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Analysing The Impact And Opportunities For Scale Economies On A Hybrid On-Site Hydrogen Refuelling Station In Aberdeen City

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ABSTRACT

This paper investigated the impact of scale economies on the cost of hydrogen production using water electrolysis from an on-site refuelling station powered by a wind energy source and grid connection (Hybrid). The study used a levelized cost (LCOH) approach to estimate the cost of production through varying the scale of production with the wind powered approximating cost of investment and operation relating to the City of Aberdeen. The scale of production analysed where 1000kg (Base Case), 2000kg, 5000kg and 10000kg per day on-site refuelling station. The base case was compared with an OHRS powered only from the grid and it was observed that the cost of production of the hybrid system was approximately 50% lesser than the grid-only powered OHRS. In alignment with the Aberdeen City Council (ACC) "Hydrogen Economy Strategy", the LCOH obtained for the 1000kg Hybrid OHRS was compared with the Aberdeen City estimates of cost of production for a 1000kg OHRS considered, based on projected opportunities for demand to increase in the nearest future and it was obtained that the result of the LCOH analysis (6.72 £ per kg) fell within the range of prices projected by the ACC (4.5 to 7.25 £ per kg).

Keywords: Hydrogen Refuelling Station, Hydrogen production, Economies of scale, Aberdeen city.

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1. INTRODUCTION

According to the BP Statistical Review, the world's primary energy demand has been rising with about 2.9% increase in 2018 which is almost twice the average over the last decade. With most of the growth in energy consumption being driven mostly by fossil fuel (approximately 43% from natural gas). Conversely, while there has been a rapid upward trend in energy demand globally, the world's carbon emission from energy consumption also followed an upward trend with about 2.0% increase from 2018 one of the fastest growing trends over the past decade. (BP, 2019)

It is however not surprising that carbon emission is correlated with the rise in global energy consumption because the main driver of the rise in energy demand has been mainly fossil fuels. The global energy demand is poised to increase in the coming decades and there is potential for further increase in the carbon emission if alternative energy solutions are not provided. One of the biggest problems the world is currently facing is to simultaneously solve the rising energy demand issues while reducing carbon emission. (BP Energy Outlook, 2019)

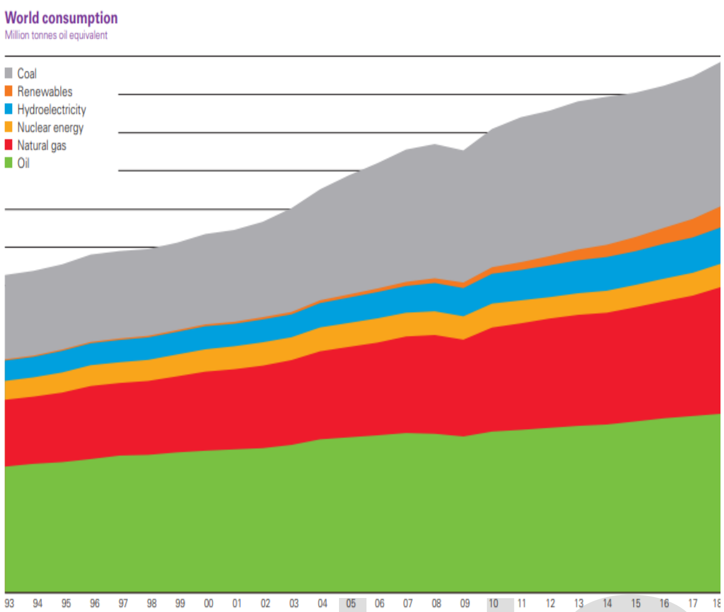

Figure 1.1 World Energy Consumption (Source: BP Statistical Review, 2019)

With respect to the problem of global warming, various debates concerning curtailing the rising global temperature has led to the development of different policies surrounding the Sustainable Development and Climate change, one of which is the Paris Agreement, an international framework to collectively hold global warming to below 2 degrees. The Paris Agreement has therefore led to the development and adoption of various strategies by the countries involved to curb global warming.

To achieve the targets of the Paris Agreement, the global energy system will need to undergo a significant change which will require a substantial decrease in carbon emission with respect to which low carbon energy from renewables will be the go to energy sources and the share of electricity in the global energy mix consumed by end users would increase to about 40% in the next 30 years (IRENA, 2018).

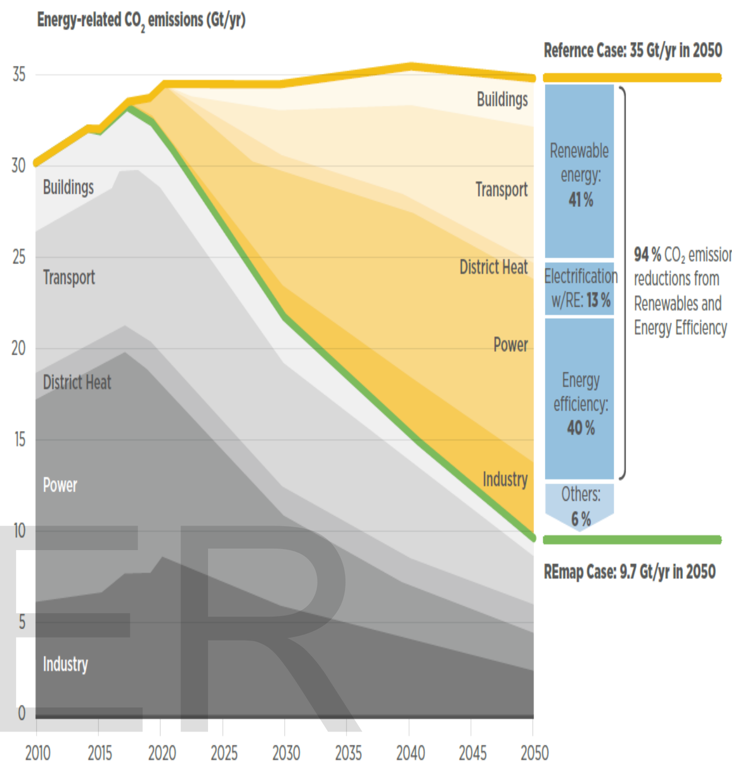

Figure 1.2 Energy-related Carbon Emissions with current policies compared to accelerated uptake of renewables, 2010 -2050 (Source: IRENA, 2018)

To solve the highlighted problem will require the total decarbonisation and electrification of sectors and industry which contributes significantly to the carbon footprint but achieving this goal might prove difficult. Fortunately, this problem could be addressed through the development of the Hydrogen driven economy. Hydrogen can be used as the bridge in the energy transition process: electricity from renewable energy sources can be used to produce hydrogen which can then be used a source of energy to sectors.

Aberdeen City has position itself to become a global energy centre in oil and gas over the past 40 years, the Aberdeen City Council has therefore recognised a very large opportunity for the city to become a hub for hydrogen technologies in Scotland. With respect to this, Aberdeen City Council has made huge investment in engaging with hydrogen technology and launched a strategic framework, "A Hydrogen Economy for Aberdeen City Region": with the city owning the largest fleet of fuel cell buses in Europe and first hydrogen production plant via water electrolysis in Scotland (Aberdeen Hydrogen Strategy, 2015).

This paper identified the impact of the demand and economies of scale on the expansion of the hydrogen production specifically to the Aberdeen City Region (Aberdeen Hydrogen Strategy, 2015).

The paper identified the: variables which impact the cost of producing hydrogen, the difference between the costs of producing hydrogen from a grid connected system and renewable wind system in Aberdeen. The paper also looked at the impact of policies on the production of hydrogen and the impact of economies of scale on the production of hydrogen in Aberdeen City using various economic evaluation tools, including, Net Present Value, Levelized Cost of Hydrogen and Sensitivity Analysis. Ultimately, relevant policy and business strategy implication were outlined based on the outcomes.

2. LITERATURE REVIEW

2.1 The Hydrogen Economy

Hydrogen is the world's simplest lightest and most abundant element constituting about 75% of all known mass. Hydrogen has the greatest yield per mole than any other compound, significantly greater than hydrocarbon fuels, producing only water as a by-product of combustion unlike hydrocarbon fuels. Unfortunately, unlike hydrocarbons, very minute amount of hydrogen is existing freely on the earth and it currently produced through various process such as steam methane reforming (SMR), biofuel- anaerobic digestion and water electrolysis. Hydrogen is a more efficient vector of energy than fossil fuels, hence if it can be produced renewably it can serve as a sustainable fuel source which will ease the transition into a total renewable economy.

The hydrogen production industry has well been established for decades with feedstock market values estimated to be about USD 115 billion which is expected to experience significant growth over the next couple of years, reaching about USD 155 billion by 2022. With total global demand of hydrogen estimated to be about of 8 exajoules (EJ) in 2015 (Hydrogen Council, 2017), with greatest share of the demand from chemical sector as feedstock for the production of ammonia and other refining processes for hydrocarbons.

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Unfortunately, over 95% of the current hydrogen supply is produced from fossil-fuel based processes, while only about 4% of the world hydrogen supply met via electrolysis (Figure 2.1) (IRENA, 2018).

