Analysing the economic viability of hydrogen-fueled gas turbines in a sustainable Dutch electricity system

An exploratory modelling approach

MSc thesis Complex Systems Engineering and Management

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Analysing the economic viability of hydrogen-fueled gas turbines in a sustainable Dutch electricity system

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by

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Acknowledgment

In front of you lies my master's thesis *'Analysing the economic viability of hydrogen-fueled gas turbines in a sustainable Dutch electricity system'*, on which I have worked over the past six months. This thesis was written to fulfill the requirements of the Complex Systems Engineering and Management program at the Faculty of Technology, Policy, and Management. With this, I have reached the end of my time as a student at TU Delft.

Throughout my studies, both the energy transition and sustainability have been central themes guiding my academic choices. My interest in this field began during my bachelor's program, where I followed the Energy and Industry specialisation and pursued the Climate Change, Adaptation, and Mitigation minor. This interest was further reinforced during my master's program through the Energy track and various elective courses. Over the past six months, my enthusiasm for contributing to the energy transition has only grown, strengthening my commitment to pursuing a career in this field.

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Executive summary

The Dutch government aims to establish a CO_2-neutral electricity system by 2035, phasing out natural gas and coal while expanding the share of variable renewable energy sources (vRES), such as wind and solar. However, the intermittent nature of these energy sources presents significant challenges to electricity reliability, particularly during prolonged periods of low renewable generation, known as Dunkelflautes. To maintain a secure electricity supply, sustainable and flexible generation capacity is needed. Hydrogen-fueled gas turbines have been identified as a potential solution, offering CO_2-free electricity generation while providing system flexibility due to their technical characteristics. Despite their technical feasibility, these turbines face considerable investment risks due to high capital costs, uncertain hydrogen availability, and volatile market conditions. Without adequate financial incentives, it remains unclear whether market participants will invest in hydrogen turbines at the scale necessary to ensure long-term supply security. Existing research highlights the financial and regulatory barriers that hinder hydrogen turbine investments but lacks a comprehensive assessment of their economic viability and the policy measures required to facilitate their deployment in the Netherlands.

This study analyses the potential role of hydrogen-fueled gas turbines in ensuring system adequacy and assessing whether, and to what extent, government intervention is necessary to stimulate investments. The research employs a quantitative exploratory modelling approach to assess the economic viability of hydrogen turbines and system reliability under various uncertainties and market conditions. Additionally, qualitative insights derived from expert interviews complement the analysis. The central research question guiding this study is: *What are robust and cost-effective government interventions to stimulate investments in hydrogen-fueled gas turbines to ensure the reliability of a sustainable Dutch electricity system?*

To answer this question, several experiments were conducted using a dynamic model made in Linny-R to simulate the Dutch day-ahead market. The model assessed electricity shortages, price fluctuations, and turbine profitability across different scenarios. The findings indicate that under the anticipated government scenarios, significant electricity shortages are expected, particularly in later years as vRES capacity increases. While demand-side response and battery storage help alleviate shortages, they are insufficient to completely replace dispatchable generation. When sufficient hydrogen is available, hydrogen turbines can play an important role in mitigating these shortages, as they are capable of providing continuous electricity. However, this study revealed several economic challenges.

Investment risks for hydrogen turbines remain high due to external uncertainties, market failures, and policy expectations. While hydrogen turbines can be profitable under specific conditions, particularly during periods of low renewable generation and high electricity demand, their financial viability is weakened in scenarios with higher renewable generation, lower electricity demand, or increased competition from alternative flexibility solutions such as conventional generators, demand flexibility, and batteries. Investors face significant revenue uncertainty, as the profitability of hydrogen turbines depends largely on market scarcity rather than consistent operational hours. Moreover, expanding hydrogen turbine capacity significantly reduces electricity shortages and stabilises prices, yet beyond a certain threshold, the marginal benefits of additional turbines diminish. Besides, the financial viability of hydrogen turbines depends on how many turbines enter the market. If too few investments are made, shortages remain, but if too many turbines enter, they cannibalise each other's revenues by reducing shortages and price peaks. The past distorting of the electricity market in favour of vRES pushed the market out of equilibrium and created unattractive conditions for dispatchable generators. The risk of underinvestment is further exacerbated by market participants delaying investments in anticipation of future government support, creating a vicious cycle.

Given these barriers, the study concludes that market forces alone are unlikely to stimulate sufficient

investment in hydrogen turbines. Without intervention, investment risks remain too high, leading to underinvestment and reliability problems. A reactive approach, waiting until shortages become severe, would ultimately result in significantly higher costs for consumers. The study emphasises that any policy intervention must provide long-term security for investors, as short-term contracts or temporary subsidies will not sufficiently reduce investment risks in hydrogen turbines.

Nevertheless, from the government's perspective, information asymmetry adds another layer of complexity, as it is difficult to determine whether market participants genuinely require financial support or are leveraging uncertainty to secure subsidies. Additionally, justifying financial support for an investment that could be viable without subsidies but carries excessive risks for private investors may be challenging for the government. Such support could potentially benefit investors unnecessarily rather than directly contributing to a reliable and affordable electricity system. This creates a dilemma between ensuring adequate investment to prevent electricity shortages and avoiding unnecessary financial support. Greater transparency on generator profitability is necessary if capacity mechanisms or subsidies are introduced, ensuring that financial support is allocated efficiently and does not result in over-subsidising.

Several policy interventions to stimulate investments in hydrogen turbines were evaluated. Capital expenditure subsidies reduce risks with initial investment costs but do not address operational risks or incentivise structural hydrogen utilisation, making them ineffective. Hydrogen exploitation subsidies, which cover the cost difference between hydrogen and natural gas plus carbon costs, improve competitiveness with natural gas turbines but do not mitigate risks with low operational hours sufficiently. Two-sided contracts for differences provide relatively more revenue stability by guaranteeing a strike price for hydrogen-generated electricity, stabilising investment revenues while preventing excessive profits through a clawback mechanism. However, additional agreements are required to prevent strategic bidding behaviour, and they do not address risks associated with low operational hours, as the strike price is only provided when electricity is sold.

Capacity remuneration mechanisms (CRMs) mitigate investment risks by reimbursing investment and fixed costs for generators based on their availability. Several forms of capacity mechanisms exist, with two being particularly effective in stimulating investments in hydrogen turbines. The first is a central capacity market, where TenneT procures a predefined amount of dispatchable capacity through competitive auctions. This form allows generators to participate in both the capacity and wholesale markets, which carries the risk of excessive generator profits. In contrast, reliability options, the second potential mechanism, offers a more balanced approach by capping scarcity prices, ensuring investment security while maintaining affordability for consumers. Under this mechanism, generators must sell electricity at a predetermined strike price during scarcity events, which prevents excessive generator profits.

Moreover, large-scale adaption of hydrogen turbines is only feasible with a reliable and adequate hydrogen supply. Stimulating investments in hydrogen turbines is therefore only effective if all parts of the hydrogen value chain progress in parallel. Given the current developments and the long lead times within the hydrogen chain, government intervention should extend beyond supporting hydrogen turbines alone. A system-wide view is essential, with targeted interventions for the individual components where necessary to ensure coordinated development.

Several limitations should be considered when interpreting the model findings. The model focuses exclusively on the Dutch day-ahead electricity market and, while it provides valuable insights into system adequacy, economic feasibility, and the impact of uncertainties on both, it does not account for potential revenues from other electricity markets or ancillary services. Future research could refine the business case of hydrogen turbines by incorporating these additional revenue streams. Furthermore, geographical constraints and grid transmission limitations were not explicitly modelled, which would probably further exacerbate the projected problems with electricity supply. Expanding the dynamic model to include network congestion effects would provide a more comprehensive understanding of how grid constraints impact electricity shortages, hydrogen turbine deployment, and their profitability. Additionally, a comparative analysis of hydrogen turbines and alternative flexibility turbines, such as natural gas with CCS and green gas turbines, would provide valuable insights into their relative cost-effectiveness and CO_2 reduction potential.

In conclusion, hydrogen turbines present a promising solution for achieving a reliable CO_2-neutral electricity system. However, their deployment is hindered by substantial investment risks, policy expectations, and the availability of hydrogen. Government intervention is required to align market incentives with long-term adequacy needs and ensure sufficient investment in hydrogen-fuel gas turbines. Among the interventions analysed, CRMs emerge as the most robust solution by reducing revenue uncertainty and improving financial feasibility. Due to the clawback mechanism in the reliability options, a specific form of CRM, excessive generator profits can be prevented and electricity affordability can be ensured. Further research should focus on optimising the design of this mechanism, including the determination of appropriate strike prices. Furthermore, for interventions to be effective and support large-scale hydrogen turbine deployment, a coordinated approach is needed to foster the maturation of the entire hydrogen chain. This parallel development must actively be monitored, with target support provided in the individual components where necessary. A proactive approach is essential to prevent supply shortages and avoid the higher costs associated with delayed intervention. Without decisive action, the transition to a sustainable, reliable, and affordable Dutch electricity system faces significant risks and delays.

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Abbreviations

Abbreviation	Definition
aFRR	e Automatic Frequency Restoration Reserve
BRP	Balance Responsible Party
BSP	Balancing Service Providers
CapEx	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CfD	Contract for Differences
CHP	Combined Heat and Power
CP	Cost Price
CRM	Capacity Remuneration Mechanism
CTR	Corporate tax rate
DAM	Day-ahead market
DRC	Delta Rhine Corridor
DSR	Demand side Response
EENS	Expected Energy Not Served
EOM	Energy-only market
ETM	Energy Transition Model
EV	Electric Vehicle
FOM	Fixed operations and maintenance costs
HCP	Highest Cost Price
KA	Klimaatambitie
KGG	the Ministry of Climate and Green Growth
KPI	Key Performance Indicator
LCOH	Levelised Cost of Hydrogen
LOLE	Loss of Load Expectation
mFRR	Manual Frequency Restoration Reserve
NAT	Nationaal Leiderschap
OCGT	Open Cycle Gas Turbine
OTC	Over the counter
OpEx	Operational Expenditures
SR	Strategic Reserve
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plans
UHS	Underground Hydrogen Storage
VOLL	Value of Lost Load
vRES	Variable Renewable Energy Sources
WACC	Weighted Average Cost of Capital
WtA	Willingness to Accept
WtP	Willingness to Pay
WY	Weather year

1 Introduction

1.1. Problem definition

The Dutch government has set the ambitious target to achieve a CO_2-neutral electricity system by 2035 [1]. To meet this target, the government is actively promoting the development of variable renewable energy sources (vRES), particularly wind and solar power. This transition already led to a substantial growth in vRES. Offshore wind capacity, for example, has increased to 4.7 GW in 2024 and is projected to reach 21 GW by 2032 and 70 GW in 2050, marking a significant step towards a sustainable electricity system [2],[3]. However, while the rapid expansion of vRES supports decarbonisation, it also presents challenges. Unlike conventional power plants, weather-dependent sources like wind and solar are subject to variability, leading to fluctuations in the electricity supply [4]. At the same time, policy measures aim to phase out coal and natural gas-fired power plants as they do not align with the sustainability objective of the Dutch electricity market [5]. The combination of an increasing share of vRES and the reduction of dispatchable conventional generators might lead to problems with the security of the electricity supply. When there is insufficient electricity generation, electricity demand cannot be met for all consumers, resulting in loss of load expectation (LOLE) hours. To keep the high voltage in balance, it might be necessary for TenneT, the Dutch transmission system operator (TSO), to involuntarily disconnect consumers from the system.

Currently, around 35% of the produced electricity originates from vRES, but this share must be doubled to meet sustainability targets [6]. At the same time, electricity demand in the Netherlands is rising and evolving too, driven by the growing adaptation of electric vehicles (EVs), heat pumps, and the electrification of industrial processes. These changes in electricity demand are further reshaping the energy landscape [7]. Consequently, the inherent intermittency of the vRES poses increasing risks to the security of the electricity supply.

Periods of extreme conditions, known as ‘Dunkelflautes’, when both wind and solar generation drop to critically low levels, pose an even greater risk to the security of electricity supply [8]. These meteorological events, which can last from a few hours to several days, severely reduce renewable electricity generation [7]. During such periods, little to no renewable electricity can be generated. As vRES becomes more abundant in the electricity system, the impact of these Dunkelflautes will present growing threats to the reliability of the electricity system [8],[9].

Trilemma of the electricity system

In addition to achieving carbon neutrality, the Dutch government also aims to maintain an electricity system that is both affordable and reliable [1]. This introduces the energy trilemma, which represents the balance between three key pillars: availability, affordability, and acceptability [10],[11]. Policy objectives for future electricity systems are generally structured around these three pillars [11]. Dutch energy policy reflects this by emphasising affordability, reliability, safety, sustainability, and equality [1].

Reliability refers to the system's ability to deliver the desired electricity at the desired time to the consumers. In a recent report, TenneT raised concerns about the future security of the electricity supply, warning that the current trajectory could undermine long-term resource adequacy [12]. The annual monitoring report projects that by 2033, the hours in which electricity demand may not be met will exceed 14 hours per year, and that problems will start arising by 2030. Such shortages could have serious societal and economic consequences [13]. These projections represent averaged values based on numerous weather years. Whenever a Dunkelflaute occurs, the LOLE hours will increase significantly [12].

For the integration of vRES and development of a CO_2-neutral electricity system, the need for sustainable, yet controllable generation capacity increases. This flexible capacity must be able to adjust electricity output quickly and generate for longer, consistent periods to address both short-term fluctuations and long-term shortages. Nuclear energy, designed to provide steady baseload power, lacks this flexibility, while batteries, though useful for short-term fluctuations, are inadequate for extended periods of low generation [14],[15]. During a Dunkelflaute, batteries would deplete rapidly, and be unable to recharge, making them unsuitable for providing the necessary long-term flexibility. In contrast, gas turbines can offer both short- and long-term flexibility due to their fast ramp-up times and capability to operate continuously over extended periods [16]. Currently, the gas turbines primarily run on natural gas, a fuel set to be phased out to meet sustainability targets [1]. Hydrogen-fueled gas turbines present an opportunity to take over the role of flexible assets in a future system. The growing offshore wind sector in the Netherlands presents a significant opportunity for the hydrogen sector. Through power-to-hydrogen electrolysis, surplus wind energy can be converted into green hydrogen, providing a long-term energy storage solution [17]. This hydrogen can then be used in hydrogen-fueled gas turbines, enabling them to play a key role in the future energy mix, offering both flexibility and sustainability.

Investments in flexible capacity

Despite the potential role of hydrogen-fueled gas turbines in a sustainable electricity system, there is currently limited incentive to invest in modernising existing or constructing new flexible capacity. In the Dutch day-ahead electricity market, prices are set by the intersection of bids submitted by electricity suppliers and consumers. For electricity suppliers, bids are influenced by fuel costs, which constitute the majority of the marginal costs. Wind and solar power have minimal to near-zero marginal costs, as they do not require fuel. As the share of vRES in the system grows, the operating hours of dispatchable generators is expected to decrease driven by the negligible marginal costs of vRES [18]. Besides, the unpredictability of vRES creates market uncertainty, making it challenging for market participants to accurately forecast future revenue streams. Historically, investment decisions have been guided by projected earnings for the coming years, but with revenues from the evolving electricity market becoming increasingly unpredictable, this approach is no longer reliable. Moreover, high capital expenditures and fixed operating costs for flexible capacity put additional pressure on the investment decision. The growing uncertainty, combined with anticipated reduced prices and operating hours, further diminishes the incentive to invest in flexible capacity. Consequently, market parties are expressing concerns about future investments in flexible capacity, which could jeopardise resource adequacy and threaten the reliability of the future electricity system [13],[19].

While TenneT's report suggests minimal immediate action from the government, the construction of new turbines or retrofitting existing ones will require at least six years to complete [13],[20]. Furthermore, implementing government interventions, such as a capacity market to ensure resource adequacy, could take several years to become fully operational [21]. This underscores the need for immediate action to stimulate investments in flexible capacity, as any further delay risks making a future supply crisis unavoidable. At the same time, the government has expressed concerns about how to secure the necessary investments without over-subsidising, as they are cautious about disrupting the electricity market [20].

1.2. Research objective

The increasing need for flexible electricity to ensure resource adequacy became evident through the problem analysis. Nevertheless, market forces alone may not guarantee these investments as long as the uncertainty and risks persist. This study focuses on hydrogen-fueled gas turbines, recognising their importance for both long-term resource adequacy and meeting sustainability targets.

The primary objective of this study is to analyse the potential role of hydrogen-fueled gas turbines in ensuring system adequacy and assessing whether, and to what extent, government intervention is necessary to stimulate investments in these turbines. The aim is to identify the conditions under which hydrogen-fueled gas turbines can be economically viable in the Netherlands, in order to meet the goals of a sustainable, reliable, and affordable electricity system [1]. This study assesses the influence of various uncertainties and market developments on the economic feasibility of these turbines, particularly from 2030 onwards, when resource adequacy challenges are expected to emerge. Furthermore, the research investigates government interventions and their impact on the investment decision in hydrogen-fueled gas turbines, providing valuable insights for both private market parties and the government. Since the projected level of resource adequacy depends on the economic viability of CO_2-free flexible capacity, the need for policy interventions also hinges on this viability [12],[22]. Consequently, assessing the economic viability of flexible capacity resources is becoming increasingly important in resource adequacy assessments. Within this research, the investment decisions in hydrogen turbines is quantitatively and qualitatively investigated. The main research question of this research is: *What are robust and cost-effective government interventions to stimulate investments in hydrogen-fueled gas turbines to ensure the reliability of a sustainable Dutch electricity market?*

1.3. Reading guide

In the subsequent chapter, a theoretical background is provided that forms the foundation of the thesis, followed by an overview of the research sub-questions. Chapter 3 details the research methodology used in this study. Next, chapter 4 provides background information about the Dutch electricity markets and the emerging challenges within this market. Chapter 5 focuses on the conceptualisation of the system, and its translation into an operational model. This is followed by a discussion on the implementation of the system in chapter 6. The chapter concludes with an overview of the utilised data and verification and validation of the model. In chapter 7, the experiment design is introduced, from which the results are shown in the subsequent chapter. Chapter 9 applies the government interventions to the Dutch context. Chapters 10 and 11 discuss, conclude, and reflect on the findings, thereby answering the research questions. Finally, the report ends with a personal reflection.

2
Theoretical background

This chapter builds upon the introduction by providing the theoretical foundation for this study, by outlining general theories and concepts relevant to the research. The chapter begins with a brief overview of the principles of the energy-only market, followed by an explanation of investments in generation capacity according to theory. The chapter then elaborates on investment risks in practice, with a specific focus on the barriers associated with hydrogen turbines. This is followed by an explanation of a type of support mechanism identified in the literature. Next, a state-of-the-art review analyses existing research on government interventions aimed at stimulating investments in flexible capacity. The chapter concludes with an outlining of the research gap, which forms the basis for the questions in this study.

2.1. The energy-only market

In an energy-only market, compensation is only provided for the electricity produced. The spot market operates as a blind auction in which electricity is traded for delivery on the next day. Market participants submit bids specifying how much electricity they wish to buy or sell at certain prices for the next day [23]. The merit order principle is used in this electricity market to determine the sequence in which different power plants are dispatched to meet demand. It ranks electricity generators based on their bids, which reflect their marginal costs [24]. The market clearing process determines the intersection of supply and demand, setting both the clearing price and the total volume to be delivered. The clearing price is the price of the last accepted bid and applies uniformly to all transactions [25].

2.2. Investment in generation capacity according to theory

Early power system investment theories proposed that spot pricing could offer optimal incentives for investment and decision-making. Caramanis [26] argues that according to the theory of spot pricing, in an unregulated market optimal spot pricing aligns individual profit-driven behaviour with socially optimal investment decisions. This optimal behaviour is largely driven by real-time price signals, which reflect marginal costs and continuously adjust to balance supply and demand. The spot theory emphasises that real-time pricing helps bring the market into equilibrium by providing immediate signals that influence both electricity demand and generation decisions [26]. Theoretically, the fixed costs of dispatched generators are covered by inframarginal rents and scarcity rents [27]. Inframarginal rents represent the gap between the market clearing prices and the marginal generation costs. Scarcity rents arise from the difference between scarcity prices, when demand exceeds available generation, and the marginal costs of the last available unit in the system. In an ideally functioning energy-only market, these revenues should be sufficient to fully cover the costs of power plants and encourage new investments, ensuring long-term adequate generation capacity in the market.

Need for flexible generation in a sustainable system

The literature highlights the increasing importance of flexibility in the future electricity market. Cruz et al. [16] provide a comprehensive review of flexibility mechanisms, their challenges and advantages and the increasing necessity for flexibility as the penetration of vRES rises continuously. Similarly, Child et al. [28] emphasise the role of flexible generation in future energy systems, particularly highlighting the importance of seasonal solutions, such as gas turbines, in maintaining a reliable electricity supply. Gas turbines are identified as valuable for their ability to enhance system flexibility, due to their fast ramp-up and startup capabilities and their ability for longer-term production [16],[28]. During Dunkelflautes, when renewable generation is limited, the need for this flexible capacity is even bigger, and dispatchable generators, with minimal operational hours, are required to meet almost all electricity demand.

2.3. Investment risks in practice

More recent research indicates, however, that the ideal conditions necessary for this theory to be applicable are difficult to achieve in the electricity system [29]. Several market failures and imperfections complicate the achievement of an optimal equilibrium in the market. A key assumption for the spot market to be working is that the price consumers pay for electricity during scarcity should rise sufficiently in real time for consumers to cut back their demand. However, the implementation of price caps limits the willingness to pay (WtP) of the consumers to be reflected in the market and can create a ‘missing money’ problem. This results in capped electricity prices during peak demand which are insufficient to cover power plants’ fixed costs and provide incentives for new investment [27]. Other potential market failures that can hinder reaching the investment equilibrium are risk-averse behaviour, imperfect information, restrictions resulting in long lead times, and regulatory uncertainties. Consequently, even when sufficient incentives exist, market participants may fail to recognise them, known as the ‘missing market’ problem [30]. Cruz et al. [16] identify several barriers hindering the development of flexible capacity in the short to medium terms. According to this research, one of the most significant challenges is the lack of an adequate business environment, which is crucial for encouraging investments in emerging flexibility options.

Effect of high share vRES on investment risks

The growing share of vRES in the electricity system introduces additional investment risks, particularly for flexible capacity. Investors face two new concerns: reduced production hours and increased market volatility [30]. Non-renewable power sources, which incur fuel expenses, consistently have higher marginal costs than renewable sources [31]. As a result, the increasing presence of vRES pushes the more expensive power plants out of the market. During periods of high renewable output, demand for flexible technologies decreases, leading to diminished utilisation of these plants and reduced electricity prices [18]. This phenomenon, known as the merit-order effect, is adverse for dispatchable plants.

Furthermore, the increasing integration of vRES amplifies supply-side uncertainty, making electricity generation less predictable. Dispatchable gas plants are forced to operate at reduced capacity and operating hours, with frequent ramping up and down to stabilise fluctuations in vRES production. This operational pattern raises costs due to the increased start-ups and shutdowns while reducing operating hours and overall capacity utilisation at the same time [31]. Despite these limited hours, the flexible generators still need to recover their fixed costs, exacerbating both the missing money and missing market problems.

Additional investment risks related to hydrogen-fueled gas turbines

In addition to the previously described challenges, investment in hydrogen-fueled gas turbines faces more risks. Giacomazzi et al. [32] analysed the barriers to hydrogen combustion and its role in the energy transition, highlighting several constraints. The study emphasises that while hydrogen gas turbines show considerable technical potential, the primary challenges lie in reaching the necessary scale and ensuring the economic viability of the turbines. Several economic barriers currently limit the development and scaling of these technologies. At present, hydrogen is significantly more expensive than natural gas, resulting in higher marginal costs for hydrogen-fueled turbines [32]. This cost disparity makes it challenging for hydrogen turbines to compete not only with renewable sources but also with conventional turbines, further reducing operating hours and making it difficult to achieve economic viability [31]. In the absence of a strong carbon pricing mechanism, there is little market incentive to transition from cheaper fossil-based alternatives to hydrogen.

The lack of a developed hydrogen market and infrastructure, including transportation and storage options, creates additional uncertainty for investors and limits the potential for widespread adoption [33]. Large-scale hydrogen production, adequate storage solutions, and a well-developed transportation infrastructure are essential for ensuring a reliable hydrogen supply. Green hydrogen production depends heavily on the scalability of electrolysers, which convert renewable energy into hydrogen [17]. The ability to scale electrolyser capacity and the import possibilities for green hydrogen will be crucial in meeting future hydrogen demand [34]. In addition, hydrogen storage will be necessary to provide a consistent supply to the turbines. Therefore, sufficient storage facilities, such as underground caverns or pressurised tanks, must be developed to manage fluctuations in hydrogen production. Storage capacity is especially important during Dunkelflautes, in order to secure hydrogen availability during these periods [35]. Finally, the development of a robust hydrogen network, including infrastructure for domestic and international transportation, is essential. Pipelines and ports must be established to facilitate hydrogen transportation. Without addressing these interconnected factors of production, storage, and infrastructure, the large-scale deployment of hydrogen-fueled gas turbines will remain out of reach [31].

2.4. Need for government intervention

Insufficient investment and resource adequacy issues are becoming more pronounced as the electricity market evolves, underscoring the growing need for sustainable market mechanisms to support flexibility providers. For flexible capacity to be effectively developed, clear and robust policies are required. Mitchell [36] emphasises that robust government support is crucial for accelerating the energy transition and ensuring its success. This is supported by Child et al. [28], who point out that clear policies and support mechanisms are essential to effectively guide the energy transition. The study highlights that market-based mechanisms alone may create uncertainty for investors, potentially reducing competition and increasing the financial costs of developing flexible solutions. Policies should be designed not only to accommodate regional needs but also to align with broader goals. Specific interventions that address local challenges while supporting overarching energy objectives will help mitigate the economic risks associated with the evolving energy market [28].

Capacity remuneration mechanisms

One type of support mechanism that is often mentioned in the literature to mitigate the investment risks emerging in the energy-only market is a capacity remuneration mechanism (CRM). Implementing a CRM represents a significant shift in market design, transitioning from an energy-only market to one that also allows for deriving value from available capacity. CRMs can take various forms, each with distinct characteristics. A short explanation of the relevant variations is provided below, with a visual overview shown in Figure 2.1. For a more detailed description, please refer to [37] and [38].

Central capacity market

A capacity auction model, often referred to as a central capacity market, is a volume-based mechanism where total capacity is determined by a central authority, such as TenneT, on behalf of the consumers [39]. Consumers are obligated to purchase capacity equal to their expected peak demand plus a fixed reserve margin. This ensures sufficient supply to meet demand, even during peak periods. Suppliers bid the volume and prices of capacity needed to recover their fixed costs. The auction ensures that the most cost-effective capacity is utilised [40]. Additionally, instead of a fixed demand, an elastic demand curve can be integrated, allowing prices to adjust based on the procured volume [37]. The PJM Interconnection in the United States exemplifies a centralised capacity market [37].

	What is the product	How is the volume determined	Who is responsible for procurement
Strategic Reserve	Physical Capacity (sub-set of generation only)	Central Authority sets volume	Central Authority (sub-set of generation only)
Ex Ante Capacity Obligation	Physical Capacity	Central Authority sets volume	LSEs or other individual entities
Ex Post Capacity Obligation	Physical Capacity	LSEs determined volume with *ex post* verification by Central Authority based on predetermined procedure and parameters	LSEs or other individual entities
Capacity Auction	Physical Capacity	Central Authority sets volume	Central Authority
Reliability Options	Financial Instrument	Central Authority sets volume	Central Authority
Capacity Payment	Physical Capacity	Central Authority sets price, volume determined by market	Central Authority
Capacity Subscription	Physical Capacity	Customers determine volume based on their preferences for uninterrupted supply and the price of capacity	Customers, directly and through intermediaries

Figure 2.1: Overview capacity remuneration mechanisms [37]

Reliability options

Reliability options are designed similarly to financial call options [39]. In this mechanism, a central entity procures a designated amount of capacity on behalf of consumers as well. However, instead of direct capacity procurement like in the central capacity market, this mechanism operates through call options [37].

Once purchased, the consumer obtains the right to purchase electricity for a pre-determined strike price from capacity providers. When the equilibrium spot price remains below the strike price, the market operates as if the reliability contract does not exist, with all electricity transactions settled at the spot price. However, during scarcity periods, consumers can activate their call options, requiring the generator to compensate for the difference between the spot and strike price, effectively selling electricity at the strike price (see Figure 2.2). If the electricity generator fails to deliver power during periods of scarcity, they are still obligated to pay the difference between the spot market price and the strike price, even without offsetting the penalty through revenues from the energy-only market [39]. This explicit penalty incentivises the reliability of the generators and ensures generators fulfill their obligations [40]. At the same time, in return for their availability, the generators receive an annual premium. An example of reliability options in practice is Columbia [37].

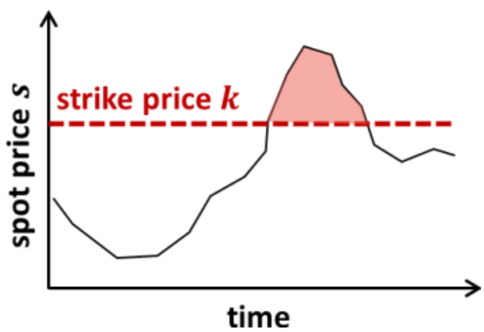


Figure 2.2: Reliability options [37]

Strategic reserve

Another alternative is the strategic reserve (SR), which involves a specific amount of capacity for emergencies, preventing those generators from participating in the wholesale market. These generators are compensated for maintaining operational readiness. An SR operates alongside the energy market, where the system operator secures contracts with a limited share of capacity to serve as an emergency reserve. This reserve is only activated when all other market-based capacity is already in use. The primary driver for capacity investment remains the energy market itself, as the majority of market participants do not receive direct revenues from this mechanism [37]. As a result, its market impact is thus limited compared to other CRMs. Early examples of an SR can be observed in Finland and Sweden [37].

Capacity payments

In addition to these mechanisms, other forms of CRMs exist, though they are less well known. Capacity payments, for instance, are a price-based mechanism that provides fixed payments to generators for available capacity. The volume traded is based on the market response to the price set by a central authority [38]. Compared to other CRMs, this mechanism is relatively simple to implement. An example of a country utilising capacity payments is Spain [37].

Capacity subscription

A last mechanism is a capacity subscription, which is a decentralised capacity market model that does actively encourage demand flexibility by allowing consumers to contract their necessary capacity directly on the market. Consumers can decide on the amount of capacity they wish to procure based on their expected demand and the price at which capacity is offered [37]. Unlike other capacity mechanisms, this approach allows consumers to set their own preferences for the security of electricity supply. As this is a relatively new mechanism, it has not yet been implemented.

2.5. Comparison of similar studies (state-of-the-art)

Sanchez Jiminez et al. [29] analysed to what extent the Dutch energy-only market can be expected to provide enough investment incentives for the market to reach long-term system adequacy. Using agent-based modelling and endogenous investment decisions, the long-term performance of the market is evaluated. The research focused on the impact of policies and gives insight into factors, such as uncertainties, that would impact the energy system through a bottom-up approach. The research demonstrated that the future energy system and generator profits will be susceptible to weather volatility. Moreover, the research concluded that in a highly renewable energy-only market, investors would have insufficient incentives to ensure the reliability of the system. Building on this research, the same models have been used to assess various CRMs on the Dutch electricity system [40]. The results from their assessment are incorporated into this research.

Öberg et al. [41] examined the competitiveness of hydrogen-fueled gas turbines in future energy systems across various countries. Using a techno-economic optimisation model, the study compares hydrogen's role in electricity generation to other flexibility options. No significant investments are projected for 100% hydrogen-fueled turbines in any country or scenario. When zooming in on the Netherlands, it consistently shows low installed capacity across all scenarios, mainly due to the absence of economic incentives and supportive market structures [41].

Drost [42] assessed several policy instruments to incentivise investments in CO_2-free dispatchable electricity generation capacity in the Netherlands. The research used a qualitative approach, employing semi-structured interviews to investigate the factors influencing investment decisions and the uncertainties connected to these factors. Three types of policy instruments were identified to both mitigate uncertainties and enhance the incentive to invest in hydrogen-fueled to allow for both decarbonisation and system reliability: capital expenditure subsidies, hydrogen operational subsidies, and CRMs. A recommendation from the study is to quantitatively assess robust scenarios under deep uncertainties while taking into account the objectives and inherent trade-offs of the future Dutch energy system. The results from the research are used as input for this study.

2.6. Knowledge gap and research questions

Given their potential contribution to resource adequacy and meeting sustainability targets, this study aims to explore the conditions necessary for hydrogen-fueled gas turbines to achieve economic viability within the future electricity system. A specific focus is placed on their role in addressing Dunkelflautes when the risks of insufficient renewable generation are highest. As elaborated in the previous paragraph, studies by Öberg et al. [41] and Sanchez Jiminez et al. [29] indicate that, under current market conditions, investments in hydrogen-fueled gas turbines are unlikely due to their lack of financial viability without government support. Literature highlights various general market failures and uncertainties influencing investments risks in the generation capacity, along with potential support mechanisms to mitigate these risks. Examining these challenges within the context of the Netherlands provides valuable insights into the effectiveness of different policy interventions in enhancing the economic viability of hydrogen turbines and reducing investment related risks.

The main objective of this study is to evaluate the role of hydrogen-fueled gas turbines in ensuring system adequacy and to determine whether, and to what extent, government intervention is needed to stimulate investment in these turbines. To achieve this, the research utilises dynamic modelling, further detailed in chapter 3, to examine the impact of various uncertainties and policy measures on investment decisions and the reliability of a sustainable Dutch electricity system. As stated in the introduction, the central question guiding this thesis is: *What are robust and cost-effective government interventions to stimulate investments in hydrogen-fueled gas turbines to ensure the reliability of a sustainable Dutch electricity system?*

Within the context of this study, the reliability of the electricity system is narrowed down to electricity shortages, occurring when there is insufficient electricity supply to meet demand. The future Dutch electricity system is subject to numerous uncertainties, some beyond policymakers' control and others that can be influenced through policy measures. Government interventions relate to financial and regulatory instruments that policymakers can implement to support investments in hydrogen-fueled gas turbines. Robust interventions are those that remain effective under a wide range of conditions influenced by uncertainties [43]. Cost-effectiveness refers to the balance between the costs and outcomes of interventions, aiming to stimulate investment while minimising unnecessary subsidies or market distortions, in alignment with government objectives [20],[44].

To account for the uncertainties within a future electricity system, different asset configurations are considered within this study, including conventional generators, renewable energy sources, and flexibility options. Additionally, external uncertainties, such as weather conditions affecting renewable generation, future electricity demand shaped by electrification, fuel price fluctuations, and demand flexibility, are examined. To assess the impact of the uncertainties, multiple experiments are conducted. The insights from these experiments are structured through sub-questions, each contributing findings that, when integrated, provide a comprehensive answer to the overarching research question.

Research sub-questions

The first step in the research is to identify key uncertainties and analyse their impact on the reliability of the electricity system. Investigating the expected electricity shortages is essential for determining the need for flexible solutions. Once the expected electricity shortages under various circumstances are established, the next step is to assess whether other flexibility solutions, beyond hydrogen turbines, can effectively mitigate the electricity shortages. This helps determine the necessity of hydrogen turbines or whether alternative flexibility solutions, such as demand flexibility and battery storage, can fulfill this role as well. This leads to the first sub-question: *SQ1: What are the expected electricity shortages in a future Dutch electricity system while accounting for the phase-out trajectory of existing power plants and various uncertainties?*

After identifying expected shortages and assessing the necessity of hydrogen turbines, the potential contribution of hydrogen turbines in reducing supply shortages is evaluated. This results in the following sub-question: *SQ2: What is the potential contribution of hydrogen turbines in ensuring a reliable, sustainable, and affordable Dutch electricity system?*

The economic feasibility of hydrogen turbines is anticipated to be sensitive to both external uncertainties and asset configurations. Since investment decisions depend on economic feasibility, it is important to examine the impact of these uncertainties. This step explores the economic viability of hydrogen turbines by analysing different future scenarios to determine whether hydrogen turbines face profitability challenges across all conditions or if specific scenarios already support their financial feasibility. The findings help determine whether investments in hydrogen turbines are likely to emerge without government interventions or if support is required in all future scenarios. The insights from this analysis help draft policy measures that can mitigate investment risks. This formulates the third sub-question: *SQ3: To what extent are government interventions needed to ensure investments in hydrogen turbines?*

Following the assessment of the economic feasibility of hydrogen turbines and identifying investment risks, the final step explores potential policy measures that could incentivise investments. Various government interventions and their effectiveness in mitigating investment risks for hydrogen-fueled gas turbines are evaluated. Unlike the previous sub-questions, which rely primarily on quantitative model-based analyses, this question is addressed qualitatively, incorporating insights from expert interviews, literature, and model results. The fourth sub-question is: *SQ4: What effect of government interventions on the investment decisions in hydrogen turbines can be expected?*

After addressing the sub-questions, the answers are analysed to provide a comprehensive discussion of the trade-offs between investment decisions and system reliability. The robustness and cost-effectiveness of government interventions are assessed in light of the key uncertainties and economic feasibility. Ultimately, these insights contribute to answering the main research question.

3

Research methodology

This chapter outlines the methodology used in this research. It begins with an explanation of the primary, quantitative, research method, including the theoretical framework used. This is followed by an elaboration on the assessment of the economic viability of hydrogen turbines and the simulation of the electricity market. Next, the qualitative research method is introduced. Finally, the chapter provides an overview of steps taken to structure the thesis, which serves as the foundation for the subsequent chapters.

3.1. Exploratory modelling approach

To evaluate the potential role and economic viability of hydrogen gas turbines in the future Dutch energy system, two interrelated yet distinct subsystems must be analysed: the electricity system and the hydrogen system. Both systems are socio-technical and are largely influenced by past, present, and future investment decisions aimed at achieving energy transition goals. As a result, the research approach must provide insights into the potential impacts of choices on these systems. Additionally, the development of these systems is accompanied by significant uncertainties, which the chosen research approach must be equipped to address.

To meet these requirements, an exploratory modelling approach has been selected as the primary research methodology. In general, models can provide a structured framework for addressing the inherent uncertainties of the electricity system. Exploratory modelling is an effective approach for understanding the consequences of deep uncertainty, making it well suited for this research [45]. Factors such as unpredictable weather patterns, fluctuating electricity consumption profiles, and evolving policy landscapes add complexity to evaluating the economic potential of the turbines. A modelling approach helps navigate these uncertainties by offering a comprehensive understanding of the system, identifying critical variables, and uncovering unknown interactions. As Epstein [46] emphasises, modelling enables the exploration of trade-offs, sensitivities, and uncertainties within a system. By simulating different scenarios with varying setups and data input, modelling becomes a powerful tool to explore potential future outcomes.

Theoretical framework

To structure the exploratory modelling approach, the XLRM framework is used. This framework organises the system's relevant information into four categories, providing a systematic method for addressing uncertainties [45]. In this framework, a model consists of three types of attributes, that include external factors (X), policy levers (L) and performance metrics (M). The relationships of the system (R) can be found inside the model, as illustrated in Figure 3.1.

