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SCHOOL OF INDUSTRIAL AND INFORMATION ENGINEERING
Master of Science - Energy Engineering

A techno-economic feasibility study of green hydrogen production with electrolysis at Biomet s.p.a.

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Sommario

Al fine di limitare il cambiamento climatico, il sistema energetico è al giorno d'oggi sottoposto a importanti sfide di decarbonizzazione. L'obiettivo è quello di raggiungere la neutralità climatica per il 2050 e limitare il riscaldamento globale a +1,5 °C. Attualmente circa un terzo delle emissioni nel campo energetico sono prodotte da settori difficilmente elettrificabili, per i quali non c'è un'alternativa tecnico-economica alle fonti fossili, gli "hard to abate". La migliore possibilità per permettere la decarbonizzazione di questi settori è mediante l'utilizzo dell'idrogeno verde. Esso è prodotto con elettrolisi dell'acqua alimentata da energia rinnovabile, un processo al momento non competitivo coi metodi tradizionali per la produzione di idrogeno in campo industriale. Tuttavia, con l'aumento dell'attenzione dei governi, degli stakeholders del settore energetico e del pubblico in generale, ci si sta muovendo verso la formazione di un vero e proprio mercato dell'idrogeno verde. In questo contesto, l'azienda Biomet s.p.a di San Rocco al Porto (LO) sta considerando la possibilità di installare un sistema per la produzione, lo stoccaggio e la distribuzione di idrogeno verde presso il suo sito produttivo. Questo lavoro di tesi è iniziato come analisi della fattibilità tecnico-economica di tale produzione, ed è stato successivamente esteso all'analisi del costo di produzione di idrogeno verde con impiego di energia fotovoltaica in Italia. Il costo di produzione dell'idrogeno è stato calcolato per un ampio range di potenza dell'elettrolizzatore e per tre configurazioni di impianto: lo scenario 1, pensato per massimizzare la produzione di idrogeno, lo scenario 2, che considera un impianto fotovoltaico off-grid, e lo scenario 3, in cui si aggiunge l'utilizzo di una batteria di accumulo. Infine, è stata condotta un'analisi si sensibilità sui principali parametri di sistema per valutare la loro influenza sul costo dell'idrogeno e si è valutata la fattibilità economica dello scenario che è risultato il più conveniente.

Parole Chiave:
Idrogeno verde
Power-to-gas
Produzione elettrica fotovoltaica
Elettrolisi
Analisi tecnico-economica
LCOH

Abstract

To prevent the dangerous impact of climate change, rapid decarbonisation has to be pursued in the whole energy sector. The goal is to achieve climate neutrality by 2050 to limit global warming to +1.5 ° C. However, about one-third of the current emissions in the energy field are produced by sectors for which there is no economic alternative to fossil fuels. These are known as "hard-to-abate" sectors. A common solution to enable the decarbonisation of these sectors is green hydrogen, produced with renewable energy, through the electrolysis of water. This process is not competitive today with traditional methods to produce hydrogen in the industrial field. However, with increasing attention from politicians, stakeholders in the energy sector and the general public, a path is forming for the development of a green hydrogen market. In this context, Biomet s.p.a, an Italian company, is considering the possibility of installing a system for the production, storage, and distribution of green hydrogen at its production site. This thesis work began as a technical-economic feasibility study of such hydrogen production, but it was subsequently extended to consider a wider range of applications. The H2 production cost has been computed for a wide range of electrolysis plant sizes and three different plant layouts. Scenario 1 is designed to maximise the hydrogen productivity of the plant, scenario 2 considers an off-grid photovoltaic plant and scenario3 employs a battery for the storage of the surplus. A sensitivity analysis was conducted to identify the most influencing parameters on the cost of hydrogen production. Finally, an economic analysis was considered for the scenario that resulted in being the most cost-effective.

Keywords:
Green Hydrogen
Power-to-gas
LCOH
Solar photovoltaic power
Electrolysis
Techno-economical study

Extended Abstract

Introduction

To limit the catastrophic consequences of global warming of more than + 2°C, the global community has set a framework to shift toward a sustainable energy system. The challenge is to reduce the global emissions of 55% by 2030 with respect to 1990 levels and to reach climate neutrality by 2050. However, the share of renewables in the total final energy consumption in 2019 was just 17.7% and, after the pandemic, the increase in renewable power generation occurred together with an increase in the global consumption of coal. The energy sector seems not yet ready for rapid full decarbonisation. Additionally, not all the sectors and industries can easily be decarbonised through the increase in the share of renewables. One-third of the global energy-related emission are produced by "hard-to-abate" sectors, for which there is presently no technical and economic alternative to fossil fuels. Nowadays, the most interesting alternative to decarbonise such sectors and stimulate the transformation of the energy sector is green hydrogen. Green hydrogen is produced from the electrolysis of water, employing renewable energy sources, with near-zero carbon production, and it is the only typology of hydrogen that can be considered "clean". The advantages that this gas may bring are plenty. Fossil-fuel based hydrogen is already used as a feedstock in some "hard-to-abate" sectors, such as the iron and steel industry, the cement, and the chemical industry. By substituting their hydrogen feedstock with a green one, such sectors may significantly decrease their impact, without the need of crossing the electrification path. Additionally, hydrogen may be used as a means to store electricity and dampen the instability effect that non-programmable renewable sources cause to the grid. Thanks to its long-time storage, it can help decouple the generation of electricity from its consumption. Finally, thanks to its double nature of industrial gas and energy carrier, it allows channelling of large amounts of renewable energy from the power sector into other non-electrified ones, such as transport, building or industry, limiting the need for electrification infrastructure. Green hydrogen is nowadays receiving unprecedented attention, and many countries have organised strategies to develop a full-scale clean hydrogen supply chain. The projection for the future years is that hydrogen will constitute from 6 to 18% of the global energy consumption by 2050. For what concerns Italy, it is estimated that up to 23% of the total energy consumption of the country will be represented by green hydrogen in 2050. The Italian market is considered by major consulting firms to be extremely attractive for investments in the hydrogen field. Thanks to its high equivalent hours of renewable electricity production and its gas infrastructure network, the country may indeed work as a hydrogen hub and distribute low-cost green hydrogen to all of Europe. Even if the Italian government appears lagging behind the European ones in the development of a clear strategy to create a green hydrogen supply chain, it is aiming in investing 3.19 billion euros in the hydrogen sector (PNRR). In this context, Biomet s.p.a., a company that deals with the production and distribution of liquid biomethane, is considering the possibility of installing a green hydrogen production and distribution facility at one of its sites. This work firstly studies the techno-economic feasibility of clean hydrogen production at Biomet, through electrolysis of water and PV electricity. Then, the feasibility is extended to a wider range of applications, so to analyse the green hydrogen productivity beyond the company's constraint.

Implemented data in the study

To study the feasibility of the hydrogen production at Biomet, all the input data of the system have to be characterised. First of all, a demineralized water flow is needed to feed electrolysis. Two possible contributions could be used to feed the process: the water obtained by scrubbing the digestate, at the outlet of the anaerobic digester of the company, and rainwater, collected with a drain system. The average hourly available water flow was assessed, which was checked to have the right quality to implement the electrolysis units. Then, the sizing of the PV plant was carried out, considering the available area for the modules in the plant site. The PVGIS-SYRAH hourly average irradiance data were used to determine the hourly PV productivity profile, and then the yearly energy produced by the modules. Finally, Biomet's plant plan was consulted to estimate the available area to place the electrolysers. By analysing the average footprint of the three considered electrolysis technologies, the maximum installable power for the three of them has been considered.

Electrolysers

The power to hydrogen electrolysis process is a very wide concept that can apply to several different layouts and can include many different plant components, depending on the specific constraints of the analysed application. In this specific case, hydrogen production is assumed to be generated at a quality of at least 99.97% and a pressure of 30 bar. For this reason, the considered electrolysers are either capable of producing H2 at such purity or a dryer is added to the analysis. For this study, storage, transportation and distribution have not been considered, and the focus lies only on the costs associated with all the expenditures associated with the production of hydrogen. Once determined the system boundaries of the hydrogen production facility, an extensive literature screening have been done to determine the technical data and the economics of the electrolysers. Currently, not much reliable data on electrolysers costs are available: many lack of information about system boundaries, technical specifications, year of installation and rated power of the electrolysers. To dampen the uncertainties in the collected data, only complete data have been taken from reliable literature sources and manufacturers. Specific cost curves have been fitted on those data, for each of the electrolysis technologies considered (PEM, ALK and AEM). From the fitting, the specific cost of the electrolysers results to be extremely affected by economies of scale. A fitting curve has been provided also for the specific cost of the PV plant, ranging from commercial to utility-scale, and for the specific cost of Lithium-ion batteries, which are considered in some of the implemented scenarios to increase productivity.

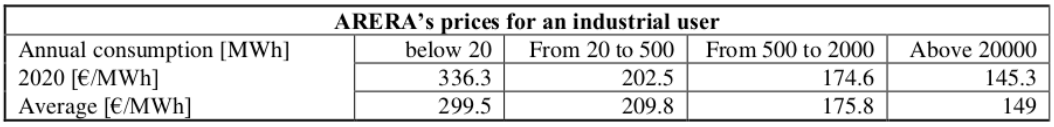
Methodology

The Power to gas hydrogen technology includes a wide range of different layouts, depending on the energy used to implement the electrolysis, the quality and pressurization of the hydrogen at the outlet and the specific final use of the gas. Considering the data and constraints of the studied application, the best layouts of the power-to-hydrogen plant have been identified to minimise the LCOH. To set a technically feasible problem, the mass and energy balances of the system are considered. Then, each stream inside the system boundaries is given a proper valorisation. Finally, the most economically feasible plant designs are identified, and a methodology is implemented to compute the Levelized cost of hydrogen. Both the inlet water and the outlet oxygen are considered zero-value streams, as the first would be discharged as wastewater if not employed for the electrolysis, and the second is assumed to be vented into the atmosphere. The hydrogen is valorised at its LCOH. For what concerns energy, the coupling of storage technology to a solar photovoltaic power plant is not a straightforward process. Being the electrical power production of the photovoltaic system intermittent, it does not always coincide with the power consumption range of the electrolyser. Surplus electricity is generated each time the photovoltaic system produces more than what the electrolysis can consume or each time it doesn't produce enough to reach the start-up power value of the electrolyser. It is necessary to identify a strategy for managing this surplus. Three main possibilities are considered for the final use of the surplus: a) Selling the surplus to the grid; b) Storing the surplus into batteries; c) Employing the surplus for the Biomet's energy needs. The energy needs of the biogas plant at Biomet's site are partially met thanks to a cogenerator, with an energy gap of 400 to 5000 kW/day. The first 500 kWh of electricity surplus of the PV plant, if available, has been considered to cover such energy needs. The valorisation of such a stream of energy is the LCOE [€/MWh] of the PV plant. Being the natural gas purchase on demand, whenever additional PV surplus is available, such excess is used to feed the digester instead of the cogenerator. This energy stream has been valorised as the LCOE of the electricity produced by the cogenerator (150 €/MWh) subtracted by the LCOE of the PV plant. The use of the surplus energy to feed the digester when available doesn't influence any decision on the optimal size of the cogenerator and thus its investment cost. Indeed, the PV electricity is available during the day only, while the digester consumes also at night-time: in such a moment the cogenerator still needs to have the possibility to work at its nominal power to fully cover the energy needs of the digester. The maximum surplus energy that can be used by the digester in one hour has been assumed to be 200 kWh. The remaining amount of surplus has been considered to be sold to the grid, at the zonal price. If the electrolyser is operated with PV electricity only, the operating hours of the hydrogen production will be surely lower than the ones of the PV plant, which are 1100 h/y. Consequently, the hydrogen productivity of the plant would be limited. Even if this document regards the production of hydrogen only, it is known that the company aims at selling the gas through a refuelling station to be installed in one of its production sites. In this perspective, it is relevant to consider the distribution constraints too. From literature studies, the specific investment cost of the station results decreases significantly as the size of the filling station increases. From a talk with Air Liquide, one of the world's leading companies in the hydrogen supply chain, the construction of a refuelling station would be justified only for H2 production capacities exceeding 100 kgH2/d. From this perspective, it is interesting to analyse the feasibility of hydrogen production for a scenario where hydrogen productivity is maximised. In this case, additional energy input has to be considered to feed the electrolysis plant in those hours of the stop of the PV plant. To produce green hydrogen, this input must necessarily be renewable. The following possibilities are considered for the purchase:

a. To purchase electricity from the grid through Acquirente Unico, together with a share of green certificates.

b. To purchase the electricity produced by a ReS plant through PPA.

The green certificates, "Garanzia di origine" (GO), have been considered as 2



ARERA's prices for an industrial user				
Annual consumption [MWh]	below 20	From 20 to 500	From 500 to 2000	Above 20000
2020 [€/MWh]	336.3	202.5	174.6	145.3
Average [€/MWh]	299.5	209.8	175.8	149

Table 1: ARERA sale price for an industrial user, Acquirente Unico.

€/MWh, while the electricity tariffs of purchasing from the grid are the reported in Table 1.

As an alternative, the possibility of purchasing electricity through a Power Purchase Agreement with a nearby producer of renewable electricity has been considered. The assumed price for this case is 110 €/MWh. All the energy inputs in the PV + electrolyser production system and their valorisation are reported in Figure 1.

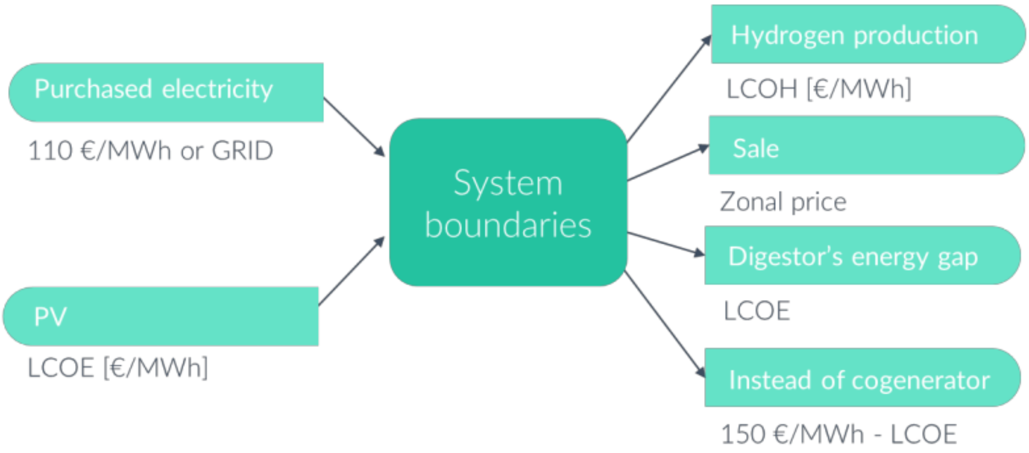


Figure 1: Scheme of all the possible energy inputs crossing the boundaries of this study.

Three layouts have been identified as the most favourable for the production of green hydrogen at Biomet. Respectively,

A) Scenario 1a: it considers a constant operation of the electrolysers, to produce a constant flow rate of hydrogen. The PV productivity is supported by an electricity purchase.

B) It considers a PV-to-H2 layout. Hydrogen production is solar source dependent.

C) It considers a PV-to-H2 layout, supported by the storage capacity of a battery.

For each of these scenarios, the part of the PV surplus that is not used to charge the batteries is devoted to the digester's energy needs and partly sold to the grid.

Beyond the company's constraints

The constraints imposed by Biomet have been loosened to investigate the feasibility of the PV + electrolysis plant at high PV and electrolyser sizes. Indeed, to allow the competitiveness of green hydrogen with the fossil-fuels produced ones, it is useful to exploit the benefit of economies of scale. All the three scenarios implemented for Biomet are here considered for a PV and electrolysis nominal sizes of 1 to 30 MW and the case of higher water availability: 1b, 2b and 3b. For these scenarios, the same valorisation of the mass and energy streams has been considered.

LCOH computation

The parameter used to determine the optimal electrolysis size for a certain system layout is the Levelized Cost of Hydrogen. The value of this parameter has been obtained both using the discounted cash flow analysis and using its theoretical definition. The Discounted Cash Flow (DCF) method was used to manage the energy and economic fluxes in the system. It is one of the most used methodologies for business analysis and permits estimating the present value of an investment based on its expected future cash flows. The time value of money is considered thanks to the discount rate, which is applied to all the capital. No difference betweendepth and equity has been considered, all the money employed in the investment is assumed to be equity, without bank loans. The CAPEX consist of the PV investment cost, the electrolysis investment cost, and the batteries investment costs (if employed in the system). They have all been referred to as year zero. The OPEX are the ones of the PV system and the electrolysis system, including the costs for the replacement of the electrolysis stack, the purchase cost of green certificates and the start-up costs. The other main assumptions in the analysis are summarized in table:

Discount rate	6%
Inflation rate	1%
Plant lifetime	20 years
Taxes	28% on profit
Amortization	11 years

The LCOH in the discount cash flow analysis is computed as the minimum price at which the hydrogen produced by the plant can be sold to have a positive net present value of the investment. The LCOH has been computed both considering and neglecting the additional revenues obtained by the sale of the surplus electricity of the PV plant. Indeed, such profit is not considered in the theoretical definition of the production cost of the hydrogen and, in case the sale of the surplus is particularly favourable, the real LCOH behaviour to the variation of the electrolysis nominal power may be hidden. Finally, the LCOH is also computed with its definition, as a second check, both considering and neglecting the electricity sale revenues.

$$LCOH = \frac{\sum_{t=0}^{n}(CAPEX + OPEX)_t + (E + W)_t - ADD.REV_t * (1 + r)^{-t}}{\sum_{t=0}^{n} H_t * (1 + r)^{-t}}$$

The LCOH values computed with the DCF were found to be consistent with the values obtained through its definition.

Results

For each scenario, the LCOH was computed for a variable electrolysis power range. The minimum LCOH plant configuration is reported for each scenario in Tables 2 and 3.

Results for Biomet

				Considering additional revenues			Not considering additional revenues		
	Electricity purchase	Ppv [MW]	C [kWh]	LCOH [€/MWh]	H2 [kg/day]	Pelectrolyser [kW]	LCOH [€/MWh]	H2 [kg/day]	Pelectrolyser [kW]
Scenario 1a	AU	0.61	-	12.09947	119.7902	260	12.1	138.2	300
Scenario 1a	PPA	0.61	-	8.5	460.7317	1000	8.5	460.7	1000
Scenario 2a	-	0.61	-	10.9	23.6	140	11.6	30.7	220
Scenario 3a	-	0.61	10	18.4	129	320	18.4	129	330

Table 2: Optimal plant configurations for the different Scenarios implemented for the Biomet installation.

The overall minimum LCOH is obtained for Scenario 1a, the one that considers the maximisation of the hydrogen productivity of the plant, for the case in which the additional electricity to implement electrolysis is purchased through a PPA. The employment of batteries to increment the hydrogen productivity resulted unsuitable for this application: the investment cost of batteries is too high to positively affect the cost of production. The LCOH trend for Scenario 1a is reported in Figure 2.

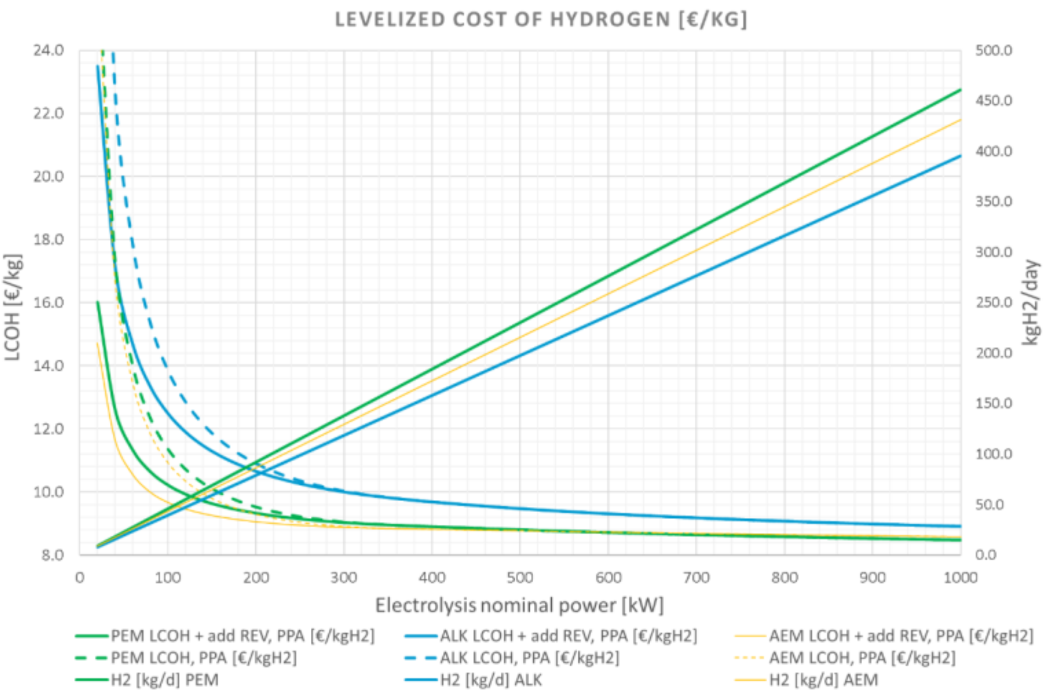
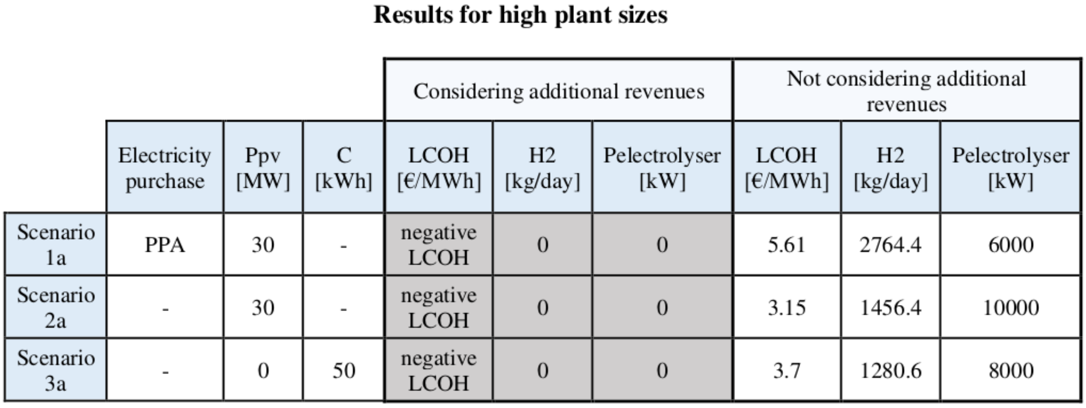


Figure 2: Trend of the LCOH [€/kgH2] and of the daily average hydrogen production [kg/d] for the PEM, ALK and AEM technologies. The continuous lines represent the LCOH computed considering additional revenues. The dashed lines neglects the revenues. Purchase of electricity with PPA.

The optimal results for all the three scenarios have been obtained for the maximum Ppv size considered in the study, 30 MW. Indeed, the higher the size of the PV plant, the higher one of the electrolysers can be and the more economies of scale are exploited. For all the three cases analysed, the LCOH computed considering the additional revenue of selling electricity to the grid has shown a negative trend for low electrolysis power. Indeed, while the LCOE of scenarios "a" was higher than the selling price of the surplus (the zonal price), the LCOE achieved by increasing the plant size to the utility scale allows obtaining a significant positive revenue linked to the surplus sale. Such revenue is so significant, especially at electrolysis low nominal powers, when the surplus is maximum, that for the 30 MW P plant it would be extremely advantageous to directly sell its production into the grid instead of feeding the electrolysis plant. For this reason, the corresponding cells in Table 3 have been cancelled out. The presence of such significant revenue corrupts the actual trend of the hydrogen cost with respect to the elec-



Results for high plant sizes

				Considering additional revenues			Not considering additional revenues		
	Electricity purchase	Ppv [MW]	C [kWh]	LCOH [€/MWh]	H2 [kg/day]	Pelectrolyser [kW]	LCOH [€/MWh]	H2 [kg/day]	Pelectrolyser [kW]
Scenario 1a	PPA	30	-	negative LCOH	0	0	5.61	2764.4	6000
Scenario 2a	-	30	-	negative LCOH	0	0	3.15	1456.4	10000
Scenario 3a	-	0	50	negative LCOH	0	0	3.7	1280.6	8000

Table 3: Optimal plant configurations for the Scenarios implemented at high plant size.

trolysis nominal power. This is the reason why the LCOH has been computed also neglecting the additional revenues, which doesn't have much sense from a practical point of view (it doesn't include a proper valorisation of the surplus) but it can theoretically show what is the optimal electrolysis nominal power the production is most convenient. At such high nominal sizes, the implementation of scenario 1a would result in a massive purchase of electricity from the grid, at a significant price. For this reason, the plant configuration that results in the minimum LCOH is Scenario 2b.

Sensitivity analysis

Both the electricity purchase price and the specific cost of the electrolysers are rather uncertain parameters. The first indeed depends on the electricity generation mix, which is highly variable, and on the size of the PV system. The second is affected by the fact that there is still no real supply chain for hydrogen produced from renewable sources and electrolysers still must reach their technological state of the art. A sensitivity analysis was performed on the LCOH by varying these two parameters, to investigate their influence on the hydrogen production competitiveness. The analysis was carried out for the PEM technology only, which was identified as the most convenient commercial technology for the coupling with renewables, and for scenarios 1a (with PPA) and 2a, i.e., the scenarios that consider the company's technical constraints. For scenario 2a, the variation of the PV investment cost was considered instead of the purchase price of electricity. The results for scenarios 1a and 2a are reported in Figures 4 and 5 respectively

The strong dependence of the Levelized cost of hydrogen on the electricity purchase cost is confirmed for Scenario 1a. The purchase price weights particularly at

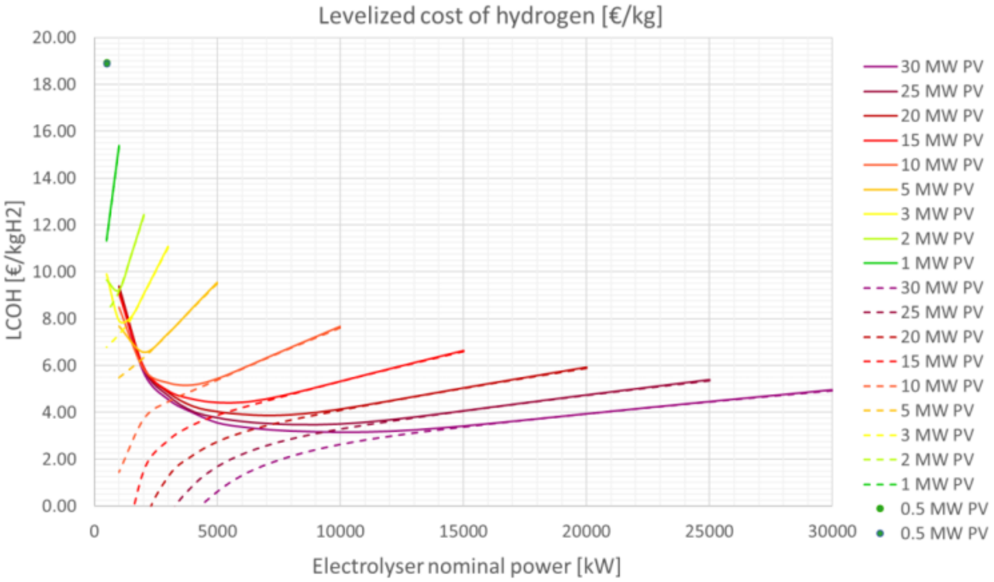


Figure 3: LCOH as a function of the electrolyser nominal power [kW] for different PV nominal sizes. Dashed line: LCOH computed considering the sale of the surplus. Continuous line: LCOH computed neglecting the sale of the surplus.

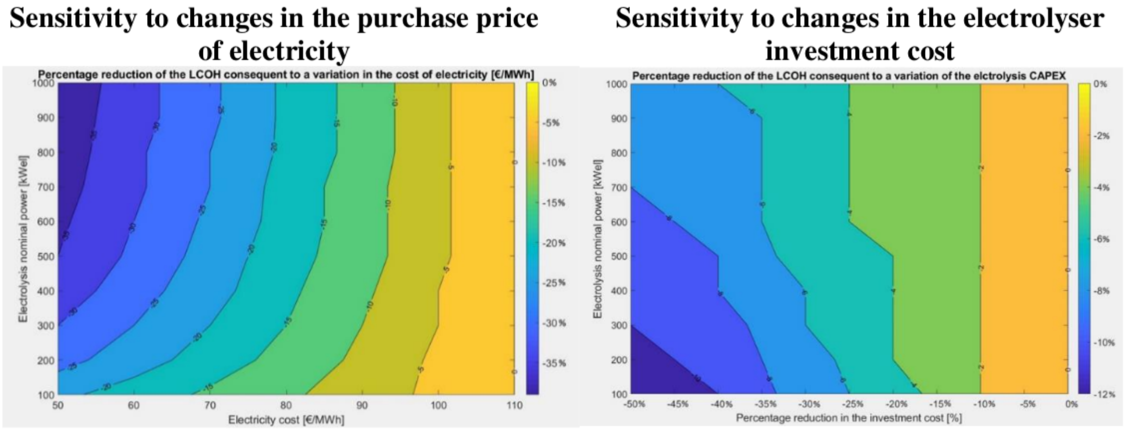
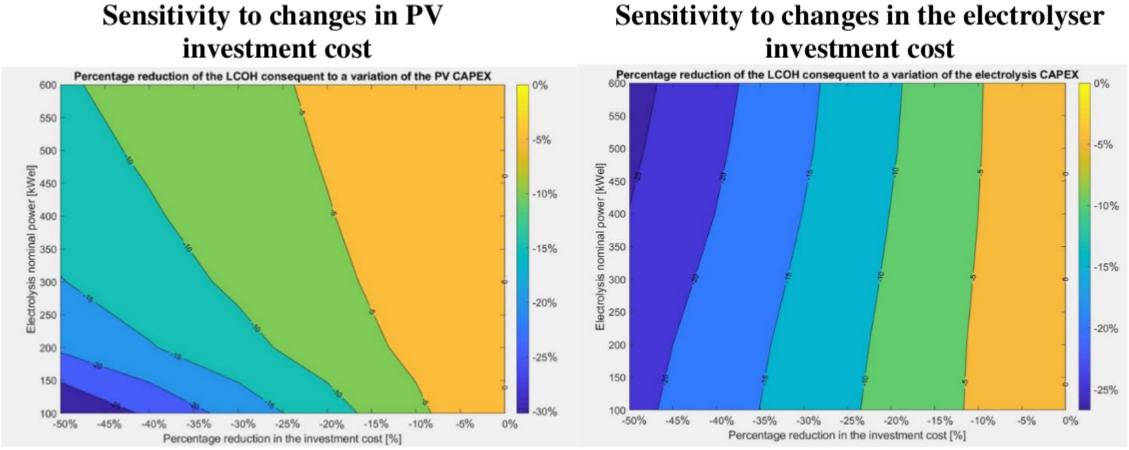


Figure 4: SCENARIO 1a, percentage LCOH variation consequent to:

- To the left: a purchase price variation $[N/MWh]$
- To the right: an electrolysis investment cost variation [%].

the electrolysis maximum rated power, i.e., when the quantity of energy purchase is the maximum. For this case, when the electricity cost is reduced of 55% (50 €/MWh), the LCOH reduces by the 40%, i.e., to 5.2 €/MWh. In Scenario 1a, the productivity of the electrolyser has been maximised for each rated power, to



Sensitivity to changes in PV investment cost

Sensitivity to changes in the electrolyser investment cost

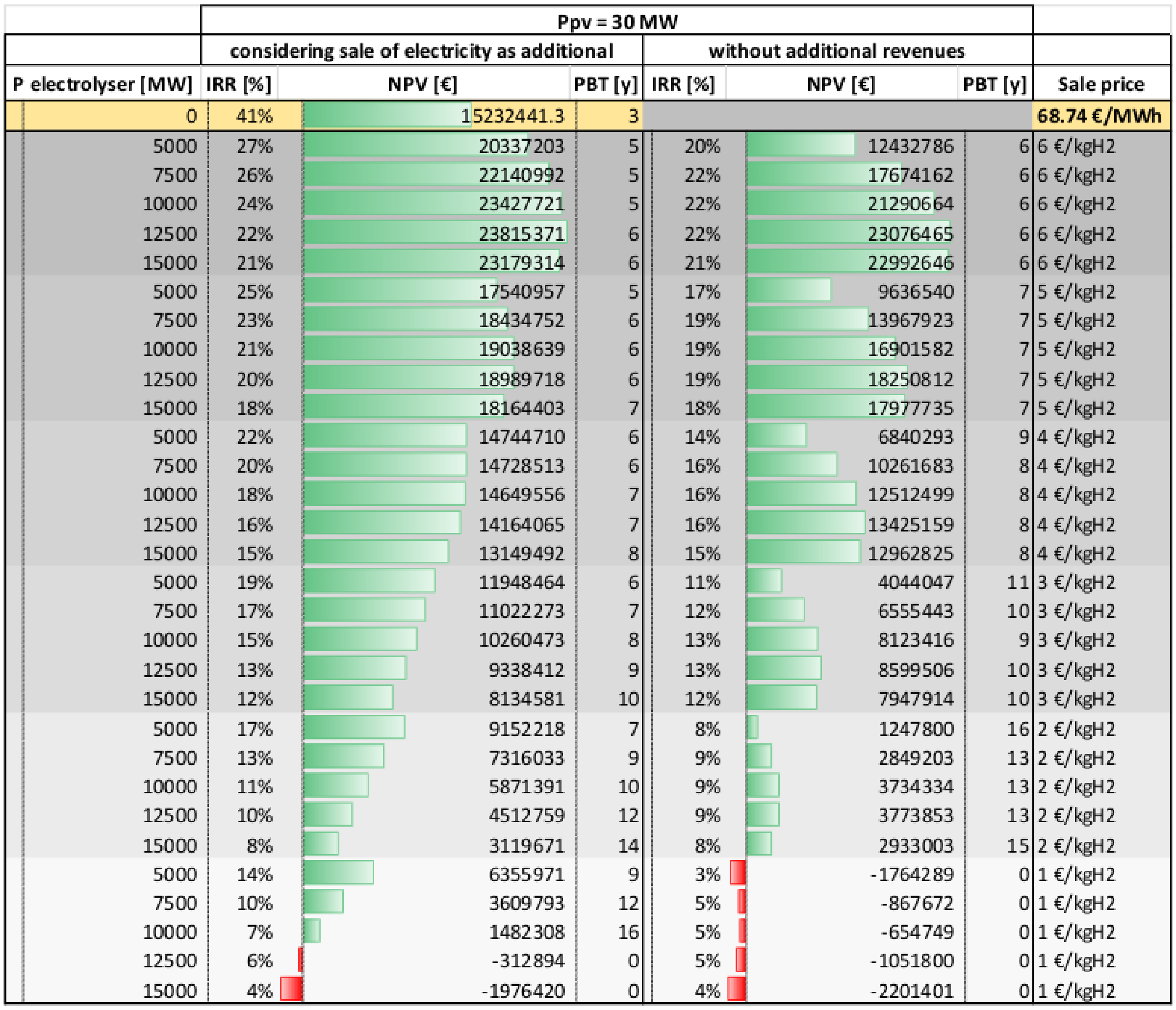
Figure 5: SCENARIO 2a, LCOH variation consequent to:
- To the left: a PV investment cost variation [%]
- To the right: an electrolysis investment cost variation [%].

decrease the dependency of the investment cost on the LCOH. This assumption is here confirmed, as a 50% reduction in the electrolysis investment cost would bring to a 12% reduction of the LCOH. The influence of the investment cost is the highest for low nominal powers, as the specific cost of the electrolysers increases with the decrease of the electrolysis size. The sensitivity of the LCOH to a variation in the electrolyser investment cost increases in Scenario 2a, as the operating hours of the plant, are lower, and the initial costs are shared among a lower hydrogen production. Differently, from what was observed in figure 5.1.2, the maximum dependency of the LCOH on the electrolyser investment occurs for the maximum electrolysis power, as for nominal sizes higher than 250 kW the electrolysis CAPEX increase but the hydrogen production remains almost unchanged. Finally, the dependency of the LCOH on the PV CAPEX is quite significant, and it is greater for a smaller electrolyser, which corresponds to the minimum production of hydrogen and therefore to the minimum use of the photovoltaic system.

Economic analysis for Scenario 2b

The Levelized cost of hydrogen is a simple indicator, that facilitates the comparison of the electrolysis produced hydrogen with the one produced with other production processes. As it represents the minimum price at which the produced hydrogen can be sold without falling into a negative profit, by comparing it with the selling price of hydrogen in the market (1-3 €/kgH2) it is possible to have a general idea regarding the feasibility of the production. Nevertheless, to properly investigate the feasibility of a certain investment, an economic analysis is needed.

Here this analysis is performed for the scenario that generates the lowest LCOH, Scenario 2b. The NPV, IRR and PBT have been computed for hydrogen selling prices of 1 to 6 €/kgH2, considering an incentive for the hydrogen production of 2 €/kgH2 and nominal size of the PV plant of 30 MW. The profitability of the investment in the hydrogen production for this layout is compared to the one of the PV plant in the basic case in which it sells the produced energy at the average zonal price, 68.74 €/MWh. The results are reported in Table 4



	Ppv = 30 MW						
	considering sale of electricity as additional			without additional revenues			
P electrolyser [MW]	IRR [%]	NPV [€]	PBT [y]	IRR [%]	NPV [€]	PBT [y]	Sale price
0	41%	15232441.3	3				68.74 €/MWh
5000	27%	20337203	5	20%	12432786	6	6 €/kgH2
7500	26%	22140992	5	22%	17674162	6	6 €/kgH2
10000	24%	23427721	5	22%	21290664	6	6 €/kgH2
12500	22%	23815371	6	22%	23076465	6	6 €/kgH2
15000	21%	23179314	6	21%	22992646	6	6 €/kgH2
5000	25%	17540957	5	17%	9636540	7	5 €/kgH2
7500	23%	18434752	6	19%	13967923	7	5 €/kgH2
10000	21%	19038639	6	19%	16901582	7	5 €/kgH2
12500	20%	18989718	6	19%	18250812	7	5 €/kgH2
15000	18%	18164403	7	18%	17977735	7	5 €/kgH2
5000	22%	14744710	6	14%	6840293	9	4 €/kgH2
7500	20%	14728513	6	16%	10261683	8	4 €/kgH2
10000	18%	14649556	7	16%	12512499	8	4 €/kgH2
12500	16%	14164065	7	16%	13425159	8	4 €/kgH2
15000	15%	13149492	8	15%	12962825	8	4 €/kgH2
5000	19%	11948464	6	11%	4044047	11	3 €/kgH2
7500	17%	11022273	7	12%	6555443	10	3 €/kgH2
10000	15%	10260473	8	13%	8123416	9	3 €/kgH2
12500	13%	9338412	9	13%	8599506	10	3 €/kgH2
15000	12%	8134581	10	12%	7947914	10	3 €/kgH2
5000	17%	9152218	7	8%	1247800	16	2 €/kgH2
7500	13%	7316033	9	9%	2849203	13	2 €/kgH2
10000	11%	5871391	10	9%	3734334	13	2 €/kgH2
12500	10%	4512759	12	9%	3773853	13	2 €/kgH2
15000	8%	3119671	14	8%	2933003	15	2 €/kgH2
5000	14%	6355971	9	3%	-1764289	0	1 €/kgH2
7500	10%	3609793	12	5%	-867672	0	1 €/kgH2
10000	7%	1482308	16	5%	-654749	0	1 €/kgH2
12500	6%	-312894	0	5%	-1051800	0	1 €/kgH2
15000	4%	-1976420	0	4%	-2201401	0	1 €/kgH2

Table 4: NPV, IRR and PBT computed for Scenario 2b and a nominal PV plant size of 30 MW. The parameters are computed for both the case with the sale of the surplus and the case that neglects it. The parameters are computed for electrolysis rated power of 5 to 15 MW and sale prices of 1 to 6 €/kgH2

Even if for most of the hydrogen sale prices assumed the IRR values of the investments are high and the NPV values are positive, the most convenient solution for a 30 MW PV plant is to inject all its production into the grid, instead of using it to produce hydrogen. The financial parameters in the case that valorises the surplus (Figure 4, columns 2 to 4) are higher than the ones computed neglecting it (columns 5 to 7). Moreover, while The only case in which the investment is unfeasible is for a selling price of 1 €/kgH2, with the NPV of the investment that is lower than zero for those values of IRR that are lower than the discount rate assumed in the analysis (6%).

Conclusions

In this document the feasibility of producing green hydrogen through electrolysis of water and photovoltaic renewable electricity was studied for a wide range of applications. First, the study focused on the case of Biomet s.p.a., with a maximum PV power of 600 kW, limited space and water availability. The minimum LCOH was found to be 8.50 €/kgH2 for a 1 MW electrolysis plant which works at maximum load thanks to the supply of 110 €/MWh electricity. Being all the components subject to strong economies of scale, the same feasibility was investigated for higher PV and electrolyser sizes, neglecting water and space constraints. In such case, the minimum LCOH obtained was 3.1 €/kgH2 for an electrolyser of 10 MW coupled to a 30 MW PV off-grid plant. The greater competitiveness of this case was mostly due to the very cheap LCOE produced by the PV plant. Despite the low price of hydrogen production, and considering hydrogen incentives, the direct sale of the PV electricity to the grid resulted to be much more convenient (IRR of 41%) than its employment for the hydrogen production for this specific case. Nevertheless, the hydrogen production would still result competitive and with the 50% expected decrease in the technology's investment cost and in the price of electricity, determined as two very influencing parameters on the LCOH, green hydrogen will surely be competitive in the global market.

