Dublin City University

Towards zero emission mobility in Ireland: Focusing on Life Cycle Assessment of hydrogen fuel for transportation

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Finally, I would like to share my joy and dedicate a special acknowledgment to my daughter, Ella, who was born during the final months of my thesis. Her arrival brought immense happiness and renewed purpose to my life during this important chapter.

List of Publications & Presentations

[1] S. Sabernia, S. Sabu, A. S. Adekanbi, C. Muilwijk, G. McNamara, and J. G. Carton, "Towards Zero Emission Mobility in Ireland: Life Cycle Assessment of Moving Green Hydrogen", Transport Transitions: Advancing Sustainable and Inclusive Mobility (Book Chapter), Proceedings of the 10th TRA Conference, 2024, Dublin, Ireland - Volume 2: Sustainable Transport Development **(Book Chapter and Oral Presentation)**

[2] A. S. Adekanbi, S. Sabernia, and J. G. Carton, "A review of politics for decarbonisation heavy goods vehicles in Ireland" Transport Transitions: Advancing Sustainable and Inclusive Mobility (Book Chapter), Proceedings of the 10th TRA Conference, 2024, Dublin, Ireland - Volume 2: Sustainable Transport Development **(Book Chapter and Oral Presentation)**

[3] S. Sabernia, C. Muilwijk, G. McNamara, and J. G. Carton, "Life Cycle Assessment of Hydrogen for Sustainable Transport Decarbonisation with utilisation of Carbon fibre vessel located underground", 3rd International Summer School on Underground Hydrogen Storage 8-12 July 2024, Edinburgh **(Poster Presentation)**

[4] S. Sabernia, S. Sabu, C. Muilwijk, G. McNamara, and J. G. Carton "Life Cycle Assessment of Green, Blue , and Grey Hydrogen for Sustainable Transport Decarbonisation" Hydrogen Ireland Conference, 28-29th November 2023, Titanic Belfast **(Poster Presentation)**

[5] S. Sabernia, G. McNamara, and J. G. Carton, "Life Cycle Assessment of Hydrogen Fuel for Zero-Emission Transport in Ireland" Navigating Challenges & Seizing Opportunities, 13-14 November 2024 Fota Island Resort, Cork, Ireland **(Poster Presentation)**

[6] Life Cycle Assessment of Hydrogen for Heavy-duty Vehicles: Hydrogen Environment Protection, Analysis, Awareness and Review (HEAR), EPA Project Report 2022-HE-1121, EPA, 2025

[7] S. Sabernia, Greg McNamara and James G Carton, Life Cycle Assessment of Hydrogen Scenarios for Heavy Transport in Ireland **(Journal Article-Drafted)**

Table of Contents

List of Abbreviations

BEV	Battery Electric Vehicle
CCS	Carbon Capture and Storage
COP	Conference of the Parties
CO_2	Carbon Dioxide
GHG	Greenhouse Gas
GWP	Global Warming Potential
HGV	Heavy Goods Vehicle
ICE	Internal Combustion Engine
LCA	Life Cycle Assessment
LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
MP	Methane Pyrolysis
NPV	Net Present Value
NZE	Net Zero Emissions
OEM	Original Equipment Manufacturer
PEMEL	Polymer Electrolyte Membrane Electrolysis
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SMR-CCS	Steam Methane Reforming with Carbon Capture and Storage
S-LCA	Social Life Cycle Assessment
SUV	Sport Utility Vehicle
UNEP	United Nations Environment Programme
V2G	Vehicle-to-Grid
ZEV	Zero Emission Vehicle

List of Tables

List of Figures

Abstract

Sevda Sabernia

Title: *Towards Zero Emission Mobility in Ireland: Focusing on Life Cycle Assessment of Hydrogen Fuel for Transportation*

The transition towards a sustainable energy future demands the development of low-carbon hydrogen production technologies. This research evaluates and compares the environmental impacts of twelve hydrogen production pathways, based on four key technologies: steam methane reforming (SMR), SMR with carbon capture and storage (SMR-CCS), methane pyrolysis (MP), and polymer electrolyte membrane electrolysis (PEMEL), corresponding to grey, blue, turquoise, and Green Hydrogen. A comprehensive Life Cycle Assessment (LCA) approach was employed, considering regional variations and potential future developments in national energy supply chains. The findings reveal that conventional Grey Hydrogen produced via SMR has the highest climate change impact, with limited potential for decarbonisation. In contrast, Green Hydrogen via PEMEL, particularly when powered by renewable energy, demonstrated the lowest greenhouse gas emissions, although challenges such as water consumption and critical material use must be addressed. Turquoise Hydrogen production through MP showed a lower climate change impact than SMR but resulted in increased impacts in other environmental categories, raising concerns about burden shifting. Blue Hydrogen via SMR-CCS presented a more balanced profile, offering immediate emission reductions with technological maturity, yet its long-term viability is constrained by reliance on fossil resources and the need for large-scale CO_2 storage.

The results of Life Cycle Cost analysis show that Green Hydrogen, while environmentally favourable, currently bears the highest Levelised Cost of Energy (LCOE) at €2.23/kWh, primarily due to high capital and operational expenses associated with electrolysis and renewable electricity. In contrast, Grey Hydrogen exhibits the lowest LCOE (€1.38/kWh), benefiting from existing infrastructure and lower upfront costs, while Blue Hydrogen offers a middle ground (€1.92/kWh) by incorporating carbon capture technologies. Sensitivity analyses further reveal that Green Hydrogen is highly dependent on electricity prices, whereas fossil-based pathways are more exposed to natural gas price volatility. These findings reinforce the need for targeted cost reductions—particularly in electrolyser technology—and supportive policy frameworks to enhance the competitiveness of low-carbon hydrogen in future energy systems.

Overall, the results highlight the environmental trade-offs associated with each technology and underscore the need for coordinated policy action, technological innovation, and investment in renewable infrastructure to fully realise the potential of Green Hydrogen. The study also emphasises the importance of holistic assessments that extend beyond climate change impacts to support sustainable decision-making. Future research should include social life cycle assessments, detailed case studies, exploration of storage technologies, and comparisons with alternative energy carriers to provide a more comprehensive evaluation of hydrogen's role in a sustainable energy system.

1 Introduction

Our climate is changing rapidly and is transforming our world, due to our use and blatant release of fossil fuel and industrial emissions. Since 1850 to date there has been an increase of 1.1°C in average global temperature, and the increase since 1970 has been faster than in any other 50-year period over the last 2,000 years. Warming is being propelled by increases in greenhouse gases (GHGs) in the atmosphere mainly produced when we burn fossil fuels and power industrial processes, together with emissions associated with land-use. These increased GHG emissions are being driven by unsustainable patterns of production and consumption. Today, atmospheric carbon dioxide (CO_2) concentrations are higher than at any time in at least 2 million years, and concentrations of methane (CH_4) and nitrous oxide (N_2O) are higher than at any time in at least 800,000 years [1].

The necessity for an energy transition is inevitable and hastened when considering the ongoing energy security issues around the world. Fossil fuels have been responsible for around 86% of the world's greenhouse gas emissions in the past ten years, making them the primary factor of the climate crisis [2]. To limit global warming to 1.5°C, the International Energy Agency (IEA) states that no new oil and gas fields can be developed. According to recent research conducted by Welsby et al. [3], to have a 50% chance of staying within the 1.5°C limit, approximately 60% of oil and fossil gas reserves, as well as 90% of coal reserves, must remain untapped by 2050.

1.1 Paris Agreement and Recent COP Developments

At the 21st Conference of the Parties (COP21) in Paris, the Paris Agreement was adopted in December 2015, marking a major milestone in global climate action. Its primary goal is to limit global warming to well below 2°C, aiming for 1.5°C above preindustrial levels, while enhancing countries' resilience to climate impacts. The agreement emphasises transparency, financial support, technology transfer, and capacity-building, particularly for developing nations. Achieving these targets is essential to mitigate climate risks, promote low-emission sustainable development, and align financial flows with climate-resilient growth [4]. At COP26 [5], countries reaffirmed their commitment to the objectives of the Paris Agreement. Recognising the urgency of the situation during this critical decade, where carbon dioxide emissions must be reduced by 45% to achieve net zero emissions by mid-century, countries emphasised the need for immediate action.

Ireland actively participated in COP26 and made significant commitments by signing various international agreements. These commitments included joining the High Ambition Coalition (HAC) to support global efforts in limiting temperature rise to 1.5°C, becoming a member of the Beyond Oil and Gas Alliance (BOGA) to lead the transition away from global oil and gas production, and actively participating in the Climate and Clean Air Coalition Ministerial to accelerate actions in reducing short-lived climate pollutants. Referring to [6], Ireland has decided to ban new licenses for oil and natural gas exploration through legislative amendments to the relevant act. The goal is to accelerate the transition to renewable energy and work towards a net-zero carbon emissions target by 2050. In addition to the ban on new licenses for oil and natural gas exploration, Ireland has also made the significant decision to divest from fossil fuels [6]. COP27 [7] witnessed significant progress across multiple fronts. The Mitigation Work Programme, with its robust annual political review mechanism, demonstrated the trust and commitment of all 198 parties to the UNFCCC in addressing climate change and safeguarding vulnerable countries and communities. COP27 also approved the first midterm action plan of the Glasgow work programme on Action for Climate Empowerment. This plan builds on the foundations established at COP26, providing an improved framework for inclusive climate action, including education, training, public awareness, participation, access to information, and international cooperation.

1.2 European Green Deal

The European Green Deal serves as Europe's comprehensive framework to tackle climate change while ensuring an equitable and inclusive transition. It acknowledges the complexities of this transformation and aims to provide support to regions, industries, and citizens that may encounter the greatest challenges in adapting to a climate-neutral society. The Green Deal commits to achieving net-zero greenhouse gas emissions in the EU by 2050 and strengthens the EU-wide emissions reduction target to at least 55% by 2030, in alignment with the Paris Agreement's objectives.

To accomplish these ambitious goals, the EU has revised its climate, energy, and transport-related legislation under the 'Fit for 55 Package.' This package aims to bring existing laws in line with the ambitious targets set for 2030 and 2050. Ireland wholeheartedly supports this heightened ambition at the EU level, necessitating increased efforts from all member states.

In response to the energy supply challenges arising from the conflict in Ukraine, the EU has introduced the REPowerEU Plan. This strategic plan seeks to phase out the use of Russian fossil fuels and address climate change by prioritizing energy savings, diversifying energy sources, and accelerating the deployment of renewable energy in homes, industries, and power generation by 2027 [8].

1.3 Ireland commitment

Ireland has directly witnessed the impacts of climate change, as outlined in the Climate Status Report for Ireland 2023 [1]. These effects include a temperature rise across all seasons, with the annual average surface air temperature increasing by over 0.9°C in the past 120 years. The number of frost days has decreased, and the frost season has become shorter. Additionally, sea levels surrounding Ireland have been rising at a rate of approximately 2 to 3mm per year since the early 1990s. Climate projections indicate a significant decrease in average spring and summer rainfall levels, coupled with a notable increase in the frequency of heavy precipitation events during winter and autumn. These observations highlight the tangible consequences of climate change on Ireland's climate patterns and underscore the need for concerted efforts to address and mitigate its impacts.

The anticipated changes in Ireland's climate will have far-reaching and significant consequences, both directly and indirectly impacting the country and its people. These effects include an increased risk of river and coastal flooding, added strain on water supply and water quality, and alterations in wind speeds and storm patterns. The impact of climate change will be felt by every individual, household, and community in Ireland. The findings from the EPA's study highlight that there is widespread awareness of climate change and its repercussions, and there is a general consensus on the urgent need for robust and early action to reduce Ireland's GHG emissions and enhance its resilience to climate change [9].

Therefore, it is our responsibility to take immediate steps to mitigate the long-term consequences of climate change by reducing GHG emissions and enhancing the capacity of natural carbon sinks such as forests and wetlands. Additionally, addressing short-lived pollutants with high global warming potential, like methane and nitrous oxide, is crucial as they not only contribute to climate change but also pose health risks, particularly respiratory diseases. By reducing these emissions, we can simultaneously tackle the climate crisis and improve our overall quality of life.

Aligned with the European Union's ambitions, Ireland's Programme for Government, 'Our Shared Future', makes a firm commitment to achieving a 51% reduction in the country's overall GHG emissions between 2021 and 2030. Ireland's coalition government has taken a significant step in addressing climate change by enacting a climate bill that sets specific emissions reduction targets in law. The legislation paves the way for carbon neutrality by 2050 and requires a 51% cut in greenhouse gas emissions by 2030 [10].

Ireland has committed to achieving net-zero emissions by 2050 under the legally binding Climate Action and Low Carbon Development (Amendment) Act 2023, which establishes clear targets and a framework for meeting national, EU, and international climate obligations. However, Ireland is currently off track to meet these targets. Recent EPA assessments indicate that existing policies will deliver only a 29% emissions reduction by 2030, well below the 51% target. Without immediate and more ambitious action, Ireland risks breaching its climate commitments, facing financial penalties, and undermining its credibility as a climate leader, highlighting the urgent need for accelerated emissions reduction and investment in clean technologies [9].

2 Contextual Background

2.1 Environmental issue

Concentrations of the key greenhouse gases have all increased since the industrial revolution due to human activities. Carbon dioxide, methane, and nitrous oxide concentrations are now more abundant in the earth's atmosphere than any time in the last 800,000 years. These greenhouse gas emissions have increased the greenhouse effect and caused the earth's surface temperature to rise. Burning fossil fuels changes the climate more than any other human activity. Reducing greenhouse gas emissions is crucial to mitigating climate change. Transitioning to renewable energy sources, improving energy efficiency, adopting sustainable agricultural practices, and promoting afforestation and reforestation efforts are among the strategies to address these emissions and their impact on the climate. Global carbon dioxide emissions from energy combustion and industrial processes grew 0.9% or 321 Mt in 2022 to a new all-time high of 36.8 Gt (see Figure 1). Last year's increase follows two years of exceptional oscillations in energy-related emissions. Emissions shrank by more than 5% in 2020, as the Covid-19 pandemic cut energy demand. In 2021, emissions rebounded past pre-pandemic levels, growing more than 6% in tandem with economic stimulus and the roll-out of vaccines [11].

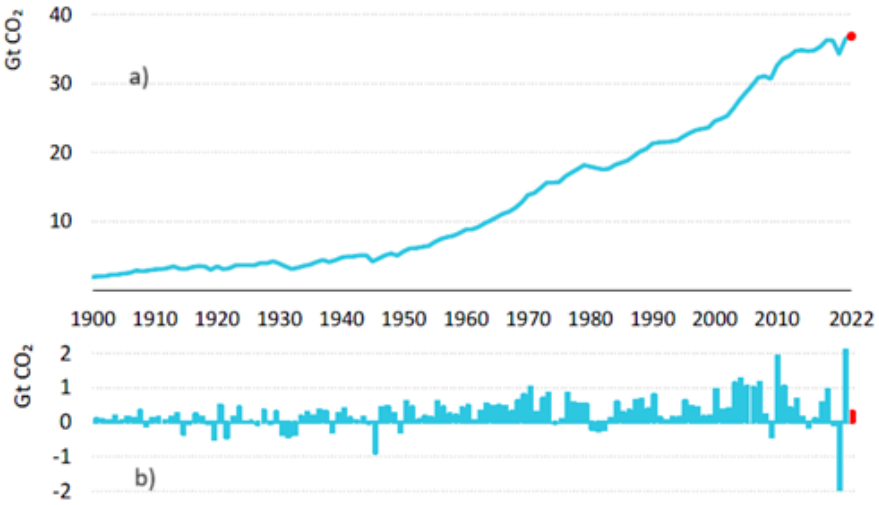


Figure 1 CO_2 emissions from energy combustion during the last century a) Global CO_2 emissions from energy combustion and industrial processes, b) Annual change in global CO_2 emissions [11]

The greenhouse gas emission inventory for 2021 marks the beginning of a ten-year period during which compliance with the European Union's Effort Sharing Regulation (EU 2018/842)

targets will be assessed. This regulation sets 2030 targets for emissions outside the Emissions Trading Scheme (known as ESR emissions) and imposes annual binding national limits for the period 2021-2030 [12]. Ireland's specific target is to reduce ESR emissions by 30% by 2030 compared to 2005 levels, and various flexibilities are available to aid in achieving this goal.

Regarding the compliance assessment for 2021, Ireland's ESR emissions annual limit was set at 43.48 Mt CO_2-eq. However, the provisional greenhouse gas ESR emissions for 2021 were reported as 46.19 Mt CO_2-eq, surpassing the annual limit by 2.71 Mt CO_2-eq, as shown in Table 2 and Figure 4. This figure accounts for national total emissions, excluding emissions generated by stationary combustion and aviation operators within the EU's emissions trading scheme [13].

Unfortunately, Ireland is not in compliance with its 2021 Effort Sharing Regulation annual limit, as it exceeded the allocation by 0.80 Mt CO_2-eq even after utilising the ETS flexibility. Agriculture and Transport were the main contributors, accounting for 73.4% of the total ESR emissions in 2021 [13].

The EU's Emissions Trading System (ETS) aims to reduce the industry's carbon emissions by obliging companies to hold a permit for each tonne of CO_2 equivalent (CO_2-eq) they emit. Companies must buy them through auctions. There are some incentives to boost innovation in the sector.

The European Emissions Trading System is the world's first major carbon market and remains the largest one. It regulates about 40% of total EU greenhouse gas emissions and covers about 10,000 power stations and manufacturing plants in the EU. To align it with the emission reduction targets of the European Green Deal, Parliament approved an update of the scheme in April 2023. Reforms include the cutting of emissions in sectors covered by the Emissions Trading System to 62% by 2030, from 2005 levels [14].

Between 1990 and 2001, Ireland's greenhouse gas emissions showed an increasing trend, peaking at 71.81 Mt CO_2-eq However, from 2001 to 2014, emissions displayed a downward trajectory. In 2015 and 2016, emissions increased by 4.2% and 3.7%, respectively, while remaining relatively stable in 2017 and 2018. In 2019, there was a notable 4.1% decrease. The COVID-19 restrictions led to a significant reduction in 2020, with total national GHG emissions reaching 58.94 Mt CO_2-eq, a 3.5% decrease from 2019 [13].

However, as COVID-19 restrictions eased in 2021, emissions rose by 5.1% compared to 2020. In 2022, there was a 1.9% increase, largely due to decreased residential sector emissions and reductions from industry, agriculture, and electricity generation.

Overall, Ireland's GHG emissions have increased by 9.2% from 1990 to 2022. In terms of the greenhouse gases, carbon dioxide accounted for 60.4% of the total, with methane (CH_4) and nitrous oxide (N_2O) contributing 29.0% and 9.4% as CO_2-eq, respectively, while F-gases contributed 1.2% (Referring to Figure 2). In 2022, the energy industries, transport, and agriculture sectors were responsible for 74.1% of total GHG emissions. Agriculture emerged as the largest contributor at 38.4%, followed by transport (19.1%), energy industries (16.6%), and the residential sector (10.0%) [13].

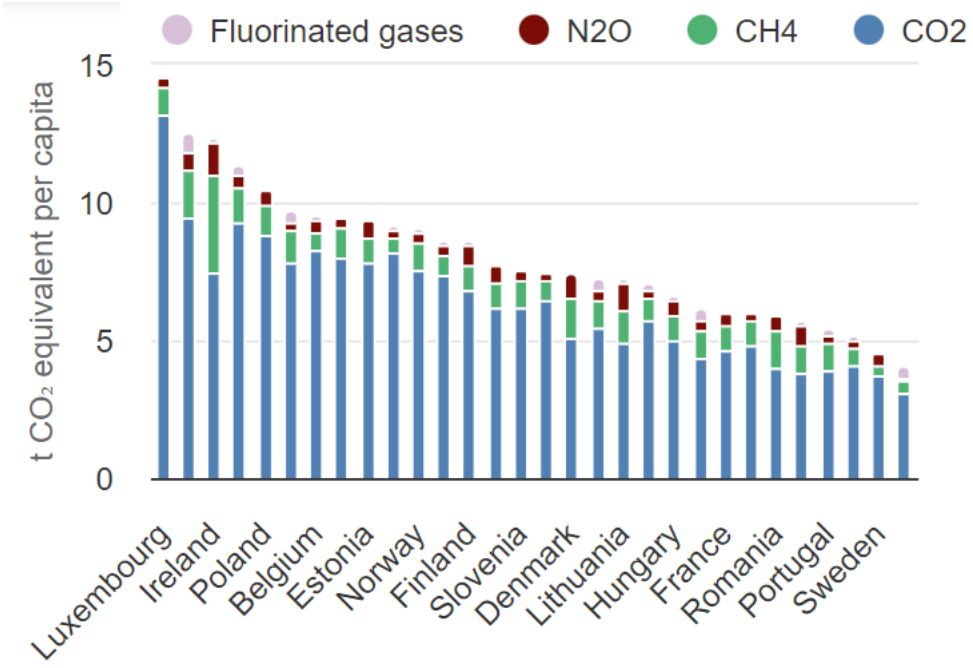


Figure 2 EU/EEA member states GHG emissions per capita by gas 2022 [13]

2.2 Greenhouse gas emissions by sector

Figure 3 provides a comprehensive overview of greenhouse gas emissions by sector, emphasizing their relative contributions on a global scale. It is evident that the agricultural sector stands out as the largest contributor, accounting for a substantial 38.4% of global greenhouse gas emissions. This significant contribution primarily results from factors such as livestock enteric fermentation, methane emissions arising from rice cultivation, and the release of nitrous oxide associated with fertilizer application and manure management within this sector. Following the agricultural sector, the transport sector emerges as the second-largest

contributor, contributing a significant 19.1% of global emissions [13]. These emissions predominantly stem from the widespread use of fossil fuels in various modes of transportation. Within the energy sector, energy industries, comprising power generation and resource extraction activities, play a crucial role in greenhouse gas emissions, contributing 16.6% of the total emissions. These emissions primarily originate from the combustion of fossil fuels like coal, oil, and natural gas [13].

In addition, residential emissions, accounting for 10% of emissions across all sectors, are driven by energy consumption within households for heating, cooling, and electricity. Beyond these prominent sectors, greenhouse gas emissions are also influenced by various other sources, including industrial processes, manufacturing combustion, waste management, and the utilisation of fluorinated gases (F-gases). These sectors each make distinct contributions to global emissions, further emphasizing the multifaceted nature of the greenhouse gas issue. This comprehensive analysis of emissions by sector underscores the importance of a multifaceted approach to address greenhouse gas emissions effectively. It is evident that emissions reduction strategies must be tailored to the specific characteristics of each sector, with a focus on sustainable practices, technology innovation, and policy measures to mitigate the impact of these emissions on the global climate [13].

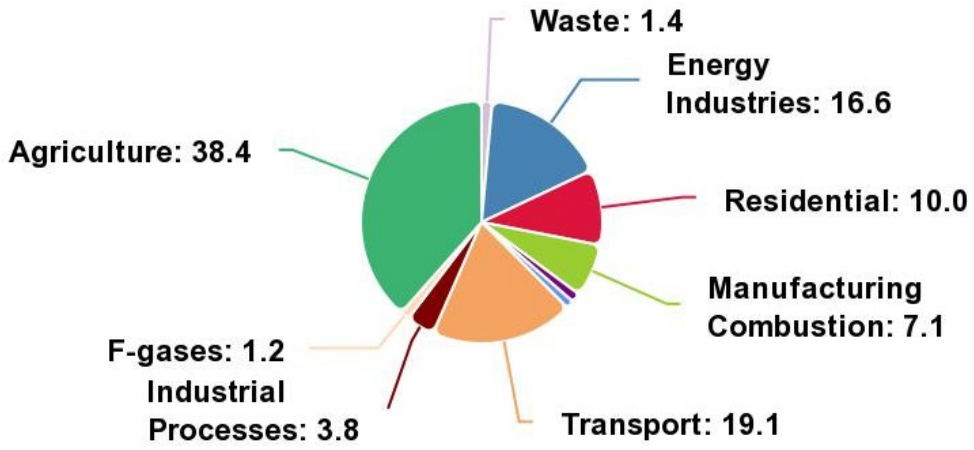


Figure 3 Greenhouse gas emissions share by sector in 2023 [13]

2.3 Carbon Tax

The carbon tax is a fee charged on carbon-emitting fuels such as coal, peat, oil, and natural gas. Carbon taxes are applicable to various greenhouse gases, including carbon dioxide, methane, nitrous oxide, and fluorinated gases. The extent of carbon tax coverage varies from one nation

to another, resulting in differing proportions of greenhouse gas emissions falling under its ambit. For instance, Spain's carbon tax is solely imposed on fluorinated gases, encompassing just 2% of the nation's total greenhouse gas emissions. In contrast, Lichtenstein's carbon tax covers over 81 percent of its emissions [15].

All European Union member states, along with Iceland, Liechtenstein, and Norway, are integrated into the EU Emissions Trading System (EU ETS), a market established for trading a limited number of greenhouse gas emission allowances. Except for Switzerland, Ukraine, and the United Kingdom, all European nations applying a carbon tax are also part of the EU ETS. As shown in Figure 4, European countries are contemplating or have published plans for implementing a carbon tax or an ETS. Austria, for instance, is set to initiate its carbon tax in July 2022 [15].