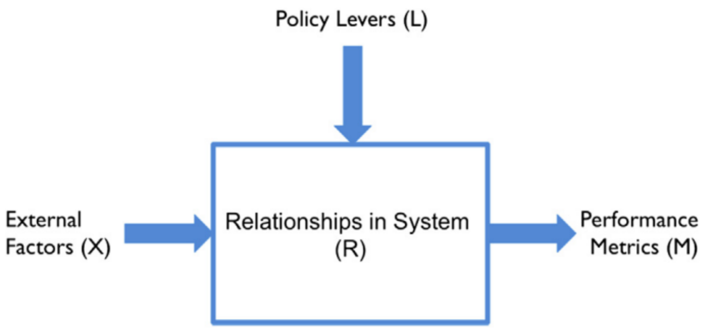


Figure 3.1: General XLRM framework [45]

The four key elements of the XLRM framework are defined as follows [45]:

- External factors (X): Uncertainties beyond the control of decision-makers that can significantly influence the system. These represent the external conditions surrounding the system under study.
- Policy levers (L): Decision-makers' actions or strategies that can be implemented to influence system outcomes. These represent interventions aimed at achieving specific objectives.
- Relationships in system (R): The relationships within the system are captured by the model's mathematical framework. These fixed relations define how the other three types of variables interact and how flows between different components are structured.
- Performance metrics (M): Criteria used to assess and compare different scenarios. These metrics quantify the system's performance and represent the outcomes of interest.

This structured approach allows for a clear identification and treatment of uncertainties as external factors, enabling the analysis of their effects on the system outcomes. The XLRM framework is particularly suited for robust decision-making under uncertainties, making it an appropriate choice for this research on the electricity system.

Evaluation of economic viability of hydrogen turbines

The business case for hydrogen-fueled gas turbines consists of initial investments, operational costs, revenues, corporate taxes, and the asset's lifespan. In practice, a business case would be evaluated over the entire economic lifespan. Due to the computational demands of exploratory modelling, which involves running numerous simulations, using this time frame would be impractical. Therefore, this research focuses on a single year, with annual profits serving as the key performance metric.

To evaluate the economic viability of hydrogen turbines under various conditions, the outputs from the simulations are incorporated. Key factors such as electricity market prices, operational hours, and production levels of the turbines vary across scenarios and are used to calculate revenues. The results from the simulations of the electricity market serve as input for calculating the annual profits, providing a feasibility range for the turbines' economic viability.

Simulation of electricity market

To simulate the future electricity market, a model is developed in Linny-R, a visual programming language created by Pieter Bots [47]. Linny-R is specifically designed for solving Mixed Integer Linear Programming problems, such as Unit Commitment. The optimisation solver can identify the most-efficient solution within a predefined set of constraints, such as electricity demand that must be met. Linny-R supports dynamic modelling by allowing data variables to change at each time step. This is particularly important in energy systems, where both electricity and hydrogen storage depend on previous time steps and forecasts of upcoming time steps. For instance, surplus electricity can be stored if the system anticipates a shortage in the near future, minimising the system costs based on predicted supply and demand fluctuations.

Compared to other tools such as Python or Excel, Linny-R offers distinct advantages, particularly in handling uncertainties through built-in sensitivity analyses and experimental setups. Given the large role of uncertainties in this research, this feature is important as it greatly simplifies the scenario discovery. Additionally, its visual and intuitive interface enhances accessibility for external parties, including Rebel, who seek to expand their knowledge about the software. Besides, the user-friendly interface facilitates straightforward validation of model behaviour with experts. Combined with the modeller's previous experience with the software, these features make Linny-R a well-suited tool for this research.

3.2. Interviews

In addition to the modelling approach, informal semi-structured interviews with experts and stakeholders were conducted to gain insights into real-world challenges. Each interview was guided by prepared questions to initiate the conversation and provide structure where necessary. However, the conversations remained open-ended, allowing interviewees to elaborate on topics beyond the predefined questions.

Two rounds of interviews were conducted. The first round, held at the beginning of the project, aimed to develop a deeper understanding of the Dutch energy system and identify market challenges. The insights gathered from these interviews were used during the scoping phase, the development of the model, and later served as the foundation for drafting government intervention.

Once the model was developed and the first results were analysed, a second round of interviews was conducted. During this round, the initial insights were revisited with interviewees to discuss the findings, assess the requirements for effective government interventions, and gather their perspectives on the proposed policy measures.

An anonymised overview of the interviewees and the three most relevant topics discussed is outlined in Table 3.1, with a more extensive version included in Appendix A. In addition, everyone was consulted on the electricity trilemma and the potential role of hydrogen turbines in a future system.

Interviewees

To gain a broad perspective and prevent a one-sided view of the problem, interviewees were selected from diverse sectors through Rebel's network. The selection process aimed to include both private market representatives and governmental employees.

Interviewee 1: Former electricity trader

The first private sector interviewee is a former electricity trader, offering expertise on revenue generation strategies for electricity producers and traders. The interviewee was consulted twice, and these interviews particularly provided a detailed understanding of the Dutch electricity market mechanisms and the economic viability of generators.

Interviewee 2 and 3: Government employees

The public sector interviewees were selected based on their roles within a governmental organisation. Their portfolios focus on ensuring electricity supply security and retrofitting gas turbines to hydrogen turbines, making their perspectives particularly relevant to this study. These interviews offered insights into the government's position, interventions, and ongoing developments in the public sector.

Interviewee 4 and 5: Private energy market employees

Additionally, two interviewees from different Dutch energy companies were consulted, both of whom are involved in their companies' investment decisions and strategic planning. These private market representatives provided insights into the uncertainties and risks influencing investment decisions. Furthermore, they provided insights into the current development and policy expectations within the companies regarding hydrogen turbines.

Table 3.1: Interview overview

Name	Specific topics
Interviewee 1 [9]	Electricity market mechanisms Trading on electricity markets Revenues and economic viability of generators
Interviewee 2 and 3 [20]	Security of supply in future electricity system Potential measures to stimulate investments General challenges related to government interventions
Interviewee 4 [13]	Societal and economic impact of electricity shortages Challenges and risks related to investment decisions Barriers for the deployment of hydrogen turbines
Interviewee 5 [19]	Current developments within hydrogen market Requirements for policy interventions Forms of flexibility in the system
Interviewee 2 and 3 [48]	Mitigating shortages through the intraday market Advantages for specific government interventions Barriers for government interventions
Interviewee 4 [49]	Uncertainties in hydrogen market development Necessity of government intervention Requirements for government interventions
Interviewee 1 [50]	Policy expectations and market failures Implications of government interventions Uncertainties in electricity markets

Processing and integration of insights

During the interviews, detailed notes were taken. Before finalising the thesis, interviewees were provided with an overview of key points that would be included in this study, and their consent was obtained to ensure that their perspectives are accurately represented. Interview findings are integrated into the text and cited with their respective references, as outlined in the table above.

The insights gained from the first round of interviews are primarily incorporated into chapter 1 and 4, where they helped identify challenges and trade-offs in the Dutch electricity market. These interviews provided valuable context on market uncertainties, investment barriers, and key factors influencing investment decisions in hydrogen turbines.

The second round of conversations focused on discussing the first model findings, evaluating the effectiveness of government interventions and hydrogen market developments. The insights from these conversations are integrated into chapter 9, where they helped with the expected effect of government interventions. Furthermore, they contribute to the broader discussion on system adequacy and the developments in the electricity and hydrogen market from chapter 10.

3.3. Structure of the thesis

The thesis is structured following the modelling cycle [51]. The cyclical process consists of six different steps that are all interconnected. The modelling cycle follows an iterative process, allowing for revisiting earlier stages when needed. This repetition allows continuous enhancement of the process. The cycle consists of the following phases:

1. Questions: The modelling cycle begins by defining questions that this study aims to answer. These questions emerge from the problem analysis and guide the thesis.
2. Conceptualisation: The second phase focuses on developing a conceptual model that defines the problem scope and represents the system under study. This involves designing a visualisation that outlines key variables, their interrelationships, and the problem scope.
3. Operationalisation: The conceptual model is translated into practical, measurable components, with the help of the XLRM framework. Furthermore, concepts and relationships are converted into specific variables and equations that can be used for the analyses.

4. Implementation: In this phase, the operational model is converted to a computational model. This phase furthermore includes data collection, and verification and validation of the model.
5. Application: The model is used to analyse the system under study. To explore the system behaviour, experiments are created and conducted, which provide insights into the model and the underlying system. Furthermore, the effectiveness of government interventions is qualitatively evaluated in this step.
6. Interpretation: In the last phase of the cycle, the results from the previous steps are interpreted. The analysis of the results help address the research questions formulated at the beginning of the cycle. Additionally, the limitations and implications of the research are discussed.

4

The Dutch electricity system

This chapter provides background information about the Dutch electricity system and the challenges it faces in ensuring long-term system adequacy. It applies the discussed literature from chapter 2 on the Netherlands and incorporates insights gathered from the interviews. The first section outlines the different electricity markets in the Netherlands, with their respective mechanisms and the potential role of hydrogen turbines within them. The second section discusses why the market does not function as predicted by theory, highlighting key market failures and uncertainties that affect investment decisions in hydrogen turbines and other flexibility solutions in the Netherlands.

4.1. The Dutch energy-only market

The Dutch electricity market operates as a decentralised energy-only market, consisting of several individual yet interconnected sub-markets [24]. Each sub-market has unique trading processes and price-determination mechanisms. Figure 4.1 depicts the various electricity markets within the Dutch electricity system, organised according to their position on the time scale. Electricity trading can occur from up to four years before delivery until real-time [52].

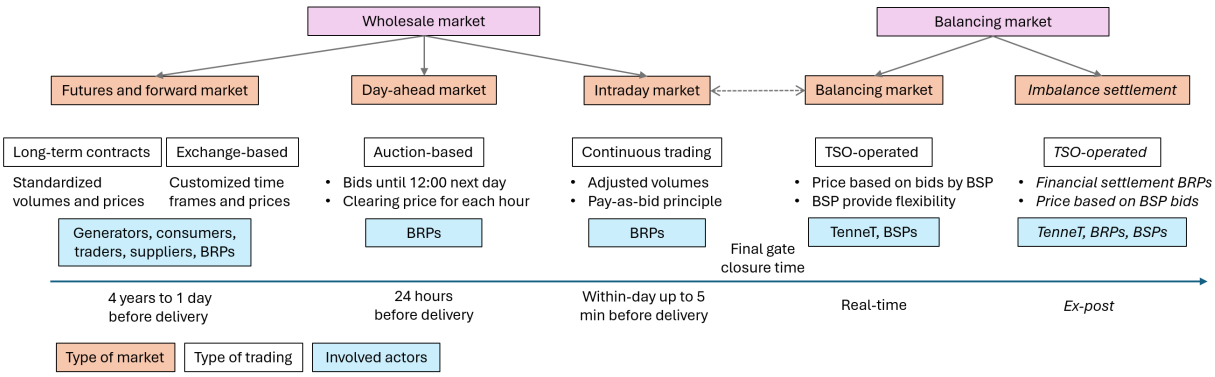


Figure 4.1: Dutch electricity markets

Futures and forward market

In the futures and forward markets, electricity can be traded from as early as four years up to one month or day before delivery. Futures are standardised contracts traded on power exchanges, with standardised volumes and prices [52]. Forwards are non-standardised contracts traded bilaterally, commonly referred to as over-the-counter (OTC) transactions. Both futures and forwards allow for the hedging of electricity, enabling parties to lock in a pre-agreed price and volume of electricity [25]. This minimises risks and ensures a more predictable income stream for the involved generators. Compared to the day-ahead market, the futures and forward markets are less regulated and the market is open for individual parties. These primarily involve producers, consumers, suppliers, traders and other third parties. The percentage that is being traded at these markets is expected to reduce, as the share of renewables increases [9]. In the context of hydrogen-fueled gas turbines, the produced electricity is, compared to other sources, too expensive to be sold via these markets [9].

The day-ahead market

The day-ahead market is the largest part of the Dutch spot market and operates as a blind auction in which electricity is traded for delivery on the next day. Balancing responsible parties (BRP) submit bids specifying how much electricity they wish to buy or sell at certain prices for each of the 24 hours of the next day. All bids must be submitted by 12:00 daily [23]. The merit order principle is used in this electricity market to determine the sequence in which different power plants are dispatched to meet demand. It ranks electricity generators from the lowest to highest bids, which reflect their marginal costs [24]. As a result, vRES are prioritised in the dispatch order. The market clearing process determines the intersection of supply and demand, setting both the clearing price and the total volume to be delivered. The clearing price is the price of the last accepted bid and applies uniformly to all transactions [9]. Unlike one-to-one matching of buyers and sellers in futures and forward markets, the entire day-ahead market is aggregated, resulting in all participants paying or receiving the same price [25]. The clearing price from the day-ahead market is often regarded as the electricity price, as it is set shortly before delivery and is determined on an hourly basis.

The increasing share of renewable sources, with their low or near-zero marginal costs, pushes more expensive power plants out of the market, reducing the overall price of electricity during periods of high renewable generation. This depressing of the overall market clearing price is known as the merit-order effect [18]. However, the intermittency of renewables can also lead to price spikes when renewable generation is insufficient, and more costly backup generation is required to meet demand. As a result, the volatility of the clearing price has increased in recent years, leading to significant fluctuations from hour to hour.

To limit the risk of market power abuse and to protect consumers from high electricity prices during scarcity conditions, the Dutch day-ahead market has a maximum price set by the regulator at 4000 €/MWh [53],[54]. This means that electricity suppliers can offer their capacity at a maximum of this price cap. Similarly, the demand bids can be placed at a maximum of this price cap, regardless of their actual WtP for a certain volume.

The intraday market

After the day-ahead market clears, the intraday market opens, allowing participants to adjust their trading positions. In this market, buyers and sellers can modify their volumes to better match revised demand, renewable energy generation forecasts or unforeseen events such as power plant outages. The intraday market offers flexibility for short-term trading, with transaction blocks available from 15 minutes and onwards, up to 5 minutes before delivery, known as the final gate closure time [55]. Unlike the aggregated pricing mechanism of the day-ahead market, intraday trades are settled on a pay-as-bid basis, where prices are determined individually for each trade [52]. Electricity prices in the intraday market can be significantly higher than those in the day-ahead market [50]. Besides, electricity traders may strategically withhold capacity on the day-ahead market, anticipating higher prices in the intraday market, the so-called optionality value [9]. If the day-ahead market indicates an electricity shortage, a LOLE hour, this will be tried to be mitigated by trading on the intraday market. Given the allowance of higher scarcity prices in this market, the demand side response (DSR) is more pronounced and gets reflected more through the so-called 'far-reaching voluntary reduction' [48],[56].

The value of electricity shortages

A LOLE hour occurs when the electricity supply is insufficient to meet demand [57]. On the day-ahead market, this means that some BRPs that placed bids at the price cap still do not receive electricity, whereas others do receive electricity. In the intraday market, these shortages can be partially mitigated through trading between market participants, through far-reaching voluntary reduction [48]. Parties that secured electricity in the forward or futures markets, or those that were allocated electricity in the day-ahead market, may choose to sell at higher intraday prices. Additionally, some consumers may reduce their demand to avoid paying excessively high electricity prices.

It is important to note that LOLE hours represent anticipated shortages. To mitigate their impact, TenneT may proactively disconnect certain consumers to maintain grid frequency balance, to prevent a system-wide collapse [48]. The economic and societal costs of such electricity shortages are significant, with the Value of Lost Load (VOLL) in the Netherlands estimated at approximately €69000/MWh [58].

Balancing market

After closing the intraday market, in real-time, it is still possible that an unexpected imbalance occurs. If an imbalance occurs, the grid frequency drops or exceeds the standard of 50 hertz, losing its stability [59]. To restore this imbalance, the following steps can be undertaken in the Netherlands, which are in visualised in Appendix B [59]:

- Frequency Containment Reserves (FCR) are activated automatically based on frequency deviations, rather than being directly controlled by the TSO. Batteries are often used for down- and upward regulation and curtailment can be used for downward regulation. This reserve capacity is activated for a maximum of 30 seconds.
- Whenever the FCR is not enough to recover the imbalance, the Automatic Frequency Restoration Reserve (aFRR) gets activated. This reserve is meant for 30 seconds to 15 minutes and is used to restore the FCR. Balancing Service Providers (BSPs) submit bids and the prices are determined by the market.
- Manual Frequency Restoration Reserve (mFRR) operates with capacity contracts to ensure available capacity at all times. TenneT can manually activate the procured amounts without using a merit order list, meaning there is no market mechanism involved. This reserve can remain activated longer than 15 minutes.
- After restoring the balance, the financial imbalance settlement takes place, where payments between the involved BSPs occur.

The balancing market is primarily designed for short-term adjustments to electricity demand and supply, instead of medium- or long-term resource adequacy. Its primary objective is maintaining network stability rather than ensuring overall system reliability. Compared to other electricity markets, revenues from the balancing market are even more uncertain, particularly for the hydrogen turbines. FCR operates on very short timeframes, where batteries are often the preferred solution due to their fast response capabilities. In contrast, the aFRR and mFRR markets offer potential opportunities for hydrogen turbines, but their role in these markets remains uncertain.

4.2. Challenges in the Dutch electricity market

According to spot pricing theory, the energy-only electricity market should facilitate sufficient investments in generation capacity. However, in practice, this might not be the case in the Netherlands due to three types of factors influencing the investment decision: uncertainties, market failures, and policy expectations.

Uncertainty in the Dutch electricity market

Uncertainty plays a significant role in investment decisions within the Dutch electricity market. One of the most impacting sources of uncertainty is weather variability. Weather conditions not only impact the electricity supply but also determine the potential role of hydrogen turbines [9]. Extreme weather events, such as Dunkelflautes, are key in determining the required level of dispatchable capacity. If such events occur only once every ten years, investing in flexible solutions may not be financially viable. However, if scarcity events become more frequent, occurring every three years, for example, the potential business case for hydrogen turbines would be considerably stronger. Given the increasing share of vRES, the impact of Dunkelflautes will likely intensify in the future [9].

Another uncertainty is the future trajectory of electricity demand, particularly regarding electrification trends. While electrification is expected to grow, the final stages of this transition will be the hardest, potentially slowing and decreasing expected demand growth [13]. If electricity demand does not increase as expected, investments in hydrogen turbines and other flexibility solutions may struggle to become profitable.

Furthermore, the role of alternative flexibility technologies remains uncertain. Batteries and hydrogen turbines may act as substitutes, meaning that advancements in battery storage technology could reduce the demand for hydrogen-fueled turbines [49]. The future capacity mix of the Dutch electricity system is still uncertain, making it difficult to predict how different flexibility solutions will compete or complement each other.

As stated in chapter 2, a specific uncertainty regarding hydrogen turbines is the development of the hydrogen market. The entire hydrogen value chain, including infrastructure, production, storage, and combustion, depends on each other, thereby creating additional uncertainty. Stakeholders from the various sectors are waiting for each other to take the first step. This interdependence creates investment doubts, making it unclear if and when large-scale development will happen [13]. Lastly, current green hydrogen price projections remain high and volatile, with no clear trajectory for how they will evolve in the coming years.

Market failures

Several general market failures are mentioned in the literature, as discussed in chapter 2.3, some of which are particularly relevant to the Dutch market. The Dutch electricity market is currently undergoing a transition and is not in equilibrium. While subsidies for vRES have been supporting in driving this energy transition, they have also disrupted market dynamics and created unfavourable conditions for dispatchable generators, including flexible technologies such as hydrogen-fueled gas turbines [9],[13]. Furthermore, in practice, the day-ahead market does not function as an optimal dispatch mechanism due to various inefficiencies. First, price caps distort price signals: The €4000/MWh cap in the day-ahead market prevents prices from reflecting the true WtP for electricity during scarcity events. The average VOLL in the Netherlands is estimated far above the price cap, which indicates that the value of non-delivered electricity is significantly higher than its cost price [50],[58].

Second, negative electricity prices can emerge in the day-ahead market due to a combination of factors, including subsidy mechanisms for vRES, must-run generators or ones with high start-up costs, and opportunity costs from batteries that capitalise on price differentials [50]. Furthermore, BRPs often use price blocks, which further limit price formation and hinder optimal resource allocation [50],[60]. Besides, experts emphasised that earlier government interventions have already disrupted the high scarcity moments in the past [9],[19]. This intervention prevented prices from becoming high enough to incentivise new investments.

These market failures diminish investment incentives for flexible generation capacity. This ‘missing money’ problem, where dispatchable technologies fail to generate sufficient revenue to cover their costs, poses a barrier to investment in hydrogen turbines.

Furthermore, there is a significant degree of information asymmetry [61]. Investors or turbine operators and policymakers often do not share the same level of insight into expected electricity shortages, investment risks, and financial challenges required to keep power plants operational [48]. Policymakers may underestimate the risks associated with underinvestment, resulting in inadequate incentives for capacity expansion. Conversely, market participants may exaggerate their need for financial support, leading to inefficiencies in policy interventions and potential misallocation of subsidies.

Policy expectations

From an investment perspective, expectations of government intervention in the day-ahead market add further investment delays. If electricity prices remain high for an extended period, policymakers are expected to step in, limiting the ability of market participants to benefit from prolonged price spikes [50]. While investors may benefit from high prices during one Dunkelflaute event, receiving €4000/MWh for an entire week for example, repeated occurrences increase the likelihood of regulatory action [50].

Uncertainty regarding future policy and market mechanisms also influences investment decisions. Companies are postponing large investments, anticipating the introduction of a CRM [49]. The risk of committing capital just before a CRM is implemented, thereby potentially missing out on long-term contracts and financial support has led investors to postpone their investments. Finally, stable and predictable government policies are essential. When there is sufficient policy clarity, market participants are more inclined to invest [19].

The primary risk for investors in hydrogen turbines is insufficient operational hours or electricity prices that are too low to recover costs, potentially leading to financial losses. Meanwhile, the primary risk for society is underinvestment in flexible generation, which could result in electricity shortages. If investment incentives remain weak and uncertainty persists, the Dutch electricity system may struggle to secure sufficient capacity, increasing the likelihood of future electricity shortages. This creates difficult trade-offs, further complicating an already complex system.

5

Conceptualisation

The Dutch electricity and hydrogen markets are complex and interconnected systems. This chapter deconstructs these subsystems to enhance the understanding of their operation, aligning with the conceptualisation phase of the modelling cycle. First, a high-level overview of the systems is presented in Figure 5.1 which highlights the relevant elements, relationships and problem scope. This is followed by an elaboration of the key elements and relationships of the electricity and hydrogen markets, clarifying what falls within the scope of the research. In the last section of this chapter, performance metrics are discussed and the conceptual system is translated into an operational model, aligning with the operationalisation phase.

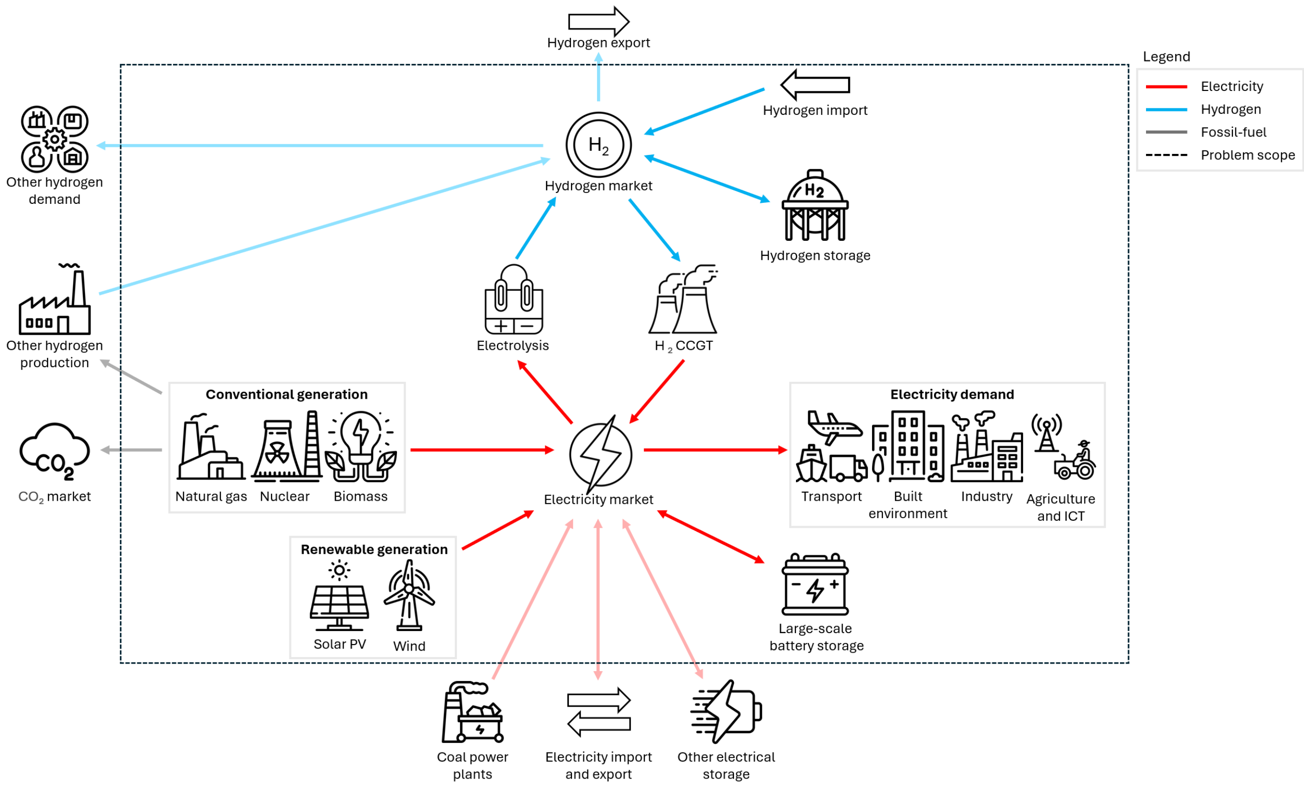


Figure 5.1: Conceptual overview of the system (icons derived from [62])

5.1. The Dutch electricity market

The model is based on a simulation of the day-ahead electricity market, assuming that all electricity is bought and sold on the day-ahead market. While this is a simplification of the complex electricity market as elaborated in the previous chapter, it still allows for the comparison of various scenarios. Besides, expected revenues from this market form the foundation for investment decisions regarding generators [13]. While trading on the intraday market can provide substantial additional revenues, its profits are far more uncertain than those from the day-ahead market, limiting its influence on investment decisions. Furthermore, electricity produced by hydrogen-fueled gas turbines is expected to be too expensive to be traded in the forward and futures market [9].

Electricity generation

To meet the sustainability goals, the electricity system must transition to carbon neutrality. Within the scope of this research, dispatchable generation comprises nuclear power plants, natural gas, biomass, and hydrogen turbines. Biomass based electricity generation is considered a CO_2-neutral manner to generate electricity [63]. Coal-fired power plants are excluded from the research, as the current policy plans aim to phase out existing plants before 2030, due to their emitting nature [64]. Fuel cells are also excluded because of their limited scalability and high investment costs. Currently, electricity generation from combined heat and power (CHPs) is primarily driven by heat demand and not by electricity demand. Given the uncertainty of whether this will remain the same in the future, due to changing prices and regulations, natural gas CHPs are included in this research, with all capacity assumed to be available to participate in the electricity market.

The research incorporates the two primary renewable energy sources in the Dutch electricity system: solar and wind energy, with wind energy further categorised into onshore and offshore turbines. The government has outlined plans to nearly tenfold the installed renewable energy capacity by 2050 [6]. In an energy system with a high penetration of vRES, weather becomes one of the most critical, yet unpredictable factors. As the share of vRES grows, the electricity system becomes increasingly sensitive to the impact of prolonged periods of low generation. During periods of excess renewable generation, curtailment may be required to maintain system balance.

Electricity import

This study focuses exclusively on the geographical scope of the Netherlands, reflecting current policy goals that emphasise self-reliance and energy independency from other countries [65]. Besides, TenneT calculated that in 74% of the hours with electricity shortages in the Netherlands, Germany simultaneously faces shortages [12]. This indicates that, for a significant portion of the hours when import capacity is needed the most, the connection with Germany cannot be relied upon. Furthermore, in times of shortages, it remains highly uncertain whether electricity will actually be exported or retained domestically to prevent LOLE hours within each country [50]. In addition, neighboring countries are also exploring or implementing government interventions, such as CRMs, which could affect the future availability and utilisation of interconnector capacity. Assuming interconnector capacity is always available may lead to an underestimation of the challenges related to security of supply in the Netherlands. Due to the high level of uncertainty surrounding future availability, this study assumes no interconnector capacity with neighboring countries.

Electricity demand

Electricity demand can be categorised into several sectors, each with its own annual consumption and demand patterns. In this study, electricity demand is divided into four sectors, consistent with the future scenarios of Netbeheer Nederland [64],[66]. These sectors include agriculture and ICT, the built environment, the industry, and the transport sector.

The built environment comprises residential households and commercial or utility buildings, where electricity demand primarily stems from heating and cooling systems, household appliances, and cooking [64]. The transport sector, also referred to as mobility sector, consists of passenger transport, freight transport, and international transport. The industry sector encompasses both large-scale basic industries and smaller enterprises. In addition to significant electricity consumption, these industries also have substantial energy and raw material demands, yet these fall outside the scope of this study. The last sector covers agriculture, particularly greenhouse farming, along with the electricity demand of ICT and data centres. Due to ongoing trends, demand from data centres is expected to grow significantly [64]. Specific demand patterns for each sector are discussed in the following chapter. This study focuses exclusively on electricity demand, excluding heat and other forms of energy demand.

Demand side response

Historically, electricity supply bids largely determined the intersection on the day-ahead market and, consequently, the electricity price. Electricity demand was considered as inflexible and static [67]. However, in the evolving electricity market, demand is becoming increasingly flexible. The WtP, defined as the maximum price an electricity consumer is prepared to pay for a specific volume, is reflected in the bids submitted to the market. If this bid price is lower than the price cap and becomes the intersection point, demand itself can act as a price setter for the entire market. Demand flexibility can play a significant role in mitigating daily fluctuations in renewable electricity generation [64]. DSR refers to the voluntary adjustment of electricity consumption by end-users in response to signals from the grid, such as changes in electricity prices and financial incentives [67]. In general, DSR can be categorised into two main types: demand shedding and demand shifting.

Demand shedding refers to temporarily reducing or cutting off non-essential electrical loads during periods of high prices [68]. This voluntary reduction of electricity does not require the deferred demand to be met at a later time. For example, avoiding the usage of a clothes dryer during peak price periods reduces demand without the need to reschedule the activity later. Demand shifting, on the other hand, entails moving electricity consumption from peak periods to times when electricity prices and relative demand are lower, without reducing the amount of electricity consumed [69]. Unlike shedding, the deferred load must be compensated at another time. This demand shifting reduces both electricity expenses for consumers as well as peak demand on the system. An example is postponing electric vehicle (EV) charging until electricity prices decline. Within this research, DSR includes various forms, such as industrial demand response, hybrid heat pumps, and smart charging of EVs [64].

Electricity storage

Similar to demand flexibility, electricity storage can also play a role in managing the volatility of vRES by mitigating daily supply fluctuations. This research considers three forms of electrical storage: large-scale battery storage, household batteries, and batteries in EVs [64]. (Super)capacitors are excluded due to their high self-discharge rates, which makes them unsuitable for longer term electricity storage and limit their impact on the day-ahead market [70]. Moreover, household and EV batteries are classified as part of DSR within their respective sectors in this study. Rather than directly participating in trading on the electricity grid, they enable demand to be delayed or reduced for sector-specific utilisation.

For large-scale batteries, the bidding strategy on the day-ahead market differs from that of other assets. The profitability of these batteries relies on arbitrage or opportunity costs: Purchasing electricity from the market when anticipated prices are low and selling it back when prices are high [9],[71]. This flexibility allows batteries to utilise price fluctuations for their profits.

5.2. The Dutch hydrogen market

The future development of the hydrogen market remains one of the most significant uncertainties within this research. It is assumed a hydrogen market will exist in the Netherlands by 2030. Likewise, it is assumed that infrastructure and storage technologies will be fully developed by then, enabling the establishment of a functional hydrogen network. For the scope of this study, hydrogen exports and hydrogen demand from sectors other than electricity are not included in the analysis.

Hydrogen storage and production

While various forms of hydrogen storage may emerge beyond 2030, this research focuses on underground hydrogen storage (UHS). UHS is considered more suitable for addressing longer term electricity shortages compared to above-ground storage due to its lower costs and significantly larger capacities

[64],[72]. Additionally, it is assumed that UHS will only be filled with green hydrogen, aligning with sustainability goals and the broader objectives of this study. Therefore, hydrogen production within the scope of this research is exclusively conducted through power-to-hydrogen electrolysis [17].

Hydrogen import

Regarding hydrogen import capacity, two potential import methods are considered. The first involves a pipeline network connecting the Dutch and German hydrogen grids, transporting hydrogen produced during periods of electricity surplus in either country. However, as discussed in chapter 5.1, electricity shortages in the Netherlands often coincide with similar deficits in Germany [12]. This makes the availability of hydrogen imports through the pipeline network uncertain. In contrast, hydrogen imports via ships are assumed to be more reliable. Unlike pipeline imports, which depend on real-time electricity generation and surpluses, ship-based hydrogen imports involve hydrogen produced and stored in advance, making them less sensitive to weather fluctuations in the Netherlands.

Hydrogen-fueled gas turbines

This section provides a brief overview of hydrogen-fueled gas turbine technology, with more technical and financial information available in Appendix C. Gas turbines generate electricity following the Brayton cycle, where air is compressed, mixed with a combustion fuel (typically methane in conventional turbines), and then combusted to produce high-temperature, high-pressure gas. This gas drives the turbine to generate electricity [73]. Hydrogen-fueled gas turbines operate similarly to conventional gas turbines and most existing gas turbines can operate with hydrogen levels up to 30% volume without requiring significant modifications [74]. However, when hydrogen ratios exceed this percentage, adjustments to their design or components become necessary. The process of modifying natural gas turbines to run on hydrogen is called ‘retrofitting’.

Gas turbines can generally be classified into two main categories: Open Cycle Gas Turbines (OCGTs) and Combined Cycle Gas Turbines (CCGTs). OCGTs release exhaust gases directly into the atmosphere, which leads to substantial energy losses due to the high heat content of these gases. Consequently, OCGTs have relatively low efficiencies compared to CCGTs [75]. This lower efficiency translates into higher fuel consumption and elevated marginal costs. Yet, due to the simplicity of OCGTs, both their initial investments and operational costs are comparatively low.

CCGTs enhance the basic OCGT system by incorporating an additional cycle that recovers heat from exhaust gases. This heat is converted into steam, which drives a steam turbine, thereby improving the overall efficiency of the system [75]. Typically, CCGTs achieve efficiencies about 20% higher than OCGTs, resulting in lower fuel costs [76]. In all utilised future scenarios, the government anticipates that by 2030 and 2035, only hydrogen CCGTs will be operational [64],[66]. Additionally, if both participate in the day-ahead market, the lower marginal costs of CCGTs enhance the turbine’s position in the merit order, increasing its expected operating hours compared to OCGTs. This further emphasises their dominance in the day-ahead market. Therefore, this study focuses exclusively on hydrogen CCGTs.

5.3. Performance metrics of the research

To assess the outcomes of the research, key performance indicators (KPIs), referring to the ‘M’ in the XLRM framework are compiled. KPIs are quantifiable metrics to evaluate the performance of the system under various conditions. For this study, the policy objectives for future electricity systems (availability, affordability, and acceptability) have been translated into three specific KPIs: LOLE, EENS, and average electricity price [11]. Regarding the business case and role of the hydrogen turbines, two KPIs are compiled: Annual profits and full load hours.

- **Loss-of-Load Expectation (LOLE) [hours/year]** represents the number of hours in which electricity demand cannot be met. This metric is commonly used to assess resource adequacy and supply security in the Netherlands [12]. LOLE serves as the first indicator for evaluating the overall reliability of the electricity system. TenneT applies a LOLE of four hours per year as its reliability standard.
- **Expected Energy Not Served (EENS) [GWh/year]** is the second indicator for assessing overall

system reliability. While LOLE measures the duration of electricity shortages, EENS quantifies the actual volume of unmet demand [12]. Together, these metrics provide a comprehensive assessment of supply shortages.

- **Average electricity price [EUR/MWh]** reflects the affordability and economic acceptability of electricity. The electricity price in the day-ahead market is determined based on hourly supply and demand dynamics within the model.
- **Annual profit of hydrogen turbines [MEUR/GW capacity]** quantifies the profitability of hydrogen turbines by calculating the difference between total cash inflows and outflows. This metric provides insight into their financial feasibility and allows for the comparison of economic viability across different scenarios.
- **Full load hours of hydrogen turbines [hours/year]** represent the equivalent number of hours it would need to operate at its maximum rated capacity to produce the total energy it generates over a specific period. This metric evaluates the utilisation rate of the generator by comparing its actual output to its potential full-capacity operation.

XLRM of the research

Using the conceptualisation developed in the previous subsections, the operational model is constructed based on the XLRM framework. Figure 5.2 provides an overview of the key variables considered within the scope of this research. The external factors, shown on the left side of the diagram, play an important role in the experimental design, allowing for an assessment of how these uncertainties impact the performance metrics, which are shown on the right side of the figure. The policy levers are the types of government interventions evaluated within this study which are further detailed in chapter 9. The relationships in the system consist of the objective function and (piecewise) linear constraints that form the mathematical basis for the structure of the model.

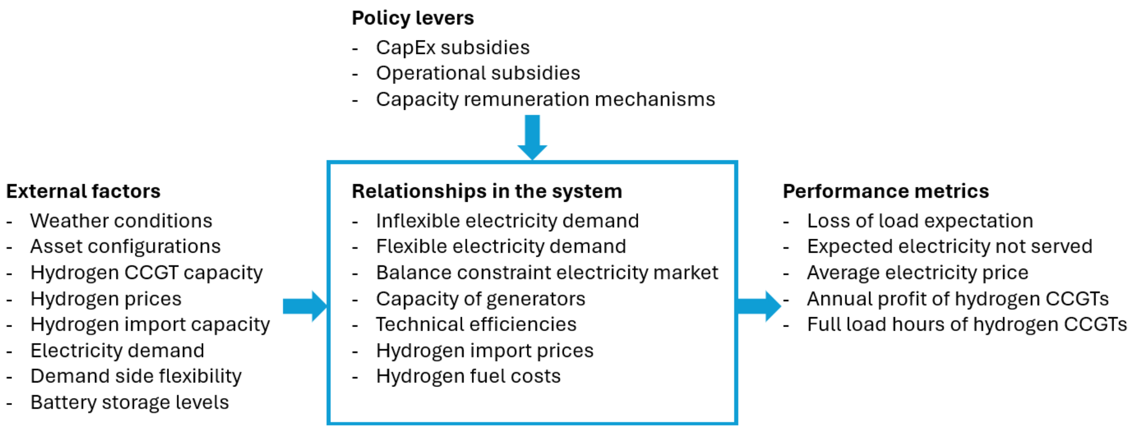


Figure 5.2: XLRM of the research

6

Implementation

This chapter elaborates on how the system is translated into a computational model, aligning with the implementation phase of the modelling cycle. It begins with an introduction of the key concepts of Linny-R, followed by a general explanation of how the system and relationships described in the previous chapter are implemented, along with the relevant modelling choices and settings. Next, the formulas used for the calculation of the annual profits of the hydrogen CCGTs are detailed. This is followed by an explanation of the model data and its incorporation. The chapter finishes with the verification and validation of the model.

6.1. Key concepts of Linny-R

Linny-R utilises various types of entities as building blocks within the model [47]. Each entity is uniquely identified by its name and can be referenced to in expressions and visual charts. Figure 6.1 provides an overview of the key concepts of Linny-R. The most relevant concepts for this research are elaborated below.

