The Green Hydrogen as a Feedstock:
A Techno-Economic Analysis of a Photovoltaic-Powered Electrolysis Plant

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ABSTRACT

It is a common opinion that the renewable sources play a primary role to reduce the greenhouse gas (GHG) emissions and that, according to the IEA, solar may become the largest source of low-carbon electricity capacity by 2040, when the share of all renewable energy sources (RES) in total power generation would reach 40%, led by China and India. In the European Union, soon after 2030, renewables will account for 80% of new capacity and wind power becomes the leading source of electricity, due to strong growth both onshore and offshore (IEA, 2017).

The weather-dependent electricity generation from RES entails that systems for energy storage are becoming increasingly important. Among the various solutions that are being evaluated, hydrogen is currently considered to be one of the key enabling technologies allowing future large scale and long term storage of renewable power.

At present, hydrogen is mainly produced from fossil fuels, and steam methane reforming (SMR) is the most widely used route for producing hydrogen from natural gas. None of the conventional methods used is GHG-free. The Power-to-Gas concept, based on water electrolysis utilizing electricity derived from renewable energies is the most environmentally friendly approach. Given its multiple uses, hydrogen is sold both as a fuel, which can produce electricity through fuel cells, and as a feedstock in several industrial processes. Just the feedstock could be, in a short term, the main market of RES-based hydrogen.

In this paper, we present the results obtained from a techno-economic-financial evaluation of a system to produce green hydrogen to be sold as a feedstock for industries and research centres. We proposed, as a case study, a system which includes a 200 kW photovoltaic plant and a 180 kW electrolyser, to be located in Messina (Italy). According to our analyses, and taking into account the current development of technologies, we found out that an investment to realize a small-scale PV-based hydrogen production plant can be remunerative.

1. Introduction

Clean energy development is vital for combating climate change and limiting its most devastating effects, but this must be achieved while maintaining the secure energy supply to warrant social and economic development. Renewable energies play a fundamental role to address all these issues. For this reason the policy of the main industrialized countries of the world are being oriented towards increasing the shares of power produced from RES. This has as a consequence the transformation of the power supply chain.

Nowadays, the power supply is mainly assured by fuels and electricity, this last largely generated from fossil fuels. The energy sector is facing two major issues: (i) growing energy demand; and (ii) environmental impact. Consequently, reducing greenhouse gas (GHG) emission means reducing the use of fossil fuels, also for generating electric power, and increasing electrification. Electricity is the rising force among worldwide end-uses of energy, making up 40% of the rise in final consumption to 2040 – the same share of growth that oil took for the last twenty-five years. By 2040, electricity demand for cooling in China would exceed the total electricity demand of Japan today. The world gains, on average, 45 million new electricity consumers each year due to expanding access to electricity.

The largest contribution to demand growth comes from developing countries in Asia, which account for two-thirds of global energy growth, with the rest coming mainly from the Middle East, Africa and Latin America. To meet rising demand, China needs to add the equivalent of today's United States power system to its electricity infrastructure by 2040, and India needs to add a power system the size of today's European Union. In this framework, the renewable sources can play a primary role to reduce the greenhouse emissions. Within renewable generation, solar and wind power are easily converted into electricity by photovoltaic panels and wind mills, while concentrated solar power is under development for its large scale deployment. At the end of 2016, solar and wind installed capacities (296 and 467 GW, respectively) accounted for almost 40% of all renewable installed power capacity. China leads the market for solar and wind with an installed capacity of 226 GW, 30% of the world total (ENI, 2017).

A key issue to be faced is that electricity generation from renewables is heavily weather-dependent, and this means: (i) fluctuations causing instability of power systems; and (ii) limited coincidence of supply and demand. As a consequence, systems for storing energy are becoming increasingly important. Hydrogen is currently considered to be one of the key enabling technologies allowing future large scale and long term green storage of renewable power.

At present, hydrogen is mainly produced (about 96%) from fossil fuels (Banerjee et al., 2017). Steam methane reforming (SMR) is the most widely used route for producing hydrogen from natural gas. Other thermo-chemical conversion technologies allow hydrogen production through different pathways (Lymberopoulos, 2007), but all these conventional processes are not GHG-free.

Water electrolysis utilizing electricity derived from renewable energies (wind, solar, geothermal, hydro) is the most environmentally friendly approach. This attractive method for hydrogen generation, based on a mature technology, currently accounts for only 4% of the hydrogen production, but its large expansion is expected in the next few years: a share of 22% is predicted for 2050 (Cornell, 2017).

Hydrogen is not only a fuel useful for electric power storage but also a raw material for a number of industrial processes that, up to now, represent almost all of the consumption of hydrogen.

Our research is focused specifically on the production and sale of hydrogen as a feedstock. Starting from a technical-economic analysis of a hypothetical plant, which is our case study, we assessed its financial and economic sustainability. We assumed that this (yet to be realized) plant is located in Messina, a Sicilian town in the South of Italy, and that the hydrogen generated is placed into the technical gases market.

We found out that, with a current alkaline electrolysis cell system, a return on investment (within 12 years) and profitability are achievable, but only if oxygen is sold in addition to hydrogen. In particular, the large amount of oxygen generated by electrolysis could be used for some medical and niche applications.

The results obtained clearly indicate that there are reasons to believe that, in the near future, hydrogen-based distributed generation could have a broad diffusion.

The paper is divided into three parts. The first (Paragraphs 2-3) includes a synthetic overview of RES hydrogen generation technologies and their use in various sectors. A specific paragraph is devoted to the use of hydrogen as a feedstock and its market trends. In the second part (Paragraph 4) a description of the case study is given, together with the methodological approach to perform the economic-financial analysis and the two hypotheses investigated. In the last part, we report the results (Paragraph 5) and conclusions.

2. Hydrogen production from RES: an overview

Hydrogen has a plurality of applications and can be produced from a variety of raw materials or recovered from some industrial processes (like chlorine-soda). The lower polluting process is production of hydrogen from water using electrolysis to generate high purity hydrogen. But this process needs electric power, consequently electrolysis is really green when the electric power comes from RES. At the moment, it is considered a more expensive system than steam methane reforming (SMR).

Three main electrolyser technologies are used or being developed today (see e.g. Aricò et al., 2016):

- ***Alkaline electrolysis cells*** (AEC): the technology is fully mature and is used in the industry, particularly in the chemical industry (e. g., chlorine manufacture). The lifetime of an AEC electrolyser is currently twenty years and is expected to remain significantly longer for the next decade. The alkaline technology was not originally designed to be flexible and has traditionally been operated at a constant load to serve industrial needs. Recent progress should nevertheless be noted, making AEC technology compatible with the provision of grid services on a short timescale. At present, however, AEC technology remains less flexible than PEMEC technology, which ultimately limits the amount of extra revenue that the operator could potentially capture.
  Alkaline electrolysers use a liquid electrolyte (e.g., KOH), and typically operates at 60-80°C.
- ***Proton exchange membrane electrolysis cells*** (PEMEC): already available in the market, are rapidly gaining market shares. They tend to have a smaller footprint and can operate more flexibly

and reactively than current AEC technology, offering a wider operating range and a shorter response time. This flexibility might improve the overall economics of power-to-hydrogen, potentially providing a new revenue stream from multiple electricity markets to compensate for the higher capital cost compared to AEC electrolysers.

PEMEC use a solid polymer electrolyte, and its working temperature is below 80°C.

