Feasibility of Hydrogen Production

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Engineering and Energy Management

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Declaration

I declare that this document is an original work of my own authorship and that it fulfills all the requirements of the Code of Conduct and Good Practices of the Universidade de Lisboa.

Best regards,
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Resumo

Portugal tem sido um dos países pioneiros da Europa em incorporação de energias renováveis no sistema elétrico, atingindo uma quota de energias renováveis em produção de eletricidade de 61% em 2020. Novos vetores como o hidrogénio têm sido alvo de atenção, como possíveis substitutos de fontes não eletrificáveis, entre outros fins. No dia 14 de Agosto de 2020, em Portugal, foi aprovada a ENH2, que prevê a instalação de 2 a 2,5 GW de electrolisadores até 2030 para produção de hidrogénio. No entanto, esta tecnologia necessida de investigação e melhoramentos em varias áreas, entre elas os custos de produção. Neste contexto, esta tese foca-se na produçao de H2, focando as tecnologias Alcalinas e PEM. Foram simulados em três locais de Portugal e sobre três possíveis cenários de produção, com o objetivo de analisar os custos nivelado da produção de hidrogénio. O primeiro cenário assume a produçao de H2 por eletrolise com a ligação direta à rede pública (RESP). O segundo considera um acordo de compra de energia a centrais renováveis locais, através de contratos ”*Power Purchase Agreements*” (PPA's). O terceiro assume o autoconsumo renovável. Sendo este o cenário mais viável, muito perto do custo de produção de hidrogénio por fontes fosseis (uma diferença de LCOH de 0,82€/KhH2 para 2030) . O cenário 1 pode ser lucrativo com preços de eletricidade baixos (20 €/MWh). Foram considerados seis modelos diferentes com o objetivo de comparar o custo final nivelado e a sua relação com alguns indicadores chave. A tecnologia Alcalina NEL apresentou o melhor desempenho.

Palavras-chave: Renováveis, Hidrogénio, Electrolisadores PEM e Alkalino, Custo Nivelado.

Abstract

Portugal has been one of the pioneering countries in Europe in incorporating renewable energy into the electricity system, reaching a share of renewable energy in electricity production of 61New vectors such as hydrogen have been the focus of attention, as possible substitutes for non-electrifiable sources, among other purposes. On August 14, 2020, in Portugal, the ENH2 was approved, which foresees the installation of 2 to 2.5 GW of electrolyzers by 2030 for hydrogen production. However, this technology needs research and improvement in several areas, among them production costs. In this context, this thesis focuses on the production of H2, focusing on the Alkaline and PEM technologies. Three possible production scenarios were simulated in three locations in Portugal, with the objective of analysing the levelized costs of hydrogen production. The first scenario assumes the production of H2 by electrolysis with direct connection to the public grid (RESP). The second considers a power purchase agreement with local renewable power plants, through "*Power Purchase Agreements*" (PPA's) contracts. The third assumes renewable self-consumption. Six different models were considered with the objective of comparing the final levelized cost and its relationship with some key indicators.

Keywords: Renewable Energy, Hydrogen, PEM and Alkaline electrolysis, LCOH

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Nomenclature

Greek symbols

η	efficiency of the compressor
γ	Ratio of the specific heat

Roman symbols

C_a	Equipment cost a
C_b	Equipment cost b
C_{comp}	Compressor Consumption
C_{elec}	Electrolyser energy consumption per unit volume of H2.
$c_{H2/kg}$	Hydrogen production cost.
$c_{H2/O2}$	Hydrogen production cost w/ Oxygen sell.
$c_{O2/O2}$	Oxygen production cost.
LF	Loaf Factor
M_{H2}	Molecular mass of hydrogen
N	number of compressor stages
n	Lifetime in years
P	Power.
$p_{(CAPEX+OPEX)stack}$	CAPEX and OPEX Costs of the electrolyzer stack
p_{elec}	Electricity price
$p_{gridfees}$	Grid fees price
P_{in}	Pressure input the compressor
p_{O2}	Water price
P_{out}	Pressure output the compressor

R	Universal constant of ideal gas
S_a	Size/Capacity of a
S_b	Size/Capacity of b
T	Inlet Temperature
Z	Compressibility factor

Subscripts

AC	Alternate Current.
APREN	Associação Portuguesa de Energias Renováveis.
AS	Armazenamento Subterrâneo.
AWE or AE	Alkaline Electrolyzer.
CAPEX	Capital Expenditure.
CCS	Carbon capture and storage.
CCU	Carbon capture and usage.
DC	Direct Current.
EC	European Commission.
EDIA	Empresa de Desenvolvimento de Infra-Estruturas do Alqueva.
EN-H2	Estratégia Nacional para Hidrogénio.
ERSAR	Entidade Reguladora de Serviçoes de Águas e Resíduos.
ERSE	Entidade Reguladora dos Serviços Energéticos.
EU	European Union.
EUROSTAT	Normal component.
FCV	Fuel Cell Vehicle.
GHG	Greenhouse gas.
GRMS	Gas Regulation and Metering Station.
H2	Hydrogen.
HHV	High Heating Value.
HP	High Pressure.
HR	Hydrogen reaction.

IEA	International Energy Agency.
IRENA	International Renewable Energy Agency.
IW	Wobbe Index.
LCOE	Levelized Cost of Energy.
LCOGH	Levelized cost of grey hydrogen.
LCOH	Levelized Cost of Hydrogen.
LH2	Liquid hydrogen.
LHP	Large Hydro Power plant.
LHV	Low Heating Value.
LNEG	Laboratorio de Energia e Geologia.
MEA	Membrane electrode assembly.
MEC	Microbial electrolysis cells.
MIBEL	Mercado Ibérico de Eletricidade.
NG	Natural Gas.
OEM	Original Equipment Manufacturer.
OMIE	Operador de Mercado Ibérico Espanhol.
OPEX	Operational Expenditure.
OR	Oxygen reaction.
P2F	Power-to-fuel.
P2G	Power-to-gas.
P2I	Power-to-Industry.
P2M	Power-to-Mobility.
P2P	Power-to-Power.
PCS	Poder Calorífico.
PEM	Proton Exchange Membrane Electrolyzer.
PEMFC	Proton-exchange membrane fuel cell.
PGM	Platinum group metals.
PNEC 2030	Plano Nacional de Energia e Clima 2030.

PPA	Power Purchase Agreement.
PV	Photovoltaic.
REN	Redes Energéticas Nacionais.
RES	Renewable Energy Sources.
RESP	Rede Elétrica de Serviço Público.
RNC2050	Roteiro para a Neutralidade Carbónica.
RNC2050	Roteiro para a Neutralidade Carbonica.
RNTIAT	Rede Nacional de Transporte, Infraestruturas de Armazenamento e Terminais.
SHP	Small Hydro Power plant.
SOE or SOEC	Solid Oxide Electrolyzer.
TGNL	Terminal de Gás Natural Liquefeito.
UGS	Underground gas storage.
UTIS	Ultimate Technology To Industrial Savings.

Chapter 1

Introduction

This first chapter describes the scenario that motivated the thesis' main purpose. Is finished with an overview of the work is provided.

1.1 Motivation

Nowadays, we have several sources of energy, fossil fuels, such as coal, petroleum, and natural gas. These sources of energy have been used for over 20 decades, resulting in excessive energy consumption, unrestrained exploitation, and considerable waste.

In figure 1.1, is illustrated the world evolution of energy consumption by source, measured in terawatt-hours (TWh). Globally we get the largest amount of our energy from oil, followed by coal, gas, then hydroelectric power [1].

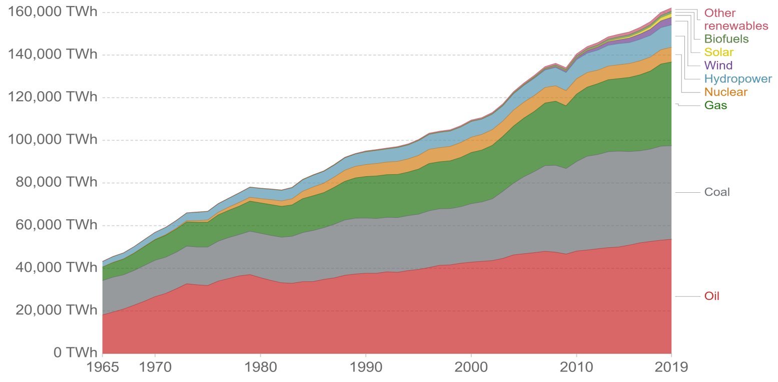


Figure 1.1: World Evolution of the Energy Consumption by Source from [2]

According with the U.S. Energy Information Administration industrial, the industrial sector is the sector that shows the higher energy consumption being natural gas and Petroleum the most used sources (for example during 2019 in the US, 10.66 quadrillions British thermal units were consumed, followed by 8.69 quadrillions British thermal units [3]). Secondly, the transport sector using (planes, trains, and automobiles) consuming mostly petroleum. In third, the residential and commercial, both consuming mostly electricity and natural gas .

Therefore, the challenge for the power sector in both developed and developing countries is not just energy production and consumption, but also to reduce carbon emissions [4].

Carbon Emissions

The energy transition must reduce emissions, while ensuring that sufficient energy is available for economic growth. Portugal had 40.43 Mt of CO2 Emissions in 2020 [5], equivalent of 3200M of euros in carbon taxes (1,5% of the PIB) Figure 1.2 from IRENA [6] shows, CO2 emissions of global economic activity needs to be reduced by 85% between 2015 and 2050, and CO2 emissions need to decline by more than 70% compared to the reference case in 2050. The result is an annual decline of energy related CO2 emissions by 2.6% on average

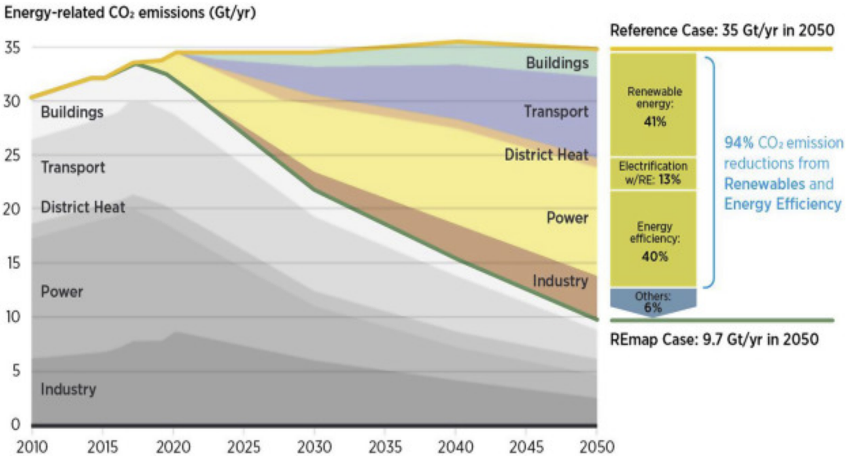


Figure 1.2: CO2 emissions target by 2050 from [6]

Energy transition urgency is mainly due to the accelerating climate change in the recent years. The average global temperature has been increasing, surpassing the value of the pre-industrial baseline by 1.04 ◦C [7]. In the next decade, the energy sector will be the one that will make the greatest contribution to decarbonization. [8]

All types of renewable energy can not only bring economic and environmental benefits, but also improve people's living standards. [9].

EU Strategy

The Climate Energy Package of 2018 for all Europeans aim, among others, to promote energy transition in the decade 2021-2030, with a view to meeting the Paris Agreement while safeguarding economic growth and job creation. Some of the agreed targets, such as reduce emissions by at least 40% compared to 1990, 32% share for renewable energy and at least 32.5% improvement in energy efficiency [10].

In late 2019, the European Commission (EC) presented the European Green Deal outlining the main policy initiatives for reaching net-zero greenhouse gas (GHG) emissions. Among the areas to be boosted and supported for their importance in the decarbonization of European economies is **hydrogen** [11] , both from a regulatory point of view and from the point of view of financing new technologies and infrastructures.

On 8 July 2020 the EU issued its “**hydrogen strategy for a climate-neutral Europe**” (the EU Hydrogen Strategy).”The aim of the EU Hydrogen Strategy is to decarbonise hydrogen production and expand its use in sectors where it can replace fossil fuels.” The path is divided into three phases. Each phase sets a specific objective to be achieved within the relevant phase.

- In **phase 1** (2020-2024), the objective is to decarbonise existing hydrogen production for current uses such as the chemical sector and promote it for new applications; 6 GW of renewable hydrogen electrolysers in the EU by 2024 and producing up to one million tonnes of renewable hydrogen. In 2020 there was 1GW of electrolysers installed. In this phase, manufacturing of electrolysers, including large ones (up to 100 MW), needs to be scaled up. These electrolysers could be installed next to existing demand centres in larger refineries, steel plants, and chemical complexes. They would ideally be powered directly from local renewable electricity sources [12].

- In **phase 2** (2024-2030), hydrogen needs to become an intrinsic part of an integrated energy system with a strategic objective to install at least 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10M tonnes of renewable hydrogen in the EU.

- In **phase 3** (from 2030 onwards and towards 2050): renewable hydrogen technologies should reach maturity and be deployed at large scale to reach all hard-to-decarbonise sectors where other alternatives might not be feasible or have higher costs.[10]

In July 2021, the Commission presented the ’Fit for 55 package’ – a set of proposals and initiatives whose aim is to revise and update EU legislation to align it to the EU’s 2030 and 2050 climate goals. The EU has led by example in setting ambitious targets for reducing net emissions by at least 55% by 2030 compared to 1990 and for being the first climate neutral continent by 2050. These goals are no longer aspirations or ambitions but obligations laid down in the first European Climate Law that create new opportunities for innovation, investment and jobs.

Portugal Strategy

Portugal’s strategy for the next decade follows Europe´s strategy and has reached several numbers that shows the commitment with the objectives. For example in 2020 Portugal reached around 60.8% of electric production from renewable sources, as stated in the APREN report of 2020, presented in figure 1.3 [13]. In 2021, renewable production in Portugal increased 2.6% compared to 2020 and supplied 59.3% of consumption: wind with 25.9%, followed by hydroelectric with 23.3%, biomass with 6.6% and photovoltaic with 3.5%. Noteworthy is the solar production that recorded a significant increase of 37% compared to 2020. Non-renewable production supplied 31% of consumption: natural gas with 29% and coal with 2%. The importing balance supplied the remaining 10% of electricity consumption [14].

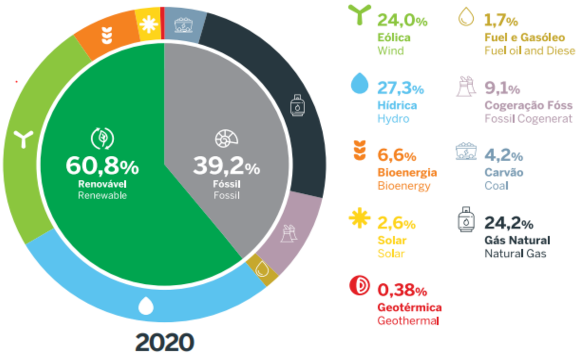


Figure 1.3: Portugal's Electrical Energy Generation, from [14]

According with Eurostat, in 2020, Portugal was the 5th country in the EU with the highest share of renewable sources in gross final consumption, with a percentage of at 34.0%, exceeding the target of 31.0% by 3 percentage points [15].

In this light, it is worth highlighting the role that renewable gases, in particular **hydrogen**, can play in the decarbonization of the various sectors of the economy (industry and transport) for reasons as: electric energy can not replace some sectors, for example burning gases like natural gas; and also will allow reaching higher levels of incorporation of renewable energy sources in the energy consumption. [13].

In 2016, Portugal committed to ensuring the neutrality of its emissions by the end of 2050, outlining a clear vision regarding the deep decarbonisation of the national economy. Aligned with the objectives of the RNC2050 ("Roteiro para a Neutralidade Carbonica"), Portugal submitted to the European Commission, in December 2019, the final version of its National Energy and Climate Plan for the horizon 2021-2030 (PNEC 2030). According to the PNEC, the most relevant changes compared to the version presented in 2018, is the role attributed to renewable gases that gain greater relevance in meeting the goals for 2030 and 2050, with emphasis on hydrogen with its advantages in the energy, economic and financial sectors. [7, 13, 16, 17].

On the 14th of August 2020 the National Hydrogen Strategy (EN-H2) was approved in the Council of Ministers. The main objective, in line with the National Energy and Climate Plan (PNEC), is to introduce an element of incentive and stability to this energy sector, promoting the gradual introduction of green hydrogen as a sustainable pillar and integrated into a broader strategy of transition to a decarbonised economy, as a strategic opportunity for the country. It also fulfils the important objective of defining a solid framework and a vision for the short, medium and long term for all companies and promoters with green hydrogen projects, already in progress or still at an early stage. [13, 17] The following targets to be met by 2030, sated that hydrogen in Portugal can represent: 5% in the final energy's consumption; 5% of consumption in the mobility's sector; 5% of consumption in the industrial sector; 15% of injection in the Natural Gas Grid; 50 to 100 refuelling stations; **An installed capacity of 2GW of electrolysers**; An investment of 7 000 Millions of euros in projects of hydrogen's production; A reduction of 300 to 600 Millions of euros in the importation of natural gas; 900 Millions of euros in funds for hydrogen's production projects.

This year, 2022, was also launched in Portugal by LNEG [18], the Hydrogen map according three major layers:

- Land: If there are slopes, the type of soil, for example if there is dunes and urban areas, industrial and agriculture areas, and environmental regulation,
- Energy Resources: Water availability and also the type of water if it is surface, sea, public, etc. Also the potential of solar, wind, bioenergy, hydroelectric power.
- Conditions for end users: Location of potential consumers (glass industry, chemicals, ceramics, cement, lime, mining, paper) as well as connection points to inject in the gas grid. And finally end users for mobility (emergency network supply stations, access to the main road haulage routes, trains, etc)

Besides, was also created 4 possible scenarios of stakeholder, a diverse client for small units and independent of the water, a client for gas injection and mobility purposes, another for gas industry and a final client for others renewable technologies like offshore technologies. Which gives us a good overview of Portugal's potential for several scenarios.

Therefore, this thesis aims to focus on this recent energy vector. Aims to study its the value chain, as well as the feasibility of hydrogen production from the different types of technologies available in the market, and its application in some locations in Portugal. The objective is to evaluate the cost of production with this variables, and see what's most promising.

1.2 Objectives and Deliverables

Hydrogen as a energy vector is the main theme of this study, and was studied with a main focus which is the production of green hydrogen through water electrolysis. The deliverables of this study can be divides into four objectives:

- An overview of the state of the art of renewable hydrogen or also called green hydrogen. What's the main advantages of this renewable vector in the energy sector? Specially in a time that we are living, of energy transition, what's the role that hydrogen can have;

- To analyse some of the available water electrolysis technologies of today, using some commercial models from Siemens, Cummins, Thyssenkrupp, Nel and McPhy in the study of some realistic cases in the Portuguese context;

- To evaluate potential Portuguese places for hydrogen production. The locations were chosen based in the 2021 Portugal's solar floating auction context, according with the available power, renewable power plants access, and the geographical potential from LNEG Hydrogen map [18];

- To analyse hydrogen production levelized costs, analysing the feasibility of its production, in the context of three possible scenarios combined with the chosen locations.

1.3 Thesis Outline

For a better reading of the thesis, an outline is depicted in the Figure 1.4. Chapters are connected by arrows and the main questions that each chapter aims to answer are presented in the respective attached box.

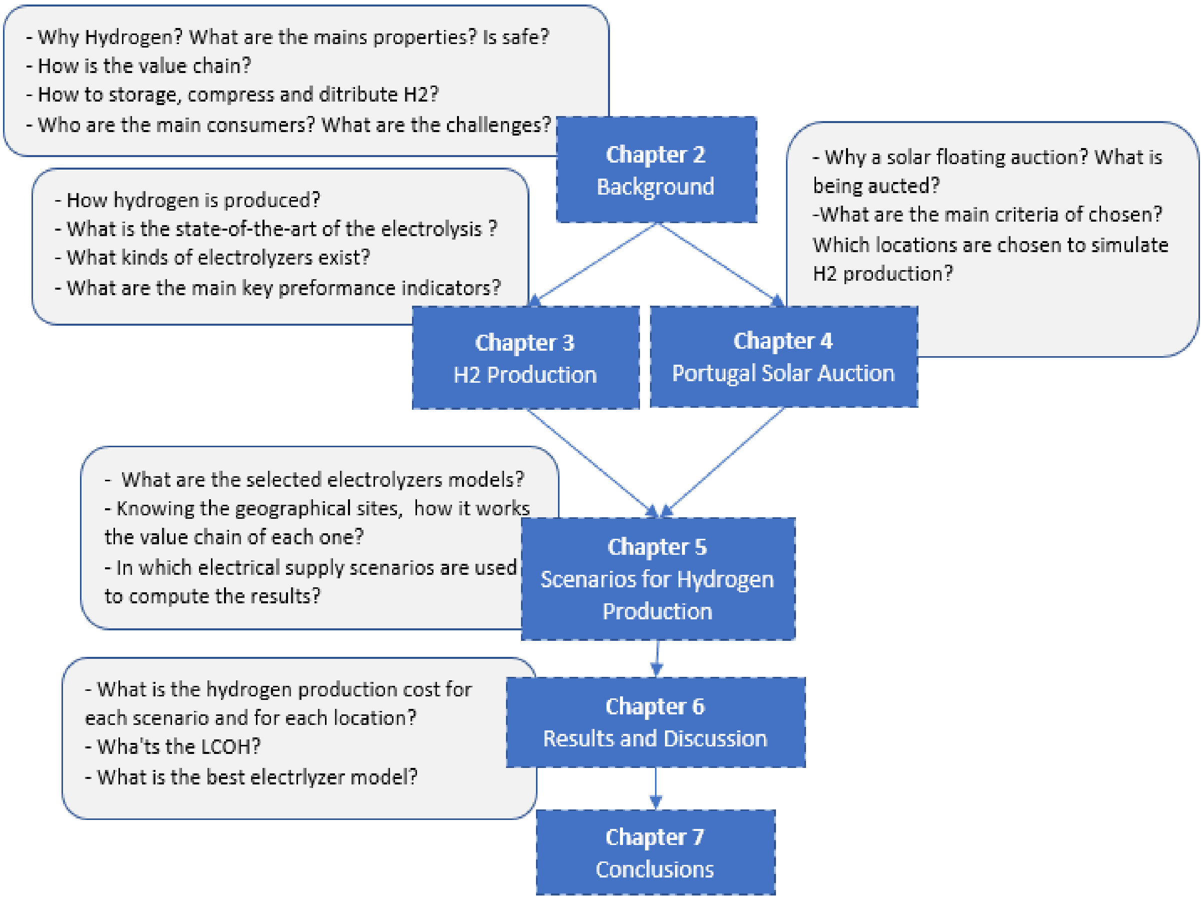


Figure 1.4: Thesis Outline

Chapter 2

Background

The hydrogen role was recognized as a potential energy carrier, both by the scientific community and the International Energy Agency (IEA) [19].

There are several aspects that make this molecule attractive:

- Hydrogen (H2) is the most abundant element in the universe, which is found on our planet earth mainly in water and organic compounds [20, 21], e.g. in water, fossil fuel, and biomass.
- Hydrogen and hydrogen-based fuels can transport energy from renewable sources over long distances [7].
- It can transform renewable energy into storage fuel, which allows the energy security in several countries, feed mobility as fuel in transport, and store energy as an additive in natural gas pipelines.
- Hydrogen is about 57 times lighter than gasoline vapor and 14 times lighter than air. This means that if it is released in an open environment, it will typically rise and disperse rapidly. This is a safety advantage in an outside environment [22].
- Some sectors, specially industry, can not be decarbonized with electrification. Hydrogen is one option viable for that purpose.
- At times renewable energy generation significantly exceeds electricity demand, instead of being curtailed by grid operators, sold into the wholesale market at depressed prices, pumping storage hydropower or the lithium-ion battery technology; excess renewable energy can be supplied to electrolysers that use the electricity to split water into hydrogen and oxygen via a process known as electrolysis. [23, 24]

2.1 Hydrogen Properties

Hydrogen is a non-poisonous, tasteless, colourless, and odourless gas and it is a material that has been known for more than 200 years. The main properties are presented in the following Table 2.1 and figure 2.1 shows the hydrogen phase diagram :

Table 2.1: Hydrogen Properties

Properties	**SI Units**	**References**
Molecular weight	1.0079	[25]
Vapor pressure at [-252.8 ℃].	101.283 kPa.	[25]
Density of the gas at boiling point and 1 atm	1.331 kg/m3	[25]
Density of the liquid at boiling point and 1 atm	67.76 kg/m3	[25]
Density (at 25 ℃ and 1 bar)	0.0813 g/L	[26]
Freezing/Melting point at (101.283 kPa)	-259.2 ℃	[27]
Boiling point at (101.283 kPa)	-252.8 ℃	[25]
Critical temperature	-239.9 ℃	[27, 28]
Critical pressure	1296.212 kPa, abs	[27, 28]
Critical density	30.12 kg/m3	[25, 27]
Triple Point	-259.3 ℃ at 7.042 kPa, abs	[27, 28]
Lower heating value, [weight/volume at 1 atm]	120 MJ/kg / 11 MJ/m3 or 3 kwh/m3	[25, 28]
Higher heating value, [weight/volume at 1 atm]	141.8 MJ/kg / 13 MJ/m3	[25]
Explosive (detonability) limits	18.2 to 58.9 vol% in air	[25]
Autoignition temperature/in air	400 ℃/571 ℃	[25]
Specific heat at constant pressure Cp	14.34 kJ/(kg) (℃)	[25, 29]
Specific heat at constant pressure Cv	10.12 kJ/(kg) (℃)	[25]

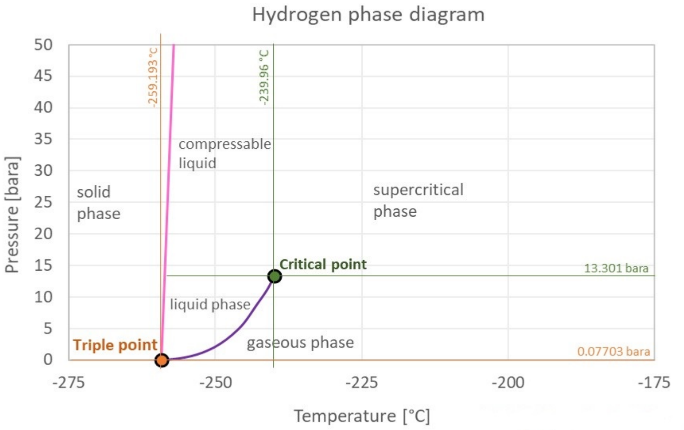


Figure 2.1: Hydrogen Phase Diagram, from [28]

As showed in table 2.1, hydrogen has a good energy density by weight, but poor energy density by volume versus hydrocarbons. It is a gas, at ambient conditions, and the lightest molecule of all substances. Therefore, hydrogen is difficult to condense to a liquid state, as in 2.1, mainly due to the very low critical point, Tc=-240.01 ℃ and Pc = 12.96 ba.

2.1.1 Safety

In terms of safety, hydrogen is non-toxic and much lighter than air, it dissipates rapidly when it is released, allowing for relatively rapid dispersal of the fuel in case of a leak which makes it relatively safer than other spilt fuels. [30]

The EIHP (Energy Institute Hrvoje Požar) working group on safety concludes that overall hydrogen is no more hazardous, than conventional fuels. However, this group, says that the many ways in which hydrogen differs from conventional fuels make it necessary to perform detailed risk assessment for every stage in the hydrogen supply chain. [31]. The primary safety concern is that if a leak goes undetected and the gas collects in a confined space, it can eventually ignite and cause an explosion. [25].

Hydrogen is a very small molecule with low viscosity, and therefore prone to leakage. In a confined space, leaking hydrogen can accumulate and reach a flammable concentration. [22]

Consequently, adequate ventilation and leak detection are important elements in the design of safe hydrogen systems. Hydrogen also burns with a nearly invisible flame, special flame detectors are required.[32, 33] The auto-ignition temperatures of hydrogen and natural gas are very similar. Both have auto-ignition temperatures over 1,000℉ [22]. Another safety issue is the mechanical failures, of vessels, pipes, etc, often caused by hydrogen embrittlement or freezing. Mainly because hydrogen has the ability to escape through materials due to its small molecule size and its destructive capability (hydrogen embrittlement) which can lead to mechanical degradation and failure to the point of leakage in certain materials.[25, 32–35] A thorough understanding of hydrogen properties and designing safety features into hydrogen systems, training in safe hydrogen storing and handling practices are key elements for ensuring the safe use of hydrogen.[33, 34, 36]

2.2 Value Chain

To frame the implementation of this ”new energy” present in this molecule, it is important first of all to define the configurations considered as priorities in the hydrogen value chain. The assessment of its sustainability is considered complex, as it includes multiple and influencing factors that at different stages of the chain are also interrelated.

In practice, the hydrogen value chain includes five stages, production/conversion from feedstocks, conditioning (compression or liquefaction), storage, distribution/transport and supply the end use. The stages could be seen in figure 2.2.

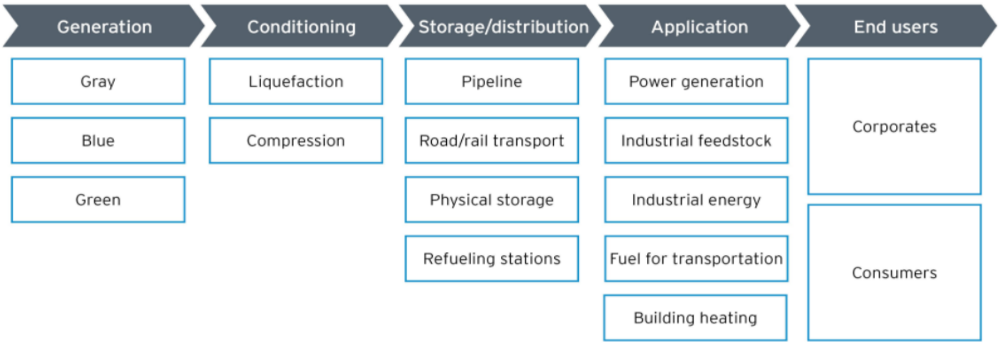


Figure 2.2: Hydrogen Value Chain, from [37]

2.2.1 Production

- The **first stage** of the hydrogen value chain comprises hydrogen **production**, with different pathways, processes and associated technologies identified. Depending on the scale required a distinction is made between large scale (centralised) and small scale (decentralised) production. This stage, as is the main thme of this work, is more deeply discussed in the following chapter 3.

2.2.2 Conditioning

Compression

Hydrogen is a gas at ambient conditions with very low density i.e. 0.0813 g/L (at 25 ℃ and 1 bar) as can be seen in Table 2.1, hence it is difficult to store H2 in an efficient and compact way. That is why it is compressed at high pressures, to store sufficient quantities of hydrogen gas.

When hydrogen is compressed to 700 bar the volumetric energy density becomes 5.6 MJ/L, which is far less than 32.0 MJ/L for gasoline. [26], and liquid hydrogen has less energy density by volume than hydrocarbon fuels such as gasoline by approximately a factor of four (i.e. density of 8 MJ/L). Several methods have been developed to attempt to increase this value

It´s represented in Figure 2.3 the division into the two categories of hydrogen compressors – mechanical and non-mechanical compressors. Mechanical compressors are the most widespread type of compressors used nowadays and are based on the direct conversion of mechanical energy into gas energy, includes systems traditionally used for gas compression such as reciprocating, diaphragm, linear and liquid compressors. In all of these, hydrogen is confined into a closed volume and compression is obtained through the reduction of this volume by means of a moving unit.

The **reciprocating compressor** is the most used typology of compressor and ensures good performances especially for high-pressure applications. It produces high-pressure hydrogen especially when a multistage configuration is used, which is particularly preferred in on-site hydrogen refuelling stations where hydrogen is generated at a pressure around 0.6 Mpa, although are not efficient for high flow rates. Embrittlement phenomena are the main drawback. [39, 40]

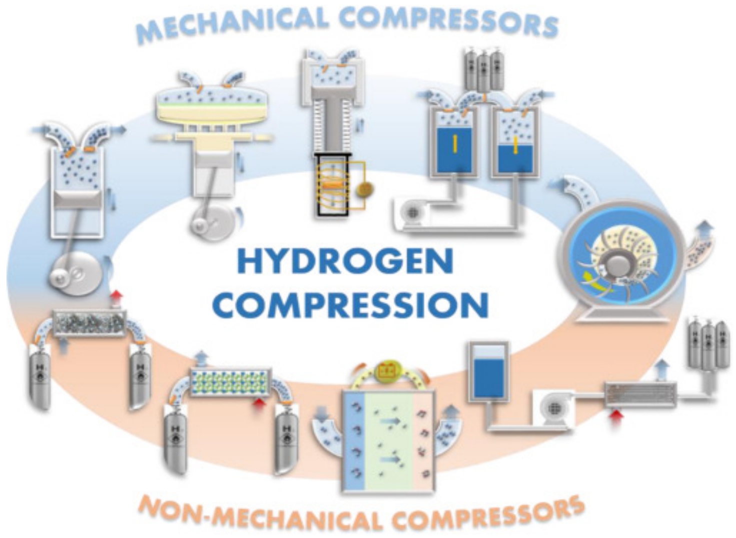


Figure 2.3: Hydrogen Compressor Types, from [38]

Still in the mechanic compressors, **diaphragm compressors** are quite suitable for applications requiring low flows of hydrogen while linear compressors are particularly used in aerospace applications and for cooling electronics. Although with high capital costs, their performance in terms of efficiency is quite good [41].

Linear compressors are especially used for cooling electronics because of their capacity to maintain low temperatures inside chips and miniature devices, for example domestic refrigeration. [38] . Innovative **ionic liquid hydrogen compressors** seem to be a very promising solution in the development of hydrogen refuelling stations in the framework of automotive applications since they allow hydrogen to be compressed to up to 100MPa in only five steps. [38, 42]. Besides there are still another type of compressors like centrifugal compressors, linear and liquid compressors (which are divided in ionic, piston and liquid rotary).

The non mechanical compressors, can be electromechanical, metal hybrid, cryogenic and absorption. As seemed, the efficiency of a mechanical hydrogen compressor is still modest in low-power applications. A possible solution might be **cryo-compression** combines hydrogen liquefaction and compression with the benefits and challenges of both storage methods. They have more than twice the volumetric efficiency of a mechanical system, nevertheless, the low temperatures involved require continuous monitoring of the system's thermal insulation and the cost of energy for liquefaction is very high, besides cryo-compressed vessels, especially in automotive applications, is that they are not yet able to ensure a 10 year-long vacuum stability [43].

Thermally-driven compressors have also proved themselves to be a good alternative as well as **electrochemical compressors**. This last one is based on the same basic principles as those of a proton-exchange membrane fuel cell (PEMFC), a proper design of an electrochemical cell allows a service life greater than 20,000h , and the achievement of high-pressure hydrogen storage, typically between 20 and 35MPa. [44] . It is also worth highlighting that one the most important advantages of this compressor is that it ensures vibration-free operation with no moving parts. [45].

