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Are electrofuels a sustainable transport fuel? Analysis of the effect of controls on carbon, curtailment, and cost of hydrogen.

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Abstract

Variable renewable electricity (VRE) decarbonises the electricity grid, but its intermittency leads to variations in price, carbon intensity, and curtailment over time. This has led to interest in utilising difficult to manage electricity to produce electrofuels (such as hydrogen via water electrolysis) for transport. The vast majority of the environmental impact of electrofuels is contained in the electricity they consume however, only consuming otherwise curtailed electricity (produced when supply exceeds demand) leads to prohibitively expensive hydrogen due to low run hours.

Using a model which bids for wholesale electricity, two operational strategies (controls) aimed at increasing sustainability without requiring policy changes were tested in electricity system models of 40% to 60% renewable electricity penetration. (1) Bid price control set a maximum price the plant will pay for electricity. (2) Wind forecast control dictated that the plant may only run when a minimum forecast VRE production is met.

It was shown that sourcing electricity at times of low cost or high forecast wind power can lead to more decarbonised hydrogen production (up to 56% more) at a lower cost (up to 57% less). When economically optimised (minimising levelised costs) the bid price control reduced the carbon intensity of the electrofuel produced by 5% to 25%, and the wind forecast control by 14% to 38%, compared to the grid average. Both controls demonstrated a high proclivity to utilising otherwise curtailed electricity and can be said to aid grid balancing. The bid price control also greatly reduced the average cost of electricity to the plant. The positive impacts increased with renewables penetration, and significant synergies between economic and environmentally conscious operation of the plants were noted.

The operational strategies tested in this paper allow for transport fuels to be produced from grid electricity, without exacerbating the mismatch of supply and demand. Future decentralised quasi-storage using these operating strategies may economically produce transport fuel, and aid grid balancing.

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Abbreviations

AC	Actual Cost	LCOE	Levelised Cost of Energy
BP	Bid Price	P2H	Power to Hydrogen
CCGT	Combined Cycle Gas Turbine	RE	Renewable Electricity
DGA	Difference from Grid Average	RED	Renewable Energy Directive (EU)
DSM	Demand Side Management	RH	Run Hours
FFC	Fossil Fuel Comparator	SMP	System Marginal Price
HGV	Heavy Goods Vehicle	SMR	Steam Methane Reforming
ISEM	Irish Single Electricity Market	VRE	Variable Renewable Electricity

Normal temperature and pressure (N): 20°C and 101.325kPa

The symbol η is used to denote efficiency

1   Introduction

In response to climate targets, high levels of Variable Renewable Electricity (VRE), in particular wind and increasingly solar, are being integrated into the electricity grid; with increasing shares of VRE come issues of grid balancing, stability, curtailment, and storage needs, potentially affecting security of supply [1,2]. It also leads to price volatility [3] and reduced system marginal prices [4,5], and as this paper aims to explore, fluctuations in the carbon intensity of the electricity generated, defined as the units of carbon dioxide emitted per unit of electricity generated, and later as units of carbon dioxide embodied per unit of fuel produced. Large scale and flexible energy storage options [6,7] as well as Demand Side Management (DSM) [8,9] and price controls [10] are seen as a means of reducing these effects with presently deployed solutions such as pumped hydro storage [11] insufficient to avoid significant dispatch down of VRE [12,13].

Electrofuels have been proposed as an advanced transport fuel, DSM of electricity, and a flexible storage mechanism for VRE. Power-to-Hydrogen (P2H) is one such electrofuel whereby electricity is stored as hydrogen (H_2) via electrolysis of water. Thus, P2H changes the energy vector to a gaseous

fuel from non-biological origin. P2H is gaining attention as a highly scalable flexible consumer [14], offering quick response for storing excess electricity and adding stability to the electricity grid [15], while producing an advanced renewable transport fuel [16,17]. The ability of P2H to rapidly ramp up and down demand allows it to utilise difficult to manage electricity [18,19] that may otherwise be curtailed [12,20]. Operating ideally, P2H offsets the need for energy imports and abates GHG emissions [21,22] by providing ancillary grid balancing services that enable further integration of VRE [15,20]. Converting electrical energy into chemical energy allows for large-scale storage through injection into existing gas grid infrastructure (subject to constraints [23]) or establishment of hydrogen fuelling stations, where it offers high storage capacity and discharge times [24]. It may also receive a fee for this service, aiding its economic viability. Many technology reviews and studies are available which detail the working principles, relative advantages and disadvantages, and trends in P2H technologies [18,25]. Besides P2H other electrofuels (P2X) include methane, ammonia, dimethyl ether, and methanol all of which rely upon the electrolysis of water as the key enabling technology; therefore insights from this work are applicable to all P2X technologies [26].

Much of the focus of electrofuel research has focused on utilising surplus [27] or otherwise curtailed VRE [28,29], or as an alternative to network expansion [20,30]. However, previous work by the authors has shown that higher run hours are required for an economical system and therefore, surplus VRE alone is insufficient even at very high penetration levels [31,32]. The intermittency too would mean that large hydrogen buffers and storage would be required, and the actual volumes of gas produced would be limited, rendering the system prohibitively expensive. Yet, as we aim for higher levels of renewable energy in power systems the production of renewable synthetic fuels, as an alternative to fossil fuel products, is a path which demands more attention [33].

Furthermore, P2H can be positioned as a novel biogas upgrading solution, utilising its CO_2 content to produce renewable methane (CH_4) via a Sabatier reaction ($CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$). This could increase the sustainability of biogas plants, practically doubling methane output, potentially offsetting some of the capital required, and promoting a circular economy [17,18,27,34].

The EU have outlined that Renewable Energy Sources in Transport (RES-T) must hold at least a 14% share of energy in transport by 2030 [35]. P2H is promoted within the EU framework due to its low indirect land use change, potentially low carbon intensity, and waste to energy/circular economy characteristics. It is expected that the hydrogen produced will be used in the transport sector as this sector has low levels of decarbonisation and there are limited alternatives for advanced renewable transport fuel production [22,36]. As electric vehicles are likely to dominate the private passenger fleet, the best route for P2H is to displace diesel in heavy commercial long distance vehicles [22].

This is due to its superior energy to mass/volume compared to batteries, growing restrictions on particulate emissions, and associated proposed bans on diesel powered engines [22,37].

It is critical to maximise the sustainability of P2H from grid electricity for use as a renewable transport fuel. Several studies have concluded that the majority of the climate impact of P2H can be attributed to the electricity consumed in the electrolysis step [38–40]. Parra et al [41] indicated that electrolysis and its associated energy consumption contribute more than 90% of the potential environmental impacts (climate change, particulate matter, ozone depletion, eutrophication) of P2H with the electricity generation method being the most sensitive parameter. Similar results were found by Collet et al. and Reiter et al. who determined low carbon electricity was mandatory to achieve a sustainable production of P2H [42,43]. As such, reductions in the carbon intensity of the electricity consumed are analogous to reductions in the environmental impact of P2H. This concept is central to the paper.

The gap in the research identified is the use of static or average values for the carbon intensity of the electricity consumed [38–44]. This is inconsistent with the complexity of the interaction with the electricity grid of such systems [12,30], and challenges the prevalent simplified assumption that P2H is sustainable as it operates on curtailed renewable electricity alone [16,27]. Potential changes in the carbon intensity of the electricity consumed dictate the carbon intensity of the gas produced and understanding this is critical to fully understand the sustainability of P2H/electrofuel systems.

To test this, a P2H system will be modelled as a large flexible consumer within an electricity market with limited interconnection at renewable electricity penetrations of 40%, 50%, and 60%. Parameters the P2H plant operator can control, herein referred to as the "plant", will be varied to assess changes to carbon intensity of the hydrogen produced, cost of electricity consumed, and potential effects on curtailment.

In line with configurations found in the latest EU Renewable Energy Directive [35] that aim for P2H to consume low carbon and/or difficult to manage electricity, two methods are proposed. One, the plant will only run when the system marginal price (SMP) is below a threshold figure (Box 2), as drops in the SMP are indicative of balancing issues [3–5]. And two, a wind forecast control, will allow the P2H plant to run only at times when forecast wind generation is above a threshold figure (Box 3). See Section 2.4 for further explanation. Within these two controls, Optimum high and Optimum low are defined. Optimum high is the application of the controls that would allow for 6000 run hours, Optimum low allows for 4200 run hours, identified in previous research as the upper and lower ends of a range that was found to minimise the levelised cost of energy (LCOE) of a P2H system [31,32].

This work advances upon previous research by the authors [31,32] in the relationship between a P2H system, the electricity grid, the running schedule, and the levelised cost of energy. To the best of the authors' knowledge this has not been done before. The objectives of the paper are to:

- Examine the effect manageable controls (operational strategies), bid price and wind forecast, have on the sustainability of an electrofuel system;
- Investigate the proclivity to utilise otherwise curtailed electricity and hence, the effect on demand for fossil fuel based electricity generation when applying these controls;
- Compare and contrast these results to the grid average carbon intensity;
- Investigate the trends and change in sustainability of electrofuels with increasing shares of VRE.