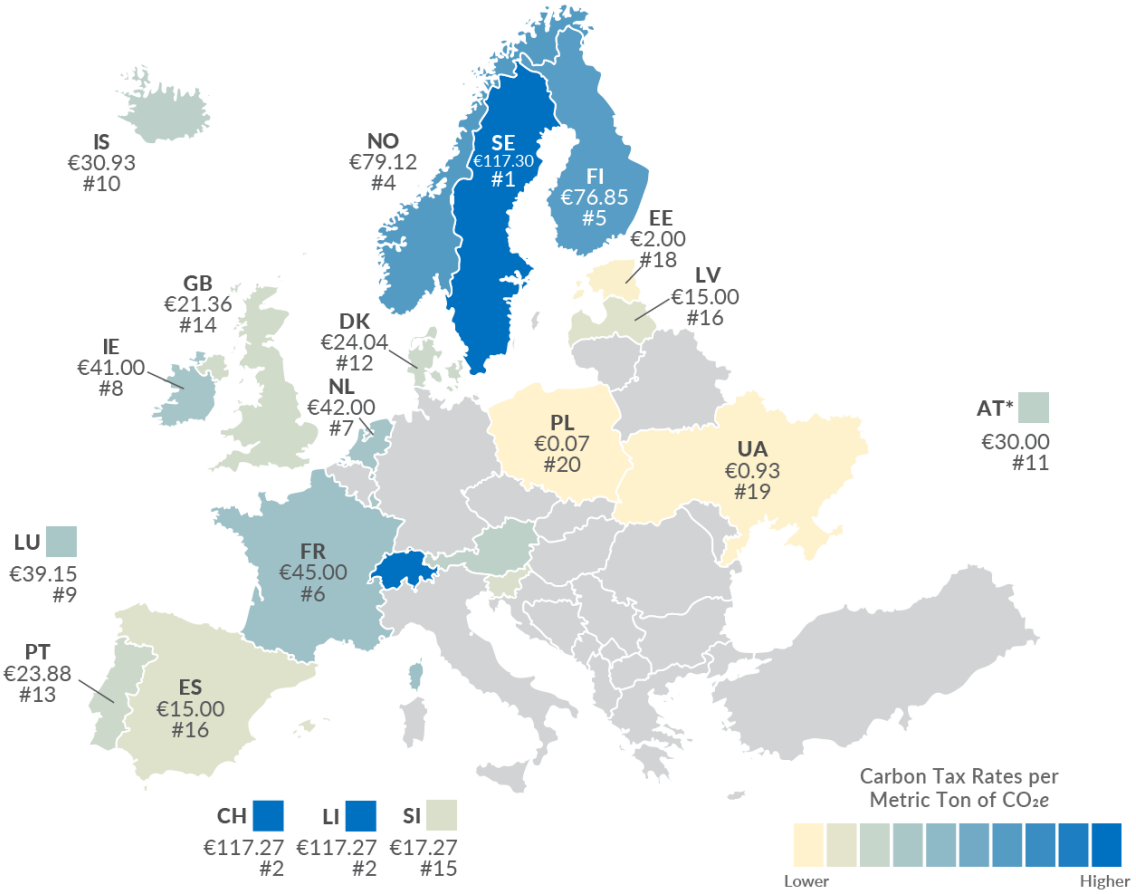


Figure 4 Carbon tax in European Union in 2022 [15]

For the case of Ireland, at present, the tax stands at €56 per tonne of CO_2 emitted from the fuel, with higher-polluting fuels incurring a greater tax burden. This rate was elevated from €41 per

tonne of CO_2 in the 2024 budget. However, numerous environmental advocates have been urging for a substantial increase in the tax, and the government has set a goal of reaching €100 per tonne by 2030. Nonetheless, as per the ESRI (Economic and Social Research Institute), the actual cost of carbon, when factoring in its warming impact, is likely to fall within the €150-€200 per tonne range. If this were implemented, it would considerably raise expenses for gas, transportation, and heating [15].

Ireland, natural gas suppliers such as Bord Gáis Energy, Electric Ireland, and Energia are obligated to incorporate a carbon tax charge into all customers' bills. This equates to approximately 1 cent (including VAT) for every kWh of gas consumed. For the typical Irish household using 11,000 kWh of gas yearly, this results in an additional cost of roughly €110 annually on natural gas bills, or slightly over €18 every two months [15].

It's important to note that the carbon tax does not influence electricity bills; however, there is the consideration of the PSO levy in this context. In terms of petrol and diesel, the current carbon tax contributes around 12.5 cents per litre. This is in addition to the VAT and excise duty, which respectively amount to about 80 cents and 70 cents for each litre of petrol and diesel. Considering that the average Irish driver covers approximately 17,000 km annually in a petrol car and 24,000 km in a diesel car, this tax translates to approximately €113 per year for petrol vehicles and €134 for diesel vehicles (assuming consumption rates of 5.5 litre per 100 km for petrol and 4.6 litre per 100 km for diesel) [15].

For those who appreciate the warmth of a coal or briquette fire, the carbon tax has contributed to recent price increases for these fuels. A bag of coal carries an additional €5.09 due to carbon tax, while each bale of briquettes includes around €1.10 in tax. If you use home heating oil, the tax results in an added cost of about €122 per fill for a 900-litres tank. While the farming and aviation sectors significantly contribute to CO_2 emissions in Ireland, they are currently granted substantial exemptions from the carbon tax [15].

The world is currently shifting towards a crucial need to reevaluate our approach to energy usage, moving away from fossil fuels and embracing renewable energy sources. Renewable energy offers viable alternatives to fossil fuels, and two main advantages must be considered: Firstly, it should be sustainable while remaining highly affordable, ideally matching or even surpassing the cost-effectiveness of fossil fuels. Secondly, renewable methods should be employed to achieve zero carbon dioxide production both during production and consumption.

Predictions indicate that by 2030 [16], we can expect significant progress towards the transition from fossil fuels to renewable energy sources. It is our hope that in the forthcoming years, a substantial portion of our energy supply will be driven by renewable fuels, marking a positive and impactful shift towards a cleaner, more sustainable energy future.

The European Union is set for significant growth in renewables, with capacity expansion expected to more than double during 2022-2027 (Figure 5). Ambitious targets and policies under the REPowerEU package aim to eliminate Russian fossil fuel imports by 2027, accelerating renewable electricity deployment. Wind and solar PV power generation offer effective ways to reduce natural gas consumption, with renewables becoming increasingly competitive due to record-high natural gas prices. Resolving deployment challenges can unlock even greater upside potential, with the EU potentially installing over 30% more renewable energy capacity [16].

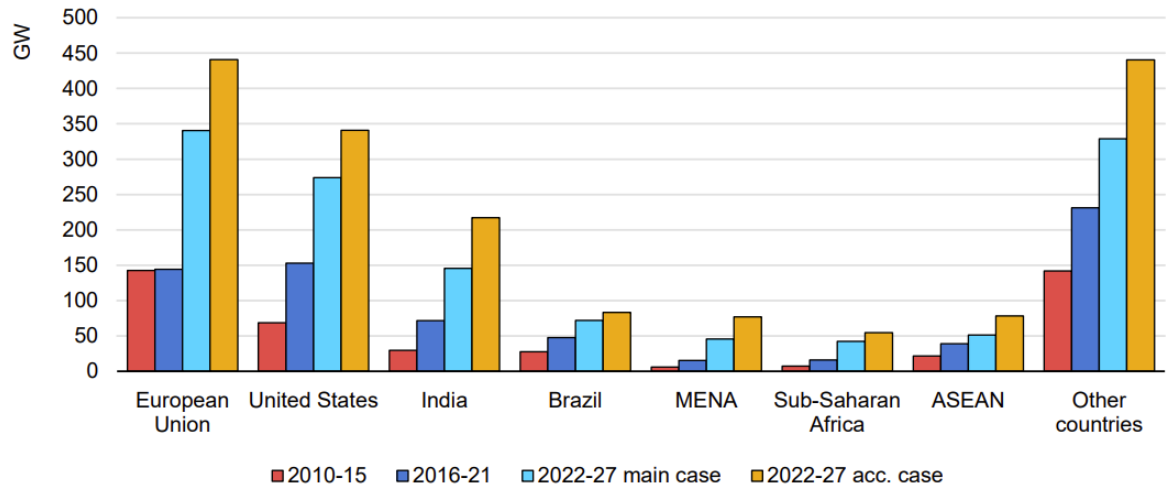


Figure 5 Renewable capacity growth main and accelerated cases, 2010-2027 [16]

Over the period from 2022 to 2027 (Figure 6), Europe is expected to witness a significant surge in renewable electricity capacity, projected to increase by nearly 60% (425 GW). This growth is more than twice the expansion observed in the previous five years (2016-2021). Leading the way in this expansion are solar PV, followed by onshore wind, offshore wind, bioenergy, and hydropower [16].

Approximately three-quarters of the growth in renewable capacity will be concentrated in seven European countries: Germany, Spain, the United Kingdom, Türkiye, France, the Netherlands, and Poland. The main drivers behind this growth are long-term renewable energy targets and competitive auctions for utility-scale projects.

For distributed solar PV, uptake is promoted through mechanisms such as feed-in tariffs or self-consumption with remuneration for excess generation. Moreover, the attractiveness of projects developed outside government-led auction schemes, using corporate Power Purchase Agreements (PPAs) or revenues from the spot market, also contributes to further growth.

Furthermore, this year's main-case forecast has been revised upwards by 30%, reflecting recent policy changes made by governments to accelerate clean energy transitions and reduce dependency on Russian fossil fuels. These policy shifts are expected to have a significant impact on advancing the adoption of renewable energy in Europe [16].

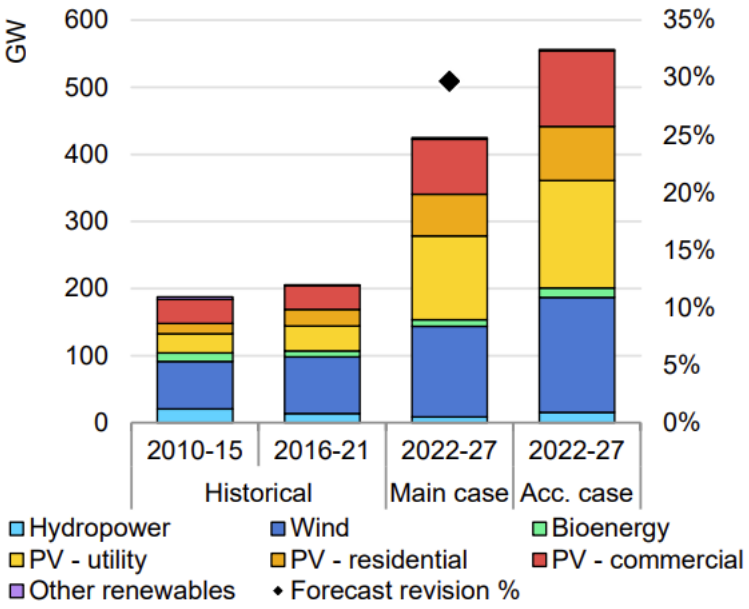


Figure 6 Europe renewable electricity capacity additions, 2010-2027 [16]

Ireland boasts immense potential for tapping into renewable energy, particularly from its abundant wind sources. The country's favourable geographical conditions make it well-positioned to seize this vast potential, leading the way towards a sustainable and environmentally friendly energy future.

While gas currently serves as the primary energy source (Figure 7), the outlook indicates a substantial increase in the utilisation of wind energy in the future. Moreover, the potential for utilising solar energy through PV systems, along with biomass and other renewable sources, presents a golden opportunity for Ireland to actively contribute to decarbonisation efforts. By embracing these renewable energy opportunities, Ireland can play a pivotal role in reducing carbon emissions and promoting a greener and cleaner energy landscape.

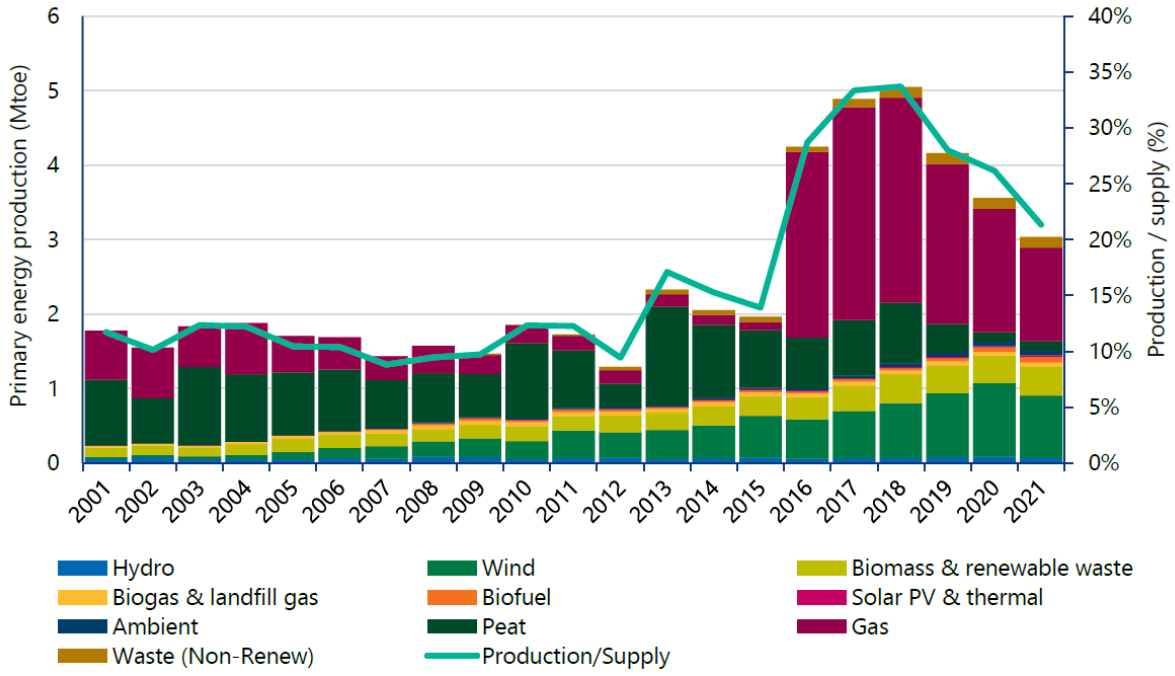


Figure 7 Annual primary energy production by fuel type with production/supply ratio [17]

Ireland is embarking on a significant expansion of its wind energy capacity in response to the energy crises triggered by Russian aggression against Ukraine. The government is committed to accelerating the deployment of offshore renewable energy to ensure a secure, sustainable, and cost-effective indigenous energy supply for future generations. This initiative will also unlock opportunities for green energy exports, reinforcing the urgency of action.

Looking ahead, Ireland's long-term vision for wind energy involves increasing its offshore wind capacity to 20 GW by 2040 and setting a minimum target of 37 GW by 2050 [17]. This strategic approach not only addresses current energy challenges but also opens doors to a cleaner, more sustainable energy future, benefitting both the economy and the environment.

2.4 Transportation

Mobility is important for economic growth, and social interaction, enabling efficient transport of people and goods. However, transportation significantly impacts the environment and public health, contributing 19.2% of global carbon emissions, according to UNEP. In 2023, transport-related CO_2 emissions rose by 4%, reaching 8.24 $GtCO_2$. In Ireland, transport sector emissions increased by 126.2% between 1990 and 2023, driven by economic growth, population rise, motorway expansion, and a surge in private car use. Road transport emissions doubled, with the sector's share of national GHG emissions rising from 9.2% to 19.1%. Although emissions

stabilized from 2015–2019, they fell in 2020 due to COVID-19 restrictions but rebounded in 2021 and 2022, remaining slightly below pre-pandemic levels [18,19].

As can be seen, while significant strides are being made in electricity generation and renewable deployment, the transport sector remains one of the most challenging areas for emissions reduction. In Ireland, transport is the second-largest source of greenhouse gas emissions, contributing approximately 19.1% of total national emissions in 2022 and rising to 21.5% in 2023 as road traffic rebounded post-pandemic. Under Ireland's legally binding sectoral carbon budgets, the transport sector must reduce emissions by 50% by 2030 compared to 2018 levels. This translates into a cumulative ceiling of 62 Mt CO_2-eq for the period 2021–2025, and 37 Mt CO_2-eq for 2026–2030, requiring annual emissions to fall from around 12 Mt to approximately 6 Mt CO_2-eq by the end of the decade [18,19].

According to the SEAI report (see Table 1), the top three contributors to total transport final energy are private cars (39.7%), aviation (21.8%) and heavy-duty vehicles (HDVs) (15.3%) [20]. Therefore, it is important to investigate the possibility of decarbonisation options for these sectors.

Table 1 Final energy in transport by sub-sector compared with previous years [20]

Energy [TWh]	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Road private car	24.45 (48.4%)	25.08 (47.7%)	25.19 (45.3%)	24.81 (43.0%)	24.35 (41.0%)	24.34 (40.0%)	24.60 (40.1%)	20.11 (44.3%)	21.33 (43.9%)	23.08 (39.6%)	24.14 (39.7%)
Road freight	6.76 (13.4%)	7.23 (13.8%)	7.28 (13.1%)	8.55 (14.8%)	8.70 (14.7%)	8.53 (14.0%)	9.18 (15.0%)	8.43 (18.5%)	9.25 (19.0%)	9.17 (15.7%)	9.32 (15.3%)
Road unspecified	2.07 (4.1%)	1.52 (2.9%)	1.55 (2.8%)	2.41 (4.2%)	5.31 (9.0%)	5.68 (9.3%)	4.52 (7.4%)	4.68 (10.3%)	3.88 (8.0%)	5.19 (8.9%)	5.23 (8.6%)
Road light goods vehicle	4.13 (8.2%)	4.33 (8.2%)	4.39 (7.9%)	4.18 (7.2%)	4.10 (6.9%)	3.97 (6.5%)	3.82 (6.2%)	3.45 (7.6%)	3.20 (6.6%)	3.51 (6.0%)	3.48 (5.7%)
Road fuel tourism	2.44 (4.8%)	2.81 (5.4%)	4.51 (8.1%)	4.47 (7.7%)	1.92 (3.2%)	2.17 (3.6%)	2.89 (4.7%)	0.94 (2.1%)	2.41 (5.0%)	2.29 (3.9%)	2.05 (3.4%)
Road public passenger	1.65 (3.3%)	1.58 (3.0%)	1.55 (2.8%)	1.54 (2.7%)	1.51 (2.5%)	1.59 (2.6%)	1.59 (2.6%)	1.38 (3.0%)	1.40 (2.9%)	1.45 (2.5%)	1.51 (2.5%)
International aviation	7.80 (15.4%)	8.65 (16.5%)	9.79 (17.6%)	10.04 (17.4%)	11.82 (19.9%)	12.77 (21.0%)	12.91 (21.1%)	4.58 (10.1%)	5.12 (10.5%)	11.76 (20.2%)	13.28 (21.8%)
Navigation	0.67 (1.3%)	0.84 (1.6%)	0.83 (1.5%)	1.00 (1.7%)	0.88 (1.5%)	0.98 (1.6%)	1.04 (1.7%)	1.27 (2.8%)	1.36 (2.8%)	1.15 (2.0%)	1.08 (1.8%)
Rail	0.45 (0.9%)	0.41 (0.8%)	0.42 (0.7%)	0.42 (0.7%)	0.44 (0.7%)	0.44 (0.7%)	0.46 (0.8%)	0.37 (0.8%)	0.40 (0.8%)	0.45 (0.8%)	0.47 (0.8%)
Pipeline	0.04 (0.1%)	0.03 (0.1%)	0.05 (0.1%)	0.25 (0.4%)	0.24 (0.4%)	0.26 (0.4%)	0.20 (0.3%)	0.18 (0.4%)	0.18 (0.4%)	0.19 (0.3%)	0.17 (0.3%)
Domestic aviation	0.06 (0.1%)	0.06 (0.1%)	0.06 (0.1%)	0.07 (0.1%)	0.07 (0.1%)	0.07 (0.1%)	0.07 (0.1%)	0.05 (0.1%)	0.08 (0.2%)	0.08 (0.1%)	0.09 (0.1%)
Total	**50.52 (100%)**	**52.54 (100%)**	**55.62 (100%)**	**57.74 (100%)**	**59.33 (100%)**	**60.80 (100%)**	**61.28 (100%)**	**45.43 (100%)**	**48.60 (100%)**	**58.31 (100%)**	**60.81 (100%)**

The most important point to note is that transportation remains almost completely dependent on fossil fuels, particularly oil products. This lack of fuel diversity is unique among the energy using sectors. Renewables made up a very small share of transport energy use in 2023. Electricity also remains a tiny share of transport energy use (0.3%), which is split between

electric rail (Dublin Area Rapid Transit (DART) and Luas) and minimal amounts of battery electric private cars. This has meant that there has been very little decarbonisation of the transport fuel mix to date, with transport CO_2 emissions remaining tightly coupled to energy use [21].

There was a clear shift from petrol to diesel over a decade, due to the switch to diesel private cars accelerated by the changes to the private car tax system from 2008 onwards. COVID-19 caused significant restrictions on personal mobility during 2020 and 2021 (Table 2), which had direct effects on transport energy use, especially on international aviation and private cars. Although, 13% reduction has accrued in CO_2 emission for private cars from 2011 to 2021, still private cars with 45% share (almost 5000 kt CO_2) have the most contribution among the others [20].

Table 2 Quantity and share of CO_2 emission by different types of transportation sectors [20]

GHG [$MtCO_2eq$]	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Road private car	6.19 (47.8%)	6.35 (47.2%)	6.37 (44.7%)	6.30 (42.4%)	6.14 (40.6%)	6.16 (39.6%)	6.19 (39.7%)	5.05 (43.9%)	5.38 (43.6%)	5.79 (39.2%)	5.97 (39.3%)
Road freight	1.75 (13.5%)	1.86 (13.8%)	1.87 (13.2%)	2.22 (14.9%)	2.22 (14.7%)	2.19 (14.1%)	2.33 (15.0%)	2.13 (18.5%)	2.34 (19.0%)	2.30 (15.6%)	2.29 (15.1%)
Road unspecified	0.52 (4.0%)	0.38 (2.8%)	0.39 (2.7%)	0.60 (4.1%)	1.34 (8.9%)	1.44 (9.3%)	1.14 (7.3%)	1.17 (10.2%)	0.97 (7.9%)	1.30 (8.8%)	1.28 (8.4%)
Road light goods vehicle	1.07 (8.2%)	1.12 (8.3%)	1.13 (7.9%)	1.08 (7.3%)	1.05 (6.9%)	1.02 (6.5%)	0.97 (6.2%)	0.87 (7.6%)	0.81 (6.6%)	0.88 (6.0%)	0.86 (5.6%)
Road fuel tourism	0.63 (4.9%)	0.72 (5.4%)	1.16 (8.1%)	1.16 (7.8%)	0.49 (3.2%)	0.56 (3.6%)	0.73 (4.7%)	0.24 (2.1%)	0.61 (4.9%)	0.57 (3.9%)	0.50 (3.3%)
Road public passenger services	0.43 (3.3%)	0.40 (3.0%)	0.40 (2.8%)	0.40 (2.7%)	0.38 (2.5%)	0.41 (2.6%)	0.40 (2.6%)	0.35 (3.0%)	0.36 (2.9%)	0.37 (2.5%)	0.37 (2.4%)
Navigation	0.18 (1.4%)	0.22 (1.7%)	0.22 (1.6%)	0.27 (1.8%)	0.24 (1.6%)	0.26 (1.7%)	0.28 (1.8%)	0.34 (2.9%)	0.36 (2.9%)	0.31 (2.1%)	0.29 (1.9%)
Rail	0.15 (1.2%)	0.14 (1.0%)	0.14 (1.0%)	0.15 (1.0%)	0.15 (1.0%)	0.15 (1.0%)	0.15 (1.0%)	0.12 (1.1%)	0.13 (1.1%)	0.15 (1.0%)	0.15 (1.0%)
Pipeline	0.01 (0.1%)	0.01 (0.0%)	0.01 (0.1%)	0.05 (0.3%)	0.05 (0.3%)	0.05 (0.3%)	0.04 (0.3%)	0.04 (0.3%)	0.04 (0.3%)	0.04 (0.3%)	0.04 (0.2%)
Domestic aviation	0.02 (0.1%)	0.01 (0.1%)	0.02 (0.1%)	0.02 (0.1%)	0.02 (0.1%)	0.02 (0.1%)	0.02 (0.1%)	0.01 (0.1%)	0.02 (0.2%)	0.02 (0.1%)	0.02 (0.2%)
Total (excl. int. aviation)	**10.94** (84.4%)	**11.22** (83.4%)	**11.71** (82.2%)	**12.23** (82.5%)	**12.08** (79.8%)	**12.25** (78.7%)	**12.25** (78.6%)	**10.32** (89.7%)	**11.02** (89.3%)	**11.72** (79.4%)	**11.76** (77.4%)
International aviation	2.02 (15.6%)	2.24 (16.6%)	2.54 (17.8%)	2.60 (17.5%)	3.06 (20.2%)	3.31 (21.3%)	3.34 (21.4%)	1.19 (10.3%)	1.32 (10.7%)	3.04 (20.6%)	3.44 (22.6%)
Total (incl. int. aviation)	**12.96** (100%)	**13.46** (100%)	**14.24** (100%)	**14.83** (100%)	**15.14** (100%)	**15.55** (100%)	**15.59** (100%)	**11.51** (100%)	**12.35** (100%)	**14.76** (100%)	**15.20** (100%)

2.4.1 Private cars

Private cars and vans remain the largest energy consumers among transport modes, with their share of global oil use and CO_2 emissions rising steadily over recent decades. From about 20% of global oil use and 7% of CO_2 emissions in the 1990s, their impact grew to over 25% of oil use and nearly 10% of emissions by 2022. In Ireland, private car energy use averaged 2,100 ktoe for a decade before falling sharply by 21% in 2020 due to COVID-19 restrictions. Recent trends show growing electrification and improved fuel efficiency, yet the increasing popularity of heavier SUVs, which are less efficient and emit more CO_2, is undermining progress. SUVs accounted for about 46% of global vehicle sales in 2022 (Figure 8), compared to just 14% for electric vehicles. In Ireland, SUV sales made up 55% of new cars in 2021, while fully electric vehicles represented only 8,600 units. As SUVs emit around 20% more CO_2 than mid-sized cars, their dominance poses serious challenges, highlighting the urgent need for stricter efficiency standards, incentives for electric vehicles, and promotion of sustainable transport [22].

According to recent report [23], the number of heavy, fuel-consuming SUVs on Irish roads is rising rapidly. In 2021, around 55,000 SUVs were sold, comprising almost 55% of all new car sales, while only 8,600 fully electric vehicles were sold in the same period. SUVs emit approximately 20% more carbon dioxide than medium-sized cars. So, the widespread presence SUVs on roads should end or they need to be decarbonised.

