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Incentivizing green hydrogen generation: proposal of an incentive scheme and its evaluation in case studies

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Abstract

In a global context that aims to reduce carbon dioxide emissions into the atmosphere, green hydrogen is seen as a viable alternative to electricity in the so-called 'hard to abate' sectors, and as a substitute to traditional polluting fuels, such as natural gas and diesel. With the targets set by Fit-for-55 and REPowerEU plan on the reduction of greenhouse gas emissions, it is required to take a step-in favour of green fuels such as hydrogen produced from renewable sources through electrolysis. Therefore, this thesis aims to develop an incentive mechanism for the production of green hydrogen and apply it in several case studies to test its effectiveness. In this thesis, after a broad overview of the various methods of hydrogen production and of the end uses that this vector can support, an incentive scheme is proposed based on two contributions, one to recover the investment costs and the other to recover the operational costs. Then, two versatile models are developed, one in an Excel environment and one in a Python environment, which compute the incentive given to a specific green hydrogen producer and the gain associated with the production and sale of hydrogen, when the proposed incentive scheme is adopted. Finally, carrying out several sensitivity analyses allows assessing the impact of the most significant parameters (such as electricity and natural gas prices, efficiency, operating hours, CAPEX, etc.) on the producer's gain and so on the effectiveness of the incentive scheme. The incentive scheme fixes a certain maximum amount of hydrogen that can be incentivised per year, computed using a number of equivalent operating hours of a photovoltaic system in Italy. Since the incentive is only given on a certain maximum production, this mechanism disadvantages plants to produce higher quantities of hydrogen than the incentivised one, favouring a non-virtuous behaviour. Under certain price conditions, the hydrogen producer obtains a gain, which is however not very high because the production is limited. Furthermore, the mechanism sets a fixed incentive that does not vary with the chosen renewable source (PV, wind, or biomass) and the investment costs of the chosen electrolysis technology, possibly leading to higher expenditure for the State than necessary. To overcome these limitations, other possible solutions can be considered, such as the implementation of an incentive that varies with the equivalent operating hours and thus the chosen renewable source. Another incentive mechanism can be the auction mechanism, as for the electricity market, which automatically brings to the incentive of the most virtuous case studies. These solutions are proposed as possible improvements to this work.

Sommario

In un contesto globale che mira a ridurre le emissioni di anidride carbonica nell'atmosfera, l'idrogeno verde è visto come una valida alternativa all'elettricità nei settori cosiddetti "Hard to abate" e come un sostituto dei tradizionali combustibili inquinanti, come il gas naturale e il diesel. Con gli obiettivi fissati dal piano Fit-for-55 e REPowerEU sulla riduzione delle emissioni di gas serra, diventa necessario fare un passo avanti a favore dei combustibili verdi come l'idrogeno prodotto da fonti rinnovabili attraverso l'elettrolisi. Questa tesi si propone di sviluppare un meccanismo di incentivazione per la produzione di idrogeno verde e di applicarlo in diversi casi di studio per testarne l'efficacia. In questa tesi, dopo un'ampia panoramica dei vari metodi di produzione dell'idrogeno e degli usi finali che questo vettore può supportare, viene proposto uno schema di incentivazione basato su due contributi, uno per il recupero dei costi di investimento e l'altro per il recupero dei costi operativi. Vengono poi sviluppati due modelli versatili, uno in ambiente Excel e uno in ambiente Python, che calcolano l'incentivo dato a uno specifico produttore di idrogeno verde e il guadagno associato alla produzione e alla vendita di idrogeno, quando viene adottato lo schema di incentivi proposto. Infine, l'esecuzione di diverse analisi di sensitività permette di valutare l'impatto dei parametri più significativi (come il prezzo dell'elettricità e del gas naturale, l'efficienza, le ore di funzionamento, il CAPEX, ecc.) sul guadagno del produttore e quindi sull'efficacia dello schema di incentivazione. Il sistema di incentivazione fissa una certa quantità massima di idrogeno incentivabile all'anno, calcolata utilizzando un numero di ore di funzionamento equivalenti di un impianto fotovoltaico in Italia. Poiché l'incentivo viene erogato solo su una certa produzione massima, questo meccanismo sfavorisce gli impianti che producono quantità di idrogeno superiori a quelle incentivate, sfavorendo così un comportamento virtuoso. A determinate condizioni di prezzo, il produttore di idrogeno ottiene un guadagno, che però non è molto elevato perché la produzione è limitata. Inoltre, il meccanismo stabilisce un incentivo fisso che non varia in funzione della fonte rinnovabile scelta (fotovoltaica, eolica o biomassa) e dei costi di investimento della tecnologia di elettrolisi scelta, comportando eventualmente per lo Stato una spesa superiore al necessario. Per superare queste limitazioni, si possono prendere in considerazione altre soluzioni possibili, come l'implementazione di un incentivo che varia con le ore di funzionamento equivalenti e quindi con la fonte rinnovabile scelta. Un altro meccanismo di incentivazione può essere quello delle aste, come per il mercato elettrico, che porta automaticamente all'incentivazione dei casi di studio più virtuosi. Queste soluzioni sono proposte come possibili miglioramenti di questo lavoro.

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Nomenclature

Abbreviations

AEM - Anion exchange membrane type of electrolysis

ALK – Alkaline type electrolysis

BEV – Battery electric vehicle

CAPEX – Capital expenditure

CF – Capacity factor

CRF – Capital recovery factor

ETS – Emission trading system

FCEV – Fuel cell electric vehicle

GHG – Greenhouse gases

GME – 'Gestore dei mercati energetici'

HTE – High temperature electrolyser

ICE – Internal combustion engine

LHV_{H2} – Lower heating value of hydrogen

LHV_{NG} - Lower heating value of natural gas

LTE – Low temperature electrolyser

MGP – 'Mercato del giorno prima', Day-ahead market

MISE – 'Ministero italiano dello sviluppo economico'

O&M – Operation and maintenance

PEM – Proton exchange membrane

PGM – Platinum group metals

PNIEC – 'Piano nazionale integrato per l'energia e il clima'

PPA – Power purchase agreement

PSA – Pressure swing adsorption

PUN – 'Prezzo unico nazionale'

PV – Photovoltaic plant

R&D – Research and development

RES – Renewable energy source

SMR – Steam methane reforming

SOE – Solid oxide electrolyser

TTF – Title transfer facility

VAT – Value added tax

WACC - Weighted average cost of capital

WTP – Willingness to pay

Symbols

C_{H2O} – Water cost in electrolysis plant

$Consumption_{avg_{diesel}}$ – The average consumption of a diesel's ICE

$Consumption_{avg_{FC}}$ – The average consumption of a FC

CP_{size} – Ratio between compressor size and electrolyser size

EL_{cap} – Electrolyser capacity

Eta_{is} – Isoentropic efficiency of the compressor

$h_{eq_{RES}}$ – Equivalent operating hours of RES plant

$h_{eq_{EL}}$ – Equivalent operating hours of electrolyser

$H2_{feedstock_{\%}}$ - Percentage of hydrogen demand for feedstock sector

$H2_{mobility_{\%}}$ - Percentage of hydrogen demand for mobility sector

$H2_{NGgrid_{\%}}$ - Percentage of hydrogen demand for heating sector

$load_{levelMIN_{\%}}$ - Minimum load level of electrolyser

$loss_{el}$ – Loss of revenue due to the sale of electricity produced by RES plant

M_{H2} – Molecular mass of hydrogen

N – Number of stages of compressor

p_{out}/p_{in} – Pressure ratio of compressor

rev_i – Revenue due to i contribution

Z – Compressibility factor

γ – Ratio between specific heats

ε_{el} – Electrolyser specific consumption

ε_{comp} – Compressor specific consumption

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Chapter 1

1 Introduction

Hydrogen is the first element in the periodic table and, despite being the most abundant element in the universe, it is difficult to find it in its pure state on Earth [1]; it is present, combined with other elements, in compounds such as water or in mineral substances, hydrocarbons and biological molecules. In addition to constituting approximately 75% of matter, it is the primary ingredient of the Sun, of which it makes up approximately 90% [2]. Hydrogen is a colourless, odourless and tasteless gas that can be used as a clean, renewable energy source [3]. Hydrogen is a low-polluting fuel with a high calorific value that makes it particularly efficient. In contrast to other fuels that have a strong impact on our planet, hydrogen does not cause acid rain, does not deplete the ozone layer and does not generate dangerous emissions. When it burns, hydrogen combines with oxygen in the air to produce water, without emitting greenhouse gases or other pollutants. For this reason, it can help replacing fossil fuels such as oil or natural gas in electricity generation and transport.

Within this first chapter of my thesis, I would like to make an introduction to hydrogen in general, its role in the decarbonisation of the energy system and how it can significantly contribute to the decentralisation of electricity production from renewable sources (section 1.1). In addition, this chapter is intended to show and describe the various methods for producing hydrogen from fossil and renewable sources (section 1.2), and the end uses of hydrogen in the various demand sectors (section 1.3). Finally, it includes a brief presentation of the current scenarios in the hydrogen sector on what the production and installation targets for electrolysis capacity in Italy and Europe are (section 1.4).

1.1 The role of Hydrogen

Hydrogen is classified as an energy carrier, because it must be produced from another form of energy [4]. In contrast, methane is an energy provider as it is already present on earth and directly usable. Thus, hydrogen represents a secondary energy source that lends itself to being transported to the place where it is used and can release the energy it contains, as in the case of electricity.

The use of hydrogen today is dominated by industrial applications. The four main uses (both in pure and blended form) are: oil refining (33%), ammonia production (27%), methanol production (11%) and steel production through direct reduction of iron ore (3%).

Hydrogen is produced almost entirely using fossil fuels. More than 60% of the hydrogen used in refineries is produced from natural gas [5]. Hydrogen can be produced using renewable energy sources, such as solar or wind power, through processes such as the electrolysis of water.

Hydrogen can be used in a variety of ways different from those most used today, such as fuel for fuel cell vehicles, energy for heating buildings, or as an energy carrier for storing energy from renewable sources, such as solar or wind power. Furthermore, used in fuel cells, it combines with oxygen to produce electricity and water. Because of its characteristics, green hydrogen can play a decisive role in a zero-emission world. Electrification through renewable energy will be the main and most efficient route to decarbonisation. However, there are some end uses that to date are more difficult to decarbonise through a direct electrification process. This is where green hydrogen can penetrate to achieve full decarbonisation. These sectors are also called 'hard to abate' and consist mainly of the industrial, aviation and maritime sectors [6].

At the COP21 (Conference of the Parties) meeting in Paris in 2015, it was clarified to keep global warming 'well below two degrees Celsius compared to pre-industrial levels, and to continue efforts to further limit the temperature increase to 1.5 degrees Celsius' within this century. This goal is ambitious, as it will require the world to limit cumulative energy-related carbon dioxide emissions to less than 900 Gt by 2100, an amount the world will exceed before 2050 if it continues on its current path. To stay within the carbon budget, the world will have to make drastic changes year after year and reduce energy-related CO2 emissions by 60 per cent until 2050. Hydrogen can play seven vital roles to meet the challenges of the transition [7]:

1. Enabling large-scale renewable energy integration and power generation;

2. Distributing energy across sectors and regions;

3. Acting as a buffer to increase energy system resilience;

4. Decarbonising transportation;

5. Decarbonising industrial energy use;

6. Helping to decarbonise building heat and power;

7. Providing a clean feedstock for industry;

In conclusion, green hydrogen can be an important solution for the future of energy because of its versatility, cleanliness and sustainability.

1.2 Hydrogen production methods – state of the art

Molecular hydrogen in its pure form, as mentioned earlier, is almost non-existent on earth, which means that it must be produced from compounds in which it is present, e.g. water and hydrocarbons.

These two chemical compounds are not the only ones from which hydrogen can be extracted, but they are the most famous ones from which the main hydrogen production methods originate: SMR (Steam methane reforming) for producing hydrogen from methane and electrolysis for producing it from water.

There are many different hydrogen production methods, reported in Figure 1.1 below, all based on very different concepts and reactions that lead to the production of hydrogen and different amounts of pollutant.

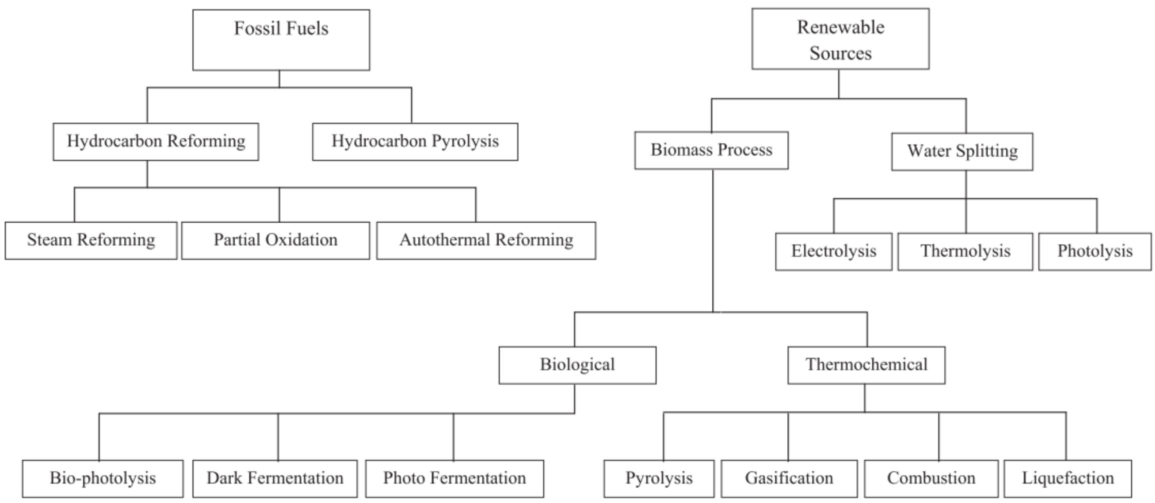

Figure 1.1 – The main processes to produce Hydrogen [8]

Depending on the production method, there are different names given to hydrogen as a final product, according to the emissions generated in the process of producing the molecule. Moreover, the cost of hydrogen varies greatly depending on how it is produced [9].

From the most to the less pollutant production process, we have [10]:

- **Black** hydrogen: which refers to hydrogen produced by coal gasification, associated with the highest CO2 emissions;
- **Grey** hydrogen: this is the name given to hydrogen produced from fossil energy sources by means of hydrocarbon dissociation processes (such as SMR in the case of methane); the colour associated with the name is placed because these are still polluting from the point of view of CO2 emitted into the atmosphere, but less than the previous one. This form of hydrogen is still the most abundantly produced and used on Earth;
- **Blue** hydrogen: this is the name given to hydrogen produced by processes like those of grey hydrogen, in which, however, a CO2 capture and storage system is implemented that drastically reduces the emissions generated during the process. With this method, the process is 90 % decarbonized, but by increasing the efficiency of CCS technology, even higher percentages can be achieved;
- **Purple** hydrogen**:** which refers to hydrogen produced by electrolysis of water using a device called an electrolyser and using electricity produced by a nuclear power plant, with no CO2 emissions as a result;
- **Green** hydrogen: this is the name given to hydrogen produced by electrolysis of water using an electrolyser and using renewable electricity sources (wind and/or solar). The process is considered completely decarbonized, without any CO2 emissions into the atmosphere;

Table 1.1 shows the main hydrogen production methods, differentiated by type (whether thermochemical or electrochemical), and the associated specific CO2 emissions per kg of hydrogen produced. The emissions associated with the process of producing hydrogen from coal are particularly high, even higher than the process of producing hydrogen from methane (SMR); however, both technologies, despite using fossil fuels and emitting large quantities of CO2 into the atmosphere, are the two most mature production technologies in terms of level of knowledge and efficiency. In fact, as said before, more than 90 per cent of the used hydrogen is produced by these two methods. On the other hand, electrolysis technologies are reaching higher levels of knowledge and efficiency in recent years, and do not contribute to CO2 emissions into the atmosphere; in fact, the specific emissions for these methods (as well as for the production of H2 from biomass gasification) are zero.

Table 1.1 - Evaluation of hydrogen production processes [11]

Hydrogen production process	Type	Specific CO2 emissions $[kg_{CO_2}/kg_{H2}]$	Primary sources availability	Technological readiness level (TRL)
Conventional Steam methane reforming	TC	8.8 – 14.1	Low	Mature
Steam methane reforming powered by nuclear energy	TC	5.5	Medium – low	RTD
Steam methane reforming powered by CSP	TC	5.5	Medium	Pilot Demo
Conventional coal gasification	TC	27-36	Medium -high	Mature
Coal gasification powered by CSP	TC	11	High	Pilot Demo
Biomass gasification	TC	0	High	Pilot Demo
Water electrolysis powered by nuclear energy	EC	0	High	Nearly mature
Water electrolysis powered by RES	EC	0	Unlimited	Nearly mature
[a] TC: thermochemical; EC: electrochemical; [b] Referred to long-term availability (effective availability also depends on local/geopolitical conditions) [c] RES = CSP, PV, wind, geothermal, etc.				

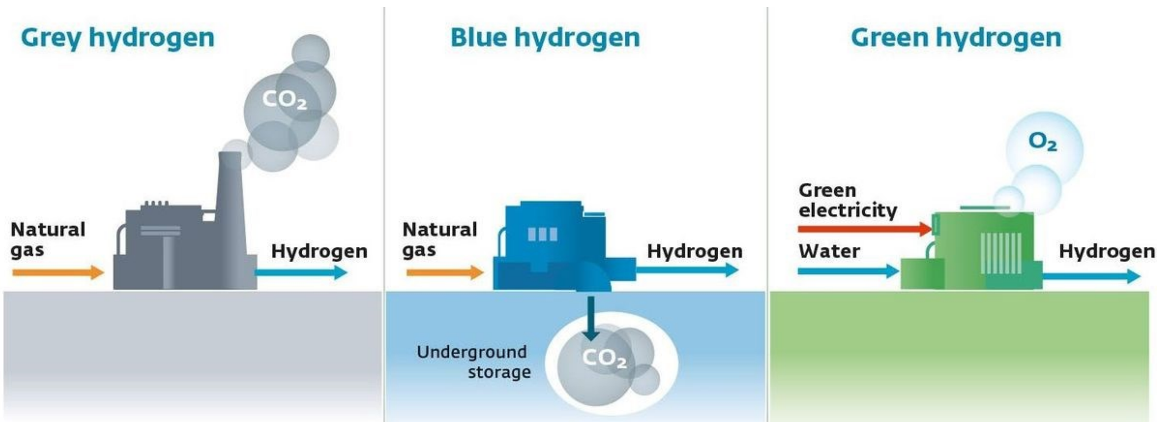

Figure 1.2 - Depiction of grey, blue and green hydrogen production [12]

The main methods of producing hydrogen in its various forms are described in the following.

1.2.1 Production of hydrogen from fossil fuels

Currently, most of the hydrogen used in industrial processes is produced from fossil fuels such as methane gas or coal. However, these processes are very polluting in terms of CO2 emissions. These processes produce, as mentioned above, grey hydrogen but nevertheless identify the 99% of the total hydrogen currently produced. The most commonly used technique is the reforming of methane with steam (SMR), and the hydrogen thus produced is mainly used for oil refining and fertiliser manufacture [13]. Most grey hydrogen is produced from natural gas by steam reforming processes and the specific emissions of CO2 per unit of hydrogen produced in this process is about 9 kg_{CO_2}/kg_{H_2} [14], a value within the range presented in Table 1.1 for CO2 emissions for the various technologies.

Some of the most significant hydrogen production methods from fossil fuels will be detailed below.

1.2.1.1 Steam methane reforming (SMR)

Steam methane reforming (SMR) is a highly commercialised chemical process used to produce hydrogen from methane. For example today, almost all hydrogen (99.3% approximately), is produced by SMR and gasification of coal [15]. SMR process is often used to produce industrial hydrogen, which can be used as fuel for fuel cell vehicles, to produce chemical fertilisers and for other industrial uses.

In SMR, methane reacts with steam at a pressure ranging from 3 bar to 25 bar in the presence of a catalyst to produce hydrogen, carbon monoxide and a small amount of carbon dioxide. SMR is an endothermic reaction, so it needs heat (generally around 700-850°C) to generate the products, hydrogen and carbon monoxide, from the reactants, methane and steam [16]. The reaction is shown below:

$$CH_4 + H_2O\ (+Heat) \rightarrow CO + 3H_2\ \ (\Delta H°_{298K} = +206\ kJ/mol\ )\ [17] \qquad \textbf{\textit{(1.1)}}$$

However, in addition to the SMR reaction, a second, subsequent reaction takes place, this time exothermic, which is called the 'water-gas shift reaction', in which the carbon monoxide produced by the first reacts with steam still in the presence of a catalyst to give the formation of carbon dioxide and more hydrogen:

$$CO + H_2O \rightarrow CO_2 + H_2\ (+heat)\ \ (\Delta H°_{298K} = -41.1\ kJ/mol\ )\ [17] \qquad \textbf{\textit{(1.2)}}$$

In a later process, carbon dioxide and other impurities are removed from the gas stream to obtain essentially pure hydrogen. The CO2 produced by the process it is emitted in the atmosphere or it can be captured and stored through a capture and storage system (CCS) to produce blue hydrogen and reduce the emissions. In the Figure 1.3 below is reported a flow diagram of SMR process to produce hydrogen and also to capture the CO2 with a CCS system.

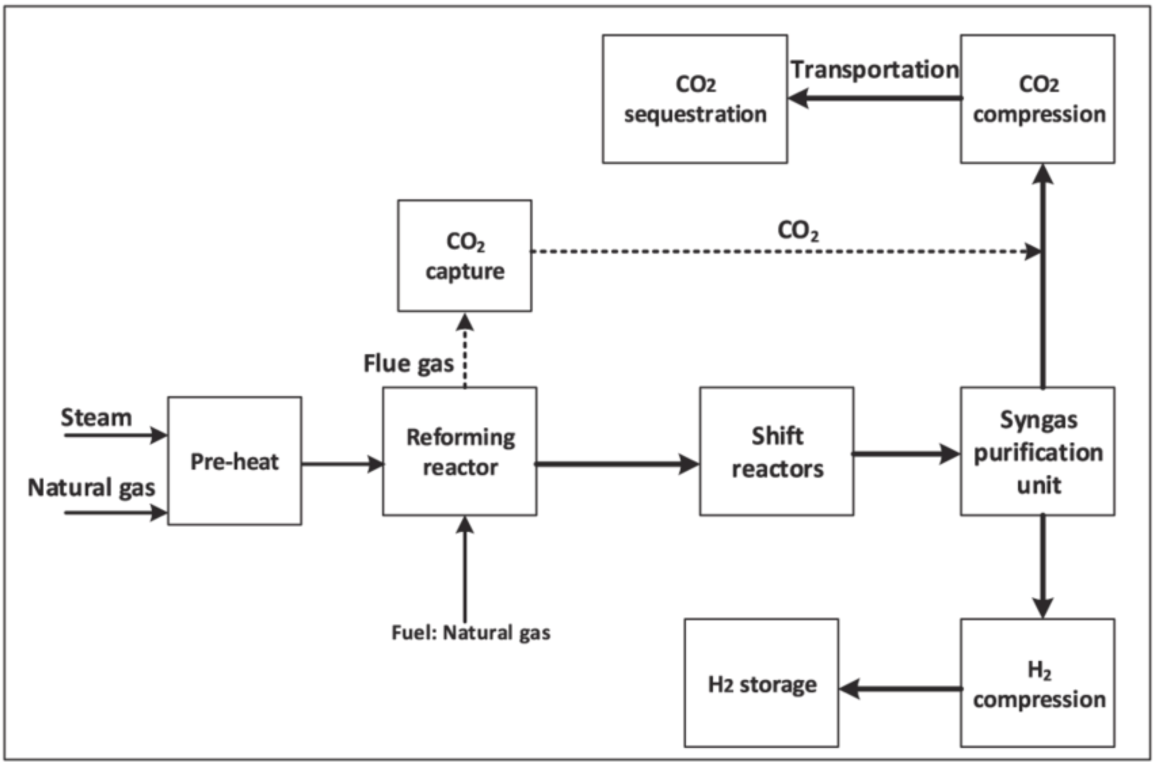

Figure 1.3 – Simplified process flow diagram of steam methane reforming [18]

In Figure 1.3 we can see a simplified block diagram of the SMR process with CCS in which are shown a reforming reactor, water-gas shift reactors (WGS, high-temperature (HT) and low-temperature (LT)), a syngas purification unit, the CO2 compression, transportation and sequestration, hydrogen compression and storage. So, as mentioned above, steam and natural gas react, after preheating, in reforming reactor to form syngas, a gas consisting of CO and H2 (equation (1.1), in presence of nickel-based catalysts; the syngas is cooled and fed into WGS reactors, where carbon monoxide is oxidised to CO2; finally the purification of hydrogen from carbon dioxide takes place in the syngas purification unit. The hydrogen produced is purified in the syngas purification unit. It is then compressed and stored in the storage tanks. CO2 emissions from the syngas purification unit are compressed and transported through a pipeline to an underground cavern. High emission efficiencies are being achieved for this technology (about 90 per cent of CO2 is sequestered by the process) but the cost of producing this hydrogen, which in this case is called 'blue hydrogen', is still too high to be competitive with the basic alternative of releasing CO2 into the atmosphere.

For the case without CCS, the syngas from the WGS reactors is directly sent to the syngas purification/pressure swing adsorption (PSA) unit after cooling, and the CO2 produced is released directly into the atmosphere [18].

1.2.1.2 Coal gasification

The method of producing black hydrogen is coal gasification. In general, the gasification process consists of the partial oxidation, in the absence of a catalyst, of a solid, liquid or gaseous substance with the aim of producing a gaseous fuel consisting of hydrogen, carbon oxides and light hydrocarbons such as methane. In this specific case, the gasification of coal converts it wholly or partially into gaseous fuels which, after being purified, can be used either as fuels or as raw materials for chemical processes but also for fertiliser production.

This technology is economically competitive with SMR technology (discussed in Chapter 1.2.1.1) only where the cost of natural gas is too high (e.g. in countries such as China or South Africa) [19].

The goal of coal gasification is to obtain a gas, called syngas, which is mainly composed of carbon monoxide (CO), carbon dioxide (CO2), hydrogen (H2), water vapor (H2O) and methane (CH4). This results in the formation of hydrogen from gasification, which is then called black hydrogen because the process produces a high amount of CO2 emissions in the atmosphere.

Different gasifier technologies are used for the gasification process, all of which use steam, oxygen or air to partially oxidize the coal and obtain gas as the final product; among these gasifiers we distinguish [20]:

- Fixed-bed gasifier: commonly operates at moderate pressures (25-30 atmospheres). Feedstocks in the form of large coal particles and fluxes are loaded into the top of the gasifier vessel and move slowly downward through the bed, while reacting with high oxygen content gas introduced at the bottom of the gasifier that is flowing counter-currently upward in the gasifier. In this configuration, the coal flows counter-current to the syngas produced, which cools as it advances towards the reactor outlet. The gas is produced at moderate temperatures (425-650°C) [19] and must be filtered from the liquid hydrocarbons, which are separated and subsequently recycled;

- Fluidised bed gasifier: in this configuration there are suspended feedstock particles in an oxygen-rich gas, so the resulting bed within the gasifier acts as a fluid. These gasifiers employ back-mixing, and efficiently mix feed coal particles with coal particles already undergoing gasification. To sustain fluidization, or suspension of coal particles within the gasifier, coal of small particles sizes (<6 mm) is normally used. Coal enters at the side of the reactor, while steam and oxidant enter near the bottom with enough velocity to fully suspend or fluidize the reactor bed. Due to the complete mixing inside the gasifier, a constant temperature is sustained in the reactor bed. The gasifiers normally operate at moderately high temperature (925-1040°C) [19] to achieve an acceptable carbon conversion rate (e.g., 90-95%) and to decompose most of the tar, oils, phenols, and other liquid by-products;

- Entrained bed gasifier: this is a combustor that operates in an oxygen deficiency. In this configuration fine coal feed and the oxidant (air or oxygen) and/or steam are fed co-currently to the gasifier. This results in the oxidant and steam surrounding or entraining the coal particles as they flow through the gasifier in a dense cloud. Entrained-flow gasifiers operate at high temperature (>1260°C) [19], pressure and extremely turbulent flow which causes rapid feed conversion and allows high performance. The gasification reactions occur at a very high rate (typical residence time is on the order of few seconds), with high carbon conversion efficiencies (98-99.5%). The tar, oil, phenols, and other liquids produced from devolatization of coal inside the gasifier are decomposed into hydrogen (H2), carbon monoxide (CO) and small amounts of light hydrocarbon gases;

There are several reactions that take place inside a coal gasifier, the most significant of which are as follows [21]:

$$C + \frac{1}{2}O_2 \rightarrow CO + 110.6\frac{kJ}{mol}$$ ***(Partial combustion) (1.3)***

$$C + O_2 \rightarrow CO_2 + 393.7\frac{kJ}{mol}$$ ***(Total combustion) (1.4)***

$$C + H_2O \rightarrow CO + H_2 - 131.4\frac{kJ}{mol}$$ ***(Gasification) (1.5)***

$$CO + H_2O \rightarrow CO_2 + H_2 + 41.2\frac{kJ}{mol}$$ ***(Water-gas shift) (1.6)***

Several reactions take place within the gasifier, however, to produce hydrogen, the two most important reactions are the gasification reaction (in which carbon reacts with steam to form syngas) and the water-gas shift in which the carbon monoxide produced in the previous reactions reacts with steam to form carbon dioxide and hydrogen.

In practice, high-temperature processes are preferred to maximize carbon conversion to gas, thereby avoiding the formation of significant amounts of char, tars, and phenols. Hydrogen production from coal is commercially established, but is more complex than the production of hydrogen from natural gas, and also less efficient (a typical efficiency value is 55%) [22]. But since coal is plentiful in many parts of the world and will certainly be used as a source of energy, exploring the production of clean technology for its use is worthwhile [16].

1.2.2 Production of hydrogen from biomass

The most important methods of producing hydrogen from fossil fuels have been defined so far. Another way to obtain hydrogen is to produce it using renewable sources. In this way, the hydrogen obtained is cleaner and can contribute to the reduction of carbon dioxide emissions from fossil fuels. One of the main sources from which to obtain hydrogen is biomass, and the most important methods of producing hydrogen from it will be presented below.

1.2.2.1 Fermentation

In this process, biomass is treated with bacteria to produce hydrogen. Biomass fermentation is a biological process that can be used to produce hydrogen. During this process, microorganisms such as bacteria and yeasts are used to convert biomass into hydrogen. In practice, biomass is fed into a reactor together with a colony of bacteria capable of fermenting the sugars in the biomass. The bacteria consume the sugars and produce hydrogen and other products such as carbon dioxide and methane. This process takes place in the absence of oxygen and produces hydrogen as a by-product.

There are two types of biomass fermentation [23]:

- Dark fermentation;
- Photo-fermentation;

The first one is a type of biological production of hydrogen and is carried out by obligate anaerobes and facultative anaerobes in the absence of light and oxygen. In dark fermentation, bacteria act on the substrate and generate hydrogen. The substrate for the dark fermentation is lignocellulosic biomass, carbohydrate materials like wastewater from industry, sugar-containing crop residues, and municipal solid waste. The equation (1.7) shows the dark fermentation process to produce hydrogen:

$$C_6H_{12}O_6 + 2H_2O \rightarrow 2CH_3COOH + 2CO_2 + 4H_2 \qquad \textbf{\textit{(1.7)}}$$

The second one is another type of biological production of hydrogen in which the biomass is converted into hydrogen in the presence of sunlight by the photosynthesizing bacteria. The performance and the efficiency of photo-fermentation depend upon the substrate and the bacteria. The efficiency of the photo-fermentation is lower than that of dark fermentation because the growth rate of the dark fermentation bacteria is faster than the photosynthesizing bacteria. For the production of the same volume of hydrogen, a large photo-fermentation reactor would be required. The equation (1.8) shows the photo-fermentation process, where the by-product acetic acid (CH_3COOH) of dark fermentation can be used as an input for the photo-fermentation:

$$CH_3COOH + 2H_2O \rightarrow 4H_2 + 2CO_2 \qquad \textbf{\textit{(1.8)}}$$

The hydrogen produced by these two processes is not green because of associated atmospheric CO2 emissions.

In conclusion, fermentation of biomass can be an effective way to produce hydrogen and other useful products from biomass. However, it is important to emphasise that this process requires the presence of specific bacteria and can be influenced by factors such as nutrient availability and environmental conditions, which means that it can be difficult to control precisely.

1.2.2.2 Biomass Gasification

The biomass gasification is a thermochemical process, which consists in the conversion of a solid/liquid organic compound in a gas/vapor phase and a solid phase. The gas phase, usually called "syngas", has a high heating power and can be used for power generation or biofuel production. The solid phase, called "char", includes the organic unconverted fraction and the inert material present in the treated biomass. The chemical reactions involved in the gasification of biomass are generally of the oxidation-reduction type. In this type of reaction, one substance (the biomass) is oxidised (i.e. loses electrons) and another substance (e.g. steam) is reduced (i.e. gains electrons). In general, these reactions are extremely complex and involve several different sub-reactions. But considering the most important steps, these are [24]:

- Oxidation (exothermic stage);
- Drying (endothermic stage);
- Pyrolysis (endothermic stage);
- Reduction (endothermic stage);

In practice, the biomass is subjected to high temperatures and low pressures in the presence of a controlled amount of oxygen, which allows the biomass to be decomposed into syngas. Then the tar removal is performed to increase the syngas production and quality. Finally, through the purification process the hydrogen is obtained.

The temperatures involved in the gasification process depend on the biomass substrate and the type of gasifier, but are in the range of 600°C to 1500°C in the presence of a gasifying agent (normally air, steam, O2, CO2) [25]. A typical biomass gasification process is shown in eq. (1.9):

$$Biomass + O_2 + H_2O(steam) \rightarrow CH_4 + CO_2 + CO + H_2 + other\ products \qquad \textbf{\textit{(1.9)}}$$

Where other products are char and tar [23].

Considering that the process is the same, the types of gasifiers used for biomass gasification are essentially the same as those defined in the section 1.2.1.2 on coal gasification.

Types of gasifiable biomass can come from different sectors, such as forestry, agriculture (dry lignocellulosic or sugar and starch energy crops), industry (industrial residues) and waste.

In conclusion, biomass gasification can be an effective way to produce hydrogen and other useful products from biomass. However, it is important to stress that this process requires high temperatures and low pressures, which means that it can be expensive and not always easy to implement in practice.

1.2.2.3 Pyrolysis

Biomass pyrolysis is a thermochemical process that can be used to produce hydrogen. During this process, biomass is heated at a temperature of 650–800 K at 0.1–0.5 MPa in the absence of air to convert biomass into liquid oils, solid charcoal, and gaseous compounds (pyrolysis gas). This gas can then be used to produce pure hydrogen through a process called 'purification'.

Pyrolysis can be further classified into slow pyrolysis and fast pyrolysis. Since the products are mainly wood charcoal, slow pyrolysis is not used for hydrogen production. On the other hand, fast pyrolysis is a high-temperature process in which biomass is heated in the absence of air to obtain products in different stages [26]:

- Gaseous products: H_2, CH_4, CO, CO_2;
- Liquid products: tar and oils that remain in liquid form at high temperature, such as acetone and acetic acid;
- Solid products: char, pure carbon and other inert materials;

So, the fast pyrolysis can be used to produce hydrogen from biomass if high temperature and sufficient volatile phase residence time are allowed. A typical biomass pyrolysis reaction to produce hydrogen is the following:

$$Biomass + heat \rightarrow H_2 + CO + CH_4 + other\ products \qquad \textbf{\textit{(1.10)}}$$

Steam reforming reaction of methane (eq. (1.1)) and water-gas shift reaction (eq. (1.2)) can be applied to increase the hydrogen production.

In conclusion, pyrolysis of biomass can be an effective way to produce hydrogen and other useful products from biomass. However, it is important to emphasise that this process requires high temperatures and the absence of oxygen, a situation not easy to implement in practice.

1.2.2.4 Secondary methods

Besides the methods already mentioned, fermentation, gasification and pyrolysis there are other ways to produce hydrogen from biomass, for example:

- Bio-photolysis;
- Biological water-gas shift (BWGS);
- Microbial Electrolysis cell (MEC);

The first process can be divided into two different types: direct or indirect. The direct bio-photolysis is a biological process using microalgae photosynthetic systems to convert solar energy into chemical energy in the form of hydrogen, following the complete dissociation of water, as given in the following reaction:

$$2H_2O \rightarrow 2H_2 + O_2 \qquad \textbf{\textit{(1.11)}}$$

The indirect bio-photolysis instead is the mechanism for producing hydrogen from the carbohydrates produced by microalgae during photosynthesis [26]. The BWGS process depends on the capacity of photoheterotrophic bacteria, using carbon monoxide as the carbon source. These microorganisms can produce hydrogen in the dark by oxidizing CO and reducing H2O through an enzymatic pathway, as in reaction (1.12):

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \textbf{\textit{(1.12)}}$$

Finally, the third production method considered is MEC, an electrochemical conversion of biomass by electrolysis. This topic will be dealt with in detail in the next section 1.2.3, however we just want to mention that the difference between electrolysis of biomass and water lies in the reaction that takes place at the anode; in this case the feedstock is oxidised instead of producing gaseous oxygen from the water [27].

In conclusion, there are several ways to produce hydrogen from biomass, each of which has advantages and disadvantages in terms of efficiency, cost and ease of implementation. Therefore, the choice of the best method depends on the specific needs and circumstances of the case.

1.2.3 Production of hydrogen from water electrolysis

The principle of water electrolysis is simply to pass a direct current between two electrodes immersed in an electrolyte to decompose water. Hydrogen is formed at the cathode and oxygen at the anode. The production of hydrogen is directly proportional to the current passing through the electrodes [28]. In recent years, there has been a growing interest in the use of electrolysers for the production of green hydrogen, i.e. hydrogen produced from renewable energy sources such as solar or wind power. Electrolysis of water is a promising technology for the production of environmentally friendly green hydrogen. The devices that enable this transformation are called electrolysers. In an electrolyser we have the electrolytic scission of the H2O molecules in its constituents, hydrogen H2 and oxygen O2, supplying electricity in form of DC current. Although there are different electrolyser types, which are introduced below, they share the same global reaction:

$$H_2O(l) \rightarrow H_2(g) + \frac{1}{2}O_2(g) \tag{1.13}$$

The process of electrolysis happens in an electrolytic cell formed by three elements: two electrodes (cathode and anode) and one electrolyte (liquid or solid, based on the technology) which allows the transfer of ions.

Electrolysers are constantly evolving and there are different types on the market, each with its own advantages and disadvantages. The electrolysis technologies can be differentiated by the different materials used and the different reactions between anode and cathode with the same overall reaction. However, there is also a classification according to operating temperature:

- Low temperature electrolysers (LTE) when the operative temperature is <100°C and liquid water is used;
- High temperature electrolysers (HTE) when operative temperature is in range 400-1000°C and steam is used;

Finally, another classification is based on the TRL ('Technology Readiness level') to see in which application that particular technology is more mature than the others.

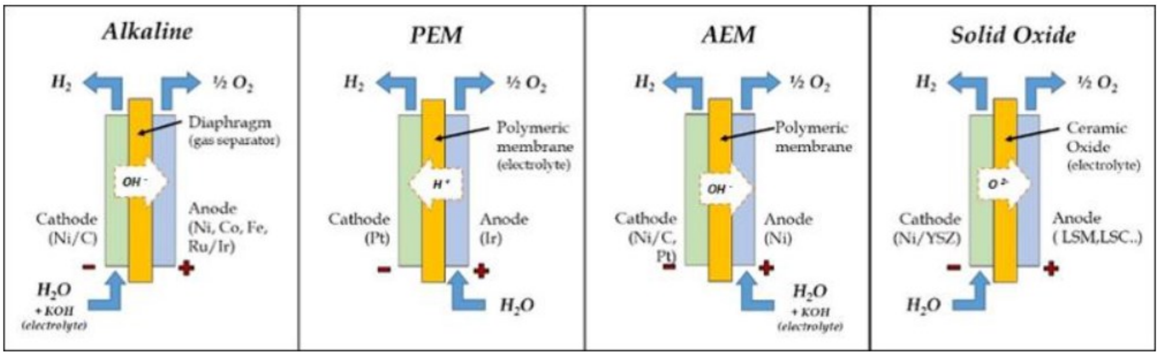

Figure 1.4 – Structure of the cell for the four most common electrolysis technologies [29]

Figure 1.4 shows the main types of electrolytic cells:

- Alkaline type;
- PEM (Proton exchange membrane) type;
- AEM (Anion exchange membrane);
- SO (Solid oxide) type;

The first three types are classified as low temperature electrolysers (LTE), while the last is classified as high temperature electrolyser (HTE). The overall reaction in the different technologies is the same, however, the materials used, the ion exchanged and the type of membrane change. These differences are shown in Table 1.2.

Table 1.2 – Characteristics of principal electrolysis technologies [29]

	Alkaline	PEM	AEM	SOE
Electrolyte	Aqueous solution of potassium hydroxide (20-40%$_{wt}$ KOH)	Polymer membrane	Aqueous solution of potassium hydroxide (<1-5%$_{wt}$ KOH) + polymer membrane	Ceramic oxide, generally Yttria stabilised zirconia (YSZ)
Ion transferred	OH^-	H^+	OH^-	O^{2-}
Materials used	Ni, Ni.Mo alloys, Ni-Co, stainless steel	Pt, Pt-Pd, RuO_2, IrO_2, Ti alloys	Ni, Ni alloys, Fe, Co, stainless steel	Ni/YSZ, LSM/LSC, Fe-Cr-Mn alloys
Operative temperature [°C]	60-80	50-70	30-60	600-900
Current density [A/cm^2]	0.2-1.2	0.6-3.0	0.2-1.0	0.5-1.5
Electric efficiency [% ref. to LHV]	45-75	50-70	50-70	>80-85
Maximum capacity plant demonstrated or under construction [MW]	100	10-20	0.1-0.2	~1
Lifetime [h]	60'000-90'000	30'000-80'000	<30'000	<30'000

The main electrolysis technologies are analysed in the next sections from the point of view of their usefulness, advantages and disadvantages in producing hydrogen.

