North Sea Energy
offshore system integration

D3.1

North Sea Energy 2023-2025

Public Value Assessment of Offshore System Integration

Navigating the North Sea transition!

For centuries, the North Sea has been a source of economic strength, ecological richness, and international cooperation. Always subject to change, yet steadfast as a connector of nations, cultures, and economies. Today, it once again takes center stage—this time as a lighthouse region for the transition to a sustainable, affordable, and reliable energy system. The North Sea Energy program marks an important step in this development.

North Sea Energy is a dynamic research program centered around an integrated approach to the offshore energy system. Its aim is to identify and assess opportunities for synergies between multiple low-carbon energy developments at sea: offshore wind, marine energy, carbon capture and storage (CCS), natural gas, and hydrogen. At the same time, the program seeks to strengthen the carrying capacity of our economy, society, and nature.

The offshore energy transition is approached from various perspectives: technical, ecological, societal, legal, regulatory, and economic. Our publications provide an overview of the strategies, innovations, and collaborations shaping the energy future of the North Sea. They reflect the joint efforts of companies, researchers, and societal partners who believe in the unique potential of this region as a hub for renewable energy and innovation.

What makes this program truly distinctive is not only its scale or ambition, but above all the recognition that we are operating in a dynamic field of research. The energy transition is not a fixed path, but a continuous process of learning, adapting, and evolving. New technologies, a dynamic natural environment, shifting policy frameworks, and changing societal insights demand flexibility and vision. Within this program, we work together to ensure that science and practice reinforce one another.

This publication is one of the results of more than two years of intensive research, involving over forty (inter)national partners. This collaboration has led to valuable insights and concrete proposals for the future of the energy system in and around the North Sea. All publications and supporting data are available at: https://north-sea-energy.eu/en/results/

We are deeply grateful to all those who contributed to the realization of this program. In particular, we thank our consortium partners, the funding body TKI New Gas, the members of the sounding board, the stakeholders, and the engaged public who actively participated in webinars and workshops. Their input, questions, and insights have enriched and guided the program.

At a time when energy security, climate responsibility, and affordability are becoming increasingly urgent, this work offers valuable insights for a broad audience—from policymakers and professionals to interested citizens. The challenges are great, but the opportunities are even greater. The North Sea, a lasting source of energy, is now becoming a symbol of sustainable progress.

With these publications, we conclude an important phase and look ahead with confidence to the next phase of the North Sea Energy program. In this new phase, special attention will be given to spatial planning in the North Sea, European cooperation, and the growing importance of security in the energy system of the future.

D3.1

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The project has been carried out with a subsidy from the Dutch Ministry of Economic Affairs and Climate, National Schemes EZK-subsidies, Top Sector Energy, as taken care of by RVO (Rijksdienst voor Ondernemend Nederland)

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Executive summary

Introduction

In order to meet climate neutrality in 2050, offshore wind production looks to be the major option for decarbonizing the Dutch energy supply. Targets of offshore wind have risen to 50 and 70 GW for 2040 and 2050, respectively (Ministerie van EZK, 2022). However, making effective use of offshore wind as our largest supplier of renewable electricity is already becoming a challenge. Increasing network congestion in the onshore high voltage system is already preventing potential electrification in industry, as well as effective roll-out of flexible demand that is needed to absorb intermittent renewable energy production. Additionally, offshore electricity infrastructure costs are rising: the estimated costs for the infrastructure needs of planned offshore wind farms up to 2031 recently rose from 26 to 36 bln€ (Ministerie van EZK, 2023), with total cost estimates rising from 40 to 90 bln€. Attempting to landfall all future offshore wind generation solely through electricity cables will be a difficult and costly effort.

Offshore integration of energy can provide a solution to this problem. Combining different types of energy generation offshore can make better use of the infrastructure available and can lead to better usage of produced energy. In this report, we aim to evaluate the societal benefits of offshore system integration, focusing on the integration of electricity and hydrogen in the offshore system. By researching both quantitative and qualitative benefits of system integration, we aim to provide a holistic overview of the costs and benefits.

We do this by deploying a system optimization approach together with an analysis from a market perspective. Finding the cost-optimal energy system from a societal perspective gives insight into how much offshore energy is needed and how it fits into the broader system. The market modelling then is able to research the dynamics of hydrogen and electricity dispatch within that system, and compare it to existing energy scenarios.

Energy system optimization – key findings

Three scenarios are presented as a result of the societal cost-optimisation, building upon the existing ADAPT, TRANSFORM and LCI scenarios developed by TNO. These *trend-reflective* scenarios provide a range of possible future developments in industry, renewable deployment, energy demand and more, for an autonomous energy system in the Netherlands.

We see that the development of the energy system is highly uncertain due to developments in technology and cost, domestic and international policy, and geopolitical factors. Therefore, a series of sensitivity analyses is performed, to assess the effects of a more conservative offshore wind profile, a European context ambitious in renewable deployment, and a case where no offshore hydrogen production is present.

Offshore wind plays a substantial role in the future Dutch energy system in all scenarios and sensitivities

The offshore wind capacity ranges from 12 to 15 GW in 2030, 29 to 45 GW in 2040 and 40 to 70 GW of installed generation capacity for 2050. These ranges include all sensitivity analyses for the trend-reflective scenarios: a more conservative production profile for offshore wind, exclusion of offshore electrolysis and a more stringent greenhouse gas reduction target of 90% in 2040. Even on the lower bound, this is a substantial contribution to the total primary energy consumption and electricity supply. Of the available space in the Dutch North Sea, the furthest (of seven available) areas are only used in the case of very high wind deployment.

Offshore electrolysis has a larger spread across the scenarios and sensitivities
Offshore production of hydrogen is present in every result of the trend-reflective scenarios for 2050, and capacities range from 3 to 12 GW_{H2} (LHV). In earlier years, offshore electrolysis is sometimes underutilized in cases of large amounts of blue hydrogen production being installed. This early focus on blue hydrogen creates a temporary lock-in effect, delaying larger-scale offshore electrolysis deployment until closer to 2050. These findings suggest that the development of initial offshore electrolysis technology is a worthwhile pursuit, as the benefits of offshore electrolysis appear to outweigh the costs of the electricity infrastructure, even with increased costs that come with deploying it offshore.

In cases where the far offshore areas have wind power installed, they are almost always accompanied by electrolysis capacity: offshore electrolysis is the most cost-effective method of unlocking the full wind potential of the North Sea. For the northern-most regions of the North Sea, any wind capacity was accompanied by significant electrolysis capacity, reaching up to 57% electrolyser-to-wind ratio. Additionally, there are no hubs that are purely used for the purpose of electrolysis.

However, higher ratios of electrolysis to wind generation capacity generate diminished returns. While the additional capacity of hydrogen production and infrastructure allows for cost savings on electricity infrastructure, this effect greatly diminishes as the ratio of electrolysis to wind capacity goes up. The underlying cause being the value of wind electricity during times of low wind and the capacity factor of both the electrolyzer and the hydrogen infrastructure decreasing as the ratio of electrolysis-to-wind increases. The cost-optimal ratio is dependent on the distance to shore, as the relative savings of reduced electricity infrastructure increase.

Offshore electricity infrastructure is generally undersized compared to wind generation capacity
The added benefit of offshore hydrogen is an avoidance of electricity cables needed to landfall the wind energy. The resulting ratio of net cable capacity to offshore wind capacity ranges from 30 to 60% in the offshore regions where hydrogen production is deployed. Thus the deployment of offshore electrolysis removes the need for a significant amount of costly electricity infrastructure. However, even with exclusion of offshore hydrogen, the infrastructure is undersized compared to the wind capacity in an offshore region that is not very close to shore. From a societal costs perspective, the infrastructure can rather be undersized than dimensioned to the capacity of the wind farm.

A more conservative offshore wind profile shows that this could stunt deployment in the long-term
The trend-reflective scenarios are modelled with 4700 full load hours of offshore wind generation. As the used weather year (2015) is considered a 'high wind year' within the North Sea Energy programme, a more conservative estimate of 3700 is also applied. In the

system optimization results, nuclear energy then becomes more of a cost-optimal option, rising from 7 to 8 GW in the ADAPT and TRANSFORM scenarios and from 0.5 to 5 GW in LCI, diminishing the need for offshore wind.

Offshore hydrogen production results in lower cost for society
The fact that offshore hydrogen production appears in the solution of the cost optimal energy system in all investigated scenarios and sensitivity cases, indicates that offshore hydrogen results in lower cost from a societal perspective. This means that producing hydrogen offshore is beneficial for society. The benefits are, however, small, ranging from 30 – 350 million euros annually for the base scenarios. This benefit is much lower than calculated in earlier studies. The most important reason for this is the much higher cost for electrolysis, including the cost factor for going offshore, than assumed in earlier studies.

The additional costs of building electrolysers offshore are outweighed by the significant costs savings in offshore electrical infrastructure. However, cost developments of offshore hydrogen versus the offshore electricity chains are very uncertain, making estimation of potential benefits also uncertain. Even if the direct financial benefit is small, another benefit of offshore hydrogen production would be a significant amount of space that can be saved onshore. The avoided onshore space ranges from 140 – 480 hectares in 2050.

Market modelling – key findings

In addition to a system cost-optimization, we evaluate the market dynamics within the energy systems defined by the OPERA scenarios and compare the results to those based on the infrastructure operators scenarios, including North Sea Energy hub design. The least-cost hydrogen dispatch, or market optimum, shows a changing hydrogen market from 2030 to 2040 and 2050.

Starting with a mix of production options in 2030 – grey, green and imported – additional hydrogen demand is met fully with seaborne imports. In 2040, the scenarios show very different hydrogen markets: demand and production from gas vary widely. A connection to the European hydrogen network does consistently cause a large net export of hydrogen, however. Finally, the market in 2050 is fully green but prospects for hydrogen demand give a very broad range. This pathway is heavily influenced by the scenario choices: the amount of renewable energy available, a zero net import assumption and more. The electricity costs show a steady decline towards 2050, whereas hydrogen costs temporarily increase in 2040 before dropping towards 2050 due to higher marginal costs for gas-based hydrogen production, higher demand and a link to the European market.

Market-based hub value in 2050 is mainly driven by congestion
To assess the societal value of offshore integration from a market perspective, the cost-optimal dispatch is calculated for the different scenarios, with and without allowing deployment of offshore electrolysis. The comparison shows a significant decrease in the curtailed amount of electricity production of 15-44 TWh on a yearly basis from installed offshore wind capacity, when introducing offshore electrolysis. The generated electricity is used more efficiently offshore, with total yearly electrolyser dispatch increasing 8-14% across scenarios.

This more efficient market dispatch is visible in the energy carrier prices resulting from the model: results widely vary between the investigated scenarios, but all configurations show a decrease in average electricity and hydrogen prices when offshore system integration is introduced. This effect can be significant: a decrease in electricity prices of up to 22% and up to 28% for hydrogen is observed. However, the price effect is very dependent on the size of the hydrogen market and renewable energy deployment and is very small for the low-hydrogen low-renewables scenario ADAPT.

These effects are due to avoidance of congestion of the transmission lines onshore, which normally results in curtailment, but inclusion of offshore hydrogen allows for the electricity to instead be allocated to electrolyzer production. We see that offshore integration allows for better landfall of energy, as well as avoiding problems with infrastructure and onshore congestion.

The modelled energy market is sensitive to a conservative wind profile assumption
A similar sensitivity analysis of lower offshore wind as described above is performed for the market modelling. Reducing the full load hours of offshore wind from 4700 to 3700 decreases electrolyser dispatch proportional to the decrease in wind production in the infrastructure operator scenario (both -21%). In this comparison no other changes have been made to the energy system. When comparing the ADAPT and LCI scenarios to their lower wind counterparts on the other hand, even larger decreases of -28% and -32% in electrolyser dispatch can be seen. In this case, the system optimization has rebalanced supply and demand based on the new wind profile. Hydrogen demand shifts to alternatives, reducing electrolyser dispatch further. Decreasing offshore wind production leads to increasing returns for wind power: using the scarce wind power for electrolysis is too costly compared to other options.

Commodity prices also rise significantly with less wind production. The marginal costs of electricity almost double in the infrastructure operators' scenario with high renewables and hydrogen. Alternatively, the increase is lower (+30%) for the ADAPT and LCI scenarios, where the energy system responds to the decrease in wind by installing alternative capacity. Hydrogen marginal costs show a similar, albeit smaller increase in costs.

Conclusions

To conclude, we see that offshore electrolysis is a consistent outcome from a societal-cost perspective across our considered energy system configurations, when expanding the offshore wind capacity to beyond 40 GW. In that case, further North Sea areas need to be accessed and the costs of electricity infrastructure are higher than those of hydrogen deployment. However, the cost difference is small and uncertain, in particular since the future cost of electrolysis and the additional cost of doing this offshore are highly uncertain. In order to reduce the uncertainty, new analyses with new insights of future cost of the components of offshore hydrogen is needed. To reduce the costs of electrolysis, innovation funds can be allocated to (offshore) electrolysis on a large scale, comparable to the DEMO 1 and 2 projects.

In addition to the quantitative benefits, other factors speak in favor of the role offshore energy integration can play. The market simulations results show a considerable increase in electrolyser dispatch and a decrease in wind curtailment due to the introduction of offshore electrolysis, mainly driven by congestion in the onshore system. Furthermore, the addition of offshore electrolysis has a dampening price effect for both electricity and hydrogen. Finally, a spatial need of up to 480 hectares onshore can be avoided by deploying electrolysis offshore – roughly a quarter the size of the Tweede Maasvlakte.

These factors need to be taken into account along with considerations of societal support of energy technologies, strategic autonomy, energy security and many more, to make a holistic and strategic decision for the future energy system. As shown in this report, offshore wind and electrolysis can play a part in that system, but much uncertainty remains about the size of their role.

1 Introduction

Challenging landfall of offshore energy calls for system integration

In order to meet climate neutrality in 2050, the Netherlands has a set amount of options of decarbonizing its energy supply. With a 99 GW potential for offshore wind (in the case of co-use of space (Taminiau & van der Zwaan, 2022)), the North Sea is the most promising source of green energy. Scarcity of onshore space, dwindling societal support for technologies causing horizon pollution and a competitive position in the market speak in favor of a substantial commitment to offshore energy production. The Dutch government has thus aimed to scale up capacity of offshore wind to 21 GW by 2030 (Klimaatakkoord, 2019), rising to 50 and 70 GW in 2040 and 2050, respectively (Nationaal Plan Energiesysteem, 2023).

Using this generated energy in an effective way is a challenge for the future energy system. Congestion on the onshore network is already prevalent with the current, limited amount of intermittent production. With electricity from variable renewable energy increasing, as well as electricity demand, the landfall of offshore wind will only become more difficult. The prospect of increasing curtailment of wind energy calls for other solutions to optimize the amount of energy brought to shore.

One of these options, central to the North Sea Energy program, is offshore system integration. Combining offshore technologies at their respective locations can bring multiple benefits to energy production, co-use of space, ecological benefits and much more, as detailed in the rest of the NSE program. Specifically hydrogen production through electrolysis can serve as a promising counterpart to offshore wind production, with its flexibility in operation and lower associated infrastructure cost. Earlier research has pointed to offshore hydrogen production being “an economically attractive addition to onshore power-to-gas installations for some energy transition scenarios” (North Sea Wind Power Hub, 2022) and a combined power-and-hydrogen North Sea Offshore Grid system leading up to 7% relative cost decrease (6 to 14.9 bn€) to its electricity-only counterpart (Martínez-Gordon, 2022).

The societal benefit of offshore integration from both a market and system cost perspective

Therefore we research the techno-economic benefits of offshore system integration in this work package (WP3). Where the rest of the work package focuses on private system value (business case and value chain analysis), this report will investigate the public system value. The goal of this research is to analyze the societal benefits of offshore system integration of electricity and hydrogen, both quantitative and qualitative.

We do this by answering four research questions:

- How does offshore integration help in unlocking the techno-economical potential of the North Sea?
- How does an energy system optimization compare to a bottom-up approach of offshore hubs?
- How do costs and physical limits of offshore infrastructure affect hub value?
- What does the avoided spatial cost of onshore electrolysis look like?

The scope of the project extends to integration of electricity and hydrogen, with the deployment of both energy carriers being modelled in an **energy system optimization** model and an **energy market** model. This approach gives insight into both the optimal build-up of a future energy system in terms of societal cost, and the market-based behaviour of that energy system, respectively.

The results of this 'top-down' approach can be compared to the 'bottom-up' approach of WP1 – hub designs. Our outcomes give insight into a cost-optimal energy system, but do not go into detail on physical restrictions, use of space, current tenders, and have a rough geographical scope. The hub designs of WP1 take those subjects into account but miss a cost-optimal perspective. Combining insights of the two work packages results in a holistic view of the optimal use of the North Sea in terms of energy production, storage and transport.

Finally, taking a closer look at the infrastructure outcomes of the optimization, and how energy flows occur in the market-based approach, the interaction between (limitations of) infrastructure and hub value can be analyzed. Additionally, the outcomes of a cost-optimal capacity of offshore hydrogen production can be used to calculate what the avoided use of onshore space is, and its qualitative societal benefit.

Modelling results of the energy system optimisation analysis can also be viewed and accessed in an interactive environment online at https://scenarios.northseaenergy.eu/. A broader range of outcomes is displayed there than in this report, for all scenarios. Results on the international context from the market modelling are also presented in Deliverable 7.1.

2 Methodology

2.1 Joint application of both a system optimisation and market model

In order to model offshore energy integration from a broader system perspective, we use two approaches employing two models: the OPERA system optimisation model and the I-ELGAS energy market model. The OPERA model optimises the Dutch energy system, but lacks an international scope: import and export flows are an input of the model. Similarly, market price data is required to base investments on in the energy system.

The I-ELGAS model can provide these insights, but needs an energy system (generation, demand, etc.) as input. We therefore deploy the two models in succession. Starting with an I-ELGAS simulation based on an infrastructure operator scenario (as a kick start), we provide price and import data to the OPERA model. The resulting energy system is used as input to the I-ELGAS model, which refines the price and import data. This model 'cosimulator' is ran in succession for four steps to arrive at a cost-optimal energy system. A more extensive description of the coupling between the two models can be found in Appendix C.

The resulting energy system gives insights into cost-optimal investments for offshore wind and electrolysis, under different assumptions. The market modelling results in turn shows the market dynamics and price behaviour within these energy systems, and allows us to compare to the infrastructure operator scenarios and hub designs of WP1. Finally, we deviate from the starting assumptions by simulating the following sensitivity analyses:

- The influence of zero net import of electricity – analogous to strategic autonomy
- A more conservative production profile for offshore wind
- Excluding offshore electrolysis as an investment option – to quantitatively analyse benefits of offshore integration
- The effect of a more stringent greenhouse gas reduction target in 2040: 90% vs. 80%

The results of these sensitivity analyses will be analysed only for the target year 2050, to maintain a clear overview of the results. The 2040 GHG reduction target is not analysed explicitly, but will be included in presented bandwidths.

2.1.1 OPERA optimisation model builds cost-optimal energy system

OPERA is an integral energy system model of the Netherlands including, next to CO_2 emissions from combustion, all other relevant Greenhouse gas (GHG) emissions, like CO_2 process emissions, CH_4 emissions from agriculture, etc (van Stralen, 2021). OPERA minimizes the total system cost based on linear programming. It uses a societal perspective (*what is the best for the Netherlands as a whole*), and therefore uses the discount rate as advised by the central planning agency (CPB) of 2.5% and does not include taxes and levies. OPERA is developed and maintained by both TNO and PBL and has been applied in an extensive amount of projects like North Sea Energy, The TNO scenario studies based on ADAPT and

TRANSFORM (Scheepers, 2022) (Scheepers, 2024) and the TVKN project by PBL (Daniëls, 2024).

To calculate the cost optimal energy system it needs to comply with certain conditions like:

- System requirements: energy service demand need to be fulfilled (like a certain amount of steel production, passenger car kilometers, heating different type of dwellings, etc.) and for parts of the energy system in which this demand is not expressed in a driver like Mton product, kilometers, etc. a final demand needs to be fulfilled.
- Policy targets (like domestic GHG targets, energy savings targets, etc.)
- Potentials/availability of options, like an annual CO_2 storage potential, a wind offshore potential, availability of imported biomass, etc.

For import (and export) of commodities exogenous annual prices are assumed. For the import of renewable commodities, like biomass, the annual potential is important as well. For trade of electricity and hydrogen, hourly prices and volumes are used, via a coupling with the I-ELGAS model (section 2.1.2). The coupling between OPERA and I-ELGAS is described in detail in 0.

The model can be run in different modi but to avoid excessive calculation times, choices have to be made. Choices can be made in:

- The type of optimization: dynamic (optimizing over a complete time horizon, like 2030 – 2050, in one go using perfect foresight) or sequential (an optimization for each individual year, but capacities installed in one year can be transferred to the next year, based on lifetime).
- Time resolution: either using time-slices, in which hours with a similar character are grouped, or using an n-hourly resolution.
- Using regions or considering the Netherlands as one node (Sahoo, 2022).

In all OPERA runs sequential optimization is applied. In general, 85 time-slices and regionalization is applied (see 2.2.1), but for the coupling with I-ELGAS also hourly runs without regions are done.

Typical outputs are the primary energy mix, electricity and hydrogen demand and supply mix, generation capacities, etc. Important to mention is that capacities, like the capacity for wind offshore, are determined endogenously as does the demand for energy.

2.1.2 I-ELGAS market model shows dispatch and pricing

The I-ELGAS market model is applied to both the energy systems generated by the OPERA model, and to infrastructure operator scenarios. It is an integrated electricity, hydrogen and methane market model, based on linear programming. The model has been detailed and applied to the Dutch Infrastructure Outlook in a paper (Koirala B. , 2021), and subsequently used in HyChain, HyXChange and North Sea Energy programmes, among others.

The model optimizes hourly system allocation at asset-level such that demand is served at least-cost, representing competitive market allocation. The resulting system dispatch (production, conversion and transport) can subsequently be used to give insights into market behaviour dynamics and sensitivity. Finally, the merit order-based system marginal costs can be used as a proxy for energy prices. An overview of the model is shown in Figure 2.1.

