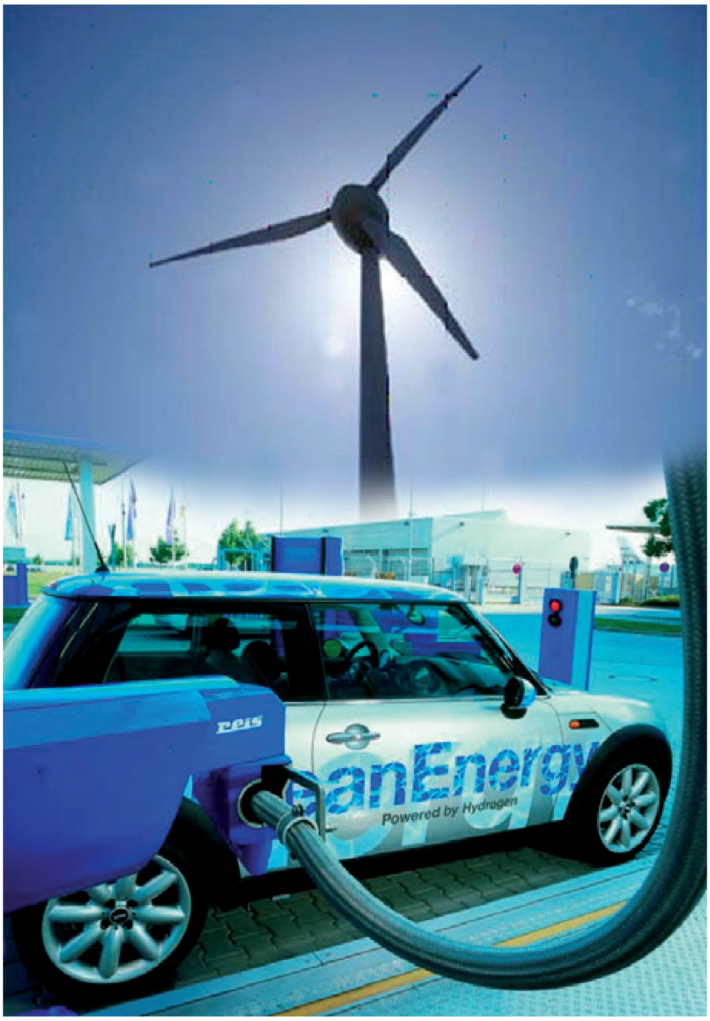
Bridging the European Wind Energy Market and a Future Renewable Hydrogen-Inclusive Economy

A Dynamic Techno-economic Assessment



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Sustainable Energy Technologies Reference and Information System (SETRIS)

The objective of SETRIS is to collect, harmonise and validate information on sustainable energy technologies and perform related techno-economic assessments to establish, in collaboration with all relevant national partners, scientific and technical reference information required for the debate on a sustainable energy strategy in an enlarged EU, and in the context of global sustainable development.

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SYMBOLS AND ABBREVIATIONS USED IN THE STUDY

Symbols:
a = Conversion kJ to kWh (1/3600 kWh/kJ)
b = Elasticity of electrolyser market with respect to relative growth in wind energy market
γ = Adiabatic exponent
η_{C} = Compressor efficiency
η_{ELYZR} = Efficiency of the electrolyser (%)
$\eta_{H2/REF}$ = Energy efficiency equivalence for reference technology used with hydrogen versus reference fuel (%)
η_{H2FC} = Tank-to-wheel fuel consumption of direct hydrogen fuel cell vehicle (for 2010) (MJ/100km)
η_{REF} = Tank-to-wheel fuel consumption of reference technology (gasoline PISI, for 2010) (litre/100km)
ρ_{H2} = Density of hydrogen at normal conditions (kg/ Nm^3)

Abbreviations:
C_{bl} = Additional balance cost per unit wind electricity in the system (€/kWh), applicable at the wind energy penetration level without the electrolyser in place
C_{BL} = Annual additional balance costs (€/yr)
C_{blX} = Additional balance cost per unit wind electricity in the system (€/kWh), applicable at wind energy penetration level with electrolyser in place
C_{CO2} = Carbon tax (€/tCO_{2eq})
C_{CRt} = Replacement cost (equipment) incurred in year t (€)
C_{Ct} = Initial capital investment (equipment, startup) costs (€)
C_{R} = Unit cost of raw material (water and electricity) (€ / unit)
C_{S} = Unit cost of service (€/unit)
C_{USER} = End-user cost-benefit of wind-hydrogen, allocated per unit of electricity consumed in the community (€/kWh)
C_{WE} = (Levelised) Cost of wind electricity production (€/kWh)
C_{WH2} = Cost of hydrogen production (€/Nm^3)
C_{WIND} = Cost-benefit of wind-hydrogen, allocated per unit of wind electricity produced in the system (€/kWh)
C_{Xel} = Lost revenues from diversion of saleable wind electricity to wind-hydrogen plant (€/y)
CB_{WH2} = Annualised annual cost-benefit of wind-hydrogen system implemented in a given reference year (€/yr)
CCS = Carbon capture and storage
CO_{2eq} = Carbon dioxide equivalent
E = Experience parameter
E_{EL} = Total annual electricity consumption of community (kWh/yr)
E_{ELYZR} = Energy requirement of the electrolyser (kWh/ Nm^3)
$E_{SWELYZR}$ = Saleable wind electricity fed to the electrolyser plant (including electricity for compressors) (kWh/ y)

E_{WELYZR} = Surplus wind electricity fed to the electrolyser (kWh/ y)
E_{WETOT} = Electricity generated annually by the wind energy system (kWh/yr)
EM_{DI} = Avoided GHG emissions per unit of hydrogen used as substitute in domestic/ industrial sectors (tCO_{2eq} /GJ H_2)
EM_{DIREF} = Equivalent GHG emissions per unit conversion of reference fuel with reference technology (tCO_{2eq}/GJ reference fuel
EM_{SECTOR} = Avoided GHG emissions per sector (tCO_{2eq}/GJ H_2)
EM_{TREF} = Equivalent GHG emissions per km travelled with reference technology (gasoline PISI, for 2010) (tCO_{2eq}/ km)
EM_{TRN} = Avoided GHG CO_{2eq} emissions per unit of hydrogen used as substitute in transport sector (tCO_{2eq} /GJ H_2)
EM_{XREF} = Emission of greenhouse gas, X, per unit conversion of reference fuel (tX /GJ reference fuel)
f_{CTL} = Fraction of wind electricity fed to the electrolyser plant and compressors, that would normally be curtailed
f_{ERR} = Prediction error (absolute value, expressed as +/- %)
f_{PK} = Wind peak power reduction (%)
f_{WE} = Penetration of wind energy in the network (based on total electricity consumption) (%)
$f_{W\text{-}ELYZR}$ = Fractional growth of electrolyser market as a result of growth in wind energy market
F_{CR} = Capital recovery factor (as a function of N and i)
F_{CRR} = Capital recovery factor for replacement incurred in year t (as a function of N and i)
GHG = Greenhouse gas
GWP_X = Global warming potential of greenhouse gas, X (tCO_{2eq}/ t X)
H_2 = Hydrogen
H_2O = Water
i = Discount rate (1/yr)
LAC_{WH2} = Levelised annual costs wind-hydrogen system (€/yr)
LHV_{H2} = Lower heating value of hydrogen (kJ/kg)
LR = Learning rate (expressed as a fraction)
M_{STOR} = Compressed hydrogen storage requirement (Nm^3)
N = Levelisation period or plant lifetime (yr)
Nm^3 = Normal cubic meter (volumetric measurement under standard conditions of 0°C (273.15 K) and 101.325 kPa (1 atmosphere of absolute pressure))
O_2 = Oxygen
O&M = (fixed) Operation and maintenance costs (€/yr)
p_0 = Hydrogen pressure at compressor inlet
p_1 = Required hydrogen outlet pressure
P_{ACT} = Compressor power required (kW)
P_{ELYZR} = Size of electrolyser (kW) (power required for maximum hydrogen production rate)
P_{WELYZR} = Surplus wind power routed to the electrolyser (kW)
P_{WENOM} = Nominal installed wind capacity (kW)
P/P_{nom} = Relative wind power production (% rated capacity)
PISI = Port injection spark ignition
PR = Progress ratio
Q_{H2HR} = Actual hourly rate of production of hydrogen (Nm^3/h)
Q_{H2MAX} = Maximum hourly rate of hydrogen from electrolyser (Nm^3/h)

Q_{H2MIN} = Minimum rate of hydrogen production from electrolyser (Nm^3/h)
$Q_{H2SECTOR}$ = Hydrogen consumed per sector (GJ H_2 / yr)
Q_{H2Y} = Annual rate of hydrogen from electrolyser (Nm^3/y)
Q_R = Annual usage of raw material for hydrogen production (units/yr)
Q_S = Annual usage of hydrogen production-related service (unit/year)
R_{BL} = Revenues from reduced balance costs (€/yr)
R_{EMA} = Total annual environmental benefit attributable to wind-hydrogen use (€/yr)
R_{GH2} = Hydrogen gas constant (kJ/(kgH_2.K))
R_{H2} = Annual revenues from hydrogen sales (€/yr)
S_0 = Initial price of commodity
S_{G-E} = Grey electricity price (€/kWh)
S_{H2} = Market price of hydrogen (€/GJ)
S_{REF} = Untaxed pump price of reference fuel (gasoline) (€/1000litre)
S_{RES-E} = Green electricity component (green certificate) price for wind (€/kWh)
S_t = Price of commodity at year t
S_{WE} = Price of wind electricity on the market (€/kWh)
t = Time (yr)
To = Inlet hydrogen temperature (K)
T/T_{total} = Fraction of time (in hours) relative to annual period (8760 hours)
TTW = Tank-to-wheel
W_{ACT} = Actual compression energy required (kWh/Nm^3)
W_{TH} = Theoretical compression energy required (kJ/kg)
X = Cumulative experience in given year
X_i = Initial cumulative experience
X_w = Cumulative operating wind capacity (installed capacity at time t) (MW)
X_{Wi} = Initial operating wind capacity (installed capacity 2005) (MW)
$Y_{W-ELYZR}$ = Effect of wind energy market on electrolyser market
Z = Hydrogen compressibility factor at inlet pressure

UNIT CONVERSION

kW(h) = Kilowatt(-hour)
MW(h) = Megawatt(-hour) = 10^3 kW(h)
GW(h) = Gigawatt(-hour) = 10^6 kW(h)
TW(h) = Terawatt(-hour) = 10^9 kW(h)
kJ = Kilojoule
GJ = Gigajoule = 10^6 kJ

1 AIM OF THE STUDY

The aim of the study is to analyse potential synergies between the European wind and hydrogen markets. This considers specifically the diversion of the wind electricity, as a wind power control mechanism in high wind penetration situations, for the production of renewable electrolytic hydrogen, thus contributing to a renewable-hydrogen-inclusive economy.

The study establishes the potential synergy between the growing wind market and the emerging hydrogen market. It outlines the boundary conditions for conducting a detailed analysis of the attractiveness of exploiting this synergy (termed here as the “wind-hydrogen strategy”). The analysis is done using cost-benefit assessment to determine the long-term competitiveness of a wind-hydrogen strategy and the duration and extent to which (financial) support, if any, would need to be provided in support of this. Most importantly, the analysis highlights the influence of certain key factors in the final attractiveness of a wind-hydrogen strategy, the short- and long- term circumstances to be considered in the decision-making process to pursue such strategy, and potential implications for both wind and hydrogen markets.

This document is structured according to the following sections:

- Chapter 2 establishes the rationale behind linking the wind energy and hydrogen markets
- Chapters 3 and 4 describe the wind-hydrogen strategy and the approach for conducting the detailed analysis
- Chapter 5 outlines the generic technical considerations for a wind-hydrogen plant, and the technical characteristics of the plant that will be adopted as the starting point for the detailed cost-benefit assessment
- Chapters 6, 7, and 8 outline the various cost and benefit streams that make up the detailed cost-benefit assessment, and Chapter 9 summarizes the main parameter values adopted for the model according to given scenario possibilities
- Chapter 10 re-groups the cost-benefit streams of Chapters 6, 7, and 8 into an overall cost-benefit equation, and outlines the cost-benefit scenarios that are examined using selected combinations of parameter values as presented in Chapter 9
- Chapter 11 describes the results of the cost-benefit exercise
- Chapter 12 identifies shortfalls of the current analysis and recommends future areas of work for enhancing the current analysis
- Chapter 13 outlines the main conclusions made

2 BACKGROUND OF WIND-HYDROGEN

2.1 WIND ENERGY – THE CHALLENGE

Wind is a fluctuating energy resource and so is the energy derived from it. Figure 1 illustrates the variability in the pattern of wind energy production over a period of 1 week. One of the main challenges with wind energy, in particular in systems where wind power represents a large proportion of total electricity consumption, is to manage the variability of the wind electricity generated to achieve efficient and effective system operation.

As the overall wind energy penetration within the electricity system increases, fluctuations in system electricity supply, as a result of wind energy, will become more apparent – over and above the fluctuations that would normally be experienced in any case, in an electricity system based primarily on conventional fossil fuel technology. The variability of the resource is not however, strictly speaking, the root of concern when it comes to effective system operation and supply-demand management, but the ability (or not) to predict this variability. As the penetration of wind energy within individual networks increases, the ability to accurately forecast wind production over short to medium time scales (1 hour to 2 days) [1] becomes more important.

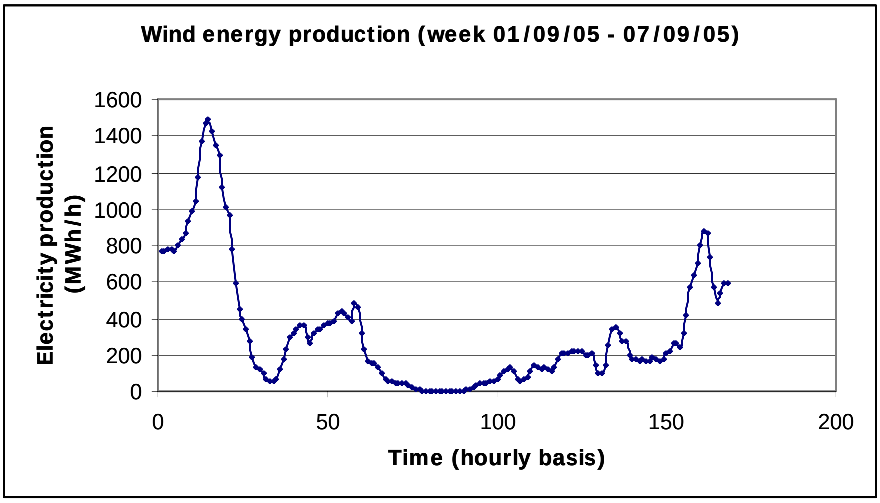


Figure 1 : Example of wind energy production profile during a 1-week period (Data source: [2])

Given current and expected rates of wind energy deployment in the European Union – an annual average growth rate of 26% from end-2000 to end-2005 (calculated from [1] and[3]), with expectations for continued growth to 2020 – in particular in specific networks, there is concern that the integration of large amounts of wind energy in certain areas of the grid could result in difficulties in power scheduling particularly in systems with limited interconnection for import/export of power production. The possibility for surplus power situations, especially in off-peak demand periods, is also of concern. Although improvements in wind energy prediction techniques are expected to relieve this to some extent, the fact remains that large scale integration into the power system of a fluctuating resource such as wind is an issue of increasing concern for network management. This issue is already a subject of discussion in

Europe (see for example [4]), particularly in countries such as Denmark and Germany, where wind already plays an important role in the energy supply (see for example [5] and [6]).

High wind penetration situations represent a special case since the variability of the wind power production becomes much more apparent in the overall system than would otherwise be the case. This may entail, for example, the need for substantial (additional) reserve and/or relatively large storage capacities in the system for network management purposes, compared to the situation where wind plays only a marginal role in overall electricity supply. Electrolytic hydrogen has been previously investigated for its potential role as a storage medium for wind energy in isolated systems (see for example [7][8]), but also in grid-connected systems with large amounts of wind, where hydrogen plays a role in network (balance) management (see for example [9][10]). In effect, electrolytic hydrogen can be used in high wind penetration situations to strategically absorb wind power to decrease the magnitude and frequency of wind power peaks, wind production variability and wind energy penetration in the network.

Of course, hydrogen is only one of several means of energy storage, and arguably not amongst the most economically competitive. Furthermore, the range and practice of network management techniques is highly complex and advanced, with a myriad of options, each more or less effective or economic than the other depending on the specific network. However, unlike other storage media or network management strategies, hydrogen, as an energy carrier, represents a potentially new market onto itself. Its role is therefore not restricted to network management and storage. This opens the door for further exploration of synergies between the wind electricity and hydrogen markets.

2.2 HYDROGEN – AN OPPORTUNITY?

A hydrogen-inclusive economy is seen to be central to achieving a clean, safe, reliable and secure energy supply in Europe in the long term [11]. Hydrogen is envisaged to displace fuel-consumption in energy sectors such as combined heat and power and transport. A number of initiatives and programmes in the field of hydrogen (and fuel cells) have been launched with a view to paving the way forward for the envisaged hydrogen-inclusive economy (see [12] [13] [14]). Central however to achieving the goals of the hydrogen-inclusive economy is the integration of a substantial amount of renewable resources either as a resource for hydrogen production or for directly meeting energy end-use requirements. This inevitably brings forth the issue of competition between the two.

Wind energy is one of the major contributors to renewable energy in the European Union. It is used most efficiently directly for electricity consumption, thus reducing its attractiveness in the competing use as input for hydrogen production. However, as previously mentioned, a situation of relatively high wind energy penetration means that the direct use of wind power production on the electricity market is not necessarily the most desirable option, for example in cases where unforeseen large amounts of wind power production would cause network management issues, wherein storage mechanisms and/or wind power curtailment would be logical recourse as part of a network management strategy. This opens the way for investigating the alternative use of wind electricity as an input for the production of hydrogen.

2.3 THE WIND-HYDROGEN STRATEGY

As described above, hydrogen produced by electrolysis with wind electricity (hereafter referred to as “wind-hydrogen”) in high wind penetration situations, can potentially contribute simultaneously to: improved system management, optimization of wind resource use, and the achievement of an enhanced, renewable, hydrogen-inclusive economy. The wind-hydrogen strategy therefore refers to the use of electrolytic hydrogen production from wind power for bridging the expanding wind energy market and the envisaged hydrogen-inclusive economy for Europe, in a common strategy for network management and renewable hydrogen production.

The main premises or pre-conditions underlying the exploration of a wind-hydrogen strategy are thus that:

- The penetration of wind in the system means that a reasonable proportion of the wind power production is potentially not suitable for exploitation on the electricity market and is thus possibly “eligible” for renewable hydrogen production
- The diversion of electricity for electrolytic hydrogen production should contribute towards network management

The following chapter looks at the process through which hydrogen is produced from (wind) electricity, and the specific considerations or boundary conditions that are stipulated for the current analysis.

3 DESCRIPTION OF THE WIND-HYDROGEN PROCESS AND CONSIDERATIONS FOR THE ANALYSIS

3.1 THE WIND-HYDROGEN PROCESS

The process of converting (wind) electricity to hydrogen is the electrolysis of water (H_2O) to produce hydrogen (H_2) (and oxygen (O_2)), according to the following basic process:

$$2H_2O \Rightarrow 2H_2 + O_2$$

The resulting hydrogen undergoes further processes, such as compression and storage, for the facilitation of downstream handling and distribution processes. The process and sub-stages of a possible electrolytic wind-hydrogen pathway are illustrated in Figure 2 below:

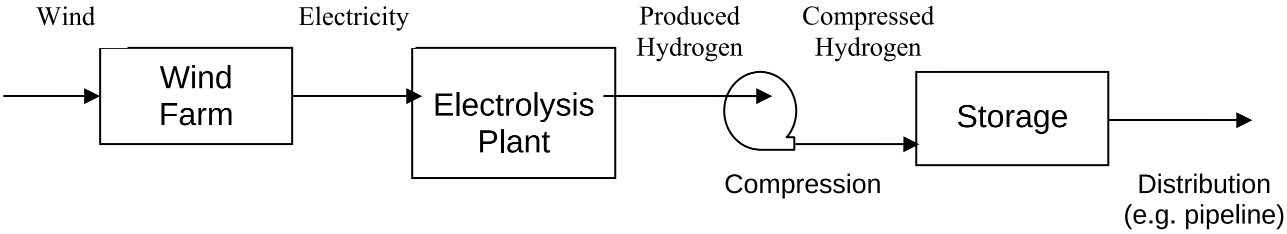


Figure 2: Schematic diagram of wind-hydrogen plant

As indicated in the diagram, the starting point of the process is the wind electricity resource. The specification of the wind-hydrogen plant, and consequent amounts of hydrogen produced for the market, therefore depend on the quantity and profile of wind electricity fed to the plant. The first step is therefore to establish a systematic basis and coherent set of criteria for determining the amount of wind power production that is "eligible" for diversion and alternative use in the wind-hydrogen process. This is discussed in the next section.

3.2 BASIS AND CRITERIA FOR EARMARKING OF WIND PRODUCTION ELIGIBLE FOR WIND-HYDROGEN

3.2.1 CONSIDERATIONS FOR EARMARKING OF WIND ELECTRICITY FOR HYDROGEN PRODUCTION

The criteria or basis on which the decision is made whether to dispatch wind energy production directly to the electricity network or to use it for electrolytic hydrogen production is in fact central to determining the final attractiveness of the wind-hydrogen strategy,. This is because, as it will be shown later, the value-for-money that can be obtained for wind (whether for use as electricity or as hydrogen) is the most decisive factor in the cost determinations for this method of hydrogen production. With a given wind power profile, the decision basis will dictate the quantity, power pattern, and potentially even the economic value of wind electricity to be diverted to the electrolysis process.

One option – the one used in this study – for earmarking wind production for the wind-hydrogen process, is to use a given target power production level as the decision-basis for diversion of wind power production. This means that all electricity generated above the given target power level is eligible for consideration for hydrogen production. This strategy contributes to network management by introducing a measure of control on the variability of the dispatched wind power (by making it approach baseload–like operation) and by reducing the effective penetration of wind in the network. The electrolyser is used as a mechanism to cap the dispatched wind power to within a given range above the target power level, by effectively providing a power buffer for wind.