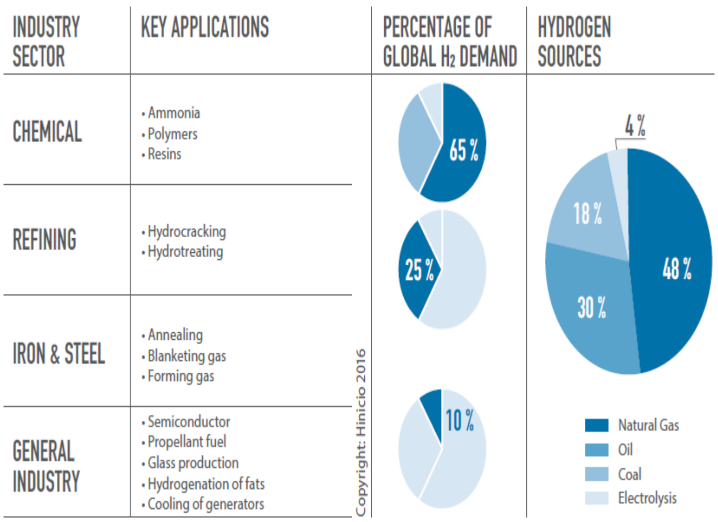

Figure 2.1 Global Hydrogen demand and production sources (Source: IRENA, 2018)

2.2 Grid Connected Hydrogen Production (Water Electrolysis)

Shayegan et al. (2006) conducted an analysis on the cost of hydrogen infrastructure for buses in London to determine the most cost-effective production delivery pathways for various hydrogen demand cases and refuelling station capacity.

Weinert et al. (2007) estimated the production costs of hydrogen for OHRS stations in Shanghai using natural **gas,** methanol, electricity, and by-product hydrogen. Schoots et al. (2008) applied learning curve to analyse the decrease of the cost of hydrogen production with increase in the distribution of hydrogen refuelling stations and an improvement of the production process. They also compared the hydrogen production costs of hydrogen stations in Shanghai with those of the California region.

To further their investigation, Shayegan et al. (2009) conducted a comparative analysis of off-site and on-site hydrogen stations for hydrogen fuel cell buses in London which takes into account various pathways of multiple steps hydrogen production, storage, transportation, and conversion.

Also, the US DOE (Department of Energy) (2009) estimated the cost of production for on-site SMR and WE hydrogen refuelling stations with a capacity of 700 Nm^3h^{-1}. The estimated cost of hydrogen production was \$3.00/kg in 2006 with target cost of \$2.00/kg in 2015 for SMR with the assumption that OHRS are sufficiently constructed. Also, the hydrogen production cost of on-site WE hydrogen stations of capacity 700 Nm^3h^{-1} was estimated to be \$4.80/kg in 2006 with a set the target of \$3.00/kg in 2015. Padro and Putsche (2009) reported a comprehensive cost data on hydrogen production, storage, transport, and utilization. Gim and Yoon (2012) adopted the LCA (life cycle analysis) approach to estimate the hydrogen production cost with respect to the economy of scale for OHRS with production capacities of 30 Nm^3h^1, 100 Nm^3h^{-1}, and 300 Nm^3h^{-1} through SMR and WE. Their investigations reported the cost of hydrogen per unit for OHRS reduced as the production capacity of the station

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increases: ranging from \$14.6/kg, \$10.0/kg, to \$7.8/kg for each production capacity using water electrolysis

Kuckshinrichs et al. (2017) presented an analysis advanced alkaline water electrolysis based on the economic assessment of the factors which affects the LCOH in three countries (Germany, Austria and Spain). By focusing on financial parameter they were able to make projections on the performance indicators. Based on a cash-flow analysis, they were able to assess the impacts of various parameters on the LCOH and they obtain that Germany performed better than the other sites largely based on the significant reduction in the cost of electricity as a result of the renewable energy Act (EEG) which reduced cost of power from renewable sources. This highlighted the impact of electricity and policy on the cost of hydrogen production cost.

Lee et al. (2017) conducted an economic evaluation for water electrolysis in terms of the unit cost of hydrogen analysis and sensitivity analysis to understand the current state of water electrolysis in Korea. The conducted an unit cost analysis based on different scales at 30 Nm^3h^{-1}, 100 Nm^3h^{-1} and 300 Nm^3h^{-1} then obtained the cost of hydrogen at ranges of 17.99 -16.54 \$ kg H_2^{-1}, 11.24-10.66 \$ kg H_2^{-1} and 8.12 – 7.72 \$ kg H_2^{-1} for the two water electrolysis processes alkaline water electrolysis(AWE) and PEM respectively. With sensitivity analysis they determined that the most influential factors which affected cost at the different scales were hydrogen production equipment and electricity price even as economies of scale was seen to impact the cost as the cost reduces with the increase in the scale of production. Lee et al. (2017) performed an economic analysis based on uncertainty using Monte-Carlo simulation methods for a 30 Nm^3h^{-1} capacity high pressure PEM water electrolysis hydrogen production facility, with results obtained from sensitivity analysis a probability curve was constructed for a unit hydrogen production which reflected the fluctuation in price of H_2 equipment, construction, electricity and other operating costs with a range of ±10% to ±50%. They also conducted a sensitivity analysis on net present value with uncertainty analysis on the revenue and capital expenditure. Their results indicated a wider cumulative probability curve for ±50 %(14.98-17.60 \$ kg H_2^{-1}) while a narrower band was obtained for ±10 % (16.23-16.75 \$ kg H_2^{-1}) for the unit cost of producing hydrogen.

Lee et al. (2019) conducted a research based on scenario analysis to find a suitable scenario for which water electrolysis will be cost-effective in terms of the levelized cost of H_2 (LCOH) on the basis of different economic parameters like the unit electricity price and technical parameters such as the learning curve and automation levels. Their results indicated that the unit electricity price had the highest significant impact on the LCOH, followed by the learning curve and the automation levels. They then suggested that the use of surplus electricity from renewable sources was crucial to the reduction of LCOH if the target of 1.25 $ kg H_2^{-1} by 2030 estimated by the US DOE is to be met.

2.3 Renewable (Wind) Energy to Hydrogen (Power to Gas) – Forecourt

Linneman et al. (2007) studied the potentials and economic interest of adopting intermittent wind-generated electricity in the form of hydrogen. In their work they considered two contrasting technical solutions: a small (experimental) system to supply 100 vehicles for one year with hydrogen produced by a single 1.5 MW wind turbine; and a large system with a group of 100 MW electrolysers supplied by a 1000 MW wind farm. While the first case considered to be onsite, the second case required a transport and distribution infrastructure to supply the refuelling stations. The overall hydrogen production cost which included the costs of production, transport and distribution (2nd scenario) and storage, was estimated to be 24 €/kg and 10 €/kg for the small scale and large-scale scenario respectively. The results of their studies indicated the potential for cost reductions due to the possibility of economies of scale, especially on the electrolysers cost, which is a huge part of the required investment. From the previous section, these results have been confirmed by several studies, including in particular that by Jorgensen et al. (2008). They noticed that for most wind energy scenarios, hydrogen production costs were extremely high when the electrolysers' rate of use was low which led to the conclusion that it would be difficult to install electrolysers that would operate essentially on excess wind-generated electricity during periods of excess production, even in situations where there is a high penetration of wind energy. Likewise, Aguado et al. (2009) established that a wind farm with hydrogen energy storage scaled the grid management issues related with the variation in wind-generated electricity, however, they also discovered that the benefits of having better control of intermittent electricity generation was not commensurate to the additional investment.

Bartholomy (2005) looked at the potentials of producing hydrogen from wind sources to fuel vehicles. With to possible options, in the first, he considered electrolysers producing hydrogen at the wind farm site itself when the wind power was available. However, this case was uneconomic due to the large investments requirements for underground storage reservoirs required for such an option. The second case on contrary, adopted a distributed production model where the wind-generated electricity was transmitted through the grid to electrolysers at the points of use. They obtained various cost from their analysis- for distributed production and a long-term centralized production (wind-alone and underground storage) the costs obtained were around 4 €/kg and 2.3 €/kg respectively. However, these results obtained were due to favourable assumption which were made in the analysis.

Also subjected to favourable assumptions, about the cost of electrolysers and the cost of wind power generation, Levene et al. (2006) found similar results - they also analysed two scenario which involved centralized hydrogen power was distributed through the grid to the production plant from the wind farm. An important peculiarity of the model is that it allowed for demand not to be met and demand to be met for the first and second cases respectively (which necessitated introducing hydrogen storage). The obtained estimated costs for centralized production with no hydrogen storage facilities and no delivery costs to be 4.0 €/kg in the short term which reduced on a long term to 1.6 €/kg, while for the decentralized production case the aggregate wind power led to an increase in the electrolysers capacity factor to about 90%.

2.4 Outlook of the Renewable Hydrogen System – Wind-to-Gas

FCHJU (2014) techno-economic analysis reported that the development of a renewable hydrogen system is based on various performance indicators which if improved will drive down the cost of producing hydrogen from water electrolysis. Based on this report, they were able to highlight various key performance indicators for the system upon which projections for potential cost reduction were made using various information from industry stakeholder, previous literatures and manufactures. This key performance indicators were highlighted as Efficiency and Lifetime, Capital cost, Pressurization, Equipment size, Operating Cost and the Dynamics and flexibility of operation. Based on the projections made on the various key performance indicators, they were able to determine the cost of hydrogen for an off-grid and grid connected water electrolysis system for the United Kingdom and Germany.