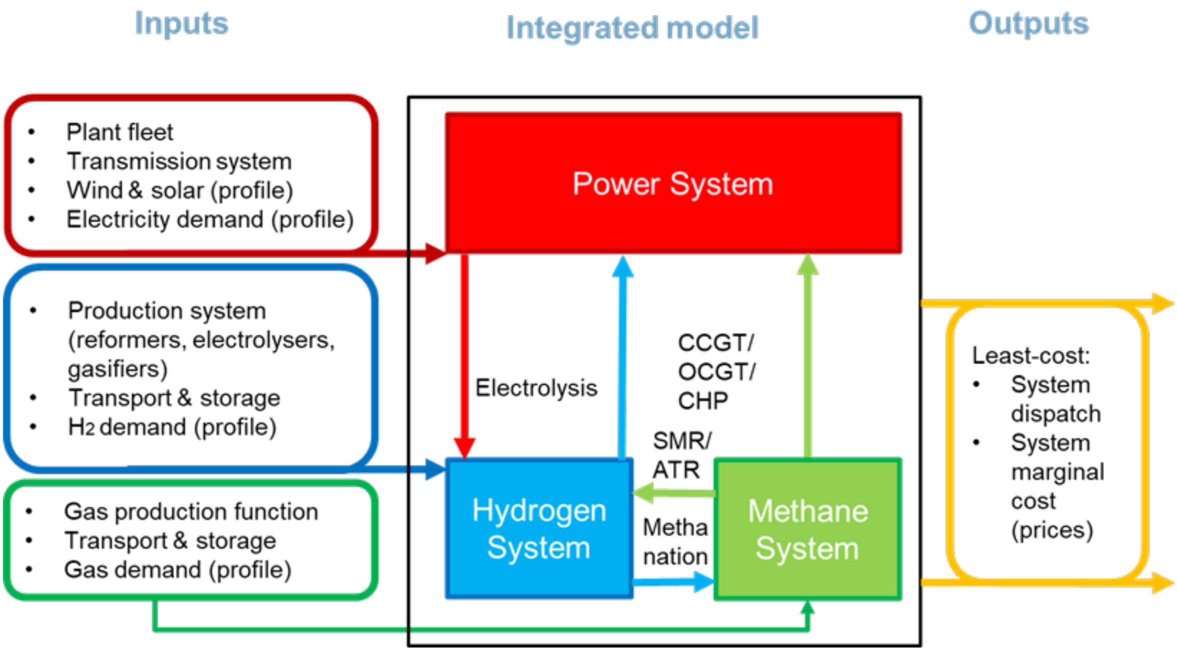

Figure 2.1. An overview of the I-ELGAS system scope.

The geographical scope of the model for this analysis includes the Netherlands (split up into 20-30 nodes per energy carrier) and eight North Sea area countries. For the electricity system, the Netherlands nodes represent the high voltage (HV) network, allowing accurate simulation of congestion on the HV-system. The three offshore hub areas, as detailed in WP1, are modelled as explicit nodes. Simulations are done for target years 2030, 2040 and 2050, optimizing for all hours of the year simultaneously.

Typical outputs are system dispatch (hourly production, transport and storage of electricity and hydrogen assets), and system marginal costs. The latter serve as proxies for energy prices, with the assumption of a competitive market of sufficient liquidity, and with perfect foresight. The values of the prices should not be taken at face value, but price effects between different simulations can provide insight into market behaviour.

A more detailed model explanation, including underlying assumptions for efficiencies, costs, etc. can be found in *Appendix B*.

In order to model the concept of strategic autonomy and to enforce a net zero import on electricity, a constraint is applied to the optimisation problem, later on in this study. This constraint states that on a yearly basis, the total net import of the Netherlands should be equal to zero. On an hourly basis, the model is free to choose the cost-optimal way to determine production, storage and transport.

2.1.3 Production profiles for variable renewable energy

As the production and conversion of variable renewable energy production by solar and wind is the focus of this modelling, choosing the right production profiles is very important. The challenge is to find a comprehensive set of profiles for offshore wind, onshore wind and solar PV production, that meets the following requirements:

- Contains data for onshore and offshore zones of the Netherlands on a NUTS-2 level, as well as surrounding European countries.
- The data is on an hourly basis and available for Climate Years (CY) that match the years of the used energy scenarios.
- Data is available for all three technologies.

The data set used for both models, that adheres to these requirements, is the Pan-European wind and solar generation time series (CorRES) developed at DTU Wind Energy (Koivisto, 2021). For offshore wind, it provides simulated hourly time series of offshore wind generation, sited at the best sites with max 100 km distance to shore, including wake losses and additional 5% of other losses and unavailability considered. Wake losses between wind areas are not taken into account. The profiles chosen for this project are for turbines with specific power of 316 W/m^2 at hub height 155m.

The only climate year that is available that matches the scenarios (both infrastructure operators' and OPERA's) and variable renewable energy (VRE) profiles, is the year 2015. In terms of offshore wind, this is considered a 'high wind year' within the North Sea Energy programme. The resulting production is thus likely to be on the higher end, with full load hours in the Netherlands averaging to around 4700.

Therefore the choice is made to do a sensitivity analysis for lower full load hours (3700 NL average). The VRE profiles with lower full load hours are created by rescaling the original profiles. The method that was used in the rescaling is based on the work of (Tejada-Arango, 2024). By choosing this method, the statistical properties of the distributions of the values in the original production profiles are preserved (e.g., the profile is not simply multiplied by a factor linearly). This allows for more realistic input data for the sensitivity analysis.

2.2 Scenario analysis

2.2.1 Dutch energy scenarios – ADAPT, TRANSFORM and LCI

For the energy system optimization, two main scenarios, ADAPT and TRANSFORM, and one scenario variant, Less Competitive and Import (LCI), are used. The ADAPT and TRANSFORM scenarios have been developed by TNO in 2020 (Scheepers, Towards a sustainable energy system for the Netherlands in 2050, 2020) and since then updated including more recent policy targets and ambitions and technology updates. In the 2024 scenario study of TNO (Scheepers, 2024) three industry variants were analysed, next to ADAPT and TRANSFORM.

In both ADAPT and TRANSFORM the 2030 and 2050 domestic GHG reduction targets are met, meaning that in both scenarios the Netherlands should be net zero. Generally speaking, ADAPT is a scenario in which society values current way of living and the industrial production and economic structure remains basically the same as the current situation. To achieve a net zero economy in 2050, the energy system relies heavily on CCS and fossil fuels can still play a substantial role. Renewable electricity potentials are modest. Domestic GHG emissions should be zero in 2050, but international bunker[1] emissions only have to be reduced by 50%.

In contrast, in TRANSFORM there is a strong societal commitment to both environmental sustainability and the urgent need to decarbonize the energy system. This results in an ambitious change of the energy system, reduction in energy intensive industry and a shift towards a more service sector based economy. There is a large potential for renewable electricity and the potential of CCS is low, but such that hard to avoid emissions like CH_4 emissions from the agricultural sector can be compensated. The scenario is more ambitious for international bunker emissions, since these emissions are assumed to be zero. Furthermore, there is an additional requirement for circular carbon for the production of chemical. In 2050 80% of the carbon used for the production of chemicals should be circular carbon.

In this study we include one of the three industrial variants that have been included in (Scheepers, 2024), the Less Competitive and Import (LCI) variant is chosen, because it is the most extreme. LCI is a variant of the TRANSFORM scenario. It is exactly the same as TRANSFORM, only not for the four most energy intensive industries activities: the chemical sector, fertilizer production, the refinery sector and steel production. In LCI those four industries are more or less halved in production volume as compared to TRANSFORM and they rely on import of semi-finished products like for example hot-briquetted iron, i.e. iron that is already reduced.

In 0an overview is given of the most important scenario parameters for this study. A more extensive overview can be found in (Scheepers, 2024). In *Table 2* the total wind offshore potential for 2030, 2040 and 2050 are given. For 2035 and 2045 interpolation is used. As mentioned in section 2.1.1 regions are used in the OPERA modelling, both onshore and offshore. These regions, seven for both onshore and offshore, are given in Figure 2.2. The 2050 offshore potentials are represented in this figure, in which the potentials per offshore region are given between brackets for ADAPT and without brackets for TRANSFORM and LCI[2]. The purple areas, the hubs, align with the hubs as used in other work packages of NSE5. To end up with 70 GW for TRANSFORM and LCI, additional searching areas, next to the area west of Zeeland and North- and South-Holland and the hubs, are needed. Therefore two additional areas have been defined, the red areas in Figure 2.2: North-West and Top-North. These areas have been inspired by similar areas defined in the TYNDP 2024 Sea-Basin ONDP report (TYNDP, 2024). Note that the shape of the red areas is just illustrative. For ADAPT the red areas are not needed to reach the potential for 40 GW.

[1] International shipping and aviation

[2] Note that with the offshore regions individual wind farms or areas are presented, for example in the area west of North- and South-Holland. Those wind farms are not individually included. The total potential, in this case 10.1 GW, is included and the red note is used to calculate cable and pipe line distances.

Table 2.1. Wind offshore potentials in Adapt, Transform and LCI in 2030, 2040 and 2050 in GW

	2030	2040	2050
ADAPT	12.2	36.0	40.0
TRANSFORM & LCI	14.2	44.9	70.0

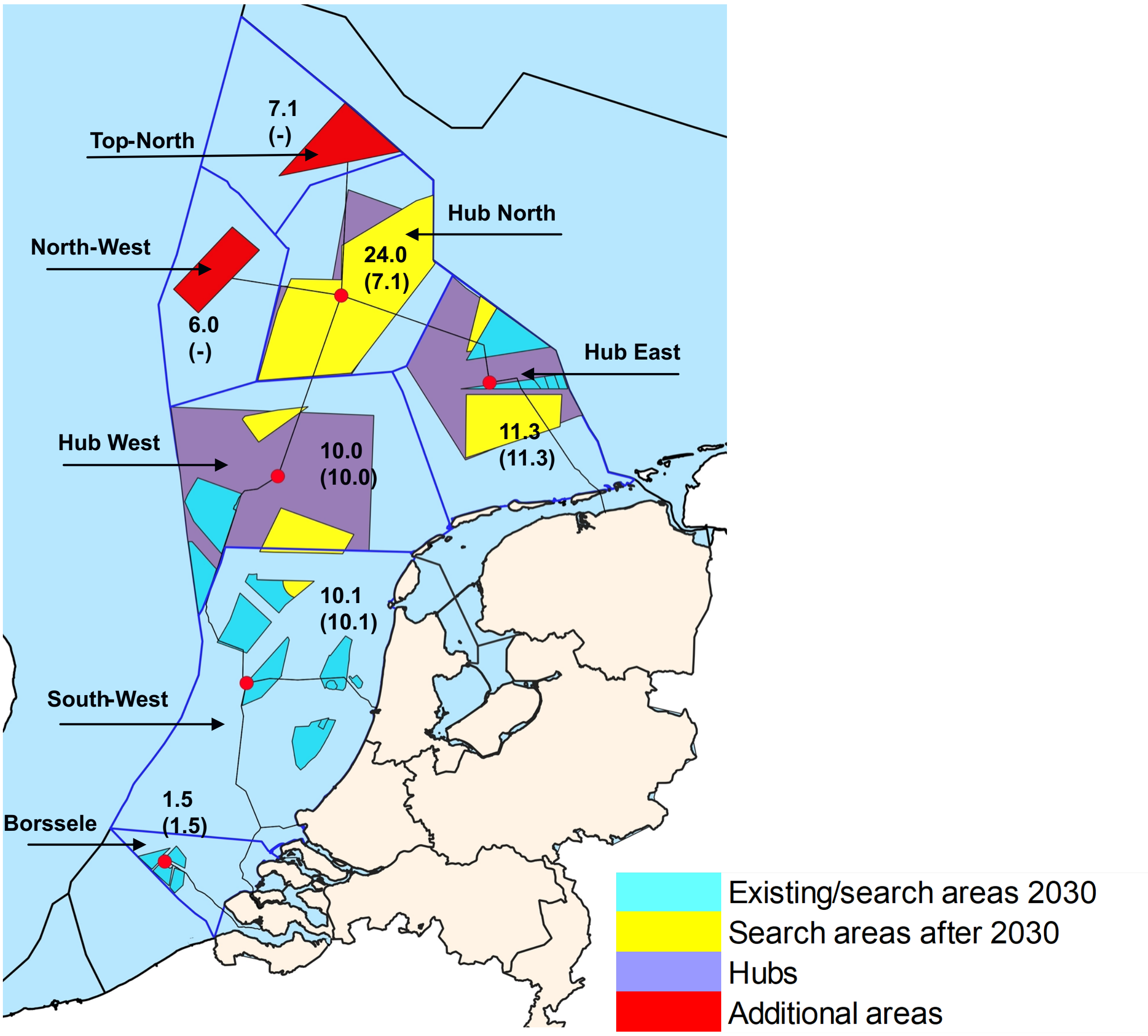

Figure 2.2 Regionalization used in OPERA, including the distribution of the 2050 offshore potential. Values for ADAPT between brackets and for TRANSFORM and LCI without brackets.

The distribution of wind offshore capacity used in this study deviates from (Scheepers, 2024). The current study is more in line with the most recent areas that are foreseen to be developed. Furthermore the currently used 2030 wind offshore potentials are not 16 GW anymore.

Other changes compared to (Scheepers, 2024) are updated costs for electrolysis (see 0), updated data for direct air capture and for the production of aromatics and increase nuclear energy potentials in 2050.

2.2.2 Dutch network operator scenarios – II3050

The market modelling approach is applied both to the OPERA scenarios described above, and the Dutch network operator scenarios, presented in the Integrale Infrastructuurverkenning 2030-2050 (II3050) (Netbeheer Nederland, 2023). The scenario's in II3050, set up by the Dutch Infrastructure Operators (IO), sketch four pathways towards climate neutrality in 2050. In order to analyse the effects of development paths on the energy infrastructure and required investments following from these effects, the scenario choices constitute a scenario base that covers all the extremes, in terms of renewable energy, hydrogen market development, autonomous production, international trade and more. The IO scenarios do not necessarily provide a 'realistic', middle-of-the-road scenario and are therefore complemented by the cost-optimal scenarios generated by OPERA.

Of the four pathways, two are chosen in WP1 of the North Sea Energy programme, in order to build a hub design in as different as possible hydrogen markets: National Leadership (NAT) and Decentralized Initiatives (DEC). The first scenario (NAT) assumes industry staying largely the same, with a large electrification effort, high amount of offshore wind (72 GW in 2050) and lower hydrogen demand and production. The latter (DEC) assumes a decrease in energy-intensive industry, 45 GW offshore wind in 2050, and more hydrogen demand production. The bottom-up approach of WP1 is then applied to place the capacities offshore wind and electrolysis in the North Sea, in order to best serve the scenario's demand. The energy hubs resulting from this work are integrated into the I-ELGAS model, albeit simplified to three nodes containing offshore wind and hydrogen production. An overview of the installed capacities for offshore wind and electrolysis is shown in the table below. Note: the numbers used are from sprint 2 results and differ slightly from the final results of WP1.

Table 2.2. Overview of hub capacities of offshore wind and electrolysis from hub design of WP1.

	2030			2040			2050		
Hub	North	East	West	North	East	West	North	East	West
Offshore wind [GW_e]	0	1	2	12	7	8	24	11	10
Electrolysis [GW_e]	0	0	0	6	2	0	12	1.5	0

2.2.3 European energy scenarios - TYNDP

Finally, the market model requires European energy scenarios as input to accurately model the hub dispatch in a broader European context. As international trade and price developments are of high influence to the Dutch electricity and hydrogen markets, a comprehensive scenario base of the surrounding countries is essential to accurately model the effects of offshore integration. The only scenario base available that has a high enough level of detail and provides data for 2030, 2040 and 2050, is the Ten Year Network Development Plan (TYNDP), published by ENTSO-E and ENTSO-G. In this research, we use the most recently published version: TYNDP2024.

Similar to the II3050 scenarios, TYNDP presents different pathways to analyse the future infrastructure needs. These pathways, Distributed Energy (DE) and Global Ambition (GA), show a split in scenario choices for industry, electrification and developments of electricity and hydrogen markets. We combine the Dutch and European scenarios according to their scenario choices: II3050-NAT and TYNDP-GA forming a combination, and II3050-DEC and TYNDP-DE. The whole system (hub design WP1 + II3050 scenario + TYNDP scenario) provides a complete energy system to be modelled in the I-ELGAS model.

Since the goal of the TYNDP scenarios is to analyse the infrastructure needs under a wide spectrum of energy system pathways the DE and GA scenarios do not represent a conservative or realistic outlook. Additionally, ACER has called for improvements on the TYNDP scenarios, notably on the DE and GA scenarios both being 'high hydrogen scenarios' (ACER, 2024). In order to provide a more realistic outlook for the European context, we therefore choose the third TYNDP scenario, National Trends (NT), for the years 2030 and 2040. The NT scenario is built up out of countries' own energy outlooks of current policy, and is not available for 2050.

To summarize, the II3050 scenarios are **existing network operator scenarios** for the Netherlands, of which Nationaal Leiderschap (NAT) is used along with the hub design from WP1. The ADAPT, TRANSFORM and LCI scenarios are **generated system optimization scenarios** for the Netherlands, as a result from the OPERA modelling. Finally, the TYNDP scenarios are **existing European network operator scenarios**, of which we use Global Ambition (GA) for 2050 and National Trends (NT) for 2030 and 2040, which match the NAT scenario best and are least extreme in terms of renewable deployment.

3 Energy system optimisation results

The results of the energy system optimization are split into two scenario sets: the **trend-reflective** scenarios and the **explorative** scenarios.

This division was necessary due to initial simulations without constraints on net electricity imports, which led to significant electricity imports of 40-113 TWh annually into the Netherlands by 2050. These high imports are caused by ambitious renewable energy deployment assumptions in neighboring North Sea countries from the TYNDP2024 scenarios. While these simulations offer insight into Dutch deployment of (offshore) energy in the context of a very high renewable deployment in neighboring countries, they tell only one side of the story. Optimizing the Dutch energy system in a situation where neighboring countries meet their most ambitious targets, will logically lead to minimal national investments. These are considered explorative scenarios.

To be able to provide a broader range of results that more accurately reflect the current trends, simulations were also performed with a constraint on the yearly net electricity imports, set to zero. This assumption, analogous to strategic autonomy of energy, is in line with the Nationaal Plan Energiesysteem (Rijksoverheid, 2023). These are considered the trend-reflective scenarios.

3.1 Trend-reflective scenarios

Below, the trend-reflective scenarios with net-zero electricity import constraints are analysed for 2030, 2040, and 2050. Additionally, given uncertainties related to technological developments, costs, policies, and geopolitical factors, extensive sensitivity analyses were conducted for 2050 to explore variations within these scenarios. Results from the explorative scenarios are presented separately. Additional graphs with energy system results can be found in Appendix E.

3.1.1 System overview

This section provides an overview of the primary energy mix under the ADAPT, TRANSFORM, and LCI scenarios. These scenarios illustrate how different assumptions regarding industrial activities, renewable energy potentials, and carbon management influence the overall structure and scale of primary energy demand.

Industrial activity significantly influences primary energy demand

Figure 3.1 illustrates the primary energy mix for ADAPT, TRANSFORM, and LCI. ADAPT consistently shows the highest primary energy demand, driven mainly by high industrial activity and substantial demand for bunker fuels. The noticeable increase from 2040 to 2050 results primarily from intensified electrolysis for hydrogen production and the corresponding conversion losses.

Furthermore, the role of fossil fuel varies by scenario. In ADAPT, fossil fuels continue to play a substantial role even by 2050. This persistence is enabled by extensive use of carbon capture and storage (CCS), moderate reduction targets for bunker emissions (50%), and the absence of requirements for using circular carbon in chemical production. In contrast, the fossil fuel use observed in TRANSFORM and LCI mainly results from allowances permitting 20% of chemical production from fossil carbon.

The potential pathways to renewable integration and net-zero ambitions are diverse
In TRANSFORM and LCI, wind energy is the predominant renewable source, supplemented by bio-energy and other renewables. ADAPT, however, relies more heavily on fossil fuels, bio-energy, and other renewables due to limited wind energy potential. Achieving net-zero domestic energy systems is challenging for ADAPT and TRANSFORM, requiring full deployment of wind, CCS, and significant nuclear energy. LCI, characterized by a smaller industrial sector dependent on imports, requires fewer nuclear and solar resources to achieve net-zero.

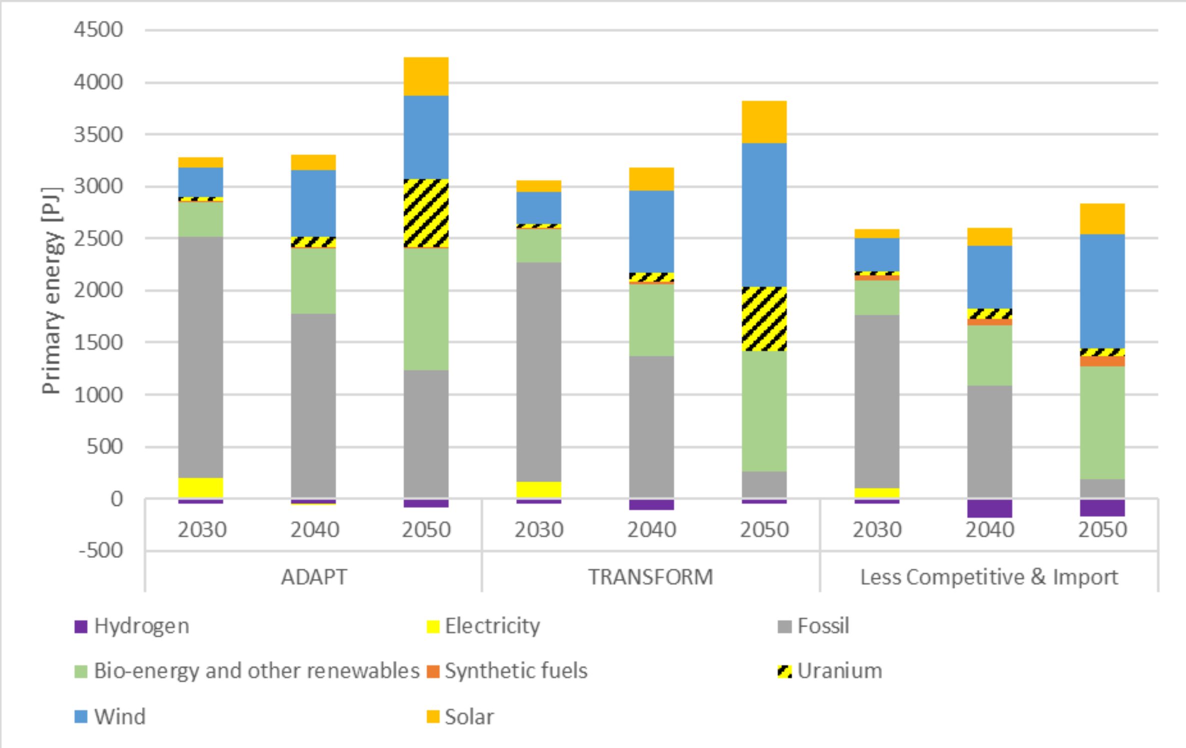

Figure 3.1: Primary energy mix for ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in PJ. Primary energy mix is including demand for bunker fuels and feedstocks.

These scenarios highlight diverse pathways towards energy transition, reflecting varying industrial scales, renewable potentials, and carbon management strategies, corroborating findings from Scheepers (2024). A more detailed analysis of primary energy and more generic parts of the energy system can be found in that report.

The development of the energy system is highly uncertain due to developments in technology and cost, domestic and international policy, and geopolitical factors. In order to gather robust insights under such uncertain circumstances, a large number of sensitivities were tested. The focus of this chapter is on the patterns and dynamics that emerge from this large dataset, with a particular interest in the boundaries and the dependencies of offshore energy infrastructure deployment.