The concept is illustrated in Figure 3 and Figure 4 below. Figure 3 shows actual wind energy production (indicated by dark blue line) for a one-week period, compared to the chosen target (indicated by the green horizontal line). The maximum (hourly-average) power (MWh/h) is represented by the highest point on the graph, and the generated electricity is the total area under the graph. Figure 4 illustrates the electricity, which if compared to a fixed-power production target or reference is in surplus, and thus eligible to be considered for exploitation via electrolytic hydrogen production – that is, all electricity generated above the horizontal reference line is eligible.

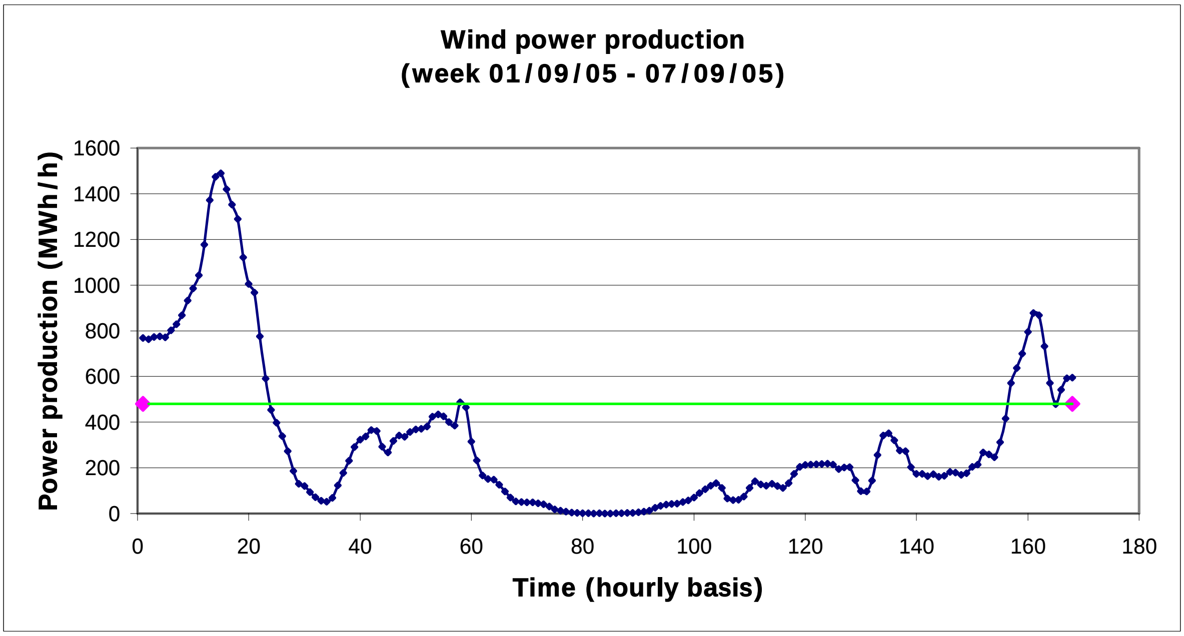


Figure 3: **Wind power production profile compared to fixed reference power level corresponding to 20% installed wind capacity (1-week period, Data source: [2])**

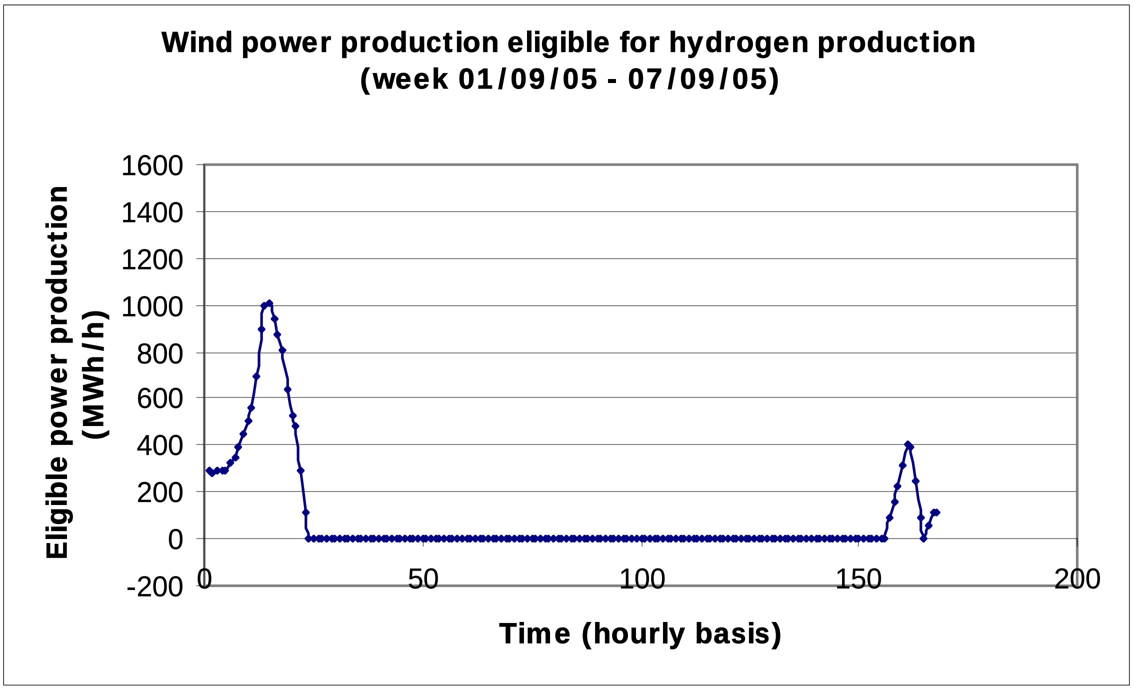


Figure 4: Wind power production eligible for hydrogen production, using fixed reference power level corresponding to 20% installed wind capacity (1-week period, Data source: [2])

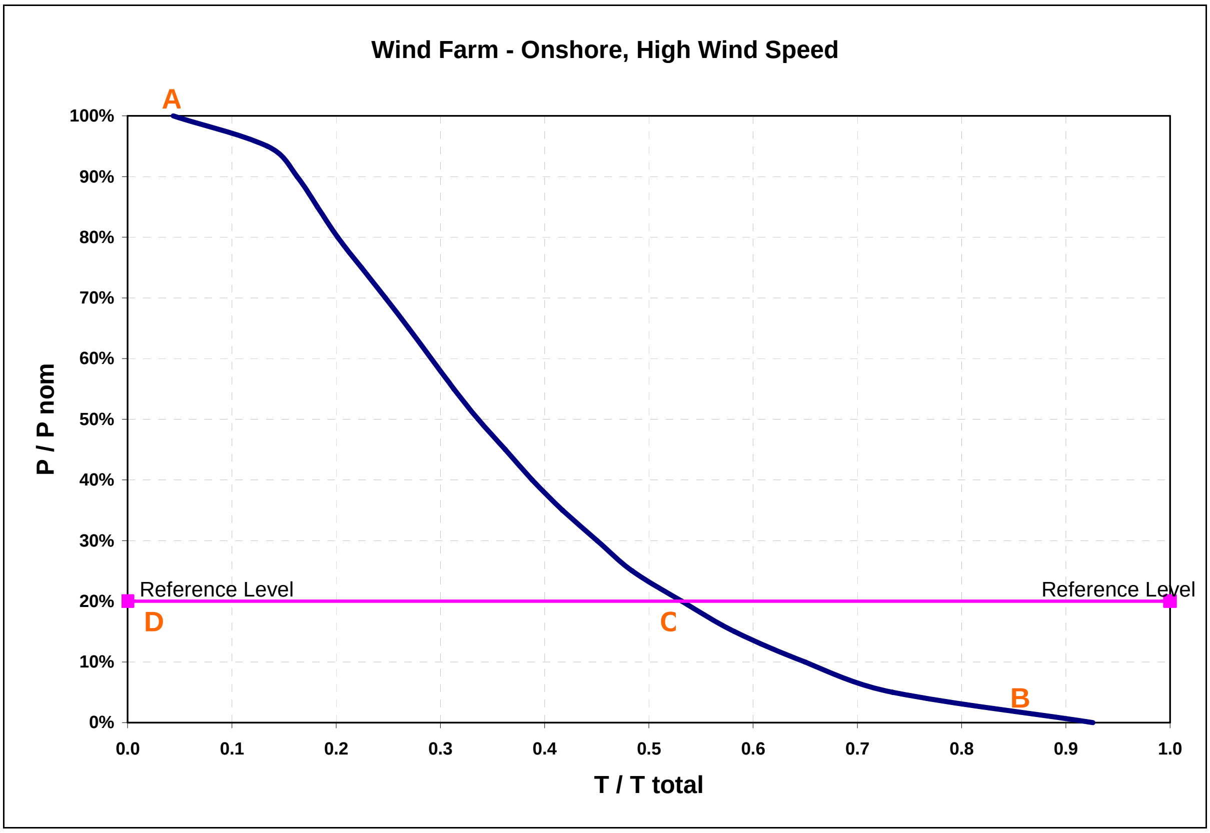
In this study, the use of a fixed target or reference power level is done for the purposes of conducting a generic analysis, independent of system-specific conditions. Depending on the specific system, other, more fitting approaches could be used, which would consider not only the pattern and level of wind energy production but also that of electricity consumption. The basis for determining wind energy eligible for hydrogen production could therefore be to match the wind power production profile to a given demand profile with which it is associated. Alternatively, one could choose to base the decision for eligible wind power on prediction error, wherein deviation of actual versus forecast wind power production in excess of a given allowable prediction error, determines eligibility for hydrogen production. These approaches require intimate knowledge and extensive data (actual and forecast) of the wind energy supply and the electricity demand, as well as supply data for other sources of energy supply in the network system to which the wind supply is connected. Furthermore, this approach would be system specific and representative of a given existing situation which does not readily lend itself to prospective analyses. The analyses therefore use a fixed target power level as the reference or decision basis together with typical, network-independent wind data as the bases for conducting a generic analysis, capable of incorporating additional future considerations (see also chapters 12 (Limitations of the Analyses and Recommendations for Future work) and 13 (Conclusions)).

In any system, the tendency for high wind energy penetration situations to actually create problems with respect to network management will depend to a large extent on the characteristics of the grid to which the wind power is connected – whether isolated or well-connected, with good import/export possibilities – as well as on the sheer instantaneous wind energy concentration at a particular point in the grid, for example in offshore situations, where large amounts of wind energy may be expected to be fed in at a given node(s) onshore. The case is therefore considered for wind energy penetration levels that are defined as “limit” or “high” by virtue of their anticipated impact on network management (as further described in section 8.2), and for a network of “limited” interconnection where, for wind penetration levels above the "limit", storage and/or wind energy curtailment would be needed for network management strategy. The concepts "limit" and "high" penetration are further elaborated in chapter 9, Table 3 of the report. The conditions defining (for the current analysis) the scope of "limited" interconnection, is given in section 4.3, with the further specification in terms of a curtailment requirement given in chapter 9, Table 3.

3.2.2 CHARACTERISING THE WIND-ELECTRICITY RESOURCE

Wind power output may be characterised by a wind power duration curve. This is essentially a graphical representation of the statistical distribution of wind power output, with respect to its nominal power, as a function of the cumulative or total time for a given period (e.g. year, summer/winter months, daytime/night-time hours).

Figure 5 illustrates the duration curve for a typical wind farm (derived according to the methodology described in [15]). The area under the curve (line AB in the diagram) is proportional to the electricity generation of the wind farm, and the slope of the duration curve indicates the variation of the generation over the specific period: the larger the slope, the greater the variability. The curve shows, for each power level, the relative proportion of time for which power is generated in excess of that level. Unlike Figure 4, which shows the real-time wind power generation eligible for exploitation as wind-hydrogen, the duration curve representation of Figure 5 shows the *annual* wind power generation eligible.



P/P nom = Relative wind power production (% rated wind capacity)
T/T total = Fraction of time (in hours) relative to annual period (8760 hours)

Figure 5: Typical wind power duration curve for a wind farm [16]

In this case, power generation in excess of the reference level ((P/ P_{nom}) of 20%, denoted by the horizontal pink line DC) is eligible – that is, the power production represented by area

ACD in the figure. All wind power generated up to 20% of nominal wind capacity (area DCB in the diagram) is undisputedly dispatched to the grid. Only when wind power is generated above the reference level (horizontal line DC in the diagram) does the electrolyser come into play as a wind power buffer.

The eligible electricity is only a *potential* resource for electrolytic hydrogen production. Not all of the electricity is expected to be used for conversion to hydrogen for two main reasons:

1. The eligible electricity converted to hydrogen is determined by the size of the electrolyser to which the wind electricity is coupled. With fluctuating electricity input such as from wind it is generally not economically advantageous to size the electrolyser on the basis of capture of maximum available power production. This is because the pattern of wind generation (generally skewed towards lower power levels) is such that increasing electrolyser plant size entails lower capacity factor usage for the electrolyser, since the wind power absorbed would be rarely at the maximum levels of the electrolyser. The unexploited capacity is capital cost that cannot be recovered. There is therefore a trade-off to be made in sizing the electrolyser for capturing the eligible wind electricity. The marginal benefit of increased hydrogen production (and sales) with a larger electrolyser plant capacity must be balanced against higher capital costs. There is in principle an optimum size for the electrolyser where the marginal cost of increased power capture is equal to its marginal benefit. However, this optimum holds true only for a given set of technological, economic and market conditions (such as: efficiency of electrolysis, electrolyser unit costs, expected selling price of hydrogen etc.). These may not remain constant with time.

2. Electrolysers generally have a lower operating limit, expressed as % of maximum capacity. If the wind power fed to the plant is not sufficient to enable electrolyser operation there is no hydrogen production. Thus, any eligible wind electricity not meeting the requirements corresponding to electrolyser operation cannot be considered a resource for electrolytic hydrogen production. Although, in the future, advances in electrolyser technology will mean that greater operating flexibility is possible for electrolysers.

As the primary function of the electrolyser in the current analyses is to provide a wind power smoothing mechanism using hydrogen storage to buffer and cap wind power peaks, the electrolyser capacity is dictated by the decided desired wind power buffer/cap to be achieved.

The overall concept is explained using an example. Using as a basis average wind power production on an hourly time scale, for a 10 MW wind farm with a reference level (P/ P_{nom}) of 20%, only power production exceeding 2 MWh/h is potentially diverted to the electrolyser for making hydrogen. All power production exceeding 2 MWh/h can thus be routed to the electrolyser, but the latter can only accept the quantity of electricity permitted by its size. Referring to Figure 6 for the situation when an electrolyser is implemented; if it is desired to be able cap wind power production using a peak power reduction of 30%, the electrolyser size used will be 30% of the nominal wind capacity, or 3 MW. The upper limit of wind power production to the electrolyser is indicated in the diagram by the horizontal line EF at P/ P_{nom} = 50% (= 20% reference level + 30% electrolyser capacity) or 5MWh/h. Thus for the 10 MW wind farm with 3 MW electrolyser, the wind power production absorption capability of the electrolyser is 2 MWh/h to 5MWh/h. 'Eligible' wind power production will therefore only be dispatched to the network for the portion that is in excess of that which is absorbed by the electrolyser. In Figure 6 therefore, the energy routed to the electrolyser is equivalent to the area CDEF, whereas electricity AEF is still dispatched to the network.

As mentioned previously, for the wind power absorbed by the electrolyser to result in actual hydrogen production, it must meet the minimum electrolyser operating requirements. In the above example, if an operating minimum of 20% electrolyser capacity (or 0.6 MW) is assumed, wind power production must be a minimum of 2.6 MWh/h (for an average hourly basis) to result in hydrogen production. The operating minimum is indicated in Figure 6 by the blue arrow. The borderline for wind power production to meet this minimum is indicated by point G on the duration curve. The amount of *eligible* wind power, therefore, that does *not* result in hydrogen production is shown by the triangle-like shape, above the pink reference line, and the wind energy effectively used for hydrogen production is shown by the green-shaded area.

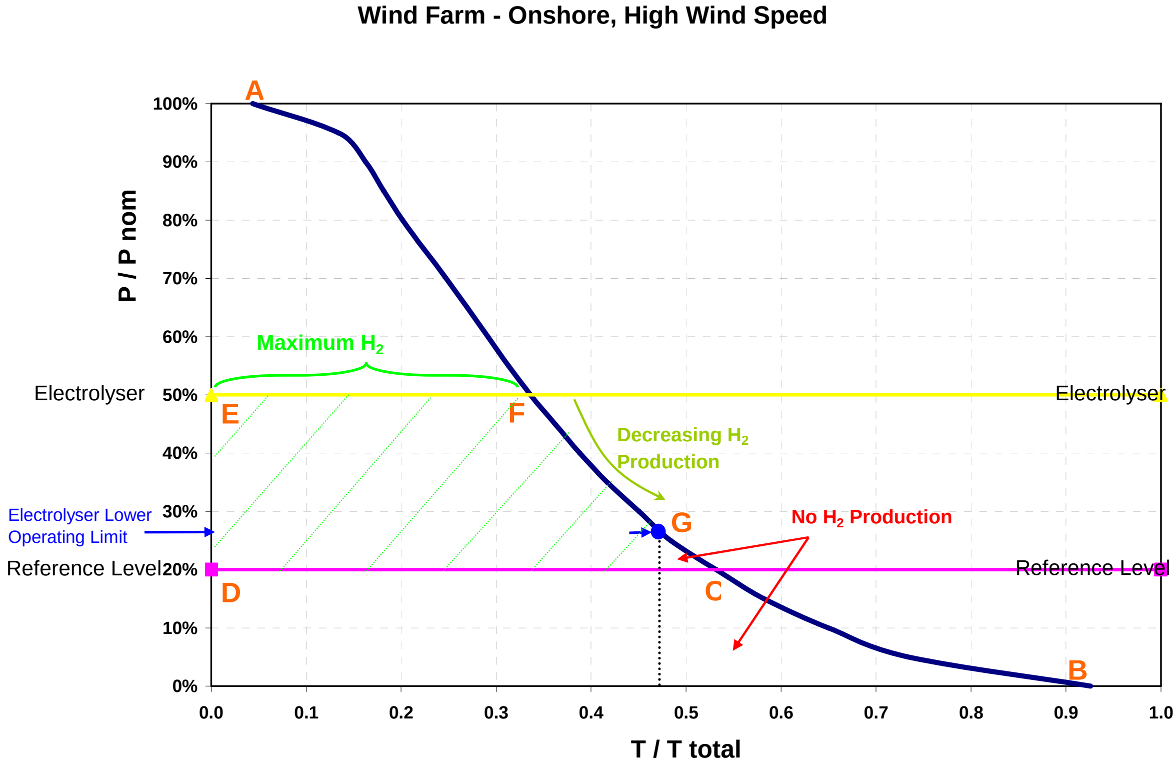


Figure 6: Typical wind power duration curve for a wind farm, showing electricity used for hydrogen production

The electrolyser effectively provides a buffer of 30% nominal wind power. Total wind power production to the network is therefore capped at a maximum of 70% of total production. This is more easily visualised in Figure 7, which shows the original (real-time) wind power production profile (red line) and the new profile (blue line) of wind power that would consequently be dispatched to the electricity network for the 1-week period, if an electrolyser of 30% nominal wind capacity is used. The reference level used to define eligible wind power production for hydrogen production is depicted by the green horizontal line in the diagram.

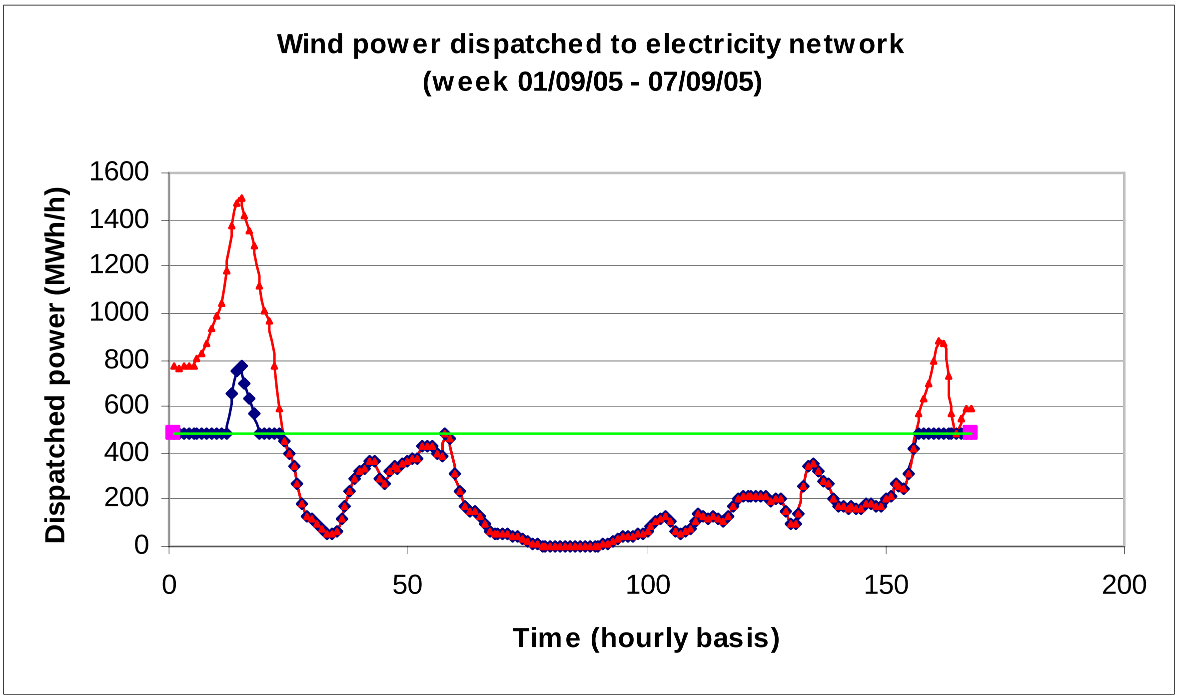


Figure 7: Wind power dispatched to the network (blue line) with an electrolyser providing power absorption equivalent to 30% nominal wind capacity (1-week period, data source for wind production: [2]). Initial wind power profile and the reference power level are indicated respectively by the red line and horizontal green line.

