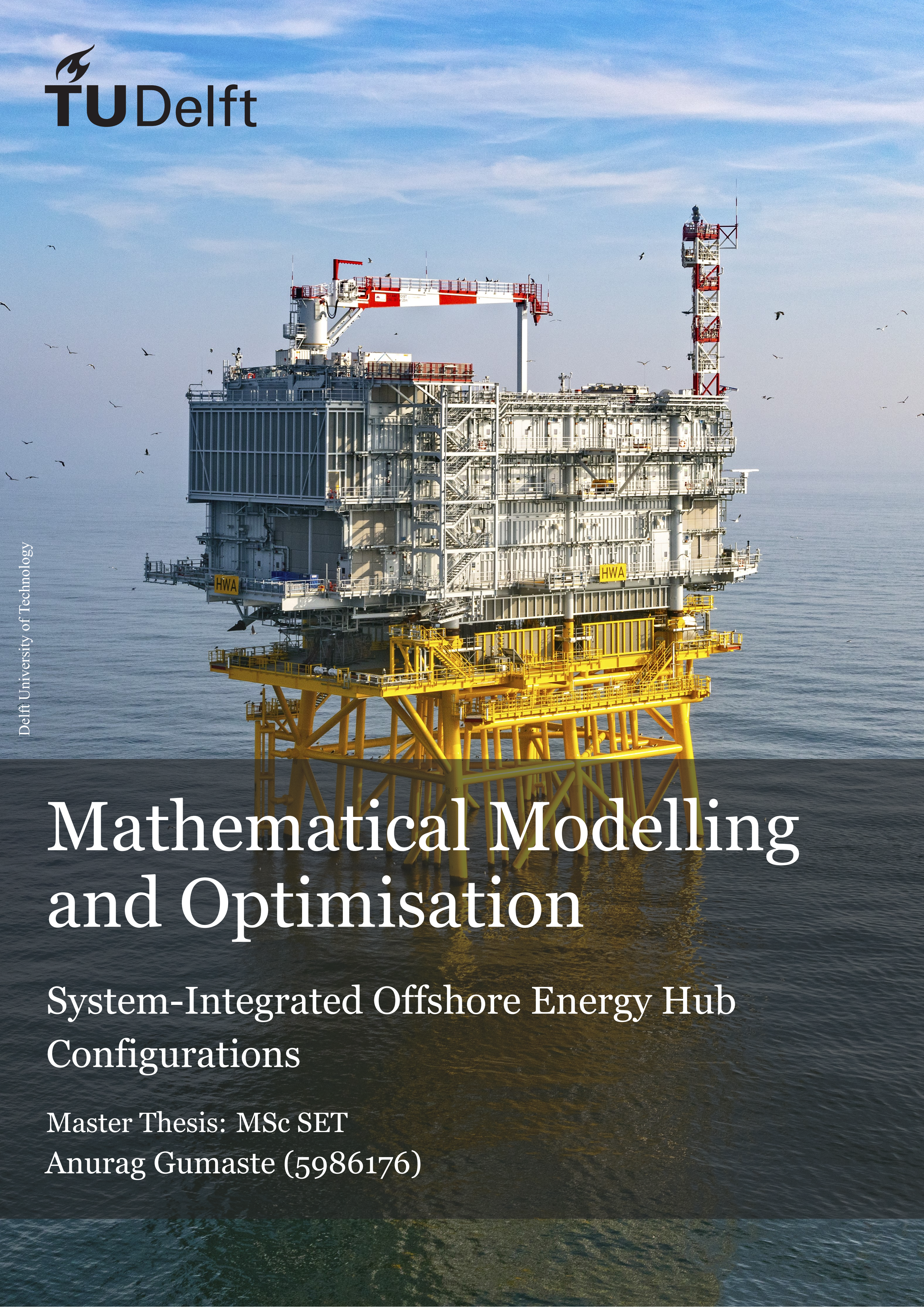

TU Delft

Delft University of Technology

Mathematical Modelling and Optimisation

System-Integrated Offshore Energy Hub Configurations

Master Thesis: MSc SET

Anurag Gumaste (5986176)

Mathematical Modelling and Optimisation

of

System Integrated Offshore Energy Hub Configurations

by

Anurag Gumaste

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Preface

Reflecting on the journey that has culminated in the writing of this thesis, I feel truly privileged to have had this tremendous learning experience. It is quite ironic how I, a mechanical engineer, initially apathetic towards coding ended up building a mathematical model from scratch in a programming language that I had never even heard of before.

But I could not have done this alone. I would like to thank my first supervisor, Kenneth Bruninx for helping me shape the thesis concept, for inundating me with brilliant ideas and challenging me to push my own boundaries at every step. My gratitude also extends to Michiel Zaayer for his unique perspective and elaborate comments that helped me present my work with greater clarity and precision. I am also grateful to Laurens Frowijn, who guided me through the writing process every step of the way and whose valuable insights greatly helped shape this thesis. A big thank you to all my SET professors for nurturing my interest in these subjects and equipping me with the necessary knowledge and skills to pursue them.

Of course, my acknowledgements would be incomplete without mentioning my industry supervisor at TenneT - Michel Dubbelboer, firstly, for offering me this opportunity, for being a sounding board throughout our many insightful discussions, and for supporting me in ways that extended far beyond the scope of this thesis. I also wish to thank the entire ESP-SO team and everyone at TenneT who generously contributed time, comments, and critiques to help me steer clear of pitfalls and continuously improve this work.

Most importantly, to my family, particularly my parents, I owe my deepest gratitude for their unwavering support, belief, and encouragement. All of my achievements would have been impossible without your love, sacrifices, and all the hardships you have endured. Finally, I would like to thank all my friends, here in Delft and those scattered all over the world for keeping me sane with encouragement, humour, and much-needed recreational reprieve throughout the arduous journey of this master's degree.

In writing this thesis, I have tried to carefully tread the tightrope between academia and industry, and in doing so, I have realised that no amount of research will ever be enough. Here are always assumptions to revisit, flaws to address, and improvements to be made, as we continue to inch closer to that elusive ideal of perfection.

This thesis marks the end of my long academic chapter as I turn a new page in my life. I will always look back fondly on this time. It has truly been an unforgettable journey and a privilege to be a student at TU Delft.

Anurag Gumaste
Delft, May 2025

Summary

Europe's ambition to become the world's first climate-neutral continent by 2050 presents several challenges in the domain of variable renewable energy generation and the development of sustainable energy carriers. In support of this mission, the North Sea is identified as a promising energy source, to be efficiently harnessed through the deployment of system-integrated offshore energy hubs combining wind farms with offshore electrolysis. The discussion around hydrogen's role as a renewable fuel in a high variable renewable energy energy system and its contribution to stable, systemic decarbonisation is acknowledged and relevant literature examined.

TenneT, alongside other European TSOs, has proposed certain hub layouts as a part of several studies and reports looking into the various aspects of ofshore enegry hubs. However, limited information exists on the financial attractiveness of these conceptual hubs for investors and developers. This study aims to determine the optimal configuration of such energy hubs from the standpoint of economic viability.

A modular mathematical model is developed to represent offshore energy hubs, enabling the testing of multiple configurations across various energy scenarios. Parameters such as electrolysis capacity, interconnection capacity, and ownership structures are varied, generating a range of configurations evaluated under different price profiles for electricity and hydrogen.

The model is applied to a case study based on the 2x2 GW offshore hub configuration, aligned with the North Sea Wind Power Hub programme. Results point to a weak business case for electrolysers under the datasets used. However, configurations featuring smaller electrolysers co-owned with relatively larger wind farms exhibit lower investment costs and greater economic benefit compared to those with larger electrolysers and smaller wind farms.

The thesis extends the analysis to consider implications for policy, tendering procedures, and broader socio-economic dynamics. Strategies such as phased build-out and public ownership of power-to-gas infrastructure are explored as potential enablers of hydrogen integration into offshore wind systems. Finally, concerns about energy security, heightened by recent disruptions in global supply chains, particularly in the energy sector, are discussed. This shifts the focus beyond pure economic considerations, toward the strategic value of system-integrated offshore hubs and their supporting infrastructure.

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Nomenclature

Abbreviations

Abbreviation	Definition
AE	Alkaline Electrolysis
AEMWE	Anion Exchange Membrane Water Electrolyser
BFOW	Bottom-Fixed Offshore Wind
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CfD	Contracts for Differences
comb	Combined (Ownership Configuration)
CRM	Critical Raw Materials
DC	Direct Current
DGM	Dual Gas Model
DHEM	Dual Hydrogen-Electricity Model
Elec	Electricity
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EPEX	European Power Exchange
ESR	Electrolyser
EU	European Union

Abbreviation	Definition
EU-27	European Union (27 member states)
FOW	Floating Offshore Wind
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hour
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEA	International Energy Agency
ILM	Interlinked Model
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
km	Kilometre
kV	Kilovolt
LCOE	Levelised Cost of Energy
LCOH	Levelised Cost of Hydrogen
MATLAB	Matrix Laboratory
MWh	Megawatt hour
MW	Megawatt
NSWPH	North Sea Wind Power Hub
NPV	Net Present Value
OPEX	Operating Expenditure
ONDP	Offshore Network Development Plan
PEC	Photoelectrochemical (Electrolysis)

Abbreviation	Definition
PEM	Proton Exchange Membrane
PGMs	Platinum Group Metals
P2X	Power to X
PS-CBA	Project-specific Cost-Benefit Analysis
PtG	Power to Gas
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of non-Biological Origin
SDG	Sustainable Development Goal
SOE	Solid Oxide Electrolyser
TSO	Transmission System Operator
TST	TYNDP Study Team
TYNDP	Ten Year Network Development Plan
VRE	Variable Renewable Energy
WF	Wind Farm
wfe	Electrical Wind Farm
wfh2	Hydrogen Wind Farm

Symbols

Symbol	Definition	Unit
€	Euro	[€]
M€	Million Euro	[M€]
$€_{\mathrm{e}}[t]$	Hourly electricity price	[€/MWh]
$€_{\mathrm{h2}}[t]$	Hourly hydrogen price	[€/MWh]

Symbol	Definition	Unit
$\mathrm{cap}_{\mathrm{cvr}}$	Converter capacity	[MW]
$\mathrm{cap}_{\mathrm{esr\text{-}cvr}}$	Interconnection capacity between converter and electrolysers	[MW]
$\mathrm{cap}^{\mathrm{w}}_{\mathrm{tot}}$	Total wind farm capacity	[MW]
$\mathrm{cap}^{\mathrm{w}}_{\mathrm{e}}$	Electrical wind farm capacity	[MW]
$\mathrm{cap}^{\mathrm{w}}_{\mathrm{h2}}$	Hydrogen wind farm capacity	[MW]
$\mathrm{cap}_{\mathrm{esr}}$	Capacity of one electrolyser	[MW]
$\mathrm{capex}_{\mathrm{w}}$	Wind farm capital expenditure	[M€/MW]
$\mathrm{opex}_{\mathrm{w}}$	Wind farm operational expenditure	[M€/MW]
$\mathrm{opex}^{\mathrm{var}}_{\mathrm{w}}$	Wind farm variable operational expenditure	[€/MWh]
$\mathrm{capex}_{\mathrm{esr}}$	Electrolyser capital expenditure	[M€/MW]
$\mathrm{opex}_{\mathrm{esr}}$	Electrolyser operational expenditure	[M€/MW]
$\mathrm{C}^{\mathrm{w}}_{\mathrm{inv}}$	Wind farm investment cost	[M€]
$\mathrm{C}^{\mathrm{w}}_{\mathrm{om}}$	Wind farm O&M cost	[M€]
$\mathrm{C}^{\mathrm{w}}_{\mathrm{var}}$	Wind farm variable cost	[M€]
$\mathrm{C}^{\mathrm{w}}_{\mathrm{tot}}$	Total wind farm cost	[M€]
$\mathrm{C}^{\mathrm{esr}}_{\mathrm{inv}}$	Electrolyser investment cost	[M€]
$\mathrm{C}^{\mathrm{esr}}_{\mathrm{om}}$	Electrolyser O&M cost	[M€]
$\mathrm{C}^{\mathrm{esr}}_{\mathrm{var}}$	Electrolyser variable cost	[M€]
$\mathrm{C}^{\mathrm{esr}}_{\mathrm{tot}}$	Total electrolyser cost	[M€]
$\mathrm{C}_{\mathrm{inv}}$	Total investment cost	[M€]
C_{om}	Total O&M cost	[M€]
$\mathrm{C}_{\mathrm{tot}}$	Total system cost	[M€]
$C^{\mathrm{inv}}_{\mathrm{eh2}}$	Investment cost for electricity-only wind farm party	[M€]

Symbol	Definition	Unit
$C^{\mathrm{inv}}_{\mathrm{wfh2}}$	Investment cost for hydrogen wind farm party	[M€]
$C^{\mathrm{inv}}_{\mathrm{h2}}$	Investment cost for only electrolyser party	[M€]
$C^{\mathrm{inv}}_{\mathrm{comb}}$	Investment cost of combined wind-hydrogen party	[M€]
$C^{\mathrm{inv}}_{\mathrm{wind}}$	Investment cost for wind farms per unit installed capacity	[M€/MW]
$C^{\mathrm{inv}}_{\mathrm{esr}}$	Total investment cost for electrolysers	[M€]
$\mathrm{gen}_{\mathrm{w}}[t]$	Hourly power generated per unit capacity	[MW/MW]
$\mathrm{eprod}_{\mathrm{ewf}}[t]$	Electricity produced by electrical wind farm	[MWh]
$\mathrm{eprod}_{\mathrm{h2wf}}[t]$	Electricity produced by hydrogen wind farm	[MWh]
$\mathrm{esup}^{\mathrm{ewf}}_{\mathrm{e}}[t]$	Electricity from ewf to grid	[MWh]
$\mathrm{esup}^{\mathrm{ewf}}_{\mathrm{h2}}[t]$	Electricity from ewf to electrolyser	[MWh]
$\mathrm{esup}^{\mathrm{h2wf}}_{\mathrm{e}}[t]$	Electricity from h2wf to grid	[MWh]
$\mathrm{esup}^{\mathrm{h2wf}}_{\mathrm{h2}}[t]$	Electricity from h2wf to electrolyser	[MWh]
$\mathrm{curt}_{\mathrm{ewf}}[t]$	Curtailment of ewf	[MWh]
$\mathrm{curt}_{\mathrm{h2wf}}[t]$	Curtailment of h2wf	[MWh]
$\mathrm{curt}_{\mathrm{w}}[t]$	Wind curtailment	[MWh]
$\mathrm{prod}^{\mathrm{e}}_{\mathrm{tot}}[t]$	Total electricity production	[MWh]
$\mathrm{prod}^{\mathrm{e}}_{\mathrm{act}}[t]$	Actual electricity production	[MWh]
$\mathrm{E}_{\mathrm{out}}[t]$	Exported electricity to shore	[MWh]
$H_2^{\mathrm{w}}{}_{\mathrm{in}}[t]$	Electrolyser input from wind	[MWh]
$H_2^{\mathrm{onshore}}{}_{\mathrm{in}}[t]$	Electrolyser input from onshore	[MWh]
$H_2^{\mathrm{tot}}{}_{\mathrm{in}}[t]$	Total electrolyser input	[MWh]
$H_{2\,\mathrm{out}}[t]$	Hydrogen output	[MWh]
$\mathrm{eff}_{\mathrm{esr}}$	Electrolyser efficiency	[%]

Symbol	Definition	Unit
N_{esr}	Number of electrolysers	[-]
N_{wf}	Number of wind farms	[-]
$rev_{tot}^{e}[t]$	Revenue from electricity export	[M€]
$rev_{tot}^{h2}[t]$	Revenue from hydrogen export	[M€]
$rev_{tot}^{w}[t]$	Wind farm revenue	[M€]
$rev_{tot}^{e,h2}[t]$	Total revenue from electricity and hydrogen	[M€]
$rev_{yr}^{e,h2}$	Annual revenue from electricity and hydrogen	[M€/yr]
R_{wind}	Annual revenue from wind electricity production	[M€/yr]
R_{H2}	Annual revenue from hydrogen production	[M€/yr]
π_{wfe}	Annual profit for electricity-only wind farm	[M€/yr]
π_{wfh2}	Annual profit for hydrogen connected wind farm	[M€/yr]
π_{h2}	Annual profit for hydrogen production system	[M€/yr]
IRR_{wfe}	Internal rate of return for electricity-only wind farm	[%]
IRR_{wfh2}	Internal rate of return for wind-hydrogen system	[%]
IRR_{h2}	Internal rate of return for hydrogen system	[%]
IRR_{comb}	Internal rate of return for combined system	[%]
NPV	Net Present Value	[M€]
r	Discount rate	[-]
i	Nominal interest rate	[-]
u	Inflation rate	[-]
T	Project lifetime	[years]

1

Introduction

The European Union (EU) has set the objective of reducing its greenhouse gas (GHG) emissions by 55% by 2030 (European Commission, 2020b) and by 90% by 2040, in comparison with 1990 levels (European Commission, 2024). The European Green Deal aims for Europe to be the first climate-neutral continent by 2050, which requires achieving net zero emissions by 2050 (European Commission, 2019). Furthermore, the United Nations has established 17 Sustainable Development Goals (SDGs), of which SDG 7 concerns affordable and clean Energy and focuses on substantially increasing the share of renewable energy in the global energy mix by 2030 (United Nations, 2016).

Given that the energy sector accounts for more than 75% of Europe's greenhouse gas emissions (European Commission, 2023a), the REPowerEU Plan has established an increased target of 45% share of energy from renewable sources by 2030 (European Commission, 2022). According to the plan, this will be achieved by a massive deployment of renewable generation capacity totalling 1236 GW across the EU by 2030. In order to achieve even a reduced target of 42.5% (European Commission, 2023a), a total of 425 GW, including onshore and offshore wind capacity has to be installed by 2030 (Costanzo & Brindley, 2024). Of this, the European Commission estimates that it is realistic and achievable to install up to 89 GW of offshore wind capacity by 2030 and up to 366 GW by 2050 (Directorate-General for Energy, 2024).

However, the significant rollout of renewable energy, coupled with the intermittent nature of solar and wind, introduces high variability in electricity supply, leading to hourly price fluctuations (Tselika, 2022), (Rosales-Asensio et al., 2024). At times, renewable electricity exceeds demand and must be dealt with accordingly (Ismail et al., 2015). For example, in Denmark, on a particularly windy day in February 2017, the entire national demand of 97 GWh could be satisfied by wind alone (Caughill, 2017).

On the other hand, there are also several timesteps when demand significantly exceeds renewable electricity supply, particularly during the "Dunkelflaute", a term that refers to cloudy and windless weather periods, which inhibit solar and wind energy generation, respectively (van Duinen, 2024). As represented by the red dot in Figure 1.1, on such a day in November 2024, Dutch energy generation from solar and wind fell to a two-year low of 17 GWh, enough to cover only 4% of the electricity demand for that day.

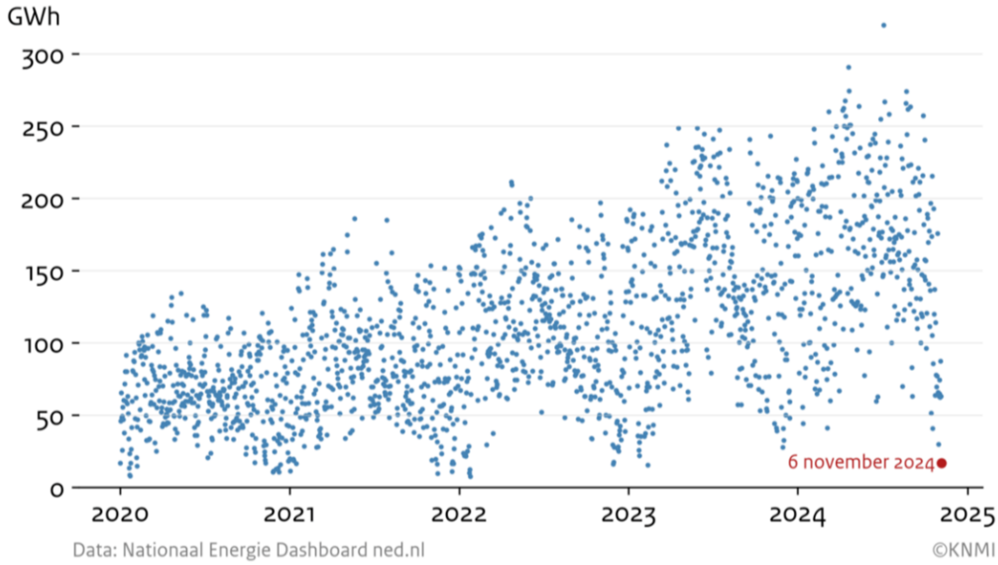


Figure 1.1: Daily generated wind and solar energy in the Netherlands (van Duinen, 2024)

In the absence of sufficient renewable energy, conventional fossil fuel-based power plants must be run to ensure adequate electricity supply (Jansen et al., 2024).

As solar and wind power become more central to electricity generation, their integration poses both technical and operational challenges for power systems. To better understand and plan for these impacts, the International Energy Agency (IEA) has delineated a six-phase Variable Renewable Energy (VRE) integration framework, as shown in Figure 1.2, outlining the increasing effects of VRE on power system operations (IEA, 2024).

These phases range from Phase 1, where VRE has no noticeable impact on system operation, to Phase 6, where electricity supply is almost exclusively from VRE and managing variability becomes central to power system design. The Netherlands is currently in Phase 4, in which uncertainty and variability in the supply-demand balance require a systemic increase in flexible operation (IEA, 2024).

However, this project focuses on a Phase 5 or Phase 6 energy system, characterised by very high levels of VRE integration and limited reliance on conventional generation. In such systems, substantial volumes of surplus renewable energy occur throughout the year, necessitating more extensive solutions, such as energy storage or demand side response to ensure a stable electricity supply.

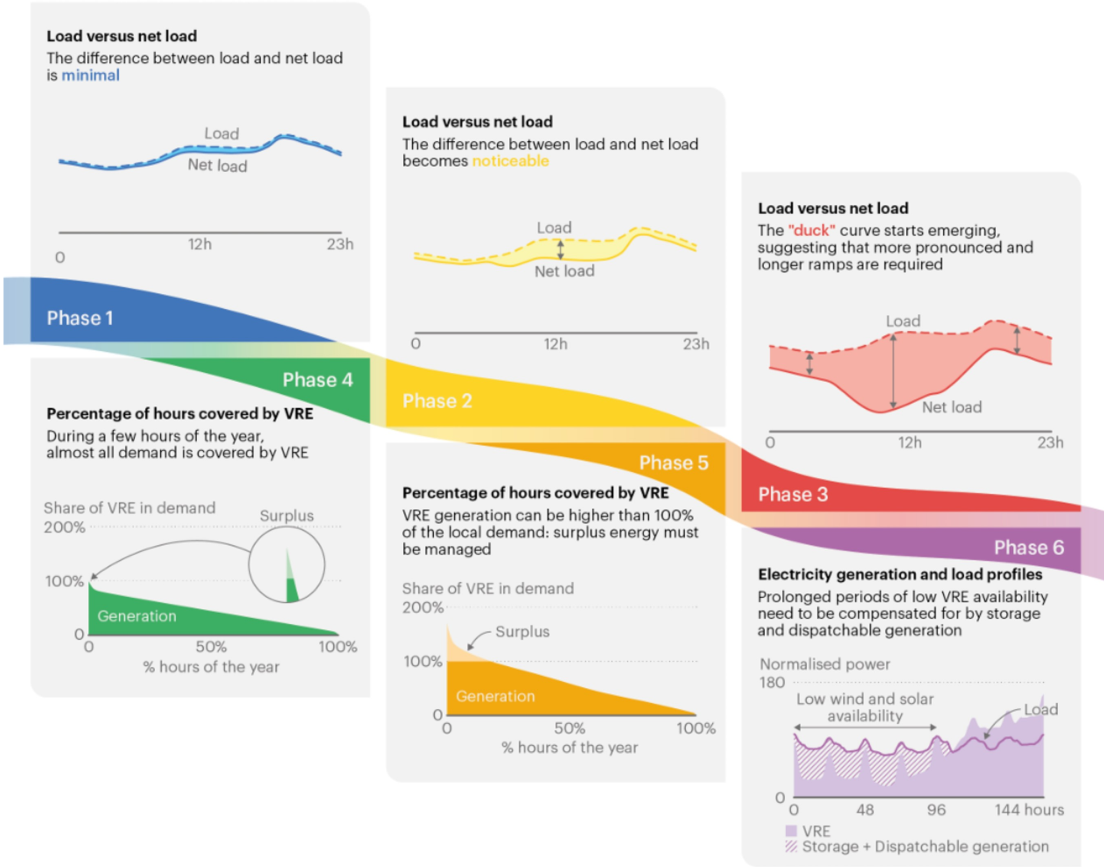


Figure 1.2: IEA Six Phases of Variable Renewable Integration (IEA, 2024)

Sometimes, during periods of excess generation, curtailment is required, wherein peaks are artificially capped by reducing the output of generation facilities to prevent grid overload. In addition, there is the issue of negative electricity prices arising from supply exceeding demand. For example, according to the European Power Exchange (EPEX SPOT) Day-ahead market, the Netherlands recorded 347 hours of negative prices in 2024 up to August alone, 31 more than in the entirety of 2023 (Bellini, 2024). In such cases, wind farms are often forced to reduce output or shut down entirely to avoid financial losses. As a result, valuable renewable energy is lost due to economic constraints rather than technical limitations. Naturally, this phenomenon is expected to intensify with further deployment of wind farms, as variable supply increases unilaterally.

Nevertheless, VRE projects must continue to be rolled out in order to meet national and regional installed capacity targets. According to the Offshore Network Development Plan (ONDP), only a small fraction of the envisioned offshore renewable energy source (RES) capacity has been installed, implying that the expansion rate must be nine times faster than in the past decade (ENTSO-E, 2024). In fact, total wind energy installations in Europe, including onshore and offshore, amounted to 16.4 GW in 2024, falling short of the required level by 23% (Costanzo & Brindley, 2024). There is therefore a clear and urgent need to both accelerate wind deployment and ensure the economic viability of these projects to secure investment and maintain momentum.

Furthermore, electricity accounts for just 22% of total final energy consumption, and while this share is growing annually, a much larger energy system exists beyond electricity (IEA, 2025a). This includes, to a large extent, natural gas and oil products, which are conventional and polluting sources (IEA, 2023). Achieving climate neutrality as outlined in the EU delegated regulation for renewable fuels of non-biological origin (RFNBO) therefore requires the introduction of renewable and sustainable fuels or energy carriers (European Commission, 2023c). These renewable fuels include hydrogen produced from water using renewable energy in the form of heat or electricity, along with its derivative fuels (Buffi et al., 2022). In this regard, hydrogen is expected to play a key role in the European energy mix by 2030. Owing to its varied applications as a feedstock, fuel, energy carrier, and storage mechanism (European Commission, 2020a), renewable hydrogen is projected to comprise 10% of the EU's energy mix (European Commission, 2022).

To offer an alternative to conventional fuels, prevent curtailment of wind energy and negative prices, and thereby maintain a strong business case for offshore wind farms, system-integrated electrolysis is considered a viable solution (NSWPH, 2024). The hydrogen produced can be transported onshore via pipelines and further integrated into the hydrogen energy system by repurposing existing natural gas infrastructure (European Commission, 2020a).

However, the role of hydrogen and its feasibility within the energy system remain subject to debate. Chief among the concerns is the significantly higher cost of clean fuels compared to unabated fossil fuels, introducing uncertainty for market participants considering a shift to clean alternatives (Eblé & Weeda, 2024). This elevated cost stems from several factors, including technological constraints in current electrolyser systems, regulatory requirements mandating the exclusive use of renewable electricity, the intermittent nature of renewable energy supply, and its impact on electricity price variability (Brandt et al., 2024). Additionally, repurposing the natural gas pipeline network for transporting hydrogen poses technical challenges due to key differences in the latter's properties, specifically its lower volumetric energy density, smaller molecular size, higher flammability, and increased reactivity (Martin et al., 2024). Moreover, uncertainties in supply volumes, value chain coordination, and the need for flexible production are closely interlinked and represent substantial obstacles, particularly in the early stages of the hydrogen economy (Klenke & Asghar, 2024). In the absence of a liquid market for clean hydrogen and a fully developed infrastructure, business models relying on hydrogen deliveries remain vulnerable to supply disruptions.

While numerous studies have explored offshore renewable energy systems, most modelling efforts remain focused on high-level system design across European energy networks. These approaches often prioritise macroeconomic optimisation and cross-border infrastructure planning rather than the detailed configuration of individual offshore nodes. Even where offshore hubs are considered, the emphasis tends to be on techno-economic feasibility or component-specific performance, rather than holistic optimisation from a developer's perspective. This highlights the need to narrow focus from system-wide strategies to the internal structure and economic potential of individual offshore energy hubs, a transition which this research undertakes.

As clean hydrogen emerges as a central pillar in future decarbonised energy systems, offshore renewable energy, particularly offshore wind, has gained attention as a key enabler of large-scale, low-emission hydrogen production. Offshore energy hubs are envisioned as multi-functional nodes that integrate wind power generation with conversion and transmission infrastructure, such as electrolysis platforms and pipelines. While numerous studies have explored offshore renewable energy systems, existing modelling efforts tend to prioritise macroeconomic optimisation and cross-border infrastructure planning, rather than the internal configuration of individual offshore nodes. Even when offshore hubs are included, the emphasis is typically on techno-economic feasibility or component-level performance, rather than holistic optimisation from a developer's perspective. As discussed in Chapter 2, few studies model these hubs in a way that supports infrastructure decision-making under long-term uncertainty. This lack of attention to hub-level configuration, particularly its economic implications—defines the research gap that this study aims to address.

1.1. Research Gap

An extensive literature review has been conducted and presented in Chapter 2, examining scientific publications, existing models, and relevant studies related to system-integrated offshore energy hubs. A key observation from the existing models is that they predominantly operate at a macro system level rather than focusing on the micro (hub) level. In other words, these models are designed to analyse and optimise energy flows across multiple nodes within a broader EU wide grid, rather than at the scale of individual hubs.

Existing models, such as the Interlinked Model (ILM) or the Dual Hydrogen Electricity Model (DHEM), as referred to in detail in Chapter 2, emphasise macro-level energy flow optimisation but offer limited guidance for hub-level decision making. However, these models are designed for pan-European analysis and are primarily concerned with optimising cross-border flows and overall system cost, rather than the internal configuration of individual offshore energy hubs.

In parallel, techno-economic studies have focused on offshore hydrogen production and the relative impact of parameters such as distance from shore, bathymetry, port access and wind conditions (Rogeau et al., 2023). Others examine the placement of electrolysers, whether in-turbine, offshore or onshore, as well as the choice of electrolysis technology and mode of operation (Singlitico et al., 2021). While useful for understanding cost drivers and technology trade-offs, these studies do not address the internal design or optimisation of offshore hubs themselves. In contrast, this research focuses explicitly on the internal configuration of a single offshore node, examining how different layouts influence developer business cases under uncertain future scenarios.

Even within the NSWPH knowledge framework, the Pathway 2.0 study explores system interactions using an EU-wide market coupling model, which seeks to minimise system costs while meeting both hydrogen and electricity demand (NSWPH, 2024). Similarly, the Cost-Benefit Analysis (CBA) study proposes a method to evaluate promising hub-and-spoke configurations, but again does so from a socio-economic perspective at the European system scale (North Sea Wind Power Hub, 2023).

What is referred to here as the hub level is the configuration within a single offshore node, and the optimisation of this configuration, particularly in the context of system-integrated offshore energy hubs. Studies that do examine energy hub configurations tend to focus on factors such as distance from shore, electrolyser technology, or method of electrolysis, factors that are exogenous to the actual internal layout of the hub. There is also little indication of an optimal configuration for these offshore hubs, with multiple possible futures currently in view.

Therefore, the impact of specific offshore hub configurations on developers, particularly in terms of a viable business case for investors, has not been studied. 4 GW system-integrated hubs are discussed in great detail regarding the technical feasibility of such offshore energy hubs (North Sea Wind Power Hub, 2024d); however, the economic analysis, especially one examining the business case for developers, is lacking and therefore presents a potential research gap.

Furthermore, there is considerable uncertainty with respect to possible future scenarios, given that they lie significantly further ahead in time. However, certain decisions, particularly regarding the layout of critical infrastructure, already need to be made to enable a hub configuration that can adapt to a wide range of future energy scenarios. Thus, in order to prepare offshore hub infrastructure for the future, the question of how to precisely design the configuration of these hubs needs to be answered. Moreover, floating offshore wind and offshore electrolysis are yet to be realised in large-scale commercial projects. Hence, before interconnections between offshore hubs are added, the optimal configuration of system integrated offshore energy hubs radially connected to one country must be analysed and optimised.

1.2. Problem Definition

While broader system-level challenges must be addressed before optimising hub configurations, the design of offshore energy hubs, though positioned further along the implementation timeline, has critical implications for strategic decisions being made today. Infrastructure elements such as converters, electrolyser platforms, and offshore DC cables require significant capital investment and are costly and difficult to modify once installed. As such, early decisions around hub configuration risk becoming locked-in, potentially misaligned with future system needs.

A key uncertainty is how different hub configurations affect economic feasibility for key actors, particularly Transmission System Operators (TSOs) and developers. The challenge lies in balancing infrastructure that is economically viable across a range of future energy scenarios. Yet, while conceptual and technical studies such as those by the North Sea Wind Power Hub (NSWPH) have advanced the vision for offshore hubs, they do not sufficiently quantify the economic viability of alternative configurations or model stakeholder behaviour in detail.

This knowledge gap is problematic. Without a clear understanding of the economic incentives, cost structures, and coordination requirements across public and private actors, early infrastructure choices may lead to suboptimal outcomes such as underutilised assets, stranded investments, or barriers to market participation.

Although multiple dimensions of complexity could be introduced into the modelling to increase realism, the analysis must be bounded by available data, time, and resources. The objective is therefore to develop a model that captures the core economic dynamics influencing offshore hub design, while remaining tractable and useful for practical decision making.

1.3. Research Questions

Based on the identified research gap and the complexity of the problem at hand, it is evident that there is a need for an economic perspective on offshore hub configurations within future offshore energy scenarios. Such a perspective is crucial in order to optimise the layout of these hubs and to establish a robust business case for both developers and investors. The research question is therefore formulated to address this optimisation problem:

What is the optimal offshore energy hub configuration with respect to value maximisation across multiple future energy scenarios?

In this context, "optimal" refers to a configuration that maximises economic value or profitability for developers, taking into account both capital and operational costs as well as potential revenue from electricity and hydrogen markets. The term "offshore energy hub configuration" refers to an integrated system comprising wind farms, power converters, electrolysers, and pipelines. The term "value maximisation" is used to reflect long-term economic benefits while accounting for depreciation. "Future energy scenarios" refer chiefly to plausible developments in electricity and hydrogen price trajectories, but also technology costs and efficiencies. These uncertainties are explicitly incorporated into the modelling process in order to identify configurations that perform well across a wide range of potential futures, rather than being optimised for a single forecast.

The hub configuration is represented as a mathematical model, which is subsequently optimised with the objective of maximising value or profit for developers. The key variables in this optimisation include the installed capacity of the wind farm, the number and size of electrolysers, the overall spatial and technical arrangement of the hub, and the ownership structure of its components. The aim is to determine a hub configuration that provides economic benefits and maintains a relatively strong business case across a range of scenarios with varying electricity and hydrogen price developments.

In order to address the main research question effectively and to structure the research process in a clear and coherent manner, four sub-questions have been developed. These sub-questions guide the analysis and help break down the broader optimisation problem into manageable components:

1. *What constitutes different configurations of offshore energy hubs?*
2. *What are the critical configuration variables affecting offshore hub profitability, and in what ways do they drive economic outcomes?*
3. *How does economic performance vary across different offshore hub configurations with respect to layout and ownership?*
4. *Which is the most economically viable offshore hub configuration considering the varying parameters?*

The first sub-question serves to establish a clear understanding of the structural components that make up an offshore energy hub. It also aims to identify how these components can be combined in different ways, resulting in a variety of technical and spatial configurations. This classification provides the foundation for all subsequent analysis.

The second sub-question investigates the key variables that influence the economic performance of these configurations. These include the installed wind capacity, the number and size of electrolysers, the overall hub arrangement, and the ownership structure of the various components. The effect of these variables is assessed across a set of plausible future energy scenarios, represented through different time series for electricity and hydrogen prices. The configurations that emerge from varying these parameters are then evaluated in terms of their economic value or profitability. The aim is to understand which factors are most impactful, and in what way they affect the business case for offshore energy hubs.

The third sub-question builds on this analysis by examining how different configurations perform economically under varying conditions, particularly in relation to the hub's physical layout and the ownership of its components. This includes comparing scenarios with varying physical constraints and asset installed capacities as well as different combinations of asset ownership. It also surveys the economic performance of such configurations when exposed to varying external conditions. This analysis supports a comparative understanding of which design and ownership choices enhance or hinder economic performance, providing a basis for more strategic infrastructure planning.

Finally, the fourth sub-question synthesises the insights gained from the previous three to determine the most economically viable configuration overall. This involves identifying the configuration that delivers the highest value across multiple future energy scenarios, thus balancing profitability with resilience. The configuration that consistently performs well under uncertainty is deemed to be "optimal", offering a compelling business case for long-term investment.

1.4. Research Approach

To address the research questions outlined earlier, mathematical modelling has been selected as the primary research method. The modelling approach allows for a structured, quantitative investigation into the interplay between technical design, economic viability, and future uncertainty. In particular, it supports the core aim of this research: to determine the most economically viable configuration of an offshore hub across multiple plausible energy futures.

The chosen approach involves constructing a modular model from scratch, designed to describe the internal composition of an offshore hub. This includes elements such as wind farm capacity, electrolyser sizing, platform arrangements, and connection infrastructure. The model is deliberately built to be flexible, both in structure and in scope, allowing for adjustments to internal as well as external parameters. This enables the testing of a wide range of configuration-scenario combinations.

In particular, the first question is approached by evaluating existing literature in its descriptions of offshore energy hub configurations, identifying what constitutes a configuration and how components can be meaningfully varied. Similarly, the critical configuration variables are also identified through literature to answer the second question in part. Their effect on driving economic outcomes is answered along with the third question through scenario-based simulations, where key variables are systematically altered to observe their influence on economic performance. Finally, the fourth question is addressed by evaluating the outcomes of these simulations to identify the configuration that delivers the highest economic value, consistently across uncertain future conditions.

Thus, a systematic research approach is adopted in order to bridge the gap between technical design and economic viability. By leveraging a flexible and modular modelling framework, this approach ensures that the optimal offshore hub configuration is identified across a range of future scenarios, providing valuable insights for both developers and investors. The structure of the remainder of this thesis reflects this research logic and is outlined below.

1.5. Thesis Outline

The structure of this thesis is as follows. Chapter 2 presents a review of the literature relevant to offshore energy hubs, covering their evolution, core design concepts, electrolysis technologies, and existing modelling efforts. Chapter 3 outlines the methodological approach, detailing the optimisation model, its parameters, and the procedures used to calculate internal values and prices. Chapter 4 introduces the North Sea Wind Power Hub as the case study, along with the scenario setup and supporting data. Chapter 5 presents the results of the simulations, analysing performance across different configurations and scenario conditions. Chapter 6 discusses the broader implications of the findings, including technical and regulatory considerations. Finally, Chapter 7 draws key conclusions and Chapter 8 outlines directions for future work.

2

Literature Review

2.1. Evolution of Offshore Wind Energy

The world's first multi-megawatt wind turbine, with a capacity of 2.0MW and a rotor diameter of 54m, was made operational in Denmark in 1978 (Enevoldsen et al., 2019). A decade later, in 1991, the first large commercial offshore wind farm was constructed at Vindeby, also in Denmark (Bilgili et al., 2011). Located 2.5km from shore, the farm comprised eleven 450kW turbines, with a total installed capacity of 4.95MW. The development in offshore wind farms since has been exponential with respect to both, installed capacity as well as distance from shore. The period from the year 2000 to 2016 reflects rapid development and investment in offshore wind technology in Europe as installed capacities grew from 22 MW to 12,631 MW or 12.6 GW (Europe, 2017). As of 2024, the global offshore wind installed capacity stands at 94 GW (IEA, 2025b). Almost all offshore turbines installed today are of the fixed foundation type, installed in shallow water depths upto 60m. These bottom-fixed offshore wind (BFOW) turbines are most commonly fixed to the ocean floor using foundation structures such as monopiles, jackets, tripods and gravity-based foundations (Díaz & Guedes Soares, 2020).

For depths exceeding 60 metres, however, traditional BFOW becomes economically unviable. In such cases, floating offshore wind (FOW) presents a more promising alternative, enabling access to stronger and more consistent wind resources located further offshore (Wind Europe, 2017). In 2009, the first full-scale floating wind turbine was installed in the North Sea with the objective of understanding the operating concept and identifying technology gaps (Magazine, 2009). Owing to its advantages including lower cost, flexible construction and installation, ease of decommissioning, and feasibility in offshore locations all over the world, FOW has since become the focus of substantial research (Liu et al., 2016), (Subbulakshmi et al., 2022). Nevertheless, as of 2023, it remains an emerging technology with only 270 MW of operational capacity (IRENA, 2024). However, 244 GW worth of new floating projects are in the global pipeline, indicating great interest and potential in this technology. A major application for FOW is in energy hubs with integrated offshore hydrogen production, the locations for which are significantly more than 60 m in depth (Glaum et al., 2024), (Swamy et al., 2019). Nevertheless, for hubs in the north sea with platform based electrolysis, BFOW turbines continue to be the economic preference (A/S et al., 2024).

2.2. Concept of Offshore Energy Hubs

The preliminary conceptual definition of an energy hub was a unit that could enable the conversion, conditioning and storage of multiple energy carriers (Geidl et al., 2007). Here, conditioning refers to voltage/frequency regulation, temperature control, pressure adjustment and purification, all applicable in the context of different energy carriers. In more contemporary terms, an energy hub is defined as a smartly controlled, decentralised energy system where the generation, consumption, storage, and conversion of different energy carriers is coordinated (Ramirez Elizondo & Palensky, 2024). Additionally, Lüth and Keles emphasise that offshore hubs must be fully renewable, fostering decarbonisation of the energy sector and preserving the environment, alongside performing the usual functions (Lüth & Keles, 2024). Alternatively, North Sea Wind Power Hub conceptualises energy hubs as performing any two of three core functions: collect, connect, and convert (North Sea Wind Power Hub, 2024c). These refer to the collection of offshore wind power, connection with other hubs to form a coordinated transnational network, and the conversion of surplus electricity into hydrogen, respectively. Thus, according to literature, offshore energy hubs must include one or more energy carriers and perform the different functions of sustainable energy generation, conversion and storage.

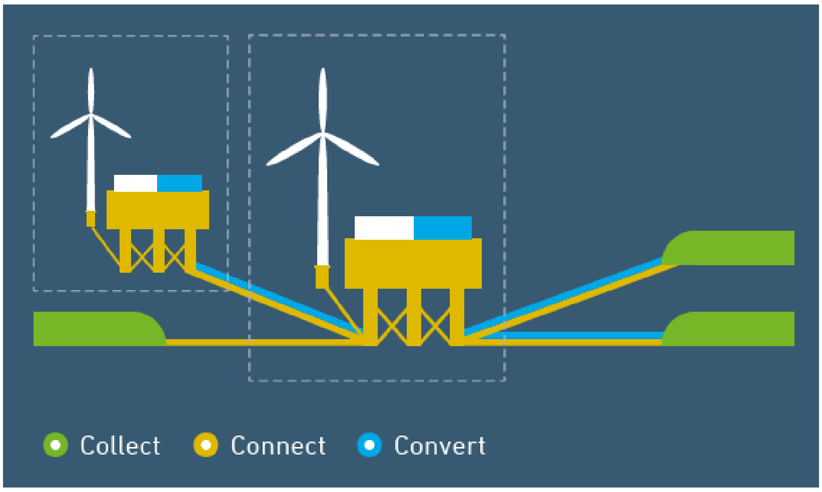


Figure 2.1: Core functions of offshore energy hubs: Collect, Connect and Convert (North Sea Wind Power Hub, 2024c)

In 2016, TenneT presented the hub and spoke concept which for building a large, interconnected offshore energy system in the North Sea (TenneT, 2016). The following year in 2017, the North Sea Wind Power Hub (NSWPH) consortium was formed as an international collaboration between three transmission systems operators (TSOs) - TenneT, Gasunie and Energinet to realise offshore wind hubs in early 2030s (NSWPH, 2022). It is aimed at utilising the full potential of the North Sea through offshore wind build-out and system integration, to facilitate Member States' 2050 decarbonisation projects (North Sea Wind Power Hub, 2024b). It was also recognised that projects with large-scale elements such as power to X (P2X), combined transmission assets and interconnectors have long lead times and therefore must be coordinated and developed parallely to ensure their timely accomplishment. Since its inception, the NSWPH has published several studies and papers that look into the different aspects of this offshore energy hubs concept (North Sea Wind Power Hub, 2024a).

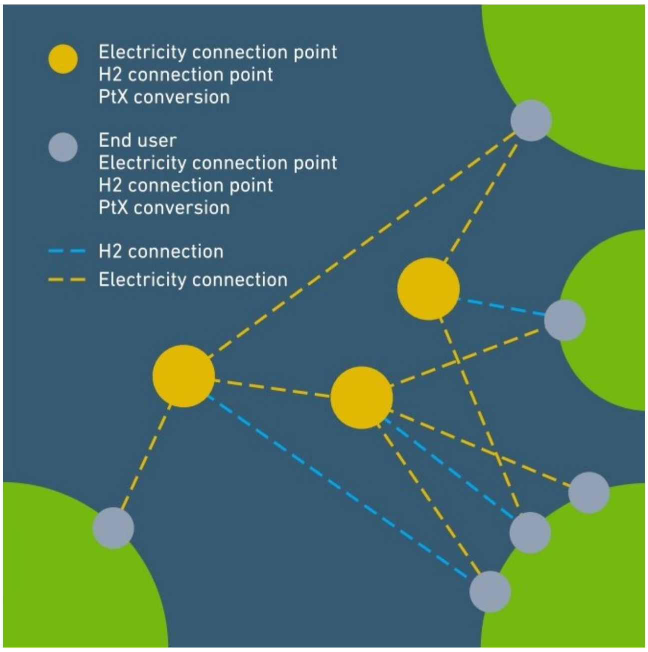


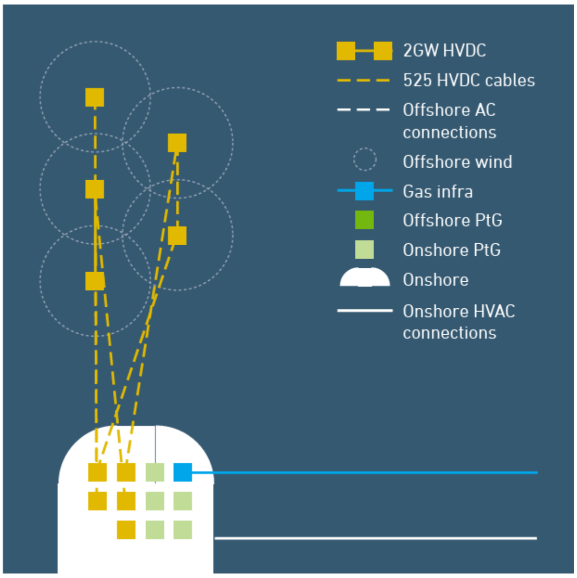
Figure 2.2: Hub and Spoke Concept (North Sea Wind Power Hub, 2022b)

2.3. Electrolysis Setup and Technologies

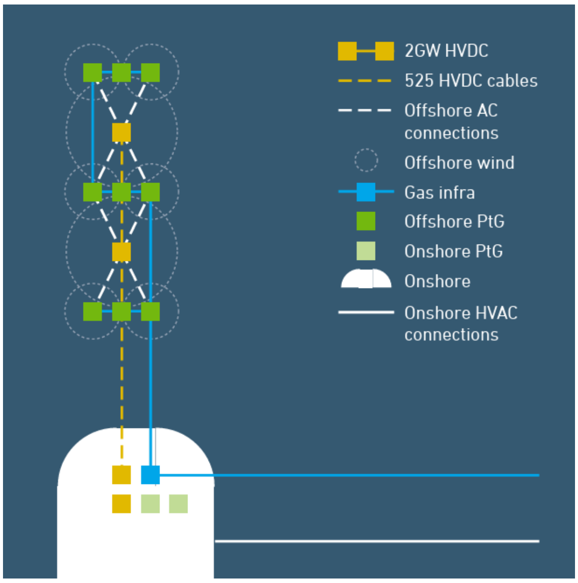
At a conceptual level, both onshore and offshore electrolysis are considered for hydrogen production the concept illustrations for which can be seen in figures 2.3 and 2.3(b) (North Sea Wind Power Hub, 2022b).

In the onshore electrolysis concept, multiple high voltage direct current (HVDC) connections, shown as yellow squares, are located offshore and surrounded by offshore wind, depicted as dotted circles. These HVDC connections transmit electricity to shore via dashed yellow HVDC cables. The onshore region, represented by the large white area, receives the electricity from offshore. From here, the electricity can either be distributed further through high voltage alternating current (HVAC) cables, shown as white lines, or used as input for the onshore power-to-gas (PtG) infrastructure, indicated by light green squares. The resulting green hydrogen can then be compressed and exported via gas infrastructure, represented by the blue square and line.

The general layout of the offshore electrolysis setup in 2.3(b) has a considerable overlap with the onshore setup in 2.3(a). However there are significant differences, notably the dark green squares representing offshore PtG infrastructure and the blue gas infrastructure extended offshore. Additionally, electrical HVAC connections (white lines) are observed between the offshore PtG and HVDC infrastructure.



((a)) Onshore electrolysis concept (North Sea Wind Power Hub, 2022b)



((b)) Offshore electrolysis concept (North Sea Wind Power Hub, 2022b)

Figure 2.3: Comparison of onshore and offshore electrolysis concepts

The number of HVDC connections is observed to be lower in quantity and is, to some extent, replaced by the offshore PtG transport infrastructure (Mott Macdonald, 2022). If electrolysis is carried out onshore, more offshore HVDC infrastucture is required to transport electricity to shore. In contrast, in the case of offshore electrolysis, wind turbines directly feed into the PtG platforms and the hydrogen thus produced must be transported to shore through pipelines.

However, there exists a counteracting trade-off between onshore and offshore electrolysis. Thus, the decision between the two options is largely dependent upon a combined evaluation of both these tradeoffs. A study by Frontier Economics estimates a reduction in the Levelised Cost of Hydrogen (LCOH) from 9% at 100 km to 16% at 400 km offshore when using offshore integrated electrolysis, as compared to onshore electrolysis where electricity is transmitted from offshore wind farms via subsea electricity cables (Janssen et al., 2025). While offshore electrolysis entails higher costs than onshore systems, this is offset significantly by lower transport infrastructure costs, specifically the considerably lower costs and higher energy transport capacity of hydrogen pipelines in comparison with subsea cables (Singlitico et al., 2021). Furthermore, (Glaum et al., 2024) also demonstrate offshore electrolysis to facilitate higher deployment of offshore wind capacity reaching up to 91 GW by 2050.

Several different technologies are available for electrolysis - Alkaline Electrolysers (AE), Proton Exchange Membrane (PEM) Electrolysers and Solid Oxide Electrolysers (SOE) (Q. Hassan et al., 2024). Certain newer technologies also exist such as Anion Exchange Membrane Water Electrolyser (AEMWE) (Vinodh et al., 2023), microbial electrolysis cells (MEC) (Bhardwaj & Jayant, 2025) and photoelectrochemical (PEC) electrolysis (Frowijn & van Sark, 2021), however, they are in the formative stages of their development and need further research to be ready for large-scale commercial applications (N. Hassan et al., 2024).

Of these, alkaline electrolysis is the most mature technology and has lower costs in comparison with other technologies, especially for large-scale applications (Niroula et al., 2023). But AE also has certain negatives such as their larger size that makes them less suitable for installation on offshore platforms (source), slower response times. Another drawback is their inefficient operation below 10 - 40% of their nominal load (Amireh et al., 2023), (Haug et al., 2017).

PEM electrolysers have the advantage of compact size, are flexible and also compatible with renewable energy (Q. Hassan et al., 2024). However, they require precious metals such as platinum and iridium, and are therefore more expensive (Christopher Selvam et al., 2025). Both these Platinum Group Materials (PGM) are included in the EU 2023 Critical Raw Materials (CRM) list as they are of high economic importance and mostly have to be imported into the EU from other parts of the world (South Africa and Russia), therefore posing considerable supply risks (European Commission, 2023b).

SOEs, while having a relatively lower technology readiness level (Schropp et al., 2024), have certain advantages such as a long lifespan and scalability. However, they require temperatures in the range of 600 - 1000°C for operation, entail higher capital costs and have significantly lower output rates than the other two technologies (Shanmugasundaram et al., 2025).

The electrolyser technology considered for onshore is alkaline electrolysis while that for the offshore platform-based option is PEM electrolysis (North Sea Wind Power Hub, 2024d). The suitability of alkaline electrolysis to onshore applications is simply due to it's lower costs in comparison with PEM. However, PEM electrolysers are significantly lighter and therefore save costs for construction of offshore platforms as well as for transportation and installation of the electrolysers.

Within the offshore electrolysis concept, three different setups are considered, namely caisson islands, hydrogen wind turbines and platform-based electrolysers (North Sea Wind Power Hub, 2024d). Among these, the platform-based option is identified to be the most advantageous, particularly with respect to scale, cost, maintenance and operability. Constructing an artificial island, by contrast, is especially challenging at the target site, where water depths exceed 40 metres (Jetten, 2024). Further, based on preliminary sizing, a platform capacity of 500 MW is found to be optimal given constraints of dry weight, operating weight and footprint, as it maximises possible capacity while considering significant allowances for unknowns, uncertainties and exclusions (Mott Macdonald, 2022). However, developments are foreseen to start with smaller, 180 MW platforms for the initial projects (North Sea Wind Power Hub, 2024d). It is judged as an ideal intermediate size for demonstration projects due to its reasonable cost and weight per MW, its suitability for power conversion from two 66 kV (90 MW) inter-array cables. Moreover, it is possible to install 180 MW with a dual crane heavy lift vessel which are less expensive and more readily available than those required for float-over installation methods required for larger capacity electrolyser platforms.

