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Economic evaluation of hybrid off-shore wind power and hydrogen storage system

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ABSTRACT

This research evaluates the economics of a hybrid power plant consisting of an off-shore wind power farm and a hydrogen production-storage system in the French region Pays de la Loire. It evaluates the concept of H2 mix-usage power-to-X, where X stands for the energy product that hydrogen can substitute such as gas, petrol and electricity. Results show that a complex H2 mix-usage design would increase investment cost in too many infrastructure components and would significantly decrease the profits. Resizing the project would result in providing two energy products only, such as power-to-power and power-to-gas or alternatively power-to-mobility and power-to-gas services. Hydrogen production costs of selected projects would range between 4 and 13 €/kg of H2 as a function of the application type, of oil and gas prices and of expectations of a further reduction in the electrolyser and fuel cell investment costs.

Introduction

The development of hydrogen production and storage has emerged worldwide with the increasing prices of oil and gas, with renewable energy deployment and concerns over the security of energy supply. Moreover, clean hydrogen could reduce carbon emissions, in substitution to coal, gas and oil, and could reduce the local pollution from road traffic as well [1]. Hydrogen could support the integration of intermittent renewables, by avoiding power curtailment, electricity grid congestion and by improving the system reliability in remote areas [2,3].

In Europe, the Fuel Cells and Hydrogen Joint Technology Initiative has been launched in 2008 as a public private partnership aiming to accelerate the market introduction of hydrogen technologies by supporting research, development and demonstration activities.[1] Among European Union Member States, Germany, Spain, UK and France have developed various pilot plants of hydrogen production and storage; for an international review of hydrogen pilot plants see Gahleitner [4]. In France, the national Association for Hydrogen and Fuel Cells has been created in 1998 for supporting the development of hydrogen technologies and fuel cells.[2] At a regional level, in the French region Pays de la Loire, the initiative *Mission Hydrogène* has been launched since 2005 several demonstrator projects on hydrogen uses for marine and fluvial applications.[3]

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1 http://www.fch-ju.eu/.
2 http://www.afhypac.org/fr/accueil.
3 http://www.mh2.fr/en/.

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Hydrogen can be used to produce electricity (power-to-power), it can be injected into a natural gas pipeline network (power-to-gas), it can fuel natural gas power plants or the production of second generation biofuels (power-to-fuel), and it can be used as a fuel in transportation (power-to-mobility). This research develops the concept of power-to-X and evaluates to what extent revenue sources could increase from multiple hydrogen usage on different energy market segments.

The research on the economics of hydrogen shows different perspectives for the market development, based on different cost ranges. The overall cost of hydrogen includes the hydrogen conditioning, compression, storage and distribution. Hydrogen technologies have high investment costs and also high energy losses during power to hydrogen and hydrogen to power conversions. Moreover, when combined with intermittent renewables, the technical lifetime of the electrolyser could be further reduced [5].

The hydrogen cost varies from 5 €/kg to 30 €/kg of H2 as a function of the size of the equipment. A large-scale hydrogen plant could reduce this cost at 3 €/kg of H2 produced for an electricity cost of 40 €/MWh [6]. The most important cost part is the fixed cost of investment. As for variable costs, the most important component of the production chain could be the cost of the electricity input.

This research investigates the case where the power used to generate the hydrogen comes from renewable energy and it is infed at zero cost. The case study consists into a contractual arrangement which is hybrid system-specific, where the two wind and hydrogen operators share their costs and benefits. The economic evaluation is based on the optimal operation of wind power and hydrogen production by means of a dynamic operational optimization model which maximizes revenues from several energy markets. A set of technological and economic constraints apply, from both demand and supply sides. The demand for hydrogen is estimated by assuming that hydrogen substitutes for primary and secondary energy sources, such as natural gas, electricity and fuel for marine and road transportation. On the supply side, the wind flow constraints the power generation used for the hydrogen production. At equilibrium, the issue is to constantly match the intermittency of the wind power with the continuous demand for hydrogen in the case of fixed commitment with refuelling stations for cars and fishing vessels.

The paper is organized as follows. The section Study case describes the study case and the database, the section Methodology details the model and the section Result analysis discusses results and policy implications. The concluding remarks show under what conditions hydrogen storage may be viable as a future investment option to help managing systems with intermittent renewable generation and to substitute scarce and carbon-emitting fuels such as gas and oil.

Study case

Description of the infrastructure

Within its National Renewable Energy Action Plan, France has committed to achieve a 23% share of the energy generated by renewables in its final energy consumption by 2020 [7]. Among energies from marine sources, off-shore wind power will represent around 6000 MW to be installed off the French coast.

The study case considers an off-shore wind power farm installed in the area of Saint-Nazaire, a French region with large off-shore wind potential and no grid interconnections to other countries. The base case assumes the large-scale deployment of off-shore wind turbines of 1 GW by 2030, and the development of hydrogen fuel cells as a technical support to the wind power integration. This is a hypothetical project where a storage facility is built close to the offshore wind farm that is connected to the rest of the power system via a dedicated transmission line. The study investigates the design of the wind-storage-transmission system such as to reduce the wind power curtailment occurring because of limited grid line capacity. The power can be transmitted to the grid by either the wind plant or the storage-fuel cell component of the hybrid plant (see Fig. 1). During periods with no wind, the power needed to produce the hydrogen could be withdrawn from the grid.

One of the current challenges is to supply electrolysers with power from intermittent energy sources, in particular when the power supply is below its idling threshold, e.g. 25% of the rated power [8]. Fell et al. [9] have demonstrated that a pressurized alkaline electrolyser and wind energy system can improve the ability to capture the fast variations in wind power production with a quick response time (<1s) and a broad operational range (10%–100%). In front of massive deployment of hydrogen and wind or solar power farms, there is a need to develop appropriate control strategies such that the electrolysers achieve full dynamic range of rated power.

There are several technological options for providing electrolytic hydrogen, such as the alkaline electrolysis, the polymer electrolyte membrane electrolysis, the alkaline polymer electrolyte water electrolysis, or the solid oxide electrolysis. They each have advantages and drawbacks making the integration of large scale off-shore wind energy challenging [10]. The alkaline electrolyte is a well mature technology and the most extended at a commercial level worldwide, while the polymer electrolysis would respond more quickly to the power input and thus being suitable to support intermittent energy integration. However more research is needed to develop these technologies, to enhance their durability and to further reduce costs.

In this paper it is assumed that a polymer electrolyte is coupled with the off-shore wind energy source and that by 2030 the system achieves full range of rated power. Two compressors are used, one of 200 bar pressure for power-to-power provision, and one compressor of 700 bars for the power-to-mobility application.

Compressed hydrogen is supplied to the gas network or to the storage tanks adapted to each pressure type (200 bars and 700 bars). The auxiliary equipment includes also a fuel cell for the electricity generation which will be supplied to the local grid. Efficiency rates are reported in Table 2 along with the investment cost of the components.

