ETN Global

HYDROGEN DEPLOYMENT IN CENTRALISED POWER GENERATION

A techno-economic case study

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List of Abbreviations

CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CF	Capacity Factor
CHP	Combined Heat-and-Power
CO_2	Carbon Dioxide
CT	Carbon Tax
DLE	Dry Low Emissions
DLN	Dry Low NO_x
EC	European Commission
EOH	Equivalent Operating Hours
ETS	Emission Trading System
EU	European Union
FC	Fuel cell
FixO	Fixed Operating Cost
GHG	Green House Gas
GT	Gas turbine
H_2	Hydrogen
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
LCOE	Levelized Cost of Electricity
NG	Natural Gas
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-Operation and Development
OEM	Original Equipment Manufacturers
PS	Post Combustion Carbon Capture
PV	Photovoltaics
RES	Renewable Energy Source
UK	United Kingdom
US	United States
VarO	Variable Operating Cost
WACC	Weighted-Average Capital Cost

Executive Summary

Gas turbines have an important role to play in delivering the energy transition and enabling the future net-zero energy system. When operated with hydrogen fuel, gas turbines emit zero CO_2 while also delivering grid stability and demand support for intermittent renewable energy sources such as wind and solar. Indeed, hydrogen gas turbines play a role in 2050 net-zero scenarios. This would require not only hydrogen volumes equivalent to today's total global hydrogen production, but also further developments in hydrogen gas turbine technology to safely, reliably, and efficiently use this zero-carbon fuel.

Gas turbine manufacturers have committed to producing state-of-the-art technology capable of 100% hydrogen operation by 2030. However, there is a gap in the current understanding of the economic and political conditions under which this technology could be brought to market. This techno-economic study addresses this gap by conducting a detailed cost analysis for the use of hydrogen in dispatchable heat and power applications. Given the current installed gas turbine asset base available in the European Union (EU), the focus is on the potential to retrofit these assets to replace hydrocarbons with hydrogen. The study considers a wide range of gas turbine technologies and hydrogen blending volumes in natural gas, while also considering the future uncertainty in hydrogen and carbon pricing. The wide range of gas turbine technologies and input parameters considered includes:

- Open cycle (OCGT), combined cycle (CCGT), and combined heat and power (CHP)
- Gas turbine cycle output load range from 20 MW_e to 650 MW_e
- Hydrogen blends in natural gas from 0% to 100% by volume
- Hydrogen price from €0.50/kg to €4.00/kg
- Carbon price from €50/ton to €325/ton

This analysis concludes that the levelized cost of electricity (LCOE) is expected to increase by at least 60% for high efficiency hydrogen gas turbine cycles (e.g., CCGT), impacted mainly by the hydrogen price which can represent over 80% of the hydrogen gas turbine LCOE. For low-efficiency gas turbine cycles (e.g., peaking OCGTs), hydrogen blending between 30%-70% may not be economically competitive with pure natural gas as the operator is required to pay enhanced retrofit costs and hydrogen costs while also paying for carbon emissions. In terms of carbon cost, it is simply too cheap at present to warrant a fuel switch from natural gas to hydrogen. Breakeven carbon costs for hydrogen gas turbines (compared with their natural gas equivalent) are shown to be in the range of €150/ton to €225/ton. This is approximately 2 to 3 times the current EU emissions trading system (ETS) price, although it is worth noting that this more than doubled year-on-year in 2021.

To enable the future development and implementation of hydrogen gas turbines in Europe, the study identifies six key areas for policy support, research and development, and demonstration. These focus areas are:

- Hydrogen cost reduction
- Carbon cost increase
- Hydrogen infrastructure development
- Hydrogen sector coupling
- Hydrogen combustion research and development
- Hydrogen knowledge transfer

Authors and involved stakeholders

This report was authored by members of the European Turbine Network's Young Engineers Committee (YEC). The YEC, established in July 2020, is a professional forum of nominated candidates from ETN member organizations. The YEC's vision is to bring together the future generation of engineers and leaders of ETN members and the wider energy sector, who will prepare the pathways for a successful energy transition towards a carbon-neutral society. The objectives of the Young Engineers Committee are:

- To promote low-carbon technologies using social media and other tools that will enable carbon emission reductions in the energy transition by providing secure, flexible and cost-competitive carbon-neutral (or carbon-negative) turbomachinery energy solutions.
- To develop future leaders in the turbomachinery field by encouraging development, retention, and promotion and by enabling cross-sector collaboration and knowledge sharing.
- To pass on experience from ETN's Emeritus Members, who are acknowledged and experienced experts and past leaders in the GT industry, to young engineers who can learn about broader aspects of the energy industry.
- To provide valuable contributions to ETN and the wider community by engaging directly with leaders in the field to perform studies, technology reviews, and projects.
- To ensure the continuity of ETN's work through a complementary network, to stimulate exchange of ideas, and further widening and dissemination of ETN's activities in the international community.

This report was also prepared in conjunction with the ETN Hydrogen Working Group, which is a coordinated effort by ETN member organizations to develop and share expertise in the production and utilization of hydrogen in gas turbines to achieve net-zero emissions. The objectives of ETN's Hydrogen Working Group are to enable and to optimize the use of hydrogen in gas turbines by:

- Highlighting potential use, applications and benefits
- Paving the way for funding opportunities by highlighting the research needs on gas turbines to burn hydrogen, in order to contribute to the deployment of those gases in future energy systems
- Addressing operational issues/effects on gas turbines components related to the use of hydrogen
- Exploring market opportunities and retrofit solutions for existing and future gas turbines fleets operating with renewable gases (containing hydrogen)
- Assessing and addressing operational safety aspects of hydrogen in gas turbines plants (and pipelines)
- Fostering the use of hydrogen and hydrogen carriers (such as ammonia) as complementary energy vectors to decarbonize the energy systems

In 2020, the ETN Hydrogen Working Group published the Hydrogen Gas Turbines report, which is complementary to this work and available at https://etn.global/hydrogen-report.

The YEC would like to thank the following ETN Hydrogen Working Group member organizations for their valuable contributions:

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His focus is to improve the development of clean, efficient combustion systems and facilitate the utilization of alternative fuels, addressing energy demand and environmental challenges.

1. Introduction

In July 2020, the European Commission (EC) released its "Hydrogen Strategy for a Climate-Neutral Europe" which highlights the specific and essential role that hydrogen (H_2) will have in supporting the European Union's (EU) goal of net-zero carbon emissions by 2050 [1]. With this strategy, hydrogen is now a key pillar in supporting the policies outlined in the European Green Deal [2] and the stepwise ambitions of the energy transition to carbon neutrality, with hydrogen enabling cross-sector decarbonisation in industry, transport, heat, and power generation. Alongside the release of the EC's "Hydrogen Strategy," a study was commissioned by the EC and produced by Cihlar et al. [3] which details the significant investments necessary to increase local production of hydrogen via two low-carbon routes:

1. Low-Carbon Hydrogen with Carbon Capture (often referred to as "Blue H_2") made from the reformation of natural gas (NG) with carbon capture and storage (CCS).
2. Renewable Hydrogen (often referred to as "Green H_2") made from electrolysis of water powered by renewable energy.

While Cihlar et al. [3] acknowledge that hydrogen is a key decarbonisation tool that can be utilised in power systems, their economic analysis of hydrogen end-use applications focusses solely on steelmaking and transport. Secure, stable, decarbonised power generation via gas turbines (GTs) and fuel cells (FCs) will also have a role as hydrogen end-use applications. The International Energy Agency's (IEA) Net Zero by 2050 report predicts that 17% of global hydrogen end use in 2050 will be for electricity [4]. This is equivalent to 88 MtH_2/yr in 2050 which is approximately equal to today's total annual global hydrogen production [4]. Indeed in 2050 net-zero scenarios developed by the EU, hydrogen's use in the power sector is acknowledged alongside transport, industry, and residential applications [5]. Furthermore, in a recent report from the European Hydrogen Backbone project produced by ten leading European gas transport companies and two renewable gas industry associations, the future role of hydrogen for power generation across Europe was outlined as given in *Figure 1* [6]. The use of hydrogen for power generation in Europe is expected to require 626 TWh of hydrogen by 2050, up from only 12 TWh in 2030, thus driving significant hydrogen demand in establishing the hydrogen economy. By 2050, this equates to 7% of European electricity generation, with local variation up to 17% in Poland, 15% in Ireland and Italy, and 14% in Germany.

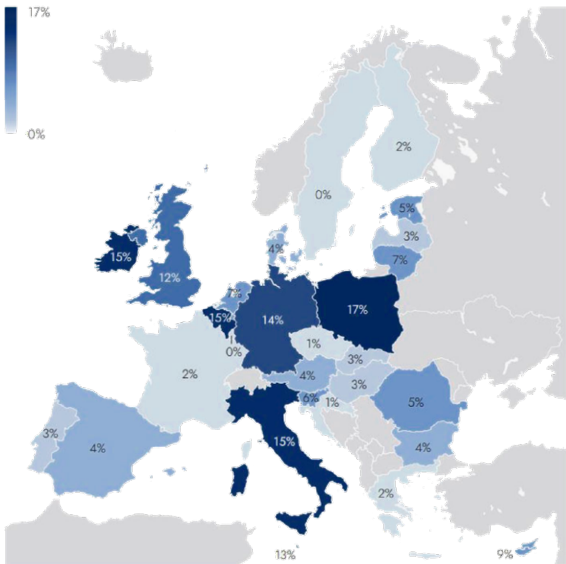

Figure 1: Fraction of hydrogen generated electricity as a function of total country electricity generation in 2050 (reproduced from [6])

This study provides a detailed cost analysis for the use of hydrogen in power end-use applications with a focus on gas turbines, given the current installed asset base available in the EU for retrofitting from hydrocarbon to hydrogen operation and the commitment by gas turbine manufacturers to produce new 100% H_2 GTs by 2030 [7]. For both retrofitting and new GTs, the use of hydrogen will focus on dry low emissions and premixed combustion technology which meets current EU emissions limits. Gas turbines, both combined cycle (CCGT) and open cycle (OCGT), already play a key role in decarbonising the European energy transition by enabling coal-to-gas switching, with gas-fired generation displacing nearly 50% of the decline in coal-fired power generation in 2019 [8], which carries with it significant, immediate reductions in carbon dioxide (CO_2) while ensuring security of electricity supply as further renewable energy sources (e.g., wind/solar/hydro) are installed. In addition to electricity production, decarbonised gas turbines can produce useful heat in combined heat and power (CHP) or cogeneration applications, enhancing sector coupling with industry and district heating while improving overall energy efficiency [9]. As the amount of installed renewable energy capacity increases, gas turbines are utilised to meet peak electricity demand at times of low renewable availability. Green hydrogen can therefore be utilised as a means of long-term renewable energy storage, with hydrogen gas turbines operating alongside other renewable energy sources to fill in the demand gap. There is indeed the opportunity to operate hydrogen gas turbines with net-negative carbon emissions if the hydrogen is produced with biogas reforming and CCS. If the European Union is to reach net-zero carbon emissions by 2050, it is therefore imperative to analyse the potential costs and feasibility of decarbonising gas turbines through the use of hydrogen[1].

1.1. Study scenarios

Given the wide range of gas turbine sizes (power output from kW_e to MW_e), configurations (OCGT, CCGT, and CHP), and applications (baseload, peaking, mechanical drive), it is necessary to focus the analysis on selected scenarios which will impact current, near-term, and future hydrogen gas turbine operation. The selected scenarios for this study are given in *Table 1*. Each scenario will also consider a 100% natural gas baseline condition.

Table 1: Hydrogen gas turbine configurations considered in this study

Gas turbine type	GT Output (MW_e)	Configuration	Operating Regime	Annual Operating Hours	Designation
Small	20	OCGT	Peak	800	S-OCGT
Small	20	CHP	Base	6000	S-CHP
Medium	60	OCGT	Peak	800	M-OCGT
Large	450	OCGT	Peak	800	L-OCGT
Large	450*	CCGT	Base	6000	L-CCGT

* Combined cycle output = 650 MW_e

1.2. Aims and outcomes of the study

The aim of this techno-economic study is to provide a measure of the current and future cost and feasibility of using blends of hydrogen in natural gas and pure hydrogen for the decarbonisation of gas turbine power generation. This is accomplished using publicly available cost information as well as input from ETN member organisations to generate a Levelized Cost of Electricity (LCOE) for each scenario that enables identification of the key mechanisms to realising zero-carbon gas turbine operation. The outcomes of this study will inform policy makers, gas turbine manufacturers and users, as well as the hydrogen value chain, electricity consumers, investors, and the public about the key role that decarbonised gas turbines will play in the energy transition and to deliver a flexible, secure, net-zero energy system for the EU.

[1] Other zero-carbon (e.g., ammonia) and carbon neutral (biogas/bioliquid) fuels are being developed for gas turbine use in addition to post-combustion carbon capture and storage (CCS), however these are outside the scope of this study.

2. Literature review

2.1. Hydrogen cost

Today, global pure hydrogen production is approximately 70 Mt H_2/year, of which >98% is produced from natural gas and coal, so called "grey hydrogen" [10]. This hydrogen is mainly used in fossil fuel refining and chemicals production, such as ammonia for fertilizer. By 2050, annual pure hydrogen production is projected to increase up to 546 Mt H_2/year [11]. Currently, hydrogen accounts for less than 0.2% of global electricity generation, compared with up to 30% from natural gas in OECD countries [12]. However, by 2050, the use of hydrogen in power generation is projected to require 88 Mt H_2/year [4], nearly equivalent to today's total global annual hydrogen production.

As the hydrogen economy develops, the cost of hydrogen produced by low-carbon methods will need to reduce dramatically to compete with the current carbon-intensive hydrogen production methods employed widely today. The totalized cost of low-carbon hydrogen, incorporating the costs of production, transportation, and storage, will be a significant driver in determining which end-use applications adopt hydrogen as either a replacement fuel or feedstock and when. This is particularly true for the use of hydrogen for power generation, which will be competing with other carbon-intensive sectors for this zero-carbon molecule.

Shown in *Figure 2* below are the ranges of current and estimated hydrogen production costs by production method (grey, blue, and green) and year (2020, 2030, and 2050). The range of costs are bounded on the lower end by those which could be achieved at an ideal global location and at the upper end by an average production cost. The current cost range of producing hydrogen through the unbated reformation of natural gas ("grey hydrogen") is €0.70/kg H_2 up to €1.21/kg H_2 [13], compared with €1.23/kg H_2 [10] to €1.79/kg H_2 [14] when including carbon capture ("blue hydrogen"). Grey hydrogen values are constant as they do not account for the expected increase in CO_2 cost in the future. The main contributor to the cost of both grey and blue hydrogen is the natural gas cost, trading at approximately €0.30/kg in Europe prior to significant 2021 market volatility. Current hydrogen production costs through the use of renewables and electrolysis ("green hydrogen") are €3.31/kg H_2 to €4.59/kg H_2 [13], equal to approximately 10 times the natural gas price prior to significant 2021 market volatility. The main contributor to the cost of green hydrogen is the electricity cost. Based on these values, price parity between low-carbon and carbon-intensive hydrogen will be achieved before 2030. Price parity between blue and green hydrogen will start to be achieved by 2030 and green hydrogen is expected to be cheaper by 2050, in ideal production locations. The timeline for price parity between low-carbon and carbon-intensive hydrogen production accelerates if increasing carbon costs are factored in [13].

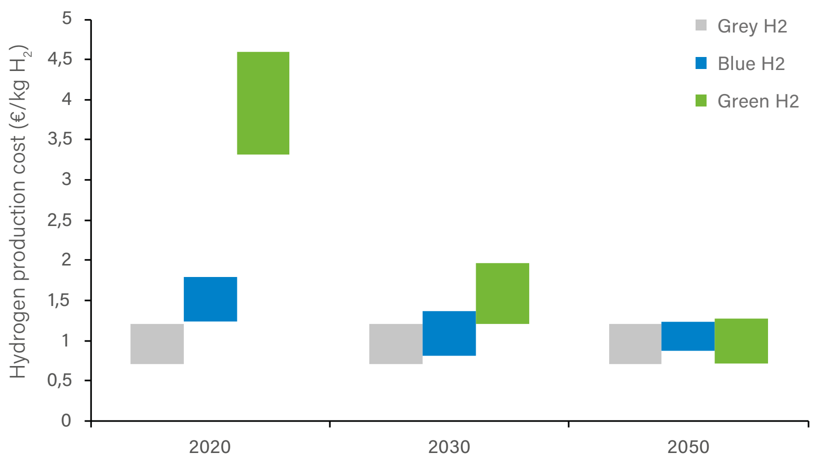

Figure 2: Hydrogen production costs by production method and year

By 2030, blue hydrogen production in Europe is expected to be below €1.50/kg H_2 and green hydrogen production below €2.00/kg H_2 [13]. By 2050, average blue and green hydrogen production costs are expected to be cost-competitive below €1.30/kg H_2 with ideal location costs below €0.90/kg H_2. This rapid reduction in green hydrogen cost is expected to accelerate in the next decade and may reach cost parity with blue hydrogen sooner than projections, perhaps reaching as low as €0.68/kg H_2 by 2050 in idealized locations [15].

It is also important to consider the relative carbon intensity of the varying hydrogen production methods, as this will impact on the true hydrogen cost. However, in this work, the hydrogen price is considered to incorporate any upstream carbon costs from the production and delivery. In general, by 2030, grey hydrogen will produce approximately 10 kg $CO_{2,eq}$/kg H_2, blue hydrogen approximately 2 kg $CO_{2,eq}$/kg H_2, and green hydrogen approximately 0.6 kg $CO_{2,eq}$/kg H_2 [16]. Refer to *Table A.1 in Appendix A* for further information on the projected carbon intensity of different hydrogen production methods in 2030.

In addition to hydrogen production costs, hydrogen transport and storage costs are not insignificant. Most hydrogen produced today is used near the point of production, so large-scale global hydrogen transport and storage infrastructure needs to be developed. It is difficult to predict future global transport and storage costs, but they have been estimated to be approximately €1.20/kg H_2 to €2.20/kg H_2 by 2030 [13], which would nearly double the cost of hydrogen at the point of delivery, depending on the production method and location.

2.2. Carbon cost

Global warming and the consequent increase in the average earth temperature is one of the most important environmental issues of the 21st century. The correlation between temperature increases and greenhouse gas (GHG) emissions is recognized worldwide by the scientific community, and it is clear the importance to control and reduce these emissions. The most abundant GHG in the atmosphere is carbon dioxide (CO_2), whose emissions have strongly increased in the last decades due to anthropogenic activities mainly correlated to the combustion of fossil fuels (e.g., stationary power production).

To limit the effects related to the CO_2 rise and meet Kyoto's targets first and then the 2050 climate target, the European Union (EU) developed and promoted the Emission Trading System (ETS) that today operates in 30 Countries (27 EU Countries, plus Norway, Iceland, and Lichtenstein) and represents the world's largest platform of this kind [17]. The system was launched in 2005 with a 3-year pilot (Phase I – 2005-2007) and today is at the beginning of the fourth phase (Phase IV 2021-2030). The EU ETS works on the "cap and trade" principle: a cap is set on the total amount of GHGs that can be emitted by installations covered by the system, and it corresponds to a number of allowances (one European Union Allowance, EUA, represents the right to emit 1 ton of CO_{2eq}). Each year, part of the allowances is given for free while the rest is sold through auctions. Within the cap, companies receive or buy emission allowances, which they can trade with one another as needed. At the end of each year, a company must surrender enough allowances to cover all its emissions, otherwise, a penalty is imposed for non-compliance (set at 100€/tCO_2 and rising with EU inflation from 2013) [18] [19]. The value of the EUAs is guaranteed to the fact that their number is limited and gradually reduced over the years forcing the companies to be virtuous in reducing emissions and promoting the technology development towards the use of alternative fuels (e.g., Hydrogen): since the start of the EU ETS in 2005, emission from stationary installations have decreased by about 35% [20]. In Phase IV, the cap for stationary installations will annually decrease with a linear factor of 2.2% [21].