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Chapter 1

Introduction

1.1 The role of hydrogen for decarbonisation

In the 2015 United Nations Climate Conference in Paris, the global community set the framework for a rapid global shift toward a sustainable energy system, to avoid the consequences of a catastrophic climate change. The challenge established by the countries was to keep the global temperature rise for this century below 2 degrees Celsius in relation to 1990 levels. To permit this, CO2 emissions would have needed to decline by around 25% from 2010 levels and reach net zero by around 2070. After three years, in 2018, the "Global Warming of 1.5°C" report by the Intergovernmental Panel on Climate Change (IPCC) defined such temperature reduction as insufficient to create a meaningful action to limit the climate crisis, suggesting the new limit of +1.5 °C. For a reasonable likelihood to stay below such temperature, the global net CO2 emissions should decline by 45% by 2030, from 2010 levels, reaching net zero by 2050 [25]. A growing number of countries are committing to respect these goals, including the European Union, which in July 2021 has published a set of proposals called 'Fit-for-55' that aims to update its legislation and bring it in line with the 2030 goal. The 55% reduction, with respect to 1990 levels, is seen as an essential step to properly prepare for the binding target of achieving climate neutrality by 2050 [8]. In contrast with these ambitions, in 2021 the global energy and industrial processes related CO2 emissions have increased by 6% from 2020 levels, up to a 36.3 gigatonnes (Gt), reaching their highest ever annual level. Despite the renewable power generation has registered its largest ever annual growth, the recovery of the energy demand after the pandemic was compounded by adverse weather and energy market conditions, which lead many countries to fall back on coal [22]. This is in contrast with the emissions reduction goal, and countries clearly must push more radically towards an energy transition to achieve climate goals. According to an analysis performed by the

International Renewable Energy, over 90% of the necessary global CO2 emission reductions could result from improvements in the renewable energy production share and energy efficiency. Nevertheless, not all the sectors and industries can easily switch from fossil fuels to electricity and therefore be decarbonised. One-third of the global energy- related emission are produced by such sectors, for which there is presently no technical and economic alternative to fossil fuels. For this reason, they are called "hard to abate", and include: the freight and long-haul road transport, the iron and steel industry, the cement and the chemical industry and the aluminium production, as shown in Figure 1.1 [24].

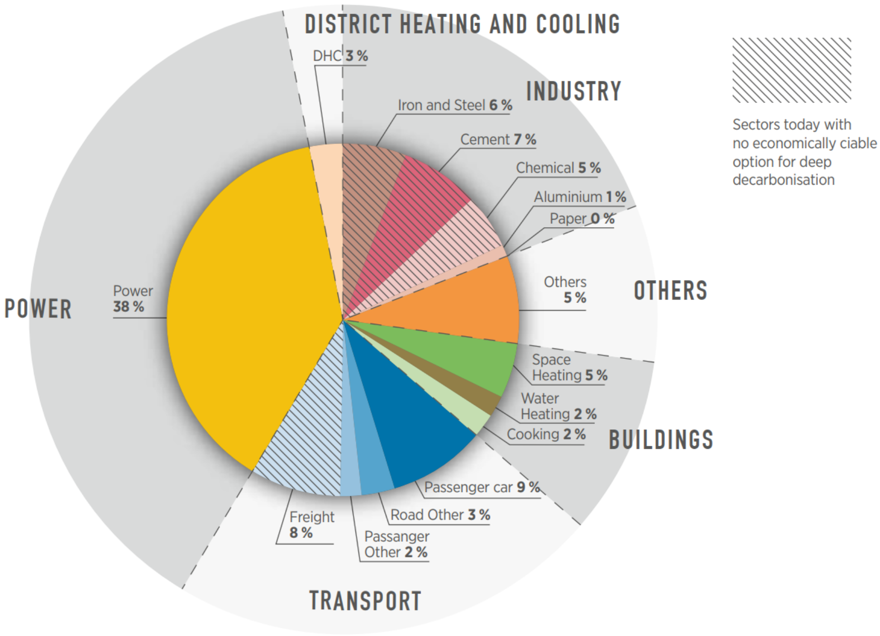


Figure 1.1: Evidence of the hard to electrify sectors over the overall energy sector [24].

The "missing link" in the energy transition may be clean hydrogen. Hydrogen is a versatile energy carrier both in terms of supply and uses that can be produced from the electrolysis of water, employing renewable sources only, with a near-zero carbon production route. It has been employed for several years in the fields of fertilizers production, the steel industry and oil refining. Lately, it has been invested with particular attention, as it is designated to be one of the main candidates to contribute to the clean transition of the energy sector. The advantages of the use of such gas are plenty. Firstly, the hydrogen industry is well established, and many sectors already use H2 as a feedstock, many of which are "hard-to-abate" ones. The majority of the hydrogen employed is however fossil-fuel based and has high embedded emissions. By substituting such hydrogen with a clean one, obtained with renewables, such sectors may significantly decrease their impact, without the need of crossing the electrification path. Secondly, hydrogen can be employed to help the integration of non-programmable renewable sources in the grid network, storing the surplus electricity to produce hydrogen and convert it back to the grid when it is needed. In this way, it can support the needed increase of renewable energy power plant deployment, damping their variability and so providing a stabilizing effect to the grid network. Differently from electricity, hydrogen can be stored for a longer time, and it can allow the decoupling of the generation of electricity to its consumption. Another interesting perspective is that hydrogen brings the possibility of channelling large amounts of renewable energy from the power sector into other sectors, such as transport, building or industry, without the need for any electrification infrastructure. Finally, hydrogen can successfully respond to the global need for decarbonisation and a flexible power system. Meanwhile, the decreasing cost of renewable energy sources and the technological advancements and cost reductions in hydrogen-related technologies are increasing the competitiveness of the clean production of this gas, which has up to now been unfavourable compared to steam methane reforming and carbon cracking. For this reason, green hydrogen nowadays is receiving unprecedented attention from international governments and investors in the energy sector, which materialized in the "European Hydrogen Strategy" of July. 2020. In this document, theEuropean Commission determines some measures to support the momentum of hydrogen as an energy carrier, such as the aim to install 6 GW of electrolysis by 2025 and 40 GW by 2050, to achieve a 13-14% increase in H2 in the energy mix. This would mean generating 400 million tons of hydrogen per year. In addition, as it is estimated that to meet the 2030 goals a strong boost to sustainable mobility is necessary, it has set the aim to build 1,000 hydrogen refuelling stations by 2025. The most prominent international agencies in the energy sector, such as the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA) and the Hydrogen Council have also predicted a future hydrogen boom, calculating that by 2050 it will constitute 6 to 18% of the global energy consumption [25]

1.2 The hydrogen market

The global production of hydrogen nowadays amounts to around 120 million tons per year, two-thirds of which are in the pure form and one-third in a mixture with other gasses. The energy equivalent of such an amount of hydrogen is 14.4 exajouls (EJ), which is 4% of the global final energy and non-energy use, according to the IEA statistics ([35]; [25]). Most of the hydrogen today is produced and used on-site in the industries. The demand for hydrogen is 115 million tons per year and it is limited to specific sectors [35]; [26]. 60% of the overall hydrogen is used for oil refining and for ammonia production, which is used to produce fertilizers. The remaining is mostly used in a mixture form for methanol production and the steel industry [35]; [25]. As the production processes and the type of primary sources used for the gas production are plenty, a colour label classification has been developed over the years to distinguish one kind of hydrogen from the other. Depending on the processes implemented for its production, hydrogen may either be a clean gas or have high embedded emissions. The bigger share of the H2 generated, 71% of the total, is obtained through steam reforming or partial oxidation and it is called “gray hydrogen”. In 30-40% of the cases, the employed primary source in this hydrogen is natural gas, but other fuels such as naphtha or other light hydrocarbons may be used. The specific emissions of the gray hydrogen are 9-10 kgCO2 / kgH2. Despite its high polluting process, gray hydrogen has very low production costs, 1-2 $/kgH2, which is the reason why it is the most implemented technology. The second most used process for hydrogen production is coal gasification, which is the high-temperature reaction of pulverized coal with pure oxygen and water vapour. Such a process has a 28% share among all the hydrogen production. This technology is mostly used in China, where the coal’s low costs allow to obtain very cheap, 1-1.5 $/kgH2, but very polluting, 18-20 kgCO2/kgH2, hydrogen. It is called “brown hydrogen”. Both the steam methane reforming and the coal gasification processes may be coupled to a Carbon Capture Utilization and Storage (CCUS) to produce “blue hydrogen”. This capture mechanism significantly reduces the emissions to 5 kgCO2 / kgH2 but brings additional costs, so that the production costs increase to 2-3$/kgH2. It represents 0.6% of global production. Finally, 0.3% of the overall hydrogen production is obtained through the electrolysis of water, employing renewable sources and so with emissions that don’t exceed 3 kgCO2 / kgH2. It is called green hydrogen. This is the only kind of hydrogen which meets the requirements of the RED II directive. Indeed, in order to be considered an activity that contributes to the mitigation of climate change and does not harm the environment, hydrogen must be produced with an emission quota below 3 kgCO2/kgH2. For this reason, the green hydrogen only can be referred as to “clean” hydrogen. The costs of producing green hydrogen are highly variable. In the work [30] an extensive literature analysis was carried out regarding the CAPEX of the electrolyser and the hydrogen production cost, and it was found that it can vary from 2 to 20 €/ kgH2 [30]. This happens due to the great variability of the assumptions and working parameters, such as the cost of the renewable energy used, the investment cost of the electrolyser, the costs of compression or purification of the gas and, most of all, the high variability of the production scale of the plants. Other sources estimate that the cost of green hydrogen is 2 to 4 times higher than the one of blue hydrogen, up to 7.6 €/kgH2 ([31]; [28]). The average production of cost of green hydrogen is found as 6 €/kgH2 ([24]). If the electricity feed used to implement electrolysis is drawn from the grid, the hydrogen is very likely to be more expensive than the one obtained from cheaper fossil fuels. This is the reason for the low employment of this technology, which is mostly used only for applications with high hydrogen purity standards. A way to reduce such costs is to couple the production to a utility-scale high-load renewable power plant. The hydrogen market price depends on many technical and economic factors and is subjected to a strong variability. This is due to the volatility of the fossil fuel prices on the market and the non- homogeneous distribution of the natural resources around the earth. For example, the cost of natural gas affects the final cost of hydrogen from 45% to 75% in the case of steam methane reforming and the main supplier of this resource, the Middle East, Russia, and the USA, are the countries that can produce the least expensive hydrogen all over the world. The final price of the hydrogen also depends on the way it is transported from the supplier to the end users. Nowadays trucks are designated to carry hydrogen into pressurized tanks in the cases of distances of less than 300 km and quantities less than 500 tons per day. If the transportation distances and the gas quantities are higher, it may be convenient to rely on designated pipelines. Such pipelines are not public as the ones used for methane but are built as integral parts of multi-year supply agreements. Overall, the H2 pipelines run for 5,000 km in the world, a minimal amount when compared to the approximately three million km dedicated to the transport of natural gas. An option that is becoming increasingly popular through the hydrogen production facilities, thanks to the increase in the demand for H2, is the possibility of building plants in the vicinity of the end user. This solution is frequently adopted in the refining field. A particular case is represented by hydrogen refuelling stations for vehicles, which may self-produce the sold hydrogen instead of purchasing it from other facilities ([30]). Another parameter that influences the price of hydrogen is investment costs, which are variable from one production process to another. Even within the same production process, the CAPEX may significantly change depending on the system layout, for example on whether the steam reforming is performed in a centralized or a decentralized reformer. Currently, the hydrogen produced by reforming is sold, on average, at a price below 3 €/ kg [20] making the green hydrogen uncompetitive on the market without incentive mechanisms.

1.3 The potential of green hydrogen in Italy

Several states in Europe (such as France, Germany, and Holland) have already integrated the European regulations into national strategies to take advantage of the development opportunities presented by hydrogen. Italy, although has yet just published preliminary guidelines ("Linee Guida preliminary") lacks a proper strategy for the development of the hydrogen supply chain. Nevertheless, some of the European ideas for hydrogen have been included in the National Recovery and Resilience Plan (PNRR, [3]) on April 6, 2021, including some investments that the government intends to make in the green revolution and ecological transition. Overall, 3.19 billion euros are aimed at promoting the production, distribution, and end uses of hydrogen, divided into:

a. 0,5 billion to promote the H2 production in abandoned industrial areas to create "hydrogen valleys";

b. 2 billion for use in the hard-to-abate sectors (financing for the installation of 1 GW of electrolysers);

c. 0.23 billion for experimentation in road transport (financing of 40 refuelling stations for wheeled vehicles);

d. 0.3 billion for experimentation in railway transport (financing of 9 refuelling stations);

e. 0.16 billion for research and development.

Finally, the government plans to update all the regulatory reforms that act as a barrier to the production, transport, and distribution of hydrogen. The Italian market is considered by major consulting firms to be extremely attractive for investments in the hydrogen field. It is estimated that it could account for up to 23% of total energy consumption by 2050, almost a quarter of the energy required by the whole nation [34]; [7]. Hydrogen may indeed be used to completely decarbonize hard-to-abate sectors which represent 45% of the Italian greenhouse gas emissions today. In Figure 1.2 a representation of such sectors is shown.

Today Italy has reduced its greenhouse gas emissions by 28% compared to 1990 levels but emissions must still be reduced by 38% compared to today's levels by 2030 to "fit- for-55 " [17]. The wide availability of renewable resources on the Italian territory allows obtaining a low cost of electricity, one of the parameters that most influences the final cost of hydrogen together with the CAPEX (Capital Expenditures) of the electrolyser and its operating hours. Furthermore, Italy could use the gas transport infrastructure network that connects it to North Africa, where hydrogen could be produced at even more competitive costs (up to -14%) thanks to high solar irradiance, to then be distributed from Italy to the rest of Europe (Italy as a European "hydrogen hub", see Figure 1.3, [34]; [7]). The pipeline network consists of over 34,000 km in transmission and 250,000 km in distribution. The transport of hydrogen into natural gas pipelines is convenient but has some difficulties: hydrogen is a much smaller molecule than methane,

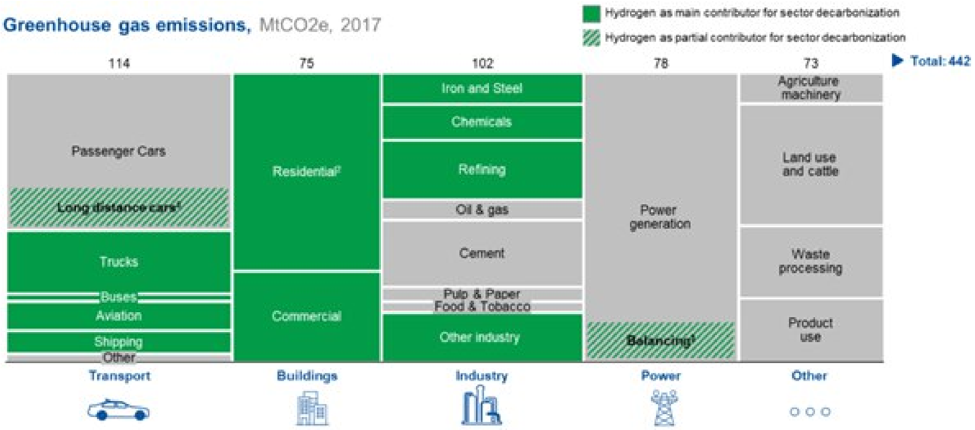


Figure 1.2: Sectors where the use of green hydrogen could contribute to decarbonisation [18].

which requires very specific pipelines for its transport and for the management of its high flammability. For this reason, its percentage in gas pipelines cannot exceed 10% nowadays. In addition, it has a much lower energy density than natural gas, and its mixing of 5-10% with methane would result in a reduction in the energy transported from 3.3% to 6.6%, thus increasing the cost. However, Snam estimates that over 70% of the pipes in its methane pipelines are already ready to transport hydrogen and has already adopted a new internal regulation to allow the transport of increasing percentages of gas, up to 100%. Thegoal is to achieve the transport of only decarbonised gas in methane pipelines (biomethane and hydrogen) by 2050 [7].

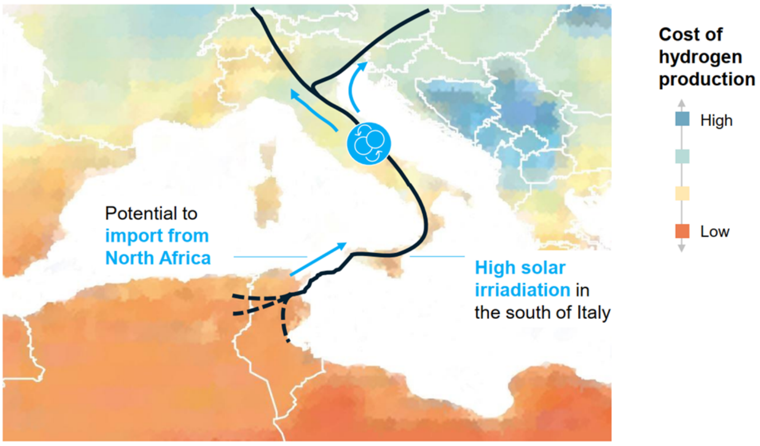


Figure 1.3: Costs of hydrogen production for hybrid solar photovoltaic and onshore wind systems [34].

The development of the hydrogen market in Italy would bring important benefits:

- Hydrogen can be used as a long-term energy storage method, and could be used to increase the use of renewable plants and reduce the "curtailment" of energy, the phenomenon by which intermittent renewable plants produce energy at times when demand is already satisfied and therefore do not sell it and are forced to pay quotas to the grid for the disservice. With the increase in the use of renewable sources in the energy mix, this "seasonal storage" service will be even more necessary.
- Hydrogen could be used to connect the points of greatest production of renewable energy (southern Italy) with the points of greatest demand (the North), being distributed in the gas infrastructure network and therefore without the construction of new infrastructure of the electric system.

In this way, Italy would assume a strategic role in the Mediterranean in addition to obtaining an almost unlimited supply of hydrogen at lower costs than the rest of Europe. To many studies, Italy will be one of the first states in Europe where green hydrogen will completely replace the fossil one. For example, McKinsey estimates that the breakeven of the technology could occur in Italy 5 to 10 years earlier than in Germany (see Figure 1.3). This technical and economic feasibility study on the installation of an electrolysis system for the production of green hydrogen using renewable energy at the Biomet company in San Rocco al Porto is part of this perspective.

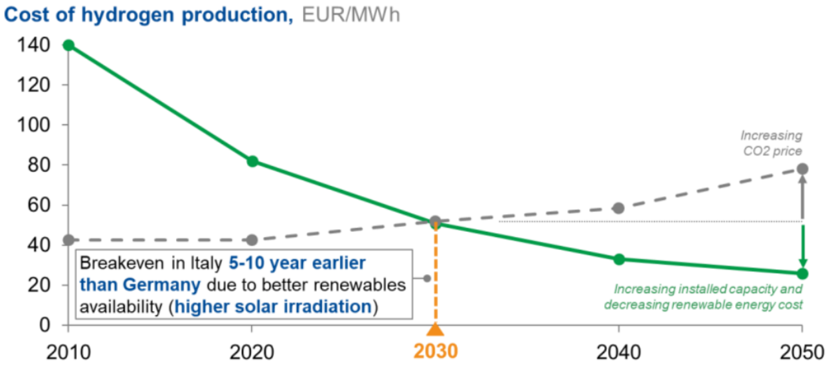


Figure 1.4: Evolution of production costs for green and gray hydrogen in Italy.

1.4 The case study: Biomet s.p.a.

Biomet s.p.a. is a company whose core business is the production, transformation, and distribution of liquid biomethane (BioGNL) from the organic fraction of urban solid waste (OFMSW). The company's activity is divided into two sites. In the San Rocco al Porto (LO) site, the wet waste obtained through the municipal waste sorting is collected and pre-treated to be cleaned from non-biodegradable materials such as plastics and metals (see Figure 1.4). It is then placed in circular digesters and decomposed through anaerobic fermentation. This process has three main outputs:

- The biogas, captured in gasometric domes and then transformed into biomethane via upgrading.
- The solid digestate, which is centrifuged to reduce the water content and then placed into bio cells together with the green waste, received from the ecological pitches, is used as a structuring agent. After screening and shredding, fertilizer is obtained for use in agriculture;
- The water obtained following the centrifuge process is purified, to be introduced into the waterways of the area.

After the upgrade, the biomethane is fed into the SNAM network. At the Belgioioso (PV) plant, a quantity of methane equal to that of biomethane produced in San Rocco al Porto is withdrawn from the national network, which is liquefied to obtain liquified natural bio-gas (bioGNL). The biomethane produced is stored here in cryogenic storage. Finally, the bioGNL produced is sold through the road distributor of the Belgioioso site and supplied to other local distributors. This fuel is used for heavy-duty vehicles (trucks or buses).
In such an advantageous moment for the investments in the field of hydrogen production and transportation, Biomet is considering the possibility to become a green hydrogen producer and supplier. The idea is to install photovoltaic modules on the roofs of the warehouses of the factory, which are already provided with a photovoltaic mounting system, and to purchase a series of electrolysers to produce clean hydrogen for the mobility sector. The water feed for electrolysis would be rainwater together with the purified discharged water of the digester. Except for the economic and political factors that favour the installation of a clean hydrogen production system, see 1, Biomet presents several reasons to be interested in the clean hydrogen sector. First, Biomet already is an active player in the production, transportation, and distribution market of renewable gas, and it may efficiently use its expertise to succeed also in the green hydrogen market. The bio-methane production process needs many energy input feeds, such as those for heating the digester, keeping the feedstock moving inside it and liquefying the bio-methane. The company provides for its energy needs with a cogenerator that uses pipelines' natural gas as a fuel. The bio-methane produced by the plant is indeed totally devoted to the Belgioioso refuelling station for heavy-duty vehicles.

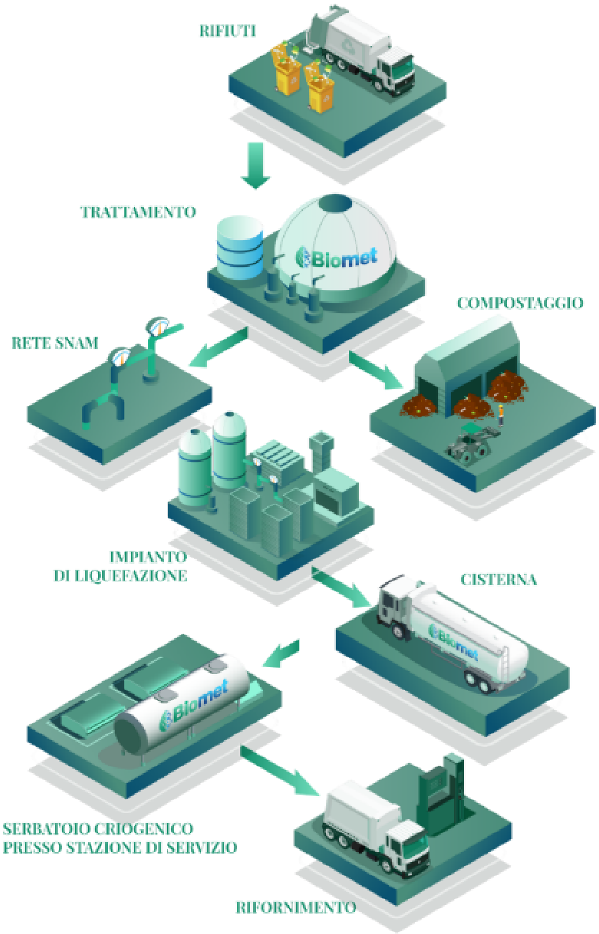


Figure 1.5: Plant scheme of Biomet s.p.a., San Rocco al Porto [4].

Natural gas is purchased on request at an expensive price. The installation of a non-programmable power plant coupled with a fixed energy consuming unit, the electrolyser, would bring to the production of a surplus that could feed the energy needs of the bio-methane power plant. In this way, less natural gas would be needed to be purchased from the grid and a smaller cogenerator could be purchased by the company. Installing a renewable power plant would be an optimal perspective for the San Rocco al Porto activity to feed the bio-methane plant with cheap electricity, independent of fossil fuels' volatile prices. Coupling such renewable production to the electrolysis process would allow taking advantage of the scrubber outlet water, which has high quality and would otherwise be discarded. Finally, the company already owns a natural gas refuelling station and the installation of a hydrogen one may benefit from the already present infrastructure. To conclude, this study focuses on the feasibility of integrating a green hydrogen production system with the existing biomethane production plant at Biomet. The idea is to enhance the water from the centrifugation of the digestate as a primary resource for electrolysis, with the help of electricity supplied by a photovoltaic system to be installed in the plant area. This feasibility study for hydrogen production at Biomet integrates the feasibility study for the installation of a hydrogen refuelling station at one of the company's sites.

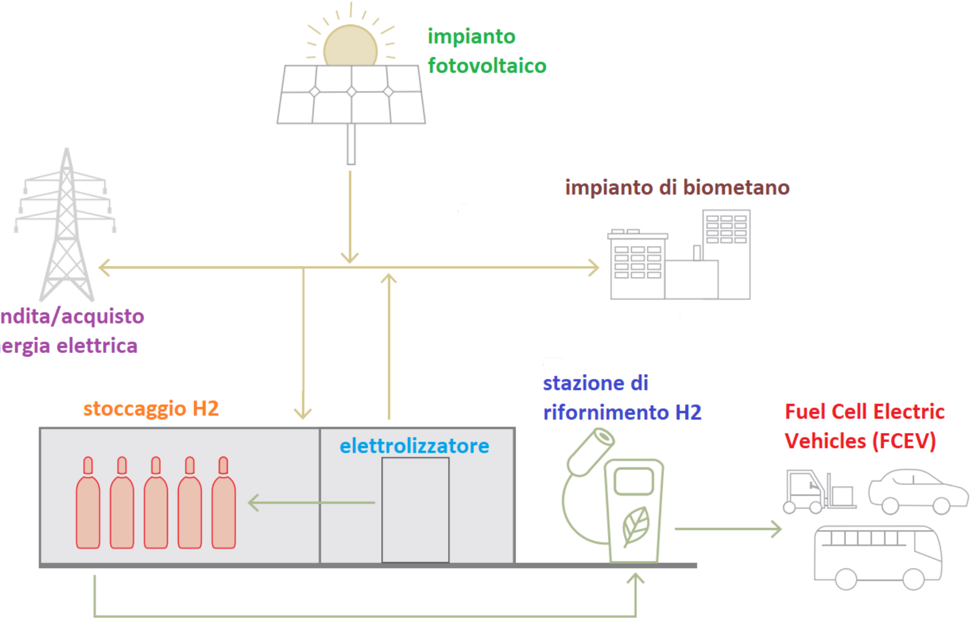


Figure 1.6: Scheme of the hydrogen production and distribution facility thought for Biomet.

Chapter 2

Hydrogen production via electrolysis

2.1 Electrolysis of water

Invented at the beginning of the 19th century, electrolysis has been for a long time the dominant process for the generation of hydrogen in the industrial sector. The increase in the use of natural gas during the 20s led to the replacement of this production process with the economically favoured steam methane reforming of methane. Nowadays, with the increasing share of renewable energy in the global electricity production and the introduction of stringent environmental limits on greenhouse gas emissions, water electrolysis is regaining importance. It is indeed the only known way to produce energy sustainable hydrogen, thanks to its employment of renewable electricity. The possibility of connecting the production of such an important technical gas to renewables proves to be of great interest as it allows renewable energy to be linked to the heavy industry and transport sectors, which have always been fossil-fuel dependent. Water electrolysis is an electrochemical reaction that allows the decomposition of the water molecule into hydrogen and oxygen in the gaseous phase.

$$H_2O \rightarrow H_2(g) + \frac{1}{2}O_2(g) \tag{2.1}$$

Being a non-spontaneous oxidation-reduction reaction, it requires the application of external energy to overcome the energy barrier between the more stable reactant, water, and the less stable products, hydrogen and oxygen. Overall, the reaction allows to accumulate the electrical energy input into the chemical energy of the products. The fundamental unit in which the reaction takes place is called the electrolytic cell. This cell is composed of two electrodes (the anode and the cathode), which are placed in contact with an electrolyte and are fed by a direct external current. Thanks to the electricity supply, the cathode, which is negatively charged, undergoes a reduction reaction while the anode, positively charged, an oxidation one. Electrolytic cells are different according to the chemical nature of the electrolyte and their functioning temperature. The electrolyte is the fundamental component of the electrolytic cell that allows the ions to flow from the anode to the cathode and thus separate the hydrogen atoms of the water from the oxygen ones. Depending on which electrolyte is used, the main charge carriers in the process change: they may be OH-, H3O+ or O2-. Depending on such a choice, the whole architecture of the electrolytic cell changes, leading to 3 main technologies:

- the alkaline electrolytic cell;
- the polymer membrane electrolysis;
- oxide electrolysis solids (SOEL).

Electrolysis strongly depends on the temperature at which the process is performed. Depending on it, two families of electrolysis cells are found: a) low-temperature cells (T of operation around 50 – 80°C); b) high-temperature cells (solid oxide cells or SOEC, T of operation $>$ 700°C). By piling up the single cells, and connecting them in parallel or series, it is possible to create a stack. A system of several stacks connected together forms the electrolyser [6].

2.2 Electrolyser technologies

Nowdays, the main technologies implemented for electrolysis are:

- the alkaline eletrolyser (ALK);
- the Anionic Exchange Membrane electrolyser (AEM);
- the Proton Exchange Membrane electrolyser (PEM);
- the Solid Oxide Electrolysis Cell Electrolyser (SOEC).

ALK and PEM cover almost the entire installed capacity today, while SOEC and AEM technologies are in the research phase and foresee future performances [6]. The main characteristics of these different technologies are outlined in the following paragraphs.

2.2.1 Alkaline electrolysers (ALK)

The alkaline cell is the first technology that has been invented and is indeed the most mature, providing a durable water electrolysis system used widely for decades in the industrial sector. Its working principle is based on the transport of the OH- ions from the cathode (the positive electrode) to the anode (the negative one), which are placed into a liquid electrolyte made of the alkaline solution KOH (dissociated in K+ and OH-) and H2O. A porous separator is placed between the positive and the negative side, as H2 and O2 bubbles accumulate at the interface, causing some leakages of the gasses in the wrong directions. This separator allows only the OH- ions to pass through. The electrolysis reaction is split in two main sub reactions:

- the hydrogen evolution reaction, occuring at the cathode

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{2.2}$$

- the oxygen evolution reaction, occuring at the anode

$$2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^- \tag{2.3}$$

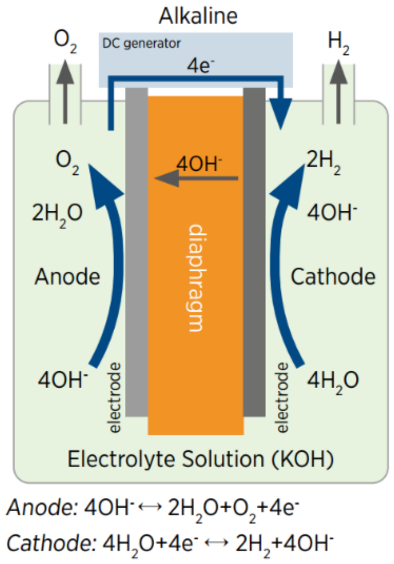


Figure 2.1: Working scheme of the ALK.

The alkaline environment is not very aggressive on the cell components and allows the employment of non-noble catalysts (Ni-based) to favour the reaction as well as cheap current collector materials (mostly steel). For this reason, and thanks to the maturity of the technology, the alkaline electrolysers are the cheapest on sale in the market. The hydrogen is produced with an efficiency of 55-65% on LHV basis. The thermodynamic efficiency of an electrolyser is defined as:

$$\eta_{el}^{th} = FU \cdot \frac{\frac{LHV_{H_2}}{2F}}{\Delta V} \tag{2.4}$$

Where the LHV_{H_2} is the low heating value of hydrogen, F is the Faraday constant and ΔV is the voltage applied across the cell. FU is the Fuel utilization, which accounts for that part of the produced H 2 by the cell that is lost due to the recombination of H 2 and O 2 inside the system. For this technology $FU \sim 0.96 - 0.98$, which means that 2 to 4% of the H2 is not actually useful. This is due to crossover, which is the biggest issue that occurs in the alkaline cell. Crossover is the phenomenon of the mixing of the H2 and O2 inside the cell after they are formed. It is mostly linked to diffusion and thus is caused by the difference in concentration between the H2 and the O2 part of the electrolytic cell. The mixing of the two gasses doesn't only imply a loss of hydrogen production, and thus of energy, but may also cause the formation of an explosive mixture and lead to important safety problems. To minimize the mixing between the two gasses, the cell is designed with a big gap between the two electrodes, to minimize the presence of H2 and O2 bubbles near the separator. Nevertheless, such a higher gap implies a higher path for the OH- ions and so higher ion transport losses and ohmic losses. Additionally, this is the reason why the alkaline electrolyser is the bulkiest among all the commercialized electrolysers, with a power density that is 25% lower than the one of the others. All these features are a consequence of the electrolyser architecture itself: the hydrogen production is obtained through the formation of H2 and O2 bubbles close to the catalyst layer, which causes a gathering of such bubbles in the active area of the system. Such bubbles act as a resistance to the passage of OH- ions, and increase the mass transport losses of the system. For this reason, the current is limited to 0.5 in the alkaline cell, and the power accordingly. A lower current corresponds to a higher voltage across the cell, which in turns brings to a low cell efficiency and to the need for bulky stacks, that are expensive to transport. Stack mobility is indeed one of the major contributing factors to the alkaline electrolysers' CAPEX. The hydrogen purity assured by this process lies in the range of 99.7% -99.9%, limited by crossover and by the presence of electrolyte traces inside the product gasses. To be used in fuel cell electric vehicles (FCEV), ALK produced hydrogen needs to undergo subsequent purification steps, as the purity requirement is at least of 99.97%. Another problem linked to crossover lies in the partial load operation of the cell. In order to prevent the creation of an exploding mixture of H2 and O2, the maximum amount of H2 that can end up inside the O2 stream is 4%. As crossover is mostly linked to diffusion, the amount of moles of the two gasses that end up following the wrong path is almost independent of the current at which the system is operated, and thus independent of the loading. In the case of a partial load operation, while the amount of moles of O2 that crosses over towards the H2 part remains constant, the amount of produced moles by the reaction decrease. The effect of the O2 crossflow is then more relevant and the safety risks for the operation are higher. This behaviour is caused by the fact that the architecture provides a porous section for the gasses' separation and not a membrane, which would limit the crossover. Due to this, in the past, the partial load operation of alkaline cells was possible up to 40% of the nominal current. This has been a problem in the past in the coupling with renewables, which are non-programmable and would need an electrolyser that charges and discharges quickly and can cover a wide range of operating power. Thanks to the improvement in the technology, the alkaline cell can nowadays guarantee a range of capacities from 20% to 100% of the nominal power. In general, it has intermediate flexibility, with an on or off time of 10 minutes and a rate of change of the power consumed from 0.2 to 20% per second. Another issue of the alkaline layout is pressurizing. The produced hydrogen needs to be pressurized to be efficiently and profitably stored (generally 30 bar), but the electrolysis system works at ambient pressure. If just the H2 side of the alkaline cell is pressurized, a crossover of H2 is promoted towards the O2 side, as the membrane of the system is not suitable to manage high-pressure differences. Differently, the pressurization of both the sides of the cells would represent an energy loss, as the pressurized oxygen would then need to be vented into the atmosphere. The best solution for pressurization, in this case, is to provide pressurized water to the system, which would cause the need of a more robust infrastructure. Summarizing: pressurizing is possible but not without a high additional cost for compression. Despite these issues, being the first electrolyser that has been commercially implemented, the alkaline technology has a high lifetime of 60000 to 100000 h. This is thanks to the choice of the catalyst materials for the electrodes, which is at the state of the art (degradation $< 3\frac{\mu V}{h}$). The use of low-cost components and the long lifetime make this technology the most widespread worldwide for H2 production [6].

2.2.2 Anionic e xchange membrane electrolysers (AEM)

During the last 20 years, a new "zero gap" configuration has been considered for the alkaline technology to overcome the issues related to the traditional one. The zero-gap technology has a totally different cell architecture with respect to the traditional alkaline electrolyser, keeping an alkaline electrolyte's employment. It considers two porous electrodes placed in direct contact and separated by a small membrane that allows OH- ions to flow through. As this cell considers the employment of a membrane, it is called Anionic Exchange Membrane (AEM) electrolytic cell. The AEM technology allows a better separation of the two sides of the cell, a lower gas mixing and lower ion transport losses (as the two electrodes are placed much closer one to the other).

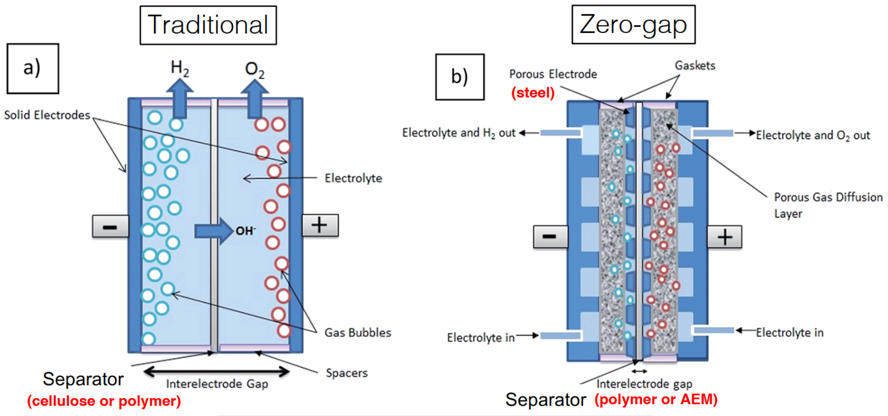


Figure 2.2: Representation of the traditional alkaline cell (a) and of the zero-gap alkaline technology (b).

AEM is the latest technology that has entered the electrolysis market, and it has been designed with the idea to combine the affordability of the alkaline cell and the better performances of the PEM cells. The design of an AEM cell can in fact be conceived both as a significant improvement in the properties of the alkaline cell separators, both in terms of resistance and impermeability, and as a morphing of the PEM technology, with the fundamental difference to be based on the transport of hydroxide ions (OH-) instead of protons (H +). This is thanks to the alkaline electrochemical environment rather than an acidic environment, allowing the use of significantly cheaper materials than those used for PEM. The AEM technology meets all the requirements needed for a future widespread of the power-to-gas technologies, being cheap, highly efficient, space-efficient, highly responsive (i.e., good to be coupled to renewables). Despite the big potential for such technology, its membrane is not yet technologically stable and fully developed. This affects the useful life of the electrolyser, which is limited to between 500 and 10,000 hours of operation. At the time of writing, a few AEM electrolyser are available on the market, most of which are in the kW range [6].

2.2.3 Proton exchange membrane electrolysers (PEM)

Proton Exchange Membrane electrolysers were first introduced in the 1960s by General Electric to overcome the drawbacks of the alkaline electrolysis technology.

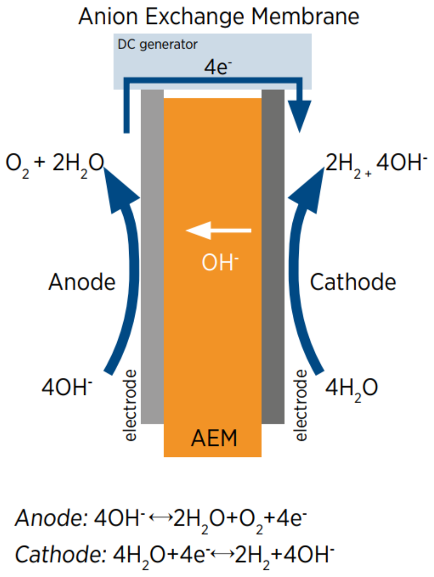


Figure 2.3: Working scheme of the AEM.