1.2.3.1 Alkaline type

Alkaline electrolysis highlights among other technologies since it is the one with greater maturity and the larger commercial outreach. The system is constituted by a pair of electrodes immersed in an alkaline solution, usually potassium hydroxide (KOH) in water at a concentration of 25 to 30% and separated by a diaphragm. At the cathode water is split to form H2 and releasing hydroxide anions which pass through the diaphragm and recombine at the anode to form O2 according to the following reactions [30]:

$$2H_2O(l) + 2e^- \rightarrow H_2(g) + 2OH^-(aq.)$$

$$2OH^-(aq) \rightarrow \frac{1}{2}O_2(g) + 2e^- + H_2O$$

The specific consumption for producing hydrogen from this electrolyser is between $4.1 - 4.3\ kWh/Nm^3$ at a current density of $0.3\ A/cm^2$ [31]. This electrolyser technology is the most mature for stationary (constant load) applications and uses a 20-40% aqueous solution of KOH as the electrolyte, as can be seen from Table 1.2 and a central diaphragm for the passage of the OH^- ion. The hydrogen produced by this type of electrolyser has a purity in the range of 99.5-99.9% [32]. The main drawbacks of this technology lie in the problem of reaching low loads and the lack of compactness of the electrolyser in question. In fact, as far as the former is concerned, the minimum load is 30-40% of the nominal load (although recently developed solutions may reach values up to 10-20%), which is high compared to other technologies; as far as the latter is concerned, since the current density is low (Table 1.2), large areas are required for installation and thus a disadvantage from a spatial point of view. However, even considering the associated disadvantages, alkaline-type electrolysis remains the most mature and widely used technology. One thing that is being implemented in these electrolysers to reduce ohmic losses is the zero-gap solution, and thus the reduction of the distance between the electrodes to minimise ion transport losses [30].

1.2.3.2 Proton exchange membrane type

The electrolyte in PEM electrolyser is a polymeric membrane with acidic nature that allows exchange of protons (H+), hence its name Proton Exchange Membrane. That membrane, along with the electrodes, form what is called Membrane Electrode Assembly (MEA). The advantages of this cell are many, including ([33][34]):

- The production of hydrogen with high purity (>99.9%) [35];
- The possibility of working at high pressures;
- Is very flexible for many applications;
- Compact as it has high current densities;
- Fast cold ramp time (5-15 min) [36];

In spite of all these advantages that this type of electrolyser can offer, there are also some disadvantages, the most important of which are the need to use noble metals as catalysts (Pt, Ir, Ti) and the need to use very pure water to obtain the high purities of hydrogen at the output [37]. The specific consumption for producing hydrogen from this electrolyser is between $4.0 - 5.0\ kWh/Nm^3$ at a current density of $1 - 3\ A/cm^2$ [38].

1.2.3.3 Anion exchange membrane type

A technology that is being developed is the Anion Exchange Membrane (AEM). Schematically it has the same structure of a PEM cell with the difference that the membrane transports anions $OH-$ instead of protons $H+$. In that sense, the reactions that occur in the electrodes are the same as for the traditional alkaline cells [30]. This type of electrolyser is promising because it combines the advantages of the alkaline type and the PEM type; in fact, the solid electrolyte is non-corrosive and allows for flexibility, low-load operation and differential pressure. In addition, due to its basic condition, this type of electrolysers does not require platinum-group-metal (PGM) catalysts such as PEM cells. Furthermore, they show lower ohmic losses because the AEM is thinner than traditional membranes and also less expensive than the PEM one. There is still not much data on the operation of this type of electrolyser, however the experimental production rate would still appear to be low ($< 1\ Nm^3/h$) compared to the alkaline ($<760\ Nm^3/h$) and PEM ($<40\ Nm^3/h$) types [39]. For all these characteristics, this technology is promising, however, it is not yet so well developed, in fact it has a low TRL and until now it is only tested in laboratory.

1.2.3.4 Solid oxide type

Solid oxide electrolyser (SOE) is a High Temperature Electrolyser (HTE). Although low temperature electrolysers have a higher degree of maturity, especially the first two, HTE has the distinction of performing electrolysis of water vapor at high temperatures, resulting in higher efficiencies compared to previous options [30]. The main advantage of this technology is that, thanks to the high operating temperature (700-1000°C [36]), it can be incorporated with low-grade waste heat from other plants (chemical or electrical plants) to reduce electricity input and increase efficiency [40]. In addition to this, the SOE-type electrolyser can be inverted, and thus be used as a fuel cell (FC). However, there are associated disadvantages:

- Heat requirement for steam generation;
- Low flexibility: very long switch-on times (hours) [41];
- High costs;
- Short useful life (500-2000 h) [42];

The long-term degradation is the main issue for the viability of this technology as a practical hydrogen production system. Several long-term degradation studies have been performed to date and all of them have concluded that further improvements are required prior to commercialization [43]. The specific consumption for producing hydrogen from this electrolyser is $< 3.5\ kWh/Nm^3$ at a current density between $0.3 - 0.5\ A/cm^2$ [38].

1.3 Hydrogen final uses

Today, the energy transition and decarbonisation of the economy is one of the main objectives at European level thanks to the adoption from December 2019 of the 'Green New Deal', i.e. a strategy aimed at making the EU economy sustainable, where there are no net GHG emissions by 2050, with the intermediate target of achieving through the ‘Fit-for-55' package, a reduction of GHG emissions by 2030 of 55% compared to 1990 values [44].

Achieving these ambitious targets will require not only further efforts at new installations of renewable energy sources (RES) and actions to increase investments in energy efficiency, but also a change in the fuel mix used in the different economic sectors (agriculture, industry, tertiary and transport) through an increased penetration of renewables in electrical and thermal consumption (thermal renewables) and the adoption of green gases and carbon capture technologies for those sectors that are difficult to electrify such as the Hard-to-Abate sectors (e.g. chemical industries, steel mills and foundries).

Now that the hydrogen production technologies, on which the colour of hydrogen depends, have been defined, the various areas in which it can be used and thus the end uses of this vector can be presented. Green hydrogen can be used as a vector to reduce emissions in sectors that are still heavy emitters; three of the most important sectors in which this is used both for energy production and as a resource to produce certain products are:

- Industries, where it is used as feedstock;
- Heating, blend with Natural gas in the gas grid;
- Mobility, where it is used instead of gasoline or diesel fuel;

In Italy, hydrogen has a great potential for development and could play a significant role, until reaching a potential penetration level of 23% of the final energy demand, with a contribution of more than $200\ TWh$ in 2050. The sector that will probably benefit most from the introduction of hydrogen will be the transport sector, which is assumed to cover 39% of the entire hydrogen demand by 2050. In 2030 hydrogen is expected to have a penetration level of 50% as a feedstock, 35% in natural gas grid and 15% in mobility sector [45].

1.3.1 Use as feedstock in industries

The global demand for hydrogen, which has tripled since 1975, is growing every year with no signs of slowing down (Figure 1.5). As of 2018, the worldwide annual hydrogen production is estimated to be ~74 Mt, with up to ~96% used in the chemical industry, ~42% alone for ammonia production, and ~54% in different refineries. The remaining hydrogen (~4%) is used in other sectors such as glass production and reduction of iron ores [46].

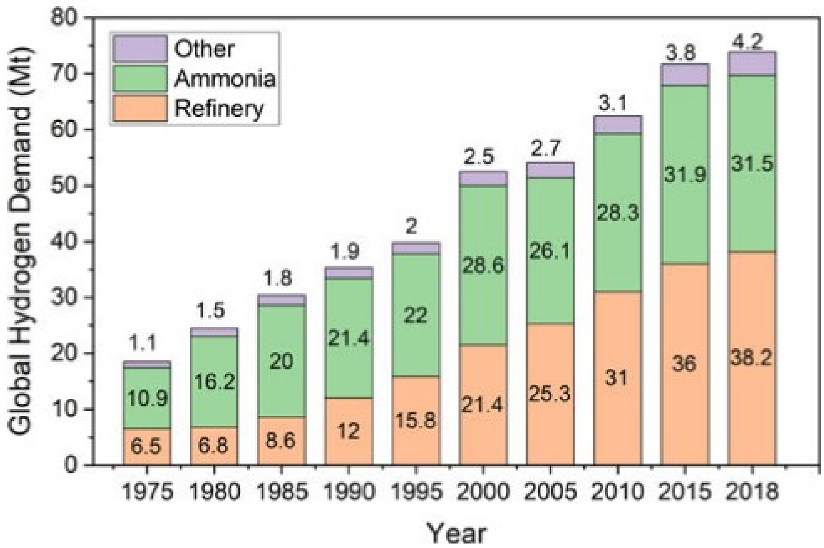

Figure 1.5 - Global demand of pure hydrogen in refinery, ammonia, and other sectors for the period 1975–2018 [46]

In 2019, Italy represents the fifth largest European country in terms of demand, amounting to approximately 0.58 $Mton_{H2}$, corresponding to just under 7% of the European total.

More than 70% of Italy's domestic demand comes from the refining sector, while about 14% comes from the ammonia sector. The remaining part of the demand comes mainly from the other sectors of the chemical industry [44].

Hydrogen can be used as a raw material (feedstock) in several industrial processes [47]:

- Chemicals: ammonia, polymer are the primary market for industrial hydrogen;
- Refining: hydrogen can be used for hydrocracking and hydrotreating;
- Iron and steel: direct reduction of iron via hydrogen (DRI-H) can be an important step in making the steelmaking process more energy efficient and less emissive in terms of CO2-equivalent emissions;

1.3.2 Blending in Natural Gas grid (Heating use)

Another area where hydrogen can be a key vector in decarbonisation is heating, which is currently mostly supplied by natural gas networks. However, hydrogen can be injected into the gas grid to reduce the CO2 equivalent emissions associated with the NG combustion. Blending hydrogen into the natural gas network can help decarbonize the energy sector by supporting the penetration of renewables.

Blending hydrogen alongside other gases into the existing gas grid is considered a possible interim first step towards decarbonising natural gas. With a 5% blending threshold, it is calculated that up to 18.4 GW electrolyser capacity could be integrated EU-wide. This is three times the EU target for 2024. With a 20% blending threshold, the figure rises to 40-70.8 GW. So, approximately 40-70.8 GW of electrolysers could be integrated EU-wide, if allowed to inject hydrogen into the gas grid up to a 20% blending threshold ([48][49]). A range of studies and reports indicate that the presence of hydrogen in the gas grid up to a maximum of approximately 5-10 vol% would be feasible without major modifications in the gas infrastructure and end consumer installations[1] [50]. A further increase to 15-20 vol% appears feasible after modifications on system components based on current knowledge. Raising the content of hydrogen beyond that would require R&D for some categories of consumers and could be considered for the mid to long term. Certain EU countries have released their own national hydrogen strategies also on targets on the hydrogen final sectors. For instance, Portugal's development target for hydrogen blending in the gas grid is 10-15 % by 2030 [51].

1.3.3 Use in Mobility sector

Nowadays, burning fossil fuels for transport has a strong negative impact on the environment. Green hydrogen can be used as a fuel to reduce emissions compared to the use of conventional fuels. Today, considering that climate-friendly means of transport and fossil fuels are incompatible, many countries are favouring the transition from conventional to low-emission vehicles to tackle environmental pollution problems. Particular attention is being paid to enhancing the more widespread use of new generation vehicles, such as electric and automated vehicles [52]. It has been shown that the massive use of electric vehicles instead of conventional ones can save about 60 per cent of greenhouse gas

[1] A simplified model on the Ireland gas network shows that, when an 11.6% hydrogen content is injected in NG grid, there is a 12% rise in pressure drop and 15% increase in flow rate, which indicates that the operational variables will not encounter significant changes and remain within the limits [50].

emissions in most EU countries. In particular, the use of electric vehicles leads to an average greenhouse gas emission saving of about 50 per cent compared to diesel in Europe. Despite these important advantages, the environmental impact of battery electric vehicles (BEVs) is not zero, as [53]:

- In many cases, batteries are charged using non-green energy;
- The entire life cycle of the EV is responsible for greenhouse gas emissions, considering that batteries must be disposed of at the end of their life cycle;

Despite this, studies have been done comparing the life cycle impact of BEVs with that of conventional vehicles on the environment, showing that BEVs achieve lower total greenhouse gas emissions than conventional vehicles with internal combustion engine (ICEs). Furthermore, if renewable energy sources are used to recharge the batteries, the environmental advantages and benefits of using BEVs are even greater. In order to address the discussed issues related to BEVs, in particular technological issues, the use of fuel cells for electricity storage was investigated.

A fuel cell is a device that generates electricity through an electrochemical reaction, not combustion. In a fuel cell, hydrogen and oxygen are combined to generate electricity, heat and water [54]. Hydrogen fuel cell electric vehicles (FCEVs) have a higher energy storage density ($550\ Wh/kg$ compared to $150\ Wh/kg$ for BEVs) than lithium-ion batteries, thus offering a major advantage in terms of autonomy and occupied space compared to BEVs. Furthermore, they show a lower charging time (<10 min, with respect to BEVs which depends on charging power, but it is not less of 1 h). However, BEVs are more efficient than FCEVs and are a mature technology (TRL of 8-9) compared to FCEVs that are not very widespread (TRL of 6-7) [55].

1.4 Decarbonisation target and hydrogen strategies

In this section, we will explore the strategies developed at European level (section 1.4.1) and at Italian level (section 1.4.2) to boost the deployment of hydrogen technologies.

1.4.1 European framework

The 'Fit for 55' is a package of measures proposed by the European Commission in July 2021 to reduce EU greenhouse gas emissions by 55 per cent by 2030 compared to 1990 levels [56]. The package of measures is named after the goal of making the EU 'fit for 55' to meet the climate targets of the European Green Deal. The package of measures includes numerous legislative proposals in different areas, including [57]:

- Emissions Trading Scheme: the proposal includes the extension of the EU Emissions Trading Scheme to new sectors, such as transport and buildings, and a target to reduce emissions by 61% by 2030 compared to 2005 levels;

- Renewable energy: the goal is to increase the share of renewable energy in the EU to 40% by 2030, with the aim of reducing CO2 emissions from energy production;

- Energy efficiency: the package includes a target to improve energy efficiency by 36-39% by 2030;

- Carbon taxation: the proposal envisages the introduction of a carbon tax on imports of carbon-intensive products, in order to reduce emissions related to the production of imported goods;

- Transport: the proposal envisages the phasing out of internal combustion engine vehicles and the promotion of low-emission vehicles, as well as a target to reduce emissions from the transport sector by 90% by 2050;

All these measures in the 'fit for 55' package aim, among other things, to support the spread of green hydrogen by increasing its demand, reducing its costs and increasing the efficiency of using this low-carbon energy carrier.

With the Russian invasion of Ukraine, EU leaders agreed in March 2022 to gradually break free from the EU's dependence on Russian gas, oil and coal imports through a series of measures, contained in the REPowerEU Plan, which aim to accelerate the implementation of the 'fit for 55' package by reducing net greenhouse gas emissions by at least 55% by 2030 and achieve climate neutrality in 2050 as envisaged in the European Green Deal [58]. REPowerEU increases the goals of the 'Fit for 55', e.g. it proposes to increase the EU's 2030 target for renewable energy from the current 40 % to 45 %. The REPowerEU plan would therefore increase the total renewable energy capacity to 1236 GW by 2030, compared to the 1067 GW envisaged in the ‘Fit for 55’ plan for 2030 [59].

For renewable hydrogen, the plan makes available EUR 27 billion in direct investments in electrolysers and hydrogen distribution in the EU, and envisages an increase in domestic hydrogen production to 10 Mton by 2030 (compared to the 'fit for 55' target of 6.6 Mton) [60]. Concerning electrolysis capacity for hydrogen production, the European Commission published the Hydrogen Strategy, which envisages the installation of 40 GW of electrolysers for renewable hydrogen production [51].

1.4.2 Italian framework

The Italian MISE ('Ministero dello Sviluppo Economico') has published a set of guidelines for the development of hydrogen in Italy. These guidelines, contained in the document ‘National Hydrogen Strategy’ published in 2020, represent a roadmap for the implementation of a green hydrogen-based energy system, in line with the objectives of the PNIEC (National Integrated Energy and Climate Plan)[61]. The guidelines highlight the various sectors where green hydrogen could have a greater penetration than traditional fuels to achieve, in line with European targets, a reduction in atmospheric emissions by 2030. These sectors include:

- Long-haul heavy-duty vehicles, which are one of the most emission-intensive sectors, accounting for 5-10% of all transport emissions;
- Trains, replacing trains currently running on diesel;
- 'Hard-to-abate' sectors such as chemicals and refining, where hydrogen is currently produced by SMR (0.5 Mton/year);
- Hydrogen blending in the gas grid, which can be an effective way to contribute to decarbonisation targets and stimulate the hydrogen market (2% of distributed natural gas could be replaced by hydrogen by 2030);

Due to the opportunities and the role hydrogen could play, the penetration of green hydrogen in final energy consumption by 2030 is estimated to be 2% (corresponding to about 0.7 Mton/year of green hydrogen). Should further opportunities be identified and the cost of green hydrogen become more competitive than today, a higher penetration may occur, up to 20% by 2050 [62]. Furthermore, the PNIEC sets the goal of increasing green hydrogen production capacity by electrolysis in Italy to 5 GW by 2030.

1.5 Thesis outline

The thesis aims at proposing and evaluate an incentive mechanism for the green hydrogen sector. The final goal is to provide policymakers with insights into how to incentivize the green hydrogen sector and promote its growth in the long run.

In this framework, Chapter 2 presents a possible incentive scheme aiming at recovering both the investment costs (CAPEX) and the operation cost of the electrolysis plant, thus making green hydrogen production economically competitive. In section 2.1, the calculation of the incentive in €/kg is detailed, considering the various demand sectors, the chosen renewable source, and the electrolyser technology. The section aims to provide a comprehensive understanding of the factors that influence the incentive amount. Then, in section 2.2, the expenditure that the Italian state must make according to this incentive mechanism by 2050 is calculated to reach the fixed hydrogen penetration targets. These analyses provide a deeper understanding of the mechanism's feasibility and long-term sustainability. Overall, Chapter 2 provides a detailed analysis of the proposed incentive mechanism, its cost implications, and the factors that could impact its success.

Then, Chapter 3 focuses on the analysis and evaluation in case studies of the proposed incentive scheme through the development of simulation models. Section 3.1 provides some general assumptions on which the models are based. Paragraph 3.2 describes the developed Excel model, solving mass, energy and economic balances on an annual basis to calculate the differential gain of producing green hydrogen with a newly installed electrolyser and renewable electricity locally generated instead than selling the renewable electricity directly into the grid. Section 3.3 describes the developed Python model, solving mass, energy and economic balances with an hourly resolution to determine the annual gain of a renewable producer who decides to install an electrolyser for the production of green hydrogen. Both models are parameterised to the installed kW of electrolysis and are therefore exploitable with different input data. The excel and the python models are then used in section 3.4 and 3.5, respectively, for the evaluation of case studies. The annual model is used to simulate the case in which the renewable energy source is photovoltaics, while the hourly model is used to evaluate a case study with electricity production from biomass.

Finally, Chapter 4 summarises the results of the analysis, highlighting the pros and cons of the proposed incentive scheme. Alternative incentive scheme, allowing to overcome the limits identified by the scheme here proposed are indicated. Additionally, advice is presented on how to expand the present work and improve the analysis.

Chapter 2

2 Proposal of an incentive scheme for green hydrogen generation

The aim of this chapter is to identify the incentives that should be provided to a renewable electricity plant owner to support the production of renewable hydrogen ("green hydrogen") as an alternative to selling electricity to the grid. In this chapter an incentive scheme is presented, which has been defined in a preliminary study conducted in the Sustainable Energy (SE) centre of research institute Fondazione Bruno Kessler (FBK). Then, in this thesis, the incentive scheme is further analysed and results are presented with the support of graphs and tables.

The proposed scheme to incentivize green hydrogen generation assumes to give a support both in terms of operating costs (related to the electricity carrier used), and in terms of fixed costs (related to the investment cost of electrolysers and ancillary components).

The objectives of the analysis conducted here are the following:

1. Determine the value of the incentive in $€/kg_{H2}$ required to support H2 production from renewable sources, as a function of the different types of demand and the relative WTP (willingness to pay);
2. Estimate the total investment of the state and its trajectory up to 2030, based on Italian declarations of hydrogen technology deployment within the various European plans;

The two objectives are detailed below.

2.1 Quantification of incentive required per kg of produced hydrogen

The analysis conducted here focuses on a single scenario, namely the case in which a possible owner/operator of a Renewable Energy Source (RES) plant chooses to produce green hydrogen to be marketed to meet the demand for hydrogen for the three most important demand sectors:

- Replacement of natural gas from the distribution network;
- Replacement of grey hydrogen as a raw material in the industrial sector;
- Replacement of diesel as a fuel for heavy mobility;

The objective of the analysis is the identification of the economic gap between the revenue from the sale of hydrogen and the loss of revenue from the sale of electricity on the grid. This gap is assumed to be the economic support (incentive) required for the sale of hydrogen for various end-uses to be competitive with the direct sale of electricity to the grid. In this study, it is assumed that the incentive is paid on the produced hydrogen.

$$\mathrm{tot}_{\mathrm{inc}}[\frac{€}{kg_{H2}}] = -Gap\ [\frac{€}{kg_{H2}}] \tag{2.1}$$

The incentive is calculated as consisting of two contributions:

1. The share related to the operation of the electrolysis plant (related to competing with the alternative grid sale of renewable electricity), $operative_{inc}$;

2. The share related to investment (CAPEX) and O&M costs of the electrolyser, $CAPEX_{inc}$;

Hence:

$$Gap\ [\frac{€}{kg_{H2}}] = \mathrm{operative}_{\mathrm{inc}}[\frac{€}{kg_{H2}}] + \mathrm{CAPEX}_{\mathrm{inc}}\ [\frac{€}{kg_{H2}}] \tag{2.2}$$

As regard the $operative_{inc}$, expressed in $€/kg_{H2}$, the mathematic formula is reported below:

$$\mathrm{operative}_{\mathrm{inc}}\left[\frac{€}{kg_{H2}}\right] = \frac{\mathrm{operative}_{\mathrm{inc}}\left[\frac{€}{kW_{inst}\cdot y}\right]}{prod_{H2}\left[\frac{kg_{H2}}{kW_{inst}\cdot y}\right]} = p_{H2,\mathrm{avg}}\left[\frac{€}{kg_{H2}}\right] - p_{el,MGP}\left[\frac{€}{kWh_{el}}\right]\cdot\left(\varepsilon_{el}+\varepsilon_{comp}\right)\left[\frac{kWh_{el}}{kg_{H2}}\right] \tag{2.3}$$

The parameters in the equation are:

- Average expected price for the sale of hydrogen for a specific sector ($p_{H2,\text{avg}}$);
- Average annual price for the sale of electricity in the MGP ($p_{el,MGP}$);
- Specific electrical consumption for electrolyser conversion, dependent on the selected electrolysis technology (ε_{el});
- Specific electricity consumption for the compression of H2 (ε_{comp});

On the demand side, as mentioned above, a number of potential hydrogen selling prices for different end uses have been assumed. The basic assumption is that hydrogen replaces the fossil fuel, ensuring no cost change in its use. With this approach, the potential hydrogen price (p_{H2}) is evaluated in 3 different sectors:

- Green H2 as a substitute for natural gas (NG) from the grid (e.g., for thermal energy production). In this case, the cost of hydrogen (€/MWh) is estimated based on energy equivalence with natural gas (i.e., to have equal €/MWh compared to the purchase of NG). A maximum and minimum value for the price of natural gas is assumed based on historical prices (annual average values from 2018 to 2021). The hydrogen selling price is then calculated in eq. (2.4) considering the lower heating value of hydrogen (LHV_{H2} = 120 [MJ/kg]):

$$H2price_{NGgrid}\left[\frac{€}{kg_{H2}}\right] = price_{NG}\left[\frac{€}{MWh}\right] * \frac{LHV_{H2}}{3600} \tag{2.4}$$

- Green H2 as a substitute for grey H2 (produced by Steam Methane Reforming - SMR), as a raw material for industrial use. In this case, the price is defined by the price of the grey H2 to be replaced, which is directly related to the price of NG. The selling price of hydrogen is calculated from the price of natural gas in €/ton, considering the lower heating value of hydrogen (LHV_{H2} = 120 [MJ/kg]) and the average lower heating value of NG (LHV_{NG} = 47 [MJ/kg]). This price is evaluated by eq. (2.5), which is an empirical equation coming from a direct exchange of uncountable information between industrial partners:

$$H2price_{feedstock}\left[\frac{€}{kg_{H2}}\right] = \left(3.8 * price_{NG}\left[\frac{€}{ton_{NG}}\right] + 80 + \frac{255555}{400}\right) * 10^{-3} \tag{2.5}$$

- Green H2 as a substitute for diesel for mobility. In this case, the target price is defined by the price of diesel, based on the average consumption resulting from the efficiencies of fuel cell systems and internal combustion engines. Energy equality wants to guarantee the same expenditure per kilometre travelled by the vehicle. The price considered is the price at which the green H2 producer sells the hydrogen to the filling station operator. The final price for the sale of hydrogen to the end user

(Fuel Cell vehicle owner) will then be higher, as it will also include the distribution and operating costs of the refuelling station itself.

$$H2price_{mobility}\left[\frac{€}{kg_{H2}}\right] = \frac{\left(price_{diesel} * \frac{consumption_{avgFC}}{consumption_{avgDiesel}}\right)}{(1+VAT)} * \left(1 - costH2_{production}\right) \quad \textbf{(2.6)}$$

Depends on:

- $price_{diesel}\left[\frac{€}{l}\right]$ = mean diesel price over the years expressed in €/l;
- $consumption_{avgFC}\left[\frac{km}{kg}\right]$= average consumption of FC system;
- $consumption_{avgDiesel}\left[\frac{km}{l}\right]$ = average consumption of an ICE;
- $costH2_{production}[-]$ = the percentage of cost of H2 involved for production and preparation of hydrogen;
- VAT = “value added tax” is the tax that the consumer must pay over the consumption of hydrogen but is not a part of the gain of the producer;

Concerning the incentive share related to the fixed costs ($CAPEX_{inc}$), in $€/kg_{H2}$, this is calculated:

$$CAPEX_{inc} = \frac{FixedCost}{prod_{H2}} \quad \textbf{(2.7)}$$

Where:

- $prod_{H2}$ is the specific yearly production for 1 kW of installed capacity of electrolysis, in $\frac{\frac{kg_{H2}}{y}}{kW_{inst}}$, calculated as:

$$prod_{H2} = \frac{EL_{cap} * h_{eq_{EL}}}{\varepsilon_{el} + \varepsilon_{comp}} \quad \textbf{(2.8)}$$

Where EL_{cap} is the electrolysis capacity and $h_{eq_{EL}}$ are the equivalent operating hours of the electrolyser.

$FixedCost$, expressed in $\frac{€}{y * kW_{inst}}$, represents the yearly capex expense, obtained from the total CAPEX considering the weighted average cost of capital (WACC) plus the O&M costs. The calculation of the $FixedCost$ $\left[\frac{\frac{€}{kWinst}}{y}\right]$ is reported below, starting from the definition of the capital recovery factor (CRF), which is the factor for dividing the capex quota annually, as:

$$CRF = \frac{1}{\sum_{y=1}^{Lifetime} \frac{1}{(1 + WACC)^y}} \tag{2.9}$$

The annual CAPEX and OPEX, both expressed in $\left[\frac{€}{y * kW_{inst}}\right]$ can be calculated:

$$CAPEX_{annual} = CAPEX_{inv} * CRF \tag{2.10}$$

Where $CAPEX_{inv}$ is the investment cost in €/kWinst.

$$OPEX_{annual} = opex_{\%} * CAPEX_{inv} \tag{2.11}$$

Where $opex_{\%}$ is the percentage of opex costs in relation to CAPEX costs. So:

$$FixedCost = CAPEX_{annual} + OPEX_{annual} \tag{2.12}$$

Here, the economic gap (Gap) is related to the electrolyser technology adopted for hydrogen production and the amount of hydrogen produced. The Gap therefore also depends on the renewable source used for electricity production and the geographical location, both of which determine the capacity factor of the renewable plant.

Before continuing with the analysis, photovoltaic and wind 'classes' are defined according to the definition in IRENA publication [63]. These classes represent location with a different availability of wind or sun, thus with different equivalent operative hours for the RES (PV or wind). The Italian territory has been classified into zones according to the classes. This analysis considers three classes of photovoltaics and two classes of wind power, taking into account the equivalent hours of operation typical of the Italian territory for these plants, as we can see in Table 2.1. For example, a photovoltaic system is in class PV2 if the annual equivalent hours of production are greater than or equal to 1523 h/y.

Table 2.1 - Equivalent operating hours ($h_{eq_{RES}}$) and capacity factor (CF) potentially detectable on Italian territory for photovoltaic plant (PV) and onshore wind plant [63]

	ITA PV2	ITA PV3	ITA PV4	ITA Onshore 3	ITA Onshore 4
$h_{eq,RES}$	1523	1392	1215	2908	1679
CF	17%	16%	14%	33%	19%

For each class, the optimal ratio between the size of the renewable plant and the size of the electrolyser identified in IRENA publication is considered, as well as the number of equivalent operating hours of the electrolyser, in Table 2.2 [63]. The optimal ratio guarantees the lowest cost of production of hydrogen depending on the renewable source and system component costs.

Table 2.2 - Optimal ratios between RES (renewable energy source) plant size and size of electrolyser [63]

	ITA PV2	ITA PV3	ITA PV4	ITA Onshore 3	ITA Onshore 4
$Ratio_{optimal}$	2.13	2.30	2.34	1.46	2.19
$h_{eq,EL}$	1340	1175	1047	2731	1552

2.1.1 Numerical assumptions and results

The analysis is performed with the following numerical assumptions:

- Photovoltaic plant in class PV3 with the following characteristics from Table 2.1 and Table 2.2:
    - $EL_{cap} = 1\ kW$;
    - $h_{eq_{RES}} = 1392\ h/y$;
    - $Capacity\ factor\ CF = 16\%$;
    - Optimal ratio $Ratio_{optimal} = 2.3$;
    - $h_{eq_{EL}} = 1175\ h/y$;

- $Lifetime = 20\ years$;
- $Opex_{\%} = 4\%$;
- Weighted average cost of capital $WACC = 10\%$;
- Electricity price in a range 20-500 €/MWh;
- Natural gas price in a range 20-140 €/MWh;
- Diesel price in a range 1.5-2.3 €/l;

The analysis considers various electrolyser technologies ([64][9]):

- Alkaline type:
  - $CAPEX_{inv} = 480\ €/kW_{inst}$;
  - Specific consumption $\varepsilon_{el} = 49 \frac{kWh}{kg_{H2}}$;
  - Specific consumption $\varepsilon_{comp} = 1.71 \frac{kWh}{kg_{H2}}$;
- PEM type:
  - $CAPEX_{inv} = 700\ €/kW_{inst}$;
  - Specific consumption $\varepsilon_{el} = 52 \frac{kWh}{kg_{H2}}$;
  - Specific consumption $\varepsilon_{comp} = 1.02 \frac{kWh}{kg_{H2}}$;
- SOE type:
  - $CAPEX_{inv} = 1250\ €/kW_{inst}$;
  - Specific consumption $\varepsilon_{el} = 39 \frac{kWh}{kg_{H2}}$;
  - Specific consumption $\varepsilon_{comp} = 2.85 \frac{kWh}{kg_{H2}}$;

The operative incentive is reported as a function of the MGP electricity price. In the next graphs some different lines are plotted, with different colours; these represent different sectors at which green hydrogen produced by the electrolyser is sold:

- In blue the situation in which the hydrogen is sold for the injection in natural gas grid;

- In grey the situation in which hydrogen is sold as a feedstock for industries;

- In green the situation in which hydrogen is sold for mobility sector;

Furthermore, for each end use considered, there are two lines of the same colour, which represent the upper and lower limits of the range considered for the hydrogen sales price on the base of:

- Natural gas price range for industrial sectors (feedstock and NG grid);
- Diesel price range for the mobility sector;

The graphical results of operative incentive for the three different electrolysis technologies considered are shown below, considering the assumptions on the parameters made above. In detail, Figure 2.1 refers to alkaline technology, Figure 2.2 to PEM and Figure 2.3 to SOE technology.

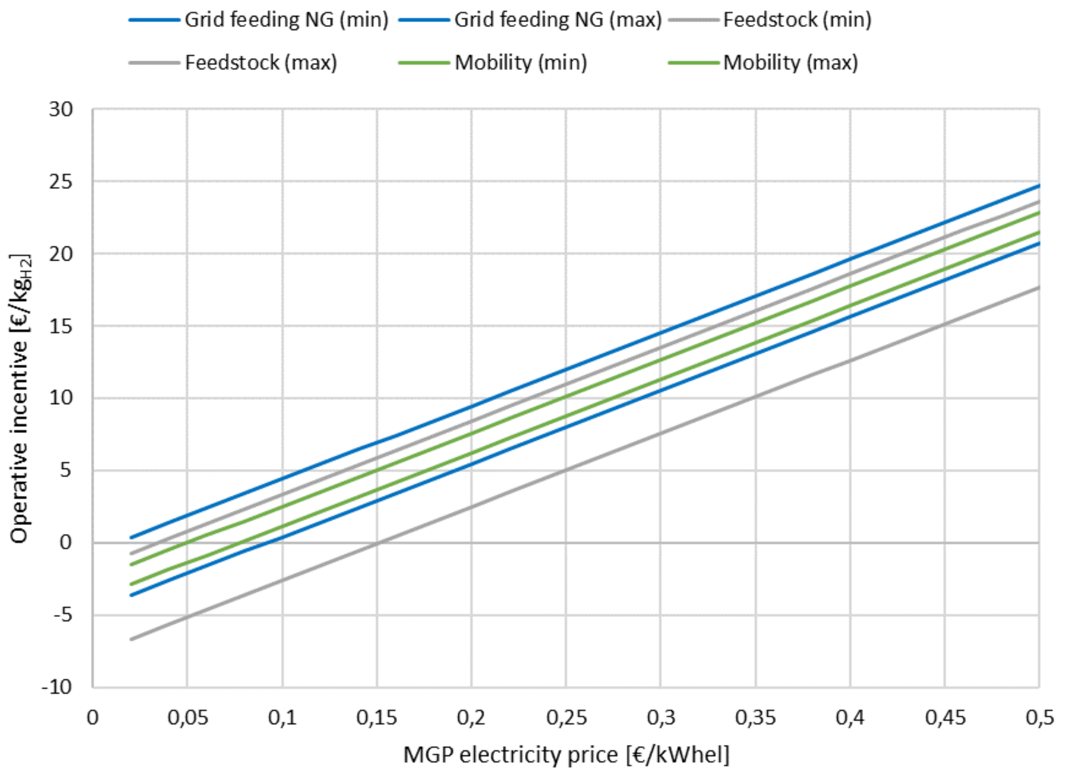

Figure 2.1 – ALK technology: operative incentive required for different industrial objectives, as a function of the electricity price in MGP market

In Figure 2.1 some considerations can be done for the alkaline electrolyser type:

- In the industrial as feedstock sector (grey line), the economic parity of green H2 and grey H2 from SMR (i.e., no need of incentive) is obtained for an MGP price between 40-150 €/MWh depending on the natural gas price considered (ranging from 20 to 140 €/MWh). Above that, H2 production must also be supported with incentives of up to 2.5-8.5 €/kg for MGP of 200 €/MWh (value chosen as representative of the price of electricity in recent months of 2022 in the day ahead market)[65];

- In the sector of industrial use as heat production, the economic parity of H2 and natural gas is achieved for an MGP price between 20-90 €/MWh, depending on the natural gas price considered. Above that, H2 production has to be sustained, even with incentives of up to 5-10 €/kg per MGP of 200 €/MWh;

- In the mobility sector, economic parity of H2 and diesel is achieved for an MGP price between 50-75 €/MWh, depending on the diesel price considered (ranging from 1.5 €/l to 2.3 €/l)). Above that, H2 production has to be sustained, even with incentives up to 6-7.5 €/kg per MGP for potential sale of the electricity into the grid at 200 €/MWh;

- The cost of natural gas weighs heavily on the incentive required to produce H2 for industrial sectors with thermal or feedstock demands as opposed to the application in mobility with diesel. This is due to the volatility of the cost of natural gas, between 20-140 €/MWh, compared to that of diesel that is very low between 1.5-2.3 €/l;

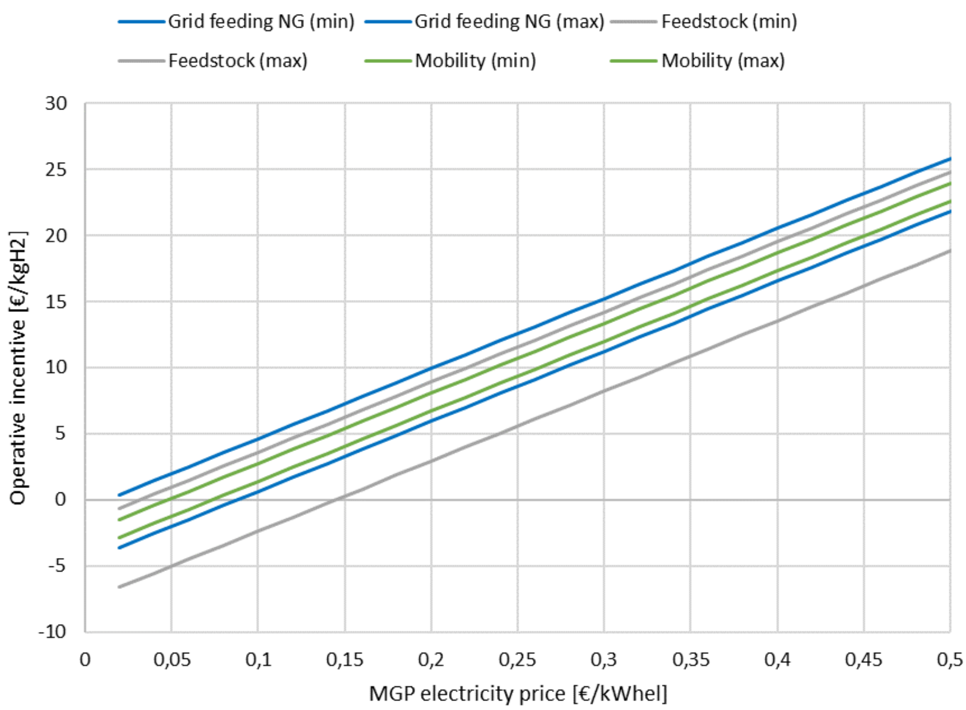

Figure 2.2 – PEM technology: operative incentive required for different industrial objectives, as a function of the electricity price in MGP market

As far as PEM electrolyser technology is concerned, as it can be seen in Figure 2.2, the operative incentive ranges in the various sectors are very similar to those of alkaline technology, with some minor differences, e.g. considering the heat production sector, hydrogen production must be supported with incentives of up to 6.5-10 €/kg per MGP price of 200 €/MWh.

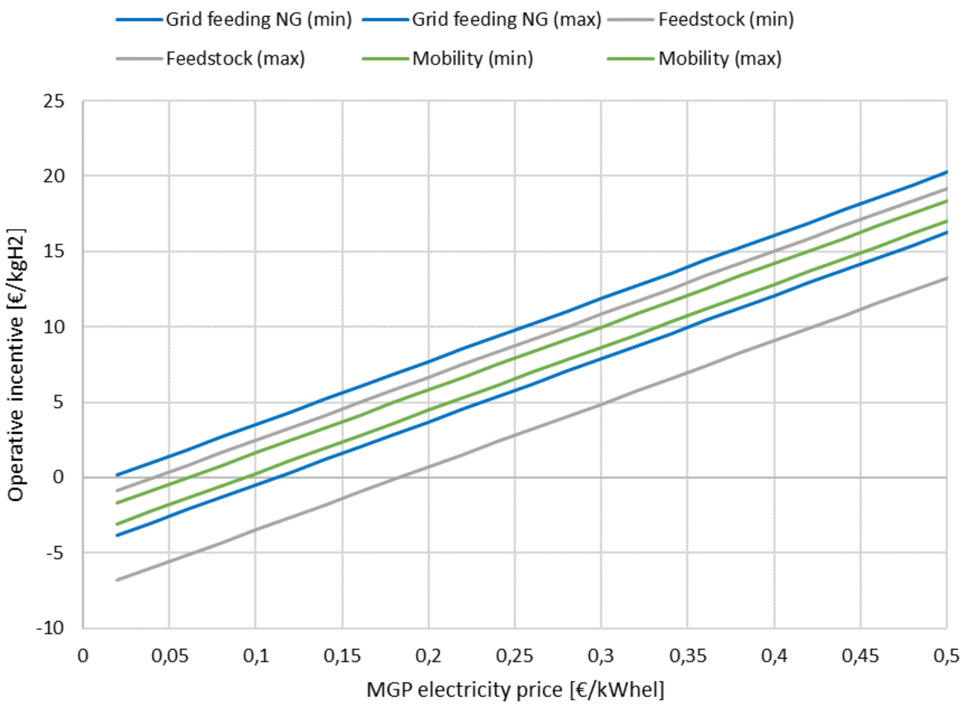

Figure 2.3 – SOE technology: operative incentive required for different industrial objectives, as a function of the electricity price in MGP market

As far as SOE-type electrolysers are concerned, these differ significantly in the operating incentive paid for a given MGP electricity price, because they represent the most operationally efficient technology and therefore the operational incentive for this technology will be lower than for other technologies considering the same end sector. In fact, we can see in Figure 2.3:

- In the mobility sector, economic parity of H2 and diesel is achieved for an MGP price between 60-90 €/MWh (the range is due to the price range considered for diesel). Above that, H2 production has to be sustained, even with incentives up to 4.5-6 €/kg for potential sale of the electricity into the grid at 200 €/MWh;

- In the industrial as feedstock sector, the economic parity of green H2 and grey H2 from SMR is obtained for an MGP price between 45-180 €/MWh. The range is due to the price range considered for natural gas. Above that, H2 production must also be supported with incentives of up to 1.5-7 €/kg per MGP of 200 €/MWh;

- In the sector of industrial use as heat production, the economic parity of green H2 and natural gas is achieved for an MGP price between 40-110 €/MWh. The spread is due to the price range considered for natural gas. Above that, H2 production has to be sustained, even with incentives of up to 4-7.5 €/kg per MGP of 200 €/MWh;

The figures above show, for the three different types of electrolysers considered, the operative incentive at varying electricity prices in the three different end-use sectors of the green hydrogen produced. For purely illustrative purposes, the operating incentive at varying electricity prices for the three different types of electrolysers, considering only feedstock as the final use, is compared in Figure 2.4. For each technology considered, there are two lines of the same colour, representing the upper and lower limits of the range considered for the selling price of hydrogen for end use as a feedstock.