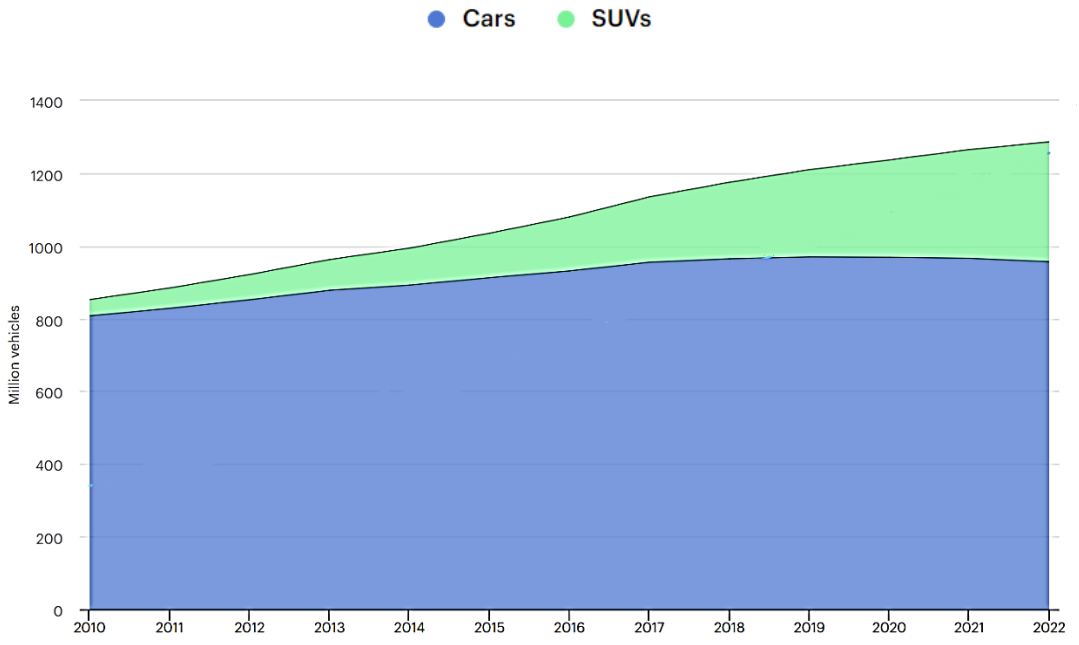


Figure 8 Passenger car fleet and SUVs in total car emissions, Global, 2010-2022 [22]

The growth in electric car sales is contributing to increased SUV sales, with approximately one-third of new electric vehicles registered in 2021 being SUVs. While electric SUVs are better for the climate compared to conventional ones, they still have downsides. They produce more carbon dioxide emissions than smaller electric vehicles, and plug-in hybrid vehicles often emit more than advertised. Moreover, their larger size requires bigger batteries, putting pressure on critical minerals and electricity demand. Electrified SUVs share the same safety concerns as fossil-fuelled ones, with increased blind zones and reduced visibility, making streets less safe for other road users. This encourages a self-reinforcing loop of driving bigger cars for perceived safety, detrimentally impacting vulnerable road users and perpetuating car dependence issues in society [23].

2.4.2 HGV (Heavy Good Vehicles)

In Ireland, approximately 40% of road transport emissions stem from the combined contribution of light and heavy goods vehicles, with private cars accounting for the remaining portion (52%), and a small fraction (8%) attributed to buses. HGVs are vehicles designed for long-distance transportation of goods weighing between 3.5 & 46 tonnes. They encompass various types of vehicles (Figure 9), including articulated trucks (semi-trailers) for long-haul transportation, rigid trucks for regional deliveries, delivery vans for urban courier services, tanker trucks for transporting liquids or gases, refrigerated trucks for perishable goods, box trucks for weather-protected transport, flatbed trucks for carrying large or irregularly shaped items, dump trucks for loose materials, and lorry trailers for heavy or oversized loads.

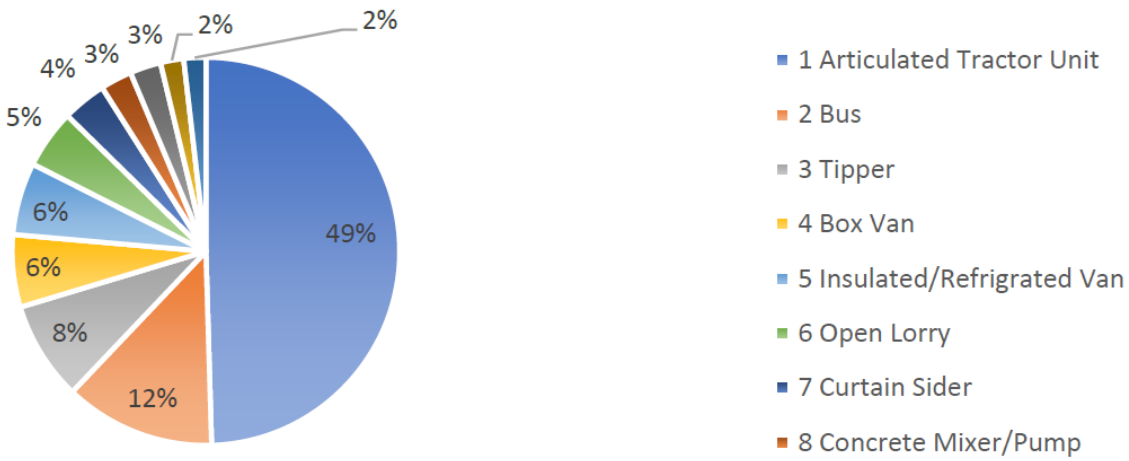


Figure 9 Heavy Commercial Vehicles by Body Type in 2023 in Ireland [24]

HGVs are crucial for global trade and supply chains, but their significant size and weight (Table 3) require adherence to strict regulations, for safety and environmental standards. Efforts are ongoing to enhance their fuel efficiency and environmental impact through technology advancements and the adoption of alternative fuels.

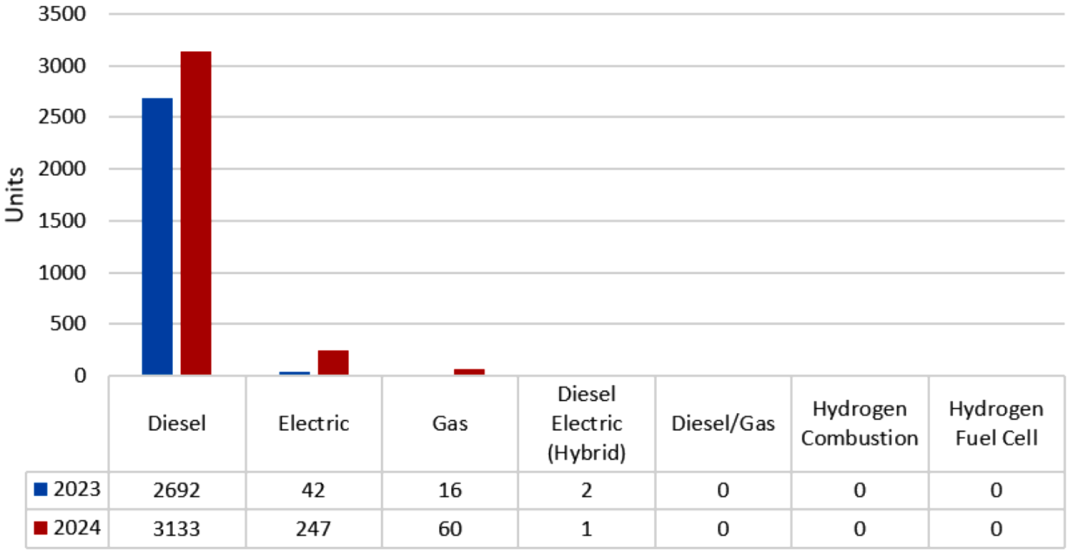
Table 3 Heavy Good Vehicles by Gross Weight in Ireland 2023 [24]

Weight	2023 Units	2024 Units
1kg -3500kg	1	9
3501kg -5000kg	1	2
5001kg -6000kg	4	18
6001kg -8000kg	137	262
8001kg -10000kg	28	36
10001kg -12000kg	85	179
12001kg -14000kg	38	55
14001kg -17000kg	47	92
17001kg+	1853	2788

HGVs typically use diesel engines (see Figure 10) and these engines consume large amounts of fuel due to their size and weight. The combustion of diesel fuel releases CO_2, a major greenhouse gas, along with harmful pollutants like NOx and particulate matter (PM). NOx contributes to smog formation, worsening respiratory issues, while fine particulate matter (PM2.5) can lead to severe health problems, including cardiovascular disease and lung cancer. These emissions degrade air quality, particularly in urban areas, posing significant public health risks. Reducing diesel-related emissions is critical for improving environmental health and meeting global air quality standards [25].

Due to their size and weight HGVs face higher aerodynamic resistance, which means they need more energy (fuel) to overcome air resistance while moving. The higher weight also contributes to increased rolling resistance, further impacting fuel consumption. Heavy goods vehicles often travel long distances, frequently on highways and motorways. This continuous travel at high speeds and for long durations leads to significant fuel consumption and subsequent GHG emissions. While there have been improvements in the efficiency of HGV engines over the years, they are generally less efficient than smaller passenger vehicle engines. This is partly due to the emphasis on power and torque required to transport heavy loads. While some advancements have been made in introducing alternative fuels like biomethane gas or electric powertrains for trucks, diesel remains the dominant fuel for heavy goods vehicles. This limits the reduction of GHG emissions from the sector. HGVs often spend considerable time idling or stuck in traffic, especially in urban areas or at loading/unloading points. Idling consumes

fuel without contributing to distance covered, leading to unnecessary GHG emissions. To mitigate their impact, efforts are being made to also optimise logistics and routing and explore electrification options for short-haul urban deliveries.



	Diesel	Electric	Gas	Diesel Electric (Hybrid)	Diesel/Gas	Hydrogen Combustion	Hydrogen Fuel Cell
2023	2692	42	16	2	0	0	0
2024	3133	247	60	1	0	0	0

Figure 10 Heavy Good Vehicles by Engine Type in Ireland 2023 (modified from [24])

Between 1990 and 2019, emissions from trucks and buses experienced a 28% increase. Based on existing policies and without further actions, HGVs are expected to consume 60.9% of the European Union's remaining carbon budget to limit global warming to 1.5°C. By 2030, there is a projected 3.8% rise in oil consumption from HGVs due to the continued growth in their activity [26] (see Figure 11). Ireland, as an island with considerable freight activity, HGVs or commonly referred to as "trucks" (which fall under the category of heavy-duty vehicles or HDVs) contribute to 14% of road transport emissions (equivalent to 1.6 $MtCO_2$-eq).

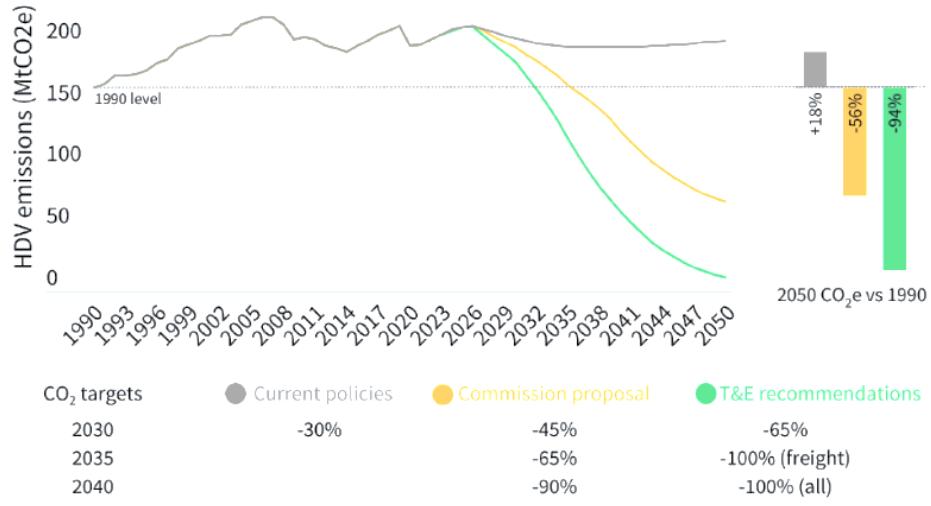


Figure 11 HGV emissions and CO_2 emissions targets [26]

Most HGVs run on diesel fuel, 61% of all HGVs licensed in Ireland at the end of 2022 were 10 years old or younger [27]. To provide perspective, an average long-distance HGV with four wheels emits approximately 102.9 grams of CO_2 per tonne-kilometre. At the end of July 2022, there were 41,850 taxed heavy goods vehicles (greater than 3.5 tonnes) in Ireland. Out of this total 22,796 were designated for licensed haulage, and 19,054 were allocated to the own account sector [27]. Moreover, there were 3,847 licensed road haulage operators in Ireland. Around 64% of these hauliers and 70% of the licensed HGVs can operate internationally, indicating the long-range distances at which these vehicles operate. Most haulage companies are classified as small operators (<5 HGVs), while those engaged in international operations tend to have slightly above-average fleet sizes. Furthermore, around 53% of hauliers within Ireland, who primarily operate domestically, possess just a single HGV, totalling approximately 2,000 vehicles [27]. Among the provinces, Dublin leads with the highest proportion of taxed HGVs at 52%, followed by Cork with 27%.

After fuel expenses, taxes constitute a significant operational cost in the freight industry, which might rise when linked to emissions from the vehicle's exhaust. In Ireland, the tax on purchasing a new vehicle includes a 23% VAT prior to applying the Vehicle Registration Tax (VRT). For commercial vehicles, the VRT is calculated using two factors: a percentage based on the open market selling price (OMSP) and the NOx calculation. This NOx calculation method is outlined in the European Automobile Manufacturers Association (ACEA) Tax Guide, as shown in Table 4.

Table 4 Vehicle Registration Tax for commercial goods vehicles in Ireland

Weight (kg)	Annual Tax due to weight (€)
≤3000	333
3001-4000	420
4001-12,000	500
≥12,001	900
Electric (not over 1500)	92

As illustrated in Figure 12, it is apparent that Ireland exhibits a notable dependence on its road infrastructure for freight transportation, as depicted in the chart showcasing the distribution of road freight among EU member states. 100% on the graph means that all freight in that country is moved by road. Ireland has about 99% of its freight transport handled by road, with very little reliance on rail. It is worth highlighting that Cyprus and Malta, the only nations with a larger share than Ireland, are devoid of rail networks entirely.

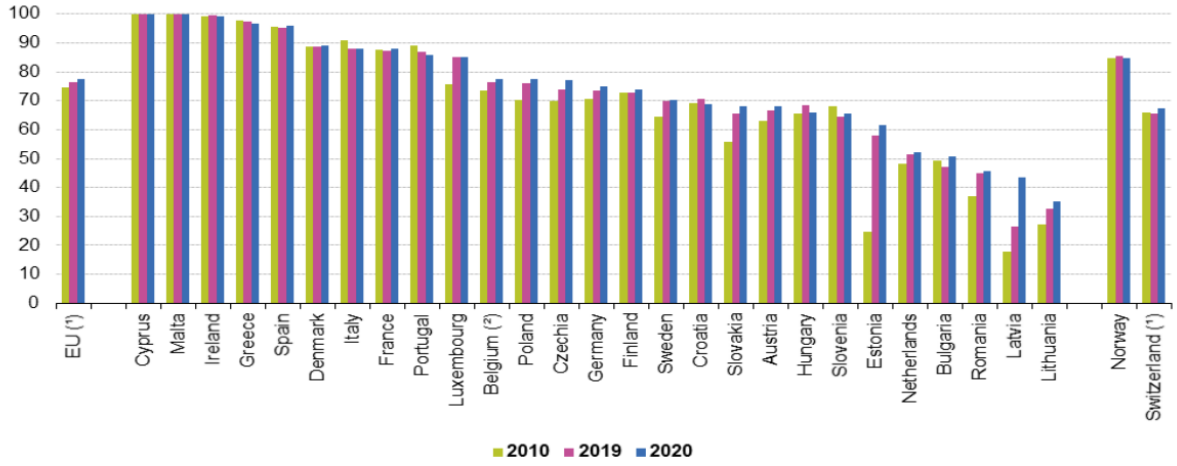


Figure 12 Share of road in total inland freight transport in EU (% based on tonne-kilometres) [27]

There remains significant uncertainty over the best technology to decarbonise HGVs, with options like biomethane, battery electric, hydrogen fuel cells, e-fuels, and advanced biofuels still competing. Hydrogen is increasingly being explored as a low-carbon fuel for hard-to-electrify transport sectors due to its high energy density and fast refuelling capability. However, its role in freight decarbonisation is likely to be limited before 2030. Major OEMs, including Scania, Renault, and Daimler, have committed to increasing electric truck sales by mid-2020s, targeting 50–60% zero-emission sales by 2030. Industry projections suggest between 480,000 and 630,000 zero-emission trucks could be on European roads by 2030 [28].

Referring to Figure 13, 2021 and projected future (2030) typical HGV daily traffic levels on National Roads. These projections are derived from analysis employing the TII National Transport Model. The model's existing HGV traffic levels have been validated against observed data from over 350 traffic sensors located on National Roads. The road network in Ireland consists of a combined length of 5,306 km, encompassing motorways, dual carriageways, and single-lane roads. Road transport plays an important role in freight movement, accounting for the remarkable percent of freight transportation. The Transport Infrastructure Ireland (TII) approximates that 80%- 90% of transported freight utilises the national primary and national secondary road network, while the remainder uses regional and local roads. Although there is potential for an increased rail freight share, the dispersed population and relatively short route distances in Ireland suggest that road transport will persist as the predominant mode. The distribution of freight traffic is particularly concentrated on specific routes, which is evident in the accompanying maps.

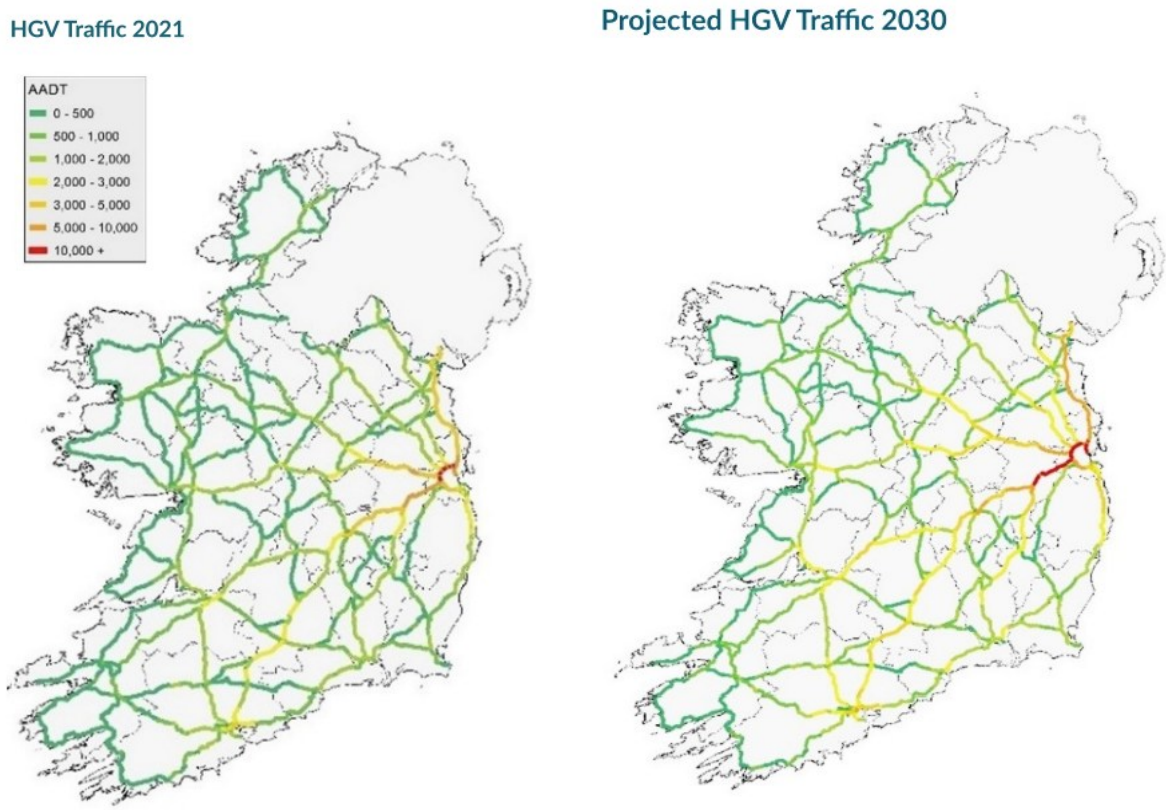


Figure 13 Existing (2021) and projected future (2030) typical HGV daily traffic levels on Irish National Roads [27]

2.4.3 Powering Sustainable Transport

In recent years, technologies such as battery electric vehicles, biofuels, synthetic e-fuels, and hydrogen fuel cell vehicles have emerged as key options to reduce greenhouse gas emissions from transportation. Hydrogen is one solution for heavy-duty vehicles which can provide long-range capabilities and fast refuelling, making it a potential part of future low-emission transport systems.

2.5 Technologies to decarbonise transport

Decarbonising transportation to address climate change requires a multifaceted approach. This entails promoting zero-emission vehicles and improved fuel efficiency. Utilising biofuel vehicles offers a potential short term renewable alternative to conventional fuels, while e-fuels, generated from renewable electricity and captured carbon dioxide, can provide carbon-neutral solutions. Hydrogen Fuel Cell Electric Vehicles (FCEVs) offers zero tailpipe emission travel and low overall emissions using renewable hydrogen. Concurrently, investments in public transportation, active transport, and thoughtful urban planning reduce reliance on individual

vehicles. Government intervention through policies, incentives, and regulations further accelerates the adoption of low-carbon transportation methods, fostering a sustainable and environmentally friendly mobility system.

2.5.1 Bio – Fuels

Biofuels, include bio-methane, biodiesel and bio-methanol and HVO (Hydrogenated Vegetable Oil, processed using hydrogen and waste vegetable oil). Biofuels are simple drop in fuels for vehicle users but can be more expensive than fossil fuels. Biofuels play a particularly important role in decarbonising transport by providing a low-carbon solution for existing technologies, such as light-duty vehicles in the near term and heavy-duty trucks, ships and aircraft with few alternative and cost-effective solutions in the long term. Biofuels present a transitional solution for HGVs and area already in use but in the long term zero emission technology is required. Biofuel demand in 2022 reached a record high of 4.3 EJ (170 000 million litres), surpassing levels seen in 2019 prior to the Covid-19 pandemic. However, a significant increase in biofuel production is needed to align with the Net Zero Emissions by 2050 (NZE) scenario and achieve the associated emission reductions. Biofuel production must exceed 10 EJ by 2030 in the Net Zero Energy Scenario, requiring an average growth rate of approximately 11% per year. This rapid expansion, while critical for meeting climate goals, is unsustainable and counterproductive if not managed carefully, as it can lead to fraud and to further deforestation, biodiversity loss, and reduced food availability for humans [29]. Without stringent sustainability and regulation measures, biofuel production risks exacerbating environmental degradation, undermining its potential benefits. These challenges are not just limited to the European Union but represent a global issue, as increased biofuel demand can place pressure on ecosystems worldwide and affect food security across regions [29].

2.5.2 Synthetic E-Fuels

Electro-fuels, also known as e-fuels or synthetic fuels, are a category of fuels produced through electrochemical conversion powered by renewable energy sources like wind or solar power (to produce hydrogen) that is then joined with carbon (or nitrogen) to produce a chemical energy carrier, usually liquid hydrocarbons (using sustainable carbon in the process or nitrogen). E-Diesel, E-Jet Fuel, E-Methanol and E-Ammonia are common examples. These fuels provide a low-carbon alternative to conventional fossil fuels, especially in hard-to-electrify sectors such as aviation, heavy industry, and long-haul transportation. However, this industry must

overcome hurdles like the vast amounts of renewable hydrogen necessary and sourcing sustainable CO_2 and the high carbon capture costs for viable e-fuel production [30,31].

2.5.3 Hydrogen ICE Vehicles

Hydrogen vehicles, utilise either an ICE to create motive force or fuel cells to generate electricity from hydrogen gas and oxygen from the air. Each option presents distinct advantages and challenges in terms of efficiency, emissions, and overall feasibility.

Using hydrogen in ICEs is an option that involves adapting existing engine technology to run on hydrogen fuel. Like gasoline, hydrogen is burned within the engine to create the combustion needed to generate power and drive the vehicle. This approach has the advantage of potentially utilising the existing infrastructure, such as service and maintenance facilities, that are already in place for gasoline vehicles [32]. However, there are challenges associated with this approach. New hydrogen refuelling infrastructure remains essential to support any hydrogen-based transport solution. While hydrogen combustion emits significantly fewer greenhouse gases than gasoline, it can still produce nitrogen oxides (NO_x), which are harmful air pollutants and contribute to poor air quality. Achieving emission reductions comparable to those of fuel cells might require incorporating emission control technologies. Additionally, the efficiency of hydrogen combustion in ICEs is 30-50% lower compared to fuel cells, limiting the overall energy efficiency of the vehicle [33]. Wróbel et al. [33] concluded that hydrogen ICEs are a cost-effective and practical solution for specific vehicle applications. While they emit nitrogen oxides and therefore need exhaust gas treatment, hydrogen ICEs excel in adapting to varying hydrogen quality, with proven reliability in demanding conditions. Their potential in areas like construction and agriculture is notable, leveraging local hydrogen storage and production [34]. While Hydrogen ICEs have potential to power some classes of vehicles ICEs are out of scope of this work and the focus on hydrogen fuel cells for HDV/HGVs.

NOTE: It is important to recognise that while e-fuels & biofuels such as methanol, biomethane, biodiesel, HVO, E-Diesel, E-Jet Fuel, E-Methanol, hydrogen combustion (to a less extent), etc aim to lower ‘net’ carbon emissions, and are often considered as alternatives, these fuels are still combusted in conventional thermal engines. Therefore, these fuels still emit pollutants like NOx and particulate matter (PM), from the exhaust systems. NOx & PM can negatively impact local air quality and public health. Proper management of these emissions is crucial to fully realising the benefits of alternative fuels [35].