It is now the second most used technology in the commercial field after the alkaline. With its fast dynamics and large partial load range (10-100%) it indeed provides modulated operating characteristics and is excellent for coupling to intermittent energy sources such as renewable ones. It has a very similar architecture to the Anionic Exchange Membrane. The principle is the same: two porous electrodes are placed in direct contact with each other, this time inside of an acidic electrolyte. The ions that promote the reaction are indeed H+ and flow from the anode to the cathode. The electrolysis reaction is split in two main sub reactions:

- the hydrogen evolution reaction, occuring at the cathode (reduction) - negative electrode
$$2H^+ + 2e^- \rightarrow H_2 \tag{2.5}$$
- the oxygen evolution reaction, occurring at the anode (oxidation) - positive electrode
$$H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^- \tag{2.6}$$

Being the environment very acid, costly materials are needed for the manufacturing of this kind of electrolytic cell. Steel, indeed, can survive in an alkaline but not in an acid environment. At the negative electrode (cathode) platinum applied on carbon is used (Pt/C), being platinum the most efficient catalyst to promote the hydrogen evolution reaction. At the positive electrode (anode), due to the high voltage of operation, platinum is no more useful, and another catalyst is needed;

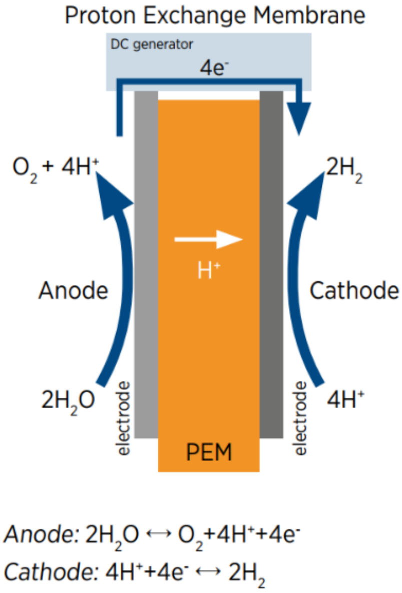


Figure 2.4: Working scheme of the PEM electrolytic cell.

generally, the picked materials are Iridium or Ruthenium in an oxidized form: IrOx or RuOx. These layers are applied on Titanium, a material that can remain stable up to a very high potential difference. Iridium and Platinum are very expensive materials, even more than platinum. Their loading generally is around 1 mg/cm2 (the aim is to reduce to mitigate the cost). The separator plate and the current collector are made by titanium. The costs of these materials are much higher with respect to the one needed for the alkaline cell. The efficiency of the PEM cell rises up to 60% - 70% on LHV. The more compact architecture of this type of cells, combined to the lower flow resistance of the ion H+ compared to OH-, guarantees very low mass transport losses. These losses are related to the feeding of water to the electrodes: while in the alkaline design the accumulation of gas bubbles around the catalyst tend to prevent the active area of the system to be properly fed by water, here the water presence in the catalyst layer is guaranteed by the ionomer, made by a very hydrophilic material, so that the active area is always available to make the electrolysis reaction occur. While an increase of the current density of more than $0.5\frac{A}{cm^2}$ for the alkaline cell would induce a higher bubble formation and an increase in the potential difference needed to make the system work, for the PEM electrolyser the limit current density can reach a value of $2\frac{A}{cm^2}$. Thanks to the higher current density, the ΔV across the cell is lower than the ones of alkaline electrolysers, which permits to increase the stack efficiency. The presence of a membrane instead than a separator allows a better detachment of the H2 and the O2 side of the cell, causing a decrease in the crossover and so an increase of the fuel utilization up to 0.98 to 0.99. Considering this and together with the fact that the electrolyte is liquid and thus there are no traces of the electrolyte in the collected gas, the purity values are higher than 99.99%. Finally, PEM electrolysers allow the pressurization of just one side of the electrolytic cell and produce pressurized hydrogen, up to 100 bar, and ambient pressure O2 at the same time. This is another achievement allowed by the membrane architecture. Nowadays, the lifetime of these cells is around 60000 and 90000 hours as the alkaline one. They take up 20% to 25% less space than alkaline electrolysers and suffer less degradation in performance. Despite the technological enhancement of this kind of electrolysers, they suffer of a much higher specific cost with respect to the other commercially available cells. In fact, platinum and iridium are two very rare elements, which could limit the scale-up of the technology. Global iridium production today could support a production of up to 7 GW of electrolysers per year. Figure 8 shows the forecast of technological improvement for the ALK and PEM electrolysers. PEM, being more recent, has a greater tendency to reduce specific consumption [kWh / kgH2], promising a significant increase in efficiency in the years to come. On the contrary, alkaline has already reached technological maturity and no improvements are expected for the years to come, as shown by the curve with zero slope [6].

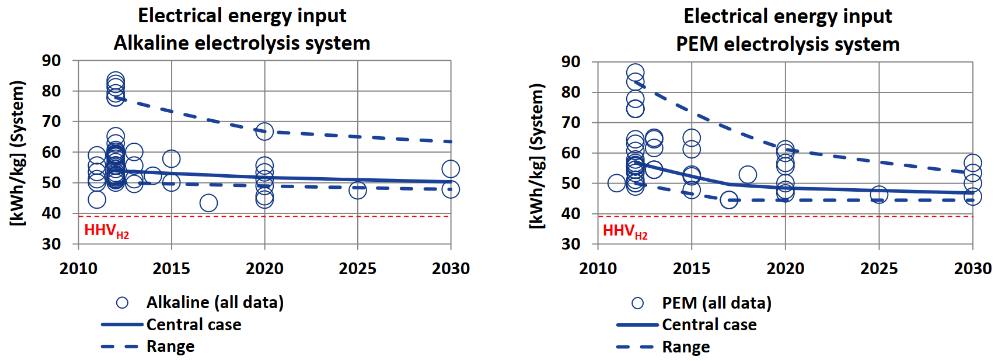


Figure 2.5: Comparison between the ALK and PEM technologies.

2.2.4 Solid Oxide Eletrolyser Cells (SOEC)

While all the electrolysers described above operate at low temperatures, around 70-80 °C, the Solid oxide electrolyser operates at high temperatures, around 700 ° C. At the cost of having an additional thermal energy input, this cell achieves a very low specific consumption of 40 kWh / kg, while it is around 50 kWh/kg for other technologies. SOEC can be integrated with industrial processes in which

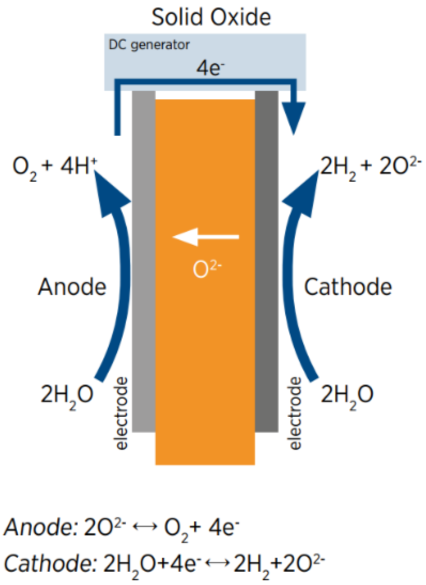


Figure 2.6: Working scheme of the SOEC

there is the generation of thermal energy as a by-product, for example the synthesis of fuels. Operation is based on a solid oxide ceramic electrolyte, permeable to the O2- ion, and uses a high temperature steam inlet to replace water. SOEC is not yet commercialized due to stack degradation and its short useful life caused by high operating temperatures. The peculiarity that only this electrolysis technology presents is that it is completely reversible: in fact, the SOECs can work as fuel cells, converting hydrogen into electricity and water, at a nominal power of 25% compared to that of electrolysis. Today this technology remains on the kW scale, with few projects on the MW scale. Nonetheless, it is highly tested in the laboratory for its promises of high energy efficiency and its versatility for use in industrial environments. Solid oxide technology will not be taken into consideration in this analysis, as the large amount of thermal energy that they require is incompatible with the structure of the biomethane system and the photovoltaic system to be installed [6].

2.3 Power to Hydrogen

The coupling of renewable sources with electrolysis systems to produce green hydrogen takes part in a wider classification of technologies called Power-to-gas. Generally, power to gas technologies includes the comprehensive group of technologies that allow transforming electricity into gaseous fuels such as hydrogen or methane. Given the well-established technologies for gasses storage, and its long-term accumulation properties, such systems are suitable to dampen the variability of non-programmable renewable sources and guarantee them a more balanced electricity generation. In a global setting in which renewables must quickly widespread, Power-to-gas may be the key to avoid curtailment, grid unbalances and limit the need for enlargement of the electricity grid infrastructure. The production of renewable gasses through electrolysis may fill the missing link between the electricity network and "hard-to-abate" sectors such as long haul and maritime transport, the steel and cement production or the chemicals industries. This is a big innovation in the gas sector and in the energy sector itself, thanks to the opportunity of substituting a big polluting share of the energy consumption with a zero-emission source. The Power to gas technology includes a wide range of different layouts, which may include different types of renewable power plants, different types of gasses, different methods to store them and different final uses of the gas. The electricity feed may be indeed generated by any renewable power plant such as photovoltaic systems, wind farms, concentrated solar power plants or hydropower plants. Moreover, such plants may either be totally devoted to the production of hydrogen or just invest their surplus in the gas generation. The storage may be carried out in different ways: in the form of compressed gas, in the form of cryogenic liquid or in underground spaces exploited by mining activities. For what concerns the final uses, the green hydrogen may be used as a means of storage, and thus reconverted into electricity when needed, used for transport purposes, i.e., in Fuel Cell Electric Vehicles (FCEV) or it may be sold to industrial consumers. One of the main tends to produce profitable green hydrogen with Power-to-gas layouts nowadays is the use of hybrid power plants, mostly the coupling of solar PV with wind farms, to enlarge the availability of the electricity input and increase the hydrogen production. The cost of hydrogen generation is indeed strongly dependent on the equivalent hours of the system, as the investment costs for electrolysers are still very high. and thus increase the specific cost of the hydrogen produced. Another direction may be to optimise the operation of the electrolysis by generating hydrogen when the price of electricity is low (or purchase curtailed electricity) and reconvert it back when the price of electricity is high. The Power-to-gas layouts implemented in this document consider an electrolysis plant coupled to a 610 kW photovoltaic system completely devoted to the hydrogen production. Several strategies have been considered to increase the affordability of the hydrogen generation, such as the maximisation of the capacity factor of the electrolyser, the extension of the photovoltaic system beyond the company's constraints and the use of a battery storage system to increase the hydrogen productivity. Chapter 5 reports all the scenarios implemented in this document regarding the Power-to-gas technology.

Chapter 3

Implemented Data

This chapter presents the data implemented in the feasibility study. Firstly, the data from Biomet are reported, such as the obtainable photovoltaic energy and the water and area availability in the location. Then, the technical specifications of the main components considered in the analysis are showed, especially the electrolyser and the battery. The last paragraph examines the current legislation on hydrogen production, transportation and distribution.

3.1 Water availability

Hydrogen production through electrolysis needs an input feed of water. The needed water quality depends on the kind of electrolytic cell in use, especially whether the cell architecture is based on an alkaline or acidic electrolyte. Alkaline systems are much more tolerant, with traditional cells using a 6.9 M (30 wt%) KOH electrolyte and AEM cells using a 1M KOH one. For an acidic system such as PEM ultra-pure water feed is needed, such as Millipore or CDI feeds. Especially, there must not be chloride or other ions as they would foul the platinum catalysts. In this study, the water is demineralized, so that it can work with each type of considered technology. In the installation of San Rocco al Porto, two possible water contributions could be used to feed the electrolysis. The first one is the water obtained by scrubbing the digestate, at the outlet of the anaerobic digester. According to the data provided by Biomet regarding their expected volume of digested treated per day, the output flow rate of the centrifuge fluctuates between 140 m3/day and 156 m3/day, with a quality that follows the parameters established in the legislative decree 152/2006 (see Table 3.1, [11]).

The scrubbed water is pure enough to be used in every type of electrolysis system analysed in this document. The second water contribution is rainwater. The Biomet biomethane plant is equipped with a proper drain system which collects

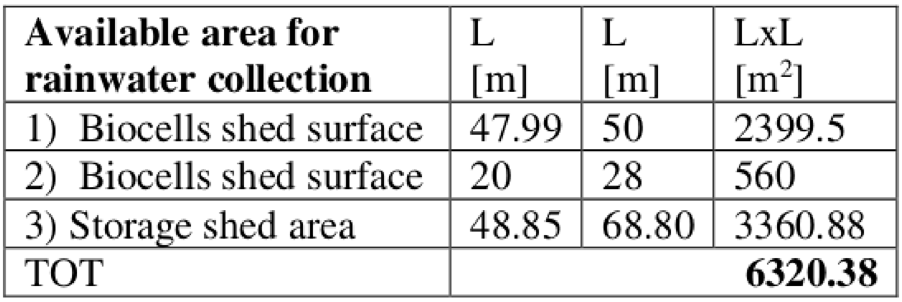
Pollutant	UM	Value	Discharge limits (*)
Treated flow rate	m^3/g	250	-
Total suspended solid	mg/l	3.500	≤ 80
COD	mg/l	11.500	≤ 160
BOD5	mg/l	3.100	≤ 40
N total	mg/l	1.300	-
$NH4^+$	mg/l	1.250	≤ 15
Total phosphoros	mg/l	110	≤ 10
Chlorides	mg/l	1.450	≤ 1.200
Design temperature	C	25	-
Maximum temperature	C	35	-

Table 3.1: Quality parameters of centrifuge wastewater in surface wastewater. (*) Compliance with the parameters from Tab. 3 - Annex 5, part III of Legislative Decree 152/2006 and subsequend amendments for C.I.S. discharge [11].

the rain falling on the roofs of the factory and drives it to rainwater collection tanks. Their total volume is 713 m3; 653 m3 of these are harvested from the roofs of the buildings while the remaining 60 m3 are filled with the first 3 mm of rainwater collected from the cemented area of the plant (first rain tank). Rainwater is essentially distilled water with a certain number of pollutants that do not affect the operation of the electrolyser. Its quality depends on the way it is collected. In this case, the portion of rainwater that is recovered from clean surfaces, i.e. the roofs of the sheds, does not require a scrubber and can be used directly as an input for electrolysis. On the contrary, the water from the first rain tank is collected from the ground and can't be used without a further purification and additional costs.

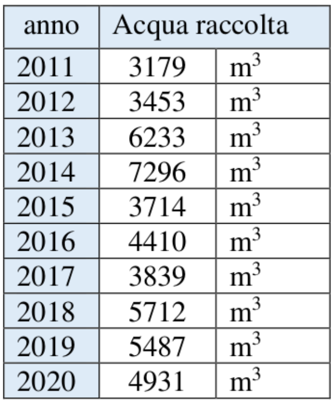
The rainwater collecting area coincides with the roofs of the two main warehouses of the factory and is highlighted in Figure 3.2. A collection system mounted at the eaves of both the warehouses conveys the rain to the tanks. The total area of rainwater collection is:

The available flow rate of water for hydrogen production depends on the amount of the rainwater resource. The Environmental Protection Agency (ARPA, [32]) precipitation data has been used to understand how much the tanks fill up and estimate the achievable intel rain flow rate. In particular, the daily rainfall data obtained from the Tosi Institute of Codogno, 8.84 km away as the crow flies from the plant area, were taken for a period of 10 years (from 1 January 2011 to 31 December 2020). From these data, the annual conveyable m3 of rainwater for a year is computed. (Table 3.3).



Available area for rainwater collection	L [m]	L [m]	LxL [m^2]
1) Biocells shed surface	47.99	50	2399.5
2) Biocells shed surface	20	28	560
3) Storage shed area	48.85	68.80	3360.88
TOT			**6320.38**

Table 3.2: Rainwater collection area at the San Rocco al Porto installation.



anno	Acqua raccolta	
2011	3179	m^3
2012	3453	m^3
2013	6233	m^3
2014	7296	m^3
2015	3714	m^3
2016	4410	m^3
2017	3839	m^3
2018	5712	m^3
2019	5487	m^3
2020	4931	m^3

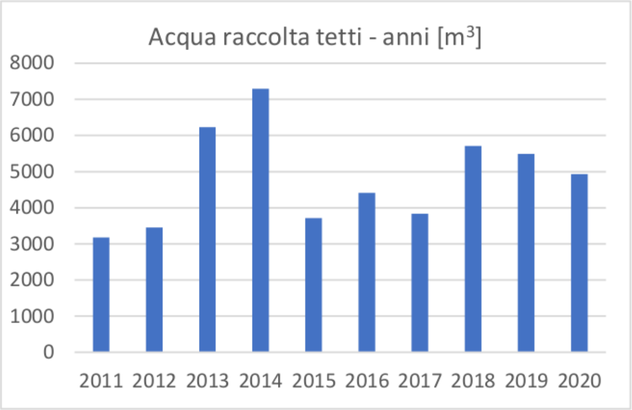


Table 3.3: Respectively, table and histogram of the collectable water by Biomet, rainfall years from 2011 to 2020.

Figure 3.1: Plant plan of Biomet s.p.a., San Rocco al Porto.

Figure 3.2: Highlighting on the planting area of surfaces for collecting rainwater.

The regional regulation of 23 November 2017 classifies San Rocco al Porto as a "Hydraulic critical area B", therefore the maximum amount of water that the plant can discharge into surface wastewater is 20 l/s per hectare of impermeable draining surface. This is defined as the surface resulting from the product of the total draining surface and its average weight runoff coefficient. From the consultation of the plant plan, it appears that the surface of the built lot is 19045 m^2 , 18579 of which consist of waterproof surfaces. The runoff coefficient, following the standard, is equal to 1 for all areas affected by roofs, coverings, and continuous flooring, 0.7 for draining or semi-waterproof flooring and 0.3 for permeable sub-areas. Therefore, the plant area of interest for the application of the law is 18579 m^2. The total rainwater flow rate that it is possible to obtain from the collecting tanks ranges from 9 m^3/day to 20 m^3/day depending on the year of analysis. If the total outlet water is higher than the dischargeable one by the factory, the following of the law may be a limiting constraint for the size of the electrolyser. Considering a 30 m^3/day flow rate, and thus the worst-case scenario concerning the respect of the law, and the entire plant area is 18579 square meters (1.86 hectares), the maximum discharge capacity allowed by law for the plant is:

$$\text{Waste water limit} = \dot{V}_{LIMIT} = 20[\frac{l}{s \cdot ha}] \cdot 1.8579[ha] = 37,158\frac{l}{s} \tag{3.1}$$

Let's consider to be in the case in which the water flow rate from the centrifuge is maximized (156 $m^3/day = 1.806\ l/s$) and assume that all the tanks are full. In this case, to comply with the constraints, the tank could be discharged at a maximum of:

$$t = \frac{V_{VASCHE}[m^3] \cdot 10^3[\frac{l}{m^3}]}{(\dot{V}_{LIMITE}[\frac{l}{s}] - \dot{V}_{CENTRIFUGA}[\frac{l}{s}]) \cdot 3600[\frac{s}{h}]} = \frac{713 \cdot 10^3}{(37,158 - 1,806) \cdot 3600} = 5,6h \tag{3.2}$$

Therefore, the constraint that applies to discharge into surface waters is respected, since the only condition that would result in its violation would lie in the eventuality that the tanks were filled and subsequently emptied in less than 5.6 hours.

3.2 Solar PV System

3.2.1 Technical data

The available area for a photovoltaic solar system installation corresponds to the maturation/storage shed of the finished compost and the roof of the office building. The sizing of this plant was done by maximizing the PV power production, so to

	Lenght [m]	**Width [m]**	**Area [m^2]**	**Azimuth [m^2]**	**tilt**
Pitch North	24,425	68,80	1680,4	-150	20
Pitch South area 1	11,3	17,93	202,63	30	20
Pitch South area 2	24,425	57,5	1404,4	30	20
Offices area 1	7,7	5,6	14,82	18	20
Offices area 2	9,5	4,18	81,04	-72	20
Offices area 3	7,7	5,6	14,82	108	10
Offices area 4	9,5	4,18	81,04	-162	10

Table 3.4: Size and orientation of the free surfaces for the installation of photovoltaic panels. The highlighted lines indicate the surfaces on which the installation of the modules was considered.

	L [m]	**L [m]**	**LxL [m^2]**
Module dimensions	1,65	1,00	1,65

Table 3.5: Size of the considered photovoltaic module.

maximise the size of the installable electrolysis plant. Indeed, the greater the capacity of the photovoltaic system is, the greater can be the electrolysis system powered by it and so the economies of scale. The aim is in fact to provide the cheapest hydrogen production for the automotive sector. The offices of Biomet have a hip roof (i.e., four pitches of different orientations). An analysis of the annual productivity was carried out on each of these four pitches. The installation of the panels was considered to be convenient on only two of these (those with the highest annual production, areas 1 and 2 respectively in Table 3.5). The roof of the compost storage shed has two pitches, which are already equipped with a structure designed for mounting the photovoltaic modules. The dimensions of the useful surfaces for mounting the panels are shown in Table 3.4.

All the surfaces considered are not affected by partial shading, as the warehouses' roof ridges are as high as the biomethane digester, and the office building is located southeast of the digesters (the trajectory of the sun in the northern hemisphere remains towards the south). The surface that was affected by shade, area 3, was not considered for the installation. The size of the roofs has been considered to evaluate the number of panels that could physically fit on each surface, considering a commercial size for the single PV module (Table 3.5).

The vertical layout of the panels has been considered (the short side of the panel parallel to the eaves line). The horizontal layout (long side of the panel parallel to the eaves line) is favoured in cases of partial shading of the roofs and in cases

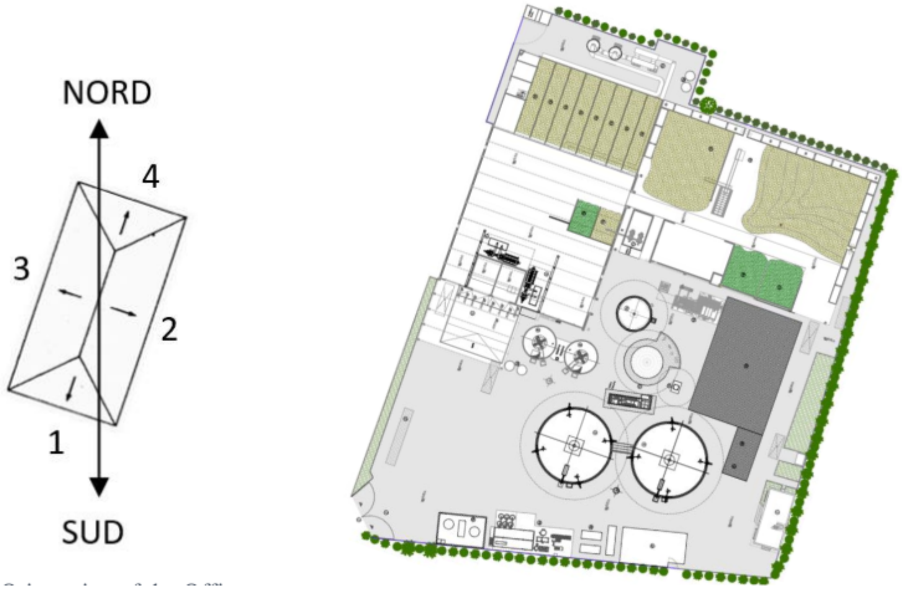
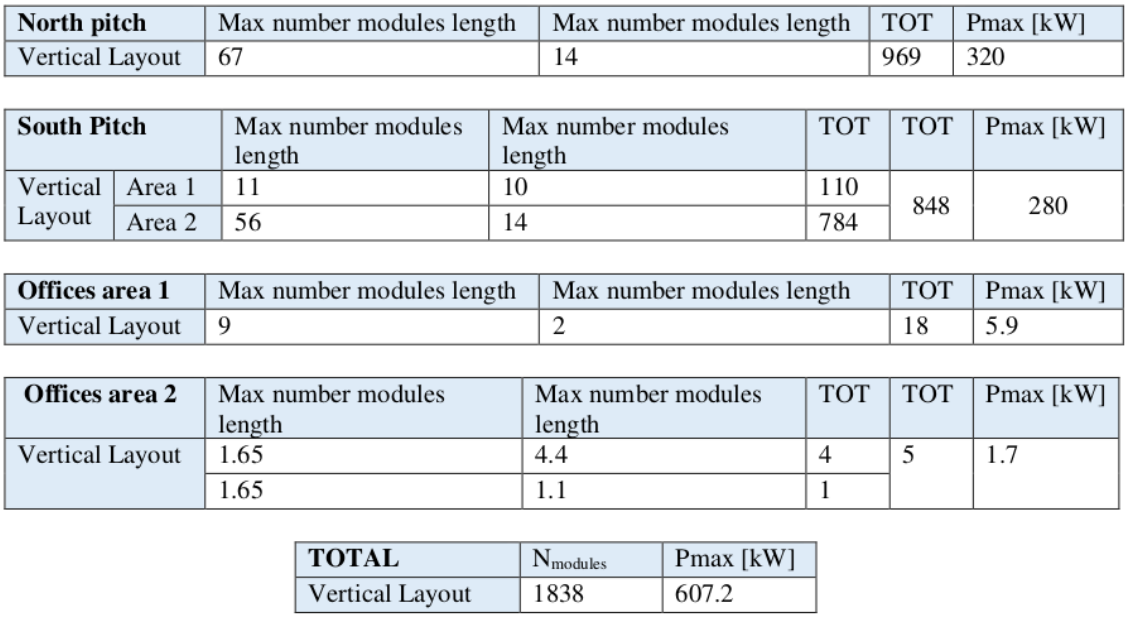


Figure 3.3: On the left, orientation of the Offices building at San Rocco al Porto. On the right, the plan of the Biomet s.p.a. plant at San Rocco al Porto.

where the panels are installed on flat surfaces, where being arranged vertically they would cast a higher shade on the panels installed behind them. However, it involves greater complication in the electrical connection of the panels, and therefore in a case like this where the tilt of the panels is constrained to the construction of the roof itself, a vertical orientation is preferred. Furthermore, the panels considered in the analysis are of the half-cut type, which means that the module is composed of two groups of cells in series connected in parallel, to guarantee productivity even in the event of shadow on one of the two parts of the panel. Therefore, photovoltaic production already has greater certainty of functioning even in the event of partial shade and there is no need to arrange the modules horizontally.
330 Wp monocrystalline half-cut modules were considered in this project. The production cost of photovoltaic panels has decreased in recent years, while the cost of installation and maintenance has remained constant. It is therefore convenient to install monocrystalline panels, which are more efficient and therefore guarantee greater productivity at the same operating costs. The technical specifications of the module have been chosen to be in line with the state of the art for monocrystalline modules. Many datasheets of such modules have been compared, converging in the technical data reported in table 4.
Since the shadow conditions are homogeneous for all the panels that are mounted on surfaces with the same orientation, it is possible to adopt the central configuration for the inverters of every single surface, which are low cost, highly efficient and



North pitch	Max number modules length	Max number modules length	TOT	Pmax [kW]
Vertical Layout	67	14	969	320

South Pitch		Max number modules length	Max number modules length	TOT	TOT	Pmax [kW]
Vertical Layout	Area 1	11	10	110	848	280
	Area 2	56	14	784		

Offices area 1	Max number modules length	Max number modules length	TOT	Pmax [kW]
Vertical Layout	9	2	18	5.9

Offices area 2	Max number modules length	Max number modules length	TOT	TOT	Pmax [kW]
Vertical Layout	1.65	4.4	4	5	1.7
	1.65	1.1	1		

TOTAL	$N_{modules}$	Pmax [kW]
Vertical Layout	1838	607.2

Table 3.6: Maximum installable PV power on the roofs of the Biomet infrastructure, considering the size of the roofs and the one of the module.

PV modules technical data		
η_{PV}	Nominal efficiency of a module	19,5%
η_{INV}	Nominal inverter efficiency	98%
η_{BOS}	Balance of System yield of the photovoltaic system	85% [2]
$\eta_{availability}$	PV plant availability	98%
-	Maximum annual decay rate	-0.5%
η_{EOL}	Efficiency at the end of the 20th year	90% of the nominal one

Table 3.7: Technical data of the PV modules considered in the model.

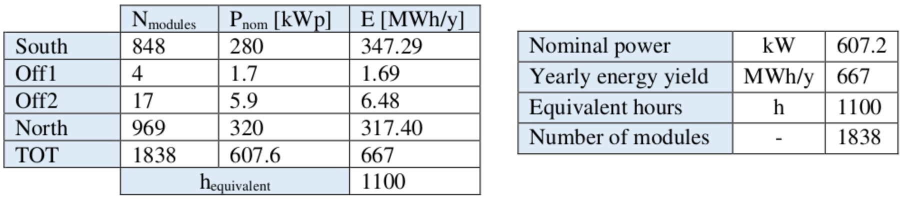
easy to be installed inverters. The efficiency assumed in this application is therefore 98%. The efficiency of the balance of the system includes all the losses that occur between the power produced by the panels and the one received from the final user, not including the inverter (for example losses in the cables, fouling of the panels, the effect of temperature on performances etc ...). To compute the productivity of the photovoltaic system, the hourly average irradiance data were collected for Berghente, San Rocco al Porto (LO) (Lat 45.1; Long 9.65) considering the orientation of the roofs' surfaces. The data are taken from the PVGIS-SYRAH19 database [2] and are the result of an average of the hourly irradiance profiles measured for 12 years (from 2005 to 2016, [19]). To compute the hourly electrical power produced by the photovoltaic system, equation 3.3 was considered, in which i = i-th hour.

$$P_{PV_i} = \sum_{i=1}^{8760} G_i \cdot A_{module}[m^2] \cdot N_{modules} \cdot \eta PV \cdot \eta_{INV} \cdot \eta_{BOS} \tag{3.3}$$

Where $G_{module}[\frac{kWh}{m^2}]$: is the solar irradiance available in the locality of Berghente (San Rocco al Porto, LO); see Table 3.7. Using equation 3.3 for each surface of different orientations, it is possible to derive the annual hourly productivity profile of each surface and the annual hourly productivity profile of the entire PV plant. By adding all 8760 annual hourly values, and considering the availability of the system, the total amount of electricity produced in a year is calculated.

$$EE_{PV} = \sum_{i=1}^{8760} P_{PV_i} \cdot \eta_{availability} \tag{3.4}$$

Table 8 shows the energy availability of the PV plant.



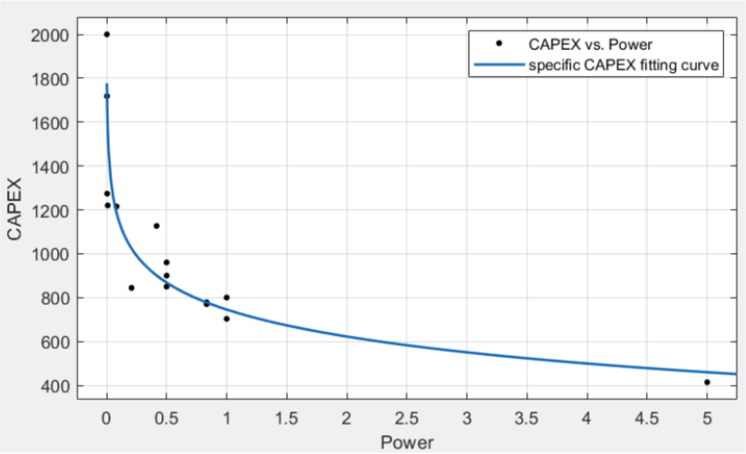
	$N_{modules}$	P_{nom} [kWp]	E [MWh/y]
South	848	280	347.29
Off1	4	1.7	1.69
Off2	17	5.9	6.48
North	969	320	317.40
TOT	1838	607.6	667
	$h_{equivalent}$		1100

Nominal power	kW	607.2
Yearly energy yield	MWh/y	667
Equivalent hours	h	1100
Number of modules	-	1838

Table 3.8: Productivity of the photovoltaic system sized for the installation of San Rocco al Porto.

3.2.2 Economics

The electricity produced by the PV system is valorised by its Levelized cost of electricity. To properly compute the LCOE, the costs of the power plant have to be determined. As in this study the hydrogen production feasibility is studied for both small and high scale productions, the PV system's nominal size is ranged from the commercial to the utility-scale. For this reason, it was decided to build a specific PV CAPEX curve by fitting literature data. As the installation is studied to be placed in Italy, the available specific cost data for solar installations in Italy have been considered. Specifically, the IEA reports in "Projected costs of generating electricity, 2020" reports the specific CAPEX for PV systems installed in Italy over the last two years. Supplementary data are taken from the IRENA report "Power generation costs, 2020", where these data are explicated as a function of the size. Additionally, the Vartinian et. al and Veronese et. al costs for utility-scale power plants in Italy have been considered. To verify the consistency of the data, they have been compared to the ones of the university course of study "Solar and Biomass Power Generation" taken by professor Giampaolo Manzolini. The built curve is here reported.



General model:
f(x) = a*log(x)+c
Coefficients (with 95% confidence bounds):
a = -177.5 (-197.1, -158)
c = 745.3 (688.6, 802)

Figure 3.4: Specific CAPEX of a PV power plant with respect its nominal power - fitting of literature data.

The specific fixed costs for the installation were assumed considering that the roofs of the warehouses are already fitted for the installation of photovoltaic modules. Thus, the costs related to the PV mounting system are neglected. The OPEX have been considered for each case to be 1.5% of the CAPEX.

3.3 Electrolysers

3.3.1 Electrolyser system boundaries

The power to hydrogen electrolysis process is a very wide concept that can apply to several different layouts and can include many different plant components, depending on the specific constraints of the analysed application. For what concerns the layout, the electricity employed for the gas production may for example come from the grid, allowing a full load electrolysis operation and a constant hydrogen production. In that case, the electrolysis plant would need a grid interconnection infrastructure, and the production would be strongly affected by the high grid electricity price and lightly by the system investment cost. Differently, the power to gas facility may be combined with off-grid renewable power plants, such as a photovoltaic power system, a wind farm, or a combination of the two (hybrid power plant). In this case, the operation of the plant would be completely different, with hydrogen production limited to those hours of sun and/or wind availability. The components involved in the system would be different too, and so the costs. The configuration of the system also depends on the final use assigned to the hydrogen, i.e., on the purity and the pressure that it must have at the output of the process. Depending on these, post-production steps, such as compressors and hydrogen purifiers, may need to be added to the layout of the system, adding other costs to the H2. It is then important to identify which are the constraints of the application in the study, to understand which technological components are included in the system boundary, and so identify the costs of the power to gas power plant. In this analysis, the energy has been assumed to be either taken from the grid or supplied by an off-grid PV power plant. The gas production constraints have been set as a degree of purity of 99,97% and pressurization of 30 bar. The quality of the hydrogen has indeed to reach such value to allow its use in FCEV. For this reason, the considered electrolysers are either capable of producing H2 at such purity or a hydrogen purifier is added to the analysis. Additionally, they have been considered to either directly produce 30 bar pressure hydrogen or a compressor is added to reach the 30 bar pressurization. For this study, storage, transportation and distribution have not been considered, and the focus lies only on the costs associated with capital expenditures and all fixed/variable costs associated with the production of hydrogen ready to be compressed for storage purposes. Nevertheless, this document is part of a joint study on hydrogen production through renewable energy in Italy for the mobility sector. For the cost of storage, transport and distribution of Hydrogen refer to the work of Matias Garces "Feasibility study for hydrogen refuelling station with tube-trailer deliverys". Figure 3.5 shows the perimeter of this study among the overall hydrogen production and consumption chain for clean hydrogen in the mobility sector.

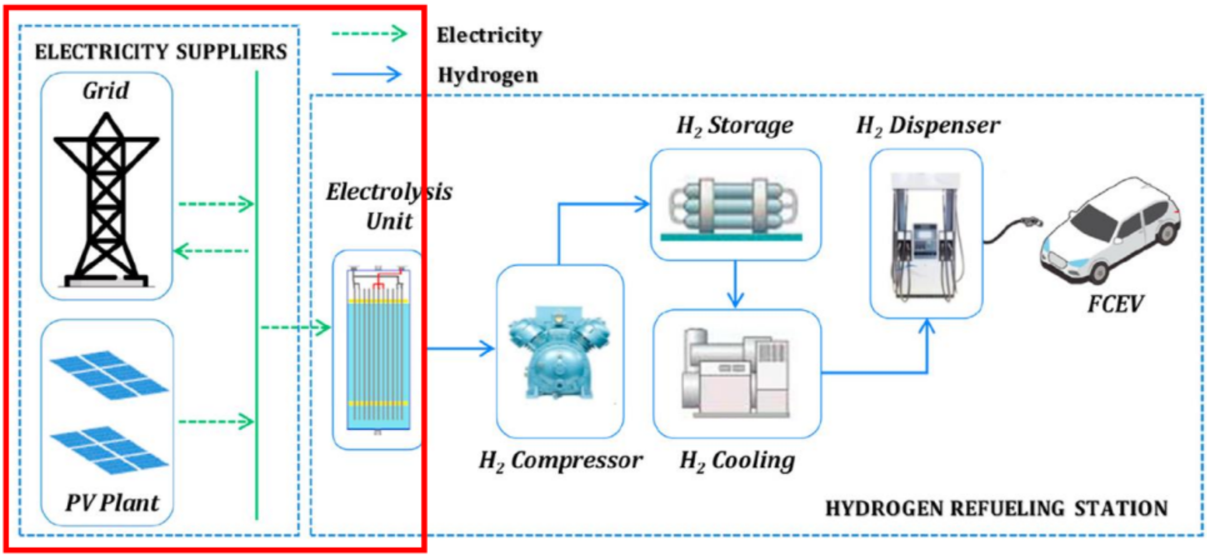


Figure 3.5: Boundaries of the system in the scheme of an hydrogen refuelling station.

Figure 8 shows the specific electrolyser system boundary which includes the stack and all auxiliary sub-systems (gas purification, cooling system, system control, power supply) that are required for the operation.

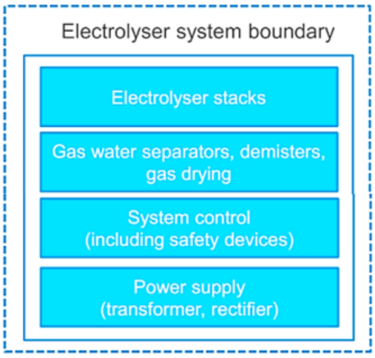
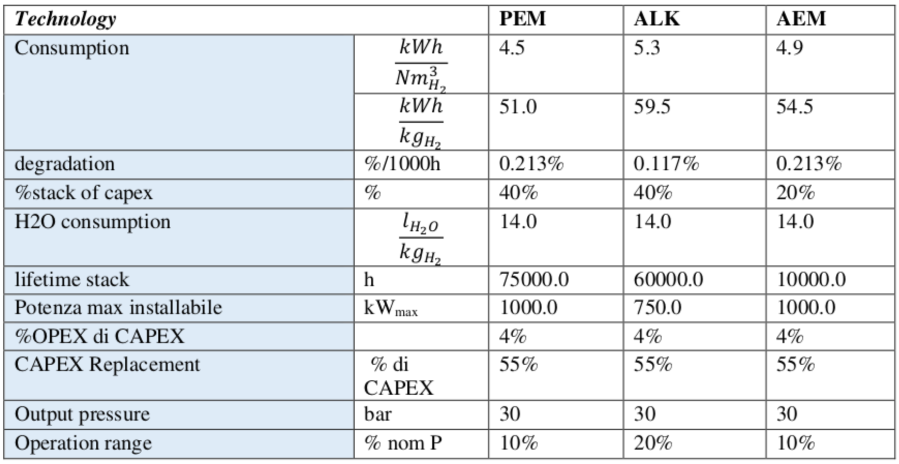


Figure 3.6: Specific electrolyser system boundaries.

Water management lies outside the confines of this study. The process has indeed been thought for an installation with high availability of demineralized water supply.

3.3.2 Technical Data

The three main common low-temperature electrolysis technologies have been taken into consideration for the feasibility of this study, respectively: the alkaline (ALK), protonic (PEM) and anionic (AEM) technologies. As already stated, the Solid Oxide Electrode Cell technology has been discarded for this application as its operation requires a heat input feed that is unavailable in the Biomet plant area. The only available energy feed for electrolysis in the plant area is the one coming from the PV renewable power plant, as the bio-methane produced by the digester is devoted to the refuelling stations that the company owns in Belgioioso (PV). The following table summarises the selected values for this study. For a more persuasive explanation of the electrolyser behaviour refer to chapter 2.



Technology		**PEM**	**ALK**	**AEM**
Consumption	$\frac{kWh}{Nm^3_{H_2}}$	4.5	5.3	4.9
	$\frac{kWh}{kg_{H_2}}$	51.0	59.5	54.5
degradation	%/1000h	0.213%	0.117%	0.213%
%stack of capex	%	40%	40%	20%
H2O consumption	$\frac{l_{H_2O}}{kg_{H_2}}$	14.0	14.0	14.0
lifetime stack	h	75000.0	60000.0	10000.0
Potenza max installabile	kW_{max}	1000.0	750.0	1000.0
%OPEX di CAPEX		4%	4%	4%
CAPEX Replacement	% di CAPEX	55%	55%	55%
Output pressure	bar	30	30	30
Operation range	% nom P	10%	20%	10%

Table 3.9: Technical and economical data for the three electrolysis technologies: AEM, ALK e PEM.

What is reported in Table 3.9 is the result of an analysis of the data taken from the literature [35], [9], [27], [37], [15], [29], from the technical data sheets of electrolysers on the market and interviews with suppliers of electrolysers [16], [1]. The values indicated were obtained by averaging the technical data of hydrogen electrolysers pressurized at 30 bar and of quality above 99.97% (minimum quality of hydrogen for operation inside Fuel Cell Electric Vehicles). The operative hours of the AEM technology are rather limited. Being a technology that is still mainly studied in the laboratory, not enough tests have been carried out to guarantee the operating of the anionic zero-gap cell after 10000 hours of operation. Even though the AEM electrolyser commercialization is still limited to small powers and the low learning rate of the technology, researchers push on this technology which could efficiently overcome the alkaline and the PEM cell issues in the future. The ALK is the technology that most of all has reached maturity. However, it has longer start-up and shutdown times than the other electrolysers. Despite the traditional alkaline cells showing a limited capability of modulating their power, modern suppliers assure that it can be operated up to 10% of the nominal power such as the PEM and AEM technology. For this reason, it has been considered a possibility to couple to renewables, even if it is generally considered less suitable for being associated with a renewable energy production plant. The best technology for combining with renewables is PEM because it has the greatest ability to modulate its production of hydrogen without safety problems. However, from an economic point of view, it is the most expensive.