The diversity of several hydrogen compression technologies makes the development of new innovative and environmentally-friendly solutions for the use of hydrogen. In Table 2.2 there is a summary of the main characteristics in a few compressors mentioned before, starting with the first four mechanical compressors and the last three non mechanical:

Table 2.2: Hydrogen Compressors Comparison

Compressor Type	**Costs**	**Efficiency**	**Stage**	**Other usage**	**References**
Reciprocating	Very Hight	45-50	Mature	-	[38]
Centrifugal	Hight	45-60	Laboratory	NG Pipeline Distribution	[38, 39]
Diaphragm	Very Hight	65-80	Under development	Fuel cell vehicles (FCV)	[38, 41]
Ionic Piston	Low	65	Under development	-	[38, 42]
Metal Hybrid	Very Hight	3 - 6	Mature	FCV, Industry	[38]
Cryogenic	Very Hight	no data	Laboratory	-	[38, 46]
Electrochemical	Very Hight	80-90	Mature	Energy storage	[38]

Liquefaction

Liquid hydrogen is produced by the cooling, expansion and the liquefaction of an expanded gaseous hydrogen feed gas stream from ambient conditions to a temperature of about 20 K (-273,15ºC) [47].

In the case of de-centralised use, hydrogen must be distributed and transported from central production facilities to intermediate end-user storages. Liquid hydrogen (LH2) may be the preferred option for bulk transport provided that energy-efficient liquefaction processes will be available. LH2 provides flexibility on the retail site as it with little effort can be transformed into any desired form on-site: liquid; gas; supercritical state.

Due to the significantly higher volumetric density of liquid hydrogen (LH2), distributing and storing the required hydrogen as a cryogenic liquid offers several advantages. As already mentioned in section 2.2.4, the distribution of liquid hydrogen for for long-distances by ship might play an important role in the future. The biggest challenges today are the relatively low efficiency of the currently used liquefaction plant cycles [48] , and high energy cost for liquefaction process (nearly, one third of energy value of produced hydrogen should be utilized for power in hydrogen liquefaction process, from published literature, best state-of-the-art performance regarding power consumption is found to be in the range 10–15 kWh/kgLH2).

2.2.3 Storage

The **third stage** of the hydrogen value chain is its **storage**.

Hydrogen storage is a materials science challenge because, for all storage methods currently being investigated, materials with either a strong interaction with hydrogen or without any kind of reaction are needed. This process basically implies the reduction of the enormous volume of the hydrogen gas, 1 kg of hydrogen at ambient temperature and atmospheric pressure takes a volume of 11 m3. There are, between others, five main storage methods, compressed hydrogen in vessels (high-pressure gas cylinders), liquid hydrogen in cryogenic tanks storage, chemical energy storage: hydrogen, biofuel, biodiesel; cryo-compressed storage and on salted caverns. In Figure 2.4 shows the relationship between the methods, density and temperature:

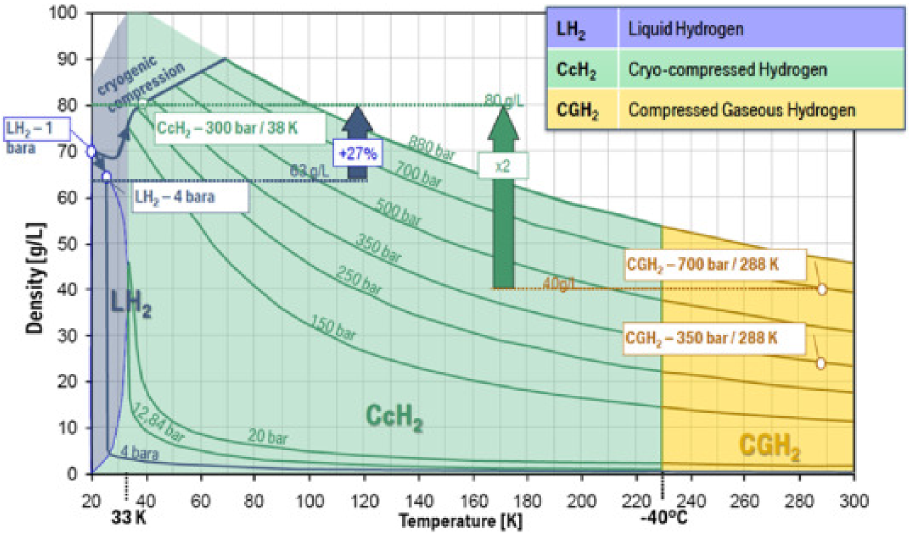


Figure 2.4: Hydrogen Storage Methods
[49]

The most used method of H2 storage is **compressing the gas in cylinders**, because is a highly efficient methodology for hydrogen storage and the energy density considering volumetric increase with the pressure increase of the gas. Usually this storage is in high pressure gas cylinders with maximum operating pressure of 20MPa (or 200bar) [50].

Currently the compressed hydrogen can be stored in 4 different types of pressures vessel, type I metallic pressure vessel is mostly use for industrial applications with pressure of 20-30 MPa, although has a limitation in storage efficiency, Type II where the cylindrical part of the vessel is wrapped with fiber resin composite; Type III and Type IV is a fully composites materials based pressure vessel, in which the composites is either made of plastic or carbon fibers embedded in polymer matrix (filament winding). [51] It is a mature technology, not too expensive, although with some challenges and opportunities like: fracture mechanics, safety, compression energy, reduction in volume, codes and standards.

Hydrogen can also be stored **liquefying** the hydrogen at -253°C , also called, cryogenic hydrogen. It is a very good efficient method of storage due to the high liquid density as seemed in Figure 2.4. It´s used usually when large quantity of hydrogen shall be transported and high gravimetric storage performance is sought. Although has some disadvantages, in terms of losses, this process is intensive energy and time consuming, and the energy content lost estimated as 40% in contrast to energy lost for compressed hydrogen, about 10% [51], also, it is difficult to store over a long period because of product loss by evaporation, not being a preferred solution for on-board storage in vehicles but more used for gas delivery using trucks which can exceed a capacity of 60,000 L. Stationary vessels can be used at customer sites for storage.The intercontinental transport of hydrogen will probably be carried out in liquid form using dedicated ships [49].

The **cryo-compressed** storage combines properties of both compressed gaseous hydrogen and liquefied hydrogen storage systems. The storage is in an insulated tank that can accept cryogenic temperatures of 20K and high pressure, at least 30MPa. The diagram depicted in 2.4 reported by BMW [52] shows that cryo-compressed H2 enables high storage density (80 g/L). The cryogenic gas is denser than liquid hydrogen. It is developed to minimize the boil-off loss (dormancy) from liquefied hydrogen storage while retaining a higher system energy density.

Finally there is the storage of hydrogen in **salted caverns**, which is also used to store for example natural gas. Natural gas storage in underground cavities has been practiced for decades. The knowledge gained by this can be transferred to the case of hydrogen storage due to the similarities in cavern design, construction and operation. [53] Materials in access wells, cavern head and transmission infrastructure are the main differences between hydrogen and natural gas storage. In the case of hydrogen, embroilment due to long-term diffusion can cause leakage and failures, especially in the steel components [53]. Unlike surface gas tanks, deep underground storages enable much higher volumes and pressures to be achieved. However, hydrogen energy density by volume is nearly one-third of that of natural gas. Thus, gaseous hydrogen energy storage is more costly than natural gas storage [54] For an efficient storage, hydrogen gas is compressed in underground salt caverns up to a pressure of 20MPa and above.

The other advantages of underground storage are the requirement of small amount of land and the higher security against external influences. An underground gas storage (UGS) facility is capable of injecting and withdrawing gas during periods of seasonal and peak demand [53, 55].

In Figure 2.5 is presented a salt cavern for hydrogen production and compressed gas storage.

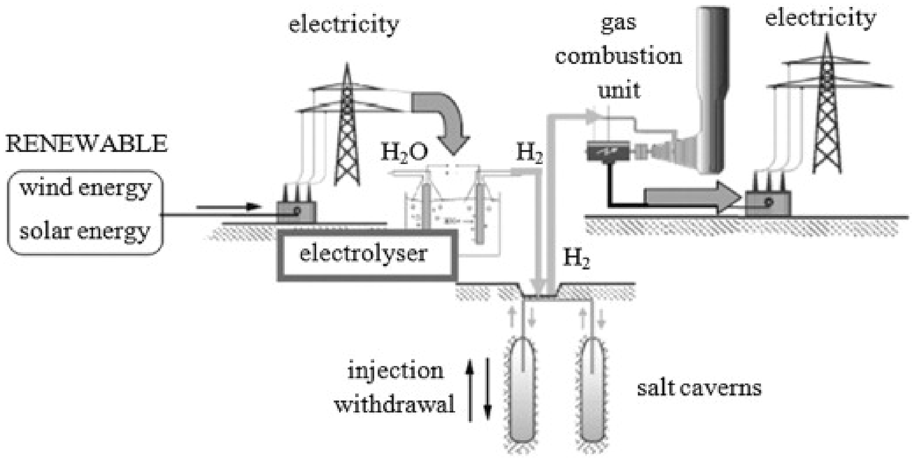


Figure 2.5: Hydrogen Salted Cavern
[53]

In Portugal, there is a national transmission network, storage infrastructures and LNG terminals (RNTIAT) [56], stated in fig. B.8, described later in section 2.3.1. Inluded in the grid, are six REN (National Grig of Energy) salted caverns, currently in operation, localized in Carriço, in the municipality of Pombal, in which gas is stored at high pressure in caverns created within a salt massif at depths of over one thousand metres. [57].

The Carriço's caverns have a total storage capacity of 3 839 GWh (322.6 Mm3); injection capacity of 24 GWh/day (equivalent to 83 000 m3(n)/h) and extraction capacity of 129 GWh/day, equivalent to 450 000 m3(n)/h, with an operational volume of gas in the cavities greater than 60% of the storage capacity of Carriço, and 71 GWh/day, equivalent to 250 000 m3, with an operational volume of gas in the cavities less than 60% of the storage capacity of Carriço [57].

2.2.4 Transport and Distribution

Hydrogen can be transported or distributed in gas, liquid, or metal hydrides form via **road, pipeline or ocean**. Compressed H2 gas can be transported from site to site in small quantities and short distances [58] , although, for long distances and a large amount of H2, using pipelines could be a better method. On the other hand, liquid H2 can largely be transported over long distances via road or ocean, while low-pressure H2 stored in metal hydrides can only be transported in a small quantity over a short distance. [59]

By Road

By **road**, the transport or distribution can be made by compressed H2 in tube-trailers, metal hydrides and by liquid H2 tankers.

Trucks hauling trailers, that are customized to carry stacked long gas cylinders, are currently used by industrial gas companies to transport compressed H2 gas over short distances (200–300 km), a trailer can carry from 2000 to 6200 m3 H2, and the pressure range for each cylinder is from 200 to 300 bar [59, 60]

The trucks hauling the tankers with liquefied hydrogen LH2 are referred to as cryogenic tanker trucks or liquid tanker trucks. Over long distances, trucking liquid hydrogen is more economical than trucking gaseous hydrogen because a liquid tanker truck can hold a much larger mass of hydrogen than a gaseous tube trailer [59, 60], in numbers, it can transport 10 times more H2 in terms of weight capacity than the tube-trailers with compressed H2.

Metal hydrides based containers can be used for transporting H2 by directly loading into a truck or railcar to the end-user sites, where it can be exchanged with the empty hydride containers [60, 61]. The main disadvantages are the cost and the low gravimetric densities (1–7 wt %). On the other hand, is a much safer way to transport hydrogen and less hazardous to transport compared to compressed H2 or LH2 transportation, besides, the existing logistics infrastructure can be used where there is no need for using pressure for transportation and storage [62].

By Pipeline

Pipelines are the most effective ones for transporting and distributing gaseous H2 in a large scale continuously (tens of thousands of m3 per hour)[59]. Pipeline infrastructure emanating from the resource field is distinguished in two main heads, high-pressure grid transport network and low-pressure grid distribution network. High-pressure lines are characterized by larger diameter and stronger piping with compression stations after regular distance intervals. Low pressure or distribution networks are identified by pressure reduction stations and relatively smaller diameter piping network [63]. Currently mostly polyethylene (PE) pipelines are used, the typical operating pressures are 10–30 bar with flow rates of 310–8900 kg/h [64] . The total H2 network in the world is estimated at around 16,000 km and mostly situated in the USA, Canada, and Europe. Overall, the H2 pipeline lengths are tiny when compared to the worldwide natural gas transport pipeline system, which exceeds 2,000,000 km. A way to expand the H2 network would, therefore, be to employ the available natural gas pipeline network, blending hydrogen into de natural gas grid, which is discussed later in section 2.3.1.

By Ocean

Finally transport can be also made by **ocean**. Liquefied natural gas has been transported by ship in the last years, for example in Portugal, the Sines Liquefied Natural Gas Terminal (LNG) is part of the set of infrastructures for the reception and dispatch of methane carriers, storage and regasification of LNG for the transport network, as well as the loading of LNG onto tanker trucks. The port facility includes a berth for ships, articulated unloading arms and discharge, recirculation and return lines for LNG steam. The discharge capacity is 10 000 m3/h of LNG for methane carriers with volumes between 40 000 and 216 000 m3 of LNG[57].

For long-distances, transport of hydrogen by ship might play an important role in the future. While the concept of transporting liquid hydrogen per ship has already been considered, the long-distance transport of compressed hydrogen, as mentioned is not attractive due to its low energy density and not feasible in existing ships. The major challenge for LH2 transportation by ship, is to keep the hydrogen chilled at minus 253 degrees Celsius, only 20 degrees above absolute zero, the coldest possible temperature to stay in liquid form, while avoiding the risk that parts of a vessel could crack.

Several projects have been implemented and explored around the world to test and study this option for hydrogen transportation. A good example was in 2014, Kawasaki along with Iwatani and J-power initiated a project to establish a supply chain model for marine transportation of LH2 . The idea is to transport H2 from Australia produced by gasification of brown coal using a LH2 tanker, the world's first liquid H2 tanker was finished in 2019 in Japan. The Suiso Frontier is a 116-meter (381-ft) ship that was fitted with a vacuum-insulated, double-shelled liquid hydrogen storage tank capable of holding 1,250 cubic meters (330,215 gal) of liquid hydrogen. [62, 65].

2.3 End User

Finally the hydrogen supply chain, as in in figure 2.2, is directed to the main end-use.

The current European and Portuguese energy strategies [11**?**], determined the selection of the following strategic configurations as end users of the hydrogen value chain: Power-to-Power, Power-to-Fuel, Power-to-Mobility, Power-to-Gas and Power-to-Industry .

In this section, the last three, Mobility, Gas and Industry, are described. Although there are also other possible end users, the Power to Fuel which basically comes to decarbonize the production of fuels, replacing them with synthetic fuels. Synthetic fuels are traditionally produced via steam reforming of methane and by gasification of coal or biomass. Finally, the power to the grid is called P2P (Power-to-Power), and allows under given operational conditions, to meet the needs of the energy system. [66]

2.3.1 Power-to-gas (P2G)

As already mentioned in section 2.2.4, a way to expand the hydrogen network would, therefore, be to employ the available natural gas pipeline network, by injection of green hydrogen with the natural gas grid.

Technically seen, this drastic changeover should be possible. After all, historically most European countries like Portugal, have switched from city gas (a mixture of about 50% CO and 50% Hydrogen to natural gas). Hereby, the grid was divided into different sectors, the replacement of city gas by NG was carried out. In the subsequent time, all end-use applications were modified or replaced and NG became the new energy carrier.

The existing natural gas (NG) transport grid mainly consists of pipelines, compression stations and pressure-reduction stations. This network serves firstly to transport a sufficient amount of energy towards any end user (actually a power flow). But is also used to store NG whenever the gas supply exceeds the demand. This (short-term) storage of NG in pipelines is called linepack, which allows an almost continuous supply of NG into the network, despite a strongly fluctuating demand pattern.[67] .

The Portuguese transmission network, storage infrastructures and LNG terminals (RNTIAT) consists of all the infrastructures for the reception and transport of gas by pipeline, underground storage and the reception, storage and regasification of liquefied natural gas (LNG). In addition to the Carriço underground storage (AS) already mentioned and the liquefied natural gas terminal (TGNL); also part of the Portuguese natural gas network are 1375 km of main pipeline and high-pressure branch lines with diameters ranging from 150 to 800 mm, intended for gas transportation. There are also currently 85 Gas Regulation and Metering Stations at delivery points (GRMS - Gas Regulation and Metering Station), which are intended for regulating the pressure and subsequent metering of the gas delivered to the distribution networks and to high-pressure (HP) customers[57].

Currently, there several projects of injection of hydrogen in the natural gas grid, one of them, is in Seixal, Portugal, led by Galp Gás Natural Distribuição with others Portuguese companies, such as Gestene and PRF, and will be the first field test in Portugal to mix hydrogen in gas. For two years will inject green hydrogen into the gasnetwork that serves a cluster of only 80 customers, of which 70 are residential and a dozen companies, including an industrial consumer [68].

Challenges

One of the challenges in pipeline transportation or distribution is the issue of the calorific value of hydrogen compared to natural gas. Currently, legislation and regulations in several countries do not allow the injection of hydrogen in natural gas networks. For example in Portugal, the Energy Services Regulatory Entity (ERSE) determines that natural gas, at the entry points of the national grid, must respect the maximum and minimum values of the Wobbe Index (IW). [**?**]

Wobbe Index is a measure of the energy content of a gas, measured on the basis of its calorific value per unit volume at standard pressure and temperature, in this case the gas network, when faced with a change in the fuel gas that feeds them.[69] The limits of the Wobbe Index imposed for natural gas transported in the national network, respectively 57.66 MJ/m3 (maximum IW) and 48.17 MJ/m3 (minimum IW). Based on these parameters, it is possible to calculate a maximum calorific value of 13.51 kWh/m3 (PCSmax) and a minimum of 10.05 kWh/m3 (PCSmin). Considering an average CV for natural gas of 11.9 kWh/m3, taking into account the natural gas circulating in the transport network, and of 3 kWh/m3 for hydrogen [28], as mentioned in section 2.1, means that the injection of hydrogen in the natural gas transport network will translate into a reduction of the calorific power of the gas that will circulate in the networks, and this constitutes a problem that limits the percentage of H2 injection so as not to exceed the limits of the Wobbe index.

In Figure 2.6, shows the maximum calorific value (13.51 kWh/m3) (PCSmax) and a minimum (10.05 kWh/m3) (PCSmin) resulted from the Wobbe index, as well as the value (in blue) for the mixing natural gas with hydrogen. It can be concluded, from a theoretical point of view, that up to a percentage of approximately 22% of incorporation of hydrogen in the natural gas the calorific value of the gas remains within the limits currently imposed by the Portuguese's regulations.

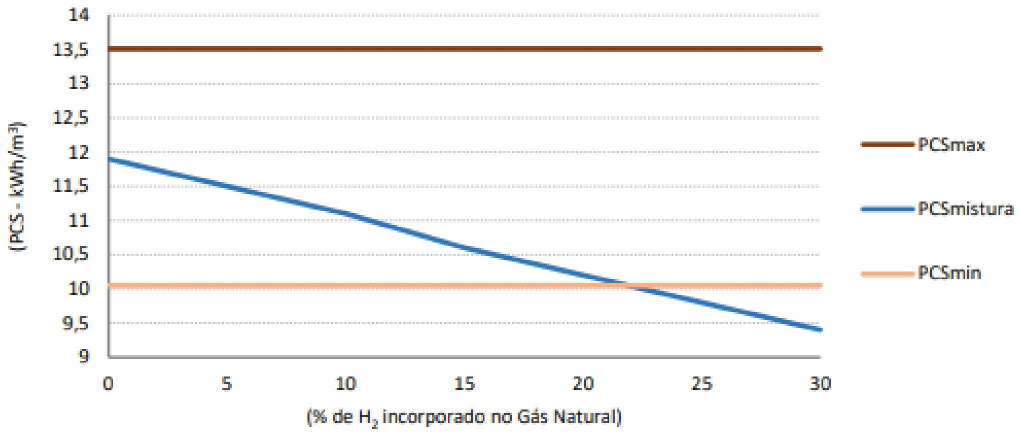


Figure 2.6: Calorific value of the gas in relation to the injection of H2 [**?**]

Another important factor, already referred in section 2.2.2, that require some attention is the high compression needs, requiring compression of a volume three times as large as when natural gas is used, due to the different density.

Also, as referred in section 2.1 The risk of hydrogen embrittlement is complicated to predict. It does not only depend on the material of the pipeline, but also on the pipeline's history. The larger the pressure fluctuations in the past have been, the higher the risk of hydrogen embrittlement and material fatigue. Therefore, only intensive testing of pipelines and welds will give a definitive answer about this potential problem [70].

In this sense it is also worth discerning whether the injection of h2 is viable with these limitations, or whether the investment in a new network adapted to the properties of this molecule, i.e. with 100% hydrogen.

2.3.2 Power-to-Industry (P2I)

The vast majority of industry's GHG emissions, 90 percent, consists of CO2 . Half of industry's CO2 emissions result from the manufacture of the four industrial commodities —ammonia, cement, ethylene, and steel. [71]

Industrial companies could lower their CO2 emissions with a combination of approaches. The most promising are energy-efficiency improvements, the electrification of heat, the use of hydrogen made with zero-carbon electricity as a feedstock or fuel, the use of biomass as a feedstock or fuel, and carbon capture and storage (CCS) or usage (CCU). [51, 72].

Currently, there are already several companies and promoters with P2I projects underway or in the project phase, which demonstrates the interest and momentum already generated in the field of hydrogen and in particular in the field of this value chain. For example, the case of UTIS - Ultimate Technology To Industrial Savings (a Portuguese company), which provides optimization of continuous combustion in industrial units, such as cement factories, and has the ongoing project of injection of small quantities of hydrogen (H2), produced locally, and oxygen (O2) in the combustion system. [71] Another example is the H2Future in Austria, the project aims to produce “green” hydrogen – using electricity generated from renewable energy sources – for use in industrial processes such as the production of chemicals, iron and steel, food and semiconductors, as well as in oil and gas refineries and in mobility applications. It started in January 2017 and the pilot plant was completed and set in operation in November 2019 [73].

Challenges

First of all, CO2 emissions that result from feedstocks cannot only be abated by changing the fuel type, process modifications are also necessary. Second, 35% of emissions from these sectors come from burning fossil fuels to generate high-temperature heat (in the focus sectors, process temperatures can reach 700 ℃ to more than 1600 ℃). Reducing these emissions by switching to alternative fuels, such as zero-carbon electricity, would be difficult because this would require significant changes to the design of furnaces. Third, industrial processes are highly integrated, so any change to one part of a process must be accompanied by changes to other parts of that process. Finally, production facilities have long lifetimes, typically exceeding 50 years with regular maintenance. Changing processes at existing sites requires costly rebuilds or retrofits. Therefore, economic factors add to the challenge of abating emissions.

2.3.3 Power-to-Mobility (P2M)

As stated in chapter 1, in fig. 1.2, the main setback for achieving a carbon-neutral society through the energy transition is the fossil fuels, and in particular, the transportation sector, specially, the engine with internal combustion. Hydrogen and batteries present a solution for reducing the negative impact that the sector of mobility has on the global environment. [74] Once in the aerospace industry hydrogen was used ,and currently starting in automobiles, instead of conventional internal combustion engine vehicles (ICEV), by two possible pathways, which are direct use in the internal combustion engine and, indirect use through fuel cells.

The Fuel Cells Eletric Vehicles, FCEVs, are the most notable example of hydrogen technology application. Fuel cells are electrochemical converters; transforming hydrogen (or energy sources containing hydrogen) and oxygen directly into electricity. The hydrogen fuel cell, invented in 1839, permits the generation of electrical energy with high efficiency through a non-combustion, electrochemical process and, importantly, without the emission of CO2 at its point of use. [75] According with a useful summary of the different types of fuel cells has been produced by the US Department of Energy [76] , the typical and widely-used fuel cell is the so-called proton exchange membrane fuel cell.

Fuel cells are especially well suited for utilization in local transport systems, like public city buses. This is vital in the first stage of hydrogen expansion, where the hydrogen refuelling stations (HRS) network is not yet branched enough. [74]

For example, recently, in Cascais, Portugal, two hydrogen-powered buses will integrate the municipal road transport service, namely the routes in the area of the Natural Park of Sintra-Cascais. They are equipped with Toyota's fuel cell, offering an autonomy of around 400km with a single supply, and also benefit from very reduced refuelling times compared to the usual charging of electric vehicles. Components such as the hydrogen tanks, the batteries and the fuel cell, which are located on the roof, allow a lowered floor and optimisation of the vehicle interior. In fig. 2.7 is presented Cascais's project. [77]

Figure 2.7: Cascais's Project [77]

Fuel cell electric vehicles running on hydrogen currently use filling stations, which deliver hydrogen at 70MPa pressure. Very few stations, worldwide, currently have hydrogen produced from renewable sources like solar energy.

Several countries have been expressed their strong intention to implement a Hydrogen Society applying fuel cells, for example the case of Japan, two out of three leading world car manufacturers of FCEVs are from Japan (the third being from the Republic of Korea). Currently, Japan has the largest network of hydrogen refuel stations (HRSs) in the world, with a total of 127 hydrogen stations operating across the country, followed by Germany (81), US (California (64)), South Korea (34), and China (61) [78]. Seven different models are already commercially available, Mercedes Benz GLC F-Cell; BMW iHydrogen Next; Honda Clarity, the Toyota Mirai I and II; the Hyundai has two models, Nexo and ix35; and the Hyperion XP-1. It is important to mention that fuel cells can also be used in ships, forklifts and other transportation means.

Besides both being carbon free, the Fuel Cells Eletric Vehicles (FCV) and battery electric vehicles (BEVs) have been compared, for example a light fuel call vehicle like Toyota Mirai with an average electric vehicle and for a range of 320Km [79]:

Table 2.3: Summary of fuel cell EV compared the battery EV for 320Km range

Properties	**Fuel Cells Eletric Vehicle** [78–80]	**Battery Electric Vehicles** [78, 79]
Fuelling time (hours)	0.07	1-12
Vehicle weight (kg)	1259	1648
Greenhouse gases (g/km)	180	285
Storage volume (Liters)	179- 382	-
Fuel cost per km (cents/km)	3.36	1.63
Range (Km)	300-500	150-500
Price (eur)	84000 (Hyundai) 60000 (Toyota)	27000 -36000

Chapter 3

Hydrogen Production

In this chapter, several hydrogen production technologies are explained, specially focusing on electrolysis. From electrolysis technologies, is stated the technologies available as well as the chemical processes associated, and all the main advantages and disadvantages. Some key performance indicators are used.

3.1 H2 production by source

Presently, the entire worldwide hydrogen production is around 500 billion cubic meters (40,6 billion kg) per year [81], and it can be produced from a variety of processes and the definition of the hydrogen depends of the source of production.

The most widely used hydrogen production technology in recent years is natural gas steam reforming and contributes more than 45% of hydrogen products, followed by oil reforming and coal gasification as shown in Figure 3.1

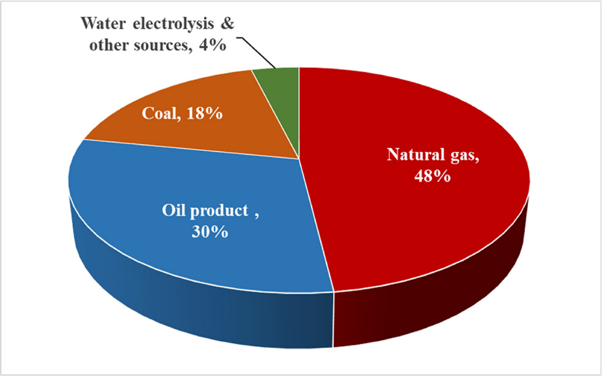


Figure 3.1: Current hydrogen gas product sources , from [82]

Among many hydrogen production methods, eco-friendly and high purity of hydrogen (99.999%) can be obtained from electrolysis of water to produce pure hydrogen and oxygen it is called as water electrolysis. [83]. Currently, there is no significant hydrogen production from this type, 0.5-4% [7] is generated from production through electrolysis. Although, the dominant production varied in the past.

Resuming:

- Between 1900 and the 20th decade, the only way of producing hydrogen was called gasification of coal with water.
- Between 1920 and around 1960, electrolysis cwas the dominant, a mature technology, being the alkaline the most competitive model.
- When the price of natural gas dropped (90% of methane) nearly in the 1950's to 5 to 10 €/MWh, the main production became the steam reforming the most competitive. Mainly to feed the chemical industry in catalytic cracking, in the agrochemical industry, in the production of ammonium nitrate and chemicals, namely methanol for polymer induction.

In the current context, the price of natural gas has risen sixfold compared to last year, from 18€/MWh to 108€/MWh [84]. Along with the rise in the price of CO2, which rose from 7€/ton to 80€/ton between 2018 and 2021.

In terms of production, hydrogen can be classified as grey, brown, blue or green.

Grey hydrogen is the most common form and it contributes almost 50% of the world's hydrogen production. It is generated from natural gas, or methane, through a process called steam reforming. The hydrocarbon is decomposed into hydrogen and carbon and it can be done with any organic material. The reaction is represented by this equilibrium:

$$CH_4 + H_2O \rightleftharpoons CO + 3H_2$$

Among the advantages of this process are fuel flexibility, relative simplicity and compactness, clean carbon by-product, and reduction in CO2 and CO emissions. [81, 85, 86]

Brown hydrogen (also called black) is the most environmentally damaging, is produced using coal gasification where the emissions are released to the air. During the process, coal is partially oxidized with steam and oxygen in a high-temperature (more than 700 degrees) and high-pressure reactor.

$$3C + H_2O + O_2 \rightleftharpoons 3CO + H_2$$

This hydrogen is also called as brown or black depending the type of coal used: brown (lignite) or black (bituminous) coal [87].

Blue hydrogen is the grey or brown/black hydrogen whose CO2 emitted during production is sequestered via carbon capture and storage (CCS).

Green hydrogen (or clean hydrogen) is produced majorly through electrolysis using renewable energy sources (RES) and it is a near-zero carbon production route [88]. Green Hydrogen production from biomass has also proved to be a cost effective solution both through the use of supercritical water gasification and fermentative processes. [38] It can be produce from one or more renewable power plants (hybrid system).

In Figure 3.2, shows the several forms of production as well as the colors associated

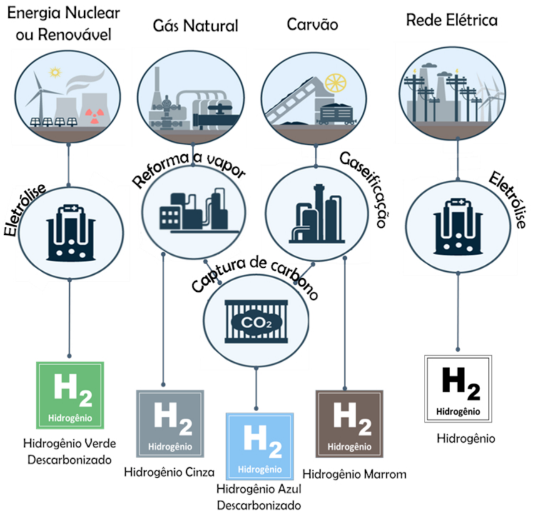


Figure 3.2: Hydrogen Production

Besides, there are also the pink and turquose hydrogen, which are produced from nuclear and methane pyrolysis. As seen in Figure 3.1, green hydrogen has low a production rate, International Energy Agency (IEA) estimates that less than 0.4% of hydrogen is produced by the electrolysis of water powered by renewable electricity [89]. It has a low rate of production, mainly because the efficiency hydrogen production by water electrolysis is too low to be economically competitive.

From IEA (International Energy Agency), in 2018 a comparative of cost of production of each production by source in US Dollars. is showed below in Figure 3.3, from [90].

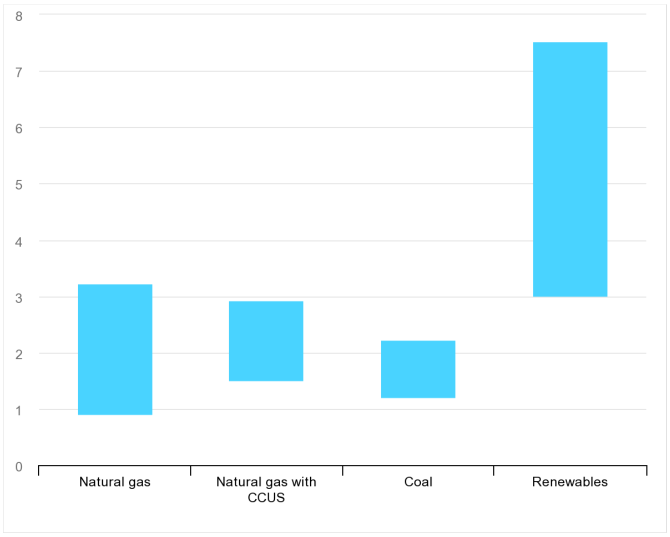


Figure 3.3: Comparative graph of cost of hydrogen production from several sources, from [90]

From Figure 3.3, an average price of hydrogen production from fossil fuels is around 2 €/kgH2. On the other hand, cost of production of hydrogen from water electrolysis powered by renewable energy can go from 2,8€/kgH2 to 7€/kgH2.

In this chapter, the **three major hydrogen electrolysis** methods from renewable energy sources along with recent developments on efficiency, durability, cost effective electrocatalysts and its challenges will be discussed and summarized.

3.2 Electrolysis

History

Jan Rudolph Deiman and Adriaan Paets van Troostwijk used, in 1789, an electrostatic machine to make electricity which was discharged on gold electrodes in a Leyden jar with water. [91]

Later, in 1800 Alessandro Volta invented the voltaic pile, and a few weeks later the English scientists William Nicholson and Anthony Carlise decompose water into hydrogen and oxygen in England. The French military in 1890 constructed a water electrolysis unit to generate hydrogen for use in airships by Charles Renard. In the 1970s , the development of the proton exchange membrane electrolyzer (that will be explained further) offered several advantages over alkaline electrolyzers with limited use in small hydrogen and oxygen production capacities due to expensive materials and a limited lifetime [92]

Today electrolysis is still expensive, but companies like Stuart Energy in Toronto and Norsk Hydro in Norway [93] see the costs rapidly declining. Others like Proton (now listed as Distributed Energy Systems Corporation, DESC on Nasdaq) integrate hydrogen systems for stationary power supply to reduce costs even more. [94]

The world's largest renewable powered electrolyser commenced operation at the Fukushima Hydrogen Energy Research Field in Japan in March 2020. The electrolyser has a capacity of 10MW, and is powered by 20MW of solar PV cells (Renew Economy 2020). Assuming that the facility has battery storage sufficient to store the excess energy produced by the PV array for later use by the electrolyser, it has the capacity to produce about 2.4tonnes of clean hydrogen per day. Much larger scale renewable hydrogen production facilities are currently being planned and developed [24].