2 Methodology

2.1 Power to Gas/Electrofuel system

The system modelled consists of electrolysis to produce hydrogen and auxiliary processes such as pumping, cooling, and compression to a minimum of 25 bar (Figure 1). It is assumed that when the controls have been met the electrolysers consume energy, without technical constraints such as ramp-up or buffer capacity. The current commercial state of the art electrolysis technology, polymer electrolyte membrane (PEM) has demonstrated the required operational flexibility [45,46]. Thorough descriptions of electrolysis can be found in past literature [47].
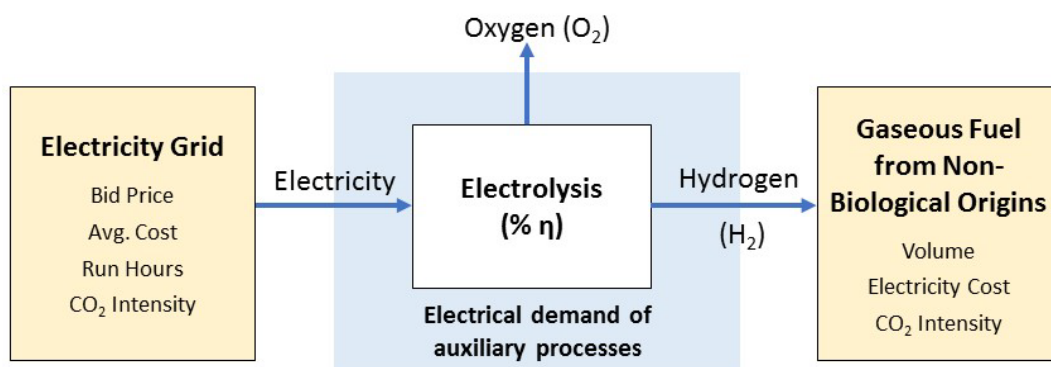

Figure 1 - Graphical representation of the model

Electrolysis stack efficiency at NTP is estimated at $4.4kWh/Nm^3$ [31,48,49], compression energy consumption of $0.2kWh/Nm^3$ [48,50,51], and auxiliary power consumption of $0.1kWh/Nm^3$ [31]. This gives an overall efficiency of converting electricity to compressed hydrogen of $4.7kWh/Nm_3$ or 75%

(H_2 HHV of 3.54kWh/Nm^3) for 2030, the period analysed. The carbon intensity of the compressed hydrogen (CO_2 embodied per unit) is then equal to the carbon intensity of the electricity (CO_2 emitted per unit) multiplied by the reciprocal of the conversion efficiency expressed as a decimal (see Box 1).

Box 1: Example of relationship between carbon intensity of electricity and that of hydrogen

An electricity carbon intensity of 200gCO_2/kWh will lead to a compressed hydrogen carbon intensity of 200/75% = 266.6gCO_2/kWh.

Inversely, a compressed hydrogen carbon intensity of 350gCO_2/kWh is indicative of an electricity carbon intensity of 350 x 75% = 262.5gCO_2/kWh.

Results can be converted from g/kWh to g/MJ by dividing by 3.6.

Use 39.4kWh/kgH_2 to convert to kgCO_2/kgH_2 if desired.

Previous work concludes that relying on curtailed energy alone is uneconomical due to the small and intermittent volume of hydrogen that would be produced [31,52]. Therefore, grid connection and market engagement are essential for P2H systems. The electricity consumed constitutes the vast majority of P2H life cycle carbon emissions and wider environmental impacts [38–43]. This allows us to equate reductions in the carbon intensity of the energy consumed, with increases in the sustainability of the process. The results of applying the operational strategies (controls) detailed in this paper will be compared to the grid average and economically optimised P2H systems in terms of overall sustainability.

2.2 The power system models

The envisaged system engages in the Irish Single Electricity Market (ISEM) without priority as a large flexible consumer, a market similar to those around the world. Therefore, consumption of electricity is technology neutral and P2H will compete for energy against demand/storage/interconnection as it would in a functioning electricity market. The P2H plants are assumed to be ideally flexible and the model does not include constraints or costs for start-up and shut-down, ramp-up, or buffer capacity. No mechanism or widespread precedence has been set that would allow a plant to consume energy, even that which would otherwise be curtailed, without engaging with an electricity market. P2H does not directly benefit from its ability to provide grid balancing services and receive "free" electricity, with some rare exceptions [53,54], though this is the subject of much discussion [6,13]. Thus, the amount the plant is willing to pay for electricity (its bid price) directly informs the number of runs hours and when these hours occur unless the plant operates according to schedule (as may be informed by wind generation forecast). The bid price and up/down times of the plant are two

parameters that a plant operator would control when interacting with the electricity market and therefore, using them to manipulate the sustainability and cost of the end product is worth investigating.

To determine the running schedule of the electrolysers, PLEXOS models of the ISEM in 2030 were developed. PLEXOS Integrated Energy Model is a power systems modelling tool used for electricity market simulations [55]. The power systems model develops an hourly System Marginal Price (SMP) for the ISEM based on current rules, and it has been benchmarked against historic market data and has been validated by the regulator to reproduce realistic results [56]. The SMP can be considered as the hourly island wide wholesale price of electricity. The model uses deterministic mixed integer linear optimisation to minimise the costs of the electricity dispatched including for fuel costs, start-up costs, penalties for unserved energy, and a penalty cost for not meeting reserve requirements [57]. In general, the SMP is low when there is more than sufficient generation capacity online to meet demand, such as when wind power is being curtailed. When the amount of generation online to meet demand is scarce, the resulting SMP is higher. The SMP is set by the marginal costs of the last generator online to meet demand. In Ireland this is often gas fired generation. The SMP is also influenced by zero-marginal cost VRE which tends to supress the SMP in times of high VRE production. In times of excess VRE generation, curtailment may take place. Current electricity market rules offer VRE priority dispatch on the electricity grid, therefore curtailment of VRE is often a last resort. The model optimises thermal generation (fossil fuel and renewable), VRE, pumped storage, interconnection, as well as reserve classes subject to operational and technical constraints [16,58]. Also included are constraints on the unit operation of each power plant including minimum and maximum generation, minimum and maximum up and down time and the system ramp up and down rates, as well as a system level constraint consisting of an energy balance equation ensuring supply meets regional demand at each period [16]. The combination of these constraints, and the objective function of minimising production cost leads to the merit order, or the sequence in which the generators will be dispatched. Due to zero-marginal cost generation and/or renewables priority dispatch, wind energy and other renewables are first in the merit order meaning they run most consistently. The deficit is then made up of traditional generators. More detail on how ISEM operates can be found online [59,60].

Three PLEXOS models were tested at 40%, 50%, and 60% renewable electricity (RE) respectively with projected planned interconnection outside the island. Thus, as outlined in Figure 2, three energy mixes were tested.
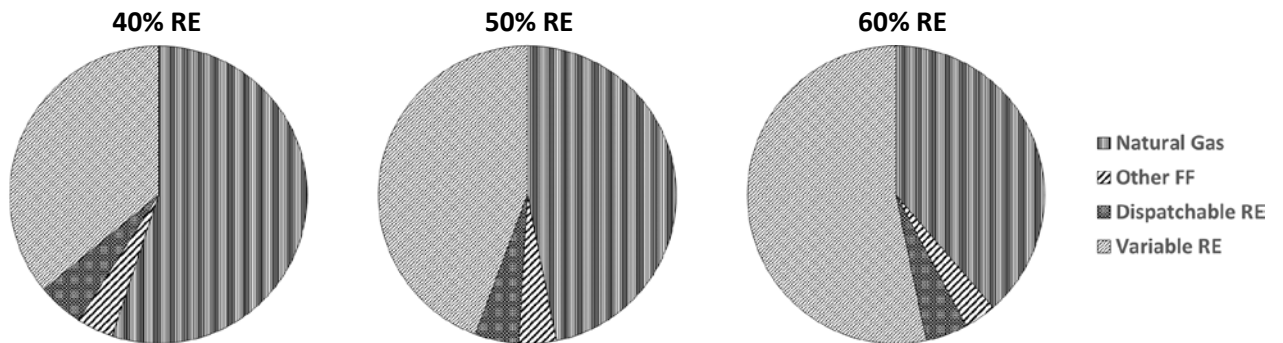
RE – Renewable Energy, FF – Fossil Fuel

Figure 2 – Energy mix of the Renewable Energy scenarios used in the model.

Renewable energy (RE) is calculated as delivered MW_eh of electricity from all renewable sources, as a percentage of total delivered electricity. VRE then only includes intermittent sources (wind, solar, and wave), and not those that are dispatchable (combined heat and power, co-firing of biomass, and hydropower) and therefore do not contribute to the fluctuations in supply that would affect price. The other Fossil Fuel (FF) portion of these charts consists mainly of coal, peat (co-fired with biomass), and small volumes of heavy fuel oil, all of which are dispatchable thermal generators.

These mixes represent potential future (2030) targets for Ireland [61]. The vast majority of this RE will be provided by wind and other intermittent sources. The 40% RE scenario is representative of a case where the rate of new installed RE capacity does not increase drastically beyond the levels seen today. The 60% RE scenario requires the rate of additional installed capacity of RE to substantially outpace that of increasing demand. The 50% RE scenario is an intermediate. Each of these is feasible and therefore their implications for P2H worthy of investigation. Table 1 outlines the various levels of VRE production in each scenario, data was obtained by analysing the output of the power systems model described above.