The EUAs price is affected by several parameters (allowances availability, supply and demand balance, Renewable Energy Sources (RESs) exploitation, general economy of the member states) and, therefore, its value fluctuated in recent years. For example, due to the financial and economic crisis of 2008, the emissions of the industrial sector sharply decreased and so did the allowances demand; as a result, between 2009 and 2013, a surplus of EUA accumulated and this reflected in a lower EUA price. In response to this situation and to avoid a "carbon lock-in", a so-called "backloading measure" was put in place and the foreseen number of allowances originally planned to be allocated between 2014 and 2016 was significantly cut and the EUA price increased again [20]. Due to the continuous evolution of the energy and EUA markets, it is difficult to predict the future values of the EUA price. However, considering the gradual reduction of the available allowances in the EU-ETS, it is reasonable to expect an increase in the EUA price in the future. *Figure 3* reports both the historical data and future projections to 2050 of the yearly allocated EUA, verified emissions, EUA Cap, and EUA Price.

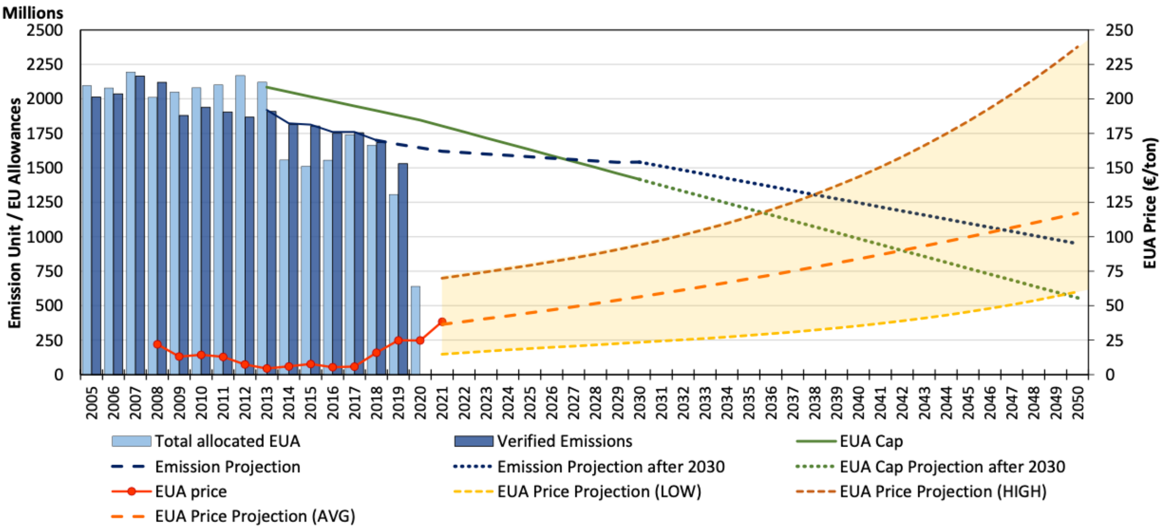

Figure 3: Historical data and future projections till 2050 of the yearly allocated EUA, verified emissions, EUA Cap, and EUA Price [20] [22] [23] [24] [25] [26]

The values reported for the EUA price projection are the results of the interpolations of different literature studies [18] [24] [25]. Due to the uncertainties affecting the EUA price, three different projections are reported: the average, low, and high scenarios to which corresponds a EUA Price range in 2050 between 60 €/tCO_2 and 235 €/tCO_2.

The use of hydrogen to decarbonise gas turbines operating on natural gas will also have an impact on the resulting carbon cost associated with the gas turbine operation. As shown in *Figure 4*, the blending of hydrogen into natural gas in a high-efficiency GE 9HA.02 CCGT will reduce the carbon intensity of the operations, resulting in an annual carbon cost savings (based on 6000 hours operation). For example, a blend of approximately 75% hydrogen by volume into 25% methane (representing natural gas), would result in a 50% reduction in CO_2 emissions and over €40M in annual carbon savings (assuming a carbon price of €50/tCO_2). Note that the analysis here does not consider the lifecycle carbon intensity of the hydrogen production, transport or storage, but rather only considers the carbon emissions at the point of hydrogen use. Refer to Section 3.2 and *Table A.1 in Appendix A* for further details on the carbon intensity of different hydrogen production methods, consideration of which is outside the scope of this study.

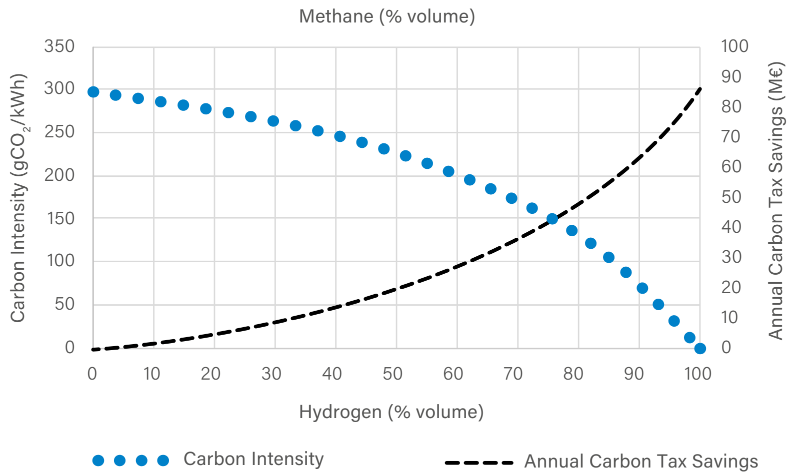

Figure 4: Carbon intensity and annual carbon tax savings for a GE 9HA.02 CCGT with increasing amounts of hydrogen blending into natural gas. Produced using GE's Hydrogen Calculator [27] assuming a carbon price of €50/tCO_2 and 6000 annual operating hours.

2.3. Levelized cost of electricity (LCOE)

Today's energy sector is more variegated than ever, with many different technologies taking part in the different markets. In particular, the electricity sector saw an increasing presence of RESs and the contemporary phasing out of coal during recent years, especially in Europe. This was the result of political maneuvers aimed to eliminate the most polluting technologies that were, at first, substituted with gas-fired CCGT. As shown in *Figure 5*, due to the low cost of gas and their high efficiency, CCGTs are a competitive choice against traditional coal plants in many parts of the world. Particularly in the US, the LCOE of CCGT can be as low as 30 €/MWh thanks to a domestic abundance of fuel. However, the situation could be the opposite for those countries (e.g., China) where natural gas must be imported while coal is cheaply available in the domestic market.

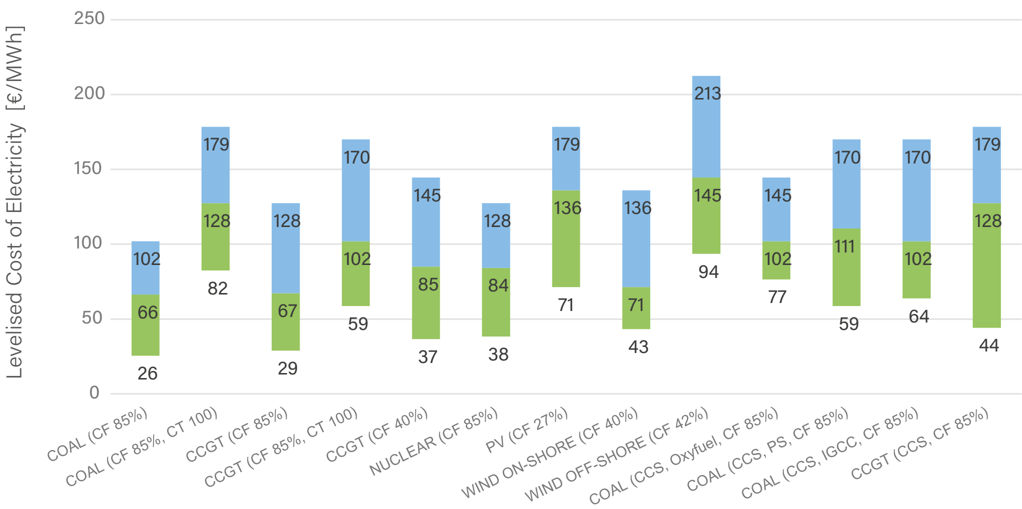

Figure 5: Levelized cost of electricity (LCOE) for different technologies active in today's electricity market. For each one, the minimum, median and maximum LCOE (10th, 50th, and 90th percentile) are shown. CF stands for capacity factor, CT for carbon tax (€/tCO_2), CCS for carbon capture and storage and PS for post combustion (referred to CCS). [28] [29].

Switching fuel from natural gas to hydrogen in gas turbines increases the LCOE. According to a recent analysis [30], running a CCGT with green or blue hydrogen is expected to increase the LCOE to a value equal to 127 €/MWh and 88 €/MWh, respectively.

Environmental regulation can also play an important role. When a carbon tax of 85 €/tCO_2 is considered, coal plants (that operate with a higher carbon intensity per unit energy generated) would be penalized in comparison with CCGT plants, which emit half of the CO_2 specific emission of an average coal plant.

Regarding CCS technology, although very few plants are currently operational, data suggest that CCGT with CCS might not be as competitive against the other coal-based technologies. However, in the US a CCS coal plant has a LCOE ranging from 100 €/MWh to 124 €/MWh, compared with as low as 60 €/MWh for a CCGT with CCS (no carbon tax) [29].

Peaking plants, which are mainly OCGTs, are characterized by an LCOE in the range of 128 €/MWh - 168 €/MWh at the current state [30]. The higher cost of electricity coming from this kind of plant results from the lower utilization factor and efficiency of the system.

Considering nuclear power, this is still the main source of electricity in some countries (e.g., France and Switzerland) and still today has a competitive LCOE. However, many plants are due to be dismantled since they have reached their design life. According to [29], by revamping the existing plants and extending their life by 10 years, an LCOE as low as 30 €/MWh could be obtained, compared with a value of 64 €/MWh for a new build.

Finally, RES have experienced both reduced capital cost and increased efficiency in the last decade. This, together with local incentives, has reduced the LCOE of both solar PV and wind turbines to levels competitive with fossil fuels. By looking at *Figure 5*, a wide range between the maximum and minimum LCOE values is evident. This is because LCOE is dependent on the weather conditions of the specific geographic location considered. In fact, while in Spain the LCOE for a solar PV field can go as low as 74 €/MWh, in the UK this value is much higher (159 €/MWh) [31]. It is important to point out that current LCOE of utility scale solar PV and wind farms could be as low as 26 €/MWh and 22 €/MWh, respectively, for some specific scenarios [30].

Despite the increasing competitiveness of renewable sources, they are still unable to compete in the ancillary services market due to their uncertain nature. For this reason, flexible and responsive power generation will continue to be necessary to provide security of supply to the grid.

2.4. Review of European natural gas-based plants installed capacity

The role of natural gas in electricity generation is essential, especially for developed and OECD countries. In 2019, the EU and US alone accounted for more than 47% of the worldwide capacity of natural gas-based plants with 176 GW_e and 526 GW_e of net installed capacity, respectively, corresponding to 24.5% and 44% of the total installed generation capacity [32], as highlighted in *Table 2*.

Table 2: Natural gas-based installed capacity for electricity generation across US, EU and worldwide [32]

	World	EU27+UK	US
NG-based capacity:	1473 GW_e	173 GW_e	526 GW_e
NG-based share of total capacity:	26.4%	24.5%	44.0%

According to the IEA [33], natural gas accounts for 22% of the share of actual electricity generation in EU countries, representing the primary source with the highest contribution to the electricity supply and the same holds in the US, where the share rises to 37%.

Figure 6 shows the regional distribution of NG-based technologies for centralized electricity production in Europe: some clusters of plants can be identified in key areas, with elevated population density and scarcity of other natural resources (e.g., hydropower).

Figure 6: Map of NG-based plants in Europe [32]

Referring to *Figure 7*, Italy has the highest total installed capacity of NG-based power plants, followed by the UK, Spain, Germany and the Netherlands. These countries alone represent about 75% of the total European installed capacity. Considering the share of electricity generation from NG, it can reach up to 50% in some countries (e.g., Italy, the Netherlands, and Ireland) and it still provides a main contribution to many national energy mixes.

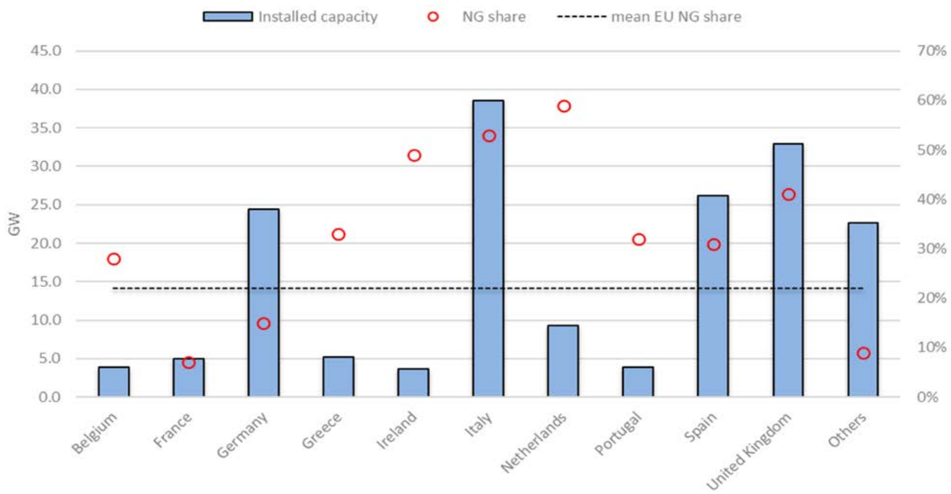

Figure 7: NG-based power plants installed capacity (blue bars) and share of NG in the total electricity production (red dots) of EU countries. Source: [32].

Figure 8 reports the cumulative capacity and the number of NG plants divided by different size ranges. There are many plants with low capacity installed (< 100 MW_e) which reduces when considering higher capacity ranges. In terms of capacity, the contribution of small to medium units (< 250 MW_e) is limited while larger plants (> 250 MW_e) are responsible for the highest generation potential, accounting for 88% of the total generation capacity.

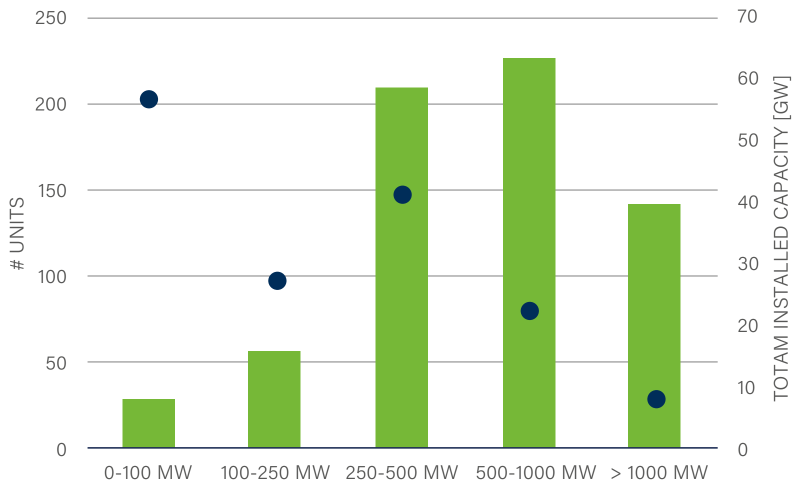

Figure 8: NG-based power plant units in EU countries classified by size range. On the right axis is reported the total capacity (GW_e output), on the left axis the number of units (black dots). Source: [32] (< 100 MW) and [34] (> 100 MW).

It should be noted that the intermediate size range (250-500 MW_e) is relevant from both unit number and installed capacity standpoints and correspond to the size bin of the average plant capacity (around 300 MW_e), computed as the total capacity divided by the total number of units. This trend could be the result of large plants decommissioning in favor of smaller plants, which are more flexible in the current and unpredictable market conditions, continuously changing because of the increase of the renewable power penetration [35].

2.5. Hydrogen gas turbines

Gas turbines can play a key role in bridging the gap between the current and future energy technologies. They can effectively facilitate the pathway towards the net-zero carbon footprint by providing high reliability, high power density, and excellent load following ability. In fact, thanks to fast start-up ramping capabilities, low minimum up- and down-time requirements, gas turbines are suitable to fill the gap between RES generation and electrical demand of virtually any kind of user (residential, commercial, or industrial). Given the inherent advantages of gas turbines, they have consistently evolved to improve efficiency while also using an increasingly variable fuel composition. As a result, while natural gas is currently plentiful, strategies for using hydrogen derived from low-carbon or renewable sources must still be pursued if a significant reduction in carbon emissions is to be achieved. Therefore, future hydrogen gas turbines, such as that shown in *Figure 9*, which are fuel flexible, operationally reliable, and cost-effective are under development by nearly all major GT manufacturers, who have pledged to bring 100% H_2-ready gas turbines to market by 2030 [36].

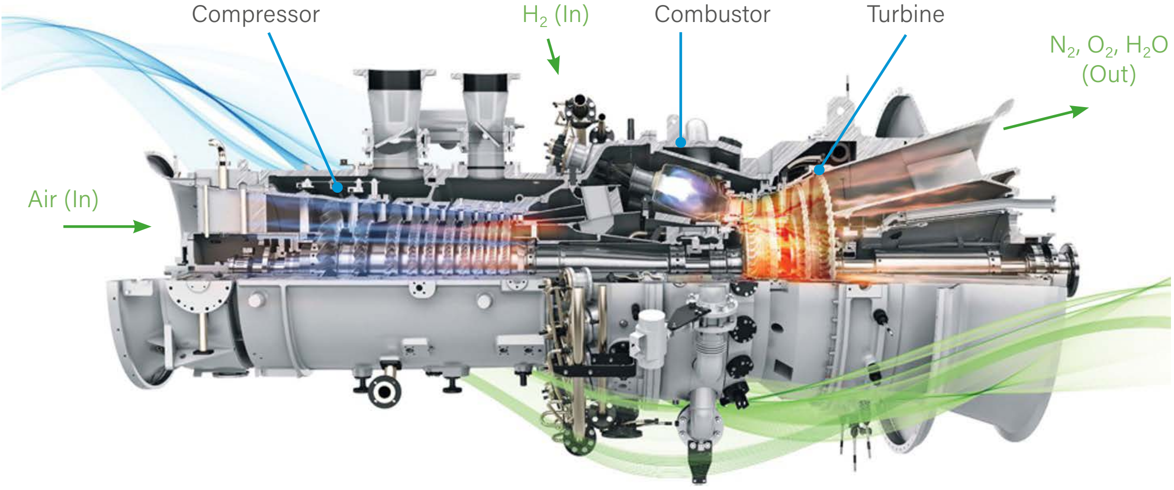

Figure 9: Sectioned view of a carbon-free gas turbine operating on hydrogen fuel

2.6. Hydrogen combustion systems

When considering the use of hydrogen as a fuel in a gas turbine, it is the combustion and fuel injection system that will be most impacted. Gas turbine combustion systems generally fall into two main categories, diffusion (or non-premixed) and lean premixed. Diffusion combustors generally offer high amounts of fuel flexibility; however, they are also characterised by high levels of regulated emissions such as nitrogen oxides (NO_x) and carbon monoxide (CO). Water or steam injection into a diffusion combustion chamber will often be used to help control these emissions. By comparison, lean premixed combustors have been optimized for decades to burn fuels such as natural gas with low NO_x and CO emissions without the need for additional dilution. As such, lean premixed systems are often referred to as dry low emissions (DLE) or dry low NO_x (DLN) by gas turbine original equipment manufacturers (OEMs).

Hydrogen, high-hydrogen syngas, and hydrogen blended with natural gas, have been used as fuels in gas turbines for many years, with OEMs compiling millions of hours of operational experience. In fact, many gas turbine OEMs offer products today which are capable of operation on up to 100% hydrogen using diluted diffusion combustion systems. However, as these use cases rely on diffusion combustion due to hydrogen's high chemical reactivity, they are therefore unlikely to meet strict emissions regulations. In DLE or DLN combustion systems, the use of hydrogen is typically limited to a maximum of approximately 20-75% by volume in a blend with natural gas, with the exact allowable amount varying across the OEMs, gas turbine types, and sizes as shown in *Figure 10*. The latter provides current commercial capability for a new-build gas turbine, and it is compiled from the recent review by Noble et al. [37] in addition updated publicly available product information and the Hydrogen Gas Turbines report from the European Turbine Network (ETN Global), which provides a comprehensive analysis of hydrogen capability across the gas turbine OEMs [7]. The hydrogen capability resulting from retrofit of existing DLN/DLE gas turbines will largely depend on the gas turbine type, current combustion system, and other key plant limitations, but in general the current retrofit capability is expected to be less than that shown in *Figure 10*. Multiple OEMs have committed to have emissions-compliant, 100% hydrogen-capable gas turbines commercially available by 2030 [36]. Thus, further research and development work is required for these DLN combustion systems in the next decade.