Wind power potential

The wind farm consists of more than 160 *Haliade*^{TM}*150-6 MW* turbines with a total installed capacity of 1000 MW. The

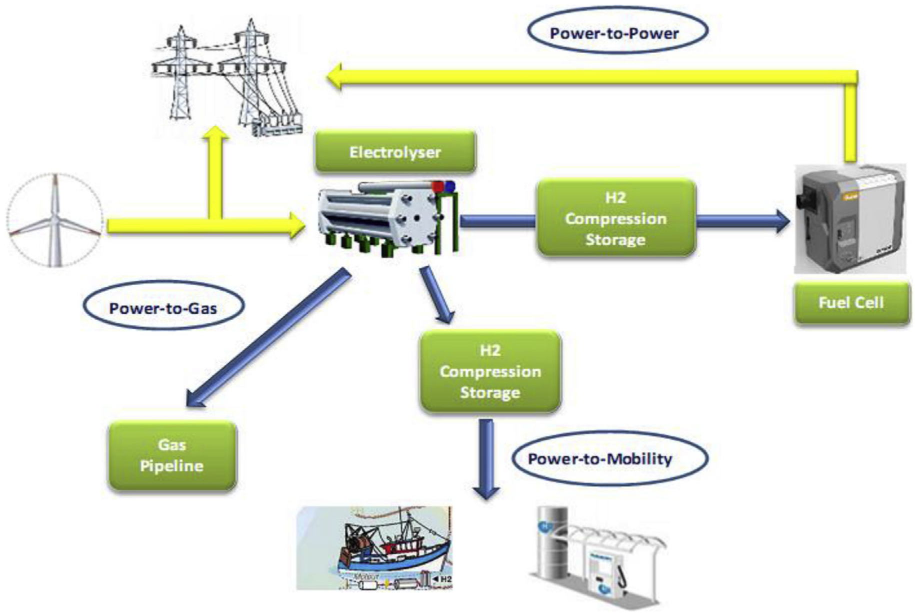

Fig. 1 – The H2 Power-to-X architecture.

database of the wind power potential consists of data provided by a weather station in 2013, which is located 40 km from the wind farm, on Belle-Ile Island, at an altitude of 34 m. The data is collected at hourly step and relates to the wind speed, temperature, relative humidity and air pressure. Wind data is adjusted for an altitude of 100 m corresponding to the hub height of each machine. Under physical limitations of wind availability, energy conversion, component efficiencies and mechanical losses, a total capacity factor of 36% is obtained.

The next part analyses the intermittency of the regional wind power potential. Fig. 2 compares two sets of hourly wind power generation data for the month of January: the blue line represents the potential production of the offshore wind power cluster, whereas the red line shows the actual electricity generated by all the onshore wind farms installed in France in 2013. While it is possible to have no electricity generation offshore locally, the onshore production is always positive due to uncorrelated wind flows at a national level. This comparison shows that the off-shore regional potential displays more intermittency, both in frequency and in amplitude, than the on-shore aggregated wind power, justifying therefore the need for back-up or storage capacities. At a national level, it is the residual intermittency, defined as the remaining fluctuating output that cannot be transported by the grid line, which may endanger the network stability.

Fig. 3 shows the wind excess which cannot be transported by the grid during one month. Variable electricity generation of the offshore wind power cluster is plotted against the ongoing building of a 225 kV grid line in the region of Saint-Nazaire, in the western part of France [11]. All the power generation above 450 MW represents an excess which cannot be transported through the line, due to grid congestion. Calculations show a potential of 35% wind power curtailment out of the total wind potential, which could partly be used for producing the hydrogen. Indeed, only a share of the wind excess could be used, due to the limited capacity of the hydrogen plant to absorb the entire wind surplus flow. When the system records wind in excess during several consecutive hours, the hydrogen storage capacity might attain the filling limit, implying that periods with wind curtailment would occur anyway.

The experience with the hydrogen pilot-plants shows that the design and sizing, control and system integration of hydrogen plants have a great influence on their overall efficiency, reliability and economics [4]. Next, the project sizing has as starting point the optimisation of the operation of the wind-hydrogen plants such as to generate profits and to supply the necessary hydrogen volumes matching the energy demands.

Table 1 – Demand for hydrogen by market type.

Usage	Demand t H2 during one year	Assumptions
Power to Power	No fixed demand	Hourly constrained by the grid line capacity (450 MW)
Power to Gas	No fixed demand	Hourly constrained by the pipeline capacity
Power to Road	117	The gas station supplies 300 vehicles and 6 buses.
Power to Shipping	102	The refuelling station supplies 18 small boats and 3 big capacity ships, with autonomy of 24 h and 48 h respectively.

Table 2 – Cost and efficiency specifications of wind-hydrogen technology components.

Technology	Investment cost, €/MW	Efficiency, %
Wind plant	2,000,000	99%
PEM Electrolyser	2,000,000	65%
Compressor 200 bars	2,000,000	91%
Compressor 700 bars	2,200,000	85%
Storage 200 bars	1,000,000	90%
Storage 700 bars	2,000,000	90%
Fuel cell	1,000,000	55%

Source: Ademe [18], Menanteau et al. [19].

Methodology

A dynamic operational optimization model is built to maximize the incomes from selling wind power and hydrogen on the market, under technical and economic constraints of the wind inflow, the transmission grid line and the installed capacity of wind and hydrogen plants.

The model

The computational model simulates the operation of wind power and hydrogen plants, by means of a dispatching dynamic model. The objective function is set to optimize the hourly operation of both electricity generation and storage over one year, with 8760 time slices. The model is implemented in GAMS, using the solver CPLEX [12]. Details of the model can be found in the Annex 1.

The model is deterministic and aims to maximize the annual value of both wind and hydrogen, i.e. revenues less operating costs, given exogenous hourly power price, annual oil and gas prices, and the hourly wind power potential. As a price taker, the storage does not influence the wholesale electricity prices. The hybrid power system operates with perfect information on the power price over one year. Market conditions are defined with respect to the market drivers such as the evolution of the spread of wholesale electricity prices between peak and off-peak periods, and the share of the storage capacity sold on the reserve market.

The model reports whether investing in the hybrid wind-hydrogen system would be cost effective in the base case scenario. The investment in the wind and hydrogen plants is not a decision variable in the model. Rather the plant capacity is specified exogenously according to the on-going off-shore wind power projects and to commitments to install additional capacity in the future, cumulating 1000 MW in 2030. As for the hydrogen plant, several iterations are made for different values of the installed capacity until the best profitability is obtained. The best case is selected combining the components of the hydrogen plant with the fixed wind power capacity of 1000 MW.