3.1.2 Offshore energy infrastructure deployment

Offshore wind plays a substantial role in a future Dutch energy system in all scenarios and sensitivities

The absolute value of wind deployment ranges from 40 to 70 GW of total installed generation capacity for 2050 across all scenarios and sensitivity analyses. In the trend-reflective scenarios, this lower bound represents the ADAPT outcomes, where the offshore wind potential is constrained to 40 GW. The upper bound of 70 GW is universally where the TRANSFORM scenario ends up in 2050, which is also the maximum wind potential. This is not a hard constraint, but a consequence of the limitations in fossil alternatives, and the demand for renewable electricity, which characterise the scenario. The LCI scenario varies within these boundaries and showcases the variations resulting from different scenarios and sensitivities. From these findings it appears that from a system cost perspective, significant offshore wind deployment is warranted and should be actively pursued in the Netherlands.

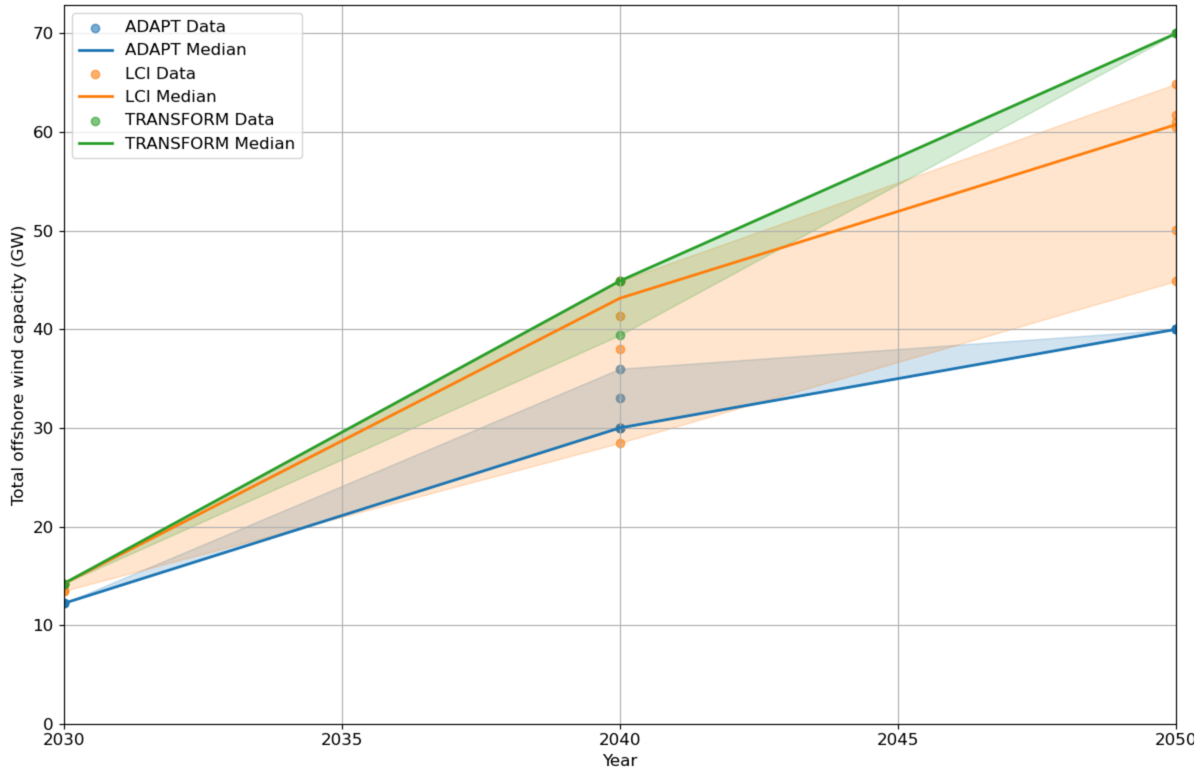

Figure 3.2: The deployment of offshore wind over the years for the trend-reflective scenarios.

Offshore electrolysis is used in all cases, but has a larger spread across scenarios
Figure 3.3 shows that all scenarios in the trend-reflective case use offshore electrolysis to some extent. The minimum appears to be around 3 GW_{H2} (LHV), and the maximum ranges all the way to 13 GW_{H2}. This significant deployment of offshore electrolysis reflects that, despite higher initial investment costs associated with offshore electrolysis, these are often offset by substantial savings in electricity infrastructure costs.

The figure also warrants some context to the results and the discrepancies between the scenario's, which might appear unintuitive. For instance, in the TRANSFORM scenario, significant early investments are made in blue hydrogen production chains utilizing carbon capture and storage (CCS). This early focus creates a temporary lock-in effect, delaying larger-scale offshore electrolysis deployment until closer to 2050. These findings suggest that the development of initial offshore electrolysis technology is a worthwhile pursuit, as they can potentially supply system benefits over time. To what extent offshore electrolysis will play a role in the end is more uncertain, as shown by the large spread in installed capacity.

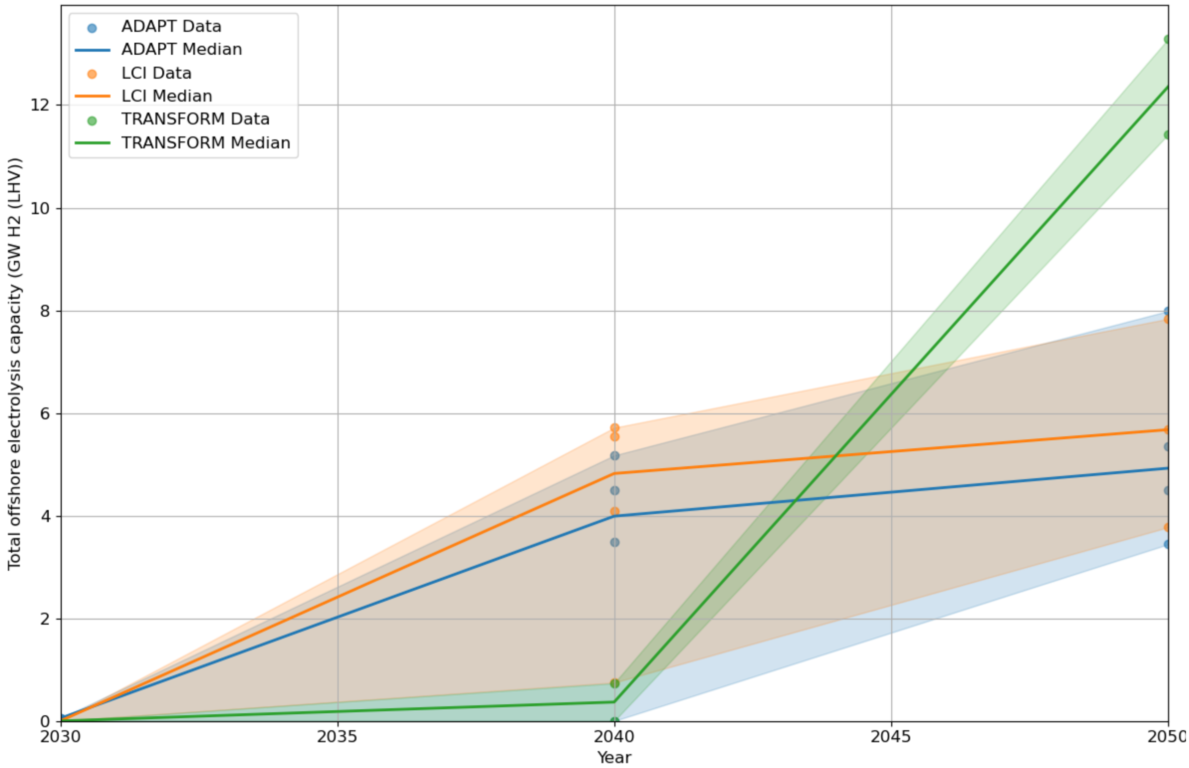

Figure 3.3: The deployment of offshore electrolysis over the years for the trend-reflective scenarios.

The furthest hubs, North-West and Top-North, are only used in case of high total wind deployment.
The median for the offshore wind deployment in the trend reflective scenario for the North-West and Top-North is mostly zero, with the exception of North-West in 2050. Generally, distant offshore hubs like North-West and Top-North remain unused due to higher infrastructure costs. Intuitively, one can imagine the process of filling the hubs as a sequential process further from shore. There is little reason to start installing capacity in the hubs that are furthest away, until the ones closer by have reached their full potential. These

findings reaffirm the notion that offshore infrastructure planning is sequential, from the shore outwards.

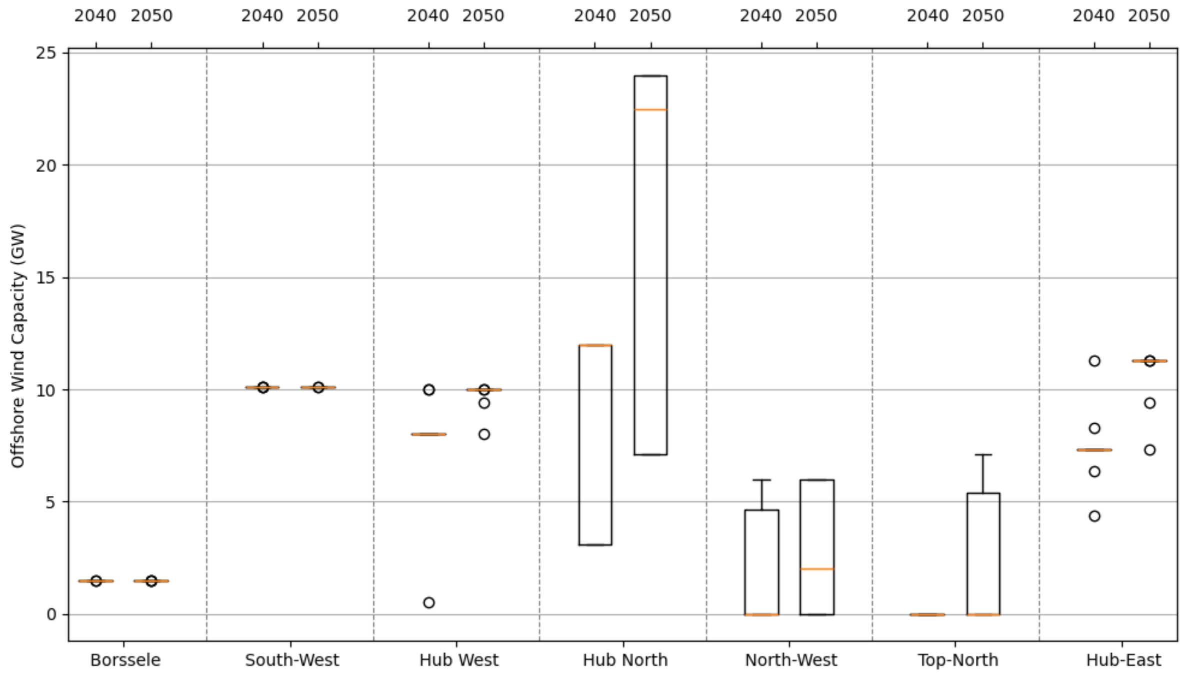

Figure 3.4: Box and whiskers plot of the offshore wind capacity per region for 2040 and 2050.

Higher ratios of electrolysis to wind generation capacity generate diminished returns
This is not immediately clear from the outcomes in the current figures, but this understanding is foundational to some of the other findings and conclusions. There are two important factors causing the diminishing returns of additional electrolysis and hydrogen infrastructure. Firstly, while initially the additional capacity of hydrogen production and infrastructure allows for cost savings on electricity infrastructure, this effect greatly diminishes as the ratio of electrolysis to wind capacity goes up. The value of wind electricity during times of low wind is high compared to the value of hydrogen at that time, and thus it is worthwhile to install electricity infrastructure to get energy to shore, even if more electrolysis and hydrogen infrastructure would be available Secondly, the capacity factor of both the electrolyzer and the hydrogen infrastructure decrease as the ratio of electrolysis to wind increases. The higher the ratio of electrolyzer capacity, the fewer the moments where additional electrolysis capacity can be used to produce additional hydrogen, decreasing the relative value.

These two effects combined dictate the diminishing returns for additional hydrogen capacity, and cause the maximum cost-optimal ratio that we see across the findings. This ratio is dependent on the distance to shore, as the relative savings of reduced electricity infrastructure increase. This understanding is important and is fundamental to the findings that there is a maximum cost-optimal ratio, which should be taken into account while planning the offshore energy infrastructure.

Initial offshore electrolysis deployment occurs in Hubs East and West, with eventual expansion to Hub North

Electrolysis deployment initially saturates in Hubs East and West before expanding significantly into Hub North around 2050. As the ratio of electrolysis to wind capacity increases, the marginal value of additional electrolysis decreases, prompting strategic shifts to less saturated hubs.

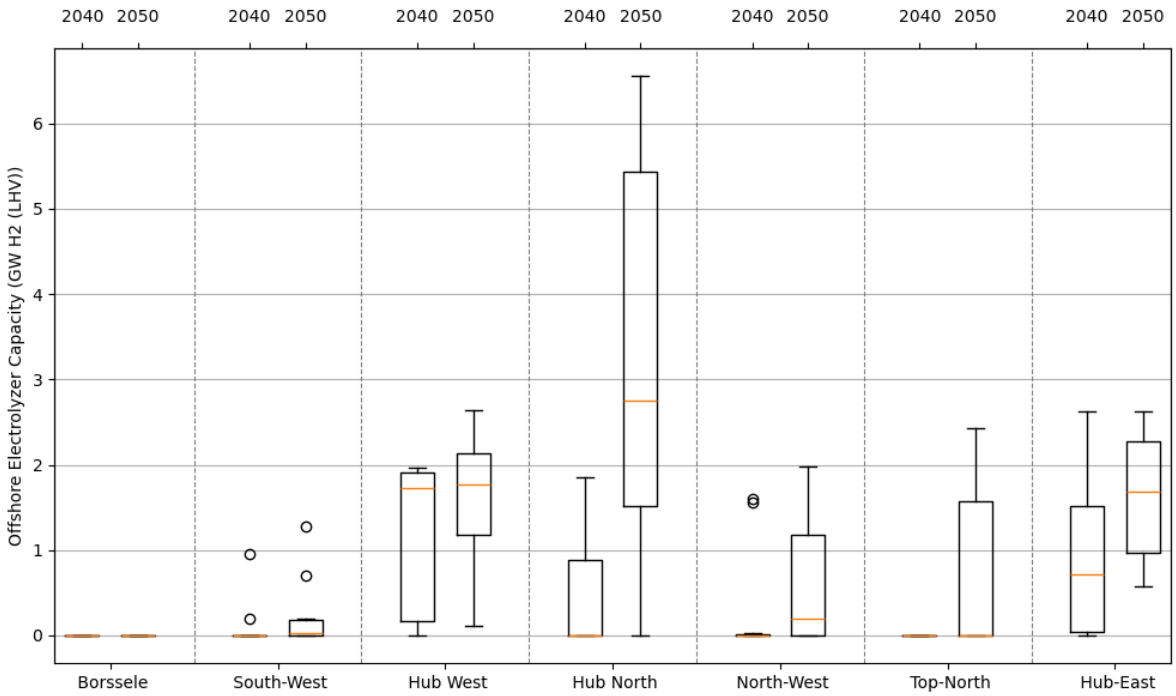

Figure 3.5: Box and whiskers plot of the offshore electrolyzer capacity in terms of rated hydrogen output capacity (LHV) per region for 2040 and 2050.

Far hubs with wind installations generally include electrolysis, but no hub is dedicated solely to electrolysis

Figure 3.6 shows that electrolysis is common for wind installations in distant hubs. For Top-North, any wind capacity was accompanied by significant electrolysis capacity, reaching up to 57%. On the other hand, exclusively hydrogen-centric hubs do not occur. This is because the value of electrolysis diminishes as its share of total wind capacity increases. Strategically balancing wind and electrolysis capacities is crucial for optimizing infrastructure investments.

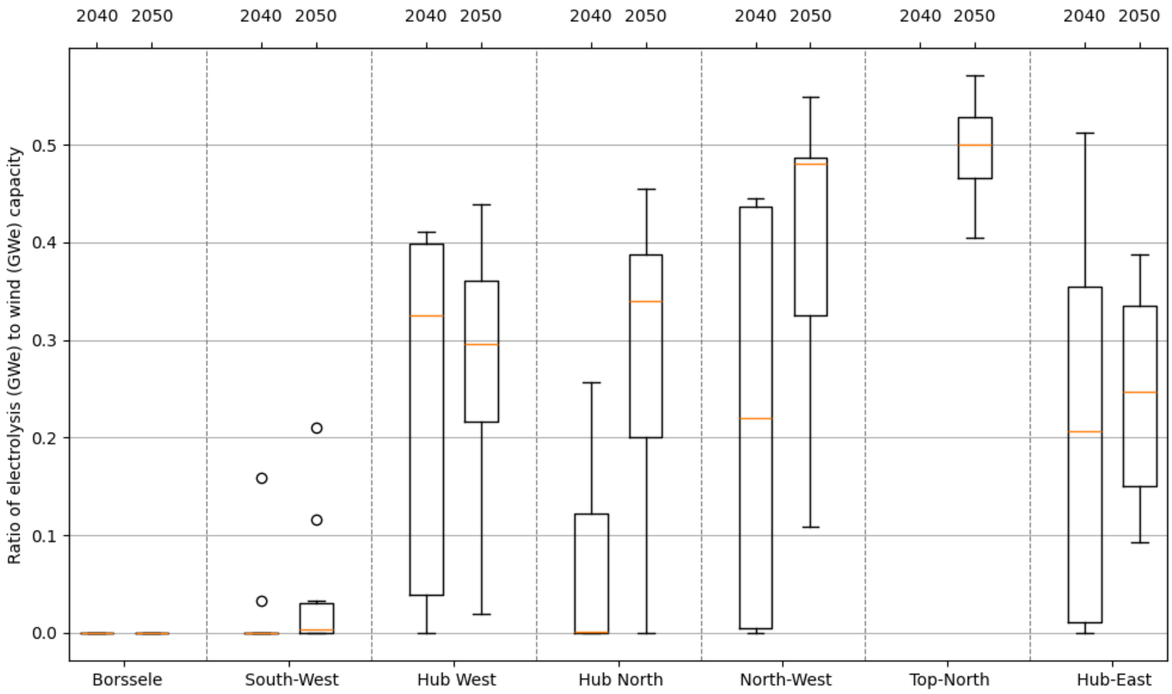

Figure 3.6: The ratio of offshore electrolysis to offshore wind, both in terms of their rated electrical capacity per region for 2040 and 2050.

3.1.3 Infrastructure deployment

An important part of the offshore energy system planning is the infrastructure. One of the most common questions on the planning of offshore infrastructure deployment is the relative sizing of electricity infrastructure to the installed generation capacity. Offshore cables are typically long and have relatively low utilization rates if scaled to the maximum electricity generation capacity of the offshore node. This makes them altogether costly, and in turn incentivizes undersizing, to increase the utilization rate and reduce costs.

In order to examine the degree of undersizing for a large amount of results, a specific metric is used. *The net shore-bound electricity infrastructure* for a hub is the difference between the capacity of the electricity infrastructure coming in from hubs further at sea, and the capacity of electricity infrastructure going from the hub to shore. This can be interpreted as the dedicated electricity infrastructure for the electricity generation in that node. To isolate electricity generation potential, we need to further take into account the electrical input capacity of electrolysis in that node. In case of peak wind generation, this electricity can also be used for electrolysis.

Infrastructure is generally undersized compared to wind generation potential
Figure 3.7 shows the ratio of the net shore-bound electricity infrastructure capacity with respect to the offshore wind generation capacity. The median values indicate that the electricity infrastructure is generally significantly undersized with respect to the electricity generation capacity.

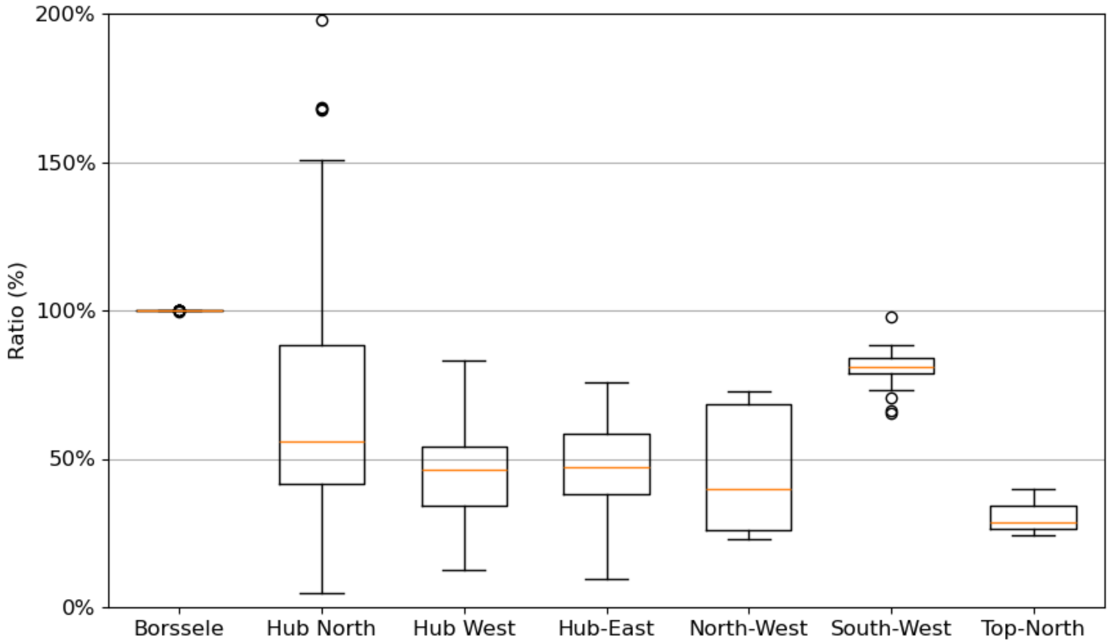

Figure 3.7: Ratio of net shore-bound electricity infrastructure to offshore wind generation capacity for the trend-reflective scenarios.

With median values from 30 to 60%, the deployment of offshore electrolysis removes the need for a significant amount of costly electricity infrastructure. From the all-electric offshore regions, we see that the wind farm capacity equals the cable capacity for a region that is very close to shore (Borssele), and is undersized for one with longer cable length (South-West).

Electricity infrastructure is partially compensated by hydrogen production and infrastructure, but curtailment is still significant

Figure 3.8 shows the ratio of shore-bound electricity infrastructure to offshore wind electricity generation minus the electrical electrolyzer input capacity. The denominator here can now be interpreted as the minimum amount of electricity that is available for transport at maximum wind speeds. If this ratio is less than one, we are sure that there is significant curtailment of wind. As we can see from the figure, the median value is still well below one in most areas. This means that at peak generation capacity, a significant chunk of the electricity generation is curtailed.