This paper only consider the following: efficiency, capital cost, operating cost and size (output) while taking efficiency as the kWh per kg of hydrogen output with respect to the FCHJU (2014).

Estimated to have the highest wind power resource in Europe, the Aberdeen City is poised to be able to capture most this renewable energy into power generation for production of renewable energy source. Even with the highest fleet of Fuel cell vehicles in Europe with the potential of become the renewable hydrogen energy hub of Europe, there however a shortage on studies tailored to the conditions in Aberdeen city which captures the peculiarities of the city. This paper made a narrowed study on the economic analysis of wind-to-gas (water electrolysis) with a case study based on the city of Aberdeen using the costs and efficiency projections from the FC HJC (2014) and based on models from previous literatures on the hydrogen economy.

3. METHODOLOGY

3.1 Model Description

Theoretical Background – Life Cycle Costing (LCC)

With respect to the economic analysis found in many studies, the concept of Life Cycle Costing (LCC) method was adopted in combination with the Levelized Cost of Hydrogen (LCOH) (Bertuccioli et al., 2014; Shaner et al., 2016) in estimating the production cost of hydrogen production which could be largely dependent on the plant and site characteristics and on the terms for electricity supply (Kuckshinrichs et al., 2017).

LCC is an essential method to estimate the total cost of a system over its given lifetime. By adopting the LCC into the early life cycle cost analysis stage various changes can be easily made to components to obtain their net impact on the overall cost of the system. Although, there is no global approach of performing the LCC analysis which is suitable for all circumstances as revealed from previous literatures, it has been the most employed approach over a long period of time.

As observed from various literatures, many general approach and methods have been proposed, which are different in nomenclature but have steps which are common to one another [(Fabrycky et al., 1991), (Woodward, 1997), (Harvey, 1976)]. These steps include:

- Definition of the cost elements;
- Definition of the cost structure;
- Establishment of the cost estimating relationships;
- Establishment of the method used for LCC formulation.

Although LCC is generally accepted as a methodology, it still has its flaws upon which engendered criticism. The main drawback of the LCC method stems from the inclusion of future estimations in the analysis which can give misleading and uncertain results. However, notwithstanding, the flaws of the LCC method its benefits outweigh its flaws as it provides a general and universal method to evaluate and compare different investments (Kuckshinrichs et al., 2017).

Levelized Cost of Hydrogen (LCOH)

Basically, the LCOH method is founded upon the levelized cost of energy (LCOE) method which is a generally adopted method in the renewable energy investment analysis, where the LCC of renewables is represented in terms of cost per energy output unit. As defined by IRENA (2016) the LCOH is represented mathematically in the equation (3.1) below.

$$LCOE = \frac{\sum_{n=0}^{N}(I_n+M_n+F_n)\cdot(1+i)^{-n}}{\sum_{n=0}^{N}(E_n)\cdot(1+i)^{-n}} \qquad 3.1$$

Where I_n , represents the initial investment cost for n years, M_n is the operating and maintenance cost for the nth year, F_n represents the fuel cost for nth year, E_n is the energy generated yearly, I is the discount rate and N is the operating life.

The LCOE approach is a very essential method when comparing various investment scenario and is not bounded to renewable energy sources but adopted widely to the assessment of the cost of hydrogen production plants of various scales. Similar to electrical calculations, since hydrogen output are usually measured in terms of energy,

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the cost can also be estimated in the form, "cost per unit energy or mass of hydrogen" (Thomas, et al., 2016).

This paper performed an economic analysis of OHRS using the Life Cycle Analysis method by taking into consideration various economic and financial parameters such as the initial investment, the annual revenue, the annual operating cost, the salvage value, the discount rate, and the lifecycle time of the system.

Cost Element Definition

Cash flows in the economic model of OHRS consist of the initial investment at time 0, the annual operating cost at different period n, the decommissioning cost, depreciation expenses, tax credit deduction, tax expenses and replacement cost of the various components at the end of the life cycle.

Initial investment ($C_{total,inv}$)

The initial investment of the hydrogen plant consists of the cost of hydrogen production plant, the cost of the wind farm based on its capacity, the construction cost of OHRS and the wind farm, and the auxiliary cost. The cost of hydrogen production plants includes the cost of the PEM hydrogen electrolyser, hydrogen storage units, compressors, dispensers, and other electric equipment. This is depicted in the equation (3.2) below as:

$$C_{total,inv} = \left(C_{wind} + C_{we} + C_c + C_{Rf} + C_{misc}\right) \quad 3.2$$

where $C_{total,inv}$, is the total investment cost, C_{wind} is the cost of the Wind energy source, C_{Rf} is the refuelling station cost (C_c is the cost of the compressor, C_s is the cost of the storage units, C_d is the cost of the dispensers at the refuelling station) and C_{misc} is miscellaneous costs or other cost such as site preparation cost and cost of grid connection.

$$C_{Rf} = C_c + C_s + C_d \quad 3.3$$

Operating and Maintenance Cost

The is calculated as a percentage of the investment cost of the major components such as the wind turbine combined with stated operating cost as obtained from other sources of information. The annual operating cost of on-site hydrogen refuelling station is made up of the cost of purchasing electricity, labour cost, wind farm operating and maintenance cost, hydrogen plant operating and maintenance cost, refuelling components operating and maintenance cost, and other variable operating cost. The annual operating and maintenance cost are approximated in the equation (3.4) as:

$$C_{om} = C_{wom} + C_{eom} + C_{rsom} + C_{vom} \quad 3.4$$

where C_{om}, C_{wom}, C_{eom} , C_{rsom} C_{vom} is the total operating and maintenance cost, the wind power source, refuelling components and variables operating and maintenance cost annually respectively.

$$C_{vom} = C_e + C_w \quad 3.5$$

Where C_e other miscellaneous expenses and C_w is the cost of the water used as the upstream feeds for the hydrogen production

Replacement Cost (C_{rep})

The replacement cost is estimated for various major components of the system such as the electrolysers which is expressed as a percentage of initial investment cost of the electrolysers.

$$C_{total,rep} = RF \times C_{comp,inv} \quad 3.6$$

where RF is the replacement factor as a percentage of the component investment cost

$C_{comp,inv}$, represents the initial investment cost for the major components.

Decommissioning Cost ($C_{decom,cost}$)

The decommission cost is estimated with approximations as a summed value of the total investment cost of the whole system, the wind-hydrogen plant decommissioning as a whole and as a percentage of the total investment cost as well.

$$C_{decom,cost} = DCFactor \times C_{total\,,inv} \quad 3.7$$

where DC Factor is the decommissioning cost factor.

Electricity Cost

Since the power consumed by the whole system is assumed to be generated partly from an offshore wind energy source near shore, also due to the fact the wind capacity factor of this region has a maximum limit at about 40% within the range of 30-40% (Mearns, 2017) this limits the power generated yearly by the wind power source. And as a result, the power system adapted for this model is taken to be a "hybrid system", a system which is sustained by both a wind power source and also connected to the grid. The wind power generated from the wind source is estimated by:

$$E_{WT} = LCnH \quad 3.8$$

Where E is the total output measured in megawatts, L is the load capacity, C is the capacity factor, n is the number of turbines and H is the number of operating hours.

To determine the amount of electricity power obtained from the grid, the amount of power generated from the wind power source is deducted from the total energy consumption of the On-site Hydrogen Refuelling Station which is expressed as:

$$E_{grid,yr} = E_{T,yr} - E_{WT,yr} \quad 3.9$$

where $E_{grid,yr}$the amount of power is obtained by the whole OHRS system from the grid annually, $E_{T,yr}$ is the total power consumption of the whole OHRS system annually and $E_{WT,yr}$ is the total power obtained from the wind source annually.

The cost of the electicity power obtained from the grid annually, is expressed in the equation (3.10):

$$C_{elect,yr} = E_{grid,yr} \times p_{elec} \quad 3.10$$

Where $C_{elect,yr}$the annual is cost of electricity used by the system – from the grid and p_{elec} is the price per kilowatt-hour from the grid.

Cost-Capacity Relationship based on Cost Exponent

In order to estimate plant cost given different capacities as in the case of this study from 1000kg to 10000kg H_2 per day to identify opportunities for scale economies due to the fact that manufacturers do not share in-house data on cost breakdown, costs for different plant capacities are then approximately estimated based on a general relationship between cost and capacity with a cost exponent based on a base scenario data as depicted in equation (3.11):

$$\frac{C_a}{C_b} = \left(\frac{A_a}{A_b}\right)^n \quad 3.11$$

where C is purchase cost, A is equipment capacity, and n is cost exponent. Often, a value of 0.6–0.7 is used as default (also referred to as six-tenths or seven-tenths rule) which is what was adopted in this study as a good approximation frequently used when no cost data with different capacities are available (Eerev and Patel, 2012).

Levelized Cost of Hydrogen (LCOH) Estimation

As stated in the previous section of this chapter, the model follows a generic structure of the LCOH at seen in previous studies (Kuckshinrichs et al. , 2017), however, this LCOH structure will be structured to suit the typical case of the hybrid system (wind-grid-hydrogen) to capture the peculiar characteristics of this system.

