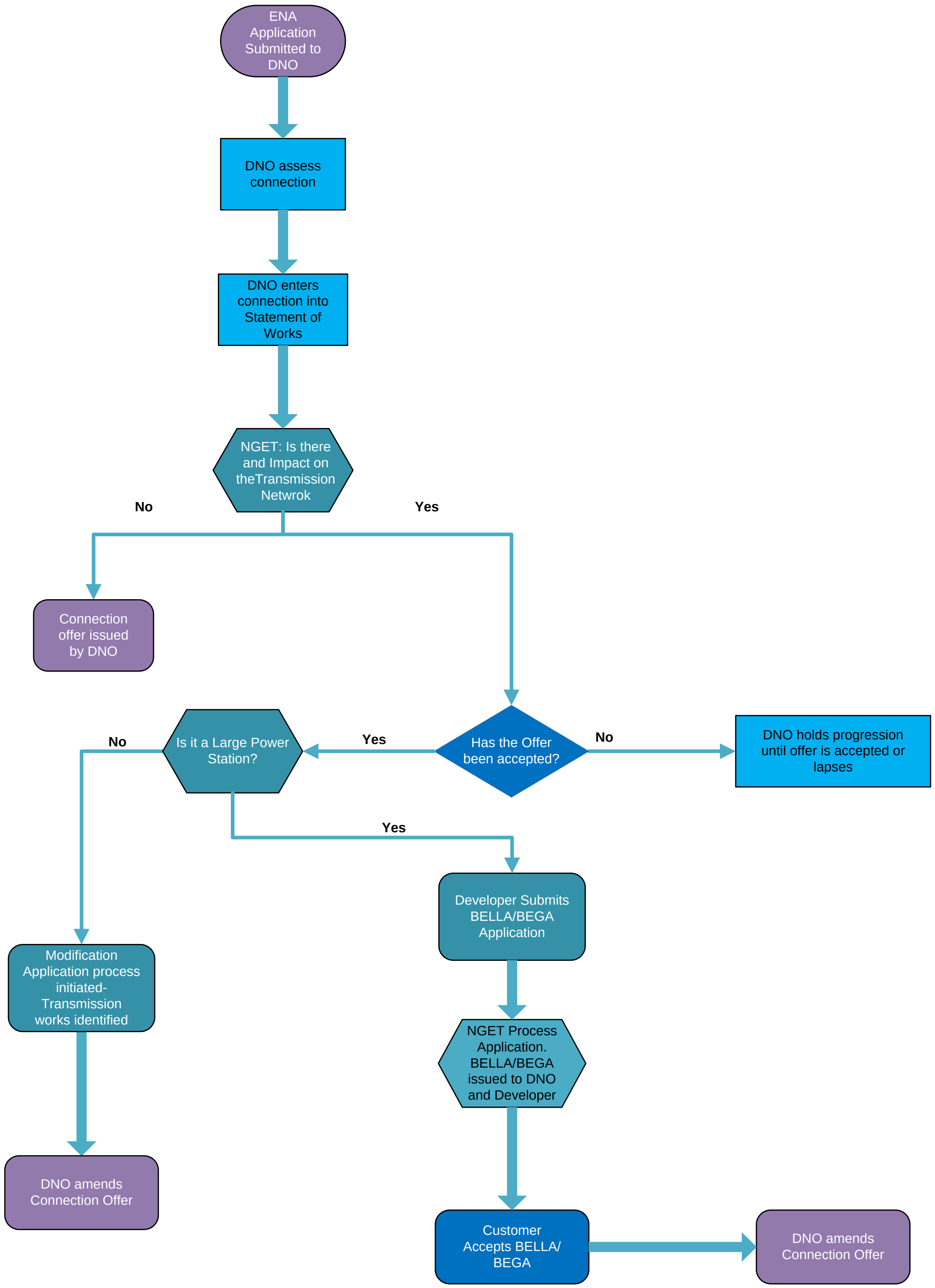
To connect into these networks, the developer must submit an ENA application form. This application form is standard across all distribution network operators and there is currently no application fee for submissions; however these fees are being reintroduced to better manage the volume of connection applications the DNOs must process. The application form provides details of the generation site so that the DNO can assess the implications of the connection and determine the cost to build the connection. The DNO will study the impact this connection will have on the local network and a decision will be made whether to enter the connection application into the Statement of Works process if they determine the transmission network will also be affected. When connecting at distribution voltages, the size of the registered capacity of the site will determine the type of agreements required. In Scotland the two DNOs have different requirements. These are detailed in Table C.1 below.