3.3.3 Economics

Total equipment costs - CAPEX

When determining the investment costs of electrolysers, it is important to specify what is included in the costs and distinguish the electrolyser stack costs and the complete electrolyser system costs. The latter includes the stack and the balance of plant costs, which are water and gas treatment costs, power conversion costs, structure housing costs, piping and measurement equipment costs. The stack together with the balance of the plant constitute the total electrolysis equipment. Equipment investment costs are usually expressed in terms of costs per electrical input (€/kWel). The investment costs of the different electrolyser technologies were analysed in an extensive literature screening, adding data collected from interviews with supplier companies. The literature review has faced three problems. Firstly, currently not much reliable data on costs is available: sources often suffer from a lack of information about the system boundary and the technical specifications of the electrolysers. Depending on the pressurization and the quality of the H2 and H2O, on the current and voltage of the electrolytic cell and on whether the system includes an additional compressor or a water scrubber in its confines, the specific costs of the H2 producer change significantly. Secondly, the data lack of information regarding the year of installation, the rated power of the electrolyser and the source of the reported costs. As determined in [33], specific costs have decreased significantly during the last years, thanks to technology improvements, and are highly dependent on the size of the system due to economies of scale. Finally, the available data in the literature have a very wide range, as electrolysers are components that haven't reached the complete technical maturity and some parameters vary from technology to technology and from manufacture to manufacturer. To dampen the uncertainties in the collected data, they have been taken from reliable literature sources that provide a wide range of information about what is included in the system boundary and that provide costs information based on offers and price inquiries, manufacturers, and expert elicitations. In this document the stack cost have been considered as 40% of the total equipment cost [5]. An overview of the data points from the literature regarding the investment costs of electrolysers (ALK, PEM and AEM) is shown in Figure 3.7.

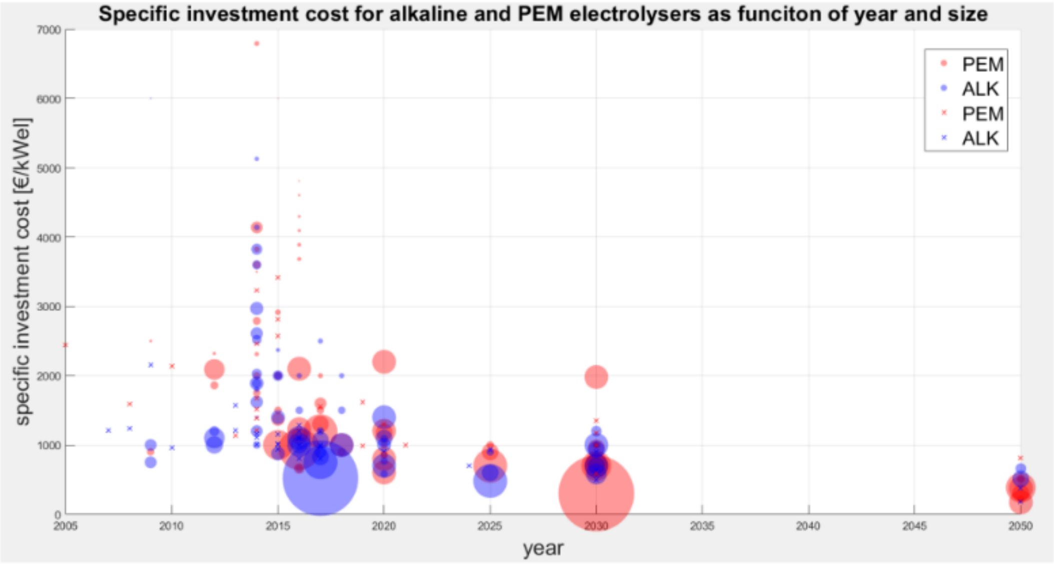


Figure 3.7: Specific investment cost for alkaline and PEM technologies as a function of year and size.

The graph shows the wide variation of the literature data regarding the specific investment costs (300 to 8000 €/kW), the year of installation (2005 – 2050) and the rated power of the electrolyser (0.05 kW to 100 MW). As can be seen in the figure, the investment costs of electrolysers decreased significantly over the past decades and will continue to decrease in the next years. The same conclusion was found by (Sabta et al. 2018) who made an overview of electrolyser investment costs over the past 30 years. To make reliable statements regarding the costs of an electrolyser system, the individual data points must be categorized. The specific cost of the electrolysis system has been analysed for variable nominal size, as electrolysis investment costs tend to become lower with increasing size [33]. Specific cost curves were fitted starting from the observed data for each of the three technologies. To better fit the data, the electrolyser data has been divided in two separate ranges of power [MW]: a) Electrolyser of size below 1 MW; b) Electrolysers of size above 1 MW. All these curves are equipment costs curves.

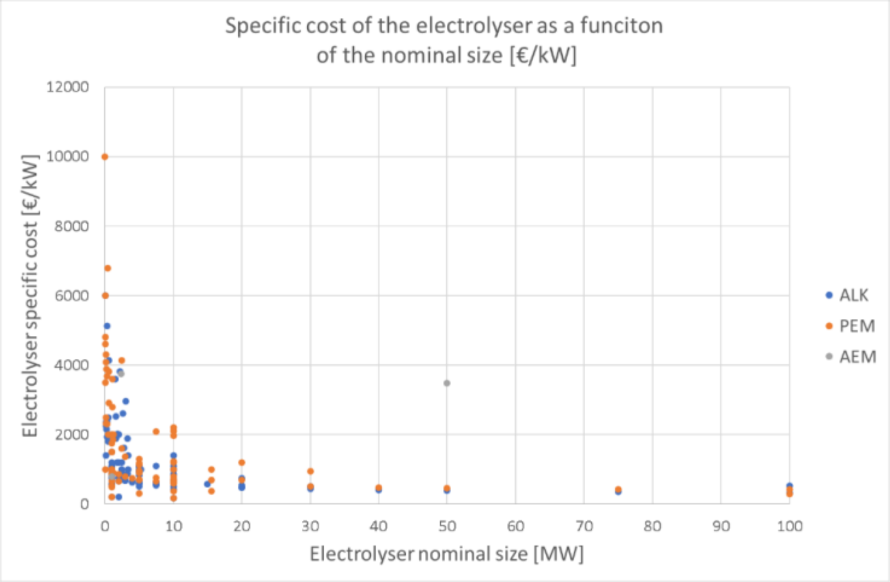
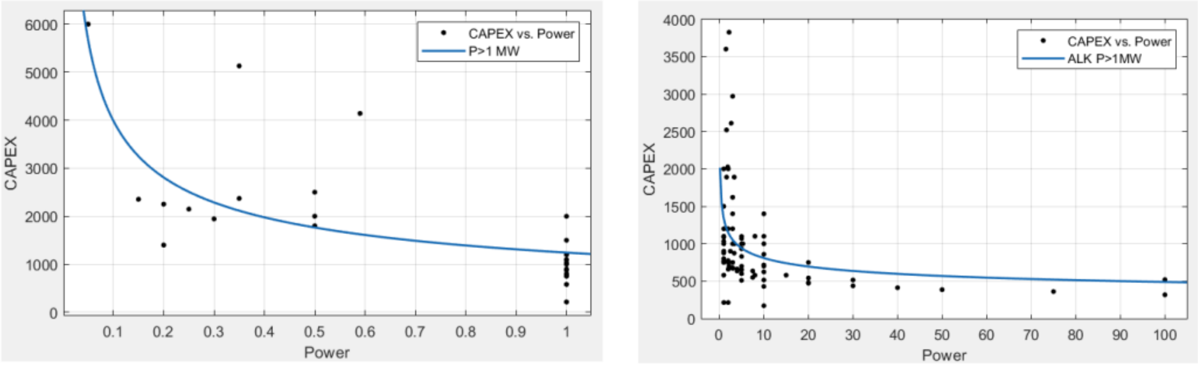
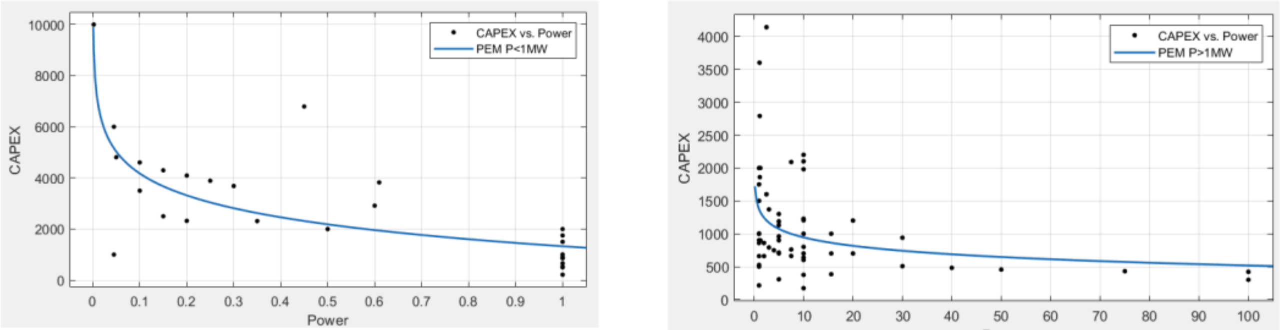


Figure 3.8: Specific cost of alkaline, PEM and AEM electrolysers as a function of their nominal size [€/kW].



P<1MW P > 1MW

Figure 3.9: To the left: specific cost of the alkaline technology for low rated powers as a result of the fitting of literature data. To the right: specific cost of the alkaline technology for high rated powers as a result of the fitting of literature data.



P<1MW

P > 1MW

Figure 3.10: To the left: specific cost of the PEM technology for low rated powers as a result of the fitting of literature data. To the right: specific cost of the PEM technology for high rated powers as a result of the fitting of literature data.

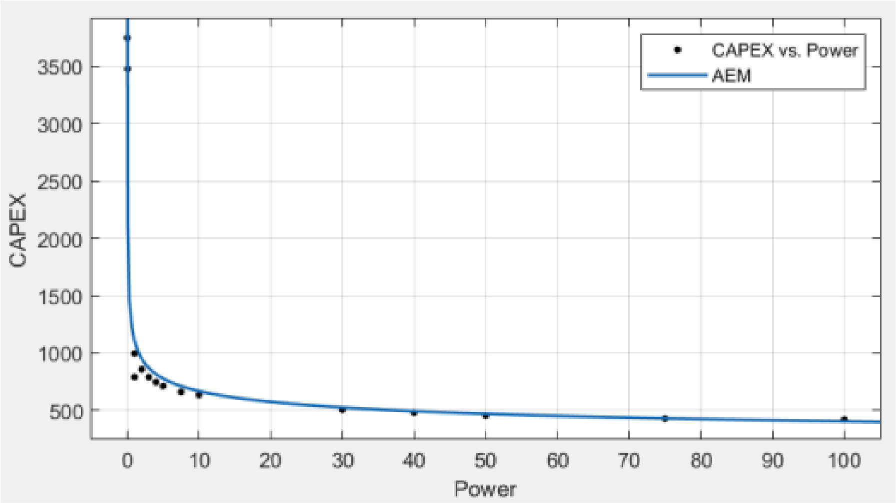


Figure 3.11: Specific cost of the AEM technology for low rated powers as a result of the fitting of literature data.

$$\textbf{ALK, P<1 MW} \rightarrow y = 1243x^{-0.5064} \tag{3.5}$$

$$\textbf{ALK, P>1 MW} \rightarrow y = 1337x^{-0.2182} \tag{3.6}$$

$$\textbf{PEM, P<1 MW} \rightarrow y = 1787x^{-0.2827} \tag{3.7}$$

$$\textbf{PEM, P>1 MW} \rightarrow y = 185.6 * \log(x) + 1372 \tag{3.8}$$

$$\textbf{AEM} \rightarrow y = 1243x^{-0.5064} \tag{3.9}$$

Total equipment costs - OPEX

Includes the maintenance, spare parts and replacement of the auxiliary components (pumps, filters...). This excludes electricity, water consumption and stacks replacement which will be considered later. The following curve summarizes the compiled data based on full load.

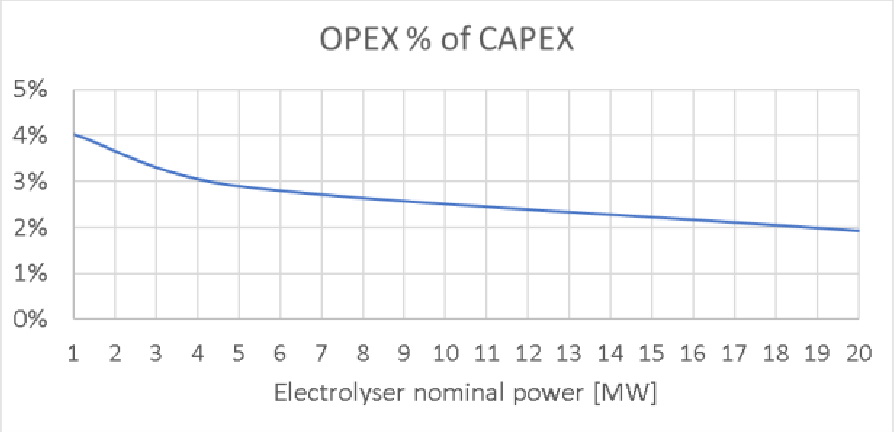


Figure 3.12: Opex as a pecentage of CAPEX for the electrolysis equipment.

Stack replacement is needed when efficiency reaches below 90% of its initial value. The stack replacement cost has been assumed to be 55% of the stack's initial value. In this analysis, the water inlet has been considered as already demineralized and no costs have been associated with it. Generally, the influence of the water purchase on the overall costs of H2 adds a maximum of 0,3% to the total costs and it doesn't significantly change the final price of hydrogen production. ("Innovative Large-Scale Energy Storage Technologies and Power-to-Gas Concepts after Optimisation Report on the Costs Involved with PtG Technologies and Their Potentials across the EU" 2018). Another constitutive assumption regards oxygen, which is considered to be vented into the atmosphere. When an electrolysis unit is started it faces operating costs, mostly due to the consumption of nitrogen for the inertization of the components. For this reason, each start-up has been considered to add a 5€specific cost to the system.

3.3.4 Other hydrogen facility costs

Previously the costs of the major equipment (stock and auxiliary costs) have been considered. Here the additional costs needed to complete the project are reported. In addition to the equipment costs, additional investments are needed to complete the project, such as civil works, engineering, DCS and EMU, interconnection, commissioning and start-up costs. In the document ... such costs are reported as a percentage of the cost of electrolysis including the electrolyser, the storage and the compression phase. In this work, just the electrolysis phase is considered, and thus the data from ... have been revisited and corrected. Moreover, most of the additional costs of an electrolysis system are already extinguished in this case. The civil expenses, such as the foundation, industrial building, lightning etc. are here already considered as the electrolyses are to be placed close to a fully operational industrial power plant. Security costs are included in the equipment costs, while fencing costs are here neglected. Water supply costs have been considered to be out of the perimeter of this study and are thus not considered. The only cost to be considered is the one for transporting the electrolyser machines from the manufacturing industry to the final location. This cost has been considered as 1% of the equipment cost for a 2.5 MW electrolyser. For what regards engineering costs, which include architectural, engineering, studies, permitting, legal fees and other pre and post construction expenses, they represent 15% of the equipment costs for a 2.5 MW electrolyser project that includes also the compression and the storage phases. Such percentage has been decreased to 5% for this case study for a 2.5 MW plant, which includes the electrolysis unit only. The Distributed Control System (DCS) and Energy Management Unit (EMU) are components that allow safe operation and optimisation of the production plant, cost depending on the complexity of the production plant. Therefore, the cost is estimated to be 5% of equipment costs for a 2.5 MW electrolyser project. The power plant where the electrolyser has to be installed already has a low and medium voltage connection to the grid as well as an interconnection to the natural gas pipelines. Interconnection costs are then not considered. For what regards commissioning and start-up costs, they have been considered to be comprehended into the equipment one. Non-equipment and civil costs ("other costs") represent in this case 11% of equipment costs for a 2.5 MW electrolyser project. To reflect the economy of scale on bigger projects, an equation model is proposed to adapt the costs.

$$Othercosts = 10\%(\frac{2.5MW}{P_{project}}) + 1\% \tag{3.10}$$

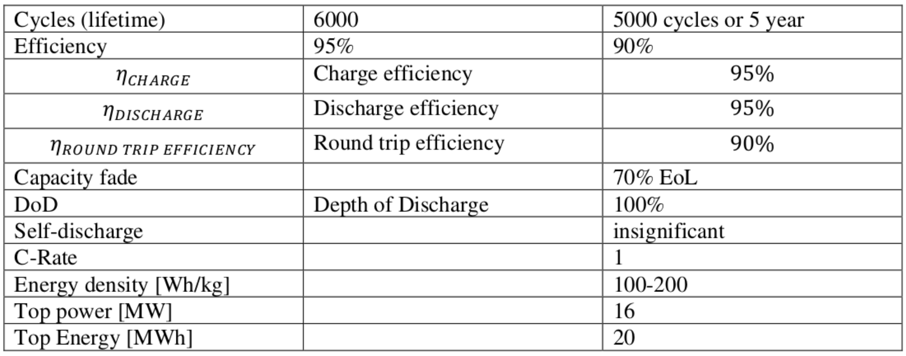
The operational expenditures for an electrolysis system can be divided into:

- Equipment OPEX, described in the previous section, covers the maintenance, spare parts and replacement associated with the equipment;
- Facility OPEX, covers the other operational expenditures related to the facility level. They include site management, land rent and taxes, administrative fees (insurance, legal fees,. . .), and site maintenance.

Generally, facility OPEX is estimated at 4% of non-equipment costs. In this analysis, the electrolyser plant has been assumed to be built in an industrial area by a company that already owns the land of construction. Thus, the rent costs have not been considered. Additionally, the hydrogen production is located close to other facilities (in the case of Biomet, to a biomethane production plant) and can share the site maintenance and management with them with a slight increase in their cost. Consequently, those have been discarded, as well as the administrative fees. Regarding the taxes, a 28% on profit has been considered, in line with the Italian regulation for industrial plants belonging to the energy sector.

3.4 Batteries

The production cost of green hydrogen from electrolysis is influenced by various technical and economic factors. The most important are the investment cost, the conversion efficiency, the electricity costs, and the annual operating hours. Many reports such as [5] have investigated the behaviour of the Levelized cost of hydrogen with respect to a variation of these operating factors. One key point to reduce the LCOH has been demonstrated to be the maximisation of the operating hours of the electrolysers, to efficiently distribute the investment costs of the plant over a higher yearly fuel production. For this reason, the possibility of including a battery storage system to support the electrolyser during the hours of stop of the PV system has been considered.



Cycles (lifetime)	6000	5000 cycles or 5 year
Efficiency	95%	90%
η_{CHARGE}	Charge efficiency	95%
$\eta_{DISCHARGE}$	Discharge efficiency	95%
$\eta_{ROUND\ TRIP\ EFFICIENCY}$	Round trip efficiency	90%
Capacity fade		70% EoL
DoD	Depth of Discharge	100%
Self-discharge		insignificant
C-Rate		1
Energy density [Wh/kg]		100-200
Top power [MW]		16
Top Energy [MWh]		20

Table 3.10: Technical specifications for the battery.

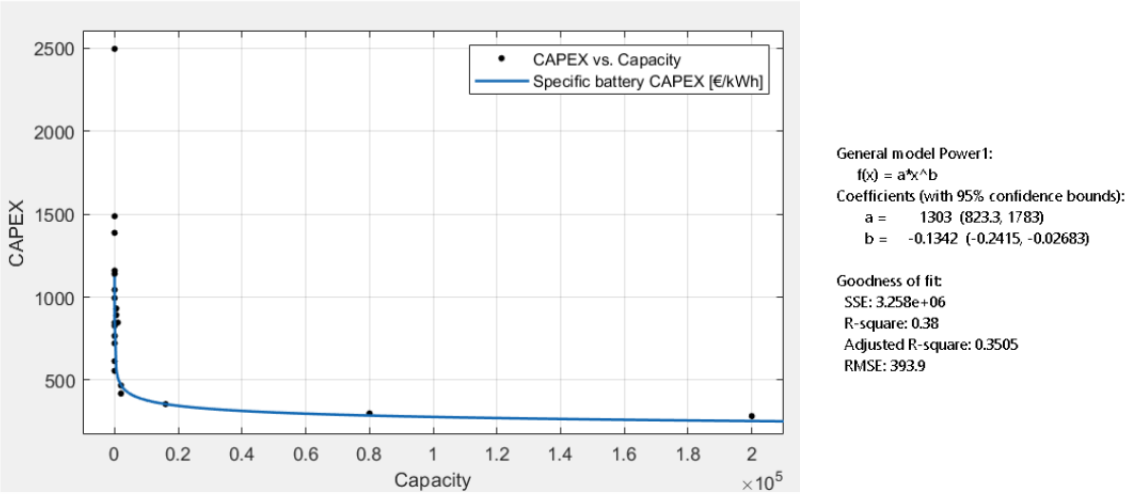
3.4.1 Techincal data

There are many typologies of batteries that can suit this application. Based on literature reviews, it was decided to focus on Lithium-ion batteries. These kinds of batteries can indeed reach a very high Depth of Discharge (DoD), allow high efficiencies and are low cost. Table 11 present the technical specifications of the considered batteries.

Under the charging/discharging rate of 1C, at 100% DoD and after 6000 cycles the battery reaches its End of Life (EOL). At that point, the battery capacity will have decreased to 70% of the Begin of Life value. The number of cycles of the battery depends on the availability of surplus from the PV system, the capacity of the battery and the size of the electrolyser. For this application, it has been studied that for a PV system of 600 kW coupled with an electrolyser of 200 kW and a battery of 60 kWh, the battery does 1 cycle per day. In the case of a bigger electrolyser, the cycles would be even lower as more PV surplus would be useful to be directly converted into H2. For this reason, it has been assumed that the battery does 1 cycle per day, which means that it would reach the 70% of its EOL after 16 years of operation. In this analysis, the battery is assumed to be replaced only one time, during the 10th year of operation of the power plant.

3.4.2 Economics

As well as for PV systems, the specific investment cost of batteries varies whether they are residential, commercial, or utility-scale batteries. Residential batteries are considered those smaller than 30 kWh, commercial between 30 kWh and 1 MWh while utility scales are the ones bigger than these.Literature cost data have been collected for batteries of variable sizes. Utility-scale lithium-ion battery prices have significantly dropped during the last years (-73% in 2016 since 2010, [10]) thanks to technological improvements, economies of scale and the high competition between the major manufacturers. Nowadays, the price for a Lithium-ion battery is around 250 €/kWh, and a further decrease to 100 €/kWh is expected for 2030. Nevertheless, the specific cost of batteries is strongly affected by the economies of scale and residential size batteries are still much more costly nowadays. Additionally, the prices result to be higher in the Italian market. As a reference, the average price for residential lithium-ion battery systems in Italy is 960 €/kWh [23] Referring to the collected data, a curve has been fitted showing the specific battery CAPEX with respect to the battery capacity, starting from literature data, figure



```
General model Power1:
    f(x) = a*x^b
Coefficients (with 95% confidence bounds):
      a =       1303  (823.3, 1783)
      b =    -0.1342  (-0.2415, -0.02683)

Goodness of fit:
  SSE: 3.258e+06
  R-square: 0.38
  Adjusted R-square: 0.3505
  RMSE: 393.9
```

Figure 3.13: Specific CAPEX [€/kWh] for a Lithium-ion battery as a function of its capacity [kWh].

3.5 Law setting

The production, distribution, and transport of hydrogen are regulated by the Ministerial Decree of 23 October 2018 [13], "Fire prevention technical regulation for the design, construction and operation of hydrogen distribution systems for motor vehicles", drawn up by the Fire Department of the Public Aid and Civil Defense of the Ministry of the Interior. This ministerial decree removed the obstacles of the previous legislation to the development of the hydrogen market, such as the maximum loading pressure for gas, which opposed the technical specifications needed for operating a FCEV refuelling station. As a consequence, in the summer of 2019, the first hydrogen distributor in Italy came into operation. This section presents the specifications of this decree, which is the only one that regulates hydrogen production in Italy. The 2018 regulation leaves uncertainties about the feasibility of hydrogen plant installations and more specific legislative acts are required to establish a univocal framework of the necessary authorization processes for H2 plants and open the window of opportunity that the hydrogen market in Italy reserves. In this document the feasibility of hydrogen production is evaluated, neglecting the distribution, transport, and refuelling station (compressors, pipes, storage volumes, etc ...), and therefore, the component whose jurisprudence is being studied is exclusively the hydrogen production unit. According to article 5, a hydrogen distribution systems for motor vehicles cannot be built:

- in the “Zona territorial omogenea totalmente edificata”, literally “The Totally built homogeneous territorial area”, identified as zone A in the general regulatory plan, art. 2 of the ministerial decree 2 April 1968, n. 1444 or mentioned in art. 17 of the law 6 August 1967, n. 765;
- in the areas of completion and expansion of the urban area indicated in the master plan or in the manufacturing program, in which a building index of more than 3 m^3 per m^2 is expected;
- in areas, wherever located, intended for public green areas.

The locality of Berghente, San Rocco al Porto, is located in an area classified as a "Rural Nucleus" (Article 6.1.4 of the NTA of the PdR) and "special area in the agricultural area" (BIOGECO Area, Article 6.4 of the NTA of the PdR). In addition, it is in the area classified as "Areas of respect of 150 m of restricted public waters" (Article 4.6 of the NTA of the PdR, with landscape constraint under Legislative Decree 42/2004, Article 142 letter c). Therefore, it is neither located in the homogeneous territorial area of type A nor in an expansion zone of the urban aggregate or in areas intended for public green areas
The Belgioioso plant, on the other hand, falls within the "Scope of consolidated production activities", and the "Scope of damage to the company at risk of a major accident". It is not located in a homogeneous territorial area of type A or in areas of expansion of the urban aggregate or intended for public parks [14]
The electrolyser is considered by the Fire Brigade as a “dangerous element of the system”. All materials used for the construction of the plant elements must be compatible with hydrogen at the temperatures and pressures of use and according to the provisions of ISO 11114-4. They must also be chosen by accounting for the phenomena of the hydrogen embrittlement, the permeability and porosity of hydrogen and the problems related to fatigue and ageing in the expected operating times. The systems must also be designed and built-in compliance with the ISO 22734-1 standard. As for the emergency system, a system controlled by safety buttons, with manual reset, must be placed near the production plant, to be able to completely isolate the production from the suction and the delivery line of the compressors. These requirements are all met by the electrolysers studied in this

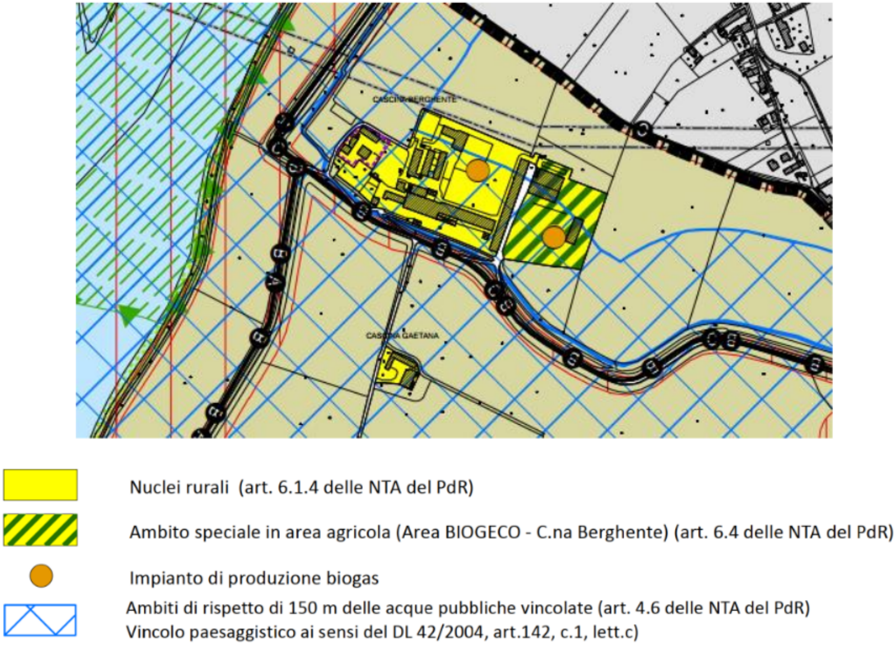


Figure 3.14: Biomet installation of San Rocco al Porto on the "Disciplina dei tessuti edificati ed agricoli" on the "Piano delle Regole" of the municipality of San Rocco al Porto.

feasibility study, which are all CE certified and made up of PED certified stacks. As far as passive safety is concerned, the entire part of the machine aimed at generating hydrogen is classified ATEX, as the electronic components are. On the active safety side, there are both mechanical and electronic safety measures:

- From an electronic point of view, there are redundant pressure switches to read the pressure inside the circuit, which interrupt production if the maximum pressure is exceeded;
- from a mechanical point of view, there is an overpressure valve which, in addition to a certain operating pressure in the circuit, vents to the outside. This valve is necessary for the event of an arrest of electronic safety.

In the event of a blackout, there are no problems affecting the production side of the system, as the cathode and the anode chamber are separated from each other, and no mixing of H2 with O2 occurs. The machine has a system constituted by open solenoid valves that can flash everything that is under pressure inside the machine in case of need. Secondly, every time the machine turns off voluntarily or accidentally, a nitrogen purge is performed to clean it up. Regarding the access to

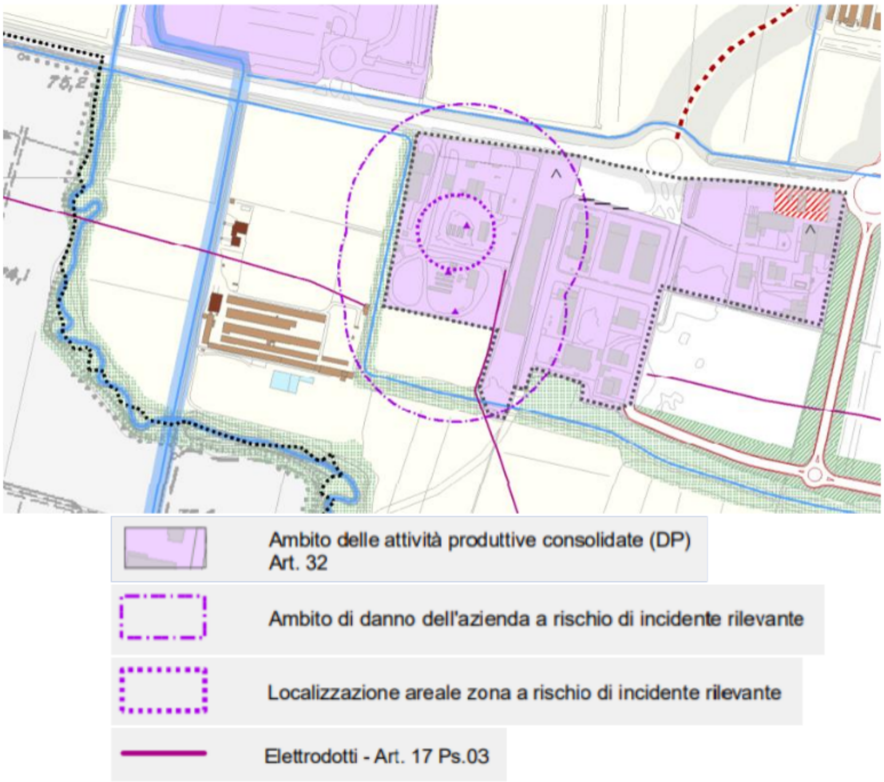


Figure 3.15: Biomet installation of Belgioioso on the "Disciplina dei tessuti edificati ed agricoli" on the "Piano delle Regole" of the municipality of Belgioioso.

the plant area, the dangerous elements of the plant must be fenced, for a height of not less than 1.8 m, to make them inaccessible and prevent tampering. This fence must be placed at a distance from the system elements that allow safe operation. A specific risk assessment must be performed on the hydrogen production unit, as it isn't included in the activities regulated by specific fire prevention provisions. This risk assessment consists of a specific technical report on the application case to identify the fire hazards, the assessment of the associated risks and describes the fire prevention and protection measures to be implemented, as described in Annex I of the decree of the Ministry of internal 7 August 2012 [12]. The production units must be placed in boxes, i.e., a structure of reinforced concrete or non-combustible material walls of adequate mechanical strength. The electrolysis system must be monitored by installing the control systems specified below:

- a temperature detection and control system;
- a gas leak detection and control system, to avoid the possibility of the formation of a dangerous explosive atmosphere;

- a flame detection system must be installed in all areas of the system likely to be affected by the ignition of any hydrogen leaks;
- portable fire extinguishers must be installed to protect the electrolyser and must have a nominal charge of not less than 6 kg with an extinguishing capacity of not less than 21 A 113 B.

The production plant must be protected with a network of hydrants designed and built following the provisions of the decree of the Ministry of the Interior of 20 December 2012. Concerning safety distances, the legislation explicitly lists a minimum distance of 15 m from other components for compressors, storage, cylinder wagon boxes and dispensing units, but not for the production units. Surely, the electrolysis system must be shielded with non-combustible material of adequate mechanical resistance from other system components. In addition, it must be located at least 22 m away from the electricity substation. The specifications regarding the safety signs are reported in the legislative decree 9 April 2008, n. 81. If the electrolysis unit is to be located at the Belgioioso plant, where the refuelling station is, the safety measures are indicated in the Title VI of the decree, referring to mixed road distribution systems for automotive. According to it, the "dangerous elements of the system", including the electrolyser, must be located at least at:

- 15 m distance from petrol and diesel tanks;
- 30 m distance from liquefied petroleum gas tanks;
- 22 m away from the dangerous elements of the natural gas distribution system.

The "hazardous plant elements" classification also includes the hydrogen storage and supply components. These are crossed by pressurized hydrogen flows, more dangerous than those in the production unit, which reaches a maximum of 35 bar. Given that the installation of an important number of safety systems is expected for all the dangerous elements of the plant, it is favourable to install the production unit at Belgioioso together with the storage and the dispenser. In such a way, the number of safety systems to be installed would be lower as some of them would be shared between more plant components.

Chapter 4

Methodology

In the previous chapter, the useful plant and literature data for the installation of a hydrogen production facility have been studied. As mentioned, the green hydrogen production with renewables is a wide concept that concerns various layout possibilities depending on what are the production or demand constraints of the specific application. Before showing the methodology used, strategic decisions on the layouts must be made consistently with the company constraints and to the final aim, i.e., the minimization of the production cost of hydrogen. To set a technically feasible problem, this chapter firstly assesses the mass and energy balances of the system. Then, such streams are given a proper valorisation. Finally the most economically feasible plant designs are identified and a methodology is implemented to compute the Levelized cost of hydrogen.

4.1 Mass and energy streams characterisation

From a mass balance perspective, the system works easily: as previously shown the only mass streams are the inlet water and the two outlet gasses, the hydrogen and oxygen, in a gaseous form. As mentioned in Chapter 3, the demineralized water inlet is considered a zero-cost stream. Indeed, if not employed for electrolysis, such water would be discharged as wastewater. Moreover, as such water already has the quality levels needed for the process, it is free from additional costs. The oxygen stream is considered a zero-value stream too. Indeed, even if such gas is produced with high purity and may be useful for many industrial processes, industrial electrolysis plants generally vent it away instead of selling it, as its compression costs more than its selling price [38]. Finally, hydrogen is valorised at the Levelized cost of hydrogen, which is the final unknown of the problem. For what concerns energy, the coupling of a storage technology to a solar photovoltaic power plant is not a straightforward process. Being the electrical power production of the photovoltaic system intermittent, it does not always coincide with the power consumption range of the electrolyser. Surplus electricity is generated each time the photovoltaic system produces more than what the electrolysis can consume or each time it doesn't produce enough to reach the start-up power value of the electrolyser. It is necessary to identify a strategy for managing this surplus. The system boundaries are represented in Figure 0.1. The energy balance sees two main energy streams: the input one, coming from the renewable power plant, and the outlet, i.e., the surplus. The electricity generated with the renewable power plant is valorised at its Levelized cost of electricity. The value of the surplus depends on the final use to which it is designated.

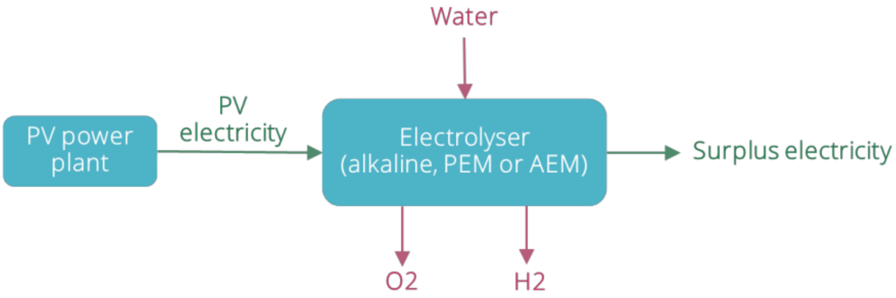


Figure 4.1: Model plan for the production of clean hydrogen.

The availability of the PV surplus is strictly dependent on the size of the PV system, the size of the electrolyser, and the availability of the solar source itself, which is not certainly predictable. It is therefore difficult to quantify the daily, monthly, or annual surplus electricity released by the system. For this reason, the surplus must be sent to a flexible consumer/storage system, which can manage the variability of this energy input. There are three main possibilities for the final use of the surplus: a) Sale the surplus to the grid; b) Store the surplus into batteries; c) Employing the surplus for the Biomet's energy needs.

a) Sale of the surplus to the grid

The first possibility considered is the sale of the surplus to the electricity grid. In this case, the surplus would be valorised by the electricity system at the hourly market zonal price (northern Italy area). Since the production profile and the energy consumption profiles in this analysis have been obtained with hourly discretization steps, so is the electricity surplus. An hourly zonal prices profile has been obtained by averaging the zonal prices hourly profiles for the North of Italy for the years from 2018 to 2021. So, for each hour, the produced surplus is valorised at the hourly price in such a profile. The zonal price profiles for years from 2018 to 2021 and their average are shown in Figure 4.2.

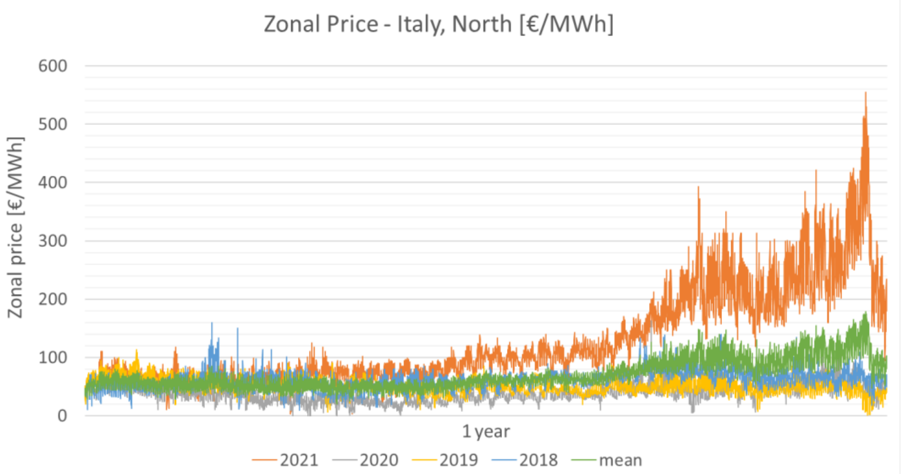


Figure 4.2: Hourly distributions of the zonal price for the North of Italy, for years from 2018 and 2021, and their average.

To have an idea, the mean annual zonal price of the average profile is 68.74 €/MWh. Generally, the lower the nominal power is chosen for the electrolysis system, the greater the surplus of the photovoltaic system. If the difference between the nominal size of these two components is significant, the surplus availability is then more systematic, and it is possible to think of selling the electricity excess through a Power Purchase Agreement. This possibility can be realized if there is an energy-intensive company operating close to where the PV plant is located which can flexibly switch its power feed to the PV surplus when it is available. In this way, the surplus may be valorised at a higher price with respect to the zonal price one. This possibility is neglected in this project, where the electrolysis nominal power is varied within a wide range and so is the surplus produced.

b) Storage of the surplus in batteries

An interesting possibility to manage the electricity excess of the PV plant is to accumulate it into batteries. In case the electrolyser is operated with the PV electricity feed only, i.e., in an off-grid configuration, the addition of batteries would increase the equivalent hours of the plant and so the hydrogen production. Such an increase in productivity may allow to distribute the plant investment costs within a higher hydrogen production and reduce the influence of the operating costs related to the continuously switching on/off the electrolysis plant.

c) Self-consumption

The electricity and heat need of the digester at Biomet's are met thanks to a cogenerator installed in the perimeter of the plant, fed by the pipeline's natural gas.

