BLUEPRINTING THE HYDROGEN MARKET – HYDROGEN SPOT MARKET SIMULATION (H2SMS)

PART 2: TECHNICAL REPORT

FINAL REPORT – February 2024

Bert den Ouden, Sebastiaan Hers, Joachim Schellekens, Sander Blom, Pieter Verstraten, Aliene van der Veen, Thijs Verboon, Jort Wolda & Wester Coenraads.

TNO innovation for life HyXchange Berenschot

In the course of this study, the approach and the intermediate results have been shared with many involved market parties and infrastructure operators during several digital meetings and working sessions. The researchers involved in this study extend their thanks to the involved private and public experts who participated, provided feedback and/or input and challenged us during the process.

This study is financially supported by the following organisations:

TABLE OF CONTENT

Part 1: Policy report

Part 2: Technical report (this document)

1. Introduction 4

1.1 Background 4
1.2 Project objectives 6
1.3 Overall approach 8
1.4 Project partners and participants 9
1.5 Reading guide 9

2. I-ELGAS - full dispatch simulation 10

2.1 Description of the model, key assumptions and limitations 10
2.2 Market outlook, regional and national system 12
2.3 Results full dispatch simulation 2027 and 2030 16
2.4 Summary, storage and sensitivity analysis for 2030 25

3. EYE – market (game) simulation 29

3.1 Description of the model, key assumptions and limitations 29
3.2 Strategies sets market participants 31
3.3 Results of the market (game) simulation 2027 and 2030 36

4. CEHIM - imbalance market simulation 44

4.1 Description of the model, key assumptions and limitations 44
4.2 Scenario's imbalance analysis 45
4.3 Results imbalance analysis 2030 45

Bibliography 49

A.I: Sensitivity analysis dispatch model 51

A.II: EYE variants 55

A.III: Roles and input from (market) participants 59

A.IV: Weekly balances dispatch 60

1. INTRODUCTION

1.1 Background

Hydrogen has an important role in the future energy mix

Hydrogen is increasingly attracting interest as an important part of the energy transition. Hydrogen acts as natural complement to the vast technical potential for intermittent renewable electricity production offered by the North Sea basin[1]. No greenhouse gas is released when hydrogen is used. Hydrogen is therefore regarded by many as a climate neutral energy carrier for the future. The Climate Agreement, as well as recent statements by the Dutch Ministry of Economic Affairs and EU COM, therefore devotes a great deal of attention to hydrogen.

A recent exploratory study[2] focussing on the pros and cons of a hydrogen exchange in the Netherlands found that the Netherlands has a unique position with vast potential for green hydrogen production from offshore wind, the landing of seaborne hydrogen imports, a solid industrial base with large hydrogen subsystems, and, of course, the unique natural gas- and industrial feedstock infrastructure as a gateway to industrial clusters in the North-western European hinterland. The Netherlands also has a track record when it comes to energy exchanges as the designer of the system of market coupling of the European electricity exchanges, and the creation of Europe's leading gas market at the TTF.

Opportunities for development of a hydrogen market in the Netherlands

Due to the position that hydrogen will occupy in the future and the many ways in which it can be produced and used, with a variety of producers and users, the development of the trade in hydrogen will become important. As a result, the possibility of a hydrogen exchange based in the Netherlands has also become of interest to both public and private stakeholders. It is expected that in the Netherlands and abroad, many new sources and customers can emerge creating a greater diversity of supply and demand, both constant and with variations over time.

A dependable and transparent trading platform, such as we have today for electricity and gas, greatly enhances market access, pools liquidity and reduces transaction costs and trading risks. Furthermore it is expected to play a crucial role in the development phase of the market and in its day-to-day balancing. The trading platform is expected to catalyse an increasing demand for climate neutral hydrogen produced by an expanding asset base and balance supply and demand through transparent pricing. An effective exchange of surpluses and deficits through a market could be jointly beneficial and also beneficial for the energy transition (see below). If this takes place via a hydrogen exchange, it can have benefits for both major and minor players.

Why a spot market in hydrogen

At this point in time, there is no spot market in (grey) hydrogen. However, a spot market in hydrogen is expected as a consequence of the move towards green hydrogen, bringing huge changes in the market.

Currently, hydrogen is largely grey hydrogen, made from natural gas (reforming), on-site where the demand is, largely as industrial feedstock. This feedstock-hydrogen is largely produced locally and continuously. The (industrial) production and (industrial) consumption are both largely local and 24/7, and often delivered within-company. There is currently no need for a market, because it is almost all local, with little time variation or transportation, and with very few parties involved.[3]

---

[1] Netbeheer Nederland, 2023. Integrale Infrastructuurverkenning: scenario's 2030-2050, 2e editie.
[2] B. den Ouden, 2020. A hydrogen exchange for the climate.
[3] There are exceptions to this: some hydrogen is also produced in industries as a by-product, and there are some transportation pipelines (largely industry-owned, without Third Party Access) and regional deliveries between industries. That has been insufficient to create a market so far.

That picture will change drastically in the years to come. The prime driver is the move to renewable hydrogen driven by energy transition policies. The production of that green hydrogen will not be local any more. It will be produced far from the demand (nationwide and international, by hydrogen carrier imports) and by a variety of producers, mostly different from the consumers, including imports. This has the following effects on the market:

- This will create the absolute need for more transportation also with Third Party Access. Thus, this market will no longer be local, but regional, national and even international.
- This will create a far bigger number of players, in numbers and greater variety: next to existing industries also energy companies, renewable producers, electrolyser operators, hydrogen carriers im- and exporters, storage operators and more.
- This market will see much higher volatility. While the demand is likely to remain steady continuous, the intermittent production of renewable hydrogen will create new volatility.
- Apart from green hydrogen, we see also a move to blue hydrogen (carriers). Part of that blue hydrogen is also expected to be imported due to strategic changes in the energy market.

These are drastic changes to the market structure. Instead of the current internal or one-on-one local continuous business, it will become a transported, many-to-many, variational, international business. According to practical experience in other commodities like electricity and natural gas, these factors have led to the establishment of, even the need for, a spot market. This is expected to happen with hydrogen as well. The character of this spot market and the drivers behind it are explored in this study report.

Need for better understanding of hydrogen market, trading and how to facilitate it

As follow-up to the exploratory hydrogen exchange for the climate report, four areas for further analysis were development with agreed upon with involved market parties. The four preliminary areas selected for further development are:

1) development of a **certificate product** encompassing green, blue, grey and imported hydrogen;
2) a **spot market** for hydrogen, due to the continuous demand from industry as well as the fact electrolysers provide intermittent output and the obligations stemming from the Delegated Act[4];
3) hydrogen **grid balancing** and storage, similar to the E- and G-net the network needs to be managed in order to ensure security of supply and other services;
4) development of an **index product**, due to the need for price transparency and possibly it can act as a precursor for spot, futures and swaps.

Based on the needs mentioned by market parties, various projects have been initiated by HyXchange. All projects aim to increase the understanding of the future hydrogen market, and provide insights in the requirements that a future hydrogen exchange would need to meet.

This (H2SMS) study focussed on development of areas 2 and 3. It aims to increase understanding of the future hydrogen trade over the regional and national hydrogen backbone that is currently being developed by HyNetwork Services (HNS) and will connect the Dutch industrial clusters going towards 2030. The goal of this study is further elaborated on in section 1.2. HyXchange is in other projects also working on a certificate product (development area 1) and an index product (development area 4), results on this and other areas can be found on Hyxchange | The future.

[4] Commission sets out rules for renewable hydrogen (europa.eu)

What is the role of a (hydrogen) exchange?

In general, an exchange pools liquidity, enhances market access and leads to greater transparency, efficiency in trading and also reduces trading costs and risks. As a result, the market is more efficient (closer to the economic optimum) and more accessible, allowing more parties to trade with less risk. It therefore promotes the volume of trade, which favours economic optimisation, and thus a better allocation of factors of production and, consequently, a better economic result. The functions of an exchange are as follows:

a. Covering surpluses and shortages
b. Market optimisation and flexibility
c. Price discovery
d. Auctioning and trading of ancillary services
e. Anonymous trading with ensured settlement, equal opportunities for large and smaller market participants
f. Forward market and portfolio optimisation
g. Catalyst of developments

1.2 Project objectives

The study seeks to better understand the requirements of the future hydrogen system in order to establish a robust blueprint for a hydrogen exchange in the Netherlands. The hydrogen exchange should allow for an expected gradual build-up of the hydrogen market and cover an expanding geographical area and include future aspects of the envisioned hydrogen system (such as storage and interconnection).

Market efficiency, integrity and robustness of exchange-based hydrogen trading is assessed through extensive market simulations, conducted in close cooperation with partners in the HyXchange Initiative and future market participants, building a shared view and confidence in the next steps towards exchanges-based hydrogen trading.[5] Findings of this study will support the timeline for platform development and roll-out of services that HyXchange will provide to the market.

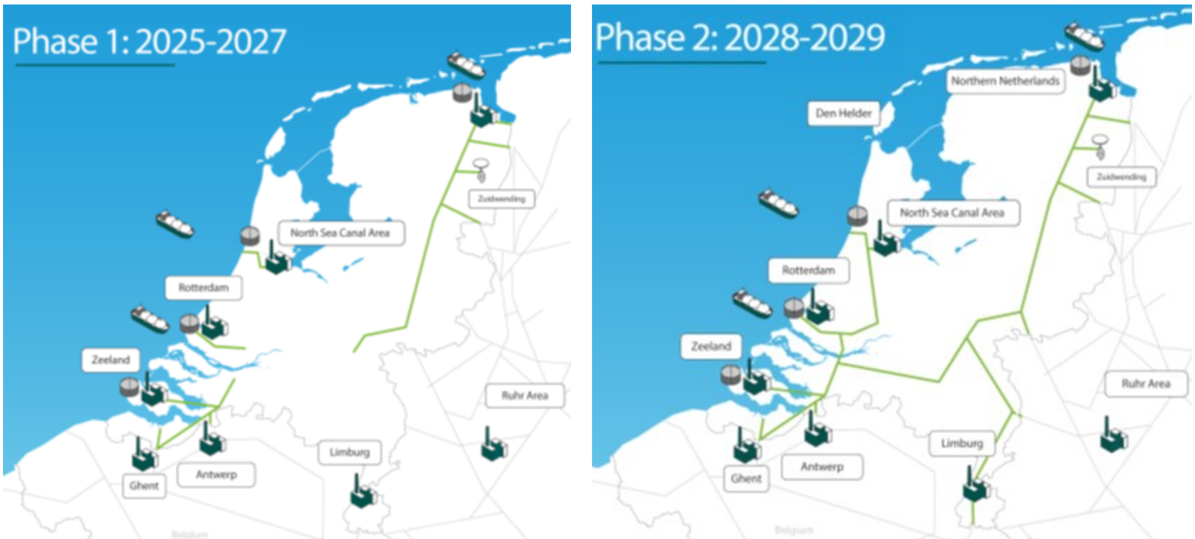
The development of the hydrogen market is strongly dependent on the development of the to be developed hydrogen infrastructure. Various organisations, such as Hydrogen Network Services, HyStock and various producers are working on the hydrogen backbone, increasing storage capacity and production of blue and green hydrogen (and import and cracking facilities for ammonia). The pace of these developments, as well as the cost price of the various types of hydrogen, is inherently uncertain. Therefore two infrastructure development scenario's for 2027 and one for 2030 will be explored (as well as a number of variations to a chosen 'import base case'):

- First the case of a **regional start-up in 2027** is analysed;
- Second the case of a **national start-up in 2027**; and
- Third the case of a **national system in the year 2030** (and a regional start-up in 2027).

The figure below shows on the left side the expected infrastructure and storage in the year 2027 in the regional start-up case. The figure on the right shows how the hydrogen system will function in the national case, either in 2027 (having lower supply and demand) or in 2030 (source: HNS).

[5] Currently little is known about the practicalities of the hydrogen market. No hydrogen spot market on a pipeline network has ever been operated: it is a new thing. Some similarities with gas spot markets may exist, but it is also clear that there are also vast differences both technically and economically. To our knowledge no design for hydrogen spot markets, spot market simulation for hydrogen or blueprinting study has been carried out to date. This study does build on prior work of regional system simulation done for the Rotterdam area with EYE in the European Elegancy project (Elegancy (ERA-Net ACT project) D5.2.6 ROADMAP for the introduction of a low carbon industry in the Rotterdam Region, 2020), but will substantiate the basis for the blueprinting significantly by use of the state-of-the-art integrated energy market model I-ELGAS and the serious game approach to build understanding and confidence with the main stakeholders.

Table 1 – Expected development of hydrogen network in the Netherlands 2025 – 2030[6] .



Additionally, this study also aims to better understand the various 'functions' of hydrogen in the future energy system, the 'role' that participants in the hydrogen system are expected/required to play and the impact of recently introduced hydrogen regulation (such as the Delegated Act on green hydrogen production). More specifically this study will provide understanding on the following market characteristics in order to better understand them and develop the exchange accordingly:

1. **Balancing** varying "green" hydrogen with flexible "blue" hydrogen from SMR + CCS. Electrolysers produce green H2, but production is expected to vary with intermittent production of solar and wind power and associated electricity prices. Most customers need a continuous flow of hydrogen however. Low-carbon or "blue" hydrogen with flexible production (natural gas reforming plus CCS) can then help fill the gaps, jointly with storage. The hydrogen exchange will bring together supply and demand variations and provide optimal market value for both green and low-carbon hydrogen production.
2. Use of **hydrogen storage** to accommodate variations in green hydrogen, balance the network and create a continuous flow of renewable H2 for end users. The hydrogen exchange can facilitate optimal use for all market players, both for "local" storage (line-pack) and national storage (salt caverns). At the start of the hydrogen market, where you do have a regional pipeline with a line pack, but no national connection to the salt caverns in Zuidwending, this option is very important to cover imbalances. As soon as the connection with the national storage facility is established, new opportunities will arise from which everyone can benefit optimally via the stock exchange.
3. Optimizing **the (renewable) feed of electrolysers**, which improves the running time. Due to a diversity of renewable sources, possible time-shift by batteries, and possibly incidental grey power, one can create a more continuous flow of renewable electricity to the electrolysers. This generates technical-economic optimization and economic value for producers. This optimization will also take place in the electricity market. A well-functioning hydrogen exchange will promote this, because it offers companies and traders opportunities to optimize on both markets simultaneously (hydrogen-electricity coupling).
4. Market role and market impact of **hydrogen imports**. Imports of hydrogen or its derivatives (liquid H2, LOHC, ammonia, methanol) arrive from ships intermittently, also with their own inherent storage and conversion with their technical and economic time dependent characteristics. Facilitated by the hydrogen exchange, such import flows can create additional market opportunities and contributes to the establishment of ports as regional or national hydrogen hubs.
5. **Interaction with demand** in different sectors. The current largest H2 consumer is industry, typically on a continuous basis. Other future demand should be expected to show more variations. Powerplants fuelled with H2 (or mixed gas/H2) fuelled will operate intermittently in the short term. The built environment will typically show seasonal and weather-driven

---

[6] Hynetwork Services, 2023. Market Update 29-6-2023.

hydrogen demand. Transport sectors have their own demand patterns, but also some H2 fuel storage and on-board storage in service stations. The interaction of this demand with the hydrogen supply can differ per region, depending on the specific situation. In addition, hydrogen offtakers can sometimes offer on the stock exchange to manage their portfolio of forward purchases and actual demand realizations.

6. **Interaction between nodes/regions** in the hydrogen network. All the above market optimizations are present in a diversity of (port) regions, with different accents depending on the regional circumstances. If a spot market initially emerged in one or more port regions, this would lead to dynamics with specific characteristics at each regional node and a need for local flexibility and storage or line-pack. Later, when all regions are connected to each other and to storage (Hystock Zuidwending) by large-scale infrastructure (hydrogen backbone, possibly others such as the "Delta Corridor" Rotterdam-Chemelot, a different dynamic situation would arise, possibly still with different regional dynamics at and between nodes.

Insight in these aspects of the future hydrogen system will help shape the next step in developing the hydrogen market and develop the rules and the trading system specification for a hydrogen exchange (HyXchange). Additionally, the simulations run in this study act as a precursor to a physical market simulation that can start when a regional start-up market has amassed sufficient liquidity.

As mentioned to get all answers a number of market simulations (both an import case and select number of variants) need to be run, both in the regions with ambitions for an early start of the spot market, and for the national integrated system (backbone and Hystock) situation later.

1.3 Overall approach

In this project four energy system models that capture the characteristics of a coupled electricity, methane and hydrogen market have been used. In a first phase the hydrogen market (supply, demand and installed capacity) for 2027 and 2030 is forecasted by adjusting the **Energy Transition Model** scenario's developed by the network operators earlier in 2023[7]. In a second phase, the modelled energy system is used in two simulations that are developed and operated by TNO, namely **I-ELGAS** (a dispatch simulation) and **EYE** (a market or game simulation):

- First, the highly detailed optimization model I-ELGAS (*dispatch simulation*) is used to evaluate dynamics of optimal market allocation under perfect foresight or certainty regarding future demand, intermittent power production, plant trips etc. The dispatch simulation is applied to all three market and infrastructure development scenario's.
- Second, we have assessed market dynamics accounting for bid behaviour in the face of uncertainty with the more proximate but flexible simulation model EYE (*market simulation*). The market simulation is applied to the national start-up in 2027 and 2030.

To better understand the system imbalance a new simulation model has been developed upon specific request of participating market parties as part of this project. This model allows for technical and financial analysis of the coupling between the electricity imbalance market and the hydrogen imbalance market. The imbalance model (**CEHIM**) is applied to the situation in 2030.

