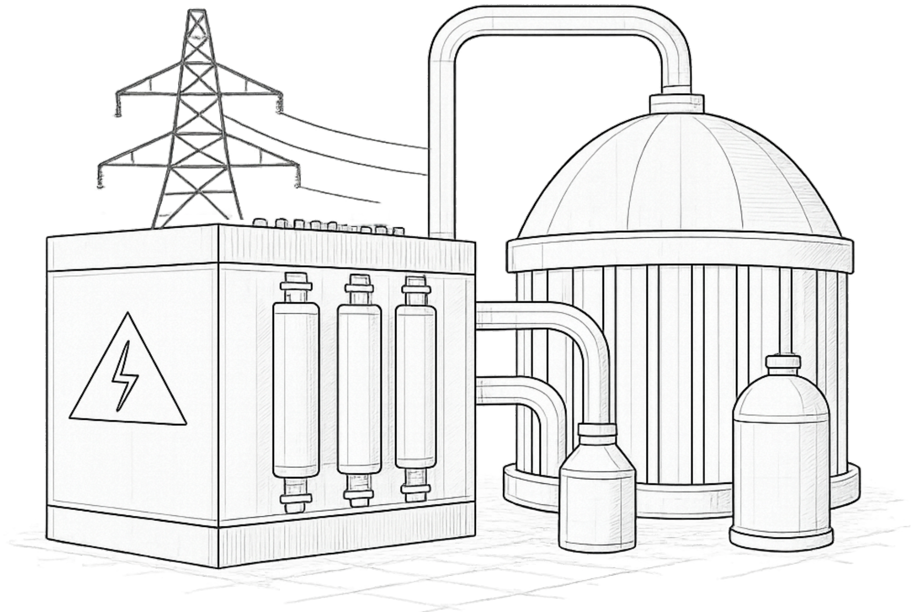
CHALMERS
UNIVERSITY OF TECHNOLOGY



Assessment of Hydrogen Infused In-situ Methanation Systems

Modeling and Analyzing from a Techno-Economic and Climate Perspective

Master's Thesis in Industrial Ecology and Sustainable Energy Systems

FRIDA ROGBRING & EMMA ROOS

DEPARTMENT OF MECHANICS AND MARITIME SCIENCES
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2025
www.chalmers.se

MASTER'S THESIS 2025

Assessment of Hydrogen Infused In-situ Methanation Systems

Modeling and Analyzing from a Techno-Economic and Climate Perspective

FRIDA ROGBRING
EMMA ROOS

Department of Mechanics and Maritime Sciences
Division of Transport, Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2025

Assessment of Hydrogen Infused In-situ Methanation Systems
Modeling and Analyzing from a Techno-Economic and Climate Perspective
FRIDA ROGBRING, EMMA ROOS

Academic Supervisor: Maria Grahn, Department of Mechanics and Maritime Sciences
Industry Supervisor: Carl Jönsson Lindholm, Euromekanik AB
Examiner: Selma Brynolf, Department of Mechanics and Maritime Sciences

Master's Thesis 2025
Department of Mechanics and Maritime Sciences
Division of Transport, Energy and Environment
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

Cover photo: Integrated digester and electrolyzer system powered by grid electricity, constructed by image generative tool DALL:E.

Typeset in LaTeX
Printed by Chalmers Reproservice
Gothenburg, Sweden 2025

Assessment of Hydrogen Infused In-situ Methanation Systems
Modeling and Analyzing from a Techno-Economic and Climate Perspective
FRIDA ROGBRING & EMMA ROOS
Department of Mechanics and Maritime Sciences
Chalmers University of Technology

Abstract

The transition away from fossil fuels requires the development of alternative technologies, as no single solution can meet all the requirements for full decarbonization. Hydrogen is a flexible energy carrier, with one potential application being methanation. A methanation process uses hydrogen to convert carbon dioxide from biogas production to bio-e-methane. This thesis offers a comparative assessment of hydrogen-infused in-situ methanation systems operating under different conditions, from a techno-economic and climate perspective, applied to a biogas plant in Linköping operated by Tekniska Verken.

The evaluation was carried out through simulations using Odyssey software, considering three cases: (1) hydrogen used for the methanation process solely, (2) hydrogen used for methanation combined with direct sales, and (3) hydrogen used solely for direct sales. The outcomes were influenced by electrolyzer characteristics, system size, and fluctuating electricity prices. Results indicated that the cost-optimal configuration was highly dependent on the operational strategy and electrolyzer capacity. Furthermore, Case 2 showed strong sensitivity to hydrogen pricing, while Case 3 showed that both methanation and direct hydrogen sales could be more profitable, depending on the specific setup. The key findings of the climate analysis showed that the emissions from the systems were small compared to if the system were placed in another country, due to the difference in grid emission factors.

Uncertainties regarding future electricity prices and market values of hydrogen and bio-e-methane pose challenges for assessing long-term feasibility. Nevertheless, this thesis highlights the importance of resource efficiency by focusing on hydrogen-infused in-situ methanation systems, which increase biogas production without additional substrate, thereby helping to reduce fossil fuel use.

Keywords: In-situ Methanation, Hydrogen, Biogas, Bio-e-methane, Electrolyzer, Modeling, Power-To-Gas fuels, E-fuels, Energy System Modeling, Cost-optimization, Electricity Price Scenarios, LCOH, Gas leakages, Resource efficiency.

Acknowledgements

We would like to express our sincere gratitude to all who supported us throughout the entire process of writing this thesis.

To Maria Grahn, thank you for always providing us with great guidance on any topic needed, insightful feedback, encouragement, and for always bringing a positive attitude towards us and this thesis. Your engagement has not been unnoticed, and we are very grateful to have had you as our academic supervisor.

To Carl Jönsson Lindholm, thank you for supporting us with guidance on how to navigate through everything from modeling to thesis writing, and for your encouragement during this thesis.

We would like to thank the personnel at Euromekanik for giving us this opportunity, for making us feel welcome, and for their support throughout the entire process. We also extend our thanks to Tekniska Verken for offering us this opportunity.

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

AFIR	Alternative Fuel Infrastructure Regulation
BoL	Beginning of Life
CAPEX	Capital Expenditures
CBG	Compressed biogas
CCT	Cost-conscious Transition
CH_4	Methane
CO_2	Carbon dioxide
CRF	Capital Recovery Factor
ESF	Energy Security First
EU	European Union
E-fuel	Electro-fuel
EoL	End of Life
GHG	Greenhouse Gas
GWP	Global Warming Potential
HHV	Higher Heating Value
H_2	Hydrogen
LBG	Liquefied biogas
LCOH	Levelized Cost of Hydrogen
LHV	Lower Heating Value
O_2	Oxygen
OPEX	Operating Expenditures
O&M	Operation and Maintenance
PBP	Payback Period
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
RSF	Renewable Sustainability First
SE3	South Central Sweden bidding area for electricity prices
TEN-T	Trans-European Transport Network

Contents

List of Figures

List of Tables

1
Introduction

Combating the climate crisis requires reducing fossil fuel dependency through technological advancements. Fossil fuel combustion remains the primary driver of climate change, especially in power generation, heavy industry, and transportation [3]. Within the energy sector, coal, gas and oil accounted for more than three-quarters of global primary energy consumption in 2023. Even as the share of non-fossil energy sources has grown globally, rising energy demand, driven by economic growth, has continued to drive an increase in fossil fuel use [4]. Substantial efforts across multiple fields are essential to prevent climate change and achieve related goals.

The transition from fossil fuels requires the advancement of alternative technologies. Decarbonization requires a mix of solutions tailored to different applications, as no single technology can meet all needs. Potential substitutes include battery electric systems, hydrogen fuel and biofuels, among others [5]. Low-carbon electricity emerges as a promising alternative for many applications that currently rely on fossil fuels. However, certain sectors are more difficult to decarbonize and cannot transition to direct electrification as easily [6].

Parts of the transportation and industrial sectors face significant challenges in achieving decarbonization. Batteries are not able to replace fuels for all modes of transportation. Aviation, shipping, and long-distance road transport have high-performance energy-density requirements and are likely to continue to rely on liquid fuels. The industrial sector's emissions are also partly linked to the performance of low-carbon energy sources. Many industrial processes, such as cement production, steelmaking from iron ore, and manufacturing plastics and other petrochemicals, require extremely high temperatures. Few low-carbon alternatives generate heat at these levels, creating technical and cost-related challenges [6]. In these sectors, alternative approaches to decarbonization are especially essential.

In sectors where direct electrification is not favorable, alternative *power-to-gas fuels*, which convert electricity into gaseous energy carriers, are gaining attention. Hydrogen (H_2) is one example of a power-to-gas fuel [7]. Later, it can be used for different purposes, and methanation technology is one such approach, where hydrogen is utilized to convert carbon dioxide (CO_2) from biogas production to bio-e-methane [8][9]. In biogas production, organic substrates are digested in a digester unit to produce biogas. The resulting biogas consists of methane and CO_2. By adding hydrogen, CO_2 reacts to form additional methane through a process known as methanation. Biogas plants adopting methanation technology need to invest in electrolysis and may consider whether to scale the system solely to meet the hydrogen demand for methanation, or to oversize the system to enable additional functions. Hydrogen has a wide range of applications, and, depending on the context, different fields of use can be considered if integrating hydrogen into the system. It is commonly understood that decisions are often highly dependent on economic factors, while climate considerations may also play a role. The use of hydrogen in a methanation system is the focus of this thesis, where various cases are analyzed and evaluated under different conditions.

Tekniska Verken operates a biogas plant in Linköping, Sweden [10]. The plant is fueled by a substrate consisting of organic raw materials, such as food waste and biological by-products from industries. For example, in the food processing industry, expired food and packaging materials are broken down. The waste is decomposed in an anaerobic environment and biogas is produced [11]. Today, biogas is upgraded to a higher methane content by clearing the gas from CO_2 and releasing it into the atmosphere. However, Tekniska Verken is currently developing new procedures to make use of the CO_2 [12]. One of the initiatives they are working on involves hydrogen-infused in-situ methanation, with the injection of hydrogen into biogas production. Thus, it is possible to increase the production of fossil-free fuels from the same amount of biogas substrate, i.e. making it more resource-efficient. If an electrolyzer is installed, it is valuable to evaluate whether investing in a larger unit is beneficial, as it can enable the production of more hydrogen than needed for biogas production, allowing for additional revenue from hydrogen sales.

This thesis analyzes and evaluates the use of hydrogen for methanation in the context of Tekniska Verken by conducting three case studies. The components in each case are schematically represented in Figure 1.1. In the first case, hydrogen production is intended solely to meet the demand for methanation in the digester. The hydrogen demand for methanation is determined by the amount of CO_2 available in the biogas plant and the quantity of hydrogen needed to fully react with it. This quantity is referred to as the hydrogen demand for methanation. In the second case, the model is expanded to include the overproduction of hydrogen to be used at a hydrogen refueling station. A third case is explored by investigating the direct sale of hydrogen in the absence of additional methane production. This case provides a comparison of different utilization options for the electrolyzer and provides valuable information on what is economically favorable when it comes to the use of the electrolytically produced hydrogen.

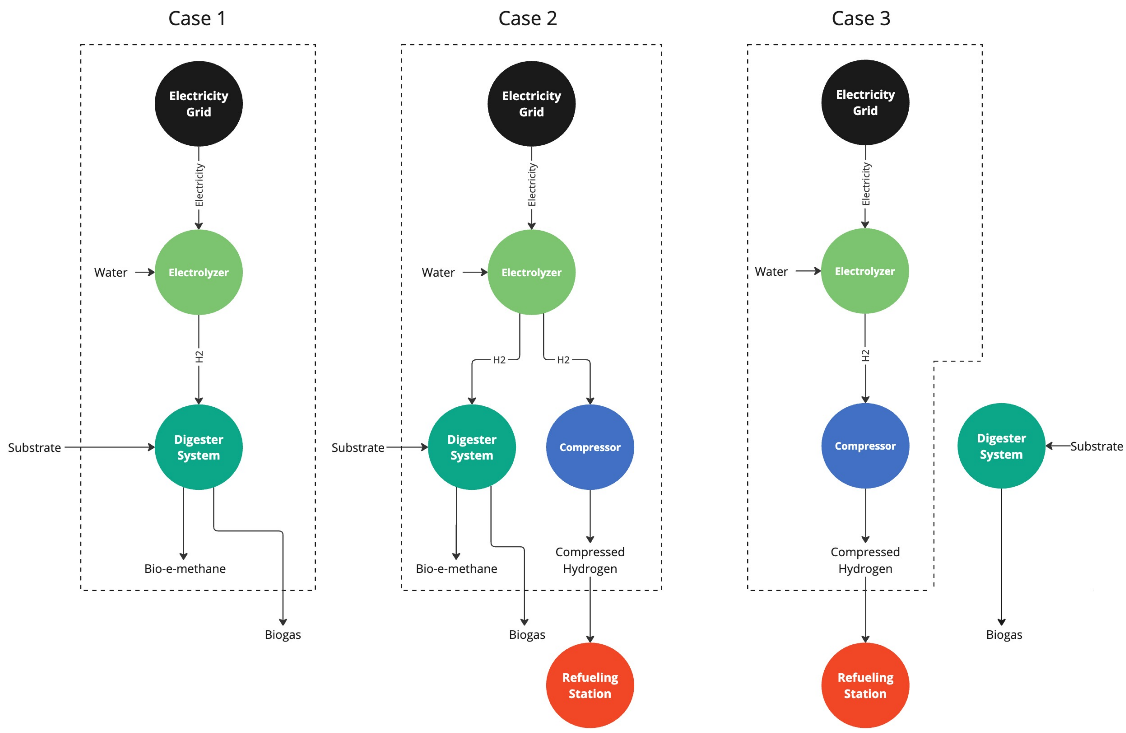


Figure 1.1: Schematics of flows included in Case 1, Case 2, and Case 3.

1.1 System Boundaries

While the three case-specific systems are described above, a clarification of the system boundaries is necessary. This thesis is limited to the components and flows visualized in Figure 1.1. The dashed lines in the figure indicate the system boundaries for each case.

It is evident from the figure that the current biogas production at Tekniska Verken falls outside the scope of this thesis and is therefore excluded from both the modeling and the comparative analysis. In addition, although the system utilizes CO_2 originating from the substrate, the carbon is already present in the system, and no additional substrate is fed into the digester. Consequently, only potential future expansions of the system are considered. The hydrogen overproduction for Case 2 and Case 3 is transported to a hydrogen refueling station for direct use of hydrogen in other applications. However, transportation from the site to the refueling station is assumed to be managed by a third party and therefore falls outside the scope of technical, economic, and climate analyses.

In addition, more flows exist beyond those shown in Figure 1.1, but only flows relevant to the scope of this thesis are included. Other flows associated with system components but not included are, for example, the production of bio-fertilizer from the substrate in the digester or CO_2 capture as part of the biogas upgrading system.

1.2 Aim

The aim of this thesis is to simulate and evaluate the techno-economic and climate perspective of an in-situ methanation system using a software called Odyssey. Three cases with different conditions are analyzed through varying configurations and constraints to achieve this objective (see also Figure 1.1). The cases are:

1. Hydrogen to bio-e-methane
2. Hydrogen to bio-e-methane and for direct sales
3. Hydrogen for direct sales

The main goal is to draw conclusions regarding the techno-economic feasibility and carbon footprint of the system.

The following research questions are evaluated:

1. What will the production costs for bio-e-methane and/or hydrogen be when it is integrated with an in-situ methanation system concerning the three cases?
2. To what extent is investing in the three cases economically viable?
3. What is the climate impact of hydrogen infused in-situ methanation production?

1.3 Limitations

Beyond the aspects mentioned in the system boundaries and those described later in the thesis, the following limitations are defined:

- Time series used to model current state are limited to a specific moment in time even though time is ever-changing.
- Time series to project future supply or demand must be approached with caution, as the future cannot be assumed with certainty.
- For the climate analysis, only newly added components, such as the electrolyzer and compressor, will be included in the calculations, while the existing biogas plant and related components will be excluded, as such analyses have already been conducted. In addition to this, only flows of electricity will be considered for each component included, i.e. no materials.
- Note: Throughout this thesis, the term “ton” refers to the metric ton (1 000 kg).

2

Theory

2.1 Electricity Supply and Grid Considerations

Electricity is a key element in power-to-gas systems, affecting both the techno-economic performance and the carbon footprint. Understanding the structure of the electricity grid, its cost and price dynamics is essential when evaluating operational strategies. This section provides an overview of the grid and how electricity prices during past and future scenarios can affect hydrogen production, with relevance to the system studied at Tekniska Verken.

2.1.1 Overview of the Electricity Grid

The electricity network constitutes the largest and most complex energy system globally, responsible for the generation, conversion, transmission and distribution of electric power [13]. The Swedish national electricity grid consists of high-voltage transmission lines connecting major generation sources, such as hydropower plants in the north, with urban and industrial demand centers mainly located in the south. High-voltage is usually assumed to be operating at 220 kV to 400 kV. After transmission, electricity is stepped down and delivered via the regional power grid (40–130 kV), the medium-voltage distribution network (10–20 kV), and the low-voltage distribution network (400 V). The latter two are also referred to as local distribution networks and are the levels at which electricity reaches homes, businesses, and small industries [14][15]. This reflects how the electricity system operates in Sweden, and the specified voltage levels follow Swedish standards. In addition, the grid is integrated with those of neighboring countries, including Norway, Finland, Denmark, Germany, and Poland, through a network of international interconnections [16].

The electricity grid must always balance supply and demand at all times [17]. Electricity plays a central role in the ongoing energy transition towards a fossil-free future, including both direct and indirect electrification solutions. Electricity use around the world is set to grow rapidly through 2027, with demand rising by nearly 4% per year as more sectors turn to electric power [18]. An important question is whether supply will be able to match the forecast demand growth. In practice, additional costs for grid connection may arise if there are capacity limitations in the electricity grid when the installation is to be constructed. Despite this, electricity from the grid is used under the assumption of unlimited access and adequate capacity to supply the electrolyzer.

Sweden is a global leader in clean energy production, with electricity generated primarily from hydro, nuclear, and wind power. In 2023, 99.4% of the country's electricity came from fossil-free sources [19]. However, it is important to make a distinction between electricity production and electricity consumption. Although the electricity consumed is also largely fossil-free, a discrepancy exists due to imports from neighboring countries such as Poland and Germany, which have different electricity mixes [20]. Therefore, data on carbon intensity for electricity must align with the electricity consumed, as it is crucial to account for both domestic production and imports to accurately reflect the environmental impact of the electricity consumed.

2.1.2 Grid Connection Cost and Fees

In Sweden, the transmission grid is operated by the National Transmission System Operator (TSO), Svenska Kraftnät [21]. The regional grids that connect the transmission grid with the local distribution networks are usually owned and maintained by larger electricity network companies, such as Vattenfall Eldistribution, which is responsible for electricity distribution in the region that includes Linköping [15]. The medium- and low-voltage networks are managed by local companies. In the context of this thesis, the local distribution network is Tekniska Verken in Linköping AB [22].

Connecting an electrolyzer requires careful consideration and involves several parameters to take into account. Electrolysis is an energy-intensive process and demands a larger connection to the power grid, but where the connection is most suitable is heavily dependent on the capacity of the electrolyzer. The electricity grid companies determine the appropriate voltage level for the connection [15], and all companies have their own guidelines based on the interaction between power, current, and voltage, due to technical and safety considerations.

The transmission grid is designed to transfer large amounts of electrical capacity, and the electrolyzer is a very small consumer in that context. The electrolyzer requires highly complex and expensive solutions to connect to the transmission grid. On the other hand, a very high current is required to transmit the same amount of power at a voltage level too low (see Eq. 2.1). High currents require thick cables and large, costly substation equipment. Additionally, there is a risk of overloading the network and causing voltage drops [23]. The power quality in a network is affected by connected customers, which is why it is important that disturbances from new connections are limited to levels the grid can handle. This ensures that the grid operator can meet the requirements to maintain good quality in the delivery of electricity [24].

$$P = \sqrt{3} \times U \times I \times \cos\varphi \tag{2.1}$$

P is the electrical power [W], U is the voltage [V], I is the current [A], and $\cos(\varphi)$ is the power factor assuming it is a three-phase connection.

The costs related to grid connections include both fixed initial connection charges and ongoing grid fees. Each connection has its own specific requirements and cost structure. The cost of a larger facility to the regional grid varies depending on several factors, including geographic location, existing grid capacity, and specific technical requirements. The grid fees for a regional grid connection consist of several components, including a fixed annual fee based on the chosen tariff level, an annual capacity charge based on the subscribed power, and a transmission fee based on a variable price.

2.1.3 Electricity Price Dynamics

The electricity price is of great importance in this thesis. It is defined as the cost of electricity alone, excluding taxes and grid-related fees. From a technical standpoint, the electricity price dictates when to run the electrolyzer, and its operation has a significant impact on the results due to factors such as ramp-up and ramp-down times, maximum and minimum stack power, efficiency linked to utilization rate, hydrogen output, and more. The variation in electricity price also plays a major role in sizing the electrolyzer, which in turn greatly affects the investment cost. A larger electrolyzer comes with a higher investment cost but provides flexibility in producing more hydrogen during hours of low electricity price and less hydrogen when the electricity price is high. The increased investment cost must be weighed against the avoided hours of high electricity prices, making the electricity price a crucial factor in the overall economics.

The electricity price is determined by availability, which depends on supply and demand within different bidding areas [17]. Sweden is divided into four bidding areas, and electricity prices in the South Central Sweden (SE3) bidding area will be used in this thesis as the study is located in this region. Figure 2.1 shows how the electricity prices varied from January 1st until December 31st in the SE3 area during the year 2023.

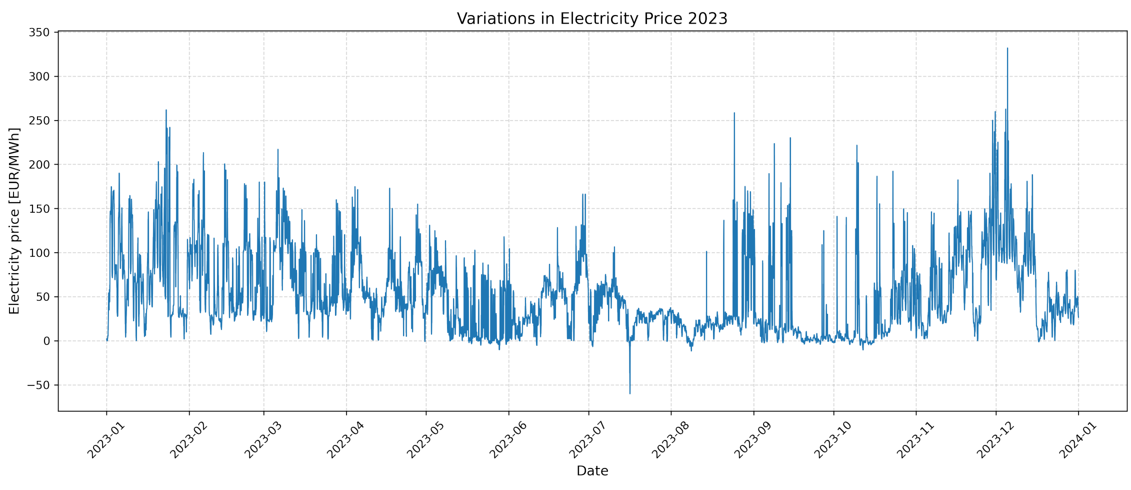


Figure 2.1: Electricity price variations in 2023 [1].

Future scenarios of electricity price variation will be used to support a more detailed analysis. The future scenarios originate from a collaborative project within the energy industry, called *Energy Price Scenarios with AI-Generated Global Context Scenarios*, carried out during the winter of 2023–2024 by Tekniska Verken and others. The scenarios are conducted to outline a reasonable range of possible outcomes for the development of energy prices. They are based on normal-year conditions and long-term trends. Short-term economic fluctuations or annual variations in weather and wind are not included. The scenarios are based on three main pillars, as illustrated in Figure 2.2. The pillars are sustainability, energy security, and economy, and the scenarios place different emphasis on each based on a clearly defined scenario logic. The scenarios are *Renewable Sustainability First (RSF)*, *Energy Security First (ESF)* and *Cost-conscious Transition (CCT)* (personal communication, Stina Berg, Tekniska Verken, February 2025).