Indeed, even if the company produces bio-methane, such gas is completely devoted to the mobility sector and so distributed through the refuelling station that the company owns in Belgioioso (PV). An analysis of the energy balances of the San Rocco bio-methane plant shows that its auxiliaries would require an additional electrical energy input of between 400 and 500 kW day to the one that can be produced by the congenator. This need for energy could be partially satisfied with the PV surplus. For each day of the year, then, the first 450 kWh of electricity surplus has been valorised at the LCOE [€/MWh] of the PV plant. The LCOE of the PV plant sized for Biomet is €82.43 / MWh. Its computation is showed in Annex I. As the size of the PV plant is then extended in this analysis, in Figure **??** the LCOE for a variable size PV plant is reported.

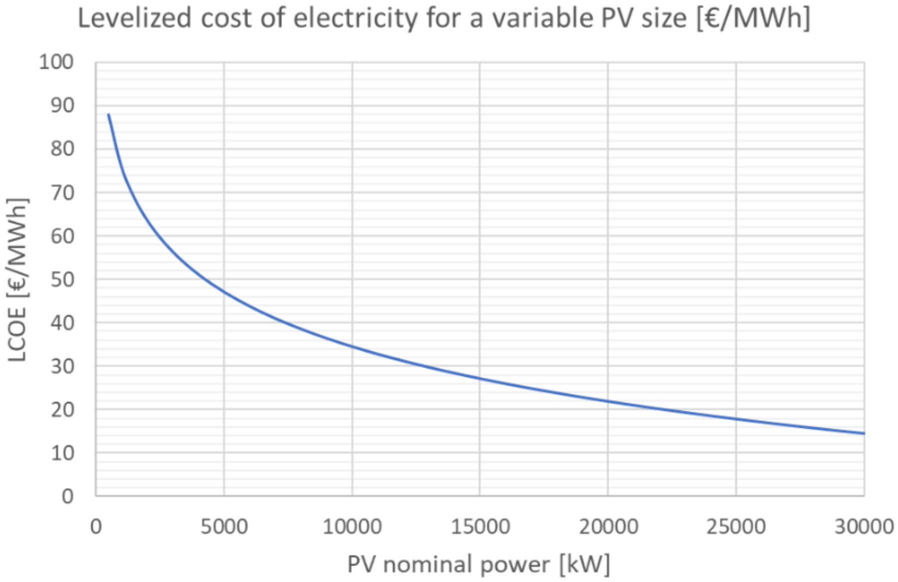


Figure 4.3: Levelized cost of electricity for a variable size PV plant [€/MWh].

As the purchase of natural gas from the grid is on demand, whenever the PV surplus is available it is possible to avoid such purchase and feed the digestor with renewable electricity. In this case, the amount of surplus energy that is consumed by the biomethane production power plant must be properly valorised. The IEA study [21]reports that the Levelized cost of the electricity production by a congenator of 415 kW placed in Italy, with 89% of capacity factor, 7% discount rate and neglecting a carbon tax is 169,62 €/MWh. Such value has been computed by subtracting a heat credit of 114.62 €/MWh from the total unit costs of the plant. For this study, to be conservative, a 150 €/MWh CHP LCOE has been considered. Thus, each time the PV surplus feeds the digester instead of the cogenerator, the bio-methane is produced at a lower energy cost. As this cost reduction occurs thanks to the addition of the PV + electrolyser plant to the system, this saving is accounted for in the financial balance of such plant. To clarify, each time the PV surplus energy is used instead of the cogenerator, a revenue of 150 €/MWh subtracted by the LCOE of the PV plant is faced into the electrolyser power plant. The use of the surplus energy to feed the digester during the day doesn't influence any decision on the optimal size of the cogenerator and thus its investment cost. Indeed, the PV electricity is available during the day only, while the digester consumes also at night-time: in such moment thecogenerator still needs to have the possibility to work at its nominal power in order to fully cover the energy needs of the digester. The maximum surplus energy that can be used by the digester in one hour has been assumed to be 200 kWh.

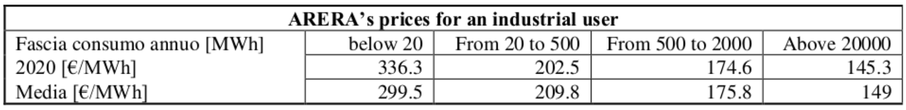
4.2 Additional electricity purchase

Productivity constraints If the electrolyser is operated with PV electricity only, the operating hours of the hydrogen production will be surely lower than the ones of the PV plant, which are 1100 h/y. Consequently, the hydrogen productivity of the plant would be limited. Even if this document regards the production of hydrogen only, it is known that the company aims at selling the gas in the mobility market. Indeed, the company owns a bio-methane dispenser in one of its production sites, and it aims to add an H2 station too. In this perspective, it is relevant to consider the distribution constraints too. From literature studies the specific investment cost of the stations results to decrease significantly as the size of the filling station increases. Stations that distribute more than 600 kg/day of hydrogen appear to have a Levelized cost of hydrogen dispensing equal to 32 €/MWhH2, while such values is doubled for stations that distribute lower quantities ([8]; [36]. From a talk with Air Liquide, one of the world's leading companies in the hydrogen supply chain, the construction of a refuelling station would be justified only for H2 production capacities exceeding 100 kgH2/d. Therefore, both from the production and the distribution point of view, the maximization of the operating hours of the plant and therefore the maximization of the quantity of hydrogen produced is an interesting strategy in this application for the purpose of minimization of the final LCOH.

Valorisation of the purchased electricity

The possibility of adding an energy feed to the electrolysis plant to increase its productivity is then considered. To produce green hydrogen, this input must necessarily be renewable. The following possibilities are considered for the purchase:

a. To purchase electricity from the grid, together with a share of green certificates.



ARERA's prices for an industrial user				
Fascia consumo annuo [MWh]	below 20	From 20 to 500	From 500 to 2000	Above 20000
2020 [€/MWh]	336.3	202.5	174.6	145.3
Media [€/MWh]	299.5	209.8	175.8	149

Table 4.1: ARERA sale price for an industrial user, Acquirente Unico.

b. To purchase the electricity produced by a ReS plant through PPA.

The renewable share of the total electricity consumed in Italy is 33%. Nevertheless, the production of green hydrogen requires a fully renewable electricity source. Thus, if grid electricity is employed as a source to produce green hydrogen, it is necessary to resort to an emission compensating mechanism to make up for the polluting share of the used electricity. This is possible thanks to the “Certificato di Origine”, literally Origin Certificates (GO), which are renewables incentive mechanisms (the new: “Green Certificates”) in Italy. They consist of "renewable energy production quotas" that a consumer of fossil energy can purchase to offset his emissions. Even if the consumer is physically using polluting electricity, through the purchase of the GO it can be sure that in some other part of Europe an amount of renewable electricity equal to the amount of GO that he has purchased is being produced. By buying as much GO as its total electricity consumption, an electricity consumer can consider himself as “zero-emitting”. The average selling price of this certificate in the last 2 years is 2 €/MWh. The electricity price for an industrial consumer that buys through “Acquirente Unico” is reported in Table 4.1. Such values have been obtained by averaging the grid electricity prices for the years from 2018 to 2021.

The alternative to purchasing from the grid is to sign a Power Purchase Agreement with a nearby producer of renewable electricity. Such contract should be signed with renewable plants located in the vicinity of the electrolysis installation, and should produce electricity mostly during hours of stop of the PV system. Power purchase agreements are a means to purchase/sell electricity that is more and more frequently adopted in the energy market, especially in those countries that have a high renewable sources availability, such as Spain and California. Thanks to the fact that the sell/buy transaction passes directly from the producer to the consumer without crossing the grid infrastructure, PPA prices are generally much lower than the grid's one. For example, current utility-scale PV plants in Spain offer a price of 40 €/MWh. In Italy, the market for such contracts is still not completely developed, and prices are still high. For this reason, a price of 110 €/ MWh was considered as the purchase price of energy with a PPA contract for this analysis.

4.3 Implemented scenarios for Biomet

In the previous paragraph, all the possible energy inputs of the PV + electrolyser production system and their valorisation are reported. A recap is shown in Figure **??**.

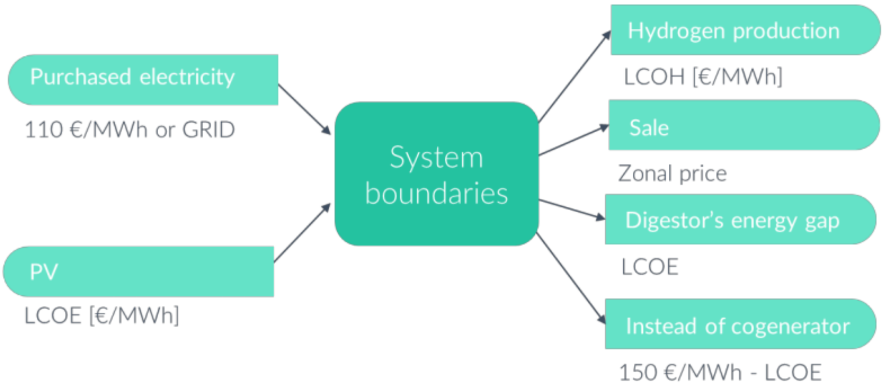
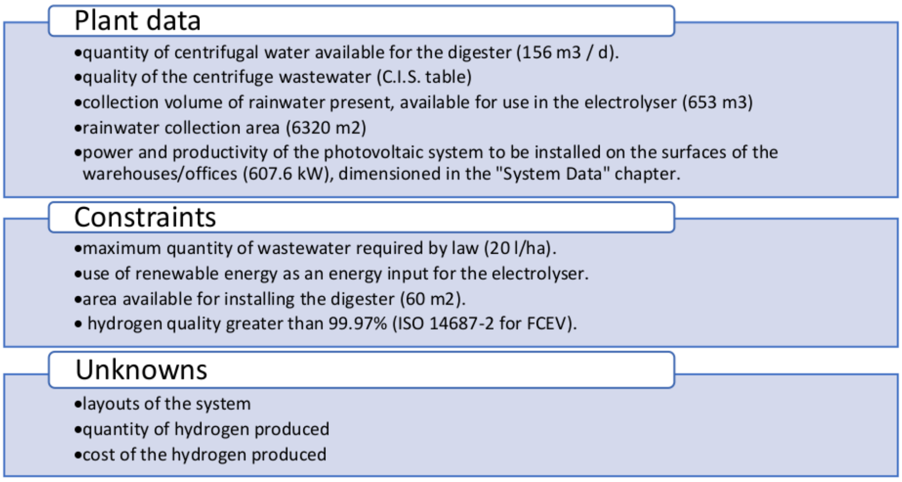


Figure 4.4: Scheme of all the possible energy inputs crossing the boundaries of this study.

The data and constraints imposed by the company and defined by the electrolysis process are recalled in Figure **??**.


Plant data

- quantity of centrifugal water available for the digester (156 m3 / d).
- quality of the centrifuge wastewater (C.I.S. table)
- collection volume of rainwater present, available for use in the electrolyser (653 m3)
- rainwater collection area (6320 m2)
- power and productivity of the photovoltaic system to be installed on the surfaces of the warehouses/offices (607.6 kW), dimensioned in the "System Data" chapter.

Constraints

- maximum quantity of wastewater required by law (20 l/ha).
- use of renewable energy as an energy input for the electrolyser.
- area available for installing the digester (60 m2).
- hydrogen quality greater than 99.97% (ISO 14687-2 for FCEV).

Unknowns

- layouts of the system
- quantity of hydrogen produced
- cost of the hydrogen produced

Figure 4.5: Recap of the plant data, the process constraints and of the unknowns for the optimization problem.

As the production profile of the PV plant is hourly, all the parameters of the analysis have been computed with an hourly time discretization step. For the calculations, the Visual Basic (Applications Edition) and Excel have been used. Considering the aforementioned data together with the existing techno-economic constraints, three layouts have been identified as the most favourable for the production of green hydrogen at Biomet. They differ in the input of the electrolysers, which may be either just produced by the PV plant or also supported by a grid purchase, and in whether the PV plant is coupled with a battery. Respectively:

A) **Scenario 1a**: it considers a constant operation of the electrolysers, as to produce a constant flow rate of hydrogen. The PV productivity is supported by an electricity purchase from the grid or with a PPA. The PV surplus is partly used for the digester's energy needs and partly sold to the grid.

B) **Scenario 2a**: It considers a PV-to-H2 layout. Hydrogen production is solar source dependent. The PV surplus is partly used for the digester's energy needs and partly sold to the grid.

C) **Scenario 3a**: It considers a PV-to-H2 layout, supported by the storage capacity of a battery. The part of the PV surplus that is not used to charge the batteries is devoted to the digester's energy needs and partly sold to the grid.

In the following paragraphs, the description of each scenario is reported.

4.3.1 Scenario 1a: 610 kW PV + PPA/grid purchase

The cost of producing hydrogen employing electrolysis depends mainly on three parameters: the cost of the input electricity, the electrolyser's investment cost, and its hours of operation. Particularly, the higher the hours of operation of the electrolyser, the higher the hydrogen production for the same investment cost of the plant. The influence of the investment costs over an electrolysis system with high operating hours would be reduced, as such cost would be amortized on a greater quantity of hydrogen produced. Moreover, as mentioned previously in the chapter, the economies of scale would be exploited. This idea is implemented in scenario 1a, in which main assumption is the constant operation of the electrolyser at its rated power. The PV electricity production, due to its intermittency, isn't enough to guarantee the constant production of hydrogen, and an additional clean energy input is required to support it. Both the possibilities of purchasing it from the grid and through a PPA are considered. Another interesting aspect of this operating strategy is the reduction of the management and operating costs, such as start-up costs, as it is easier to manage the gas distribution if its production is constant. The electricity surplus of the PV plant is either used by the digester of Biomet or sold to the grid, as stated in paragraph 4.1. As the input energy availability for this case is practically unlimited, the maximum possible electrolyser's size is set by the area availability constraints. In this scenario, the fundamental parameters of the analysis have been computed for an electrolysis size range of 10 kW to 1 MW.

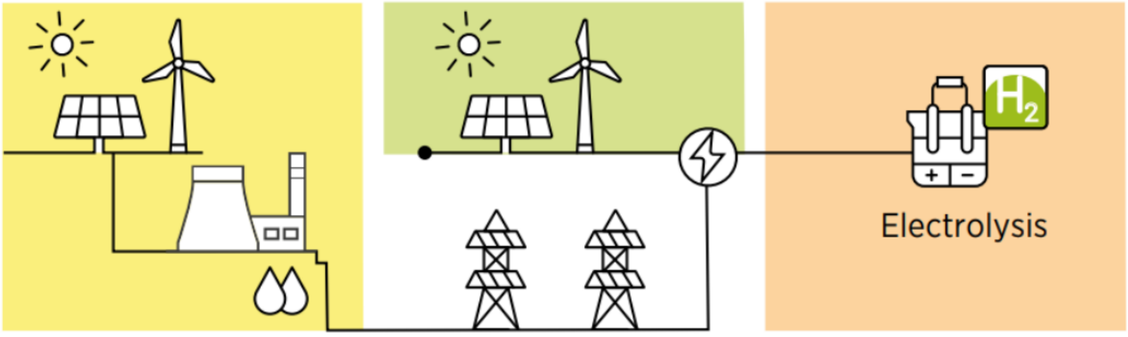
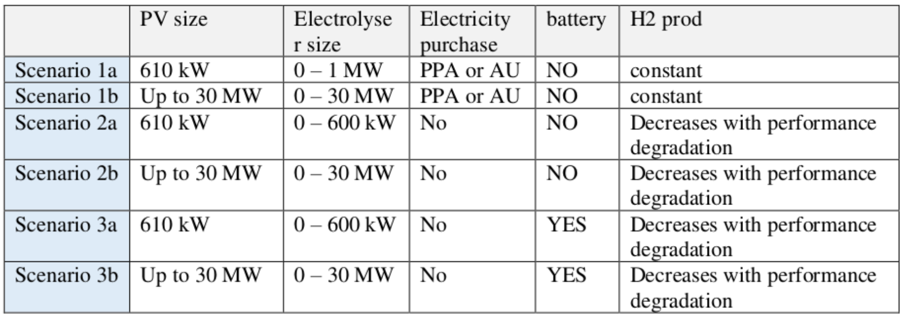


Figure 4.6: Plant scheme of scenario 1a.

4.3.2 Scenario 2a: 610 kW PV plant

In the second scenario, the electrolyser is off grid, as it uses the renewable energy derived from the PV power plant only. Differently, the PV plant is connected to the grid so to sell the surplus whenever it is available.

Even if the hydrogen productivity of this design is limited, this alternative is particularly interesting when considering European incentives. Even though an official incentive mechanism for green hydrogen hasn't been determined, it is likely that it will support the newly built off-grid electrolysis plants only. This is because if any renewable plant currently injecting into the grid could benefit from a significant hydrogen subsidy, they would be interested in switching their production from electricity to hydrogen, leaving a gap in the electricity grid. In this contest, if the incentives are particularly high, adding a battery to store the PV surplus and increase the hydrogen productivity may increase the affordability of the production. Such case is considered in Scenario 3a. In this scenario, the fundamental parameters of the analysis have been computed for an electrolysis size range of 10 kW to 600 kW. Figure 4.9 shows the hourly energy profiles for three sample days in one year. For those hours in which the PV power is higher than zero but lower than the minimum start-up power of the electrolyser, surplus is generated.



	PV size	Electrolyser size	Electricity purchase	battery	H2 prod
Scenario 1a	610 kW	0 – 1 MW	PPA or AU	NO	constant
Scenario 1b	Up to 30 MW	0 – 30 MW	PPA or AU	NO	constant
Scenario 2a	610 kW	0 – 600 kW	No	NO	Decreases with performance degradation
Scenario 2b	Up to 30 MW	0 – 30 MW	No	NO	Decreases with performance degradation
Scenario 3a	610 kW	0 – 600 kW	No	YES	Decreases with performance degradation
Scenario 3b	Up to 30 MW	0 – 30 MW	No	YES	Decreases with performance degradation

Table 4.2

4.3.3 Scenario 3a: 610 kW PV plant + battery

This plant layout is similar to the one of scenario 2a, except for the addition of a storage battery. The behaviour of the main parameters of the analysis has been investigated for an electrolysis range size of 10 kW to 600 kW and for a battery capacity range of 10 kWh to 1 MWh.

4.3.4 Beyond company's constraints

The constraints imposed by Biomet have been loosened to investigate the feasibility of the PV + electrolysis plant at high PV and electrolyser sizes. Indeed, to allow the competitiveness of green hydrogen with the fossil-fuels produced ones, it is useful to exploit the benefit of economies of scale. All the three scenarios implemented for Biomet are here considered for a PV and electrolysis nominal sizes of 1 to 30 MW and for the case of a higher water availability. For these scenarios, the same valorisation of the mass and energy streams have been considered.

4.4 LCOH computation

The implemented LCOH computation strategy differs from an implemented case to another in this analysis. The main operational choice for scenario 1 is indeed the maximization of the hydrogen production throughout the working years of the plant, at the expense of an increasing yearly purchased energy input. The electrolyser is therefore operated to work constantly at its nominal power throughout the year. Differently, in the second scenario, the electrolysis plant operation depends on the availability of the renewable source and in the third also on the capacity of the battery. The methodology used in scenario 1 to compute the LCOH is presented separately from the one of scenarios 2 and 3, which only differ on the employment of a battery and are thus pretty similar. For each case, the simulations are implemented with an hourly time resolution; for each hour, a value is reported for the solar PV available energy, the electrolyser consumed energy, the grid electricity purchased energy, the charging or discharging the energy of the battery, the potential surplus energy and the amount of hydrogen produced.

4.4.1 Scenario PV + PPA/grid purchase

Energy and Mass balances The main assumption of this scenario is the maximization of the productivity of the electrolysis plant. The electrolyser is then set to operate at nominal power for all the hours of the year, excluding scheduled and extraordinary maintenance intervention requirements. The hourly electricity consumption profile of the electrolyser is therefore constant and equal to its nominal power.

$$P_{EL_i} = P_{EL_{NOM}} \tag{4.1}$$

$i = ithhour$

With the hourly consumption profile of the electrolyser and the hourly production profile of the photovoltaic system P_{PV_i}, (PVGIS tool, n.d.), it is possible to set up the power balance for the electrolyser. For the ith hour, if $P_{PV_i} > P_{EL_i}$ surplus is produced:

$$P_{SURPLUS_i} = P_{PV_i} - P_{EL_i} \tag{4.2}$$

For the ith hour, if $P_{PV_i} < P_{EL_i}$, additional energy must be purchased from the grid network to properly operate the electrolyser.

$$P_{GRID_i} = P_{EL_i} - P_{PV_i} \tag{4.3}$$

With the hourly surplus profile and the hourly grid purchased electricity, the power flows in the system are entirely defined. Given the electricity and the water requirements needed for the process and the hourly input feed of available water by the biomethane power plant, the hydrogen production can be computed. The hourly amount of water consumed or discharged in the wastewater and the flow rate of hydrogen production are calculated as in the following equations.

$$M_{H_2i} = \frac{P_{EL_i}}{E_{CONSUMOEL}} \tag{4.4}$$

$$Q_{H_2O,USED_i} = E_{CONS_{H_2O}} \cdot M_{H2_i} \tag{4.5}$$

$$Q_{H_2O_{discharged,i}} = Q_{H_2O_i} - Q_{H_2O,USED_i} \tag{4.6}$$

The annual consumption of the electrolyser is corrected considering its availability:

$$E_{EL} = \sum_{i=1}^{8760} P_{EL_i} \cdot \eta_{availability} \tag{4.7}$$

The yearly availability of the photovoltaic system has already been considered in Chapter 3. The so far reported calculations refer to the electricity that the electrolyser consumes at the beginning of the year. To consider the increase in specific consumption of the electrolyser over the 20 years of operation:

$$E_{EL_j} = E_{EL} \cdot \frac{E_{CONSUMOEL,j}}{E_{CONSUMOEL}} \tag{4.8}$$

j=jth year

The decay of the electrolyser performance is reported in the data in Chapter 3 as a percentage decay every 1000 hours of operation (%/1000 h). In this analysis, the average percentual decay of the operation over 1 year is considered (%/8760 h), so to have a value for the annual decline in performance. The PV modules decay rate has already been studied in Chapter 3. The main assumption at the basis of this scenario is that the hydrogen production during the plant operating lifetime is constant. Therefore, it doesn't depend on the increase in the specific consumption of the electrolyser. Since the hydrogen production remains constant while the machine gets more energy-intensive, the energy that must be purchased from the grid increases year by year. The amount of energy purchased has considered to be "unlimited" for this scenario.

$$E_{GRID_j} = \sum_{i=1}^{8760} P_{SURPLUS_i} \cdot \eta_{availability} \cdot \frac{E_{CONSUMOEL,j}}{E_{CONSUMOEL}} = E_{EL_j} - E_{PV_j} \tag{4.9}$$

The surplus, which will be lower from year to year, must also be corrected:

$$E_{SURPLUS_j} = \sum_{i=1}^{8760} P_{SURPLUS_i} \cdot \eta_{availability} \cdot \frac{E_{CONSUMOEL,j}}{E_{CONSUMOEL}} = E_{PV_j} - E_{EL_j} \tag{4.10}$$

$$M_{H_2} = \sum_{i=1}^{8760} M_{H_{2_i}} \tag{4.11}$$

The consumption of water has been assumed to be constant over the years. In fact, as previously shown in this document, the biomethane system guarantees

a much greater water flow rate than theone required by the electrolysis system. Therefore, an increase in water consumption would only lead to a reduction in the discharge of water into surface wastewater and would not affect the production of hydrogen.
Variables:

- electrolysis modules power at hour i: $P_{EL_i}[kW]$;
- electrolysis modules nominal power: $P_{EL_{NOM}}[kW]$;
- electrolysis availability: $\eta_{EL,AVAILABILITY}$;
- annual energy consumption of the electrolyser: $EEL[kWh]$;
- PV power at hour i: $P_{PV_i}[kW]$;
- surplus power at hour i: $P_{SURPLUS_i}[kW]$
- purchased power from the grid at hour i: $P_{GRID_i}[kW]$;
- annual surplus energy from the PV plant: $E_{SURPLUS}[kWh]$
- annual energy purchased from the grid: $E_{GRID}[kWh]$;
- mass flow rate of hydrogen produced at hour i: $M_{H_2i}[\frac{kg}{h}]$;
- annual quantity of hydrogen produced: $M_{H_2}[\frac{kg_{H_2}}{y}]$;
- specific water consumption of the electrolyser: $E_{CONS_{h_2O}}[\frac{l_{H_2O}}{kg_{H_2}}]$;
- hourly electrolyser water consumption: $Q_{H_2O,USED_i}[\frac{l_{H_2O}}{h}]$;
- average available water flow rate at hour i: $Q_{H_2O_i}[\frac{l_{H_2O}}{h}]$;
- average discharge water flow rate at hour i: $Q_{H_2O_{discharged,i}}[\frac{l_{H_2O}}{h}]$;
- electrolyser specific electricity consumption at the beginning of life: $E_{CONSUMO,EL}[\frac{kWh}{kg_{H_2}}]$;
- electrolyser specific electricity consumption in year j: $E_{CONSUMO,EL,j}[\frac{kWh}{kg_{H_2}}]$;
- annual photovoltaic energy production in year j: $E_{PV_j}[kWh]$;
- annual photovoltaic energy consumption in year j: $E_{EL_j}[kWh]$;
- annual energy purchase from the grid in year j: $E_{GRID_j}[kWh]$
- annual surplus energy from the PV plant in year j: $E_{SURPLUSS_j}[kWh]$

4.4.2 Scenario off-grid PV plant

In this scenario, the electrolyser operation is variable and limited to the hours of production of the PV power plant. The electrolyser can operate between 10% and 100% of its rated power, so that its power in the i-th hour will be equal to:

$$\begin{cases} P_{EL_i} = P_{PV_i} & if \quad 10\% \cdot P_{EL_{NOM}} < PPV_i < P_{EL_{NOM}} \\ P_{EL_i} = P_{EL_{NOM}} & if \quad P_{PV_i} > P_{EL_{NOM}} \\ P_{EL_i} = 0 & if \quad P_{PV_i} < 10\% \cdot P_{EL_{NOM}} \end{cases} \tag{4.12}$$

When the electrolysis unit is actived it the Start-up procedure. The surplus value for the i-th hour is:

$$\begin{cases} P_{surplus_i} = P_{PV_i} - P_{EL_i} & if \quad P_{EL_i} < P_{PV_i} \\ P_{SURPLUSS_i} = 0 & if \quad P_{EL_i} > P_{PV_i} \end{cases} \tag{4.13}$$

Start up costs. This parameter takes into account the fact that when an electrolysis unit is activated, it goes through operating costs, in particular due the consumption of nitrogen for the inertization of the components [52]. Each start-up is associated with a specific cost And the electricity consumed annually by it:

$$E_{EL} = \sum_{i=1}^{8760} P_{EL_i} \cdot \eta_{AVAILABILITY} \tag{4.14}$$

While the total annual surplus results:

$$E_{surplus_i} = \sum_{i=1}^{8760} P_{surplus_i} \cdot \eta_{AVAILABILITY} \tag{4.15}$$

The amount of hydrogen produced turns out to be:

$$M_{H_{2_i}}\left[\frac{kgH_2}{h}\right] = \frac{P_{EL_i}\left[\frac{MWh}{y}\right]}{E_{CONSUMOEL}\left[\frac{kWh}{kgH_2}\right]} \tag{4.16}$$

$$M_{H_2}\left[\frac{kgH_2}{y}\right] = \sum_{i=1}^{8} 760 M_{H_{2_i}}\left[\frac{kgH_2}{h}\right] \tag{4.17}$$

While the consumption of water:

$$Q_{H_2O_i} = E_{CONS_{H_2O}}\left[\frac{l_{H_2O}}{kg_{H_2}}\right] \cdot M_{H2_i} \tag{4.18}$$

$$Q_{H_2O_{discharge,i}} = Q_{available}\left[\frac{l_{H_2O}}{h}\right] - Q_{H2O_i} \tag{4.19}$$

By adding up the hours in which the electrolyser is in operation, the hours of operation are calculated, different from its equivalent hours, equal to:

$$h_{eq} = \frac{E_{EL}}{P_{EL_{NOM}}}[h] \tag{4.20}$$

Here too, as in the previous case, the calculations are corrected considering the decay of the component efficiencies. In this case, since there is no external “unlimited” energy source but the system is off-grid, it will not always be possible to guarantee a constant production of hydrogen for the entire 20 years of operation of the system. In fact, due to the annual decline in the performance of the panels and due to the annual increase in the specific consumption of the electrolyser (decrease in efficiency), the energy available for electrolysis will be less and less while the energy used to produce the hydrogen more and more. This also involves a progressive reduction of the surplus of energy during the useful life of the plant.

$$\begin{cases} E_{EL_j} = E_{EL} \cdot \frac{E_{CONSUMOEL,j}}{E_{CONSUMOEL}} \\ M_{H_{2j}}\left[\frac{kgH_2}{y}\right] = \sum_{i=1}^{8} 760 M_{H_2} \cdot \frac{P_{EL_i}\left[\frac{MWh}{y}\right]}{E_{CONSUMOEL_j}\left[\frac{kWh}{kg_{H_2}}\right]} \\ E_{GRID_j} = E_{EL_j} - E_{PV_j} E_{SURPLUS_j} = E_{PV_j} - E_{EL_j} \end{cases} \tag{4.21}$$

anno j esimo n = 20 anni, vita utile dell’impianto If a battery is used, it is necessary to add a strategy for its operation and for the calculation of system variables. The logical scheme for the battery is shown at Annex II In order to consider the decay of the electrolyser performance, the values were subsequently adjusted as reported in equation 35.

LCOH computation For the calculation of the LCOH, the Discounted Cash Flow (DCF) method or discounted cash flow method was used, one of the most used methodologies for business analysis. It is based on the determination of the present value of the expected cash flows of a given asset. The three basic elements on which it is based are: the volume of cash flows, their temporal distribution during the entire production period of the plant and the discount rate. In the analysis, all revenues and expenses referred to year zero, that is the year of construction of the plant. This discounting is essential to take into account the value of money over time and is accomplished by defining the discount rate (or discount rate) which takes into account the investment risk. The discount rate was considered to be 6%. Inflation is considered separately and is assumed to be 1%. The useful life of the plant was assumed to be 20 years. Cash flows referred to year zero, which is the year in which the plant is built. The CAPEX have all been referred to year zero. OPEX calculated as:

$$OPEX_n = \frac{OPEX_1}{(1+IR)^n} \tag{4.22}$$

Where the OPEX of year 1 for the PV plant were considered to be 1.5% of the CAPEX while the OPEX of year 1 of the electrolyser were considered to be 4% of its investment costs. The OPEX of the electrolyser include also the stack replacements costs, which depend on how the production capacity of the electrolyser is exploited. Since cash flows do not occur in the year of construction but are estimated for future years, it is necessary to correct them for inflation. The taxes for the plant are assumed as 28% of the profit. Amortization is considered over 11 years. In addition to the investment and maintenance costs of the two plants previously shown, it is necessary to consider the cost of purchasing electricity:

$$COST_{GRID_j} = E_{GRID_j}\left[\frac{MWh}{y}\right] \cdot Costoenergia\left[\frac{N}{kWh}\right] \tag{4.23}$$

Where the cost of energy is corrected from year to year taking into account inflation, exactly as done for the plant's OPEX. Finally, in addition to the revenues produced from the sale of hydrogen, the plant has revenues linked to the sale of the surplus of electricity from the PV plant. These revenues will be as large as the size of the electrolyser is lower than the nominal capacity of the photovoltaic system.

$$REVENUE_{SURPLUS_j} = E_{SURPLUS_j}\left[\frac{MWh}{y}\right] \cdot Saleprice\left[\frac{N}{kWh}\right] \tag{4.24}$$

The selling price is also corrected by considering inflation. Having defined all the energy and economic flows of the plant, it is now possible to calculate the Levelized Cost of Hydrogen of the hydrogen produced. The basic equation for calculating the LCOH does not provide for the presence of additional revenues derived from the sale of a "by product", and therefore the revenues obtained from the sale of the surplus in this case. However, in many plant applications in which, in addition to the production of a priority final product, there is also the generation of a "by product", valued at a precise selling price, such as the production of fertilizers from the centrifugation of the compost in the plants for the production of biogas, the additional revenues are considered in the equation for the calculation of the LCOE. In this analysis it was considered significant to show both the cost of producing hydrogen per se and the same cost considering the additional sale of the surplus of electricity. Two methods were considered for the calculation of the LCOE: The LCOH was calculated considering the selling price of hydrogen for which the Net Present Value of the investment is zero, using the Excel "Goal Search" tool. Proceeding with the cash flow analysis, an indicative initial value is assumed for the hydrogen sale price, which will then be converged to the actual LCOH. The following are calculated:

$$EXPENSES_j = (CAPEX_j + OPEX_j)_{PV} + (CAPEX_j + OPEX_j)_{EL} + COST_{GRID_j} \tag{4.25}$$

$$REVENUES_{TOT_j} = REVENUES_{H_2 j} + REVENUES_{SURPLUS_j} \tag{4.26}$$

$$PROFIT_j = REVENUES_{TOT_j} - EXPENSIVE_j - AMORTIZATION \tag{4.27}$$

$$TAX_j = tax\% \cdot PROFIT_j \tag{4.28}$$

$$CASHFLOW_j = CF_j = REVENUES_{TOT_j} - EXPENSES_j - TAX_j \tag{4.29}$$

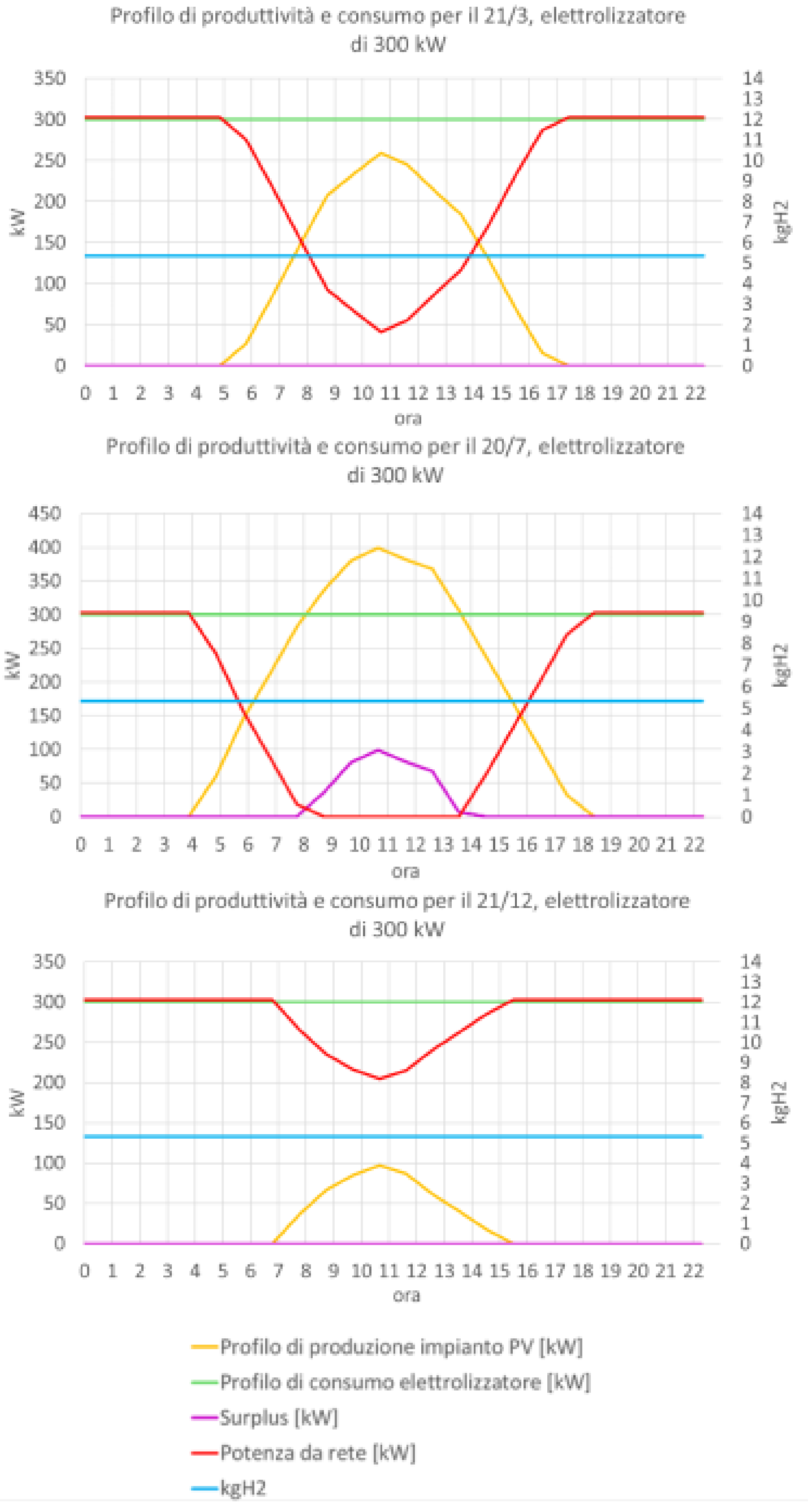
$$DISCOUNTEDCASHFLOW_j = DCF_j = \frac{CF_j}{(1+r)^n} \tag{4.30}$$

$$CUMULATIVEDISCOUNTEDCASHFLOW_j = CDCF_j = DCF_j + DCF_{j-1} \tag{4.31}$$

The quantity of hydrogen is multiplied by the initially assumed selling price, a variable which we will then vary by bringing the NPV of the investment to zero and thus reaching the selling price of hydrogen beyond which it is possible to have a negative investment, i.e. the LCOH. With the definition of LCOH:

$$LCOH = \frac{\sum_{t=0}^{n}(CAPEX + OPEX)_t + (E + W)_t - ADD.REV_t * (1+r)^{-t}}{\sum_{t=0}^{n} H_t * (1+r)^{-t}} \tag{4.32}$$

The LCOH does not include taxes, since it is aimed at providing the selling price of hydrogen in order to balance over the useful life of the plant regardless of where it is planned to be built and its production technology.



Profilo di produttività e consumo per il 21/3, elettrolizzatore di 300 kW

Profilo di produttività e consumo per il 20/7, elettrolizzatore di 300 kW

Profilo di produttività e consumo per il 21/12, elettrolizzatore di 300 kW

Figure 4.7: Hourly production profile of the PV system, Hourly consumption profile of the electrolysis plant, Hourly profile of production of the surplus, Hourly profile of energy purchased from the grid and Hourly hydrogen production profile, for three sample days in l an average year.

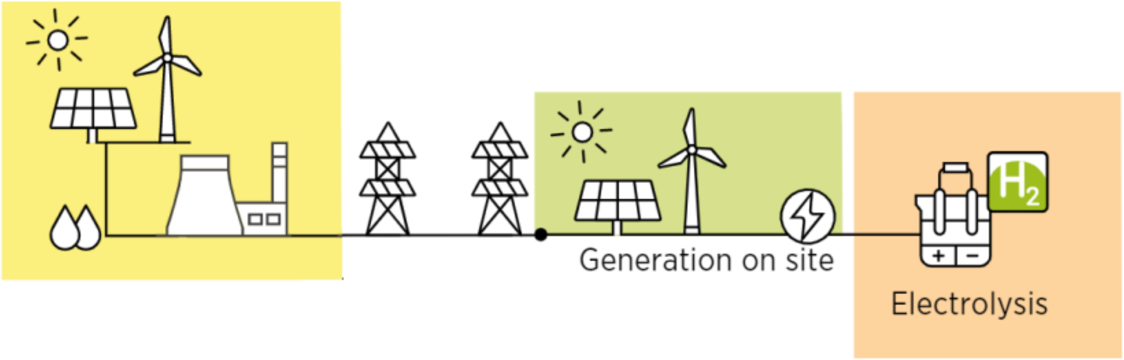


Figure 4.8: Plant scheme of scenario 2a.