The figure below shows the key characteristics of the four model simulations. This figure provides at a glance where certain information from one model is used as input in another model.

---

[7] Transitie Nederlands energiesysteem | Berenschot nieuws

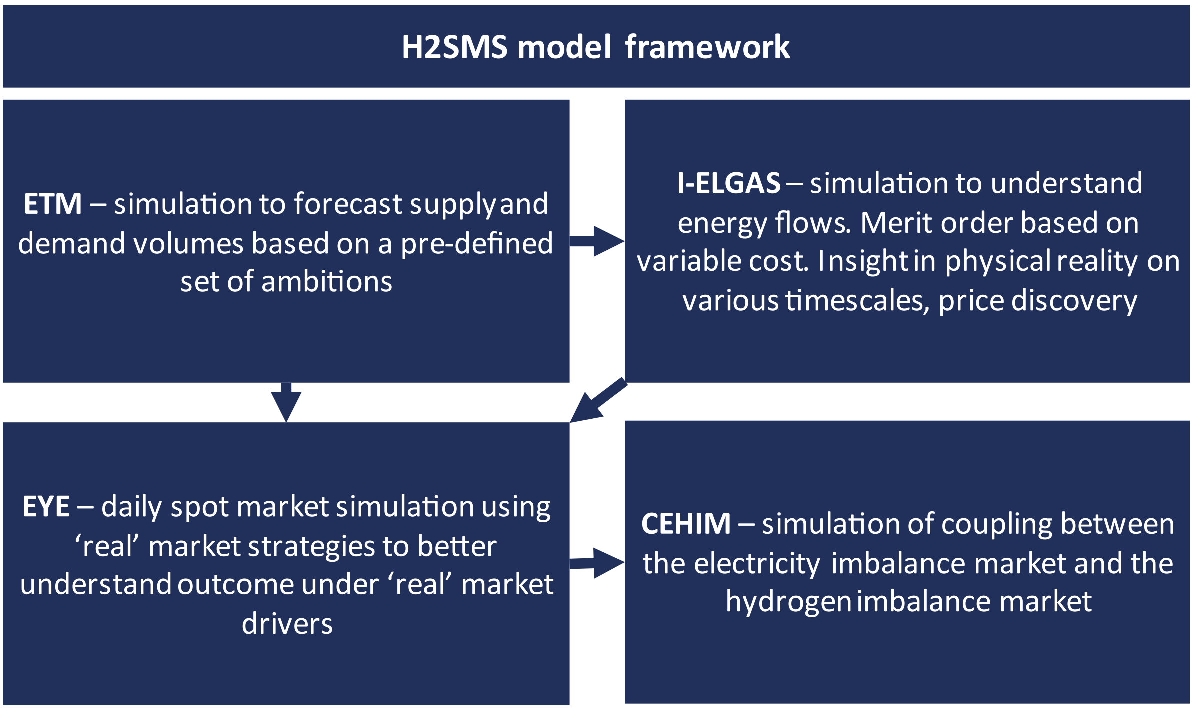


Figure 1 - Overview of H2SMS model framework and interconnections

1.4 Project partners and participants

This project is led by HyXchange. HyXchange is supported by TNO and Berenschot. HyXchange leads the various discussions between market parties and act as point of contact for internal and external participants/ interested parties to this project (for instance EZK, IenW, RVO, NEa, Vertogas, BMWI, EU COM, etc). TNO leads the modelling exercise and runs the full dispatch simulation, the market simulation model and the imbalance model. Berenschot contributes to this project by providing supply and demand side data (amended from the IP2024 scenario study), coordinating the work effort and by facilitating the various stakeholder sessions.

Other partners in this project are: the HyXchange steering committee members (Port of Rotterdam, Groningen Seaports, Port of Amsterdam, North Sea Ports and Gasunie), the province of Zuid-Holland and Zeeland, and Smart Delta Resources (see Annex III for the complete list). This study received financial support from TKI New Gas and is part of their PPS-scheme. Most importantly, many market parties involved with the HyXchange Initiative (voluntarily participating) provided feedback on the approach and draft results of the study, as well as participated in many workshops and online sessions. We thank all parties for their input and feedback.

1.5 Reading guide

Chapter 2 focusses on the full dispatch simulation. First the model, its key assumptions and limitations are explained (2.1), then the input for the scenario is shown (2.2), third the findings both for the import (base) case and seven variants are presented (2.3) and discussed (2.4). Chapter 3 follows a similar structure, but for the market simulation. Here attention is given to the effect that possible strategies of market participants have on market outcome in 2027 and 2030. Chapter 4 sets out the approach for CEHIM and presents the results for five scenario's. In Annex I the results of the sensitivity analysis regarding the 2030 simulation and production hours of green hydrogen is shown. In Annex II further information on EYE is available. Annex III provides background on the various workshops and meetings held with market participants.

2. I-ELGAS - FULL DISPATCH SIMULATION

The highly detailed optimization model I-ELGAS (dispatch simulation) is used to evaluate dynamics of optimal market allocation under perfect foresight or certainty regarding future demand, intermittent power production, plant trips etc. The dispatch simulation is applied to all three market and infrastructure development scenario's.

2.1 Description of the model, key assumptions and limitations

Description of the model

TNO's integrated market model I-ELGAS provides insights on the full system dispatch and commodity pricing of a cost-optimal market allocation. I-ELGAS is a linear-programming-based nodal market model that allows to simultaneously simulate hydrogen, electricity and methane markets. Covering the full supply chain from generation & extraction, through transport (transmission, pipelines, shipping), storage (salt caverns and depleted gas fields) and conversion (power production, electrolysis, reforming, methanation) to demand.
The model currently optimizes hourly system allocation at asset-level such that demand is served at least-cost against system marginal cost per commodity, representing competitive market allocation. The resulting system dispatch (production, conversion and transport) can subsequently be used to give insights into market dynamics and sensitivity. Finally, the merit order-based system marginal costs can be used as a proxy for energy prices. To expand on this, the following results on an hourly time scale are generated in the model:

- Electricity production from power plants and renewable sources.
- Hydrogen production, including green, blue and grey.
- Transport flows of electricity, hydrogen and methane between nodes.
- Storage injection, extraction and energy level for batteries and hydrogen salt cavern storage.
- Seaborne import shipping volumes for LNG and liquid hydrogen carriers.
- Nodal prices for electricity, hydrogen and methane.

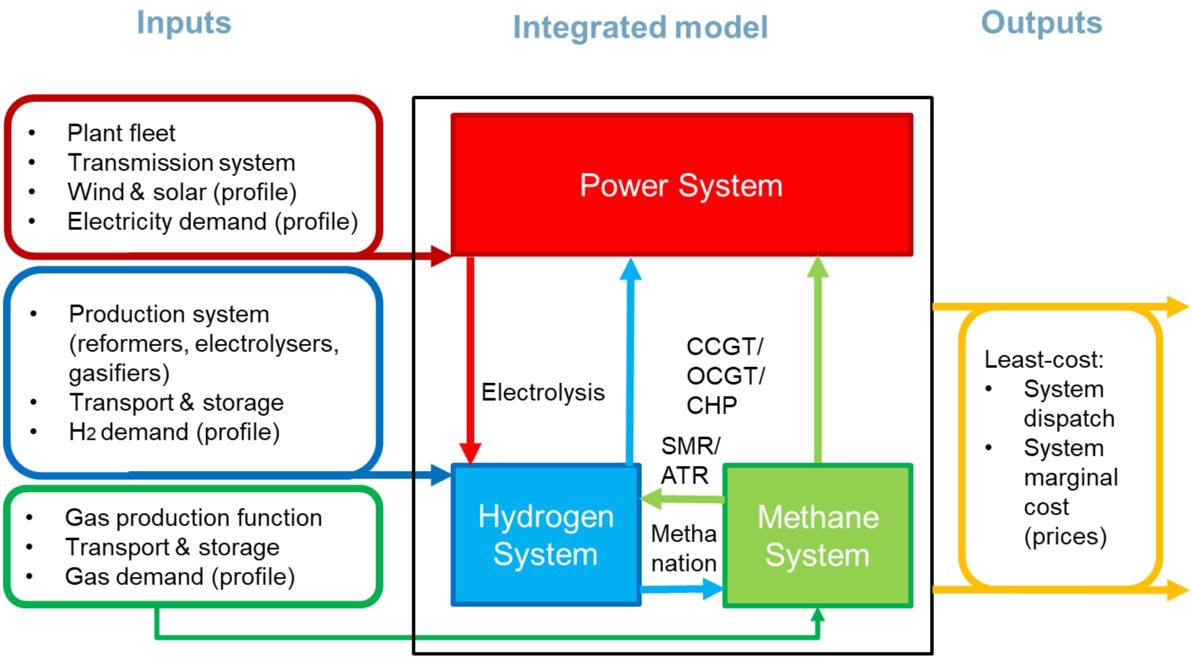


Figure 2 - Overview of I-ELGAS full dispatch simulation scope

Before this study exercise, the model was applied to the IO2050 study of TenneT and GTS and results were discussed with representatives of that study in two workshops. The model description and the case study were published in a journal paper, see (TNO, 2021). Since then, the model was deployed for joint analysis of market dynamics in several research programs and projects, like HyChain and the North Sea Energy program.

Assumptions

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 and Gasunie in 2019.

Efficiency

Four different technologies for hydrogen production are included in the system simulation: Electrolysis, Autothermal Reforming (ATR), Steam-Methane Reforming (SMR) and SMR with Carbon Capture and Storage (SMR + CCS). Additionally, an ammonia cracker is included as a means of hydrogen production. The SMR assets with CCS are assumed to use PSA tail gas absorption. An overview of the assumptions for efficiencies and capture rates is given inTable 2. As neither the IP2024 nor the CES scenarios discuss PEM and Alkali electrolysis specifically, the choice is made to include general electrolysis with 75% efficiency (HHV), based on PEM technology, the lower of the two.

Table 2 - Overview of efficiencies and capture rates for different technologies implemented in the market simulations.

Technology	Efficiency (HHV)	CO_2 capture rate	Sources
Electrolysis	75%	-	(Fraunhofer-Institut für Produktionstechnologie und Automatisierung [Fraunhofer IPA], 2018)
Autothermal Reforming (ATR)	82%	88%	(H-Vision, 2019)
Steam Methane Reforming (SMR)	81%	-	(TKI nieuw gas 2018, 2018)
SMR with PSA tail gas absorption	77%	45%	(International Energy Agency Greenhouse Gas R&D Programme [IEAGHG], 2017; Berenschot & TNO, 2017)

Flexibility and bid strategy

All hydrogen production technologies were assumed to be able to ramp up and down on an hourly rate and no minimum load constraints were applied. In reality, a minimum operation of 10% is used for Alkaline electrolysers for safety reasons (Matheus de Groot, 2022). This is a modelling detail we have not been able to include in these simulations and is a point of discussion. Additionally, market parties have mentioned that SMR technology has a similar minimum load. However, in analysing the results we found production to occur between 0 and 40% of capacity a negligible amount of hours throughout the year. Furthermore, production assets were assumed to bid on the market according to the marginal costs of operation. The underlying reasoning of this bid strategy for individual hydrogen producers is that other hydrogen producers with higher marginal costs will regularly be price setting, during which hours they can earn back their investment costs. This reasoning is similar to current investment strategies in the European gas and electricity markets.

Constraints

Next, two constraints were assumed to be in place for the simulated scenarios. Firstly, a constraint on the electrolysers, making them run a minimum of 4200 full load hours. The underlying assumption is that there is a subsidy in place, covering the losses up to 4200 FLH. Secondly, a constraint on the whole system is in place to ensure compliance with the European revision of the Renewable Energy Directive (RED III). For the 2030 scenario, the model includes a constraint to ensure the sum of all green hydrogen production is equal to or greater than 42% of the total annual demand[8]. Green hydrogen production here consists of electrolyser production and hydrogen from seaborne green ammonia imports.

Pricing assumptions

Finally, an ETS price of €136/ton was assumed for 2030, in line with the Dutch Emissions Authority's CO_2 tariff projection (NEA, 2023). For 2027, the ETS price was taken from the IP2022 scenario assumption (€53/ton). Other commodity prices (for hydrogen, electricity and methane) are determined endogenously. Methane supply costs underlying the gas price are based on an LNG shipping route from the United States, with a Henry Hub gas price assumption of €30 /MWh and transport costs totalling €3,40 / MWh. This price assumption is an estimate based on historical gas prices. Since a lot of uncertainty exists surrounding the methane market, a variant with a higher cost assumption is simulated to illustrate the effects on the hydrogen market. The price of storage and imports are further explained in section 2.2.

Limitations

As the full dispatch model uses a merit order based on marginal costs of the individual production assets, the resulting market simulation is heavily dependent on the marginal cost assumptions. Especially for technologies with nearly flat cost profiles throughout the year, being higher up in the merit order can drastically change the results. We aim to show the dependency of the market on these marginal cost levels in the discussion of the variants on the import case. Also, the optimisation only includes marginal costs of production, conversion, transport and storage. The model takes all investments and installed capacities as input parameters and optimises the dispatch of said assets based on their marginal costs. This excludes CAPEX decisions and optimisation of asset capacity. Therefore, the outcomes can show market dynamics and marginal cost bidding of an existing market, but can not answer questions on how this market comes to be. The model does not differentiate (or correct if you will) for household consumption of solar production. As such, the total volume of solar production is slightly overestimated. In the year 2030 this effect is expected to be limited, but should be addressed in model version that forecast the energy market in future years.

2.2 Market outlook, regional and national system

This section provides information on the assumed hydrogen system in 2027 and 2030, detailing both how supply (including import), demand, transport and storage of hydrogen will develop in both years. The information on the assumed hydrogen market in 2027 and 2030 is used as input in the I-ELGAS model that assumes an optimal market outcome. The main interest in this analysis involves dispatch dynamics. While the assessement deploys cost figures (or bandwidths) building on literature in order to explore alternate dispatch regimes, it does not involve detailed validation of these cost figures.

Energy system scenarios for 2030 function as starting point for hydrogen market outlook

The energy supply will change significantly in the coming years, shifting from predominantly fossil fuels (natural gas, oil, and coal) to an almost entirely sustainable energy mix by 2050. Netbeheer Nederland, the Dutch association of grid operators has modelled (four scenarios) how the energy mix will change towards 2050[9]. Additionally, the developed and analysis for the short run (three scenarios) that takes into account actual investment decisions.

The scenario studies show that initial supply of hydrogen will likely be largely fulfilled through imports, steam crackers, and industrial waste gases. Green hydrogen production will start before 2030 (4-8 GW in 2030) and will grow significantly in the following years (16-45 GW in 2050). With the development of import facilities, the Netherlands will become a transit country for hydrogen, with an estimated transmission of 10 to 40 TWh by 2030 and between 50 and 150 TWh by 2050, mainly towards Germany. Initially, shipping transportation will be used for imports from outside the

---

[8] The 42% constraint follows the discussion between European Parliament and the European Commission regarding the green hydrogen target for industry in 2030. By adding this constraint to the model it is ensured that the 42% target is met at the national level.

[9] Netbeheer Nederland (and partners) (June 2023) - Het energiesysteem van de toekomst: de II3050-scenario's, Integrale energiesysteemverkenning 2030-2050

EU, with ammonia and compressed hydrogen playing a significant role. Over the longer term, (liquid) hydrogen will also be transported by ships, and pipeline imports will become possible. The demand for hydrogen is also increasing significantly in all evaluated scenarios. In the short term, the industry's consumption determines the demand for hydrogen. Additionally, electricity generation will start using hydrogen as early as 2030. By 2040, hydrogen becomes demand further increases in all sectors and is expected to also play a role in the built environment, where it becomes the primary technology for peak demand in the built environment, for example as a (hybrid) heating solution for buildings. To make this possible, a significant portion of the gas networks will have been converted by then. By 2040, the use of hydrogen for flexibility and balancing the electricity system becomes important. In 2050, the demand for hydrogen continues to grow.

The climate scenarios developed by Netbeheer Nederland have been adopted and amended for the purposes of this study. In the following subsequent sections we outline what additions or changes have been made for i) development of a (non-existing) 2027 scenario, and ii) a national hydrogen system in 2030 where we incorporated more recent developments such as plans of TATA steel, ammonia cracking and so on. Figure 3 shows some key choices for the 2030 system.

Storage	10 GW
4 caverns & linepack	9.5

Supply	14 GW
Seaborne ammonia import & cracker • Blue ammonia (Henry Hub) • Green ammonia (MENA)	7.7
Gas reforming • SMR • SMR/CCS • ATR/CCS	6.4 3.5 1.6 1.3
Electrolysers (PEM)	4

Demand	72 TWh / 8 GW
Netherlands	59 / 6.7
Belgium /Gent	0.5 / 0.1
Germany/NRW	12 / 1.4

Market & policy	
Green hydrogen obligation	42%
PEM full load hours (subsidy)	>4200 hours/year
Market clearing	hourly

Figure 3 - Summary of assumptions w.r.t. hydrogen system in the national market of 2030

Supply

2027 scenario

For the 2027 scenario, the supply side is still similar to today's market, being dominated by gas reforming, with green hydrogen production starting to play a limited role. The gas reforming capacity consists of the current SMR installations, which are assumed to be partially able to provide hydrogen to the rest of the market. The capacity of the SMR installations is taken from IP2022 and the installed capacities of ATR and SMR + CCS is zero for this year. The total capacity is distributed over industry clusters Chemelot, Zeeland and Rotterdam according to an overview of known SMR locations.

The total electrolysis capacity is 750 MW and is distributed over the industry clusters Zeeland, Noordzeekanaalgebied, Rotterdam and Eemshaven according to an overview of announced plans for electrolysis projects.

