Conditions for Profitability and Grid Effects of PV-Electrolysis

Master's Thesis

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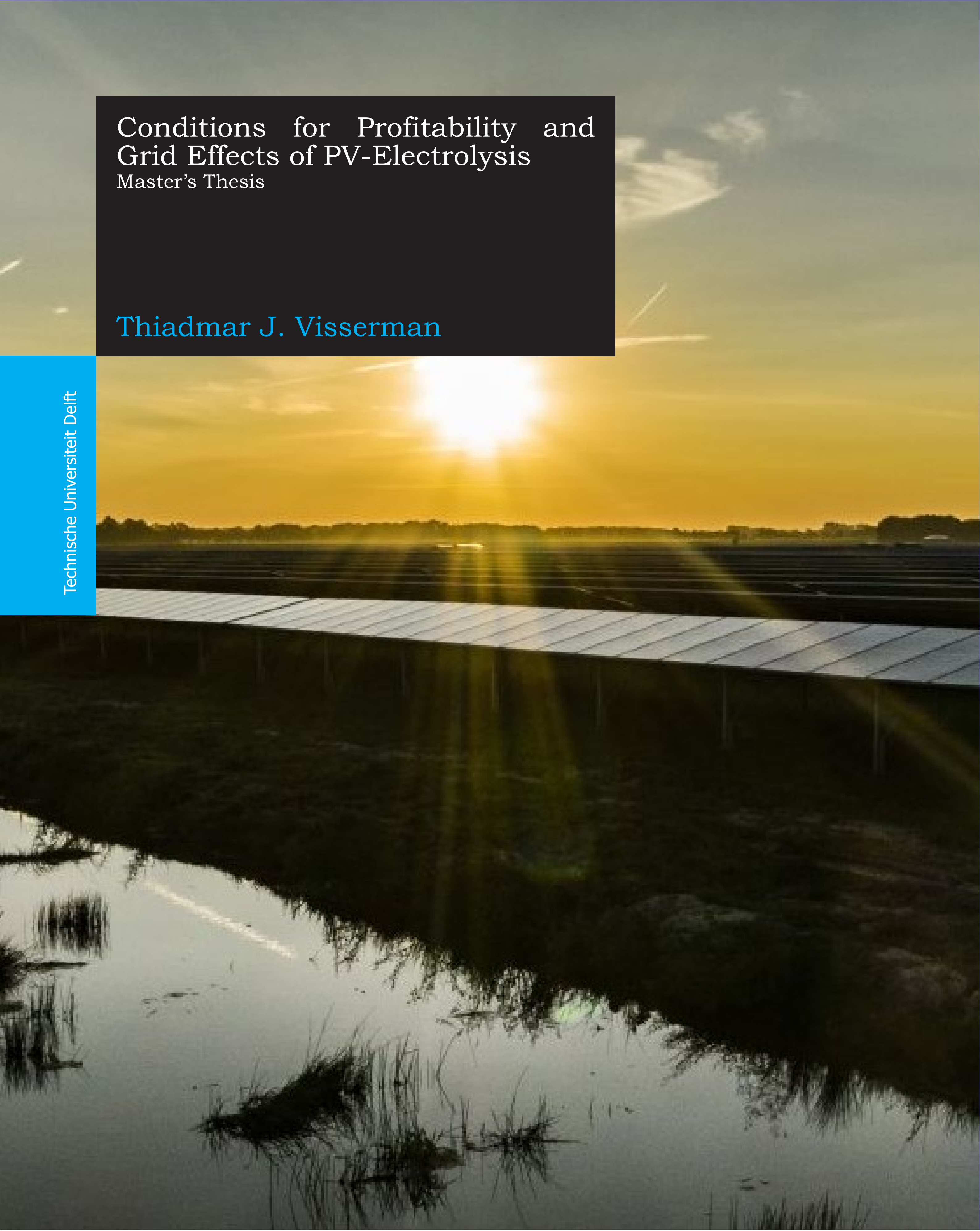

TU Delft Delft University of Technology

Challenge the future

Conditions for Profitability and Grid Effects of PV-Electrolysis

Master's Thesis

by

Thiadmar J. Visserman

in partial fulfillment of the requirements for the degree of

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Context

To avoid excessive effects of climate change the international community has agreed on reductions of greenhouse gas (GHG) emissions in the near future to limit the temperature increase to 1.5°C above pre-industrial levels [1]. Especially the European Union (EU) has made serious commitments to reduce GHG emissions in an effort to tackle challenges related to climate and environment. To that end the European Commission (EC) has laid out its Green Deal, aiming for net zero GHG emissions by 2050 [2]. In consequence the European Commission has proposed the European Climate Law, legally binding the Union to the climate neutrality objective [3]. The European Commission has also stepped up the intermediate objective for 2030 to a reduction of net GHG emissions of at least 55% compared to 1990 [4]. A provisional agreement exists between the Union's co-legislators on both the European Climate Law and the increased intermediate goal for 2030 [5]. The EU has committed an impressive 30% of its EUR 2.0bn 2021-2027 budget, comprising of EUR 1,210.9bn long-term budget and EUR 806.9bn from NextGenerationEU, a temporary instrument to boost recovery from the COVID-19 crisis, as part of an investment plan to support the climate objectives [6].

Most of the emission reductions globally up to 2030 will originate from technologies that are already on the market today, while almost half of the emission reductions by 2050 will be driven by technologies that are currently being developed. The most promising innovations are expected in the field of advanced batteries, direct air capture and water electrolysis [7]. Green hydrogen and green hydrogen-based synthetic fuels will play a major role in sectors where emissions are hardest to abate. The initial use cases for hydrogen will lie in replacement of existing fossil energy consumption while not requiring large changes in infrastructure, such as replacing fossil hydrogen use in industry, power plants and hydrogen blending in the natural gas grid [7]. Many early green hydrogen projects have also contracted end users in mobility and some in steel manufacturing [8]. A breakdown of hydrogen demand by sector can is displayed in Figure 1.1. Global hydrogen demand is expected to grow to over 200 Mt in 2030 from just under 90 Mt in 2020, while low-carbon hydrogen will increase its share to 70% in 2030 from 10% in 2020. In 2030 this low-carbon hydrogen will originate in approximately fifty-fifty proportion from fossil sources with CCUS and water electrolysis [7].

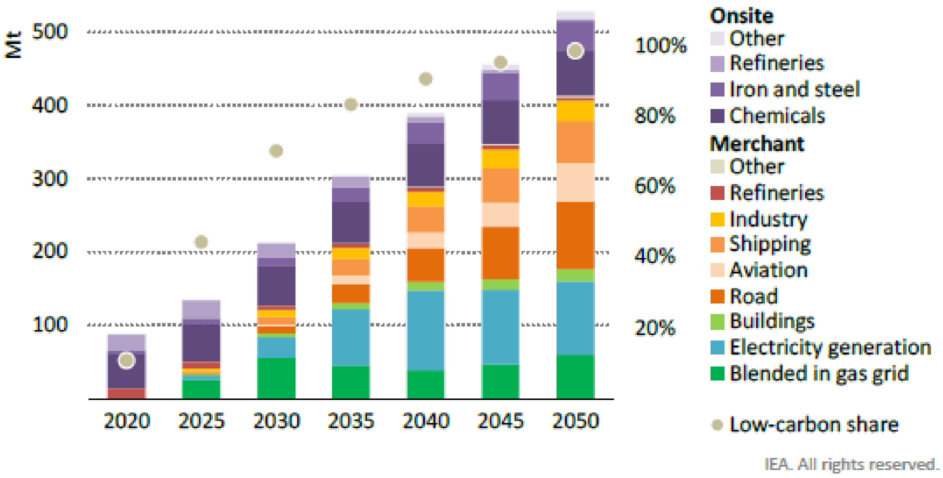


Figure 1.1: Global hydrogen demand based on Net Zero Emissions scenario [7]

The global pipeline of hydrogen electrolysis projects to be realised before 2040 has showcased an impressive growth over the recent period, from 3.2 GW in October 2019 to 213.5 GW in 2021 [9][10]. The global project pipeline is led by Germany [10]. Germany's largest electrolyser with a capacity of 6 MW has been operational since 2017 and is located in Mainz, whereas a 100 MW electrolyser is planned to come online in 2023 [11]. Because of the rapidly changing landscape, both in technological and regulatory respect, the business case around electrolysis technology coupled to a decentralized renewable energy generation system remains relatively undiscovered territory.

This subject has also gained the interest of two energy players in The Netherlands. GroenLeven, a renewable energy developer and Alliander, the largest DSO in The Netherlands, are interested in the commercial optimisation of electrolysis coupled to decentralized renewable generation assets and hence have offered their support to this study. GroenLeven and Alliander have been occupied by this subject themselves and are jointly developing an electrolysis pilot project in Oosterwolde, where a 1.3 MW electrolyser will be coupled to 6 MWp of PV capacity out of the 53 MWp PV park Oosterwolde. The PV plant is operated by GroenLeven and connected to the Alliander distribution network. The pilot project will reach operational phase in the summer of 2021.

1.1. Background

The increasing political support for reaching net zero GHG emissions is reason for optimism. Current commitments to achieve net-zero emissions have increased drastically over the past few years, now representing around 70% of CO_2 emissions globally [7]. The energy transition that is required to meet the emission reduction pledges will mean that many energy systems have to change rapidly and drastically. Variable renewable energy (VRE), such as solar and wind, will be a driving force in this transition and consequently many industrialized countries have adopted policies aimed towards expanding the share of renewable energy in the energy mix. Apart from the power sector, VRE can be used to decarbonise other sectors in the future, such as heating and transport, through a phenomenon called sector coupling. The increasing shares of VRE in electricity generation pose new physical and commercial challenges to developers and owners of the generating assets, who actively participate in the electricity market, as well as operators of transport and distribution infrastructure. These challenges, as well as the possible solution that is studied in this research, electrolysis technology, will be illustrated with more background information in this section.

1.1.1. Introduction to hydrogen

Hydrogen is a gas that is used in many processes today, such as the production of fertilizer and in refinery processes. It is also possible to use hydrogen as an energy carrier, to be used in combustion processes or fuel cells where the carried energy can be used as heat or electricity, respectively. Hydrogen, or more specifically 'green' hydrogen is seen by many as a possible solution for energy storage and decarbonisation of hard-to-abate processes in the energy transition.

Hydrogen is conventionally produced from natural gas or methane in a process called steam methane reforming (SMR), which is referred to as 'grey' hydrogen. This route produces large amounts of GHG emissions: 99 gCO_2-eq./MJ or 14 $kgCO_2$-eq./kgH_2 [12]. A lower carbon option is 'blue' hydrogen, via this route the CO_2 produced in the SMR process is stored using carbon capture and storage (CCS) technology in combination with SMR. Investments in CCS equipment and storage space would however drive up the cost of the produced hydrogen. SMR combined with CCS is considered to be a possible temporary solution for as long as green hydrogen is still too expensive, but it is not sustainable in the end due to inevitable limitations on storage locations and natural gas supply. The most common 'green' or renewable option to produce hydrogen that seems feasible on large scale is by water electrolysis, powered by renewable energy. See Figure 1.2 for an impression of a PV-Electrolysis system. In this process water is split into its constituents, hydrogen and oxygen, using electricity. Electrolysis can play a valuable role in utilizing renewable electricity supply peaks and it can be an enabling technology for seasonal renewable energy storage. The technology has been around since a long time, the phenomenon was first observed in experiments by a German and a Dutchman in 1789, Jon Rudolph

Deiman and Adriaan Paets van Troostwijk [13]. An electrolyser is the device that is used to perform electrolysis. The main difference between electrolysis technologies is the type of electrolyte the cells are based on. The electrolysis technology will be discussed in more detail in Section 2.2.1.

Figure 1.2: A 10 MW PV-Electrolysis plant in Fukushima, Japan [14]

1.1.2. The hydrogen economy

The behaviour of VRE such as wind and solar is different from dispatchable technologies in that they only produce electricity when the environment provides the right conditions, such as wind or solar irradiation. The availability of these conditions is not homogeneously distributed geographically, with more and less favourable locations for VRE generation. Hydrogen as an energy carrier can be the facilitator of an energy system based on VRE on the level of time and geographical location, since it can be stored and transported from favourable VRE locations and meet energy demand in a timely fashion on other locations, cost effectively. A future hydrogen economy in which hydrogen will the climate neutral energy carrier and a globally traded commodity can enable this role for the element. In providing these functions as a gaseous energy carrier, the system around hydrogen in the future will much resemble current day natural gas systems. The infrastructure required for the hydrogen economy can be established with moderate adaptations of the current natural gas storage and distribution infrastructure, including salt caverns, pipelines and shipping [15].

In a collaboration of European gas infrastructure operators, a roadmap towards a European hydrogen network was created. The system is called the 'European Hydrogen Backbone' and it comprises 39,700 km of hydrogen pipeline infrastructure, of which 69% repurposed infrastructure and 31% newly constructed hydrogen infrastructure (Fig. 1.3). The collaborating network operators envision the system's realization by 2040 [16]. From a cost effectiveness point of view for long distance transportation of energy, hydrogen pipelines have a large advantage over transportation of electricity through HVDC (high voltage direct current) infrastructure. The costs for transportation per unit of energy using hydrogen pipelines is estimated at 4.97 USD/MWh/1000 miles (equating to 0.07 EUR/kgH_2/1000 km), while the costs for HVDC lines are estimated at 41.50 USD/MWh/1000 miles, roughly a factor 8.5 more expensive [17].

In the medium term, not enough renewable hydrogen will be available to facilitate the full transition of the system. During this period blue hydrogen can play a role, this is hydrogen produced from natural gas, which is currently the most common hydrogen production process, but with capturing of CO_2.

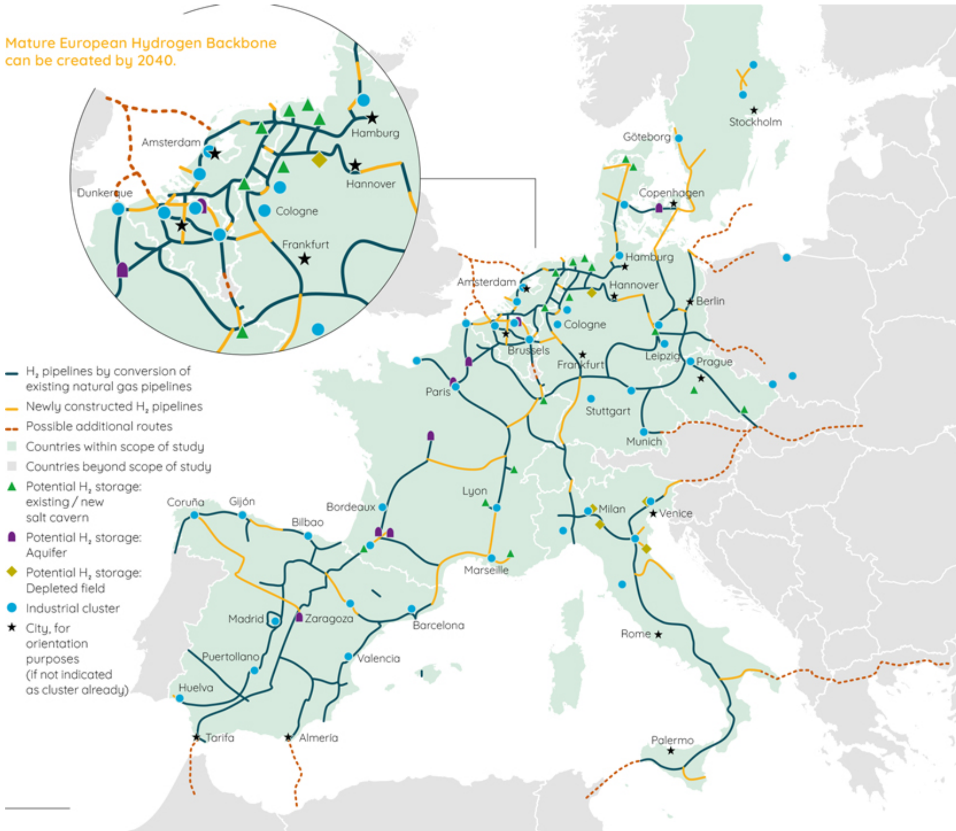


Figure 1.3: European Hydrogen Backbone: 39,700 km hydrogen pipeline infrastructure, of which 69% repurposed infrastructure and 31% newly constructed hydrogen infrastructure [16].

The energy system facilitated by a hydrogen system reaches wider than the electricity system. Hydrogen can play an important role in decarbonizing sectors that are otherwise hard to abate such as certain mobility needs, chemical or heating processes in industry, heating in the built environment and balancing functions in the electricity system. A new balance between local production and imports of the gaseous energy carrier in this newly mapped energy system will crystallize over time, based on costs of production and transportation.

The important role for hydrogen in energy systems of the future is acknowledged globally. Halfway through 2021 hydrogen strategies were announced by over thirty countries. The objectives of these strategies are not limited to integrating electricity from VRE and reducing emissions in sectors that are hard to abate. The objectives are also economically strategic: diversification and security of energy supplies, stimulation of the local economy and technology development and the development of the international hydrogen economy [18].

Today hydrogen is mostly produced from natural gas, and also from coal. The production usually takes place close to where hydrogen is consumed. Today hydrogen is consumed mainly in chemical processes, for example in refinery processes producing fuels or in the chemical industry in the production of methanol, ammonia and fertilizer. In a transition towards integration of hydrogen in the energy system the gaseous energy carrier can be combusted, much alike natural gas, in turbines, boilers and even combustion engines, providing mechanical power, electricity or heat, requiring moderate adaptations. However, progressing along the timeline of this transition, the electrochemical conversion of hydrogen in fuel cells will gain in relevance [15].

In recent years fuel cell development was driven by the mobility industry to a large extent, as alternative drive trains for long-haul and high 'up-time' mobility forms. Projections are that eventually the costs and conversion losses will sink below and the levels currently achieved with combustion engines and turbines, making fuel cell technology a clean and cheaper alternative to modern combustion technology [19]. When the projected cost reductions and efficiency gains materialize, fuel cell systems will be more widely adopted for other applications within the energy system. For example in domestic heating and power generation, fuel cells can play a role when VRE are not available. Large scale fuel cell systems can even provide balancing services for the electricity system when VRE are not meeting demand [15].

1.1.3. Challenges for electricity market participants

Electricity markets are constrained by simultaneity of supply and demand. Electricity demand in most markets shows significant temporal variability, and little sensitivity to electricity prices in the short term. As a result, supply of electricity must continuously meet the variable demand. Conventional electricity markets are typically based on large, centralized, dispatchable generation technologies that adjust their output to demand continuously. Generally a distinction is made between base load technologies, which run on more or less the same power all day and peak load technologies which are more flexible in terms of load and are used to meet demand when it is high. Base load technologies have largely inflexible output in the short term and are characterized by high capital costs and low variable costs. Conversely, peak load technologies are characterized by lower capital costs and higher variable costs [20].

The economics of VRE such as wind and solar are different from dispatchable technologies in that they only produce electricity when the environment provides the right conditions, such as wind or solar irradiation. This currently leaves operators without power over production, besides curtailment of surpluses. Furthermore, these technologies have a different cost structure, with high capital costs and essentially no variable costs [21]. Variability for these technologies occurs on multiple timescales, which also differ for solar and wind, as can be observed from the normalized example for Germany in Figure 1.4. Variability on the very short term can occur locally due to cloudiness with solar PV. On the system level this effect can be smoothed by geographical diversification. Secondly there are within-day fluctuations, due to environmental characteristics of day and night, e.g. no sunshine at night. Then there is seasonal variability, due to the characteristics of the seasons [20]. Daily and seasonal patterns for solar are fairly predictable, generating only during daylight hours and more during summer than during winter. Wind is more dependent on location but generally more at night than midday, and in Europe more during autumn and winter. The seasonal cycles for wind and solar may enable some smoothing of their combined variability, as their mean seasonal generation shows a pronounced negative correlation [22].

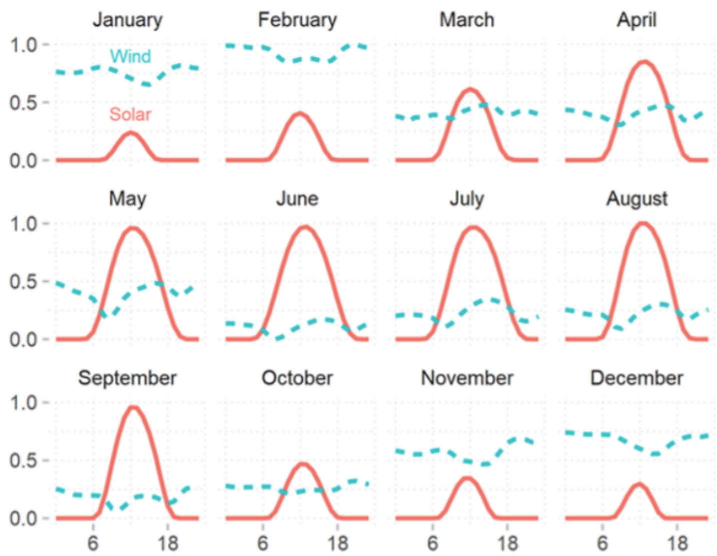


Figure 1.4: Normalized average hourly electricity production from wind and solar in Germany in 2016 [20].

Electricity is a perfectly homogeneous good in time, space and lead times between contract and delivery [21]. This results in a market clearing at marginal cost for each time, location and market period. The equilibrium price and traded quantity of electricity is determined by the intersection of the demand and supply curve. As most consumers do not yet respond to electricity prices in real-time, demand is typically assumed to be price inelastic in the short term. The supply curve is constructed from the marginal cost of all available power generators in ascending order. Since VRE have essentially no marginal cost, the available capacity bid by VRE operators appears on the lower left side of the ascending supply curve, driving the clearing price down. This phenomenon is known as the merit-order effect (MOE), of which a simplified representation can be observed in Figure 1.5. Due to the low marginal cost and inherent variability, high levels of VRE in the system will drive down average electricity prices and introduce more electricity price volatility [23].

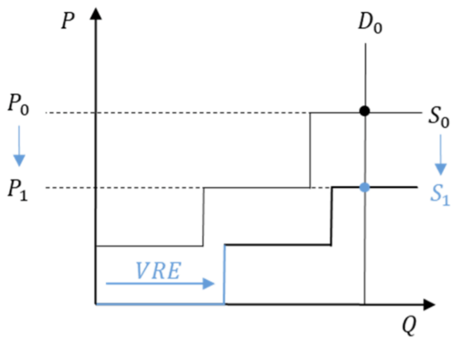


Figure 1.5: A simplified representation of the merit-order effect in the electricity market [20]

The low marginal cost and variable and uncontrollable generation potential of VRE together with the market contstraint of supply and demand simultaneity result in a drop of prices when the share of VRE in the market grows. The drop in electricity prices with growing VRE share is called the cannibalization effect. This effect is illustrated in Figure 1.6 by price duration curves (PDC), depicting the clearing prices for all hours of the year in descending order. In Figure 1.6a the merit-order effect in the electricity market is visualised, the PDC shifts downwards with growing share of VRE and this movement reduces the average clearing price from p_0 to p_1. In Figure 1.6b the PDC for a VRE generator is depicted, representing the realized price by this generator during its production hours. In the case of solar PV there is a positive correlation between its production and electricity demand. At low VRE penetration this results in an average realized price (also know as market value) which is higher than the average clearing price. Increasing VRE penetration reverses this effect, as the MOE is strongest at times of high VRE availability, which causes the average realized price of a VRE generator to fall faster than the average clearing price. The difference between the realized prices by the VRE generator with high and low VRE penetration is known as the absolute cannibalization effect, while the realized price by the VRE generator with respect to the average realized price in the market is known as the relative cannibalization effect [20].

Even though annual renewable energy surpluses are not easily reached, high peak surpluses will quickly arise with growing VRE penetrations. Sometimes the VRE may produce too much electricity and at other times too little. The remainder after subtraction of non-dispatchable and inflexible power generators from the actual demand is known as residual load. A positive residual load means that there too little VRE supply to meet actual demand and a negative residual load means that there more VRE supply than there is demand, so when residual load is zero the actual demand and VRE generation are equal. Positive residual load can be met using dispatchable generators, which are often supplied by fossil energy sources, or for example biomass fired installations. Negative residual load is commonly curtailed, but can also be stored or converted [24]. Similar to PDCs, residual demand duration curves (RLDC) are a useful tool to illustrate this phenomenon. To illustrate the transformation of the RLDC with increasing VRE penetration, we look at some results from Prol and Schill [20], obtained for a stylized German setting with a model derived from the DIETER model, which is described in [25]. This is a linear cost-minimizing model for the electricity sector, including investment and variable costs. Figure 1.7a shows

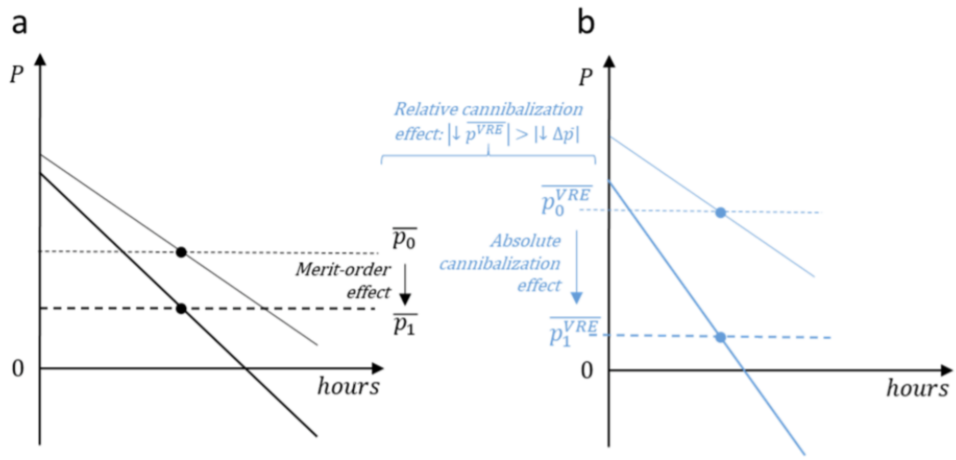


Figure 1.6: The MOE and the cannibalization effect represented by PDCs for the market (a) and for a VRE generator (b) with low (0) and high (1) VRE shares [20].

how the RLDC curve moves downwards on the right with increasing VRE penetration, if it increases to 90%, negative residual load occurs nearly half of the year. The changes on the left-hand side of the RLDC are less radical, showing limited reduction with increasing VRE, illustrating the remaining necessity of dispatchable generators to meet positive residual demand.

The common solution for negative residual load is currently curtailment, which means the installations are shut off from the grid and the electricity is lost. Curtailment of renewable energy peak surpluses can also occur because of local transport & distribution infrastructure constraints. These constraints can be physical due to lack of transmission capacity in the local infrastructure, or legal because the supplier has contracted grid capacity lower than its generated power. Either way curtailment results in loss of energy. This energy can also be utilised or stored using the right technologies. One way to utilise this energy is power-to-X, which includes smart charging of battery-electric vehicles, heat storage and electrochemical conversion to hydrogen or derived fuels. Power-to-X technologies can behave as new flexible loads, consuming the surplus energy produced during hours with negative residual load and thereby productively exploiting the otherwise lost energy. However, power-to-X technologies do not necessarily return energy to the grid, but can also be used for sector coupling. While power-to-X technologies can create a new use for otherwise curtailed electricity for the supplier, they can also reduce the burden on transmission and distribution infrastructure and such defer or dismiss investments in transport & distribution infrastructure [25].

Figure 1.7b shows the PDC for the same setting with increasing VRE penetration, including weighted average electricity prices. The PDC moves down on the right, analogous to the generation surplus in the RLDC. Even though this is not an explicit representation of market prices, as the model uses a cost-minimization approach with a constrained generation capacity by VRE and dispatchable generators, it gives an impression of what the market prices may do. The price may even drop below zero, reflecting that overall system cost can be minimized when more electricity would be consumed in these hours.

The increasing penetration of VRE will drive overall electricity prices down due to the MOE, and will especially impact owners and operators of VRE generators due to the cannibalization effect. Flexibility options such as electricity storage or sector coupling can mitigate these effects [20]. Energy storage is an attractive solution as it may be easier to implement than vast expansion of transmission infrastructure and it can time-shift great quantities of energy more easily than demand-side management while achieving higher reductions in GHG emissions compared to using fossil fuel powered back-up generation [26].

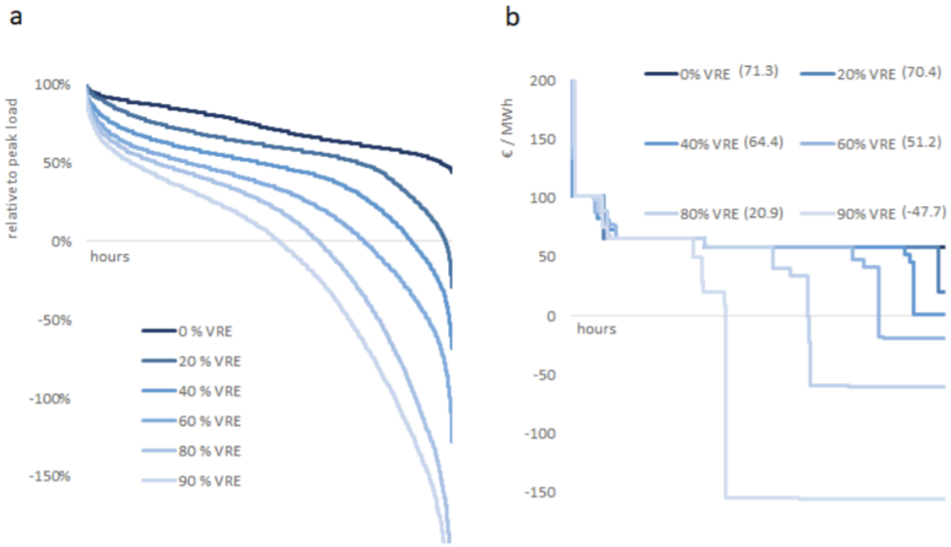


Figure 1.7: RLDCs and PDCs for increasing VRE penetration in Germany [20].

1.1.4. Challenges for infrastructure operators

High penetrations of variable renewable energy sources can produce high supply variability in the power supply. Even though annual renewable energy surpluses are not easily reached, high peak surpluses will quickly arise with growing penetrations of variable renewable energy sources [24]. Besides the temporal variability of solar and wind generation patterns, the geographical distribution of VRE generators does not necessarily coincide with the layout of grid infrastructure, which has largely been designed for a centralized power system [25].

VRE generators require substantial surface area and are often located in lightly populated areas for a variety of reasons, including land prices and availability. This is transforming rural regions from net consumers of electricity to net producers of electricity. The electricity transmission and distribution capacity in these regions has historically been low, a heritage from a centralized electricity generation system combined with typically low consumption of lightly populated regions. The distribution network in these areas was not designed to transport high volumes of electricity back to the transmission network and needs to be reinforced if renewable generating capacity is to continue to grow in such areas. An investigation by Dutch transmission- and distribution system operators (TSO's and DSO's) in June 2020 indicated that with the current pace of infrastructure enhancements two thirds of the existing stations will not meet the required capacity capacity in 2030 for the projected renewable generating capacity developments [27]. In quantitative terms, the largest dutch DSO Alliander expects that on top of its' 39,000 kilometres of cable and 45,000 low and medium voltage substations an additional 16,000 to 24,000 kilometres of cable and 4,000 to 12,000 stations will be required by 2030 [28]. As can be observed in Figure 1.8 the availability of capacity in the distribution system for electricity suppliers in the Alliander service area is already very limited, in the red-coloured areas no additional capacity is available today.