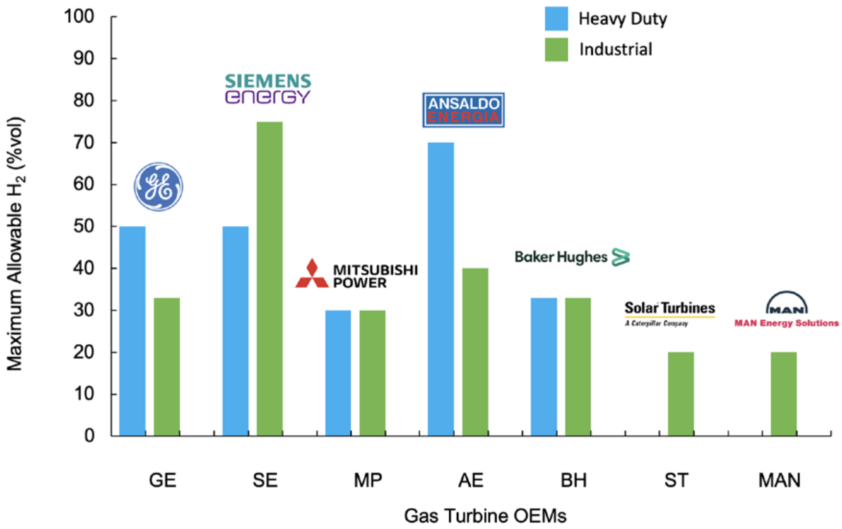

Figure 10: DLN hydrogen capability in a blend with natural gas by GT OEM (GE: General Electric, SE: Siemens Energy, MP: Mitsubishi Power, AE: Ansaldo Energia, BH: Baker Hughes, ST: Solar Turbines, MAN: MAN Energy Solutions)

2.7. Hydrogen gas turbine R&D, projects, and targets

Most of the research and development effort that is relevant to the use of hydrogen for centralized power generation is localized in the EU27, Norway, UK, US, and Japan. Below is an overview of ongoing projects and announced targets:

EUROPE	
EU-funded Projects	
FLEXnCONFU (2020-2024)	**FLE**xibilize combined cycle power plant through power-to-**X** solutions using non-**CON**ventional **FU**els
HYFLEXPOWER (2020-2024)	**HY**drogen as a **FLEX**ible energy storage for a fully renewable European **POWER** system
ROBINSON (2020-2024)	Smart integ**R**ation **O**f local energy sources and innovative storage for flexi**B**le, secure and cost-efficIent e**N**ergy **S**upply **ON** industrialized islands
H2-IGCC (2009-2014)	To provide and to demonstrate technical solutions which allow the use of state-of-the-art highly efficient, reliable gas turbines (GTs) in the next generation of Integrated Gasification Combined Cycle (IGCC) power plants
Joint Industry Projects	
Nuon Magnum Power plant (NL) Key Partners: Equinor, Vattenfall, Mitsubishi More details: link |link	**Conversion of Vattenfall's Magnum gas-fired power plant to run on hydrogen**. 440MW unit on 100% Hydrogen By 2023
NorthH2 project Key Partners: Equinor More details: link | link	**Use of renewable electricity coming from offshore wind off the Netherlands coast to produce green hydrogen**: 2030: About 4 GW 2040: About 10+ GW

H2morrow steel (GER) Key Partners: Equinor More details: link	**Generation and transport blue hydrogen to the biggest steel plant in Germany**: Entire project's value chain could be established by 2027 (earliest) Two production capacity scenarios: 1.4 GW or 2.7 GW
H-vision blue hydrogen project (NL) Key Partners: Equinor More details: link | link	**To produce and to use of blue hydrogen in Rotterdam industries to significantly reduce their CO_2 emissions well before 2030**. 1st plant of 750 MW by 2026
High Hydrogen Gas Turbine Retrofit to Eliminate Carbon Emissions (NL) Key Partners: OPRA Turbines, Thomassen Energy More details: link | link	**To develop a cost-effective ultra-low emissions (sub 9ppm NOx and CO) combustion system retrofit for existing installed gas turbines** Output range: 1 MW to 300 MW Fuel flexibility: stable operation from 100% natural gas to 100% hydrogen 1st engine demonstrator by 2023.
Keadby Hydrogen (UK) More details: link | link	**To become the first 100% hydrogen-fired power station in the region**, 900 MW gas turbine (OEM not known) Project announced, no financial decision yet
H2GT-Lingen Key partners: RWE Generation SE & Kawasaki Heavy Industries More details: link	**H2GT-Lingen will be one of the world's first pilots to test 100% hydrogen-to-power conversion on an industrial scale turbine**. H_2 load ranges: 30%-100% Operational mid-2024
JAPAN	
Japan's Basic Hydrogen Strategy More details: Key points | Full text | Specific projects | link	**Commercialisation of hydrogen power generation at the GW scale and development of an international H_2 supply chain** Domestic Power-to-Gas. Budget of $238M (¥26bn) Demonstration project of a hydrogen-fired or co-fired gas turbine power generating technology (April 2021)
Mitsubishi Power More details: link	**Achieving 100% hydrogen combustion technology for power generation by 2025**. 30% H_2 – 70% H_2 commercial operations by 2025
Kawasaki Heavy Industries More details: link | link	**1 MW H_2 CHP gas turbine in urban area** Demonstration project (2018) 100% Hydrogen
NORTH AMERICA	
US DoE FE Hydrogen Strategy	**Achieve a carbon pollution-free electricity sector by 2035** $6.4M to develop hydrogen-fueled gas turbines (December 2020) $2.2M to develop hydrogen energy storage systems integrated with NG power generation (December 2020) **Achieve economy-wide net-zero emissions by 2050** Large frame turbines and internal combustion engines able to fire 100% H_2 by 2030
Long Ridge Energy Terminal Key Partners: General Electric	485 MW, 7HA.02 gas turbine 15% hydrogen to start, up to 100% hydrogen by 2030
IPP + ACES More details: link | link | link	**Hydrogen storage and power facility project by Mitsubishi Power and Magnum Development in Utah**. 250MW underground storage by 2025 **Mitsubishi Power with 600MW JAC-series gas turbines** 150GWh storage
Western Canada Net-Zero Hydrogen Energy Complex More details: link | link	**Blue hydrogen production and hydrogen power plant in Alberta, Canada** Auto-thermal reforming (ATR) with 95% carbon capture Baker Hughes NovaLT16 gas turbines

3. Case study description and main assumptions

3.1. Levelized cost of electricity (LCOE)

The levelized cost of electricity (LCOE) is a parameter used to compare different methods of electricity generation. It is defined as the ratio between the sum of all the costs needed to build, operate, maintain, upgrade, and dispose a power plant over its lifetime, and the sum of the electrical energy produced over its lifetime.

Considering a generic thermal power generation plant, equipped with a gas turbine burning natural gas (NG)/Hydrogen (H_2) blends, the LCOE can be expressed as:

$$\mathrm{LCOE} = \frac{\sum_{i=0}^{N} \frac{(I_i + U_i + FixO_i + VarO_i + NG_i + H_i + CO_{2i})}{(1+r)^i}}{\sum_{i=0}^{N} \frac{E_i}{(1+r)^i}}$$

Legend:

I_i Plant investment cost per year. The investment cost is an initial cost depending on plant's size and configuration.

U_i Plant upgrading costs annual rate. These costs are relevant to all the upgrades needed in the plant to burn NG/H_2 blends up to 100% H_2. They are calculated as a percentage value of the investment cost and depend on the volume percentage of hydrogen in the fuel blend. The plant upgrading costs annual rate. Is calculated as follow:

$$U_i = U * \frac{r * (1+r)^n}{(1+r)^n - 1}$$

$FixO_i$ Plant fixed operation and maintenance costs per year. The fixed costs are considered over the plant's lifetime and depend on the plant's size, configuration and operating regime (e.g., peaking or baseload). These costs include scheduled gas turbine maintenance.

$VarO_i$ Plant variable operation and maintenance costs per year. The variable costs are considered over the plant's lifetime.

NG_i Natural gas cost per year. This is the cost of the tons of natural gas burnt in the gas turbine over the plant's lifetime. The overall cost is estimated by predicting the trend of the natural gas market price (€/tNG) over the life of the plant and calculating the tons of natural gas needed for gas turbine operation. The calculated amount of natural gas depends on gas turbine size, operation and on the percentage in volume of natural gas present in the fuel blend, if any.

H_i Hydrogen cost per year. It is the cost of the tons of hydrogen burnt in the gas turbine over the lifetime. The overall cost is estimated by predicting the trend of the hydrogen market price (€/tH_2) over the life of the plant, considering the different hydrogen production methods: blue, green and grey. The calculated amount of hydrogen depends on gas turbine size, operation and on the percentage in volume of hydrogen present in fuel blend, if any.

CO_{2i} Carbon tax cost per year (€/tCO_2). The carbon tax price is estimated over the life of the plant, while the amount of CO_2 emitted is calculated for the entire lifetime of the plant and depends on gas turbine size, operation and fuel blend mixture.

E_i Energy produced over the plant's lifetime. It depends on plant size configuration and operation.
$E_i = P_{out} * h_i$ (MWh), with P_{out} the plant's power output (MW_e) and h_i the gas turbine running hours per year.

r Weighted Average Cost of Capital (WACC). This parameter has been used to estimate the annual rate of the initial investment for the plant upgrade. A 6% of WACC is considered as an approximate average European value [38].

N Number of years of plant's lifetime

The LCOE is therefore influenced both by technical and economic parameters. The technical parameters affecting the LCOE are the GT plant size and configuration, nominal power, efficiency, and the GT operating conditions. The economic parameters taken into consideration include investment costs, fixed costs, variable costs, upgrading costs, natural gas purchasing cost, hydrogen purchasing cost, and CO_2 taxation cost.

Focusing on the retrofit of a gas turbine in an existing power generation plant, the initial plant investment is neglected in the LCOE calculation, other than in calculating the plant upgrading cost. Therefore, the plant's initial investment is assumed to be paid back at the time of upgrade and plant's lifetime after upgrade is assumed to be 20 years. No internal rate of return has been considered.

3.2. Case study description and main assumptions

To analyse the impact of hydrogen utilisation in centralised power generation units, LCOE has been calculated for the upgrade of five types of thermal power plants, selected to cover a wide range of possible scenarios. The analysed case studies are summarised in *Table 3*. Note that efficiencies are reported on an LHV basis at ISO conditions.

Table 3: Hydrogen gas turbine case studies considered in the LCOE evaluation

GT Type	GT Output (MWe) @ISO	GT Efficiency @ISO	Overall Efficiency @ISO	Configura-tion	Operating regime	Annual equivalent operating hours	Annual start and stop cycles	Designa-tion
Small	20	36.5%	36.5%	OCGT	Peak	800	150	S-OCGT
Small	20	36.5%	70%	CHP	Base	6000	10	S-CHP
Medium	60	41%	41%	OCGT	Peak	800	150	M-OCGT
Large	450	44%	44%	OCGT	Peak	800	150	L-OCGT
Large	450*	44%	64%	CCGT	Base	6000	10	L-CCGT

*Combined cycle output = 650 MW_e @ ISO

The S-OCGT case study refers to the retrofit of a 20 MW_e gas turbine operating in a peak mode in an open cycle configuration.

The S-CHP case study refers to the retrofit of a 20 MW_e gas turbine operating in a Combined Heat and Power (CHP) plant with a heat output of 23.6 MW_{th}.

The M-OCGT case study refers to the retrofit of a 60 MW_e gas turbine operating in a peak mode in an open cycle configuration.

The L-OCGT case study refers to the retrofit of a 450 MW_e gas turbine operating in a peak mode in an open cycle configuration.

The L-CCGT case study refers to the retrofit of a 450 MW_e gas turbine operating in a combined cycle power plant with a total output of 650 MW_e.

For each case study, the LCOE has been assessed comparing different natural gas-hydrogen blends from 0% to 100% of hydrogen content by volume, as shown in *Table 4*.

Table 4: Natural gas-hydrogen blends considered in LCOE evaluation

Blend NG-H_2 (vol%)					
Natural Gas	100%	70%	50%	30%	0%
Hydrogen	0%	30%	50%	70%	100%

The NG-H_2 blends mass (mass%) and volume (vol%) balance and CO_2 reduction potential are shown in *Figure 11* and *Figure 12*, respectively. Similar to *Figure 4*, *Figure 12* shows that carbon-free emissions from the point of use can be achieved when operating a GT with 100% H_2. This does not account for the carbon intensity associated with the hydrogen production method or transport and storage. It is therefore assumed that the GT operator is not responsible for the carbon costs associated with the hydrogen production method, and that low-carbon hydrogen is available for delivery to the site. A consideration of the lifecycle carbon intensity of the hydrogen is outside the scope of this study, as well as consideration of the interconnected relationship between natural gas price and hydrogen price in the production of blue hydrogen. However, it is reasonable to assume that any carbon costs associated with the hydrogen production would be represented in the hydrogen delivery cost to site, which further necessitates the sensitivity analysis undertaken on hydrogen price. For an indicative carbon intensity based on the hydrogen production method, refer to *Table A.1 in Appendix A*.

Hydrogen purity is assumed to be 100% in this work, however, it is noted that in practice hydrogen may contain impurities based on the application. For example, ISO 14687 [39] provides for a minimum gaseous hydrogen quality of 99.9% for Type I, Grade B applications which include industrial fuel for power generation and heat generation while EN 17124 [40] stipulates a hydrogen purity of 99.97% for proton-exchange membrane (PEM) fuel cell road vehicles. Note that GTs are expected to tolerate a wider variation in fuel composition, including hydrogen purity, than PEM fuel cells for transport, power, and heat applications. The Lower Heating Values (LHV) used for a standard NG blended with H_2 are reported in *Appendix A, Table A.2*.

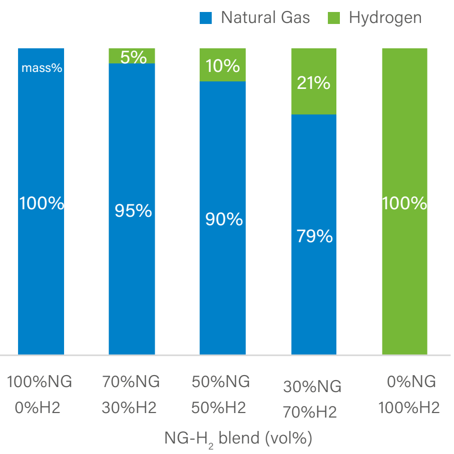

Figure 11: Natural gas-hydrogen blend mass and volume balance

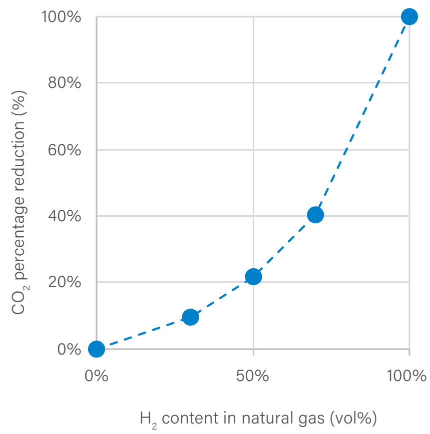

Figure 12: CO_2 reduction resulting from hydrogen blending into natural gas

For retrofit of existing gas turbines, it is assumed that in order to maintain the NO_x emissions less than or equal to 25 ppm (dry, 15% O_2) by using DLN gas turbine combustion technology, it would be required to derate the GT output power to reduce the flame temperature when, in NG-H_2 blends, the hydrogen content increases above 10 vol%. Therefore, the nominal gas turbine power output after the upgrade has been decreased assuming a derating factor that increases linearly with hydrogen content in volume > 10%, as shown in *Table 5*. A further additional case has also been considered which assumes that the GT OEMs are able to provide a future DLN retrofit solution for 100% hydrogen firing without GT power output derating for NO_x emissions compliance.

Due to the assumed derating of the GT output power described above, a decrease factor has also been applied to the GT efficiency for hydrogen above 10 vol% in the NG-H_2 mixtures, with efficiencies shown in *Table 5*. The decreasing factor has been estimated considering typical values for a given power output derating. It is worth noting that at this stage it is not possible to predict the impact on the efficiency of a specific optimization of machine design. An ideal case has also been considered which assumes that the GT OEMs are able to provide a future DLN retrofit solution for 100% hydrogen firing without an efficiency penalty for NO_x emissions compliance.

Considering the GT power output (P_{out}), the LHV of the fuel mixture (LHV_{blend}), the plant efficiency (η), and the GT operating conditions, it is possible to estimate the tons of H_2 and NG burnt per year ($\dot{m}_{\mathrm{blend}}$).

$$\dot{m}_{\mathrm{blend}} = \frac{P_{out}}{\eta * LHV_{blend}}$$

Focusing on the retrofit of a gas turbine in an existing power generation plant, the initial investment cost to build the power plant has been neglected in the LCOE calculation, however this value has been considered in the evaluation of the upgrading costs. The initial investment costs considered for the case studies are given in *Table 6*. The initial investment costs (I_i) for the reference case (100% NG) have been derived from the 2021 GT World Handbook [41], reporting the GT bare equipment cost, assuming a ratio of the equipment cost to the total investment cost of 50% [42].

The costs needed to upgrade the gas turbine and the plant to burn NG-H_2 blends have been considered as a percentage of the plant's initial investment costs as shown in *Table 5*. The upgrading costs are limited to only the retrofit of the GT combustion chamber and minor control system changes to either 25 vol% H_2 (ISO/IEC 80079-20-1:2019 [43]) or 30 vol% H_2 (IEC 60079-10-1:2020 [44]) content in NG-H_2 blend, depending on the safety standard employed. Above 30 vol% H_2 content, in addition to the gas turbine retrofit, plant equipment must be adapted to the process gas to ensure functionality and compliance with regulations (IEC60079-10-1:2020, Annex H [44]).

The costs related to the plant's operation and scheduled maintenance have been considered in $FixO_i$. They have been estimated over the plant's lifetime of 20 years and can vary significantly depending on the plant's size, GT type and operating regime (*Table 6*). These costs exclude fuel and carbon costs, considered separately. As it is difficult to provide a prediction, an average value per year has been considered. The increased maintenance cost due to NG-H_2 blend has been considered by introducing a maintenance factor increasing linearly with vol% of H_2 in the blend as shown in *Table 6*. Assuming no technology development costs, the Variable Operation and maintenance costs ($VarO_i$) have been assumed not varying with vol% of H_2 in the blend and equal to the reference values reported in *Table 6*.

The GT upgrade and fixed maintenance costs, the GT derating factor, and GT efficiency, which vary as a function of H_2 blending level, have been developed through extensive internal consultation and review with ETN member organizations, including GT OEMs and GT users. For low levels of hydrogen blending, the values are currently well-developed, but for higher H_2 blending retrofits applications are currently limited and therefore assumptions were made on these values.

Table 6 summarises the power plant initial investment cost $I_{i,}$ the fixed operation cost ($FixO_i$), and the variable operation and maintenance costs ($VarO_i$) considered for the reference case (100% NG).