VRE production (MW)*	40% RE	50% RE	60% RE
Min	140	169	196
Average	2079	2540	3048
Max	5931	6510	7370

*Refers to the MW of VRE generated in a given hour.

2.3 Calculation of carbon intensity of electricity consumed

Should the control criteria be met for a given hour, the plant will consume electricity. As PLEXOS gives hourly data this calculation can be ran for each interval and hence a total number of run hours in a year established (Equations 1 and 3). Similar methods give us the average cost of electricity for said run hours (Equations 2 and 4). As well as SMP, the model also calculates the volume of CO_2 produced from electricity generation during each hour. By dividing the CO_2 emissions by the energy generated we calculate the carbon intensity in gCO_2/kWh in each hour (Equation 5).

Equations for bid price control:

$$Run\ Hours\ =\ \sum Hourly\ intervals\ for\ which\ SMP < Bid\ price \tag{1}$$

$$Average\ Electricty\ Cost = \frac{\sum SMP\ of\ Intervals\ for\ which\ SMP < Bid\ Price}{Resultant\ Annual\ Run\ Hours} \tag{2}$$

Equations for wind forecast control:

$$Run\ Hours\ =\ \sum Hourly\ intervals\ for\ which\ VRE\ forecast > Threshold \tag{3}$$

$$Average\ Electricty\ Cost = \frac{\sum SMP\ of\ Intervals\ for\ which\ VRE\ forcast > Threshold}{Resultant\ Annual\ Run\ Hours} \tag{4}$$

Carbon intensity equation is applicable to both controls:

$$Carbon\ intenisty\ per\ interval = \frac{Hourly\ CO_2\ Emissions}{Hourly\ System\ Generation} \tag{5}$$

2.4 Derivation and explanation of controls

2.4.1 Bid price control

Due to the effects of market interactions, merit order, the priority dispatch of renewables, zero-marginal cost VRE generators, and curtailment on the SMP, the authors hypothesised that low-cost electricity should be analogous to more sustainable electricity, as would be reflected in its lower carbon intensity. As the relationships between SMP, VRE production, and carbon intensity are complex, a direct correlation does not exist (as exemplified by an R^2 value, statistical measure of how close the data is to the fitted regression line, of 0.08 for VRE versus SMP in the 50% RE scenario). Export of electricity, pumped hydro storage, imports, priority dispatch, and the mixed portfolio of efficiencies and costs for generators make the relationship difficult to define and would require information beyond that available to those participating in the market. However, the bid price is controllable and if a P2H facility's bid price is below the marginal cost of generation of fossil fuel plants (Coal, Oil, Peat, and Gas) then the likelihood of it operating at times of high carbon intensity is much lessened, allowing operation on a majority VRE through market forces alone.

When generators are placed in descending order of capacity factor (ratio of actual output to maximum output) it is roughly equivalent to the merit order and hence, we can see how carbon intensity will change as demand increases and more generators are brought online. Market effects dictate that the low-cost and renewable generators tend to run first therefore, they have the highest capacity factors on the system. The same would not be true for an electricity market where coal was the ubiquitous low-cost baseload generator, however it is expected that an effective Emission Trading Scheme (ETS) price will be in place to act against this. Figure 3 shows that the plants with the highest capacity factor typically also have the lowest emissions; the first ten plants in Figure 3 are modern combined cycle gas turbines (CCGT).
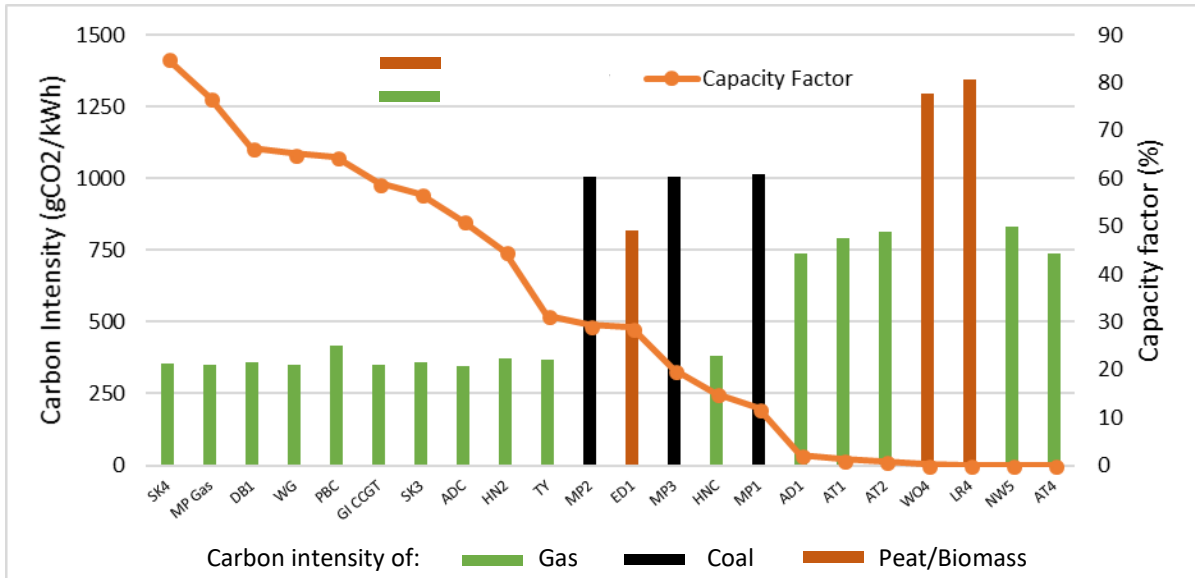
Figure 3 - Capacity factor and carbon intensity of electricity produced by large dispatchable thermal generators on the ISEM for 50% RE scenario. Each bar represents a single generator/plant.

In Figure 4 a marked increase in carbon intensity can be seen once cumulative capacity exceeds approximately 4500MW. It is at this point that additional older, more expensive, and less efficient generators will be dispatched beyond those already generating for power quality or network stability reasons, this will then be reflected in the SMP. This is due to the fact that the lowest marginal cost generators also tend to be the cleanest as seen in Figure 3.
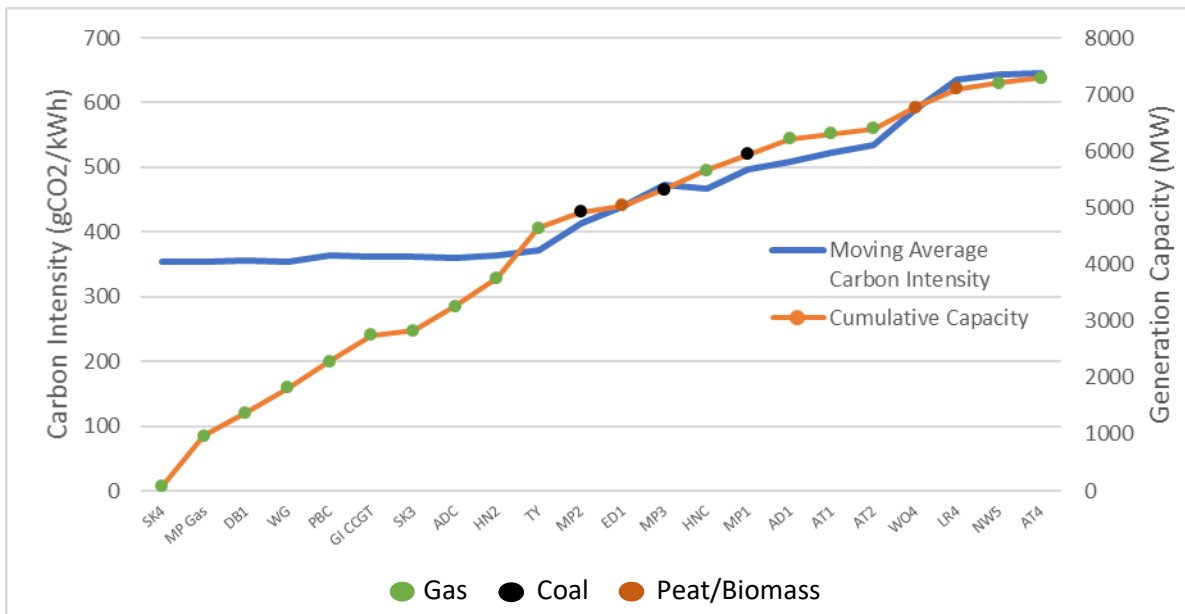

Figure 4 - Cumulative generation capacity and moving average carbon intensity of electricity produced by large dispatchable thermal generators on the ISEM for 50% RE scenario. Each dot corresponds to a single generator/plant along the X-axis.

In analysing the electricity market data, it is proposed that lower SMPs can be equated with lower emissions and higher VRE production; positive correlation has been found between increased shares of VRE and the periodic availability of low-cost electricity in other studies too, but this has not then been linked to carbon intensity [3–5,10,33]. For the analysis, the plant was only to run when the SMP was below a fixed value (Box 2).