Matching transmission and distribution capacity to electricity supply can be achieved by either reducing the quantity of electricity that is supplied to the infrastructure or by increasing the capacity of the infrastructure. Reducing surplus electricity supply can be attained by curtailing supply peaks, temporary storage of electricity in storage facilities such as batteries, heat and cold storage or by electrochemical conversion to e.g. hydrogen. Reinforcing transmission- and distribution infrastructure is highly time consuming and puts a burden on the system operators [28], which are legally obliged to connect anyone who requests a connection to the distribution network. At the same time the long lead times of transport & distribution infrastructure expansion limits renewable energy developers in the generating capacity they can develop. Both types of stakeholders are looking for a solution to the infrastructure bottleneck.

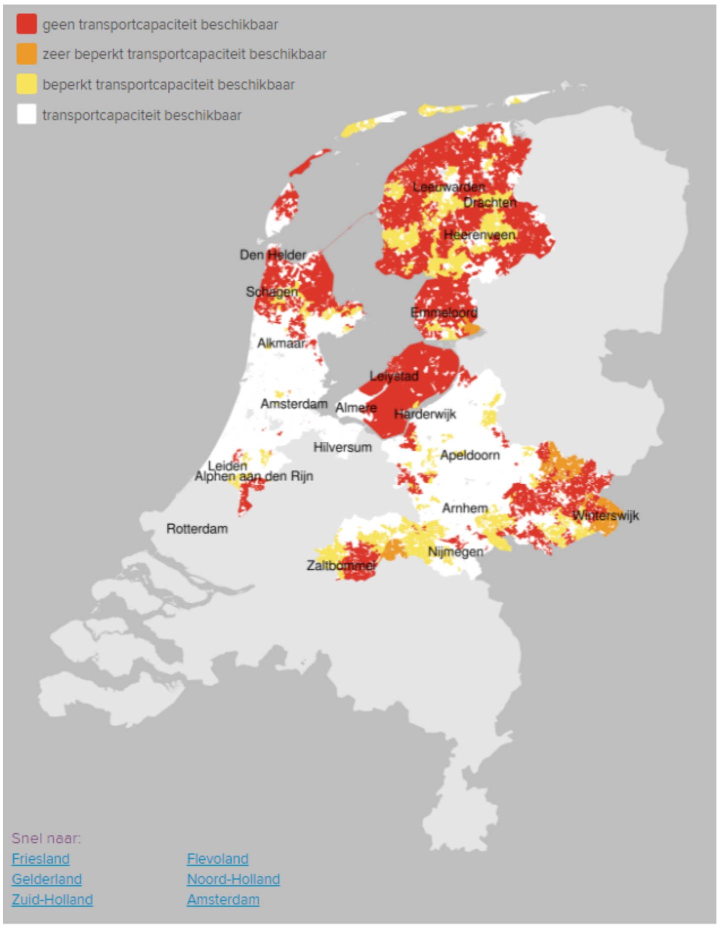


Figure 1.8: Remaining transport capacity for energy producers in the Alliander service area [29]

The red-coloured areas in Figure 1.8, short of any distribution capacity, have been and still are favourable locations for renewable energy development. To reduce the demands on the transport & distribution infrastructure operators a dutch collective of solar PV developers has agreed to limit their future network connection requests to maximum 70% of the peak installed capacity of a PV plant, a phenomenon known as overplanting [30]. Reducing the connection capacity to 70% of the peak generation capacity requires sacrificing just 3% to 4% of the electricity yield of a PV plant [28]. Since the reduction of connection capacity results in just a small yield loss, this agreement makes commercial sense. This way more PV capacity can be developed, serviced by the same distribution capacity. To further reduce infrastructure demands and possibly increase a generating asset's income streams, a combination of measures mentioned before can be considered. This research will focus on the opportunities that conversion to hydrogen by electrolysis offers in this context.

1.2. Research Structure

With rising shares of VRE in electricity generation in the future, electricity supply profiles will change. The inherent variability of VRE will result in a different shape of the RLDC, with more negative residual load. This will pose both physical and commercial challenges to the energy sector. Due to the low marginal cost and inherent variability, high levels of VRE in the system will drive down average electricity prices and introduce more electricity price volatility. To utilise the electricity surpluses and capitalise on the associated low and variable prices, water electrolysis is an often mentioned solution. Owners and operators of solar PV installations are amongst the parties challenged by these developments in the electricity generation industry. Complementing PV installations with water electrolysis technology could be a way to capitalise on these developments by offering alternative income streams to electricity. Hence, this graduation research will look into the commercial feasibility of a PV generator with an electrolyser in 2025, which will be verified by simulation in a real world case, specifically the Oosterwolde site where currently the SinneWetterstof pilot PV-Electrolysis project is realized.

1.2.1. Research Questions

This research is a techno-economic evaluation of the conditions that enable the business case for a PV-Electrolysis system to become profitable and an assessment of the effects on congestion in the electricity grid under these conditions. Relevant information to analyse the business case will be subject of study, such as developments in the electricity and hydrogen markets, developments of technology and price in the electrolyser market and possible income streams for the PV-Electrolysis system. Based on this information a selection of parameters will made of which the effects on the profitability of the business will be tested by simulation for a real world case, specifically the PV plant in Oosterwolde where the SinneWetterstof pilot project is currently being constructed. To conclude an assessment will be made of the effects of the PV-Electrolysis system on the distribution grid.

To guide this research several research questions have been composed. The research questions are presented below. Starting with the main question:

- Under which conditions can a PV-Electrolysis system become profitable and what are the effects on grid congestion under these conditions?

In support of the main research questions several sub-questions have also been formulated, which can be found below. Roughly every sub-question will have its own chapter. A reading guide is provided below, which further illustrates the contents of the chapters and the approach used to answer the corresponding sub-questions.

- Which market developments will impact the business case of a PV-Electrolysis system during its lifetime?
- What are the possible income streams and costs for a PV-Electrolysis system?
- Which parameters should be considered in the evaluation of the PV-Electrolysis business case?
- What are the parameters' effects on the business case in the real world case of Oosterwolde?
- Under which conditions does the business case for Oosterwolde become positive?
- What are the effects on grid congestion in the Oosterwolde case?

1.2.2. Reading Guide

This section provides an overview of the contents of this report and where to find them, with a detailed description of the contents of each chapter. The chapters in this research are ordered in a sequence in which they support each other, each chapter building on context given in the previous chapter, corresponding to the sub-questions presented in section 1.2.1. A list of the chapters is found directly below, followed by a detailed description of all chapters.

- Chapter 1: Context
- Chapter 2: Market Developments

- Chapter 3: Income Streams & System Cost
- Chapter 4: Case Study Oosterwolde
- Chapter 5: Evaluation Method
- Chapter 6: Results
- Chapter 7: Discussion
- Chapter 8: Conclusion

The first chapter of this report constitutes the context, which includes an introduction to this research, the theoretical background required to understand basic decisions in the rest of the report, the research questions, including the scope of the study and this reading guide, which simultaneously serves as a representation of the approach used to answer the research questions in this study.

The second chapter, 'Market Developments', will give insight in upcoming developments in the energy market that create a demand for solutions such as the PV-Electrolysis system that is investigated in this study. This chapter will describe future changes in electricity supply, which will shift from conventional sources to VRE, and demand, which will grow due to increasing electrification of energy uses currently supplied by other energy sources. This shift in electricity supply and demand will produce supply and demand curves that differ from typical curves in today's market. This will considerably affect electricity prices in the future. As electricity prices are a vital element of the business models that are evaluated in this study, price forward curves must be created for the duration of these business models. This is done by fundamental modelling of the power market, using a demand curve and a constructed merit order to determine power prices for each hour along the duration mentioned previously. The model used for this excercise is derived from the PyPSA model developed by the Frankfurt Institute for Advanced Studies [31]. The merit order will be constructed from forecasts for the Dutch electricity market of installed capacity and marginal costs, by generation technology. The forecasted demand curve will be constructed based on literature, taking into account forecasts of increasing electricity demand, due to the changing uses of electricity. Furthermore, developments of the price of renewable hydrogen are considered, which will be affected by scale-up of production and cost reductions for electrolysis equipment are evaluated, alongside developments in prices for PV and electrolysis equipment.

In the third chapter, 'Income Streams & System Cost', the sources of income that can be tapped by the PV-Electrolysis system are discussed. The direct products of the PV-Electrolysis system are (green/ renewable) electricity and (green/ renewable) hydrogen. Oxygen and waste heat can also be viewed as products of the Electrolysis process, however business cases that utilise these byproducts are rare. Another source of income that must be considered are subsidies, the extent to which they are expected to be available during the lifetime of the business models is discussed in this chapter. When evaluating a business model, costs must be subtracted from revenues. Hence, this chapter also presents the Capex and Opex cost items that must be considered for a PV-Electrolysis system. The Capex cost items include hardware costs and installation costs, whereas the Opex includes maintenance costs but more importantly, expenses for grid connection and purchased electricity. The cost items are evaluated for their respective relevant timeframe, this means for Capex items projected prices for 2025 will be used.

In the chapter 'Case Study Oosterwolde', the subject of the case study is presented: the site in Oosterwolde where the SinneWetterstof pilot project is realized. After presenting the case study, suitable modes of operation for the PV-Electrolysis system are presented. The system components and boundaries that constitute this case study will be presented in this chapter, as well as the simulation model used to evaluate this case study.

Considering all the information from the previous chapters, market developments, sources of income and cost items, in chapter 'Evaluation Method' it is laid out how the PV-Electrolysis business case is evaluated. A selection is made of research parameters of which scenarios are composed to assess the effects on the business case later on. Building on the market developments presented in the previous chapter, strategies exist to achieve high income producing and selling products in the right mix at the right time. For example, by producing hydrogen instead of selling the electricity when electricity prices are low. The assessment of the business case on protitability will follow the internal rate of return (IRR), which is explained in this chapter. The models used in this study to simulate the behaviour of the system and assess the profitability are presented in this chapter.

In chapter 'Results', the effects of several scenarios on the profitability of the PV-Electolysis system are assessed and the grid effects of a PV-Electrolysis system are evaluated by the hand of volumes and timeliness of electricity fed into the grid. In the Discussion chapter the probability and feasibility of the results of the case study will be discussed, and the implications of the results will be projected on the energy industry in the context of the energy transition. In the concluding chapter the conclusions of the research are presented, by answering the research questions.

2
Market Developments

This chapter, 'Market Developments', will give insight in upcoming developments in the energy market that create a demand for solutions such as the PV-Electrolysis system that is investigated in this study. These market developments include the shift in electricity generation from conventional sources to VRE, increased electrification, developments in the green hydrogen market as well as developments in the markets for PV and Electrolysis equipment.

2.1. Electricity

This section will describe future changes in electricity supply, which will shift from conventional sources to VRE, and demand, which will grow due to increasing electrification of energy uses currently supplied by other energy sources. This shift in electricity supply and demand will produce supply and demand curves that differ from typical curves in today's market. This will considerably affect electricity prices in the future. As electricity prices are a vital element of the business models that are evaluated in this study, price forward curves must be created for the duration of the business case. The duration of the business case is assumed at 20 years, which is the lifetime of an electrolyser system. The lifetime of a PV system is 25 years, so 5 possible years of individual PV operation remain after the initial 20 years. The base year for the business case is 2025, so electricity market projections are needed up to 2050.

This is done by fundamental modelling of the power market, using a residual load curve and a merit order for all years up to 2050 to determine the power prices for each hour along the duration mentioned previously. The model used for this excercise is derived from the PyPSA model developed by the Frankfurt Institute for Advanced Studies [31]. The merit order will be constructed from forecasts for the Dutch electricity market of installed capacity and marginal costs per generation type. The forecasted residual load curve will be constructed based on forecasts of increasing electricity demand, renewable generation and correspondingly scaled curves.

To achieve meaningful price forward curves, several assumptions have to be made. Where possible these assumptions are made based on scientific literature or other official sources, however due to the rapidly changing environment in the power market literature is sometimes lacking or outdated, in which case educated guesses are made to achieve more meaningful forecasts.

The first thing to be discussed in this section is the Fundamentel Power Market Model, after which the inputs and results achieved with the model are presented. The first input that is needed is a projection of the installed generation capacity per technology up to 2050. After that a merit order must be constructed reflecting the marginal cost at which a generator of each technology bids its capacity in the electricity market. Finally the demand must reflect the growing trend in electricity consumption up to 2040. The assumptions made to achieve this and construct the price forward curve are discussed in the sections below.

2.1.1. Fundamental Power Market Model

To produce suitable electricity price forward curves for this study a Fundamental Power Market Model (FPMM) was created. The inputs for this model are timeseries of Load and VRE to calculate a Residual Load Curve (RLC), and projections of installed capacity of dispatchable generation technologies and corresponding projections for marginal costs per generation technology to calculate a Merit Order (MO).

These marginal costs are calculated with projections commodity costs and generation efficiency. For each year, the FPMM calculates the residual load by subtracting VRE generation from Load for that year. The MO is calculated with the marginal cost projections of dispatchable generating technologies for each year. When the RLC and the MO are calculated, the clearing price for every period can be calculated. Due to the large size of the datasets it is chosen throughout the model to work with a time delta of one hour.

The FPMM for this study was created in Python, using amongst others an open source Python toolbox by the name of Python for Power System Analysis (PyPSA) [31], which was created at the Frankfurt Institute for Advanced Studies. A flowchart describing the way the FPMM works is displayed in Figure 2.1. The inputs of the FPMM: Installed Generation Capacity, Marginal Costs, Load and VRE generation, displayed as parrallellograms in Fig. 2.1, are discussed in the following sections.

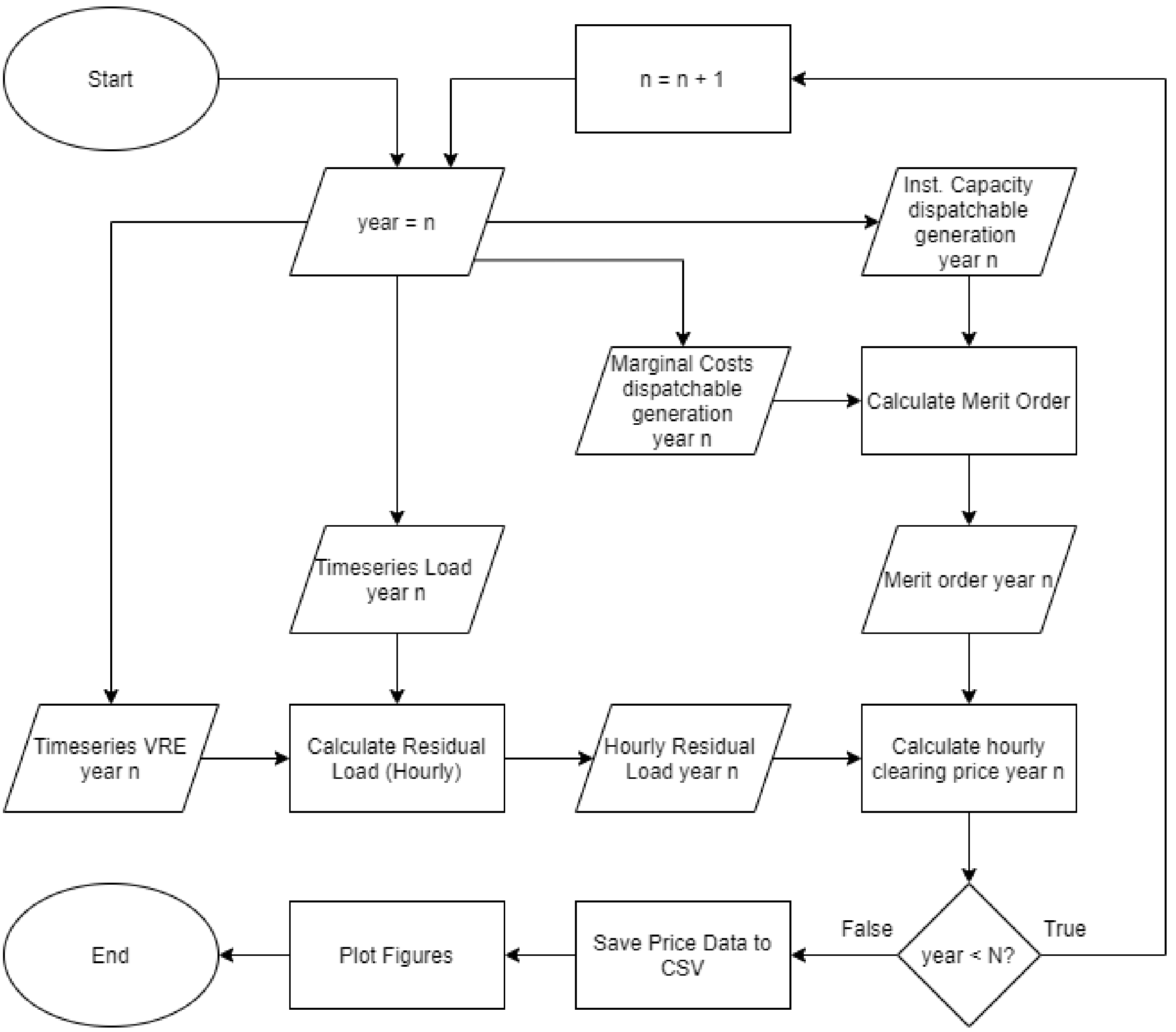


Figure 2.1: Flowchart of the Fundamental Power Market Model created for this study.

2.1.2. Installed Generation Capacity

The technology on which generation capacity is based is going to shift from conventional to VRE generators. Coal powered generation is most affected by CO_2 prices and is going to be phased out in 2030 altogether. Gas powered generation is forecasted to be a part of the mix for much longer, but is also affected by CO_2 prices, driving gas generators further to the right in the merit order.

To create a scenario of installed generation capacity up to 2039 three reference years are considered, which are subjected to linear interpolation to achieve a forecast for the years 2025-2039. The reference years are 2020, 2030 and 2050. For 2050 the European CO_2 scenario provides a forecast, for 2030 the scenario derived from the Climate Accord (KA 2030) [32] is used, while the installed generation capacity for the Netherlands in 2020 reported by the ENTSO-E transparency platform is used [33]. The installed capacity in 2020 and the projections for 2030 and 2050 are presented in the figures below.

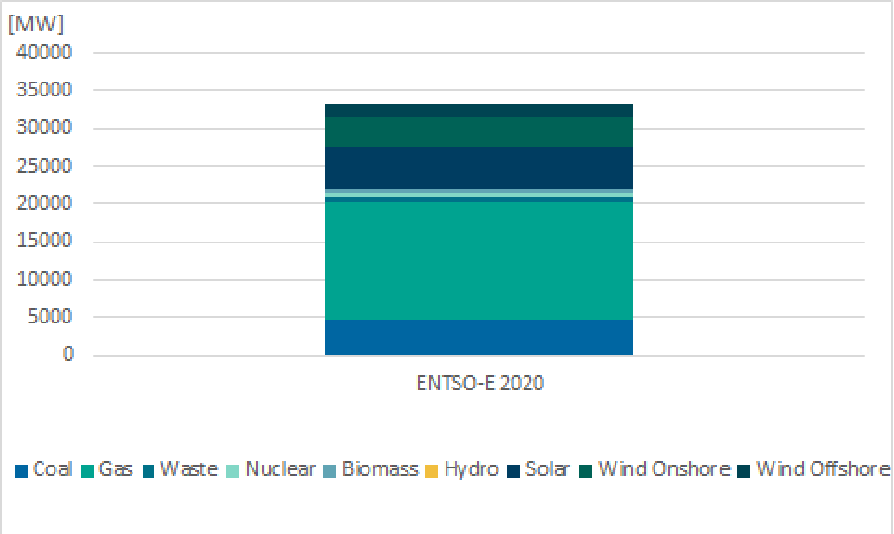


Figure 2.2: Installed capacity per production type in 2020 [SOURCE ENTSO-E]

To make a projection for the installed power generation capacity per technology in this study it is chosen to use the scenario study 'Klimaatneutrale energiescenario's 2050' by advisory groups Berenschot and Kalavasta as a basis [32]. This study illustrates four possible scenarios for a climate neutral energy supply in the Netherlands in 2050, where the Dutch Climate accord from 2019 [34] serves as the starting point for the developments up to 2030. The report was published as a concluding step of the first phase of the project 'Integrale Infrastructuurverkenning 2030-2050' (II3050), a collective effort of network operators, industry, energy companies, the ministry of economic affairs and climate (EZK), to create four climate neutral energy scenarios for the Netherlands in 2050. Though in this study several scenarios for the development for the Dutch energy industry are considered, it is chosen to use only the 'European CO_2' scenario for the price forward curve in this graduation research. It is the most likely scenario based on the current state of commitments by governments in the form of regulations and ambitions, with the EU responsible for a large share of current commitments. The assumptions of this scenario are presented in the list below.

- Europe reaches CO_2 reduction goals and is the front-runner in the world
- 100% CO_2 reduction
- General CO_2 levy, import tariffs & compensation charges at EU borders
- Energy-intensive industry grows
- Global hydrogen- and biomass market
- Substantial role for CCS

The main feature of this scenario is the introduction of a CO_2 levy in a European context. This levy will apply to all sectors, so it will be a more advanced system than the current ETS, which only applies for the energy-intensive industries and the electricity industry. The CO_2 levy is progressive towards 2050, rendering CO_2-intensive products and processes increasingly unattractive. This way changes take place there where the business cases are most attractive and the effects on CO_2 emissions are largest. The solidarity between European countries will be high, reinforcing the multilateral electricity markets. The Netherlands will import electricity from abroad, where sustainable energy of European origin is preferred. In this scenario projects and initiatives are only launched when the business case is positive, in which the CO_2 tax is included. This leaves a role for hybrid technologies and CCS in the near future. In this scenario CCS will have a material role up to 2050, assuming it will still be cheaper than some alternative technologies. To prevent a deterioration of the competitive position of the European industry the CO_2 levy is compensated at the EU borders. The proceeds of the levy are also returned to the concerned sectors, by subsidizing sustainable processes, feedstock and circularity. This will allow the industry to grow steadily. For the electricity supply there will still be a large number of gas-fired power plants available, which will allow flexibility in electricity generation and back-up power. These plants will either use CCS or run on green gas by 2050.

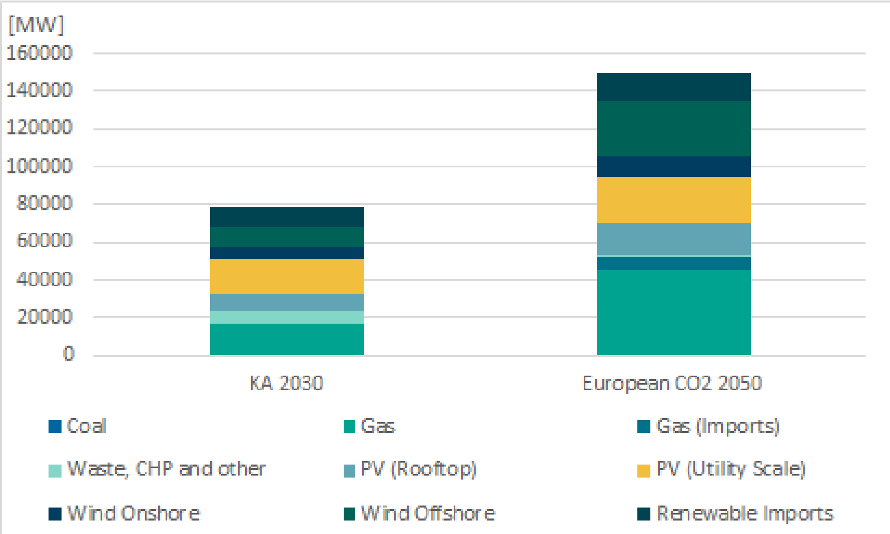


Figure 2.3: Projections of installed capacity per production type in 2030 and 2050 [32].

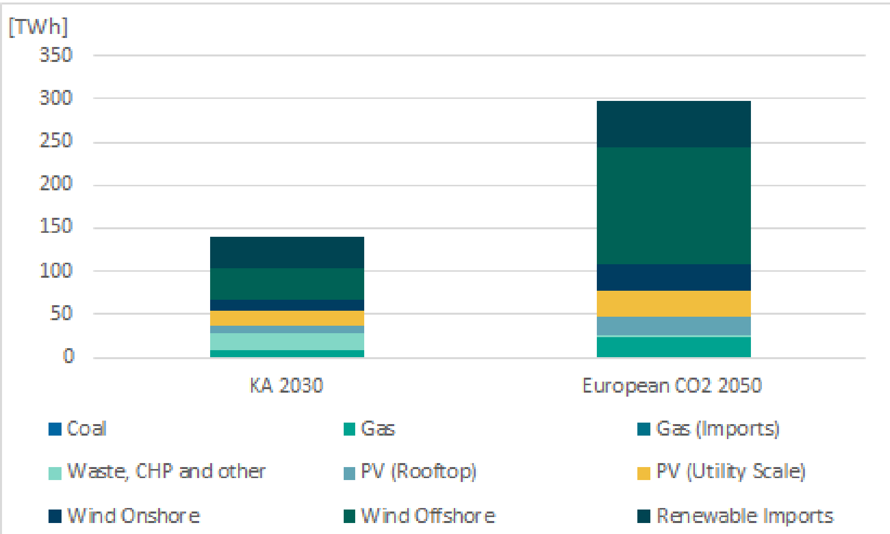


Figure 2.4: Projections of electricity production per production type in 2030 and 2050 [32].

As can be observed, the categorization of production types is not aligned between the two sources. This is homogenized to create a workable projection. In the ENTSO-E data the installed capacity of biomass, nuclear, waste incineration and hydro plants is spread out proportionally over the installed coal and gas capacity. For the 2030 and 2050 scenarios the waste, CHP and remaining category is added up to the installed gas capacity, since there is no remaining coal capacacity after 2030. Rooftop solar and utility scale solar are joined to form a single category of solar PV. This is deemed justified since in these scenarios the installed capacity of both categories is so large that the geographical distribution between the two presumably does not deviate materially. The resulting homogenized dataset for the installed capacity per production type and the interpolated projection for the timeline 2025-2039 are presented in the figures below.

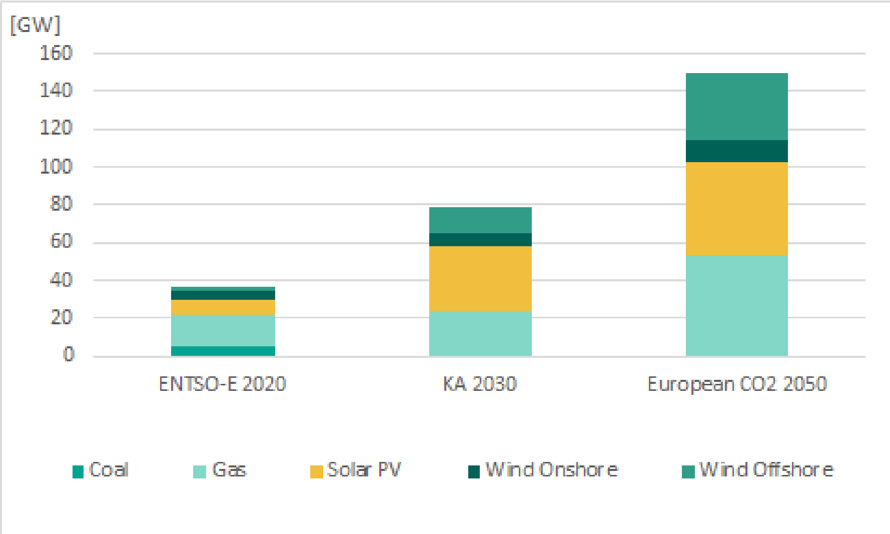


Figure 2.5: Homogenized installed capacity per production type in 2020, 2030 and 2050.

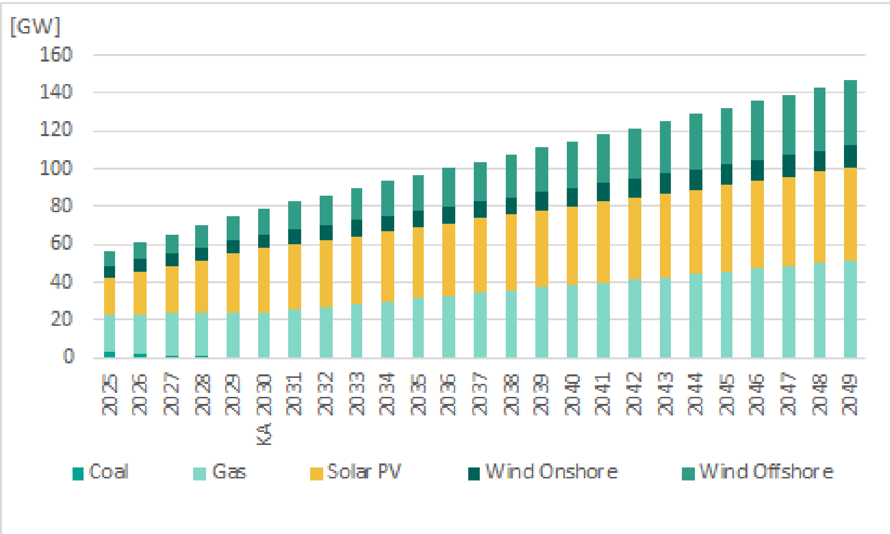


Figure 2.6: Projection installed capacity per production type for years 2025-2049 (interpolated).

2.1.3. Marginal Cost

Marginal cost is the cost of producing one additional (incremental) MW of power. This is the price at which a generator operator bids it capacity into the electricity market, so it is necessary to construct the merit order. In conventional generators it is constituted by the cost of the extra fuel that is used and the price of CO_2 credits that have to be obtained for the emissions. A projection of fuel and CO_2 prices into the future is obtained from BNEF's New Energy Outlook 2015. The BNEF's New Energy Outlook 2015 are presented below. An overview of the energy commodity prices is displayed in Table 2.1.

Commodity	Unit	2020	2025	2030	2035	2040	2045	2050
Hard Coal	EUR/MWh	7.7	8.4	9.2	10.2	11.1	11.1	11.1
Natural Gas	EUR/MWh	22.2	30.0	32.7	36.1	40.2	40.2	40.2
ETS Price	EUR/t CO_2	28	52	61	68	75	100	150

Table 2.1: Prices of energy commodities up to 2050 [35]

Furthermore, it is notable that in accordance with several sources, a CO_2 abatement cost of 70 USD/tCO_2 is a reasonable estimate for CCS applied to gas-fired power generation, this translates to approximately 59 EUR/tCO_2 [36] [37] [38]. It is likely that when a carbon price of this value is reached, CCS technology will be developed and available and generators will prefer to install this technology over purchasing more expensive CO_2 credits. Therefore in the price forecasts it is decided to curb the cost of emitting carbon to 59 EUR/tCO_2 in 2021EUR, after which producers will choose to use CCS technology at this cost, or alternatives such as green gas which are assumed equally expensive for the purpose of this research. These assumptions lead to an effective CO_2 cost development as displayed in Figure 2.7.