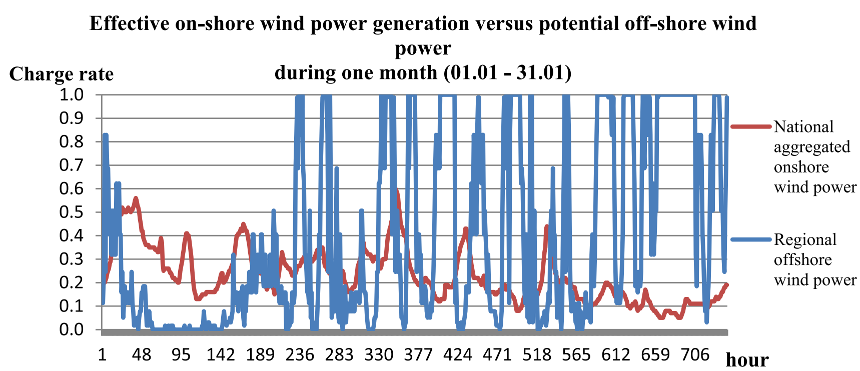

Fig. 2 – Fluctuation of effective on-shore wind power and potential off-shore wind power.

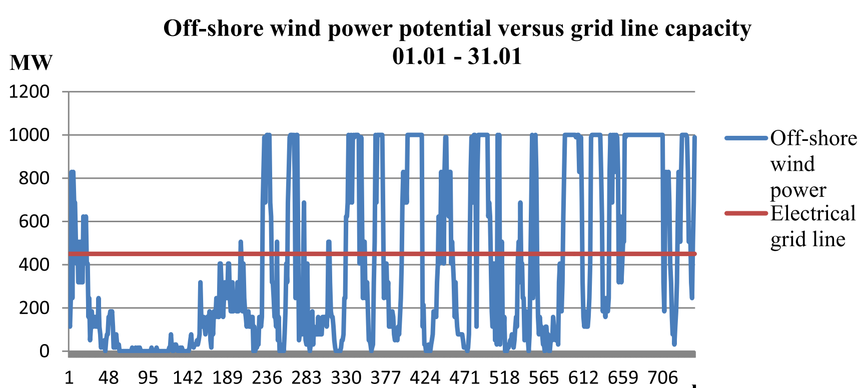

Fig. 3 – Representation of the potential wind power and the grid transmission line during one month.

The profitability is assessed by summing up all hourly revenues, net of costs, recorded during one year, which is 2030, assuming that the same behaviour is reproduced during the entire lifetime of the system. The case could be considered as an average of the multiple up and down variations, streaming from the wind energy inflow, power prices, and oil and gas prices.

The economics of the project is assessed by calculating a uniform €/MWh value of the hybrid plant over its economic lifetime, by means of the net present value (NPV) indicator. The NPV indicator is calculated as the difference between the present value of the cash inflows and outflows during the project's economic life, and the investment cost, divided by the plant's discounted net generated electricity:

$$NPV = \frac{\sum_{t=1}^{T}\left[(REV_t - COST_t)/(1+r)^t\right] - INV_0}{\sum_{t=1}^{T}\left[EG_t/(1+r)^t\right]}$$

where t is the year, T the economic life in years, REV the annual revenue from the sale of energy, COST is the annual cost of operation including the electricity cost (if any) and the variable operational and maintenance cost, INV_0 is the total investment cost (reported in Table 2), EG is the annual electricity sold on the market, and r is the discount rate, set at 10%.

Revenues streams are from the energy provision to the wholesale market, and from the capacity reserved and from the power provided as ancillary service to the System Operator. The wholesale market price is endogenously computed in a separate multi-unit power plant dispatching model described in Ref. [13]. In this national-wide dispatching model, a carbon tax is applied according to the 2030 policy scenario described in EC [14], where the carbon price is projected to reach 35 €/tCO2 in 2030.

For the reserve provision, it is considered that both secondary and tertiary reserves are supplied to the System Operator. Prices are regulated at fixed rates of 18.12 € by MW by hour for the capacity and of 10.43 € by MWh for the energy delivered [15]. From the perspective of hydrogen operator's strategy, the fuel cell capacity reserved to the secondary reserve market is restricted at 5% of the total capacity; while 5% more of the total capacity is reserved for providing the tertiary reserve market. The remaining 90% of the fuel cell capacity is used for bidding on the wholesale power market at fluctuating prices. From the reserve demand side, the System Operator might not rely high shares of reserves on a single technology or on a single device, thus limited volumes are expected.

Costs are considered in terms of their variable and fixed components. Variable costs account for the power withdrawn from the grid, and the variable costs of the system operation. During periods with no wind power, the power can be withdrawn from the grid and it is paid at the market price. Fixed costs account for the fixed annual operating and maintenance costs, and for the investment costs (see Table 2).

Scenarios in 2030

The main assumptions made in the scenarios for 2030 (described in the section 3.2.1) concern the energy demand (3.2.2), the cost structure (3.2.3) and the price evolution (3.2.4).

Scenarios description

Several scenarios are built for the year 2030, assuming different architectures of the hydrogen system as a function of the energy applications which are covered.

1. A first scenario assumes a complex system power-to-X providing all power, gas and fuel applications, *SCE_H2-to-X_Wind*.
2. A second scenario assumes each of the three applications individually, in order to evaluate the cost and the benefits on each market segment, *SCE_Power*, *SCE_Gas*, *SCE_Fuel*.
3. Combinations of energy applications are performed in order to diversify the supply, *SCE_PowerGas*, *SCE_FuelGas*. A third combination could be possible also, consisting of H2-to-power and H2-to-fuel applications, but the infrastructure would be too heavy, since it would need both types of compressor and storage facilities, at 200 bars and at 700 bars.
4. For comparison purposes, we test the case where the power used to produce the hydrogen is withdrawn from the power grid, *SCE_H2-to-X_alone*. In this case, the power used by the electrolyser has a cost, which is the market power price. All the above-mentioned energy applications (H2-to-X) are provided by the hydrogen operator in this case as well. However, the contribution of this test is to make the contrast with the wind power generated offshore which is used for free to produce the hydrogen in the first scenario, *SCE_H2-to-X_Wind*.
5. Finally, let us consider the case where the wind power operator acts alone, without the support of the hydrogen production and storage plant, *SCE_Wind_alone*.

The energy demand

Table 1 summarizes the assumptions on the demand for hydrogen by energy type.

Demand for bus and vehicle refuelling stations. The refuelling station supplies at a regularly basis 300 cars and 6 buses. The demand for hydrogen is estimated based on the assumptions that the yearly distance covered by a car is 10 000 km and that 1 kg of H2 is required to drive 100 km. This means a daily demand of 0.32 kg H2 for a car, and of 37.5 kg H2 for a fuel cell bus [16]. The supply of refuelling station is a fixed commitment which occurs every 3 day at 10 o'clock am, by means of adapted trucks. See in Ref. [17] an interesting optimization of the H2 network applied to France consisting in trucks and pipelines.

Demand for maritime fuelling stations. It is assumed that 21 boats refuel at the hydrogen station. There are two ship types, small and big, with a different frequency for refuelling. Small boats need 24 h fuel autonomy, while big boats need fuel recharging for 48 h. Small vessels refuel every day and it is assumed that the refuelling station planning provides three timelines during the day to recharge the 18 small boats, at 8 am, at 4 pm and at 12 pm. The remaining 3 big boats have a large reservoir capacity and they refuel every 48 h; the refuelling planning in this study case is based on a 16 h time scale.