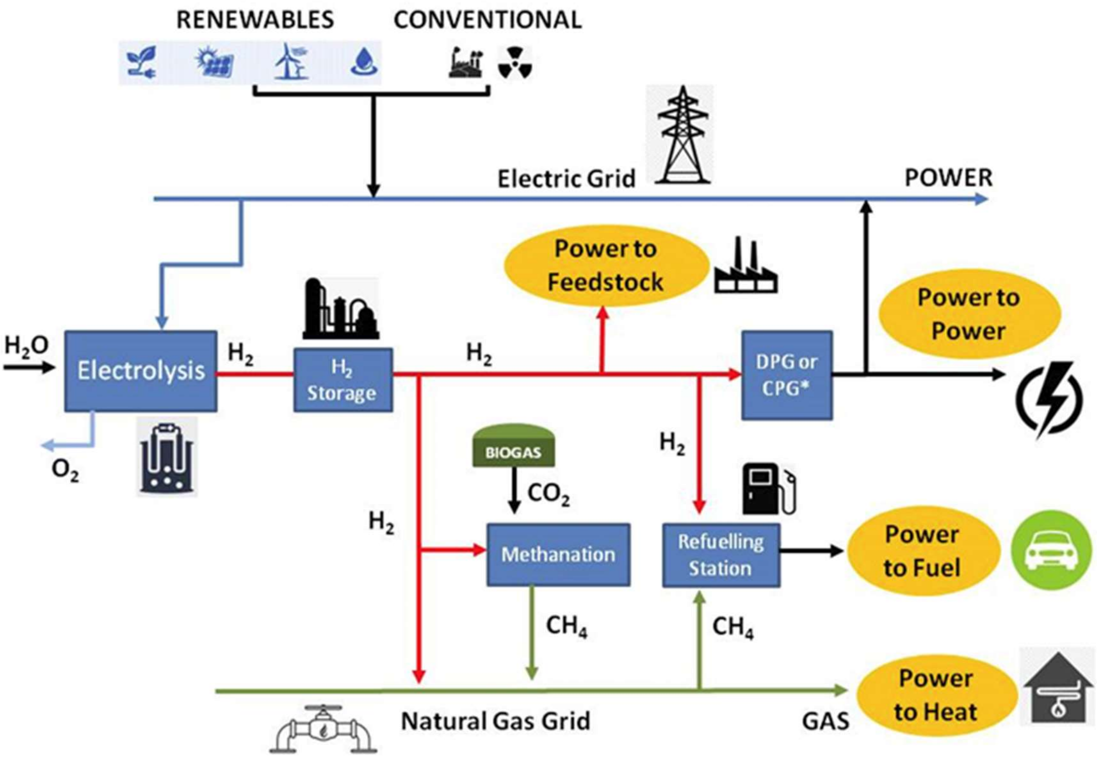
– ***Solid oxide electrolysis cells*** (SOEC): hold the potential of improved energy efficiency but are still in a early stage of development. SOEC uses a proton conducting ceramic membrane and operates at high temperatures (600-1000 °C).

Achieving technology scale-up and cost reductions from wider adoption are currently the most critical challenges, mainly for PEMEC but also for AEC electrolyser manufacturers.

As already mentioned, electrolysis-hydrogen is used when high purity hydrogen is requested, or when there is a large availability of electric power at a very low cost, better if close to zero, like in the case of surplus of electric production. For this reason, since early deployment of RES, hydrogen via electrolysis was considered an interesting energy storage method, due to the fluctuating nature of the renewables.

As remarked by Dickinson et al. (2017), hydrogen produced via electrolysis – referred as *Power-to-Hydrogen* (P2H) – can be employed for a variety of end-uses, which include a range of high value products and services, mentioned as *Hydrogen-to-X* (H2X). The potential role of hydrogen as a key factor towards a low-carbon economy for decarbonisation of the transport, industry and energy sectors (power, gas and heating/cooling) is clearly evident.

A representation of the pathways of the hydrogen produced by electrolysis is shown in Fig. 1, where possible applications and uses are shown.



*DPG = Decentralized Power Generation (e.g., fuel cells or microturbines). CPG = Centralized Power Generation (e.g., turbines).

Figure 1: Schematic of the mentioned Power-to-X pathways.

As widely reported in our previous work (Nicita et al., 2018), applications like *Power-to-Power* (P2P) – i.e., production of hydrogen by electrolysis, storage and reconversion of hydrogen into clean electricity (re-electrification), by fuel cells or gas turbines – are promising for off-grid applications (e.g. remote communities and back-up power), but not yet competitive for grid-connected ones. In this case, the underground storage in salt caverns, aquifers and depleted oil and gas fields is mentioned as the most economic way of storing large volumes of hydrogen (see e.g. Al-Subaie et al., 2017).

Hydrogen will cover not only electric power demand, but also other demands like heat (*Power-to-Heat*) and fuel (*Power-to-Fuel*). By utilizing a *Power-to-Gas* pathway, hydrogen generated by electrolysis can also be directly injected into the existing natural gas network (blending), for use in combined heat and power (CHP) systems (cogeneration). Another *Power-to-Gas* process is to transform electricity, through electrolysis and subsequent methanation, into synthetic methane which can then be stored or injected into the gas grid. Hydrogen produced from electrolysis can also be distributed at the refuelling stations as a clean fuel (*Power-to-Fuel*) for mobility applications in fuel cell electric vehicles (FCEVs), or used as a chemical feedstock in the industry (*Power-to-Feedstock*).

3. Hydrogen as a feedstock

As mentioned above, the hydrogen produced by SMR or by electrolysis can be used in many sectors. For instance, it can be used as a feedstock in several industrial processes. The hydrogen feedstock market has a total estimated value of USD 115 billion, and is expected to grow significantly in the coming years, reaching USD 155 billion by 2022 (IRENA, 2018). In 2015, total global hydrogen demand was estimated to be 8 Exajoules (Hydrogen Council, 2017).

The main industrial productions, in which hydrogen is used, are:

- Chemicals: ammonia, polymer and resin productions. These represent the primary industrial markets for hydrogen.
- Refining: globally, refineries are the second-largest consumers of hydrogen in industry. Hydrogen is used for hydro-cracking and for desulphurisation of fuels (hydrotreating).
- Iron and steel: an alternative and innovative process called direct reduction of iron via hydrogen (DRI-H), avoiding coke usage, is currently at a demonstration stage and could be a stepping stone for energy-efficient and low-carbon steelmaking. Taking into consideration that the system is an experimental phase, the total global demand for hydrogen in the sector is relatively small.

The largest share of hydrogen demand is from the chemicals and refining sectors. Other industry sectors also use hydrogen, but their combined share of total global demand is small (just 1%; IRENA, 2018). These include: manufacturing of glass, food products (hydrogenation of fats), bulk and specialty chemicals, semiconductors, cooling of electrical generators, propellant fuel for rockets in aerospace, etc.

Therefore, the large industrial sectors, as refineries and chemicals production, are expected to be key early markets for power-to-hydrogen. In particular, Al-Subaie et al. (2017) claimed that the hydrogen can be consumed instantaneously by the oil refining and chemical industries without the necessity for increasing FCEV market penetration.

At the moment, the hydrogen used as industry feedstock is mainly produced on-site in dedicated plants or as a by-product from other processes (20 to 30%; Hydrogen Council, 2017). For instance, in Europe and the United States, SMR is the primary option. In China, the valorisation of by-product hydrogen dominates the scene, although coal gasification is also used for metal and petrochemical production. In Australia, most hydrogen is generated by coal gasification.

According to the Hydrogen Council (2017), by 2050, the demand for hydrogen could rise to 70 million tons (10 EJ) in current applications alone, driven by the growth in global chemicals production. But, if the hydrogen will continue to be produced mainly from fossil sources, this will contribute to increase emissions estimated in around 500 Mt of CO_2. For this reason, the international community's purpose is decarbonisation of the hydrogen production through carbon capture, electrolysis, or increased use of by-product hydrogen. This will allow to reduce annual CO_2 emissions as much as 440 million tons in 2050.

Therefore, the green hydrogen used as a feedstock can contribute to decarbonisation in two ways:

- by producing it from clean sources, such as natural gas with carbon capture and storage (CCS), or through electrolysis from renewable electricity.

- by replacing carbon (from natural gas or coal) as a reducing agent in the iron-making process, and by using it together with captured CO_2 to replace fossil feedstock in the production of hydrocarbon-based chemicals, such as methanol and derived products.

The hydrogen demand forecasts – in the industry sectors as oil refining, fertilizers (based on ammonia) and chemicals (based on methanol) – present different trends. In the oil refineries, the hydrogen is used to lower the sulphur content of fuels. The desulfurization requirements around the world are increasing, and it is expected that the hydrogen use will grow till 2030, then the increasing electrification of the transport sector will lead to a reduction of the overall demand. In the fertilizer and chemicals industries, the demand for hydrogen will grow, driven by the demand for ammonia and methanol. Both ammonia and methanol are considered important alternative fuels on which some countries have been investing to face the challenge of increasing their energy consumption and simultaneously decreasing their emissions. For instance in China, the ammonia, besides being one of the most important fertilizers, is considered the most realistic and clean fuel that can be utilized for the near future, due to its significantly lower price than gasoline and diesel.