4 METHODOLOGY OF ANALYSIS FOR THE WIND-HYDROGEN SYSTEM

4.1 OVERALL APPROACH AND SCOPE

As already described in section 2.3, the underlying principle is the diversion of wind power in high wind penetration areas for use in electrolytic hydrogen production. The approach of the study is to determine, via life-cycle cost-benefit assessment, the long-term competitiveness and economic implications for the end-user of the exploitation of this "wind-hydrogen strategy".

An annualised cost-benefit assessment is conducted for a wind-hydrogen system over its lifetime, implemented in a given reference year, assuming a given set of technological, economic and market conditions. The annualised cost-benefit assessment (CBA) takes into account, for the expected lifetime of the system:

- Investment and running costs of the hydrogen production plant and the costs of inputs to the system (water and electricity)
- Expected benefits from: the sale of hydrogen product, improved electricity balance management, and offset of carbon dioxide emissions by substitution of fossil fuels with renewable hydrogen

Moreover the analysis looks at the would-be evolution of the result for annualised life cycle cost-benefit, in the period 2005-2050, which is influenced by:

- Cost reductions from technology development and experience in both electrolytic hydrogen and wind energy sectors
- Inter-market stimulation effects between hydrogen market and wind energy markets

The outcome is a single (annualised) cost-benefit result for each successive reference year (of 2005-2050) which is the supposed year of implementation of the wind-hydrogen system.

In the economic assessment it is important to take into consideration that the portfolio of costs and benefits from the implementation of a wind-hydrogen system are aggregated at different economic levels, for example:

- The investment costs and product revenues are assumed by the project proponent (who may be the wind energy producer, energy storage supplier, electricity supplier etc.)
- The benefits from improved network management (i.e. elimination/reduction of *additional* balancing costs) are realised by the end-consumer of electricity in the price s/he pays for electricity (benefits are assumed to be passed on from the network operator)
- The benefits from improved local environmental conditions, as a result of avoided particulate emissions from hydrogen end-use, such as in the transport sector, are enjoyed by community of end-users
- The benefits for global environmental conditions from reduced greenhouse gas (GHG) emissions, as a result of the use of renewable (hydrogen) fuel, is enjoyed by all members of society

A consistent basis must be used for the aggregation of these costs and benefits. All costs and benefits are therefore aggregated at the level of the end-consumer. This is reasonable since it is assumed that for an emerging technology to prove competitive and sustainable in the long term it will be funded through market demand, represented by the end-consumer. Thus, assuming a fully competitive environment, all costs borne and all benefits enjoyed by the actors at various economic levels are taken to be passed on to the end-consumer.

In the specific case analysed, the end-consumer is the consumer whose electricity needs are met through connection to a network in which the level of wind penetration and available interconnection capacities are such that storage and/or wind energy curtailment would be part of a network management strategy, potentially justifying the implementation of a wind-hydrogen system. The collection of end-consumers connected to the high wind penetration network are assumed to form a distinct community for whom wind electricity and hydrogen are an integral part of the energy supply base. Costs and benefits are allocated across all members of this community via the electricity price. Thus, in the case where costs outweigh benefits, consumers would effectively have to subsidize the wind-hydrogen system by paying a higher unit price for their electricity, and, in the case where benefits outweigh costs they would benefit from lower electricity prices. The method thus assumes that all members of the community consume electricity. It also assumes a global market initiative for greenhouse gas (GHG) reductions. In this way the local contribution to global GHG emissions reductions' can be attributed an economic value at the local level.

4.2 STATIC AND DYNAMIC ANALYSES

The entire system, comprising the electricity network, wind-hydrogen system, and end-user community, represents an economic sub-system which interacts with other economic (sub-) systems. The analysis therefore incorporates a systems approach, in which the influences of factors, both internal and external to the economic sub-system, are taken in to account in the cost-benefit assessment.

The assessment is approached from both a static and dynamic point of view. The static dimension is annualised life cycle cost-benefit result for the wind-hydrogen system implemented in a given reference year, with a given set of technological, economic and market conditions. The dynamic dimension comes into play for each successive reference year in the period 2005-2050, where certain cost-benefit parameters are expected to change with time. For example, technological evolution and market developments influence, at different times and to different extents, certain factors (for e.g. technology costs), which have the effect of changing the cost-benefit result depending on the reference year. The dynamic analysis therefore shows the evolution of the annualised cost-benefit result as a result of this.

The life cycle cost benefit assessment considers initial investment and expected costs and benefits over the expected lifetime of the system. These are primarily determined by:

- Electrolyser size, as dictated by the decided level of wind peak power reduction (cap) or buffer
- Cost of inputs (primarily of wind electricity)
- Hydrogen production rates, determined by the electrolyser size and the wind power production profile (duration curve)
- Product market conditions (for hydrogen and for avoided GHG emissions)

- Revenues from improved network management (balancing)

The dynamic dimension considers:

- Reduction in the cost of wind electricity supplied to the plant
- Reduction in the cost of electrolyser technology
- Improvements in electrolyser technology (efficiency)
- Evolution of demand for hydrogen
- Cross effects between wind energy and electrolyser markets as both markets develop and interact over time

The elements considered in the life cycle cost-benefit assessment and dynamic considerations are outlined in chapters 5 to 10.

A model for the life cycle cost-benefit assessment, incorporating static and dynamic aspects, was created using the Vensim® software interface, which is specifically designed for analysis of dynamic systems. The results of the model calculations are given in chapter 11.

4.3 THE SCOPE OF THE ANALYSIS

As stated in section 3.2.1, the tendency for a high wind penetration situation to have significant consequences for network management, either entailing additional system costs (e.g. balancing costs, network upgrade) or wind power curtailment, or both, will depend to a large extent on the characteristics of the overall system within which the wind power installation is located. The case is therefore considered for a system whose interconnection/export possibilities are “limited”, in that wind penetration (with respect to overall energy consumption) greater than or equal to 10% means:

- Significant *additional* balance management costs due to the additional requirements for response and reserve
- Recourse to wind energy curtailment

The threshold of 10% is used since studies (see [4]) suggest that the impact of wind power in terms of additional balance costs only start to become significant at wind penetration levels of 10% upwards. Further details on the justification of the use of the 10% threshold are given in section 8.2. The specification of balance cost and wind energy curtailment levels are explained in section 8.2 and specified in chapter 9, Table 3. The impact of different values for these parameters on the cost-benefit outcome is examined through scenarios (see chapters 11 and 12).

Since the electrolytic hydrogen effectively acts as a storage mechanism, one may seek to evaluate its competitiveness compared to other storage technologies. This study however looks specifically at electrolytic hydrogen in its multiple roles as a network management tool, as an alternative use for wind electricity resources, and as a contributor to a European Union renewable hydrogen economy. Direct comparison with other storage technologies, such as pumped hydro, batteries etc., which have no direct contribution to the hydrogen economy, is therefore not relevant in the scope of this study.

Finally, the analysis considers only the selling of hydrogen for use as a fuel in the energy sector (transport and stationary applications) and does not examine the case of re-conversion of all or a portion of the hydrogen to electricity for re-sale to the network for further supply-demand balancing (see chapter 12).

5 WIND-HYDROGEN PLANT SPECIFICATION

5.1 BASIS FOR PLANT SPECIFICATION

As mentioned (section 3.2.1), in the specification of the electrolyser size (and consequently the remaining balance of plant[1]), a balance must be made between the peak power reduction capability and the cost-benefit implications. Although the wind-hydrogen plant (electrolyser + balance of plant) can be optimised for a given set of technological and market conditions, this is not a relevant approach for the current analysis since these technological and market conditions are projected to change with time (see section 4.2, "dynamic analysis"). Moreover, it is the effect of these dynamic aspects on the competitiveness of the wind-hydrogen strategy that are being analysed, not the conditions for optimal plant configuration for a specific point in time. The size of the electrolyser is therefore treated as a variable in the analysis, determined in accordance with the (modeller's) decision for the level of wind peak power reduction desired (see subsequent section 5.2, Table 1, and chapter 9, Table 3). The balance of plant is specified according to the expected hydrogen production rates. This is determined by the electrolyser capacity and expected wind power production profile. It is therefore not explicitly determined here but considered as an integrated part of the electrolyser plant.

The following sections outline the theoretical approach and equations used for the specification of the plant, independent of the actual data used for the analysis. In addition, some specific assumptions and boundary conditions are outlined for the actual system upon which the cost-benefit assessment of this study will be based. Although the system specification can be more accurately determined using process flow design and modelling, this is beyond the scope of the present study.

5.1.1 ELECTROLYSIS PLANT

Since the size (in kW) of the electrolyser is dictated by the desired level of wind peak power reduction, the basic equation applicable is:

Equation 1: Nominal capacity of the electrolyser

$P_{ELYZR} = f_{PK} * P_{WENOM}$

Where:

P_{ELYZR} = Size of electrolyser (kW) (power required for maximum hydrogen production rate)

f_{PK} = Wind peak power reduction (%)

P_{WENOM} = Nominal installed wind capacity (kW)

At full load, the hourly rate of hydrogen production by the electrolyser of size P_{ELYZR} is determined by:

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[1] Balance of plant includes: rectifier, water purification unit, hydrogen purification unit, auxiliaries

Equation 2a: Maximum hourly hydrogen production rate via electrolysis

$Q_{H2MAX} = P_{ELYZR} / E_{ELYZR}$

Where:

Q_{H2MAX} = Maximum hourly rate of hydrogen from electrolyser (Nm^3/h)
E_{ELYZR} = Energy requirement of the electrolyser plant (kWh/ Nm^3)

Alternatively:

Equation 2b: Maximum hourly hydrogen production rate via electrolysis

$Q_{H2MAX} = \eta_{ELYZR} * P_{ELYZR} / [\rho_{H2} * LHV_{H2} * a]$

Where:

η_{ELYZR} = Efficiency of the electrolyser plant (%)
LHV_{H2} = Lower heating value of hydrogen (kJ/kg)
ρ_{H2} = Density of hydrogen at normal conditions (kg/ Nm^3)
a = Conversion kJ to kWh (1/3600 kWh/kJ)

These equations represent the maximum rate of hydrogen production corresponding to continuous plant operation at maximum power. Actual hourly hydrogen production will however depend on real-time wind power fed to the electrolyser, and will thus fluctuate between maximum and minimum capacity, according to:

Equation 2c: Actual hourly hydrogen production rate via electrolysis

$Q_{H2HR} = P_{WELYZR} / E_{ELYZR}$

Where:

Q_{H2HR} = Actual hourly rate of production of hydrogen (Nm^3/h)
P_{WELYZR} = Surplus wind power routed to the electrolyser (kW)

On an annual basis, the rate of hydrogen production is approximately given by:

Equation 3 : Annual rate of hydrogen production

$Q_{H2Y} = E_{WELYZR} / E_{ELYZR}$

Where:

Q_{H2Y} = Annual rate of hydrogen from electrolyser (Nm^3/y)
E_{WELYZR} = Surplus wind electricity fed to the electrolyser (kWh/ y)

It is assumed that, for the periods where wind power is eligible for electrolytic hydrogen production (i.e. above the reference power threshold, as indicated in section 3.2), the electrolyser is always available.

It should be noted that the efficiency of the electrolyser (Equation 2b) may be expected to be affected by intermittent operation, as would be the case here with wind power. The efficiency of the electrolyser also varies with the load factor of the electrolyser plant; the specific manner of this variation differs according to the load-efficiency relationship for the particular electrolyser type. For the purpose of the analysis it was decided to adopt a fixed, but relatively conservative value for electrolyser efficiency (see section 9), to take into account these factors.

5.1.2 COMPRESSED HYDROGEN STORAGE

Since the fluctuating nature of the electricity source means hourly hydrogen production rates will be variable, thus not necessarily coinciding with hydrogen demand, a storage facility is required to ensure ability to meet market expectations regardless of variability in upstream hydrogen production. Storage therefore effectively provides a buffer between production and demand, ensuring hydrogen availability during periods where wind generation is insufficient for producing the required quantities of hydrogen, but also ensuring hydrogen production can occur when it is opportune to do so (that is when wind is abundant), regardless of the downstream hydrogen usage rate.

For the purpose of specifying the storage system, it is assumed that the electrolytic hydrogen produced is contracted on the basis of a regular fixed average daily supply. The contracted supply is based on the year-averaged daily rate of hydrogen production or $Q_{H2Y} / 365$.

During the contracted period for hydrogen supply it is necessary to be able to assure the average daily supply of hydrogen, regardless of actual hydrogen production rates at any point in time. The maximum storage requirement is therefore that which is needed to meet the daily supply requirement for the duration of a situation of ‘zero actual hydrogen production’, that is where there is insufficient wind to enable the generation of hydrogen. In order to determine maximum storage requirements, therefore, the number of days of ‘zero hydrogen production’ is estimated. The approach has been to determine the maximum short-term hydrogen storage requirements for a weekly time frame on the basis of annual data for wind power production. In the specific case under examination, with a reference basis of 20% nominal wind power, above which wind power production is eligible, the data reveal that wind power production is eligible for hydrogen production 53% of the time. When taking into account the lower operating limit of the electrolyser, the proportion of time for which wind power production actually results in hydrogen production is 49% (refer also to Figure 6, where the vertical line from point G shows the percentage time for which wind power production is equal to or greater than the minimum requirement). Thus for approximately 51% of the time or, on a weekly time frame, roughly 3.5 days out of 7, there is potentially no hydrogen production. In order to assure sustained supply of the hydrogen market, therefore, the storage facility is sized to ensure a *minimum* of 3.5 days market supply. Thus:

Equation 4: Compressed hydrogen storage requirement

$$M_{STOR} = 3.5 * Q_{H2Y} / 365.$$

Where:
M_{STOR} = Compressed hydrogen storage requirement (Nm^3)

5.1.3 COMPRESSORS

Because the density of hydrogen is very low, storing at atmospheric pressure would require disproportionately large storage facilities, which is neither technically nor economically advantageous. The hydrogen is therefore compressed for storage. The compressor power requirement is dictated by the ratio of desired outlet pressure to inlet pressure and the rate of hydrogen flow. As a minimum, the compressor capacity must handle the minimum hydrogen production of the electrolyser plant. This is taken as the basic “unit size” for compressors. Hydrogen flows will range between the minimum and maximum hydrogen production rates of the electrolysis plant. The total compression capacity is therefore met using a number of compressors of “unit size” needed to attain the maximum required compressor power. An allowance of 25% extra compressor capacity is made for breakdown eventualities.

The following equations are used for (adiabatic) compressor calculations:

Equation 5 : Theoretical unit energy requirement for compression [17]

$$W_{TH} = [\gamma/(\gamma -1)] * Z * R_{H2} * To * [((p_1/ p_0)^{(\gamma -1)/\gamma)} - 1]$$

Where:

W_{TH} = Theoretical compression energy required (kJ/kg)
γ = Adiabatic exponent = 1.41 for diatomic gas
Z = Hydrogen compressibility factor at inlet pressure (dimensionless)
R_{GH2} = Hydrogen gas constant (kJ/(kgH_2.K))
To = Inlet hydrogen temperature (K)
p_1 = Required hydrogen outlet pressure
p_0 = Hydrogen pressure at compressor inlet

It is assumed that the hydrogen pressure at the compressor inlet, p_0, is the same as the pressure of the hydrogen leaving the electrolyser unit, thus, pressure losses are not taken into account.

Equation 6 : Actual unit energy requirement for compression

$$W_{ACT} = a * (W_{TH} / \eta_C) * \rho_{H2}$$

Where:

W_{ACT} = Actual compression energy required (kWh/N m^3)
η_C = Compressor efficiency

The compressor size (kW) is therefore:

Equation 7: Total compressor power requirement

$$P_{ACT} = W_{ACT} * Q_{H2MAX}$$

Where:

P_{ACT} = Compressor power required (kW)

For the determination of the unit compressor size Q_{H2MAX} is replaced by $Q_{H2MIN,}$ where:

Q_{H2MIN} = Minimum rate of hydrogen production from electrolyser (Nm^3/h)

5.2 WIND-HYDROGEN PLANT SPECIFICATIONS

The specific characteristics of the system for the starting point of the analyses are given in Table 1. The table contains both exogenous inputs – which are the specifications decided by the modeller for the basic system upon which other (downstream) calculations are based – as well as endogenous values, calculated via the methodology and equations as specified in sections 5.1.1 to 5.1.3.

The wind power output data used in the base case analysis uses the aggregated wind power duration curve data [16] for an onshore wind farm in an area 40km², with a local mean wind speed of 7.5m/s. The average annual power output from the wind farm is assumed, for the base case analysis, to constitute 10% of total electricity consumption in the system (thus wind penetration level is 10%). Scenarios for different levels of wind energy penetration in the system are investigated, as specified in chapter 9, Table 3.

Table 1: Base case wind-hydrogen plant specification

Wind energy system	**Symbol**	**Calculation Method**	**Value**
Nominal (installed) wind power	P_{WENOM}	(exogenous)	20 MW
Reference basis for "eligible" wind power for electrolytic hydrogen		20% nominal wind power	
Wind power reference level		= 20% * P_{WENOM}	4 MW
Electrolysis plant			
Wind peak power reduction	f_{PK}	(additional) 20% nominal wind power capacity	
Nominal electrolyser rating	P_{ELYZR}	Equation 1	4 MW
Electrolysis energy requirement (incl. auxiliaries, excl. compression to 150bar) Or, Electrolyser plant efficiency (LHV)	E_{ELYZR} η_{ELYZR}	(assumed, using [18], [19], [20])	5.3 kWh/ Nm^3 56% (LHV)
Maximum H_2 production capacity	Q_{H2MAX}	Equation 2a (taking into account energy for compression to 150 bar)	727 Nm^3/h
Minimum H_2 production capacity	Q_{H2MIN}	Equation 2c (taking into account energy for compression to 150 bar)	145 Nm^3/h
H_2 delivery pressure		(assumed, using [18], [19], [20])	10 bar
Feed water requirement		(assumed, using [18], [20], [21])	0.9 L/ Nm^3
Compressors			
Inlet pressure	p_0	= H_2 delivery pressure from electrolyser	10 bar
Delivery pressure	p_1	(exogenous)	150 bar
Compressor efficiency	η_C	(assumed, based on [21])	60%
Compression energy requirement	W_{ACT}	Equation 6	0.2 kWh/ Nm^3
Total compressor power requirement	P_{ACT}	Equation 7 + 25% breakdown provision	180 kW
Storage			
Storage unit capacity		(based on [22])	4400 Nm^3 at 200 bar
Storage unit operation pressure		= p_1	150 bar
Storage requirements,	M_{STOR}	Equation 4	3.5 days hydrogen supply

In the analyses, no consideration is given to energy losses for the electricity from the wind farm to the electrolyser plant (including compressors). Furthermore material (hydrogen) and pressure losses between electrolyser and compressor; compressor and storage facility; storage facility and distribution facility are not taken into account. Electrolyser plant characteristics (exogenous inputs) are stipulated (on the conservative side), using as a reference the characteristics of (pressurised) alkaline electrolysers as the main commercially available electrolyser type (with reference to [18] [19] [20]). Although proton exchange membrane (PEM) electrolyser technology is expected to play a more important role in the future with respect to hydrogen production from intermittent sources of power such as wind, due to their ability to cope with transient variations in electrical power, and their relatively high efficiency. PEM technology, however, is still a relatively immature, hence the use of technical parameters of alkaline technology as the reference. Compressor characteristics are assumed based on [21]. Storage characteristics (exogenous inputs) are based on [22].

6 WIND-HYDROGEN PRODUCTION COSTS

For the purposes of the analysis it is assumed that the wind energy producer is the project proponent and thus the owner and operator of the wind-hydrogen plant[2].

The cost factors for wind-hydrogen production are classed 'direct costs' and 'indirect costs'. The direct costs relate to all costs that are incurred as a result of the construction and operation of the wind-hydrogen plant. The indirect costs here refer to the opportunity cost or lost revenue of exploiting wind energy via the wind-hydrogen strategy versus on the electricity market (status quo). The direct and indirect costs of the system are outlined below in sections 6.1 and 6.2 respectively. Section 6.3 gives the specific cost parameters used in the analysis (Table 2), as well as the treatment of these parameters in the calculation of the overall wind-hydrogen production cost (Equation 11).

6.1 DIRECT COSTS

The direct costs of the wind-hydrogen plant are categorised as either fixed/one-time or variable/recurrent. Fixed/one-time costs relate to all investment (equipment and start up) costs for the plant. Variable/recurrent costs include costs for raw materials and process inputs and services, which are incurred annually, often in accordance with plant output.

The plant considered is fictitious. Cost data used for the economic analysis do not pertain to any specific commercially available plant. The cost figures used are a mixture of quoted and assumed data, based as far as possible on data available for equipment of similar size. For non-equipment related costs, assumptions were made on the basis of information available in the literature and personal communications with various actors in the sector.

In the analysis, it is assumed that the electrolyser plant is provided on a turn-key basis, including all necessary connection and integration equipment, whether this relates to supply of raw materials and electricity or to processing downstream e.g. compression, storage (and potentially pipeline delivery) of produced hydrogen. This means that no consideration is needed for construction time for the plant, and that installation and start-up times are negligible. Decommissioning costs and salvage value are not taken into account, nor are taxes and inflation rates. It is important to note that the wind installation is assumed to exist regardless of whether or not the wind-hydrogen strategy is applied. This means that investment and start up costs related to the wind farm are not part of the analysis; the only costs pertaining to the wind installation that are relevant for the analysis are those related to the *use* of the wind electricity since this is a "raw material" to the wind-hydrogen process. This is accounted for in the recurrent costs.

The physical boundary for the system is taken at the plant gate. No detailed consideration is therefore given in the economic analysis to costs of transportation and distribution of the hydrogen post-storage, apart from the inclusion of a nominal cost for pipeline distribution

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[2] The designation of a specific project proponent is done purely for illustrative purposes to be able to have a reference basis for the various economic streams that must be taken into consideration. In the final analysis, in an economic assessment where all costs and benefits are aggregated at the end user, the origin of the investment is not significant for the final result.

services within the area of end-use. These services are assumed to be provided by a third party, with the further assumption of a suitable existing pipeline in the proximity of the wind-hydrogen plant. The hydrogen exiting the storage unit is already considered merchant hydrogen (refer also to section 8.1) and no further consideration is given in the analysis to additional processes to which the hydrogen may be subject before actual end-use.

