Title and Authors

Hydrogen from offshore wind: Investor perspective on the profitability of a hybrid system including for curtailment

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Abbreviations:

CAPEX – Capital Expenditure
FFH_2 – Fossil Fuel derived Hydrogen
HGV – Heavy Goods Vehicle
HHV – Higher Heating Value
LCOE – Levelised Cost of Electricity
LCOH – Levelised Cost of Hydrogen
L_{diesel} – Litre of diesel equivalent by energy
NPV – Net Present Value
O&M – Operation and Maintenance
OWF – Offshore Wind Farm
PtG – Power-to-Gas
SMC – System Marginal Cost

Abstract

Accommodating renewables on the electricity grid may hinder development opportunities for offshore wind farms (OWFs) as they begin to experience significant curtailment or constraint. However, there is potential to combine investment in OWFs with Power-to-Gas (PtG), converting electricity to hydrogen via electrolysis for an alternative/complementary revenue. Using historic wind speed and simulated system marginal costs data this work models the electricity generated and potential revenues of a 504MW OWF. Three configurations are analysed; (1) all electricity is sold to the grid, (2) all electricity is converted to hydrogen and sold, and (3) a hybrid system where power is converted to hydrogen when curtailment occurs or when the system marginal cost is low, analysing the effect of curtailment in each scenario. These represent the status quo, a potential future configuration, and an innovative business model respectively. The willingness of an investor to build PtG are determined by changes to the net present value (NPV) of a project. Results suggest that configuration (1) is most profitable and that curtailment mitigation alone is not sufficient to secure investment in PtG. By acting as an artificial floor in the electricity price, a hybrid configuration (3) is promising and increases NPV for all hydrogen values greater than €4.2/kg_{H2}. Hybrid system attractiveness increases with curtailment only if the hydrogen value is significantly above the levelised cost of €3.77/kg_{H2}. In order for an investor to choose to pursue configuration (2), the offshore wind farm would have to anticipate 8.5% curtailment and be able to receive €4.5/kg_{H2}, or 25% curtailment and receive €4/kg_{H2}. The capital costs and discount rates are the most sensitive parameters and ambitious combinations of technology improvements could produce a levelised cost of €3/kg_{H2}.

1. Introduction

As we continue to attempt to decarbonise our energy systems there is an increasing interest in and potential to develop offshore wind farms (OWFs) [1]. This is driven by a number of factors including climate targets, decreasing costs, greater offshore wind resources, and competition for suitable onshore sites [2]. Additionally, ambitions to electrify much of our heat and transport demand [3] mean that electricity from OWFs will be required to play an increasing role in electricity generation. 23GW of OWFs were installed worldwide as of

2018, with the IEA Stated Policies Scenario estimating that this will increase 5-fold by 2030, and 15-fold by 2040 [4]. 560GW of installed capacity of OWFs is anticipated in their Sustainable Development Scenario, and so best utilisation of this capacity is a highly relevant topic.

Issues such as accommodating intermittent electricity [5] or in decarbonising industry and heavy transport [6], mean that conversion of some or all of the electricity generated by OWFs into the more flexible energy carrier hydrogen has significant potential as an alternative to traditional grid interaction [7,8]. Dedicated hydrogen production facilities produced 70Mt_{H2} or 2758TWh_{H2} (HHV of 39.4kWh/kg) in 2018 [9]. OWFs (at 50% capacity factor and 75% efficiency) could provide almost 67% of world demand from 560GW (installed capacity of OWFs anticipated in IEA's Sustainable Development Scenario goal for 2040). That said, it is expected that demand for hydrogen will grow in sectors that currently rely heavily on fossil fuels and so ambitions to install OWF would also need to grow. In fact, many future low carbon or net-zero emissions systems significantly feature the conversion of electricity to hydrogen via electrolysis (splitting water into hydrogen and oxygen), also known as Power-to-Gas (PtG) [10–12]. Continued advancements in PtG technology and falling OWF costs, along with anticipated changes in policy suggest that their combination could constitute an emerging business model. Previous work by the authors show that capacity factor and the electricity purchase are the two main drivers of levelised cost in a PtG facility [13,14] thus, direct connection to selected high capacity factor OWFs may provide a comparable economic return to electricity-only OWFs in the near future [15].

The results of this paper apply to any use of the hydrogen produced, for example to replace fossil fuel derived hydrogen (FFH_2) as a feedstock in industrial processes [10,16]. However, the authors consider the PtG and back to power route to be too inefficient (maximum ca. 45%) given the advancements in alternative storage technologies [17] thus, not including it in this investigation. Conversion back to power may feature in future 100% renewable electricity systems though it more often appears as a sector coupling solution than as traditional electricity storage [18]. One potential market for produced hydrogen is in heavy goods vehicles (HGVs) where it offers an opportunity to couple the transport and electricity sectors without exacerbating the mismatch of supply and demand [19]. It has been shown that hydrogen fuel cell vehicles can under certain conditions outperform other transport

options under multicriteria analysis including efficiency, emissions, and cost [20]. This result is further enforced by the limited potential of electric or hybrid options (other highest performing fuel options in [20]) for long haul HGVs [21]. Other works also conclude that selling hydrogen directly (as opposed to conversion back to electricity) is far more economic [22,23].

For investors this hybrid system (OWF and PtG) is seen as having the potential to offset some of the decreased revenue due to periods of suppressed electricity prices [24], as a means of capturing lost energy due to curtailment or constraint [25], and as providing an option between the electricity and hydrogen markets based on real time pricing [26]. For those researching future low-carbon energy systems, it can mitigate some of the storage requirements and provide a low carbon alternative fuel or feedstock in areas where decarbonisation is difficult [27]. The improving efficiencies, cost reductions, high pressure production, and ability of Proton Exchange Membrane (PEM) electrolysis to ramp up and down to match OWF output with limited technical constraint means that the combination is technically feasible [28]. Previous analysis has also shown that PEM can provide a greater economic return than AEL despite the higher capital cost, due in most part to the higher efficiency [13]. The success of such ventures will depend on the economic performance and hence the willingness to invest in such hybrid technologies [29].