A dedicated seaborne import route of hydrogen is included, with ammonia used as energy carrier. The choice is made to include the capacity and costs of a forecast of green ammonia production in Morocco. Local green electricity is produced at an LCOE of €30,- / MWh, and levelized costs of hydrogen and ammonia production, as well as an export terminal in Morocco are taken into account. Finally, transportation and fuel costs are included before the shipping route arrives at the port of Rotterdam. These costs are based on a study for possible Dutch hydrogen import routes (CE Delft, 2018).

A cracker of 7 Mton NH_3 to 1 Mton H2 capacity is in place to convert the imported ammonia to hydrogen. (Port of Rotterdam, 2022) This cracker is assumed to have an efficiency of 80%. As the cracker follows the same bidding strategy as other assets, the levelized cost of the import terminal are *not* included in the marginal costs, which total €66,-/MWh. (IEA, 2019).

For long-term hydrogen storage, one salt cavern of the HyStock project was assumed to be operating in 2027, with 6 kton of storage capacity (HyStock, 2023). For short-term storage, linepack storage in the pipelines is available. From discussions with HyNetwork Services, we arrived at an assumed 8.4 GWh total available system linepack storage, from which individual nodes are able to extract according to their demand, and inject into according to their production capacity.

2030 scenario

For the 2030 scenario, multiple types of gas reforming assets are available: the existing SMR installations, ATR and SMR + CCS. Of the existing SMR installations, those located in Rotterdam are assumed to have access to the Porthos project and utilise carbon capture and storage. Additionally, an ATR plant is in operation in Den Helder, capable of producing 20 PJ yearly according to the H2 Gateway project (H2 Gateway, 2020). For electrolysis, the 3 GW mentioned in the IP2024 is taken as installed capacity. Additionally, an extra 1 GW electrolyser is installed on-site at TATA Steel Netherlands (Roland Berger, 2021).

The costs underlying the green ammonia import route remain unchanged compared to the 2027 case, except for an LCOE for dedicated hydrogen production in Morocco of €23,- /MWh for the import case. In the import cost variant, the two major underlying cost assumptions are increased: an LCOE of €30,- /MWh (CE Delft, 2018) and a cracker efficiency of 75%. These higher cost assumptions increase the marginal cost of imported green ammonia to €88 /MWh. *Note: ammonia as feedstock is not part of the market simulation, as such no choices were made how ammonia is e.g. transported to ammonium using industries. LOHC and other H2 carriers are not included, they could provide an alternative to green and blue ammonia depending on their price.*

Following discussions during the presentation of preliminary results to the market parties, the choice was made to include a blue ammonia import route, in addition to the proposed green import route. A dedicated import shipping route, similar to the green import, was constructed with ammonia produced from natural gas in the United States and transported to the cracker in the port of Rotterdam. Natural gas with an assumed Henry Hub price of €30,- / MWh is converted to ammonia and bids on market with a marginal cost of €61,55 / MWh, slightly *lower* than the green imports (Carlo Arnaiz del Pozo, 2022).

Storage assumptions are similar to the 2027 scenario, but with four salt caverns of the HyStock project in operation, totalling 24 kton of storage capacity.

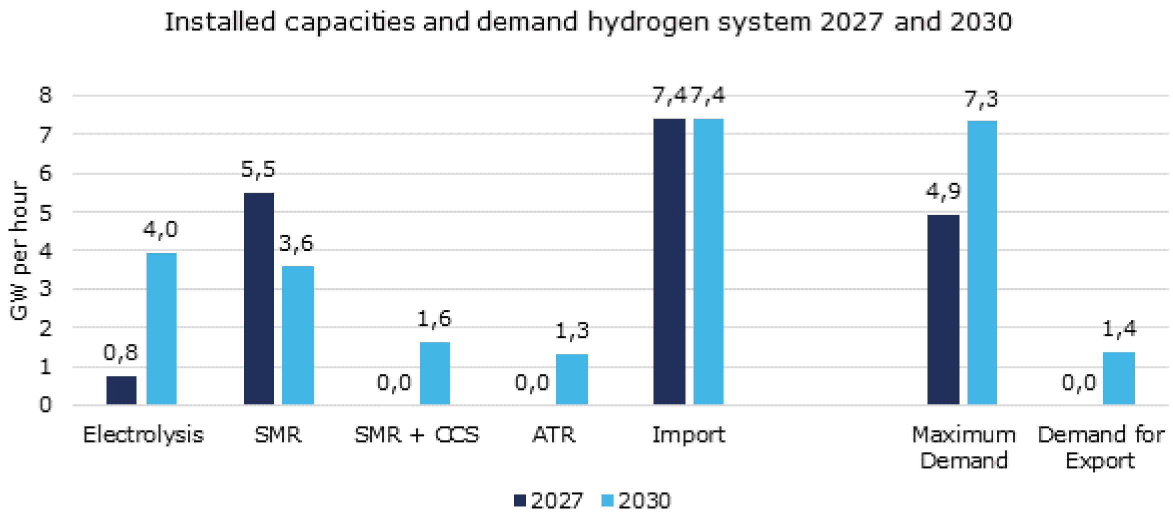


Figure 4 - Installed capacities and demand hydrogen system for 2027 and 2030 scenarios

Demand

2027 scenario

For the hydrogen demand in 2027, the yearly national demand curve for 2030 from IP2022 was taken as a starting point. To make a projection for 2027, the demand sectors mobility and built environment were removed, ending up with a demand total corresponding to today's industry demand. This national number was subsequently distributed over the industry clusters, proportionally to installed SMR capacity.

2030 scenario

The 2030 scenario demand likewise has the yearly national demand curve from IP2024 as a basis. However, in publication of IP2024 the hydrogen demand for ammonia is assumed to be no longer on-market, which was the case in IP2022. To be able to make an accurate comparison and to shine light on the dynamics of this part of the hydrogen market, we assume half of the hydrogen demand for ammonia is on-market and included in these simulations. The other half is assumed to be directly provided by (seaborne) ammonia imports. Despite the uncertainty surrounding this assumption, the choice is made to include this volume in the simulations; to test the effect of an increased demand, a variant is simulated with a higher (German) demand.

Additionally, steel manufacturer TATA Steel Netherlands (TSN) projects to have one blast furnace replaced by DRPs combined with an electric furnace by 2030 (Roland Berger, 2021). Electricity demand is added to IP2024 data in a flat profile and extra hydrogen + methane demand is incorporated in the simulation as a general, constant energy demand and it is to be determined by the model what the mix of the two fuels is going to be, depending on prices. Additionally, a constraint is in place to ensure that a minimum of 50% of this energy demand is met by hydrogen, representing TSN's reduction targets.

Another addition to the 2030 scenario is the hydrogen demand in surrounding countries. We assume pipeline connections to Nordrhein-Westfalen (Germany) and Gent (Belgium). To estimate the demand for import in both countries, we estimate the residual hydrogen demand. The total demand on the main network of the NRW-region in 2030 is 45 TWh (Fernleitungsnetzbetreiber [FNB] Gas, 2022). Hydrogen from own production is 8 TWh, and of the remaining 37 TWh it is assumed bordering state Niedersachsen can provide two-thirds. The remaining third that the Netherlands can provide equals 12 TWh, which is modelled as a flat profile in these simulations. The net demand corrected for local production in Gent is 0.5 TWh, which is again modelled as a flat profile.

The electricity, gas and hydrogen markets of nine North Sea countries are modelled with TYNDP2020 data amended to REPowerEU plans, and their electricity and gas markets are connected to the Netherlands. Their hydrogen markets are not, except for the aforementioned regions Nordrhein-Westfalen & Gent.

Infrastructure (transport & storage)

The national market created by the national Gasunie Hydrogen backbone in 2028/2029 (see figure below), may be preceded by regional markets in the industrial clusters and harbour regions, where a Hydrogen infrastructure may be ready earlier, e.g. 2026/2027.

Consequently we have simulated the regional start-up markets, as well as the evolution to the national market based on the backbone infrastructure later on. In the regional simulations, at present there are two regions of special interest who have also submitted additional funding for the regional simulation giving insight in selected infrastructure cases and market impact: Rotterdam harbour including the connection to Chemelot and North Rhine-Westphalia (NRW), and the Delta-Scheldt region with simulated connections between Vlissingen-Terneuzen-Gent. In the national market simulation we will be interested in the additional role of Hystock storage and line pack, with greatly improved possibilities for storage and balancing, and of course the additional exchange and trade between the regions which is facilitated by the backbone, also facilitating wider deliveries and demand patterns.

The hydrogen transport capacity is assumed to be high enough as to not cause congestion, both for internal transport and cross-border capacity. We assume the backbone connects the Rotterdam and Zeeland clusters with Chemelot approximately through Noord-Brabant. Chemelot is then connected to the Eemshaven through Gelderland / Overrijssel, but the north of the Netherlands is not connected to the Noordrijnkanaalgebied through a north connection pipeline.

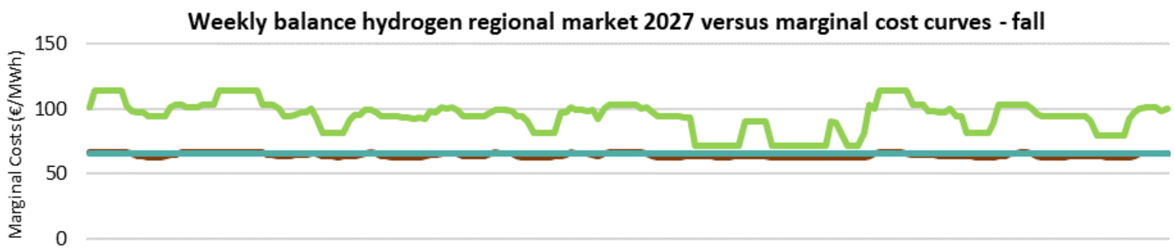
Below the results will be shown separately for the situation in 2027 both with a regional start-up and with a national system, results will be compared and discussed. For 2030 a national system will be in place and the regional situation will not be addressed separately.

2.3 Results full dispatch simulation 2027 and 2030

Results and interpretation for 2027

Regional market, 2027

As explained in the previous chapter, the 2027 scenario is still very comparable to the current hydrogen system. Consequently, the expectation is that the market is still dominated by SMR technology, with some additional production from electrolysis and ammonia imports. In order to visualise the market dispatch, a time slice containing a week of the hydrogen balance is plotted in Figure 5, together with the associated marginal costs of production assets. Production from electrolysis occurs even on hours where it is more expensive, to be able to meet demand. No access to linepack or cavern storage is possible, so flexible assets are needed to balance the system. Green imports in one location, and SMR and electrolysis in others are able to provide this flexible supply.



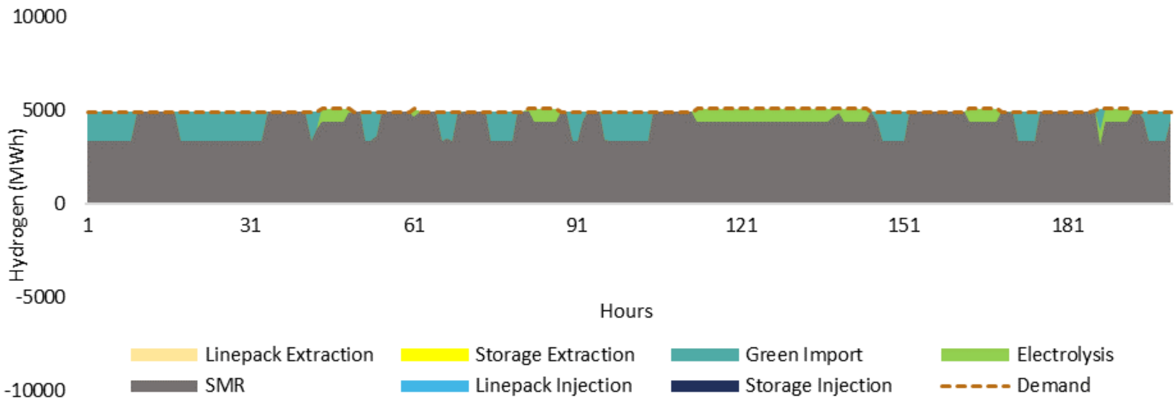


Figure 5 - Example of weekly hydrogen balance for a week in October (2027) of the regional market results. The stacked plot below shows the hydrogen dispatch per hour, with production and storage extraction positive, and injection negative. The curve above shows the hourly marginal costs.

To compare the difference between the regional market and the national market, an overview of the hourly dispatch is given in the load duration plot below; a load duration curve shows the hourly production sorted in descending order.

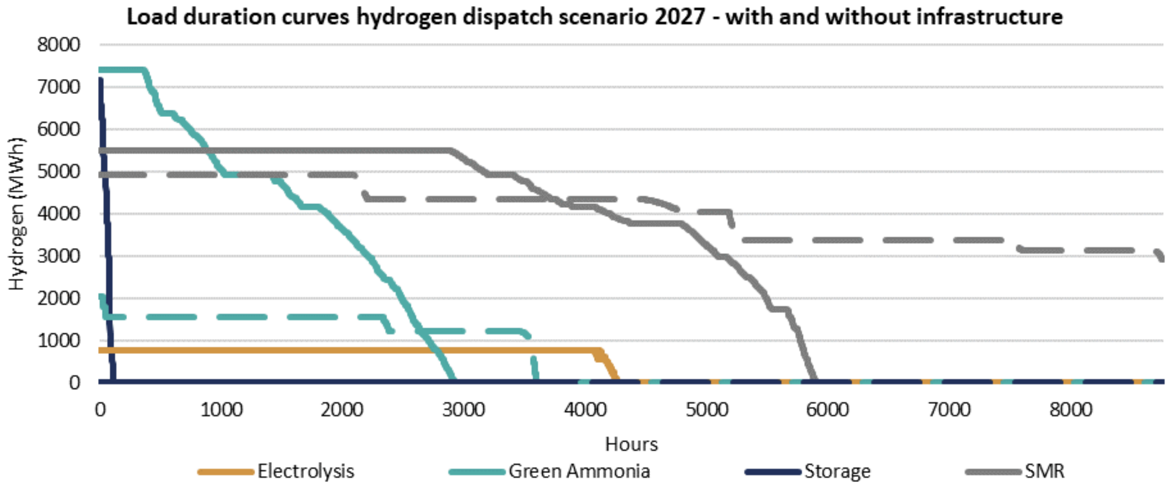


Figure 6 - Load duration curves of hydrogen supply of four different technologies for the 2027 scenario. The regional and national market, with and without infrastructure, are compared. The dashed lines represent the regional market.

We indeed see a main role for SMRs in 2027, providing 81% of the hydrogen in the regional market. Green ammonia imports are also cost-competitive for a significant part of the year, resulting in 12% of total hydrogen supply. Finally, the electrolysers are producing at the subsidised 4200 full load hours, providing 7% of the total mix. Hydrogen storage is only used in sharp peaks for a limited amount of hours in the year for the national market. The regional market has no access to storage.

National market, 2027

The national market allows for transport of hydrogen throughout the Netherlands and is therefore more flexible. The biggest difference is seen in green ammonia imports, that now are no longer only able to supply the Rotterdam cluster, where the cracker is assumed to be, but are able to provide the rest of the demand as well. The annual balance for the national market is shown in Figure 7

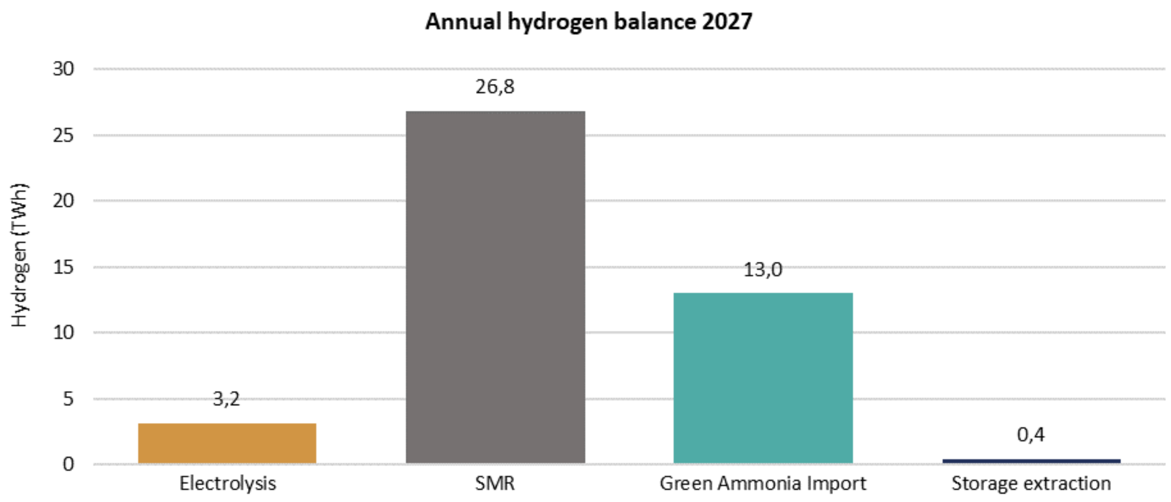


Figure 7 - Annual hydrogen balance for the 2027 scenario. The total yearly dispatch for four technologies is shown in TWh.

A smaller share for SMR production is seen, covering 62% of the supply. Ammonia imports increase to 30% and electrolyser production remains the same.

A weekly balance for the national market is shown in Figure 8, along with the marginal costs of producing assets. Here, linepack and cavern storage can be seen operating on an hourly basis, providing flexibility to the system. In this week, no green ammonia is imported as the (constant) cost level is lower than SMR costs due to gas prices.