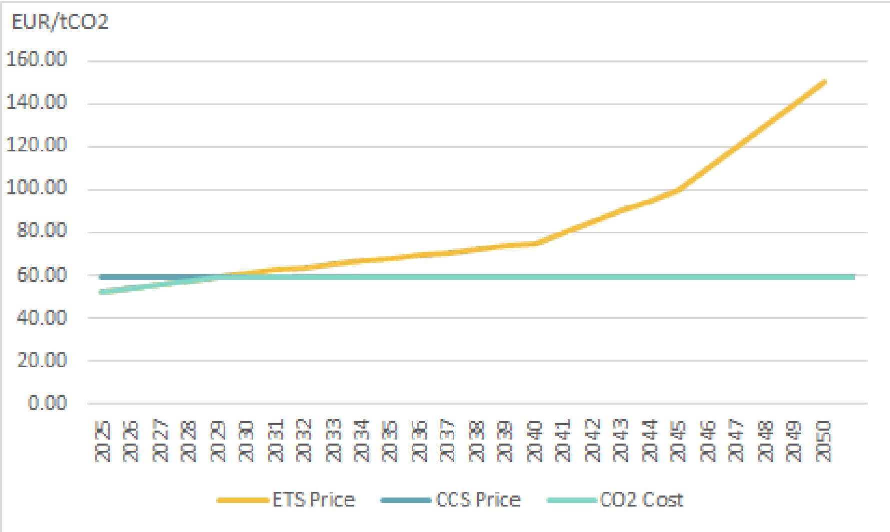


Figure 2.7: Projection of effective CO_2 cost for years 2025-2049 (interpolated).

As no public sources were found displaying a distribution of generation efficiency and installed capacity for the dispatchable power generation technologies used in this study, being coal and gas, an educated approximation was made for this distribution. This should be viewed as a highly simplified representation of reality, as it is highly uncertain how these technologies will develop. This educated approximation does not take any breakthrough developments in the considered technologies into account. For gas-fired power generation the distribution is by low, medium and high efficiency. Low efficiency is attributed to peaker plants and CHP such as used by horticulture farmers. The medium and high efficiency categories allow for some differentiation between average and highly efficient plants. The low eficiency category evolves with the Waste, CHP and other category in the Berenschot and Kalavasta scenarios, while the remainder of gas-fired capacity is split between medium and high. For coal-fired generation as well a split is made between low and high efficiency to allow for some differentiation in efficiency between coal-fired power plants in the merit order. A schematic overview of this subdivision is displayed in Table 2.2. The development of marginal costs for each category of dispatchable generation technology resulting from the energy commodity prices and efficiency distribution is displayed in Figure 2.8.

Category	Efficiency	2020	2025	2030	2040	2050
Coal Low	0.46	2539 MW	0 MW	0 MW	0 MW	0 MW
Coal High	0.53	2539 MW	2539 MW	0 MW	0 MW	0 MW
Gas Low	0.4	3376 MW	4088 MW	4800 MW	7700 MW	10600 MW
Gas Lower	0.45	3376 MW	4088 MW	4800 MW	7700 MW	10600 MW
Gas Medium	0.5	3376 MW	4088 MW	4800 MW	7700 MW	10600 MW
Gas Higher	0.55	3376 MW	4088 MW	4800 MW	7700 MW	10600 MW
Gas High	0.6	3376 MW	4088 MW	4800 MW	7700 MW	10600 MW

Table 2.2: Generation efficiencies of dispatchable generation technologies.

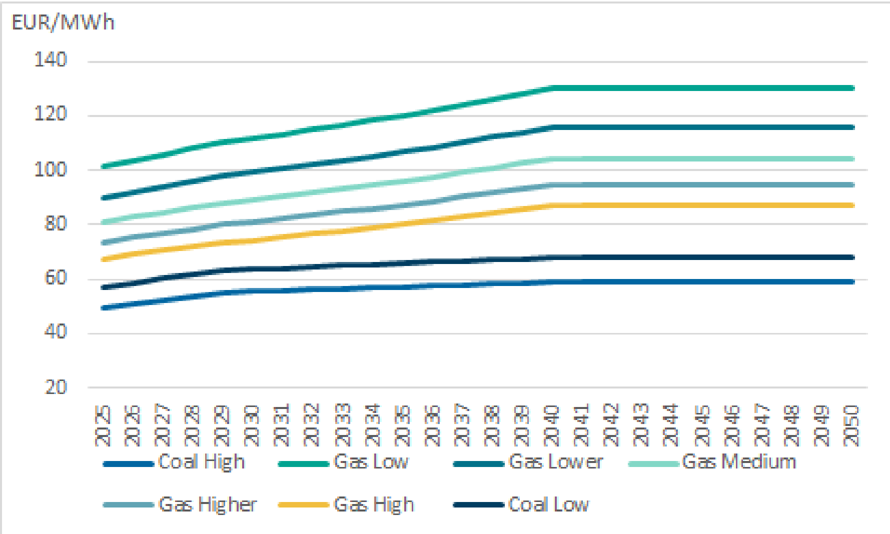


Figure 2.8: Projection of marginal costs per dispatchable production type for years 2025-2049 (linear interpolation).

2.1.4. Residual Load

To create the price forward curve with the FPMM, apart from the MO based on installed capacity and marginal costs, a RLC is required. To create a RLC, projections must be made for the load, and VRE generation. To this end timeseries of load, solar PV, on- and offshore wind covering all hours of 2020 were retrieved from ENTSO-E Transparency Platform [33]. The offshore wind curve for 2020 was distorted by the commisioning of the Borssele 1 & 2 wind farm in the middle of that year, so the timeseries for offshore wind has been adjusted as if Borssele had not been commissioned. The timeseries profiles have been scaled by their surface area with cumulative renewable generation numbers of 2020 from the CBS [39][40], as the magnitude of the timeseries graphs were not convincing (especially PV generation, which was 114 MW at most while installed capacity was 5.7 GW, also according to ENTSO-E). The PV curve was scaled by 7.5 TWh instead of the 8.3 TWh reported by the CBS, as that would lead to maxima of the curve beyond the installed capacity of 5.7 GW. A graphic representation of the base timeseries can be found in Fig. 2.9. For subsequent years, this timeseries is scaled with respect to the base year 2020 by the installed capacity projections discussed before.

The shapes of the VRE generation curves are left unchanged, following the assumption that the geographical distribution of PV generation as well as onshore and offshore wind in 2020 is distributed enough that no dramatic changes in the generation pattern are expected. Demand is forecasted to grow but changes in the shape of the demand curve due to changing uses of electricity are hard to predict. It is well possible that the shape of the load curve will change in the future, due to electrification of current non-electric energy uses on one side or increased availability of energy storage technologies such as electrolysis or battery storage, or even large scale use of fuel cells. However, the extent of these changes is highly unsure. Hence, due to reasons of complexity and uncertainty it is chosen to maintain the load profile from 2020 for this power market modelling exercise.

Graphical images of the scaled timeseries of load, VRE generation, residual load and corresponding

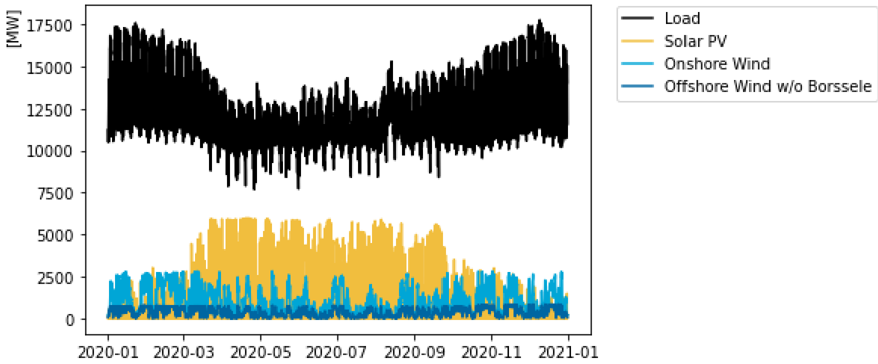


Figure 2.9: Base timeseries for Load, Solar-PV, Onshore and Offshore Wind in year 2020 [33][39][40].

clearing prices calculated by the FPMM are displayed in Figures 2.10, 2.11 & 2.12. These figures show daily averages, as plotting the hourly values produced rather amorphous graphs. The definitive result of the fundamental power market model in terms of hourly clearing prices is discussed in Subsection 2.1.5.

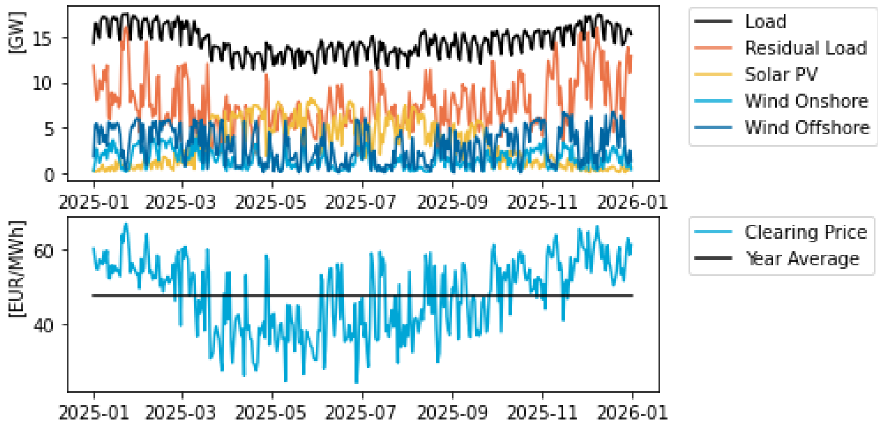


Figure 2.10: Daily averages of load, renewable generation, residual load and corresponding clearing prices for 2025.

From the daily averages in the graphs above several things can be concluded. Firstly, in absolute terms the load and renewable generation curves display very significant growth. The load curve grows a lot from 2025 to 2044, from an average just below 15 GW to somewhere around 30 GW. Renewable generation also shows a dramatic upward trend, also relative to load. This results in a (relative) decrease of the residual load. The development of the yearly average clearing price is relatively constant, moving from slightly below 50 to around 50 EUR/MWh. However, the deviations from the average price increase in magnitude, both in negative and in positive direction. The pattern also becomes less seasonal with progressing years, increasing in volatility with larger positive and negative deviations year round. The large negative price deviations happen when renewable generation is high, this development is in line with the cannibalization effect discussed earlier. Keep in mind these are daily averages, the exact hourly clearing prices are displayed and discussed in Subsection 2.1.5.

2.1.5. Clearing Prices

The price forward curve for the period 2025 to 2049 that were created with the FPMM can be observed in Figure 2.13. The upper graph is the actual hourly price forward curve, but due to the poor readability two averaged graphs are displayed as well, averaged by Day (middle) and by Week (lower). Features of the curve will be discussed in this subsection.

The first feature of the price forward curve that draws attention is the gradual decline of the frequency of positive clearing price deviations from the yearly average. Also, clearing prices of 0 EUR/MWh are

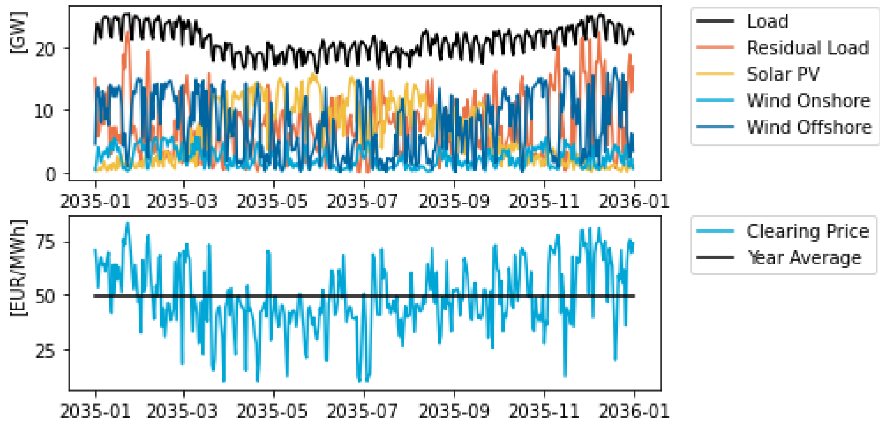


Figure 2.11: Daily averages of load, renewable generation, residual load and corresponding clearing prices for 2035.

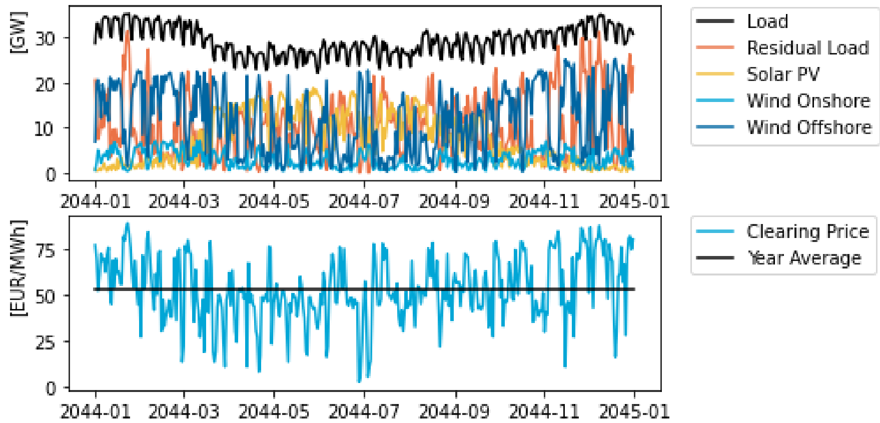


Figure 2.12: Daily averages of load, renewable generation, residual load and corresponding clearing prices for 2044.

already present in 2025 (Fig. 2.14) and after this year the frequency of such price drops increases (Fig. 2.15). The average yearly price first declines due to increasing frequency of low prices and limited upward trend in marginal costs of the dispatchable generators up to 2030, after which the average price starts to climb due to increasing marginal costs for dispatchable generators caused by faster rising carbon prices and rising fuel costs (Fig. 2.8). This upward trend is limited by the price for CCS, after carbon prices meet the cost of CCS the increase in average electricity price is only driven by rising fuel costs, which flattens after 2040 according to the sources used (Tab. 2.1).

The price forward curve created in this study may be subject to some downward bias, as the merit order is constructed of marginal costs for all market participants. This neglects the possibility of market participants bidding small portions of their capacity at very high prices to profit in cases of very high demand. Due to the generalization that was necessary to construct this curve without access to non-public data which professional power market modellers may have access to, the distribution of prices is relatively low resolution. Exceptional cases that happen in the real world are therefore not represented in this price forward curve, such as negative prices.

The increasing frequency of low clearing prices is in line with the cannibalization effect discussed earlier, and offer opportunities for the PV-Electrolysis system. Producing and selling hydrogen will without doubt be more lucrative than selling electricity for 0 EUR/MWh. Apart from the frequency of times with clearing prices at zero the variability of the clearing prices also increases, the possibilities a PV-Electrolysis system offers to shift the production between two commodities may be attractive in that respect, for example in cases when the electricity price is high and the PV system produces power.

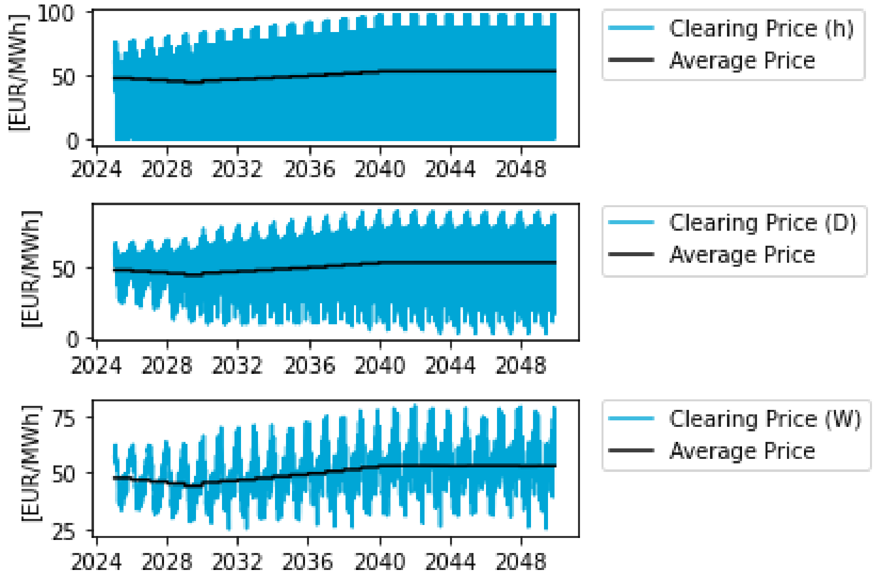


Figure 2.13: Price forward curve produced with the fundamental power market model for years 2025 to 2049.

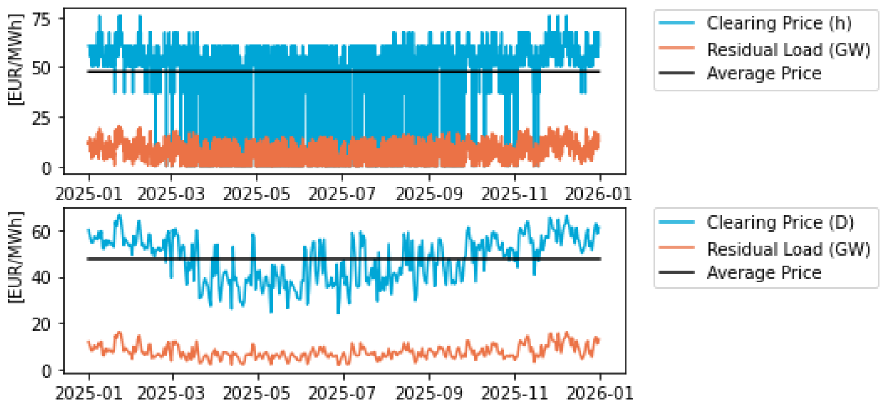


Figure 2.14: Clearing prices from the forward curve for 2025.

2.1.6. Solar PV Equipment

Photovoltaic (PV) solar panels have become an established technology over the past decades, however a downwards development in equipment prices is still ongoing. For the costs of solar PV equipment this study refers to Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) values reported by Topsector Energie [41]. In a 2020 study values for 2020 have been reported as well as a projection for the costs in 2030. In Table 2.3 an overview including a linear interpolation for the costs in 2025.
The downward trend in CAPEX for solar PV equipment projected in this study is characterized by a drop from 687 EUR/kWp in 2020 to 584 EUR/kWp in 2030, a 15% decrease over a time span of 10 years. A linear interpolation then results in an estimated 636 EUR/kWp in 2025. The cost items under Operating Expense are not considered subject to any foreseeable significant price developments and are assumed to be constant, but adjusted for inflation.

The lifetime of a solar PV installation is typically 25 years. After 25 years the PV panels will have degraded and have lost capacity, usually around 80% of the original peak capacity remains after this lifespan. Estimations for the residual value of the equipment are tedious, so much so that the residual value is too unsure to be considered in SDE++ subsidy applications [41] [42]. Besides residual value of the equipment plant owners are also burdened with decommissioning costs at the end of the project, which may well even out the residual value.

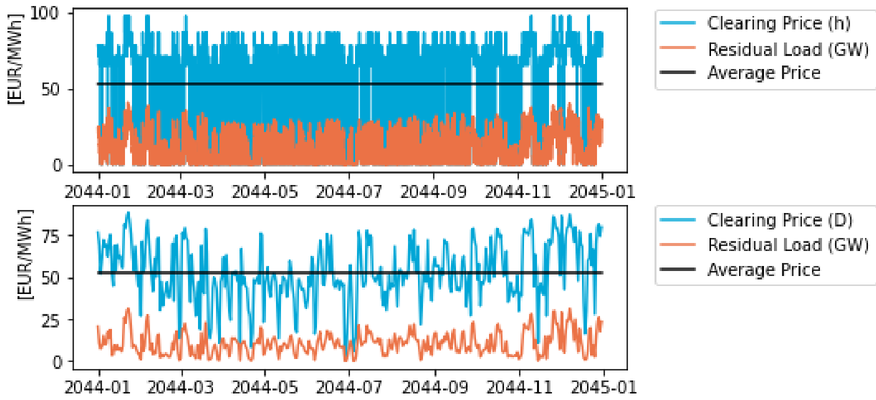


Figure 2.15: Clearing prices from the forward curve for 2044.

Solar PV System Cost

Capital Expenditure [2020EUR/kWp]			
	2020	2025	2030
PV Modules	240	206*	172
Inverters	63	58*	52
Balance of Plant	329	317*	305
Grid Connection	55	55*	55
Total CAPEX	687	636*	584
Operating Expense [2020EUR/(kWp*yr)]			
Land Lease	4.4	4.4**	4.4**
Property Tax	2.1	2.1**	2.1**
Variable Grid Charge	2.0	2.0**	2.0**
Metering Services	0.2	0.2**	0.2**
Asset Management	1.0	1.0**	1.0**
O&M	6.0	6.0**	6.0**
Insurance	1.0	1.0**	1.0**
Security	0.5	0.5**	0.5**
Total OPEX	17.2	17.2**	17.2**

Table 2.3: Overview of solar PV CAPEX and OPEX [41] [42] [43]. * Linear interpolation ** Assumed constant, corrected for inflation

2.2. Hydrogen

Renewable hydrogen can be produced using renewable electricity to split water into its constituents hydrogen and oxygen using an electrolyser. Hence, the costs of producing renewable hydrogen are mainly derived from the cost of the renewable electricity used and the costs of an electrolyser. The cost of wind and solar energy continues to fall, so if the cost of electrolysers comes down the cost of renewable hydrogen can follow.

2.2.1. Electrolysers

For this study the commercially available water electrolysis technologies are considered, including Alkaline Electrolysis (ALK) and Proton Exchange Membrane Electrolysis (PEM). These two technologies are operated at near ambient temperature (up to 90°C). Historically, ALK is the oldest technology. The first PEM water electrolyser was built by General Electric for the United States space program in 1966 and has been further developed to a fairly mature state since then. Alkaline electrolysis technology is well-established, MW-scale alkaline electrolysers are commercially available today. ALK uses an aqueous solution of KOH as liquid electrolyte. PEM uses a thin proton-conducting polymer membrane and is characterized by rapid start/stop and control response capabilities. The CAPEX of PEM systems remains higher than the CAPEX of alkaline electrolysis systems, however the majority of experts expect a paradigm shift from ALK to PEM between 2020 and 2030 as preferred technology for installations coupled to renewable electricity generation installations [44] [45].

The main benefit of ALK is that the technology is very mature and significantly cheaper in terms of Capex than the other technologies (700-800 EUR/kW), making it a good option for situations where compact dimensions and high power density are not required. PEM electrolysis systems are more compact and can operate with higher current densities with good efficiencies. Because it is more flexible in handling load shifts it is very suitable for providing grid services. The technology is however still expensive with Capex at around 1000-1500 EUR/kW [44].

An expert elicitation study by Schmidt et al. in 2017 states that under the most favourable circumstances (i.e. 10x R&D funding relative to 2017 levels and production scale-up) Capex for Alkaline electrolysers would go to 500 EUR/kW by 2030 and Capex for PEM electrolysers to 604 EUR/kW [45]. Even more rapid price drops are predicted for ALK and PEM technology by IRENA. The techno-economic characteristics predicted for 2025 are displayed in Figure 2.4.

Characteristics		**ALK**		**PEM**	
	Unit	2017	2025	2017	2025
Efficiency	kWh_{el}/kgH_2	51	49	58	52
Efficiency (HHV)	%	77	80	67	76
Stack lifetime	Operating hours	80,000	90,000	40,000	50,000
CAPEX (incl. installation)	2017EUR/kW	750	480	1,200	700
OPEX	% of CAPEX/yr	2%	2%	2%	2%
CAPEX stack replacement	EUR/kW	340	215	420	210
Output pressure	bar	atm.	15	30	60
System lifetime	years	20		20	
Load range	% nom. load	15-100		0-160	
Start-up (w - c)	minutes	1-10		0-5	
Ramp-up/down	%/sec.	0.2-20		100	
Shutdown	minutes	1-10		seconds	

Table 2.4: Techno-economic characteristics of ALK and PEM electrolysers (2017, 2025) [46]

On paper PEM electrolysis technology appears very attractive. It provides higher output pressure, a broader load range, quicker start-up, ramping and shutdown times. From a cost perspective it is a different view, PEM technology is characterized by much higher CAPEX and shorter stack lifetime. For a renewable hydrogen production business case, the broad load range is perhaps the most promising feature of PEM technology. However the higher than nominal loads can only be sustained for short periods of time, in the range of 10 to 30 minutes. This temporary upward regulation capacity could be provided to the frequency containment reserve (FCR) without having to sacrifice regular production capacity [46]. In practice however ALK technology is often favoured for electrolysis. As for the flexibility of the technologies in terms of start-up, ramping and shutdown times, the state of ALK technology in 2021 in practice is on the sunny end of the indications in Table 2.4, which is in practice not so far apart from the features offered by PEM, while ALK technology is available at much lower cost. The most notable difference in practice remains the minimum load barrier of 15% for ALK electrolysers.

The simulation model used in this research uses a granularity of hours. In that light start-up and shutdown times of few minutes and the differences between ALK and PEM in that respect are not significant. For reasons of complexity and uncertainty these features are neglected. The difference in load range between ALK and PEM can however not be neglected. The extent to which higher than nominal loads can be sustained with PEM electrolysers is not exactly clear and the shorter periods of time are incompatible with the hourly granularity of the model. That leaves only the absence of the 15% minimum load barrier to compensate for the high CAPEX and short lifetime of PEM electrolysers. It is highly unlikely that this will produce more profitable business cases than with ALK electrolysers using the simulation model in this study, and hence it is chosen to concentrate on ALK technology for the rest of this study. The electrolysis technolgy will therefore follow the features provided in Tab. 2.4 for 2025, where an efficiency of 75% is used to account for compression and balance-of-plant losses.

2.2.2. Hydrogen Prices

Calculations by Bloomberg New Energy Finance (BNEF) suggest that when electrolyser manufacturing is scaled up and costs will fall, renewable hydrogen prices can be reduced to 0.7-1.6 USD/kg across the world by 2050. This will allow renewable hydrogen to be competitive with current natural gas prices based on energy content and cheaper than production of hydrogen from fossil sources with CCS. Projections of levelized cost of hydrogen (LCOH) were made by Bloomberg New Energy Finance (BNEF) for renewable hydrogen from 2019 to 2030 and 2050 [47]. The projections by BNEF are available in Figure 2.16, expressed in 2019EUR.

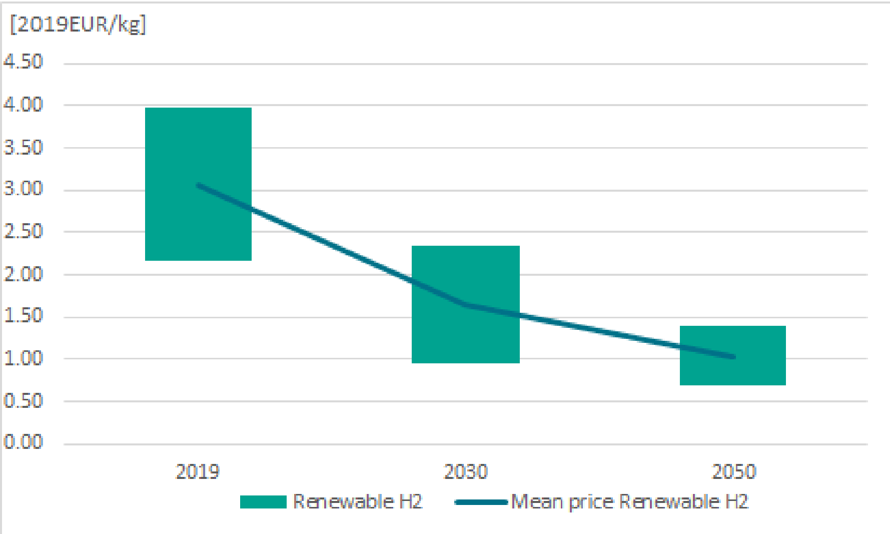


Figure 2.16: LCOH projections by BNEF [47]

To translate these projections to a useful dataset for this study a linear interpolation was made for the years 2025-2049, available in Figure 2.17. During the years 2025-2049 a steadily declining trend is observable, with LCOH ranging 1.50-3.08 EUR/kg in 2025 downwards to 0.84-1.91 EUR/kg in 2039. This significant downward trend must be considered in business cases around renewable hydrogen production.

What else should be considered, is that the price of Hydrogen from SMR, without CCS will drastically go up in the same period of time. This is represented by the grey line in Figure 2.17, based on a calculation used to calculate the SDE++ Subsidy Amounts for 2022 for Hydrogen from electrolysis [48] and the Natural Gas prices derived from BNEF's New Energy Outlook 2015 [35]. The calculation was verified with a IEAGHG report describing the Economic Evaluation of SMR [49], where this calculation method fits neatly with the lower end of the sensitivity analysis to Natural Gas prices.

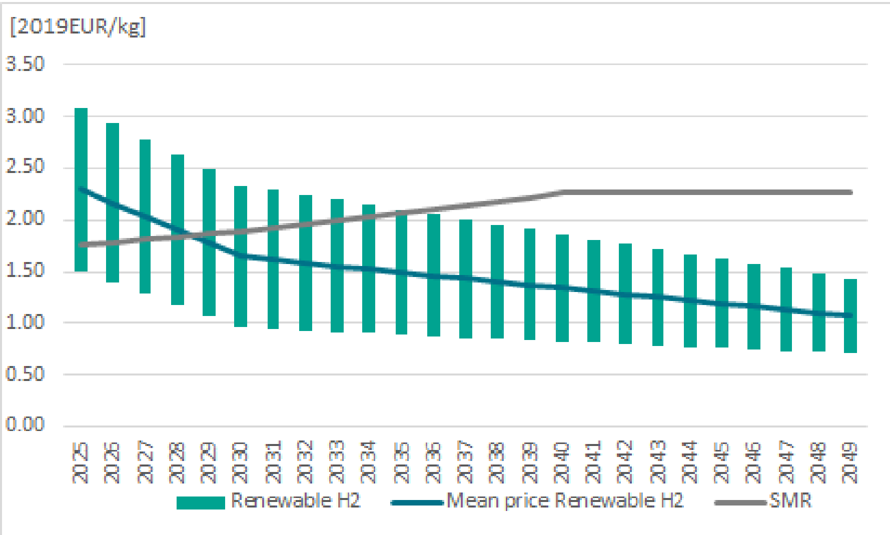


Figure 2.17: Interpolation of LCOH projections for years 2025-2049.