Box 2: Bid price control, example of operation

Should the plant bid price be €50/MWh, and the current system marginal price (SMP) be €30/MWh, the plant will run. Once the SMP exceeds €50/MWh, the plant will turn off until such a time as the SMP falls below €50/MWh again.
This applies to the results in Figure 9, Tables 5 and 6, and throughout.

2.4.2   Wind forecast control

Should the P2H plant only run at times when the levels of VRE in the energy mix are sufficiently high, the authors theorise that the likelihood of consuming high carbon electricity is lessened. In the case of the ISEM, VRE is almost entirely wind energy, thus, it is proposed that the P2H plant only run when predicted wind energy is above a certain level, referred to as the minimum wind forecast. Wind and solar energy forecast methodologies for the ISEM can be found online [62].

Information was collected to examine if forecast and actual wind generation closely matched, to verify the applicability of this operational strategy. The relationship between wind energy (99% of VRE in the ISEM) and the carbon intensity of the electricity was examined for similar reasons. Three separate approximately 30-day periods were tested, one of which included extreme weather events in order to fully test the robustness of the correlation. Data was downloaded from the EirGrid website as referenced; Table 2 outlines the information collected [63]. The periods examined are representative of an average wind energy (VRE) penetration of 34% and thus, overall RE penetration of 36% when including hydropower and other existing RE sources.

Table 2 - Data downloaded from EirGrid to test correlations

Period/Data	Forecast Wind Generation (MW)	Actual Wind Generation (MW)	Carbon Intensity (gCO$_2$/kWh)	Extreme Weather
1. 20/9/17 – 19/10/17	✓	✓	✓	✓
2. 28/1/18 – 26/2/18	✓	✓	✓	✗
3. 27/2/18 – 28/3/18	✓	✓	✓	✗

Figure 5 is graphical representation of the clear positive correlation between the forecast and actual wind generation for period 2. Regression analysis was carried out to quantify the relationship between the variables. The three periods were found to have very high levels of correlation (R-squared values of 0.83, 0.91, and 0.90 respectively). It can be concluded that forecasts provide sufficiently accurate data for the method to hold up to scrutiny at this stage.
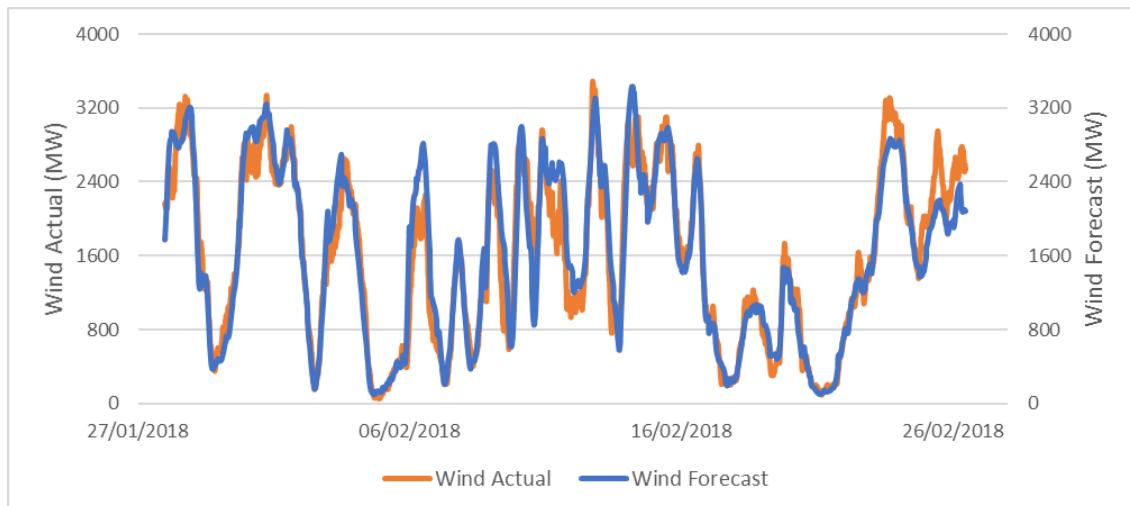

Figure 5 – Forecast wind generation and actual wind generation for period 2.

Figure 6 indicates a clear negative correlation between actual wind generation and the carbon intensity of the electricity for period 2. Again, this is true for all three periods which have R-squared values of 0.81, 0.89, and 0.92 respectively.
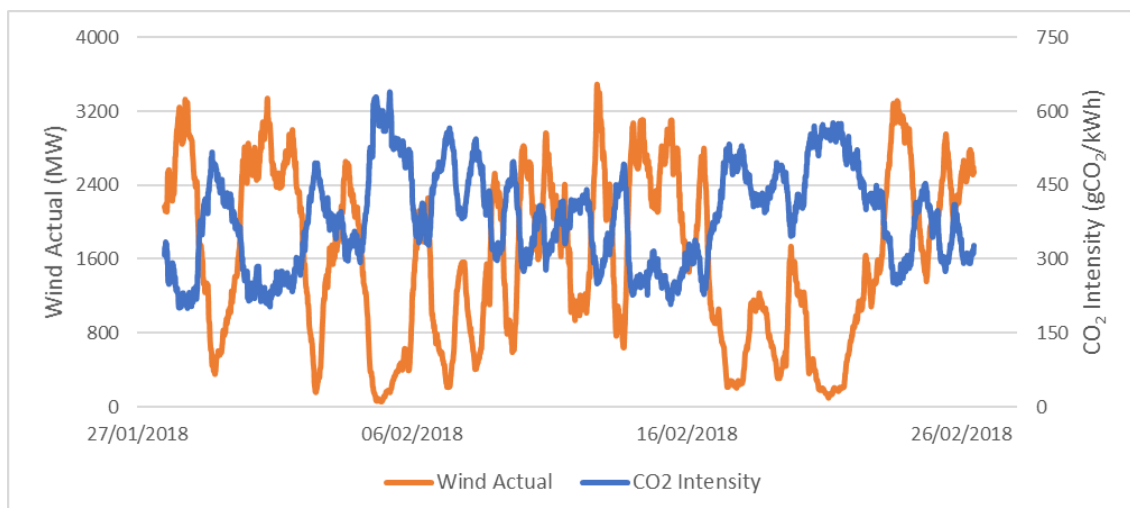
Figure 6 – Actual wind generation and carbon intensity of electricity for period 2.

The same regression analysis was carried out on the data from the PLEXOS models in an effort to further validate the models and ensure that correlations seen in real world data still applied (Figure 7). The 40%, 50%, and 60% RE models produced R-squared values of 0.91, 0.92, and 0.88 respectively across one complete year, confirming the relationships.
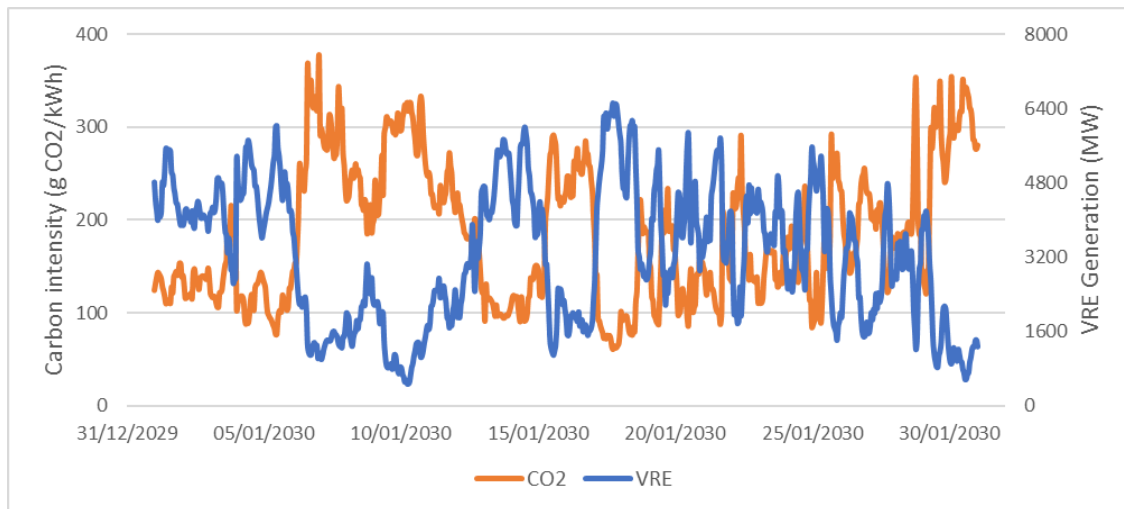
Figure 7 - Carbon intensity of electricity and VRE generation for a thirty-day period of the 50% RE model, illustrative of the correlation.

In conclusion, if a P2H plant is to base its operating schedule on forecast wind generation it will lead to consuming energy in times of reduced carbon intensity electricity. For the analysis, the plant was only to run when certain levels of wind were predicted, expressed as a percentage of the average wind generated; this will be known as the wind forecast control (Box 3).

> **Box 3: Wind forecast control, defining a "150% wind" operational strategy**
>
> If average wind generation is 2500 MW, and the Wind forecast control dictates a 150% minimum for the P2H to run, therefore, P2H will "turn on" only when the forecast wind generation is above 3750 MW (2500 x 150%).
> This applies to the results in Figure 10, Tables 7 and 8, and throughout.