Electrolysis's Concept

In the electrolysis process, water molecule is the reactant it is dissociated into hydrogen (H2) and oxygen (O2) under the influence of electricity.

Like fuel cells, a water electrolysis cell consist of an anode and a cathode, also called electrodes, placed front-to-front and separated by a thin layer of an ion-conducting material which is called electrolyte. They could be made of an aqueous solution containing ions, a proton exchange membrane (PEM) or an oxygen ion exchange ceramic membrane. Electrolysis of water is not a spontaneous phenomenon, it needs an external intervention (power source), so a direct current (DC) is applied from the negative terminal of the DC source (from the anode) to the cathode (seat of the reduction reaction), where the hydrogen is produced. The reactions vary with the technologies used, and it will be explained sections 3.2.1 , 3.2.2 and 3.2.3. [95–97]

The cell

A cell can have different designs and materials, and those characteristics give them the different advantages and disadvantages. The resulting assembly of cells is called a stack. Three of the most common designs of electrolysis cell are:

- **Gap-cell**: In the gap cell the electrodes are submerged in the electrolyte with a separator to avoid recombination of the products involved. Although being a simple design, the gap between the cathode and the anode cause high ohmic loses [92].

- **Zero gap cell**: Has a design to reduce the gap between the electrodes consequently ohmic loses reduce. The zero-gap cell has become state-of-the-art in modern alkaline electrolyzer. Zero gap system is able to reduce cell voltage in alkaline water electrolysis.

- **Solid polymer electrolyte cell**. Has a separator constituted by a thin film (ion-conducting polymeric film) that conducts the electric charge and replaced the liquid electrolyte used in the gap and zero gap cells. The PEM and SOEC electrolysers use this solid polymer electrolyte cell design [92, 98].

Types of Electrolysis

Water electrolysis can be classified in to the four types based on their electrolyte, cell design, operating conditions, and ionic agents (OH-,H+,O2-), however operating principles are both the cases same. The four kinds of electrolysis methods are: [7, 83].

- Alkaline water electrolysis (AWE) ,

- Solid oxide electrolysis (SOE),

- Proton Exchange Membrane (PEM) water electrolysis

- Microbial electrolysis cells (MEC)

Microbial electrolysis, is under development, being a recent technology (invented in 1931 by Barnett Cohen) and also because there is less data and information available, this study is going to be focused on the first three. Solid Oxide (SOE) is also under development, although already with some data available.

The different technologies are represented in figure 3.4.

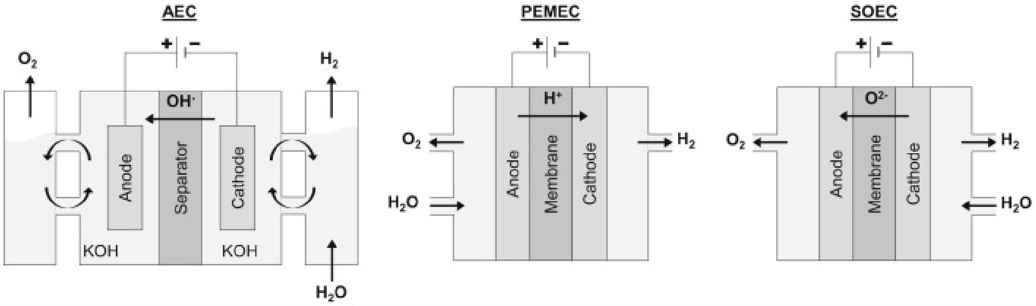


Figure 3.4: Alkaline, PEM and SOEC Electrolysis [99]

3.2.1 Alkaline Water Electrolysis (AWE)

History

Hydrogen production by alkaline water electrolysis is an already well established technology and is a simple and suitable technology for hydrogen production.

It is a technology up to the megawatt range for commercial level in worldwide and the phenomenon first introduced by Troostwijk and Diemann in 1789.

With the invention of the Gramme machine in 1869 by Zénobe Gramme, water electrolysis became an economical method of producing hydrogen. A technique for industrial synthesis of hydrogen and oxygen through water electrolysis was developed later in 1888 by Dmitry Lachinov. By 1902, more than 400 industrial water electrolyzers were already in operation. Figure 3.5 illustrates such early plants used for water electrolysis [100, 101]. As stated in the introduction in chapter 1, the period between the 1920s and the 1970s was the ”golden age” for the development of water electrolysis technology, when most of the traditional designs were created. Driven by the industrial need for hydrogen and oxygen, the knowledge established in the first stage was applied to the industrialization of water electrolysis technologies [101].

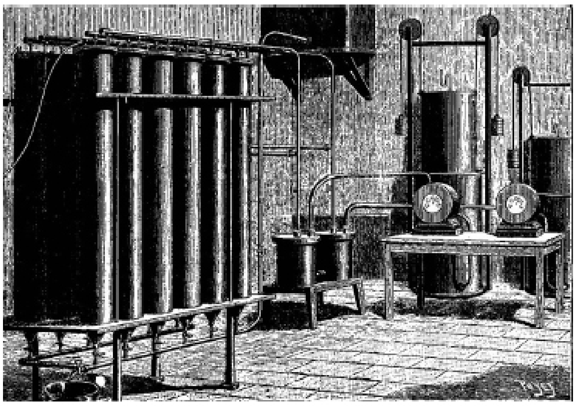


Figure 2. *Early plants for the industrial electrolysis of water*[32]

Figure 3.5: Early plants used for water electrolysis, from [101]

Process

The two electrodes are separated by a diaphragm (ZrO2) that must also be permeable to the hydroxide ions and water molecules. The diaphragm has the function of keeping the product gases apart from one another for the sake of efficiency and safety [102]. The electrolyte is Potassium hydroxide (KOH) in liquid state.

In terms of design, alkaline cells with the gap-cell design are limited in the maximum operating current density of approximately 400 mA/cm2, because of gas screening effects appearing during gas production at higher current densities. Later the zero-gap design was introduced for alkaline electrolyzers, being a compact cell arrangement, allowing gases and liquids to be transported to and from the electrodes by utilizing various shapes of separators [103, 104].

In the next figure 3.6 is presented the Alkaline electrolysis technology:

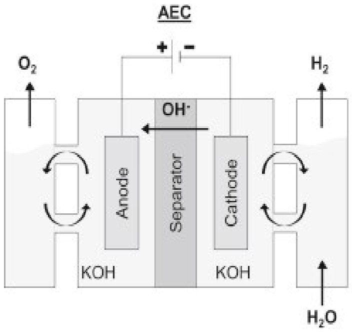


Figure 3.6: Scheme of the working principle of an alkaline electrolysis cell [99]

Equations

The next chemical equations, describe the process in the cathode where hydrogen and the charge carrier OH- are produced, and in the anode where the water and oxygen are produced together with 2 electrons. The sum of these 2 equations give the water splitting in hydrogen and oxygen:

Cathode:

$$2H_2O + 2e^- \rightleftharpoons H_2 + 2OH^-$$

Anode:

$$2OH^- \rightleftharpoons 1/2O_2 + 2e^-$$

Overall cell:

$$H_2O \rightleftharpoons H_2 + 1/2O_2$$

There are some issues associated with the alkaline electrolyzers, some of them: the low partial load range, corrosive electrolyte, slow dynamics, Gas permeation, durability and safety [83, 92].

The diaphragm does not completely prevent the product gases from cross-diffusing through it. The diffusion of oxygen into the cathode chamber reduces the efficiency of the electrolyzer, since oxygen will be catalysed back to water with the hydrogen present on the cathode side. Then, another drawbacks is the low maximum achievable current density, due to the high ohmic losses across the liquid electrolyte and diaphragm. And finally, a problem, also attributed to the liquid electrolyte, is the inability to operate at high pressure, which makes for a bulky stack design configuration.

3.2.2 Proton Exchange Membrane Water Electrolysis (PEM)

History

After the alkaline water electrolysis, in the 1960s, it was invented a new and revolutionary electrolysis by the General Electric, the first water electrolyzer based on a solid polymer electrolyte concept. This concept was idealized by Grubb where a solid sulfonated polystyrene membrane was used as an electrolyte. Also referred to as proton exchange membrane or polymer electrolyte membrane water electrolysis, both with the acronym PEM.

It was then sold to United Technologies in the 1980s. Throughout this period of time, PEM electrolysis was used primarily for life support in closed environments such as space and submarines, leveraging oxygen generation rather than focusing on hydrogen.

PEM electrolysis was firstly applied to commercial applications at a small scale, for laboratory applications and weather balloon filling. Larger systems were then introduced for power plant cooling and small process lines for metal heat treating and glass manufacturing [83, 98].

Currently, PEM electrolyzers are predicted to become the most prominent technology in the close future

The Process

The PEM cell is composed by a bipolar plate, the anode collector, membrane electrode assembly (MEA) and the cathode current collector. In the following figure 3.7 it can be noticed the typical PEM water electrolyzer, as the PEM cell stack and finally the four cell components; the Bipolar plate, Anode current collector, MEA, and Cathode current collector.

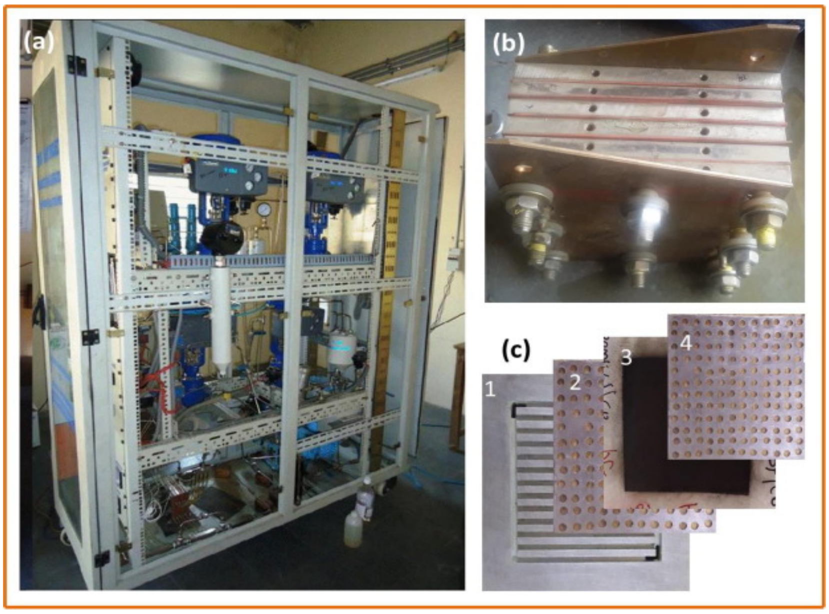


Figure 3.7: (a) Overview of typical PEM water electrolyzer (b) PEM cell stack (c) Cell components; 1-Bipolar plate, 2-Anode current collector, 3-MEA, 4-Cathode current collector. [83]

In this technology is used an acidic membrane as solid electrolyte, usually made of Nafion, Fumapem, Flemion, or Aciplex [83], more or less between 20 and 300 µm in thickness. This membrane is used instead of a liquid electrolyte, that conducts H+ ions from anode to cathode, and separates hydrogen and oxygen that are produced in the reactions. It is responsible for providing high proton conductivity (0.1 +- 0.02 S cm-1) as the electrolyte in the alkaline electrolysis, but also provides low gas crossover, compact system design and high-pressure operation [98].

It has a cross-linked structure and strongly acid character due to the presence of functional groups of the sulfonic acid type (SO3H) [83]. As represented in figure 3.7, together, the membrane and the electrodes, typically made by noble metals such as platinum and iridium, constitute the membrane electrode assembly (MEA), which are pressed between the current collectors and bipolar plates usually made by titanium [83, 96, 98]. Current collectors have a significant role on the overall cell mechanism and efficiency, since they allow the electric current to flow between the electrodes and end-plates, and act as gas diffusion layers of the products

The PEM electrolyzer can operate at a current density of 2000 mA cm–2 at 90 ℃, at about 2.1 V [102]. The low membrane thickness, is in part the reason for many of the advantages of the solid polymer electrolyte. [105]. It also provides high current density (above 2Acm-2), good efficiency, fast response, operates under lower temperatures 20 to 80 degrees. All the data is available in the next table 3.1.

This technology produces ultra pure hydrogen and also produced oxygen as a by-product [106]. On the other hand, one of the main challenges, is to reduce the production cost and to maintain the high efficiency. Since then, substantial research has been devoted to improve the PEM water electrolysis components, and as a result, this technology is approaching commercial markets [106].

In the next figure 3.8 is presented the electrolysis technology:

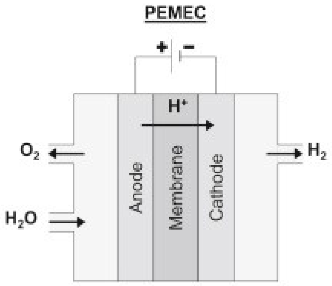


Figure 3.8: Scheme of the working principle of a PEM electrolysis cell, from [99]

Equations

Anode:

$$H_2O \rightleftharpoons 2H^+ + 1/2O_2 + 2e^-$$

Cathode:

$$2H^+ + 2e^- \rightleftharpoons H_2$$

Overall cell:

$$H_2O \rightleftharpoons H_2 + 1/2O_2$$

3.2.3 Solid oxide electrolysis (SOE)

Dönitz and Erdle were the first to report, results from a solid oxide electrolyzer (SOECs) from within the HotElly project at Dornier System GmbH using a supported tubular electrolyte in the 1980s. It was a big attraction due to the electrical energy conversion into chemical energy along with producing the ultra-pure hydrogen with greater efficiency. In terms of operation has the particularity of operation at really high pressure and high temperatures 500–850 ℃ and utilizes the water in the form of steam [83, 107].

SOECs has the potential to produce hydrogen from steam with higher electrical efficiency than alkaline or PEM technologies, taking advantage of the energy in the steam to split water into hydrogen and oxygen.

It can be observed in the following figure 3.9, which provides an overview of the split between electrical energy and heat that can be used to provide the energy required to produce the electrolysis [108]. For processes where an exothermic reaction occurs, the energy in the steam could effectively be supplied with no further energy input requirement. For example for the ammonia or methanol production.

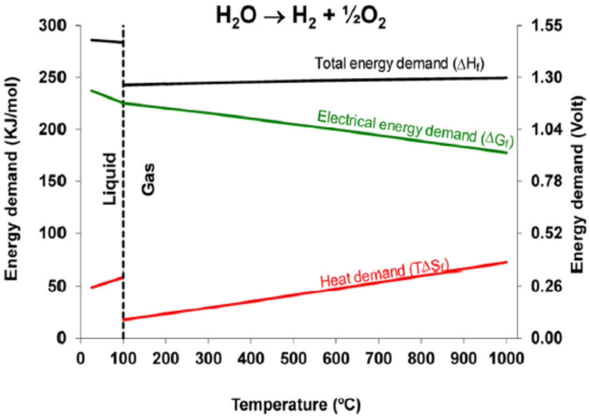


Figure 3.9: Thermodynamics for H2O electrolysis at atmospheric pressure

The higher operating temperature makes advantageous compared to low temperature electrolysis, although, the SOE has some issues related to lack of stability and degradation, which have to be solved before going to commercialization on a large scale.

SOEC is currently still under development but research has grown exponentially in the last decade, companies, research centres and universities around the world have shown interest in this field. For example, Relhy project, a remarkable project funded by the European Commission mainly focused on the development of novel, improved, low cost, and highly durable materials for SOECs. They are also focused on the development of the inherent manufacturing processes, and the integration in an efficient and durable SOEC. [109]

An example of SOEC technology from industrial technology companies, such as Haldor Topsoe from Europe and Toshiba from Japan, are shown in 3.10. These systems are currently only being manufactured on the kW scale [110].

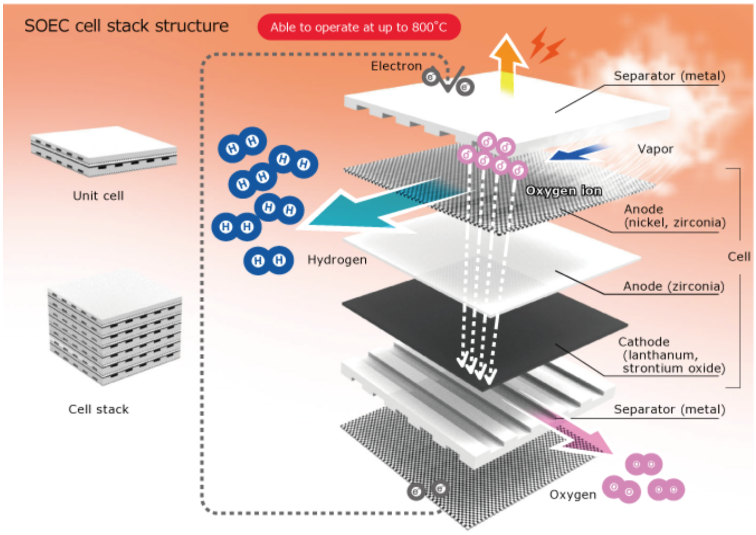


Figure 3.10: Toshiba solid oxide electrolytic cell , from [110]

This technology has a good potential for the future mass production of hydrogen, but for that, the issues related to the durability of the ceramic materials at high temperature and long-term operation have to be solved. For future developments, the understanding of the structure and electrochemistry of the materials is essential in order to solve these reactions.

In Figure 3.11 is presented the electrolysis technologies stated before, as well as the equations of the hydrogen production process.

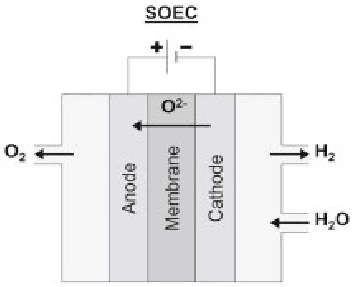


Figure 3.11: Scheme of the working principle of a SOEC electrolysis cell, from [99]

Cathode:

$$H_2O + 2e^- \rightleftharpoons 2H^+ + O^2-$$

Anode:

$$O^2- \rightleftharpoons 1/2O_2 + 2e^-$$

Overall cell:

$$H_2O \rightleftharpoons H_2 + 1/2O_2$$

Other Conversion Technologies

Besides these three technologies, there are also some others under development, like the Microbial electrolysis cell (MEC) technology, that is achieved by organic matter including renewable biomass and waste waters. It was firstly presented in 2005, is still under development and having several challenges towards hydrogen production rate, high internal resistance, electrode materials and complicated design need to be addressed before and commercialization of this technology [111]. Other example is the Anion exchange membrane electrolysis, a new approach in the alkaline electrolysis, which many research organizations and universities are actively involved in this research, largely due to its low cost and the high performance it offer. But it still requires further investigations, specially in power efficiency, membrane and catalyst stability, ease of handling, reduction of cell cost, etc. [106]

3.2.4 Overview

In order to compare the chemical processes as well as other important indicators already mentioned in each technology, the following Table 3.1 compares each electrolysis. Although the conditions or components can present significant variations among different companies.

Table 3.1: Alkaline, PEM and SOEC Electrolysis Comparison, from [95–97]

	Alkaline	PEM	SOEC
Electrolyte	20–30% KOH	Polymer membrane	Yttria stabilised Zirconia (YSZ)
Electrolyte State	Liquid	Solid (polymeric)	Solid (ceramic)
Charge carrier	OH-	H+	O2-
Temperature [ºC]	55-90	55-90	500-1000
Oxygen reaction (OR) catalyst	Ni2CoO4	Ir/Ru oxide	(La,Sr)MnO3
Hydrogen reaction (HR) catalyst	Ni	Platinum	Ni-YSZ
Separator	ZrO2	Solid electrolyte	Solid electrolyte
Operating pressure	1-30 bar	$< 70bar$	1 bar
Cell area (m2)	< 4	< 0.3	< 0.01
Applicability	Commercial	Commercial	Laboratory scale / Demonstration

3.3 Key Performance Indicators

In order to compares more deeply each technology, in this chapter, it will be used some essential key performance indicators, some of them already stated before.

Some of the KPI's below are: maturity, scalability of technology, durability, oxygen generation, water requirements (consumption and quality demand), flexibility and reactivity to changes in input conditions and loading effect, and capital investment (CAPEX) and operational (OPEX) costs.

3.3.1 Maturity

In terms of maturity, as referred, Alkaline Water Electrolysis is the oldest, firstly presented in 1789, it is a well established technology and constitutes the most extended electrolytic technology at a commercial level worldwide. Being followed by Proton Exchange Technology in the 1960s and the Solid Oxide electrolysis in the 1980s and it is in laboratory stage. In Figure 3.12 is presented the Cumulative capacity of the Alkaline and PEM technologies, in 2018, over 20 MW of electrolyser capacity has been commissioned and, since then, projects of up to 20 MW and 100 MW been announced [112].

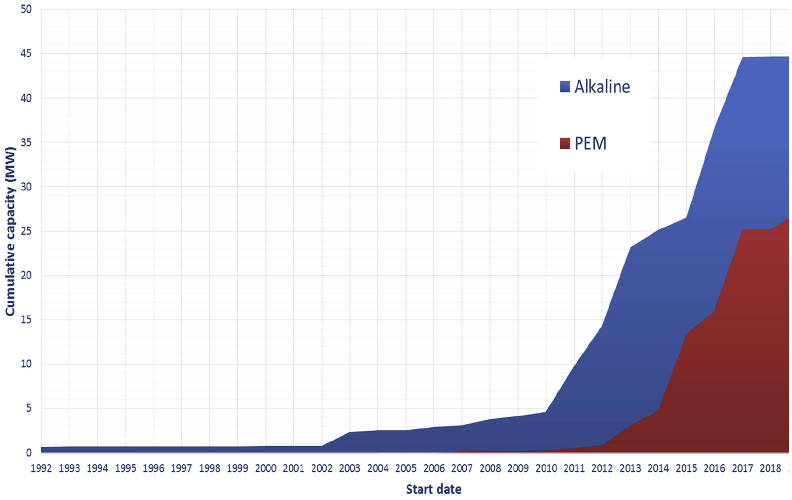


Figure 3.12: Cumulative capacity of the Alkaline and PEM technology, from [112]

3.3.2 Scalability of the Technology

The scale of the water electrolysis projects to date is quite low, so the size of the modules installed by the Original Equipment Manufacturer (OEMs) is, at most, in the 2 MW range. However, because of the growing interest of governments in green hydrogen already mentioned in chapter 1 , the electrolyser size requested by end-user quotations, pre-orders and orders that the OEMs are currently receiving is much larger, in the hundreds of MW or even in the GW scale. As such, most of the OEMs have pre-engineered larger-size modules that could be installed at large-scale plants.

- In **Alkaline** technology, Thyssenkrupp is one of the most relevant vendors in water alkaline electrolysers, has pre-engineered 20 MW modules.The 20 MW modules, with an approximate hydrogen production of 4,000 Nm3/h, can be installed in parallel to reach the required hydrogen capacity, up to GW scale [110]. Another commercial producer is Nel Company with several series of electrolysers Alkaline in the series A, and PEM in series M,C, H and S.

- With regard to **PEM** technology, one of the most remarkable scale-up design is the one developed by Siemens. The largest module is 17.5 MW that consists of 24 stacks and several separators with an approximate hydrogen production capacity of 3,650 Nm3/h [113]. Similar to the alkaline electrolysers case, in a GW-scale design, the modular installation of equipment will be mainly applicable to the electrolysis unit and the dedicated electrical systems (transformers and rectifiers). The compression and purification stages may be more cost-effective if larger equipment is installed.

- The **SOEC** is a technology still in the demonstration phase, with projects in the kW range.

IRENA produced with up-to-2018 data the expected number of projects and their sizes for the coming years. As in the following Figure 3.13:

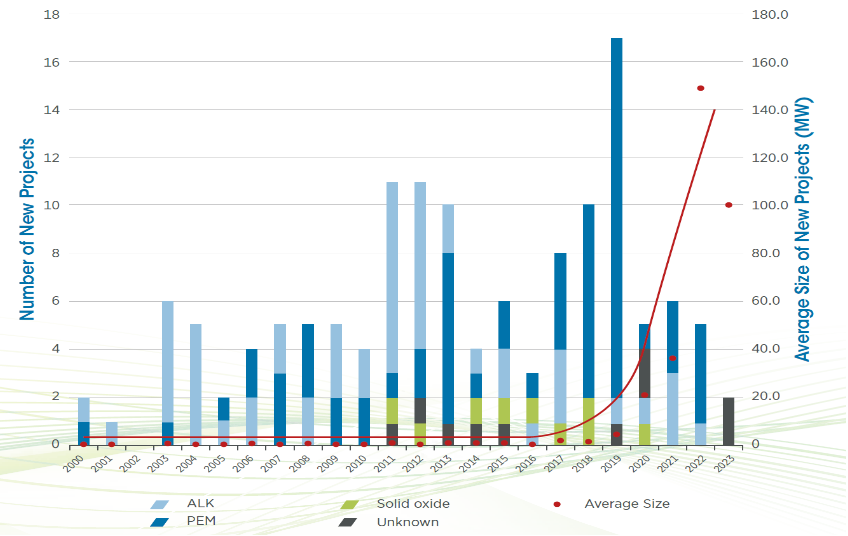


Figure 3.13: Timeline of power-to-hydrogen projects by electrolyser technology and project scale [6]

3.3.3 Durability

In terms of durability, Alkaline is the one that processes long term stability, also because has much more maturity [114]. Although, the annual degradation of the alkaline electrolyser cells falls within the 1 to 1.4% range. [104]

For PEM, the expected annual degradation is a bit higher, in the 1.2 to 2% range. Today, the annual degradation of the solid oxide cells is much higher, in the 4% to 8%.The stack replacement or refurbishment needs to be performed every 8 to 10 years for both alkaline and PEM, the decision as to when to do it is not only a technical decision but an economic one, since the installation of new stacks will need some investment but will also reduce significantly the OPEX. After the replacement/refurbishment the power required to produce the same amount of electricity will be, at least, 10% lower. [104]

Solid oxide electrolysis presents worst performance. SOEC has low durability mainly due the fact of working at high temperatures, and consequently having ceramic materials working at 500 to 800 ºC. Three durability tests were made recently and were performed at 800, 750, and 700 ℃ for electrolysis of steam at thermo neutral voltage of 1290 mV. Rapid degradation occurred in the first 300 h in all three tests [115]. Prolonged durability testing is recommended to observe the truly long-term degradation.

3.3.4 Oxygen generation

The oxygen's production is similar for each technology, around 8 kg of oxygen for each kg of hydrogen. The oxygen produced is saturated with water vapour, but most of it is recovered by condensation once the oxygen is cooled by the cooling system of the plant. Downstream of the cooling stage, the oxygen is sent to another system or vented to the atmosphere depending on project specific requirements. [98]

3.3.5 Water Requirements

Water Consumption

In terms of water consumption there are little differences between the three technologies analysed in this work. The data available states that around 9 kg of water are required to produce 1 kg of hydrogen [116]. In real plants there are some water losses associated to the hydrogen generation reaction since, for example, the produced hydrogen and oxygen are saturated with water that needs to be removed and not all of it is sent back to the water circulation circuit. As a result, usually is assumed that 10 kg of demi water are required to produce 1 kg of hydrogen.

Water Quality

The quality of the water supplied to the stack, ideally, should be as pure as possible, because all the impurities that are present will accumulate and will not be eliminated unless the system is purged.

For all 3 technologies the water quality that enters the stacks must be demineralized water. Some of these impurities may form deposits on the electrodes or membrane surfaces increasing the ohmic losses in the electrolysis system and the rate of degradation. [116]

3.3.6 Flexibility of Operation

In terms of flexibility of operation, both PEM and Alkaline present good performances, both can adapt well to the intermittency of renewables. Although PEM have a quicker response to power supply changes as it has the ability to ramp up and down very quickly and also can deliver peak shaving frequency regulation and continency services. [98, 102] While Alkaline takes minutes to do it. The times of start-up time from hot and cold are also stated in the table 3.2.

SOEC works at high temperatures and receives steam from external sources, what makes a technology with less flexibility to adapt to sudden changes in the load. [104]

3.3.7 General KPI's

A summary is presented in the following table 3.2.

Table 3.2: Important parameters of the main water electrolysis technologies

KPI	Alkaline [96, 103]	PEM [83, 96, 98, 106]	SOEC [96, 104]
Technology status	Mature	New / Mature for small scale	lab-scale
Current density (mA/cm2)	200 - 500	800 - 2500	250-500
Cell voltage (V)	1.8–2.4	1.8–2.2	0.7–1.5
Energy consumption (kW h / N m3)	4.6-4.8	4.9-5.2	3.7-4.1
Energy consumption (kW h / Kg h2)	40-60	40-60	20-40
Production Rate (m3 H2/ h)	≤ 760	≤ 40	≤ 40
Temperature range (℃)	ambient - 120	70-90	500-850
Hydrogen purity (vol%)	99.3–9.99	99.9999	99.9
Efficiency	63–70%	56–60%	74–81%
System lifetime (year)	20-30	10-20	-
Annual Degradation (%/year)	20-30	20-30	-
Cold start up time (min)	15	5–10	> 60
Warm start up time (min)	1-5	0,2	-
Flexibility of Operation	High	Very High	Low
Water Consumption (ton H2O/ton H2)	Approx. 18	Approx.18	Approx.18
Oxygen production (ton O2/ton H2)	8	8	-
Plant footprint (m2/kWe)	0.095	0.048	-
Largest Project (Power,Location, Application)	25 MW, Malaysia, Silicon	10 MW, Germany, Refinery	kW Range, Testing

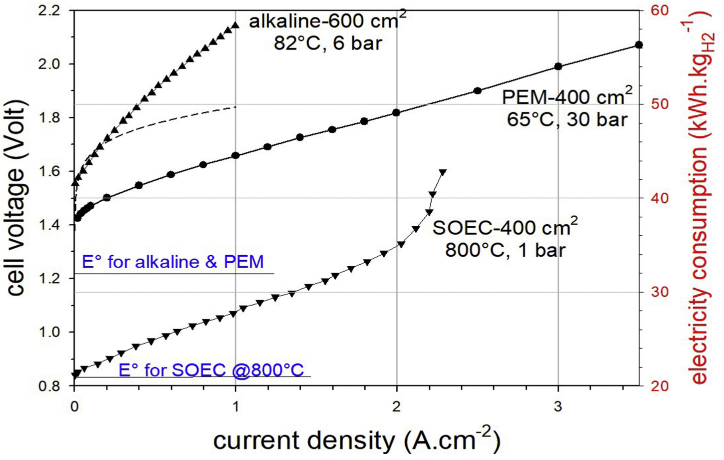


Figure 3.14: Electrolysis comparison [103]

Due to being at lab-scale level, the values of Solid Oxide Electrolysis are estimations with high level of uncertainty. The performances of these different technologies of water electrolysis can be also compared by a plot , as in figure 3.14, with their current–voltage curves (i–V curves). As already mentioned before, for PEM and alkaline cells, a standard water electrolysis voltage of 1.23 V is required to initiate the reactions and 0.85 V for SOECs. On the right-hand side, a scale with the specific energy consumption, in kWh of electricity per kg H2, is included.

From fig. 3.14, it can easily conclude the main advantages and disadvantages of each technology.

Starting with the **PEM** technology, due to the platinum group metals (PGM) electrocatalysts and the thin (< 200 micrometres thick) and highly conducting protonic membrane, the kinetics are much more efficient. As seemed in figure 3.14, it can operated in the multi-A/cm2 range, mainly because the cell is more compact [103, 117]. PEM cells can be operated under pressure, up to 80 bars, so the compression cost of hydrogen is reduced, the management of the oxygen that is released to the atmosphere is made simpler and safer.

The situation for conventional **alkaline** cells water electrolysis is quite different, despite the fact that the required voltage is the same. The high electrolyte concentration (KOH) increases the boiling point of the electrolyte and so it can be operated close to 100 ℃. On the other hand, as plotted in figure 3.14 the cell voltage and the energy consumption tend to increase rapidly, and the maximum operating current density is limited to a few hundreds of mA/cm2. This is mainly because the cell materials, the gas production and related screening effects [103, 117]. The cells can be pressurized, but the management of pressure differences between both sides is not a simple matter and potentially dangerous [103].

Regarding **SOECs** the standard water electrolysis voltage is much lower. Water electrolysis at high temperature requires a lower voltage, which means lower energy consumption [97, 118].

3.3.8 Electrolyzers Cost: Current Status

Electrolysis represents around 20% of the hydrogen productions costs. Being the electricity costs the more expensive (around 40%) [89]. A study made by edp renewables states that the hydrogen production and delivery costs are:

- **Electrolysis: 20%**
- Auxiliar Services: 6%
- Others (civil works, installation, electrical installation, etc): 9%
- Operation and Maintenance: 6%
- Grid access fees: 21%
- Electricity Costs: 37%

In terms of electrolysis costs, the alkaline technology is the least expensive of the three technologies, in terms of CAPEX, and is well suited for operations where high power density and compacity are not required, and preferably for operation in stationary conditions.

The PEM technology is still expensive. For the SOEC technology, the CAPEX is much more expensive than the other two and, furthermore, it is not as developed in terms of size, productivity, and commercial availability. The prices range, from bibliography are presented below in Table 3.3, and the

OPEX is referenced as 1,5% of the CAPEX per year. [95, 96, 119].

Today, stack costs (stack costs includes the cells plus, bipolar plates, end plates and other small parts such as spacers, seals, frames, bolts and others), typically contribute about half of the technology costs in both alkaline and PEM electrolysis. However, the breakdowns are very generic, as system designs are manufactured specifically and continually evolving to enable optimisation and simplification. Comparable breakdowns for AEM and high temperature electrolysis (SOEC) are not available, due to the limited number of products available (AEM) and the early stage of development activities (SOEC) [96].

Table 3.3: Alkaline, PEM and SOEC CAPEX

	Actual Price (€/kW)	Price in 2030 (€/kW)	Long Term (€/kW)
Alkaline	450–1260	360–765	180–630
PEM	990–1620	585–1350	180–810
SOEC	2.520–5040	720–2520	450–900

The cost of stack components in alkaline technology is largely driven by the size and weight of the components, typically larger than in PEM due to the larger cell geometries necessitated by the low current densities of contemporary systems. [96].

In PEM electrolysis, bipolar flow field plates dominate the stack component costs. Both the material used and geometric requirements make these plates costly to manufacture, as they are typically made of thermally sintered spherically shaped titanium powder. In fig. 3.15 it's represented the indicative system cost breakdowns for alkaline and PEM electrolyser systems: [98].