- A **product** refers to something that can be consumed or produced by a process. This can be both a tangible item, such as electricity or fuel in this model, or an intangible item. An intangible item, such as information or a price, is represented as a data product and is depicted with a dashed line. A stock, which serves as a storage product, is illustrated with a double line. Products can have defined or undefined upper- and lower limits. A product has a price, shown in the right corner of the products, and a weighted cost price (CP), which is displayed in the left corner of the products and processes.
- A **process** represents the transformation of one or more products into other products, for example, the generation of renewable electricity through solar PV. The processes can be constrained by upper- and lowerbounds as well.
- A **link** defines the relation between products and processes. Links can contain information about the efficiencies, delay of the relationship and the share of costs that can be attributed to the next product. In this research, this share is set at 100%, meaning that costs are completely passed on to the next products.
- **Datasets** are used to connect (external) information to the entities in the model. Typically, these datasets contain numerical data that can be interpreted as time series. For example, datasets can store hourly or yearly information about electricity demand.
- **Clusters** structure the model into subsystems, thereby improving the model's clarity without affecting the optimisation itself. Furthermore, clusters can be set to 'ignored', which enables the deactivation of the subsystem in a specific run if needed. Processes can only belong to one cluster, while products can appear in multiple clusters.
- **Block arrows**, which are shown in Figure 6.2, illustrate hidden flows. Similar to clusters, these block arrows are solely used to enhance the visual overview and do not impact the optimisation.

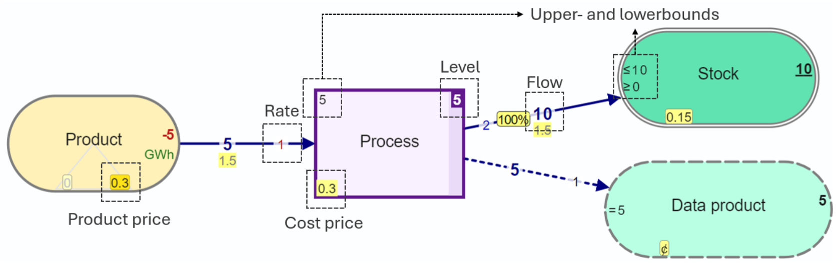


Figure 6.1: Linny-R: Key concepts

6.2. The model

Figure 6.2 provides an top-level overview of the model, showing the electricity and hydrogen market and the clusters involved in the markets. In the following sections, for each model component, the most important modelling choices and assumptions are elaborated. General assumptions that apply to the entire model and not just to a specific cluster are as follows:

- No distinction is made between the different locations of production and consumption and the distribution of electricity and hydrogen is not considered. It is assumed that there are no transmission losses or constraints. This ‘copper plate approach’ enables the analysis of the potential for hydrogen CCGTs within the high-voltage grid.
- The ‘highest cost price’ (HCP) of the processes supplying the electricity market per time step in Linny-R is used as a proxy for the market price. In a similar manner, the HCP of the hydrogen market is used as a proxy for the hydrogen market price.
- The solver minimises total system costs and searches for the optimal dispatch per time step, aligning with the clearing mechanism on the day-ahead market. It is important to note that this might not be the optimal dispatch for the individual assets.
- Both generator capacities and electricity demand are aggregated for the entire country and represented as a single process or product.
- Due to this aggregation, several technical characteristics of individual assets are omitted. No startup times and ramping constraints are included, indicating that output levels can be adjusted within one time step. Furthermore, assets operate at a single efficiency point which remains constant regardless of output levels. In practice, a power plant operating at 50% of its total capacity, for example, has a slightly lower efficiency than a power plant operating at full capacity.
- Production assets are assumed to bid on the market according to their marginal fuel costs, to ensure the dispatch to follow the merit order principle.
- Consequently, strategic bidding, deliberate withholding of capacity, and startup costs are not included in the model. This approach ensures that the solver can reach the optimal dispatch without selectively distorting the bids.
- Finally, the capital expenditures (CapEx) and operational expenditures (OpEx) of generators are excluded from the simulations. CapEx is disregarded as it is not directly related to marginal costs and thus does not influence the bidding mechanism of the day-ahead market. Variable OpEx, which depends on asset output, is excluded under the assumption that it does not affect the merit order, as marginal costs primarily consist of fuel costs.

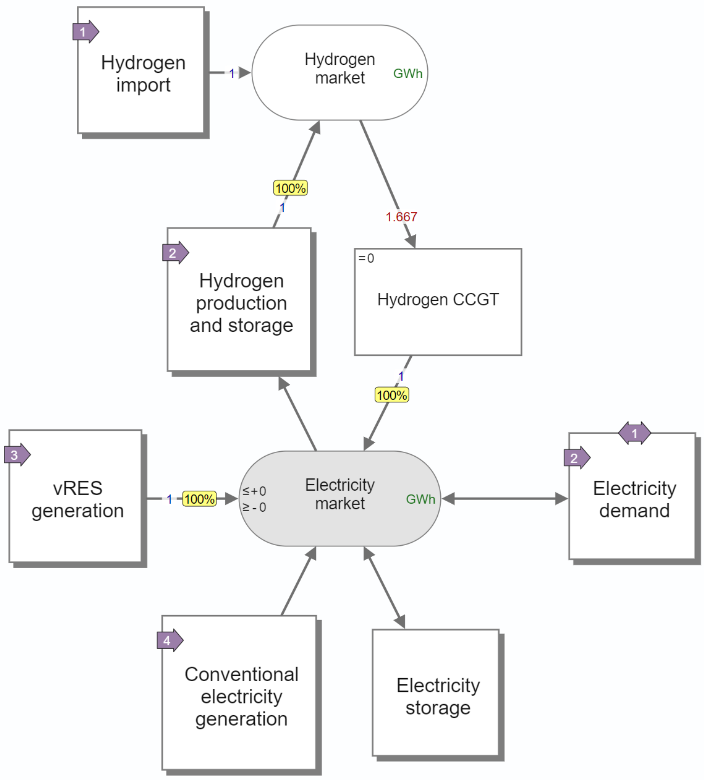
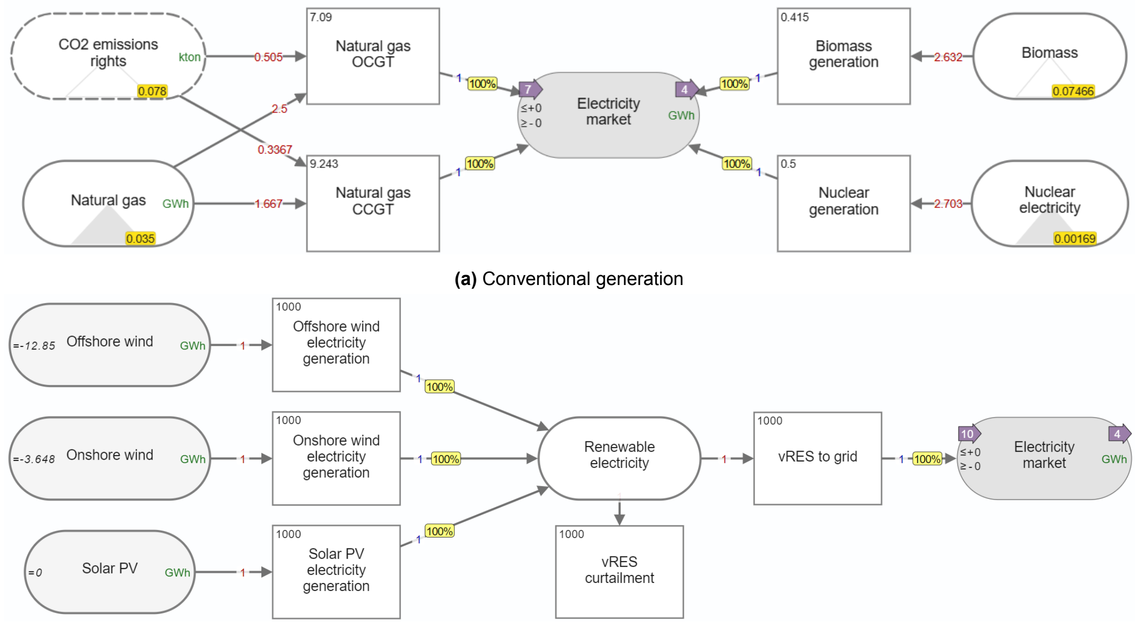


Figure 6.2: Linny-R: The top-level model

Electricity generation

Electricity generation, besides the production through hydrogen CCGTs, is divided into two clusters: Conventional electricity generation (Figure 6.3a) and vRES generation (Figure 6.3b). The following assumptions are made while modelling these clusters:

- CCO_2 emissions rights are separately included for the utilisation of natural gas, based on the emissions per GWh natural gas and the efficiency of the turbines.
- Natural gas CHPs and OCGTs are combined since heat production is not considered, resulting in their electrical output being aggregated.
- If there is a surplus of generated renewable electricity that cannot be integrated into the system, the excess electricity may be curtailed through the ‘vRES curtailment’ process.
- The generation of renewable electricity depends on the installed capacity and the historical weather year activated during the run.



(a) Conventional generation

(b) VRES generation

Figure 6.3: Linny-R: Electricity generation clusters

Electricity demand

Figure 6.4 illustrates the electricity demand cluster of the model. First, the general components of the demand cluster are elaborated, then the implementation of the DSR in the model is explained.

- In the model, all electricity demand is aggregated to a single product with an hourly electricity demand. Both annual demand and demand patterns for individual sectors are incorporated in this hourly electricity demand.
- If electricity supply fails to meet demand, the process 'Loss-of-Load' will be used as a last-resort unit. If no other options are left, it provides the market with 'virtual' electricity at the cost of the market price cap. This ensures that all other electricity sold on the market has the price of this cap through the HCP principle. Furthermore, it enables the solver to find a feasible solution within the model's constraints.
- Shedding of electricity demand is modelled with three processes, each with an increasing level of WtP. The WtP is the threshold price at which consumers are willing to scale down electricity demand, implemented through three distinct rates on the links between the data product to the processes. Additionally, each process has a maximum percentage of the total demand it can reduce per time step, the flexibility share, which is incorporated as the upper bound of the process. As explained in the previous chapter, this voluntary reduction of demand does not need to be compensated at a later time.
- The processes are directly connected to the electricity market, to ensure that their WtP can be reflected in the market and the demand side can thus be the price setter for the entire electricity market.
- In contrast, shifted electricity, which can both be forward and backward, must be compensated at a later moment. Shifting of demand is modelled as a process ('Shift demand') which flows to the electricity demand and into a storage product 'Shifted demand'. This storage product then remembers how much load is shifted and thus must be taken off the grid at a later moment to meet total demand, which is done through the process 'Compensate for shifted demand'.
- The upper limit of the 'Shifted demand' storage product reflects the maximum load that can be shifted in sequence, determined as a multiple of the flexibility available per time step. In other words, the sectors can delay the maximum flexibility up to this predefined upper limit.

- The consumers' willingness to accept (WtA) delays in electricity demand is modelled through a data product. The inconveniences associated with deferring load are incorporated as a penalty, which depends on the threshold price and the storage level. As the storage level increases, meaning more demand is shifted, the penalty rises, reflecting reality where the initial portion of deferred demand is more flexible and causes fewer inconveniences than the last portion. To ensure this penalty is actually paid in the model, a payment process has been added.
- A switch is implemented to prevent the solver from conducting the two shift processes at the same time.

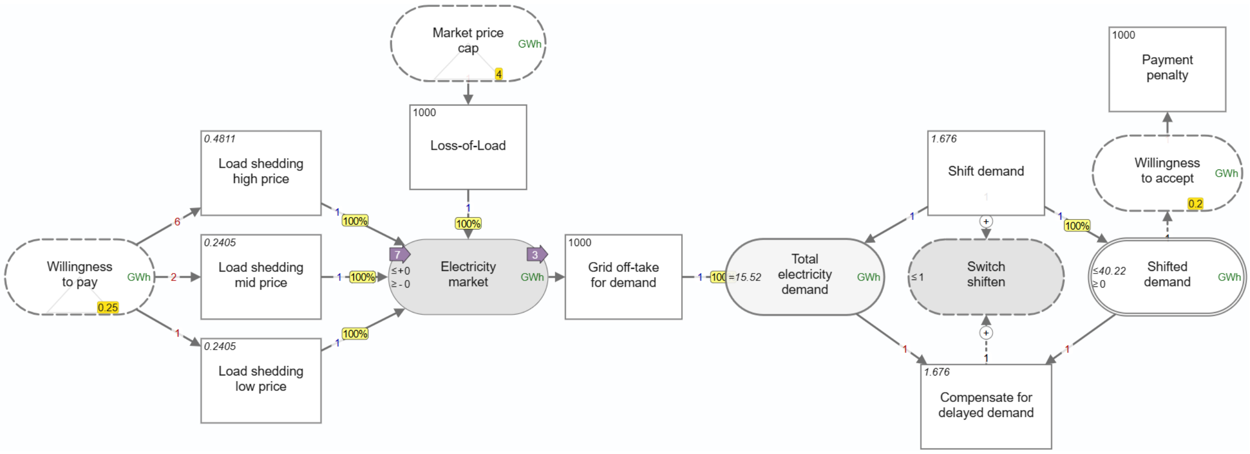


Figure 6.4: Linny-R: Electricity demand cluster

Electricity storage

Electricity storage (Figure 6.5) in this study consists only of large-scale batteries as explained in the previous chapter. In Linny-R, electricity storage is included in the following way:

- Large-scale batteries are modelled exclusively as lithium-ion batteries, as they are expected to offer the greatest potential for short-term grid balancing and have the most significant impact on system performance.
- Only the technical potential is incorporated in the model, without considering the economical ratio of capacity and volume.
- The self-discharge rate of the battery is modelled with the help of a special constraint. Due to this piecewise constraint, the self-discharge losses are higher when the battery is fully charged compared to when it is partially charged. The daily rate is converted to an hourly self-discharge rate.
- A switch is implemented to prevent charging and discharging from both occurring within the same time step. This ensures that the solver does not eliminate the surplus of electricity through electrical losses instead of through curtailment.

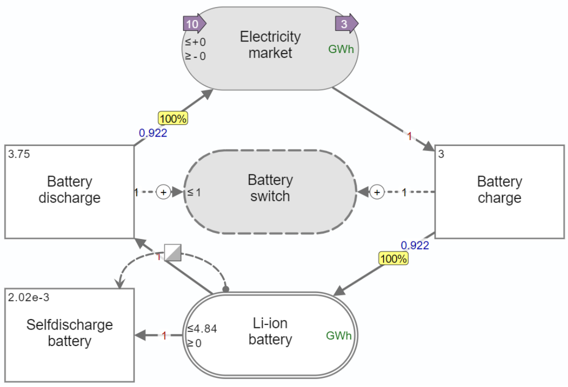


Figure 6.5: Linny-R: Electricity storage

Hydrogen production and storage

To represent electrolysis and hydrogen storage, the following modelling choices are made:

- Hydrogen is produced through electrolysis. The production costs of hydrogen depend on a fixed component, which accounts for 60% of the default price and the endogenous costs of electricity of that time step. This calculation is further detailed in chapter 7.2.
- Electrolyser capacity is expressed in GWe. As a result, the efficiency of the electrolyser is applied to the outflow link of the electrolysis process rather than the input link.
- Only the electricity required for hydrogen compression is accounted for in the model. No additional costs related to underground hydrogen storage are incorporated.
- Additionally, potential hydrogen leakage after storage and specific technical characteristics of hydrogen storage, such as injection and withdrawal rates, are not included.
- To ensure that the initial level of hydrogen in the UHS, which is stored at the beginning of the run, is assigned a marginal cost price, the process 'Initial fill storage' and data product 'Initial hydrogen' have been incorporated. This prevents the initial stored hydrogen from being treated as free in the model, which would influence the merit order. This principle is further elaborated in chapter 6.3.

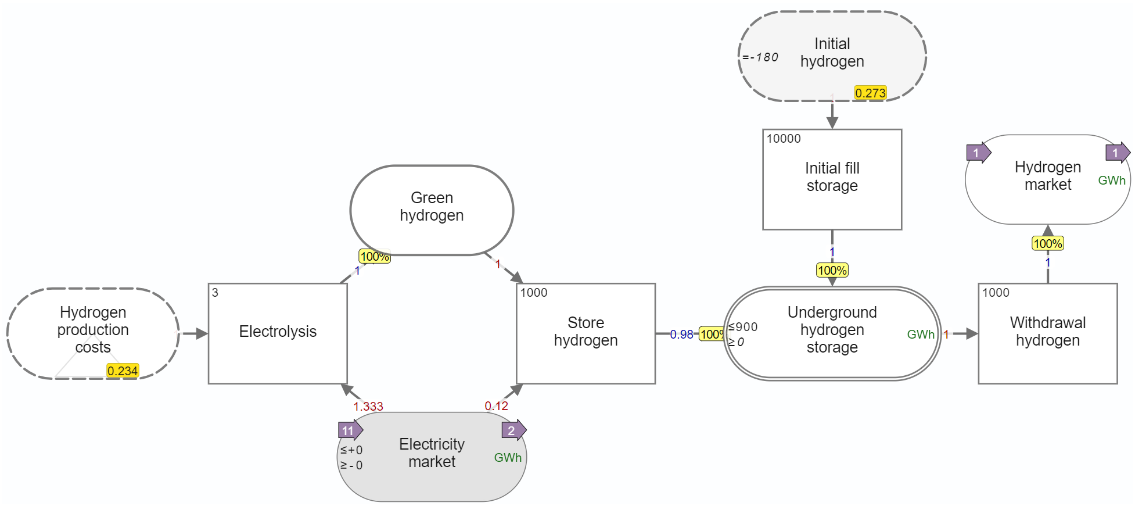


Figure 6.6: Linny-R: Hydrogen production and storage

Hydrogen import

Hydrogen import has been modelled under the assumption that prices elevate with an increased hydrogen demand. This is modelled as follows:

- The price of imported hydrogen in the model is determined by a combination of a base price and additional import costs. The base price is set by the costs of 'hydrogen from the international market'. As import levels increase, hydrogen costs rise accordingly, modelled through a specific constraint.
- The piecewise linear constraint on the process 'Additional import costs' approximates a cubic function. This means that as the volume of imported hydrogen grows, the additional costs rise at an accelerating rate.
- Consequently, the final import price exhibits a quadratic growth pattern. At lower import levels, additional costs remain minimal, leading to only a slight increase in total import price. However, as import volumes expand, additional costs increase disproportionately, significantly impacting the final price.
- For example, at an import level of 10%, with a base price of €0.39/GWh, the additional cost is only €0.00039/GWh, resulting in a final price of €0.39039/GWh. At 50%, the additional cost increases to €0.04875/GWh, leading to an import price of €0.43875/GWh. At 100% import capacity, the additional cost reaches €0.39/GWh, doubling the initial base price to €0.78/GWh.
- This constraint reflects the economic principle that higher demand drives market prices up.

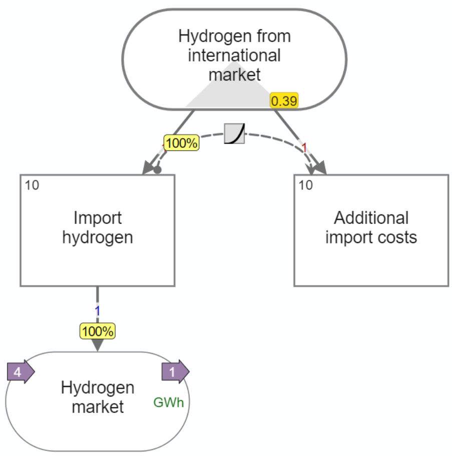


Figure 6.7: Linny-R: Hydrogen import

6.3. Model settings

The simulation operates on an hourly basis for one year, starting on January 1st and ending on December 31st, resulting in an optimisation period of 8760 hours. In Linny-R, the block length defines the number of time steps the solver optimises over during a single iteration, effectively corresponding to the number of hours considered in the optimisation process. A longer block length provides the model with more information for its optimisation. In this study, a block length of 8760, equivalent to one year, is used along with a look-ahead of 0. This configuration means that the solver minimises system costs for the entire year, so-called perfect foresight, without incorporating additional information about the subsequent year. An overview of the base model settings is provided in Table 6.1.

A key consideration for this setting choice is that the model incorporates various types of data with varying foresight time horizons in practice. Certain factors, such as electricity demand in the built environment, can be projected with high accuracy for the upcoming year as electricity demand follows patterns and predictable quantities. While weather data cannot be forecasted with precision on a daily or weekly basis, seasonal trends are consistent and gas reserves are managed accordingly. For example, solar PV generation is in general higher during spring and summer months than during winter and autumn months. If the information is not given to the model, it operates as if it has no knowledge about the upcoming time steps, failing to account for known patterns that shape system behaviour throughout the year. With the help of UHS constraints, which are detailed below, it is prevented that the model empties the storage at the end of the year, thereby automatically considering the next year.

Table 6.1: Overview base model settings

Settings	Value
Time step	1h
Optimisation period	1-8760
Block length	8760
Look-ahead	0
Unit currency	MEUR
Unit electricity and hydrogen	GWh
Default weather year	2019
Default asset configuration	2030

When using the external solver Gurobi, the base model settings result in a run time of 22 seconds, making it highly suitable for the exploratory modelling approach [77].

Underground hydrogen storage constraints

Toward the end of a single run, Linny-R automatically tends to empty all storage. Since the objective function focuses on cost minimisation, this helps reduce any expenses associated with electricity generation. In practice, natural gas reserves are typically required to maintain a minimum fill level and are not permitted to be entirely depleted [78]. It is assumed that the same principle applies to hydrogen storage. To ensure robustness against extreme weather events, such as Dunkelflautes, or other disruptions, the model's hydrogen reserves must be maintained at a minimum level, similar to natural gas reserves. However, during such events, storage levels may need to drop significantly, even approaching zero, to meet electricity demand. To capture this behaviour, the model includes a constraint requiring storage to be refilled to at least 20% of its capacity every three weeks and at the end of the simulation run. This three-week interval is a realistic assumption for hydrogen reserves, as Dunkelflautes rarely persist longer than three weeks [79]. Between these intervals, the model allows storage levels to deplete as needed.

The initial storage level is also set at 20%. Nevertheless, to ensure that the initially stored hydrogen has a marginal cost price in the model, the hydrogen is added to the storage during the first time step using a process and data product. The price of this initial hydrogen is set at 70% of the price during that run. This percentage is determined by running the model and calculating the average cost price of domestically produced green hydrogen during the last three weeks of the year.

6.4. Annual profits of hydrogen CCGTs

In this study, as elaborated in chapter 3, the business case is expressed as annual profits. To ensure clear comparisons between the scenarios, annual profit is expressed in MEUR per GW of installed hydrogen CCGT capacity. A financial model is built in Excel, enabling the simultaneous calculation of annual profits across multiple scenarios using a data table. Relevant data from Linny-R is integrated into the model to determine the annual profits for each simulation run. The formula for the annual profit is presented first, followed by a detailed explanation of its components. A comprehensive overview of the financial input parameters can be found in Appendix C in Table C.1.

$$\text{Annual profit per GW} = \frac{\text{Total gross profit}}{\text{Installed capacity}} \tag{6.1}$$

The total gross profit of hydrogen CCGTs can be calculated with the following formula:

$$\text{Total gross profit} = \text{Revenues} - \text{Marginal costs} - \text{Annual OpEx} - \text{Annualised CapEx} \tag{6.2}$$

Revenues of the day-ahead market

In an energy-only market, compensation is only provided for the delivery of electricity. In this research, the operational revenues of hydrogen turbines are influenced by their operational hours, production levels, and the market prices during the corresponding hours in the day-ahead market. The electricity market prices and production levels per time step are derived from the Linny-R simulations. The income stream for the hydrogen turbines in a certain period can be calculated with the following formula:

$$\text{Revenues} = \sum_{t=1}^{T} \text{Electricity market price}_\text{t} \times \text{Production level CCGT}_\text{t} \tag{6.3}$$

Marginal costs day-ahead market

The marginal costs consist of the fuel expenditures of the turbine. Since the hydrogen market price and production level fluctuate over time, the costs are determined for each time step using the Linny-R simulation. With the following formula, the total fuel costs can be calculated:

$$\text{Marginal fuel costs} = \sum_{t=1}^{T} \text{Hydrogen market price}_\text{t} \times \frac{\text{Production level CCGT}_\text{t}}{\text{Efficiency H}_2\text{ CCGT}} \tag{6.4}$$

Annual OpEx

The annual OpEx are determined by the level of installed capacity and the fixed operations and maintenance costs (FOM) [80]. This can be calculated with the following formula:

$$\text{Annual fixed OpEx} = \text{FOM} \times \text{Installed capacity} \tag{6.5}$$

Annualised CapEx

Since profits are evaluated on an annual basis, the capital expenditure (CapEx) must be adjusted accordingly. Annualised CapEx incorporates several factors to ensure an accurate representation of the initial investment costs. First, investors expect a return on their investment, and any borrowed capital must be repaid with interest [81]. This requires factoring in the Weighted Average Cost of Capital (WACC), which reflects the combined cost of debt and equity. Second, the economic lifespan determines the period over which costs are distributed. While the technical lifetime of the CCGTs is estimated to be 25 to 30 years, the economic lifetime is typically shorter [41],[80]. The economic lifetime reflects the period during which investors aim to recover their investments [82]. Lastly, depreciation plays a significant role in calculating annualised CapEx, as it is considered an expense that is deducted from revenues when determining profits. This reduces taxable income and, in turn, the overall tax burden [83].

The formula for calculating annualised CapEx (Equation 6.6) consists of two primary components. The first component calculates the annualised payment by distributing the total CapEx evenly over the economic lifespan (n), while accounting for the annual WACC, which is set at 8% [81]. This interest rate is relatively high due to the immaturity of the technology and uncertainties regarding market development. The total CapEx depends on the installed capacity of hydrogen CCGTs [80].

The second component addresses the tax savings associated with asset depreciation. Depreciation is assumed to follow a linear method over the economic lifespan of the asset. The annual depreciation is multiplied by the corporate tax rate (CTR), set at 25.8%, to calculate the resulting tax savings [84]. These savings effectively reduce the annualised costs payment, reflecting the financial advantage of depreciation [83].

$$\text{Annualised CapEx} = \frac{-\text{WACC} \cdot \text{CapEx}}{1-(1+\text{WACC})^{-n}} - \frac{-\text{CTR} \cdot \frac{\text{CapEx}}{n}}{1-\text{CTR}} \tag{6.6}$$

Where:

- CapEx: Total Capital Expenditures
- WACC: Weighted Average Cost of Capital
- n = Economic lifetime of turbine
- CTR = Corporate Tax Rate

By combining these two components, the formula provides a comprehensive calculation of annualised CapEx. This approach ensures that the annual amount required to cover both the return on equity and the interest on debt by the end of the asset's lifespan is accurately determined. By accounting for both the return on investment and the tax benefits of depreciation, the formula is well-suited for determining annual profits.

6.5. Model data

The model integrates three types of data: static parameters, scenario parameters, and dynamic data. Static parameters remain constant throughout all runs and are independent of the selected simulation year. Scenario parameters are designated to the future years 2030, 2035, 2040, and 2050. While they may vary between years, they remain unchanged within a single simulation. Dynamic data fluctuates on an hourly basis, with unique values for each time step. Each data type is discussed in more detail below.

Static model data

Static data remains constant throughout the runs and includes technical parameters such as efficiencies and emission factors. An overview of all technical parameters used in the model is provided in Table D.1 in Appendix D. These parameters are assigned to the respective entities in Linny-R using datasets.

In addition to technical parameters, DSR parameters are also incorporated as static data in the model. These include threshold prices, representing the WtP for load shedding and the WtA for load shifting, as well as the corresponding percentages of the total load. These values are aggregated across all demand sectors and are based on hourly electricity demand. The following assumptions are made for the default values, with an overview of the values presented in Table D.3 in Appendix D.

- The potential (industrial) DSR is estimated at 17% in the Netherlands [68]. This potential includes both shifting and shedding of electricity demand.
- The load flexibility percentages from total demand for load shedding are based on the estimates of Sanchez et al. [29]. In the base settings, a total of 6.2% can be shifted, with three varying prices.
- Consequently, the share of the total load that can be shifted is assumed to be 10.8%.
- The WtA threshold price to shift electricity demand to a later moment is based on the energy transition model (ETM) and is assumed to be applicable for all sectors [80].
- The deficit limit of the load that can be shifted is set at 24 hours [80]. This is incorporated in the model as the upper limit of the shifted demand storage product.
- DSR rates are defined as a fixed percentage of the hourly demand, remaining constant regardless of demand patterns. This means that DSR rates do not exhibit seasonal variations, based on research of TenneT [69].

Base scenario parameters

While the technical and DSR parameters remain constant across all years, the model also incorporates asset year-specific data. Each year features a set of parameters tailored to its specific scenario. In Linny-R, the input values for the four years are added as modifiers of the scenario variable, with the year 2030 designated as the default modifier.

The year-specific data is primarily derived from development scenarios constructed by Netbeheer Nederland. For 2030 and 2035, the 'Klimaatambitie (KA)' scenario from the IP2024 report is used [66]. KA is one of three scenarios in IP2024, integrating both existing and planned energy and climate policies, along with the ambitions outlined in the Dutch government's Coalition Agreement. Using this scenario as the baseline for 2030 and 2035 aligns with the research objectives. Since the KA scenario does not provide projections for 2040 and 2050, an alternative scenario is required. To maintain consistency, the 'Nationaal Leiderschap (NAT)' scenario from the II3050 scenario study, also developed by Netbeheer Nederland, is adopted [64]. In the NAT scenarios, the Netherlands consists of an energy-efficient system primarily powered by domestic resources and production, aligning with the current political focus on self-reliance and energy independence from foreign markets [65].

While these scenarios are tied to specific years, their exact timeline for realisation remains uncertain. However, they provide valuable insights into potential asset configurations and their impact on the electricity system. The projected fuel prices from the KA and NAT scenarios are based on the Ten Year Network Development Plans (TYNDP) [85]. Therefore, this reference serves as the primary input for fuel data, supplemented by additional data from the integration of the KA and NAT scenarios in the ETM [80]. In the Netherlands, additional levies are imposed on top of the European carbon prices to ensure a minimal carbon price. However, the latest coalition program outlined plans to reverse these increased Dutch levies to create a more level playing field [65]. Therefore, this study uses the TYNPD forecasts for European carbon prices, which are lower than Dutch projections. The base scenario values are presented in Table D.2 in Appendix D.

Electricity demand patterns

The final type of data consists of dynamic data, which varies at each time step. These datasets contain hourly-specific values that fluctuate over time. The dynamic data employed in this study includes demand patterns and weather years.

To determine the hourly electricity demand, predefined demand patterns are used. Electricity demand is divided into four distinct sectors, each with its own total demand and demand pattern [64]. The total demand is detailed in Table D.2 in Appendix D. The demand patterns follow specific assumptions, as outlined below:

- Electricity demand from the industrial sector is assumed to remain constant over the year, with no significant differences between day and night and seasons. The same assumption applies to the agriculture and ICT sectors.
- Electricity demand in the built environment sector consists mainly of heating and cooling of buildings, appliances, and cooking [64]. Charging of electric vehicles, whether at homes or at offices, for example, is considered part of the transport sector. The demand pattern for the built environment sector, derived from the ETM, is illustrated in Figure D.1 in Appendix D [80]. In general, nighttime electricity demand is lower than daytime levels. Two demand peaks are notable: one in the morning when people wake up and another in the early evening as individuals return home from work and begin cooking. Additionally, there is a seasonal variation in electricity demand, with an increased demand during winter periods.
- The demand pattern for the transport sector is based on the insights from the ETM, with adjustments made to reflect the aggregated demand for the entire sector [80]. A consistent base demand is assumed throughout both day and night, driven by activities such as vehicle charging, the continuous operation of public transport, and shipping. In addition to this base demand, the dataset incorporates two distinct peak periods. The first is a short morning peak (6:00-9:00) when demand surges as people commute to work and peak moments exist in public transport. The second, longer peak occurs in the evening (16:00-22:00) as individuals return home, partly relying on public transport, and connect their electric vehicles to the grid. Weekends are categorised as completely off-peak with no significant demand fluctuations. No seasonal variations are accounted for in this sector [86].

Weather years

The second type of dynamic data employed in the model is weather conditions. Weather plays an important role in energy systems with high levels of vRES integration. As it is impossible to predict exact weather data for 2030 and beyond, historical data from Renewables.ninja is used [87]. This database provides hourly capacity factors for solar PV, onshore and offshore wind in the Netherlands, from 1980 to 2019. Three representative weather years are utilised to capture the variability of weather conditions: a normal weather year, a favourable weather year characterised by a relatively low number of electricity shortages, and a year marked by a Dunkelflaute. The literature utilises various years for representing favourable conditions or Dunkelflaute events [34],[35],[40]. Seven of these years have been tested to determine which best encompasses the range of possible weather conditions. Simulations using these weather years have been conducted for the four future asset years with base settings, excluding hydrogen CCGTs. The LOLE hours and EENS for selected weather years are shown in Table 6.2, where the color scale illustrates their position rather than their relative scores. Appendix D presents an overview of the results of all seven tested weather years. In the tables, the weather years are abbreviated as 'WY'.

Table 6.2: Results for selected weather years

(a) LOLE (hours/year)

WY	2030	2035	2040	2050
1987	348	1134	1640	2411
2018	166	615	1132	1896
2019	189	714	1107	1992

(b) EENS (GWh/year)

WY	2030	2035	2040	2050
1987	1940	9110	19800	42700
2018	854	4300	10700	28100
2019	834	4870	11200	29200

The year 2019 is selected as the standard weather year because it is the most recent available year, shows moderate results, and does not exhibit extended periods without wind or sunlight. In contrast, 1987 is selected to represent a Dunkelflaute, a year marked by limited renewable generation and a prolonged period of low wind at the beginning of the year. 2018 is used as a good year, in which the electricity shortages are lowest. The three weather years are incorporated in the model as datasets.

6.6. Verification of the model

This section evaluates whether the conceptual system has been implemented accurately in Linny-R. The model's correctness is assessed through verification, to ensure it is built properly and exhibits logical, accurate behaviour. During the construction of the Linny-R model, small test runs were continuously conducted to ensure the model functioned correctly and no errors were introduced. These test runs are replicated while varying the input variables to verify whether the core functionalities of the model demonstrate the expected behaviour. The verification of the model is divided into two steps. First, several functionalities of the model are individually verified within the model. Secondly, a sensitivity analysis is employed to further test the integrity of the model. This analysis evaluates the impact of changes in all input variables on the KPIs. By observing whether these changes produce the expected responses, any deviations can be identified and their causes can be investigated to explain their behaviour. This comprehensive approach ensures the reliability and robustness of the model.

Electricity generation

The electricity generation in the model is analysed using the residual load curve. The residual load represents the net electricity demand that must be met by non-vRES for each hour and is calculated using the following formula:

$$\text{Hourly residual load}_t = \text{Total electricity demand}_t - \text{Total vRES production}_t \tag{6.7}$$

To construct the residual load duration curve, hourly residual load values are sorted from highest to lowest shown in Figure 6.8. In the figure, the x-axis represents the hours of the year, and the y-axis displays the sorted residual load values. The residual load curve provides a clear overview of the demand of non-vRES over the year, focusing on the magnitude of the demand rather than its timing. Additionally, curtailment is sorted in the figure in ascending order to highlight its relationship with the residual load.

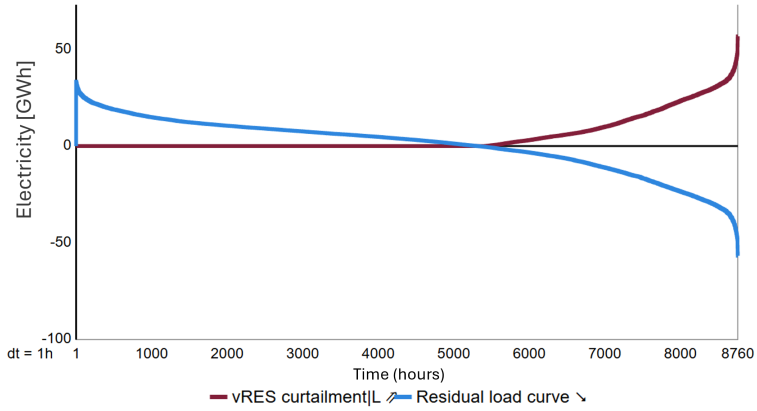


Figure 6.8: Verification: Residual load curve 2030, weather year 2019

The peak residual load, represented by the highest point on the curve, shows the maximum demand that dispatchable sources must meet. The base load is depicted in the flatter, lower section of the curve, indicating periods where conventional generation, primarily nuclear and natural gas CCGT, is consistently required. The negative residual load, where the curve dips below zero, represents periods of a renewable energy surplus. This surplus of renewable electricity must be curtailed whenever it cannot be fed into the system, which is confirmed by the red line. Between approximately 5200 and 5500 hours in the figure, there is neither curtailment nor production from non-vRES, which indicates that the electricity demand is met by stored electricity. Table 6.2 presents the differences in electricity shortages when incorporating different weather years. These results, combined with the verification through the residual curve, confirm that electricity generation is modelled correctly.

Dunkelflaute

Figure 6.9 highlights a Dunkelflaute at the beginning of the year when incorporating weather year 1987. For clarity, offshore and onshore wind generation is aggregated. During this period, around hour 800 at the beginning of February, both solar and wind generation remain limited for consecutive hours, which leads to severe electricity shortages, as shown by the stacked area.

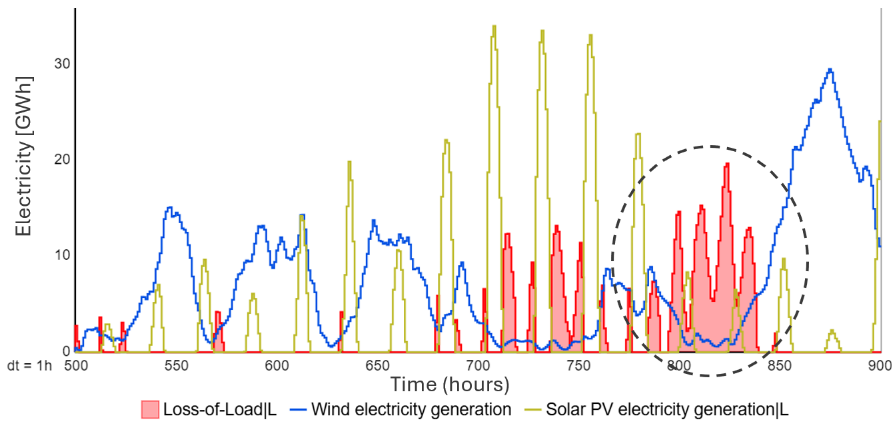


Figure 6.9: Verification: Zoomed in Dunkelflaute 1987

Verification of storage behaviour

LOLE hours should only occur as a last resort unit: when all storage is fully depleted, and both vRES and conventional power sources are operating at maximum capacity. Whenever hydrogen is available, hydrogen turbines must be utilised to prevent LOLE hours. Through electrolysis, the excess electricity can be converted into hydrogen, which lowers the curtailment. Additionally, batteries should store electricity whenever there is available capacity, ensuring that curtailment is limited during these moments. They must be capable of charging and discharging frequently, with no curtailment occurring while the battery still has unused capacity. Lastly, curtailment should never take place during LOLE hours, as these represent periods of insufficient electricity supply. Figure 6.10 and 6.11 illustrate the model behaviour of the battery and UHS in the first two weeks of 2035 with weather year 2019.