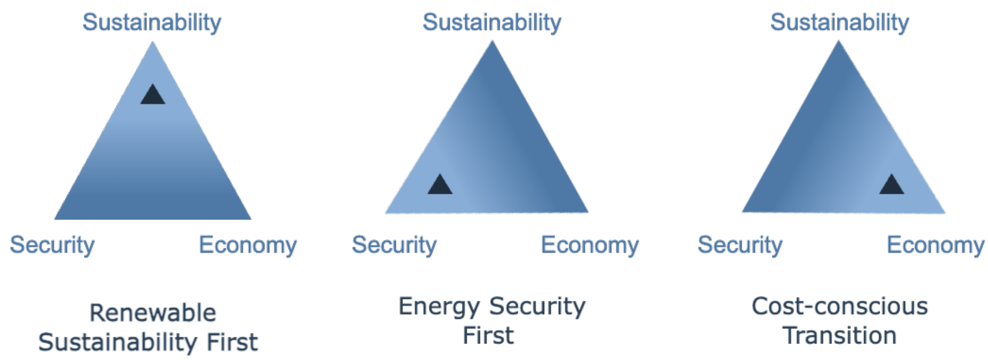


Figure 2.2: Foundation for the Future Electricity Price Scenarios.

In broad terms, RSF includes extensive electrification with a heavy focus on renewable electricity and rapid technological development within renewables, energy storage, and flexibility solutions. It is also characterized by high global cooperation and reduced political tensions (personal communication, Stina Berg, Tekniska Verken, February 2025). Figure 2.3 shows the predicted electricity prices in the RSF scenario year 2035.

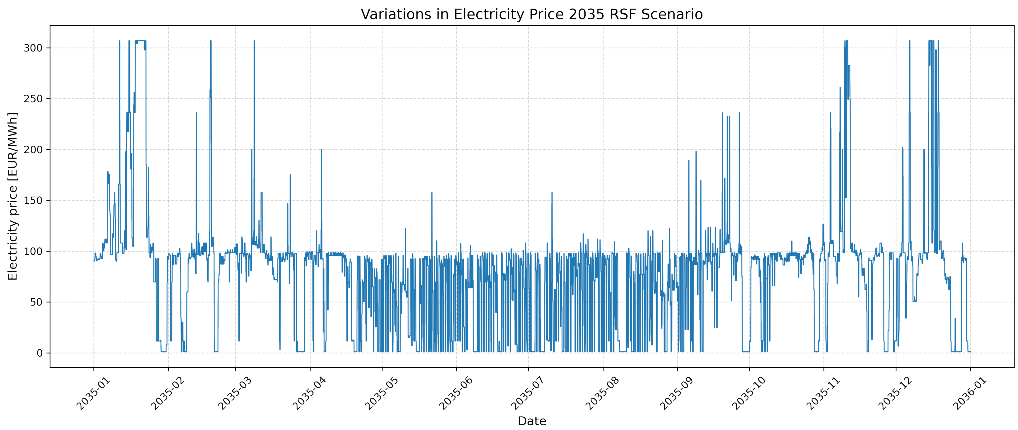


Figure 2.3: Predicted electricity price variations in the RSF scenario (personal communication, Emelie Algebrant, Tekniska Verken, February 2025).

Similarly to RSF, the ESF scenario involves extensive electrification but places a greater emphasis on energy security and supply reliability due to increasing geopolitical tensions. Figure 2.4 shows the predicted electricity prices in the ESF scenario year 2035. It supports national production with new nuclear power and local biofuel production at the same time as imports and efforts to develop electricity transmission to Continental Europe decrease (personal communication, Stina Berg, Tekniska Verken, February 2025).

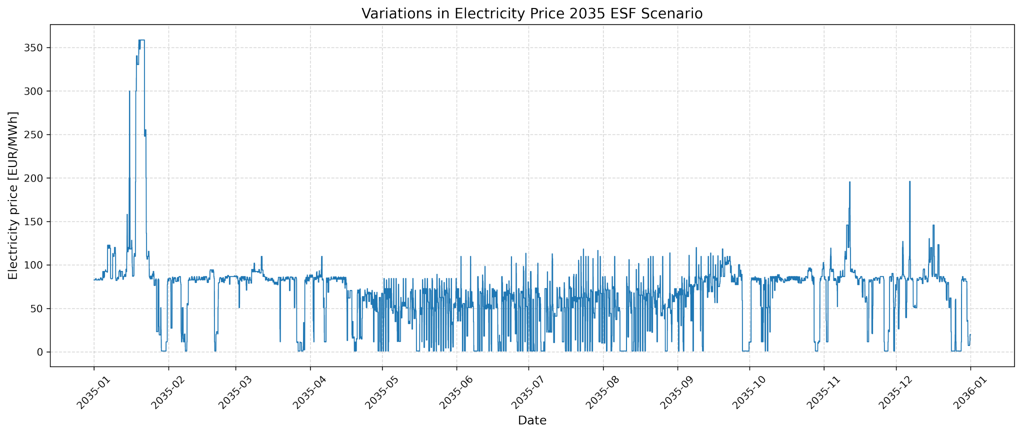


Figure 2.4: Predicted electricity price variations in the ESF scenario (personal communication, Emelie Algebrant, Tekniska Verken, February 2025).

The third scenario, CCT, represents relatively limited electrification with moderate climate ambitions as a result of recurring periods of high interest rates and inflation. Technological development and energy security are subordinate to the economic profitability (personal communication, Stina Berg, Tekniska Verken, February 2025). Figure 2.5 shows the predicted electricity prices in the CCT scenario year 2035.

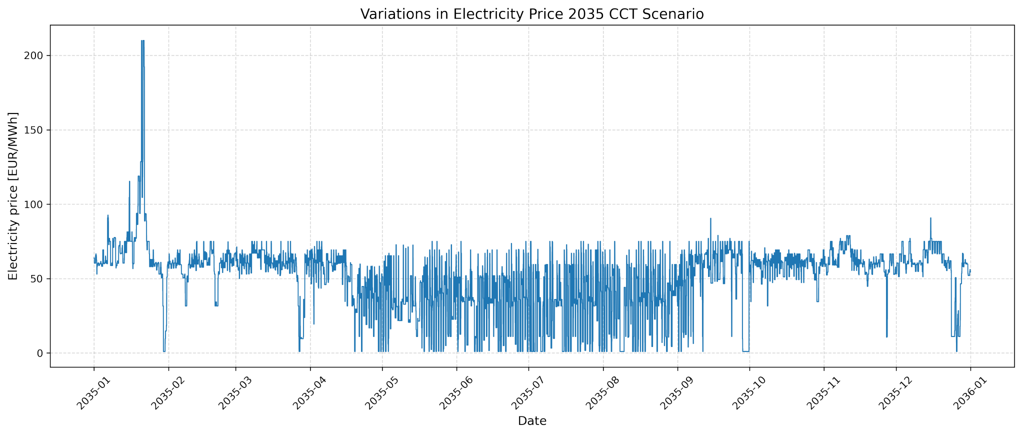


Figure 2.5: Predicted electricity price variations in the CCT scenario (personal communication, Emelie Algebrant, Tekniska Verken, February 2025).

The different settings lead to three scenarios for projected future electricity prices in 2035. The annual average price is 78 EUR/MWh for the RSF scenario, 67 EUR/MWh for ESF and 50 EUR/MWh for CCT. For the 2023 scenario, the annual average price is 52 EUR/MWh for 2023. Figure 2.6 shows the price duration curve for each scenario, including the scenario of 2023 and the future scenarios. A price duration curve displays electricity prices sorted in descending order over a specific period and is used to analyze price variability over time. It provides insights into price volatility, the profitability of power generation, and the optimization of energy systems by identifying periods of high and low prices.

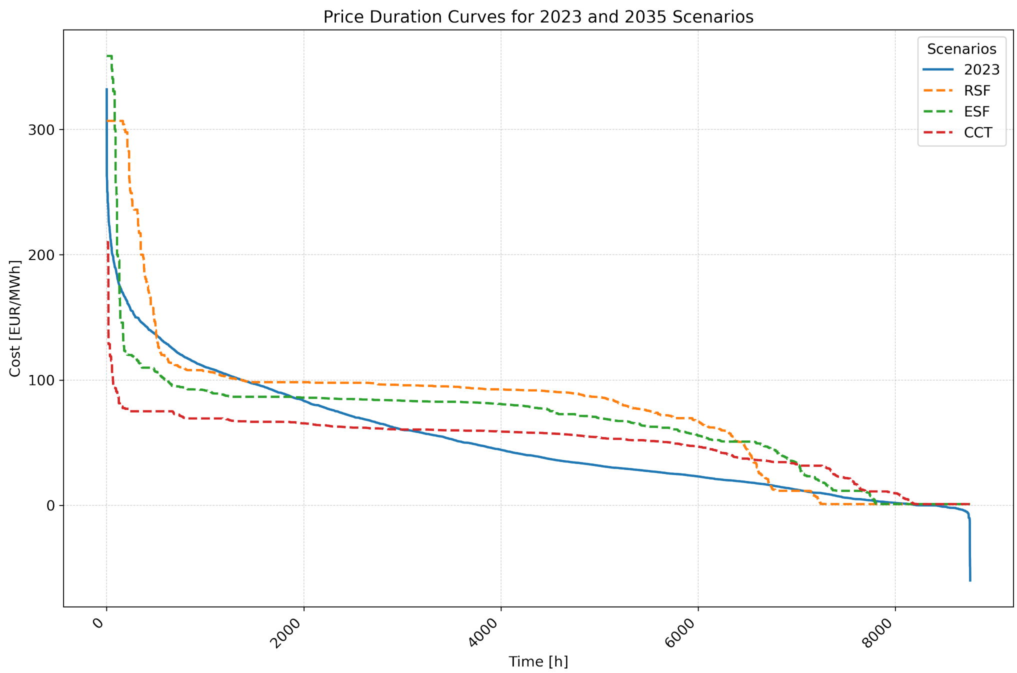


Figure 2.6: Price Duration Curves for 2023 and projected electricity price in 2035 using three scenarios.

2.2 Hydrogen Production via Electrolysis

Hydrogen is a promising and versatile clean energy carrier when produced from low-emission energy sources. If not produced from renewable sources, the climate benefits of the product reduce, and today only 4% of hydrogen is produced by low-emission sources globally [25], highlighting that the share needs to increase significantly.

One hydrogen-producing technology is the electrolyzer, where water is split into oxygen and hydrogen using electricity, see Eq. 2.2 [26]. In addition to hydrogen, pure oxygen and excess heat at low temperatures are produced as a by-product of the reaction. Both oxygen and heat have the potential to be sold to generate additional revenue [27].

$$H_2O + \text{electricity (237.2 kJ/mol)} \rightarrow H_2 + \frac{1}{2}O_2 + \text{heat (48.6 kJ/mol)} \tag{2.2}$$

As energy supply from renewable sources varies due to their intermittent nature, hydrogen production through electrolysis is a key technology to utilize excess power. Hydrogen can be produced at a low cost during periods of high supply and low demand, such as a sunny day at noon, and stored for later use. This is more resource-efficient than curtailing excess energy, which remains more common today [2].

Hydrogen has a wide range of applications, such as feedstock in the chemical industry and in refineries, steel production, and heat and power [28], and it will also play a key role in the transport sector by reducing emissions. For example, clean hydrogen produced through electrolysis can be combined with a fuel cell and a battery for transportation, i.e., in a fuel cell-driven vehicle. Moreover, hydrogen can be used as a fuel in both industry and transportation.

Electro-fuels (e-fuels), also referred to as power-to-gas fuels, are carbon-based fuels produced from CO_2 and water using electricity as the primary energy source [29]. The process in which electricity is applied to water is shown in Eq. 2.2, and it is the hydrogen molecule that reacts with the CO_2 molecule to produce e-fuels. One common type of e-fuel is methane, which can either be produced in a stand-alone facility (e-methane) or within a biofuel production facility (bio-e-methane). More details are provided in the following sections. The application of interest in this thesis is considered a type of bio-e-fuel: the injection of hydrogen into a digester during biogas production to enhance methane yield.

2.2.1 Electrolyzer Technology

The three most common water electrolysis technologies are Alkaline electrolysis, Proton Exchange Membrane (PEM) electrolysis, and Solid Oxide cell electrolysis

[30]. Each has its own advantages, disadvantages, and level of technological maturity, making them suitable for different applications. This thesis focuses on the use of a PEM electrolyzer due to its ability to operate at high current densities and its fast response time. These features make PEM technology particularly suitable for integration with renewable energy sources (RES), thus improving system efficiency [31]. All scenarios for projected future electricity prices foresee an increased share of renewables to some extent, further supporting the choice of PEM electrolysis as it can handle price fluctuations caused by intermittent power generation. The feature of quick start-up times can also be essential for intermittent biogas production, making PEM electrolysis especially suitable for biogas applications [9]. In addition, its compact design and ease of operation make it an attractive choice for industrial use [26].

The PEM electrolyzer has been under development since the 1960s. Compared to the alkaline electrolyzer, which is the most mature and widely used electrolyzer type on the market, the PEM electrolyzer requires more expensive materials, such as platinum and iridium, increasing the price. A typical PEM electrolyzer consists of three main components: a cathode, anode and membrane [31], and the components can be seen in Figure 2.7. The PEM electrolyzer is an electrochemical energy converter, meaning that it uses electricity to oxidize water, producing oxygen and protons on the anode side. When oxygen has been produced, it leaves the device, while protons pass through the membrane and electrons flow through an external circuit. On the cathode side, the electrons reduce the protons to form hydrogen gas [32].

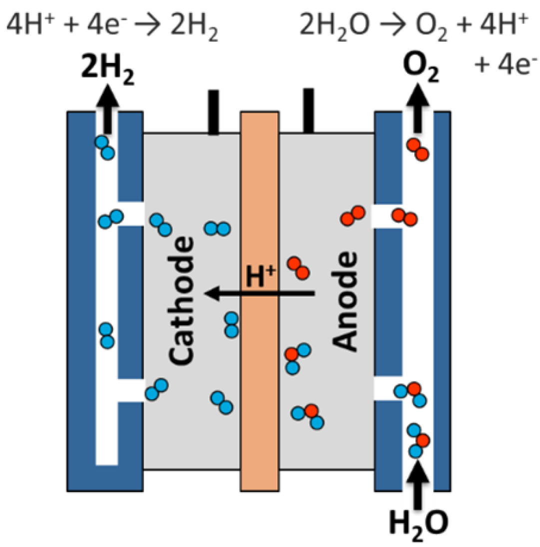


Figure 2.7: Components of a PEM electrolyzer [2].

2.2.1.1 Performance Factors

The performance of an electrolyzer is influenced by various parameters. One such parameter is the variation in efficiency with the utilization rate of the electrolyzer. An efficiency curve was derived and visualized in Figure 2.8 (personal communication, Carl Jönsson Lindholm, Euromekanik, February 2025). As shown, the efficiency variation in relation to the power output is matched with a sixth-order polynomial equation. The figure suggests that there is a slight decrease in efficiency and this is accounted for in the model.

Note that the efficiency is calculated using the lower heating value (LHV) of hydrogen. When discussing electrolyzer performance, it is important to specify whether LHV or higher heating value (HHV) is being used to accurately represent the hydrogen produced. HHV includes the energy from the water vapor produced during hydrogen combustion. In contrast, LHV excludes this latent heat and for green hydrogen production, it is more common to refer to the LHV since it better represents the practical, usable energy from hydrogen [33].

The capacity of the electrolyzer is vital and is calculated using Eq. 2.3.

$$\text{Electrolyzer capacity [MW]} = \frac{\text{H}_2 \text{ demand [ton/yr]}}{\text{H}_2 \text{ output [ton/yr/MW]}} \tag{2.3}$$

H_2 demand varies between the cases and the H_2 output is the produced hydrogen from the electrolyzer per MW electrolysis. The H_2 output is calculated using Eq. 2.4 [33].

$$\text{H}_2 \text{ output} = \eta_{\text{electrolyzer}} \times \frac{8760}{\text{LHV}_{\text{H}_2}} \quad \left[\frac{\text{ton}}{\text{yr} \cdot \text{MW}}\right] \tag{2.4}$$

H_2 output is the mass flow of hydrogen per MW electrolysis [ton/yr/MW], $\eta_{\text{electrolyzer}}$ is the efficiency [-], LHV_{H_2} the LHV of hydrogen [kWh/kg] and 8760 is the conversion factor from hours to year. The conversion from kilograms to tons has also been made.

The age of the electrolyzer stacks is another factor of great importance for electrolyzer performance. Since modern electrolysis for large-scale hydrogen production is a relatively recent development and has gained widespread adoption only in recent years, assumptions regarding the lifetime of electrolyzer stacks remain uncertain. The degradation rate varies between different electrolyzer technologies and depends on factors such as utilization, operating conditions, maintenance practices, and the specific design of the electrolyzer. The end of life (EoL) of an electrolysis stack is typically defined as the moment when its power consumption during operation increases by 10% [30]. The lifetime of PEM electrolyzers is expected to improve over time as a result of technological advancements, with 2030 projections ranging from 6.8 to 9.5 years under full load operation [30]. However, given the associated uncertainties and the expected part-load operation, this thesis applies a simplified assumption of a 10-year stack lifetime for all cases.

Assuming a constant mass flow and LHV, and a 10% increase in power consumption due to the stack degradation, the electrolyzer efficiency at the end of the stack's life can be calculated using Eq. 2.4. This results in a decrease of 5.6%, which corresponds to an average annual degradation rate of 0.56% over a 10-year lifespan. Operational data from commercial PEM electrolyzers demonstrate an annual efficiency degradation in the range of 0.5 to 2.5 %, suggesting that the calculated value falls within the lower end of this range. Degradation is taken into account during the dimensioning of the electrolyzer to ensure that the required demand is met throughout its entire operational lifetime, including at the EoL. The efficiency curves for the beginning of life (BoL) and EoL of the electrolyzer are visualized in Figure 2.8.

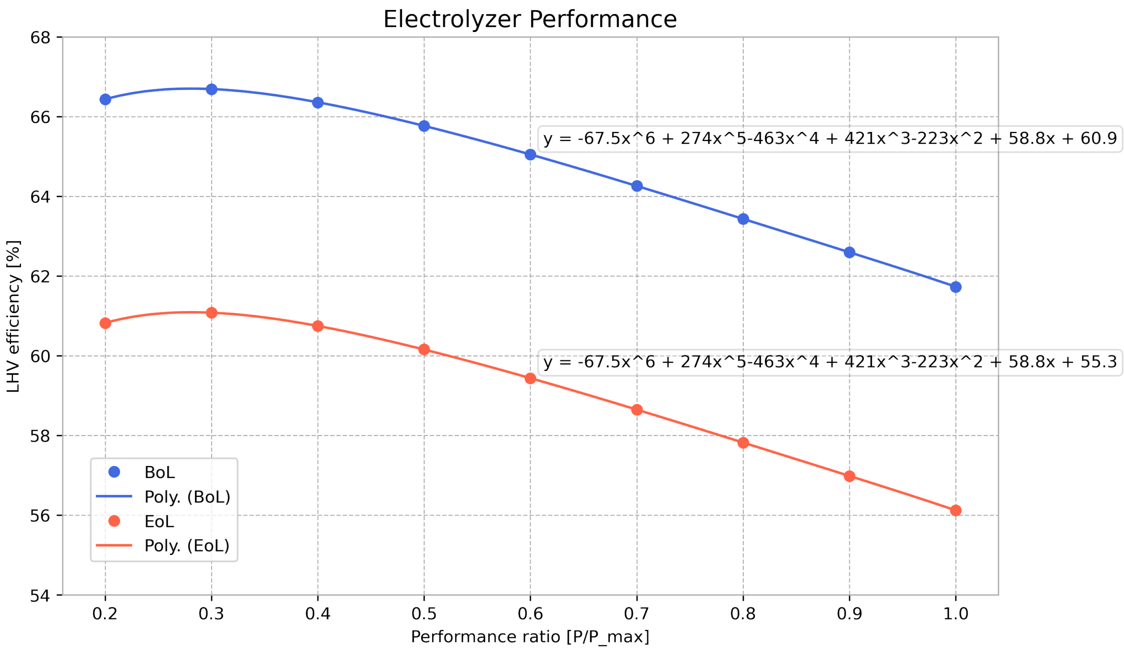


Figure 2.8: Change in efficiency based on utilization rate and age of the electrolyzer stacks (personal communication, Carl Jönsson Lindholm, Euromekanik, February 2025).

Varying the load when operating the electrolyzer has several consequences for its performance in addition to efficiency variations, mainly related to degradation and, consequently, the lifetime of the electrolyzer. Operating under variable load conditions may influence degradation, but the exact effects remain uncertain. While downtime can extend the total operational lifetime, it may also initiate new degradation mechanisms. These mechanisms occur not only from operating at part load but also from the ramping process itself. Frequent ramp-up and ramp-down cycles or shutdowns, in which the system is not actively producing hydrogen, can accelerate degradation. The degradation mechanisms include gas crossover and reduced catalyst stability. Degradation is also sensitive to improper operation, such as running at high voltages or high current densities. Continuous operation at high currents can lead to membrane thinning, hotspot formation, and electrode damage due to gas bubbles or heat [34].

PEM electrolyzers typically handle rapid variations better than alkaline electrolyzers and the ramping capabilities are faster [34]. The electrolyzer used goes from standby to nominal load in 30 seconds and since the accuracy is based on an hourly basis, the ramp-up time is assumed to be zero [35].

The limitations of electrolyzers operating in variable loads are also associated with the minimum and maximum operating limits. The minimum limit is required mainly due to safe operation. Operating below this level can lead to uneven gas production and potential instability. PEM electrolyzers can go down to 5% of nominal capacity which offers more flexibility in part load operation compared to other electrolyzer technologies [34]. However, the specific electrolyzer used has a hydrogen production modulation range between 20 and 100% of its maximum power [35]. An electrolyzer is typically not operated at full load continuously due to maintenance requirements and other operational interruptions. The nominal maximum capacity of the electrolyzer is typically around 95% (personal communication, Carl Jönsson Lindholm, Euromekanik, April 2025). However, for the purposes of this thesis, it is assumed that there is no downtime due to maintenance or other such reasons. The maximum and minimum power capacities for the electrolyzer in focus are reflected in the x-axis of Figure 2.8, which ranges from 0.2 to 1 in operational variability.

2.2.2 Downstream Hydrogen Handling

The following section describes the downstream handling of hydrogen after its production, specifically in the context of surplus sales in Case 2 and Case 3. The two main aspects of this process include hydrogen compression and storage, followed by distribution to the refueling station.

2.2.2.1 Hydrogen Compression and Storage

Once the hydrogen has been produced, it exits the electrolyzer at an output pressure of approximately 20–30 bar (g) [35]. After this, it can be stored as a gas, a liquid, or as a part of a chemical structure [36], and the focus will be on the first option. Since hydrogen has the lowest volumetric energy density of all fuels, hydrogen must be compressed to achieve high energy density and storage levels, so it can be sold for surplus sale [37]. Hence, it is necessary to invest in a compressor for Case 2 and Case 3.

The hydrogen can be compressed to different pressure levels, and there are both mechanical (also known as physical) and non-mechanical (also known as material) types of compressors. Mechanical compressors are the most widely used compressors today, where the "positive displacement" devices are typically used for hydrogen. They reduce the confined volume by the use of pistons, where the hydrogen is compressed into a smaller space. This increases the number of collisions between the particles and therefore results in a higher gas pressure [38]. The non-mechanical/material approach is when hydrogen is adsorbed through a porous carbon material with high hydrogen attraction, or to adsorb hydrogen atoms through a chemical reaction [39].

After compression, hydrogen is typically stored in some kind of high-pressure tank, mainly around 350 to 700 bar [40]. It is the most common and economical way to store hydrogen in all-metal pressure vessels of aluminum or steel alloys, which can withstand a pressure of up to 50 MPa [39].

The required pressure is assumed to be 350 bar using a mechanical compressor and the storage unit is assumed to be an on-board/mobile storage system. However, the onboard storage unit is assumed to be handled by a third party and will therefore not be included in technical, economic, and climate analysis. Only the compressor and its electricity consumption will be taken into account.