2.5.4 Electric Vehicles

Electric vehicles (EVs) are automobiles powered by electric motors instead of traditional ICE's that are fuelled using gasoline or diesel or biofuels. Electric vehicles use electricity stored in either batteries or stored in fuels like hydrogen (via a fuel cell) to drive the electric motor to move the vehicle. Ireland's 2030 policy target is for 944,600 electric vehicles on Irish roads [36].

2.5.4.1 Battery Electric Vehicles

Battery electric vehicles (BEV) have a battery pack installed in the vehicle, typically located at the bottom to provide a low centre of gravity for better vehicle stability. When the driver activates the vehicle by turning it on, electricity from the battery is sent to the electric motor. The motor then converts this electrical energy into mechanical energy, which drives the wheels, propelling the vehicle forward.

To recharge the batteries, electric vehicles can be connected to the electric grid at charging stations or outlets. Charging times can vary depending on the battery capacity and the charging speed, but advancements in charging technology have significantly reduced charging times.

BEVs have made small inroads in the passenger car market and as of the end of 2024, Ireland has experienced a notable decline in EV adoption compared to previous years. In 2024, 17,459 new electric vehicles were registered, representing a 23.6% decrease from the 22,852 EVs registered in 2023. This downturn has raised concerns about meeting the national target of having 945,000 EVs on Irish roads by 2030 [34].

2.5.4.2 Hydrogen Fuel cell Electric Vehicles

Hydrogen fuel cells are electrochemical devices that facilitate the conversion of hydrogen gas and oxygen from the surrounding air into electrical energy through a chemical reaction. This process results in the generation of water liquid and vapor as a benign by-product.

Hydrogen fuel cell electric vehicles have a similar design (Figure 14) and layout and components to a battery electric vehicle, both have electric motors and batteries, the fuel cell electric vehicle having a smaller battery and replacing the space with the fuel cell and hydrogen tank.

Hydrogen fuel cell electric vehicles exhibit a heightened level of energy conversion efficiency, signifying that a substantial proportion of the energy contained within hydrogen is harnessed to generate propulsive power for the vehicle. The remarkable efficiency of fuel cells, coupled with the inherent compactness of hydrogen storage tanks, empowers fuel cell vehicles with

significantly extended driving ranges illustrated in Figure 14. Hydrogen Fuel cell electric vehicles present various advantages including higher efficiency, performance, reduced emissions, and minimal pollution in comparison with hydrogen ICE vehicles.

Hydrogen fuel cell vehicles can contribute to transport decarbonisation through many avenues; zero tailpipe emissions (except water), carbon emission-free operation, extended driving ranges, rapid refuelling, fuel source diversity. However, challenges such as infrastructure establishment, cost reduction, hydrogen storage enhancement, and regulatory/policy support must be overcome for hydrogen fuel cell electric vehicles. Several complex challenges warrant consideration in this context. The establishment of a comprehensive network of hydrogen refuelling stations stands out as a pivotal hurdle. Unlike the prevalent infrastructure of gasoline stations, the deployment of hydrogen refuelling points remains restricted, potentially impeding consumers' access to fuel. Furthermore, the sustainable and cost-effective production of hydrogen, along with its safe storage and distribution, are essential dimensions demanding intricate deliberation. The initial capital outlay associated with fuel cell technology and the hydrogen production process remains relatively elevated when compared to alternative solutions, potentially influencing the affordability of hydrogen fuel cell electric vehicles.

Wang et al. [37] introduced a collaborative planning model to boost hydrogen fuel cell electric vehicle adoption. This model integrated energy, hydrogen and transportation systems, focusing on carbon reduction through Green Hydrogen production. It optimised traffic flow and hydrogen station locations to minimise congestion and travel time, effectively lowering carbon emissions and traffic duration within the integrated network; a potential valuable tool for fleet operators.

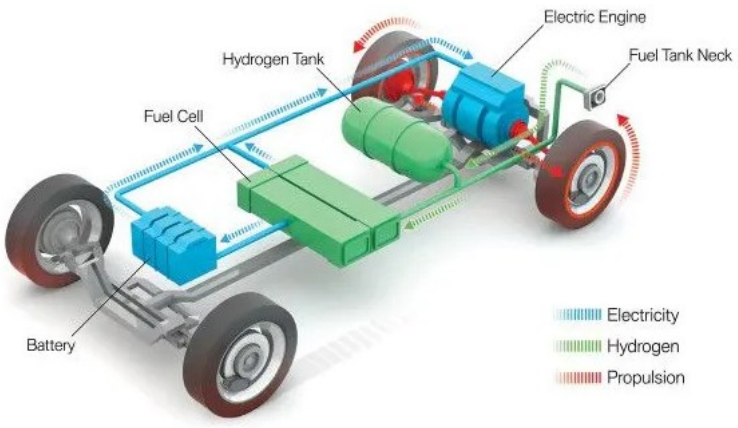


Figure 14 Schematic diagram of a hydrogen car including hydrogen tank, fuel cell and the interconnectors [38]

Electric vehicles, both battery and hydrogen fuel cell types, are vital for decarbonising transport due to their zero tailpipe emissions, higher energy efficiency, and compatibility with renewable energy sources. As technology advances, battery costs are decreasing, making electric vehicles more accessible, while BEVs can also contribute to grid stability through smart charging. Hydrogen offers potential for large-scale energy storage to support the electricity grid. Although BEVs and hydrogen trucks have higher upfront costs compared to diesel, BEVs generally benefit from much lower operational costs.

However, several challenges persist for heavy-duty transport. Range anxiety and the lack of adequate charging and hydrogen refuelling infrastructure limit the practicality of zero-emission trucks, particularly for long-haul. Charging times for battery trucks remain longer than diesel refuelling, and grid constraints can hinder charger deployment, particularly in countries like Ireland. Although BEV upfront costs are declining faster than hydrogen trucks, initial investment remains a major barrier. Hydrogen fuel remains expensive and uncertain in Ireland and across the world, impacting its attractiveness compared to diesel. Further technological improvements are needed in battery performance, durability, and Green Hydrogen production. Supply chain issues around critical raw materials for batteries and electrolysers also pose concerns. Additionally, uncertainties over the resale value of electric trucks and lingering doubts about their performance compared to diesel models could slow adoption. Addressing these challenges through innovation, investment, and supportive policies is essential for scaling up zero-emission trucks and achieving transport decarbonisation [39].

2.6 Hydrogen

Despite the rising interest as a decarbonising agent across the globe, hydrogen remains underutilised in its role as a decarbonisation solution. At present, approximately 90% of global hydrogen production, totalling 70-100 million tonnes annually, primarily serves petrochemical industries, with half of it directed towards ammonia production for agricultural use. The remaining 10% serves various sectors, including fat hydrogenation and glass manufacturing [40].

Hydrogen is an energy carrier; it is produced by input energy that can be then stored or moved to be used later to expel its energy at a certain efficiency. A significant challenge lies in the current hydrogen production process, which generates around 830 million tonnes of CO_2-eq yearly due to its heavy dependence on fossil fuels. Within the European Union (EU), hydrogen consumption amounts to roughly 10 million tonnes annually, with notable production hubs in

Germany, the Netherlands, and the UK. While low-carbon hydrogen production currently stands at nearly 0.5 million tonnes, projections suggest that demand will rise significantly, reaching 16.4 million tonnes by 2030 [41].

A review article provided by Nemmour et al. [42] shows that in the realm of sustainable hydrogen production via electrolysis, critical findings highlight Solid Oxide Electrolysis (SOE), while in research stages, holds potential for water electrolysis; the efficacy of Alkaline Electrolysis Cells (AEC) for large-scale commercial use while Proton Exchange Membrane (PEM) electrolysis has benefits with its cost-efficiency and adaptable performance.

For hydrogen to fully realise its potential as a low-carbon energy carrier, substantial progress is imperative in developing sustainable hydrogen production methods. These methods involve leveraging renewable energy sources to create hydrogen through processes like electrolysis. This transition towards "Green Hydrogen" and other colours of hydrogen has the potential to considerably curtail carbon emissions, expediting the integration of hydrogen as a cleaner energy alternative across diverse industries.

The EU Hydrogen Strategy promotes HFCEVs by supporting their adoption in public transportation, such as buses, and in heavy-duty logistics. It provides incentives and support mechanisms to boost the use of hydrogen-powered commercial fleets, with a focus on sectors where direct electrification is not feasible, such as trucks, buses, and specialized transport. The strategy aims to accelerate the deployment of hydrogen refuelling infrastructure across Trans-European Transport Network (TEN-T) corridors (Figure 15) to support FCEVs effectively [43,44].

In addition, the European Union's ambitious hydrogen strategy is anchored in a series of regulatory frameworks and strategic initiatives designed to accelerate the adoption of renewable hydrogen as a cornerstone of its clean energy transition. The Commission Delegated Regulations (EU) 2023/1184 and 2023/1185 [45] establish stringent criteria and methodologies for the production and greenhouse gas emissions calculations of renewable hydrogen, ensuring its alignment with the EU’s decarbonization goals. The Renewable Energy Directive (RED III), which entered into force in 2023, updates and strengthens the targets previously set under RED II, raising the EU-wide renewable energy target to 42.5% by 2030, with a further aspirational target of 45% [46]. RED III also introduces specific sub-targets for renewable hydrogen in industry and transport, including a binding target for industry that 42% of hydrogen used must come from renewable fuels of non-biological origin (RFNBOs) by 2030, and a transport sector target of 5.5% for advanced biofuels and RFNBOs combined [47].

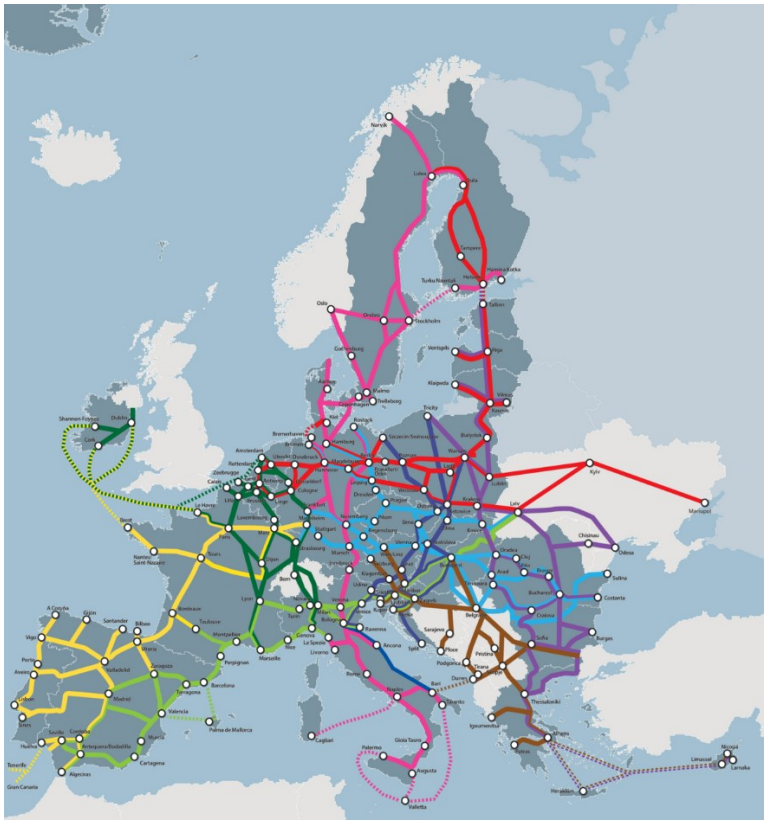


Figure 15 Trans-European Transport Network (TEN-T) [43,44]

Complementary regulations on RFNBOs set clear mandates for integrating Green Hydrogen, particularly in challenging sectors such as industry and heavy transport. These efforts are further supported by the REPowerEU plan [48], which, in response to the energy crisis, sets an ambitious target of producing 10 million tonnes of renewable hydrogen domestically and importing an additional 10 million tonnes by 2030. This holistic approach not only supports the EU's vision of energy independence but also underscores hydrogen's critical role in achieving a climate-neutral Europe by 2050, fostering resilience, and creating new economic opportunities in the green energy sector.

According to Ireland's National Hydrogen Strategy, the short-term strategy (before 2030) focuses on enabling the development of the hydrogen sector by producing hydrogen from grid-connected electrolysis using surplus renewable energy, targeting specific end-use sectors such as transport to meet EU targets. The strategy aims to remove barriers to early hydrogen projects and enhance knowledge through targeted research and innovation, with a 2 GW target of offshore wind for hydrogen production by 2030. In the long-term strategy (post-2030), Ireland plans to scale up hydrogen production using its extensive offshore wind resources, aiming to become a net exporter of renewable hydrogen. The strategy also envisions the development of

a national hydrogen network and large-scale geological storage to support the transition to a net-zero energy system by 2050 [49].

2.6.1 The Colours of Hydrogen

2.6.1.1 Green Hydrogen

A highly promising and flexible approach for producing hydrogen on a large scale is water electrolysis. This process involves using electrical power to split water into hydrogen and oxygen using an electrolyser. Importantly, this method does not result in direct carbon emissions. Water electrolysis can achieve an efficiency of over 75% based on the input power. The fundamental operational concept of the three most advanced electrolysis technologies, namely Alkaline and Polymer Electrolyte Membrane (PEM), and Solid Oxide Electrolyser Cell (SOEC) is shown in Figure 16. A brief comparison of these three technologies is also presented in Table 5.

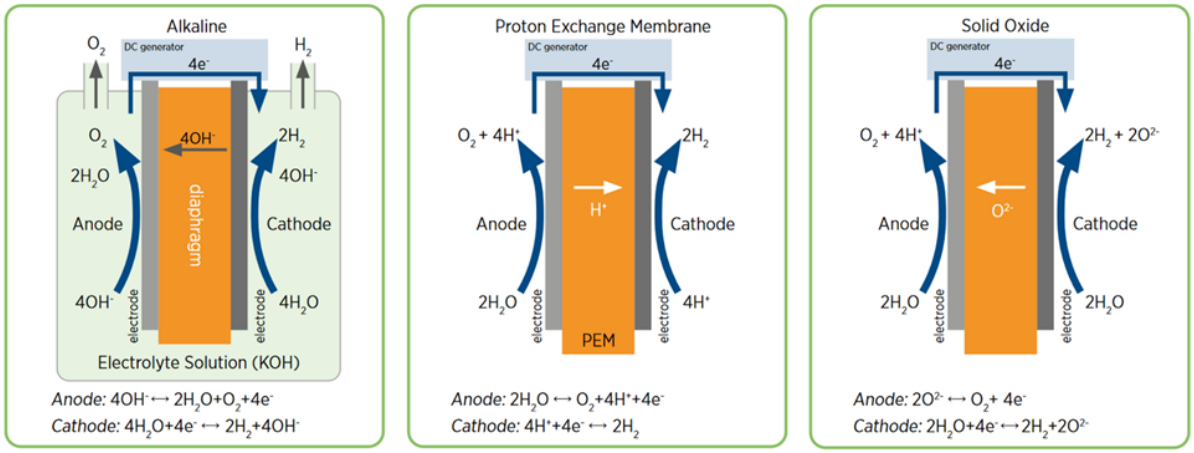


Figure 16 Schematic of Alkaline and PEM, and SOEC electrolysis, with associated equations [50]

The carbon intensity of the hydrogen produced through electrolysis depends on the origin of the electricity used to power the electrolysis process. In the case of Ireland, the current electricity grid is not the best energy source for electrolysis because most of the electricity comes from burning fossil fuels, which leads to greenhouse gas emissions.

By the third quarter of 2021, the carbon intensity of Ireland's electricity grid rose to 375 gCO_2/kWh, up from 296 gCO_2/kWh in 2020. This increase was largely driven by the impact of COVID-19, which led to a higher reliance on fossil fuels such as coal, oil, and gas to meet energy demands [51]. However, as of 2024, projections indicate a significant reduction in

carbon intensity to 234 gCO_2/kWh, attributed to a decline in coal-fired power generation and a rise in electricity imports from lower-emission sources [52].

Table 5 Highlighting the main features, advantages, and disadvantages of each electrolysis technology [50]

Parameter	Alkaline Electrolysis (AEL)	PEM Electrolysis (PEMEL)	Solid Oxide Electrolysis (SOEC)
Electrolyte	Potassium Hydroxide (KOH)	Solid Polymer (Nafion™, fumapem™)	Solid Oxide (Ceramic)
Anode Material	Nickel	Iridium	Perovskite or Nickel-based materials
Cathode Material	Nickel	Platinum	Nickel-based materials
Operating Temperature (°C)	60-100	50-80	500 - 1000
Pressure	low	high	moderate
Key Advantage	Low-cost, mature technology	Fast response, high purity hydrogen	High efficiency, can produce syngas
Key Disadvantage	Slow response to dynamic loads	High cost due to precious metals	High temperature leads to material degradation

This improvement would also extend to the carbon intensity of hydrogen produced from grid electricity. Therefore, using renewable energy technologies, either independently or as a growing portion of the grid's energy mix, would make it possible to generate clean hydrogen through electrolysis.

Figure 17 Simplified process of Green Hydrogen production

Growing interest in hydrogen production and the deployment of electrolysers is becoming increasingly evident across Europe and on the island of Ireland. In Northern Ireland, Energia, the electricity provider, has initiated the operation of an electrolyser that generates Green Hydrogen from surplus electricity. This hydrogen is then supplied to a refuelling station for hydrogen buses situated in Belfast. Several companies have also publicly declared their involvement in this burgeoning sector. For instance, Indaver and Bord na Móna have outlined plans in the eastern region of Ireland. In the west, ESB is making advances, and in the northwest region, Hone and Mercury Renewables are progressing hydrogen-related projects. Previously,

efforts were also underway to establish the Galway Hydrogen Hub (GH_2) and the SH2amrock initiative around the Galway Harbour area [53].

Water electrolysis stands as a well-established technology, although it has encountered historical cost challenges that are now gradually being resolved. As the technology gains global traction, considerable cost reductions are anticipated. IRENA's insights indicate that presently, the cost of Green Hydrogen is notably higher, around two to three times, compared to fossil-based hydrogen. However, a substantial decrease to below \$2/kgH_2 (€1.74/kgH_2) by 2030 is projected in scenarios of low electricity costs, aligning the cost with current levels of fossil-based hydrogen. Similarly, Qahtani et al. [54], through life cycle analysis, estimated the 2019 cost of Green Hydrogen derived from wind energy at \$5.61/kgH_2 (€4.88/kgH_2), aligning with IRENA's and other's findings [55]. However, with continued global energy security and political shocks as well as inadequate EU and national hydrogen policy and support Green Hydrogen costs could stay stubbornly high [41].

2.6.1.2 Grey Hydrogen

One well-established method used worldwide is called Steam Methane Reforming (SMR), as mentioned above [56,57] with over 80% of global hydrogen coming from SMR. This involves natural gas reacting with steam to make hydrogen, but it also produces carbon dioxide which can be as much as 29.33 kg CO_2-eq /kgH_2 [58]. This results in making what's known as "Grey" hydrogen, mainly used because it is the cheapest way to make hydrogen for industries. In the process hydrocarbons, with methane, undergo heating and sulphur removal in a steam system to prevent contamination and hinder catalyst activity [59]. Methods like hydrodesulphurisation and activated carbon-based adsorption can effectively eliminate sulphur [60]. Then, steam and purified methane are led through a catalyst, transforming into hydrogen through an endothermic reaction as illustrated in Figure 18.

Figure 18 Simplified process of Grey Hydrogen production

Anguita et al. [61] suggested that in the short-to-medium term, Grey Hydrogen from SMR could meet road transport demand, but electrolysis could take over by around 2035 due to lower costs and favourable carbon impact. SMR might play a role during the transition to Green Hydrogen, but international strategies should consider broader factors outlined in the European

Hydrogen Strategy. There are no SMR facilities in Ireland, as there has not been a large demand for hydrogen from major petrochemical or chemical industries.

2.6.1.3 Blue Hydrogen

SMR is currently the most common method for producing hydrogen, but it relies on fossil fuel natural gas, emitting significant amounts of carbon dioxide 4 - 20 $kgCO_2$-eq /kgH_2 in the process. This creates a contradiction: while hydrogen is promoted as a clean energy carrier solution, using SMR shifts emissions from the point of energy use to the point of hydrogen production, merely relocating the carbon emissions rather than eliminating them.

Experts emphasise the need to adopt cleaner methods, such as Blue Hydrogen production. In this context, low-carbon approaches have gained more attention and economic feasibility in recent years. Some of these methods still use fossil fuels as starting materials but capture most of the greenhouse gases like CO_2 and store them geologically underground, a process called Carbon Capture and Storage (CCS). This results in what's known as Blue Hydrogen, which emits significantly fewer carbon emissions compared to traditional methods (see Figure 19). Blue Hydrogen depending on the storage location, methane release and other factors release 4 - 20 kg CO_2-eq /kgH_2 [62].

Figure 19 Simplified process of Blue Hydrogen production

Bauer et al. [63] presented that Blue Hydrogen is only synonymous with "Low Carbon" hydrogen if two conditions are met. Firstly, natural gas supply must have minimal greenhouse gas emissions, achieved by minimising methane leaks across the supply chain. Secondly, effective CO_2 capture technology should be employed with capture rates ideally exceeding 90%. However, a recent analysis of Blue Hydrogen conducted by Howarth and Jacobson raised concerns about methane emissions during the process [64]. Their study indicated that the total CO_2-eq emissions of Blue Hydrogen could be almost as high as those of Grey Hydrogen. There is not a clear agreement yet about the full environmental impact and commercial feasibility of CCS or Blue Hydrogen. The UK Government has committed £21.7 billion over the next 25 years to support Blue Hydrogen and carbon capture initiatives, such as the HyNet and east coast cluster projects. These efforts are aimed at reducing carbon emissions in heavy industries

by capturing and storing CO_2 emissions, making Blue Hydrogen a key part of the UK's strategy to reach Net Zero by 2050 [53].

2.6.1.4 Turquoise Hydrogen

Turquoise Hydrogen is generated using a technique called methane pyrolysis or methane splitting (Figure 20). This process involves breaking down natural gas (methane) into its fundamental components – hydrogen and solid carbon – without directly emitting carbon dioxide. The significance of Turquoise Hydrogen lies in its potential to notably diminish the carbon emissions linked with hydrogen production -10 - 0.91 kg CO_2-eq /kgH_2, achieved by avoiding the release of CO_2, and using renewable natural gas as an input, over fossil fuel natural gas, a major greenhouse gas.

The importance of Turquoise Hydrogen stems from its ability to act as a bridge between Grey and Blue Hydrogen (created with carbon capture and storage) and Green Hydrogen (formed using renewable energy sources). By utilising Turquoise Hydrogen, one can work towards reducing the carbon impact of hydrogen production without solely depending on renewable energy inputs. This method effectively utilises the existing fossil natural gas infrastructure while markedly decreasing the carbon intensity in comparison to conventional Grey Hydrogen production. It is crucial to note that the technology and its scalability are currently in development, and the extent of its environmental benefits hinges on factors such as methane leakage, the efficiency of the pyrolysis process and the practical utilisation or storage of the solid carbon by-product.

Figure 20 Simplified process of Turquoise Hydrogen production

2.6.2 Hydrogen Storage – Medium Scale

2.6.2.1 Compressed gas hydrogen

To store hydrogen for transportation e.g. tube trailers or in transport applications, hydrogen gas is compressed at high-pressure in containers. Merkids [65] have explored the correlation between pressure and volumetric density of to enhance storage capacity, utilising lightweight composite cylinders capable of withstanding pressures up to 800 bar. Also, pressure-density

relationship is investigated at three temperatures (273 K, 298 K, and 373 K), revealing insights illustrated in Figure 21.

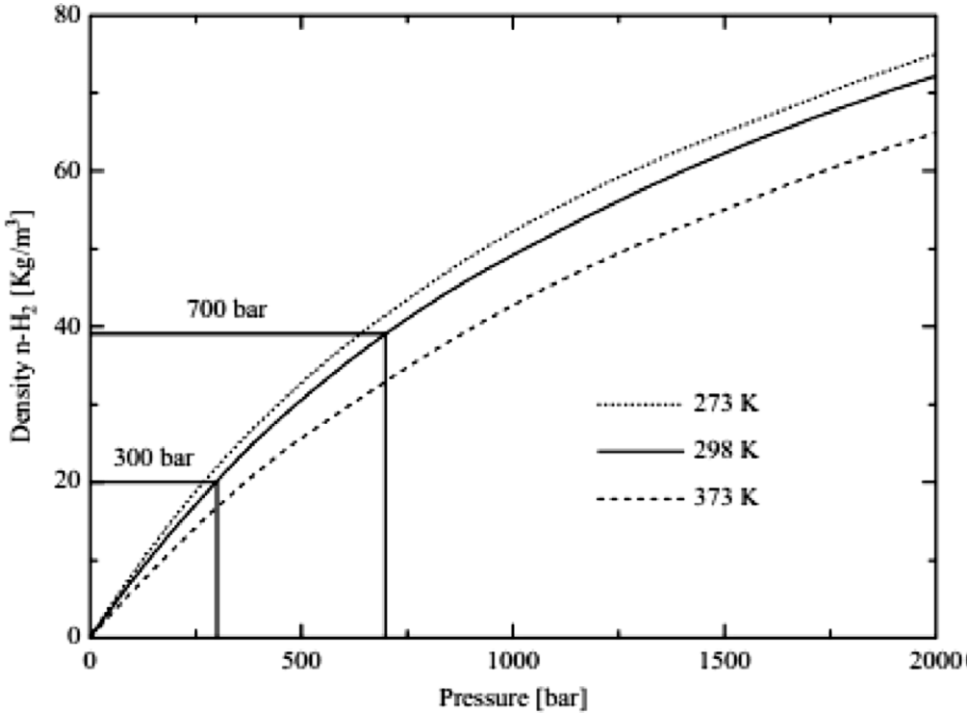


Figure 21 Pressure-Volume Relationship in Hydrogen Storage [65]

2.6.2.2 Liquid hydrogen

Liquid hydrogen (LH_2) presents an appealing solution with its remarkable energy density achieved at temperatures below 21 K, resulting in a density of 71 kg/m³. Nonetheless, the energy-intensive liquefaction process, requiring 12 to 15 kWh/kg [66], poses a significant challenge, accounting for 36% to 45% of total hydrogen energy. Despite this hurdle, LH_2's storage employs cryogenic tanks with low pressure (<10 bar) and high energy densities, demanding careful management of hydrogen boil-off. These tanks are designed with robust insulation to minimise heat transfer, addressing hydrogen boil-off due to inevitable heat inflow [66]. The liquefaction process involves compressors, heat exchangers, expansion engines, and throttle valves. Two primary techniques are the Linde cycle and Joule-Thomson expansion cycle. In the Linde cycle, gas undergoes compression and cooling before a throttle valve induces Joule-Thomson expansion, resulting in liquid formation. Cryogenic cooling is necessary for hydrogen, involving temperatures below -150°C (123 K). Cryogenic liquefaction transforms a gas under atmospheric conditions into a liquid under both atmospheric pressure and cryogenic temperature. Cooling hydrogen below -253°C (20 K) employs gases like helium, neon, nitrogen, oxygen, or air at atmospheric or higher pressures. Liquid hydrogen has a density

of 70.9 g/L, surpassing compressed gas at 42 g/L. However, challenges within liquid storage encompass boil-off (evaporation due to heat transfer) and potential leakage. To combat energy losses during liquefaction, effective solutions encompass refrigeration and insulating containers [66,67].