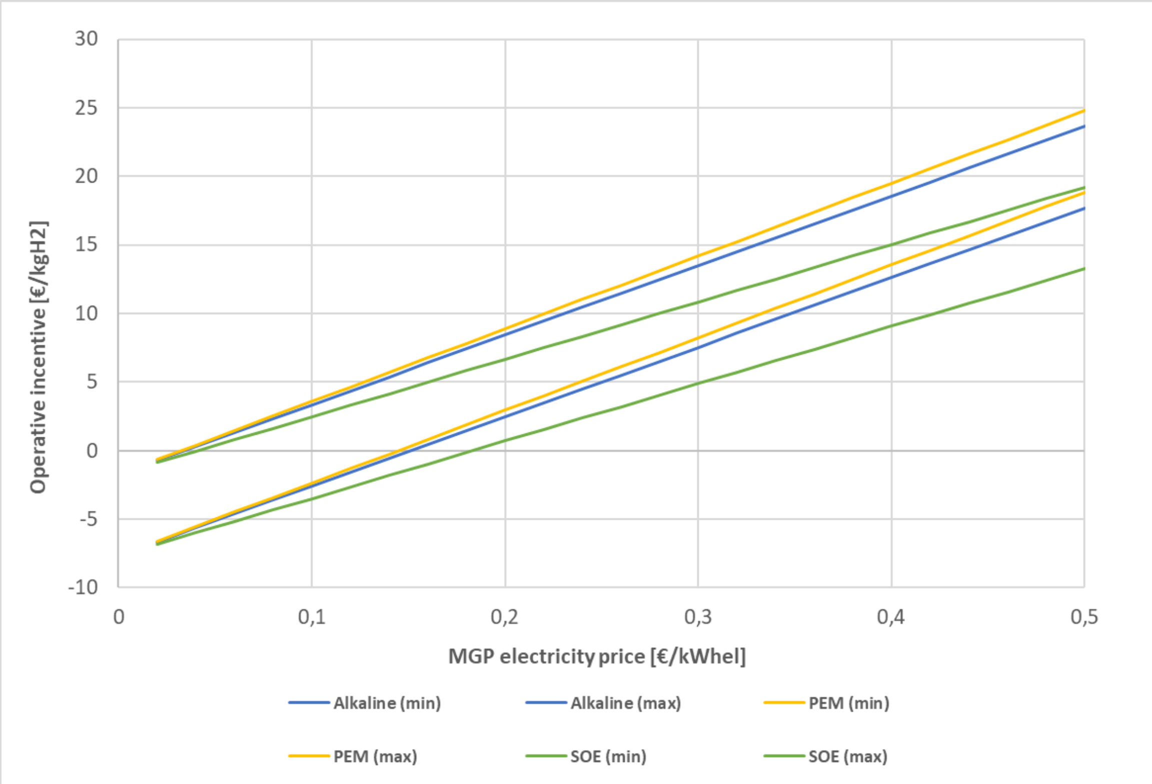

Figure 2.4 – Operative incentive range on green hydrogen produced and used as feedstock, for different electrolyser technologies

In Figure 2.4 it can be seen, as explained in detail above, that the range for the operating incentive of the highest efficiency SOE technology includes smaller values than the ranges for alkaline and PEM technologies, which, as the price of electricity increases, nevertheless remain very similar to each other.

Figure 2.5, Figure 2.6 and Figure 2.7 show how the CAPEX incentive varies with the investment costs (for the three electrolyser technologies in question) and according to the equivalent hours available from the renewable source chosen for the plant. Depending on the renewable source and its class, it can be seen that the incentive for the investment decreases as the number of equivalent operating hours increases.

Also, in this case the graphs show CAPEX incentive results in different colours, due to the different renewable source used to produce the electricity then fed into the electrolyser:

- In yellow the situation in which the electrolyser produces hydrogen from electricity generated by a photovoltaic system;

- In blue the situation where the electrolyser produces hydrogen from electricity produced by onshore wind power plant;

The points within the graph represent the various classes of RES described in section 2.1, and correspond to the number of equivalent operating hours of the renewable source shown on the x-axis. Below are the graphical results for the CAPEX incentive for the three electrolyser technologies considered, starting with the alkaline type. In detail, Figure 2.5 refers to alkaline type of electrolyser, Figure 2.6 refers to PEM and Figure 2.7 to SOE-type technology.

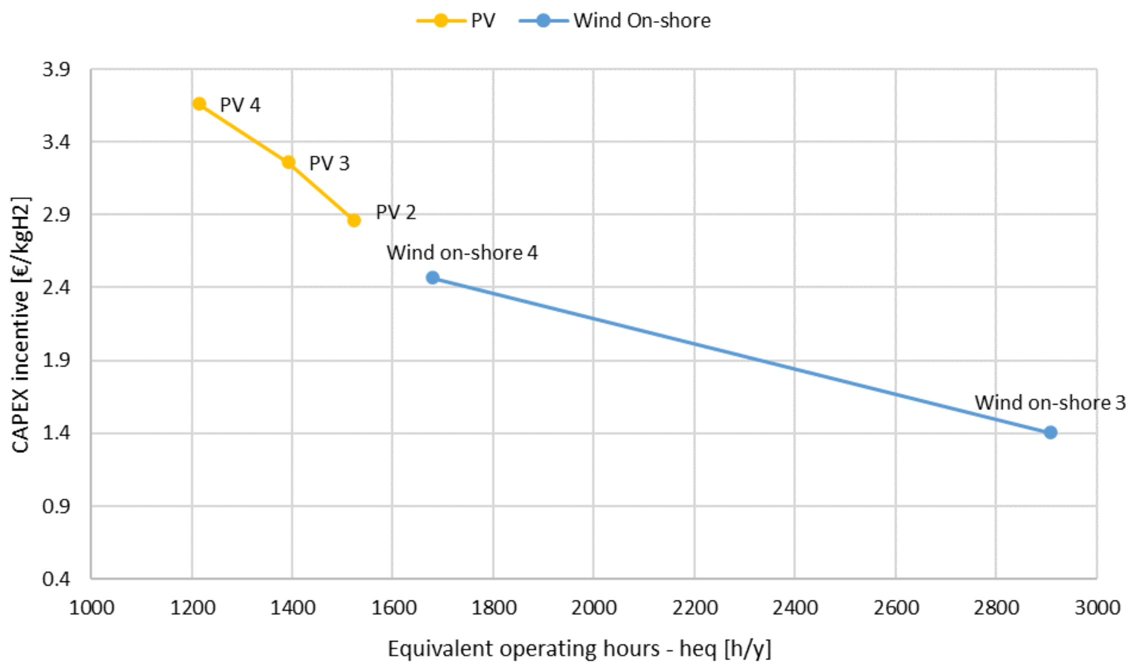

Figure 2.5 - Alkaline technology: incentive to support the fixed capital costs of installation

In Figure 2.5 some considerations can be done for the alkaline electrolyser type:

- With solar energy as the renewable energy source for hydrogen production, the equivalent operating hours for this source are low and therefore the CAPEX incentive has to be high in order to cope with the lack of hydrogen sales at many times of the year. In fact, incentives are needed between 2.8 and 3.7 €/kg when coupled with PV, and the range depends on the different class of PV considered;

- With wind energy as the renewable energy source for hydrogen production, it can be seen that the equivalent operating hours for this source are higher (especially in the case of onshore wind class 3) and therefore the CAPEX incentive can be lower with respect to the solar energy source. In fact, incentives are needed between 1.4 and 2.5 €/kg when coupled with wind power, and the range depends on the different class of wind onshore considered;

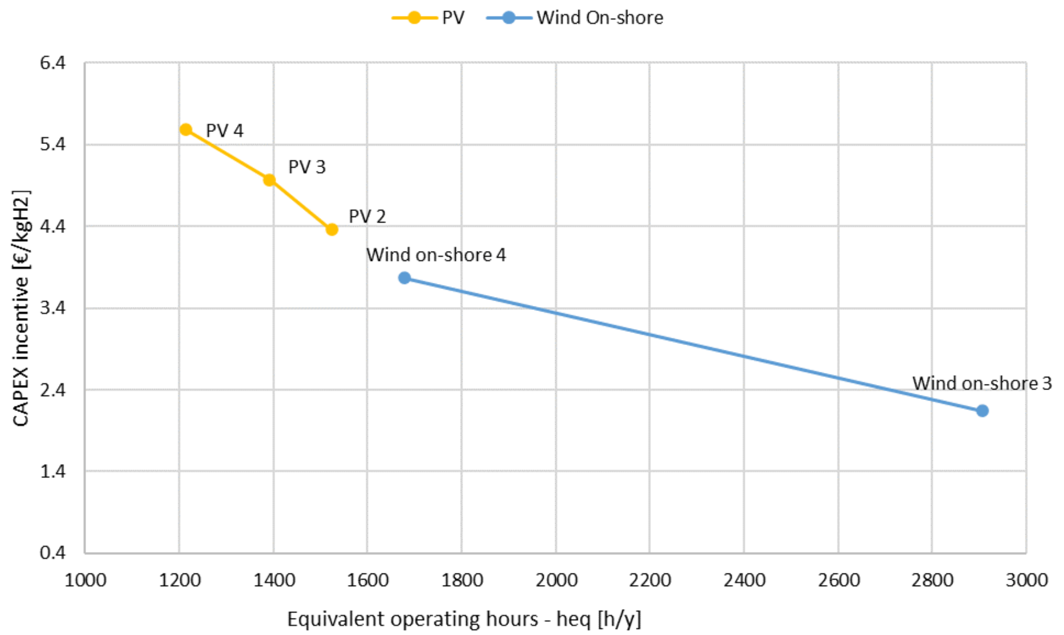

Figure 2.6 - PEM technology: incentive to support the fixed capital costs of installation

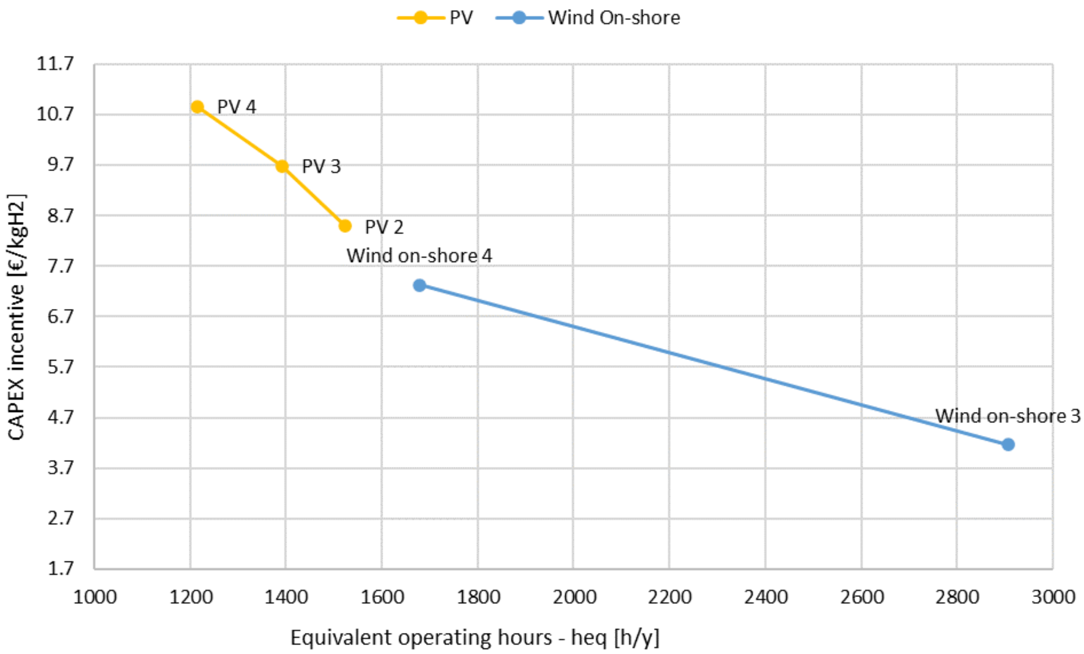

Figure 2.7 – SOE technology: incentive to support the fixed capital costs of installation

For PEM technology (in Figure 2.6), incentives rise between 4.4 and 5.6 €/kg when coupled with PV, between 2.2 and 3.8 €/kg when coupled with wind power. Finally, in Figure 2.7, for SOE technology, incentives are between 8.5 and 10.9 €/kg when coupled with PV, and between 4.2 and 7.3 €/kg when coupled with wind power.

2.1.2 Conclusions

Thus, the following important conclusions emerge:

- The total incentive to be paid must therefore consider the two real contributions to hydrogen production: operational and fixed. Depending on the technology adopted for hydrogen production, on the nature of the renewable source (load factor, hourly production profile), and on the selling price of hydrogen and electricity on the MGP, the relative weight of the two contributions may vary;

- The type of hydrogen production technology impacts the sensitivity of the graphs related to the operative incentive in Figure 2.1, Figure 2.2 and Figure 2.3, disadvantaging the least efficient production systems (PEM>ALK>>SOE) in terms of the necessary operating incentive;

- The type of electrical production technology influences the parameters of the system, with necessarily higher incentives for technologies with higher fixed costs (SOE>>PEM>ALK); considering an alkaline-type electrolyser, with the various assumptions made, a CAPEX incentive on investment costs of $3.26\ €/kg_{H2}$ is set (from Eq. (2.7));

- Another particularly burdensome element is the renewable source production technology considered (PV and wind), with different associated capacity factors (13.6-33.1%, in Figure 2.5), which has a significant impact on the CAPEX incentive;

2.2 Quantification of the total state expenditure to meet the hydrogen penetration targets

In this section, the total state incentive is determined based on Italian declarations under the various European plans. Two different scenarios have been identified for the study, achieving different levels of hydrogen production by 2030 [62]:

- Scenario 1: installation of 5 GW of electrolysis for green hydrogen production;
- Scenario 2: installation of the necessary electrolysis capacity to reach a production of 0.7 Mton of hydrogen per year produced by direct coupling with renewable plants;

2.2.1 Assumptions

The assumptions for this target are the following:

- Linear growth of installed capacity is assumed between 2024 and 2030;

- The hydrogen produced is used in three different identified sectors (hydrogen as a raw material for industrial processes, hydrogen to satisfy both industrial and residential thermal energy demand, hydrogen for transport);

- Incentives are given for each kg of hydrogen produced/sold, for an annual production equal to that calculated from the typical equivalent hours of operation of PV or wind power plants on Italian territory. For the extra quantity produced each year (e.g., thanks to PPAs, for positioning in strategic areas, etc.) no incentive will be given;

- The incentive is provided for the first 20 years of each plant's life, guaranteeing full recovery of the investment cost (CAPEX) and the plant's fixed costs. Furthermore, as a first approximation, it is assumed that the investment cost of the plant remains constant between 2024 and 2030. This assumption allows us to consider the worst-case scenario (maximum expenditure by the state);

- The cost of electricity and natural gas, thus the cost of the non-green hydrogen that hydrogen from electrolysis would replace, is assumed to be constant over the entire time period considered;

Assuming that the actual variable expenditure incentive is updated periodically (e.g., monthly, or even daily depending on the results of the electricity and natural gas market), the actual expenditure of the state will depend on the performance of the energy markets. It should be noted that, depending on the price of electricity and natural gas, the operating incentive can assume positive values (corresponding to the case where it would be cheaper to sell electricity than to produce hydrogen) or negative values (corresponding to the case where it is more profitable to produce hydrogen). In the case of a negative operating incentive, the latter is set equal to zero, while the investment incentive remains unchanged. This allows the investor to make a profit.

On the basis of the assumptions made, a 'base case' is defined to which the results refer:

- Target of 5 GW by 2030 (scenario 1);
- Installation of alkaline-type electrolysers;
- Power generation from PV with 1392 equivalent hours (PV3 zone);
- Natural gas cost of 160 €/MWh (gas purchase cost for storage in September 2022) [65];
- Electricity cost of 300 €/MWh (average electricity price on the day-ahead market in December 2022) [66];

2.2.2 Results

In the first analysis of the study, the two scenarios can be better parameterized:

- Scenario 1: the target is the installation of 5 GW of electrolysers by 2030. In this case, with the installation of alkaline-type electrolysers, a hydrogen production of 0.12 Mton per year is calculated with the assumption of 1392 equivalent hours (band PV3) and 0.15 Mton per year with the assumption of 1679 equivalent hours (band 4 wind);

- Scenario 2: the target is the installation of the necessary electrolysis capacity to achieve a production of 0.7 Mton of green hydrogen per year produced by direct coupling with renewable plants. In this case, the required capacity is calculated to be 29.0 GW under the assumption of 1392 equivalent hours (band 3 PV) and 22.9 GW per year under the assumption of 1679 equivalent hours (band 4 wind);

Figure 2.8 shows the results of the study for the base case in terms of total incentive paid (in blue), annual incentive (in green) and installed capacity (in orange) over the next years.

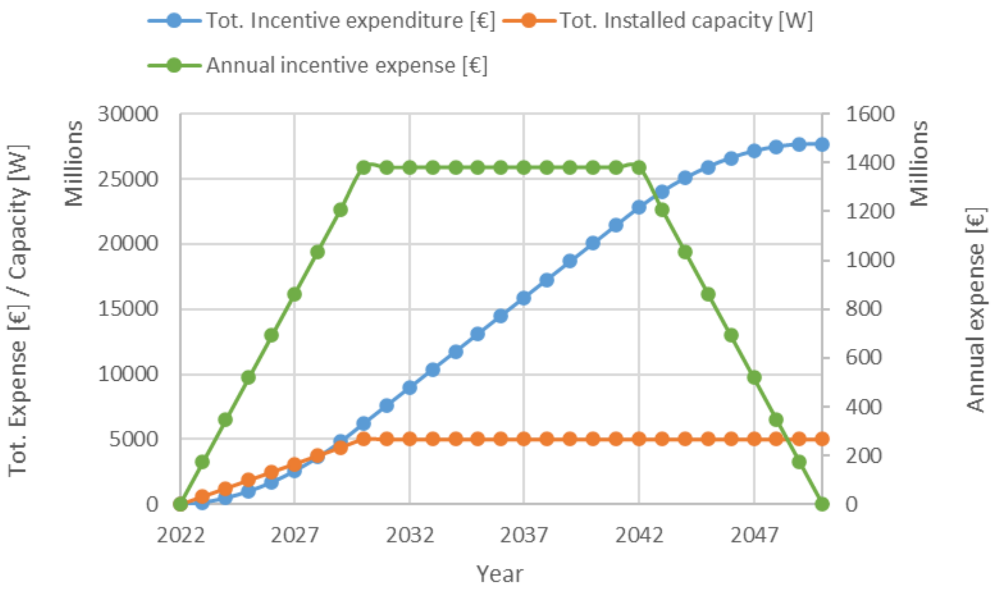

Figure 2.8 - Base Case: total expenditure from 2022 at an established year in millions of euros (left axis), installed capacity until an established year in W (left axis), and annual expense in millions of euros (right axis)

Furthermore, in Figure 2.9, the division of the operative (in orange) and CAPEX incentive (in blue) shares with respect to the total incentive paid out by the state is shown, and it can be seen how the share linked to the operative incentive is preponderant with respect to the CAPEX share.

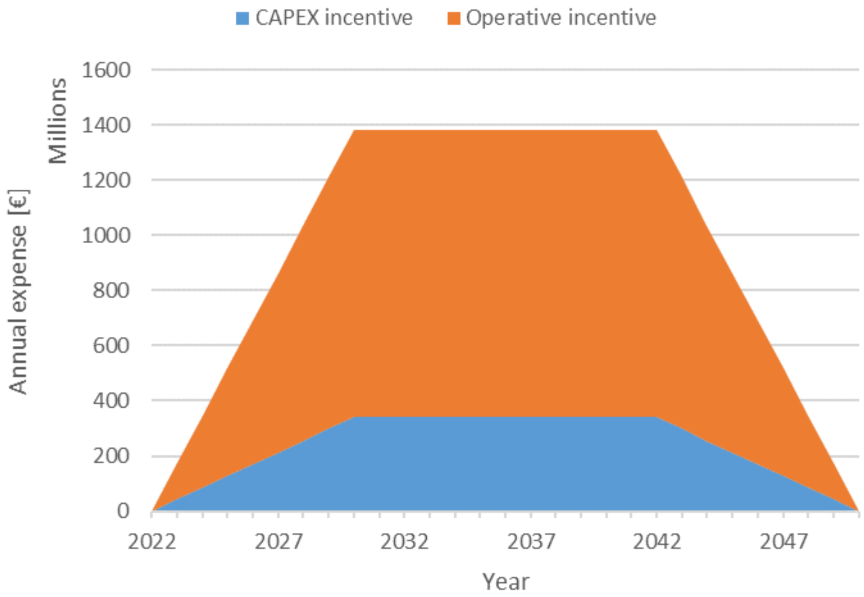

Figure 2.9 – Base case: breakdown of annual expense in two parts: a part connected with fixed costs (CAPEX) and a part with operative costs

As regard the base case:

- In Figure 2.8, the installed capacity increases linearly between 2022 (where the installed capacity is zero) and 2030 (where the 5 GW target is reached);

- Furthermore, Figure 2.8 shows the annual cash flow related to the investment. It grows linearly until 2030, proportional to the installed capacity and for which the incentive is intended. From 2042 onwards, it decreases linearly as the plants gradually reach 20 years of life, after which the incentive is no longer paid out;

- With the assumptions adopted here, the maximum annual expenditure is €1.38 billion;

- Finally, Figure 2.8 also shows the cumulative expenditure. The total expenditure at the end of 2050 is € 28 billion;

- Figure 2.9 shows how the annual expenditure is mainly related to operating costs, which account for 75%, compared to investment costs, which account for 25%;

However, Figure 2.8 and Figure 2.9 are specific to the assumptions of the chosen base case. The total expenditure to provide the incentive, as well as the division between the fixed cost share and the operating cost share, varies as the costs of natural gas and electricity change, and according to their ratio. Conversely, the cost trend over time remains the same if the assumptions of constant prices over time and a linear increase in installed capacity are maintained. So, a sensitivity analysis in terms of total state expenditure for incentive is necessary and is performed in both scenarios considering alkaline-type electrolysers. The analysis considers different combinations of cost and operating hours. The values assumed by the parameters are:

- Renewable source equivalent hours: 1392 hours (PV3 band) – 1679 hours (wind 4 band). These are in fact the bands into which most of Italy falls;

- Natural gas cost: 80 €/MWh (reference cost, prior to the energy crisis) – 160 €/MWh (gas purchase cost for storage in September 2022) – 240 €/MWh;

- Electricity cost: 60 €/MWh (price set for sale of electricity from renewable sources – RES [67]) – 150 €/MWh – 300 €/MWh (current average price of electricity on the day-ahead market);

Below are reported two tables, Table 2.3 and Table 2.4, in which are presented the results of two sensitivity analyses on the two different studied scenarios. The blue line represents the values assumed as base case and already detailed in Figure 2.8 and Figure 2.9.

Table 2.3 –Total incentive expenditure for different combinations of renewable plant equivalent hours, electricity cost and natural gas cost, taking scenario 1 (installation of 5 GW of electrolysis) into account

Operating hours [h/y]	Natural gas price [€/MWh]	Electricity price [€/MWh]	Total expenditure [billions of €]	CAPEX total expense [billions of €]	Operative total expense [billions of €]
1392	80	60	7	7 (100 %)	0 (0 %)
	80	150	16	7 (42%)	10 (58 %)
	80	300	35	7 (20 %)	28 (80 %)
	160	60	7	7 (100%)	0 (0 %)
	160	150	9	7 (73 %)	2 (27%)
	160	300	28	7 (25 %)	21 (75%)
	240	60	7	7 (100 %)	0 (0 %)
	240	150	7	7 (100 %)	0 (0 %)
	240	300	21	7 (33%)	14 (67 %)
1679	160	60	7	7 (100 %)	0 (0 %)
	160	150	12	7 (55 %)	6 (45 %)
	160	300	53	7 (13 %)	46 (87 %)

From the first sensitivity analysis, in Table 2.3, some considerations on the first scenario can be made:

- For the base case (in blue) the total expenditure at 2050 is 28 billion of €, broken down into 7 for fixed costs and 21 for operating costs;

- It can be seen that the CAPEX incentive expenditure, for a given renewable source considered, always remains the same: €7 billion. This is due to the fact that the CAPEX expenditure depends neither on the price of natural gas nor on the price of electricity from RES;

- Contrary to what we might expect, the CAPEX expenditure remains the same (7 B€) even if the equivalent operating hours of the renewable plant are changed, i.e. from PV3 to wind on-shore 4; this is due to the fact that the analysis here made refers to scenario 1, in which the installed capacity is fixed at 5 GW, and therefore the CAPEX incentive expenditure on investment costs does not change because the investment is fixed;

- At constant natural gas price, if the electricity price increases the total expenditure increases because the operative incentive must be higher to promote the production of hydrogen from electrolyser with respect to the alternative of selling directly the electricity to the grid;

- Therefore, on the basis of the previous points, it can be seen that, with the price of natural gas constant, as the price of electricity increases, since the expenditure for the CAPEX incentive does not vary, the ratio between the two contributions to total expenditure also changes; in fact, the ratio between operating and CAPEX expenses increases, as the price of electricity increases, going from being 0 (100% CAPEX expenditure) when the price of NG is much greater than the price of electricity, to a much higher operating contribution than CAPEX when the price of electricity is much greater than the price of gas; for example, considering the case $price_{NG} = 160\ €/MWh$:

    - When $p_{el_{MGP}} = 60\ €/MWh \ll price_{NG}$, the operative incentive – CAPEX incentive ratio is 0%/100%;

    - When $p_{el_{MGP}} = 150\ €/MWh \cong price_{NG}$, the ratio is 27%/73%;

    - When $p_{el_{MGP}} = 300\ €/MWh \gg price_{NG}$ then the ratio is 75%/25%;

Table 2.4 below shows the results of the sensitivity analysis carried out on the second scenario, where, in blue, the values assumed by the study parameters taking into account the assumptions of the base case are represented.

Table 2.4 – The same analysis is made for scenario 2 (installation of the necessary electrolysis capacity to achieve a production of 0.7 Mton of hydrogen per year)

Operating hours [h/y]	Natural gas price [€/MWh]	Electricity price [€/MWh]	Total expenditure [billions of €]	CAPEX total expense [billions of €]	Operative total expense [billions of €]
1392	80	60	39	39 (100 %)	0 (0 %)
	80	150	95	39 (42 %)	55 (58 %)
	80	300	201	39(20 %)	162 (80 %)
	160	60	39	39 (100 %)	0 (0 %)
	160	150	54	39 (73 %)	14 (27 %)
	160	300	160	39 (25 %)	121 (75 %)
	240	60	18	39 (100 %)	0 (0 %)
	240	150	18	39 (100 %)	0 (0 %)
	240	300	120	39 (33 %)	80 (67 %)
1679	160	60	18	18 (100 %)	0 (0 %)
	160	150	32	18 (55 %)	14 (45%)
	160	300	139	18 (13 %)	121 (87 %)

For Table 2.4, the same considerations made for Table 2.3 apply, however with some differences that are mentioned below:

- In blue is reported the situation of prices for the base case but for the second scenario, in which the capacity is determined to reach a fixed value of hydrogen production (0.7 Mton/y); the main difference with the previous sensitivity analysis is in terms of values of B€. In fact, in the second scenario the incentives delivered are the ones to reach a fixed production, with an installed capacity which is much higher than the 5 GW considered in the first scenario;

- The other main difference concerns the CAPEX incentive expenditure, which in this case, since the installed capacity is not fixed but varies according to the fixed hydrogen production, changes according to the equivalent operating hours of the renewable production plant; so, as can be seen:

    - Considering the photovoltaic plant PV3 (with $h_{eq_{RES}} = 1392\ h/y$) the total CAPEX expense for incentive is 39 B€;

    - Considering the wind onshore 4 plant (with $h_{eq_{RES}} = 1679\ h/y$) the total CAPEX expense for incentive is 18 B€;

  This large difference in expenditure between the two renewable production technologies is due to the fact that, for the wind power plant with a greater number of $h_{eq_{RES}}$, the production of hydrogen per kW installed, and the consequent hydrogen sale, is much greater than in the case of the photovoltaic plant, and therefore a smaller installed capacity will be sufficient to reach the set hydrogen production target.

2.2.3 Conclusions

Assuming:

- Electricity and natural gas resource costs are constant until 2050;
- The average market price of hydrogen is constant;
- Hydrogen is generated by RES with simultaneous production-use;
- The investment increases linearly, with a constant increase until 2030, in order to reach EU targets;
- CAPEX is valued at 2022 (present value) and considered constant until 2030;
- The incentive on CAPEX is calculated for a total payback of the investment over the 20-year life of the electrolyser;

The main conclusions of this study are:

- Scenario 1, which considers the installation of 5 GW of electrolysers, does not allow the production of 0.7 Mton/year with only RES (PV or wind); in fact, depending on the renewable source, the production reached is much lower:
    - $0.121\ Mton/y$ for a photovoltaic plant of class PV3;
    - $0.153\ Mton/y$ for a wind onshore plant of class 4;

- Scenario 2 allows the production target of 0.7 Mton/year with RES (PV or wind) and the installed capacity required to reach this value of production is:
    - $29\ GW$ for a photovoltaic plant of class PV3;
    - $22.9\ GW$ for a wind onshore plant of class 4;

- The total incentive by 2050 weighs, depending on the scenario evaluated, between:
    - 7-53 B€ if the target is the implementation of scenario 1 from RES;
    - 18-201 B€ if the target is scenario 2;

- The minimum total expenditure related to the CAPEX of plants is in a range between 7 and 39 B€ by 2050;

- Total operating incentive expenditure lies between 0 and 46 B€ in scenario 1 or between 0 and 162 B€ in scenario 2;

- In the scenarios, the operative incentive weighs more than 50% where the electricity cost exceeds 300 €/MWh, but zero when considering an electricity cost similar to that determined by decree for renewables (60 €/MWh);

Chapter 3

3 Evaluation of the incentive scheme in case studies

This chapter aims at computing the annual gain of an investor who decides to install an electrolysis system and produce hydrogen with renewable energy, receiving the incentive (as identified in Chapter 2).

To do that, two models have been developed within this thesis. Both models compute the investor annual gain on the basis of various parameters, such as (but not limited to) the RES electricity profile at the inlet of the electrolyser for the production of hydrogen, the electricity price and the selling price of hydrogen.

The two models are characterized by a different level of complexity. The first model has an annual resolution (e.g., energy balances and cash flows are solved on an annual basis) while the second model has an hourly resolution.

Given the different complexity of the two models, the first one is realized in Microsoft Excel while the second one is implemented in Python.

In section 3.1, general assumptions are made for the understanding of the two created models. In fact, the purpose of sections 3.2 and 3.3 is to describe and explain the model developed at the two different levels of detail, respectively in Excel and in Python environment. Then, in section 3.4 the Excel model is applied for the annual evaluation of a defined case study and for the evaluation of different scenarios by performing different sensitivity analyses. Finally, in section 3.5 the Python model is applied for an hourly evaluation of the same incentive scheme.

3.1 General assumptions

The model is implemented based on certain considerations and aims at computing the gain for the electrolyser owner through energy and economic balances.

General assumptions valid for both models must be made regarding:

- The renewable plant considered to produce electricity;
- The type of electrolysers supposed to be installed and so:
  - CAPEX of electrolyser in $€/kW$;
  - OPEX of the electrolyser, expressed as a percentage of CAPEX;
  - Specific consumption of electrolyser ε_{el} , expressed in kWh/kg_{H2};
- WACC (“weighted average cost of capital”);
- The annual average value for the excel model or the hourly profile for the python model of:
  - Electricity price;
  - Natural gas price;
  - H2 selling price;
- The equivalent operating hours $h_{eq_{EL}}$ of the electrolyser in h/y;

3.2 Excel model description

The purpose of this model is to calculate the differential gain of a producer of hydrogen from electrolysis compared to the case where he decides not to install the electrolyser and consequently sell all the electricity to the grid.

The model is parameterized on the size of the installed electrolyser; thus, it can be applied to evaluate electrolysers of different sizes and types.

The producer’s differential gain in one year (expressed in $€/y$), whose calculation is the purpose of this model as mentioned above, is calculated as follows:

$$\Delta gain_y = rev_{sellH2_y} + rev_{inc_y} - CAPEX_{expense} - loss_{el} \tag{3.1}$$

The producer’s gain over the year is presented as the sum of four different contributions, all expressed in €/y:

- rev_{sellH2_y} is the positive contribution from the sale of green hydrogen produced by the electrolysis plant;
- rev_{inc_y} is the positive contribution from the incentive for green hydrogen produced;
- $CAPEX_{expense}$ is the negative contribution due to the annual CAPEX expenditure related to the investment costs of the electrolysis plant;

- $loss_{el}$ is the negative contribution due to the loss of revenue from the sale of electricity produced by the renewable plant, because it is used for hydrogen production;

The four individual contributions of annual gain's formula are explained in detail in the following.

Revenue for H2 sale (rev_{sellH2_y})

To determine this contribution, we start with the calculation of green hydrogen production of the electrolyser; the total annual production is then calculated for a certain electrolysis capacity since the model is parameterized on the installed electrolysis capacity. Then the average hydrogen sale price is calculated and finally with these two values, the revenue from the sale of the hydrogen produced annually is determined. This calculation is better detailed in the following.

Since the incentive scheme provides the incentive per kg of hydrogen produced, firstly the annual hydrogen production for a given installed electrolysis capacity (EL_{cap}) is calculated:

$$prod_{H2} = \frac{electricity_{in_{EL}}}{\varepsilon_{comp} + \varepsilon_{el}} \tag{3.2}$$

And:

$$electricity_{in_{EL}} = EL_{cap} * h_{eq_{EL}} \tag{3.3}$$

Where:

- $prod_{H2}$ is the yearly production of hydrogen, expressed in $\frac{kg_{H2}}{y}$;
- $electricity_{in_{EL}}$ is the yearly electricity at the inlet of the electrolyser, is expressed in $\frac{kWh}{y}$ and depends on the class of renewable source (as defined in chapter 2.1) and so on the equivalent number of hours for the considered Italian zone;
- EL_{cap} is the installed electrolysis capacity;
- $h_{eq_{EL}}$ are the equivalent operating hours of the electrolyser;
- ε_{el} is the electrolyser specific consumption in $\frac{kWh}{kg}$;
- ε_{comp} is the compression specific consumption in $\frac{kWh}{kg}$ and it is equal to:

$$\varepsilon_{comp} = \left(\frac{Z * T * R}{M_{H2} * eta_{is}}\right) * \left(N \frac{\gamma}{\gamma - 1}\right) * \frac{\left((p_{ratio})^{\frac{\gamma-1}{N\gamma}} - 1\right)}{10^3 * 3600} \tag{3.4}$$

And:

$$p_{ratio} = \frac{p_{out}}{p_{in}} \tag{3.5}$$

Where:

- Z=compressibility factor;
- T=temperature of hydrogen at inlet [K];
- R=gas constant [J/K mol];
- M_{H2} = molecular mass of hydrogen;
- eta_{is} = isentropic efficiency of the compressor;
- N = the number of stages of the compressor;
- γ =1.4, the ratio between the specific heats (c_p/c_v);
- p_{out} = the compressor outlet pressure (for injection into the NG distribution network is 80 bar, for use as a feedstock, e.g. for ammonia production, it is 200 bar, and for mobility it varies between 350 bar and 700 bar depending on the application) [68];
- p_{in} = the compressor inlet pressure (for alkaline electrolyser is 10-30 bar, for PEM is 20-50 bar and for SOE is 1-15 bar) [32];

Now that production has been calculated, we want to calculate the average selling price in $€/kg_{H2}$ at which we expect that the green hydrogen produced by electrolysis can be sold. To this end, we consider, as mentioned earlier in Chapter 2, the demand shares of each sector ($H2_{NGgrid_{\%}}$, $H2_{feedstock_{\%}}$ and $H2_{mobility_{\%}}$) to calculate the weighted average selling price of the green hydrogen produced:

$$p_{H2_{avg}} = H2_{NGgrid_{\%}} * H2price_{NGgrid} + H2_{feedstock_{\%}} * H2price_{feedstock} + H2_{mobility_{\%}} * H2price_{mobility} \tag{3.6}$$

Where $H2price_{NGgrid}, H2price_{feedstock}, H2price_{mobility}$ are all expressed in $€/kg_{H2}$ and are calculated respectively by equations (2.4), (2.5) and (2.6) in previous chapter.

So, the revenue due to the sale of green hydrogen produced by electrolysis can be calculated as:

$$rev_{sellH2_y} = prod_{H2} * p_{H2_{avg}} \tag{3.7}$$

Revenue for incentive (rev_{inc_y})

The incentive given to the producer for the production of green hydrogen is calculated as the sum of two contributions, related to the CAPEX and the operational costs. As far as the CAPEX incentive per kg of hydrogen produced is concerned, this is not calculated in the model since, according to the considered incentive scheme, it is the state that defined it, based on the cost of electrolysers, type and percentage interest of the investment (Chapter 2). As for the operative incentive, on the other hand, this varies according to the prices situation on the energy market. Thus, the calculation of this incentive contribution related to the operation of the electrolyser involves variables that change over time (e.g., from a year to the other) which are:

- Selling price of hydrogen;
- Production of green hydrogen from electrolyser;
- Electricity price in the day-ahead market;
- Profile of electricity input to the electrolyser;

In the model, a unique value is used for each of these parameters, representing the average annual value.

This calculation is based on the producer's convenience in producing hydrogen compared to send electricity produced from a renewable source directly into the grid. In fact, the analysis has a fundamental concept behind it, which is the so-called 'willingness to pay', representing the maximum price a customer is willing to pay for a product or service. While potential customers are likely willing to pay less than this threshold, it's important to understand that, in most cases, they won't pay a higher price [69].

Therefore, the operative incentive is an incentive that is only given to the hydrogen producer if hydrogen production is not already cost-effective compared to feeding electricity into the grid. In this way, including the incentive, the produced hydrogen has always a cost which is not higher than the willingness to pay. Thus, this operative incentive is the difference between the gain from selling the hydrogen and the loss of revenue due to the fact that electricity used to produce hydrogen is not sold directly to the grid. It is now assumed that this incentive can never be negative, so in the case that the gain from the sale of hydrogen is greater than the loss of profit from the sale of electricity on the grid, this takes the minimum value of 0. In practice, it is assumed that the producer does not have to give money to the state in the event that the sale of hydrogen is profitable, and this is done for a certain reason: in fact, in the event that the sale of hydrogen is profitable then there will be an actual gain, while in the event that the opposite happens, then the incentive is given to put the producer's economy on a par with sending electricity to the grid.

Therefore, the formula for the calculation of the operative incentive in $€/kg_{H2}$ is:

$$operative_{inc} = \max\left(0, -\frac{\left(prod_{H2} * p_{H2_{avg}} - electricity_{in_{EL}} * p_{el_{MGP}}\right)}{prod_{H2}}\right) \qquad \textbf{\textit{(3.8)}}$$

Where:

- $p_{el_{MGP}}$ is the price in the day-ahead market at which the electricity is sold to the grid;

Now that both incentive contributions have been defined, the total incentive in $€/kg_{H2}$ can be calculated as the sum of the two contributions:

$$tot_{inc} = CAPEX_{inc} + operative_{inc} \tag{3.9}$$

Now, as mentioned above, according to the proposed incentive scheme there are certain conditions to be met for the incentive to be paid out and these are as follows:

1. The incentive scheme is on hydrogen production and the incentive is per kg of green hydrogen produced, so when electrolyser does not work and so it doesn't produce hydrogen, the incentive is not delivered;

2. The incentive scheme is based on assumptions about the renewable source used and the operating hours of the electrolysis plant; based on these and the installed electrolysis capacity, the incentive is only paid out for a total number of hours per year equal to the number of hours needed to reach the value of the maximum hydrogen production that can be incentivised in kg/y. Thus, the incentivised production is:

$$prod_{H2_{inc}} = \min\left(prod_{H2}, prod_{H2_{max,inc}}\right) \tag{3.10}$$

The maximum incentivised production $prod_{H2_{max,inc}}$ is equal to the hydrogen production that would be obtained if the electrolyser operates for the number of hours assumed by the state as average equivalent hours for that technology. Therefore, if the site is not favourable enough in terms of energy produced from the chosen renewable source, thus not guaranteeing a number of operating hours equal to the design number, the incentivised production will be less than the maximum and equal to the actual production. If, on the other hand, the site is favourable and the operating hours increase above the design hours, the hydrogen production may increase, but the incentivised production will still be equal to the maximum incentivised production over the year.