6.2 INDIRECT COSTS

In addition to the direct equipment and raw material costs borne by the wind-hydrogen producer, the indirect cost of lost revenues must be taken into account. By diverting some of the saleable electricity for hydrogen production, the wind energy operator (= wind-hydrogen producer) decreases the revenue that would have been accrued were s/he to sell the electricity to the network. Since the production cost of the wind electricity is already taken into account as an input cost to the wind-hydrogen system, the lost revenue is simply the difference between the production cost and the expected sale price for the wind electricity on the market[3]. The saleable wind electricity is effectively the amount of the wind electricity that is diverted to the wind-hydrogen plant that could be considered as having value on the electricity market. Thus, in a situation where all wind production can be accommodated by the network, the lost revenues are given by:

Equation 8 : Lost revenues

$$C_{Xel} = E_{SWELYZR} * (S_{WE} - C_{WE})$$

C_{Xel} = Lost revenues from diversion of saleable wind electricity to wind-hydrogen plant (€/y)

$E_{SWELYZR}$ = Saleable wind electricity fed to the electrolyser plant (including electricity for compressors) (kWh/ y)

S_{WE} = Price of wind electricity on the market (€/kWh)

C_{WE} = (Levelised) Cost of wind electricity production (€/kWh)

However, in a high wind penetration network of limited interconnection capacity wind power, curtailment may be employed as a network management tool. The curtailed wind energy effectively has zero value on the electricity market. The electricity to be taken into account for the loss of revenues is therefore calculated by “correcting” the quantity of electricity fed to the electrolysis system to an effective quantity of saleable electricity via the curtailment factor. That is:

Equation 9: Accounting for wind energy curtailment in saleable electricity

$$E_{SWELYZR} = E_{WELYZR} * (1 - f_{CTL})$$

Where:

f_{CTL} = Fraction of wind electricity fed to the electrolyser plant and compressors, that would normally be curtailed

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[3] From the perspective of the wind energy producer as the owner/operator of the wind-hydrogen plant, the total cost for using wind electricity for hydrogen production is actually the wind energy production cost plus the revenues lost by not selling the wind electricity directly. This is effectively the market price of wind electricity or the amount that would be paid for the wind electricity for use in the wind-hydrogen plant if the plant were owned and operated by a third party who was not the wind energy producer.

An average annual curtailment factor (assumed) is used for the analysis. The effect of different levels of curtailment on the economics of the system is examined in different scenarios, as specified in chapter 9, Table 3.

In terms of its price on the market, wind electricity, as electricity from a renewable energy source, benefits from premium prices in many countries of the European Union. This is essentially the effect of compensating for negative externalities of non-renewable electricity generation, e.g. carbon dioxide emissions. The price of wind electricity can be considered as made up of two components: the ‘grey electricity’ market component (which denotes the actual physical energy) and the ‘green electricity’ [27][4] (hereafter referred to as RES-E) premium (which acknowledges the additional environmental benefit of producing electricity from renewable resources). In the analysis, a decoupled market-based regime[5] is assumed to apply with respect to the wind electricity price. Here, the (physical) wind energy bids into the market on the same basis as electricity from non-renewable resources – the market clearing price is therefore the price accorded to the grey electricity component. At the same time a green electricity component (or green certificate) is added for the internalisation of externalities of carbon emissions.

The market price for wind electricity is therefore determined using the equation:

Equation 10 : Wind electricity price

$$S_{WE} = S_{G\text{-}E} + S_{RES\text{-}E}$$

Where:
$S_{G\text{-}E}$ = Grey electricity price (€/kWh)
$S_{RES\text{-}E}$ = Green electricity component (green certificate) price for wind (€/kWh)

Both grey electricity and green electricity prices may be expected to vary according to the distinct market conditions for any given period of time.

The grey electricity price will vary spatially (between different countries) as well as temporally (for any given country or region) in accordance with supply and demand conditions, for example in one day, one can distinguish different brackets of prices corresponding to high-peak, peak, and off-peak periods.

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[4] The term ‘green electricity’ refers to electricity generated by renewable energy sources (RES), as defined in the Directive on the promotion of electricity from renewable energy sources [27]. It may be referred to in the text in abbreviated form as RES-E

[5] There are in general two regimes for attributing a price for ‘green electricity’. The first is the fixed-price regime (feed-in tariff), in which an overall flat price (higher than the non-renewable-based electricity price on the market) is attributed for a given period of time to the RES-E as a whole – grey and green components are aggregated into an overall price. The second is a market-based regime, in which the overall RES-E price is disaggregated into a “grey electricity” market price (based on the non-renewable-based electricity market price) and a “green electricity” premium price (commonly in the form of a so-called “green (electricity) certificate”, hereafter referred to as RES-E certificate). In the latter case, a market demand for green electricity is usually promoted by the electricity regulator who imposes a RES-E quota obligation for e.g. on electricity suppliers, who would then be required to supply a given % of the electricity demand from renewable energy sources, as evidenced by the rendering of a corresponding number of RES-E certificates. This obligation may be accompanied by a minimum fall-back (support) price for the RES-E certificates. The minimum and indeed market price of a green certificate can vary depending on the renewable energy resource associated with the electricity generation. The main difference between the two mechanisms is that in the latter, by the clear distinction of separate pricing schemes, the markets for physical energy and for environmental benefit are decoupled.

In the analysis a constant average grey electricity price is used. This is because wind electricity, having low operational cost, usually forms part of the base electricity supply and, as long as demand is not exceeded, is generally fed into the system regardless of the demand period (peak or off-peak). This means that the average situation (e.g. over a 1-year period) is more relevant to the wind energy producer, compared to the instantaneous market situation. It is therefore reasonable to use an average grey electricity price, which reflects the average price fetched by a producer for the physical energy he delivers to the market.

In the case of the green certificate price, spatial and temporal variation in price is also expected. Factors that may be expected to influence the price include: the specific market governing rules put in place by the regulating authority of the given country or region (e.g. existence and severity of quota limitations and penalties, minimum and maximum price thresholds, possibilities for import and export of green electricity etc.); the indigenous potential for green electricity production; and the response of the electricity market actors. For the purpose of the analysis, an average EU green electricity price component is assumed for the lifetime of the plant. The effect of different values for the green certificate price is considered in a sensitivity analysis (see section 11.5).

According to [28], under green certificate (GC) regimes, minimum GC prices ranged between 12 and 82 €/MWh (0.012 – 0.082 €/kWh), with the grey electricity component ranging between 21 and 37 €/MWh (0.021 – 0.037 €/kWh). The values used for grey and green electricity prices in the base case analysis are shown in section 6.3, Table 2. In the case of the green certificate price, no account is taken of transaction costs related to trading of green certificates.

6.3 WIND-HYDROGEN PRODUCTION COST PARAMETERS

The economic analysis for the cost of hydrogen production is conducted using life cycle cost analysis on a levelised annual cost basis, assuming a 20-year plant lifetime, and a discount rate of 5%. The general equation is:

Equation 11: Levelised annual cost of wind-hydrogen production system

$$LAC_{WH2} = \Sigma(C_{Ct} * F_{CR}) + \Sigma (C_{CR\,t} * F_{CRR}) + O\&M + \Sigma (C_{R} * Q_{R}) + \Sigma (C_{S} * Q_{S}) + C_{Xel}$$

Where:

LAC_{WH2} = Levelised annual costs wind-hydrogen system (€/yr)
C_{Ct} = Initial capital investment (equipment, startup) costs (€)
F_{CR} = Capital recovery factor (as a function of N and i)
C_{CRt} = Replacement cost (equipment) incurred in year t (€)
F_{CRR} = Capital recovery factor for replacement incurred in year t (as a function of N and i)
O&M = (fixed) Operation and maintenance costs (€/yr)
C_{R} = Unit cost of raw material (water and electricity) (€ / unit)
Q_{R} = Annual usage of raw material for hydrogen production (units/yr)
C_{S} = Unit cost of service (€/unit)
Q_{S} = Annual usage of hydrogen production-related service (unit/year)
t = Time (yr)
N = Levelisation period or plant lifetime (yr)
i = Discount rate (1/yr)

The major cost parameters of the wind-hydrogen production process are outlined in Table 2. The specific values for the cost components described above will depict a snapshot of the situation, for the plant in question, for a *given reference year* (assumed year of implementation of the plant).

Table 2: Costs parameters associated with wind-hydrogen production (for items subject to cost reductions, the year of reference is 2005, as indicated in the table)

Parameter	Symbol	Calculation Method	Unit Value
Economic parameters			
Plant lifetime	N	(assumed)	20 years
Discount rate	i	(assumed)	5%
Investment (Fixed) Costs			
Capital Investment Costs	C_{Ct}	(1) + (2)	
Equipment Costs	(1)	(1a) + (1b)	
Electrolyser system, reference year 2005 (including water purification and hydrogen purification systems)	(1a)	(assumed, using [23][24][25][26]) (see section 7.1.2)	600 €/kW
Compressors	(1b)	(assumed)	1600 €/kW
Start Up Costs (Land, engineering, component integration)	(2)	Fixed fraction of (1) (assumed)	15% * (1)
Replacement Costs	C_{CRt}	(3)	
Electrolyser cell stack replacement (10 years, based on [20])	(3)	Fixed fraction (50%) of (1a) (assumed)	= 300 €/kW
Recurrent (Variable) Costs			
Water charges, C_R (water)		(based on [29])	1.3 €/m^3H_2O
Wind electricity cost (levelised cost of production), C_R (wind electricity), reference year 2005		(assumed) (based on [1] [30]) (see section 7.1.1)	0.055 €/kWh
Compressed storage unit rental, C_S (compressor)		(assumed, based on [22])	2000 €/unit/month
Pipeline distribution service, C_S (distribution)		(assumed, based on [26])	0.01 €/Nm^3 H_2
O&M		Fixed fraction of (1) (assumed)	2% * (1)
Lost Revenues,	C_{Xel}		
Wind energy curtailment (relative to wind electricity diverted to electrolyser)	f_{CTL}	(exogenous)	50%
Green certificate price (base case)	S_{RES-E}	(assumed) (based on [28])	0.03 €/kWh
Grey electricity average price (base case)	S_{G-EL}	(assumed)	0.03 €/kWh
Wind electricity price (base case)	S_{WEL}	Equation 10	0.06 €/kWh

Although PEM electrolyser technology is potentially more relevant for hydrogen production from intermittent power sources, such as wind, the cost parameters shown above reflect the case alkaline electrolysers, since PEM technology is still in the early stages and not yet commercially available on wide scale. Although a slightly higher unit cost would be expected to apply to PEM technology today, compared to alkaline electrolyser technology, this is expected to decrease significantly within the next couple of decades [31], attaining alkaline technology cost level and even lower. Thus, in the absence of reliable commercial data on PEM technology, alkaline technology costs are used as a proxy.

The cost of wind-hydrogen production is determined using Equation 11 (with the parameters in Table 2) together with the annual rate of hydrogen production, Q_{H2Y}, from Equation 3, according to:

Equation 12: Cost of hydrogen production with wind-hydrogen system

$C_{WH2} = LAC_{WH2} / Q_{H2Y}$

Where:
C_{WH2} = Cost of hydrogen production (€/Nm^3)

7 WIND-HYDROGEN COST REDUCTIONS

7.1 COST REDUCTIONS FROM LEARNING

The analysis considers the evolution of the costs associated with a wind-hydrogen system implemented in a given year during the period 2005-2050.

Cost reductions as a result of technological and market development are central for steering a product towards market competitiveness and viability. Cost reductions may be expected along the entire chain of processes in the wind-hydrogen system due to 'learning by doing' or what is known as the experience-curve phenomenon.

The experience curve is used to obtain an indication of the expected future performance of emerging or immature technologies[6], based on historic market trends – generally with price as a gauge. The experience curve equation is given by as:

Equation 13 : Experience curve equation (adapted from [32])

$$S_t = S_0 * (X / X_i)^{-E}$$

Where
S_t = Price[7] of commodity at year t
S_0 = Initial price of commodity
X = Cumulative experience in given year
X_i = Initial cumulative experience
E = Experience parameter

The (positive) experience parameter, E, indicates the rate of learning – higher values of E showing higher learning rates – and varies depending on the technology under consideration. The rate of learning for a technology is often indicated in terms of the progress ratio, PR, which is related to the experience parameter by the following equation:

Equation 14a: Progress ratio

$$PR = 2^{-E}$$

A progress ratio of 100% represents no learning, and thus zero cost reductions attributable to experience accumulation. There is no generally applicable rule for assigning expectations of progress ratios for a given pathway or process, however many energy technologies appear to yield progress ratios of 70% - 90% (see [32]).

The learning rate, as used in the analysis, is expressed as:

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[6] This however does not exclude that mature technologies also undergo cost reductions, for example as a result of R&D breakthrough that results in a major technical change or shift referred to as "technology structural changes" [32]

[7] Note that cost is sometimes used instead of price as a reflection of technology/market development, for example in the wind turbine industry, the levelised cost of electricity is used as an indicator of learning for the sector as a whole.

Equation 15b: Learning rate

$LR = 1 - PR$

Where:
LR = Learning rate (expressed as a fraction)

In general, historical data on technology prices and market volume are used to determine the learning rate for a given technology.

In the analysis, based on the information available, the gauge for learning is not technology price, but cost, which is assumed to be directly proportional to the price, and thus suitable for giving an indication of general trends.

Since the analysis is conducted for a medium to long-term perspective, cost reductions using the experience curve concept[8] have been integrated to examine the effect on market competitiveness for the wind-hydrogen system. Cost reductions have been considered for:

- Levelised cost of wind electricity
- Electrolyser system costs

In this study, no consideration is given to possible cost reductions for mature technologies. Furthermore, consideration is given to the varying levels of maturity of the technologies considered (for e.g. electricity from onshore wind is a more mature technology than electrolysers in an intermittent power application).

Cumulative experience in this analysis is measured using as input (projected) installed capacities (in the case of wind) or (projected) cumulative sales (in the case of electrolysers). Data on costs and markets (sales or installed capacities, as appropriate) incorporated into the model are based on industry predictions or targets for industry/market growth rates and/or future costs, as well as on assumptions described in sections 7.1.2 and 8.1.2 and further specified in Table 3. These projections are coupled with the experience curve equation to give cost estimations for the entire period under consideration. The main assumptions used in the cost reduction analyses are outlined in the subsequent sections.

7.1.1 WIND ELECTRICITY

A total of roughly 40 GW (mainly onshore) of wind power capacity is reported as installed in the European Union at the end of 2005 [34] [3]. The European Union White Paper [35] expresses a target of 40 GW of wind power capacity by 2010, whereas the European Wind Energy Association (EWEA) maintains a target of 75 GW for the same timeline (corresponding to an average growth rate of approximately 14% per year for start-2005 to end-2010). The 2010 EU target has, from all evidence, already been achieved, and indications are that the EWEA target for 2010 is indeed feasible [32], principally through growth in the onshore wind sector. Therefore, given current installed capacity and recent growth rates, it is assumed that growth to 2010 in the EU25 onshore wind energy sector will continue in line with the EWEA target, thus, at a rate of 14% per year. Growth in EU25 onshore capacity is

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[8] "The experience curve is a long-range strategic rather than short-term tactical concept. It represents the combined effects of a large number of factors… … it cannot be used for operating controls or short-term decision making. But in the formulation of competitive strategy, the experience curve is a powerful instrument, indeed" [33]

however expected to diminish significantly after the 2010 period due to factors such as limited land availability and fewer good wind resource sites. After 2010 the onshore wind growth rate is therefore assumed to drop to an average 3% per year. At the same time, the saturation point for total onshore wind capacity is assumed to be at 200GW (due to lack of suitable sites, planning regulations etc.), thus, once this threshold is attained (if before 2050) no further growth is assumed to occur for onshore wind. These assumptions give compatible results with studies such as [36]. Under the above assumptions of current installed capacity, and projected growth rates, and assuming a wind farm capacity factor of 25%, the calculated EU25 onshore wind electricity generation is 170 TWh in 2010 and 230 TWh in 2020, compared to 167 TWh and 270 TWh (policy scenario) stated by [36] for the same timelines. The assumed growth rates are therefore reasonable.

In terms of cost reductions for wind electricity production using the experience curve approach, a number of studies, including [1] [32] [37] [38], have been dedicated to this subject. According to [38], global progress ratios for wind farms may lie between 77-85% (with an average of 81%). A similar value of 83% progress ratio is determined by [37] with respect to the levelised cost of wind electricity generation. [1] quotes a range of 83% to 91% on the basis of specific costs of electricity (€/kWh) as gathered from a range of publications. For the purpose of the analysis a progress ratio of 83% - alternatively a learning rate of 17% - is used.

The starting point for the analysis is the current levelised cost of wind electricity production, for which estimates (and assumptions related to their calculation) are well documented (see for example [1] and [30]). According to [1] the cost of producing electricity with an average size wind turbine (0.85-1.5 MW) sited (onshore) at a medium wind regime lies in the range of 50 to 60 €/MWh. According to [30] the projected costs for wind electricity generation onshore (calculated at 5% discount rate, ex-transmission and -distribution costs) range between roughly 32 and 83 €(2005)/MWh (approximately 35 to 90 USD(2003)/MWh), with most values lying below 55 €/MWh (60 USD/MWh). For the purpose of the analysis a value of 55 €/MWh (0.055 €/kWh) is used for the levelised cost of wind electricity generation in 2005.

7.1.2 ELECTROLYSERS

The technical (namely, efficiency) and cost parameters used as a starting point for the analysis for the electrolysis plant are based on alkaline electrolysers, since the majority of current electrolyser experience lies with this technology. However, it should be noted that the less mature proton exchange membrane (PEM) electrolyser technology is expected to play a more important role in the future with respect to intermittent sources of power such as wind, since they can cope with transient variations in electrical power, and have relatively high efficiency.

The starting point for the analysis is the current unit cost of the highest capacity range of commercially available alkaline electrolysers, estimated to be approximately 600 €/kW.

A progress ratio (PR) of 85% is initially assumed – similar to the PR used for wind. The cost of electrolysers is therefore assumed to decrease according to a learning rate (LR) of 15%, with the minimum unit cost cut off at 200 €/kW.

One can imagine a kind of interaction between the wind energy and electrolyser markets in the future, where the development of either market stimulates development of the other, although not necessarily in the same way or to the same extent. For instance, as the wind electricity market develops more opportunities arise for the use of electrolyser technology since there is more and cheaper renewable electricity resource available for electrolytic hydrogen production. The effect could be increased electrolyser deployment. Similarly, developments in the hydrogen economy and ultimately in the market for electrolyser technology as a means of hydrogen production, mean that the use of electrolyser technology could become more attractive as an option for wind energy storage or for controlling variability in high wind penetration situations. This would relieve some of the issues associated with high wind penetration and positively influence (further) wind energy deployment. The two markets are therefore, in principle, mutually reinforcing.

Such interaction would mean that market growth, and thus learning, in the electrolyser market is not only dependent on developments and accumulation of experience in the hydrogen energy market but also on developments in the wind energy market (and vice versa). An important implication is therefore that, as the wind energy market develops in parallel with a hydrogen market, the rate of installation (capacity addition) of electrolysers for hydrogen production (wind-hydrogen systems) may be expected to increase.

The applicable equation for describing this (adapted from [39]) is:

Equation 16: Effect of development in the wind energy market on the electrolyser market

$$Y_{W\text{-}ELYZR} = 1 + f_{W\text{-}ELYZR} = (X_w / X_{Wi})^b$$

Where:

$Y_{W\text{-}ELYZR}$ = Effect of wind energy market on electrolyser market

$f_{W\text{-}ELYZR}$ = Fractional growth of electrolyser market as a result of growth in wind energy market

X_w = Cumulative operating wind capacity (installed capacity at time t) (MW)

X_{Wi} = Initial operating wind capacity (installed capacity 2005) (MW)

b = Elasticity of electrolyser market with respect to relative growth in wind energy market

One can also describe the elasticity parameter in terms of the expected fractional increase in electrolyser deployment with each doubling of installed wind capacity. From Equation 16:

Equation 17: Elasticity parameter

$$\ln(1+f_{W\text{-}ELYZR}) = b * \ln(2) \quad \Rightarrow \quad b = \ln(1+f_{W\text{-}ELYZR}) / \ln(2)$$

By formulating the elasticity parameter in this way, one can test various theoretical values for the fractional growth in the electrolyser market as a result of a doubling in the wind energy market. This effect of different values of elasticity parameter, b, on the final outcome of the analysis is tested via a sensitivity analysis (see section 11.5). The value used for the baseline analysis is shown in chapter 9, Table 3.

In a similar way, one can imagine that market value and growth in wind energy could also be influenced by developments in the electrolyser market, since the reduction in wind variability provided by the electrolyser could facilitate continued expansion of wind energy in the electricity network. However, to remain conservative, this reinforcing feedback effect is not taken into account, given the already relatively advanced stage of maturity of the onshore wind energy market, and the other more decisive factors influencing (indeed limiting) wind energy penetration, namely: the availability of wind resources, land availability, and planning regulations.

Future improvements in electrolyser efficiencies are also expected to have an impact on the production costs of electrolytic hydrogen. The analysis considers the effect of improved electrolyser plant efficiency (excluding compression to 150 bar) according to the following path: 56% in 2005, 60% in 2020, 66% in 2030, and 75% in 2040, and 2050. The short-term estimates are conservative (cf. [18] [19] [20]) to account for expected efficiency penalties for intermittent operation, however technology development is expected to remedy this in the future and enable higher efficiencies to be obtained. These efficiencies take into account the energy consumption of auxiliary equipment (excluding compression to high pressure (>10 bar)).

8 WIND-HYDROGEN MARKET BENEFITS

8.1 HYDROGEN PRODUCTION

As previously mentioned the main product considered is hydrogen. Although oxygen is also directly produced – in not insignificant quantities – via the electrolysis process, the potential revenue from exploiting this product is not considered in the analysis. However, the possible exploitation of this by-product should not be ruled out since oxygen is an important industrial gas, and is used as an oxidant in conventional combustion, waste treatment, electrochemical processes, and in the medical industry (with respect to the latter two cases, see for example [40] [41] for specific analysis of the re-utilization of oxygen from electrolytic hydrogen production processes).