2.4.3   Grid average and economically optimised P2H system

To assess whether positive carbon effects are seen and ensure that the controls do not sacrifice economic viability in an attempt to improve environmental sustainability, the results are compared to the carbon intensity of hydrogen from the grid average and of the economically optimised system. Too low run hours of the P2H plant may maximise environmental benefits but will not allow for project amortisation. Too high run hours and the system may be unnecessarily consuming energy, increasing its environmental impact without reducing the Levelised Cost of Energy (LCOE) [32]. Optimisation was defined as minimising the LCOE by adjusting the bid price until the rise in average electricity cost was no longer compensated for by the subsequent increase in run hours under base 2030 cost assumptions, as per McDonagh et al. [31]. More details on this rationale and methodology can be found in McDonagh et al. [32].

As can be seen in Figure 8 sharp rises in LCOE are observed as P2H plant run hours fall below approximately 3800 p.a. with the plant no longer producing enough hydrogen to effectively pay back the capital cost. The optimum number of run hours was found to be between 4200 and 6000 p.a across all three %RE scenarios. In this case increasing run hours further will not reduce the levelised cost of the product hydrogen (LCOE) as the electricity during these additional hours is more expensive, and more emissive [32]. Thus, for the plant to remain economical two strategies to be tested were conceived: Optimum low is the required minimum wind forecast/bid price to allow 4200 run hours p.a.; Optimum high allows for 6000 run hours p.a.

Box 4: How to read Figure 8

Green dashed line (more economic, less carbon sustainability)
- Bid price €60/MWh, ca. 6300 run hours, LCOE ca. €110/MWh.

Red dashed line (less economic, more carbon sustainability)
- Bid price ca. €37/MWh, ca. 3300 run hours, LCOE €200/MWh.
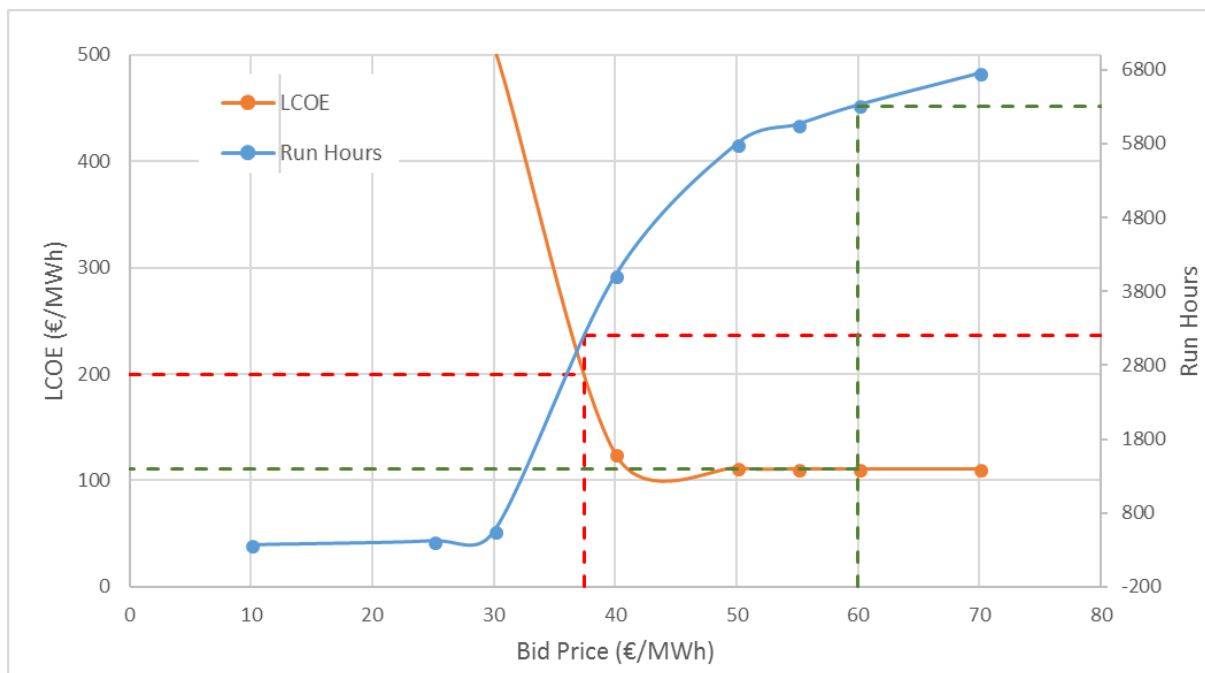

Figure 8 - Change in LCOE and run hours of a P2H system with increasing bid price for the 50% RE scenario. Equivalents for the 40% and 60% scenarios can be found in supplementary data.

Table 3 contains the results for each scenario in terms of the carbon intensity of the compressed hydrogen produced.

Table 3 – The carbon intensity of compressed hydrogen when consuming grid electricity assuming 75% conversion efficiency (box 1) and the average SMP in each of the %RE scenarios.

Hydrogen carbon intensity (gCO$_2$/kWh)	40% RE	50% RE	60% RE
Min	104	81	75
Average	324	295	303
Max	720	641	711
Econ. optimised	308	274	269
Average SMP (€/MWh)	59	57	56

For reference Fossil Fuel comparator from the EU RED for transport is 338.4gCO$_2$/kWh.

The total emissions from the electricity grid are greater at 60% RE than at 50% RE due to increased (5.5 times) exports to the UK via an interconnector in the 60% RE scenario, and increased use of pumped hydro storage, indicative of the difficulties in facilitating very high VRE penetration. This is reflected in the increase in hydrogen carbon intensity between the 50% and 60% scenarios. The 40% RE scenario is a net importer via the interconnector and does not show such issues. The carbon intensity results of each of the economically optimised hydrogen systems is less than it would be from production from the respective grid average.

2.4.3.1 Measuring effects on curtailment

Ultimately the installed capacity of P2H is what determines the effect on curtailment, larger systems will capture more potentially curtailed electricity. However, should the plants have a tendency to consume at times of curtailment above that which could be attributed to randomness then the presence of P2H can be said to have a positive externality on the grid. By consuming during curtailment, P2H acts as a surrogate storage mechanism and reduces the peaks and troughs of the supply/demand curve. The consumption profiles that result from each control will be compared to Table 4, data which was collected by analysing the output of the power systems model.

Table 4 - Occurrence of curtailment in each scenario calculated over each one-hour period

| Scenario	40% RE	50% RE	60% RE
Hours of curtailment	70	422	1213
Proportion of year	0.8%	4.8%	13.8%
Highest curtailment	823 MW	2131 MW	3686 MW
Typical curtailment*	300 MW	654 MW	1132 MW

*Typical curtailment calculated as the average of the non-zero hourly curtailment values thus, is the average value of curtailment when it occurs.

3 Results and Discussion

3.1 Bid price method

3.1.1 Bid price method optimises low cost hydrogen

Both the carbon intensity and run hours experience large increases at bid prices of approximately €32-35/MWh (Figure 9). Below this the carbon intensity is significantly lower, showing a correlation between lower cost and lower carbon intensity electricity. A bid price of €30/MWh leads to a 55-58% reduction in carbon intensity but only allows for 150, 557, and 1264 run hours in the 40%, 50%, and 60% scenarios respectively which even at the resultant low average costs of electricity will not make a viable system. However, the resource of low cost/low carbon electricity is shown to increase with increasing VRE penetration.
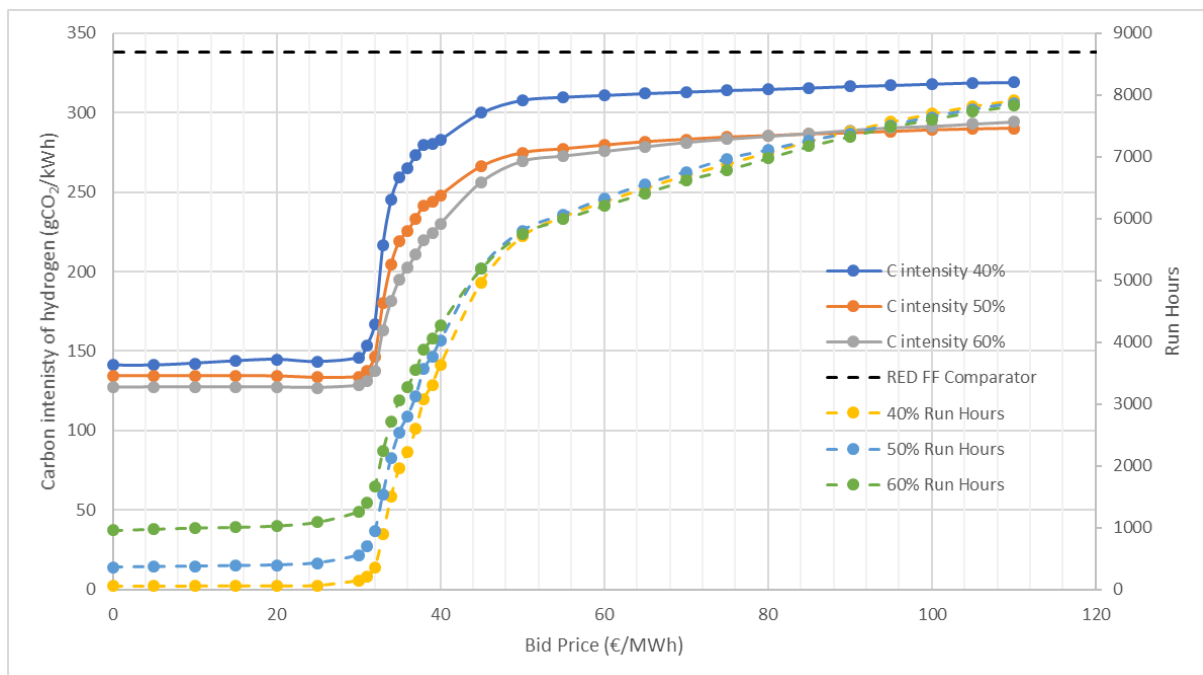
Note: 40%, 50%, and 60% relate to the percentage renewable electricity penetration. Therefore, "C intensity 50%" is the carbon intensity of hydrogen in the 50% renewable electricity penetration scenario, "Run hours 50%" is similarly defined. "RED FF Comparator" (334.8 gCO2/MJ) is the standard emissions value for fossil fuel transport, against which renewables are compared [35].