Parallel to technical design choices, effective governance and regulatory models are essential for enabling the deployment of offshore electrolysis at scale. A centralised governance model for offshore hubs is described by NSWPH, where national entities and Transmission System Operators (TSOs) are primarily responsible for planning, ownership and operation of infrastructure assets including the hub foundation, hub-to-shore transmission cables, and hydrogen pipelines (North Sea Wind Power Hub, 2022a). However, it is mandatory for generation and Power-to-Gas (PtG) assets to be privately owned by commercial developers (Autoriteit Consument & Markt, 2021). This is envisioned to be beneficial for competition in offshore wind development as private developers can depend upon TSOs to realise critical infrastructure, while engaging in mutual competition.

2.4. Existing Models and Studies

To support such coordinated infrastructure planning and investment, system-level modelling tools have been developed at the European level to evaluate interdependencies and optimise cross-border energy flows. The Interlinked Model(ILM) 2024 developed by ENTSOE and ENTSOG is a market model that uses interconnectors to simulate flows between European bidding zones. The model is made within the scope of the Ten Year Network Development Plan (TYNDP), i.e., for identifying infrastructure needs and conducting cost benefit analyses on a pan-European scale (ENTSO-E & ENTSOG, 2024). It is similar to ENTSO-E's TYNDP Study Team's (TST) electricity models with the addition of allowing hydrogen production during renewable energy excess while assuming a hydrogen copperplate (ENTSO-E and ENTSOG, 2021). Parallely, the TYNDP 2024 Project-specific Cost-Benefit Analyses (PS-CBA) involves two essentially identical models - Dual Hydrogen-Electricity Model (DHEM) and the Dual Gas Model (DGM), which concern the interactions between the hydrogen-electricity systems and the hydrogen-natural gas systems respectively (ENTSOG, 2024). The objective of the DHEM model is to minimise overall system cost through joint modelling of the two energy carriers (electricity and hydrogen), considering energy exchanges through multiple bidding zones across Europe and beyond into North Africa and the Middle East.

In developing a CBA framework for hub-and-spoke projects, certain issues are identified in applying the ENTSOE guidelines to the NSWPH framework directly, as they would need to take into consideration the international, cross-energy sector character of the hub-and-spoke concept (North Sea Wind Power Hub, 2021). Therefore, a three-level methodology for CBAs is recommended starting with Pathway Studies as the first step to analyse general tendencies and long-term energy pathways (North Sea Wind Power Hub, 2023). The latter two are said to be comparable to ENTSO-E's TYNDP and consist of a Pragmatic CBA and an Advanced CBA. On the one hand, pragmatic CBAs focus on the feasibility of specific hubs-and-spokes configurations and for the assessment of their overall socio-economic value. While on the other hand, Advanced CBAs are aimed at increasing the level of detail on the impacts for grid operators and market participants in the context of specific configurations, and taking into consideration regulatory market setup and impact on the physical grid.

(Rogeau et al., 2023) conduct a comprehensive techno-economic analysis of offshore hydrogen production at the European scale, using the Levelised Cost of Hydrogen (LCOH) as the primary metric. Their study systematically investigates how spatial variables such as distance to shore, proximity to ports, water depth, and average wind speed affect the economic viability of offshore hydrogen projects. By incorporating geospatial variability and infrastructure considerations into their model, they provide valuable insights into the optimal siting of offshore hydrogen production facilities across Europe. Alternatively, (Singlitico et al., 2021) focus on the component-level design and operational aspects of hydrogen production from offshore wind. Their study evaluates the techno-economic implications of different electrolyser placements, within turbines, on offshore platforms, and onshore, as well as alternative electrolyser technologies, including Alkaline Electrolysis (AE), Proton Exchange Membrane (PEM), and Solid Oxide Electrolysis (SOE). Additionally, they explore distinct operational modes, comparing hydrogen-driven and electricity-driven optimisation strategies. This allows for a nuanced understanding of how design and control decisions influence overall system performance and cost-efficiency.

Together, these studies highlight the breadth of modelling approaches in the literature, from large-scale geospatial optimisation to detailed component-level techno-economics, each contributing complementary insights into the configuration of offshore hydrogen systems.

2.5. Addressing Key Research Questions Through Literature

The literature review contributes primarily to the first two sub-questions. In response to the question *"What constitutes different configurations of offshore energy hubs?"*, the review identifies a range of hub configurations distinguished by their functional roles, including collection, conversion, and connection, as well as their constituent infrastructure components such as wind farms, electrolysers, conversion platforms, pipelines, and cables. Configurations are further differentiated by technology choices such as onshore versus offshore electrolysis, the use of hydrogen or electricity as energy carriers, and platform design, ranging from artificial islands to fixed or floating structures. These variations reflect the multiple strategic pathways available for hub development.

In addressing the second question *"What are the critical configuration variables affecting offshore hub profitability, and in what ways do they drive economic outcomes?"*, the literature highlights a set of key variables. These include the location of electrolysis, the type of electrolyser technology employed, platform size and type, distance and depth from shore, and the selected transport vector. The literature provides qualitative insights into the economic implications of these variables, which are supported by underlying quantitative assessments. These include the trade-offs between onshore and offshore conversion, capital cost differences between electrolyser technologies, and the comparative benefits of hydrogen versus electricity transport.

The remaining questions concerning the variation in economic performance across configurations and the identification of the most economically viable configuration are not addressed directly through existing literature. These are instead explored through scenario-based simulation in subsequent chapters, where key variables are systematically altered to assess their influence on economic outcomes across different future conditions.

3

Methodology

The objective of this thesis is to evaluate multiple configurations of offshore energy hubs by subjecting them to a wide range of potential future energy scenarios. The aim is to identify the most economically optimal hub configuration. To begin, the model components, constraints, decision variables, and other relevant parameters are clearly defined.

Category	Elements	Description
Components	• Power converter • Offshore cable • Cable connecting converter and electrolyser platform • Electrolyser • Compressor • Hydrogen pipeline	These are the fundamental building blocks of the model, each with a fixed capacity that constrains the model setup and operation.
Decision Variables	• Wind farm size (Individual + Cummulative)	These are the model's output values, determined after solving the optimisation problem. They vary based on the model objective, components, parameters values and constraints.
Parameters	• Electricity Prices • Hydrogen Prices • Electrolyser Quantity • Electrolyser Capacity • Interconnection Capacity	These define future scenarios as well as hub configurations in the model, with different combinations forming distinct variations.

Table 3.1: Summary of Components, Decision Variables, Parameters, and Meta-level Parameters

The components are fixed, while the decision variables are optimised to obtain their optimal value. The parameters are varied within limits to generate different scenarios and configurations. The decision to fix certain elements is driven by two factors: evaluative simplicity and industrial practicality. Some elements listed under components are constrained by industry standards, such as 15 MW wind turbines (NSWPH, 2024) or 2 GW power converters and offshore cables (TenneT, 2023). Although varying these "fixed" components could provide insightful results from an objective, academic perspective, the scope of the research must be constrained to ensure operational simplicity given limited time and resources. It is therefore, most instructive to vary parameters that have the highest likelihood of variance in real-world situations to generate meaningful results with practical implications.

Research is also conducted to understand as many factors that may impact the hub configuration as possible. The objective of this model is to maximise value or profit, thus building a business case for developers and ensuring efficient utilisation of the energy transport infrastructure. Further, relevant scenarios are generated by varying these different parameters based on existing market models and interviews with industry experts, to focus on likely future conditions and eliminate certain scenarios with an extremely low likelihood or relevance. The scenarios that remain will then be simulated in the model by inputting their respective distinct characteristics and then the operation and economic output of the energy hub for each such scenario will be studied for different hub configurations. Finally, a robust configuration with a particular set of characteristics is identified and the ideal configuration, thus established is suggested for further research and investment in order to facilitate acceptable value generation over a wide range of likely scenarios with minimum risk.

The model has been built given system integrated hub configuration as can be seen in figure 3.1.

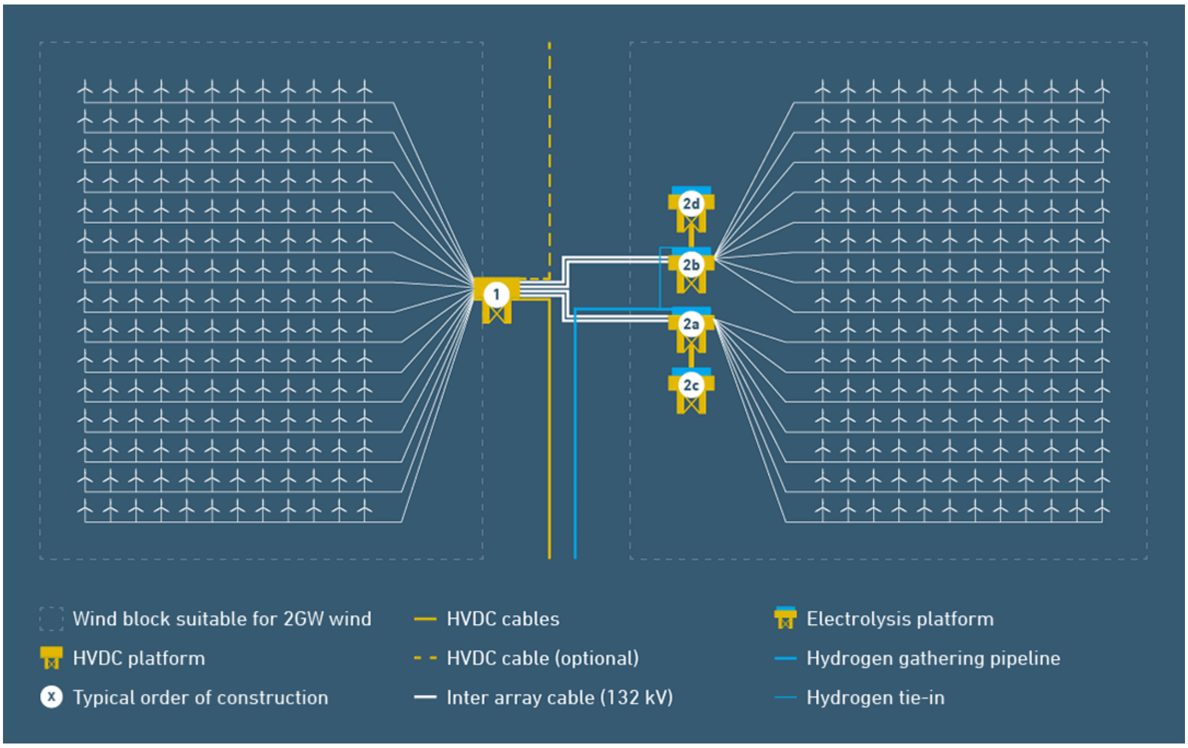


Figure 3.1: North Sea Wind Power Hub System-Integrated Hub Concept (North Sea Wind Power Hub, 2024d)

It represents a 2x2GW hub configuration with solely electrically connected wind farms, electrolysers and wind farms connected to electrolysers (North Sea Wind Power Hub, 2024d). The 2x2GW name refers to two 2 GW wind farms ignoring overplanting. The hub also contains a converter, an offshore HVDC cable, four electrolysers, interconnecting cables, and hydrogen export infrastructure. The discussed methodology must be considered in the context of this configuration. This configuration is discussed further in depth in Chapter 4.

3.1. Approach

Mathematical modelling is the preferred approach for this project. Various programming languages and software were considered for this purpose, and the programming language - Julia was chosen due to its superior performance, particularly for the purpose of parallel computing and optimisation. Other programming languages such as MATLAB and Python were contemplated but ignored owing to the relative higher computational power and ease of modelling in Julia. Software such as PLEXOS were also briefly considered, however, it is more suited for market modelling, whereas this project involves optimisation of the hub configuration. Moreover, as there were simply no pre-existing models available to build upon, the decision was taken to build this model from scratch. This allowed for complete autonomy over the modelling process and to add layers of complexity as and when required. It is understood, however, that this decision invokes certain disadvantages, primarily the absence of a pre-existing model to build upon and the consequent increased requirement of time and resources to develop the model from the ground up. While the model has multiple functionalities, it is structured with layers of complexity.

Before understanding the model setup, it is essential to clearly define what constitutes 'optimal' in terms of the hub configuration. This definition is critical to determine the model objective and ensure that the model would optimise for a specific variable. For this project, the value maximisation approach is chosen over the LCOE/LCOH approach. In this approach, energy prices are considered along with the hourly energy yield. The revenue generated per hour is then calculated by multiplying the two. Finally, the net present value of the hub is calculated by summing up the revenue for a life time of 30 years, subtracting the costs from it, and adjusting for discounting. The model considers all probable installed capacities within the provided constraints and the capacity associated with the highest value, is obtained as output. In the value maximisation approach, the model reacts to the prices which may warrant higher installed capacity than suggested by the LCOE approach and better reflects real-world elements.

3.2. Model Description

The model simultaneously performs several functions to accurately simulate real-world conditions. An important feature of this model is its modularity, which implies that the model is free from hard coded values. Designed with a modular approach, the model can thus easily be used for different scenarios and configurations, by simply inputting different data files or time series for wind speeds and electricity or hydrogen prices. Its functioning itself involves wind capacity optimisation followed by post-optimisation individual party value computation.

A relatively simplified overview of the model's functioning is provided in this section

3.2.1. Wind Capacity Optimisation

The optimisation of the model treats the model as a single entity together with a converter, wind farms, electrolysers, interconnection capacity and export capacity. The electricity export capacity is constrained to the physical limits of converter or the attached DC cable and is considered to be constant. Similarly, the interconnection is also considered to be constant given the capacities of the connecting cables between the electrolyser/s and the converter.

The quantity, capacity and efficiency of the electrolysers is fixed for a single optimisation iteration, along with the associated cost. Owing to the modular nature of the model, these values can be modified between iterations through the input data file. However, the model does not optimise for them directly. The reasoning behind this design choice is that electrolysers were observed to have high values of Capex and Opex, which, if included in the optimisation, would result in the model favouring their exclusion altogether. This method, on the other hand, allows electrolysers to be enforced into the built infrastructure, thereby enabling observation of outcomes for different configurations, and facilitating manual optimisation of the hub configuration through multiple iterations.

The model methodology is represented pictorially in figure 3.2.

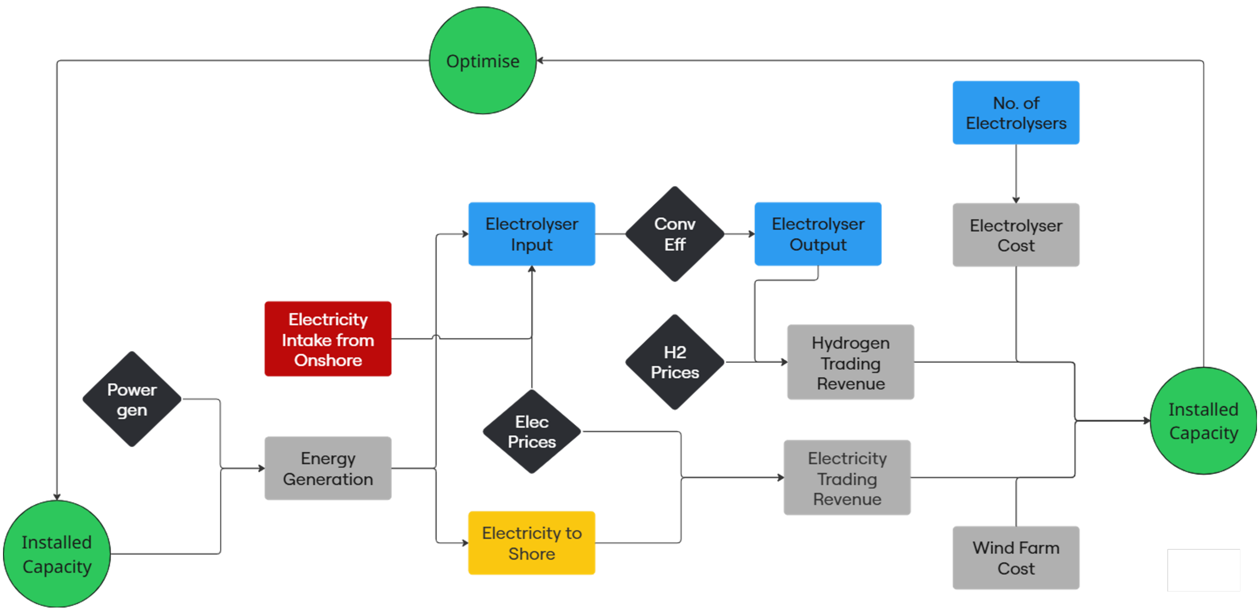


Figure 3.2: Visual representation of the model structure and optimisation workflow.

Figure 3.2 provides a schematic overview of the model's optimisation structure and workflow. The black rhombuses represent external inputs and pre-processed data, which feed into the model as foundational parameters. Grey boxes indicate key numerical outputs generated through internal calculations involving both model variables and exogenous data. The blue rectangles correspond to components related to electrolysers, including configuration-specific variables and outputs. This blue colour scheme is consistently applied across the results section in electrolysis related figures and ownership structure illustrations. The yellow rectangle denotes electricity transmitted from offshore to shore, while the red rectangle represents electricity supplied from shore to offshore assets, again, aligned with the same colour scheme used throughout the results. The green circles symbolise the optimisation process, encapsulating the loop structure that adjusts system variables to achieve a NPV-optimal configuration.

As a starting point, the wind farm installed capacity is considered to be variable. The hourly electricity output of the wind farm (per MW of installed capacity) is obtained from the NSWPH dataset at the given location. The energy production of the wind farms is then allowed to split up into electricity output to shore and input for electrolysers for the purpose of hydrogen production. Here, the production of hydrogen through the electrolyser entails energy conversion losses, which are governed by the electrolyser efficiency.

Hourly electricity and hydrogen prices for onshore are collected from external datasets and the hourly revenues are computed by multiplication of these onshore prices with the hourly electricity and hydrogen output respectively. The hub can also import a limited amount of electricity from shore while paying the onshore price for it. The cost of the imported electricity is considered to be the variable operational cost of the electrolyser. However, the constraints in the model are formulated in such a way that they do not allow for simultaneous electricity inflow and outflow through the cable.

The model chooses to produce either hydrogen or electricity based on their respective prices and whether the difference between them is enough to account for the electrolyser efficiency. As a result, energy is dynamically routed towards the most economically viable pathway.

The Capex and Opex costs of the wind farm and electrolysers scale with their respective installed capacities and together with the revenues, are used to calculate the net present value of the hub. The number of electrolysers required is linked to the electrolyser capacity and contributes to the total cost. The installed wind capacity is optimised in order to ensure the highest net present value, for a predetermined project lifetime. This also allows for overplanting and subsequent curtailment if required, for optimal utilisation of the electrical infrastructure.

3.2.2. Metrics of Profitability

Net Present Value

While the calculation of the net present value is intrinsic to the optimisation algorithm, it is not included in figure 3.2 owing to its specific computation and is explained separately in this section.

The net present value of an asset is the current value of future cash flows given discounting. It is a metric used to calculate the profitability of investments, and it forms the third layer of this model. NPV is a more informative metric than profit for ascertaining the value of the investment as money loses its value with time and the same amount of money has greater value in the present than in the future. The hub configuration is optimised for this net present value. Given that equal annual cashflows are considered throughout the entire project lifetime, the net present value is computed as follows:

$$\text{NPV} = (R - C_{\text{OM}}) \cdot \frac{1 - (1 + r)^{-T}}{r} - C_{\text{inv}} \tag{3.1}$$

Where:

- NPV: Net Present Value (M€)
- R: Annual revenue (M€/year)
- C_{OM}: Annual operating and maintenance (O&M) costs (M€/year)
- r: Real rate of Interest
- T: Project lifetime (years)
- C_{inv}: Initial investment cost (M€)

Here, the real rate of interest (r) is calculated as follows:

$$r = \left(\frac{1 + i}{1 + u}\right) - 1 \tag{3.2}$$

Where:

- r: Real rate of interest
- i: Nominal interest rate
- u: Inflation rate

Internal Rate of Return

Additionally, the internal rate of return is also calculated, which uses a similar concept as the net present value. While it is not used directly for the purpose of the optimisation directly, it is a more intuitive metric of profitability than the NPV and is often relied upon by developers to ascertain the financial viability of projects. It is the real rate of interest or rate of discount which equalises the present cummulative value of annual cash inflows with the initial investment. It can be calculated by setting the net present value to be zero in equation 3.1 and obtaining the discount rate.

$$\text{NPV} = (R - C_{\text{OM}}) \cdot \frac{1 - (1 + IRR)^{-T}}{IRR} - C_{\text{inv}} = 0 \tag{3.3}$$

Where:

- NPV: Net Present Value (M€)
- R: Annual revenue (M€/year)
- C_{OM}: Annual operating and maintenance (O&M) costs (M€/year)
- IRR: Internal Rate of Return

- T: Project lifetime (years)
- C_{inv}: Initial investment cost

Both these metrics are indicators of financial viability and a business case for investment in the offshore hub infrastructure.

3.3. Optimisation Problem

The optimisation problem is central to this research as it addresses the primary objective of identifying the optimal configuration for an offshore hub. This problem involves determining the most efficient allocation of resources while maximising the net present value of the infrastructure over a specified operational lifespan. The optimisation model incorporates various physical, operational, and economic factors that govern the offshore hub's performance.

The problem is structured around a set of key variables, which include wind farm capacities, energy production rates, electricity and hydrogen supply to various components, as well as associated costs and revenues. These variables are then subject to several constraints, ensuring that the energy balance is maintained, capacities do not exceed certain limits, and costs are controlled within specified bounds.

The model optimises the functioning of the hub, making a decision at every time step to utilise the wind-generated electricity as electrolyser input to produce hydrogen or to export it to shore. It manipulates these energy flows based on the electricity and hydrogen prices for that time step in order to maximise economic value.

The objective of the optimisation model is to find the configuration of parameters that maximises the Net Present Value (NPV), which is a marker of overall financial viability of the offshore hub. To achieve this, the model uses the defined variables and constraints to explore different configurations and identify the one that provides the best return on investment, taking into account the dynamics of electricity and hydrogen markets represented by their price profiles. The Julia code for representing the model is mentioned in Appendix C.

3.3.1. Model Input Parameters

The model input parameters provide the necessary data that defines the system's characteristics and operation within the optimisation problem. These parameters include information such as the installed capacities of wind farms and electrolysers, the hourly prices of electricity and hydrogen, and the capital and operational expenditure associated with each component. These values are essential for the functioning of the optimisation model and their values are sourced from external datasets. By using these input parameters, the model is able to simulate real-world conditions and generate optimal solutions that respect the physical constraints and maximise the economic benefits of the system.

cap_{cvr} : Converter capacity (MW)

$\text{cap}_{\text{esr-cvr}}$: Interconnection Capacity between converter and electrolysers (MW)

$€_{\text{e}}[t]$: Hourly onshore electricity price (%)

$€_{\text{h2}}[t]$: Hourly onshore hydrogen price (%)

$\text{gen}_{\text{w}}[t]$: Hourly power generated by wind farms per unit installed capacity (MW/MWh)

capex_{w} : Capital expenditure for wind farms per unit installed capacity (M€/MW)

opex_{w} : Operational expenditure for wind farms per unit installed capacity (M€/MW)

$\text{opex}_{\text{w}}^{\text{var}}$: Variable operational expenditure for wind farms per unit electricity generated (€/MWh)

$\text{capex}_{\text{esr}}$: Capital expenditure for electrolysers per unit installed capacity (M€/MW)

opex_{esr} : Operational expenditure for electrolysers per unit installed capacity (M€/MW)

cap_{esr} : Installed capacity of one electrolyser (MW)

N_{esr} : Number of electrolysers (quantity)

eff_{esr} : Efficiency of electrolysis (%)

3.3.2. Variables

The variables in the optimisation model represent the key operational, financial, and energy flow aspects of the wind farm and electrolyser systems. These variables are essential for modelling the system's dynamics and ensuring that the optimisation process accurately reflects the real-world conditions. The wind farm variables track electricity production, curtailment, and the distribution of energy between the electrical grid and electrolysers. The energy flow variables model the transfer of energy, both for hydrogen production and export to the grid, while also considering curtailment and energy imports. Cost-related variables capture the financial aspects, including capital and operational expenditure, which are critical for assessing the economic viability of the system. Revenue-related variables, on the other hand, represent the income generated from electricity and hydrogen production, providing insights into the profitability of the system. All variables with a "[t]" following them represent time-dependent data, corresponding to values for each time step within the model. These variables work together to create a comprehensive and realistic representation of the system, allowing for efficient optimisation and decision-making.

Wind Farm Variables:

This set of variables pertains to the wind farms, which play a crucial role in the generation of both electricity and indirectly hydrogen. The variables defined here are used to track the individual as well as combined installed capacities, electricity production, curtailment, and how the generated electricity is distributed to the electrical grid or the electrolyser. These variables are fundamental in representing the operational characteristics of wind farms. The electrical and hydrogen wind farms refer to the total installed wind capacity connected directly to the converter and the electrolyser/s respectively.

$$\mathrm{cap}^{\mathrm{w}}_{\mathrm{tot}} : \text{Total hub wind installed capacity (MW)}$$

$$\mathrm{cap}^{\mathrm{w}}_{\mathrm{e}} : \text{Electrical wind farm installed capacity (MW)}$$
$$\mathrm{esup}^{\mathrm{ewf}}_{\mathrm{e}}[t] : \text{Hourly electricity supply to DC cable from electrical wind farm (MWh)}$$
$$\mathrm{esup}^{\mathrm{ewf}}_{\mathrm{h2}}[t] : \text{Hourly electricity supply to electrolyser from electrical wind farm (MWh)}$$
$$\mathrm{eprod}_{\mathrm{ewf}}[t] : \text{Hourly total electricity produced by electrical wind farm (MWh)}$$
$$\mathrm{curt}_{\mathrm{ewf}}[t] : \text{Hourly electrical wind farm curtailment (MWh)}$$

$$\mathrm{cap}^{\mathrm{w}}_{\mathrm{h2}} : \text{Hydrogen wind farm installed capacity (MW)}$$
$$\mathrm{esup}^{\mathrm{h2wf}}_{\mathrm{e}}[t] : \text{Hourly electricity supply to DC cable from electrical wind farm (MWh)}$$
$$\mathrm{esup}^{\mathrm{h2wf}}_{\mathrm{h2}}[t] : \text{Hourly electricity supply to electrolyser from electrolyser wind farm (MWh)}$$
$$\mathrm{eprod}_{\mathrm{h2wf}}[t] : \text{Hourly total electricity produced by electrolyser wind farm (MWh)}$$
$$\mathrm{curt}_{\mathrm{h2wf}}[t] : \text{Hourly electrolyser wind farm curtailment (MWh)}$$

Energy Flow Variables:

Energy flow variables are critical for modelling the dynamics of energy transfer from the wind farms to the electrolyser and the onshore electrical grid. The variables defined here represent the produced energy and its divisions as exported to shore as electricity, used for hydrogen production, or curtailed. This section outlines the interplay between electricity and hydrogen production, including the import of energy for electrolysis. By defining these relationships, we can represent the energy flows in the system and assess the balance and efficiency of energy distribution within the system.

$$\mathrm{prod}^{\mathrm{e}}_{\mathrm{tot}}[t] : \text{Hourly total electricity production (MWh)}$$
$$\mathrm{E}_{\mathrm{out}}[t] : \text{Hourly electricity output exported to shore (MWh)}$$
$$\mathrm{H2}^{\mathrm{w}}_{\mathrm{in}}[t] : \text{Hourly electrolyser input from wind (MWh)}$$
$$\mathrm{H2}^{\mathrm{onshore}}_{\mathrm{in}}[t] : \text{Hourly electrolyser input from onshore (MWh)}$$
$$\mathrm{H2}^{\mathrm{tot}}_{\mathrm{in}}[t] : \text{Hourly total electrolyser input (MWh)}$$
$$\mathrm{H2}_{\mathrm{out}}[t] : \text{Hourly hydrogen production (MWh)}$$
$$\mathrm{prod}^{\mathrm{e}}_{\mathrm{act}}[t] : \text{Actual hourly electricity production (MWh)}$$
$$\mathrm{curt}_{\mathrm{w}}[t] : \text{Hourly wind curtailment (MWh)}$$

Cost-related Variables:

The cost-related variables capture the financial aspects of the wind farms and electrolysers. These variables account for both the capital expenditure (CAPEX) and the operating expenses (OPEX), including maintenance and variable costs. Accurately defining these costs is the primary essential aspect of assessing the overall economic viability of the project, which is an integral part of the optimisation problem. The costs also help in calculating the total financial burden of establishing and maintaining the infrastructure required for the wind farm and electrolysis systems.

$$
\begin{aligned}
\mathrm{C}^{\mathrm{w}}_{\mathrm{inv}} &: \text{Investment cost of wind farms (M€)}\\
\mathrm{C}^{\mathrm{w}}_{\mathrm{om}} &: \text{O\&M cost of wind farms (M€)}\\
\mathrm{C}^{\mathrm{w}}_{\mathrm{var}} &: \text{Variable O\&M cost of wind farms (M€)}\\
\mathrm{C}^{\mathrm{w}}_{\mathrm{tot}} &: \text{Total wind farm cost (M€)}\\
\mathrm{C}^{\mathrm{esr}}_{\mathrm{inv}} &: \text{Investment cost of electrolysers (M€)}\\
\mathrm{C}^{\mathrm{esr}}_{\mathrm{om}} &: \text{O\&M cost of electrolysers (M€)}\\
\mathrm{C}^{\mathrm{esr}}_{\mathrm{var}} &: \text{Variable O\&M cost of electrolysers (M€)}\\
\mathrm{C}^{\mathrm{esr}}_{\mathrm{tot}} &: \text{Total electrolyser cost (M€)}\\
\mathrm{C}_{\mathrm{inv}} &: \text{Total investment cost (M€)}\\
\mathrm{C}_{\mathrm{om}} &: \text{Total O\&M cost (M€)}\\
\mathrm{C}_{\mathrm{tot}} &: \text{Total cost (M€)}
\end{aligned}
$$

Revenue-related Variables:

The other aspect of assessing the overall economic viability of the project is system revenues. The revenues of the different components are represented by the revenue-related variables. These are used to calculate the financial benefits generated from the electricity and hydrogen production. These variables play a key role in the optimisation process by allowing the calculation of potential revenues over time, which can be compared to the associated costs to determine profitability. They also further allow for the computation of Net Present Value (NPV) and total revenue from both the wind farm and hydrogen production, offering a clearer picture of the financial returns from the system.

$\text{rev}_{\text{tot}}^{\text{e}}[t]$: Revenue from exporting electricity for each time step (M€)

$\text{rev}_{\text{tot}}^{\text{w}}[t]$: Wind farm revenue for each time step (M€)

$\text{rev}_{\text{tot}}^{\text{h2}}[t]$: Revenue from exporting hydrogen for each time step (M€)

$\text{rev}_{\text{tot}}^{\text{e,h2}}[t]$: Combined revenue from electricity and hydrogen for each time step (M€)

$\text{rev}_{\text{yr}}^{\text{e,h2}}$: Annual electricity and hydrogen revenue (M€)

NPV : Net Present Value (M€)

3.3.3. Constraints

The constraints define the operational limits within which the wind farms and electrolyser systems must function. They ensure that the optimisation problem respects physical, operational, and financial limitations, such as electricity output limits, curtailment, and capacity constraints. Constraints also govern the energy balance, ensuring that the generated energy from wind farms is properly allocated between the electrical grid and the electrolyser. These constraints are essential for ensuring the feasibility of the system's operation and guiding the optimisation process toward practical solutions within physical and economic confines. All variables with a "[t]" following them are arrays representing the values for that variable for each time step, i.e., for each of the 8760 hours of the year.

Electricity Constraints:

Actual energy production is the summation of electricity exported and the wind farm component of electrolyser input:

$$\text{prod}_{\text{act}}^{\text{e}}[t] = \text{E}_{\text{out}}[t] + \text{H2}_{\text{in}}^{\text{w}}[t]$$

Electricity export to shore is limited by the converter and cable capacity:

$$\text{E}_{\text{out}}[t] \leq \text{cvr\_capacity}$$

Electrolyser Constraints:

Hydrogen input from shore is limited by the interconnection capacity between the converter and the electrolyser/s:

$$\text{H2}_{\text{in}}^{\text{onshore}}[t] \leq \text{esr\_cvr\_connect}$$

Total electrolyser input is a summation of the energy generated by wind farms and the energy imported from shore:

$$\mathrm{H2}_{\mathrm{in}}^{\mathrm{tot}}[t] = \mathrm{H2}_{\mathrm{in}}^{\mathrm{w}}[t] + \mathrm{H2}_{\mathrm{in}}^{\mathrm{onshore}}[t]$$

Electrolyser output is a product of the electrolyser input multiplied by its energy conversion efficiency:

$$\mathrm{H2}_{\mathrm{out}}[t] = \mathrm{H2}_{\mathrm{in}}^{\mathrm{tot}}[t] \cdot \mathrm{esr\_eff}$$

Electrolyser input is limited simply by the cummulative installed electrolysis capacity, represented by the capacity of one electrolyser multiplied by the quantity of electrolysers installed:

$$\mathrm{H2}_{\mathrm{in}}^{\mathrm{tot}}[t] \leq \mathrm{esr\_capacity} \cdot \mathrm{esr\_no}$$

Wind Farm Constraints:

Energy potentially produced by the electrical wind farm is equal to the installed capacity(MW) of the electrical wind farm multiplied by the wind farm output per MW. ("Potentially" because there is an option to curtail if it is not economical to generate electricity):

$$\mathrm{eprod}_{\mathrm{ewf}}[t] = \mathrm{cap}_{\mathrm{e}}^{\mathrm{w}} \cdot \mathrm{power\_out}[t]$$

Electrolyser input for the electrical wind farm, connected directly to the converter is limited by the interconnection capacity between the converter and the electrolyser/s:

$$\mathrm{esup}_{\mathrm{h2}}^{\mathrm{ewf}}[t] \leq \mathrm{esr\_cvr\_connect}$$

The total potential electricity generation by the electrical wind farm is a summation of its electricity exported onshore, supplied to the electrolyser input and curtailed:

$$\mathrm{esup}_{\mathrm{e}}^{\mathrm{ewf}}[t] + \mathrm{esup}_{\mathrm{h2}}^{\mathrm{ewf}}[t] + \mathrm{curt}_{\mathrm{t}}^{\mathrm{ewf}}[t] = \mathrm{eprod}_{\mathrm{ewf}}[t]$$

Energy potentially produced by the hydrogen wind farm is equal to the installed capacity(MW) of the hydrogen wind farm multiplied by the wind farm output per MW:

$$\mathrm{eprod}_{\mathrm{h2wf}}[t] = \mathrm{cap}_{\mathrm{h2}}^{\mathrm{w}} \cdot \mathrm{power\_out}[t]$$

Electricity export for the hydrogen wind farm, connected directly to the electrolyser/s is limited by the interconnection capacity between the electrolyser/s and the converter:

$$\mathrm{esup}_{\mathrm{e}}^{\mathrm{h2wf}}[t] \leq \mathrm{esr\_cvr\_connect}$$

The total potential electricity generation by the hydrogen wind farm is a summation of its electricity exported onshore, supplied to the electrolyser input and curtailed:

$$\mathrm{esup}_{\mathrm{e}}^{\mathrm{h2wf}}[t] + \mathrm{esup}_{\mathrm{h2}}^{\mathrm{h2wf}}[t] + \mathrm{curt}_{\mathrm{h2wf}}[t] = \mathrm{eprod}_{\mathrm{h2wf}}[t]$$

Total wind curtailment is the addition of wind curtailment in both, the electrical and hydrogen wind farms:

$$\mathrm{curt}_{\mathrm{w}}[t] = \mathrm{curt}_{\mathrm{ewf}}[t] + \mathrm{curt}_{\mathrm{h2wf}}[t]$$

Totals:

Total installed wind capacity is a summation of the installed capacities of the electrical and hydrogen wind farms:

$$\mathrm{cap}_{\mathrm{e}}^{\mathrm{w}} + \mathrm{cap}_{\mathrm{h2}}^{\mathrm{w}} = \mathrm{cap}_{\mathrm{tot}}^{\mathrm{w}}$$

Total electricity exported is a summation of electricity output from the electrical and hydrogen wind farms:

$$\mathrm{E}_{\mathrm{out}}[t] = \mathrm{esup}_{\mathrm{e}}^{\mathrm{ewf}}[t] + \mathrm{esup}_{\mathrm{e}}^{\mathrm{h2wf}}[t]$$

Total electrolyser input is a summation of electricity output from the hydrogen and electrical wind farms:

$$\mathrm{H2}_{\mathrm{in}}^{\mathrm{w}}[t] = \mathrm{esup}_{\mathrm{h2}}^{\mathrm{ewf}}[t] + \mathrm{esup}_{\mathrm{h2}}^{\mathrm{h2wf}}[t]$$

The total potential electricity production of the hub is equal to the potential electricity production of the electrical and hydrogen wind farms:

$$\mathrm{prod}_{\mathrm{tot}}^{\mathrm{e}}[t] = \mathrm{eprod}_{\mathrm{ewf}}[t] + \mathrm{eprod}_{\mathrm{h2wf}}[t]$$

Energy Balance Constraint - The sum of the total potential electricity production of the hub and the electricity imported from shore should be greater than the electricity exported or supplied as input for the electrolyser.

$$\mathrm{prod}_{\mathrm{tot}}^{\mathrm{e}}[t] + \mathrm{H2}_{\mathrm{in}}^{\mathrm{onshore}}[t] \geq \mathrm{E}_{\mathrm{out}}[t] + \mathrm{H2}_{\mathrm{in}}^{\mathrm{tot}}[t]$$

Cost Constraints:

Wind Farm Investment Cost:

$$\mathrm{C}_{\mathrm{inv}}^{\mathrm{w}} = \mathrm{capex}_{\mathrm{w}} \cdot \mathrm{cap}_{\mathrm{tot}}^{\mathrm{w}}$$

Wind Farm O&M Cost:

$$\mathrm{C}_{\mathrm{om}}^{\mathrm{w}} = \mathrm{opex}_{\mathrm{w}} \cdot \mathrm{cap}_{\mathrm{tot}}^{\mathrm{w}}$$

Wind Farm Variable O&M Cost:

$$\mathrm{C}_{\mathrm{var}}^{\mathrm{w}} = \mathrm{opex}_{\mathrm{w}}^{\mathrm{var}} \cdot \sum \mathrm{prod}_{\mathrm{act}}^{\mathrm{e}}[t]$$

Total Wind Farm Cost:

$$\mathrm{C}_{\mathrm{tot}}^{\mathrm{w}} = \mathrm{C}_{\mathrm{inv}}^{\mathrm{w}} + (\mathrm{C}_{\mathrm{om}}^{\mathrm{w}} + \mathrm{C}_{\mathrm{var}}^{\mathrm{w}}) \cdot T$$

Electrolyser Investment Cost:

$$\mathrm{C}_{\mathrm{inv}}^{\mathrm{esr}} = \mathrm{capex}_{\mathrm{esr}} \cdot \mathrm{N}_{\mathrm{esr}}$$

Electrolyser O&M Cost:

$$\mathrm{C}_{\mathrm{om}}^{\mathrm{esr}} = \mathrm{opex}_{\mathrm{esr}} \cdot \mathrm{N}_{\mathrm{esr}}$$

Electrolyser Variable O&M Cost:

$$\mathrm{C}_{\mathrm{var}}^{\mathrm{esr}} = \sum (\mathrm{H2}_{\mathrm{in}}^{\mathrm{onshore}}[t] \cdot €_{\mathrm{e}}[t])$$

Total Electrolyser Cost:

$$\mathrm{C}_{\mathrm{tot}}^{\mathrm{esr}} = \mathrm{C}_{\mathrm{inv}}^{\mathrm{esr}} + (\mathrm{C}_{\mathrm{om}}^{\mathrm{esr}} + \mathrm{C}_{\mathrm{var}}^{\mathrm{esr}}) \cdot T$$

Total Investment Cost:

$$\mathrm{C}_{\mathrm{inv}} = \mathrm{C}_{\mathrm{inv}}^{\mathrm{w}} + \mathrm{C}_{\mathrm{inv}}^{\mathrm{esr}}$$

Total O&M Cost:

$$\mathrm{C}_{\mathrm{om}} = \mathrm{C}_{\mathrm{om}}^{\mathrm{w}} + \mathrm{C}_{\mathrm{var}}^{\mathrm{w}} + \mathrm{C}_{\mathrm{om}}^{\mathrm{esr}} + \mathrm{C}_{\mathrm{var}}^{\mathrm{esr}}$$

Total Cost:

$$\mathrm{C}_{\mathrm{tot}} = \mathrm{C}_{\mathrm{tot}}^{\mathrm{w}} + \mathrm{C}_{\mathrm{tot}}^{\mathrm{esr}}$$

Revenue Constraints:

Electricity Trading Revenue:

$$\mathrm{rev}^{\mathrm{e}}[t] = \mathrm{E}_{\mathrm{out}}[t] \cdot €_{\mathrm{e}}[t]$$

Actual Wind Farm Revenue:

$$\mathrm{rev}^{\mathrm{w}}[t] = \mathrm{prod}^{\mathrm{e}}_{\mathrm{act}}[t] \cdot €_{\mathrm{e}}[t]$$

Hydrogen Revenue:

$$\mathrm{rev}^{\mathrm{h2}}[t] = \mathrm{H2}_{\mathrm{out}}[t] \cdot €_{\mathrm{h2}}[t]$$

Combined Revenue:

$$\mathrm{rev}^{\mathrm{e,h2}}[t] = \mathrm{rev}^{\mathrm{w}}[t] + \mathrm{rev}^{\mathrm{h2}}[t]$$

Annual Revenue:

$$\mathrm{rev}^{\mathrm{e,h2}}_{\mathrm{yr}} = \sum \mathrm{rev}^{\mathrm{e,h2}}[t]$$

3.3.4. Model Objective: Maximise NPV

Net Present Value:

$$\mathrm{NPV} = (\mathrm{rev}^{\mathrm{e,h2}}_{\mathrm{yr}} - \mathrm{C}_{\mathrm{om}}) \cdot \frac{1 - (1 + r)^{-T}}{r} - \mathrm{C}_{\mathrm{inv}}$$

3.4. Internal Value Computation

While the optimisation problem treats the hub as a single entity, it is recognised that, in practice, the constituent components of the hub, namely wind farms and electrolysers, are likely to be owned by different parties. This is primarily due to the substantial capital investment required to develop all assets, which often exceeds the capacity of any single investor. As a result, it becomes necessary to compute the individual net present values (NPVs) associated with different asset groups, so as to evaluate the financial viability for each stakeholder involved in the hub infrastructure.

Although the model is optimised for the overall hub NPV, it does not explicitly account for internal electricity transactions between wind farms and electrolysers during the optimisation process. These transactions, however, are essential for accurately calculating the individual NPVs of the hub's components. To address this, the internal profit split assumes that electrolysers purchase electricity at the prevailing onshore market price, regardless of whether the electricity is sourced from co-located wind farms or imported from shore. This onshore electricity price is used because the hub is considered to be radially connected to the Netherlands and is therefore part of the Dutch bidding zone. As a result, wind farms are compensated for every megawatt-hour (MWh) of electricity they generate, irrespective of whether it is exported to shore or consumed locally for hydrogen production.

3.4.1. Mathematics of Value Splitting

As is delineated in the previously mentioned figure 3.1, the electrical wind farm refer to the wind farm directly connected to the converter, while the hydrogen wind farm refer to the wind farms connected to the electrolysers. Electrical wind farm ownership is allowed to be split into an arbitrary number of owners. However, electrolysers and hydrogen wind farms are each considered to be split between a number of owners equal to the number of electrolysers. This is because owning two 500 MW electrolysers for one party is unlikely owing to high investment costs. The same ownership structure is extended to the hydrogen wind farms in order to explore combined ownership which refers to a single party owning an electrolyser along with a share of the hydrogen wind farms.

It is important to distinguish between the different asset configurations used in the model:

- Electrical Wind Farm (wfe): Wind farm connected directly to the electric converter.
- Hydrogen Wind Farm (wfh2): Wind farm connected directly to electrolysers.
- Electrolyser (h2): Electrolyser
- Combined Asset Party (comb): Joint ownership of one electrolyser and the corresponding share of a hydrogen wind farm, such that both are proportionally divided (e.g., 4 electrolysers imply 4 equal hydrogen wind farm shares).

The number of parties owning the electrical wind farm (N_{wf}) can be set arbitrarily, allowing flexible ownership distribution. In contrast, ownership of the hydrogen wind farm is tied to the number of electrolysers (N_{esr}) to simplify the combined ownership structure. Since per unit costs and revenues are equivalent for both wind farm types within the model, splitting the hydrogen wind farm into arbitrary shares offers no additional modelling advantage.

This structure results in the formation of *identical parties*, each holding the same share of an asset type. For instance, if there are N_{esr} electrolysers, then N_{esr} identical parties exist, each owning one electrolyser. The same logic applies to the *wfh2* assets abnd the comb assets, while the ownership split of *wfe* can be defined arbitrarily in (N_{wf}) parties. While total investment costs and profits scale with the number of parties, the internal rate of return (IRR) remains consistent across parties holding identical assets.

All costs and revenues are allocated in proportion to the ownership of each infrastructure component. In cases where a single party owns both wind farms and electrolysers, internal electricity transactions between these components cancel out, up to the limit of their respective capacities. This approach ensures that the calculated individual value accurately reflects the appropriate economic contribution of each party's assets without overlap.

Importantly, the full set of equations is not applied simultaneously. In each iteration of the model, ownership is considered either in separate or combined form, and only the relevant set of equations is used accordingly. However, for the purpose of generating results, the combined configuration is typically preferred, as discussed in more detail in Chapter 5.

$C^{\text{inv}}_{\text{eh2}}$: Investment cost for electrical wind farm party (M€)

$C^{\text{inv}}_{\text{wfh2}}$: Investment cost for hydrogen wind farm party (M€)

$C^{\text{inv}}_{\text{h2}}$: Investment cost for only electrolyser party (M€)

$C^{\text{inv}}_{\text{comb}}$: Investment cost of combined wind-hydrogen party (M€)

$\text{cap}^{\text{w}}_{\text{e}}$: Electrical wind farm installed capacity (MW)

$\text{cap}^{\text{w}}_{\text{h2}}$: Hydrogen wind farm installed capacity (MW)

$\text{cap}^{\text{w}}_{\text{tot}}$: Total hub wind installed capacity (MW)

$C^{\text{inv}}_{\text{wind}}$: Investment cost for wind farms per unit installed capacity (M€)

$C^{\text{inv}}_{\text{esr}}$: Total investment cost for electrolysers (M€)

N_{wf} : Number of wind farms

N_{esr} : Number of electrolysers

π_{wfe} : Annual profit for electricity-only wind farm (M€)

π_{wfh2} : Annual profit for hydrogen connected wind farm (M€)

π_{h2} : Annual profit for hydrogen production system (M€)

R_{wind} : Annual revenue from wind electricity production (M€)

R_{H2} : Annual revenue from hydrogen production (M€)

$C_{\text{w,var}}$: Variable operating cost for wind (M€)

C_{w} : Fixed annual O&M cost for wind (M€)

$C_{\text{esr,var}}$: Variable operating cost for electrolysis (M€)

C_{esr} : Fixed annual O&M cost for electrolysis (M€)

IRR_{wfe} : Internal rate of return for electricity-only wind farm (%)

IRR_{wfh2} : Internal rate of return for wind-hydrogen system (%)

IRR_{h2} : Internal rate of return for hydrogen system (%)

IRR_{comb} : Internal rate of return for combined wind-hydrogen investment (%)

T : Project lifetime (years)

Investment Costs

CapEx: Single Electrical Wind Farm Party

$$C_{\text{wfe}}^{\text{inv}} = C_{\text{wind}}^{\text{inv}} \cdot \left(\frac{\text{cap}_{\text{wfe}}}{N_{\text{wf}} \cdot \text{cap}_{\text{wf,tot}}} \right)$$

CapEx: Single Hydrogen Wind Farm Party

$$C_{\text{wfh2}}^{\text{inv}} = C_{\text{wind}}^{\text{inv}} \cdot \left(\frac{\text{cap}_{\text{wfh2}}}{N_{\text{esr}} \cdot \text{cap}_{\text{wf,tot}}} \right)$$

CapEx: Single Electrolyser

$$C_{\text{h2}}^{\text{inv}} = \frac{C_{\text{esr}}^{\text{inv}}}{N_{\text{esr}}}$$

CapEx: Single Combined Asset Party

$$C_{\text{comb}}^{\text{inv}} = C_{\text{wfh2}}^{\text{inv}} + C_{\text{h2}}^{\text{inv}}$$

Annual Profits

Annual Profit: Electrical Wind Farm

$$\pi_{\text{wfe}} = (R_{\text{wind}} - (C_{\text{w,var}} + C_{\text{w}})) \cdot \left(\frac{\text{cap}_{\text{wfe}}}{N_{\text{wf}} \cdot \text{cap}_{\text{wf,tot}}} \right)$$

Annual Profit: Hydrogen Wind Farm

$$\pi_{\text{wfh2}} = (R_{\text{wind}} - (C_{\text{w,var}} + C_{\text{w}})) \cdot \left(\frac{\text{cap}_{\text{wfh2}}}{N_{\text{esr}} \cdot \text{cap}_{\text{wf,tot}}} \right)$$

Annual Profit: Combined Asset Party

$$\pi_{\text{h2}} = \frac{(R_{\text{H2}} - (C_{\text{esr,var}} + C_{\text{esr}}))}{N_{\text{esr}}}$$

IRR Equations

IRR: Electrical Wind Farm

$$\frac{\pi_{\text{wfe}} \cdot \left(1 - (1 + \text{IRR}_{\text{wfe}})^{-T}\right)}{\text{IRR}_{\text{wfe}}} - C^{\text{inv}}_{\text{wfe}} = 0$$

IRR: Hydrogen Wind Farm

$$\frac{\pi_{\text{wfh2}} \cdot \left(1 - (1 + \text{IRR}_{\text{wfh2}})^{-T}\right)}{\text{IRR}_{\text{wfh2}}} - C^{\text{inv}}_{\text{wfh2}} = 0$$

IRR: Electrolyser

$$\frac{\pi_{\text{h2}} \cdot \left(1 - (1 + \text{IRR}_{\text{h2}})^{-T}\right)}{\text{IRR}_{\text{h2}}} - C^{\text{inv}}_{\text{h2}} = 0$$

IRR: Combined Asset Party

$$\frac{(\pi_{\text{wfh2}} + \pi_{\text{h2}}) \cdot \left(1 - (1 + \text{IRR}_{\text{comb}})^{-T}\right)}{\text{IRR}_{\text{comb}}} - C^{\text{inv}}_{\text{comb}} = 0$$

3.5. Internal Prices Computation

Another post-optimisation calculation concerns the determination of internal prices, which are introduced to quantify the marginal value of electricity within the offshore hub. These internal prices, often referred to as shadow prices, reflect the cost or value of supplying one additional unit of energy to the system at a particular time step, and are derived from the dual variables associated with specific constraints in a linear programming problem.

To calculate these internal prices, an energy balance constraint is implemented within the model. This constraint ensures that, at each hour, the total electricity produced and imported must be equal to or greater than the sum of all electricity consuming processes. The dual variable, or Lagrange multiplier, associated with this constraint represents the internal marginal value of electricity, effectively the price at which the system is indifferent to producing or consuming one more unit of energy at that time. In this context, these duals are interpreted as internal electricity prices.

However, in order to extract dual values from a mathematical programme, the model must be cast in a linear form. This requirement necessitates the exclusion of binary and integer decision variables, as the computation of duals is only well-defined in the context of continuous linear programming problems. Once this condition is met, solving the linear optimisation problem yields not only the optimal values for the decision variables but also the dual variables for all constraints—including the energy balance equation.

The energy balance constraint implemented in the model is defined as follows:

$$\text{prod}_{\text{tot}}^{\text{e}}[t] + \text{H2}_{\text{in}}^{\text{onshore}}[t] \geq \text{E}_{\text{out}}[t] + \text{H2}_{\text{in}}^{\text{tot}}[t]$$

Here, $\text{prod}_{\text{tot}}^{\text{e}}[t]$ refers to the total electricity produced by the wind farm, while $\text{H2}_{\text{in}}^{\text{onshore}}[t]$ accounts for the electricity required to transport hydrogen onshore via compression or conversion. On the right-hand side, $\text{E}_{\text{out}}[t]$ captures the electricity exported to the grid, and $\text{H2}_{\text{in}}^{\text{tot}}[t]$ represents the electricity consumed by electrolysis processes within the hub. The dual associated with this constraint at each time step gives the internal electricity price for that hour, revealing valuable insight into the value of energy within the system.

While these internal prices are computed and presented in the results, further research is required to fully explain them and test their validity. Hence, for most of the results, the onshore prices are used for the computation of individual profits. Nonetheless, some results have been provided for individual NPVs calculated using internal prices.

The use of internal electricity prices to calculate individual NPVs serves as an exploratory step toward understanding how value might be distributed within the hub under alternative market configurations. Specifically, this approach reflects a hypothetical scenario in which the offshore hub operates as an independent bidding zone, separate from the onshore system. In such a case, local prices would emerge from the internal balance of generation, consumption, and transmission constraints, rather than being pegged to the onshore market price.

While the current regulatory and market framework treats the hub as part of the Dutch bidding zone (hence the use of onshore prices for most results), computing internal prices via dual variables provides insight into the marginal value of electricity within the hub itself. This is particularly relevant in future market designs where offshore hubs may evolve into meshed or hybrid systems with multiple interconnections and potential offshore price zones.