2.6.3 Transporting Hydrogen

2.6.3.1 Piped Hydrogen

Carrying gases in pipe networks allows for cost-effective, long-distance, and sizable amounts of energy to be transported hundreds to thousands of kilometres. Hydrogen pipelines aim to be rated for and transport pure hydrogen safely. At a 100% utilisation rate consumption and a 100 km distance, hydrogen transport via pipeline costs 0.155 Euro/kg. For a 500 km distance, the cost becomes 0.388 Euro/kg. If utilisation dips below 20%, the cost becomes unfavourable [57].

Some proponents have suggested either converting existing pipe networks to carry hydrogen which could be feasible to reduce capital infrastructure investment. Others suggest using existing pipe networks that carry fossil fuel gases e.g. methane and blend in hydrogen but this has its own challenges once the blend reaches even small percentages by volume.

The length of China's hydrogen transportation pipeline network is currently c.400 km, and the construction of future pipeline networks across the world is accelerating [68]. Currently, the European Hydrogen Backbone pipe network (Figure 22), which Ireland is part of, has plan in excess of 6,000km of new or repurposed hydrogen pipe network. In Ireland the Irish gas network operator Gas Networks Ireland has published a 2050 roadmap "Pathway to a Net Zero Carbon Network by 2045" which aims to repurpose the existing pipe network into two networks, one dedicated to biomethane (30%) and one to hydrogen (70%) to accommodate indigenous hydrogen production, as well as export via the interconnectors to Europe through the UK [69].

Figure 22 European Hydrogen Backbone pipe network

2.6.3.2 Trucked Hydrogen

Commercial tube trailers consist of around 12 to 20 elongated steel cylinders placed on a trailer bed and are subject to regulation. These trailers are regulated with a gas pressure limit of 160 atm (approximately 2400 psi), although some higher-pressure trailers (up to 400 atm) have received special certification. The hydrogen capacity per trailer is relatively small (~300 - 1000kg) but can be increased with higher pressure systems. Tube trailers are widely used in commercial settings due to their well-established technology and safety measures. Tube trailers can also serve as secondary storage at hydrogen refuelling stations. For transporting hydrogen to a refuelling station, a full tube trailer can be exchanged with an empty one to enhance loading and unloading efficiency, taking about 1 hour. In point-to-point hydrogen distribution, a truck & tube trailer move hydrogen between the hydrogen production plant and the station. The number of trucks and trailers depends on factors like hydrogen demand, trailer capacity, transit time, loading/unloading time, and truck availability [70]. At the central plant, stationary compressors fill the trailers, which are then driven to refuelling sites where extra compression is applied to meet the pressure requirements for onboard vehicle storage. Tube trailers are cost-effective for small hydrogen markets due to their lower capital costs but limited capacity [71,72]. Also transporting hydrogen by truck is a flexible solution for delivering hydrogen to areas without pipeline infrastructure. While trucking gaseous hydrogen is more common for

shorter distances, liquid hydrogen becomes more economical for longer routes due to its higher energy density. However, transporting hydrogen by truck several challenges arise that need to be addressed:

Capacity Limitations: Trucks transporting hydrogen, particularly gaseous hydrogen, face limitations due to the low energy density of the gas. For example, steel tube trailers typically carry only about 300 kg of hydrogen, which is a relatively small amount considering the energy requirements of industrial applications and heavy-duty transportation [72].

Weight Constraints: The weight of the storage tanks themselves significantly reduces the available payload capacity. Hydrogen needs to be stored either under high pressure (gaseous form) or at cryogenic temperatures (liquid form), which requires specialised and heavy equipment, impacting the overall efficiency of hydrogen transportation by road.

Safety Concerns: Transporting hydrogen introduces significant safety risks, as hydrogen is highly flammable and requires specialised containment. Leaks or exposure to embrittled materials could lead to dangerous situations, especially during long-distance transportation where constant monitoring is difficult [73].

High Delivery Costs: Due to the limited carrying capacity and the need for frequent trips, the cost of delivering hydrogen by truck can be prohibitively high compared to other delivery methods, such as pipelines. The cost per kilogram of hydrogen increases as the distance grows, making it less economical for longer trips.

2.6.4 Hydrogen refuelling station

The significance of hydrogen refuelling (Figure 23) within the broader hydrogen supply chain cannot be overstated. As hydrogen gains traction establishing a well-developed refuelling network becomes pivotal. Hydrogen refuelling stations serve as critical nodes, ensuring the accessibility and viability of hydrogen-powered vehicles across various sectors, specifically heavy-duty transportation and captive fleets. Hydrogen delivery mechanisms are also crucial, necessitating efficient distribution systems to ensure a reliable and steady supply to these refuelling stations. Strategically positioned refuelling hubs along major transportation routes and urban centres, e.g. the European TEN-T Network, offer convenient access, encouraging broader adoption. The industry group, Hydrogen Mobility Ireland, has indicated that the establishment of between 20 & 70 hydrogen refuelling stations across the island could enable an all-island hydrogen transportation sector, which holds immense significance for advancing sustainable transportation in Ireland [74]. With the growing interest in hydrogen as a clean

energy carrier, having strategically located refuelling hubs is vital to support widespread adoption. Alternative Fuels Infrastructure Regulation (AFIR) is one of the EU's frameworks to support the shift towards sustainable transport in Europe. It includes a mandatory target set for member states on charging and refuelling infrastructure development. Commencing in April 2024, the initiative is to encourage zero-emission passenger and freight road transport, enabling sustainable trade and engineering economic growth within the EU [75]. Specifically, it is to generate economies of scale for producers and managers of infrastructure for alternative fuels. The regulation includes having HDV charging stations with a minimum 350kW output placed every 60 km along the TEN-T core network and every 100 km on the TEN-T comprehensive network starting in 2025. It also requires at least one hydrogen refuelling station every 200km on the TEN-T Core network and at least one HRS in every urban node by the end of 2030 [76].

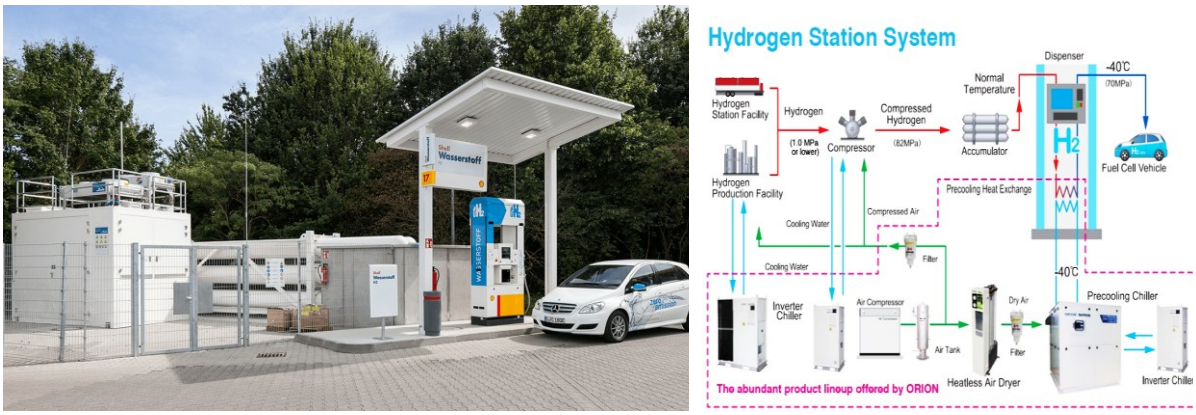


Figure 23 Hydrogen refuelling station in Germany, b) schematic hydrogen refuelling station [77]

3 Critical Literature review and research gap

3.1 Overview of Life Cycle Assessment Framework

3.1.1 Introduction and definition

Life Cycle Assessment (LCA) is a holistic approach employed to assess the environmental consequences associated with a product, process, or service across its entire life cycle, spanning from the extraction of raw materials to the final disposal at the end of its life. In contrast to conventional assessments of focusing on carbon emissions which concentrate on particular life phases, like manufacturing or usage, LCA considers every stage, encompassing raw material extraction, production, distribution, utilisation, and end-of-life management, which may involve disposal or recycling [78]. The main objective of LCA is to offer a comprehensive perspective on the environmental impacts linked to a product or process. This aids decision-makers in recognizing possibilities for enhancement and making informed decisions that reduce the overall environmental footprint. By examining the entire life cycle, LCA facilitates a more precise evaluation of environmental factors, such as resource depletion, energy use, emissions, and waste production LCA employs a methodical approach, defined by global standards ISO 14040 and 14044, to guarantee uniformity and dependability in the assessment procedure. It examines the relationships between diverse stages in the life cycle and evaluates environmental effects within different categories, including climate change, human toxicity, and ecosystem quality. The main framework of LCA is structured into four stages, as shown in (See Figure 24).

3.1.2 Goal and scope definition

Defining the goals and scope of an LCA is essential as it establishes clear objectives, keeps the study focused, and ensures relevance to decision-making. A well-defined scope enhances practical value by aligning outcomes with intended decisions and guiding efficient resource use. Key elements in setting the scope include defining system boundaries (life cycle stages considered), the functional unit (quantifiable product or service performance for comparison), and factors such as time, geography, data quality, and availability. Careful consideration of these aspects strengthens the reliability and applicability of the LCA for decision-makers.

3.1.3 Inventory analysis

Inventory analysis is a key phase of LCA that involves collecting and quantifying data on materials, energy, and emissions across all life cycle stages, from raw material extraction to disposal. Challenges such as data availability, accuracy, and variability arise due to proprietary restrictions, inconsistent reporting, and industry differences. To address these, practitioners combine direct measurements, secondary data from databases and literature, and modelling techniques to fill gaps. This integrated approach improves data reliability and strengthens the overall LCA study [79].

3.1.4 Impact assessment

In LCA, the impact assessment phase translates the LCI results into potential environmental impacts by applying established characterization models. This phase aims to evaluate how quantified inputs and outputs from each life cycle stage contribute to different environmental impact categories, such as climate change, water use, toxicity, and resource depletion.

Impact assessment does not involve data collection; rather, it builds upon the inventory data generated during the LCI phase. The primary step in impact assessment is characterization, in which inventory flows are converted into impact indicators using scientifically defined characterization factors. This allows results to be expressed in a common unit within each impact category while preserving transparency regarding the underlying assumptions.

Optional steps such as normalization and weighting may be applied in some studies to support internal decision-making; however, these steps are inherently value-based and introduce subjectivity. As a result, weighting and aggregation of multiple impact categories into a single score are discouraged in comparative assessments intended for public communication, as they may obscure trade-offs between impact categories rather than clarify them.

3.1.5 Interpretation

Interpreting LCA results translates complex data into actionable insights for stakeholders such as policymakers, businesses, and consumers. Results highlight life cycle hotspots, enabling sustainable practices, resource optimisation, and eco-friendly choices, while transparency fosters responsible decision-making. Since LCAs involve data gaps and uncertainties, acknowledging these limitations is essential to ensure balanced interpretations and enhance credibility. Clear communication of uncertainties helps stakeholders assess risks and make more reliable, informed decisions.

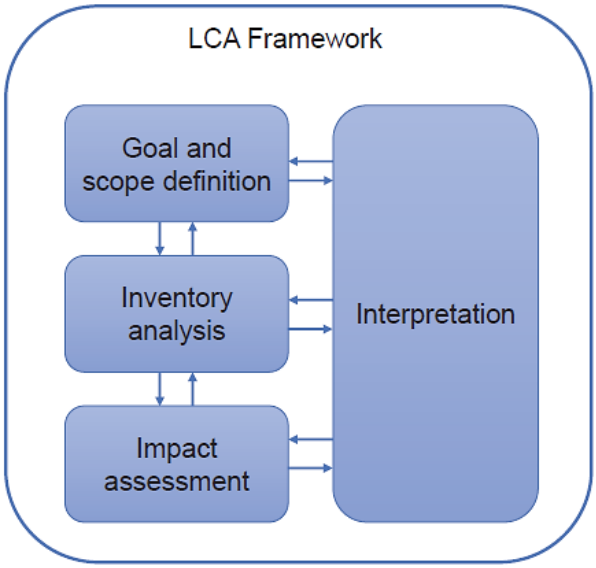


Figure 24 Schematic flowchart of LCA framework [79]

3.2 Hydrogen in the Transport Sector

A growing body of research highlights the environmental benefits of hydrogen integration into transportation systems, despite notable challenges. Giacomelli et al. [80] examined the North Adriatic Hydrogen Valley initiative, underscoring how regional infrastructure development, policy integration, and technological innovation can accelerate hydrogen adoption in European transport and industry. Their analysis projected a reduction of approximately 50,000 tons of CO_2 emissions annually through such initiatives. Similarly, Martines and Santos [81] explored the role of Green Hydrogen in reshaping energy and transportation systems, emphasising that strong public policies and regulatory frameworks are critical to overcoming barriers like high production costs. Their modelling suggested that reaching 20% hydrogen utilisation in transportation by 2035 could reduce sectoral emissions by 45 million tons of CO_2 equivalent per year, with policy support (e.g., subsidies) needed to make Green Hydrogen cost-competitive. Expanding on the global perspective, Seibert [82] stressed hydrogen's essential contribution to achieving net-zero targets, particularly through its versatility in hard-to-decarbonise sectors like shipping and heavy transport. Seibert estimated that by 2050, international collaborations enabling the production of 50 million tons of hydrogen annually could meet 12% of global transport energy demand and lower CO_2 emissions by 3.5 billion tons each year.

At the fleet level, Guo et al. [83] analysed mixed hydrogen and diesel truck fleets, finding that hydrogen trucks could significantly cut freight transport emissions, though high costs remain

a barrier. They showed that with carbon pricing mechanisms (e.g., $100/ton CO_2), hydrogen trucks could achieve cost competitiveness by 2030, making large-scale emission reductions feasible. In the rail sector, Lizette and Carrillo [84] assessed hydrogen-powered locomotives in Canada, revealing that hydrogen could reduce rail emissions by up to 40% compared to diesel, offsetting 2.5 million tons of CO_2 annually, although substantial infrastructure investments (around $15 million per station) would be required.

Ireland has taken significant early steps toward hydrogen integration in transport, notably introducing hydrogen-powered buses in 2020 under the National Transport Authority's pilot programme [85]. More recently, the SH2AMROCK project, an EU-funded initiative [86], plans to expand Ireland's hydrogen fleet by establishing the country's first hydrogen valley and a multi-modal H_2 transport hub in Galway. This project aims to accelerate decarbonisation across multiple end-use sectors by coupling local hydrogen production with demand in transport and industry.

The success of such initiatives relies on building a robust hydrogen supply chain. Martins and Carton [87] emphasise that Ireland, despite strong renewable energy resources, needs rapid action to integrate hydrogen into its broader decarbonisation strategy. They argue hydrogen can significantly reduce emissions—up to 6.1 $MtCO_2$-eq annually—through applications in heavy transport, heating, and energy storage. However, the effective deployment of hydrogen technologies requires addressing supply-side challenges such as production scale-up, infrastructure, and policy support.

A practical example is provided by Laguipo et al. [88], who explored decarbonising Ireland's heavy-duty transport sector using Green Hydrogen. Their findings highlight that heavy-duty vehicles represent a critical early market for hydrogen, estimating potential hydrogen demand between 1,141 and 4,626 tonnes per year for haulage alone. Their study further shows that hydrogen delivery costs could be as low as €1.63/kg, making it a viable option if hydrogen production and demand are developed in parallel—a key lesson for initiatives like SH2AMROCK.

3.3 Life Cycle Assessment (LCA) of Hydrogen Pathways

A growing body of literature has examined the environmental performance of hydrogen across its production, transport, and delivery stages, with LCA increasingly used to quantify associated impacts. Across these studies, results consistently indicate that hydrogen's life cycle

emissions are highly sensitive to electricity source, system boundaries, and delivery configuration, leading to a wide range of reported impacts.

With respect to hydrogen production, several studies highlight electricity supply as the dominant contributor to life cycle impacts for electrolysis-based hydrogen. Comparative analyses show that wind-powered electrolysis consistently delivers the lowest global warming potential (GWP), with reported values below 1 kg CO_2-eq/kg H_2 in multiple studies, whereas solar-powered pathways often exhibit higher impacts due to greater electricity input, land use requirements, and associated infrastructure burdens [89]. Projections of future electricity systems further reinforce this dependency: under fully decarbonised electricity mixes, hydrogen GWP may fall below 0.3 kg CO_2-eq/kg H_2, while current European grid conditions yield values comparable to fossil-based pathways [90]. These findings underline the importance of regional electricity context, which remains underexplored for Ireland specifically.

In contrast, fossil-based hydrogen pathways, particularly steam methane reforming (SMR), show more consistent but substantially higher emissions across the literature. Meta-analyses report SMR emissions typically ranging between 8–12 kg CO_2-eq/kg H_2, while Blue Hydrogen outcomes vary widely depending on methane leakage assumptions, carbon capture efficiency, and system boundaries [90]. Importantly, reviews have highlighted a lack of harmonisation in allocation methods and boundary definitions, limiting comparability across studies and introducing uncertainty into policy-relevant conclusions.

Hydrogen transport and delivery also play a critical role in determining overall environmental performance. Several studies converge on the finding that pipelines are the most environmentally efficient delivery option for large-scale and long-distance hydrogen transport due to strong economies of scale and relatively low operational emissions [91], [92]. In contrast, pressurised gas trucks are more favourable for short-distance delivery, while liquid hydrogen trucks and Liquid Organic Hydrogen Carriers (LOHCs) generally exhibit higher life cycle impacts due to energy-intensive compression, liquefaction, or dehydrogenation processes [91], [93]. However, many studies assume idealised infrastructure availability and do not explicitly consider countries without existing hydrogen pipeline networks, limiting their applicability to regions such as Ireland.

Emerging research has also explored alternative hydrogen sources, such as waste-derived hydrogen, which can offer meaningful emission reductions compared to conventional SMR when integrated with fuel cell vehicle deployment [94]. While promising, these pathways are

highly context-specific and depend strongly on waste availability, conversion efficiencies, and local energy systems.

While existing studies provide valuable insights into hydrogen life cycle impacts, they also reveal significant methodological fragmentation, particularly regarding electricity assumptions, allocation approaches, delivery system modelling, and geographic specificity. These limitations highlight the need for regionally grounded, integrated assessments that simultaneously evaluate hydrogen production and delivery pathways under consistent assumptions. Addressing these gaps forms the basis for the research approach adopted in this thesis.

3.4 Research gap

While existing research clearly demonstrates hydrogen's potential to support transport decarbonisation; particularly, for heavy-goods vehicles (HGVs), rail, and public transport—most life cycle studies remain narrow in scope, typically focusing on hydrogen production only, with a strong emphasis on Green Hydrogen via electrolysis. Alternative production pathways, such as grey, blue, and turquoise hydrogen, are comparatively underrepresented, particularly within transport-focused assessments.

Moreover, integrated life cycle assessments that extend beyond production to include compression, storage, and delivery to the refuelling station are limited, despite these stages having a significant influence on overall environmental performance. This gap is especially pronounced for HGV applications, where fuel logistics and infrastructure requirements differ substantially from passenger transport. In addition, region-specific LCAs reflecting Irish energy systems, infrastructure constraints, and delivery routes remain scarce, limiting the applicability of international studies to national policy and planning.

Furthermore, relatively few studies combine environmental LCA with techno-economic analysis under a consistent framework, despite cost competitiveness being a critical determinant of hydrogen deployment. The separation of environmental and economic analyses in the literature restricts holistic evaluation and can lead to incomplete or misleading conclusions.

In response to these gaps, this research provides a comprehensive, Ireland-focused assessment of hydrogen for HGV applications by evaluating four hydrogen production pathways (green, blue, grey, and turquoise) and multiple delivery routes (pipeline and truck transport) using a

unified life cycle framework. By integrating environmental LCA with life cycle cost analysis, the study offers a more complete understanding of the trade-offs associated with hydrogen deployment, supporting evidence-based decision-making aligned with both decarbonisation targets and broader sustainability objectives.

3.5 Research objectives

This study applies LCA to quantify the environmental impacts of hydrogen production and delivery pathways, in accordance with ISO 14040 and ISO 14044 standards. In parallel, Life Cycle Cost Analysis (LCCA) is employed to assess economic performance using indicators such as Net Present Value (NPV) and Levelised Cost of Energy (LCOE). While LCA evaluates environmental burdens across the life cycle, LCCA provides a complementary economic perspective. These methods are applied separately but interpreted together to support holistic decision-making.

Some specific objectives can be proposed as follows:

- To investigate and compare four key hydrogen production pathways—green (PEM electrolysis), blue (SMR with CCS), grey (SMR), and turquoise (methane pyrolysis)—in terms of their environmental performance.
- To conduct a comprehensive LCA of each hydrogen production route, considering upstream and downstream processes including electricity mix, feedstock sources, and emissions across multiple impact categories (e.g., GWP, AP, EP, MAETP).
- To evaluate the environmental impact of hydrogen distribution methods, specifically comparing delivery via pressurised gas trucks and pipelines, and identifying the most sustainable delivery pathway for different production scales and distances.
- To develop and analyse full hydrogen fuel supply chain scenarios, from production to refuelling station, and compare them with the baseline diesel scenario for heavy goods vehicles in Ireland.
- To perform a LCCA of the studied hydrogen pathways, including capital and operational expenditures, and to calculate Net Present Value (NPV) and Levelised Cost of Energy (LCOE) for each scenario.

- To explore the sensitivity of hydrogen fuel economics to key variables such as electricity price, PEM electrolyser cost, and natural gas price, identifying the main cost drivers and tipping points for economic competitiveness.
- To identify the environmental trade-offs associated with each hydrogen colour, including the potential for burden shifting between impact categories, and to provide recommendations for sustainable hydrogen deployment strategies.

4 Methodology

The methodology adopted in this research consists of two distinct but complementary components: (i) an environmental LCA and (ii) an economic Life Cycle Cost Analysis (LCCA). Although both assessments consider the same hydrogen production and delivery scenarios, they differ in scope, functional intent, and evaluation metrics. The environmental LCA focuses on impact categories such as global warming potential, while the LCCA evaluates financial performance using NPV and levelized cost of energy.

4.1 Goal and scope

This research evaluates and compares the environmental impact of hydrogen production using both established and emerging technologies, with a focus on their contribution to energy system transformation. The study investigates four distinct hydrogen production methods, SMR, SMR-CCS, MP as well as PEMEL. The scope of this LCA follows a "cradle-to-gate" perspective, encompassing processes from resource extraction to the hydrogen production facility, prior to distribution. Since transport and storage stages are not directly influenced by the production technology, their environmental effects are not considered in the comparison. Therefore, in accordance with ISO 14044, the assessment focuses solely on the hydrogen production phase, ensuring a relevant and unbiased comparison of the selected technologies. In contrast, all life cycle phases up to and including the production of hydrogen were within the system boundaries. There are 12 scenarios: four scenarios for four types of hydrogen and three scenarios for hydrogen transport (Figure 25).

4.1.1 Functional unit

The functional unit is defined as production of 1 kg of hydrogen, compressed and delivered to the hydrogen refuelling station.

The functional unit of 1 kg H_2 delivered to the refuelling station was selected to enable direct comparison of hydrogen production and delivery configurations under consistent system boundaries. This unit reflects a standardised quantity of fuel supplied to the transport system and is commonly applied in hydrogen LCAs. While cross-fuel comparisons based on delivered energy (MJ) or distance travelled (km) are possible, they require additional assumptions regarding vehicle efficiency and drivetrain performance. These factors were intentionally excluded to maintain methodological transparency and focus on supply-chain impacts.

4.1.2 System boundaries

This study focuses on multiple hydrogen production pathways, including 'Green', 'Blue', 'Grey', and 'Turquoise' hydrogen and the scope of this study is cradle to gate, i.e., the technical boundaries cover processes from raw material extraction to hydrogen production and delivery to the refuelling stations. The geographical boundaries of the hydrogen production study are focused on Ireland. The datasets for hydrogen production, transport, and refuelling are sourced from the GaBi professional database. The study began in January 2023 and ran until June 2024. The LCI datasets used in this study range from 2020 to 2023.

The hydrogen types are defined as:

(1) Polymer electrolyte membrane electrolysis (PEMEL) from renewable energy - Green Hydrogen

(2) SMR with carbon capture and storage (SMR-CCS) from fossil natural gas – Blue Hydrogen

(3) Steam Methane Reforming (SMR) from fossil natural gas – Grey Hydrogen

(4) Methane Pyrolysis (MP) from fossil natural gas – Turquoise Hydrogen

The first three scenarios are related to Green Hydrogen. In the first Scenario (GN), hydrogen is produced from a PEM electrolyser with a capacity of 1 MW per stack with an assumed specific electricity consumption of 55 kWh/kg H_2 (η_{HHV} = 71.59%). There are also 12 kg of water required for the process [95].