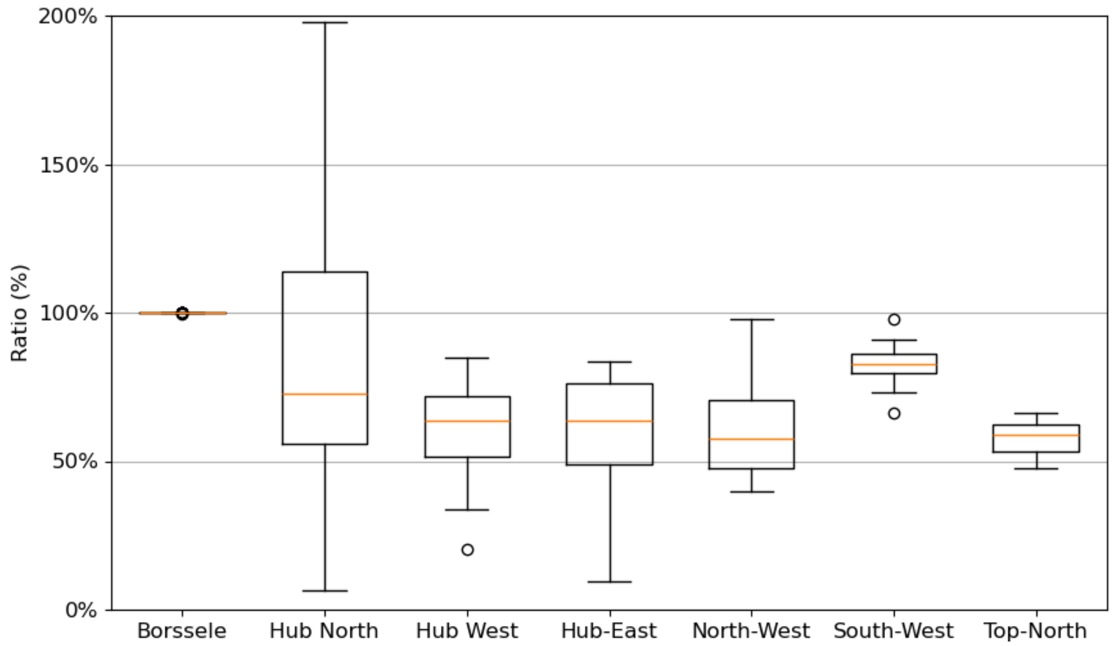

Figure 3.8: Ratio of net shore-bound electricity infrastructure to offshore wind generation minus electrical rated electrolyzer capacity for the trend-reflective scenarios. This accounts for the fact that some part of the missing electricity infrastructure is compensated by hydrogen production and infrastructure.

In a cost-optimization, oversizing the wind farms with respect to the cable capacity bringing the electricity to shore, seems to be a consistent result for regions that are not very close to shore.

For Hub-North, transmission capacity is sometimes oversized, in order to handle imports and allow for the delivery of electricity to different landing points

Interestingly, Hub North has a ratio that is well above 100% in various scenarios. This is understandable, considering the architecture of the system. Firstly, Hub North is the hub that is connected to import cables, which are not accounted for in the denominator. Additionally, Hub North has cables going to Hub West and Hub East, both of which end up going to shore at important (industrial) consumption clusters. In some cases, it appears optimal to have the freedom to switch, to some extent, to transport more electricity to one shore or another. This likely prevents larger investments in onshore infrastructure to handle the congestion.

There are two important caveats to the infrastructure results, which are both consequences of the OPERA model. Firstly, since OPERA is an optimization model without stochasticity, it will install exactly the perfect amount of electricity infrastructure required to minimize the total costs of the system. This is typically not a robust outcome, and changes from year to year. This is combined with the fact that regional OPERA runs use representative periods, in order to reduce the run time. As a consequence, it will underestimate issues with congestion and black – and grey swan events. These caveats mean that OPERA's capacities are likely on the lower end of a desirable, robust electricity infrastructure system. Nonetheless, the degree of undersizing is significant, with median's consistently between 60% and 80%.

3.1.4 Avoided system cost of offshore hydrogen production

Since in all base cases for ADAPT, TRANSFORM and LCI offshore hydrogen production enters in the solution in 2050, it means that offshore hydrogen production lower the system cost, otherwise it would not appear. The magnitude of these avoided system costs are determined by comparing the system cost with optimizations in which offshore hydrogen production is excluded. The results are presented in *Figure 3.9.*

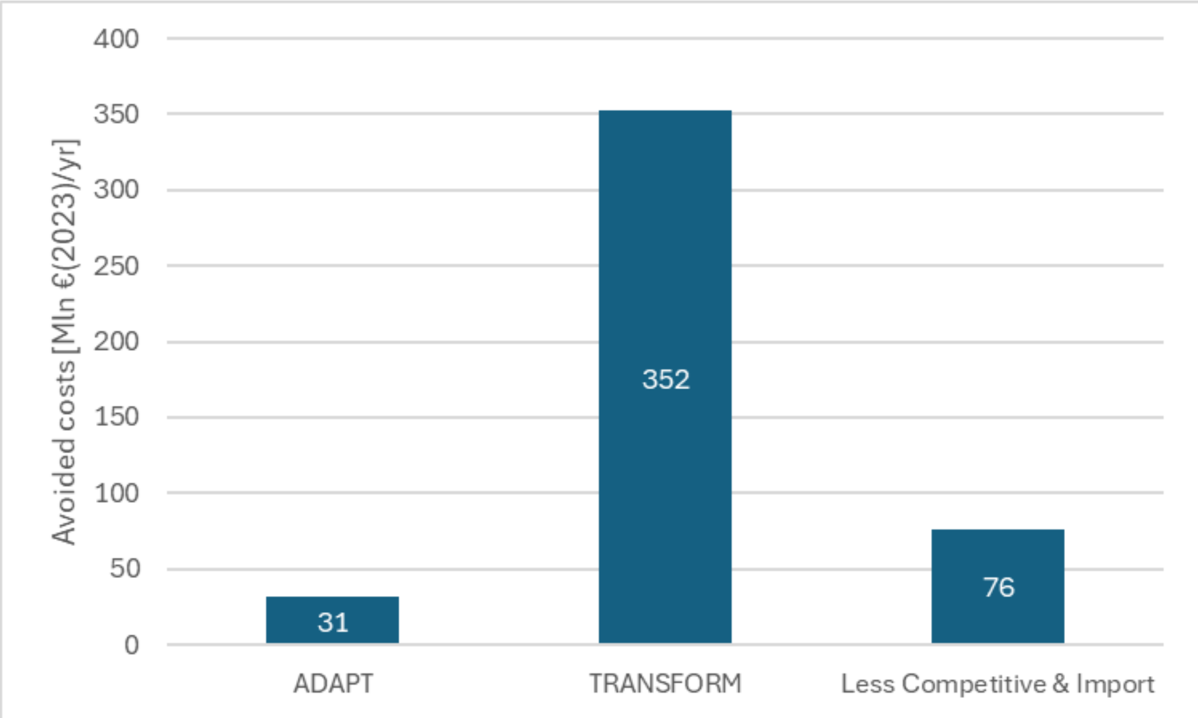

Figure 3.9 Avoided annual system costs of offshore hydrogen production in 2050 for ADAPT, TRANSFORM and LCI in mln€(2023) / yr.

The avoided annual system costs, or system benefits, are modest for ADAPT and LCI, respectively 31 and 76 million euros per year in 2050. For TRANSFORM they are on the order of magnitude of a few hundred million euros per year, which is significant, but also much lower than the 3 billion euros annually presented in (van Stralen, 2025) for TRANSFORM. The reason that the system benefits have reduced by almost a factor of 10 for TRANSFORM, can mainly be attributed to the significantly more expensive cost for electrolysis that have been assumed in the current study and the offshore CAPEX and OPEX factor being significantly higher[3]. Furthermore, the lower full load hours for wind offshore (10% lower) assumed in the current study, results in a lower production in offshore hydrogen production and therefore a lower system benefit.

A decomposition for the avoided system cost are given in *Figure 3.10* for the TRANSFORM scenario. The most significant cost elements that are avoided are related to the offshore electricity grid, including the connection points onshore. The additional cost of producing

[3] Techno-economic parameters of technologies that have the most significant impact on offshore system integration are given in
of Appendix A.

offshore are significant, in particular for the electrolysis, the most significant component in the entire graph. Additional cost for offshore hydrogen infrastructure are much lower than the avoided cost of offshore electrical infrastructure, since it is much cheaper to transport 1 unit of energy via a pipeline than via an electricity cable. The component 'Other' consists of all kind of small system shifts, which can result from higher losses of bringing all energy to shore as electricity, differences in full load hours of electrolysis, etc. The underlying components are too small to represent in more detail.

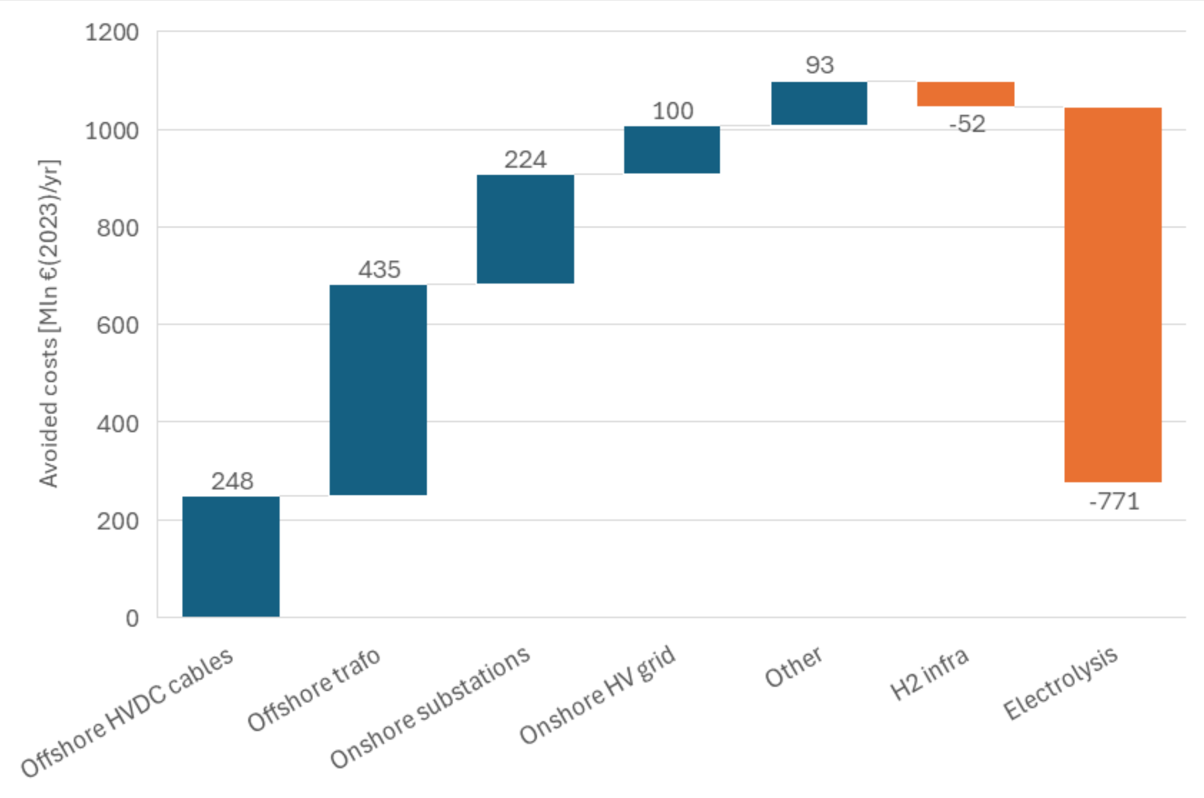

Figure 3.10 Decomposition of avoided system costs for TRANSFORM in 2050 in Mln €(2023)/yr.

The fact that the system benefits of offshore hydrogen production are much lower than presented before, also indicates that the system benefits are very uncertain. Projected cost of electrolysers have changed significantly over the past years, the additional cost of electrolysis offshore are inherently uncertain since only the first demonstration projects are under development and the cost of electrical infrastructure have increased over the past years. New analysis, with new insights of future cost of the components indicated above might result in other conclusions for the role of offshore hydrogen production.

3.2 Explorative scenarios

The following section presents the results for the explorative scenarios. These are scenarios in which there is no limit on electricity import and export, which leads to significant electricity imports for the Netherlands due to the TYNDP scenarios' high renewable energy deployment.

High electricity imports temporarily slow offshore wind development in explorative scenarios.
Although offshore wind capacity slightly decreases by 2050, the primary impact is a significant delay in wind deployment observed around 2040. High levels of imported electricity initially reduce immediate offshore wind investment needs. This strategic use of imports encourages a phased investment approach, seemingly without major long-term impacts on wind capacity.

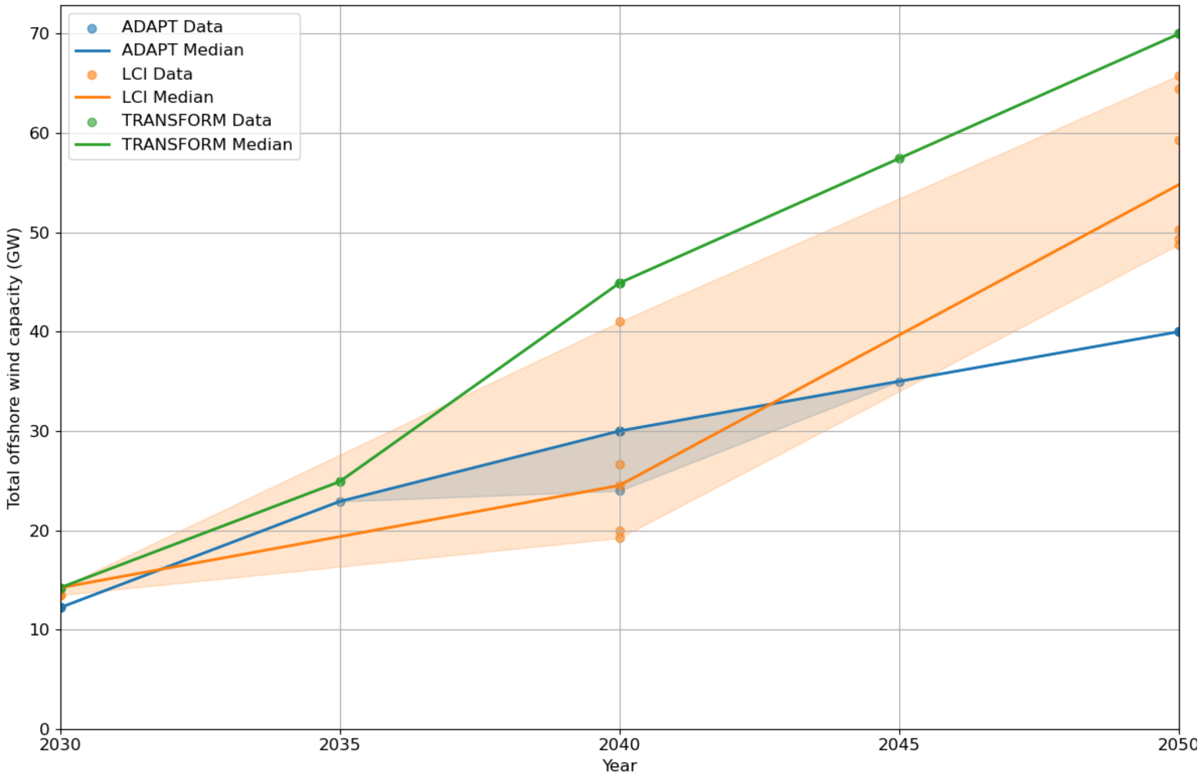

Figure 3.11: The deployment of offshore wind over the years for the explorative scenarios.

Electricity imports substantially increase hydrogen production for export
Electricity imports primarily displace domestically produced wind electricity, which then becomes available for hydrogen production. This indirect use of imported electricity significantly boosts hydrogen production for export purposes. Such strategic import utilization shapes domestic offshore electrolysis investments. Further details are provided in the appendix.

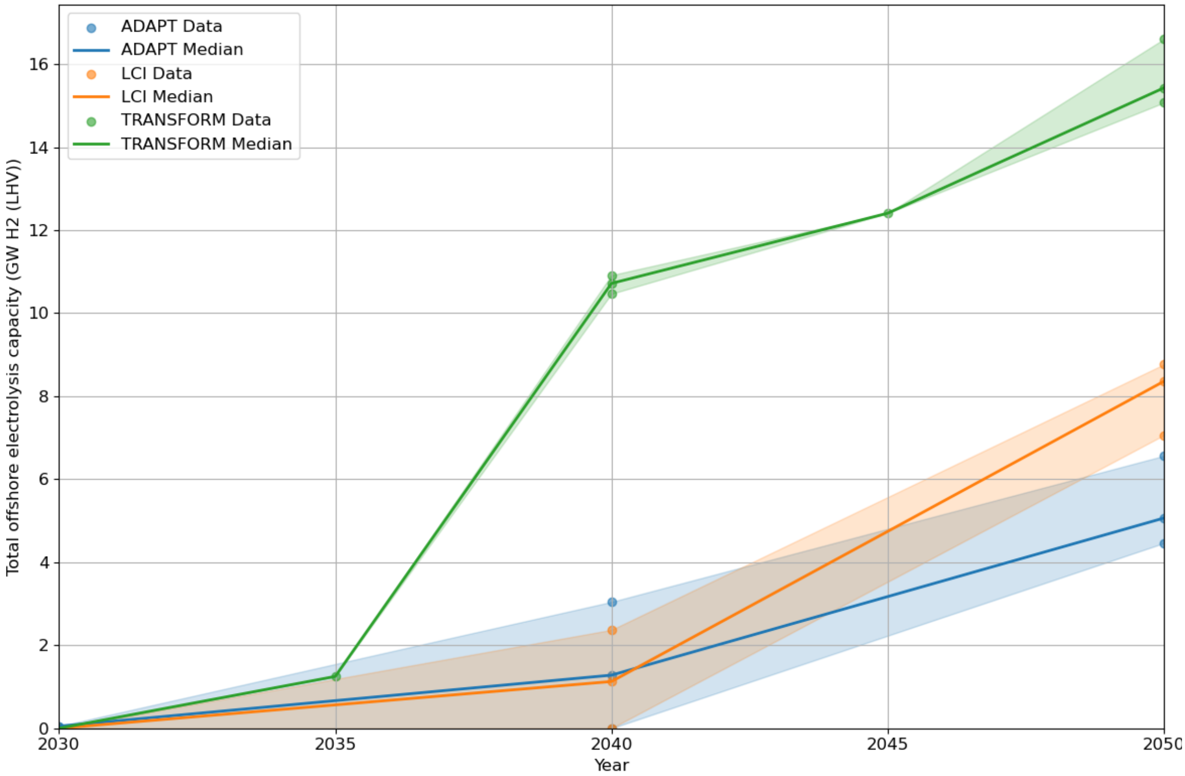

Figure 3.12: The deployment of offshore electrolysis over the years for the explorative scenarios.

3.3 Sensitivity analysis – reduced full load hours offshore wind

Lower full load hours significantly reduce offshore wind deployment, especially in LCI scenarios

In ADAPT and TRANSFORM, wind deployment still achieves its potential despite lower full load hours of offshore wind. However, LCI sees a notable reduction due to diminished wind energy yields. This shifts economic viability toward alternative generation technologies. Recognizing this shift could prove important for diversifying energy strategies to include viable alternatives like solar PV and nuclear energy.

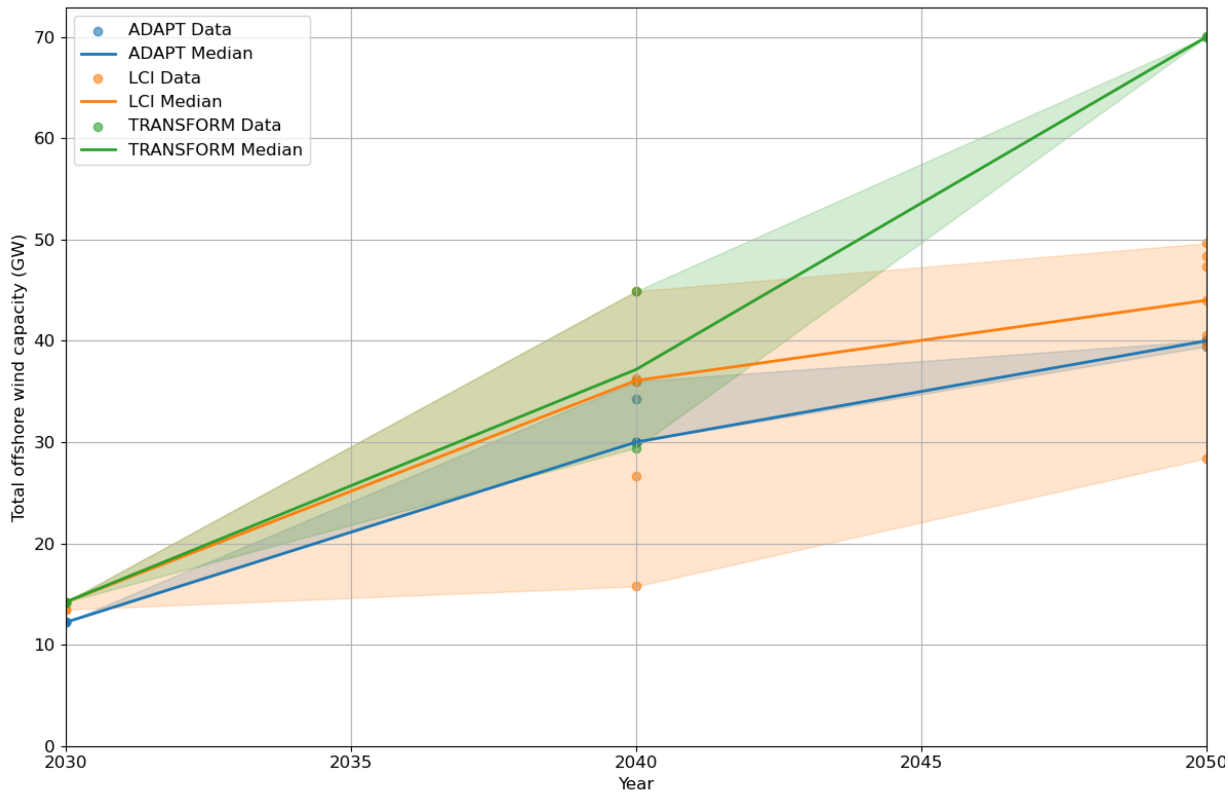

Figure 3.13: The deployment of offshore wind over the years for the trend reflective scenarios in the case of lower full-load hours for offshore wind.