Table C.1 Requirements for Distribution Connections in Scotland

Size	Scottish Power	SSE	Type of Connection Agreement for Distribution Connected Generators
Large	30 MW+	10MW+	Distribution Connection Agreement plus BEGA (Bilateral Embedded Generator Agreement) or BELLA (Bilateral Embedded License Exemptible Large Power Station Agreement) (See Sections 5.1.3 and 5.1.4)
Small	< 30 MW	<10MW	Distribution Connection Agreement No Generator agreement required; BEGA (optional)

If the Statement of Works process highlights that the connection will impact the transmission network, the DNO will inform the developer as these reinforcement works could add additional CAPEX costs to the development. At this stage a decision to progress with the project will be made by the developer. The full distribution connection process is detailed in the flow chart in Figure C.2 below. Key processes and agreements presented in the flow chart are discussed in the sections to follow.

Figure C.2 Distribution Connection Application Process



Statement of Works (SOW)[97]

Once a connection application is submitted, the DNO will perform system studies and make an initial assessment on whether the connection will have an impact on the transmission network. If the results demonstrate that the transmission network will be affected, an offer will be submitted to the developer detailing the need to enter the Statement of Works process. A fee must be paid by the developer to enter this process. Once this fee is paid the DNO will submit the SOW application to National Grid (NGET).

Once the SOW application is made, NGET will assess the connection and advise the DNO of any wider works that are required in order to facilitate the connection. This will require a Modification Application to be made. The DNO will relay this information to the developer to determine if the project will progress. A Modification Application fee must also be paid which will provide the developer details of the transmission works required as well as the associated costs. NGET will then issue a Construction Offer to the DNO which will lead to a variation notice from the DNO to the developer detailing the transmission construction works. Due to widespread constraints in the existing network in Scotland, it is very unlikely an embedded generation connection will not impact the transmission network and often the Modification Application process will be initiated without the preliminary SOW process.

Bilateral Embedded Generator Agreement (BEGA)

A BEGA is an agreement that is required when a generator is categorised as a large power station (see Table C.1) requiring access to the transmission network but is not directly connected at a transmission voltage.

A BEGA provides the generator with Transmission Entry Capacity (TEC), which is the maximum amount the generator can export onto the transmission network, and the right to participate in the Balancing Mechanism[98]. As a result the generator must comply with the Balancing and Settlement Code[99]. If the generation connection is greater than 100 MW, transmission network use of system (TNUoS)[100] charges will apply. The generator will subsequently have a contract with NGET as well as the appropriate connection agreement with the DNO.

Bilateral Embedded Licence Exemptible Large Power Station Agreement (BELLA)

A BELLA is an agreement available to generators categorised as large (see Table C.1) but that are smaller than 100 MW. A BELLA is only applicable in Scotland. This agreement will not provide the generator with access to the transmission network and they will be exempt from obtaining a generation licence. A generator with a BELLA will contract with NGET and also have the relevant connection agreement with the DNO. It should be noted that a generator owning a large power station less than 100 MW can choose whether to obtain a BELLA or a BEGA.

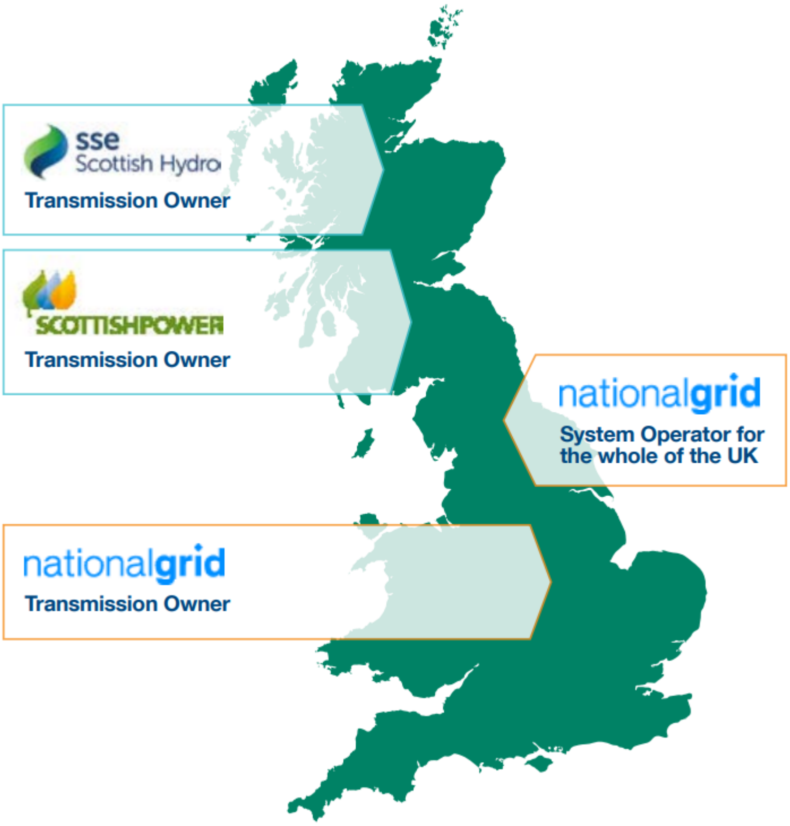
Transmission Connection Application Process