Table 5: Key parameters modification with increasing hydrogen content, *detailed tables in Appendix A*

	Blend NG-H_2 (H_2 vol%)					
	NG (0)	**NG-H_2 (10)**	**NG-H_2 (30)**	**NG-H_2 (50)**	**NG-H_2 (70)**	**H_2 (100)**
Derating factor (% of power of GT / cycle)	reference value *(Table 3)*	0%	-3%	-7%	-10%	-15%
Efficiency impact (efficiency points of GT / cycle)	reference value *(Table 3)*	0 pts	-0.3 pts	-0.6 pts	-0.9 pts	-1.3 pts
Upgrading cost factor, U (% of $I_{i,}$ *Table 6*)	n/a	3%	4%	20%	22.5%	25%
Maintenance factor (% of $FixO_{i,}$ *Table 6*)	reference value	+0%	+15%	+25%	+35%	+50%

Table 6: Power plant initial investment cost I_i, fixed operation and maintenance costs $FixO_i$ and variable operation and maintenance costs

	I_i [€/kW]	$FixO_i$ [€/kW]	$VarO_i$ [€/kW]
S-OCGT	850	25	0.002
S-CHP	1100	30	
M-OCGT	600	25	
L-OCGT	300	30	0.004
L-CCGT	550	35	

Table 7 reports the value of Hydrogen cost, Natural Gas cost, and CO_2 price considered for the reference case.

Table 7: Hydrogen cost, Natural gas cost, and CO_2 price reference value

Hydrogen cost	Natural gas cost	CO_2 price
1.5€/kg	20€/MWh	50€/ton

Where necessary throughout this paper, US dollar values were converted to Euros using an exchange rate of $1.00 = €0.85.

4. Case study results

The following section provides results for each of the five case studies detailed in *Table 3*. The economic impact of hydrogen blending into natural gas up to 100% hydrogen is therefore determined for a range of possible gas turbine sizes and configurations. Unless otherwise stated, each set of results utilises the reference conditions given in *Table 7* as a basis for the analysis.

4.1. S-OCGT

The S-OCGT case considers the progressive decarbonisation of a small open cycle gas turbine, used in peak operation mode with increasing levels of hydrogen blending. The selected operating regime considered in this analysis is provided in *Table 8*.

Table 8: S-OCGT case study parameters used in the LCOE evaluation

GT Type	GT Output (MWe) @ISO	GT Efficiency @ISO	Overall Efficiency @ISO	Configura-tion	Operating regime	Annual equivalent operating hours	Annual start and stop cycles	Designa-tion
Small	20	36.5%	36.5%	OCGT	Peak	800	150	S-OCGT

A first consideration of the impact of hydrogen blending on CO_2 emissions is reported in *Table 9*, and follows the trends described in *Figure 12*.

Table 9: Specific CO_2 emissions for the S-OCGT case with increasing H_2 blending in NG (%vol)

	Blend NG-H_2 (H_2 vol%)				
	NG (0)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Emissions [kgCO_2 / MWhe]	521	466	411	319	0

4.1.1. LCOE and LCOE breakdown

Figure 13 reports both the LCOE value and the LCOE contribution breakdown for the S-OCGT case considering different H_2 volume percentage blended with natural gas up to 100% hydrogen.

For the base case (100%NG), the LCOE is 101€/MWh and the most significant cost contribution is the NG cost (53.5%) followed by the CO_2 cost and the FixO cost at 25.9% and 18.6%, respectively.

By increasing the H_2 content in the blend the contributions of the NG cost and the CO_2 cost progressively decrease until reaching 0% for the 100%H_2 case. On the other hand, the FixO costs slightly increase, and the upgrading cost and the hydrogen cost must be added, resulting in an increasing LCOE value: from 113€/MWh for the 30%H_2 case up to 191€/MWh for the 100%H_2 case (+89% compared to the base case).

The contribution of the H_2 cost increases when increasing the H_2 content and becomes the main cost item in the 70%H_2 case at 33.0% and in the 100%H_2 case at 67.1%.

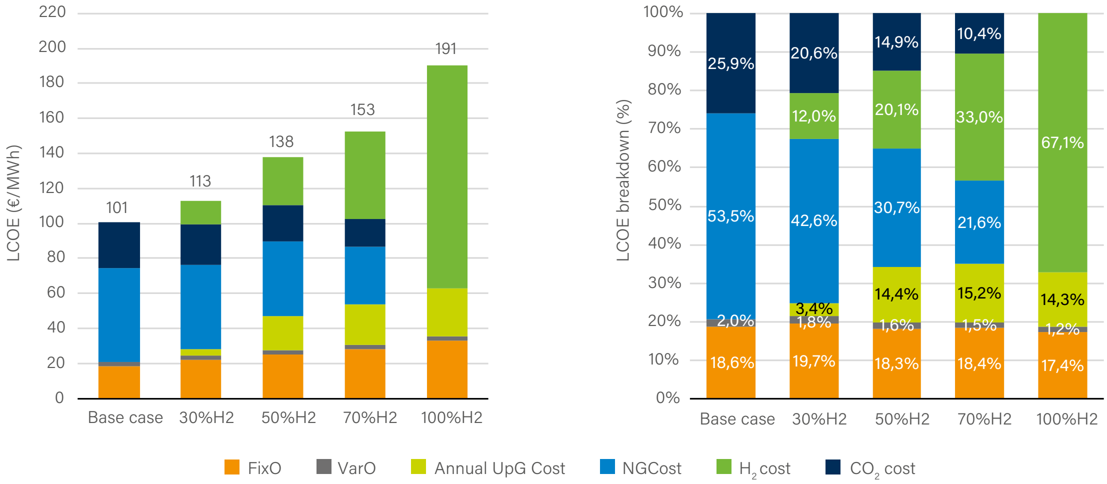

Figure 13: S-OCGT LCOE value (left) and LCOE breakdown (right) for increasing H_2%vol in NG

4.1.2. Sensitivity analysis – LCOE variation with CO_2, NG and H_2 price variations

Based on the LCOE calculation results, a sensitivity analysis was carried out to evaluate and compare the impact of the three main variable costs (i.e., NG price, CO_2 price, and H_2 price) and of the plant capacity factor (represented by Equivalent Operating Hours, EOHs) on the LCOE. The analysis considers an increment of 50% of the reference price values given in *Table 7* for different EOHs (800, 2000, 4000, 6000) and evaluates the LCOE percentage increase for the different cases. The results are plotted in *Figure 14*.

Considering the EOH reference value for the S-OCGT case (800 EOH), the results show that for the NG price variation, the maximum percentage increment (27%) on the resulting LCOE is for the reference case (100%NG) and then decreases with the increasing H_2 percentage in H_2-NG blend. The same trend can be observed for the CO_2 price impact with a maximum LCOE increment (13%) for the reference case. The impact of the H_2 price on LCOE increases as the H_2 content in fuel increases and it is maximum (34%) at 100% H_2.

It is worth noting that, comparing the 100%H_2 and 100%NG cases at 800 EOH, a 50% increment in H_2 price has a higher impact (34%) on LCOE than the NG price (27%).

Regarding the impact of the EOH, it can be observed how the increase of the operating hours of the plant impacts on the LCOE in non-linear, almost logarithmic, way and the increase of the EOH has an incremental impact on the LCOE percentage variation. It should also be noted that increasing the EOH has the effect, in general, of reducing the absolute value of the LCOE which also contributes to the increased sensitivity observed in *Figure 14*. For reference, absolute LCOE values as a function of EOH have been plotted for each H_2-NG blend in *Appendix B, Figure B.1*.

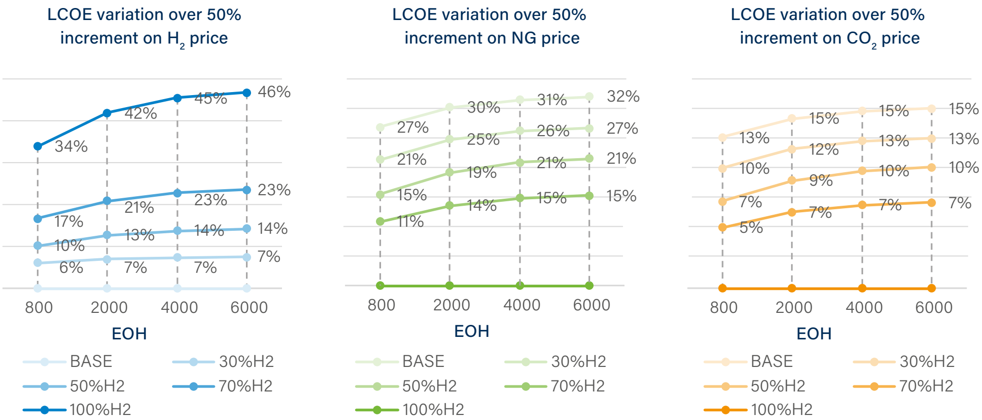

Figure 14: S-OCGT sensitivity plots: impact of 50% variation of H_2, CO_2 and NG price on LCOE for different H_2% in fuel and different EOHs

4.1.3. Sensitivity analysis – LCOE variation with gas turbine efficiency variation

As previously reported, the increasing H_2 content in the fuel blend for a retrofitted gas turbine may lead to power derating in order to be compliant with the NO_x emission limit. *Figure 15* reports the impact of power derating on the LCOE for the different cases compared to the ideal case in which no derating is considered.

When increasing the H_2 content in fuel, the GT power derating factor increases as well as the resulting LCOE.

For the 30%H_2 case, the impact of power derating is estimated to increase LCOE by 1.4%. This impact increases up to 7.9% for the 100% H_2 case. For other OCGT cases, refer to *Appendix B*.

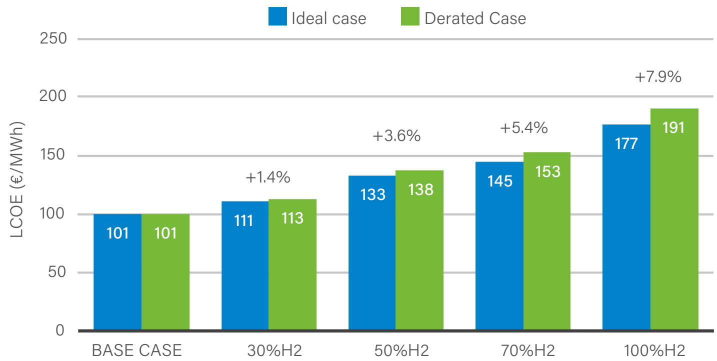

Figure 15: S-OCGT LCOE comparison between "Ideal" and "Derated" case for different H_2% in fuel

4.1.4. CO_2 break-even point

Figure 16 reports the LCOE values for different H_2 %vol content in fuel (from 0% to 100%vol) and increasing CO_2 price. In the case of current CO_2 price (50€/ton), the lowest LCOE is for the reference case (100%NG) and the LCOE increases as the H_2 content increases to about 190€/MWh for 100%H_2 case (see also Section 4.1.1). However, increasing the CO_2 price, the LCOE values increases except for the 100%H_2 case which is not affected by the CO_2 price. Therefore, it is possible to identify a CO_2 price break-even value (223€/ton) for which the LCOE of the NG reference case is equal the LCOE of the 100%H_2 case.

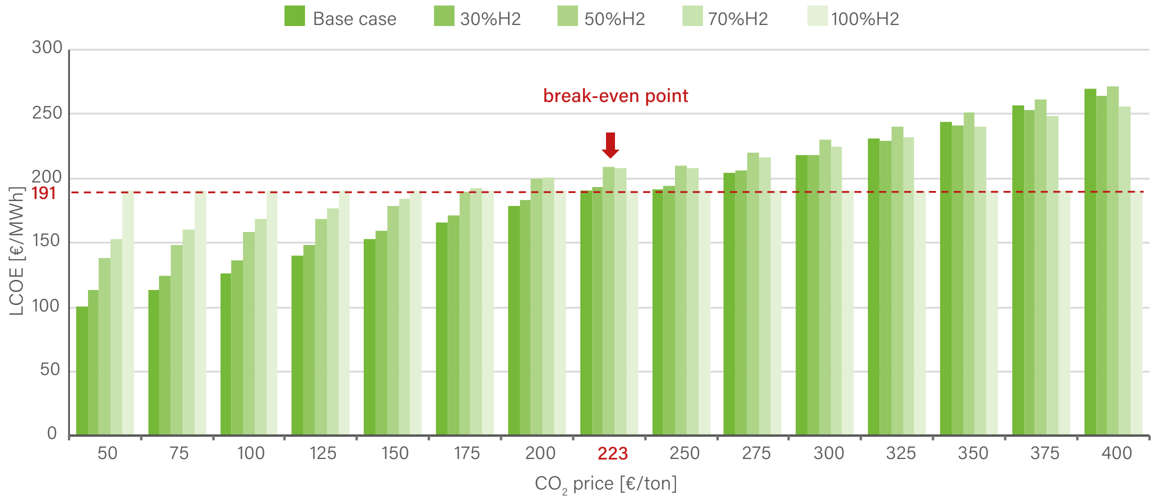

Figure 16: S-OCGT LCOE value as function of CO_2 price for different H_2% in fuel

4.1.5. Sensitivity analysis – LCOE map / variations with H_2 price and H_2 content share

Figure 17 reports the LCOE maps as a function of both the hydrogen percentage content in the H_2-NG blends and the hydrogen cost for two different CO_2 prices (50€/ton on the left plot and 200€/ton on the right plot).

In both the plots, the red line is the level curve corresponding to the LCOE value of the reference case (100%NG). Therefore, the area shaded blue under the red line represents all the cases in which the resulting LCOE is lower than the NG reference case, and therefore, the H_2-based plant is more feasible than the 100%NG based plant. The grey area therefore represents scenarios in which the 100% NG based plant is more feasible.

Considering the 50€/ton case, the blue area exists only for low (<30%) and high (>70%) H_2 content in the fuel blend and low H_2 price (0-0.4 €/kg). For the higher CO_2 price (200€/ton), the LCOE of the reference case increases up to 191€/MWh, but the CO_2 emission reduction due to the H_2 content in the fuel now has a higher impact on the LCOE. As a result, the blue area can be extended both in the H_2% content range and in H_2 price (as reported in *Figure 17*). It is interesting noting that in the range of H_2% content between 30% and 70%, the blue area has a concavity due to the fact that in this range, the economic benefit due to the reduction in CO_2 emission does not compensate the increase in upgrading and maintenance costs. Effectively, in this region, the operator must pay for hydrogen fuel, carbon emissions, and increased upgrading and maintenance costs.

The maps reported here are a useful tool to define, given an H_2-NG fuel blend and a CO_2 price, the maximum viable H_2 price (yellow line). Or, vice versa, given an H_2 price, it is possible to define the required H_2 content in fuel to achieve the desired LCOE value (green line).

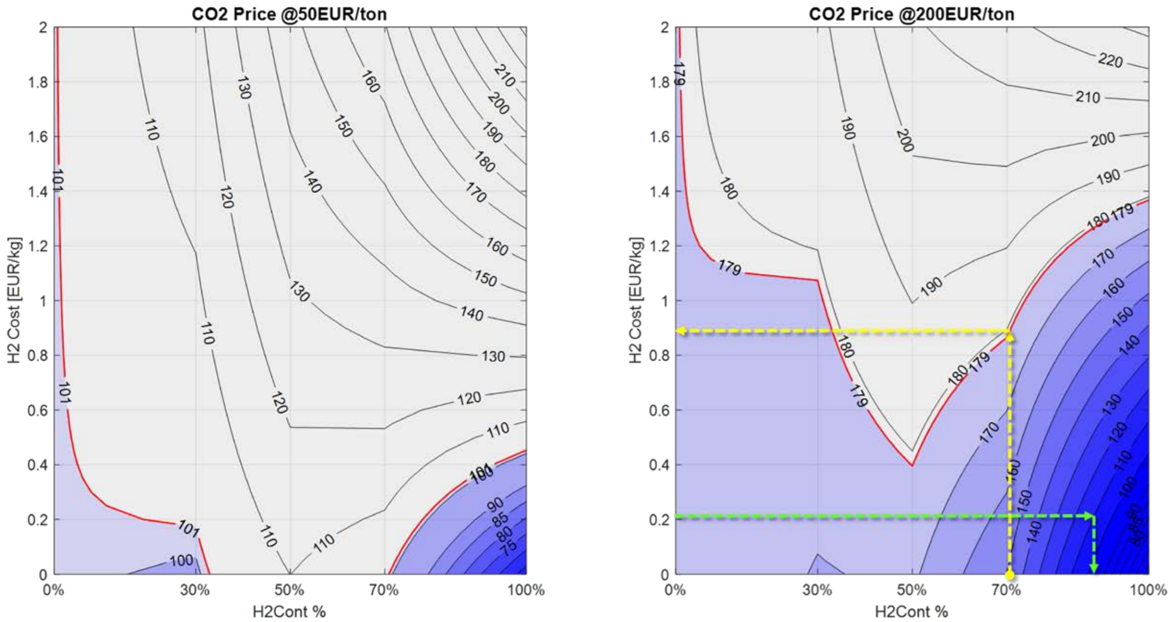

Figure 17: S-OCGT LCOE maps as function of H_2 price and H_2% content in fuel and different CO_2 price (50€/ton on the left and 200€/ton on the right)

4.2. S-CHP

The S-CHP case considers the progressive decarbonisation of a small gas turbine in combined heat and power mode, operating at baseload with increasing levels of hydrogen blending. The selected operating regime considered in this analysis is provided in *Table 10*. It is important to note that the LCOE calculation does not account for the value of the heat produced by the CHP. This will be addressed at the end of this section.

Table 10: S-CHP case study parameters used in the LCOE evaluation

GT Type	GT Output (MWe) @ISO	GT Efficiency @ISO	Overall Efficiency @ISO	Configuration	Operating regime	Annual equivalent operating hours	Annual start and stop cycles	Designation
Small	20	36.5%	70%	CHP	Base	6000	10	S-CHP

Table 11 shows the impact of the fuel blending on CO_2 emissions, specific to the electricity and electricity and thermal power combined generated, respectively.

Table 11: Specific CO_2 emissions for the S-CHP case with increasing H_2 blending in NG (%vol)

	Blend NG-H_2 (H_2 vol%)				
	NG (0)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Emissions [kgCO_2 / MWhe]	521	466	411	319	0
Emissions [kg CO_2 / MWh (el + th)]	272	242	212	163	0

4.2.1. LCOE and LCOE breakdown

Figure 18 reports both the LCOE value and the LCOE breakdown for the S-CHP case considering different H_2 volume percentage blended with natural gas up to 100% hydrogen.

The resulting LCOE is lower with respect to the previous case (S-OCGT) because of the higher number of operating hours and range from 85€/MWh (100%NG) to 141€/MWh (100%H_2), while the share of each cost in the LCOE breakdown remains the same and the considerations from Section 4.1.1 still hold. The LCOE breakdown between S-OCGT and S-CHP remains the same because the S-CHP LCOE does not account for the value of the heat generated and therefore is based on the GT efficiency rather than the overall thermal efficiency of the cycle.

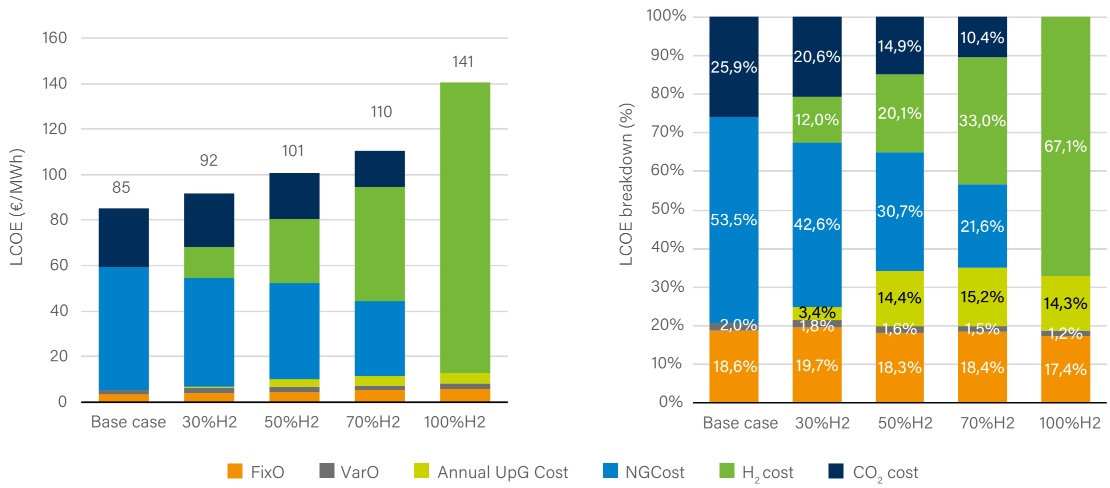

Figure 18: S-CHP LCOE value (left) and LCOE breakdown (right) for increasing H_2%vol in NG

4.2.2. Sensitivity analysis – LCOE variation with CO_2, NG and H_2 price variations

The results of sensitivity analysis comparing the impact of the natural gas price, CO_2 price, and hydrogen price variations on the LCOE are shown in *Figure 19*. The most impactful element is represented by the hydrogen price, followed by the natural gas price and CO_2 price whose 50% increment causes only a 15% increase in the LCOE for the 6000 EOH case. The increase in H_2 and NG price sensitivity in the S-CHP case compared with the S-OCGT case is due mainly to the higher number of operating hours (6000 EOH) which reduces the reference case LCOE.