Green Hydrogen production was modelled assuming electricity supplied entirely from wind power, reflecting Ireland's renewable electricity profile. Electricity inputs for electrolysis were sourced from the GaBi professional database, using wind electricity datasets representative of the Irish energy system. Where Ireland-specific datasets were unavailable, European wind electricity datasets were applied as proxies. This approach ensures consistency with national renewable deployment while maintaining data robustness.

In this scenario, the annual operating hours of 8,000 hr/yr are assumed. The lifetime of the stack is estimated to be 10 years and the plant lifetime of 20 years [96]. According to Green

Scenario 2 (GN-T), produced hydrogen from a PEM electrolyser is compressed and is transported to the refuelling station by truck for utilisation as a fuel in HGVs. In GN-P (Scenario 3), the compressed hydrogen produced from PEM electrolyser is transported to the refuelling station by pipeline.

Blue BE (Scenario 4) refers to Blue Hydrogen production via Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS). The system operates at a capacity of 100,000 Nm^3/h H_2, with 8,000 operating hours per year and a lifetime of 20 years. CO_2 sequestration from the shifted syngas is achieved through chemical absorption, utilising state-of-the-art pre-combustion capture technology, reaching a capture efficiency of approximately 56% [96].

Methyldiethanolamine (MDEA) is a liquid amine and widely used solvent for capturing CO_2. MDEA is not explicitly considered in the LCA software as no reliable information could be referenced during the study. However, during the literature review the following was determined and the best data were used to compile the inventory:

- The additional energy requirements for CO_2 capture and solvent regeneration indirectly affect the overall process efficiency, leading to changes in fuel and water demands – these have been accounted for in the study.
- MDEA is not typically categorised as a greenhouse gas but can degrade over time to which can indirectly contribute to GWP, but specific data on their GWP contributions are limited and the indirect effects of MDEA's degradation products on GWP remain uncertain. Its primary environmental concern lies in its potential ecotoxicity, particularly affecting marine environments. While its degradation products could theoretically influence GWP, current data are insufficient to quantify this effect – for the purposes of this study GWP is deemed low/ negligible impact compared to other parts of the SMR/CCS process.
- Regarding the Marine Aquatic Ecotoxicity Potential (MAETP) for MDEA, it can be referenced to be 1.3 kg 1,4-dichlorobenzene (1,4 DCB) eq per kg of MDEA used. Considering that c.0.15 kg of fresh MDEA is required per kg of CO_2 captured in a well-managed system, adding c.1 kg DCB-eq /kgH_2 to MAETP. It is noted that MDEA regeneration significantly reduces the environmental impact [97].

The use of MDEA in CO_2 capture presents environmental challenges, particularly in terms of toxicity, water pollution, and emissions. MDEA exhibits moderate toxicity to aquatic organisms, with an EC_{50} of 35 mg/L for algae and 190 mg/L for Daphnia magna. If released into water bodies, it can degrade into nitrosamines, which are highly carcinogenic and have

been detected at levels exceeding 1 µg/L in industrial wastewater, far above the WHO drinking water limit of 0.1 µg/L. Also, MDEA degradation in high-temperature environments releases ammonia (5–50 ppm) and formaldehyde (0.1–5 ppm), contributing to air pollution and secondary aerosol formation. Given these environmental risks, careful waste management, emission control, and alternative solvent exploration are necessary to mitigate long-term impacts [98,99].

Grey Hydrogen produced from SMR with a capacity of 100,000 Nm_3/h H_2, annual operating hours of 8,000 hr/yr and a lifetime of 20 years were assumed in GY (Scenario 7). In GY-T and GY-P (Scenario 8 and Scenario 9) the hydrogen is produced from SMR transport to the compressor then at the end of this process it moved to the refuelling station by truck and pipeline.

For the case of Turquoise Hydrogen which is produced from methane pyrolysis connects to a compressor and then at the end of this process it connects to the refuelling station in Turquoise TE, TE-T, and TE-P (Scenario 10 and Scenario 11 and Scenario 12). For the methane pyrolysis plant, a lifetime of 20 years with 8,000 hours of operation per year is assumed.

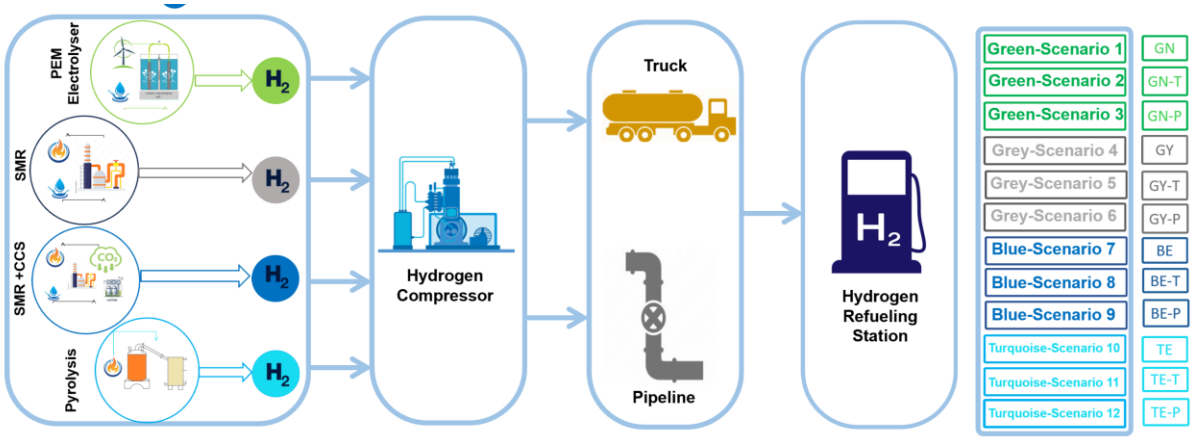


Figure 25 Scenarios developed based on various hydrogen production and transport pathways.

In this study, co-products arising from hydrogen production processes—namely oxygen from PEM electrolysis and solid carbon from methane pyrolysis—were not allocated environmental credits and were excluded from the system boundary. This choice was made to maintain a conservative and consistent comparative framework across all hydrogen pathways and to avoid introducing additional uncertainty related to co-product utilisation, market substitution, or future demand scenarios. In practice, oxygen from electrolysis is often vented or used in low-value local applications [100], while the environmental benefit of solid carbon from pyrolysis is highly dependent on its purity, storage, or downstream use, which remains uncertain at

present. Previous studies have shown that including such co-product credits has a minor influence on overall GWP results and does not alter the relative environmental ranking of hydrogen production pathways. Accordingly, co-products were excluded to ensure transparency, robustness, and comparability of the LCA results across all scenarios assessed.

4.1.3 Data collection

The data used in the study come from a mix of academic literature sources, technical reports, LCA software datasets.

4.1.4 Life Cycle Impact Assessment Methodology

Figure 26 illustrates the step-by-step Life Cycle Assessment (LCA) methodological framework applied in this study, following ISO 14040 and ISO 14044 principles. The workflow begins with goal and scope definition and functional unit selection, followed by system boundary definition encompassing hydrogen production, compression, storage, delivery, and refuelling. Life cycle inventory (LCI) modelling and life cycle impact assessment (LCIA) are conducted using the CML2001-Jan2016 midpoint methodology, selected for its scientific robustness, widespread acceptance in energy and industrial LCA studies, and strong alignment with ISO standards. The CML approach employs midpoint indicators without weighting or normalisation, reducing subjectivity and ensuring transparency in comparative assessments, and is commonly applied in hydrogen and energy system LCAs, enabling meaningful comparison with existing literature [101]. Data consistency, assumptions (see Table 6), and key parameters are systematically checked through sensitivity and uncertainty analysis, and results are evaluated against existing studies. Where inconsistencies are identified, the model is iteratively refined by updating assumptions or inventory data prior to final interpretation and reporting. Endpoint-oriented methods were not adopted due to their higher uncertainty and reliance on value-based aggregation, which were not aligned with the comparative, technology-focused objectives of this study [102].

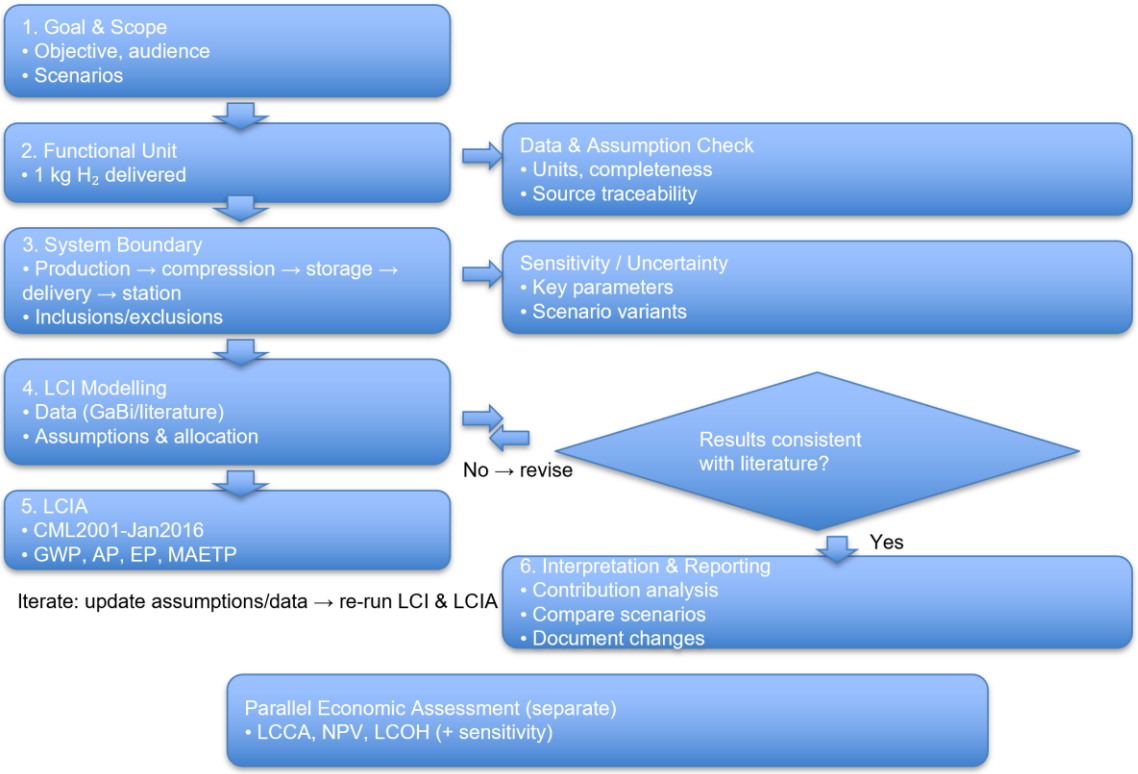


Figure 26 Step-by-step LCA methodological framework applied in this study

The selection of the four key LCIA categories presented in Table 7 was driven by their relevance in capturing the environmental impacts associated with hydrogen production aligning with the global sustainable development goals. While most previous studies have concentrated on GWP [90], this research broadens the scope of the impact assessment by including AP, EP, and MAETP. GWP is critical for assessing the contribution of carbon emissions to climate change, a key focus in hydrogen production pathways. AP and EP were included due to their ability to capture acidifying emissions and nutrient runoff, both of which are common by-products of energy-intensive processes like hydrogen production. Finally, MAETP was selected to address the ecotoxicity impacts on marine ecosystems, particularly important given the potential for effluents and emissions to impact water bodies.

Table 6 Assumption used for the LCA in this studied

Parameter	**Value**	**Unit**	**Applied to**	**Source/Reference**
Functional unit	1 kg H_2 compressed and delivered to refuelling station	kg H_2	All scenarios	Section 4.1.1
LCA scope	Cradle-to-gate (Desktop LCA)	–	All scenarios	Section 4.1.2

	(production → delivery)			
Geographic scope	Ireland	–	All scenarios	Section 4.1.2
Electricity source (Green H_2)	Wind electricity	–	GN	Section 4.1.3
Electricity consumption (PEMEL)	55	kWh/kg H_2	GN	[103]
Water consumption (PEMEL)	12	kg/kg H_2	GN	[103]
Natural gas consumption (SMR)	5.01	m^3/kg H_2	GY, BE	[95]
CO_2 capture efficiency (SMR-CCS)	56	%	BE	[95]
Operating hours	8,000	h/year	All production plants	[95]
Plant lifetime	20	years	All scenarios	[95]
PEM stack lifetime	10	years	GN	[104]
Delivery distance	100	km	Truck/Pipeline scenarios	-
LCI database	GaBi (Sphera LCA for Experts v10.7.1.28)	–	All scenarios	Section 4.2
LCIA method	CML2001–Jan2016 (midpoint)	–	All scenarios	Section 4.1.4

Table 7 Life cycle impact assessment categories used in this study

Impact category	Abbreviation	Units
Global Warming Potential100 years	GWP_{100}	kg CO_2-eq.
Acidification Potential	AP	kg SO_2, -eq.
Eutrophication Potential	EP	kg PO_4^{3-}-eq.
Marine Aquatic Ecotoxicity Potential	MAETP	kg 1,4DCB -eq.

4.1.5 Intended Audience

The result of the study aims to provide policymakers, industry stakeholders, and researchers with valuable insights into the environmental sustainability of hydrogen in the transport sector. The findings will help inform decision-making processes in future sustainable infrastructure development and sustainable fuel policy.

4.2 Life Cycle Inventory Analysis

The elementary flow datasets for this study are provided by Sphera's LCA for Experts, 2023, V 10.7.1.28. The LCI data include inputs for chemicals, thermal energy, electricity, and wastewater treatment.

The assumptions regarding the LCI data for hydrogen production through SMR, SMR-CCS, MP, and PEMEL were based on information obtained from referenced literature [95]. In cases where data were incomplete, additional information was sourced from the LCA software.

The first column in Table 8. presents LCI data of the PEMEL-based hydrogen production, SMR-CCS, SMR, and methane pyrolysis. In addition, LCI data for the compressor, refuelling station and pipeline are provided in Table 9.

Table 8 Inventory for PEM electrolyser, SMR with CCS, SMR, and methane pyrolysis [95,103,105,106]

PEM Electrolyser		**SMR+CCS**	
INPUT FLOWS		**INPUT FLOWS**	
Electricity	55 kWh [103]	Natural gas	5.01 m^3 [95]
Deionised water	12 kg [103]	water	257 kg [95]
OUTPUT FLOWS		**OUTPUT FLOWS**	
Oxygen	8.00 kg	Carbon dioxide	4.12 kg
CONSTRUCTION MATERIALS [95]		**CONSTRUCTION MATERIALS** [95]	
Titanium	3.63×10^{-4} kg	Concrete	6.60×10^{-6} m^3

High alloyed steel	7.22×10^{-4} kg	Steel	5.06×10^{-3}
Copper	3.75×10^{-5} kg	Aluminium	4.17×10^{-5}
Nafion™	1.10×10^{-5} kg	Cast Iron	6.18×10^{-5}
Activated carbon	6.19×10^{-6} kg		
Low alloyed steel	1.65×10^{-3} kg		
Aluminium	5.29×10^{-5} kg		
SMR		Methane Pyrolysis	
INPUT FLOWS		**INPUT FLOWS**	
Natural gas	4.85 m^3 [95]	Natural gas	7.44 m^3 [95]
water	387 kg [95]	Electricity	1.67 kWh
OUTPUT FLOWS		**OUTPUT FLOWS**	
Carbon dioxide	9 kg		
CONSTRUCTION MATERIALS [95]		**CONSTRUCTION MATERIALS** [95]	
Concrete	6.60×10^{-6} m^3	Copper	7.33×10^{-6} kg
Steel	5.06×10^{-3} kg	Silica sand	8.04×10^{-5} kg
Aluminium	4.17×10^{-5} kg	Tin	3.36×10^{-2} kg
Cast Iron	6.18×10^{-5} kg	Silicon carbide	4.20×10^{-6} kg
		Palladium	1.10×10^{-4} kg
		Low alloyed steel	2.59×10^{-3} kg
		High alloyed steel	5.07×10^{-4} kg

Table 9 Inventory for compressor, fuel station and pipeline [95,103,105,106]

Compressor		**Fuel station**		**Pipeline (100km)**	
INPUT FLOWS		**INPUT FLOWS**		**INPUT FLOWS**	
Electricity	9.4 kWh/kgH_2 [103]	**Electricity**	14.2 kWh	**Polyurethane**	0.0137 kg [106]
CONSTRUCTION MATERIALS		**CONSTRUCTION MATERIALS [107]**			
Low alloyed steel	3.98×10^{-3} kg	**Low alloyed steel**	7.89×10^{-2} kg		
High alloyed steel	6.95×10^{-4} kg	**High alloyed steel**	8.10×10^{-3} kg		
Cast iron	2.47×10^{-4} kg	**Cast iron**	2.30×10^{-3} kg		
Copper	9.32×10^{-5} kg	**Copper**	9.10×10^{-4} kg		
Aluminium	2.58×10^{-5} kg	**Aluminium**	3.84×10^{-4} kg		
Polymer	2.16×10^{-5} kg	**Polymer**	2.80×10^{-4} kg		
Electronics	8.67×10^{-6} kg	**Carbon Fibers**	1.35×10^{-3} kg		

4.3 Life Cycle Cost Analysis

The LCC analysis from production of Blue and Grey Hydrogen to the fuel station includes several phases, including capital investment, operation, maintenance, and decommissioning (Table 10). The assumptions are as follows:

A setup involving a 1 MW electrolyser with 70% efficiency that produces approximately 21 kg/hr of hydrogen. To produce 1kg of hydrogen, 4.85 m^3 of natural gas and 6.62 kg of water are required based on SMR capacity calculations. The compression process involves hydrogen produced via PEM (Proton Exchange Membrane) and SMR methods, initially at 25°C and 1 bar, which is then pressurised to 700 bar at a temperature of 50°C. The energy required for compression is calculated using the formula:

$$W_{com}=M_{H2}\times(h_{out}-h_{in}) \quad (1)$$

Where, W_{com} is the compressor required energy, and M_{H2} is the mass of hydrogen, h is the enthalpy in the inlet and outlet of the compressor. Regarding logistics, a DAF XF480 diesel-fuelled truck is utilised to transport 600 kg of hydrogen, equipped with type III storage tanks capable of withstanding 700 bar pressure. The truck is required to travel 100 km daily from the production site to the fuel station, situated on a 5000 m^3 plot of land. This comprehensive LCC framework helps to assess the economic viability of adopting hydrogen fuel cell technology in commercial transport.

Table 10 Assumption and parameters used for the LCCA in this study

Category	Parameter	Value / Assumption	Unit	Applied to	Source/reference
System scale	Plant capacity	1 MW hydrogen production facility	MW	All scenarios	Section 4.3
	Hydrogen production rate	≈ 21	kg H_2/h	All scenarios	Section 4.3
Operational profile	Plant lifetime	20	years	All scenarios	Section 4.3.2, Table 11
	Operating hours	~8,000	h/year	All scenarios	Section 4.3.2
Feedstock & utilities	Natural gas consumption	4.85	m^3/kg H_2	Grey, Blue	Section 4.3/ [95]

	Water consumption (SMR)	6.62	kg/kg H_2	Grey, Blue	Section 4.3/ [95]
	Water consumption (PEM)	12	kg/kg H_2	Green	[103]
	Electricity price	0.0999	€/kWh	Green, compression	[108]
	Natural gas price	1.187	€/m³	Grey, Blue	[107]
	Water price	1.3	€/m³	All scenarios	[109]
Compression & storage	Inlet conditions	25°C, 1 bar	–	All scenarios	Section 4.3
	Outlet pressure	700	bar	All scenarios	[110]
Transport logistics	Transport mode	Diesel truck (DAF XF480)	–	Truck scenarios	Section 4.3/[111]
	Hydrogen transported	600	kg/trip	Truck scenarios	Section 4.3/ [111]
	Travel distance	100	km/day	Truck scenarios	Section 4.3
Financial parameters	OPEX discount rate	0.06	–	NPV	[112]
	Energy discount rate	0.12	–	LCOE	[113]
	Tax depreciation rate	0.04	–	LCOE	[114]
	Depreciation period	20	years	LCOE	[115]

4.3.1 Capital Expenditure

The capital expenditures for HFVCs encompass equipment, engineering, and labour costs from the production of both Green and Grey Hydrogen to the fuel station. While data for most equipment costs are up-to-date for the target year of 2023, the costs for the PEM electrolyser are from 2021 and for the SMR from 2020. The figures have been adjusted to 2023 levels using

the EU Construction Cost Index as depicted in Figure 26. The calculation of CAPEX utilises Equation (1) and the CAPEX figures presented in Table 11 of this study.

$$C_b = \frac{C_o \times CI_b}{CI_o} \quad (2)$$

Where C_b is CAPEX at the base year.

C_o is the CAPEX at the year of construction/production.

C_{Ib} is the cost index at the base year.

C_{Io} is the cost index at the construction/production year.

In order to calculate the CAPEX for the current year, it is needed to consider the cost indices of the construction using the graph as given in [107] Figure 26.

To calculate the total CAPEX, four main components are considered for each scenario. These components include the cost of purchased equipment, installation costs—assumed to be 10% of the equipment cost—and a contingency allowance set at 15% of the equipment cost. It is important to note that for trucks, installation costs are not included as they are not applicable. Additionally, for fuel stations, a land requirement of 500 m^2 is assumed.

Table 11 CAPEX of the Hydrogen production, compressor, Truck, Fuel station

	Green	Grey	Blue
PEM			
Equipment purchased cost PEC(€)=1860*W_PEM @2021	1,860,000 [116]	-	-
Equipment purchased cost Adjusted to 2023	1,919,190	-	-
Installation (10% PEC)	191,919	-	-
Contingency 15%	287,878.50	-	-
SMR			**SMR (+ CCS)**
PEC(€)=978(€/kW) @2020	-	762,149.53 [117]	1,359,023.06
Equipment purchased cost Adjusted to 2023	-	799,118.08	1,424,943.34
Installation	-	76,214.95	135,902.31
Contingency 15%	-	114,322.43	203,853.46
Compressor			

Equipment purchased cost	19,782[118]	19,782	19,782
Installation	1,978.21	1,978.21	1,978.21
Contingency 15%	2,967.31	2,967.31	2,967.31
Truck			
Equipment purchased cost	355,000 [111]	355,000	355,000
Vessel purchased cost	318000[119]	318000	318000
Contingency 15%	100,950.00	100,950.00	100,950.00
Fuel Station			
Equipment purchased cost	1,869,158.88 [120]	1,869,158.88	1,869,158.88
Installation	86,915.89	86,915.89	86,915.89
Land Cost (€)	100,000.00	100,000.00	100,000.00
Contingency 15%	280,373.83	280,373.83	280,373.83

As demonstrated by the cost functions and the assumed factors for identical hydrogen production capacities, the capital cost of Scenario 1, which involves Green Hydrogen, is higher than that of Scenario 2, which utilises Grey Hydrogen as well as that of Scenario 3 (Blue Hydrogen).

4.3.2 Operation and Maintenance Costs

Operating and maintenance (O&M) costs are critical components that account for the ongoing expenses required to keep a system functioning effectively over its lifespan. These costs include routine maintenance, repairs, labour, replacement parts, and the energy consumed during operation. Accurately estimating O&M costs is essential for assessing the economic viability and sustainability of a project, as they directly impact the total cost of ownership and the return on investment. These costs can vary significantly based on the technology used, the frequency of maintenance required, the efficiency of operations, and the complexity of the system's components. As such, O&M costs are integral to a comprehensive financial analysis, providing insights into the long-term financial demands and operational efficiency of a project. The lifespan of all process is around 20 years in which it operates to nearly 8,000 hours [100]. The operation and the maintenance cost of all process shown in Table 12.

For the O&M of the PEM electrolyser system, it was assumed that a total of 13 personnel are required: 1 Project Manager (€100,000/year), 5 Engineers (€400,000/year in total), 1 Safety Manager (€90,000/year), 5 Technicians (€300,000/year in total), and 1 Administrative & Support Staff (€50,000/year). The total annual labour cost is estimated at €940,000. These

salary figures are based on standard industry estimates and were incorporated into the OPEX to accurately represent the workforce required for the operation, maintenance, and safe management of the electrolyser facility.

For the O&M of the SMR facility producing Grey Hydrogen, it was assumed that 14 personnel are required: 1 Project Manager (€100,000/year), 5 Engineers (€400,000/year in total), 1 Safety Manager (€90,000/year), 6 Technicians (€360,000/year in total), and 1 Administrative & Support Staff (€50,000/year). The total annual labour cost is estimated at €1,000,000. These salary assumptions, based on typical industry rates, were integrated into the OPEX to realistically represent the staffing needed for continuous, safe, and efficient operation of the SMR hydrogen production process.

For the O&M of the Blue Hydrogen production facility, based on SMR with 56% CCS, it was assumed that 14 personnel are required: 1 Project Manager (€100,000/year), 8 Engineers (€640,000/year in total), 1 Safety Manager (€90,000/year), 8 Technicians (€480,000/year in total), and 1 Administrative & Support Staff (€50,000/year). The total annual labour cost is estimated at €1,360,000. These labour assumptions, reflecting higher engineering and technical requirements due to the integration of CCS systems, were incorporated into the OPEX to ensure an accurate representation of staffing needs for operating and maintaining the advanced Blue Hydrogen infrastructure.