Now that total incentive and the incentivised production are evaluated, we can calculate the incentive revenue as:

$$rev_{inc_y} = prod_{H2_{inc}} * tot_{inc} \tag{3.11}$$

CAPEX expenditure ($CAPEX_{expense}$)

Concerning the calculation of the negative contribution to profit from the electrolyser's CAPEX investment expenditure, this is determined by considering the value of the specific CAPEX (in $€/kW_{inst}$) for the purchased system, the CRF (that depends on the expected lifetime, and the bank interest rate - WACC), the opex percentage on the CAPEX investment and the electrolysis capacity installed by the producer from RES. Based on this, the CAPEX expenditure in €/y is calculated as:

$$CAPEX_{expense} = CAPEX_{inv} * (CRF + opex_{\%}) * EL_{cap} \tag{3.12}$$

Loss of revenue due to non-sale of electricity to the grid ($loss_{el}$)

The loss of revenue due to the fact that the electricity available is used to produce hydrogen and is not sent to the grid is calculated as the electricity going to the electrolyser multiplying the price at which it would be sold if it were sent directly to the grid:

$$loss_{el} = p_{el_{MGP}} * electricity_{in_{EL}} \tag{3.13}$$

Where:

- $p_{el_{MGP}}$ is the electricity price in the day-ahead market, in €/MWh;
- $electricity_{in_{EL}}$ is the yearly electricity entering the electrolysis plant, in MWh/y;

Thus, all contributions to the producer's final annual differential gain have been determined and thus it can be computed with equation (3.1).

3.3 Python model description

The purpose of this model is to evaluate the total annual gain of a producer of electricity from renewable sources who decides to install an electrolyser for hydrogen production. The result of the model is compared a posteriori with the total annual gain of the same producer who has no installed electrolysis capacity and thus sends all the electricity produced to the grid, to evaluate the differential gain (or loss).

As for the excel model, the model is parameterized on the size of the installed electrolyser; thus, it can be applied to evaluate electrolysers of different sizes and types.

One of the key aspects of this model is the hourly analysis. This means that all variables must be calculated hourly and that we have to consider hourly price profiles of electricity and natural gas in the day-ahead market, an hourly profile of electricity from renewable source entering the electrolyser, and finally an hourly profile of hydrogen sales price.

The producer's gain in the year (expressed in $€/y$), which is the purpose of this model as mentioned above, is calculated as follows:

$$gain_y = rev_{sellH2_y} + rev_{inc_y} - CAPEX_{expense} + rev_{electricity_y} \tag{3.14}$$

It can be seen that the producer's annual gain is represented by an equation very similar to the one presented in section 3.2 for calculating the differential gain (Eq.(3.1)). In fact, three of four contributions to the annual gain (rev_{sellH2_y}, rev_{inc_y}, $CAPEX_{expense}$) are identical to those assessed above for the Excel model; however, one contribution changes in this case. In fact, the loss of revenue due to the non-sale of electricity to the grid assessed in the Excel model is replaced here by the annual revenue due to the sale of electricity directly to the grid ($rev_{electricity_y}$).

Since this model has a higher level of detail than the corresponding model in Excel, here the various contributions to the gain are calculated for each hour of the year considered and then summed over the entire year to derive the actual annual gain.

Although the first three contributions are calculated almost identically to how they are done in the Excel model, it may be useful to see some key steps in the calculation as in this model all quantities become hourly, thus changing the expression of the various formulas.

Revenue for H2 sale (rev_{sellH2_y})

In this model, for the calculation of hourly hydrogen production, an hourly profile of electricity from renewable source entering the electrolyser must be found ($electricity_{inEL}$). Then from equation (3.2), the hourly hydrogen production profile $prod_{H2}$ over a year can be determined.

However, there are conditions that must be met for the electrolyser to operate at a given time of the year and produce hydrogen. These conditions are required to compute the electricity entering the electrolyser starting from the electricity profile generated by the RES ($electricity_{RES}$):

1. One of these is the willingness to pay of the producer, which is the maximum price of the electricity [€/MWh] which the producer accepts to produce hydrogen. If, in a specific hour, the WTP is bigger than the electricity price in the day-ahead market, so there is a will for the producer to use the electrolyser to produce hydrogen because there is a gain in this case with respect to send the electricity directly to the grid; so, the condition is:

$$WTP \geq p_{el_{MGP}} \quad \textbf{\textit{(3.15)}}$$

Where both WTP and $p_{el_{MGP}}$ are expressed in $€/MWh$. The WTP in this model depends on:

- The selling price of hydrogen (which depends on the price of natural gas), as it is also due to the increase in this price whether it is more profitable for the producer to produce hydrogen using the electrolyser than to feed the electricity produced directly into the grid;

- The incentive on the hydrogen produced, which allows the producer to achieve a willingness to pay high enough to prefer producing hydrogen over feeding electricity into the grid;

The WTP $\left[\frac{€}{MWh}\right]$ in this analysis is calculated as follows:

$$WTP = \frac{\left(\frac{\left(p_{H2_{avg}}\right)}{1 + C_{tax}} + tot_{inc} - C_{H20} - C_{tr}\right)}{\varepsilon_{el} + \varepsilon_{comp}} \quad \textbf{\textit{(3.16)}}$$

Where:

- $p_{H2_{avg}}\left[\frac{€}{kg_{H2}}\right]$ is defined in equation (3.6);
- $C_{tax}[-]$ is the VAT but is considered to be zero;
- $tot_{inc}\left[\frac{€}{kg_{H2}}\right]$ is the total incentive for kg of hydrogen produced as the sum of the $CAPEX_{inc}\left[\frac{€}{kg_{H2}}\right]$ and the $operative_{inc}\left[\frac{€}{kg_{H2}}\right]$, defined in equation (3.8);
- $C_{H20}\left[\frac{€}{kg_{H2}}\right]$ is the water cost (considered as about $0.02\frac{€}{kg_{H2}}$for water electrolysis) [70];
- $C_{tr}\left[\frac{€}{kg_{H2}}\right]$ is the transport cost (zero in this case);
- ε_{el} is the specific consumption of electrolyser in kWh/kg_{H2} (3.1);
- ε_{comp} is the specific consumption of compression defined in equation (3.4);

2. Another important condition is the respect of the minimum load level of electrolyser; so, if the electricity from RES ($electricity_{RES}$) in MW is lower than the minimum load the electricity cannot be used to produce hydrogen; the condition is:

$$electricity_{RES} \geq EL_{cap} * (1 + CP_{size}) * load_{levelMIN\%} \tag{3.17}$$

Where:

- EL_{cap} is in MW;
- CP_{size} represents the ratio between the compressor size and the electrolyser size;
- $load_{levelMIN\%}$ is the percentage of minimum load of electrolyser to be respected for the actual profile of electricity;

The willingness to pay and the minimum load conditions have to be respected simultaneously in order to produce hydrogen. If both these conditions are true, so the electricity from RES is sent to the electrolyser for the production of hydrogen, and the hourly production of H2 is calculated from eq. (3.2) considering the electricity profile at the inlet of the electrolyser as:

$$electricity_{in_{EL}} = \begin{cases} \min\left(electricity_{RES}, EL_{cap} * t\right) & if\ both\ conditions\ are\ true \\ 0 & otherwise \end{cases} \tag{3.18}$$

Where $t = 1\ h$ because is an hourly analysis.

At this point it can be ascertained at what times of the year the electrolyser is operating. The cumulative electricity at inlet of electrolyser over the year ($electricity_{in_{EL,cum}}$) is calculated for the evaluation of the equivalent operating hours, in h/y, of the studied configuration:

$$electricity_{in_{EL,cum}} = \sum_{h=1}^{8760} electricity_{in_{EL}} \tag{3.19}$$

$$h_{eq_{EL}} = \frac{electricity_{in_{(EL,cum)}}}{EL_{cap}} \tag{3.20}$$

The annual cumulative hydrogen production can then be determined from the hourly production calculated using equation (3.2):

$$prod_{H2_{cum}} = \sum_{h=1}^{8760} prod_{H2} \tag{3.21}$$

Now, to calculate the revenue from the sale of hydrogen, the hourly profile of the average hydrogen sales price in the various demand sectors is required. To obtain this, equation (3.6) is used as in the previous model to calculate the mean selling price of hydrogen, adopting an hourly price profile of natural gas from the day-ahead market for the reference year considered.

At this point, the equation below can be used to determine the hourly revenue from the sale of hydrogen produced:

$$rev_{sellH2} = prod_{H2} * p_{H2_{avg}} \tag{3.22}$$

To determine the annual revenue from hydrogen sales, all hourly revenue contributions from hydrogen sales must be added together for each hour of the year, as follows:

$$rev_{sellH2_y} = \sum_{h=1}^{8760} (rev_{sellH2}) \tag{3.23}$$

Revenue for incentive (rev_{inc_y})

In order to determine the revenue due to the incentive paid for the production of hydrogen from the electrolyser, considering that the CAPEX incentive contribution is fixed by the state, it is necessary to calculate the operative contribution of the incentive from equation (3.8) of the previous model, but considering all the hourly profiles of the parameters $prod_{H2}, p_{H2_{avg}}, electricity_{in_{EL}}$ and $p_{el_{MGP}}$ that were previously averaged over the year.

In this way, the hourly profile of the operative incentive is obtained in $€/kg_{H2}$ which, adding up to the constant CAPEX incentive per hour, determines the hourly profile of total incentive per kg of hydrogen produced, as in eq. (3.9).

The hourly revenue for the incentive comes from:

$$rev_{inc} = prod_{H2} * tot_{inc} \tag{3.24}$$

At this point, the same incentive payment conditions provided for the Excel model are valid for the Python model and therefore the annual incentive production $prod_{H2_{inc}}$ is again defined in equation (3.10). The incentive is given until the maximum incentive production is reached, which is:

$$prod_{H2_{max,inc}} = prod_{H2_{eq}} * EL_{cap} \tag{3.25}$$

Where $prod_{H2_{eq}}$ is the annual hydrogen production considering that the electrolyser works for all operating hours, defined in Chapter 2, depending on the renewable source used to produce electricity. Further hydrogen production above $prod_{H2_{max,inc}}$ will not be incentivised.

So, the yearly revenue due to this contribution is:

$$rev_{inc_y} = \sum_{h=1}^{8760} rev_{inc} \tag{3.26}$$

CAPEX expenditure ($CAPEX_{expense}$)

As far as CAPEX expenditure is concerned, it is considered in the model to be made at a single point in time, and thus the calculation of the previous model (eq. (3.12)) applies for this contribution without taking hourly values into account.

Revenue due to the sale of electricity to the grid ($rev_{electricity_y}$)

Unlike the Excel model, in which we want to immediately determine a differential gain, in this case we want to calculate the total gain that the producer would have with the installation of an electrolysis plant to produce hydrogen, and then compare it with the alternative of selling all the electricity produced on the grid. In this model, therefore, a contribution linked to the sale of electricity on the grid appears.

Taking into account the above definition of $electricity_{in_{EL}}$ (eq.(3.18)) based on the operating conditions of the electrolyser, the revenue from the sale of electricity to the grid can be calculated by compressing all conditions into the following formula:

$$rev_{electricity} = p_{el_{MGP}} * \left(electricity_{RES} - electricity_{in_{EL}}\right) \tag{3.27}$$

Where:

- $p_{el_{MGP}}$ is expressed in €/MWh;
- $electricity_{RES}$ is the profile of electricity available from RES, expressed in MWh;
- $electricity_{in_{EL}}$ is the electricity profile at the inlet of electrolyser, which depends on the installed capacity (in MWh);

In fact, this expression (3.27), together with eq. (3.18), makes it possible to condense all the conditions and thus define a revenue from the sale of electricity to the grid. In fact, when the electrolyser is working, and thus conditions (3.15) and (3.17) are fulfilled, the electricity to the electrolyser is the minimum between that available from RES and the maximum for the electrolyser, depending on the capacity. If, on the other hand, the electrolyser does not work, the electricity input to the electrolyser is 0 and the sales revenue is simply the price for the amount of electricity available from RES.

Now that the hourly contribution to the sale of electricity on the grid in the various hours of the year has been determined based on the level of load of the electrolyser, the annual contribution of revenue from the sale of electricity on the grid can be determined by adding, hourly, all various contributions, as follows:

$$rev_{electricity_y} = \sum_{h=1}^{8760} (rev_{electricity}) \tag{3.28}$$

Thus, all contributions to the producer's final annual gain have been determined and thus, from equation (3.14), the gain can be calculated.

3.4 Application of the excel model on a case study

In this chapter, we would like to implement the model described in chapter 3.2, in an excel environment, based on the incentive scheme described in chapter 2.

We want to analyse a well-defined case study using the Excel model described above. The next sub-section 3.4.1 contains the assumptions made for the use of the annual model in Excel. After making the necessary assumptions, the Excel model is used for the analysis of a particular case study, then, in the other subsections, some sensitivity analyses are made on parameters that may vary annually. The scenarios that are studied from the point of view of assessing a producer's gain from installing electrolysis capacity are as follows:

1. Scenario with variable MGP electricity price;
2. Scenario with variable Natural gas price;
3. Scenario with variable selling price of hydrogen;
4. Scenario with variable operating hours of plant;
5. Scenario with variable CAPEX expense;

These will be reported and studied in detail below, after the assumptions and the evaluation of the base case.

3.4.1 Case study assumptions and evaluation of the base case

In this paragraph assumptions are made for the Excel model; many of the assumptions are common with the python model, so some assumptions made here will be mentioned later in the analysis of the Python model and these will be reported in the subsection 3.5.1; however, there are substantial differences in the Python model which will be described separately in a specific section.

The assumptions made for this study are as follows:

- The renewable energy source chosen is the solar one with a photovoltaic plant owned by the producer;

- The photovoltaic plant is considered to be in the Italian territorial zone corresponding to the class PV3 (described above in paragraph 2.1) with a certain number of equivalent operating hours for the plant and an established ratio of PV peak power to installed electrolysis power. An installed electrolysis capacity $EL_{cap} = 1\ kW$ is assumed and:

    - The ratio of PV peak power to installed electrolysis power is considered equal to 2.3, the optimal one for PV3 in Table 2.2, so the photovoltaic peak power is 2.3 kW_p;

- The number of equivalent operating hours of the electrolyser $h_{eq_{EL}}$ is considered equal to $1175\ h/y$, the one from Table 2.2 for PV3 class;

- Yearly mean prices of electricity and natural gas are supposed for the base case on the basis of the prices of electricity and natural gas of the last years in the day ahead market;

- In this study, it is assumed that the hydrogen produced is sold in the three demand sectors considered in the previous chapter (2) in predetermined percentages [45]:

  - $H2_{feedstock_{\%}}$ = 50%;
  - $H2_{NGgrid_{\%}}$ = 35%;
  - $H2_{mobility_{\%}}$ =15%;

- Hydrogen selling prices (for NG grid and feedstock) are dependent on the natural gas price considered and are calculated, respectively, in equations (2.4) and (2.5), considering a LHV_{H2} of 120 MJ/kg_{H2} and a LHV_{NG} of 47 MJ/kg. While the selling price of H2 for mobility (calculated in equation (2.6)) is dependent on the diesel price and other parameters assumed below:

  - Diesel price, taken as the average for previous years, is 1.5 $€/l$;
  - Mean consumption of fuel cell considered as 5 $kg_{H2}/100km$ [71];
  - Mean consumption of diesel considered as 24 $l/100km$ [72];
  - H_2 cost for production and preparation (is not considered the distribution phase) is considered the 57 % of the total cost [73];

- Installation of alkaline-type electrolysers is considered, so:

  - The specific consumption of alkaline electrolyser is taken as 49 kWh/kg_{H2} (ε_{el});
  - The specific consumption of the compressor (ε_{comp} expressed in kWh/kg_{H2}) is calculated from the equation
  - (3.4), considering:

    - Z = 1;
    - T = 298 K;
    - R = 8.314 $J/(mol * K)$;
    - M_{H2} = 2.016 g/mol;
    - eta_{is} = 0.65;
    - N = 3;
    - γ =1.4;
    - p_{out} = 200 bar;
    - p_{in} = 10 bar;

With these parameter values results in a compressor specific consumption of 1.707 kWh/kg_{H2};

- $CAPEX_{inv}$ is supposed to be 480 $€/kW_{inst}$ and the $opex_{\%}$ to be 4% of $CAPEX_{inv}$;

- The sale of heat and oxygen as by-products of the electrolysis process is not considered;

- The service life of the electrolyser is $lifetime = 20\ years$;

- The CAPEX incentive is fixed by the State as $CAPEX_{inc} = 3.26\ €/kg_{H2}$, defined for a number of equivalent operating hours of the electrolyser decided by the State ($h_{eq_{st}} = 1175\ h/y$) and calculated considering a WACC value of 10%;

- The number of equivalent operating hours of the electrolyser is considered to be equal to that defined for PV3, thus $h_{eq_{EL}} = h_{eq_{st}}$;

- The operative incentive $operative_{inc}$, in $€/kg_{H2}$, depends on the mean selling price of electricity and hydrogen considered; it does not depend on installed capacity and is only paid out when there is no profit for the producer to produce and sell hydrogen (i.e. when it would be profitable to sell electricity directly to the grid); this incentive is never negative, at a minimum it is zero;

Now that all the assumptions for the excel model have been made, we can define the base case from which to start the analysis. This case, since the excel analysis is an annual analysis and we want to calculate the producer's differential gain in one year, represents a single prices situation.

For the base case study, these average annual electricity and natural gas prices, even taking into account the high prices seen in the year 2022, are considered:

- $p_{el_{MGP}} = 300\ €/MWh$;
- $price_{NG} = 160\ €/MWh$;

With the assumptions made, following the description of the Excel model given in section 3.2, we begin by determining the electricity input to the electrolyser for the subsequent calculation of hydrogen production.

Hence, from eq. (3.3):

$$electricity_{in_{EL}} = 1175\ \frac{kWh}{y}$$

And, considering the values ε_{el} and ε_{comp} assumed above, the annual hydrogen production is calculated from equation (3.2):

$$prod_{H2} = 23.17 \frac{kg_{H2}}{y}$$

Then, following the model described in Chapter 3.2, the mean selling price of hydrogen is calculated. Considering that sales prices of green hydrogen in the various sectors are evaluated:

- From eq. (2.4) $H2price_{NGgrid} = 5.33 \frac{€}{kg_{H2}}$;
- From eq. (2.5) $H2price_{feedstock} = 8.66 \frac{€}{kg_{H2}}$;
- From eq. (2.6) $H2price_{mobility} = 2.55 \frac{€}{kg_{H2}}$;

So, from equation (3.6):

$$p_{H2_{avg}} = 6.58\ €/kg_{H2}$$

Now, following the model described in chapter 3.2, the first positive contribution to the gain at the end of the year is calculated. Equation (3.7) is used to calculate the annual revenue from the sale of green hydrogen produced:

$$rev_{sellH2_y} = 152.41 \frac{€}{y}$$

For the evaluation of the second positive contribution, it is needed the total incentive given to the production that can be incentivised. While the contribution of incentive related to the CAPEX is fixed by the State, for the contribution related to the operation of the electrolysis plant, the operative incentive, this is derived from equation (3.8) and is equal to:

$$operative_{inc} = 8.64 \frac{€}{kg_{H2}}$$

Now that both incentive contributions are known, the total incentive paid for hydrogen produced in the defined base case can be determined using eq. (3.9):

$$tot_{inc} = 11.90 \frac{€}{kg_{H2}}$$

The CAPEX incentive is always paid out in any price situation so as not to burden the producer with the investment costs of the electrolyser. As far as the operative incentive is concerned, this is provided because, for this electricity and natural gas price situation, defined by the base case, there would be no profit on the part of the producer in using the electrolysis plant; therefore this incentive contribution is provided to put the producer on an economic parity with respect to the alternative of selling all the electricity produced by RES into the grid (on the basis of annual willingness to pay).

The production that can be incentivised, considering that $h_{eq_{EL}} = h_{eq_{st}}$ and so the equivalent number of operating hours supposed for the electrolyser are exactly equal to the one decided by the State for the calculation of $CAPEX_{inc}$, derived from eq. (3.10):

$$prod_{H2_{inc}} = 23.17 \ \frac{kg_{H2}}{y}$$

Then, from eq. (3.11) the revenue for the incentive on the production of green hydrogen is calculated:

$$rev_{inc_y} = 275.67 \frac{€}{y}$$

For the calculation of annual CAPEX expense, given the assumptions made about the type of electrolyser and the installed capacity EL_{cap}, the equation (3.12) is used:

$$CAPEX_{expense} = 75.58 \frac{€}{y}$$

Finally, we must consider the loss of revenue due to producing hydrogen instead of selling the electricity produced to the grid. From eq. (3.13):

$$loss_{el} = 352.50 \frac{€}{y}$$

Now that all gain contributions, positive and negative, have been determined, the annual differential gain can be calculated. From eq. (3.1):

$$\Delta gain_y = 0 \ \frac{€}{y}$$

It can be seen immediately that in the defined base case, in this given very unfavourable prices situation, there is no gain for the producer from RES in installing some electrolysis capacity for hydrogen production; therefore, the operative incentive is provided to send the producer into economic parity. Considering that the analysis is differential to the case of selling all electricity to the grid, there is no profit in installing an electrolyser.

However, the base case studied represents a very unfavourable situation in terms of the price of electricity and natural gas. In a situation such as this, the producer with a certain installed capacity has neither a loss nor a gain over the year. It is interesting to see how the producer's gain varies as the annual average prices in the market change, and which situations are most favourable for hydrogen production. To do this, a series of sensitivity analyses on key evaluation parameters are performed below.

3.4.2 Sensitivity analysis on the electricity price

In this first simulation it is considered a scenario in which the electricity MGP price can vary while the natural gas price is fixed. It is important to remember that the analysis is annual, so there is a fixed mean price for electricity and a fixed mean price for natural gas in the specific year, but this simulation has the purpose to see what happens for different yearly average electricity price varies and the same NG price.

The value of NG price chosen is the one chosen for the base case definition, so $160\ €/MWh$, at which corresponds a selling price of $6.58\ €/kg_{H2}$.

From this scenario it is expected that the return from selling hydrogen remains constant as the electricity price varies because rev_{sellH2_y} doesn't depend on the electricity price, while the loss of revenue increases as the electricity price increases because the higher the electricity price the more the revenue that producer would have if sends the electricity directly to the grid instead of using it to produce H2. Finally the $CAPEX_{inc_y}(= CAPEX_{inc} * prod_{H2} = 75.58\ €/y)$ and $CAPEX_{expense}$ are expected to be constant because they don't depend on the price of electricity.

Figure 3.1 shows total incentive and the yearly gain of the producer as a function of the average yearly electricity price.

Figure 3.1 – Trend of total incentive and yearly gain for a fixed NG price = 160 €/MWh and variable electricity price

There are some remarks on the Figure 3.1 that are reported below:

- When the electricity price is low, there is a gain to produce H2 and to sell it instead of sell electricity directly to the grid; in fact, as from hypothesis, in this case $operative_{inc}$ is zero and there is only the $CAPEX_{inc_y}$;

- Increasing electricity price, the yearly gain decreases until it reaches $0\ €/y$ at $140\ €/MWh$. At higher MGP prices ($\geq 140\ €/MWh$) it would be convenient to sell directly electricity to the grid and so there must be $operative_{inc} > 0\ €/y$ in order to have no loss due to the choice of producing hydrogen;

- Increasing electricity price above $140\ €/MWh$, the total incentive to be delivered increases from the value of $CAPEX_{inc_y}$ because the $operative_{inc}$ increases when there is no revenue to produce hydrogen;

- The $CAPEX_{expense}$ is always incentivated by the $CAPEX_{inc_y}$ in order not to charge the producer for electrolysis capacity;

3.4.3 Sensitivity analysis on the natural gas price

In this second simulation, that is specular of the previous one (chapter 3.4.2), it is considered a scenario in which the natural gas price is varied while the MGP electricity price is fixed. The value of electricity price chosen is 300 €/MWh, which is the one for the definition of the base case. The selling price of H2, which depends on NG price, is not constant in this case but varies as the NG price changes.

From this scenario it is expected that the loss of revenue due to no-injection in grid is constant because doesn't depend on NG price, while in this case the return from selling hydrogen rev_{sellH2_y} changes as the NG price varies. Finally, $CAPEX_{inc_y}$ and $CAPEX_{expense}$ are expected to be constant as in previous simulation because don't depend on the price of gas.

Figure 3.2 shows total incentive and the yearly gain of the producer as a function of the average yearly natural gas price.

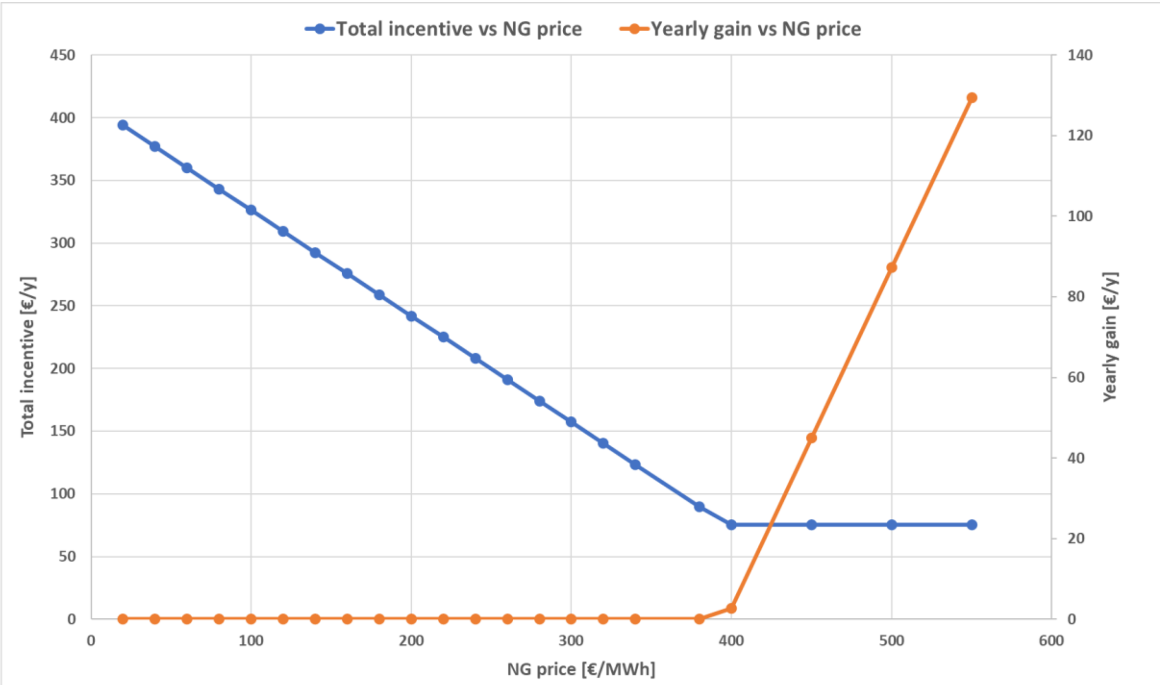

Figure 3.2 - Trend of total incentive and yearly gain for a fixed MGP price = 300 €/MWh and variable NG price

Some considerations can be made on the Figure 3.2:

- When the NG price is high, there is a gain to produce H2 and to sell it instead of selling electricity directly to the grid; in fact, as from hypothesis, in this case $operative_{inc}$ is zero and there is only the $CAPEX_{inc_y}$;

- Decreasing the natural gas price, the yearly gain decreases until it reaches $0\ €/y$ at $380\ €/MWh$. At $price_{NG} \leq 380\ €/MWh$ it would be convenient to sell directly electricity to the grid and so there must be $operative_{inc}\ > 0\ €/y$ in order to have no loss due to the choice to produce hydrogen;

- Decreasing $price_{NG}$ below $380\ €/MWh$, the total incentive to be delivered increases from the value of $CAPEX_{inc_y}$ because the $operative_{inc}$ increases when there is no revenue to produce hydrogen;

- The $CAPEX_{expense}$ is always incentivated by the $CAPEX_{inc_y}$ in order not to charge the producer for electrolysis capacity;

3.4.4 Sensitivity analysis on both the electricity and the natural gas price

Now that the sensitivity analyses on natural gas and electricity prices have been done separately, in this section we want to perform a sensitivity analysis in which both of these prices are varied; the aim is to obtain a map in which, for each price combination, we know what the incentive paid to the producer and what the differential gain for the producer should be.

Six different NG prices have been taken and, of each of them, the electricity prices have been changed between 20 €/MWh and 550 €/MWh. The producer's annual gain and the annual paid incentive have been plotted. The values of $price_{NG}$ considered are as follows:

- 60 €/MWh;
- 110 €/MWh;
- 160 €/MWh (base case);
- 210 €/MWh;
- 260 €/MWh;
- 310 €/MWh;

The result of the case for the evaluation of yearly gain is reported in the Figure 3.3 below.

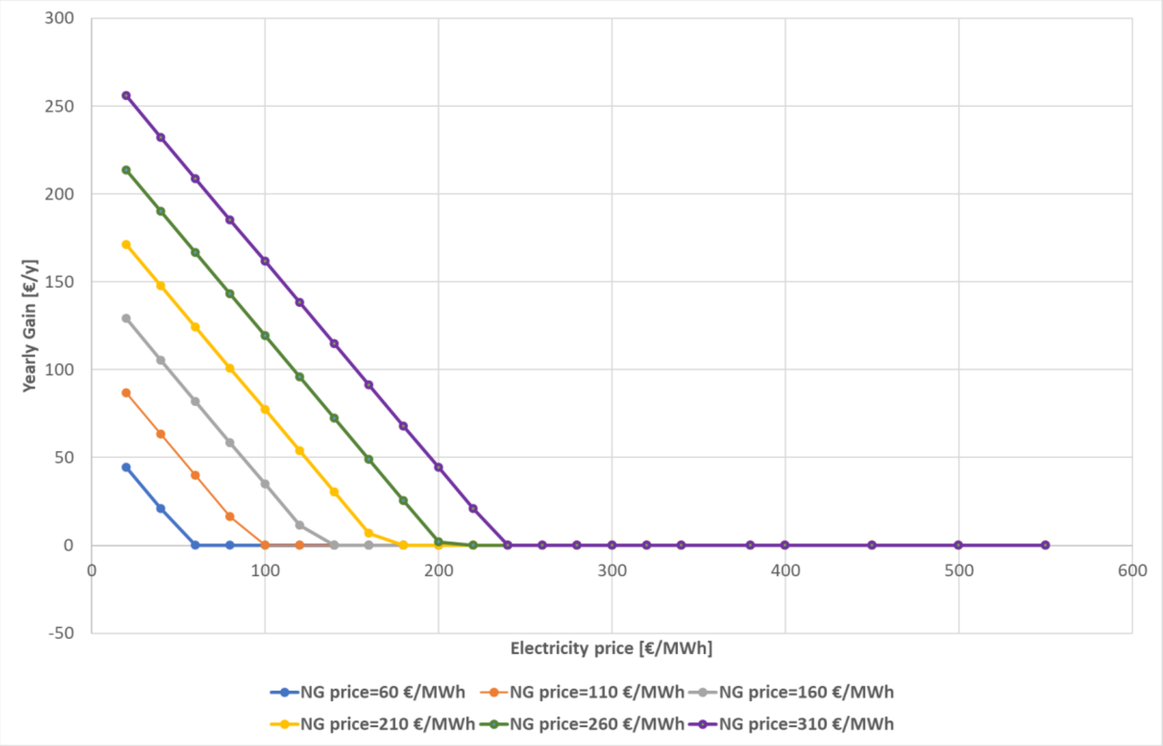

Figure 3.3 – Yearly gain vs electricity price for different fixed natural gas prices

In Figure 3.3 some considerations can be made:

- Increasing the electricity price, the yearly gain decreases because selling directly electricity to the grid becomes more and more convenient rather than producing H2;

- When $electricity_{price}$ is low, the operative incentive is not delivered because there is already a gain for the producer; when $electricity_{price}$ is high the loss of revenue becomes high and the operative incentive is delivered in order to send the producer into economic parity (for example, for $price_{NG} = 210\ €/MWh$, when $electricity_{price} \geq 180\ €/MWh$, the operative incentive is delivered to send into parity the producer and the yearly differential gain becomes equal to 0€;

- At the same $electricity_{price}$, increasing the $price_{NG}$ the yearly gain increases (for low electricity prices); this is due to the fact that increasing $price_{NG}$ increases also the selling price of H2 ($p_{H2_{avg}}$, which is assumed to depend directly on NG price) and so increases the gain without operative incentive; for example, taking $electricity_{price} = 100\ €/MWh$:

    - With $price_{NG} = 60\ €/MWh$, $\Delta gain_y = 0\ €/y$;
    - With $price_{NG} = 110\ €/MWh$, $\Delta gain_y = 0\ €/y$;
    - With $price_{NG} = 160\ €/MWh$, $\Delta gain_y = 34.91\ €/y$;
    - With $price_{NG} = 210\ €/MWh$, $\Delta gain_y = 77.17\ €/y$;
    - With $price_{NG} = 260\ €/MWh$, $\Delta gain_y = 119.42\ €/y$;

- With $price_{NG} = 310\ €/MWh$, $\Delta gain_y = 161.68\ €/y$;

As regard the total incentive that must be supplied to the producer in function of MGP electricity price and NG price, the below Figure 3.4 shows the trend.

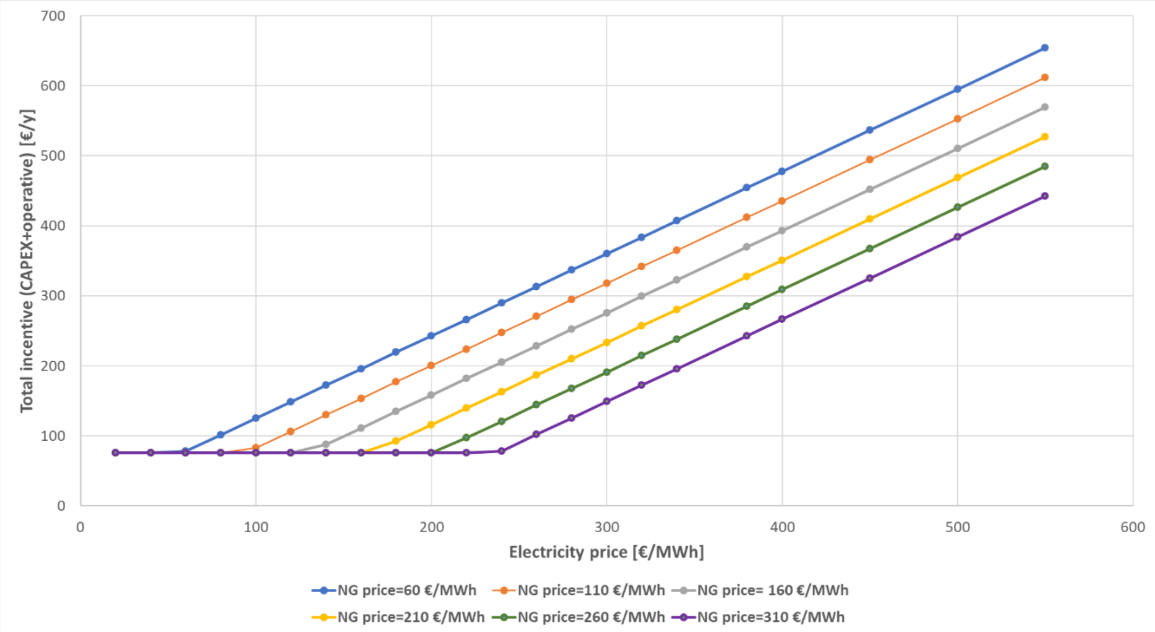

Figure 3.4 – Total incentive vs electricity price for different fixed natural gas prices

In Figure 3.4 some observations can be made:

- The curves don't start from 0 €/y of incentive but start from 75.58 €/y; in fact, for hypothesis, for 1 kW_{inst} of electrolysis capacity the CAPEX incentive is 75.58 €/y and this is always delivered to the producer for the production of hydrogen;

- Increasing the electricity price, it would be more and more convenient to send directly into grid the electricity, because the loss of revenue ($loss_{el}$ in eq. (3.13)) increases; if this increases, the operative incentive must increase to bring the producer in a situation of economic parity;

- It can be noticed that the total incentive to be delivered starts to increase from only $CAPEX_{inc_y}$ value increasing the electricity price for different NG prices. As the NG price increases, the rise of the operative incentive happens at higher $electricity_{price}$ (e.g. for $price_{NG} = 60\ €/MWh$, the operative incentive is > 0€/y when $electricity_{price} \geq 60\ €/MWh$, while with $price_{NG} = 210\ €/MWh$, the operative incentive becomes > 0 €/y for a $electricity_{price} \geq 160\ €/MWh$);

- At the same electricity price, increasing the NG price the total incentive decreases (for the correlation between NG price and selling price of H2); for example, considering $electricity_{price} = 200\ €/MWh$, the yearly total incentive (considering yearly values from eq. (3.9), so $tot_{inc_y} = CAPEX_{inc_y} + operative_{inc_y}$) is:

- With $price_{NG} = 60$ €$/MWh$, $tot_{inc_y} = 75.58\frac{€}{y} + 167.10\frac{€}{y} = 242.69$ €$/y$;
- With $price_{NG} = 110$ €$/MWh$, $tot_{inc_y} = 75.58\frac{€}{y} + 124.85\frac{€}{y} = 200.43$ €$/y$;
- With $price_{NG} = 160$ €$/MWh$, $tot_{inc_y} = 75.58\frac{€}{y} + 82.59\frac{€}{y} = 158.17$ €$/y$;
- With $price_{NG} = 210$ €$/MWh$, $tot_{inc_y} = 75.58\frac{€}{y} + 40.33\frac{€}{y} = 115.91$ €$/y$;
- With $price_{NG} = 260$ €$/MWh$, $tot_{inc_y} = 75.58\frac{€}{y} + 0\frac{€}{y} = 75.58$ €$/y$;
- With $price_{NG} = 310$ €$/MWh$, $tot_{inc_y} = 75.58\frac{€}{y} + 0\frac{€}{y} = 75.58$ €$/y$;

At this point, maintaining the sensitivity analysis approach described above, we can determine the tables of incentive paid annually to the producer of green hydrogen from electrolysis (tot_{inc_y}) and its annual differential gain ($\Delta gain_y$); these tables, Table 3.1 and Table 3.2 below, allow the instantaneous visualisation of what would be, in a given electricity (column) and natural gas (line) average price situation, the incentive and gain for a producer of electricity from RES who decides to install an electrolyser to produce hydrogen, respectively. The range considered for the $electricity_{price}$ and $price_{NG}$ is between $0 - 600$ €$/MWh$ at intervals of 20 €$/MWh$.

Please note that the analysis is parameterised to the kW_{inst} of electrolysis capacity, and the results reported here are based on the assumption of $EL_{cap} = 1\ kW_{inst}$.