For reference, absolute LCOE values as a function of EOH have been plotted for each H_2-NG blend in *Appendix B, Figure B.2*. The impact of derating on LCOE for the S-CHP case can also be found in *Appendix B*.

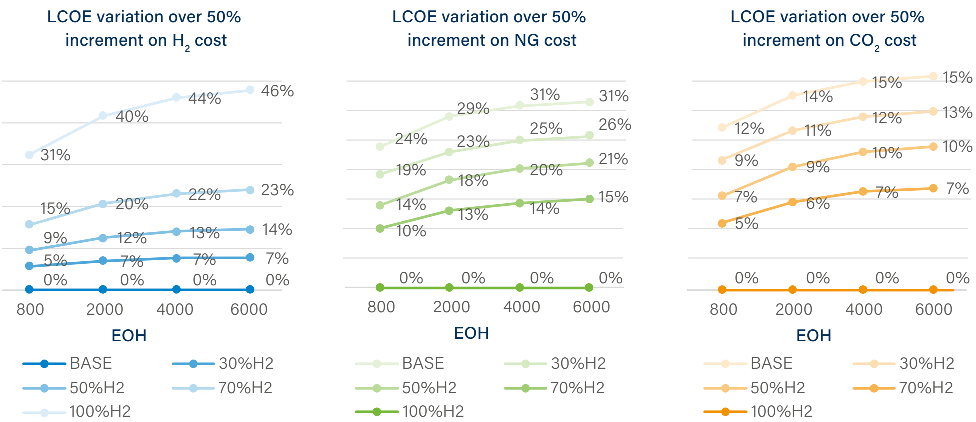

Figure 19: S-CHP sensitivity plots: impact of 50% variation of H_2, CO_2 and NG price on LCOE for different H_2% in fuel and different EOHs

4.2.3. CO_2 break-even point

Considering the plot reporting the LCOE values for different H_2% blending and increasing CO_2 price (*Figure 20*), it is possible to identify the CO_2 breakeven point for the S-CHP case, which occurs at a CO_2 price of 157 €/ton. This value is lower with respect to the S-OCGT case since the impact of the CO_2 variation on the LCOE is higher in this case (see *Figure 19* in Section 4.2.2).

Moreover, it must be noted that the LCOE metric alone does not account for the additional advantages deriving from heat production in this case. Therefore, it would be expected that an economic case could be made for small GT-based hydrogen CHP systems at carbon prices below 157€/ton, when the value of the heat is included. This highlights the value of integrating waste-heat recovery and sector coupling for these hydrogen GT systems.

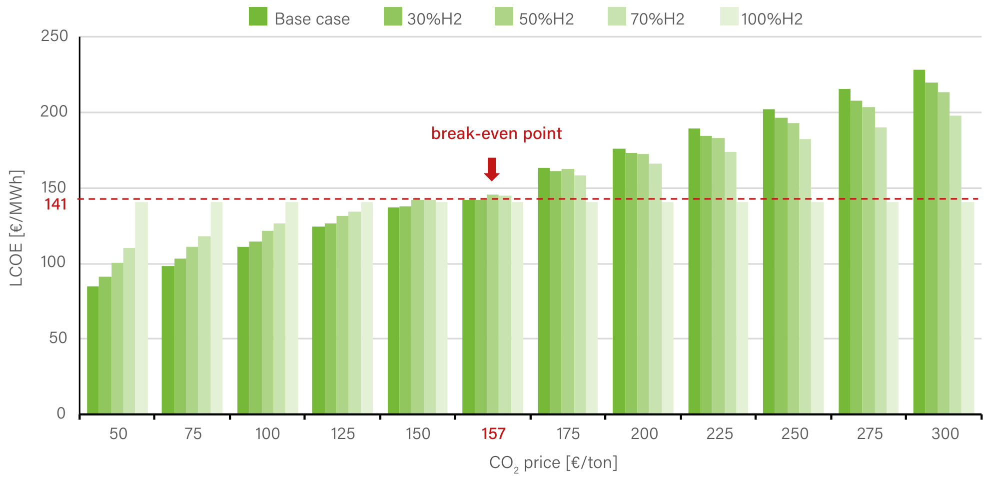

Figure 20: S-CHP LCOE value as function of CO_2 price for different H_2% in fuel

4.2.4. Sensitivity analysis – LCOE map / variations with H_2 price and H_2 content share

LCOE maps of the reference case as a function of both the hydrogen blends and cost for a CO_2 price of 50€/ton and 200€/ton, respectively, are reported in *Figure 21*. For a detailed description on interpreting these plots, refer to Section 4.1.5. Considering the 50€/ton plot on the left, the extension of the blue area is limited to relatively low H_2 prices (0-0.8 €/kg), although this area is much wider than the S-OCGT case. The region increases for the 200€/ton plot on the right which enables economic parity with NG at higher hydrogen prices up to 1.52 €/kg. This means that the maximum viable H_2 price for each blending percentage increases.

For carbon prices between 50€/ton and 200 €/ton, it would be expected that the minimum viable hydrogen price for LCOE parity with NG would therefore lie between 0.8€/kg and 1.52 €/kg.

The concavity observed in Section 4.1.5 in the blue region in the H_2% blending range between 30% and 70% is still visible, even though less pronounced. This highlights a key distinction between the LCOE of peak and baseload GTs with respect to hydrogen blending. Increasing the GT operating hours reduces the relative impact of hydrogen blending on LCOE.

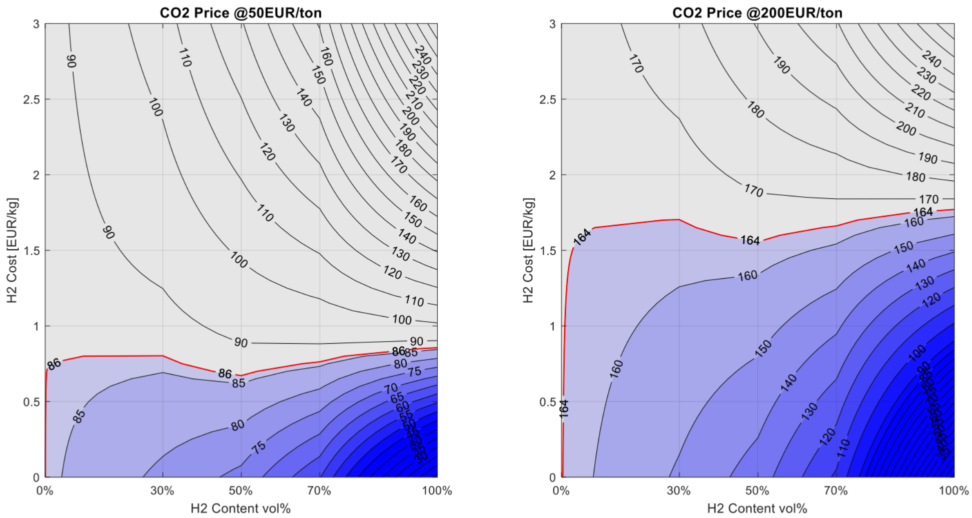

Figure 21: S-CHP LCOE maps as function of H_2 price and H_2% content in fuel and different CO_2 price (50€/ton on the left and 200€/ton on the right)

4.3. M-OCGT

The M-OCGT case considers the progressive decarbonisation of an open cycle gas turbine of 60 MW output, used in peak operation mode with increasing levels of hydrogen blending. The selected operating regime considered in this analysis is provided in *Table 12*.

Table 12: M-OCGT case study parameters used in the LCOE evaluation

GT Type	GT Output (MWe) @ISO	GT Efficiency @ISO	Overall Efficiency @ISO	Configuration	Operating regime	Annual equivalent operating hours	Annual start and stop cycles	Designation
Medium	60	41%	41%	OCGT	Peak	800	150	M-OCGT

Table 13 provides the data regarding the specific CO_2 emissions from the electricity generation. Those values are lower with respect to the S-OCGT case because of the higher efficiency (41%) of the reference case under consideration.

Table 13: Specific CO_2 emissions for the M-OCGT case with increasing H_2 blending in NG (%vol)

	Blend NG-H_2 (H_2 vol%)				
	NG (0)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Emissions [kgCO_2 / MWhe]	464	414	365	283	0

4.3.1. LCOE and LCOE breakdown

With increased H_2 blending, LCOE values range from 92€/MWh (100%NG) to 168€/MWh (100%H_2). Due to the higher GT efficiency, the contributions of NG, CO_2 emissions and H_2 cost to the absolute LCOE (*Figure 22*) are reduced with respect to the small GT cases (see Sections 4.1.1 and 4.2.1), however, they still represent the major variable contribution in the LCOE calculation, FixO costs excluded.

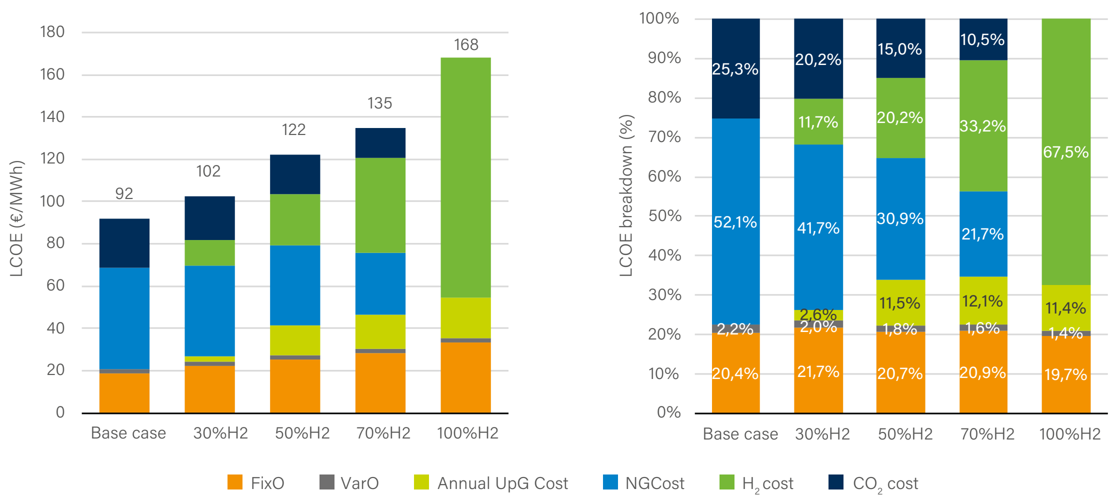

Figure 22: M-OCGT LCOE value (left) and LCOE breakdown (right) for increasing H_2%vol in NG

4.3.2. Sensitivity analysis – LCOE variation with CO_2, NG and H_2 price variations

The sensitivity analysis shown in *Figure 23* confirms the benefits deriving from a GT with a higher efficiency, as the impact caused by a 50% variation in the H_2 price, CO_2 price, and NG price can be contained and are generally lower than the S-OCGT case. The highest impact occurs in the 100%H_2 case where a 50% H_2 price increment results in a 34% increase in the LCOE.

For reference, absolute LCOE values as a function of EOH have been plotted for each H_2-NG blend in *Appendix B, Figure B.3*.

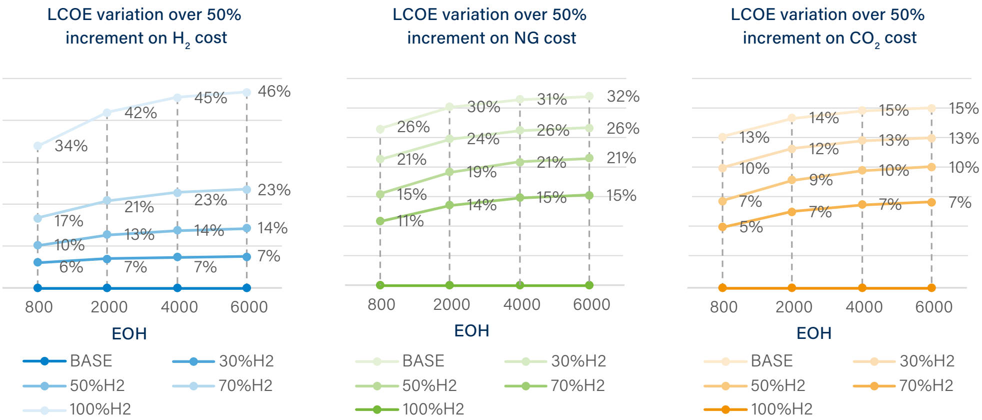

Figure 23: M-OCGT sensitivity plots: impact of 50% variation of H_2, CO_2 and NG price on LCOE for different H_2% in fuel and different EOHs

4.3.3. CO_2 break-even point

The variation of LCOE for increasing H_2-NG blending and CO_2 price is reported in *Figure 24* for the M-OCGT case. The CO_2 breakeven point for the M-OCGT case occurs at a CO_2 price of 214 €/ton, at a corresponding LCOE value of 168€/MWh. This compares similarly with a CO_2 breakeven point of 223 €/ton in the S-OCGT case.

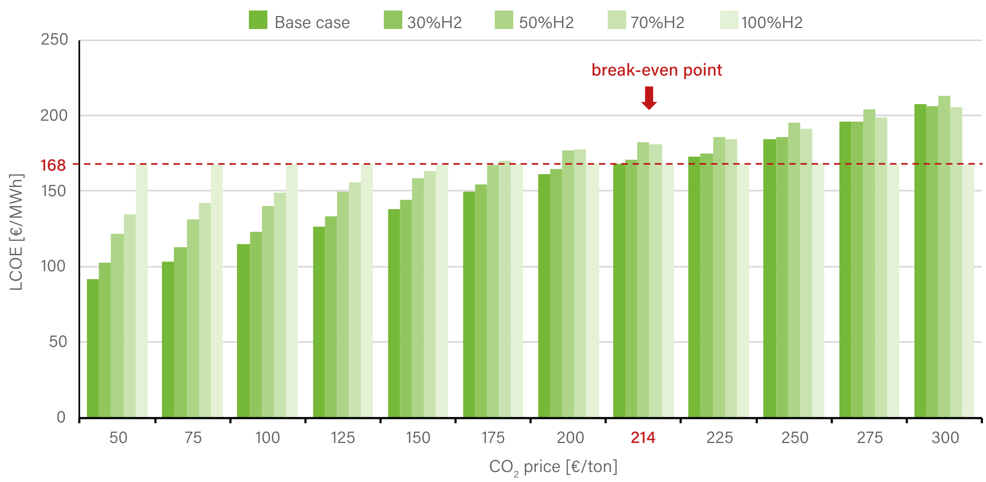

Figure 24: M-OCGT LCOE value as function of CO_2 price for different H_2% in fuel

4.3.4. Sensitivity analysis – LCOE map / variations with H_2 price and H_2 content share

LCOE level curves as a function of H_2 blending and H_2 price for 50€/ton and 200€/ton, respectively, are reported in *Figure 25*. For a detailed description on interpreting these plots, refer to Section 4.1.5. It is evident that a 50 €/ton CO_2 price is not sufficient to encourage the use of H_2, except for very high values of H_2 content (> 75%) and low H_2 prices (< 0.4 €/kg). On the contrary, at a CO_2 price of 200€/ton, burning H_2 becomes more viable, especially at respectively low (< 30%) and high (>70%) H_2 content in the fuel, for the same reasons explained in Section 4.1.5. At a CO_2 price of 200 €/ton, a similar concave region between 30% H_2 and 70% H_2 is observed as was seen in the S-OCGT case, which may make it difficult to justify operation of a medium-sized OCGT with these levels of H_2 blending.

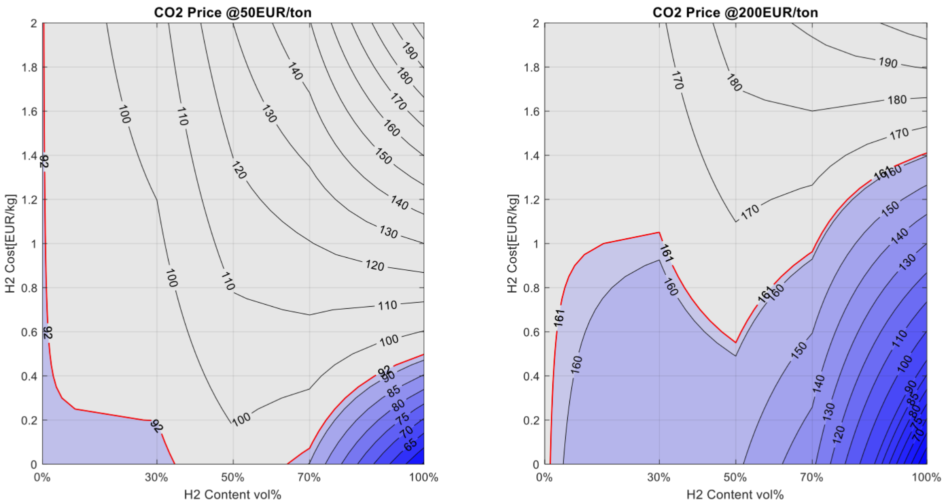

Figure 25: M-OCGT LCOE maps as function of H_2 price and H_2% content in fuel and different CO_2 price (50€/ton on the left and 200€/ton on the right)

4.4. L-OCGT

The L-OCGT case considers the progressive decarbonisation of an open cycle gas turbine of 450 MW output, used in peak operation mode with increasing levels of hydrogen blending. The selected operating regime considered in this analysis is provided in *Table 14*.

Table 14: L-OCGT case study parameters used in the LCOE evaluation

GT Type	GT Output (MWe) @ISO	GT Efficiency @ISO	Overall Efficiency @ISO	Configura-tion	Operating regime	Annual equivalent operating hours	Annual start and stop cycles	Designa-tion
Large	450	44%	44%	OCGT	Peak	800	150	L-OCGT

Table 15 provides the specific CO_2 emissions from electricity generation with increased H_2 blending. The L-OCGT specific CO_2 emissions are lower than the M-OCGT and S-OCGT cases due to the higher GT efficiency (44%).

Table 15: Specific CO_2 emissions for the L-OCGT case with increasing H_2 blending in NG (%vol)

	Blend NG-H_2 (H_2 vol%)				
	NG (0)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Emissions [kgCO_2 / MWhe]	432	386	340	263	0

4.4.1. LCOE and LCOE breakdown

Figure 26 reports both the LCOE value and the LCOE contribution breakdown for the L-OCGT case considering increasing H_2 volume percentage blended with natural gas up to 100% hydrogen. For the base case (100%NG), the LCOE is 95€/MWh, compared with 101€/MWh (S-OCGT) and 91 €/MWh (M-OCGT), and the most significant cost contribution is the NG cost (46.9%).

By increasing the H_2 content in the blend, the contributions of the NG cost and the CO_2 cost progressively decrease until reaching 0% for the 100%H_2 case, however the LCOE increases from 105€/MWh for the 30%H_2 case up to 164€/MWh for the 100%H_2 case. The contribution of the H_2 cost increases when increasing the H_2 content and becomes the main cost contribution in the 100%H_2 case at 64.3%.