3
Income Streams & Costs

In this chapter the sources of income that can be tapped by the PV-Electrolysis system and the associated costs are discussed. The direct products of the PV-Electrolysis system are (green) electricity, (green) hydrogen. Another source of income that must be considered are subsidies. When evaluating a business model, costs must be subtracted from revenues. Hence, this chapter also presents the Capex and Opex cost items that must be considered for a PV-Electrolysis system. The Capex cost items include hardware costs and installation costs, whereas the Opex includes maintenance costs but more importantly, expenses for grid connection and purchased electricity. The cost items are evaluated for their respective relevant timeframe, this means for Capex items projected prices for 2025 will be used.

3.1. Income Streams

The income that is generated by a PV-Electrolysis system is constituted mainly by the volume and the price realized by the sale of its products, green electricity and green hydrogen. The trends in electricity prices and green hydrogen prices have been discussed in the previous chapter. This section will discuss the realization of cash flows based on the market developments in Chapter 2.

3.1.1. Sale of Electricity

One of the main products of a PV system is renewable electricity. The cash flows generated by the sale of green electricity are heavily dependent on the realized electricity price. The electricity price can vary heavily throughout days and years, as discussed in Section 2.1.5. Solar-based electricity generation is subject the cannibalization effect (as discussed in Section 1.1.3), and as a result the realized electricity price is often lower than the average electricity price. The objective for a PV-Electrolysis system in this respect is to profit from high electricity prices when they can be realized and to increase the otherwise reduced cash flows at times of low electricity prices by switching to production and sale of green hydrogen.

3.1.2. Sale of Hydrogen

The other main product of a PV-Electrolysis system is green hydrogen. Referring to Figures 2.13 and 2.17, it is observed that the green hydrogen price is not volatile, showing a steadily declining trend. The price of green hydrogen is relatively constant compared to the highly volatile electricity prices and hence by switching to hydrogen production the PV-Electrolysis can act as a hedge against low electricity prices when the realized income by the production and sale of green hydrogen is higher compared to the otherwise realized electricity price.

As explained above, the PV-Electrolysis system can act as a hedge for low electricity prices to the PV installation. Alternatively, the electrolyser can operate autonomously, producing hydrogen irrespective of the activity of the PV installation. In this case the electrolyser consumes electricity from the grid, purchased on the spot market when spot prices are low enough to make green hydrogen production profitable. The price level at which this makes economic sense depends mainly on the green hydrogen price and the efficiency of the electrolyser. It should be considered that electricity purchased from the market is subject to electricity tax and the hydrogen that is produced only qualifies as green when the consumed electricity is covered by GOs, incurring some extra cost.

Currently there is a market for green hydrogen based on bilateral agreements between off-takers and producers characterized by high prices for green hydrogen. The implementation of new tariffs or a Guarantees of Origin system do not necessarily lead to a different sales remuneration level for green hydrogen, but mostly redistribute the costs on the offtake side. Hence, it is chosen to consider the renewable hydrogen price forecasts by BNEF (Figure 2.17) as an indication of the future market price level for green hydrogen.

Oxygen and waste heat can also be viewed as products of the Electrolysis process, however business cases that utilise these byproducts to date are rare. It is conceivable that electrolysis projects located close to a heating district or a chemical cluster will be able to monetize these product streams in the future. However, in the case of decentralized PV-Electrolysis projects such as at the site in Oosterwolde will not be able to monetize the product streams in the short term due to lacking infrastructure. Due to the uncertainty in the development of the required infrastructure it is assumed that it is not possible to monetize the waste heat and oxygen product streams.

3.1.3. Subsidies

A third source of income for the PV-Electrolysis system could be subsidies. In this section some subsidy options will be discussed. Most subsidies for renewable energy in The Netherlands are distributed through the SDE++ (Stimulering Duurzame Energie ++) instrument. As context for the rest of this section a brief illustration of the system behind the SDE++ instrument will follow here.

To apply for the subsidy parties must submit an application amount ('indieningsbedrag') which the subsidy amount will be based on. This application amount is maximized at a base amount ('basisbedrag') for every technology. The applications sometimes occur in phases, where the base amounts are slightly higher in each phase, until the subsidy budget is depleted. Signals were received from market parties that in practice the application amounts lie very close to the base amount.

The amount of subsidy to be received is calculated as the difference between the application amount and a correction amount ('correctiebedrag'), which is determined yearly and based on the market remuneration per unit eligible for the subsidy, including Guarantees of Origin. The subsidy amount is limited by a minimum amount ('basisenergieprijs/ basisbroeikasgasbedrag'), if the correction amount sinks below the minimum amount, the subsidy amount is limited at the difference between the application amount and the minimum amount. Generally there is a maximum number of Full Load Hours (FLH) for every technology that applies to the subsidy as well. Figure 3.1 shows a visual representation of the SDE++ system for a subsidy with a lifetime of 15 years, which is common for SDE++ subsidies [50].

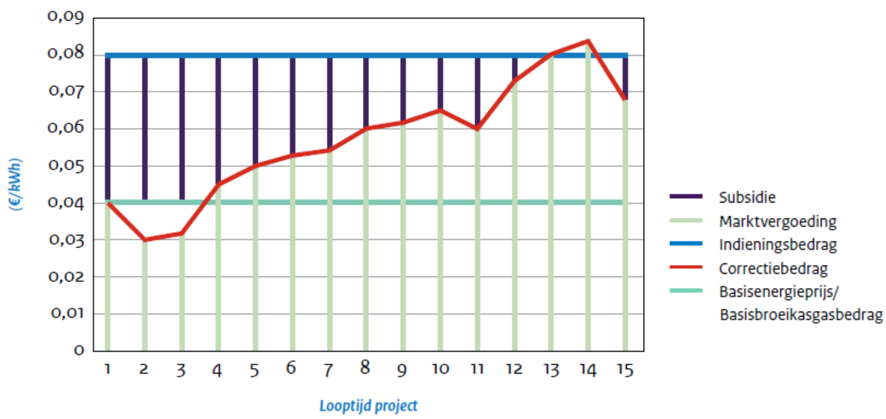


Figure 3.1: Functioning of the SDE++ system [50].

3.1.4. PV Subsidies

For large scale Solar-PV the appropriate subsidy instrument is SDE++, the instrument has been around for Solar-PV since 2008. The subsidy functions according to the SDE++ system illustrated above, and the category for the Oosterwolde solar park would be Solar-PV ≥1 MWp, surface mounted. For this category, in 2021 the phase 1 base amount is 0.0503 EUR/kWh, the minimum amount is 0.0238 EUR/kWh and the correction amount estimated for 2021 is 0.0312 EUR/kWh. The maximum number of full load hours (FLH) for this category is 950 and the lifetime of the subsidy is 15 years.

Technology	Unit	Base Amt.	Min. Amt.	Corr. Amt.	max. FLH
PV≥1 MWp, surface mtd.	EUR/kWh	0.0503	0.0238	0.0312	950

Table 3.1: SDE++ amounts Solar-PV 2021 .

3.1.5. Green Hydrogen Subsidies

The subsidy landscape for hydrogen from electrolysis is currently in its establishing phase. An attempt has been made in the 2021 SDE++, but this was not satisfactory for the industry as only 3000 FLH of the electrolyser would be eligible [50]. For 2022 the advice for the SDE++ subsidy is to increase the number of FLH to 3500 for grid connected electrolysis and increase the base amount [51]. This advice differentiates between electrolysis coupled directly to a wind park or a solar plant, or electrolysis connected to the grid. The FLH numbers are based on the expected FLH the electrolyser can run, provided that the emission intensity of the consumed electricity is 0 kg/kWh. The advice does not mention minimum amounts or projected correction amounts.

Even more recently the Dutch ministry of Economics and Climate has held a market consultation about a new possible subsidy instrument specifically for hydrogen from electrolysis. This instrument, named 'Tijdelijke Opschalingsregeling Waterstof uit Electrolyse' (TOW), is aimed at scaling up electrolysis capacity in the short term and is aimed to go live in Q1 or Q2 of 2022. This instrument will be a combination of an exploitation compensation such as the SDE++ and a CapEx subsidy. Base, minimum, or correction amounts are not mentioned, just that it will resemble the SDE++. However, the maximum number of FLH will be stretched to 6000 for this instrument. The CapEx subsidy is mentioned as 40/50/60 % of the CapEx in excess of the CapEx for SMR. Because of this rather vague indication, in this study the CapEx support is assumed to be 20% of the Electrolysis equipment CapEx for the TOW instrument. Two types of projects will be eligible for this subsidy: Electrolysers coupled directly to renewable electricity installations and electrolysers coupled to the grid where electricity is procured through PPAs with renewable GOs.

Technology	Unit	Base Amt.	Min. Amt.	Corr. Amt.	max. FLH
SDE++ 2021 H2	EUR/kWh_{hhv}	0.0463	0.0242	0.0257	3000
SDE++ 2022 Grid	EUR/kWh_{hhv}	0.1715	-	-	3500
SDE++ 2022 PV	EUR/kWh_{hhv}	0.2160	-	-	3000
TOW	EUR/kWh_{hhv}	-	-	-	6000

Table 3.2: Exploitation compensation amounts for the subsidy instruments for Hydrogen from Electrolysis.

3.2. Costs

In the previous section the income streams of a PV-Electrolysis system have been discussed. To assess the profitability of the system it is required to weigh the costs against the benefits. The items to consider on the cost side are presented and discussed in this section. A distinction is made between cost items attributed to either investing activities or operating activities.

3.2.1. Capital Expenditure

The business case of a PV-Electrolysis system is characterized by a large initial investment followed by a long payback time. The initial investment involves the purchase of PV and Electrolysis equipment and installation. Although the simultaneous installation of the equipment may incur synergies, it is assumed these are neutralized by the costs of integrating the two systems. For capital expenditure data of PV and Electrolysis equipment please refer to Tables 2.3 and 2.4. For Electrolysis equipment the initial investment may not be the only capital expenditure during the lifetime of the system, as the lifetime of the electrolyser stacks is not limitless. In case the electrolyser would be operated at an average of 4500 hours per year, an AE stack would last 20 years (90,000h), while the PEM stack would have to be replaced after roughly 11 years (50,000h).

To transport the hydrogen from the electrolyser exit to the off-taker requires transportation infrastructure. Further in the future, although possibly before the end of a 2025 PV-Electrolysis project's lifetime pipeline infrastructure may be available for transportation of hydrogen. Currently however this is not available for decentralized hydrogen production sites and scaling the infrastructure up is a monumental operation which will take years. Today's common practice for decentralized hydrogen production projects is transportation with high-pressure tube trailers. Hence for this study the costs associated with pressurized tube trailers are assumed as the costs of transportation infrastructure. Time will tell how high the charge for a project to be connected to the hydrogen grid will be. The FCH has developed a formula to approximate the cost of a compression system for an electrolysis system which will be used in this study [52]. This formula is presented in Equation 3.1.

An overview of the essential cost items is available at the end of this section in Table 3.3.

$$CAPEX_{CS} = CAPEX_{ref} * \frac{Q}{Q_{ref}}^{a} * \frac{P_{out}/P_{in}}{P_{out_{ref}}}^{b} * \frac{P_{out}}{P_{out_{ref}}}^{c} \tag{3.1}$$

$CAPEX_{CS}$ = CAPEX of compression system
$CAPEX_{ref}$ = CAPEX of reference plant: 600 kEUR (filling centre & compressor system)
Q = Site capacity
Q_{ref} = Reference site capacity (50kg/h)
P_{out} = Ouput pressure
P_{in} = Input pressure
$P_{out_{ref}}$ = Reference output pressure
$P_{out_{ref}}$ = Reference input pressure
a = 0.66
b = 0.25
c = 0.25

3.2.2. Operating Expenses

After installation of the PV-Electrolysis system there will be recurring costs for the operation and maintenance of the equipment. For the exact operating expenses related to PV and Electrolysis equipment please refer to Tables 2.3 and 2.4.

In case it is chosen to operate the Electrolyser not only in response to the output of the PV system, but also autonomously, incentivized by the level of electricity prices, the cost of electricity will become a substantial cost item in the operating expenses. This type of operating expense is referred to in accounting as Cost of Goods Sold (COGS). The amount of the cost depends on the realized electricity price, plus electricity tax plus the cost of GOs. For a projection of electricity prices please refer to Figure 2.13. The electricity tax charge for corporate electricity consumers consuming over 10 GWh per year amounts to 0.56 EUR/MWh in The Netherlands [53]. GOs have been very volatile in The Netherlands in recent years. It is difficult to make meaningful projections for the development of GO prices in The Netherlands as the unpredictable price fluctuations do not show a clear trend, and there are no indications of any decisive policy change in this area (e.g. a compliance market as exists in Poland) [54]. The price development for GOs for Dutch wind power from 2012 to 2020 can be found in Figure 3.2. As it is difficult to make any meaningful prediction of GO prices in the future, in this study the price level will be simulated starting in 2021 with a price equal to the latest five year average

(4.30 EUR/MWh, 2016-2020), declining to zero in 2050, as all electricity generation will be renewable by then. This projection is also included in Figure 3.2.

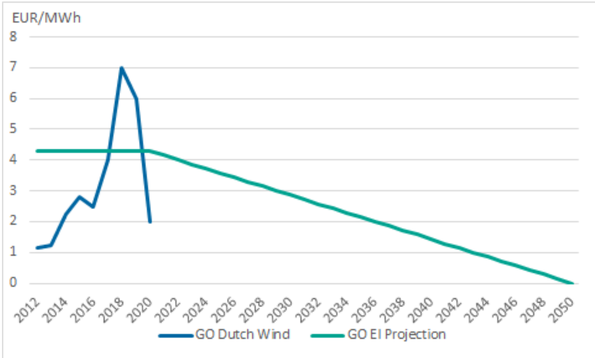


Figure 3.2: Price development GOs for Dutch Wind 2012-2020 and projection 2020-2050 [54].

A substantial initial capital expenditure is required to purchase and install the equipment of a PV-Electrolysis system. After commissioning there will be fixed and variable costs associated with the operation of a PV-Electrolysis system. A portion of operating expenses is connected to the operation of equipment while another portion is connected to the purchase of electricity for the electrolyser, the balance between these portions depends on the realized electricity price and volume of purchased electricity. To conclude, an overview of all costs of the PV-Electrolysis system is presented in Table 3.3.

PV-Electrolysis System Cost

Capital Expenditure			
	Units	2025	Comments
PV Equipment	EUR/kWp	636.00	
AE Plant	EUR/kW	480.00	
AE Stack	EUR/kW	215.00	lifetime 90,000h
PEM Plant	EUR/kW	700.00	
PEM Stack	EUR/kW	210.00	lifetime 50,000h
Operating Expenses			
PV Equipment	EUR/(kWp*y)	17.2	
AE Equipment	EUR/(kW*y)	9.60	
PEM Equipment	EUR/(kW*y)	14.00	
Cost of Goods Sold			
Electricity Spot Price	EUR/MWh	-	variable (Fig. 2.13)
Electricity Tax	EUR/MWh	0.56	
GO Price	EUR/MWh	-	variable (Fig. 3.2)

Table 3.3: Overview of PV-Electrolysis system Costs.

4
Case Study Oosterwolde

Central to the Case Study in this research is the Oosterwolde PV park site where currently the SinneWetterstof pilot project is being realised. The system components of this site are presented in this chapter, along with the dataset to simulate the PV park in the Simulation Model. In the next chapter the Scenarios that will be evaluated are discussed, and the Simulation Model and Financial used to evaluate them are presented.

4.1. System description

In this section the subject system of this case study is presented. The case study will reflect the system as is present in Oosterwolde at the location of the SinneWetterstof pilot project. However, this case study will not be directly related to the pilot project. The emphasis of this study is on the conditions for profitability of a PV-electrolysis system which is connected to the local distribution network. The hardware present at the Oosterwolde site will constitute the fixed parameters of the system. A set of parameters related to the electrolysis system are variable in this research, to enable the techno-economic investigation of possible business cases. These variable parameters are the same as mentioned in Section **??** and Table 5.1. In this section the Fixed Parameters of the Oosterwolde site are presented.

4.1.1. System features

The fixed components of the system are a representation of the finalized Oosterwolde site, composed of a 53 MWp PV park and the DG interface, being an Alliander substation with a maximum capacity of 32 MVA.

PV installation

The PV park in Oosterwolde that is operated by GroenLeven has a capacity of 52.96 MWp, this will be the electricity generating asset in this analysis. The PV park actually consists of two seperate PV plants of 6.17 MWp and 46.78 MWp, respectively. An overview of the most relevant technical features can be found in Table 4.1.

System Feature	Value
Nominal DC-Power	52.96 MWp
Nominal AC-Power	41.95 MW
Maximum AC-Power	45.97 MVA
Area	50 ha
Module tilt angle	15°
Module orientation	-28.8°

Table 4.1: Table of system features PV park Oosterwolde

The PV installation has been operational in its full capacity since August 2020, however the connection capacity to the distribution network is still only 20 MW. The yield of the park is logged after curtailment, so the dataset that is logged of the PV park Oosterwolde provides a very disturbed generation profile due to heavy curtailment. For this reason it is decided to look for an alternative PV generation dataset that is representative of the Oosterwolde park.

Figure 4.1: PV park Oosterwolde under construction.

Significant fluctuations in PV generation can arise due to the variability of solar irradiance. The variable character of solar irradiance on the ground is in large due to the effects of cloudiness. How a PV installation is impacted by the effects of irradiance variability varies highly with the surface area of the installation. A study into power fluctuations in large scale PV plants shows that the intensity of power fluctuations decreases quickly with increasing surface area for smaller PV plants (e.g.<5ha), while the curve smoothens for larger installations [55].

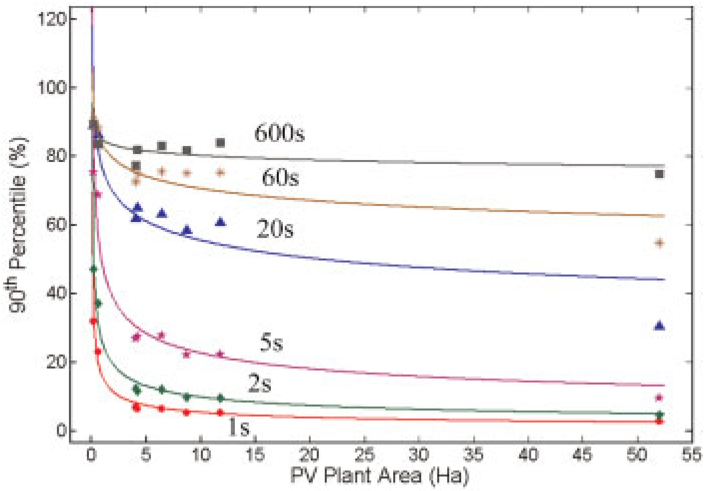


Figure 4.2: 90th percentile of the registered power fluctuations [55]

It was possible to find a dataset of a PV installations with similar features to Oosterwolde in the systems of BayWa r.e., the mother company of GroenLeven which takes care of the operation of their PV installations. This park has a surface area of 19.6 ha and a nominal DC-capacity of 21.8 MWp and is located in Eelde, approximately 25 kilometres to in North-Eastern direction as the crow flies in a similar geographic situation.

System Feature	Value
Nominal DC-Power	21.80 MWp
Nominal AC-Power	17.12 MW
Maximum AC-Power	18.86 MVA
Area	19.6 ha
Module tilt angle	10°
Module orientation	0°

Table 4.2: Table of system features PV park Eelde

The other features are similar as well: the tilt angle is 10°instead of 15°and the orientation 0°instead of -28.8°. The PV plant is hardly curtailed, only 10 out of 307 inverters are slightly under-dimensioned and is not limited by its connection to the distribution grid. In this study a sampling size of 5 minutes, or 300s, is used. In Figure 4.2 it can be observed that the curves for a sampling size of 60s and 600s show very little slope when the PV plant area exceeds 19.6 ha. Based on the above observations, it is deemed acceptable to use the generation dataset of PV park Eelde, scaled by a factor reflecting the nominal DC-Power of both installations. The resulting scaled PV Generation Dataset for the Oosterwolde PV park can be observed in Fig. 4.3.

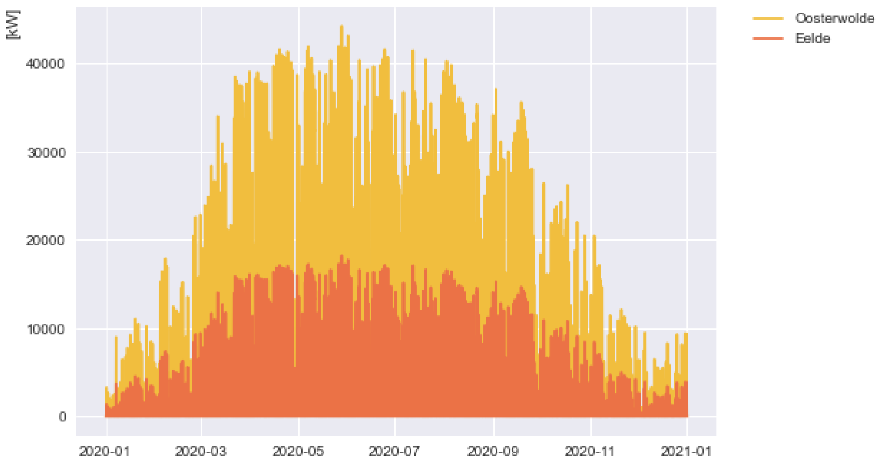


Figure 4.3: Scaled PV Generation Dataset for the Oosterwolde PV Park.

5
Evaluation Method

Considering all the information from the previous chapters, introduction, market developments, sources of income and cost items, and the description of the case study, in this chapter the Evaluation Method for the assessment of the PV-Electrolysis system is presented.

To evaluate the PV-Electrolysis system on the level of profitability and grid effects, a Simulation Model was created for this study, as well as a Financial Model to evaluate the financial performance of the system. Using these models several scenarios, tailored to the Oosterwolde Case Study, will be evaluated in the next chapters. In this chapter the scenarios are presented, as well as an explanation of the two models that have been created to evaluate them.

5.1. Scenarios & Simulation Model

In this section the Scenarios that have been composed are discussed alongside an explanation of the Simulation Model. This is done because the Simulation Model uses different functions based on which Mode of Operation is chosen. The functions of the Simulation Model are discussed in the sections where each Mode of Operation is illustrated. Both the Simulation Model and Financial Model were created in Python, and are represented in Flowcharts in this section. The actual code can be found in the Appendix.

From the Scenario Parameters mentioned in Table 5.1 several scenarios have been composed with the goal of assessing under which conditions the PV-Electrolysis system can become profitable. A division is made between Scenario Parameters and Sizing Parameters. First a combination of the Scenario Parameters is tested with a fixed set of Sizing Parameters and a Base Price Scenario, later the sensitivity to changes in Sizing Parameters and Price Parameters is evaluated.

Scenario Parameters	**Definition**	**Values**
MOO	Mode of Operation	GC, IM, PVI
$Subs$	Subsidy Scenario	As discussed in Sec. 3.1.3
EM	Electricity Market Scenario	spot/ PPA
Sizing Parameters		
C_{Grid}	Grid Connection Capacity	Iteration
$C_{Electrolyser}$	Electrolyser Capacity	Iteration

Table 5.1: Explanation of Simulation Parameters.

The MOO Parameter can assume three values: The PV-Electrolysis system can operate in either 'Grid Connected' (GC), or 'Island Mode' (IM), and for reference of the third MOO that is evaluated is 'PV Individual' (PVI), in which case no Electrolyser is involved. In the Scenarios the Subsidy and Electricity Market Scenarios assume all compatible values for each Mode of Operation, whereas the Sizing Parameters will be set at sensible values for the Mode of Operation at hand.

5.1.1. Base Price Scenario

Initially all scenarios will be simulated with a Base Price Scenario. The Price Parameters that constitute the Base Price Scenario are discussed in this section.

The electricity prices in the Base Price scenario follow the hourly electricity price forward curve from Section 2.1.5. When electricity is sold and fed into the grid on top of the electricity price, a remuneration for the Guarantees of Origin is also received, just as when electricity is procured to produce green hydrogen, GO's will have to be acquired. The price level for GO's in the Base Price Scenario follows the projection from Fig. 3.2. Additionally for electricity procured from the grid an Electricity Tax is charged, it is assumed this will stay constant in at 0.56 2020EUR/MWh, as discussed in Sec. 3.2.2. Lastly, the the Electricity Price can vary with the setting of the Electricity Market (EM) Scenario. When EM is set to 'spot', the hourly values from the Fig. 2.13 are used, while in case of EM Scenario 'PPA', the average yearly values from Fig. 2.13 are used.

The green hydrogen prices will follow the projections discussed in section 2.2.2, the base green hydrogen price scenario follows the top end of the projections in Fig. 2.17. The low- and mid range of the LCOH projections are likely not attained in The Netherlands, but are estimated based on sites with cheaper land and more favourable VRE conditions. It is assumed that after costs for transportation and intermediaries, the cost of hydrogen produced at cheaper levels will also be available in The Netherlands at market prices equal to the high end of the LCOH projections curve. Furthemore the projections of PV and Electrolysis equipment from Table 3.3 are assumed.

The subsidies discussed in section 3.1 are assumed for the baseline scenario, where the SDE++ Solar, SDE++ Hydrogen subsidy from 2022 and 'Tijdelijke Opschalingsregeling Waterstof uit Electrolyse' will be referred to as SDEZ, SDEW and TOW, respectively. For the TOW subsidy it is assumed that the exploitation compensation component will follow the SDEW amounts. The missing values in SDEW in turn follows the values reported for the SDE++ Hydrogen 2021 subsidy.

Price Parameters	**Definition**	**Values**
P_{El}	Electricity Price	spot/PPA, acc. to Fig 2.13
P_{GO}	GO Price	Acc. to Fig. 3.2
P_{eltax}	Electricity Tax	0.56 2020EUR/MWh
P_{H2}	Green Hydrogen Price	Top end of curve in Fig. 2.17
A_{Subs}	Subsidy Amounts	Acc. to Sec. 3.1.3
$CAPEX_{PV}$	PV Equipment CAPEX	Acc. to Tab. 3.3
$OPEX_{PV}$	PV Equipment OPEX	Acc. to Tab. 3.3
$CAPEX_{P2G}$	P2G Equipment CAPEX	Acc. to Tab. 3.3
$OPEX_{P2G}$	P2G Equipment OPEX	Acc. to Tab. 3.3

Table 5.2: Values of Price Parameters in the Base Price Scenario.

5.1.2. PV Individual

To establish a background for the financial performance of a PV-Electrolysis system, the scenario of an individual PV plant is analysed. In this case the lifetime of the project is 25 years, as that is the usual lifetime of PV equipment. In this scenario it is assumed that the remaining value of system components at the end of the 25 year lifetime equal the decommissioning costs, an assumption which is commonly used in the PV industry [41].

Simulations of this scenario are run with SDE++ subsidy for solar generation (SDEZ) and without subsidies. Each subsidy scenario is simulated with electricity sales through the spot market and PPAs, the two electricity market (EM) scenarios. For PV Individual a Grid Capacity , C_G, of 67% of peak PV capacity is chosen. The 67% MWp grid connection is inspired on the industry agreement of contracting a maximum 70% of peak PV capacity [30]. An overview of the scenarios using the PVI MOO is available in Tab. 5.3.

The Simulation Model function for MOO 'PVI' (Fig. 5.1) is relatively simple. The inputs (in parallellograms) that can be varied are the Scenario Parameters 'Subsidy Scenario' and 'Electricity Market Scenario'. Furthermore the inputs are PV Generation Data from Fig. 4.3, Grid Capacity C_G, and the Subsidy Criteria and Amounts. Then it is determined whether the PV Power is higher than the Grid

MOO	Subs	EM	C_G [MW]	C_{EI} [MW]
PV Park Individual (PVI)	-	spot	35.30	-
		PPA	35.30	-
	SDEZ	spot	35.30	-
		PPA	35.30	-

Table 5.3: Overview of scenarios for MOO PVI.

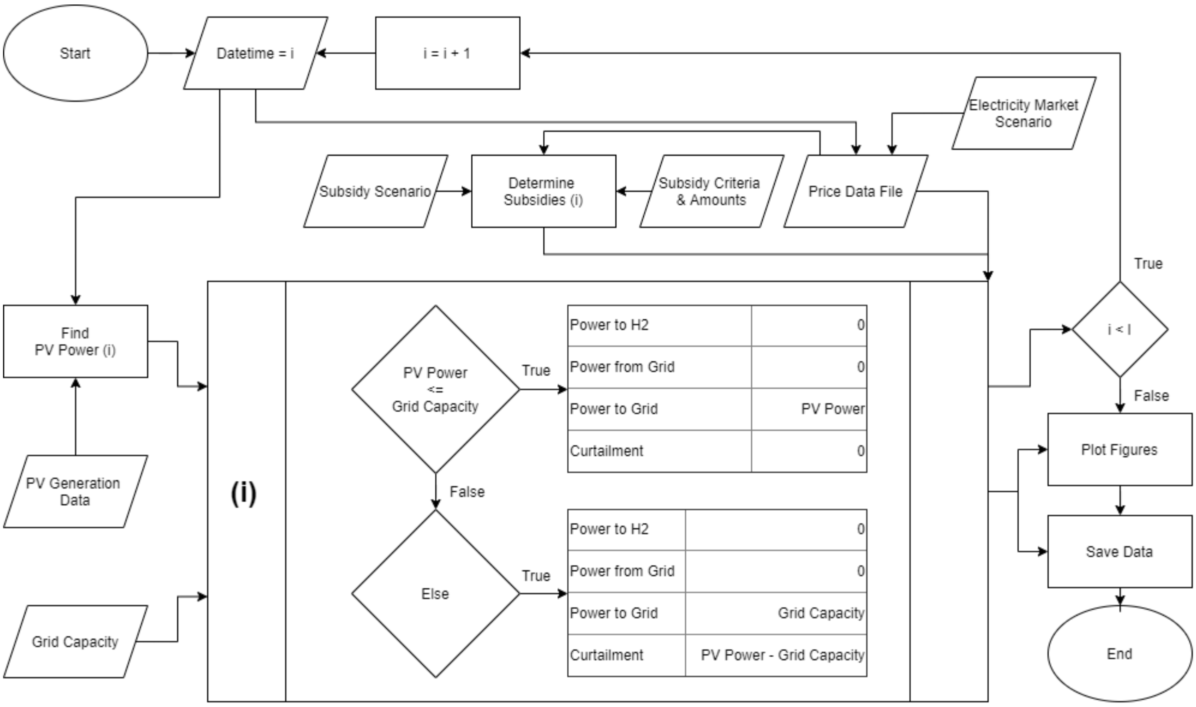


Figure 5.1: Flowchart of PVI Scenario in Simulation Model.

Capacity and how much power is delivered to the grid. For each hour of the simulation period data of volumes of hydrogen and electricity produced or curtailed as well as current price data, subsidy tarriffs and full load hours are combined and saved automatically in the end.

5.1.3. Island Mode

Next Mode of Operation to discuss is the the Island Mode (IM). In this scenario a PV-Electrolysis system is simulated, which is not connected to the electricity grid. In this case two subsidy types are simulated, the SDE++ Hydrogen subsidy (SDEW) and the temporary upscaling instrument for electrolysis (TOW). These subsidies have different subsidy amounts with tailored to and in favour of PV-Electrolysis projects without a grid connection. No differentiation is made with respect to the electricity market, since the system in this scenario does not have a grid connection and hence does not interact with the electricity market. The baseline Electrolyser capacity used in C_{EI} is 67% of peak PV capacity, mimicking the grid connection of the individual PV park. An overview of the IM scenarios is available in Tab. 5.4.