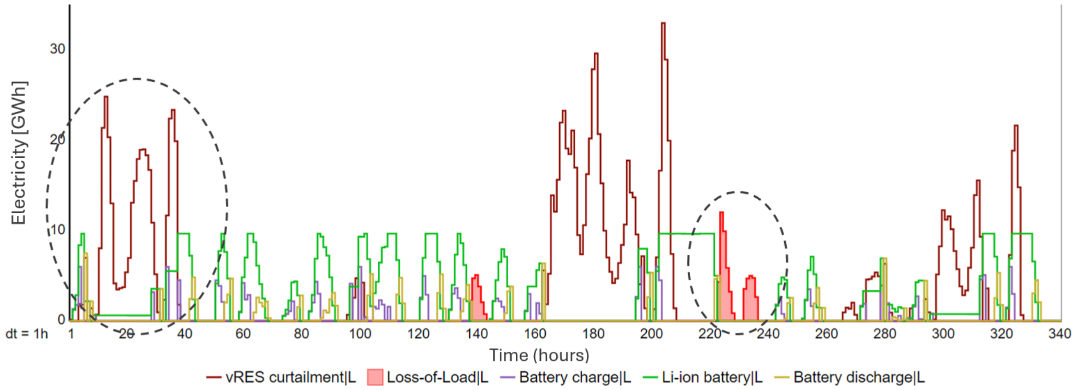


Figure 6.10: Verification: Battery behaviour

Figure 6.10 illustrates that batteries undergo numerous charge and discharge cycles to address short-term fluctuations between electricity demand and supply, which aligns with reality. Curtailment only occurs when the battery is either already fully charged or will reach full capacity shortly after, which the solver already accounts for. This behaviour is shown between approximately 15 and 40 hours in the figure. During LOLE hours, stored electricity from the battery is utilised to mitigate shortages. If the battery contains stored electricity, it will be discharged to help reduce the deficit. Besides, the battery should not be able to be charged during shortages, as there is no surplus of electricity to do so. This is illustrated between 220 and 240 hours in the figure.

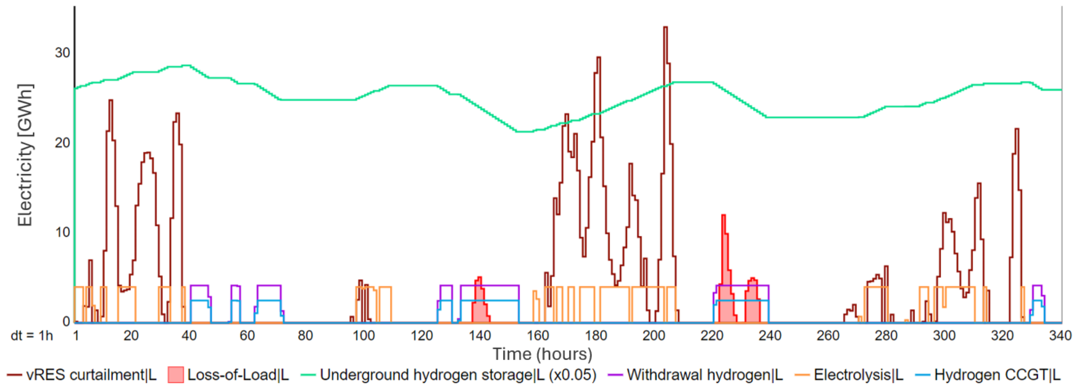


Figure 6.11: Verification: UHS behaviour

Figure 6.11 provides insights into the system's behaviour regarding hydrogen production and storage, with the level of UHS scaled by 0.05 for better comparison with other variables. The model produces hydrogen whenever there is excess electricity and curtailment only occurs when the maximum capacity of electrolysis has already been reached. When hydrogen is produced through electrolysis, it is directly stored in the UHS, leading to an increase in storage levels. Notably, hydrogen CCGTs and electrolysis are never utilised simultaneously, as this would result in unnecessary electricity losses. During LOLE hours, the hydrogen CCGT operates at its full capacity, which for this particular run, was set at 2.5 GW.

Sensitivity analysis

The second method employed to verify the model is through sensitivity analyses. This approach allows for a systematic evaluation of how changes in the input variables affect the KPIs, presenting the results clearly and concisely in a single table. By conducting this analysis, input variables that significantly influence the model's output can be identified and examined. The analysis follows the one-variable-at-a-time method, where each input variable is individually adjusted by a predetermined percentage, set at +20%, as this is the default value in Linny-R, while all other variables are held constant at their default values. This is done to assess the impact of each variable on KPIs compared to the base case. The profits for hydrogen turbines are expressed in operational profits instead of annual profits since the analysis is conducted in Linny-R. The CapEx and OpEx of the hydrogen CCGTs are thus not considered in this analysis.

To gain a complete overview, the sensitivity analysis is conducted for simulation years 2035 and 2050, using the default values from both the KA and NAT scenarios and weather year 2019. Simulation year 2035 is selected because it comprises all conventional generators as well as hydrogen CCGTs, with the results presented in Table 6.3. The results from the sensitivity analysis conducted for simulation year 2050, which does not include natural gas and biomass turbines, are shown in 6.4. Variables with high or notable values are discussed below the tables. Furthermore, these variables are used as input for the experiment design, detailed in chapter 7.

Table 6.3: Sensitivity analysis 2035 KA scenario, weather year 2019

	KPI	**LOLE**	**EENS**	**Average electricity price**	**Operational profits H_2 CCGT**	**Full load hours H_2 CCGT**
Variable	*Unit*	*Hours*	*GWh*	*MEUR/GWh*	*MEUR/GW*	*Hours*
Base scenario		343	2118	0.2934	1780	1266
Installed capacity offshore wind	20%	-15%	-15%	-15%	-16%	-15%
Installed capacity onshore wind	20%	-4%	-5%	-4%	-4%	-4%
Installed capacity solar PV	20%	-4%	-4%	-4%	-4%	-2%
Installed capacity biomass turbines	20%	-1%	-2%	-1%	-1%	-1%
Installed capacity nuclear plants	20%	-1%	-3%	-1%	-2%	-1%
Installed capacity natural gas CCGT	20%	-27%	-27%	-19%	-24%	-16%
Installed capacity natural gas OCGT	20%	-27%	-28%	-19%	-24%	-16%
Installed input capacity batteries	20%	0%	0%	0%	0%	0%
Installed storage volume batteries	20%	-4%	-4%	-3%	-4%	-2%
Hourly electricity demand	20%	162%	248%	106%	129%	79%
Flexibility rate shifting of load	20%	-6%	-4%	-2%	-3%	0%
Flexibility rate shedding low price	20%	-1%	-2%	-1%	-1%	0%
Flexibility rate shedding mid price	20%	-1%	-2%	-1%	-1%	0%
Flexibility rate shedding high price	20%	-3%	-5%	-1%	-2%	0%
Installed capacity electrolysis	20%	0%	0%	0%	0%	1%
Hydrogen storage volume	20%	0%	0%	0%	0%	1%
Hydrogen import capacity	20%	0%	0%	0%	0%	0%
Installed capacity hydrogen CCGT	20%	-16%	-17%	-9%	-16%	-7%

Table 6.4: Sensitivity analysis 2050 NAT scenario, weather year 2019

	KPI	**LOLE**	**EENS**	**Average electricity price**	**Operational profits H_2 CCGT**	**Full load hours H_2 CCGT**
Variable	*Unit*	*Hours*	*GWh*	*MEUR/GWh*	*MEUR/GW*	*Hours*
Base scenario		400	3955	0.3377	2129	2200
Installed capacity offshore wind	20%	-14%	-15%	-19%	-15%	-15%
Installed capacity onshore wind	20%	-3%	-4%	-5%	-4%	-3%
Installed capacity solar PV	20%	-4%	-5%	-4%	-3%	-3%
Installed capacity nuclear plants	20%	-6%	-9%	-6%	-6%	-4%
Installed input capacity batteries	20%	0%	0%	0%	0%	0%
Installed storage volume batteries	20%	-8%	-8%	-7%	-8%	-3%
Hourly electricity demand	20%	165%	137%	238%	131%	38%
Flexibility rate shifting of load	20%	-2%	-3%	-1%	-1%	0%
Flexibility rate shedding low price	20%	-1%	-2%	-1%	-1%	0%
Flexibility rate shedding mid price	20%	-1%	-2%	-1%	-1%	0%
Flexibility rate shedding high price	20%	-3%	-4%	-1%	-2%	0%
Installed capacity electrolysis	20%	0%	0%	-2%	0%	1%
Hydrogen storage volume	20%	0%	0%	0%	0%	0%
Hydrogen import capacity	20%	0%	0%	0%	1%	0%
Installed capacity hydrogen CCGT	20%	-32%	-40%	-21%	-37%	-10%

A 20% increase in electricity demand leads to an enormous rise in electricity supply issues in both analyses, greatly exacerbating the existing problems compared to the base scenario. When electricity demand rises, the issues become substantially worse, which could be expected. Understandably, the increase in shortages also leads to a higher average electricity price in both years, as shortages have extremely high scarcity prices. Both the operational profits and full load hours of hydrogen CCGTs increase significantly as their role in meeting electricity demand and scarcity rents grow.

Conversely, as expected, for all three forms of vRES, an increase in installed capacity mitigates supply issues and lowers electricity prices. Furthermore, it also decreases the full load hours of hydrogen CCGTs and simultaneously reduces their profits. Offshore wind capacity has a notably greater impact compared to other renewable sources for two reasons. First, offshore wind already has a higher baseline capacity than onshore wind, meaning a 20% increase results in a larger absolute change. This effect, however, does not apply when comparing to solar PV. The primary reason for offshore wind's greater influence lies in its higher capacity factor, which causes the additional capacity to generate significantly more electricity. It is important to note that for all RES, an increase of 20% in installed capacity results in a less than proportional impact on the KPIs.

Furthermore, for 2035, the increase in natural gas CCGT and OCGT capacity results in a substantially larger reduction in supply issues compared to other conventional generators. While all generators contribute to some extent to alleviating these problems, the impact of natural gas capacity is most pronounced. This is again due to their much higher baseline capacity compared to other assets, resulting in a larger absolute increase in capacity and, consequently, a greater overall impact on the system. The increase of natural gas CCGT and OCGT has a strong negative influence on the operational hours and profits of hydrogen CCGTs.

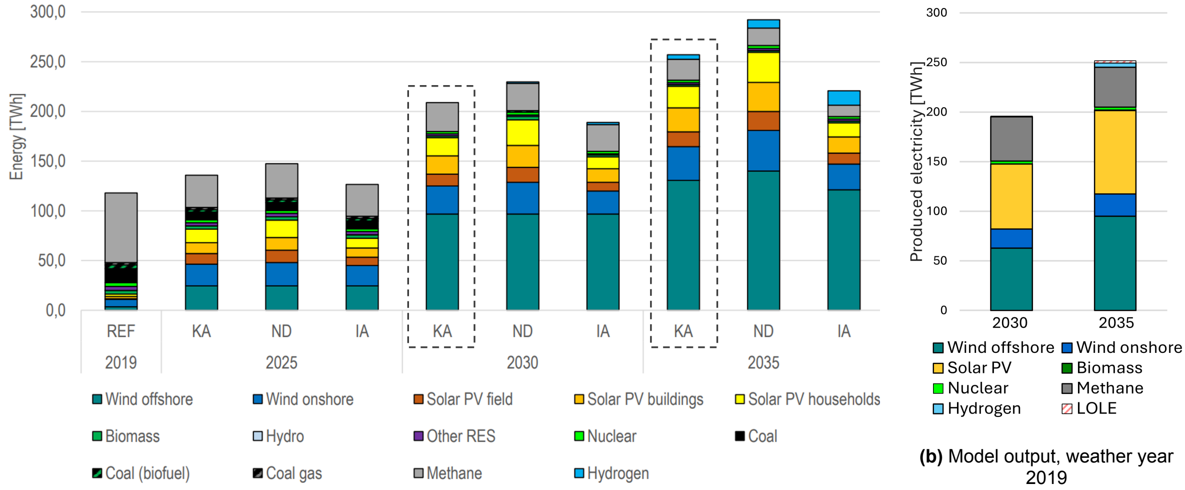
It is important to note that the analyses show almost no sensitivities to increases in battery capacity and individual DSR processes. This is because these forms of flexibility consist of multiple interconnected processes in the model, which renders this method ineffective for analysing their impact. Similarly, under these scenario parameters, a 20% increase in electrolyser, UHS, or hydrogen import capacity has no influence on the KPIs as the capacity of hydrogen CCGT is the limiting factor for electricity generation through hydrogen CCGTs in this sensitivity analysis. Nonetheless, these processes are incorporated and evaluated during the experiment design to gain insights into their potential and influence on the electricity system and hydrogen CCGTs.

6.7. Verification of incorporation of model data

To verify that the scenario data is correctly incorporated into the model, the output of the model is compared to the output of the Netbeheer Nederland scenarios. For the base scenarios of 2030 and 2035, verification is performed using the IP2024 report, since the input parameters are based on the KA scenario within this report [66]. For simulation years 2040 and 2050, the NAT scenarios from the II3050 report are utilised [64]. Besides, this step evaluates whether the model is capable of generating similar outcomes as the model used in the government scenarios.

Figure 6.12 illustrates the electricity supply mix for three scenarios during the simulation years 2030 and 2035. The KA scenarios, encircled with a dashed line, are replicated for this comparison, with the results organised as uniformly as possible for comparison. Since electricity demand is not completely met in the model when incorporating this data, the share of LOLE hours is also added to the graph.

In both years, the total electricity produced in the model is slightly lower than in the IP2024 scenarios. In the model, total wind generation is lower despite having the same installed capacity. Conversely, the solar electricity generation in the model is higher for both years. The differences in total generation can thus be attributed to the weather data used in the simulations. Despite these small variations, the overall generation ratios are quite similar in the IP2024 report and the model output.

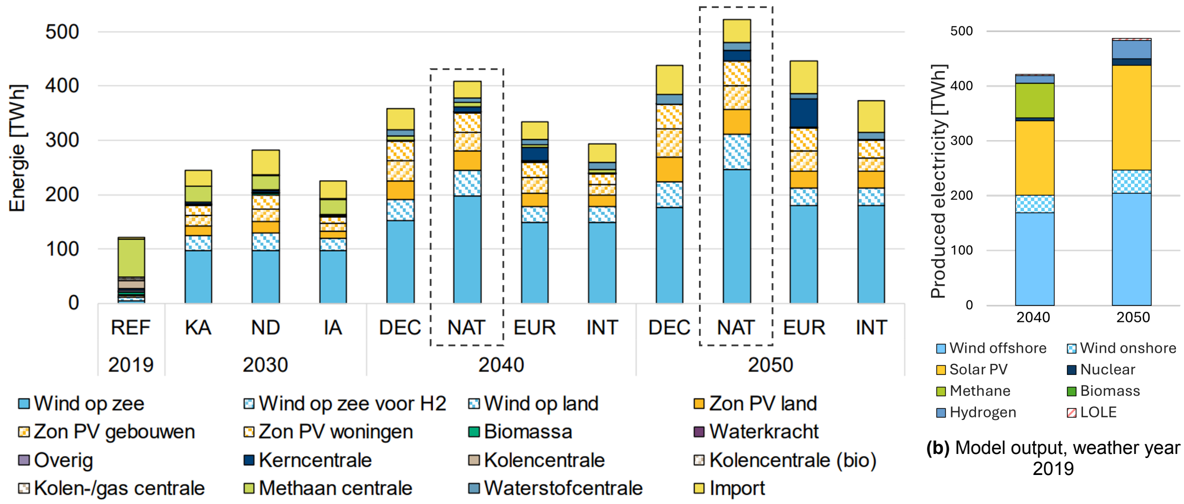


(b) Model output, weather year 2019

(a) IP2024 KA scenarios [66]

Figure 6.12: Verification: Electricity supply 2030 and 2035

To verify the data incorporation for year 2040 and 2050, the electricity supply mix from the NAT scenario of II3050 is replicated. Figure 6.13 depicts the comparison of the electricity supply in the NAT scenarios and the results from the model for year 2040 and 2050. Similar to the other years, the generation levels from wind and solar are lower and higher, respectively. Another significant difference between these graphs is the imported electricity and methane utilisation. Since interconnector capacity is excluded from the model, methane and hydrogen generation is higher in the model as it replaces this import possibility to meet electricity demand. Again the overall supply mix shows similar results. The incorporation of the data from the KA and NAT scenarios into the model is therefore considered verified. Furthermore, it shows that the model is capable of generating similar outcomes as the model used in the Netbeheer Nederland.



(b) Model output, weather year 2019

(a) II3050 NAT scenarios [64]

Figure 6.13: Verification: Electricity supply 2040 and 2050

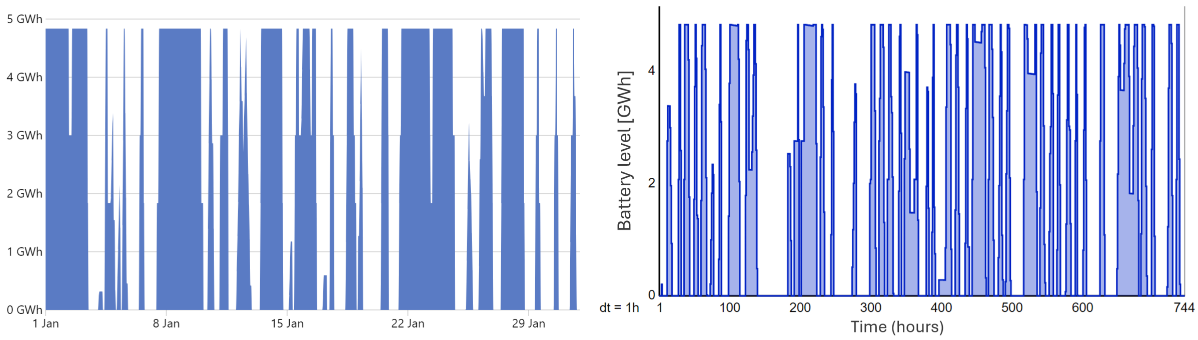
6.8. Validation of the model

Model validation involves determining whether the outcomes generated by the simulation model can adequately address the research question. This determines the model's fitness for this study by assessing whether the results align sufficiently with empirical observations of the system [88]. A common method of validation is to compare the model's outcomes with historical data. However, since this model focuses on future simulation years, historical data is not available. Instead, validation relies on comparing the model's outcomes with other models of the future electricity system.

The validation consists of several steps. First, battery and hydrogen storage behaviour is compared to the ETM [80]. Next, the full load hours of the generators are compared to historical data and a report by Kalavasta and Berenschot about the role of nuclear generators in a future electricity network [89]. Finally, the expected shortages are compared to TenneT's annual monitoring report. Furthermore, expert conversations were conducted throughout the process and insights from these interviews are embedded in the problem scope and modelling assumptions during the implementation phase.

Validation of battery storage

To validate the behaviour of the large-scale lithium-ion battery, the level of the battery and its charge and discharge cycles are compared to the ETM model [80]. For both models, the capacity is aggregated to allow comparison. Figure 6.14 illustrates the charging cycles of the 2030 KA scenario from the ETM and the model.



(a) ETM [80]

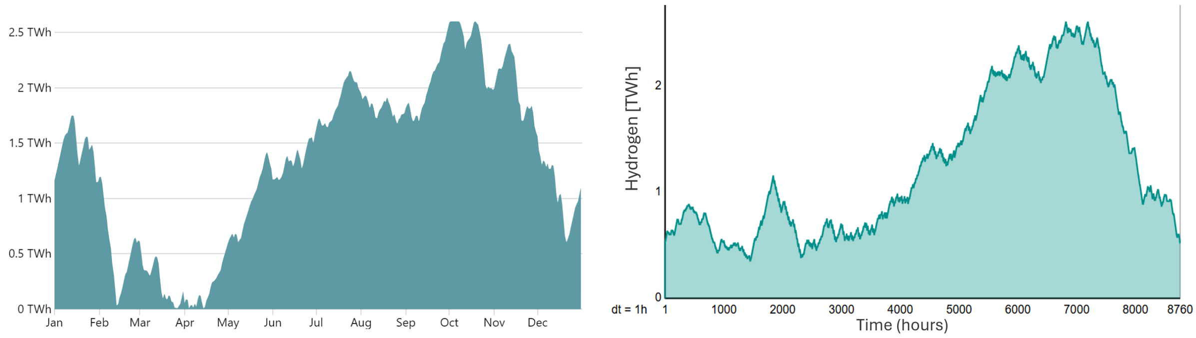
(b) Model, weather year 2019

Figure 6.14: Validation: Battery behaviour January 2030 - KA scenario

While the exact charging pattern varies depending on the weather year used, due to the battery only charging when there is an excess of renewable electricity, the overall charging behaviour remains comparable across the two model as both figures show multiple charging cycles. However, in the ETM (Figure 6.14a), the battery occasionally remains fully charged for extended periods, whereas in the model (Figure 6.14b), this occurs less frequently. This discrepancy is likely due to the inclusion of strategic bidding in the ETM, which is not considered in the model. In the ETM, the battery operates based on arbitrage, using a forecasting algorithm to optimise its performance, whereas in the model, it is utilised by the solver to minimise total system costs [71]. Despite these methodological differences, the overall battery storage behaviour remains consistent between both models and is therefore considered validated.

Validation of hydrogen storage

To validate the behaviour of the UHS, the storage levels of the 2035 KA scenario from the ETM are analysed against the behaviour of the model. The ETM storage levels (Figure 6.15a) are expressed in TWh, therefore, the results from the model (Figure 6.15b) are also scaled to TWh. To ensure consistency between the two models, the year 2035 is used, as the KA scenario does not include hydrogen CCGTs for 2030, and the lowest hydrogen price is applied in the simulation.



(a) ETM [80]

(b) Model, weather year 2019

Figure 6.15: Validation: UHS behaviour 2035 - KA scenario

Both graphs exhibit a similar trend, with an initial increase in storage levels at the beginning of the year, followed by a decline between February and early April, interrupted by a small peak in March. In the second half of the year, storage levels rise again, showing minor fluctuations along the way. The absolute peak in storage occurs around the same period in both cases, reaching maximum storage capacity. From November onward, storage levels decline sharply, followed by a slight recovery in December.

The model incorporates an additional storage constraint, which forces the hydrogen storage to be filled to at least 20% of its total volume every three weeks to align with natural gas reserves. Although the exact storage levels and refilling rates vary depending on the specific weather year used in the simulation and the storage constraint included in the model, the overall trends remain consistent across both graphs. This consistency indicates that the model is capable of generating similar results as the ETM.

Validation of full load hours of generators

The full load hours of the various generators have been calculated to provide insights into their utilisation rates, which are illustrated in Table 6.5. Generators with lower marginal costs should have more full load hours than generators with higher marginal costs, which indicates that the dispatch in the model is functioning correctly. The table below presents the full load hours for the future year 2030, based on weather conditions from 2019. The capacity of the hydrogen CCGT is set at 0 GW, to ensure consistency with the KA scenario.

Table 6.5: Verification and validation of full load hours generators 2030

Type of generator	Full load hours
Nuclear	5259
Natural gas CCGT	3800
Natural gas OCGT	1349
Biomass	742

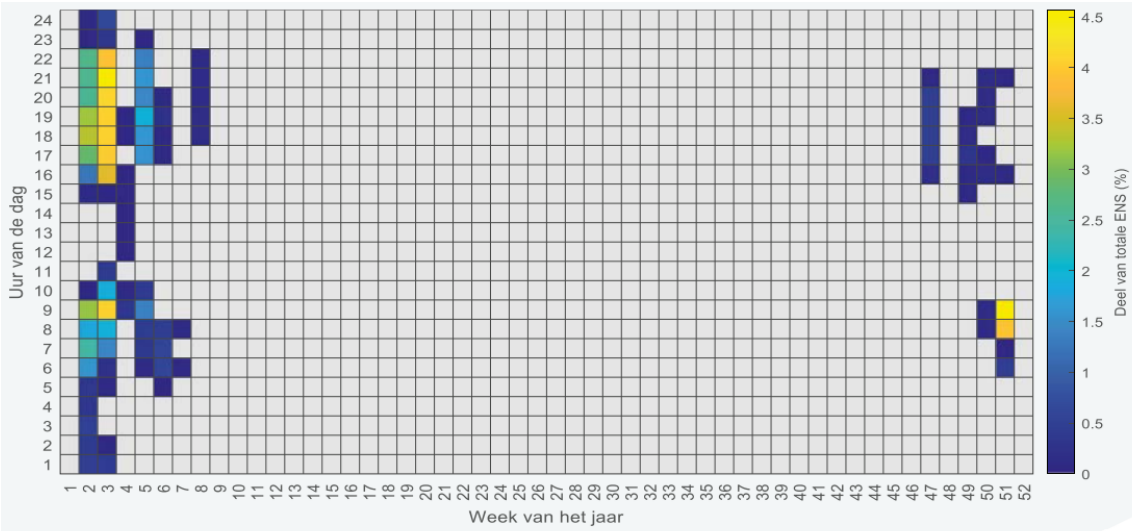
The full load hours of natural gas CCGT and OCGTs, and biomass turbines correspond logically with their position in the merit order and the finding of TNO [90]. However, compared to historical data, nuclear generation operates for significantly fewer hours, achieving only 5259 hours annually compared to the expected 7000-8000 hours per year [91]. This discrepancy arises because of two reasons. First, the model seeks the optimal dispatch rather than taking must-run generators and strategic bidding into consideration. Second, the model incorporates a higher installed capacity of vRES compared to current conditions. Consequently, all non-vRES are utilised less frequently in the model's dispatch. These findings regarding the reduction in full load hours are consistent with the findings of Kalavasta and Berenschot about the role of nuclear generation in a future electricity network when generators are dispatched optimally based on the merit order [89].

Comparison with Tennet monitoring report

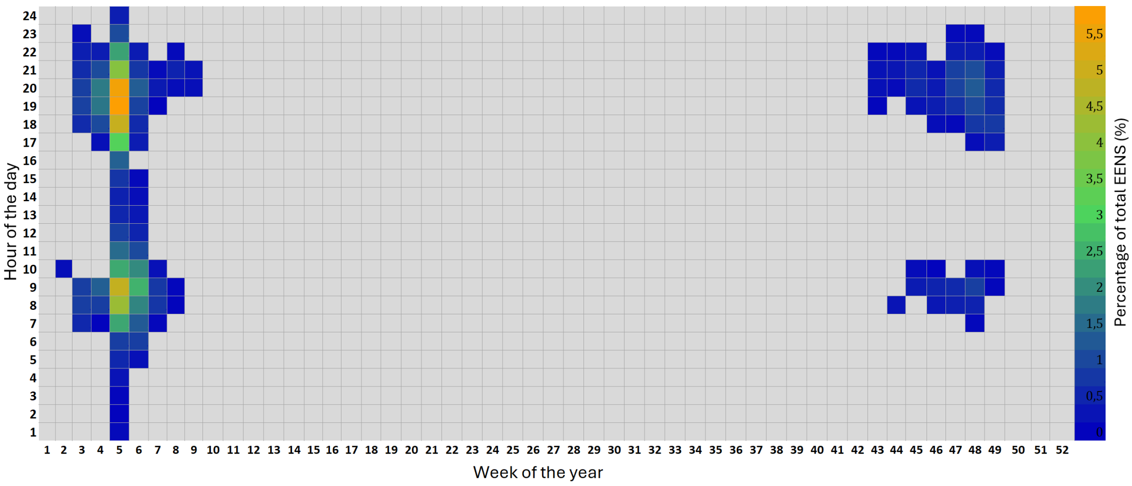
The last step of the validation includes comparing the electricity shortages observed in the model with TenneT's reported shortages and their distribution as outlined in the annual monitoring report [12].

Distribution of shortages

When comparing the distribution of electricity shortages between the model and TenneT's results, as shown in Figure 6.16, similar overall patterns are found. These figures visualise the distribution of electricity shortages across the weeks of the year (horizontal axis) and the hours of the day (vertical axis) in the 2030 scenario. The colour scale represents the percentage of total shortages (EENS) occurring at specific times. An important note is the fact that the model's output is based on a single simulation year, whereas TenneT's results represent an average across multiple years. As a result, precise differences may arise due to variability in weather conditions.



(a) Averages monitoring report TenneT [12]



(b) Model, weather year 2019

Figure 6.16: Validation: Distribution of expected shortages 2030

Total electricity shortages

The number of LOLE hours in the model is significantly higher than in TenneT's report, as illustrated in the tables below. This discrepancy arises due to several factors. A primary difference between the assumptions in the model and those in TenneT's report is the absence of import capacity in the model. In this study, interconnector capacity has been intentionally excluded from the model, as discussed in Chapter 5.1, to avoid underestimating the severity of electricity shortages due to over-reliance on uncertain interconnection capacity. As a result, the model relies solely on domestic generation, leading to more frequent shortages over multiple periods. In contrast, TenneT's projections account for electricity imports, which play an important role in mitigating shortages in their results [12].

Another key difference is that the model focuses exclusively on the day-ahead market, assuming that all trading occurs within this market. TenneT, on the other hand, considers multiple markets. As explained in Chapter 4.1, the intraday market operates under a different pricing mechanism than the day-ahead market, and during scarcity events, electricity prices within this market can rise significantly, incentivising consumers to trade electricity among themselves. This price-driven DSR is more pronounced in the intraday market, as higher prices lead to more 'far-reaching voluntary reduction' in electricity consumption [48]. The exclusion of intraday trading contributes to the observed discrepancies between the model's LOLE estimates and TenneT's reported results.

year	LOLE [hours per year]	EENS [GWh per year]
2028	0.0	0.0
2030	1.4	2.2
2033	14.2	49.8

Figure 6.17: Shortages monitoring report TenneT [12]

Table 6.6: Shortages model, weather year 2019

Year	LOLE [hours/year]	EENS [GWh/year]
2030	188	833
2035	343	2118

Since the model is not designed to predict exact shortages or financial outcomes, but rather to analyse the impact of various conditions and uncertainties on the KPIs, these discrepancies do not undermine its validity. Despite some deviations from other models, it provides valuable insights into the impact of external uncertainties on system reliability and the profitability of hydrogen turbines. By consistently applying the same simplifications and assumptions, the model can offer relevant insights into relative comparisons. Therefore, the model is considered suitable for addressing the research questions and is thus deemed validated.

7

Exploratory modelling approach

A series of experiments are designed to evaluate the impact of uncertainties on system reliability and hydrogen turbine profitability, aligning with the application phase of the modelling cycle. These experiments aim to generate the insights needed to answer the research sub-questions. The chapter begins with an overview of the experimental approach, followed by an explanation of the variables varied across all experiments. Subsequently, each experiment is elaborated individually with its corresponding objective and experiment-specific parameters.

7.1. Exploratory modelling approach

In total, six series of experiments have been designed. A single combination of input variables represents one run in the simulation model, referred to as a scenario. Each experiment consists of multiple scenarios. Table 7.1 presents an overview of the parameter variations and the experiments in which they are varied.

General parameters are varied across multiple experiments, while experiment-specific parameters are adjusted within individual experiments. In each experiment, a maximum of one specific experiment parameter is varied at the time, while all other variables remain at their default values. This approach isolates the individual influence of each parameter on the KPIs.

Table 7.1: Parameters of the experiment design

General parameters					**Specific experiment parameter**			
Simulation year	**Weather year**	**H_2 CCGT capacity [GW]**		**Hydrogen prices [€/kg]**	**Hydrogen import**	**Electricity demand**	**DSR rates**	**Battery level**
2030	1987	0	15	13	Unlimited	-20%	17%	1
2035	2018	2.5	17.5	6			34%	2
2040	2019	5	20	2			51%	3
2050		7.5	22.5					
		10	25					
Varied across experiment:								
All	All	3,4,5,6		3,4	2	4	5	6

7.2. General parameters

The experiment design includes four general parameters, which are varied across multiple experiments. Simulation and weather years are adjusted in all experiments to capture a comprehensive range of possible generation scenarios. Hydrogen CCGT capacity and price levels are incorporated and varied in the relevant experiments.

Simulation years

As elaborated in chapter 6.5, input values from the KA and NAT scenarios are utilised for four simulation years. Years 2030 and 2035 use values derived from the KA scenario, and 2040 and 2050 use the NAT scenario values [64],[66]. Each simulation year consists of a set of corresponding variables, which are detailed in Appendix D. These predefined values serve as default data for all experiments.

Weather years

Weather conditions are expected to significantly impact both the business case for hydrogen turbines and the reliability of the electricity system, yet, are beyond the control of the government and investors. To account for this weather uncertainty and investigate its influence, all experiments are conducted using the three selected weather years, detailed in chapter 6.5.

Hydrogen CCGT capacity

For the relevant experiments, the aggregated capacity of hydrogen CCGTs is incrementally increased in steps of 2.5 GW up to a maximum of 25 GW. This step-by-step addition allows for a detailed assessment of the marginal effects of additional capacity on the KPIs.

Hydrogen prices

Currently, green hydrogen is more expensive than fossil fuels such as natural gas, making it uncompetitive with conventional generators in terms of marginal costs. This limits the operational hours of hydrogen turbines and the high prices discourage investments. Given the high level of uncertainty about future hydrogen costs and the government's limited influence on these prices, this factor is varied separately across the relevant scenarios.

The highest hydrogen price is set at €13/kg, based on TNO's evaluation of the levelised costs of hydrogen, which estimated a range between €12 and €14/kg [92]. Approximately 60% (€8.5/kg) of this cost comprises capital expenses and taxes, while the remaining 40% is attributed to electricity costs, assumed in their scenarios to be bought through power purchase agreements with fixed prices. However, the study highlights that connecting electrolysers to the grid and utilising cheaper electricity could lower overall production costs, though this reduces certainty about production costs. Since no reviewed studies predict future hydrogen prices exceeding €13/kg, this value is used as the upper limit in this research.

The lowest hydrogen price used in this study is €2/kg, in line with the projections outlined in the TYNDP scenarios [85]. Additionally, an intermediate price of €6/kg (€180/MWh) is included to cover the range of potential price variations.

Table 7.2: Values for hydrogen prices

Name	Value in €/kg	Value in €/MWh
Hydrogen price high	13	390
Hydrogen price middle	6	180
Hydrogen price low	2	61

To reduce the computational burden, only the medium hydrogen price is used in experiments evaluating system reliability, as hydrogen prices do not impact electricity shortages.

7.3. Experiment design

The overview of the experiment design is provided in Table 7.3, outlining their main objectives, varied parameters, and number of scenarios analysed per experiment. Since simulation and weather years are varied across all experiments, they are not included in the table. A detailed explanation of each experiment follows the table.

Table 7.3: Overview of the experiment design

Experiment name	Objective	Varied parameters	Scenarios
1. Government scenarios	Investigate expected electricity shortages	-	12
2. Missing capacity	Determine capacity to prevent all shortages	H_2 import	8
3. Capacity comparison default	Investigate influence of uncertainties on business case Determine contribution of H_2 turbines on reliability	H_2 CCGT capacity Hydrogen prices	279
4. Low electricity demand	Explore influence of lower electricity demand Determine contribution of H_2 turbines on reliability	Electricity demand H_2 CCGT capacity Hydrogen prices	243
5. Demand side response	Investigate influence of DSR Determine need for H_2 turbines	DSR rates H_2 CCGT capacity	126
6. Batteries	Investigate influence of batteries Determine need for H_2 turbines	Battery level H_2 CCGT capacity	126

Experiment 1: Government scenarios

The objective of this initial experiment is to determine the expected electricity shortages based on the values of the KA and NAT scenarios. Hydrogen CCGT capacity is set according to these scenarios, with values of 0 GW, 3.5 GW, 8.9 GW, and 15 GW for 2030, 2035, 2040, and 2050, respectively. The experiment consists of 12 runs, using four simulation and three weather years. As this experiment is primarily conducted to explore electricity shortages, only the middle hydrogen price is used. The experiment does not include specific experimental parameters but instead relies on general model parameters.

Experiment 2: Missing capacity

The second experiment series is conducted to determine the missing capacity, defined as the hydrogen CCGT capacity required to eliminate all LOLE hours. The objective is to determine the total amount of dispatchable or flexible generation capacity required alongside vRES to ensure system reliability. For this experiment, the hydrogen import capacity is assumed to be unlimited to gain insights into the capacity needed to address all supply shortages. To prevent the solver from utilising excessive hydrogen CCGTs capacity levels, this capacity is not left unrestricted. When capacity is left unconstrained in the model, the solver tends to allocate higher maximum capacity levels, as it does not account for investment decisions or costs. To address this, hydrogen CCGT capacity is incrementally increased by 1 GW, enabling the precise assessment of the capacity needed to prevent electricity supply issues. Once the LOLE hours are below the reliability standard of four hours, the corresponding level of capacity is considered sufficient. Again, only the medium hydrogen price scenario is used, and the results are analysed solely based on adequacy KPIs. The runs are conducted with weather years 2019 and 1987, to see the influence of a Dunkelflaute on the missing capacity compared to a ‘regular’ weather year. While multiple runs are performed per asset and weather year, only those where the LOLE falls below four hours are considered for further analysis, resulting in a total of eight scenarios being examined.

Experiment 3: Capacity comparison default

This experiment investigates the potential role and profitability of hydrogen turbines under varying conditions. In the previous experiment, the missing capacity is determined under the assumption of unlimited hydrogen availability. In contrast, this experiment incorporates limited hydrogen import capacity, aligning with the KA and NAT scenarios. The upper bound of the process ‘import hydrogen’ is set according to the import capacity from the KA and NAT scenarios for the specific asset years, detailed in Table D.2 in Appendix D. Hydrogen CCGT capacity is added in steps of 2.5 GW until shortages stop decreasing. This analysis first examines the impact of hydrogen turbines on the reliability of the electricity system by exploring their contribution to mitigating the shortages. Subsequently, the economic feasibility of the turbines is examined for the distinct capacity levels, and full load hours are calculated to determine their utilisation rates. This experiment is conducted across the four future years, the three weather years, and the three varying hydrogen prices to provide a comprehensive understanding of the impact of these factors.

Experiment 4: Low electricity demand

The sensitivity analyses, provided in chapter 6, highlight the significant impact of electricity demand on KPIs. Given this influence, it is valuable to further investigate how variations in total electricity demand affect the system. This experiment examines the impact of reduced electricity demand growth, reflecting a slower pace of electrification. Such a slowdown could result from delays in the adoption of electrification technologies or the emergence of alternative energy solutions that decrease reliance on electricity. This experiment is particularly relevant given that the current pace of electrification is progressing more slowly than anticipated and may continue to stagnate in the future [49].

This analysis focuses on how lower electricity demand affects system adequacy and the financial viability of hydrogen CCGTs. Therefore, the electricity demand is reduced by 20%, leading to a total of 80% of the electricity demand projections of the KA and NAT scenarios. The demand patterns, so the distribution of the relative demand per hour, remain unchanged. Similar to the previous experiment, hydrogen CCGT capacity is increased in steps of 2.5 GW until shortages are prevented or stop decreasing. Due to the lower electricity demand, the maximum level per simulation year is lower in experiment 3, resulting in fewer total runs.

Experiment 5 and 6: Flexibility in the system

In addition to flexible generators, there are three other things to enhance system flexibility: electrical storage, DSR, and interconnector capacity [13],[20],[64]. The following two experiments focus on the first two forms of flexibility. Interconnector capacity falls behind the scope of this research, as elaborated in chapter 5.1, and is therefore not incorporated. Additionally, the effect of interconnector capacity is assumed to be similar to the load-shedding processes, which both reduce the level of domestic production required to meet demand. These experiments have two objectives. Firstly, to assess whether alternative forms of flexibility can address electricity shortages without hydrogen turbines. It aims to evaluate the extent to which other carbon-neutral forms of flexibility can provide adequate support to mitigate electricity supply issues. Second, it seeks to gain insights into the impact of increasing these forms of flexibility on the business case of hydrogen turbines. This gives insights into the influence of these forms of flexibility on electricity shortages, the necessity of hydrogen turbines in a future electricity system, and the impact of these forms of flexibility on the economic feasibility of the turbines.