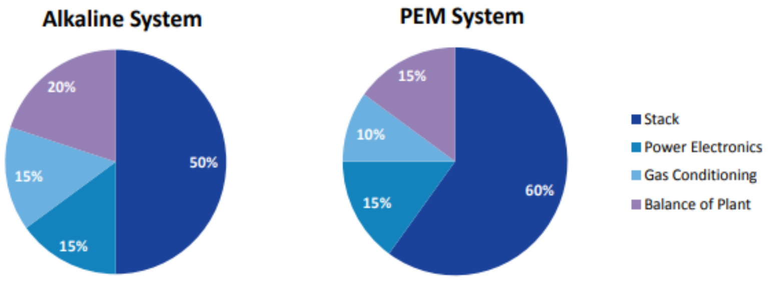


Figure 3.15: Indicative system cost breakdowns for alkaline and PEM electrolyser systems [96]

According with studies of Saba [119] and Schmidt [99] is expect that in 2030, the costs of PEM electrolyzers will drop below those of alkaline. Others see the costs of both technologies in 2030 close to each other, but with the option of operating PEM electrolyzers.

Due to the fact SOEC being a recent technology, this electrolysis method has the biggest price at the moment. According with some experts [99], this systems could experience the strongest relative cost reduction by 2030, previewing the costs dropping to the level of 500–1000 €/kW [99].

In the following table 3.4, is presented some advantages and disadvantages already mentioned in this chapter, as well as some of the challenges associated to each technology.

3.4 Summary Table

Table 3.4: Summary Table

KPI	Alkaline [96, 103, 120]	PEM [83, 96, 98, 106, 120]	SOEC [96, 104, 120]
Technology status	Mature	New / Mature for small scale	lab-scale
Applicability	Commercial	Commercial	Lab-scale/Demonstration
Advantages	-Well-stablished - Large-scale - Long-term stability - Low CAPEX	- High current density - Compact system - Dynamic operation - Significant improvement potential - High gas purities - H2 and O2 at pressure (up to 35bar(g))	- Potential higher efficiencies - Integration with exothermic processes - Non-noble materials
Disadvantages	- Low current density - Corrosive electrolyte - Slow dynamics - Gas permeation	- High membrane and electrode cost - Noble materials - Low efficiency	- Demo scale - Unstable electrodes - Brittle ceramics - Sealing issues
Challenges (between others)	- Reduce noble-metal utilization - Mitigate critical degradation	- New / Mature for small scale, - Mitigate membrane poisoning - Reduce the ohmic losses and gas permeation - Reduce capital and operation cost	- Eliminate thermal instability issues -Scaling up of stack components towards larger stack MW units - Stabilise the chemical structure and compatibility of the electrodes

Chapter 4

Hydrogen Production Case study

After knowing the current technologies for hydrogen production as well as the main parameters that define the Alkaline, Proton Exchange and Solid oxide technologies. This chapter aims to evaluate possible locations for hydrogen production plant implementation

4.1 Objectives

The geographic locations, were chosen based on a license auction system that was implemented in Portugal launched last year (2021) for the production of energy from renewable sources, with a focus on floating solar [121]. In Figure 4.1, is presented the 218 kW floating solar plant on Portugal's Alto Rabagão hydroelectric dam. Connected to the grid in late 2016, the floating system supports 840 PV modules, with bottom anchoring designed to meet a maximum depth of 90 m and a level variation of 30m.

Figure 4.1: Solar Floating Pannels in Alto Rabagao [122]

One of the advantages of solar floating technology is:

- No land occupation because it will be in the water, so there is low impact in the biodiversity and in the ecosystems;

- Higher efficiency of the panels (due to the low temperature near by the water);

- If there is hydroelectric implemented, there is already a connection to the grid, so makes the process much simpler.

Besides the locations, three different scenarios are considered and explained in chapter 6. One of the scenarios aims to use the renewable energy produced in the solar floating projects as well as the renewable energy that could be near by the lots/dams.

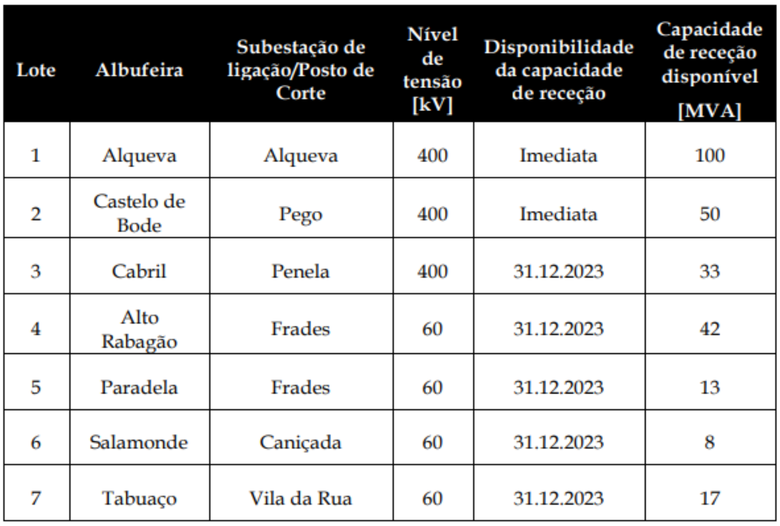
Regarding electrolysis technologies, were considered Alkaline and PEM. Solid oxide presents, as described before in chapter 3, is sill under development. A good scenario for this technology would be the usage of the heat released from electrolysis process for some industrial process. But will not be considered in this work.

4.2 Solar Floating Auction

Following two solar auctions, in 2019 and 2020 respectively, the Portuguese government has been studying alternative solutions for installing new solar projects allocated by auction on ”unconventional surfaces” that do not occupy land, such as dams. In this sense, on November 26th 2021 was presented the third floating solar auction that will be held in Portugal.[121]

Seven dams have been identified, which are going to be auctioned for the installation of solar panels. The confirmed reservoirs as well as the location of the substation of connection, the voltage level, the availability, and the available reception capacity can be observed in Table 4.1 [121],

Table 4.1: Characterization of the lots and connection points admitted to Auction [121]



Lote	Albufeira	Subestação de ligação/Posto de Corte	Nível de tensão [kV]	Disponibilidade da capacidade de receção	Capacidade de receção disponível [MVA]
1	Alqueva	Alqueva	400	Imediata	100
2	Castelo de Bode	Pego	400	Imediata	50
3	Cabril	Penela	400	31.12.2023	33
4	Alto Rabagão	Frades	60	31.12.2023	42
5	Paradela	Frades	60	31.12.2023	13
6	Salamonde	Caniçada	60	31.12.2023	8
7	Tabuaço	Vila da Rua	60	31.12.2023	17

For each of the lots admitted to Auction, is attributed one connection substations, with identification of the voltage level and the availability of the reception capacity. The hydrogen production central, is assumed to be near by the substation of reception.

The ”voltage level [kV]”, should be understood as the minimum guaranteed voltage level for the respective batch and the ”available reception capacity [MVA]” must be understood as the maximum power available for injection into the RESP, in Apparent Power [MVA], corresponding to the sum of the Active Power [MW] and the Reactive Power [MVAR].

Dam’s Selection

Each lot or dam evaluated in terms of:

- Solar Auction **power capacity**, and the proximity of the substation of reception.
- **Renewable energy** near by the dams.

  Each dam was located in the Arcgis software as well as renewable power plants. The description for each includes (Latitude, Longitude, Official start of operation, Type of renewable (either wind or solar or solar floating), Distance to the hydro power plant, Installed generating capacity [MW]).

  Will be considered wind or solar, mainly because wind turbines have been wide invested in Portugal and lately solar parks. (Today Portugal has an 7.1 GW of hydroelectric plant’s installed capacity, 5.6 GW of wind power, and 1.8 GW of photovoltaic [14].) Besides, wind and solar energy are a good par to combine and produce electric energy in a hybrid way, producing more and for more hours per day.

  The main objective is to use as mush green energy as possible during the year, in a way that hydrogen price of production will go down. This can be measured with the load factor.

  The **Load factor (LF)** is an expression of how much energy was used in a time period, versus how much energy would have been used, if the power had been left on during a period of peak demand. It is a useful indicator for describing the consumption characteristics of electricity over a period of time.

  Even not considered, it was also included, in the data available, other types of energy produced in the surroundings. For future projects, as is the case of small hydro plants or biomass power plants.

  Hydro power plants were also identified, because, in the future, it can be interesting to considered to feed the hydrogen production, because once the solar floating energy is not available, for example at night (”periodo vazio”), the hydro power can be used.
- **Hydrogen map from LNEG**, as mentioned in 1, the Hydrogen map launched by LNEG [18] was also used as a criterion for the location’s selection.

The selected lots description are presented below:

4.2.1 Alqueva

The southeast dam, is Alqueva, located on the Guadiana River with the respective dam located in the municipality of Moura, district of Beja. The geographical location is showed in Figure 4.2. Its associated uses are agricultural irrigation, production of hydroelectric power, has an available power of 520 MW and a volume of 2685,8 hm3.

In the table A.1 is presented the available renewable energy implemented in 2008, 2014 and in 2020 in a maximum radius of 30 km from the reservoir. And geographically presented in the next figure 4.3, there are 63,8 MW of available renewable power.

Figure 4.2: Portugal's Photovoltaic Power Potential, from [123]

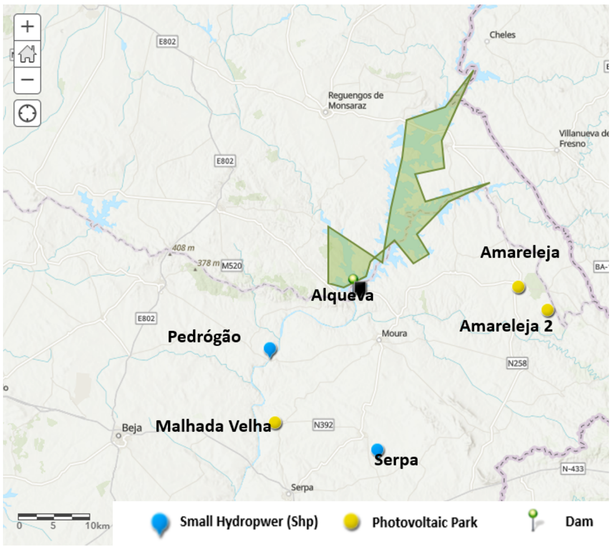


Figure 4.3: Alqueva's Site

Some reasons that make this dam, an interesting site for hydrogen production, are:

- It was defined a maximum area of 250 hectares for the purpose of this action, being the best project in terms of **power capacity (100 MVAr)**.

- In terms of renewable access, has a good potential as well. As in figure 4.2, Alqueva has the advantage of being in one of the best places in terms of solar radiation, and so photovoltaic parks have been developed in the last years. For example the Amareleja Park.

- Another good advantage is the connection substation which is near by the dam, [124], also called substation of Alqueva from the national transportation grid (REN), So, the irrigation system localized in Alqueva [125] as well as the water from the dam, can be a future option to feed the electrolyzer.

- It is also presented in fig. 4.4 the Hydrogen map by LNEG [18], with a good evaluation in one of the scenarios created.

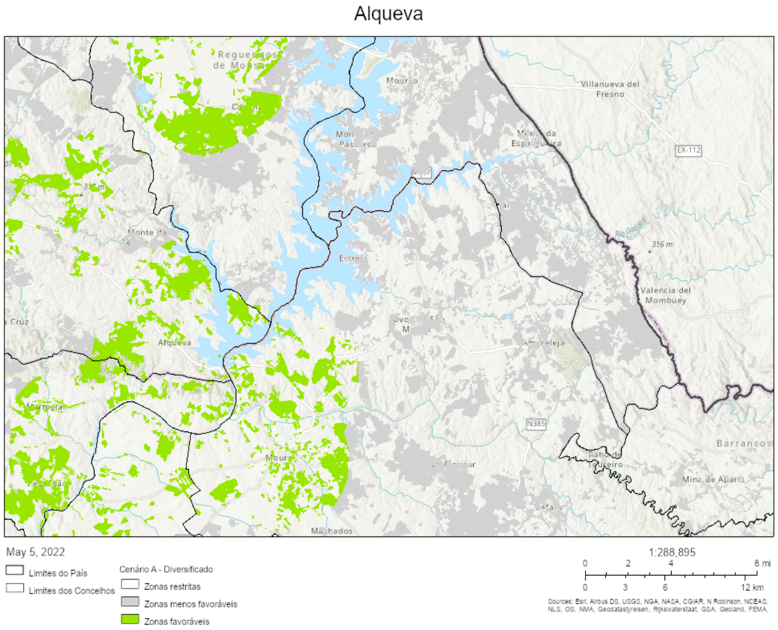


Figure 4.4: Alqueva's Site from LNEG [18]

Besides these available technologies, there are two small hydro power stations (shp) near by (Pedrogão station with an Installed generating capacity of 10 MW) and the station of Serpa (with an Installed generating capacity of 1.7MW).

Alqueva is one of the sites to test the hypothesis of installation of a green hydrogen production plant.

4.2.2 Castelo de Bode - Pego

Castelo de Bode reservoir, located on the Zêzere river, an affluent of the right margin of the Tejo river.

The dam is located in the municipality of Tomar, district of Santarém. This reservoir has uses associated with the production of hydroelectric power, with an installed capacity of 159 MW, also public supply, bathing water and other recreational and leisure activities, such as recreational boating, maritime-tourism, water skiing tracks/cable parks and the supply of aircraft for firefighting.

- A maximum area of 60 hectares has been defined for the purpose of this procedure, the solar floating power available is around 50 MVA. The substation is located in Pego's central. In terms of power available, as in the table A.2 and in figure 6.3 there is only solar park in Casal dos Cabeços 8 Km from the dam, with 2.3 MW of capacity.

- Tagus river passes near by the substation which can be a future option for the usage of water.

- Near the substation of connection, Pego's substation, is located the Pego's a combined cycle central. Could be also, an option to integrate H2 replacing natural gas.

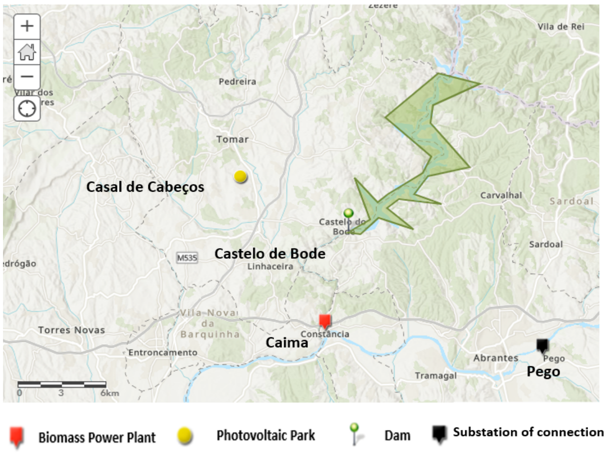


Figure 4.5: Alqueva's Site

- Presented in fig. 4.6 the Hydrogen map by LNEG [18], with a promising evaluation in one of the scenarios created for H2 blending into the natural gas grid, as end user. The red/pink colour (not included in the legend) means the best evaluation for hydrogen production purposes, due to natural gas grid that passes in Pego's central, it can be noticed in the figure B.7 in the Annex B. So it is possible option as end user.

Castelo de Bode's lot, in Pego's substation, is one of the locations to test the hypothesis of installation of a green hydrogen production station.

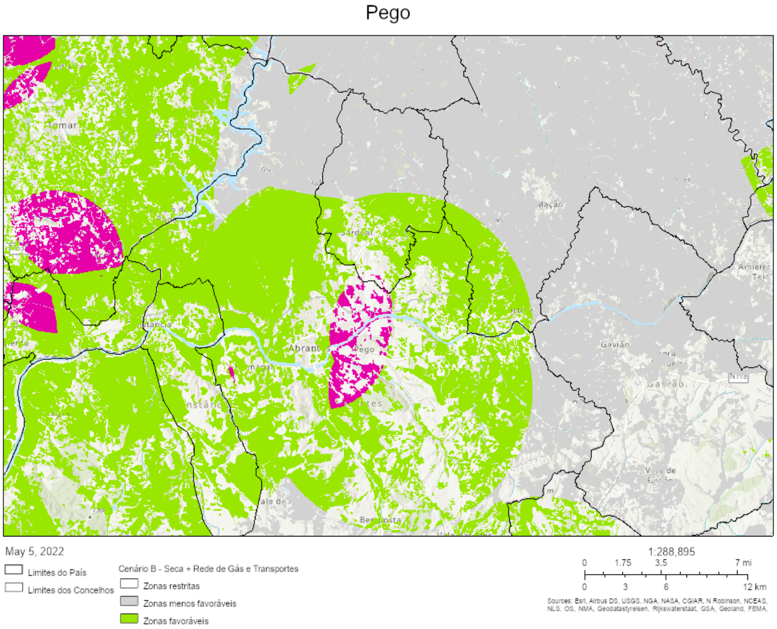


Figure 4.6: Pego's Scenario from LNEG [18]

4.2.3 North's site (Alto Rabagão + Paradela)

As in figure 4.1, there is 3 dams located up north of Portugal. Two of them have the same substation, and so can be merged in one site.

Alto Rabagão reservoir is located in the Rabagão river, in the municipality of Montalegre in district of Braga. Paradela is located in the Cávado river in the municipality of Montalegre, district of Vila Real. Regarding Paradela and Alto de Rabagao's geographically location and renewable availability, it can be noticed in tables A.4 and A.3 and also in Figure 4.7. The substation is located in Frades, cen be seen near Salamonde dam, in Figure A.3.

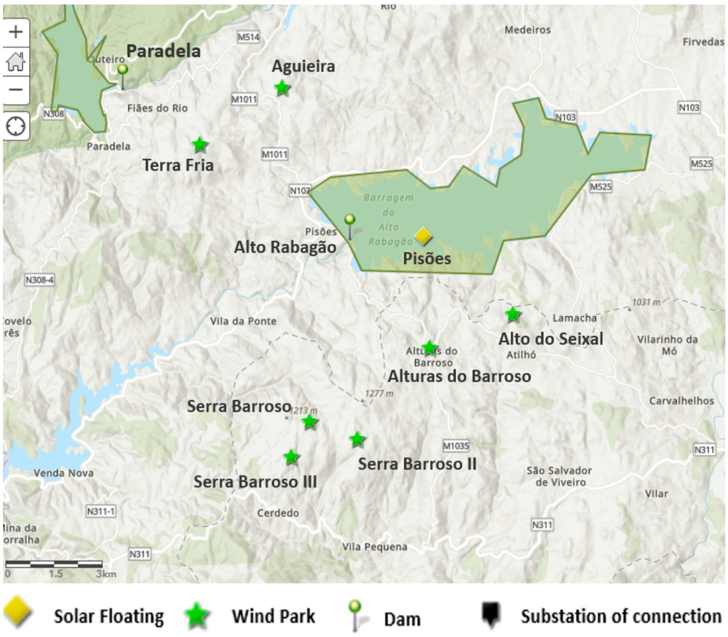


Figure 4.7: Alto Rabagao's Site

Regarding Paradela a 13MVA has been defined for solar floating panels. Regaring Alto Rabagao, a capacity around 42 MVA. There is also a solar floating system already installed in the dam, as already represented in the figure 4.1 with an installed generating capacity of 0,22 MW. It will be considered Alto Rabagao´s case together with the potential Paradela:

- As in figure 4.1 it can be noticed that the substation that receives these solar floating case (Frade's Station) is the same that receives Paradela's, which gives us a potential solar power of 55MVA.
- According with figure A.1 in the Annex A, Frade's substation, is near by Salamonde's reservoir, for future prospective, it can be also integrated.
- According with E redes [124], and REN (in figure B.7 there is connection between Frade's substation and Caniçada's substation.
- Wind power near Frades's substation can be considered to be a good amount.And has good potential for future installations, as in fig.4.9.

- It is also presented in fig.4.8 the Hydrogen map by LNEG [18], good evaluation and several cubic meters for H2 installation, although not for gas injection of industrial clients users.

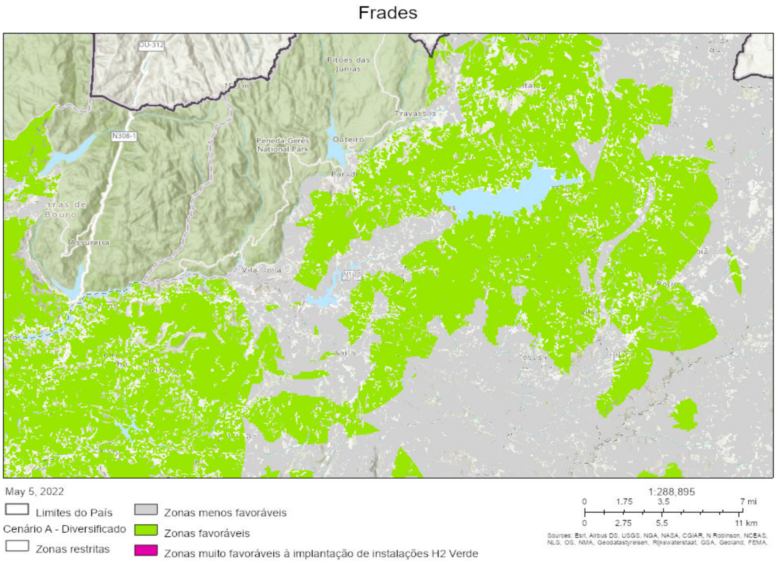


Figure 4.8: Frades's Site from LNEG [18]

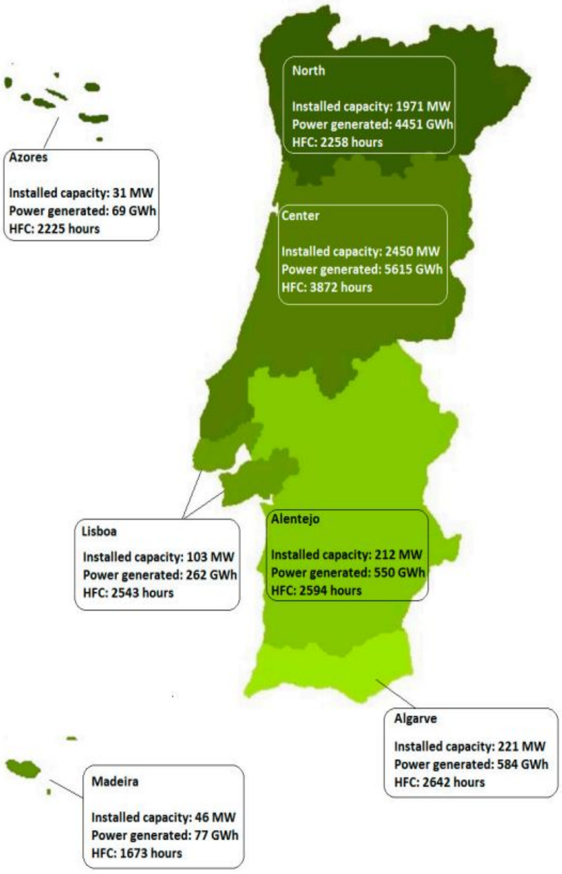


Figure 4.9: Portugal's Wind Power Potential [126]

It can be called North's Site, because will include solar floating system of two different reservoirs and will be located in the north region, specifically around Frade's substation. A total of 55 MVA, plus the renewable around. The same procedure was made for the other lots, Vilar-Tabuaço, Salamonde, and Cabril. Besides the potential involved in the three locations, the future calculations are focused on the three sites described above (Alqueva, Pego/Castelo de bode and Frades). The data for each site is still available in Appendix A for future analysis.

4.2.4 Resume

All the lots are summarized in table 4.2, from [56, 127]. SHP states for - Small Hydro Power and LHP is a Large Hydro Power plant:

Table 4.2: Sites's Resume

Dam	Hydro Power [MW]	Volume [hm3]	Solar Floating Capacity [MVA]	Wind [MW]	Solar [MW]	SHP , LHP, Biomass [MW]	Gas grid passing by? From fig B.8
Alqueva	255.6	2685.8	100	0	63.8	11.7	No
Castelo de Bode	156	902.5	50	0	2.3	7.04	Yes
Cabril	106	615	33	160	0	46.3	Yes [a]
Alto Rabagão	66	550.1	42	0.22	159.7	-	No
Paradela	53	158.2	13	116.3	0	-	No
Salamonde	222.7	-	8	69	0	276	No
Tabuaço	57	95.5	17	422	0	0. 6	Yes [b]

[a] 15Km from Condeixa, [b] 23Km from a Grid in study

Chapter 5

Scenarios for Hydrogen Production

This chapter aims to get together all the data and equations to study some scenarios of hydrogen production.

It starts with the definition of the hydrogen production plant as well as the electrolyzers chosen from the market. Followed by the value chain of each site chosen in chapter 4. Three scenarios for hydrogen production are chosen and described. Finally the calculation of all the data needed for future calculations, capital and operational costs of all the stages of production, costs of tap water, costs of grid fees, etc.

5.1 Hydrogen production Plant

A generic layout for all the sites is represented in Figure 5.1.

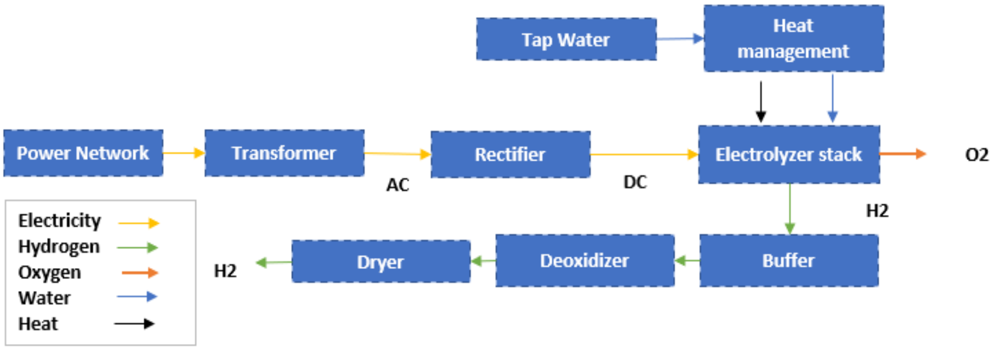


Figure 5.1: Generic Hydrogen Plant Layout

The electrolyzer system receives AC electricity, which is converted via transformer and rectifier subsystems into DC electricity for use by the electrolyzer stack. The transformer subsystem is an oil-immersed, ambient air-cooled unit, manufactured to IEC-76. The rectifier subsystem converts the AC voltage to DC voltage using thyristors. Water is supplied in the cathode side, pumped to ensure the cooling temperature in the stack. Usually after the stack, a buffer for hydrogen storage shall be installed to guarantee higher hydrogen purity and a constant hydrogen flow. For the same purpose, purity, a deoxidizer and dryer should be installed after the buffer.

This work is focused in the hydrogen production. Although, oxygen is also produced, and the its selling from electrolysis is an option under investigation in general. Selling price of oxygen vary in literature and depends on form (gaseous/liquid) and end-use application. A promising end user, one of the main consumers, is the medicine sector. Although, the liquefied oxygen should have high levels of purity, between other processes associates to its treatment. Due to the high costs associated to this processes, it is not a priority do this work. Nevertheless the option of liquefaction and short term storage is provided in section 5.3.1.

After hydrogen generation, compression and storage are considered. In terms of compression, it depends on the hydrogen end user. For example for the mobility sector the pressure needed in the hydrogen produced is 700 bar (example in the Toyota Mirai).

In this case, is assumed that there is a regular demand and the plant needs a short term storage. A mature solution, is to compress at 200 bar in tanks of type I, as seen in section 2.4, and from the literature [49], due to the fact of being a mature solutions, and is one of the best options of tanks, since they have the best cost performance and the weight of the tank is not a significant decision factor.

After compressed, it must be transported to demand centres either though pipelines or tanker truck/train. These post-production steps add additional costs that are not captured in this work.

5.1.1 Electrolyzers models

The electrolyzers used for the calculations, were chosen from some of the most commercialized companies in the market. These companies have a wide range of electrolyzers, PEM or Alkaline. The models chosen were for large scale installations.

For alkaline technology, McPhy (McLyzer 800-30), Thyssenkrupp 20 MW and Nel (A2000). For PEM technology, the Siemens electrolyzer silyser 300, and Cummins (Hylyzer 1000-30 and the 4000-30) . The specifications of each, are in tables below 5.1 and 5.2.

Table 5.1: Specifications - Alkaline electrolyser's models

Electrolyser's company	**McPhy** [128]	**Nel** [129]	**Thyssenkrupp** [110]
Model	McLyzer 800-30	A2000	Thyssenkrupp 20MW
H2 Production (Nm3/h)	800	1940	4000
Power consumption (KWh/Kg)	50.04	46	47.84
Purity (%)	NA	99.9995%	99.95%
Pressure	30 bar	NA	30 mbar
Temperature (ºC)	NA	2 to 90 ℃	up to 90 ℃
Equivalent Power (MW)	4	8,5	20

Table 5.2: Specifications - PEM electrolyser's models

Electrolyser's company	**Cummins** [130]	**Cummins** [130]	**Siemens** [131]
Model	HyLyzer 1000-30	HyLyzer 4000-30	Silyzer 300
H2 Production (Nm3/h)	1000	4000	3725.2
Power consumption (KWh/Kg)	51	51	51.5
Purity (%)	NA	NA	99.9999%
Pressure (bar)	30	30	Customize
Equivalent Power (MW)	10	20	17.5

5.2 Three sites - Chain definition

The three sites that were chosen to apply electrolysis were Alqueva, Pego (Castelo de Bode) and a North (Frades) which is an integration of two reservoirs (Alto Rabagao and Paradela). As in figure 5.2:

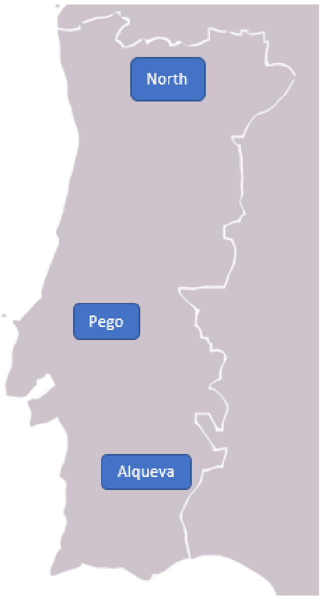


Figure 5.2: The three sites for the simulation purpose

The three locations are evaluated according with two main parameters:

1. Possible quantity of hydrogen produced
2. Cost of production

Power input

The three sites have different combinations of renewable power plants, so the capacity will vary with the locations as well as the PV and wind incidence in each region.

The values of average efficiency and hours of production of the power plants, are based in a work made in Portugal by LNEG [132], that studied the potential of a wind and a solar power plant installation (with a nominal power of 10MW).

The results of the study are presented in Annex B divided in 4 figures: The first refers to the average solar PV power, spatial distribution of each solar power profiles (SPP) and the current solar PV power capacity in each SPP (a total o 6) , stated as B.3. The second, the daily and monthly solar PV power profiles for all SPPs identified is in B.5. The third and fourth, are the same but for Wind Energy, stated in Figures B.4 and B.6. A total of 10 regions/zones WPP (Wind Power Plant)

The following Table 5.3 defines Alqueva, Pego and North´s Renewable power profiles according with the study described as well as the assumed Power input for the purpose of hydrogen production.

Table 5.3: Three sites definition based on LNEG study

Site	**Technology**	$Power_{available}$ **(MW)**	**Zone**	**Hours per day (h)**	**Efficiency (%)**	**Power input (MW)**
Alqueva	PV	160	5	9	20	30
Pego	PV	50	1	8	20	10
North	PV	55	3	10	10	40
	Wind PP	75	6	15,5	50	

In Figure 5.3 is presented the daily PV profile from LNEG study [132], and applied to Alqueva and Pego's sites although the Solar PV power stated are fora 10MW plant. Alqueva is located in a better zone in terms of solar radiation, is expected that has more daily solar exposure (in this case more 1 hour than in Pego). The same was done, for the hybrid case in north site, presented in Figure 5.4, although the solar profile is not presented, is assumed that full fills the missing power that wind power do not, between 6 to 18h to maintain a constant power input (in the 10MW plant considered in LNEG study, between the 4 MW and 5 MW).

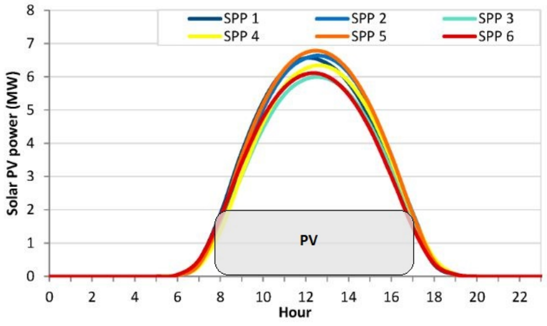


Figure 5.3: Daily PV Profile, from [132]

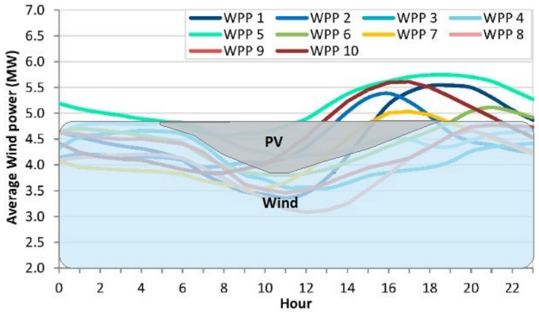


Figure 5.4: Daily Wind + PV Profile, from [132]

Alqueva's Site

Alqueva´s has an equivalent 100 MW of solar floating system plus the 60 MW of PV solar around. Taking into account the assumed values of Power input and hours of production in Table 5.3

Figure 5.5 shows Alqueva´s diagram:

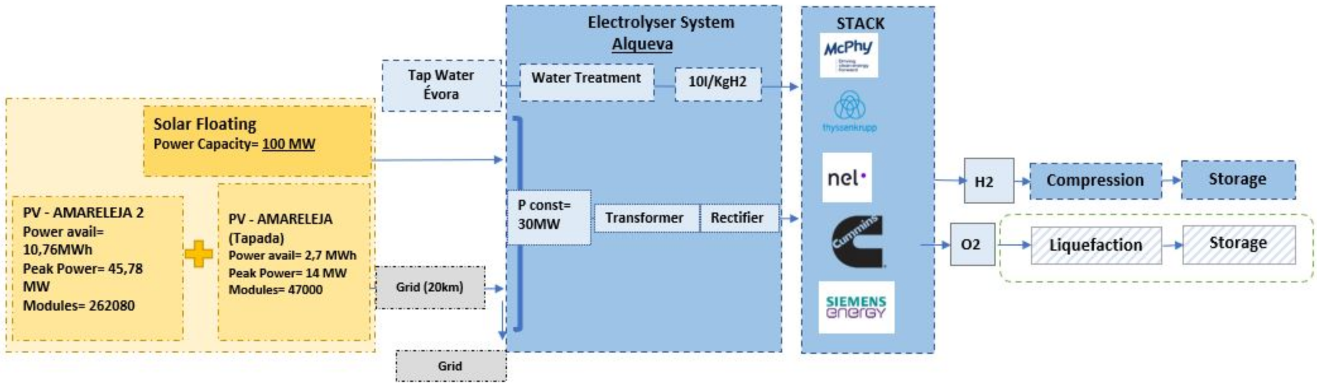


Figure 5.5: Alqueva's Diagram

In terms of water usage, it can be from river/sea but it needs purification processes. From a study made by LNEG [133], the results have shown that, currently, given the high levels of water purity requirements and the distance between the water origin and its final use for H2 production, the preferred available option is the public grid water, which has lower risk of supply, lower supply costs and does not require complex permitting processes.The cost of water are taken from ERSAR (Entidade Reguladora dos Serviços de Águas e resíduos) [134] for each site. In case of Alqueva, it is considered the water for the city of Évora. Stated as non domestical users in ERSAR [134] (also stated as for economic activities), is considered 1.3255 €/m3 or 0.001355 €/kg. So the final price of water for Alqueva´s site would be 0.01355 €/kg_H2.