Concerning other sectors, in the iron and steel production, currently, about 4% of global crude steel is produced through the DRI (direct reduced iron) process, which is mainly based on natural gas as a reducing agent. It is expected that, by 2050, about 10% of crude steel could be produced through DRI using hydrogen from renewable power, then the emissions could be reduced up to 190 million tons of CO_2 annually.

Moreover, hydrogen can be used to convert captured CO_2 to chemicals. Carbon capture and utilisation (CCU) systems offer the opportunity to convert CO_2 into high-value chemicals and drive the uptake of carbon capture technologies. But some barriers, as the cost of carbon capture (about \$100 per ton of CO_2 for small capture plants) as well as the cost of electrolysis, hinder a broad use of CCU.

By 2050, considering the development of the captured carbon and electrolysis technologies (and their related cost reduction), it is expected that 30% of methanol, olefins, and aromatics could be produced from these two approaches. In this way, the request of hydrogen would increase reaching about 50 million tons, and the industry could recycle 360 million tons of CO_2 into some 260 million tons of product (Hydrogen Council, 2017). According to the Hydrogen Council (2017), in order to reach all the above mentioned aims, it will be necessary to make investments equal to \$50 billion over the next 12 years, the majority of which in existing industries.

Around the world, some plants have already been implemented and others are going to be realized in the next future. Multiple projects are underway (Hydrogen Council, 2017; HE, 2018); some examples are specified below.

- **REFHYNE:** Shell and ITM Power are planning to install a 10 MW electrolyser on the Rhineland refinery which currently relies on SMR to produce hydrogen. This is the Germany's largest refinery, consuming about 180,000 tonnes of hydrogen annually. The new electrolyser will be able to provide an additional 1,300 tonnes of hydrogen per year.
- **HyBalance:** In Denmark, through a project coordinated by Air Liquide, a demonstration plant has been developed in Hobro; it produces hydrogen from water electrolysis using surplus electricity from renewables to balance the grid. The delivered hydrogen will be used for transportation and in the industrial sector.
- **HyBrit:** A Swedish joint venture by SSAB, LKAB, and Vattenfall is demonstrating zero-carbon steelmaking using DRI with green hydrogen from electrolysis.
- **H2FUTURE:** In a steel plant in Linz, Austria, green hydrogen from renewable energy is used to produce steel with a lower carbon footprint, called "green steel". The gas is either sold to industry or used for powering hydrogen cars.
- Another initiative has been implemented in Iceland: Carbon Recycling International's George Olah plant produces hydrogen from electrolysis and captures CO_2 from a geothermal power plant to produce about 4,000 tons of methanol per year and recycle about 5,500 tons of CO_2.

Other projects are investigating advanced processes to recycle the CO_2 emissions and produce hydrogen from surplus renewable electricity.

The sectors and applications described above mainly require large amounts of hydrogen, while there is also a request of hydrogen from SMEs, research centres and craftsmen. This market is usually referred as "technical gases", a local market that suffer of the transportation costs related to centralised production of gases. This market is well organised and is based on a number of local gases distributors/resellers. The opportunity of placing the hydrogen produced by electrolysis on the feedstock market of "technical gases" obviously depends on the local context, to be evaluated on a case-by-case basis. Due to the fact that this market is served by a network of local distributors/resellers, we considered the technical gases market as a possible market outlet for distributed hydrogen generation.

4. The case study

4.1. Introduction to the case study

Taking into consideration the above information and data, coming from the literature, we focused our research to assess the return on investment and the profitability of an alkaline electrolysis system for the production of hydrogen to be placed on the market of technical gases, therefore mainly industries and research centres.

The case study, in particular, concerns a techno-economic-financial evaluation of a system – not yet realized – that includes a 200 kW photovoltaic plant and a 180 kW electrolyser, to be located in Messina (Italy). The analysis was conducted from the perspective of an entrepreneur or investor who wants to assess whether it is advisable to invest in a new industrial activity aimed at selling hydrogen, produced by renewable sources, as a feedstock.

Two possible hypotheses have been investigated:

- the installation of electrolyser alone, connected to an existing PV plant.
- the implementation of the whole system, both PV plant and electrolyser.

Besides, we tested the two hypotheses under two different scenarios: one which assumes the sale of the produced hydrogen, and the other envisaging the possibility to sell also the co-produced oxygen.

4.2. Methodological approach

To perform the economic-financial analysis, we adopted the method proposed by Kuckshinrichs et al. (2017). Thus, starting from cash flow (*CF*) data, we used different metrics such as levelized cost of hydrogen (*LCH*) to carry out a cost assessment, and net present value (*NPV*) to evaluate the investment attractiveness. Besides, the project's profitability has also been measured in terms of standard and modified internal rate of return (*IRR* and *MIRR*).

A key financial parameter is the weighted average cost of capital (*WACC*), defined as

$$WACC^{real} = \left(\frac{1 + WACC^{nom}}{1 + infl}\right) - 1 \qquad (1)$$

with

$$WACC^{nom} = \frac{e}{e+d}\, e_r + \frac{d}{e+d}\, e_d \qquad (2)$$

where e is the share of equity, d the share of debt, e_r the equity rate of return, e_d the interest rate on debt, and $infl$ the inflation rate.

Assuming no debt financing ($d = 0$), we obtain

$$WACC^{real} = \frac{1 + e_r}{1 + infl} - 1 \qquad (3).$$

The net present value (*NPV*) is defined as the present (discounted) value of all the future cash flows (negative and positive) generated over the lifetime of the project. Therefore, it can be calculated as the sum of discounted net cash flows:

$$NPV = \sum_{n=0}^{N} \frac{CF_n}{(1+r)^n} = \sum_{n=1}^{N} \frac{CF_n}{(1+r)^n} - I_0 \tag{4}$$

where CF_n is the net cash flow (i.e., cash inflows less cash outflows) at time n, r is the discount rate (equal to $WACC$), N is the number of periods, and I_0 is the initial investment cost, also known as CAPEX (capital expenditure). When $NPV > 0$ the revenues are greater than the costs, and the investor makes a profit. The projects with higher *NPV* are better, if one wants to compare or chose between mutually exclusive projects.

In our case, the *NPV* can be further specified as

$$NPV = -CAPEX + (1 - TR) \sum_{n=1}^{N} \frac{REV_n - OPEX_n}{(1+r)^n} \tag{5}$$

being REV_n the revenues (annual incomes obtained by the project) at time n, $OPEX_n$ the operative expenditure (fixed and variable O&M costs) at time n, and TR the tax rate on earnings.

To better distinguish between costs and revenues, equation (5) can be rewritten as

$$NPV = -CAPEX - \sum_{n=1}^{N} \frac{OPEX_n}{(1+r)^n} - TR \sum_{n=1}^{N} \frac{REV_n}{(1+r)^n} + \sum_{n=1}^{N} \frac{REV_n}{(1+r)^n} + TR \sum_{n=1}^{N} \frac{OPEX_n}{(1+r)^n} \tag{6}$$

where the first three terms represent costs, while the other two terms are incomes; in particular, the last term is a "tax redemption".

Contrarily to the approach of Kuckshinrichs et al. (2017), equation (6) does not account for loan payments (for investment by debt) and interest on debt, as a consequence of our assumption (no debt financing). Besides, we excluded non-cash deductions (i.e., depreciation and amortization). Since we used a RES-based power system owned by a company, neither fuel costs nor electricity costs have been included in our analysis.

In our case, we assume the project revenues can arise from the sale of the hydrogen produced from the electrolysis plant and, eventually, from the sale of the oxygen co-produced (8 kg for each kg of hydrogen).

Therefore,

$$\begin{aligned}\sum_{n=1}^{N} \frac{REV_n}{(1+r)^n} &= \sum_{n=1}^{N} \frac{REVH_n + k\, REVO_n}{(1+r)^n} \\ &= \sum_{n=1}^{N} \frac{M_{H2}\,(1-SRD)^n}{(1+r)^n} P_{H2} + k \sum_{n=1}^{N} \frac{8\, M_{H2}\,(1-SRD)^n}{(1+r)^n} P_{O2}\end{aligned} \tag{7}$$

where $REVH_n$ are the revenues related to the selling of hydrogen, $REVO_n$ are the revenues related to the selling of oxygen, M_{H2} is the yearly mass of hydrogen produced (initial value), SRD is a system degradation rate, P_{H2} is the selling price of hydrogen, P_{O2} is the selling price of oxygen, and k is a flag (0=when only hydrogen is sold, 1=when hydrogen and oxygen are sold).