Experiment 5: Demand side response

Current estimates suggest that approximately 17% of the electricity demand is flexible, while 83% remains inflexible [68],[80]. This experiment aims to determine whether increasing DSR can effectively mitigate electricity supply issues. To explore this, the default flexibility rates are scaled by factors of 2 and 3, resulting in total flexibility levels of 34% and 51%, respectively. This implies that approximately one-third or even half of the electricity demand becomes flexible. While reaching such flexibility levels within the electricity system, particularly in such a short time period is unlikely, it is interesting to see whether this theoretical rate would solve the anticipated problems. In the model, all forms of DSR are scaled simultaneously to see the potential. This includes multiplying the three voluntary load-shedding rates, the shift rate, and the deficit limit by the same scaling factors. Hydrogen CCGT capacity is here also incrementally added in steps of 2.5 GW. To limit computational burden, only the middle hydrogen price is utilised.

Experiment 6: Batteries

The second form of flexibility includes large-scale batteries. The government scenarios remain the base for this experiment, however, the installed power and storage capacity of the batteries are scaled by factors two and three to analyse their impact. In this experiment, the values from the KA and NAT scenarios are multiplied, increasing both the input and output power of the batteries and their storage capacity. This experiment gives insight into the effect of batteries on mitigating shortages and on the business case of hydrogen CCGTs. The latter is interesting as market participants face a decision: whether to invest in batteries, dispatchable generators, the hydrogen turbines in this case, or refrain from investing altogether. Again, hydrogen CCGT capacity is gradually increased and the middle hydrogen price is used. In the displaying of the results, the multiplication factors of the battery capacity and storage levels are shortened to ‘battery’.

8 Results of the experiments

This chapter provides the results of the experiments. It begins with a brief explanation of how the results are visually presented. Then, the results from the separate experiments are depicted, accompanied by an explanation of the most relevant findings. These results are structured according to the experiment design outlined in the previous chapter. Finally, the chapter concludes with a summary of the model results.

8.1. Presentation of the results

Before presenting the results, it is important to highlight a consideration regarding the interpretation of the findings. As the model is a simplification of reality, the reported values do not reflect the exact problems of electricity supply or annual profits of hydrogen CCGTs. The results are used for comparing the outcomes of different experiments and analysing the effects of uncertainties on the system. In other words, these values are intended for relative comparison. Furthermore, it is important to note that the average of the scenarios cannot be used in the analysis, as there is no certainty about the likelihood of specific scenarios, such as a particular weather year, becoming reality.

The results are displayed in tables, histograms, or boxplots. In the tables, the colours are used solely to enhance comparison between scenarios and do not indicate absolute differences. In the histograms, each run is represented by its own bar. The boxplots display the distribution of the results, where the lower edge of the box represents the 25th percentile (Q1) and the upper edge represents the 75th percentile (Q3). The whiskers extend to the smallest and largest data points within a defined range, while excluding outliers, which are displayed separately as dots. With this context in mind, the following sections present the results.

8.2. Results of experiment 1: Government scenarios

The first experiment is conducted to investigate the expected electricity shortages under different government scenario asset levels. 12 runs are conducted using the hydrogen CCGT capacity levels as outlined in the KA and NAT scenarios, to gain insights into the expected shortages.

The modelled capacity levels of 0 GW, 3.5 GW, 8.9 GW, and 15 GW indicate significant electricity shortages, as shown in Table 8.1. The LOLE and EENS reveal major supply security risks, particularly under weather year 1987, where shortages approximately triple compared to the other years. In all runs, LOLE hours exceed the four-hour reliability standard. Toward 2050, the shortages increase due to the growing share of vRES and the decline in conventional capacity. The results suggest that with the projected generator capacities and electricity demand from the KA and NAT scenarios, significant supply shortages will arise without additional flexible turbines.

Table 8.1: Experiment 1: Electricity shortages

(a) LOLE (hours/year)

WY	2030	2035	2040	2050
1987	348	649	720	993
2018	166	284	237	363
2019	189	343	284	400

(b) EENS (GWh/year)

WY	2030	2035	2040	2050
1987	1935	4660	6180	11400
2018	854	1960	2150	3800
2019	834	2120	2240	3960

Table 8.2 presents the average electricity prices observed across the 12 runs, which were conducted with the middle hydrogen price of €6/kg. In line with expectations, average electricity prices are higher in weather year 1987 compared to the other two years.

Interestingly, while electricity shortages are lower in 2035 than in 2040, average electricity prices show an opposite trend in weather years 2018 and 2019. This discrepancy arises from the significant increase in installed vRES capacity between these years (detailed in Appendix D). Since vRES generation has a production cost of €0/MWh, it has a suppressing effect on average electricity prices. In contrast, in weather year 1987, where vRES generation is low, average electricity prices align more closely with electricity shortages observed in simulation years 2035 and 2040.

Table 8.2: Experiment 1: Average electricity prices (€/MWh)

WY	2030	2035	2040	2050
1987	283	463	521	710
2018	167	261	219	319
2019	189	293	242	338

8.3. Results of experiment 2: Missing capacity

In this series of experiments, the missing electricity generation capacity, based on the vRES production and electricity demand is determined. The missing capacity shows the hydrogen CCGT capacity needed to keep the LOLE hours under the four-hour standard. Table 8.3 summarises the missing capacity across the distinct simulation years, distinguishing between normal weather conditions (using weather year 2019) and a Dunkelflaute (using weather year 1987). Furthermore, it presents the configuration of other dispatchable technologies in the asset years, providing an overview of the total capacity required alongside vRES to ensure system reliability.

Table 8.3: Experiment 2: Missing capacity (GW)

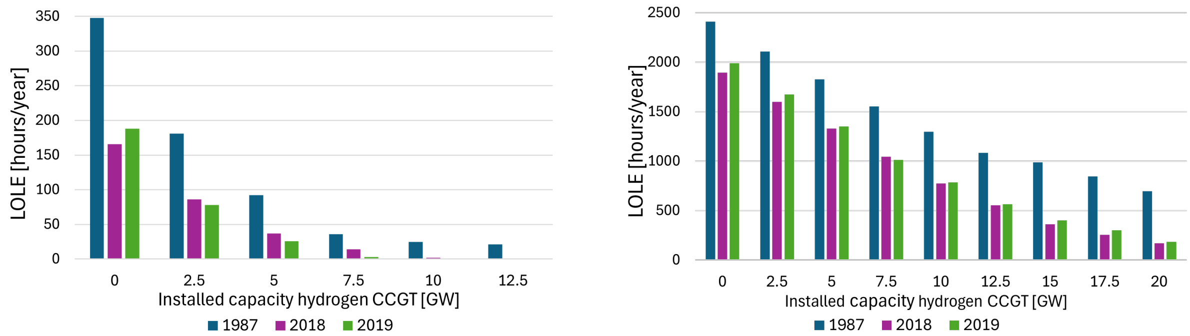
	2030	2035	2040	2050
Missing capacity regular year	8	14	21	31
Missing capacity Dunkelflaute	11	20	27	38
Other dispatchable capacity	17	13	8	3

8.4. Results of experiment 3: Capacity comparison default

This experiment is conducted to assess the potential contribution of hydrogen turbines on system reliability and to investigate the influence of external uncertainties on the profits of the hydrogen turbine. In these runs, default values for all parameters, except hydrogen CCGT capacity, according to government scenarios KA and NAT are utilised. Hydrogen CCGT capacity is added in steps of 2.5 GW. The three weather years and hydrogen prices are implemented in this experiment. The most relevant results from 2030 and 2050 are presented in this chapter, as they show the two outermost, while a complete overview of all results, including the other simulation years are shown in Appendix E.

Figure 8.1 presents the LOLE hours for years 2030 and 2050 with increased hydrogen CCGT capacity. As anticipated, increased hydrogen CCGT capacity leads to a decline in shortages. The initial capacity additions result in a sharp reduction in electricity shortages. However, beyond a certain threshold, the marginal benefits of reducing shortages stagnate. Further reductions become increasingly challenging, as eliminating the remaining LOLE hours requires significantly more capacity. These final shortages are the most difficult to address since they occur during periods of peak residual load. Mitigating the shortages requires substantial additional capacity, which operates with very low full load hours, as further detailed in Table 8.5.

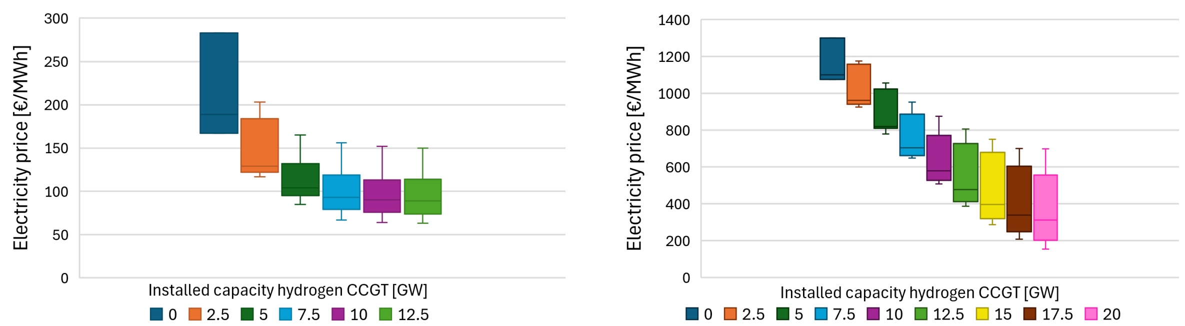
The figure also highlights the strong influence of weather conditions on electricity shortages. This pattern is consistent across all other simulation years, as illustrated in Appendix E. However, an important difference is that in later years (2035, 2040, and 2050), under the KA and NAT scenarios, complete elimination of LOLE hours is not possible due to limited hydrogen availability and storage capacity. An enlarged installed capacity does not reduce the shortages further from a certain level, indicating that under these conditions, there is too little hydrogen to solve the problems completely with hydrogen. Storage, production, and import levels reach a maximum during these runs. As a result, even with increasingly high levels of hydrogen CCGT capacity, shortages still occur.



(a) 2030 **(b)** 2050

Figure 8.1: Experiment 3: LOLE hours

A similar trend is observed in electricity prices, as shown in Figure 8.2. The initial capacity additions lead to a sharp decline in average electricity prices by mitigating extreme price spikes. With fewer shortages, exceptionally high prices reaching the €4000/MWh price cap occur less frequently, resulting in an overall reduction in average prices. Similar to electricity shortages, as hydrogen capacity continues to increase, the impact on price reductions diminishes and eventually stagnates.



(a) 2030 **(b)** 2050

Figure 8.2: Experiment 3: Average electricity prices

Profits hydrogen CCGTs

Increasing hydrogen CCGT capacity results in a substantial decrease in profit per GW, illustrated in Table 8.4, due to diminishing returns. Even total profits from all installed capacity turbines together decline as capacity increases (Figure 8.3), primarily due to reduced scarcity and therefore reduced electricity prices. Additionally, as hydrogen consumption rises, the availability of cheaper hydrogen becomes more constrained, further impacting profitability. While annual profits vary depending on weather conditions and hydrogen prices, the overall trend remains consistent: as installed capacity increases, operational profits decline. At the same time, higher installed capacity leads to greater investment costs, accelerating the decline in financial performance per installed GW. During a weather year with low vRES generation, the profits for the turbine are significantly higher than during a year without prolonged Dunkelflautes.

Table 8.4: Experiment 3: Hydrogen turbine profits (MEUR/GW) - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW
	1987	682	266	81	23	-19
13	2018	309	91	-18	-42	-50
	2019	298	73	-55	-79	-88
	1987	863	400	181	86	48
6	2018	390	145	17	-41	-55
	2019	394	128	-19	-59	-72
	1987	1002	488	267	151	101
2	2018	458	180	37	-16	-37
	2019	476	165	-4	-45	-54

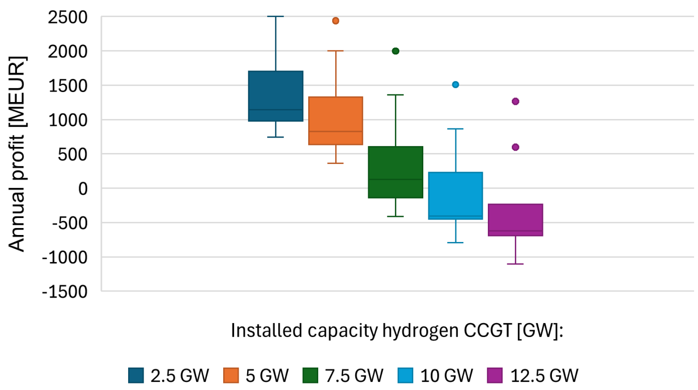


Figure 8.3: Experiment 3: Total turbine profit - 2030

Full load hours and position in merit order

The full load hours of hydrogen CCGTs, shown in Table 8.5, increase when hydrogen prices decline. This results from their changing position in the merit order. The specific merit order in the model fluctuates per hour since hydrogen production costs are influenced by endogenous electricity prices. Despite this variation, a general cost range can be established for each base hydrogen price, which is shown in Figure 8.4.

Table 8.5: Experiment 3: Full load hours - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW
	1987	645	474	342	263	211
13	2018	336	253	192	146	116
	2019	402	294	221	167	134
	1987	722	536	400	307	247
6	2018	420	305	233	182	146
	2019	508	362	268	204	163
	1987	2136	1290	904	685	549
2	2018	2025	1085	757	571	458
	2019	2012	1113	785	593	474

The lowest possible electricity price is €0/MWh, resulting in the minimum production cost for hydrogen CCGTs (highlighted in purple for the low H_2 price). At this level, hydrogen CCGTs become more cost-competitive than natural gas CCGTs. The base hydrogen import price (illustrated in blue) remains more expensive than electricity from natural gas CCGTs but is still cheaper than natural gas OCGTs and biomass, leading the solver to prioritise hydrogen turbines over these other assets. However, when the maximum import capacity is utilised, hydrogen prices rise due to increased demand, reaching the maximum cost level, depicted in green. The hourly marginal production costs can fluctuate between these three points, determining the range in which hydrogen turbines are positioned within the merit order.

With the middle and highest hydrogen price levels, hydrogen turbines consistently remain at the end of the merit order in 2030, even during periods of the lowest electricity prices for hydrogen production. Consequently, the difference between these two price levels has a limited impact on full load hours. The remaining variation results from the activation of the lowest-cost demand-shedding processes, where the WtP is higher than the minimum production cost of the middle hydrogen price but lower than the highest hydrogen price.

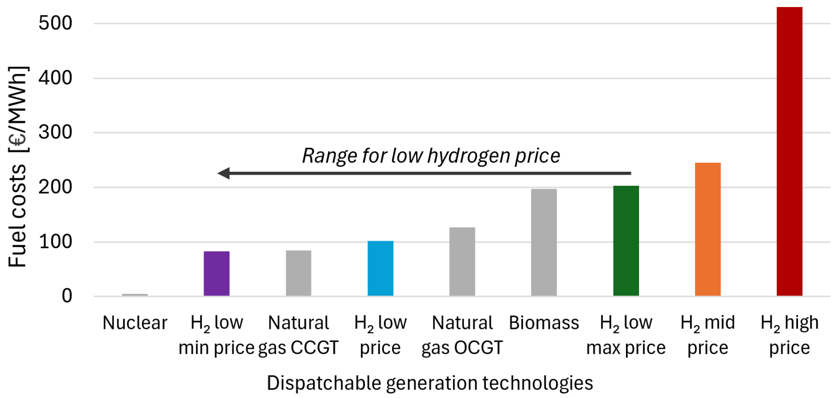


Figure 8.4: Experiment 3: Merit order - 2030

As installed capacity increases, full load hours decline since total electricity generation is distributed across a larger capacity level, while overall electricity production grows at a slower rate than the capacity expansion. This results in a lower utilisation rate per installed capacity. Interestingly, while full load hours increase significantly as hydrogen prices decrease, this does not translate into a similar rise in profits. The main reason for this is that at lower hydrogen prices, the turbine more frequently sets the market price, meaning it does not generate marginal profits during that hour. Consequently, despite operating for more hours, its financial gains remain limited, or at least do not increase proportionally to the rise in full load hours.

Conclusion experiment 3: Capacity comparison default

The results of this experiment show that the initial addition of hydrogen CCGT capacity significantly reduces electricity shortages and prices. As capacity increases, however, the marginal benefits diminish. Eliminating the final LOLE hours requires substantial additional capacity with low utilisation rates, or is not completely possible due to limited hydrogen availability. A similar trend is observed in electricity prices, which initially decline sharply but stagnate as more capacity is added.

Hydrogen prices have a relatively limited impact on the business case for hydrogen CCGTs, whereas weather variations and installed capacity play a more decisive role. Years with prolonged Dunkelflautes yield higher profits, whereas years with stable renewable generation, such as 2018 and 2019, result in lower profitability. This underscores the strong dependency of hydrogen turbine profits on external conditions rather than fuel costs alone. From a societal perspective, increasing capacity improves system reliability, while from an investment standpoint, less installed capacity might be preferable for maintaining profitability, as price spikes increase revenues.

8.5. Results of experiment 4: Low electricity demand

This experiment is conducted to investigate the impact of lower electricity demand on system reliability and the economic viability of hydrogen turbines. This section presents the results for 2030, with the results for the other simulation years available in Appendix F.

Figure 8.5 illustrates the LOLE hours for year 2030 with 80% of the electricity demand from the KA scenario. For 2030, the reliability standard is met for all weather years when 5 GW of hydrogen CCGTs is incorporated in the KA scenario asset portfolio. In contrast to scenarios with higher electricity demand, sufficient hydrogen production and storage are available in later simulation years to resolve all remaining LOLE hours with additional hydrogen CCGT capacity. However, eliminating these final hours still requires substantially more capacity and the marginal benefits of adding more capacity stagnate.

More installed hydrogen capacity reduces electricity shortages, which in turn lowers average electricity prices (Figure 8.6). As expected, this follows a similar pattern observed under the scenarios with higher electricity demand.

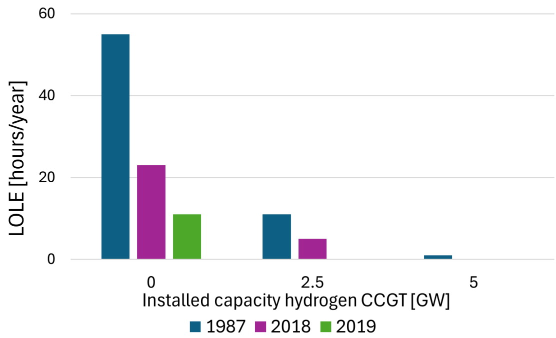


Figure 8.5: Experiment 4: LOLE - 2030

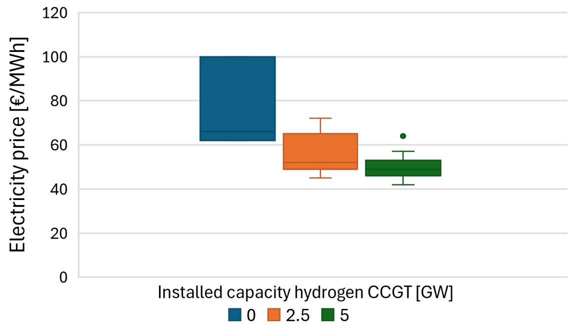


Figure 8.6: Experiment 4: Average electricity prices - 2030

When looking at the profitability of the hydrogen turbine in the 2030 scenario, illustrated in Table 8.6, it becomes clear that these conditions are not favourable for the turbines. Hydrogen turbines only achieve profitability in adverse weather conditions and when the total installed capacity is limited to 2.5 GW. In other scenarios, the turbine would generate losses. During these runs, the turbines reach a very low number of full load hours when hydrogen prices are high or moderate. This means that the profits rely on very limited operational periods, introducing even more risks and uncertainties. When hydrogen prices are low, the turbines have significantly more full load hours, again, due to the shift in merit order. Nevertheless, the inframarginal and scarcity rents are low during these runs as they are more often the last dispatched turbine, which prevents the turbines from becoming profitable.

Table 8.6: Experiment 4: Hydrogen turbine profits (MEUR/GW) - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW
	1987	6	-79	-91
13	2018	-47	-78	-87
	2019	-78	-87	-87
	1987	36	-64	-86
6	2018	-32	-74	-85
	2019	-67	-85	-87
	1987	69	-47	-78
2	2018	-15	-69	-85
	2019	-51	-84	-90

Table 8.7: Experiment 4: Full load hours - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW
	1987	180	119	82
13	2018	80	52	37
	2019	73	43	29
	1987	234	161	114
6	2018	114	77	56
	2019	121	75	52
	1987	2143	1093	734
2	2018	2080	1052	707
	2019	2146	1116	744

Comparison to higher demand

To further analyse the impact of reduced electricity demand, this section compares the results of the high and lower demand scenarios. Figure 8.7 illustrates the residual load curves for simulation year

2030 with weather year 2019, for both demand levels. The other asset levels are kept at default rates, meaning the system includes 17 GW of other dispatchable generators, 4.8 GWh large-scale batteries, and 900 GWh hydrogen storage. The total load that must be met by non-vRES, indicated with the positive values at the left side of the graph, is significantly lower whenever electricity demand is reduced. Besides, solely vRES generation is more often sufficient to comply with the electricity demand, which is indicated by the intersection of the residual curve on the x-axis.

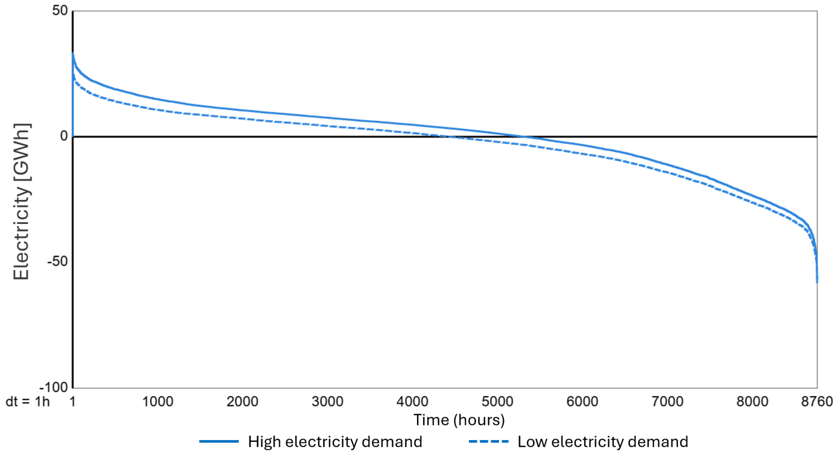


Figure 8.7: Residual load curves 2030 - High and low electricity demand

Figure 8.8 compares the LOLE of between the 80% and 100% demand scenarios in one figure, demonstrating that, as expected, lower electricity demand leads to a substantial reduction in electricity shortages. Figure 8.9 shows the electricity prices under the middle hydrogen price scenarios, illustrating that average electricity prices decrease substantially with lower electricity demand. The decline in LOLE hours translates to fewer hours with extreme electricity prices, which lowers the average electricity prices. As more hydrogen CCGT capacity is added and electricity shortages become minimal, price differences between the high and low-demand scenarios become smaller. However, even with, for example, 10 GW hydrogen CCGTs, electricity prices remain lower under reduced demand. This is because vRES, which have no fuel costs, can more frequently meet electricity demand, which reduces average electricity prices. With all other parameters held the same, a lower electricity demand improves both the affordability and availability of the electricity.

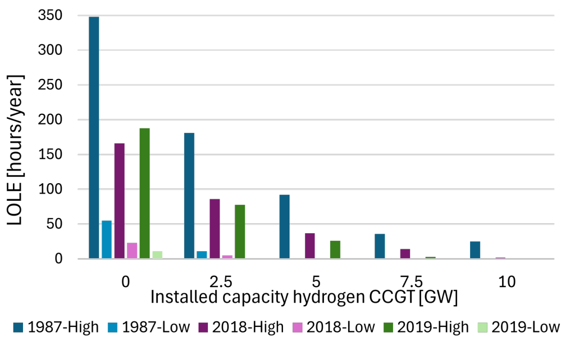


Figure 8.8: LOLE 2030 - High and low electricity demand

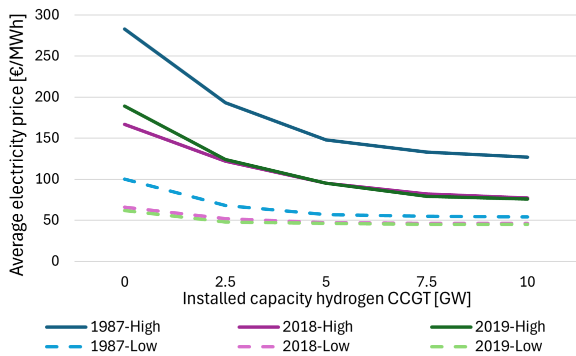


Figure 8.9: Average electricity prices 2030 - High and low electricity demand

When comparing the profits of the turbines under high electricity demand (Table 8.4) and lower demand (Table 8.6), there is a clear difference. Under lower demand conditions, hydrogen CCGTs struggle to remain financially viable unless hydrogen CCGT capacity is limited and vRES output is low. Lower electricity demand improves system reliability and reduces market prices but also weakens the business case for hydrogen turbines by reducing scarcity rents and limiting their operational hours. Electricity demand has thus a significant impact on the profitability of hydrogen turbines. Since investors have little control over the pace of electrification, and future electricity demand remains highly uncertain, this introduces significant investment risks.

8.6. Results of experiment 5: Demand side response

The objective of this experiment is to investigate the influence of DSR on system reliability and determine the necessity for hydrogen turbines to reduce electricity shortages. Furthermore, the impact of increased flexibility on the profitability of the turbines is evaluated. The most relevant findings of the experiment are elaborated in this section, with a comprehensive overview of all KPIs provided in Appendix G. The experiment was initially conducted for the four simulation years to explore the effects; however, the observed trends remain consistent throughout. Therefore, only the results for 2030 and 2050 are presented in the appendix, as these two years represent the two most extreme cases within this study.

Impact of DSR on electricity system

The impact of increased DSR on system reliability is depicted in Table 8.8, where hydrogen capacity is incrementally expanded in steps of 2.5 GW. As expected, higher DSR rates lead to a reduction in shortages. Doubling demand flexibility from 17% to 34% reduces LOLE hours in 2030 by approximately 55-70%, depending on the weather year. Tripling flexibility rates lowers LOLE hours by around 80–90%. Nevertheless, even with 51% flexibility, a level unlikely to be achieved in the near future, electricity demand cannot be fully met. This is because shifted demand must eventually be fulfilled at an earlier or later time.

In 2050, shown in Appendix G, the relative impact of increased DSR is lower. Doubling the DSR rate to 34% in this simulation year results in only a reduction of 20 - 25% in LOLE hours. This diminished effect is due to the significantly higher initial levels in 2050, caused by the high penetration of vRES. During prolonged periods of electricity scarcity, which occur more frequently with an increased share of vRES, the effectiveness of shifting demand declines, as this needs to be compensated for at another moment shortly before or after. The load-shedding processes remain equally effective in both years, as they directly reduce total electricity demand without requiring later compensation. It is thus important to note that, while DSR alleviates shortages, it cannot completely eliminate them.

Table 8.8: Experiment 5: LOLE hours - 2030

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW
17%	1987	348	181	92	36
	2018	166	86	37	14
	2019	189	78	26	3
34%	1987	156	60	19	8
	2018	62	31	7	0
	2019	55	18	0	0
51%	1987	65	25	9	0
	2018	30	5	0	0
	2019	21	4	0	0

An increase in demand flexibility leads to lower electricity prices, as shown in Table 8.9, yet the influence is less substantial. In 2030, a flexibility rate of 34% reduces electricity prices by approximately 25-30%. Further increases in demand flexibility do not result in a proportional decline. In 2050, increasing flexibility from 17% to 34% results in only a 12-15% reduction in average electricity prices, aligning with the patterns in the reduction of electricity shortages. As flexibility rises, market prices are more frequently set by the WtP of load-shedding processes. The highest WtP is set at €1500/MWh, keeping prices elevated despite the overall reduction in shortages.

Table 8.9: Experiment 5: Average electricity prices (€/MWh) - 2030

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW
17%	1987	283	193	148	133
	2018	167	122	95	82
	2019	189	124	95	79
34%	1987	207	144	113	105
	2018	124	97	81	75
	2019	132	95	80	74
51%	1987	161	119	101	95
	2018	105	83	74	73
	2019	107	85	75	73

Impact of DSR on hydrogen turbines

The results also demonstrate that both increased hydrogen capacity and DSR contribute to mitigating electricity shortages, suggesting they operate as substitutes up to a certain level. As anticipated, higher demand flexibility has a large effect on the annual profits of the hydrogen turbines, illustrated in Table 8.10. At all capacity levels, higher DSR rates strongly diminish the profitability of hydrogen CCGTs.

Interestingly, the full load hours of the turbines (Table 8.11) do not decline at the same rate as their profits. This indicates that the DSR does not take over the role of hydrogen turbines, but it primarily flattens or influences the hourly demand curve. Consequently, while it reduces profits, it does not significantly impact the total produced electricity from the hydrogen turbines. The decline in profit occurs because periods of scarcity are substantially reduced, lowering the periods where hydrogen turbines could earn high scarcity rents.

Table 8.10: Experiment 5: Hydrogen turbine Profits (MEUR/GW) - 2030

DSR rate	WY	2.5 GW	5 GW	7.5 GW
17%	1987	863	400	181
	2018	390	145	17
	2019	394	128	-19
34%	1987	440	131	22
	2018	172	25	-35
	2019	145	6	-48
51%	1987	244	64	-24
	2018	56	-28	-50
	2019	58	-33	-57

Table 8.11: Experiment 5: Full load hours - 2030

DSR rate	WY	2.5 GW	5 GW	7.5 GW
17%	1987	722	535	400
	2018	420	305	233
	2019	508	362	268
34%	1987	694	497	351
	2018	410	296	218
	2019	497	338	243
51%	1987	652	446	322
	2018	395	291	203
	2019	470	333	226

8.7. Results of experiment 6: Batteries

This experiment assesses the influence of batteries on electricity shortages and consequently determines the need for hydrogen turbines in a sustainable electricity system. Additionally, the influence of increased battery capacity on the economic viability of hydrogen turbines is explored. The results of the battery experiment for 2030 are presented in this section, with the findings for 2050 available in Appendix H. The results for the other simulation years follow a similar pattern and are therefore not illustrated.

Impact of batteries on electricity system

While increasing battery capacity reduces electricity shortages to some extent, its overall impact remains limited, as can be seen in Table 8.12. Even when tripling the battery capacities outlined in the KA and NAT scenarios, LOLE hours persist across all weather years. This is in line with the expectation of the potential role of batteries in mitigating supply shortages. As explained in chapter 6.6, through the verification of battery behaviour, batteries are not designed for electricity delivery over extended periods. Once depleted, they require excess electricity to recharge, which is not available during prolonged shortages or Dunkelflautes. Consequently, they cannot provide the necessary electricity when it is most needed. A similar trend is observed in electricity prices, depicted in Table 8.13. While additional battery capacity leads to a small decline in price levels, the overall impact remains marginal.

Table 8.12: Experiment 6: LOLE hours - 2030

Battery	WY	0 GW	2.5 GW	5 GW	7.5 GW
x1	1987	348	181	92	36
	2018	166	86	37	14
	2019	189	78	26	3
x2	1987	281	142	69	21
	2018	130	65	31	9
	2019	137	55	19	0
x3	1987	254	122	57	17
	2018	104	59	24	7
	2019	114	43	14	0

Table 8.13: Experiment 6: Average electricity prices (€/MWh) - 2030

Battery	WY	0 GW	2.5 GW	5 GW	7.5 GW
x1	1987	283	193	148	133
	2018	167	122	95	82
	2019	189	124	95	79
x2	1987	255	173	135	121
	2018	146	109	87	76
	2019	163	109	86	73
x3	1987	238	161	123	112
	2018	132	101	81	72
	2019	149	100	80	69

Impact of batteries on hydrogen turbines

When examining the impact of increased battery capacity on annual profits, the effects are relatively small, as expected, as shown in Table 8.14. Higher battery capacity slightly reduces the profitability of hydrogen CCGTs, as batteries can partly take over the role of the hydrogen turbines, leading to a slight reduction in their full load hours (Table 8.15). However, during prolonged shortage periods, when electricity prices peak for consecutive hours, hydrogen CCGTs maintain an advantage. Unlike batteries, which deplete quickly and cannot provide sustained output, hydrogen turbines can continue generating electricity, capturing these high market prices and maintaining profitability.

Table 8.14: Experiment 6: Hydrogen turbine profits (MEUR/GW) - 2030

Battery	WY	2.5 GW	5 GW	7.5 GW
x1	1987	863	400	181
	2018	390	145	17
	2019	394	128	-19
x2	1987	728	330	125
	2018	312	113	1
	2019	297	82	-32
x3	1987	654	279	102
	2018	269	82	-9
	2019	242	53	-40

Table 8.15: Experiment 6: Full load hours - 2030

Battery	WY	2.5 GW	5 GW	7.5 GW
x1	1987	722	535	400
	2018	420	305	233
	2019	508	362	268
x2	1987	666	481	355
	2018	354	263	201
	2019	440	311	232
x3	1987	619	449	325
	2018	304	231	176
	2019	386	272	201

8.8. Summary of model results

The experiments were primarily focused on investigating the influence of various uncertainties on the reliability of the future electricity system, measured through LOLE and EENS, the electricity prices, and the economic feasibility of hydrogen turbines, including their utilisation rates. The findings are structured per topic in this section.

Reliability of the electricity system

The results from the experiments show that, given the model assumptions, the KA and NAT government scenarios include insufficient generation capacity to prevent electricity shortages. While all scenarios show similar trends, the severity of electricity shortages highly depends on uncertainties such as asset configurations and weather conditions. Across all simulation years, significant supply shortages remain, particularly with a higher share of vRES capacity and during Dunkelflautes.

Moreover, while a reduction of 20% of the anticipated electricity demand naturally reduces estimated supply shortages, it still does not eliminate them entirely. Similarly, the model results showed that an increase of solely demand flexibility is insufficient to prevent shortages. Increases in DSR significantly reduces the LOLE hours through shedding and shifting electricity demand during scarcity moments. Yet, due to the fact that delayed electricity demand must eventually be compensated for, it can only mitigate shortages to some extent. As expected, the role of batteries in mitigating electricity shortages remains limited. Even with significantly increased capacities, they fail to prevent LOLE hours from occurring. The impact of batteries on reducing shortages is thus limited. This suggests that while demand reductions and flexibility, as well as battery storage, alleviate anticipated reliability issues to some extent, they are not a complete solution.

Role of hydrogen turbines

Hydrogen turbines can play an important role in mitigating electricity shortages, particularly during periods of low renewable generation and limited flexibility options. Furthermore, their presence helps lower average market prices by preventing extreme scarcity pricing on the day-ahead market, which would apply uniformly to all consumers during these moments. However, several key challenges emerged from the results.

When increasing the installed capacity of hydrogen turbines, the first LOLE hours can easily be mitigated, however eliminating the final LOLE hours requires incrementally large capacity investments. The missing capacity, defined as the capacity required to keep below the LOLE standard of four hours, is very high, and during Dunkelflautes, the missing capacity is even higher than during regular years. Beyond a particular threshold, with the exact value depending on the specific scenario, the benefits of adding more capacity become smaller. Besides, the effectiveness of hydrogen turbines in mitigating electricity shortages is highly dependent on the availability of hydrogen production, storage, and import capacity. During later asset years, even with unlimited hydrogen CCGT capacity, the ability of hydrogen turbines to fully eliminate shortages is constrained by hydrogen availability.

Profitability of hydrogen turbines

The model and financial analysis indicate that under the KA and NAT scenarios, hydrogen turbines can become economically viable under some scenarios, however, this is highly dependent on various uncertainties. First, weather variability significantly affects full load hours and revenue potential: In years with extreme weather conditions, hydrogen turbines run more frequently and generate higher profits compared to years with more renewable generation. Additionally, electricity demand plays an important role. If demand turns out to be lower than anticipated in government scenarios, the potential role and profits of hydrogen CCGTs decline drastically. A low electricity demand significantly reduces the revenue potential for hydrogen turbines, eventually leading to financial losses rather than profits. Moreover, DSR has a strong negative impact on hydrogen turbine profitability, as it reduces scarcity events where these turbines earn most of their revenues.

The expansion of total installed hydrogen CCGT capacity itself diminishes profitability as well. As more GWs of hydrogen CCGT capacity are added, total profits decline because the additional capacity alleviates electricity shortages, thereby reducing scarcity rents. The annual profit per GW decreases even more sharply due to diminishing returns. The first turbines in the system generate the highest revenues with the lowest costs, while subsequent additions face reduced operational hours and lower market prices, making them less profitable.

Influence of hydrogen prices on profitability

The influence of hydrogen prices on their profitability appears to remain limited compared to the other uncertainties, particularly in scenarios with high vRES penetration and low conventional generation capacity. In simulation year 2050, the only other conventional generator is nuclear, which has lower marginal fuel costs than the hydrogen turbines. In this case, the hydrogen turbine has the highest marginal costs, regardless of the price level. When the hydrogen turbine is the last generator in the merit order, its bid price sets the electricity price for all generators, meaning it earns no inframarginal rents. Furthermore, during scarcity events, the difference between production costs and the market cap is affected by hydrogen prices, but this impact is relatively minor. For instance, at a hydrogen price of 13 €/kg, the scarcity rent during a LOLE hour is €3350/MWh (4000 - 390/0.6%), while at 6 €/kg, it increases relatively only slightly to €3700/MWh.

In asset configurations containing other dispatchable generators, particularly natural gas turbines, lower hydrogen prices have a more significant effect. A reduction in hydrogen prices improves the merit order position of hydrogen turbines, allowing them to achieve more full load hours and consequently benefit more from inframarginal rents. Profits scale, however, not proportionally with full load hours, as hydrogen CCGTs become more frequently the marginal unit in the merit order. In these moments, it sets the market price rather than benefiting from inframarginal rents.

9

Government interventions

This chapter qualitatively evaluates potential government interventions to stimulate investment in hydrogen turbines within the Dutch electricity market. This assessment is based on findings from literature, expert interviews, and model findings. Insights from the second round of interviews, as detailed in chapter 3, are incorporated into this analysis.

Drost [42] identified three policy instruments that effectively support both decarbonisation and electricity system reliability in the Netherlands: a CapEx subsidy, hydrogen operational subsidies, and capacity remuneration mechanisms CRMs. Other regulatory, pricing, and facilitation instruments were found to be ineffective in achieving both objectives and are therefore excluded from further analysis. This study builds on these findings by assessing the expected impact of the three selected instruments on investment decisions in hydrogen turbines.

9.1. CapEx subsidy

The first intervention involves reimbursing the initial capital costs of building new hydrogen turbines or retrofitting existing natural gas plants. This reduces the financial risks associated with high capital costs. However, once the turbines are operational, financial support stops, meaning it does not address risks related to low operational hours. Additionally, as long as hydrogen remains more expensive than natural gas, operators will not want to use hydrogen as a primary fuel but rather utilise natural gas [50]. Governmental research indicates that a retrofitting subsidy alone is insufficient to ensure structural usage of hydrogen [48]. To ensure that turbines will operate on hydrogen, a structural support mechanism is needed [48]. Besides, to stimulate investments in new turbines, long-term contracts within financial government support are needed [49]. Consequently, a CapEx (retrofit) subsidy alone is thus considered ineffective in stimulating investments in hydrogen turbines.