Pego's Site

In Figure 5.6, is represented the Pego's diagram.

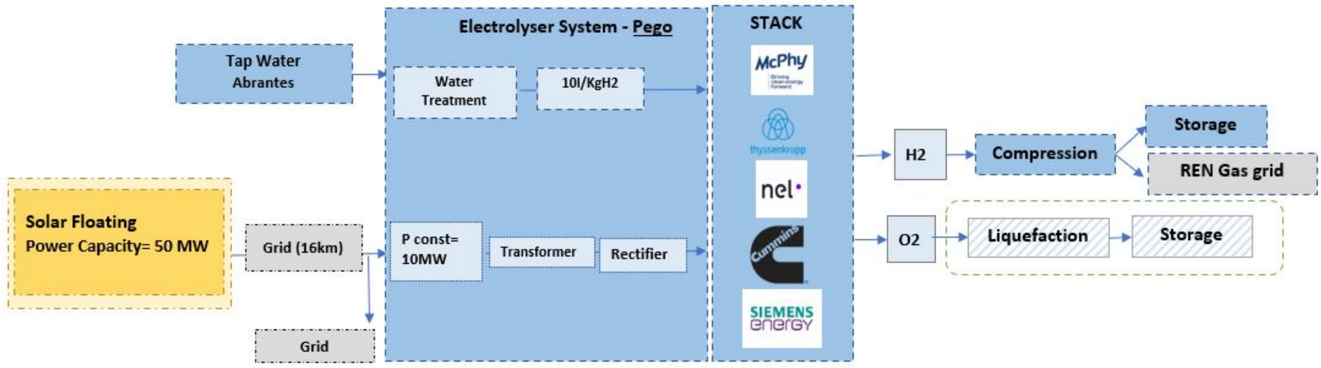


Figure 5.6: Pego's Diagram

A solar floating power plant with an equivalent power of 50 MW. As stated in Figure 4.1, it is assumed that the central is in Very high tension grid line. From Table 5.3, its considered a constant input 10 MW during 8 hours per day.

From REN [56], there is a grid passing by Pego, because of the combined cycle central that is also located in Pego. What makes this site interesting, is the hypothesis hydrogen injection into the natural gas grid. It can´t be measured the exact quantity that would be injected in the grid, because, as mentioned in section 2.3.1, just a small percentage of hydrogen can be injected into the grid mainly due the calorific value (approximately 22%).The injection should be gradually growing. Due to this fact, a short therm storage is also considered.

For both cases, Pego and Alqueva, the transmission of the electricity into the electrolyzer system is at high-voltage (400KV) (as showed in Table 4.1 and from REN map stated in Annex B, in Figure B.7). Transmission losses, being residuals, are not taking into account.

North's Site

The same procedure was made for North's Site. In Figure 5.7, is represented the North's assumed diagram.

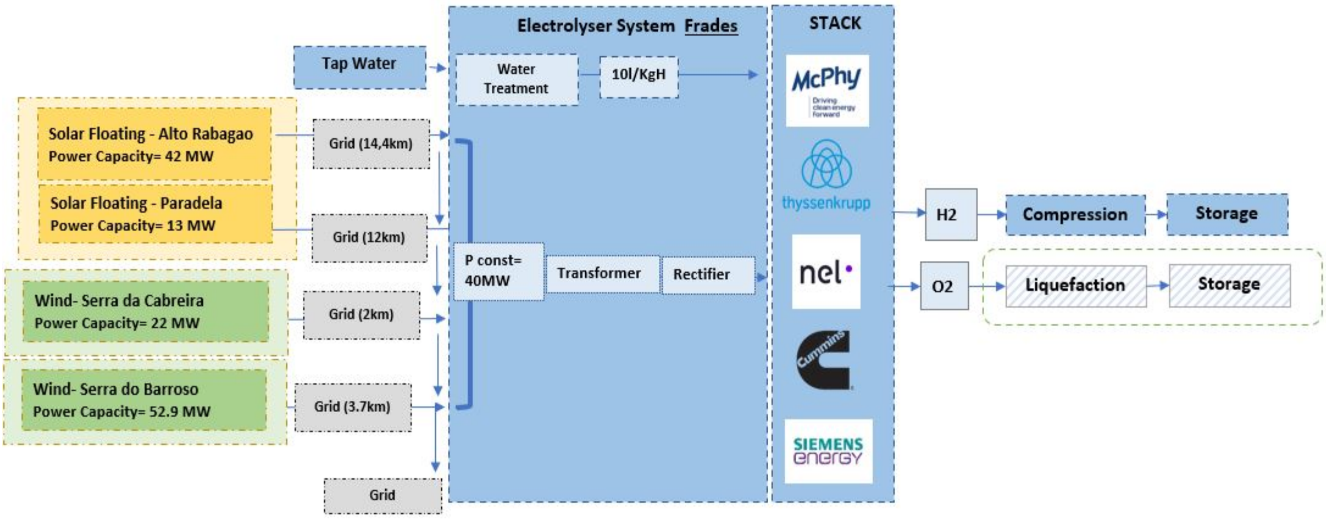


Figure 5.7: North's Diagram

From Table 5.3, it is considered a hybrid renewable power input, a constant input 40 MW. Due to the uncertainly of the wind and solar hybrid system during the year up North, it is considered a lower hours of production per day, considering 7000h per year (19h per day). It is considered production in Frades. As in Table 4.1, the level of tension is 60KV, which means that the central is in high tension grid line.

5.2.1 Scenarios of study

For each site, it is considered three different scenarios that attempt to capture different ways that an electrolyzer could be physically connected to a renewable electricity generator. This type of analysis, using possible scenarios of hydrogen production, was also made in the ”Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe by the International Council on Clean Transportation. [135].

The three scenarios are:

- *Scenario 1 – ”Direct Grid Connect*”: It is assumed assume that the electrolyzer is grid connected and therefore can produce hydrogen gas at full capacity factor for 8760 hours per year, $LoadFactor = 1$. Basically a contract with a reseller entity (energy company) from the retail market (also called a virtual PPA) is signed, and the energy supplied is green, because guarantees of origin are bought in an action in [136], and the seller entity does the management of all of the energy, according with the consumption profile. The prices vary with the market [136] and time of contract and the energy company. In this scenario taxes and grid fees are taking into account. The grid fees are stated in Figures B.1 and B.2, in Annex B, from 2021. Not from 2022, because are not representative of a normal price, due to the actual scenario of Ukraine.

  A scheme of Scenario 1 is stated in 5.8:

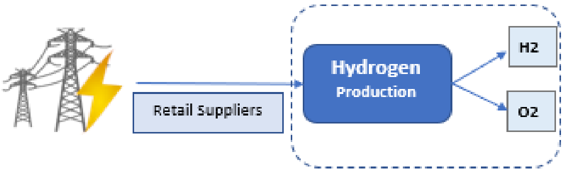


Figure 5.8: Scheme Scenario 1

- *Scenario 2 – ”Direct Renewable Connect*”: It is assumed that the electricity comes through long-term Power Purchase Agreements (PPA) to procure only renewable electricity. The contract is made with the locals renewable power plants. Under this scenario, the intermittency of the renewable electricity generator means that the electrolyser’s capacity factor is equal to the generator’s capacity factor. In this scenario taxes and grid fees are also taking into account, from [137]. The electricity prices vary with the contract made and time of contract [136]. A scheme of Scenario 2 is stated in 5.9:

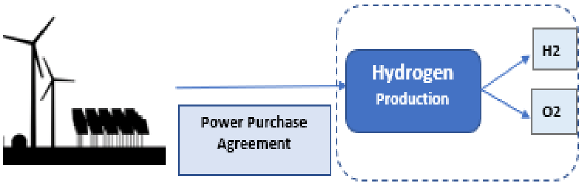


Figure 5.9: Scheme Scenario 2

- *Scenario 3 – ”Auto-consumption”* In this scenario it is assumed that the electrolyzer is only connected to the on site renewable power plant. It is assumed that the renewable power plants are the same technologies, capacity and number of plants as the ones of scenario 2. In other words, in this case the energy, instead of being bought, is owned by the hydrogen producer. Under this scenario, as in scenario 2, the intermittency of the renewable electricity generator means that the electrolyser's capacity factor is equal to the generator's capacity factor. The excess of energy produced can be sold to the grid (price of selling is 0.096 €/kWh [138]), being residual, is not considered in this study. Taxes and grid fees are not taking into account. A scheme of Scenario 3 is stated in 5.10:

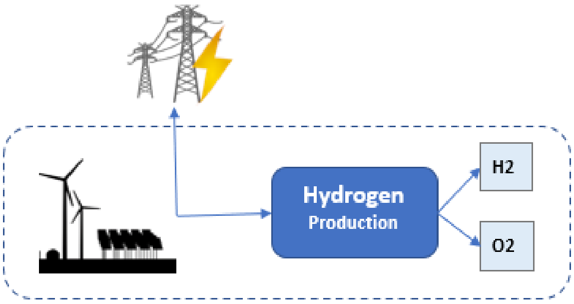


Figure 5.10: Scheme Scenario 3

In Table 5.4, it is stated the three scenarios resume as well as the electricity payment model, and grid fees. Besides grid fees, there are other taxes that, being residual, are not included in this study, also because the lack of data.

Table 5.4: Three Scenarios overview

Site	Parameters	Scenario 1	Scenario 2	Scenario 3
Alqueva	Hours of production [132]	8760	3285	3285
	LF	1	0.375	0.375
Pego	Hours of production [132]	8760	2920	2920
	LF	1	0.33	0.33
North	Hours of production	8760	7000	7000
	LF	1	0.79	0.79
	Electricity fees	Retail Market	Power Purchase Agreement	0€/KWh
	Grid fees from [137]	yes	yes	no

5.3 Data Collection - CAPEX and OPEX

Electrolysers

Capital and operation costs for this specific electrolyzers are not available. In the literature, it is presented the calculation of the CAPEX values in function of the power installed [139]. Using investment cost data for 1MW taken from the literature review from Franco et al.[140], the CAPEX values of today, for Alkaline around 1.260 M€/MW and for PEM around 1.620 M€/MW. The values for 2030 for Alkaline around 0.765 M€/MW, and for PEM around 1.350 M€/MW

OPEX is assumed to be 5% of the total CAPEX, which includes all the operation manufacturing costs, including the stack replacement.

The cost is calculated for the three sites, using a scale factor (logarithmic relationship as a method of estimating costs by scaling) for Alkaline and PEM are calculated using:

$$C_b = Ca * \left(\frac{Sb}{Sa}\right)^f \tag{5.1}$$

Where C_b stands for the unknown equipment costs at the appropriate scale S_b (size, capacity, nominal power) and the components, C_a and S_a represent the cost sand scale of the known reference component, respectively. In this case 1MW reference from Franc et al.[140]. f is the scale factor applied to the technology . As a result from the report [139] , the scale factors can be deduced from:

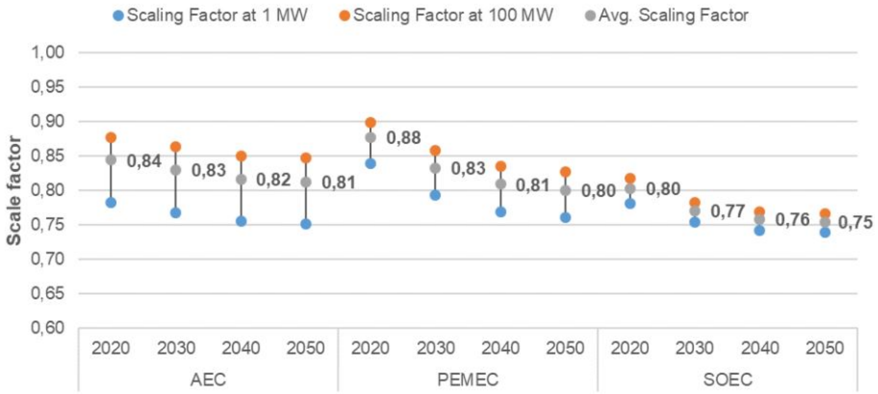


Figure 5.11: Scale Factor from [139]

The scale factor for small-scale electrolyzers ($< 5MW$) is lower than that for large-scale ones ($> 5MW$). The scale factors from Figure 5.11 as well as the results for CAPEX per year [M€/MW.y], for 2020 and 2030 is stated in the following table 5.5:

Table 5.5: Electrolysers CAPEX

Site	Technology	f (Scale factor of 2020)	CAPEX 2020 M€/MW.y	f (2030)	CAPEX 2030 M€/MW.y
Alqueva	Alkaline	0.8	0.638	0.79	0.374
	PEM	0.85	0.960	0.82	0.81
Pego	Alkaline	0.78	0.759	0.77	0.450
	PEM	0.83	1.08	0.8	0.912
North	Alkaline	0.81	0.625	0.8	0.365
	PEM	0.85	0.954	0.82	0.805

Compression and Storage

To calculate the power needed to compress an idealized gas, a relationship is used from Christensen et al. [**?**] and André et al. [141], as presented in equation 5.2:

$$P(kW) = Q\left(\frac{1}{24 * 3600}\right)\frac{ZTR}{M_{H2}\eta}\frac{N\gamma}{\gamma-1}\left(\left(\frac{Pout}{Pin}\right)^{\frac{\gamma-1}{N\gamma}}-1\right) \tag{5.2}$$

Where, Q is the flow rate (kg/day), the subtraction for 24 times 3600 is a factor that converts day units into seconds, Pin is the inlet pressure of the compressor, $Pout$ is the outlet pressure of the compressor, Z the hydrogen compressibility factor equal to 1.031, N is the number of compressor stages (assumed to be 2 for this work), T is the inlet temperature of the compressor (310.95 K), γ is the ratio of specific heats (1.4), M_{H2} is the molecular mass of hydrogen $(2.15g/mol)$, η is the compressor efficiency ratio (taken as 75%), the universal constant of ideal gas $R = 8.314J/molK$.

To find the CAPEX for the compression station, the National Research Council [141] developed relationships that allow the conversion between the rated compressor power and the CAPEX, stated in equation 5.3:

$$CAPEX_{COMPRESSOR} = 2545P[kW] \tag{5.3}$$

For example, in Alqueva, to compress a flow rate of 720 kg/h in the HyLYZER 4000-30 from 30 to 200 bars, the power needed is 489kW. For a flow rate of 575kW in the McLyzer, the power needed is 482 kW. The power needed for the thyssenkrupp is higher, because the output pressure is $30mbar$, so the power needed for a flow rate of 720 kg/h, is 2375 kW.

On-site short therm storage is assumed 0.6 €/kg [135].

About some other costs associated, from literature [142], the CAPEX of Balance of Plant components, construction and assembly costs with the quantity of hydrogen produced, is 200 000 €/MW.

Costs Data Resume

After the all the data collection for the three sites, and using as an example the electrolyzer McLyzer 800-30 installed in Alqueva under Scenario 1; in table 5.6 is stated all the capital and operating costs:

Table 5.6: Capital and operational costs

Example Costs Data - Scenario 1 for 2020 - Electrolyzer - McLyzer (Alkaline)				
	Alqueva	Pego	North	Source
$(CAPEX)_{Compression}$ [M€]	1.228	0.307	1.638	[135]
$(CAPEX)_{Storage}$ [M€]	2.83	0.944	2.779	[135]
$(CAPEX)_{Electrolyzer}$ [M€]	19.1	7.592	25	[139]
$(\ CAPEX)_{BoP+Construction}$ [M€]	6	2	8	[142]
$(\ OPEX)_{total}$ [M€/y]	0.065	0.024	0.095	[142]
$TapWater$ [€/m3]	1.3255	1.242	1.077	[134]
$Gridfees$ [€/kWh]	0.0291	0.0291	0.0377	[134]

The calculation of the hydrogen cost of production, $c_{H2/kg}$ in [€/kg_{H2}], based in the calculations made by Jovan et al. [142], it is made in 4 parcels, in order: the price of electricity consumption of the electroyser C_{elect}, the capital and operational costs $p_{CAPEX+OPEX}$, the price of electricity consumption of the compressor C_{comp}, the price of the tap water p_{water} in [$/kg_H 2$] and the price of grid fees $p_{gridfees}$. Stated in Equation 5.4.

$$c_{H2/kg} = (C_{elect} * p_{elec}) + (C_{elect} * p_{(CAPEX+OPEX)stack}) + (C_{comp} * P_{elec}) + p_{water} + +(C_{elect} * p_{gridfees}) \tag{5.4}$$

Where C_{elect} stands for the specific electrolyzer energy consumption [$kWh/kgH2$] which varies with the electrolyzers models,; p_{elec} the electricity cost [€/kWh] , varies with the scenarios stated in table 5.4. The calculation of the price per kilogram fom the capital and operational costs, is presented below in Eq. 5.5:

$$p_{(CAPEX+OPEX)stack} = (\frac{CAPEX_{electrolyser+compressor+storage+BoP} + OPEX_{total}}{h * LF * n * P}) \tag{5.5}$$

Where $CAPEX_{electrolyser+compressor+storage+BoP}$ states for the sum of the prices in table 5.6 [€], as well as $OPEX_{total}$ [€]. The P [kW] is the power capacity which is considered to be the Power input to the stack system. LF is the load factor and n the system's lifetime, which was considered to be 20 years for all the models, and h states for the number of hours per year equivalents for the scenario in study.

Adapting equation 5.4, the hydrogen production cost would vary for each scenario:

- Scenario 1 and 2:

$$c_{H2/kg} = (C_{elect} * p_{elec}) + (C_{elect} * p_{(CAPEX+OPEX)stack}) + (C_{elect} * p_{gridfees}) + (C_{comp} * p_{elec}) + p_{water} \tag{5.6}$$

- Scenario 3

$$c_{H2/kg} = (C_{elect} * p_{(CAPEX+OPEX)stack}) + \frac{CAPEX_{Renewables} + OPEX_{total}}{h * LF * n * P} + p_{water} \tag{5.7}$$

For the purpose of scenario 3, an approximation of how much would cost the installation of the equivalent renewable power plants was made. The values of IRENA [7], are presented in Table 5.7, for 30 years of lifetime:

Table 5.7: Renewable Power Plants Installation CAPEX, from [7]

Site	Technology	CAPEX M€	CAPEX M€/year	OPEX €/year
Alqueva	Onland PV and Floating PV	130.8	6.539	3.05
Pego	Floating PV	44.23	2.211	1.034
North	Floating PV and Wind tourbines	168.8	8.44	4.283

5.3.1 Levelized Cost of Hydrogen (LCOH)

To better understand the feasibility of a H2 production project, and to compare with other technologies of H2 production, LCOH must also be calculated since it represents the average net present cost of the hydrogen generation for a generating plant over its lifetime. The LCOH is calculated using Eq 5.8 in €/kgH2, from [143]:

$$LCOH = \frac{I_0 + OPEX * K_a}{P_{H2} * Ka} \tag{5.8}$$

Where,

$$K_a = \frac{(1+r)^n - 1}{r * (1+r)^n} \tag{5.9}$$

Where P_{H2} stands for yearly H2 production [kg]; n the lifetime of the project [years]; and r the discount rate.

Discount rate corresponds to the minimum rate of return on an investment project, i.e. the return that an investor requires to develop a project. This rate is used to update the future cash-flows generated as of today and it consists of three components/rate.

$$r = [(1+R_1) * (1+R_2) * (1+R_3) - 1] \tag{5.10}$$

Where, R1 the desired actual return on equity; R2 the annual risk premium, which is indicative of the economic, financial, overall and sectoral development of the project, as well as the total amount involved in the project; and finally R3 the inflation rate.

For the LCOH is assumed a a discount rate of 10%, a typical return required by private investors.

Oxygen selling option

As mentioned, is considered an otions o costs of hydrogen production selling the oxygen produced. For each kg (or m3) of hydrogen produced from electrolysis, 8 kg (or m3) of oxygen are produced. Oxygen has the largest global industrial gas market share (26%) , but, on the other hand, potential of selling all the oxygen is considered low, unless the location of the plant is favourable to use it on site, in local industry for instance. Nevertheless, due to the high production rates it is considered the possibility to sell O2 in liquid state and high purity for end users like for industry and also for medical applications.

Considering selling the produced oxygen, its summed the parcel that has impact on the price of hydrogen, $c_{O2/kg}$ [€/kg]. This parcel, is composed by the capital and operating costs of the O2 liquefier and tanks for storage $CAPEX_{O2} + OPEX_{O2}$ [€]. The, liquefaction from [144] can be calculated as 0.125 [M€//$MW_{electrlyser}$], being the OPEX values 5% of the CAPEX, and a second parcel, the liquefied consumption can be calculated as C_{liq} as 0.52 [kWh/kgO2] from the same source.

In terms of storage, assuming storage for 24 hours, from [145], a factory price wholesale vertical cryogenic liquid Oxygen ,present a price 73.352 €, with 100 m^3 of capacity.

The equation below, Eq. 5.11, presents the sum of the two parcels, where the '8' states for the ration value between Oxygen and Hydrogen mass production,:

$$c_{O2/kg} = (C_{elect} * \frac{CAPEX_{O2} + OPEX_{O2}}{h * LF * n * P}) + (8 * p_{elec} * C_{liq}) \tag{5.11}$$

Finally in Eq. 5.12, capital and operating costs, liquefied consumption and finally O2 selling price must be considered p_{O2} [€/kgO2]. Selling price of oxygen vary in literature and depends on form (gaseous/liquid) and with the end-user. From [144], its assumed a price of 100 €/ton, which represents the minimum selling price for industrial use of oxygen, rates are higher for medical use.

$$c_{H2/O2} = c_{H2/kg} + c_{O2/kg} - 8 * p_{O2} \tag{5.12}$$

In table 5.8 is stated the capital and operational costs of the equipment's as well as the respective references.

Table 5.8: Oxygen Capital and operational costs

Costs Data - McLyzer (Alkaline)				
	Alqueva	Pego	North	Source
$CAPEX_{Liquifier}$ [M€]	3.75	1.25	5	[144]
$CAPEX_{Storage}$ [M€]	33.1	12.6	50.6	[145]
$OPEX_{totat}$ [€]	0.187	0.112	0.3	-
Price of sell Oxygen [€/m3]	100			[144]
Liquefier Consumption [kWh/kgO2]	0.52			[144]

Chapter 6

Results and Discussion

The calculation of the produced amount for each site is presented in this chapter. The costs of production are also included for each scenario. Included in the costs of hydrogen production, is also presented the costs of hydrogen with the hypothesis of selling the oxygen produced.

For each site is also calculated the levelized cost of hydrogen, and a cumulative representation of each parcel of the levelized costs. Finally a comparison between the electrolyzers models chosen.

6.1 Production of Hydrogen

The number of electrolyzers to install, depend on each model and its equivalent power. In Figure 6.1 it´s calculated the number of units that would be needed to full-fill the power input of each site.This is measured depending of the net production rate of each model.

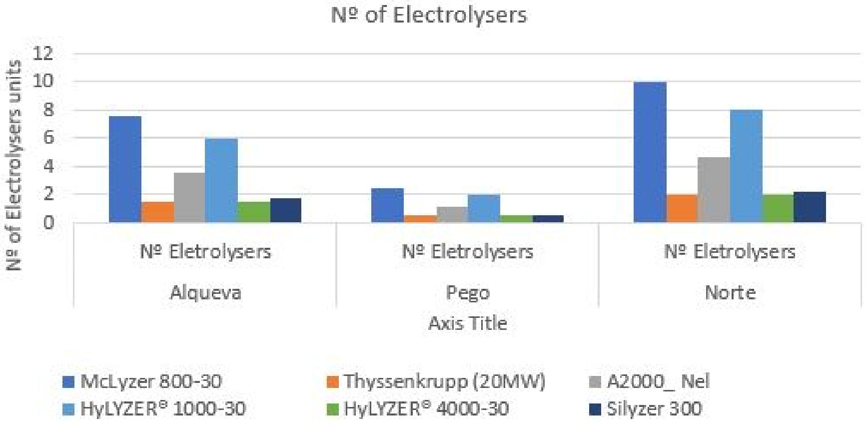


Figure 6.1: Nº of Electrolyzers

The total amount of hydrogen produced in each site, is directly proportional to the Power Input, the load factor and the maximum capacity of production of each electrolyzer. A total of 2 models of Thyssenkrupp are needed in North site, because has a net production rate of $4000 Nm3/h$ ($1 kg/h = 11.12 Nm3/h$ of hydrogen), giving an equivalent power of $20MW$. So for an input of 40MW, 2 units cover the power input. Comparing with the McLyzer 800-30, for example, has net production rate of $800Nm3/h$, an equivalent Power of $4MW$, a total of 10 units in North are needed.

As more power available, and more time of production, more tones per year of hydrogen is produced. As in Figure 6.2, and fixing an Alkaline model (McLyzer), it can be noticed that in scenario 1 the energy is full load, and consequently it has the best performance of production.

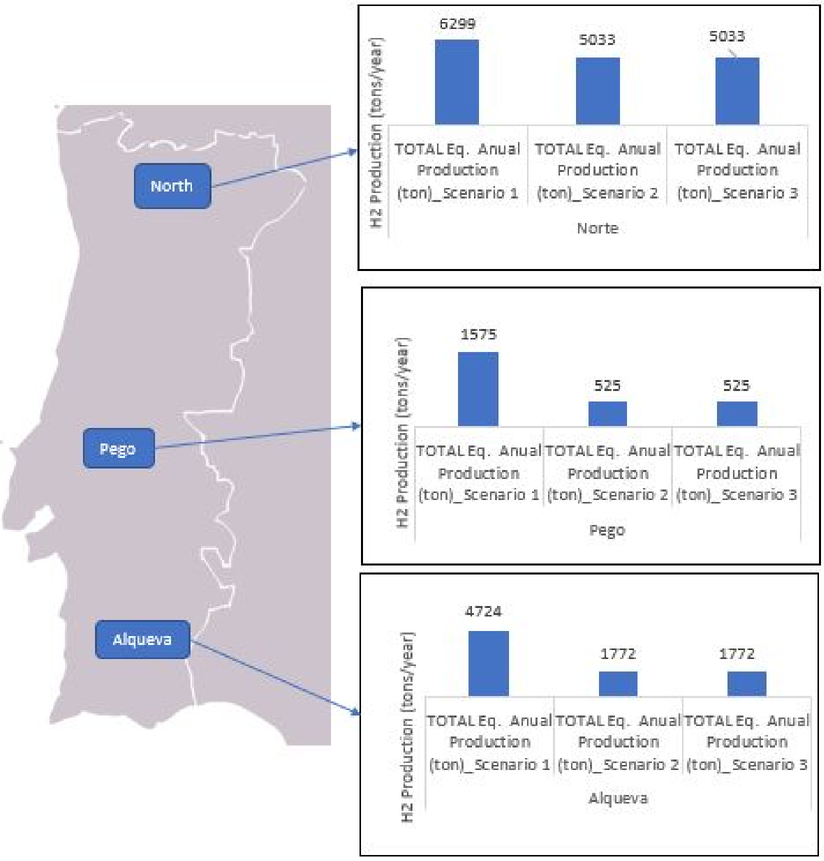


Figure 6.2: Three Sites - Hydrogen Production

Scenario 2 and 3 have the same production, due to the same load factor (hours of production). Comparing with Scenario 1, Scenarios 2 and 3 have H2 productions 20% lower in North, 70% in Pego and 60% in Alqueva. The difference is smaller in North than in Pego and Alqueva, due to the fact of having more hours of production, a total of 7000h, due to the hybrid system installed.

6.2 Cost of Hydrogen analysis

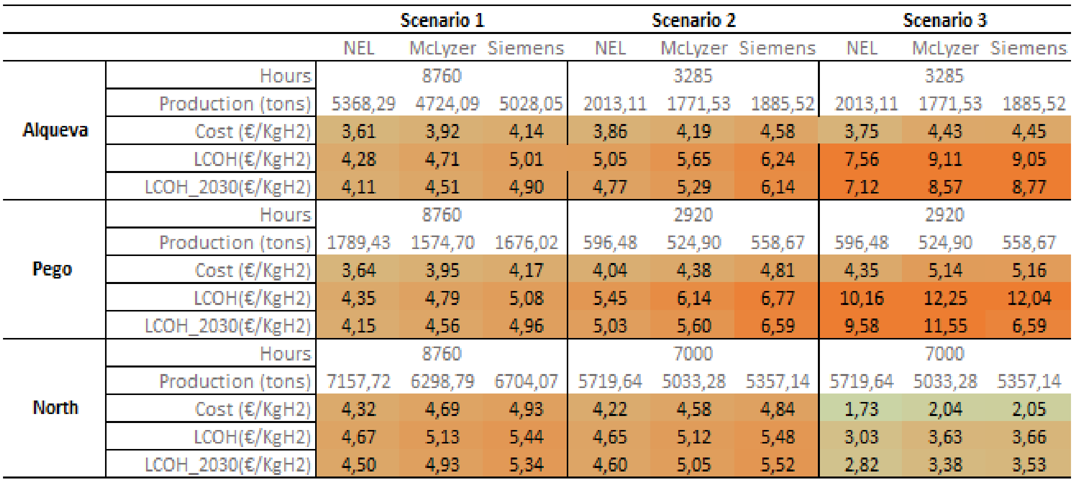
Currently, there is limited information about electrolyzer plant costs and how it varies with the available power. All the capital and operational costs, including the stack replacement costs, are not detailed and are assumed as fixed cost and equivalent to the data stated in chapter 5. The costs of renewable power plants installation are also assumed as fixed.

To simplify the first analysis of each scenario and each site, and also because it is used to presented results of production in Figure 6.2, the McLyzer Alkaline electrolyzer is fixed as an example.

The results of hydrogen costs of production, and LCOH for today and for 2030 were determined, applying the Equations 5.6 for scenario 1 and 2, 5.7 for scenario 3 and 5.8 also adapting for the three scenarios, and are summarized in Table 6.1.

The results are for all scenarios and sites, and assuming an electricity price of 50€/MWh. From the 6 models, only three are presented, NEL, McLyzer and Siemens silyzer 300, were chosen due to both being the most costly compatible term cost.

Two other tables of results are also provided for an electricity price of 35€/MWh and 100€/MWh, in Annex C, in Figure C.2 and in Figure C.4.

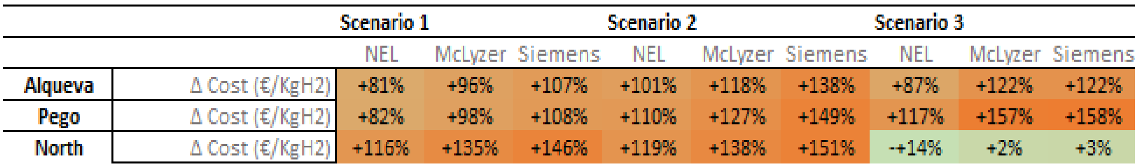


		Scenario 1			Scenario 2			Scenario 3		
		NEL	McLyzer	Siemens	NEL	McLyzer	Siemens	NEL	McLyzer	Siemens
Alqueva	Hours	8760			3285			3285		
	Production (tons)	5368,29	4724,09	5028,05	2013,11	1771,53	1885,52	2013,11	1771,53	1885,52
	Cost (€/KgH2)	3,61	3,92	4,14	3,86	4,19	4,58	3,75	4,43	4,45
	LCOH(€/KgH2)	4,28	4,71	5,01	5,05	5,65	6,24	7,56	9,11	9,05
	LCOH_2030(€/KgH2)	4,11	4,51	4,90	4,77	5,29	6,14	7,12	8,57	8,77
Pego	Hours	8760			2920			2920		
	Production (tons)	1789,43	1574,70	1676,02	596,48	524,90	558,67	596,48	524,90	558,67
	Cost (€/KgH2)	3,64	3,95	4,17	4,04	4,38	4,81	4,35	5,14	5,16
	LCOH(€/KgH2)	4,35	4,79	5,08	5,45	6,14	6,77	10,16	12,25	12,04
	LCOH_2030(€/KgH2)	4,15	4,56	4,96	5,03	5,60	6,59	9,58	11,55	6,59
North	Hours	8760			7000			7000		
	Production (tons)	7157,72	6298,79	6704,07	5719,64	5033,28	5357,14	5719,64	5033,28	5357,14
	Cost (€/KgH2)	4,32	4,69	4,93	4,22	4,58	4,84	1,73	2,04	2,05
	LCOH(€/KgH2)	4,67	5,13	5,44	4,65	5,12	5,48	3,03	3,63	3,66
	LCOH_2030(€/KgH2)	4,50	4,93	5,34	4,60	5,05	5,52	2,82	3,38	3,53

Table 6.1: Results Overview of Hydrogen Production Costs

As stated in Figure 3.3, from section 3.1, was identified from IEA, that LCOH from fossil fuels, as in average 2 €/kgH2.

The following Table 6.2, presents the difference (in percentage) of the LCOH with the reference levelized cost of grey hydrogen (LCOGH), (2 €/kgH2). Assuming an electricity price of 50€/MWh. The same was made for an electricity price of 35€/MWh, in Annex C in Table C.3



		Scenario 1			Scenario 2			Scenario 3		
		NEL	McLyzer	Siemens	NEL	McLyzer	Siemens	NEL	McLyzer	Siemens
Alqueva	Δ Cost (€/KgH2)	+81%	+96%	+107%	+101%	+118%	+138%	+87%	+122%	+122%
Pego	Δ Cost (€/KgH2)	+82%	+98%	+108%	+110%	+127%	+149%	+117%	+157%	+158%
North	Δ Cost (€/KgH2)	+116%	+135%	+146%	+119%	+138%	+151%	-+14%	+2%	+3%

Table 6.2: Results Overview - Comparison with cost of Grey Hydrogen (2 €/kgH2)

6.2.1 Scenarios Analysis

Scenario 1

Scenario 1 is highly dependant of the electricity costs which can be a big risk. The major advantage of this scenario, is the non-risk, the input of electricity is managed by the reseller entity, so the load factor is defined by the hydrogen producer. On the other hand, in the retail market, the payment is higher, due to a fee that is paid to the company (in Portugal could be EDP, Endesa, Galp, etc). This fee can be in the order of 1 or 2€/MWh.

The costs of hydrogen production tend to be similar in both sites Alqueva and Pego. On the other hand, in North's site, the cost of production is higher, being High tension line, the grid fees tend to be higher as published annually from the entity of regulation from the state ERSE, [137].

From Table 6.2, costs of hydrogen for scenario 1 are far from the reference costs (2€/kgH2).