3.6. Model Validation

This section presents a validation of the model by testing its performance under controlled, extreme input scenarios. These tests are designed to assess whether the model behaves as expected, based on an intuitive understanding of the optimisation formulation. In most of the validation cases, constant values are used for wind generation, electricity prices, and hydrogen prices across all time steps, allowing for clear interpretation of the results.

For the wind input, a constant normalised wind generation of 0.6 MW per MW of installed capacity is assumed. This corresponds to a generation of 9 MW for a 15 MW wind turbine. All other parameters — component costs, electrolyser efficiency, and financial variables such as the inflation rate and nominal interest rate, are kept consistent with those used in the main case study. These are listed in Chapter 4, specifically in Tables 4.1 and 4.2.

The hub layout considered for validation includes an “electrical” wind farm (WFe) connected directly to the converter platform, a set of electrolysers (Esr), and a “hydrogen” wind farm (WFh2) connected directly to the electrolysers, as shown in Figure 3.1. As described in Section 3.4.1, ownership of the electrical wind farm is split between two identical parties. This decision is informed by interviews with NSWPH officials and reflects realistic and comparable investment structures. Each of the four electrolysers is treated as a distinct ownership entity, and the hydrogen wind farm is divided into four equal parts, each linked to an individual electrolyser. An additional ownership configuration, referred to as “combined” (Comb), is introduced. This is not a separate infrastructure category, but rather a grouping in which each of the four identical parties owns one electrolyser and a quarter of the hydrogen wind farm capacity.

The results of these validation tests are summarised in Table 3.2. For each scenario, the fixed electricity and hydrogen prices along with the utilisation of the cable and the electrolyser are reported. In addition, the Net Present Values (NPVs) and Internal Rates of Return (IRRs) for a party in each ownership category — WFe, Esr, WFh2, and Comb are provided. The WFe party corresponds to one of the two owners of the electrical wind farm, and therefore represents half of the infrastructure. Each of the other categories (Esr, WFh2, and Comb), consists of four identical parties, with each party representing a quarter of the corresponding infrastructure.

It is important to emphasise that parameters such as component costs, electrolyser capacity, number of electrolysers, and other technical or financial inputs are held constant across all scenarios. As such, the absolute numerical outputs (e.g., NPVs and IRRs) are less critical than the directional behaviours exhibited by the model in response to changing price signals. The purpose of these tests is not to replicate real-world outcomes, but rather to ensure that the model responds in a logical and internally consistent manner when subjected to well-defined economic drivers. The results should therefore be interpreted within the context of these fixed baseline assumptions.

Test	Elec Price	H_2 Price	Cable Util (%)	ESR Util (%)	WFe Party NPV & IRR	WF_{H2} Party NPV & IRR	ESR Party NPV & IRR	Comb Party NPV & IRR	Hub Wind Cap (MW)	Hub NPV & IRR
1	100	50	100	100	19041 28.08%	9521 28.08%	-10977 0.0%	-1456 0.0%	6667	32258 8.93%
2	50	100	100	100	6419 11.30%	3210 11.30%	-248 0.00%	2962 5.28%	6667	24684 7.19%
3	25	0	100	0	54 0.52%	27 0.52%	-2773 0.0%	-2746 0.0%	3333	-10874 0.0%
4	0	36	50	100	-3101 0.00%	0 0.00%	408 1.64%	408 1.64%	1667	-4570 0.00%
5	95.81 (2023)	80	70.49	48.69	11041 19.24%	3967 19.24%	-4643 0.0%	-677 0.0%	5156	19377 6.65%

Table 3.2: Model validation results under flat-price test scenarios. Each NPV (M€) and IRR (%) pair corresponds to a single ownership party in its respective category.

3.6.1. Test 1: H_2 Price = 50 €/MWh, Elec Price = 100 €/MWh

In the first test, the electricity price (100 €/MWh) is significantly higher than the hydrogen price (50 €/MWh). The model responds by installing a total wind capacity of 6667 MW, split evenly between the electrical and hydrogen wind farms. Given the assumed normalised generation of 60 % (0.6), this capacity corresponds to a steady output of approximately 4 GW. This overplanting behaviour persists for all normalised generation values above 60%, up to 100%. A similar tendency is also seen as the normalised generation reduces, but with drastically varying amounts of overplanting till 10%, where the model does not build out any wind altogether.

The 4 GW output is evenly divided according to the considered configuration: 2 GW is exported as electricity to shore, and 2 GW is supplied to the electrolysers. Consequently, both the offshore cable and electrolysers operate at full capacity, reflected in 100 % utilisation of each. However, the cable is used exclusively for export; no electricity is imported from shore, as the onshore electricity price is always higher than the value of hydrogen production.

Despite full utilisation, the economic returns are uneven. The electrical and hydrogen wind farm parties both show strong positive NPVs of 19041 M€ and 9521 M€, respectively, with high IRRs of 28.08 %. However, the electrolyser party incurs a substantial loss, with an NPV of -10977 M€ and an IRR of 0.0 %, reflecting the low hydrogen price. The combined ownership entity (Comb) also posts a negative NPV of -1456 M€ and an IRR of 0.0 %. The overall hub NPV is 32258 M€, with an IRR of 8.93 %, reflecting strong export revenue offset by losses in hydrogen production.

3.6.2. Test 2: H_2 Price = 100 €/MWh, Elec Price = 50 €/MWh

In the second test, the hydrogen price (100 €/MWh) is significantly higher than the electricity price (50 €/MWh). As in the first test, a total wind capacity of 6667 MW is installed, evenly split between the electrical and hydrogen wind farms. The cable and electrolyser utilisation rates remain at 100 %, indicating full operation of both export and conversion infrastructure. The continued absence of electricity imports suggests a clear economic preference for wind generation over purchasing electricity from shore, despite the relatively low cost of the latter.

While the infrastructure sizing mirrors that of Test 1, the economic outcomes shift notably. Losses incurred by the combined electrolyser and wind farm parties are smaller, and the combined ownership entity achieves a positive NPV of 2962 M€ with an IRR of 5.28 %, supported by the elevated hydrogen price. However, the overall hub NPV decreases to 24684 M€, with an IRR of 7.19 %, primarily due to the lower market value of electricity exports and conversion inefficiencies associated with hydrogen production.

3.6.3. Test 3: H_2 Price = 0 €/MWh, Elec Price = 25 €/MWh

In the third test, both the hydrogen price (0 €/MWh) and the electricity price (25 €/MWh) are set at very low values, representing an extreme scenario where neither hydrogen production nor electricity export is economically attractive. These values are specifically chosen because below them, the model does not build any wind infrastructure at all. Despite this, the model installs a total wind capacity of 3333 MW, evenly split between the electrical and hydrogen wind farms, which is half the capacity installed in the previous tests. This capacity results in half the electricity generation of the previous two tests - 2 GW. The cable utilisation remains at 100 %, indicating full use of the export infrastructure, whereas the electrolyser utilisation drops to 0 %, reflecting no hydrogen production due to the zero hydrogen price.

Economic returns are poor across all parties. The electrical and hydrogen wind farm parties both show negligible positive NPVs of 54 M€ and 27 M€, respectively, with IRRs close to zero (0.52%). The electrolyser parties incur significant losses, with an NPV of -2773 M€ and an IRR of 0.0 %. The combined ownership entity also posts a substantial negative NPV of -2746 M€ and zero IRR. The overall hub NPV is strongly negative at -10874 M€, with an IRR of 0.0 %, highlighting that the low market values render the entire investment economically unviable under these conditions.

3.6.4. Test 4: H_2 Price = 36 €/MWh, Elec Price = 0 €/MWh

In the fourth test, the electricity price is set to zero, while the hydrogen price is moderate at 36 €/MWh. This represents an extreme scenario in which neither electricity export nor hydrogen production is sufficiently profitable to drive substantial investment. These values are specifically chosen because below them, the model does not build any wind infrastructure at all.

The model installs a reduced total wind capacity of 1667 MW, which is allocated solely to the electrical wind farm. However, from experimentation with the model code, it becomes apparent that the model is agnostic to which wind farm installs the capacity and selects the variable appearing earlier in the code. Cable utilisation decreases to 50 %, reflecting full use of import capacity coupled with no export activity. Electrolyser operation remains at 100 %, indicating full operation of hydrogen production. This configuration demonstrates the model's preference to prioritise hydrogen production when electricity export is not economically viable.

Economic performance is mixed. The electrical wind farm party incurs losses with an NPV of -3101 M€ and zero IRR, unable to generate value from electricity sales. The hydrogen wind farm party does not build out any wind capacity, resulting in an NPV of 0 M€ and zero IRR, while the electrolyser party achieves a modest positive NPV of 408 M€ and an IRR of 1.64 %. The combined ownership entity reflects the electrolyser's performance with identical NPV and IRR values. Overall, the hub posts a negative NPV of -4570 M€ and a zero IRR, indicating that moderate hydrogen prices alone are insufficient to compensate for losses on the electricity side under this extreme economic environment.

3.6.5. Test 5: H_2 Price = 80 €/MWh, Elec Price = 95.81 €/MWh (2023)

The fifth test represents a more realistic scenario, with a constant hydrogen price of 80 €/MWh and an electricity price of 95.81 €/MWh, reflecting 2023 market conditions. This time series is chosen to demonstrate the model's response to extreme price signals, ranging from -400 €/MWh to 500 €/MWh within the same dataset. The wind profile used remains consistent with the rest of the results and is detailed in 4. The model installs a total wind capacity of 5156 MW, which falls between the capacities observed in earlier tests, reflecting a balance between market values and generation efficiency. Cable utilisation reaches 70.49 % and electrolyser utilisation is 48.69 %, indicating partial operation of both export and hydrogen conversion infrastructure. The relatively high cable utilisation is driven by the elevated average electricity price, which reduces the relative attractiveness of hydrogen production. If the constant hydrogen price were increased, opposing utilisation trends would be observed between the two infrastructures.

Economic results show positive returns for both the electrical and hydrogen wind farm parties, with NPVs of 11041 M€ and 3967 M€, respectively, each achieving IRRs of 19.24 %. However, the electrolyser party continues to incur losses, with an NPV of -4643 M€ and an IRR of 0.0 %, reflecting the current cost structure and efficiency constraints. The combined ownership entity posts a modestly negative NPV of -677 M€ and an IRR of 0.0 %. Overall, the hub achieves a positive NPV of 19377 M€ with an IRR of 6.65 %, indicating moderate profitability, primarily driven by electricity exports, partially offset by underperformance in the hydrogen segment.

Despite the use of a highly volatile 2023 electricity price series, with frequent negative prices and sharp peaks, the internal electricity price within the hub never drops below zero and closely tracks onshore prices throughout the year. Negative onshore prices, often resulting from excess solar generation, correspond with periods of electricity import into the hub. The model also records approximately 500 hours of wind curtailment, occurring mainly during peak generation and low demand periods, highlighting operational constraints that emerge under real-world price fluctuations.

3.6.6. Summary of Validation Findings

The validation tests demonstrate that the model behaves in a consistent and intuitive manner under a wide range of price conditions, confirming its internal logic and reliability. Across all scenarios, infrastructure sizing and utilisation patterns align closely with the relative values of electricity and hydrogen, while capital deployment and operational strategies adjust accordingly. The results also highlight several key trends that underpin the system's economic performance. Most notably, the model consistently prioritises electricity export when market prices are high, while hydrogen production is only pursued in earnest when the relative price advantage justifies the associated conversion losses and capital expenditure.

A critical insight from these tests is the consistently poor business case for the electrolyser as a standalone investment. Even under favourable hydrogen pricing conditions, the returns to the ESR party remain marginal or negative, often resulting in zero internal rates of return. This persistent underperformance underscores the financial challenge of hydrogen production in isolation, particularly when considered against the relatively strong returns available to wind export infrastructure. It is for this reason that the combined ownership configuration, wherein each party owns both an electrolyser and a portion of the hydrogen wind farm, becomes especially important in subsequent analysis. This integrated structure reflects a more practical and commercially viable arrangement, better aligned with the risk-reward considerations of investors and developers.

These validation results therefore serve not only to confirm the model's operational coherence, but also to guide the interpretation of outcomes in the main case study. They help frame the broader economic dynamics of the hub, revealing how infrastructure interdependencies and market signals shape both technical deployment and investment performance. With these foundational behaviours established, the results presented in the next chapter can be evaluated with greater confidence and contextual understanding.

4 Case Study

The model has been designed with as many modular elements as possible, thus allowing the testing of different case studies, each with it's distinct parameters and configurations. This modular nature of the model allows for testing of a wide variety of cases with varying number of electrolysers, cable capacity, wind turbine rated power, lifetime, price timeseries, component cost values, efficiencies and minimum thresholds.

4.1. North Sea Wind Power Hub

The primary case study for this model is the 2x2GW Hub for the NSWPH. As can be inferred from the model name, this configuration is characterised by two 2 GW wind farms, as can be seen in 4.1. It is important to note however, that this "2 GW" installed capacity does not account for overplanting.

The first wind farm, which can be seen to the left in fig. 4.1 is connected to a 2 GW converter via 66 kV or 132 kV cables. Throughout the document, this wind farm is referred to as the "electrical wind farm". The converter, in turn, is connected to shore by means of a 2 GW DC cable, recognisable by it's green colour in the figure. The second wind farm, referred to in its entirety as the "hydrogen wind farm" is divided into four equal parts, each of which is connected to a 500 MW electrolyser. Each electrolyser is further connected to the converter by a cable capacity of 250 MW. Thus, there is a cumulative 1 GW interconnected capacity between the converter and electrolyser, which further implies that both, the converter as well as the electrolysers are each connected to a 3 GW electrical input. Lastly, the configuration includes a 90 MW compressor with a hydrogen pipeline for molecule transport to shore. However, it has little significance for the functioning of the model, and is therefore ignored for the purpose of this study. The pipeline is also considered to have a standardised transport capacity of 10 GW and due to the easily scalable nature of pipelines, it is not considered to be a physical or financial constraint in the model.

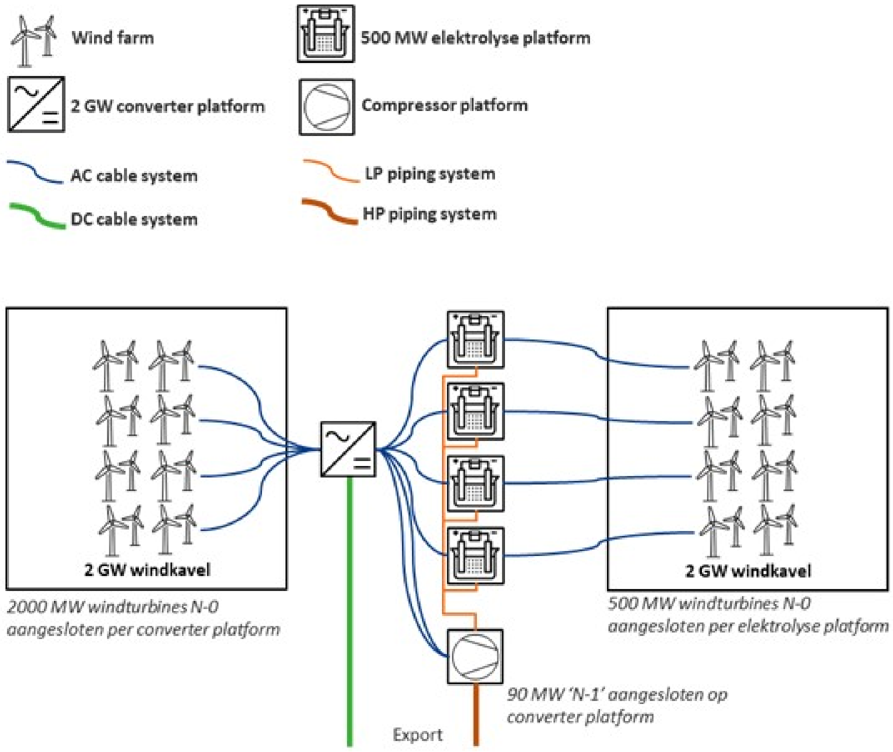


Figure 4.1: Base Hub Configuration (North Sea Wind Power Hub, 2024d)

There are several elements to be optimised within this hub, including but not limited to wind overplanting, electrolyser capacity, number of electrolysers and converter-electrolyser interconnection capacity. Issues regarding ownership of different entities within the hub are pertinent. Also of importance, is the build-out process of the hub, which starts with the first 2GW wind farm (left) and the converter, followed annually by a simultaneously developed 500 MW electrolyser and 500 MW wind farm. The revenues of individual parties are expected to change over the process of the build out.

The proposed location for this project is in areas 6 and 7, which are the two large northmost areas seen in figure 4.2.

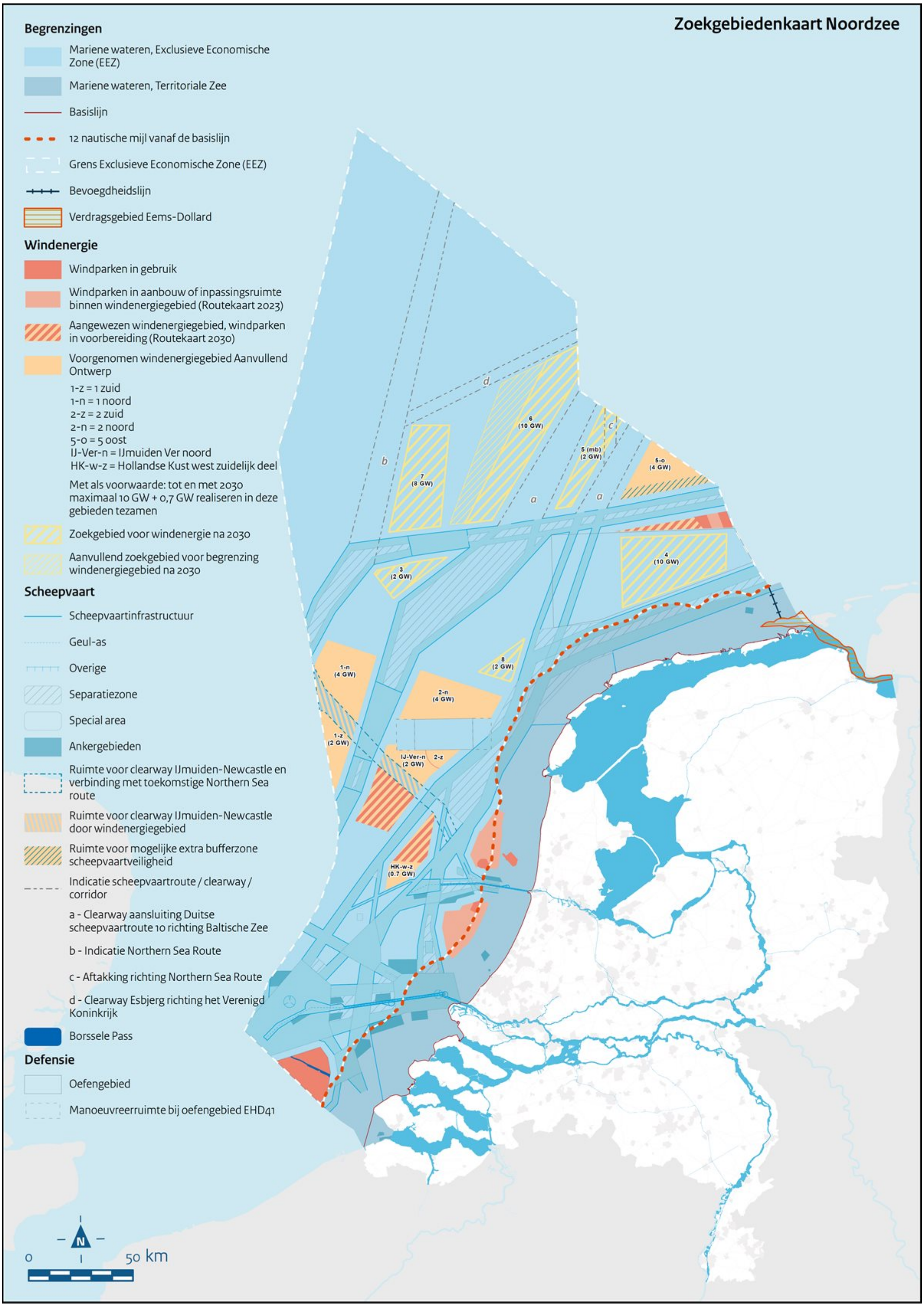


Figure 4.2: NSWPH Wind Areas

The wind turbine output for each hour of the year, considering mesoscale wake for these areas has been obtained through NSWPH datasets (van Uden et al., 2023). The wind data is available for a range of years from 2012 to 2018 and for different locations within the large areas. Unfortunately, these years do not overlap with the wind years referred to for the energy price time series. Therefore, for simplicity and comparability, the location with most average values (NL1264) has been chosen and the average wind turbine output over the years for each timestep has been used so as to not skew the results. The exact location of this sub-area within the larger areas 6/7 is mentioned in Appendix A. The normalised wind output for wind farms installed in area NL1264 are presented in figure 4.3 below. These are the output values per MW of installed wind capacity and scale with installed capacity. Given that these values have been obtained while considering mesoscale wake, additional calculations do not have to be made to account for wake losses with increasing installed capacity.

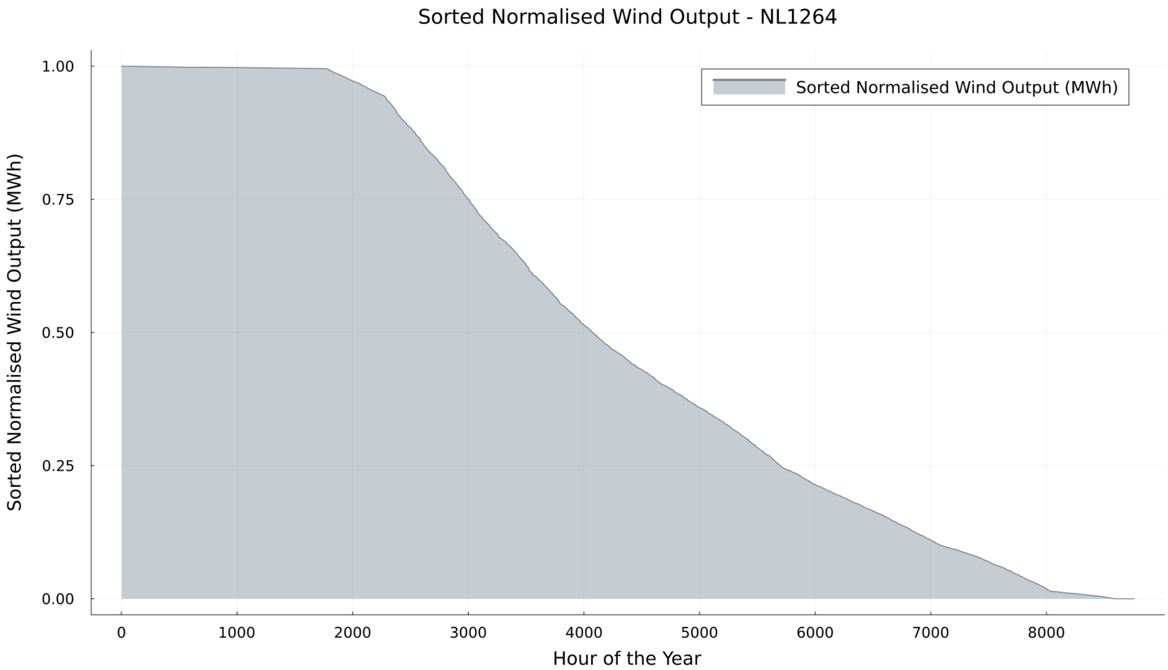


Figure 4.3: Sorted Normalised Wind Output for NSWPH Wind Area NL1264

All values are expressed in terms of million euros in order to avoid large numbers and reduce the computational complexity of the model. The 2030 value for wind farm cost is utilised from the Pathway Databook with a foundation depth of 40 - 50 m for areas 6 and 7 (Jetten, 2024). For 2 GW of electrolysis, a comprehensive estimate of € 7.3 billion is provided, which is used for scaling with capacity.The variable opex of the electrolyser is considered to be the cost of electricity and is not separately available in the databases. Additionally an electrolyser efficiency of 70% is considered for all configurations and scenarios which corresponds with the 2030 value in the NSWPH database (A/S et al., 2024).

The cost values for all components within the hub - wind farms and electrolysers that are used to run the model have been obtained through the NSWPH - Pathway 2.0 Databook (A/S et al., 2024) and the platform based electrolysis package (Mott Macdonald, 2022) respectively, both of which are publicly available. This data has been mentioned below in table 4.1.

Component	**Parameter**	**Value (M€)**
Wind Farm	Capex per MW of installed capacity	1.610
	Opex per MW of installed capacity	0.047
	Variable Opex per MWh generated	0.000005
Electrolyser	Capex per MW of installed capacity	3.656641
	Opex per MW of installed capacity	0.065537

Table 4.1: Economic Input Parameters for Hub Components (A/S et al., 2024)

4.2. Energy Price Scenarios

The model itself is a price taker, not a price setter as it reacts and takes production decisions according to price inputs from onshore. Hence, different price time series are required to simulate possible future energy scenarios. Six pairs of time series for hydrogen and electricity prices were obtained as output from the Ten Year Network Development Plan (TYNDP) 24 Model. These are based on the wind years 1995, 2008 and 2009 and are simulated for the years 2030 and 2040 each. This involves using the wind profiles of these specific years as input for the TYNDP24 model and obtaining results for the target years. The price profiles for the 1995-2030 scenario are included in figure B.1 below for reference.

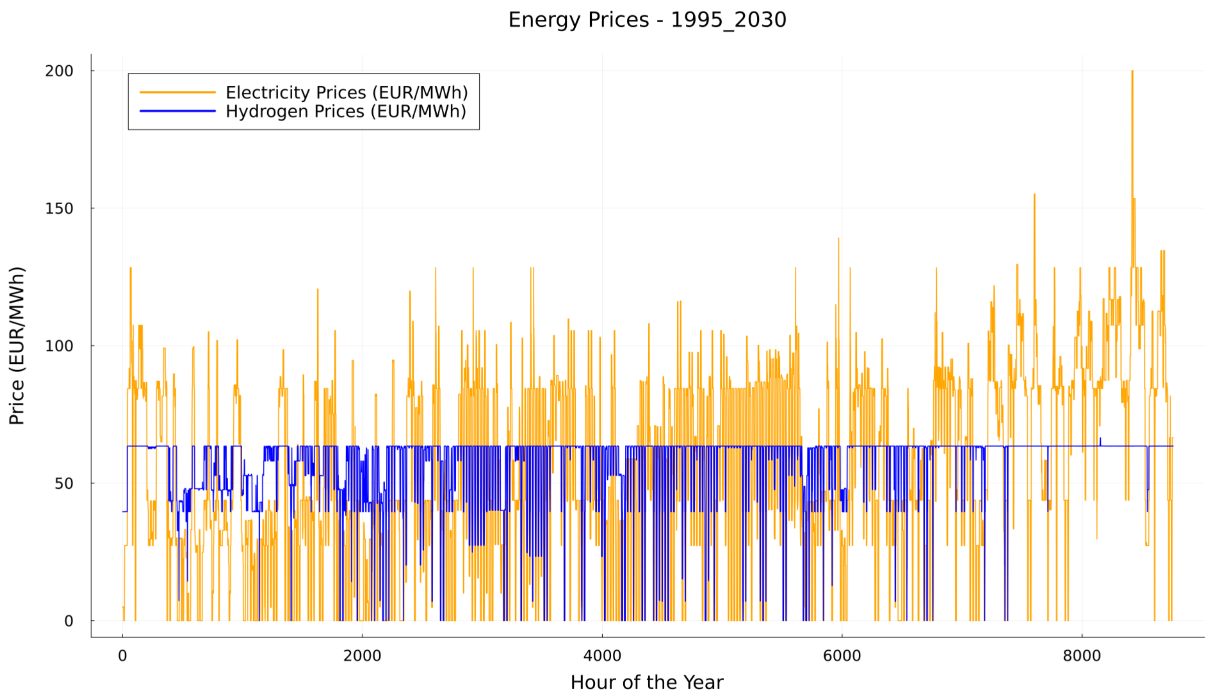


Figure 4.4: Electricity and Hydrogen Prices for Scenario 1995-2030

4.3. Ancilliary Data

Finally, in order to calculate the real rate of interest, values for the nominal rate of interest and the inflation rate are required. These are sourced based on the 2024 averages from the European Central Bank and Centraal Bureau voor de Stistiek have been presented in table 4.2 below (Statistics Netherlands (CBS), 2025), (European Central Bank, 2025). The Main Refinancing Operations (MRO) rate is utilised for the nominal interest rate.

Parameter	**Value (%)**
Nominal Interest Rate (i)	3.61
Inflation Rate (u)	3.34

Table 4.2: Financial Parameters utilised in Real Interest Rate Calculation

5

Results

This chapter presents both numerical and graphical results derived from varying key parameters within the model. First, Section 5.1 provides a detailed analysis of the model results for one of the six TYNDP scenarios, namely the 2009–2040 scenario. This includes various components such as energy prices, electricity and electrolyser flows, internal prices, and wind curtailment.

Next, Section 5.2 compares the individual net present values (NPVs) for different stakeholders within the hub across all six TYNDP scenarios. Section 5.3 examines the impact of varying interconnection capacities, while Section 5.4 explores the effects of different electrolysis capacities in the hub.

Section 5.5 evaluates how increasing hydrogen prices influence the NPV and internal rate of return (IRR) for individual components. This is followed by Section 5.6, which investigates the sensitivity of hub economics to changes in electrolyser efficiency. In Section **??**, a combined tendering approach is assumed, and outcomes for four identical parties are computed. Finally, Section 5.8 presents a new configuration informed by insights from the preceding analyses.

5.1. TYNDP Scenario 2009-2040

To begin with, a scenario has been chosen and the relevant results for the scenario are presented in detail. This is done to help illustrate the full range of numerical and graphical outputs that the model can produce. In the NSWPH 2x2 GW hub, the tenders are expected to be of 2 x (1 GW wind farm) (WFe) parties and 4 x (500 MW Electrolyser + 500 MW wind farm) combined (Comb.) parties, each demarcated in Figure 5.1 in orange and blue respectively.

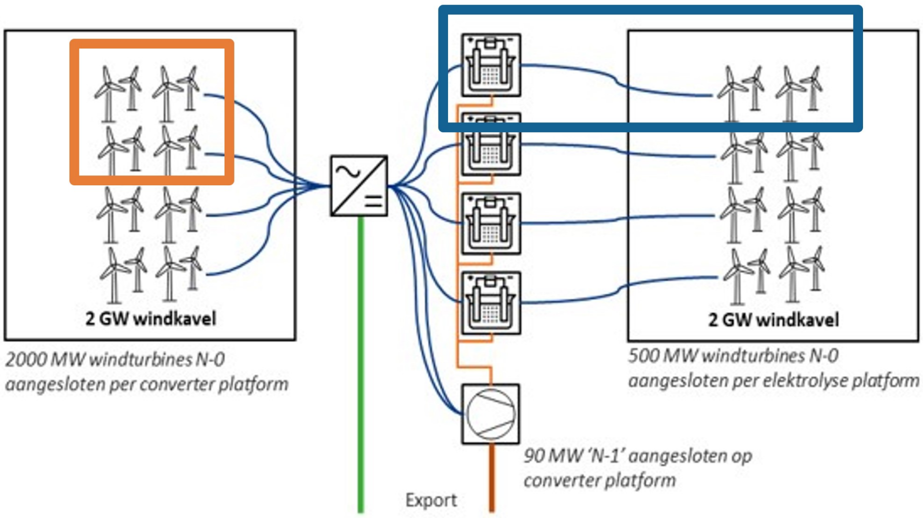


Figure 5.1: Individual Parties and Tendering in 2x2 GW Hub

The hub is split up into six parties for the purpose of tendering such that there are two identical electrical wind farm parties and four identical electrolyser + hydrogen wind farm parties. Thus, there are two wind farm parties on the left, each with 1 GW connection capacity to the converter and four 500 MW electrolyser parties, each with a 500 MW wind farm and 250 MW interconnection capacity with the converter. This configuration provides the baseline for evaluating further scenario and parameter variations.

The numerical results firstly include the installed wind capacity for the configuration in Figure 5.1. The electrical wind farm is the cumulative installed capacity of wind directly connected to the converter and depicted on the left in the figure, while the electrolyser wind farm is the one on the right, connected directly to the electrolysers. The total installed capacity of the hub is a summation of the two. As mentioned before, the hub is split into six parties, of which, two are of one type while the remaining four are identical to each other. The capital expenditure (CAPEX), net present value and internal rate of return are calculated for each type of party.

The CAPEX is calculated by summing up the investment cost of the components owned by one party. This metric is instructive as it indicates to the amount of money that is required at the inception of the project, thus outlining the risk involved. The net present value (NPV) represents the worth of party assets throughout their lifetime discounted to current value.

The detailed numerical model results for the 2009_2040 scenario are included below in Table 5.1. The following table summarises the key economic and technical performance indicators of the hub under the 2009–2040 scenario. It captures the installed capacities, capital investments, and financial viability metrics of NPV and IRR for the different party types within the hub. These results serve as a reference case, offering insights into the baseline economic performance of the system under current assumptions. They also establish a benchmark against which the impacts of parameter variations in subsequent sections can be evaluated.

Metric	**Value**
Electrical Wind Farm Capacity (MW)	2462
Electrolyser Wind Farm Capacity (MW)	1970
Total Hub Installed Capacity (MW)	4432
Electrical Wind Farm (WFe) CAPEX (M€)	1981
Electrical Wind Farm (WFe) (M€)	4725
Electrical Wind Farm (WFe) (%)	11.27
Offshore Cable Utilisation (%)	65.20
Electrolyser Party (ESR) CAPEX (M€)	1828
Electrolyser Party (ESR) NPV (M€)	-2941
Electrolyser Party (ESR) IRR (%)	0.0
Electrolyser Utilisation (%)	43.76
Combined Party (Comb.) CAPEX (M€)	2621
Combined Party (Comb.) NPV (M€)	-1050
Combined Party (Comb.) IRR (%)	0.0
Annual Hub Electricity Trading Revenue (M€/year)	1129
Annual Hub Hydrogen Trading Revenue (M €/year)	389
Total Hub Net Present Value (M €)	5252

Table 5.1: Hub Economics for Scenario 2009_2040

The results in Table 5.1 provide key economic insights into the viability of different party configurations within the 2x2 GW hub under the 2009–2040 TYNDP scenario. The electrical wind farm parties (WFe) show strong financial performance, with a net present value (NPV) of €4725 million and a positive internal rate of return (IRR) of 11.27%, indicating a viable and attractive investment profile.

In contrast, both the electrolyser-only (ESR) and combined (Comb.) party configurations yield negative NPVs of -€2941 million and -€1050 million respectively, with IRRs of 0%, indicating that these setups are not financially viable under the current scenario assumptions. Notably, the substantially lower NPV of the ESR configuration suggests that the electrolyser on its own presents a significantly weaker business case. In the Combined configuration, this financial gap is partially offset by the co-located wind farm, which subsidises the underperforming electrolyser component. This interpretation is reinforced by the relatively low electrolyser utilisation rate of 43.76%, which limits its ability to generate sufficient revenue.

The offshore cable utilisation is moderate at 65.2%, implying that while infrastructure is used effectively, there may be some capacity that remains untapped, particularly due to low electrolyser activity.

From a system-wide perspective, the total hub NPV is positive at €5252 million, driven largely by revenues from electricity trading (€1129 million/year) and to a lesser extent hydrogen trading (€389 million/year). This highlights a profitable hub operation overall, but with uneven benefit distribution among party types.

5.1.1. Energy Prices 2009-2040

This section presents the energy price inputs used for the 2009–2040 scenario. This data is exogenous to the model but it critically influences its outcomes. Figure 5.2 shows the hourly electricity and hydrogen prices used as inputs for the simulation.

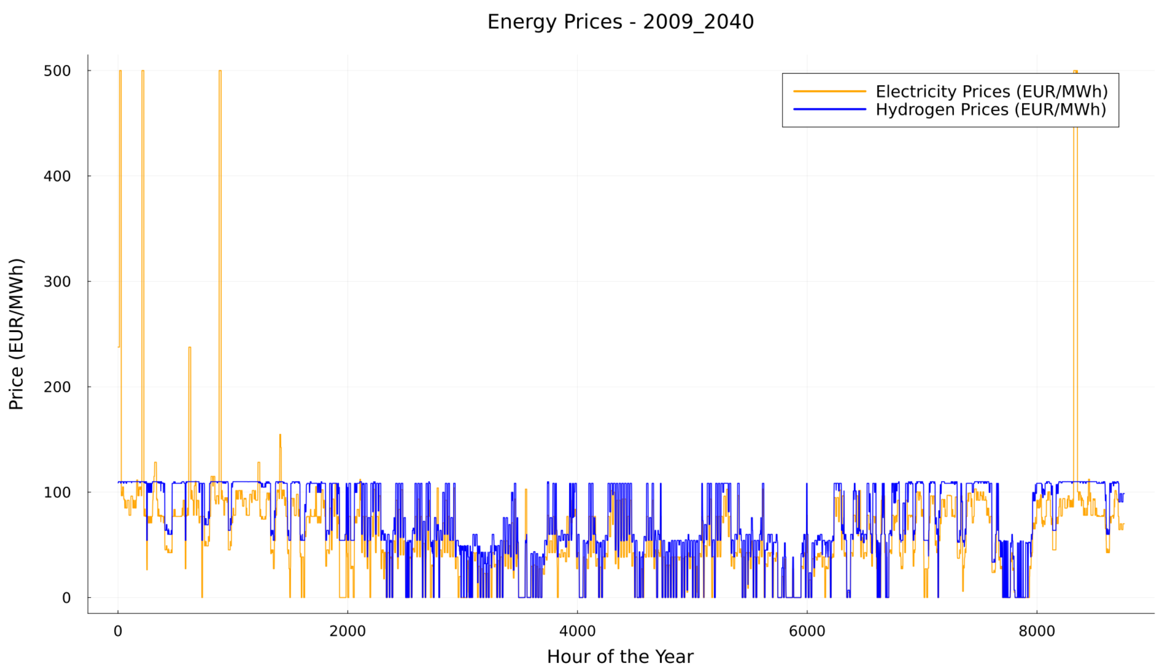


Figure 5.2: Energy Prices - 2009-2040

On average, the hydrogen price is observed to be higher than the electricity price. However, the relatively low electrolyser utilisation at 44% in Table 5.1 suggests that this difference is not high enough to overcome electrolyser losses and demonstrate a willingness to pay for hydrogen production over electricity export. This implies that, under current conditions, electricity export remains more attractive than hydrogen production in many hours.

Electricity prices reach zero, the lower bound for this dataset, for a significant number of hours, with only occasional spikes to the dataset maximum of 500 €/MWh. Both electricity and hydrogen prices follow similar temporal patterns, reflecting their shared dependency on upstream market conditions. Notably, hydrogen prices are more stable than electricity prices.

To better visualise the price distribution, Figure 5.3 presents the sorted prices as duration curves for comparison. The hydrogen price remains above 100 €/MWh for more than 3500 hours, whereas electricity exceeds this value for only about 500 hours. From this graph, it is apparent that the electricity price is zero for 1500 hours while the hydrogen price is zero for close to 1000 hours. These differences in price frequency and magnitude significantly impact the economic feasibility of hydrogen production.

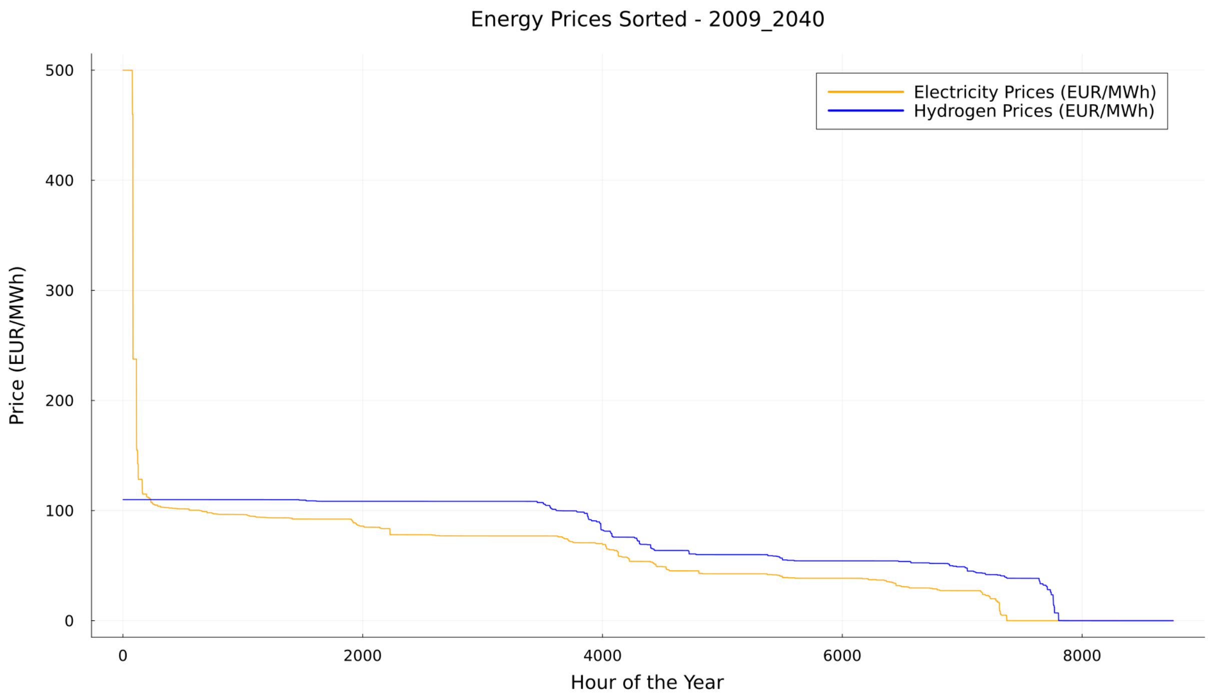


Figure 5.3: Energy Price Duration Curve - 2009-2040

5.1.2. Electricity Flows

This section analyses the internal and external electricity flows within the hub under the 2009–2040 scenario. These flows determine how wind-generated electricity is allocated between hydrogen production and grid export, and under what conditions electricity is imported from shore. The behaviour of these flows reflects the interplay between market prices, cable constraints, and electrolyser operation, offering key insights into the hub's energy management strategy. In Figure 5.4, a zoomed-in snapshot of electricity flows for 500 hours is presented to illustrate typical operational patterns without the visual clutter of the full-year dataset.

The green curve represents the aggregate wind electricity used to power electrolysers within the hub. This occurs when hydrogen prices significantly exceed electricity prices, compensating for conversion losses, or when the cable is fully utilised and hydrogen production remains marginally profitable.

The yellow line denotes electricity exported to shore via the DC cable. This tends to occur when electricity prices exceed hydrogen prices or when electrolyser capacity is saturated.

The red line represents electricity imported from shore, primarily during periods of low local wind output and relatively higher hydrogen prices. Notably, the model constrains simultaneous imports and exports; hence, the red and yellow curves do not overlap in time.

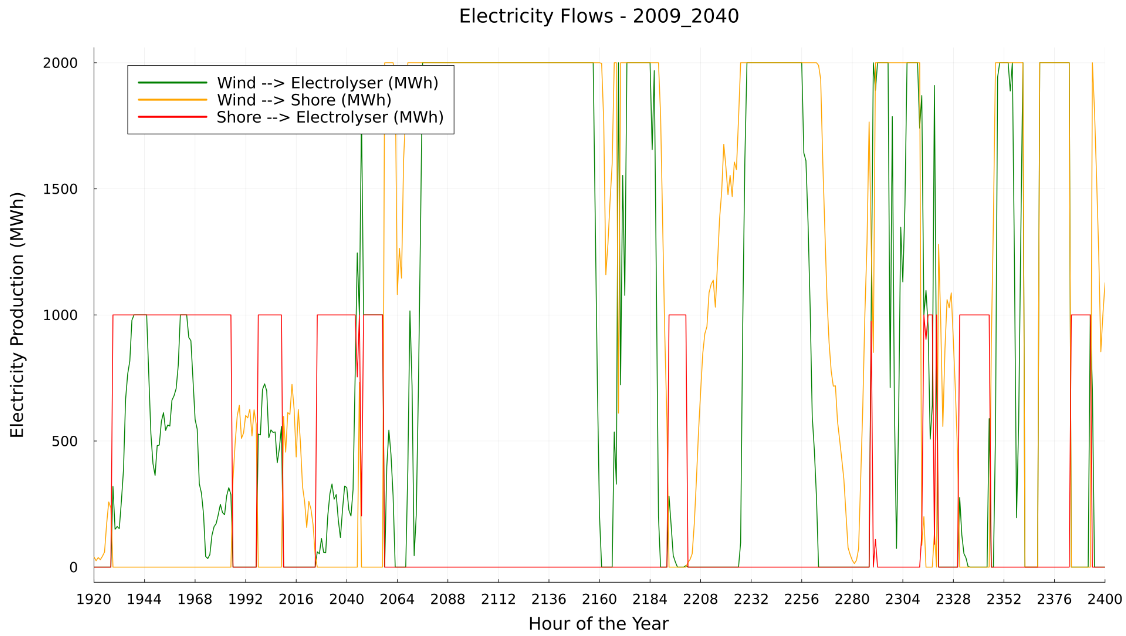


Figure 5.4: Electricity Flows Zoomed - 2009-2040 (500 hours)

Figure 5.5 presents the same flows across the entire year as duration curves. The sorted values are used instead of unsorted ones to improve clarity.

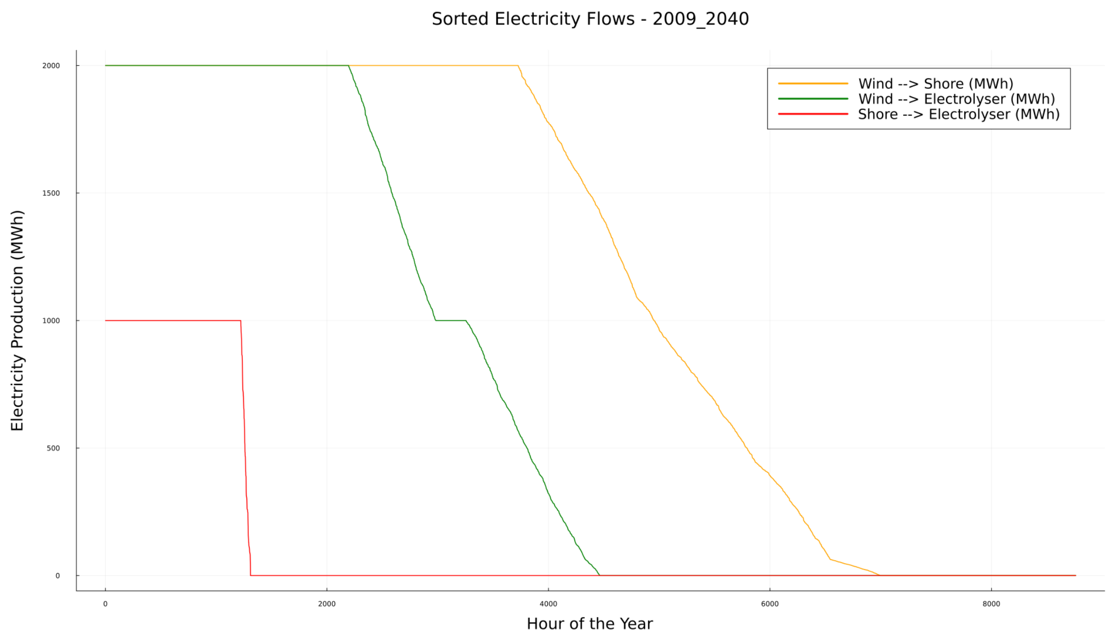


Figure 5.5: Electricity Flows - 2009-2040

The percentage of cable capacity utilised for electricity export and import are represented as duration curves. The cable is utilised to its full capacity for almost 4000 hours, while it is not used at all for a little over 1500 hours with intermediate values of export in between the two ends of the graph. This cable is observed to be utilised to 65.20% according to Table 5.1. Of this, electricity exports account for 58%, while imports constitute 7.2%.

5.1.3. Hydrogen Flows

This section presents hydrogen-related flows within the hub, focusing on the interaction between electricity inputs to the electrolyser and the resulting hydrogen production. Similar to the electricity flow analysis, Figures 5.6 and 5.7 illustrate both detailed and aggregated representations of electrolyser operation over the 2009–2040 scenario.

Figure 5.6 shows a zoomed-in view of hourly electrolyser behaviour over 500 hours. The blue curve represents hydrogen production, while the green and red curves denote electricity input from offshore wind farms and onshore imports, respectively. Due to efficiency limitations, the electrolyser's output remains significantly below its maximum electrical input capacity of 2 GW.

Notably, peaks in the red line often align with daytime summer hours, indicating solar PV contributions to the onshore grid that are subsequently imported by the hub. These periods typically correspond to low wind availability offshore, illustrating a complementary relationship between solar and wind inputs in maintaining hydrogen production.

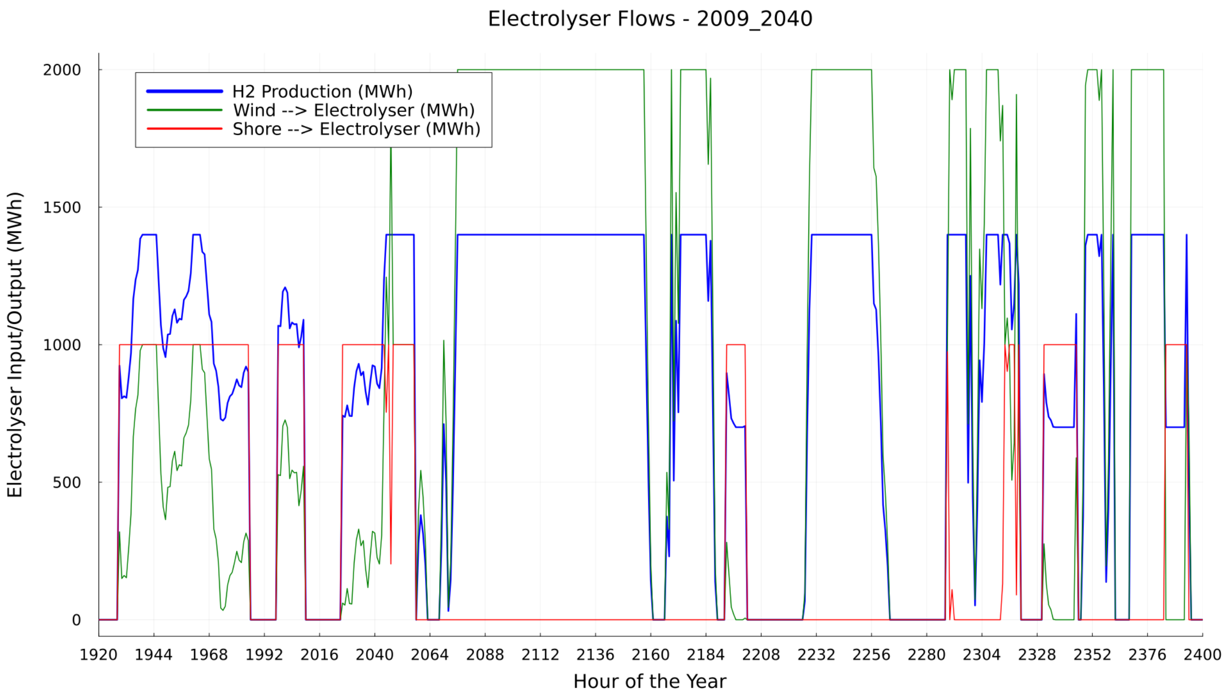


Figure 5.6: Hydrogen Flows Zoomed – 2009–2040 (500 hours)

The corresponding duration curves in Figure 5.7 offer an annual overview of electrolyser utilisation. The blue curve shows hydrogen output as a percentage of maximum electrolyser capacity, with green and red curves again indicating the respective wind and onshore electricity inputs. As reported in Table **??**, the electrolyser operates with a capacity utilisation of 43.76% over the year, calculated as the ratio of actual hydrogen production to the theoretical maximum output over 8760 hours.

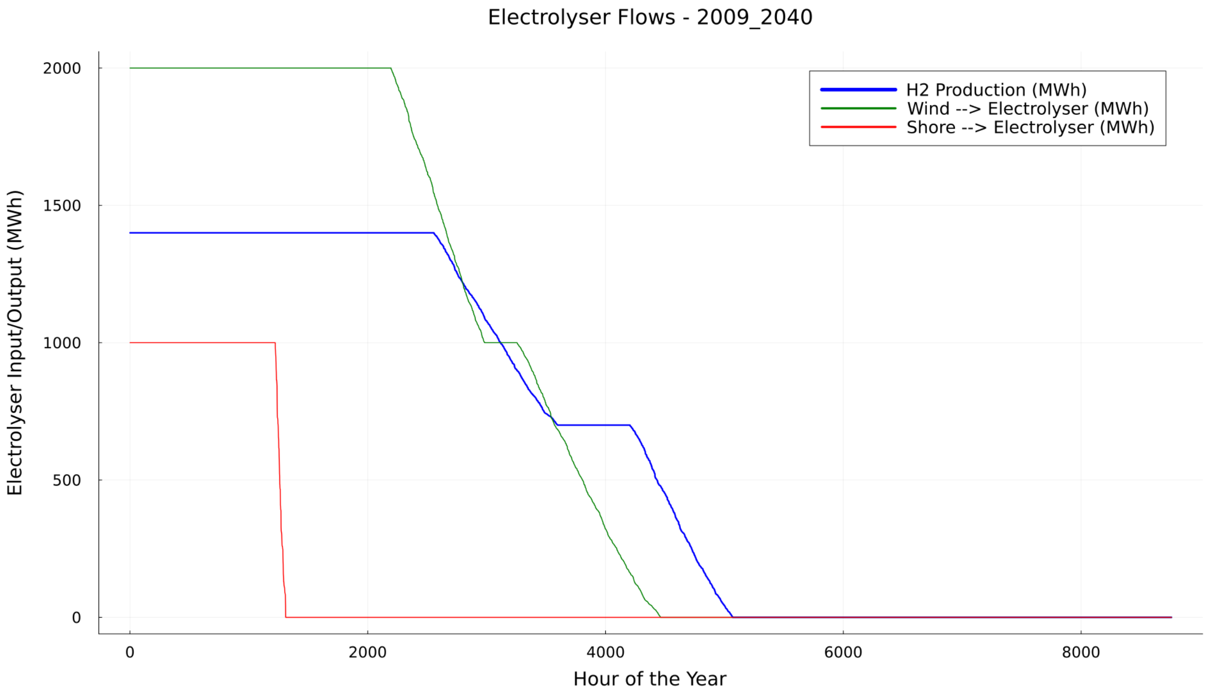


Figure 5.7: Hydrogen Flows Duration Curve – 2009–2040

The electrolyser reaches its maximum output of approximately 1400 MW for around 2500 hours annually. The gradual decline from this peak down to a plateau at 700 MW reflects hours when only onshore electricity is available and wind contribution is absent. The middle section of the curve, between 700 MW and 1400 MW, corresponds to mixed input conditions, both wind and onshore electricity are partially contributing. Beyond this range, the curve reflects hydrogen production powered solely by wind after cable congestion has limited electricity export. Notably, the absence of onshore electricity imports in this tail segment indicates that when onshore imports are economical, they are always used to their full capacity, unless the electrolyser input capacity has already been saturated by wind power. Lastly, the electrolyser remains inactive for approximately 4000 hours, pointing to insufficient economic incentives or energy availability for operation during these periods.