Lower wind yields increase reliance on nuclear and more expensive solar PV technologies
Alternative energy sources, particularly nuclear power and costlier solar PV options, become necessary as offshore wind yields decrease and onshore wind potentials are fully utilized, as shown in Figure 3.14. This highlights the importance of accurate wind profiles for energy system planning, but also the potential impact of increased wake effects from higher total deployment, or the impact of wind turbines that yield higher capacity factors.

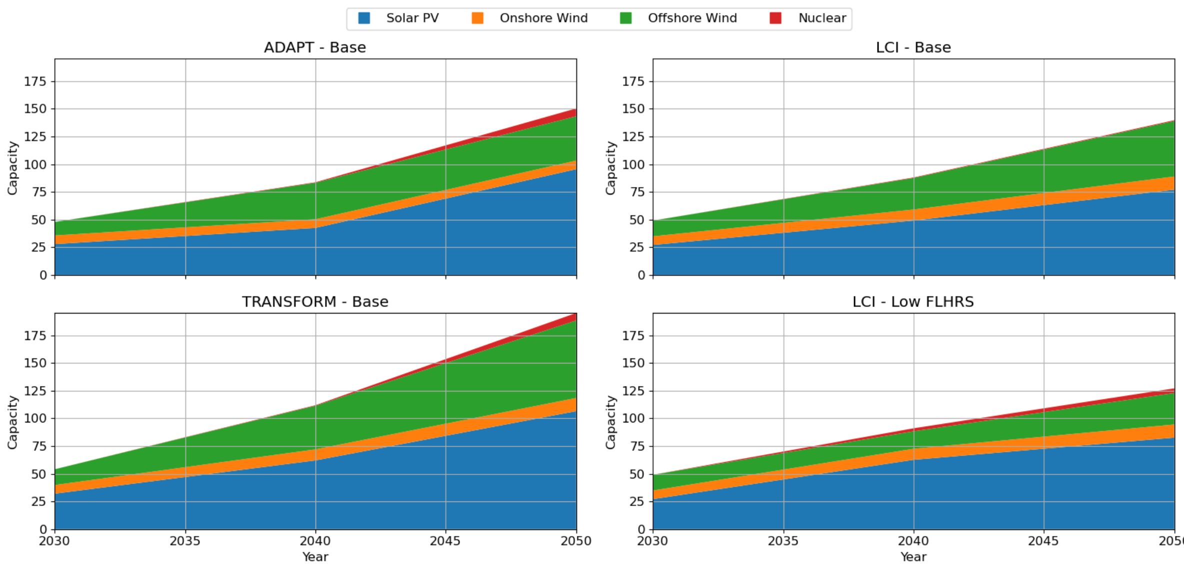

Figure 3.14: Renewable electricity generation technologies for the trend reflective scenarios in four specific cases, split out per region. Note that these technologies have different capacity factors and thus different yields.

4 Market analysis results

Having analyzed offshore integration from a system optimization perspective, we now turn to a market perspective and the public value assessment of offshore integration through that lens. This assessment involves the price dynamics of energy carriers in the different markets (electricity, natural gas, hydrogen) and the cost-optimal dispatch of technologies in the Dutch energy system. We model these topics for the generated OPERA energy scenarios and the Dutch infrastructure outlook used for the hub design of WP1. We make a selection of the available scenarios, to most effectively define a bandwidth on *offshore wind capacity* and *hydrogen market size* (production capacity and demand). The TRANSFORM scenario scores high on both and therefore including it holds no added benefit compared to the II3050 scenario with hubs as designed in WP1. An overview of the selected scenarios is shown in Table 4.1.

Table 4.1. The selection of Dutch energy system scenarios, used for the market modelling approach of this chapter. 'Offshore Wind' concerns installed capacity and 'hydrogen market size' includes both electrolyser capacity and hydrogen demand.

	II3050 – NAT	OPERA – LCI	OPERA – ADAPT
Offshore Wind	High	Medium	Low
Hydrogen market size	High	Medium	Low

For all simulations, the trend-reflective scenarios will be used: the net import in the model will be set to zero. This chapter will first look at the timeline towards 2050 in which the proposed offshore energy hubs can be integrated and in which the energy system transforms between three target years: 2030, 2040 and 2050. As explained in section 2.2, the National Trends TYNDP scenario will be used for the European system in 2030 and 2040, and the Global Ambition scenario for 2050.

To summarize, we will be analyzing nine energy systems, spread out over three target years and three scenarios for the Dutch system. Additionally, for the energy systems in 2050, more in-depth analysis is done with respect to the added value of offshore integration and sensitivity to offshore wind production profiles.

4.1 Timeline towards 2050 shows transformation from grey to green

More hydrogen demand in 2030 will be met with seaborne imports

The 2030 market model outcomes of each input scenario (II3050, LCI and ADAPT) produce a market-optimal hydrogen dispatch, shown in the annual hydrogen balances in Figure 4.1.

Given that the Dutch hydrogen network is not connected to the European system in the model, net hydrogen exports are logically zero. Production from SMR installations is cost-competitive with electrolysis, with the latter generating in hours of low electricity prices.

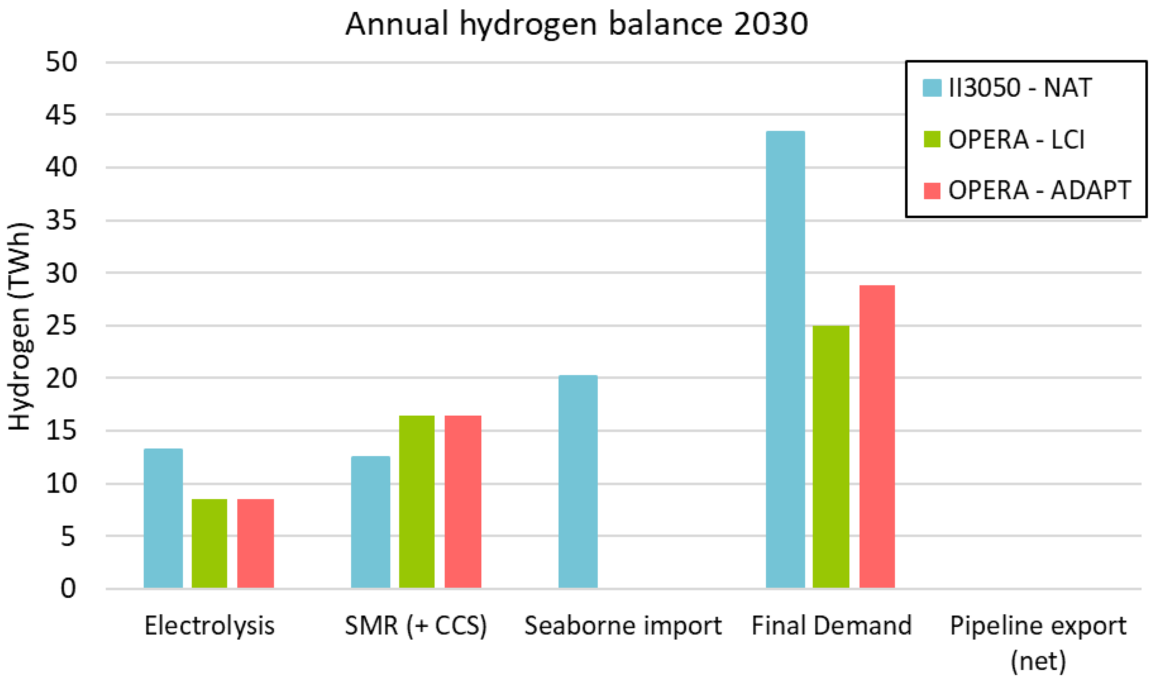

Figure 4.1. The annual hydrogen balance as a result of the market modelling of three scenarios. SMR production with and without CCS is grouped, as well as static (input) demand with endogenously calculated demand for power.

The ‘high hydrogen’ scenario, II3050, indeed has a notably higher demand and electrolysis production than the OPERA scenarios. This increased demand, however, appears to mostly be met by hydrogen via seaborne imports. In both LCI and ADAPT the system optimization does not invest in import capacity for the hydrogen market, only in direct ammonia imports for industry. For the decarbonization targets of 2030, it is more cost-effective to decarbonize this part of industry demand through other routes than hydrogen.

Large spread in demand and blue hydrogen production in 2040

The 2040 annual balance shows a major shift in production for the II3050 and LCI scenarios. With surpluses of renewable electricity becoming more abundant, electrolysis becomes a major contributor to the hydrogen market. While in the ADAPT scenario there is heavy investment in blue hydrogen (SMR + CCS), hydrogen demand in the other scenarios is mostly met with green, local production. The difference can be explained by the low CCS potential in LCI, with the model choosing other sectors with harder to abate emissions to apply carbon capture technology in.

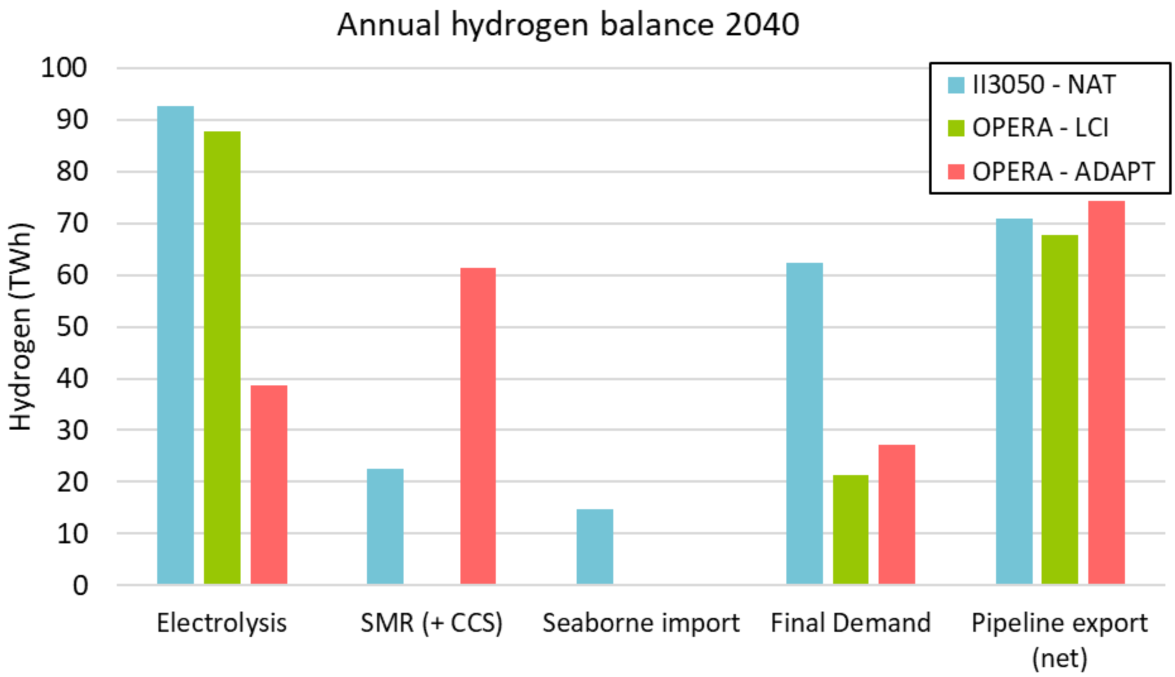

Figure 4.2. The annual hydrogen balance as a result of the market modelling of three scenarios. SMR production with and without CCS is grouped, as well as static (input) demand with endogenously calculated demand for power.

The coupling with the international hydrogen market leads to a large net export for all scenarios. With relatively large amounts of offshore wind and electrolysis capacity, the Netherlands are in a good position to produce and export hydrogen, mostly to Germany.

Green hydrogen market in 2050 of uncertain size

Finally, we see a fully green market arise in 2050. Net exports have decreased compared to 2040, likely due to changes in the (European) electricity market. Demand has doubled compared to 2040 and the Netherlands is able to meet its demand completely by local production. The difference between the II3050 scenario and the two OPERA scenarios is large: the cost-optimal extent of decarbonization through hydrogen is lower than that of the infrastructure operators' outlook. Given that National Leadership is a high hydrogen scenario and the scenarios are constructed to estimate the extent of infrastructure requirements in the future, it is sensible that the system cost-optimal solution is more conservative.

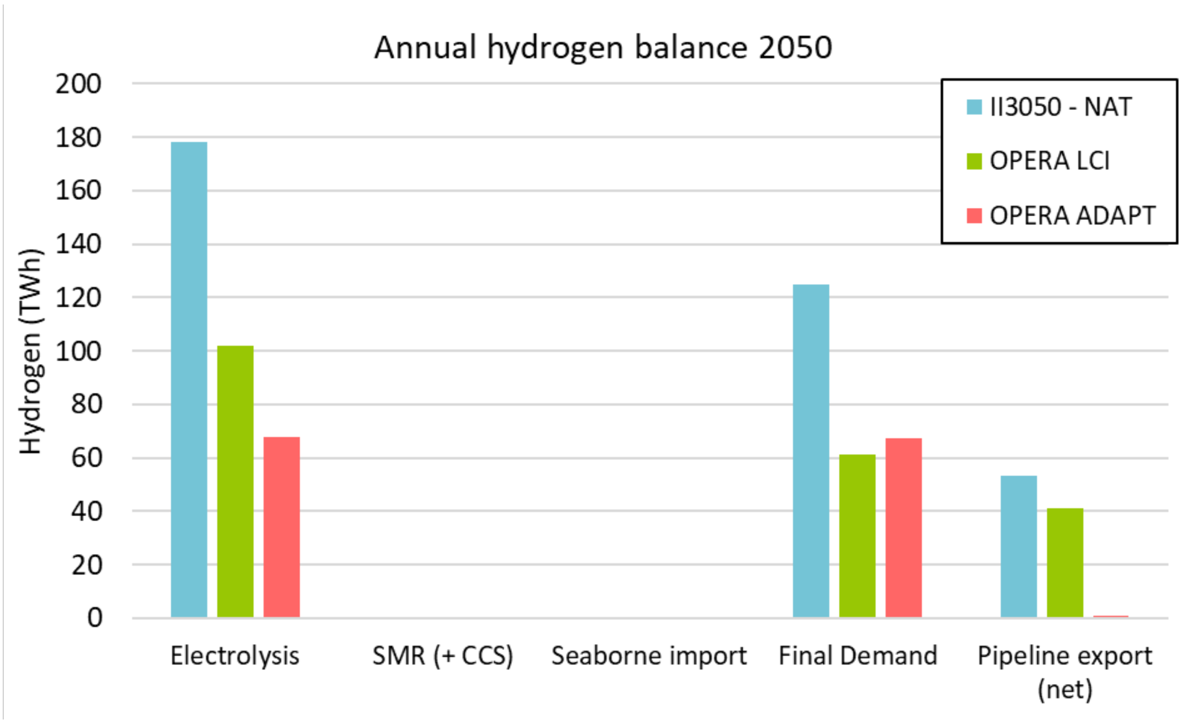

Figure 4.3. The annual hydrogen balance as a result of the market modelling of three scenarios. SMR production with and without CCS is grouped, as well as static (input) demand with endogenously calculated demand for power.

A major driver of the hydrogen dispatch is the underlying (marginal) cost of electricity. The model produces marginal cost curves associated with the cost-optimal production. These curves can serve as a proxy for electricity prices but are decidedly not the same: perfect foresight and a fully competitive market with no scarcity determine these cost curves, leading to differences in price setting compared to the actual European electricity market. The marginal cost curves *can* however be used to analyze price sensitivity to scenario choices and differences between scenarios. A box-whisper plot of the electricity marginal cost of all scenario years is shown in Figure 4.4.

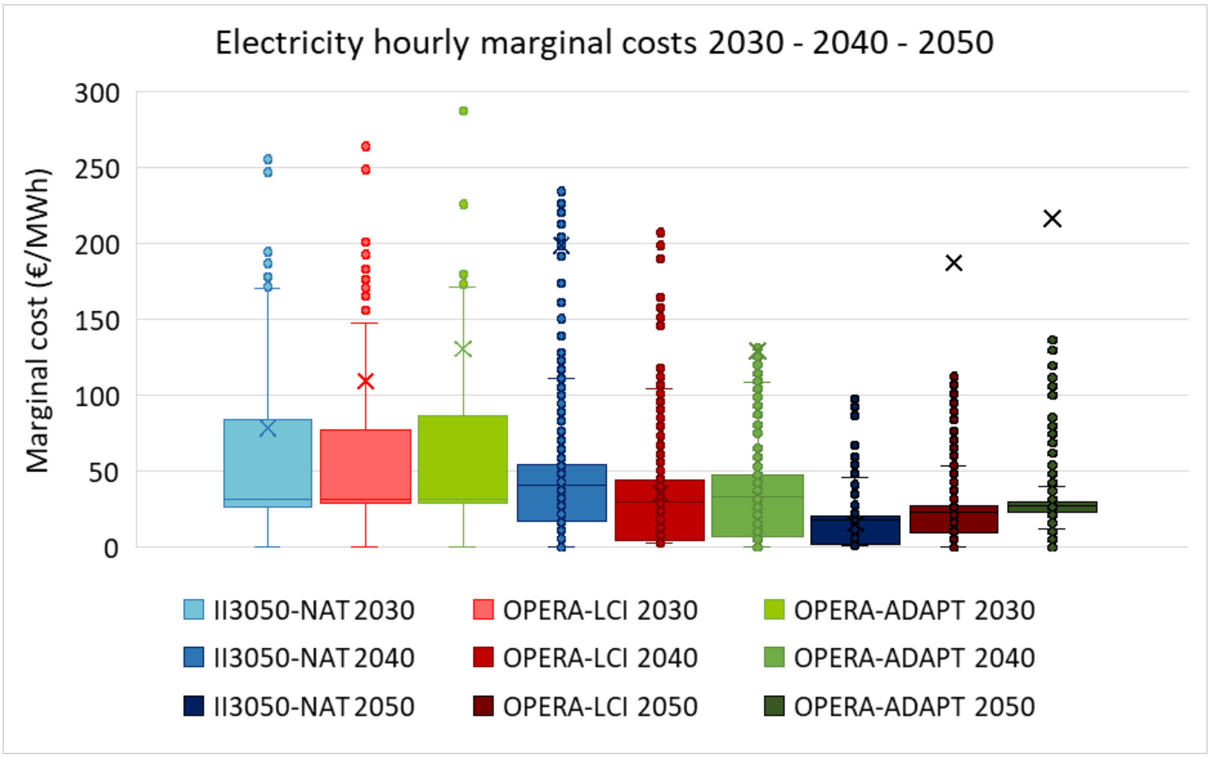

Figure 4.4. Marginal costs of electricity for each hour of the simulation year. The cut-off point in the graph is at 300 €/MWh; up to some hundreds of hours of extreme prices occur, where energy not able to be served leads to a marginal cost equal to the Value of Lost Load (VoLL) of 10,000 €/MWh. These figures are cut off to allow visualisation of price behaviour throughout the largest part of the year.

As expected, the median costs decline towards 2050, with more renewable electricity coming into the mix. However, the median costs in 2050 seem exceptionally low. Most of the year they are at somewhat the same price of €30/MWh, with the II3050 scenario even staying at €20/MWh. With a large share of zero marginal cost producers (wind & solar) and lack of market reform or equal share of flexible demand, electricity prices can be expected to sink towards 2050. Producers of electricity must then rely on contracts for difference, long-term contracts and other mechanisms to still get a positive business case. Additionally, the low electricity costs provide an explanation for the high amount of green hydrogen being locally produced.

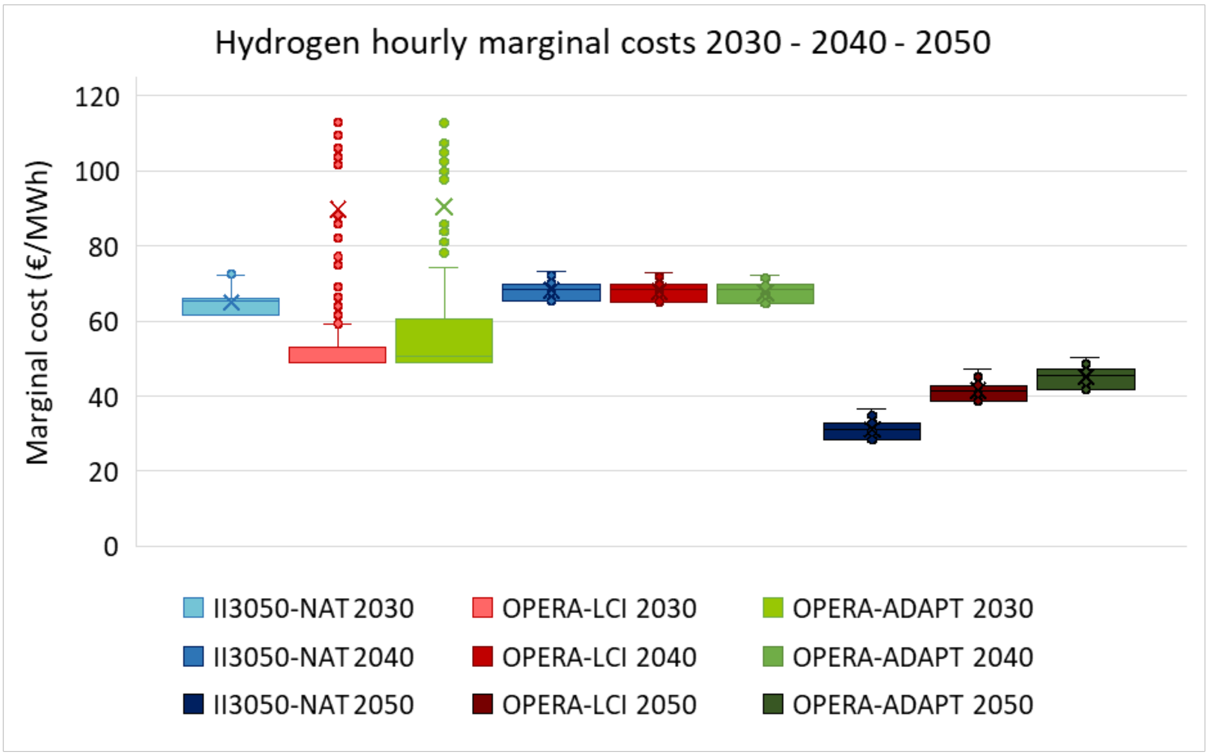

Figure 4.5. Marginal costs of hydrogen for each hour of the simulation year.

The hydrogen costs show an interesting pattern towards 2050. With electricity costs declining and electrolysis making up a large part of the mix, one would expect the hydrogen prices in 2040 to be lower than in 2030. However, higher marginal costs for gas-based production, higher demand and a link to the European market in this case actually drive up the costs temporarily, before lowering again towards 2050, where the low costs are driven by low electricity costs. Additionally, the volatility of the costs decrease in 2040 as compared to 2030, with electricity prices stabilizing.

In summary, we see a hydrogen market moving from dependency on gas-based hydrogen production and seaborne imports in 2030, to being dominated by local, green production in 2050. This behavior is heavily influenced by the scenario choices: the amount of renewable energy available, a zero net import assumption and more. Therefore we zoom in on the year 2050 in the next sections, to analyze sensitivity of the outcomes to these underlying assumptions.