There is a strong body of literature post-2014 examining the viability of hybrid systems, particularly with respect to onshore wind. However, it is difficult to find directly comparable papers on the topic. Substantial cost reductions have been achieved since their publication and many are highly location specific or focus only on a specific element of the system [23,30]. Some authors focus on the viability of simpler systems to minimise economic losses [22,30], with the PtG hybrid system producing a low cost production of €4.2/kg_{H2} [23]. Jiang et al and Hou et al approach the problem from the perspective of an investor aiming to optimise their PtG investment [22,31]. Hou et al. conclude that hydrogen wholesale prices (values) above €2-5/kg_{H2} are required [22], while Jiang et al. report that levels of curtailment from 5-11% will still be seen in an optimised system [31]. Olateju et al. conclude that the costs involved mean that the hydrogen produced is not competitive with FFH_2 [30]. However, their cost assumptions, methodologies, and results make it difficult to draw additional conclusions relative to this work. Glenk et al. derived the optimal installed

capacity of PtG relative to the wind energy capacity; the work assessed the advantage of PtG to an investor in two different electricity markets (Germany and Texas) [26]. Their perspective is that producing renewable hydrogen will be benefical to investors and competitive with FFH_2 in the future given current cost reduction trends [26]. A gap in the state of the art is that no paper specifically addresses the viability of hydrogen with respect to the curtailment experienced by the wind farm during its opperational lifetime.

In this paper, investor interest is determined by the net present value (NPV) of a project and its annual revenues. Other indicators such as the levelised cost of the hydrogen (LCOH) produced will be used to determine the necessity or likelihood of incentivisation. If the NPV of a hybrid system is equal to that of an OWF alone, it can be said that the hybrid configuration would be of interest to investors. The conditions and incentives necessary for this result are determined by modelling one such potential project. A 504MW OWF in the Irish Sea was chosen as a it is currently under consideration; Europe was chosen as it leads the development and installation of OWFs [1,2]. This paper focuses on the year 2030, in order to allow likely technology cost reduction for both OWF and PtG to be considered. Using real wind speed [32] and electricity price data [33] a model was developed to calculate the NPV of an OWF. PtG of varying capacity, producing hydrogen at varying value was included in the model. Sensitivity analysis was performed on the system specifications/costs as well as the levels of curtailment experienced. To the best of the authors' knowledge, this is the first paper to examine configurations combining real wind speed and electricity price data from an OWF with a PtG system of varying capacity, with an ambition to inform academics, developers and policymakers on the potential of OWF and PtG hybrid systems.

The objectives of this paper are to:

- Develop the NPV of an OWF and compare it to that of a hybrid system to assess investor interest;
- Examine the effects of curtailment with respect to increasing attractiveness of a hybrid system;
- Perform sensitivity analysis on the system costs in terms of levelised cost of hydrogen and NPV;

- Derive insights suitable for policymakers on potential benefits and incentivisation.

2. Methodology

2.1 Introducing the system components

The systems modelled consist of an offshore wind farm (OWF) and a Power-to-Gas (PtG) installation including compression and storage, in various configurations, in order to evaluate and compare the viability of producing hydrogen to the business as usual case (electricity only). Respective systems are assumed to commence operation in 2030, therefore beginning construction ca. 2027.

2.1.1 The Offshore Wind Farm (OWF)

Distance to shore and water depth are primary cost drivers of OWF development [34,35]. Therefore, closer to shore OWFs are likely more suitable for consideration of the hybrid concept as the cost of hydrogen produced would be smaller than for more distant OWFs. The conditions necessary (for example, higher hydrogen value) for more expensive OWFs to provide comparable returns to their less expensive counterparts through the hybrid concept would likely not occur until further in the future. Dismukes et al. found no evidence of significant economies of scale or country-specific learning effects in the offshore wind market [35], with project cost more a function of local conditions though future costs reductions are anticipated [36]. Thus, the OWF modelled will be a 504MW installation in the Irish Sea (14.5km from shore) currently at the development process [37], representative of OWFs that would be suitable for PtG (high projected capacity factors, relatively close to shore, and shallow waters). Europe may be leading the development and installation of OWFs, but the model used here is representative of OWFs as a whole [1,2]. The development consists of 63 No. 8MW LEANWIND reference turbines, with a hub height of 110m and whose technical specifications are found in literature [38].

2.1.2 Power-to-Gas (PtG) and compression

In the period analysed it is expected that Proton Exchange Membrane (PEM) electrolysis will be the dominant electrolysis technology given anticipated cost reductions, transient operation capabilities, and efficiency improvements [28]. It is suggested to be superior to alkaline electrolysis or solid oxide electrolysis in terms of producing pressurised high purity

hydrogen, operating under variable or low power, and commercial availability [39]. It is justified to pay significantly more upfront cost due to the lifecycle benefits of PEM in 2030 [13]. Due to the low volumetric energy density of hydrogen additional compression up to 500 bar is required to efficiently ship the gas via tube trailer or for transport applications (c. 3.54kWh/mn^3 for hydrogen versus 10 MWh/m^3 for diesel). Therefore, total efficiency is given by the electrolysis stack efficiency (4.6kWh/m^3 [13]) plus the compressor efficiency (2.2kWh/kg$_{H2}$ [40] or 0.2kWh/m^3), yielding an overall efficiency of 4.86kWh/m^3. This figure is reduced to 4.8kWh/m^3 to account for synergies between pressurised electrolysis and compression, and slight scale effects on auxiliary power consumption, and is still in agreement with literature at 74% energy return (H_2 HHV of 3.54kWh/m^3) [41,42]. The PtG element of this project would be located onshore to reduce cost (electricity brought ashore alone as opposed to both hydrogen pipeline and electricity cable) and avail of a freshwater supply.

2.2 Operational model

The power generated, and hence electricity or hydrogen sold, is determined by historical wind speed data. The hourly system marginal (wholesale electricity) cost, sometimes referred to as system marginal price or clearing price, and system load for the project lifetime are generated based on historical data from the transmission system operator. Using these an estimate for curtailment can be calculated. Finally, this information is used to calculate economic indicators for the proposed project configurations.

2.2.1 Electricity market data

System Marginal Cost (SMC) and system load data were required in order to estimate revenues and curtailment over the lifetime of the project. In order to obtain this, historical data between 01/01/2008 and 29/01/2018 were investigated [33]. Blank entries were removed, and the half hourly data was converted to hourly by averaging consecutive entries in order to correspond with the available wind speed data. Data was sorted by delivery hour and month across the period. It was found that the data as a whole displayed a non-parametric distribution, and only weak correlations existed between SMC and system load. Therefore generating SMC data for the project lifetime was achieved by finding the mean and covariance in each hour of a month, and using multivariate normal random numbers

function to generate values [43]. This methodology was also used for system load. This approach produced data sufficiently realistic for this study, accounted for hourly and seasonal variations, and was validated against an existing model of the electricity market being analysed. Details of this validation are provided in Appendix 1.2 and 1.3.