The LCOH is expressed below as:

$$LCOH = \frac{PV(Capital)+PV(Annaul\ Cost)-PV(Deductibles)}{PV(Hydrogen\ Produced)} \quad 3.12$$

$$PV(Capital\ Investment) = \sum_{t=0}^{t=n} \frac{C_{total,inv}}{(1+i)^t} \quad 3.13$$

$$PV(Annual\ Cost) = \sum_{t=0}^{t=n} \frac{\left(C_{om,yr} + C_{elect,yr} + C_{vom,yr} + C_{decom,yr}\right)}{(1+i)^t} \quad 3.14$$

$$PV(Tax\ Deductibles) = TR \times \sum_{t=0}^{t=n} \frac{\left(C_{om,yr} + C_{elect,yr} + C_{vom,yr} + Dep_{yr}\right)}{(1+i)^t} \quad 3.15$$

$$PV(Hydrogen\ Produced) = \sum_{t=0}^{t=n} \frac{M_{yr}}{(1+i)^t} \quad 3.16$$

Where $C_{total,inv}$ is the total initial investment for the whole system (wind-grid connection-hydrogen), $C_{om,yr}, C_{elect,yr}, C_{vom,yr}, C_{decom,yr}$ represents the annual operating and maintenance cost, annual grid electricity cost, annual variable operating and maintenance cost, and decommissioning cost. Dep_{yr} is the depreciation expense, M_{yr} is the hydrogen produced yearly, t is the period in years, TR is the tax rate and i is the discount rate.

Net Present Value

The NPV obtained for this model is based on the LCC approach used in estimating the LCOH but without the hydrogen produced component of the estimation. It is represented in the equation below as:

$$NPV = PV(Capital) + PV(Annaul\ Cost) - PV(Deductibles) \quad 3.17$$

As seen above NPV estimation is more like an approximation from the LCOH model which is used to determine the attractiveness of the project apart from the LCOH

Model Assumptions

System Power System Assumption

The wind power source was assumed to be from a wind farm in which the current operator of the on-site hydrogen refuelling station had a percentage stake in terms of the amount of energy to be obtain from the farm yearly. To further elaborate this, the wind farm is assumed to be an investment such that the companies share the power output from the farm in accordance with the percentage investment in the farm. A constant capacity factor from the wind turbine is used through the operating life of the field in order for simplicity of the estimation and also because the focus of the analysis was not on the wind farm.

Cost Estimations

The cost estimation for majority of the various components of the system is estimated through approximations using cost data from a base case typical OHRS field analysis (NREL, 2009) and the cost exponent as show in the previous the subsections of the chapter. The capital cost of the major component and their operating & maintenance cost were approximated by scaling up from the base case1500kg H_2 per day OHRS using the cost exponent equation with corrections made for inflations using an average inflation rate index in the United Kingdom. It is therefore imperative to state that most of the cost estimations are approximated values which are generic but not specific.

Operating Life

To estimate the LCOH or hydrogen production costs of the on-site hydrogen refuelling station, a suitable economic analysis period is required. This is further analysed based on a typical operating life which is inputted into the LCOH model. However, for the simplicity purpose also a constant operating life is used for the wind and hydrogen plant which yielded a more representative analysis for the system to be integrated.

Depreciation Method

For simplicity and ease of calculation, the depreciation of the various components of the system is estimation by assuming the wind- system and the hydrogen plant system depreciated through an approximated approach of a straight-line depreciation method over a certain period of years. The various expenses were calculated then summed to obtain the depreciation of the whole OHRS system.

3.2 Data Description

General Background Data

The data used in the analysis of this study which is fundamentally based on the major and most significant cost driving components of the system has been obtained basically from various sources which afterwards where approximated to suit the purpose of the various model scenario and analysis of this work.

The data have been split into three subsections which are the Technical data basically comprise of data for the Wind

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system, the hydrogen (PEM) electrolyser system and the refuelling portion of the system, the Financial data and the electric variable cost data.

Technical Data

Base on the research purpose of this work, which is to determine the impact of scale economies on the cost of production of a hybrid powered on-site hydrogen refuelling station. The technical data will be section into three case studies according to the scale of production of hydrogen and according to the wind power output from the wind power source.

Technical Data of the OHRS

The base data used in the study and analysis were obtained from the FCHJU 2014 report on hydrogen production plant and the PEM Electrolysis H2A Production Case study Documentation and data spreadsheet which was connected to the grid for electricity power source. The base data was then used to obtain other cost when scaling up the capacity of the plant by using the cost exponent as represented in the previous section.

The capital cost for the whole hydrogen electrolyser system component of the system was calculated based on the equation below:

$$Electrolyser\ Stack_{\ Capex} = \frac{S_{prop} \times S \times N \times C_{H_2} \times F_{inst}}{T} \qquad 3.18$$

$$Other\ components_{\ Capex} = \frac{C_{prop} \times S \times N \times C_{H_2} \times F_{inst}}{T} \qquad 3.19$$

Where $S_{prop}, S, C_{prop}, N, C_{H_2}, F_{inst}, T$ are the electrolyser stack percentage of capital, other components percentage of the capital, stack capital cost ($/Kw), the plant energy usage in kWh/kg, plant hydrogen production capacity per day, installation factor and number of operating hours per day.

Equation 3.18 and 3.19 are then applied after the various cost have been scaled down using the cost exponent equation described earlier. The first case study was for an on-site hydrogen refuelling station with the production capacity of 1000kg per day.

Afterward due to the unavailability of data the operating cost data obtained from the NREL documents for the various major components (electrolyser stacks, other electrical components of the plants and the refuelling components) of the whole system are also scaled using the cost exponent equation to get approximations for the various operating cost of the scenarios being considered in this paper.

The wind power source capital investment cost and the operating cost of the wind turbines at various 2.5MW capacity were obtained from the International Renewable Energy Agency documentation on renewable power generation costs (IRENA, 2018). While the capital and operating cost for subsequent case studies for the wind output capacities (5MW, 12MW and 24MW) were obtained from the InnoEnergy Future renewable energy costs: offshore wind report (InnoEnergy, 2017).

Table 3.1 Capital Cost Base of the OHRS with production capacity of 1000kg per day

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Cost Description	**Cost Estimate**	**Source**
Hydrogen Plant		
Plant Energy Usage (kWh/kg)	50	FCHJU, 2014
Plant Number of operating hrs	22	Saur et al.,(NREL), 2018
Refuelling station operating hrs	18	Saur et al.,(NREL), 2018
Dispenser Cost (Installed) ($)	490068	Saur et al.,(NREL), 2018
Compressor Cost (Installed) ($)	808262	Saur et al.,(NREL), 2018
Low Pressure Storage Capacity (Installed)($)	1966220	Saur et al.,(NREL), 2018
Cascade Storage (Installed) ($)	143164	Saur et al.,(NREL), 2018
Installation Factor	1.10	Saur et al.,(NREL), 2018
Electrolyser % of total capex for plant	38	Saur et al.,(NREL), 2018
Other components % of total capex for plant	62	Saur et al.,(NREL), 2018
Electrolyser stack capex cost ($/kWh)	1000	FCHJU, 2014
Electrolyser Stack Capital Cost (Installed) ($)	950000	Saur et al.,(NREL), 2018
Other Component(Installed) ($)	1550000	Saur et al.,(NREL), 2018
Other Capital Cost Site Preparation ($)	1154640	Saur et al.,(NREL), 2018
Wind Components		
Wind Farm capex plus site preparation and installation for 2.5MW wind turbine ($/Kw)	1477	IRENA, 2018
Output capacity (MW)	2.5	FCHJU, 2014
Wind Capacity Factor (%) approx.	40	Euan, 2014
Non-Elect. Operating Cost		

Plant Operating Cost (Non-Electricity)	65831	Saur et al.,(NREL), 2018
Refuelling Station Operating cost(Non - Electricity)	151494	Saur et al.,(NREL), 2018
Wind - Farm Operating Cost/year % of CapEx	1 to 8	IRENA, 2018

The second case scenario involves scaling up the OHRS to an output production capacity of 2000kg per day. Where the cost of the hydrogen production components and refuelling components of the system were approximated using the cost exponent equation.