Alqueva LCOH goes from [4.28-5.10]€/kgH2, Pego [4.35-5.08]€/kgH2 and in North [4.67-5.44]€/kgH2. Still far from the reference value of cost of hydrogen production from fossil fuels.

As mentioned, it is scenario highly dependant of the electricity costs. which has high weight in the final hydrogen production cost, as mentioned in chapter 3.2.

Varying the electricity price, from 200 €/MWh to 35 €/MWh, the next Figure 6.3, presents the evolution of hydrogen production cost for Scenario 1, in each site:

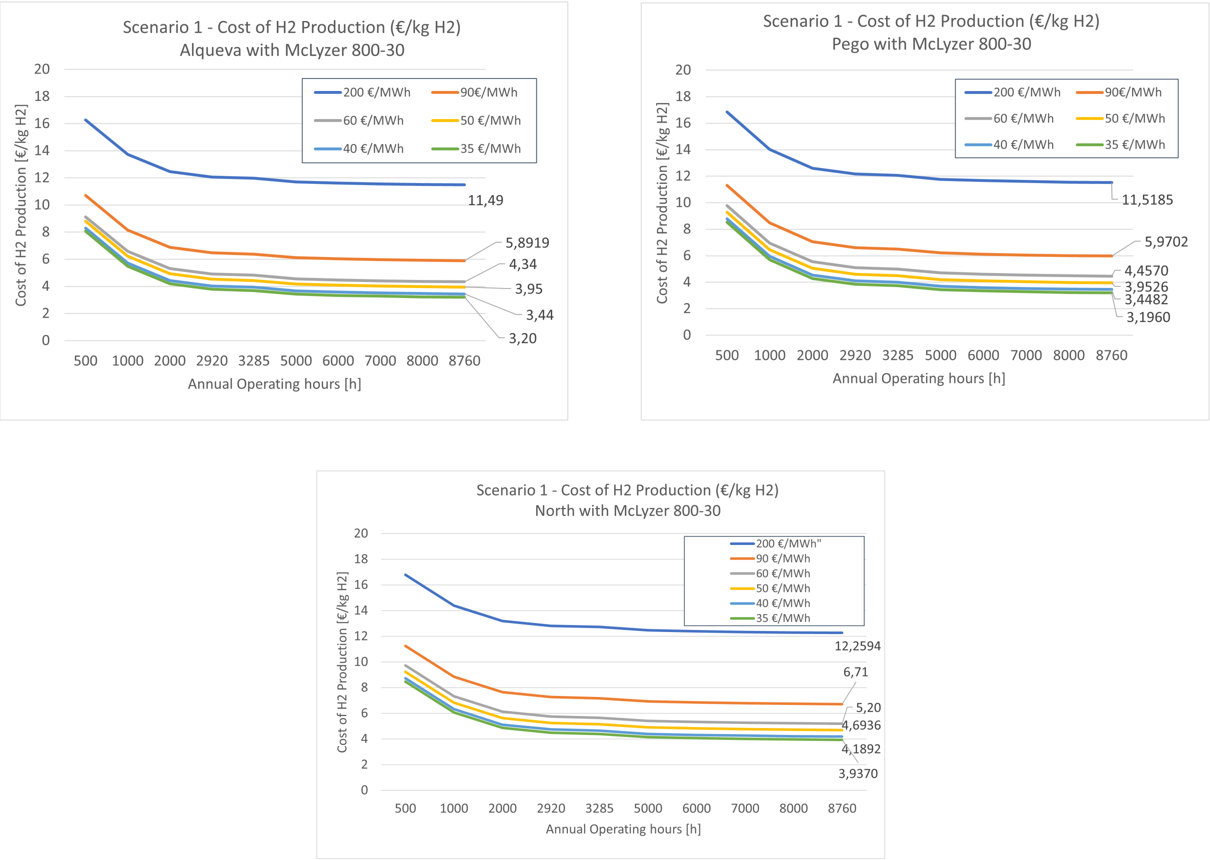


Figure 6.3: Scenario 1 - Alqueva, Pego and North- H2 production cost for different number of operating hours, electricity price

In Alqueva and Pego the H2 costs vary from around 11.5 €/kgH2 to 3.23 €/kgH2. In North, from 12.3 €/kgH2 to 3.92 €/kgH2. For an electricy price of 35 €/MWh,, states 3.2 €/kgH2 for Alqueva, 3.19 €/kgH2 for Pego, and 3.91 €/kgH2 in north. It can be seened also in Table C.2 for 35€/MWh, the costs vary from 46% to 108%.

Resuming, **Scenario 1**, buying electricity in the retail market, considers full load in every sites/locations, plus, has a clear advantage of being risk free of interruptibility of power input, in other words, hydrogen power plant is not dependant of any other power plant. On the other hand, for this case, even paying a low electricity price of 35€/MWh, it is far from being a competitive scenario, being the best cost a surplus of 46% compared with grey hydrogen reference.

Scenario 2

The same procedure of Scenario 1 was applied for Scenario 2, in this case, for a Power Purchase Agreement, as in table 5.4. Immediately it is assumed the dependence of the renewable power plants in the PPA, and so, the number of hours of production varies according with the Power Plant capacity and the number of plants. In this case, 3285 hours in Alqueva, 2920 in Pego, and 7000 in North.

Varying the electricity price, from 200 €/MWh to 35 €/MWh, in Figure 6.4 is stated the hydrogen cost of production curves.

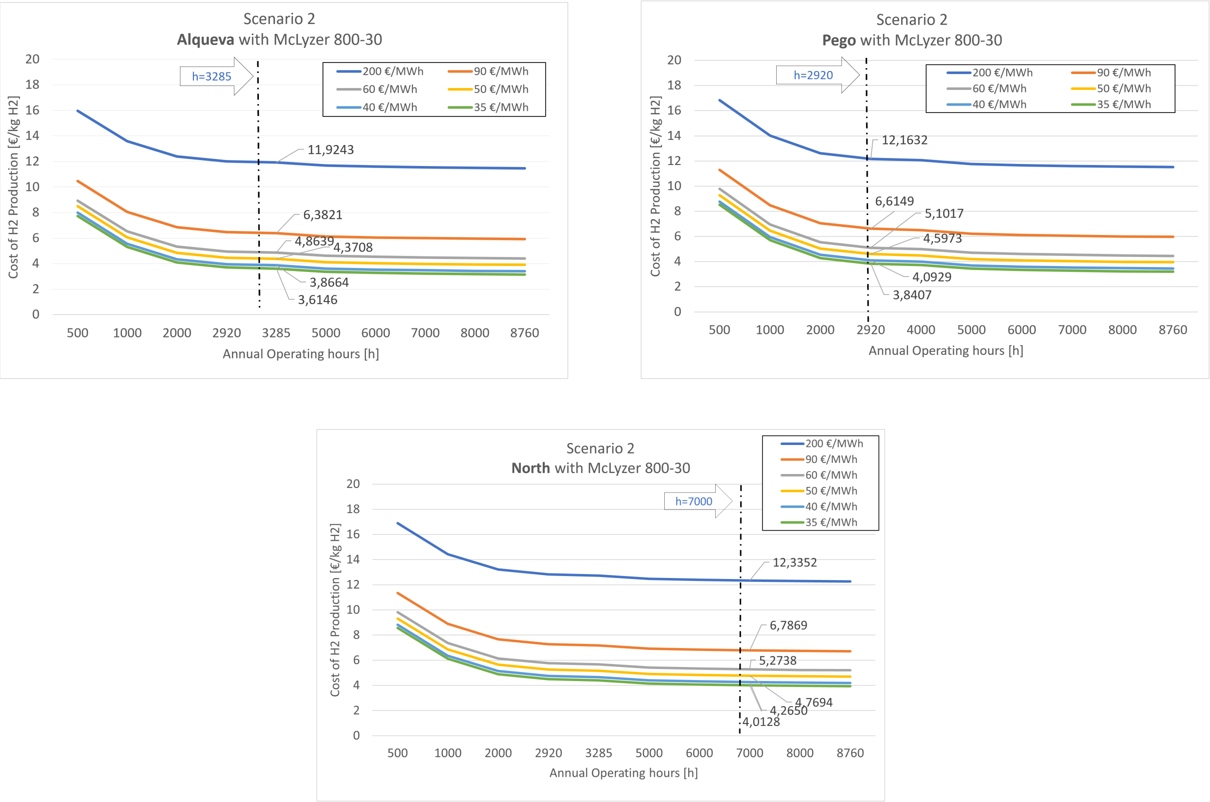


Figure 6.4: Scenario 2- Alqueva, Pego and North - H2 production cost for different number of operating hours, electricity price

Scenario 2, can be a good option if the accorded price are lower than scenario 1. Obviously, for a similar price for both scenarios 1 and 2, is not worth it, because having less hours of production, there is no advantages. From the values in table 6.1 it is more expensive, an so, a scenario to refuse.

The electricity cost for Scenario 2 has to be 22.25 €/MWh lower in Alqueva, 30€/MWh in Pego and 3,4€/MWh in North to have he same LCOH as Scenario 1.

The results are inconclusive because the price accorded in the PPA is unknown. For an electricity price of 50€/MWh, and comparing with the reference cost of grey hydrogen, the surplus goes from 101% to 151% , more than the double.

Scenario 3

The same procedure of Scenario 1 was applied for Scenario 3. In Figure 6.5 is presented the results of the costs of production for Scenario 3. A estimate for the prevision costs to 2030 is also presented, based in the prices stated in Table 5.5.

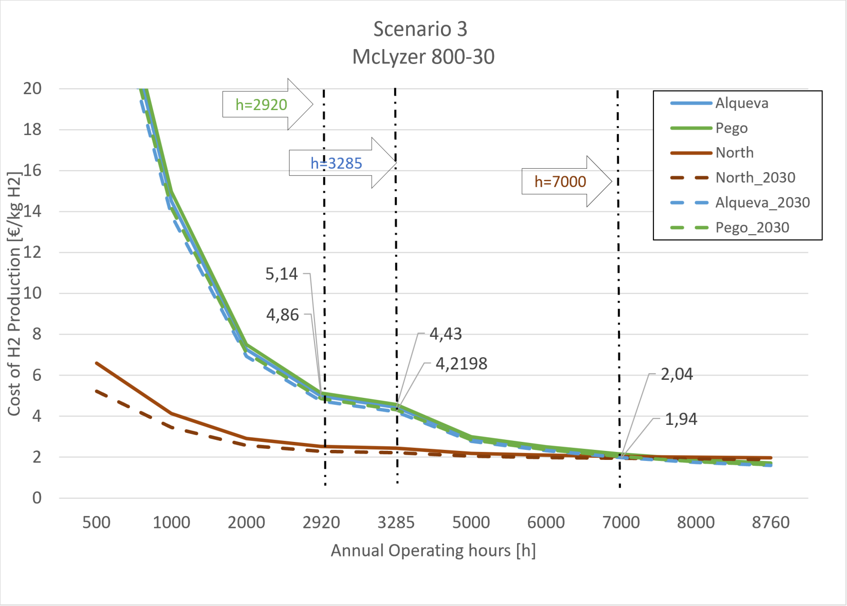


Figure 6.5: Scenario 3 - H2 production cost for different number of operating hours

Scenario 3, the auto consumption case, achieves very competitive costs in North site, for several reasons:

- There is no grid fees associates to the costs.
- In auto-consumption, the electricity price paid, is the CAPEX and OPEX of renewable power pants installed onsite costs, presented in table 5.7. - The question is, if the installations costs are competitive with the electricity price that would be paid in the retail market or in a PPA.

  In this scenario, the renewable technologies, were assumed to be the same as in Scenario 2 (in the PPA), but the renewable power plants installed can be designed according with the amount of hydrogen that is needed to be produced. Depending of the end users.
- Secondly, North has an hybrid systems combining renewable system of solar and wind energy. These hybridization, is clearly the way to convert the hydrogen production costs competitive, due

to the fact of create more time of production and higher power input. As in Table 6.1, LCOH of NEL, McLyzer and Siemens, offer prices of 3.03€/kgH2 (17% more expensive than LCOGH), 3.63 €/kgH2 and 3.66€/kgH2. In 2030 is expected that the price would be 2.82 €/kgH2, only 13% missing to reach the LCOGH.

On the other hand, the levelized costs in Alqueva and Pego are really high, it can be seen in Table 6.2 from 87% to 158% higher than the reference cost. This is specially because being just one technology of renewable production, in this case floating PV power plant, results in a low load factor, giving less time of production, 3285 hours per year in Alqueva and 2920 in Pego. It can be noticed, that for higher load factor, as the case of North site has, Alqueva and Pego's sites would achieve better competitive prices.The difference between present costs and 2030 previsions is low, mainly because only the electrolyzer's CAPEX and OPEX was took into account, renewable installations costs are expected also to go cheaper and more efficient. Nevertheless it can be noticed a drop of 5% in the costs in the three sites.

From Figure 6.5, it is possible to conclude that the scenario of auto consumption has the best performance in North. The cost of production are in the order of 2.04€/kgH2 for the present and 1.94€/kgH2 for 2030.

Hydrogen Production with Oxygen's sell

In Figure 6.6 the option of selling liquid oxygen with and without storage applied to scenario 3.

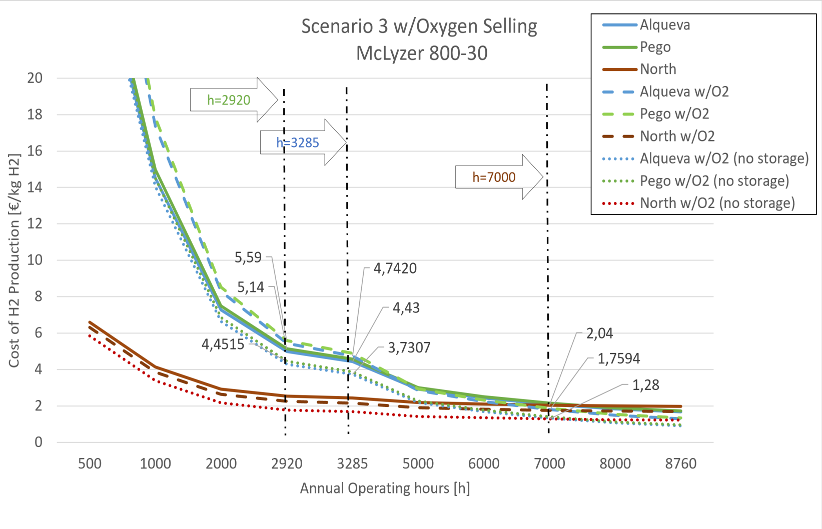


Figure 6.6: Scenario 3 - H2 production cost for different number of operating hours with Oxygen selling option

As mentioned in section 5.3.1, it is also provided the option of selling Oxygen. The oxygen selling option presents high levels of uncertainty, due to the high costs associated in its production, storage and transport (as in table 5.8. As mentioned, the share market is considered large (26%), for example for the medical sector, hospitals, health centres, etc. Although the oxygen demand comes associate very high levels of purity. But the oxygen demand for this sector needs high levels of purification, which brings very expensive processes.

Figure 6.6 shows that, with the oxygen selling option, Alqueva and Pego costs of production tend to become higher (until the 5000h, load factor of 0.57). From 5000h of production, the price starts do go lower. This is mainly because of the storage costs, stated in the data collection in section 5.3.1.

On the other hand, the price is always lower (0.7€/kg H2 lower in both cases) if there would be no storage, in this case assuming that exists a pipeline for distribution of gaseous oxygen for local industry.

In North, otherwise, under an hybrid system, the costs reach 1.75€/KgH2 with storage and to 1.28€/kgH2 with no storage associated.

6.2.2 Cumulative Production

Considering the LCOH, now is provided a cumulative production overview, for each location. Starting at the highest electricity price (300 €/MWh) and finishing at the lowest electricity price (20 €/MWh) where hydrogen is still produced.

The representation of the cumulative production is done for each site. Due to the fact of Scenario 2 reveals a very similar scenario comparing to 1, and the unknown data of electricity price, the cumulative is considering only Scenario 1 and 3 because. For scenario 2 is just presented only the total. In Annex C is represented cumulative productions for Scenarios 2. Is also presented an average cost of hydrogen from fossil fuels (2 €/kgH2).

Alqueva

The three scenarios applied in Alqueva's site are presented firstly considering cumulative in Scenario 1 in Figure 6.7 and in Scenario 3 in Figure 6.8 :

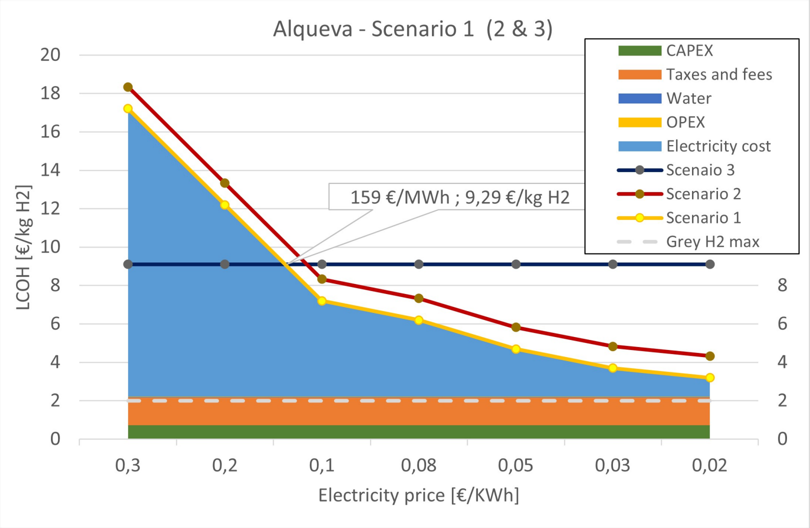


Figure 6.7: LCOH Alqueva- Cumulative in Scenario 1; Total of Scenarios 2 and 3

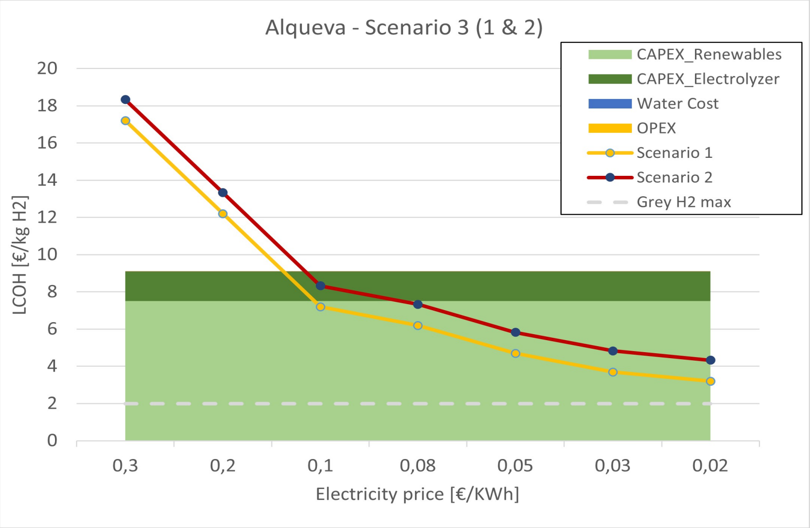


Figure 6.8: LCOH Alqueva- Cumulative in Scenario 3; Total of Scenarios 1 and 2

The electricity varies from 300 €/MWh to 20 €/MWh, scenario 3 has the best performance from 300 €/MWh to 159 €/MWh followed by scenario 1. The representation confirm what stated in the scenarios analysis. Unless with a low electricity price as 20€/MWh ,there is no competitive scenario in this site when comparing with grey hydrogen production cost.

Pego

In the same line as Alqueva, scenario 3 has the best performance from 300 €/MWh to 200 €/MWh followed by scenario 1. The results are stated in Figure. 6.9 and in Figure 6.10

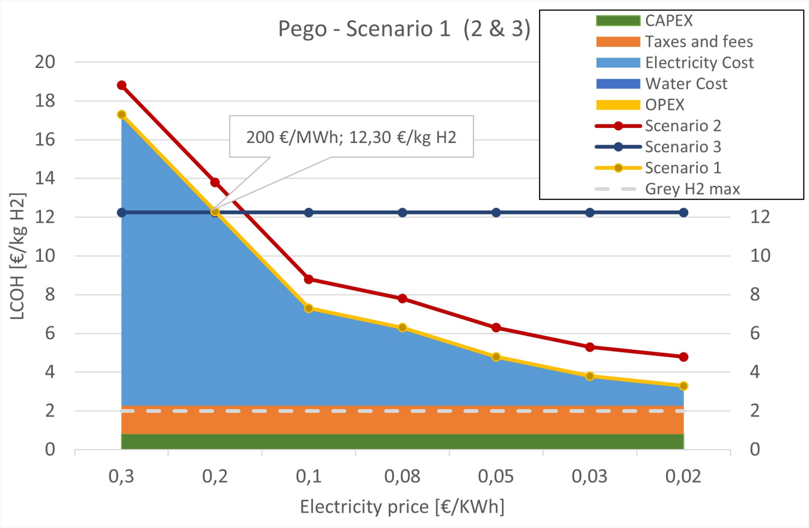


Figure 6.9: LCOH Pego- Cumulative in Scenario 1; Total of Scenarios 2 and 3

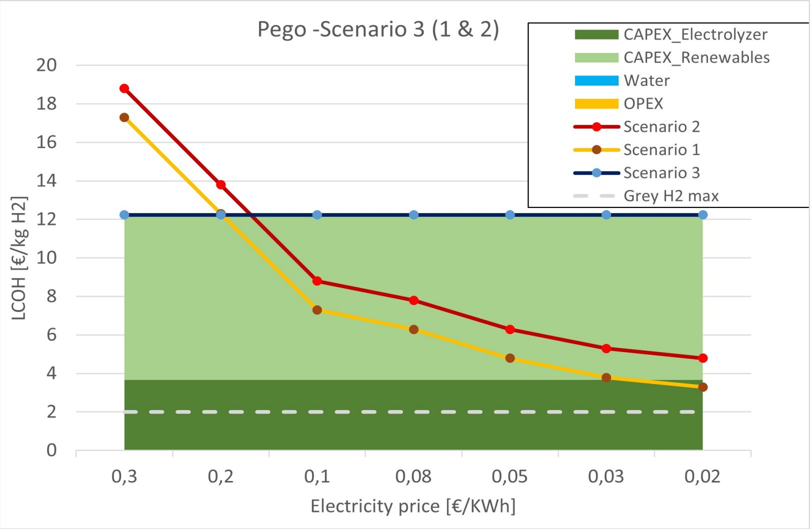


Figure 6.10: LCOH Pego- Cumulative in Scenario 3; Total of Scenarios 1 and 2

The conclusions in Alqueva can be applied in Pego. Unless with a low electricity price, there is no competitive price in all the Scenarios.

It can be noticed, that the levelized costs of renewable installation goes really high, (in the order of 8.5€/kgH2) mainly due to the low production time per year in the case of Pego, as in Table 4.2, 2920 hours per year.

North

Up North, as concluded, the results of scenario 3, have the best performance, since is an auto consumption case, without electricity and grid fees, and an hybrid renewable input. The best levelized cost is (For scenario 1 and 2, with an electricity cost of a 20 €/MWh), is 3.62 €/kgH2 for the case using the McLyzer, presented in Figure 6.11. Figure 6.12 presents the cumulative for the best scenario of this work.

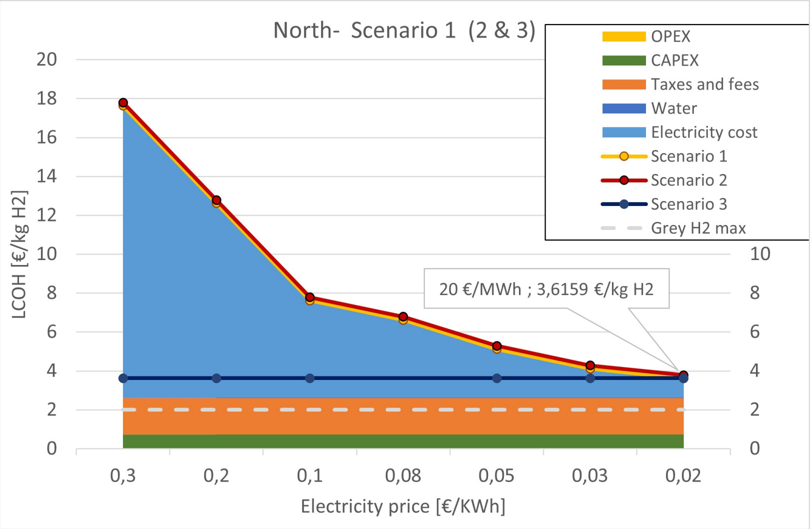


Figure 6.11: LCOH North- Cumulative in Scenario 1; Total of Scenarios 2 and 3

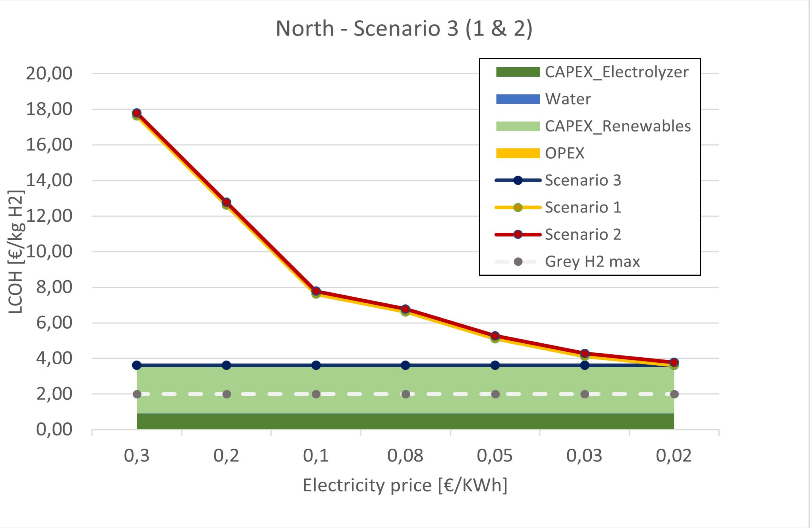


Figure 6.12: LCOH North- Cumulative in Scenario 3; Total of Scenarios 1 and 2

In general, all the sites and scenarios, even in lower electricity prices, present levelized costs higher than the reference price of grey hydrogen, 2 €/kgH2. Although most of them are in the expected range of values mentioned in chapter 3.2 in Graph 3.3, according with IEA [90].

6.2.3 Electrolyser's models comparison

After the sites and scenarios analysis, the same calculations were made, but taking into account the others five electrolysers presented in Tables 5.1 and 5.2. For simplicity, **Scenario 1 in Alqueva** with a price of 50 €/MWh is taken as example. In the next Figure 6.13, is presented the levelized costs of hydrogen for the 6 elecrolysers.

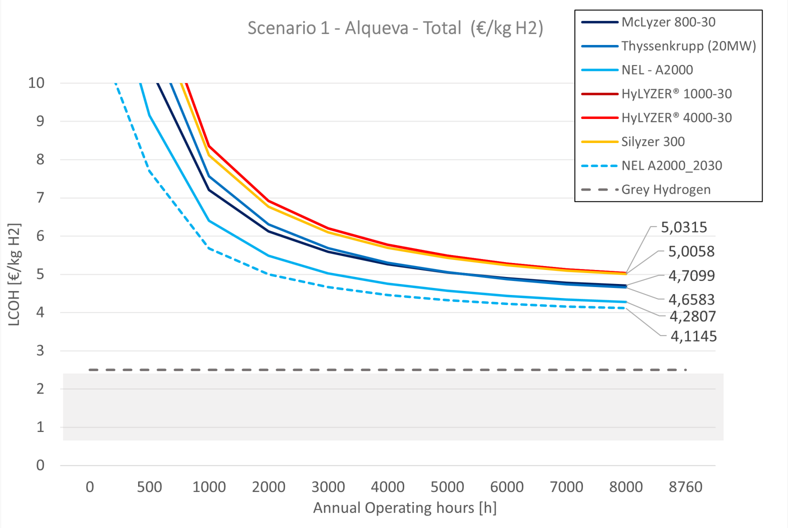


Figure 6.13: Comparative Overview of each electrolyzer - Levelized Costs of Hydrogen

NEL electrolyzer model has the lowest LCOH (4.28 €/kgH2), followed by the others alkaline Mclyzers and thyssenkrupp around (4.65 €/kgH2 and 4.7 €/kgH2), followed by the PEM technologies, with very similar LCOH the siemens and both Hylyzers (around 5 €/kgH2 and 5.03 €/kgH2). A lower price in NEL model, is reached using the values for 2030 from 5.5, of 4.1145 €/kgH2. The difference in the LCOH have several factors to take into account.

One of them, stated in the bibliography in section 3.3.8 is the CAPEX and OPEX of each technology, PEM ad Alkaline. The alkaline technology the best cost competitive, and the prices assumed in this work are in Table 5.6. In Figure 6.14 is presented levelized costs of CAPEX, which are incuded in the overall LCOH already stated in Figure 6.1. It is also presented the overall LCOH.

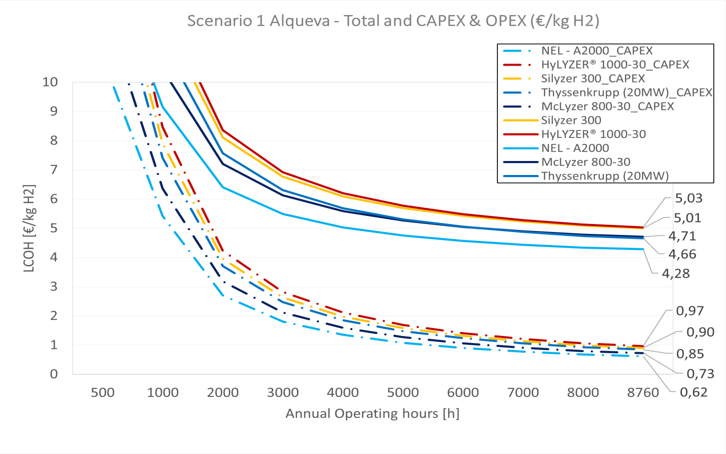


Figure 6.14: CAPEX comparinson between models

The levelized cost of CAPEX of Alkaline NEL, presents the lowest values with (0.62 €/kgH2), and the PEM Hylyzers the highest prices (0.97 €/kgH2).

A more clear comparison is presented in Figure 6.15 for the cheapest alklaine, Nel model and the cheapest PEM, silyzer model. The production is also presented.

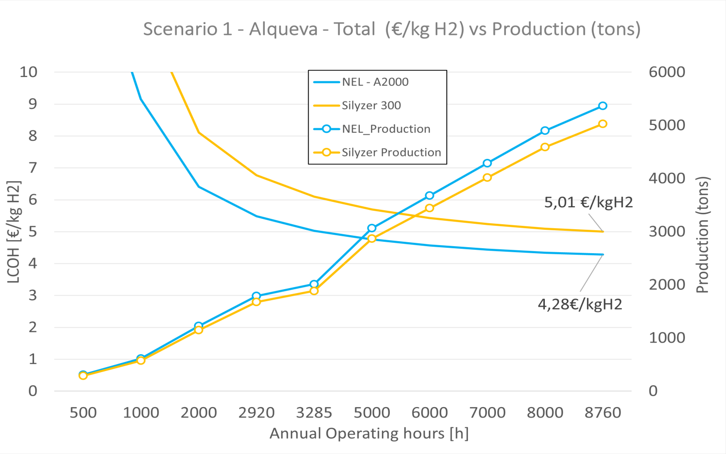


Figure 6.15: NEL vs Siemens LCOH and Production - Scenario 1 in Alqueva

Other parameter to take into account is the efficiency/ power consumption, the values can be seened in tables 5.1 and 5.2 that varies with the models from McLyzer 50.04 kWh/kg, Thyssenkrupp, 47.84kWh/kg, Nel 46kWh/kg and the PEM models (Hyluzers and Silyzer) with 51kWh/kg. As in Figure 6.16 it can be noticed the variation of levelized cost with the power consumption.

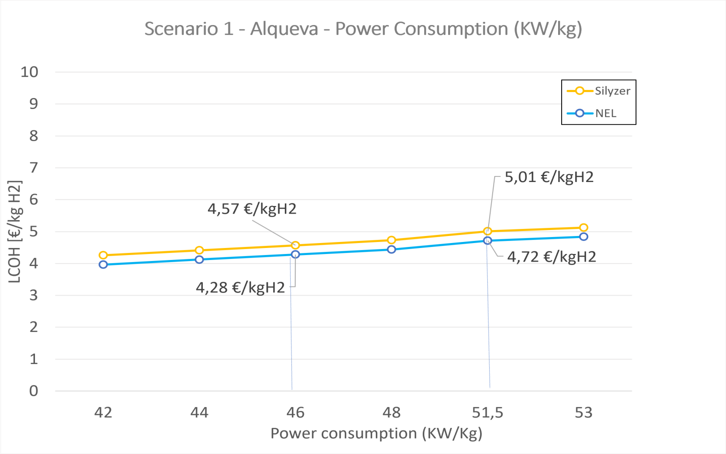


Figure 6.16: NEL vs Siemens - Power Consumption - Scenario 1 in Alqueva

Notice that, with a similar power consumption, the models have similar prices, being, in this case, just the CAPEX and OPEX variation the main reason for the price comparison. As in fig.6.16, the variation comparing the alkaline NEL and the PEM siemens, consuming 46 kW/kg, is around 7%.

As mentioned in table 3.2, the lifetime of each technology can differ, in Alkaline can go from 20 to 30 years and PEM, due to be a more recent technology have less lifetimes than Alkaline, from 10 to 20 from [103]. As mentioned in section 5.3, in this work was considered the same lifetime (20 years) for all the models. Nevertheless, a sensitive analysis of different lifetime is presented in Figure 6.17.

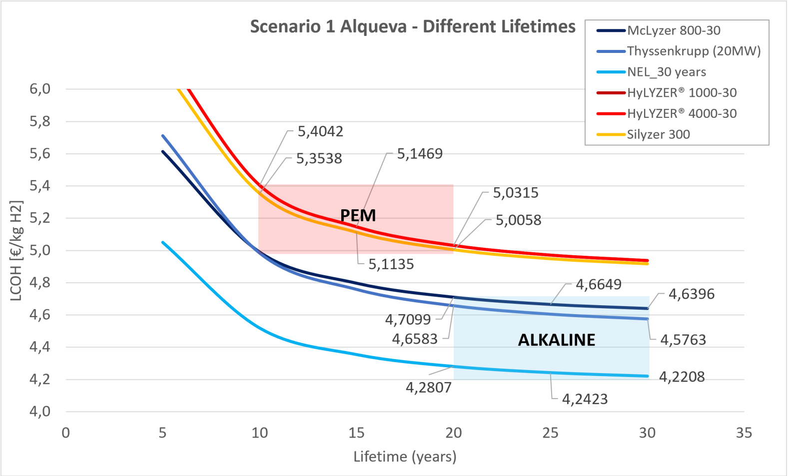


Figure 6.17: Levelized Cost of Hydrogen North for different Lifetimes

As in the Figure 6.17 , it can be noticed, that for the alkaline models, the levelized cost of hydrogen can go from 4.2€/kgH2 to 4.7€/kgH2 and for the PEM models, from 5€/kgH2 to 5.4€/kgH2.