Figure 9 - Change in carbon intensity of hydrogen produced and run hours of the P2H system with increasing bid price.

The trends in the lines for run hours are largely explained by the availability of less than €1/MWh electricity in the 60% scenario (962 hours), symptomatic of balancing issues, and the relative lack

thereof in the 40% scenario (56 hours). Above bid prices of €30/MWh the lines begin to converge as the average costs are similar (Table 3) however, the maximum SMP is largest in the 60% scenario. Therefore, the number of run hours achieved at the highest end of the bid price range will be greater in the 40% scenario. The 50% scenario represents intermediate values.

Low (€35/MWh) and High (€70/MWh) bid prices were chosen as values that lay either side of the large increase in run hours observed in Figure 9. In all bid price controls the carbon intensity was reduced with the greatest effect seen at the lowest bid prices, confirming the hypothesis that lower cost electricity would be more sustainable in the ISEM. This effect was more pronounced as VRE penetration increased.

From Table 5 we see that a bid price of €35/MWh reduces the carbon intensity of the electricity consumed by 20-36% scenarios, but the system operates for sub-optimal run hours in all scenarios. A €70/MWh bid price allows for 3-7% reduction, and can in fact run for longer than is necessary to minimise the LCOE while still producing positive carbon effects. In the economically optimised range we see a 5% (optimum high 40% RE) to 25% (optimum low 60% RE) reduction in carbon intensity. The synergies between economic and environmental operation are striking with reductions of 34-50% in the cost of electricity compared to the grid average within the optimised range. All scenarios see large drops in electricity cost, by far the largest contributor to P2H LCOE.

In Tables 5 and 6 "Optimum low" and Optimum high" refer to the required minimum bid price to achieve 4200 and 6000 run hours per annum respectively, see Box 1 and 2.4.3 for further details. "Low" and "High" are bid prices that lie either side of the large increase in run hours seen in Figure 9.

Table 5 - Results for carbon intensity and cost of bid price method

	40% RE penetration					50% RE penetration					60% RE penetration			
	BP	RH (AC)	H_2 CO_2	DGA		BP	RH (AC)	H_2 CO_2	DGA		BP	RH (AC)	H_2 CO_2	DGA
Low	35	1967 (32)	**260**	**-20%** (-46%)		35	2543 (29)	**219**	**-26%** (-49%)		35	3057 (24)	**195**	**-36%** (-57%)
Optimum low	43	4200 (36)	**289**	**-11%** (-39%)		41	4200 (32)	**251**	**-15%** (-44%)		39	4200 (28)	**228**	**-25%** (-50%)
Optimum high	55	6000 (39)	**309**	**-5%** (-34%)		54	6000 (36)	**276**	**-6%** (-37%)		55	6000 (33)	**273**	**-10%** (-41%)
High	70	6702 (41)	**313**	**-3%** (-31%)		70	6757 (39)	**283**	**-4%** (-32%)		70	6622 (36)	**281**	**-7%** (-36%)

RE = Renewable Electricity, BP = Bid Price in €/MWh, RH = Run Hours, AC = Average Cost of electricity in €/MWh, H_2 CO_2 = Carbon intensity of hydrogen produced in gCO_2/kWh, DGA = Difference from Grid Average, the % difference between the resultant value and the average carbon intensity or average cost of electricity from that scenario

Example interpretation of Table 5:
We can see that in a 60% RE scenario bidding "Low" for electricity at €35/MWh will lead to run hours of 3057, an actual electricity cost of €24/MWh, and a hydrogen carbon intensity of 195 gCO2/kWh. These are 36% less emissive and 57% cheaper respectively than the grid average.

3.1.2   Bid price method enhances demand side management reducing curtailed electricity

The P2H system runs the vast majority of times during which VRE is being dispatched down as the bid price control disproportionally consumes otherwise curtailed electricity, likely due to curtailment being reflected in the SMP. The percentage of run hours that coincide with curtailment is greater than the average in all scenarios. Again, this has the effect of acting as both DSM and storage with the effect increasing with VRE penetration.

Table 6 - Results for effect on curtailment of bid price control

BP control	40% RE penetration					50% RE penetration					60% RE penetration			
	RH	HC	RH% (0.8%)[1]	C% (70)[2]		RH	HC	RH% (4.8%)[1]	C% (422)[2]		RH	HC	RH% (13.8%)[1]	C% (1213)[2]
Low	1967	61	3.1%	87.1%		2543	359	14.1%	85.1%		3012	974	32.4%	80.3%
Optimum low	4200	66	1.6%	94.3%		4200	373	9.0%	88.4%		4200	986	24.3%	81.3%
Optimum high	6000	70	1.2%	100%		6000	395	6.6%	93.6%		6000	1050	17.5%	86.6%
High	6702	70	1.0%	100%		6757	400	5.9%	94.8%		6622	1100	16.6%	90.7%

RE = Renewable Electricity, RH = Run Hours, HC = Hours where consumption coincides with Curtailment, RH% = % of Run Hours during which curtailment occurs, C% = % of total number of hours during which curtailment occurs that have been captured.
[1] % of the year during which curtailment occurs in the given scenario from Table 4.
[2] Number of hours per year during which curtailment occurs in the given scenario from Table 4.

Example interpretation of Table 6:
We can see that in a 50% RE scenario bidding "Optimum high" in order to achieve 6000 run hours, the plant will run for 395 hours during which curtailment is occurring. This represents 6.6% of the system run time and a 93.6% match to times when curtailment is occurring, significantly greater than the grid average.

3.2   Wind forecast method

3.2.1   Wind forecast method allows synergies between decarbonisation and cost of P2H

If we recall Box 3 and the wind forecast control, the minimum wind forecast is the minimum volume of wind generation forecast in order for the P2H plant to run under this strategy. The plant will produce hydrogen if the forecast is greater than or equal to this set point.

From Figure 10, we see that the carbon intensity of hydrogen decreases as the minimum wind forecast for the plant to run increases however, associated run hours decline faster. This means the most environmentally beneficial system is unlikely to be economical without large incentives, as exemplified by the sub 3000 run hours above 120% minimum wind forecast.
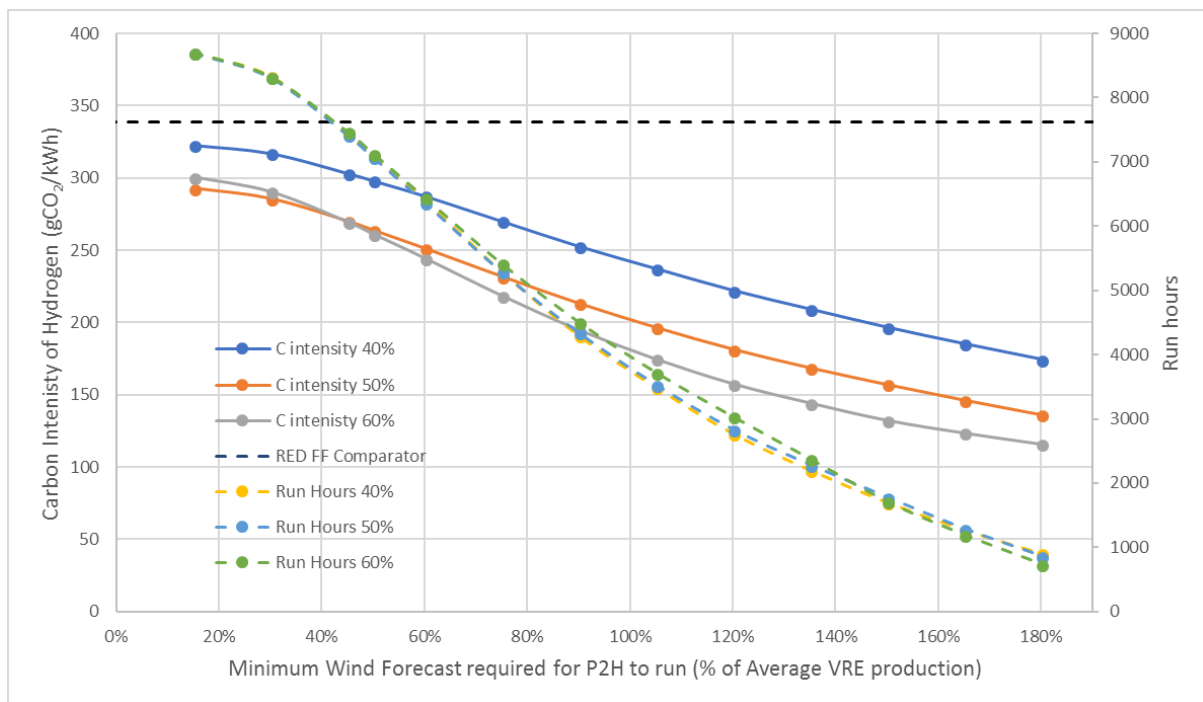
Note: 40%, 50%, and 60% relate to the percentage renewable electricity penetration. Therefore, "C intensity 50%" is the carbon intensity of hydrogen in the 50% renewable electricity penetration scenario, "Run hours 50%" is similarly defined. "RED FF Comparator" is the standard emissions value for fossil fuel transport, against which renewables are compared [35].