We also calculate the levelized cost of hydrogen (*LCH*) defined as

$$LCH = \frac{Total\ Lifetime\ Cost}{Total\ Lifetime\ H_2\ Production} = \frac{CAPEX + \sum_{n=1}^{N} \frac{OPEX_n}{(1+r)^n} + TR \sum_{n=1}^{N} \frac{REVH_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{M_{H2}\,(1-SRD)^n}{(1+r)^n}} \quad (8).$$

With respect to the paper of Kuckshinrichs et al. (2017), we above introduced a degradation rate (*SRD*) to account for a loss of the plant yield.

Besides, we included in our analysis two other financial metrics to estimate and compare the project's profitability: the internal rate of return (*IRR*) and the modified internal rate of return (*MIRR*). The first is defined as the discount rate that makes the present value of cash inflows equal to the present value of cash outflows; or the discount rate that makes the *NPV* of an investment equal to zero. It can be derived from the following equation

$$\sum_{n=0}^{N} \frac{CF_n}{(1+IRR)^n} = 0 \quad (9).$$

A general rule is to accept a project when $IRR > WACC$, while reject it when $IRR < WACC$. Moreover, when comparing two or more projects, the project with higher IRR should be preferred.

But IRR implicitly assumes that net cash inflows generated by the project are reinvested at a rate which is the same as *IRR*, which is not a market-derived discount; and multiple *IRR* values can exist for some projects (when cash flows are irregular). To overcome these problems, a modified internal rate of return is introduced, which is defined as the rate of return at which *NPV* of terminal inflows is equal to the outflow

$$MIRR = \sqrt[N]{\frac{Future\ value\ of\ positive\ cash\ flows}{-Present\ value\ of\ negative\ cash\ flows}} - 1 \quad (10).$$

Therefore, *MIRR* is given by

$$MIRR = \sqrt[N]{\frac{\sum_{n=1}^{N} CF_n^{+}(1+k_{rr})^{N-n}}{-\sum_{n=0}^{N} \frac{CF_n^{-}}{\left(1+k_{fr}\right)^n}}} - 1 \quad (11)$$

where CF_n^{+} is the net cash inflow at time *n*, CF_n^{-} the net cash outflow at time *n*, k_{rr} the reinvestment rate, and k_{fr} the finance rate.

In our calculations we assumed $k_{rr} = k_{fr} = WACC$.

4.3. Hypothesis 1: Installation of electrolyser connected to an existing 200 kWp PV plant

As a first hypothesis, we considered the case of a private, as a micro-business or SME, who manages a 200 kWp PV plant and wants to assess the opportunity to use the generated electricity to produce hydrogen to be sold as a feedstock for industry.

We assumed that the PV plant is located in the roof of an industrial building and was realized with public subsidies delivered by a government programme called "*conto energia*" (an incentive mechanism to the use of photovoltaic and wind energy in Italy). These incentives have an endurance of 20 years from the power plant start up, and the last incentive call to get subsidies was launched in 2012.

Consequently, we assumed that the plant is 20 years old and its efficiency has been reduced by 10% with respect to the beginning. Moreover, to calculate the annual energy production we located the plant in Messina (Lat. 38° 11' N, Long. 15° 33' E), Sicily, Italy.

4.3.1. Key parameters technology and plant characteristics of electrolyser system

To be more close to practical applications, we considered also the compression and storage of the products (hydrogen and oxygen), and not only the electrolyser alone.

The electrolyser system, which we assume to use in this case study, is based on the alkaline water electrolysis technology and has the following technical characteristics:

- Hydrogen production plant 32 Nm^3/h (peak) @ 5 bar outlet, 99.999% purity (power consumption 175 kW).
- Hydrogen compression plant from 5 bar up to 200 bar.
- Hydrogen storage plant equipped with 49 cylinders of 50 L, each as a void volume. Total volume: 2,450 L. Total H_2 stored @ 200 bar: 35 kg.

Main plant characteristics are summarized in Table 1. They include expected plant lifetime (20 years), stack lifetime (83,000 h operation; or 38 years), operational time (2,190 h/year), and hydrogen output (2.11 kg H_2/h). In particular, to calculate the hydrogen production, we assumed that the plant works an average of 6 hours per day, and estimated that the electricity generation from the PV plant is 260,000 kWh/y. Since the equivalent energy content of hydrogen is 39.4 kWh/kg, by assuming an efficiency of 70% for a conventional alkaline electrolysis, the actual specific energy consumption is about 56.3 kWh/kg H_2.

Therefore, the hydrogen output is about 4,620 kg H_2/y, or 12.7 kg H_2/day, which corresponds to an expected daily production of about 140.8 Nm^3/day (based on a gaseous hydrogen density of 0.08990 kg/Nm^3 @ 0° C, 1 atm).

Table 1: Plant characteristics

Parameter	Value	Note
PV plant peak power	200 kW	
Total power generation by PV plant	260,000 kWh/y	PVGIS estimate[a]
Efficiency of electrolyser	70%	Stolten & Emonts (2016)
Plant lifetime	20 years	
Stack lifetime	83,000 h	Koj et al. (2015)
Average daily operation	6 h/day	
Hydrogen output	12.7 kg/day	

[a] From http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php, for a building-integrated plant located in Messina.

4.3.2. Financial analysis

Through the financial analysis, we calculated the return on investment and financial sustainability. To do this, we start to find out the costs and determined them through the levelized cost of hydrogen (*LCH*) that includes: the direct depreciable capital costs (investments components) and indirect ones (site preparation, engineering and design, permissions, project contingency, etc.), operative and maintenance (O&M) costs.

As already mentioned, we assumed that the investment is only made by equity funds and the entrepreneur does not take loan funds. We considered that the year of investment was 2018 (year 0, for financial analysis); therefore the 20 years of the plant lifetime span from 2019 to 2038.

About the costs of the hydrogen production system, we requested quotations to companies that today commercialise alkaline electrolysis systems. This will allow us to use real investments costs instead of literature ones. The costs of the studied system are summarized in Table 2. In particular, about the investment, the direct depreciable capital costs (ddcc) concerning the whole electrolysis system – electrolyser, storage system and compressor – amount to about 543 k€. We assumed the indirect depreciable capital costs (idcc) to be 20% of ddcc. Therefore, total investment costs are about 652 k€. The O&M costs are split between fixed and variable costs. The fix ones include material and labour. Kuckshinrichs et al. (2017) assumed for both a share of 2.5%/ddcc. We used the same value for material costs, which corresponds to about 14 k€/y. Instead, for the labour costs we assumed to be equal to 7%/ddcc, corresponding to 38 k€/y. Such a value, based on the average labour cost for manufacturing industry in European Union (27.0 €/h in the EU-28, close to the 27.4 €/h in Italy; as reported in DESTATIS 2018), corresponds to a requested average labour time slightly lower than 4 h/day, which we consider to be an acceptable requirement for the examined system. Then total fix O&M costs amount to about 52 k€/y.

Table 2: Alkaline water electrolysis plant costs

Investment:	
Electrolyser[b,c]	270 k€
Compression plant[c]	252 k€
Storage system[d]	20.75 k€
Total direct depreciable capital cost (ddcc)	542.75 k€
Indirect depreciable capital cost (idcc)	20%/ddcc
Fix O&M costs:	
Material	2.5%/ddcc
Labour	7.0%/ddcc
Variable O&M costs:	
See Table 3	

[b] Water treatment included.
[c] Electrics, gas equipment, safety system and control system included.
[d] Outdoor installation.

In agreement with Kuckshinrichs et al. (2017), the variable O&M costs include the costs related to the use of deionised water, KOH solution (electrolyte), process steam (used during run-up to heat up the system), and nitrogen (used for cleaning purpose). Based on specific demand and costs of these upstream products reported in literature (see Table 3), we determined that total variable O&M costs are about 490 €/y, with the deionised water accounting for more than 90% of these costs.

Table 3: Demand and cost of upstream products

Product	Specific demand[e]	Cost[f]
Deionised water	10 kg/kg H_2	0.01 €/kg
KOH	1.9 g/kg H_2	2.5106 €/kg
Steam	0.11 kg/ kg H_2	0.01 €/kg
Nitrogen	0.29 g/kg H_2	0.2783 €/kg

[e] From Koj et al. (2017).
[f] From Kuckshinrichs et al. (2017).