5.1.4. Internal Prices

Internal electricity prices represent the marginal value of electricity within the offshore hub and are derived from the dual values of the hub's energy balance constraint, as described in Section 3.5. These prices reflect the internal economic conditions that govern electricity allocation within the hub and are critical for understanding how wind power is valued in different operational states.

Figure 5.8 overlays internal electricity prices with onshore electricity prices over the full year. It can be visually inferred from the graph that the two expectedly follow almost identical trends. However, the internal prices can be observed to diverge from the onshore prices and fall to zero, likely in timesteps with congestion in the offshore cable. These differences are more apparent and can be easily observed towards the ends of the graph, i.e., between 0 and 2000 hours and beyond 8000 hours.

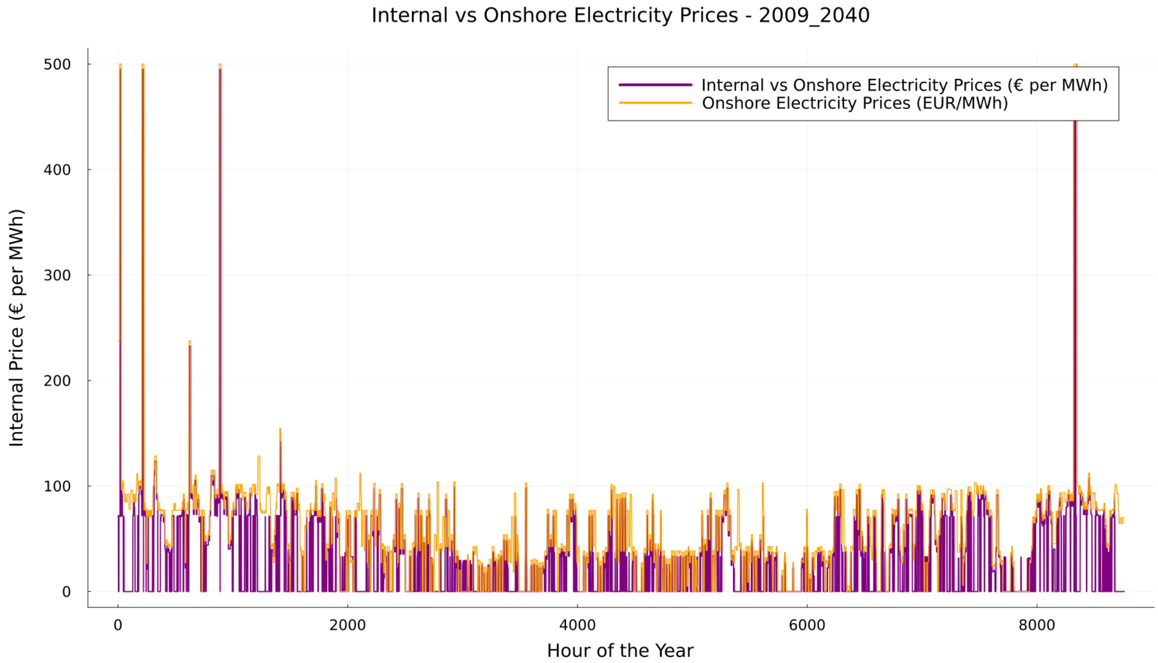


Figure 5.8: Internal Prices - 2009-2040

The comparative price duration curves in Figure 5.9 offer deeper insight into the dynamics between internal and onshore electricity prices. At first glance, the two curves appear to closely track each other, with the onshore price generally higher than the internal price across the year. This might imply that the onshore price consistently exceeds the internal price at every time step. However, such a conclusion would be misleading. A closer examination reveals important deviations, particularly in how frequently prices fall to zero and how internal pricing is affected by physical infrastructure constraints.

Specifically, while the onshore electricity price drops to zero for approximately 1500 hours, the internal hub price does so for nearly 3500 hours, a difference of around 2000 hours. This extended period of zero internal prices can be explained by congestion in the offshore DC cable and converter. When the transmission infrastructure is fully utilised, exporting the maximum 2 GW, any additional offshore electricity generation cannot be exported and thus has no marginal economic value within the hub. As a result, the internal price falls to zero. This phenomenon highlights how internal prices are not only shaped by market signals but are also highly sensitive to physical limitations in transmission capacity. It underscores the need to consider infrastructure constraints when interpreting internal price signals in offshore energy systems.

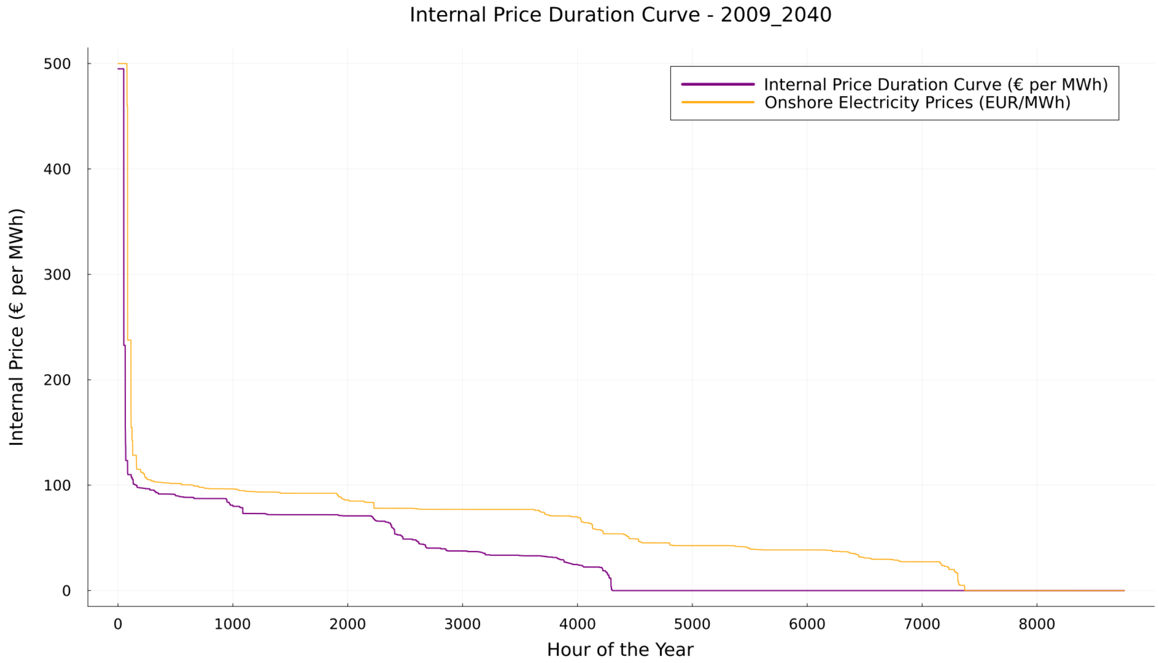


Figure 5.9: Internal Price Duration Curve - 2009-2040

To examine this, the internal price is subtracted from the onshore price for every time step and the results are represented graphically below in Figure 5.10.

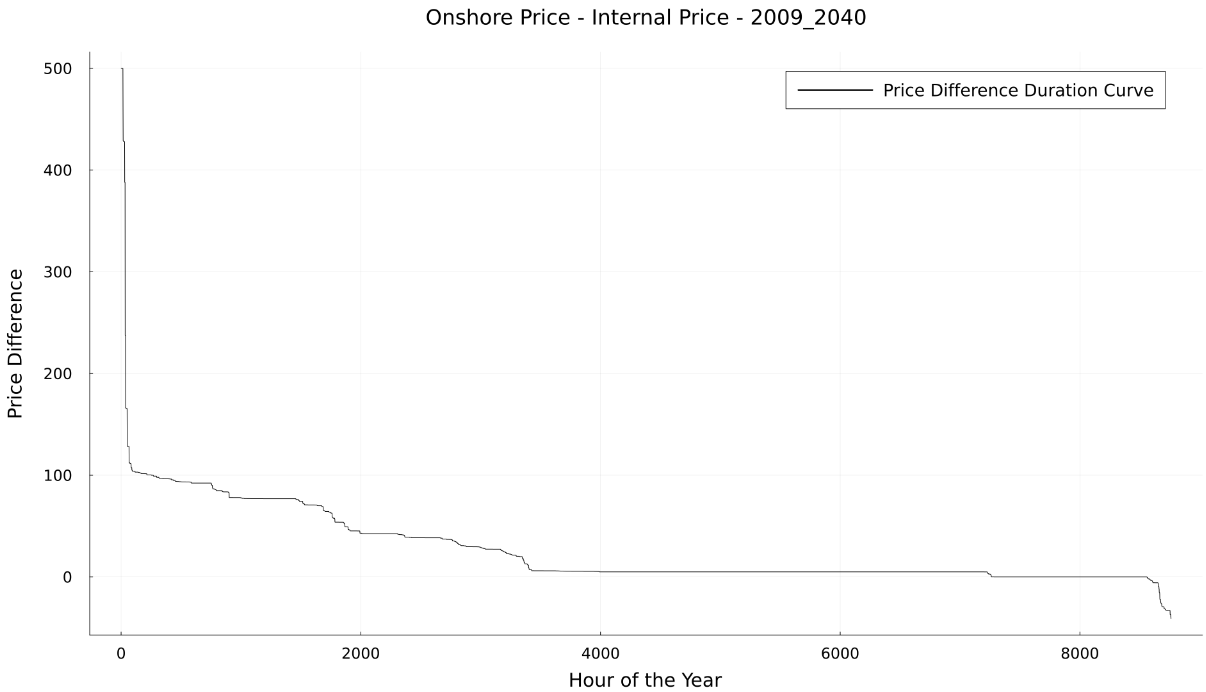


Figure 5.10: Difference between Onshore and Internal Electricity Prices - 2009-2040

As can be observed in the above figure, for most time steps, the difference is positive, indicating that the onshore price is greater than the internal price. There is an almost constant difference of 5 €/MWh for 4000 hours that can be attributed to the variable opex cost of the wind farms which corresponds to the same value. However, for a few time steps, this difference can be observed to be negative, thus suggesting that the internal price is the higher of the two. Therefore, to further investigate this, a snapshot of 500 hours near the 2000 hour mark in Figure 5.8 is presented in Figure 5.11.

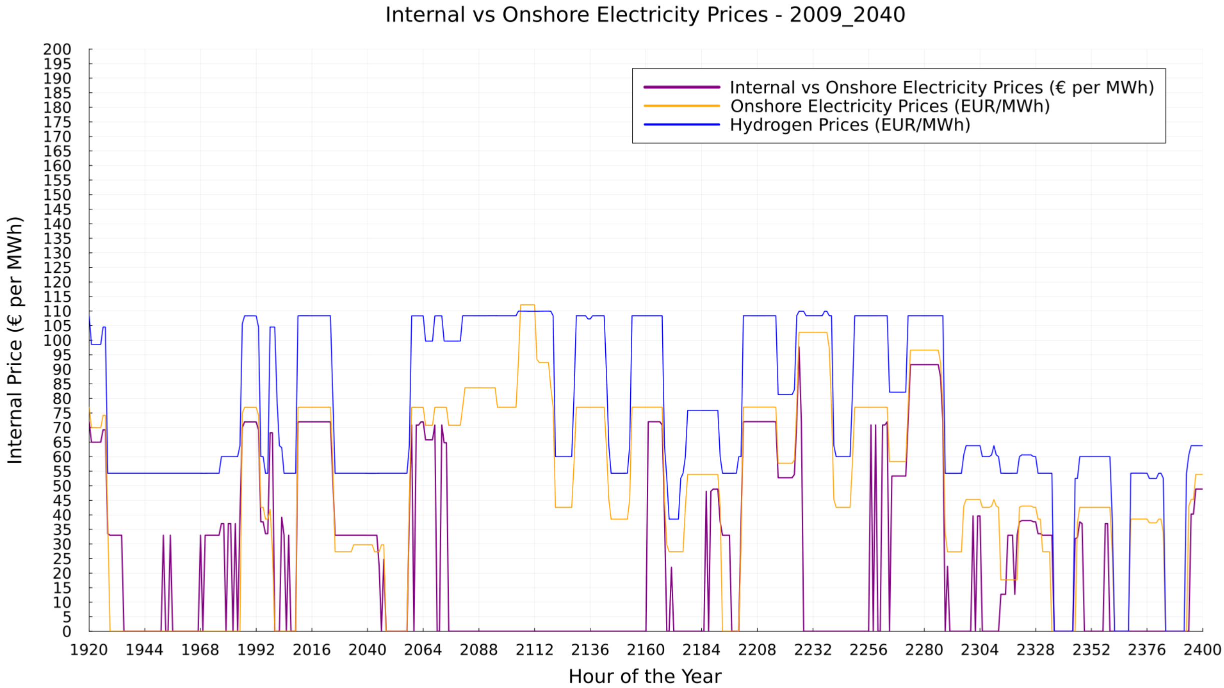


Figure 5.11: Internal Price Zoomed - 2009-2040

Here, it is evident between hours 1920 and 1992 that the internal electricity price remains positive, even while the onshore electricity price is zero. Similarly, at hour 2040, the internal price exceeds the onshore price, despite the latter being distinctly above zero. These phenomena can be attributed to the influence of hydrogen prices on internal price formation. When the onshore electricity price drops to zero but the hydrogen price remains positive, hydrogen production becomes the primary source of value for electricity within the hub. In such cases, the hydrogen price effectively sets a floor for the internal electricity price, reflecting the opportunity cost of diverting electricity to electrolysis. As shown in Figure 5.6, during these periods, the hub imports electricity from shore and combines it with wind power to produce hydrogen.

This demonstrates that electricity retains economic value as long as it enables hydrogen generation, even in the absence of a market-clearing power price. Sector coupling ensures that internal prices stay responsive to hydrogen markets. It is interesting to examine the individual NPVs in the case that internal prices are used to compute profits instead of onshore prices. The individual NPVs and IRRs thus calculated for all the different entities, separate and combined are presented in Table 5.2. As is evident, the NPV for all entities is negative due to which the internal rate of return is zero.

This can be explained and understood intuitively by referring to Figure 5.9, where the internal electricity price can be seen to be zero for approximately three times as many hours as for the onshore price. This especially affects wind farms which can be seen from the −€2 billion NPV of the electrical wind farm party which in all other cases is observed to have a significantly high NPV and IRR. Alternatively, while this improves the business case for the electrolyser by making available low price electricity for more hours, its high CAPEX continues to be a barrier for profitability.

Metric	**Value**
Total Hub Optimal Capacity (MW)	4432
1 GW Wind Farm NPV (M€)	-2054
1 GW Wind Farm IRR (%)	0.0
500 MW H2 Wind Farm NPV (M€)	-822
500 MW H2 Wind Farm IRR (%)	0.0
500 MW Electrolyser NPV (M€)	-362
500 MW Electrolyser IRR (%)	0.0
500 MW Electrolyser + Wind Farm NPV (M€)	-1184
500 MW Electrolyser + Wind Farm IRR (%)	0.0
Total Hub Net Present Value (M€)	5252

Table 5.2: Internal Prices-based Hub Economics for Scenario 2009-2040

In conclusion, the internal pricing dynamics within the offshore hub reveal the critical influence of infrastructure constraints and multi-market interactions on economic outcomes. While internal prices offer a more accurate representation of local electricity value, they expose the financial vulnerability of wind generation in periods of isolation from the main grid. Conversely, although lower internal prices enhance the electrolyser's access to affordable electricity, this benefit is insufficient to overcome the technology's high capital costs. These findings underscore the importance of coordinated infrastructure investment and market design to ensure viable business models for all stakeholders within future offshore energy hubs.

5.1.5. Wind Curtailment

In Figures 5.12 and 5.13, the wind farm curtailment has been presented. Peaks rising all the way to 4000 MWh can be observed in Figure 5.12, in which case the entire installed wind capacity of the hub has to be curtailed. This curtailment coincides with the zero electricity price hours in Figure 5.2, suggesting cause and effect. It can be intuitively understood that the model chooses to curtail wind production when electricity prices are zero as it results in higher opex costs for the wind farm than revenues.

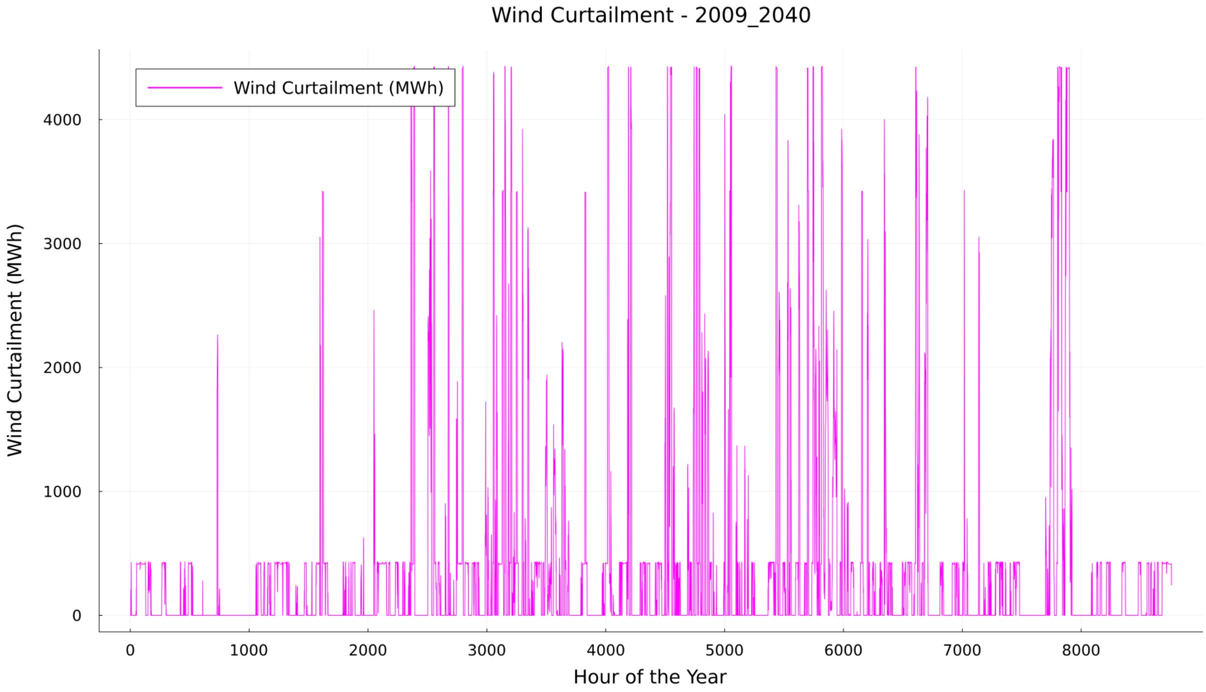


Figure 5.12: Wind Curtailment - 2009-2040

Further, in Figure 5.13, all individual peaks are aggregated and it can be observed that curtailment takes place for a little over 1000 hours.

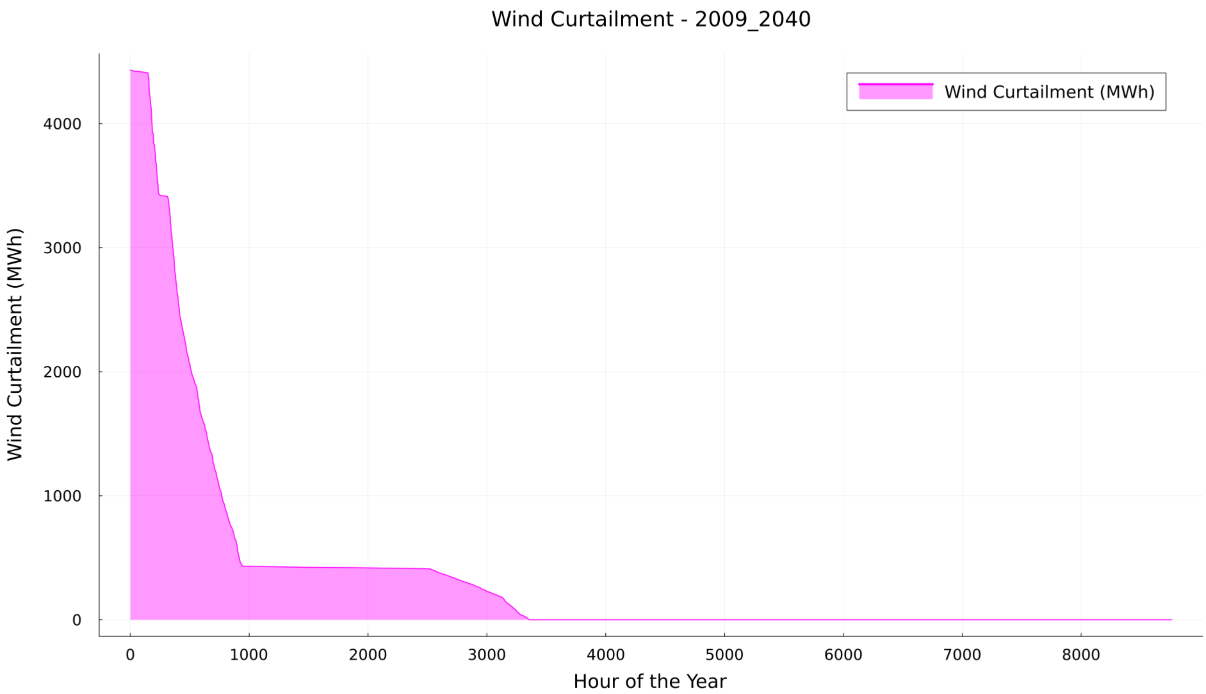


Figure 5.13: Wind Curtailment Duration Curve - 2009-2040

Figures 5.12 and 5.13 present the magnitude and temporal distribution of wind energy curtailment in the 2009–

2040 scenario. As seen in Figure 5.12, curtailment peaks occasionally rise to approximately 4000 MWh, corresponding to the full installed capacity of the hub. These events align with hours of zero electricity price, as shown in Figure 5.2, implying a direct causal relationship. During such hours, the model curtails generation entirely, as the operational expenditure (OPEX) from running the wind farm would exceed potential revenue.

The aggregated impact is further illustrated in the duration curve in Figure 5.13, which shows that serious curtailment occurs for slightly over 1000 hours annually, around 11% of the year. In the subsequent 1500 hours, curtailment consistently hovers around 500 MW, which corresponds to the level of overplanting in the hub configuration (432 MW). This suggests that these curtailed volumes occur during periods of full wind output, where both electricity export capacity and electrolyser utilisation are saturated. Such curtailment is thus not due to insufficient demand, but rather to hard infrastructure limits.

5.2. 2x2 GW Configuration with TYNDP Scenarios

Results have been generated for the 2x2 GW configuration mentioned in 4.1, using the six TYNDP electricity and hydrogen price timeseries from Section 4.2. In the NSWPH 2x2 GW hub, tenders are expected to be 2 x 1 GW wind farms and 4 x (500 MW Electrolyser + 500 MW wind farm) units, shown in Figure 5.1 in orange and blue respectively. The profits for individual entities are presented below in Table 5.3. The plots and graphs as included for the 2009-2040 scenario in Section 5.1, are included for all remaining scenarios in Appendix B.

Scenario	Avg. Elec. Price (€/MWh)	Avg. H2 Price (€/MWh)	Hub Wind Capacity (MW)	WFe Party NPV (M€) & IRR (%)	Comb. Party NPV (M€) & IRR (%)	Total Hub NPV (M€)
1995-2030	54	57	4017	3356 10.04%	-1261 0.0%	1667
1995-2040	60	67	4147	4379 11.34%	-1146 0.0%	4174
2008-2030	53	60	4018	3200 9.68%	-1053 0.0%	2186
2008-2040	52	68	4159	3164 9.08%	-1045 0.0%	2149
2009-2030	58	60	4071	4044 11.45%	-1104 0.0%	3673
2009-2040	59	73	4432	4253 11.26%	-814 0.0%	5252

Table 5.3: Financial and Capacity Data for Different Scenarios

From the results, it is evident that the electrical wind farm party consistently yields a positive net present value across all six scenarios. In contrast, the combined party, comprising a 500 MW electrolyser and a 500 MW wind farm, operates at a loss in every case, resulting in a negative NPV throughout. The wind farm party reliably achieves an internal rate of return exceeding 9%, peaking at 11.45% in the 2009–2030 scenario.

While the IRR of the wind farm party generally correlates with average electricity prices, rising from just over 9% at 52€/MWh to 11.45% at 58 €/MWh, it does not follow a strictly linear trend. Notably, two scenarios exhibit higher electricity prices (60 €/MWh and 59c€/MWh) but lower IRRs. This deviation can be attributed to elevated hydrogen prices in those scenarios (67 €/MWh and 73 €/MWh vs 60 €/MWh), which enhance the competitiveness of the combined party and slightly reduce the relative profitability of the purely electrical wind farm. These dynamics highlight the interdependence of electricity and hydrogen prices in a system-integrated configuration, where price shifts in one market can influence the economic performance of actors primarily exposed to the other.

Meanwhile, the IRR for the electrolyser party remains zero, reflecting the unviable economics of offshore electrolysis under current assumptions. This trend aligns with expectations, as profitability for each party scales with the commodity they primarily sell. For example, in the 1995–2030 scenario, where the average hydrogen price is relatively low at 57 €/MWh, the electrolyser party records its largest loss of –€1.26 billion. In contrast, in the 2009–2040 scenario where hydrogen prices peak at 73 €/MWh, this party's NPV improves significantly to –€814 million. However, even under these more favorable conditions, hydrogen production remains economically challenging under the current setup.

Across all scenarios, the total installed wind capacity at the hub stays consistent at just over 4 GW, with a near-even division between the electrical and hydrogen wind farms. Higher energy prices expectedly incentivise overplanting, to an extent where the model suggests over 10% overplanting in the hub for the 2009-2040 scenario.

5.3. Interconnection Capacity

In Figure 4.1, there are four cables connecting the electrolysers to the converter, each with an interconnection capacity of 250 MW. This constraint, however, is varied to test the sensitivity of the NPVs to the interconnection capacity. The rest of the conifguration is maintained to be exactly the same as the 2x2GW base configuration. The results for the NPVs and IRRs of individual parties are tabulated below in Table 5.4.

Inter-connection Capacity (MW)	Hub Wind Capacity (MW)	WFe Party NPV (M€)	WFe Party IRR (%)	Comb. Party NPV (M€)	Comb. Party IRR (%)	Total Hub NPV (M€)
0	4495	4501	11.12	-1294	0.0	3824
500	4425	5373	11.27	-1434	0.0	5012
1000	4432	4253	11.27	-814	0.0	5252
1500	4415	3872	11.31	-594	0.0	5369
2000	4409	3877	11.34	-580	0.0	5435

Table 5.4: Individual party profits for varying interconnection capacity

When the interconnection capacity is zero, the hub effectively splits into two separate entities: a wind farm connected directly to the converter and another connected to the electrolysers. In this scenario, the hub's total NPV is the lowest, while the installed capacity is the highest, presumably to compensate for the lack of interconnection. In subsequent cases, the installed capacity stabilises. The hub NPV improves with increasing interconnection but tends to plateau, as the marginal benefit of additional interconnection diminishes. Since the electrical and hydrogen wind farms are assumed to operate identically, they generate nearly the same amount of electricity at each time step, with slight differences due to overplanting. In practice, the benefits of increased interconnection would likely be somewhat higher, given real-world discrepancies in wind speeds and availability during maintenance.

5.4. Electrolysis Capacity

Considering the 2009-2040 scenario for the price time series, the number of electrolysers in the hub is varied from zero till four. In Table 5.5, the individual NPVs for the electrical wind farm party, electrolyser party and the combined (electrolyser + wind farm) entity are noted for different number of electrolysers (ESRs) in the hub configuration. The table is colour coded such that the electrical wind farm party is in orange, while the parties with electrolyser assets are blue. The interconnection capacity between the capacitor and electrolyser/s also scales proportionally with electrolysis capacity, i.e., from 250 MW interconnection for 500 MW electrolysis to 1000 MW for 2000 MW electrolysis capacity.

Number of 500 MW ESR	Total Hub Wind Capacity (MW)	WFe Party NPV (M€)	WFe Party IRR (%)	ESR Party NPV (M€)	Comb. Party NPV (M€)	Total Hub NPV (M€)
0	2382	4279	10.68	-	-	8557
1	2887	4671	10.93	-2857	-1522	7819
2	3405	4797	11.07	-2890	-1291	7013
3	3907	4657	11.21	-2918	-1054	6150
4	4432	4253	11.27	-2941	-1049	5251

Table 5.5: Individual entity profits for different number of 500 MW electrolysers

It is evident that the hub has the highest total NPV of € 8.56 billion when no electrolysers are present. As electrolysers are added, the total hub NPV steadily declines, indicating that the addition of electrolysis capacity reduces overall profitability under the current pricing scenario. This is primarily because the standalone electrolysis operation is unprofitable in every case, with the ESR party consistently reporting large negative NPVs.

The overplanting of wind in the hub increases gradually as more electrolysis capacity is added. In the configurations with lesser electrolysers, the NPV of the electrical wind farm party is higher due to higher overplanting on its side of the hub. Due to lower interconnection capacity in these configurations, the hub overplants on the electrical wind farm and underplants on the electrolyser side to effectively utilise the electrical infrastructure. Interestingly, the IRR for the wind farm party also improves gradually, from 10.68% with no electrolysers to 11.27% at the highest electrolysis capacity, indicating the positive correlation between the business case for the wind farms and the electrolysis capacity of the hub.

Meanwhile, although the combined party (electrolyser + wind farm) remains unprofitable throughout, its losses decrease as more electrolysis capacity is added. However, the NPV of the electrolyser party itself reduces slightly as more electrolysers are added. Hence, the increase in the NPV of the combined party can be attributed to the increasing business case of the hydrogen wind farms that overcompensate for the minorly diminishing business case of the electrolysers. Nevertheless, the total hub NPV consistently declines with increasing electrolysis capacity.

Similar results are generated for 180 MW electrolysers instead of 500 MW. This is a deviation from the 2x2GW case wherein four 500 MW electrolysers are considered. Alternatively, while 500 MW electrolysers per platform are found to be optimal, the possibility of smaller 180 MW platforms for initial projects is considered (North Sea Wind Power Hub, 2024d). It is interesting to simulate results for those values in the context of the 2x2GW configuration. In contrast with the previous case, the interconnection capacity is increased proportionally to the installed capacity in a 1:1 ratio rather than 1:2; from 180 MW interconnection for 180 MW electrolysis to 720 MW interconnection for 720 MW electrolysis capacity. This is because the 66kV cables used for interconnection for the 180 MW electrolyser setup have a minimum capacity of 180 MW. The electrolysers are built up from zero to four and the results for the same are presented in Table 5.6.

Number of 180 MW ESR	Total Hub Wind Capacity (MW)	WFe Party NPV (M€)	WFe Party IRR (%)	ESR Party NPV (M€)	Comb. Party NPV (M€)	Total Hub NPV (M€)
0	2381	4279	10.68	-	-	8557
1	2576	4244	10.74	-1017	-178	8309
2	2754	4139	10.85	-1020	-111	8054
3	2919	3964	10.98	-1023	-45	7791
4	3106	3754	11.04	-1026	2.3	7519

Table 5.6: Individual entity profits for different number of 180 MW electrolysers

Table 5.6 presents the economic outcomes when smaller, 180 MW electrolysers are deployed instead of 500 MW units, with interconnection scaled 1:1. The hub's total NPV is highest at €8.56 billion when no electrolysers are present. As additional electrolysers are introduced, the total hub NPV steadily declines to €7.52 billion with four units, though this reduction is notably less severe than in the 500 MW electrolyser case. This follows logically as electrolysis capacity is added in smaller steps here.

The electrolyser party is unprofitable across all configurations, with its NPV decreasing marginally from –€1017 million to –€1026 million as more units are added. Unlike in the 500 MW case, where the ESR party's losses worsened slightly with scale, here the decline is almost negligible due to the proportionally smaller wind capacity additions and interconnection scaling that better match electrolysis capacity.

Interestingly, the combined party transitions from being unprofitable to marginally profitable when all four 180 MW electrolysers are installed, suggesting a slight benefit from economies of scale or better proportionality between the associated wind assets and interconnection capacity. Meanwhile, the wind farm party's NPV decreases gradually from €4279 million to €3754 million as more electrolysers are added, but its IRR increases modestly from 10.68% to 11.04%, reflecting improved asset utilisation.

Overall, the 180 MW electrolyser configuration offers a more balanced degradation of hub value compared to the 500 MW case. The smaller capacity additions appear to better accommodate gradual integration of hydrogen production with minimal economic disruption, making them a potentially attractive option for phased or early stage projects.

5.5. H2 Prices vs NPV

Using the data for the 2009-2040 scenario, the electricity prices are kept constant while the hydrogen prices are multiplied with a steadily increasing factor from 1 to 2. The cable utilisation has been expressed as a split between the export and import utilisation. This is performed as a sensitivity analysis of the present values, both individual and consolidated, to the hydrogen prices. However, it is also important to note that these datasets are closely related and this exercise must be viewed within that context. Nonetheless, it yields meaningful results.

H2 Prices Factor	**WFe Party NPV (M€)**	**WFe Party IRR (%)**	**Cable Util (%) [exp+imp]**	**Comb. Party NPV (M€)**	**Comb. Party IRR (%)**	**ESR Util (%)**	**Total Hub NPV (M€)**
1.0	4253	11.27	57.97 + 7.18	-814	0.00	43.76	5252
1.1	4560	11.09	44.52 + 21.30	-390	0.00	72.36	6959
1.3	4265	10.84	40.89 + 25.43	598	1.60	81.39	10922
1.5	4885	10.68	39.72 + 26.39	1731	3.77	84.34	15404
2.0	4941	10.35	40.42 + 26.36	2448	8.25	85.22	26842

Table 5.7: Impact of H2 Price Multiplication Factor on Hub Economics

Table 5.8 presents a sensitivity analysis of the hub's performance against varying hydrogen price levels, while electricity prices remain constant. As the hydrogen price increases (through a multiplication factor ranging from 1.0 to 2.0), the impact on both infrastructure utilisation and economic performance is significant.

At a price factor of 1.1, the hub already shows a marked shift toward hydrogen production. Cable export utilisation drops from 58% to 45%, while import rises to over 21%, indicating increased offshore hydrogen generation and a shift away from electricity export. Electrolyser utilisation also surges from 44% to 72%. This suggests that in relation to this dataset and the electrolyser efficiency considered, even a modest 10% increase in hydrogen prices is sufficient to tip the economic preference of the model toward hydrogen production. The difference between the hydrogen and electricity prices is now high enough to offset the efficiency losses associated with electrolysis, thus demonstrating a willingness to pay for hydrogen production over electricity export. This confirms that it is the relative price of hydrogen compared to electricity that drives electrolyser viability.

The electrolyser + wind farm (Comb.) party, which is loss-making at the base hydrogen price (factor 1.0, NPV = – € 814 million), becomes profitable at a price factor of 1.3, achieving an NPV of € 598 million and an IRR of 1.6%. This positive trend continues as hydrogen prices increase, reaching an NPV of € 2448 million and an IRR of 7.07% at a factor of 2.0. The standalone 500 MW electrolyser remains unprofitable until a price factor of 1.5; however, at a factor of 2.0, it achieves a positive NPV of €2.4 billion with an IRR of 7.07%. These figures indicate a strong and steadily improving business case for integrated offshore hydrogen production under higher hydrogen price scenarios.

The standalone wind farm party (WFe) maintains a positive NPV across all scenarios, ranging from € 4.25 billion to € 4.94 billion, although its IRR gradually declines. This reflects a shift in value distribution as hydrogen production becomes more attractive. The total hub installed wind capacity increases from 4432 MW to 4936 MW and is evenly split between the electrical and hydrogen-linked wind farms. This overplanting trend, driven by rising hydrogen prices, benefits the electrolyser party and boosts overall hub value. However, it reduces the relative profitability of the electrical wind farm party due to increased curtailment and underutilisation of wind infrastructure resulting in diminishing returns from export revenues.

Electrolyser utilisation increases consistently, plateauing near 85% by a factor of 2.0. This suggests that capacity is near saturation under these conditions. Meanwhile, the hub's total NPV increases sharply and non-linearly with hydrogen prices, from € 5.25 billion at baseline to over € 26.8 billion at a factor of 2.0, indicating significant upside potential for hydrogen under favourable market conditions.

The data confirms that even modest increases in hydrogen prices can render offshore electrolysis economically viable. However, wind farms maintain a stronger economic position across all scenarios. The turning point for combined party profitability appears at around 1.3× the base hydrogen price, highlighting the crucial role of hydrogen price policy and market incentives in enabling offshore hydrogen investments.

5.6. Electrolyser Efficiency vs NPV

For the purpose of this study, the value of electrolyser efficiency assumed is 70% as mentioned in 4 in accordance with the NSWPH database. However, the same database provides multiple possible values for electrolyser efficiency for different scenarios and years, ranging from 61% in 2020 to 79% in 2050 (A/S et al., 2024). In this section, the effect of this wide range of efficiencies on the economics of the hub assets is analysed. The 2x2GW hub configuration is considered for this analysis along with the 2009-2040 TYNDP scenario. Further, the results include the NPV and IRR for the electrical wind farm party, the electrolyser party and the combined party.

ESR Efficiency (%)	WFe Party NPV (M€)	WFe Party IRR (%)	Cable Util (%) [exp+imp]	ESR Party NPV (M€)	Comb. Party NPV (M€)	ESR Util (%)	Total Hub NPV (M€)
61	4229	11.67	64.54 + 6.92	-3267	-1152	41.46	3849
66	4241	11.48	57.99 + 7.20	-3087	-966	42.67	4619
70	4253	11.27	57.97 + 7.18	-2941	-814	43.76	5252
72	4253	11.21	44.84 + 20.88	-2840	-710	71.04	5665
74.5	4560	11.15	44.81 + 21.55	-2680	-702	72.03	6311
79	4582	11.06	44.29 + 22.18	-2389	-419	73.64	7490

Table 5.8: Impact of Electrolyser Efficiency on Hub Economics

Table 5.8 presents the impact of varying electrolyser efficiency on the economic performance of the 2×2 GW hub configuration. As efficiency increases from 61% to 79%, the NPV of the standalone electrolyser party improves considerably, from –€3.27 billion to –€2.39 billion, while its utilisation rises from 41.5% to 73.6%. This improvement in asset productivity directly contributes to better combined party economics, with NPV shifting from –€1.15 billion at 61% efficiency to –€419 million at 79%. a sharp jump in electrolyser utilisation occurs between 70% and 72% efficiency, driven by the same underlying dynamic seen in the previous section: a shift in value preference from electricity export to hydrogen production. In that case, the driver was rising hydrogen prices while here, it is higher conversion efficiency. In both cases, the outcome is a greater willingness to allocate offshore wind energy to hydrogen rather than electricity export.

Interestingly, while the combined party remains loss-making across the efficiency range, the steady upward trend suggests that higher electrolyser performance could bring it closer to viability. Total hub NPV increases from €3.85 billion to €7.49 billion over this range, indicating significant system-wide gains. This trend once again highlights the recurring dynamic of increased overplanting by the electrical wind farm to enhance electrolyser utilisation. This improves the economic performance of hydrogen assets but results in greater curtailment on the electrical side. Consequently, this reduces the reduces the NPV of the standalone wind farm party and leads to a slight deterioration in its relative profitability.

In summary, increasing electrolyser efficiency leads to higher utilisation, reduced losses, and enhanced overall hub value. While not sufficient alone to ensure profitability for hydrogen infrastructure, it clearly plays a critical role in narrowing the economic gap.

5.7. Clustered Tendering

Clustered tendering builds upon the ownership model introduced in the combined tendering configuration. Instead of dividing the hub into six separate parties, as has been the approach until now, the hub is split into four identical infrastructure groups. Each entity owns an electrolyser and associated wind farms on both sides of the converter station. This configuration is illustrated in Figure 5.14, where the blue box outlines the boundaries of a single party. In a standard 2×2 GW setup without overplanting, each party would thus own 500 MW of wind generation capacity on either side of the converter, along with a 500 MW electrolyser.

This configuration is explored to assess whether integrating wind and hydrogen assets within a single party, rather than separating them, provides a decent business case while still including electrolysis. In previous configurations, wind farm parties consistently achieved high IRRs and positive NPVs, while electrolyser parties struggled to achieve profitability. By combining these asset types into one ownership group, the goal is to examine whether internal cross-subsidisation can improve the financial viability of hydrogen production, while still preserving the strong returns from wind generation. Although NPVs can be estimated from prior results, the internal rate of return for such integrated entities requires fresh analysis, as it depends on the specific clustered arrangement.

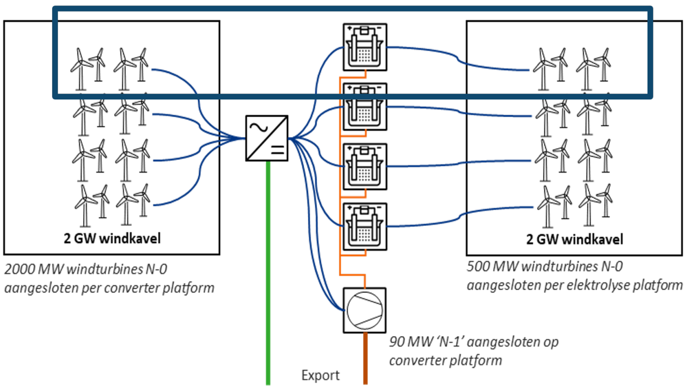


Figure 5.14: Combined Tendering in 2x2 GW Hub

The economic results for this configuration are mentioned below in Table 5.9. All values of NPV and IRR are for the combined party of wind farm + electrolyser + wind farm.

ESR Capacity (MW) [4 x ESR]	CAPEX (M€)	NPV (M€)	IRR (%)	Total Hub Wind Capacity (MW)	Total Hub NPV (M€)
180	1909	1880	5.51	3107	7519
500	3612	1313	2.43	4432	5252

Table 5.9: Economics of Clustered Tenders

These results suggest that clustering assets under a single party does improve the economic viability of hydrogen integration, particularly in the 4 × 180 MW electrolyser configuration, which yields an NPV of €1.88 billion and an IRR of 5.51%. This performance approaches the threshold of a viable business case, especially considering it balances investment across generation and conversion infrastructure.

In contrast, the 4 × 500 MW setup, despite having the same fundamental structure, suffers from overinvestment in electrolysis relative to hydrogen market revenues. The result is a significantly lower IRR of 2.43% and a modest NPV of €1.31 billion, reinforcing earlier findings that large-scale electrolysis remains economically constrained without further market or policy support.

While clustered ownership helps spread risk the IRRs remain below typical investor expectations. This indicates that further optimisation, whether through moderated electrolyser sizing, improved hydrogen pricing, or support mechanisms would still be necessary to make this configuration widely bankable.

5.8. 2 GW + 2 x 180 MW Configuration

Based off previously generated results, a new configuration can be envisioned containing two parties, each with a 180 MW electrolyser + 1 GW wind farm and 1 GW interconnection capacity. However, it can be alternatively arranged with all the infrastructure on "left side" of the converter with 180 MW capacity cables between the wind farm and electrolyser as well as the electrolyser and converter.

Metric	**Value**
Total Hub Optimal Capacity (MW)	2754
180 MW Esr + 1 GW WF CAPEX (M€)	2876
180 MW Esr + 1 GW WF NPV (M€)	4027
180 MW Esr + 1 GW WF IRR (%)	7.33
Offshore Cable Utilisation (%)	52.81
Electrolyser Utilisation (%)	43.86
Annual Electricity Trading Revenue (M€/year)	683
Annual Hydrogen Trading Revenue (M€/year)	63
Total Hub Net Present Value (M€)	8054

Table 5.10: Hub Economics for 2 x (1 GW + 180 MW) Configuration

This configuration demonstrates a notably strong business case for moderate-scale electrolysis when paired with a 1 GW wind farm. An IRR of 7.33% and NPV of €4.03 billion for each party marks a significant improvement over other electrolyser-inclusive setups explored earlier. Offshore cable utilisation (52.85%) and electrolyser utilisation (43.86%) indicate a well-balanced operational profile, while the capital expenditure remains manageable at €2.88 billion per party.

Compared to configurations with higher ESR capacities or split ownership models, this setup achieves better financial performance by aligning generation, conversion, and export infrastructure under a single entity at a scale that avoids overinvestment in hydrogen production. It suggests that smaller electrolysers, integrated with large-scale wind assets, may represent the optimal compromise between risk, efficiency, and profitability under current market conditions.

5.9. Final Remarks

The analysis highlights the intricate relationship between technical design decisions and market conditions in determining the viability of offshore hydrogen hubs. While standalone offshore wind farms consistently demonstrate robust financial performance, integrating electrolysis assets presents significant economic challenges due to high capital costs and limited utilisation under current market frameworks. Key infrastructure factors, such as interconnection capacity and electrolyser sizing, play a critical role in enhancing operational flexibility and asset utilisation, with smaller, modular electrolysers showing more promising economic outcomes compared to larger units.

Hybrid business models that unify ownership of wind generation and hydrogen production can improve overall financial sustainability by internalising value streams and mitigating market risks. Nonetheless, achieving commercial viability for electrolysis investments will likely depend on supportive policy measures aimed at reducing upfront costs and fostering hydrogen market development.

These findings offer a foundational understanding of the technical and economic trade-offs inherent in offshore hydrogen hub development. They provide a basis for the subsequent discussion chapter, which will delve deeper into strategic implications, optimisation opportunities, and policy considerations to accelerate the transition towards integrated offshore renewable energy systems.

6

Discussion

6.1. Results Overview

Several key insights emerge from the analysis. Most obviously, the standalone wind farm party consistently achieves a positive Net Present Value (NPV) and a acceptable Internal Rate of Return (IRR), in the range of 9 - 12% across configurations. Even under scenarios with elevated hydrogen prices, the IRR remains stable, indicating that the business case for standalone offshore wind remains robust and largely insensitive to other hub configuration changes.

In contrast, the electrolyser party generally experiences a negative NPV across most scenarios. However, smaller electrolyser capacities, here 180 MW, tend to perform better, with reduced investment costs limiting financial losses. The primary challenge for the electrolyser business case is the high CAPEX, which depresses profitability under current market and operational assumptions.

Increasing the interconnection capacity between converters and electrolysers improves the electrolyser party's NPV up to a point, beyond which the benefits plateau. This is primarily because both wind farms operate under identical conditions and generate similar output patterns. Once sufficient interconnection allows for basic balancing between the two sides of the hub, additional capacity provides little added value. Export opportunities are limited by the symmetry in generation, and import flexibility yields only marginal gains under typical conditions. As a result, beyond a certain threshold, more interconnection does not significantly influence dispatch decisions or overall profitability.

Importantly, high hydrogen prices alone are insufficient to ensure profitability for electrolysers. Hydrogen prices must remain significantly higher than electricity prices for extended periods to prioritise electrolyser operation.

However, once a certain price differential is exceeded, further increases in hydrogen price do not meaningfully affect electrolyser utilisation or overall hub behaviour.

Similarly, improvements in electrolyser efficiency by themselves do not significantly enhance business viability. This effect mirrors the impact of increasing hydrogen prices, as both factors influence the economic incentive to produce hydrogen rather than export electricity. This underscores the critical role of the relative value between hydrogen and electricity in determining operational priorities.

Clustered tendering, where wind and electrolysis are co-located within a single party, provides a more promising route. While the 4×500 MW electrolyser configuration yields a low IRR of 2.43%, the 4×180 MW configuration achieves a modestly positive NPV with an IRR of 5.5%.

A final configuration combining elements of successful cases - 2×(1 GW wind + 180 MW electrolysis)—achieves an IRR of over 7% with a total party investment cost of €2.8 billion. Although this IRR is still below that of standalone offshore wind, it demonstrates the potential for viable hybrid business models. The gap could be bridged with targeted policy instruments such as CAPEX-based subsidies or contracts for difference (CfDs), which would support early offshore electrolysis, improve competitiveness, and promote learning effects that drive cost reductions over time.

6.2. Technical Limitations

While models may suggest that certain ownership structures or capacity deployments are optimal, real-world constraints often restrict these theoretical solutions. For instance, the tendering process typically involves connection agreements that offer capacity access to specific infrastructure components: conditioning and transport elements for hydrogen such as compressors and pipelines, and converter platforms and offshore cables for electricity. Moreover, tenders issued to wind farm developers are geographically bound to defined offshore areas or 'wind plots'. These procedural elements place physical and temporal limits on what can be developed and when, thereby requiring local optimisation within predefined constraints.

There are also certain technical constraints that cannot be ignored. Current offshore cables and converters are capable of transporting only small amounts of electricity for enabling auxiliary functions offshore. However, allowing large amounts of bidirectional flow requires the modification of these infrastructure assets. These bring new technical and logistical challenges as well as increased costs, which must be weighed against the added economic benefit of allowing bidirectional flow.

All cables, both those linking hub components and the main offshore DC cable are modelled with fixed transmission capacities. In reality, these values are affected by cable length, ambient conditions, and seasonal changes, with higher temperatures in summer likely to reduce transmission capacity due to thermal limits. While these effects are less pronounced in subsea cables, incorporating dynamic cable performance based on environmental and spatial factors would improve the fidelity of the model, particularly for detailed layout studies.

While choosing the ideal electrolyser size as well, several other factors need to be considered beyond the mathematical optimum alone. While costs are assume to scale linearly with capacity for this project, such is not the case in reality. For example, different platform transportation methods are applicable for platforms supporting different electrolyser sizes. While the dual crane heavy lift vessels, less in complication and expense can be used for smaller electrolysers, float-over installation methods are required for larger electrolysers which are more expensive, require careful coordination and have significantly higher logistical challenges.

Electrolysers do not have a fixed conversion efficiency; rather, their efficiency varies dynamically with operational and environmental conditions. Additionally, they have operational constraints such as minimum baseload requirements and ramp-up/ramp-down times. Although the current model includes an optional constraint to enforce a minimum operational threshold, it has not been activated based on industry expert feedback indicating that offshore PEM electrolysers do not require a strict minimum operating load.

6.3. Grid Tariffs

Electrolysers are not generation assets in the traditional sense but rather power-to-gas conversion units, meaning they function as energy consumers. This distinction carries significant regulatory implications. As consumers, electrolysers may be subject to connection fees typically levied on demand assets. Such fees could negatively affect the economics of electrolysis, both onshore and offshore, further complicating its already challenging business case. However, there is still no clarity as to their exact nature when co-tendered with wind farms, which are indeed generation assets.

In parallel, there are discussions surrounding the introduction of generator charges, which, if implemented, could undermine the already diminishing investor confidence in offshore wind. It is also unclear as to the ramifications of such a tariff to P2X assets, co-tendered with wind or otherwise. The addition of such costs would further erode profitability, reducing the attractiveness of projects at a time when investment in renewable infrastructure is critical.

In the current modelling framework, a simplification is made to exclude such connection fees, generator charges, and other grid-related tariffs. While these are relatively straightforward to implement from a technical coding standpoint, their design and application remain uncertain at the policy level. Nevertheless, investigating multiple tariff structures within the model could provide useful insight into their impact on project economics and inform future regulatory discussions.

6.4. Public Ownership for Pilot Projects

Given the high capital intensity of offshore electrolysis and the significant uncertainties surrounding its deployment, there is a compelling argument for transmission system operators (TSOs), or consortia thereof, to initially own electrolyser platforms. This would allow pilot projects to be implemented without placing the financial burden on private developers who are typically driven by internal rate of return calculations. A publicly led initial phase could enable greater experimentation, uncovering technical and operational challenges, and accelerating the learning curve necessary to make offshore electrolysis commercially viable. Over time, this may help to de-risk the technology sufficiently to enable private sector participation.

Conversely, it is also reasonable to argue that public ownership of energy generation or conversion assets can result in reduced market efficiency and provide distored investment signals. This also goes against unbundling principles designed to prevent conflicts of interest and ensure non-discriminatory grid access. Additionally, private sector involvement from the outset has its own merits. The competitive dynamics of private developers often drive cost reductions, as evidenced by the rapid cost declines in wind and solar technologies. Private actors, incentivised to submit low bids to win tenders, may deliver cost efficiencies more quickly than public entities, which may lack comparable financial motivations.

6.5. Tendering Procedures

The roll-out of offshore hydrogen hubs is necessarily incremental. Current proposals envisage the initial construction of a 2 GW converter platform, followed by the deployment of wind farms and, subsequently, electrolyser units added one by one. This sequencing has economic implications. The first electrolyser will enjoy a temporary advantage due to greater and more frequent access to the offshore DC cable, which would otherwise be split between all installed electrolysers. As a result, earlier participants stand to benefit from enhanced access and profit until the installations of other participants, whereas each successive electrolyser will face marginally diminishing gains until this advantage is ultimately exhausted. It can be argued that this is a fair reward for those willing to assume the highest early-stage risks. Nevertheless, it is essential that all stakeholders have transparency over the full layout of the hub and the scheduled order of connections. This would enable informed decision-making and prevent misaligned expectations regarding returns.