Demand for power. There is no fixed commitment to supply the power market; H2-to-power is instead price responsive: the hydrogen is transformed into power when the electricity price is high under the constraint that enough hydrogen is compressed and stored well in advance. Since the power demand is large enough at a regional, national and even European level by 2030, there is no constraint set on the supply of H2-to-power vector from the demand side. The only constraint is the limit of the grid line which transports the electricity from the fuel cell device to the system operator; this sets an hourly constraint on the power delivery, which is the nominal capacity of the grid, which is 450 MW.

Demand for gas. With energy markets liberalisation in the European Union, less long-term contracts for gas are assumed to be effective by 2030, being thus replaced by spot short-term transactions. Similarly with the H2-to-power supply, no fixed commitment is assumed in the case of H2-to-gas as well. The limit fixed however is the physical capacity of the pipeline which can carry the gas during one hour, such that hydrogen could be transported and sold on the market every hour.

Hydrogen and wind cost assumptions

The cost structure is documented by various studies with cost estimates for each technology component. Table 2 reports the main cost assumptions for both off-shore wind power and hydrogen plants.

A power-to-power application includes an electrolyser, a compressor of 200 bars, a storage tank of 200 bars and a fuel cell; the round trip efficiency is of 29%, reflecting improved performances compared to the current available technologies, of around 25%.

The cost projections for 2030 are based on the assumptions that further research and demonstrator projects which are worldwide planned or already conducted would enhance the efficiency, reliability and durability of components when operated variably and intermittently. This translates into reduced investment costs and longer lifetime or higher number of cycles of components, with an extrapolation to a lifetime of 20 years in 2030.

Energy price evolution

Revenue streams of wind-hydrogen plant are from selling the power on the wholesale market and on the power reserve market, and from selling the pure hydrogen to the natural gas market at the market price of natural gas, and to the hydrogen refuelling stations at the oil market price.

The hourly wholesale spot prices in 2030 are derived from a power plant dispatching model run for the French power system in the year 2030 [13]. The oil and gas prices are documented from the report on the European Commission on energy trends by 2050 [14] (Fig. 4). Their variations by 2030 could be considered as being optimistically low as compared to other price projections; see for instance the EIA report [20]. Hence sensitivity tests are conducted for the economics of hydrogen with concern to higher energy price variations (section Sensitivity tests).

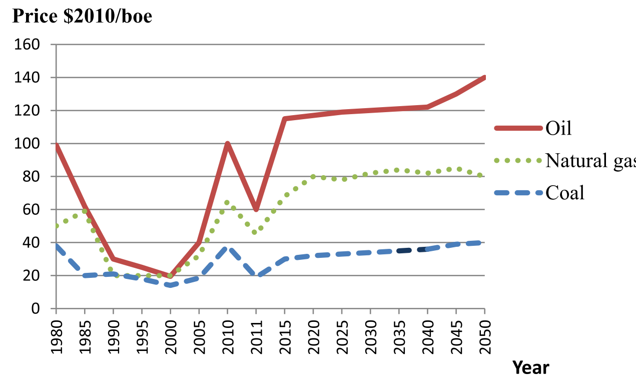

Fig. 4 – Fossil fuel import prices [14].

Result analysis

Sizing the infrastructure

Table 3 reports the design of the hydrogen plant by component, which is obtained for given capacities of the wind farm and the transmission line. The data for each component results from a repetitive iterative exercise based on profits obtained with the optimization operational model. The electrolyser, the compressors at 200 and 700 bars, and the corresponding storage and fuel cell capacities are chosen such as to meet fixed demand for fuel and to obtain maximum profits. Oversizing is avoided, because of very high investment costs of components. As a reminder, the wind electricity in excess can be used to produce the hydrogen, which further reduces grid congestion, but this is not the objective function.

Results show that the wind power curtailment which is avoided can be low in some simulations, about one third from the total excess, due to limited capacity to store the hydrogen. It should be noted that when the wind power is in excess, the hydrogen storage cannot discharge the power loaded since the transmission line is used at its maximum capacity by the wind farm. The wind excess is recorded during several consecutive hours, and the storage capacity attains its filling limit very quickly as mentioned above.

The possibility to discharge the storage or to produce the hydrogen during the period of wind excess could be limited by a temporary absence of demand for hydrogen as fuel, by the limited capacity of the gas pipeline or the congestion of the electrical transmission line. The power-to-power application occurs under the double condition that the transmission line is available and that the system needs additional power.

These constraints together with the transmission line sharing condition, restrain the load factor to 47% over the year for the electrolyser, to 62% of the compressor at 200 bars (77% at 700 bars), to 51% and 48% of the storage at 200 bars and at 700 bars respectively, and at 55% of the fuel cells.

Model results

The next table presents the results obtained in terms of profitability in all the scenarios considered (Table 4). For the analysis of the project economics, when the NPV indicator equals zero, the stream of income enables the investor to exactly recover the project's investment costs during the economic lifetime of the project. A negative value for the NPV indicator shows the additional value required for each unit of generated electricity in order for the investor to recover the project's investment and financing costs (also called the

Table 3 – The size of the hydrogen plant by component, by scenario, MW.

MW	Scenario						
	Mix usage		Single application			Two applications	
	H2-to-X _Wind	H2-to-X _alone	H2-to-power	H2-to-gas	H2-to-fuel	H2-to-gas, H2-to-power	H2-to-gas, H2-to-fuel
Wind plant	1000	1000	1000	1000	1000	1000	1000
Electrolyser	170	170	100	130	1.1	170	170
Compressor 200 bars	80	80	80	–	–	80	–
Compressor 700 bars	1.2	1.2	–	–	1.2	–	1.2
Storage 200 bars	900	900	900	–	–	900	–
Storage 700 bars	200	200	–	–	200	0	200
Fuel cell	50	50	50	–	–	50	–

missing money). A positive value for the NPV indicator would show positive profits of the project over its technical lifetime.

None of the project is economically viable under the assumptions set in our case study, since the indicator of the NPV is overall negative, despite the optimization of the operation and the sizing procedure. The comparison of different scenarios shows that the highest loss is recorded in the case *SCE_H2-to-X_alone*, since the operator should pay for the electricity consumed for the hydrogen production. The second worst economic case is the mix-usage wind-hydrogen hybrid plant, due to the high investment cost of all the hydrogen system components. Cumulating hydrogen utilisation vectors which do not use the same process infrastructure harms the viability of the project. For instance, the H2-to-Gas application, which has the best NPV result, is using the existing transport-distribution-storage infrastructure of the natural gas network and hence has limited infrastructure costs; for the other applications, additional investments are needed for the auxiliary equipment.