2.2.2 Modelling Curtailment

In order to evaluate the effects of curtailment on the performance of the OWF or hybrid system, a model to generate curtailment frequency and extent was produced. The model operates on the basis that a limited amount of variable generation can be accommodated on the grid at any given time. This is generally known as the System Non-Synchronous Penetration (SNSP) limit, Equation 1 [44]. The variable renewable generation in the jurisdiction being examined is almost exclusively wind, and so Equation 1 is simplified and can be described as below with "wind generation" replacing "variable generation" as would be the case where solar and/or wave were also present.

$$SNSP = \frac{Wind\ generation + Imports}{System\ demand + Exports} \quad (1)$$

As there exists an upper limit of SNSP, curtailment is most likely to occur when wind generation is high relative to system demand. Comparing the wind speed across the whole jurisdiction against the wind speed at the planned OWF site, we find them to be highly correlated (R^2 of 0.92). Therefore, when estimating curtailment of the planned OWF it is more likely to occur, and to a greater extent, when the wind generated across the whole jurisdiction is high relative to system demand in a given hour. Estimating the wind power generated across the jurisdiction was achieved by assuming the same characteristics (including power and wake effects losses [36]) as the turbines in the OWF, but with a hub height of 80m and 10% reduced performance across all wind speeds [45], analogous to the older fleet of turbines that would be installed onshore in 2030. In line with national targets it is assumed that 9GW of wind capacity will be installed by 2030. The Z component (vector sum of northward and eastward wind speed values) of the averaged MERRA-2 data across the whole jurisdiction (Ireland) was then used to calculate the hourly wind power. Maximum storage, flexible demand, and export capacity together are equivalent to

"Exports" in Equation 1 and are assumed to sum to 1500MW, and so with this a pseudo-SNSP (P-SNSP) can be developed for each hour, Equation 2.

$$P - SNSP = \frac{Wind\ generation\ across\ jurisdiction}{System\ demand + 1500MW} \qquad (2)$$

The P-SNSP is normalised with respect to the maximum value in the set. Due to the methodology used (normalising results), the assumptions made here do not affect the results with respect to the OWF being examined and are simply a means of introducing curtailment into the model. If the P-SNSP in an hour is above a threshold input value (which is adjusted to achieve the desired overall curtailment figure), the power generated by the OWF will be curtailed according to the value of the P-SNSP. This is superior to randomisation as curtailment is most likely to occur during high wind generation and lulls in system demand. The market then responds as supply exceeds demand and system marginal (hourly wholesale) costs fall as a result, as is the case in reality; this can be explored in Lagarde et. al [24]. This method is also compatible with the structure of the electricity market [46].

Box 1: How the P-SNSP and curtailment work in the model

A threshold value (T) is varied representing the OWF generation that can be accommodated. If P-SNSP < T, then no curtailment occurs. If P-SNSP ≥ T, then curtailment does occur.

Example: Threshold value (T) of 0.65.
P-SNSP is 0.54, below threshold, no curtailment occurs and a value of 1 is then applied, implying 100% of power can be accommodated on the grid.
P-SNSP is 0.7, above the threshold, this implies only 70% of the power generated can be accommodated on the grid, 30% is curtailed.

The threshold P-SNSP value can be varied to achieve desired levels of curtailment, which is sufficient for our purposes. In reality some OWFs are shut down while others continue uncurtailed. The asset chosen to be shut down will vary and over the lifetime of an OWF will be the equivalent to the methodology used here. How curtailment is dealt with is detailed in the following sections.

2.2.3 Offshore wind farm

The power generated by the OWF was calculated based on hourly MERRA-2 wind speed data at the planned site [32] and the characteristics of the LEANWIND 8MW reference

turbine [38]. The Z component of the wind speed was extrapolated to 110m (turbine hub height) using the power law with an exponent of 0.13 [47]. The turbine cuts in at 4m/s, is rated for 12.5m/s, and cuts out at 25m/s. Power losses of 2%, and wake effects losses of 1.5% were assumed [36]. Using these the power generated at each hour is calculated for the lifetime of the OWF. In the electricity only system, the power generated is then multiplied by the corresponding hourly curtailment figure (1 represents no curtailment), before it is sold at the SMC to produce a figure for revenue in that hour.

2.2.4 Hybrid system

In a hybrid system, in each hour a decision between selling the power generated as electricity or as hydrogen is made, or if curtailment is occurring, both simultaneously. When producing hydrogen, the power generated by the OWF (minus losses) is converted to kilograms of hydrogen at an overall efficiency of 4.8kWh/m3 (74%) to include for compression and other auxiliary processes, and assuming 39.4kWh/kg_{H2} (HHV). This model uses the value of hydrogen with respect to the hourly SMC to choose an option. The SMC at which it becomes more profitable to produce hydrogen (set point) is given in Equation 3 and derived in Appendix 2.

$$Set\ point = \frac{PtG\ efficiency \times H_2\ sale\ price\ (€/kg)}{H_2\ energy\ density\ (MWh/kg)} \qquad (3)$$

In the model PtG can be installed at various fractions of the capacity of the OWF (see Figure 2). If the installed PtG is less than the OWF, hydrogen is produced at maximum capacity when the SMC is below the set point, with the remaining power sold as electricity. If curtailment is occurring and the SMC is above the set point the curtailed power is diverted to PtG, only in the case that curtailment exceeds PtG capacity is power unused.

2.2.5 Economic model

This is intended to be a representation of a 504MW_e OWF with and without PtG of various capacity, examining specific questions, therefore a number of assumptions are made with respect to the calculations:

- Commissioning and decommissioning periods are not included, associated costs are incurred wholly in year one and the final year respectively.

- No faults or delays throughout the project lifetime are modelled, however standard operation and maintenance costs are included.
- Day ahead price information allows the hybrid system to operate purely off a set of constraints (set point) with perfect foresight and constant efficiency.
- All of the hydrogen produced is sold and the value is fixed throughout the project lifetime.
- No alternative incomes or debt to equity ratio effects are considered.

The equations for revenue, levelised costs, and net present value in each of the configurations can be found in Appendix 2. They are standard economic indicators and allow for the comparison of each project from the perspective of a potential investor.

Although previous work has shown that the sale of oxygen produced during electrolysis can reduce the levelised costs, is not considered here as the volumes produced would saturate most markets; further assessing this is beyond the scope of this paper [13]. Incentives, taxes, and other region-specific variables are also not considered in order to maintain the general relevance of the results. Respective high-level system costs and specifications are detailed below and used in the model.

Table 1: Simplified costs for the components of an OWF/PtG hybrid system.