Table 3.2 Capital Cost Base of the OHRS with production capacity of 2000kg per day

Cost Description	**Cost Estimate**	**Source**
Hydrogen Plant		
Plant Energy Usage (kWh/kg)	50	FCHJU, 2014
Plant Number of operating hrs	22	Saur et al.,(NREL), 2018
Refuelling station operating hrs	18	Saur et al.,(NREL), 2018
Dispenser Cost (Installed) ($)	490068	Saur et al.,(NREL), 2018
Compressor Cost (Installed) ($)	985734	Saur et al.,(NREL), 2018
Low Pressure Storage Capacity (Installed)($)	2397948	Saur et al.,(NREL), 2018
Cascade Storage (Installed) ($)	174598	Saur et al.,(NREL), 2018
Installation Factor	1.10	Saur et al.,(NREL), 2018
Electrolyser % of total capex for plant	38	Saur et al.,(NREL), 2018
Other components % of total capex for plant	62	Saur et al.,(NREL), 2018
Electrolyser stack capex cost ($/kWh)	1000	FCHJU, 2014

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Electrolyser Stack Capital Cost (Installed) ($)	1900000	Saur et al.,(NREL), 2018
Other Component(Installed) ($)	3100000	Saur et al.,(NREL), 2018
Other Capital Cost Site Preparation ($)	2028319	Saur et al.,(NREL), 2018
Wind Components		
Wind Farm capex plus site preparation and installation for 2.5MW wind turbine ($/Kw)	1765	InnoEnergy, 2017
Output capacity (MW)	6.0	FCHJU, 2014
Wind Capacity Factor (%) approx.	40	Euan, 2014
Non-Elect. Operating Cost		
Plant Operating Cost (Non-Electricity)	150000	Saur et al.,(NREL), 2018
Refuelling Station Operating cost(Non - Electricity)	138396	Saur et al.,(NREL), 2018
Wind - Farm Operating Cost/year % of CapEx	1 to 8	IRENA, 2018

Table 3.3 Capital Cost Base of the OHRS with production capacity of 5000kg per day

Cost Description	**Cost Estimate**	**Source**
Hydrogen Plant		
Plant Energy Usage (kWh/kg)	50	FCHJU, 2014
Plant Number of operating hrs	22	Saur et al.,(NREL), 2018
Refuelling station operating hrs	18	Saur et al.,(NREL), 2018
Dispenser Cost (Installed) ($)	490068	Saur et al.,(NREL), 2018
Compressor Cost (Installed) ($)	1664483	Saur et al.,(NREL), 2018
Low Pressure Storage Capacity (Installed)($)	4049108	Saur et al.,(NREL), 2018
Cascade Storage (Installed) ($)	294823	Saur et al.,(NREL), 2018

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Installation Factor	1.10	Saur et al.,(NREL), 2018
Electrolyser % of total capex for plant	38	Saur et al.,(NREL), 2018
Other components % of total capex for plant	62	Saur et al.,(NREL), 2018
Electrolyser stack capex cost ($/kWh)	1000	FCHJU, 2014
Electrolyser Stack Capital Cost (Installed) ($)	4750000	Saur et al.,(NREL), 2018
Other Component(Installed) ($)	7750000	Saur et al.,(NREL), 2018
Other Capital Cost Site Preparation ($)	3424962	Saur et al.,(NREL), 2018
Wind Components		
Wind Farm capex plus site preparation and installation for 2.5MW wind turbine ($/Kw)	1765	InnoEnergy, 2017
Output capacity (MW)	12	FCHJU, 2014
Wind Capacity Factor (%) approx.	40	Euan, 2014
Non-Elect. Operating Cost		
Plant Operating Cost (Non-Electricity)	195270	Saur et al.,(NREL), 2018
Refuelling Station Operating cost(Non - Electricity)	194954	Saur et al.,(NREL), 2018
Wind-Farm Operating Cost/year % of CapEx	1 to 8	IRENA, 2018

Table 3.4 Capital Cost Base of the OHRS with production capacity of 10000kg per day

Cost Description	**Cost Estimate**	**Source**
Hydrogen Plant		
Plant Energy Usage (kWh/kg)	50	FCHJU, 2014
Plant Number of operating hrs	22	Saur et al.,(NREL), 2018
Refuelling station operating hrs	18	Saur et al.,(NREL), 2018
Dispenser Cost (Installed) ($)	4900680	Saur et al.,(NREL), 2018

Compressor Cost (Installed) ($)	2522885	Saur et al.,(NREL), 2018
Low Pressure Storage Capacity (Installed)($)	613730	Saur et al.,(NREL), 2018
Cascade Storage (Installed) ($)	223434	Saur et al.,(NREL), 2018
Installation Factor	1.10	Saur et al.,(NREL), 2018
Electrolyser % of total capex for plant	38	Saur et al.,(NREL), 2018
Other components % of total capex for plant	62	Saur et al.,(NREL), 2018
Electrolyser stack capex cost ($/kWh)	1000	FCHJU, 2014
Electrolyser Stack Capital Cost (Installed) ($)	9120000	Saur et al.,(NREL), 2018
Other Component (Installed) ($)	14880000	Saur et al.,(NREL), 2018
Other Capital Cost Site Preparation ($)	5191272	Saur et al.,(NREL), 2018
Wind Components		
Wind Farm capex plus site preparation and installation for 2.5MW wind turbine ($/Kw)	1765	InnoEnergy, 2017
Output capacity (MW)	12	FCHJU, 2014
Wind Capacity Factor (%) approx.	40	Euan, 2014
Non-Elect. Operating Cost		
Plant Operating Cost (Non-Electricity)	720000	Saur et al.,(NREL), 2018
Refuelling Station Operating cost (Non - Electricity)	168782	Saur et al.,(NREL), 2018
Wind - Farm Operating Cost/year % of CapEx	1 to 8	IRENA, 2018

Financial Parameters

The financial parameter used in this work were obtained from a combination of reports on renewable energy development projects in the United Kingdom and the EU. The paper considered the project to be fully equity funded based on assumptions and the various fiscal terms such as the discount rate, tax rate and the depreciation schedule rate were adopted from various past studies made on renewable power projects relative to the UK and the EU.

Table 3.5 Financial Parameters

Parameter	Value	Source
Depreciation Type	Straight Line	Assumed
Depreciation Schedule	7	Saur et al.,(NREL), 2018
Analysis Period/Plant Life	30	Assumed
Tax Rate	20%	Saur et al.,(NREL), 2018
Inflation Rate	2.4%	Average projections in the UK
Discount Rate	8%	Green Initiative, 2017
Equity Financing	100%	Assumed
Replacement Period (years)	10	Saur et al.,(NREL), 2018
Replacement Cost 12% of Direct Cap	12%	Saur et al.,(NREL), 2018
Decommissioning Cost 10% of Direct Cap	10%	Saur et al.,(NREL), 2018

Most of the financial parameters and data used in the data were also based on averaging across previous studies like the H2A techno-economic analysis of an on-site hydrogen refuelling station, the Element Energy Hydrogen Production studies FCHJU, 2014), (NREL), IRENA studies and the Green Initiatives.

Depreciation Method was assumed to be a straight-line method for ease and simplicity of estimation, while the depreciation schedule was chosen based on the H2A study analysis spreadsheet. Tax Rate and Discount Rate were chosen based on the Green Initiative 2017 a documentation which analysed the viability and trends of renewable energy projects in the United Kingdom. Other parameters of the work such as replacement schedule, operating life and decommissioning cost percentage were all based on previous studies which closely matched this work.

Basis for Cost Estimation and Parameters.

The electricity cost was estimated and projected using a random walk approach which yield the values which was the analysis. Electricity price data in p/kWh was obtained from the 2018 National Statistics Report on Industry energy price in the IEA (BEIS, 2018). Based on estimation of a growth rate from the previous annual price data from the year 1979 to 2018, further projections were made using a random walk approach to forecast the price of electricity in the UK. The average of the projections was further estimated to obtain a single value which was used as an approximated price for all the periods in the analysis. The method for estimating the cost of electricity was based on the distribution of electricity price in the UK close approached a random walk over the past few decades as depicted in the figure below. Figure 3.1 is a graphical representation of the random walk price projection from 2019 to 2050. Other cost parameters and data used in the analysis were based on model used in previous research and studies which were closely related to this analysis conducted in this work.

The cost parameters were founded based on the analysis conducted by IRENA, H2A, Element Energy and other research works highlighted in the literature review. Although most of the research work related to the one conducted in this study were techno-economical in nomenclature the parameters used where based on how frequent certain parameters used in the analysis of the previous studies appeared. The data used are then approximated based on the limitation of the technical engineering analysis conducted in most of these studies.

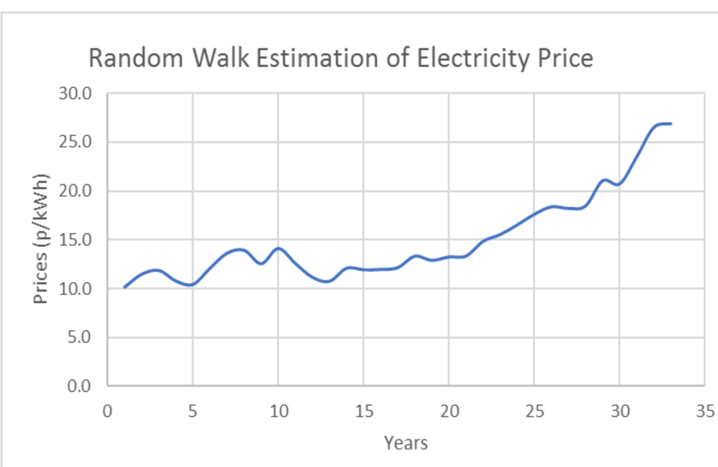

Figure 3.1 Projections of Electricity Prices with Random Walk

The wind farm cost estimates were based on the InnoEnergy report which made projection based on improvements in technology and efficiency and increase demand in the coming next decades. These data were considered based on the projections of hydrogen demand trend estimated by the Aberdeen City Council Hydrogen Strategy. Although most of these estimates are approximations, they can still be obtainable following due to the fact that they follow closely previous trends in data for renewable energy technology efficiency, cost reduction and demand.