9.2. Hydrogen operational subsidies

Two types of operational subsidies are assessed in this chapter: A hydrogen exploitation subsidy and a two-sided contract for differences (CfD).

Exploitation subsidy

A hydrogen exploitation subsidy offsets the cost difference between hydrogen and natural gas plus carbon costs, improving the financial competitiveness of hydrogen turbines compared to natural gas plants [48]. While this measure reduces some operational risks, it does not eliminate them. In years with high renewable generation, hydrogen turbines will still have low operational hours, which limits their profitability. Additionally, the €1 billion currently allocated for hydrogen exploitation subsidies would be quickly depleted and is insufficient for sustained long-term support, according to governmental research [48].

Two-sided contract for differences

Two-sided CfDs are a financial mechanism designed to stabilise revenues for vRES by mitigating wholesale market price volatility. One-sided CfDs are already in use to support renewable energy projects, providing predictable returns for developers [60]. Under this arrangement, a predetermined price for electricity is agreed upon between the producer and the counterparty, in this case, TenneT. The strike price includes a margin for profitability to ensure that the producer can recover investment and fixed costs. If the market price falls below the strike price, the CfD counterparty compensates the electricity producer for the difference. Two-sided CfDs introduce an additional agreement: if the market price exceeds the strike price, the producer reimburses the excess revenue to TenneT [93]. This symmetrical arrangement protects consumers from excessively high electricity prices, as surplus earnings are returned to the system and capping the producer's profits at the strike price [93].

A drawback of this intervention is that hydrogen turbines could have an incentive to bid in the day-ahead market below their actual costs to increase their operational hours, knowing they are guaranteed the strike price with a built-in margin. This could distort the merit order by displacing vRES. To prevent such strategic bidding, an additional measure can be introduced, by implementing a minimum bidding price, ensuring that hydrogen turbines cannot bid below a certain level. Given that the number of hydrogen turbines in the future electricity system will likely remain limited, monitoring these turbines should be feasible [49].

More importantly, similar to exploitation subsidies, two-sided CfDs do not mitigate risks associated with low operational hours as the strike price is only received when the turbine sells its generated electricity. As a result, the operational risks related to low utilisation rates remain unresolved.

9.3. Capacity remuneration mechanisms

Experts emphasised the limitations of the current (energy-only) market conditions to ensure long-term adequacy in the electricity system, especially given the previous disruptions [9],[13],[19]. Unlike the previously discussed measures, CRMs require a significant shift away from the energy-only market design, as reimbursement is provided based on capacity availability. While Drost's research does not specify the exact form of a CRM, this study further explores its potential design and implementation [42]. The principles and functioning of CRMs are detailed in chapter 2.4, with the most relevant mechanisms repeated briefly here.

A well-designed CRM could provide revenue stability for investors while ensuring that sufficient dispatchable capacity is available when needed. A CRM with annual contracts could play a significant role in keeping existing power plants operational while supporting minor upgrades to extend their life span. If investments in new hydrogen turbines are required, or existing natural gas plants are to be converted for continued operation over the next 15 to 20 years, long-term contracts will be essential to mitigate investment risks [13].

Central capacity market

A central capacity market is a volume-based mechanism where capacity is procured by TenneT through a bidding process [39],[40]. This ensures sufficient electricity to meet demand, even during peak periods or low vRES generation. Suppliers submit bids reflecting the volume and price needed to recover their fixed costs, and an auction mechanism ensures that the most cost-effective capacity is selected. The capacity market operates alongside the wholesale market, allowing generators to continue selling their electricity at market prices while receiving certain revenues from capacity payments. For hydrogen turbines, participation in a capacity market could provide the additional income required to keep the turbines operational or to help recover investment costs. This added revenue stream enhances financial certainty and strengthens the business case for hydrogen turbines.

A notable drawback of a central capacity market is its limited encouragement for demand-side flexibility, as it primarily focuses on the supply side of the electricity system rather than incentivising consumer participation in balancing supply and demand [38]. Demand-side flexibility can also be incorporated in the capacity markets, although this might increase the complexity of the design of the capacity market

[38]. Another concern with capacity markets is the potential for excessive profits for turbines, as they can earn revenues from both capacity reimbursements and electricity markets. This could result in overcompensation for generators and consequently, high costs for consumers [48].

Reliability options

Reliability options are a form of CRM designed to ensure system adequacy while preventing excessive generator profits. It functions similarly to financial call options, where TenneT in this case, procures a fixed amount of capacity from generators through competitive auctions [37]. Thereafter, if wholesale market prices rise above this strike price, the generator must sell electricity at the agreed-upon price, preventing extreme price spikes and ensuring affordability for consumers. Furthermore, if the generator fails to supply electricity during shortages, it must pay the difference between the market price and the strike price, creating a strong incentive for generators to fulfill their obligations [40]. In return for committing capacity, generators receive a fixed capacity payment to cover their fixed costs or their investment costs, thereby reducing investment risk certainty.

Reliability options have a significant advantage compared to the previous CRM: they explicitly prevent excessive generator profits in the wholesale market by capping revenue through the strike price. This makes them a more balanced approach compared to a central capacity market. Like the central capacity market, reliability options do not inherently promote DSR, though DSR can be incorporated into the mechanism [38]. Despite their advantages, reliability options are more complex to implement than a central capacity market, requiring precise strike price determinations and market design to function effectively [38].

Other CRMs

In addition to these two mechanisms, other forms of CRMs exist, though they are estimated less effective for stimulating investments in hydrogen turbines, and therefore elaborated shortly. While an SR minimises market distortions, by operating outside the electricity market, it is considered unsuitable for hydrogen-fueled gas turbines, as these require new investments rather than prevent existing capacity from retirement [42].

Capacity payments, though simple to implement, have been criticised for their effectiveness. Capacity payments are relatively expensive and fail to guarantee sufficient investment to ensure system adequacy [39]. This mechanism does not secure adequate investment in new capacity, raising concerns about its ability to maintain system reliability and consistently meet demand.

Capacity subscription, in contrast to the other mechanisms, does actively encourage DSR by allowing consumers to contract their necessary capacity directly on the market. However, it is a new mechanism that has not been implemented yet, and due to the great responsibility on individual consumers, it is assumed that it will not be ready to be implemented on a large scale in the short term. Besides, the absence of long-term contracts increases the risks of investment cycles and fails to provide the stability needed for hydrogen turbines [40].

10

Discussion and recommendations

This chapter begins with an analysis and reflection of the model results presented in chapter 8. Next, the government interventions elaborated in chapter 9 are evaluated in relation to the model findings. Through these analyses, the sub-questions of the research are addressed. This chapter further outlines the limitations of the study and the relevance of the insights, followed by a discussion on the broader implications of the research. Finally, policy recommendations and suggestions for future research are provided.

10.1. Interpretation of findings

To investigate the influence of various uncertainties on the reliability and affordability of the future electricity system, as well as the economic feasibility and utilisation rates of hydrogen turbines, multiple experiments were conducted. Chapter 8.8 provides a summary of the model results, this section discusses the insights gained from these experiments and the trade-offs they reveal.

The findings indicate that electricity shortages are likely to occur, highlighting challenges in maintaining system reliability under the anticipated phase-out trajectories. The results suggest that the anticipated KA and NAT government scenarios provide insufficient generation capacity to meet the expected electricity demand, with shortages worsening as the share of vRES increases and conventional turbines decrease. While various forms of flexibility, including DSR, battery storage, and flexible capacity are expected to enhance system reliability, the results demonstrate that neither increasing demand flexibility nor battery storage is sufficient to fully eliminate shortages, as elaborated in chapter 8.6 and 8.7, respectively. DSR can alleviate electricity shortages through shedding and shifting of electricity demand during scarcity moments. However, due to the fact that delayed electricity demand must eventually be compensated for, it can only mitigate LOLE hours to some extent. Moreover, while batteries may be effective in addressing short-term imbalances, although this is not captured in this study, their impact on resolving the anticipated shortages in the day-ahead market remains limited.

These findings emphasise the necessity of dispatchable generation capacity. The results show that the missing capacity, defined as the capacity required to keep shortages below the LOLE standard of four hours, increases as vRES penetration grows and conventional generators phase out, with even greater values required during Dunkelflautes. With their ability to provide continuous electricity generation and flexible output, gas turbines can offer the necessary flexibility to maintain system reliability, even with a high share of vRES. In contrast, nuclear and coal turbines are less suited as flexible assets due to their slower startup and ramping capabilities [14],[94]. Given the policy commitment to phasing out fossil fuels, hydrogen turbines emerge as a promising solution by balancing sustainability and system reliability in a future electricity system with high renewable energy penetration [1].

Uncertainty affecting the investment decision

While hydrogen turbines present a potential solution to electricity shortages, the results highlight several challenges related to their profitability and investment risks. Under the KA and NAT scenarios, hydrogen turbines have the potential to generate profits in certain years, but their viability is highly dependent on various uncertainties. Several external factors, including weather conditions, electricity demand, other forms of flexibility, and market competition influence their profitability. Some of these factors can be controlled, while others remain beyond the influence of the government and market participants. Notably, these uncertainties have opposite effects on system reliability and turbine profitability.

While Dunkelflautes exacerbate electricity shortages, they also lead to higher revenues for hydrogen turbines due to elevated scarcity prices. Conversely, lower electricity demand improves problems with electricity shortages but simultaneously lowers turbine profits, as there are fewer high-price hours. A similar dynamic applies to DSR, which is expected to grow in the coming years. DSR helps mitigate supply shortages but it also reduces the scarcity rents that hydrogen turbines depend on for profits, thereby negatively impacting the economic feasibility of the turbines. The uncertainty and influence of these external factors increase the investment risks.

One key factor that can be influenced, yet presents conflicting interests, is the amount of installed hydrogen turbine capacity. The results highlight a trade-off between system reliability and the profitability of the turbines. Additional hydrogen turbines improve system reliability, reduce price volatility, and lower average electricity prices. However, from an investor's perspective, profitability is maximised when only a limited number of hydrogen turbines are installed, as they can take full advantage of high scarcity rents. Besides, beyond a particular threshold, which varies depending on the specific scenario, the benefits of additional hydrogen turbines capacity in reducing shortages diminish. Limiting the final electricity shortages requires significant capacity levels with low utilisation rates.

Hydrogen prices

Future green hydrogen production costs are highly uncertain, with projections varying widely. To evaluate the impact of hydrogen prices on the profitability of hydrogen turbines, the experiments incorporated three distinct price levels, ranging from €2 to €13 per kg. The influence of hydrogen prices on profitability appears to be relatively limited, particularly in scenarios with high vRES penetration and low conventional generation capacity.

When hydrogen turbines are the last dispatched generator in the merit order, their bid price sets the electricity price for all generators, meaning it earns no inframarginal rents. In simulation year 2050, nuclear power plants remains the only other type of conventional generator, with lower marginal fuel costs, even at the lowest hydrogen price level. Consequently, hydrogen turbines can only profit from scarcity rents rather than inframarginal rents.

In asset configurations that include multiple other types of dispatchable generators, such as simulation year 2030 or 2035, lower hydrogen prices have a slightly stronger effect. At a hydrogen price of €2 per kg, hydrogen turbines become more competitive compared to natural gas and biomass turbines, allowing them to achieve more operational hours and benefit from inframarginal rents. Despite the significant increase in full load hours at lower hydrogen prices, profitability does not rise proportionally, as hydrogen turbines set the market price more frequently. With price levels of €6 or €13 per kg, hydrogen turbines remain the last generators in the merit order. Compared to the other uncertainties, the impact of hydrogen prices on profitability remains minor, even in the earlier simulation years.

Low number of full load hours

A low number of full load hours puts additional pressure on the limited scarcity periods during which the turbines must generate their profits. Investors would generally prefer a model with slightly more operating hours at moderate prices, rather than one that relies heavily on a few extreme price spikes per year. A more stable revenue stream reduces dependence on price spikes and consequently, lowers investment risks. However, as electricity demand decreases, DSR rates increase, battery storage expands, hydrogen prices increase or more hydrogen turbines enter the market, full load hours decrease, thereby increasing investment risks.

Market failures and policy expectations

In addition to external uncertainties, several market failures also impact investment decisions in dispatchable generators. Previous renewable subsidies have significantly distorted the energy-only market, pushing it out of equilibrium. Moreover, the electricity market's price cap prevents the WtP from being reflected in the market, and past government interventions during high electricity price periods have further influenced investment signals [13],[19].

Another challenge identified during the interviews is that policy expectations also play an important role in investment decisions. Investors who anticipate the introduction of a CRM or other government support may delay investments in turbine upgrades or new plants, to prevent the risk of missing out [49]. This investment delay exacerbates reliability issues in the electricity system, which in turn increases the need for government intervention. This cycle creates a self-fulfilling prophecy, where expectations of future policy action discourage investment, ultimately making government intervention even more necessary.

Additionally, investors face uncertainty regarding competitor behaviour, which may lead to two suboptimal potential market outcomes. Underinvestment in hydrogen turbines could jeopardise supply security. On the other hand, excessive investment could oversaturate the market and make it unattractive for investors. Early investors may initially profit but face the risk that additional entrants will lower profitability. The situation becomes more complex if early investments are made by private market parties alone, while later ones will receive government subsidies. If later investors are expected to receive financial support, early investors may also demand subsidies, further distorting market dynamics. This type of competition behaviour can be analysed through game theory, where two competing parties must decide whether to invest without knowing the other's decision [95]. If both invest, they incur financial losses due to reduced profitability. If only one party invests, it achieves significant profits. If neither invests, they both break even. Given the risks, game theory suggests that the most likely outcome is that neither party will invest, as the financial risks outweigh the potential gains.

Necessity of government intervention

The conflicting interests between society and investors highlight the complexities of the Dutch energy-only market. Experts emphasised the limitations of relying solely on the market mechanisms to ensure long-term adequacy in the electricity system, particularly during the current energy transition [9],[13],[19]. The findings of this study indicate that market forces alone are unlikely to stimulate sufficient investments, especially not enough to cover shortages during Dunkelflautes. In theory, and under particular conditions, hydrogen turbines could be economically viable. Nevertheless, under current market conditions, investments will not materialise without support in practice [49],[50]. Without policy support, the investment risks related to the hydrogen turbines remain too high. The combination of external uncertainties, market failures, and uncertain policy expectations discourage investors from committing capital and it underscores the necessity of government intervention. Government action is required to bridge the gap between market incentives and societal needs, to ensure system reliability within a sustainable electricity system.

Literature emphasises the importance of clear and consistent government policies in facilitating the transition to a sustainable energy system [28],[36]. This was reinforced during the interviews, which highlighted that clear and predictable government policies are important, as they make market parties more willing to invest [19]. Nevertheless, from a government perspective, there is a significant degree of information asymmetry, placing them in a difficult position [48],[61]. It is unclear whether market participants genuinely require financial support to proceed with operations and future investments or if they are merely using this argument to secure subsidies [48]. This lack of transparency further exacerbates the complexity of conflicting interests among stakeholders. The government must weigh the risk of unnecessary financial intervention, and thus unnecessary market disruption, against the consequences of insufficient investment. Additionally, justifying financial support for an investment that could be viable without subsidies but carries excessive risks for private investors may be challenging for the government as well. Such support risks primarily benefiting investors rather than directly contributing to a reliable and affordable electricity system.

Effective interventions in mitigating investment risks

Effective government interventions should focus on reducing financial risks for investors by increasing long-term revenue certainty [49]. Without such measures, investment risks in hydrogen turbines remain too high, which leads to insufficient investments, jeopardising resource adequacy in a sustainable Dutch electricity system. Chapter 9 elaborates on the potential government instruments for stimulating investments in hydrogen turbines, and their corresponding advantages and drawbacks. This section discusses which interventions are considered effective.

Given the need for long-term revenue certainty, CapEx subsidies are deemed ineffective as they solely lower initial investment costs without addressing operational risks or incentivising structural usage of hydrogen. Exploitation subsidies improve competitiveness with natural gas turbines but do not reduce risks with low operational hours. Besides, they require substantial government funding, more than would currently be available. Two-sided CfDs provide relatively more profit certainty by guaranteeing a strike price that includes a profit margin for electricity generated by hydrogen turbines while preventing excessive profits, as revenues above the strike price must be given back. To avoid strategic bidding within this scheme, additional agreements would be required, increasing complexity and transaction costs. However, with this additional agreement, two-sided CfDs do not address risks related to low operational hours as the strike price is only provided if electricity is produced, which makes them an inadequate solution. Similarly, while an SR, a form of CRM, minimises market distortions, by operating outside the electricity market, it is considered unsuitable for hydrogen-fueled gas turbines, which require new investments rather than preventing existing capacity from retirement.

In contrast, a central capacity market with long-term contracts can effectively mitigate risks through the reimbursement of investment and fixed costs. It does however carry the risk of excessive generator profits, which would increase the CRM costs and contradict government objectives to avoid oversubsidisation. Reliability options, a specific, lesser-known form of CRM, balance investment incentives and affordability by capping the generator profits through a clawback mechanism. Additionally, they guarantee a maximum electricity price for consumers through a prearranged electricity price ceiling, ensuring the affordability of electricity for consumers, while reducing investment risks.

In conclusion, CRMs with long-term contracts stand out as robust interventions for stimulating investments in hydrogen turbines due to their ability to provide sustained support and mitigate operational risks associated with low full load hours.

10.2. Limitations of the study and relevance to real-world insights

While the model results contain valuable insights, it is important to acknowledge the limitations before discussing its practical implications.

In practice, hydrogen turbines can have multiple revenue sources, but this study focuses solely on the day-ahead market, with all electricity assumed to be traded in this market. In reality, the electricity markets are highly interconnected and influence each other. Forward and futures markets are expected to have a limited impact on electricity shortages and the profits of the turbine unless consumers want to hedge against the expensive electricity generated by hydrogen turbines, which could increase turbine revenues. Furthermore, electricity shortages can to some extent be mitigated through the intraday market, where far-reaching voluntary demand reductions play a role, as discussed in chapter 4.1. As a result, the model may overestimate the electricity shortages compared to other reports. For example, the number of LOLE hours predicted in the model is significantly higher than those reported by TenneT [12].

Another limitation of only modelling the day-ahead market is that the intraday market could also influence the business case for hydrogen turbines; however, its revenue potential remains constrained. Given their relatively fast ramping capabilities, CCGTs have the potential to trade on the intraday or balancing market and earn substantial revenues. However, in order to trade on the intraday market, the turbine must already operate at the minimum load level, which is around 30-35% of maximum capacity [96]. If a turbine does not clear in the day-ahead market, it is unlikely to engage in intraday trading.

A more common practice among traders is withholding a portion of their capacity from the day-ahead market, a strategy known as optionality, allowing them to sell electricity later at potentially higher intraday prices [9]. Nevertheless, participation in the intraday or balancing market reduces the available capacity in the day-ahead market. For example, generators could sell 90% of their capacity in the day-ahead market while reserving 10% for intraday trading. This reserved capacity can then be sold at higher intraday prices. The projected revenues from trading on these markets are thus constrained and more importantly, even more uncertain. The final limitation of only incorporating the day-ahead market is that other potential revenue streams, such as congestion management services, are also not considered in the model. This means the actual business case for hydrogen turbines could be more favourable than estimated.

Another limitation stems from the solver's dispatch, which minimises total system costs using weighted cost prices. This approach can lead to operational losses for individual assets within the model, which occurs in cases where the model used the battery or hydrogen turbine for dispatch based on total system costs rather than individual market profitability. For instance, in simulations, batteries buy and sell electricity based on weighted system costs rather than direct market prices, which can lead to operational decisions that would not occur in reality. Similarly, for hydrogen turbines, fuel costs and revenues are calculated using the HCP, which is determined at the end of the model run. Due to the 60% efficiency of hydrogen turbines, there are a few instances where the fuel cost for a specific time step exceeds the electricity market revenue, leading to negative operational margins. In reality, a turbine would not operate under these conditions. Furthermore, the model does not account for strategic bidding behaviour, price blocks, or must-run constraints, all of which are important elements of real-world dispatch [50].

Moreover, the copper plate assumption means that transmission constraints, regional grid congestion, and locational differences in supply and demand are ignored in the model. This may lead to an overestimation of system flexibility, as real-world grid congestion can prevent electricity supply from being transported across the network. Incorporating transmission constraints would probably further exacerbate the reliability problems found in this study. For hydrogen turbines, their location would, in practice, influence their ability to sell electricity to some extent, which could both have a positive or negative impact, depending on the specific location.

A last important limitation is that hydrogen demand from other sectors besides the electricity market is not incorporated in the study. Leaving out this demand may affect the availability of hydrogen for the hydrogen CCGT, which may in turn have a negative influence on the profits of the turbine and system reliability. Similarly, electricity import and export are not considered in the study, which can also impact both the shortages and the business case of hydrogen turbines.

Interpreting model findings in real-world context

The objective of this study is not to predict exact shortages or financial outcomes but rather to analyse how various conditions and uncertainties influence the system reliability and profitability of turbines. As such, the limitations outlined above do not directly undermine its validity but rather highlight factors to consider when interpreting the results.

The model provides a structured approach for assessing the impact of deep uncertainties, and since the same assumptions and simplifications are consistently applied across all scenarios, the relative comparisons offer relevant insights. While absolute values should be interpreted with caution, the overall trends identified in the model offer meaningful insights into system behaviour. Furthermore, by incorporating expert insights, the study acknowledges and evaluates the limitations, thereby ensuring that the findings can be meaningfully translated into real-world implications, which is done in chapter 10.4.

10.3. Uncertainty regarding development of hydrogen market

The potential contribution of hydrogen CCGTs depends on the availability of hydrogen. During the conceptualisation phase, elaborated in chapter 5, it was assumed that the Dutch hydrogen market would be developed by 2030. However, as discussed in chapter 4, the development of the hydrogen market remains uncertain with a high level of interdependency within the hydrogen supply chain. These interdependencies create additional uncertainty and risks for investors [13]. This section examines the separate components of the hydrogen supply chain and recent developments in the Netherlands.

Hydrogen network

HyNetwork, a subsidiary of Gasunie has initiated the development of a national hydrogen network by repurposing existing natural gas pipelines for hydrogen transport [97]. Once the hydrogen network is operational, the location of hydrogen turbines will no longer be a limiting factor for hydrogen supply. Similar to the distribution of natural gas, hydrogen gas turbines can be supplied via pipelines connected from storage.

HyNetwork began construction in 2023, starting in the Port of Rotterdam. In late 2024, an updated rollout plan was published, with an adjustment to the previously announced timeline. The revised schedule, illustrated in Appendix I, is as follows [97]:

- Phase 1 (2023-2026): Initial deployment in the Port of Rotterdam, plan is to be operational in 2026.
- Phase 2 (Before 2030): Expansion of hydrogen infrastructure within the four coastal industrial clusters, including a connection to HyStock (UHS) in Zuidwending. Completion is targeted before or by 2030.
- Phase 3 (2031-2033): Interconnection of four clusters and expansion to other regions in the Netherlands. This phase also includes the Delta Rhine Corridor (DRC).
- Phase 4 (After 2033): Further reinforcement of the hydrogen network where necessary. The timeline for this phase has not yet been announced, but this will be after 2033.

Delta Rhine Corridor project

The DRC project aims to connect industrial clusters in the Netherlands and Germany through a network of hydrogen and CO_2 transport pipelines. Initially, the project included multiple transport modalities, such as ammonia pipelines and electricity cables. However, due to the project complexity and delays, the scope has been narrowed to focus exclusively on hydrogen and CO_2 [98]. This revision results in a more targeted and feasible approach.

The DRC project is divided into two segments: DRC West and DRC East. According to the latest timeline, DRC West, which connects Rotterdam and Boxtel, the project is scheduled for completion between 2031 and 2032 [99]. DRC East, which extends the corridor from Boxtel to the German border, is expected to be completed between 2032 and 2033. Once operational, hydrogen import through the DRC can directly be integrated into the network, as it will be connected to the Dutch hydrogen network.

Hydrogen import through ships

The Netherlands has established hydrogen collaborations with countries that are well-positioned for green hydrogen production and export, such as Norway, Chile, and Namibia [100]. The majority of this international hydrogen transport will take place via ships. Whereas in the model the imported hydrogen can directly be utilised from the international market into the turbines, in practice, the hydrogen must be stored to ensure availability at a later moment, increasing the need for UHS.

Green hydrogen production

The Dutch government has set a target of 3-4 GW of electrolyser capacity by 2030, with an increase in target to 8 GW by 2032 [101]. However, there are doubts about the feasibility of these ambitious targets [102]. If all planned projects are successfully developed and executed, the target is achievable. However, currently, only one project, the Holland Hydrogen I from Shell, has reached the final investment decision and is at present under construction [103]. This 200 MW electrolyser is planned to become operational in 2025.

Several additional projects are in various stages of planning, development, and permitting, led by different companies, for example, Eneco, RWE, and ENGIE [104],[105],[106]. Most of these projects will receive government support in the form of subsidies and are scheduled for completion shortly before

2030. However, it is highly uncertain whether and how many of these projects will ultimately go through and be materialised [102]. This makes it unclear whether sufficient investments will be realised to meet the target of 8 GW by 2032.

For new large-scale projects, the lead time takes multiple years due to the various development phases. This consists of feasibility and concept engineering, including site selection, a permission and subsidy trajectory, and the project financing, construction, and commissioning [107]. CE Delft estimated the total lead time for new electrolyser projects, without reinforcing the electricity network, to be 5 to 8 years, underscoring the long development timelines and the necessity of current investments to reach future targets [107].

Underground hydrogen storage

HyStock, another subsidiary of Gasunie, is developing the first UHS salt cavern facility in Zuidwending [108]. In 2025, an agreement was signed between the involved companies to formalise their collaboration for the safe and successful realisation of UHS in Zuidwending [109]. The initial salt cavern, with a capacity of 216 GWh, is expected to become operational by 2031. Plans are in place for three additional caverns in the same area, bringing the total storage capacity in Zuidwending to nearly 1 TWh [110]. The lead time for new caverns in Zuidwending is estimated to be 3 to 5 years, while the development of onshore salt caverns at new locations is projected to take 5 to 7 years [111]. Currently, the salt cavern in Zuidwending remains the only definitive investment decision for UHS within the Netherlands.

The technology of storing pure hydrogen in depleted gas fields is still under development and pilot projects are necessary [111],[112]. A feasibility study conducted by EBN and TNO suggests that offshore UHS appears to be technically viable for both salt caverns and gas fields [111]. However, implementation must first be demonstrated through pilot projects before offshore storage can be deployed. The study furthermore highlights the complexity and long lead times of UHS. Developing offshore salt caverns for hydrogen storage is a complex process with an estimated development time of 10 to 15 years from initial planning to commissioning [111]. If the technology of pure hydrogen storage is developed, the lead time is anticipated to be 8 to 13 years. Appendix I outlines two general development timelines for offshore salt caverns and offshore depleted gas fields [111].

Meanwhile, Germany is actively exploring and demonstrating hydrogen storage projects, but it remains uncertain how much storage capacity they will develop and how much of it will be accessible to the Dutch hydrogen market [111]. To ensure energy self-sufficiency, in line with current Dutch policy, further research and investment in domestic UHS development is necessary.

Hydrogen market development outlook

The assumption that the Dutch hydrogen market will be fully developed by 2030 appears unrealistic. Phase 3 of the hydrogen network, which will interconnect industrial clusters is not expected to be completed until 2033. While some parts of the network will become operational earlier, large-scale utilisation of the network will not be feasible before then.

Furthermore, the first salt cavern storage in Zuidwending is not expected to become operational until 2031, with three potential additional caverns becoming available even later. Moreover, these caverns are likely to also be used by the industry, potentially reducing the available storage capacity for the electricity market. The development of both new onshore salt caverns or offshore UHS, whether in salt caverns or depleted gas fields, requires several years and faces long lead times.

Although hydrogen production is expected to expand significantly before 2030, this expectation remains uncertain due to potential delays or withdrawals in investment decisions. Additionally, hydrogen turbines will only operate when vRES are insufficient to meet electricity demand. During such periods, hydrogen production via electrolysis will not occur, as there will be no surplus electricity. Consequently, hydrogen used in turbines will always be sourced from storage. Thus, even if the hydrogen production capacity is sufficient, without adequate storage or network infrastructure, hydrogen cannot be used for large-scale electricity generation. This highlights the importance of expanding hydrogen storage capacity in parallel with production.

Since hydrogen turbines are the last component in the hydrogen chain, their adoption depends on the development of the other components. Stimulating the investments in hydrogen turbines is only effective if the full hydrogen supply chain is developed or expected to be in the near future. As it stands, the hydrogen supply chain remains underdeveloped, making it neither technically feasible nor desirable to rely on hydrogen-fueled turbines within the next five to ten years [49]. Addressing this challenge requires a coordinated approach that ensures that infrastructure, production, and storage capacities develop in parallel, to enable a stable and scalable hydrogen market. A comprehensive perspective on the entire hydrogen value chain is essential for the successful deployment of hydrogen turbines.

10.4. Implications of the research for the Netherlands

The study shows that severe electricity shortages can be expected under current phase-out trajectories. During a LOLE hour, the market price on the day-ahead market reaches €4000/MWh, yet the actual societal costs for non-delivered electricity far exceed this clearing price. The VOLL is estimated at €69000/MWh, reflecting that the economic impact of electricity shortages is significantly greater than its cost price [50],[58].

Before an actual LOLE event occurs, an already undesirable situation arises in which market participants resort to emergency negotiations and extremely high payments on the intraday market to secure electricity. This is done to prevent TenneT from cutting them off, opting instead for a 'far-reaching voluntary' reduction of demand [48]. Although intraday market prices can exceed day-ahead prices, they do not reflect the full societal value of non-deliverd electricity, nor is it desirable for them to do so. Even if disconnections by TenneT can be avoided, extreme electricity prices would undermine the overarching Dutch policy objectives of ensuring an energy system that is affordable, reliable, safe, sustainable, and fair [1].

Price fluctuations, particularly increases during periods of scarcity, play an important role in signaling market conditions and incentivising demand flexibility. Although price fluctuations can enhance market efficiency, as they encourage consumers to shift or reduce their consumption in response to market prices, they also introduce significant challenges. Certain sectors, for example, hospitals and other essential services, lack the flexibility to adjust their demand, making them particularly vulnerable to extreme price spikes. Additionally, prolonged high prices not only affect industrial consumers but also households with dynamic contracts, who may face significant financial consequences. In extreme cases, electricity could become, to some extent, a luxury good, disproportionately affecting lower-income households and further raising concerns about energy affordability and social equity.

Besides, high electricity prices coupled with the growing risk of supply shortages, create an unfavourable investment climate in the Netherlands, making it less attractive for industries and businesses to establish or expand operations [19]. This could have long-term consequences for economic growth, industrial activity, and employment in the Netherlands.

Reflection on current government policy

Current government policy regarding electricity security largely follows a wait-and-see approach, still relying on market forces to resolve adequacy challenges [56],[65]. The indication that electricity supply security in the Netherlands is well ensured until 2030, results in a withholding of immediate action [12]. However, this passive stance carries significant risks, particularly when financial support continues to be provided to other areas of the electricity market, thereby further reducing investment incentives, and long-term consistency in policy is missing.

While the government faces challenges due to information asymmetry and the risks of over-subsidisation, this study highlights that targeted intervention is needed to stimulate hydrogen turbine investments. As long as policy interventions distort the market in favour of renewables, without addressing investment barriers for hydrogen turbines, market participants are unlikely to invest in hydrogen turbines. Additionally, natural gas turbines may delay or cancel large investments, as they either expect to be phased out within a few years or expect government support to be kept operational. This cycle increases the risk of insufficient dispatchable generation capacity, threatening both system reliability and electricity affordability.

Achieving CO_2-neutrality by 2035

The policy approach of setting ambitious targets without concrete implementation measures might be insufficient to actually reach these targets. The goal of reaching a CO_2-neutral electricity system by 2035 lacks clear investment sub-targets and replacement strategies for retiring power plants. Coal and gas phasing-out trajectories have defined targets for 2030 and 2035, but there is no clear plan regarding the replacement of this capacity with dispatchable, CO_2-free alternatives [113]. Moreover, within the current policy program, funding allocation appears misaligned with the goals [65]. The budget of the Climate Fund for green hydrogen development and battery storage has been reduced, whereas funding for nuclear power development has been increased [65].

Nuclear power plants

Although government plans include the construction of four new nuclear power plants, nuclear energy alone cannot provide a comprehensive solution for addressing peak shortages [65]. Nuclear power plants are primarily designed for steady baseload generation and lack the flexibility to respond to fluctuating vRES electricity generation [14]. While nuclear power can reduce overall shortages by providing consistent electricity, its must-run constraints limit operational flexibility [114]. This could lead to situations where additional capacity is needed, but nuclear generators are still in their startup phases or constrained by ramping limitations. Conversely, it could also result in curtailment during periods when vRES generation alone would suffice, yet nuclear plants must continue to operate. Thus, expanding nuclear capacity has the potential to reduce electricity shortages but it may simultaneously increase curtailment.

Furthermore, given the financial risks associated with the high CapEx of nuclear plants, private market parties are not willing to be responsible for constructing and exploiting the power plant, even with government support [115]. Due to their long lead times, any investment decisions, whether made by the government or through a collaboration, would likely result in new nuclear plants not being operational by 2035, making them an ineffective solution for the reliability issues until then [116]. Notably, the capacity assumptions in this study already account for an increase in nuclear power capacity in 2040 and 2050, which still resulted in shortages, highlighting the need for more dispatchable capacity.

Need for clear transition plan

The trilemma of the electricity system, balancing sustainability, reliability, and affordability, becomes increasingly complex as the 2035 deadline approaches. Achieving a CO_2-neutral electricity system within 10 years requires immediate actions and investments. Without decisive action, the transition to a sustainable, yet reliable, and affordable Dutch electricity system faces significant risks and delays.

Both this study and TenneT's monitoring report raise concerns about future electricity system reliability [12]. Since new capacity development takes at least six years, delaying investment decisions increases the chance of severe shortages [13]. Consequently, even if the 2035 sustainability target is reconsidered, investments must start immediately to prevent future reliability problems. Waiting until shortages become severe before taking action regarding the security of supply, could ultimately result in significantly higher costs for consumers than proactively preventing them [49]. Experts argue that the security of supply is too important to be left to market forces alone, and interventions should be considered before reliability issues escalate [13],[19].

Shorter term resource adequacy

This study focused on hydrogen-fueled gas turbines from the period 2030 to 2050 due to their expected role in a sustainable electricity system. However, as elaborated in chapter 10.3, the deployment of hydrogen turbines before 2033 is unrealistic. But, as indicated by this study and TenneT's report, problems with the electricity supply are anticipated to arise before then [12].

An important consideration is whether government interventions should focus on hydrogen turbines immediately or prioritise maintaining and extending the operational lifespan of existing natural gas plants while allowing and supporting the hydrogen market to develop. Until the hydrogen value chain reaches sufficient maturity, other policy interventions may be more effective in ensuring the security of supply than a central capacity market and reliability options.

Strategic reserve as short-term solution

An SR is considered ineffective for stimulating investments in hydrogen turbines, as discussed in chapter 9.3, but it could help improve the reliability of the electricity system in the shorter term without significantly distorting market dynamics. Unlike other CRMs, an SR operates outside the market, while most generators continue to operate under normal market conditions. Reserve capacity is only activated in extreme scarcity events, ensuring that market price signals remain largely intact.

However, an SR has disadvantages as well. One risk is strategic behaviour where generators claim they need financial support to avoid decommissioning, even if they might remain operational without assistance [37]. This behaviour is already observed in the market and is expected to increase with the announcement of an SR. Additionally, an SR reduces economic efficiency, as designated reserve generators are withdrawn from the system and only used when all other generators have already been dispatched. This therefore makes an SR more of a temporary intervention rather than a long-term solution.

Nevertheless, an SR can be particularly useful during the current energy transition as it provides a flexible mechanism to prevent capacity shortages by preventing retirements of dispatchable capacity. Under the SR, natural gas turbines can execute maintenance investments to prolong their lifespan. Given its temporary nature, it can be scaled up or phased out as needed, depending on market developments. Over time, as the hydrogen supply chain matures, the SR could gradually be phased out or transition into a broader capacity mechanism.

10.5. Concrete policy recommendations

The previous section already discusses several implications and recommendations for the government. This section provides an overview of the concrete recommendations that should be implemented to ensure the reliability, affordability, and sustainability of the future Dutch electricity system.

Adopt a proactive approach and provide policy clarity

To ensure sufficient flexible capacity in a sustainable electricity system, targeted intervention is necessary. Investments in hydrogen turbines will not emerge without government support. To prevent future electricity shortages and ensure a successful transition, the government must provide clear, consistent, and forward-looking energy policies. Both the development and construction of new turbines and a well-designed capacity remuneration mechanism require several years. Therefore, the government must act now to secure an affordable, reliable, and sustainable electricity system for the future. Clear long-term policy objectives must be provided to investors, as with stable and clear policy, market parties are more willing to invest [19]. Without decisive action, the Netherlands risks electricity shortages and underinvestment in hydrogen turbines, making it impossible to achieve a reliable and sustainable electricity system by 2035.

Develop a timeline with clear milestones

A structured transition plan with sub-targets is needed to ultimately achieve the goal of a CO_2-neutral electricity system. The government should develop a detailed timeline of which milestones need to be achieved when and what policy actions are required to achieve these targets. Continuous evaluation of investments and the feasibility of reaching the sub-targets is necessary. Investment must be stimulated according to these milestones, with adjustable forms of support. Without a long-term plan, the lack of investment threatens the energy transition.

Monitor and stimulate the development of hydrogen value chain

Given that the hydrogen market is still in its early stages, large-scale deployment of hydrogen turbines before 2033 is unlikely. The hydrogen value chain is highly interdependent, requiring simultaneous development of hydrogen production, storage, infrastructure, and turbines. However, the lack of investment certainty across these components hinders the large-scale deployment. To support the adoption of hydrogen turbines and achieve CO_2-neutrality by 2035, investments in the hydrogen chain must be made now due to the long lead times of the separate components. The government must take a comprehensive, system-wide approach to identify where targeted support is needed and ensure that all components of the hydrogen value chain develop in parallel. Government interventions should be in place where needed. Without coordinated action, bottlenecks in one part of the chain will delay the overall transition.

Regarding hydrogen turbines, a CRM should be designed to mitigate long-term investment risks. Without clear long-term incentives, investment in hydrogen-fueled gas turbines will remain insufficient, increasing the risk of capacity shortfalls and delaying the transition away from fossil fuels.

Implementation of an SR for short-term reliability

To maintain system reliability during this transition period until the hydrogen chain matures, an SR should be implemented to prevent electricity shortages while allowing time for hydrogen turbines to develop. Transparency requirements regarding profitability should be enforced on natural gas generators participating in the SR, ensuring that financial support is justified and that costs remain controlled. Given the relatively small number of power plants involved, monitoring their financial performance should be feasible [49]. This would prevent disproportionate financial support and ensure that electricity prices and network tariffs do not rise unnecessarily, maintaining affordability for consumers

Balance stimulation of DSR

Not only should the hydrogen supply chain be considered as a whole, but the broader energy system must also be viewed in its entirety. DSR can play an important role in balancing electricity supply and demand by (temporarily) reducing electricity demand during scarcity periods. Stimulating DSR is seen as an effective measure to increase the flexibility of the electricity system. In line with this, the government has outlined plans to actively focus on further developing DSR to ensure the security of supply [56].