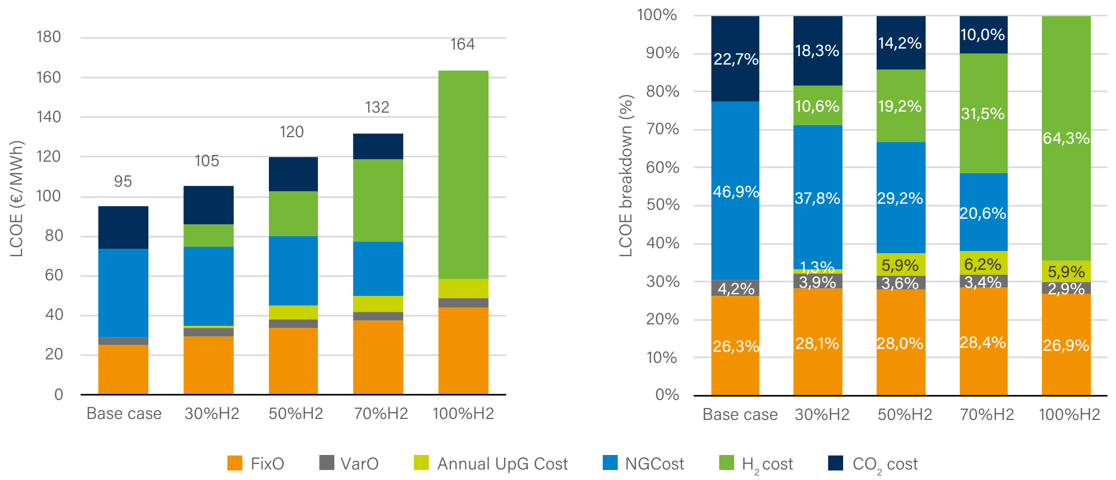

Figure 26: L-OCGT LCOE value (left) and LCOE breakdown (right) for increasing H_2%vol in NG

4.4.2. Sensitivity analysis – LCOE variation with CO_2, NG and H_2 price variations

The sensitivity analysis shown in *Figure 27* further confirms the benefits deriving from utilising a higher efficiency GT, as the impact caused by a 50% variation in the H_2 price, CO_2 price, and NG price is lower than for the S-OCGT and M-OCGT cases. The highest impact occurs in the 100%H_2 case where a 50% H_2 price increment results in a 32% increase in the LCOE.

For reference, absolute LCOE values as a function of EOH have been plotted for each H_2-NG blend in *Appendix B, Figure B.4*.

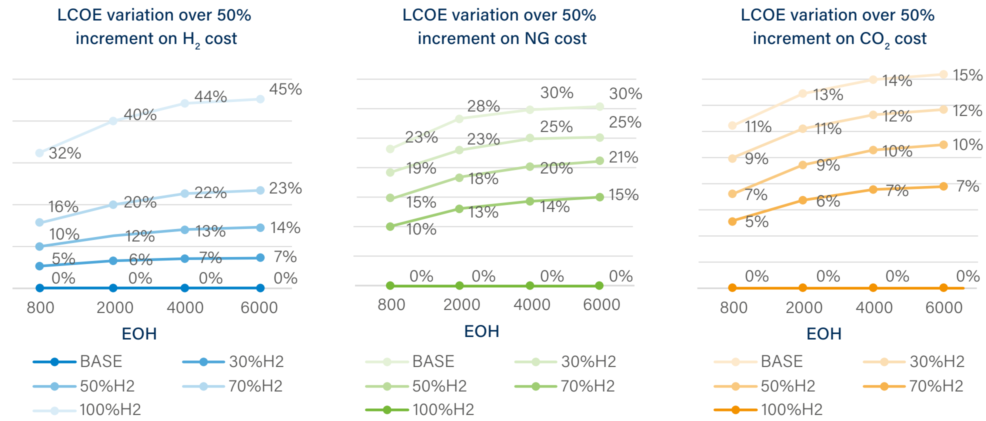

Figure 27: L-OCGT sensitivity plots: impact of 50% variation of H_2, CO_2 and NG price on LCOE for different H_2% in fuel and different EOHs

4.4.3. CO_2 break-even point

The variation of LCOE for increasing H_2-NG blending and CO_2 price is reported in *Figure 28* for the L-OCGT case. The CO_2 breakeven point for the L-OCGT case occurs at a CO_2 price of 209 €/ton and a corresponding LCOE value of 164€/MWh. This compares similarly with a CO_2 breakeven point of 223 €/ton and 214 €/ton in the S-OCGT and M-OCGT cases, respectively.

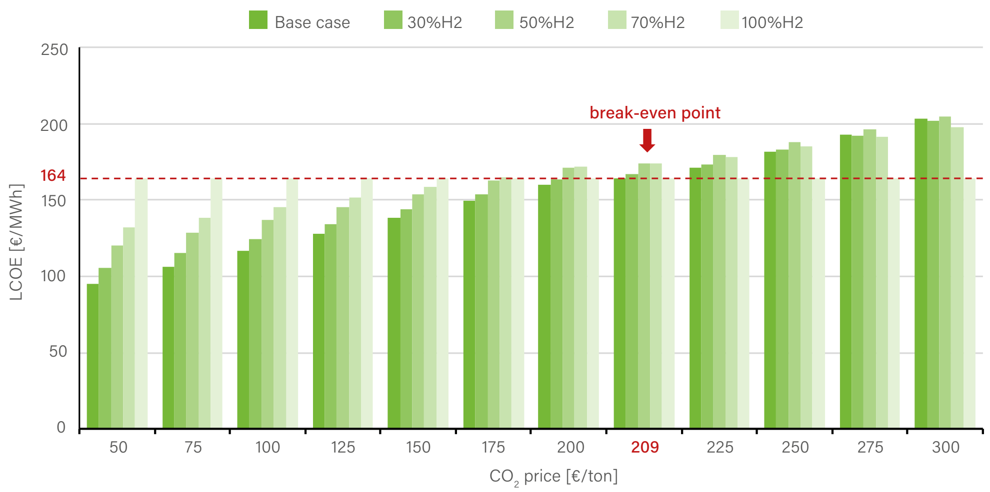

Figure 28: L-OCGT LCOE value as function of CO_2 price for different H_2% in fuel

4.4.4. Sensitivity analysis – LCOE map / variations with H_2 price and H_2 content share

Figure 29 presents the LCOE maps as a function of both the hydrogen percentage content in the H_2-NG blends and the hydrogen cost for two different CO_2 prices (50€/ton on the left plot and 200€/ton on the right plot). For a detailed description on interpreting these plots, refer to Section 4.1.5. At a CO_2 price of 50 €/ton, hydrogen use in L-OCGT would only reach parity (or better) with NG operation at very high blending levels (>70%) and low prices (<€0.5/kg). However, at a CO_2 price of 200 €/ton, the blue area expands, representing a wider selection of conditions which would result in a lower LCOE than the reference NG case. At a CO_2 price of 200€/ton, hydrogen prices below €1.5/kg would be necessary to reach parity with NG.

The concave region between 30% and 70% hydrogen is observed again, similar to the other peak operating cases (S-OCGT and M-OCGT). As seen in the S-CHP case, this effect diminishes when increasing the number of operating hours.

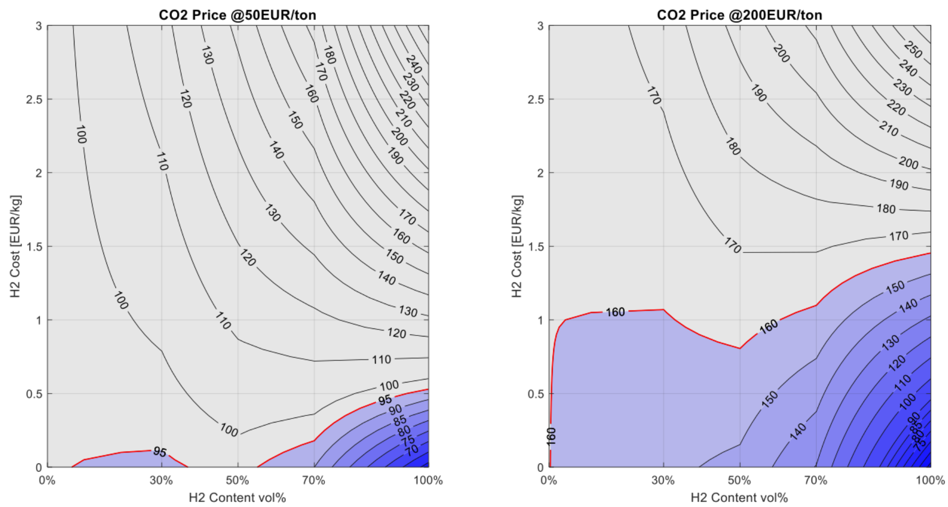

Figure 29: L-OCGT LCOE maps as function of H_2 price and H_2% content in fuel and different CO_2 price (50€/ton on the left and 200€/ton on the right)

4.5. L-CCGT

The L-CCGT case considers the progressive decarbonisation of a large, combined cycle gas turbine of 650 MW total electrical output (gas turbine and steam turbine), used in baseload operation mode with increasing levels of hydrogen blending. The selected operating regime considered in this analysis is provided in *Table 16*.

Table 16: L-CCGT case study parameters used in the LCOE evaluation

GT Type	GT Output (MWe) @ISO	GT Efficiency @ISO	Overall Efficiency @ISO	Configura-tion	Operating regime	Annual equivalent operating hours	Annual start and stop cycles	Designa-tion
Large	450 / 650 (CC)	44%	64%	CCGT	Base	6000	10	L-CCGT

Table 17 provides the specific CO_2 emissions from electricity generation with increased H_2 blending. The L-CCGT has the lowest specific CO_2 emissions of all cases due to its high cycle efficiency when operating with NG (64%). The specific CO_2 emissions could be reduced below 200 $kgCO_2$/MWh with H_2 blending over 70%vol in NG.

Table 17: Specific CO_2 emissions for the L-CCGT case with increasing H_2 blending in NG (%vol)

	Blend NG-H_2 (H_2 vol%)				
	NG (0)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Emissions [$kgCO_2$ / MWhe]	297	265	233	180	0

4.5.1. LCOE and LCOE breakdown

Figure 30 presents the absolute LCOE value and is constituent contribution breakdown for the L-CCGT case considering increasing H_2 volume percentage blended with natural gas up to 100% hydrogen. For the base case (100%NG), the LCOE is 54€/MWh, compared with 95€/MWh in the L-OCGT case, highlighting the impact of the increased cycle efficiency. In this case, the most significant cost contribution is the NG cost (57.1%).

By increasing the H_2 content in the blend the contributions of the NG cost and the CO_2 cost progressively decrease until reaching 0% for the 100%H_2 case, however the LCOE increases from 58€/MWh for the 30%H_2 case up to 86€/MWh for the 100%H_2 case. The 100% H_2 LCOE is lower than the NG reference case of the OCGT cases, albeit with quite different operating regimes. The contribution of the H_2 cost increases when increasing the H_2 content and becomes the main cost contribution in the 100%H_2 case at over 80%. The remainder of the 100% H_2 GT LCOE consists of the fixed operating cost, the variable operating cost, and the upgrading cost.

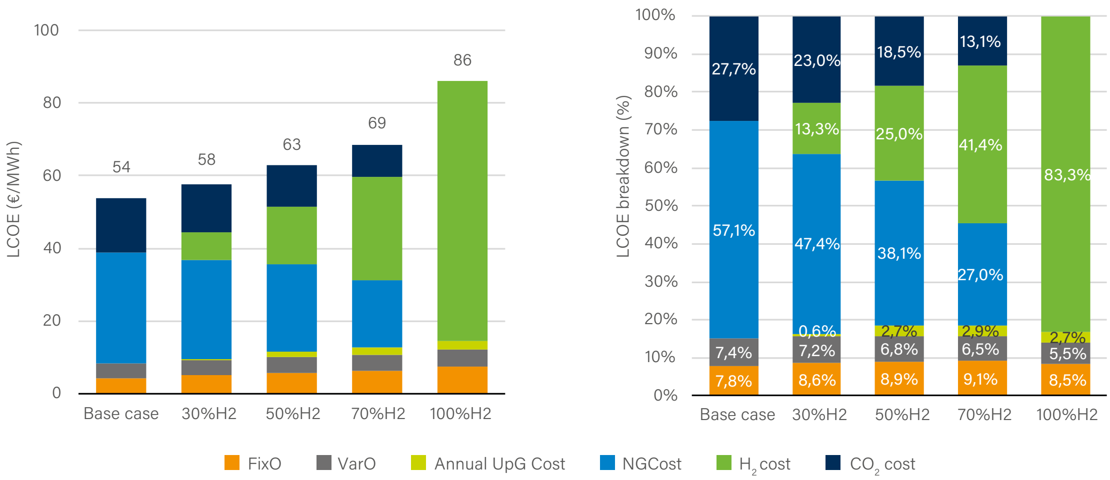

Figure 30: L-CCGT LCOE value (left) and LCOE breakdown (right) for increasing H_2%vol in NG

4.5.2. Sensitivity analysis – LCOE variation with CO_2, NG and H_2 price variations

The sensitivity analysis shown in *Figure 31* reinforces the findings in *Figure 30* that for a baseload large CCGT, the fuel price will be the single most significant factor impacting the LCOE. Therefore, a 50% increment in H_2 price would result in a 42% increase in LCOE for a 100% H_2 L-CCGT.

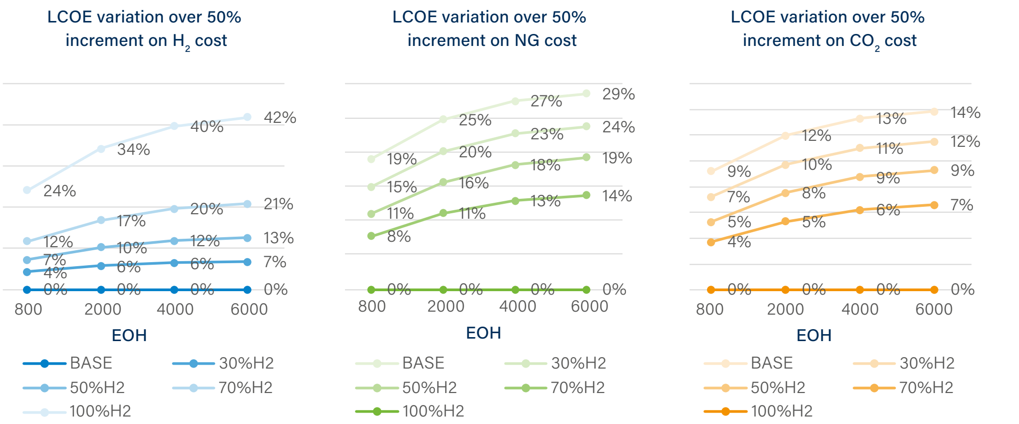

Figure 31: L-CCGT sensitivity plots: impact of 50% variation of H_2, CO_2 and NG price on LCOE for different H_2% in fuel and different EOHs

4.5.3. Sensitivity analysis – LCOE variation with gas turbine efficiency variation

As previously reported, the increasing H_2 content in the fuel blend for a retrofitted gas turbine may lead to power derating in order to be compliant with the NO_x emission limit. This impact could be quite significant for high-efficiency cycles such as the L-CCGT case. *Figure 32* reports the impact of power derating on the LCOE for the different cases compared to the ideal case in which no derating is considered.

When increasing the H_2 content in fuel, the GT power derating factor increases as well as the resulting LCOE.

For the 30%H_2 case, the impact of power derating is estimated to increase LCOE by 0.9%. This impact increases up to 4.4% for the 100% H_2 case. Reducing the impact of derating on LCOE presents an opportunity for the GT OEMs to develop hydrogen combustion technology which is emissions compliant while also being retrofittable. There is significant, positive economic impact for utilities, and their customers, if this can be achieved.

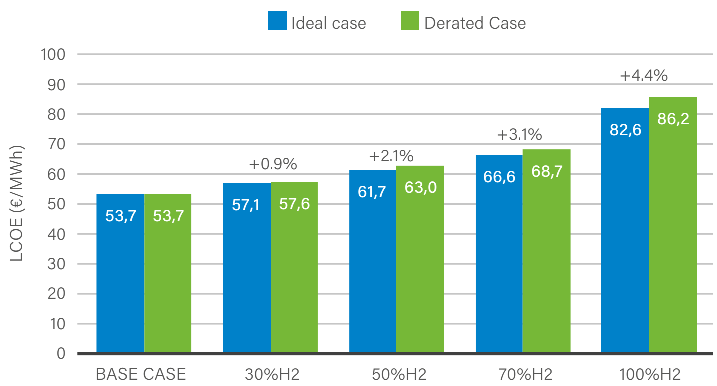

Figure 32: L-CCGT LCOE comparison between “Ideal” and “Derated” case for different H_2% in fuel

4.5.4. CO_2 break-even point

The variation of LCOE for increasing H_2-NG blending and CO_2 price is reported in *Figure 33* for the L-CCGT case. The CO_2 breakeven point for the L-CCGT case occurs at a CO_2 price of 159 €/ton, and a corresponding LCOE value of 86€/MWh. This compares similarly with the baseload S-CHP case CO_2 breakeven of €157/ton.

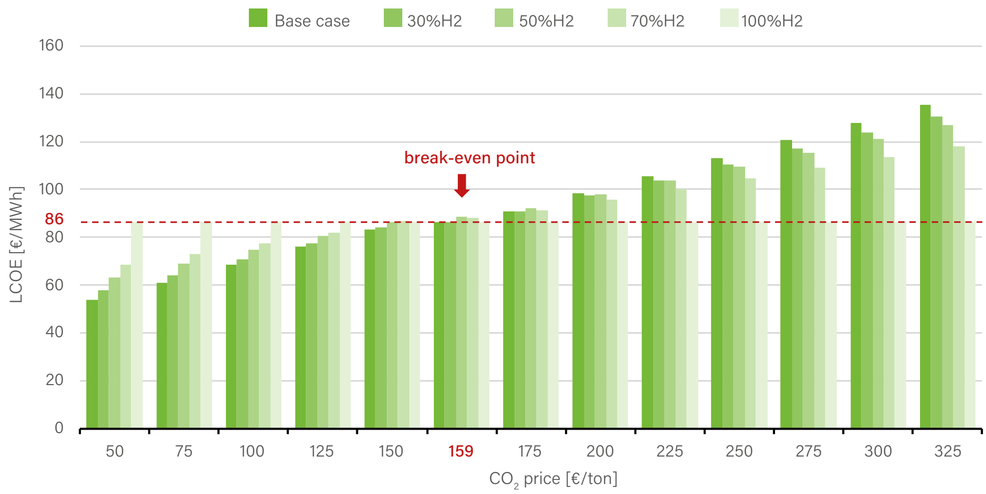

Figure 33: L-CCGT LCOE value as function of CO_2 price for different H_2% in fuel

4.5.5. Sensitivity analysis – LCOE map / variations with H_2 price and H_2 content share

Figure 34 presents the L-CCGT LCOE maps as a function of the hydrogen content in the H_2-NG blend and the hydrogen cost for two different CO_2 prices (50€/ton on the left plot and 200€/ton on the right plot). For a detailed description on interpreting these plots, refer to Section 4.1.5. At a CO_2 price of 50 €/ton, it can be seen that very low levels of hydrogen blending could reach parity with the NG reference case. At higher levels of H_2 blending, a H_2 price of around €0.8/kg would be required. However, at a CO_2 price of 200 €/ton, the blue area expands significantly and even some hydrogen prices above €1.5/kg would be acceptable to achieve parity with NG.

The slight concave region between 30% and 70% hydrogen is observed again similar to the S-CHP case, although the valley is not as dramatic as the OCGT cases. However, all cases raise an important consideration about the economic viability of hydrogen blending between 30% and 70% in natural gas for GT operation.

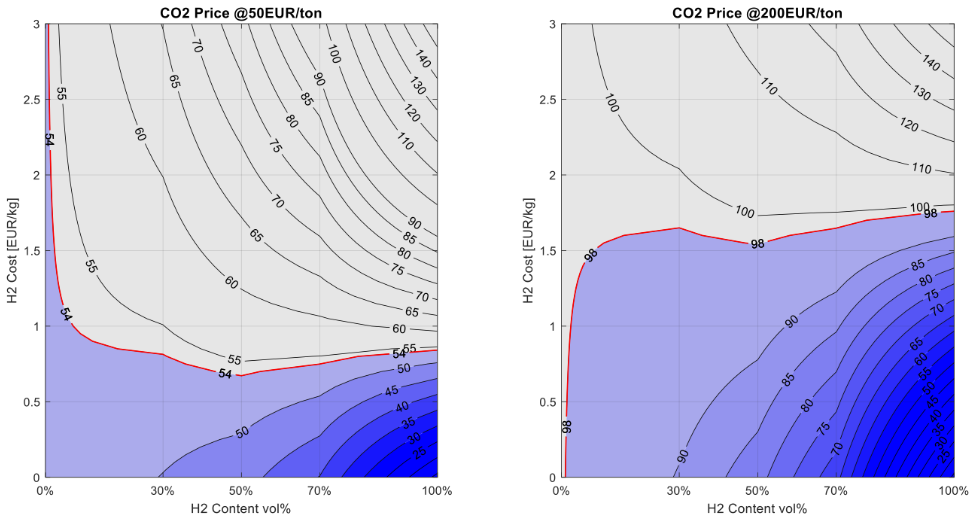

Figure 34: L-CCGT LCOE maps as function of H_2 price and H_2% content in fuel and different CO_2 price (50€/ton on the left and 200€/ton on the right)

4.6. Comparison

For final comparison, *Figures 35*, *36*, and *37* present the LCOE, break-even CO_2 price, and their combination, respectively, for 100% hydrogen gas turbine operation from each of the five case studies presented herein. Note that each of these plots utilised the reference conditions given in *Table 7*. However, for the 100% H_2 cases, the NG cost and the CO_2 price do not influence the LCOE values of the different cases. Therefore, the constant parameter across each case is the hydrogen price of €1.5/kg.