However, certain rough estimates were made based on the daily output capacity of the OHRS, which meant that the some cost data which weren't available as the output capacity increased were scaled using the cost exponent equation and some assumption based on engineering related estimates with respect to the output scale and capacity. Other parameters such as the wind power requirement for each OHRS were derived based on estimations from the FCHJU 2014 report which approximated the power requirement (in Watts) estimated based on the model employed in the analysis.

4. RESULTS

4.1 Base Case LCOH comparison for a Hybrid and Grid OHRS

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A model for the base case hybrid on-site hydrogen refuelling station was developed for an OHRS capacity of 1000kg per day to further understand the cost reduction effect of the wind power source on the LCOH, a LCOH model analysis for an OHS of the same capacity but only powered by the grid was conducted using the same data but excluding the data for the wind power source. The summary showed that although the initial capital investment of the hybrid OHRS was about 57% higher than the initial capital for the grid connected system, the LCOH for the hybrid OHRS was seen to have decreased by about 52%. To further understand the reason for this cost reduction is LCOH for the hybrid system an annuity base analysis was conducted on the annual cost of electricity obtained from the grid for both system (assuming constant annual electricity power usage by both plant and hence constant annual cost of electricity), the present value annuity due estimate on the annual cost of electricity for the hybrid OHRS was about 66% lower than the grid connected OHRS' even when the cost of the wind power system was added to the present value of cost of electricity of the hybrid system, it was still 57% lower than the ACOE of the grid connected OHRS. The formula below was used to analyse the annual cost of electricity over the life operating period of the OHRS system.

$$PV(C_{elect,yr}) = C_{elect,yr}\left[1 + \left(\frac{(1+i)^{-(n-1)}}{i}\right)\right] \qquad 4.1$$

Where $PV(C_{elect,yr}), C_{elect,yr}, i\ and\ n$ are the present value of the annual grid cost of electricity, the annual grid cost of electricity, the discount rate and the period of estimation (operating life of the OHRS system).

Table 4.1. Base Case Scenario for the OHRS (1000kg per day)

Values	**Hybrid OHRS**	**Grid Connected OHRS**
Capital Investment Cost ($)	11297354	7187498
Grid Electricity Consumption - kW	519293	2316379
Annual Cost of Electricity ($ per year)	1415177	4146733
Present Value of (ACOE) $	16713209	48972825
LCOH ($/$H_2$ kg)	8.51	17.37

4.2 Cost Component Sensitivity Analysis

To further explore more opportunities for LCOH reduction the cost component analysis of the entire OHRS system was conducted from the wind power source to the dispensing system to understand the impact of various major components of the system on the LCOH. By making approximations on cost as described in chapter 5 and 6, it certain components of the systems were identifies to have highly impacted the LCOH (Viktorsson et al., 2017) as shown in the Figure 4.1. Based on this components the cost to scale of the entire system of the different OHRS output system was approximated using the cost exponent, after which they are cost are used to identify the opportunities for economies of scale.

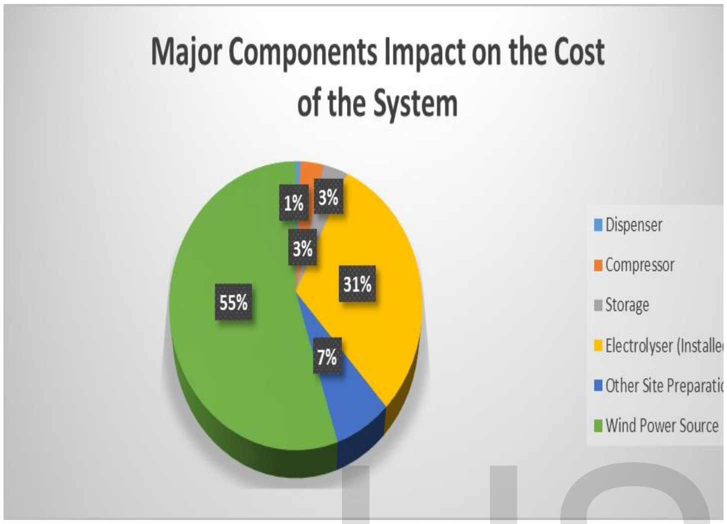

Figure 4.1 Major Components impact on LCOH

Also, to buttress the findings from the previous section, a sensitivity analysis based on the operating and maintenance and capital cost of the three major sections of the system was conducted to identify the main cost driver for the whole system. Based on the results the main cost factors were identified and the effects of changes analysed in terms of the LCOH. The main factors considered were the electricity cost, electrolyser capital cost, wind power capital expenditure and operating expenses, refuelling station component capital and operating expenses. A sensitivity Tornado diagram was developed as seen in in Figure 4.2 where those factors were subject to a change of ±60% (Viktorsson et al., 2017) from their base values, estimated at an assumed maximum plausible change over the operating period, which is explained further below.

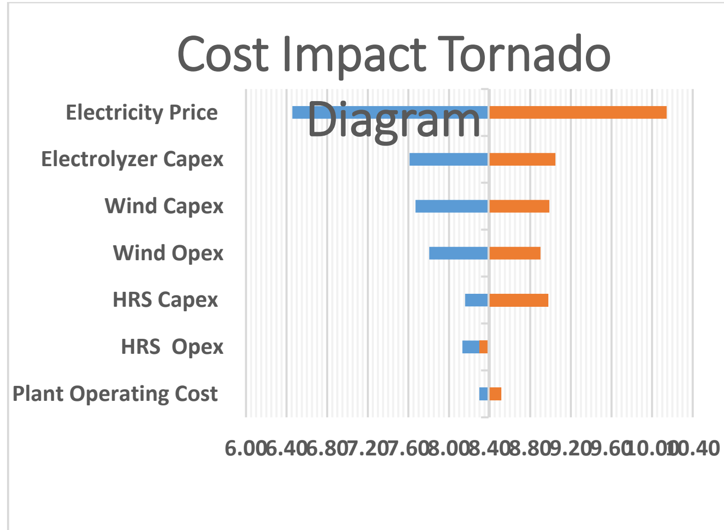

Figure 4.2 Sensitivity Analysis for 30 years on the Hybrid OHRS

As indicated in Figure 4.2, the LCOH can be reduced to approximately 6.40 $/kg with an electricity price reduction of 0.09 $/kWh. In the case of a -60% reduction in electrolyser, wind power source and refuelling station capital cost, the LCOH could be decreased to about 7.60, 7.62 and 8.25 $/kg respectively over the operating life of the whole hybrid OHRS system, together with reduction in price estimated by the electricity price reduction, the combined impact could reduce the LCOH to approximately about 4.67 $/kg.

4.3 Aberdeen City Cost-Benefit Analysis Based on Present and Projected Demand

In a bid to meet the Scottish 2030 target of phasing out energy petrol and diesel, obtaining 50% of all energy transport/ heating from renewables, reducing carbon

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emission by 80% by 2050 and realizing the Scottish Government Energy Strategy the Aberdeen City has through a diversified economic strategic approach developed the "Hydrogen Strategy" and action plans for a period between 2015-2025 to stimulate the various sectors of the city's economy to make Aberdeen a world leading hydrogen economy. On this note, the Aberdeen City Council has been seeking out ways to increase the hydrogen demand by increasing the amount of Fuel Cell Vehicles in their fleet which includes first public buses, cars, vans and other heavy duty vehicles with a total of about 65 FCEVs additions by the early 2019 to 2020 (ACC, 2019). The Aberdeen City Council have also sort to develop a more private sector inclusive approach to meets its hydrogen economy targets due to the projected reduction in the cost of FCEVs made by stakeholders invariably could lead to an increase in privately owned FCEVs on the roads of Aberdeen, as results of these potential increase in the demand for hydrogen, it was identified that various cost advantages might be available for a green hydrogen production cycle.

Based on the hydrogen demand in Figure 4.3 projections made by the Aberdeen City Council an extensive demand-cost project analysis considering the suitable scales for OHRS facility to cater for the increase in demand from 1000kg to 10000kg per day of hydrogen production from one facility. The base scenario of 1000kg was further scaled up using various component cost approximations to estimate the various capital investment cost and operating cost on the various projections.