For the period 2030. Where large variations in estimates were found, median value were used. These represent base values. Sensitivity analysis is performed and detailed in the results and discussion.				
Component	**CAPEX (€/MW)**	**O&M per annum**	**Notes**	**Source**
Wind Turbines	1,500,000	3% of CAPEX	Estimate based on literature and assuming reductions to 2030. DECEX of 10% of CAPEX in final year.	[2,36,48]
Electrolysis & Compression (located onshore)	850,000	3.2% of CAPEX	Additional 15% balance of plant. Catalyst replacement and system overhaul every ca. 8 years at 32% of CAPEX. Water cost €1.2/m^3.	[13,26,49]
Hydrogen storage	€6,000/MW per hour	-	24 hours storage at full load considered.	[31,50]

CAPEX – Capital expenditure, O&M – Operation and Maintenance, DECEX – Decommissioning expenditure

Table 2: Base economic considerations used in the model.

Assumptions used in the model are listed here and varied in the sensitivity analysis.		
Variable	**Value**	**Notes**
Discount rate	6%	Project is assumed low risk by 2030
Hydrogen value (wholesale price to the producer)	€4/kg_{H2}.	€3/kg_{H2} to €5/kg_{H2} is equivalent to €0.75 to €1.25 per litre of diesel by energy* (L_{diesel}) in 2019. Hydrogen contains 39.4kWh/kg (HHV).
Project lifetime	25 years	Standard assumption.

*Diesel contains ca. 10MWh/litre and is used for comparative purposes throughout.

The hydrogen value can be comprised of any combination of wholesale price and incentive, for example a hydrogen value of €4.5/kg_{H2} may include a wholesale price of €3.5/kg_{H2} (8.9c/kWh_{H2} or €0.89 L_{diesel}) and a transport fuel production incentive of €1/kg_{H2}

(2.54c/kWh$_{H2}$). The additional costs of for example installing a hydrogen filling station are not included in this figure. Any incentive scheme introduced would have to satisfy legislation on state aid, though examples like this already exist [51].

3. Results and discussion

The NPV in all cases involving hydrogen production (sections 3.2 and 3.3) is based on the combined cost of the OWF, electrolysis, and all peripheries as all must be in place to produce hydrogen. Only electricity alone (section 3.1) NPV is based on the cost of the OWF alone. It is assumed that the same entity owns and operates both assets to maximise profit and thus electricity transmission from OWF to electrolysis is an internal cost.

3.1 Selling all the power as electricity

Considered alone the OWF (selling only electricity) has a LCOE of between €38.1 and €47.6/MWh$_e$ and an NPV of between €498M and €192M when experiencing 0-20% curtailment (Figure 1 and Appendix 3.1). This level of profitability (NPV) is the benchmark against which other configurations will be compared. An investor would be unwilling to build alternative projects (including PtG) unless they provided a comparable return to the OWF only selling electricity.

Before curtailment but including for losses the OWF has a capacity factor of 47.5% (comparable OWF in the Irish sea built in 2011 has a capacity factor of 44.8% [52]). Such a high capacity factor allows for approximately 32.5% curtailment before the OWF achieves a negative NPV, indicating that this is the point at which the project is no longer viable due to inability to sell the electricity produced. It is unlikely an OWF would be built if pre-construction testing indicated high curtailment levels like this would be experienced. However, an OWF experiencing this level of curtailment may be an ideal candidate for a hybrid system.

Included in Appendix 1.1 is a discussion on the LCOE of similar planned or already operational OWFs in order to validate the feasibility of the results above. Appendix 3.1 contains detailed results on NPV and LCOE with respect to curtailment.

3.2 Producing only hydrogen

Converting all the power produced to hydrogen, herein referred to as H_2 only, and therefore avoiding issues of curtailment requires PtG of equal capacity to the OWF. The decision to build H_2 only will be dictated by the value of hydrogen and the anticipated levels of curtailment the OWF alone would have experienced. A candidate for this, or indeed a hybrid system, would be an area of high wind resources but limited grid access.

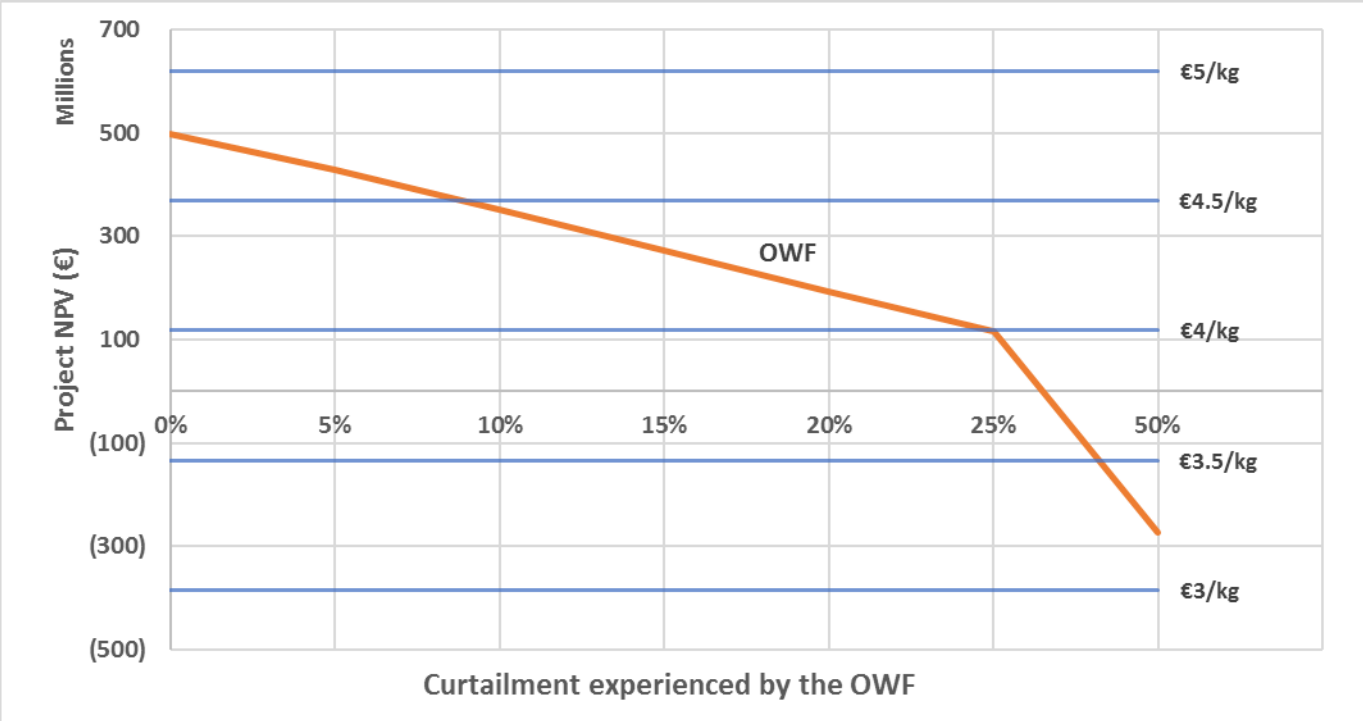

Figure 1: Decreasing NPV of the OWF (orange line) with increasing levels of curtailment. Each blue line is the NPV of building PtG capacity equal to the OWF and converting all available power to hydrogen and being sold at a given value. Slope change is due to X-axis break between 25% and 50%.