This is why the application H2-to-gas, using only the electrolyser, is easy to combine with other applications such as H2-to-power and H2-to-fuel. As a reminder, the demand for gas is not fixed since it concerns the spot market and not the supply of a particular power plant, which would constrain instead the supply of hydrogen. The potential demand for hydrogen of a combined heat and power plant would have a continuous load charge curve [21]. The case study considers transactions on the spot gas market, where the supply is discontinuous and driven by the price only, with no commitment contractually fixed in advance such as done with the refuelling stations.

The costs and revenues structure of the wind-hydrogen plant in the scenario *SCE_PowerGas* indicates a high share of the investment cost; at the revenue side, the wind revenues are the highest. Investing in a hydrogen plant to avoid the power curtailment has a high cost, with relative low incomes because the hydrogen-to-power is sold at a relative low power market price, i.e. 90 €/MWh in average, with a maximum price of 165 €/MWh over the simulation year 2030.

Next, a windy day is selected for graphical representation purposes, e.g. January 17. The intermittency of the wind inflow during that day, on one hand, and the energy demand constraints, on the other hand, make the model results an interesting case to represent and to discuss. This pattern is not representative of the other days of the year; choosing another day would lead naturally to a different dispatch of the power plant due to different wind fluctuations and to different patterns of the power price.

Fig. 5 shows the energy trade-off between the wind power supplied to the Transmission System Operator and the wind power used for the hydrogen production. When the power grid limit of 450 MW is not attained and still the wind power is

Table 4 – Results of model simulations, by scenario in 2030.

Results, 2030	Scenario							
		Mix usage		Single application			Two applications	
	Wind_alone	H2-to-X _Wind	H2-to-X _alone	H2-to-Power	H2-to-Gas	H2-to-Fuel	H2-to-Gas, H2-to-Power	H2-to-Gas, H2-to-Fuel
Wind power generation, GWh	2 123	1 931	2 103	2 015	2 124	2 124	1 934	2 121
Wind to H2, GWh	-	800	480	-	499	-	0	-
Withdrawal, GWh	-	361	542	377	-	10	355	6
Production of H2, t	-	20 911	18 402	14 387	8 981	276	20 731	11 096
Potential curtailment, GWh	**963**							
Avoided curtailment, GWh	0	608	460	314	499	958	356	356
NPV, €/MWh	**-40**	**-118**	**-352**	**-103**	**-27**	**-56**	**-97**	**-50**
Cost Wind-H2, €/MWh	-	210	-	192	127	154	190	151
Cost of H2, €/kg	**-**	**13**	**47.1**	**6.4**	**4.2**	**5.1**	**6.3**	**5.0**

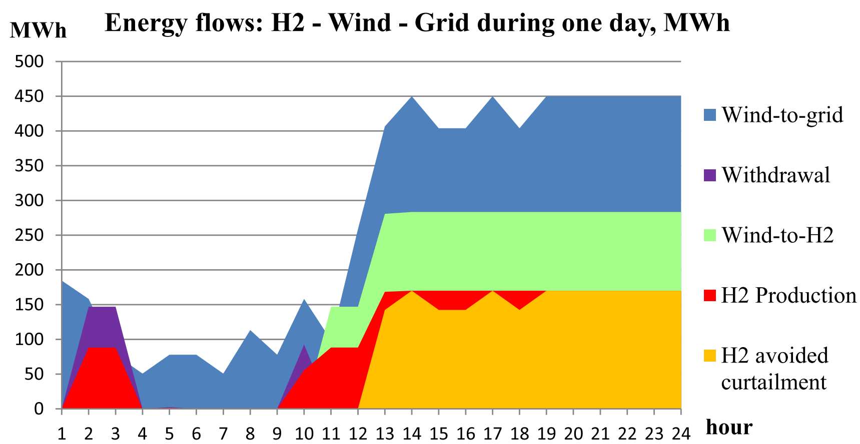

Fig. 5 – Wind and hydrogen energy flows during one day.

used for the hydrogen production, this means that the wind power could have supplied electricity to the power market. Yet, due to low power prices on the market, it is economically more interesting to produce hydrogen during those hours; or, due to a fixed fuel demand constraint, the system must produce hydrogen that can supply the refuelling stations.

Fig. 6 illustrates the wind power generation, the hydrogen production and the gas compression at different pressure levels. The decision for the usage of the hydrogen is driven by the energy market prices and also by the technical constraints, such as the compression capacity and the limit of the storage tanks. Fixed demands for refuelling the cars and boats stations can add to the decision of the timing of hydrogen production. Continuous production of hydrogen could be an advantage to the hydrogen system from the technology usage point of view, since it would avoid too frequent start-up and shut-down operations, which add fatigue and stress to the system and materials [4].

For the fuel cell usage for instance, the operation during one day (Fig. 7) shows the discontinuous power supply of hydrogen fuel cell to the grid, since it is price responsive and has no constraint of firm capacity. This is also because the

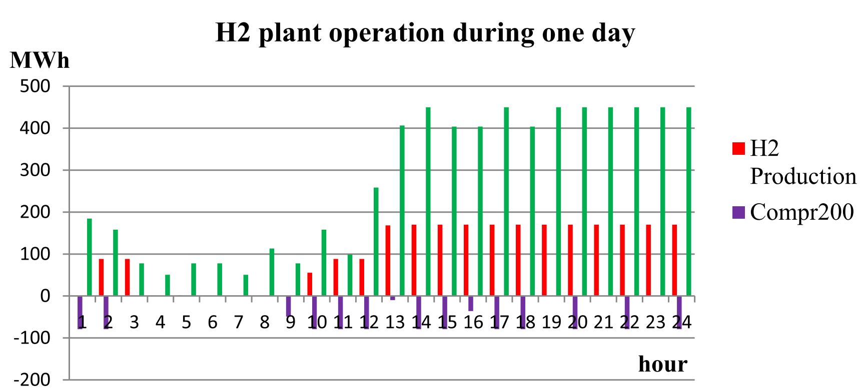

Fig. 6 – The operation of the hydrogen plant during one day.

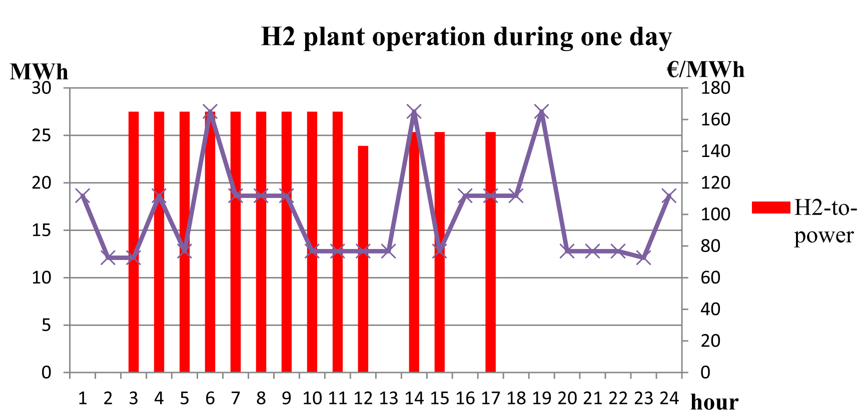

Fig. 7 – Power supply from hydrogen fuel cell as a function of the market price.

region of the case study, around Saint-Nazaire, is not a remote area, but it is connected to the rest of the national system. The figure shows also that the hydrogen operator would have a discontinuous activity and suggests that it should diversify the usage of hydrogen by a multi-product energy supply. The intermittent use of the fuel cell exerts in this case a pressure on the system and could reduce by half its technical lifetime with the current technology performance [19].