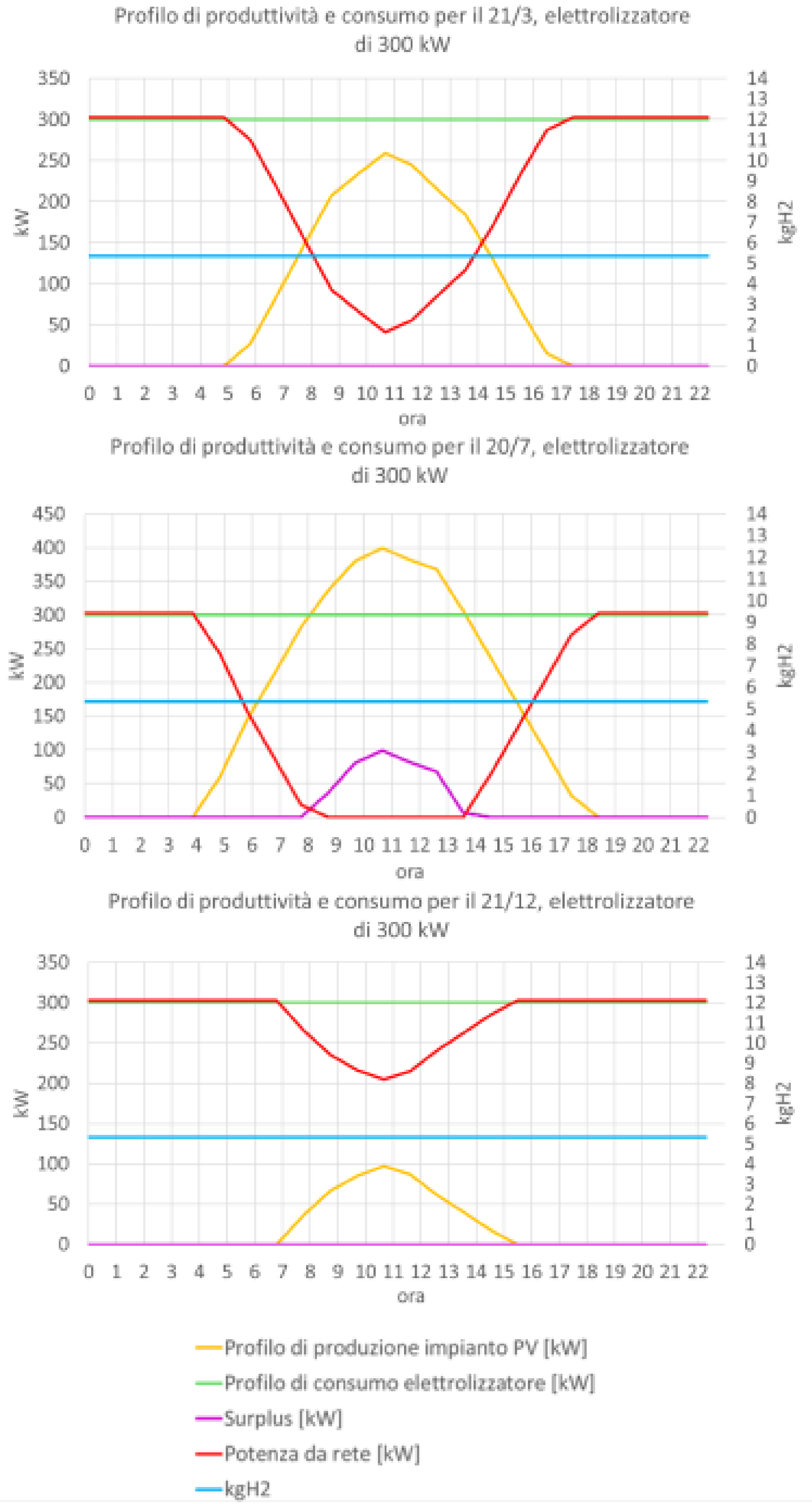
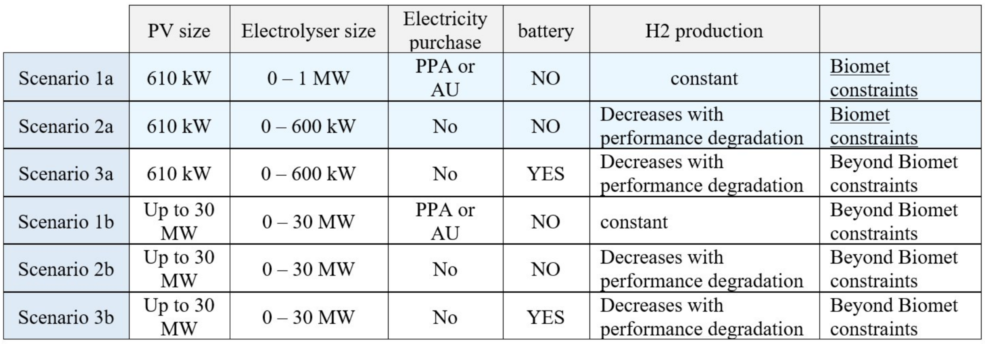


Figure 4.9: Hourly production profile of the PV system, Hourly consumption profile of the electrolysis plant, Hourly profile of production of the surplus, Hourly hydrogen production profile, for three sample days in l an average year.

Chapter 5

Analysis of the results

In this chapter, the results of the computations for the different scenarios are presented and analysed. The aim is to evaluate the main energy and economic parameters of the PV to-H2 power plant, identifying the system configuration that generates the lowest hydrogen production cost. At first, hydrogen production feasibility has been studied considering the Biomet's constraints for the PV plant size, the electrolyser size and the water availability. Then the analysis has been extended beyond the company's constraints, to study the impact of the economies of scale on the hydrogen productivity. The main parameter used to investigate the economic viability of the production is the Levelized cost of hydrogen (LCOH). In Table 5.1 an overview of the analysed cases is reported to help the reader's comprehension.



	PV size	Electrolyser size	Electricity purchase	battery	H2 production	
Scenario 1a	610 kW	0 – 1 MW	PPA or AU	NO	constant	Biomet constraints
Scenario 2a	610 kW	0 – 600 kW	No	NO	Decreases with performance degradation	Biomet constraints
Scenario 3a	610 kW	0 – 600 kW	No	YES	Decreases with performance degradation	Beyond Biomet constraints
Scenario 1b	Up to 30 MW	0 – 30 MW	PPA or AU	NO	constant	Beyond Biomet constraints
Scenario 2b	Up to 30 MW	0 – 30 MW	No	NO	Decreases with performance degradation	Beyond Biomet constraints
Scenario 3b	Up to 30 MW	0 – 30 MW	No	YES	Decreases with performance degradation	Beyond Biomet constraints

Table 5.1: Recap of the studied scenarios; a) with Biomet's constraints, b) beyond company's constraints.

5.1 Hydrogen productivity at Biomet

The main constraints imposed by company layout:

- the PV nominal power of 610 kW, to which corresponds an LCOE of 84.46 €/MWh;
- A maximum available area for the electrolyser installation of 60 m^2, i.e., a maximum PEM and AEM electrolysis installations of 1000 kW and ALK installation of 750 kW;
- the maximum available water input for electrolysis: 160 m^3/d.

5.1.1 Scenario 1a: 610 kW PV + PPA/grid purchase

Scenario 1a consists of the hydrogen productivity study of a 610 kW photovoltaic power plant coupled with a varying size electrolysis plant. The electrolyser nominal power is ranged from 10 kW to 1 MW. The assumption that regulates this scenario is the continuous and constant power operation of the electrolyser during the year, to produce a constant flow rate of hydrogen during the plant's operational lifetime. For this purpose, the PV renewable supply is supported by an additional energy feed, either purchased from the grid by means of Acquirente Unico (AU) or with a Power Purchase Agreement (PPA) with a renewable plant adjacent to the plant location. The assumptions at the basis of this scenario are specified in greater detail in Chapter 4. The surplus was managed as reported in Paragraph 4.1. Table 5.2 shows the specific basic assumptions of this scenario.

For seek of clarity, Figure 5.1 represents the working mechanism of these scenarios:

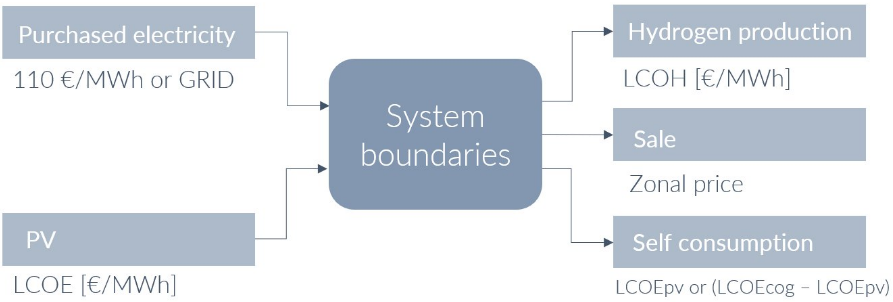


Figure 5.1: Working scheme of the PV + electrolysis, scenario 1.

Figure 5.2 shows the main energy flows in the system in relation to the varying size of the electrolysis power plant for the two main technologies considered in

	PV size	Electrolyser size	Electricity purchase	battery	H2 prod
Scenario 1a	610 kW	0 – 1 MW	PPA or AU	NO	constant

Table 5.2: Basic assumptions of scenario 1a.

this study, i.e. PEM and ALK. As already stated, the PV plant size is fixed at 610 kW and so is its yearly energy productivity. Consequently, the contribution of the energy purchased from the grid to the overall inlet electricity of the system increases with the size of the electrolyser. Both the portion of the surplus that is self-consumed and the one that is sold to the grid decrease with the increase of the size of the electrolyser. Around 350 kW, the electrolyser plant is big enough to fully consume the energy coming from the PV plant and the surplus vanishes. All the energy streams in this representation are averaged over the plant lifetime (20 years), considering the degradation of the electrolyser and the decay rate of the PV plant. Indeed, during the years of operation, the amount of energy that must be purchased from the grid increases to compensate for the higher specific consumption of the electrolyser (due to the degradation of the electrolytic cell) and the lower production of the PV modules (due to their performance decay). Coherently, the surplus of the plant decreases as the specific consumption of the electrolyser increases and as the modules deteriorate.

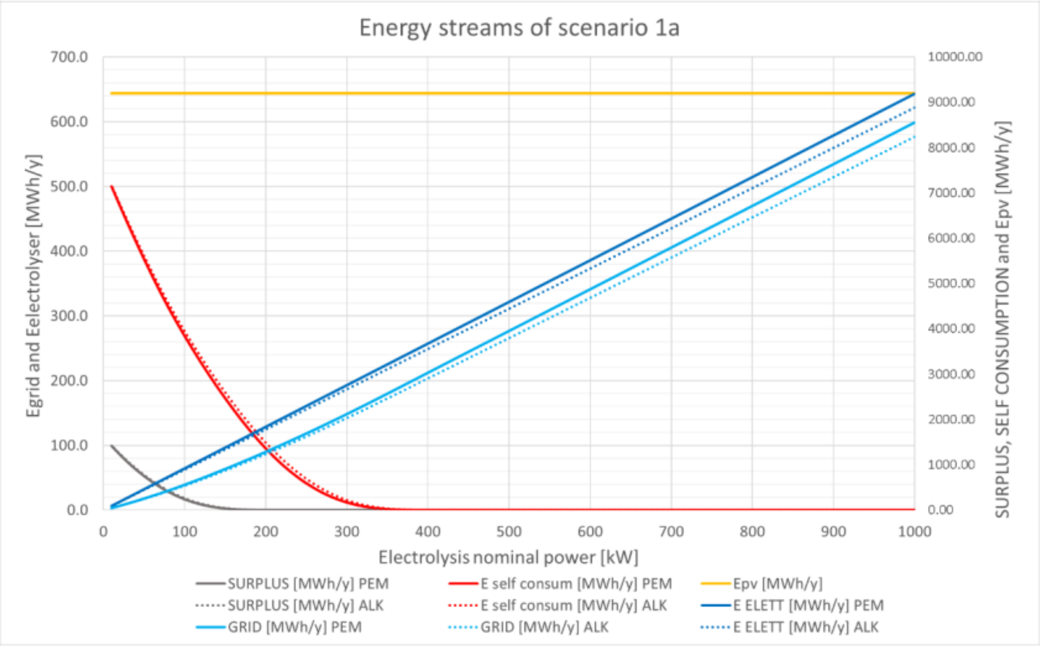


Figure 5.2: Main energy streams in Scenario 1a. The continuous line represents the PEM technology while the dotted one the ALK technology.

The amount of energy purchased from the grid depends on two factors:

- The useful life of the electrolytic cell (and therefore the number of stack replacements in the plant lifetime). The shorter the useful life, the higher the number of replacements and therefore the average operating efficiency of the component.
- The degradation of the electrolytic cell (the percentage decay of performance that occurs every 1000 hours of operation). As it increases, the average operating efficiency of the component decreases.

The purchase of energy is therefore maximum for PEM, for whom a higher degradation and longer useful life was assumed. Finally, obviously, as the nominal capacity of the electrolysis plant increases, the energy that must be purchased to make it work increases.

Figures 5.3 and 5.4 represent the value of the Levelized cost of hydrogen for the variable size of electrolysis respectively for the PEM, the ALK and the AEM technologies. The parameters referring to the AEM, in yellow in the two figures, have been reported in a thinnerline as it is a new technology which has not been fully commercialized. Currently, only a few low size AEM electrolysis systems are used for industrial applications. The performance of this technology is therefore not fully proventechnology at higher sizes is not fully proven. Despite this, being one of the most promising technologies for the future, it has been plotted. In Figure 6.1.4 the purchased electricity feed is valorised at the prices of Acquirente Unico while in Figure 6.1.5. at the PPA price, assumed to be 110 €/MWh. In both figures, the continuous lines represent the LCOH computed including the sale of the surplus and the savings of the self-consumptions as additional revenues for the electrolysis plant. The literature's traditional formulas for the LCOH don't comprehend an additional income to the sale of the hydrogen itself, and the presence of such contribution in the equation may conceal the real trend of the LCOH parameter with respect to the electrolysis nominal power. For this reason, the LCOH has been computed a second time neglecting the value of both the surplus energy streams and it is represented by the dotted curve in such group of figures. It is important to stress the fact that such a parameter has a theoretical value only while having no sense from an energetic point of view, as it is computed by assuming that the surplus electricity generated by the PV plant is just dissipated. The optimal configuration will be determined by means of the continuous line. The trend of the hydrogen flow rate produced with the electrolysis nominal power is plotted too. As the hydrogen production is maximised for each electrolysis size, the H2 production increases linearly with the electrolysis power.

For both the cases represented, the minimum LCOH for this scenario is obtained with the PEM technology. This technology represents indeed the best trade-

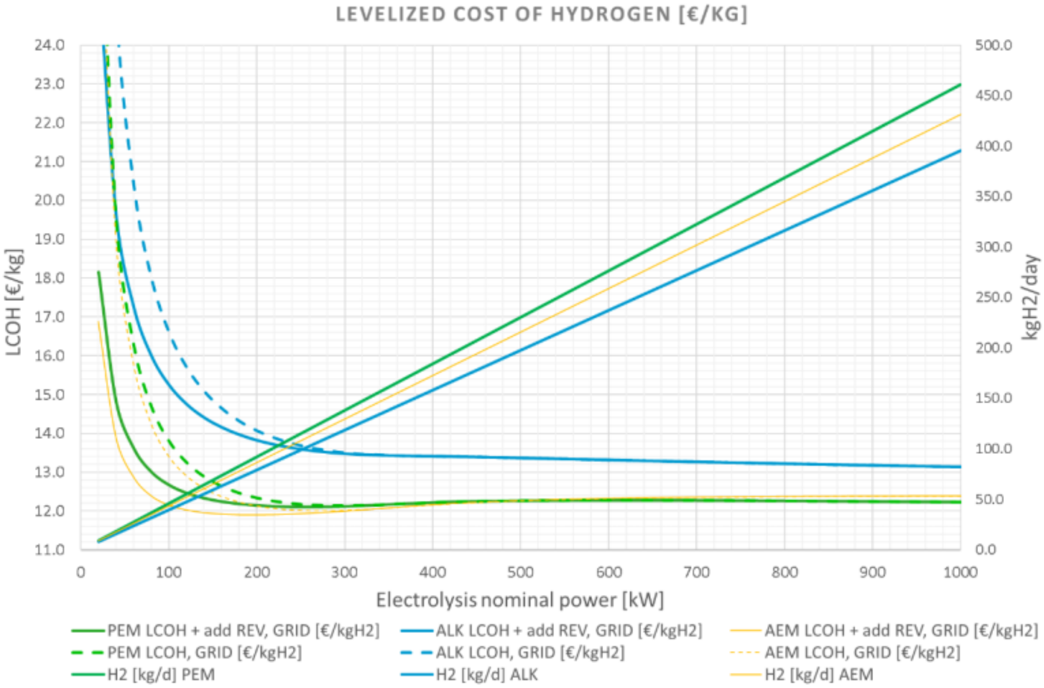


Figure 5.3: Trend of the LCOH [€/kgH2] and of the daily average hydrogen production [kg/d] for the PEM, ALK and AEM technologies. The continuous lines represent the LCOH computed considering additional revenues. The dashed lines neglects the revenues. The additional electricity is purchased from the grid

.

off between investment and component replacement costs and stack efficiency. In the case the electricity is purchased from the grid with Acquirente Unico, the optimum is obtained for an electrolysis nominal power of 260 kW and results in an LCOH of 12.1 €/kgH2. Differently, in the case of the purchase through PPA, the optimum is found at the maximum electrolysis power, 1MW, and results in an LCOH of 8.5 €/kgH2. By comparing Figures 5.3 and 5.4 it is possible to notice the significant effect that the electricity price has on the LCOH: thanks to a decrease in the price of electricity from the ARERA values to 110 €/MWh, the production reduces of 3.6 €/kgH2. Moreover, the more favourable price in the PPA case makes the optimum shift towards an higher generation capacity, i.e. to a higher hydrogen production and where the quantity of electricity purchased from the grid is maximum. The strong dependency of the LCOH on the electricity purchase price is in line with what was expected for this case, in which the maximisation of the hours of operation of the plant was considered in order to reduce the influence of the investment costs on the final hydrogen production price. From all the figures reported, it can be noticed the influence that the surplus sale has on the

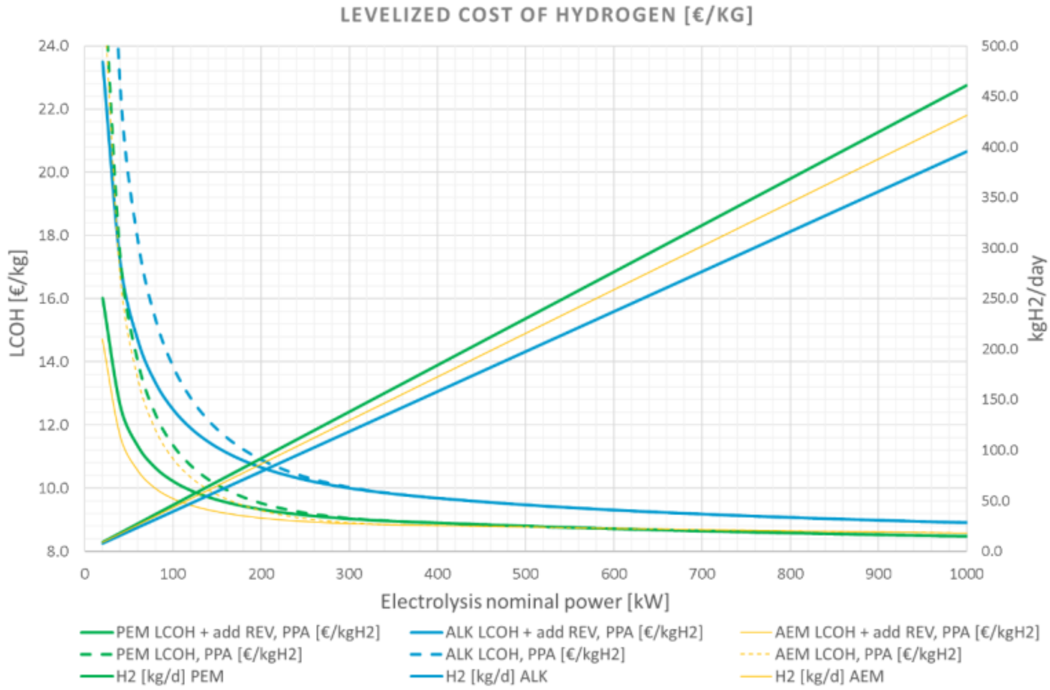


Figure 5.4: Trend of the LCOH [€/kgH2] and of the daily average hydrogen production [kg/d] for the PEM, ALK and AEM technologies. The continuous lines represent the LCOH computed considering additional revenues. The dashed lines neglects the revenues. The additional electricity is purchased with a PPA

competitiveness of the hydrogen price. In line with Figure 5.2, when the surplus becomes null, at 350 kW, the two LCOH curves collide, as no additional revenues are generated in the system anymore. Below that value and moving towards the minimum electrolysis power, i.e. towards increasing surplus values, the sale of the additional revenues brings to increasing reductions in the LCOH values. Thus, the sale of the surplus has a strong impact too on the production cost of the gas. All the reported production costs refer to a non-incentivized hydrogen production plant: no incentives for the production of hydrogen or for the photovoltaic system have been considered.

5.1.2 Scenario 2a: 610 kW off-grid PV plant

In scenario 2a, the electrolysis system is fed by the 610 kW PV plant only. The electrolyser's nominal power is ranged from 10 kW to 600 kW, i.e., the maximum PV power. The assumption at the basis of this scenario are specified in greater detail in Chapter 4. The surplus was managed as reported in Paragraph 4.1.

	PV size	Electrolyser size	Electricity purchase	battery	H2 prod
Scenario 2a	610 kW	0 – 600 kW	No	NO	Decreases with performance degradation

Table 5.3: Basic assumptions of scenario 2a.

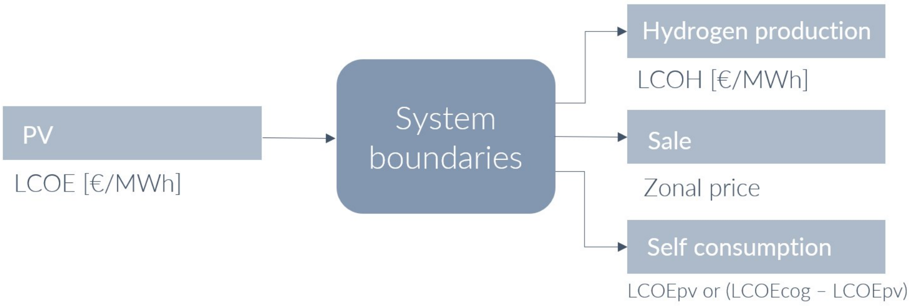


Figure 5.5: Mass and energy streams of scenario 2a which have a non-zero valorisation.

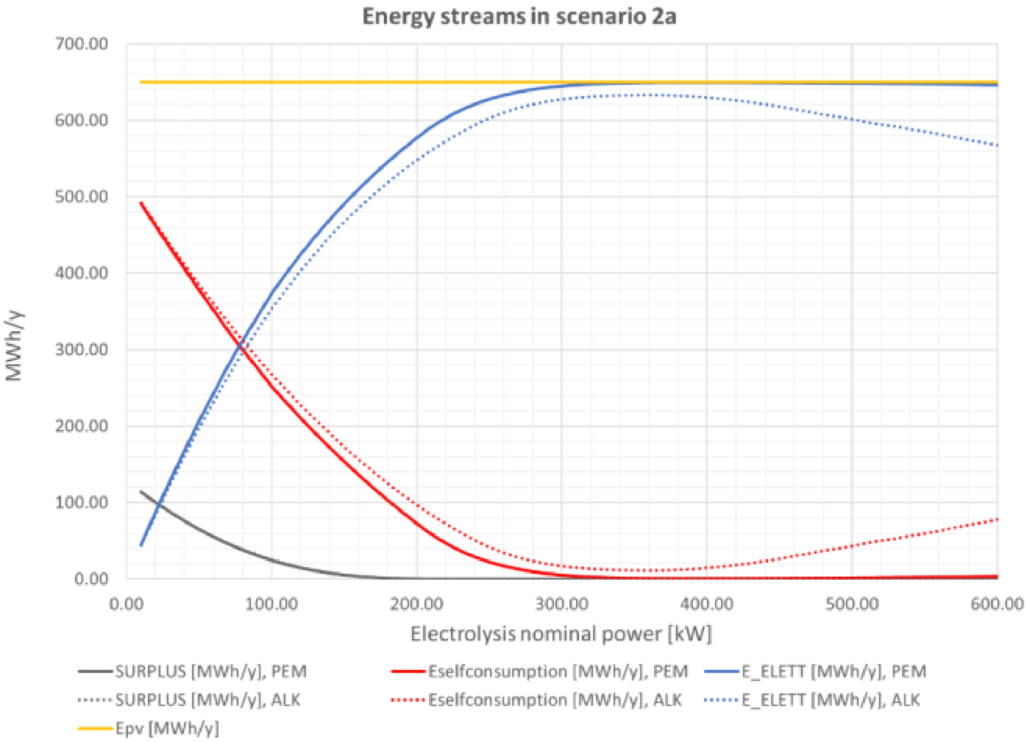


Figure 5.6: Main energy streams in Scenario 2a. The continuous line represent the PEM technology while the dotted one the ALK technology.

In Figure 5.6, the main energy streams involved in the system are shown both for the PEM and for the alkaline technology. As the productivity of the PV plant is constant, while the electrolysis rated size increases, the share of its production that is sold to the grid or is used for Biomet decreases. For the PEM technology, no electricity is used for self-consumption for a rated power higher than 320 kW, while no electricity is sold to the grid is absent for powers higher than 200 kW. The alkaline technology shows a similar trend, even if the surplus electricity seems to increase back to higher values for a rated powers over 350 kW. This is mostly because the alkaline technology has a narrower range of operating power, i.e., from 20% to 100% of its nominal capacity. Whenever the PV plant has a power production below the minimum start-up power of the alkaline electrolyser, such energy is either sold to the grid or used digester as it is not enough to start up the electrolyser. The greater the electrolyser is, the higher are the hours in which the PV produces less than its start-up limit and so the higher the surplus generation is. The same effect is clear in Figure 5.7 and **??**: the daily average H2 production of the alkaline technology reduces for rated powers higher than 350 kW. In general, the increasing trend of the H2 production with the nominal electrolysis power arrests at around 300 kW for each considered technology. Exceeded this value, a further increase in the size of the plant would result in an increase in investment costs without an actual benefit in the production. This is reflected on the LCOH parameters, which increases for higher powers than 300 kW for all the considered technologies. The minimum LCOH in this case would be obtained for a 100 kW AEM electrolyser, and it is 8.8 €/kgH2. As previously stated, AEM technology is a non-fully demonstrated one, and so this valuehas a higher value of uncertainty with respect to the ones of other technologies. This is the reason why it has been plotted with a thinner line. The reason for the uncertainty on the operation of the AEM electrolysers is the fact that an optimal and stable material for the membrane of the electrolytic cell has still to be founded. The minimum for the PEM technology, which is differently fully commercialized, is 10.91 €/kgH2 for a nominal power of 140 kW. This corresponds to a hydrogen production of 23.60 kgH2/day and to a capacity factor of 38.3%.

Since in this case study the operation of the electrolyser is not constant, the LCOH curve is also shown as a function of the capacity factor, which consists of the following parameter:

$$CAPACITYFACTOR[\%] = \frac{h_{eq}}{8760} \tag{5.1}$$

Where the equivalent hours of a production plant are the number of hours at which it should hypothetically work at its maximum power to produce the same energy that it actually produces in a year.

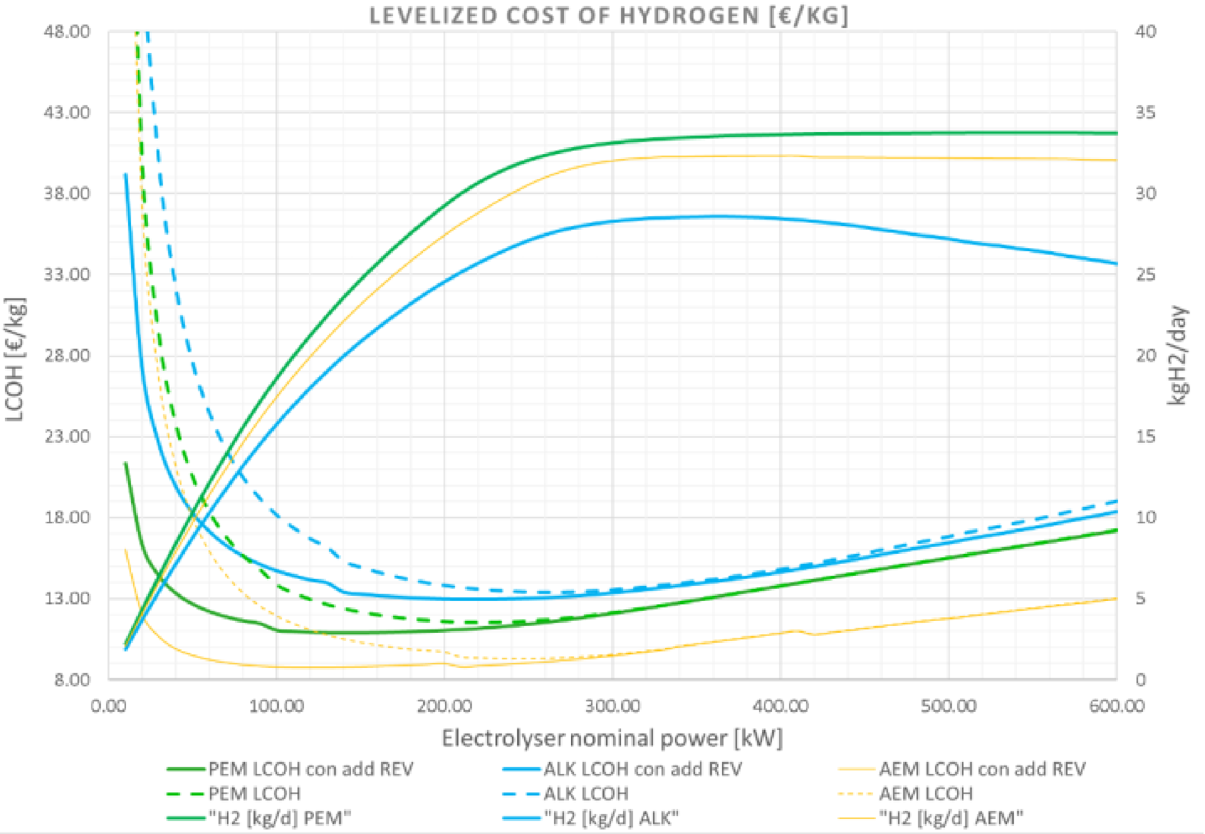


Figure 5.7: Trend of the LCOH [€/kgH2] for the PEM, ALK and AEM technologies. The continuous lines represent the LCOH computed considering additional revenues. The dashed lines neglects the revenues.

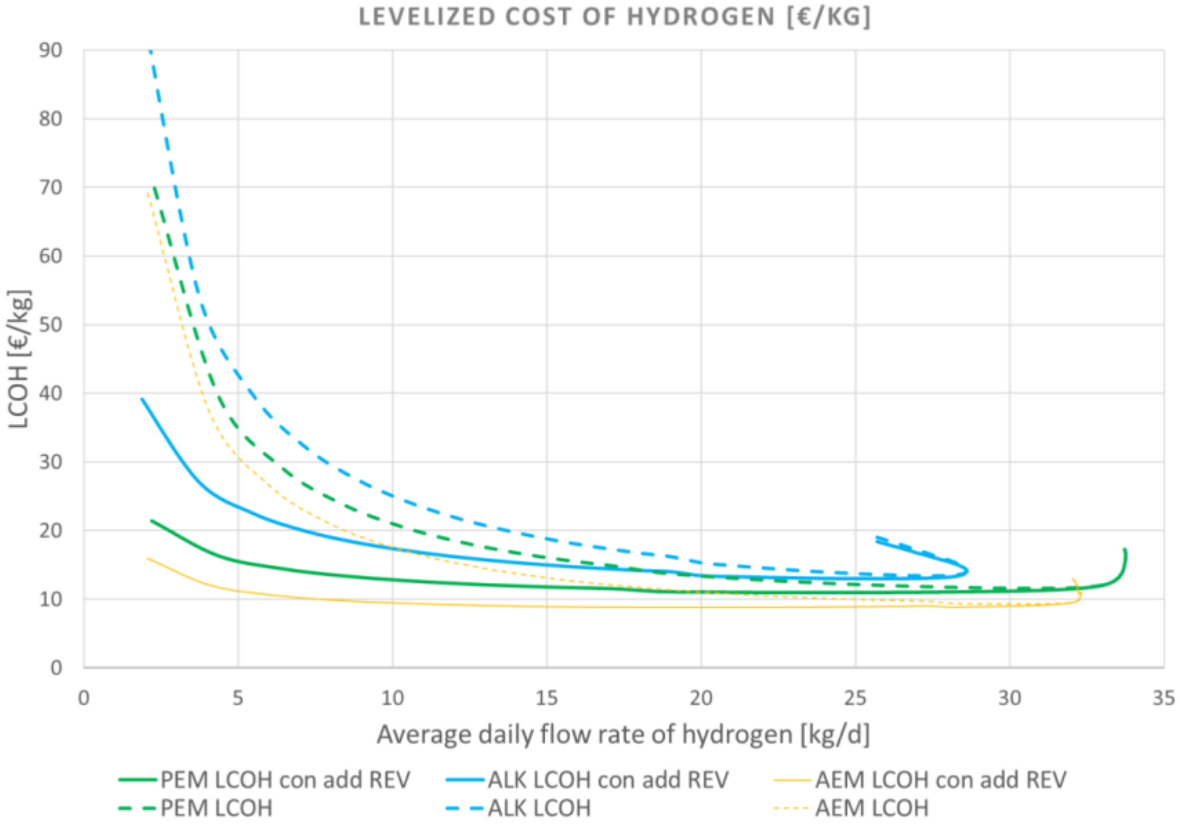


Figure 5.8: Average daily flow rate of hydrogen [kg/d] for the PEM, ALK and AEM technologies. The continuous lines represent the LCOH computed considering additional revenues. The dashed lines neglects the revenues.

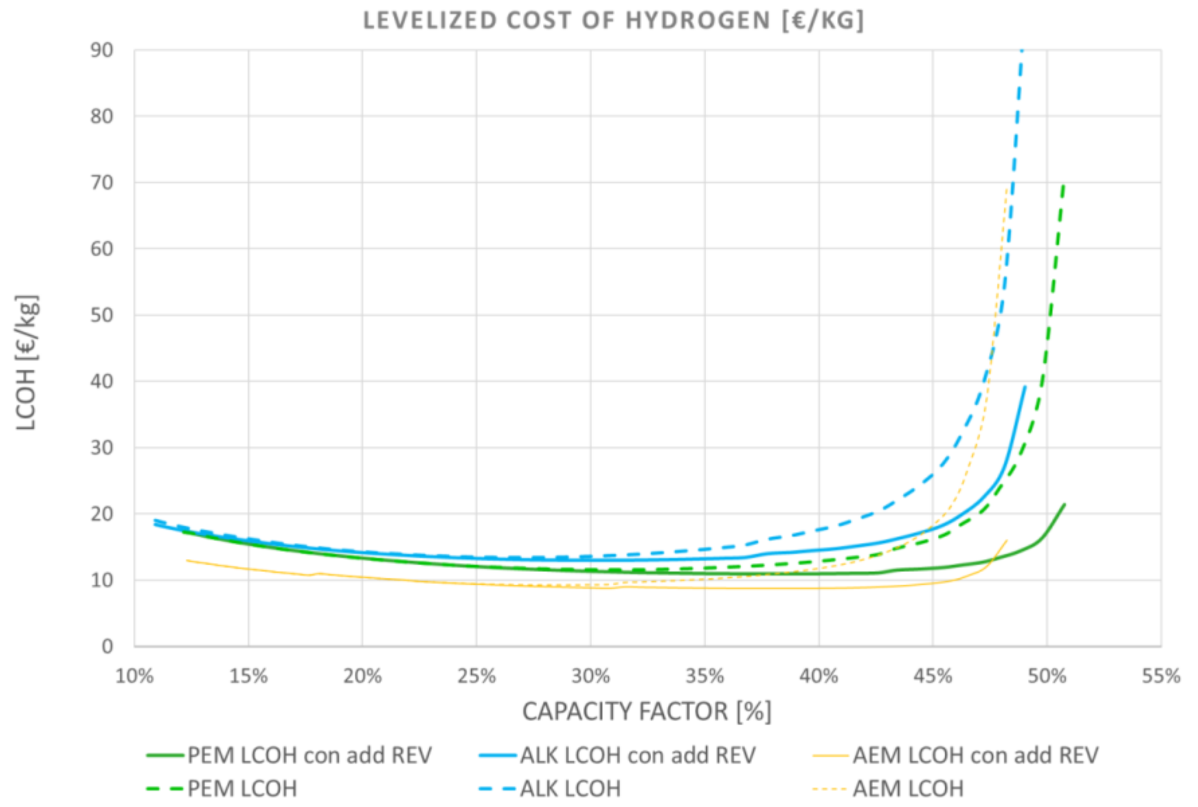


Figure 5.9: Capacity factor [%] for the PEM, ALK and AEM technologies. The continuous lines represent the LCOH computed considering additional revenues. The dashed lines neglects the revenues.

5.1.3 Scenario 3a: 610 kW off-grid PV plant + batteries

As seen in the previous chapters, the hydrogen productivity of an electrolysis plant coupled to a 600 kW PV plant is quite limited. If the hydrogen production is too low, the installation of the electrolyser would surely be unfeasible, due to the high specific costs for producing, stocking, and distributing hydrogen. In this context, the employment of a battery is considered, as it may increase the overall hydrogen productivity. The capacities of the batteries have been ranged from 10 to 50 kWh. As noticed in Figure 5.11, the employment of batteries for this scenario is extremely unsuitable, as they increase the LCOH of at least 6 €/kgH2. Indeed, the addition of a battery brings to a strong increasse of the systems' specific costs, while their contribution in terms of additional H2 flow rate is very limited, as noticed in Figure 5.10.

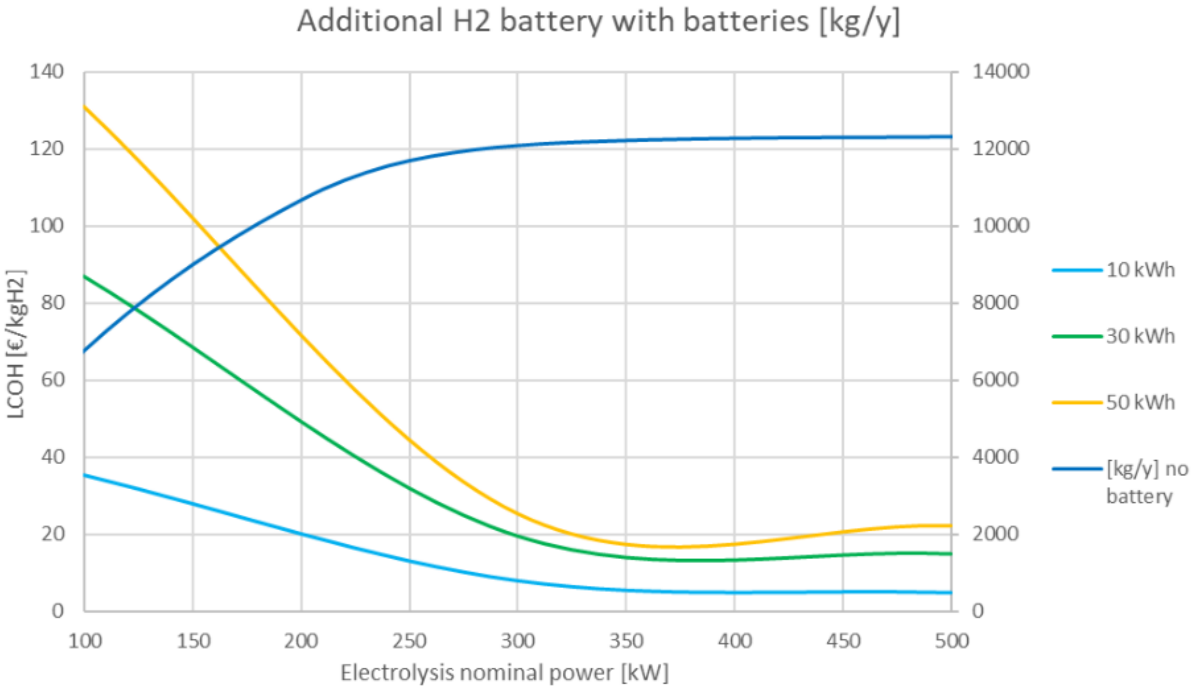


Figure 5.10: Additional annual H2 production thanks to batteries and annual hydrogen production without batteries [kg/y] as a function of electrolysis power, for a 5 MW PV plant.

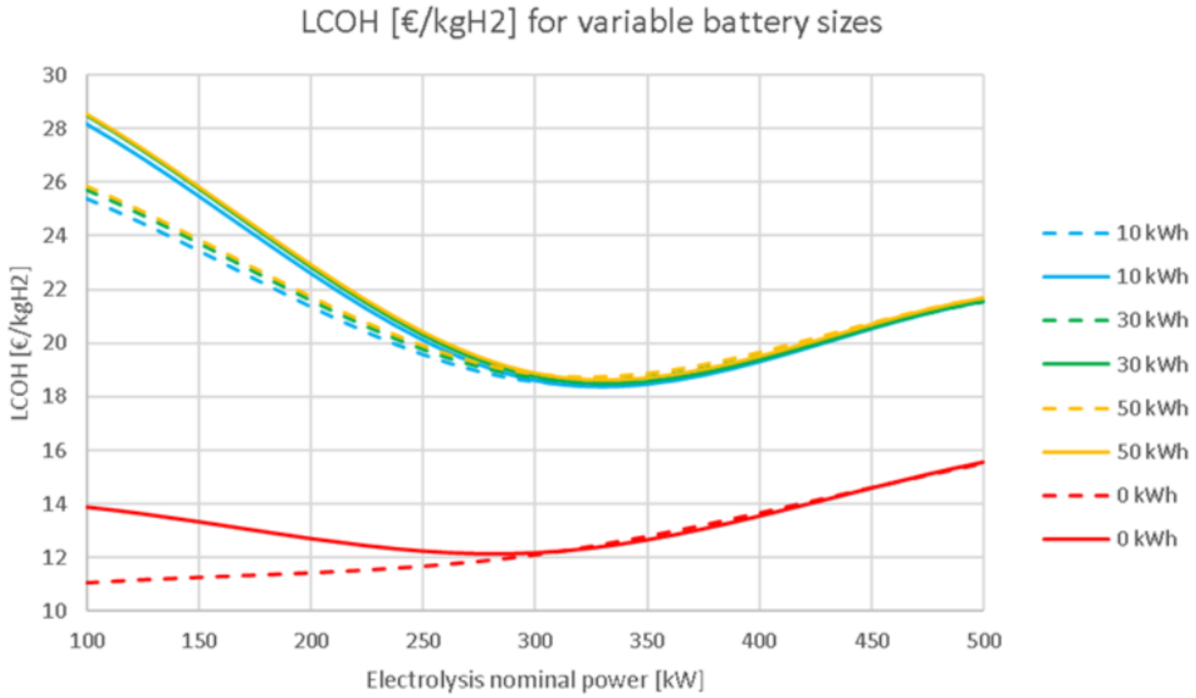


Figure 5.11: LCOH computed for batteries of capacities from 10 to 500 kWh and for the base case, as a function of the nominal electrolysis power, 5 MW PV plant.