The LCOH for H_2 only is €3.77/kg_{H2} (95.7c/L_{diesel}), therefore hydrogen values above this provide a positive NPV. Building PtG capacity equal to that of the OWF can therefore be profitable given reasonable hydrogen values, but it is still less attractive to an investor than building an OWF for electricity alone. Only at hydrogen values greater than approximately €4.65/kg_{H2} (€1.18/L_{diesel})) can H_2 only equal the profitability of an OWF producing electricity only, provided the OWF experiences only moderate curtailment. For example, Figure 1 shows that even for a hydrogen value of €4.5/kg_{H2}, an OWF is more profitable provided it

experiences less than approximately 8.5% curtailment. Detailed results from Figure 1 can be found in Appendix 3.1.

Thus, the future viability of this configuration depends more so on cost reductions (reduced LCOH) or the increased value of hydrogen than as an alternative for OWFs likely to experience high levels of curtailment. High grid access fees for intermittent generators or further suppressed electricity prices may also increase the attractiveness of H_2 only.

3.3 Hybrid system of varying installed PtG capacity

Previous work has shown that by applying a price premium for converting electricity to hydrogen and modelling a fixed cost, an optimum installed capacity can be found beyond which additional installed PtG capacity decreases the NPV [26]. This paper however establishes a set point (function of the hydrogen value) as an artificial floor in the electricity price below which electricity will be converted to hydrogen (section 2.2.4). This leads to a situation where the NPV of a project only increases significantly if the hydrogen value is much greater than the LCOH from section 3.2. In general, at hydrogen values below the LCOH no PtG should be installed, above the LCOH PtG capacity equal to the OWF should be installed (Figure 2). This assumes all of the hydrogen produced can be sold at said value, there are no restrictions on project capital, and that fixed costs are negligible. Should negative SMCs feature in the electricity market then the electrolysers may generate an additional revenue by consuming grid electricity, where for example they are paid to use it to aid grid balancing. This adds another dynamic to the optimisation of installed capacity problem not considered in this paper. A hybrid system may also represent a solution to a wind farm that is already built and due to changes in the energy landscape is now regularly experiencing curtailment or find their electricity grid access reduced, putting them at financial risk.

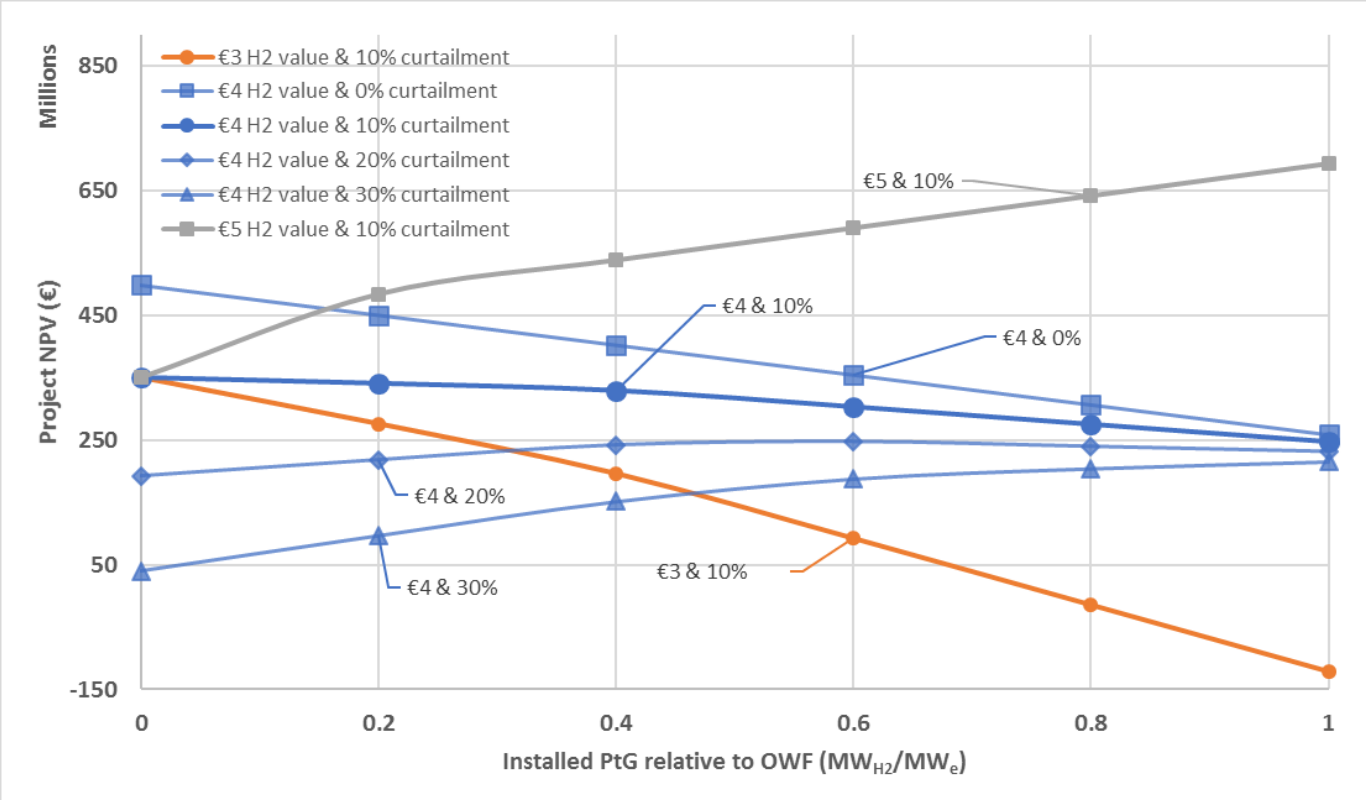

Figure 2: NPV of a hybrid OWF/PtG project as a function of installed capacity for given hydrogen values (wholesale price plus incentive) and levels of curtailment.

For a hydrogen value of €4/kg$_{H2}$ we see that unless curtailment levels are greater than 10%, installing PtG will reduce the NPV of the project. At hydrogen values of €5/kg$_{H2}$ there is a clear business case, increasing the NPV at any capacity, whereas no business case exists at €3/kg$_{H2}$ where the NPV decreases with increasing capacity. Thus, an investor's willingness to build a hybrid system will depend again more so on hydrogen value than on curtailment. A hybrid system equals the profitability of an OWF producing electricity alone (10% curtailment) at a hydrogen value of €4.25/kg$_{H2}$ (€1.08/L$_{diesel}$)). Additional results are available in the appendices.