Figure 10 - Change in carbon intensity of the hydrogen produced and run hours of the P2H system with increasing minimum forecast wind energy required to run, expressed as a percentage of average wind generation.

From Table 7 we see that dictating for a minimum forecast of 150% wind reduces the carbon intensity of the electricity consumed by 39-56%, but as with the bid price control the system operates for sub-optimal run hours in all. A 50% wind threshold allows for an 8-14% carbon intensity reduction and again similarly to the bid price control means the system can in fact run for longer than is deemed optimal. In the economically optimised range we see a 14% (optimised high 40% RE)

to 38% (optimised low 60% RE) reduction in carbon intensity. This implies there are synergies between economically and environmentally conscious driven operation of the P2H system, with all scenarios producing an average cost of electricity less than the grid average. The positive carbon effects of the wind forecast control are enhanced as the level of VRE penetration increases.

In Tables 7 and 8 "Optimum low" and Optimum high" refer to the required wind forecast to achieve 4200 and 6000 run hours per annum respectively, see Box 2 and 2.4.3 for further details. "150% wind" is used as an example of an operational strategy focused on producing low carbon fuel, and "50% wind" is a compromise of economic and environmentally conscious operation. These tables can be interpreted similarly to Tables 5 and 6.

Table 7 - Results for carbon intensity and cost of wind forecast method.

	40% RE penetration					50% RE penetration					60% RE penetration			
	MW	RH (AC)	H_2 CO_2	DGA		MW	RH (AC)	H_2 CO_2	DGA		MW	RH (AC)	H_2 CO_2	DGA
150% wind	3118	1706 (45)	**197**	-39% (-24%)		3810	1781 (45)	**157**	-47% (-21%)		4573	1713 (46)	**132**	-56% (-18%)
Optimum low	1909	4200 (50)	**250**	-23% (-15%)		2352	4200 (50)	**210**	-29% (-12%)		2922	4200 (50)	**187**	-38% (-11%)
Optimum high	1364	6000 (54)	**280**	-14% (-8%)		1656	6000 (54)	**245**	-17% (-5%)		2029	6000 (54)	**233**	-23% (-4%)
50% wind	1039	7097 (56)	**299**	-8% (-5%)		1270	7075 (56)	**264**	-10% (-2%)		1524	7127 (56)	**261**	-14% (-0.2%)

RE = Renewable Electricity, MW = Minimum Wind forecast in MW, RH = Run Hours, AC = Average Cost of Electricity in €/MWh, H_2 CO_2 = Carbon intensity of hydrogen produced in gCO_2/kWh, DGA = Difference from Grid Average, the % difference between the resultant value and the average carbon intensity or average cost of electricity from that scenario

3.2.2 Wind forecast method prioritises consumption of curtailed electricity

Table 8 shows that the wind forecast control could have a significant effect on curtailment. In all scenarios the percentage of run hours that contain curtailment are above average, meaning that they disproportionally consume otherwise wasted electricity. This effect is increased with increasing penetration of VRE and is somewhat intuitive as high levels of wind energy in the mix generally lead to some dispatch down of VRE. The wind forecast control inherently prioritises the consumption of potentially lost electricity generation acting as a form of DSM/storage.

Table 8 - Results for effect on curtailment of wind forecast control

WF control	40% RE penetration					50% RE penetration					60% RE penetration			
	RH	HC	RH% (0.8%)[1]	C% (70)[2]		RH	HC	RH% (4.8%)[1]	C% (422)[2]		RH	HC	RH% (13.8%)[1]	C% (1213)[2]
150% Wind	1706	70	**4.1%**	100%		1781	403	**22.6%**	95.5%		1713	887	**51.8%**	73.1%
Optimum low	4200	70	**1.7%**	100%		4200	422	**10.0%**	100%		4200	1213	**28.9%**	100%
Optimum high	6000	70	**1.2%**	100%		6000	422	**7.0%**	100%		6000	1213	**20.2%**	100%
50% Wind	7097	70	**1.0%**	100%		7075	422	**6.0%**	100%		7127	1213	**17.0%**	100%

RE = Renewable Electricity, RH = Run Hours, HC = Hours where consumption coincides with Curtailment, RH% = % of Run Hours during which curtailment occurs, C% = % of total number of hours during which curtailment occurs that have been captured.

[1] % of the year during which curtailment occurs in the given scenario.

[2] Number of hours per year during which curtailment occurs in the given scenario.

3.3 P2H systems generate advanced transport fuels without irregular charging associated with electric vehicles

In purely carbon emissions terms all scenarios outperform the Renewable Energy Directive (RED) Fossil Fuel Comparator (FFC) within the energy mixes examined when producing hydrogen at 75% efficiency [35]. Electrofuels may have significant positive externalities before a fixed reduction target is met and there are advantages in terms of air quality, indigenous low input fuel production, facilitation of additional VRE, leveraging VRE in transport, and grid stability. The results in this work add weight to the argument that regulations should be adapted in relation to electrofuels as present regulations hinder their development, with special consideration paid to preventing a situation where grid electricity is consumed and substituted elsewhere with fossil generation [39]. The latest RED is an attempt at this [35]. Electrofuel contributions to renewable targets are complex but at a minimum are based upon the average share of RE in the country; for example, in a country with 70% RE, 70% of the hydrogen is counted as renewable [35]. When renewable generation can be matched with consumption and guarantees of origin given, or when the installation is used to relieve grid congestion the fuel may be counted as 100% renewable but may require a premium on the electricity cost [35]. These are significant as the volume of energy required to meet the RES-T targets

is large, sufficient alternatives for advanced transport fuels are in short supply, and there is a proposed cap on first generation biofuels [35]. Electrofuels then contribute to a country's RES-T targets in much the same way as Electric Vehicles (EVs).

A possible criticism of electrofuels is their possible support of inflexible fossil fuel thermal generators. The operational strategies proposed in this paper largely avoid such issues as these same generators tend to have higher marginal costs and thus, in the presence of market forces, overarching RE targets, and increasing carbon taxes, will play a decreasing role in the future energy system. The load shifting characteristics mean P2H at various scales does not create additional peak load demand, may lessen the frequency of CCGT start-up/shut down, and act as DSM reducing need for less efficient generators to come online [10]. Employing these operational controls in P2H overcome disadvantages of EVs where charging is decentralised and erratic and may exacerbate the peaks and troughs that produce difficulty in balancing supply and demand.

3.4   Operational strategies reduce carbon intensity and cost of hydrogen produced

Both operational strategies reduced the carbon intensity of the hydrogen produced and disproportionately consumed otherwise curtailed energy, largely avoiding consumption in times of excess demand, with the wind forecast control doing both to a greater extent. The controls also allowed for reduced electricity costs aiding financial sustainability. By providing demand during times of curtailment the facility reduces the need to dispatch down VRE boosting its economic viability [16]. However, operating the plant only during periods of greatest environmental benefit would not allow for amortisation of the capital expenditure without significant grid services payments/incentives for either control [31,32]. Sufficiently monetising the services offered to the electrical grid could negate the need to consume unsustainable electricity; this is independent of the size of the system. What is most promising is that economically optimised systems showed GHG savings and this effect increased with increasing VRE penetration.

Across all scenarios the wind forecast control had greater environmental benefits, and more effectively captured curtailment than the bid price control. Periods of reduced carbon intensity and curtailment aligned well with high forecast generation delivering GHG savings. Wind forecast controls would be most applicable when the primary concern is maximising the use of VRE in electrofuels (positive carbon effects) and a sufficient incentive to produce electrofuels exists.

Dictating a maximum bid price for the system resulted in GHG savings too, though not as significantly as the wind forecast control. The mixed portfolio of marginal costs, efficiencies, and ramp capabilities mean that the point at which the electricity mix moves from VRE supported by

CCGT, to more emissive generators (such as coal fired) is difficult to define. However, the bid price control also delivers large savings in electricity costs. Bid price controls are most applicable in a free market where P2H plant aims to minimise costs, and carbon savings are coincidental and synergistic.