5.2 Hydrogen productivity beyond company's constraints

As noticed in Scenario 1a and 2a, the Levelized cost of producing hydrogen in the Biomet plant context is extremely higher with respect to the market current selling price. By adding the storage and distribution costs to the ones computed for production, the hydrogen production would even result less feasible, making this project impossible to be realized. The main weakness of the Biomet's designed electrolysis plant is the limited size of the photovoltaic system, and thus the limited size of the electrolyser and the limited hydrogen productivity of the plant. As economies of scale cannot be exploited in the production, storage and distribution of the hydrogen, the specific cost of this project would be extremely high. It is then essential to exploit economies of scale in order to make the green hydrogen production competitive with the fossil fuel based one. For this reason, the feasibility of the hydrogen production has been considered for three additional layouts, in which the space and water constraints of Biomet are neglected. The two system's layouts studied for Biomet in Chapter 5.1. have been extended to higher photovoltaic nominal powers, to decrease the LCOE of the renewable plant and so the price of the energy input needed for electrolysis. Figure 5.12 shows the variability of the LCOE with the PV nominal power. The price of the electricity used to implement electrolysis is indeed a determining factor in the affordability of the hydrogen production.

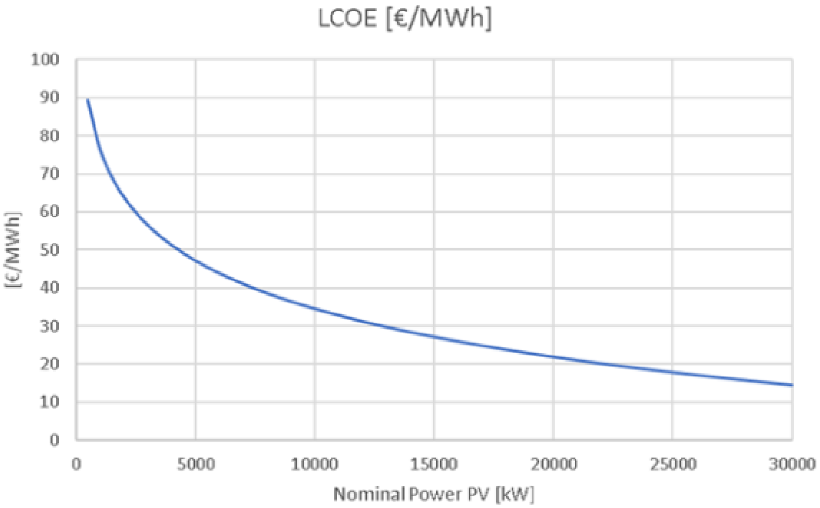
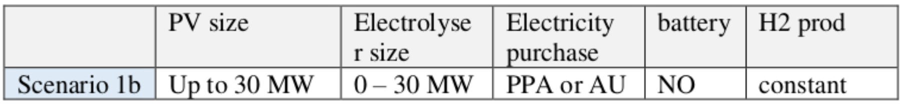


Figure 5.12: LCOE of the PV power plant for different nominal powers.

5.2.1 Scenario 1b: unlimited PV plant + PPA/grid purchase

As in scenario 1a, here the electrolyser is assumed to work at its maximum power and the PV power plant production is sustained by the purchase of electricity from the grid or through a Power Purchase Agreement. The same technical and economic data and constraints of Scenario 1a are considered, except for the maximum photovoltaic rated power, the maximum electrolysis nominal power, the maximum amount of exploitable water and the space limitations. The hydrogen productivity is evaluated for a PV system size of 1 to 30 MW. Table 5.4 shows the specific basic assumptions of this scenario.



	PV size	Electrolyser size	Electricity purchase	battery	H2 prod
Scenario 1b	Up to 30 MW	0 – 30 MW	PPA or AU	NO	constant

Table 5.4: Basic assumption of scenario 1b.

For sake of simplicity, the electricity in this assumption is purchased at 110 €/MWh, i.e., the assumed PPA price, while the purchase with Acquirente Unico has been disregarded. The energy streams involved in the system, for the case of a 30 MW PV system, are considered in figure

The continuous line in Figure 5.14 represents the LCOH computed without any valorisation of the energy surplus produced by the PV plant. In reality, it is not possible to neglect an energy stream into a whatever system, as this would affect the energy balance of the system. A proper strategy has to be considered to manage each energy stream, as energy cannot just be dissipated. Nevertheless, this assumption is completely theoretical, and its aim is to analyse the production cost trend of the hydrogen without adding any possible additional revenue. The dotted line in Figure 5.14 represent the real LCOH, computed by respecting the energy balance of the system and assigning a proper valorisation to each energy stream of the system. As it is possibleto notice, the LCOH computed in such way tends to zero for electrolysis rated power below 200 kW. To explain this apparently nonsense result, the fundamental hypothesis of this layout need to be recalled.

By increasing the size of the PV system, the renewable electricity is progressively subject to higher economies of scale, and so the LCOE of the production decreases significantly, as showed in Figure 5.12. When the price of producing electricity with the PV system is lower than the zonal price, the sale of electricity to the grid brings to a benefit of the hydrogen production. The revenues of selling the surplus to the grid is so high, that for low electrolysis rated powers, i.e., when the surplus is maximum, they would make the hydrogen production feasible even with negative costs, i.e., if the hydrogen is sold without any revenue.

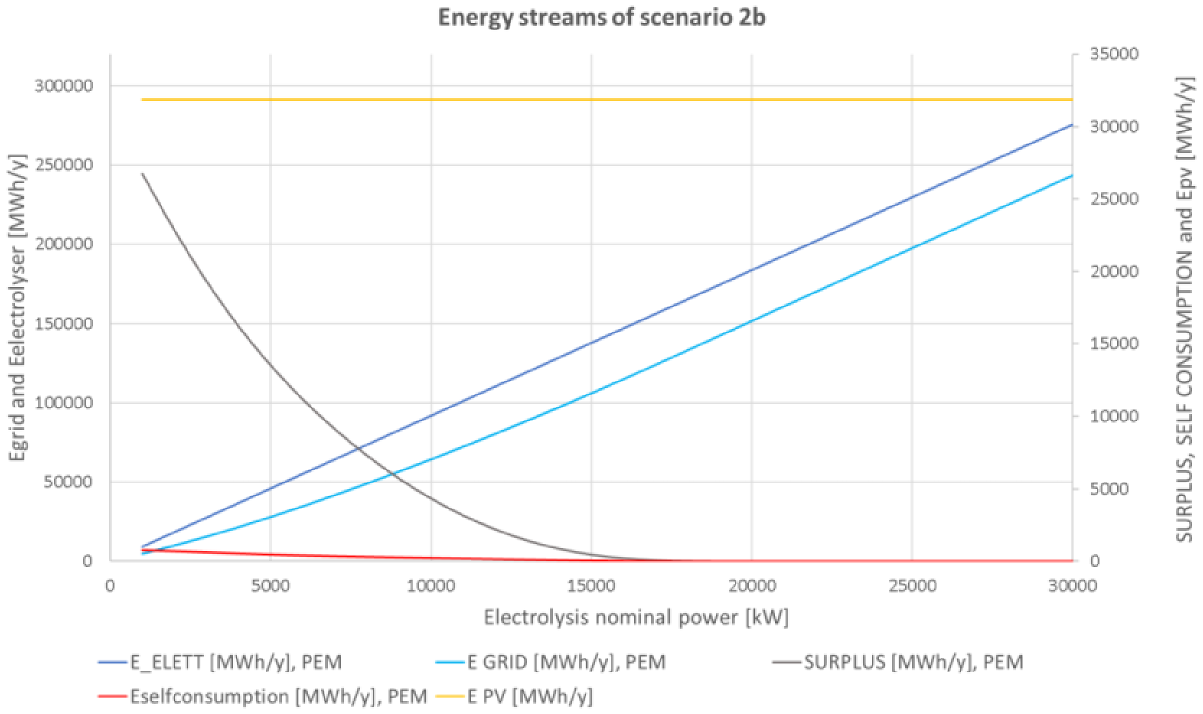


Figure 5.13: Main energy streams in scenario 2b.

Ppv [MW]	30
LCOE [€/MWh]	14.56242
electricity cost [€/MWh]	110
Average zonal price [€/MWh]	68.74
Revenue of self-consumption [€/MWh]	135.4376
Cogenerator LCOE [€/MWh]	150

Table 5.5: Recap of the valorisation of the electricity streams in scenario 1b.

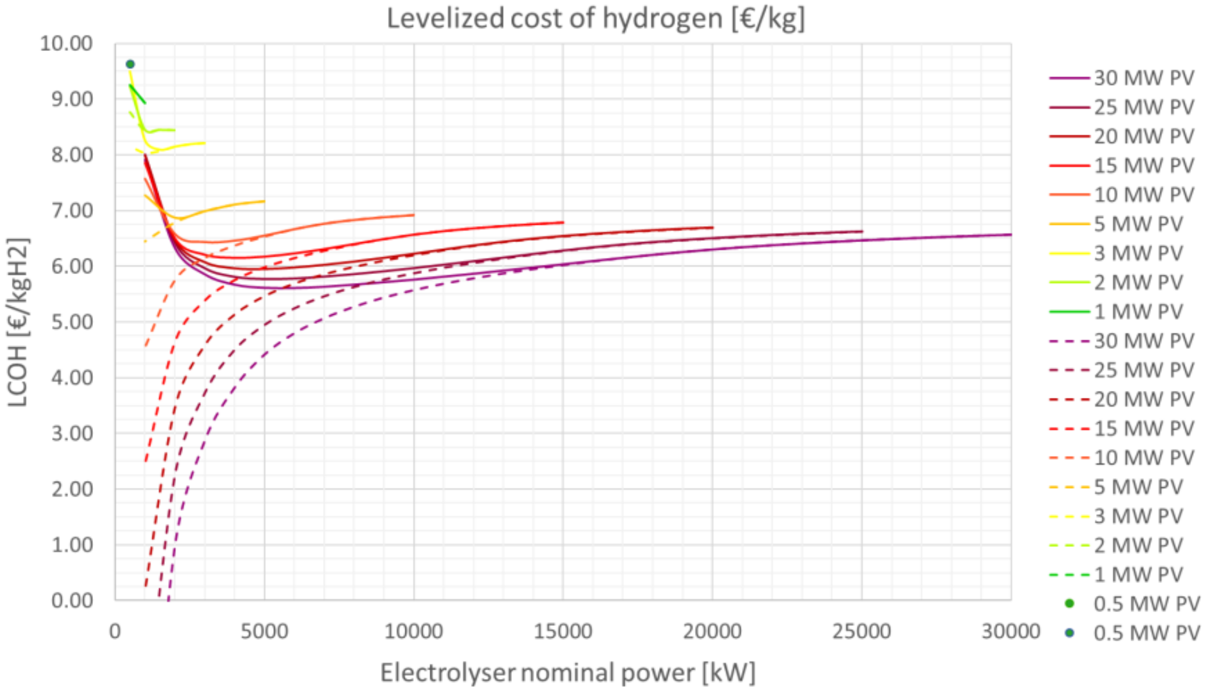


Figure 5.14: Trend of the LCOH [€/kgH2] for the PEM technology and for a variable size of the PV plant. The continuous lines represents the LCOH computed considering additional revenues. The dashed lines neglects the revenues. The additional electricity is purchased with a PPA

The main result of this analysis is that producing hydrogen would consist in a loss of profit for the PV plant. Thus, the hydrogen production with this strategy would be unfeasible, as, for seek of the maximum income the PV plant would inject all its production into the grid. In this context, the theoretical LCOH computed not considering the additional revenues assumes more of a meaning, as its trend actually reports what is the optimal electrolysis plant configuration for the different PV nominal sizes.

5.2.2 Scenario 2b: unlimited off-grid PV plant

Coherently to case 2a, this scenario considers the hydrogen production of an electrolyser coupled with an off-grid renewable PV plant. The power range of the solar plant is here varied from 1 MW to 30 MW and so is the electrolysis nominal power.

	PV size	Electrolyser size	Electricity purchase	battery	H2 prod
Scenario 2b	Up to 30 MW	0 – 30 MW	No	NO	Decreases with performance degradation

Table 5.6: Basic assumption of scenario 2b.

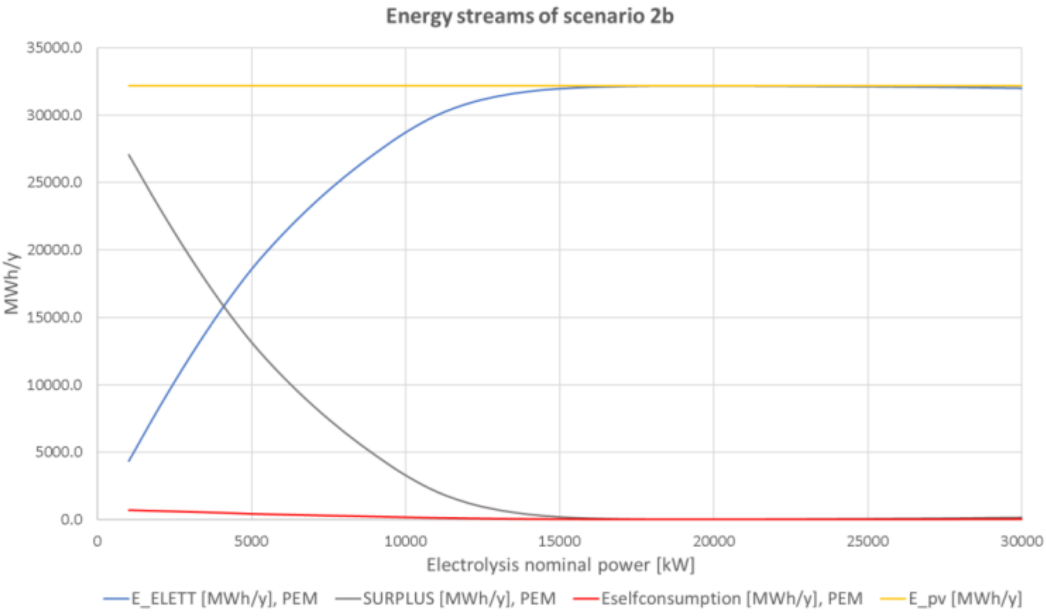


Figure 5.15: Main energy streams in scenario 2b.

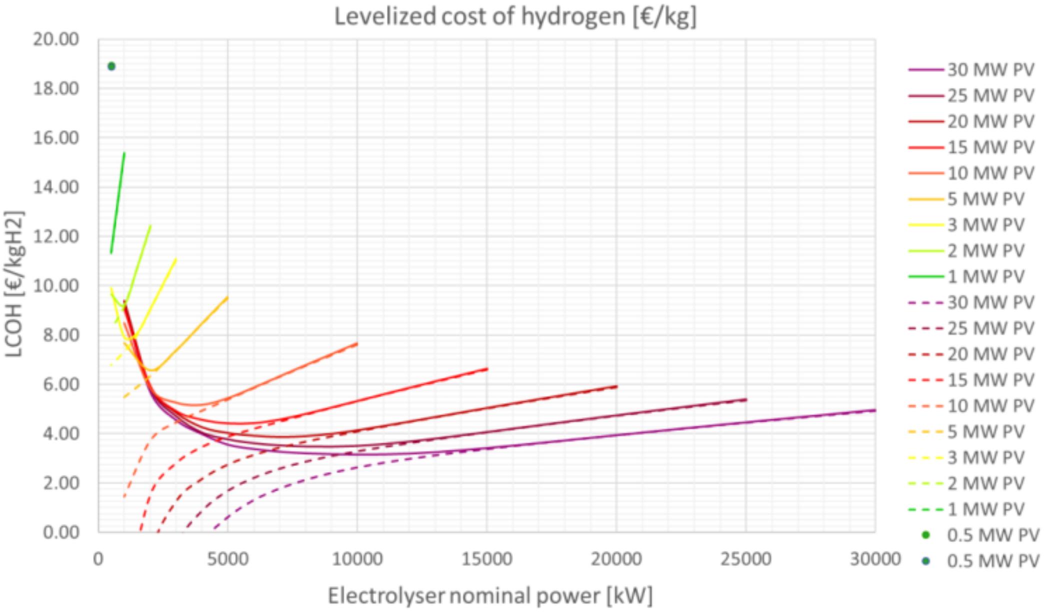


Figure 5.16: Trend of the LCOH [€/kgH2] for the PEM technology and for a variable size of the PV plant. The continuous lines represents the LCOH computed considering additional revenues. The dashed lines neglects the revenues.

5.2.3 Scenario 3b: unlimited off-grid PV plant + batteries

The plant layout of scenario 2b is here integrated with a battery storage system. The size of the battery was varied from 10 kWh to 1 MWh, depending on the nominal size of the PV system. The results are here reported for respectively: a) a PV plant of 5 MW; b) a PV plant of 10 MW; c) a PV plant of 30 MW.

Figure 5.17 represents the additional kilograms of H2 that are produced in an average year in scenario 3b thanks to the employment of batteries. The maximum H2 production occurs for the minimum electrolyser power, as it is the case in which the available PV surplus to be stored in batteries is maximum. Then, the additional H2 production decreases with the size of the electrolyser up to a nominal power of 3 MW, where it reaches a minimum, and then starts to increase again for higher rated powers. This is due to the fact that when the electrolyser size is high, its minimum start-up power is higher and so the number of hours in which the PV under the minimum electrolysis power range is greater. This causes an increase of surplus which can be stored by the batteries to increase the H2 yearly production. The same effect is clear in the yearly production of the case without batteries, where for a size greater than 3 MW the yearly production decreases while increasing the size of the electrolyser.

Another apparent fact is that the additional H2 production provided by the bat-

a) 5 MW PV plant

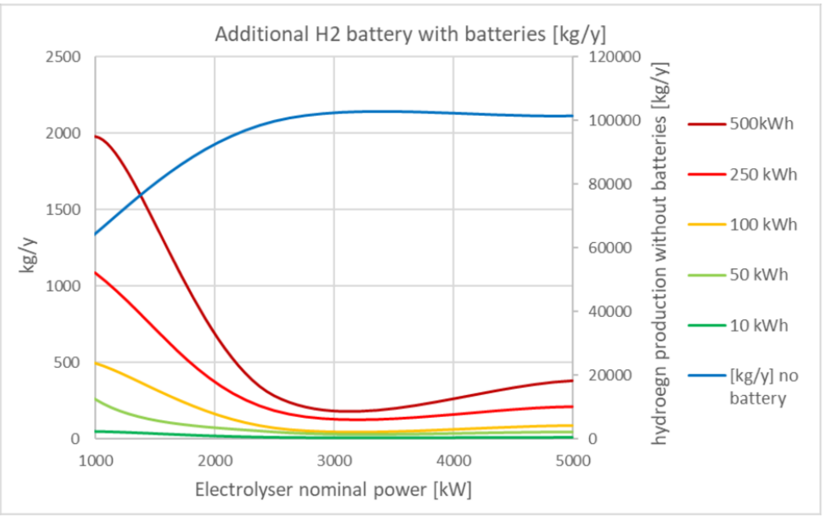


Figure 5.17: Additional annual H2 production thanks to batteries and annual hydrogen production without batteries [kg/y] as a function of electrolysis power, for a 5 MW PV plant.

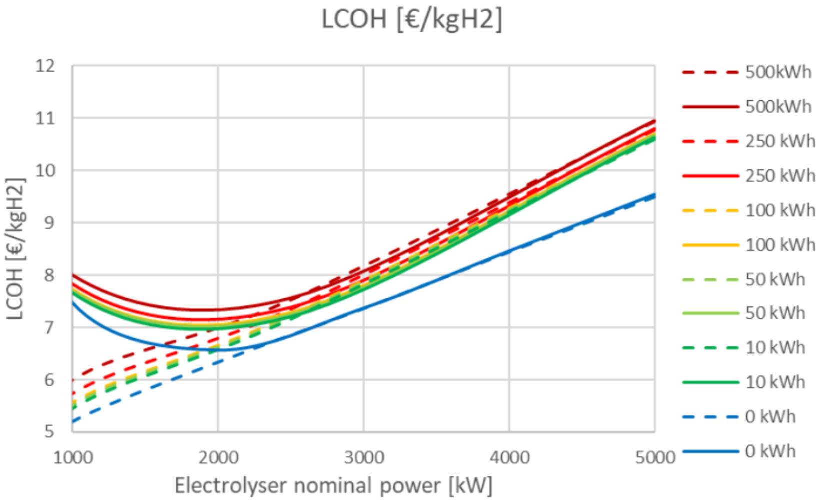


Figure 5.18: LCOH computed for batteries of capacities from 10 to 500 kWh and for the base case, as a function of the nominal electrolysis power, 5 MW PV plant.

teries is significantly lower than the yearly total production without batteries. As shown in Figure 5.18, the minimum LCOH obtained with the employment of a battery is 7.1 €/kgH2 for a 10 kWh capacity and a nominal electrolyser of 2 MW. It is higher than the LCOH computed for the case of a 5 MW PV plant without any battery, which is 6.55 €/kgH2 for an electrolysis power of 2 MW. The slight increase in the hydrogen productivity thank to the addition of a storage capability is not enough to recover the capital costs' increase due to the battery. The higher the size of the battery, the higher the LCOH. Additionally, most of the revenues of this power plant come from the sale of the surplus, which decreases by adding a storing battery to the system. After a nominal size of 3 MW, the LCOH curves of the cases with batteries are steeper than the one of the base case. This is because the first include the investment costs of the battery, which adds a cost without causing any benefit to the system, as for high powers the surplus that could be stored is very low. Finally, the employment of a battery for H2 production purposes in this case is unsuitable.

b) 10 MW PV plant

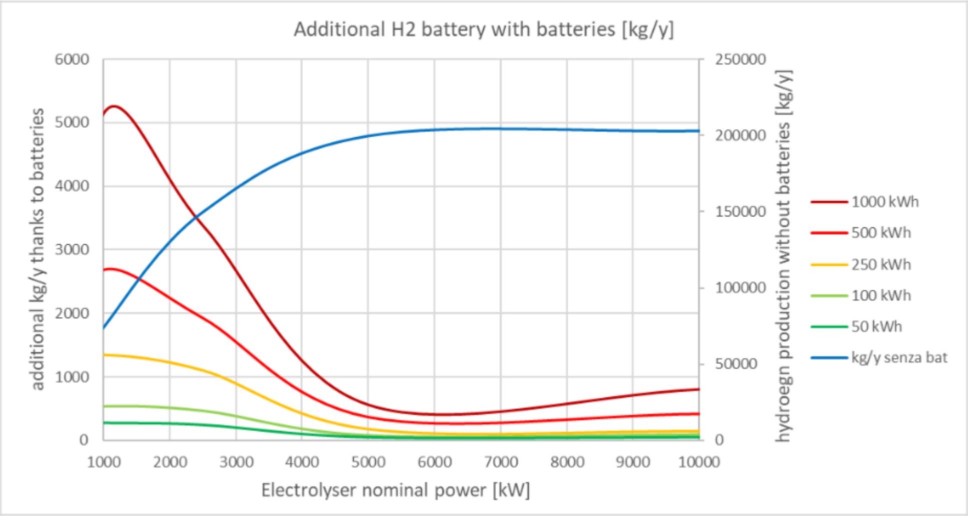


Figure 5.19: Additional annual H2 production thanks to batteries and annual hydrogen production without batteries [kg/y] as a function of electrolysis power, for a 10 MW PV plant.

The same considerations made for a 5 MW PV can be applied to this case. The addition of a battery to the layout of the system causes an increase of the minimum LCOH.

The same observations made for case a (5 MW PV plant) apply for this case. In addition to those, in Figure 5.21 batteries show a decreasing trend for electrolysis

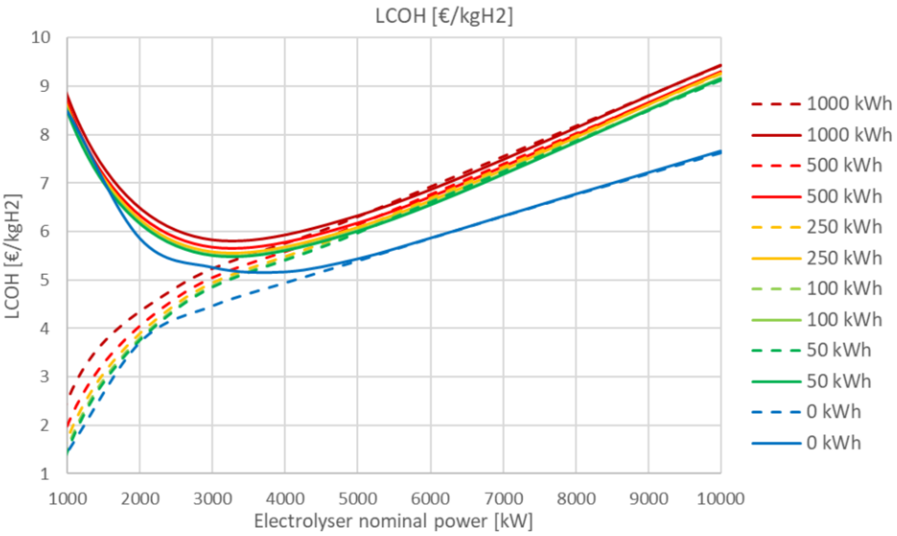


Figure 5.20: LCOH computed for batteries of capacities from 10 to 500 kWh and for the base case, as a function of the nominal electrolysis power, 10 MW PV plant.

c) 30 MW PV plant

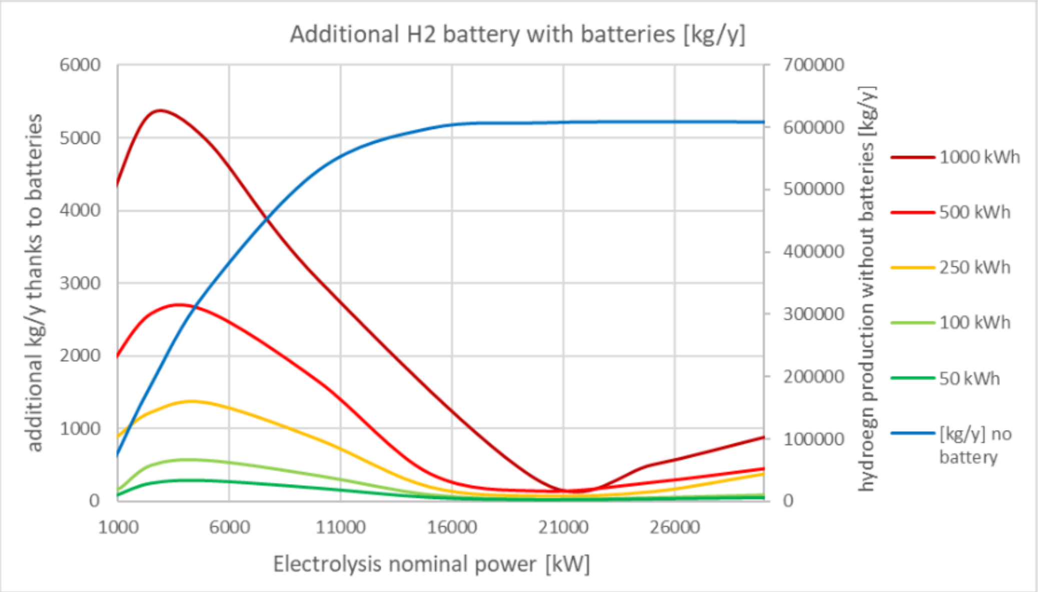


Figure 5.21: Additional annual H2 production thanks to batteries and annual hydrogen production without batteries [kg/y] as a function of electrolysis power, for a 30 MW PV plant.

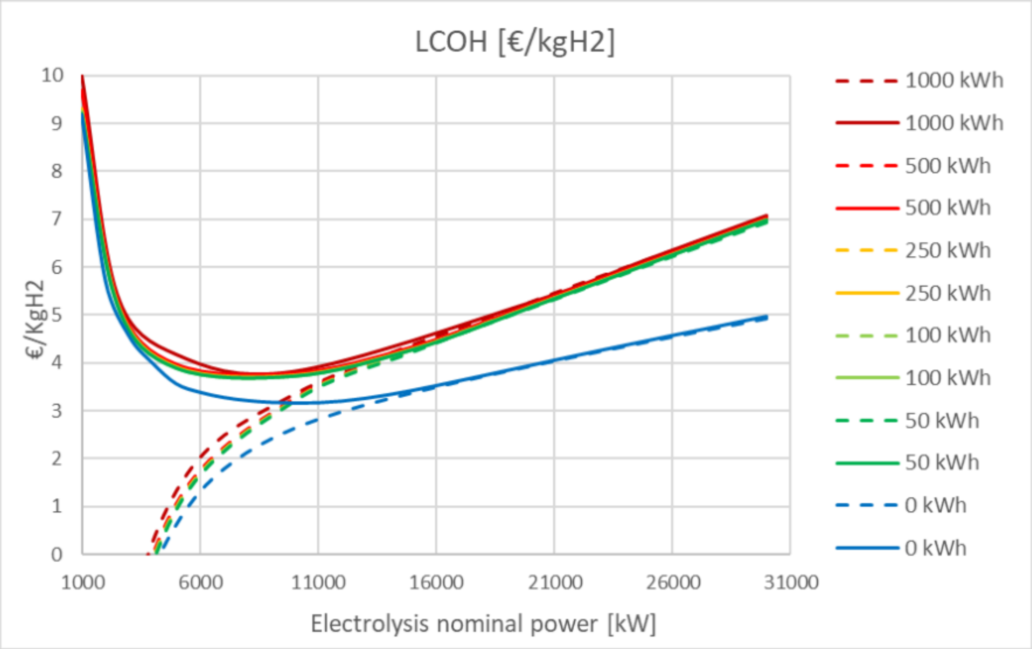


Figure 5.22: LCOH computed for batteries of capacities from 10 to 500 kWh and for the base case, as a function of the nominal electrolysis power, 30 MW PV plant.

powers below 2.5 MW. This may be due to the fact that for very low electrolysis powers, even if the available surplus is very high, the electrolyser capabilities of producing hydrogen decrease and even if the batteries store electricity, they have to discharge slowly as the electrolyser can consume a lower amount of energy.

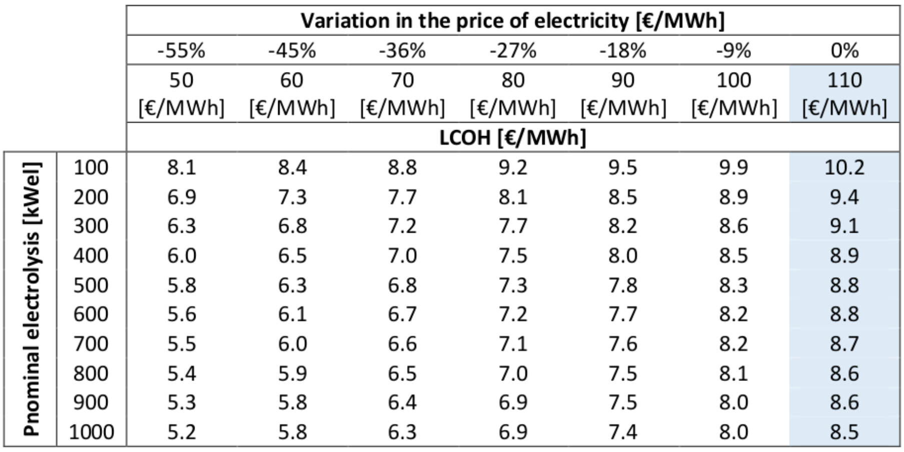
Chapter 6

Sensitivity Analysis

In this chapter, a sensitivity analysis is performed to understand how much the Levelized cost of hydrogen is affected by the most important drivers. As anticipated in Chapter 3, available literature studies demonstrate that the cost of producing green hydrogen depends mainly on three parameters: the cost of the input electricity, the electrolyser's investment cost, and its hours of operation. Both the electricity cost and the specific cost of the electrolysers are rather uncertain parameters. The first indeed depends on the electricity generation mix, which is quickly shifting towards renewables, and the second is affected by the fact that there is still no real supply chain for hydrogen produced from renewable sources and electrolysers still must reach their technological state of the art. For this reason, the sensitivity has been here carried out for the first two parameters, while the hours of operation are kept still as they are what distinguishes one scenario from the other. The sensitivity analysis was performed for a PEM electrolyser only, which from Chapter 5 resulted to be the most convenient commercial technology for the coupling with renewable. This analysis has been implemented for scenario 1a and 2a only, i.e., the scenarios that consider company technical constraints. The possibility of adding a battery to case 2a has been discarded, as it is too costly to bring a benefit to the hydrogen productivity, as shown in Chapter 5.

6.1 Scenario 1a: 610 kW PV + PPA/grid purchase

The choice of maximising the operating hours of the plant and so the hydrogen productivity in scenario 1a was made with the idea of reducing the influence of the electrolyser's investment cost on the final production cost of hydrogen. An increase in the hours of activity of the electrolyser necessarily follows an increase in the electricity input and so in the amount of energy purchased from the grid, since the nominal capacity of the PV plant is fixed. Therefore, a strong dependence



		Variation in the price of electricity [€/MWh]						
		-55%	-45%	-36%	-27%	-18%	-9%	0%
		50 [€/MWh]	60 [€/MWh]	70 [€/MWh]	80 [€/MWh]	90 [€/MWh]	100 [€/MWh]	110 [€/MWh]
		LCOH [€/MWh]						
Pnominal electrolysis [kWel]	100	8.1	8.4	8.8	9.2	9.5	9.9	10.2
	200	6.9	7.3	7.7	8.1	8.5	8.9	9.4
	300	6.3	6.8	7.2	7.7	8.2	8.6	9.1
	400	6.0	6.5	7.0	7.5	8.0	8.5	8.9
	500	5.8	6.3	6.8	7.3	7.8	8.3	8.8
	600	5.6	6.1	6.7	7.2	7.7	8.2	8.8
	700	5.5	6.0	6.6	7.1	7.6	8.2	8.7
	800	5.4	5.9	6.5	7.0	7.5	8.1	8.6
	900	5.3	5.8	6.4	6.9	7.5	8.0	8.6
	1000	5.2	5.8	6.3	6.9	7.4	8.0	8.5

Table 6.1: LCOH [€/kgH2] computed for different electrolysis rate powers [kW] and different electricity sale prices [€/MWh]. The base case values are emphasized in blue.

of the cost of hydrogen on the change in the purchase price of energy and a weaker relationship with the investment cost is expected from this sensitivity analysis.

6.1.1 Sensitivity to changes in the purchase price of electricity

As highlighted in the last column of Table 6.1, 110 €/MWh is here considered as the reference purchase price for the electricity purchased. A strong dependence of the LCOH on the purchase cost of electricity is confirmed by the analysis. Such dependence increases with the electrolysis nominal power, as the higher the nominal size of the unit, the higher its electricity purchase from external sources. When the electrolyser reaches a size of 1 MW, the energy feed of the PV plant would represent just 8% of the total electricity consumption of the electrolyser. A 55% decrease in the electricity price, down to 50 €/MWh, can bring to a LCOH reduction of 40% for an electrolysis power of 1 MW. In such a case, the LCOH would be 5.2 €/MWh. As the market price of hydrogen is nowadays lower than 3 €/kgH2, it is clear that even a strong variation of this parameter by itself wouldn't allow the plant designed in this scenario to become economically feasible.

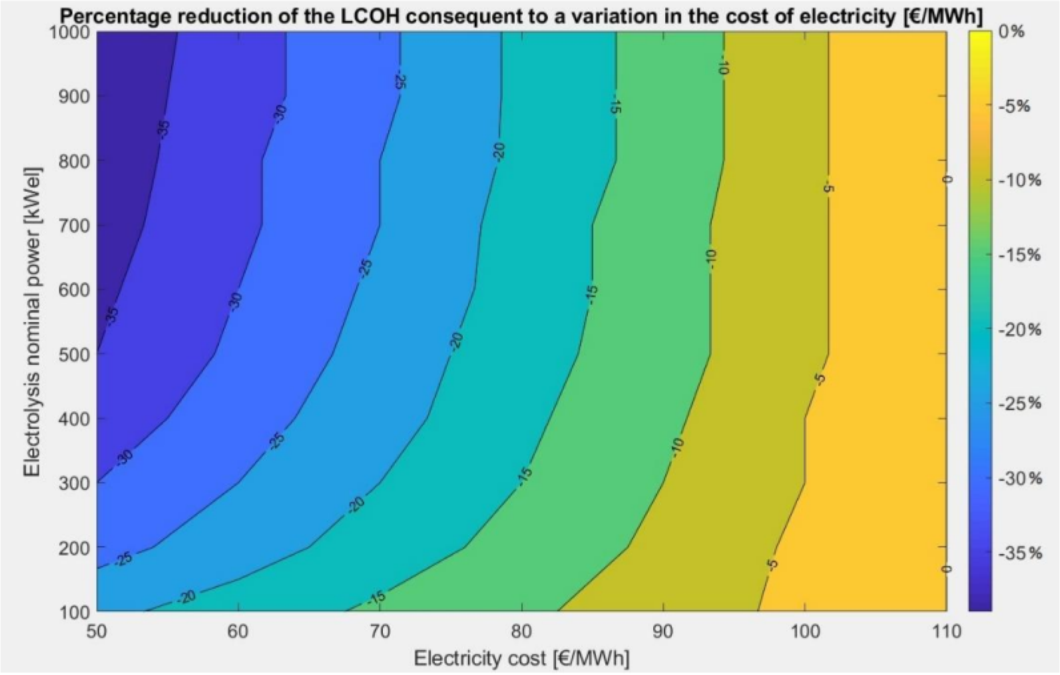


Figure 6.1: Percentage LCOH reduction consequent to a variation in the cost of electricity [€/MWh], plotted for different electrolysis sizes [kW].

6.1.2 Sensitivity to changes in the electrolyser investment cost

The LCOH in this scenario results to be less sensitive to a variation in the electrolysis investment cost than it is to the change in the electricity price. A 50% reduction in the investment cost of the electrolysis plant can in fact lead to a maximum reduction of 12% of the LCOH. This is in line with the assumptions made in the design of the scenario: by maximizing the hours of operation of the electrolyser, the electrolysis CAPEX influence over the LCOH would reduce. This behaviour is confirmed in paragraph 4.3.2, where the same sensitivity analysis is applied to a scenario with different basic hypothesises. The greatest dependence of the LCOH on the CAPEX occurs at the minimum power, as the specific costs of the electrolysers decrease with the increase in size. The smaller the electrolyser is, the higher is its cost of producing 1 kg of H2, and thus the highest is the benefit that it faces in case of a reduction in the production costs. The reference CAPEX for this scenario are represented in Figure 6.3. These include the equipment costs and the "other costs" of the plant (see Chapter 3).

The electricity purchase price is here considered as 110 €/MWh (purchase with a PPA).

		Variation in electrolysis CAPEX [€]					
		-50%	-40%	-30%	-20%	-10%	0%
		LCOH [€/MWh]					
Pnominal electrolysis [kWel]	100	9.0	9.2	9.5	9.7	10.0	10.2
	200	8.3	8.5	8.7	9.0	9.2	9.4
	300	8.2	8.2	8.5	8.7	8.9	9.1
	400	8.1	8.2	8.4	8.6	8.8	8.9
	500	8.1	8.2	8.4	8.5	8.7	8.8
	600	8.0	8.1	8.3	8.5	8.6	8.8
	700	8.0	8.1	8.3	8.4	8.5	8.7
	800	7.9	8.0	8.2	8.4	8.5	8.6
	900	7.9	8.0	8.2	8.3	8.4	8.6
	1000	7.9	8.0	8.1	8.3	8.4	8.5

Table 6.2: LCOH [€/kgH2] computed for different electrolysis rated powers [kW] and different electrolysis investment costs [€]. The base case values are emphasized in blue.