Table 3.1 – Matrix of total revenue due to incentive delivered for different natural gas and electricity prices

TOTAL INCENTIVE (operative+CAPEX)[€/y]		Electricity price [€/MWh]																													
		20	40	60	80	100	120	140	160	180	200	220	240	260	280	300	320	340	360	380	400	420	440	460	480	500	520	540	560	580	600
NG price [€/MWh]	20	75,58	88,49	111,99	135,49	158,99	182,49	205,99	229,49	252,99	276,49	299,99	323,49	346,99	370,49	393,99	417,49	440,99	464,49	487,99	511,49	534,99	558,49	581,99	605,49	628,99	652,49	675,99	699,49	722,99	746,49
	40	75,58	75,58	95,09	118,59	142,09	165,59	189,09	212,59	236,09	259,59	283,09	306,59	330,09	353,59	377,09	400,59	424,09	447,59	471,09	494,59	518,09	541,59	565,09	588,59	612,09	635,59	659,09	682,59	706,09	729,59
	60	75,58	75,58	78,19	101,69	125,19	148,69	172,19	195,69	219,19	242,69	266,19	289,69	313,19	336,69	360,19	383,69	407,19	430,69	454,19	477,69	501,19	524,69	548,19	571,69	595,19	618,69	642,19	665,69	689,19	712,69
	80	75,58	75,58	75,58	84,78	108,28	131,78	155,28	178,78	202,28	225,78	249,28	272,78	296,28	319,78	343,28	366,78	390,28	413,78	437,28	460,78	484,28	507,78	531,28	554,78	578,28	601,78	625,28	648,78	672,28	695,78
	100	75,58	75,58	75,58	75,58	91,38	114,88	138,38	161,88	185,38	208,88	232,38	255,88	279,38	302,88	326,38	349,88	373,38	396,88	420,38	443,88	467,38	490,88	514,38	537,88	561,38	584,88	608,38	631,88	655,38	678,88
	120	75,58	75,58	75,58	75,58	75,58	97,98	121,48	144,98	168,48	191,98	215,48	238,98	262,48	285,98	309,48	332,98	356,48	379,98	403,48	426,98	450,48	473,98	497,48	520,98	544,48	567,98	591,48	614,98	638,48	661,98
	140	75,58	75,58	75,58	75,58	75,58	81,07	104,57	128,07	151,57	175,07	198,57	222,07	245,57	269,07	292,57	316,07	339,57	363,07	386,57	410,07	433,57	457,07	480,57	504,07	527,57	551,07	574,57	598,07	621,57	645,07
	160	75,58	75,58	75,58	75,58	75,58	75,58	87,67	111,17	134,67	158,17	181,67	205,17	228,67	252,17	275,67	299,17	322,67	346,17	369,67	393,17	416,67	440,17	463,67	487,17	510,67	534,17	557,67	581,17	604,67	628,17
	180	75,58	75,58	75,58	75,58	75,58	75,58	75,58	94,27	117,77	141,27	164,77	188,27	211,77	235,27	258,77	282,27	305,77	329,27	352,77	376,27	399,77	423,27	446,77	470,27	493,77	517,27	540,77	564,27	587,77	611,27
	200	75,58	75,58	75,58	75,58	75,58	75,58	75,58	77,37	100,87	124,37	147,87	171,37	194,87	218,37	241,87	265,37	288,87	312,37	335,87	359,37	382,87	406,37	429,87	453,37	476,87	500,37	523,87	547,37	570,87	594,37
	220	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	83,96	107,46	130,96	154,46	177,96	201,46	224,96	248,46	271,96	295,46	318,96	342,46	365,96	389,46	412,96	436,46	459,96	483,46	506,96	530,46	553,96	577,46
	240	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	90,56	114,06	137,56	161,06	184,56	208,06	231,56	255,06	278,56	302,06	325,56	349,06	372,56	396,06	419,56	443,06	466,56	490,06	513,56	537,06	560,56
	260	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	97,16	120,66	144,16	167,66	191,16	214,66	238,16	261,66	285,16	308,66	332,16	355,66	379,16	402,66	426,16	449,66	473,16	496,66	520,16	543,66
	280	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	80,25	103,75	127,25	150,75	174,25	197,75	221,25	244,75	268,25	291,75	315,25	338,75	362,25	385,75	409,25	432,75	456,25	479,75	503,25	526,75
	300	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	86,85	110,35	133,85	157,35	180,85	204,35	227,85	251,35	274,85	298,35	321,85	345,35	368,85	392,35	415,85	439,35	462,85	486,35	509,85
	320	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	93,45	116,95	140,45	163,95	187,45	210,95	234,45	257,95	281,45	304,95	328,45	351,95	375,45	398,95	422,45	445,95	469,45	492,95
	340	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	76,55	100,05	123,55	147,05	170,55	194,05	217,55	241,05	264,55	288,05	311,55	335,05	358,55	382,05	405,55	429,05	452,55	476,05
	360	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	83,14	106,64	130,14	153,64	177,14	200,64	224,14	247,64	271,14	294,64	318,14	341,64	365,14	388,64	412,14	435,64	459,14
	380	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	89,74	113,24	136,74	160,24	183,74	207,24	230,74	254,24	277,74	301,24	324,74	348,24	371,74	395,24	418,74	442,24
	400	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	96,34	119,84	143,34	166,84	190,34	213,84	237,34	260,84	284,34	307,84	331,34	354,84	378,34	401,84	425,34
	420	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	79,43	102,93	126,43	149,93	173,43	196,93	220,43	243,93	267,43	290,93	314,43	337,93	361,43	384,93	408,43
	440	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	86,03	109,53	133,03	156,53	180,03	203,53	227,03	250,53	274,03	297,53	321,03	344,53	368,03	391,53
	460	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	92,63	116,13	139,63	163,13	186,63	210,13	233,63	257,13	280,63	304,13	327,63	351,13	374,63
	480	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,73	99,23	122,73	146,23	169,73	193,23	216,73	240,23	263,73	287,23	310,73	334,23	357,73
	500	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	82,32	105,82	129,32	152,82	176,32	199,82	223,32	246,82	270,32	293,82	317,32	340,82
	520	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	88,92	112,42	135,92	159,42	182,92	206,42	229,92	253,42	276,92	300,42	323,92
	540	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	95,52	119,02	142,52	166,02	189,52	213,02	236,52	260,02	283,52	307,02
	560	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	78,61	102,11	125,61	149,11	172,61	196,11	219,61	243,11	266,61	290,11
	580	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	85,21	108,71	132,21	155,71	179,21	202,71	226,21	249,71	273,21
	600	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	75,58	91,81	115,31	138,81	162,31	185,81	209,31	232,81	256,31

In Table 3.1 two colours are used, defined below:

- In orange are represented all price situations, electricity and natural gas price pairs, for which the operative incentive is not paid, and therefore the incentive revenue is represented by the $CAPEX_{inc_y} = 75.58$ €$/y$ only;

- In blue are shown all price situations in which, in addition to the CAPEX incentive, the producer needs operational support for hydrogen production; the different scales of blue refer to the amount of operational incentive disbursed, the darker the blue, the more unfavourable the price situation is for hydrogen production and thus the incentive to be disbursed increases;

Some considerations can be made in this figure:

- There is a clear separation between the two colours and therefore, between the different price combinations, two completely different zones can be distinguished from the point of view of the incentive granted; in the first zone, i.e. the one demarcated by a uniform orange colour, the total incentive granted to the producer of green H2 is constant and equal to the $CAPEX_{inc_y}$ incentive only, while in the second zone, demarcated by gradations of blue, the total incentive granted is equal to the sum of the annual CAPEX incentive and the annual operating incentive;

- For a fixed electricity price value, as the price of natural gas increases, the total incentive decreases until it reaches the constant value of $CAPEX_{inc_y}$; for example, for $electricity_{price} = 300$ €$/MWh$, the total yearly incentive is:
    - $tot_{inc_y} = 292.57$ €$/y$ for a $price_{NG} = 140$ €$/MWh$;
    - $tot_{inc_y} = 174.25$ €$/y$ for a $price_{NG} = 280$€$/MWh$;
    - $tot_{inc_y} = CAPEX_{inc_y} = 75.58$ €$/y$ for a $price_{NG} = 400$ €$/MWh$;

- For a fixed natural gas price value, as the price of electricity increases, the total incentive increases from the constant value of $CAPEX_{inc_y}$; for example, for $price_{NG} = 160$ €$/MWh$, the total yearly incentive is:
    - $tot_{inc_y} = CAPEX_{inc_y} = 75.58$ €$/y$ for a $electricity_{price} = 40$ €$/MWh$;
    - $tot_{inc_y} = CAPEX_{inc_y} = 75.58$ €$/y$ for a $electricity_{price} = 100$ €$/MWh$;
    - $tot_{inc_y} = 87.67$ €$/y$ for a $electricity_{price} = 140$ €$/MWh$;
    - $tot_{inc_y} = 275.67$ €$/y$ for a $electricity_{price} = 300$ €$/MWh$;

The matrix for the producer's annual differential gain under different price situations is shown below in Table 3.2.

Table 3.2 – Matrix of total differential gain for different natural gas and electricity prices

YEARLY GAIN [€/Y]	Electricity price [€/MWh]																													
NG price [€/MWh]	20	40	60	80	100	120	140	160	180	200	220	240	260	280	300	320	340	360	380	400	420	440	460	480	500	520	540	560	580	600
20	10,6	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
40	27,5	4,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
60	44,4	20,9	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
80	61,3	37,8	14,3	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
100	78,2	54,7	31,2	7,7	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
120	95,1	71,6	48,1	24,6	1,1	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
140	112,0	88,5	65,0	41,5	18,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
160	128,9	105,4	81,9	58,4	34,9	11,4	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
180	145,8	122,3	98,8	75,3	51,8	28,3	4,8	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
200	162,7	139,2	115,7	92,2	68,7	45,2	21,7	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
220	179,6	156,1	132,6	109,1	85,6	62,1	38,6	15,1	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
240	196,5	173,0	149,5	126,0	102,5	79,0	55,5	32,0	8,5	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
260	213,4	189,9	166,4	142,9	119,4	95,9	72,4	48,9	25,4	1,9	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
280	230,3	206,8	183,3	159,8	136,3	112,8	89,3	65,8	42,3	18,8	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
300	247,2	223,7	200,2	176,7	153,2	129,7	106,2	82,7	59,2	35,7	12,2	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
320	264,1	240,6	217,1	193,6	170,1	146,6	123,1	99,6	76,1	52,6	29,1	5,6	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
340	281,0	257,5	234,0	210,5	187,0	163,5	140,0	116,5	93,0	69,5	46,0	22,5	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
360	297,9	274,4	250,9	227,4	203,9	180,4	156,9	133,4	109,9	86,4	62,9	39,4	15,9	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
380	314,8	291,3	267,8	244,3	220,8	197,3	173,8	150,3	126,8	103,3	79,8	56,3	32,8	9,3	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
400	331,7	308,2	284,7	261,2	237,7	214,2	190,7	167,2	143,7	120,2	96,7	73,2	49,7	26,2	2,7	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
420	348,6	325,1	301,6	278,1	254,6	231,1	207,6	184,1	160,6	137,1	113,6	90,1	66,6	43,1	19,6	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
440	365,5	342,0	318,5	295,0	271,5	248,0	224,5	201,0	177,5	154,0	130,5	107,0	83,5	60,0	36,5	13,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
460	382,5	359,0	335,5	312,0	288,5	265,0	241,5	218,0	194,5	171,0	147,5	124,0	100,5	77,0	53,5	30,0	6,5	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
480	399,4	375,9	352,4	328,9	305,4	281,9	258,4	234,9	211,4	187,9	164,4	140,9	117,4	93,9	70,4	46,9	23,4	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
500	416,3	392,8	369,3	345,8	322,3	298,8	275,3	251,8	228,3	204,8	181,3	157,8	134,3	110,8	87,3	63,8	40,3	16,8	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
520	433,2	409,7	386,2	362,7	339,2	315,7	292,2	268,7	245,2	221,7	198,2	174,7	151,2	127,7	104,2	80,7	57,2	33,7	10,2	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
540	450,1	426,6	403,1	379,6	356,1	332,6	309,1	285,6	262,1	238,6	215,1	191,6	168,1	144,6	121,1	97,6	74,1	50,6	27,1	3,6	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
560	467,0	443,5	420,0	396,5	373,0	349,5	326,0	302,5	279,0	255,5	232,0	208,5	185,0	161,5	138,0	114,5	91,0	67,5	44,0	20,5	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
580	483,9	460,4	436,9	413,4	389,9	366,4	342,9	319,4	295,9	272,4	248,9	225,4	201,9	178,4	154,9	131,4	107,9	84,4	60,9	37,4	13,9	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
600	500,8	477,3	453,8	430,3	406,8	383,3	359,8	336,3	312,8	289,3	265,8	242,3	218,8	195,3	171,8	148,3	124,8	101,3	77,8	54,3	30,8	7,3	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0

Also, in Table 3.2 two colours are used, defined below:

- In yellow are represented all price situations, electricity and natural gas price pairs, for which the yearly differential gain of the producer is 0 €/y and therefore there is no convenience to install electrolysis capacity and produce hydrogen in these situations;

- In green are shown all price situations in which, contrary to the ones described above, the producer of hydrogen has a differential gain different from zero, and so is convenient to install the electrolyser, produce and sell the hydrogen; the different scales of green refer to the amount of yearly total gain, the darker the green, the more favourable the price situation is for hydrogen production and thus the total gain increases;

Some considerations can be made on this table:

- The two tables are linked, in fact this table is a mirror of Table 3.1; this is because, in price situations where there is a differential gain by the producer (in green), the operating incentive disbursed is equal to zero and only the $CAPEX_{inc_y}$ incentive share is sent (in orange in Table 3.1); while in price situations where the differential gain is equal to zero (in yellow), the total incentive is equal to the CAPEX share plus an operating share that is disbursed to send the producer to economic parity;

- For a fixed electricity price value, as the price of natural gas increases, the gain increases from the situation of economic parity ($\Delta gain_y = 0\ €/y$); for example, for $electricity_{price} = 300\ €/MWh$, the yearly gain is:
  - $\Delta gain_y = 0\ €/y$ for a $price_{NG} = 140\ €/MWh$;
  - $\Delta gain_y = 0\ €/y$ for a $price_{NG} = 280 €/MWh$;
  - $\Delta gain_y = 2.7\ €/y$ for a $price_{NG} = 400\ €/MWh$;
  - $\Delta gain_y = 87.3\ €/y$ for a $price_{NG} = 500\ €/MWh$;

- For a fixed natural gas price value, as the price of electricity increases, the gain decreases until it reaches 0 €/y in economic parity situation; for example, for $price_{NG} = 160\ €/MWh$, the yearly gain is:
  - $\Delta gain_y = 105.4\ €/y$ for a $electricity_{price} = 40\ €/MWh$;
  - $\Delta gain_y = 34.9\ €/y$ for a $electricity_{price} = 100\ €/MWh$;
  - $\Delta gain_y = 0\ €/y$ for a $electricity_{price} = 140\ €/MWh$;
  - $\Delta gain_y = 0\ €/y$ for a $electricity_{price} = 300\ €/MWh$;

This table, together with Table 3.1, allows us to determine the most favourable annual average electricity and natural gas price situations for the hydrogen producer, and we can see that, in general and with some exceptions, the most favourable situations are where the $price_{NG} \gg electricity_{price}$.

3.4.5 Sensitivity analysis on the selling price of hydrogen

In this simulation, as opposed to the previous one, in which the sale price of hydrogen is linked to the price of natural gas, we want to untie these parameters and perform a sensitivity analysis on the sale price of hydrogen from electrolysis; thus, this simulation aims to see how the incentive paid and the annual gain varies annually as the sale price of H2 varies with the same electricity and natural gas prices. This decoupling between the selling price of hydrogen and the price of natural gas can be determined by external mechanisms such as the ETS ('Emission Trading System') market [74]; in fact, considering a price per share of CO2 emitted, the buyer of green H2 may be willing to pay more than the equivalence with methane because green hydrogen does not emit CO2, and consequently has no cost due to emissions.

To do this, the electricity prices (in relation to the PUN 'Prezzo unico nazionale', which is the single national price [75]) and the natural gas prices (in relation to the TTF [76] 'Title transfer facility' market) of a few months of the 2021-22 time frame are taken in Table 3.3; the idea is to set an average value of the ratio between the two prices and to fix one of the two prices, so also the other one is fixed, and then use as variable the selling price of H2.

Table 3.3 – Electricity price (PUN) and natural gas price (TTF) from April 2021 to September 2022

Month	TTF spot price NG [€/MWh]	PUN price for electricity [€/MWh]
set-22	188,69	424,00
ago-22	222,33	540,85
lug-22	171,68	441,65
giu-22	103,92	271,31
mag-22	89,34	230,00
apr-22	92,80	245,98
mar-22	125,42	308,07
feb-22	83,07	211,69
gen-22	83,63	224,50
dic-21	110,12	281,24
nov-21	81,70	225,95
ott-21	87,47	217,63
set-21	63,45	158,59
ago-21	44,12	112,40
lug-21	36,23	102,66
giu-21	29,12	84,80
mag-21	25,21	69,91
apr-21	20,50	69,02

In Table 3.3, the correlation between the two prices is not well visualised, so the two trends in the graph in Figure 3.5 are plotted to actually see the relationship between the two. In fact, as can be seen, in the various months considered, the two prices rise or fall in the same way, however with different numerical scales.

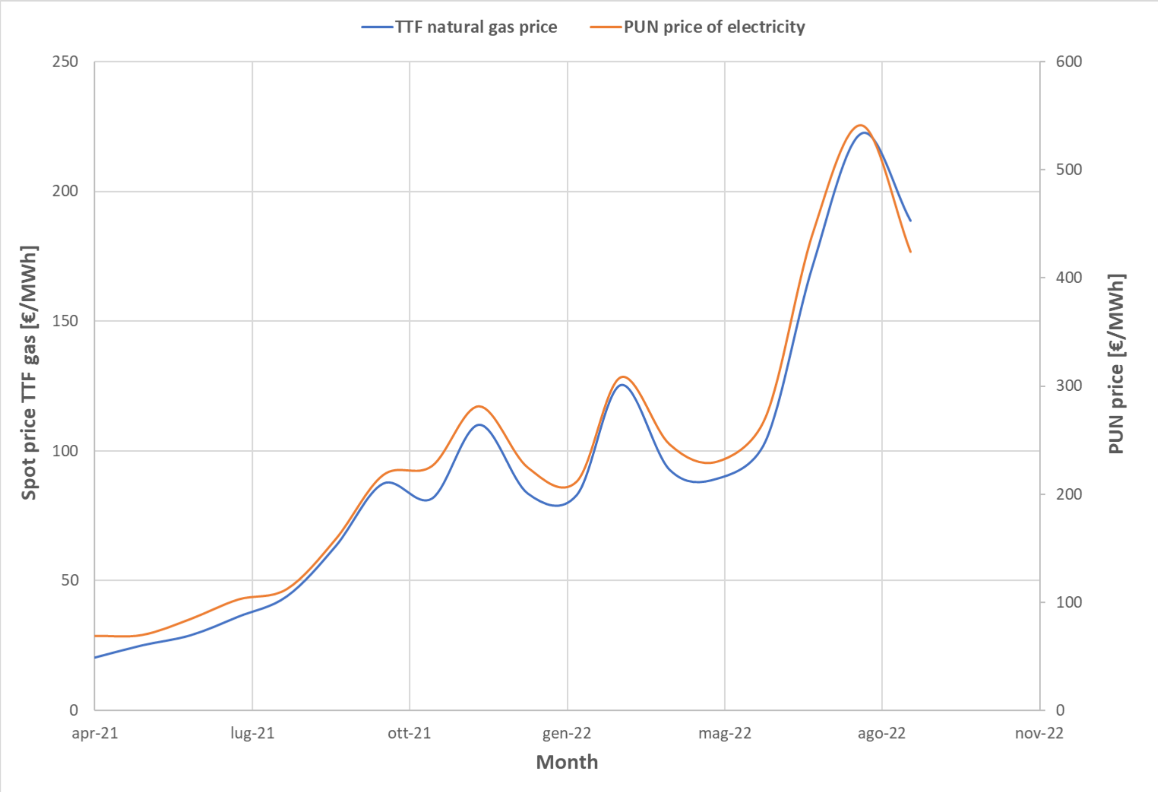

Figure 3.5 – Correlation between TTF natural gas price and PUN price of electricity

The result of the correlation is an average ratio between the two prices: $ratio_{avg} = \frac{electricity_{price}}{price_{NG}} = 2.64$.

At this point, for the purpose of the simulation in question, some scenarios are considered with annual average price values of natural gas which are set and, given $ratio_{avg}$, the annual average prices of electricity are also determined:

- 1) Scenario: $price_{NG} = 50$ €$/MWh$, so $electricity_{price} = 132$ €$/MWh$;
- 2) Scenario: $price_{NG} = 100$ €$/MWh$,so $electricity_{price} = 264$ €$/MWh$;
- 3) Scenario: $price_{NG} = 150$ €$/MWh$, so $electricity_{price} = 396$ €$/MWh$;
- 4) Scenario: $price_{NG} = 200$ €$/MWh$, so $electricity_{price} = 528$ €$/MWh$;

So, four price scenarios have been defined, and now we want to see how the annual gain and the total annual incentive paid varies as the hydrogen sales price changes. We expect a similar behaviour to the case already studied in which the price of natural gas is varied in 3.4.3, because, despite the independence between the selling price of H2 and the price of natural gas, they both exert a variation in the rev_{sellH2}, and consequently in the total annual incentive and the annual gain.

The results of this simulation with regard to the yearly gain are shown in Figure 3.6.

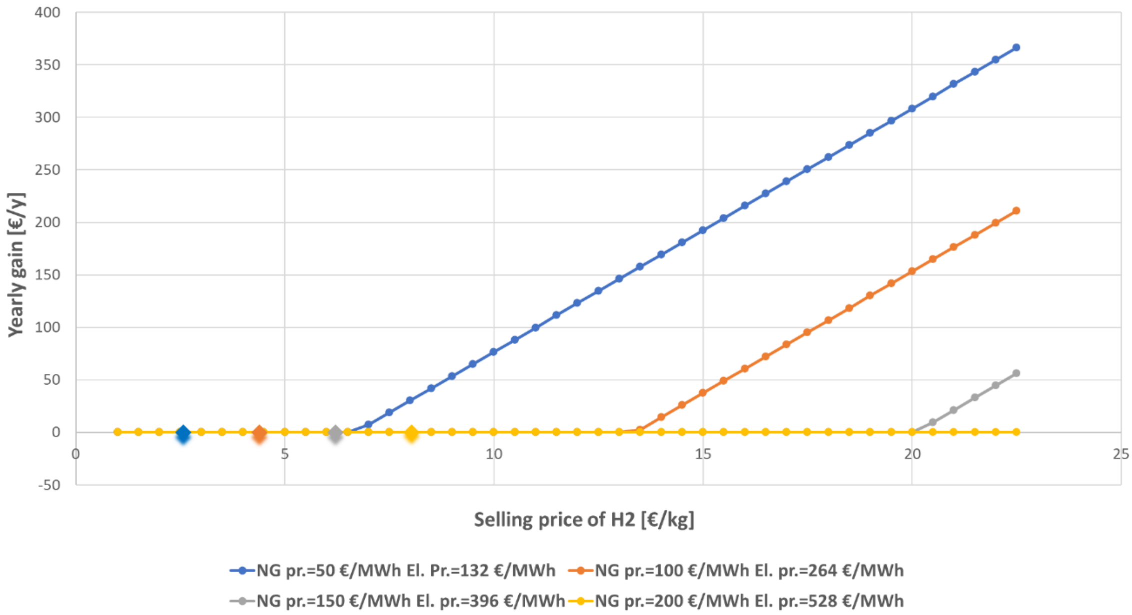

Figure 3.6 – Yearly gain vs selling price of hydrogen for different scenarios of electricity and NG prices

The graph shows also with square markers the points to which the annual gains correspond in the situation discussed in the sections above, in which the correlation between natural gas price and hydrogen sales price is considered to exist. Considering the correlation between the two, the natural gas prices considered correspond to certain hydrogen prices on this graph, plotted accordingly:

- $price_{NG} = 50$ €$/MWh$ corresponds to $p_{H2_{avg}} = 2.6$ €$/kg_{H2}$;
- $price_{NG} = 100$ €$/MWh$ corresponds to $p_{H2_{avg}} = 4.4$ €$/kg_{H2}$;
- $price_{NG} = 150$ €$/MWh$ corresponds to $p_{H2_{avg}} = 6.2$ €$/kg_{H2}$;
- $price_{NG} = 200$ €$/MWh$ corresponds to $p_{H2_{avg}} = 8.0$ €$/kg_{H2}$;

Some considerations can be done about Figure 3.6:

- Firstly, as expected, in the various electricity and natural gas price scenarios, the annual gain increases from 0 €$/y$ (economic parity) as the sales price of H2 increases because the term for hydrogen sales revenue $rev_{sell_{H2}}$ increases; however, the gain growth from the economic parity value changes as the scenario considered changes, in fact:
    - Considering first scenario, $price_{NG} = 50$ €$/MWh$ and $electricity_{price} = 132$ €$/MWh$, $p_{H2_{avg}} \geq 6.7$ €$/kg_{H2}$ in order to have an yearly gain $\neq 0$ €$/y$;

- Considering second scenario, $price_{NG} = 100\ €/MWh$ and $electricity_{price} = 264\ €/MWh$, $p_{H2_{avg}} \geq 13.4\ €/kg_{H2}$ in order to have an yearly gain $\neq 0\ €/y$;

- In the scenarios with high natural gas and electricity prices, for the same hydrogen sales price, the annual gain decreases as high electricity prices cause the $loss_{el}$ (calculated by eq. (3.13)) to increase by a large amount and consequently the differential yearly gain decreases even at high hydrogen sales prices; for example, considering $p_{H2_{avg}} = 21\ €/kg_{H2}$ (not real, only for the purpose of the analysis):
  - In (1) $\Delta gain_y = 331.52\ €/y$ and $tot_{inc_y} = 75.58\ €/y$;
  - In (2) $\Delta gain_y = 176.42\ €/y$ and $tot_{inc_y} = 75.58\ €/y$;
  - In (3) $\Delta gain_y = 21.32\ €/y$ and $tot_{inc_y} = 75.58\ €/y$;
  - In (4) $\Delta gain_y = 0\ €/y$ and $tot_{inc_y} = 209.36\ €/y$;

- We now want to see, in this simulation, the annual gains in the previous scenarios in which there is a correlation between the price of natural gas and the selling price of H2; in the figure these are represented with square markers, since a specific price of natural gas corresponds to a specific selling price of hydrogen; however, all the price scenarios assumed for this simulation, that are in the yellow part of the matrix in Table 3.2, have the characteristic that $price_{NG} << electricity_{price}$ and therefore the annual differential gain is $0\ €/y$ in all the cases studied; for example, in the scenario $price_{NG} = 50\ €/MWh$ and $electricity_{price} = 132\ €/MWh$:
  - If the correlation between $price_{NG}$ and $p_{H2_{avg}}$ is considered, $p_{H2_{avg}} = 2.6\ €/kg_{H2}$ and $\Delta gain_y = 0\ €/y$;
  - If the correlation between $price_{NG}$ and $p_{H2_{avg}}$ is not considered, it is possible to have $\Delta gain_y > 0\ €/y$ if $p_{H2_{avg}} \geq 6.7\ €/kg_{H2}$;

The results of the simulation regarding the total yearly incentive are shown in Figure 3.7.

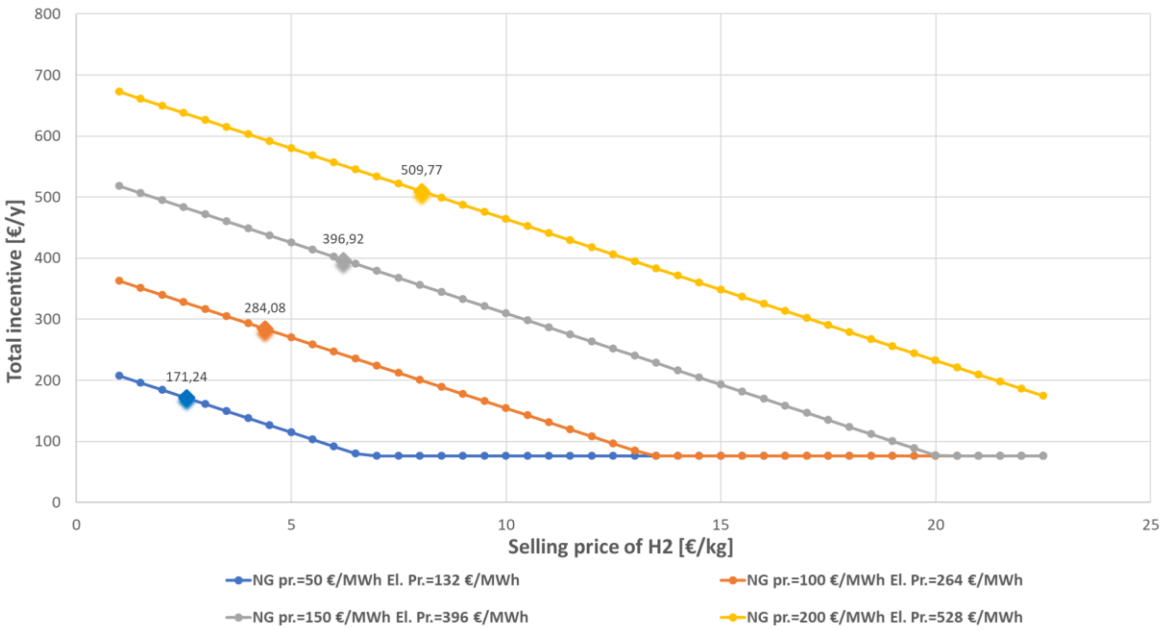

Figure 3.7 – Total incentive vs selling price of hydrogen for different scenarios of electricity and NG prices

As in Figure 3.6, also in Figure 3.7 are plotted the points corresponding to the values of the incentive paid when there is a correlation between the price of natural gas and the sale price of hydrogen.

In Figure 3.7 some considerations can be made:

- As $p_{H2_{avg}}$ increases, the total yearly incentive tot_{inc_y} decreases in the various price scenarios until it reaches the value of the $CAPEX_{inc_y}$ incentive alone; the selling price of hydrogen at which the incentive becomes only the CAPEX one is the same at which the yearly differential gain becomes more than zero; for example, considering first scenario, $price_{NG} = 50$ €$/MWh$ and $electricity_{price} = 132$ €$/MWh$, $p_{H2_{avg}} \geq 6.7$ €$/kg_{H2}$ in order to have $tot_{inc_y} = CAPEX_{inc_y}$;

- We now want to see, in this simulation, the total yearly incentive in the previous scenarios in which there is a correlation between the price of natural gas and the selling price of H2; in the figure these are represented with square markers, since a specific price of natural gas corresponds to a specific selling price of hydrogen; the yearly total incentive in all the cases studied is bigger than the $CAPEX_{inc_y}$ and the values are reported near the points in the Figure 3.7;

3.4.6 Sensitivity analysis on the equivalent operating hours of the electrolyser

The purpose of this simulation is to see how the annual gain of a hydrogen producer might change if the number of equivalent operating hours of the electrolyser increases above the assumed number of hours. Recall that one of the main assumptions of the case study is $h_{st} = h_{eq_{EL}} = 1175\ h/y$, so the number of incentivised equivalent operating hours is only h_{st}; in the event that $h_{eq_{EL}} > h_{st}$, for example if the spot where the plant is installed is particularly lucky in terms of solar radiation and so $h_{eq_{RES}}$ increase and consequently $h_{eq_{EL}}$ increases, additional hydrogen production will not be incentivised and this is determined by eq. (3.10), as well as in the opposite case where $h_{eq_{EL}} < h_{st}$ and thus the incentivised production is equal to the actual production.

Considering the assumption that the electrolyser works whenever it can, thus utilising all available $h_{eq_{EL}}$, we want to determine how the gain varies for $h_{eq_{EL}} \neq h_{st}$. To do this, the price scenario of the base case is considered first:

- $electricity_{price} = 300\ €/MWh$;
- $price_{NG} = 160\ €/MWh$;

The variation of yearly gain and total incentive is reported in the Figure 3.8 below.

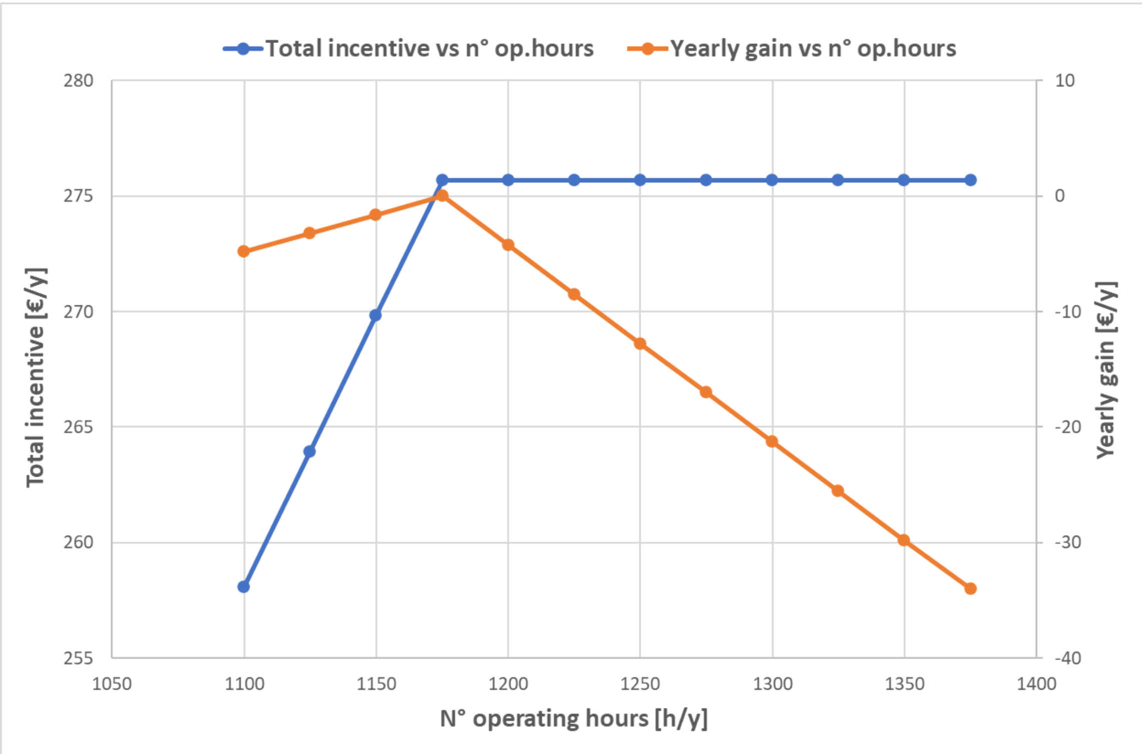

Figure 3.8 – Yearly gain and total incentive vs equivalent operating hours of the electrolyser

Some considerations can be made on Figure 3.8:

- It can be seen immediately that the total incentive given depends on the equivalent operating hours of the electrolyser; in fact, for $h_{eq_{EL}} < h_{st}$, this increases until the number of equivalent operating hours reach $h_{st} = 1175\,\mathrm{h/y}$, because from equation (3.10) the production incentivised is the actual production $prod_{H2_{inc}} = prod_{H2} < prod_{H2_{\mathrm{max,inc}}}$; while, for $h_{eq_{EL}} > h_{st}$, the incentive is constant and equal to $275.67\ €/y$, due to the fact that the incentive is only given for a total number of operating hours per year equal to h_{st}, and thus the incentivised production $prod_{H2_{inc}} = prod_{H2_{\mathrm{max,inc}}}$ (from eq. (3.10));
- With regard to the annual differential gain, this increases until $h_{eq_{EL}}$ reaches the value of h_{st}, for which $\Delta gain_y = 0\ €/y$, due to the fact that, as $h_{eq_{EL}}$ increases, the hydrogen production which is incentivised increases, and also the term rev_{sellH2}; for $h_{eq_{EL}} > h_{st}$ the differential gain decreasing again, even if production increases, because this additional production is not incentivised and consequently the $loss_{el}$, due to the lower electricity injection into the grid, increases by more than the revenue term rev_{sellH2} alone; for this reason a loss of $-34.06\ €/y$ is recorded for $h_{eq_{EL}} = 1375\ h/y$;

At this point, we want to define different scenarios to evaluate the sensitivity parameter $h_{eq_{EL}}$ in different price situations. Some of these are taken directly from section 3.4.5, while others are assumed on the basis of the Renewables Decree for which the price for selling electricity from renewable sources is 60 €/MWh [67]. In addition to the price scenarios already defined, the new scenarios are given below:

- 5) Scenario: $price_{NG} = 80\ €/MWh$, so $electricity_{price} = 60\ €/MWh$;
- 6) Scenario: $price_{NG} = 120\ €/MWh$, so $electricity_{price} = 60\ €/MWh$;
- 7) Scenario: $price_{NG} = 220\ €/MWh$, so $electricity_{price} = 60\ €/MWh$;
- 8) Scenario: $price_{NG} = 280\ €/MWh$, so $electricity_{price} = 60\ €/MWh$;

In Figure 3.9 the annual gain as a function of the equivalent operating hours of the electrolyser for the different price scenarios assumed are depicted.

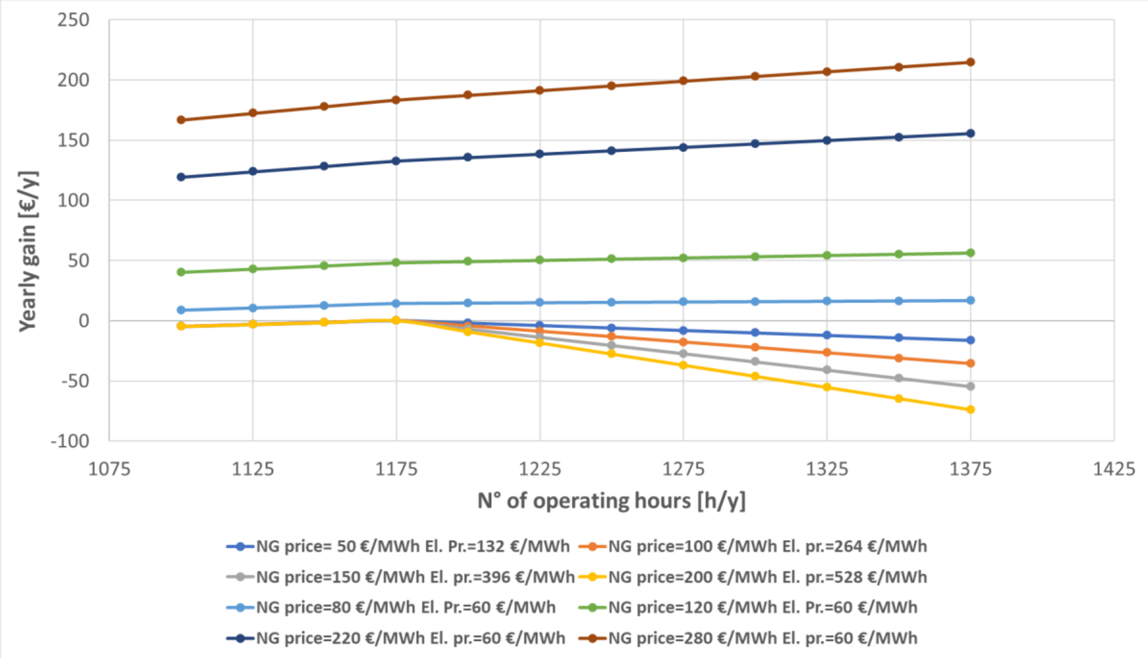

Figure 3.9 – Yearly gain vs n° of equivalent operating hours of the electrolyser for different price scenarios

Some comments about Figure 3.9:

- It can be noticed that, considering the first four scenarios, at the base number of operating hours ($h_{eq_{EL}} = 1175\ h/y$) the yearly gain is always $\Delta gain_y = 0\ €/y$ because there is always the delivery of the operative incentive (yellow part of matrix in Table 3.2); as $h_{eq_{EL}}$ decreases from h_{st} value, $\Delta gain_y$ becomes negative (and a loss will occur) because the $rev_{sell_{H2}}$ decreases; even if $h_{eq_{EL}}$ increases from h_{st}, $\Delta gain_y$ becomes negative, due to the fact that the incentive is provided to put the producer on an economic parity in the situation where $h_{eq_{EL}} = h_{st}$, and therefore if $h_{eq_{EL}} > h_{st}$ the incentive is not delivered for additional hydrogen production while the loss of revenue $loss_{el}$ increases and makes a loss, which is greater as electricity and natural gas prices increase;
- Considering the last four scenarios (green part of matrix in Table 3.2), with a fixed value of $electricity_{price}$, if $h_{eq_{EL}} = 1175\ h/y\ \Delta gain_y \neq 0\ €/y$ and increases as the $price_{NG}$ increases; in fact:
  - In (5) scenario $price_{NG} = 80\ €/MWh$ and $electricity_{price} = 60\ €/MWh$, with a $\Delta gain_y = 14.30\ €/y$;
  - In (7) scenario $price_{NG} = 220\ €/MWh$ and $electricity_{price} = 60\ €/MWh$, with a $\Delta gain_y = 132.62\ €/y$;

  As $h_{eq_{EL}}$ increases in these scenarios, the $\Delta gain_y$ increases more and more, due to the fact that $loss_{el}$ remains constant due to the constancy of electricity price, while $rev_{sell_{H2}}$ increases and so the gain increases;

3.4.7 Sensitivity analysis on the CAPEX investment cost of electrolyser

In this simulation, we want to perform a further sensitivity analysis on a basic parameter of the analysis, the $CAPEX_{inv}$. The idea is to vary the CAPEX cost of the electrolyser in terms of $€/kW_{inst}$, assumed in the base case to be $CAPEX_{inv} = 480\ €/kW_{inst}$ for an alkaline-type electrolyser, and see how the total annual incentive and the annual gain on the part of the hydrogen producer varies.

The same price scenarios as in section 3.4.5 are considered, however, it should be noted that as $CAPEX_{inv}$ varies, the only parameter that varies is $CAPEX_{expense}$, and thus within the various scenarios considered, the total incentive is constant, while the total gain varies because the capex expense varies. The result is plotted in the graph in Figure 3.10 below.

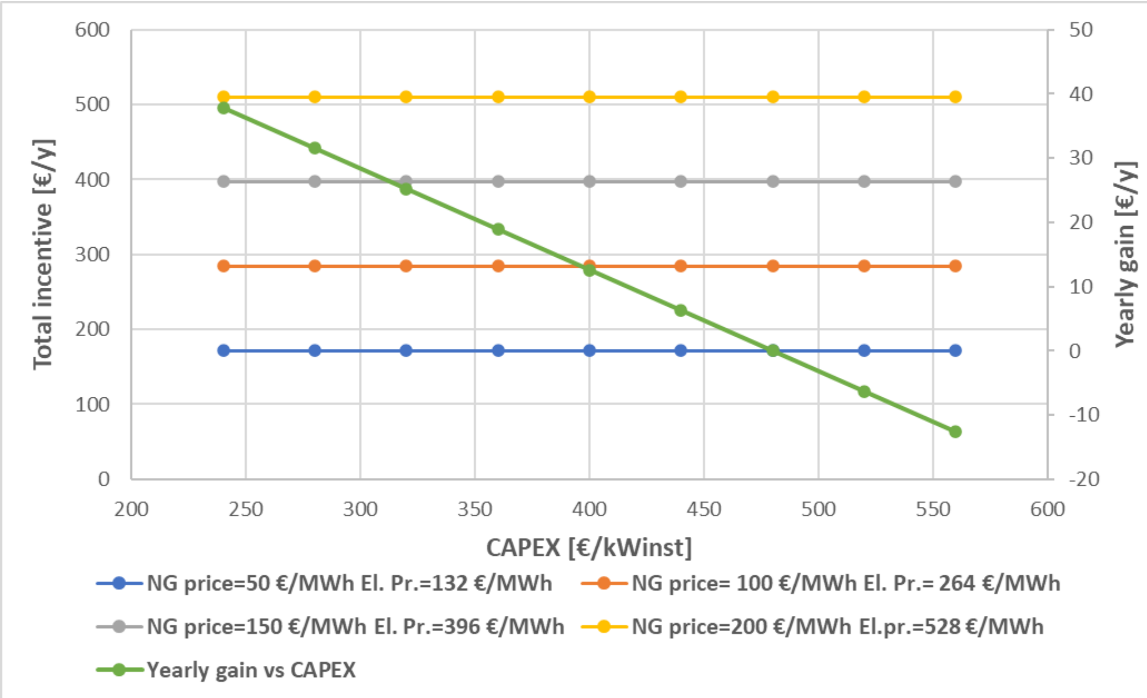

Figure 3.10 – Yearly gain and total incentive vs $CAPEX_{inv}$ for different price scenarios

From Figure 3.10 some considerations can be done:

- First of all, it can be seen, as mentioned above, that the total incentive remains constant as $CAPEX_{inv}$ varies; for example, the scenario (1) in which $electricity_{price} = 132\ €/MWh$ and $price_{NG} = 50\ €/MWh$ is taken into account, thus the total incentive is $tot_{inc_y} = 171.24\ €/y$. The total incentive varies in the various price scenarios but does not vary by changing the $CAPEX_{inv}$;

- With regard to the annual gain, this is represented as a single green line in this graph since, in all price scenarios considered, as the $CAPEX_{inv}$ varies, the annual gain varies in the same way; this is due to the fact that, changing the price scenario, considering $h_{eq_{EL}} = 1175\ h/y$ as hypothesis, in all situations $\Delta gain_y = 0$ €$/y$, therefore the only factor that varies the annual gain is precisely the $CAPEX_{expense}$, which varies in the same way in the various scenarios. The yearly gain decreases as the CAPEX increases; it means that when the CAPEX is low, the producer have the $CAPEX_{inc_y}$ on the base value of $CAPEX_{inv} = 480 \frac{€}{kW_{inst}}$, but he buys electrolysers at a lower price and so he can get a gain;

- If $CAPEX_{inv} = 480$ €$/kWinst$ the $\Delta gain_y = 0$ €$/y$ because for the scenarios considered the $CAPEX_{inc_y}$ perfectly matches the $CAPEX_{expense}$ and there is no gain because there is the delivery of the op. incentive to send the producer in economic parity;

- If the CAPEX is bigger than this value of 480 €$/kWinst$, there is a loss for the producer also with the delivery of incentive on the production of H2;

3.5 Application of the Python model

In this chapter, we would like to focus on the model in the Python environment which takes up the assumptions made earlier in the section 3.1, and which is described in section 3.3.