The process of connecting to the national electricity transmission system (NETS) is different in Scotland to that in England & Wales, since NGET operate the transmission system but they do not

[97] The ENA has recently announced plans for a new SOW process through their Open Networks project however the specific details are not yet available
[98] https://www.elexon.co.uk/knowledgebase/what-is-the-balancing-mechanism/
[99] https://www.ofgem.gov.uk/licences-codes-and-standards/codes/electricity-codes/balancing-and-settlement-code-bsc
[100] https://www.nationalgrid.com/uk/electricity/charging-and-methodology/transmission-network-use-system-tnuos-charges

own it. The transmission network in Scotland is owned by two parties: Scottish Hydro Electric (SHE) Transmission and Scottish Power Transmission (SPT) split over the same general geographic areas as the distribution network areas of SSEPD and SPD. This arrangement is highlighted in Figure C.3.

Figure C.3 Transmission System Ownership and Operation



Generators smaller than 100 MW can be connected to the transmission system in Scotland, where 132 kV is considered a transmission voltage (but is considered distribution in England & Wales). Embedded connections to the network were covered in Section 4.1 and so this section explains the process of applying for a direct connection to the transmission system. Unlike with ENA distribution connection applications, there are application fees for each submission to NGET due to the time and complexity of assessing and designing a connection. These can be anything up to £400,000 + VAT and so developers are offered a pre-application meeting to discuss their project and areas of particular constraint are highlighted at this early stage to discuss optimal connection points.

The first step in applying for a direct connection to the NETS is to complete a CUSC (Connection and Use of System Code) Exhibit B application form. It is at this stage the transmission entry capacity (TEC) of the project is defined and the connection entry capacity (CEC) which can be higher than the TEC in anticipation of future expansion.

A completed copy of the Data Registration Code (DRC) must also be submitted. This details all the generation developments technical information. To complete the DRC it is necessary to conduct fault level studies to determine the fault level infeeds from the generator at the point of connection.

Similar to the process by DNOs, at this stage the connection would be assessed, designed and costed. Issues and constraints would be highlighted which were not readily identified in the pre-application phase meeting.

Once an application is made, NGET will assess the project to determine if it is technically competent. If the project is declared technically competent, NGET will issue a connection offer within three months of this assessment. For generation developments which are directly connecting to the transmission network, these projects will be issued with a Bilateral Connection Agreement (BCA). This agreement highlights how the generator will need to comply with the Grid Code, CUSC and the Balancing Settlement Code. It will also detail the connection to the transmission network and state the requirements for balancing services.

In line with this, if a development needs to build or modify a direct connection to the transmission system, a Construction Agreement will be issued. This details any construction works required as a result of the connection. It will also provide information on the design, cost and construction programme.

Three months prior to the energisation date, the developer must provide NGET with details of the wind farm design and plant for approval. System studies will also be required from the developer at this stage. If the wind farm gains approval from National Grid an interim operational notification (ION) will be issued allowing the site to generate 20% of the registered capacity. The voltage control system will then be tested and if it passes the site can be commissioned to full capacity. Once the wind farm has been fully commissioned a final test will be carried out will be witnessed by National Grid. If these tests are successful the wind farm will received a final operational notification (FON) and will be issued a licence to generate.

Transmission connected generation will have to pay Transmission Network Use of System (TNUoS) charges. These charges largely depend on the TEC of the connection and also what area of network the development will be connecting into, whereby different areas have different tariffs. Scotland is split into two zones, Northern Scotland and Southern Scotland, where the tariffs in Northern Scotland are almost double those of Southern Scotland in some cases.