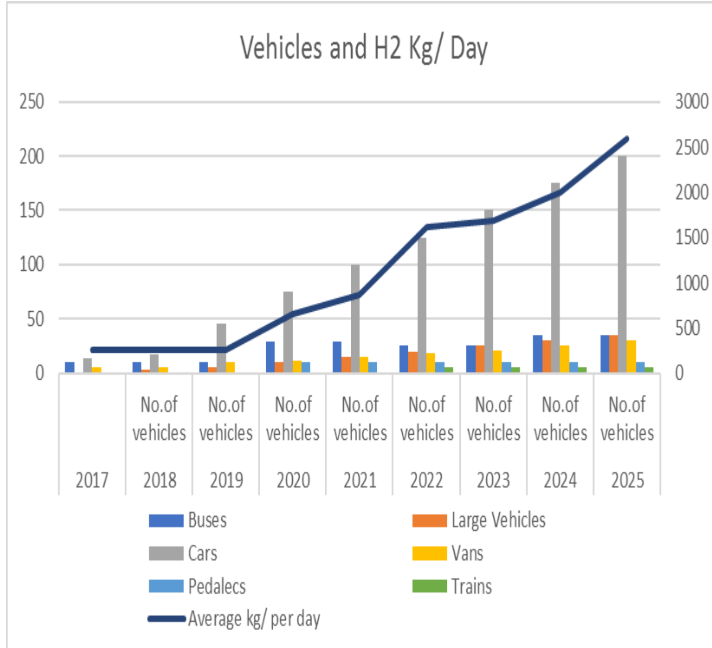

Figure 4.3 ACC Hydrogen Demand Projection (Aberdeen City Council, 2019)

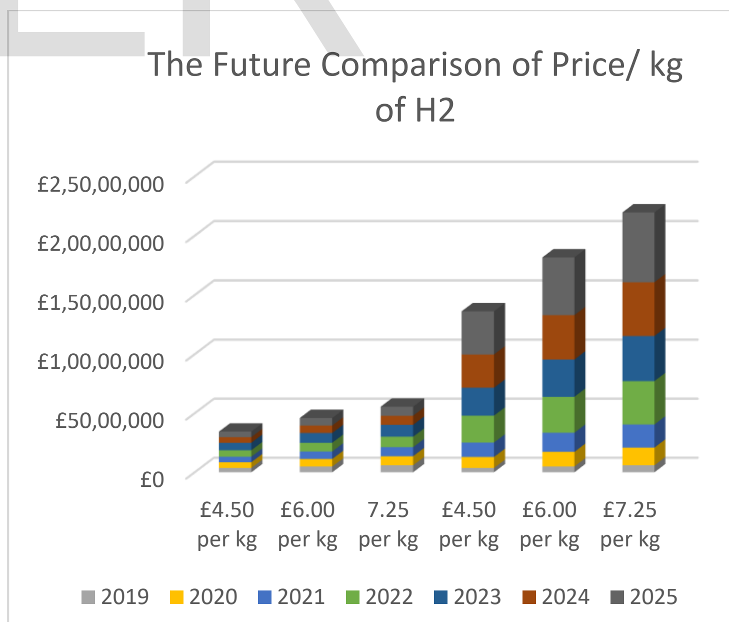

Figure 4.4 Project Hydrogen Cost of Production in Aberdeen City (Aberdeen City Council, 2019)

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As illustrated in Figure 4.4, the ACC has made specific cost projections based on the various demands projections for a grid connected (maximum of 2500kg per day output) On-site Hydrogen Refuelling station based on approximated estimations to arrive at a cost range of between £4.5 to £ 7.25 per kg.

Grid Connected and Hybrid OHRS Output Scale -LCOH (Cost) Analysis

One demand-cost case study analysis (1000kg grid connected system) and four demand-cost Scenario (1000 – 10000kg hybrid OHRS system) were considered. Upon completion of the LCOH modelling analysis, it was observed as seen in Table 3 that the LCOH of the grid connected system was 17.37 $ per kg which is almost double the LCOH of the Hybrid system (8.51 $ per kg). This results stems from the fact that operating cost driven up by electricity purchased from the grid (grid system) was the main driver of cost at that scale of hydrogen output and that opportunities were available for the further cost reduction if the system became fully or partially power by renewable energy. As shown in the Figure 4.5, the LCOH reduced output capacity of the system which confirms the existence for the opportunities for economies of scale in the hydrogen production. The results of the Hybrid OHRS system yields a LCOH range for the various output between the range 8.51 to 5.80 $ per kg (£6.72 to £4.64 per kg) which falls within range of the Aberdeen city council cost projections.

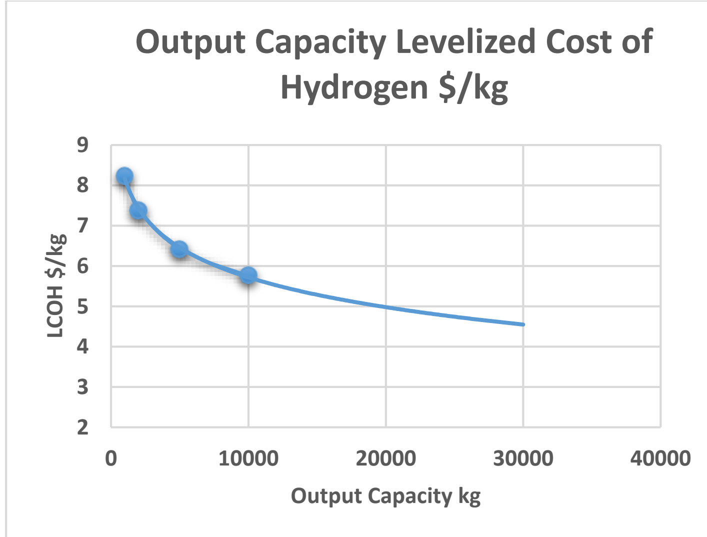

Figure 4.5 Impact of Output Scale on LCOH (Hybrid System)

System Component Cost Distribution Scale-LCOH

To broaden the analysis of the impact components cost on the LCOH, a demand-cost analysis was performed to identify opportunities for scale economies within the system. The installed capacity of the wind power to plant scale has been observed to significantly impact the cost of investment and also the cost LCOH as seen in Figure 4.3 and Figure 4.5. Thus, the impact analysis of the wind farm capacity adapted in the LCOH model was performed. To achieve this, a range of wind farm sizes scale to meet the plant power consumption per year were considered (2.5MW – 1000kg, 6MW – 2000kg, 12MW – 5000kg, 24MW – 10000kg plant capacities respectively). The hourly wind power generated for the different sizes was assumed to have an identical profile (hourly capacity factor). Additionally, the hourly grid power price was kept constant for all sizes evaluated. It was observed that wind farm significantly reduced the LCOH by half on various occasions and that significant economies of scale are realised for smaller wind farm sizes which was within the range of investigation analogous to the observation made by previous authors (IRENA, 2012) and that as the size of the wind increase farm increases the scale economies diminishes as shown in Figure 4.7. It is however important to note that one of the reasons for such favourable results is based on the assumption of a cost sharing working interest type investment model from oil exploration and production investment model adopted for the wind farm where investors pool together investment into a wind farm and the output in terms of megawatt-hour is shared based on the cost sharing percentage of the individual investors.

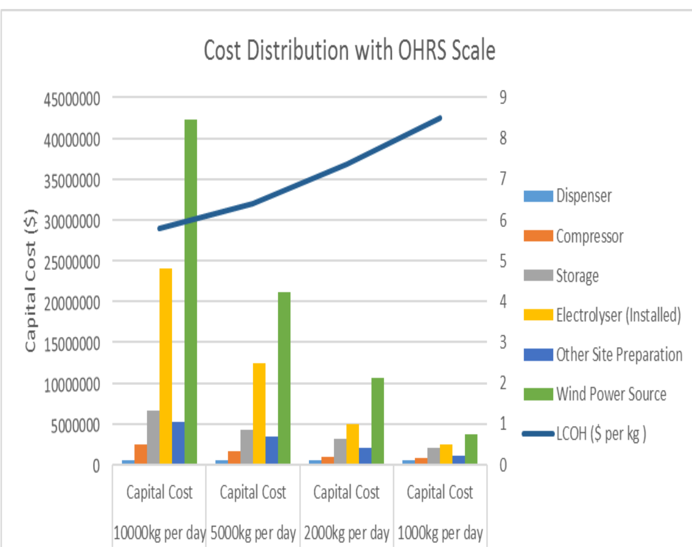

Figure 4.6 Component Cost Distribution

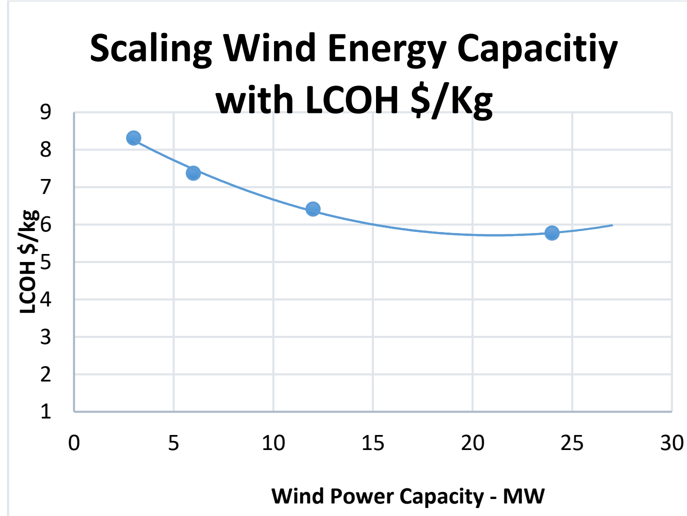

Figure 4.7 Wind Power Capacity Scale with LCOH $/Kg

As shown in Figure 4.6, further opportunities for scale economies lies in the capital cost of the Refuelling components (i.e. the dispenser, compressor, storage components of the system) and site preparation cost of the OHRS as these cost have been seen to barely increasing with the increasing output scale of production. Also, the non-electricity portion of the operating cost of the OHRS has also been identified as the source of scales economies as it can be observed that this cost barely increased with scale of output as well.

To further understand the impact of various components on the overall LCOH, a cost-capacity elasticity approach was used to analyse impact of the cost driving components. The cost-capacity elasticity measures the relative changes and how fast the LCOH changes for increase in the cost of the various components highlighted as the output capacity of the OHRS changes. Although, an approximate approach was adopted, the equation below describes how the analysis was conducted.

$$\varepsilon = \frac{\Delta x}{\Delta y} \times \frac{y}{x} \qquad 4.2$$

Where ε is the cost-elasticity, x is the component cost and y is the LCOH.