Now that the annual model has been evaluated in the excel environment in section 3.4, we want to implement the hourly model and to do this we use the Python environment. In this environment we make some of the assumptions made in chapter 3.4.1, and want to write a code for the hourly calculation of total gain at the end of the year, evaluating whether it is now more cost-effective to use the electricity produced from renewable sources for the production of hydrogen using an electrolyser, or to sell this produced electricity directly to the grid.

The objectives of the analysis are as follows:

- Evaluate the annual gain as the sum of the various hourly contributions considering the hours when the electrolyser is used to produce hydrogen and the hours when the electricity produced is sold directly to the grid, with respect to a case study considered;

- Calculate the incentive and assess how much this affects the choice of installing a certain electrolysis capacity for hydrogen production versus selling electricity into the grid;

- Perform a sensitivity analysis with respect to the reference and the base case where the size of the electrolysis plant EL_{cap} or the selling price of the green hydrogen produced $p_{H2_{avg}}$ are varied;

3.5.1 Case study assumptions

In this analysis in the Python environment, annual average values cannot be taken into account since an hourly analysis is to be performed; for this reason, the case study considered is not the same as the excel model described in section 3.4.1. In fact, the following are considered in this analysis:

- Hourly prices both for natural gas and electricity prices and for the selling price of green hydrogen;

- Hourly willingness to pay; in fact, while in the previous model done in Excel, this was considered annual and was included within the calculation of the operating incentive, in this analysis it represents, together with the minimum load of the electrolyser, as described in section 3.3, the necessary condition for the electrolyser to produce hydrogen hourly;

As mentioned earlier, some of the assumptions made in 3.4.1 are taken up for this analysis, however there are some important differences in this case study to be evaluated:

- The renewable energy source chosen is the biomass with a biomass plant possessed by the producer in central Italy; the hourly electricity profile $electricity_{RES}$ considered is the actual profile of this plant in the reference year 2019;

- An installed capacity $EL_{cap} = 5\ MW$ of alkaline electrolyser is assumed;

- Natural gas and electricity prices are in accordance with the hourly profiles in the Italian GME ('Gestore dei mercati energetici') for the year 2019;

- Since the selling price of hydrogen produced $p_{H2_{avg}}$ depends on the hourly price of natural gas, the selling price of H2 also varies hourly in the three demand sectors; the hydrogen selling percentages in the three sectors $H2_{feedstock_{\%}}$, $H2_{NGgrid_{\%}}$, $H2_{mobility_{\%}}$ are the same as assumed in section 3.4.1;

- The minimum load level of alkaline-type electrolyser $load_{levelMIN_{\%}} = 30\ \%$ [30];

- $CAPEX_{inc}$ is assumed equal to that considered in the previous model in Excel and decided by the state for the Italian class PV3; $CAPEX_{inc} = 3.26\ €/kg_{H2}$;

All other parameters not mentioned, e.g. for the calculation of sales prices and specific compressor consumption, are assumed as in the previous Excel model.

Before moving on to the definition of the reference case, we would like to make a brief excursus on the Italian day-ahead market and how it works.

The day-ahead market (‘Mercato del giorno prima’ MGP) in Italy is an electricity market where buyers and sellers can trade electricity for the next day. The GME (‘Gestore dei mercati energetici') manages the day-ahead market by conducting an auction to determine the price of electricity for the next day. Participants can submit offers to sell or purchase a given amount of electricity at specific prices, and the GME uses a market clearing algorithm to match these offers and determine the final price.

The opening of the Day-Ahead Market session is set at 8 a.m. on the ninth day prior to the day of delivery. Closing, on the other hand, takes place at noon on the day preceding the day of delivery. Communication of the results of the Day-Ahead Market takes place by 12.55 p.m. on the day preceding the day of delivery. Bids are accepted after the closure of the market session, according to economic merit and in compliance with the transit limits between zones. Accepted purchase bids are valued at the so-called PUN ('Prezzo Unico Nazionale', Single National Price), which is equal to the average of the sale prices of the geographical zones in which Italy is divided weighted by the quantities purchased in those zones [77].

Advantages of the day-ahead market include increased price transparency, improved market efficiency, and lower electricity prices for consumers.

We can therefore proceed to define the reference case for this hourly analysis.

3.5.2 Reference case: No incentive

We want to define a specific case, which will be the reference case in this analysis and will be evaluated in its entirety before proceeding with the sensitivity analysis for the various parameters described above.

The reference case is defined as the case in which a producer of electricity from biomass decides to install an electrolyser with a capacity of 5 MW to produce hydrogen, but the defined incentive scheme is not active, so there is no incentive to produce hydrogen. This reference case is analysed in order to be able to compare it with the base case of the incentive scenario, thus seeing if the incentive is effective in order to have a higher annual gain from the sale of hydrogen than in the case of selling electricity directly to the grid. Thus, in the reference case, one has:

$$tot_{inc} = 0 \frac{€}{kg_{H2}}$$

Then, we follow the model described in paragraph 3.3 for the determination of the total gain by the producer.

In this first simulation the target is to see the result in terms of gain without the application of the incentive scheme (nor CAPEX incentive and nor operative incentive). This simulation is made to see the producer's disadvantage in installing electrolysis capacity without a government incentive and thus visualise how much would be the difference in gain in the case of non-incentivised hydrogen production compared to feeding electricity produced from renewable sources directly into the grid.

Following the above, the first thing we want to determine is the revenue from the sale of green hydrogen produced by electrolyser. To do this, it is necessary to calculate the production of hydrogen, but to calculate this, it is first necessary to check when the electrolyser is working and producing hydrogen and when the electricity is not used to produce hydrogen but is sold directly into the grid.

Two conditions must be verified simultaneously for the electricity produced from biomass to be sent to the electrolyser for hydrogen production:

1) The first condition to be verified is the hourly willingness to pay of the hydrogen producer. From equation (3.16), the hourly WTP is calculated, which depends on various constants and the hourly hydrogen selling price. At this point, the values obtained are compared with the hourly electricity price in the day-ahead market to verify when condition (3.15) is met. The graph in Figure 3.11 below is obtained.

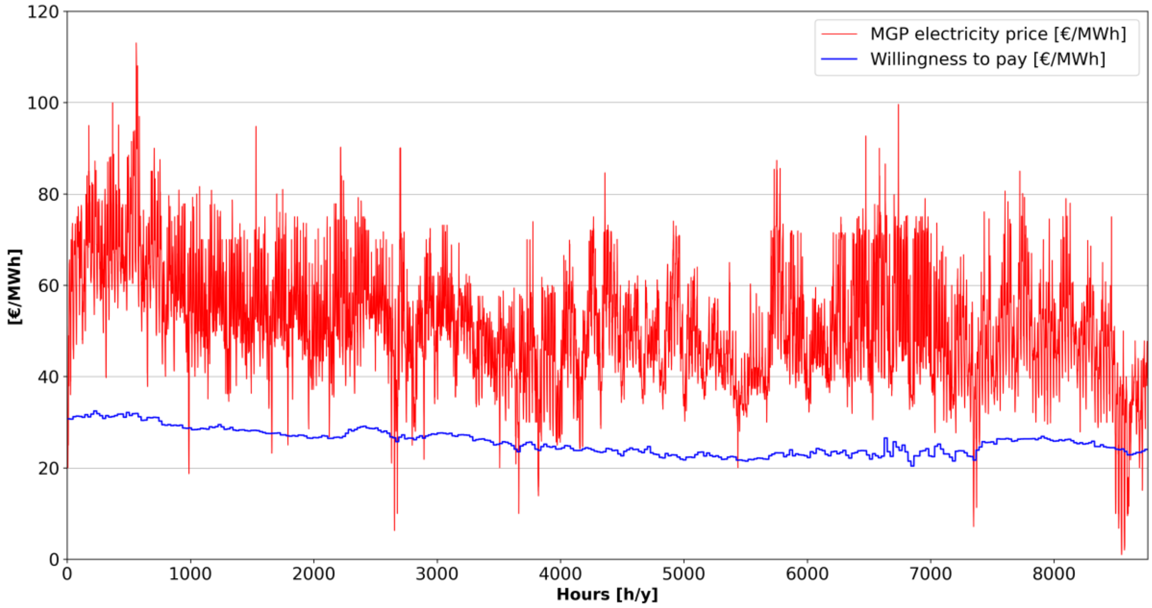

Figure 3.11 – Electricity price and WTP vs hours of the year (without incentive)

It can be seen from Figure 3.11 that the hourly willingness to pay assumes low values within the year and almost constant, being dependent only on the hydrogen sales price, which varies daily with the price of natural gas from GME. It can be seen that condition (3.15) is not met at most times of the year, as the price of electricity is almost always higher than the willingness to pay at various times, and this is due to the fact that willingness to pay is dependent also from total incentive but in the reference case $tot_{inc} = 0\ €/kg_{H2}$ and so the WTP is low;

2) The second condition to be checked is compliance with the minimum load level of the electrolyser, $load_{levelMIN_{\%}}$. From equation (3.17), it is calculated the right term of the equation, which can be called $load_{level_{MIN}} = 1.556\ MW$, which is a constant. At this point, this is compared with the profile of electricity from RES, $electricity_{RES}$, to verify when the condition (3.17) is fulfilled. The graph in Figure 3.12 below is obtained.

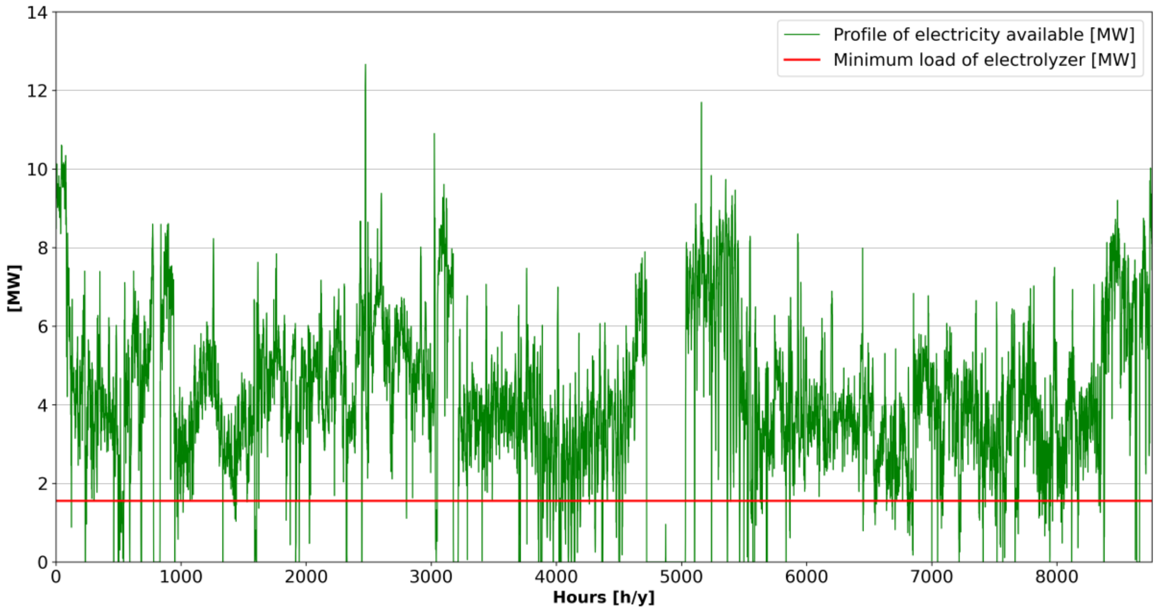

Figure 3.12 – Minimum load of electrolyser and $electricity_{RES}$ profile vs yearly hours

It can be seen that the minimum load level of the electrolyser is respected (so equation (3.17)) in the majority of the annual hours. It can be seen that this condition is less stringent than the one concerning willingness to pay, although it depends on the case study considered;

At this point, the hours of actual use of the electrolyser to produce hydrogen can be determined by cross-referencing the results obtained from the evaluation of the willingness to pay and the minimum load of the electrolyser. In the hours when both these conditions are met, then electricity from the biomass plant is sent to the electrolyser to produce hydrogen, and the hydrogen production in these hours is calculated from equation (3.2), this time in hourly values, by knowing the actual electricity profile at the electrolyser input from eq. (3.18). So, considering the conditions described above, we determine from eq. (3.18) the actual electricity input to the electrolyser $electricity_{in_{EL}}$ in Figure 3.13.

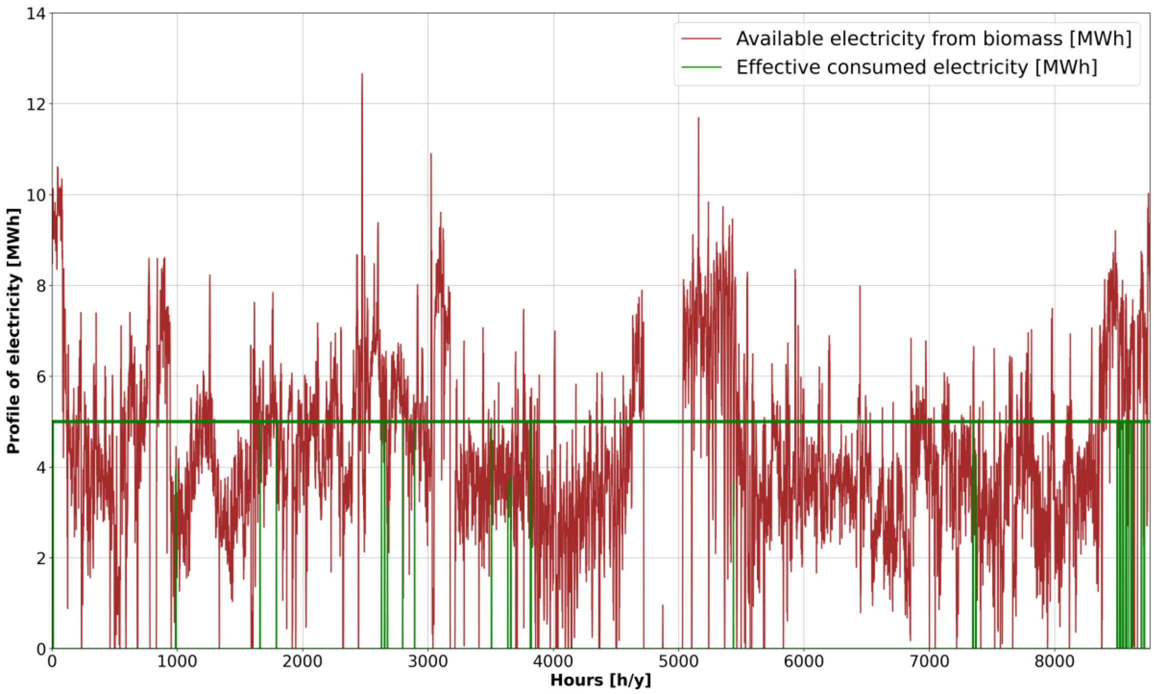

Figure 3.13 – Trend of total available electricity and consumed by electrolyser (without incentive)

Figure 3.13 shows in green the actual profile of electricity input to the electrolyser, which depends, as per eq. (3.18), on $electricity_{RES}$ and electrolyser capacity EL_{cap}, considered to be 5 MW in this case study. In the graph above it can be seen that there is a horizontal line at 5 MWh on the vertical axis of profile of electricity; this line represents the upper limit of electricity in input to the electrolyser for the configuration that is studied. In fact, in this case the producer installs 5 MW of electrolysis and so the maximum amount of electricity that can be put at the inlet of the electrolyser to produce hydrogen in one hour is 5 MWh (which is exactly the upper limit in the graph). Another important thing to see, in addition to the fact that the electrolyser runs for a few hours a year without incentive, is that at times when the electrolyser is running at full load, a certain amount of electricity remains available from the original profile from biomass, and this difference is sent directly to the grid and sold at the MGP electricity price.

At this point, the working conditions of the electrolyser can be known, and Figure 3.14 shows the hours during which the electrolyser operates.

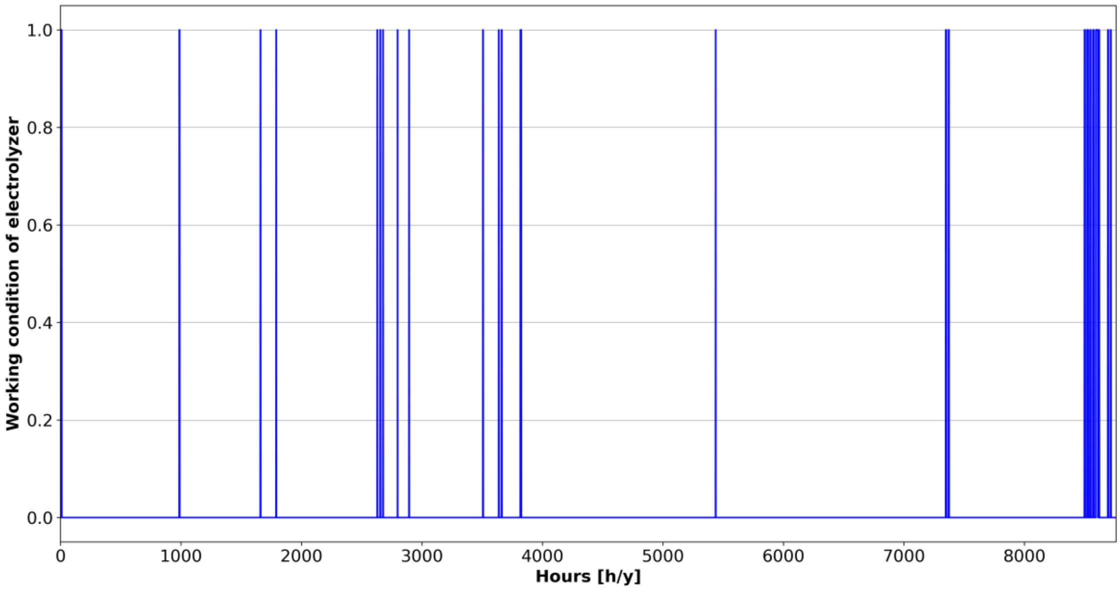

Figure 3.14 – Working conditions of electrolyser vs hours of the year (without incentive)

In the hours when the graph goes to 1, the electrolyser is working, otherwise the electricity from RES is sent directly to the grid. It can be seen that the electrolyser is off (doesn't produce hydrogen) for the most time of the year, only in some hours the electrolyser is on and produce hydrogen, more markedly at the end of the year.

We therefore wish to calculate the equivalent operating hours of the electrolyser; initially, from equation (3.19), we calculate the cumulative electricity input to the electrolyser over the course of a year:

$$electricity_{in_{EL,cum}} = 531\ MWh/y$$

Then, from equation (3.20), the equivalent hours of use of the electrolyser in the reference case are determined:

$$h_{eq_{EL}} = 106\ h/y$$

The number of equivalent operating hours of the electrolyser is very low, and this is due to the fact that, in the absence of an incentive for hydrogen production, it is convenient during most hours of the year to sell the electricity produced from biomass directly into the grid.

From eq. (3.6) the hourly mean selling price of hydrogen can be evaluated. The 2019 profiles of electricity price (from GME) and selling price of H2 are reported in the Figure 3.15 below.

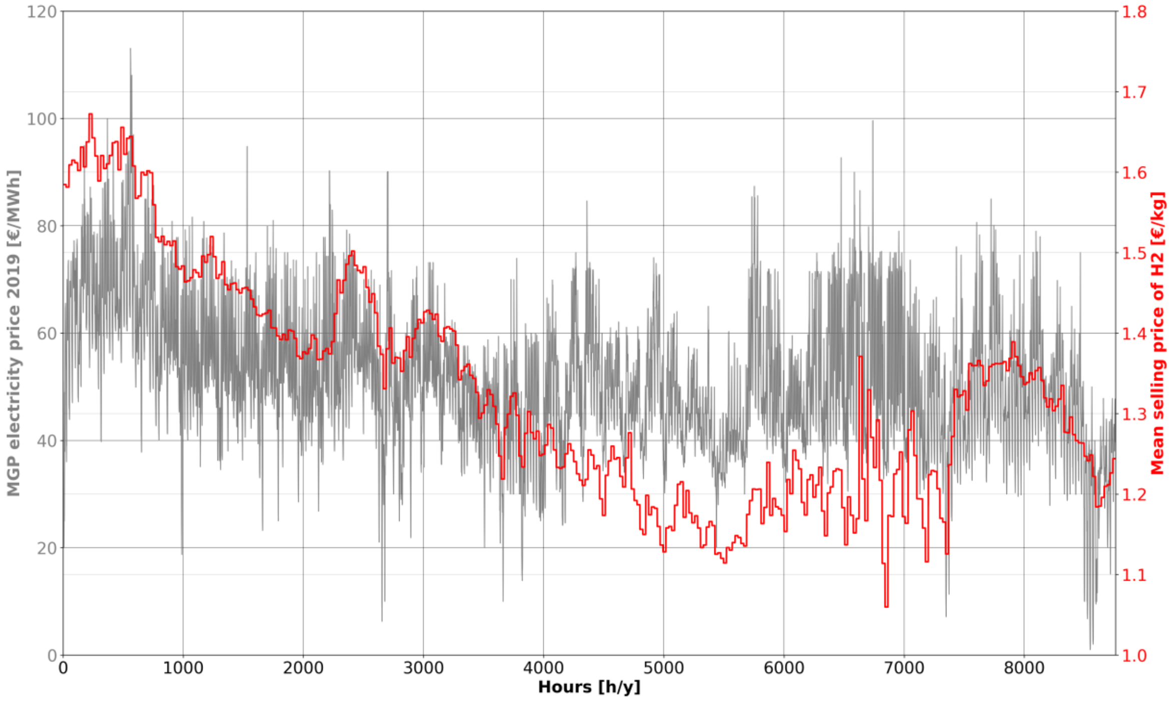

Figure 3.15 – Trend of hourly MGP electricity price and selling price of H2 over the 2019 year

The hourly hydrogen production can then be calculated from equation (3.2) and thus a trend can be defined for the cumulative production in this reference case, which is depicted in Figure 3.16.

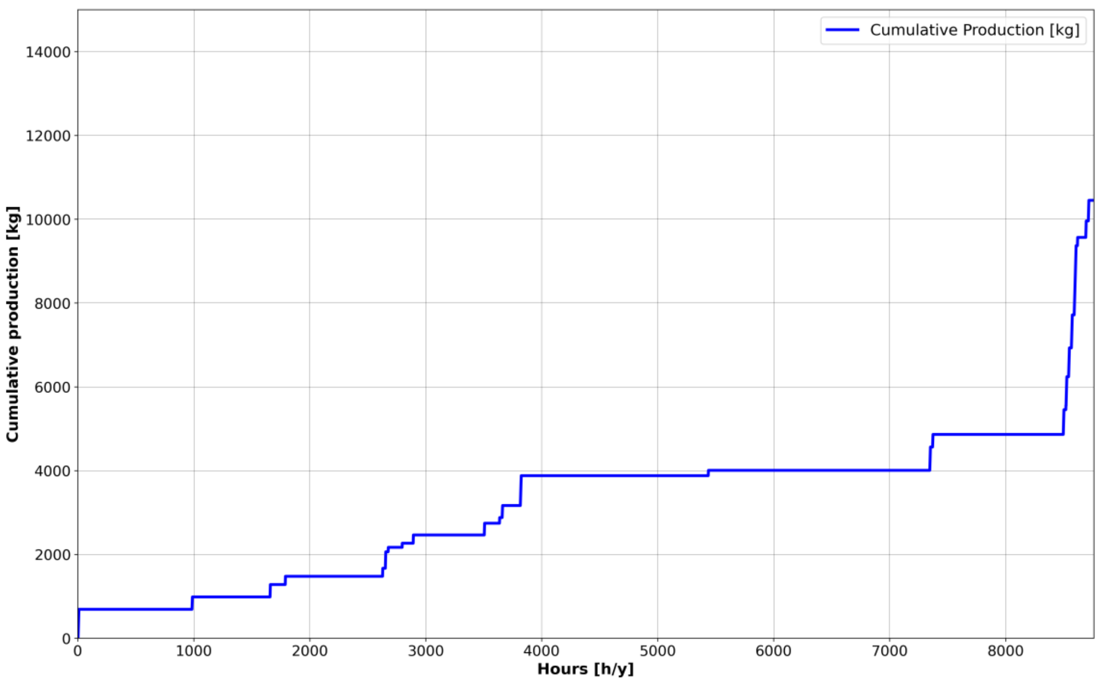

Figure 3.16 – Cumulative production of hydrogen from electrolyser vs the yearly hours

The cumulative annual hydrogen production is then determined using equation (3.21):

$$prod_{H2_{cum}} = 10450\ kg_{H2}/y$$

Comparing Figure 3.13 and Figure 3.16, some considerations can be made:

- Considering an hour where electrolyser is working at full load (5 MWh), the hourly production of hydrogen is about 98.4 kg_{H2}/h;

- In the hours where electrolyser does not work at full load the minimum level of load must be observed because electricity at the inlet must be higher than 30% of electrolysis capacity. For the $electricity_{RES}$ profile chosen, the electrolyser, when operating at part load, never reaches the minimum load level of 30 %, which would correspond to $load_{level_{MIN}} = 1.556\ MWh$ with a $prod_{H2} = 30.69\ kg_{H2}$; on the other hand, during the hours when the electrolyser is operating at partial load, the lowest amount of electricity input to the electrolyser is $2.3\ MWh > load_{level_{MIN}}$, resulting in a production of $45.3\ kg_{H2}/h$;

- The trend of the cumulative production of hydrogen is not a linear trend but it is a step trend, and this is due to the fact that for the most time of the year there is no production of H2 and so there are many periods of the year when cumulative production remains the same;

- In the central part of the year, the cumulative production doesn't increase because there are no favourable situations of electricity price and selling price of hydrogen in order for the electrolyser to work;

- Finally at the end of the year there is a rapidly growing of the cumulative production from about 5000 kg to the final value of cumulative production because the electricity prices in the last hours of 2019 were low (Figure 3.15) and this led to the choice of producing hydrogen instead of feeding electricity into the grid. In fact, in the last 300 hours of the year the cumulative production doubled;

Then, following the model described in section 3.3, the hourly revenue due to the sale of green hydrogen is determined from equation (3.22), and finally the annual revenue due to this contribution from equation (3.23):

$$rev_{sellH2_y} = 13292\ €/y$$

In the reference case under consideration, the most important assumption is that no incentive is given for the production of hydrogen from an electrolyser, so as far as the income from the incentive is concerned, this applies:

$$rev_{inc_y} = 0\ €/y$$

Continuing with the evaluation of the various contributions to the total annual gain for the producer, the contribution related to CAPEX expenditure is calculated from the same equation used for the Excel model as it represents the annual expenditure for the installation of the electrolyser. Thus, from eq.(3.12):

$$CAPEX_{expense} = 377903 \text{ €}/y$$

Finally, as far as the contribution to the total annual profit due to the sale of electricity fed directly into the grid is concerned, this is calculated hourly from equation (3.27), taking into account the hours during which the electrolyser is in operation and also whether or not it is working at full load during these. Then, from eq.(3.28), the annual revenue due to this contribution is determined:

$$rev_{electricity_y} = 1.811 * 10^6 \text{ €}/y$$

The contributions to the total annual gain assessed so far are compared on the graph in Figure 3.17 in order to assess the differences between the contributions qualitatively; the negative contribution related to CAPEX expenditure is omitted from the graph as it is not an hourly contribution and cannot be cumulated over the various hours of the year. The net total gain at the end of the year is then obtained subtracting the $CAPEX_{expense}$ contribution.

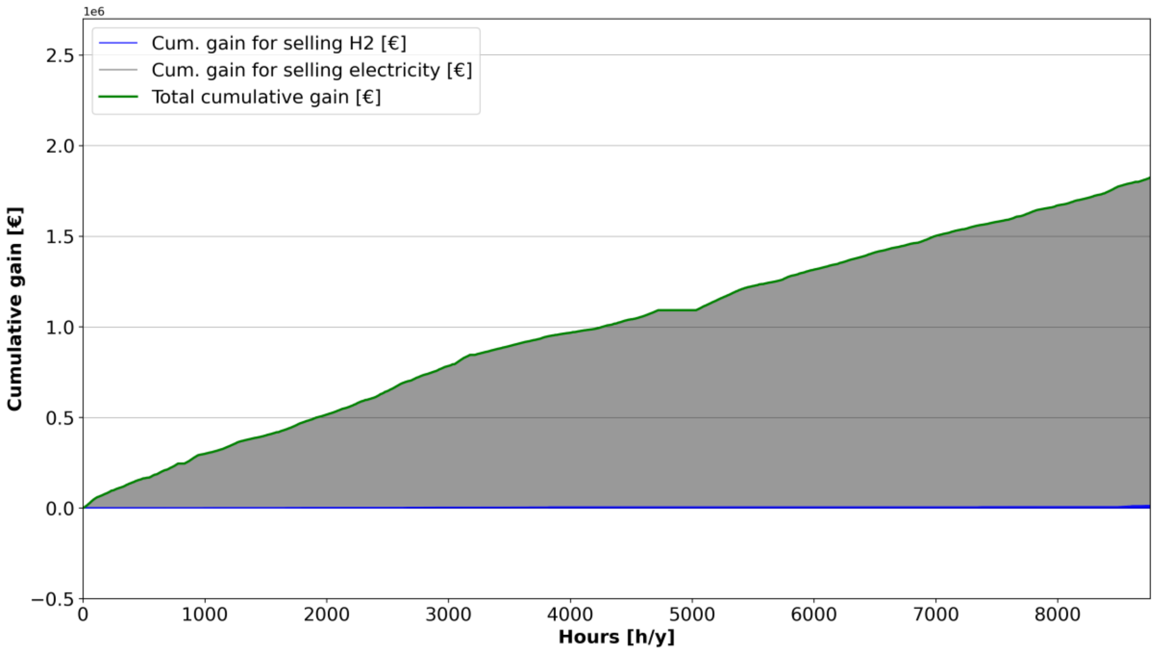

Figure 3.17 – Breakdown of contributions to total yearly gain vs yearly hours

In Figure 3.17 we can visualise how much the relative gain from feeding electricity into the grid (in grey) in this particular configuration equals the total cumulative gain at the end of the year, without considering $CAPEX_{expense}$. In fact, the share of profit related to the sale of hydrogen (in blue) is practically negligible when compared to that of electricity sales, since the number of equivalent hours of the electrolyser is very low and consequently the annual production of hydrogen is low, as is the associated revenue. A slight increase in the share of hydrogen sales can be seen in the latter part of the year (in Figure 3.18 a zoom has been made to better visualize this increase), but this is not enough to think of a net gain from hydrogen sales due to the installation of 5 MW of electrolysis. The total cumulative gain, in green, follows the trend of the revenue from electricity fed in as the sale of hydrogen is almost nil in comparison.

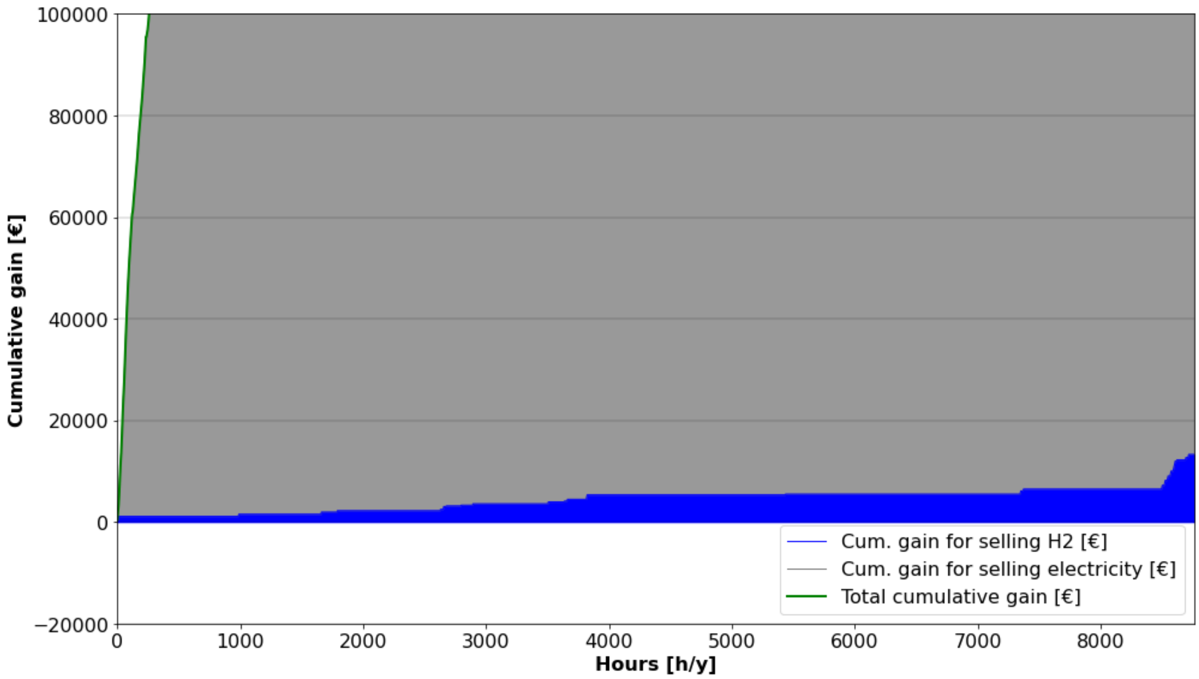

Figure 3.18 – Zoom of Figure 3.17 to see the increase of sale of Hydrogen in the last part of the year

Finally, considering $CAPEX_{expense}$, the total annual gain by the hydrogen producer can be calculated from equation (3.14), and this results:

$$gain_y = 1.446 * 10^6 \text{ €}/y$$

Where this $gain_y$ represents the amount in terms of €/y that the producer earns over the year with the assumptions made and without incentive scheme on hydrogen production.

3.5.2.1 Sensitivity analysis on the electrolyser size: no incentive

Now that the reference case has been analysed, we want to perform a first sensitivity analysis of this configuration by changing the electrolyser size, as mentioned in the introduction to chapter 3.5.

The simulation made for the reference case without incentive scheme assumed the installation by the producer of 5 MW of electrolysis capacity; however, we want to analyse various situations with the same basic assumptions but different installed capacity values. The sizes used for this sensitivity analysis are as follows:

- $0\ kW$;
- $1000\ kW$;
- $2500\ kW$;
- $7500\ kW$;
- $10000\ kW$;

The base case of installing 5 MW of electrolysis capacity was taken as the best value of a previous study on green hydrogen production based on the same biomass electricity profile as this simulation. The other values in the analysis are taken to see how the gain varies in case a producer decides to invest less or more in electrolysis capacity, always paying attention to the electricity profile without overestimating the plant and not to make it always work at partial load.

In fact, for the analysis, the maximum size of the electrolyser, $10\ MW$, was chosen in accordance with the profile of available electricity from biomass (Figure 3.13), as this only exceeds the $10\ MWh$ limit in a few hours of the year, so choosing an even larger size would have meant working practically all year round at partial load and the result would have been an over-dimensioning of the plant.

The other sizes were chosen in order to have a range to be displayed in the results of the total yearly gain divided into the various contributions, by including central sizes smaller or larger than 5 MW. Finally, we also want to see the case in which, in a non-incentivised situation, the 'producer' decides not to install any electrolysis capacity and instead decides to feed all the energy into the electricity grid at the price of electricity in the day-ahead market.

Now that the various cases for electrolyser size have been defined for the sensitivity analysis, in a situation where the selling price of hydrogen is the average price in the various demand sectors and no incentive is given to either the investment or the operation of the plant, results are shown in terms of:

- Total cumulative gain in the year divided into the various shares (Figure 3.19);
- The percentage of electrical energy consumed by the electrolyser for hydrogen production or sent directly to the grid (Figure 3.20);

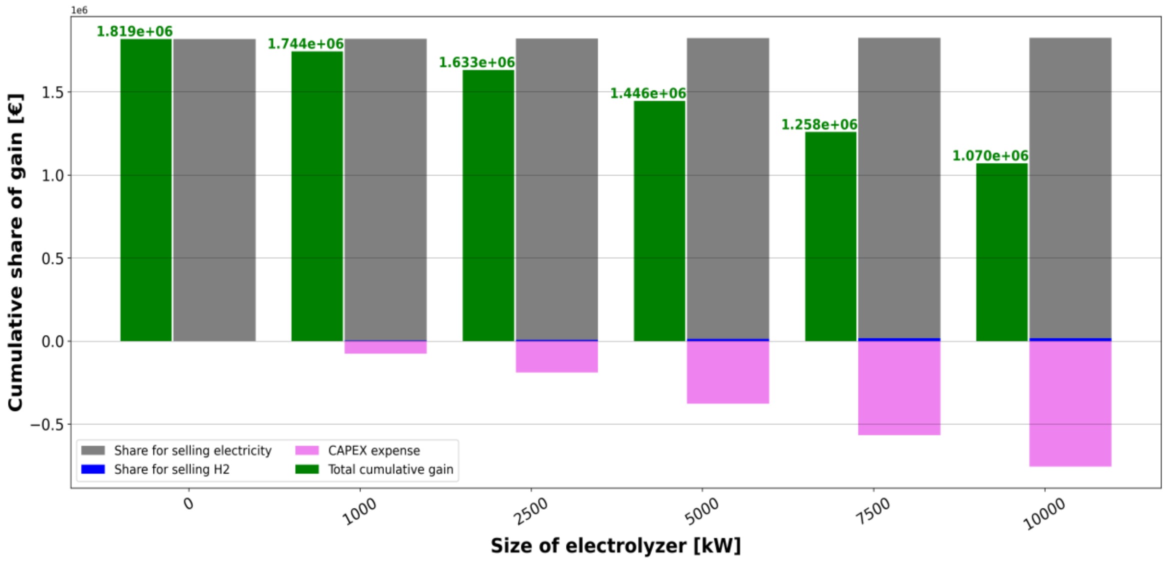

Figure 3.19 – Shares of gain at the end of the year for different sizes of electrolyser

The diagram in Figure 3.19 shows the annual total gain (green bar) with the various positive contributions (in grey the revenue due to selling electricity to the grid, in blue the revenue due to selling hydrogen) and the CAPEX expense (pink bar) for the different electrolyser sizes analysed in this sensitivity analysis.

Some considerations can be made on the graph above:

- If the owner of the biomass plant decides not to install an electrolysis capacity (case where the capacity is $0\ kW$) it can be seen that, with the assumptions made and without incentive scheme on green hydrogen production, he gets the maximum cumulative total gain of all the various configurations, which in this case will be equal only to the share from the sale of electricity directly to the grid. Since there is no expense for the electrolysis plant in this case, the actual gain is equal to the revenue from electricity sold to the grid, so:

$$rev_{sellH2y_{0kW}} = 0\ €/y$$

$$CAPEX_{expense_{0kW}} = 0\ €/y$$

$$gain_{y_{0kW}} = rev_{electricity_{0kW}} = 1.819 * 10^6\ €/y$$

- As the size of electrolyser increases, i.e., in cases where an electrolyser is installed for hydrogen production, the profit share related to the sale of hydrogen increases. However, this growth is very low going from 1000 kW to 10000 kW installed, and this is due to the fact that the operating hours of the electrolyser remain constant as the size increases, furthermore, the selling price of hydrogen varies in the same way in the various simulations of the analysis done; here in fact the only thing that changes is the cumulative production of hydrogen, which increases as the size of the electrolyser increases in that, for example, a larger hourly production is allowed for the 7500 kW case than for the 2500 kW case in the hours when full load would be worked with this second electrolyser. In fact, a 7500 kW electrolysis plant would allow the achievement of a larger production than the 2500 kW plant, and this is a consequence of the relative increase in gain from hydrogen sales by increasing the size. In fact, going from 1000 kW to 10000 kW:

$$rev_{sellH2_{y_{1000kW}}} = 2828\ €/y$$

$$rev_{sellH2_{y_{10000kW}}} = 16886\ €/y$$

In any case, revenues from the sale of hydrogen are relatively very low compared to the sale of electricity fed into the grid that is in the order of M€:

$$rev_{electricity_{y_{1000kW}}} = 1.817 * 10^6\ €/y$$

$$rev_{electricity_{y_{10000kW}}} = 1.809 * 10^6\ €/y$$

Therefore, as expected, as the size increases, the revenue from electricity decreases and, furthermore, the increase in rev_{sellH2_y} is greater than the increase in loss revenue from electricity sales $rev_{electricity_y}$;

- As the size of the electrolyser increases, the CAPEX expense related to the investment in the electrolysis plant increases; to give an example, from 1000 kW to 10000 kW, the investment increases 10 times:

$$CAPEX_{expense_{1000kW}} = 75581\ €/y$$

$$CAPEX_{expense_{10000kW}} = 755806\ €/y$$

- One of the most evident results in this graph concerns the actual gain (in green), which is the sum of the two shares related to electricity and hydrogen sales minus the CAPEX expense. In fact, as the size increases, one notices a rapid decrease in the actual gain, and this is due to the fact that the sale of the hydrogen produced is not enough to balance or even surpass the CAPEX expenditure. While with the first sizes (1000 kW and 2500 kW) the actual gain is not too far from the base value without electrolysis plant (0 kW), it can be seen that with a large size (10000 kW) there is a collapse in the actual gain compared to the configuration without electrolyser. Considering:

$$rev_{electricity_{y_{10000kW}}} = 1.809 * 10^6\ €/y$$

$$gain_{y_{10000kW}} = 1.070 * 10^6\ €/y$$

That is very lower with respect to $gain_{y_{0kW}} = 1.819 * 10^6$ €$/y$;

It follows that without an incentive on production or on investment it is better for a producer, for the configuration studied, not to install electrolysis capacity and feed all the electricity produced from biomass directly into the grid (the case of 0 kW has the highest gain).