The calculated LCOE for the 100% H_2 case in each of the five case studies is given in *Figure 35*. Also plotted is a comparative contemporary value for the LCOE of a NG CCGT, taken from the NG reference case in the L-CCGT case study. The use of hydrogen to replace natural gas increases the LCOE relative to today's high-efficiency NG CCGT in all cases. The impact of efficiency and operating regime on LCOE, delineated between the peak OCGT and baseload CHP/CCGT cases, is evident as the peak load OCGT LCOE is approximately 160 – 200€/MWh, compared with less than 90€/MWh for the baseload L-CCGT case.

The CO_2 breakeven point for the 100% H_2 case in each of the five case studies is given in *Figure 36*. Also plotted is a comparative contemporary value for the EU ETS price, although this has been subject to further upward pressure in 2021. The high-efficiency CHP/CCGT cycles have the lowest CO_2 breakeven point of approximately €160/ton, while the OCGT cases require carbon prices of €200 – €225/ton.

It is important to note that the LCOE (€/MWh) and CO_2 breakeven point (€/ton) would reduce if the hydrogen price was reduced from the reference case of 1.5€/kg. Similarly, if the GT does not have to be derated for 100% H_2 operation, the LCOE and CO_2 breakeven point also would reduce. A higher NG price than the reference case of 20€/MWh, as has been seen in 2021, would further impact on the CO_2 breakeven point by increasing the LCOE of the NG reference case.

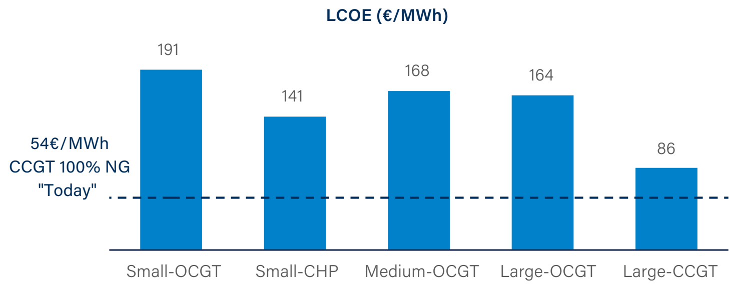

Figure 35: LCOE of 100% H_2 operation for the five GT case studies
(CO_2 price = 50€/ton, H_2 price = 1.5€/kg, and NG price = 20€/MWh)

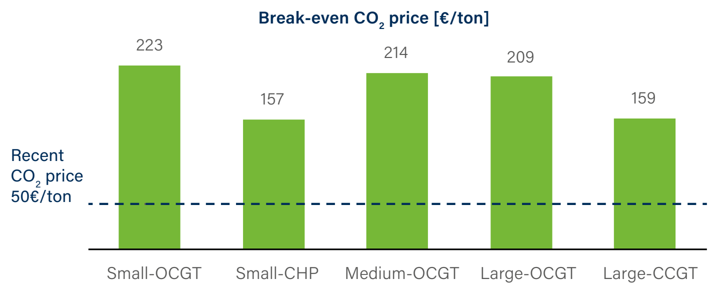

Figure 36: Break-even CO_2 price for the five GT case studies at 100% H_2
(H_2 price = 1.5€/kg and NG price = 20€/MWh)

Figure 37 combines the CO_2 breakeven point with the LCOE at breakeven, and two distinct groups emerge, the high-efficiency baseload CHP/CCGT cycles and the lower efficiency, peak OCGT cycles. Using this plot, it could reasonably be expected that the CO_2 breakeven point of other cases not considered in this study (e.g., flexible peaking CCGT cycles) would fall between these two groupings.

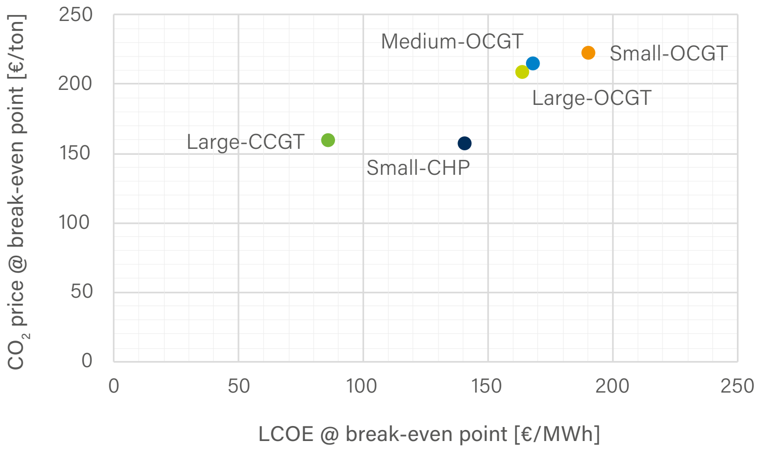

Figure 37: Break-even CO_2 price plotted against LCOE at break-even for 100% H_2 operation of the five GT cases studied (CO_2 price = 50€/ton, H_2 price = 1.5€/kg, and NG price = 20€/MWh)

As the natural gas price has fluctuated significantly recently, it is also critical to consider the importance of high natural gas prices in driving a fuel switch towards hydrogen. *Figure 38* reports the NG price at the breakeven point (i.e., LCOE of reference NG case is equal to the LCOE of the 100%H_2 case) for the five GT cases considered and at three different CO_2 price values (50, 100, and 150 €/tonCO_2). This plot considers a fixed hydrogen price of 1.5€/kg. For a CO_2 price at 50€/ton, the NG price at breakeven would more than double the reference scenario value (20€/MWh). However, for increasing CO_2 price, the NG price at breakeven point would decrease and at 150€/ton of CO_2, would be enough to make the LCOE of the 100%H_2 case close to the reference NG case at the reference NG price (20€/MWh).

However, it is important to emphasize that these results have been calculated considering a H_2 price (1.5€/kg) that is quite low relative to the current green H_2 production price (see *Figure 2*). To further explore the impact of hydrogen price, the correlation of the H_2 price and related LCOE values at the breakeven point for the five GT cases at three different NG price is given in *Figure 39*. Note that the CO_2 price is fixed at 100 €/ton in this plot. As the NG price increases, the LCOE of the reference NG case increases and therefore breakeven can be achieved at higher H_2 prices. This shows the increased competitiveness of the H_2 based power plant at high natural gas prices, with the L-CCGT plant being most competitive (as shown here, the S-CHP plant does not account for the value of the heat).

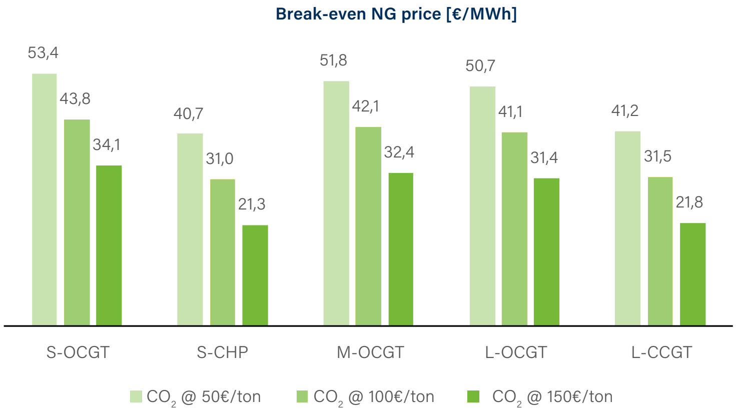

Figure 38: Break-even NG price for the five GT cases at three different value of CO_2 price values (H_2 price = 1.5€/kg)

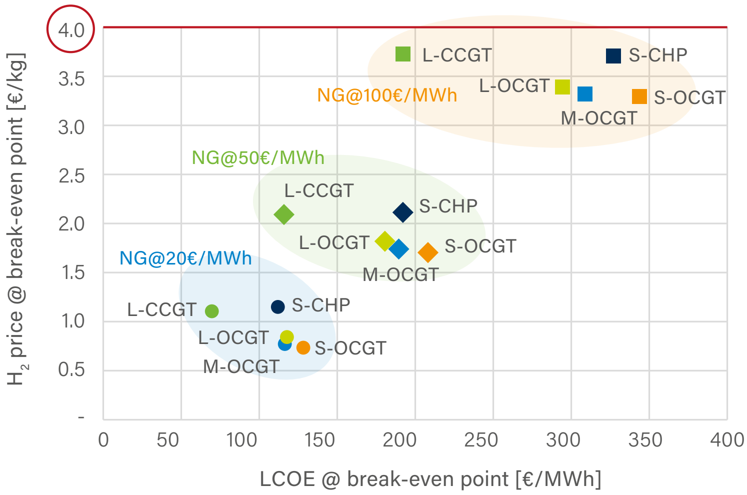

Figure 39: Break-even H_2 price plotted against LCOE at break-even for 100% H_2 operation of the five GT cases at three different NG price values (CO_2 price = 100€/ton)

5. Roadmap for Policy Support, R&D Funding, and Demonstration

As a result of the analysis presented in the report, 6 key areas for policy support, R&D, and demonstration have been identified to enable the transition and development of zero-carbon gas turbines operating on hydrogen fuel. These 6 key areas are summarized in *Figure 40*, which emphasizes the interconnected and interdependent nature of the necessary developments. The timescale for this transition and development is out to 2030, when GT OEMs have committed to commercialize hydrogen-compatible technology [36], and thus represents a decade of tangible steps that can be taken to support the development of the hydrogen economy in Europe.

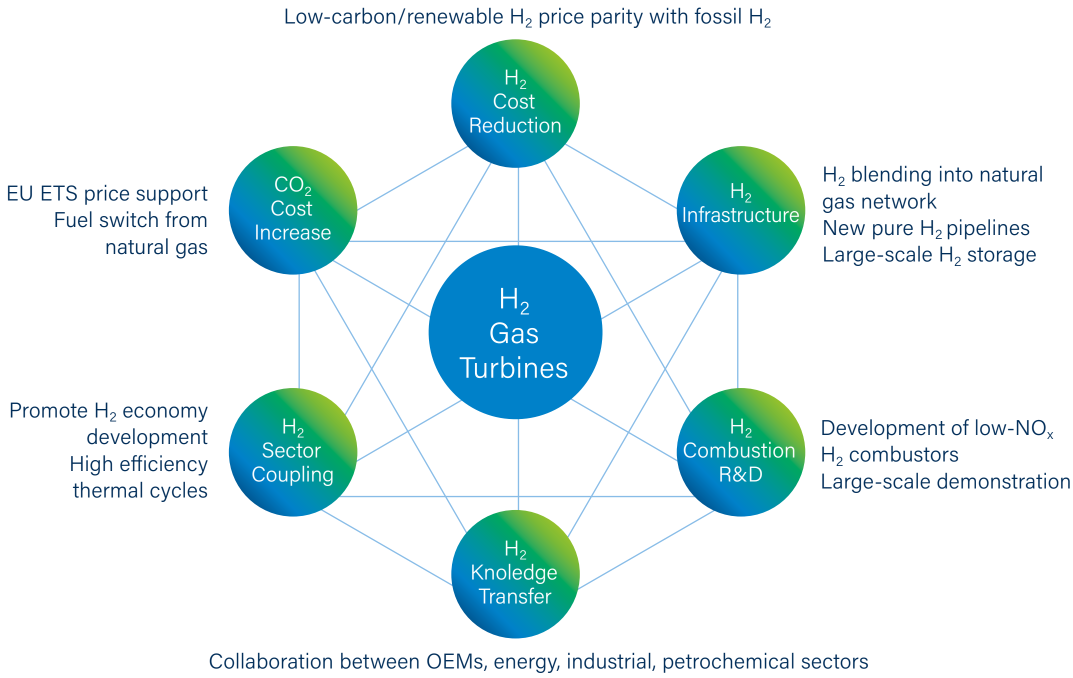

Figure 40: Key enablers of hydrogen gas turbine deployment in future net-zero energy system

5.1. H_2 Cost Reduction

Hydrogen fuel cost is the single largest contributor to hydrogen GT LCOE, representing up to 80% depending on the configuration. Whereas the retrofit of existing GTs is advantageous in terms of capital expense, significant cost reduction in low-carbon and renewable hydrogen production, transport, and storage will be necessary to enable hydrogen GTs to be competitive in the future net-zero energy system. Price parity of **blue** and **green** hydrogen with fossil-based hydrogen at the point of use should be the goal. This can be supported through increased investment in scaling up hydrogen production, investment to reduce capital costs of hydrogen production and carbon capture, and providing the economic framework for large-scale hydrogen trading. Gas turbines can play a key role in this as even low percentage volume blending into natural gas fuel, which is technically feasible today, requires significant quantities of hydrogen. Gas turbines can therefore provide a viable use case for investment in large-scale hydrogen production with the flexibility to adapt to pure hydrogen operation as production increases and costs reduce.

5.2. CO_2 Cost Increase

Coupled with the necessary reductions in H_2 cost, GT fuel switching from natural gas to hydrogen will be enabled by policies which support the price of carbon in the EU ETS, including continued reduction in EUAs. Breakeven carbon costs for hydrogen GTs are in the range of €150-225/tCO_2 for the scenarios presented, which is approximately 2 to 3 times the current EU ETS price, which has more than doubled year-on-year in 2021. However, this breakeven carbon cost reduces significantly as the price of hydrogen reduces, and so both entities must be addressed in parallel to enable deployment of hydrogen GTs.

5.3. H_2 Infrastructure

Given the large volumes of hydrogen that will be required for the operation of hydrogen GTs, it is necessary for new large-scale hydrogen infrastructure to be developed and deployed in the coming decade. Today, gas turbines with DLN/DLE combustion systems can run on low volume blends of hydrogen with natural gas without significant capital investment. This analysis has shown that hydrogen blending between 30-70% volume in natural gas may have limited economic benefit compared with natural gas GTs under certain conditions. This promotes the initial blending of hydrogen into existing natural gas infrastructure up to 30% volume while infrastructure is developed to enable a fuel switch to 100% hydrogen. In the longer term, large-scale hydrogen storage in the form of underground salt caverns will be required to supply the large volumes required for pure hydrogen GTs while also enabling long duration seasonal storage of renewable energy. This requirement for storage in the H_2 infrastructure is essential for either green or blue hydrogen. Storage of green hydrogen is necessary as production is intermittent and therefore out of phase with utilization in gas turbines, which would be used to fill the demand gap when output from renewable electricity reduces. Storage of blue hydrogen is also necessary as hydrogen production is a more consistent process, and therefore storage provides a bridge between continuous hydrogen production and intermittent hydrogen usage in gas turbines.

5.4. H_2 Sector Coupling

Due to their high efficiency, useful heat production, and operational flexibility, hydrogen GTs enable sector coupling which will be key in the future hydrogen economy. Hydrogen GTs used in high-efficiency and novel thermal cycles can produce both heat and power for industry, transport, residential, and commercial sectors that are increasingly electrified and difficult to abate in future net-zero scenarios. A hydrogen GT could be used just as easily to provide zero-carbon heat for a residential district heating network as it could to provide on-demand power supply for electric vehicle charging at times of low renewable energy availability. As a zero-carbon source of heat and power, hydrogen GTs provide fast response to changes in grid demands, much like today's natural gas GTs, and are not weather dependent. Thus, energy is available when it is needed, providing security of supply and high reliability backed by decades of experience, millions of operational hours, and established global supply chains.

5.5. H_2 Combustion R&D

In terms of technology development, hydrogen combustion represents the key area to focus hydrogen GT R&D efforts. While pure hydrogen combustion is technically feasible today using older GT combustor technology, it is unlikely to meet NO_x emissions regulations due to hydrogen's high reactivity and flame temperature as a fuel. Additionally, fuel flexibility is key for hydrogen combustion systems to operate on a range of hydrogen, natural gas, and their blends. GT OEMs and suppliers are working towards the development of hydrogen combustion systems that are emissions compliant without derating or efficiency penalty, as was applied in this study, which will further reduce the LCOE of hydrogen GTs (refer to *Figure 34*). A 10% reduction in hydrogen GT LCOE would potentially reduce global electricity generation costs by almost €10B/yr by 2030 up to €20B/yr by 2050. The EU has often led the way in terms of hydrogen combustion R&D through previous funding programs such as Seventh Framework Program (FP7) and Horizon 2020. It will be essential for the future Horizon Europe funding program to support not only fundamental hydrogen combustion research at Europe's world-leading universities and research institutes, but also large-scale industrial GT demonstrations which will require significant quantities of hydrogen. Knowledge gained in hydrogen combustion R&D by the GT sector in Europe can then be exported across the world to support other regions in achieving their net-zero ambitions using hydrogen. Other governments such as Japan, US, and the UK are actively supporting these developments at both fundamental and demonstration level.

5.6. H_2 Knowledge Transfer

Hydrogen knowledge sharing across European and global industry, academia, and government institutions will be essential to the successful deployment of hydrogen gas turbines and the wider development of the hydrogen economy. Hydrogen will be moving out of sectors with longstanding experience, such as refining and chemicals, and into all areas of the economy including power generation, aviation, transport, maritime, agriculture, and even directly into the public's homes. The knowledge that has been gained by decades of experience should move with it. Organizations such as ETN Global, EUTurbines, Electric Power Research Institute, Gas Technology Institute, and Hydrogen Europe are already collaborating to share knowledge on hydrogen and hydrogen gas turbine developments. Cross-sector knowledge sharing should be promoted and fostered within Europe and globally for efficient hydrogen technology development for the net-zero future.

6. Summary and Conclusions

Gas turbines have an important role to play in delivering the energy transition and enabling the future net-zero energy system. When operated with hydrogen fuel, gas turbines emit zero CO_2 while also delivering grid stability and demand support for intermittent renewable energy sources such as wind and solar. Indeed, hydrogen gas turbines play a role in 2050 net-zero scenarios developed by the European Union [5] and International Energy Agency [4], the latter of which estimates that over 15% of global hydrogen end use will be for electricity in 2050. This would require not only hydrogen volumes equivalent to today's total global hydrogen production, but also further developments in hydrogen gas turbine technology to safely, reliably, and efficiently use this zero-carbon fuel.

Gas turbine manufacturers have committed to producing state-of-the-art technology capable of 100% hydrogen operation by 2030. However, there is a gap in the current understanding of the economic and political conditions under which this technology could be brought to market. This techno-economic study addresses this gap by conducting a detailed cost analysis for the use of hydrogen in dispatchable heat and power applications. Given the current installed gas turbine asset base available in the European Union (EU), the focus is on the potential to retrofit these assets to replace hydrocarbons with hydrogen. The study considers a wide range of gas turbine technologies and hydrogen blending volumes in natural gas, while also considering the future uncertainty in hydrogen and carbon pricing. The wide range of gas turbine technologies and input parameters considered includes:

- Open cycle (OCGT), combined cycle (CCGT), and combined heat and power (CHP)
- Gas turbine cycle output load range from 20 MW_e to 650 MW_e
- Hydrogen blends in natural gas from 0% to 100% by volume
- Hydrogen price from €0.50/kg to €4.00/kg
- Carbon price from €50/ton to €325/ton

This analysis concludes that the levelized cost of electricity (LCOE) is expected to increase by at least 60% for high efficiency hydrogen gas turbine cycles (e.g., CCGT), impacted mainly by the hydrogen price which can represent over 80% of the hydrogen gas turbine LCOE. For low-efficiency gas turbine cycles (e.g., peaking OCGTs), hydrogen blending between 30%-70% may not be economically competitive with pure natural gas as the operator is required to pay enhanced retrofit costs and hydrogen costs while also paying for carbon emissions. In terms of carbon cost, it is simply too cheap at present to warrant a fuel switch from natural gas to hydrogen. Breakeven carbon costs for hydrogen gas turbines (compared with their natural gas equivalent) are shown to be in the range of €150/ton to €225/ton. This is approximately 2 to 3 times the current EU emissions trading system (ETS) price, although it is worth noting that this more than doubled year-on-year in 2021.