2.2.2.2 Hydrogen Refueling Station

Although the hydrogen refueling station and its associated transportation are assumed to be managed by a third party and are therefore beyond the scope of this thesis, it remains important to address the anticipated developments in the hydrogen refueling infrastructure and to consider the possible future implications.

Hydrogen-powered vehicles are currently under development, and progress varies between different types of vehicles. Hydrogen fuel-cell road vehicles are already available on the market, whereas smaller hydrogen vessels are expected to reach commercial viability in the coming years. Despite their presence on the market, the current adoption of hydrogen-powered vehicles remains limited within the transport sector. To enable a larger implementation and support future market expansion, it is crucial to establish an extensive and reliable network of hydrogen refueling stations [41].

In April 2024, the European Union (EU) adopted the Alternative Fuel Infrastructure Regulation (AFIR), establishing legally binding targets for the deployment of alternative fuel infrastructure across all member states. Among other objectives, the regulation supports the deployment of hydrogen refueling stations. It states that by 2030, stations should be deployed in every urban node and at intervals no greater than 200 km along the Trans-European Transport Network (TEN-T) [41]. TEN-T is a policy designed to create a sustainable, efficient and interconnected transport network for people and goods throughout the EU, linking major cities, ports, airports, and inland waterways [42]. Each hydrogen refueling station is required to deliver a minimum cumulative dispensing capacity of 1 ton of hydrogen per day and must be equipped with at least a 700 bar dispenser [41].

For Sweden, expansions to at least 34 refueling stations by 2030 are required to meet the obligations set out by the AFIR. As of September 2024, eight hydrogen refueling stations were in operation and 55 new stations were planned in Sweden. When summarizing the existing and planned hydrogen refueling stations along the TEN-T core network that meet the technical requirements of the AFIR, only a few road sections and urban nodes are not covered to meet all the criteria. The key nodes that lack an existing or planned hydrogen refueling station are, among seven other cities, Linköping, where the biogas plant is located. There are proposals for an action plan to ensure that the requirements are met [43]. However, in order to fulfill the requirements set by AFIR, the establishment of a hydrogen refueling station in Linköping or nearby would be necessary.

2.3 Biogas and Bio-e-Methane Production

In this section, the biogas and bio-e-methane production process is described. First, a foundational understanding of biogas and its related upgrading process is described, followed by an explanation of how hydrogen can be integrated into the biogas process to produce bio-e-methane. Finally, the methanation process in the studied system is presented.

2.3.1 Biogas: Fundamentals and Upgrading

Biogas is produced by the decomposition of organic material and is therefore considered a green energy source with multiple advantages from a sustainability perspective. The residues are degraded by microorganisms in an anaerobic (oxygen-free) environment, resulting in the production of biogas. Digesters, or reactor vessels, are used to create the anaerobic environment and harvest the produced gas. That is, it supports waste management and transition to a more circular economy and is a natural part of the carbon cycle [44].

Biogas can be transformed into different forms, such as compressed biogas (CBG) and liquefied biogas (LBG). These two forms have different purposes; CBG is mainly used for light vehicle traffic and LBG is mainly used for heavy vehicle traffic and industry. However, before these steps, biogas is upgraded into bio-methane [11].

Biogas generally consists of 50 - 70 % methane, and the majority of the non-methane components in biogas consist of CO_2. The concentration of methane can exceed 90% by decreasing the CO_2 content, which can be done through various methods. High methane-containing gas produced biologically is normally referred to as bio-methane [45].

The removal of excess CO_2 from biogas increases the energy content, resulting in a wider range of uses. It broadens the area of use for biogas beyond applications with low energy efficiency, such as heating, to the possibility of powering households, factories, and vehicles. Furthermore, upgrading biogas allows it to reach natural gas quality, allowing it to be used in the natural gas grid [46]. These expanded uses improve incentives for and add value to biogas adoption. [45].

2.3.2 Bio-e-methane

There are many methods to achieve high methane content. Among various upgrade technologies, the injection of exogenous hydrogen has been discussed as an interesting technology. With carefully executed hydrogen injection, CO_2 can be converted to methane and water according to Eq. 2.5 [46], which occurs through microbial activity of methane-forming microorganisms.

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \tag{2.5}$$

The process of biogas upgrading using hydrogen can be performed either in-situ or ex-situ. In-situ refers to injecting hydrogen directly into the digester where biogas production occurs. Ex-situ, on the other hand, involves injecting hydrogen into an external chamber after it has been produced. Since the in-situ approach is performed directly within the digester, there is no need to invest in an external reactor. Therefore, it is less costly than the ex-situ approach [46]. However, the in-situ method has limitations to avoid disturbing the metabolic processes that occur within the digester, and the constraints concern various parameters, including pH levels, concentrations of volatile fatty acids, alkalinity, levels of ammonium and ammonia, as well as the amounts of total and volatile solids [8]. This thesis investigates hydrogen injection with a focus on the in-situ methanation approach.

Bio-e-fuels are a concept that is considered a hybrid between biofuels and e-fuels [47]. Biofuels could be of different sorts, however, the one considered is bio-methane. Since the thesis investigates hydrogen infused in-situ methanation, i.e., producing bio-methane by methanogenic microorganisms inside the digester, in combination with electrolytic hydrogen without the presence of a catalyst and captured CO_2, the corresponding bio-e-fuel under investigation is bio-e-methane, and this is the term that will be used throughout in the thesis.

The process increases the gas yield by utilizing the excess CO_2 generated in the biomass conversion process. Hence, it generates additional fuel without the need for carbon capture [47].

2.3.3 Methanation in the Studied System

Tekniska Verken is planning to expand its facility, increasing annual production from approximately 125 GWh to around 225 GWh (personal communication with J. Moestedt, Tekniska Verken, March 2025). The increased capacity for methane production will result in 23 000 tons of CO_2 as a byproduct annually. A substantial portion of this CO_2 will be used for food-grade applications, such as the carbonation of beverages. However, regulatory constraints prevent the full recovery of CO_2 for this purpose. The allocation of CO_2 for food-grade use limits the requirement for hydrogen, which leaves approximately 3 000 tons of CO_2 available for methanation each year, according to the future production plan. The availability of CO_2 is directly linked to the raw gas flow to the post-digestion chamber, which can be regulated by adjusting the amount of glycerol and alcohol used, according to Tekniska Verken.

The theoretical reaction Eq. 2.5 assumes 100% hydrogen utilization. A reaction efficiency of 90% is assumed, meaning only 90% of the supplied hydrogen participates in the reaction [8]. To compensate for this loss, the required amount of hydrogen must be adjusted upward by a factor of 1/0.9 to account for the efficiency loss in practical applications.

With a given amount of CO_2 available per year, the amount of hydrogen needed for methanation, as well as the amount of bio-e-methane produced could be calculated using Eq. 2.5, and Eq. 2.6 and parameters given in Table 2.1.

$$\text{Amount of substance} = \frac{Mass}{Molarmass} \tag{2.6}$$

Table 2.1: Parameters to calculate H_2 demand for methanation in the digester.

General Parameters	**Value**	**Unit**	**Source**
Molar mass CO_2	44.01	g/mol	[48]
Molar mass H_2	2.016	g/mol	[48]
Molar mass CH_4	16.04	g/mol	[48]
Projected available CO_2 for methanation	3 000	tons CO_2/yr	Tekniska Verken
Amount of substance CO_2	6.82×10^7	mol/yr	Calculated
Amount of substance H_2	3.03×10^8	mol/yr	Calculated
Amount of substance CH_4	6.82×10^7	mol/yr	Calculated
H_2 demand	610.16	tons H_2/yr	Calculated
CH_4 production	1 093	tons	Calculated

2.4 Renewable Fuels of Non-Biological Origin

Renewable Fuels of Non-Biological Origin (RFNBO) are liquid and/or gaseous fuels produced from RES other than biomass, as defined in the Delegation Acts by the EU. Hydrogen produced by feeding renewable electricity into an electrolyzer is therefore considered RFNBO [49].

Besides being produced from a renewable energy source, other important criteria must be met for an energy carrier to be considered an RFNBO, as follows [50]:

- **Additionality**: This ensures that electricity is supplied from new renewable energy installations. The hydrogen producer is therefore required to establish a power purchase agreement (PPA) with renewable energy facilities that are new and not supported by subsidies for the generation capacity.
- **Temporal and Geographic Correlation**: This ensures that the produced hydrogen avoids an increased demand for fossil electricity generation - it is produced when and where renewable electricity is available. This means that

the electrolyzer must operate at the same time that renewable power is being generated and within the same geographical area.

However, concerning the Additionality criterion, renewable hydrogen producers can sign long-term renewable PPAs with existing renewable installations until January 1, 2028, to support early scale-up [50].

Moreover, additional measures support countries in developing RFNBOs. For instance, in bidding zones where the dominant share (approx. 90%) of the electricity comes from renewable sources, electricity drawn from the grid can be considered fully renewable. This applies as long as the production of renewable liquid and gaseous fuels (of non-biological origin) remains within the share of renewable electricity in the zone. However, any production exceeding this share must be classified as non-renewable. Additionally, in bidding zones where the emission intensity of electricity is below 18 gCO_2/MJ, additional installations are not required [51]. This means that Sweden, which has a high proportion of fossil-free electricity production, can use the existing renewable electricity production and does not need to install more of it to achieve the Additionality criteria. However, a PPA is still required to fulfill the Temporal and Geographic Correlation criteria [52].

2.5 Climate Considerations

As previously mentioned, the effects on climate are crucial factors to consider, and a standardized method for assessing the greenhouse gas (GHG) impact is necessary. Two key characteristics determine the climate impact of a GHG [53]:

1. The length of time the gas remains in the atmosphere
2. The gas' ability to absorb energy.

There are various ways of combining these two characteristics, however, the most common type is the Global Warming Potential (GWP). This is used to describe one ton of GHG emitted in CO_2 equivalent terms over a period of time [53], i.e., the impact of 1 kg of a specific GHG in the atmosphere expressed as the equivalent amount of CO_2 released over the same time period. A GWP over 20 years (GWP_{20}) and 100 years (GWP_{100}) will be considered for methane and hydrogen.

2.5.1 Methane Leakage

It is problematic with methane emissions when producing biogas, as it decreases the climate benefits of biogas production since methane is a powerful GHG and the second largest anthropogenic contributor to climate change after CO_2. Although it has a shorter atmospheric lifetime compared to CO_2, it is significantly more effective in retaining heat in the atmosphere [54], making it a critical GHG from a GWP point of view. However, when effectively utilized, biogas will be crucial in fossil-free energy supply and waste management strategy.

The Intergovernmental Panel on Climate Change, IPCC, has identified that methane has a GWP_{100} between 28-36 and a GWP_{20} between 84-87 [53]. Methane also affects air quality due to being an ingredient in the formation of ground-level (tropospheric) ozone, causing dangerous air pollution [53]. Given the significant environmental impact of methane, it is crucial to consider the potential consequences of methane leakages.

Achieving a completely leak-free system in the production of biogas is nearly impossible, as emissions are inevitable at certain stages of the production chain. Several studies have been conducted on this subject, where one study, for example, shows that the most critical component of methane leakage is the digestate handling stage in a plant [55]. However, there are different types of sources of leakage in a biogas plant, and some of the most relevant sources of emissions are:

- Emissions from tanks upstream of the digester
- Leakages at gas holders and gas holders fixation
- Emissions from safety valves (pressure relief valves)
- Emissions from open or non-gas-tight covered digestate storage tanks
- Emissions from biogas utilization units (e.g., Combined Heat and Power and biogas upgrading units).

Besides the negative environmental effects of methane leakage, small losses of methane can lead to considerable financial losses for the producers. Plant operators aim to use the largest possible amount of methane produced, and leakages become lost revenues. Therefore, it should be of double concern to minimize leakages. Mitigation measures could, for example, be:

- Sealing of leakages
- Gas-tight covering of tanks, e.g., storing or mixing tanks
- Installing an exhaust gas treatment
- Regular replacement of aged gas holder membranes
- Regular leakage detection
- Regular maintenance
- Mass balance calculation to identify losses

And several other measures, involving both technical and organizational actions [56].

A study analyzing the emissions of 23 biogas plants showed that the overall average loss of methane was 10.4 kg methane/h and an average of 4.6%. It also showed that, in general, the losses tended to decrease with increased production [57].

This thesis has been provided with data from Tekniska Verken which presented a methane leakage of 0.2% from the production in 2023.

2.5.2 Hydrogen Leakage

Hydrogen is expected to play a crucial role in reducing GHG emissions, as previously stated, with a growing global interest in replacing fossil fuels. However, increasing attention has been paid to the actual impact of hydrogen leakage into the atmosphere and the environmental consequences of leakages during production, transportation, storage, etc. Hydrogen is not a direct GHG, however, the simplicity of the molecule easily creates chemical reactions and therefore changes the concentrations when it comes to other, more potent GHGs such as methane, ozone, aerosols, etc. Today, there is very little data on the magnitude of leakage within the value chain and how this will evolve in a future growing hydrogen economy [58].

As stated, the main concern with hydrogen leakage is the reactions it triggers and their impact on atmospheric chemistry. The primary reaction is with hydroxyl radicals (OH), see Eq. 2.7, which reduces the concentration of OH radicals. Those radicals are crucial for breaking down methane, hence, without them present, methane persists longer in the atmosphere as a result. This is because of the absent reaction shown in Eq. 2.8, and the prolonged lifetime of methane in the atmosphere contributes to climate change. It has been identified that hydrogen has a GWP_{20} of 40 and GWP_{100} of 13 [59].

$$H_2 + OH = H_2O + H \tag{2.7}$$

$$CH_4 + OH = CH_3 + H_2O \tag{2.8}$$

Hydrogen leakage can occur at different stages in the supply chain, depending on the kind of production chain it is produced by. The generalized largest leakage risks along various pathways when it comes to green hydrogen production by electrolyzer have been identified as equipment failure, faulty seals, and venting during maintenance activities [60].

Moreover, it is easier for the hydrogen molecule to infiltrate materials because of its small molecular size, a process known as hydrogen embrittlement. The effect of this is that it reduces the strength of the metal, making it more vulnerable to cracks and leaks, increasing the potential for hydrogen leakage [60].

Considering potential hydrogen leakage is important due to the knowledge of its occurrence and because hydrogen has an indirect effect on climate change. The rate of hydrogen leakage depends on various conditions and is therefore difficult to approximate. A rate of 4% was used, as suggested by [61]. It is also assumed that the leakage occurs in the production state, which means that all of the produced hydrogen will be accounted for in the analysis, although a part of it will go to the digester and become bio-e-methane. This parameter will be added to the climate analysis as it affects total GHG emissions.

3
Method and Material

3.1 Thesis Framework

The work of this thesis began with a literature search and data collection to provide a solid foundation of knowledge and understanding of the modeled system. Relevant background knowledge covered current technologies, including hydrogen production through electrolysis, biogas production in digesters, in-situ methanation for biogas upgrading, climate effects of methane and hydrogen, etc. The search primarily relied on databases such as Scopus and Google Scholar.

The data collection was based on further literature review and case-specific data provided by Tekniska Verken. When examining the selected cases, numerous parameters were required, serving both as input to the model and for subsequent calculations and analysis. Careful data collection was essential to conduct a realistic model and generate reliable outputs. Additionally, data provided by Tekniska Verken was used to generate case-specific results.

3.2 Technical Analysis

The capacity of the electrolyzer was a key parameter in this thesis. To determine the optimal capacity or maximum capacity, for each case, different methods were used. However, similar for all cases were the technical parameters found in Table 3.1.

Table 3.1: Technical parameters regarding the performance of a PEM electrolyzer.

Parameter	Value	Unit	Source
Efficiency	Varies w/ utilization & age	%	Fig. 2.8
Degradation	6.4×10^{-5}	%/ hr of operation	Calculated
Stack lifetime	10	yr	Assumption, [30]
LHV H_2	33.33	kWh/kg	[62]
H_2 production BoL	162.25	tons/MW/yr	Calculated
H_2 production EoL	147.5	tons/MW/yr	Calculated
Max stack power	100	% of max capacity	[35]
Min stack power	20	% of max capacity	[35]

Case 1: Hydrogen to bio-e-methane
For the first case, hydrogen was produced to cover the demand set by the available

CO_2 from the digester. The capacity of the electrolyzer running at full load was calculated using Eq. 2.3 and 2.4. The capacity of the electrolyzer was adjusted to account for the degradation of the electrolyzer stacks over time. To ensure that the required amount of hydrogen could still be produced throughout the lifetime, the installed capacity was increased to perfectly meet demand at the EoL. However, to avoid overproduction at the beginning of the electrolyzer lifetime, the system was modeled to operate the electrolyzer less in the early years. Once the annual production target was reached, the electrolyzer switched to standby mode. This approach minimized electricity consumption and cost while still meeting the overall hydrogen production targets.

In this context, *operation* refers to the frequency with which the electrolyzer runs at full load compared to at part load. An example of the operational behavior of the electrolyzer during its lifetime is illustrated in Figure 3.1. In contrast, Figure 3.2 showing full-load operation.

Figures 3.1 and 3.2 illustrate the degradation pattern, which restarts after 10 years when the electrolyzer stacks are assumed to be replaced. Standby time is also shown in the figures as a drop in production at the end of every year.

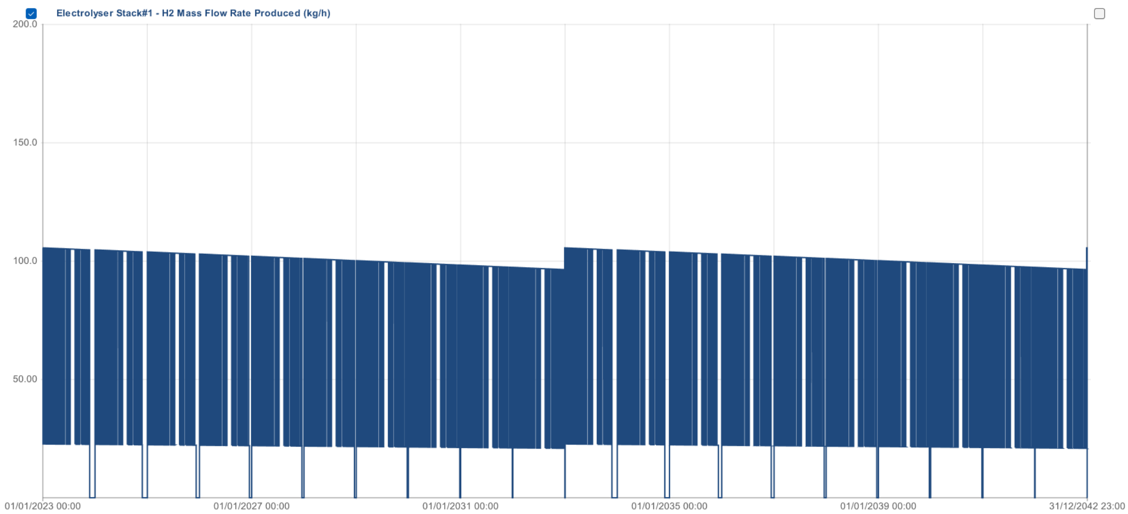


Figure 3.1: Electrolyzer operation in Case 1 under price constrain.

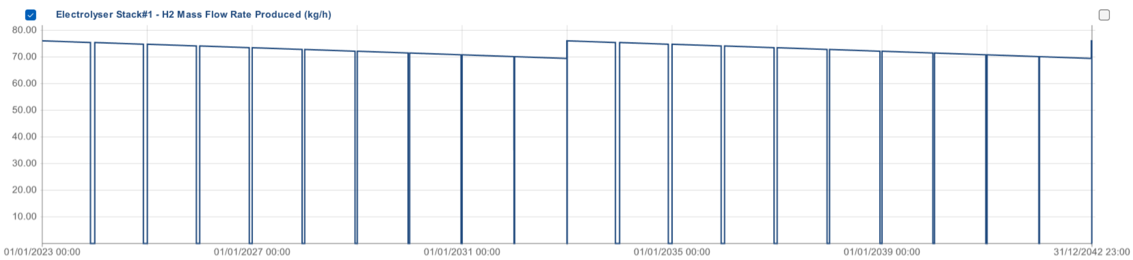


Figure 3.2: Electrolyzer operation in Case 1 at full load.

After the required electrolyzer capacity was found to cover the hydrogen demand for the biogas plant, the capacity was optimized to find the lowest total cost. As the price of electricity plays a crucial role, running at full load independent of the cost of electricity tends to result in a higher total cost. By operating the electrolyzer by setting a limit of the maximum electricity price, the highest price hour can be avoided. However, a larger electrolyzer is needed to cover the hours in which the electrolyzer runs at minimum load. Different electricity price limits were tested and the total cost was calculated iteratively until the lowest total cost was identified.

The operational setup was to run the electrolyzer at full load or minimum load, depending on the electricity prices. To calculate the required capacity needed to cover the hours when the electrolyzer operated at minimum load, the share of hours with prices at or above the specified price threshold was identified. This share was later used to scale the electrolyzer capacity. The formula developed to scale the electrolyzer capacity is presented in Eq. 3.1.

$$\text{Oversized Electrolyzer} = \frac{\text{Electrolyzer Capacity}}{x \times 0.2 \times \eta_{\text{part load}} + (1 - x) \times \eta_{\text{full load}}} \times \eta_{\text{full load}} \tag{3.1}$$

Where *Electrolyzer Capacity* is the required capacity if operating at full load independent of electricity price, x is the share of hours with electricity prices at or above the specified limit and $\eta_{\text{part load}}$ and $\eta_{\text{full load}}$ the efficiency based on the utilization rate from Figure 2.8. The fraction 0.2 represents the production level at minimum load. At maximum load, the fraction reaches 1 and is therefore not explicitly shown in the equation. The limit values of the electricity price were selected by analyzing the duration curves of the electricity price and distributing them evenly to capture the full range of electricity prices and avoid identifying a local minimum. Once initial trends were identified, a value closer to the likely minimum was tested through an iterative process. As a last step, a curve was fitted to the points to ensure that the optimal value was found. Python was used for polynomial fitting and minimum value analysis, utilizing the NumPy library for calculations and Matplotlib for visualization. The optimal value was compared with a fixed price for sales of bio-e-methane, assumed to be equal to the current market price of biogas.

Case 2: Hydrogen to bio-e-methane and for direct sales
The second case includes hydrogen sales, which enables the use of a larger electrolyzer and operation without standby mode. In contrast to Case 1, there is no defined demand for hydrogen. The electrolyzer is oversized and the overproduced hydrogen is sold. Because of this, there is no need to operate the electrolyzer in standby mode. Starting from an electrolyzer capacity that exceeds the methanation demand of Case 1 at the nearest integer, to achieve overproduction, additional capacities were modeled in steps of 1 MW up to a maximum of 10 MW. To ensure that the observed trends remain consistent at larger scales, 15 MW and 20 MW systems were also modeled. The price limits used as thresholds in Case 2 are equivalent to the most cost-optimal value found in Case 1.

The operation of a 10 MW electrolyzer in the 2023 scenario is shown in Figure 3.3. Unlike Case 1, the electrolyzer operates continuously without entering standby mode, as there is no hydrogen production limit. This allows to take advantage of low-price electricity hours throughout the entire year and over the full lifetime.

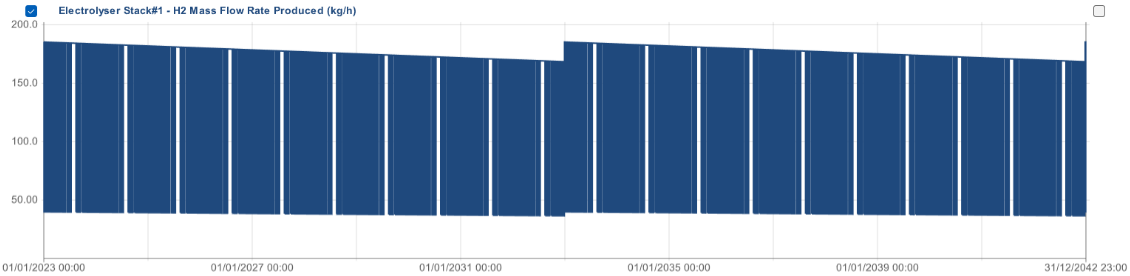


Figure 3.3: Electrolyzer operation for a 10 MW electrolyzer - Case 2, 2023 scenario.