As already mentioned, concerning the revenues, we forecast two scenarios, one that envisages only the sale of hydrogen and the other that includes the sale of oxygen as well. In the first case, the hydrogen selling price is assumed to be 20 €/kg. In the second case, we assumed that the oxygen can be sold at 2 €/kg.

In fact, based on the considerations reported in Appendix A, high quality compressed hydrogen can be surely competitive at a price lower than 30–40 €/kg. On the other hand, the price of compressed high purity (4.5 grade) oxygen goes up to 4.20 €/kg, and higher prices are present for medical use (due to quality controls for contaminants). For instance, based on some recent studies made by VTT Technical Research Centre (Hurskainen, 2017), in some countries (Finland), the price of bottled oxygen for medical use is markedly high: 3–7 €/kg, not including bottle/bottle rack rental costs. Therefore, a price lower than 3 €/kg can be competitive on the market.

Based on these figures, we could define the cash flow needed to calculate the levelized cost of hydrogen (*LCH*) and the net present value (*NPV*). Through *NPV*, discounting all the costs and the revenues, we established the return on investments. In particular, referring to this first hypothesis examined – and considering the financial parameters listed in Table 4 – the *LCH* value resulted to be 30.3 €/kg H_2. We find a negative *NPV* (–352.3 k€) for the first scenario considered (sale of hydrogen), while a positive *NPV* equal to +228.7 k€ is found for the second scenario which includes the selling of the co-produced oxygen. In such a case, the *IRR* resulted to be 9.8% and *MIRR* 7.3%; therefore, both internal rates of return exceed the *WACC* (about 5.7%).

Comments on these results are reported on Paragraph 5, and compared with other hypotheses (see below).

Table 4: Financial and tax parameters

Parameter	Value
Equity rate of return	7.0%
Inflation rate[g]	1.2%
Tax rate on earnings	30%
System degradation rate	0.5%

[g] ISTAT (2019), referred to Italy in 2018.

4.4. Hypothesis 2: Implementation of a photovoltaic powered electrolysis system

As a second hypothesis, we assumed that – differently from the first hypothesis – the entrepreneur must invest also to realise a photovoltaic (PV) plant with a capacity of 200 kWp. The electrolyser system is the same as in the first hypothesis. About the costs for the PV power plant, literature data have been used, due to the fact that these were close to the quotations we received by local installers.

4.4.1. Financial analysis

Based on data reported in Table 5, and assuming a unity cost of PV plant equal to 1.2 k€/kWp, the PV investment cost is 288 k€. Then, the total investment costs pass from about 652 k€ (first hypothesis) to about 940 k€ (referred to electrolysis system and PV plant).

It should be remarked that the costs reported in literature for a 200 kW photovoltaic plant (1.3–1.5 k€/kWp; in ES, 2018) refer to "turnkey costs" (including design and installation); therefore, we considered a slightly lower value (1.2 k€/kWp) to calculate the direct depreciable capital cost, and assumed for indirect depreciable cost the same share of the first hypothesis (20%/ddcc).

In addition, we assumed that the O&M costs, for materials and labour related to PV plant, are both 2.5% of the direct depreciable capital costs, which correspond to an overall cost of 12 k€/y. In particular, based on the above mentioned EU-28 labour cost (DESTATIS 2018), the calculated labour cost corresponds to an equivalent average commitment time of about 40 minutes per day, associated to the PV plant alone. Then, total fix O&M costs amount to about 64 k€/y (52 k€/y, in the first hypothesis).

Table 5: PV plant costs

Investment:	
Direct depreciable capital cost (ddcc)	240 k€
Indirect depreciable capital cost (idcc)	20%/ddcc
Fix O&M costs:	
Material	2.5%/ddcc
Labour	2.5%/ddcc
Variable O&M costs:	
None	

Based on these data, the *LCH* value resulted to be 40.7 €/kg H_2. Besides, for this second hypothesis, the investment resulted to be unattractive: in fact, the calculated *NPV* value is equal to –157.8 k€, even if we consider the scenario that involves the selling of hydrogen at 20 €/kg and oxygen at 2 €/kg (–738.8 k€ when only hydrogen is sold). But, based on our previous considerations, it is reasonable to considered a third proposal (called Hypothesis 2b) which assumes a higher hydrogen selling price (27 €/kg), by leaving unvaried (2 €/kg) the selling price of oxygen. In such a case, *NPV* becomes positive (+96.4 k€); but, this is again obtained when both products are sold (–484.6 k€ when only hydrogen is sold). In such a case, the *IRR* resulted to be 7.0% and *MIRR* 6.2%.

Comments on these results, and comparison with the previous hypothesis, are reported on the next Paragraph.

5. Results and discussion

5.1. Results of the financial analysis

To better compare and discuss the findings of our analysis, the results are shown in Figs. 2–6. All figures refer to the three hypotheses detailed in Table 6; but, as a first instance we made calculations assuming that only hydrogen is sold.

Table 6: Summary of the three hypotheses examined

Hypothesis			Hydrogen selling price	Oxygen selling price[h]
#	Electrolysis system	PV		
1	Purchased	Already own	20 €/kg	2 €/kg
2a	Purchased	Purchased	20 €/kg	2 €/kg
2b	Purchased	Purchased	27 €/kg	2 €/kg

[h] Referred to the second scenario examined (in the first scenario only hydrogen is sold).

In particular, in Fig. 2 the levelized costs of hydrogen (*LCH*) calculated for the three hypotheses are compared. All the obtained *LCH* are higher than those reported by Kuckshinrichs et al. (2017) – about 5–6 €/kg H_2 for a 6 MW AWE plant –; this is due to the higher specific cost of the electrolyser[1] and the lower daily operation (just 6 hours per day, according to average daily sun availability) and, consequently to the lower mass of hydrogen produced (about 200 times lower). In addition, in our case, costs of gas compression and storage system are included. The *LCH* corresponding to the first hypothesis is about 30 €/kg H_2, while the other two hypotheses are characterized by higher *LCH* values. As evident from Fig. 4, the difference between the Hypothesis 2a and 2b (*LCH* is about 2 €/kg more, for 2b) is related to a major cost associated to the taxes on earning (the higher revenues coming from the selling of hydrogen imply higher taxes).

A consideration that could be drawn from these first results is that, based only on costs and exclusive hydrogen production, the proposed investments appears to be unsustainable.

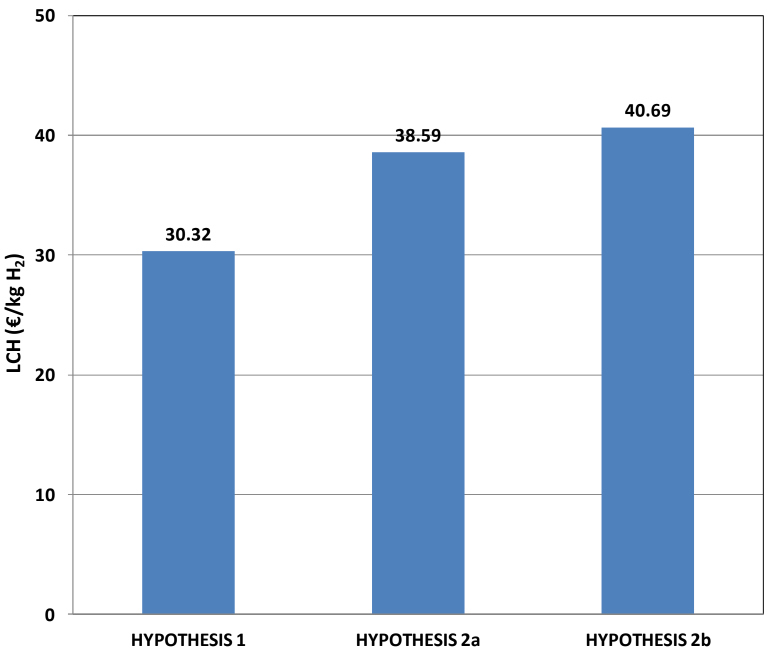


Figure 2: Levelized Cost of Hydrogen (*LCH*), for the three hypotheses examined, assuming a preliminary scenario (no sale of oxygen).