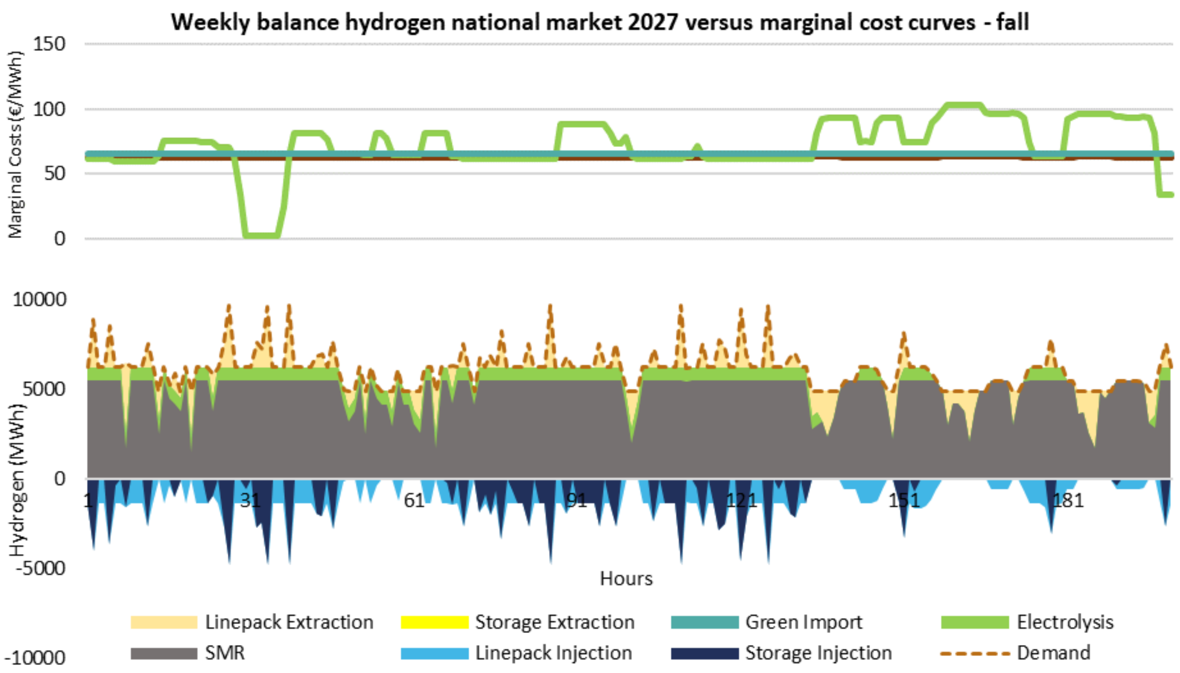


Figure 8 - Example of weekly hydrogen balance for a week in October (2027) of the national market results. (2027). The stacked plot below shows the hydrogen dispatch per hour, with production and storage extraction positive, and injection negative. The curve above shows the hourly marginal costs.

Another result of the market model are marginal cost curves. Determined by the production asset employed with the highest marginal costs, they are analogous to a merit order based marginal pricing system. For the three commodities modelled endogenously (electricity, hydrogen and methane), the marginal cost curves are shown in Figure 9.

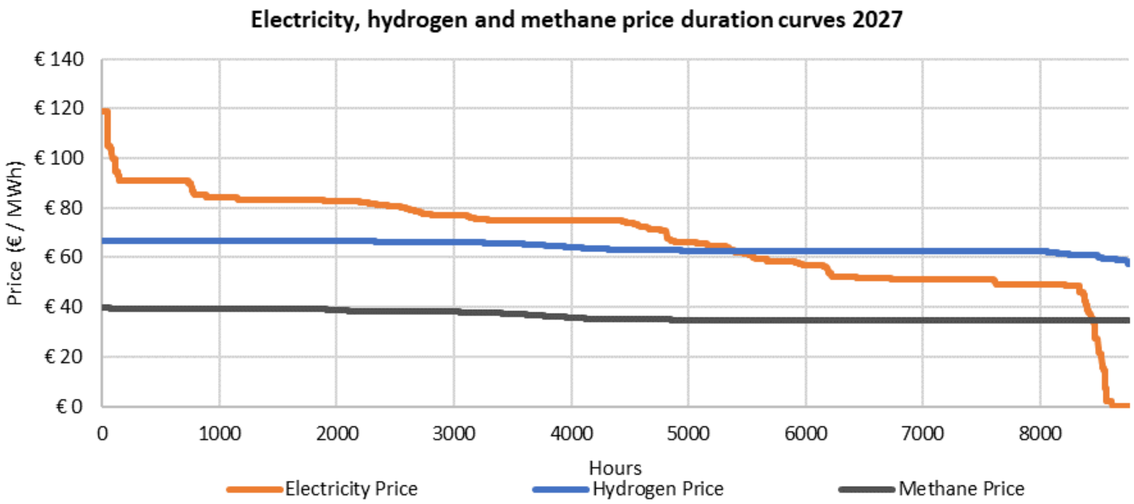


Figure 9 - Price duration curve of the marginal costs of electricity, hydrogen and methane, as a result of the 2027 scenario simulation.

The electricity cost curve clearly shows the effect of intermittent production of renewable electricity, resulting in a larger spread in prices. The methane curve is, as expected, relatively stable. Finally, the hydrogen curve shows similar behaviour, being mostly determined by the relatively constant gas price and constant import marginal costs.

Results and interpretation for 2030

In total eight scenarios for 2030 were simulated, as an analysis of several variants will provide us with the most complete understanding of how the hydrogen system could function in the near future. Furthermore, it provides a better understanding what a ‘shock’ to the system will do. For completeness sake we would like to stress that we have no preference for or expect that one scenario is more likely to occur then another scenario, as this depends on many factors.

The scenarios or variants can be divided into two categories: physical variants and market variants. The physical variants include reducing the capacity of the ammonia cracker and increasing hydrogen demand in Germany, and finally a ‘worst storm’ scenario involving both alterations to the import case, as well as a reduced storage capacity. The market variants include an investigation into spot market-based electrolysis dispatch, as well as sensitivity analyses of the import prices of ammonia and LNG.

Table 3 - Overview of 2030 scenario's and key differences

Physical variants	Market variants
A: Low import prices: reflected in cost assumptions for green and blue ammonia cracked into H2, marginal cost (HHV): - Green: 66 €/MWh H2 - Blue : 62 €/MWh H2 B. Ammonia cracker analysis – like A, but reduction of capacity of ammonia cracker by 50%	E.1 Import shipping marginal cost analysis – green ammonia cracked into H2, marginal cost (HHV): 88 €/MWh H2 E.2 Import shipping marginal cost analysis – LNG cost at Henry Hub price of 35 €/MWh and blue ammonia cracked into H2, marginal cost (HHV) €67 /MWh
C. Increased export analysis – increasing hydrogen demand in Germany D. Worst case scenario – involving both alterations to the import case and halve storage capacity	F.1 Market based electrolysis dispatch – low green import ammonia cracked into H2: marginal prices (HHV): 66 €/MWh F.2 Market based electrolysis dispatch – high green import ammonia cracked into H2: marginal cost (HHV): 88 €/MWh

Below we show the main results for each of the scenarios. The results for one of the scenarios, A Low import prices, are shown more in-depth to provide a more complete understanding of the hydrogen system for 2030 and how it differs from the 2027 situation, as this specific case is most comparable to the 2027 price assumptions.

A. Low import prices

We first show here the results of the import case, with favourable assumptions for green ammonia import costs, of 66 €/MWh marginal production costs at the cracker site. The load duration curves are again shown for the different supply technologies, shown in Figure 10.

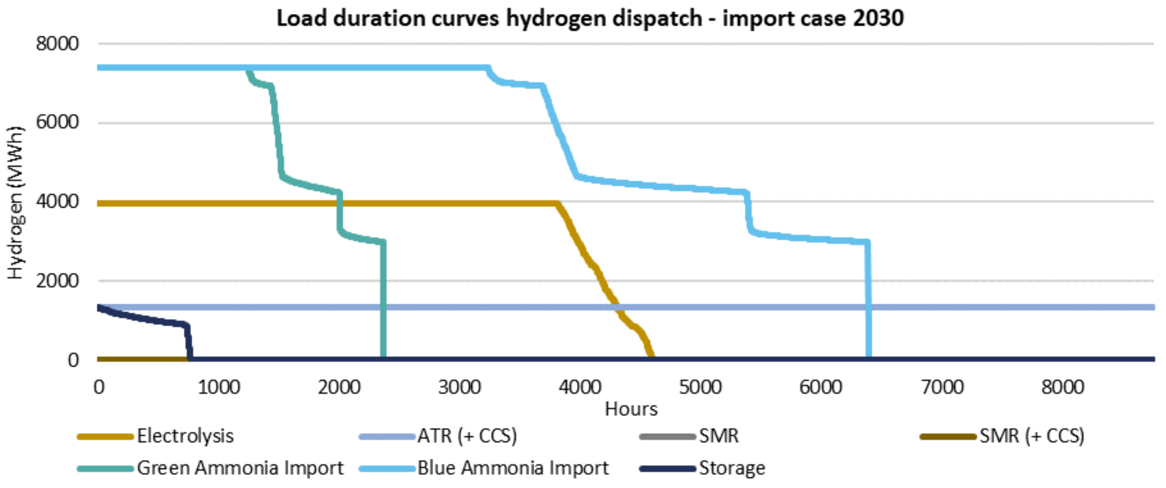


Figure 10 - Load duration curve of different supply options included in the 2030 scenario.

As a result of the higher emission costs, the ammonia cracker is by far the biggest supplier in the year 2030, as the green and blue ammonia imports it converts respectively make up 22% and 47% of the total yearly supply. Blue imports have a lower constant marginal cost level than their green counterpart, but the constraint for green hydrogen production requires the system to use green imports. Electrolysis production, again positioned at 4200 full load hours, amounts to 20% of the total, reaching the 42% green hydrogen target together with green imports. Finally, ATR production is due to its low costs by avoided emissions, producing throughout the year. Its yearly production amounts to 14% of the total.

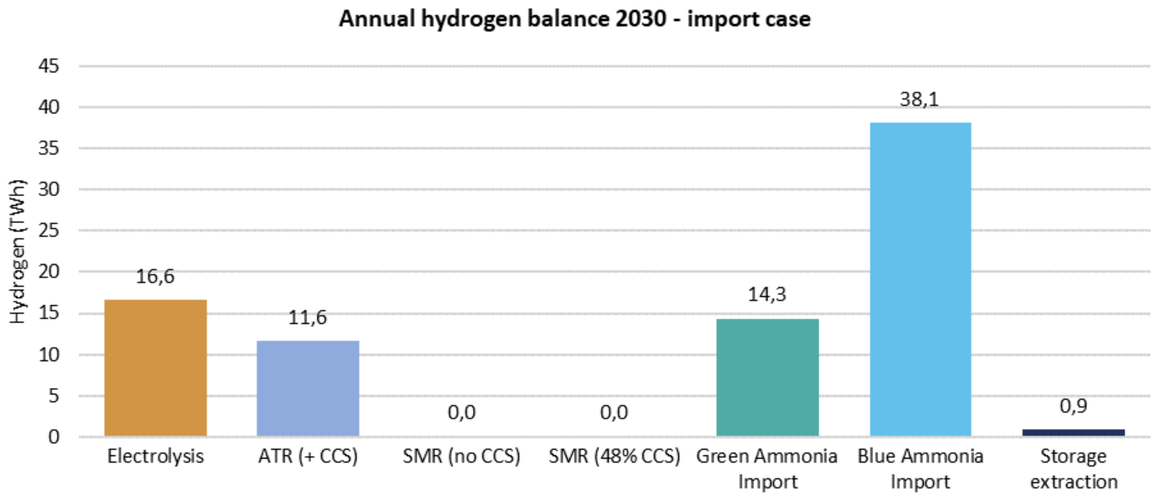


Figure 11 - Annual hydrogen balance for the results of the 2030 scenario market simulation.

- The annual balance confirms the large role for ammonia imports in the import case, which is also visualised in the weekly balance in

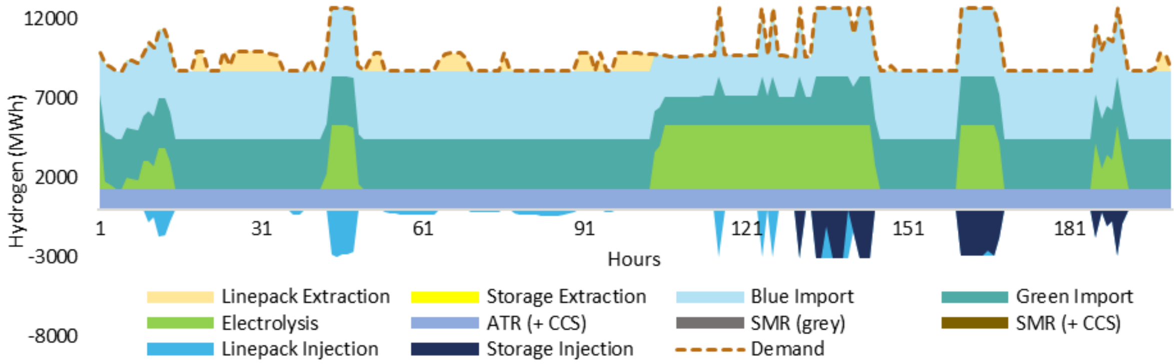


Figure 12. ATR, blue and green ammonia operate as relatively constant suppliers, with intermittent production from electrolysis entering the mix when electricity prices are low. Weekly balances for all seasons can be found in Annex IV.

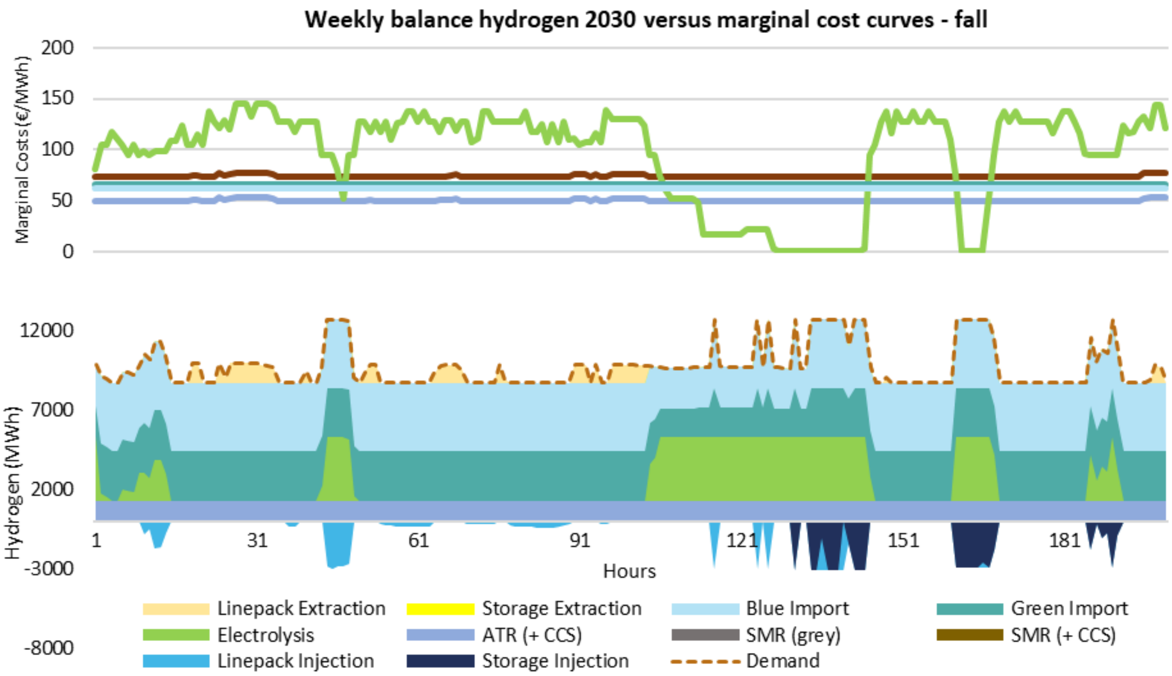


Figure 12 - Weekly hydrogen balance for a week in October (2030). The stacked plot below shows the hydrogen dispatch per hour, with production and storage extraction positive, and injection negative. The curve above shows the hourly marginal costs.

Finally, the marginal cost curves are shown again in Figure 13. Here we see two main plateaus in the hydrogen cost curve: one corresponding to the green ammonia import at €66,- /MWh, and one corresponding to blue ammonia import at €62.- /MWh.

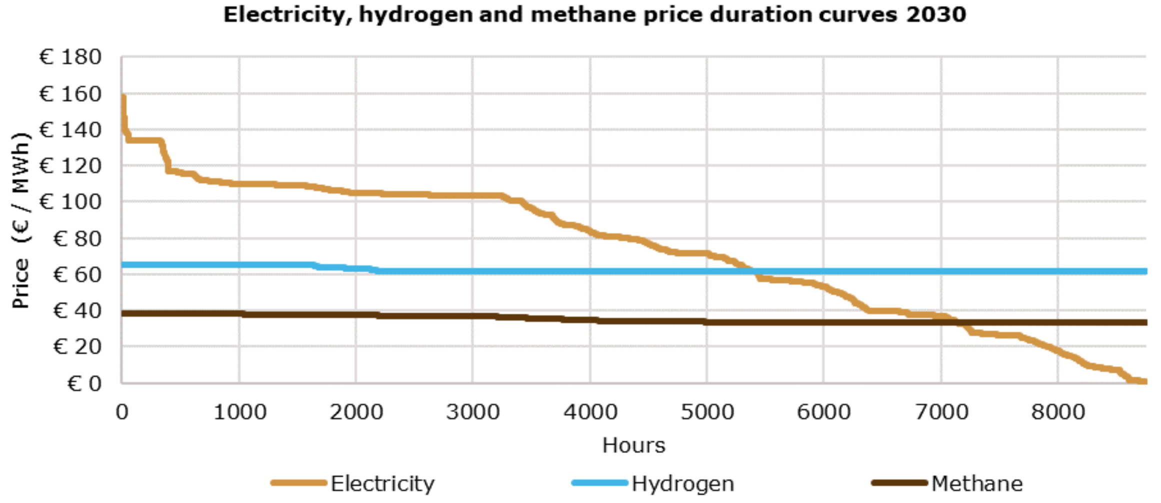


Figure 13 - Price duration curves of the marginal costs of electricity, hydrogen and methane, as a result of the 2030 scenario market simulation of the import case.