With respect to the actual hubs analysed in this report, there is also the matter of priority access to the offshore DC cable. It has been established through the results that existence of interconnection between the converters and electrolysers, thus granting partial access to both wind farms to the electrolyser and the converter, is beneficial for all parties and results in overall higher profits. However, it is unclear as to how the cable capacity will be split between the different parties through connection agreements.

One setup may involve an equal split access to each of the two electrical wind farm parties with the leftover capacity accessible to the hydrogen wind farms, as has been considered in this study. In such a case, the electrical wind farms would have to estimate their peak generation for the next day and if this were to be in total lesser than the cable capacity, the remainder of the capacity would be allocated to the hydrogen wind farms parties. However, in the absence of an incentive for the electrical wind farms to accurately estimate capacities, it would lead to frequent overestimation on their part and therefore, result in inefficienct socio-economic outcomes. This may also bring with it a parallel issue, of priority access to the electrolysis infrastructure. Allocation of efficient transmission capacity is pivotal to a good business case for all parties in the hub, particularly the electrolyser-owning parties.

6.6. Profit Sharing

There is also an argument for profit sharing between the different ownership parties within offshore energy hubs. The results demonstrate that electrolyser assets enhance the business case for electrically connected, co-located wind farms. This synergy aligns with the necessity of system integration in the broader energy system discussed in the introduction and literature review, where sustainable alternative fuels like hydrogen and the production assets such as electrolysers are crucial for the practical and economically viable expansion of renewable generation assets like offshore wind.

Conversely, the business case for wind farms is currently under pressure, with major developers retreating from Europe and the North Sea region. Against this backdrop, proposals to allocate a portion of wind farm profits to electrolyser owners risk further discouraging investment in wind infrastructure. Such profit-sharing arrangements need to be carefully balanced to avoid undermining incentives for wind farm development while still recognising the value electrolysers bring to the overall system.

6.7. Data Availability

Perhaps the most critical limitation of this study lies in the availability of consistent, geographically and temporally aligned datasets for wind and energy prices. Although the model aligns wind and price data along the same hourly structure, the actual years from which these datasets originate do not match. While the electricity and hydrogen price series are drawn from the wind years 1995, 2008, and 2009, no corresponding wind data for the designated offshore project areas is publicly available for those specific years. Instead, the model uses an averaged wind profile compiled from the available wind data across the demarcated regions of the North Sea.

A more robust analysis could be achieved by testing the model on a wider dataset, especially with price series from alternative energy models featuring different trajectories for electricity and hydrogen prices. This would also help improve the reliability of the results.

The model also assumes the same wind and price profiles to repeat every year over a 30-year project lifetime. In practice, annual variations in both datasets would be expected, and while acquiring such high-resolution, long-term data remains challenging, its inclusion would substantially improve the realism and accuracy of the model.

6.8. Price Endogenisation

The current model relies on externally defined price series as fixed inputs, meaning it does not account for the dynamic feedback loops between supply, demand, and prices — a process known as price endogenisation. In a real-world market, the prices of electricity and hydrogen are influenced by the amount of energy produced and consumed. For example, if a hub consistently generates large volumes of electricity and hydrogen, this increased supply could suppress market prices, which in turn would affect the profitability and operational decisions of the hub's assets.

By not modelling this price feedback, the analysis may overestimate revenues in scenarios with high production or overlook potential market saturation effects. Furthermore, price endogenisation allows for the representation of strategic interactions among market participants, including how they respond to changing market conditions, investment signals, and regulatory policies. The absence of this feature limits the model's ability to capture equilibrium outcomes and the true value of flexibility and coordination between assets within the hub.

Incorporating price endogenisation would provide a more holistic and realistic understanding of how offshore hubs influence and are influenced by market dynamics, thereby improving the robustness of investment and operational decisions derived from the model.

6.9. Broader Socio-Political Context

Although current estimates suggest offshore electrolysis remains economically unviable, discussions often omit the strategic value of energy autonomy. The European energy crisis resulting from the Russia-Ukraine conflict demonstrated the high costs of dependency. In the absence of energy self-sufficiency, countries across Europe were exposed to volatile prices, prompting governments to commit billions of euros to shield households and industry from the effects of constrained supply. Hypothetically, had this capital been pre-emptively invested in the development of domestic energy systems, including offshore hydrogen production, the impact of such disruptions may have been significantly mitigated.

This principle extends to the broader issue of climate change. The direct costs of global warming are rarely included in energy project economics, yet they manifest persistently in the form of increasingly frequent natural disasters, rising sea levels, disrupted agricultural cycles, and biodiversity loss. In the long term, these consequences are not only economic but existential. As such, the economic case for offshore electrolysis may be understated if these wider costs are not incorporated into planning and investment frameworks.

6.10. System Integration

Achieving a fully renewable and carbon-neutral energy system hinges on effective system integration, as highlighted extensively in the literature review. Electrolysers, integrated within offshore energy hubs, play a crucial role in this transition by enabling the conversion of excess renewable electricity into green hydrogen. This facilitates sector coupling, linking power generation with industrial and transport sectors that are difficult to electrify directly.

Offshore energy hubs combining wind power and electrolysis present a promising pathway to enhance system flexibility and reliability. However, the high capital costs and technological uncertainties of offshore electrolysis remain significant barriers to widespread deployment. Despite these challenges, the urgency of decarbonisation means that system integration strategies involving hydrogen production must be pursued alongside direct electrification pathways.

Even among critics who favour direct electrification over hydrogen, there is broad recognition that some form of system integration is essential to balance supply and demand, manage variability, and maximise renewable energy utilisation. Therefore, while the exact role of hydrogen and offshore hubs is still evolving, the imperative to develop integrated solutions that link generation, storage, and end-use remains undeniable. The future energy system will likely require a combination of approaches, with system integration, whether via hydrogen, electrification, or both, at its core.

6.11. Stakeholder Perspectives

This study has important takeaways for offshore developers, transmission system operators (TSOs), policy makers, and the academic community.

For developers, the results reinforce the need for cautious investment into system-integrated offshore hubs, particularly where electrolysis is concerned. While the standalone business case for offshore wind remains robust across scenarios, the inclusion of electrolysers introduces new layers of financial uncertainty. Developers must be acutely aware of how electrolyser sizing, interconnection capacity, and sequencing of hub build-out affect returns. Early electrolyser entrants may enjoy temporary advantages due to preferential access to cable capacity, but subsequent entrants face diminishing marginal returns. This study also signals that co-tendering models with smaller electrolysers may yield a more favourable investment profile than configurations involving high-capacity electrolysis assets. A clear understanding of infrastructure access rights, both in terms of converter platforms and shared offshore cables, is essential for developers to make informed investment decisions.

For TSOs, the findings lend weight to the argument for public sector involvement, at least during early-stage deployment of offshore electrolysis. High capex requirements, uncertain returns, and the unproven nature of offshore hydrogen production point to the need for risk-mitigating measures that can be better accommodated under public ownership. Such an approach would enable pilot projects to be deployed without the burden of investor-grade returns, allowing for greater technical experimentation and a smoother learning curve. Furthermore, as neutral entities responsible for grid planning and system integration, TSOs are well-positioned to coordinate shared infrastructure, including converter platforms, cables, and potential interconnection points. This role becomes especially relevant given the modelling insight that interconnection between wind farms and electrolysers can improve system-wide economics and utilisation rates.

For the North Sea Wind Power Hub programme, this study is a step in the right direction by modelling system-integrated, radially connected offshore energy hubs that can serve as a foundation for extending the analysis to full hub-and-spoke configurations. In order to represent the latter, the model would need to incorporate interconnectors to other hubs or countries, thus exposing the hub to different demand and price profiles from multiple bidding zones. This would also require capacity within the hub to be reserved for cross-border electricity flows. Under such a configuration, the now-optimised variables could be expected to rearrange themselves significantly, potentially even favouring underplanting of wind farms to make way for transit flows. In such a case, it would also become necessary to compare a home-market model against an offshore bidding zone arrangement to identify the most effective regulatory and market setup. As such, while the insights derived from radially connected configurations provide valuable inputs, they may differ under a meshed or hub-and-spoke topology where exposure to cross-border trade and demand-side variation plays a more prominent role in asset behaviour and optimisation outcomes.

For policy makers, several threads emerge from the analysis. First, the current lack of clarity surrounding grid tariffs—particularly connection fees and generator charges—poses a risk to investor confidence in both hydrogen and offshore wind. Explicit and consistent regulatory treatment for power-to-gas assets, especially those co-tendered with wind farms, is necessary to reduce uncertainty and enable long-term planning. Second, given the current negative business case for electrolysis, the study highlights the importance of support mechanisms such as capital expenditure subsidies or contracts for difference. Such instruments would not only enable a more equitable comparison between integrated and non-integrated assets but also accelerate technology adoption by improving the economics of offshore hydrogen production. Lastly, the discussion around energy security and climate resilience underscores the broader strategic role of offshore hydrogen infrastructure. The recent energy crisis has demonstrated that long-term energy autonomy is not merely a technical or economic issue but one of national resilience, and investment planning should reflect this reality.

From the perspective of the academic community, this thesis acknowledges the importance of renewable fuels in the future energy system and presents economically viable solutions for integrated offshore electrolysis. It is a novel contribution that pioneers the mathematical modelling and optimisation of system-integrated offshore energy hubs, offering a distinct alternative to existing system-scale and techno-economic analyses. The scenario-based, modular modelling framework allows for the exploration of multiple configurations under uncertain market conditions, highlighting the interplay between asset sizing, infrastructure interconnection, ownership structures, and energy pricing. While the model remains a stylised abstraction of real-world systems, it serves as a critical first step in the academic exploration of such integrated hubs. It scratches the surface of a broader mathematical and economic analysis needed for the planning and implementation of these concept hubs, especially in shaping early decisions related to critical infrastructure such as converters and cables. Future research could build on this foundation to incorporate added layers of complexity such as endogenised prices, dynamic environmental constraints, and long-term climate-related costs, thereby enhancing the model's applicability to real-world decision-making.

7 Conclusion

The main research question posed in Section 1.3 sought to identify the optimal system-integrated offshore energy hub configuration using a value maximisation approach, particularly given a wide range of potential future energy scenarios. This question comprised four core elements. The first one involves the definition of different configurations of offshore energy hubs. This is followed by an identification of critical configurational variables that influence the economic viability of an offshore energy hub. The third sub-question has to do with the variation in performance of different hub configurations. Finally, the end goal of this exercise is the determination of the most profitable hub configuration, of course within the confines of available data.

The analysis began by establishing what constitutes a configuration of an offshore energy hub within the context of this study. These were defined as varying combinations of wind capacity, electrolyser quantity and size, interconnection capacity between the converter and electrolyser, ownership structures, and the spatial arrangement of components within the hub. Converter and cable capacity were considered to be fixed given industry standards. Based on literature, offshore electrolysis rather than onshore is the chosen method of electrolysis due to its lower cost and PEM is the chosen technology for this application. In line with the first sub-question, this classification laid the foundation for modelling different hub layouts.

The second sub-question was addressed by exploring which configuration variables had the most significant impact on the economic outcomes of the hub. Through scenario-based modelling, it was found that electrolyser size and quantity, in particular, were decisive in shaping profitability. This is largely attributable to the relatively high capital costs associated with electrolysers, which significantly increase their weighting in the overall economic assessment. It was observed that not only layout, but also component ownership structures had a measurable impact on economic value as large wind farms, if co-owned with smaller electrolysers were observed to make up for the latter's poor business case while facilitating system integration.

In response to the third sub-question, the study compared how different configurations performed under variable conditions. These hub configurations were mathematically defined by varying the identified factors - electrolysis capacity, hub interconnectione and ownership structures. The model optimised for installed wind capacity given these constraints for each iteration, and the corresponding NPV for the hub as well as its individual components was calculated. Small amounts of overplanting were observed across almost all configurations surveyed. On the whole, configurations with lesser amount of electrolysis in general were found to have higher profitability.

On surveying the profit breakdown between individual parties, the robustness of the business case for the electrical wind farm is apparent, reflected by a stable internal rate of return across different hub configurations and energy scenarios. The profitability of the electrolyser + integrated wind farm however, is greatly dependent upon hydrogen prices and especially on the positive difference between hydrogen prices and electricity prices. The negative business case of electrolysers can be mitigated to a certain extent by firstly, reducing the electrolysis installed capacity of the hub and secondly, by co-tendering electrolysers with large enough wind farms.

With respect to the final sub-question, the analysis concluded that among all configurations, the layout with a lesser amount of low capacity electrolysers layout with significant overplanting of wind farms compared to the cable capacity emerged as the most economically attractive solution.

In the context of the North Sea Wind Power Hub, this configuration would be the 2 x (1 GW + 180 MW) layout. In this layout, apart from the converter and cable, there are in total two 180 MW electrolysers and a cumulative wind installed capacity of 2385 MW. These assets are equally divided between and owned by two separate parties, each with access to 1 GW capacity of the offshore cable. They make identical profit with an internal rate of return of 7.9% and a net present value of € 1.38 billion. This configuration offers a viable entry point for offshore electrolysis, due to its comparatively lower capital expenditure and higher internal rate of return than alternative system-integrated configurations.

This study demonstrates that while standalone offshore wind remains economically viable, the integration of electrolysis into offshore energy hubs introduces substantial complexity and financial risk, primarily due to high capital costs and uncertain market conditions. Nonetheless, system integration, whether through hydrogen, electrification, or both, is essential to achieving a renewable and resilient energy system. Smaller, co-tendered electrolyser configurations show modest potential, especially when supported by targeted policy instruments such as CAPEX subsidies or contracts for difference. The findings also highlight the importance of clear regulatory frameworks, particularly regarding grid tariffs and infrastructure access, as well as the potential role of public ownership in de-risking early projects. Ultimately, integrated offshore hubs can deliver greater system value through flexibility and sector coupling, but their success will depend on thoughtful coordination between stakeholders, supportive policy, and continued research into optimal configurations under real-world constraints.

Ultimately, this thesis provides a robust framework for evaluating offshore energy hub configurations under uncertainty, combining technical modelling with economic optimisation to support evidence based decision making. By bridging the gap between engineering feasibility and financial viability, the research illustrates that strategic design and ownership decisions, especially around electrolysis, can unlock greater system value and foster more resilient energy infrastructures. The findings serve as a timely contribution to the discourse on Europe's offshore renewable future, emphasising the need for iterative deployment strategies, stakeholder alignment, and targeted policy interventions. As offshore energy systems evolve, such integrated assessments will be indispensable in effectively steering investments toward sustainable, scalable, and system-beneficial solutions.

8

Future Work

While this study presents a foundational exploration into system-integrated offshore energy hubs, it is important to acknowledge that it is by no means exhaustive. The modelling framework developed here, though robust in many respects, inevitably contains simplifications and assumptions that warrant further scrutiny. Readers are encouraged to critically examine the logical consistency of the approach as well as the model setup itself and highlight areas where refinements or alternative formulations may yield better insights. This invitation to constructive criticism and further research is made in the spirit of collaborative progress, recognising that meaningful innovation in this field will require iterative, multi-disciplinary efforts. Several avenues remain open for future research and model refinement. These directions span both technical and policy dimensions, each with the potential to enhance the accuracy, realism, and applicability of the model outcomes.

First, dynamic cable performance should be incorporated into future modelling iterations. The current framework uses fixed transmission capacities, which simplifies the model but omits the real-world variability introduced by factors such as ambient temperature, cable length, and seasonal fluctuations. Furthermore, there are losses to be considered while transporting electricity through these cables as well which are required to be taken into consideration. Modelling cable capacity as a function of these parameters would allow for more granular insights, particularly in relation to operational constraints and infrastructure planning.

Second, the treatment of electrolyser capital costs warrants further refinement. Presently, costs are assumed to scale linearly with capacity; however, real-world deployment reveals significant non-linearities due to logistical and installation complexities. Larger electrolysers often require float-over installations and involve higher coordination efforts, both of which introduce diseconomies of scale. Incorporating non-linear cost functions that reflect these practical considerations would yield a more accurate representation of investment dynamics.

Additionally, the model currently applies a flat percentage for electrolyser efficiency, but in practice, efficiency is influenced by operational and environmental conditions, such as ambient temperature and load factor. Furthermore, technical limitations related to ramping up and down of electrolyser stacks, particularly at large scale, can constrain their flexibility and responsiveness, which should also be accounted for to improve the model's realism.

Another important extension involves the inclusion of grid-related tariffs, specifically, connection fees, generator charges, and other potential levies that may be applicable to both generation and consumption assets. While these elements are currently excluded due to policy-level uncertainties, their impact on project economics is likely to be substantial. Modelling multiple tariff structures could offer valuable insights into how various regulatory designs influence asset profitability and investment viability.

A fundamental modelling advancement would be the integration of endogenous price mechanisms. In its current form, the model relies on exogenous energy price series that do not respond to system-level supply and demand dynamics. Introducing endogenous feedback loops would enable simulation of price impacts resulting from hub activity itself, especially relevant for high-capacity systems that may influence market prices through large-scale production.

From a structural perspective, a transition from the radially connected hub model to a hub-and-spoke configuration is a natural next step. This would involve modelling cross-border interconnectors and integrating offshore bidding zones, thus exposing the system to multiple demand profiles and regulatory jurisdictions. Such a setup would not only diversify the economic environment in which the hub operates but may also alter optimisation outcomes significantly—potentially shifting the balance in favour of underplanting to prioritise transit flows. Comparing different market arrangements, such as home-market participation versus offshore bidding zones, would provide crucial insights into optimal regulatory design.

Additionally, further investigation into public ownership models is warranted, particularly for early-stage offshore electrolysis deployments. The high capital intensity and uncertain returns associated with these projects suggest a potential role for transmission system operators (TSOs) or public consortia in de-risking initial investments. Future models could simulate scenarios under different ownership structures to assess their impact on build-out strategies, risk allocation, and system efficiency.

Tendering procedures and sequencing effects also merit closer examination. As identified in this study, the order in which infrastructure components, particularly electrolysers, are deployed has material consequences on asset utilisation and profitability. Developing a modelling layer that explores alternative tendering strategies and connection schedules could enable a more equitable and efficient rollout of integrated offshore hubs.

On the data front, substantial improvements can be made through the use of geographically and temporally aligned datasets. The current model aligns wind and price data at the hourly level, but discrepancies remain in the origin years of these datasets. Employing harmonised datasets across time and location would enhance model fidelity. Furthermore, rather than repeating the same annual profile over a 30-year horizon, incorporating long-term inter-annual variability would provide a more robust picture of asset performance under real-world uncertainty.

Policy instruments to support electrolysis should also be further explored. While this study touches upon capital expenditure subsidies and contracts for difference (CfDs), future work could simulate the effects of varying subsidy structures and levels on asset viability. Understanding the interplay between support mechanisms and hub configuration could guide more effective policy design for accelerating the uptake of offshore hydrogen production.

Lastly, there is scope to deepen stakeholder analysis, particularly in the context of coordinating shared offshore infrastructure. As this study highlights, interconnection between wind farms and electrolysers yields systemic benefits, but realising these benefits requires clearly defined access rights and coordination frameworks. Future research could explore governance models and incentive structures that facilitate cooperation among multiple asset owners, especially in increasingly complex multi-party hub arrangements.

Collectively, these areas of future work offer a path toward a more comprehensive, realistic, and policy-relevant modelling framework. They not only build on the limitations identified in this study but also respond to the emerging technical, economic, and regulatory challenges that will shape the future of offshore energy hubs in Europe and beyond.

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A

Appendix A

Below in figure A.1, are the different areas in the North Sea for which wind data is available in the NSWPH database.

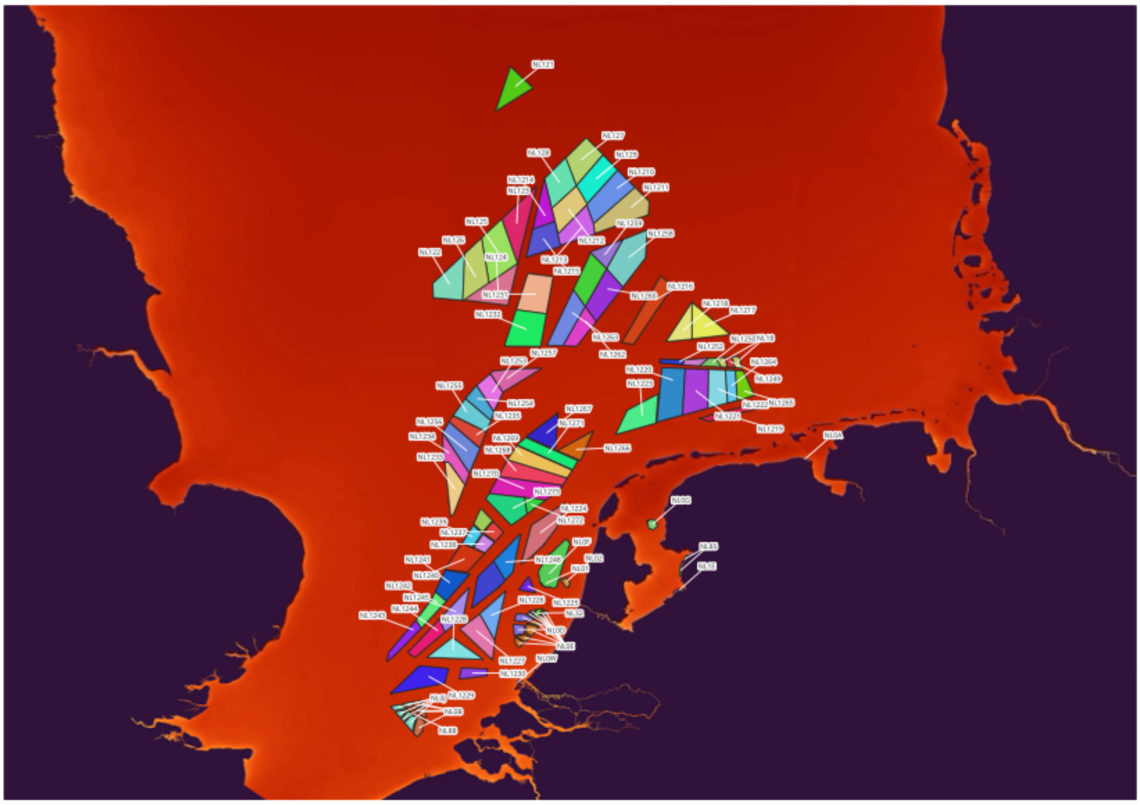

Figure A.1: Subdivisions of NSWPH Wind Areas

Areas 6 and 7, which are relevant for this project can be seen to the left of and in line with the rectangular orange block to thr right centre of the image. These can be corroborated with figure 4.2. The chosen wind area with average values for wind output - NL1264 is the purple area immediately to the left of the orange area previously mentioned. The wind profile for area NL1264 is shown in A.2.