In Case 2, the profit consists of revenue from both bio-e-methane and hydrogen sales. The price of bio-e-methane is assumed to remain equal to the current market price of biogas. However, as there is a very limited market for hydrogen today, its pricing remains highly uncertain. To address this, a break-even price was calculated, and a range of hydrogen price scenarios was tested to analyze how the revenue changes with varying hydrogen pricing.

Case 3: Hydrogen for direct sales
The third case aimed to compare the economic viability of the previous cases. To do this, the same settings as in Case 1 and Case 2 were used, but only for direct hydrogen sales.

Both current (2023) and projected future (2035) electricity prices were considered for all cases, with three different scenarios for the future.

3.3 Overview of Odyssey Software Tool

The model was created using the software program Odyssey from Seed Energy, developed to model complex energy systems. The software assesses technical, economic, and environmental parameters. In this thesis, the program was used to build and optimize the energy system needed for the three cases. After modeling the cases, the output from Odyssey was transferred to Excel to perform calculations to generate the final results. An overview of how the software tool looks can be seen in Figure 3.4.

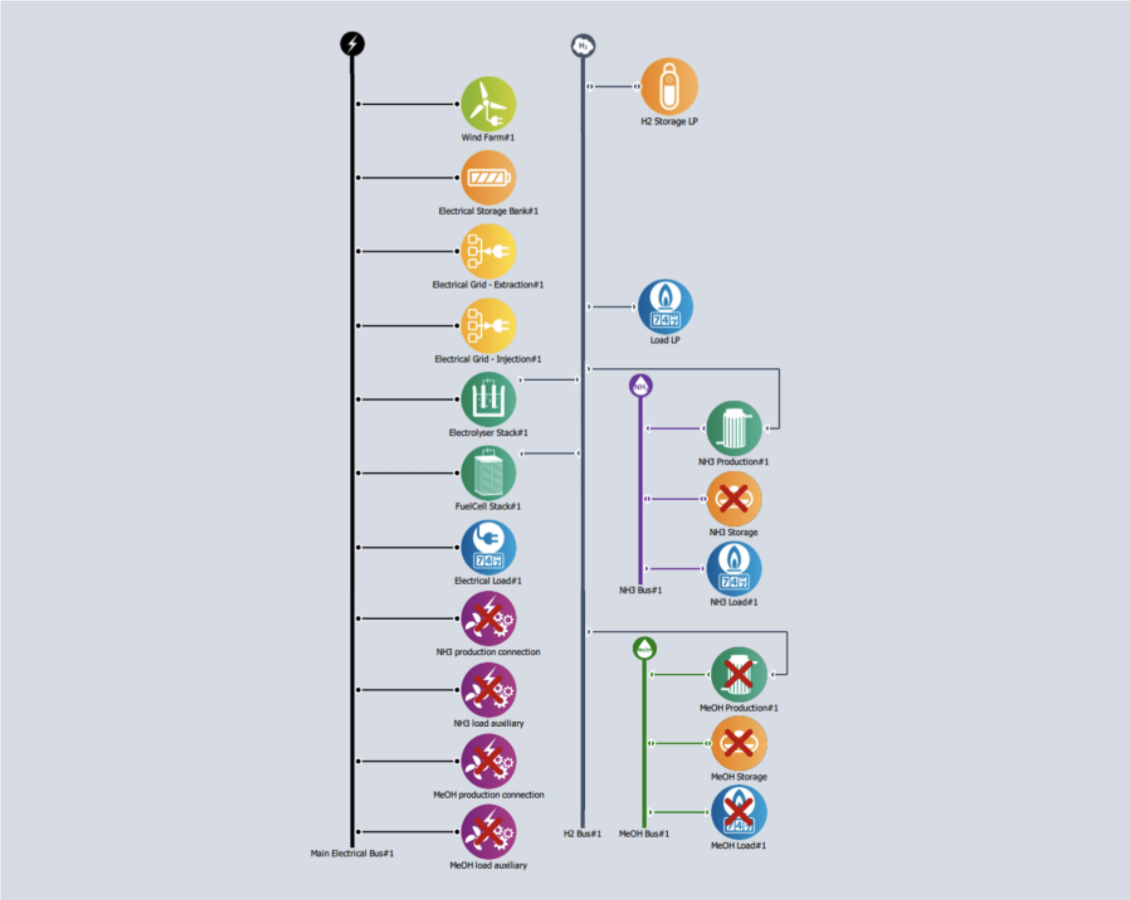


Figure 3.4: Overview of the system architecture in Odyssey.

The Odyssey modeling consists of several steps. First, the system architecture was developed by selecting the relevant components and technologies and defining the connections between them. Once the architecture was established, the components were configured to meet the desired system properties, including technical, economic, and environmental parameters. After the settings were completed, an energy management strategy had to be defined. This strategy defines how the system should operate and consists of controllers and algorithms. When all settings and strategies were in place, the dynamic simulation could be executed. Odyssey performs a time-dependent simulation considering all provided input data. The simulation results can then be analyzed through time series, performance indicators, energy flows, cost structures, and other relevant outputs.

Odyssey contains various components, each with individual settings and operational strategies (controllers). Multiple components are available to model complex systems that involve energy production, storage technologies, conversion processes, and consumption. For the purposes of this thesis, components related to hydrogen production were selected, including the main electrical bus, electrical grid extraction, electrolyzer stack, hydrogen storage tank, and hydrogen load, as illustrated in Figure 3.4. In addition to configuring individual components, general system settings were also defined, for example, system lifetime, and other overarching factors.

The main electrical bus serves as a shared connection point for distributing electrical power among various components. The electrical grid extraction component models the limitations and possibilities of electricity supply. Here, constraints on maximum grid extraction and supply availability are defined. Additionally, this component is used to configure grid extraction settings and to input electricity prices as a time series with hourly time resolution for 2023, as well as future scenarios for 2035. Key outputs from this component include the total amount of electricity extracted and the associated energy purchase costs.

The electrolyzer stack component is what has been referred to as the electrolyzer. All input data require manual input from the user in Odyssey. The parameters entered included minimum and maximum power, efficiency (defined through polynomial coefficients), ramping rates, efficiency degradation per operating hour, water consumption, stack lifetime and maximum capacity. The capacity of the electrolyzer, described in Section 3.2, varied for each case and is the only setting that differs between the cases in the electrolyzer component. The technical specifications used in the simulation are summarized in Table 3.1. Many parameters can be defined as either constant values or dynamic time-dependent profiles.

The operation of the electrolyzer can be constrained by controllers and algorithms. Controllers are used for managing the operation of the system and its components, predefined by rules and/or constraints. Algorithms are used for processing and simulating data. They define how the software calculates the outcome based on parameters, time series, and controllers.

The modeling was governed by controllers 8 or 10 and 2 (see Table 3.2). The outputs from the electrolyzer component include the consumed electrical power, the produced hydrogen mass flow rate, and other relevant performance indicators.

Control	**Description**
Start stop control - Algorithm 10	H_2 production units are started as soon as they are commissioned and/or leave maintenance and are never stopped.
Start stop control - Algorithm 8	H_2 production units are started when the H_2 storage reaches <SOC Start> and stops when it reaches <SOC Stop>.
Production constraint - Algorithm 2	Hydrogen production operates at maximum power when the electrical flexible extraction price is lower than <Grid extraction - Maximum price> (defined either by a constant or by $a_0 + a_1$ $\cdot timeseries).Hydrogenproductionoperatesatminimumpowe$

Table 3.2: Overview of hydrogen production control strategies

Finally, the hydrogen tank together with the hydrogen load component is used to simulate the hydrogen demand. The hydrogen tank is used as a tool since there is no real storage within the system. The hydrogen load is the component where the consumption profile is defined.

3.4 Economic Analysis

The economic analysis was centered on the total annual costs and revenues associated with each case, as defined by Eq. 3.2. The calculations were performed using Odyssey and Excel, with an emphasis on modeling the scenarios based on key economic parameters such as hydrogen demand, electrolyzer capacity, and electricity consumption. A complete overview of the parameters applied in the economic evaluation is presented in Table 3.3. All economic values are given in euros (€, EUR) for the final results.

The total annual cost (see Eq. 3.2) includes both Capital Expenditures (CAPEX) and Operating Expenditures (OPEX), which together form the basis of the economic assessment. Particular emphasis was placed on the resulting production costs of bio-e-methane and hydrogen, as these are directly related to the research questions guiding the thesis.

$$\text{Total Annual Cost} = (CAPEX \cdot CRF) + OPEX_{fix} + OPEX_{var} \tag{3.2}$$

CAPEX is the money invested for new assets, facilities, and to deliver new products [63]. It includes the cost of investment, such as the cost of the electrolyzer, installation costs, etc. The total CAPEX is the sum of all investment and fixed costs per unit, see Eq. 3.3. CRF is the *Capital Recovery Factor*, see Eq. 3.4, which is used to obtain the annual investment cost by multiplying CAPEX with CRF (as seen in Eq. 3.2). The technical lifetime of our system was 20 years and the rate 6%, which are thesis-specific numbers given by Tekniska Verken.

$$CAPEX_{tot} = \sum_{n=1}^{n} CAPEX_n \tag{3.3}$$

$$CRF = \frac{r \cdot (1+r)^t}{(1+r)^t - 1} \tag{3.4}$$

Where r is the interest rate and t the lifetime of the investment.

Furthermore, in contrast to CAPEX, OPEX includes the operating expenses, i.e. costs for employees' salary, day-to-day expenditures, maintenance costs, utility consumption, repair costs, etc [63]. Hence, it includes both fixed and variable costs. The total OPEX is calculated as the sum of all individual operating cost components, as shown in Eq. 3.5.

$$OPEX_{tot} = \sum_{n=1}^{n} OPEX_n \tag{3.5}$$

For the purposes of this thesis, OPEX is divided into two main categories:

- **Fixed, $\mathbf{OPEX_{fix}}$**: This includes Operation and Maintenance (O&M) costs, which are calculated as a fixed percentage of CAPEX, and 4% was used [64]. This approach reflects common industry practice and was applied throughout the analysis, as shown in Eq. 3.6.
- **Variational, $\mathbf{OPEX_{var}}$**: This category includes electricity costs, water consumption, and other operational expenses that vary with system performance or external conditions, and are of particular relevance in the context of this thesis.

$$OPEX_{fix} = CAPEX \cdot 4\% \tag{3.6}$$

In addition, the Payback Period (PBP) [years], see Eq. 3.7, was calculated for the cases where it was found to be suitable. This was done to identify which scenarios, based on hydrogen price and electrolyzer capacity, resulted in an acceptable time frame. It is important to note that this calculation differs from the others, as it does not include the CRF. In this thesis, it was assumed that the PBP should be calculated without taking financial costs into account. Instead, the PBP was calculated by dividing the initial investment cost from the first year [EUR] by the annual cash flow [EUR/year], defined as the yearly profit, subtracting the variable costs.

$$\text{Payback period} = \frac{\text{Initial Investment Cost}}{\text{Annual Cash Flow}} \tag{3.7}$$

Table 3.3: Parameters used for the economic analysis.

Parameter	Value	Unit	Reference
Electrolyzer investment cost	1 800	EUR/kWe	[65]
Electricity cost (2023)	Time series	EUR/MWh	[1]
Electricity cost RSF (2035)	Time series	EUR/MWh	Tekniska Verken
Electricity cost ESF (2035)	Time series	EUR/MWh	Tekniska Verken
Electricity cost CCT (2035)	Time series	EUR/MWh	Tekniska Verken
Water cost	0.07	SEK/liter	[66]
O&M cost	4	% of CAPEX	[64]
Intrest rate	6	%	Tekniska Verken
Lifetime	20	yrs	Tekniska Verken
CRF	0.087	-	Calculated
Stack replacement cost	234	EUR/kWe	[67]
Biogas market price	23.05	SEK/kg	[68]
Compression cost	1.75	EUR/kg	[69]
Annualized investment cost	156.9	EUR/kW/yr	Calculated
Annualized replacement cost	20.4	EUR/kW/yr	[67]
SEK to EUR	0.09	EUR/SEK	*Assumption* (March, 2025)

The difference between the first case and the others is that the cost of compression was added since this was not needed for Case 1, but when hydrogen is produced for direct sales, it was needed.

The terms electricity cost and electricity price are used alternately throughout the thesis, depending on the context. Electricity price refers to market scenarios and price variations, whereas electricity cost refers to the expense generated when electricity is consumed. Recall that the electricity price is defined as the cost of electricity alone, excluding taxes and grid-related fees.

3.5 Climate Analysis

The carbon footprint analysis was applied to all three cases, focusing specifically on electricity flows and gas leakages. The scope of this assessment was intentionally limited, as a broader analysis, such as incorporating the existing biogas plant, materials for various system components, and other factors, fell outside the scope of this thesis. The electricity consumed associated with the water consumption was assumed to be integrated into the electricity consumption of the electrolyzer. This assumption was based on the fact that the electrolyzer under consideration required water of quality in line with the EU Directive 2020/2184-EU [35], which defines water suitable for human consumption [70]. Consequently, it was assumed that water could be sourced directly from the tap, removing the need for additional purification processes that would otherwise consume electricity.
Using case-specific data, the total emissions were calculated as the sum of all relevant sources, expressed in terms of both GWP_{20} and GWP_{100}. The following tables present the input data for each component considered in the respective cases.

Case 1: Hydrogen to bio-e-methane
For the purpose of producing bio-e-methane by injection of hydrogen into the post-digester, hydrogen production meets only the demand to convert existing CO_2 to bio-e-methane. See Table 3.4 for all parameters.

Table 3.4: Parameters used for carbon footprint analysis of Case 1.

Parameter	Value	Unit	Reference
Electrolyzer electricity consumption			
2023	34 429.6	MWh/yr	Calculated
RSF	33 938.2	MWh/yr	Calculated
ESF	34 072.1	MWh/yr	Calculated
CCT	34 381.3	MWh/yr	Calculated
H_2 production	610.16	tons H_2/yr	Calculated
Bio-e-methane production	1 093.4	tons	Calculated
Grid electricity emission factor	0.019	ton CO_2/MWh	[71]
H_2 leakage rate	4	%	[61]
Methane leakage rate	0.2	%	Tekniska Verken
GWP_{20} - CH_4	85.5	kg CO_2eq/kg CH_4	[53]
GWP_{100} - CH_4	28	kg CO_2eq/kg CH_4	[53]
GWP_{20} - H_2	40	kg CO_2eq/kg H_2	[59]
GWP_{100} - H_2	13	kg CO_2eq/kg H_2	[59]

Case 2: Hydrogen to bio-e-methane and hydrogen to refueling
For the purpose of producing and injecting hydrogen into the post-digester to produce bio-e-methane, and to over-produce hydrogen to sell as a product by itself at a nearby refueling station. See Table 3.5 for all parameters. Produced hydrogen and compressed hydrogen are treated separately, as not all the hydrogen produced is compressed; a portion is directed to the digester, while the remaining hydrogen is compressed. Therefore, the difference between the hydrogen demand and the actual hydrogen production represents the volume of hydrogen that requires compression.

Table 3.5: Parameters used for carbon footprint analysis of Case 2.

Parameter	Value	Unit	Reference
Electrolyzer electricity consumption			
2023	50 137.6	MWh/yr	Calculated
RSF	40 579.2	MWh/yr	Calculated
ESF	45 993.6	MWh/yr	Calculated
CCT	65 846.4	MWh/yr	Calculated
H_2 production			
2023	893 600	kg H_2/yr	Calculated
RSF	728 050	kg H_2/yr	calculated
ESF	821 850	kg H_2/yr	Calculated
CCT	1 166 000	kg H_2/yr	Calculated
Compressed hydrogen			
2023	283 440	kg H_2/yr	Calculated
RSF	117 890	kg H_2/yr	Calculated
ESF	211 690	kg H_2/yr	Calculated
CCT	555 840	kg H_2/yr	Calculated
H_2 Demand	610.16	tons H_2/yr	Calculated
Bio-e-methane production	1 093.4	tons	Calculated
Grid electricity emission factor	0.019	ton CO_2/MWh	[72]
H_2 leakage rate	4	%	[61]
Methane leakage rate	0.2	%	Tekniska Verken
Compression electricity consumption	3	kWh/kg H_2	[73]
GWP_{20} - CH_4	85.5	kg CO_2eq/kg CH_4	[53]
GWP_{100} - CH_4	28	kg CO_2eq/kg CH_4	[53]
GWP_{20} - H_2	40	kg CO_2eq/kg H_2	[59]
GWP_{100} - H_2	13	kg CO_2eq/kg H_2	[59]

Case 3: Direct sale of Hydrogen for refueling
For the purpose of producing hydrogen solely to sell to a refueling station, it is assumed that the entire amount of hydrogen produced is compressed. See Table 3.6 for all parameters.

Table 3.6: Parameters used for carbon footprint analysis of Case 3.

Parameter	Value	Unit	Reference
Electrolyzer electricity consumption			
2023	50 137.6	MWh/yr	Calculated
RSF	40 579.2	MWh/yr	Calculated
ESF	45 993.6	MWh/yr	Calculated
CCT	65 846.4	MWh/yr	Calculated
H_2 production			
2023	893 600	kg H_2/yr	Calculated
RSF	728 050	kg H_2/yr	calculated
ESF	821 850	kg H_2/yr	Calculated
CCT	1 166 000	kg H_2/yr	Calculated
Compressed hydrogen			
2023	893 600	kg H_2/yr	Calculated
RSF	728 050	kg H_2/yr	Calculated
ESF	821 850	kg H_2/yr	Calculated
CCT	1 166 000	kg H_2/yr	Calculated
Grid electricity emission factor	0.019	ton CO_2/MWh	[72]
Compression electricity consumption	3	kWh/kg H_2	[73]
H_2 leakage rate	4	%	[61]
GWP_{20} - H_2	40	kg CO_2eq/kg H_2	[59]
GWP_{100} - H_2	13	kg CO_2eq/kg H_2	[59]

Calculations

For each case, the total emissions were calculated by summing all individual emission sources, as defined in Equation 3.8. Specifically, this includes emissions from electricity consumption by the electrolyzer, hydrogen leakage, methane leakage, and hydrogen compression, both from the production of bio-e-methane and any additional hydrogen produced for sale. The resulting values are expressed as total CO_2 equivalents for each case and scenario, across the different GWP values.

$$\text{Total } CO_2\text{eq} = \sum (\text{Consumed Energy} \cdot \text{Emission Factor}) + \text{Leaked Emissions} \tag{3.8}$$

Comparison

It was of interest to compare the cases and scenarios. What was the carbon footprint for each case? Which scenario had the lowest carbon footprint?

Moreover, a reference point was added for perspective. Germany is one of the largest biogas producers in the world [74], and therefore, the same calculations for the process emissions were added to the analysis, however, with the grid emission factor for Germany (0.354 kg CO_2/kWh [71]). This was done to estimate the emissions and to see a potential difference if the system was implemented in Germany instead of Sweden.

4

Results and Analysis

In this chapter, the results for each case are presented from a techno-economic and climate perspective. The modeling with Odyssey, analysis, and other calculations were based on information from Tekniska Verken: that 3 000 tons CO_2 is available for methanation per year. From this, Eq. 2.5 is used to calculate that 610.16 tons of hydrogen per year would be needed to match the available CO_2 supply from the digester, and then the calculations and modeling were based on this information.

4.1 Case 1

This section presents results for Case 1: Hydrogen for Bio-e-methane. The techno-economic analysis begins with the annual cost at full electrolyzer load, followed by system optimization for cost minimization. Economic viability is assessed by comparing costs with revenues. Lastly, climate impact is evaluated using GWP_{20} and GWP_{100}, and compared to other electricity mixes.

4.1.1 Techno-Economic Analysis

The objective of the techno-economic analysis for Case 1 is to find the optimal electrolyzer capacity in combination with the optimal electricity price constraint to achieve the lowest total cost while meeting the demand for hydrogen to the digester for each scenario.

Before optimizing the system, the minimum electrolyzer capacity required to cover the demand was calculated. The minimum capacity assumes continuous operation at full load, regardless of electricity cost and is therefore valid across all scenarios. The required capacity was determined to be 4.1 MW. The corresponding annual costs are 2.59 MEUR for the 2023 scenario, 3.48 MEUR for RSF, 3.12 MEUR for ESF, and 2.52 MEUR for the CCT scenario. A cost breakdown for the 2023 scenario is shown in Figure 4.1 as an example. A similar pattern can be observed in all cases.

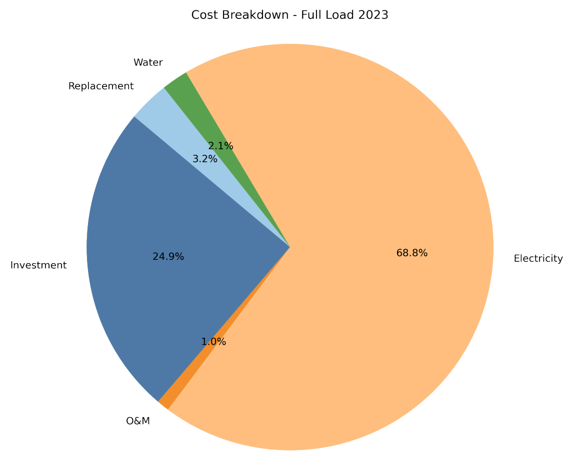


Figure 4.1: Cost breakdown for an electrolyzer operating at full load - Case 1, 2023 scenario.

The total cost could be divided into two parts: the cost of electricity and other associated costs. The latter includes the investment cost, replacement cost, O&M costs, and water cost. All of these costs increase linearly with the capacity of the electrolyzer, with the exception of the cost of water, which remains constant regardless of the capacity. In contrast, the cost of electricity decreases non-linearly as the electrolyzer capacity increases. The balance between these two components results in a minimum point, representing the lowest total cost. The results can be found in Table 4.1.

Table 4.1: Results on cost-optimal electrolyzer for each scenario, together with which price constraint, the resulting operational time, the total cost and PBP.

	2023	**RSF**	**ESF**	**CCT**
Electrolyzer capacity [MW]	5.7	7.0	6.2	4.4
Price Constraint [EUR/MWh]	59	90	82	75
Operational Time [%]	64	47	57	92
Total Cost [MEUR/yr]	2.17	3.08	2.94	2.49
Payback Period [yr]	10.3	31.8	28.3	15.7

As shown in Table 4.1, adapting operation to low electricity price hours reduces annual costs across all scenarios. The cost reduction reaches up to 16%, as observed in the 2023 scenario. The cost breakdown for optimal operation in the 2023 scenario is shown in Figure 4.2.

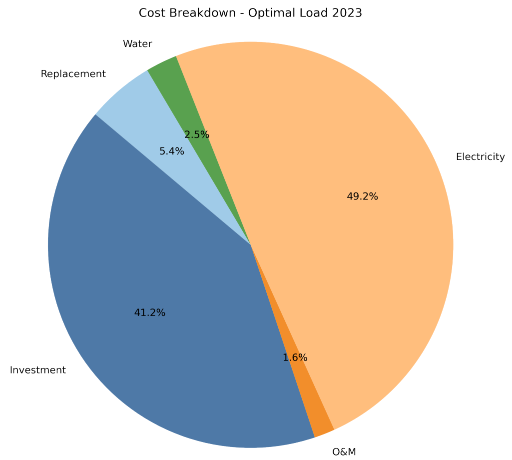


Figure 4.2: Cost breakdown for an electrolyzer operating at optimal load - Case 1, 2023 scenario.

The cost-optimal price constraint results in variable operation of the electrolyzer across the different scenarios. The cost-optimal point is visualized in Figure 4.3.