MOO	Subs	EM	C_G [MW]	C_{EI} [MW]
Island Mode (IM)	-	-	-	35.30
	SDEW	-	-	35.30
	TOW	-	-	35.30

Table 5.4: Overview of scenarios for MOO IM.

The Island Mode function in the Simulation Model (Fig. 5.2) is slightly different from the PVI function.

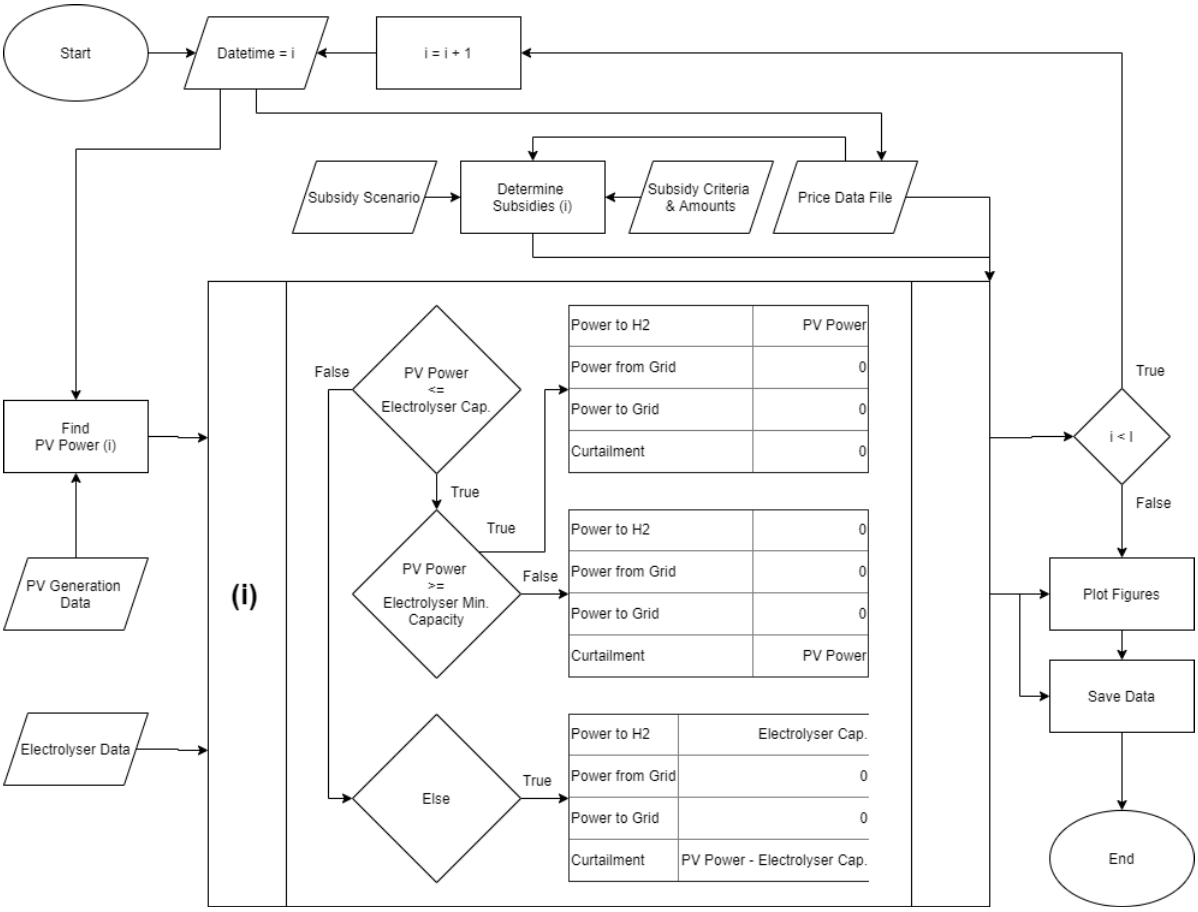


Figure 5.2: Flowchart of IM Scenario in Simulation Model.

The main differences in inputs (parallellograms) are that there is now an input related to the Electrolyser instead of Grid Connection and the EM scenario is not an input in this case. Furthermore, instead of comparing the PV Power to the Grid Capacity, it is now compared to the load range (minimum and maximu capacity) to determine if and how much power can go to the Electrolyser. For each hour of the simulation period data of volumes of hydrogen and electricity produced or curtailed as well as current price data, subsidy tarriffs and full load hours are combined and saved automatically in the end.

5.1.4. Grid Connected

The system in the Grid Connected (GC) scenario is a PV-Electrolysis system which is connected to the electricity grid. This is the most versatile scenario. This scenario uses a decision mechanism, which decides which is more profitable for each moment in time: selling electricity produced by the PV plant or converting it to hydrogen instead. Which of the two is preferred depends on the electricity price and the hydrogen price for each moment in time, as well as possible subsidy tariffs if applicable. Several subsidies are considered apart and combined, these are SDE++ for solar generation and hydrogen (SDEZ,SDEW) and the temporary upscaling instrument hydrogen from electrolysis (TOW). For the Grid Connected scenarios a baseline setup for the sizing parameters is chosen for C_G and C_{El} of 67% and 33% of peak PV capacity (53 MWp). The 67% MWp grid connection is inspired on the industry agreement of contracting a maximum 70% of peak PV capacity [30]. An overview of GC scenarios is available in Tab. 5.5.

The Grid Connected function in the Simulation Model (Fig. 5.3) is the most complicated function. This is due to the Decision Mechanism which chooses if the preference is to produce hydrogen or electricity, and due to the fact that now both an Electrolyser and a Grid Connection are available. This means

MOO	Subs	EM	C_G [MW]	C_{El} [MW]
Grid Connected (GC)	-	spot	35.30	17.65
		PPA	35.30	17.65
	SDEZ	spot	35.30	17.65
		PPA	35.30	17.65
	SDEW	spot	35.30	17.65
		PPA	35.30	17.65
	TOW	PPA	35.30	17.65
	SDEZ+W	spot	35.30	17.65
		PPA	35.30	17.65
	SDEZ+TOW	PPA	35.30	17.65
		PPA	35.30	-

Table 5.5: Overview of scenarios for MOO GC.

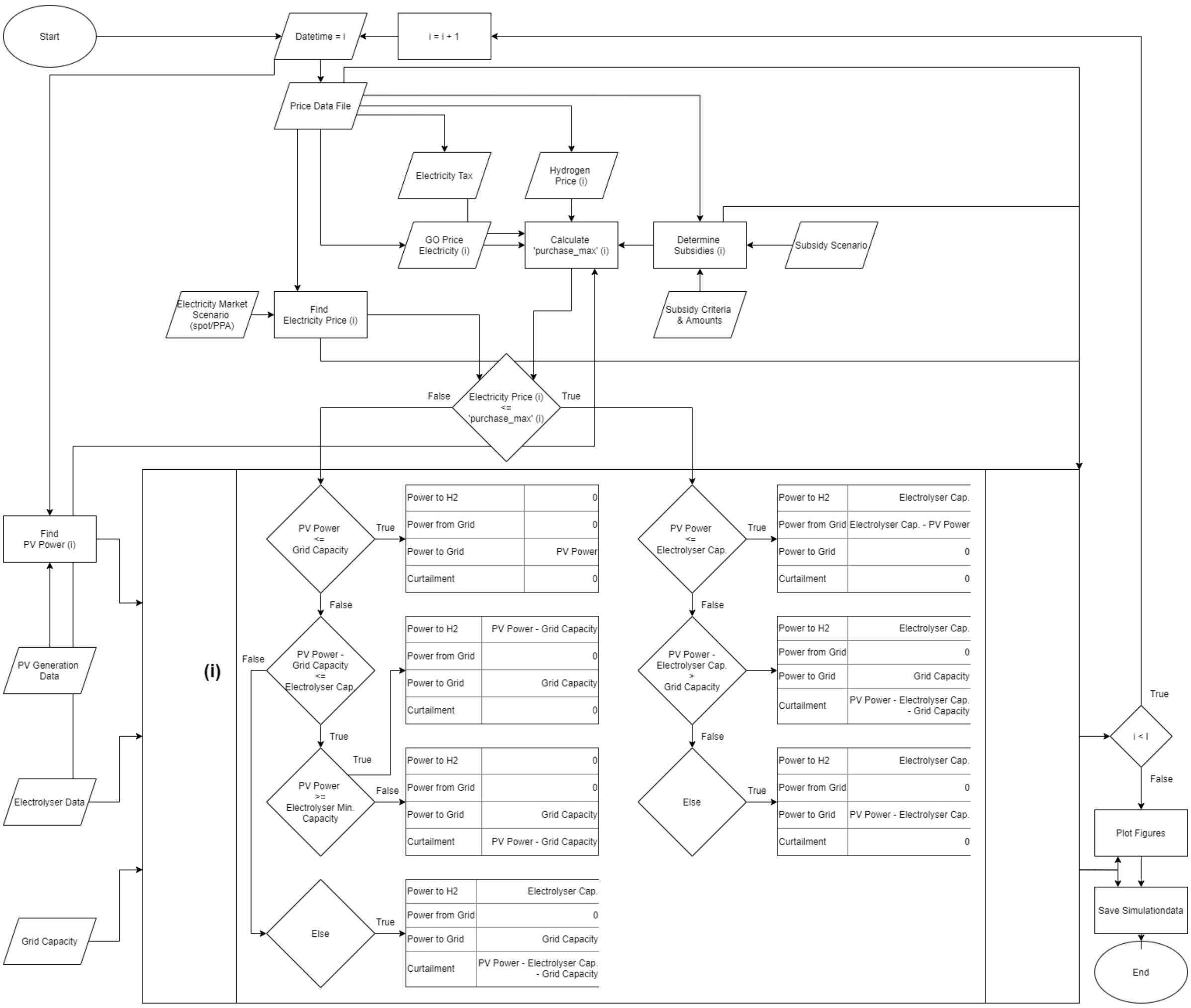


Figure 5.3: Flowchart of GC Scenario in Simulation Model.

that if e.g. the preference goes to producing hydrogen, but the PV Power exceeds the Electrolyser Capacity, the excess power can still be fed to the grid.

The upper half of the Flowchart (Fig. 5.3) represents the Decision Mechanism. The Price Data File contains all price related information with hourly granularity for the whole simulation period. It contains the Electricity prices, which are easily referred to if the current 'Datetime' (pandas language for Date + time) and EM scenario are known. Furthermore, it contains the Data required to calculate the maximum Electricity price at which procuring Electricity from the Grid to produce Hydrogen is still profitable, in the model this value is called 'purchase_max'. As long as the Electricity price stays below this value, the preference is to produce as much Hydrogen as possible, and vice versa.

The lower half of the Flowchart (Fig. 5.3) represents the allocation of power dependent on the preference decided by the Decision Mechanism. Here the PV Power is compared with the load range of the Electrolyser and Grid Capacity to make the most profitable allocation of power from the PV Park and in case the Electricity Price is below the 'purchase_max', potentially of additional Grid Power. In the end, for each hour of the simulation period data of volumes of hydrogen and electricity produced or curtailed as well as current price data, subsidy tarriffs and full load hours are combined and saved automatically.

5.2. Financial Model

As was mentioned before, the Simulation Model saves all its data with hourly granularity at the end of each simulation. Some Price Parameters actively influence the behaviour of the system during the simulation, such as Electricity Prices, Subsidies and Hydrogen Prices. Some other Price Parameters do not influence the behaviour of the system, but do have a significant impact on the business case, such as CAPEX or OPEX of the equipment.

To evaluate the financial performance of several simulations of the PV-Electrolysis system, a Financial Model was created for the purpose of this study. The model was created in Python, and is represented as a Flowchart in Fig. 5.4, the actual code can be found in the Appendix. To give insight in the financial performance of a simulation, the model calculates the NPV, IRR and LCOH and LCOE for each simulation. In this section the calculations on which the Financial Model is based are discussed, after which a Flowchart of the model is presented.

5.2.1. NPV & IRR

To evaluate the profitability of the PV-Electrolysis system 'Net Present Value' (NPV) and Internal Rate of Return (IRR) are used. The For a prospective investment, the NPV tells an investor whether or not the investment is profitable (profitable if NPV > 0, not profitable if NPV ≤0). However, NPV is the absolute amount in today's money that the sum of the cash flows available to the investor is worth based on some discount rate. The discount rate reflects the minimum rate of return an investor wants to make, e.g. as compensation for his own costs such as financing costs. Investors often use their weighted average cost of capital (WACC) as the discount rate, which can be considered a compensation for providers of debt and equity capital to finance an activity for the risks of providing capital. The value of the WACC depends on the ratio of debt and equity capital and the desired interest or returns by the providers. In this study the WACC that will be used is 4%, the same as the WACC for private investors in solar PV applications according to Topsector Energie [41]. Furthermore, to avoid unnecessary complexity, inflation is considered zero throughout this study. The formula used to calculate NPV is presented in Equation 5.1.

$$NPV = \sum_{n=1}^{N} \frac{FCF_n}{(1+r)^n} - C_0 + TV \tag{5.1}$$

where:
NPV = Net Present Value
r = Discount Rate
FCF = Free Cash Flow
C_0 = Initial Investment
TV = Terminal Value
n = current year
N = final year

The Terminal Value of an investment usually means the transaction sum received when an investor makes its 'exit', meaning when it liquidates its position. Since the lifetime of the PV system and the electrolyser are not equal, in this study the TV will be used in simulations of the 'grid connected' scenarios. The lifetime of a PV system is 25 years. In the case of a grid connected PV system, the business will be simulated for 20 years, the lifetime of the electrolyser system. A terminal value (TV) is used to account for the five useful life years of the PV system that are left after the lifetime of the electrolyser system. The terminal value that is used represents the last five years ('45-'49) of operation of the PV park with electricity prices from Fig. 2.13, using PPAs with a value of the yearly average electricity price. This amounts to a positive cash flow of 6.62 mEUR added to the FCF in 2045. This equates to a net present value in 2025 of 2.90 mEUR. This TV does not apply in case of a PV-Electrolysis system in Island Mode, since there is no way to monetize the last five life years of the PV system and it is assumed that the value of the remaining equipment are equal to the decommissioning costs.

The NPV does not provide any insight in how good the return is in relation with the initial investment sum, and it does not give insight in the investment's profitability with respect to alternative investments. The IRR does provide this information, presented as the expected annual rate of return (as a percentage) of an investment. The profitability of the PV-Electrolysis business case will be assessed using Internal Rate of Return (IRR). IRR is a metric commonly relied on in financial analysis to assess the profitability of a prospective investment. The main benefit of IRR is that it gives a clear indication of profitability irrespective of the amount of invested capital or investment horizon (/project lifetime). This makes it easer to compare the profitability of the PV-Electrolysis system when varying e.g. the Electrolysis technology, or comparing profitability to just a PV installation.

IRR is essentially the discount rate for which the Net Present Value (NPV) of becomes equal to zero. Calculating IRR uses the same equation as NPV, setting NPV to zero and keeping the discount rate, now IRR, variable. This means that for a business case to become 'profitable' the IRR should be greater than or equal to 4%, with the WACC of 4% that is assumed. Equation 5.2 presented below shows the equation used to calculate IRR, where n is in years and N is the final year of the lifetime of the business case.

$$0 = \sum_{n=1}^{N} \frac{FCF_n}{(1+IRR)^n} - C_0 + TV \tag{5.2}$$

where:
FCF = Free Cash Flow
IRR = Internal Rate of Return
C_0 = Initial Investment
TV = Terminal Value
n = current year
N = final year

Central to this equation is the financial metric Free Cash Flow (FCF). In the first year FCF will have a large negative value, due to the large cash outflow associated with the initial capital expenditure. In consequent years the FCF should be positive assuming the revenues generated by the sale of electricity and hydrogen will cover the operating expenses.

$$FCF = EBIT - Tax + D\&A - CAPEX - \Delta OWC \tag{5.3}$$

where:
$EBIT$ = Earings before Interest and Tax
$D\&A$ = Depreciation & Amortisation
$CAPEX$ = Capital Expenditure
ΔOWC = Change in Operating Working Capital

Central to the equation for FCF is Earings before Interest and Tax (EBIT), which is in turn calculated using Equation 5.4. EBIT equals Revenue minus Cost of Goods Sold minus Operating Expenses. Depreciation and Amortisation (D&A) is a bookkeeping term allowing to spread capital expenditure over the useful lifetime of an acquired asset. Changes in operating working capital are ignored in the case of a PV-Electrolysis system, as in this study the project's current assets and liabilities are negligible.

$$EBIT = Revenue - COGS - OPEX \tag{5.4}$$

where:
$COGS$ = Cost of Goods Sold
$OPEX$ = Operating Expenses

5.2.2. LCOH & LCOE

Two other metrics to evaluate the financial performance of the PV-Electrolysis system are LCOE and LCOH. These are measures to assess how expensive it is to produce a kilogram of Hydrogen or a MWh of electricity considering all the costs incurred during the lifetime along which electricity or hydrogen is produced. These measures therefore provide insight in the cost side differentiated by product stream of a PV-Electrolysis system. See Equations 5.5 and 5.6 for the formulas used to calculate the LCOE and LCOH.

$$LCOE = \frac{\sum_{n=1}^{N} \frac{OPEX_{PV}}{(1+r)^n} + CAPEX_{PV}(-TV)}{\sum_{n=1}^{N} \frac{V_{El}}{(1+r)^n}} \tag{5.5}$$

where:
$LCOE$ = Levelized cost of electricity
$OPEX_{PV}$ = Operating expenses PV equipment
r = Discount rate
$CAPEX_{PV}$ = Capital expenditure PV equipment
TV = Terminal value, if applicable
V_{El} = Volume of rlectricity produced [MWh]
n = current year
N = final year

The LCOE is calculated with the Capital and Operating Expenditures associated with the PV equipment, including the costs associated with the grid connection. The LCOH is calculated with the Capital and Operating Expenditures associated with the electrolyser system including the compression system, which is referred to as P2G in the formula.

$$LCOH = \frac{\sum_{n=1}^{N} \frac{OPEX_{P2G}+PC+IPC}{(1+r)^n} + CAPEX_{P2G}}{\sum_{n=1}^{N} \frac{M_{H2}}{(1+r)^n}} \tag{5.6}$$

where:
$LCOH$ = Levelized cost of hydrogen
$OPEX_{P2G}$ = Operating expenses P2G equipment
PC = Costs of procured electricity, if applicable
IPC = Internal power cost
r = Discount rate
$CAPEX_{P2G}$ = Capital expenditure P2G equipment
M_{H2} = Mass of hydrogen produced [kg]
n = current year
N = final year

The LCOH depends much on the costs of the consumed electricity, which is in represented by PC and IPC in Eq. 5.6. PC represents costs of electricity procured and consumed from the grid, while IPC represents the costs of electricity produced by the PV system and consumed by the electrolyser. In the 'grid connected' scenarios this is calculated as the unrealized revenue by not selling the power on the market at the specific time it is instead consumed by the electrolyser. In the 'island mode' scenarios the IPC is calculated with the LCOE as the electricity price.

5.2.3. Flowchart

Finally, in Figure 5.4 a Flowchart of the Financial Model is displayed. The Model uses the calculations discussed in the previous sections to get its results. The input is fully derived from the Simulationdata file that is produced by the Simulation Model at the end of each simulation.

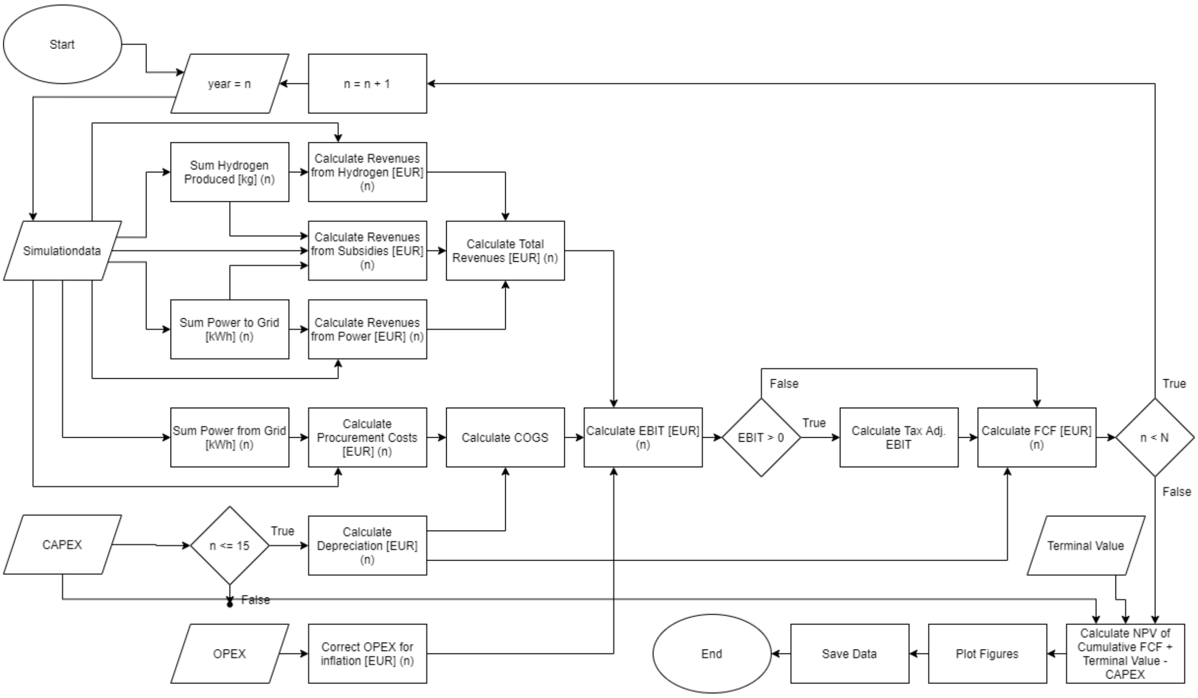


Figure 5.4: Flowchart of Financial Model.

MOO	Subs	EM	C_G [MW]	C_{EI} [MW]
Grid Connected (GC)	-	spot	35.30	17.65
		PPA	35.30	17.65
	SDEZ	spot	35.30	17.65
		PPA	35.30	17.65
	SDEW	spot	35.30	17.65
		PPA	35.30	17.65
	TOW	PPA	35.30	17.65
	SDEZ+W	spot	35.30	17.65
		PPA	35.30	17.65
	SDEZ+TOW	PPA	35.30	17.65
Island Mode (IM)	-	-	-	35.30
	SDEW	-	-	35.30
	TOW	-	-	35.30
PV Park Individual (PVI)	-	spot	35.30	-
		PPA	35.30	-
	SDEZ	spot	35.30	-
		PPA	35.30	-

Table 5.6: Overview of scenarios for all MOO.

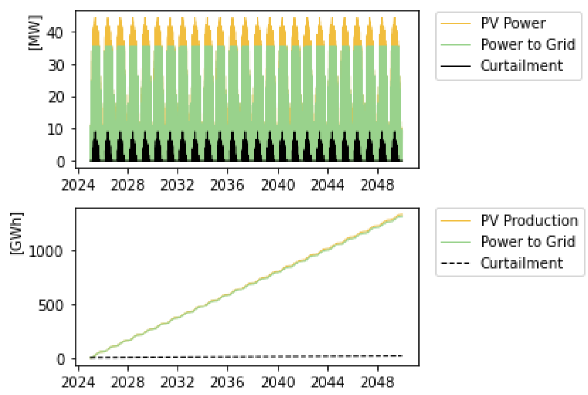
6
Results

6.1. Results

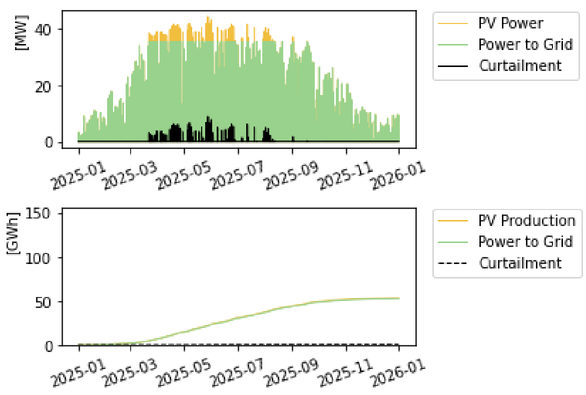
In this section the results of the simulation model for the Case Study are presented. At the end of the section in Table 6.7 an overview is provided of all scenarios and their performance measured in IRR and NPV. The rest of this section will discuss the results for each scenario in more detail.

6.1.1. PV Individual

In Figure 6.1 the simulation results for the PVI scenario are presented. The operation of the PV system in the PVI scenario is not affected by price dynamics on the electricity market and the physical behaviour of the system is therefore the same for all scenario variants. Figure 6.1a shows the simulation results for all hours of the whole 25 year lifetime of the PV system and Figure 6.1b shows the operation of the system during a single year. Some curtailment is observed due to the grid capacity of 67% (35.3MW) of peak PV capacity. The curtailment seems substantial in Fig. 6.1a, however when looking at the lower graphs it becomes clear that in terms of energy the curtailment remains very low relative to the power delivered to the grid.



(a) Full lifetime

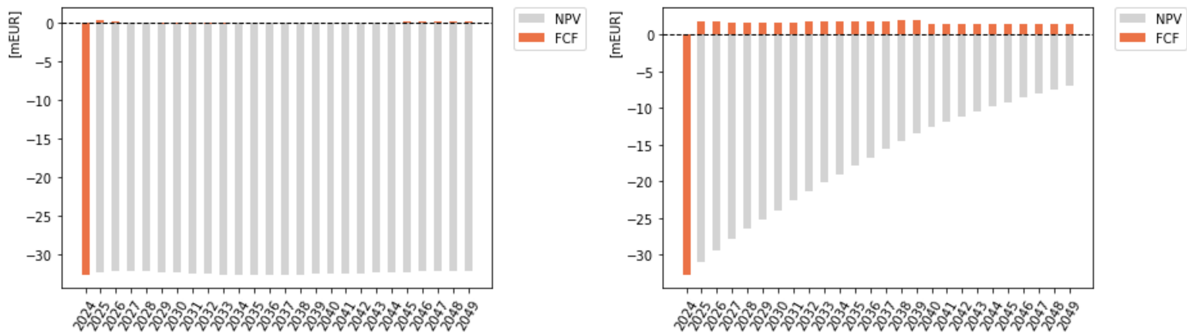


(b) Single year

Figure 6.1: PV Individual simulation, operation is the same for all years and scenario variants, hence a cut-out of the first year in Fig. 6.1b. Note that curtailment remains very low in cumulative terms in the lower graphs, however substantial it may seem in the upper graphs. For the same reason 'PV Production' remains hardly visible behind 'Power to Grid', they virtually coincide.

It is observed that an individual PV plant is not profitable under any combination of conditions which have been simulated. When the electricity is sold on the spot market the plant is generating very little FCFs, resulting in an IRR of -15.08% and a NPV of -32.191 mEUR, barely above the initial investment (32.71 mEUR). When the electricity is sold through PPAs, more positive FCFs emerge. This dramatically improves the business case, leading to a positive IRR of 1.80%.

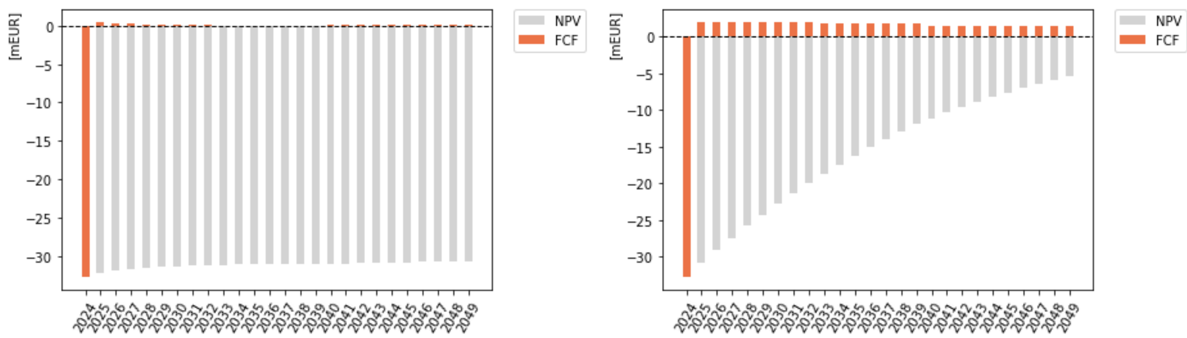
The scenarios with SDE++ subsidies very slightly increase the business case with respect to the scenarios without subsidies, however the dramatic difference between the scenario variants on the spot and PPA market remains. The dramatic difference between business cases based on the spot market versus PPAs can be attributed to the cannibalization effect discussed in Section 1.1.3: when the PV



(a) EM: spot. IRR: -15.08%, NPV: -32.191 mEUR.

(b) EM: PPA. IRR: 1.80%, NPV: -6.937 mEUR.

Figure 6.2: Financial performance PVI scenario variants without subsidies.



(a) EM: spot. IRR: -14.63%, NPV: -30.647 mEUR.

(b) EM: PPA. IRR: 2.26%, NPV: -5.393 mEUR.

Figure 6.3: Financial performance PVI scenario variants with SDE++ Solar Subsidy (SDEZ).

system produces power the spot prices are often below average. This effect can be observed in both Figures 6.2 and 6.3. In the PPA scenario variants it is notable that the FCF from 2040 on is suddenly substantially lower, this is a result of depreciation. The equipment is depreciated linearly over 15 years, keeping EBIT below zero in all PVI scenarios and hence sheltering the FCF from tax. From 2040 on there is no more depreciation so no more tax shelter, that is why the FCF drops. In the end none of the business cases generate a positive NPV, as the IRRs remain below 4%. The system delivers 1316.2 GWh of electricity to the grid at a LCOE of 54.88 EUR/MWh.