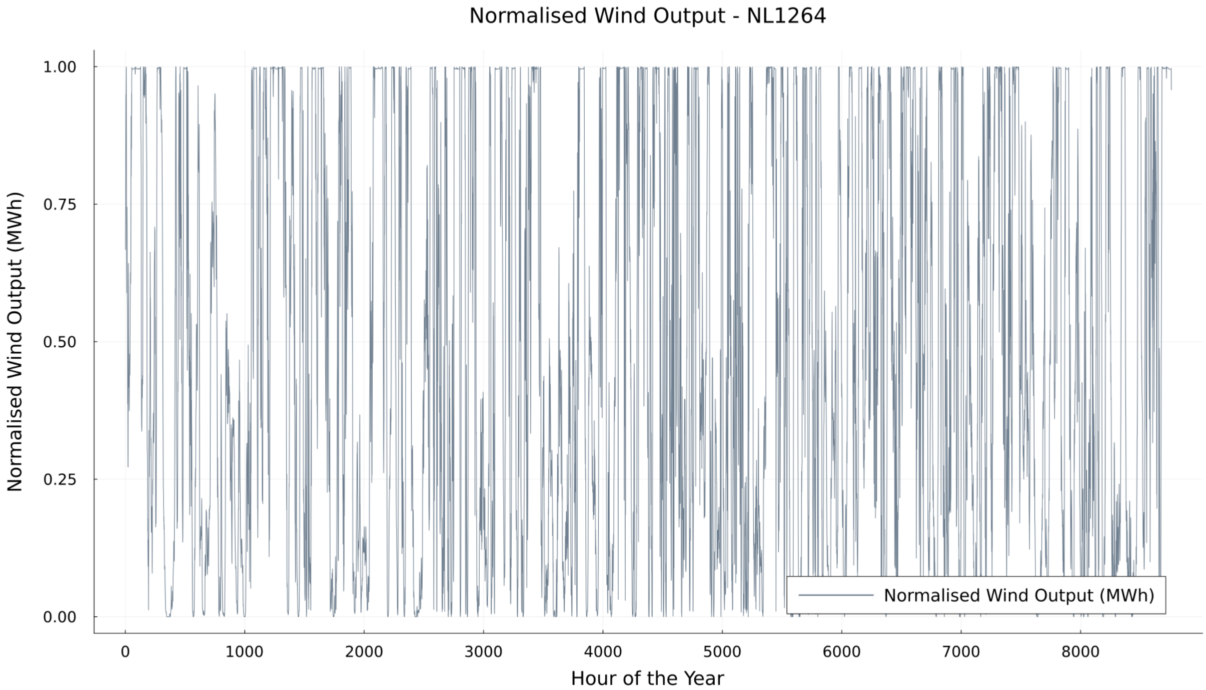

Figure A.2: Normalised Wind Output for Wind Area NL 1264

B

Miscellaneous Results

B.1. Scenario 1995-2030

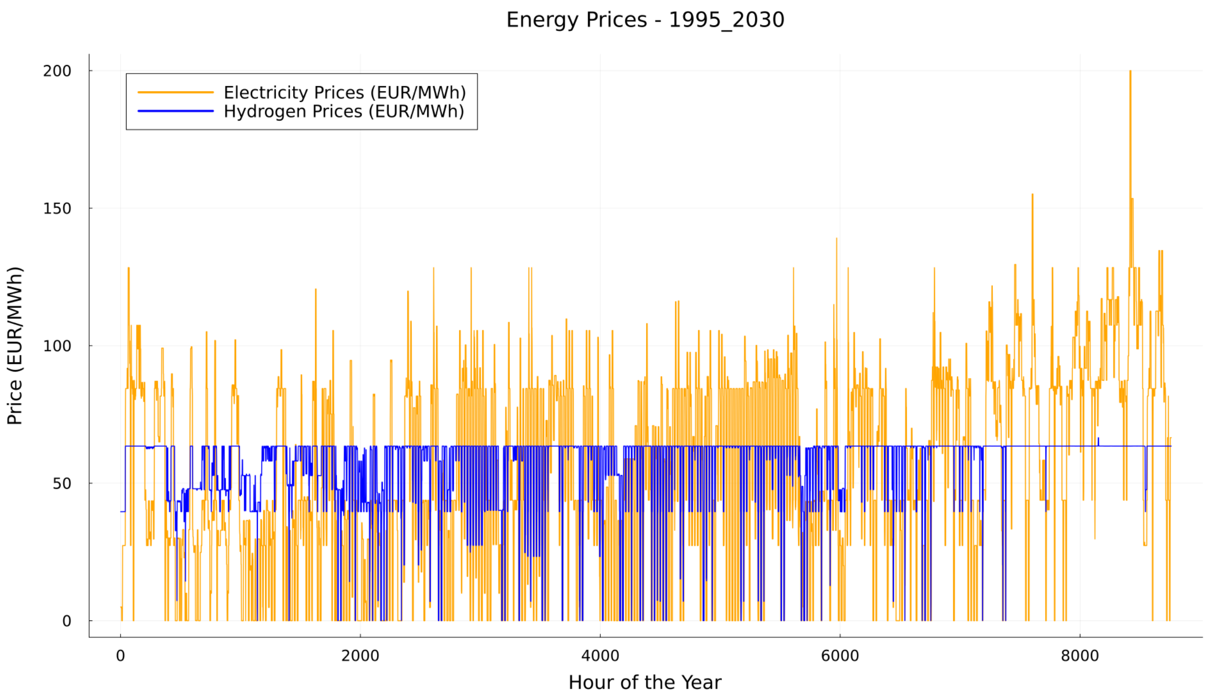

Figure B.1: Energy Prices - 1995_2030

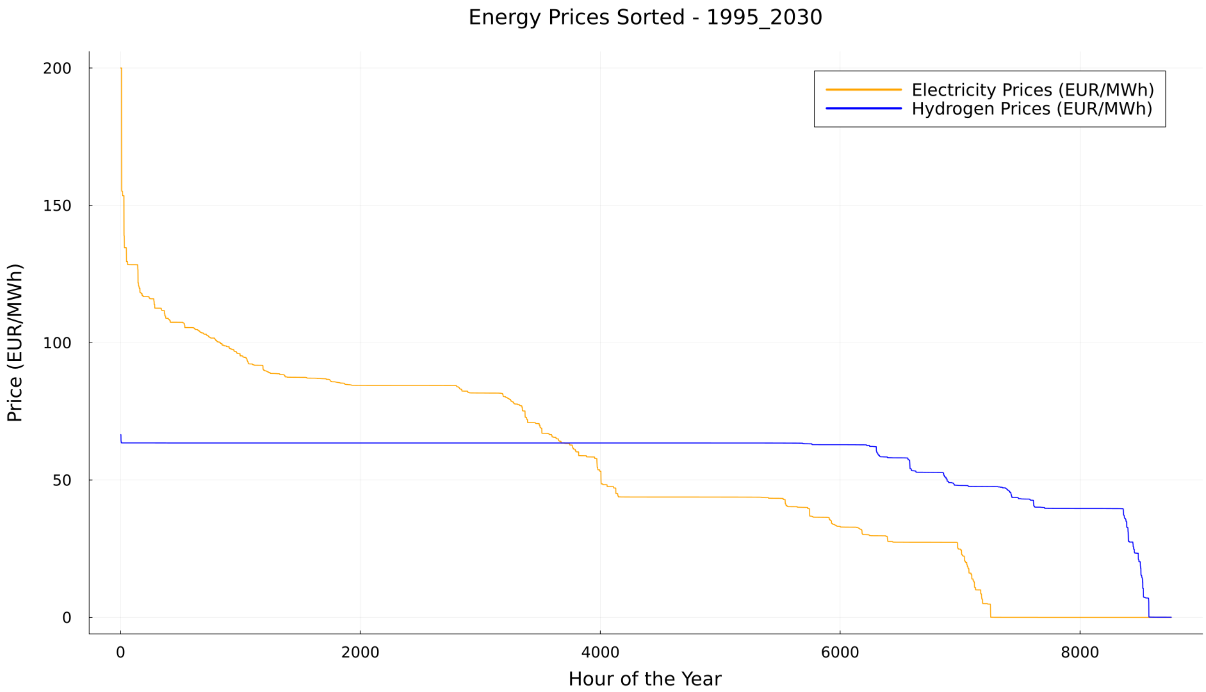

Figure B.2: Energy Price Duration Curve - 1995_2030

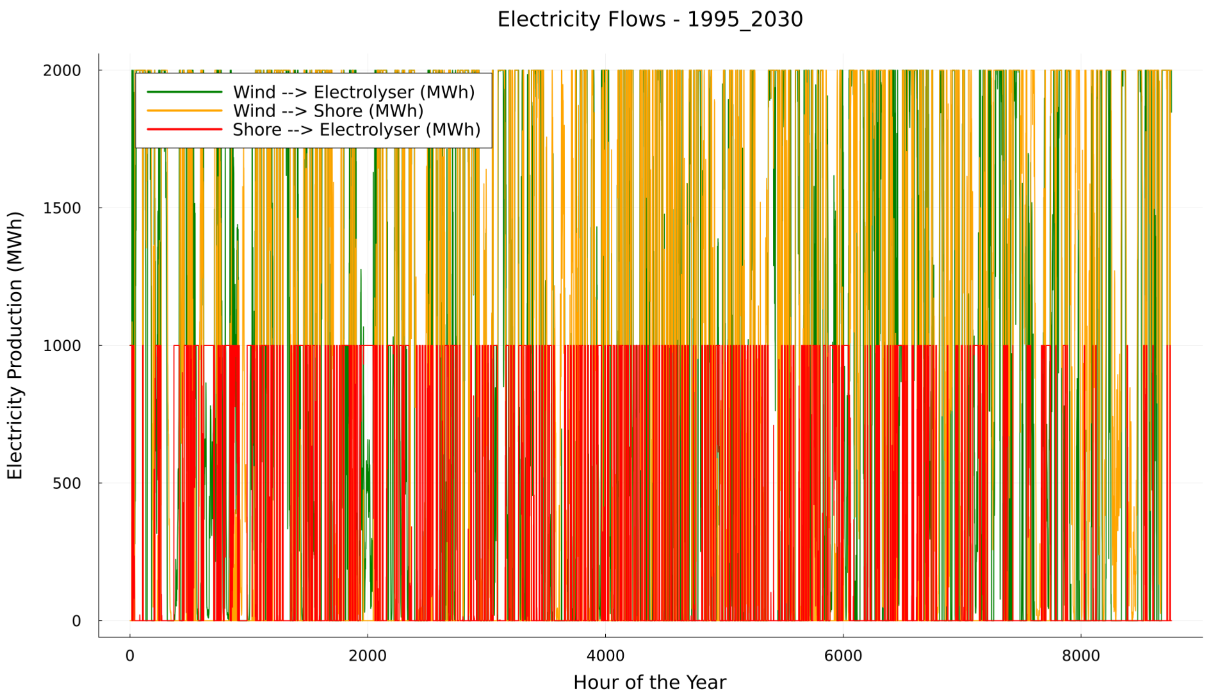

Figure B.3: Electricity Flows - 1995_2030

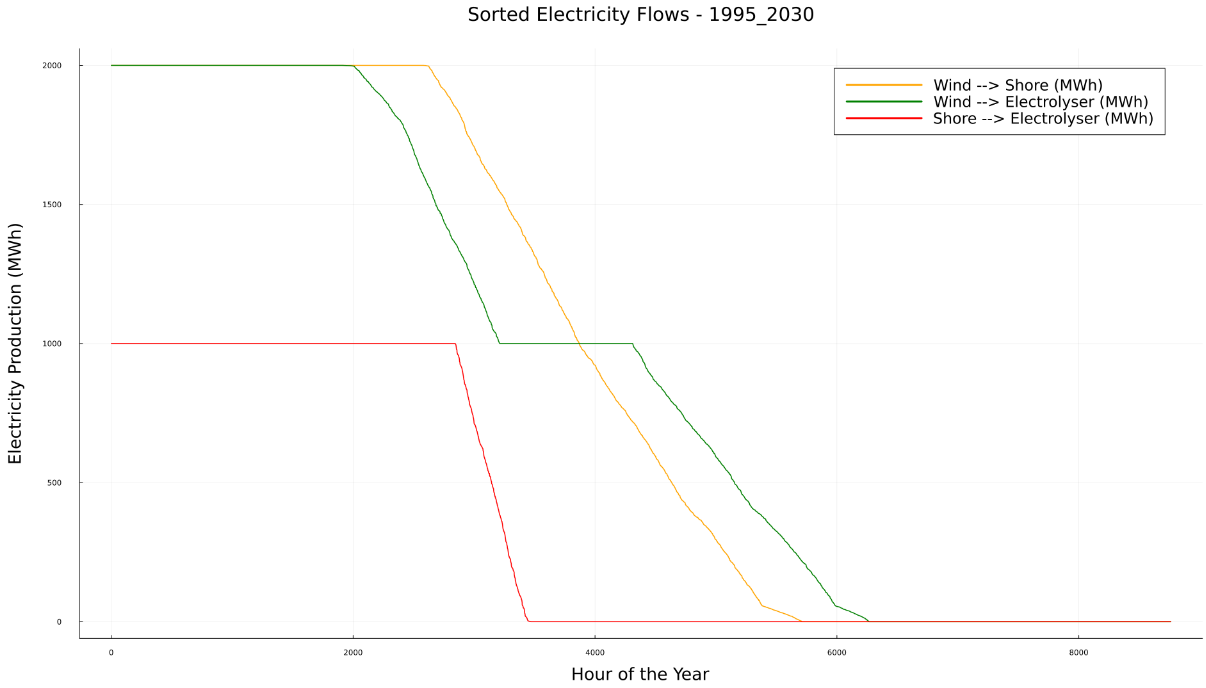

Figure B.4: Electricity Flows Sorted - 1995_2030

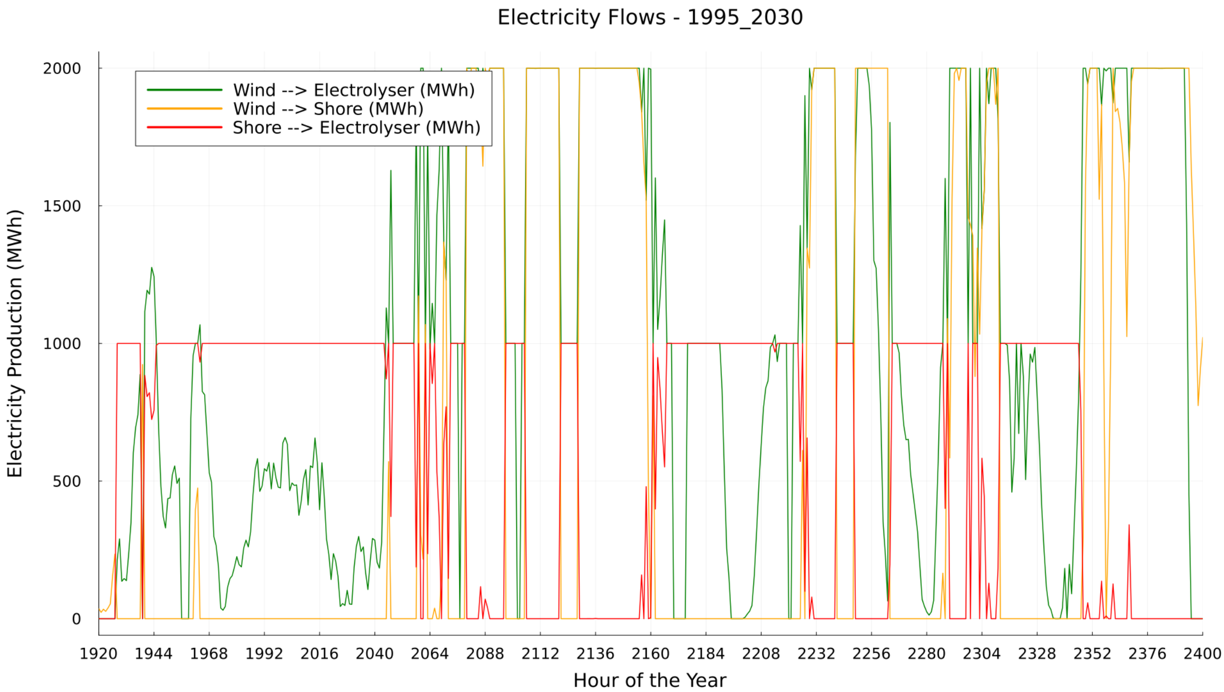

Figure B.5: Electricity Flows Zoomed - 1995_2030

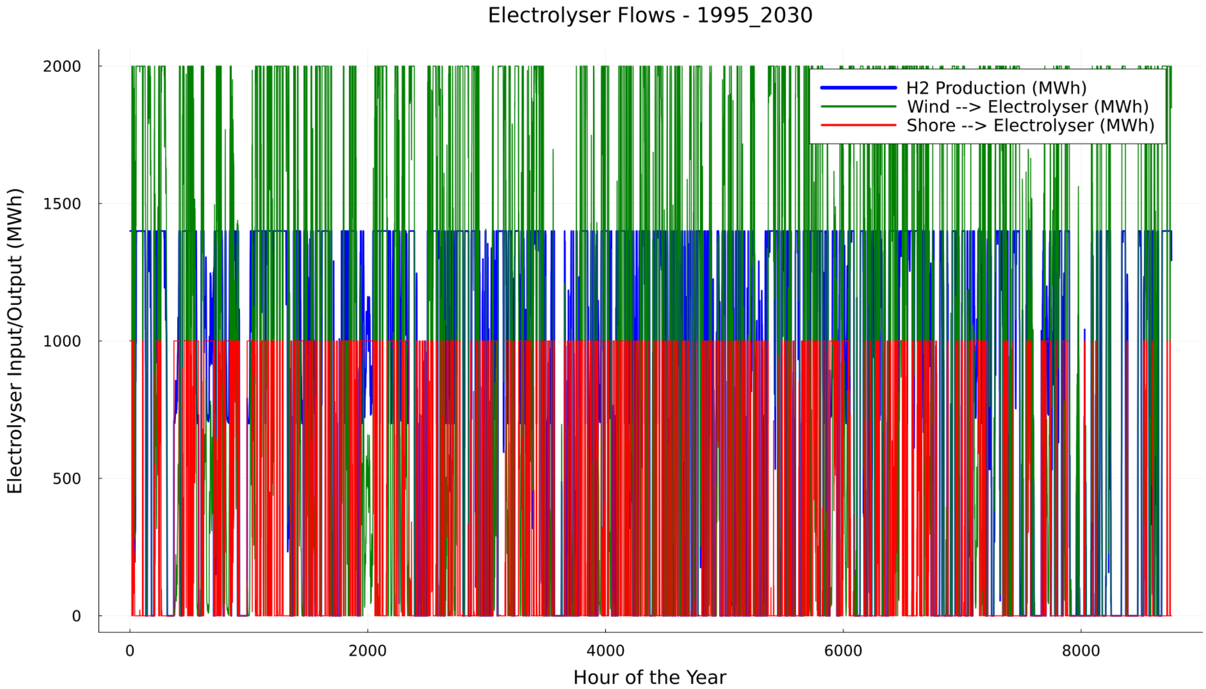

Figure B.6: Hydrogen Flows - 1995_2030

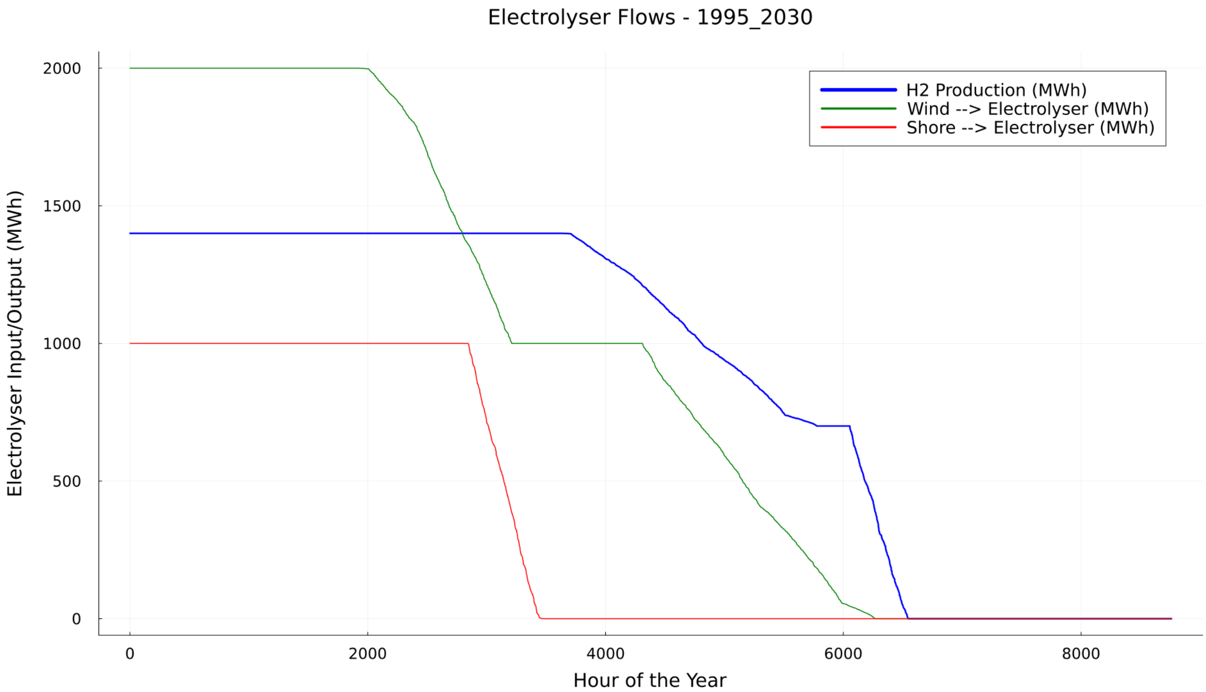

Figure B.7: Hydrogen Flows Sorted - 1995_2030

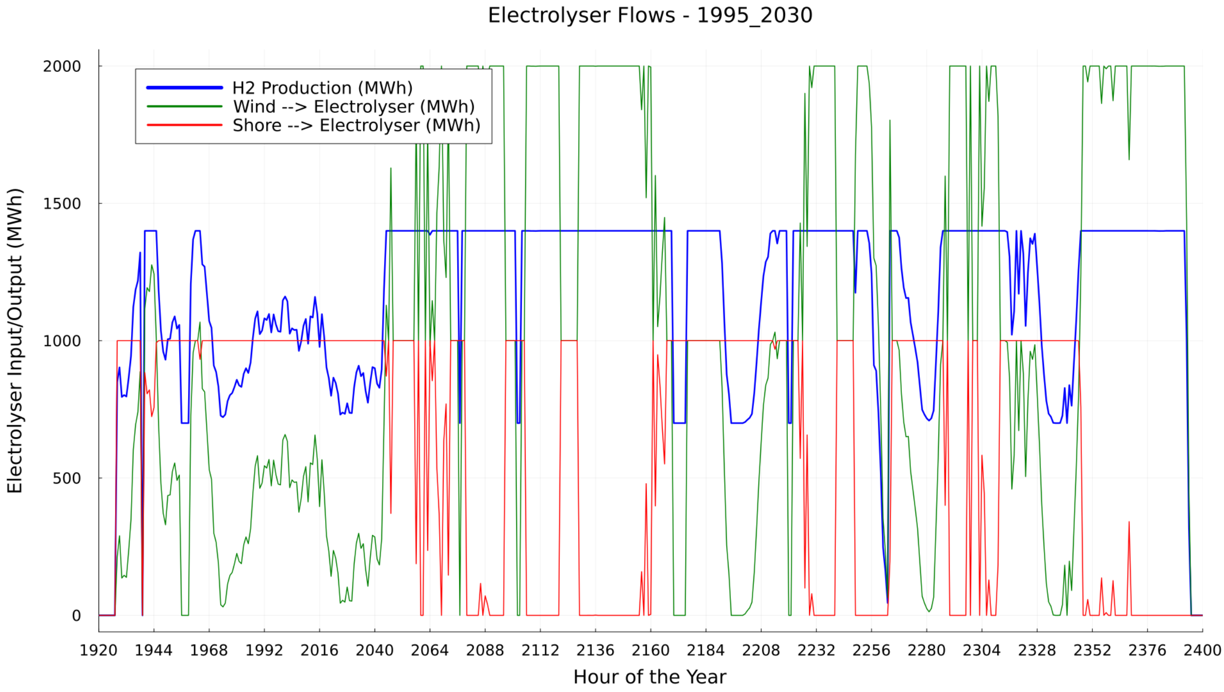

Figure B.8: Hydrogen Flows Zoomed - 1995_2030

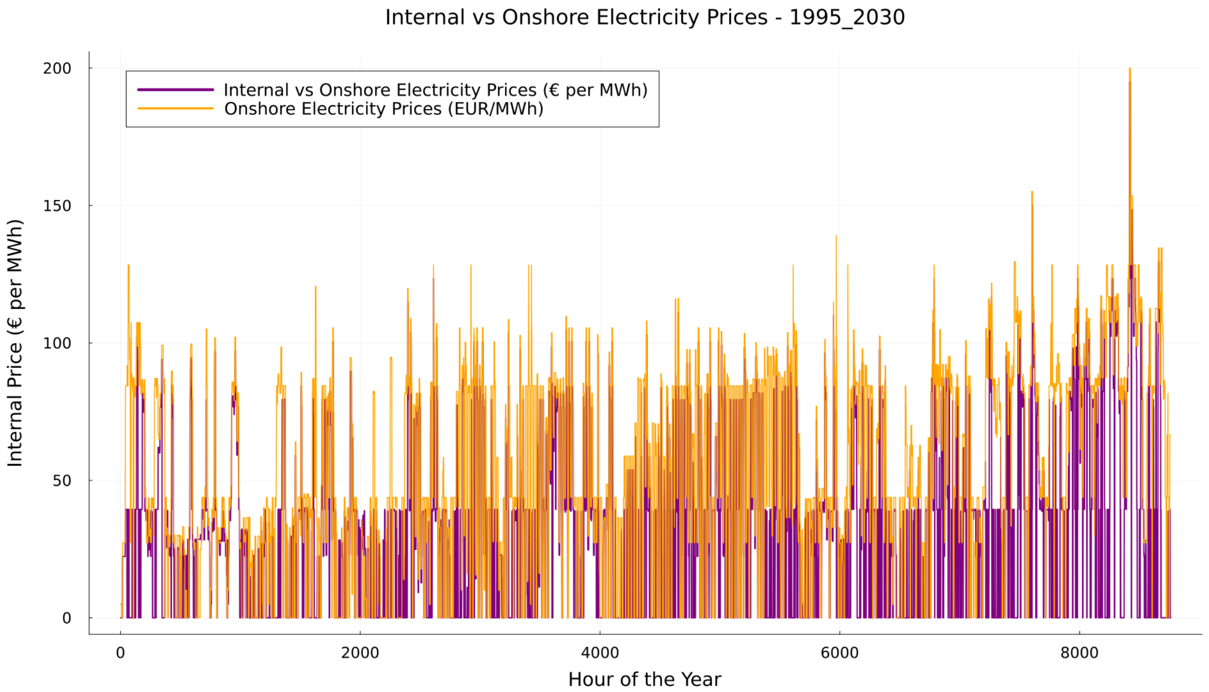

Figure B.9: Onshore vs Internal Prices - 1995_2030

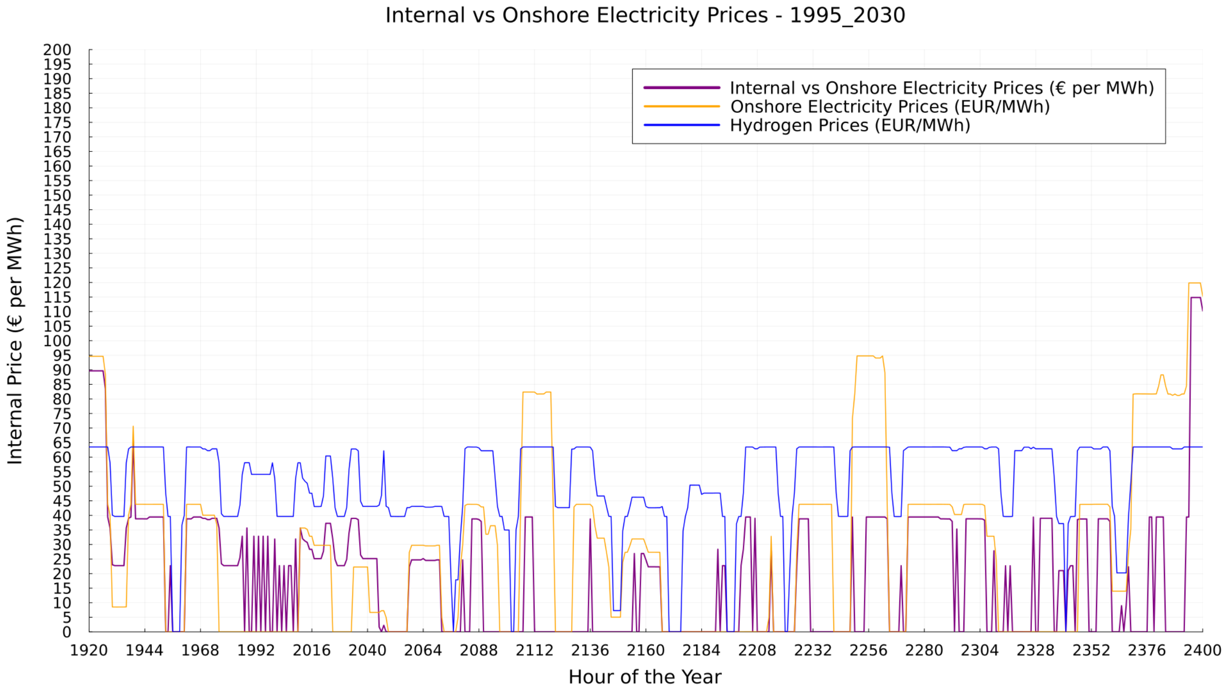

Figure B.10: Internal Prices Zoomed - 1995_2030

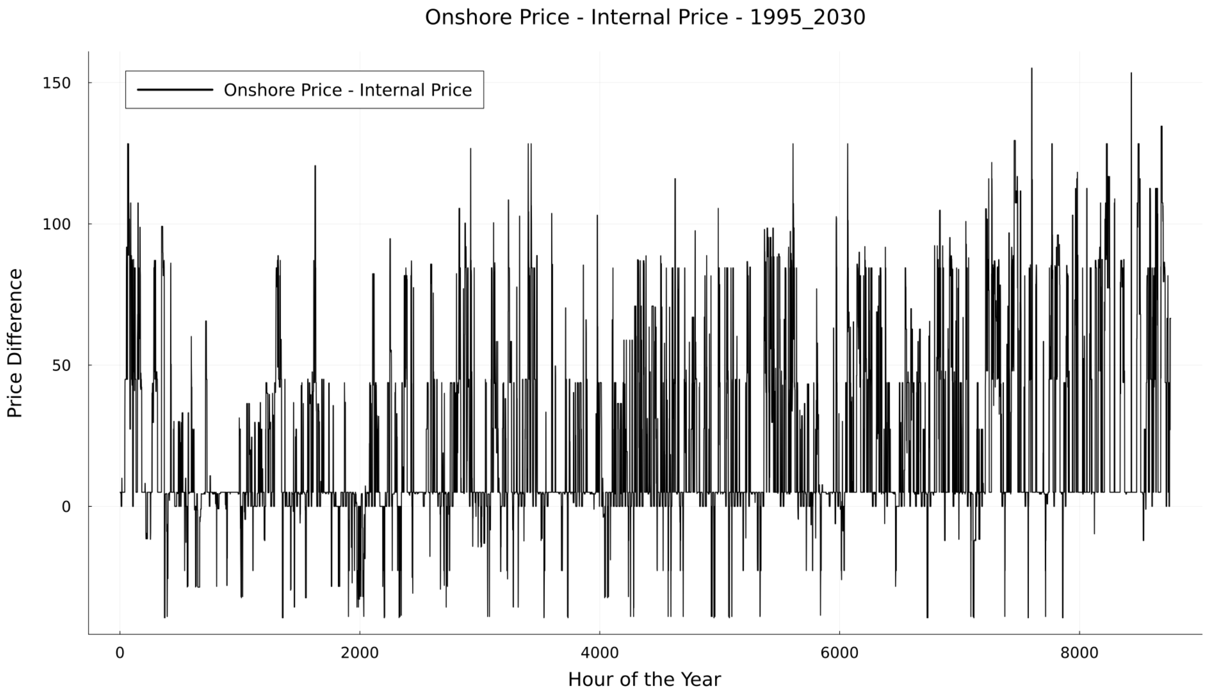

Figure B.11: Onshore - Internal Prices - 1995_2030

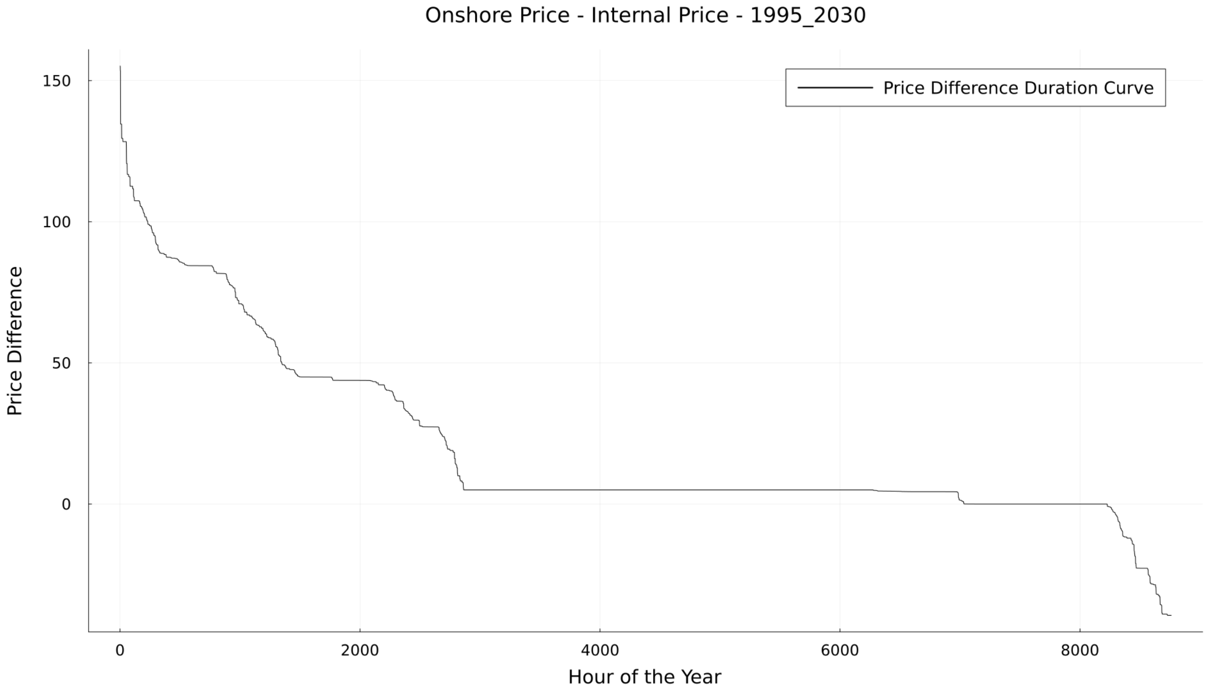

Figure B.12: Onshore - Internal Prices Sorted - 1995_2030

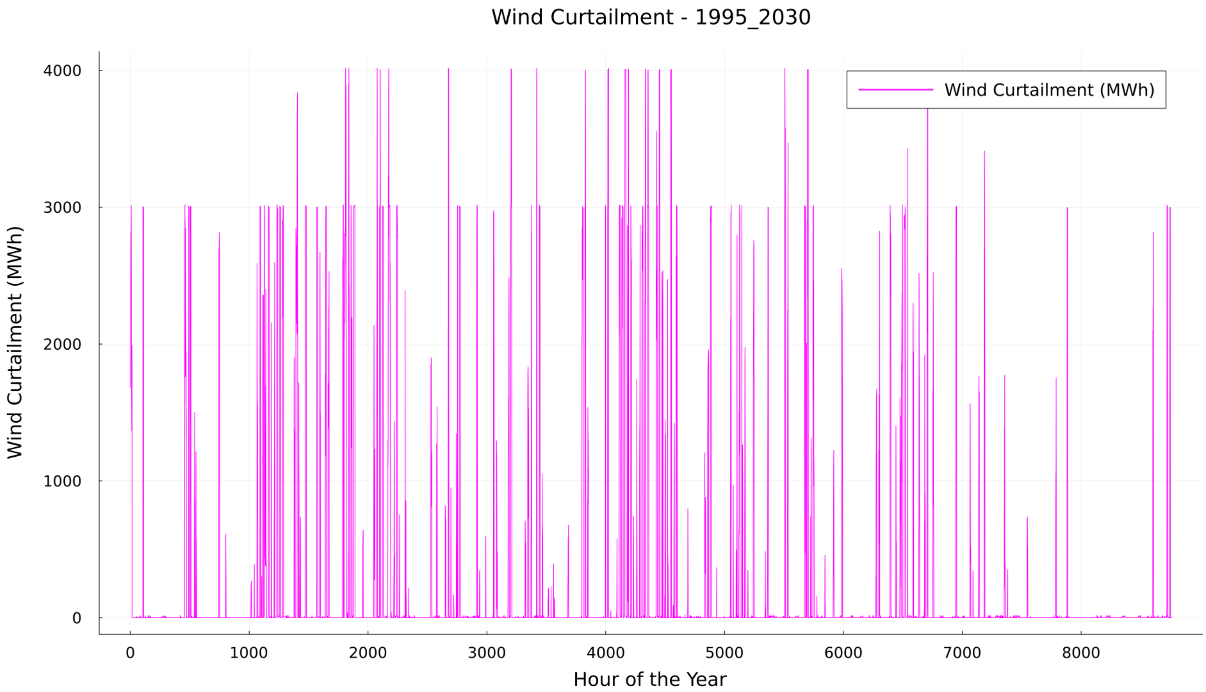

Figure B.13: Wind Curtailment - 1995_2030

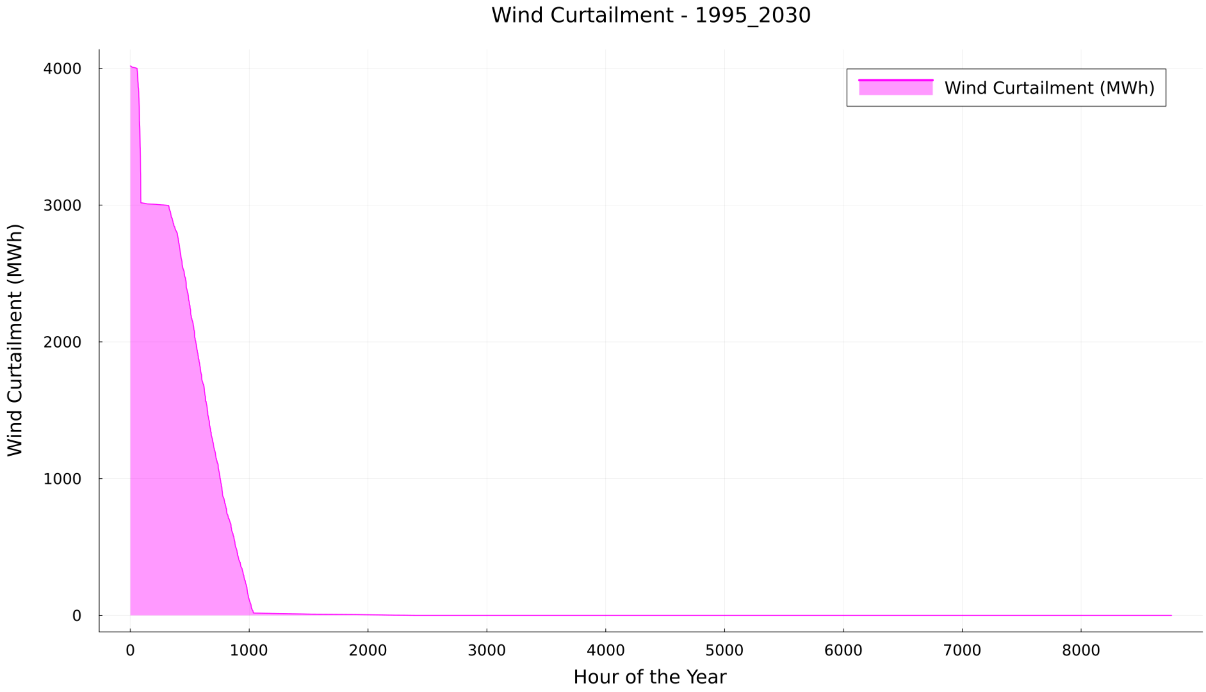

Figure B.14: Wind Curtailment Duration Curve - 1995_2030

B.2. Scenario 1995-2040

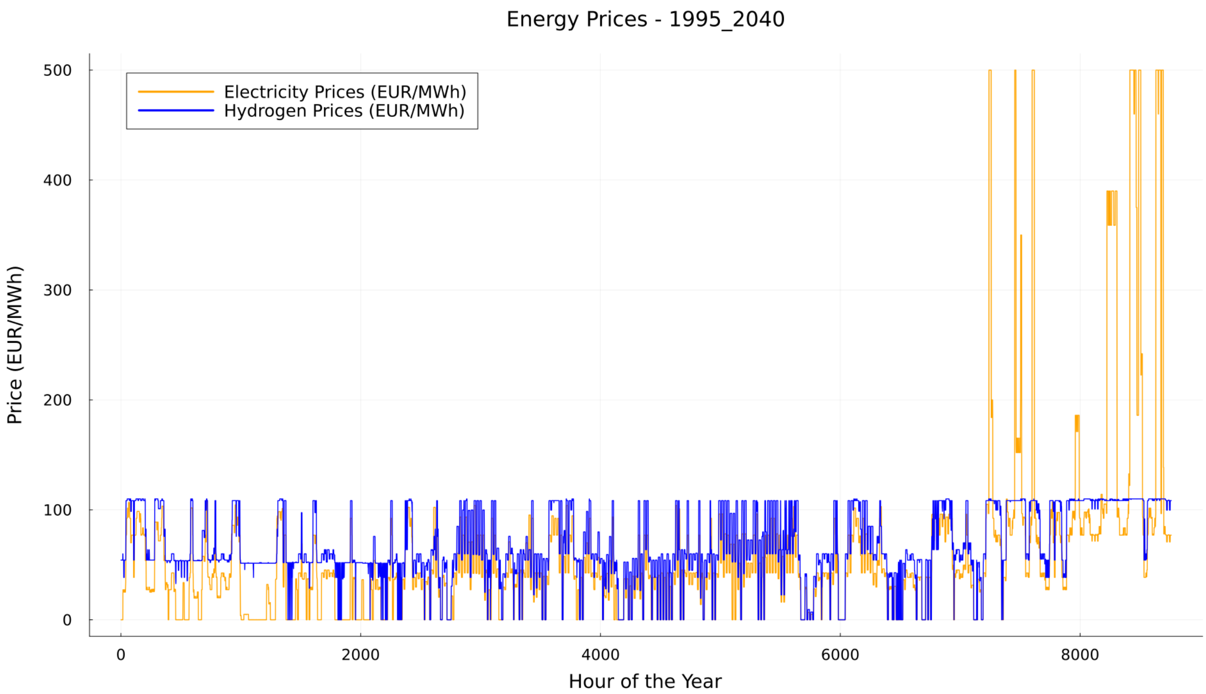

Figure B.15: Energy Prices - 1995_2040

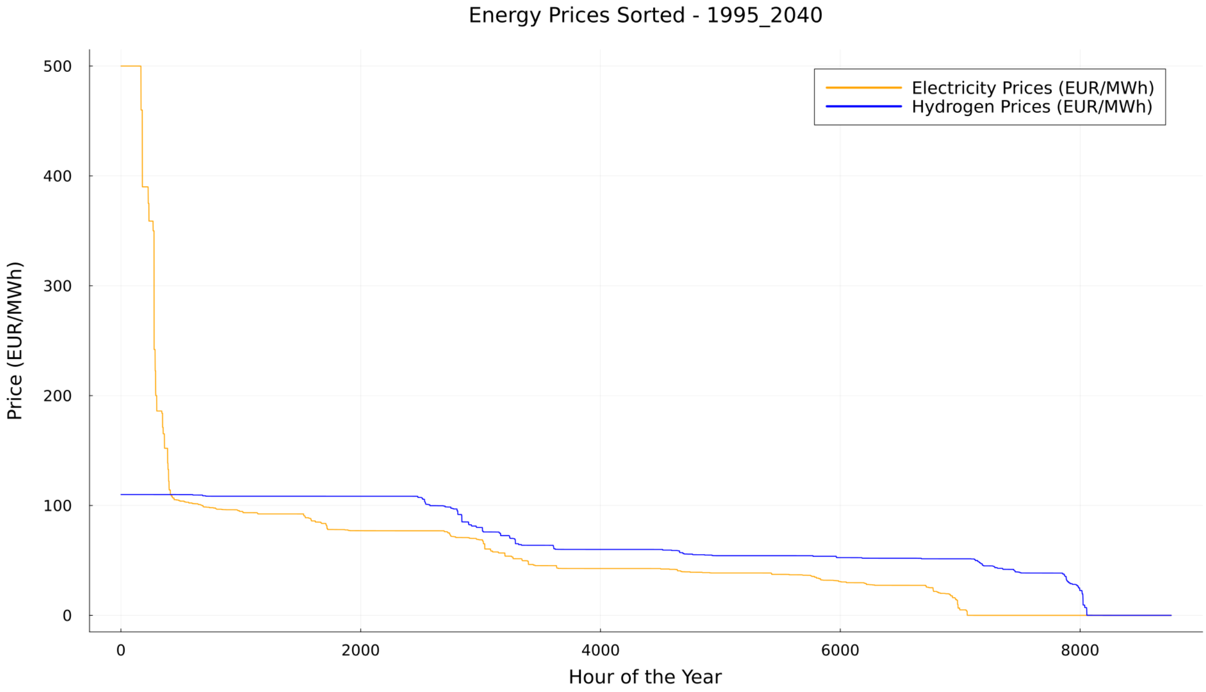

Figure B.16: Energy Price Duration Curve - 1995_2040

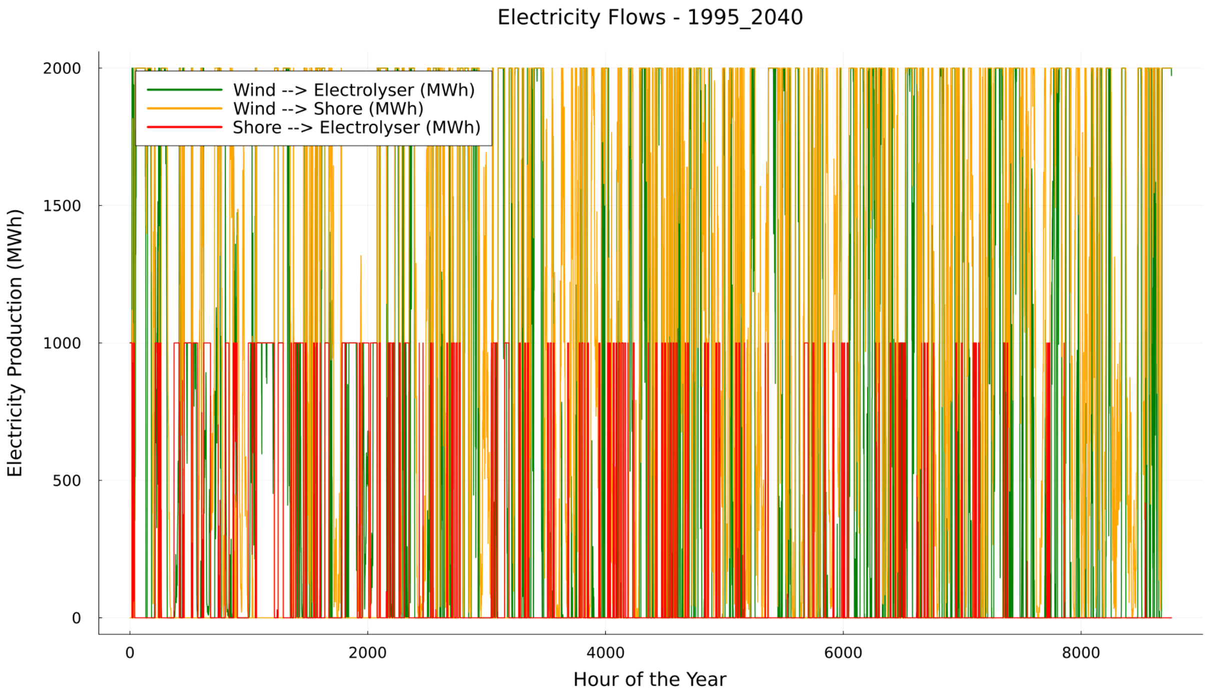

Figure B.17: Electricity Flows - 1995_2040

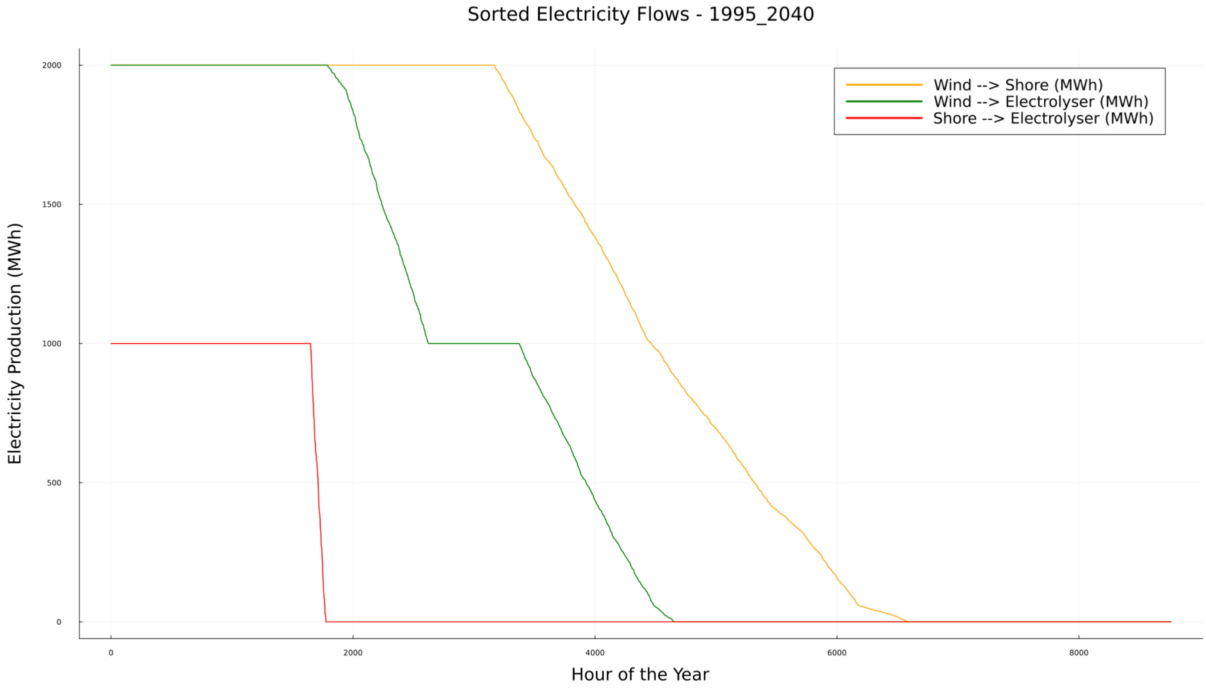

Figure B.18: Electricity Flows Sorted - 1995_2040

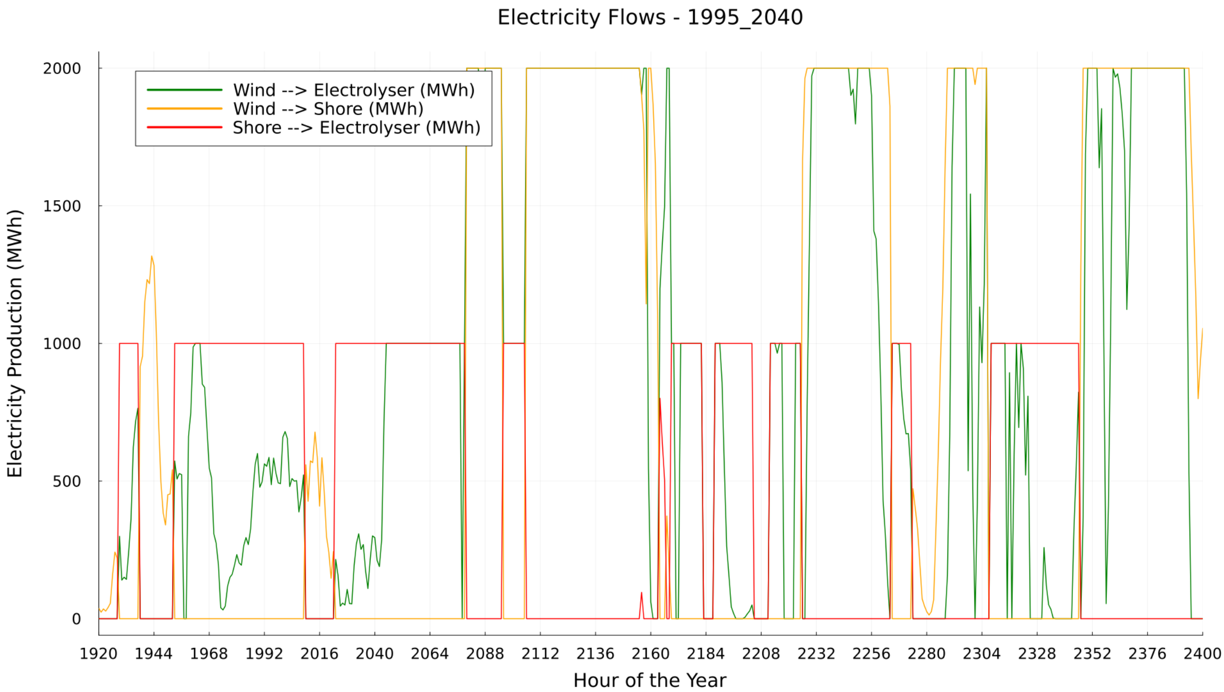

Figure B.19: Electricity Flows Zoomed - 1995_2040

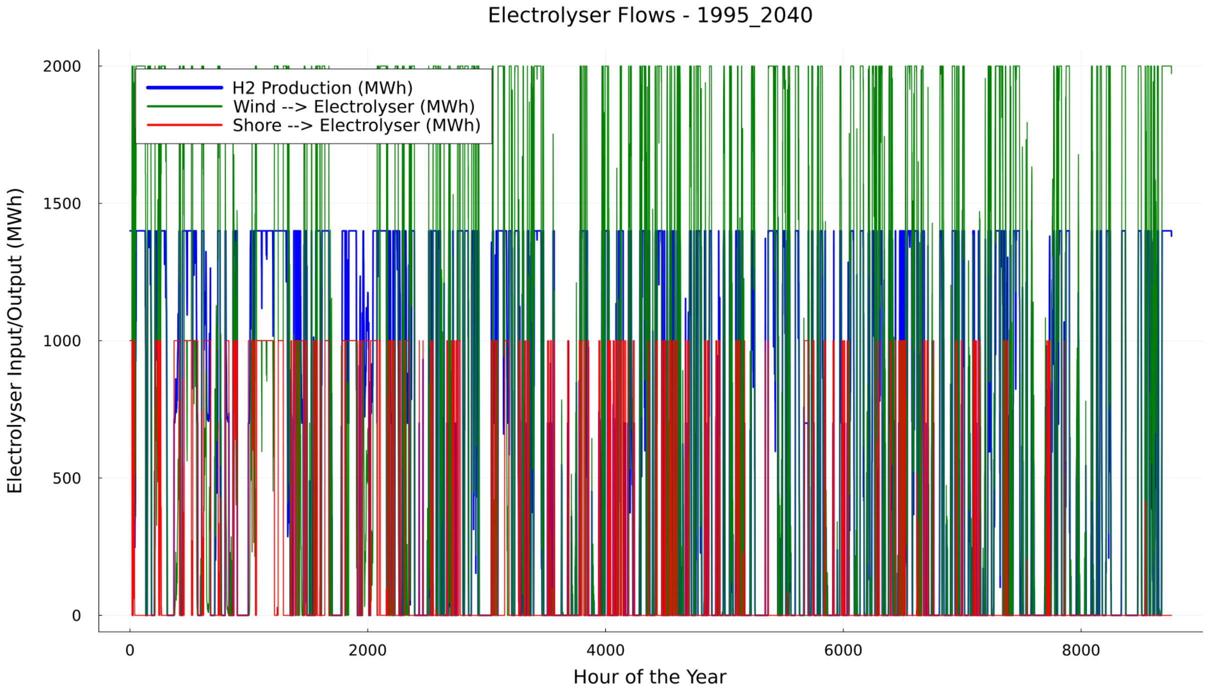

Figure B.20: Hydrogen Flows - 1995_2040

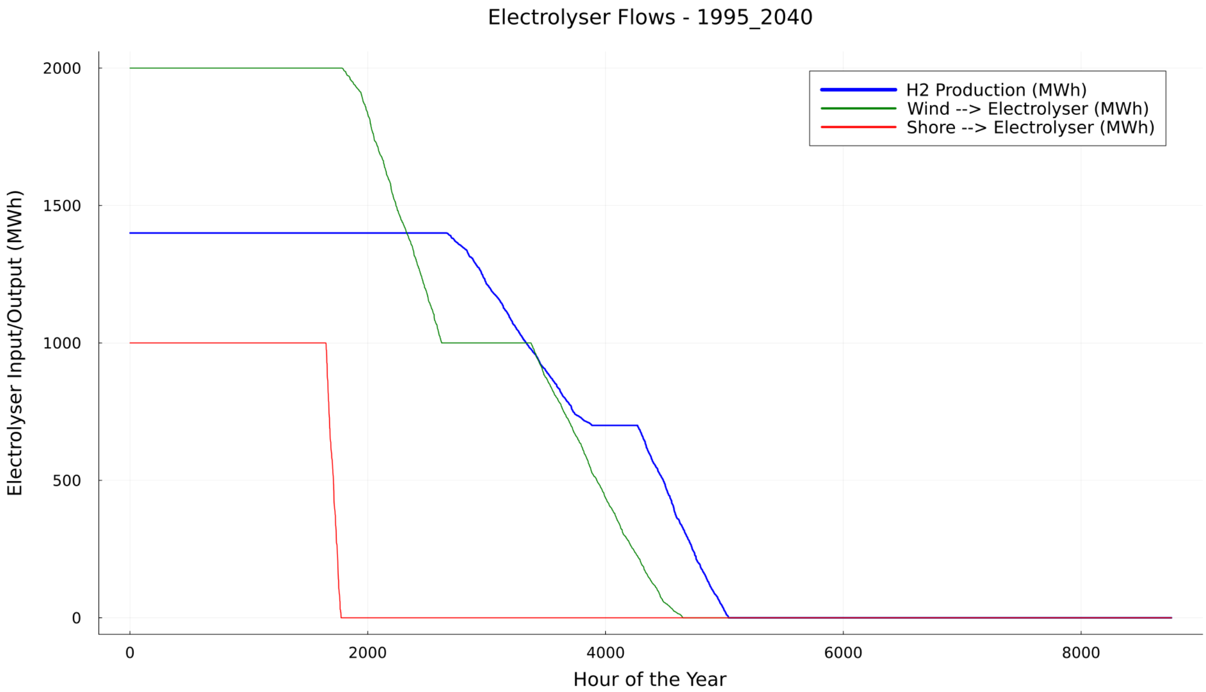

Figure B.21: Hydrogen Flows Sorted - 1995_2040

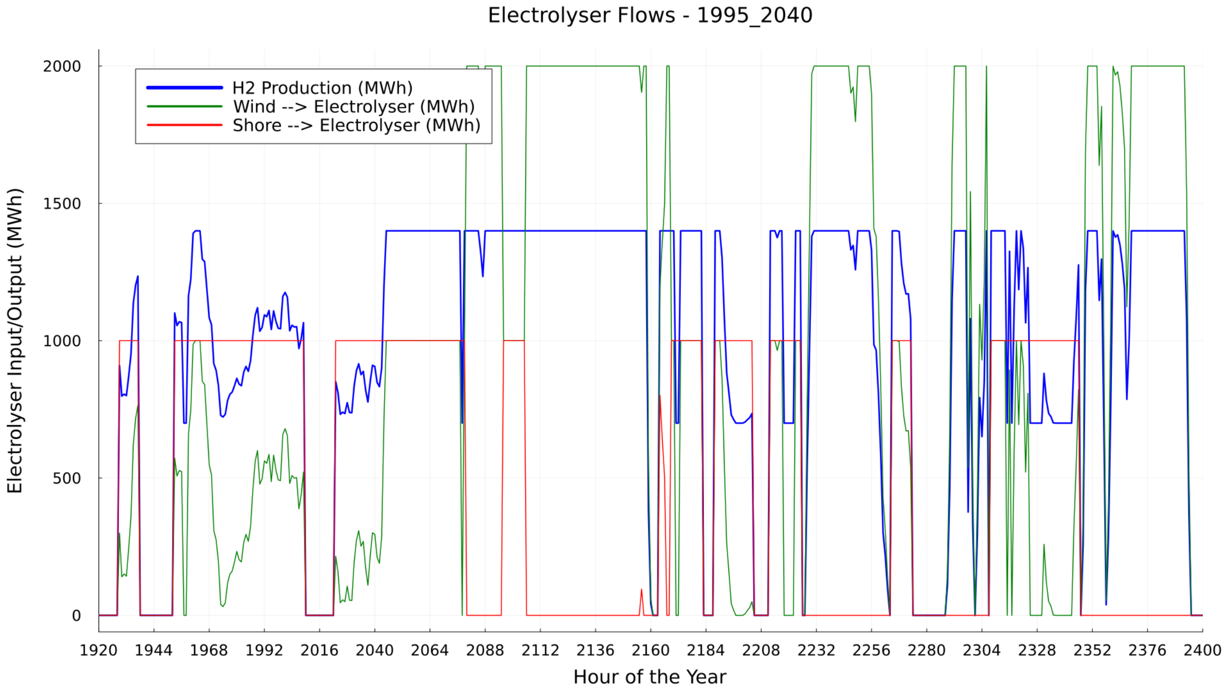

Figure B.22: Hydrogen Flows Zoomed - 1995_2040

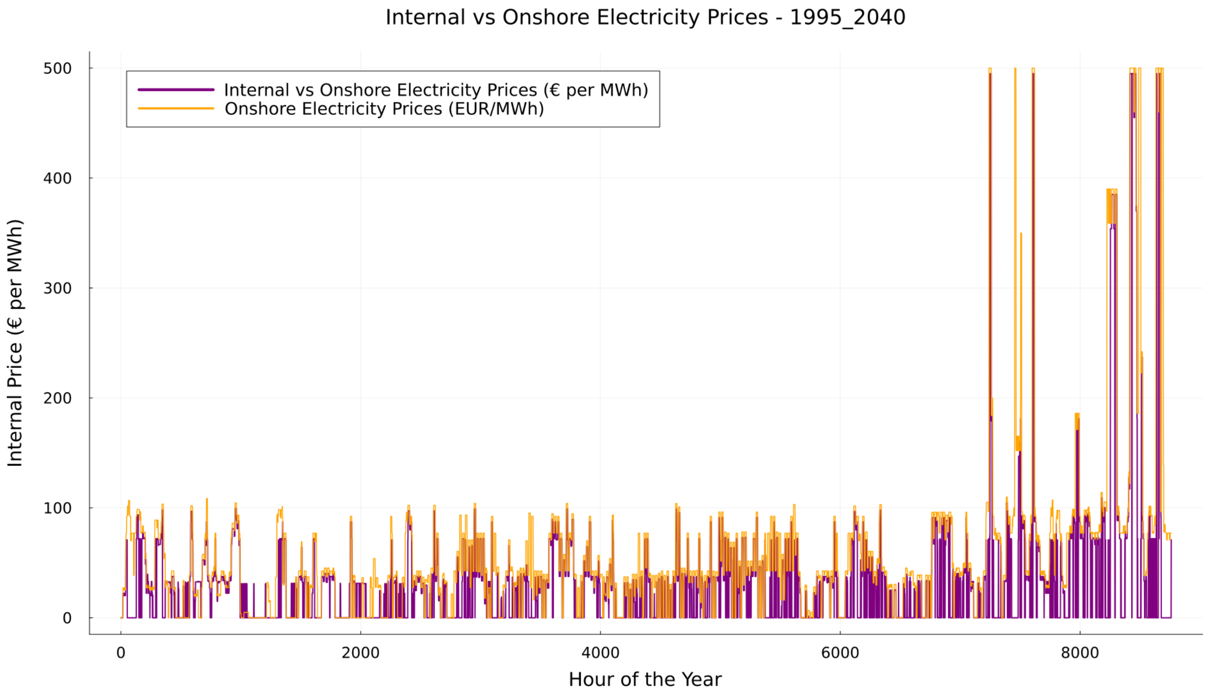

Figure B.23: Onshore vs Internal Prices - 1995_2040

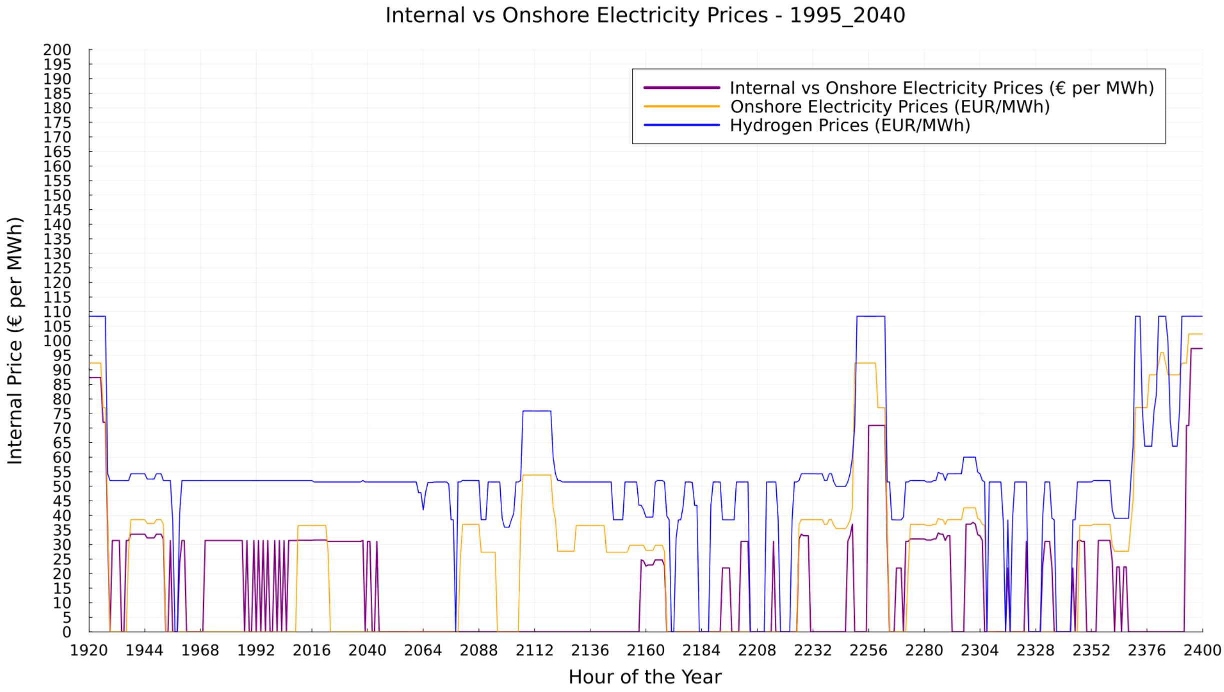