4.2 Market-based hub value in 2050 is mainly driven by congestion

To determine the market-based value of offshore system integration, the energy system dispatch and associated prices are analyzed with and without offshore electrolysis and hydrogen infrastructure for each 2050 scenario. For the ADAPT and LCI scenarios, this entails running the OPERA model with no option for offshore hydrogen. The required electrolyser capacity is distributed over the modelled regions according to the least-cost solution. In the modelled II3050 scenario NAT, we distribute the capacity manually over the Dutch industry clusters, proportional to current announced electrolyser plans. The resulting marginal costs of electricity and hydrogen are shown in the figures below.

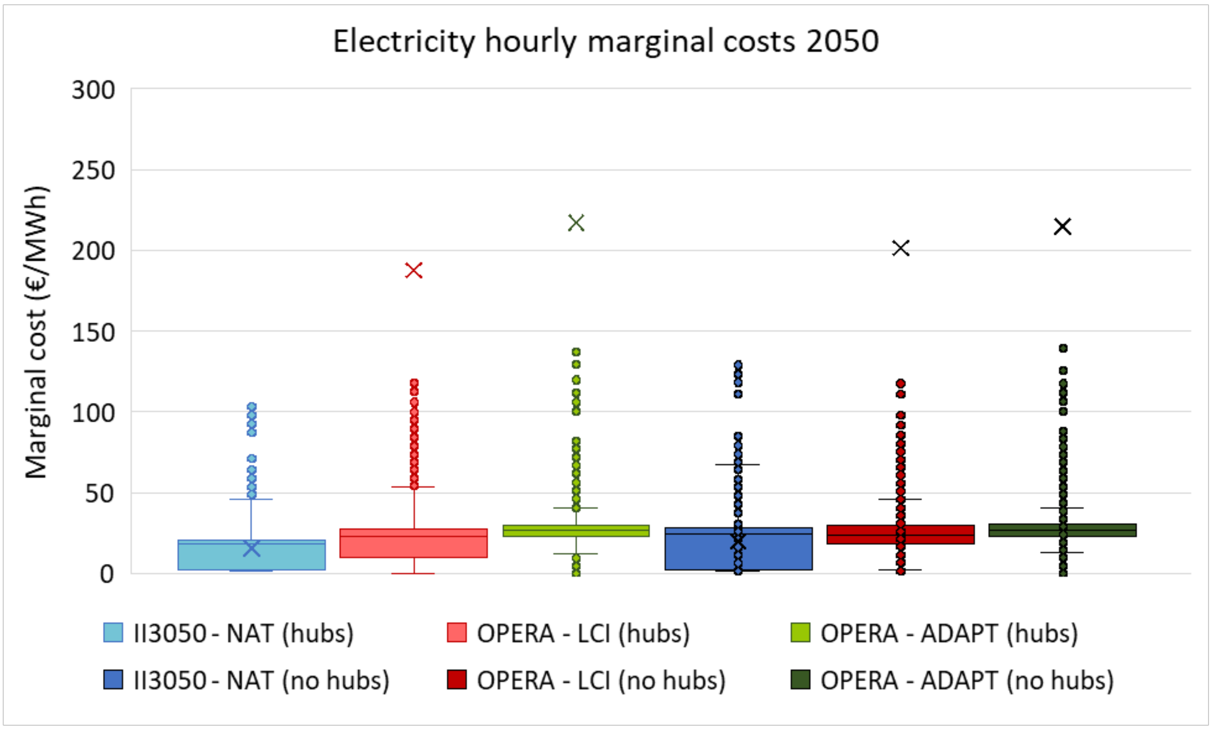

Figure 4.6. Electricity marginal cost comparison between scenarios with and without offshore electrolysis deployed (hubs/no hubs).

An decrease in marginal costs for electricity when allowing for offshore integration is seen for all scenarios, but the differences vary: whereas the II3050 scenario sees a decrease of 22%, this effect is smaller for LCI with 10%, and almost negligible for ADAPT: a 1% decrease. The approach is of course different for the OPERA scenarios, with the optimization being able to react to the changing constraint. Furthermore, the difference between the OPERA scenarios is explained by the measure of electrolysis deployed in the original scenarios. With higher dependency on (offshore) electrolysis comes a larger price decrease when allowed to deploy that electrolysis offshore.

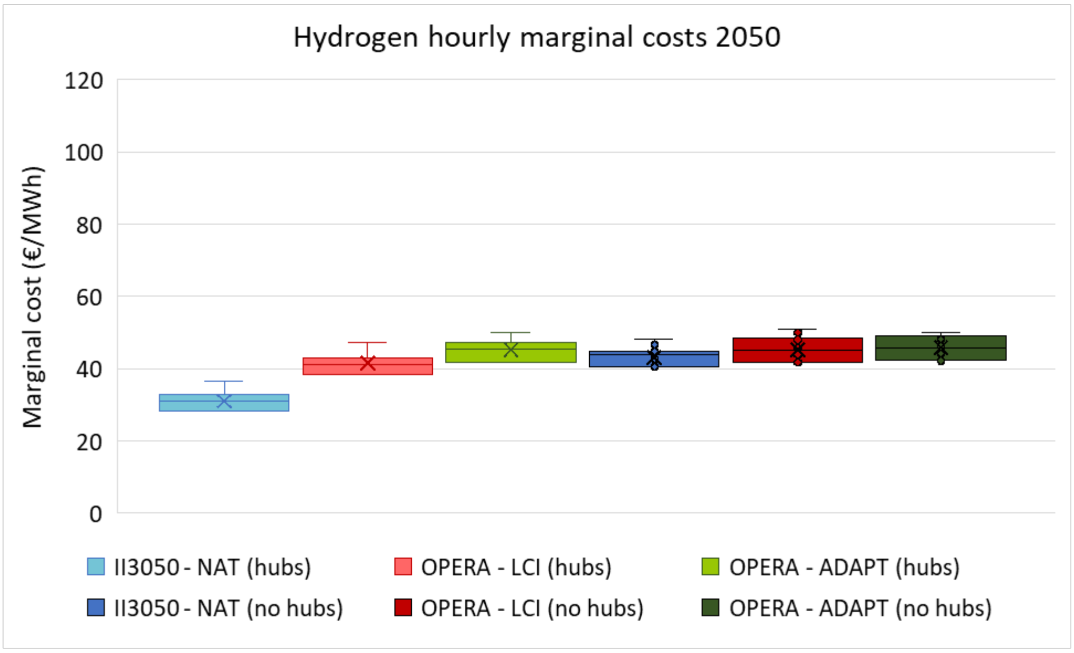

Figure 4.7. Hydrogen marginal cost comparison between scenarios with and without offshore electrolysis deployed (hubs/no hubs).

Next, the hydrogen costs show similar behavior: a larger price decrease of 28% in the II3050 scenario is seen, whereas LCI and ADAPT show lower cost decreases, of 8% and 2% respectively. As the hydrogen market is fully dominated by green, local production in 2050, the hydrogen cost decrease is directly proportional to the electricity cost decrease.

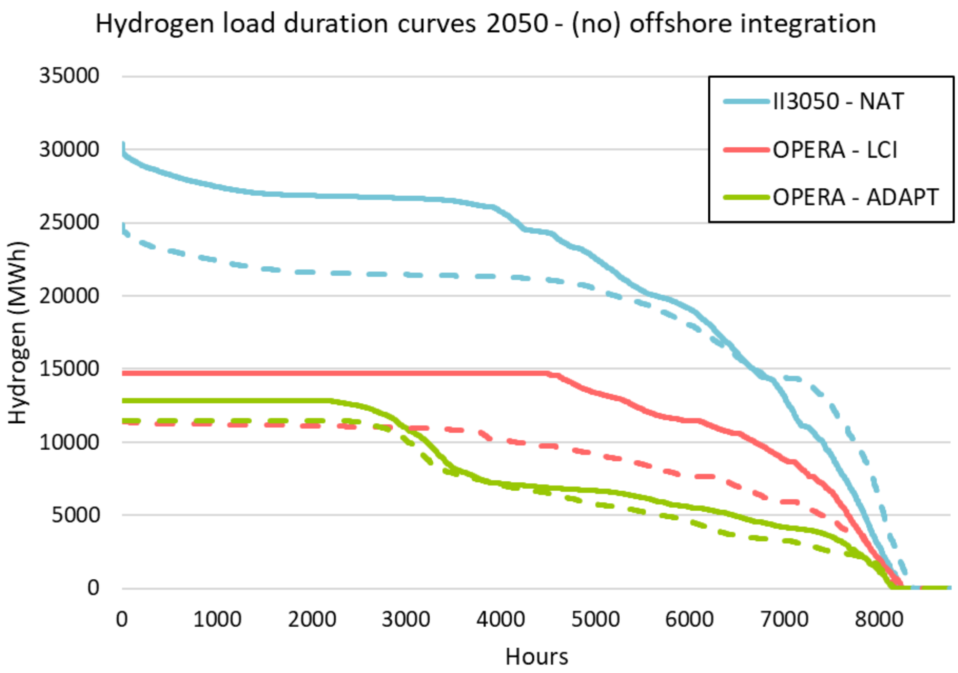

Figure 4.8. Comparison of electrolyzer dispatch with and without energy hubs for the three scenarios. Hourly production is sorted from high to low to show utilization throughout the year. The full lines correspond to the scenario with offshore electrolysis, the dashed lines with the scenario without offshore electrolysis.

A significant increase in electrolyzer dispatch is seen for all scenarios. In this case, all scenarios show similar increases when allowing offshore electrolysis: 14% higher full load hours in the II3050 and 8% and 13% in the LCI and ADAPT scenarios respectively. Here the difference in approach is clearly visible: not only does the location of electrolyser deployment change between the simulations, the total capacity is different as well. Still, the utilization of the electrolyzers is higher in the case of offshore integration.

Additionally, we see a decrease in electricity curtailment when applying offshore system integration. When offshore electrolysis is introduced, the total amount of energy curtailment in the system decreases by 21 TWh for II3050, 44 TWh for the LCI scenario and 15 TWh for ADAPT. The biggest difference here (and the only difference in case of the II3050 simulations) is the geographical distribution, meaning electrolyzers are less affected by (onshore) congestion on the electricity network in the case of offshore integration. They are thus able to make better use of the wind energy, decreasing curtailment and increasing electrolyzer dispatch.

An overview of the effect of introducing offshore system integration in the form of energy hubs in the different energy configurations can be seen in *Table 4.2.*

Table 4.2. Summary of results for the change in average electricity and hydrogen marginal costs, electrolyzer dispatch and curtailed electricity production in the different scenarios for 2050, when comparing offshore integration and no offshore integration.

	II3050 – NAT	OPERA – LCI	OPERA – ADAPT
Change in average electricity costs (%)	-22%	-10%	-1%
Change in average hydrogen costs (%)	-28%	-8%	-2%
Change in electrolyzer dispatch (%)	+14%	+8%	+13%
Change in curtailment (TWh)	-21	-44	-15

From a market perspective, offshore system integration seem to largely provide value in more efficient dispatch through less curtailment of produced electricity. This is caused by the alleviation of congestion that stems from introducing offshore system integration, in turn resulting in lower overall costs to satisfy the energy demand of the system. This is the case for all three energy system configurations analyzed for 2050. The largest impact can be seen for the average energy carrier prices is in the II3050-NAT scenario, as this energy system configuration heavily involves hydrogen as an energy carrier.

The difference in outcomes between the scenarios that are tested is significant, and can be explained by their inherent assumptions on the supply and demand of energy. For example, the II3050-NAT scenario considers a significantly higher hydrogen demand in 2050 than both OPERA scenarios. This could result in a larger sensitivity to hydrogen prices if national electrolyzer utilization is significantly increased.

Another point to consider is the difference in system build-up between the two OPERA based energy system configurations and the II3050-NAT energy system configuration. For the latter, the change in the system is quite isolated as just an implementation of offshore system integration. This allows for a more direct conclusion to be drawn for the effects of such a system integration, in the form of for example the effect on energy carrier pricing due to an isolated change. For the OPERA scenarios as results of an optimization, the entire build-up of the energy system is optimized according to whether or not offshore system integration is a possible or not. This causes more changes than just the isolated difference of the existence of offshore energy hubs or not. As such, the differences that are observed in these two scenarios do indeed stem from the possibility of offshore system integration, but the effects can not necessarily be entirely ascribed to offshore system integration.

4.3 Market sensitivity to a conservative wind profile assumption

Finally, we investigate the sensitivity of the system to the assumed offshore wind profile. As explained in section 2.1.3, the climate year 2015 is used for the simulations analyzed so far. However, since this is considered a 'high wind' year, we are also interested in the outcomes under more conservative assumptions. To that end, the market model is used with the refitted offshore wind profile for the II3050 scenario, as well as run again based on the updated OPERA scenarios with lower full load hours for offshore wind.

It needs to be mentioned that the comparisons between cases are different for both scenario sets: the II3050 scenario is rerun with the same capacities, demand, etc. On the other hand, the OPERA scenarios are regenerated, results of which are shown in section 3.3, and as mentioned before they produce a different energy system. A comparison can therefore not be made of the size of the difference due to lower full load hours, between the scenario sets. However, it can provide insight into the sensitivity of the system to the offshore wind profile as an input parameter.

Electrolyser dispatch decrease is proportional to the decrease in wind

The missing offshore wind production is visible for a long range of hours in the electrolyzer production profile, shown in Figure 4.9. In the change between the two IO scenario cases, a 1:1 electrolyzer production loss is visible: the average offshore wind full load hours change from 4700 to 3700, a 21% decrease – equal to the decrease in electrolyzer full load hours, which is likewise -21%.

For the OPERA scenarios, the results are different: not only the wind profile has changed between simulations, the energy system is defined differently. However, a 28% decrease in electrolyzer full load hours is visible for LCI, even with the capacity decreasing. The ADAPT scenario shows a decrease in full load hours of 32%, with electrolyzer capacity staying the same. Further changes in the energy system decrease the production: the hydrogen demand has decreased with lower wind production, adding to the effect. In conclusion, there is a direct effect visible on the electrolyzer production, due to decreased offshore wind. This effect is proportional to the wind decrease, or possibly even larger if changes in the energy system are modelled.

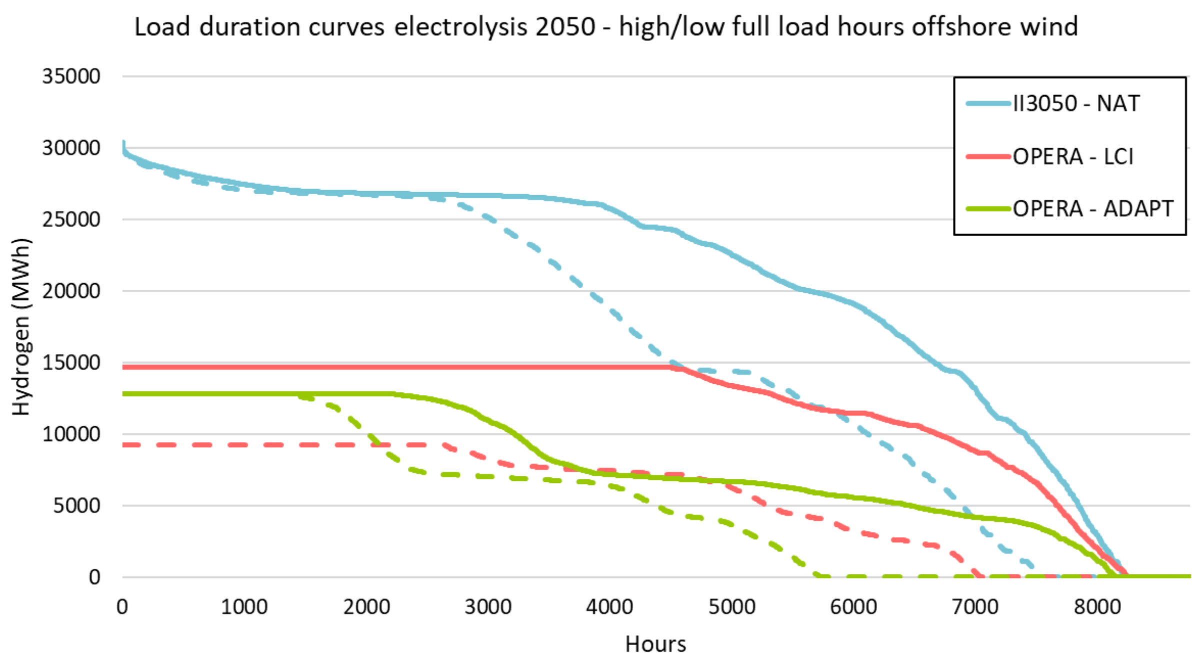

Figure 4.9. Load duration curves of electrolysis (hourly production sorted from high to low), as a result of the market modelling of the scenarios with high and low full load hours of offshore wind. The dashed lines represent the case with lower full load hours.

Commodity prices rise significantly with less wind production

Finally, the sensitivity of commodity prices to the offshore wind profile is significant. The average electricity and hydrogen marginal costs of the trend-reflective scenarios and the lower wind case, are displayed in *Table 4.3*.

Table 4.3. Marginal cost figures for electricity and hydrogen between the two cases. For electricity, the marginal costs higher than €300/MWh, according to the Value of Lost Load (VoLL), are disregarded when taking the average.

	II3050 – NAT	OPERA – LCI	OPERA – ADAPT
Average MC electricity (trend-reflective) [€/MWh]	16	20	25
Average MC electricity (low wind) [€/MWh]	28	27	32
Difference	**+79%**	**+31%**	**+30%**
Average MC hydrogen (trend-reflective) [€/MWh]	31	42	45
Average MC hydrogen (low wind) [€/MWh]	48	47	48
Difference	**+54%**	**+15%**	**+7%**

The largest difference is visible in the II3050 results: the electricity costs were exceptionally low with high full load hours for offshore wind and almost double when assuming a different wind profile. With the hydrogen market being fully dominated by electrolysis, it stands to reason that the hydrogen costs increase significantly as well. The OPERA scenario prices show a lower increase, where we keep in mind that this is for a transformed energy system:

solar and nuclear capacity has increased between simulations, most likely dampening the increased price effect we see in the II3050 scenario. However, a significant price increase for both electricity and hydrogen is the apparent result of a more conservative offshore wind profile.

To conclude, decreasing the full load hours of offshore wind in these simulations leads to a proportionate or even larger decrease in electrolyser production. The underlying marginal costs of electricity almost double in the high renewables, high hydrogen scenario. Alternatively, the increase is lower (approx. +30%) for the system optimization, where the energy system responds to the decrease in wind by installing alternative capacity.

5 Spatial need of electrolysis

The increasing spatial need for the hydrogen sector can be costly

With one of the highest population densities in the world, space is a scarce commodity in the Netherlands. A negligible amount of space is currently *not* assigned to either agriculture, built environment or nature, and the ongoing nitrogen emission crisis shows the negative externalities of the space-intensive land use in the Netherlands. Additionally, the energy transition is expected to increase land use for energy significantly, by moving from relatively spatially condensed fossil generation to renewable generation. Furthermore, energy infrastructure is expected to take up more space, with an estimated extra 350 km of high-voltage connections and with high voltage substations to double in required area (Rijksoverheid, 2024).

Adding to this rising need for space for energy, the hydrogen system will have its own spatial requirements. The total area requirement of the hydrogen system is estimated at **80-101 km^2 in 2030**, rising to **99-280 km^2 in 2050** (HyDelta3, 2024). These numbers include a (mostly repurposed) pipeline network, underground storage and refueling stations, import terminals and production, and are based on II3050 estimates for the future hydrogen system. No land area is assigned to offshore hydrogen production, although the II3050 numbers already do include offshore electrolysis. If all the offshore hydrogen production would instead take place on land, these numbers would be even higher.

Increasing spatial needs come with significant costs. Determining the value of a square kilometer of space in the Netherlands can be a difficult exercise, but the recent addition of the Maasvlakte 2 to the port of Rotterdam gives some insight into it. The Tweede Maasvlakte, a typical site for industrial activity such as hydrogen production, expanded the port area with approximately 2.000 hectares. The total cost of construction amounted to €2.8 billion, resulting in a cost of €140 million/km^2. This figure should not serve as a general spatial cost figure, but rather as an illustration of the potential societal benefit of spatial alleviation of hydrogen production by moving it offshore.

Offshore integration can offer up to 480 hectares of spatial alleviation

In order to estimate the spatial alleviation of offshore hydrogen production, we compare the spatial need of the model outcomes with the case in which all electrolysis production would happen onshore. For this analysis, we need a number for the specific footprint of electrolysis. The HyDelta report on spatial requirement of hydrogen projects details that for a large-scale onshore electrolyser, an estimated **10-44 ha/GW$_e$** is required (HyDelta3, 2024). This number is based on data derived from ongoing development projects like Shell Holland Hydrogen and insights presented in a "One-GigaWatt Green-Hydrogen Plant" study (ISPT, 2022).

A point of discussion here is the possibility of vertical integration of onshore electrolysis. While no large-scale vertically stacked electrolyzers are being built currently, the possibility of building upwards instead of taking more land space becomes more attractive when spatial need is very high. When considering the trade-off between offshore and onshore electrolysis, project developer costs increase significantly going offshore, leading to vertical integration of onshore electrolysis becoming attractive. Therefore, we add to the calculated ranges the possibility of stacking electrolysers three stories high.

Combining the specific footprint of electrolysis with the resulting production capacities for green hydrogen production from the modelling results, as well as the hub designs from WP1, results in the following total avoided spatial requirements shown in *Table 5.1*.

Table 5.1. Overview of spatial requirements for each energy scenario, for the year 2050. The trend-reflective scenario numbers are used for the OPERA results.

	OPERA - TRANSFORM	OPERA - ADAPT	OPERA - LCI	II3050 – NAT + hub design WP1
Offshore electrolysis [GW_e]	18	5	11	16
Associated avg. land-use [ha]	0	0	0	0
Onshore electrolysis [GW_e]	22	14	19	37
Associated avg. land-use [ha]	580	370	510	1000
Total electrolysis [GW_e]	40	19	30	53
Hypothetical avg. land-use [ha]	1060	510	800	1420
Avoided onshore space [ha]	**480**	**140**	**290**	**420**

Though the total electrolyzer capacity is much higher in the II3050 scenario, the offshore share is roughly as large as the TRANSFORM results, which determines the upper end of the range. To conclude, deploying electrolysis offshore can save onshore space ranging from 140-480 hectares in 2050 without vertical integration. When stacking electrolyzers three stories high, this range decreases to 47-160 hectares. With all electrolysis happening onshore, up to 1420 hectares of space could be needed: a plot of land roughly the size of the Tweede Maasvlakte.

6 Discussion and conclusions

The goal of the work done in this research is to assess the techno-economic benefits of offshore system integration. To that end, we have taken a public value assessment approach, combining a system optimization with a market view. The results individually show added value for deploying electrolysis offshore, ranging from very direct, quantitative benefits to indirect and qualitative.