From literature Figure 5.11, increasing the manufacturing scale of the electrolyser plants can have a positive impact on their specific cost. In Figure 6.18 is plotted the levelized costs of CAPEX and OPEX of the McLyzer model, in order to compare it in the final price.

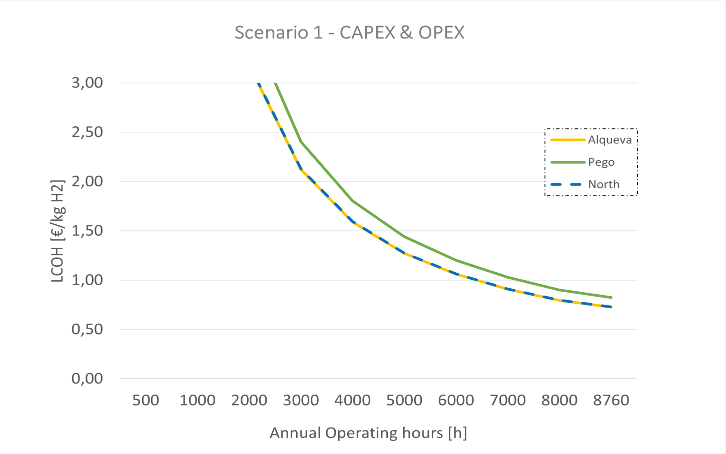


Figure 6.18: CAPEX comparison between sites

In this case, the impact is representative, even in low values. Pego, with a power capacity of 10 MW with 0.822€/kgH2; Alqueva and North with 30 and 40 MW of power capacity, with 0.7286€/kgH2 and 0.7262€/kgH2.

Comparing the models chosen for this purpose, the alkaline models present the most competitive prices. The difference in the final levelized cost, is in average 0,8€/kgH2. For 2030, it is expected prices 7% lower than actual times. PEM models present not so different prices, and for 2030 as in fig. 6.14 for example the Silyzer, reaches costs around 3.55% lower than presently.

Chapter 7

Conclusions

Main achievements obtained throughout this research work are presented in Section7.1.Some ideas for future work are given in Section 7.2.

7.1 Achievements

As explained in chapter 1, the expected growth of greenhouse gas emissions and the strong dependence on fossil energy sources are strong reasons for the transition new green energy technologies. Hydrogen is a promising energy vector/carrier, but the methods of today's production has several challenges for a more competitive cost of production. Electrolysis was chosen to be investigated in this work, specially in the costs perspective.

Based in the more recent national publications, like PNEC; the National strategy for hydrogen [**?**]; or LNEG, that launched a new map [18], that studies the feasibility of hydrogen production in several scenarios around the country, it can be concluded that Portugal is compromised with the objectives stated in Paris [11], and presents wide potential not only for renewable installations, but for hydrogen production plants. Although a configuration of the hydrogen power plant, needs to be carefully designed for a competitive LCOH. Three sites were chosen to study hydrogen production in Portugal.

The main conclusions of the present work are:

- The costs results in Alqueva, Pego and North, are in general, according with the literature, in the range of 2€/kgH2 to 7€/kgH2.
- If the hydrogen production plant is connected to the grid, a low electricity price is the major priority .Secondly installations connected to low grid densities results in high grid priced, associated to the processes of transportation of electricity, as is the case of North (using the Silyzer PEM model, around 20% higher than Alqueva and Pego).
- In general, for Scenario 1, Alqueva, Pego and North is far from being competitive. Even paying a low electricity price of 35 €/MWh, the cost has to low 46% to reach the reference fossil fuels hydrogen reference cost (2€/kgH2).

- Scenario 2 has lower quality results comparing with scenario 1, because of the low load Factor. Also, has high levels of uncertainty due to the electricity price differences unknown from scenario 1. To be cost competitive with scenario 1, the electricity cost for Scenario 2 has to be 22.25 €/MWh lower.
- Scenario 3 shows the best performance in North site. Being an auto consumption scenario, combined with a hybrid renewable system, rices will tend to go down, due to a bigger load factor. The best case representative is the case of North Site. When comparing with the reference fossil fuels hydrogen reference cost (2€/kgH2), prices in North are 14% lower to 3% higher, depending of the electrolyser model in usage.
- Alqueva and Pego present high costs due to the not hybridisation, only having a solar floating plant. Renewable installation costs are the major cost. In this case, a possible solution would be to add batteries to the systems in a way that the surplus of energy produced could be stored and used in off pick times, and so the load factor would be higher and the costs would go down. Another obvious option is to integrate other renewable technologies for example Wind turbines to hybridize with the solar floating installed. As mentioned, the surplus can also be sold to the grid, or to local consumers.
- North has the best performance, reaching a LCOH of 3.08€/kgH2 for today's electrolyzer CAPEX prices, and a value of 2.82€/kgH2 for 2030's prices. It will need to low 40% to reach the reference cost from fossil fuels.
- Currently, there are three main technologies of electrolyzers: alkaline, proton exchange membrane (PEM) and solid oxide electrolyzer (SOEC). Alkaline and PEM were used in calculations for three sites in Portugal, mainly due to the maturity and already having commercial models in the market.
- Electrolyzers price counts as stated, around 20% of the final costs. In this case, for example in scenario 1, grid connected, NEL presents 0.62 €/kgH2 around 15% of the total costs, Hylyzer 0.92€/kgH2 around 18%. Taking NEI's levelized cost of CAPEX as reference, Siemens CAPEX is 48% more expensive.
- PEM Silyzer and Hylyzer, both reach the highest prices, mainly due to the high power consumption. If the PEM's power consumption is equal do the NEL's (46 KW/kg) the LCOH will lower 9% (around 0.44€/kgH2).
- Another important factor analysed, is the variability of lifetime. Alkalines have higher lifetimes in years around [20-30] and PEM electrolyzers [10-20]. For a middle term, 25 year for NEL reaches 4.24€/kgH2 and 15 years for Hylyzer 21% higher (5.149€/kgH2).
- The effect of scale is noticed. For scenario 1, using the Alkaline McLyzer model, Pego's site present a LCOH 13% higher than Alqueva's.

7.2 Future Work

Some possible ideas for future work are presented below:

- Study the feasibility of hydrogen production in other strategic places presented national strategy of hydrogen as well as in the hydrogen map of LNEG [18]. For example the case of Sines.
- Complete the study with the transportation and distribution stages.
- Integrate other hypothesis of storage or compression, as well as the costs associated. For example, other mechanical processes as in section 2.2.2, the liquefaction option, the storage in caverns if applicable, etc.
- Include real accorded prices of a Power Purchase Agreement with the local renewable power plant, to better understand the feasibility of Scenario 2.
- Study other H2 production configurations. For example, in the autoconsumption case (Scenario 3), the excess of energy produced by the renewable power plant can be sold to the grid as an option or even to be stored in batteries.
- Integrate other options of water usage, such as the water from the dams or even the irrigation system located in Alqueva from EDIA ("Empresa de Desenvolvimento de Infra-Estruturas do Alqueva") [125].
- Include in the electrolyzers analysis, the capacity of reception the interruptibility renewable energy, in other word, the capacity of adaptation of renewable power that comes in phases as PV or wind can come as input power. From literature PEM models are expected to have better performances.
- Integrate the selling price of the hydrogen, as well as the NPV analysis, and see the feasibility of each site and scenario.
- Finally, to better understand the environmental impacts, a life-cycle analysis for all sites and scenarios shall be done.

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Appendix A

Annex

A.1 Geographic Location's Data

A.1.1 Alqueva

Table A.1: Alqueva's Renewable's, from [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance to the dam (Km)	Installed generating capacity [MW]
Amareleja	38,214267	-7,257248	7/2020	Solar	23	14
Amareleja 2	38,18610194	-7,216107778	12/2008	Solar	27	45,8
Malhada Velha	38,02992222	-7,6229375	2014	Solar	20	4

A.1.2 Pego

Table A.2: Pego's Renewable's, from [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance to the dam (Km)	Installed generating capacity [MW]
Casal dos Cabeços	39,578722	-8,405736	1/2014	Solar	8	2,3

A.1.3 North - Frades (Alto Rabagao + Paradela)

Table A.3: Alto Rabagão's Renewable's, from [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance to the dam (Km)	Installed generating capacity [MW]
Aguieira	41,776468	-7,866659	10/2003	Wind	4,6	0,6
Terra Fria	41,742136	-7,942847	1/2010	Wind	5,4	104
Alto do Seixal	41,715906	-7,796935	2006	Wind	7,5	1,6
Alturas do Barroso	41,710303	-7,823979	2003	Wind	4,6	0,6
Serra do Barroso	41,685645	7,872798	2003	Wind	5,7	18
Serra do Barroso II	41,691744	-7,843077	2009	Wind	6,21	12
Serra do Barroso III	41,680585	-7,849732	2009	Wind	6,94	22,9
Pisões	41,737834	-7,852443	1/2017	Solar Floating	0,1	0,22

Table A.4: Paradela's Renewables, from [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance to the dam (Km)	Installed generating capacity [MW]
Aguieira	41,776468	-7,866659	10/2003	Wind	4,9	0,6
Terra Fria	41,742136	-7,942847	1/2010	Wind	2,9	104
Cabeço Alto	41,876	-7,836356	2000	Wind	13,7	11,7

North Map

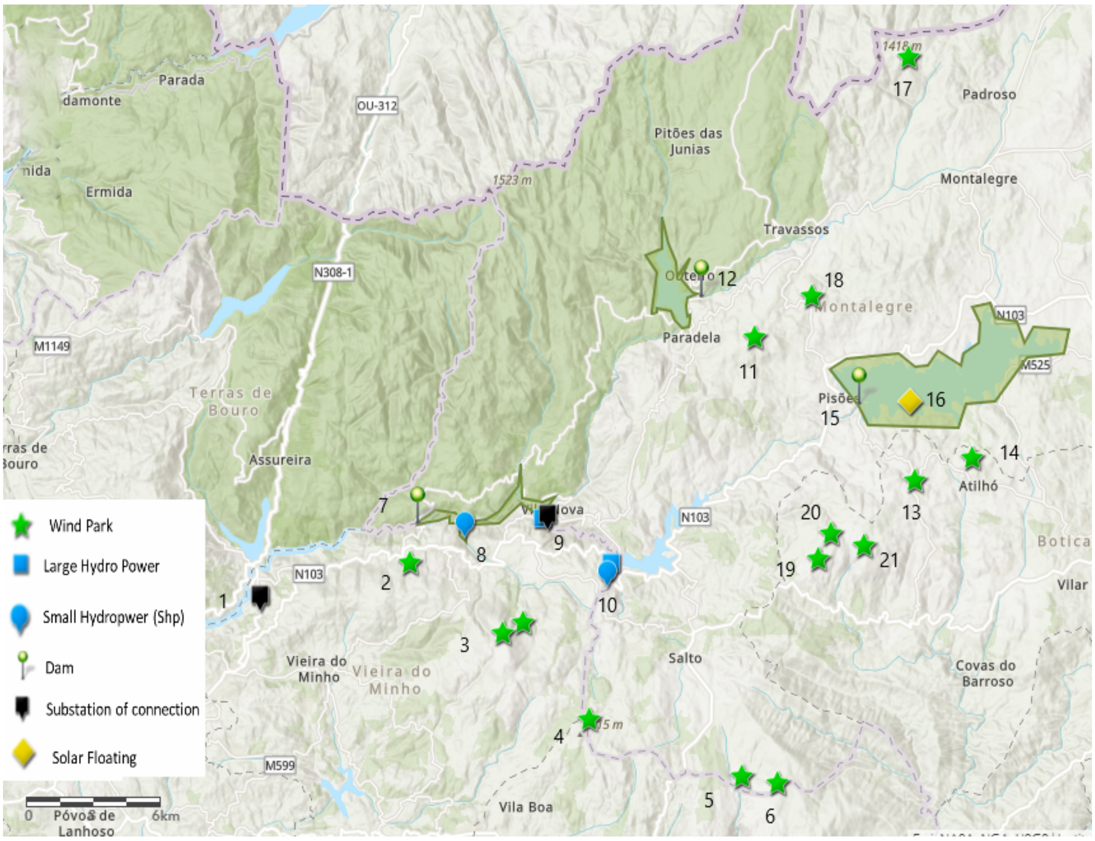


Figure A.1: North Overview

, from [127]

1 - Caniçada Substation ; 2 - Ruviães ; 3 - Serra da Cabreira ; 4 - Vilar Chão ; 5 - Lomba de Seixa ; 6- Lomba de Seixa II ; 7 - Salamonde ; 8 - Ruviães ; 9 - Frades Substation ; 10- Venda Nova ; 11 - Terra Fria ; 12- Paradela ; 13 - Alturas do Barroso ; 14 - Alto do Seixal ; 15 - Alto Rabagão ; 16 - Pisões ; 17 - Cabeço Alto ; 18 - Aguieira ; 19 - Serra do Barroso III ; 20 - Serra do Barroso ; 21 - Serra do Barroso II

A.1.4 Other Dams

Salamonde

Salamonde reservoir, located in the Cávado river, and 5km downstream of the confluence with the Rabagão river, in the municipality of Vieira do Minho district of Vila Real. The associated uses of this reservoir are the production of hydroelectric, with an installed generating capacity of 222,7 MW [127], and the supply of aircraft for fire-fighting.

Regarding this reservoir, a maximum area of 10 hectares has been defined for the purpose of this procedure. The capacity is around 8 MVA.

In therms of geographically location and renewable availability, it can be seened in table A.5 and also in figure A.2 that there are some wind energy arround, a total of 69 MW.

Besides there are small and large hydropower plants, 2 small hydropower (Ruviães) 2km from Salamonde's hydroplant and Mesa de Galo; and also two large hydropower Frades 5,5Km from Salamonde's hydropower and Venda Nova with an installed generating capacity of 188 and 88 MW.

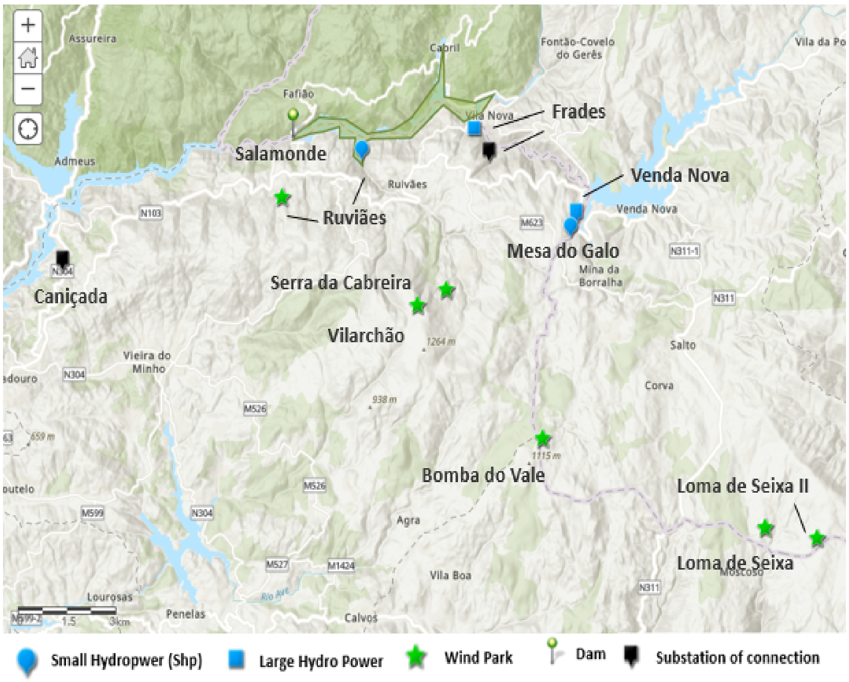


Figure A.2: Salamonde's Scenario

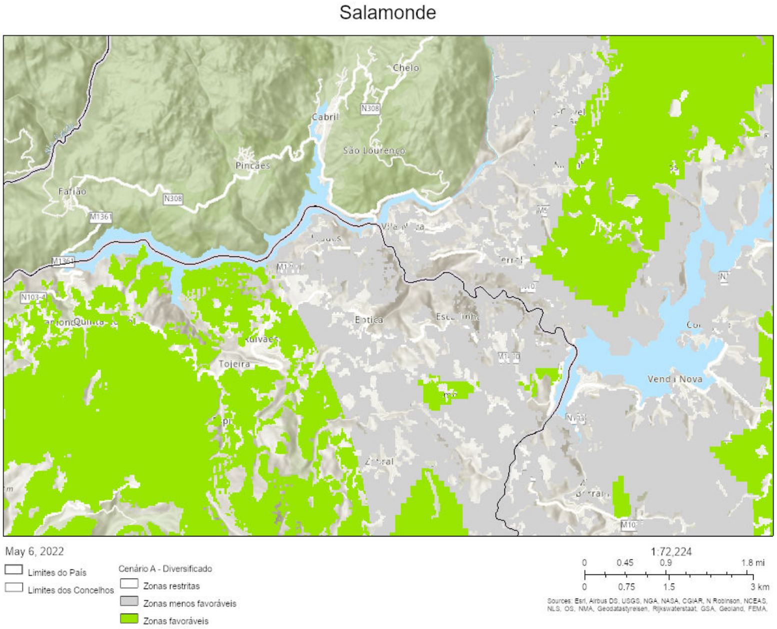


Figure A.3: Salamonde's Site from [18]

Table A.5: Salamonde's Renewable's, from [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance to the dam (Km)	Installed generating capacity [MW]
Ruviães	41,663555	-8,091246	1/2016	Wind	1,5	0,9
Vilarchão	41,644298	-8,054825	2005	Wind	6	2
Serra da Cabreira	41,648338	-8,043393	2004	Wind	6,4	20
Lomba do Vale	41,602608	-7,989601	2010	Wind	11,4	21,1
Lomba da Seixa	41,602385	-7,895751	2001	Wind	18,1	13
Lomba da Seixa II	41,598152	-7,893616	2004	Wind	19,4	12

Cabril

Cabril reservoir is also located on the Zêzere River (upstream from the Castelo de Bode reservoir), on the affluent of the Tejo river's right margin, in the municipality of Sertã, district of Castelo Branco. The production of hydroelectric power has an installed capacity of 106 MW. Also used as public supply, bathing water and other recreational and leisure activities, such as recreational boating, maritime-tourism and the supply of aircraft for firefighting.

Regarding this reservoir, only a maximum area of 40 hectares has been defined for the purpose of this action, so the capacity of reception from the solar floating park is 33 MVA.

In therms of renewable power as presented in the table A.6 and geographically in figure A.4, Pinhal interior produce a good amount of energy, around 144 MW, together with Bravo Park, a total of 160 MW.

Besides around 10Km from Cabril's hydro power station, there are the biomass power plant of Palser as well as a large hydro power pant of Bouçã both with a capacity of 3,3 and 43 MW.

Carbil has a good amount of wind power, the substation where it works is in Penela, which is far a way from the dam. Also the reservoir is located in the frontier of three three different zones of connection, as in E-Redes map[124], which turns difficult the connection between the wind parks, and the substation.

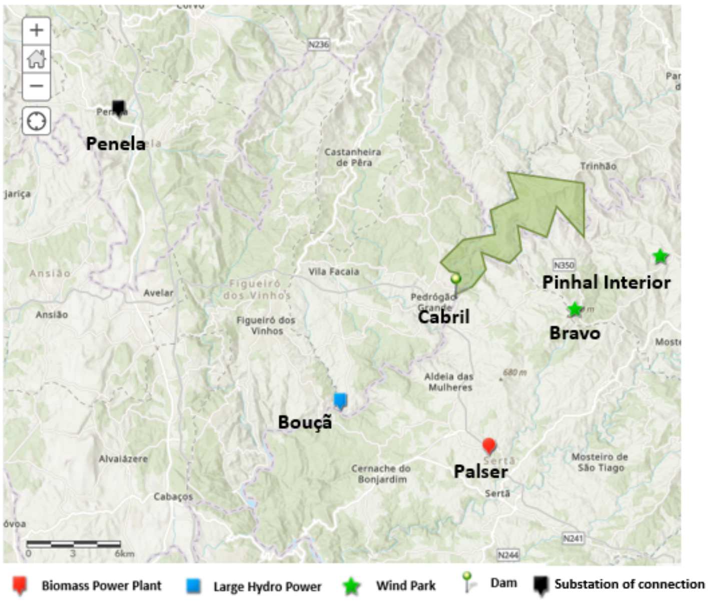


Figure A.4: Cabril's Scenario

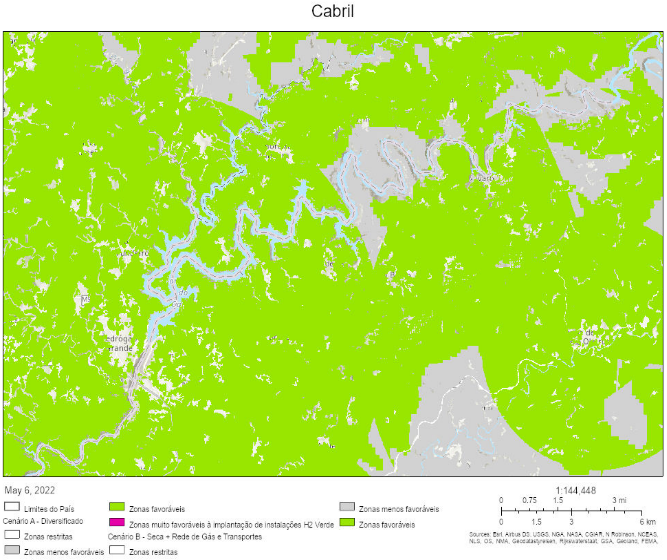


Figure A.5: Cabril's Site from [18]

Table A.6: Cabril's Renewable's, from [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance (Km)	Capacity [MW]
Pinhal	39,941586	-7,965533	7/2008	Wind	13	144
Bravo	39,908592	-8,045217	5/2009	Wind	7.5	16

Tabuaço

Vilar-Tabuaço Reservoir, located in the Távora River, a affluent of the left margin of the Douro River, with the respective dam located in the municipality of Moimenta da Beira, district of Viseu. It's used for production of hydroelectric power, with an installed generating capacity of 57 MW and a volume of 95,5 hm3 [127]. Also used as a public supply water supply, recreational boating, and the supply of aircraft for firefighting. firefighting.

Regarding this reservoir, a maximum area of 20 hectares has been defined for the solar floating action, having a capacity is around 17 MVA.

In therms of geographically location and renewable availability, it can be seened in table A.7 and in A.6 that has a good potential in terms of wind energy, due to the fact that it is surrounded by high ground, specially Alto Douro Wind Power Plant.

The Alto Douro Wind Power Plant is one of the largest wind power plants in the country, constituted by 8 parks distributed by the municipalities. The injection capacity of the Alto Douro wind farm in the grid, or connection power, is 253.2MVA, with the Reception Point located in Valdigem, of the National Electric Network (REN) [146]. It brings a total of 422 MW of wind energy available in Tabuaço´s dam.

Also there is two small stations of hydropower, Barreiros and Ponte Nova both with 0,3 Mw.

Concluding, this project would have a lot of potential, if the substation of receiving the solar floating energy (Vila de Rua) would be the same as close than Alto Douro Wind Power Plant which is Valdigem. Besides the solar floating capacity is low. On the other hand, acording with E redes, and Ren maps [56, 124], there is a connection (of 150Kv) between Tabuaço and Valdigem, as in figure B.7-

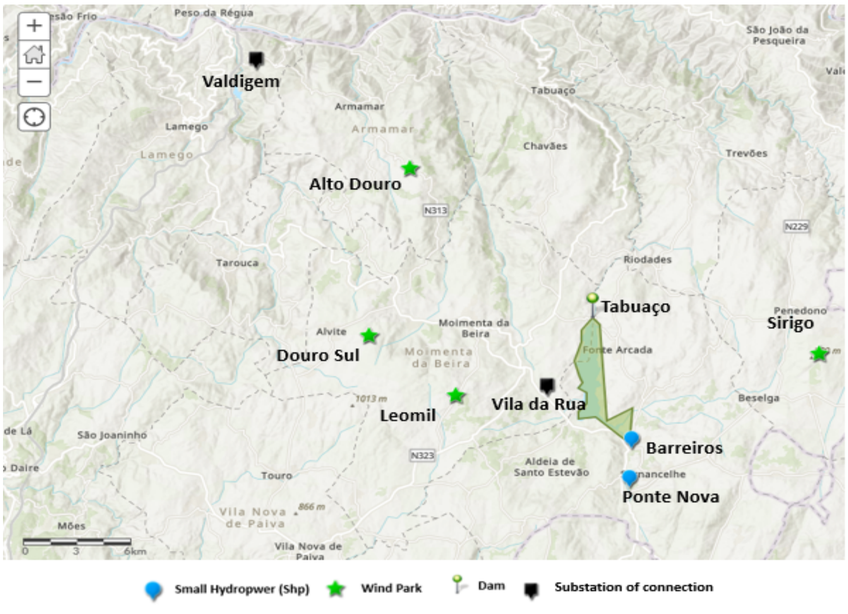


Figure A.6: Tabuaço's Scenario

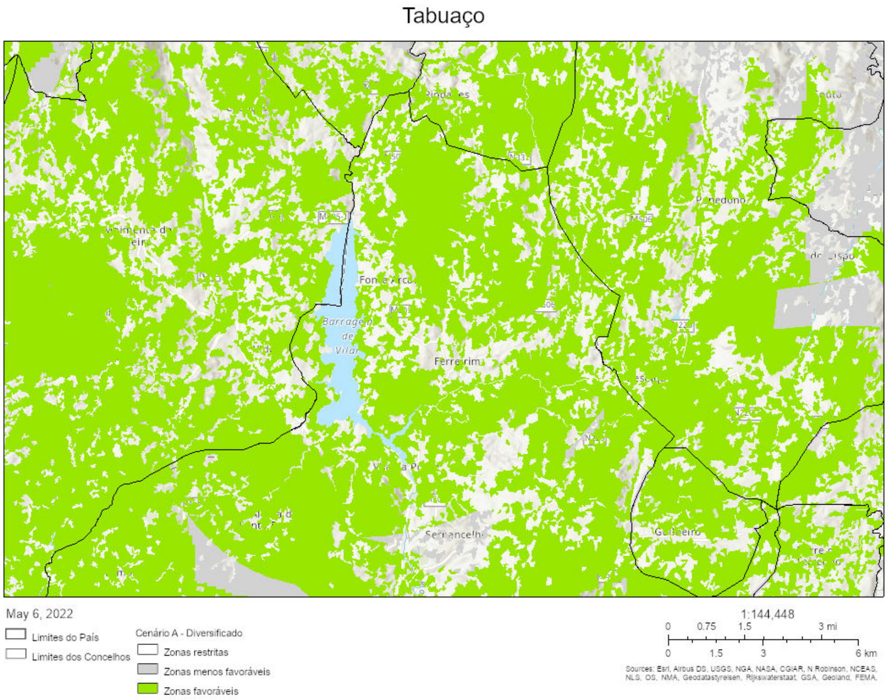


Figure A.7: Tabuaço's Site from [18]

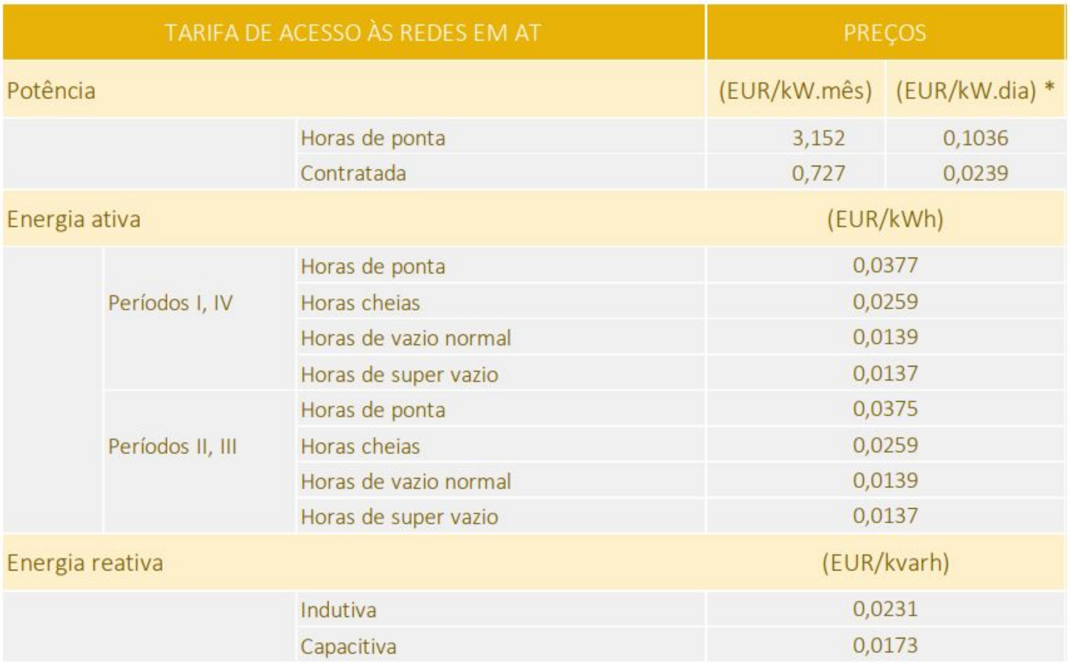
Table A.7: Tabuaço's Renewable's [127]

Place	Latitude	Longitude	Start of operation	Renewable	Distance to the dam (Km)	Installed generating capacity [MW]
Alto Douro	41,069607	-7,576865	2/2010	Wind	13,5	253,2
Douro Sul	40,973825	-7,688766	2016	Wind	12.7	149,1
Leomil	40,957532	-7,658981	2007	Wind	9	16,1
Sirigo	40,963741	-7,390294	2005	Wind	12,8	4

Appendix B

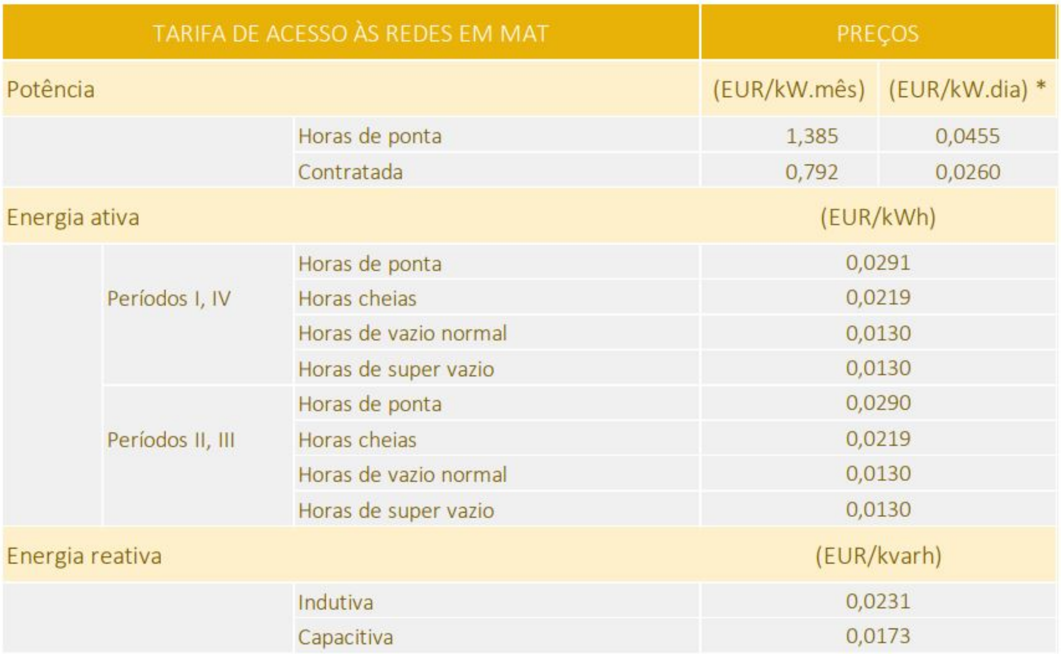
Annex

B.1 Data - Assumptions



TARIFA DE ACESSO ÀS REDES EM AT			PREÇOS	
Potência			(EUR/kW.mês)	(EUR/kW.dia) *
		Horas de ponta	3,152	0,1036
		Contratada	0,727	0,0239
Energia ativa			(EUR/kWh)	
	Períodos I, IV	Horas de ponta	0,0377	
		Horas cheias	0,0259	
		Horas de vazio normal	0,0139	
		Horas de super vazio	0,0137	
	Períodos II, III	Horas de ponta	0,0375	
		Horas cheias	0,0259	
		Horas de vazio normal	0,0139	
		Horas de super vazio	0,0137	
Energia reativa			(EUR/kvarh)	
		Indutiva	0,0231	
		Capacitiva	0,0173	

Figure B.1: Grid Fees High Tension from ERSE [137]



TARIFA DE ACESSO ÀS REDES EM MAT			PREÇOS	
Potência			(EUR/kW.mês)	(EUR/kW.dia) *
		Horas de ponta	1,385	0,0455
		Contratada	0,792	0,0260
Energia ativa			(EUR/kWh)	
	Períodos I, IV	Horas de ponta	0,0291	
		Horas cheias	0,0219	
		Horas de vazio normal	0,0130	
		Horas de super vazio	0,0130	
	Períodos II, III	Horas de ponta	0,0290	
		Horas cheias	0,0219	
		Horas de vazio normal	0,0130	
		Horas de super vazio	0,0130	
Energia reativa			(EUR/kvarh)	
		Indutiva	0,0231	
		Capacitiva	0,0173	

Figure B.2: Grid Fees Very High Tension from ERSE [137]

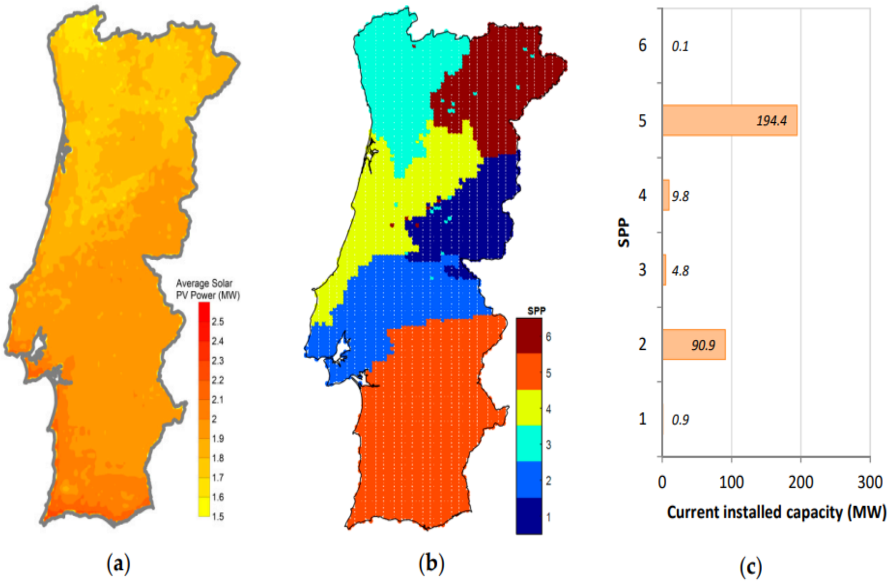


Figure B.3: (a) Average solar PV power]; (b) spatial distribution of each solar power profiles (SPP) and (c) the current solar PV power capacity in each SPP;(c) the current solar PV power capacity in each SPP. From [132]