Table 12 OPEX of the Hydrogen production, compressor, truck, fuel station

	Green	Grey	Blue
PEM			
wind power(kW)	1000		
Electricity cost (€/kWh)	0.0999 [108]		
Electricity consumption (€)	799,200		
water consumption (m^3/hr)	0.2520		
water consumption (kg/kg H_2)	12		
water cost (€/m^3)	1.3 [109]		
water cost (€)	2,621.06		
number of labour required	13		
Labour cost (€)	940,000.00		
maintenance cost (€/year)	137,094.38		
SMR			**SMR+CCS**

NG consumption (m^3/hr)		101.860186 [100]	105.2205221
NG cost (€/kWh)		0.1187[117]	0.1187[117]
NG cost (€/m^3)		1.187	1.187
NG cost (€)		967,264.33	999,174.08
water consumption (m^3/hr)		8.12	5.39
water cost (€/m^3)		1.3[109]	1.3 [109]
water cost (€/hr)		10.56	7.01
water cost (€)		84,450.62	56,090.73
number of labour required		14	14
Labour cost (€)		€1,000,000.00	€1,360,000.00
maintenance cost (euro/year)		49,482.77	
Compressor			
electricity consumption (kWh)	40,277.36	40,277.36	40,277.36
electricity cost (€/kWh)	0.0999	0.0999	0.0999
compressor energy cost (€)	4,023.71	4,023.71	4,023.71
maintenance cost (€/year)	1,427.46	1,427.46	1,427.46
Truck			
diesel consumption (litre/100km)	29.7	29.7	29.7
truck travel (day/yr)	365	365	365
travel (km/day)	100	100	100
travel (km)	36,500	500	500
diesel consumption (litre/yr.)	10,840.50	10,840.50	10,840.50
diesel cost (€)	1.7	1.7	1.7
diesel consumption cost (€)	18,428.85	18,428.85	18,428.85
Labour-Specialised or Hazardous Material (Hazmat) Driver	1	1	1
Labour cost (€)	60,000.00	60,000.00	60,000.00

maintenance cost (€year)	1000	1000	1000
Fuel station			
number of labours required	5	5	5
Station Manager	1	1	1
Fuelling Technicians	2	2	2
Maintenance Personnel	2	2	2
Labour cost (€)	300,000.00 [120]	300,000.00 [120]	300,000.00 [120]
maintenance cost (€/year)	93,457.94	93,457.94	93,457.94

4.3.3 Net Present Value

NPV is a financial metric used to evaluate the profitability of an investment by calculating the difference between the present value of cash inflows and the present value of cash outflows over a period of time. NPV incorporates the time value of money, acknowledging that a dollar today is worth more than a dollar in the future due to its potential earning capacity. To determine NPV, future cash flows are discounted back to their present value using a specific discount rate, which often reflects the cost of capital or required rate of return. A positive NPV indicates that the projected earnings generated by a project or investment, in present dollars, exceed the anticipated costs, also in present dollars, making it a financially viable option. Conversely, a negative NPV suggests that the project would result in a net loss, considering the time value of money.

In order to calculate of NPV for each scenario CAPEX and OPEX are considered using the following equation:

$$NPV = CAPEX + OPEX_{UPV} \quad (3)$$

$$UPV = \sum A_{O,i}\left(\frac{(1+d)^n - 1}{d(1+d)^n}\right) \quad (4)$$

where, $A_{0,i}$ represents the annual operational expenditure for component i, and d denotes the discount rate used to calculate the present value. The term n refers to the project lifetime or the number of years considered.

In our analysis, we accounted for the scheduled replacement costs of key components over the project lifetime. The PEM electrolyser stack was assumed to be replaced every 6 years—resulting in three replacements over a 20-year period—each costing 20% of the initial PEMEL CAPEX. For the H_2 compressor, a single full replacement was assumed at year 10, with a cost estimated at 50–70% of the initial compressor CAPEX, consistent with industry norms. These

replacement costs were incorporated into the OPEX calculations and appropriately discounted using the uniform present value (UPV) method described above.

4.3.4 Levelised Cost of Energy

The LCOE is a key metric for comparing energy systems, representing the average cost per unit of electricity over a project's lifetime. It incorporates capital, operational, maintenance, and fuel costs alongside system life and output, allowing technologies to be assessed on a common economic basis. LCOE is vital for guiding policymakers, investors, and utilities, particularly in balancing renewable and conventional options during the energy transition. By providing clear cost benchmarks, it supports strategic resource allocation and the development of a sustainable, cost-effective energy portfolio.

In order to calculate LCOE for green and Grey Hydrogen scenarios the following equation is used:

$$LCoE = \frac{C_{cap} + \sum_{i=1}^{n} \frac{C_{O\&M}}{(1+d)^i} - \sum_{i=1}^{n} \frac{(C_{dep} \times R_{tax})}{(1+d)^i} - \frac{C_{res}}{(1+d)^n}}{\frac{[\sum_{i=1}^{n} E_1 \times (1-R_{deg})^n]}{(1+R_{deg})^n} Cf} \quad (5)$$

In this equation, C_{cap} represents the initial capital cost, $C_{O\&M}$ is the annual operation and maintenance cost, d is the discount rate, and n is the project lifetime in years. C_{dep} denotes the depreciable capital cost, and R_{tax} is the corporate tax rate, accounting for tax savings. C_{res} is the residual (salvage) value of the system. E_1 is the initial annual energy output, and R_{deg} is the annual degradation rate. C_f refers to the capacity factor. The numerator gives the net present cost of the system, while the denominator calculates the present value of total energy produced.

To accurately calculate the LCOE it is imperative to incorporate the entirety of the CAPEX and the OPEX, while also accounting for depreciation and residual values, alongside the total energy output over the plant's operational lifespan, as defined by the denominator in the LCOE formula. This comprehensive approach ensures that all financial aspects, including initial investment, ongoing maintenance, tax implications, and the end-of-life economic impact, are factored into the assessment of the cost per unit of energy produced, thereby providing a holistic view of the economic viability of an energy-producing asset.

Table 13 presents a compilation of input parameters and the computed LCOE for the scenarios under review. It is noteworthy that the depreciation expense was determined using a linear formula predicated on the salvage value estimation, which was posited to be 10% of the initial capital expenditure (CAPEX).

$$C_{dep} = \frac{CAPEX - C_{res}}{n} \quad (6)$$

Table 13 input values and LCOE for two studied cases

INPUT PARAMETERS	VALUES
Technical Lifetime	20 years [115]
OPEX discount rate	0.06 [112]
Energy discount rate	0.12 [113]
Tax depreciation rate	0.04 [114]
Tax depreciation period	20 [115]
Salvage value, C_{res}	10% (CAPEX) [122]
Operation	8000 hrs/year

5 Results and discussion

Following an initial screening of the midpoint impact categories available within the CML2001-Jan2016 methodology, four indicators were selected for detailed assessment: GWP, AP, EP, and MAETP. These categories were chosen based on their relevance to hydrogen and energy systems and their ability to capture the dominant environmental impacts associated with hydrogen production, compression, storage, and delivery. GWP was selected to assess climate-related impacts, while AP and EP represent emissions affecting air and water quality arising from fossil fuel use, electricity generation, and upstream material processing. MAETP was included to account for potential ecotoxic impacts linked to material use and infrastructure development. Other midpoint categories were not reported in order to maintain analytical focus and avoid over-interpretation, particularly where indicators exhibited higher uncertainty or limited relevance to the comparative objectives of this study.

5.1 LCIA results for hydrogen production scenarios

	GWP [kg CO2-eq]	MAETP [kg DCB-eq.]	AP [kg SO2-eq.]	EP [kg Phosphate-eq.]

Green Hydrogen	0.773	85	0.00115	0.000139
Grey Hydrogen	11.6	170.013	0.00418	0.000411
Blue Hydrogen	6.28	158.31	0.00347	0.000302
Turquoise Hydrogen	4.16	271.446	0.00616	0.000341

Table 14 presents the GWP, MAETP, AP and EP associated with the production of 1 kg of hydrogen regarding the technologies considered in this study.

Table 14 The environmental impacts of hydrogen productions

	GWP [kg CO_2-eq]	MAETP [kg DCB-eq.]	AP [kg SO_2-eq.]	EP [kg Phosphate-eq.]
Green Hydrogen	0.773	85	0.00115	0.000139
Grey Hydrogen	11.6	170.013	0.00418	0.000411
Blue Hydrogen	6.28	158.31	0.00347	0.000302
Turquoise Hydrogen	4.16	271.446	0.00616	0.000341

5.1.1 Global Warming Potential Hydrogen Production

The GWP for hydrogen production varies significantly depending on the method used, ranging from 0.773 to 11.6 kg CO_2-eq /kg H_2. Grey Hydrogen, produced by SMR without CCS, has the highest GWP of 11.6 kg CO_2-eq /kg H_2. This is due to process-related GHG emissions, which contribute 9.00 kg CO_2-eq /kg H_2, accounting for 77% of the total, while the remaining 2.6 kg CO_2-eq /kg H_2 (23%) comes from the supply and processing of natural gas. The 9.00 kg CO_2-eq/kg H_2 refers to the direct emissions generated during the SMR process, where methane reacts with steam, producing hydrogen and carbon dioxide, as well as the additional CO_2 released from the combustion of natural gas to provide the required heat for the reaction. Significant emissions arise from the combustion of methane and reforming reactions, coupled with

methane leakage during natural gas extraction and transportation, making Grey Hydrogen particularly carbon intensive.

Blue Hydrogen, produced via SMR with CCS, lowers the carbon footprint compared to conventional SMR by capturing 56% of CO_2 emissions. This results in a GWP of 6.28 kg CO_2 -eq/kg H_2, which can be further reduced to 4.12 kg CO_2-eq/kg H_2 when process-related emissions are considered. Turquoise Hydrogen, produced via methane pyrolysis, has a GWP of 4.15 kg CO_2-eq/kg H_2 since it generates solid carbon instead of gaseous CO_2; however, its impact depends on the fossil fuel supply and heat source. Green Hydrogen, produced through electrolysis powered by renewable energy, achieves the lowest GWP at 0.773 kg CO_2-eq/kg H_2 , as it does not rely on fossil fuels and has minimal emissions beyond the electricity source.

5.1.2 Contribution analysis for hydrogen production scenarios in terms of GWP

The analysis of GWP across the twelve-hydrogen production and transport scenarios highlights clear differences in environmental impact, driven primarily by the energy sources, production methods, and material inputs used as shown in Figure 27.

Green Scenario 1 to Scenario 3 primarily depend on renewable energy, particularly wind-generated electricity, which, despite its zero-carbon nature, still contributes to the overall GWP. The material inputs, including aluminium, steel, and copper, are substantial, reflecting the infrastructure needs for electrolysis systems. In GN-P, additional materials such as polyethylene and fiberglass further increase the GWP slightly. Nonetheless, due to low operational emissions, these Green scenarios remain more sustainable in the long term.

In scenarios related to Grey & Blue Hydrogen, natural gas and the steam reformer are the dominant contributors to GWP. However, the use of carbon capture mitigates emissions, reducing the overall environmental impact. The contribution of materials like steel, aluminium, and concrete is still high due to the infrastructure needed for carbon capture facilities. The combination of fossil fuels and the need for carbon capture infrastructure results in moderate GWP, positioning these scenarios as an intermediate solution between renewable energy and fossil-fuel systems without carbon capture.

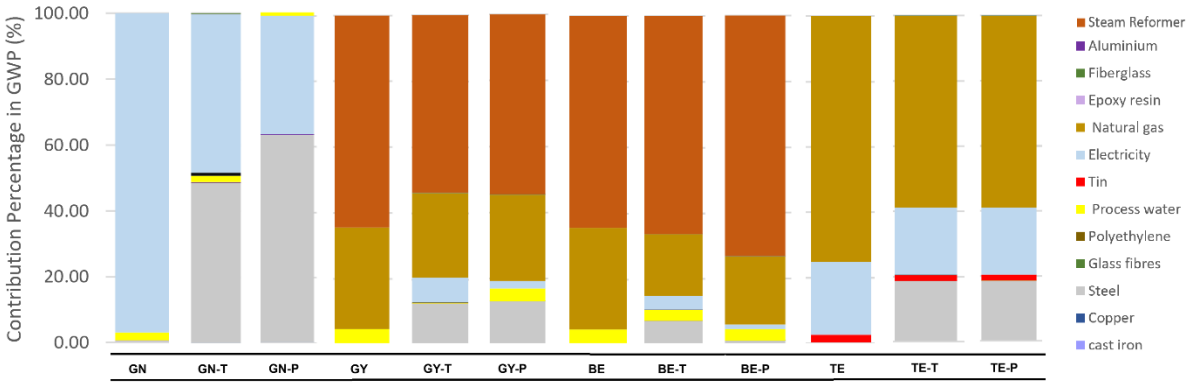


Figure 27 Contribution assessment of different components of the proposed scenarios in GWP

The Grey scenarios exhibit the highest GWP contributions, driven by the emissions from natural gas and the steam reformer. Without carbon capture, the fossil fuel combustion leads to a significant environmental burden, despite similar material use as in the carbon capture scenarios. The absence of CO_2 mitigation mechanisms makes these scenarios the least sustainable option for hydrogen production, highlighting the critical role of carbon capture in reducing emissions.

The pyrolysis Scenarios introduce new materials such as fiberglass and epoxy resin, which contribute to GWP but are less impactful than fossil fuels. These scenarios show a lower GWP compared to steam reforming without carbon capture, as pyrolysis generates solid carbon as a by-product, reducing CO_2 emissions. However, the increased material inputs necessary for the process suggest that optimising material use could further enhance the environmental performance of pyrolysis-based hydrogen production.

The differences in GWP are primarily driven by the energy sources (renewables vs. fossil fuels) and the presence or absence of carbon capture. Renewable-based Green Scenarios have high initial material impacts but much lower operational emissions. Carbon capture in Blue Scenarios significantly reduces GWP, but steam reforming without carbon capture (Grey Scenarios) remains highly carbon-intensive. Pyrolysis (Turquoise Scenarios) provides a promising alternative with lower emissions but requires further optimisation of material efficiency.

These results underscore the need for material optimisation and the importance of integrating renewable energy or carbon capture to minimise the environmental impacts of hydrogen production.

5.1.3 Sensitivity analysis for the LCA results

As shown in Figure 28 to 31, the sensitivity analysis conducted for the four hydrogen production pathways—Green, Grey, Blue, and Turquoise—provides important insights into the robustness of the LCA results and the dominant drivers of Global Warming Potential (GWP). For Green Hydrogen, variation in electricity consumption (±15%) leads to a proportional change in total GWP, confirming that electricity input is the primary environmental driver. However, even under the highest positive variation, the total GWP remains substantially lower than all fossil-based pathways, reinforcing the environmental robustness of renewable-based electrolysis. This demonstrates that while Green Hydrogen is sensitive to electricity assumptions, its relative environmental superiority is preserved across a realistic uncertainty range.

For Grey and Blue Hydrogen, the sensitivity analysis shows a strong dependence on natural gas consumption. A ±15% variation in natural gas input results in approximately ±4% change in total GWP for Blue Hydrogen and a similar or slightly higher response for Grey Hydrogen. This reflects the dominant contribution of both upstream natural gas supply and reforming processes to overall emissions. Although Blue Hydrogen benefits from CO_2 capture, its sensitivity to natural gas input highlights that improvements in methane leakage control, reformer efficiency, and fuel substitution are critical to achieving meaningful emission reductions. These results indicate that Blue Hydrogen can act as a transitional solution, but its environmental performance remains tightly coupled to fossil fuel dynamics.

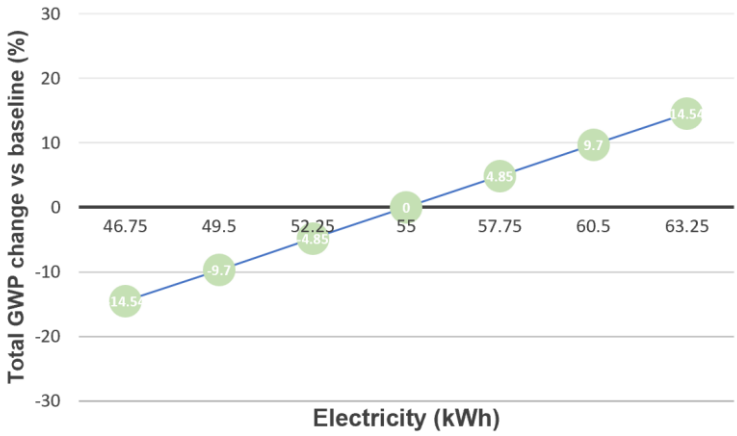


Figure 28 Effect of change in the amount of electricity used on the total GWP for the green hydrogen scenario (GN)

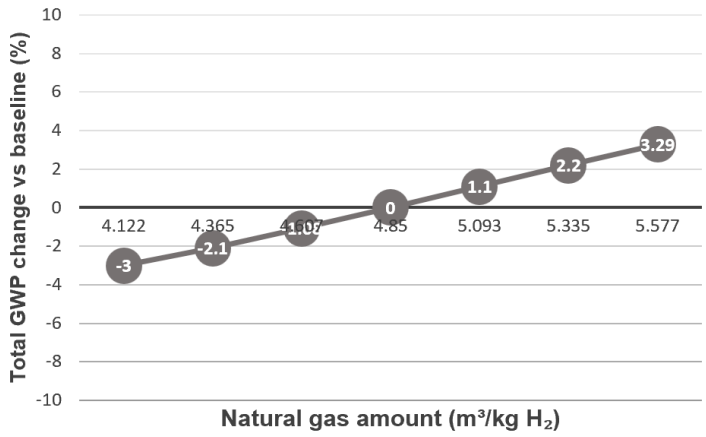


Figure 29 Effect of change in the amount of natural gas used on the total GWP for the Grey hydrogen scenario (**GY**)

Turquoise Hydrogen exhibits the highest sensitivity to natural gas variation among the fossil-based pathways, with a ±15% change in natural gas input leading to approximately ±9% change in total GWP. This is due to the substantial contribution of methane feedstock to the process, despite the avoidance of direct CO_2 emissions through solid carbon formation. While Turquoise Hydrogen demonstrates lower GWP than Grey Hydrogen, the sensitivity results underline the importance of feedstock efficiency and process optimisation. Overall, the sensitivity analysis confirms that across all pathways, GWP results are most strongly influenced by energy and feedstock inputs rather than material contributions, and that the comparative conclusions of the study remain robust within reasonable uncertainty ranges. This strengthens the credibility of the LCA and supports informed decision-making for hydrogen deployment strategies.

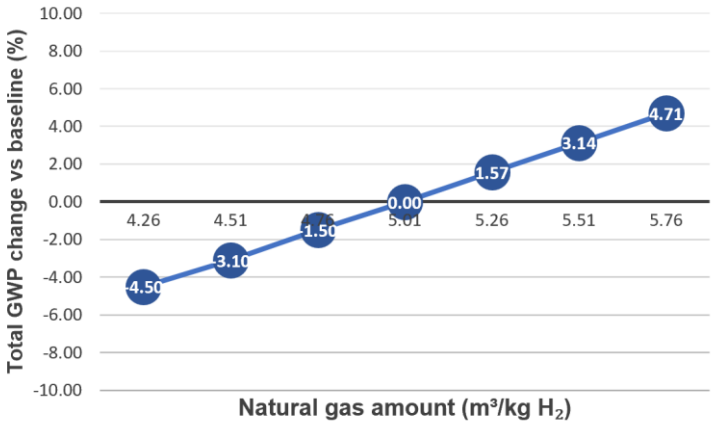


Figure 30 Effect of change in the amount of natural gas used on the total GWP for the Blue hydrogen scenario (**BE**)

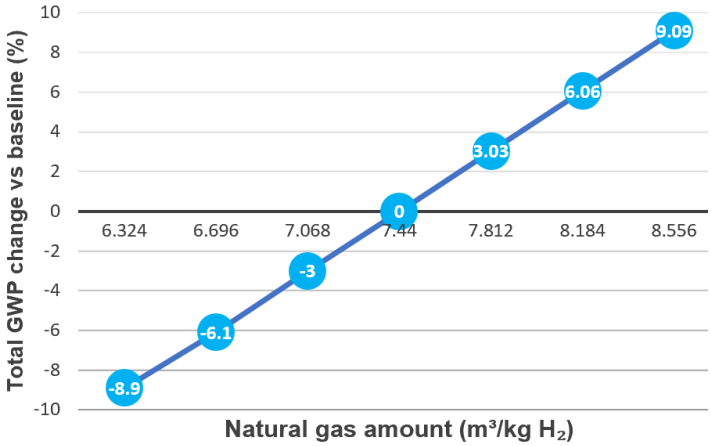


Figure 31 Effect of change in the amount of natural gas used on the total GWP for the Turquoise hydrogen scenario (**TE**)

5.2 LCIA results from hydrogen production and delivery

5.2.1 GWP and MAETP

The LCA results for hydrogen production and delivery reveal distinct environmental impacts across different pathways (Figure 32 and Figure 33).

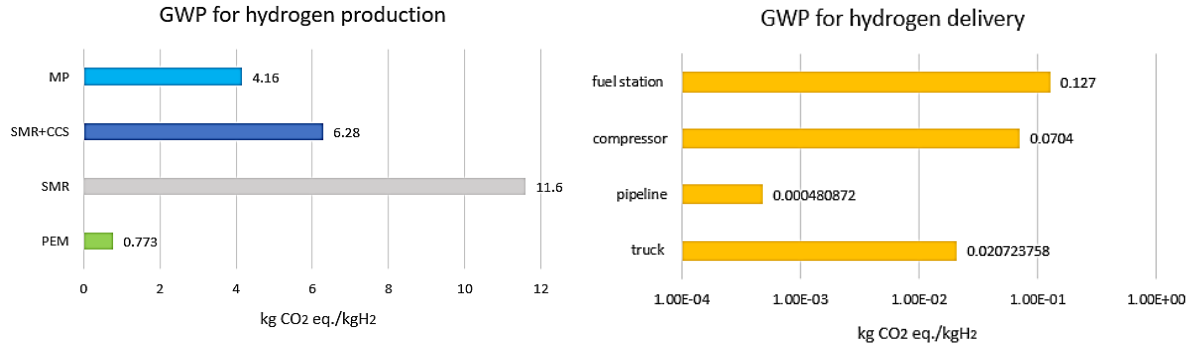
For Green Hydrogen (PEM electrolysis), the GWP is the lowest among all pathways, at 0.773 kg CO_2-eq/kg H_2. However, the process remains electricity-intensive, making its impact highly dependent on the energy source. Delivery-related emissions are mainly associated with the fuel station (0.127 kg CO_2-eq/kg H_2) and compression (0.0704 kg CO_2-eq/kg H_2), while transport by truck and pipeline contributes minimally. In terms of MAETP, Green Hydrogen has a relatively low impact (85 kg DCB-eq/kg H_2) compared to other pathways, though delivery stages such as fuel station (51.4 kg DCB-eq/kg H_2) and compression (14.7 kg DCB-eq/kg H_2) remain notable contributors.

For Grey Hydrogen (SMR), the GWP is the highest at 11.6 kg CO_2-eq/kg H_2, reflecting its heavy reliance on fossil fuels. Delivery-related GWP impacts follow the same trend as Green Hydrogen, with fuel station and compression as the main contributors. The MAETP for Grey Hydrogen is also significant, with the SMR process contributing 170.01 kg DCB-eq/kg H_2.

For Blue Hydrogen (SMR + CCS), the GWP decreases to 6.28 kg CO_2-eq/kg H_2, showing the effect of partial CO_2 capture. Delivery impacts mirror those of other pathways, with fuel station and compression remaining the largest contributors. However, the MAETP is still considerable, with the SMR+CCS process contributing 158.31 kg DCB-eq/kg H_2. This reflects the environmental burden of CCS handling and storage despite its lower GWP compared to Grey

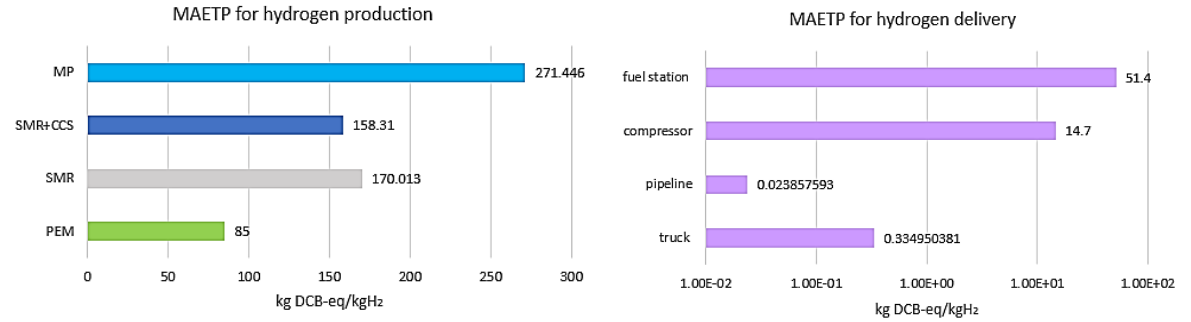
Hydrogen.For Turquoise Hydrogen (methane pyrolysis pathway), the GWP is 4.16 kg CO_2-eq/kg H_2, lower than Grey and Blue Hydrogen but higher than Green Hydrogen. Its MAETP, however, is the highest of all pathways at 271.45 kg DCB-eq/kg H_2, reflecting significant ecological concerns associated with the methane pyrolysis process. Delivery stage contributions are similar to those in other pathways, but comparatively minor when assessed against production impacts.

Overall, the results highlight that while Green Hydrogen offers the lowest GWP, its impacts remain tied to electricity source. Grey and Blue Hydrogen are associated with high fossil-fuel-related burdens, with CCS reducing but not eliminating impacts. Turquoise Hydrogen provides a moderate GWP but exhibits the highest ecotoxicity, underscoring the environmental trade-offs across hydrogen production routes.



a) b)

Figure 32 GWP results for Green, Grey, Blue and Turquoise hydrogen a) production and b) delivery scenarios



a) b)

Figure 33 MAETP results for Green, Grey, Blue and Turquoise hydrogen a) production and b) delivery scenarios

5.2.2 Hydrogen delivery pathway comparison (pipeline vs. truck)

Figure 34 compares the contributions of different delivery processes to GWP and MAETP following hydrogen production. For both truck and pipeline delivery, the largest contributor is

the fuel station, accounting for 58–64% of GWP and 77–78% of MAETP. Compressors are the second-largest contributor, responsible for 32–36% of GWP and around 22% of MAETP. Truck transport adds a minor share to GWP (10%) and negligible impact to MAETP (1%), while pipeline transport has virtually no impact in either category.