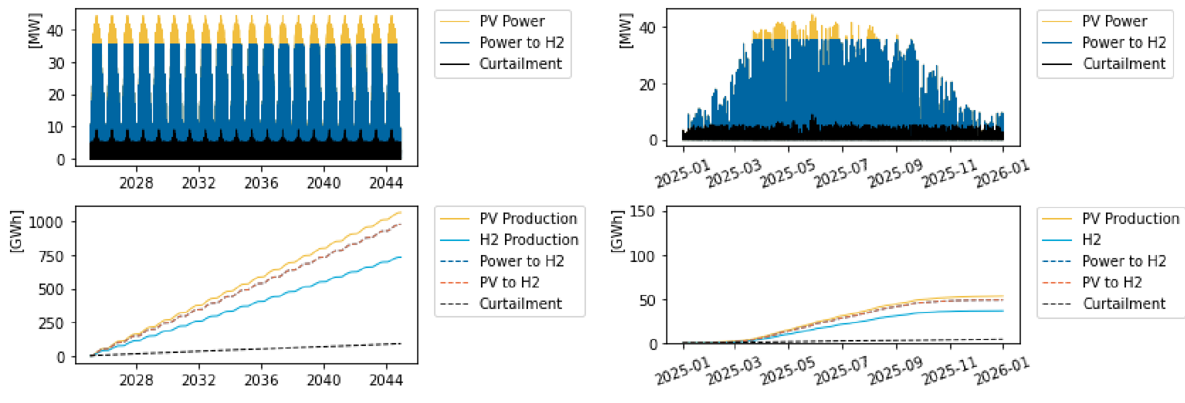
MOO	**Subs**	**EM**	**C_G** [MW]	**C_{P2G}** [MW]	**IRR** [%]	**NPV** [m€]	**LCOH** [€/kg]	**LCOE** [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	**FLH P2G** [avg. h/y]
PVI	-	spot	35.30	-	-15.08	-32.191	-	54.88	-	1316.2	-
		PPA	35.30	-	1.80	-6.937	-	54.88	-	1316.2	-
	SDEZ	spot	35.30	-	-14.63	-30.647	-	54.88	-	1316.2	-
		PPA	35.30	-	2.26	-5.393	-	54.88	-	1316.2	-

Table 6.1: PV Individual financial performance.

6.1.2. Island Mode

In this section the Island Mode scenario is discussed. In this scenario the physical system contains a PV plant and an electrolyser without a connection to the electricity grid. The electrolyser is sized at 67% (35.3MW) of peak PV capacity.

In Figure 6.4 it is observed that besides curtailment when PV generation exceeds the electrolyser capacity, some curtailment also takes place when PV generation is below 15% of the electrolyser capacity, as the alternative of feeding it into the grid is not available. In Figure 6.5 it is observed that without subsidies the business case remains very negative, and FCF shrinks over the years along with the green



(a) Full lifetime

(b) Single year

Figure 6.4: Island Mode simulation, operation is the same for all years and scenario variants, hence a cut-out of the first year in Fig. 6.4b. Note that curtailment, although relatively low in cumulative terms in the lower graphs, is higher than in the PVI scenarios. This is caused by the lower capacity limit of 15% of the electrolyser.

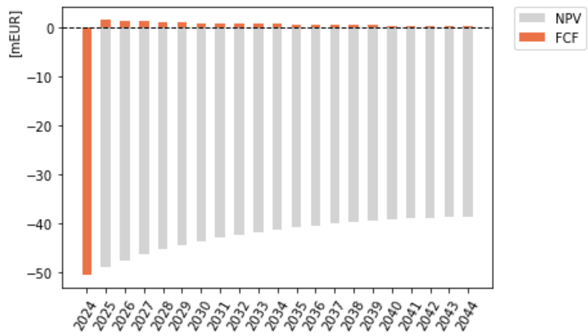
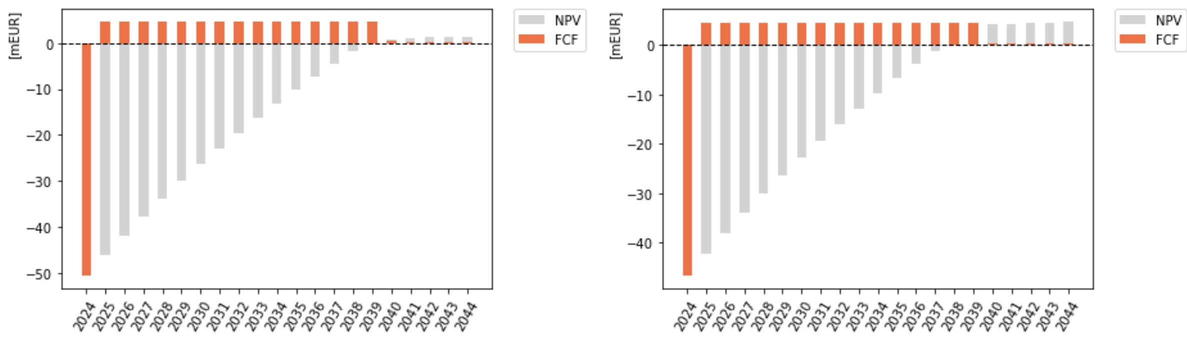


Figure 6.5: Financial performance 'island mode' without subsidies. IRR: -11.67%, NPV: -38.716 mEUR.

hydrogen market price.



(a) SDE++ Hydrogen (SDEW). IRR: 4.40%, NPV: 1.438 mEUR.

(b) TOW. IRR: 5.37%, NPV: 4.659 mEUR.

Figure 6.6: PVI financial performance with SDE++ Hydrogen (SDEW) and TOW subsidy.

Simulations were done with the SDE++ Hydrogen and TOW subsidy, of which the financial performance can be observed in Figures 6.6a and 6.6b. It is clear that adding a subsidy increases the IRR dramatically, to values which become acceptable for investors. There is not much difference between the SDEW and TOW subsidies here, because the number of full load hours of the electrolyser does not exceed the maximum number of full load hours of the SDE++ subsidy (3000) in Island Mode. The main difference is the slightly lower initial CAPEX, because of the assumed 20% CAPEX support for the electrolyser.

The system produces 18.6 Mt of renewable hydrogen at a LCOH of 4.929 EUR/kg in the scenario variants without subsidies and with the SDE++ subsidy, and a LCOH of 4.628 EUR/kg in the TOW scenario due to the CAPEX support. This is achieved with a LCOE of 57.95 EUR/MWh as the determining factor for the internal power cost. The reason the LCOE is higher here than in the PVI scenario despite the absence of costs for the grid connection is the lower lifetime of the system of 20 years. Because there is no link to the grid, it is not possible to operate the PV plant after the electrolyser lifetime has expired, hence no Terminal Value is included in the financial analysis for the IM scenarios. In all cases the LCOH is much higher than the market price for renewable hydrogen, which is 3.12 EUR/kg at its highest point in 2025, before declining steadily to 1.66 EUR/kg in 2044. Hence, no profitable business case can be realized without subsidies in the 'island mode' configuration. It is however noteworthy that the IRR of -11.67% without subsidies is, although dramatic, better than the IRRs realized on the spot market in the PVI configuration.

MOO	**Subs**	**EM**	$\mathbf{C_G}$ [MW]	$\mathbf{C_{P2G}}$ [MW]	**IRR** [%]	**NPV** [m€]	**LCOH** [€/kg]	**LCOE** [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	**FLH P2G** [avg. h/y]
IM	-	-	-	35.30	-11.67	-38.716	4.929	57.95	18.6	-	1384
	SDEW	-	-	35.30	4.40	1.438	4.929	57.95	18.6	-	1384
	TOW	-	-	35.30	5.37	4.659	4.628	57.95	18.6	-	1384

Table 6.2: Island Mode financial performance.

6.1.3. Grid Connected

Scenarios without subsidies

In this subsection the simulations of the scenarios for the Grid Connected mode of operation are discussed. Since for this mode of operation the behaviour of the physical system varies heavily with each scenario, due to the decision mechanism which decides whether to produce hydrogen or to feed power into the grid (as explained in Sec. 5.1.4). The physical behaviour of the system is heavily influenced by the level of compensation for production of hydrogen and electricity, the latter of which can fluctuate on an hourly basis while the hydrogen price level varies with yearly granularity in this study. These levels of compensation are influenced by the market prices of both product streams, but also by subsidies. Subsidies may be limited by a number of full load hours within a year and hence cause additional fluctuations within a year.

The 'grid connected' mode of operation is the mode of operation with the most scenario variants, due to many different subsidy and electricity market scenarios. All this variation results in simulations which vary heavily throughout scenario variants and time. The results discussed in this section illustrate the complexity of the business case of the PV-Electrolysis system in 'grid connected' configuration. First the most 'pure' simulation will be discussed, followed by some other examples to illustrate how the 'grid connected' PV-Electrolysis system responds to varying circumstances.

The first scenario variant that is discussed is the spot market scenario without subsidies. The results for all hours of all years is plotted in Figure 6.7. Due to the hourly granularity the upper graph is not very transparent. Note in the upper graph that 'Power to Grid' only rises above 30 MW in the last two years, while the grid connection is 35.3 MW and the 'PV Power' is also clearly higher. This indicates that at times of high 'PV Power', hydrogen production is favoured over delivery to the grid by the decision mechanism. Also note the initial steepness and quick downward bend of the 'H2 Production' curve and the associated power streams 'Power to H2' and 'Power from Grid', a move which is mirrored by the 'Power to Grid' curve.

To gain more insight in the physical behaviour of the simulated PV-Electrolysis system two single years are presented in Figure 6.8. The difference between the two years is immediately apparent: in 2025 much more power is consumed from the grid than in 2032. This is observable in the upper graphs where the frequency, volume and duration of 'Power from Grid' is much higher in 2025 than in 2032. The volume of 'PV to H2' is also much higher in 2025 than in 2032. The result is a much higher output

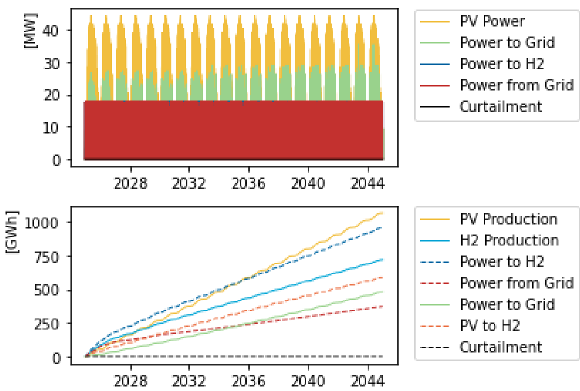
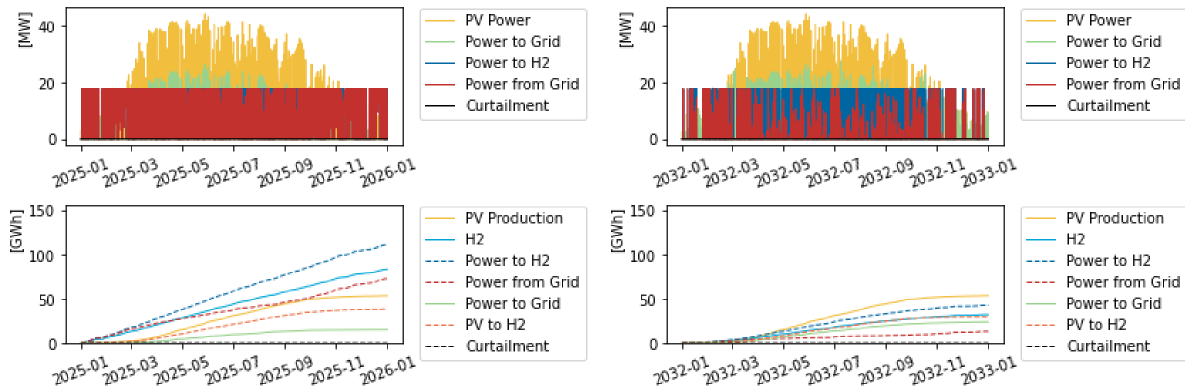


Figure 6.7: Simulation of full lifetime of the GC spot market scenario without subsidies. Note in the upper graph that 'Power to Grid' only rises above 30 MW in the last two years, while the grid connection is 35.3 MW and 'PV Power' is also clearly higher. Also note the initial steepness and quick downward bend of the 'H2 Production' curve, a move which is mirrored by the 'Power to Grid' curve.



(a) Simulation results for 2025. H2: 2.1 Mt, Power to Grid: 15.1 GWh, Electrolyser FLH: 6279

(b) Simulation results for 2032. H2: 0.8 Mt, Power to Grid: 23.9 GWh, Electrolyser FLH: 2415

Figure 6.8: Simulations of single years 2025 and 2032 of the GC spot market scenario without subsidies. Note the great contrast between the two years of 'Power from Grid', 'H2' and substantial contrast of 'Power to Grid'.

of hydrogen ('H2') and lower output of 'Power to Grid' in 2025, and the contrary for 2032. These observations are supported by the number of full load hours of the electrolyser in both years: 6279 for 2025 and 2415 for 2015.

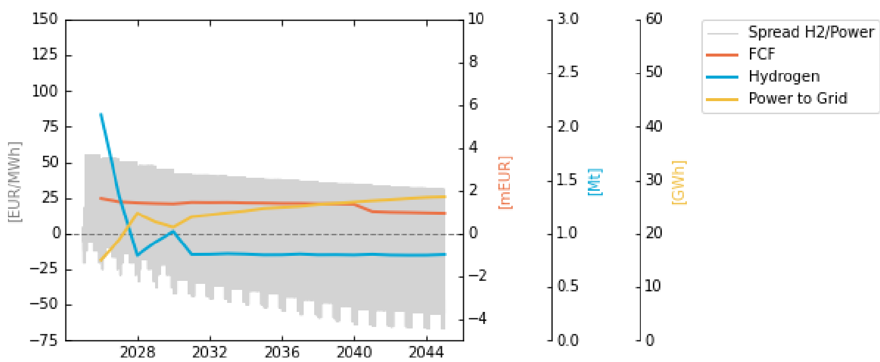


Figure 6.9: Earnings and Production Profile GC NS spot. Spread H2/Power is plotted with hourly granularity to provide insight in its fluctuations. 'FCF', 'Hydrogen' and 'Power to Grid' are plotted with yearly granularity.

The cause for the strong variation of the simulation results for the two years are the levels of compensation for hydrogen and electricity, which cause the decision mechanism of the simulation model to strongly favour hydrogen production over delivery of electricity to the grid in 2025, and contrarily for 2032. To illustrate this dynamic the metric 'Spread H2/Power' is introduced. This refers to the difference in compensation (spread) for producing hydrogen or electricity at a given point in time. It is expressed in EUR/MWh and it represents the compensation that can be earned by directing one MWh of electricity either into the electrolyser or into the power grid. When this spread is positive, it is in favour of hydrogen, while electricity is favoured when the spread is negative. This value is calculated with hourly granularity for every simulation.

Figure 6.9 presents 'Spread H2/Power' along with the yearly production of hydrogen and power delivered to the grid and the accompanying free cash flows. It is apparent that with more positive spread hydrogen production is higher and power output to the grid is lower. The latter starts to climb when the spread becomes more negative. Interestingly, the substantial shift in product output does not seem to impact the FCF much. The financial performance of the GC spot market scenario without subsidies is presented in Figure 6.10. The FCFs in this scenario are relatively constant apart from a clear drop which is observable from 2040 onwards: when the tax shelter provided by depreciation disappears. A clear contribution of the terminal value of the PV park is observed in 2045. This is not enough for a convincing business case however, producing an IRR of -2.02% and a NPV of -21.257 mEUR.

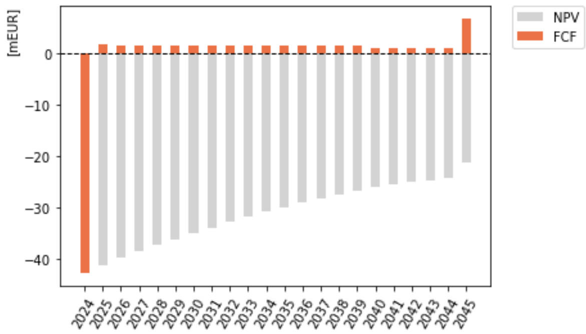


Figure 6.10: Financial performance of GC spot market scenario without subsidies. IRR: -2.02%, NPV -21.257 mEUR.

In the scenario variants with PPAs the decision mechanism becomes fairly absolute: when the decision is in favour of hydrogen as much hydrogen as possible is produced, and when electricity is favoured hardly any hydrogen is produced at all, except a little in cases where electricity would have otherwise been curtailed. The bold shift in 2030 is clearly visible in Figure 6.11, coinciding with the hydrogen/ power spread dropping below zero. Before 2030 the yearly hydrogen production is 2.9 Mt and from 2030 onwards it shrinks to 0.01 Mt, corresponding to 8500 and 36 full load hours of the electrolyser, respectively.

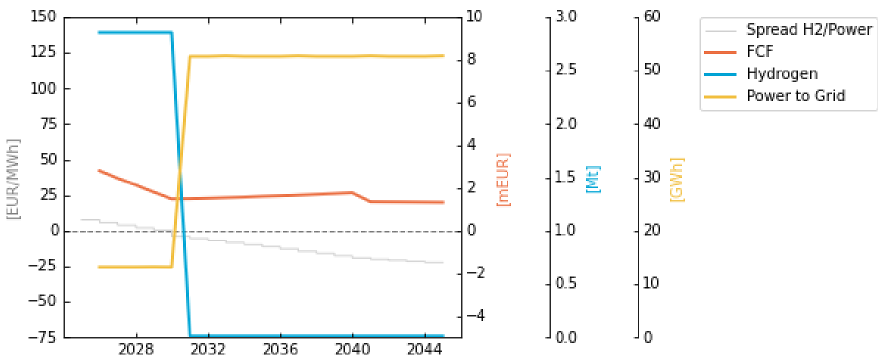
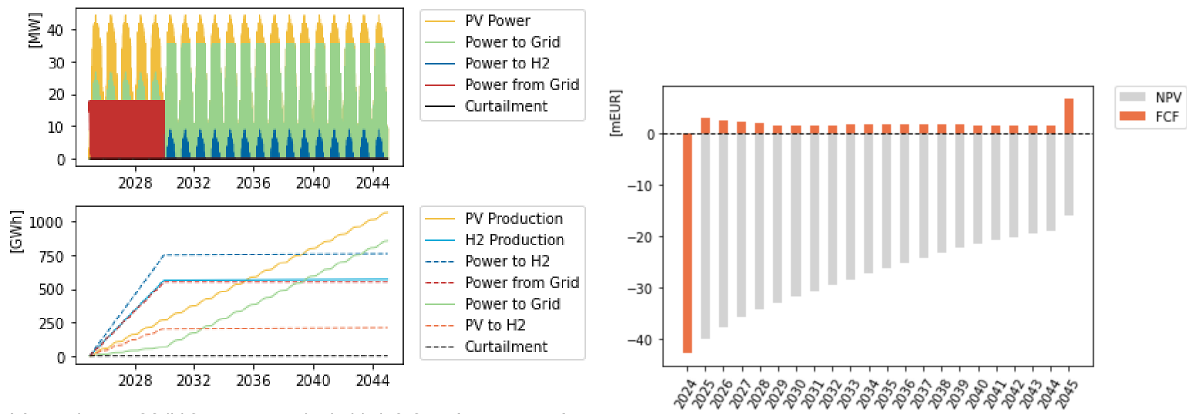


Figure 6.11: Earnings and Production Profile GC NS PPA. Spread H2/Power is plotted with hourly granularity to provide insight in its fluctuations. 'FCF', 'Hydrogen' and 'Power to Grid' are plotted with yearly granularity.

The bold shift in 2030 is very apparent in the simulation results in Figure 6.12a. Also note that otherwise curtailed electricity from 2030 onwards is now fed to the electrolyser. The output of 'Power to Grid' much lower before 2030, with maxima around 25 MW, while from then onwards the maximum capacity of 35.3 MW is reached much more frequently. The GC PPA scenario without subsidies does produce a less negative business case than the variant on the spot market. Two reasons for this are a higher realized electricity price due to mitigation of the cannibalization effect by PPAs, and a high volume of hydrogen produced in the first years. This is facilitated by the constant electricity price throughout the year, if the PPA price is below the compensation for hydrogen production it stays that way throughout the year. This means the spread remains positive throughout the year and the electrolyser is loaded to its maximum capacity for all hours of the year, only limited by the maximum number of full load hours of 8500 (remaining hours reserved for O&M etc.).



(a) Simulation of full lifetime. Note the bold shift from 'Power to H2' to 'Power to Grid' in 2030.

(b) Financial performance. IRR: -0.49%, NPV: -15.996 mEUR.

Figure 6.12: Simulation and financial performance of scenario variant GC PPA without subsidies.

The high volumes in the first years translate to higher FCFs, although immediately in decline as observed in Figures 6.11 and 6.12b. As the volumes remain constant, the decline is due to the downward trend in renewable hydrogen prices (Fig. 2.17). The LCOH in this scenario is 3.543 EUR/kg, much higher than the 1.702 EUR/kg of the spot market variant. This is due to the lower volume of hydrogen produced, 14.5 Mt instead of 18.2 and the higher realized electricity price, since the system is not able to profit from low prices on the spot market. This is not automatically negative for the business case, since the higher volumes made possible by the PPA electricity price may compensate for lower margins. A way to bring down the LCOH may be decommissioning of the electrolyser in 2030 and thereby eliminating the OPEX associated with the electrolyser system, and possibly liquidate some residual value of the electrolyser system. All in all, the system does not generate sufficient income to produce an attractive business case, with an IRR of -0.49% and a NPV of -15.996 mEUR.

Scenarios with subsidies

It is established that positive business cases (meaning business cases with a NPV higher than zero) are not attainable without subsidies. Subsidies will however introduce more complexity to the business case, as the subsidy schemes have their own requirements, such as a maximum number of full load hours. This can introduce more fluctuations in the H2/Power spread which determines the operation of the PV-Electrolysis system to a large extent. The fluctuations of 'Spread H2/Power' resulting from the application of the SDE++ 'hydrogen from electrolysis' subsidy (SDEW) to the GC spot market scenario can be observed in Figure 6.13. The SDEW subsidy is limited by a maximum of 3500 full load hours (Tab. 3.2). Note that the spread is graphed with hourly granularity and the other curves with yearly granularity.

In the simulation model the SDEW subsidy is interpreted as a tarriff for hydrogen during the first 3500 full load hours of the electrolyser. Other interpretations are possible, such as a more evenly spread lower tarriff during a higher number of full load horus. The subsidy just states a number of eligible full load hours which limits the total subsidy amount. Note that the spread is graphed with hourly granularity and the other curves with yearly granularity.

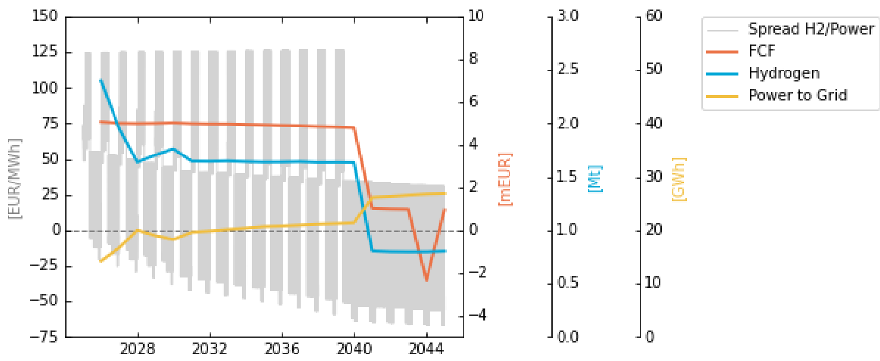
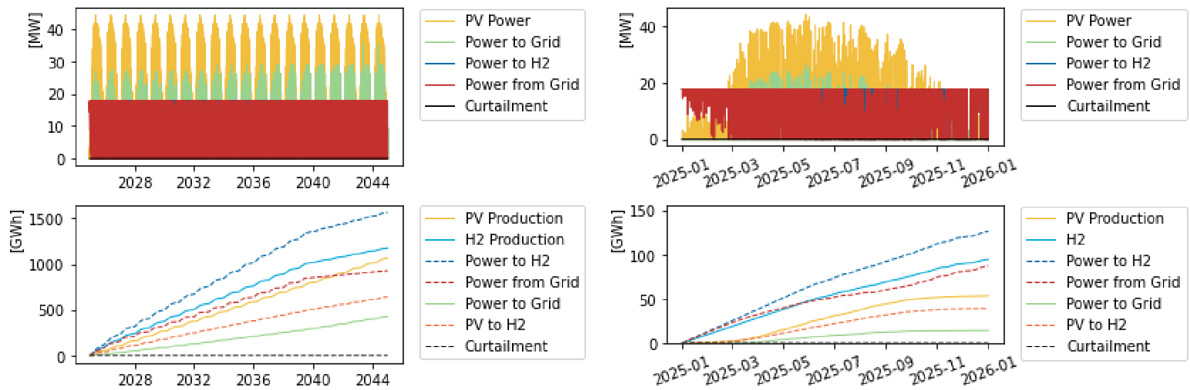


Figure 6.13: Earnings and Production Profile GC SDEW spot. Spread H2/Power is plotted with hourly granularity to provide insight in its fluctuations. 'FCF', 'Hydrogen' and 'Power to Grid' are plotted with yearly granularity.

To gain more insight in what happens within a single year of operation under the SDEW subsidy spot market scenario the simulation results are provided in Figures 6.14 and 6.15. At first glance in Figure 6.14 the simulation results very much resemble those of the spot market scenario without subsidies (Fig. 6.7, 6.8a), however a closer look reveals that the hydrogen output is much higher. Another difference is that in the first two months of 2025 'Power from Grid' does not oscillate as much as in the case without subsidies (Fig. 6.14b vs. 6.8a), this is because the spread is always positive in these months (Fig. 6.13) and hence the electrolyser is constantly loaded to its maximum capacity, and 'Power from Grid' is only reduced when some 'PV Power' is available.



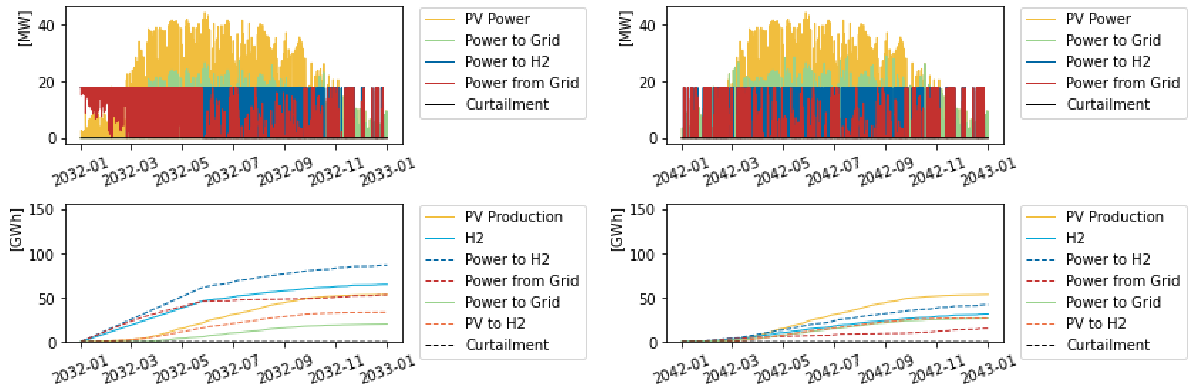
(a) Simulation results for 2025. H2: 2.4 Mt, Power to Grid: 14.2 GWh, Electrolyser FLH: 7136

(b) Simulation results for 2025. H2: 2.4 Mt, Power to Grid: 14.2 GWh, Electrolyser FLH: 7136

Figure 6.14: GC SDEW spot

A clearer effect of the subsidy is observed in Figure 6.15a, when the 'Spread H2/Power' becomes negative more often after the first 3500 full load hours. The hydrogen production decreases substantially from 2.4 to 1.6 Mt and the electricity delivered to the grid increases from 14.2 to 20.1 GWh, with respect to 2025. This shift in product streams does again not have a material impact on the FCF (Fig. 6.13). In 2042 the operation of the PV-Electrolysis system is not affected by the subsidy anymore, since it only applies for the first 15 years. The 'Spread H2/Power' is however often negative in this year, leading to low hydrogen production and a relatively low number of full load hours of 2371.

The application of the SDEW subsidy greatly improves the attractiveness of the business case: the IRR shoots up to 8.61% and the NPV to 16.272 mEUR (Fig. 6.16). The LCOH is considerably higher than in the spot market scenario without subsidies: 2.497 instead of 1.702 EUR/kg. This is however more than offset by the higher compensation for a kilogram of hydrogen and the higher volumes produced in this scenario.



(a) Simulation results for 2032. H2: 1.6 Mt, Power to Grid: 20.1 GWh, Electrolyser FLH: 4905

(b) Simulation results for 2042. H2: 1.4 Mt, Power to Grid: 26.5 GWh, Electrolyser FLH: 2371

Figure 6.15: GC SDEW spot

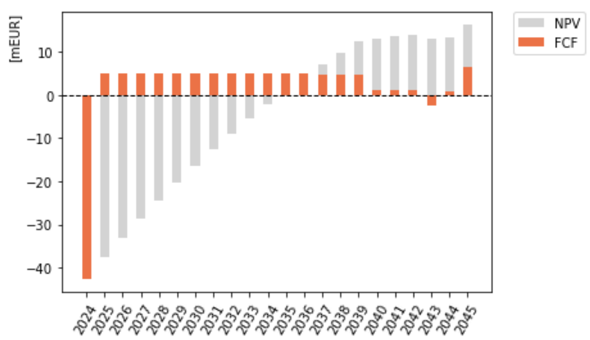


Figure 6.16: Financial performance of GC spot market scenario with the SDEW subsidy. IRR: 8.61%, NPV 16.272 mEUR.

This section has provided insight into the dynamics of the PV-Electrolysis system in 'grid connected' configuration and its behaviour in response to price signals, which come together in the H2/Power spread. Clearly applying a subsidy can improve the business case around the PV-Electrolysis system a lot. Simulations have been done with a whole lot of other subsidies than the SDEW subsidy discussed above. The other subsidy schemes will not be discussed in great detail in this section, but the results of these simulations can be observed in Table 6.3. The most profitable scenario is the one with a combination of the TOW and SDEZ subsidy, which generates an IRR of 18.77% and a NPV of 54.541 mEUR. Figures describing the simulation results and financial performance just as for the scenarios described in this section are available in Chapter A.

Observing the results of the 'grid connected' simulations in Table 6.3, the complexity of the PV-Electrolysis business case is once again emphasized. Under constant external market conditions, a scenario with higher LCOH and equal LCOE can lead to a more attractive business case (SDEW spot vs. PPA). The production volumes of hydrogen and electricity are heavily impacted by the level of compensation for each product and whether the price is constant throughout the year (PPA) or variable by the hour.

It is worth noting that even in the scenario with the highest number of full load hours of the electrolyser, the TOW scenario, this number is just 5134. An important factor in this is that the subsidy lifetime is 15 years, and after 2039 the H2/Power spread remains negative in any PPA scenario, leading to very low

MOO	Subs	EM	C_G [MW]	C_{P2G} [MW]	IRR [%]	NPV [m€]	LCOH [€/kg]	LCOE [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	FLH P2G [avg. h/y]
GC	-	spot	35.30	17.65	-2.02	-21.257	1.702	56.68	18.2	479.8	2714
	-	PPA	35.30	17.65	-0.49	-15.996	3.543	56.88	14.5	855.7	2152
	SDEZ	spot	35.30	17.65	-1.87	-20.617	1.508	56.88	16.3	495.2	2428
		PPA	35.30	17.65	-0.28	-15.253	4.361	56.88	7.7	967.1	1140
	SDEW	spot	35.30	17.65	8.61	16.272	2.497	56.88	29.9	426.7	4443
		PPA	35.30	17.65	10.96	26.142	3.211	56.88	26.2	700.7	3892
	TOW	PPA	35.30	17.65	18.67	54.231	3.165	56.88	34.5	527.8	5134
	SDEZ+W	spot	35.30	17.65	8.98	18.267	2.391	56.88	28.8	436.9	4280
		PPA	35.30	17.65	11.06	26.518	3.395	56.88	21.1	772.6	3145
	SDEZ+TOW	PPA	35.30	17.65	18.77	54.541	3.118	56.88	32.0	547.8	4759

Table 6.3: Grid Connected financial performance.

activity of the electrolyser. Many of the PPA scenarios could be improved by earlier decommissioning of the electrolyser and thereby eliminating the OPEX associated with the electrolyser system, and possibly liquidating some residual value of the electrolyser system.