B. Ammonia cracker analysis

As we see from the import case results, the ammonia cracker takes up a dominant role in the supply of hydrogen for the 2030 scenario. A first analysis of interest would therefore be to limit the capacity of this cracker, to see what supply options replace the ammonia imports. For scenario B we assume the cracker to be at half capacity (0.5 Mton yearly instead of 1 Mton) and look at the resulting load duration curves of the different supply options, shown in Figure 14.

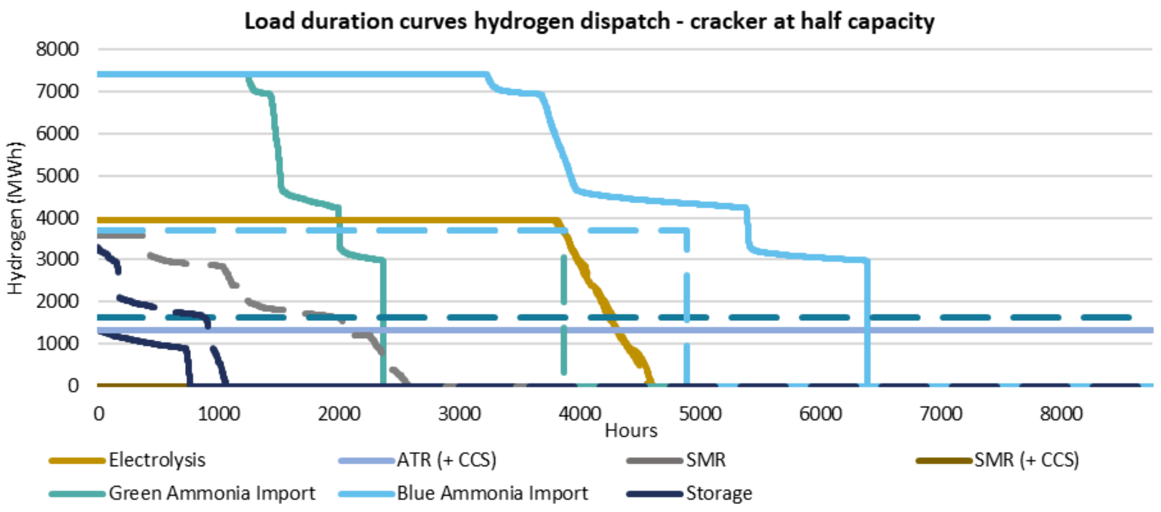


Figure 14 - Load duration curves of hydrogen dispatch for the 2030 scenario variant with the ammonia cracker at half capacity versus import case results. The dashed lines represent the variant with half capacity.

Lowering the cracker capacity causes it to be running constantly throughout the year, in combination with an increased use of storage. For the remaining demand, there is need for SMR with and without CCS, with the former producing constantly throughout the year. The average marginal costs of the system amount to €85,- /MWh, which is an increase of +27% compared to the import case (scenario A).

C. Increased export analysis

Another impactful assumption is the residual demand in Nordrhein-Westfalen, causing a need for export from the Netherlands to Germany. Based on the projections of hydrogen production and demand, as well as the assumption that Niedersachsen could provide two-thirds of this residual demand, the import case assumes 12 TWh of demand for export to NRW. As both these projections are highly uncertain, we take a look at the impact of a larger demand. In this variant, we change the demand in Nordrhein-Westfalen to 30 TWh, increasing total demand (Dutch + export) from 73 to 91 TWh. The effects on the Dutch market are seen below.

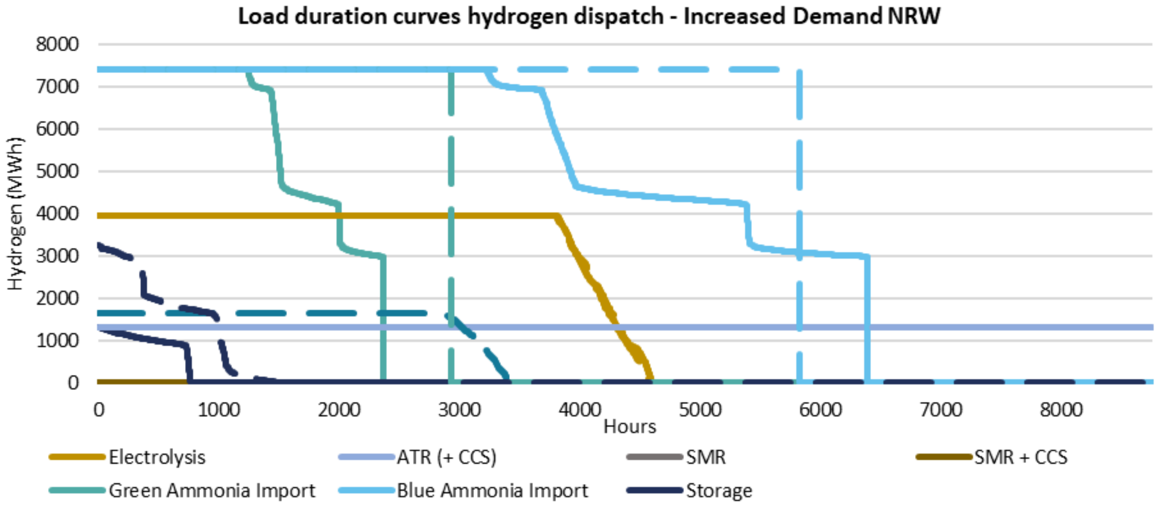


Figure 15 - Load duration curves of hydrogen dispatch for the 2030 scenario variant with an increased demand in Nordrhein-Westfalen versus import case results. The dashed lines represent the variant with increased demand.

The increased export calls for more production under similar cost conditions. As a result, it makes sense that both blue and green ammonia imports are heavily increased. When demand exceeds the cracker capacity, SMR with CCS is deployed.

D. Worst case scenario

For the final physical variant, a combination of the previous variants is simulated for a 'worst case' scenario, to see how the market fares under more difficult conditions. The cracker is at half capacity, the demand from NRW at 30 TWh and only one storage cavern is available.

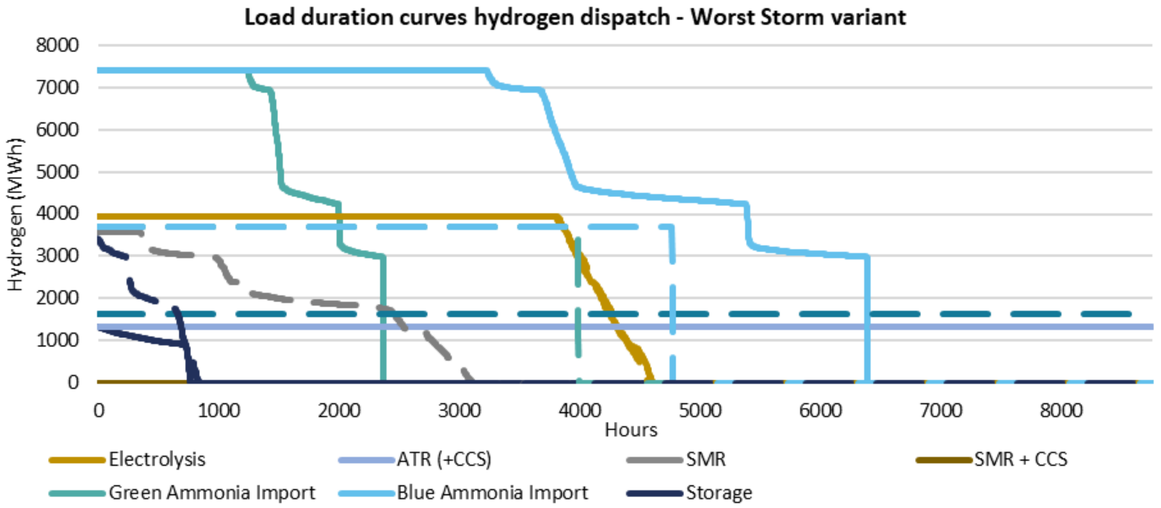


Figure 16 - Load duration curves of hydrogen dispatch for the 2030 'worst storm' variant, with increased NRW demand and halved cracker capacity, versus import case results. The dashed lines represent the worst storm variant.

The market dynamics of the worst storm case is similar to previous cases, fully utilising the cracker causing constant imports throughout the year, as well as deployment of SMR. In Annex IV the weekly dispatches for four seasons are included in the report.

E. Import shipping marginal cost analysis

Finally, the sensitivity of the market to marginal cost levels of import shipping is analysed. The import costs of methane are increased: previously based on a €30,- /MWh Henry Hub price, the cost is increased to €35,- / MWh, excluding transport costs. This effect is also seen in the blue ammonia import price, which rises from €62 to €67 /MWh.

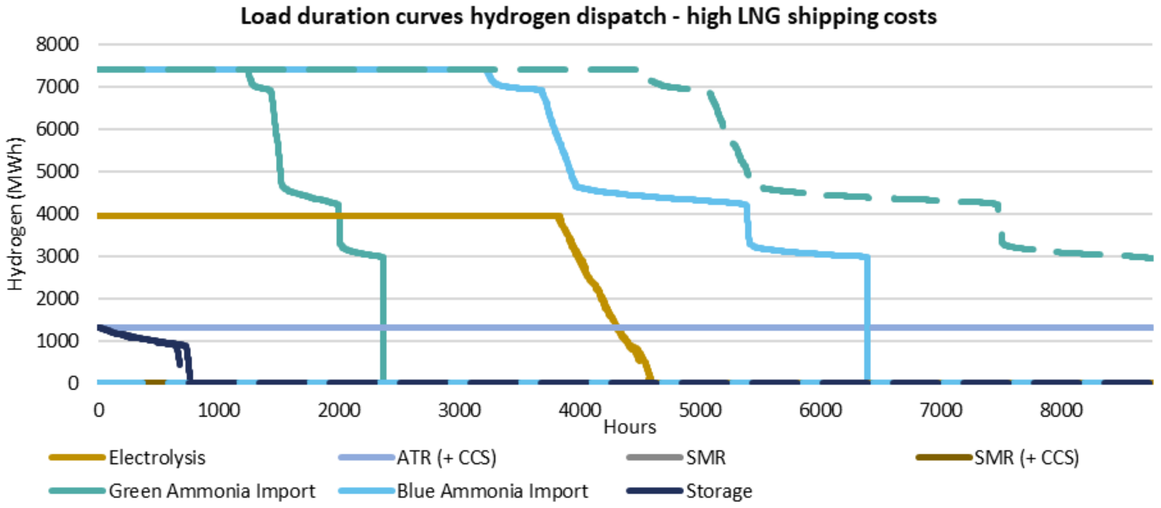


Figure 17 - Load duration curves of hydrogen dispatch for the 2030 variant with a high LNG price assumption versus import case results. The dashed lines represent the high LNG price variant.

The marginal cost level of blue ammonia imports rise above the level of the green ammonia import costs, making green imports the cost-optimal shipping option throughout the year. Consequently, we see in Figure 17 that green ammonia imports have taken up all the production previously done by blue imports.

Additionally, the effects of an increase in ammonia import costs is modelled for both blue and green. The cracker, assumed to be operating at an optimistic 80% efficiency in the import case, is now operating at 75%, negatively affecting its marginal costs. Additionally, electricity prices underlying ammonia production are increased from 23 to 30 € /MWh. The marginal costs increase for green ammonia imports from 66 to 88 € /MWh, and blue ammonia costs rise to 66 € /MWh. The results are shown in the figure below.

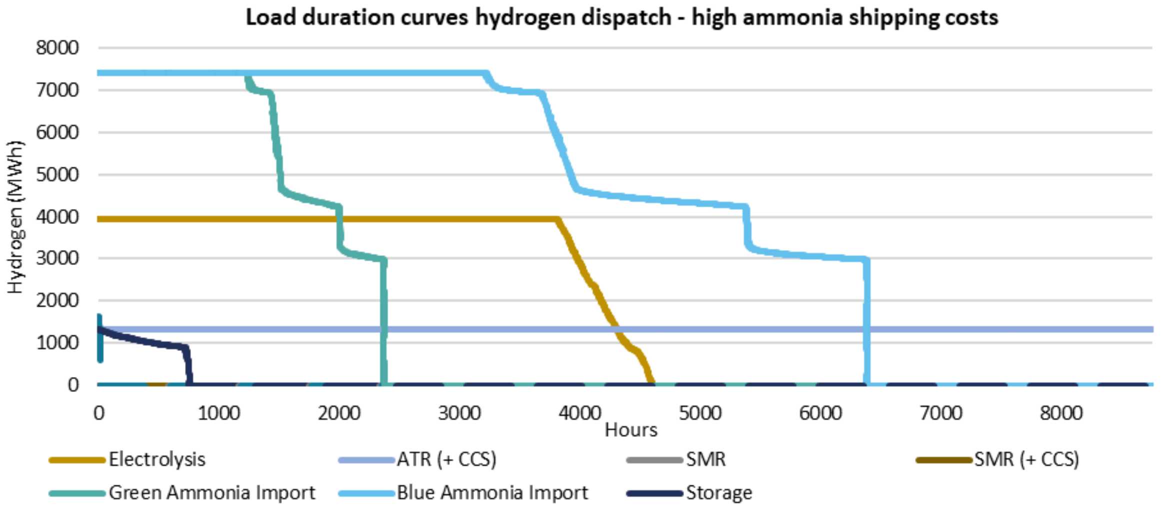


Figure 18 - Load duration curves of hydrogen dispatch for the 2030 variant with a high cost assumption for both ammonia import shipping options, versus import case results. The dashed lines represent the high ammonia price variant.

A slight shift in dispatch can be seen from the ammonia cracker, but the volumes stay almost the same. As the blue ammonia marginal costs rise, the cost level of SMR with CCS just dips below it for a few hours of the year due to gas price fluctuations. Making the cost level of shipping imports rise even further would have blue imports give way to more gas reforming production throughout the year.

F. Spot market-based electrolysis dispatch

The first market variant is an analysis where we relieve the constraint on the full load hours of the electrolysers, to gain an insight into the spot market-based dispatch. In the import case, electrolysers are required to run at least 4200 full load hours, whereas this variant allows them to run for whatever is cost-optimal. We do this for both ammonia import cost assumptions. The resulting electrolyser dispatch is shown in the figure below.

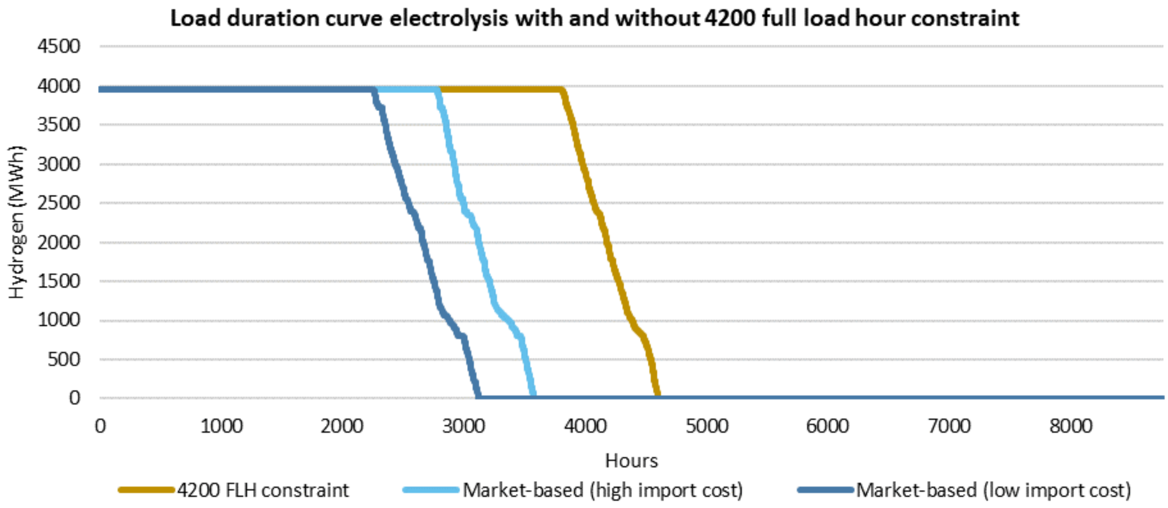


Figure 19 - Load duration curves of electrolysis with and without a constraint forcing them to run a minimum of 4200 full load hours.

Similar shapes of the curve can be seen, but at an earlier cut-off point. The cost-optimal amount of full load hours for the high ammonia cost assumption is 3150, whereas the low cost case results in 2700 full load hours. The full load hours of electrolysers are dependent on import cost level, as expected. The impact of the subsidy constraint is expected to be larger before and smaller after 2030, as the share of renewable electricity rises.

2.4 Summary, storage and sensitivity analysis for 2030

Summary of results for 2030

Several variants of the 2030 hydrogen system have been simulated. These variants can be divided into two categories: physical variants and market variants. The physical variants include reducing the capacity of the ammonia cracker and increasing hydrogen demand in Germany compared to the import scenario. A 'worst storm' scenario involving all three alterations has also been investigated. The market variants include an investigation into spot market-based electrolysis dispatch, as well as sensitivity analyses of the import prices of ammonia and LNG. The scenario's key differences in number of full-load hours and MWh are shown in the two tables below.