The revenue from hydrogen production is based on the price expected to be obtained in the market, and the quantity that can be delivered to the market.

8.1.1 HYDROGEN MARKET PRICE

Hydrogen gas is already used in the industrial sector, primarily in the chemical and refinery industries. Estimates for global hydrogen consumption are 103 million kg per day [42] or 500 billion cubic meters per year [43]. Of this, 95% is estimated to come from carbon-containing sources such as hydrocarbons or alcohols [43]. Furthermore, only a very small percentage (1% according to [43]) of hydrogen produced globally is for the production of energy.

In the context of the analysis, the produced hydrogen is considered for sale in the energy market, where it may be used as a fuel for conversion to electrical energy or heat. Hydrogen (either on its own or in combination with another fuel, such as natural gas) may be used in stationary or mobile energy sectors, using either conventional technologies (such as gas turbines) or emerging technologies, such as fuel cells. Applications include combined heat and power (CHP), transportation, stationary power, and auxiliary power.

The sale of electrolytic hydrogen in established chemical and refinery markets is not considered in the analysis, for the short to medium term. This is because these industries have already built up a large amount of experience in providing cost-effectively for their own hydrogen needs, in some cases through their own production facilities. They are therefore considered internally self-sufficient.

A central parameter in the determination of revenues from hydrogen as an energy product is of course its expected market price. However, since the hydrogen energy market is still in its very early stages, not only is it impossible to attribute a price on the basis of historical observation, but it is entirely uncertain how the market and thus price will emerge and evolve in the future. The attribution of a market price for hydrogen in this context is therefore, for the moment, a purely theoretical exercise. It is not possible to infer a reference price directly on the basis of conventional fuel prices, since conventional fuels are not directly substitutable by hydrogen. This is because the use of hydrogen may entail an entirely different technology chain, conversion processes and infrastructure from that of conventional fuels. A reference or base price for hydrogen can however be derived using a price-per-utility basis in comparison with conventional fuels. The basis used is the (untaxed) price per-kilometre-driven equivalence of a direct hydrogen fuel cell (FC) vehicle with the gasoline Port Injection Spark

Ignition (PISI) vehicle as the reference technology. The reference fuel is Premium unleaded gasoline, 95 Ron (Euro Super 95). The basis for the determination of the reference price of hydrogen is according to:

Equation 18: Hydrogen market price determination

$$S_{H2} = \eta_{REF} / \eta_{H2FC} * S_{REF}$$

Where:
S_{H2} = Market price of hydrogen (€/GJ)
η_{REF} = Tank-to-wheel (TTW) fuel consumption of reference technology (gasoline PISI, for 2010) (litre/100km)
η_{H2FC} = TTW fuel consumption of direct hydrogen FC vehicle (for 2010) (MJ/100km)
S_{REF} = Untaxed pump price of reference fuel (gasoline) (€/1000litre)

The price obtained using the above equation is that adopted for the baseline scenario ("low" market price scenario) in Table 3. In reality the market price for hydrogen would be expected to vary depending on developments in the hydrogen market (i.e. the demand for hydrogen, see section 8.1.2), as well as on developments in substitute and raw material markets, such as natural gas (which is relevant for both the raw material and substitute markets). Alternative market prices for hydrogen are examined according to an additional "high" market price scenario (see Table 3, page 48).

In accordance with the hydrogen market price employed, the revenues from the sale of hydrogen are determined by:

Equation 19 : Revenues from sale of hydrogen

$$R_{H2} = 10^{-6} * S_{H2} * Q_{H2Y} * \rho_{H2} * LHV_{H2}$$

Where:
R_{H2} = Annual revenues from hydrogen sales (€/yr)

8.1.2 HYDROGEN DEMAND CONDITIONS

Since the hydrogen energy market is still in its very early stages, it is impossible to stipulate realistic projections for demand for even the next few years, let alone to 2050 (although some work in this area is underway, see for example [44]. Hydrogen demand is therefore theoretical. The basic assumed EU demand for hydrogen for energy purposes (electricity, CHP, transport) is based on the "slowly grown" scenario formulated in [45]. This scenario uses a projected hydrogen demand equivalent to roughly 1% of total EU 25 energy demand by 2020, increasing to 3% in 2030, 14% in 2040, attaining 29% by 2050.

In terms of hydrogen consumption at the level of the end-user community it is assumed that, in the short to medium term (to 2015), all hydrogen is consumed in stationary power generation and CHP within the community, as the necessary transport infrastructure for hydrogen use in transport is not yet assumed to be in place[9]. After 2015, a gradual development of the transport infrastructure is assumed to occur with a progressive increase in the use of hydrogen for transport. Thus, in the end-user community, it is considered that 0% of the overall hydrogen consumption may be attributed to the transport sector, up to 2015.

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[9] Own assumption based on [14]

Thereafter, it is assumed that in 2020, 10% of all hydrogen consumed may be attributed to the transport sector, growing to 25% in 2030 and 50% in 2050. These percentages, which show the percentage of the overall hydrogen consumption attributable to each end-use sector for *all* hydrogen consumed in the end-user community, are assumed to apply equally for the quantities of hydrogen originating from the wind-hydrogen system. That is, in 2020, 10% of the wind-hydrogen produced is used in the transport sector of the end-user community; likewise, in 2030, 25% of wind-hydrogen production is used in transport and 50% in 2050; the remainder is used in the non-transport (stationary) sector. This trend of consumption of wind-hydrogen production according to end-use sector is also important for determining avoided end-use emissions (refer to section 8.3).

It is assumed that, within the hydrogen uptake community, there always exists a demand for the quantities of hydrogen produced from the wind-hydrogen plant, at the attributed market price.

8.2 NETWORK MANAGEMENT (BALANCING) CONTRIBUTION

Balancing power is an integral part of any electricity network. It is not coupled to any particular power generation type (e.g. wind) but to the system as a whole, for dealing with overall uncertainty in matching demand and supply, as a result of fluctuations in generation (conventional and renewable) as well as in demand. Primary (operating in the second/minute time interval) and secondary/tertiary (operating in the 10 minute/hour time scale) reserves are operated continuously to compensate any deviations from anticipated supply/demand, and maintain balance in the system. The impact from large scale wind power is mainly relevant for secondary (and to some extent tertiary) reserve [4]. The impact of wind power on the need for secondary/tertiary reserves in the system is usually referred to in terms of *additional costs*. At relatively low wind energy penetration levels there is little or no additional system cost as a result of wind energy, since the mechanisms that are in any case foreseen for dealing with overall system uncertainty would cover deviations in actual versus forecast wind power production. However, at higher wind penetration levels, the uncertainties in wind output as a result of prediction error – above the normal level of uncertainty in balancing supply and demand – become evident. Studies (see [4]) suggest that the impact of wind power with respect to secondary/tertiary reserve requirements only start to become significant at wind penetration levels (with respect to overall energy consumption) of 10% upwards. The additional costs arise from the use of existing reserve capacity (operating costs), and, where existing system reserves are not sufficient for meeting the extra reserve requirement necessitated by wind, additional costs may also arise from the need for increased reserve capacity (capacity costs). In most cases, the existing reserve capacity is sufficient for meeting the increase in reserve requirements [4]. The additional cost from high wind penetration therefore results mainly from the operating costs i.e. the use of dedicated reserves or the increased part-loading (inefficient operation) of plants.

The wind-hydrogen system could contribute to improved balance management and reduced additional costs since the diversion of all or a portion of the wind electricity to the electrolysis plant has the effect of:

- Reducing extremes in variability. The use of the electrolyser for peak power reduction effectively smoothes the wind power profile and introduces measure of controllability on wind variability (namely on the surplus side), reducing the magnitude of hourly (and longer) variations and their frequency of occurrence. The electrolyser effectively provides a power buffer in peak wind power situations.

- Effectively decreasing the penetration of wind energy in the network since not all the production of the wind installation is dispatched

Also noteworthy, is the fact that high levels of wind penetration in the system could in some cases precipitate the need for network reinforcements. Storage, as provided by electrolytic hydrogen, could postpone or eliminate the need for such investments. The potential benefit of this is not however included in the analysis. The analysis considers only the additional costs related to balancing, namely the operating costs.

It is difficult to determine the exact quantitative effect that the reduced wind power variability achieved with the electrolyser would have with respect to additional balance costs, and thus its impact on the overall cost-benefit result and end-user electricity price (to which all balance management costs are eventually passed). The approach taken by [46], which is based on the ability of the electrolyser (wind-hydrogen) system to bid into the downward–regulating balancing market, is one way by which the balance management contribution can be concretised in the market context. Effectively, it is assumed that the electrolyser, by bidding into the downward-regulating market, reduces the price paid for its own energy usage by the amount of the average yearly electricity price on the downward regulating market. The benefit is therefore accounted for in terms of avoided electricity cost.

The approach used here is to estimate the potential avoided additional balancing (operating) costs based on the effective wind energy penetration in the system with and without the wind-hydrogen system in place. This assumes different applicable balance costs per unit wind energy according to the level of wind penetration in the system. As one could expect, there will be merit order for the provision of additional balancing services, with the cheapest options for balancing service deployed first, getting progressively more expensive as the requirement for balancing service increases – which would be the expected case with increased wind energy penetration. Routing some of the generated wind electricity via the electrolyser reduces variability and effective wind energy penetration in the system, negating some (or all) of the additional balance costs incurred, hence a lower balance cost can be assumed to be applicable.

The balance cost incurred per unit wind energy applies to the (annual) quantity of wind energy wrongly predicted, determined using the absolute prediction error. For clarity, an absolute prediction error, or deviation between actual and predicted production, of +/- 10% means that 10% of production is in surplus relative to the predicted production and, equally, that 10% of production is in deficit relative to predicted production. In total the electricity balance market must settle the equivalent of 20% annual wind energy production, or 2 times the absolute value of the prediction error times the annual wind generation. The resulting additional balance costs for wind power in the system are therefore:

Equation 20 : Balance costs for wind electricity, no wind-hydrogen system

$$C_{BL} = C_{bl} * (2 * f_{ERR} * E_{WETOT})$$

Where:

C_{BL} = Annual additional balance costs (€/yr)

C_{bl} = Additional balance cost per unit wind electricity in the system (€/kWh), applicable at wind energy penetration level *without* electrolyser in place. Thus,

$C_{bl} = f(f_{WE})$, for f_{WE} without electrolyser

f_{WE} = Penetration of wind energy in the network (based on total electricity consumption) (%)
f_{ERR} = Prediction error (absolute value, expressed as +/- %)
E_{WETOT} = Electricity generated annually by the wind energy system (kWh/yr)

Where, the factor 2 in Equation 20 is used to account for the deviation between actual and predicted production on both *surplus and deficit* sides.

With the electrolyser, a lower balance cost is applicable. Furthermore, the (lowered) balance costs would apply to a lower quantity of the wind electricity, given by [$E_{WETOT} - E_{WELYZR}$], where E_{WELYZR} is the surplus electricity routed to the wind-hydrogen plant. The overall result for balance costs with the electrolyser in place is therefore expressed by:

Equation 21: Balance costs for wind electricity, with wind-hydrogen system

$$C_{BL} = C_{blX} * (2 * f_{ERR} * [E_{WETOT} - E_{WELYZR}])$$

Where:
C_{blX} = Additional balance cost per unit wind electricity in the system (€/kWh), applicable at wind energy penetration level *with* electrolyser in place. Thus,
$C_{blX} = f(f_{WE})$, for f_{WE} with electrolyser

The avoided cost, or revenues from reduced balance costs is thus:

Equation 20 - Equation 21 = Equation 22; or

Equation 22: Avoided balance cost with wind-hydrogen systems

$$R_{BL} = 2 * f_{ERR} * E_{WETOT} * (C_{bl} - C_{blX}) + 2 * f_{ERR} * E_{WELYZR} * C_{blX}$$

Where:
R_{BL} = Revenues from reduced balance costs (€/yr)

A number of studies examine and quantify the effect of wind forecast error on additional balance and/or system costs in high penetration wind situations (see for example [5] [47] [48] [49] [50] [51]). The studies use different assumptions, for example with respect to the time horizon for wind power forecasts in the system operation, and are therefore not directly comparable. However, some results from these studies are given here.

According to [5], in 2000, approximately 38% of total wind production was miscalculated, with a resulting additional cost (from purchase of real-time imbalance power) of approximately 9.5 M€ (DKK 65 million) or approximately 3 €/MWh (DKK 0.02 per kWh). [47] determines the reduction in the market value of wind power to be in the range of 1.3-2.7 €/MWh for wind electricity, attributable to the need for power regulation to balance wind power unpredictability. This includes transmission costs between production sites for wind power (Denmark) and production sites (Sweden and Norway) for hydropower that are assumed to deliver the main power regulation. Extra balancing costs used in [48] are 3.4[10] €/MWh wind (2.38 £/MWh) for a 10% wind energy penetration level, 3.8 €/MWh (2.65 £/MWh) at 15% and 4.1 €/MWh (2.85 £/MWh) at 20%. In [50] for wind penetration of 20% and 30% additional balancing costs (for a baseline of 10% wind penetration) are estimated to

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[10] Values quoted refer to 2003 prices. Exchange rate used is 1 € = 0.692 £ [52]

be of the order of 3.5 – 4[11] €/MWh wind generated (2.1 – 2.5 £/MWh), on the basis of operating costs, for a high electricity demand scenario. [51] states total additional costs (operating plus capacity) of around 1€/MWh for a 10% wind (energy) penetration and almost 2 €/MWh for a 20% wind penetration for the Nordic power system.

The absolute prediction error for wind power production depends to a large extent on the time horizon for prediction. [51] shows estimations of absolute prediction error for wind power production for different prediction time horizons, as a % of total realised wind power production (for 2001). For the Nordpool electricity market the error in the quantity of energy produced is determined to be 38% of yearly wind power production [51] (alternatively, +/- 19%), for a prediction horizon 13-37 hours ahead. In [47], expected prediction (in-)accuracy for wind power in Northern Europe is reported as +/-10% and +/- 25% of annual electricity production for 2005.

For the analysis, two scenarios ("limit" and "high") are considered for wind energy penetration and associated balancing costs. The "limit" wind energy penetration is the assumed level of wind (energy) penetration above which significant additional balancing costs start to become apparent in the system – this is assumed to be 10% (based on [4]). The "high" wind penetration scenario is for a 30% wind penetration level. The prediction error is assumed to be +/- 20% for all scenarios. The additional balancing costs associated with the "limit" and "high" scenarios, are assumed to be 2 €/MWh (0.002 €/kWh) and 4 €/MWh (0.004 €/kWh) wind energy respectively. All parameters are outlined in Table 3. Although prediction accuracy is expected to increase in the future with anticipated improvements in prediction techniques, this is not taken into account in the analysis.

8.3 INTERNALISING REDUCTION IN EMISSIONS AT END-USE

Hydrogen as an alternative to conventional fossil-based fuels has the advantage that it does not result in particulate or gaseous emissions, other than water vapour, at its point of use. Furthermore, hydrogen produced via wind electrolysis is a fully renewable fuel, which does not result in greenhouse gas emissions at the point of its production and is not affected by resource supply restriction. Hydrogen produced from wind energy may be considered therefore to provide an additional benefit to society, compared to fossil alternatives, by virtue of its cleanness and contribution to security of energy supply. Part of this benefit is incorporated into the cost-benefit analysis by attributing a societal benefit from the offset of carbon dioxide emissions.

The approach is based on the assumption that a carbon tax would be imposed on conventional fossil fuels sold to the end-user, calculated on the basis of expected greenhouse gas (GHG) emissions (measured in carbon dioxide equivalent (CO_{2eq})) per unit of fossil-fuel based energy to be converted in meeting a specific end-user need. The consumer of renewable hydrogen (as a substitute for fossil fuels) would therefore benefit from the avoided costs of the carbon tax, taking into account that the effective level of substitution by hydrogen is on the basis of equivalence in utility i.e. *meeting the same end-use need*[12].

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[11] Values quotes refer to April 2002 prices. Exchange rate used is average price for April 2002: 1 € = 0.614 £ [52]

[12] Alternatively, one could imagine direct internalisation of the CO_2 benefit via the price accorded to the renewable hydrogen fuel, in a similar way to that used in the case of wind electricity, that is, via some sort of environmental certificate. In this case, the renewable hydrogen seller would receive a premium (equivalent to the value of the carbon tax) per unit of CO_2-free utility afforded by the hydrogen fuel.

In this case, the main end-use markets for which hydrogen has been considered as a substitute are as vehicle fuel in the transport sector and as fuel for provision of electricity and heat in the domestic and industrial sectors. In order to have a basis for comparison, some assumptions have been made to determine a level of substitution of hydrogen for fossil fuels, in terms of carbon dioxide equivalent offset. In the transport sector, the level of substitution is on a per-kilometre travelled basis, taking into account the tank-to-wheel (TTW) fuel consumption (efficiencies) of hydrogen fuel-cell vs. gasoline vehicles. In the domestic and industrial sectors, the level of substitution is on the basis of per unit energy delivered by conversion of fuel (whether hydrogen or fossil) using a single given reference technology. The relationships are given by:

Equation 23: Avoided emissions for the transport sector

$$EM_{TRN} = 10^{5} * EM_{TREF} / \eta_{H2FC}$$

Where:

EM_{TRN} = Avoided GHG emissions per unit of hydrogen used as substitute in transport sector (tCO_{2eq} /GJ H_2)

EM_{TREF} = Equivalent GHG emissions per km travelled with reference technology (gasoline PISI, for 2010) (tCO_{2eq}/ km)

η_{H2FC} = Tank-to-wheel fuel consumption of direct hydrogen fuel cell vehicle (for 2010) (MJ/100km)

Equation 24: Avoided emissions for domestic/industrial sectors:

$$EM_{DI} = \eta_{H2/REF} * EM_{DIREF}$$

EM_{DI} = Avoided GHG emissions per unit of hydrogen used as substitute in domestic/ industrial sectors (tCO_{2eq} /GJ H_2)

$\eta_{H2/REF}$ = Energy efficiency equivalence for the reference technology used with hydrogen versus reference fuel (%)

EM_{DIREF} = Equivalent GHG emissions per unit conversion of reference fuel with reference technology (tCO_{2eq}/GJ reference fuel)

Where:

$$EM_{DIREF} = \Sigma (EM_{XREF} * GWP_X)$$

Where:

EM_{XREF} = Emission of greenhouse gas, X, per unit conversion of reference fuel (tX /GJ reference fuel)

GWP_X = Global warming potential of greenhouse gas, X (tCO_{2eq}/ t X)

The proportions of the wind-hydrogen production used in the transport sector and non-transport (domestic/industrial) sectors of the end-user community are consistent with that described in section 8.1.

Equation 25: Total benefit of hydrogen-fossil fuel substitution at point of end-use

$$R_{EMA} = \Sigma\,(EM_{SECTOR} * Q_{H2SECTOR}) * C_{CO2}$$

Where:

R_{EMA} = Total annual environmental benefit attributable to wind-hydrogen use (€/yr)
EM_{SECTOR} = Avoided GHG emissions per sector (tCO_{2eq}/GJ H_2)
$Q_{H2SECTOR}$ = Hydrogen consumed per sector (GJ H_2 / yr)
C_{CO2} = Carbon tax (€/tCO_{2eq})

In the analysis the effect of different levels of CO_2 tax is examined (refer to Table 3).

9 WIND-HYDROGEN SYSTEM PARAMETERS AND SCENARIOS

The specific parameters, as described in chapters 7 and 8, used in the cost-benefit analysis scenarios are given in Table 3 below. The values used for the base case analysis, as well as in any additional scenarios, are shown. Scenarios are described in further detail in section 10.2.

Table 3: Wind-hydrogen system parameters and scenarios

Wind (onshore) electricity parameters and scenarios

Scenarios for wind energy penetration in the hypothetical grid network:

- Limit: 10%
- High: 30%

Note: Non-wind electricity generation is assumed to remain constant for all scenarios. Thus:
Baseline = Limit penetration: 10%, nominal wind capacity = 20MW (Table 1)
Assumed capacity factor ~ 35%
Wind electricity generation: ~ 62 GWh/y
Non-wind electricity generation: 556 GWh/y
High penetration: 30% (generation) => nominal wind capacity = 77.1 MW

Scenarios for forced wind energy curtailment, f_{CTL}:

- Low: 0%
- High: 50% (of the electricity diverted to the electrolyser)

Note: This is the proportion of diverted wind electricity (i.e. to the electrolyser) that would not be put into the electricity network as it would be in excess of system capacity and/or demand (including export). Curtailed wind electricity is considered to have zero economic value.

Parameters for wind electricity cost reductions (section 7.1.1):
Levelised wind electricity cost (2005 money), C_{WEL}:

- All scenarios: 55 €/MWh (0.055 €/kWh)

Learning rate for onshore wind production cost, LR (wind):

- All scenarios: 17%

Installed onshore wind capacity in the European Union, X_w :

- All scenarios: 2005 capacity: 40 GW; Saturation capacity: 200 GW

Growth rates in onshore installed wind capacity in the European Union

- 2005 – 2010: 13%
- 2011 – 2030: 3%
- 2031 – 2050: 0%

Electrolyser parameters

Peak power reduction specification, f_{PK} :

- All scenarios: 20% nominal wind capacity

Electrolysis plant efficiency (including auxiliaries, excluding compression to 150 bar), η_{ELYZR}:

- All scenarios: 2005: 56% ; 2040/2050: 75%

Parameters for cost reductions (section 7.1.2):
Learning rate for electrolyser equipment cost, LR (electrolysers):

- All scenarios: 15%

Effect of wind market growth on electrolyser market growth:

- All scenarios: Fractional growth of electrolyser market, $f_{W\text{-}ELYZR}$, with each doubling of cumulative wind capacity: 25% (assumed)

Fraction of electrolyser in hydrogen production technology for energy purposes (2005):

- All scenarios: 5%

Note: this represents a maximum, since, according to [43], 5% is the relative proportion of hydrogen produced from all non-carbon-containing sources (refer to section 8.1.1)

Hydrogen market parameters and scenarios (section 8.1)

Hydrogen demand:

- 2005: negligible (*)
- 2020: 1% of total EU 25 energy demand
- 2030: 3% of total EU 25 energy demand
- 2040: 14% of total EU 25 energy demand
- 2050: 29% of total EU 25 energy demand

(*) A value for 2005 is estimated using the assumption that 1% of all hydrogen produced in the EU is for the production of energy (based on the estimation of [39] that 1% of hydrogen produced globally is for the production of energy).