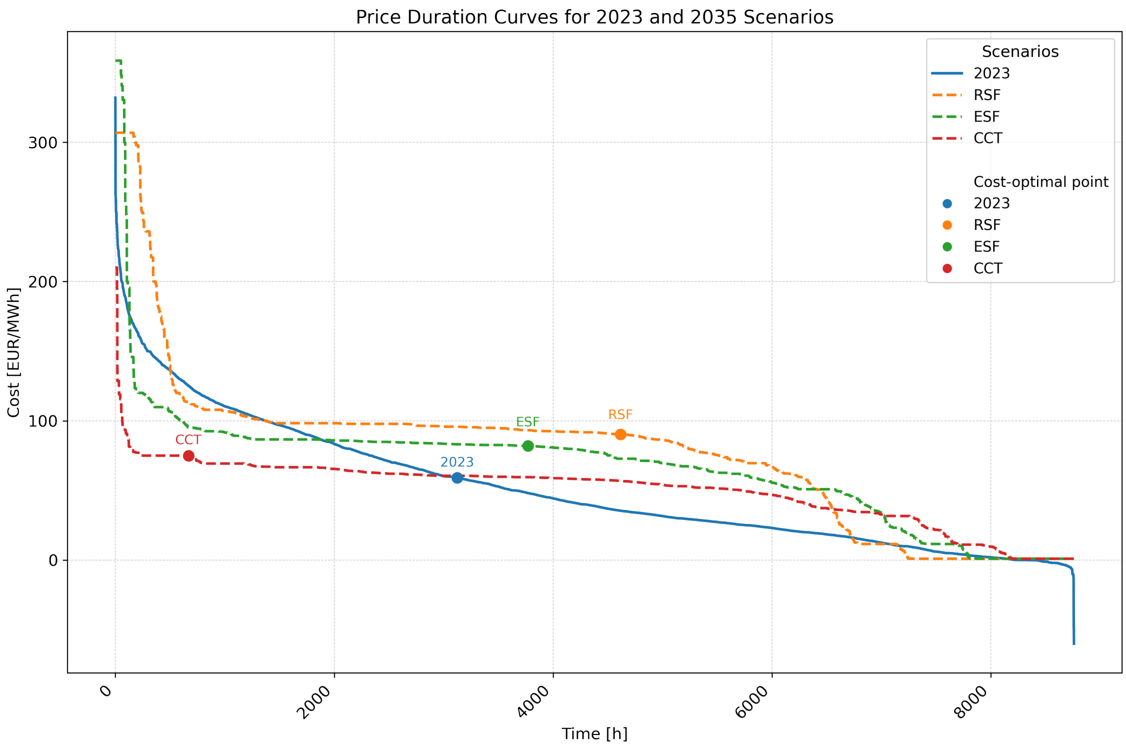


Figure 4.3: Price duration curves for each scenario including cost-optimal point.

It is evident from Figure 4.3 that variations in electricity prices have a great impact on the electrolyzer operation strategy to minimize the total cost. For instance, the cost-optimal point for the RSF scenario occurs after half of the total hours in a year, meaning it is most cost-efficient to operate the electrolyzer only about 50% of the time under this specific electricity price variation. In contrast, the CCT scenario, characterized by generally lower predicted electricity prices, makes it more cost-effective to invest in a smaller electrolyzer and operate it over 90% of the time. The share of hours in operation for each price scenario can be found in Table 4.1.

In addition, the variability in operation greatly affects the required capacity to meet the demand. Since the electrolyzer in a RSF scenario only operates half of the time, an electrolyzer with a capacity of 7 MW is required. With the CCT scenario, an electrolyzer capacity of 4.4 MW is sufficient to cover the demand.
The total revenue represents the profit made from the sale of bio-e-methane, which is produced by injecting hydrogen into the digester. In Case 1, the electrolyzer is adjusted to match the hydrogen demand of the digester. As a result, the total amount of bio-e-methane produced remains constant regardless of the electrolyzer capacity, and therefore the revenue is constant at 2.29 MEUR/yr across all electrolyzer capacities and all scenarios. The revenue, together with the total cost over varying electrolyzer capacity, is shown in Figure 4.4 - 4.7 for the different scenarios of the future electricity price.

Furthermore, the electrolyzer capacities that result in profit are marked in green while the capacities that result in a loss are indicated in red. At an electrolyzer capacity of 4.1 MW, the system operates at full load regardless of the electricity price. At this point, electricity costs are at their highest and investment costs are at their lowest level, while still producing enough hydrogen to meet the demand. Regarding the 2023 price variation, the cost exceeds the revenue up to a capacity of 4.68 MW, and from this point up to 7.06 MW, the revenue exceeds the total cost. Beyond this point, electricity costs continue to decrease, but the increasingly high investment cost prevents further profitability, which is visualized in Figure 4.4.

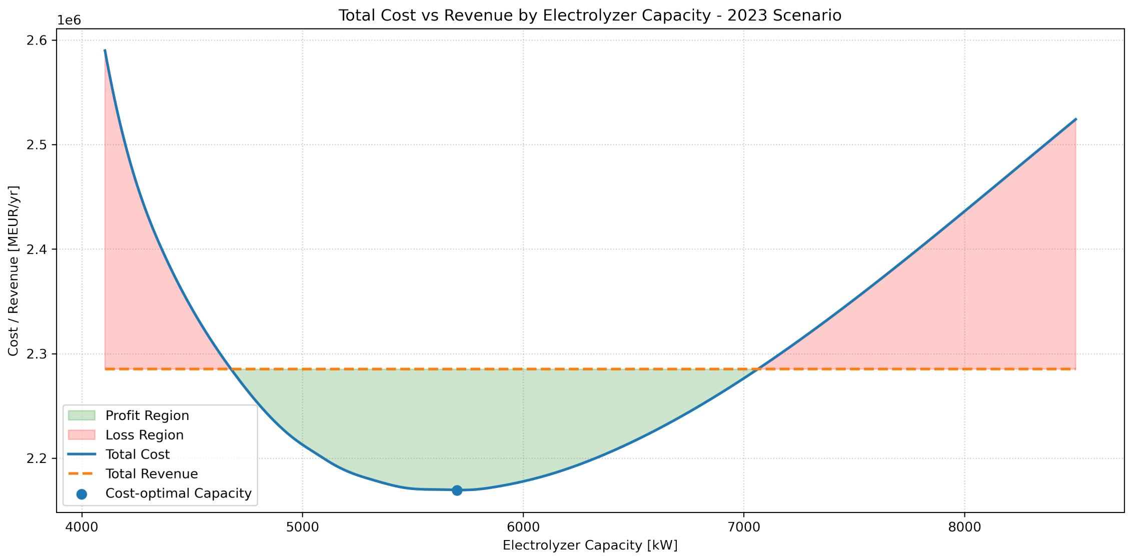


Figure 4.4: Total cost and revenue by electrolyzer capacity for electricity variations 2023, Case 1.

When examining the future scenarios, it is evident from Figure 4.5, 4.6, and 4.7 that the total cost exceeds the total revenue in all cases. However, since the revenue is based on the current market price of biogas, the results remain insightful despite the lack of profitability, for instance, how the total cost varies with different electrolyzer capacities. In the RSF scenario, the total cost drops at first, followed by a relatively stable trend, with only a small difference in total cost between 4.5 MW and 9.5 MW. A similar pattern with a stable range between 4.5 MW and 7.5 MW is also observed in the EST scenario. The wide range of relatively similar total costs allows for investment flexibility with respect to interests beyond just total cost. In contrast, the CCT scenario shows a notable increase in total cost for capacities that deviate from the cost-optimal point, indicating lower flexibility in the CCT scenario.

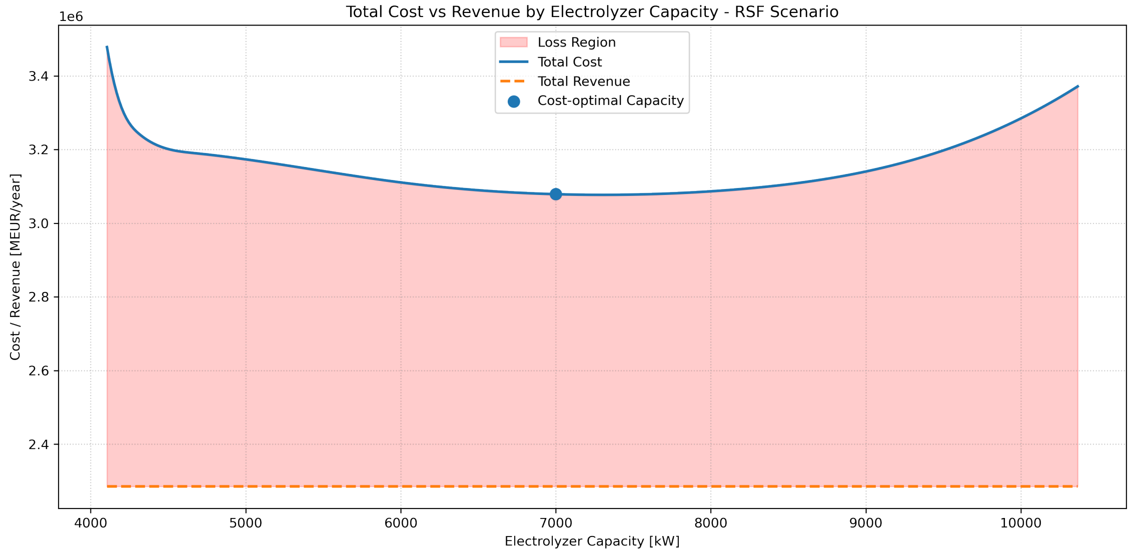


Figure 4.5: Total cost and revenue by electrolyzer capacity for electricity variations in the RSF scenario, Case 1.

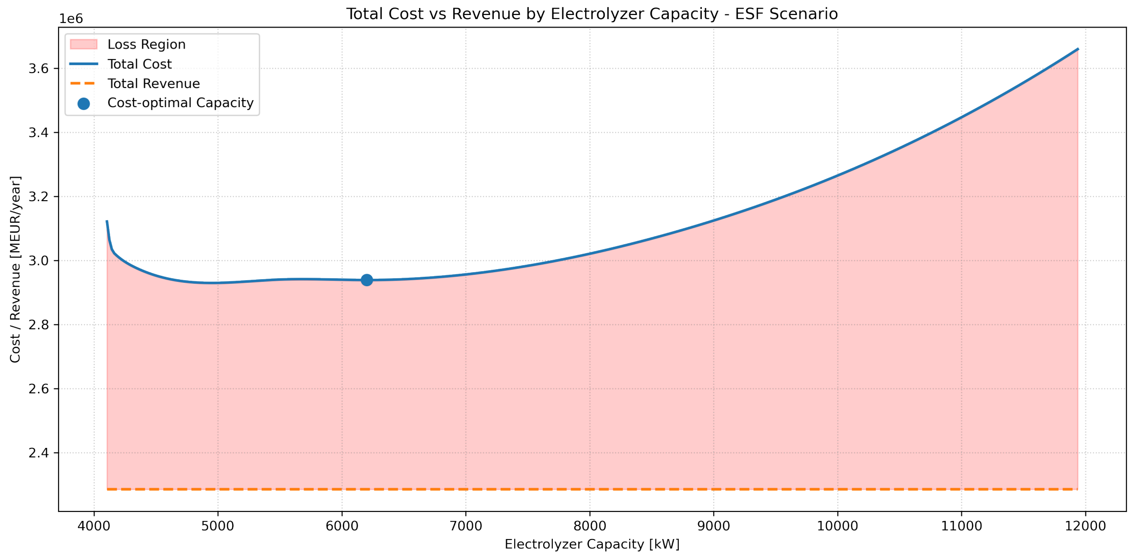


Figure 4.6: Total cost and revenue by electrolyzer capacity for electricity variations in the ESF scenario, Case 1.

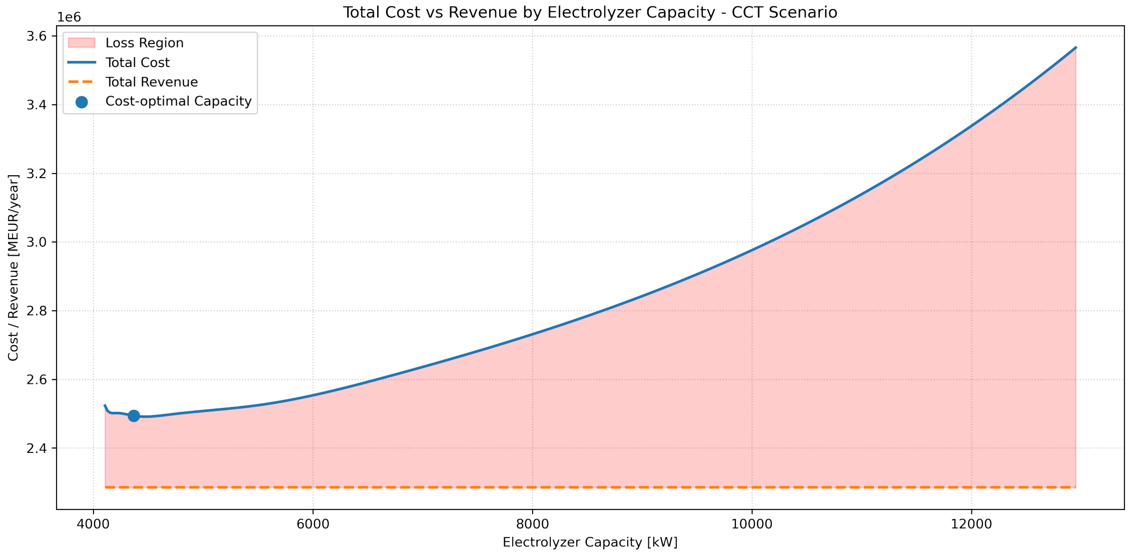


Figure 4.7: Total cost and revenue by electrolyzer capacity for electricity variations in the CCT scenario, Case 1.

For future scenarios to break even, a bio-e-methane price of 2.82 EUR/kg, 2.69 EUR/kg and 2.28 EUR/kg for RSF, ESF and CCT would be required respectively. The corresponding value for 2023 is 1.98 EUR/kg. This could be compared to the current market price of methane of 2.09 EUR/kg.

As seen in Table 4.1, the PBP for the 2023 scenario was calculated to be 10.3 years, indicating a relatively long time in relation to the system lifetime. For the RSF and ESF scenarios, the PBP is more than 20 years, which is more than the system's lifetime. For the CCT scenario, the PBP was 15.7 years.

4.1.2 Climate Analysis

The carbon footprint results for Case 1 are presented in Table 4.2, with both specific and common emissions detailed. The total emissions have been summarized using the two GWP values.

Table 4.2: Carbon Footprint by Emission Source and Scenario – Case 1

Emission source	**Value [ton CO_2eq]**
Electrolyzer electricity emissions (per scenario)	
2023	654.2
RSF	644.8
ESF	647.4
CCT	653.2
Total emissions per source (independent of scenario)	
$E_{H2,leak,GWP20}$	976.3
$E_{H2,leak,GWP100}$	317.3
$E_{CH4,leak,GWP20}$	187.0
$E_{CH4,leak,GWP100}$	61.2
Total CO_2 emissions 2023 - GWP_{20}	1 817
Total CO_2 emissions 2023 - GWP_{100}	1 033
Total CO_2 emissions RSF - GWP_{20}	1 808
Total CO_2 emissions RSF - GWP_{100}	1 023
Total CO_2 emissions ESF - GWP_{20}	1 811
Total CO_2 emissions ESF - GWP_{100}	1 026
Total CO_2 emissions CCT - GWP_{20}	1 816
Total CO_2 emissions CCT - GWP_{100}	1 032

For clarity and ease of analysis, the summarized carbon footprint for each scenario and GWP value for Case 1 is illustrated in Figure 4.8.

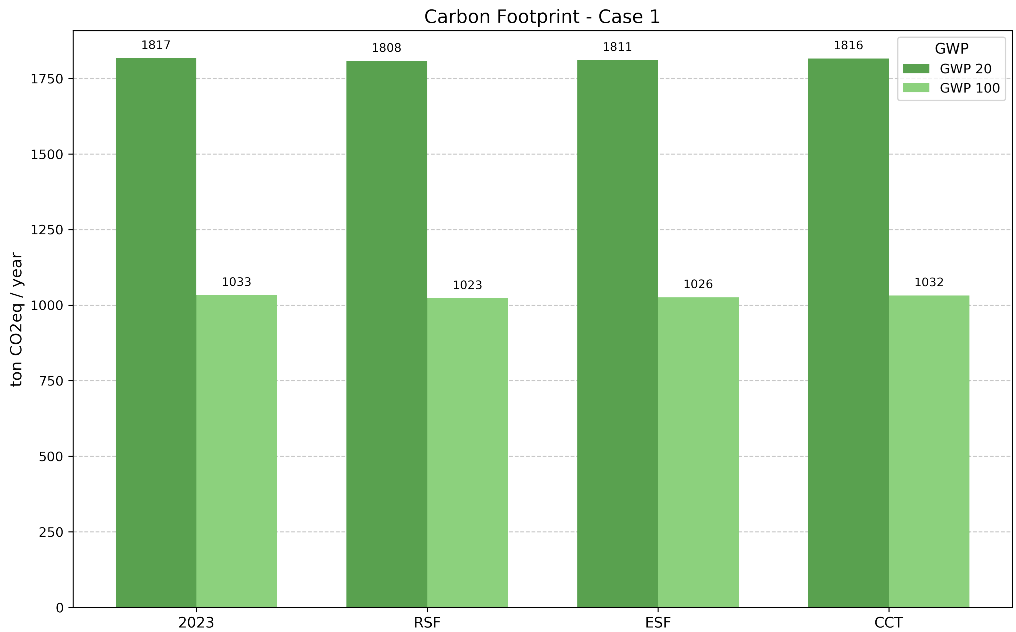


Figure 4.8: Carbon Footprint by Scenario for Case 1.

The results show that the differences between the scenarios are minimal. This was expected, as the amount of hydrogen and bio-e-methane produced is the same in each case, and the electricity consumption is also nearly identical. As a result, the carbon footprints of the cases are very similar. The small differences in electricity consumption can be attributed to rounding during the calculation and modeling processes. Moreover, the results show a significant difference between the two GWPs, with GWP_{20} yielding the highest emissions across all scenarios.

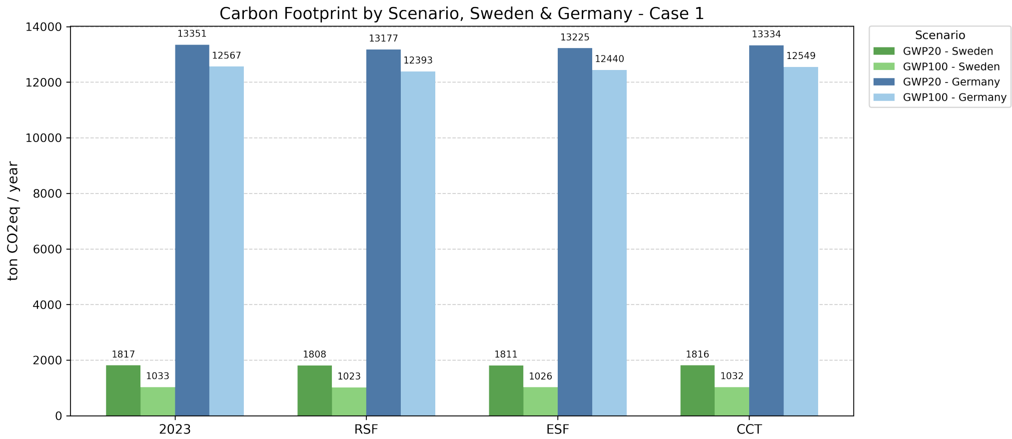


Figure 4.9: Carbon Footprint by Scenario, Sweden & Germany - Case 1.

Figure 4.9 shows how large the emissions would be if the exact same system was placed in Germany. Important to note that the green bars are the same as in Figure 4.8, only now some perspective is added. From this, it is clear that the emissions in Sweden are small in comparison to if the system were placed in Germany. This indicates how important it is with a low-carbon electricity mix.

4.2 Case 2

In this section, the results for Case 2 are presented. Case 2 includes hydrogen production for direct sales in addition to production for the digester. As in Case 1, the total annual cost is presented. However, since there is no fixed hydrogen demand, a range of electrolyzer capacities is modeled. The Levelized Cost of Hydrogen (LCOH) is calculated, and a sensitivity analysis on hydrogen pricing is carried out to evaluate economic viability. Finally, the climate impact is assessed, analyzed, and compared using different electricity mixes.

4.2.1 Techno-Economic Analysis

In Case 2, the objective was to evaluate whether investing in a larger electrolyzer would be profitable by increasing the revenue from direct hydrogen sales. Thus, in Case 2, the profit is a combination of bio-e-methane and hydrogen sales. Since the demand for hydrogen in the digester is fixed, the revenue from bio-e-methane remains constant for all electrolyzer capacities and is independent of the hydrogen pricing. To avoid an excessive number of unknown parameters, the price of bio-e-methane is assumed to be the current market price of biogas for all scenarios, including future scenarios.

Since all electrolyzer capacities in each scenario have the same electricity price threshold, all parts of the total cost depend on the capacity of the electrolyzer. Hence, the total cost increases linearly with the electrolyzer capacity (see Figure 4.10). Note that the starting point differs between scenarios. This is because each scenario requires a specific electrolyzer capacity to meet the hydrogen demand for bio-e-methane production due to the defined price threshold. The starting point reflects the capacity needed to meet the demand for the digester as well as an over-production of hydrogen for direct sales.

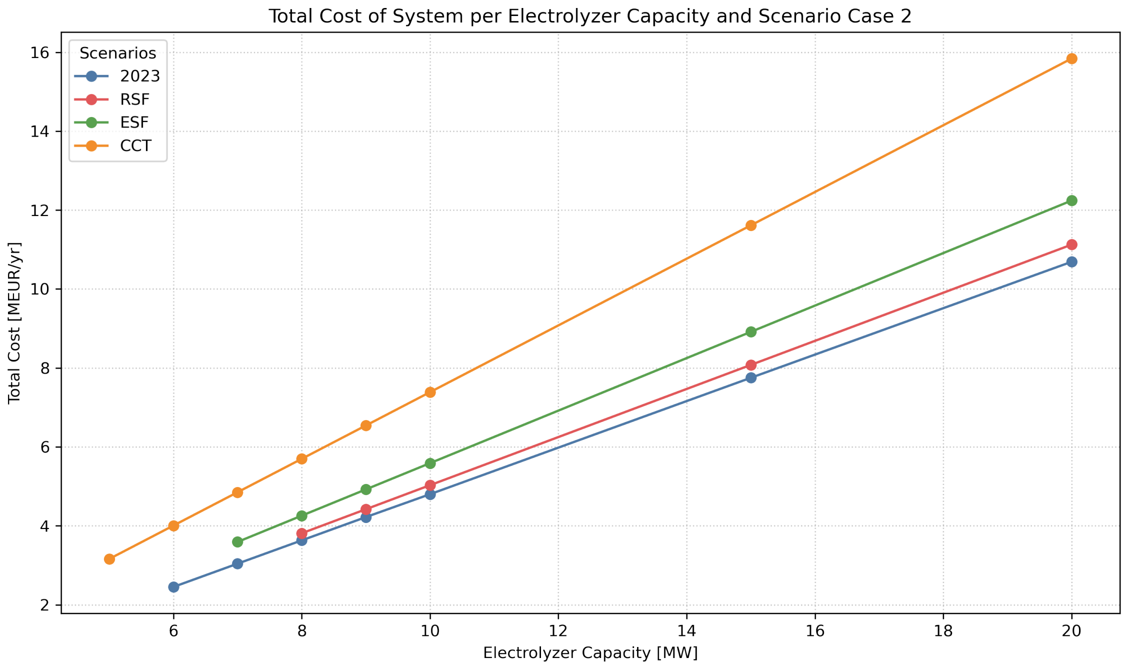


Figure 4.10: Total system cost for different electrolyzer capacities and scenarios, Case 2.

Figure 4.11 shows how the costs are divided for a 10 MW electrolyzer in the 2023 scenario. Although all parts of the total cost increase linearly with rising electrolyzer capacity, the rate of increase differs between them. As a result, the relative share of each part in the total cost varies depending on the electrolyzer capacity, meaning that this share is not equal for all electrolyzer capacities.