Table 4 - Summary of results 2030 variants, full-load hours

Scenario / Source	**A**	**B**	**C**	**D**	**E1**	**E2**	**F1**	**F2**
Electrolysis	4200	4200	4200	4200	4200	4200	2700	3150
Green ammonia	1900	3900	3000	4000	1900	7100	2700	2500
Blue ammonia	5100	4900	5800	4800	5100	0	5100	5100
ATR	8760	8760	8760	8760	8760	8760	8760	8760
SMR	0	1600	0	1900	0	0	0	0
SMR+CCS	0	8760	3200	8700	20	0	0	0
Storage	900	1100	1100	1000	800	800	1000	1000

Table 5 - Summary of results 2030 variants, TWh

Scenario / Source	A	B	C	D	E1	E2	F1	F2
Electrolysis	16,6	16,6	16,6	16,6	16,6	16,6	10,6	12,4
Green ammonia	14,3	14,3	21,7	14,8	14,3	52,4	20,3	18,5
Blue ammonia	38,1	18,1	43,1	17,6	38,1	0	38,1	38,1
ATR	11,6	11,6	11,6	11,6	11,6	11,6	11,6	11,6
SMR	0	5,7	0	6,7	0	0	0	0
SMR+CCS	0	14,3	5,2	14,3	0	0	0	0
Storage	0,8	2,0	2,4	1,7	0,8	0,7	1,0	0,9

Storage (in-depth) analysis

Yearly hydrogen storage levels give another perspective of storage behaviour in the aforementioned simulations. The volumes presented in previous paragraphs show extraction for a certain amount of hours in the year, but are missing seasonal behaviour. A constraint in the model enforces storage level to be equal on the first and last hours of the year. The resulting seasonal storage behaviour can be seen in the figure below.

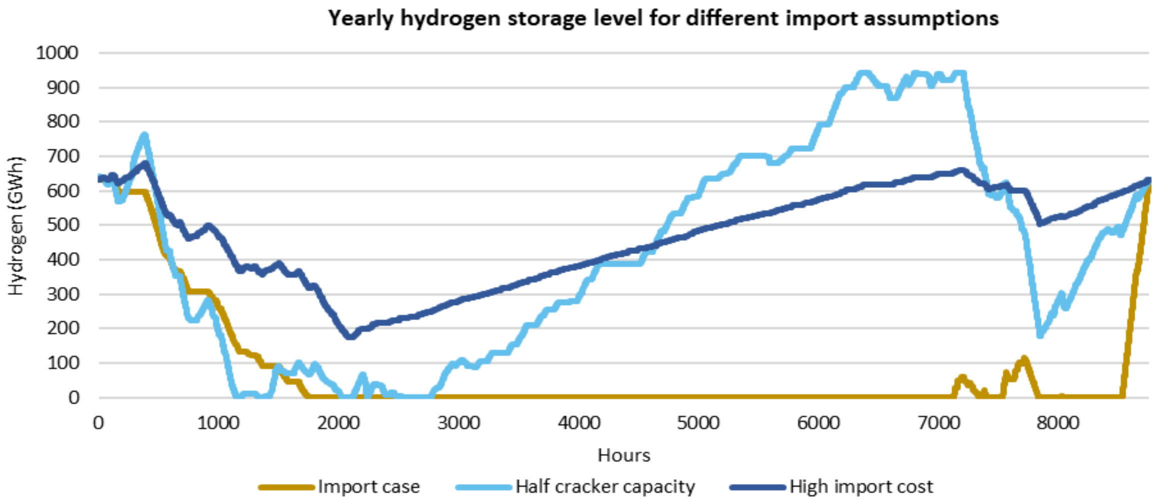


Figure 20 - Hydrogen storage level throughout the year for the import case and variants with half cracker capacity and high import costs.

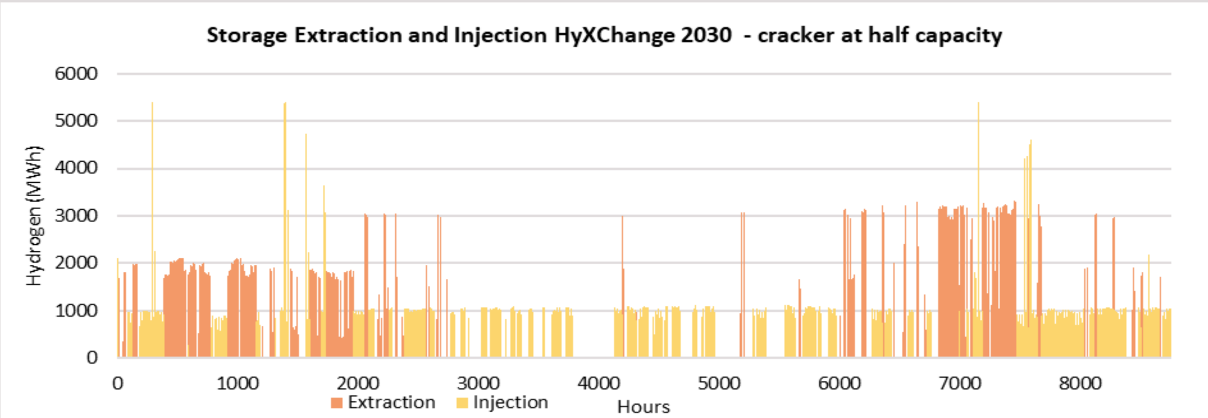


Figure 21 - Storage extraction and injection over one year, 2030, scenario B.

There is a notable difference in the shape of the curve between the import case and the variants shown. The variants show seasonal storage behaviour, where injection takes place largely during summer (see also figure 25), whereas the import case makes no use of storage during that time. With a relatively low cost cracker that is able to provide the peak hydrogen demand on an hourly basis, a storage asset can not use arbitrage to use price differences throughout the year to turn a profit. However, when that cracker operates under higher cost assumptions, or if its capacity is decreased, the storage facility takes a role in providing seasonal storage, being able to exploit hydrogen scarcity and price differences.

Sensitivity analysis

The I-ELGAS model is a is a full dispatch model that takes renewability conditions for hydrogen production only indirectly into account. From sustainability perspective as well as in reality because of the EU criteria for green hydrogen, it is expected and desirable that electrolysers operate only if the produced hydrogen is fully renewable. Therefore a sensitivity analysis to test the hourly correlation between renewable electricity production and electrolyser dispatch is conducted.

In Annex I the results of the following sensitivity analysis questions are discussed:

- How do low electricity prices, and therefore electrolyser activity, correlate with renewable electricity production?
- How many renewable hours are excluded by the electrolyser dispatch and how can these so-called 'missed opportunities' be explained?
- How much non-renewable hydrogen production occurs and how can it be explained?

The sensitivity analysis shows among others that most hours (72% - 81% depending on the scenario) with electrolyser activity are hours with a surplus of renewable electricity generation. However, 15%-38% of hours with a surplus are not utilised. The electricity in these hours is not curtailed, however, it is exported. High demands in neighbouring countries can cause hours in which there seems to be a surplus of renewable energy to have high prices and therefore no electrolyser activity. Therefore these hours should not be counted as missed opportunities. In reality hydrogen might be produced during these hours however, depending on the PPAs that are in place.

Some electrolyser activity occurs in hours with a low share of renewables. Most notably, 1%-3% of electrolyser activity even occurs in hours where the electricity demand of electrolysers exceeds the generation of wind and solar power. Hydrogen production in these hours would realistically not occur in reality as it could not be sold as renewable, decreasing its value. In conclusion, the I-ELGAS model results show a minor error compared to what is likely to happen in practice. See Figure 22 and Annex I for more detailed results of this sensitivity analysis.

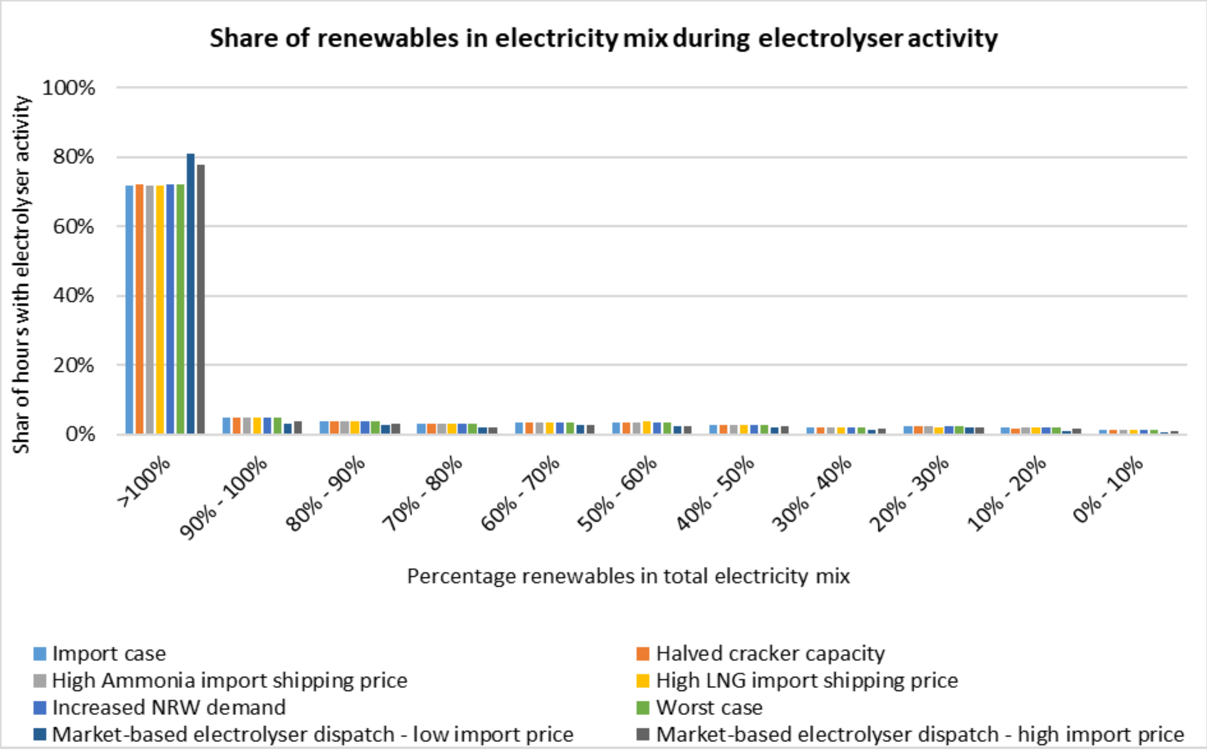


Figure 22 – Percentage of renewables in hours with electrolyser activity

3. EYE – MARKET (GAME) SIMULATION

The market dynamics accounting for bid behaviour in the face of uncertainty is assessed using the flexible simulation model EYE (*market simulation*). The market simulation is applied to the national start-up in 2027 and 2030 and assessed strategies are co-developed with market participants over the course of two working sessions.

3.1 Description of the model, key assumptions and limitations

Description of the model

TNO's market simulation model EYE represents a simplified merit order model for power and hydrogen in the Netherlands. It dynamically allocates the system, typically over the course of a year. The model can be best described as a simplified heuristic for joint electricity and hydrogen market simulation for the Netherlands on an hour-by-hour basis consecutively.

Since the heuristic is flexible, it allows to take bid strategies other than marginal cost bidding as an input. Furthermore commercial constraints like PPA's are covered in the algorithm as well. Finally, since EYE does not optimize the system allocation across a pre-set horizon it allows to evaluate the impact of uncertainty, rather than the typical perfect foresight assumption construed in optimization modelling. As the EYE-model allows for quick simulation on-the-fly with clear visualizations of the market dynamics, it offers an accessible platform to evaluate several trading aspects. The model has been deployed for joint analysis of market dynamics in several research programs and projects, like VoltaChem and H-Vision.

Basic system scope

The market model takes the following system characteristics of energy system as an input: prices of fuels and CO2; installed capacities of renewables (offshore wind, onshore wind and solar PV) and their hourly production profiles; yearly electricity and hydrogen demand and their hourly demand profiles; production capacities of SMRs and electrolysers; storage capacities and (dis)charge rates of electricity and hydrogen storage; hydrogen import capacity and cost; power plant capacities for each type of fuel and efficiencies of technologies such as SMR and electrolyser.

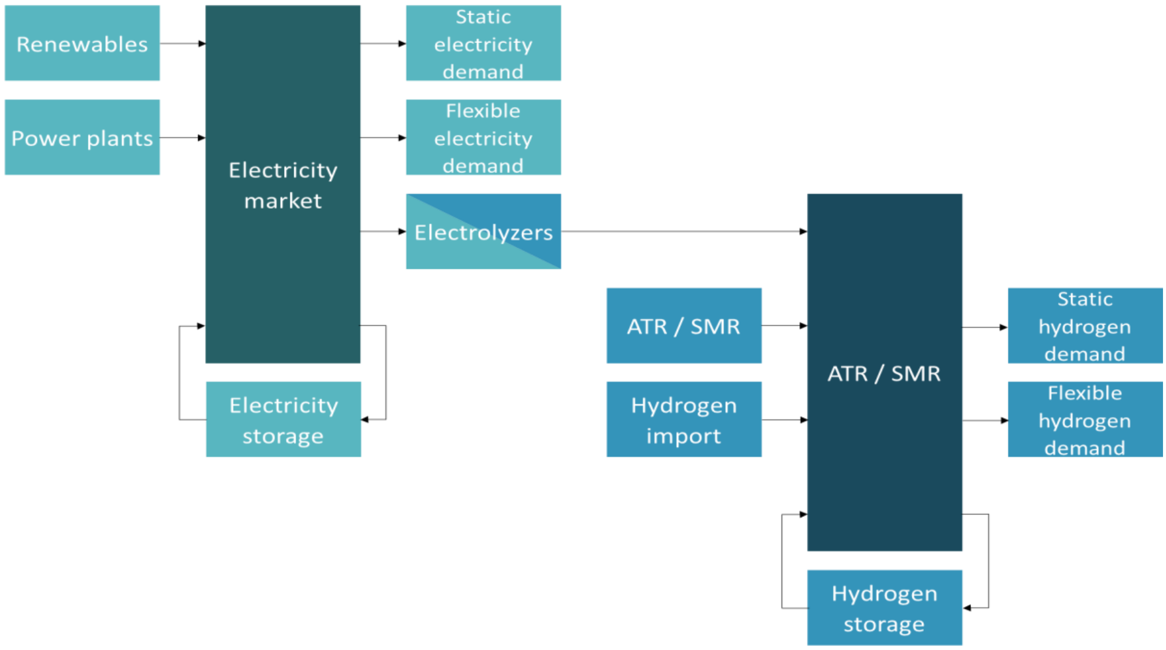


Figure 23 – Overview of EYE system scope

Bidding strategies framework

Besides input on the system scope, additional input is necessary for an EYE run, as it does not perform an optimization based on marginal costs, as is done in the full dispatch simulation. This input does not require additional data, it requires a logic behind a bidding strategy. Therefore the BDI model (*Believe, Desire, and Intention)* has been used. Based on the beliefs and desires of actors, their intentions are determined. We refer to these intentions as operational/bidding strategies. Different beliefs or desires will result in different bidding strategies. Beliefs can be public, e.g. the electricity price of the previous day, or private, e.g. the specific details of a PPA contract. An example of the BDI model structure for an SMR is presented in the textbox. The beliefs, desires and the resulting intentions in this project have been determined in collaboration with market parties. The resulting bidding strategies are presented in Section 3.2.

Example: Belief-Desire-Intention for an SMR

For SMR a public belief might be that there is a competitive hydrogen market: an overcapacity of hydrogen production w.r.t. the fixed hydrogen demand. Private knowledge might be the efficiency of the SMR. There can be several desires:

a. Long term contract with demand;
b. Generate additional revenue on the hydrogen market;
c. Provide flexibility to produce a certain volume with an electrolyser.

The first desire fits the current situation in which the owner of an SMR is also the user of the produced hydrogen. The second desire can be seen as an add-on for the first desire. By bidding the SMR in the hydrogen market, additional revenue can be generated. The third desire is in combination with an electrolyser, where the SMR adds the required flexibility to produce a certain volume of hydrogen. These beliefs and desires result into three intentions:

a. Follow the demand profile;
b. Bid marginal cost into the hydrogen market;
c. React to operational strategy of electrolyser to produce a certain production profile.

We will refer to these intentions as operational strategies. For the first and third strategy the volume for each hour is assumed to be known and based on the operational strategies of other assets. In the second strategy the SMR is bid into the hydrogen market and the operator knows its bidding price, but the clearing volume is unknown. That an SMR will be bid in its marginal cost is based on the public belief that there is a competitive market. In a competitive market an asset will bid in marginal costs to maximize the probability of being cleared. Only the asset owner knows the specific bidding price of that SMR, as it depends on private knowledge.

Assumptions

For the system scope the EYE simulations use the same input as the I-ELGAS simulations.
For the bid strategies in 2027 we assume that there is a competitive market for hydrogen production, since there is an overcapacity of SMR and import of hydrogen. This results in SMR and import bidding their marginal costs. Since the capacity of electrolysers is relatively small compared to the hydrogen demand, we assume electrolysers act as price takers.