It is difficult to produce a true LCOH for the hybrid system. Appropriating costs and benefits between the OWF and PtG is somewhat arbitrary, hence the authors' choice to use changes in NPV at given hydrogen values to determine the benefits. There is not yet a set methodology for this configuration and alternative methodologies such as including revenue from electricity sales may produce unhelpful results [53]. For example, a negative LCOH could occur should all the electricity revenue be counted in the LCOH (hydrogen value to the

producer required to achieve zero NPV) as electricity is highly profitable in the simulated market.

3.4 Curtailment in these scenarios

As expected, Figure 1 (H_2 only) shows that increasing levels of curtailment make the OWF less profitable. However, the nature of curtailment means that the reduction in profitability of an OWF does not directly translate to an increase in the attractiveness of PtG as a means of capturing the otherwise lost energy. When curtailment occurs, it is as a fraction of OWF generation, not all of the power generated in that hour. An overall curtailment figure of 10% across the project lifetime could result from an OWF regularly being curtailed by 20% on average, it is the cumulative effect that matters. Similarly, an overall curtailment figure (total curtailment in a year) of 10% could result from an OWF being curtailed by a mean value of hourly curtailment of 60% but much less frequently than the example above (when curtailment occurs the wind farm is dispatched down by 60% on average). For the market analysed even at very high levels of overall curtailment of 30%, sufficient to generally deem an OWF not viable, an average of only 50% of the generation is unable to be accommodated on the grid when curtailment occurs (Figure 3). That means even a high (30% overall) curtailment scenario, rarely is more than half of the power available being curtailed and therefore available to be converted to hydrogen as opposed to being wasted.

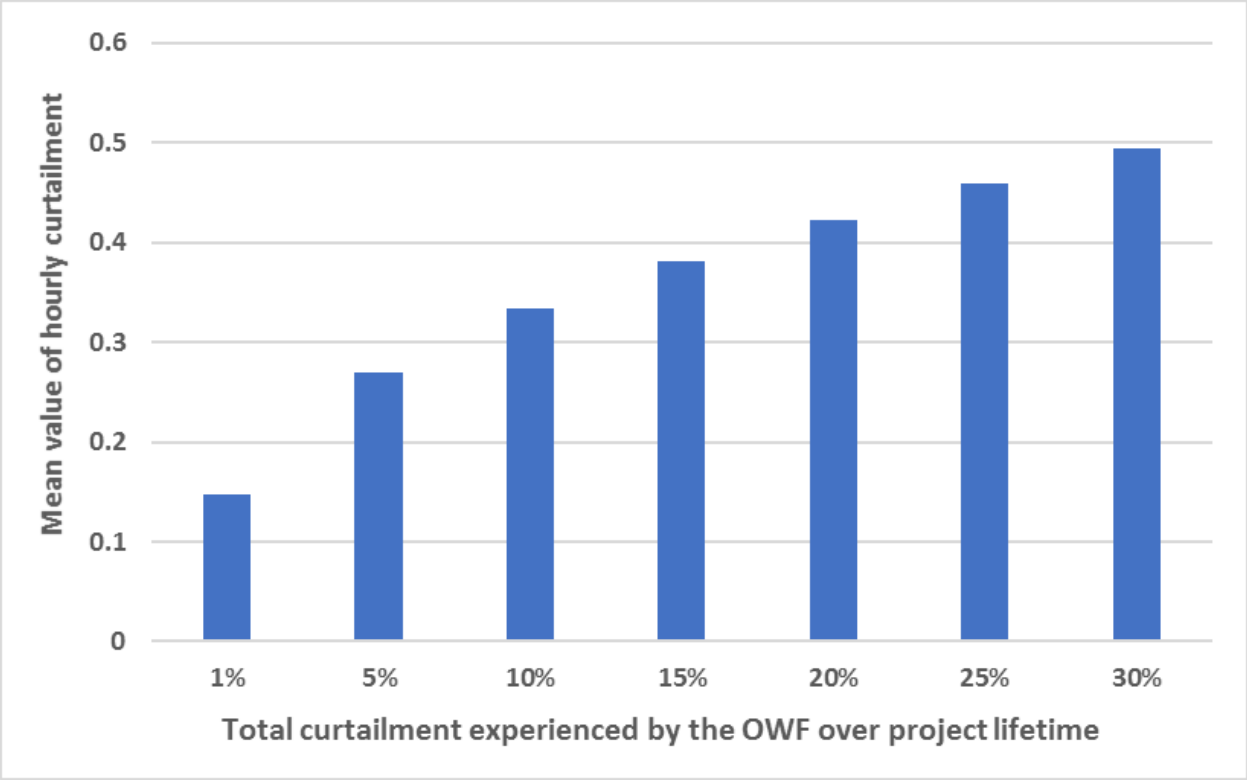

Figure 3: The mean value of hourly curtailment (average value of curtailment when it occurs, Y-axis) as a fraction of OWF generation in that hour for a number of curtailment scenarios over the project lifetime (X-axis).

3.4.1 Considering market size

Should the assumption that all of the hydrogen produced can be sold at a fixed price prove false, as in limited market, there exists an additional opportunity to optimise the system. Here one would select the PtG capacity that optimally consumes otherwise curtailed energy while producing sufficient hydrogen as per the demand profile. As per section 3.3 this would involve a fixed cost, making optimisation possible.

When considering satisfying hydrogen demand it is more economical to over-size the electrolysis facility, sell electricity, and use the PtG capabilities to minimise the negative effects of curtailment and suppressed electricity prices by providing a floor to the marginal price. This strategy would be highly applicable to satisfying ferry or HGV hydrogen demand as per section 3.6.

3.5 Sensitivity analysis

Base cost assumptions as given in Tables 1 and 2 and a hydrogen value of €4/kg_{H2} are used throughout this section for the analysis (hydrogen value affects NPV calculation not LCOH). The PtG installed capacity is equal to that of the OWF and 10% curtailment is assumed.

Changes to the hydrogen value have the greatest effect on project NPV, as examined in Figures 1 and 2. It was found that the wind turbine CAPEX, the hydrogen CAPEX (electrolysis, compression, and balance of plant), and the discount rate were the three most sensitive endogenous parameters.