To enable the future development and implementation of hydrogen gas turbines in Europe, the study identifies six key areas for policy support, research and development, and demonstration. These focus areas are:

- Hydrogen cost reduction
- Carbon cost increase
- Hydrogen infrastructure development
- Hydrogen sector coupling
- Hydrogen combustion research and development
- Hydrogen knowledge transfer

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Appendix A

Case Study Description and Main Assumptions – Detailed Tables

Table A.1: Carbon-equivalent emissions intensity for different hydrogen production methods including CAPEX-related emissions, hydrogen plant supply (e.g., coal, natural gas or electricity), and direct GHG emissions from the plant. Values reproduced for the year 2030 from [16].

Hydrogen Production Method	GHG Emissions $kg_{CO2eq}/kg_{H2,LHV}$
Grid Electricity + Electrolysis	11.1
Natural Gas (5000 km) + Steam Reforming	11.0
Natural Gas (1700 km) + Autothermal Reforming	9.3
Natural Gas (1700 km) + Steam Reforming	9.2
Coal Gasification	9.2
Natural Gas (5000 km) + Steam Reforming (90% CCS)	3.9
Coal Gasification (CCS)	3.5
Biogas (energy crops) + Steam Reforming	3.3
Wood chips + Biomass Gasification	1.7
Natural Gas (1700 km) + Steam Reforming (90% CCS)	1.5
Natural Gas (1700 km) + Autothermal Reforming (90% CCS)	1.2
Biogas (waste) + Steam Reforming	1.0
Solar Power (1500 hours/year) + Electrolysis	1.0
Nuclear Power + Electrolysis	0.6
Onshore Wind (2400 hours/year) + Electrolysis	0.5
Hydropower (5000 hours/year) + Electrolysis	0.3

Table A.2: LHV of NG-H_2 blends, with selected blends highlighted used in this report

Blend (% vol.)	LHV (BTU/lb)	LHV (MWh/kg)
100% NG	**20607**	**0.0133**
90% NG-10% H_2	21003	0.0136
80% NG-20% H_2	21484	0.0139
70% NG-30% H_2	**22081**	**0.0143**
60% NG-40% H_2	22841	0.0147
50% NG-50% H_2	**23841**	**0.0154**
40% NG-60% H_2	25217	0.0162
30% NG-70% H_2	**27230**	**0.0176**
20% NG-80% H_2	30457	0.0197
10% NG-90% H_2	36465	0.0236
100% H_2	**51579**	**0.0333**

Table A.3: GT/cycle power output and derating with increasing hydrogen content

Blend NG-H_2 (H_2 vol%)	NG (0)	NG-H_2 (10)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Derating Factor (% of power)	0%	0%	-3%	-7%	-10%	-15%
S-OCGT P_{out} (MWe) @ ISO	20	20	19.4	18.6	18	17
S-CHP P_{out} (MWe) @ ISO	20	20	19.4	18.6	18	17
M-OCGT P_{out} (MWe) @ ISO	60	60	58.2	55.8	54	51
L-OCGT P_{out} (MWe) @ ISO	450	450	436.5	418.5	405	382.5
L-CCGT P_{out} (MWe) @ ISO	650	650	630.5	604.5	585	552.5

Table A.4: GT/cycle efficiency with increasing hydrogen content

Blend NG-H_2 (H_2 vol%)	NG (0)	NG-H_2 (10)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Decreasing Factor	0 pts	0 pts	-0.3 pts	-0.6 pts	-0.9 pts	-1.3 pts
S-OCGT - efficiency @ ISO	36.5%	36.5%	36.2%	35.9%	35.6%	35.2%
S-CHP- efficiency @ ISO	36.5%	36.5%	36.2%	35.9%	35.6%	35.2%
M-OCGT - efficiency @ ISO	41%	41%	40.7%	40.4%	40.1%	39.7%
L-OCGT- efficiency @ ISO	44%	44%	43.7%	43.4%	43.1%	42.7%
L-CCGT- efficiency @ ISO	64%	64%	63.7%	63.4%	63.1%	62.7%

Table A.5: GT plant initial investment cost

	S-OCGT	S-CHP	M-OCGT	L-OCGT	L-CCGT
Investment Cost, I_i [€/kW]	850	1100	600	300	550

Table A.6: Plant upgrading cost with increased H_2 blending as % of initial investment cost

Blend NG-H_2 (H_2 vol%)	NG (0)	NG-H_2 (10)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Upgrading Cost Factor, U	0	3%	4%	20%	22.5%	25%

Table A.7: Fixed operation and maintenance costs with increased H_2 blending

Blend NG-H_2 (H_2 vol%)	NG (0)	NG-H_2 (10)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
Maintenance factor	+0%	+0%	+15%	+25%	+35%	+50%
S-OCGT $FixO_i$ [€/kW]	15	15	17.25	18.75	20.25	22.5
S-CHP $FixO_i$ [€/kW]	20	20	23	25	27	30
M-OCGT $FixO_i$ [€/kW]	15	15	17.25	18.75	20.25	22.5
L-OCGT $FixO_i$ [€/kW]	20	20	23	25	27	30
L-CCGT $FixO_i$ [€/kW]	25	25	28.75	31.25	33.75	37.5

Table A.8: Variable operation and maintenance costs with increased H_2 blending

Blend NG-H_2 (H_2 vol%)	NG (0)	NG-H_2 (10)	NG-H_2 (30)	NG-H_2 (50)	NG-H_2 (70)	H_2 (100)
S-OCGT $VarO_i$ [€/kW]	0.002	0.002	0.002	0.002	0.002	0.002
S-CHP $VarO_i$ [€/kW]	0.002	0.002	0.002	0.002	0.002	0.002
M-OCGT $VarO_i$ [€/kW]	0.002	0.002	0.002	0.002	0.002	0.002
L-OCGT $VarO_i$ [€/kW]	0.004	0.004	0.004	0.004	0.004	0.004
L-CCGT $VarO_i$ [€/kW]	0.004	0.004	0.004	0.004	0.004	0.004

Appendix B

Case Study Results – Additional Material

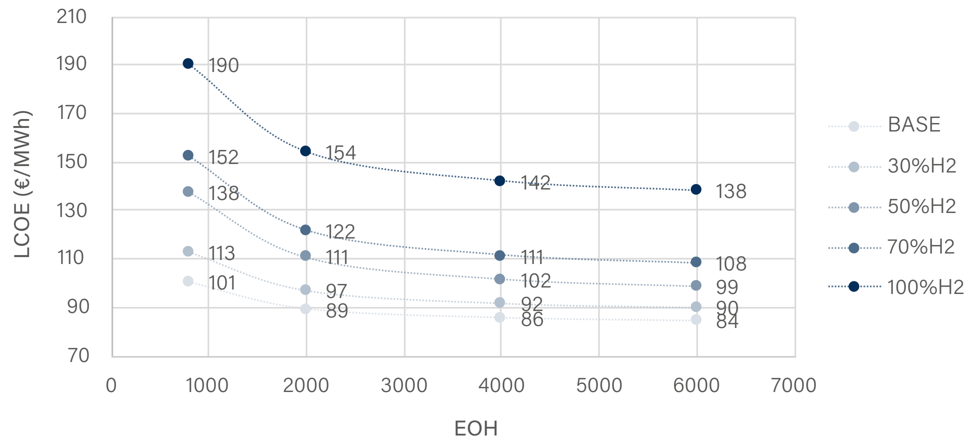

Figure B.1: S-OCGT LCOE as a function of EOH and H_2%vol in NG

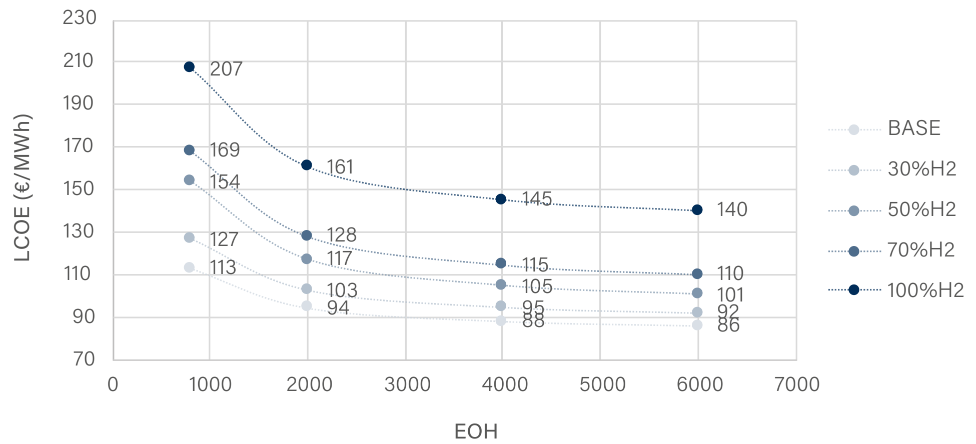

Figure B.2: S-CHP LCOE as a function of EOH and H_2%vol in NG (note LCOE does not account for value of heat produced by the CHP plant).

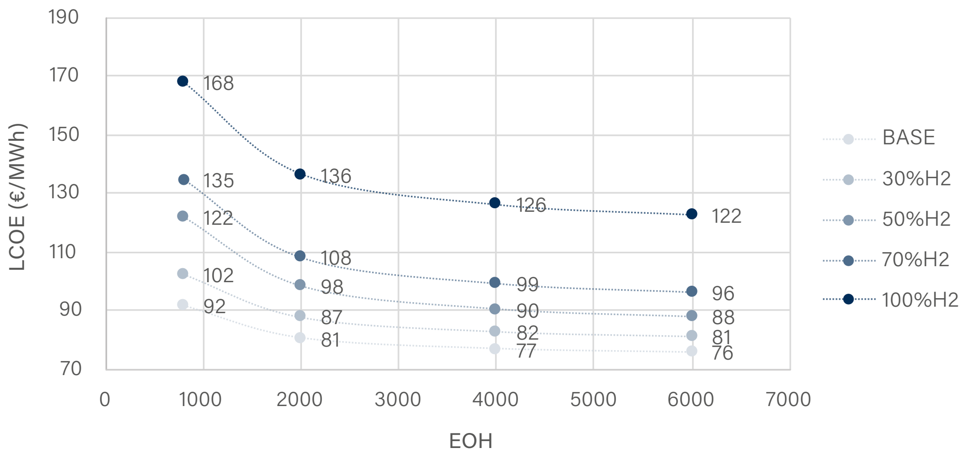

Figure B.3: M-OCGT LCOE as a function of EOH and H_2%vol in NG

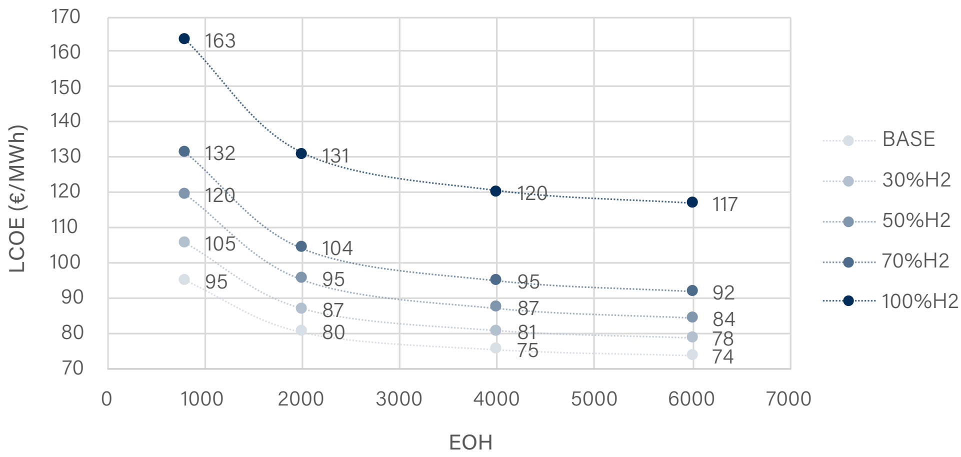

Figure B.4: L-OCGT LCOE as a function of EOH and H_2%vol in NG

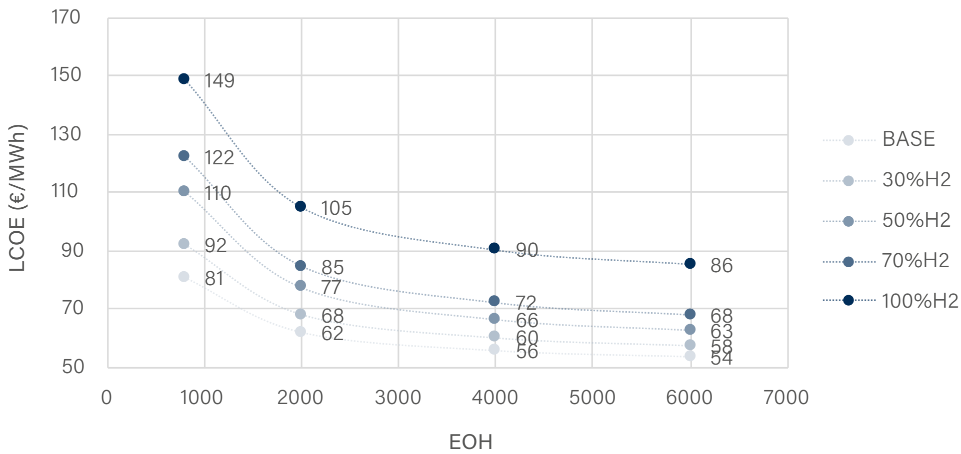

Figure B.5: L-CCGT LCOE as a function of EOH and H_2%vol in NG

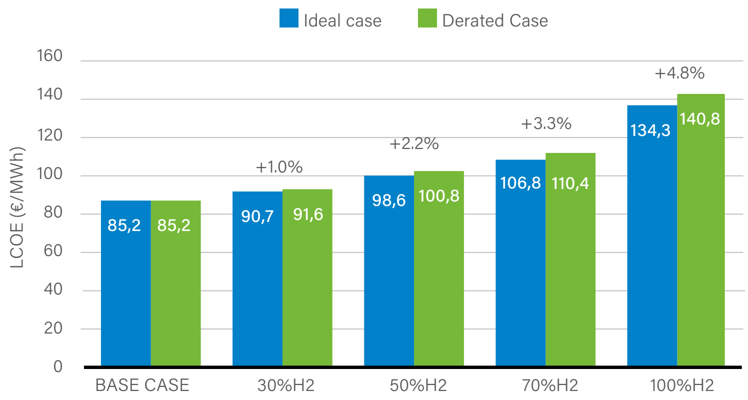

Figure B.6: S-CHP LCOE comparison between “Ideal” and “Derated” case for different H_2% in fuel

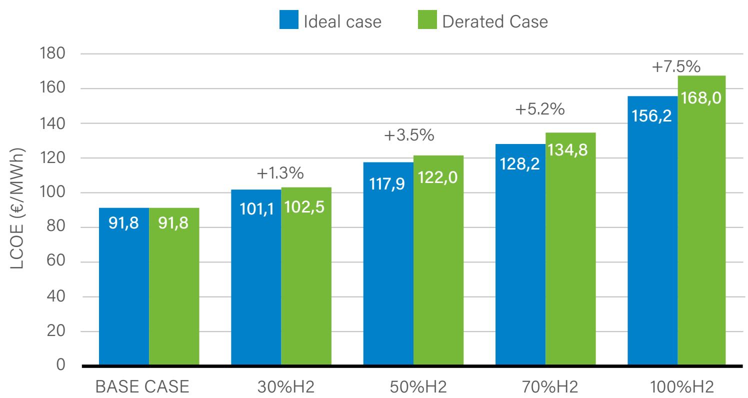

Figure B.7: M-OCGT LCOE comparison between “Ideal” and “Derated” case for different H_2% in fuel

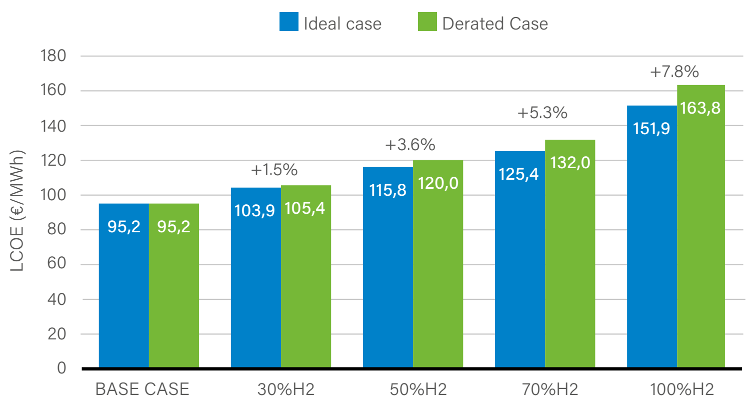

Figure B.8: L-OCGT LCOE comparison between “Ideal” and “Derated” case for different H_2% in fuel

ROBINSON - smart integ**R**ation **O**f local energy sources and innovative storage for flexi**B**le, secure and cost-efficient e**N**ergy **S**upply **ON** industrialized islands - aims to help decarbonise islands through developing an intelligent, flexible and modular Energy Management System (EMS), better integration of Renewable Energy Sources (RES), biomass and wastewater valorisation, industrial symbiosis, and the optimisation and validation of innovative technologies.

To support islands' decarbonisation, ROBINSON's EMS will integrate across different energy vectors (electricity, heat and gas) existing and newly developed energy and storage technologies, such as a small gas turbine based Combined Heat and Power unit (CHP), Anaerobic Digester assisted by Bio-Electrochemical Systems (AD+BES) to enable the conversion of liquid waste into biomethane, a mobile innovative wind turbine, a gasifier to covert bio-waste, and hydrogen-related technologies (electrolyser and storage system).

The system will be demonstrated on the island of Eigerøy (Norway) and lab-scale level replication studies will be conducted for the island of Crete (Greece) and the Western Isles (Scotland). The user-friendliness and high modularity of the system ensure a great potential for replication on other islands, as well as in remote areas in Europe and beyond, with the potential to contribute to their decarbonisation by helping to decrease CO_2 emissions.

www.robinson-h2020.eu

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 957752.

The **FLEXnCONFU** - **FLE**xibilize combined cycle power plant through power-to-**X** solutions using non-**CON**ventional Fuels- project is a H2020 project (Grant Agreement n.884157) which started in April 2020 and will end in March 2024.

The use of alternative carbon-free fuels in existing power plants and a high penetration of renewable energy sources into the grid are required in order to meet EU 2030 and 2050 climate and energy goals. As such, combined-cycle gas turbine plants represent a crucial technology with the required flexibility to compensate for the intermittency of renewable energy sources like wind and solar.

The FLEXnCONFU project will develop innovative, economical, viable and replicable power-to-X-to-power (P2X) solutions to be integrated to existing and new power plant to level the load, and to un-tap their flexibility, converting electricity into hydrogen (H_2) or ammonia (NH_3) to be in turn locally re-used in the same power plant to respond to varying demand, thus reducing time their environmental impact. A 1MW scale power-to-hydrogen-to-power (P2H2P) system will be integrated in a real operational environment in Portugal (EDP's Ribatejo power plant) while a small-scale power-to-ammonia-to-power (P2A2P) solutions will be coupled with a micro gas turbine (mGT) properly modified to burn ammonia in Savona Smart Microgrid laboratory.

https://flexnconfu.eu

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement N° 884157.

ETN Global is a non-profit membership association bringing together the entire value chain of turbomachinery technology. Through cooperative efforts and by initiating common activities and projects, ETN addresses the main challenges and concerns of the global gas turbine user community in technical working groups and projects, composed of experts across the whole value chain.

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