Now we want to study the behaviour of electricity produced from biomass in terms of the percentage of electricity sold to the grid and consumed in the various size configurations, as this provides support for the graph in Figure 3.19 for determining the various contributions to earnings on the basis of the electricity that is consumed to produce hydrogen and that fed directly into the grid.

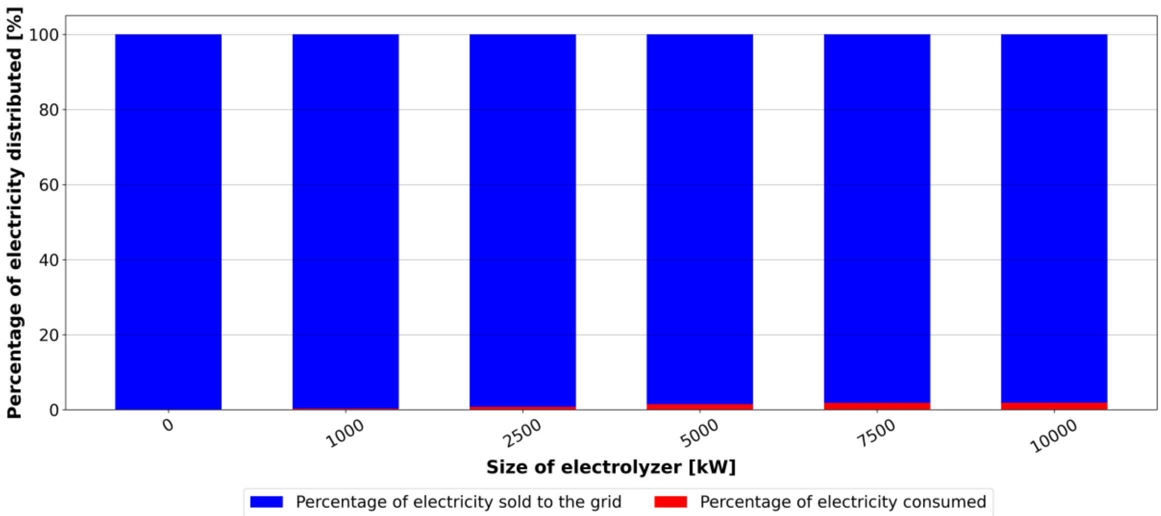

Figure 3.20 – Percentage distribution of available electricity to the electrolyser and grid sale for different sizes of electrolyser

The graph in Figure 3.20 explains why in Figure 3.19 the revenue share from the sale of hydrogen remains very low as the size of the electrolyser increases. In fact, as the size increases, the electricity consumed by electrolyser for hydrogen production grows very little as a percentage of the electricity produced by the biomass plant respect to the electricity fed directly into the grid and sold at the day-ahead market price. This is due to the fact that, during most of the annual period, the willingness to pay is lower than the day ahead market price of electricity (Figure 3.11Figure 3.12) and this results in direct feed-in rather than consumption to produce hydrogen. The increase in size does not lead to a substantial increase in the electricity consumed for electrolysis as the hours of operation are the same. What changes is that, in the hours of operation at full load of an electrolyser of a smaller size, the energy consumed and so the produced hydrogen is lower than considering the hours of operation at full load of an electrolyser of higher size, since equation (3.2) applies.

The increase in yearly electricity consumed from a 2500 kW size to 5000 kW is not the same as from 7500 kW to 10000 kW. The jump is different in that with 2500 kW installed capacity the electrolysis plant is undersized in relation to the profile of electrical energy available from biomass, so increasing the size to 5000 kW is very favourable from this point of view, in fact:

$$electricity_{in_{EL,cum_{2500kW}}} = 282\ MWh/y$$

$$electricity_{in_{EL,cum_{5000kW}}} = 531\ MWh/y$$

The electrical consumption at the electrolyser is almost doubled (with a consequent increase in hydrogen produced), whereas the change from 7500 kW to 10000 kW (with the same previous jump in kW) leads to:

$$electricity_{in_{EL,cum_{7500kW}}} = 655\ MWh/y$$

$$electricity_{in_{EL,cum_{10000kW}}} = 670\ MWh/y$$

In this case the increase in percentage of electricity consumed by the electrolyser is equal to 2.24%, due to the fact that an electrolysis plant of 10000 kW for this profile of available electricity is not well sized. This very small increase does not bring concrete advantages, therefore not even from the point of view of hydrogen produced as the investment is such as to overwhelm the share of profit relating to the sale of hydrogen.

3.5.2.2 Sensitivity analysis on the hydrogen selling price: no incentive

Now we want to perform a second sensitivity analysis of this configuration by changing the selling price of hydrogen, as mentioned in the introduction to chapter 3.5.

The simulation made for the reference case without incentive scheme assumed a selling price of hydrogen averaged in the various sectors of demand and variable daily based on the price of natural gas in the day-ahead-market; however, we want to analyse various situations with the same basic assumptions (installation of 5000 kW of electrolysis capacity as reference case) but with different selling prices of hydrogen. The selling prices used for this sensitivity analysis are as follows:

- $1\ €/kg_{H2}$;
- $2\ €/kg_{H2}$;
- $3\ €/kg_{H2}$;
- $4\ €/kg_{H2}$;

- $5\ €/kg_{H2}$;
- $6\ €/kg_{H2}$;

The values are chosen deviating from the average prices used for the reference case (which vary daily in the range of $1 \div 2\ €/kg_{H2}$ throughout the year).

$1\ €/kg_{H2}$ was chosen as the lowest value since even assuming a low price of natural gas it must be considered that this product is green hydrogen and therefore cannot be sold below a limit value, considering also the ETS market. The Emissions Trading System (ETS) is a market-based mechanism designed to reduce greenhouse gas emissions. It operates by setting a cap on the total amount of certain greenhouse gases that can be emitted by covered entities and then allocates or auctions off allowances that represent the right to emit a specific volume of those gases. Companies are required to return allowances equivalent to the number of emissions they produce, and if they emit more than their allotted amount, they must purchase additional allowances. The ETS is implemented at the European level and covers more than 11,000 power plants and industrial facilities in 31 countries.

Within the cap, companies receive or buy emission allowances, which they can trade as needed. The cap decreases every year, ensuring that total emissions fall [74].

As regards the upper values, they were chosen to make a comparison of the gain contributions and the distribution of the electrical energy available from biomass. Furthermore, the higher selling prices ($5 \div 6\ €/kg_{H2}$) can be hypothesized on the basis of the fact that for a company operating in the sector that needs hydrogen for the production chain, the fact of buying green hydrogen brings benefits in terms of quotas of ETS emissions described before, and therefore this company could be willing to accept to buy green hydrogen at a higher price instead of the grey one from SMR in order not to exceed the emission limits and thus also have ETS quotas to be able sell to get income.

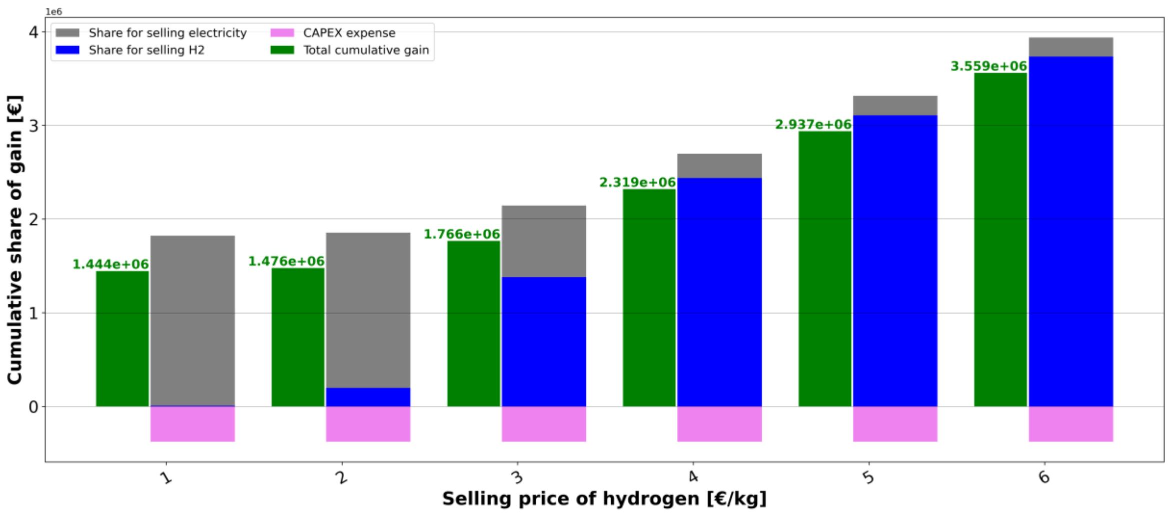

Figure 3.21 - Shares of gain at the end of the year for different selling price of hydrogen

In Figure 3.21 some considerations can be done:

- Firstly, it can be seen that, as the price of hydrogen increases, the revenue from the sale of hydrogen obviously increases; however, the increase does not occur continuously, as the revenue depends on the sale price and the production of hydrogen. The selling price is the sensitivity parameter that is made to vary, however hydrogen production, as described in section 3.3, depends on the operating hours of the electrolyser. The equivalent operating hours of the electrolyser, unlike in the previous sensitivity analysis on electrolyser size (3.5.2.1), here vary with the selling price of H2 as the hourly willingness to pay varies with this parameter (eq.(3.16)). The hourly willingness to pay may consequently become higher than the electricity price in the day-ahead market and cause an increase in the equivalent operating hours of the electrolysis plant.
  For example, going from a selling price of 1 $€/kg_{H2}$ to 2 $€/kg_{H2}$ the equivalent operating hours change a lot:

  $$h_{eq_{EL_{1€/kg}}} = 63\ h/y$$

  $$h_{eq_{EL_{2€/kg}}} = 998\ h/y$$

  And consequently the revenue for selling H2 results in:

  $$rev_{sellH2_{y_{1€/kg}}} = 6244\ €/y$$

  $$rev_{sellH2_{y_{2€/kg}}} = 196367\ €/y$$

  This increase in rev_{sellH2} is relatively low considering the same price difference as hydrogen but for higher selling prices, in fact for $3€/kg_{H2}$:

  $$h_{eq_{EL_{3€/kg}}} = 4674\ h/y$$

  $$rev_{sellH2_{y_{3€/kg}}} = 1.380 * 10^6\ €/y$$

  This sharp increase is due to the fact that, with low hydrogen sales prices, the producer's willingness to pay remains, for most hours of the year, lower than the price of electricity in the day-ahead market and therefore it is more profitable for the producer to sell electricity directly to the grid than to produce hydrogen; however, if the sales price reaches a value where WTP is greater than $p_{el_{MGP}}$ in most hours of the year, then the revenue rev_{sellH2} increases by a large amount, making hydrogen production much more profitable than selling electricity to the grid. Between $5€/kg_{H2}$ and $6€/kg_{H2}$ operating hours do not increase because WTP at certain times of the year is still lower than electricity prices in the day-ahead market, even in the face of high hydrogen sales prices; thus, the growth of

rev_{sellH2} is only due to the increase in the sales price and not to the increase in hydrogen production;

- The revenue from the sale of electricity to the grid is maximum for a minimum H2 sale price of 1 $€/kg_{H2}$, equal to:

$$rev_{electricity_{y}}{}_{1€/kg} = 1.815 * 10^6\ €/y$$

As the selling price of hydrogen increases, as the operating hours of the electrolyser increase, the electricity sent to the grid decreases and thus the revenue from the sale of electricity to the grid decreases. At hydrogen selling prices of $5€/kg_{H2}$ and $6€/kg_{H2}$ the revenue share from the sale of electricity remains more or less the same as the operating hours of the electrolyser remain practically constant at these hydrogen selling prices; in fact:

$$rev_{electricity_{y}}{}_{5€/kg} = 208328\ €/y$$

$$rev_{electricity_{y}}{}_{6€/kg} = 204206\ €/y$$

- As the selling price of hydrogen increases, the CAPEX expense related to the investment in the electrolysis plant remains constant, because this depends on the electrolyser size and not on the working conditions of electrolyser or on prices; so:

$$CAPEX_{expense} = 377903\ €/y$$

- Thus, the total annual gain increases as the hydrogen selling price increases, because revenue for selling H2 increases, with almost linear increases in the case of $p_{H2_{avg}} > 3\ €/kg_{H2}$; with low hydrogen prices, the total gain increase is small:

$$gain_{y_{1€/kg}} = 1.444 * 10^6\ €/y$$

$$gain_{y_{2€/kg}} = 1.476 * 10^6\ €/y$$

While with higher hydrogen selling prices the total gain increase is more substantial:

$$gain_{y_{4€/kg}} = 2.319 * 10^6\ €/y$$

$$gain_{y_{5€/kg}} = 2.937 * 10^6\ €/y$$

It follows that, considering the installation of 5 MW of electrolysis capacity, without an incentive scheme on the production of hydrogen, the producer can still obtain a greater total $gain_y$ than if he does not install electrolysis capacity and thus send all the electricity produced by biomass into the grid; in fact, remembering:

$$gain_{y_{0kW}} = rev_{electricity_{0kW}} = 1.819 * 10^6 \text{ €}/y$$

With a $p_{H2_{avg}} \geq 4 \text{ €}/kg_{H2}$, a higher gain ($gain_{y_{4€/kg}}$) is achieved than if all the electricity produced is fed into the grid (for 0 kW of electrolysis, evaluated in 3.5.2.1).

Now we want to see the behaviour of electricity produced from biomass in terms of percentage of electricity sold to the grid and consumed by electrolyser for different selling prices of hydrogen, as this provides support for the graph in Figure 3.21 for determining the various contributions to total earnings.

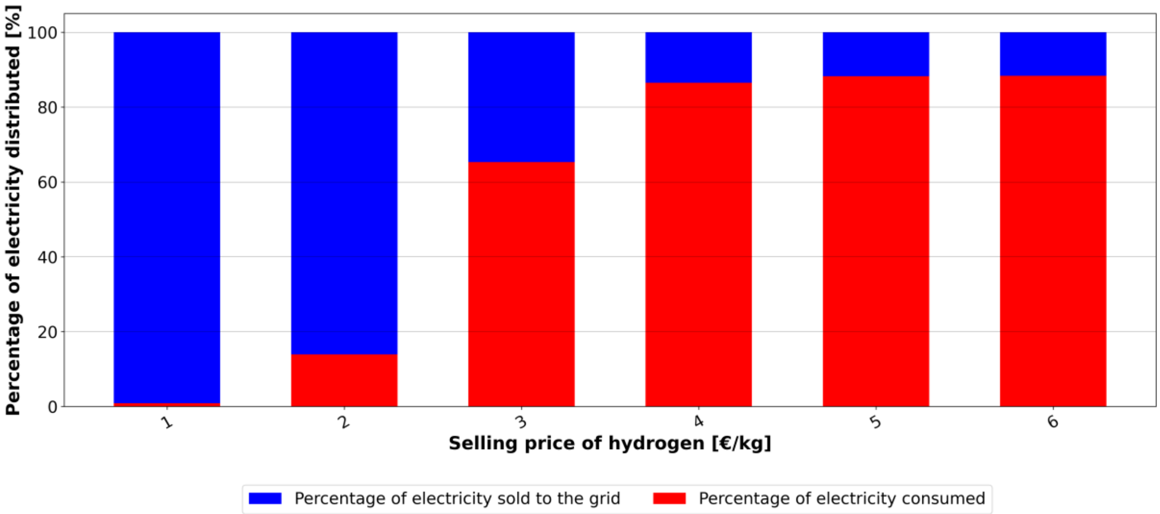

Figure 3.22 - Percentage distribution of available electricity to the electrolyser and grid sale for different selling prices of hydrogen

The graph in Figure 3.22 represents the percentage distribution of electricity produced from biomass in grid or in electrolyser. In this sensitivity analysis, where 5 MW of electrolysis capacity is fixed, the revenue share from the sale of hydrogen increases as the selling price of hydrogen increases. In fact, as the selling price increases, the electricity consumed by electrolyser for hydrogen production grows a lot as a percentage of the electricity produced by the biomass plant respect to the electricity fed directly into the grid and sold at the day-ahead market price.

This is due to the fact that the willingness to pay becomes higher than the price of electricity in the day-ahead market at more and more times of the year as the selling price of H2 increases. This graph supports the graph in Figure 3.21, as we can see that as $p_{H2_{avg}}$ increases, the energy input to the electrolyser increases because the operating hours of the electrolyser increase. However, this percentage does not increase linearly because, with the same difference in selling price of $1\ €/kg_{H2}$, going from $2\ €/kg_{H2}$ to $3\ €/kg_{H2}$ the percentage of energy consumed increases by a lot compared to going from $4\ €/kg_{H2}$ to $5\ €/kg_{H2}$, this is because in the first case the operating hours increase by a lot and consequently the revenue from the sale of hydrogen makes the biggest jump. One therefore has, in numbers:

$$electricity_{in_{EL,cum_{2€/kg}}} = 4990\ MWh/y$$

$$electricity_{in_{EL,cum_{3€/kg}}} = 23372\ MWh/y$$

The electricity fed to the electrolyser with $p_{H2_{avg}} = 3\ €/kg_{H2}$ is almost five times that fed with $p_{H2_{avg}} = 2\ €/kg_{H2}$, whereas the change from $4\ €/kg_{H2}$ to $5\ €/kg_{H2}$ (with the same previous jump in $€/kg_{H2}$) leads to:

$$electricity_{in_{EL,cum_{4€/kg}}} = 30961\ MWh/y$$

$$electricity_{in_{EL,cum_{5€/kg}}} = 31579\ MWh/y$$

In this case the increase in percentage of electricity consumed by the electrolyser is equal to 1.99%, due to the fact that for high selling price of hydrogen the number of equivalent operating hours remains more or less constant. In all situations considered for the sensitivity analysis, there is never a condition that all electricity produced from biomass is sent to the electrolyser for hydrogen production. This is due to the fact that, with the assumption of 5 MW installed electrolyser and the biomass electricity profile considered, even if the conditions for hydrogen production are fulfilled, there is still a difference between the electricity produced from biomass and the maximum amount of electricity that the electrolyser can have as input, and this difference is sold to the grid.

3.5.3 Base case with incentive

Now we want to define the base case of the Python analysis, which will be evaluated in its entirety before proceeding with the sensitivity analysis for the various parameters described above.

The base case is defined as the case in which a producer of electricity from biomass decides to install an electrolyser with a capacity of 5 MW to produce hydrogen in presence of the incentive scheme described in chapter 2. This base case represents the heart of this analysis because it is intended to demonstrate the actual functioning of the incentive scheme and in fact will then be compared with the reference case without incentive to assess the effectiveness of this scheme in order to obtain a higher annual gain from the installation of the electrolysis plant than from sending all electricity to the grid. Thus, in the base case, the CAPEX part of incentive is fixed by the state (hp. in 3.5.1):

$$CAPEX_{inc} = 3.26\ \frac{€}{kg_{H2}}$$

While the operative part of incentive depends on various hourly parameters, as equation (3.8) said.

We then follow the model described in paragraph 3.3 for the determination of the total gain for the producer. So, initially we calculate the production of hydrogen, and to calculate this it is first necessary to check when the electrolyser is working and producing hydrogen and when the electricity is not used to produce hydrogen but it is injected directly into the grid.

The same two conditions of previous paragraph (3.5.2) must be verified simultaneously for the electricity produced from biomass to be sent to the electrolyser for hydrogen production:

1) The first condition to be verified is the hourly willingness to pay of the hydrogen producer. So from equation (3.16), the hourly WTP is calculated but, since the willingness to pay in the base case also depends on the total incentive paid, and this depends on the hydrogen production, which in turn depends on the willingness to pay, the calculation of the electricity input to the electrolyser and consequently of the hourly hydrogen production is iterative. The iteration begins by evaluating an hourly hydrogen production considering that the incentive is present all year round without limitations; then the willingness to pay is calculated and on the base of this and of the minimum level of load of electrolyser, the new production of hydrogen is determined from equation (3.2). Finally, the maximum incentivable production is set and the final willingness to pay is recalculated accordingly.

   So WTP is finally calculated, and the values obtained are compared with the hourly electricity price in the day-ahead market to verify when condition (3.15) is met. The graph in Figure 3.23 below is obtained.

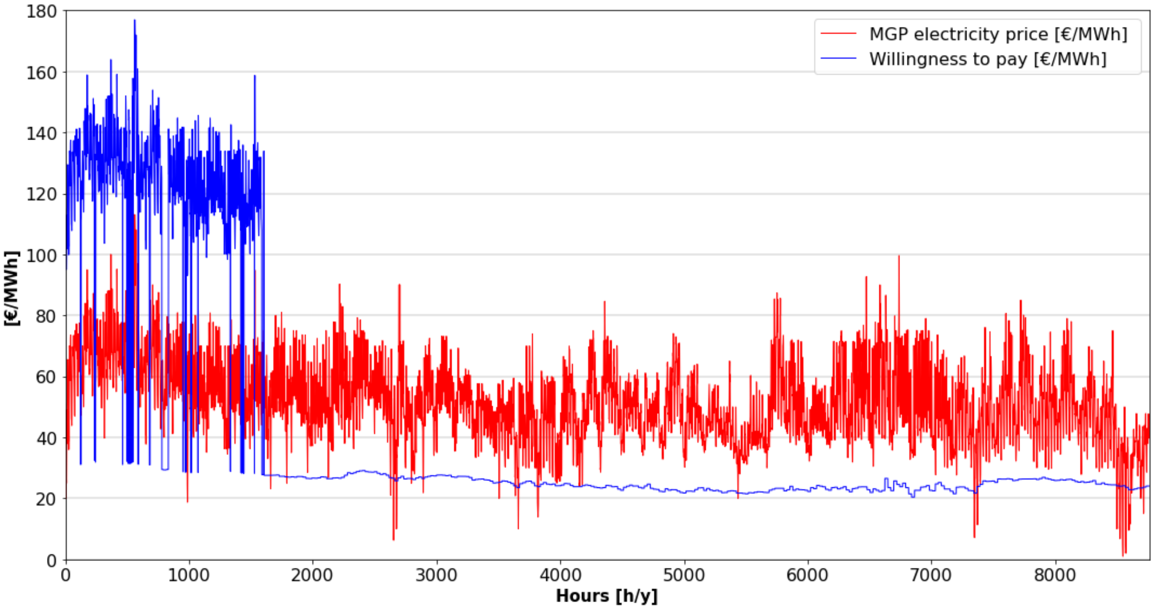

Figure 3.23 – Electricity price and WTP vs hours of the year (with incentive)

It can be seen from Figure 3.23 that the hourly willingness to pay takes on very high values, in the order of $120 - 130\ €/MWh$, in the first part of the year when the incentive is paid to the producer for the production of hydrogen from electrolyser; in this period, condition (3.15) is verified most of the time. However, not in all hours of the first period the condition is fulfilled, as there are some hours when WTP drops and becomes less than $p_{el_{MGP}}$ and therefore in these hours the hydrogen is not produced and the electricity is all sold to the grid. The most important and significant thing to see in this graph is that, at a certain point, after 1574 hours of the year, the WTP drops dramatically and becomes equal to the WTP seen in the reference case without the incentive; this is due to the fact that the producer reaches the $prod_{H2_{max,inc}}$(eq. (3.25)), and therefore after these hours of the year the incentive is no longer distributed to the hydrogen producer. In fact, in the second part of the graph, the WTP remains steadily below the $p_{el_{MGP}}$, and consequently condition (3.15) is not met, except for a few hours especially concentrated towards the end of the year;

2) The second condition to be checked is compliance with the minimum load level of the electrolyser, $load_{levelMIN_{\%}}$. From equation (3.17), it can be seen that there are no terms that vary with respect to the reference case without an incentive and therefore, as far as this condition is concerned, the same graph in Figure 3.12 can be evaluated and the same conclusions can be drawn; in fact, in the majority of the hours of the year, condition (3.17) is fulfilled as the electricity profile only at certain times of the year is below $level_{load_{MIN}}$;

After verifying the two conditions, the hours of actual use of the electrolyser to produce hydrogen can be determined. In the hours when both these conditions are met, then electricity from the biomass plant is sent to the electrolyser to produce hydrogen, and the hydrogen production in these hours is calculated from equation (3.2) by knowing the actual electricity profile at the electrolyser input from eq. (3.18). So, considering the conditions described above, we determine from eq. (3.18) the actual electricity input to the electrolyser $electricity_{in_{EL}}$ and this is compared with the total available electricity from biomass ($electricity_{RES}$) in Figure 3.24.

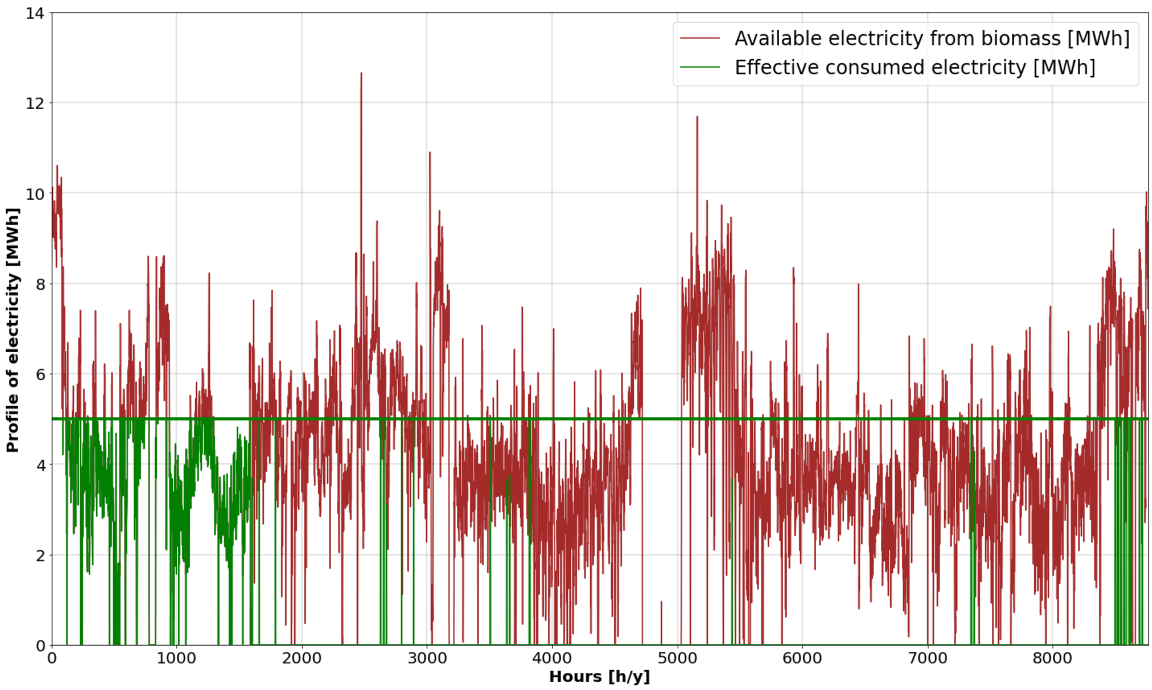

Figure 3.24 – Trend of total available electricity and consumed by electrolyser (with incentive)

Figure 3.24 shows the actual profile of electricity input to the electrolyser, which depends, as per eq. (3.18), on $electricity_{RES}$ and electrolyser capacity EL_{cap}, considered to be $5\ MW$ in this case study. From the graph, it can be seen that the electrical energy at the input of the electrolyser has increased greatly with the application of the incentive scheme compared to the graph in Figure 3.13 referring to the reference case. This is due to the fact that the willingness to pay in this case, for the first part of the year when production has not yet reached $prod_{H2_{max,inc}}$, is above $p_{el_{MGP}}$ and thus the operating hours of the electrolyser are increased considerably from the reference case, as can be seen in Figure 3.25.

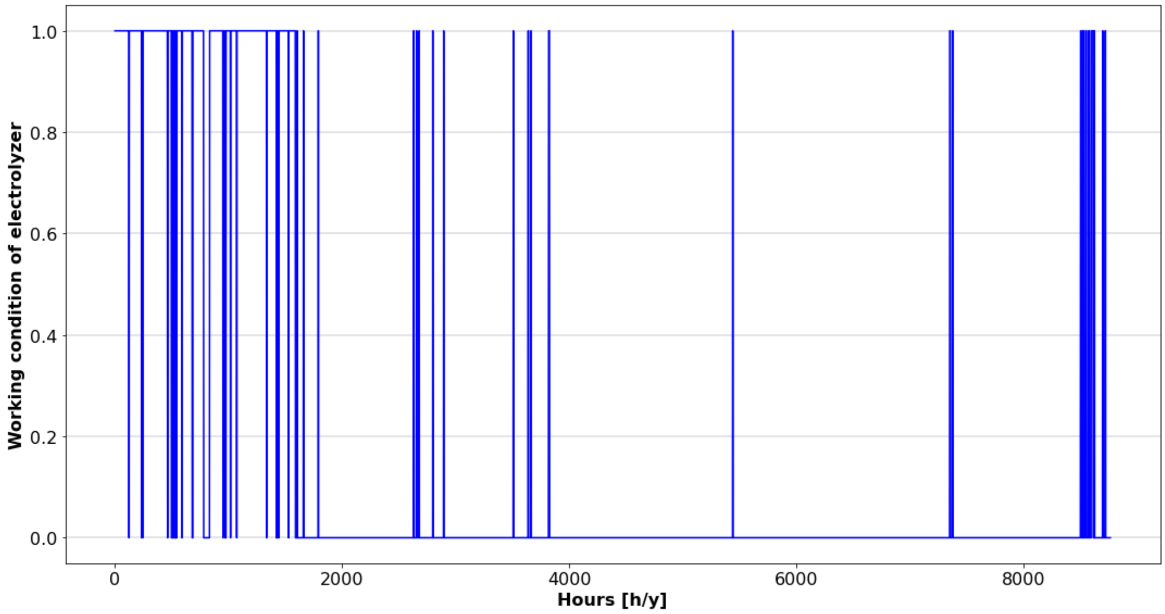

Figure 3.25 – Working conditions of electrolyser vs hours of the year (with incentive)

It can be seen in Figure 3.25 how the hours of operation of the electrolyser, and thus of hydrogen production, have increased significantly in the first 1500 hours of the year; this result is a consequence of the calculation of WTP seen in Figure 3.23, as the electrolyser operates in the first part of the year when condition (3.15) is fulfilled. In the other times of the year, the electrolyser only operates at times when the electricity price is so low that it is less than the WTP without incentive, as in the last hours of the year.

Then, we calculate from the Python model, via equation (3.19), the actual annual electricity at the input of the electrolyser, which results:

$$electricity_{in_{EL,cum}} = 6359\ MWh/y$$

Then, from equation (3.20), the equivalent operating hours of the electrolyser in the base case are determined:

$$h_{eq_{EL}} = 1272\ h/y$$

The number of equivalent operating hours of the electrolyser has increased greatly compared to the value of 106 h/y in the base case, and this increase is related to the contribution of the incentive in fulfilling condition (3.15). The average selling price of hydrogen is the same as in the reference case, hence the same as in Figure 3.15.

One of the most important things to see when considering the base case with an incentive, even before the actual annual gain by the producer, is the evaluation of the effectiveness of the incentive scheme applied and Figure 3.26 supports this assessment.

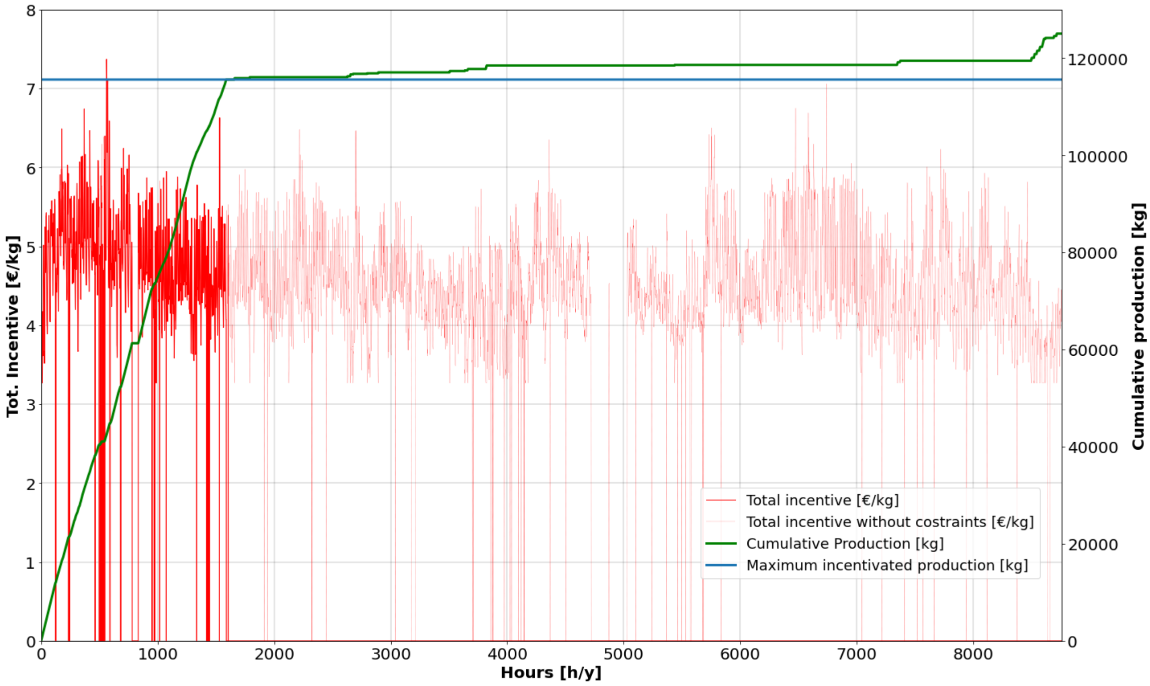

Figure 3.26 – Total incentive and cumulative production of hydrogen vs hours of the year

In Figure 3.26 some considerations can be made:

- The total incentive tot_{inc} (equation (3.9)) is given in the first part of the year in the hours in which conditions (3.15) and (3.17) for hydrogen production are met; from the 1604th hour of the year, the hour in which the maximum production which can be incentivised $prod_{H2_{max,inc}}$ (in blue) is reached according to the assumptions made, the incentive is no longer given for hydrogen production and therefore $tot_{inc} = 0\ €/kg_{H2}$;

- The cumulative hydrogen production in the base case, unlike in the reference case (Figure 3.16), has an almost linear course until $prod_{H2_{max,inc}}$ is reached, with only a few consecutive hours of non-production due to non-compliance with the condition on the minimum load level of the electrolyser (condition (3.17)); when production reaches the maximum annual production that can be incentivised, production grows in a much less marked manner, in more defined, non-linear steps. The electrolyser operates and produces hydrogen at times of the year when no incentive is given only when the price of electricity in the day-ahead market is lower than the WTP without incentive. In fact, at the end of the year:

$$prod_{H2_{cum}} = 125068\ kg_{H2}/y$$

Considering that, with the assumptions made, the maximum production that can be incentivised is, from equation (3.25):

$$prod_{H2_{max,inc}} = 115602\ kg_{H2}/y$$

In which $prod_{H2_{eq}}$ is calculated from equation (3.2) considering $h_{eq_{EL}} = 1175\ h/y$ for PV3 Italian zone. Most of the annual hydrogen production, therefore, is done during the first annual period where the incentive is paid, while, when the incentive goes to zero, production is only about $10000\ kg_{H2}$; this happens because the electrolyser only works during the few times when the price of electricity is so low that it is less than the WTP without incentive (Figure 3.23);

- Finally, we also wanted to show, in transparent red, the total incentive profile in case there were no limitations on the maximum production that could be incentivised; in this case the production of green hydrogen would increase by a lot compared to the case with limitations and would be equal to:

$$prod_{H2_{cum}} = 622081\ kg_{H2}/y$$

Now that the effectiveness of the incentive in significantly increasing the number of operating hours of the electrolysis plant and consequently the production of green hydrogen has been demonstrated, we want to evaluate, as for the model described in section 3.3, the total gain of the producer in the base case to see if there is indeed gain in installing an electrolyser instead of sending all the electricity to the grid.

Then, following the model described in section 3.3, the hourly revenue due to the sale of green hydrogen is determined from equation (3.22), and finally the annual revenue due to this contribution from equation (3.23):

$$rev_{sellH2_y} = 190839\ €/y$$

In the base case, contrary to what was assumed in the reference case, the incentive is disbursed for hydrogen production when the two conditions (3.15) and (3.17) are met, until the $prod_{H2_{max_{inc}}}$ is reached; thus, after 1604 hours of the year, the incentive is no longer disbursed, and from equation (3.26) it results:

$$rev_{inc_y} = 563043\ €/y$$

Then the contribution related to CAPEX expenditure is equal to the one calculated in the reference case; so:

$$CAPEX_{expense} = 377903\ €/y$$

For the calculation of the producer's total annual gain, the sale of electricity directly to the grid must be calculated and will certainly be less than $rev_{electricity_y}$ in the reference case because the number of operating hours of the electrolyser has increased and consequently the amount of electricity fed into the grid has decreased; in fact, from equation (3.28) we have:

$$rev_{electricity_y} = 1.448 * 10^6 \text{ €}/y$$

At this point, the various contributions to the total annual gain are viewed in the graph in Figure 3.27 in cumulative form over the course of the year; the CAPEX expenditure is then subtracted from the total revenue value to obtain the total annual gain.

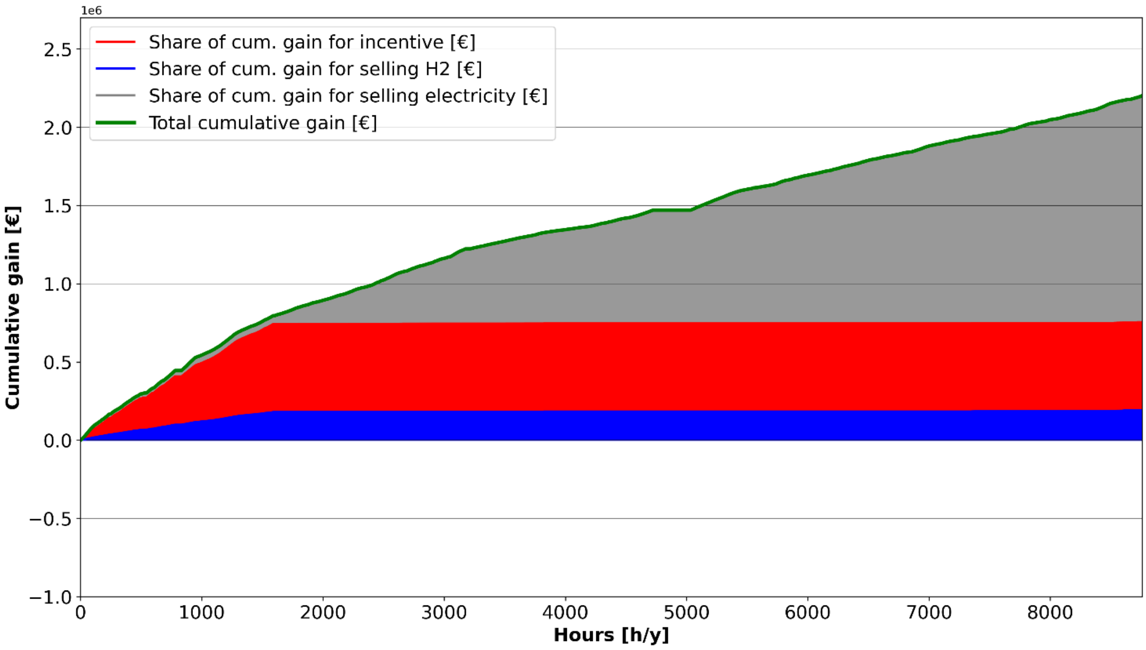

Figure 3.27 – Breakdown of contributions to total yearly gain vs yearly hours (with incentive)

In Figure 3.27 some considerations can be done:

- At the beginning of the year, when the cumulative production is less than the $prod_{H2_{max,inc}}$, and thus the incentive is paid for the production of hydrogen during the hours when the electrolyser is in operation, the total revenue comes mainly from the combination of incentive revenue and revenue from the sale of hydrogen, and only to a small extent from the revenue due to the sale of electricity to the grid; this is due to the fact that, even in the first hours of the year when the incentive can be paid, there are moments either (3.15) or (3.17) condition is not met, or times when the electrolyser is working at full load and therefore excess electricity is sold directly to the grid;

- When $prod_{H2_{max,inc}}$ is reached, the incentive is no longer disbursed and in fact it can be seen how the incentive revenue settles at a constant value until the end of the year, rev_{inc_y}, while rev_{sellH2_y} is more or less constant but, as seen in Figure 3.26, with a few hours of operation mainly concentrated in the end of the year; therefore the $rev_{electricity_y}$ contribution becomes preponderant with respect to the others as condition (3.15), without the incentive payment, is only satisfied a small number of hours in the second part of the year and therefore the vast majority of electricity is fed and sold to the grid;

Finally, the total annual gain by the hydrogen producer can be calculated from equation (3.14) and results:

$$gain_y = 1.824 * 10^6 \text{ €}/y$$

Where this $gain_y$ represents the amount in terms of €/y that the producer earns over the year with the assumptions made and with the application of the incentive scheme on hydrogen production. One can immediately make a comparison between this result and the one obtained in the reference case (no incentive), where, with the same assumption of $5\ MW$ installation, a gain of $1.446 * 10^6$ €$/y$ results. Furthermore, in reference case the producer has a convenience to send all the electricity produced by RES to the grid without installing electrolysis capacity, as the gain for $EL_{cap} = 0\ kW$ is maximum and equal to $gain_{y_{0kW}} = 1.819 * 10^6$ €$/y$; it can therefore be seen how the application of the incentive allows a higher gain by installing electrolysis capacity instead of sending all the electricity directly to the grid. Therefore, the application of the incentive scheme, as defined in Chapter 2, leads to a significant gain for the hydrogen producer with respect to the reference case, which, however, will have to be investigated in the sensitivity analyses that are considered below.