Figure B.24: Internal Prices Zommed - 1995_2040

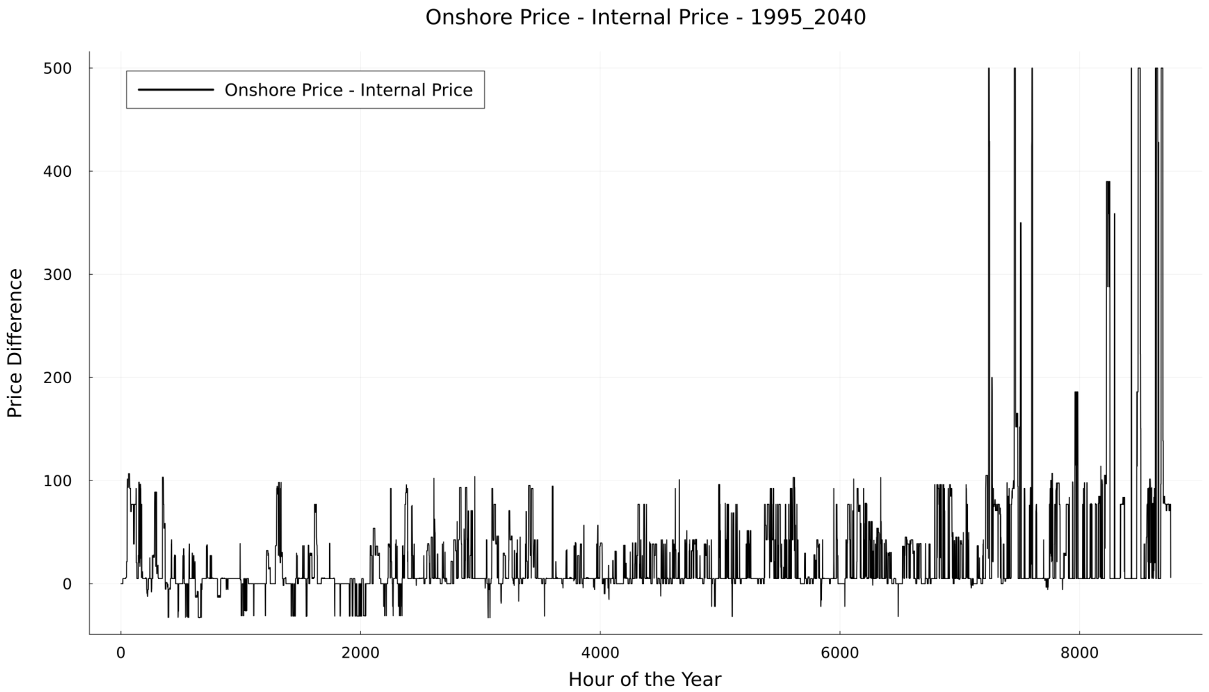

Figure B.25: Onshore - Internal Prices - 1995_2040

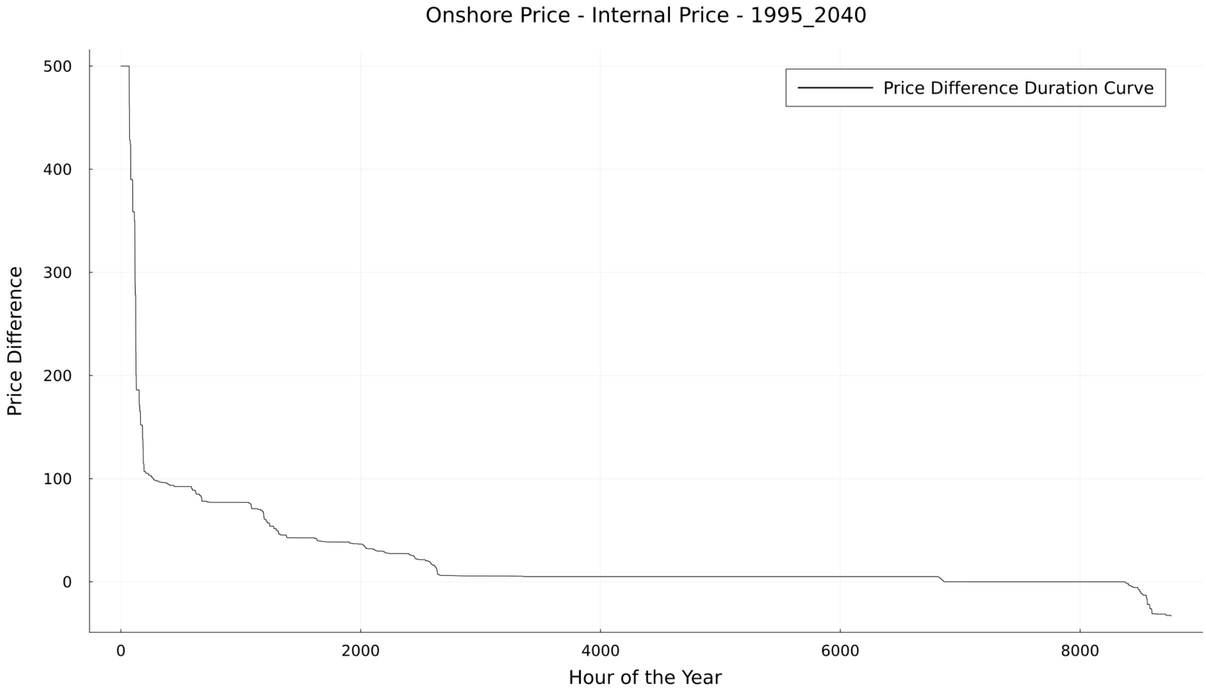

Figure B.26: Onshore - Internal Prices Sorted - 1995_2040

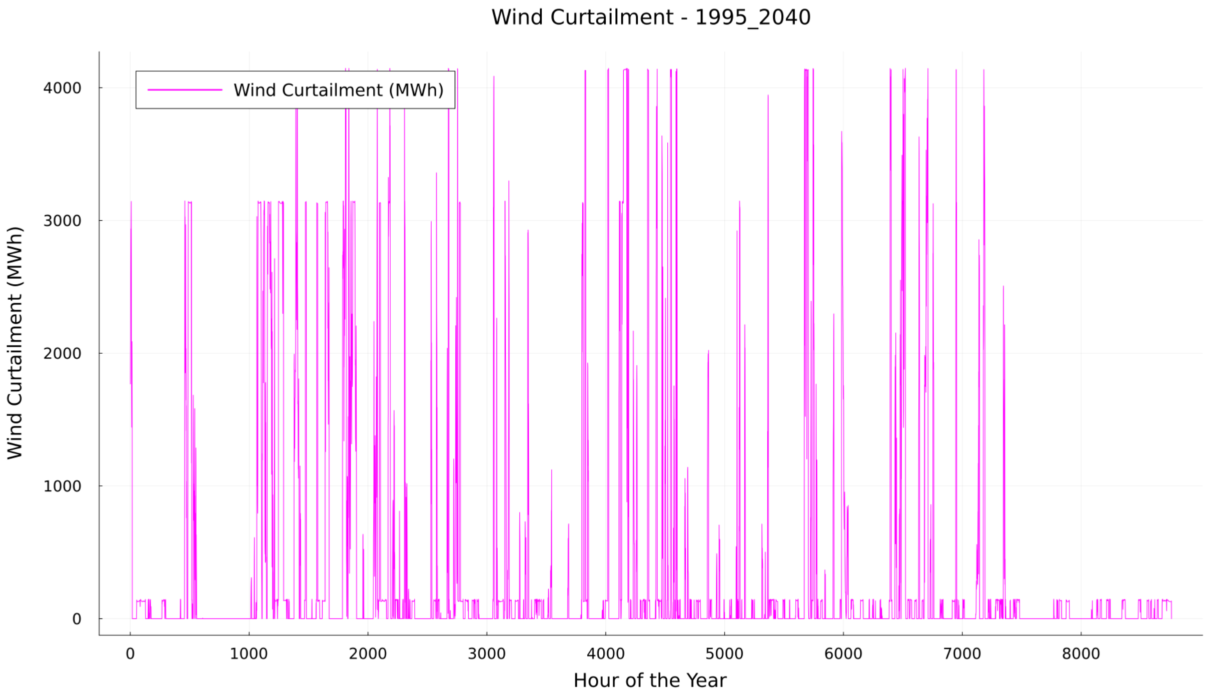

Figure B.27: Wind Curtailment - 1995_2040

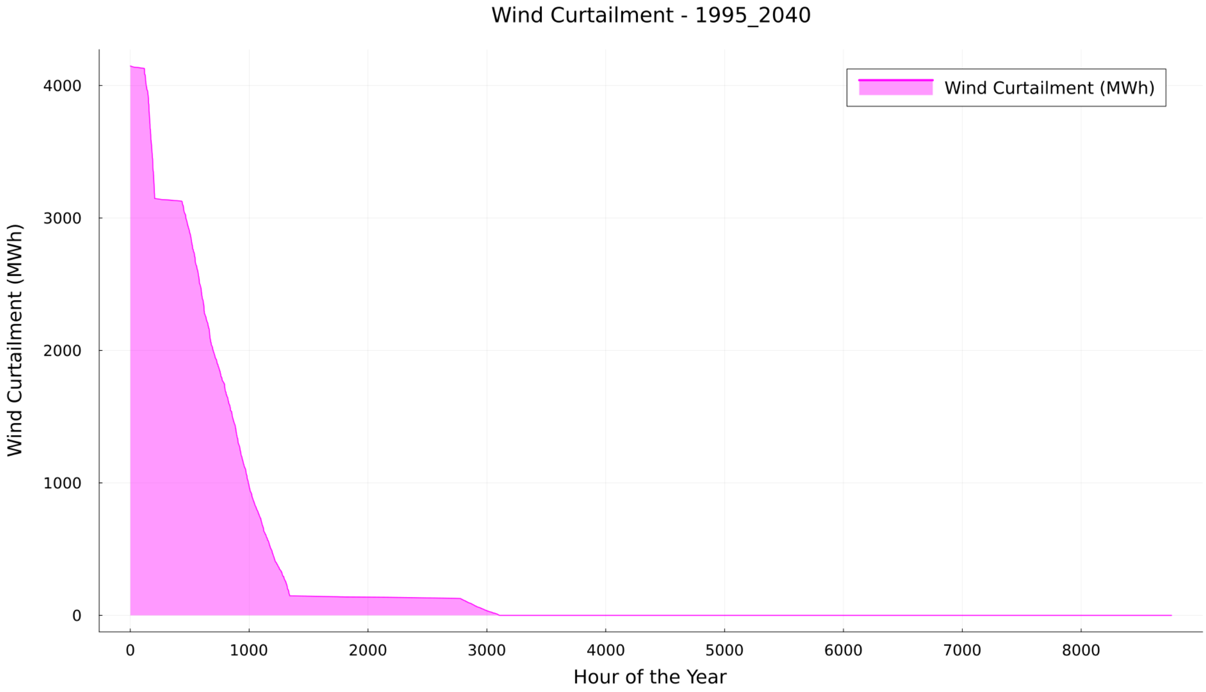

Figure B.28: Wind Curtailment Duration Curve - 1995_2040

B.3. Scenario 2008-2030

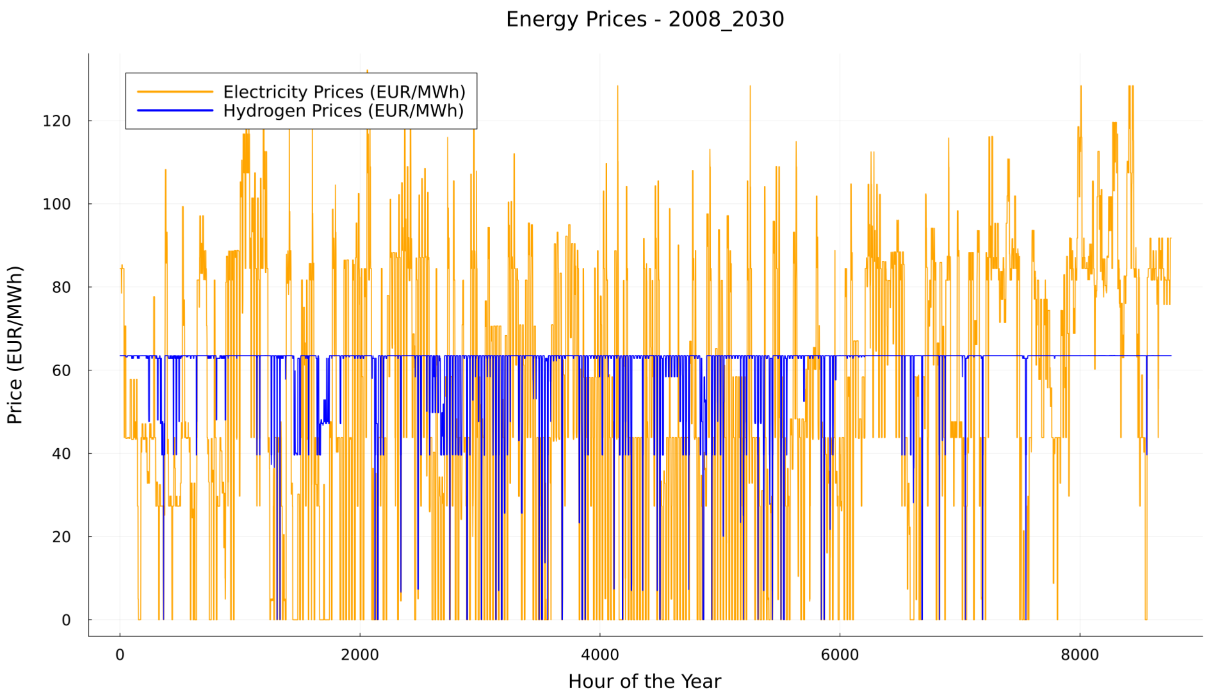

Figure B.29: Energy Prices - 2008_2030

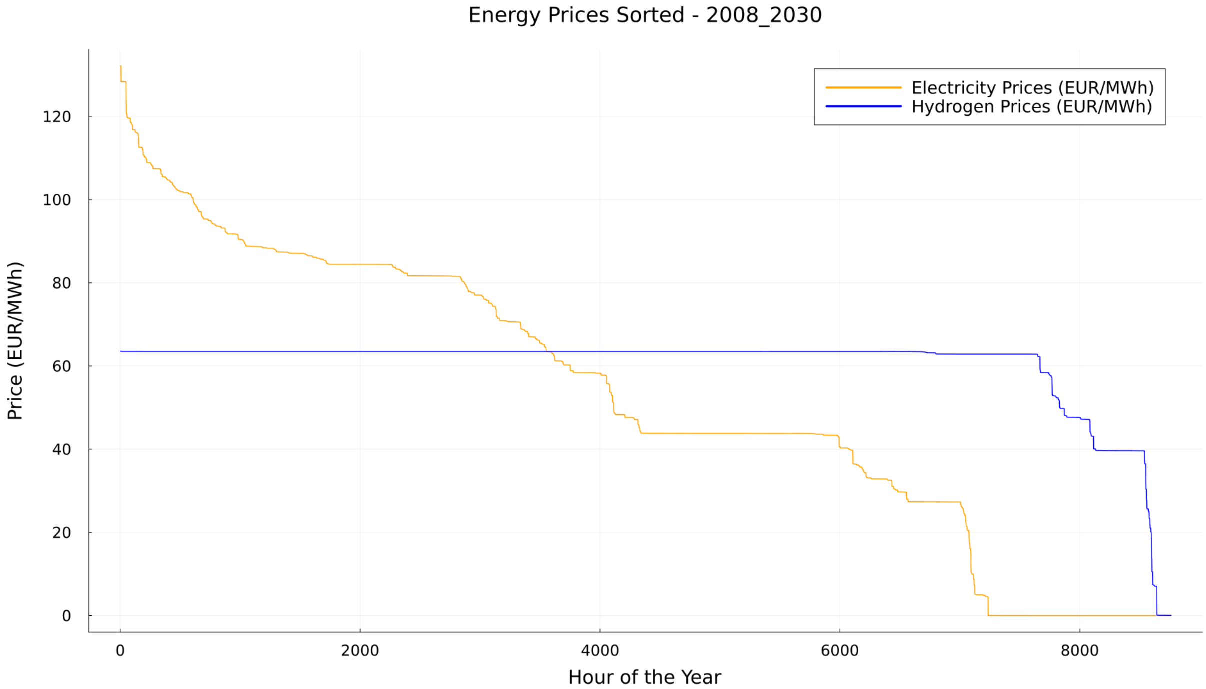

Figure B.30: Energy Price Duration Curve - 2008_2030

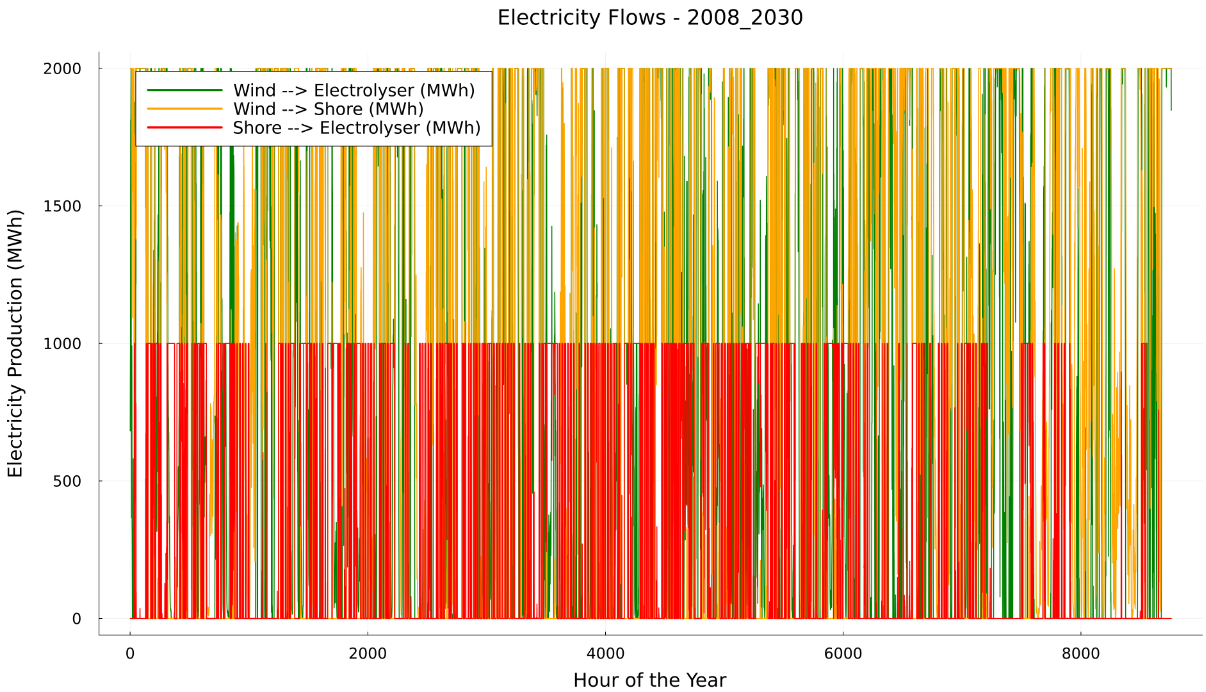

Figure B.31: Electricity Flows - 2008_2030

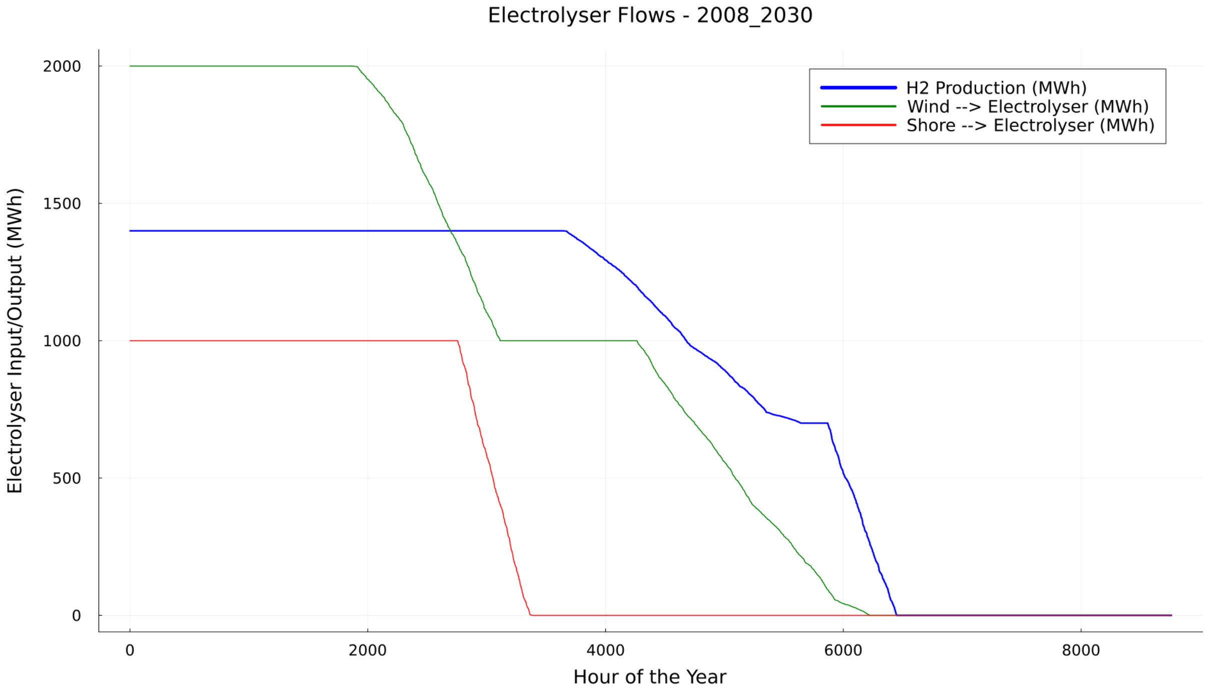

Figure B.32: Electricity Flows Sorted - 2008_2030

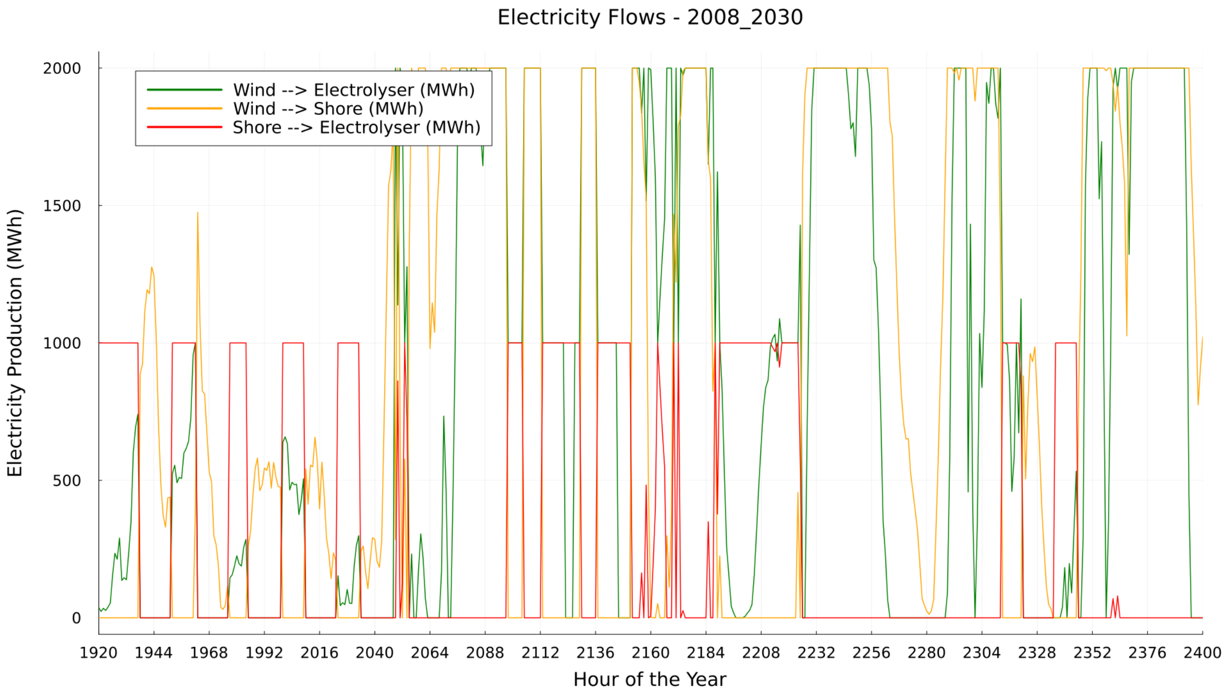

Figure B.33: Electricity Flows Zoomed - 2008_2030

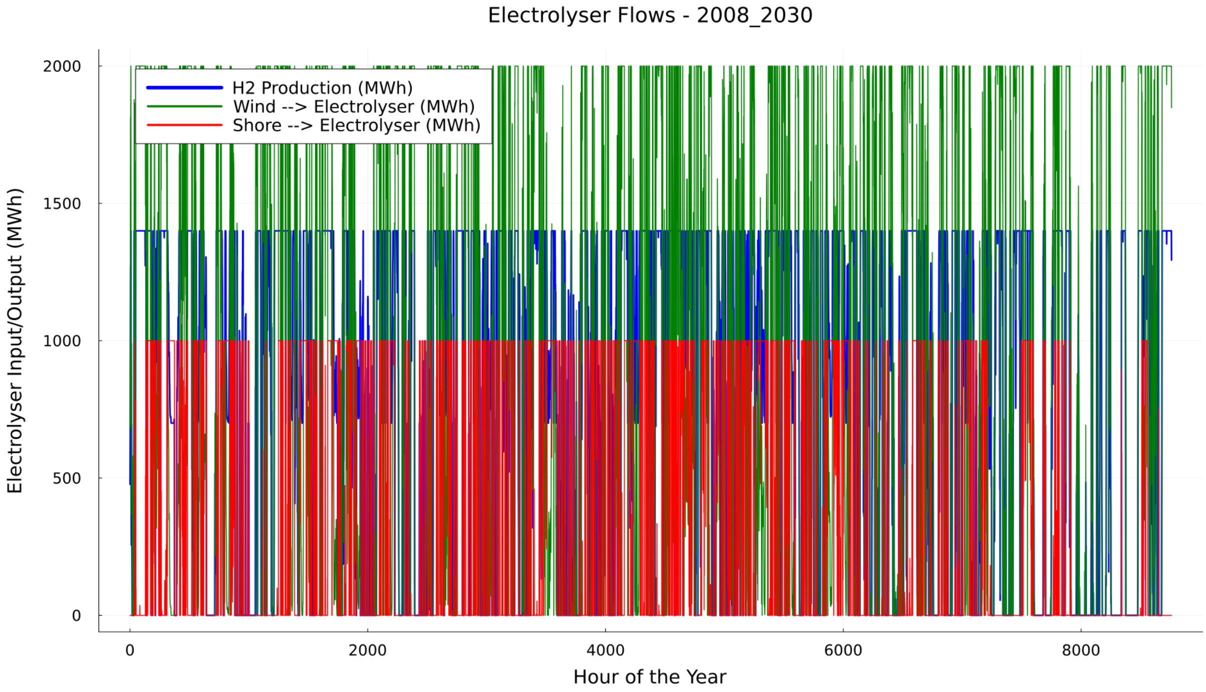

Figure B.34: Hydrogen Flows - 2008_2030

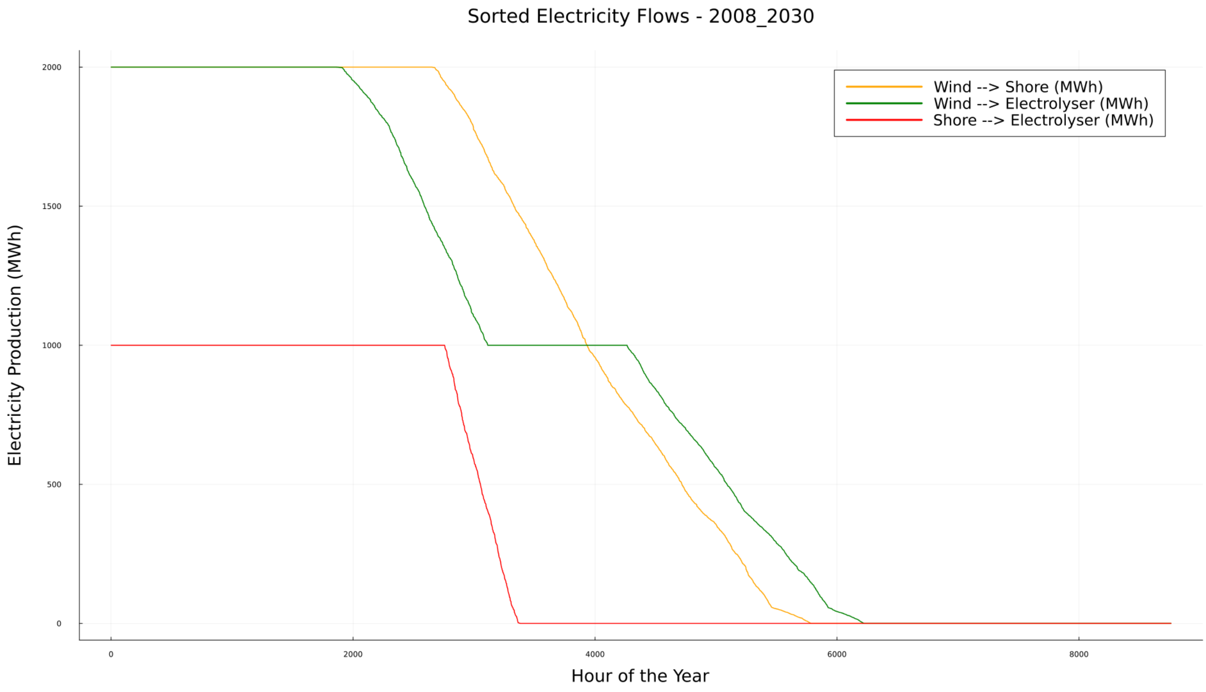

Figure B.35: Hydrogen Flows Sorted - 2008_2030

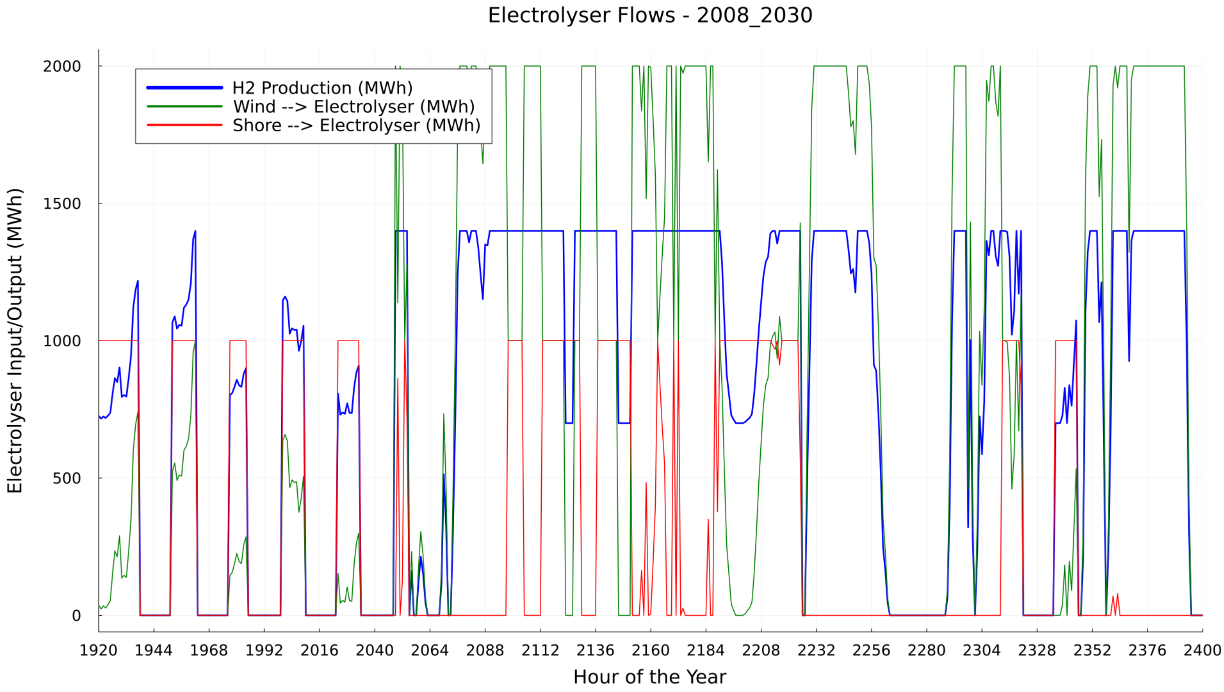

Figure B.36: Hydrogen Flows Zoomed - 2008_2030

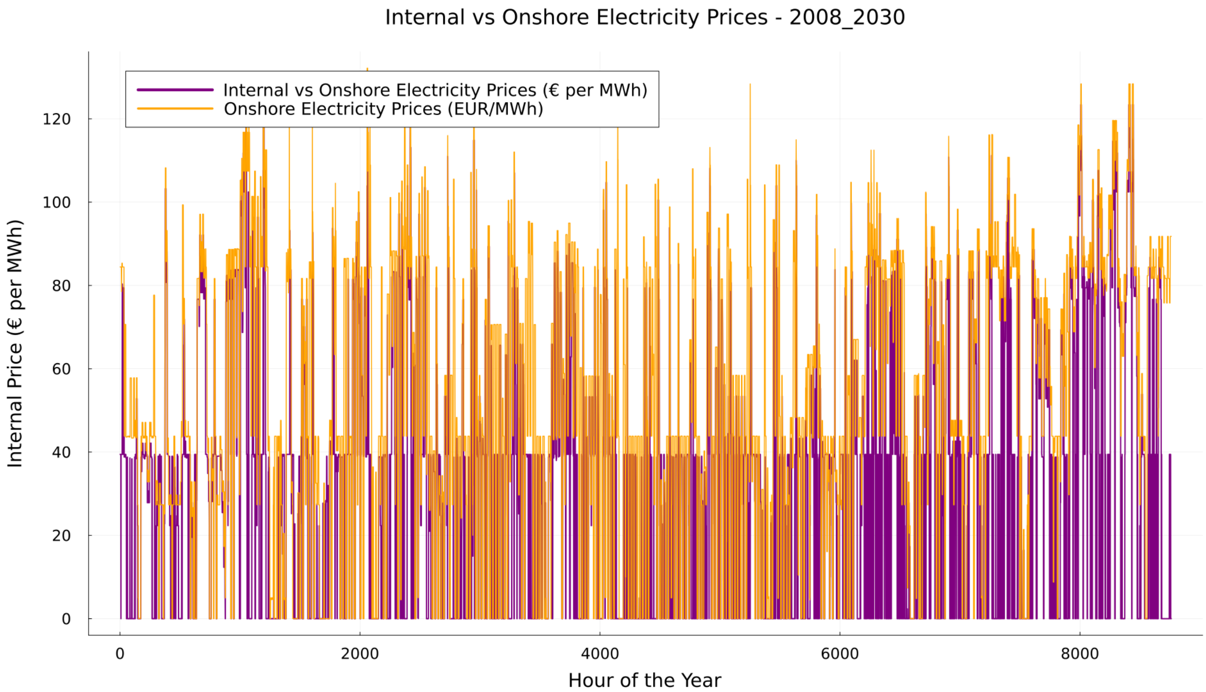

Figure B.37: Onshore vs Internal Prices - 2008_2030

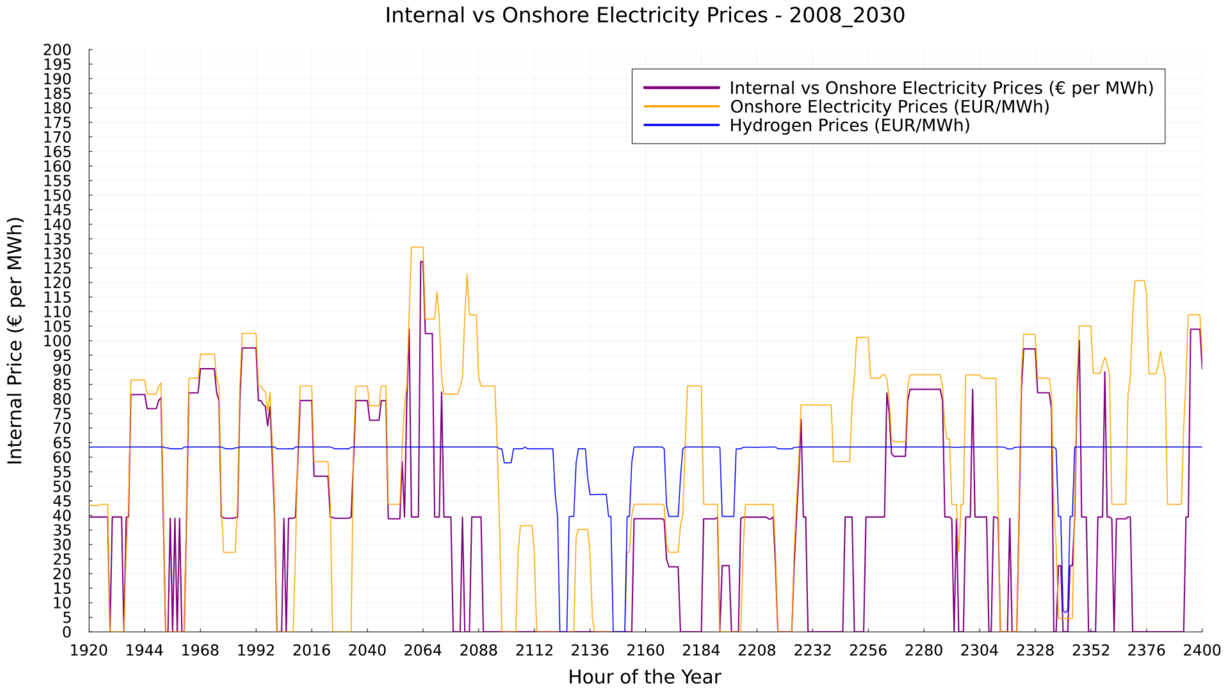

Figure B.38: Internal Prices Zommed - 2008_2030

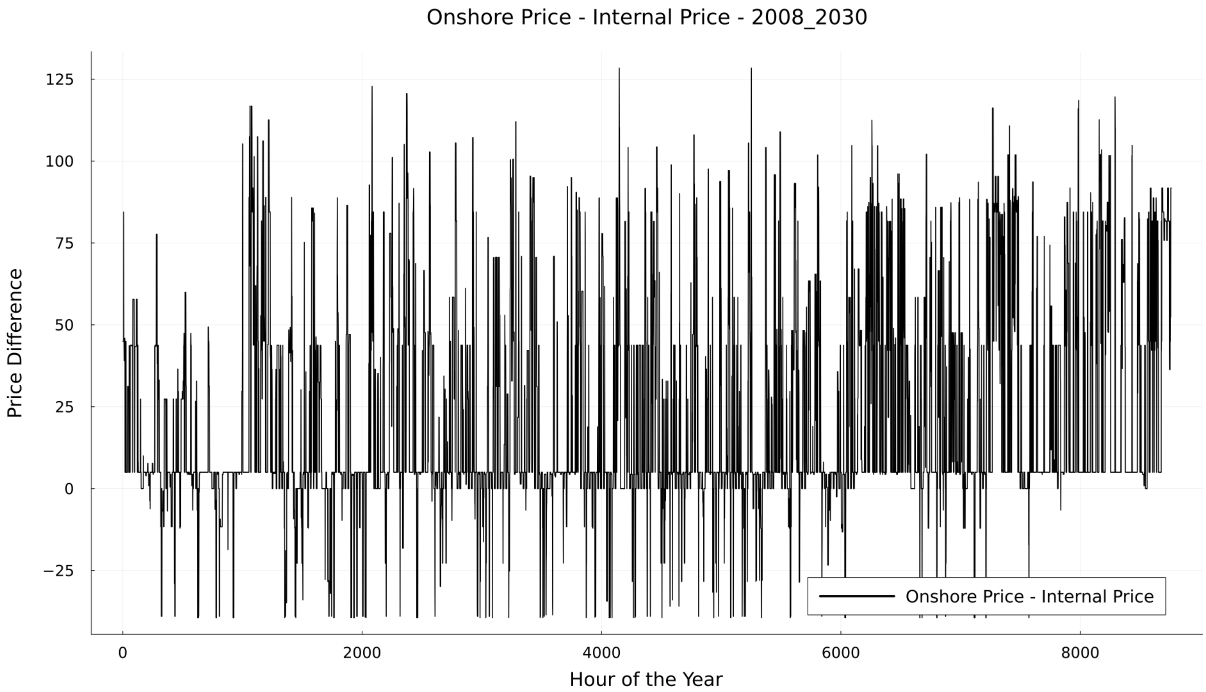

Figure B.39: Onshore - Internal Prices - 2008_2030

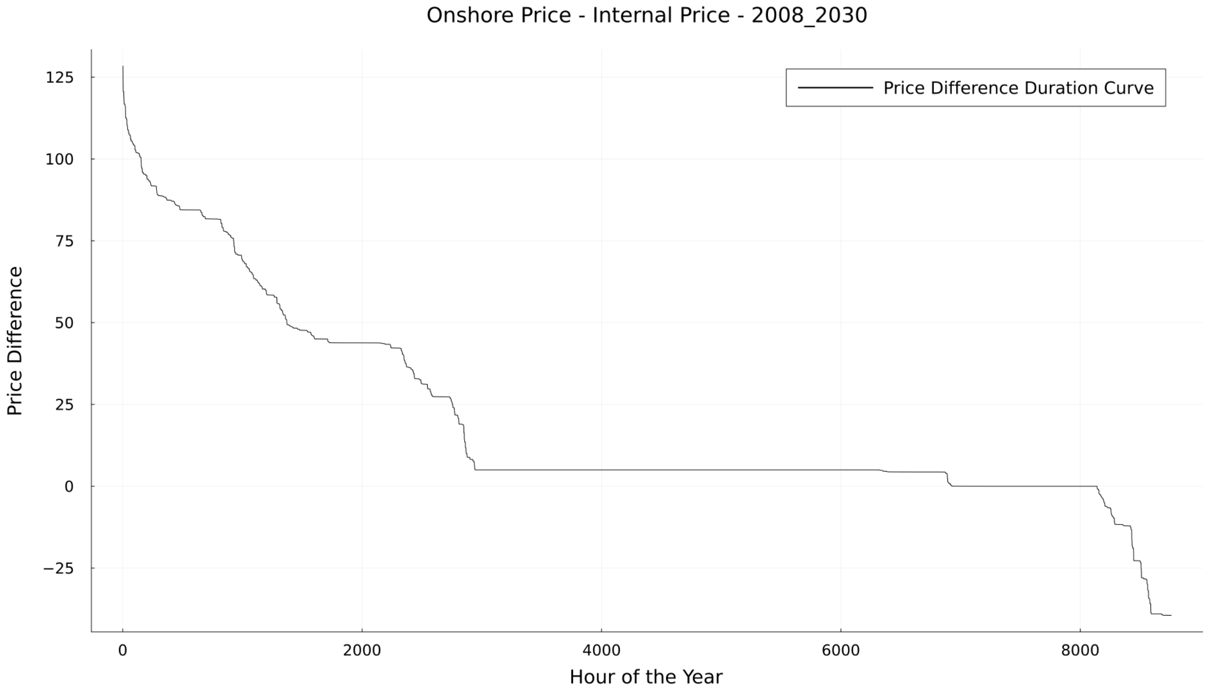

Figure B.40: Onshore - Internal Prices Sorted - 2008_2030

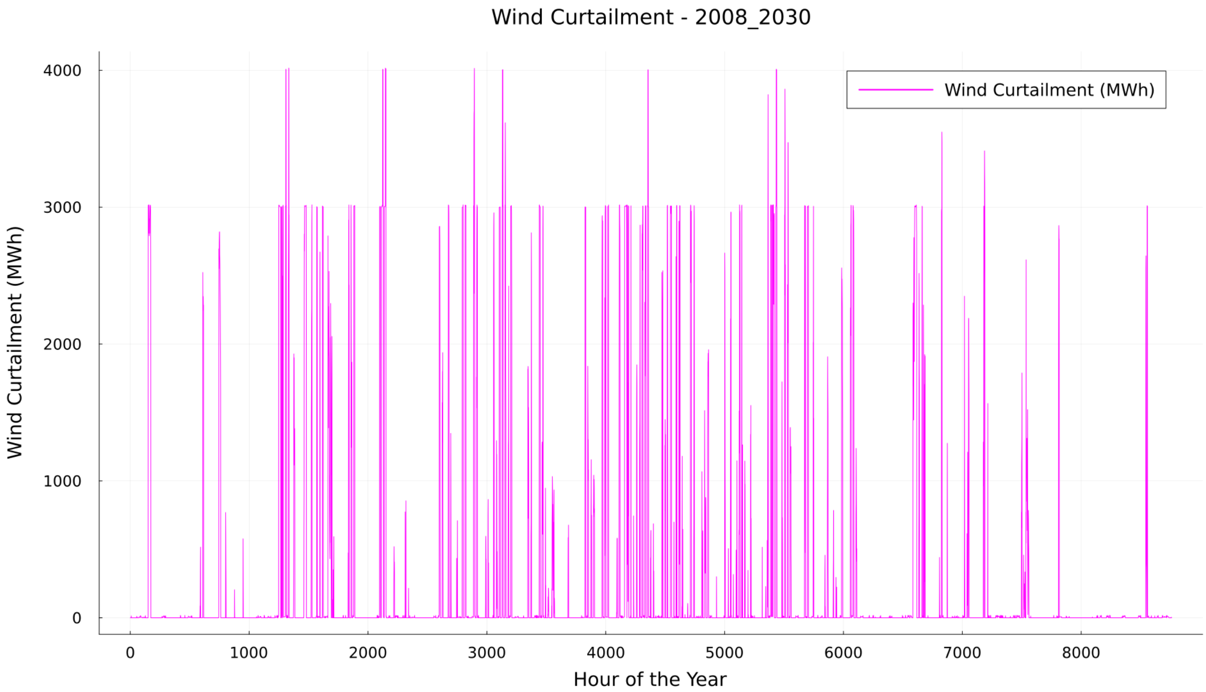

Figure B.41: Wind Curtailment - 2008_2030

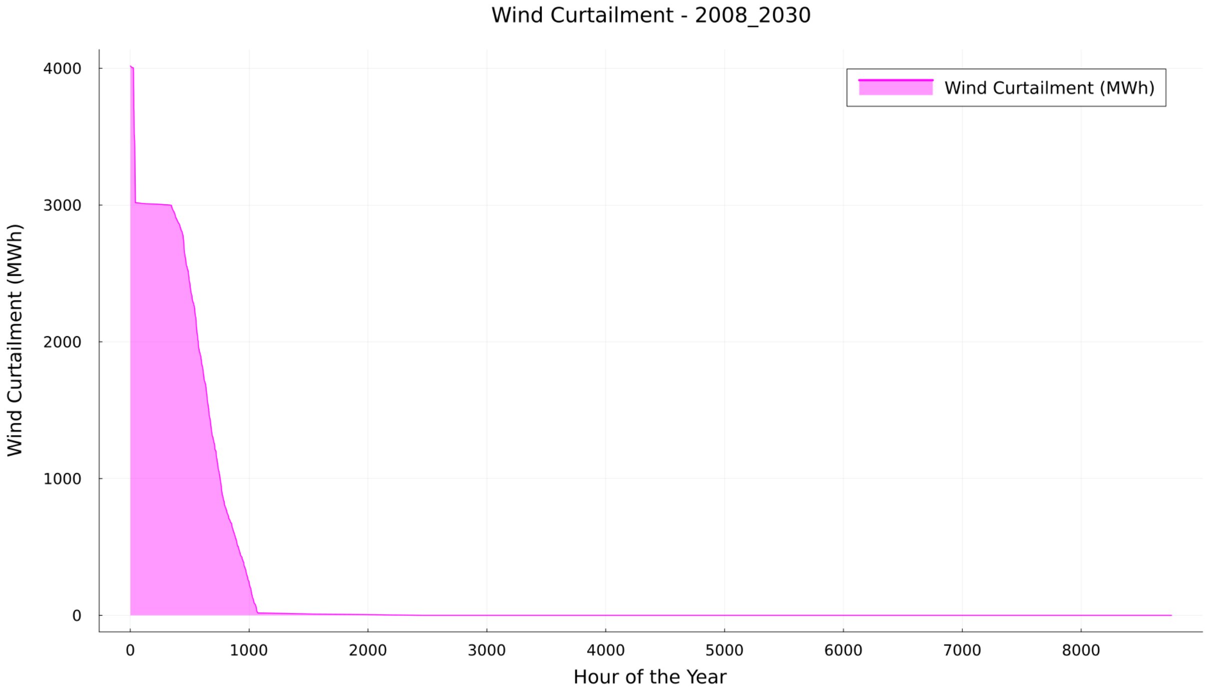

Figure B.42: Wind Curtailment Duration Curve - 2008_2030

B.4. Scenario 2008-2040

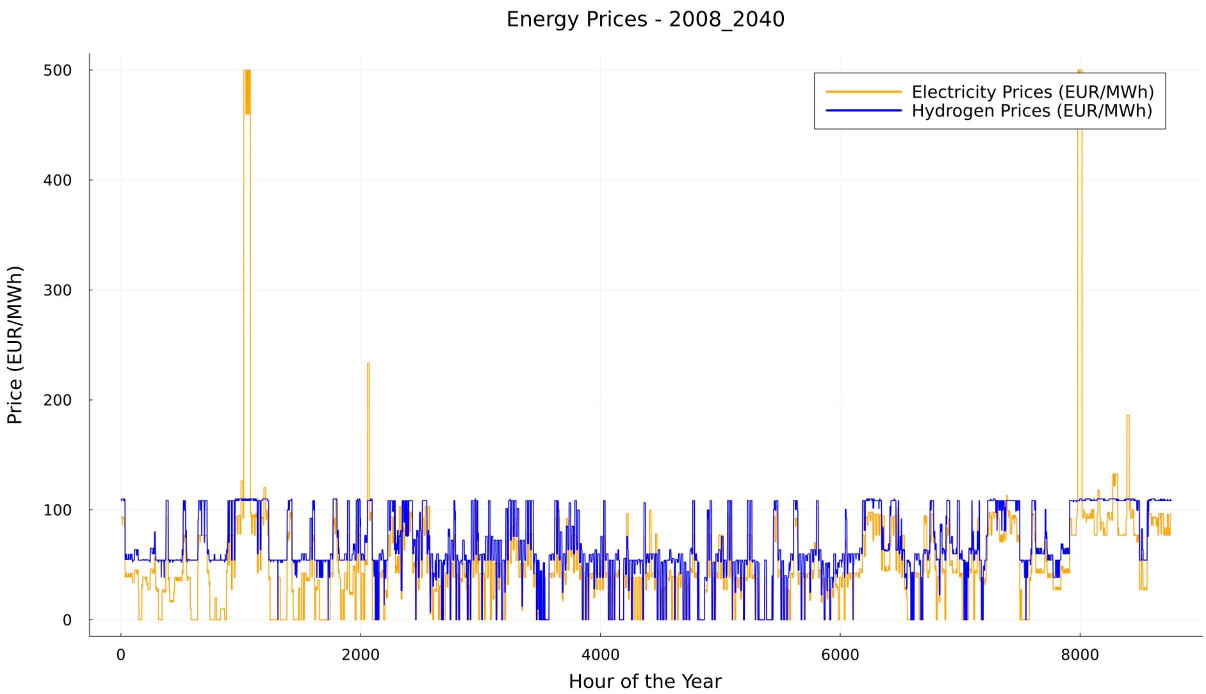

Figure B.43: Energy Prices - 2008_2040

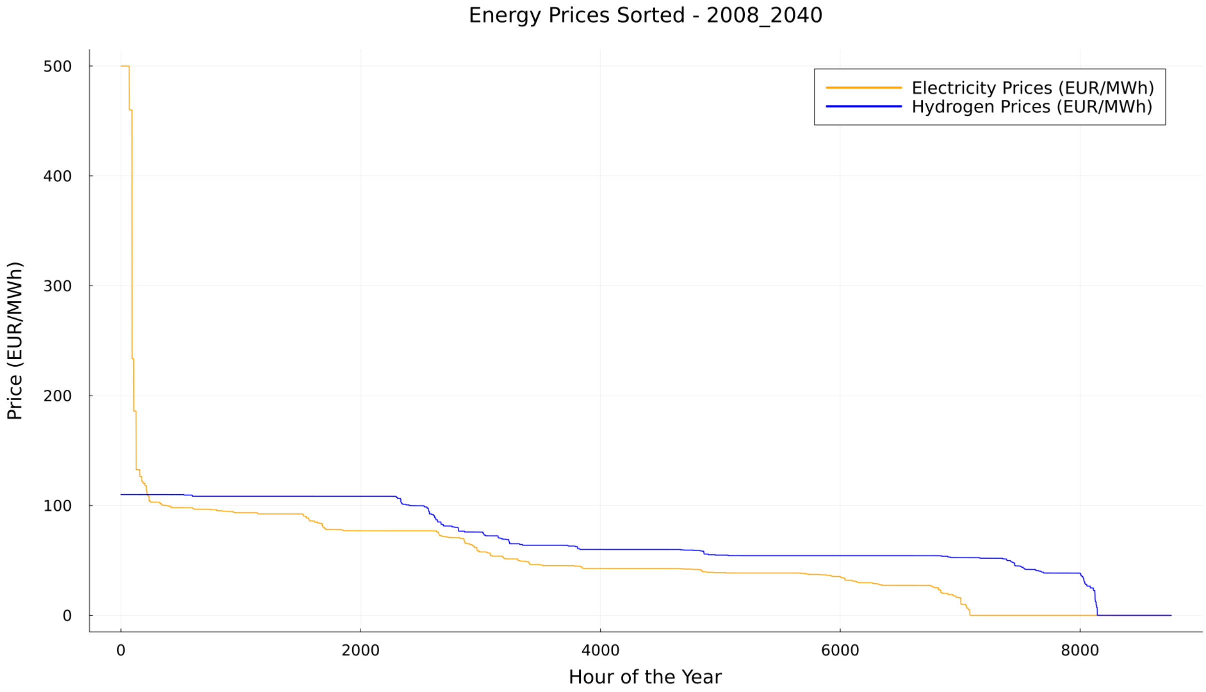

Figure B.44: Energy Price Duration Curve - 2008_2040

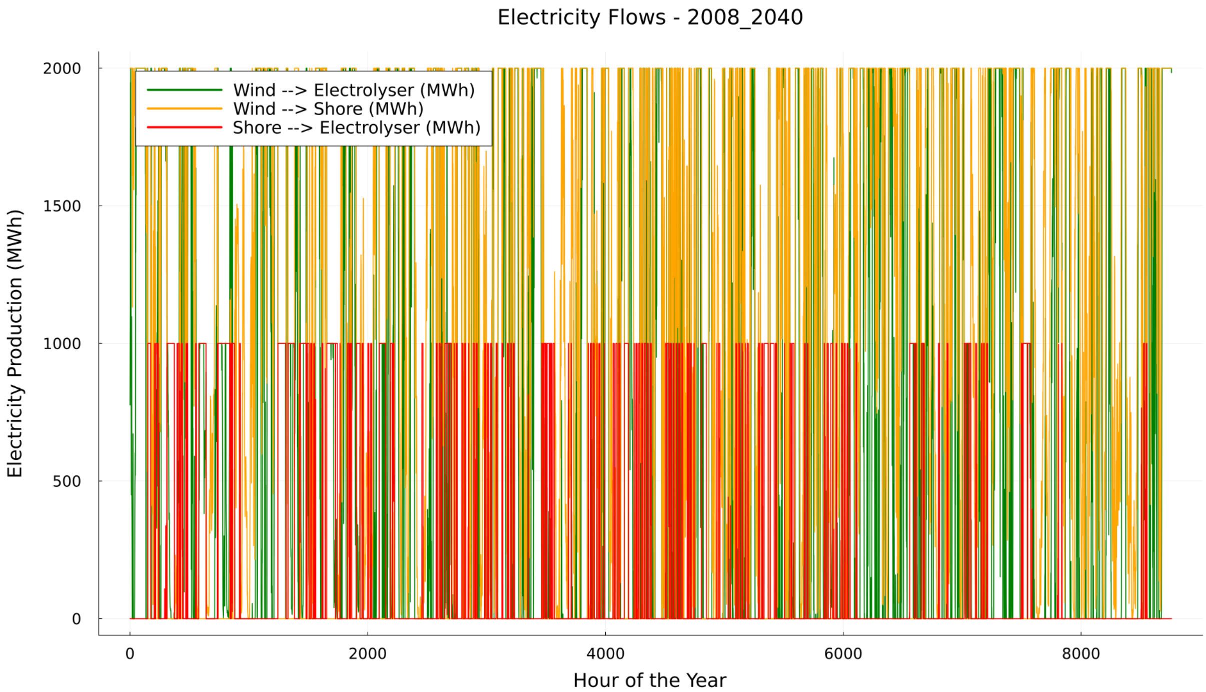

Figure B.45: Electricity Flows - 2008_2040

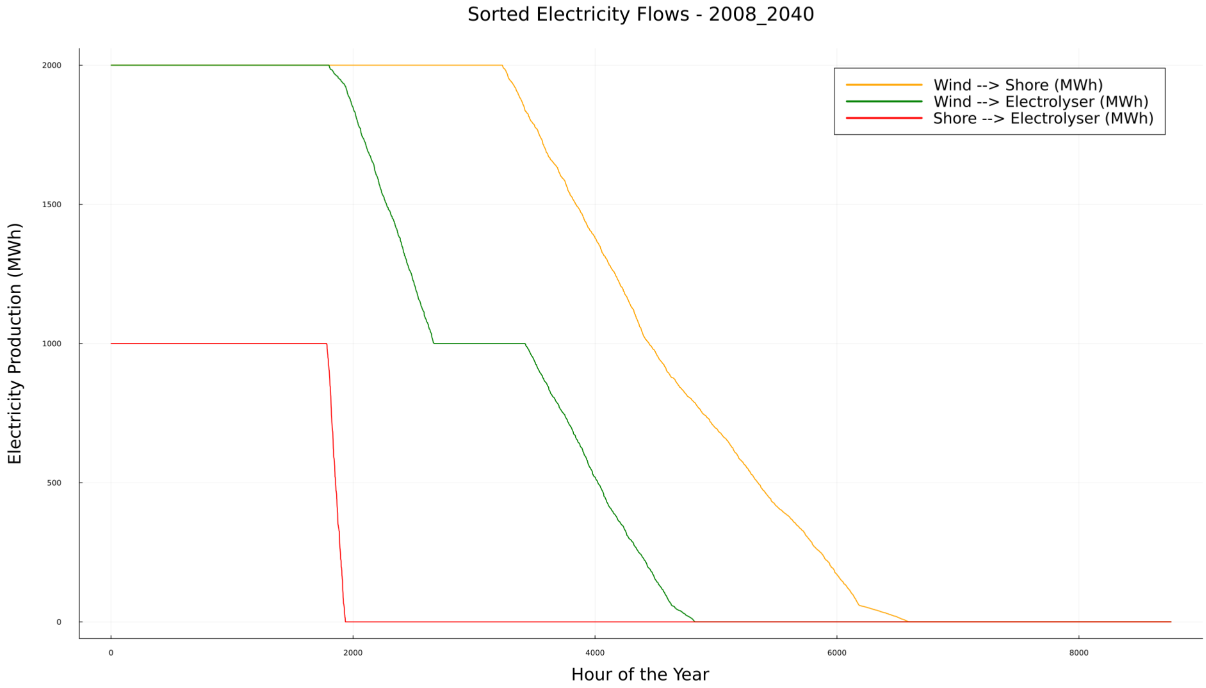

Figure B.46: Electricity Flows Sorted - 2008_2040

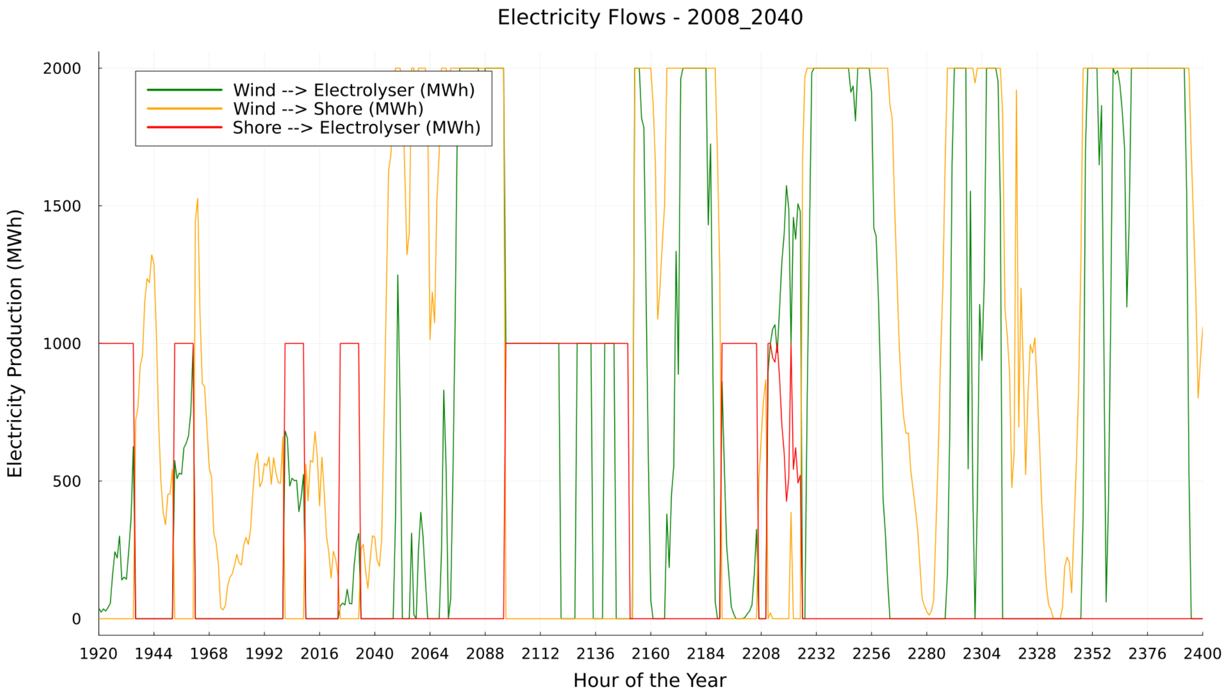

Figure B.47: Electricity Flows Zoomed - 2008_2040

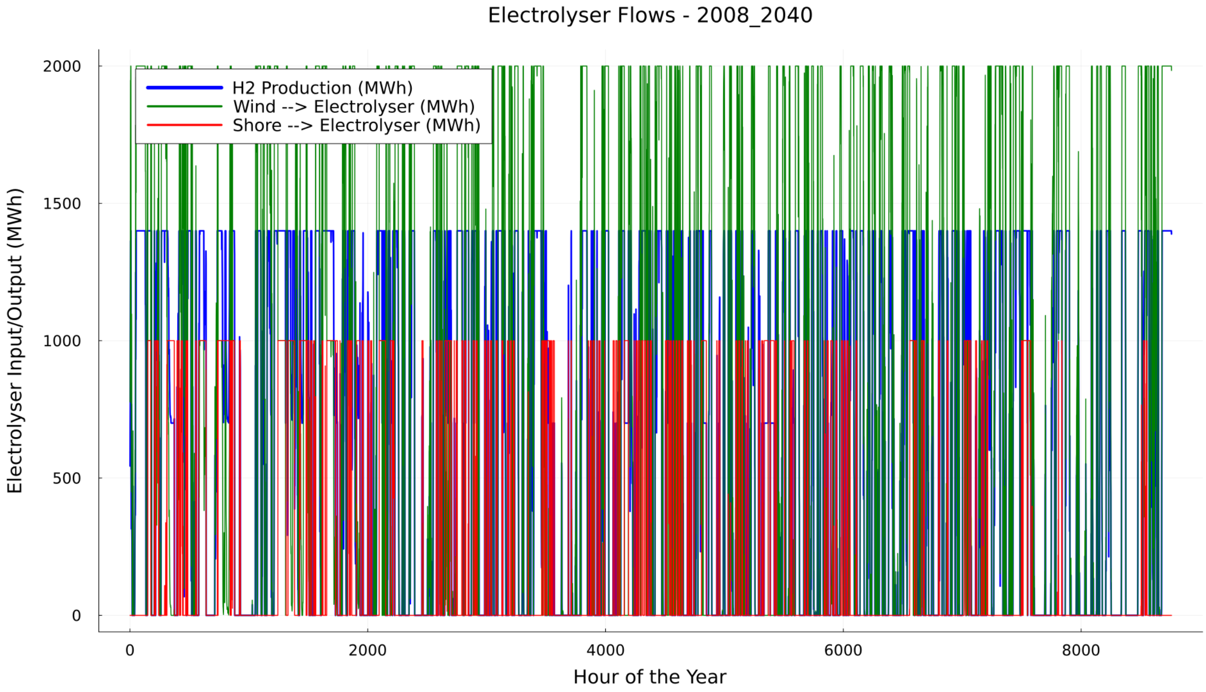