Firstly, we see that a societal cost-optimization of the energy system leads to a consistent outcome for offshore electrolysis when expanding offshore wind capacity beyond 40 GW in 2050. Under widely varying scenario assumptions, it is consistently a cost-optimal solution to deploy offshore electrolysis when increasing the roll-out of wind deployment in the Netherlands. The northernmost areas of the Dutch North Sea, with furthest distance to shore, then need to be accessed to fulfill demand for wind energy and the trade-off between electricity and hydrogen infrastructure costs becomes the determining factor. We can conclude that ambitious wind targets can go hand in hand with offshore electrolysis, from a societal cost perspective.

However, quantifying the societal benefit shows how close to the tipping point these results are, with the avoided yearly societal costs ranging from 30 to 350 million euros in the three scenarios. This comparison is built on assumptions concerning the future cost of electrolysis and the cost difference with producing offshore. The uncertainties regarding these assumptions are so high that additional analysis needs to be done with a wide range of cost assumptions, to more strongly support the claim that offshore electrolysis has large quantitative societal benefits for system planning.

Even so, other factors should be considered in the decision making regarding offshore integration. We have shown that from a market perspective there is a significant benefit to a system with offshore electrolysis, compared to one without. Moving towards a fully green system with local production, the effects of deploying electrolysis offshore are visible in a 8-14% increase of electrolyzer full load hours. Additionally, the marginal system costs, comparable to commodity prices decrease with offshore electrolysis: a decreasing price effect of up to 22% was shown for electricity, and up to 28% for hydrogen. Finally, curtailment decreased by 15-44 TWh. The dispatch of the system is more cost-effective and makes better use of the energy produced, with the avoidance of congestion onshore being the main driver.

Another effect to consider is the reduction of use of onshore space that offshore integration brings. The North Sea is by no means empty, but the spatial concerns and societal support it depends on are very different in the onshore system. Offshore electrolysis freeing up a possible 140-480 hectares of space onshore certainly needs to be taken into account in system planning. A point to consider for this spatial requirement is that if offshore electrolysis is not considered, this space is most likely required (relatively) close to demand or the landing of electricity from the offshore system to minimize effects of onshore congestion on green hydrogen production.

The outcomes of the system value assessment show are heavily dependent on the European context. The assumed European energy system configuration that is used for both approaches is the TYNDP scenario study. In general, the selection of European scenario studies to choose from is quite limited. Even though the TYNDP scenario study is best suited for our modelling of a future Dutch energy system, it should be contextualized properly for any meaningful conclusions that can be drawn from this work. Firstly, the scenario study is constructed through the viewpoint of European transmission system operators. The focus is therefore on proposed interconnection capacity between European countries. Such a viewpoint might not prioritize the actual business case of large-scale variable renewable electricity generating installations or reflect the most realistic pathways towards net neutrality from a market perspective. This was mainly visible in the large amounts of overproduction of renewable electricity, when calculating market dispatch.

The choice was therefore made to opt for trend-reflective scenarios that reach net zero electricity imports. This less-than-ideal solution gave insight into offshore integration in a broad range of possible energy futures, but calls for a more comprehensive approach in the future: the need for a European energy outlook (at least) ranging from conservative to ambitious in terms of renewable production is significant for this kind of studies.

However, the whole process provides food for thought: energy system planning in the Netherlands is heavily subject to changes in the European context. The less likely scenario that our neighboring countries reach ambitious targets and we do not, may not be important to base investment decisions on, but reminds us of the importance of taking international developments into account when considering the energy strategy for the Netherlands.

In conclusion, there is a role for offshore electrolysis from a societal-cost perspective. However, how large this role becomes and the associated avoided societal costs are still uncertain. The choice for offshore integration will need to be assessed with a holistic view, taking into account these avoided costs along with the benefits from a market perspective, spatial benefits, as well as many more aspects not taken into account in this research. These will need to be weighed against the cons, among which the gap in private business cases is of most significance at this time. With uncertainties concerning energy outlooks and cost projections becoming less significant, this holistic view may be used to determine the future energy strategy, in which offshore wind and electrolysis could play a significant role.

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Appendix A
OPERA model – additional details

The OPERA model is shown schematically in *Figure 8.1*. The OPERA model calculates an energy system for a given year with which the energy demand can be met and industrial production can be realized while at the same time certain preconditions are met (e.g. maximum GHG emissions). An important feature of the model is that the technology deployment and energy mix (both supply and demand mix) are determined by the model's optimization algorithm (i.e. endogenous). The model chooses the technologies and energy sources that lead to the lowest cost of the energy system The model uses social costs based on investment and operating costs for the entire energy system (excluding subsidies and taxes) and the cost balance of energy imports and exports. Input parameters that the OPERA model uses are:

- Scenario objectives: maximum greenhouse gas emissions (total and per sector) and maximum energy use.
- Demand for energy, demand for mobility and production of certain industrial products.
- Techno-economic data.
- Price of imported feedstocks and commodities.
- Certain restrictions on the use of technologies.

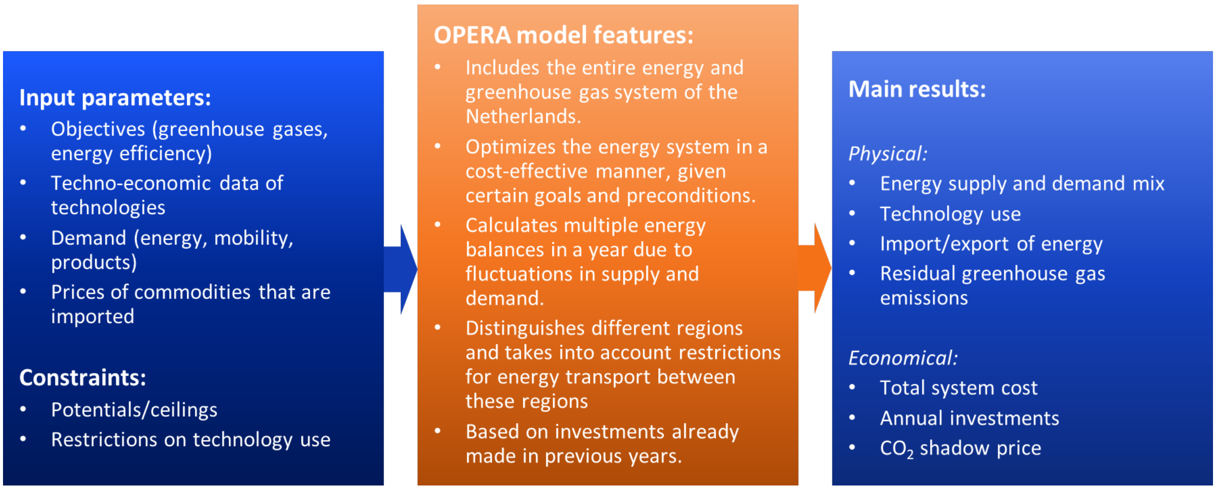

Figure 8.1 OPERA: Integral energy system model for the Netherlands (taken from (Scheepers, 2024)).

The model distinguishes different regions in the Netherlands, in the current study seven regions on land (each industry cluster falls in a separate region) and seven regions on the North Sea with distinctive wind regimes and distances to the coast. The model also takes into account fluctuations in energy demand and supply. For each subsequent year for which an energy system is calculated, the model takes into account the assets already present from the previous period based on the technical lifetime of these assets. The model determines whether additional capacity needs to be invested to meet demand[4].

[4] It is possible to have investments determined by the OPERA model at the lowest social costs over the entire period (i.e. 2030-2050), i.e. with perfect foresight. However, in practice, the future for investors is uncertain. In this study, the energy system is optimized per year and not over the entire period. In principle, this will lead to higher system costs.

The model results of the calculated energy system can be categorized into physical and economic aspects:

- Physical aspects: energy supply and demand mixes (total and per sector), technologies used (e.g. installed capacities, full load hours), import and export of energy (e.g. fossil energy, biomass, electricity, hydrogen), residual greenhouse gas emissions.
- Economic aspects: shadow prices (CO2, electricity, hydrogen), annual system costs and annual investments (total and per sector).

The exchange of electricity and hydrogen with neighbouring countries is important for the energy system. To cover this a coupling with I-LEGAS is made, see Appendix C.

Techno-economic parameters of technologies that have the most significant impact on offshore system integration are given in *Table 8.1*.

Table 8.1. Techno-economic data used in this study of the main technologies for offshore electricity and hydrogen. Costs are given in €(2023).

Technology	Parameter	Unit	2030	2040	2050	Offshore multiplication factor	Source
Offshore substation	Investment cost	M€/GW	575	575	575	-	(van der Veer, 2020)
	Efficiency	%	99%	99%	99%	-	
Offshore HVDC cables	Investment cost	k€/(MW*km)	1.45	1.45	1.45	-	(van der Veer, 2020)
	Losses	%/km	0.00033%	0.00033%	0.00033%	-	
Onshore substation	Investment cost	M€/GW	214	214	214	-	(van der Veer, 2020)
	Efficiency	%	98.5%	98.5%	98.5%	-	
HVAC onshore cables	Investment cost	M€/GW	2.71	2.71	2.71	-	(TNO, 2025)
	Efficiency	%	0.035%	0.035%	0.035%	-	
Large scale electrolysis	Investment cost	M€/GW_e	2970	2376	2376	1.68	(Eble, 2024)
	Fixed O&M cost	M€/(GW_e*yr)	73	63	63	3.5	
	Efficiency	%	60%	60%	60%	-	
Hydrogen pipelines	Investment cost	k€/(inch*km)	63.9	63.9	63.9	1.5	(van Schot, 2020)
	Losses	%	0%	0%	0%	-	
Wind offshore	Investment cost	M€/GW	2071	1988	1904	-	(TNO, 2025)
	Fixed O&M cost	M€/(GW*yr)	30.0	29.5	29.0	-	
	Variable O&M cost	€/MWh	2.1	2.1	2.1	-	

A more detailed description of the OPERA model can be found in (van Stralen, 2021).

Appendix B
I-ELGAS model – additional details

Assumptions underlying the market model

The I-ELGAS model uses a nodal structure of 20-30 nodes for each carrier. For all nodes individually, the hydrogen balance is made up hourly, comparable to an hourly market clearing. The geographical locations of the nodes are taken from the high-voltage and high-pressure networks published in the Infrastructure Outlook 2050 by (Tennet, Gasunie, 2022).

Transport on the HV-network is thus modelled in detail, including congestion. The onshore infrastructure capacities are based on the current HV-network capacity with additional investments from the IP2022 investment plans (TenneT, 2022) for the short-term (up to 2031). For long-term investments, the II3050 results are used, specifically the National Trends outcomes for additional HV-network investments. As for the offshore electricity network, the OPERA model investment results are taken into account for the OPERA scenarios and the cables are sized equal to wind farm capacity.

Prospects for the hydrogen network in the Netherlands are too uncertain to use at face value. Additionally, the network will most likely be dimensioned to demand or production size and attempting to model congestion accurately does not weigh up to the possible errors made in loss of production, etc. The hydrogen network on and offshore is therefore overdimensioned. For cross-border connections, the Netherlands is isolated for target year 2030 and connected to the European system with capacities mentioned in TYNDP2024.

Hydrogen production details

The efficiencies of hydrogen production technologies are detailed below.

Technology	Efficiency (LHV)	Source	Comment
Electrolysis	65%	Factsheet North Sea Energy	Based on PEM
SMR + CCS	77%	IEAGHG (2017)	
SMR	81%	Weeda (2018)	

Additionally, a hydrogen seaborne import route is available to the model. The model is agnostic to which hydrogen carrier this is (ammonia, LOHC, etc.), but is based on literature study of import costs of several carriers and countries of origin and the lowest cost is taken. In the model, a cracker installation is able to produce hydrogen flexibly and is seen as a production asset. The *marginal cost* with which the cracker can provide hydrogen is €82 / MWh in 2030, decreasing towards 2050.

Appendix C
Coupling between OPERA and I-ELGAS

Since OPERA only covers the energy system of the Netherlands, while hourly trade patterns for electricity and hydrogen are very important for energy systems with high shares of VRE, a coupling has been made with I-ELGAS. Vice versa does I-ELGAS need generation capacity, demand volumes and profiles for electricity and hydrogen. Via this information from the coupling it can be used to analyse the electricity and hydrogen markets for the scenarios used by OPERA.

For the coupling between the two models a sequential soft coupling scheme has been set up as indicated in the flow chart in *Figure 8.2*. As a first step I-ELGAS is executed using an infrastructure operator scenario as a starting point for 2030, 2040 and 2050. In the second step OPERA is used in both the regional modus using time-slices and a single node modus using an hourly time-resolution. For regional OPERA runs, the nodal cross-border results from I-ELGAS are mapped on the OPERA regions (*see Figure 2.2*). In both the regional and 1 node runs, the same hourly border prices are used for electricity and hydrogen.

Step 2 is run for ADAPT, TRANSFORM and LCI using the same information from step 1 for each of these scenarios. In further steps in which I-ELGAS is used (step 3 and 5), the I-ELGAS runs are specific for each scenario. As mentioned above, OPERA is used in two modi, regional/time-slices and 1-nodal/hourly. The reason for this approach is that it is computationally too demanding to use both regions and an hourly resolution in OPERA. However, I-ELGAS needs both hourly and regional information. Therefore the results of the two OPERA runs are combined. The resulting hourly demand profiles and volumes from the hourly run is distributed over the nodes that I-ELGAS uses for the Netherlands using a mapping procedure. A similar approach is applied for the generation capacity.

Using this information for the Netherlands for each individual scenario, I-ELGAS is applied again in step 3. Step 4 is a repetition of step 2, with the exception that this are the final OPERA runs. The results presented in section 3 correspond to step 4 results based on regional runs using time-slices.

As a final step in the schema, step 5, I-ELGAS is used to generate final energy market results. Note that this step is not executed for the TRANSFORM scenario, since TRANSFORM is not covered in the final analysis using I-ELGAS, see section 4.

Formally we could have included all steps below step 1 in an iterative manner, so repeating OPERA and I-ELGAS until a certain convergence criterium is reached. Due to the significant calculation times and the fact that the procedure is not automated, the scheme has been limited to two iterations. Prio tests, using a similar model as I-ELGAS, indicated that a third iteration does not significantly change the results.

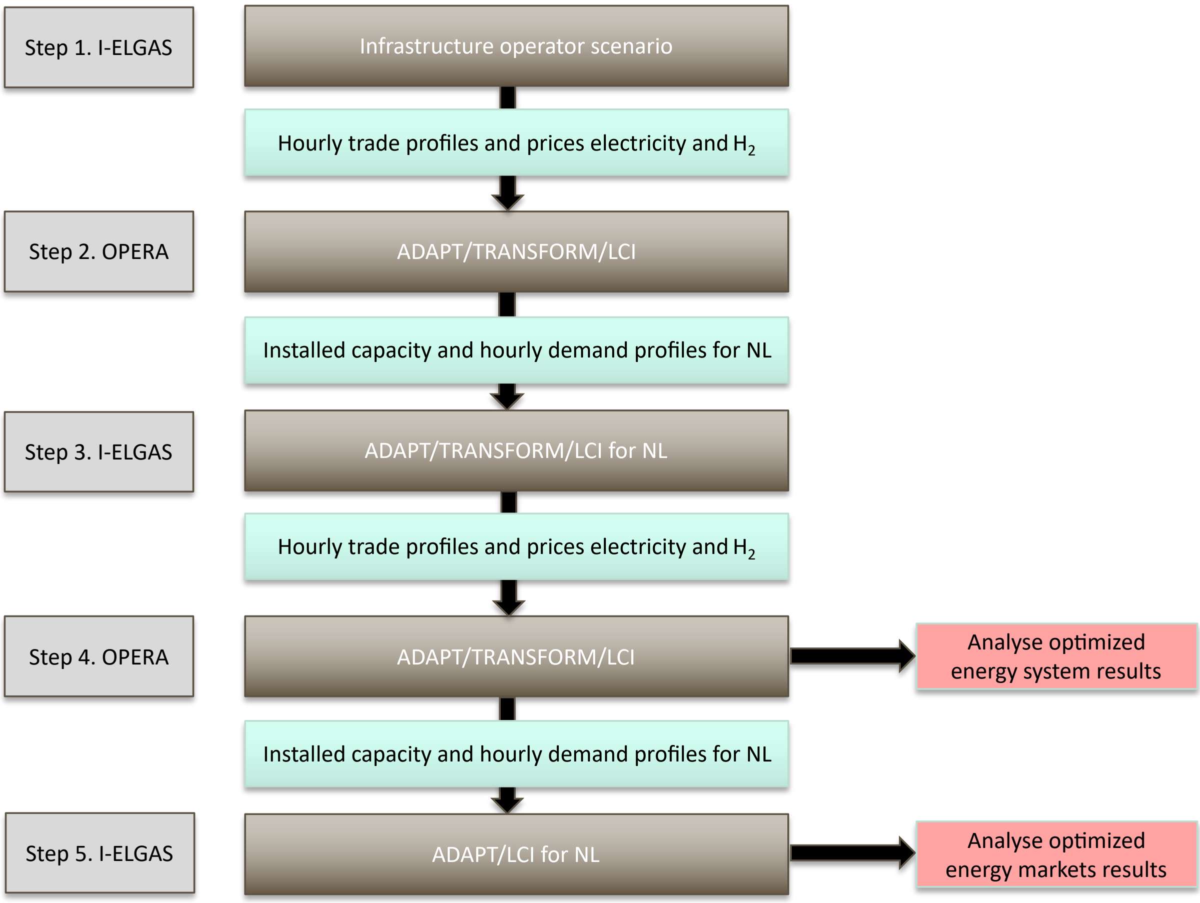

Figure 8.2 Flow chart representing the coupling between I-ELGAS and OPERA

Appendix D
Scenario assumptions for energy system modelling

The main scenario assumptions in 2050 for ADAPT, TRANSFORM and LCI are given in *Table 8.2* a more extensive description of scenario parameters, including the values for 2030 and 2040, can be found in (Scheepers, 2024).

Table 8.2 Main scenario parameters for ADAPT, TRANSFORM and LCI in 2050

Item	Unit	ADAPT	TRANSFORM	LCI
GHG reduction target wrt 1990	-	100%	100%	100%
GHG reduction target international bunkers wrt 2005/2008	-	50%	100%	100%
Wind offshore potential	GW	40	70	70
Solar PV potential	GW	109	132	132
Nuclear potential	GW	8.3	8.3	8.3
CO_2 storage potential	[Mton CO_2/yr]	40	15	15
Domestic biomass potential	[PJ/yr]	241	209	209
Woody biomass import potential	[PJ/yr]	650	650	650
Index steel wrt 2019	-	109%	82%	41%
Index fertilizer wrt 2019	-	118%	49%	30%
Index fossil refineries wrt 2019	-	50%	20%	10%
Index chemical sector wrt 2019	-	133%	80%	40%
Additional restrictions steel sector	-	DRI excluded	100% DRI with hydrogen	100% via imported HBI
Additional restrictions fertilizer sector	-	15% using imported NH_3	15% using imported NH_3	100% using imported NH_3
Additional restrictions refinery sector	-	-	-	Half of the renewable fuel production of TRANSFORM is forced to be imported
Circular carbon target for production of chemicals	-	0%	80%	80%
Additional possibility chemical sector	-	-	-	Import of plastic waste and renewable naphtha

Prices of primary energy sources can be found in *Table 8.3*.

Table 8.3 Energy prices in €(2023)/GJ

	2030	2040	2050
Natural gas	13.7	13.7	14.3
Oil	18.6	19.7	23.8
Coal	3.7	4.0	4.5
Biomass, used cooking oil (UCO)	20.7	20.7	20.7
Biomass woody, domestic	10.9	10.9	11.0
Biomass woody, import cheap	10.9	10.9	11.0
Biomass woody, import expensive	16.4	16.4	16.4

Appendix E
Additional energy system optimization results

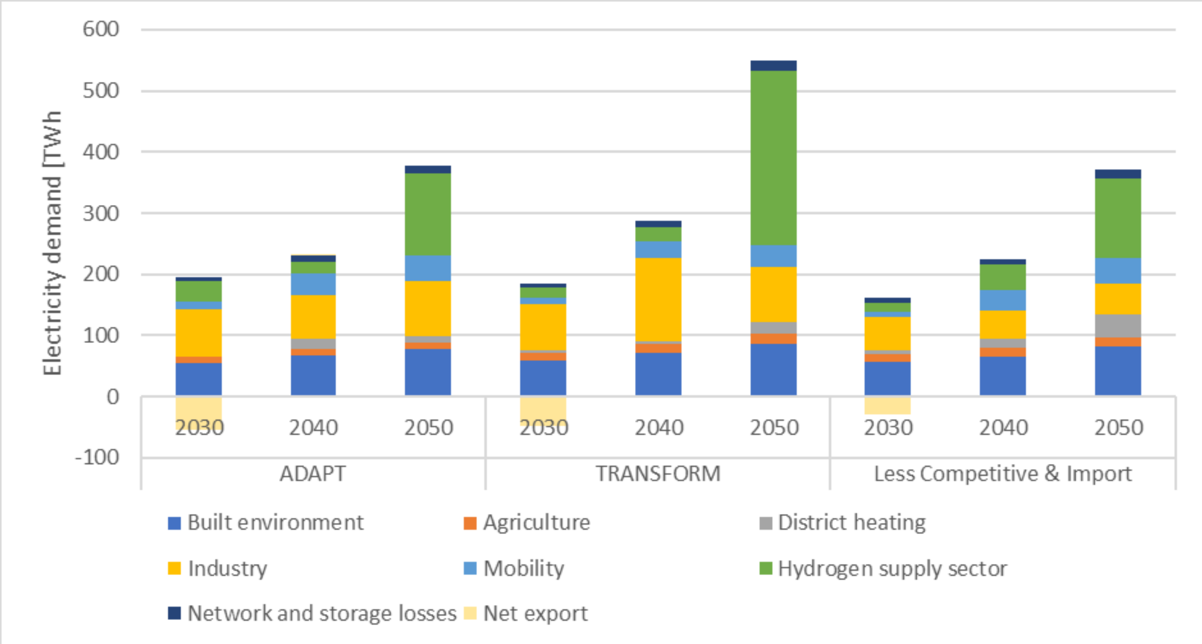

Figure 8.3 Electricity demand for ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in TWh.