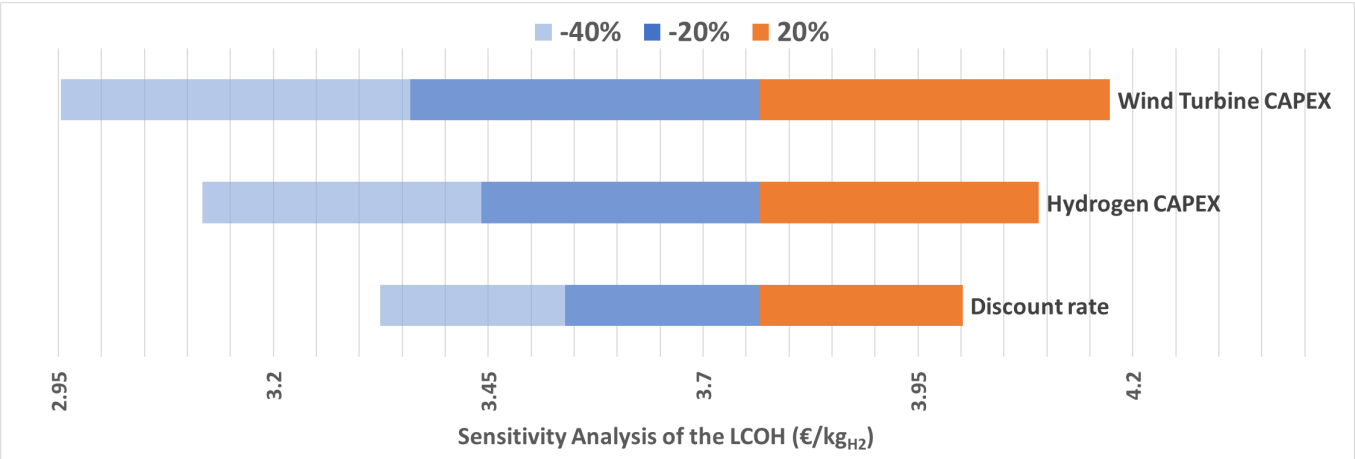

Figure 4: Change in the levelised cost of hydrogen (LCOH) for a given percentage change in the selected parameter. Base cost assumptions produce a LCOH of €3.77/kg_{H2}.

A 20% increase in wind turbine CAPEX would be indicative of unfavourable geography, stunted cost improvements, or difficulties in commissioning. A 40% decrease is unlikely before 2030 but serves to show that very large reductions would be required to achieve a LCOH of €3/kg_{H2}. A 20% decrease in hydrogen CAPEX is feasible should the rate of installation increase and manufacturing improve, beyond this is ambitious and would rely on significant economies of scale. The discount rate could be improved by favourable debt to equity ratios or risk reduction provided by policy. Combinations of the above improvements would improve LCOH competitiveness as discussed in section 3.6.

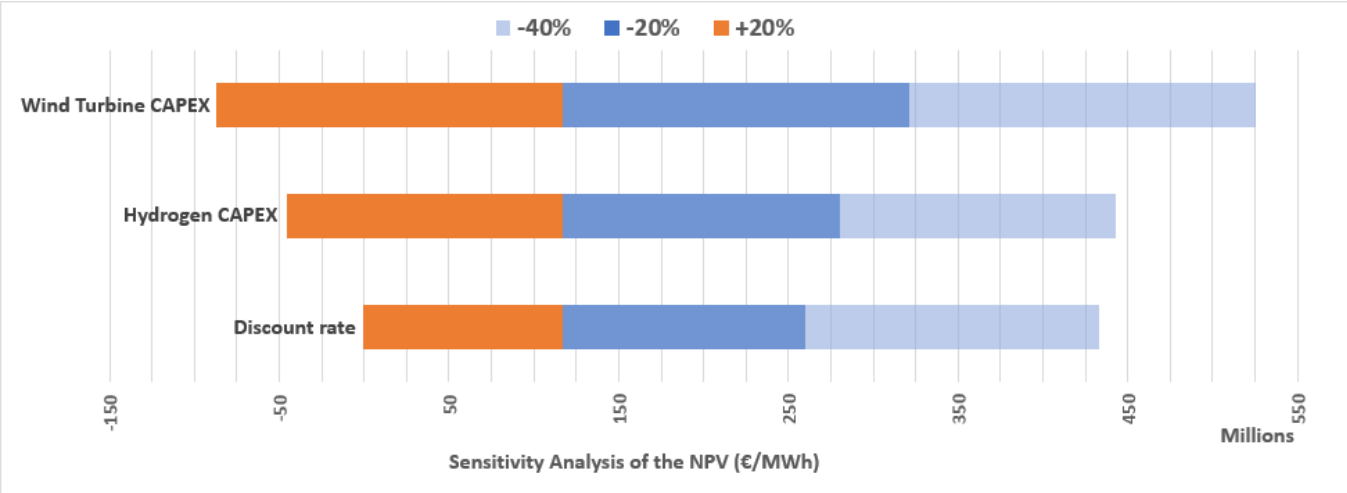

Figure 5: Change in the project net present value (NPV) for a given percentage change in the selected parameter. Base cost assumptions and a hydrogen value (wholesale price plus incentive) of €4/kg_{H2} produce a NPV of €117 million.

Beyond the hydrogen value, the NPV is most sensitive to the same parameters as the LCOH. 20% increases in either the wind turbine or hydrogen CAPEX will deem the system unprofitable at a hydrogen value of €4/kg_{H2}. As the system is NPV positive under base assumptions any improvements in cost or discount rate will increase profitability. In terms of investor interest, decreases in wind turbine costs will increase the attractiveness of an OWF to an equal or greater extent than a hybrid system. In order for a hybrid system to provide an equal NPV to an OWF alone, the hydrogen CAPEX would need to fall from €850,000/MW_e to €600,000/MW_e, a 30% decrease from the assumed cost in 2030; this is challenging [13]. However, at this point an investor would in theory be willing to invest in PtG.

Also modelled were an increase in the project lifetime and PtG efficiency. Should the system last 32 years instead of the 25 supposed the LCOH falls slightly from €3.77/kg_{H2} to €3.5/kg_{H2} but NPV climbs to €274 million, including for additional PtG refurbishment and O&M costs. If the system achieves a total efficiency for compressed hydrogen of 4.6kWh/m^3 (77%) LCOH falls to €3.61/kg_{H2} and NPV increases to €202 million.

3.6 Cost of refuelling and potential for incentivisation

Fossil fuel derived hydrogen (FFH_2) price varies with scale (volume produced) and purity. Large, medium, and small application scale prices may be €1.5-2.5/kg_{H2}, €3-4/kg_{H2}, and above €4/kg_{H2} respectively [26]. Each of these production scales would require an 875MW, 440MW, and 90MW OWF and PtG facility respectively. This means that hydrogen from an OWF may be competitive in niche applications without incentivisation in 2030, with various improvements also allowing competitiveness in medium scale applications. However, in terms affecting transport, the target is to displace diesel which retails at €1.2-1.6/L (€4.7-6.3/kg_{H2} equivalent) in Europe in 2019 [54], 30-70% of which may be taxes [55].