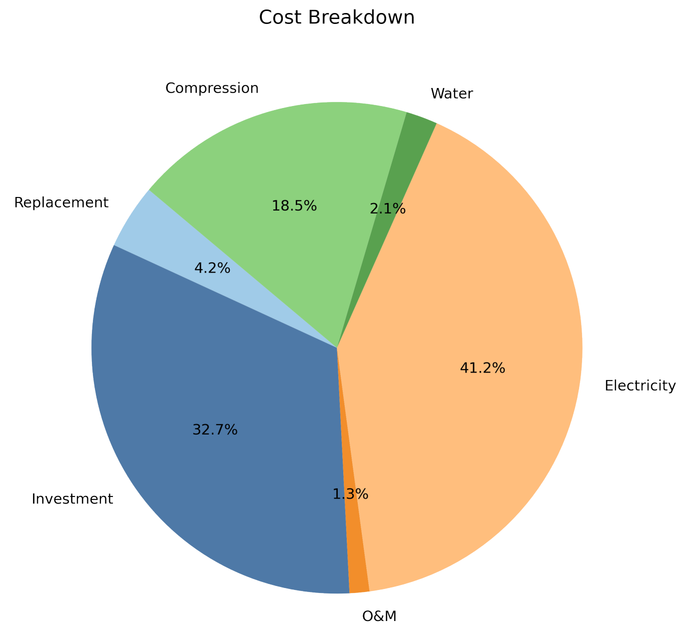


Figure 4.11: Cost breakdown for a 10 MW electrolyzer - Case 2, 2023 scenario.

Moreover, different capacities produce different amounts of hydrogen, which results in a varying break-even price for hydrogen to cover the corresponding total cost. Figure 4.12 shows the LCOH for each electricity price scenario and every capacity. The difference in starting points between the scenarios remains consistent with the explanation provided in the previous paragraph.

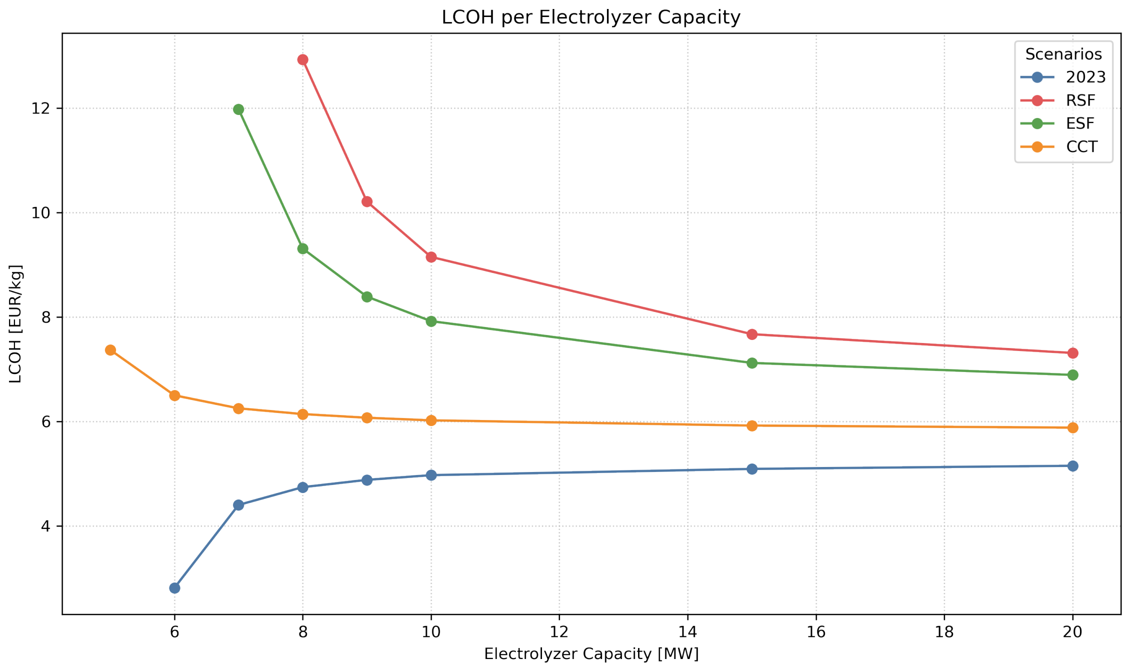


Figure 4.12: LCOH for different electrolyzer capacities and scenarios, Case 2.

For all future scenarios, the LCOH decreases from a high initial value and gradually stagnates at a lower value. In contrast, the 2023 scenario begins with a lower LCOH that steadily increases over increasing electrolyzer capacity. The LCOH stabilizes slightly above 5 EUR/kg of hydrogen for the 2023 scenario. In the RSF scenario, it levels off at approximately 7.3 EUR/kg, while in the ESF and CCT scenarios, it stabilizes at around 6.9 EUR/kg and 5.9 EUR/kg, respectively.

This pattern can be explained by the profitability of bio-e-methane production. From the results of Case 1, it was evident that the 2023 scenario was the only scenario with profitability. The future scenarios showed more or less unprofitable outcomes. With an unprofitable bio-e-methane production, hydrogen sales must compensate. As the capacity of the electrolyzer increases, a growing share of hydrogen becomes available for direct sale, making the share of unprofitable bio-e-methane production per kilogram of hydrogen less significant. Among the unprofitable scenarios, the RSF scenario results in the highest LCOH across all electrolyzer capacities, primarily due to the generally higher electricity cost associated with this scenario. On the other hand, the 2023 scenario has a profit from bio-e-methane production, therefore, there is a profit to divide the produced hydrogen to lower the break-even price. This profit also becomes less significant with increasing electrolyzer capacity, i.e. with increasing hydrogen production.

The LCOH represents the minimum price of hydrogen required to break even. Any increase in the price of hydrogen beyond this threshold results in a profit, and the profitability is highly sensitive to the hydrogen price. As there is currently no stable market for hydrogen, a range of price scenarios are tested to evaluate how the revenue changes. Figures 4.13 to 4.16 illustrate the impact of hydrogen pricing on overall profits.

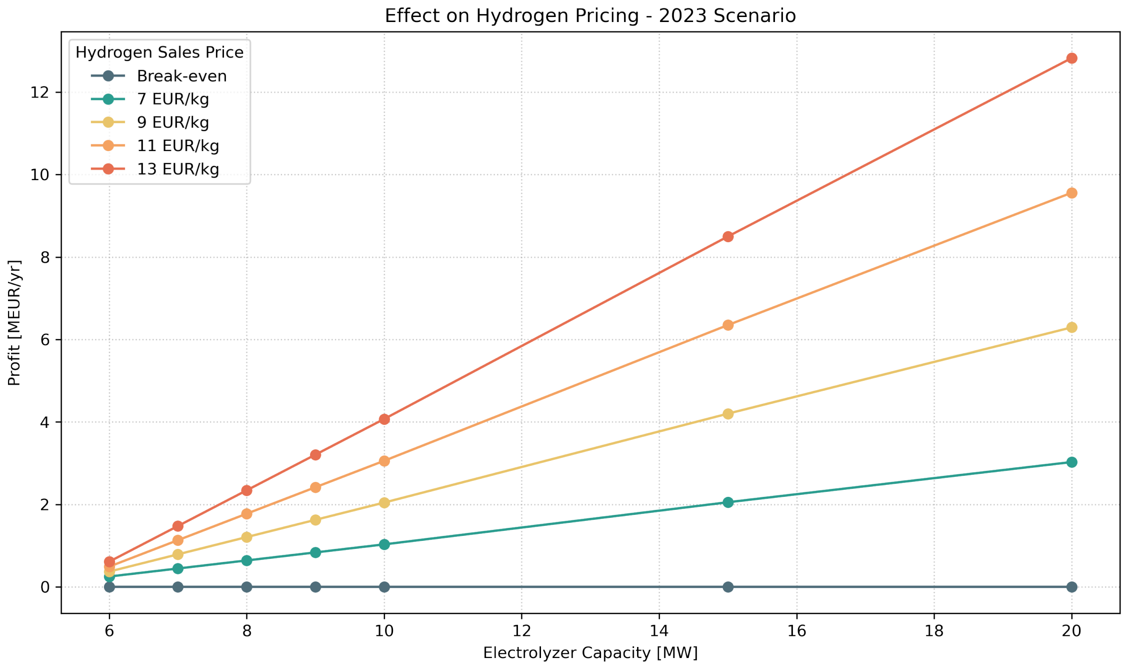


Figure 4.13: Effect on hydrogen pricing for Case 2, 2023 scenario.

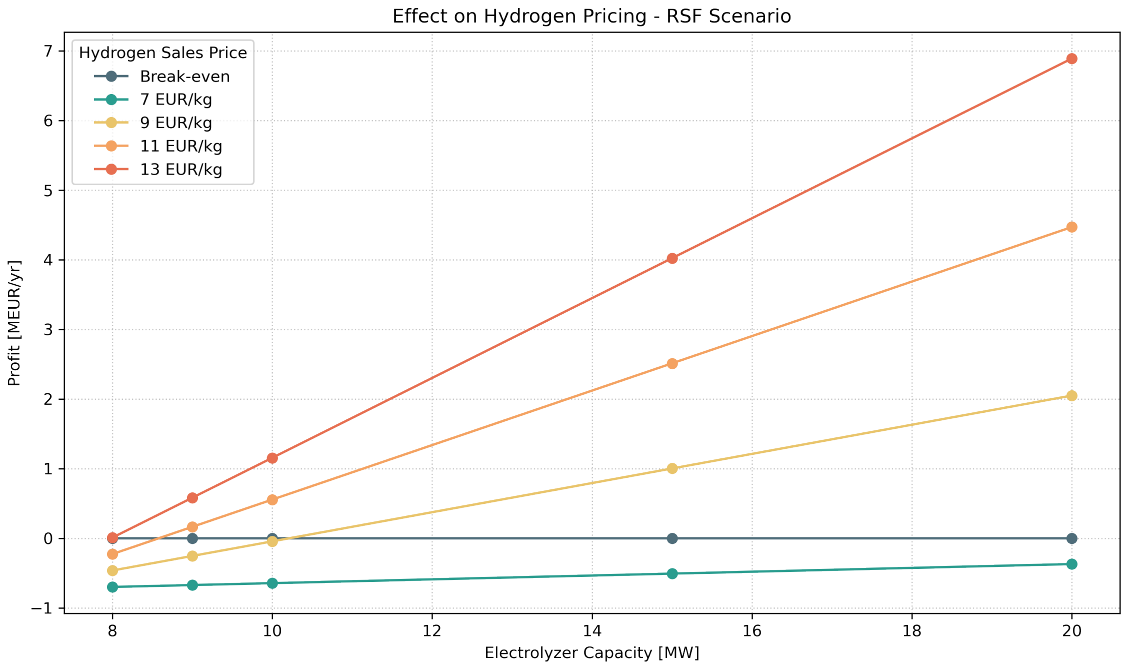


Figure 4.14: Effect on hydrogen pricing for Case 2, RSF scenario.

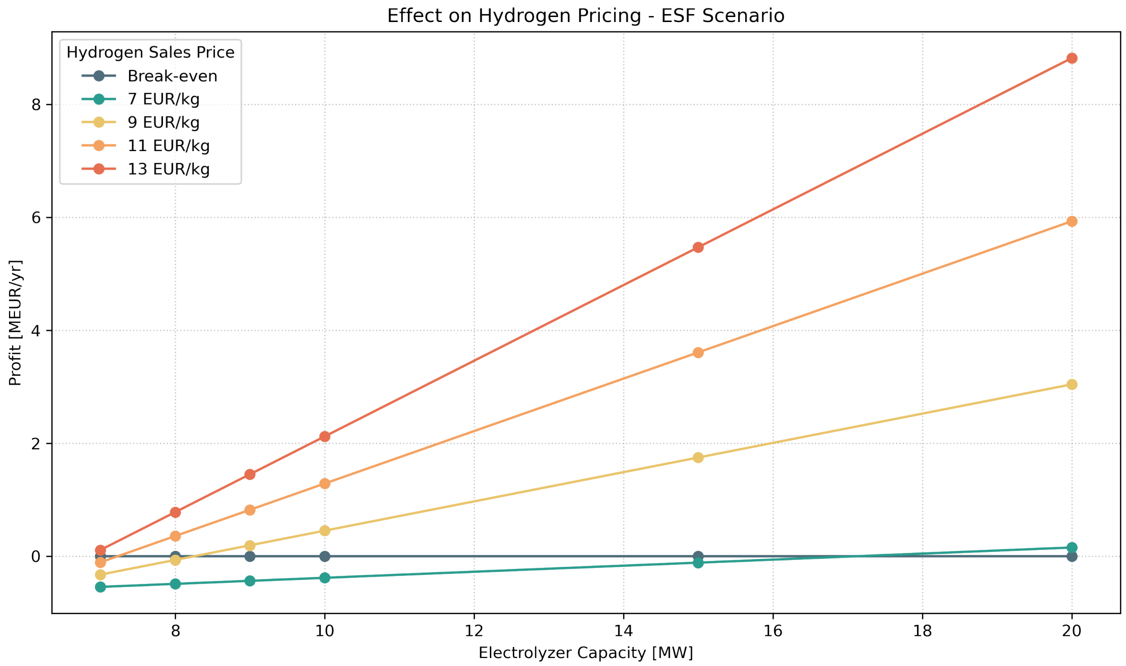


Figure 4.15: Effect on hydrogen pricing for Case 2, ESF scenario.

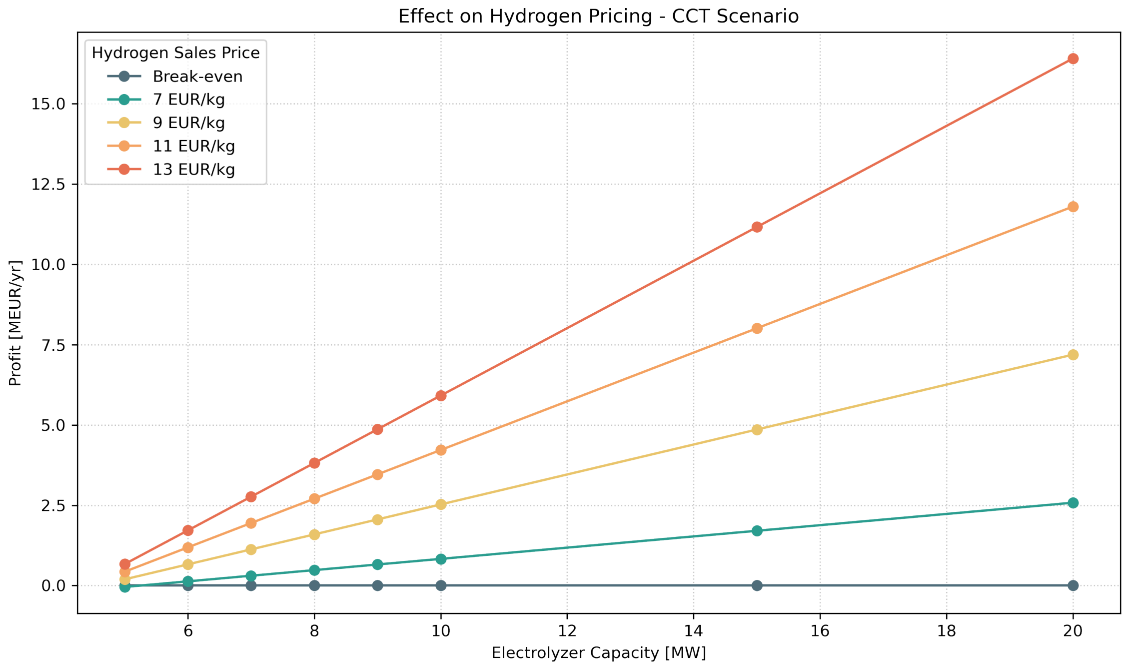


Figure 4.16: Effect on hydrogen pricing for Case 2, CCT scenario.

It is clear from the figures that higher hydrogen pricing offers a higher potential for revenue for all scenarios and capacities. The larger the electrolyzer, the greater the hydrogen production and consequently, the higher the potential revenue.

Profit has a direct impact on the PBP, which is displayed in Table 4.3. The results indicate that the PBP of the electrolyzer systems is highly sensitive to the hydrogen price, system capacity, and electricity price scenario. In general, a higher price of hydrogen and a larger system capacity lead to significantly shorter periods due to higher hydrogen production and improved revenue generation, i.e. lower costs per unit of hydrogen produced.

As stated in previous figures, the 2023 scenario consistently delivers favorable outcomes. The CCT scenario compares well with the 2023 scenario for lower hydrogen prices and performs even better than the 2023 scenarios for prices higher or equal to 9 EUR/kg. This can be explained by the fact that, although the electricity price is generally higher in the CCT scenario, it produces more hydrogen. This is because a smaller electrolyzer capacity is needed for the methanation process. As a result, with higher hydrogen prices, the profit from hydrogen sales exceeds the electricity costs. In contrast to the 2023 and CCT scenarios, the RSF and ESF scenarios show longer PBPs, especially at lower hydrogen prices. This is due to the large electrolyzer capacities needed for the methanation process in combination with the higher cost of electricity.

In Table 4.3, the PBP is presented for each case, different electrolyzer capacities, and hydrogen prices. The cells in green indicate a PBP below 10 years, which is defined as acceptable since it is half of the system's lifetime. Red indicates that the PBP exceeds 20 years, where no payback occurs during the system's lifetime. Orange indicates a PBP between 10 and 20 years.

Table 4.3: PBP [years] for different hydrogen prices and electrolyzer capacities under the different scenarios.

Hydrogen price [EUR/kg]	Electrolyzer capacity [MW]	2023	RFS	ESF	CCT
7	8	7.9	22.6	17.5	8.6
	10	7.3	18.0	14.6	7.8
	15	6.5	14.2	12.0	7.0
	20	6.2	12.8	11.0	6.6
9	8	6.2	17.0	12.0	5.4
	10	5.3	11.8	9.1	4.7
	15	4.4	8.3	6.9	4.1
	20	4.1	7.3	6.2	3.8
11	8	5.1	13.7	9.2	3.9
	10	4.2	8.7	6.6	3.4
	15	3.4	5.9	4.9	2.9
	20	3.1	5.1	4.3	2.7
13	8	4.3	11.4	7.4	3.1
	10	3.5	6.9	5.2	2.6
	15	2.7	4.6	3.8	2.2
	20	2.5	3.9	3.3	2.0

The results indicate that the most attractive investments are found in the 2023 and CCT scenarios, combined with large-scale electrolyzer systems and high hydrogen pricing. Caution is advised for the RSF and ESF scenarios at low hydrogen prices, as several configurations remain unprofitable within the system's lifetime.

4.2.2 Climate Analysis

The carbon footprint results for the different scenarios in Case 2 are presented below. To achieve comparable results, all scenarios have been modeled with an 8 MW electrolyzer capacity. The emissions associated with the 2023 scenario are shown in Table 4.4, followed by the corresponding results for the RSF, ESF, and CCT scenarios in Tables 4.5, 4.6, and 4.7, respectively. Figure 4.17 summarizes the results of GWP_{20} and GWP_{100}.

The 2023 scenario has been run with an 8 MW electrolyzer with a price constraint to use only hours where electricity prices are lower than 59 EUR/MWh, as the results of Case 1 indicated was the optimal solution for this scenario.

Table 4.4: Carbon Footprint by Emission Source for the 2023 Scenario – Case 2

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	952.6
$E_{H2,leak,GWP20}$	1 429.8
$E_{H2,leak,GWP100}$	464.7
$E_{CH4,leak,GWP20}$	187.0
$E_{CH4,leak,GWP100}$	61.2
$E_{compression}$	16.2
Total CO_2 emissions - GWP_{20}	2 585
Total CO_2 emissions - GWP_{100}	1 495

The RSF scenario has been run with an 8 MW electrolyzer with a price constraint to use only hours where electricity prices are lower than 117 EUR/MWh, as the results of Case 1 indicated was the optimal solution for this scenario.

Table 4.5: Carbon Footprint by Emission Source for the RSF Scenario – Case 2

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	771.0
$E_{H2,leak,GWP20}$	1 164.9
$E_{H2,leak,GWP100}$	378.6
$E_{CH4,leak,GWP20}$	187.0
$E_{CH4,leak,GWP100}$	61.2
$E_{compression}$	6.7
Total CO_2 emissions - GWP_{20}	2 130
Total CO_2 emissions - GWP_{100}	1 218

The ESF scenario has been run with an 8 MW electrolyzer with a price constraint to use only hours where electricity prices are lower than 82 EUR/MWh, as the results of Case 1 indicated was the optimal solution for this scenario.

Table 4.6: Carbon Footprint by Emission Source for the ESF Scenario – Case 2

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	873.9
$E_{H2,leak,GWP20}$	1 315.0
$E_{H2,leak,GWP100}$	427.4
$E_{CH4,leak,GWP20}$	187.0
$E_{CH4,leak,GWP100}$	61.2
$E_{compression}$	12.1
Total CO_2 emissions - GWP_{20}	2 388
Total CO_2 emissions - GWP_{100}	1 375

The CCT scenario has been run with an 8 MW electrolyzer with a price constraint to use only hours where electricity prices are lower than 75 EUR/MWh, as the results of Case 1 indicated was the optimal solution for this scenario.

Table 4.7: Carbon Footprint by Emission Source for the CCT Scenario – Case 2

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	1 251.1
$E_{H2,leak,GWP20}$	1 865.6
$E_{H2,leak,GWP100}$	606.3
$E_{CH4,leak,GWP20}$	187.0
$E_{CH4,leak,GWP100}$	61.2
$E_{compression}$	31.7
Total CO_2 emissions - GWP_{20}	3 335
Total CO_2 emissions - GWP_{100}	1 950

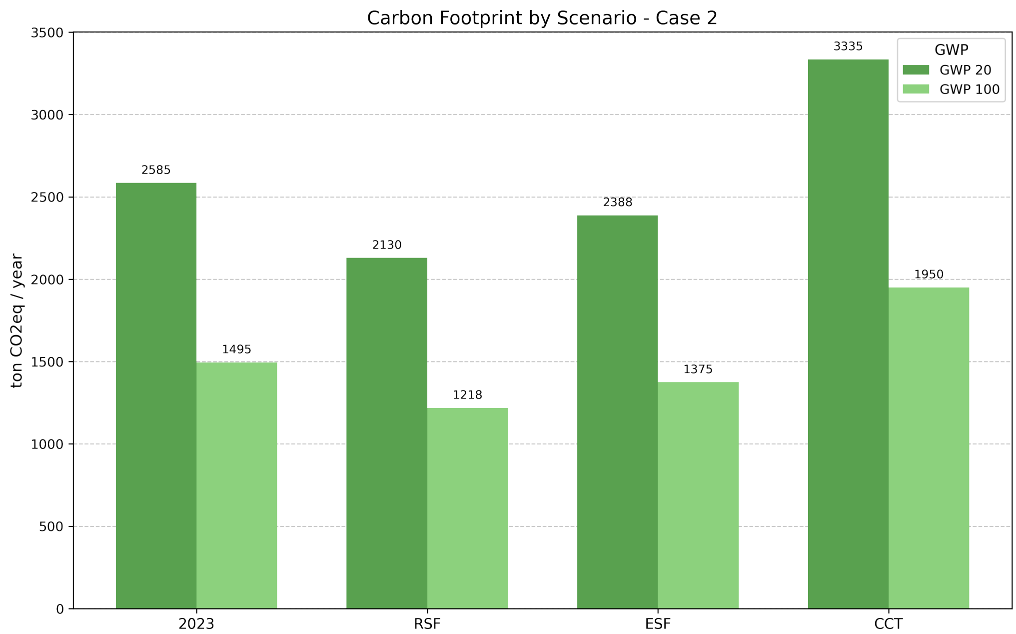


Figure 4.17: Summary Carbon Footprint by Scenario - Case 2.

The results show that the CCT scenario has the highest carbon footprint, while the RSF scenario results in the lowest. The 2023 and ESF scenarios demonstrate very similar emission levels, indicating minimal variations.

These results were anticipated, as the carbon footprint is primarily influenced by electricity consumption and the volume of hydrogen produced, both of which are determined by the electrolyzer capacity and the electricity price conditions under which the system operates. Since the CCT scenario has the lowest annual average electricity price (50 EUR/MWh), and the price duration curve (Figure 2.6) shows a high number of hours during which the electrolyzer can operate within the defined price constraint, the system can run for more hours. This leads to increased electricity consumption and higher hydrogen production, which in turn results in a larger overall carbon footprint.

Another key finding from the results is, just as in Case 1, that hydrogen leakage from GWP_{20}, is the primary contributor to total emissions across all cases. The second largest contributor is the electricity consumed by the electrolyzer, followed by hydrogen leakage under GWP_{100}. This indicates that methane emissions constitute only a small share of the total carbon footprint in all scenarios, together with compression emissions (due to the smaller amount of hydrogen that needs to be compressed).