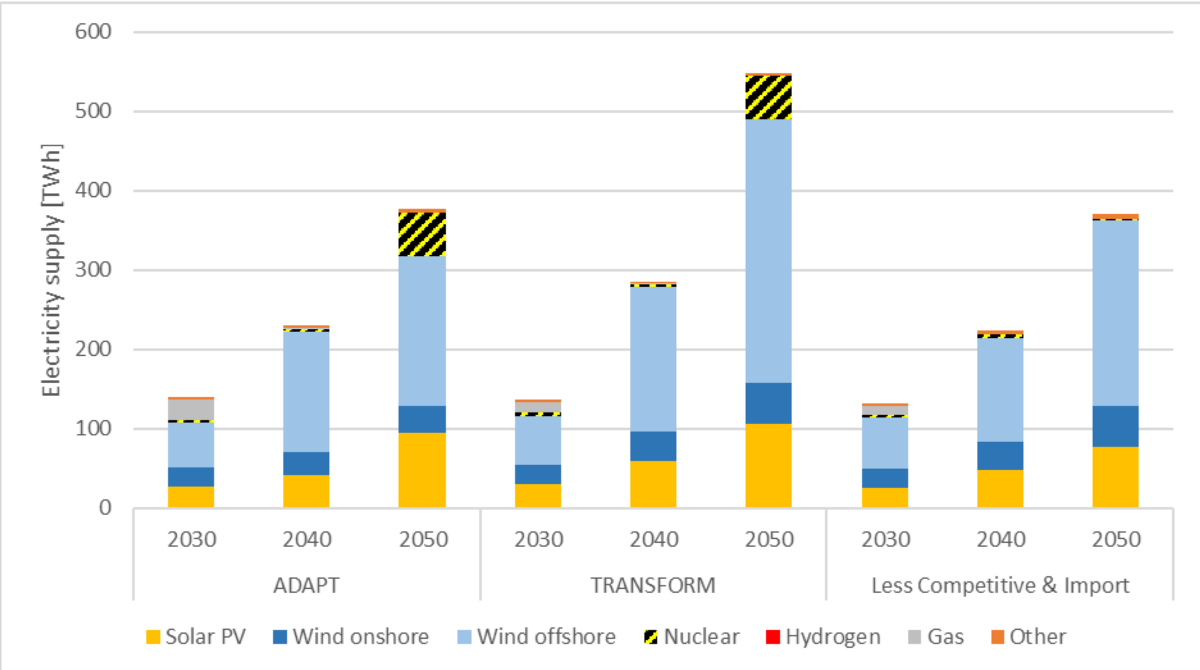

Figure 8.4 Electricity supply for ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in TWh/yr.

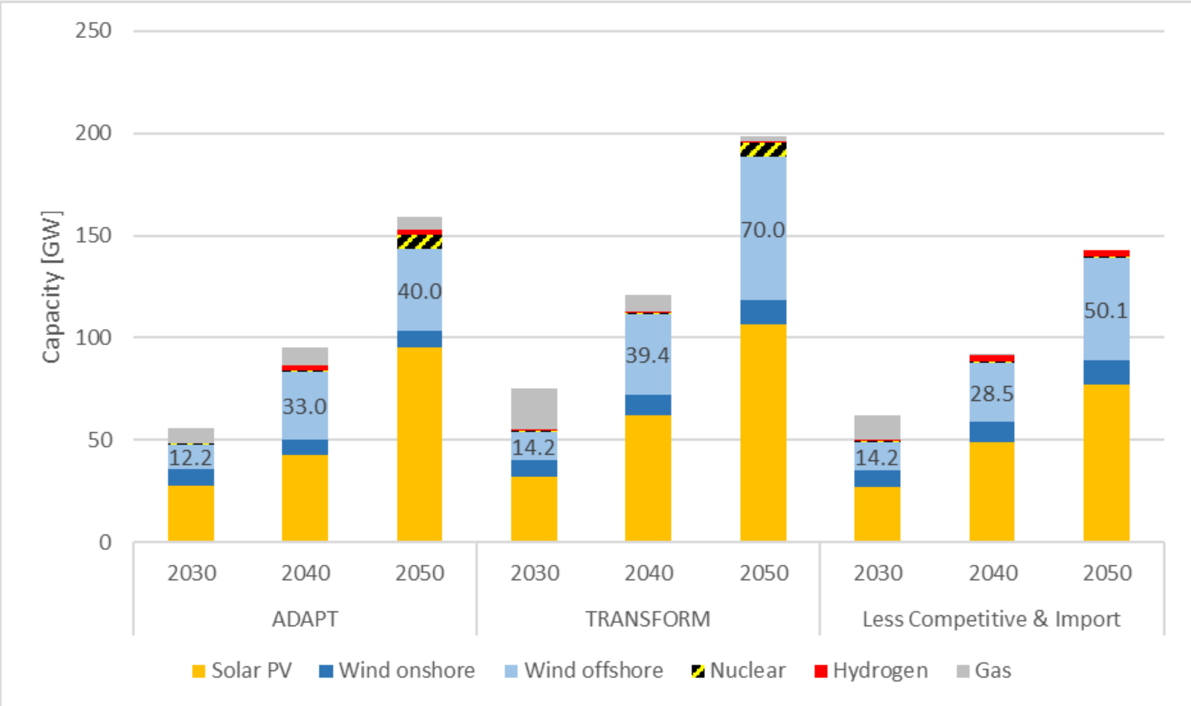

Figure 8.5 E7lectrical capacity for ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in GW[5].

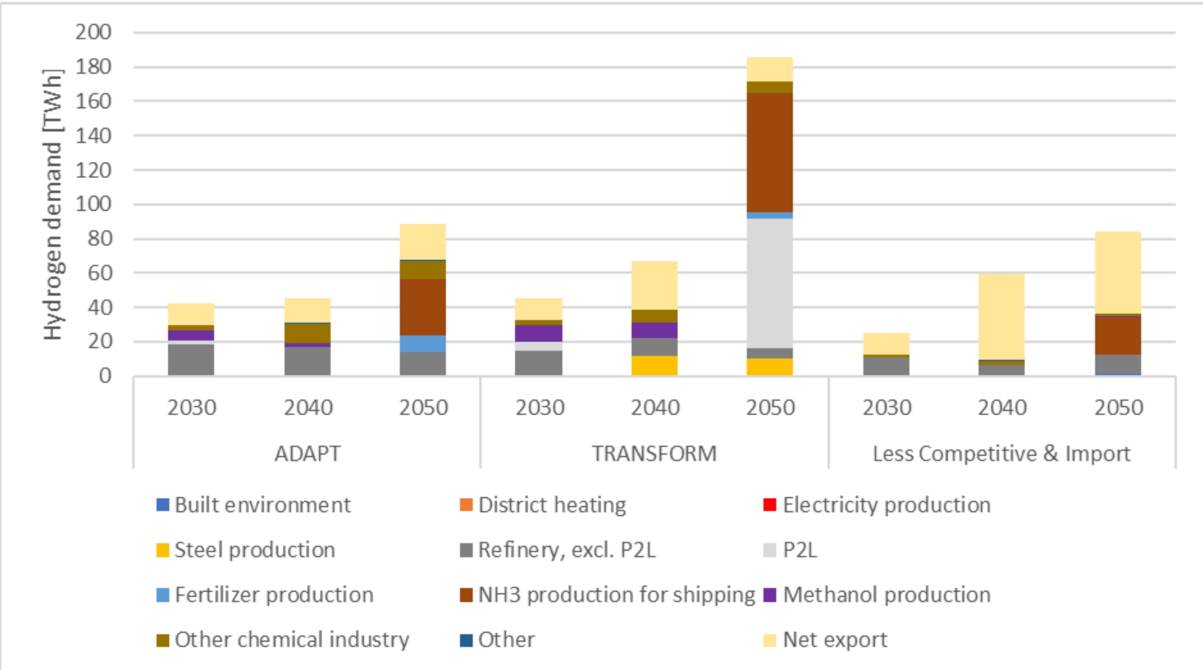

Figure 8.6 Hydrogen demand for ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in TWh.

[5] The electrical capacity of the category other is excluded, since it also contains technologies that have electricity as a by-product, like bio-refineries.

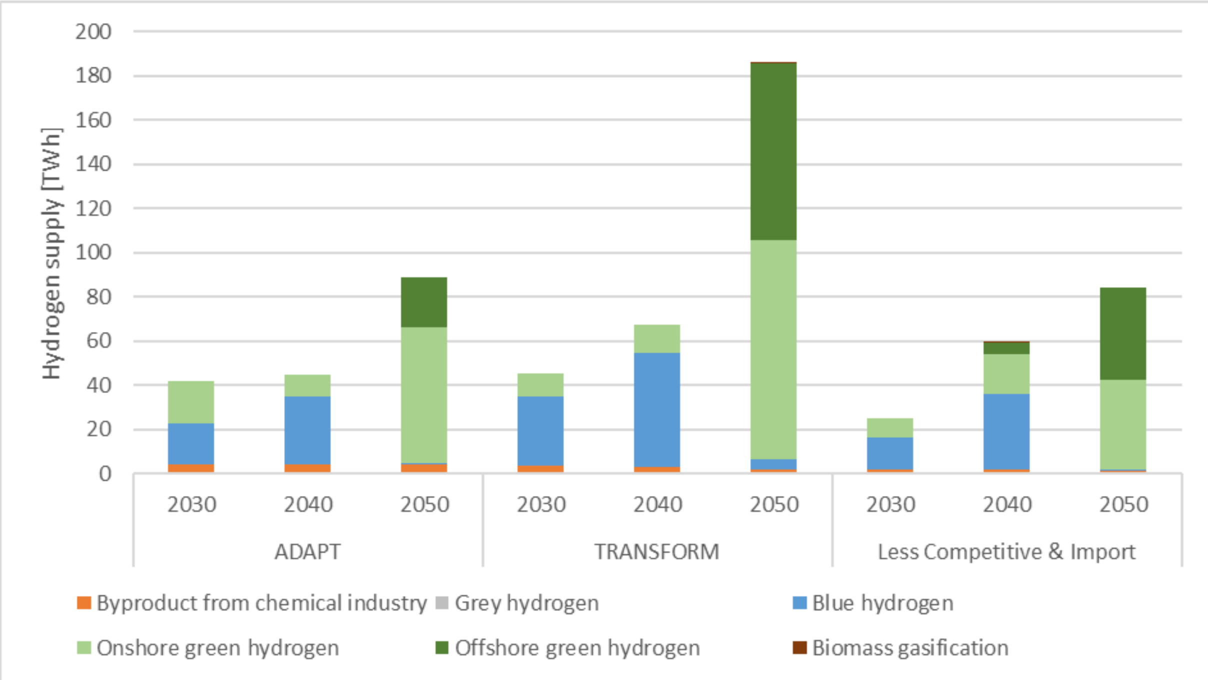

Figure 8.7 Hydrogen supply for ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in TWh.

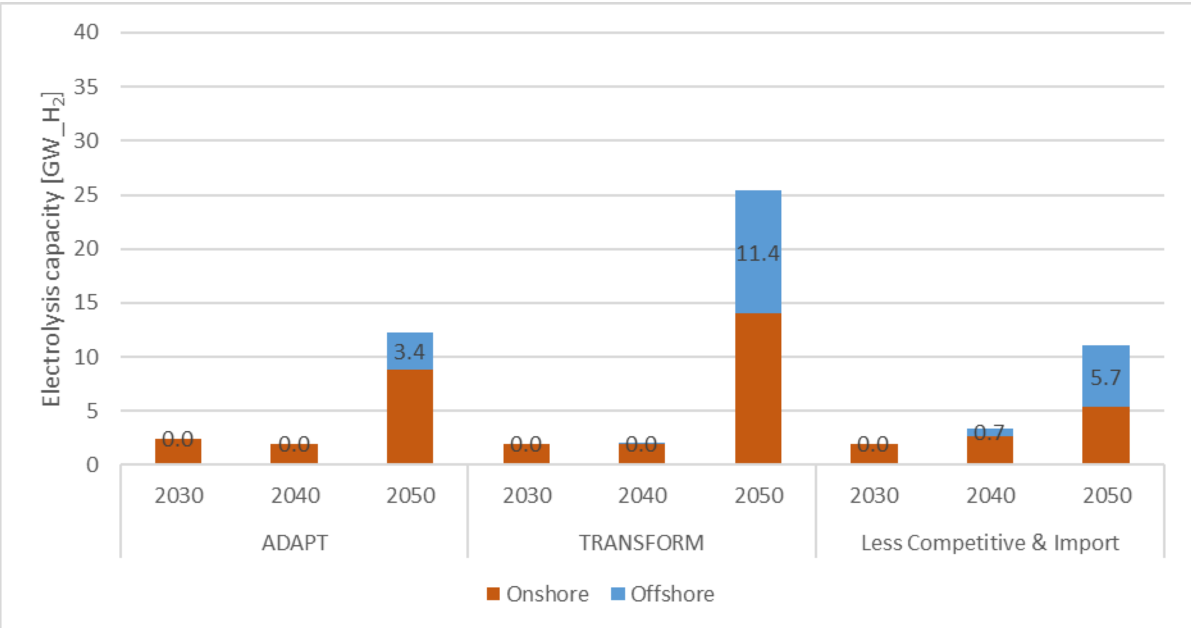

Figure 8.8 Onshore and offshore installed electrolysis capacity in ADAPT, TRANSFORM and Less Competitive & Import for 2030, 2040 and 2050 in GW_{H2}.

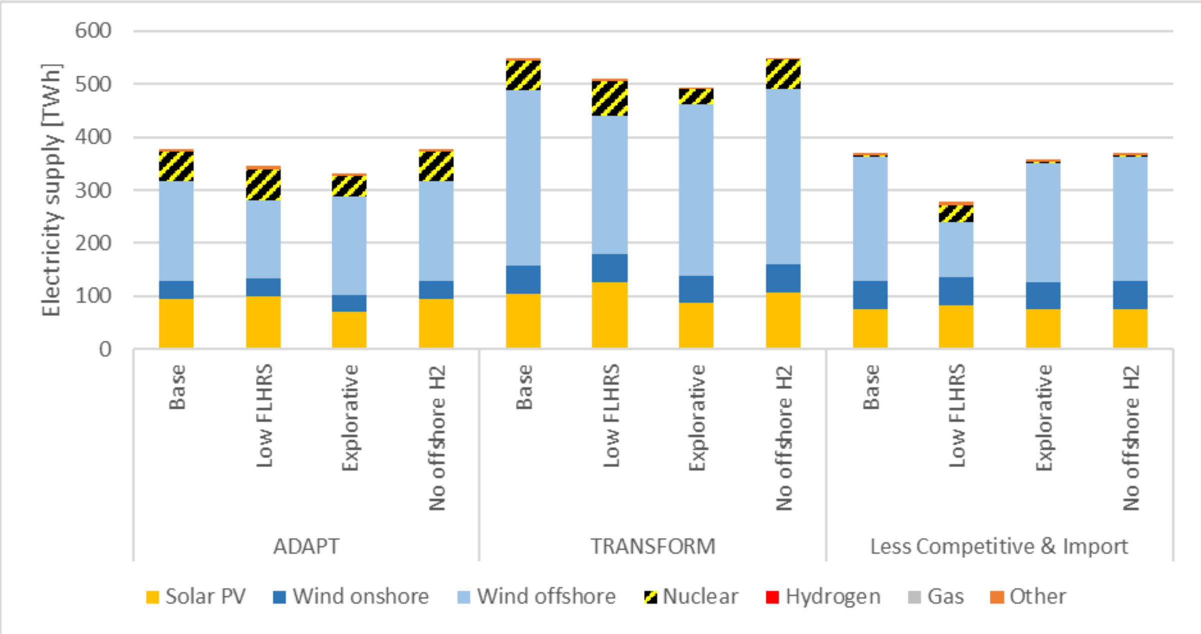

Figure 8.9 Electricity supply in 2050 for the base case and sensitivity cases of ADAPT, TRANSFORM and Less Competitive & Import in TWh.

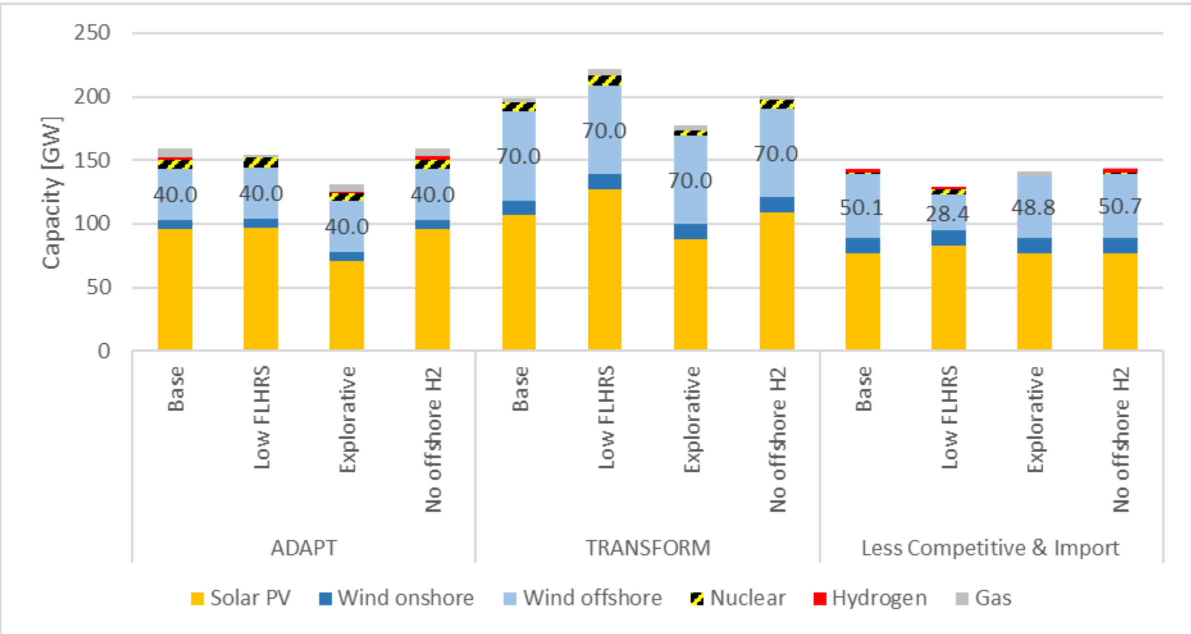

Figure 8.10 Electrical capacity in 2050 for the base case and sensitivity cases of ADAPT, TRANSFORM and Less Competitive & Import in GW.

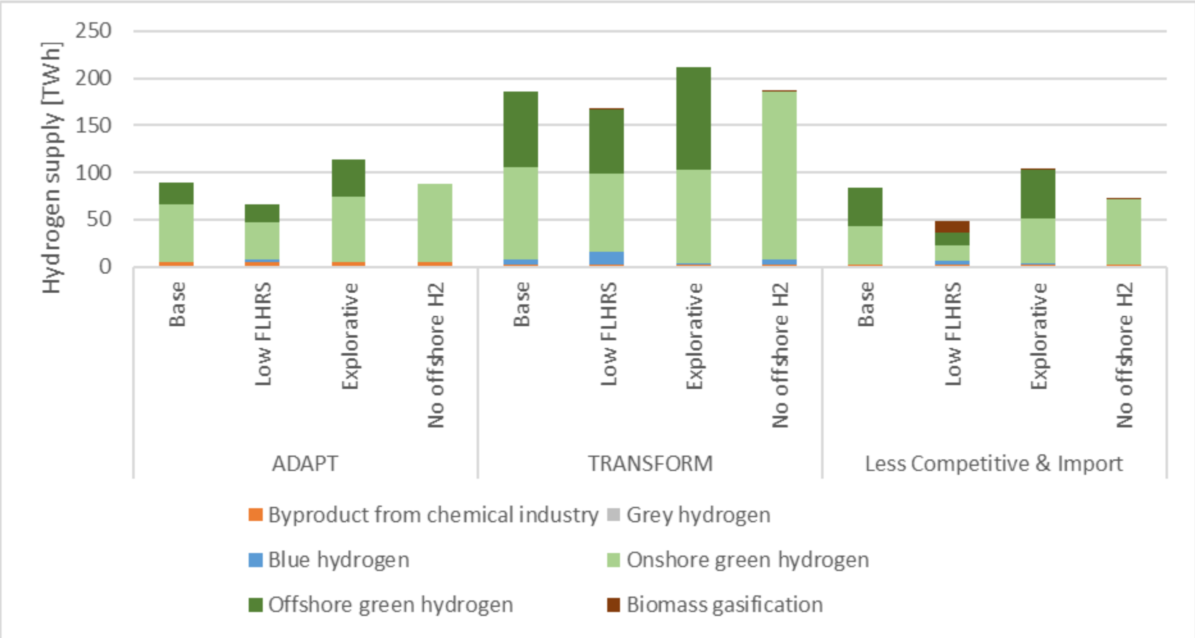

Figure 8.11 Hydrogen supply in 2050 for the base case and sensitivity cases of ADAPT, TRANSFORM and Less Competitive & Import in TWh.

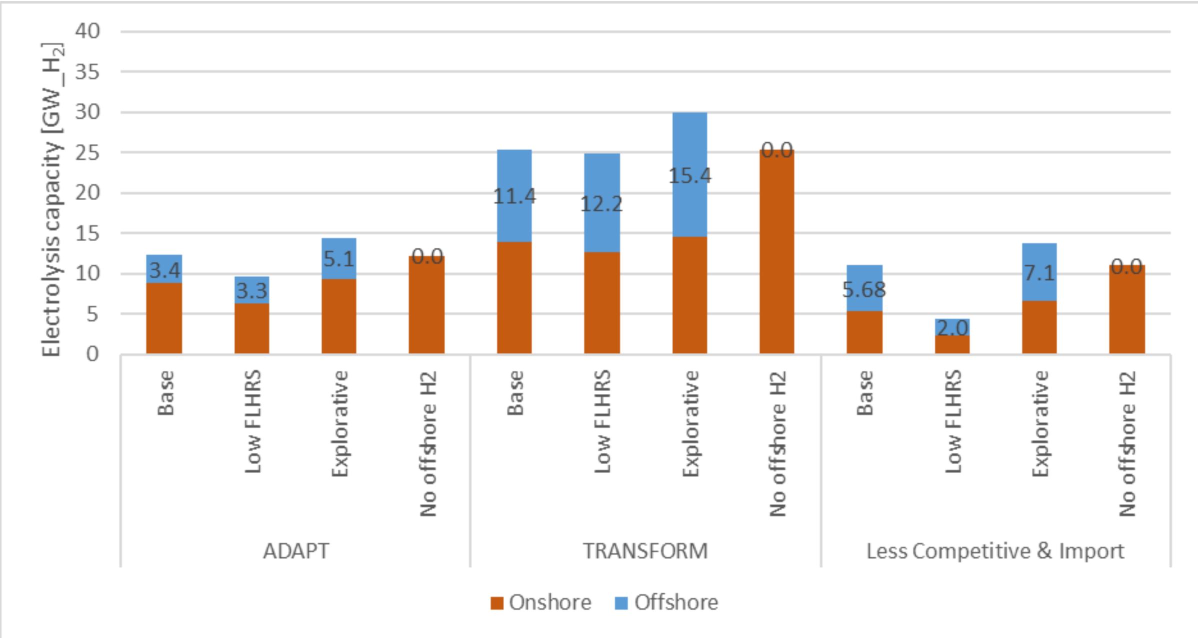

Figure 8.12 Onshore and offshore installed electrolysis capacity in 2050 for the base case and sensitivity cases of ADAPT, TRANSFORM and Less Competitive & Import in GW_{H2}.

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