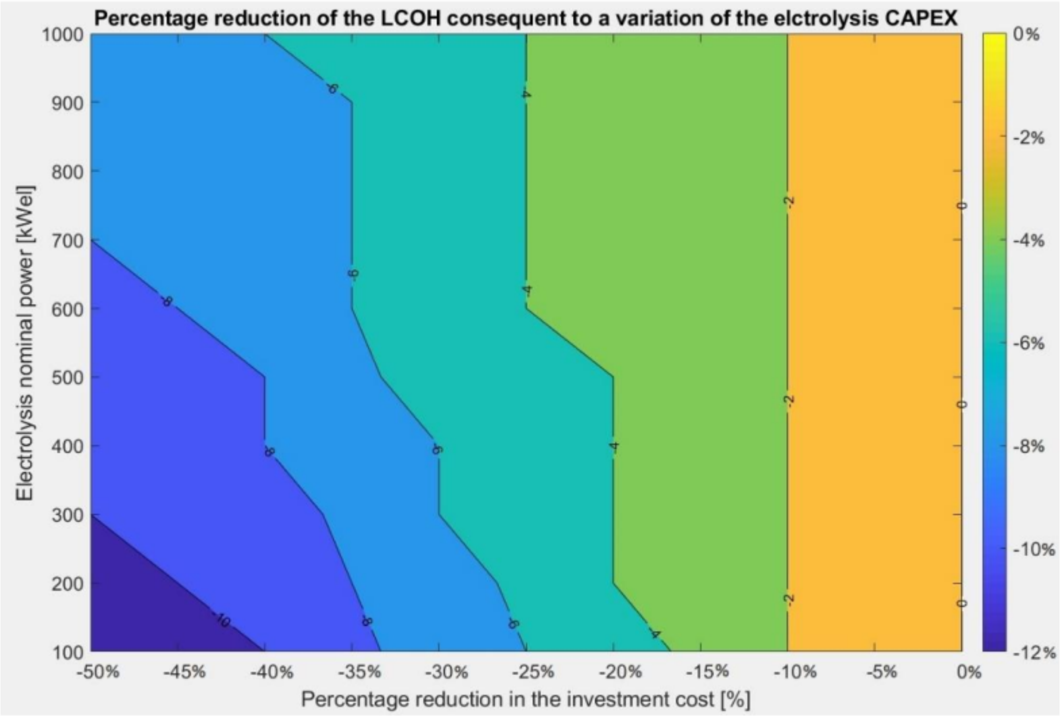


Figure 6.2: Percentage of LCOH reduction consequent to a variation in the electrolyser's investment cost [€], plotted for different electrolysis sizes [kW].

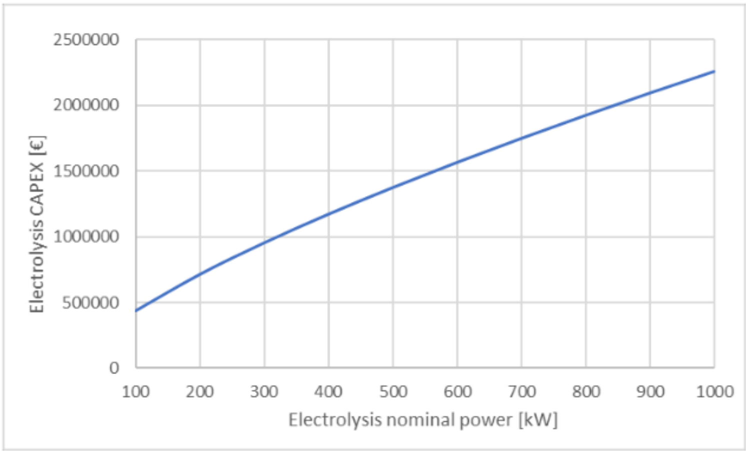


Figure 6.3: Electrolysis CAPEX as a function of the nominal power [kW].

6.2 Scenario 2a: 610 kW off-grid PV

In scenario 2a, the operating hours of the electrolyser are limited to the ones of the PV plant. The hydrogen production is much lower than the one in the previous case and so are the costs, as no electricity is purchased from external suppliers. The sensitivity of the LCOH is here studied with respect to the electrolyser's investment cost and to the PV investment cost.

6.2.1 Sensitivity to changes in the electrolyser investment cost

		Variation in electrolysis CAPEX [€]					
		-50%	-40%	-30%	-20%	-10%	0%
		LCOH [€/MWh]					
Pnominal electrolysis [kWel]	100	8.7	9.2	9.7	10.1	10.6	11.1
	200	8.6	9.1	9.6	10.1	10.6	11.1
	300	9.3	9.8	10.4	11.0	11.5	12.1
	400	10.4	11.1	11.7	12.4	13.1	13.8
	500	11.5	12.3	13.1	13.9	14.7	15.5
	600	12.6	13.5	14.5	15.4	16.3	17.2

Table 6.3: LCOH [€/kgH2] computed for different electrolysis rated powers [kW] and different electrolysis investment costs [€]. The base case values are emphasized in blue.

The sensitivity of the LCOH to a variation in the electrolyser investment cost is more significant in Scenario 2a than it was in Scenario 1a. Indeed, in the pre-

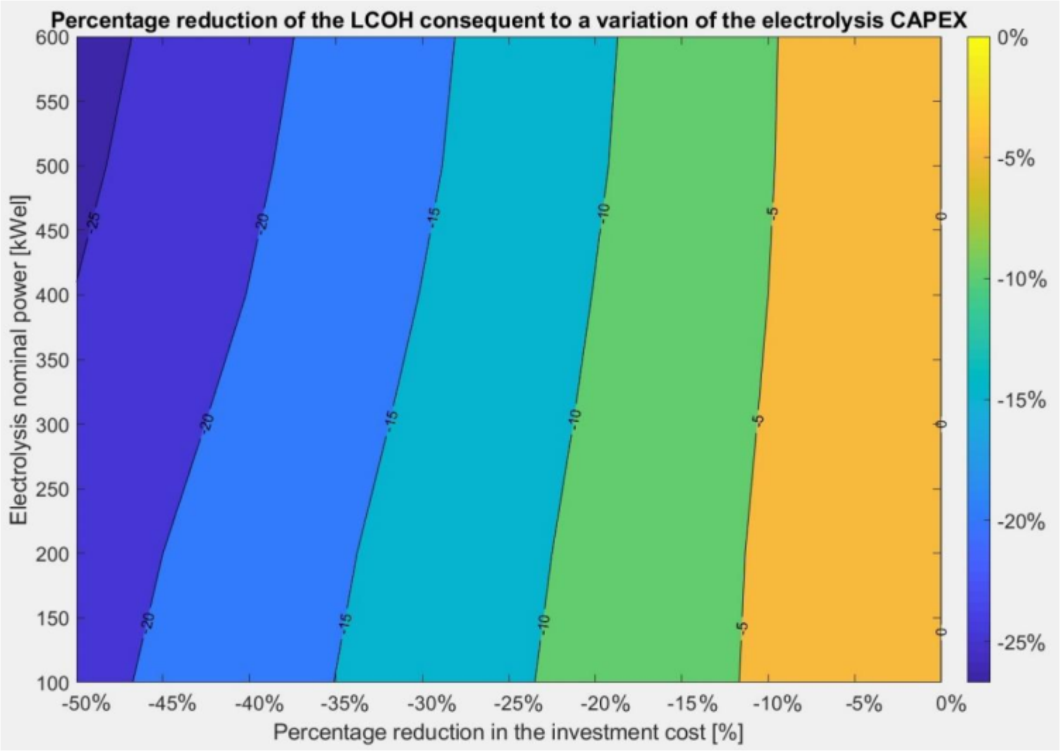
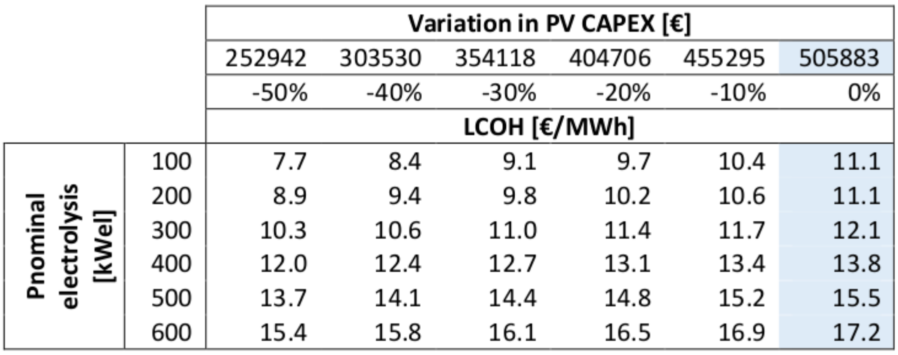


Figure 6.4: Percentage LCOH reduction consequent to a variation in the electrolyser's investment cost [€], plotted for different electrolysis sizes [kW].

vious case, a big share of the production cost was represented by the electricity purchase, which is here missing. Moreover, while the investment cost is the same for both the scenarios, in 1a the hydrogen productivity is higher, so the influence of such cost is shared among a higher quantity of hydrogen.A 50% reduction in the electrolysis investment cost results here in a maximum LCOH decrease of 30%, for an electrolysis nominal power of 600 kW. Differently from what was observed in Figure 6.4, the maximum variation of the LCOH occurs for the maximum electrolysis power. While in scenario 1a the operating hours of the electrolyser were fixed for each electrolysis power, they here depend on the size of the plant. Indeed, the lower the size of the electrolyser is with respect to the one of the PV system, the higher are the hours at which it operates at its nominal size. Additionally, as the electrolyser cannot work below 10% of its nominal power, the lower are the hours in which the PV power is not enough to start up the electrolysis unit. With the increase of the size of the electrolyser, the operating hours of the electrolyser decrease as the hours in which the PV availability is not enough to reach the 10% of the electrolyser nominal size increase. Thus, a percentage reduction in the investment cost would be more impacting at high powers, as the hydrogen productivity remains fixed but with higher investment costs.
(See Chapter 6.1 for a clearer explanation).

6.2.2 Sensitivity to changes in the PV plant investment cost



		Variation in PV CAPEX [€]					
		252942	303530	354118	404706	455295	505883
		-50%	-40%	-30%	-20%	-10%	0%
		LCOH [€/MWh]					
Pnominal electrolysis [kWel]	100	7.7	8.4	9.1	9.7	10.4	11.1
	200	8.9	9.4	9.8	10.2	10.6	11.1
	300	10.3	10.6	11.0	11.4	11.7	12.1
	400	12.0	12.4	12.7	13.1	13.4	13.8
	500	13.7	14.1	14.4	14.8	15.2	15.5
	600	15.4	15.8	16.1	16.5	16.9	17.2

Table 6.4: LCOH [€/kgH2] computed for different electrolysis rated powers [kW] and different PV investment costs [€]. The base case values are emphasized in blue.

Since in this case there is no additional purchase of energy from the grid but the energy input to the system is exclusively that of the photovoltaic system, the dependence of the LCOH on the investment cost of the RES plant has been considered. The dependence is quite significant and is greater for a smaller electrolyser

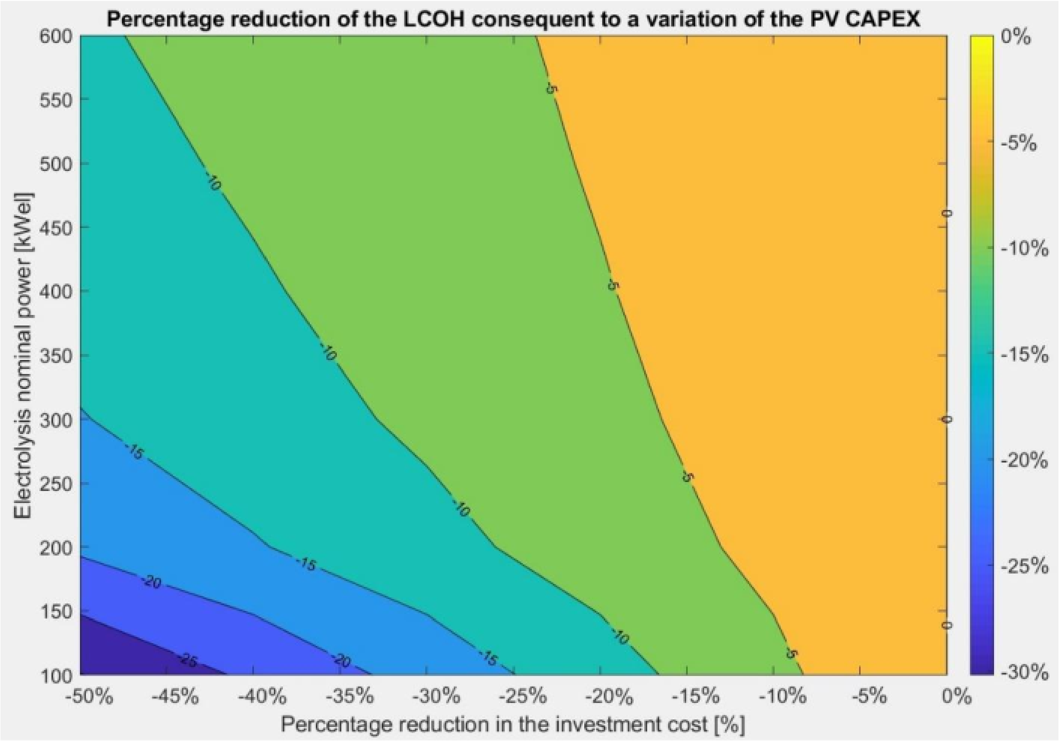


Figure 6.5: Percentage LCOH reduction consequent to a variation in the electrolyser's investment cost [€], plotted for different electrolysis sizes [kW].

since it corresponds to the minimum production of hydrogen and therefore to the minimum use of the photovoltaic system. The PV CAPEX are reported in Table ??.

6.3 Future scenarios

6.3.1 Incentives

Since 2016, the year in which the Italian government recognized hydrogen as a renewable energy resource (Legislative Decree 257 of 15 December 2016), several steps have been taken to allow the expansion of its uses in the Italian market. First, the ministerial decree of 23 October 2018 was introduced to regulate the production and distribution of gas, as already mentioned in Chapter 3, in the Paragraph 3.5. Then, in December 2019 the Minister of Economic Development approved the National Energy and Climate Plan for 2030 (PNIEC) followed by the Preliminary Guidelines of the "National Hydrogen Strategy" of November 2020. Finally, in May 2021 the National Recovery and Resilience Plan (PNRR, [3]) was presented as part of the European Next Generation EU (NGEU) program, which defines how much the Italian government intends to invest in the hydrogen market development (see Chapter 3). Despite the great attention to the development of the hydrogen opportunity, no incentive mechanism to help green hydrogen widespread in the industrial market has been outlined. Without that, clean hydrogen would result uncompetitive with brown or gray hydrogen which is nowadays sold at around 1-3 €/kgH2. Nevertheless, clear legislation for incentives is expected by the end of 2022. Although it is not possible to estimate the weight of these incentives, they will likely be directed to electrolysers powered by newly built RES plants only. Indeed, if such incentives would be devoted to all the renewable existing plants, some of them may find it favourable to switch their production from electricity to hydrogen, causing a gap in the energy supplied by the grid. In the specific case of this study, incentives on green hydrogen may work exclusively for the 2 and 3 scenarios, which are the ones where the energy feed to the electrolyser is grid independent. Even if proper mechanisms are not defined for Italy, it is interesting to look at the ones defined by other countries. In May 2021, the US Treasury Department published the "Green Book", which proposes a tax credit on the production of low-carbon hydrogen in plants whose construction begins before 2026, for use in the industrial, transport or energy sector. This credit amounts to 3 $/kg for the years from 2022 to 2024 and 2 $/kg for the years from 2025 to 2027. With low-emission hydrogen, it is here meant the one produced from nuclear energy, renewables or natural gas with a carbon capture system (CCUS).

6.3.2 Economic analysis

The Levelized cost of hydrogen is a simple indicator, that facilitates the comparison of the hydrogen produced via electrolysis with the one produced by means of other production processes. As it represents the minimum price at which the produced hydrogen can be sold without falling into a negative profit, by comparing it with the selling price of hydrogen in the market (1-3 €/kgH2) it is possible to have a general idea regarding the feasibility of the production.For this reason, the LCOH has been adopted as the reference parameter for this analysis, to compare the feasibility of one scenario with respect to another. Nevertheless, in actual business, when there is the need to state whether an investment is competitive or not, it is not the best approach from the financial point of view. Indeed, even if it gives remarkable information concerning the costs involved in the production process, it does not consider the revenues and the fact that high interest rate increases the revenues of an investment as well as its cost, and this can affect economic competitiveness. To properly implement an economic analysis and investigate the feasibility of a certain investment, other indicators are needed. In this paragraph, the feasibility of the hydrogen production is investigated for the most favourable case in this analysis, i.e., the 30 MW off-grid PV plant coupled to a variable size electrolyser (Scenario 2b). The discounted cash flow method is used. Firstly, the Net Present Value (NPV) parameter is computed, which is a financial indicator that measures the difference between the present value of cash inflows and the present value of cash outflows. In other words, it is the cumulative discounted cash flow obtained at the last year of operation in the analysis. Generally, if an investment has a positive NPV it can be considered profitable, while if it has a negative NPV it results in a net loss. It is possible to compare the NPV of two projects with equivalent investment amounts, but to compare the economics of two projects with different capital investment, the Internal Rate of Return (IRR) is used. The IRR is a metric used in financial analysis to estimate the profitability of potential investments. It is the discount rate that makes the NPV of all cash flows equal to zero in the discounted cash flow analysis. In general, when comparing investment options with other similar characteristics, the investment with the highest IRR probably would be considered the best. Figure 6.6 shows the IRR as for a variable size electrolyser and for a variable selling price of electricity. As incentives for green hydrogen are expected for the years to come, an incentive of 2 €/kgH2 has been considered as an assumption in this analysis. In Figure 6.6, two curves are reported for each sale price of hydrogen. Indeed, the same convention of Chapter 5 is here used, and the financial indicators have been computed both considering and neglecting the profit of the sale of the PV surplus. The dotted line represents the IRR computed considering the additional revenues. As reported in Chapter 5, Paragraph 4.3.2, the implementation of this hydrogen production scheme wouldn't be the best choice for the considered PV plant, which would need to inject its energy into the grid rather than producing hydrogen to maximise its profit. Indeed, Figure 6.6 shows how the IRR of the dotted lines increases with the decrease of the electrolysis nominal power, i.e., with the increase of the amount of PV energy that is sold to the grid instead of being used into the electrolyser. With the increase of the selling price of hydrogen, though, the dotted IRR curves adopt a lower slope, as for the same amount of electricity used for the hydrogen production, the revenue increases and becomes more comparable with the revenue of selling the surplus. Nevertheless, even with a hydrogen sale price of 6 €/kgH2, and considering the incentives, the best option for the PV plant would be the selling 100% of the electricity to the grid instead of producing hydrogen. The continuous curves represent the IRR computed neglecting the additional revenues. In this curve, even if theoretical, the right trend of the LCOH with respect to the electrolysis power can be spotted. For each electricity sale price, the maximum IRR is for an electrolysis power of around 10 MW.

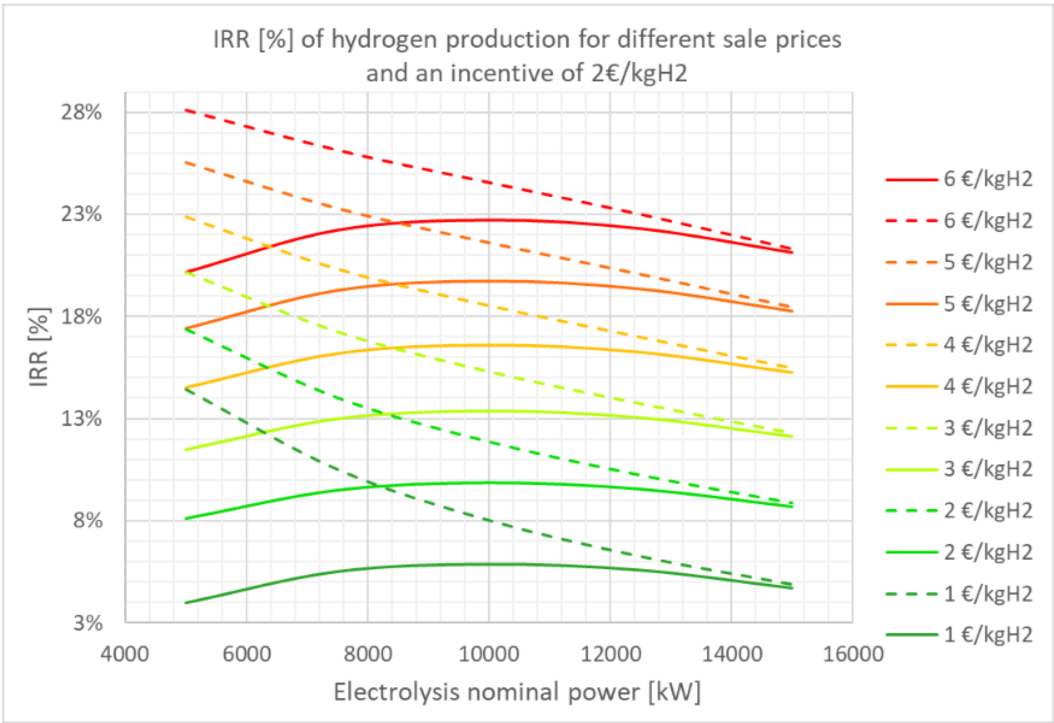
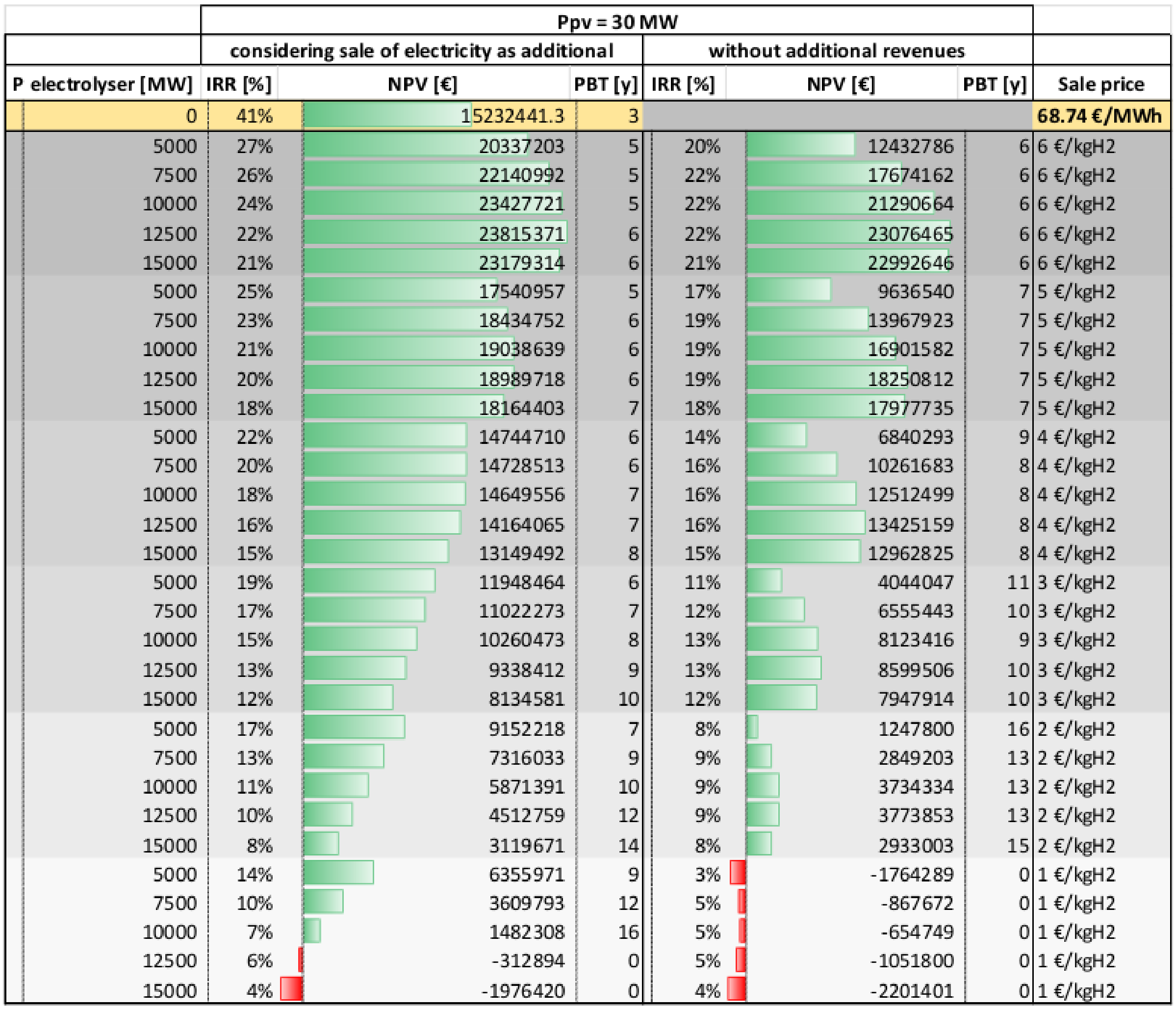


Figure 6.6: Internal Rate of Return of hydrogen production for sale prices from 6 to 1 €/kgH2, considering on incentive on green hydrogen of 2 €/kgH2.

In Table 6.5, the values of NPV, IRR and PBT are reported for the cases with and without additional revenues and for a variable selling price of hydrogen. Even if for most of the hydrogen sale prices assumed the IRR values of the investments are high and the NPV values are positive, the most convenient solution for a 30 MW PV plant is to inject all its production into the grid, instead of using it to produce hydrogen. The financial parameters in the case that valorises the surplus (Figure AYYA, column 2 to 4) are higher than the ones computed neglecting it (column 5 to 7). The only case in which the investment is unfeasible is for a selling price of 1 €/kgH2, with the NPV of the investment that is lower than zero for those values of IRR that are lower than the discount rate assumed in the analysis (6%).

Even considering an incentive of 2 €/kgH2 and exploiting economies of scale, the hydrogen production through electrolysis results here to be less convenient than the direct sale of renewable electricity to the grid. Nevertheless, significant changes will occur both to the energy system, to the electrolysis technology and to the sale price of fossil-hydrogen. With the increase of the share of the renewable electricity in the production mix, instabilities problems will occur, as well as a higher amount of renewable electricity will be curtailed. Even if at the moment the renewable power plants don't pay for the grid balancing costs, it is predictable that they one day will. For what concerns the technology, the costs of the electrolysers have already decreased by 60% in the last ten years and it is expected that, thanks to the economies of scale and the growth in the learning rate of the technology, they will be halved by 2030. With the increase of installations of renewable production plants , the price of electricity should also decrease, which is already occurring in countries as Spain and Portugal, where large utility-scale photovoltaic plants sell renewable energy at less than 40 € / MWh, a much lower price than the market price. In regions where renewable electricity is cheap, electrolysers should be able to compete with fossil fuel-based hydrogen by 2030. In a future context in which the carbon tax is increased, the great dependence of fossil-hydrogen on the supply price of fossil fuels, could lead to a substantial increase in the commercial price of hydrogen, and thus increase the competitiveness of green hydrogen in the global market.



	Ppv = 30 MW						
	considering sale of electricity as additional			without additional revenues			
P electrolyser [MW]	IRR [%]	NPV [€]	PBT [y]	IRR [%]	NPV [€]	PBT [y]	Sale price
0	41%	15232441.3	3				68.74 €/MWh
5000	27%	20337203	5	20%	12432786	6	6 €/kgH2
7500	26%	22140992	5	22%	17674162	6	6 €/kgH2
10000	24%	23427721	5	22%	21290664	6	6 €/kgH2
12500	22%	23815371	6	22%	23076465	6	6 €/kgH2
15000	21%	23179314	6	21%	22992646	6	6 €/kgH2
5000	25%	17540957	5	17%	9636540	7	5 €/kgH2
7500	23%	18434752	6	19%	13967923	7	5 €/kgH2
10000	21%	19038639	6	19%	16901582	7	5 €/kgH2
12500	20%	18989718	6	19%	18250812	7	5 €/kgH2
15000	18%	18164403	7	18%	17977735	7	5 €/kgH2
5000	22%	14744710	6	14%	6840293	9	4 €/kgH2
7500	20%	14728513	6	16%	10261683	8	4 €/kgH2
10000	18%	14649556	7	16%	12512499	8	4 €/kgH2
12500	16%	14164065	7	16%	13425159	8	4 €/kgH2
15000	15%	13149492	8	15%	12962825	8	4 €/kgH2
5000	19%	11948464	6	11%	4044047	11	3 €/kgH2
7500	17%	11022273	7	12%	6555443	10	3 €/kgH2
10000	15%	10260473	8	13%	8123416	9	3 €/kgH2
12500	13%	9338412	9	13%	8599506	10	3 €/kgH2
15000	12%	8134581	10	12%	7947914	10	3 €/kgH2
5000	17%	9152218	7	8%	1247800	16	2 €/kgH2
7500	13%	7316033	9	9%	2849203	13	2 €/kgH2
10000	11%	5871391	10	9%	3734334	13	2 €/kgH2
12500	10%	4512759	12	9%	3773853	13	2 €/kgH2
15000	8%	3119671	14	8%	2933003	15	2 €/kgH2
5000	14%	6355971	9	3%	-1764289	0	1 €/kgH2
7500	10%	3609793	12	5%	-867672	0	1 €/kgH2
10000	7%	1482308	16	5%	-654749	0	1 €/kgH2
12500	6%	-312894	0	5%	-1051800	0	1 €/kgH2
15000	4%	-1976420	0	4%	-2201401	0	1 €/kgH2

Table 6.5: NPV, IRR and PBT computed for Scenario 2b and a nominal PV plant size of 30 MW. The parameters are computed for both the case with the sale of the surplus and the case that neglects it. The parameters are computed for electrolysis rated power of 5 to 15 MW and sale prices of 1 to 6 €/kgH2.

Chapter 7

Conclusions

This document investigates the competitiveness of hydrogen production through the electrolysis of water and photovoltaic renewable electricity for a wide range of applications. The study started from the idea of Biomet s.p.a., an Italian company that produces and distributes bio-methane, of evaluating the feasibility of green hydrogen production at its production site. Green hydrogen is indeed identified by the technical-scientific community as an essential energy vector for the decarbonisation of the "hard-to-abate" sectors and therefore to aim at climate neutrality by 2050. Following a general explanation on the electrolysis process and on the electrolysers available in the market, the main resources to implement the process were determined considering Biomet's data; mostly: the available water sources in the system and the available space for electrolysers and modules installations. The sizing of the photovoltaic system was carried out, which resulted to be 606.54 kW. Once determined the plant data, the main technologies involved in the system, the electrolyser, the PV plant and batteries, have been technically and economically characterised. As the analysis covers a wide range of PV and electrolyser sizes and battery capacities, specific costs curves have been fitted from a vast number of literature data. Once determined all the useful data to implement the analysis, the mass and energy balances of the streams involved in the process have been guaranteed, and each stream received a proper economic valorisation. The hydrogen productivity was studied for three different scenarios: 1a) assuming the maximising hydrogen production and the coupling of the PV with an additional energy stream; 2a) assuming an off-grid PV plant; 3a) employing batteries. The LCOH was both computed using the discount cash flow methodology and the parameter's definition. Moreover, it was computed both considering the sale of the surplus of the PV plant and neglecting it, for a more theoretical LCOH curve extrapolation. The minimum LCOH was found to be 8.50 €/kgH2 for a 1 MW electrolysis plant which works at maximum load thanks to the supply of 110 €/MWh electricity. This cost is much higher than the current hydrogen sale price, i.e., 1-3 €/kgH2.

Such high production price could be caused by the limited size of the PV and electrolysis systems. Being such components subject to strong economies of scale, the same feasibility study was investigated for higher PV and electrolyser sizes, neglecting water and space constraints, to look for a lower LCOH at higher sizes. For all the three cases analysed, the LCOH computed considering the additional revenues of selling electricity to the grid has shown as negative, as for high PV plant sizes, the LCOE is much lower than the zonal price and selling electricity to the grid is convenient. Such revenue is so significant, especially at electrolysis low nominal powers, when the surplus is maximum, that for the 30 MW PV plant it would be extremely advantageous to directly sell its production into the grid instead of feeding the electrolysis plant. Neglecting the revenus, the minimum LCOH was found to be 3.1€/kgH2 for an electrolyser of 10 MW coupled to a 30 MW PV off-grid plant. An economic analysis was performed on such case, which confirmed that despite the low price of hydrogen production, and considering hydrogen incentives, the direct sale of the PV electricity to the grid is more convenient (IRR of 41%) than its employment for the hydrogen production for this specific case. Nevertheless, the hydrogen production would still result competitive and with the 50% expected decrease in the technology's investment cost and in the price of electricity, which have been demonstrated to be two very influencing parameters on the LCOH, green hydrogen will surely be competitive in the global market. An examination of the Ministerial Decree of 23 October 2018, which regulates the construction of plants for the production of hydrogen, showed that there is no general regulation and the firefighters require an ad hoc evaluation of the technical data sheet of the plant to assess its feasibility. This brings a certain degree of uncertainty to the investment and there is a need for more specific legislative acts that establish a unambiguous framework of the necessary authorization processes. These specifications are essential to open the window of opportunity that the ID market reserves.

Appendix A

LCOE computation

The cost of hydrogen production via electrolysis is considerably influenced by the one of electricity. The cost at which the electricity is purchased to supply the electrolysis process plays a decisive role in the return of investment of the project. In the analysis, the part of the electricity that is purchased from the grid or with a Power Purchased Agreement has a well-defined price, whereas the self-produced part by the PV system lacks a determined price. For this reason, the levelized cost of the electricity (LCOE) produced by the renewable price has been computed. LCOE is the minimum price at which the electricity produced by the plant can be sold to have a positive revenue and net present value of the investment. For the calculation of the Levelized Cost of Electricity, the discounted cash flow method was used, which will subsequently also be used for the calculation of the cost of hydrogen production. This is one of the most used methodologies for business analysis and it is based on the determination of the present value of the cash flows expected from a specific asset. It is based on the three main elements: the cash flows, their temporal distribution throughout the operative period of the activity and the discount rate. Thanks to this methodology it is possible to account for the value of money over time. Regarding the energy production, it has been corrected each year considering the annual decline in module performance:

$$E_{PV_j} = EE_{PV} \cdot (1 - \%decay) \cdot decay_{j-1} \tag{A.1}$$

Where:

- j=year of analysis;
- decay rate of PV module $= -0.5\frac{\%}{year}$.

For what concerns the economics hypothesis:

- construction time: 1 year;

- inflation is considered IR=1%, and the annual variation of the OPEX, considering the increase of the value of money over time, has been computed as:
$$OPEX_n = \frac{OPEX_1}{(1+IR)^n} \tag{A.2}$$
- discount rate = 6%;
- tax rate = 28% (Tax on profit);
- deprecation = 11 anni;
- useful life = 20 anni.

$$EXPENDITURES_j = (CAPEX_j + OPEX_j)_{PV} \tag{A.3}$$

$$RICAVI_{TOT_j} = Price_{electricity} \cdot E_{PV_j} \tag{A.4}$$

$$PROFIT_j = REVENUES_{TOT_j} - OPEX_j - DEPRECIATION_j \tag{A.5}$$

$$TAX_j = tax\% \cdot PROFIT_j \tag{A.6}$$

$$CASHFLOW_j = CF_j = REVENUES_{TOT_j} - EXPENDITURES_j - TAX_j \tag{A.7}$$

$$DISCOUNTEDCASHFLOW_j = DCF_j = \frac{CF_j}{(1+r)^n} \tag{A.8}$$

$$CUMULATIVEDISCOUNTEDCASHFLOW_j = CDCF_j = DCF_j + DCF_{j-1} \tag{A.9}$$

Finally, bringing the CDCF of the 20 th year to zero by varying the assumed price of electricity, the Levelized cost of electricity value is obtained. This model has been implemented on Microsoft Excel. Another possibility to compute the LCOE is to use its definition:

$$LCOE = \frac{I_0 + \sum_{n=1}^{n_S} \frac{c_n}{(1+d)^n}}{\sum_{n=1}^{n_S} \frac{e_n}{(1+d)^n}} \left[\frac{N}{kWh}\right] \tag{A.10}$$

where I_0 is the investment cost, C_n the cost in year n, d is the discount rate, n is the energy produced in year n and n_s is the number of operating years of the plant. The two methodologies converge to the same LCOE definition: 82.43 €/MWh. It is in line with the electricity generation cost by commercial size PV plant in Italy nowadays. In this analysis no incentives were considered for the renewable plant.

Appendix B

Battery strategy

The battery strategy is shown below, in which all calculations refer to the i-th hour.

→ Se $P_{SURPLUS_i} = 0$

- Se $E_{BATTERY_{i-1}} \leq E_{NOM_{BATTERY}}$
  - $P_{DISCHARGE_i} \cdot 1h = E_{BATTERY_{i-1}}$
- Altrimenti, se $E_{BATTERY_{i-1}} > E_{NOM_{BATTERY}}$
  - $P_{DISCHARGE_i} \cdot 1h = P_{MAX_{DISCHARGE}} \cdot 1$

$E_{BATTERY_i} = E_{BATTERY_{i-1}} - P_{DISCHARGE_i} \cdot 1h$
$E_{OUT_i} = 0$
$M_{H_2BATTERY_i} = \frac{P_{MAX_{DISCHARGE}} \cdot 1h \cdot \eta_{DISCHARGE}}{Consumption_{EL}}$
$P_{EL,BATTERY_i} = M_{H_2BATTERY_i} \cdot Consumption_{EL}$
$P_{EL_{TOT}} = P_{EL_i} + P_{EL,BATTERY_i}$

- Se $P_{EL_{TOT,i}} = P_{EL_{NOM}}$
  - $M_{H_2BATTERY_i} = \frac{(P_{EL_{NOM}} - P_{EL_i}) \cdot 1h}{Consumption_{EL}}$
  - $P_{DISCHARGE_i} \cdot 1h = M_{H_2BATTERY_i} \cdot \frac{Consumption_{EL}}{\eta_{DISCHARGE}}$
  - $E_{BATTERY_i} = E_{BATTERY_{i-1}} - P_{DISCHARGE_i} \cdot 1h$
  - $P_{EL,BATTERY_i} = M_{H_2BATTERY_i} \cdot Consumption_{EL}$
  - $P_{EL_{TOT,i}} = P_{EL,BATTERY_i} + P_{EL_i}$

→ Se $P_{SURPLUS_i} > 0$

- Se $E_{BATTERY_{i-1}} = E_{NOM_{BATTERY}}$
    - $P_{DISCHARGE_i} \cdot 1h = P_{MAX_{DISCHARGE}} \cdot 1h$
    - $E_{BATTERY_i} = E_{NOM_{BATTERY}} - P_{DISCHARGE_i} \cdot 1h$
    - $M_{H_2BATTERY_i} = \frac{P_{MAX_{DISCHARGE}} \cdot 1h \cdot \eta_{DISCHARGE}}{Consumption_{EL}}$
    - $E_{OUT_i} = P_{SURPLUS_i} \cdot 1h$
- Se $E_{BATTERY_{i-1}} < E_{NOM_{BATTERY}}$
    - Se $P_{SURPLUS_i} \cdot 1h \cdot \eta_{CHARGE} > P_{BATTERY_{NOM}} \cdot 1h - E_{BATTERY_{i-1}}$
        - $*$ $\rightarrow$ Se $P_{BATTERY_{NOM}} \cdot 1h - E_{BATTERY_{i-1}} > P_{NOM_{BATTERY}}$
        - $*$ $P_{CHARGE_i} = P_{NOM_{BATTERY}}$
        - $*$ $\rightarrow$ Altrimenti: $P_{CHARGE_i} \cdot 1h = P_{BATTERY_{NOM}} \cdot 1h - E_{BATTERY_{i-1}}$
    - Se $P_{SURPLUS_i} \cdot 1h \cdot \eta_{CHARGE} \leq P_{BATTERY_{NOM}} \cdot 1h - E_{BATTERY_{i-1}}$
        - $*$ $\rightarrow$ Se $P_{SURPLUS_i} \cdot 1h \cdot \eta_{CHARGE} < P_{MAX_{DISCHARGE}}$
        - $*$ $P_{CHARGE_i} = P_{MAX_{DISCHARGE}}$
        - $*$ $\rightarrow$ Altrimenti: $P_{CHARGE_i} \cdot 1h = P_{SURPLUS_i} \cdot 1h \cdot \eta_{CHARGE}$

$E_{BATTERY_i} = E_{BATTERY_{i-1}} + P_{CHARGE_i} \cdot 1h$
$E_{OUT_i} = P_{SURPLUS_i} \cdot 1h - \frac{P_{CHARGE_i}}{\eta CHARGE}$

- Se $P_{EL_{TOT,i}} > P_{EL_{NOM}}$
    - $M_{H_2BATTERY_I} = \frac{(P_{EL_{NOM}} - P_{EL_i}) \cdot 1h}{Consumption_{EL}}$
    - $P_{DISCHARGE_i} \cdot 1h = M_{H_2BATTERY_i} \cdot \frac{Consumption_{EL}}{\eta_{DISCHARGE}}$
    - $E_{BATTERY_i} = E_{BATTERY_{i-1}} - P_{DISCHARGE_i} \cdot 1h$
    - $P_{EL,BATTERY_i} = M_{H_2BATTERY_i} \cdot Consumption_{EL}$
    - $P_{EL_{TOT,i}} = P_{EL,BATTERY_i} + P_{EL_i}$

In this way, the hourly profile of the battery charge status for year 0 was calculated. Summarizing the code, in the event that the surplus of the photovoltaic system is zero, the battery, if charged, will discharge at the maximum available discharge rate, considering the operating constraints of the battery. Conversely, in the case of a positive surplus, the battery will charge if it has a state of charge lower than the maximum achievable and vice versa it will discharge if it is already completely full. In any case, the surplus energy not useful for recharging the battery will be considered as "Eout", ie energy that will be managed outside the boundaries of the electrolysis plant. When the battery is discharged, its energy is transmitted to the electrolyser. Therefore, in addition to the control of not exceeding the maximum discharge speed of the battery, a control has also been added to the code for the possible exceeding of the maximum power of the electrolyser.

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