[1] It is well known that scale factor is very important: in literature, estimations for high power electrolysers (>1MW) are usually reported.

This is also confirmed by the net present values (*NPV*) associated to the three hypotheses, that are always negative when calculated upon the assumption that only hydrogen is sold.

But, we also have the objective of evaluating the opportunity to sold oxygen produced from the electrolysis plant examined. As evidenced in Fig. 3, in such a case the effect on the profitability of the project changes. In fact, a part of Hypothesis 2a – whose *NPV* still remains negative – the other two hypotheses are characterized by a quantifiable economic benefit for our hypothetical entrepreneur. In particular, at the end of the 20 years (2038), the net present value corresponding to the first hypothesis is +228.7 k€; while, that of Hypothesis 2b (which assumes the hydrogen be sold at 27 €/kg, and oxygen at 2 €/kg) is +96.4 k€.

Therefore, in terms of profitability, we may deduce the following conclusions: Hypotheses 1 and 2b both represent a project that should be undertaken, with the first one more attractive; Hypothesis 2a is a project which should be rejected, on a financial basis.

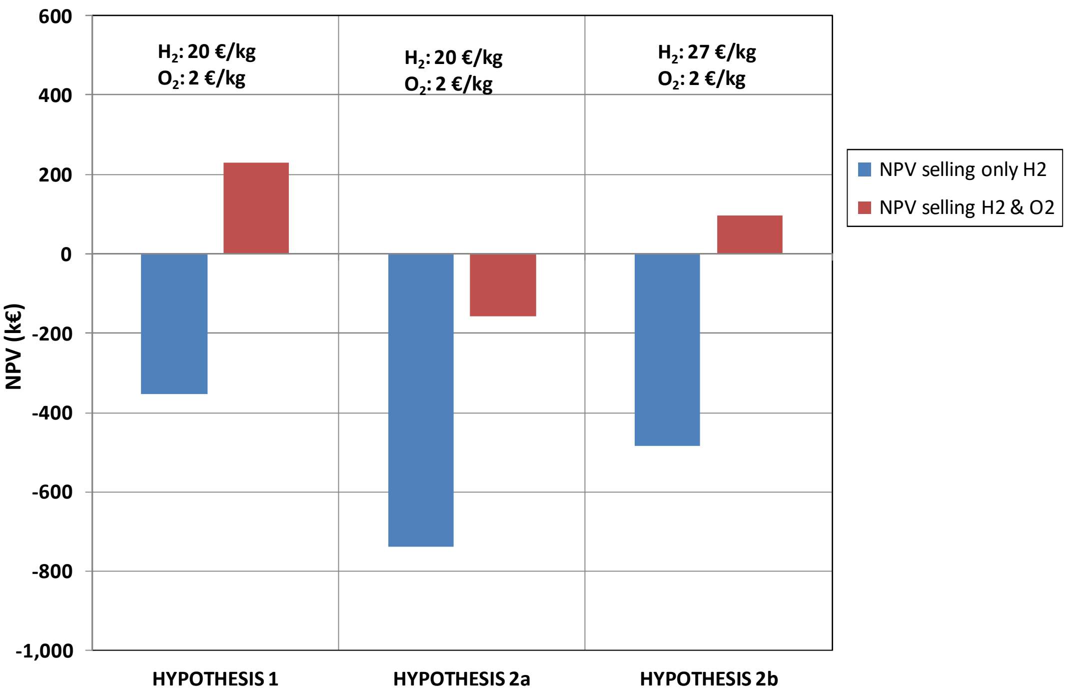


Figure 3: Net Present Value (*NPV*), for the three hypotheses examined, assuming two different scenarios (including or not the sale of oxygen).

Figures 4–6 all refer to the scenario that involves the selling of hydrogen and oxygen. A comparison of costs and revenues, associated to the three hypotheses examined, is shown in Fig. 4. In practice, this histogram shows the share of each term included in the calculation of the net present value. Based on Eq.(6), the tax rate on earnings (*TR*) influences two terms with opposite effects: one is due to the taxes paid on revenues coming from the selling of products (hydrogen and oxygen), while the other is due a tax redemption (i.e., lower taxes associated to reduced earnings). Since global O&M costs are almost the same (610 k€ for Hypothesis 1, and about 750 k€ for Hypotheses 2a and 2b), the main difference between Hypothesis 1 and 2a is related to the CAPEX (about 290 k€ more when the PV plant is purchased). And this is also the reason for the negative *NPV* value of Hypothesis 2a: the higher investment costs make the total expenditures of the project not balanced from the revenues. To reverse this result, we need to increase revenues by selling the hydrogen at a higher price (27 €/kg). In fact, in such a case (Hypothesis 2b) the inflows from selling hydrogen rise (about 1,400 k€; i.e. 360 k€ more than the other two hypotheses). This leads the downside of slightly higher taxes on revenues (about 110 k€ more, with respect to the Hypotheses 1 and 2a); however, the final balance shifts to profits.

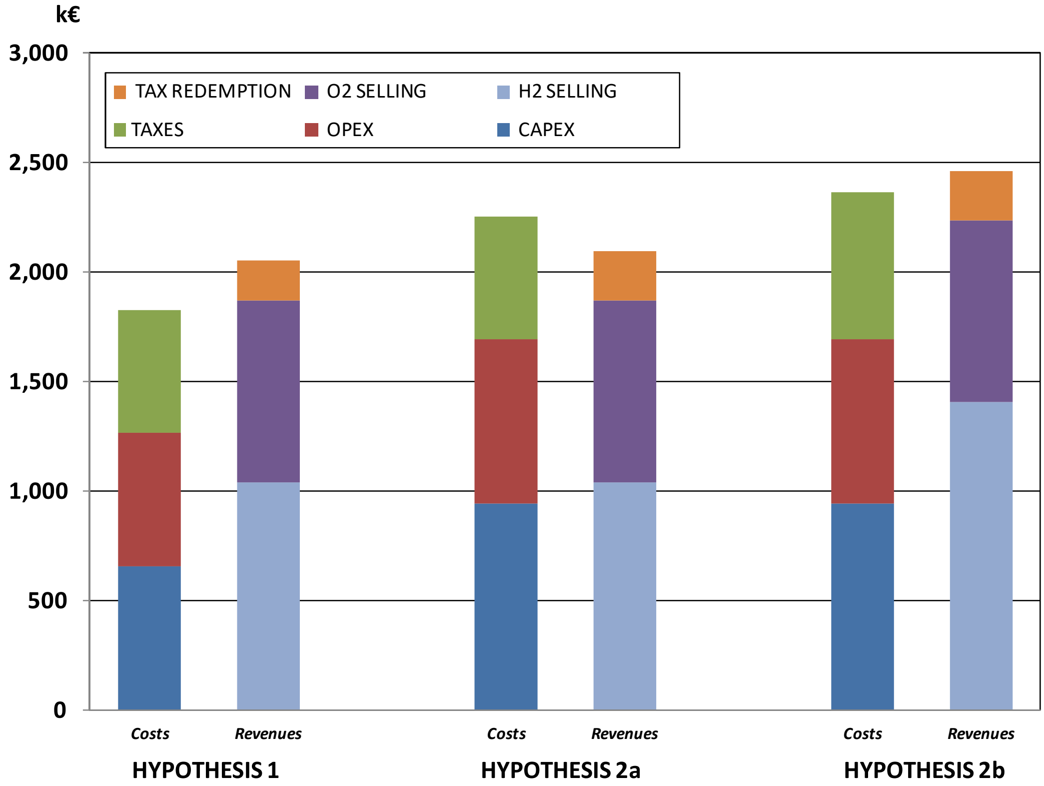


Figure 4: Comparison of costs and revenues, for the three hypotheses examined.