Figure 4.18 visualizes the same as in Case 1, the difference between placing the system in Germany instead of Sweden, but for Case 2. Important to note here also is that the green bars that represent the emissions in Sweden are the same as in Figure 4.17. Again, it is clear that the emissions in Sweden are small compared to the emissions in Germany.

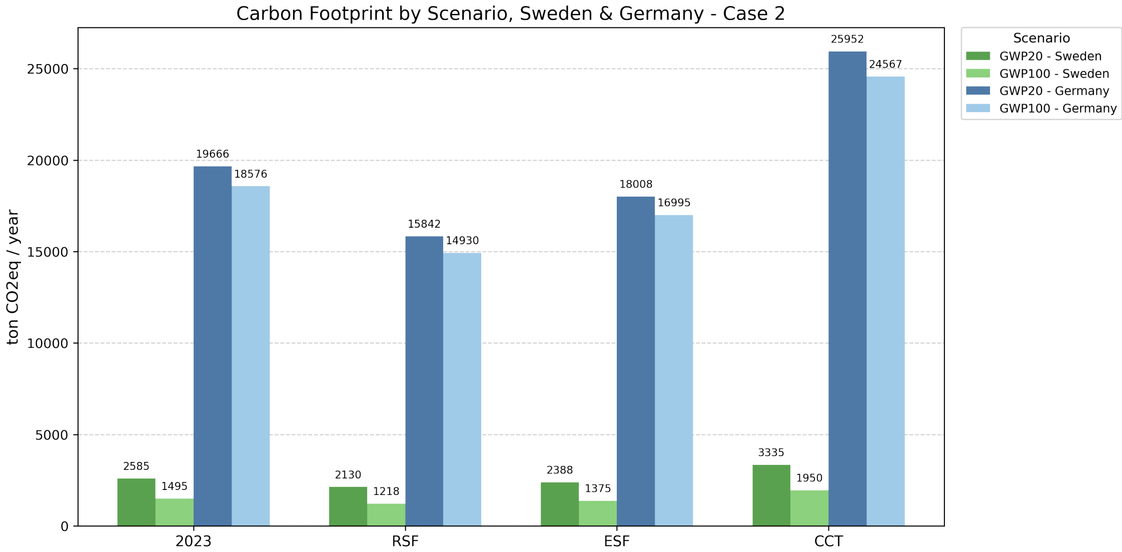


Figure 4.18: Carbon Footprint by Scenario, Sweden & Germany - Case 2.

4.3 Case 3

In this section, the results for Case 3 are presented. Case 3 includes hydrogen production for direct sales only. This case acts as a reference case to further evaluate Case 1 and Case 2. Therefore, this section offers a comparison with the two previous cases from both a techno-economic and climate perspective.

4.3.1 Techno-Economic Analysis

Using the same configurations as for the cost-optimal solution of Case 1 for each scenario, the LCOH could be calculated and compared to the costs found in Case 1. However, the comparison between Case 1 and Case 3 is not straightforward, as the product in Case 1 is bio-e-methane and hydrogen in Case 3. For better comparison, the production cost per energy unit could be calculated. With an energy content of 13.89 kWh/kg (LHV) [75] for methane and 33.33 kWh/kg (LHV) for hydrogen [62], the cost could be calculated to the values shown in Table 4.8 for each case and scenario.

Table 4.8: Cost comparison of bio-e-methane and hydrogen in different scenarios with Case 1 settings.

	Unit	2023	RSF	ESF	CCT
Cost of bio-e-methane (Case 1)	[EUR/kg]	2.96	3.79	3.66	3.26
	[EUR/kWh]	0.21	0.27	0.26	0.23
Cost of hydrogen (Case 3)	[EUR/kg]	5.30	6.80	6.57	5.84
	[EUR/kWh]	0.16	0.20	0.20	0.18

Hydrogen has a significantly higher energy content per kilogram compared to methane. Although the cost per kilogram is higher for hydrogen, the cost per delivered unit of energy is often comparable, or even lower. However, it is important to note that these are two different fuels with different characteristics. The different prices of the two fuels are also an important factor to consider.

Using the same settings as in Case 2, the LCOH is calculated to be 5.25 EUR/kg for the 2023 scenario, 6.7 EUR/kg for the RSF scenario, 6.48 EUR/kg for the ESF scenario, and 5.8 EUR/kg for the CCT scenario. These values are in line with the converging trend observed in Case 2, as illustrated in Figure 4.12, although the ESF and CCT scenarios have not yet fully converged at an electrolyzer capacity of 20 MW. The reason why LCOH remains constant regardless of capacity is that the investment in electrolyzer capacity increases proportionally with hydrogen production. As a result, when costs are divided by the amount of hydrogen produced (kg), the value remains unchanged.

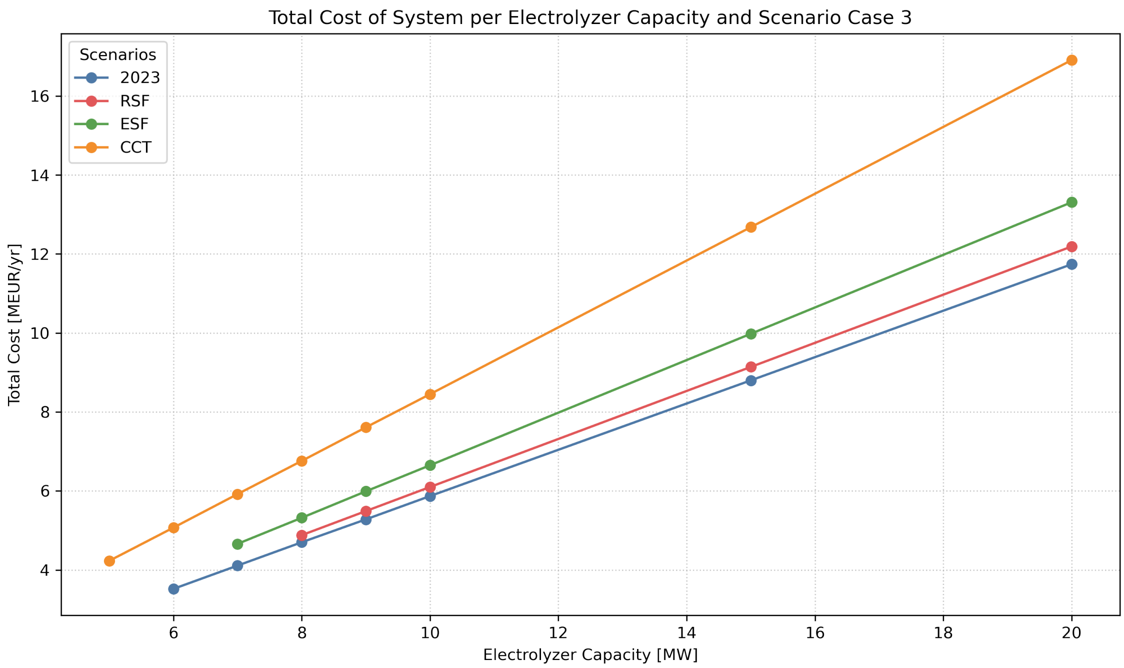


Figure 4.19: Total system cost for different electrolyzer capacities and scenarios, Case 3.

With a sufficiently large electrolyzer capacity to allow for convergence, there is no difference in lost or gained profit between producing hydrogen for the digester and direct hydrogen sales. However, at smaller electrolyzer capacities, there is a clear potential for either profit gains or losses.

The potential gains are highest in the 2023 scenario, while the largest losses are in the RSF future scenario. The differences between Case 2 and 3 are illustrated in Figure 4.20.

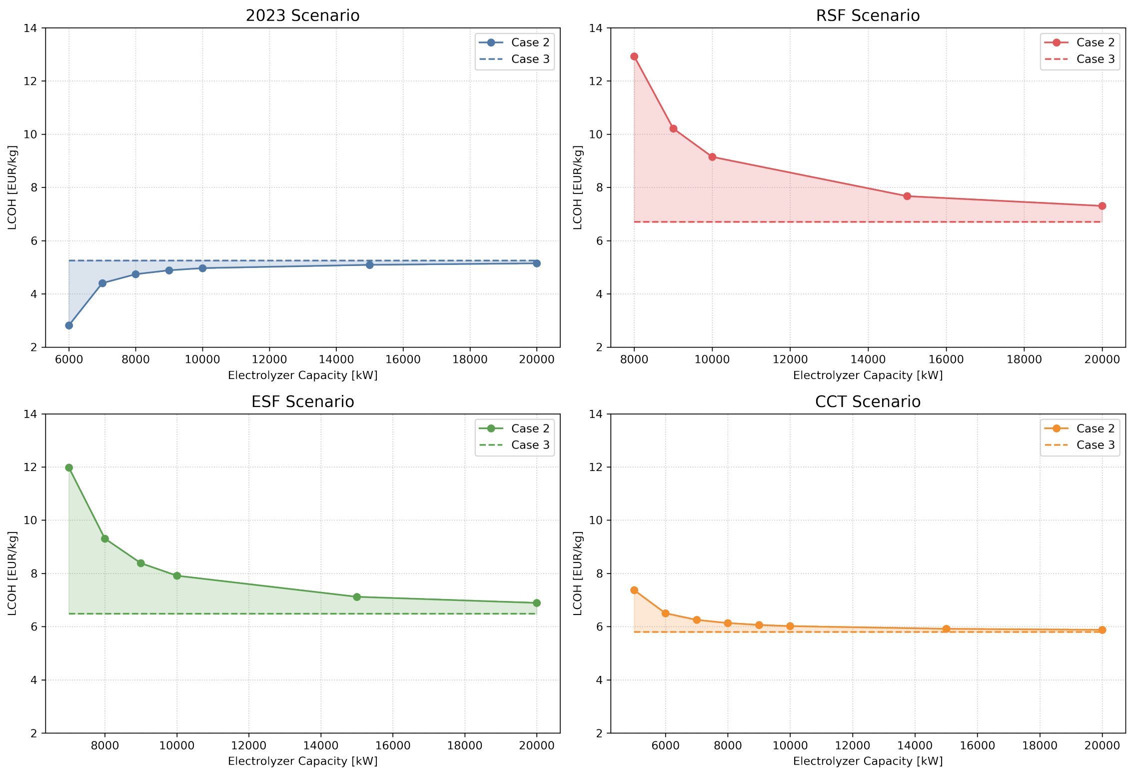


Figure 4.20: Comparison of LCOH for Case 2 and Case 3 all electricity scenarios.

4.3.2 Climate Analysis

For Case 3, the carbon footprint analysis is based on the results of Case 1, and the results for the different scenarios are presented below. As for Case 2, to achieve comparable results, all scenarios have been modeled with the same 8 MW electrolyzer capacity. The emissions associated with the 2023 scenario are shown in Table 4.9, followed by the corresponding results for the RSF, ESF, and CCT scenarios in Tables 4.10, 4.11, and 4.12, respectively. Figure 4.21 summarizes the results of GWP_{20} and GWP_{100}.

Table 4.9: Carbon Footprint by Emission Source for the 2023 Scenario – Case 3

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	952.6
$E_{H2,leak,GWP20}$	1 429.7
$E_{H2,leak,GWP100}$	464.6
$E_{compression}$	50.9
Total CO_2 emissions - GWP_{20}	2 433
Total CO_2 emissions - GWP_{100}	1 468

Table 4.10: Carbon Footprint by Emission Source for the RSF Scenario – Case 3

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	771.0
$E_{H2,leak,GWP20}$	1 164.9
$E_{H2,leak,GWP100}$	378.6
$E_{compression}$	41.5
Total CO_2 emissions - GWP_{20}	1 977
Total CO_2 emissions - GWP_{100}	1 191

Table 4.11: Carbon Footprint by Emission Source for the ESF Scenario – Case 3

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	873.9
$E_{H2,leak,GWP20}$	1 315.0
$E_{H2,leak,GWP100}$	427.4
$E_{compression}$	46.9
Total CO_2 emissions - GWP_{20}	2 236
Total CO_2 emissions - GWP_{100}	1 348

Table 4.12: Carbon Footprint by Emission Source for the CCT Scenario – Case 3

Emission source	**Value [ton CO_2eq]**
$E_{electrolyzer}$	1 251.1
$E_{H2,leak,GWP20}$	1 865.6
$E_{H2,leak,GWP100}$	606.3
$E_{compression}$	66.5
Total CO_2 emissions - GWP_{20}	3 183
Total CO_2 emissions - GWP_{100}	1 924

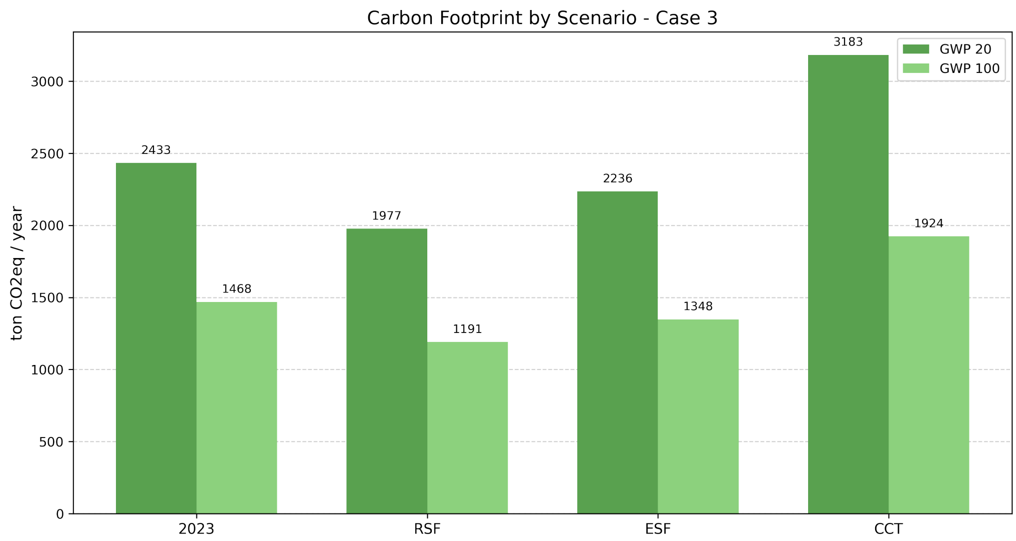


Figure 4.21: Summary Carbon Footprint by Scenario for Case 3.

These results show a pattern similar to that observed in Case 2: the CCT electricity price scenario results in the highest emissions, while the RSF scenario results in the lowest. This outcome was anticipated, as the main difference between the carbon footprint assessments for Case 2 and Case 3 is the absence of methane leakage in Case 3, due to the lack of bio-e-methane production. Instead, Case 3 involves an increase in hydrogen production, leading to increased hydrogen leakage and larger compression requirements. Given that methane leakage contributed only marginally to total emissions in Case 2, the exclusion of bio-e-methane production in Case 3 does not significantly affect the overall carbon footprint.

Furthermore, the results confirm the findings of Case 2 (and Case 1), indicating that hydrogen leakage under the GWP_{20} metric is the dominant contributor to total emissions, followed by emissions from electricity consumption and hydrogen leakage under the GWP_{100} metric.
Figure 4.22, again visualizes the difference between placing the system in Germany instead of Sweden, but for Case 3. Once again, the green bars representing the emissions in Sweden are the same as in Figure 4.21.

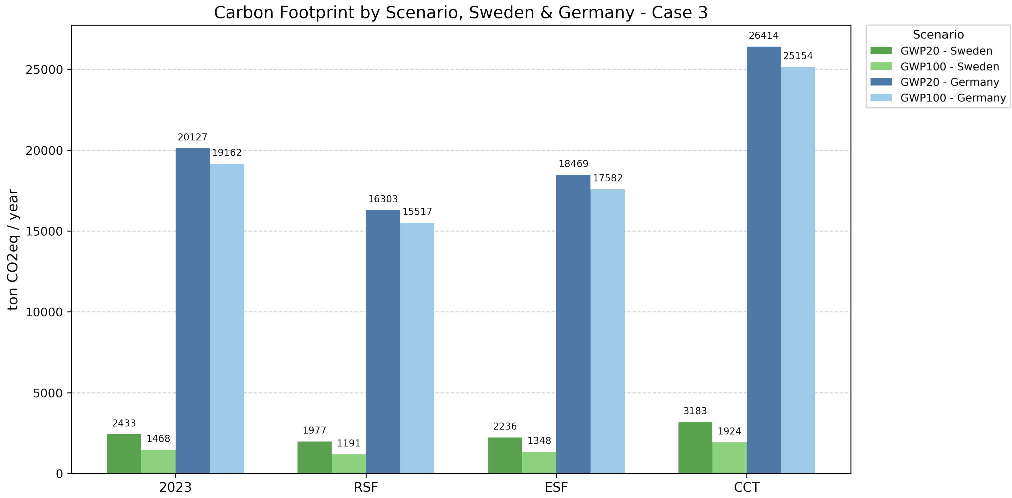


Figure 4.22: Carbon Footprint by Scenario, Sweden & Germany - Case 3.

5
Discussion

5.1 Techno-Economic Aspects

This section discusses uncertainties related to techno-economic aspects, such as future time series and parameters, compression and grid connection costs, as well as the role of RFNBO.

5.1.1 Future Time Series and Parameters

The time series for the RSF, ESF and CCT scenarios are, as mentioned, possible future outcomes. This in itself brings uncertainties, since the future cannot be predicted. The scenarios can only show a possible outcome for each case, which means that the results could potentially be different.

Furthermore, these prospective scenarios have been combined with parameters that are fixed or known based on present-day conditions. For example, the climate analysis is based on the electricity emission factor for Sweden in 2023. This value will most likely not stay the same until the year 2035 and is therefore expected to change with time. There is the possibility that the value will be lower in the future, as emission factors vary annually and there is generally a downward trend. The speculation of a lower emission factor in the future is supported by Sweden's goal of achieving net zero emissions by 2045 and negative emissions after that [76]. However, according to the Swedish Climate Policy Council, the gap towards these long-term climate goals is still significant [77], which supports evidence that the emission factor might not decrease as much as expected. Therefore, and due to the lack of projections for future emission factors, the 2023 value was used as an assumption for the 2035 scenarios. Consequently, the calculated carbon footprint could be an overestimation, but this is difficult to establish.

Moreover, there are uncertainties when it comes to other parameters, both technical and economic. Technology and society develop with time, and there are values that have been used for future scenarios that could be different in 2035, i.e., 10 years into the future. For example, the efficiency of the electrolyzer, the price of the electrolyzer, the price of water, etc. Moreover, the same applies to the biogas price that has been used during this thesis. The price from today could be different in the future, creating slightly different results. However, as mentioned already, as the future cannot be predicted with certainty, this thesis relies on current and well-established parameter values.

Furthermore, since the purpose of this thesis was to evaluate the appropriate electrolyzer capacity for Tekniska Verken's near-future investment while considering potential future electricity prices, it was considered not essential to adjust parameters of this nature.

5.1.2 Hydrogen Compression Costs

One source of uncertainty in this thesis relates to the cost of hydrogen compression. During the literature search on hydrogen compression costs for Case 2 and Case 3, it was found that the reported cost values vary depending on multiple factors, such as compressor type, capacity, included costs/excluded costs, etc.

The primary reference used to state these costs is from 2014, which introduces potential uncertainties. This with respect to the included costs, which are the electricity cost and the investment cost. In particular, the electricity cost component included in the compression cost can be underestimated, as electricity prices have generally increased since 2014. However, this reference was chosen because it is a relatively old technology where there has not been much development in general since 2014, and the source clearly stated which costs were included, which many other sources did not. Moreover, the included costs suited well for this thesis in regard to modeling and it would have been too complex to outline the hours the compressor would run to calculate the electricity cost based on the provided time series. Therefore, it was well suited with a reference that had the cost of electricity included as the one chosen did.

As a result, the specific compression cost used represents only one possible value among many and may not fully capture current or future cost conditions. These uncertainties should be considered when interpreting the economic results, especially for Case 2 and Case 3 where hydrogen compression plays a critical role.

5.1.3 Grid Connection Cost and Fees

For an electrolyzer with a capacity of 5–10 MW, it is suitable to connect it to the regional grid operated by Vattenfall Eldistribution. This is assumed after a discussion with the local distribution network owner Tekniska Verken in Linköping AB. An attempt was made to contact Vattenfall Eldistribution in order to obtain an estimated cost for grid connection and associated grid fees. However, they were unable to provide this information due to limited resources. As a result, the cost of the grid connection was excluded from the thesis, despite its potential impact on the results.

5.1.4 Role of Electricity - RFNBO and Costs

The role of electricity is significant in this thesis, and the characteristics of the energy system vary significantly depending on the geographic region and the year under consideration. In general, electricity availability, pricing, and carbon intensity differ widely. This variability is particularly relevant in the context of RFNBO, as previously discussed. Given the increasing importance of RFNBO, it was therefore of interest to find out how the Swedish electricity mix aligns with the RFNBO requirements, which indicated strong compatibility.

In addition, the differences between the electricity price scenarios were of analytical interest. The price duration curve (Figure 2.6) clearly illustrates significant variations among the scenarios. In particular, the RSF scenario showcased the highest annual average electricity price (as also calculated), while the CCT scenario presented a different shape, characterized by a steep initial decline followed by a nearly horizontal segment, resulting in the lowest annual average price among the scenarios.

These outcomes correspond, to some extent, with the cost-optimal price constraints presented in Case 1. Specifically, the RSF scenario had the highest price constraint (90 EUR/MWh), while the CCT scenario had the second lowest (75 EUR/MWh) after the 2023 scenario.

At first glance, it may seem counterintuitive that the CCT scenario, despite having only the second-lowest price constraint, achieved the lowest annual average price. However, this becomes more understandable upon closer examination of the price duration curve. The prolonged linearity of the curve indicates that the electrolyzer could operate at a relatively stable and low price for a longer period of time than the other scenarios. In contrast, the 2023 scenario, which had the lowest cost-optimal price constraint, produced at an annual average electricity price only marginally higher than CCT (52 EUR/MWh vs. 50 EUR/MWh). However, the greater variability in the price duration curve of the 2023 scenario explains this outcome, as it suggests more frequent fluctuations in electricity prices throughout the year.

5.2 Model Aspects

This section discusses uncertainties and considerations related to the modeling and calculations. Alternative calculation methods are outlined, along with limitations associated with the software used.

5.2.1 Alternative Methods

Calculations can be performed in different ways, and there are several alternative methods to assess the same problem. For example, calculating the electrolyzer capacity when operating at partial load due to electricity price limits was done starting from a chosen electricity price. From this, the electrolyzer capacity was determined, followed by a calculation of the total cost. Using this approach results in an overly precise electrolyzer capacity, which is not realistic since electrolyzer investments are typically made in discrete steps. An alternative approach would be to reverse the process, starting with choosing an electrolyzer capacity, calculating the corresponding electricity price, and then determining the total cost. By doing this, more control would be gained over the electrolyzer capacity while allowing the electricity price to have more decimal places.

The selection of assumed and known parameters plays a key role in the analysis throughout the thesis. This is especially relevant for the electrolyzer performance parameters that form Eq. 2.4, which is essential to calculate the electrolyzer capacity. Depending on the chosen known parameter (hydrogen output, electricity demand, or efficiency), slightly different results may be obtained. In this thesis, efficiency was assumed to be known, and all calculations are based on this assumption.

5.2.2 Software Limitations

As mentioned, all cases in this thesis were modeled using the Odyssey software. Odyssey is a relatively recent software developed primarily for modeling intermittent energy sources such as solar and wind, in combination with storage technologies and power-to-gas alternatives. It was used, although it was not fully tailored to the specific needs of this thesis, as the focus here was on grid electricity and hydrogen production without storage. However, once the architecture, configurations, and energy management strategies were defined, the software provided many useful data and visualizations.

Given the original design of Odyssey, some parts of the software were used in ways that differ slightly from their primary purpose. For example, to make the process work in Odyssey, a storage component had to be added to the system. This storage does not exist in reality and is not part of the actual system but was necessary for the software to run the model properly.