In order to provide context to the results and as hydrogen transport is not well established, the example of replacing a diesel HGV with a hydrogen fuel cell equivalent is considered in terms of fuel costs. Similar calculations would apply to replacing diesel ferries with fuel cell equivalents, though the initial higher purchase costs are not included for either case. This is purely comparative and not intended as an analysis of the cost of ownership.

Box 2: Diesel versus hydrogen fuel cell HGVs, fuel costs per 100km

The diesel costs are based on the range of values seen in the EU today, from lowest exclusive of tax, to highest inclusive of tax [54]. Hydrogen costs are exclusive of tax.

Formula for fuel costs per 100km:

$$Fuel\ economy\left(\frac{litre\ diesel\ (l_{diesel})\ or\ kg_{H2}}{100km}\right) \times Fuel\ cost\ \left(\frac{Lower -\ Upper\ value\ in\ Euro}{Unit\ of\ fuel\ (l_{diesel}\ or\ kg_{H2})}\right) = \boldsymbol{Range\ of\ costs\ per\ 100km}$$

Diesel vehicle allowing for efficiency improvements to 2030 [56]**: 37l/100km**

$$\frac{37l}{100km} \times \frac{€0.60 -\ 1.60}{l_{diesel}} = \boldsymbol{€22.2 - 59.2/100km}$$

Fuel cell vehicle combined efficiency of 55% [57]**: 282kWh/100km = 7.2kg_{H2}/100km**

$$\frac{7.2kg_{H2}}{100km} \times \frac{€3 - 6}{kg_{H2}} = \boldsymbol{€21.6 - 43.2/100km}$$

The calculations in Box 2 assume that hydrogen is not subject to the same level of taxation as diesel. If taxes similar to diesel were imposed on hydrogen it would not be competitive.

Burning 37L of diesel produces 104.6kg of CO_2. If an incentive of €1/kg_{H2} (25c/L_{diesel}) was required in order for producers and consumers to switch to hydrogen vehicles that would

represent a marginal cost of abatement of €69/t_{CO2}. Not of course accounting for the infrastructural changes required. However, many EU schemes operate on figures of €260/t_{CO2}, up to €666/t_{CO2} when special items such as grants, favourable motor tax, or free charging are included [58].

In the H_2 only system if a simple incentive was to be considered with a desired hydrogen wholesale price of €3.5/kg_{H2} (88c/L_{diesel}) for example, then a minimum of €0.27/kg_{H2} (7c/L_{diesel}) is required for profitability. €1/kg_{H2} (25c/L_{diesel}) would be required to match the profitability of an OWF alone. An incentive between these figures would be sufficient to encourage installation of some capacity of PtG in a hybrid system under certain conditions such as negative SMCs or significant curtailment. This level of incentivisation is feasible for most European governments.

3.7 Policy implications

We should be cognisant of the benefits of PtG such as the increased reliability and quality of the power supply, energy independence, and climate change targets when considering incentivisation [23]. PtG internalises the cost of the positive externalities and therefore, it should be considered not just on the cost of the hydrogen produced but on the potential for offsetting investments elsewhere such as in energy storage. In addition, by placing an artificial floor in the SMC, analogous to creating demand in low-load hours, PtG investments provide system wide benefits to generators similar to demand side management. The upper range of the price duration curve is unaffected but low-cost and off-peak prices increase.

An Economic and Social Research Institute (ESRI) study on this found that the increase in profits by renewable generators this causes is greater than the losses made on a PtG investment [59]. Therefore, it may be possible to increase taxes/tariffs on renewable generation in order to fund a hydrogen production credit at net zero effect to said generators. Perhaps even a preferential rate on transmission system charges to producers who also convert difficult to manage energy into hydrogen could be considered. This is a high-level concept and care would have to be taken to ensure costs are not directly passed on to consumers. However, as system balancing costs and risk to the electricity supplier would be reduced, and the markets are liberalised this is conceivable. This at least provides a route to affordable hydrogen that is also a desirable investment.

Although negative pricing or consistently low SMCs increase the attractiveness of PtG, the results of this research demonstrate that future investments in PtG will be guided by policy and appropriate incentivisation, and not as a means of capturing otherwise curtailed electricity.

Finally, it is also important to note that hydrogen production from alternative renewable sources may become cheaper over time and across different regions. The competitiveness of the configurations tested in this paper would be affected and emphasis would have to be placed on the positive externalities. In the future hydrogen from solar energy in North Africa for example could be shipped to Europe at a potentially lower cost than it could be produced indigenously [60].

4. Conclusions

The power and/or hydrogen generated by an offshore wind farm (OWF) with and without an associated Power-to-Gas system was simulated based on historic market and wind speed data. System costs and various hydrogen values, which could be comprised of a combination of wholesale price and incentive, were tested as well as varying levels of curtailment experienced by the wind farm. The OWF alone with no curtailment has an LCOE of €38.1/MWh_e and should all the power generated be converted to hydrogen we find a levelised cost of hydrogen of €3.77/kg_{H2}. Additionally, given 10% curtailment we find a NPV of €350M for the OWF alone and that a 30% decrease in total hydrogen production capital cost would be required for the hybrid system to match this. In a hybrid system where Power-to-Gas provides a real option between the electricity and hydrogen markets, hydrogen values greater €4/kg_{H2} are required to provide an equal or greater NPV than an offshore wind farm producing electricity alone. This finding holds true even for significant levels of curtailment, up to 17% at €4/kg_{H2}. Sensitivity analysis reveals only ambitious cost reductions will lead to a levelised cost of hydrogen approaching €3/kg_{H2}. Given that curtailment alone will not drive investment in PtG, and that hydrogen vehicle running costs are potentially lower than their diesel equivalents the authors conclude incentivisation should be considered in some form. The system wide benefits provided by a hybrid system converting difficult to manage energy into hydrogen warrant further appraisal. Therefore, it

is conceivable to incentivise hydrogen production from offshore wind at net zero loss to the electricity system. The hybrid concept is most suited to areas of high wind resources but where curtailment or constraint may hinder deployment, or where a hydrogen production credit exists. When considering hydrogen demand the authors conclude it is best to build a hybrid system that engages in the electricity market and converts excess or low value electricity to satisfy said demand.

Limitations of the model

- Curtailment is an independent variable in this study and trade-offs with grid expansion, storage, or demand response are outside of the scope of the paper.
- Market modelled does not include negative pricing, which may increase PtG viability.
- There is weak correlation between curtailment and suppressed SMCs, whereas there may be some correlation in future real-world electricity markets with increasing levels of variable renewable generation.
- Fixed and variable costs are not differentiated which hinders optimisation.

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