3.5.3.1 Sensitivity analysis on the electrolyser size with incentive

Now that the base case has been analysed with its relative total annual gain, an initial sensitivity analysis is to be carried out on the size of the electrolyser to see if and how a change in this parameter might affect the various contributions to the producer's total annual gain.

The simulation made for the base case with incentive scheme assumed the installation by the producer of 5 MW of electrolysis capacity; however, we want to analyse various situations with the same basic assumptions but different installed capacity values. The sizes used for this sensitivity analysis are the same evaluated in the reference case (3.5.2.1).

After defining the same sensitivity parameter values as in the reference case, we want to display the results in terms of:

- Total cumulative gain in the year divided into the various shares (Figure 3.28);
- The percentage of electrical energy consumed by the electrolyser for hydrogen production or sent directly to the grid (Figure 3.29);

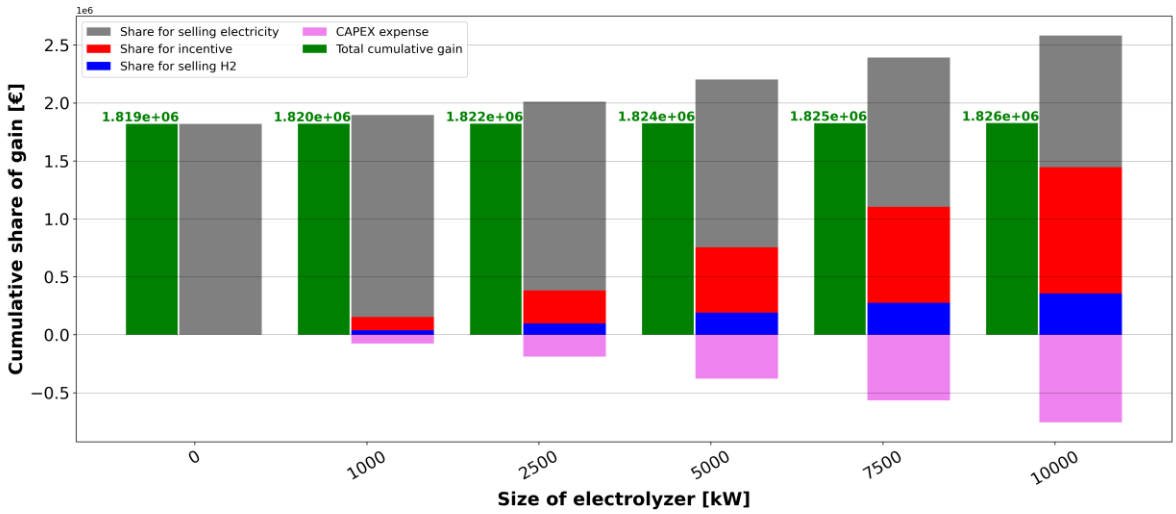

Figure 3.28 – Shares of gain at the end of the year for different sizes of electrolyser

Some considerations can be made on the graph above in Figure 3.28, where it is shown the annual total gain (in green) with the various positive contributions (electricity sale in grey, revenue due to incentive in red and revenue due to sale of hydrogen in blue) and the CAPEX expense (in pink) for the different electrolyser sizes analysed:

- If the case of $EL_{cap} = 0\ kW$ is considered, then the results obtained are the same as for the reference case with an installed capacity of 0 kW (3.5.2.1) since without an electrolyser, there is no hydrogen production and thus no incentive income either:

$$rev_{sellH2_{y_{0kW}}} = 0\ €/y$$

$$rev_{inc_{y_{0kW}}} = 0\ €/y$$

$$CAPEX_{expense_{0kW}} = 0\ €/y$$

$$gain_{y_{0kW}} = rev_{electricity_{0kW}} = 1.819 * 10^6\ €/y$$

- As the size of the electrolyser increases, hydrogen production increases considerably compared to the sensitivity analysis on the reference case; in fact, the revenue from the sale of H2, due to the incentive given which increases the operating hours of the electrolyser, increases greatly:

$$rev_{sellH2_{y_{2500kW}}} = 96682 \text{ €}/y$$
$$rev_{sellH2_{y_{7500kW}}} = 275038 \text{ €}/y$$
$$rev_{sellH2_{y_{10000kW}}} = 355773 \text{ €}/y$$

As a comparison, the revenue from the sale of hydrogen for an $EL_{cap} = 10000\ kW$ in a situation without an incentive (3.5.2.1) is $rev_{sellH2_{y_{10000kW}}} = 16886$ €; it can therefore be seen immediately how effective the incentive scheme is for increasing the production of green hydrogen from electrolyser;

- As the size of the electrolyser increases, the CAPEX expense related to the investment in the electrolysis plant increases in the same way of reference case sensitivity analysis, because the sizes considered are the same;

- With regard to the incentive income (in red), it can be seen that this increases as the size increases, and this is due to the fact that as the size of the electrolyser increases, so does the electricity that can be sent to the electrolyser for hydrogen production. The cumulative hydrogen production increases, and thus, from equation (3.24), the hourly incentive income increases. As the size increases, the operating hours of use do not increase, so production does not increase for that reason, but increases because $electricity_{in_{EL}}$ increases;

- The revenue from the sale of electricity to the grid decreases as the size increases because the electricity to be sold to the grid in excess of that fed into the electrolyser decreases:

$$rev_{electricity_{y_{2500kW}}} = 1.629 * 10^6 \text{ €}/y$$

$$rev_{electricity_{y_{7500kW}}} = 1.290 * 10^6 \text{ €}/y$$

- The most important result obtained from this simulation, which goes against that obtained in sub-section 3.5.2.1, is that since the incentive covers all investment costs and part of the operating costs, thanks to the positive contribution from the sale of hydrogen, the producer's total annual gain increases as the installed capacity of the electrolyser increases; therefore, whereas in the reference case the producer was not in a position to install a certain electrolysis capacity for the production of hydrogen without an incentive, in the base case the producer is incentivised to install an electrolyser and, the larger the size, the higher the gain, with the upper limit due to the oversizing of the plant compared to the $electricity_{RES}$ profile:

$$gain_{y_{2500kW}} = 1.822 * 10^6 \text{ €}/y$$

$$gain_{y_{7500kW}} = 1.825 * 10^6\ €/y$$

Thus, when comparing with the case where $EL_{cap} = 0kW$, there is gain in installing an electrolyser to produce hydrogen instead of selling all electricity to the grid, and this gain increases as the size increases;

Therefore, with the application of the incentive scheme, defined in Chapter 2, it is better for a producer to install an electrolyser for hydrogen production than to sell all electricity produced from biomass into the grid.

Now, as for the objective of the sensitivity analysis, we want to visualise the breakdown of the electricity produced from biomass into the part used in the electrolyser for hydrogen production and the part sold directly to the grid at $p_{el_{MGP}}$, to support the Figure 3.28.

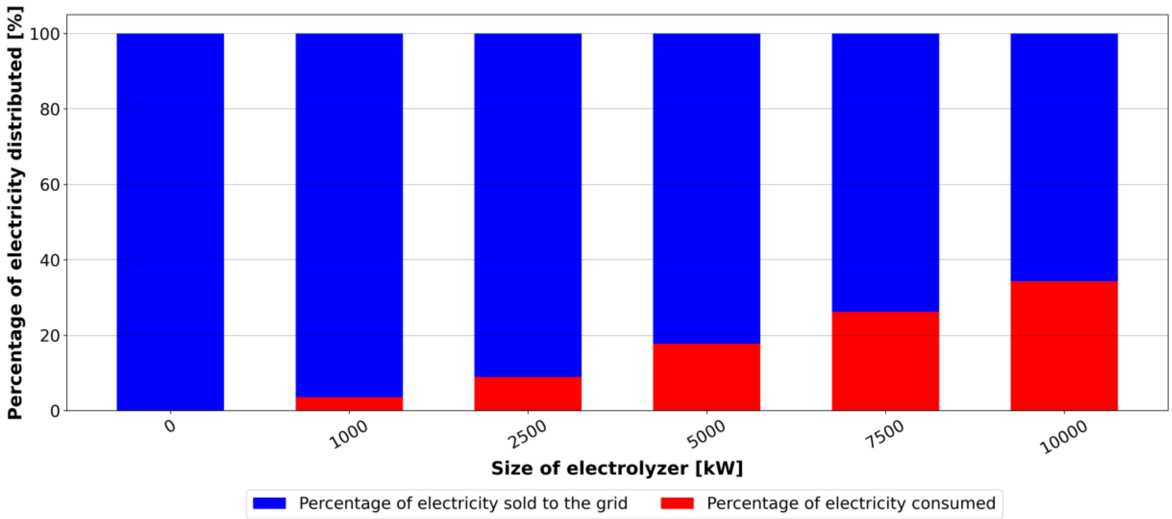

Figure 3.29 – Percentage distribution of available electricity to the electrolyser and grid sale for different sizes of electrolyser

In Figure 3.29, it can be seen that, in contrast to the reference case without an incentive, as the size of the electrolyser increases, the electricity input to the electrolyser increases significantly, this behaviour is due to the fact that, although the operating hours of the electrolyser do not vary with the size, the $electricity_{RES}$ profile is better coupled to the electrolyser and consequently the $electricity_{in_{EL}}$ quantity increases. This in fact supports the fact that, as can be seen in Figure 3.28, the revenue from the sale of hydrogen increases as the size of the electrolyser increases.

The increase in the amount of electrical energy input to the electrolyser is quite linear as the size increases, in fact evaluating the central sizes we have:

$$electricity_{in_{EL,cum_{2500kW}}} = 3193\ MWh/y$$

$$electricity_{in_{EL,cum_{5000kW}}} = 6359\ MWh/y$$

$$electricity_{in_{EL,cum_{7500kW}}} = 9374\ MWh/y$$

The amount of electricity input to the electrolyser increases considerably compared to the case without incentive, e.g. $electricity_{in_{EL,cum_{2500kW}}}$ in the base case increases elevenfold compared to the case without incentive.

3.5.3.2 Sensitivity analysis on the hydrogen sale price with incentive

In this second sensitivity analysis, we want to evaluate the base case as the hydrogen sales price changes, as we did for the reference case in section 3.5.2.2, taking the values of hydrogen sales prices as those in the aforementioned section. The considerations for the various prices considered, including the ETS mechanism, are the same as those made above.

The objectives of this simulation are to assess how the total annual profit of the hydrogen producer varies and to split the electricity produced from biomass between sale to the grid and use to produce hydrogen. The first of the two objectives is evaluated in Figure 3.30 below.

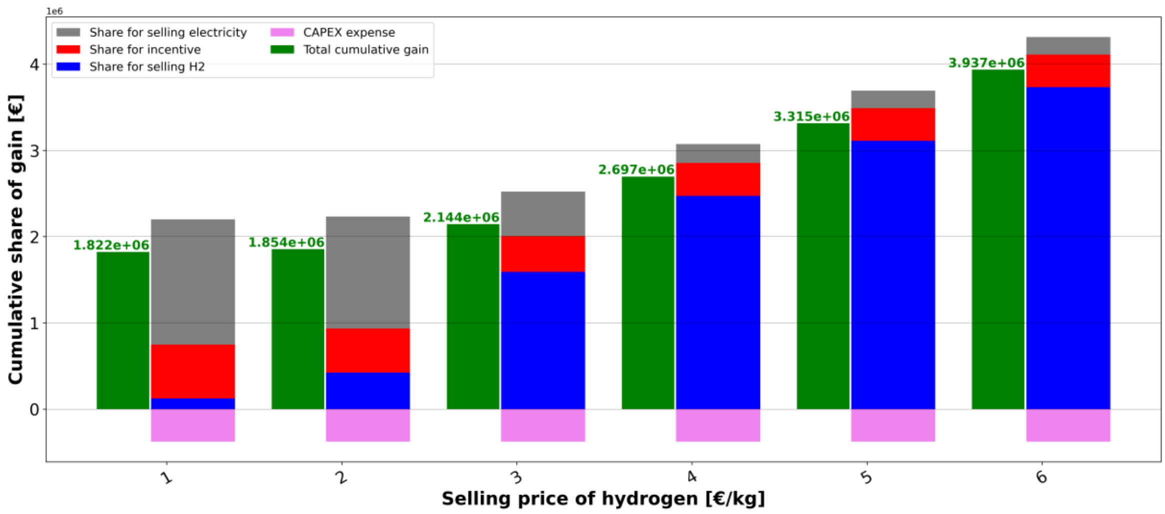

Figure 3.30 - Shares of gain at the end of the year for different selling price of hydrogen

In Figure 3.30 some considerations can be done:

- Compared to the reference case, in the base case with incentive the number of equivalent operating hours of the plant is much higher, since with the incentive payment WTP increases above the $p_{el_{MGP}}$ in more hours of the year and consequently the electrolyser operates more often; in fact, the hydrogen production increases and in addition the incentive revenue rev_{inc_y} must also be taken into account, so in general the total gain increases compared to the reference case. As the price of hydrogen increases, since this is part of the WTP calculation (equation (3.16)), the number of operating hours increases; for comparison, from eq. (3.20), taking into account the same sales price volatilities as in subsection 3.5.2.2, here we have:

$$h_{eq_{EL}}{}_{1€/kg} = 1238\ h/y$$

$$h_{eq_{EL}}{}_{2€/kg} = 2144\ h/y$$

These are much higher values of equivalent hours than in the reference case, and this is due to the application of the incentive scheme.

And consequently, the revenue for selling H2 results in:

$$rev_{sellH2_y}{}_{1€/kg} = 121830\ €/y$$

$$rev_{sellH2_y}{}_{2€/kg} = 421957\ €/y$$

For higher selling prices the revenue is much higher and the electrolyser works most of the year, for example for $3€/kg_{H2}$:

$$h_{eq_{EL}}{}_{3€/kg} = 5392\ h/y$$

$$rev_{sellH2_y}{}_{3€/kg} = 1.592 * 10^6\ €/y$$

As mentioned in section 3.5.2.2, again, going from a hydrogen selling price of $5\ €/kg_{H2}$ to $6\ €/kg_{H2}$ does not change the number of operating hours as we must take into account the excess electricity, during the operating hours of the electrolyser of $EL_{cap} = 5\ MW$, that is sold to the grid or the failure to comply with the condition on the minimum load of the electrolyser (Eq.(3.17)). There will therefore always be, even at high hydrogen sales prices, a portion of electricity that is sold to the grid and thus does not allow the electrolyser's operating hours to increase;

- The revenue from the sale of electricity to the grid is maximum for a minimum H2 sale price of 1 $€/kg_{H2}$, equal to:

$$rev_{electricity_{y_{1€/kg}}} = 1.452 * 10^6 \text{ €}/y$$

As the selling price of hydrogen increases, the operating hours of the electrolyser increase, and the electricity sent to the grid decreases and thus the revenue from the sale of electricity to the grid decreases. In fact, at for example 3 $€/kg_{H2}$:

$$rev_{electricity_{y_{3€/kg}}} = 514298 \text{ €}/y$$

- As the selling price of hydrogen increases, the CAPEX expense related to the investment in the electrolysis plant remains constant at the value of $CAPEX_{expense} = 377903 \text{ €}/y$;

- The incentive income decreases as the selling price of hydrogen increases because the operating incentive decreases as it becomes more and more profitable to produce and sell hydrogen rather than to send electricity produced from biomass to the grid; in fact, the electricity sent to the grid becomes less and less as the amount of energy at the input of the electrolyser for hydrogen production increases. At a certain point, however, the operating hours of the electrolyser no longer increase, due to compliance with the minimum load and excess electricity with respect to the 5 MW size, so the production of hydrogen remains constant and consequently so does the incentive revenue; the only thing that changes is the valorisation of the hydrogen produced, which increases the revenue from the sale of H2; in fact, we have:

$$rev_{inc_{y_{5€/kg}}} = 378390 \text{ €}/y$$

$$rev_{inc_{y_{6€/kg}}} = 378105 \text{ €}/y$$

- As in section 3.5.2.2, with low hydrogen prices, the total gain increase is small:

$$gain_{y_{1€/kg}} = 2.200 * 10^6 \text{ €}/y$$

$$gain_{y_{2€/kg}} = 2.232 * 10^6 \text{ €}/y$$

While with higher hydrogen selling prices the total gain increase is more substantial:

$$gain_{y_{4€/kg}} = 3.075 * 10^6 \text{ €}/y$$

$$gain_{y_{5€/kg}} = 3.693 * 10^6 \text{ €}/y$$

The thing that can be immediately compared with the reference case is that in the base case, compared to the previous case, the actual annual gain is much larger in the various hydrogen sales price configurations, and this is due to the application of the incentive scheme which, due to the investment and operation support, produces a net gain for the producer that is always higher than in the case of $EL_{cap} = 0\ kW$ where the producer sells all electricity to the grid (3.5.3.1).

Remembering the gain if the producer decides not to install electrolysis capacity for hydrogen production:

$$gain_{y_{0kW}} = rev_{electricity_{0kW}} = 1.819 * 10^6 \text{ €}/y$$

In this sensitivity analysis, it can be seen that, for each hydrogen sales price considered, the gain is always greater than the gain from the complete sale of electricity to the grid, unlike in the reference case (3.5.2.2). It follows that the producer therefore has an incentive to install a certain amount of electrolysis capacity in order to have a higher actual gain.

The second objective of this sensitivity analysis is to visualise the distribution of electricity produced from biomass, and this is accomplished in the graph in Figure 3.31 below.

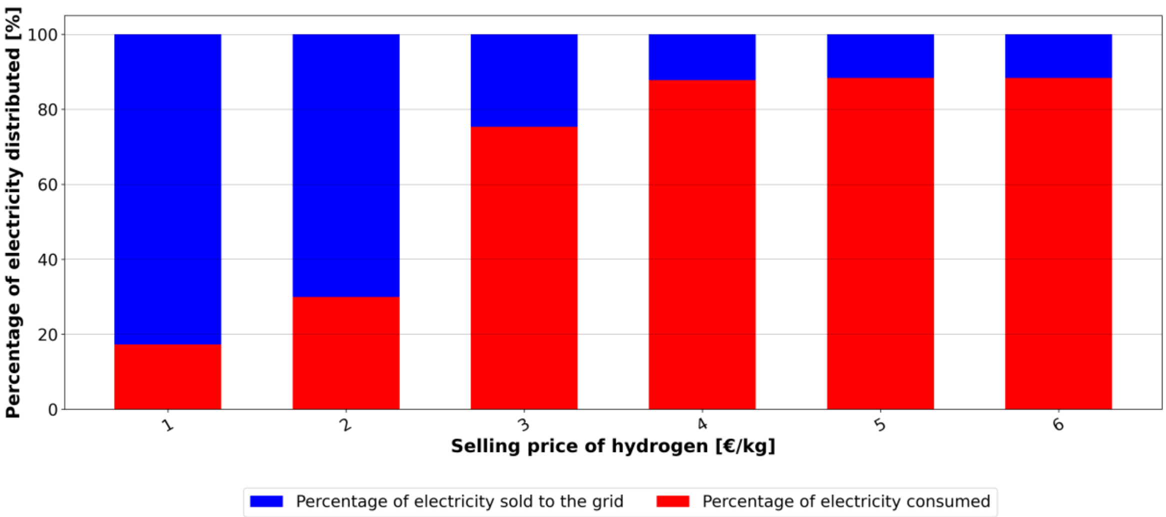

Figure 3.31 - Percentage distribution of available electricity to the electrolyser and grid sale for different selling prices of hydrogen

We can immediately see in Figure 3.31, in comparison with the graph in Figure 3.22 which takes the reference case without incentive into account, how for a $p_{H2_{avg}} \geq 4\ €/kg_{H2}$ there is no difference between the two distributions. However, the main difference relates to lower $p_{H2_{avg}}$ values, as the electrical energy, even for low hydrogen sales price values, is higher than in the case without the incentive; this is due to the fact that the incentive payment has a positive effect on the operating hours of the electrolyser, which increase, and consequently the electrical energy at the electrolyser input for hydrogen production also increases. Furthermore, as the selling price of H2 increases, the percentage of electricity from biomass consumed by the electrolyser increases, until it stabilises as in the reference case for high $p_{H2_{avg}}$ values, due to the fact that the electricity at the input no longer depends on the selling price of hydrogen but on the minimum load and size condition. To give an example comparing the two cases studied, for the reference case applied:

$$electricity_{in_{EL,cum_{2€/kg}}} = 4990\ MWh/y$$

$$electricity_{in_{EL,cum_{3€/kg}}} = 23372\ MWh/y$$

While for the base case:

$$electricity_{in_{EL,cum_{2€/kg}}} = 10722\ MWh/y$$

$$electricity_{in_{EL,cum_{3€/kg}}} = 26966\ MWh/y$$

We can estimate a net increase in electricity at the input of the electrolyser for hydrogen production compared to the reference case, due to the incentive paid on hydrogen production. However, at low hydrogen selling prices, the increase in electricity input, and consequently in production, is more pronounced as the plant's operating hours increase more than at high H2 selling prices where operating hours are more stable.

Chapter 4

4 Discussion, conclusions and future work

Discussion and conclusions

In this thesis, after a general overview of the state of the art of hydrogen production methods, end-uses and regulatory frameworks, an incentive scheme is proposed based on two incentive contributions, one linked to investment costs and the other linked to the operation costs of the plant (Chapter 2). The incentive value is computed for different renewable source used for hydrogen production, different demand sector and different electrolysis technology. It can be seen that, depending on the electrolyser technology considered, the incentive contribution linked to the operation varies, being the highest for the technologies with the lowest efficiency (PEM and alkaline), resulting more disadvantageous and costly than the SOE-type electrolyser which needs a lower operative incentive to produce. As far as the investment cost contribution is concerned, it varies by favouring the electrolyser technologies with the lower investment costs (ALK and PEM), while for SOE, with higher CAPEX, a higher incentive is required. Additionally, it depends on the renewable source and thus the operating hours of the plant: the highest is the source availability, the lowest is the incentive contribution per kg of produced hydrogen. Overall, a wide range of values is obtained both the incentive CAPEX, spanning from $1.4\ €/kg$ to $10.9\ €/kg$, depending on renewable source and electrolysis technology, and operative incentive, spanning from $3\ €/kg$ to $13\ €/kg$, depending on final demand and electrolysis technology, when typical values of prices for NG and electricity are considered. Then, under certain assumptions and based on two different hydrogen production targets to be reached by 2030, the expenditure to be made by the state to incentivise hydrogen production in 20 years is determined. The impact of the CAPEX-related incentive and of the operational cost-relate incentive is also highlighted. Sensitivity analyses are then carried out with different electricity and natural gas prices to assess the expenditure under different possible scenarios but maintaining price constancy over the time period considered. It can be seen that, as the price of natural gas increases, keeping the price of electricity constant, the government's expenditure on the operating incentive decreases, since the sale of hydrogen is always cheaper than the sale of electricity on the grid; on the contrary, as the price of electricity increases with the same price of natural gas, the operating incentive to be given increases, since the sale of electricity is always cheaper. Furthermore, while to reach the first target (5 GW of electrolysis capacity), the spending range goes from a minimum of €7 billion (CAPEX incentive only), in the case of an advantage in hydrogen production, to a maximum of €53 billion, for high electricity and natural gas prices, the spending range to reach the second target (0.7 Mton/year to 2030) is much higher: 39-201 billion €, due to the fact that much more installed capacity is needed (22.9-29 GW depending on the renewable source considered, instead than 5 GW) and thus a high incentive expenditure on the investment but also on the operation cost is required to guarantee the higher production.

After proposing the incentive scheme and evaluating the possible expenditure for the state, in the second part of the thesis two models are developed to evaluate the proposed incentive scheme in particular case studies. One model is developed in an Excel environment and the other in Python environment. The special feature of these models is that they are versatile, thus able to be used in a variety of case studies by varying the input data (i.e. costs, efficiencies, and other parameters representative of the case study). Furthermore, both models are parameterized to kW_{inst}, thus making it possible to evaluate cases where a manufacturer would like to install different electrolysis capacity. In detail, the Excel model is an annual model with a longer horizon and evaluates the differential gain of the hydrogen producer compared to the case where all electricity produced from renewable sources is sold to the grid; it also calculates the incentive received for hydrogen production. Several sensitivity analyses have been performed on various parameters to graphically visualize how the differential gain and the required incentive vary. For example, considering a photovoltaic system with a given capacity factor coupled with $1\,kW$ of installed electrolysis capacity, as the price of natural gas increases, at the same price of electricity, the required incentive decreases until it reaches the value of 75.58 €/y, so only the CAPEX part, with a positive differential gain. In the proposed incentive scheme, the incentive is set for a certain number of equivalent operating hours for a photovoltaic system in the PV3 zone; consequently, the incentive is paid for a certain maximum production corresponding to this number of equivalent operating hours of the electrolyser. Therefore, by changing the renewable source to one with a higher capacity factor, e.g. wind or biomass vs PV, or considering a favourable situations (e.g., thanks to PPAs, for positioning in strategic areas, etc.), and consequently increasing the operating hours of the electrolyser, does not lead to an increase in the producer's annual profit, because no incentive will be given for the extra quantity of hydrogen produced each year. On the contrary, assuming that all operating hours of the electrolyser are used to produce hydrogen, the producer has a loss, as the increase in loss of revenue due to the non-sale of electricity to the grid is greater than the increase in revenue due to the higher hydrogen production, while the incentive is only paid for the maximum production that can be incentivised, and not for the actual one. Indeed, taking into consideration the base case with $electricity_{price} = 300\,€/MWh$ and $price_{NG} = 160\,€/MWh$:

- For a $h_{eq_{EL}} = 1175\,h/y$ (the one for PV3 plant) the incentive value related to the investment costs is equal to $3.26\,€/kg_{H2}$ and the operative incentive is equal to $8.63\,€/kg_{H2}$. The differential gain for the producer will be $\Delta gain_y = 0\,€/y$, because the incentive is used to send the producer into economic parity with the alternative of sending all electricity to the grid;

- For a $h_{eq_{EL}} = 1800\ h/y$ (for a biomass plant) we have the same incentive values related to the investment costs ($3.26\ €/kg_{H2}$) and to operation ($8.63\ €/kg_{H2}$). Since the extra quantity of hydrogen produced is not incentivised, in this case the producer records an annual loss of $\Delta gain_y = -106.4\ €/y$;

It can therefore be seen that, as the operating hours of the electrolyser increase above the base number of 1175 h/y for the calculation of incentive, the two contributions of incentive, at the same electricity and gas prices, remain constant, because the CAPEX part is fixed and the operative part does not depend on the operating hours of the electrolyser. If, on the other hand, once the operating hours of the electrolyser are fixed, and thus with the same hydrogen production, electricity and natural gas prices change, then the operative incentive changes, in fact:

- If $price_{NG}$ increases, for the same $electricity_{price}$, the operating incentive decreases as the production and subsequent sale of hydrogen becomes not only competitive, but also cost-effective;
- If $electricity_{price}$ increases, at the same $price_{NG}$, the operating incentive increases as it becomes increasingly cheaper to sell the electricity produced to the grid than to use it in the electrolyser;

Finally, since the CAPEX incentive has been fixed for a specific CAPEX for the alkaline electrolyser ($480\ €/kW_{inst}$), if the investment expenditure increases above this value, e.g. $CAPEX_{inv} = 520\ €/kW_{inst}$, in the price situation of the base case, $CAPEX_{inc}$ remains equal to $3.26\ €/kg_{H2}$, however the $CAPEX_{expense}$ increases and the producer records a loss ($\Delta gain_y = -\ 6.30\ €/y$).

The Python model, on the other hand, is more specific, based on an hourly level of detail, and aims at calculating the total annual gain of the producer of green hydrogen from electrolyser ($EL_{cap} = 5\ MW$) and then comparing this gain with that obtained in the case of selling all electricity on the grid. In this model, a specific case study (electricity profile from a biomass plant in central Italy for the year 2019) is presented and evaluated under two different scenarios: one case in which there is no incentive on hydrogen production and the other in which the incentive on the produced hydrogen is active. The two scenarios are evaluated according to the same scheme, initially considering the original biomass electricity profile, then finding the actual operating hours of the electrolyser by setting various limits (WTP and minimum load level) and then computing the hydrogen production for the plant. Different sensitivity analyses are then carried out to evaluate the gain and the electrical energy fed into the electrolyser for hydrogen production in the two different scenarios. The key results obtained from this analysis are as follows:

- The total annual gain in the reference case without incentive is $1.446 * 10^6\ €/y$; while a producer who decides not to install electrolysis capacity for hydrogen production would have an annual gain of $1.819 * 10^6\ €/y$, thus making the installation of an electrolyser for hydrogen production inconvenient;

- In the case without the incentive scheme, the equivalent operating hours of the electrolyser are $106\ h/y$ compared to $1272\ h/y$ in the base case with the incentive scheme active, thus making the implementation of the scheme, for the production of green hydrogen from the electrolyser, effective; in fact, the annual production varies from $10450\ kg_{H2}/y$ to $125068\ kg_{H2}/y$ between the two cases;

- A sensitivity analysis on the electrolyser size (fixed the size of the PV plant connected to it), has shown that, in reference case, as the installed size of the electrolyser increases, the electricity consumed by the electrolyser increases almost insignificantly, which is due to the fact that the operating hours of the electrolyser remain approximately constant with size;

- The total annual gain, if the incentive scheme is active (base case), would be $1.824 * 10^6$ €$/y$. In this case, there is a benefit in installing electrolysis capacity for hydrogen production with respect to not installing the electrolyser (annual gain of $1.819 * 10^6$ €$/y$);

- Furthermore, in base case, as the installed size of the electrolyser increases, the electricity consumed by the electrolyser increases even if the operating hours remain constant, as there is already an increase in operating hours initially compared to the case without an incentive; considering the base case of installing 5 MW of electrolysis capacity, the differential gain, between the case with incentive and the case without incentive, is $378'000$ €$/y$;

- In both scenarios considered, performing a sensitivity analysis on the selling price of hydrogen, it is concluded that, as the selling price of hydrogen increases, in both scenarios the revenue from the sale of hydrogen increases significantly as, in addition to the trivial increase in revenue due to the higher price, the fact that the operating hours of the electrolyser increase, making the production of hydrogen increasingly cheaper at most times of the year. For example:

    - For an H2 selling price equal to 1 €$/kg_{H2}$ the revenue for hydrogen sale is $121'830$ €$/y$ and the revenue for electricity sale is $1.452 * 10^6$ €$/y$;

    - Whereas if the H2 selling price is 3 €$/kg_{H2}$, the revenue for hydrogen sale is $1.592 * 10^6$ €$/y$ and the revenue for electricity sale is $514'298$ €$/y$;

It has to be highlighted that all conclusions depend on the assumption made on prices, on renewable source and on electrolysis technology considered. For example, if the renewable source is changed, in favour of photovoltaics, the operating hours also change and therefore different results will be obtained. The electrolyser+biomass plant hypothetically, considering the availability of electricity, would be able to run a greater number of operating hours for hydrogen production than the electrolyser+PV plant, however, the former does not as the incentive is given on an established hydrogen production (assumed on the PV3 plant), which is less than the biomass plant could produce. Consequently, the electrolyser+biomass plant, which could be more virtuous than the electrolyser+PV plant, is not used to its full capacity with this type of incentive, given on an established quantity of hydrogen regardless of the RES source. The mechanism is therefore ineffective, as it disadvantages virtuous plants in favour of a more horizontal incentive over a range of production plants, giving the same kind of incentive to those that produce hydrogen in an inconvenient way as to those that produce it in a convenient way ("virtuous plants").

In the Python model, electricity and natural gas prices for the reference year 2019 are taken into account, and, as a result, the sales prices for hydrogen produced are in the range of $1\ €/kg_{H2}$ to $2\ €/kg_{H2}$, which is strongly underestimated for green hydrogen. In fact, if we assume higher values as for the literature [9], e.g. taking $p_{H2_{avg}} = 3\ €/kg_{H2}$, we would obtain a considerable change in results. In support of this, SNAM's Levelised cost of hydrogen (LCOH) forecasts a decrease in green hydrogen production costs until the breakeven point is reached with the cost of grey hydrogen production in 2030, as in one case the installed capacity of renewable sources increases while in the other the price of CO2 on the emissions market increases, as can be seen from Figure 4.1. Figure 4.1 shows that the breakeven is reached for about $2\ €/kg_{H2}$, however, now, the production cost of green hydrogen is still high, thus confirming the sale price assumption of $3\ €/kg_{H2}$.

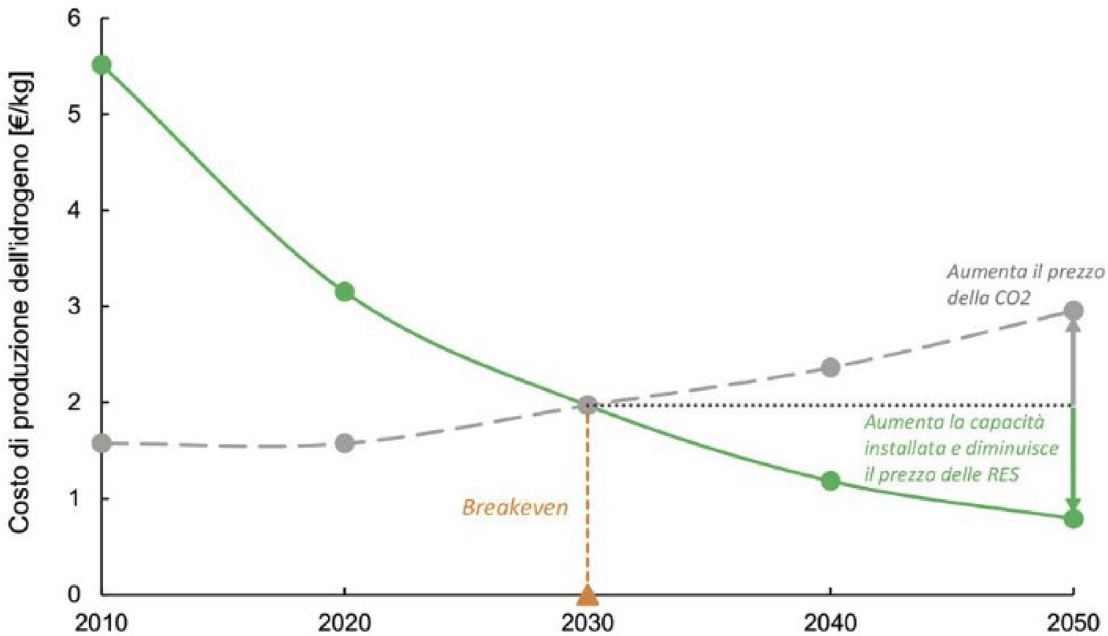

Figure 4.1 – Evolution of green and grey hydrogen costs [9]

In addition to this, if we hypothesize to incentivize production for the whole year and not just for a certain number of hours to reach the maximum incentivable production, the annual actual gain would be equal to $2.108 * 10^6\ €/y$, thus making the investment much more profitable.

To summarise, the proposed incentive scheme is valid because, it allows the producer to have a differential annual gain compared to the case of not installing electrolysis capacity and then selling the electricity directly into the grid. However, in most cases, this gain is not high enough to justify the investment. For example, in the investigated case study, with a 5 MW electrolyser and a biomass plant, the annual differential gain, with respect to the case of not installing electrolysis capacity, is around 5’000 €/y, a gain such that an investment of this type might not be so welcome. The developed simulation models have allowed to conclude that the incentive scheme, under certain assumptions, allows the producer to have a profit and can therefore be considered effective. However, the incentive scheme shows several limitations.

Among them:

1. The first limitation is that incentive value is set for all renewable source plants indiscriminately; this means that, regardless of the operating hours at which a plant can work and on the production cost itself, the incentive that is given is always the same, thus favouring the growth of non-virtuous plants (e.g. with low efficiency, limited hours of operation, or non-favourable business cases);

2. The second limitation is that the incentive is given until a maximum annual production that can be incentivised is reached, decided by the State and equal for each plant. This limitation means that any production plant, from the most virtuous to the least virtuous, has an identical maximum production above which the incentive is no longer given; however, there will be plants in which the maximum production will be easily reached (more virtuous) and plants in which the maximum production is not reached and which nevertheless receive the incentive. This favours the installation of many plants which are then underused;

Future work and improvement

Other incentive mechanisms could be used to overcome these limitations on the proposed incentive scheme. One could be to fix more incentives, in terms of € or total tons of hydrogen produced, on the basis of the RES plant chosen, thus considering the equivalent operating hours $h_{eq_{RES}}$ (and then $h_{eq_{EL}}$) that various plants may have, thus avoiding the problem of having the same incentive fixed for all the different situations. The main advantage of this solution is that it would incentivise plants according to their operating hours, thus giving a greater incentive to plants that can produce more, thus favouring a kind of virtuosity in terms of production. The disadvantage of this solution is that the incentive is always fixed; so, if a plant fails to reach the target of tonnes of hydrogen produced, then the incentive is overestimated, in which case it could be used to fund more projects instead of just a few. Another disadvantage for this type of mechanism is that the producer's gain may be too high as the incentives are fixed for the various renewable sources anyway and are not variable according to the selling price of hydrogen on the market.

Another work for the future to overcome both limitations of the incentive scheme could be to propose an auction mechanism to obtain the incentive. In classic auction mechanisms, e.g. for the electricity market, producers demand a certain sales price for a certain amount of electricity, while buyers offer to buy a certain amount of electricity at a certain price; the market price is established at the intersection of supply and demand. In the auction mechanism for obtaining the incentive in this specific case, hydrogen producers wishing to receive the incentive for the production and subsequent sale of hydrogen demand a certain incentive in $€/kg_{H2}$ for a certain expected annual hydrogen production. At this point, the bids are taken and placed in ascending order starting with the lowest incentive requested, which of course is taken first as the demand is not high. At the end of the auction section, the state decides on an incentive on the basis of a total annual production of green hydrogen it wants to achieve, or on the basis of a maximum annual incentive expenditure.

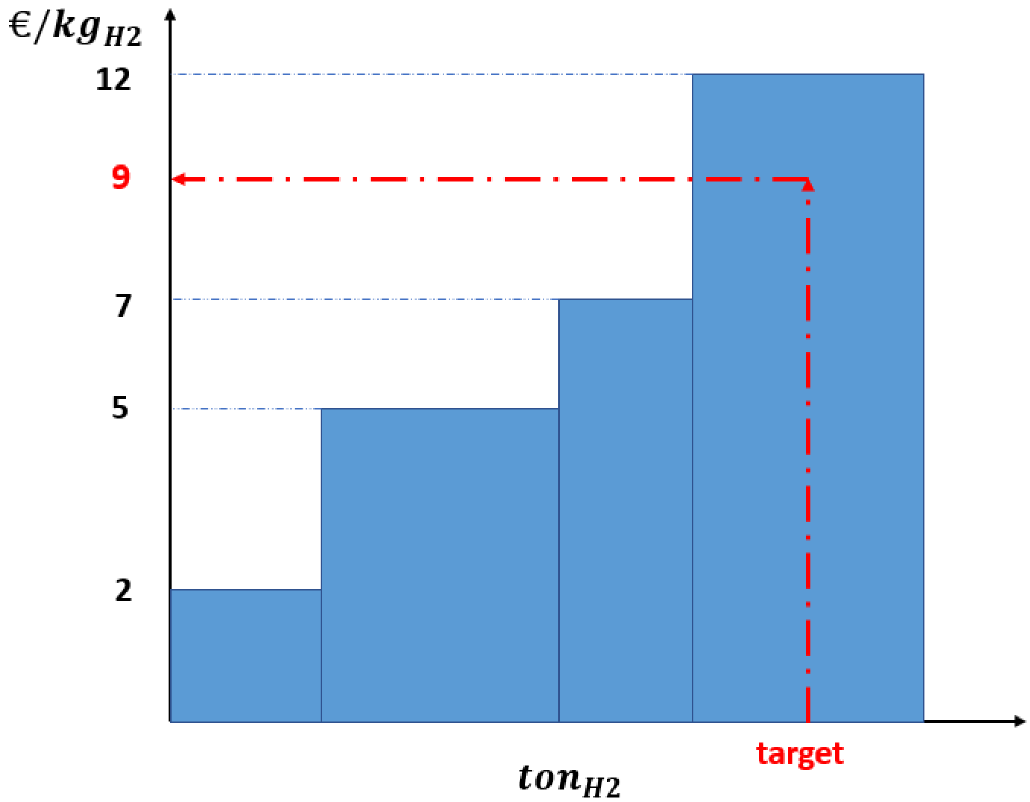

Figure 4.2 - Auction mechanism for receiving the production incentive

An example of how this mechanism might develop is presented in Figure 4.2. The auction bids are placed in ascending order from the one with the lowest incentive demand to the one with the highest incentive demand for a total of tonnes of hydrogen produced annually (thickness of the various columns); at the end of the auction, on the basis of a certain target set by the state to achieve a certain annual production of green hydrogen, a maximum incentive is assigned (in this case 9 $€/kg$, an example value), to incentivise hydrogen production for all plants that have requested a lower or at most the same incentive; for this reason the plant requesting an incentive of 12 $€/kg$ for a certain production will not be assigned the incentive as it is outside the auction perimeter. In this way, the mechanism incentivises the more virtuous plants that manage to produce green hydrogen at a lower cost, and therefore need a lower incentive.

Within the thesis, the ETS market has been mentioned in the sensitivity analysis section on hydrogen prices for the calculation of the annual gain; however, an improvement of the model would certainly be to include the CO2 cost in the detail that contributes to the variation of the hydrogen sales price. In fact, an increase in the CO2 price (in terms of €/ton) would increase the selling price of green hydrogen as the consumer would avoid emitting CO2 into the atmosphere and consequently have a gain in terms of ETS quotas; as the selling price of hydrogen increases, the required incentive for production would decrease.

Another improvement of the model is to evaluate more specific case studies and increase the level of detail in the perimeter of the electrolyser, thus taking into account more aspects than production, such as compression, transport and distribution. Furthermore, the incentive could vary if the hydrogen is used on-site or has to be brought to high pressure for use in mobility.

Finally, a further improvement to the thesis could be to make and improve forecasts of future prices by means of scenario studies in order to try to be as specific as possible when carrying out an analysis on the possible inclusion of an incentive in a future context.

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