The intermittency of the wind power makes the hydrogen production intermittent as well. Hence, the flexibility of the gas and power spot market segments gives the system the freedom to make the trade-off between favourable periods to produce and supply the hydrogen. Firm contracts with refuelling stations instead constrain the periods of hydrogen production and storage, but ensure on the other hand the security of selling the hydrogen at a fix price. This could give more visibility to investors on the energy market volumes and on the expected profitability of the project. This allows also sizing the system components in connection with the expected market volume. Yet, in both cases, firm and flexible contracts, the uncertainty holds on the wind flow; if the wind does not blow as expected, power withdrawal from the local grid is required, which would lower the profits given the electricity cost incurred.

Sensitivity tests

The model is highly sensitive to the input values, especially the prices of hydrogen substitutes, such as power, gas and oil; and to investment costs assumed for each component, as well. Alternative scenarios on oil prices are found in different roadmaps used by the policy makers [20]. The figure below illustrates three potential oil price evolutions according to three scenarios, based on assumptions of low, medium and high oil prices.

Our sensitivity tests are carried out for four different paths of the oil price: the scenario Base is documented by the EC [14] and reports the results obtained in the core paper; and the three other scenarios (Low, Medium and High) are documented by the EIA [20] and are based on oil prices represented in the Fig. 8 for the year 2030.

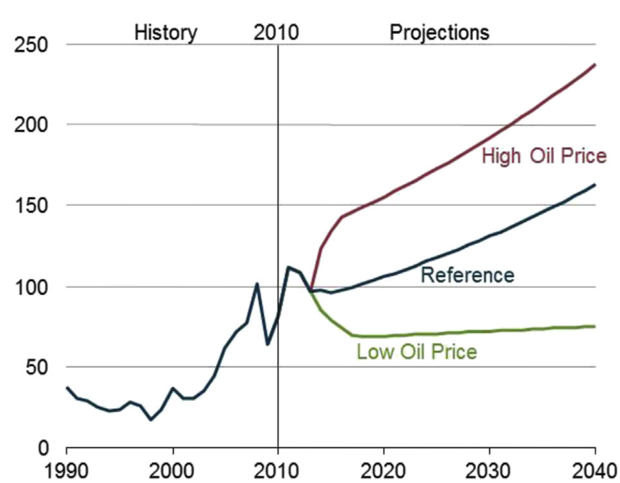

Fig. 8 – Oil price paths during 1990–2040, $2011/barrel [20].

Next it is assumed that scenario with low oil price has zero probability to occur in 2030, while the three remaining cases would have each an equal probability of happening. As for the gas and power prices, it is assumed that they vary with the oil price (Table 5).

The rational of selecting zero probability for the case of an oil price at 60 $/barrel is that the price projection trends are generally deflated with temporary cycles and price fluctuations. A low price of oil in 2030 would mean a sustainable low level which is hardly foreseeable during 15 years from now, despite low levels recorded since several months during the period 2014-2015. According to IAE reports on the oil market, the falls in the price of the oil are likely to be temporary before medium-term forces do their work [22]. These drivers act on the supply side, arising from postponing or cancelling investments in new projects of field exploration and oil production, and from high extraction costs of non-conventional oils. On the demand side, the increase in demand for oil will continue due to the urbanization and industrialization of emerging economies such as China and India. The growth of their middle classes will continue to trend up the oil demand, at a moderate pace however in China for instance, due to consumption taxes on oil products or to air-quality-control measures that restrict traffic [22].

The values of the NPV indicators are reported in the table below together with the NPV expectation. The results of sensitivity tests show negative values of the expected NPV, as a combination of each scenario profitability and probability to occur in the future. One single case taken individually would record a positive NPV, the scenario Hydrogen-to-gas, for an increase of the fuel price by 80% from the current level (Table 6).

Policy implications

The system impacts of the hybrid wind-hydrogen system are evaluated at four levels of the stakeholders involved in this project:

- **The wind power operator** has a lower profitability when it invests in hydrogen production as compared to the case where it operates alone, excepting the case where it would generate hydrogen for the natural gas network. Unless the regulation would oblige intermittent energies to balance their intermittency by means of storage, there would be no economic incentive to invest in such a capital intensive project. In France, the provision of firm capacity and ancillary services is not mandatory, neither for wind power plants nor for other generators. In the future, this arrangement could change with the contraction of the current over-capacity and the increase in wind power penetration.

Table 5 – The evolution of energy prices.

Scenario	Oil price 2013	Oil price 2030	*Variation*	Proba Sce
SceLow	100	60	−40%	0%
SceMedium	100	130	30%	33%
SceHigh	100	180	80%	33%
SceBase	100	120	20%	33%

Table 6 – Results on the NPV expectation.

Scenario		NPV, €/MWh			Expected NPV, €/MWh
		Base	Medium	High	
Mix usage	H2-to-X _Wind	-125	124.9	-82	**-111**
	H2-to-X _alone	-352	-306	-352	**-337**
Single application	H2-to-Power	-109	-109	-68	**-95**
	H2-to-Gas	-34	-34	12	**-19**
	H2-to-Fuel	-64	-64	-18	**-48**
Two applications	H2-to-Gas, H2-to-Power	-104	-104	-61	**-90**
	H2-to-Gas, H2-to-Fuel	-57	-57	-10	**-42**

The regulation of intermittent renewable energy is ongoing and has as starting point the experience gained in islands, such as Corsica and Reunion Island. The Ministry of Environment launched in 2009 a call for tender for photovoltaic energy systems in French islands under the constraint for generators to control the intermittency of their power flows [23]. To that the endowment of PV generators with storage systems was mandatory in order to stabilize the frequency of the system. A similar context could be designed in the metropolitan France where constraints could be set on the generators to limit their power fluctuations.

Using large-scale storage technologies other than hydrogen medium, such as compressed air or pumped hydro storage, would limit the energy vectors to Power-to-Power applications and would exclude the applications of mobility and gas. Therefore, other economic models for wind and storage would be necessary [24,25].