Scenarios for hydrogen market price, S_{H2}:

- Low: 24 €/GJ
- High: 50 €/GJ

Note: The "low" price is stipulated (S_{H2}) based on Equation 18 with the following data:

- Reference technology [53]: Port Injection Spark Ignition (PISI), Gasoline (2010)
- η_{REF} , Tank-to-Wheel (TTW) fuel consumption PISI 2010 [53]: 5.9 litre/ 100km
- η_{H2FC}, TTW fuel consumption direct hydrogen fuel cell (FC) vehicle 2010 [53]: 94 MJ/ 100km
- S_{REF}, Average EU-25 untaxed gasoline (Euro Super 95) pump price 2005 [54]: 386 €/1000 litre

Balance management parameters and scenarios (section 8.2)

Wind power production absolute prediction error, f_{ERR}:

- All scenarios: +/- 20%

Scenarios for additional balance cost per unit wind energy, C_{bl}, based on wind penetration level:

- Limit: 2 €/MWh (10% wind penetration) (0.002 €/kWh)
- High: 4 €/MWh (30% wind penetration) (0.004 €/kWh)

Balance costs, C_{blX} , for intermediate penetration levels (in the case when some of the wind electricity is diverted to the electrolyser) are determined by linear interpolation. It is assumed that for 0% wind penetration the additional balance cost is 0 €/MWh

Emissions reduction parameters and scenarios (section 8.3)

Transport:
All scenarios: Emissions reduction for substitution by hydrogen in the transport sector calculated using Equation 23, where:

- Reference technology [53]: Port Injection Spark Ignition (PISI)
- Reference fuel: Gasoline
- EM_{TREF} , Equivalent GHG emissions per km travelled PISI: 168 gCO_{2eq}/km 2002 [53]; 140gCO_{2eq}/km 2010 [53], unchanged after 2010 (assumed)

Industrial & domestic:
All scenarios: Emissions reduction for substitution by hydrogen in the transport sector calculated using Equation 24, where:

- Reference technology: Combustion plant >= 50MW (boilers)
- Reference fuel: Natural gas (NG)
- $\eta_{NG/H2}$, Efficiency equivalence reference technology used with NG vs. H_2 =1 : 0.95 [55]
- EM_{XREF} , Emission of greenhouse gas, X, per unit conversion of reference fuel [56]: 0.056 tCO_2/GJ, $2.5*10^{-6}$ tCH_4/GJ, $2.4*10^{-6}$ tN_2O/GJ
- GWP_X, Global warming potential of greenhouse gas (100-year time horizon), X [57]: $CO_2 = 1$, $CH_4 = 23$, $N_2O = 296$

Scenarios for carbon dioxide tax, C_{CO2}, for fuel at end-use (transport, industry, domestic):

- Low: 20 €/ton CO_{2eq}
- High: 50 €/ton CO_{2eq}

10 COST BENEFIT EVALUATION

10.1 DETERMINING THE END-USER COST FOR WIND-HYDROGEN

On the basis of all the cost and benefit streams established in the previous sections the total cost-benefit of the wind-hydrogen system, implemented in a given year, is determined according to:

Equation 26: Cost-benefit wind-hydrogen system

$CB_{WH2} = (R_{H2} + R_{BL} + R_{EMA}) – (LAC_{WH2})$

Where:

CB_{WH2} = Annualised annual cost-benefit of wind-hydrogen system implemented in a given reference year (€/yr)

This value gives an indication of the extent to which wind-hydrogen systems are attractive from the point of view of the community of end-users, to whom all costs and benefits are assumed to be transferred. The premise of transferring all costs and benefits to the end-consumer is that for any emerging technology to be competitive and sustainable in the long term it will be funded through market demand, represented by the end-user. The cost-benefit analysis has been used to calculate to what extent (if at all) and for how long the wind-hydrogen system must be economically supported in order for it to “break-even” with the status quo. This economic support (or benefit) is measured in terms of an additional cost (or gain), imposed on each end-user within the community, via the electricity price. Thus, in practical terms this would represent the extra charge (or gain) on the overall end-use electricity price.

Equation 27: Wind-hydrogen technology cost to the energy system end-user

$C_{USER} = CB_{WH2} / E_{EL}$

Where:

C_{USER} = End-user cost-benefit of wind-hydrogen, allocated per unit of electricity consumed in the community (€/kWh)

E_{EL} = Total annual electricity consumption of community (kWh/yr)

It is assumed in that the non-wind electricity consumption of the community remains unchanged. The wind electricity supply in the system will however vary depending on the wind energy penetration level assumed, and consequently so will the overall electricity supply (wind + non-wind) in the system. For wind energy penetration above the “limit” 10% threshold, it is assumed that the system can accommodate and trade a certain amount of additional wind electricity. The amount of wind that can be accommodated is however limited, and this is embodied in the curtailment factor, f_{CTL} (refer to Table 3).

For comparison, the technology cost to the end-user is also calculated in terms of the cost per unit wind electricity in the system, as given by:

Equation 28: Wind-hydrogen technology cost per unit wind electricity in the system

$C_{WIND} = CB_{WH2} / E_{WETOT}$

Where:

C_{WIND} = Cost-benefit of wind-hydrogen, allocated per unit of wind electricity produced in the system (€/kWh)

10.2 SCENARIO AND SENSITIVITY ANALYSES

It is interesting to analyse a number of possible situations with respect to certain key parameters and the values they could adopt under different circumstances (refer to Table 3). In particular, the analyses look at the effect of the following parameter variations:

- High and limit wind energy penetration in the system
- High and low forced wind energy curtailment
- High and low hydrogen market price
- High and low carbon tax

In order for the investigation to be meaningful, the possibilities have been grouped into 4 composite scenarios, or storylines, as outlined below:

Scenario 1: Baseline

This scenario relates most closely to the situation as it is today or as it is expected to be in the near future as the hydrogen market is still in the embryonic stages. The principal characteristics of this scenario are:

Limit wind penetration:

Currently, relatively high levels of wind penetration are found in only a few network areas in the EU. This scenario therefore considers that for the theoretical electricity system in question, with a fixed, limited level of interconnection capacity, the level of wind penetration in the system is such that the impact, in the form of additional balance costs, is relatively low. The wind penetration level is however assumed to be at a critical turning point as far as such additional costs are concerned. This turning point is considered to be at 10% wind energy penetration level (with respect to total electricity consumption).

Low wind energy curtailments:

The level of wind power production and in particular peak production in the baseline scenario is assumed to remain within expected demand (including demand met through electricity export) at all times, such that recourse to wind energy curtailment for supply-demand balancing is not necessary.

Low hydrogen market price:

The baseline scenario assumes a lower price for hydrogen based on the calculated (untaxed) price-per-km equivalent for direct hydrogen fuel cell (FC) vehicle using the gasoline Port Injection Spark Ignition (PISI) vehicle as a reference basis.

Low carbon tax:

The scenario assumes that there is limited policy push for climate change mitigation and greenhouse gas reduction via fuel taxation, resulting in a relatively low carbon tax for fuels.

Scenario 2: High wind penetration, strong hydrogen/climate change push

This scenario is essentially the anti-thesis of the baseline scenario. It assumes that a relatively high level of wind penetration exists in the system and that EU political push and industry have facilitated a strong move towards a hydrogen-inclusive, climate friendly economy. The key features of the scenario are therefore:

High wind penetration:
The scenario considers that for the theoretical electricity system in question, with a fixed, limited level of interconnection capacity, the level of wind penetration in the system is such that significant impacts, in the form of higher additional balance costs, are encountered.

High wind energy curtailments:
The level of wind power production and in particular peak production in this scenario mean that wind energy supply must sometimes be curtailed for reasons of network management and to keep supply in line with demand (including demand met through electricity export).

High hydrogen market price:
This scenario assumes a higher price for hydrogen, which is slightly more than double that of the baseline scenario.

High carbon tax:
This scenario assumes that there is strong policy push for climate change mitigation and greenhouse gas reduction measures via fuel taxation, resulting in a relatively high carbon tax for fuels in all sectors.

Scenario 3: High wind penetration, weak hydrogen/climate change push
The wind penetration and curtailment situation in this scenario is the same as that in scenario 2, however it is not backed by a strong push for hydrogen and climate change mitigation measures, such that the market price for hydrogen is low, as is the level of carbon tax employed for fuels.

Scenario 4: Low wind penetration, strong hydrogen/climate change push
This scenario is also a hybrid of scenarios 1 and 2, with the wind penetration and curtailment situation as depicted in scenario 1, however, with a strong policy push for hydrogen and climate change mitigation measures, resulting in a relatively high hydrogen market price and carbon tax for fuels in all sectors.

The visualisation of the four scenarios is shown in Figure 8.

Sensitivity Analyses
In addition to the scenario analyses, sensitivity analyses are performed with respect to:

- Discount rate, i
- Effect of wind market growth on electrolyser market growth, $f_{W\text{-}ELYZR}$
- Green certificate price, $S_{RES\text{-}E}$

The results of the sensitivity analyses are presented in section 11.5.

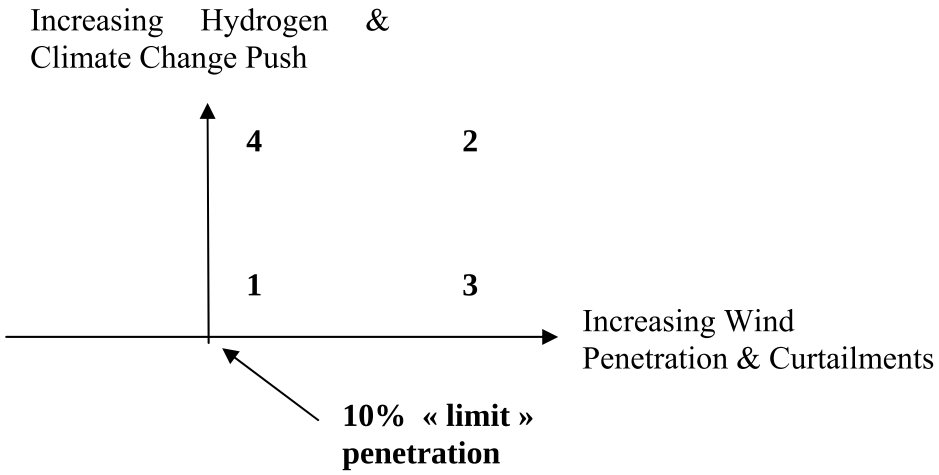

Figure 8: Visualisation of the four scenarios (indicated respectively by numbers: 1, 2, 3, 4) showing wind penetration/curtailment levels and the extent of policy push for hydrogen and climate change mitigation measures.

11 RESULTS

11.1 INTRODUCTION

The analysis incorporates a static dimension, which is the annualised life cycle cost-benefit result of a wind-hydrogen system implemented in a given reference year, starting with year 2005. It also incorporates a dynamic dimension, which considers the evolution of the annualised cost-benefit result for the given wind-hydrogen system, as it is assumed to be implemented for different reference years for the period 2005-2050.

A model for conducting the cost-benefit assessment was created using the Vensim® software interface, which is specifically designed for analysis of dynamic systems. The model determines the annualised cost-benefit result (€/yr) according to Equation 26, for each reference year in 2005-2050, as well as the overall technology cost to the end-user (Equation 27 and Equation 28).

The results presented are:

- The calculated cost of hydrogen production (Equation 12) with the wind-hydrogen system, and its evolution over time for the period 2005-2050, for **scenario 1: baseline**. This is presented mainly for information purposes and to enable a general comparison with other hydrogen production processes
- The results and evolution of the (annualised) cost-benefit assessment (Equation 26) for the period 2005-2050, for the **baseline**. The aim is to provide insight to the most important factors (relative contribution) in deciding the competitiveness of the strategy in the long term
- The evolution of the final technology cost to the end-user (Equation 27 and Equation 28) for the period 2005-2050, for the **baseline** and the other **scenarios (2 to 4)**.

The technology cost to the end-user is the main result of interest, since it shows the duration and extent to which (financial) support would need to be provided (if at all) by the consumer in order to exploit synergies between European wind and potential (renewable) hydrogen markets using a wind-hydrogen strategy. It also shows under what circumstances it may be worth pursuing this strategy in the medium- to long- term.

11.2 COST OF HYDROGEN PRODUCTION

The cost of hydrogen, C_{WH2} (Equation 12), produced from the wind-hydrogen system provides a basis for comparison with other hydrogen production technologies.

Figure 9 shows the hydrogen production cost for the baseline scenario. The resulting cost of hydrogen is of the order of 48 €/GJ in 2005 decreasing to around 32€/GJ in 2050. This hydrogen production cost is relatively high compared to the cost of electrolytic hydrogen production of similar scale determined in other studies (see for example [23] [24] [26], wherein hydrogen costs are of the order of half the cost calculated in this study). This may be attributed to the fact that the capacity factor usage of the plant – which the model results reveal to be around 40% – is low, and also to the high price of the input wind electricity, the cost for which is a primary factor in the overall cost as can be seen from Figure 10.

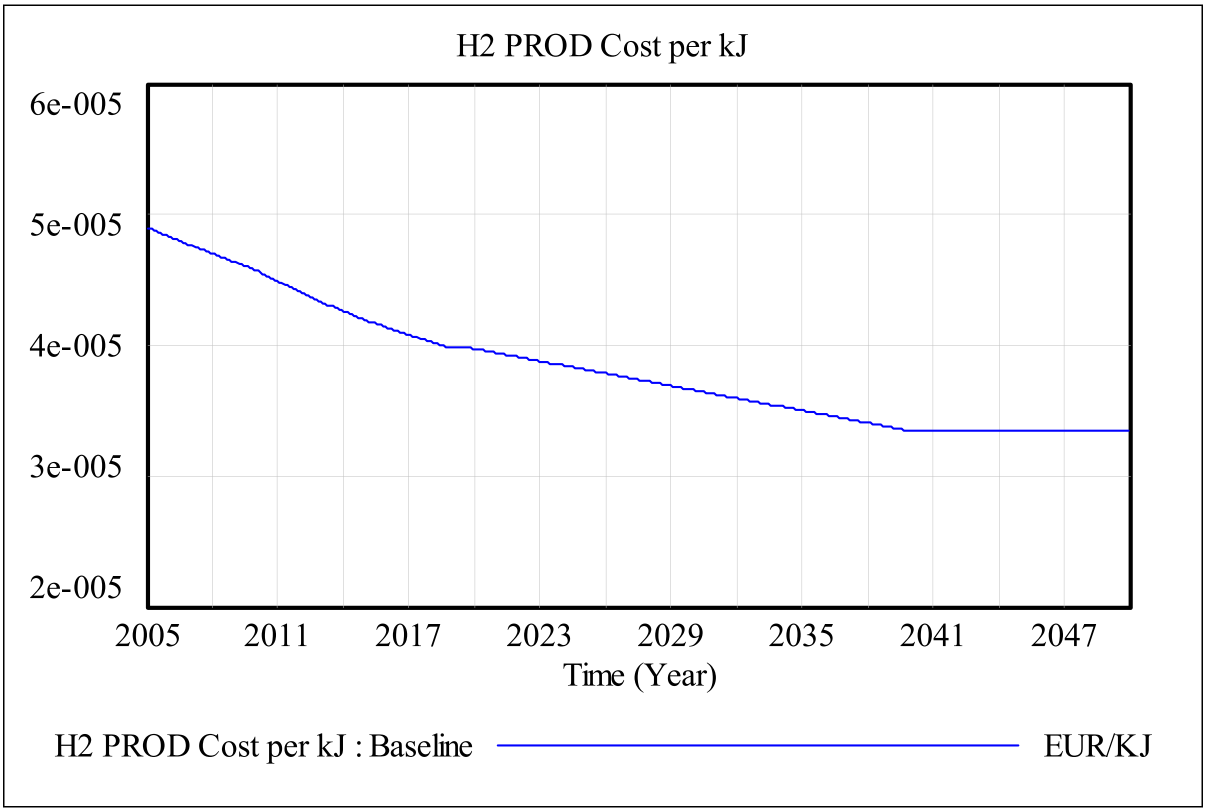

Figure 9: **Hydrogen production cost with wind-hydrogen strategy. The unit of the vertical axis is €/kJ.**

Figure 10 shows that the cost of using electricity alone (including the loss of revenues for not selling the wind electricity on the market) accounts for over 60% of the overall hydrogen production cost. Of note is the decrease in the relative contribution of direct wind electricity costs compared to lost revenues to the overall cost of using electricity from 2005 to 2050. This observation is further explained using Figure 11.

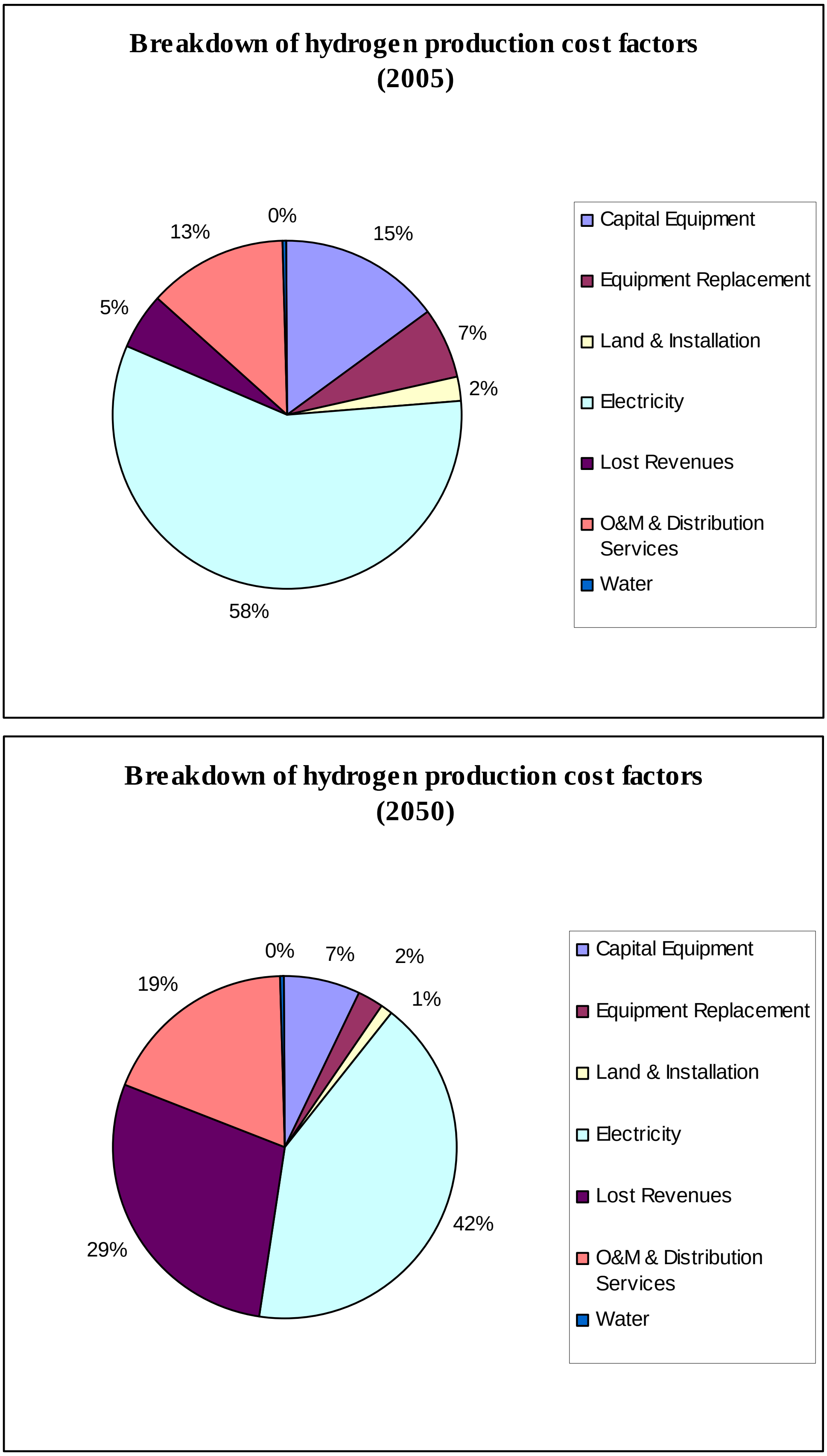

Figure 10: Relative importance of factors in determining the final hydrogen production cost (snapshot for 2005 and 2050)

Figure 11 shows a breakdown of the hydrogen production cost according to direct costs (fixed and recurrent costs) and indirect costs (lost revenue or opportunity cost). A distinct decrease in the cost of hydrogen production is observed over the period 2005 to 2050. The results of the model reveal that the major contributor to this decrease is the accumulation of experience (or technological learning) in the electrolyser market sector. From Figure 11 it is apparent that the annualised fixed and recurrent (direct) costs for the wind-hydrogen plant actually decrease as a result of decreasing electrolyser technology cost and, primarily, decreasing wind electricity cost due to learning in both cases. On the other hand, the cost of lost revenues (indirect cost) increases over time because, whereas wind electricity production cost decreases, the preferential price (grey electricity price plus green certificate price) it fetches in the market is assumed constant. This means that, in a situation where the price of wind electricity in the market is high, the potential revenue from selling wind electricity directly (as opposed to diverting it to the electrolyser for hydrogen production) increases. In other words, the opportunity cost of using the wind electricity for hydrogen production increases and the wind electricity is more valuable if exploited directly as electricity on the market. As a corollary, lower wind electricity market prices favour conversion to hydrogen. For a specific system, the impact of wind electricity price is best modelled using real-time economic data. This is further elaborated in chapter 12.