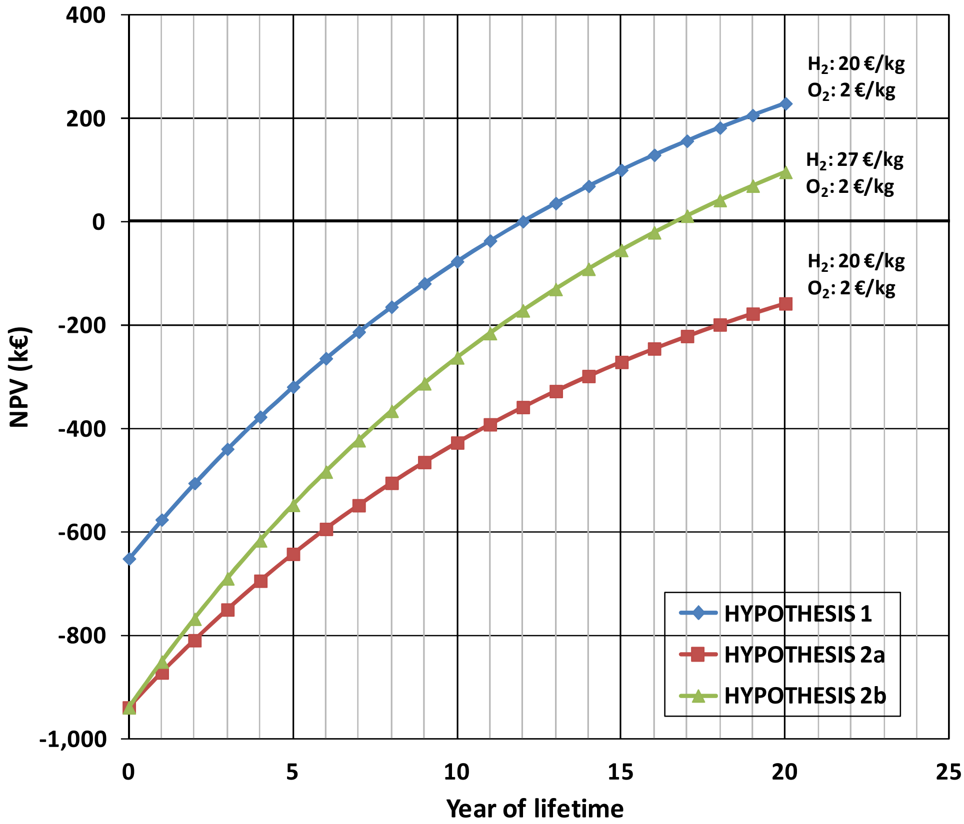


Figure 5: Net Present Value (*NPV*) evolution, for the three hypotheses examined.

Figure 5 shows how the net present value, calculated for the three hypotheses here investigated, evolves during the lifetime of the project, from 2019 to 2038. The information we can get from this graph is that the payback period for the investment represented by the first hypothesis is 12 years (i.e., in 2030). On the contrary, for the unprofitable Hypothesis 2a there is no a break-even point; i.e., the payback period is longer than the lifetime of the project. Hypothesis 2b shows an intermediate behaviour, with a payback period within the project lifetime, but higher than the first hypothesis: about 17 years (i.e., in 2035).

To complete our financial analysis, we calculated the standard (*IRR*) and modified internal rate of return (*MIRR*), which are shown in Fig. 6. For Hypotheses 1 and 2b both these values are higher than the weighted average cost of capital (*WACC*=5.7%) and therefore confirm the profitability of these two projects, demonstrating again a preference for the first one (*IRR*=9.8% and *MIRR*=7.3%; against *IRR*=7.0% and *MIRR*=6.2%). As expected, for Hypothesis 2a the internal rates of return obtained are lower than the *WACC* (*IRR*=3.5% and *MIRR*=4.8%); thus, this project does not satisfy the criterion for financial sustainability. In this latter case, the value of *MIRR* is higher than *IRR*, because the standard *IRR* underestimates the profitability of the project by assuming that positive cash flows are reinvested at a rate much lower than the capital cost of the investment. In general, the *MIRR* values – which assume a reinvestment rate equal to *WACC* – are more realistic than *IIR*. It should be remarked that, based on Eq.(11), in our specific case the finance rate does not influence the *MIRR* because all the net cash flows are positive, a part from that associated to the initial investment (year 0).

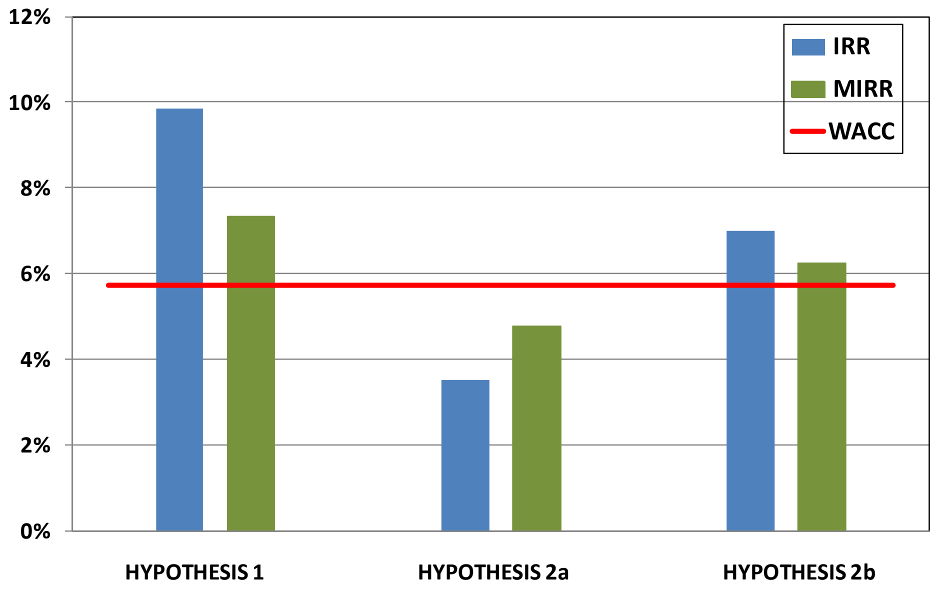


Figure 6: Internal Rate of Return (*IRR*) and Modified Internal Rate of Return (*MIRR*), for the three hypotheses examined.

5.2. Estimation of external costs

As already mentioned, the system we proposed here is based on electrolysis from renewable sources, which is a carbon-free technology to produce hydrogen; but today most hydrogen (about 96%) is produced from the conventional steam methane reforming (SMR). Therefore, in our opinion, it would be interesting to have also an idea of the avoided external costs (CO_2 emissions) associated to the considered electrolyser plant. In addition to the economic aspects, the transition to a decarbonised energy economy will also have a positive social impact, in terms of sustainability and environmental protection; but such an evaluation is beyond this paper's scope.

Based on data reported by Cantuarias-Villessuzanne et al. (2016), the carbon emissions associated to the SMR on-site process is equal to 9.42 kg CO_2 per kg H_2. On the other hand, in agreement with the central estimate of European Investment Bank (EIB, 2013), we assumed a "carbon tax" of 33 € per tonnes of CO_2 equivalent (in 2018), and a subsequent annual increment of 1 €/tonnes. On this basis, we estimated that the external costs related to the abatement of CO_2 should be in the order of 20.3 k€. This value could be a further revenue (e.g., by carbon credit sales) for our three hypotheses examined, whose extent is negligible compared to the other costs/revenues (see Fig. 4) and, therefore, does not change the above considerations on the project's profitability. However, it should be evidenced that this value refers to a small-scale electrolysis plant. Then, better economic profits and environmental benefits could be achieved for large-scale and/or broadly diffused plants.

5.3. Estimation of the market size for by-product oxygen

A key question, which could arise from our analysis, is whether or not the oxygen produced by the electrolysis plant examined can be placed in the market.

Some interesting studies on the subject are present in literature (Kato et al., 2005; Hurskainen, 2017). Even if they refer to specific countries (Japan, and Finland), according to them the following general considerations can be made: most of the oxygen demand comes from steel industry – blast furnace, electric arc furnace, stainless steel –, mining & metal refining, and pulp & paper industries. Other small-scale uses include glass industry, chemical industry, hospitals (medical oxygen), and waterworks for drinking water purification (ozonation). Oxygen is also used for oil refining, welding, calibration, food industry, etc. In particular, as evidenced by Rivarolo (2014), a very interesting application of oxygen generated by electrolysis – due to its high pressure – is use in thermo-chemical processes such as biomass gasification, to produce "chemicals" (i.e., hydro-methane and methanol) whose market diffusion can have a crucial role for sustainable development in many countries.

We likely consider as our possible prevalent target basin the technical gases market, small and medium enterprises and craft industries (e.g., artisans using blowtorches), and research centres. But, it is difficult to quantify the corresponding oxygen demand.