Figure B.48: Hydrogen Flows - 2008_2040

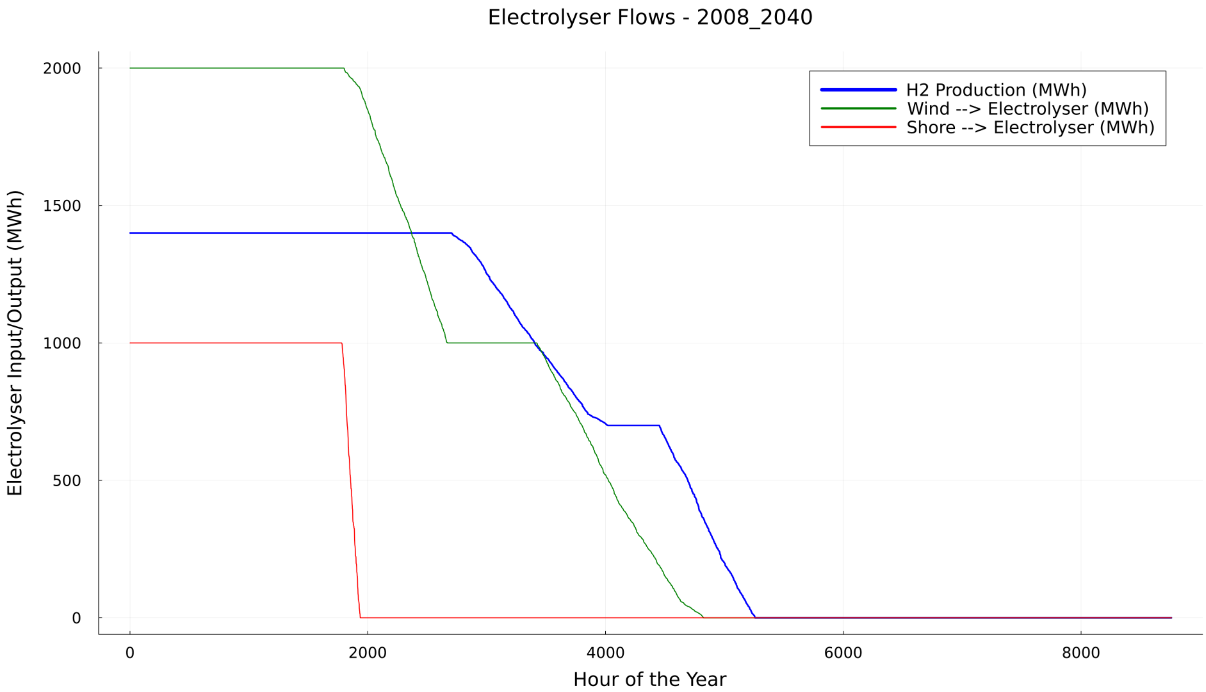

Figure B.49: Hydrogen Flows Sorted - 2008_2040

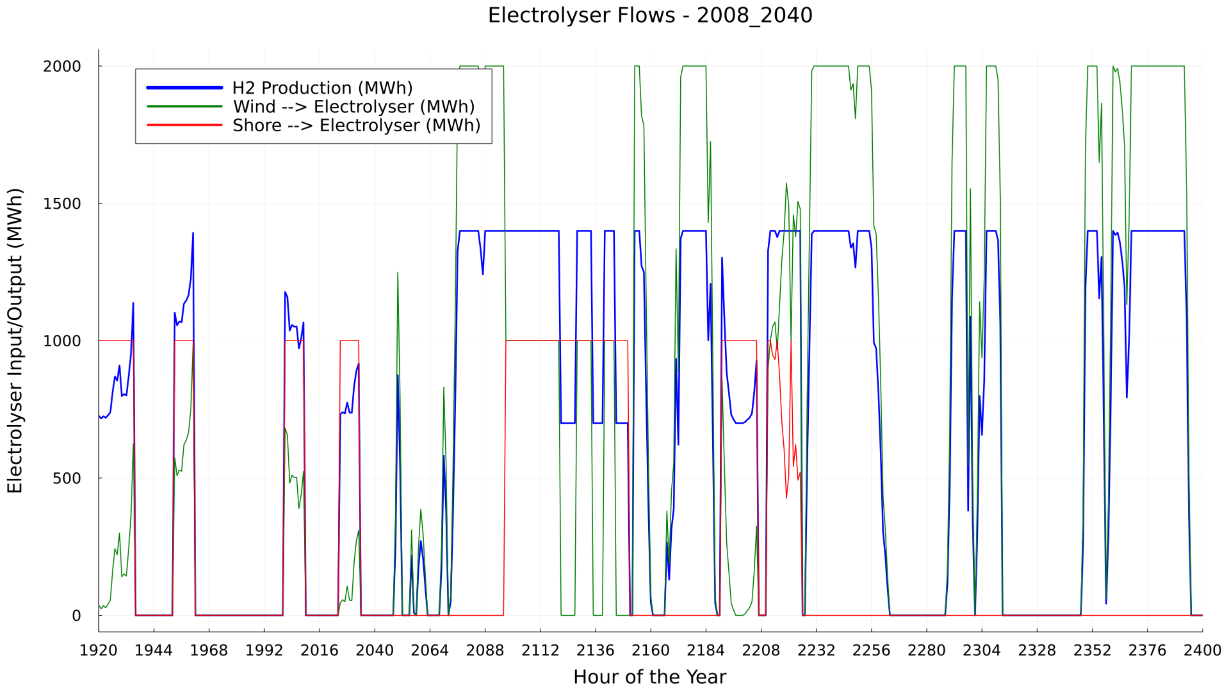

Figure B.50: Hydrogen Flows Zoomed - 2008_2040

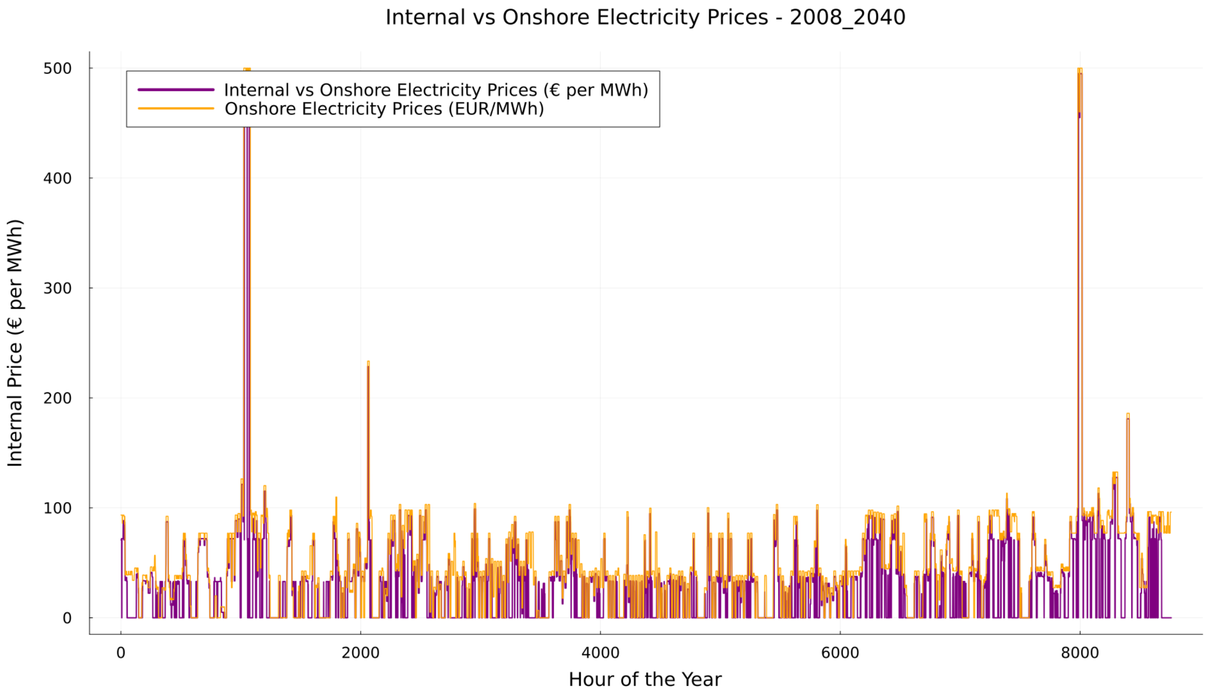

Figure B.51: Onshore vs Internal Prices - 2008_2040

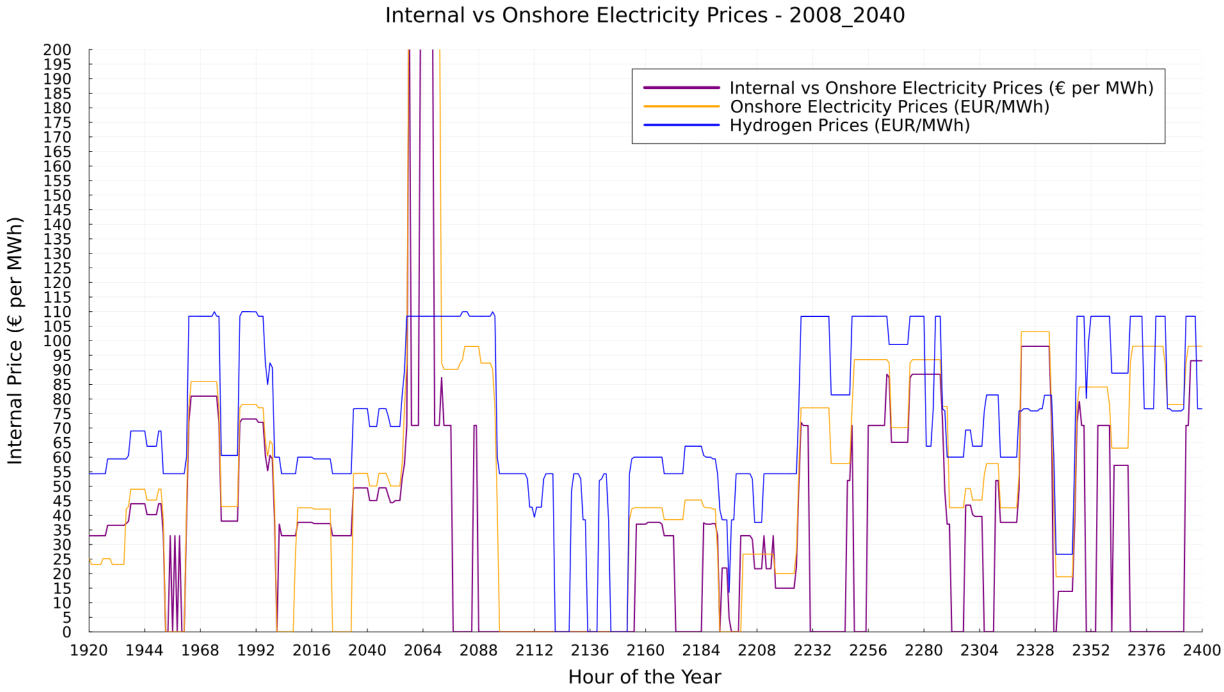

Figure B.52: Internal Prices Zommed - 2008_2040

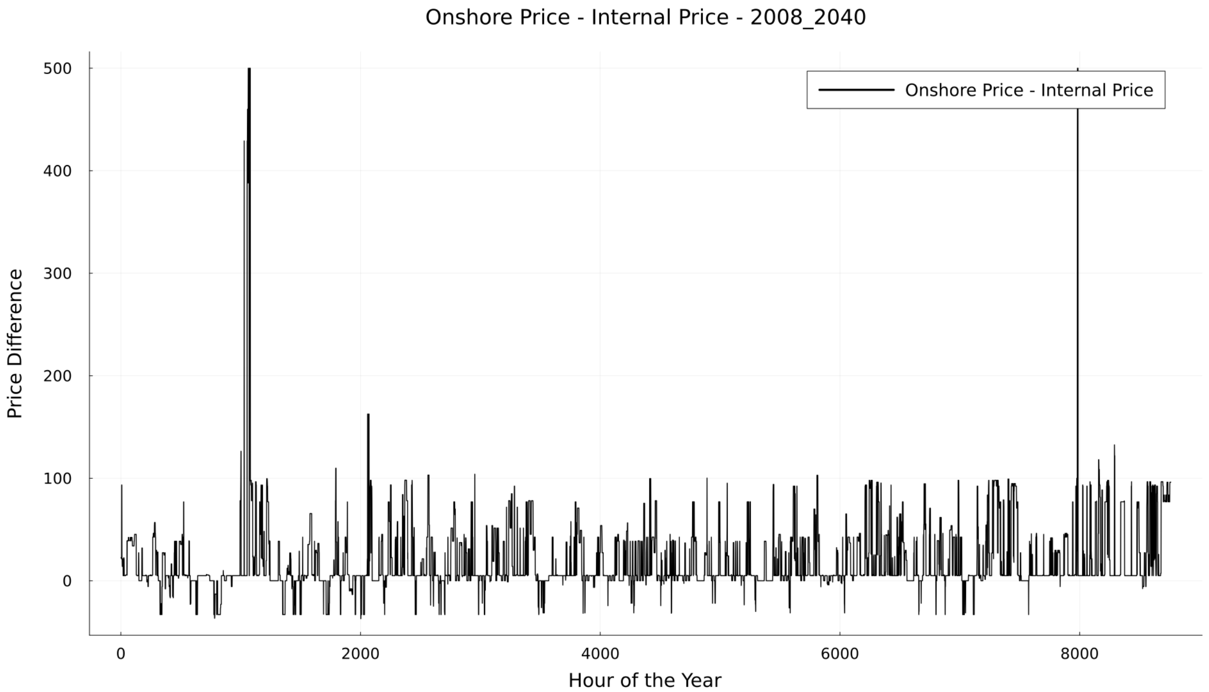

Figure B.53: Onshore - Internal Prices - 2008_2040

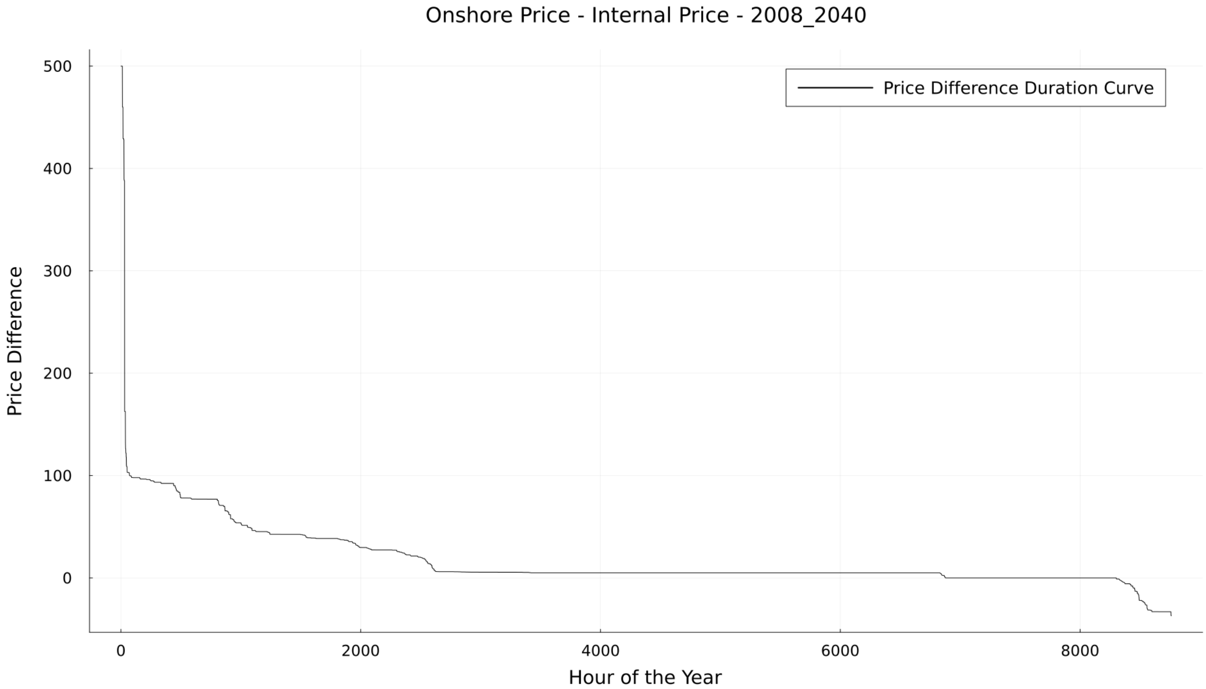

Figure B.54: Onshore - Internal Prices Sorted - 2008_2040

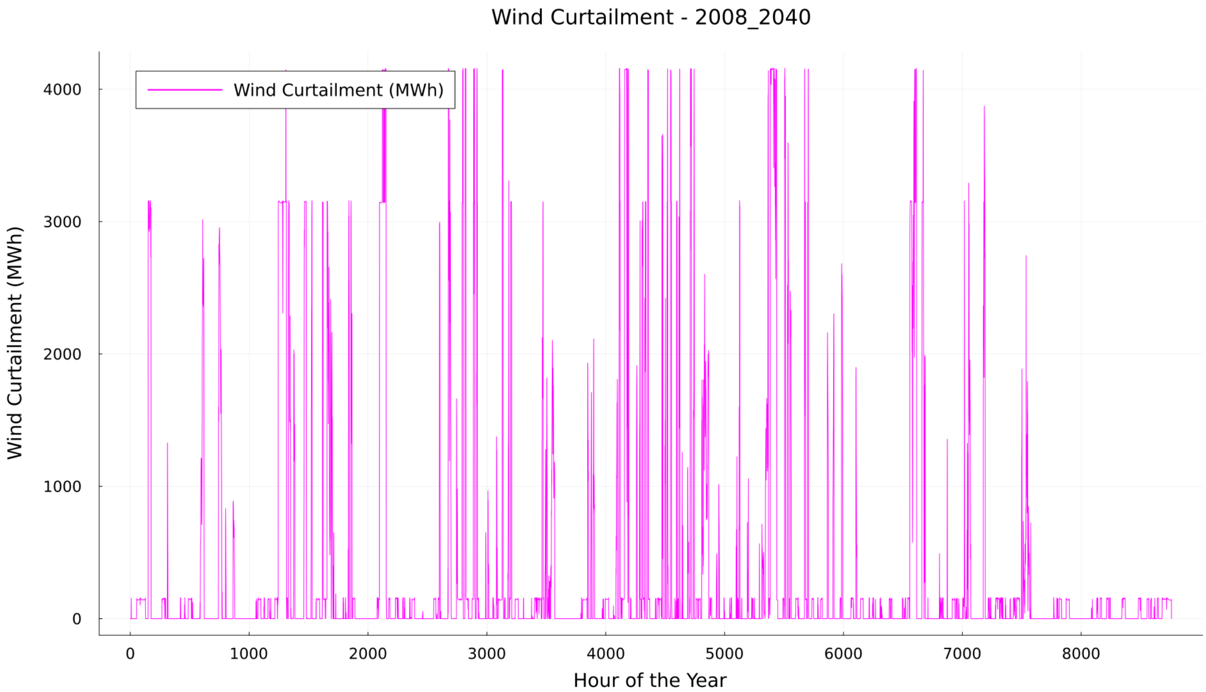

Figure B.55: Wind Curtailment - 2008_2040

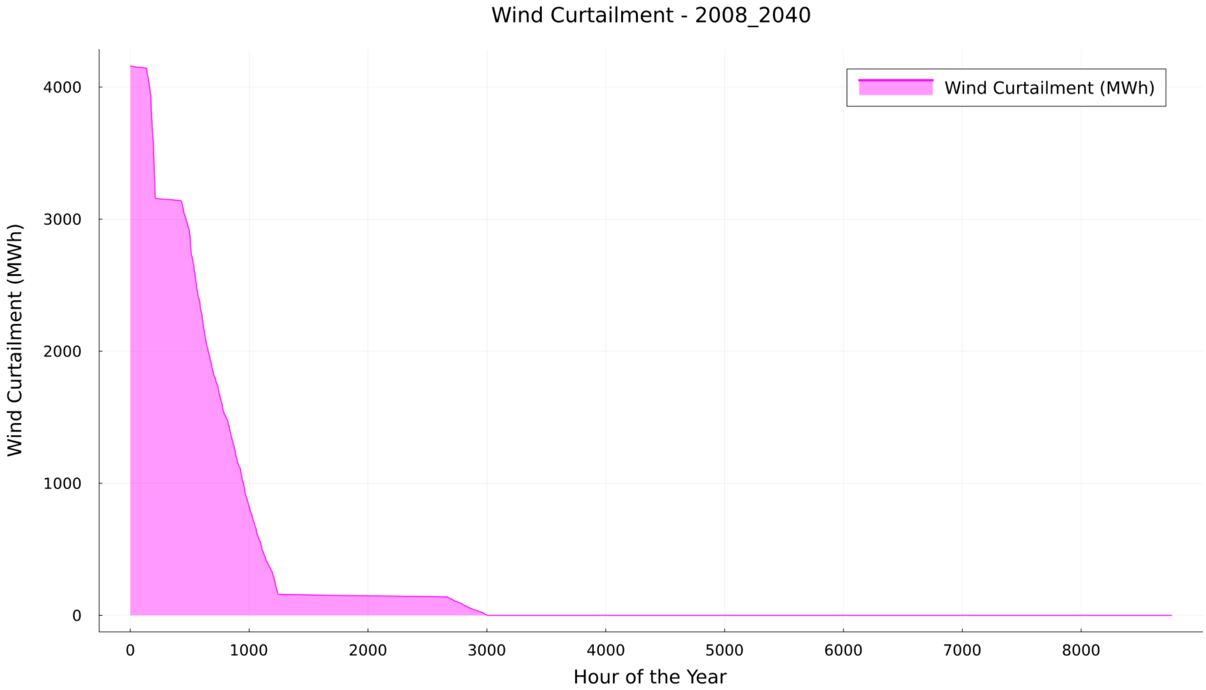

Figure B.56: Wind Curtailment Duration Curve - 2008_2040

B.5. Scenario 2009-2030

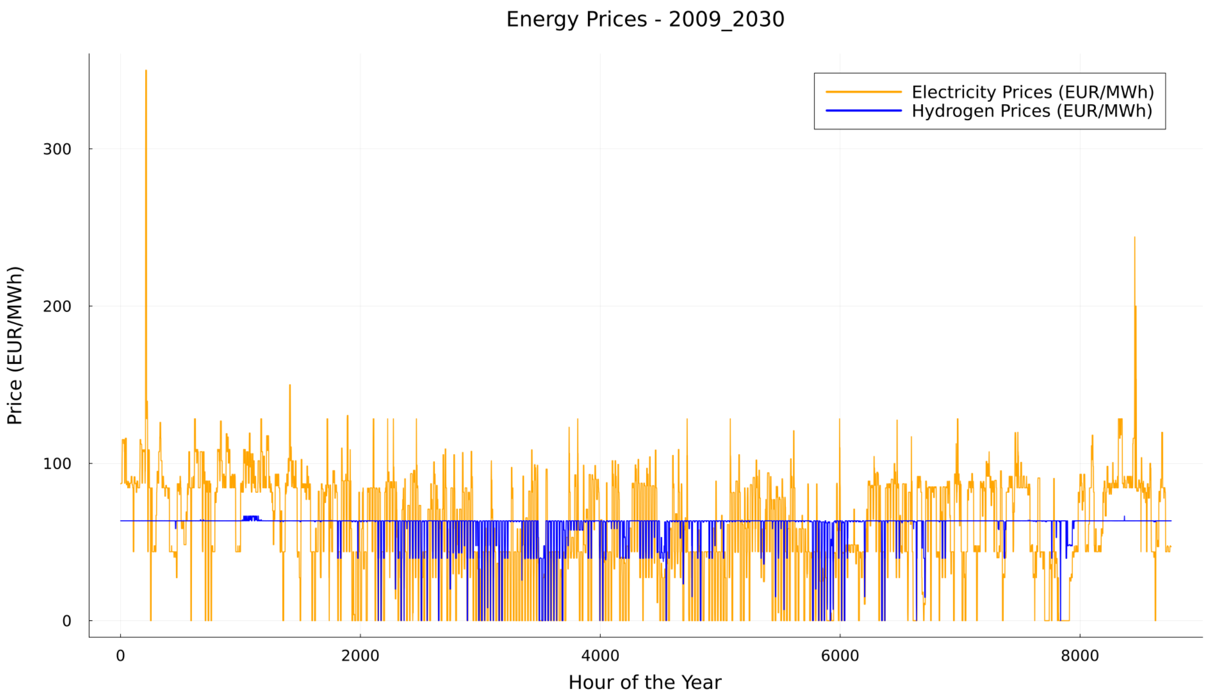

Figure B.57: Energy Prices - 2009_2030

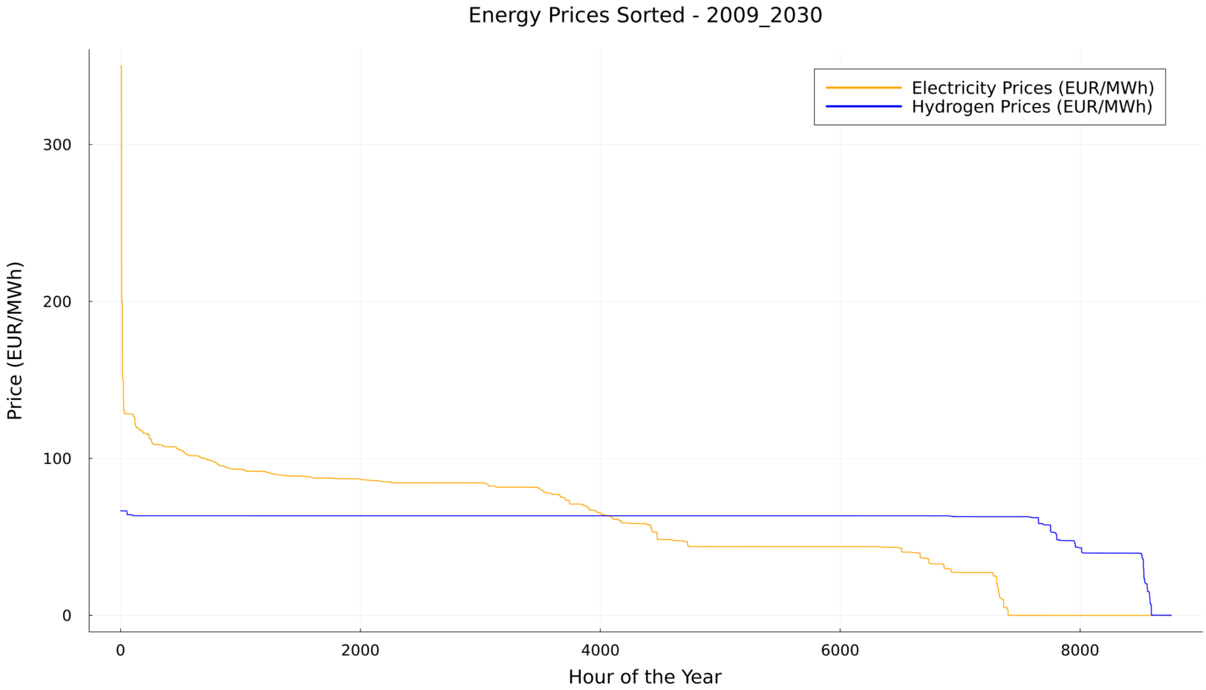

Figure B.58: Energy Price Duration Curve - 2009_2030

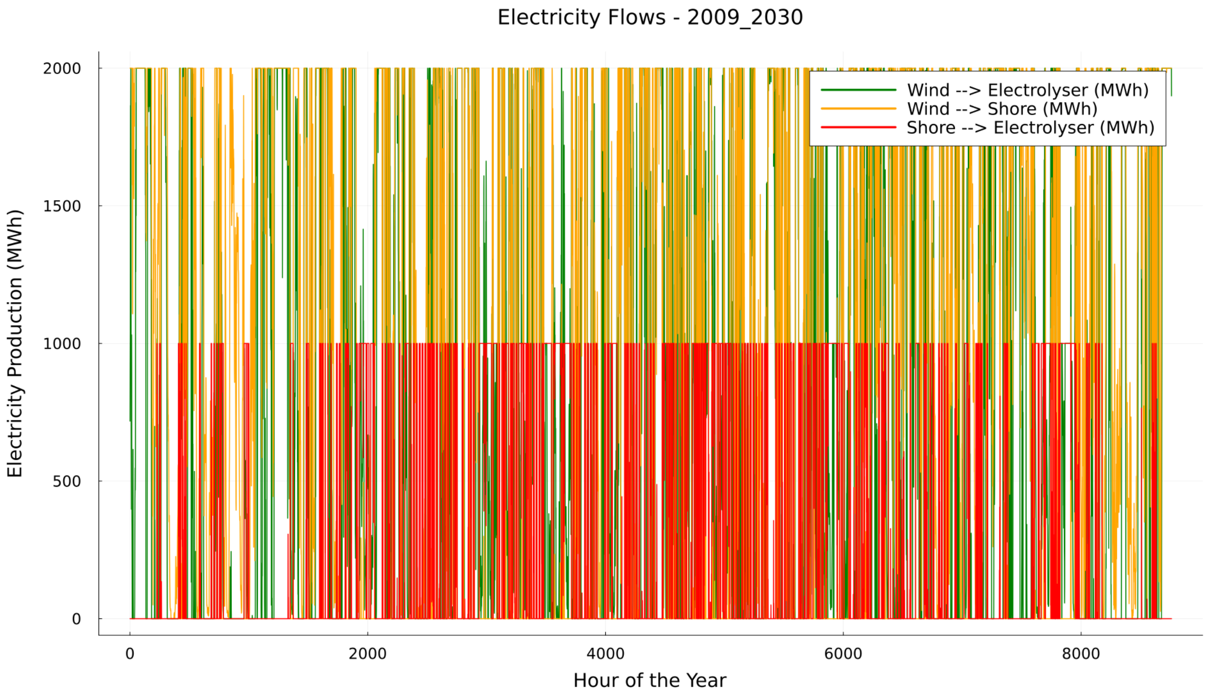

Figure B.59: Electricity Flows - 2009_2030

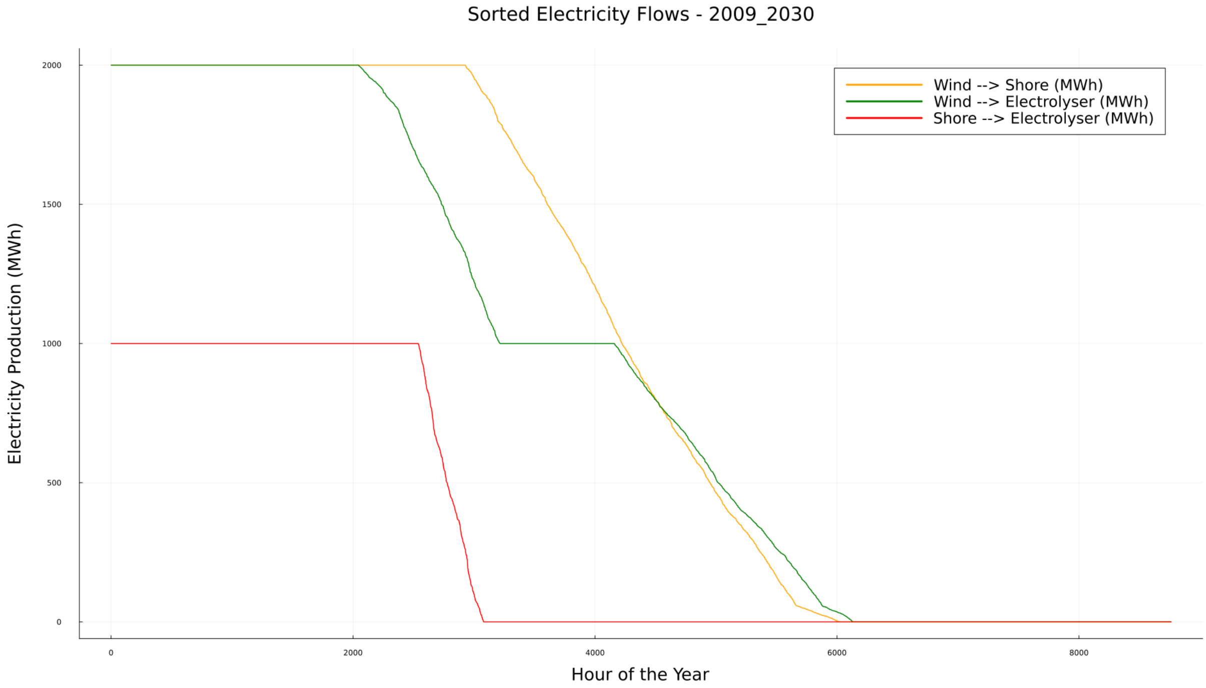

Figure B.60: Electricity Flows Sorted - 2009_2030

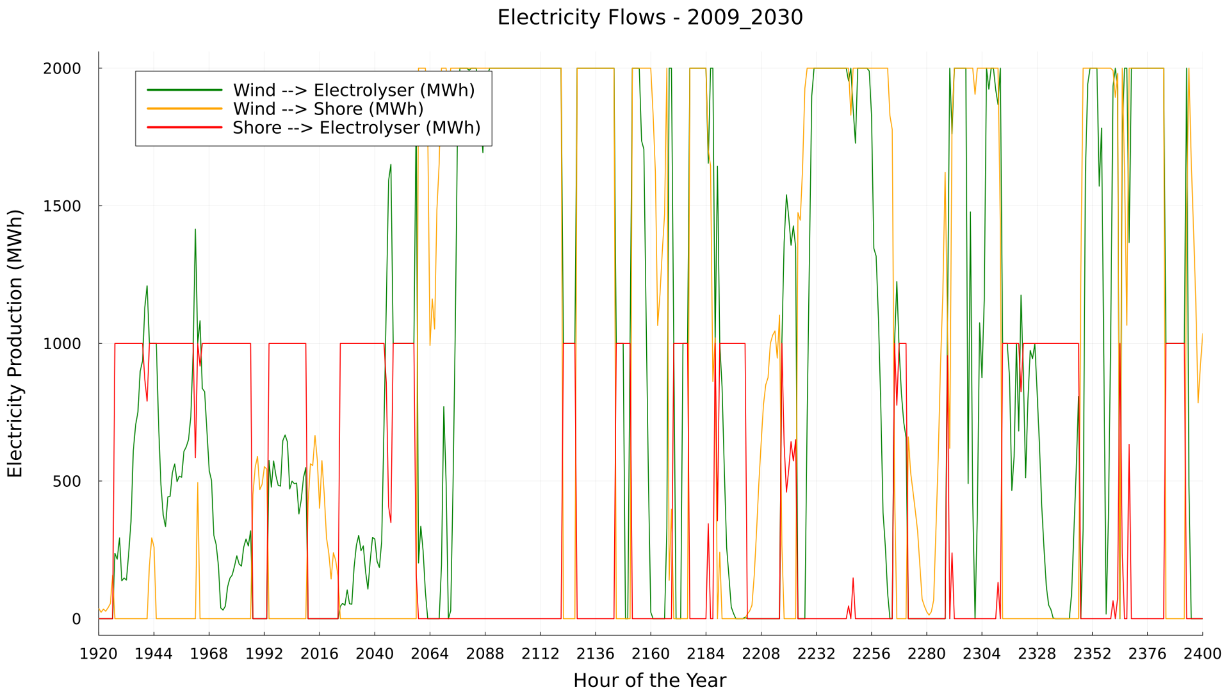

Figure B.61: Electricity Flows Zoomed - 2009_2030

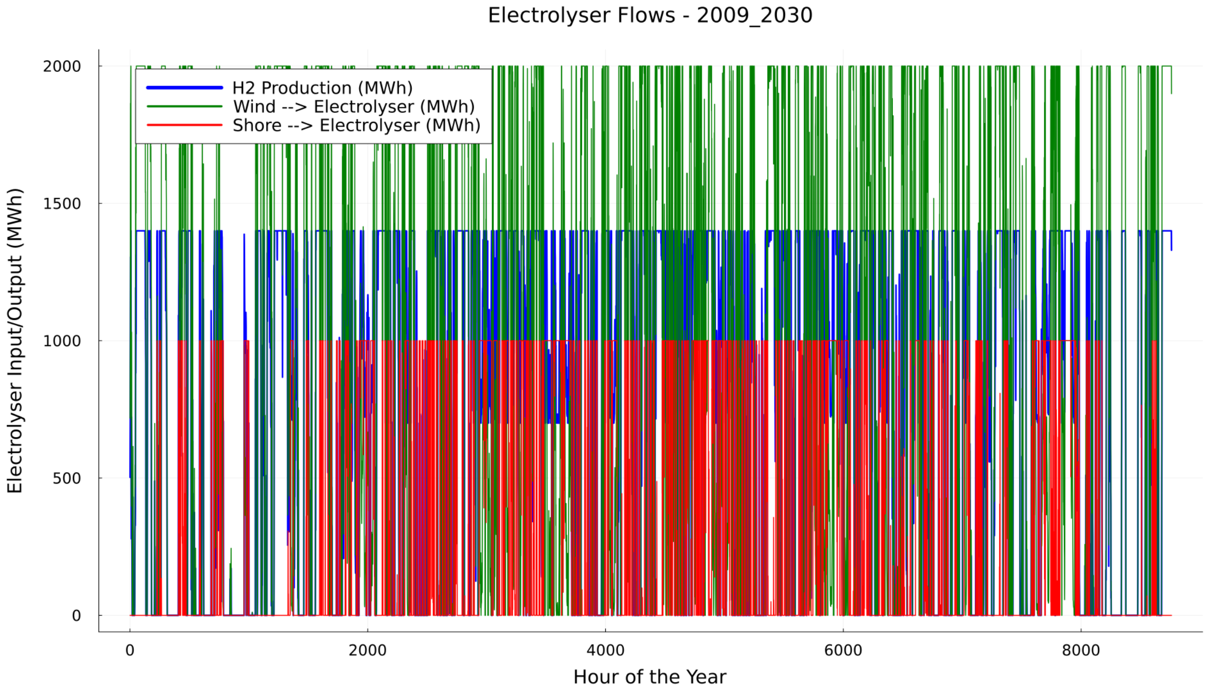

Figure B.62: Hydrogen Flows - 2009_2030

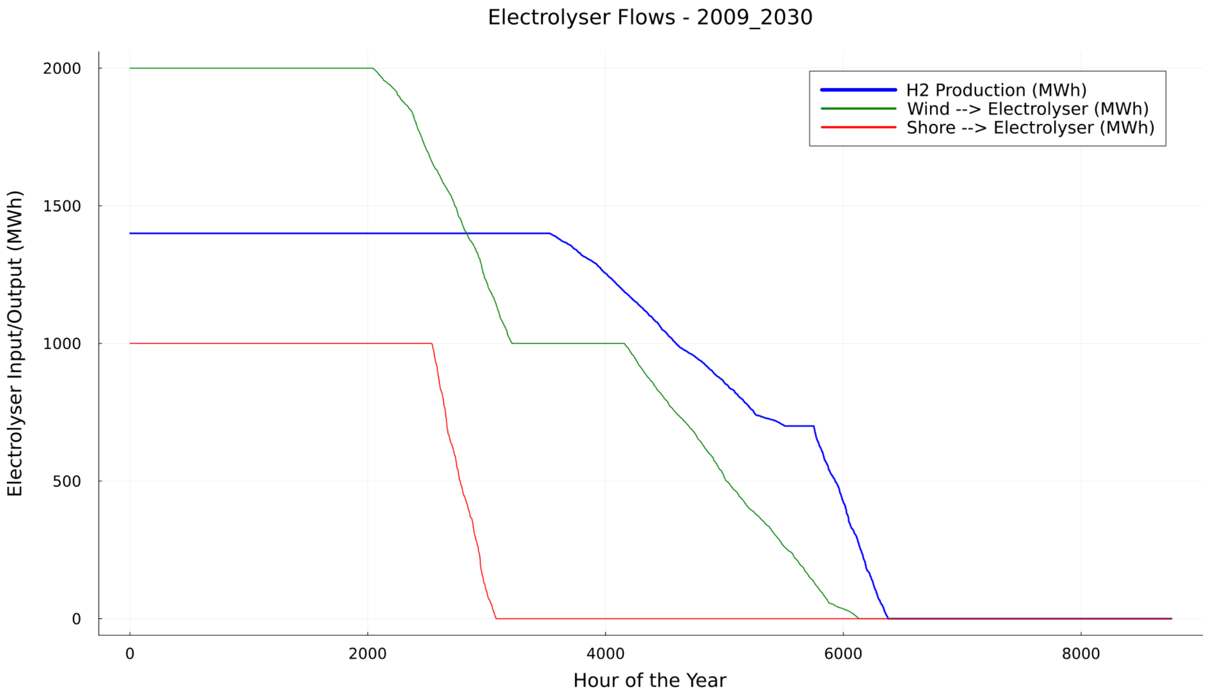

Figure B.63: Hydrogen Flows Sorted - 2009_2030

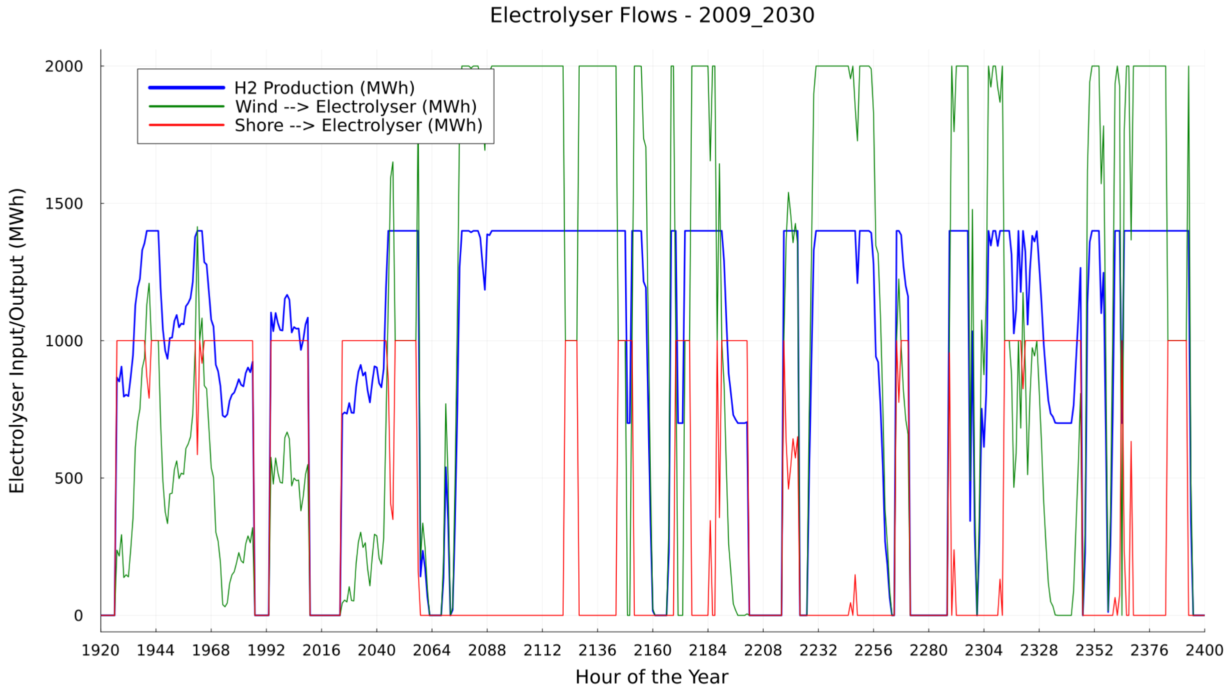

Figure B.64: Hydrogen Flows Zoomed - 2009_2030

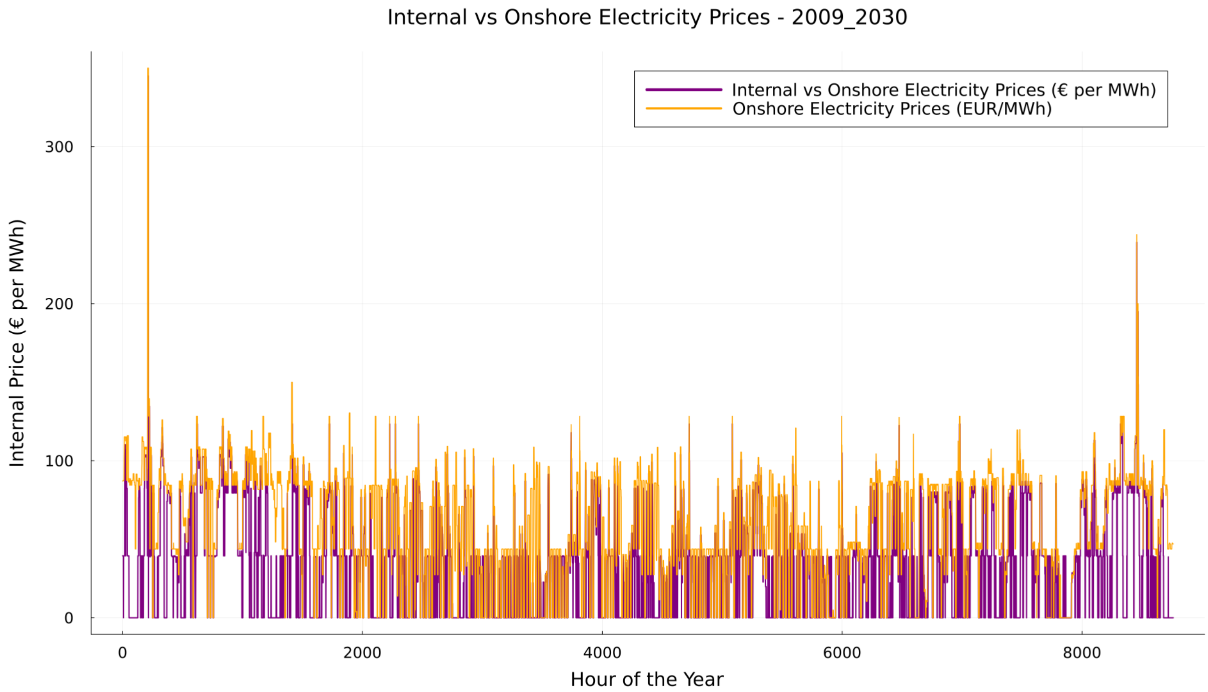

Figure B.65: Onshore vs Internal Prices - 2009_2030

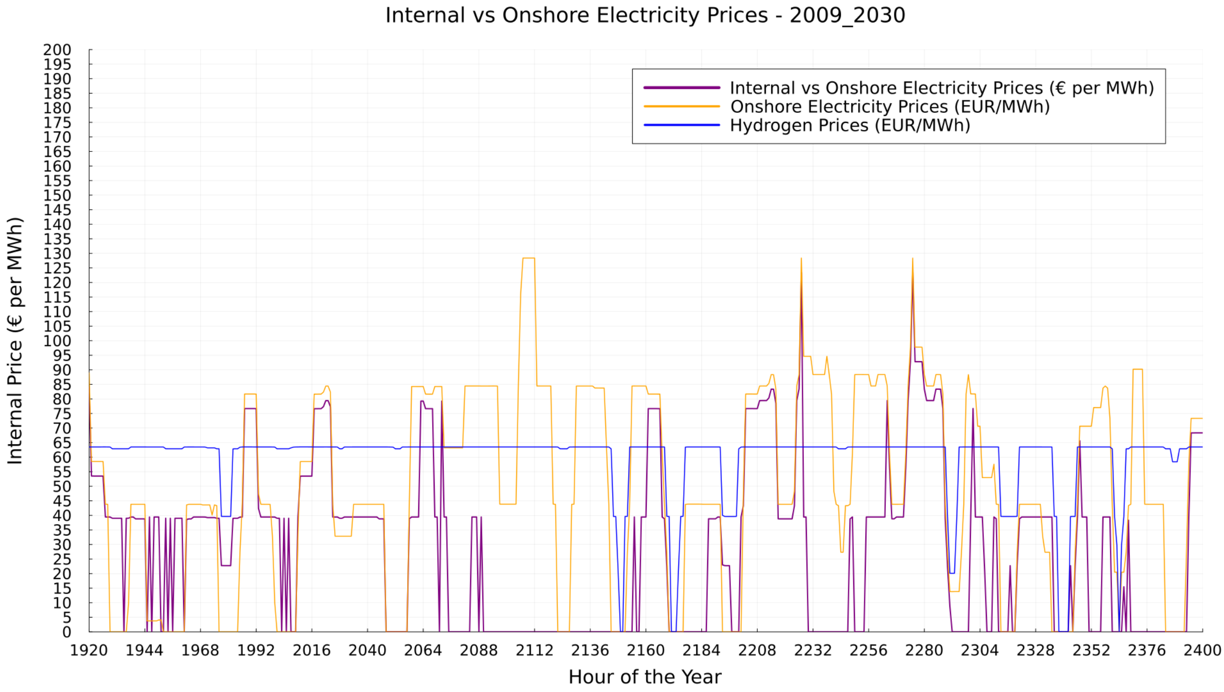

Figure B.66: Internal Prices Zommed - 2009_2030

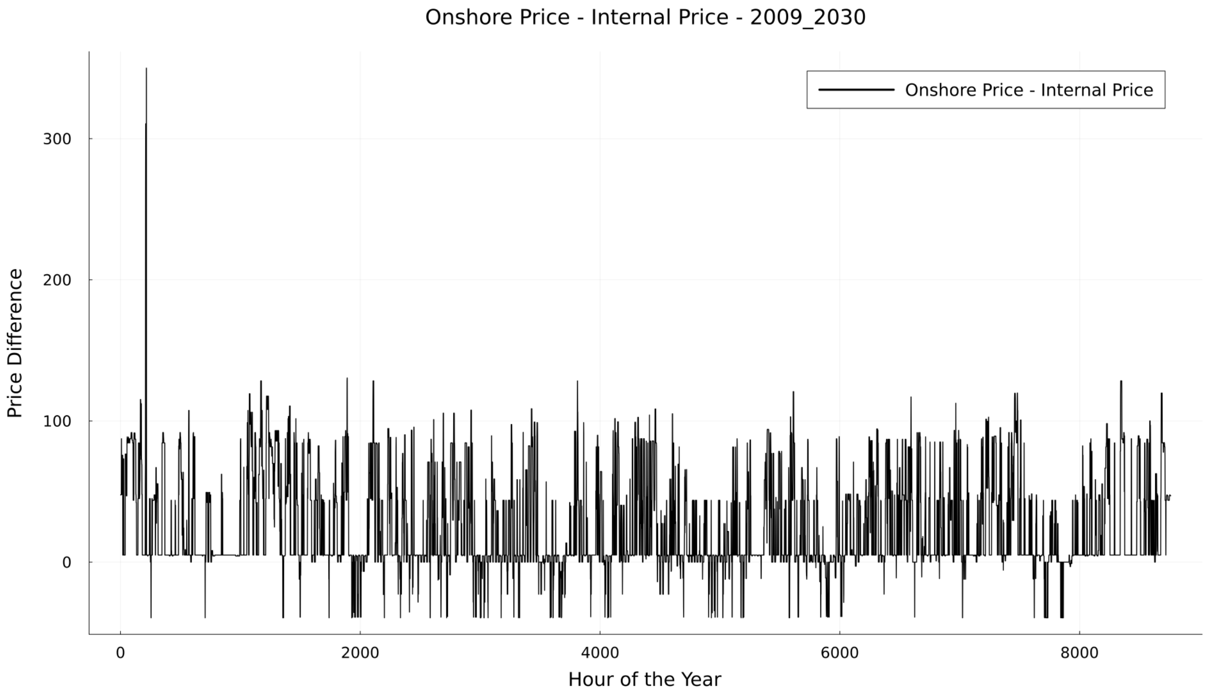

Figure B.67: Onshore - Internal Prices - 2009_2030

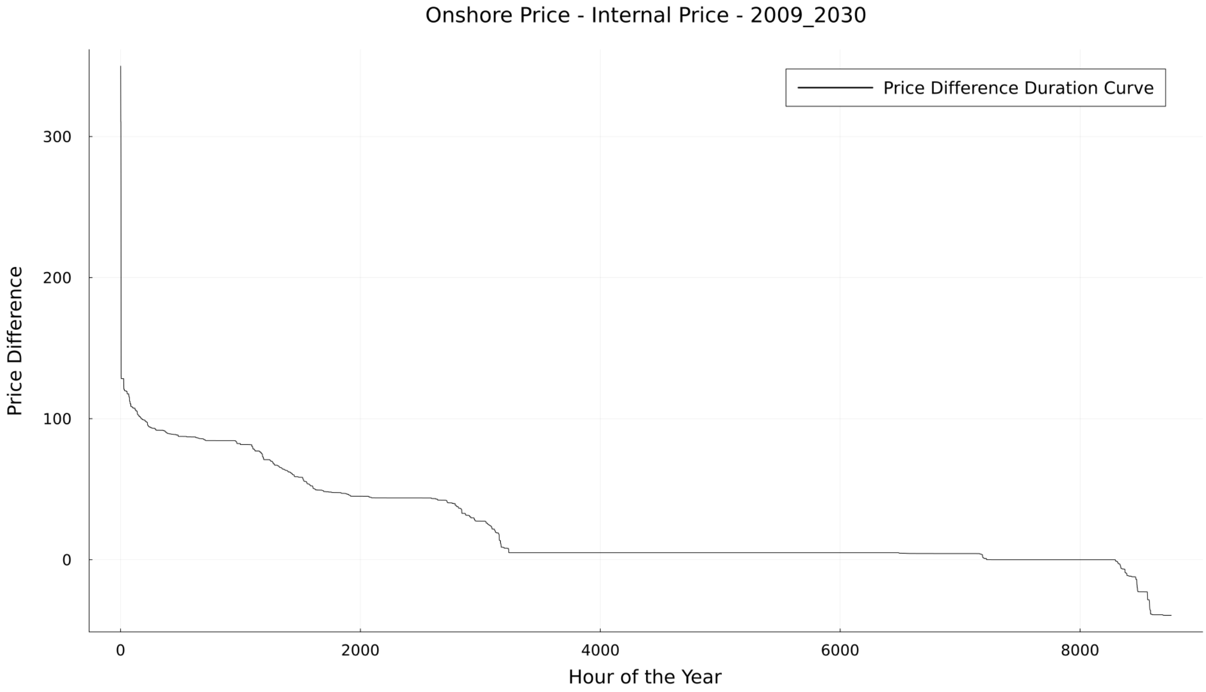

Figure B.68: Onshore - Internal Prices Sorted - 2009_2030

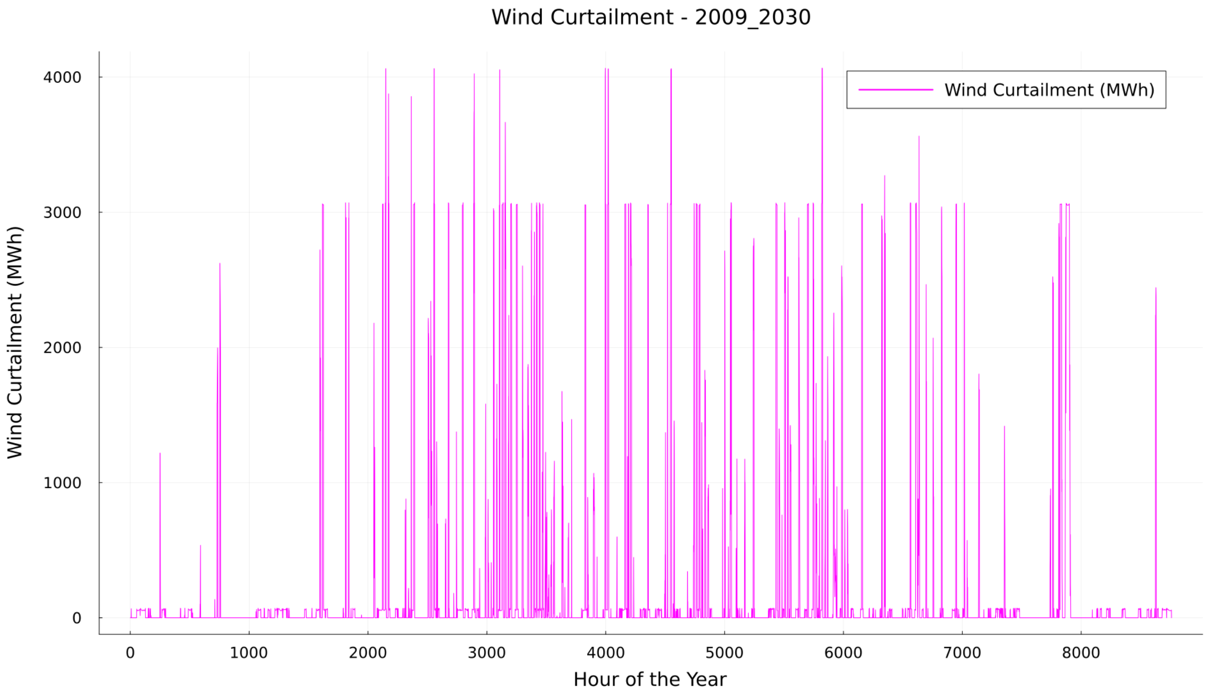

Figure B.69: Wind Curtailment - 2009_2030

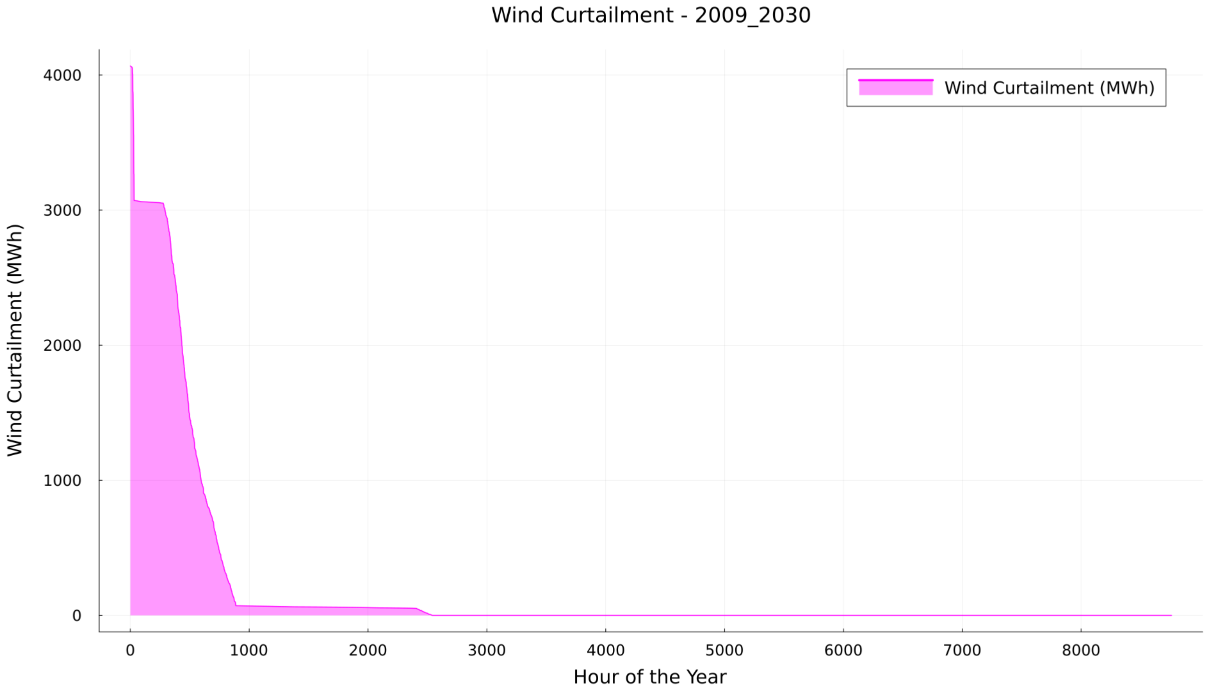

Figure B.70: Wind Curtailment Duration Curve - 2009_2030

C

Julia Code

The Julia code along with test files for energy price data and the original wind output file can be found on this Github Repository: https://github.com/GumasteAnurag/thesis-hub-config.git