Nevertheless, it is important to recognise that enhanced DSR weakens the business case for dispatchable generators, including hydrogen-fueled gas turbines. If policies are introduced to encourage DSR they risk further disrupting market dynamics, which decreases the likelihood of sufficient investment in dispatchable capacity even more. Since increasing DSR alone is insufficient to prevent all electricity shortages, any measures promoting DSR should be accompanied by targeted incentives for flexible generation. To maintain long-term system adequacy, it is important to ensure that investments in dispatchable technologies remain sufficient and avoid an overreliance on demand flexibility. Therefore, a coordinated approach is essential to prevent unintended consequences of policy measures.

10.6. Future research

This study has generated valuable insights that can serve as a foundation for future research, supporting both extensions of the current work and new research directions. This section presents recommendations for further research, with the first set of suggestions building upon the model, and the latter proposing a new direction for exploration.

Within the scope of this study, several questions remain open for further research:

- What level of compensation is required for reliability options or a central capacity market to cover investment costs and potentially fixed costs?
- What is the optimal strike price for reliability options to balance investment incentives and electricity affordability?

As outlined in the study's limitations, this research focused exclusively on the day-ahead market and employed an exploratory modelling approach to assess the impact of uncertainties. Now that these uncertainties have been analysed, an interesting next step is to examine revenue potential from additional electricity markets. The first recommendation is to evaluate the business case of hydrogen turbines based on the six value drivers of generation capacity [22]. Since hydrogen turbines can generate revenues beyond the day-ahead market, it would be valuable to investigate how other markets could be integrated into the model. However, incorporating these markets poses challenges due to differences in market dynamics and pricing mechanisms. A potential solution could involve clustering the various market mechanisms and using the delay function in Linny-R to approximate their effects. If direct integration proves too complex, a post-calculation approach could be used to estimate projected revenues. This would involve analysing the hourly output of the Linny-R simulations alongside company data on revenue distribution across markets.

Another suggestion is expanding the model to include interconnections with other countries. The Linny-R model currently focuses on the Netherlands and excludes interconnector capacity due to uncertainties regarding its availability during shortages. Extending the model to cover multiple countries, each with its own aggregated generation capacity and demand, could provide a more comprehensive assessment of system adequacy. This is particularly interesting to research as the annual monitoring report from TenneT uses high import levels to mitigate electricity shortages [12]. Historical data from various countries could be used to determine how often interconnectors were available and how this affected electricity shortages in the Netherlands. The historical weather data of all countries connected to the Netherlands via interconnections is available on Renewables.ninja [87]. Furthermore, the Euphemia model, which optimises electricity market clearing across Europe, could serve as a useful reference for this approach [117].

Furthermore, this study uses a copper plate approach, disregarding geographical and transmission constraints in the model. Future research could explore how hydrogen turbines could be integrated into the electricity grid to alleviate congestion, particularly in areas experiencing significant grid constraints. Modelling grid constraints could provide valuable insights for grid planning and determining optimal turbine locations. The model could be expanded to include an electricity grid representation to identify major congestion bottlenecks and assess the potential of hydrogen turbines as a congestion mitigation solution. Linny-R supports power grid constraints and offers the option to activate Kirchhoff's voltage law, making it a suitable tool for such an analysis. It is, however, important to disaggregate asset capacities and electricity demand before this model can be utilised.

This study examines the necessity of robust government intervention to stimulate investments in hydrogen turbines. However, given the high interdependency of the hydrogen value chain, it is equally important to identify the required interventions for the other components. A comprehensive, system-wide approach is essential to ensure the coordinated development of the entire chain. While this study briefly discusses developments within the hydrogen chain in chapter 10.3, further research is needed to define a structured timeline with clear sub-targets for investment across the value chain. Establishing this structured, long-term plan will enable the government to effectively monitor and guide the parallel development of the hydrogen market, ensuring a successful transition.

Finally, another area for future research is the comparison of different turbine technologies. A comprehensive study examining hydrogen-fueled turbines, natural gas turbines, natural gas with carbon capture and storage (CCS), and green gas turbines could offer valuable insights into their relative advantages and challenges. A first question can be how much CO_2 reduction is actually achieved by switching to hydrogen turbines, considering their low operational hours and the resulting limited emissions. Further research could also explore whether green gas or natural gas with CCS presents a viable alternative for flexible power generation and how its potential compares to hydrogen. Evaluating which turbine technology offers the most favourable business case, based on investment and operational costs, fuel availability, and emissions, would provide broad insights into the most cost-effective and sustainable solution for the energy transition.

11 Conclusion

The Dutch government aims for a CO_2-neutral electricity system by 2035 by phasing out coal and natural gas and increasing the share of vRES. To meet this goal while maintaining a high level of reliability and affordability of the Dutch electricity system, hydrogen turbines are necessary. This study shows that electricity shortages will occur without sufficient flexible generators and highlights the potential role of hydrogen turbines in mitigating these shortages by generating CO_2-free electricity. However, several barriers hinder their deployment, with high investment risks discouraging market parties from committing capital. The study was guided by the following question: What are robust and cost-effective government interventions to stimulate investments in hydrogen-fueled gas turbines to ensure the reliability of a sustainable Dutch electricity system?

Government support in the form of a capacity remuneration mechanism is necessary to stimulate investment in hydrogen turbines. This can be either through a central capacity market or reliability options. Furthermore, support should not only be focused on hydrogen turbines, as their deployment depends on the entire hydrogen value chain. The government should take on a helicopter view and actively monitor and support the development of the separate components. A system-wide approach, with additional targeted support, is required to ensure that the necessary hydrogen infrastructure, production, storage, and turbines mature in parallel. The current approach of setting ambitious targets without concrete measures is insufficient for a successful energy transition. Without decisive action, the transition to a sustainable, reliable, and affordable Dutch electricity system faces significant risks and delays.

Hydrogen turbines are needed for reliability in a CO_2-neutral electricity system

Under the phase-out trajectory of fossil-fuel generators, significant electricity shortages are expected, particularly as the share of renewable sources increases. As the electricity system moves toward full decarbonisation, the decline of dispatchable fossil-fuel generators along with the rising share of vRES amplifies the problems with the electricity supply. Weather conditions significantly influence electricity shortages as renewable electricity generation is affected by this. Additionally, the pace of electrification, which influences annual electricity demand, has a significant impact on the severity of the anticipated electricity shortages as well.

While battery storage and demand-side flexibility can help mitigate electricity shortages, these measures alone cannot resolve the expected shortages. Battery storage has limited effectiveness in addressing long-duration shortages, as batteries deplete quickly and cannot recharge in time. Similarly, demand flexibility can alleviate electricity shortages, but cannot compensate for prolonged periods of low renewable generation, as deferred demand must eventually be met. Given these limitations, hydrogen turbines are necessary to achieve a reliable CO_2-neutral electricity system by 2035. Their ability to deliver continuous CO_2-free electricity makes them particularly valuable in mitigating consecutive supply shortages.

Investments in hydrogen turbines require government support

Despite their potential contribution, market forces alone will not drive sufficient investments in hydrogen turbines to guarantee supply security. Their profitability is highly sensitive to several external market conditions. In years with low renewable electricity generation and high scarcity pricing, hydrogen turbines have the potential to generate substantial revenues. However, a higher share of conventional generators, lower electricity demand, or increased competition from batteries and demand flexibility, weakens their financial viability. These external uncertainties lead to unpredictable operational hours and profits for hydrogen turbines. Furthermore, the interdependency of the hydrogen chain and uncertainty regarding the large-scale development of the separate components introduce additional investment risks.

The Dutch electricity market is undergoing a transition and is not in equilibrium. Subsidies for renewable sources have accelerated the energy transition but have simultaneously disrupted market dynamics and created unfavourable conditions for dispatchable generators, including hydrogen turbines. Price caps on the day-ahead market and past interventions to suppress high scarcity pricing have prevented electricity prices from becoming high enough to attract new investments.

The combination of external uncertainties and market failures leads to high investment risks for hydrogen turbines. Without government intervention, these risks remain too high, leading to underinvestment and electricity reliability challenges. For investors, the primary risks are that hydrogen turbines have insufficient operational hours and electricity prices that are too low to recover costs, potentially leading to financial losses. Meanwhile, the greatest risk for society is underinvestment in flexible generation, which could cause severe electricity shortages.

Investors also delay investment decisions in anticipation of future government support, further reinforcing the risk of underinvestment by creating a vicious cycle. These policy expectations, coupled with high investment risks, hinder the deployment of hydrogen turbines, jeopardising both the reliability and affordability of the future sustainable electricity system.

CRMs offer a robust solution for stimulating investments

To stimulate investment in hydrogen turbines, government intervention must provide long-term support and reduce risks related to low operational hours. Annual contracts offer insufficient certainty, meaning longer-term commitments are necessary.

Capital expenditure subsidies reduce initial investment costs but do not address operational risks, making them ineffective for investment in hydrogen turbines. Hydrogen exploitation subsidies improve competitiveness with natural gas turbines but do not minimise risks regarding low operational hours and inframarginal rents. Two-sided contracts for differences provide relatively more revenue certainty by guaranteeing a strike price for electricity generated by hydrogen turbines while preventing excessive profits. However, they do not address risks with limited operational hours, as payments only occur when electricity is sold.

In contrast, capacity remuneration mechanisms, where payments are provided for capacity availability rather than solely the produced electricity, reduce financial risks by ensuring investors can recover fixed costs. Two forms emerge as robust policy measures for hydrogen turbines. First, a central capacity market, which ensures revenue certainty through a capacity auction where TenneT procures the generation capacity on behalf of the consumers. However, this mechanism risks excessively high profits for generators as participants can still earn revenues from the spot market, including from high scarcity prices.

Reliability options, similarly mitigate investment risks but include an additional clawback mechanism. Under this mechanism, consumers receive the right to purchase electricity at a predetermined strike price. When spot prices exceed this level, generators must return excess profits. Effectively, this means that generators sell their electricity at this strike price during scarcity, thereby preventing high scarcity prices for consumers. Since generators must pay this difference back, the mechanism also incentivises generators to fulfill their obligations and prevents generators from withholding capacity to drive up prices. Besides, the revenues of generators are capped, thereby balancing the profits of the generators and the affordability of the mechanism.

A system-wide approach is needed for hydrogen chain development

The effectiveness of hydrogen turbines depends on the entire hydrogen value chain. When sufficient hydrogen is available, hydrogen turbines can contribute to a sustainable, reliable, and affordable electricity system. However, if hydrogen supply is limited, their contribution remains constrained. As long as hydrogen production, storage, or infrastructure remains underdeveloped, large-scale deployment of hydrogen turbines is not feasible.

The hydrogen network is currently under construction, with a detailed rollout plan for the coming years. Nevertheless, large-scale utilisation of the infrastructure will not be possible before 2033. While the green hydrogen production technology is mature and the first large-scale electrolyser is being built, substantial investments are still required to scale production. Underground hydrogen storage is in its early stages; the first onshore salt cavern is being developed, with plans to expand to four in the future. However, a clear trajectory for this has yet to be established. The technology for storage in offshore salt caverns and depleted gas fields remains in the early stages of development and will take years before commissioning.

Given these ongoing developments in the hydrogen chain, government intervention should extend beyond supporting investments in hydrogen turbines. A coordinated approach is needed to ensure the parallel development of all components. The government must take on a helicopter view, actively monitoring the parallel development of hydrogen production, storage, and infrastructure while ensuring that the necessary support is in place. Targeted interventions may be required to address specific challenges within individual segments of the chain.

Proactive approach to prevent future shortages

A proactive approach is essential to prevent future supply shortages and avoid the higher costs associated with delayed intervention. A reactive approach, waiting until shortages become severe, would ultimately result in significantly higher costs and consequences. Without sufficient flexible capacity, electricity shortages will occur.

Clear sub-targets must be established to ensure the success of the energy transition. Achieving a CO_2-neutral electricity system by 2035 requires decisive action now. The implementation of a well-designed CRM, as well as the development of the separate parts of the hydrogen chain takes multiple years. Without a structured plan for the replacement of fossil-fuel generators, the risk of electricity shortages increases. A consistent, long-term approach is necessary to align market incentives with the overarching goals of a future electricity system: availability, affordability, and acceptability.

12 Reflection

This chapter reflects on the process of writing this master's thesis. First, a reflection on the process is provided, including several topics. Thereafter, a reflection on working with Linny-R is given, as well as some areas for improvement.

12.1. Reflection on the process

Overall, I am satisfied with both the process of my thesis and the final outcome. From the very beginning, before selecting a company for my internship and defining my research topic, I knew I wanted to work on something related to the energy sector. With this in mind, I started selecting the company and TU Delft supervisors.

Reflection on topic and method

The final research topic was chosen in consultation with my supervisors from Rebel, and from the very first moment, I found it interesting. As I delved deeper into the subject, my interest only grew, but so did the complexity of the topic. This became particularly evident during the interviews, where it became clear that the stakeholder field, future supply security, and the government's complex role in the energy transition were even more nuanced than I initially expected. The deeper I explored the subject, the more I realised how interconnected and layered these issues were.

Initially, I intended to incorporate different government interventions into the simulation model. However, I soon realised that this was not feasible within my model, as it did not include investment decision-making. A bottom-up model, such as an agent-based model, would have been better suited for that. Despite this limitation, I believe my model still provided valuable insights that contributed to the understanding of the subject, particularly the influence of uncertainties. Nevertheless, the combination of the quantitative and qualitative methods and insights was challenging at moments.

Reflection on the modelling phase

Throughout the research process, particularly during the modelling phase, I had to make several choices and assumptions, which I did find difficult at moments. One of the biggest decisions was deciding what to include in the model scope and what not. For example, whether to incorporate the hydrogen market into the model and, if so, to what extent and in what manner. While I felt comfortable with the technical aspects of modelling, determining the system boundaries and the focus of the research remained challenging.

Another challenge was selecting the input data, as the chosen data significantly impacted the KPIs, making the reference selection a big choice for me. Consequently, it took quite long to select the final data utilised in the study. Furthermore. my research focused on the period between 2030 and 2050, but as I progressed, I discovered that the deployment of hydrogen turbines before 2030 was not realistic due to the underdevelopment of the hydrogen supply chain.

Reflection on working with Rebel

My experience working at Rebel was very positive. Going to the office daily helped me structure my workflow and stay organised. Collaborating with my supervisors and other colleagues provided me with practical insights that greatly enriched my knowledge. The support from my supervisors, along with our brainstorming meetings on insights was very helpful. Additionally, through Rebel's connections, I was able to conduct interviews with private market experts and governmental employees, which gave me insights into real-world challenges within the energy sector.

Personal reflection

Looking back, I have a positive feeling about the past six months. I remained engaged and motivated throughout the process because I found my topic interesting from start to finish and was able to establish a productive workflow. During the first half of the project, I initially struggled to keep an overview of all the tasks I needed to complete. However, after structuring my thesis by outlining the main chapters and creating a general framework, managing my progress became much easier. Towards the end, the process became at bit more stressful, particularly when I had to prioritise my focus within the limited timeframe. Determining how to process additional insights, those that did not directly fit within my research scope but that I gained during my time at Rebel and through the interviews, was challenging for me.

Finally, this thesis has reinforced my desire to work in the energy sector and contribute to the energy transition. It has been a valuable learning experience, and I look forward to applying the knowledge and skills I have gained in my future career.

12.2. Reflection on working with Linny-R

Reflecting on the decision to use Linny-R, it was a good choice. The ability to integrate datasets and easily invoke them in experiments proved extremely useful during the experimental design. Additionally, the visual interface allowed me to discuss the model with multiple employees within Rebel to get their input and feedback on the model. As I became more familiar with Linny-R, I recognised its potential for incorporating additional components of the electricity system and increasing the model's complexity. However, given the exploratory modelling approach of this study, further expansion was unnecessary. Both my supervisors from TU Delft and Rebel advised me multiple times to refrain from making the model more complex.

Linny-R is still under development, and throughout this process, there were a few instances where I encountered system bugs that I did not know how to resolve. Fortunately, after reaching out to the developer, these issues were either fixed or we found a workaround together.

Furthermore, during the modelling, I identified several areas for improvement. The most significant is the automatic saving function. While I never had to use it to recover a lost model since I saved my work frequently, the autosave feature would activate every few minutes, often causing the model to freeze temporarily, preventing any modifications. Allowing users to adjust the autosave frequency to their preference would make the modelling more user-friendly.

Additionally, for this thesis, I used Excel for visualising the experiment results. This was necessary because Linny-R currently lacks the capability to present multiple experiments in a single descriptive graph, such as the boxplots used to illustrate the range of average electricity prices. If Linny-R were to incorporate this functionality, the need for post-processing in Excel would be significantly reduced.

The addition of axis titles and tick marks would also significantly reduce the need for post-processing of graphs. Currently, axis titles must be manually added, which I did using powerpoint. The frequency of tick marks is automatically adjusted based on the graph, but in some cases, this resulted in a range that was too broad, as seen in Figure 6.15b and Figure 8.7. Increasing the frequency of tick marks would enhance the readability of these graphs by ensuring that units are displayed more consistently.

Finally, the manual for Linny-R is currently in development. Once completed, it will make the software more accessible and user-friendly for future researchers. A recommendation for this manual is to include an explanation of the RAM-based limitations on the size of the experiments. Initially, I was unaware of this constraint and attempted to run large-scale experiments overnight, consisting of 500 runs to explore system behaviour. By morning, I would discover that the experiment had not finished and that the results were not stored. Assuming this was due to an error in my code or the software itself, I repeatedly attempted to run these large experiments, which became increasingly frustrating. It was only later that I realised the issue was caused by insufficient RAM memory, requiring experiments to be scaled down. A more effective approach was to conduct simulations per asset year or in smaller batches rather than running all four asset years simultaneously. Including this information in the manual would help prevent similar issues for future users.

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A

Interviews

- Interviewee 1: Former electricity trader
- Interviewee 2 and 3: Employees at governmental organisation
- Interviewee 4: Strategic analyst at Dutch energy company 1
- Interviewee 5: Commercial manager at Dutch energy company 2

Table A.1: Interview topics

Name	Date	Topics
Interviewee 1 [9]	09-2024	- Dutch electricity market mechanisms - Revenues and economic viability of generators - Value of Lost Load and price caps - Flexibility in the electricity system
Interviewee 2 and 3 [20]	09-2024	- Security of supply in future electricity system - General challenges related to government interventions - Long lead time of large investments - Position of government and cabinet in energy transition - Potential measures to stimulate investments
Interviewee 4 [13]	09-2024	- Societal and economic impact of electricity shortages - Market failures and risks related to investment decisions - Barriers for deployment of hydrogen turbines - Lead times investments and government intervention - Electrification and other flexibility options
Interviewee 5 [19]	10-2024	- Current developments within hydrogen market - Requirements for policy interventions - Current role of gas turbines within electricity system - Different forms of flexibility in the system - Carbon neutral electricity generation
Interviewee 2 and 3 [48]	01-2025	- Mitigating shortages through the intraday market - Advantages for specific government interventions - Barriers for specific government interventions - Information asymmetry from government perspective
Interviewee 4 [49]	01-2025	- Uncertainties in development of hydrogen chain - Impact of price fluctuations - Future scenarios and developments of electricity system - Necessity and requirements of government intervention - Possibilities to monitor future revenues
Interviewee 1 [50]	01-2025	- Policy expectations and market failures - Demand side response and impact high electricity prices - Requirements of future government interventions - Current government support and effects on investment decisions - Uncertainties in development of hydrogen chain

B

The Dutch electricity market

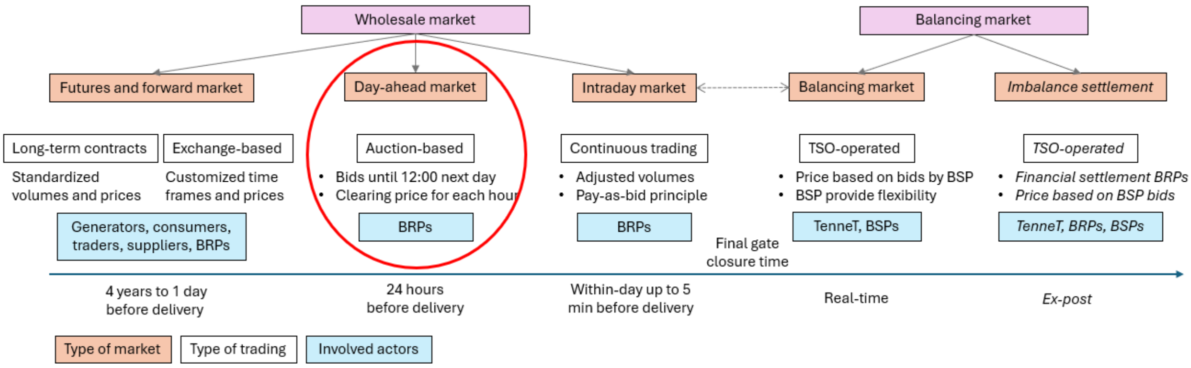


Figure B.1: Dutch electricity market

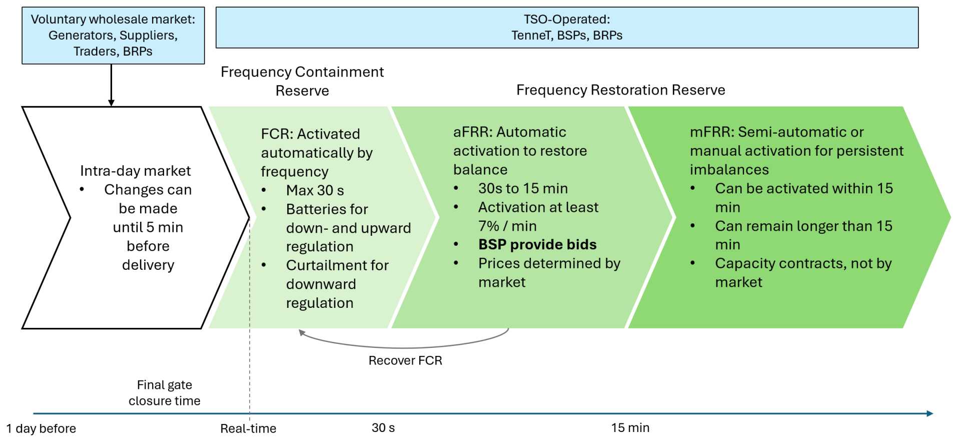


Figure B.2: Dutch balancing Market

C
Hydrogen-fueled gas turbines

C.1. The gas turbine technology

Gas turbines generate electricity following the Brayton cycle, in which air is compressed, mixed with a combustion fuel (typically methane in conventional turbines) and then combusted to produce high-temperature, high-pressure gas. The gas drives the turbine to generate electricity [73]. The Brayton cycle involves three key components: the compressor, combustor, and gas turbine. Hydrogen-fueled gas turbines operate similarly to conventional gas turbines, but the distinct properties of hydrogen significantly can influence the combustion process [118]. Most existing gas turbines can operate with hydrogen levels up to 30% volume without significant modification or adjustments to their design or components [74]. However, when the hydrogen ratio exceed the 30% volume, changes to the gas turbines are considered necessary. The change of the natural gas turbines into hydrogen-fueled gas turbines is called retrofitting. Because the technology is very similar to natural gas turbines, it is assumed that both plants have the same efficiencies and startup time [80],[41]. Generally, gas turbines fall into two main categories; Open Cycle Gas Turbines (OCGTs) and Combined Cycle Gas Turbines (CCGTs).

Open Cycle Gas Turbines

An Open Cycle Gas Turbine, illustrated in Figure C.1, releases exhaust gases directly into the atmosphere. These gasses contains a lot of heat leading to substantial heat losses. As a results, the efficiency of OCGTs is relatively low, ranging between 35-42% [75]. This low efficiency translates into higher fuel consumptions and therefore elevated marginal costs compared to CCGTs. However, due to the simplicity of OCGTs, both the initial investments and operational costs of the turbines are comparatively low. With limited operational hours, the yearly costs can be lower than of a CCGTs, despite their high marginal costs. Additionally, OCGTs can start-up completely within one hour, making it extra flexible.

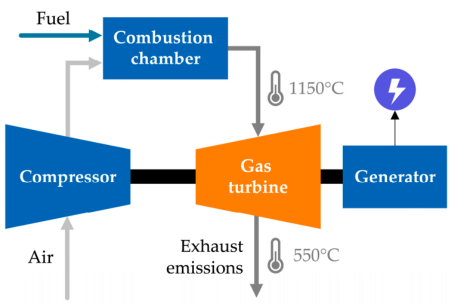


Figure C.1: Open-cycle gas turbine [119]

Combined Cycle Gas Turbine

A Combined Cycle Gas Turbine (CCGT) consists of an OCGT with an additional bottoming cycle. This extra cycle recovers the heat from the exhaust gases and converts it into steam, which is then used to drive a steam turbine. The purpose of this added cycle is to improve overall efficiency of the system, resulting in an increase in electrical efficiency up to 60% [75]. The complexity of the turbine leads to higher investment and operational costs compared to a simple OCGT [76]. On the other hand, the increased efficiency leads to lower fuel expenses. Besides, these lower marginal costs affect the position in the merit order and thus the expected operating hours.

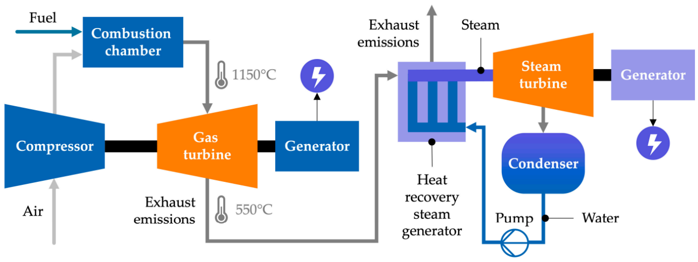


Figure C.2: Closed-cycle gas turbine [119]

Technical challenges with hydrogen as a fuel

While this is not the focus of this study, it is important to recognise the technical challenges associated with hydrogen as fuel in gas turbines. Hydrogen-fueled gas turbines operate similarly to conventional gas turbines, but the distinct properties of hydrogen influence the combustion process. Hydrogen has a lower heating value (LHV) of approximately 120 MJ/kg and a higher heating value (HHV) of 141.75 MJ/kg, which are substantially higher than methane's LHV of 35.8 MJ/kg and HHV of 55.5 MJ/kg [120]. However, hydrogen's low molecular mass (2 g/mol) results in a lower energy density by volume compared to methane [121]. In fact, the volumetric heating value of hydrogen is about one-third that of natural gas, meaning that roughly three times more hydrogen is needed to generate the same power output as natural gas [32]. Nevertheless, due to hydrogen's combustion characteristics, it requires approximately 20% less air by volume to produce a comparable flame when using 100% hydrogen. When electricity efficiency is calculated based on the energy content of the fuel, expressed in MWh, it is estimated to be comparable between hydrogen turbines and natural gas turbines [80].

However, the development of hydrogen-fueled gas turbines does presents several technical challenges. The transition to hydrogen affects the flame stability, pollutant emissions, and radiant energy transfer [73],[32]. A 100% hydrogen flame is generally shorter and burns much closer to the burner compared to a methane flame under similar conditions. This is largely due to hydrogen's higher flame speed and shorter ignition times. The increased flame speed poses the risk of flashback, which can lead to explosions or material damage [73],[121]. Moreover, hydrogen can negatively interact with certain materials, as it is prone to absorption by containment and piping systems, potentially causing embrittlement or reduced ductility [32]. While hydrogen combustion does not produce inherent pollutants, it can lead to increased NOx emissions in the exhaust gases.

Ongoing research is actively addressing these technical challenges, focusing on solutions to mitigate their impact and ensure the reliable operation of hydrogen-fueled turbines. NOx emissions, for instance, can be managed through various techniques, such as modifying the design of the combustor's fuel injection zone and implementing flame dilution methods. Additionally, several pilot projects and prototypes are currently being tested by researchers to refine technologies and address these challenges [122],[120],[32]. Since the focus of this thesis is on economic challenges rather than technical ones, it is assumed that 100% hydrogen-fueled gas turbines can be operational by 2030.

C.2. Financial overview of hydrogen CCGT

The CapEx, and OpEx are based on the values used in the energy transition model [80]. The variable OpEx are converted and integrated with the fixed OpEx. For the investment costs to retrofit the existing turbines, a percentage of the total CapEx for new investment is used. These costs mostly stem from the extra components required to integrate hydrogen into the existing fuel system connected to the gas turbine [41]. The costs for retrofitting the existing gas turbines into hydrogen turbines are 25 to 45% of the investment costs for constructing an entire new plant.

Table C.1: Financial details of hydrogen turbines

Parameters	Value	Unit	Reference
Capex new hydrogen CCGT	750	MEUR/GW	[80]
Capex retrofit	25- 45	% of total CapEx	[41],[123]
Corporate tax rate	25.8	%	[84]
Economic lifetime of turbines	20	years	[82]
Efficiency hydrogen CCGT	60	%	[124],[80]
Fixed O&M costs CCGT	11.5	MEUR/GW/year	[80]
Technical lifetime of turbines	30	years	[80],[41]
Weighted Average Cost of Capital	8	%	[81]

D

Model data

This appendix provides an overview of the input values used in the model. This consists of technical parameters that stay constant over the entire study, and the parameters that vary over the different future years.

D.1. Static parameters of the model

Table D.1: Technical parameters of the model

Parameters	Value	Unit	Reference
CO_2 emissions natural gas	0.202	kton/GWh	[125]
Default hydrogen price	0.39	MEUR/GWh	[92]
Efficiency biomass turbine	38	%	,[80],[124],[126]
Efficiency electrolyser	75	%	[127],[128]
Efficiency hydrogen CCGT	60	%	[80],[124]
Efficiency natural gas CCGT	60	%	[80]
Efficiency natural gas OCGT	40	%	[80]
Efficiency nuclear power plant	35	%	[40]
Efficiency underground hydrogen storage	98	%	[108]
Electricity consumption hydrogen compression	0.12	GWhe/GWhH_2	[129]
Lithium-ion roundtrip efficiency	85	%	[80],[125]
Lithium-ion selfdischarge	1	% per day	[125]
Price cap electricity market	4	MEUR/GWh	[54]

D.2. Base scenario input parameters

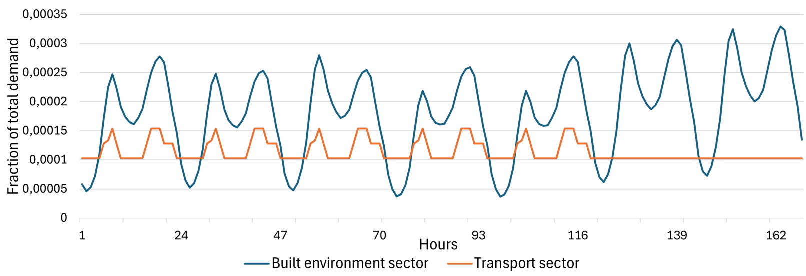
These parameters vary between the four future years, yet are constant throughout the year.

Table D.2: Base input parameters for the different years

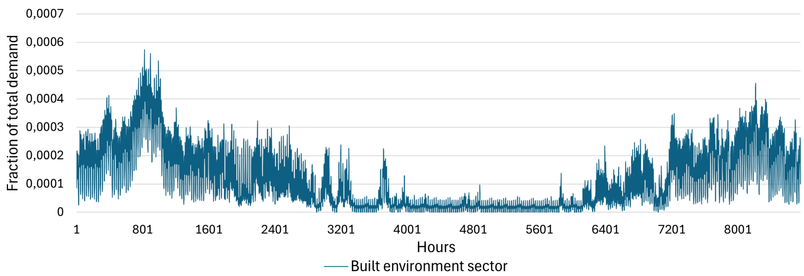
Parameters	2030	2035	2040	2050	Unit	Reference
Capacity biomass turbines	0.415	0.415	0.155	0	GW	[80]
Capacity electrolysers	3.0	4.0	16.8	25.0	GWe	[64]
Capacity input large scale batteries	3	6	17	25	GW	[80]
Capacity output large scale batteries	3.8	7.5	21.3	31.3	GW	[80]
Storage volume batteries	4.8	9.7	27.4	40.3	GWh	[80]
Capacity natural gas CCGT	9.2	6.1	4.9	0	GW	[80]
Capacity natural gas OCGT and CHP	7.1	6.2	1.4	0	GW	[80]
Capacity nuclear	0.5	0.5	1.5	3	GW	[64]
Capacity solar PV	59.3	75.9	122.7	172.6	GW	[64]
Capacity wind onshore	9.1	10.6	15.1	20.0	GW	[64]
Capacity wind offshore	22.1	30.5	50.5	52	GW	[64]
Capacity hydrogen import	2.6	5.8	1.7	6.4	GW	[64],[66]
Capacity hydrogen turbines	0	3.5	8.9	15	GW	[64]
Electricity demand agriculture and ICT	25.8	29.9	34.1	33.8	TWh	[64]
Electricity demand built environment	52.1	57.9	59.0	63.4	TWh	[64]
Electricity demand industry	54.1	64.9	88.0	139.5	TWh	[64]
Electricity demand transport	18.5	33.4	49.4	55.8	TWh	[64]
Hydrogen storage volume	0.9	2.6	8.5	13.6	TWh	[64]
Biomass price	0.075	0.068	0.061	0.050	MEUR/GWh	[85]
Carbon price	0.078	0.100	0.123	0.168	MEUR/kton	[85]
Natural gas price	0.035	0.035	0.025	0.025	MEUR/GWh	[80],[85]
Nuclear price	0.0017	0.0017	0.0017	0.0017	MEUR/GWh	[85]

D.3. Electricity demand patterns

Historical data has been used to analyse electricity demand in the built environment [80]. Figure D.1a and D.1b present the hourly demand patterns, with the first illustrating the variation over a single week and the latter depicting the pattern across the entire year.



(a) Demand patterns for one week



(b) Demand pattern for whole year

Figure D.1: Hourly demand patterns

Figure D.1a illustrates two peaks in electricity demand in built environment: in the morning and evening. Besides, nighttime demand is lower than daytime demand. Seasonal differences in electricity demand for the built environment are shown in D.1b. It gives insight into the decreased demand during the summer period and increased demand in the winter period, with the peak around time step 800.