For the bidding strategy of the electrolyser an important part is a PPA with a renewable energy source. In this project we model a PPA between an electrolyser and offshore wind. There is a choice to be made for the ratio of electrolyser capacity and offshore wind capacity. When both have the same capacity, offshore wind can always deliver all the produced energy to the electrolyser park. However, there will also be many hours in which the electrolyser is performing at partial load. To increase the full load hours of the electrolyser, the capacity of the electrolyser can be taken to be smaller than the capacity of offshore wind. In these cases the offshore wind park will have a remaining load for some hours, which it needs to sell on the electricity market. In the simulations we assume a ratio of 1:2, so an electrolyser with capacity 1 GW will have a PPA with an offshore wind park with a capacity of 2 GW.

Limitations

When marginal cost based bid strategies are used, the key uncertainty is that the market behaviour is highly dependent on the marginal cost assumptions, similar as for the full dispatch model. For this study, this is the case because SMR and import are believed to be bidding marginal costs on the hydrogen market.

An additional uncertainty is the bidding strategies that for bidding assets into the market. It is unsure if most hydrogen demand is satisfied by a dedicated SMR as it is today, or if demand is sourced from the hydrogen market while the SMR is bid into the market. This uncertainty is assessed by performing a multitude of simulations and evaluating the impact of altering the bidding strategies on the market behaviour. The results of this analysis are shown in section 3.3.

3.2 Strategies sets market participants

For the market simulation we model a market in which assets can use strategies which deviate from the optimal system dynamics. This is modelled with the EYE model. As explained in section 2.2 there are strategy sets which consist of assets and their associated strategies, e.g. an SMR and demand where the SMR follows the demand profile.

2027 strategies

There are four strategy sets for the 2027 simulations. Table gives a description and overview of each strategy set. Table 6 shows the strategy of each asset for each of these strategy sets:

- 2027-A: Demand & SMR/Import;
- 2027-B: Demand & SMR/Import & Electrolyser;
- 2027-C: Demand & Electrolyser & Hydrogen storage;
- 2027-D: Market.

Table 6 - A description and overview of each strategy set

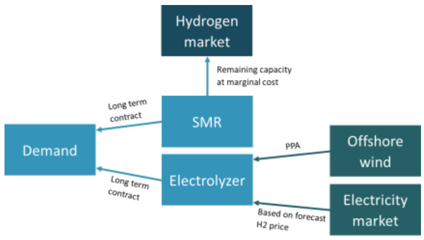
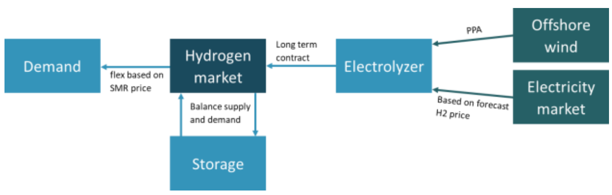
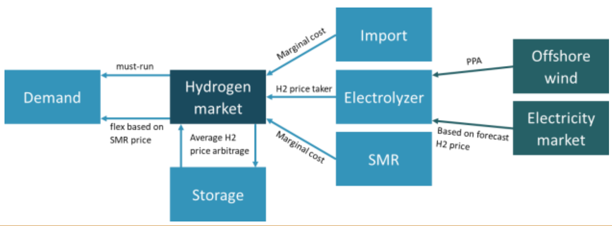
Set	Description	Overview
2027-A	SMR or import delivers hydrogen to a demand	
2027-B	An electrolyser produces hydrogen from a PPA with offshore wind and possibly from the electricity market for low prices. An SMR supplies hydrogen to the remaining demand and bids its remaining capacity on the hydrogen market	
2027-C	An electrolyser produces hydrogen from a PPA with offshore wind and possibly from the electricity market for low prices. Storage balances supply and demand.	
2027-D	On the market Import and SMR bid their marginal costs. Electrolyser is a price taker on the market. Storage performs arbitrage based on an average hydrogen price. Demand can bid a static profile and a flexible demand based on the SMR price.	

Table 7 - Overview of bidding strategies and active set of assets for the 2027 simulations.

Set	Asset	Strategy
2027-A	Demand	Bid a static demand profile
	SMR / Import	Follow the demand profile
2027-B	Demand	Bid a static demand profile
	SMR / Import	Provide flexibility to the variable hydrogen supply of the electrolyser
	Electrolyser	Receive from PPA (offshore wind) and/or electricity market (at low prices) and supply hydrogen
2027-C	Demand	Bid a static demand profile
	Electrolyser	Receive electricity from PPA (offshore wind) and/or electricity market (at low prices) and supply hydrogen
	Hydrogen storage	Demand hydrogen when there is an abundance and supply when there is a shortage
2027-D	Demand	Bid a static demand profile
	SMR / Import	Bid marginal cost
	Electrolyser	Receive electricity from PPA (offshore wind) and/or electricity market (at low prices) and supply hydrogen
	Hydrogen storage	React to differences in prices on the hydrogen market: buying at low prices and selling at high prices

These strategies are evaluated on the import case scenario of the full dispatch simulation. Within this scenario we distinguish two variables: the presence of ammonia crackers (for import) and whether SMR is one-sided or two-sided. A two-sided SMR is able to both deliver to its associated demand and to the hydrogen market, whereas an one-sided SMR is only able to scale down its production, but not able to deliver to the hydrogen market. These two variables have been chosen in collaboration with market parties. We have chosen these two variables, because the presence of ammonia crackers in 2027 and whether SMRs will bid on a hydrogen market is both considered uncertain. If the ammonia crackers are not present, then we assume that the hydrogen demand is halved, and the SMR capacity is lowered as well. Two variables with two options each create four variations which we model.

- 2027-I: Plain spot trading. Ammonia crackers are present and SMRs are two-sided. All assets bid on the hydrogen spot market.
- 2027-II: Bilateral contracting. Ammonia crackers are present and SMRs are two-sided. A part of the hydrogen demand is fulfilled directly by a combination of electrolyser and SMR production. The remaining part is traded on the hydrogen spot market.
- 2027-III: High bilateral contracting. Ammonia crackers are not present and SMRs are two-sided. A large part of the hydrogen demand is fulfilled directly by electrolyser and SMR production. The remaining part is traded on the hydrogen spot market.
- 2027-IV: Low SMR market entry. Ammonia crackers are not present and SMRs are one-sided. SMRs do not enter the hydrogen market, but can scale down production if cheap hydrogen is available on the spot market. Only a flexible hydrogen demand enters the spot market for green hydrogen.

2027-I: Plain spot trading

In the first case crackers are present and there are two-sided SMRs. The bidding strategy is totally on the hydrogen market.

Table 8 - Overview of strategy sets for the 2027-I: Ammonia crackers and two-sided SMRs simulation.

2027-D Market		
SMR	5,500	MW
Import	7,405	MW
Electrolyser	750	MW
Demand	51	TWh
	6,303	MW
Storage	0.2	TWh
	840	MW

2027-II: Bilateral contracting

The second case is again with crackers present and two-sided SMRs, but with different strategies. There is a demand of 8.1 TWh which, given our profile, has a maximum hourly demand of 1 GW. This demand is coupled with an SMR of 1 GW and an electrolyser of 0.5 GW. The electrolyser has a PPA with an offshore wind park of 1 GW and supplies all the produced hydrogen directly to the hydrogen demand. The SMR provides the flexibility to match the production profile of the electrolyser and the demand profile. The remaining assets all bid on the hydrogen market with their associated bidding behaviour.

Table 9 – Overview of strategy sets for the 2027-II: Ammonia crackers and two-sided SMRs, different strategies simulation.

2027-B SMR & Electrolyser		
SMR	1,000	MW
Import		*MW*
Electrolyser	500	MW
Demand	8	TWh
	1,000	MW
Storage		*MWh*
		MW

2027-D Market		
SMR	4,500	MW
Import	7,405	MW
Electrolyser	250	MW
Demand	43	TWh
	5,303	MW
Storage	0.2	TWh
	840	MW

2027-III: High bilateral contracting

For the third case the SMRs remain two-sided, but there are no ammonia crackers available. The strategy set of the demand, SMR and electrolyser remains the same as in the previous case. The demand and SMR capacity on the hydrogen market is lowered.

Table 10 - Overview of strategy sets for the 2027-III: Two-sided SMRs simulation.

2027-B SMR & Electrolyser		
SMR	1,000	MW
Import		*MW*
Electrolyser	500	MW
Demand	8	MWh
	1,000	MW
Storage		*MWh*
		MW

2027-D Market		
SMR	2,300	MW
Import		*MW*
Electrolyser	250	MW
Demand	18	MWh
	2,151	MW
Storage	0.2	TWh
	840	MW

2027-IV: Low SMR market entry

For the fourth and final case there are again no ammonia crackers available, and the SMRs become one-sided. This means that there is no SMR and import available on the hydrogen market. Only electrolysers can be present on the market to supply, together with hydrogen storage. This means that only a flexible part of hydrogen demand remains on the hydrogen market, which it buys at the cost of SMR. The SMR is taken off the market and coupled with demand which is satisfied by the SMR only.

Table 11 - Overview of strategy sets for the 2027-IV: One-sided SMRs simulation.

2027-A SMR only		
SMR	2,300	MW
Import		*MW*
Electrolyser		*MW*

2027-B SMR & Electrolyser		
SMR	1,000	MW
Import		*MW*
Electrolyser	500	MW

2027-D Market		
SMR		*MW*
Import		*MW*
Electrolyser	250	MW

2027-A SMR only		
Demand	17	MWh
	2,044	MW
Storage		*MWh*
		MW

2027-B SMR & Electrolyser		
Demand	8	MWh
	1,000	MW
Storage		*MWh*
		MW

2027-D Market		
Demand	1	MWh
	108	MW
Storage	0.2	MWh
	840	MW

2030 strategies

For 2030 the focus is on how to comply with the green hydrogen targets as formulated in the Delegated Act: 42% of the hydrogen demand must be green. There are multiple ways for hydrogen to be considered green. We consider two:

- A direct connection with a renewable energy source; and
- From the grid when the emission intensity is low.

For a demand there can be multiple strategies to achieve the target of 42%. For this we need to distinguish between green and grey hydrogen. I-ELGAS is not able to cope with this. For the spot market simulation with EYE we consider two ways to do this: a green hydrogen market and through PPAs.

In the green hydrogen market, industry buys green hydrogen on a dedicated spot market with green import and electrolysers. This assumes that there is value for green hydrogen as a separate commodity. Without a target for green hydrogen, there is no difference between green and grey hydrogen in this framework and no separate markets would be required for the simulation. In this case green hydrogen is competitive at low electricity prices.

For the PPAs industry contracts electrolysers in combination with storage, or has long term contracts with green hydrogen importers. The electrolysers have a PPA with offshore wind and an hourly correlation for production of green hydrogen.

There are two strategy sets for a PPA:

- Demand & Green import;
- Demand & Electrolyser & Storage.

There is one strategy set for a green hydrogen market:

- Green H2 market.

And there remains a hydrogen market in which there is no distinguishment between green and grey hydrogen:

- Mix H2 market.

In Table the strategies for all assets within these four strategy sets are described. Electrolysers are important suppliers of green hydrogen. We consider two ways in which electrolysers produce green hydrogen: a direct relation with offshore wind and from the grid when the emission intensity is low. The latter case is done through pricing: when the electricity spot market price is lower than 36% of the CO2 price. This does require an electrolyser to show that it has produced hydrogen in exactly these hours.

Table 12 - Overview of bidding strategies and active set of assets for the 2030 simulations.

Set		Asset	Strategy
2030-A	Demand & Green Import	Demand	Bid a static demand profile
		Green import	Follow the demand profile
2030-B	Green H2 market	Demand	Bid a static demand profile
		Green import	Bid marginal cost
		Electrolyser	Receive electricity from PPA (offshore wind) and/or electricity market (at low prices) and supply hydrogen
2030-C		Demand	Bid a static demand profile

Set		Asset	Strategy
	Demand & Electrolyser & Storage	Electrolyser	Receive electricity from PPA (offshore wind) and/or electricity market (at low prices) and supply hydrogen
		Storage	Demand hydrogen when there is an abundance and supply when there is a shortage
2030-D	Mix H2 market	Demand	Bid a static demand profile
		SMR / ATR / Blue import	Bid marginal cost
		Electrolyser	Receive electricity from PPA (offshore wind) and/or electricity market (at low prices) and supply hydrogen
		Hydrogen storage	React to differences in prices on the hydrogen market: buying at low prices and selling at high prices

Again we use the import case of the full dispatch simulations and we will consider two cases in which we differ the strategies. In the first case industry will satisfy its green hydrogen target by going to a dedicated spot market in which green hydrogen can be supplied by green imports and electrolysers. In the second case industry has long term contracts with green import or electrolysers to satisfy this target. These two cases were chosen because of the focus on the green hydrogen targets in 2030.

2030-I: Green H2 spot trading

In the first case there is a green hydrogen market, and a mix hydrogen market. The demand is split into a part that must be green (42% of the total demand) and a part for which it does not matter. On the green hydrogen market the supply comes from electrolysers (with and without PPAs) and green imports. On the mixed market the hydrogen is supplied by SMRs, ATRs, blue imports. Storage is only available on the mixed market.

Table 13 - Overview of strategy sets for the 2030-I simulation.

Green H2 market		
Import (green)	3702	MW
Electrolyser	5900	MW
Demand	30	TWh
Storage	0	TWh

Mix H2 market		
SMR	5200	MW
ATR	1350	
Import	3703	MW
Electrolyser	0	MW
Demand	43	TWh
Storage	0.94	TWh

2030-II: Green H2 contracting

In the second case industry satisfies its green demand with long term contracts with green import and an electrolyser and storage combination.

Table 14 - Overview of strategy sets for the 2030-II simulation.

Demand & Green import		
Import (green)	3702	MW
Demand	20	TWh

Demand & Electrolyser & Storage		
Electrolyser	5900	MW
Demand	12	TWh
Storage	0.94	TWh

Mix H2 market		
SMR	5200	MW
ATR	1350	MW
Import (blue)	3703	MW
Electrolyser	0	MW
Demand	41	TWh
Storage	0	TWh

3.3 Results of the market (game) simulation 2027 and 2030

Results and interpretation for 2027

Four cases have been simulated for 2027:

- 2027-I: Plain spot trading. Ammonia crackers are present and SMRs are two-sided. All assets bid on the hydrogen spot market.
- 2027-II: Bilateral contracting. Ammonia crackers are present and SMRs are two-sided. A part of the hydrogen demand is fulfilled directly by a combination of electrolyser and SMR production. The remaining part is traded on the hydrogen spot market.
- 2027-III: High bilateral contracting. Ammonia crackers are not present and SMRs are two-sided. A large part of the hydrogen demand is fulfilled directly by electrolyser and SMR production. The remaining part is traded on the hydrogen spot market.
- 2027-IV: Low SMR market entry. Ammonia crackers are not present and SMRs are one-sided. SMRs do not enter the hydrogen market, but can scale down production if cheap hydrogen is available on the spot market. Only a flexible hydrogen demand enters the spot market for green hydrogen.

Clearing of the hydrogen market

Figure 24 shows the price duration curve of the hydrogen market for 2027-I. The clearing price is determined by the SMR marginal costs for the majority of the time. For a small number of hours the price is determined by the marginal costs of import. In 2027-II, the number of hours in which the price is determined by import increases, however still the majority of the time the price is determined by SMR. In 2027-III there is no import anymore, so the price is solely determined by SMR. In 2027-IV the price is determined by the flexible demand, which bids at the price of SMR. Furthermore, there are also hours without a clearing price, as there is a lack of supply and no hydrogen is traded.

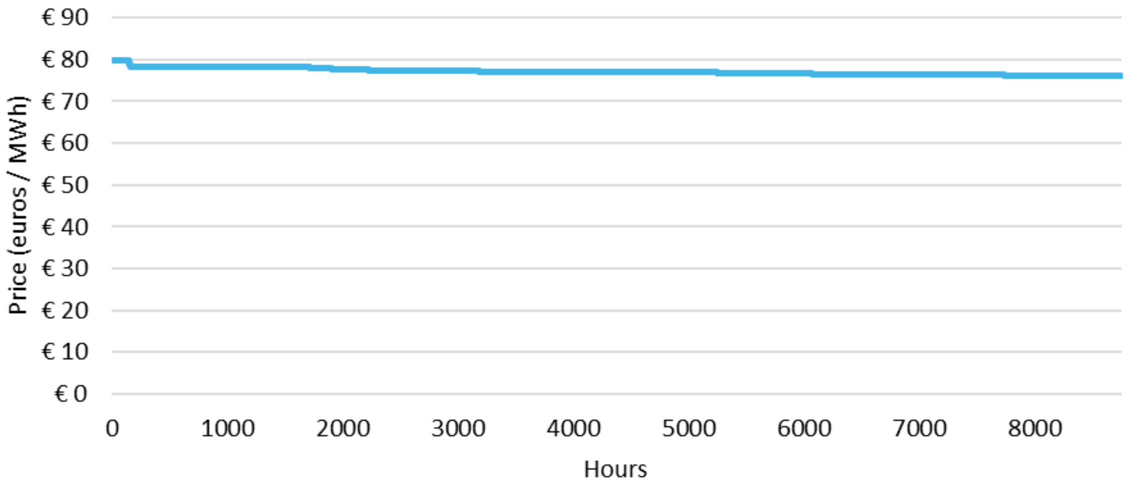


Figure 24 - Price duration curve for 2027-I.

Dispatch of the electrolyser

Figure 25 shows load duration curves for an electrolyser with and without PPA for 2027-I. The electrolyser with PPA follows the load duration curve of offshore wind. The electrolyser without PPA has almost 3000 hours in which the price of electricity is favourable with respect to the hydrogen price. The electrolyser with PPA has more running hours by having secured a PPA with offshore wind. With this we deviate from a full integrated spot market dispatch. The PPA ensures a better individual business case for the electrolyser, but higher private and societal costs, as the electricity could have had a higher value on the electricity spot market.