Following the cost-elasticity analysis, as illustrated in Figure 4.8, the responsiveness in terms of cost is lower with the refuelling components and highest in the wind power source which highlights the facts the scale economics opportunities are largely based on the refuelling components. Figure 4.8 also corresponds to the decline in the wind power scale economies diminishing as the wind power source output capacity increases.

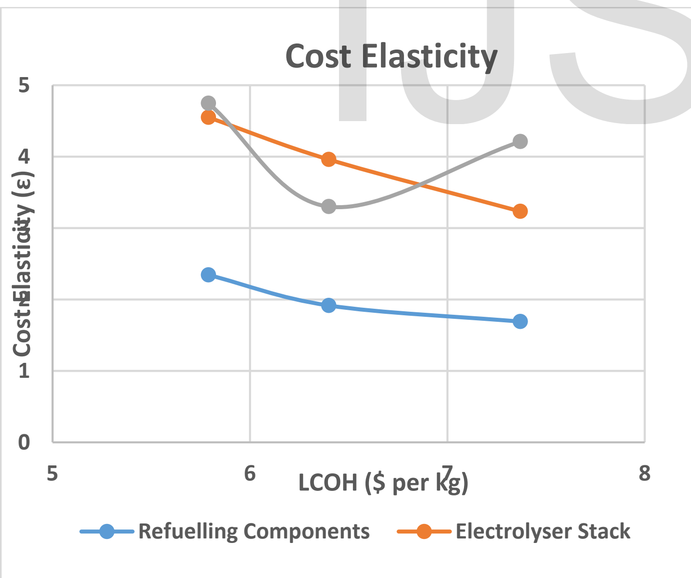

Figure 4.8 Major Components Cost Elasticity

Impact of Renewable Electricity Production Tax Credit (RTC)

The renewable electricity production tax credit (RPTC) is tax credit for electricity generated using specific energy source that qualify measured in per kilowatt-hour of electricity generated. A short analysis of the impact on the LCOH was made if the hybrid system was given a RTC for every electricity in kilowatt-hour the wind power source component generated. Although, the RTC is only given to systems that are connected to the grid, this study assumes that the whole OHRS is allowed the RTC. Based on this a range of RTC (0.05 to 0.09 $ per KWh) is considered and their impact on the LCOH is illustrated in figure 4.9.

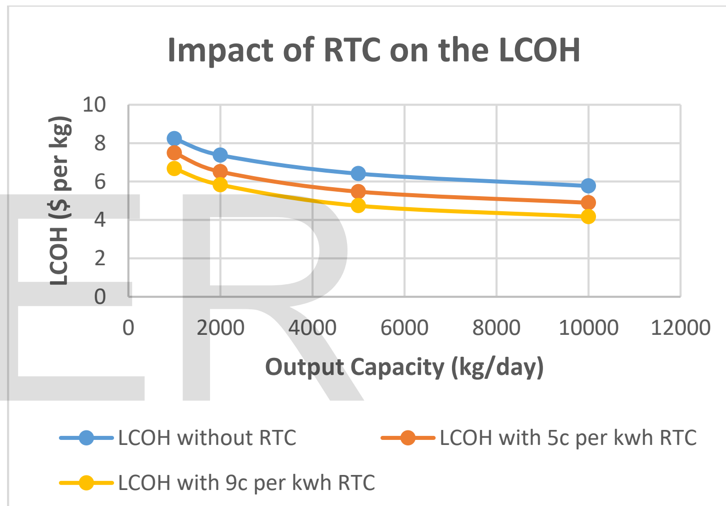

Figure 4.9 Impact of Renewable Tax Credit on LCOH

As seen in the figure above, the reduction in the LCOH is quite significant with the range of RTC assumed for the analysis the LCOH reduction was within the about 10% to 20% for the RTC range used in the analysis.

5. CONCLUSION AND RECOMMENDATION

5.1 Conclusion

This paper investigated the impact of scale economies on the cost of hydrogen production from an on-site refuelling station which is powered by a wind energy source and a grid connection. The study used a levelized cost (LCOH) approach to estimate the cost of production through varying the scale of production with the wind powered source output with approximate cost of investment and operation relating to the City of Aberdeen. The scale of production analysed where 1000kg (Base Case), 2000kg, 5000kg and 10000kg per day on-site refuelling station. The base case of 1000kg Hybrid OHRS was compared with an OHRS powered only from the grid and it was observed that the cost of production of the hybrid system was approximately 50% lesser than the grid-only powered OHRS.

In alignment with the Aberdeen City Council's "Hydrogen Economy Strategy", the LCOH value obtained for the 1000kg Hybrid OHRS case was compared with the Aberdeen City projection of per kilogram hydrogen cost of production for a 1000kg OHRS in consideration based on projected opportunities for demand to increase in the nearest future and it was obtained that the result of the LCOH analysis (6.72 £ per kg) fell within the range or close to the approximate projected profitable cost or prices from the Aberdeen City Council which was within 4.5 to 7.25 £ per kg. Sensitivity analysis was conducted on the base case by classifying the various components of the OHRS systems into cost components and it was observed that the electricity component cost the grid electricity cost and the wind power source had the most impact on the LCOH. A scale sensitive cost study and a cost-capacity elasticity approach was used to investigate the possibilities for economies of scale for the Hybrid OHRS systems, it was observed that a wind energy power source contributed significantly to the return to scale effect as cost dropped with smaller wind output capacity (initially 2.5MW), however, as the wind output capacity increased due to production needs, the scale economies opportunities from the wind power source decreased and the refuelling stations and electrolyser component of the system contributed to the scale economies as their cost-capacity elasticity were lower with respect to that of the wind power source.

Based on the results of the work, it is logical to conclude that adequate production cost reduction can be achieved considering the scales of production and maximizing the various scale opportunities to make hydrogen at the pump of hybrid on-site refuelling stations become more competitive. As identified during the analysis, various business model and policy assumptions were made in other to obtain the results which were obtained from the LCOH analysis, these sets the basis for the policy and business operation recommendations as seen in the following section.

5.2 Recommendations

Hydrogen could bridge the gap of the energy transition process and hydrogen could be the link to sustain the supply of large amounts of renewable power to sectors that are relatively difficult to decarbonise by direct electrification for example the sectors such as transport and manufacturing industry. It is noteworthy to state that the recommendations suggested herewith are with respect to the Aberdeen City Council's approximate projections on the city hydrogen demand and selling prices, ,however while this work is related to the Aberdeen these recommendations can also be applied to a broader perspective outside Aberdeen City. Also, based on the results of this work, rapid scaling up is required to achieve the necessary production cost reductions, make the economic viability of hydrogen possible and ensure a long-term enabler of the process of energy transition.

Large efforts are needed to be focused on large-scale applications that will engender rapid generation of economies of scale, with minimal requirements for infrastructures such as large manufacturing industries and heavy-duty transport (increased city fleets of hydrogen buses, trucks, non-electrified train lines and maritime vessels).

Flexible Business Models Adoption for Renewable Power Generation in Aberdeen

Considering the fact that renewable energy resources are variable in nature, to efficiently capture the impact of scale economies power-to-hydrogen can provide (and reduction in cost) flexible business investment and operating models should be adopted to provide the flexibility needed to accommodate the large shares of variable renewable energy expected to be provided in the market in the not too distant future during the transition process. In light of this, investment business models such as the Production Sharing contracts in the Oil and Gas industry can be adopted for investing in wind power source so that smaller player can pull investment into a pool to fund wind farms with a cost-production sharing approach to the output, with this, the scale economies impact of the wind power source will be amplified. Also, flexible operating models such as energy storage in form of stored hydrogen should be considered for cases of peak renewable energy resources availability, low hydrogen demand and low energy consumption to be able to balance the impact of period of low renewable energy availability on production cost.

Implementation of Enabling Policies for Renewable Power Generation in Aberdeen

With respect to earlier recommendations, in order to achieve a rapid scale-up, a flexible and supportive policy framework would be required to encourage and attract the private investments (even smaller investors) across the entire supply and value chain such as equipment manufacturers, infrastructure operators and FCE vehicle manufacturers. To trigger a jump in hydrogen demand that supports adequate scale economies on cost from final consumers, technology-neutral instruments should be adopted into the entire supply chain. These instruments may include carbon pricing, emissions restrictions zone and sectors, targeted renewable energy content or carbon pricing in specific sectors. In addition, further short-term cost reduction measures that can either totally or partially cover the initial cost difference with existing technologies are needed to encourage new entrants and private sector participation and inclusion in the energy transition, most especially in the stages of the value chain such as the vehicle applications (FCEVs manufacturers) and infrastructural development (renewable energy and hydrogen production infrastructure) investments. Those measures includes CAPEX subsidies and favourable Renewable Energy Production Tax Credits (RTC) directed to specific technologies and sectors with a clear purpose of de-risking infrastructure investment, encouraging significant infrastructure investment to supply end users with hydrogen produced from renewables and improve the economics across the supply chain while being entirely in sync with the long-term vision of the hydrogen economy strategy.

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