Finally, note that the PV-Electrolysis system in 'grid connected' configuration performs better than in 'island mode' configuration under any subsidy scenario. At the same time, the 'PV individual' system outperforms the PV-Electrolysis system in 'grid connected' configuration in the PPA scenario variants. In the spot market scenario variants however, the PV-Electrolysis system in 'grid connected' configuration produces seriously improved financial results, although still negative. In the next section some more sensitivity tests are discussed.

6.1.4. Sensitivity Analysis

To gain more insight in the effects of varying sizing parameters: grid and electrolyser capacity (C_G, C_{P2G}), and a range of electricity and hydrogen prices (P_E, P_{H_2}), a sensitivity analysis was conducted. Due to the relatively long computing time of the simulation model it was not possible to optimize for the parameters that were picked. The results of the analysis are presented in this section.

First a variation of the sizing parameters is discussed. The first step was to iterate electrolyser capacity C_{P2G} by whole MWs towards an optimum for the 'island mode' configuration, without subsidies. The best, or least bad, IRR was obtained with a C_{P2G} of 28.00 MW. See Table 6.4, where the results of a simulation with a C_{P2G} of 28.00 MW and the adjacent values are summarized, along with the base scenario.

MOO	Subs	EM	C_G [MW]	C_{P2G} [MW]	IRR [%]	NPV [m€]	LCOH [€/kg]	LCOE [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	FLH P2G [avg. h/y]
IM	-	-	-	35.30	-11.67	-38.716	4.929	57.95	18.6	-	1384
IM	-	-	-	27.00	-11.05	-34.388	4.651	57.95	17.7	-	1720
IM	-	-	-	28.00	-11.03	-34.400	4.601	57.95	17.9	-	1676
IM	-	-	-	29.00	-11.06	-35.259	6.643	57.95	18.0	-	1632
GC	-	spot	35.30	17.65	-2.02	-21.257	1.702	56.68	18.2	479.8	2714
GC	-	spot	35.30	28.00	-0.05	-16.492	1.705	56.68	28.9	296.8	2714
GC	-	spot	35.30	35.30	1.05	-13.158	1.707	56.68	36.5	237.8	2714
GC	-	spot	20.00	17.65	-1.88	-20.45	1.705	55.56	18.3	473.0	2720

Table 6.4: Sensitivity to sizing parameters of 'island mode' configuration and 'grid connected' configuration without subsidies, operated on the spot market.

Following the observation that 28.00 MW is the optimum electrolyser capacity by whole MWs for the PV-Electrolysis system in 'island mode' configuration, a simulaton was done using the same C_{P2G} for the 'grid connected' spot market scenario variant without subsidies. The increased electrolyser capacity improved the business case substantially, from an IRR of -2.02% to -0.05%. Another simulation was done for the 'grid connected' configuration, spot market variant without subsidies with a C_{P2G} of 35.30 MW. The reason for this value is that the simulation model currently does not allow electrolyser capacities higher than the grid capacity, since the grid connection is also used to provide power to the electrolyser. The simulation with a C_{P2G} of 35.30 MW produced an even better result than than the previous simulation, raising the IRR to 1.05%. This still produces a negative business case (NPV -13.158 mEUR), but the results indicate that electrolyser capacity is a substantial influence factor on the business case of the PV-Electrolysis system, and for the 'grid connected' spot market scenario without subsidies the optimum value is at least higher than 28.00 MW. Finally, a simulation was done with a reduced grid capacity from 35.30 MW to 20.00 MW. The reason for the value 20.00 MW will become clear in Section 6.2. Somewhat surprisingly, this strong reduction of grid capacity has a positive effect on profitability. As will be discussed in Section 6.2, the reason for this is the limited loss of power output to the grid.

Next the sensitivity of the PV-Electrolysis system to electricity prices is examined, by simulating for a range of constant electricity prices. The values of P_E range from 20 to 100 EUR/MWh with steps of 20, with an additional simulation for 50 EUR/MWh for some additional granularity around the average prices that were projected by the power price forward curve developed in this study (Fig. 2.13). For reference, simulations for the same values of P_E of the PVI spot market scenario without subsidies are displayed as well.

P_E [€/MWh]	**MOO**	**IRR** [%]	**NPV** [m€]	**LCOH** [€/kg]	**LCOE** [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	**FLH P2G** [avg. h/y]
BPS*	GC	-2.02	-21.257	1.702	56.68	18.2	479.8	2714
20	GC	3.73	-0.903	1.569	56.88	57.1	263.9	8500
40	GC	-1.52	-18.560	2.903	56.88	23.0	737.3	3422
50	GC	-0.64	-16.481	4.985	56.88	5.9	974.1	883
60	GC	1.12	-10.777	75.438	56.88	0.2	1053.0	36
80	GC	4.41	1.622	76.489	56.88	0.2	1053.0	36
100	GC	6.98	12.354	77.540	56.88	0.2	1053.0	36
BPS*	PVI	-15.08	-32.191	-	54.88	-	1316.2	-
20	PVI	-12.12	-28.933	-	54.88	-	1316.2	-
40	PVI	-0.92	-13.670	-	54.88	-	1316.2	-
50	PVI	2.01	-6.039	-	54.88	-	1316.2	-
60	PVI	4.31	1.070	-	54.88	-	1316.2	-
80	PVI	7.77	13.353	-	54.88	-	1316.2	-
100	PVI	10.81	25.69	-	54.88	-	1316.2	-

Table 6.5: Sensitivity to electricity price. * Base Price Scenario, as in Tab. 5.2

The first observation is that a positive IRR of 3.73% emerges for a P_E of 20 EUR/MWh, accompanied by the highest possible number of full load hours of the electrolyser of 8500, and a LCOH of 1.569 EUR/kg. The IRR of 3.73% is much higher than under the base price scenario (-2.02%), however it remains a slightly negative business case. When the electricity price is increased to 40 EUR/MWh, initially the profitability declines, but starts to improve again with further increasing electricity price. With an electricity price of 80 EUR/MWh the system outperforms the scenario with P_E of 20 EUR/MWh with an IRR of 4.41%. Note that from 50 EUR/MWh and up the number full load hours for the electrolyser is very low, from 60 EUR/MWh just 36, only producing hydrogen when PV power exceeds the grid capacity.

When the results for the 'grid connected' configuration of the PV-Electrolysis system are compared to the individual PV plant (PVI), it is observed that a dramatic difference exists between the scenario with P_E of 20 EUR/MWh, where the 'GC' system achieves an almost positive business case, while the IRR of -12.12% produced by the 'PVI' system is very weak. It is however interesting to see that even the dramatic case of the 'PVI' system with a P_E of 20 EUR/MWh produces a better result than the base scenario, in which the electricity price follow the spot market, demonstrating the severity of the cannibalization effect. Furthermore, note that the 'PVI' scenarios outperform the 'GC' scenarios for all values of P_E except 20 EUR/MWh.

A similar exercise was done for a range of constant hydrogen prices, P_{H_2}, from 2.00 to 4.00 EUR/kg in steps of 0.50. For both the 'grid connected' and 'island mode' configuration, all except the 2.00 EUR/kg simulation exceed the financial performance achieved with the base price scenario, in which case the average hydrogen price is 2.06 EUR/kg, starting at 3.12 EUR/kg in 2025 and ending at 1.69 EUR/kg

P_{H_2} [€/kg]	MOO	IRR [%]	NPV [m€]	LCOH [€/kg]	LCOE [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	FLH P2G [avg. h/y]
BPS*	GC	-2.02	-21.257	1.702	56.68	18.2	479.8	2714
2.00	GC	-2.62	-24.454	1.355	56.68	14.7	521.3	2192
2.50	GC	-1.15	-19.589	1.448	56.68	16.0	499.8	2378
3.00	GC	0.33	-14.281	1.668	56.68	18.0	478.7	2684
3.50	GC	2.00	-7.466	2.541	56.68	34.2	366.6	5091
4.00	GC	5.11	4.339	2.886	56.68	50.0	281.4	7443
BPS*	IM	-11.67	-38.716	4.929	57.95	18.6	-	1384
2.00	IM	-11.88	-42.814	4.929	57.95	18.6	-	1384
2.50	IM	-7.93	-36.78	4.929	57.95	18.6	-	1384
3.00	IM	-5.12	-30.747	4.929	57.95	18.6	-	1384
3.50	IM	-2.86	-24.713	4.929	57.95	18.6	-	1384
4.00	IM	-0.91	-18.680	4.929	57.95	18.6	-	1384

Table 6.6: Sensitivity to hydrogen price. Scenario variants on the spot market and without subsidies. * Base Price Scenario, as in Tab. 5.2

in 2044. Note that the number of full load hours is not directly proportionate to improved profitability, for example, the profitability with 2.50 and 3.00 EUR/kg is better than with the BPS, while the average number of full load hours remains below the BSP simulation. Furthermore, it is observed that the 'island mode' configuration under performs in terms of profitability compared to the 'grid connected' configuration.

6.2. Grid Effects

In this section the effects of the PV-Electrolysis system on the distribution grid are discussed. This is done by comparing the profiles of electricity fed into the grid of the 'PV Individual' system and the PV-Electrolysis system in 'grid connected' configuration. The power output to the grid is compared of the individual PV plant and several simulations of the PV-Electrolysis in 'grid connected' configuration.

A single year of the simulation of the individual PV plant is displayed in Figure 6.17. The power output to the grid, 'Power to Grid', closely follows 'PV Power' up to the grid connection limit of 35.3 MW, above which some curtailment takes place. The 35.3 MW grid limit virtually coincides with with the 97.5th percentile of 'PV Power', the 'available power' to the grid (97.5th percentile is 35.4 MW). The 97.5th percentile of 'available power' is indicated with a black dashed line in the graph.

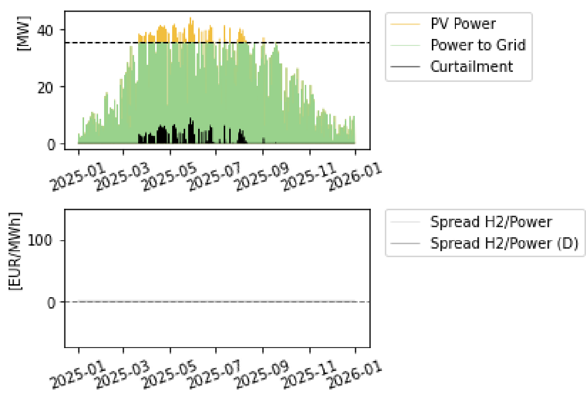
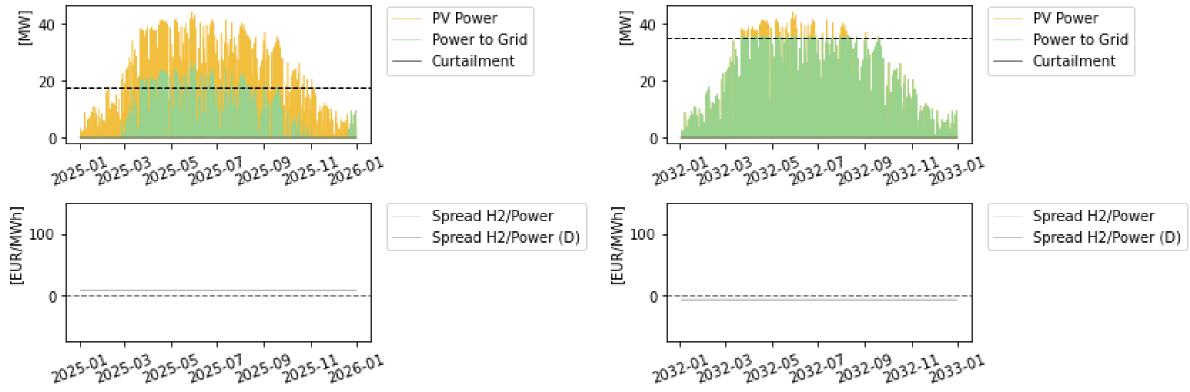


Figure 6.17: Power fed to the grid for the 'PV Individual' system during a single year (2025), for reference. Grid capacity (35.3 MW) coincides with 97.5th percentile of 'PV Power', represented by the black dashed line in the upper graph.

Analysing the results of the simulations that were done for this study, it was observed that the PV-Electrolysis system can reduce the power output to the grid with respect to the PVI scenario, under certain conditions. A determining factor in how the power output to the grid is affected by the PV-

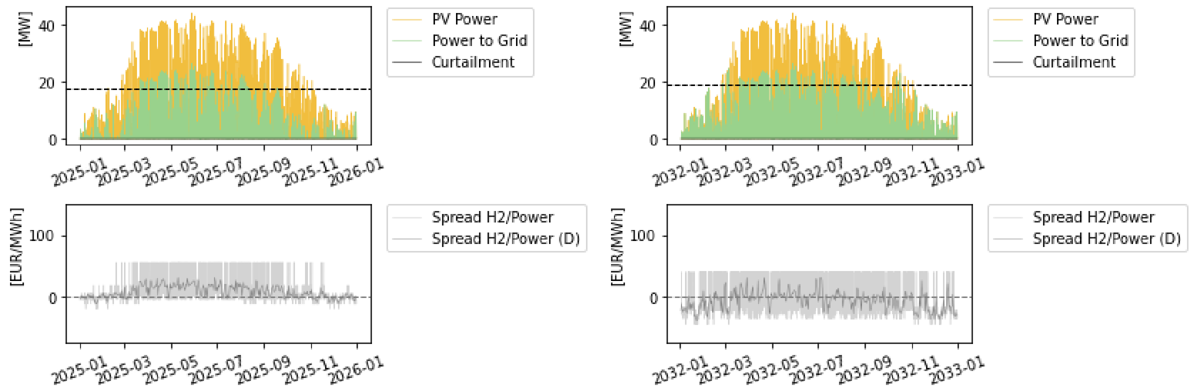


(a) 2025 (b) 2032

Figure 6.18: Power fed to the grid and compensation spread for the GC PPA market scenario without subsidies. 97.5th percentile of 'Power to Grid' indicated by the dashed black line in the upper graphs.

Electrolysis system is the compensation spread of hydrogen and electricity, 'Spread H2/Power'. The first scenario that is considered is the GC PPA scenario without subsidies. In Figure 6.18 power output to the grid is displayed for this scenario in 2025 and 2032. A stark contrast between the two years is observed: in 2025 (Fig. 6.18a) the 'Power to Grid' curve closely follows the 'PV Power' curve, minus the electrolyser capacity of 17.65 MW, except for a short period towards the end of the year, due to the limitation of 8500 full load hours for the electrolyser. In 2032 (Fig. 6.18b) the 'Power to Grid' curve exactly mirrors the curve of the individual PV plant (Fig. 6.17).

Again, the 97.5th percentile of 'available power' to the grid is indicated with a black dashed line. The stark contrast is also reflected here, with the 97.5th percentile line at around 18 MW in 2025, almost half what the black dashed line indicates in 2032, which virtually coincides with the 35.3 MW the grid connection. This can be explained on the basis of the 'spread', in 2025 it is above zero during the entire year, while it remains below zero throughout 2032. This means the decision mechanism will always favour hydrogen production over delivery of power to the grid in 2025, and always favour electricity to the grid over hydrogen production in 2032.



(a) 2025 (b) 2032

Figure 6.19: Power fed to the grid and compensation spread for the GC spot market scenario without subsidies. 97.5th percentile of 'Power to Grid' indicated by the dashed black line in the upper graphs.

The next scenario that is considered is the GC spot market scenario without subsidies, plotted in Figure 6.19 for years 2025 and 2032. In this scenario the 'spread' is not fixed throughout the year, but alternates up and down. This results in a much reduced contrast between the two years. Note that the 'Power to Grid' curves are also smoother than in Fig. 6.18a, with higher output towards the beginning and the end of the year. This coincides with more negative values of 'Spread H2/Power' and this smoothing effect is also stronger in 2032, when the 'Spread H2/Power' is more evenly distributed around zero. From an electricity system perspective the picture observed in Figure 6.19b is quite attractive: a much reduced peak in the summer, requiring a lower grid connection capacity for the same peak PV capacity and a more evenly spread power output profile throughout the year, reducing seasonal effects. Note that the 97.5th percentile line is in a similar place for both years, and remains below 20 MW. This is positive for the network operator, since no peaks above 20 MW have to be processed for this PV-Electrolysis system, and for project developers, since this reduced grid capacity can become available for other projects. Reducing the grid capacity to 20 MW also actually improves the profitability of the PV-Electrolysis system, as was observed in Section 6.1.4.

MOO	**Subs**	**EM**	C_G [MW]	C_{P2G} [MW]	**IRR** [%]	**NPV** [m€]	**LCOH** [€/kg]	**LCOE** [€/MWh]	M_{H_2} [Mt]	E_{Grid} [GWh]	**FLH P2G** [avg. h/y]
PVI	-	spot	35.30	-	-15.08	-32.191	-	54.88	-	1316.2	-
		PPA	35.30	-	1.80	-6.937	-	54.88	-	1316.2	-
	SDEZ	spot	35.30	-	-14.63	-30.647	-	54.88	-	1316.2	-
		PPA	35.30	-	2.26	-5.393	-	54.88	-	1316.2	-
IM	-	-	-	35.30	-11.67	-38.716	4.929	57.95	18.6	-	1384
	SDEW	-	-	35.30	4.40	1.438	4.929	57.95	18.6	-	1384
	TOW	-	-	35.30	5.37	4.659	4.628	57.95	18.6	-	1384
GC	-	spot	35.30	17.65	-2.02	-21.257	1.702	56.68	18.2	479.8	2714
	-	PPA	35.30	17.65	-0.49	-15.996	3.543	56.88	14.5	855.7	2152
	SDEZ	spot	35.30	17.65	-1.87	-20.617	1.508	56.88	16.3	495.2	2428
		PPA	35.30	17.65	-0.28	-15.253	4.361	56.88	7.7	967.1	1140
	SDEW	spot	35.30	17.65	8.61	16.272	2.497	56.88	29.9	426.7	4443
		PPA	35.30	17.65	10.96	26.142	3.211	56.88	26.2	700.7	3892
	TOW	PPA	35.30	17.65	18.77	54.541	3.165	56.88	34.5	527.8	5134
	SDEZ+W	spot	35.30	17.65	8.98	18.267	2.391	56.88	28.8	436.9	4280
		PPA	35.30	17.65	11.06	26.518	3.395	56.88	21.1	772.6	3145
	SDEZ+TOW	PPA	35.30	17.65	18.77	54.541	3.118	56.88	32.0	547.8	4759

Table 6.7: Scenarios and their financial performance.

7 Discussion

This chapter provides an interpretation of the observations from the simulations in the previous chapter. Many scenarios have been simulated, with a wide range of outcomes, some of which performed terribly in financial terms and some outstanding business cases. The wide range of outcomes provides ammunition to assess the influence of several conditions on profitability in the business case of a PV-Electrolysis system.

7.1. Assumptions

The outcome of a modelling excercise is only as good as the inputs that are used, and hence in this section the underlying assumptions that were made in this study are discussed.

7.1.1. Product prices

The profitability of the PV-Electrolysis system is highly dependent on the remuneration received for its product streams: renewable electricity and hydrogen. Hence, in this section the assumptions concerning the price level of electricity and hydrogen are discussed.

To be able to model the business case of a PV-Electrolysis system and to understand its response to price signals, a price forward curve up to 2050 with hourly granularity was created (Fig. 2.13). To project electricity prices this far into the future is challenging, as the developments depend on many variables. The pace of the energy transition for example, and the extent to which certain technologies will become available. Also, the fuel price projections could easily be proven false by events such as the Natural Gas price spikes in Q3 of 2021.

An important assumption underlying the price forward curve is that CCS will become widely used when the ETS CO_2 price rises above the CCS cost (59 EUR/t CO_2). While it is realistic that the CO_2 cost will not keep rising indefinitely and alternatives such as CCS or Green Gas will find their way into the system when the ETS prices rise high enough, it is highly uncertain at which price level this will be and whether CCS will actually be available at the 59 EUR/t that was assumed.

Another limitation of the forward curve created for this study is that it fails to reflect the complexity of the electricity market in reality. The dispatchable generators are classified in seven large groups with a given efficiency to calculate their marginal costs, while in reality the variety of generation technology and associated efficiencies and marginals costs is much higher. Hence, the price forward curve created for this study should be viewed as a simplified representation of reality, but it serves its purpose for this exploratory study.

The ratio of the volumes of hydrogen and electricity produced by the PV-Electrolysis system is highly dependent on the spread of the compensation for hydrogen and electricity, dubbed 'Spread H2/Power' in this study, more than on the absolute price levels for both product streams.
Concerning the hydrogen price projections, an interesting development to monitor on the long term is whether renewable hydrogen prices will eventually drop below the prices for SMR hydrogen, as the BNEF and IEGHG projections suggest (Fig. 2.17), and what the geographical distribution of the hydrogen cost will be. Low LCOH is attainable on favourable locations with cheap and reliable renewable energy, that is clear, but the main question is how quick and how much transportation infrastructure will be scaled up and at which cost. With cheap transportation infrastructure and the low predicted

LCOH as in the BNEF curves (Fig. 2.17) the business case for a PV-Electrolysis system will quickly become unattractive in places with less favourable conditions for LCOH such as The Netherlands. Hence, more detailed projections of when and at which cost transportation infrastructure will become available are desirable for an improved assessment of the PV-Electrolysis business case.

7.1.2. Equipment

Concerning the equipment of the PV-Electrolysis system the greatest uncertainty is the price. Developments of physical performance are less unfluential, since a percentage point more or less in efficiency is not detrimental to the business case. Major performance developments for PV technology are not to be expected and for alkaline electrolysis the increase in efficiency from 77% in 2017 to 80% in 2025 is also not a game-changer.

A determining factor on the price side could be scarcity of materials used in the manufacturing of PV panels or electrolysers, which could lead to inflated equipment prices. Another factor could be deferred scale up of electrolyser production, resulting in a less than projected drop in electrolyser prices. The electrolyser prices used are also relatively low compared to figures used by PBL [51], 750 EUR/kW in 2017 (Tab. 2.4) versus 1800 EUR/kW in 2022. This is explained in part by the fact that in the 1800 EUR/kW stated by PBL a grid connection, hydrogen pipeline/ compression system, installation costs and even a battery are included. Still, the difference is large. For the PV-Electrolysis business case it is highly relevant to monitor how the electrolyser equipment prices develop towards 2025.

7.1.3. Subsidies

The profitability of the PV-Electrolysis system can be greatly improved by applying a subsidy. The question is however whether the subsidies that are currently available (Sec. 3.1.3) will persist until at least 2025 for the sake of this study.

Solar subsidies are likely to be phased out over time when PV generation becomes more mainstream. However this will probably not happen overnight and the SDEZ subsidy scheme only induced minor improvements of the business case in the simulations done for this study (Tab. 6.1, 6.3). Hence, based on the results of this study, the developments of solar PV subsidies is not critical for the business case of either the PV-Electrolysis system or an individual PV system.

The ratio of the volumes of hydrogen and electricity produced by the PV-Electrolysis system is highly dependent on the spread of the compensation for hydrogen and electricity, dubbed 'Spread H2/Power' in this study, more than on the absolute price levels for both product streams. A relatively higher remuneration for hydrogen would boost the hydrogen production. For the short term financial support for hydrogen from electrolysis seems realistic, judging by the availability of subsidies, as discussed in Sec. 3.1.3. However, observing the exceptional financial results obtained with the TOW subsidy, it is unlikely that a subsidy in this form still exists in 2025.

Apart from direct subsidies, a future possibility is the incorporation of hydrogen from electrolysis in the Dutch HBE (Hernieuwbare Brandstof Eenheid/Renewable Fuel Unit) system, which is an ongoing discussion at the moment [56]. This would provide extra payments on top of the wholesale hydrogen price, much like the Guarantees of Origin system for renewable electricity. This would mean extra payments on top of the grey hydrogen price, instead of the BNEF curve that is used in the Base Price Scenario in this study. A scenario using HBE's would require additional modelling, but is possible with the models developed in this study.

7.2. Model limitations

One limitation of the model is the hourly granularity. This does not allow studying of short-term effects, and eliminates the possibility to realistically compare AE and PEM electrolysers, since the major differences between the two: quicker response times and short-term overloading capacity of PEM electrolysers cannot be differentiated with the hourly granularity (Tab. 2.4).

The choice for the hourly granularity is because of computing time of the simulation model, which is currently around 45 minutes for a full lifetime simulation. Increasing the granularity to the minute level or smaller required to differentiate on response times would massively increase the computing time to impractical levels. The model is built with an interchangeable $delta_t$, which is currently set to 1 (hour), but can be changed if more detailed simulations are desirable. A more detailed simulation would require additional granularity in the input data. The computing time is also a limitation in the sense that optimisation of e.g. sizing parameters for each scenario variant is overly time consuming, while it would provide interesting additional insights.

Another limitation of the model is caused by the assumptions underlying the power price forward curve: the way dispatchable generation capacity is grouped by efficiency means that the clearing price can only assume a limited number of values: zero or one of the marginal cost levels, so in total 8 different values and 6 different values after coal is phased out. This creates quite a granular curve, while in reality the clearing price can assume numerous values which would produce a much smoother curve. A smoother curve could produce different outcomes of the simulations which could lead to either increased or decreased attractiveness of the PV-Electrolysis business cases.

A final limitation is related to the interpretation in the model of the literature about electrolysis technology. The literature reports a minimum load threshold of alkaline electrolysers of 15%. It is true that alkaline electrolysis stacks have a minimum load threshold, however in practice the minimum load of an electrolyser is often much lower than 15%, because most large scale electrolysers consist of multiple stacks. For example, for an electrolyser composed of three stacks with a 15% threshold, the minimum load of the electrolyser would be 5%. In the beginning, functionality to reflect the (de)activation of electrolyser stacks was included in the model, however the increased complexity added much computing time and this functionality also introduces new uncertainties with assumptions about future electrolyser stack configurations. Hence, it was chosen to drop the functionality.

7.3. Contracts & decision algorithms

In this study two electricity market scenarios have been used: spot market or PPA. In the spot market scenario the hourly electricity price follows the clearing prices from the power price forward curve, and in the PPA scenario the electricity price follows the yearly average clearing price from the power price forward curve. This approach may however not be legitimate far out into the future.

In an electricity market with increasing solar PV generating capacity, the cannibalization effect discussed in Sec. 1.1.3 will become increasingly apparent in the electricity market. When PV power is sold on the spot market the realized electricity prices are much lower than the average electricity price, which is reflected in the PVI simulations in this study (Tab. 6.1). It is likely the cannibalization effect will have an effect on the PPA price level for PV power in the future, reducing the PPA prices for PV power to levels below the average clearing price. This would deteriorate the business case for the individual PV plant, however if a lower electricity price can be realized the PV-Electrolysis may sooner be inclined to produce hydrogen, through which some lost income could be regained. This could make the PV-Electrolysis business case relatively more attractive.

It is conceivable that for a PV-Electrolysis system in the future a certain volume of PV power is sold through PPAs, sheltering some PV power revenues from the cannibalization effect, while the electrolyser system responds to price signals on the spot market, enabling the system to profit from periods with low clearing prices. Additionally, a portion of the power for the electrolyser can be contracted using PPAs as well. This requires much more advanced decision algorithms than the mechanism used for this study, but could boost profitability of the system, especially if PPAs for PV power are to become cheaper. More research into different contractual power purchase arrangements is therefore recommended.

7.4. Future of PV-Electrolysis

The immature and rapidly developing landscape of the hydrogen economy made it difficult to do this study, since the reality which is studied is constantly changing. Adding to the complexity is the large variety of highly dynamic influence factors on the business case. These factors include the pace of the energy transition, determining the installed power generation capacity in the future consequently the level of electricity prices, but also the development and geographical distribution of hydrogen prices and associated tarriffs, GOs, or integration in HBE-like systems, and electrolyser equipment price levels. Examples of the rapidly changing environment are the decision to integrate renewable hydrogen in the HBE system, which was only taken weeks before this study is submitted, or the developments in natural gas prices during this research (feb.-nov. 2021), which went in a straight line up from just having recovered to 2019 levels, from the lows of mid 2020 when the COVID-19 crisis had landed, to extraordinary levels in october 2021.

Clearly attractive business cases for the PV-Electrolysis system are attainable with the help of subsidies, both in 'grid connected' and 'island mode' configuration. Without subsidies it is unlikely to achieve a profitable business case, starting in 2025. This is not very surprising considering the underdeveloped state of the hydrogen economy in many aspects, such as cheap and widespread transportation infrastructure and large scale production capacity for electrolysers. It is also likely that subsidies will remain available in the short term. Whether attractive business cases will be possible without subsidies on the long term remains hard to predict, due to a large variety of uncertainties within the novel hydrogen economy that can impact the PV-Electrolysis business case.

The momentum of the hydrogen economy seems to have picked up since the announcements of monumental COVID-19 recovery packages globally, with large amounts of funding aimed towards the development of the energy transition, and the hydrogen economy specifically. The scale-up of the hydrogen economy could have both positive and negative effects on the business case for PV-Electrolysis in The Netherlands. It could be positive if cheap and widespread transportation becomes available within The Netherlands, making the hydrogen delivery process easier and cheaper compared to tube trailers or on-site consumption. However when cheap transportation infrastructure stretches towards locations with more favourable conditions for hydrogen production, e.g. Iceland or the Sahara region, this could exert downward pressure on renewable hydrogen price levels, deteriorating the PV-Electrolysis business case in The Netherlands.

With high hydrogen prices (4 EUR/kg), a positive business case starting in 2025 is attainable without subsidies, however a hydrogen price of 4 EUR/kg is not very likely along the whole duration of the business case. With very low electricity prices (20 EUR/MWh) a profitable business case under the assumptions in this study also comes close. These price levels may be attainable in regions with more favourable conditions for renewable energy generation such as Iceland or the Sahara region. For a region such as The Netherlands, these extreme levels of electricity and hydrogen prices are not likely. Hence, to attain a profitable business case without subsidies in the future, downward developments in the prices of PV and Electrolysis equipment, and cheaper transportation infrastructure are desirable.

7.5. Grid effects

From the perspective of the grid operator the magnitude and timeliness of the supply peaks are important. Analysing the grid effects under different conditions, it became clear that the 'spread' between compensation for hydrogen and electricity was a determining factor in the shape of the curve of the power output to the grid. As long as the spread remains above zero, the profile of the power output curve to the grid follows the PV power curve, minus the electrolyser capacity. When the spread remains above zero, the profile power output curve is the same as an individual PV system. It was discovered that when the 'spread' is allowed to alternate across the zero line, the system can respond to price signals, and the power output curve is smoothed. Power output is spread out more evenly over the year, and the 97.5th percentile of power output of the PV-Electolysis system is reduced to almost half the value of the individual PV plant. This effect was stronger when the 'spread' was distributed most evenly around the zero line (Fig. 6.19b). The much reduced 97.5th percentile of power output allows for a major reduction in grid capacity, which also turned out to be more profitable.