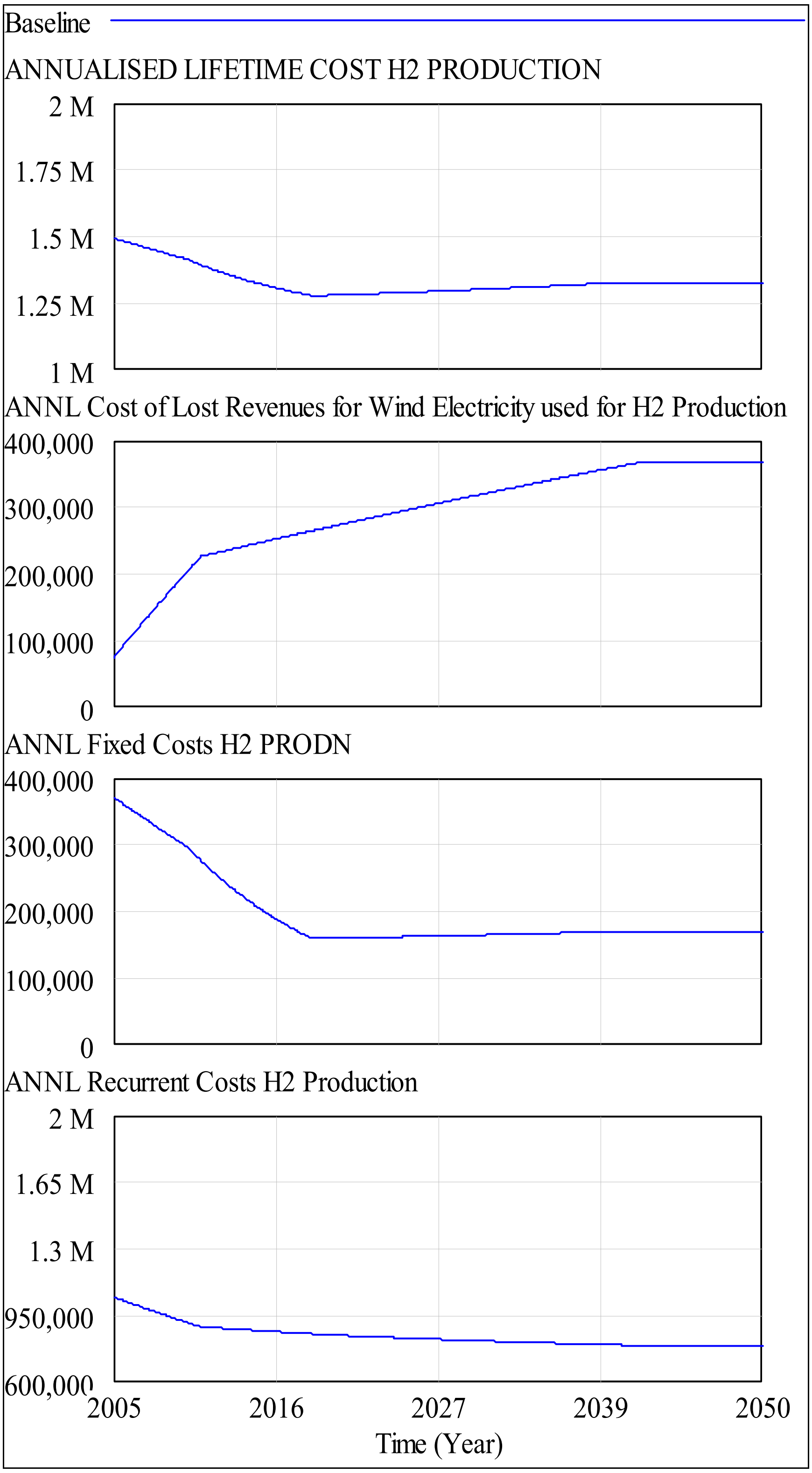

Figure 11: Breakdown of graph ‘Cost-benefit H2 sold’ (R_{H2}–LAC_{WH2}).The vertical axis unit is €/yr.

The uppermost graph is the hydrogen production cost (Annualised lifetime cost of hydrogen production), and is the aggregated sum of the following 3 inputs:

- Annualised cost of lost revenues for wind electricity (opportunity cost) – 2nd uppermost graph
- Annualised fixed costs for wind-hydrogen production – 3rd uppermost graph
- Annualised recurrent costs for wind-hydrogen production – bottom-most graph

Comparing the cost of hydrogen production via the wind-hydrogen system with that of steam reforming (see Table 4), the wind-hydrogen system appears to be highly uncompetitive, even in the long term. Hydrogen production via natural gas steam reforming on small scale is estimated to be currently around 11€/GJ and on large scale, roughly 4 €/GJ [24]. When internalising the carbon dioxide effect of this method of hydrogen production, the costs rise marginally to respectively, 14€/GJ and around 5 €/GJ currently. Needless to say, these results are also highly dependent on the cost of the natural gas raw material input to the process. However, it is clear that on the basis of hydrogen production cost alone, the wind-hydrogen system is not very competitive.

However, the attractiveness of the wind-hydrogen option must also consider the *overall* costs *and benefits* of the system, since the attractiveness also depends on the potential revenues from selling the hydrogen (Equation 19), and other benefits, such as improved network management (balancing) (Equation 22), that are not offered by alternative methods of hydrogen production, such as natural gas steam reforming. Moreover, natural gas as a resource for hydrogen production does not, unlike the proposed wind-hydrogen strategy, contribute in the way of security of supply. Although this latter benefit is not quantified in the cost-benefit analysis it is nonetheless a significant factor to bear in mind. The results for the overall cost-benefit assessment are considered in section 11.3 below.

Table 4: Cost of hydrogen via natural gas steam reforming (taken from [24] (original source: [31]))

	Large scale (78bar)	Small scale (340 bar)
Natural gas price(€/GJ)	*2.4*	*3.2*
Hydrogen Cost (€/GJ) Without Carbon Capture & Storage (CCS)	4.4 (current) 3.9 (future*)	11 (current) 8 (future)
Hydrogen Cost (€/GJ) With CCS (large scale) With CO_2** tax (small scale)	5.4 (current) 4.4 (future)	14 (current) 11 (future)

* Date not indicated

** CO_2 tax = 50 €/t CO_2 (The cost of hydrogen with CO_2 tax shown in the table is based on own calculation)

11.3 COST-BENEFIT OF WIND-HYDROGEN STRATEGY

The annualised cost-benefit result for the wind-hydrogen strategy, and the evolution with time, are shown in Figure 12 for the **baseline** (**scenario 1**) in successive reference years for the period 2005-2050. As expected, the overall annualised cost-benefit result improves with time as technological learning drives costs down.

In order to better understand the various factors that influence the evolution of the cost-benefit result, and to what extent they do so, the individual costs and benefits contributing to the overall result are shown in Figure 13. The figure shows a series of graphs. The uppermost graph represents the final cost-benefit outcome for the wind-hydrogen system, and all graphs below represent the various determinants contributing to this final cost-benefit result. In all cases the vertical axis denotes money, in euros per year (€/year), and the horizontal axis, time, in years (yr).

Recalling Equation 26:

$$CB_{WH2} = (R_{H2} + R_{BL} + R_{EMA}) - (LAC_{WH2})$$

We can see that:

- The uppermost graph, ‘Total cost-benefit wind’, represents CB $_{WH2}$
- The second uppermost graph ‘Avoided costs from CO_2 offset’, represents R $_{EMA}$
- The third graph ‘Cost-benefit H_2 sold’, represents (R_{H2} – LAC_{WH2})
- The bottom-most graph ‘Revenues from avoided balancing costs’, represents R_{BL}

From Figure 13 is clear that the most dominant contributing factor to the cost-benefit result is the cost-benefit outcome for the hydrogen sold to the market (third uppermost graph), that is, the difference between market price and production cost for hydrogen (R_{H2} – LAC_{WH2}). The negative value of the cost-benefit for *hydrogen sales* means that hydrogen production costs exceed the assumed hydrogen market price. As previously mentioned (section 11.2), the high hydrogen production cost is due primarily to the increasing opportunity cost (or lost revenues) with time of diverting saleable wind electricity for hydrogen production, as a result of (assumed) high wind market electricity prices. The hydrogen market price, if sufficiently high, could offset this cost, and is therefore an essential parameter to consider.

From Figure 13, one can see that, as expected, internalisation of carbon dioxide emissions and accounting for improvement for network management (balancing) have a favourable contribution towards the overall cost-benefit result. However, the effect compared to the other economic streams is lower by one order of magnitude, and even if the benefits from these streams were doubled (for example by a doubling of the carbon tax or the balance charge), the net overall effect would not change.

More detailed investigation, of other scenarios and the influence of various factors, is done in section 11.4.

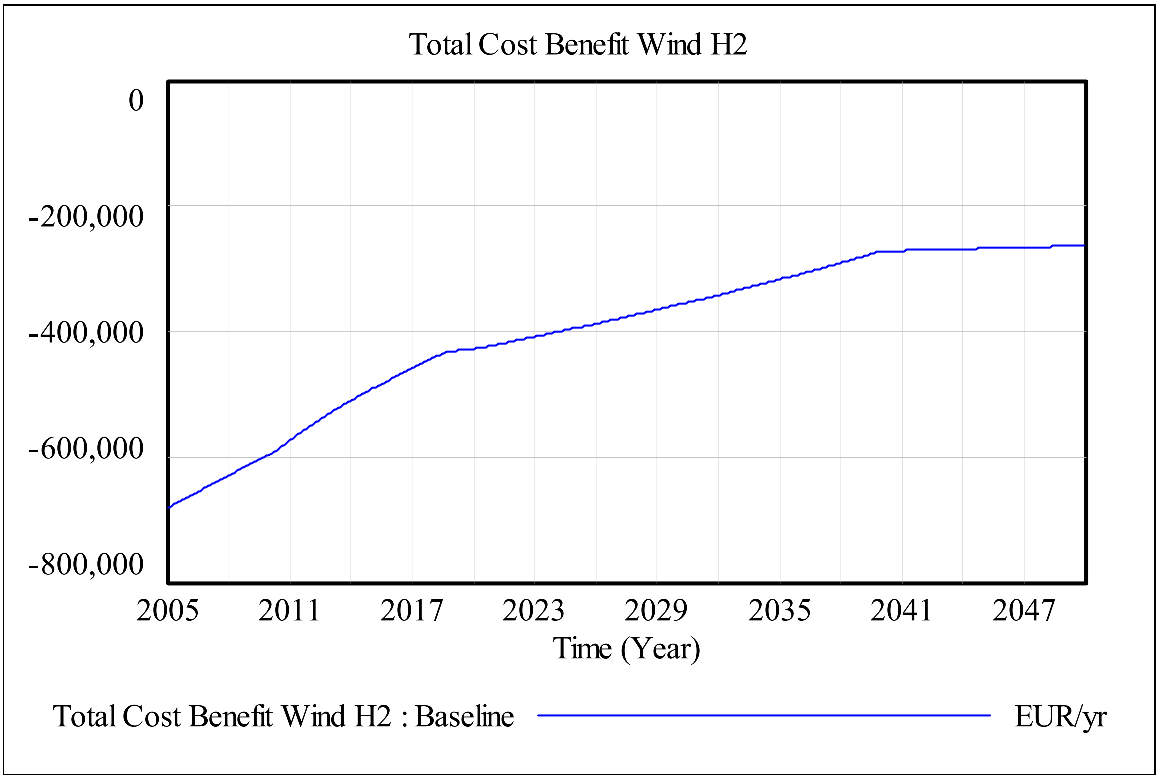

Figure 12: Annualised cost-benefit results for successive reference years (year of plant start-up) – Baseline Scenario (10% wind penetration). The vertical axis unit is €/yr.

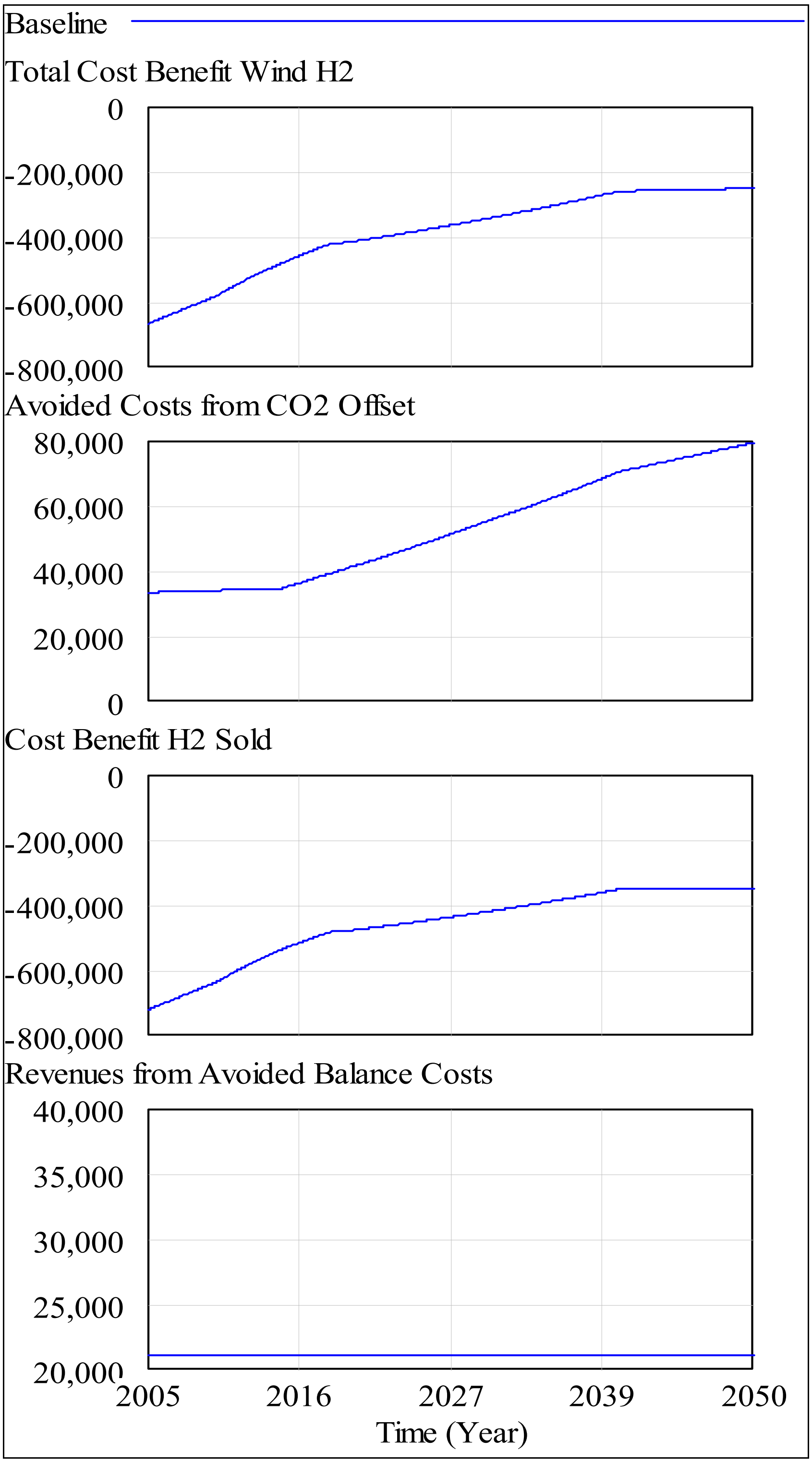

Figure 13: **Contribution of different costs and benefits to the overall annualised cost-benefit result. The unit of the vertical axis is €/yr.**

The uppermost graph is the overall cost-benefit result for a wind-hydrogen strategy (Total cost-benefit wind H2), and is the aggregated sum of the following 3 inputs:

- Avoided costs from CO_2 (carbon dioxide) offset – 2nd uppermost graph
- Cost-benefit H_2 (hydrogen) sold – 3rd uppermost graph
- Revenues from avoided balance costs – bottom-most graph

11.4 WIND-HYDROGEN TECHNOLOGY COST TO THE END-USER

The annualised cost-benefit result for consecutive reference years in the period 2005-2050 was translated into an equivalent impact or technology cost for the end-user, C_{USER}, allocated via overall electricity price (wind and non-wind electricity together) for the community of consumers served by the network in question. This technology cost was determined for the various scenarios outlined in chapter 10, namely:

- Scenario 1/ Baseline: Limit wind penetration, weak hydrogen/climate change push
- Scenario 2: High wind penetration, strong hydrogen/climate change push
- Scenario 3: High wind penetration, weak hydrogen/climate change push
- Scenario 4: Limit wind penetration, strong hydrogen/climate change push

The results for the impact on the end-user electricity price according to the various scenarios are shown in Figure 14 below. A positive value indicates that the end-consumer of electricity (and hydrogen) would have to subsidize the wind-hydrogen strategy – the absolute value indicating the amount by which the price paid for electricity would have to increase in order to accommodate the subsidy. A negative value means that, globally, the benefits from the wind-hydrogen strategy outweigh the costs, and that the consumer would benefit from reduced electricity prices, by the amounts indicated in the graph. The analysis of results, however, focuses primarily on the overall trends as opposed to absolute values of results obtained, since the latter are very dependent on the specific system configuration.

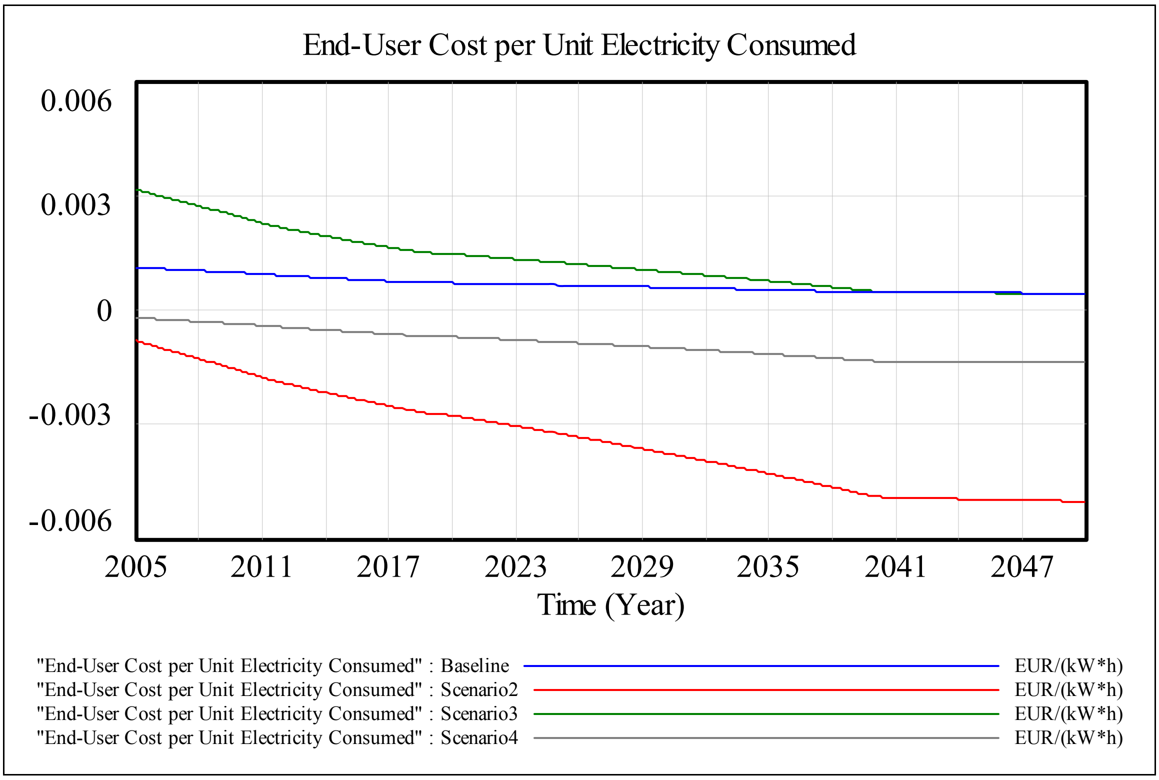

Figure 14: Impact on end-user electricity price, C_{USER}, of wind-hydrogen strategy. The unit of the vertical axis is €/kWh electricity consumed.

As expected, the trend in all scenarios is towards lower overall cost (or higher overall benefit) with time, as a result of technological advancement and learning.

In the baseline scenario, the wind-hydrogen strategy is not economically advantageous, although it can be considered as a borderline situation, approaching break-even. By way of illustration, for the specific system in question implemented in 2005, a subsidy of about 0.001 €/kWh or 0.1 €c/kWh for each unit of electricity consumed in the system, would need to be provided for the 20-year lifetime of the plant. This subsidy would decrease to around 0.05 €c/kWh for 2050 (all prices refer to 2005 money). Thus, for the situation where wind energy penetration is still relatively low and where there is no apparent economic incentive for renewable hydrogen and where carbon tax on fuels is relatively low, there is apparently no benefit to the end-user for adopting the wind-hydrogen strategy. The wind energy is seemingly more valuable if exploited directly on the electricity market instead of for producing hydrogen. The observation is also made for scenario 3 where wind power capacity in the system is greater, and where an even greater proportion of wind energy is diverted for hydrogen production. In this scenario, despite the fact that 50% of wind energy diverted for hydrogen production is wind energy that would be curtailed and therefore of no economic value, hydrogen production is the less attractive option. As shown in section 11.3 the (assumed high) price for wind electricity in the market has a direct implication on the model outcome: a change in the assumed average wind electricity price will produce a vertical shift in the trends for each of the scenarios, which could change the overall result for the end-consumer from one of cost to benefit if the a lower price is assumed to apply.

The presence (or otherwise) of a supportive framework is also important in the overall outcome. This can be observed in the results for the two borderline cases: the baseline scenario and scenario 4, where the existence of higher carbon tax and higher hydrogen market price are key to the turning point seen in a limit wind penetration situation from one of overall cost (baseline / scenario 1) to overall benefit (scenario 4).

Scenarios 2 and 4, where hydrogen market price and carbon tax are both relatively high, show an overall benefit for the consumer for adopting a wind-hydrogen strategy. In these situations therefore, the use of wind electricity for hydrogen production is more beneficial compared to its use for direct electricity consumption. For scenario 4, where there is only limit wind penetration, the wind-hydrogen strategy is only marginally attractive. For scenario 2, where wind penetration is 30% and where 50% of electricity diverted for hydrogen production (roughly 12% of all produced wind electricity) is assumed curtailed and would thus have no value, the consumer would benefit more significantly from the adoption of a wind-hydrogen strategy. The difference in attractiveness between these two scenarios highlights the impact of wind penetration level in the choice to implement such a strategy.