These results highlight that the environmental burden of hydrogen delivery is dominated by downstream infrastructure, particularly refuelling stations and compressors, rather than the transport mode itself. Pipeline delivery is the most efficient option, showing negligible contributions compared to truck-based transport. Overall, reducing the energy intensity of fuel stations and compressors emerges as the key opportunity for minimising delivery-related environmental impacts.

Although Ireland does not currently operate a dedicated hydrogen pipeline network, pipeline delivery was included in this study as a future-oriented scenario consistent with national infrastructure strategies. Gas Networks Ireland identifies the existing gas transmission and distribution network as renewable-ready, with planned repurposing to accommodate hydrogen as part of Ireland's long-term decarbonisation pathway. Including pipeline delivery therefore enables the assessment of scalable, low-impact hydrogen distribution options relevant to future deployment. The LCA results further indicate that pipeline delivery contributes negligibly to overall environmental impacts compared to truck-based transport, with downstream impacts dominated by compression and refuelling infrastructure.

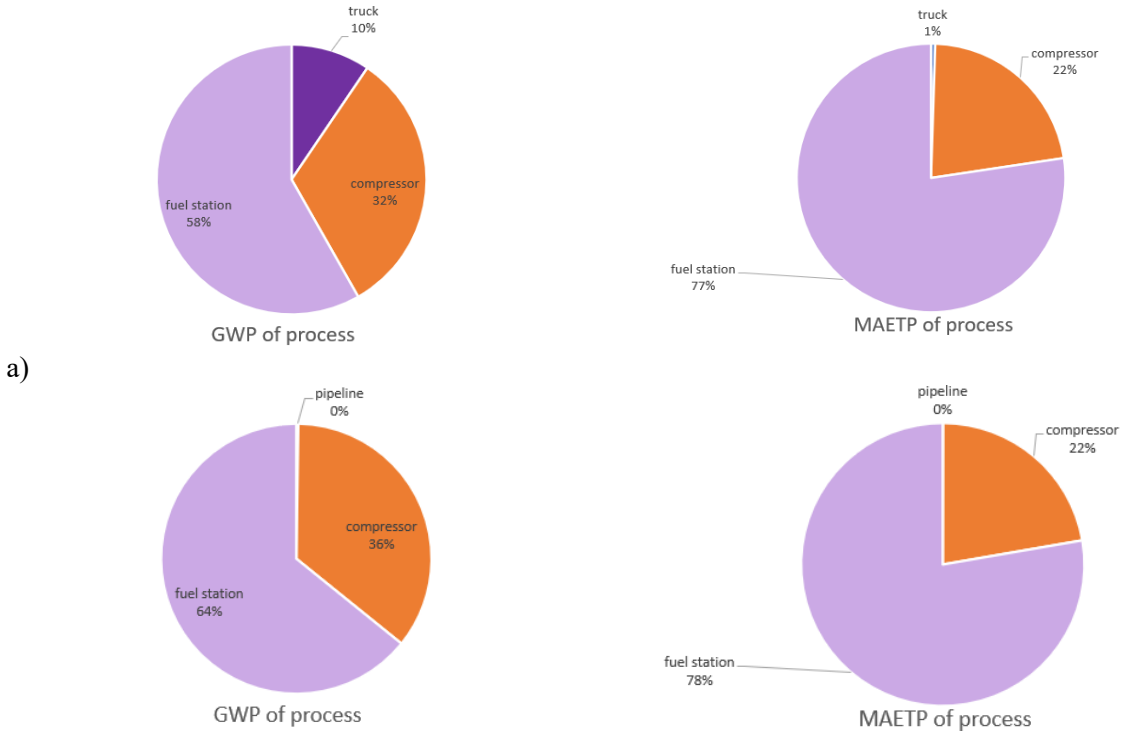


Figure 34 Comparison of GWP and MAETP contributions across hydrogen delivery processes by a) truck and, b) pipeline

5.3 LCA results from hydrogen and diesel delivery to the refuelling station

To provide some relatable context to the results of the study, the team assessed the environmental impacts associated with the production and delivery of diesel and hydrogen up to the refuelling station, excluding the combustion phase for both fuels. The results reveal that while GWP is an important metric for assessing the long-term climate impact, it alone does not capture the full environmental burden of these energy sources.

The results in Figure 35 reveal that diesel's GWP falls within a similar range to fossil-fuel-based hydrogen types, such as Grey and Blue Hydrogen. However, diesel has significantly higher impacts in other environmental metrics, such as MAETP, AP, and EP. MAETP values for diesel exceed those of all hydrogen processes, indicating a greater potential for harming aquatic ecosystems. Additionally, diesel's AP and EP values are substantial, highlighting the release of pollutants like sulphur oxides and nitrogen oxides, which contribute to acid rain and nutrient pollution in water bodies, respectively.

Quantitatively, diesel's AP stands at approximately 0.0073 kg SO_2-eq., which is higher than all hydrogen options, including Grey and Blue Hydrogen, which are around 0.0049 kg SO_2-eq. This suggests diesel production releases more acidifying pollutants, such as sulphur and nitrogen oxides, that also contribute to acid rain and soil degradation.

In terms of EP, diesel again shows a high value of around 0.00092 kg PO_4^{-3}-eq., compared to Green Hydrogen's much lower EP of approximately 0.0003 kg PO_4^{-3}-eq. This reflects diesel's considerable nutrient pollution impact, which can lead to algal blooms and disruption of aquatic ecosystems, particularly in freshwater bodies.

These findings suggest that, while GWP is essential for understanding climate effects, additional metrics like AP and EP are equally important for capturing local ecological and health impacts. This comprehensive perspective emphasizes the environmental hazards of diesel beyond global warming, underscoring the need to consider multiple sustainability dimensions in energy decisions.

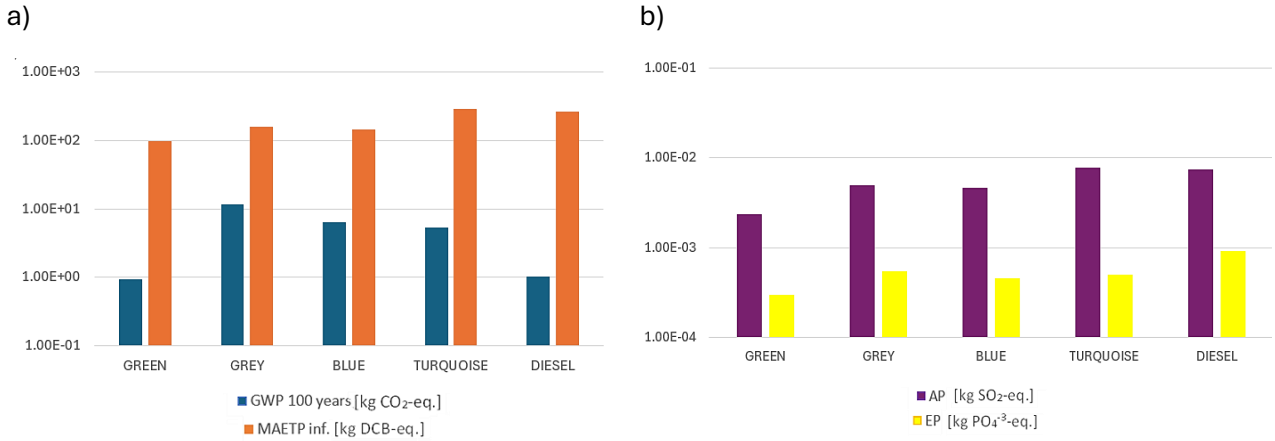


Figure 35 : a) GWP and MAETP of hydrogen and diesel production systems; b) AP and EP of hydrogen and diesel production systems

5.4 LCCA results

5.4.1 LCOE and NPV

The techno-economic analysis presented highlights significant differences in LCOE for hydrogen production pathways (Table 15). Green Hydrogen production pathway, produced via PEM electrolysis and including compression, transport, and fuelling infrastructure, exhibits the highest LCOE at €2.23/kWh. This elevated cost is primarily attributed to the higher CAPEX of €6.28 million and relatively high OPEX of €1.53 million/year, driven by the cost of renewable electricity and lower capacity factors. In contrast, Grey Hydrogen shows the lowest LCOE at €1.38/kWh, benefiting from a lower CAPEX of €4.44 million and utilising existing natural gas infrastructure without carbon capture, thus incurring lower production costs. Blue Hydrogen, incorporating CCS technologies, yields an intermediate LCOE of €1.92/kWh, reflecting higher CAPEX and OPEX compared to Grey Hydrogen, but offering reduced carbon emissions.

These findings align well with recent literature values, validating the assumptions and cost breakdowns applied in this study. Importantly, while Green Hydrogen is the most expensive route currently, it represents the most sustainable long-term option, particularly as renewable energy costs continue to decline and electrolyser technologies mature. The relatively close LCOE between blue and Green Hydrogen suggests that with targeted cost reductions in electrolysis, Green Hydrogen could become increasingly competitive against fossil-fuel-based production methods. Furthermore, the negative NPVs for all pathways highlight the need for supportive policy mechanisms, subsidies, or carbon pricing to enhance the economic viability of hydrogen as a clean energy carrier.

It is important to note that the NPVs shown in Table 15 are negative across all pathways. This outcome arises because, in the scenarios assessed, the produced hydrogen is not sold; instead, it is assumed to be consumed in hydrogen vehicles. As such, the NPV calculations account only for CAPEX and OPEX, without incorporating revenue from hydrogen sales. The negative values therefore do not indicate that the pathways are economically non-viable, but rather reflect the study boundaries. In this context, the relative differences in NPV (less negative values) can still highlight comparatively better economic performance between pathways, while the LCOE remains the most meaningful indicator for evaluating techno-economic competitiveness.

Table 15 Results of LCCA for proposed scenarios in this study

	Green	Grey	Blue
CAPEX (€)	6,279,877.05	4,440,033.38	5,253,829.20
OPEX (€/yr)	1,532,979.78	1,505,368.17	1,904,120.36
Total energy cost (€/yr)	2,232,993.69	1,074,167.51	1,077,717.36
NPV (€)	-42,063,413.99	-31,223,681.85	-37,033,326.71
LCOE (€/kWh)	2.23	1.38	1.92

5.4.2 Sensitivity analysis

As shown in Figure 36, the sensitivity analysis on gas cost variations reveals that the NPV of grey and Blue Hydrogen production is strongly influenced by changes in natural gas costs,

while Green Hydrogen remains largely unaffected. It can be seen that, 40% increase in natural gas costs leads to a significant decrease in NPV for grey and Blue Hydrogen, reflecting their dependence on natural gas as the primary feedstock. Grey Hydrogen, with no carbon capture, maintains a higher NPV compared to Blue Hydrogen, which carries additional costs associated with CCS. In contrast, the NPV of Green Hydrogen remains virtually constant across different gas costs scenarios, confirming that Green Hydrogen production, based on electrolysis powered by renewable electricity, is independent of natural gas market fluctuations.

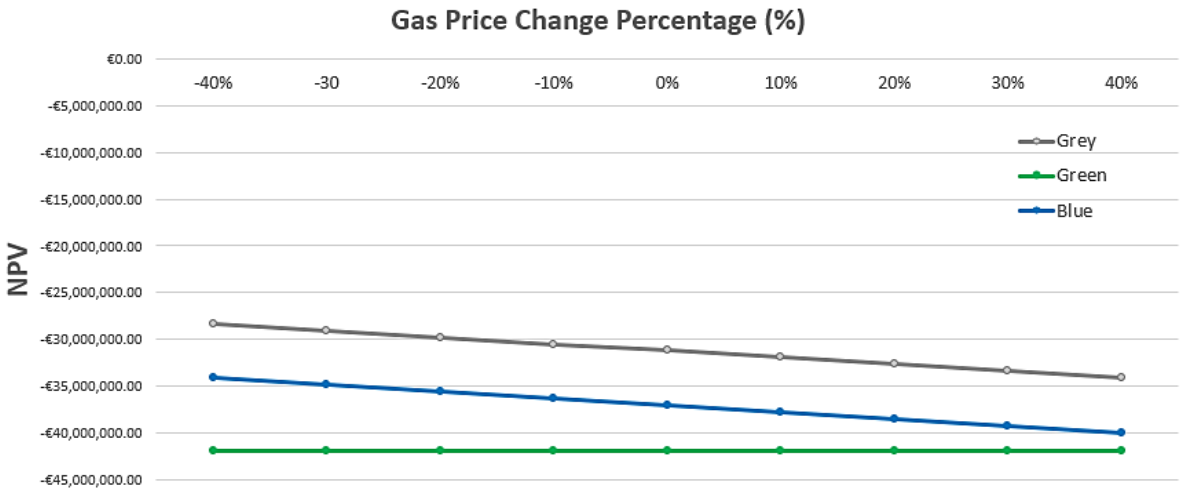


Figure 36 Effect of gas costs on NPV for the studied hydrogen scenarios

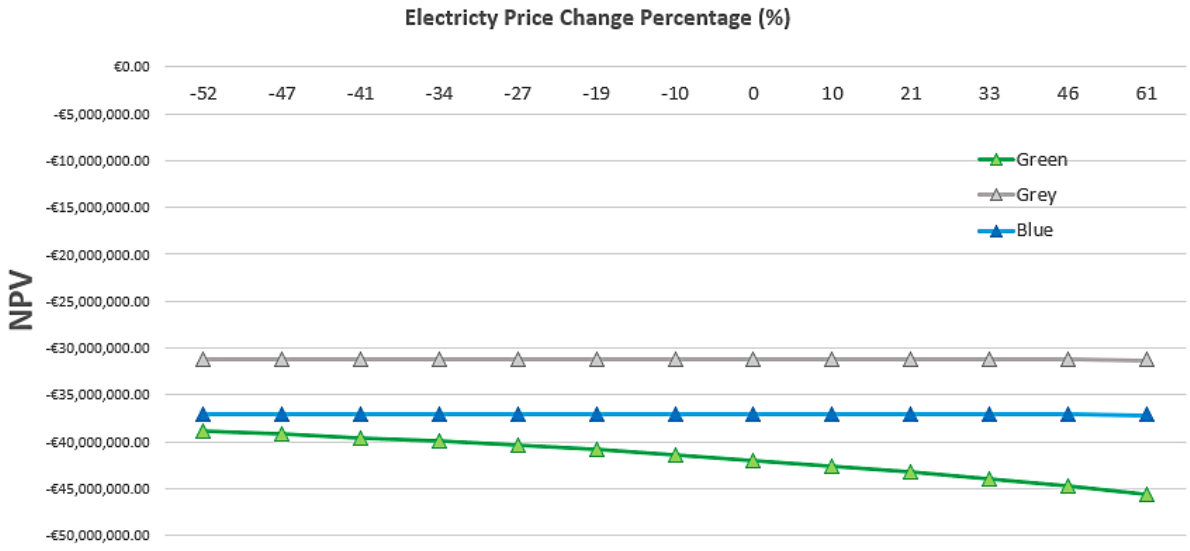


Figure 37 Effect of electricity cost on NPV for the studied hydrogen scenarios

Figure 37 illustrates the impact of electricity cost variations on NPV for the three hydrogen pathways. Here, Green Hydrogen exhibits a pronounced sensitivity to changes in electricity costs, as expected due to its complete reliance on renewable electricity input. As electricity costs increase, the NPV for Green Hydrogen declines sharply, reinforcing the importance of

securing low-cost renewable energy to ensure its economic competitiveness. Meanwhile, the NPVs of grey and Blue Hydrogen remain relatively stable, as their electricity usage constitutes a smaller fraction of their total operational costs.

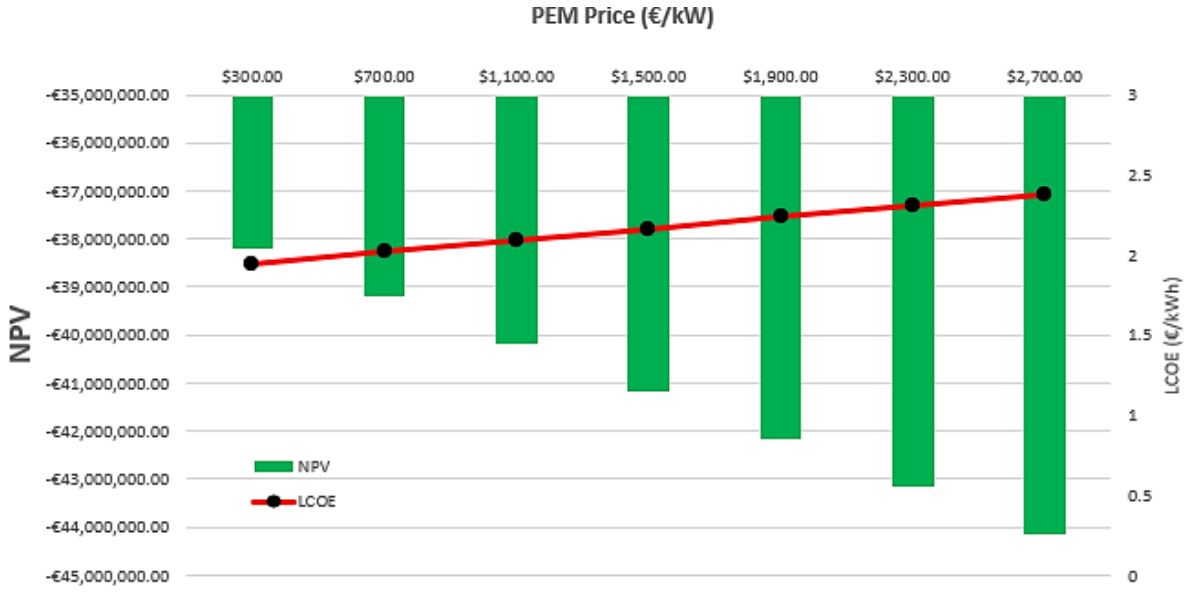


Figure 38 Effect of PEM costs on NPV and LCOE for the Green Hydrogen scenario

As shown in Figure 38, the impact of varying PEM electrolyser costs (€300/kW to €2700/kW) on the NPV and LCOE for the Green Hydrogen production scenario. As shown in the figure, an increase in PEM capital cost leads to a more negative NPV, indicating a deterioration in the project's financial viability. Specifically, as the PEM cost rises, the upfront capital investment increases, resulting in higher annualized costs and thus a lower economic attractiveness of the project over its lifetime. At lower PEM costs (e.g., €300–€700/kW), the NPV, while still negative, is comparatively less severe, suggesting that significant reductions in electrolyser costs are critical for improving the financial performance of Green Hydrogen projects.

Regarding the LCOE, the trend similarly shows a gradual increase as the PEM cost rises. At lower PEM costs, the LCOE is closer to €2.0/kWh, whereas at higher PEM costs, it approaches €2.5/kWh. This upward trend reflects the direct influence of capital cost on the cost per unit of energy produced, emphasizing the strong sensitivity of Green Hydrogen's competitiveness to electrolyser pricing. Overall, these results highlight that reducing PEM electrolyser costs is essential not only to enhance the NPV but also to achieve a more competitive LCOE, positioning Green Hydrogen more favourably against fossil-based hydrogen alternatives.

It can be concluded that the results of the LCCA reveal the economic challenges currently limiting the large-scale deployment of Green Hydrogen. As expected, the Green Hydrogen

pathway demonstrates the highest CAPEX among all scenarios, primarily due to the cost of electrolysers and renewable energy infrastructure. Notably, it also incurs the highest total energy cost per year (€2.23 million), further contributing to its comparatively unfavourable NPV. This reflects the compounded impact of both high initial investment and ongoing operational expenses driven by electricity costs. In contrast, grey and Blue Hydrogen benefit from existing fossil fuel infrastructure and lower production costs, but remain vulnerable to gas cost volatility and carbon-related penalties.

The sensitivity analyses reinforce that electricity cost and PEM electrolyser cost are the most influential parameters affecting the NPV of Green Hydrogen. A sharp decline in NPV is observed with increasing electricity cost, emphasising the need for stable, low-cost renewable electricity supply. Likewise, higher PEM capital costs significantly worsen both NPV and LCOE, whereas reductions in PEM costs can improve the economic outlook considerably. This highlights a critical opportunity: with ongoing global investments in electrolyser manufacturing and anticipated cost reductions, the Green Hydrogen pathway—though currently the most expensive—could become increasingly viable and competitive.

The results of this study are broadly consistent with existing life cycle assessments of hydrogen production pathways, while also providing new insights by explicitly incorporating hydrogen delivery routes and Irish-specific assumptions. The calculated GWP for Green Hydrogen (0.773 kg CO_2-eq/kg H_2) aligns with values reported in wind-powered electrolysis studies, which typically range below 1 kg CO_2-eq/kg H_2 under renewable electricity supply. Similarly, the GWP values obtained for Grey Hydrogen (11.6 kg CO_2-eq/kg H_2) and Blue Hydrogen (6.28 kg CO_2-eq/kg H_2 with 56% CO_2 capture) fall within the ranges reported in previous SMR-based LCAs, confirming the robustness of the modelling approach.

However, a key distinction of this study lies in the explicit inclusion of hydrogen delivery and refuelling infrastructure, which is often simplified or excluded in comparable studies. The results demonstrate that downstream infrastructure—particularly compression and refuelling stations—dominates delivery-related environmental impacts, while the choice of transport mode (pipeline versus truck) plays a secondary role. This finding reinforces recent literature suggesting that system-wide optimisation, rather than focusing solely on production technology, is critical for minimising hydrogen's environmental footprint.

From a methodological perspective, the use of a cradle-to-gate system boundary combined with an iterative LCA framework enabled transparent comparison across twelve production-delivery

configurations. While this approach ensures consistency, it also highlights limitations, particularly regarding the exclusion of vehicle operation and end-of-life stages. Future work could extend the analysis to a full well-to-wheel perspective to capture end-use efficiency differences between hydrogen and alternative fuels.

The results have important implications for Ireland's National Hydrogen Strategy [49] and hydrogen deployment in transport. Environmentally, Green Hydrogen is the only pathway capable of achieving near-zero lifecycle emissions, supporting long-term decarbonisation goals, but it currently has the highest LCOH due to high CAPEX and electricity costs. Blue Hydrogen offers a transitional option, reducing GWP by approximately 45% relative to Grey Hydrogen while remaining more cost-competitive in the near term.

These findings support a phased deployment strategy, with Blue Hydrogen enabling early adoption in heavy-duty transport, followed by large-scale Green Hydrogen deployment as renewable capacity and electrolyser costs decline. The negligible environmental impact of pipeline delivery further supports investment in hydrogen-ready infrastructure as a key enabler of cost-effective, low-carbon hydrogen distribution, highlighting the need for coordinated technological, infrastructural, and policy action in Ireland.

6 Conclusions

The primary objective of this research was to evaluate the environmental performance of hydrogen production technologies and identify sustainable long-term pathways for zero-emission mobility in Ireland. A comparative Life Cycle Assessment was conducted across twelve configurations representing four key production routes: steam methane reforming (SMR), SMR with carbon capture and storage (SMR-CCS), methane pyrolysis (MP), and polymer electrolyte membrane electrolysis (PEMEL), corresponding to Grey, Blue, Turquoise, and Green Hydrogen, respectively.

The results clearly demonstrate that Grey Hydrogen produced via SMR has the highest environmental impact, with a global warming potential (GWP) of approximately 9.5 kg CO_2-eq/kg H_2, confirming its incompatibility with long-term decarbonisation objectives. In contrast, Green Hydrogen produced via PEMEL using renewable electricity exhibited the lowest climate impact, reaching values as low as 0.77 kg CO_2-eq/kg H_2 under wind-based scenarios. These findings confirm Green Hydrogen as the most environmentally sustainable option, although

challenges related to water demand and critical material use must be addressed to enable large-scale deployment.

Blue Hydrogen (SMR-CCS) achieved intermediate emissions (approximately 2.8–3.0 kg CO_2-eq/kg H_2) and demonstrated meaningful reductions compared to Grey Hydrogen, with higher technological readiness and fewer burden-shifting effects than methane pyrolysis. However, its reliance on fossil gas and long-term CO_2 storage constrains its role to a transitional solution rather than a permanent decarbonisation pathway. Turquoise Hydrogen showed lower GWP than SMR but introduced significant trade-offs in other impact categories, highlighting concerns around burden shifting, technological maturity, and uncertain co-product markets.

Overall, the analysis confirms that no single hydrogen pathway is impact-free and that technology choice involves inherent environmental trade-offs influenced by regional energy systems and infrastructure. Nevertheless, the results consistently indicate that the long-term sustainability of the hydrogen economy depends on large-scale deployment of renewable-based Green Hydrogen, supported by robust policy frameworks and investment in renewable energy infrastructure.

From an economic perspective, the Life Cycle Cost Analysis highlights that Green Hydrogen currently remains the most expensive pathway, with LCOH values ranging from €1.3 to €2.7/kg depending on assumptions. Cost competitiveness is strongly influenced by electrolyser capital costs and electricity prices, underscoring the importance of technological learning, scale-up, and access to low-cost renewable electricity. Sensitivity analysis further demonstrates that reductions in PEM electrolyser costs and stable renewable power supply are critical for improving the economic viability of Green Hydrogen.

In conclusion, this research provides an integrated environmental and economic assessment of hydrogen production pathways relevant to the Irish context. The findings highlight both the opportunities and challenges associated with hydrogen deployment and reinforce the need for coordinated policy action, technological innovation, and targeted investment to enable a transition toward a sustainable and economically viable hydrogen-based transport system.

7 Future research recommendations

Building on the findings of this study, future research should consider extending the analysis through Social Life Cycle Assessment (S-LCA) to capture the broader societal impacts of hydrogen production technologies, such as labour rights, community wellbeing, and ethical supply chain issues. Investigating real-world case studies across different regions would provide valuable insights into the practical challenges and regional variations affecting hydrogen deployment. Further work could also explore the environmental impacts and economic viability of hydrogen storage technologies, such as liquid hydrogen, compressed gas, and underground storage, to assess their influence on the overall hydrogen value chain. Moreover, a comparative evaluation of hydrogen production against emerging alternative energy carriers, such as synthetic fuels and advanced battery technologies, would offer a more comprehensive understanding of the role hydrogen could play within an integrated, low-carbon energy future.

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