Moreover, the software was quite sensitive to the way the time series was constructed. In order for certain performance parameters of the electrolyzer to function properly, such as degradation and standby mode, a time series that covered the entire system lifetime was required. Since this thesis aimed to simulate different scenarios using one year of data (or projected data for future scenarios), these price variations had to be repeated over a 20-year period to represent the full system lifetime. Thus, each scenario simulates a 20-year period as if the same yearly electricity price variation were repeated every year.

5.3 External Aspects

This section addresses external uncertainties and factors. Climate-related aspects, including the two types of GWP, are discussed alongside a comparison of the results in relation to AFIR regulations.

5.3.1 GWP_{20} vs. GWP_{100}

A part of the environmental analysis was to identify and analyze the difference between the GWP_{20} and GWP_{100} results for each case, to be able to show how important it is to keep track of the methane and hydrogen leakages in a system like this.

The difference between GWP_{20} versus GWP_{100} is the time frame, i.e. the short- and long-term climate impact and the effects they bring on the calculation of the carbon footprint. It is clear from the results that what GWP is used for a study has a large impact on such calculation since the GWP_{20} value was larger than GWP_{100} for each case and every scenario within the cases.

Although the difference in results from the cases was expected due to their variations in extent and included parts, it was still of interest to see how large the carbon footprint was for each case and scenario, to be able to identify which case and/or scenario would contribute the most to global warming.

However, since the methane content was the same for Case 1 and Case 2 (due to the fixed amount of CO_2 that was able to be converted), the results of methane leakage are the same for all cases. Moreover, since hydrogen's GWP values are less certain due to being more recently studied, there may be additional uncertainty when interpreting hydrogen's climate impact compared to methane. Methane has a very high GWP over 20 years compared to 100 years since it is a potent but short-lived GHG. This means methane's climate impact appears much larger under GWP_{20}, which the calculations confirm.

Thus, the results show how important it is to have leakages under control and try to minimize them as much as possible.

5.3.2 AFIR

As mentioned in Section 2.2.2.2, the AFIR supports the deployment of hydrogen refueling stations, where each station is required to deliver a minimum cumulative dispensing capacity of 1 ton of hydrogen per day. This equals a minimum production of 365 tons per year required. It is therefore of interest to see what minimum capacity for our cases and scenarios would be able to achieve this requirement.

Case 2:

Table 5.1: Minimum Electrolyzer capacities to AFIR requirements – Case 2

Scenario	**Electrolyzer capacity (MW, EUR/MWh)**
2023	9 MW, (50 EUR/MWh) **1.08 ton/day**
RSF	15 MW, (117 EUR/MWh) **2.07 ton/day**
ESF	10 MW, (82 EUR/MWh) **1.14 ton/day**
CCT	7 MW, (75 EUR/MWh) **1.12 ton/day**

From Table 5.1, it can be noted that:

- For RSF, an 11 MW electrolyzer is likely sufficient, but this capacity has not been modeled and, therefore, lacks data on how much hydrogen was produced for this size to be able to calculate the produced hydrogen per day.
- All modeled electrolyzer capacities above the specified minimums in each scenario also meet the 365 tons/year requirement.

Case 3: In contrast to Case 2, all modeled electrolyzer capacities fulfill the 365 tons/year production requirement in all scenarios.

This means that many of the proposed electrolyzer capacities would meet the AFIR requirements.

6
Conclusion

6.1 Research Questions

Research Question 1: What will the production costs for bio-e-methane and/or hydrogen be when it is integrated with an in-situ methanation system concerning the three cases?

In Case 1, the most cost-optimal configuration was found for an electrolyzer capacity of 5.7 MW and a price threshold of 59 EUR/MWh under the 2023 scenario. For the future scenarios, the optimal capacities were identified as 7 MW for RSF, 6.2 MW for ESF, and 4.4 MW for the CCT scenario, corresponding to electricity price thresholds of 90.2 EUR/MWh, 82 EUR/MWh, and 75 EUR/MWh, respectively.

The resulting total annual production costs for these optimized configurations were 2.17 million EUR for the 2023 scenario, 3.10 million EUR for RSF, 2.94 million EUR for ESF, and 2.49 million EUR for CCT.

For Case 2, determining the production cost was more complex, as there was no single optimal electrolyzer capacity identified. The production costs are highly sensitive to both the electrolyzer capacity and the electricity price scenario. Since the modeling and calculations were based on the results from Case 1, illustrative examples of production costs can be presented.

The same conditions apply to Case 3, where no single optimal electrolyzer capacity could be identified, and the production costs remain highly dependent on both the electrolyzer capacity and the electricity price scenario. As such, selected examples of total production costs are presented for illustrative purposes.

Research Question 2: To what extent is investing in the three cases economically viable?

Assuming a fixed price for bio-e-methane equal to the current market price of biogas, Case 1 proved profitable for the 2023 electricity price scenario. For this scenario, it is profitable from an electrolyzer capacity of 4.8 MW up to 7.0 MW, as the green area shown in Figure 4.4. The most cost-optimal configuration also corresponds to the most profitable electrolyzer capacity, 5.7 MW, under the price constraint of 59

EUR/MWh.

For the future price scenarios (RSF, ESF and CCT), the results showed that it is not profitable under any conditions, and the worst conditions came from the RSF scenario. The results could be different if a future price for bio-e-methane was used since these scenarios used the market price of today, and not adapted for the future. For future scenarios to break even, a bio-e-methane price of 2.82 EUR/kg, 2.69 EUR/kg and 2.28 EUR/kg for RSF, ESF and CCT would be required respectively. This could be compared to the current market price of methane of 2.09 EUR/kg. There is a large likelihood that the price will be different in the future, leading to a different outcome.

Moreover, PBP for all scenarios in Case 1 exceeded 10 years. The shortest PBP was observed in the 2023 scenario at 10.3 years, followed by 15 years for the CCT scenario, 28.3 years for ESF, and 31.8 years for the RSF scenario.

For Case 2, the results were positive for the 2023 and CCT price scenario in regard to the PBP. Regardless of hydrogen price and electrolyzer capacity, the PBP was below 10 years, which was defined as reasonable for this thesis. The RSF and ESF scenarios are not as strong and only profitable with a higher hydrogen price or a large electrolyzer capacity. However, a higher hydrogen price and larger electrolyzer give the most profitable results for all scenarios.

Case 3 serves as a reference to evaluate whether in-situ methanation is justified or if allocating the hydrogen for direct sales would be more profitable. When compared to Case 1, it was found that the LCOH would be 5.3 EUR/kg, 6.8 EUR/kg, 6.6 EUR/kg, 5.8 EUR/kg hydrogen for 2023, RSF, ESF and CCT electricity price scenarios respectively. The pricing of hydrogen will likely be higher than the break-even price, making direct hydrogen sales more profitable. However, the system under study includes a digester with a certain amount of CO_2 available for methanation, and there is also inherent value in utilizing the available resources.

Research Question 3: What is the climate impact of hydrogen infused in-situ methanation production?

The climate impact varies, ranging from 1 023 to 3 335 tons CO_2/year depending on the case, scenario, and the GWP used. The choice of GWP metric has an essential influence on the results, with GWP_{20} leading to higher reported emissions across all cases and scenarios. Controlling and minimizing methane and hydrogen leakage is crucial to prevent significant emissions.

To assess whether these carbon emissions are relatively high or low, a reference scenario was included. The same system was modeled as if located in Germany, to demonstrate the influence of a different electricity mix. The results revealed a substantial difference in emissions, emphasizing that the carbon intensity of the electricity mix has a major impact on the overall carbon footprint. This highlights the importance of using a low-carbon electricity mix for such a system.

6.2 General Insights

In general, there have been many important insights when conducting the thesis and analyzing the results. For example, the development of the electricity market will be significant for the cost of electrolysis, since the outcomes of the different electricity price scenarios vary. Electricity cost is the largest operational expense for electrolysis, accounting for up to 50% in Case 1 under optimal operation, and an even higher share under full-load operation.

Adapting the production to low electricity price-hours reduces costs in all scenarios by up to 16% annually. Due to the different price constraints, the operation of the electrolyzer varies between 50 and 90 %. Thus, there are scenarios where the most cost-effective solution is to invest in significantly higher electrolyzer capacity and operate it only half the time.

Moreover, several scenarios show a range of small variations in the total cost across different electrolyzer capacities, allowing flexibility in the dimensioning of the electrolyzer. This could be of importance if there are other interests than the total cost alone.

One factor that significantly affected the results is the assumption of using the current market price of biogas as the basis for bio-e-methane pricing. Future market prices for bio-e-methane and hydrogen will be crucial to the economic viability depending on the scenario.

In addition, the development of the technologies under study on a component- and system-based level will also have an effect in the future, since it can change the dynamics used in the thesis. Since electrolysis for large-scale hydrogen production is a relatively recent development, with widespread adoption only in recent years, performance factors such as system lifetime and degradation are not yet well established. Furthermore, the development of electrolyzer investment costs will be interesting to follow. On top of this, the development of other technologies alongside electrolysis and methanation will impact the potential of hydrogen and bio-e-methane, as well as influence their interactions in a system perspective.

Lastly, the value of resource efficiency is important, which this thesis highlights when focusing on that hydrogen infused in-situ methanation systems produce more biogas without adding any substrate, assisting in reducing the use of fossil fuels.

Bibliography

[1] Nord Pool | Day-ahead prices;. Available from: https://data.nordpoolgroup.com/auction/day-ahead/prices?deliveryDate=2024-02-19&currency=EUR&aggregation=DeliveryPeriod&deliveryAreas=AT.

[2] Hydrogen Production: Electrolysis | Department of Energy;. Available from: https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

[3] Causes and Effects of Climate Change | United Nations;. Available from: https://www.un.org/en/climatechange/science/causes-effects-climate-change.

[4] Energy Mix - Our World in Data;. Available from: https://ourworldindata.org/energy-mix#article-citation.

[5] Sandaka BP, Kumar J. Alternative vehicular fuels for environmental decarbonization: A critical review of challenges in using electricity, hydrogen, and biofuels as a sustainable vehicular fuel. Chemical Engineering Journal Advances. 2023 5;14:100442.

[6] An Innovation Agenda for Hard-to-Decarbonize Energy Sectors on JSTOR;. Available from: https://www.jstor.org/stable/26949082?casa_token=_PCJ9M33d1UAAAAA%3A95vjWQXCOiqQIOiJrQ8rorT1aGiPGsA35gPnlJlClHRcZIDcTKRjCJZ18ZzSdZXEqZrbgJrQjDLSdprRuapgf7nusprs2SU_PrfjGV3O4LFbZ-Kk3gXZ&saml_data=eyJzYW1sVG9rZW4iOiIzYjg0MWE4My1mMWExLTQ1N2QtYTgzZi00Yzk3ODQ3Y2Y3NWEiLCJpbnN0aXR1dGlvbklkcyI6WyJjYzY1MWYzNC1iYzhjLTQxODQtYjc3ZS05NDQ4Mzg3Y2ZjZWIiXX0&seq=1.

[7] Ozturk M, Dincer I. A comprehensive review on power-to-gas with hydrogen options for cleaner applications. International Journal of Hydrogen Energy. 2021 9;46(62):31511-22. Available from: https://www.sciencedirect.com/science/article/abs/pii/S0360319921027075.

[8] Moestedt J, Algebrant E. In-situ methanation of hydrogen Intermittent injection of hydrogen to a post-digester Ronja Löw. Available from: www.liu.se.

[9] Calbry-Muzyka AS, Schildhauer TJ. Direct Methanation of Biogas—Technical Challenges and Recent Progress. Frontiers in Energy Research. 2020 12;8:570887. Available from: www.frontiersin.org.

[10] Vad vi gör - Tekniska verken;. Available from: https://www.tekniskaverken.se/om-oss/vad-vi-gor/.

[11] Hur produceras biogas? Så här blir matavfall ett förnybart bränsle - Svensk Biogas;. Available from: https://www.svenskbiogas.se/biogas-miljo/produktion-av-biogas/.

[12] Forskning och pilotprojekt - Tekniska verken;. Available from: https://www.tekniskaverken.se/om-oss/vad-vi-gor/forskning-pilotprojekt/.

[13] Hossain E, Roy S, Mohammad N, Nawar N, Dipta DR. Metrics and enhancement strategies for grid resilience and reliability during natural disasters. Applied Energy. 2021 5;290:116709.

[14] Sveriges elnät | Svenska kraftnät;. Available from: https://www.svk.se/om-kraftsystemet/oversikt-av-kraftsystemet/sveriges-elnat/.

[15] Företag elintensivanslutning | Vattenfall Eldistribution;. Available from: https://www.vattenfalleldistribution.se/kund-i-elnatet/anslutning/anslutning-foretag/storre-anslutning/?

[16] Map of the national grid | Svenska kraftnät;. Available from: https://www.svk.se/en/national-grid/map-of-the-national-grid/.

[17] Operations and Electricity Markets | Svenska kraftnät;. Available from: https://www.svk.se/en/national-grid/operations-and-electricity-markets/.

[18] Growth in global electricity demand is set to accelerate in the coming years as power-hungry sectors expand - News - IEA;. Available from: https://www.iea.org/news/growth-in-global-electricity-demand-is-set-to-accelerate-in-the-coming-years-as-power-hungry-sectors-expand?

[19] Sweden - Countries & Regions - IEA;. Available from: https://www.iea.org/countries/sweden/electricity.

[20] Sverige | App | Electricity Maps;. Available from: https://app.electricitymaps.com/zone/SE/72h/hourly.

[21] Vårt uppdrag | Svenska kraftnät;. Available from: https://www.svk.se/om-oss/verksamhet/.

[22] Nätområden.se;. Available from: https://www.natomraden.se/.

[23] Understanding Voltage Drop Across a Resistor: A Practical Guide for Ev – Wray Castle;. Available from: https://wraycastle.com/blogs/knowledge-base/voltage-drop-across-resistor.

[24] Energimarknadsinspektionen. Spänningskvalitet i elnäten. 2018. Available from: www.ei.se.

[25] Renewable Energy Agency I, Methanol Institute t. INNOVATION OUTLOOK RENEWABLE METHANOL in partnership with. 2021. Available from: www.irena.org.

[26] Shiva Kumar S, Himabindu V. Hydrogen production by PEM water electrolysis – A review. Materials Science for Energy Technologies. 2019 12;2(3):442-54.

[27] 30 Sale of electrolysis by products;. Available from: https://www.irena.org/Innovation-landscape-for-smart-electrification/Power-to-hydrogen/30-Sale-of-electrolysis-by-products-oxygen-and-heat.

[28] Hydrogen;. Available from: https://www.irena.org/Energy-Transition/Technology/Hydrogen.

[29] Brynolf S, Taljegard M, Grahn M, Hansson J. Electrofuels for the transport sector: A review of production costs. Renewable and Sustainable Energy Reviews. 2018 1;81:1887-905.

[30] Roeder T, Rosenstiel A, Monnerie N, Sattler C. Impact of expected cost reduction and lifetime extension of electrolysis stacks on hydrogen production costs. International Journal of Hydrogen Energy. 2024 12;95:1242-51.

[31] Hernández-Gómez Ramirez V, Guilbert D. Investigation of PEM electrolyzer modeling: Electrical domain, efficiency, and specific energy consumption. International Journal of Hydrogen Energy. 2020 5;45(29):14625-39.

[32] Falcão DS, Pinto AMFR. A review on PEM electrolyzer modelling: Guidelines for beginners. Journal of Cleaner Production. 2020 7;261:121184.

[33] Energy Transitions Commission: The Making Mission Possible Series. 2023.

[34] Martinez Lopez VA, Ziar H, Haverkort JW, Zeman M, Isabella O. Dynamic operation of water electrolyzers: A review for applications in photovoltaic systems integration. Renewable and Sustainable Energy Reviews. 2023 8;182:113407.

[35] Elektrolysör för 1 MW - Euromekanik;. Available from: `https://www.euromekanik.se/produkter/elektrolysor/komplett-elektrolysor-1mw/`.

[36] Elberry AM, Thakur J, Santasalo-Aarnio A, Larmi M. Large-scale compressed hydrogen storage as part of renewable electricity storage systems. International Journal of Hydrogen Energy. 2021 4;46(29):15671-90.

[37] Lebrouhi BE, Djoupo JJ, Lamrani B, Benabdelaziz K, Kousksou T. Global hydrogen development - A technological and geopolitical overview. International Journal of Hydrogen Energy. 2022 2;47(11):7016-48.

[38] Sdanghi G, Maranzana G, Celzard A, Fierro V. Review of the current technologies and performances of hydrogen compression for stationary and automotive applications. Renewable and Sustainable Energy Reviews. 2019 3;102:150-70.

[39] Jiang K, Tian Z, Cullis I, Proud WG, Hillmansen S. Towards sustainable mobility: A systematic review of hydrogen refueling station security assessment and risk prevention. International Journal of Hydrogen Energy. 2025 3;105:1266-80.

[40] Hydrogen Storage | Department of Energy;. Available from: `https://www.energy.gov/eere/fuelcells/hydrogen-storage`.

[41] Council of the European Union. Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on the deployment of alternative fuels infrastructure, and repealing Directive 2014/94/EU. Brussels: European Union; 2023. Available from: `32023R1804`.

[42] Trans-European Transport Network (TEN-T) - European Commission;. Available from: `https://transport.ec.europa.eu/transport-themes/infrastructure-and-investment/trans-european-transport-network-ten-t_en`.

[43] Regeringen - Landsbygds- och infrastrukturdepartementet. Utkast till handlingsprogram enligt artikel 14 i AFIR; 2025.

[44] About biogas and biomethane | European Biogas Association;. Available from: `https://www.europeanbiogas.eu/about-biogas-and-biomethane/`.

[45] Sun ZF, Zhao L, Wu KK, Wang ZH, Wu Jt, Chen C, et al. Overview of recent progress in exogenous hydrogen supply biogas upgrading and future perspective. Science of The Total Environment. 2022 11;848:157824. Available from: `https://linkinghub.elsevier.com/retrieve/pii/S0048969722049233`.

[46] Voelklein MA, Rusmanis D, Murphy JD. Biological methanation: Strategies for in-situ and ex-situ upgrading in anaerobic digestion. Applied Energy. 2019 2;235:1061-71.

[47] Grahn M, Malmgren E, Korberg AD, Taljegard M, Anderson JE, Brynolf S, et al. Review of electrofuel feasibility—cost and environmental impact. Progress in Energy. 2022 6;4(3):032010. Available from: https://iopscience.iop.org/article/10.1088/2516-1083/ac7937https://iopscience.iop.org/article/10.1088/2516-1083/ac7937/meta.

[48] Al NM, S SP, Ar C, Ce L, Nd P, Eu S, et al. H He Li Be B C N O F Ne Ac Th Pa U Np Pu Am Cm Bk Cf Es Fm Md No Lr. Available from: www.acs.org/outreach.

[49] EU Delegated Acts on Renewable Hydrogen;. Available from: https://ec.europa.eu/commission/presscorner/detail/en/qanda_23_595.

[50] Renewable hydrogen - European Commission;. Available from: https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen/renewable-hydrogen_en.

[51] Delegated regulation - 2023/1184 - EN - EUR-Lex;. Available from: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32023R1184&qid=1704969010792.

[52] Kommissionens delegerade akter om förnybar vätgas (RFNBO) och återvunna kolbränslen är äntligen beslutade och publicerade - Energigas Sverige;. Available from: https://www.energigas.se/om-oss/nyheter-och-press/nyheter/kommissionens-delegerade-akter-om-fornybar-vatgas-rfnbo-och-atervunna-kolbranslen-ar-antligen-beslutade-och-publicerade/.

[53] Methane and climate change – Methane Tracker 2021 – Analysis - IEA;. Available from: https://www.iea.org/reports/methane-tracker-2021/methane-and-climate-change.

[54] Importance of Methane | US EPA;. Available from: https://www.epa.gov/gmi/importance-methane.

[55] Bakkaloglu S, Cooper J, Hawkes A. Methane emissions along biomethane and biogas supply chains are underestimated. One Earth. 2022 6;5(6):724-36.

[56] Scheutz C, Gudmundsson E, Fredenslund AM. Methane emissions from biogas production plants. 2022.

[57] Scheutz C, Fredenslund AM. Total methane emission rates and losses from 23 biogas plants. Waste Management. 2019 9;97:38-46.

[58] Sand M, Skeie RB, Sandstad M, Krishnan S, Myhre G, Bryant H, et al. A multi-model assessment of the Global Warming Potential of hydrogen. Communications Earth & Environment 2023 4:1. 2023 6;4(1):1-12. Available from: https://www.nature.com/articles/s43247-023-00857-8.

[59] Hauglustaine D, Paulot F, Collins W, Derwent R, Sand M, Boucher O. Climate benefit of a future hydrogen economy. Available from: https://doi.org/10.1038/s43247-022-00626-z.

[60] Review of Hydrogen Leakage along the Supply Chain: Environmental Impact, Mitigation, and Recommendations for Sustainable Deployment Abdurahman Alsulaiman, OIES Visiting Research Fellow. 2024.

[61] Fan Z, Sheerazi H, Bhardwaj A, Corbeau AS, Longobardi K, Castañeda A, et al. HYDROGEN LEAKAGE: A POTENTIAL RISK FOR THE HYDROGEN ECONOMY. 2022. Available from: https://energypolicy.columbia.edu/about/partners.

[62] What is the energy content of hydrogen? - Enapter;. Available from: https://www.enapter.com/kb_post/what-is-the-energy-content-of-hydrogen/.

[63] Farrer LM. Cost Modeling: Terms and Definitions. The RF and Microwave Handbook: RF and Microwave Applications and Systems. 2015 1:579-609.

[64] How to evaluate the cost of the green hydrogen business case? Assessing green hydrogen production costs. 2022.

[65] Detz R, Weeda M. Projections of electrolyzer investment cost reduction through learning curve analysis. 2022. Available from: www.tno.nl.

[66] Fakta om dricksvatten, vårt mest kontrollerade livsmedel | Svenskt Vatten;. Available from: https://www.svensktvatten.se/om-oss/verksamhet-och-strategi/fakta-om-vatten/dricksvattenfakta/.

[67] Krishnan S, Koning V, Theodorus de Groot M, de Groot A, Mendoza PG, Junginger M, et al. Present and future cost of alkaline and PEM electrolyser stacks. International Journal of Hydrogen Energy. 2023 10;48(83):32313-30.

[68] Biogas - förnybar gas för era transportbilar och arbetsbilar - Svensk Biogas;. Available from: https://www.svenskbiogas.se/produkter/transportbilar/.

[69] Giorgio. IEA-ETSAP© Technology Brief P12-February 2014-www.etsap.org ENERGY TECHNOLOGY SYSTEM ANALYSIS PROGRAMME Hydrogen Production & Distribution. Available from: www.etsap.org.

[70] Directive - 2020/2184 - EN - EUR-Lex;. Available from: https://eur-lex.europa.eu/eli/dir/2020/2184/oj/eng.

[71] CO2 emissions per kWh in Germany - Nowtricity;. Available from: https://www.nowtricity.com/country/germany/.

[72] CO2 emissions per kWh in Sweden - Nowtricity;. Available from: https://www.nowtricity.com/country/sweden/.

[73] DOE Hydrogen and Fuel Cells Program Record 9013: Energy requirements for hydrogen gas compression and liquefaction as related to vehicle storage needs. 2009. Available from: http://www.eere.energy.gov/hydrogenandfuelcells/hydrogen_publications.html#h2_storage.

[74] State of the biogas industry in 12 member countries of IEA Bioenergy Task 37 – Bioenergy;. Available from: https://www.ieabioenergy.com/blog/publications/state-of-the-biogas-industry-in-12-member-countries-of-iea-bioenergy-task-37/.

[75] Energy Density of Methane - The Physics Factbook;. Available from: https://hypertextbook.com/facts/2004/BillyWan.shtml.

[76] Regeringskansliet Ro. Sweden's climate policy framework. 2021. Available from: https://www.government.se/articles/2021/03/swedens-climate-policy-framework/.

[77] Klimatpolitiska rådet: Sverige kommer inte nå klimatmål;. Available from: https://www.di.se/hallbart-naringsliv/varningen-sverige-kommer-att-bomma-klimatmalen/.

DEPARTMENT OF SOME SUBJECT OR TECHNOLOGY
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden
www.chalmers.se

CHALMERS
UNIVERSITY OF TECHNOLOGY