The effect of a wind-hydrogen strategy with respect to network management benefits through avoided balancing costs, and maximization of wind resource use, can be observed considering the end-user cost per unit of *wind* electricity produced in the system (refer to Figure 15). The figure shows a slightly more beneficial outcome for scenarios 3 and 2 (which both have high wind penetration), when compared respectively to scenarios 1 (baseline) and 4. Within each set of scenarios (baseline and scenario 3; scenarios 2 and 4) the conditions regarding the supportive framework are identical; the only difference being the level of wind penetration (and curtailment) in the system. The difference in attractiveness can therefore be attributed to the lower opportunity cost of wind (since the curtailed wind has no value) and the avoided balancing costs. The benefit of a wind-hydrogen strategy, in terms of balancing costs and wind resources use, is therefore more pronounced for higher wind penetration situations.

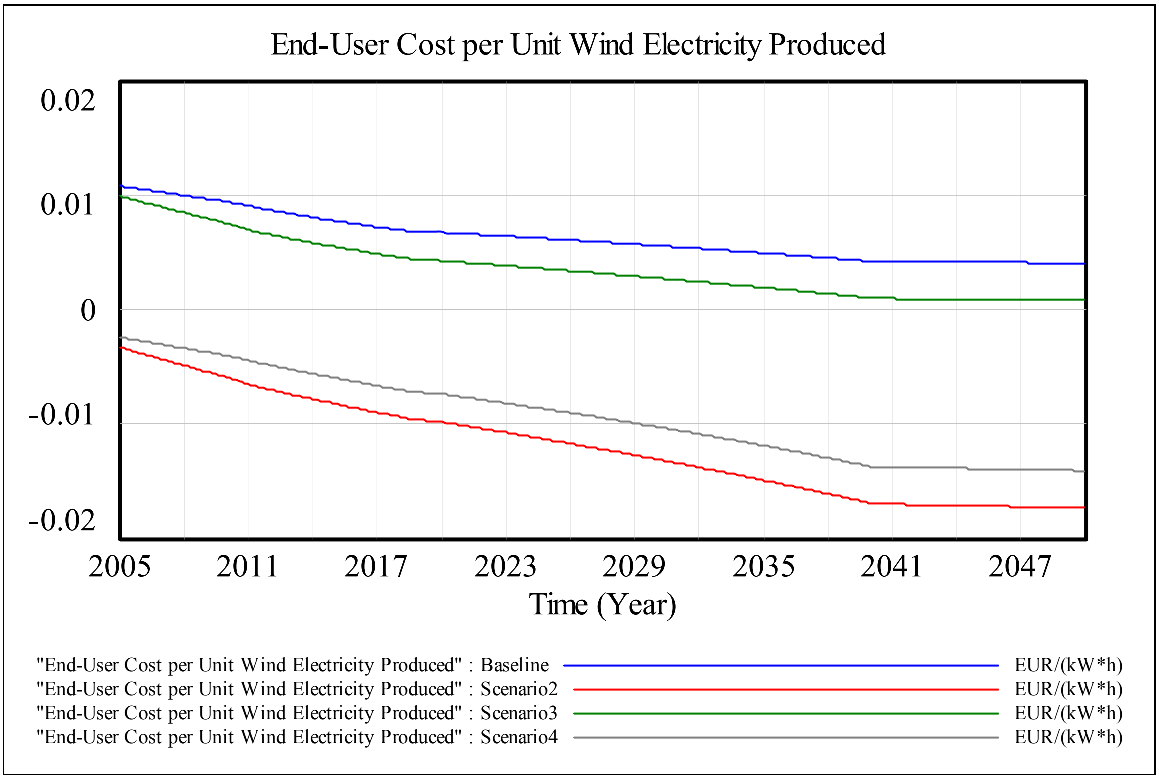

Figure 15: Impact of wind-hydrogen strategy in terms of technology cost per unit wind electricity in the system, C_{WIND}. The unit of the vertical axis is €/kWh *wind* electricity produced.

11.5 SENSITIVITY ANALYSES

Sensitivity analyses were performed to test the impact of the values used in the model for the following selected parameters:

- Discount rate, i
- Effect of wind market growth on electrolyser market growth, $f_{W\text{-}ELYZR}$
- Green certificate price, $S_{RES\text{-}E}$

Univariate sensitivity testing is conducted for each of the parameters, based on the baseline scenario. For each parameter, the model is run a number of times, each time using a different value for the given parameter, the value being selected at random by the model from a defined range of values (the minimum and maximum values of which are decided by the modeller). For each model run, the result (in terms of the end-user cost per unit electricity consumed) is plotted. In so doing, a range of possible outcomes is displayed. The outcome of the model with the baseline situation (indicated in the figures below by a blue line) is also displayed. In this way it is possible to gauge the extent to which the assumed values are important for the outcome of the analysis.

Discount rate

The effect on the outcome of the model was tested for discount rates of 5 to 10%. The results, depicted in Figure 16, show that in relative terms, the discount rate does not have a significant effect on the outcome, since doubling the discount rate from 5% to 10% results in only approximately a 15% increase in the overall end-user cost. This is not surprising since, as illustrated Figure 10 and Figure 11, and explained in section 11.2, the costs in the analysis are dominated by non-capital related costs, for which the discount rate has no impact (refer also to Equation 11).

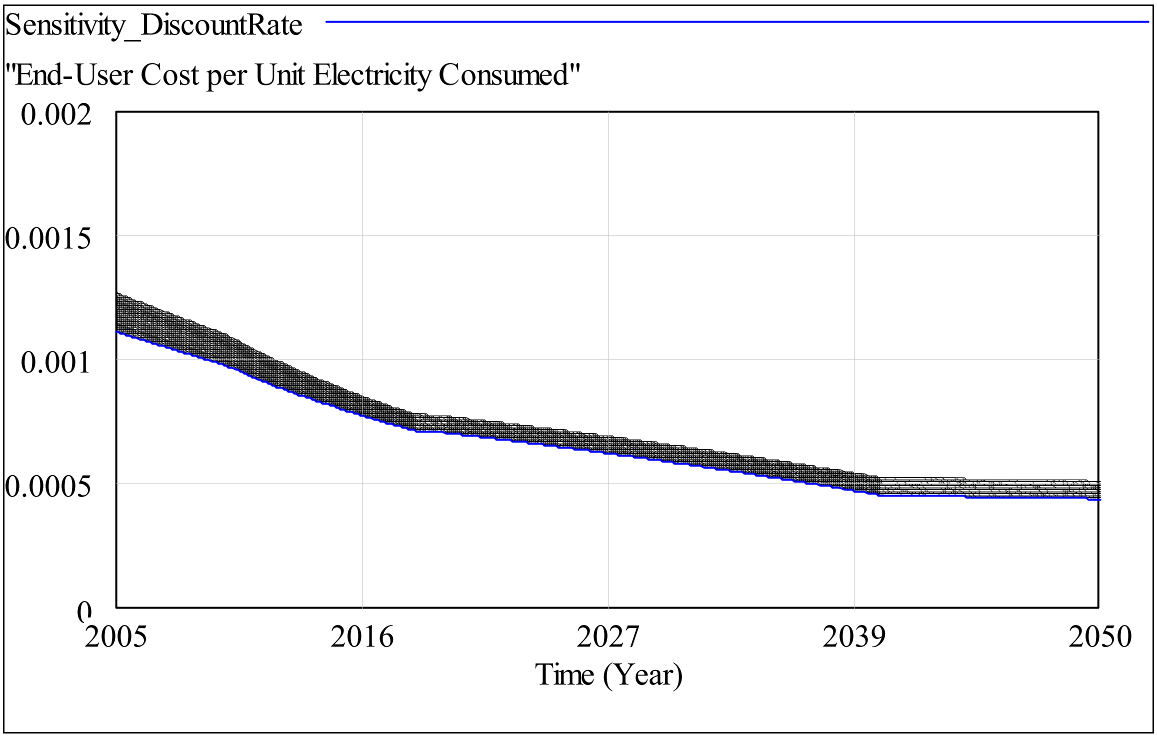

Figure 16: Sensitivity analysis for discount rate (5-10%). The unit of the vertical axis is €/kWh electricity consumed.

Effect of wind market growth on electrolyser market growth

The effect on the outcome of the model was tested for different levels of inter-market effect between 0% and 100%, that is, the model was tested assuming that each doubling in wind power capacity in the European Union would, at a minimum, directly result in 0% additional growth in the electrolyser market or, at a maximum result, in 100% additional growth (or a doubling) in the electrolyser market. The results of the sensitivity test (see Figure 17) show that, as expected, higher feedback effects result in lower end-user costs. The lower end-user cost is the result of increased electrolyser market growth (due to wind energy market growth), which increases the accumulation of experience, and cost reductions, in electrolyser technology. Notably, however, once a certain level of end-user cost is attained (approximately 0.007 €/kWh) there is no apparent influence of the inter-market effect (whether inter-market effect is 0% or 100%) on end-user cost. This insensitivity of the outcome is due to the fact that the electrolyser technology cost is assumed to have a floor of 200 €/kW. For the baseline parameters, the rate of experience accumulation means that this minimum electrolyser cost is achieved by around 2019. With a doubling of electrolyser market for each doubling of the wind energy market (100% inter-market effect) the 200€/kW minimum is achieved by 2014, whereas in the absence of an inter-market effect the minimum is achieved by 2021. Higher levels of inter-market effect therefore serve to accelerate the cost reduction process for electrolyser technology, enabling it to attain maturity earlier. Once market maturity is attained technology cost is considered stabilised and further growth in the electrolyser market does not have an impact the final end-user cost.

Green certificate price

The effect of the green certificate (GC) price was tested for values between 0 and 90 €/MWh. The results (see Figure 18) show that the outcome is very sensitive to the model value used for the green certificate price. A 200% increase in the GC price from 30 €/MWh (baseline model value, indicated by the blue line in the diagram) to 90 €/MWh (the upper most line in the diagram) results in approximately a 150% increase in end-user electricity cost as a result from the wind-hydrogen strategy (from approximately 0.001 €/kWh or 0.1 €c/kWh to approximately 0.0025 €/kWh or 0.25 €c/kWh for each unit of electricity consumed in the system). A similar proportional effect is seen if the green certificate price is decreased. This is explained by the fact that the green certificate price is a significant part of the overall price that wind electricity can attract on the market, which itself is a crucial factor in determining the opportunity cost (or lost revenues) of using wind electricity for hydrogen production as opposed to for direct consumption. As was shown in Figure 11, this cost (lost revenues) stream is a major factor in the overall cost-benefit result.

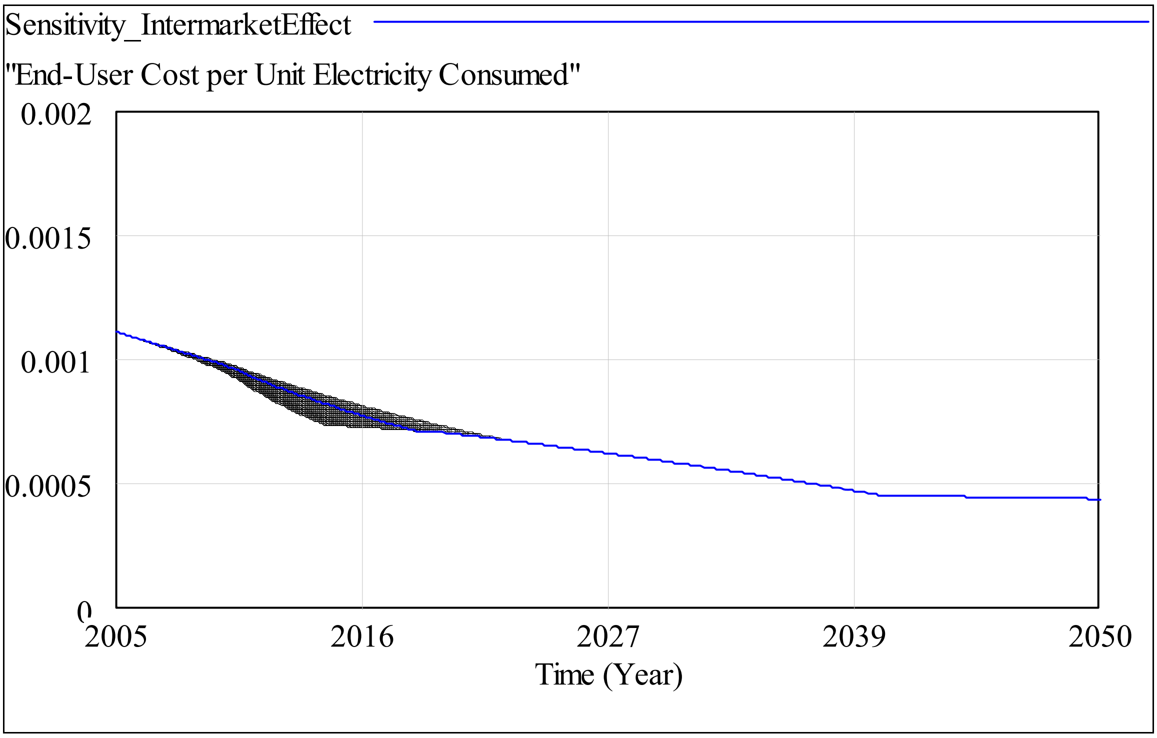

Figure 17: Sensitivity analysis for the effect of wind market growth on growth in the electrolyser market. The unit of the vertical axis is €/kWh electricity consumed.

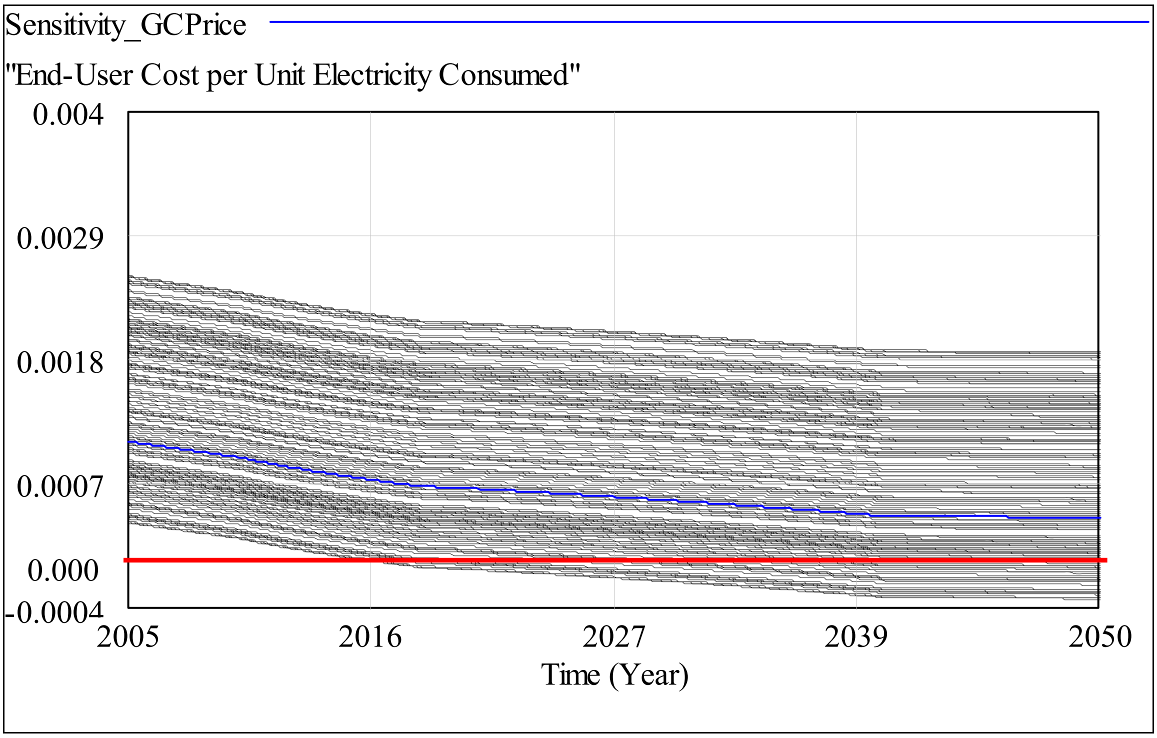

Figure 18: **Sensitivity analysis for green certificate price. The unit of the vertical axis is €/kWh electricity consumed.**

12 LIMITATIONS OF THE ANALYSES AND RECOMMENDATIONS FOR FUTURE WORK

The intention of this study is to establish the main considerations, and their relative importance, for the exploitation of synergies between the European wind and hydrogen markets in the long term. It considers specifically the diversion of the wind electricity, as a wind power control mechanism in high wind penetration situations, for the production of renewable electrolytic hydrogen, itself interesting as a component of a renewable-hydrogen-inclusive economy. The study establishes the potential synergy between the two markets, and the boundary conditions for detailed analysis of exploiting this synergy, termed the "wind-hydrogen strategy".

There are a number of limitations to this study that should be taken into account when considering the results. The over-riding consideration is the fact that the key parameters for the analysis are very system-specific, and the outcome for different system configurations can be very different. A study such as this one, conducted on a generic basis, highlights the most important factors influencing the outcome of the analysis but cannot be used to make conclusions about specific systems. One major, system-specific aspect that should be considered is the basis used for the determination of eligible wind electricity for hydrogen production. The use of a fixed power level as the threshold is not necessarily the most logical approach, from the point of view of network management or a specific system's operation. It is more likely that the decision to divert electricity for hydrogen production would be made on the basis of forecast versus actual real-time wind power production, as explained in section 3.2.1. This would, amongst other things, enable the use of a smaller electrolyser, lowering capital costs and increasing capacity factor usage. Another system-specific aspect is electricity prices, which vary depending on physical factors (e.g. extent of interconnection of the specific network area) as well as on policy and market influences (e.g. the mechanisms determining final wind electricity price, e.g. whether feed-in tariff, green certificate systems, or other market-based mechanisms). Since electricity prices play a major role in the final outcome, it is expected that results could differ significantly from those obtained here, if physical and market conditions would significantly alter the wind electricity price compared to the one used in the current analysis.

Another consideration that should be made is that some aspects have not been taken into account, or only in a very rudimentary manner, due to the complexity and uncertainties of the system being modelled. For example, the boundary for the analysis is taken at the plant gate, with no detailed considerations given to additional costs for transportation and in particular distribution/dispensing of hydrogen to the end-user. This would add further to the overall cost of the wind-hydrogen strategy. Other factors that could enhance the benefit of the wind-hydrogen strategy are also not taken into account, for example the exploitation of the oxygen product from electrolysis, or the internalisation of security of supply aspects. In addition, it should be taken into account that certain factors, considered constant for the purpose of the analysis, would in actual fact be expected to experience significant variation on an annual and even daily or hourly time scale, for example: green certificate price, grey electricity price, balance costs, the value of curtailed wind energy (which may in fact be negative) etc. Other factors are even entirely uncertain, such as: hydrogen market price, hydrogen demand, performance and cost expectations of PEM technology (which is more relevant for this type of electrolyser application), not to mention technology breakthroughs that could significantly change the attractiveness of this (but also competing) options.

While it is not the intention of this study to consider in detail all of these aspects, some of these considerations should be taken into account for conducting future work. The following recommendations are therefore made for further investigations in the future:

- Analysis with real-time system and economic/market data, in particular for shorter (e.g. hourly) time scales. This would enable more accurate analysis for specific systems and different approaches for network management, taking into account amongst others:
  - Real-time wind power prediction error (actual production exceeding forecast production) to act as the decision basis for the diversion of wind for hydrogen production
  - Real-time electricity prices
  - Real-time balance costs.
- Re-conversion of part or all of the produced hydrogen into electricity to be fed into the network, for example:
  - during periods of high electricity demand (when higher electricity prices could be obtained); or
  - for "active" grid balancing, to compensate for unforeseen under-production of wind power (actual production is lower than forecast production)
- Extension of the analyses for the case of offshore wind farms
- Internalisation of security of supply benefits
- The potential for exploiting the oxygen by-product, for example in the energy (combustion) and medical (e.g. hospitals) sectors

13 CONCLUSIONS

The results show that the most dominant factor in the wind-hydrogen production cost, and in the final end-user cost, is the cost (both direct and indirect) of using wind electricity. The indirect cost or opportunity cost of using wind electricity for hydrogen production as opposed to direct electricity consumption is the most decisive factor in the long term for the hydrogen production cost and is a significant factor in the overall cost-benefit result and in the end-user cost (or benefit). The price that is expected for wind electricity in the market is therefore central to the attractiveness of a wind-hydrogen strategy.

The results also indicate that, if successfully executed in parallel to wind energy deployment, the wind-hydrogen strategy can accelerate the attainment of critical mass (and associated cost reductions) in electrolyser technology, enhancing the perspectives for this pathway in the short to medium term. With respect to the onshore wind energy market, which is expected to experience a decline in growth after 2010 eventually reaching saturation in the next few decades, initiatives would need to be taken in the short term if the wind-hydrogen synergistic effect for electrolyser cost reductions is to be successfully exploited.

The market price for hydrogen is another major factor in the cost-benefit outcome and will therefore be a primary consideration for the adoption of the wind-hydrogen strategy. The internalisation of environmental benefits of the renewable (wind) hydrogen and accounting for benefits from improved network management with the wind-hydrogen system also contribute positively to the overall cost-benefit outcome, however, the effect is much smaller. Clearly, however, a supportive framework for renewable fuels (via a carbon tax), and a sufficient market price for hydrogen, will positively influence the linking of wind and renewable-hydrogen markets.

Finally, it is important to bear in mind the limitations of a generic analysis such as this one, which may not reflect the situation for specific systems; site-specific data and analyses will be key to the final decision-making process.

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§ European Commission, Joint Research Centre, Institute for Energy

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Abstract

The study establishes the link between the growing wind market and the emerging hydrogen market of the European Union, in a so-called “wind-hydrogen strategy”. It considers specifically the diversion of wind electricity, as a wind power control mechanism in high wind penetration situations, for the production of renewable electrolytic hydrogen – a potentially important component of a renewable-hydrogen-inclusive economy. The analysis examines the long-term competitiveness of a wind-hydrogen strategy via cost-benefit assessment. It indicates the duration and extent to which (financial) support, if any, would need to be provided in support of such a strategy, and the influence over time of certain key factors on the outcome.

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