3.5 Comparing electrolytic hydrogen from our scenarios to steam methane reforming

Hydrogen is a valuable input to many chemical processes, and the potential to produce low carbon hydrogen has also generated interest in its use as a transport fuel. It can be combined with carbon dioxide to create methane in the power to gas process [18] or used directly in fuel cells where compressed hydrogen offers superior charging times and energy density to batteries. Figure 10 provides a direct comparison between the electrolytic hydrogen produced in the scenarios tested and that derived via Steam Methane Reforming (SMR). Values of 8.9 to 12.9$kgCO_{2-eq}/kgH_2$ were found in literature representing the upper and lower limits of carbon intensity for SMR [40]. A value of 11.5$kgCO_{2-eq}/kgH_2$ is used in Figure 10 to allow for reduced fugitive emissions and the use of partially decarbonised energy in the process. No fugitive methane is produced during electrolysis and so $kgCO_2/kgH_2$ to $kgCO_{2-eq}/kgH_2$ provides a fair comparison.
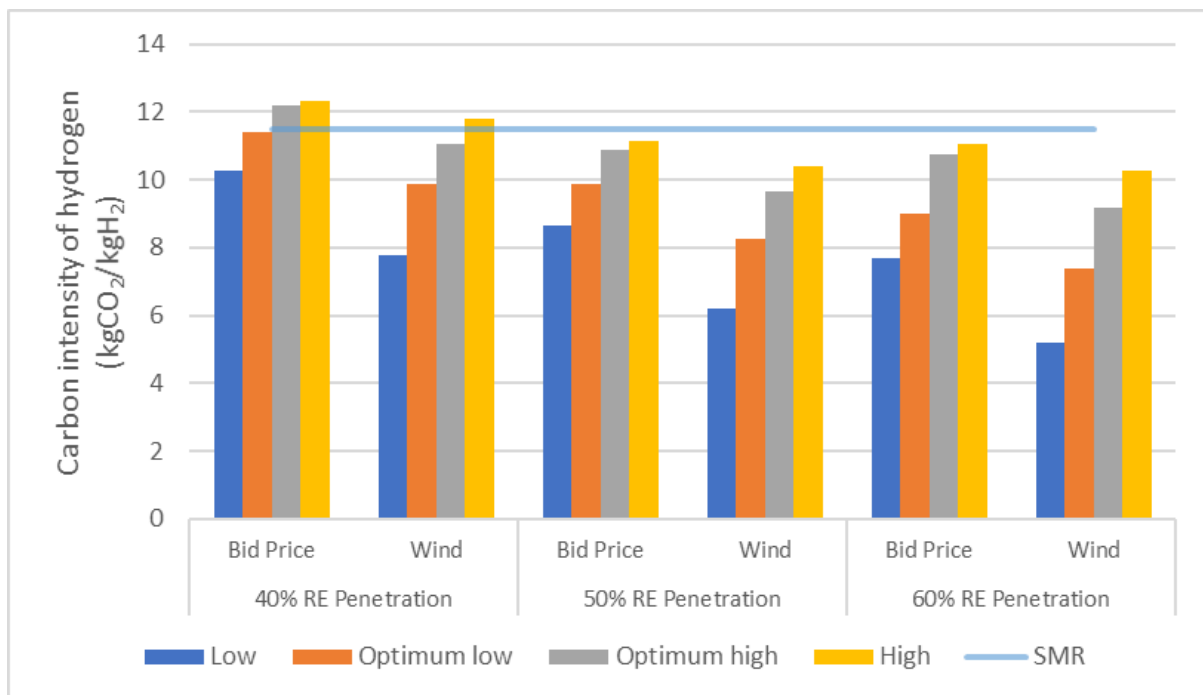
Note: Section 2.4.3, Table 5, and Table 7 provide brief explanations of the derivation of "Low", Optimum Low", "Optimum High", and "High"

Figure 10 - Carbon intensity of the hydrogen produced from electrolysis using the Bid Price and Wind Forecast methods in each RE penetration scenario, the carbon intensity of SMR is shown for reference.

From Figure 10 it can be seen that at least 50% RE penetration is required to outperform SMR under all bid strategies in terms of carbon emissions. At penetrations of 50% and above significant reductions are noted implying that when aiming to displace fossil derived hydrogen, electrolytic

hydrogen is suitable under these controls. These results are also of importance to those attempting to reduce the environmental impact of processes that consume hydrogen such as oil refining and fertiliser production.

3.6 Potential to displace fossil fuels in heavy goods transport

It is the author's opinion that the thermodynamic inefficiencies of hydrogen production and use, combined with the vast improvement in passenger Electric Vehicle (EV) technology make hydrogen passenger transport unattractive in the short to medium term. The figures below do not account for the difficulties the grid faces when charging a large number of electric vehicles, or the advantages of decentralised hydrogen production but they do illustrate the unsuitability of hydrogen to passenger transport in this context. From Box 5 it is clear that passenger EVs are far less emissive than Fuel Cell Vehicles (FCVs) and this unlikely to change significantly by 2030.

Box 5: Passenger electric vehicle (EV) versus fuel cell vehicle (FCV) emissions per 100km

Taking the 50% RE penetration scenario and assuming the EV charges at the grid average.

Hyundai Ioniq (EV) [64] **: 15.5kWh/100km**

$$\frac{15.5 kWh/100km}{90\% \, \eta \, charging} \times \frac{221 g CO_2}{kWh} = \mathbf{3.8 kg CO_2/100km}$$

Toyota Mirai (FCV) [65]**: 67MPG$_e$ ≈ 1kgH$_2$/100 km**

$$From \; "150\%" \; Wind \; forecast \; to \; "High" \; Bid \; price = \mathbf{6.2 - 11.1 kg CO_2/100km}$$

However, unlike passenger vehicles a clear alternative to fossil fuels suitable for Heavy Goods Vehicles (HGVs) has not arisen largely due to their energy density requirements, policy constraining first generation liquid biofuels (such as 3.6% cap for 2030 in RED), and prohibitive costs [66]. Hydrogen fuel cells are a promising technology for HGVs offering zero PM, NO$_x$, and SO$_x$ emissions, and a route to low carbon transport.

<div style="border:1px solid black; padding:10px;">

Box 6: Diesel versus hydrogen fuel cell heavy goods vehicle (HGV) emissions per 100km

Taking the 50% RE penetration scenario and a standard diesel truck in 2030.

Diesel HGV allowing for η improvements to 2030 [67]**: 37l/100km**

$$\frac{37l}{100km} \times \frac{2827gCO_2}{l_{diesel}} = \mathbf{104.6kgCO_2/100km}$$

Fuel cell HGV combined η of 55% [68]**: 282kWh/100km**

$$From \ "150\%" \ Wind \ forecast \ to \ "High" \ Bid \ price = \mathbf{44.3 - 79.8kgCO_2/100km}$$

HGV operating on EU RED liquid biofuel [35]**: Minimum 65% savings versus FFC of 94gCO_2-eq/MJ**

$$Combusted \ in \ diesel \ engine \ assuming \ equal \ \eta = \mathbf{47kgCO_2/100km}$$

References and calculations can be found in the supplemental data.

</div>

Box 6 demonstrates a clear carbon saving in utilising hydrogen in FC HGVs well in advance of a fully decarbonised electricity system when utilising the controls tested. The FC HGV can deliver carbon emissions reductions comparable to that of an EU approved transport biofuel at 50% RE penetration while avoiding issues of air pollution. It is hypothesised that with the continued decarbonisation of the electricity system and the superior efficiency of FC HGVs, they will significantly outperform renewable liquid biofuels in the future.

4   Conclusion

This work examined the effect that two operational strategies (controls) which do not require changes in policy would have on sustainability: (1) dictating a plant maximum bid price for electricity and (2) a minimum forecast VRE production. Sustainability was measured through: changes in the carbon intensity of the hydrogen produced in a P2H (electrofuel) system; the effect on curtailment; and the cost of electricity consumed. Both controls were found to produce significant benefits in terms of reducing the carbon intensity. Also shown was the increased proclivity to consuming otherwise curtailed energy and to act as a quasi-storage mechanism, especially for the wind forecast control. Notably, synergistic effects between operating an electrofuel system to minimise levelised costs and environmental impacts were demonstrated, particularly for the bid price control. However, when greater environmental benefits were sought this was at the sacrifice of an economically optimised system. The carbon intensity of the hydrogen was found to be less than the fossil fuel comparator of the EU Renewable Energy Directive (RED) in all scenarios tested (40-60%

renewable electricity generation) and particularly suitable for use in fuel cell heavy goods vehicles. Environmental and cost benefits were found to increase with increasing renewable penetration. Applying these operational strategies is in line with the visions of the RED and would make electrofuel production more sustainable in advance of a fully decarbonised electricity system, and at a time when increased options for decarbonised transport are required.

The results in this paper are applicable to power-to-X, cooperative charging, or any grid interaction when engaging as a wholesale consumer/agent in an electricity market.

Acknowledgements

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