Another interesting market is the medical oxygen, mainly used for prevention and treatment of respiratory failure (hypoxemia, pulmonary vasoconstriction, etc.), both for hospital and homecare use. In fact, the oxygen obtained by electrolysis is pure and – contrarily to the other technologies commonly used for this purpose, i.e. cryogenic distillation and on-site generation by pressure swing adsorption (PSA) – does not require additional costs for contaminants removal.

Based on the above mentioned literature (Kato et al., 2005; Hurskainen, 2017), the oxygen consumption for medical use is around 1.1 kg/year per capita. This value allowed us to estimate in about 705,000 kg, the market size for Messina and the province; and about 260,000 kg for the town of Messina. Therefore, considering that the yearly mass of oxygen produced by the electrolysis plant examined in this study is about 37,000 kg (initial value), the market share to be satisfied should be in the order of 5% (Messina and the Province) or 14% (Messina).

6. Conclusions

In this paper, an economic-financial approach has been used to evaluate the profitability of an alkaline water electrolysis (AWE) plant powered by renewable energy sources (RES). The system studied was a 180 kW electrolyser coupled with a 200 kW photovoltaic (PV) plant, to be realized in Messina, Italy.

The analysis was carried out from the perspective of an entrepreneur who wants to invest in an industrial activity aimed at selling hydrogen from RES. We also assumed that the investment is made by equity funds (no debt financing) in 2018, and the plant lifetime is 20 years (2019–2038). Two alternatives have been considered: the first one (Hypothesis #1) assumes that the investor merely purchases the electrolysis system (electrolyser, compressor and storage unit); while, the second one (Hypothesis #2) considers a more challenging investment which also includes the purchase of the PV plant.

In a preliminary scenario we assumed that the only revenues of the proposed investment are generated from the selling of hydrogen. We focused our attention on the technical and/or medical gases market, which could be seen as a niche of the chemical feedstock market. On this purpose, based on some investigations (interviews, web researches, literature) carried out on the Italian case, we assumed a hydrogen selling price of 20 €/kg (Hypotheses 1 and 2a). But, the results obtained – levelized cost of hydrogen (*LCH*) higher that 30

€/kg, and calculated net present values (*NPV*) negative – indicated the unprofitability of the investment, even when the hydrogen selling price was raised up to 27 €/kg (Hypothesis 2b).

Therefore, we considered a second scenario which – in addition to the hydrogen – includes the selling of the oxygen co-produced by electrolysis (about 8 kg for each kg of hydrogen), assuming an oxygen selling price of 2 €/kg, again in line with the Italian market for technical and/or medical gases. In such a case, both Hypothesis 1 and Hypothesis 2b become profitable investments: *NPV* values at the end of the 20 years of the plant lifetime are +228.7 k€ and +96.4 k€, respectively. On the contrary, Hypothesis 2a – purchase of combined electrolysis system and PV plant, and hydrogen selling price of 20 €/kg – resulted to be economically unaffordable, even when the oxygen is sold (*NPV* equal to –157.8 k€).

We also determined the payback periods (12 years, for Hypothesis 1; 17 years, for Hypothesis 2b), and the standard and modified internal rates of return (*IRR* and *MIRR*) whose values allowed us to confirm our conclusions: Hypothesis 1 and Hypothesis 2b both represent affordable projects, with the first one more attractive; Hypothesis 2a is a project which should be rejected, on a financial basis.

A consideration which could be drawn from our study is that there are reasons to believe that, in the near future, hydrogen-based distributed generation could have a widespread development.

Based on literature data, we estimated that an additional revenue in the order of 20 k€ could be obtained when the external costs related to the abatement of CO_2 are included in the financial analysis of our small-scale electrolysis plant. Even if this value is negligible (compared to the other revenues), it should be remarked that better economic profits and environmental benefits could be achieved for large-scale and/or broadly diffused plants.

Finally, by assuming as our local market basin the town of Messina and its province, we estimated that it would be "sufficient" to cover a market share of 5% of the potential demand of medical oxygen in order to sold all the oxygen produced by the electrolysis plant studied; or about 14% when considering the oxygen demand of the urban hospitals and health centres of Messina.

These values represent just a preliminary rough estimation of the market size related to the local oxygen demand, limited to its medical use. More details on market issues will be the subject of a future work.

APPENDIX A. Considerations on hydrogen and oxygen selling prices

Looking at the recent literature, it can be noted that the estimation of the hydrogen costs by electrolysis are usually conducted looking at the electrolyser alone. This because the comparison is made with SMR mass production for immediate use (no storage); this means hydrogen at the exit of the reformer at room pressure and temperature, usually without regard to the hydrogen purity. Instead, to better compare the hydrogen costs, one should consider that: (i) hydrogen storage is necessary to meet fluctuations in demand and delivery; (ii) hydrogen from SMR needs to be purified for most applications, while hydrogen from electrolysis is extremely pure (99.999%).

Moreover, in estimating the costs of hydrogen from SMR usually the costs of natural gas feedstock are not considered, just in few country-based case studies the local methane price is considered (TerMaath et. al, 2006; Lee et al., 2017; Viesi et al., 2017). While, considering the electrolytic hydrogen, the price used for electricity is the local price, and the necessity of uniform legislation for distribution costs and taxes on electricity is claimed as a necessary condition for electrolytic hydrogen commercialisation.

Another important point is that in cost estimations of electrolytic hydrogen production, the production of oxygen is totally neglected, although by electrolysis 8 kg of oxygen are produced for each kilogram of hydrogen. This approach is reasonable if only centralised mass production is considered, both because the today pure oxygen market is limited and cannot be able to consume such a big production, and because by SMR no oxygen is produced while a lot of CO_2 is emitted.

Finally, we noticed that there is a regulated trade market for oil and natural gas with official quotations, the same for electricity, while a regulated trade market of hydrogen does not exist. This because today hydrogen is produced and consumed on-site or locally; no large scale trade is on place. A question rise up, what is the market price of hydrogen to make realistic comparisons?

In Tab. 1, hydrogen and oxygen prices obtained by private interviews on Italian local market and tender analysis are reported, in comparison with some relevant literature data. On this regard, it should be evidenced that industrial price of hydrogen is less than 3 €/kg for centralised SMR (FC-grade) (Viesi et al. 2017) – in agreement with the value reported by Cantuarias-Villessuzanne et al. (2016) for the European project DEMCAMER – and about 5 €/kg when transportation costs are included. As it can be seen, the end user prices are very high (up to 70 €/kg H_2), and local technical gases distributors declared us that a company able of supplying them pure hydrogen at about 1 €/Nm^3 (i.e., about 11 €/kg H_2) is competitive with current suppliers. Technical gases suppliers also sell oxygen, both technical grade and high purity grade, this last for industrial uses (e.g., welding in the aerospace sector) and laboratory applications. Finally, the technical gases market is based on a network of local distributors already well established and with installations complying with national explosive gas regulations. This means that they could be able to set-up a hydrogen production system and also a refuelling car station with relatively low costs.

Table A1: Prices for technical hydrogen and oxygen, in Italy

Gas (supply pressure)	Prices[i] €/Nm^3	€/kg	Source	Notes
H_2 (not clearly reported)		5.00–11.30[j]	Viesi et al., 2017	Including remunerations: 20% for production, 20% for transportation to refuelling stations
H_2 – 4.5 (@ 200 bar)	1.00 ca.	11.00 ca.	Interviews	Competitive price for resellers
H_2 – 4.5 (@ 200 bar)	2.20–3.50	24.50–38.90	WEB	Public tenders for supply 2014–2018
H_2 – 5.0 (@ 200 bar)	3.00–6.50	33.40–72.30	WEB	Public tenders for supply 2014–2018
O_2 – 2.5 (@ 200 bar)	2.00–3.00	1.40–2.10	WEB	Public tenders for supply 2014–2018
O_2 – 3.5 (@ 200 bar)	3.00–4.50	2.10–3.15	WEB	Public tenders for supply 2014–2018
O_2 – 4.5 (@ 200 bar)	3.38–6.00	2.35–4.20	WEB	Public tenders for supply 2014–2018

[i] Prices for technical and research gases are usually reported in normal cubic meters. To have the prices in kg, specific volumes of 11.12 and 0.7 Nm^3/kg have been used, for hydrogen and oxygen respectively.

[j] The lower price refers to hydrogen produced in centralized plants by large scale SMR, the higher to hydrogen produced on-site by electrolysis with grid electricity.

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