- **The Transmission System Operator** benefits from the hybrid system operation, with more reliable output and the potential to have a continuous power supply. Avoiding the curtailment of the wind power and feeding it into the grid as H2-to-power vector makes increasing the use of the grid line and ensures a better use of the grid asset. The transmission line capacity factor increases from 54% to 67%.
- **The society overall** records a double benefit: upstream, the hydrogen plant supports the integration of intermittent wind energy having positive local impacts on employment and regional dynamics; downstream, it provides clean hydrogen which substitutes to gas and oil. The wind power curtailment has been reduced significantly which further replaces other forms of energy in the French energy mix. On the road and sea transportation side, other benefits than carbon-emission free traffic would result, such as local pollution and noise removal. If the carbon market still does not fully internalize the carbon value in 2030, the clean hydrogen value will continue to remain highly underestimated on the energy market, despite its social benefits. In this paper, the carbon tax amounts to 35 €/tCO2 in 2030; while other studies estimate the social benefit of hydrogen at a much higher social carbon cost of 130 €2014/tCO2 per tonne of CO2 emissions [26].
- **The industry** involved in all chains of the hydrogen production and storage needs a clear vision of the hydrogen market development potential. This implies from the regulation side the harmonization of standards of security among regions and countries for operating hydrogen plants, and the building of the infrastructure such as hydrogen pipelines and distribution stations for cars and ships. The components which have been optimized in this study to match the size of the wind power cluster (1 GW as a reminder) are not yet available on the market at this large scale; all the existing hybrid pilot plants have installed capacities of kWs orders of magnitude. Creating large-scale components would take years of R,D&D for the applications to become available on the market and mature as well. Therefore, signals should be created well in advance to ensure the emergence of hydrogen technologies.

Policy makers' involvement is crucial at this stage for the development of the hydrogen economy. This can take the form of supply-push and demand-pull policies. Supply push policies could stimulate innovation by supporting research and development activities. R&D funds, public-private partnerships, cost-sharing schemes and hydrogen infrastructure building are some of the supporting policies which would enhance the large-scale deployment of hydrogen. Demand pull policies can send a market signal to investors that the potential hydrogen demand is high. In France, the use of hydrogen is exempted from energy taxes [27]. By contrast, other countries, such as Germany, Austria, Netherlands, apply taxes on hydrogen when it is used as motor fuel. Ultimately, carbon taxation together with long-term environmental objectives would be the strongest signal which would guide the investors in low-carbon technologies, clean hydrogen included.

Concluding remarks

This research has investigated the project investment into a hybrid wind-hydrogen plant located in the French region Pays de la Loire. The hybrid scheme is based on cost-benefit sharing, where hydrogen is produced based on zero cost wind power supply. Several energy applications of the hydrogen are tested, such as power-to-power, power-to-gas and power-to-mobility. This paper has built realistic scenarios on the demand for hydrogen and the hydrogen production and storage cost projections for the year 2030. An optimization model has been built to optimize the operation of the wind-hydrogen plant and has resized the design of hydrogen plant components such as to maximize profits.

The results show negative profits for all scenarios due to high investment costs in both wind and hydrogen infrastructures which remain expensive related to the low energy prices of power, oil and gas. The production cost of hydrogen is of 4.2 €/kg H2 in the most economically interesting case (Hydrogen-to-gas) and is up to 47 €/kg H2 in the scenario of an hydrogen plant in isolation from the wind farm.

The main finding concerning the project design is that combining too many usages, each of them requiring a different production and distribution infrastructure, could cumulate losses on the market. As for the contractual forms of the usages, the intermittency of the wind power and the hydrogen production makes the hybrid system favourable to flexible contracts on the spot markets such as gas and power markets. For the fixed fuel supply for refuelling gas stations, other factors, regulatory and policy oriented, would trigger the investment in such expensive projects. Oil prices should more than double to make the hydrogen production-storage-distribution an interesting economic option.

The wind power curtailment could be totally reduced; however, valuating the wind power excess would have a high investment cost related to the low market value. Yet, to the hydrogen market value one should add the social and system values that benefit to various stakeholders. These benefits are the support of hydrogen to the wind power integration, increased reliability to the grid power, improved quality of the power supply, clean fuel for road and sea transportation and increased energy independency by reducing oil and gas consumption.

At a national scale, the main policy recommendations are towards helping consumers and industries selecting carbon-free technologies by means of carbon taxation and ambitious targets set for the long term. Regionally, policy support could make industrials and consumers familiar with the technology and the hydrogen use, and could further involve them in R&D activities. With the decentralization of the energy production, a strong commitment of regional policy makers is essential to the development of hydrogen infrastructure. This would give confidence in the investment possibilities and could guide the equipment manufacturers, energy operators and car and shipping stakeholders where hydrogen technology could find fertile ground.

Building the necessary infrastructure to produce, transport, store and deliver the hydrogen requires first of all licenses and operating permits; this is why the authorities should be involved at the earliest stage of the process. The relevant authorities in the region Pays de la Loire are working together with scientists, fishing industrials and shipping manufacturers in order to accelerate the development of the fishing vessel of the future, hydrogen fuel cell driven [28]. Regional concern to set basis for hydrogen along with marine energies in Pays de la Loire and the initiatives undertaken by *Mission Hydrogène* show that the policy makers have already committed in creating prospects for developing hydrogen and sustainable power projects in the region.

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Annex 1. The methodology used for wind power data collection.

Several constraints are taken into account when estimating the electricity output of the offshore power cluster. The power actually captured by the turbines is lower than the total wind energy. This is the physical law known as the Betz limit which states that only a maximum of 59.26% of the kinetic energy can be extracted from the wind regardless of turbine design. Kinetic energy is converted into mechanical energy by the gearbox and then into electrical energy by the generator. The production function is hence given by:

$P = 0,5\ C_t\ \rho\ A\ v^3$, where C_t is the average efficiency of each turbine, ρ is the average air density (1, 23 kg/m^3), A is the rotor swept area (17,869 m^2) and v is the wind speed.

It is considered that no electricity is produced for wind speeds lower than 2.77 m/s and the production function is applied for v ranging from 2.77 to 11.22 m/s. Technical documentation provided by Alstom suggests that the *Haliade™150-6 MW* turbines reach full power at wind speeds of 13 m/s. However, due to incomplete data, a rated wind speed of 11.22 m/s is calculated. It is considered that the machines are at their full rated power for wind speeds up to 25 m/s. The turbines are stopped for security reasons for wind speeds higher than 25 m/s. The capacity factor found is of 35.2%.

Annex 2. The equations of the model.