Demand side response

Table D.3: Default demand side response parameters

Parameters	WtP/ WtA (€/MWh)	Load share (%)	Reference
Shedding low price	250	1.55	[29]
Shedding medium price	500	1.55	[29]
Shedding high price	1500	3.1	[29]
Shifting of load	200	10.8	[68],[80]

D.4. Weather year specifications

Table D.4: LOLE for tested weather years (hours/year)

WY	2030	2035	2040	2050
1987	348	1134	1640	2411
1997	239	928	1440	2266
2008	163	772	1172	1803
2009	220	842	1346	2070
2015	204	671	1034	1775
2018	166	615	1132	1896
2019	189	714	1107	1992

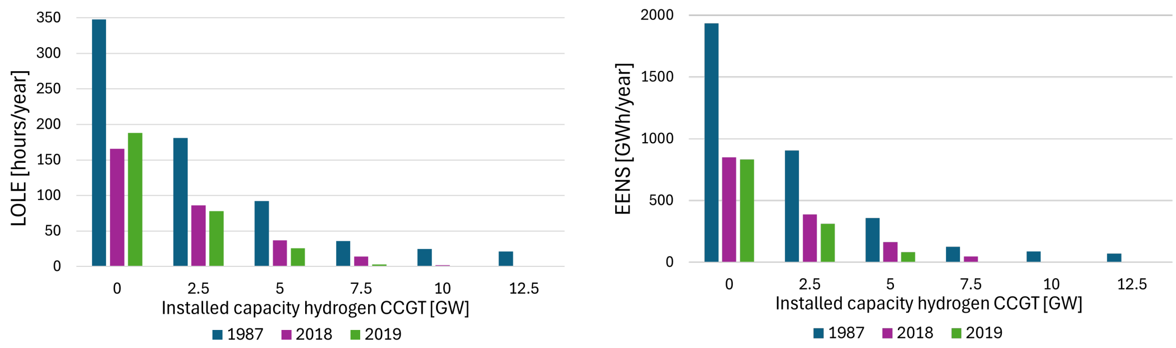
Table D.5: EENS for tested weather years (GWh/year)

WY	2030	2035	2040	2050
1987	1940	9110	19800	42700
1997	1030	6450	15300	36200
2008	657	5030	11900	28300
2009	1150	5910	13500	32500
2015	1240	5170	11000	27100
2018	854	4300	10700	28100
2019	834	4870	11200	29200

E

Experiment 3: Capacity comparison

Results 2030



(a) LOLE **(b)** EENS

Figure E.1: Experiment 3: Adequacy KPIs - 2030

Table E.1: Experiment 3: Average electricity price (€/MWh) - 2030

H_2 price (€/kg)	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW
	1987	283	203	165	156	152	150
13	**2018**	167	129	104	93	93	93
	2019	189	133	106	93	90	89
	1987	283	193	148	133	127	128
6	**2018**	167	122	95	82	77	77
	2019	189	124	95	79	76	74
	1987	283	184	132	119	113	114
2	**2018**	167	117	87	72	68	67
	2019	189	118	85	67	64	63

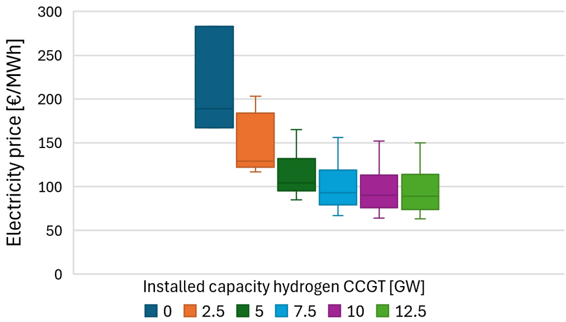


Figure E.2: Experiment 3: Average electricity price - 2030

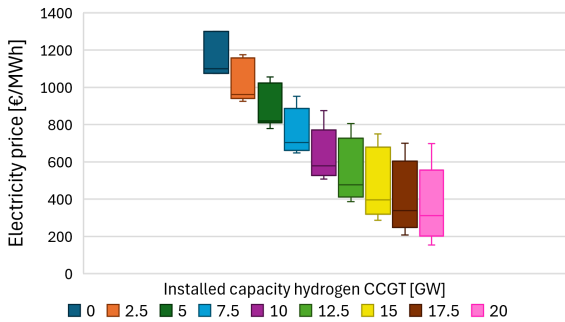


Figure E.3: Experiment 3: Total generator profits - 2030

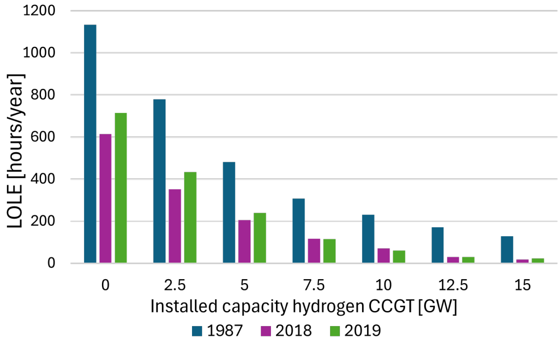
Table E.2: Experiment 3: Annual profits (MEUR/GW) - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW
13	1987	682	266	81	23	-19
	2018	309	91	-18	-42	-50
	2019	298	73	-55	-79	-88
6	1987	863	400	181	86	48
	2018	390	145	17	-41	-55
	2019	394	128	-19	-59	-72
2	1987	1002	488	267	151	101
	2018	458	180	37	-16	-37
	2019	476	165	-4	-45	-54

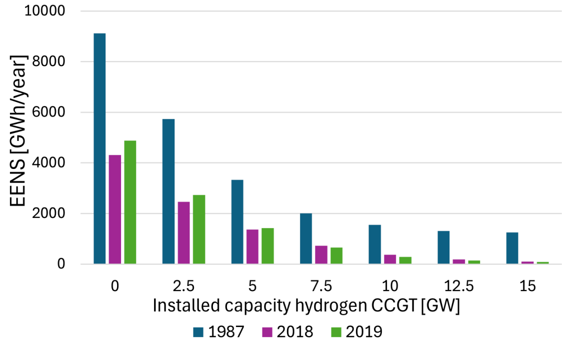
Table E.3: Experiment 3: Full load hours - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW
13	1987	645	474	342	263	211
	2018	336	253	192	146	116
	2019	402	294	221	167	134
6	1987	722	536	400	307	247
	2018	420	305	233	182	146
	2019	508	362	268	204	163
2	1987	2136	1290	904	685	549
	2018	2025	1085	757	571	458
	2019	2012	1113	785	593	474

Results 2035



(a) LOLE



(b) EENS

Figure E.4: Experiment 3: Adequacy KPIs - 2035

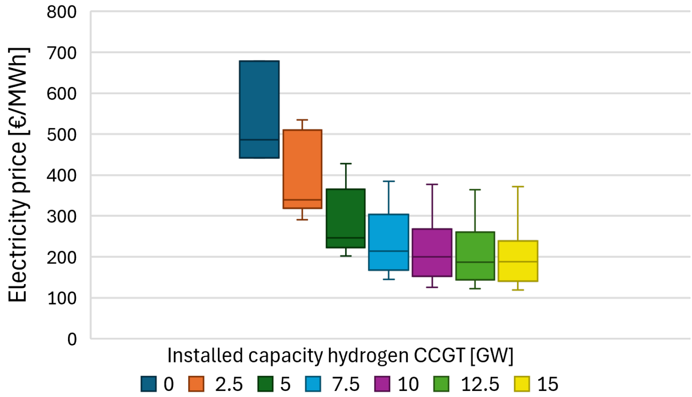


Figure E.5: Experiment 3: Average electricity price - 2035

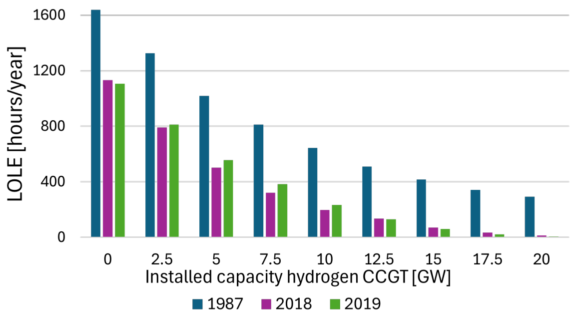
Table E.4: Experiment 3: Annual profits (MEUR/GW) - 2035

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
13	1987	3081	1777	1060	645	365	282
	2018	1513	813	440	214	49	37
	2019	1793	937	416	148	41	30
6	1987	3545	2185	1432	829	568	403
	2018	1793	1009	516	316	154	86
	2019	2121	1177	577	330	162	105
2	1987	3897	2485	1712	1115	813	520
	2018	2037	1155	625	403	263	175
	2019	2389	1351	719	475	276	215

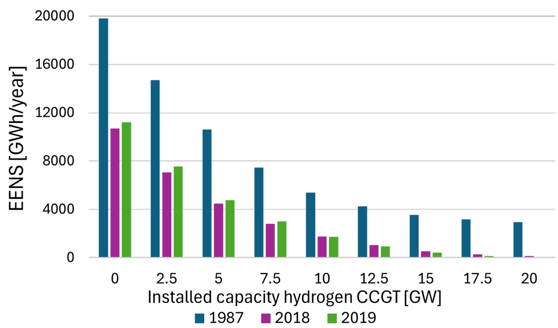
Table E.5: Experiment 3: Full load hours - 2035

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
	1987	1696	1434	1167	910	750	635
13	2018	1148	898	707	580	491	417
	2019	1232	988	789	656	543	454
	1987	1808	1550	1289	1050	872	727
6	2018	1324	1028	816	671	562	480
	2019	1376	1100	908	751	625	526
	1987	3336	2520	1933	1530	1264	1060
2	2018	3052	2120	1520	1200	976	820
	2019	3028	2100	1613	1270	1032	867

Results 2040



(a) LOLE



(b) EENS

Figure E.6: Experiment 3: Adequacy KPIs from - 2040

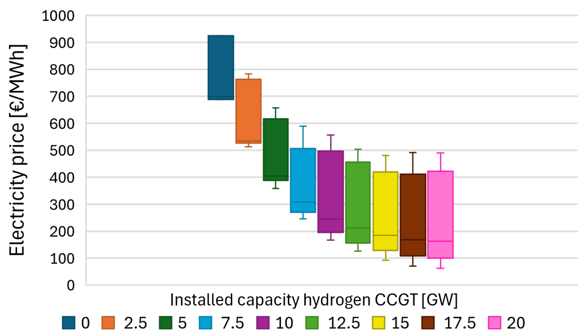


Figure E.7: Experiment 3: Average electricity prices - 2040

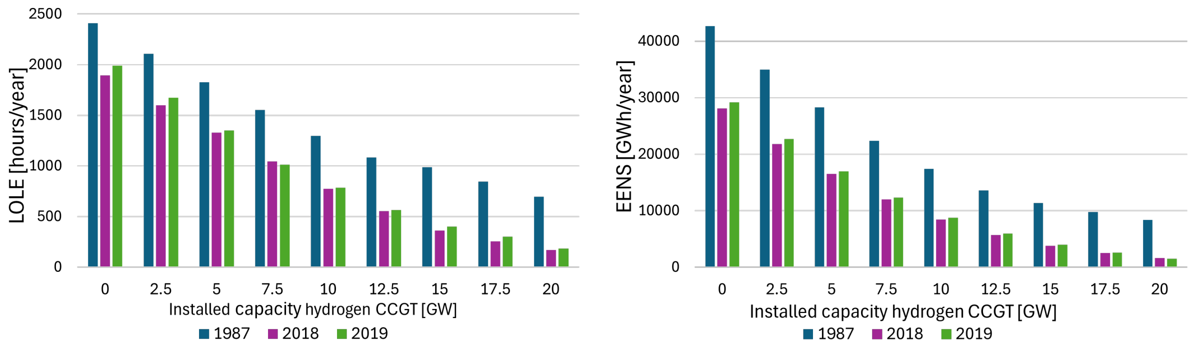
Table E.6: Experiment 3: Annual profits (MEUR/GW) - 2040

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW
	1987	5285	4045	3005	2295	1469	885	668	445
13	2018	3393	2245	1432	891	552	293	106	11
	2019	3473	2465	1619	1065	580	251	63	-56
	1987	5925	4605	3445	2825	1997	1312	988	865
6	2018	3861	2605	1672	1045	664	395	188	57
	2019	3965	2845	1872	1235	720	372	171	11
	1987	6325	4945	3859	3145	2301	1645	1262	1110
2	2018	4165	2825	1832	1135	749	436	221	112
	2019	4285	3065	2032	1335	829	431	215	76

Table E.7: Experiment 3: Full load hours - 2040

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW
	1987	2480	2240	1987	1730	1496	1293	1114	985
13	**2018**	1932	1678	1453	1240	1072	933	823	730
	2019	2016	1738	1507	1300	1128	993	874	770
	1987	2624	2380	2160	1860	1616	1400	1229	1075
6	**2018**	2104	1844	1600	1380	1200	1040	920	815
	2019	2184	1908	1667	1440	1256	1100	966	860
	1987	3524	3160	2987	2530	2232	1993	1766	1555
2	**2018**	3060	2840	2547	2280	2000	1780	1594	1425
	2019	3096	2900	2547	2280	2016	1773	1571	1390

Results 2050



(a) LOLE

(b) EENS

Figure E.8: Experiment 3: Adequacy KPIs from - 2050

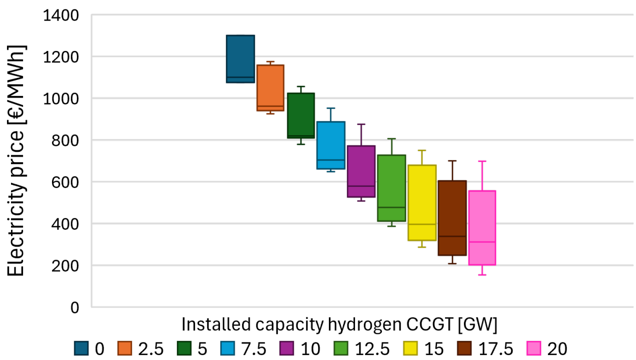


Figure E.9: Experiment 3: Average electricity prices - 2050

Table E.8: Experiment 3: Annual profits (MEUR/GW) - 2050

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW
	1987	8325	7225	5992	4855	4045	3165	2354	1830
0.39	**2018**	6525	5405	4432	3365	2421	1665	1045	700
	2019	6805	5645	4445	3425	2445	1652	1251	845
	1987	9245	8065	6859	5665	4829	4059	3119	2355
0.18	**2018**	7285	6085	5019	3845	2821	1992	1319	805
	2019	7565	6365	5085	3925	2861	2052	1399	945
	1987	9765	8585	7352	6225	5373	4532	3554	2835
0.061	**2018**	7765	6485	5352	4135	3069	2179	1474	935
	2019	8045	6765	5445	4225	3133	2272	1588	1150

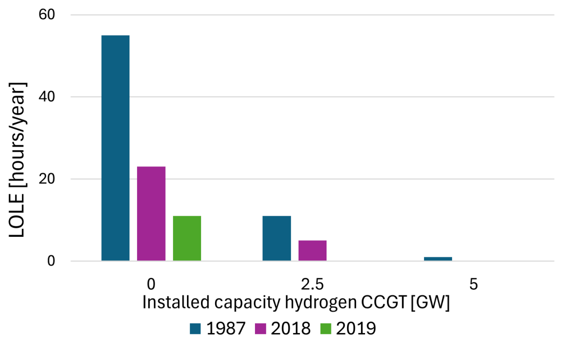
Table E.9: Experiment 3: Full load hours - 2050

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW
	1987	3476	3280	3093	2920	2720	2453	2217	2000
0.39	**2018**	3012	2800	2587	2400	2200	2013	1834	1655
	2019	3028	2840	2667	2480	2272	2073	1869	1690
	1987	3604	3420	3227	3080	2912	2633	2383	2180
0.18	**2018**	3152	2940	2747	2540	2344	2153	1960	1795
	2019	3160	2980	2800	2610	2408	2200	2011	1860
	1987	3632	3460	3267	3160	2952	2667	2417	2235
0.061	**2018**	3184	2980	2773	2580	2392	2200	2011	1860
	2019	3184	3000	2827	2650	2456	2247	2080	1925

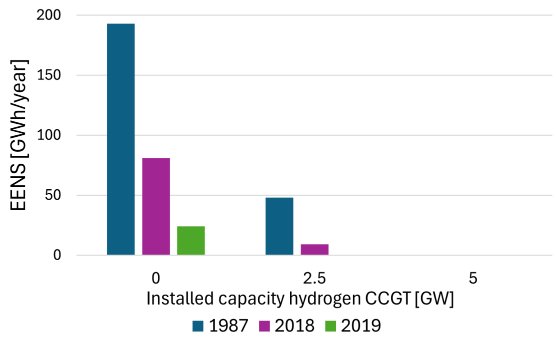
F

Experiment 4: Low electricity demand

Results 2030



(a) LOLE



(b) EENS

Figure F.1: Experiment 4: Adequacy KPIs - 2030

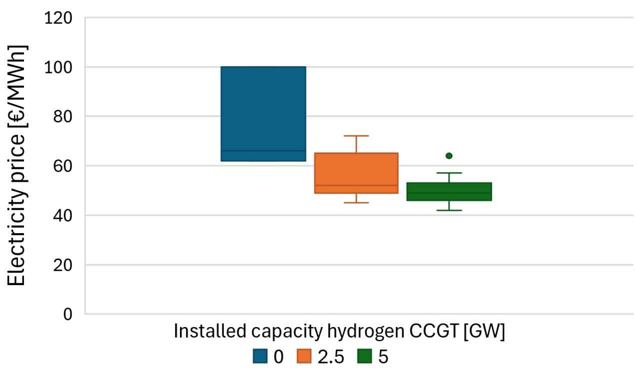


Figure F.2: Experiment 4: Average electricity prices - 2030

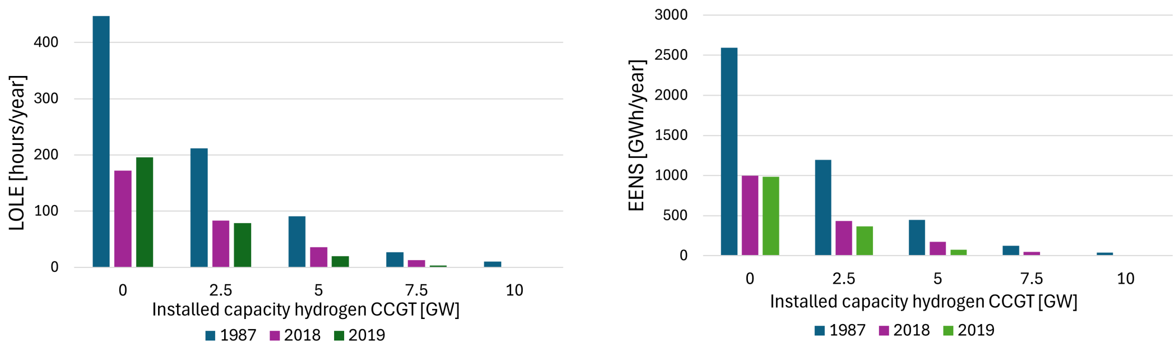
Table F.1: Experiment 4: Annual profits - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW
	1987	6	-79	-91
13	2018	-47	-78	-87
	2019	-78	-87	-87
	1987	36	-64	-86
6	2018	-32	-74	-85
	2019	-67	-85	-87
	1987	69	-47	-78
2	2018	-15	-69	-85
	2019	-51	-84	-90

Table F.2: Experiment 4: Full load hours - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW
	1987	180	119	82
13	2018	80	52	37
	2019	73	43	29
	1987	234	161	114
6	2018	114	77	56
	2019	121	75	52
	1987	2143	1093	734
2	2018	2080	1052	707
	2019	2146	1116	744

Results 2035



(a) LOLE

(b) EENS

Figure F.3: Experiment 4: Adequacy KPIs - 2035

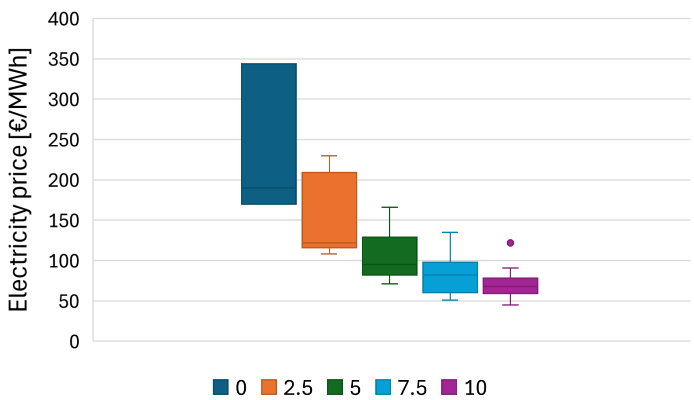


Figure F.4: Experiment 4: Average electricity prices - 2035

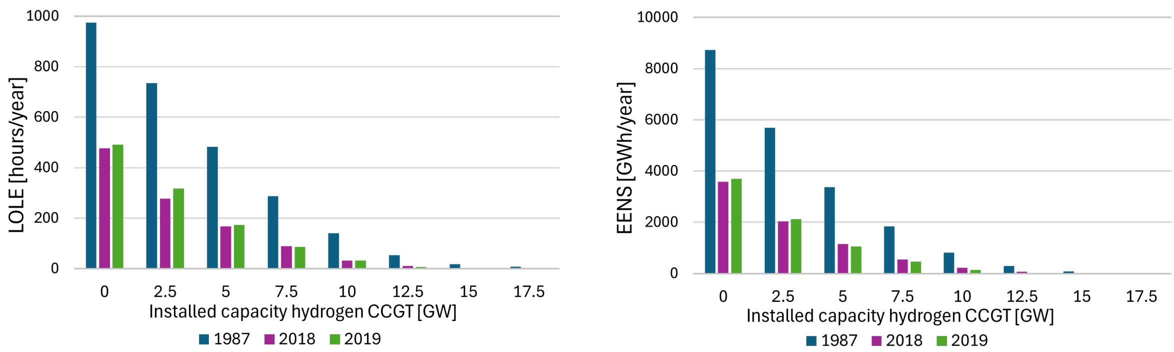
Table F.3: Experiment 4: Annual profits (MEUR/GW) - 2035

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW
	1987	964	389	93	-39
13	2018	343	115	-13	-80
	2019	381	53	-50	-95
	1987	1185	510	165	-2
6	2018	426	173	17	-65
	2019	494	124	-28	-85
	1987	1373	617	227	41
2	2018	529	232	41	-48
	2019	602	193	-1	-66

Table F.4: Experiment 4: Full load hours - 2030

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW
	1987	898	688	527	414
13	**2018**	414	299	233	187
	2019	498	375	276	213
	1987	1013	787	594	470
6	**2018**	506	364	288	233
	2019	592	454	345	269
	1987	3146	1885	1352	1056
2	**2018**	3118	1691	1204	941
	2019	3156	1785	1266	962

Results 2040



(a) LOLE **(b)** EENS

Figure F.5: Experiment 4: Adequacy KPIs - 2040

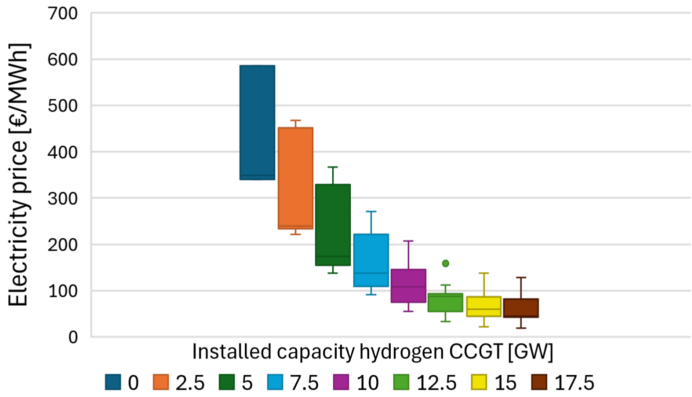


Figure F.6: Experiment 4: Average electricity prices - 2040

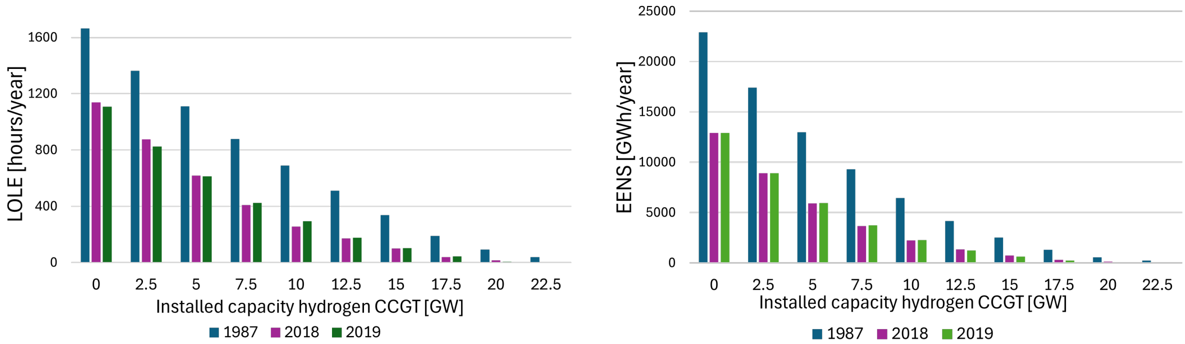
Table F.5: Experiment 4: Annual profits (MEUR/GW) - 2040

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW
	1987	2993	2105	1272	658	232	39	-73
13	**2018**	1289	733	420	159	33	-32	-67
	2019	1389	851	419	160	3	-61	-72
	1987	3397	2405	1485	817	323	122	-9
6	**2018**	1521	867	505	209	65	-15	-63
	2019	1621	999	523	220	28	-56	-73
	1987	3649	2585	1632	925	408	143	7
2	**2018**	1677	963	557	245	88	-2	-57
	2019	1781	1099	596	261	48	-46	-70

Table F.6: Experiment 4: Full load hours - 2040

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW
	1987	1628	1404	1236	1061	915	787	685
13	**2018**	1007	807	655	546	460	395	341
	2019	1030	837	704	587	494	418	359
	1987	1767	1550	1359	1177	1017	873	761
6	**2018**	1151	947	773	648	548	472	412
	2019	1187	977	820	692	589	502	434
	1987	2695	2493	2153	1896	1676	1442	1255
2	**2018**	2101	1873	1685	1500	1333	1173	1026
	2019	2223	1970	1745	1549	1375	1206	1055

Results 2050



(a) LOLE **(b)** EENS

Figure F.7: Experiment 4: Adequacy KPIs - 2050

Table F.7: Experiment 4: Average electricity prices (€/MWh) - 2050

H_2 price (€/kg)	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
	1987	934	813	696	593	505	428	377	342	308	285
13	**2018**	682	567	455	358	281	221	186	161	141	133
	2019	699	568	457	364	291	239	196	166	147	134
	1987	934	800	669	554	455	368	292	229	200	177
6	**2018**	682	555	430	320	232	161	119	88	65	55
	2019	699	557	430	325	239	176	127	90	67	52
	1987	934	795	661	540	436	338	256	188	142	126
2	**2018**	682	550	422	307	215	140	96	63	39	28
	2019	699	553	419	310	220	154	103	64	40	24

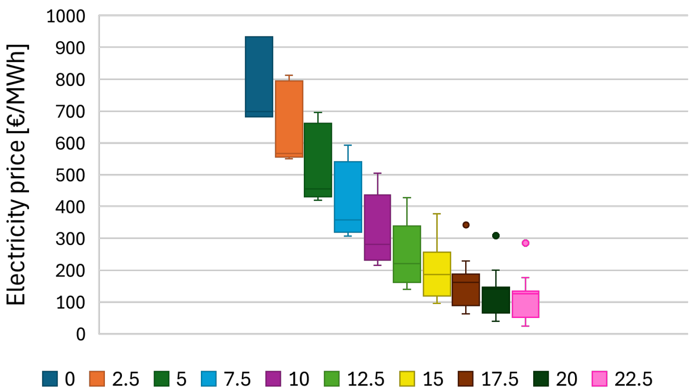


Figure F.8: Experiment 4: Average electricity prices - 2050

Table F.8: Experiment 4: Annual profits (MEUR/GW) - 2050

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
	1987	5605	4565	3672	2805	2053	1399	897	460	219
13	**2018**	3761	2765	1939	1275	765	461	240	70	-1
	2019	3697	2745	1939	1305	861	490	229	68	-44
	1987	6285	5145	4152	3245	2437	1659	999	645	379
6	**2018**	4285	3205	2245	1505	909	561	299	99	20
	2019	4245	3165	2272	1535	1013	605	294	102	-24
	1987	6645	5485	4432	3515	2637	1852	1205	720	494
2	**2018**	4565	3445	2459	1655	1005	619	338	126	35
	2019	4565	3405	2459	1685	1109	672	337	132	-9

Table F.9: Experiment 4: Full load hours - 2050

H_2 price (€/kg)	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
13	1987	2600	2428	2229	2044	1864	1690	1521	1387	1258
	2018	2000	1818	1633	1456	1288	1136	1009	901	810
	2019	2149	1913	1694	1498	1318	1171	1040	929	835
6	1987	2752	2572	2377	2177	1989	1814	1675	1532	1389
	2018	2140	1959	1773	1595	1421	1261	1125	1009	909
	2019	2269	2069	1846	1652	1465	1305	1166	1047	943
2	1987	2783	2599	2406	2217	2043	1872	1739	1611	1452
	2018	2173	1990	1805	1624	1451	1287	1147	1029	928
	2019	2302	2108	1878	1682	1494	1329	1190	1066	962

G

Experiment 5: Demand side response

Results 2030

Table G.1: Experiment 5: LOLE - 2030

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW
17%	1987	348	181	92	36
	2018	166	86	37	14
	2019	189	78	26	3
34%	1987	156	60	19	8
	2018	62	31	7	0
	2019	55	18	0	0
51%	1987	65	25	9	0
	2018	30	5	0	0
	2019	21	4	0	0

Table G.2: Experiment 5: EENS - 2030

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW
17%	1987	1935	906	359	127
	2018	854	389	164	48
	2019	834	313	82	3
34%	1987	875	310	110	39
	2018	335	131	28	0
	2019	274	80	0	0
51%	1987	387	132	50	0
	2018	138	31	0	0
	2019	107	9	0	0

Table G.3: Experiment 5: Average electricity prices (€/MWh) mid hydrogen price - 2030

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW
17%	1987	283	193	148	133
	2018	167	122	95	82
	2019	189	124	95	79
34%	1987	207	144	113	105
	2018	124	97	81	75
	2019	132	95	80	74
51%	1987	161	119	101	95
	2018	105	83	74	73
	2019	107	85	75	73

Table G.4: Experiment 5: Annual profits (MEUR/GW) - 2030

DSR rate	WY	2.5 GW	5 GW	7.5 GW
17%	1987	863	400	181
	2018	390	145	17
	2019	394	128	-19
34%	1987	440	131	22
	2018	172	25	-35
	2019	145	6	-48
51%	1987	244	64	-24
	2018	56	-28	-50
	2019	58	-33	-57

Table G.5: Experiment 5: Full load hours - 2030

DSR rate	WY	2.5 GW	5 GW	7.5 GW
17%	1987	722	535	400
	2018	420	305	233
	2019	508	362	268
34%	1987	694	497	351
	2018	410	296	218
	2019	497	338	243
51%	1987	652	446	322
	2018	395	291	203
	2019	470	333	226

Results 2050

Table G.6: Experiment 5: LOLE - 2050

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
	1987	2411	2107	1828	1553	1299	1085	993
17%	2018	1896	1601	1330	1046	774	555	363
	2019	1992	1674	1352	1013	785	565	400
	1987	1955	1679	1383	1135	921	763	637
34%	2018	1439	1172	875	633	420	282	180
	2019	1479	1141	842	642	471	326	189
	1987	1516	1248	1012	814	631	496	360
51%	2018	1029	745	518	336	198	138	93
	2019	981	740	541	380	224	134	78

Table G.7: Experiment 5: EENS - 2050

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
	1987	42700	35000	28300	22400	17400	13600	11400
17%	2018	28100	21800	16500	12000	8430	5730	3800
	2019	29200	22700	17000	12300	8780	5950	3960
	1987	32000	25600	20100	15400	11600	8670	6560
34%	2018	19000	14000	9860	6710	4400	2900	1900
	2019	19500	14200	10100	7000	4610	2970	1810
	1987	23700	18400	14000	10500	7630	5400	3680
51%	2018	12100	8300	5560	3650	2350	1550	917
	2019	12300	8740	5920	3820	2360	1430	783

Table G.8: Experiment 5: Average electricity prices (€/MWh) mid hydrogen price - 2050

DSR rate	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
	1987	1301	1163	1033	906	800	747	710
17%	2018	1076	929	789	663	527	412	319
	2019	1101	962	820	672	539	424	338
	1987	1149	1014	877	761	661	602	565
34%	2018	909	772	635	508	393	305	232
	2019	933	787	647	524	414	324	244
	1987	993	859	743	638	550	489	432
51%	2018	758	620	497	391	296	231	183
	2019	763	638	517	409	310	235	191

Table G.9: Experiment 5: Annual profits (MEUR/GW) - 2050

DSR rate	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
	1987	9245	8065	6859	5665	4829	4065
17%	2018	7285	6085	5019	3845	2821	1992
	2019	7565	6365	5085	3925	2861	2052
	1987	7925	6665	5565	4465	3757	3059
34%	2018	5925	4745	3645	2665	1885	1239
	2019	6045	4825	3779	2825	1989	1259
	1987	6565	5485	4485	3525	2861	2159
51%	2018	4565	3525	2632	1825	1245	825
	2019	4725	3685	2779	1925	1221	819

Table G.10: Experiment 5: Full load hours - 2050

DSR rate	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW
17%	1987	3604	3420	3227	3080	2912	2633
	2018	3152	2940	2747	2540	2344	2153
	2019	3160	2980	2800	2610	2408	2200
34%	1987	3672	3440	3227	3070	2872	2640
	2018	3184	2980	2760	2550	2336	2140
	2019	3216	3020	2840	2610	2400	2173
51%	1987	3704	3440	3227	3040	2808	2580
	2018	3200	2980	2747	2520	2320	2113
	2019	3228	3040	2840	2600	2376	2147

H

Experiment 6: Batteries

Results 2030

Table H.1: Experiment 6: LOLE - 2030

Battery	WY	0 GW	2.5 GW	5 Gw	7.5 GW
	1987	348	181	92	36
x1	2018	166	86	37	14
	2019	189	78	26	3
	1987	281	142	69	21
x2	2018	130	65	31	9
	2019	137	55	19	0
	1987	254	122	57	17
x3	2018	104	59	24	7
	2019	114	43	14	0

Table H.2: Experiment 6: EENS - 2030

Battery	WY	0 GW	2.5 GW	5 Gw	7.5 GW
	1987	1935	906	359	127
x1	2018	854	389	164	48
	2019	834	313	82	3
	1987	1757	794	300	103
x2	2018	739	337	140	35
	2019	704	246	61	0
	1987	1643	726	262	93
x3	2018	667	307	122	22
	2019	617	213	45	0

Table H.3: Experiment 6: Average electricity prices (€/MWh) mid hydrogen price - 2030

Battery	WY	0 GW	2.5 GW	5 GW	7.5 GW
	1987	283	193	148	133
x1	2018	167	122	95	82
	2019	189	124	95	79
	1987	255	173	135	121
x2	2018	146	109	87	76
	2019	163	109	86	73
	1987	238	161	123	112
x3	2018	132	101	81	72
	2019	149	100	80	69

Table H.4: Experiment 6: Annual profits (MEUR/GW) - 2030

Battery	WY	2.5 GW	5 GW	7.5 GW
	1987	863	400	181
x1	2018	390	145	17
	2019	394	128	-19
	1987	728	330	125
x2	2018	312	113	1
	2019	297	82	-32
	1987	654	279	102
x3	2018	269	82	-9
	2019	242	53	-40

Table H.5: Experiment 6: Full load hours - 2030

Battery	WY	2.5 GW	5 GW	7.5 GW
	1987	722	535	400
x1	2018	420	305	233
	2019	508	362	268
	1987	666	481	355
x2	2018	354	263	201
	2019	440	311	232
	1987	619	449	325
x3	2018	304	231	176
	2019	386	272	201

Results 2050

Table H.6: Experiment 6: LOLE - 2050

Battery	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
	1987	2411	2107	1828	1553	1299	1085	993	846	695	529
x1	**2018**	1896	1601	1330	1046	774	555	363	256	169	65
	2019	1992	1674	1352	1013	785	565	400	303	183	67
	1987	1995	1704	1425	1213	981	837	800	686	573	404
x2	**2018**	1445	1185	915	690	493	349	243	171	113	33
	2019	1554	1212	888	666	505	373	265	169	108	27
	1987	1678	1406	1178	969	820	686	661	618	524	366
x3	**2018**	1134	884	665	472	338	241	175	114	71	18
	2019	1171	874	671	500	375	259	167	111	76	13

Table H.7: Experiment 6: EENS - 2050

Battery	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
	1987	42700	35000	28300	22400	17400	13600	11400	9750	8370	7010
x1	**2018**	28100	21800	16500	12000	8430	5730	3800	2510	1640	568
	2019	29200	22700	17000	12300	8780	5950	3960	2600	1540	443
	1987	37000	30000	23900	18800	14500	11400	9590	8130	7030	5760
x2	**2018**	22700	17100	12500	8700	5900	4000	2670	1770	1080	318
	2019	23500	17500	12700	9130	6250	4120	2650	1610	906	168
	1987	32800	26300	20900	16300	12700	9970	8310	7110	6120	4950
x3	**2018**	18500	13500	9500	6450	4400	2950	2000	1260	720	173
	2019	19000	14100	10200	7150	4760	2940	1790	1060	590	69

Table H.8: Experiment 6: Average electricity prices (€/MWh) mid hydrogen price - 2050

Battery	WY	0 GW	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
	1987	1301	1163	1033	906	800	747	710	638	594	583
x1	**2018**	1076	929	789	663	527	412	319	248	203	177
	2019	1101	962	820	672	539	424	338	279	234	214
	1987	1150	1007	871	756	664	640	617	574	533	537
x2	**2018**	895	759	620	504	384	297	224	179	154	124
	2019	932	792	642	496	400	319	245	201	174	144
	1987	1017	882	755	647	583	572	560	531	507	515
x3	**2018**	758	629	506	392	283	218	171	138	120	94
	2019	778	636	499	401	321	247	191	150	133	105

Table H.9: Experiment 6: Annual profits (MEUR/GW) - 2050

Battery	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
	1987	9245	8065	6859	5665	4829	4065	3097	2334	1798
x1	2018	7285	6085	5019	3845	2821	1992	1299	785	439
	2019	7565	6365	5085	3925	2861	2052	1379	925	568
	1987	7925	6665	5579	4515	3877	3372	2652	1935	1545
x2	2018	5885	4685	3712	2685	1917	1279	837	537	212
	2019	6165	4865	3605	2785	2045	1359	923	566	213
	1987	6885	5705	4659	3825	3333	2959	2351	1791	1462
x3	2018	4805	3765	2792	1885	1325	899	581	358	75
	2019	4845	3685	2872	2185	1501	992	598	346	54

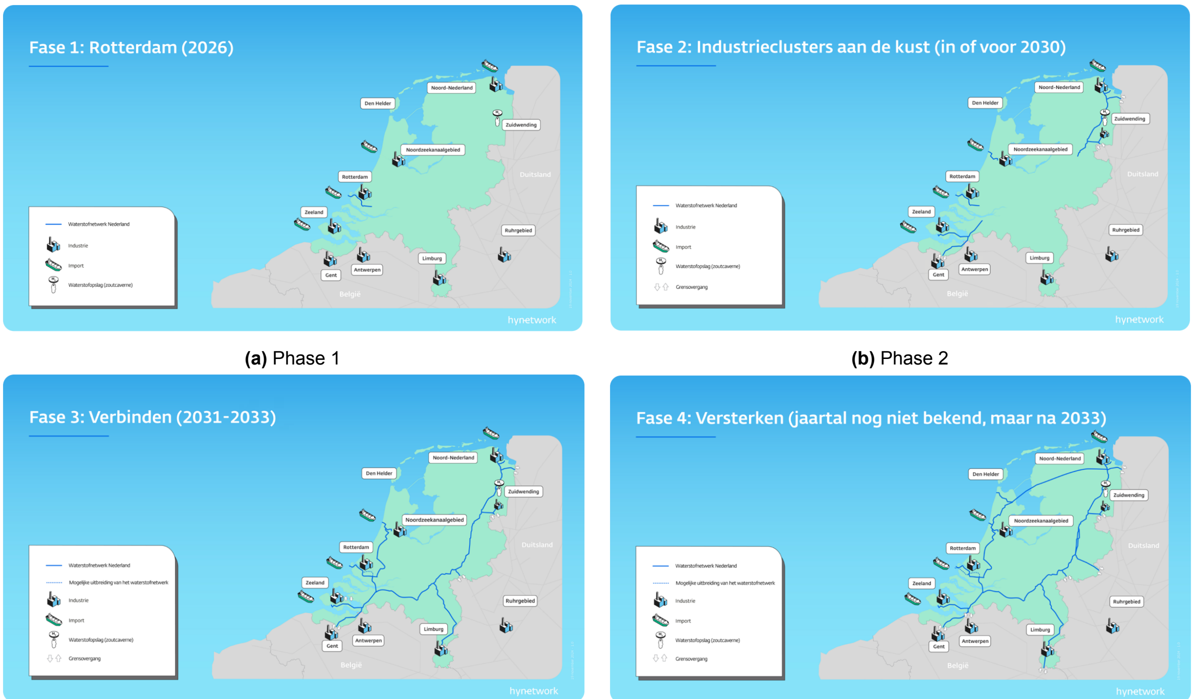
Table H.10: Experiment 6: Full load hours - 2050

Battery	WY	2.5 GW	5 GW	7.5 GW	10 GW	12.5 GW	15 GW	17.5 GW	20 GW	22.5 GW
x1	**1987**	3604	3420	3227	3080	2912	2633	2383	2180	2044
	2018	3152	2940	2747	2540	2344	2153	1960	1795	1671
	2019	3160	2980	2800	2610	2408	2200	2011	1860	1720
x2	**1987**	3412	3200	2973	2850	2648	2367	2126	1950	1818
	2018	2860	2640	2440	2240	2032	1833	1651	1500	1409
	2019	2904	2740	2547	2320	2104	1900	1709	1560	1458
x3	**1987**	3180	2960	2733	2580	2376	2120	1897	1735	1604
	2018	2576	2360	2173	1960	1752	1560	1394	1255	1178
	2019	2648	2440	2213	1990	1808	1613	1446	1305	1218

I

Development of hydrogen market

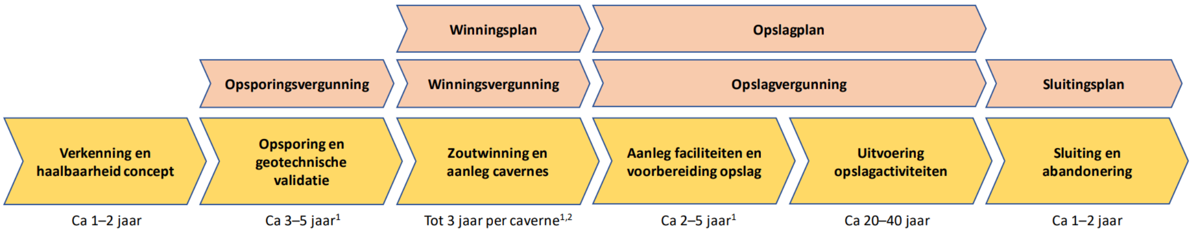
Hydrogen network



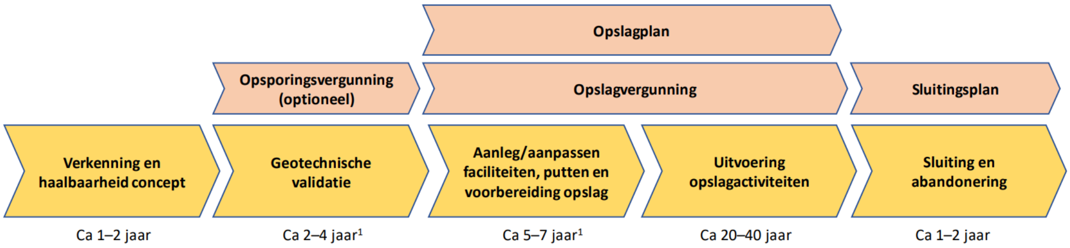
(a) Phase 1 **(b)** Phase 2 **(c)** Phase 3 **(d)** Phase 4

Figure I.1: Phases of the rollout plan for the hydrogen network [97]

Offshore underground hydrogen storage



(a) Offshore salt caverns



(b) Offshore depleted gas fields

Figure I.2: General development schedules UHS [111]