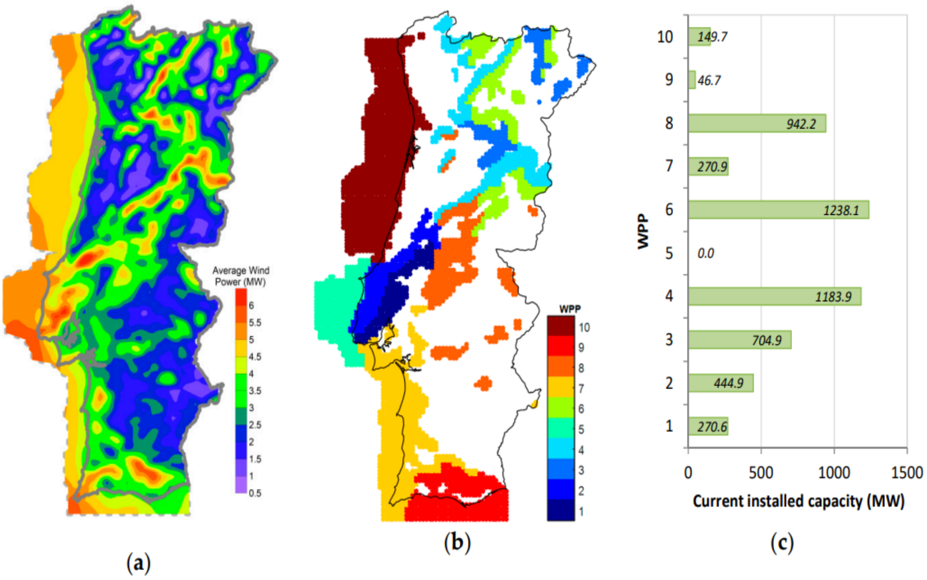


Figure B.4: Figure 4. (a) Average wind power production, (b) spatial distribution of the wind power profiles (WPPs) (only spatial points with an average wind speed above 5.5 m/s are presented and used, and wind power capacity in each WPP, (c) current wind power capacity in each WPP. From [132]

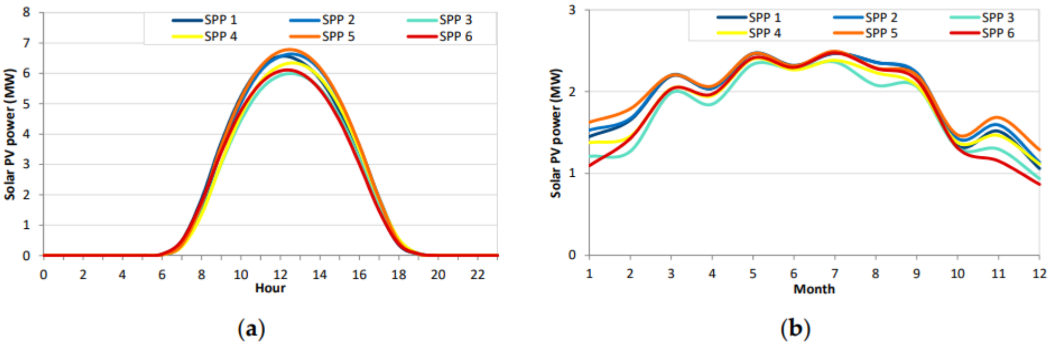


Figure B.5: Average (a) daily and (b) monthly solar PV power profiles for all SPPs identified from [132]

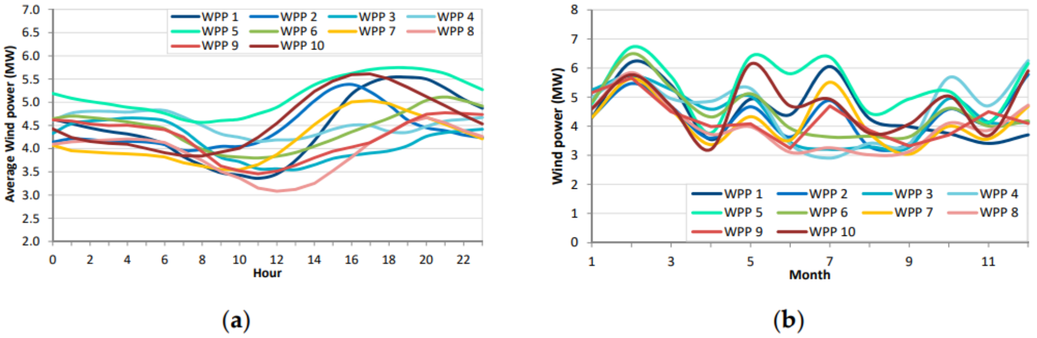


Figure B.6: Average (a) daily and (b) monthly wind power profiles for all ten WPPs identified from [132]

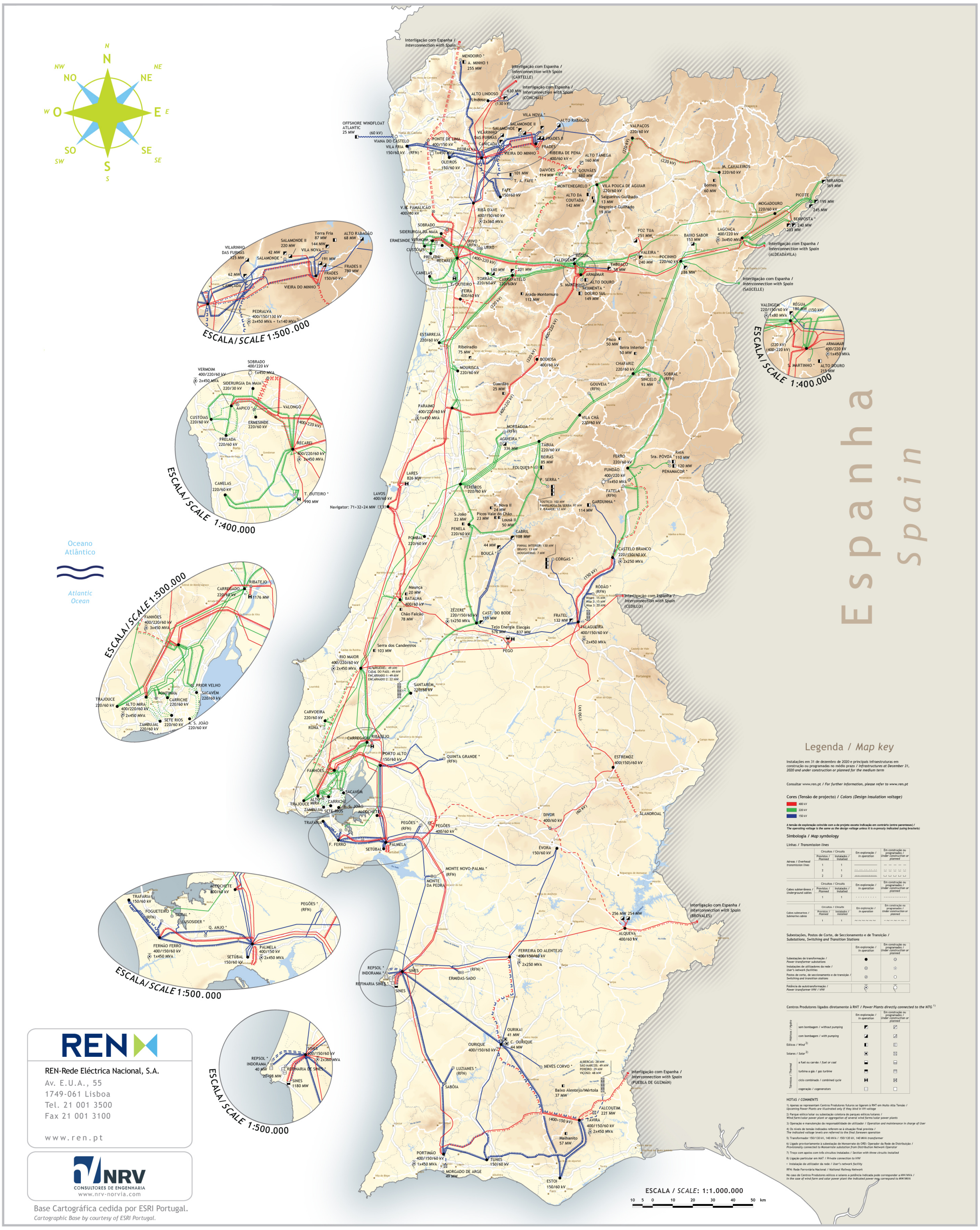


Figure B.7: REN Map

[56]

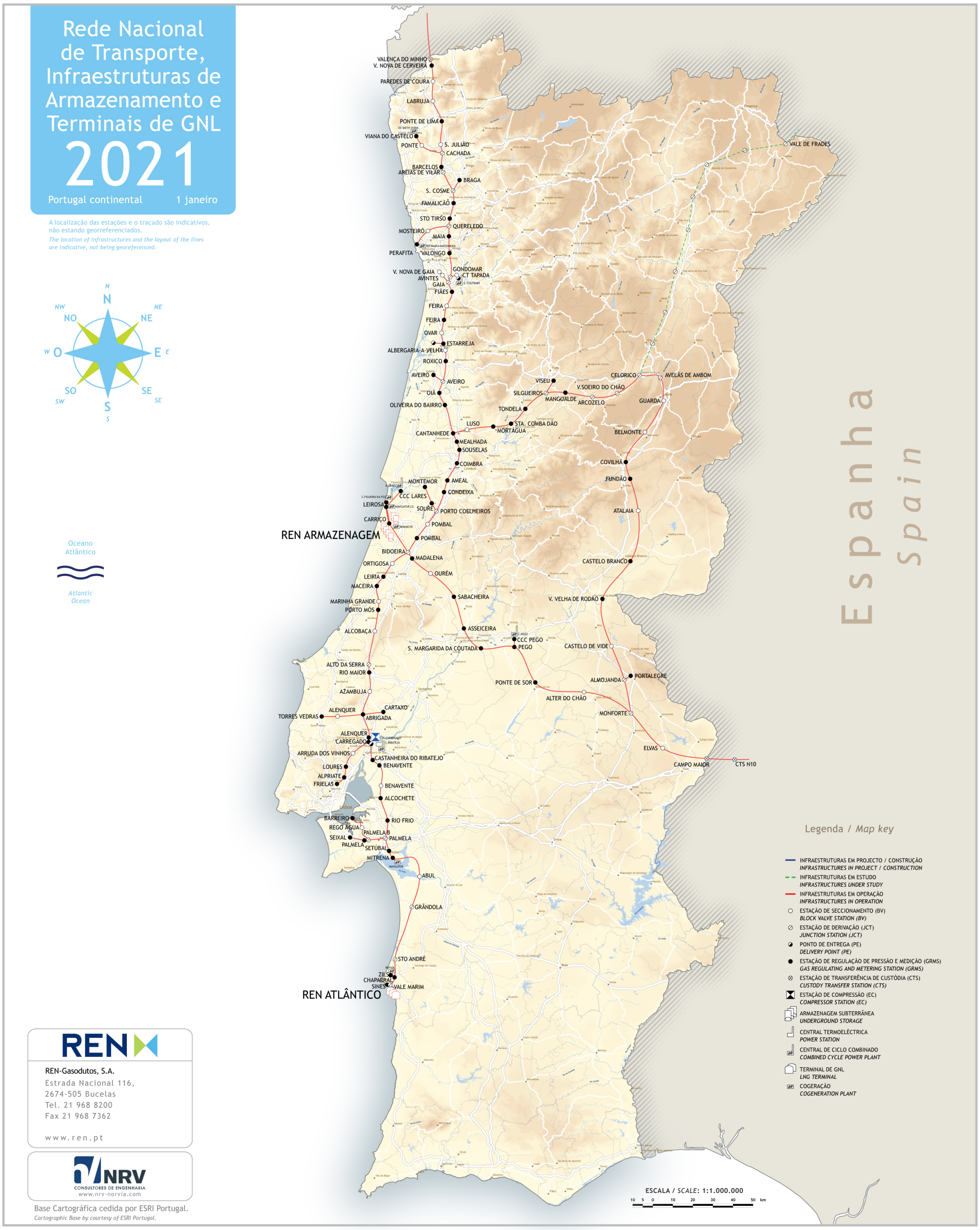


Figure B.8: REN Gas Map

[56]

Appendix C

Annex

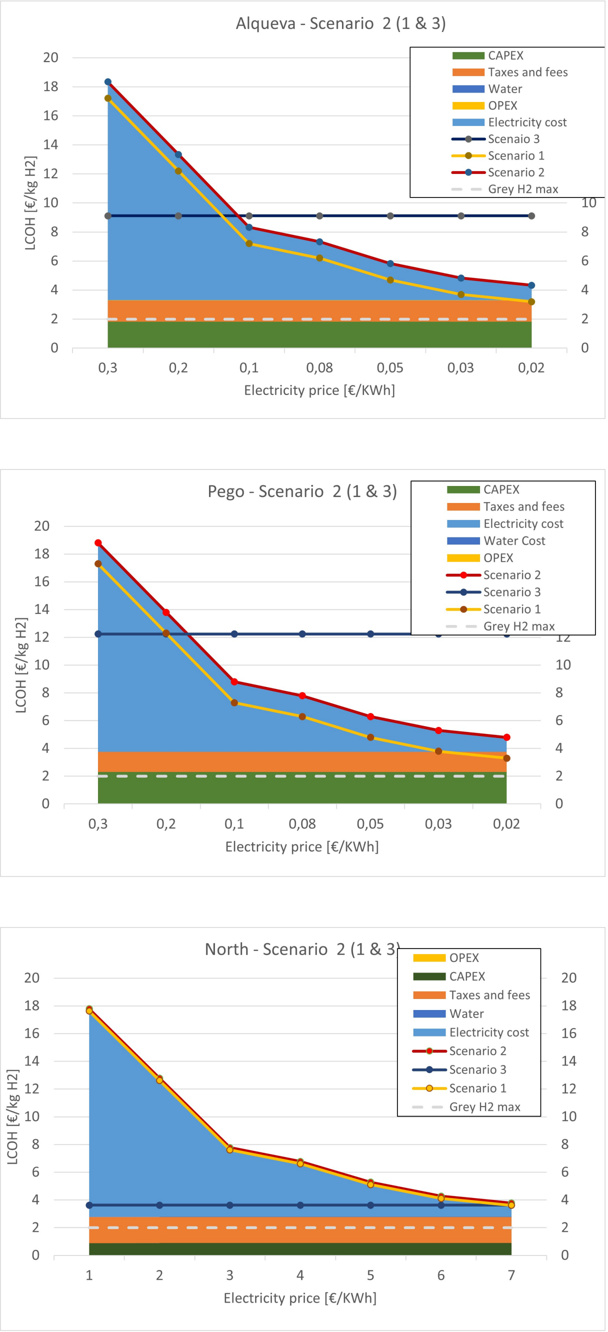
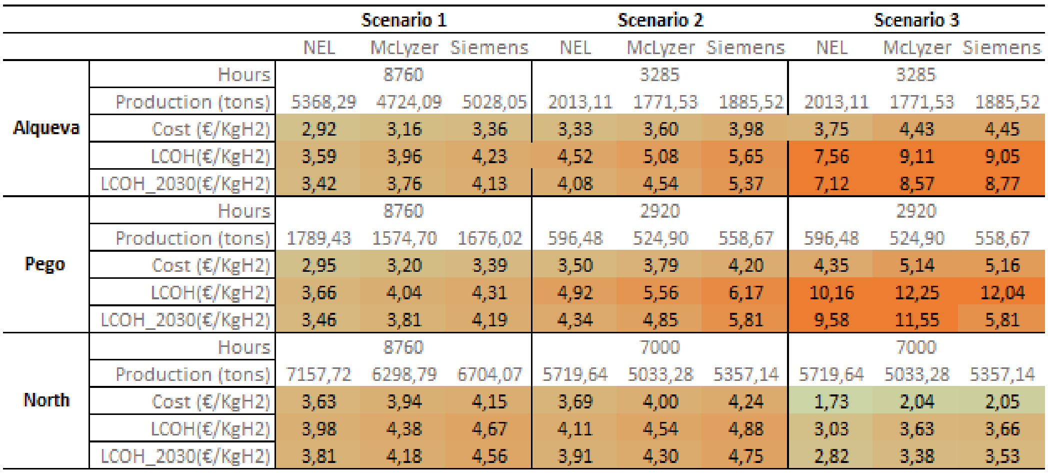
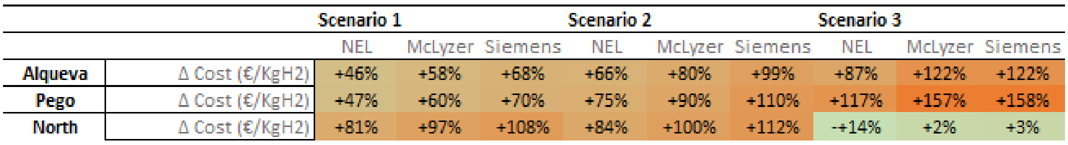


Figure C.1: Scenarios 2 and 3 for each site - Cumulative analysis



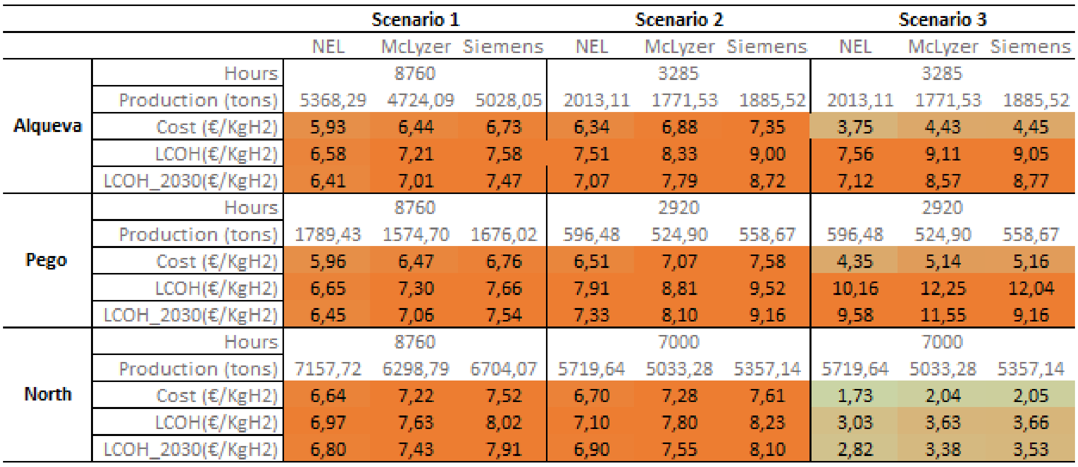
		Scenario 1			Scenario 2			Scenario 3		
		NEL	McLyzer	Siemens	NEL	McLyzer	Siemens	NEL	McLyzer	Siemens
Alqueva	Hours	8760			3285			3285		
	Production (tons)	5368,29	4724,09	5028,05	2013,11	1771,53	1885,52	2013,11	1771,53	1885,52
	Cost (€/KgH2)	2,92	3,16	3,36	3,33	3,60	3,98	3,75	4,43	4,45
	LCOH(€/KgH2)	3,59	3,96	4,23	4,52	5,08	5,65	7,56	9,11	9,05
	LCOH_2030(€/KgH2)	3,42	3,76	4,13	4,08	4,54	5,37	7,12	8,57	8,77
Pego	Hours	8760			2920			2920		
	Production (tons)	1789,43	1574,70	1676,02	596,48	524,90	558,67	596,48	524,90	558,67
	Cost (€/KgH2)	2,95	3,20	3,39	3,50	3,79	4,20	4,35	5,14	5,16
	LCOH(€/KgH2)	3,66	4,04	4,31	4,92	5,56	6,17	10,16	12,25	12,04
	LCOH_2030(€/KgH2)	3,46	3,81	4,19	4,34	4,85	5,81	9,58	11,55	5,81
North	Hours	8760			7000			7000		
	Production (tons)	7157,72	6298,79	6704,07	5719,64	5033,28	5357,14	5719,64	5033,28	5357,14
	Cost (€/KgH2)	3,63	3,94	4,15	3,69	4,00	4,24	1,73	2,04	2,05
	LCOH(€/KgH2)	3,98	4,38	4,67	4,11	4,54	4,88	3,03	3,63	3,66
	LCOH_2030(€/KgH2)	3,81	4,18	4,56	3,91	4,30	4,75	2,82	3,38	3,53

Figure C.2: Results Overview for a price of electricity of 35€/MWh



		Scenario 1			Scenario 2			Scenario 3		
		NEL	McLyzer	Siemens	NEL	McLyzer	Siemens	NEL	McLyzer	Siemens
Alqueva	Δ Cost (€/KgH2)	+46%	+58%	+68%	+66%	+80%	+99%	+87%	+122%	+122%
Pego	Δ Cost (€/KgH2)	+47%	+60%	+70%	+75%	+90%	+110%	+117%	+157%	+158%
North	Δ Cost (€/KgH2)	+81%	+97%	+108%	+84%	+100%	+112%	-+14%	+2%	+3%

Figure C.3: Results Comparison - Comparison with cost of Grey Hydrogen (2 €/KgH2) for electricity price of 35€/MWh



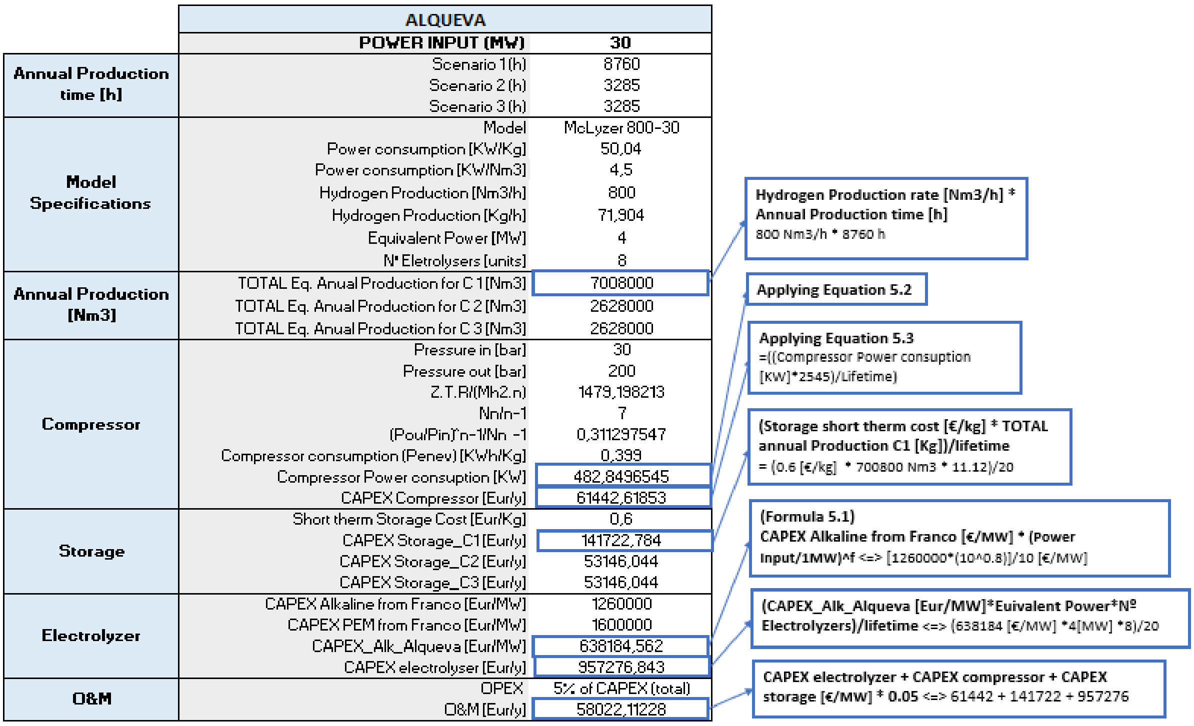
		Scenario 1			Scenario 2			Scenario 3		
		NEL	McLyzer	Siemens	NEL	McLyzer	Siemens	NEL	McLyzer	Siemens
Alqueva	Hours	8760			3285			3285		
	Production (tons)	5368,29	4724,09	5028,05	2013,11	1771,53	1885,52	2013,11	1771,53	1885,52
	Cost (€/KgH2)	5,93	6,44	6,73	6,34	6,88	7,35	3,75	4,43	4,45
	LCOH(€/KgH2)	6,58	7,21	7,58	7,51	8,33	9,00	7,56	9,11	9,05
	LCOH_2030(€/KgH2)	6,41	7,01	7,47	7,07	7,79	8,72	7,12	8,57	8,77
Pego	Hours	8760			2920			2920		
	Production (tons)	1789,43	1574,70	1676,02	596,48	524,90	558,67	596,48	524,90	558,67
	Cost (€/KgH2)	5,96	6,47	6,76	6,51	7,07	7,58	4,35	5,14	5,16
	LCOH(€/KgH2)	6,65	7,30	7,66	7,91	8,81	9,52	10,16	12,25	12,04
	LCOH_2030(€/KgH2)	6,45	7,06	7,54	7,33	8,10	9,16	9,58	11,55	9,16
North	Hours	8760			7000			7000		
	Production (tons)	7157,72	6298,79	6704,07	5719,64	5033,28	5357,14	5719,64	5033,28	5357,14
	Cost (€/KgH2)	6,64	7,22	7,52	6,70	7,28	7,61	1,73	2,04	2,05
	LCOH(€/KgH2)	6,97	7,63	8,02	7,10	7,80	8,23	3,03	3,63	3,66
	LCOH_2030(€/KgH2)	6,80	7,43	7,91	6,90	7,55	8,10	2,82	3,38	3,53

Figure C.4: Results Overview for a price of electricity of 100€/MWh

Appendix D

Spreadsheet and Equations

A spreadsheet extract and the main equations for Alqueva´s Site, using McLyzer Alkaline model is presented below:



	ALQUEVA	
	POWER INPUT (MW)	**30**
Annual Production time [h]	Scenario 1 (h)	8760
	Scenario 2 (h)	3285
	Scenario 3 (h)	3285
Model Specifications	Model	McLyzer 800-30
	Power consumption [KW/Kg]	50,04
	Power consumption [KW/Nm3]	4,5
	Hydrogen Production [Nm3/h]	800
	Hydrogen Production [Kg/h]	71,904
	Equivalent Power [MW]	4
	Nº Eletrolysers [units]	8
Annual Production [Nm3]	TOTAL Eq. Anual Production for C 1 [Nm3]	7008000
	TOTAL Eq. Anual Production for C 2 [Nm3]	2628000
	TOTAL Eq. Anual Production for C 3 [Nm3]	2628000
Compressor	Pressure in [bar]	30
	Pressure out [bar]	200
	Z.T.R/(Mh2.n)	1479,198213
	Nn/n-1	7
	(Pou/Pin)^n-1/Nn -1	0,311297547
	Compressor consumption (Penev) [KWh/Kg]	0,399
	Compressor Power consuption [KW]	482,8496545
	CAPEX Compressor [Eur/y]	61442,61853
Storage	Short therm Storage Cost [Eur/Kg]	0,6
	CAPEX Storage_C1 [Eur/y]	141722,784
	CAPEX Storage_C2 [Eur/y]	53146,044
	CAPEX Storage_C3 [Eur/y]	53146,044
Electrolyzer	CAPEX Alkaline from Franco [Eur/MW]	1260000
	CAPEX PEM from Franco [Eur/MW]	1600000
	CAPEX_Alk_Alqueva [Eur/MW]	638184,562
	CAPEX electrolyser [Eur/y]	957276,843
O&M	OPEX	5% of CAPEX (total)
	O&M [Eur/y]	58022,11228

Hydrogen Production rate [Nm3/h] * Annual Production time [h]
800 Nm3/h * 8760 h

Applying Equation 5.2

Applying Equation 5.3
=((Compressor Power consuption [KW]*2545)/Lifetime)

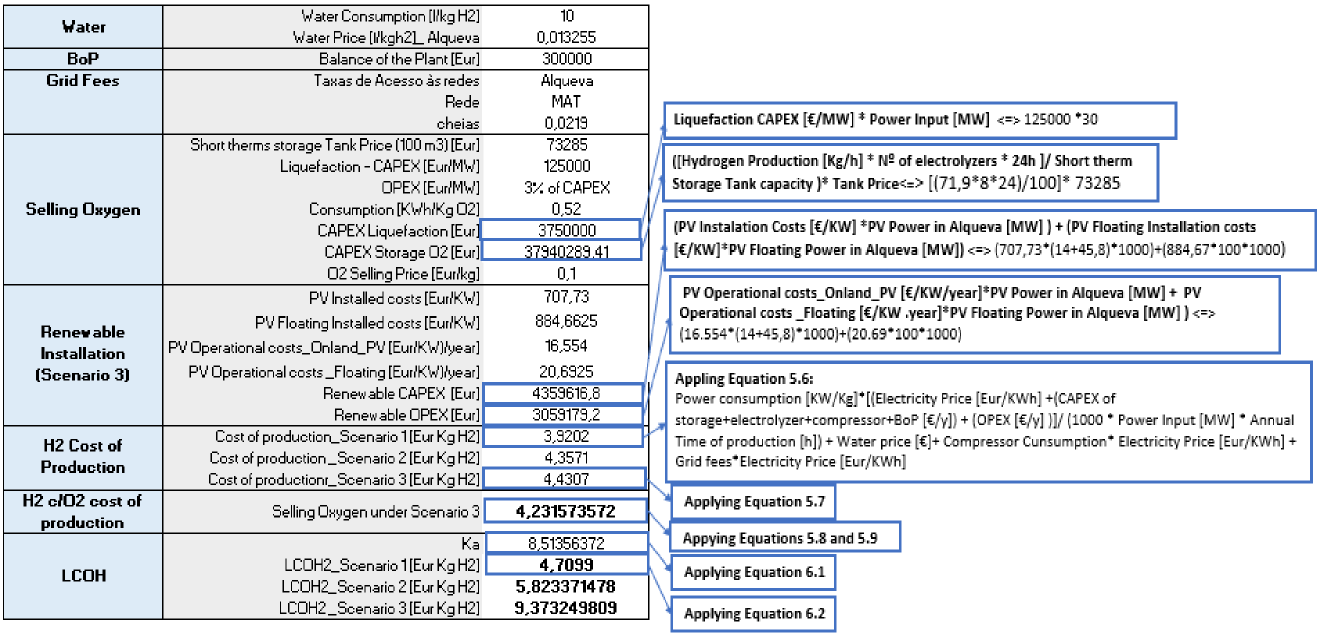
(Storage short therm cost [€/kg] * TOTAL annual Production C1 [Kg])/lifetime
= (0.6 [€/kg] * 700800 Nm3 * 11.12)/20

(Formula 5.1)
CAPEX Alkaline from Franco [€/MW] * (Power Input/1MW)^f <=> [1260000*(10^0.8)]/10 [€/MW]

(CAPEX_Alk_Alqueva [Eur/MW]*Euivalent Power*Nº Electrolyzers)/lifetime <=> (638184 [€/MW] *4[MW] *8)/20

CAPEX electrolyzer + CAPEX compressor + CAPEX storage [€/MW] * 0.05 <=> 61442 + 141722 + 957276

Figure D.1: Alqueva (McLYzer Alkaline) extract from the spreadsheet and equations



Water	Water Consumption [l/kg H2]	10
	Water Price [l/kgh2]_ Alqueva	0,013255
BoP	Balance of the Plant [Eur]	300000
Grid Fees	Taxas de Acesso às redes	Alqueva
	Rede	MAT
	cheias	0,0219
Selling Oxygen	Short therms storage Tank Price (100 m3) [Eur]	73285
	Liquefaction - CAPEX [Eur/MW]	125000
	OPEX [Eur/MW]	3% of CAPEX
	Consumption [KWh/Kg O2]	0,52
	CAPEX Liquefaction [Eur]	3750000
	CAPEX Storage O2 [Eur]	37940289,41
	O2 Selling Price [Eur/kg]	0,1
Renewable Installation (Scenario 3)	PV Installed costs [Eur/KW]	707,73
	PV Floating Installed costs [Eur/KW]	884,6625
	PV Operational costs_Onland_PV [Eur/KW)/year]	16,554
	PV Operational costs _Floating [Eur/KW)/year]	20,6925
	Renewable CAPEX [Eur]	4359616,8
	Renewable OPEX [Eur]	3059179,2
H2 Cost of Production	Cost of production_Scenario 1 [Eur Kg H2]	3,9202
	Cost of production_Scenario 2 [Eur Kg H2]	4,3571
	Cost of productionr_Scenario 3 [Eur Kg H2]	4,4307
H2 c/O2 cost of production	Selling Oxygen under Scenario 3	**4,231573572**
LCOH	Ka	8,51356372
	LCOH2_Scenario 1 [Eur Kg H2]	**4,7099**
	LCOH2_Scenario 2 [Eur Kg H2]	**5,823371478**
	LCOH2_Scenario 3 [Eur Kg H2]	**9,373249809**

Liquefaction CAPEX [€/MW] * Power Input [MW] <=> 125000 *30

([Hydrogen Production [Kg/h] * Nº of electrolyzers * 24h]/ Short therm Storage Tank capacity)* Tank Price<=> [(71,9*8*24)/100]* 73285

(PV Instalation Costs [€/KW] *PV Power in Alqueva [MW]) + (PV Floating Installation costs [€/KW]*PV Floating Power in Alqueva [MW]) <=> (707,73*(14+45,8)*1000)+(884,67*100*1000)

PV Operational costs_Onland_PV [€/KW/year]*PV Power in Alqueva [MW] + PV Operational costs _Floating [€/KW .year]*PV Floating Power in Alqueva [MW]) <=> (16.554*(14+45,8)*1000)+(20.69*100*1000)

Appling Equation 5.6:
Power consumption [KW/Kg]*[(Electricity Price [Eur/KWh] +(CAPEX of storage+electrolyzer+compressor+BoP [€/y]) + (OPEX [€/y])]/ (1000 * Power Input [MW] * Annual Time of production [h]) + Water price [€]+ Compressor Cunsumption* Electricity Price [Eur/KWh] + Grid fees*Electricity Price [Eur/KWh]

Applying Equation 5.7

Appying Equations 5.8 and 5.9

Applying Equation 6.1

Applying Equation 6.2

Figure D.2: Alqueva (McLYzer Alkaline) extract from the spreadsheet and equations