Endogenous variables

Objective function – the model maximizes the wind-hydrogen profits over the entire year 2030 (€)

Profits, Revenues, Costs – are the yearly profits, revenues and variables costs of both hydrogen production and wind power generation sold on different market segments (€)

Costs – the sum of power costs used for electrolysis and of variable operation and maintenance costs (€)

Revenues – the sum of all revenue streams on the power, oil and gas market segments (€)

Wind_power – the hourly wind power sold at the wholesale power market (MWh)

H2_to_compressor – the hourly volume of hydrogen infed into the compressor, at 200 or 700 bars (MWh)

H2_compressed – the hourly volume of hydrogen compressed at different pressure levels (MWh)

H2_from_Wind – the hourly volume of hydrogen produced with wind power inflow (MWh)

H2_from_Withdrawal – the hourly volume of hydrogen produced with electricity withdrawn from the grid (MWh)

H2reserve – the hourly power supplied by the fuel cell to the reserve market (MWh)

H2_to_gas – the hourly hydrogen energy supplied to the gas network (MWh)

H2_to_mobility – the hourly hydrogen supplied to maritime and vehicle refuelling stations (MWh)

H2_to_power – the hourly power generated by the fuel cell sold on the wholesale power market (MWh)

H2_to_road – the hourly volume of hydrogen sold to the vehicle refuelling station (MWh)

H2_to_shipping – the hourly volume of hydrogen sold to the maritime refuelling station (MWh)

H2_Prod_Total – the total hourly production of hydrogen (MWh)

StorageH2 – the hourly volume of hydrogen stored for different applications, at 200 bars for H2_to_power, at 700 bars for H2_to_mobility (MWh)

Wind_Production – the hourly wind power generation sold on the wholesale power market (MWh)

Wind_to_Hydrogen – the hourly wind power generation used in the electrolysis (MWh)

Withdrawal – the hourly power withdrawn by the hydrogen operator and fed into the electrolyser (MWh)

Exogenous variables

Capacity_Compressor – the capacity of the compressor, 200 or 700 bars (MW)

Capacity_electrolyser – the capacity of the electrolyser (MW)

Capacity_fuelcell – the capacity of the fuel cell (MW)

Capacity_pipeline – the capacity of the pipeline (MW)

Capacity_Storage – the capacity of storage (MW)

Grid_line – the capacity of the power grid line (MW)

K_price – the regulated capacity price paid by the System Operator for the share of fuel cell reserved for secondary and tertiary reserves (€/MW)

Negative_reserve – the hourly volume of hydrogen produced from the negative reserve (€/MWh)

Price_oil, Price_gas – the oil and gas price with a yearly definition (€/MWh)

Price_elec – the hourly electricity price fed into the model (€/MWh)

Price–reserve – the regulated power price of ancillary services paid by the System Operator (€/MWh)

Wind_Profile – the hourly wind potential flow, computed such as described in Annexe 1 (MWh)

ShipFuel_Demand – the hourly volume of hydrogen contracted with the maritime refuelling station (MWh)

RoadFuel_Demand – the hourly volume of hydrogen contracted with the road vehicle refuelling station (MWh)

Each demand vector of mobility has 8760 items, corresponding to 365 days and to 24 h each day. The demand for shipping fuel has three no zero elements by day, corresponding to boat refuelling at different specific times. The hydrogen demand of the road vehicle station has only one no zero element by day. They commit the hydrogen operator to supply a fixed energy volume at specific times of the day over the year.

Parameters

efficiency – efficiency by component: electrolyser, compressor200, compressor700, storage, fuel cell (%)

$$Objective\ \ Function\ :Profits = Revenues - Costs$$

$$\begin{aligned}Revenues = \sum_{hour=1}^{8760} & price\_elec_{hour} \times (Wind_{Power_{hour}} + H2\_to\_power_{hour}) \\ & + price\_reserve \times H2reserve_{hour} + K\_price \times K\_reserved \\ & + price\_gas \times H2\_to\_gas_{hour} \\ & + price\_oil \times H2\_to\_mobility_{hour}\end{aligned}$$

$$Costs = \sum_{hour=1}^{8760} price\_elec_{hour} \times Withdrawal_{hour} + VOM$$

$$Wind\_Production_{hour} + Wind\_to\_H2_{hour} \le Wind\_Profile_{hour}$$

$$\begin{aligned}& Wind\_Production_{hour} + H2\_to\_power_{hour} + H2reserve_{hour} \\ & + Withdrawal_{hour} \le grid\_line\end{aligned}$$

$$\begin{aligned}H2\_Prod_{Total_{hour}} = & H2\_from\_Withdrawal_{hour} + Negative\_reserve_{hour} \\ & + H2\_from\_Wind_{hour}\end{aligned}$$

$$H2\_Prod_{Total_{hour}} \le Capacity\_electrolyser$$

$$H2\_from\_Wind_{hour} = Wind\_to\_H2_{hour} \times efficiency_{electrolyser}$$

$$H2\_from\_Withdrawal_{hour} = Withdrawal_{hour} \times efficiency_{electrolyser}$$

$$\begin{aligned}H2\_Prod_{Total_{hour}} = & H2\_to\_gas_{hour} + H2\_to\_Compressor200_{hour} \\ & + H2\_to\_Compressor700_{hour}\end{aligned}$$

$$\begin{aligned}H2\_compressed200_{hour} = & H2\_to\_Compressor200_{hour} \\ & \times efficiency_{compressor200}\end{aligned}$$

$$\begin{aligned}H2\_compressed700_{hour} = & H2\_to\_Compressor700_{hour} \\ & \times efficiency_{compressor700}\end{aligned}$$

$$\begin{aligned}StorageH2\_200bars_{hour} = & StorageH2\_200bars_{hour-1} \\ & + H2\_compressed200_{hour} \\ & - (H2\_to\_power_{hour} + H2reserve_{hour}) \\ & \div efficiency_{fuelcell}\end{aligned}$$

$$\begin{aligned}StorageH2\_700bars_{hour} = & StorageH2\_700bars_{hour-1} \\ & + H2\_compressed700_{hour} \\ & - (H2\_to\_road_{hour} + H2\_to\_shipping_{hour}) \\ & \div efficiency_{destorage}\end{aligned}$$

$$\begin{aligned}\sum_{hour=1}^{8760} H2\_compressed200_{hour} \ge \sum_{hour=1}^{8760} & (H2\_to\_power_{hour} \\ & + H2reserve_{hour})\end{aligned}$$

$$\begin{aligned}\sum_{hour=1}^{8760} H2\_compressed700_{hour} \ge \sum_{hour=1}^{8760} & (H2\_to\_road_{hour} \\ & + H2\_to\_shipping_{hour})\end{aligned}$$

$$\sum_{hour=1}^{8760} H2\_Prod_{Total_{hour}} \geq \sum_{hour=1}^{8760} (H2\_to\_gasnetwork_{hour} + H2\_to\_power_{hour} + H2reserve_{hour} + H2\_to\_road_{hour} + H2\_to\_shipping_{hour})$$

$$H2\_to\_gas_{hour} \leq Capacity_{pipeline}$$

$$H2\_to\_shipping_{hour} = ShipFuel\_Demand_{hour}$$

$$H2\_to\_road_{hour} = RoadFuel\_Demand_{hour}$$

$$\sum_{hour=1}^{8760} H2reserve_{hour} \leq 10\% \times Capacity\_fuelcell$$

$$StorageH2\_200bars_{hour} \leq Capacity\_Storage200$$

$$StorageH2\_700bars_{hour} \leq Capacity\_Storage700$$

$$H2\_compressed200_{hour} \leq Capacity\_Compressor200$$

$$H2\_compressed700_{hour} \leq Capacity\_Compressor700$$

$$H2\_to\_power_{hour} + H2reserve_{hour} \leq Capacity\_fuelcell$$

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