From an electricity system perspective this is attractive: it means that less grid capacity would be required for the same peak PV capacity and the power output profile would be smoother, reducing seasonality effects in the electricity system. In case distributed PV-Electrolysis becomes more widespread, this could introduce a new burden for network operators: increased demand for hydrogen pipelines. However, per transported MWh, pipelines are cheaper than cables. In case distributed PV-Electrolysis becomes more widespread, it is also desirable to analyze the effects of the newly introduced load of the grid connected electrolysers.

In this study another configuration of the PV-Electrolysis system was analyzed, which completely bypasses the electricity grid: the Island Mode. This configuration could be a convenient solution for locations with acute grid limits. In that light it is good news that the Island Mode setup can achieve attractive business cases with subsidy support, while requiring no grid connection at all.

8 Conclusion

In this graduation research conditions affecting the profitability as well as the grid effects of a PV-Electrolysis system have been studied using the Oosterwolde site as a case study. During the study a wide variety scenarios have been created from a set of influential parameters on the PV-Electrolysis business case, which have produced meaningful insights into the conditions for profitability and grid effects of such a system and at the same time have emphasized the complexity of the business case as it can be affected by a wide variety of factors of which the future development remains uncertain. Nonetheless, the results of this techno-economic evaluation provide a basis to answer the main question of this research:

- Under which conditions can a PV-Electrolysis system become profitable and what are the effects on grid congestion under these conditions?

To establish the market conditions during the lifetime of a PV-Electrolysis system the first chapter of this study was dedicated to market developments. One important market development were the electricity prices. A fundamental power market model was created and combined with projections of installed capacity per generation technology and energy commodity prices, an hourly electricity price forward curve up to 2050 was created (Fig. 2.13). Due to a profound transformation of the electricity industry towards more VRE the dynamics on the electricity market change. This is not immediately visible from the average yearly electricity price, which rises slightly up to 2050. The change becomes clear when examining the clearing prices on the spot market, which have been modelled with hourly granularity: the deviations from the average price become larger and longer in duration, aggravating the cannibalization effect for PV systems. Furthermore, the price developments for renewable hydrogen are examined. Due to a scale-up of production capacity and a continuing downward trend in electrolysis technology, a downward trend is projected in the production costs for renewable hydrogen. The high end of the projections of renewable hydrogen production costs is followed as an indication of market price in The Netherlands, which sinks from roughly 3.00 EUR/kg in 2025 to roughly 1.70 EUR/kg in 2044.

A downward trend is also observed in the equipment prices for a PV-Electrolysis system. The total development costs for a PV plant will shrink by another 7% from 2020 to 2025, while price developments in electrolysis equipment show a more dramatic decrease: a projected 35% reduction from 2017 to 2025.

The income streams identified for a PV-Electrolysis system are renewable electricity and hydrogen, which follow the developments mentioned above. In the current environment an additional income stream in the form of subsidies is available as well, of which there are currently many. It is likely they will be adjusted but still available by 2025. In theory oxygen and waste heat could be income streams as well, however for projects like a PV-Electrolysis system this is currently uncommon and it was not deemed realistic in 2025, especially for decentralized projects such as the Oosterwolde site examined in this study, due to lacking infrastructure. The costs of the system are associated with investment in and maintenance of the equipment, following the trends described above.

Then several parameters were identified that have decisive influence on the business case of the PV-Electrolysis system: Mode of operation, subsidy scenario, electricity market scenario, grid connection capacity and electrolyser capacity. The first three of these were chosen as the main subject of study. Mode of operation includes two modes for the PV-Electrolysis sytem: 'island mode' and 'grid connected', and a 'PV individual' mode for comparison. The effects on the business case were examined in a case study, where profitability was measured by internal rate of return (IRR).

According to the Base Price Scenario in this study there are multiple ways that lead to profitable PV-Electrolysis business cases in 2025, all of which including a subsidy. This is due to favourable developments in several areas, most notably electricity prices, renewable hydrogen prices, PV and Electrolysis system costs and subsidies. Sizing of the electrolyser and the grid connection can have significant effects on the business case as well, but under the scenarios simulated in this study are not able to attain profitable business cases alone in 2025.

The sensitivity analysis indicates the necessity of careful consideration of price forecasts for electricity and green hydrogen. Detailed projections of electricity and green hydrogen prices than the approximations used for this study are commercially available for that purpose. The subsidies are currently very high with respect to the Base Price Scenario, producing very profitable business cases in this study. Hence, if the market conditions unfold in a less favourable manner, positive business cases will likely still be attainable using the current subsidies. However when the market conditions in 2025 approximate the Base Price Scenario used in this study, it is likely the subsidies will be adjusted downwards, since this level of stimulation may not be required or socially justifiable.

An analysis of the grid effects of the PV-Electrolysis results in two key takeaways: 'island mode' business cases can achieve attractive returns when supported by subsidies, and: years where the 'Spread H2/Power' is mobile around the zero line reflect the response to price signals with a more balanced power-to-grid profile compared to the individual PV system, which is desirable from an electricity system point of view, leading to improved utilization of the power grid. It is observed that this behaviour does not take place or is reduced in years where either electricity or green hydrogen remuneration have a strong or absolute advantage. A policy recommendation derived from this observation is to adapt the subsidies for PV generation and Electrolysis such that a balanced H2/Power spread is attained.

As a first recommendation for further research it is suggested to investigate the right blend of subsidy amounts to attain a balanced H2/Power spread specifically for PV-Electrolysis systems, to achieve a balanced power output. Another idea is to look into the future development of PPA contracts, more specifically the PPA price levels for purchase of electricity and sale of electricity by VRE systems, as increasing levels of VRE in the electricity system and cannibalization effects may affect the PPA market. Adjacent to the PPA topic, a topic for further research would be the attractiveness of operating the PV-Electrolysis system operating with PPA contracts for electricity sales while procurement of electricity happens on the spot market, as such a dual electricity market scenario is not simulated in this study. Lastly, in this study much time has gone in the creation of a power price forward curve, which is still not the most detailed. Not only for research into PV-Electrolysis, but for any research in which the electricity market has a role it would be very useful if power price projections with high granularity were available. A study producing a detailed power price forward curve which can be made available for other research involving the electricity market is therefore recommended.

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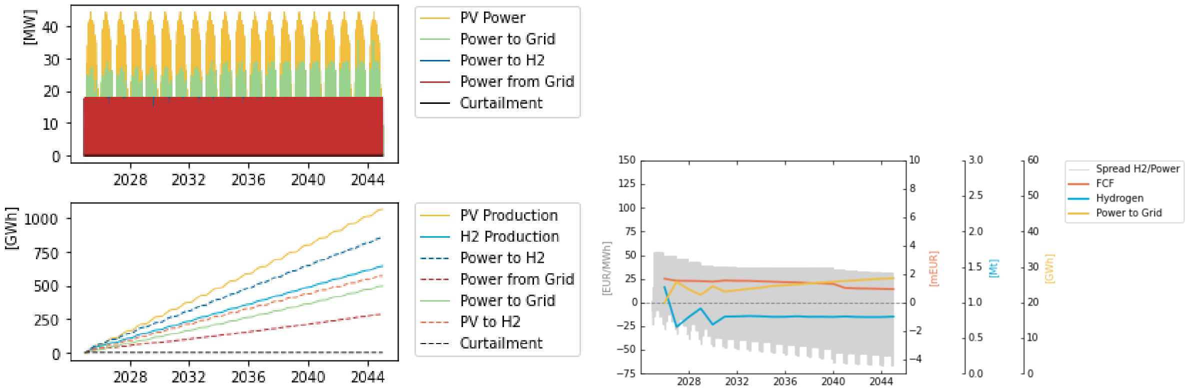
A
Appendix



(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.1: Simulation and Earnings and Production Profile GC SDEZ spot.

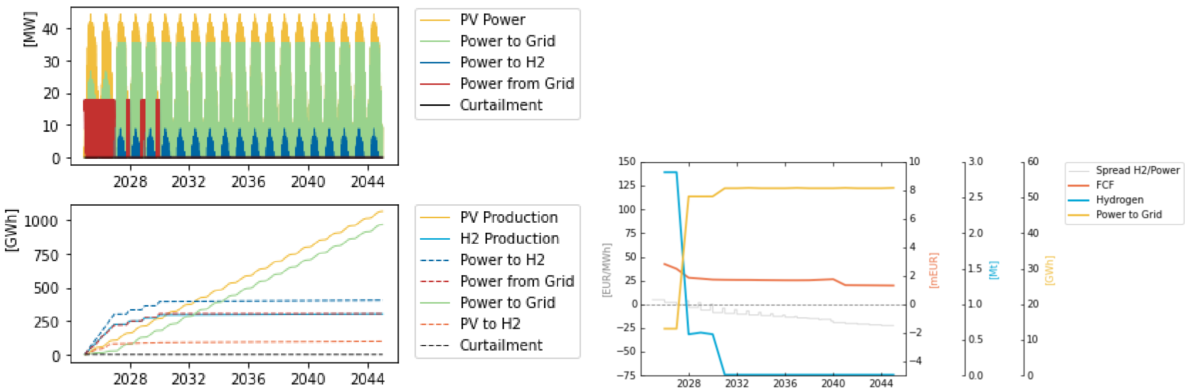


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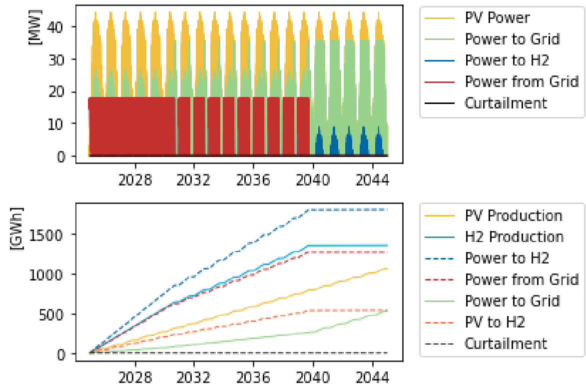
Figure A.2: Simulation and Earnings and Production Profile GC SDEZ PPA.



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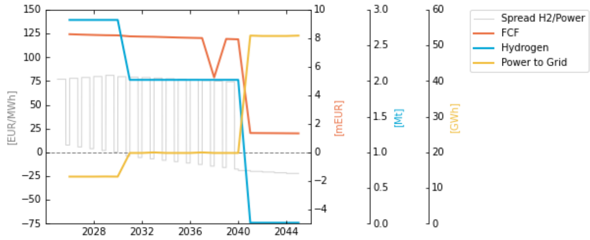
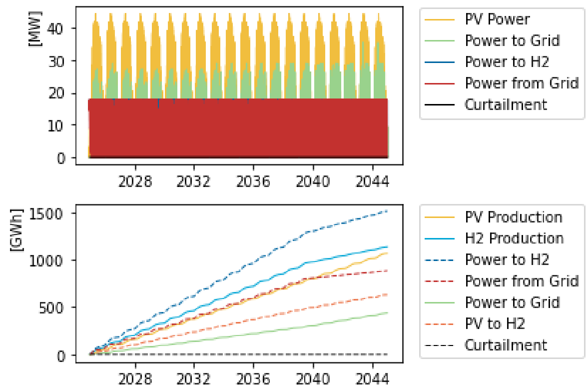


(b) Earnings and Production Profile.

Figure A.3: Simulation and Earnings and Production Profile GC TOW PPA.



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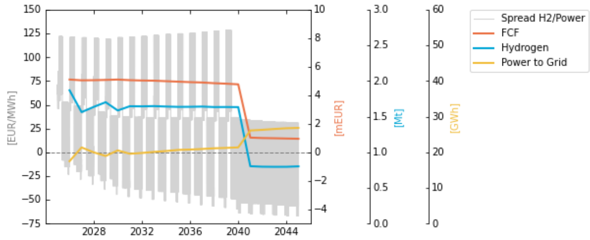
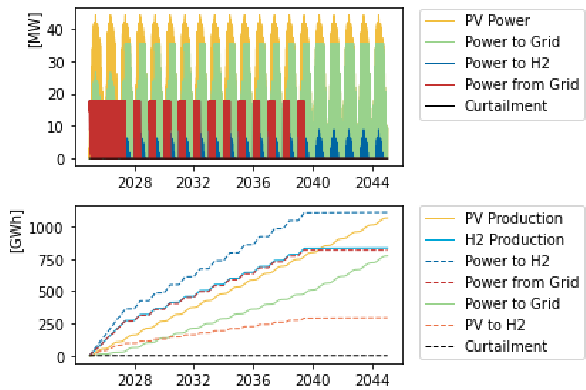


(b) Earnings and Production Profile.

Figure A.4: Simulation and Earnings and Production Profile GC SDEZ+W spot.



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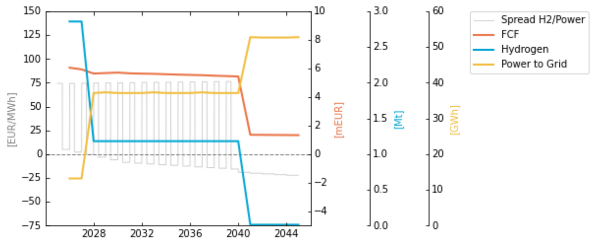
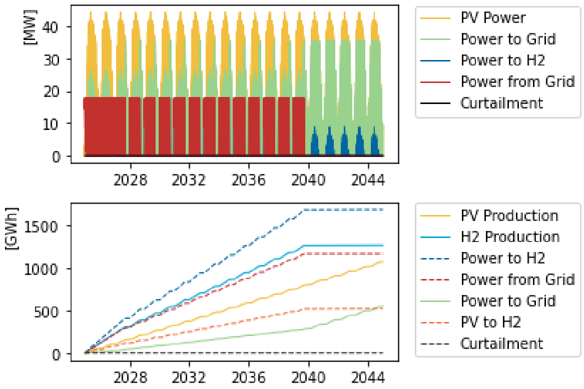
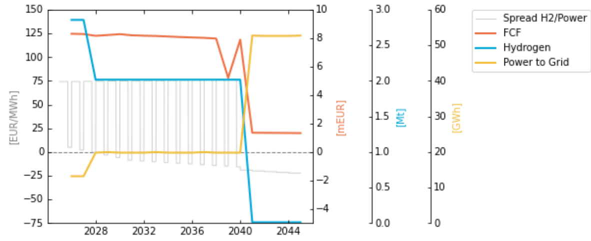


(b) Earnings and Production Profile.

Figure A.5: Simulation and Earnings and Production Profile GC SDEZ+W PPA.

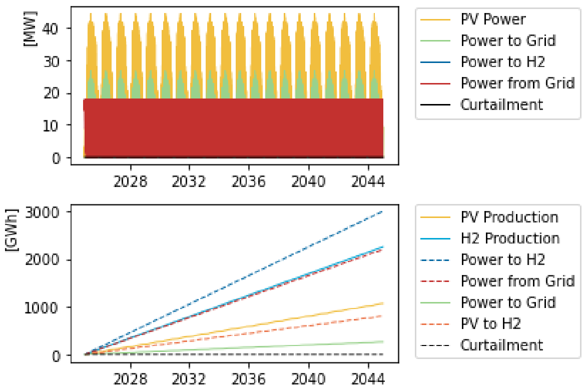


(a) Simulation of full lifetime.



(b) Earnings and Production Profile.

Figure A.6: Simulation and Earnings and Production Profile GC SDEZ+TOW PPA.



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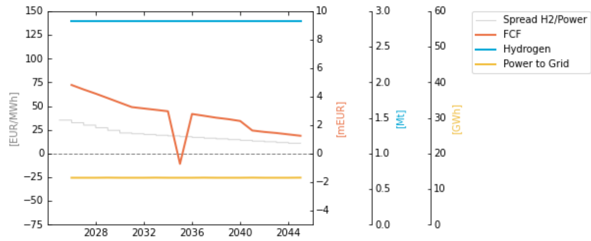
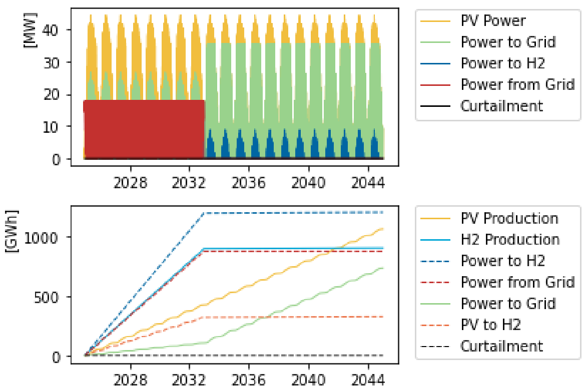


(b) Earnings and Production Profile.

Figure A.7: Simulation and Earnings and Production Profile GC no subs spot P_e=20 EUR/mWh.



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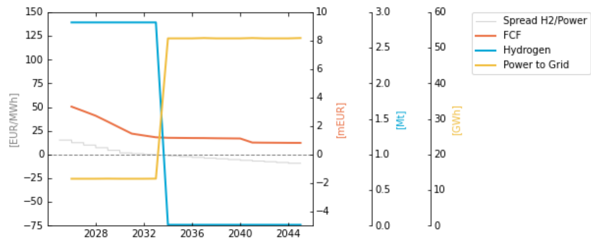
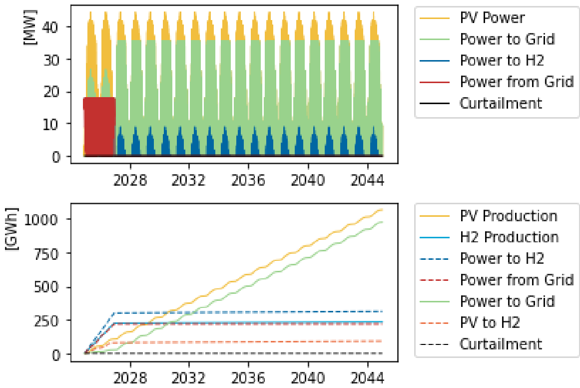
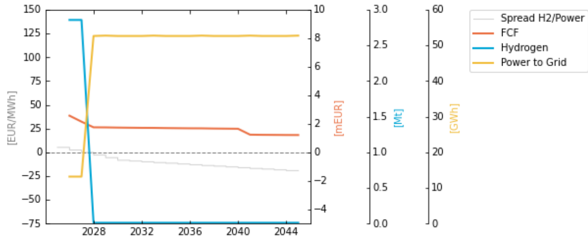


(b) Earnings and Production Profile.

Figure A.8: Simulation and Earnings and Production Profile GC no subs spot P_e=40 EUR/mWh.

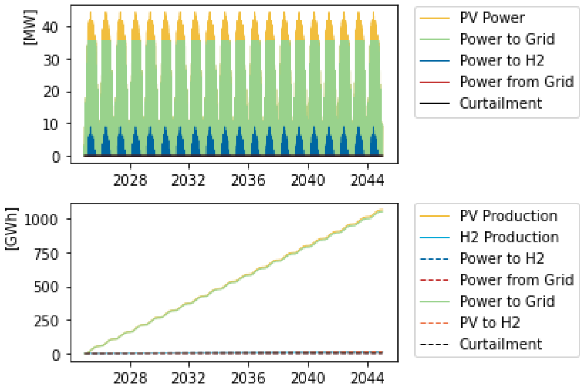


(a) Simulation of full lifetime.



(b) Earnings and Production Profile.

Figure A.9: Simulation and Earnings and Production Profile GC no subs spot P_e=50 EUR/mWh.



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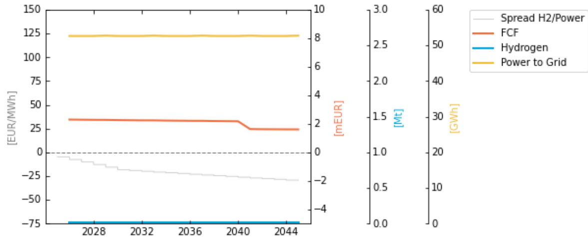
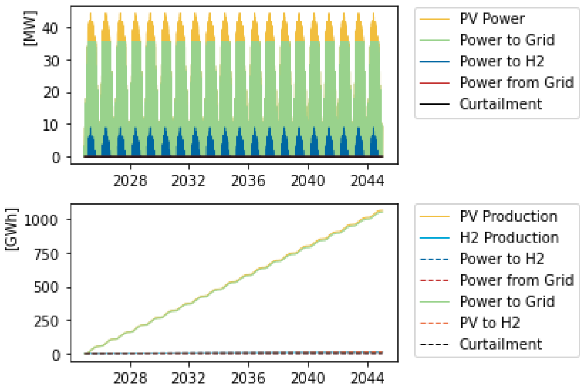


(b) Earnings and Production Profile.

Figure A.10: Simulation and Earnings and Production Profile GC no subs spot P_e=60 EUR/mWh.



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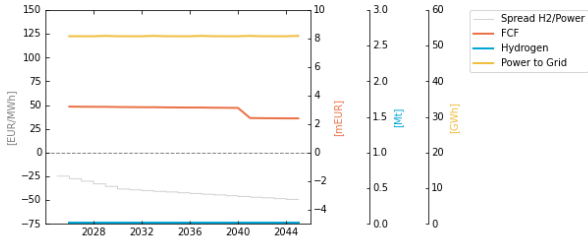
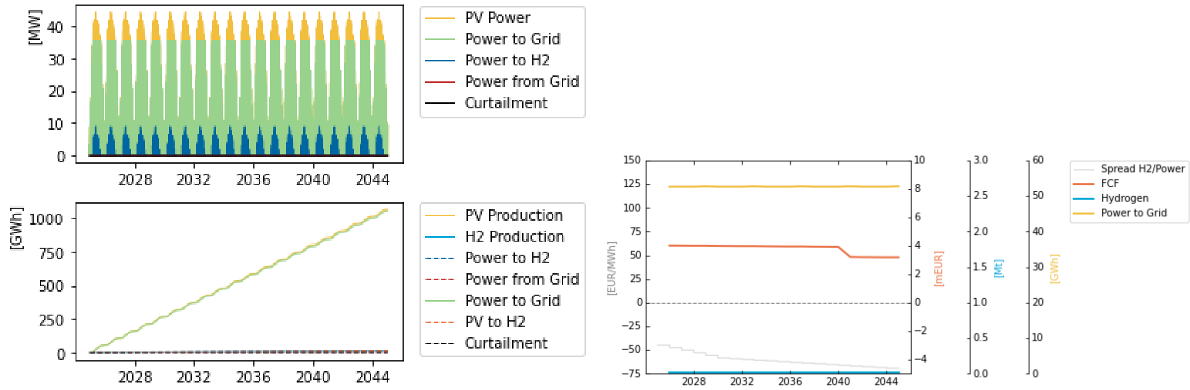


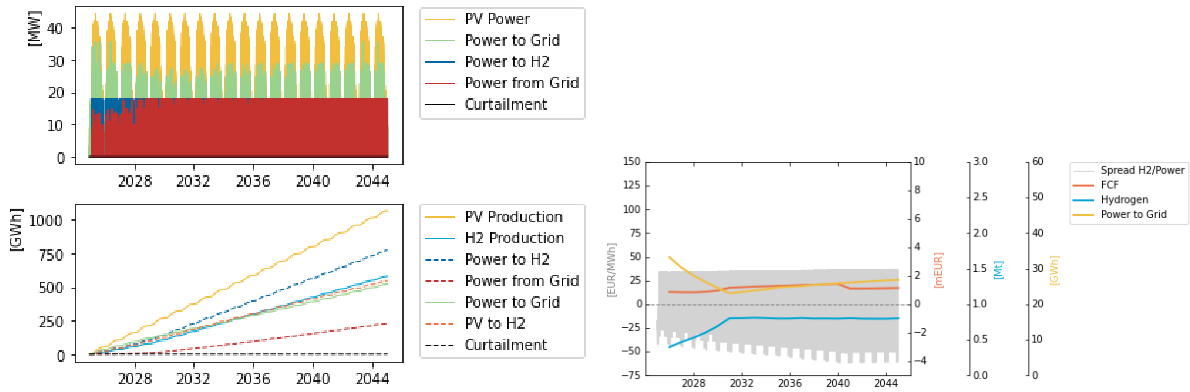
(b) Earnings and Production Profile.

Figure A.11: Simulation and Earnings and Production Profile GC no subs spot P_e=80 EUR/mWh.



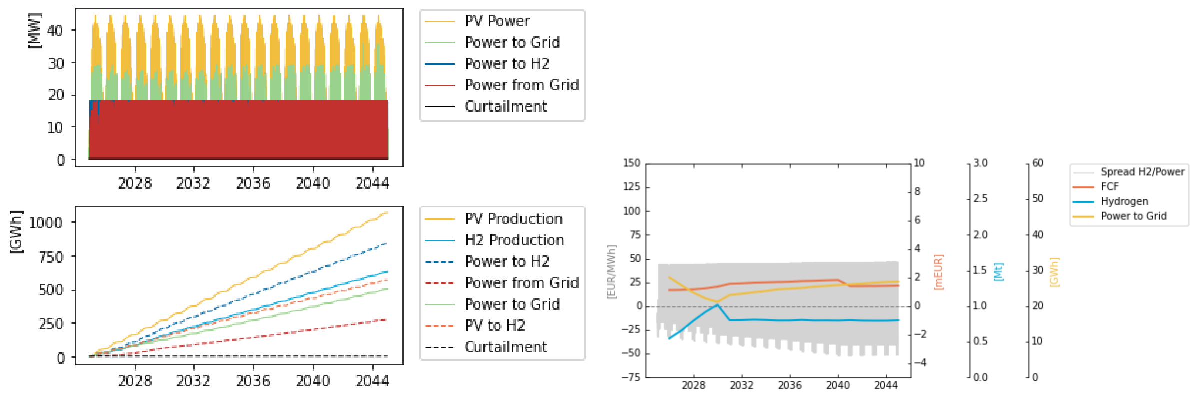
(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.12: Simulation and Earnings and Production Profile GC no subs spot P_e=100 EUR/mWh.



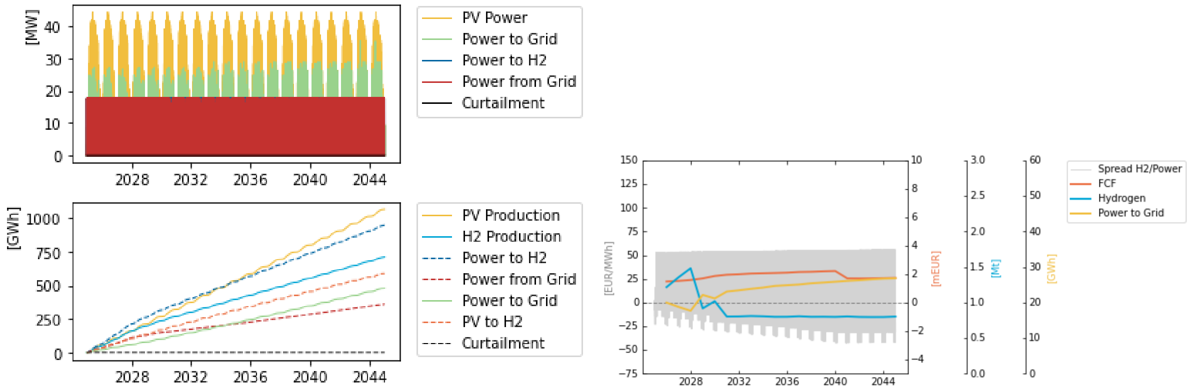
(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.13: Simulation and Earnings and Production Profile GC no subs spot P_{H_2}=2.00 EUR/kg.



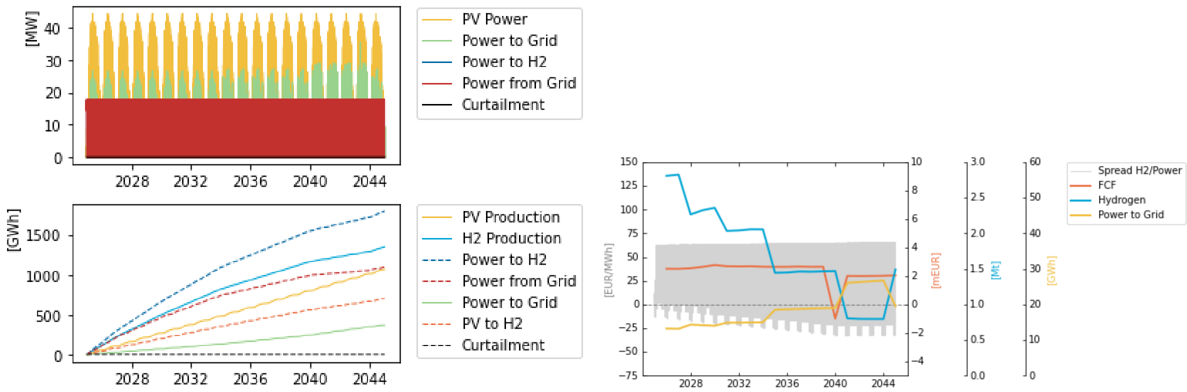
(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.14: Simulation and Earnings and Production Profile GC no subs spot P_{H_2}=2.50 EUR/kg.



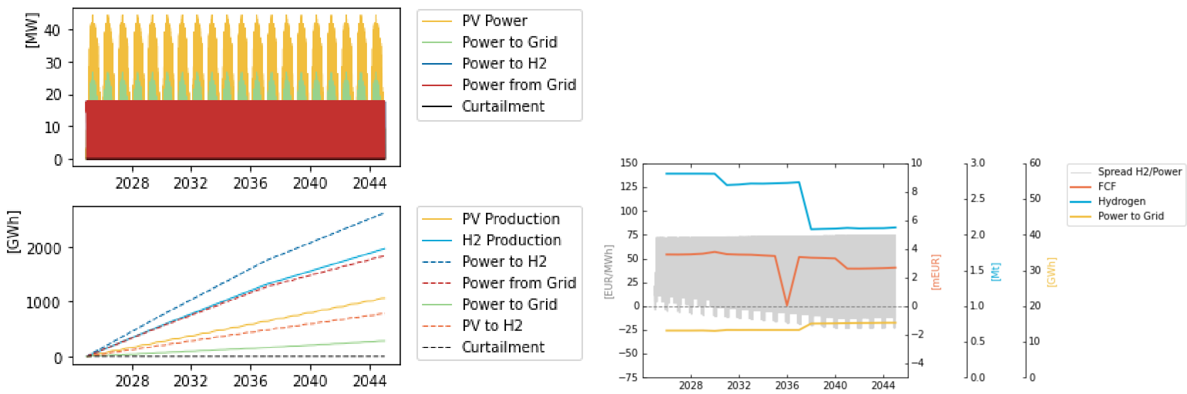
(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.15: Simulation and Earnings and Production Profile GC no subs spot P_{H_2}=3.00 EUR/kg.



(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.16: Simulation and Earnings and Production Profile GC no subs spot P_{H_2}=3.50 EUR/kg.



(a) Simulation of full lifetime. (b) Earnings and Production Profile.

Figure A.17: Simulation and Earnings and Production Profile GC no subs spot P_{H_2}=4.00 EUR/kg.