Note that these loads are about the hydrogen production, so they include the efficiency of transforming electricity to hydrogen.

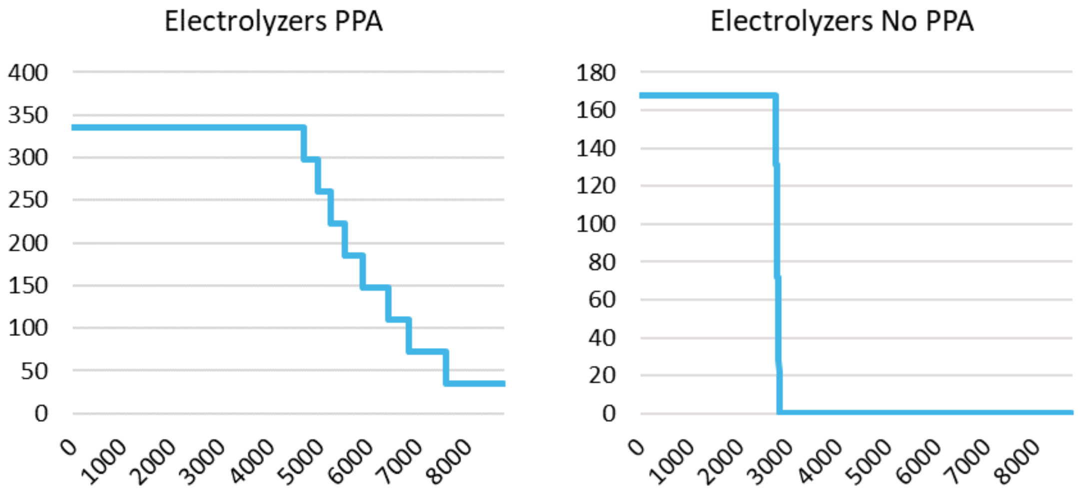


Figure 25 - Load duration curves for an electrolyser with PPA (left) and an electrolyser without PPA (right).

Sources of hydrogen supply

Figure 26 shows the distribution of the hydrogen supply by electrolysers, SMR and import for 2027-I. The majority of hydrogen is supplied by SMR, and a small part is supplied by electrolysers. The part supplied by import is indistinguishable, for the year 2027.

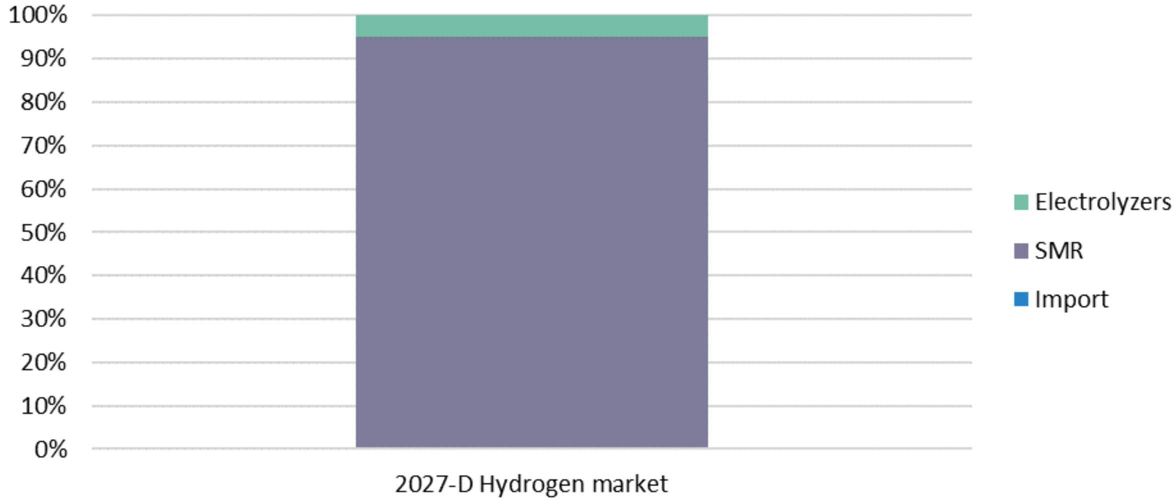


Figure 26 - Distribution of the hydrogen supply on the hydrogen market by electrolysers, SMR and import for 2027-I.

Figure 27 shows the distribution for 2027-II for the hydrogen market and the local market with SMR and electrolyser. In the latter market an electrolyser and SMR are dedicated to a certain demand. The import part becomes distinguishable on the hydrogen market, but remains small. The SMR part decreases, and the electrolyser part increases.

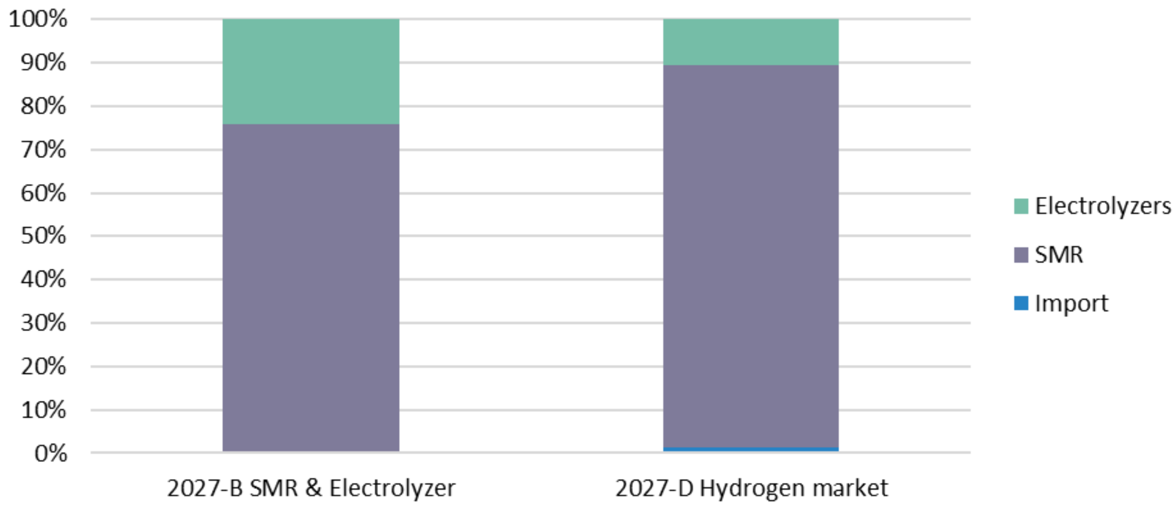


Figure 27 - Distribution of the hydrogen supply on the hydrogen market and local SMR & Electrolyser market (electrolyser and SMR are dedicated to a certain demand) by electrolysers, SMR and import for 2027-II.

Figure 28 shows the same for 2027-III. In this case there are no ammonia crackers. Consequently, import is not available. We have also lowered the hydrogen demand, as the ammonia is directly available. Import played a small role in the hydrogen supply in 2027-I and 2027-II, so removing it does not alter the results greatly. This does assume that the marginal costs of import are higher than the marginal costs of SMR. This assumption leads to SMR being the main supplier of hydrogen. If the marginal costs of import are lower, than the marginal costs of SMR, then import would become the main supplier of hydrogen. If this were the case, then the unavailability of crackers would have a great impact on the dynamics of the hydrogen market.

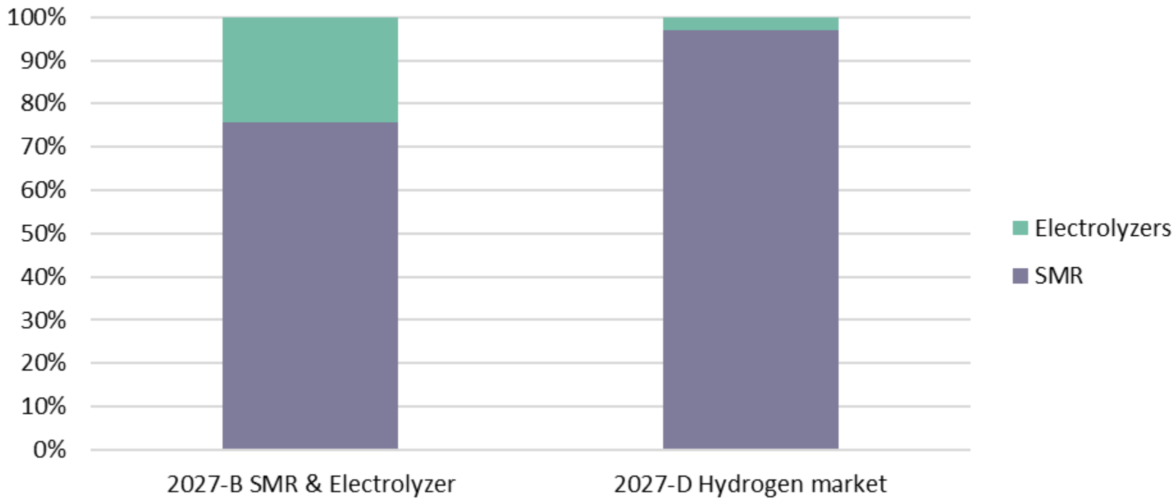


Figure 28 - Distribution of the hydrogen supply on the hydrogen market and local SMR & Electrolyser market (electrolyser and SMR are dedicated to a certain demand) by electrolysers and SMR for 2027-III.

Clearing of the flexible hydrogen demand

The hydrogen demand is split into a static and a flexible part. The static part must be satisfied at any cost. The flexible part will shut off at high prices. We assume that the flexible demand bids at the marginal costs of SMR. For hydrogen prices equal to or lower than the SMR price, this demand is cleared, but for higher prices it is not. In these cases this means that the flexible demand is cleared when there is a remaining SMR capacity and it is not cleared when import supplies hydrogen.

Figure 29 shows for each case which percentage of this flexible demand is cleared on the hydrogen market. In the first case 80% of this demand is cleared. Going to the second case, this decreases to 75%. This is caused by the fact that import plays a more important role in 2027-II than in 2027-I, and the marginal costs of import are higher than the willingness-to-pay of the flexible demand.

In 2027-III there is no import anymore and the demand decreases. With these input, 100% of flexible demand is cleared. Finally, in 2027-IV only flexible demand is present on the hydrogen market, which can be supplied by electrolysers with the help of storage. 50% of this demand is satisfied.

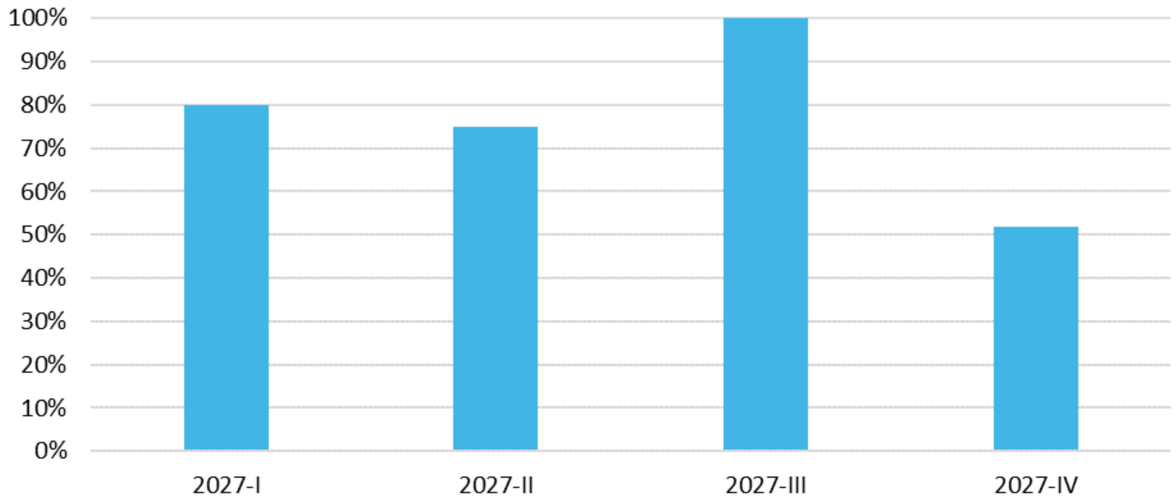


Figure 29 - Percentage of the flexible hydrogen demand which is cleared on the hydrogen market.

The role of hydrogen supplies differs between the cases. In the first and second case the role of hydrogen storage is to provide seasonal flexibility. In the summer it charges and in the winter it discharges. In the third case there is no role for storage as the price is nearly constant. In the fourth case it's role becomes short-cyclical as it is constantly matching electrolyser supply and flexible demand.

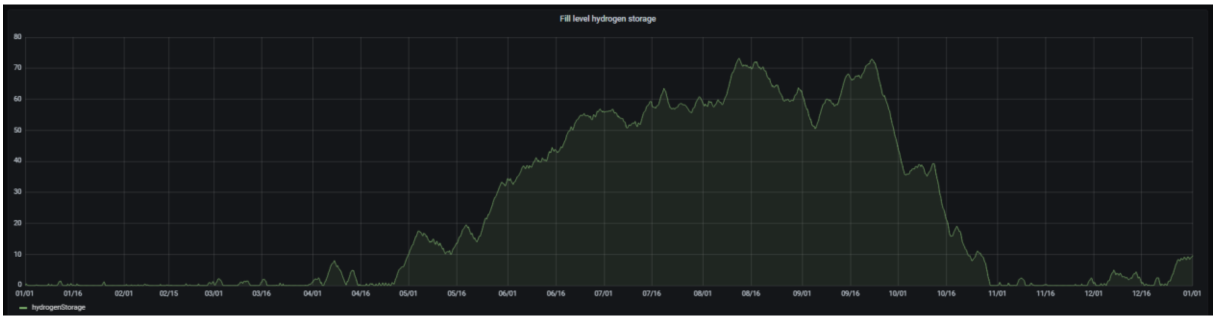


Figure 30 - The fill level of hydrogen storage in the first case.

Based on these four cases we can conclude that the dynamics of the hydrogen market can change significantly due to the bidding strategies of assets. In plain spot trading the market dynamics closely resemble that of an optimal dispatch. By removing ammonia crackers and taking SMRs off the market, this changes. The share of hydrogen demand traded on the spot market decreases: 100% in the first case, 84% in the second, 68% in the third and only 3% in the final case. The dynamics of the hydrogen market and local markets differ, as the hydrogen supply is covered by different assets. These lower volumes impact the added value of a hydrogen spot market. If existing dedicated hydrogen production remains to be dedicated to on-site hydrogen demand, private price and volume risk might be limited at cost of optimal system dispatch. As such transparancy in hydrogen spot pricing will suffer, while pricing transparancy is one of the core benefits of an exchange. In 2027 we are only three years away from 2030, when there are actual targets for green hydrogen. More transparency in prices in 2027 can be beneficial – maybe even crucial – to reach these targets.

Results and interpretation for 2030

For 2030 two cases have been simulated:

- Green H2 spot trading - Industry satisfies its green hydrogen target via a dedicated spot market;
- Green H2 contracting - Industry satisfies its green hydrogen target via long term contracts.

Figure 31 shows the green hydrogen supply for each hour throughout the year for the first case. The percentage for each hour fluctuates around 42%. Hydrogen demand has a naïve strategy where it tries to have 42% of green demand for each hour, instead of 42% over a whole year. In hours where there is an oversupply of green hydrogen due to the electrolysers, the storage demands this green hydrogen. At a later time storage replaces the import of green hydrogen. Over a whole year the percentage is 42%.

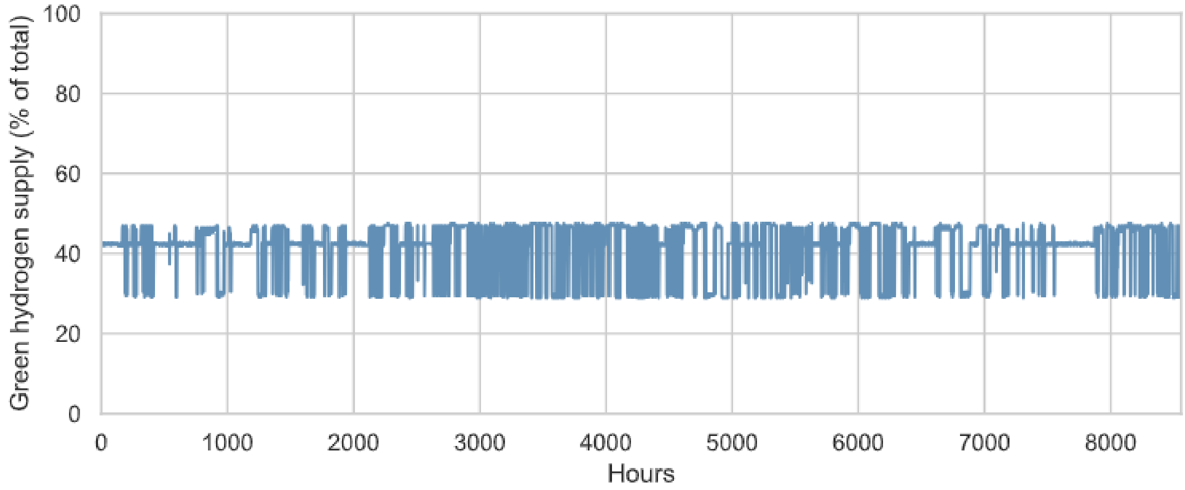


Figure 31 - Green hydrogen supply for each hour throughout the year for green H2 spot trading.

Figure 32**Error! Reference source not found.** shows the price duration curves for green hydrogen market and Figure 33 for the mix hydrogen market for the green H2 spot trading case. In the mix H2 market the price is nearly constant throughout the year and determined by blue import. In the green hydrogen market there are two main plateaus: a higher price set by the green import and a lower price set by the electrolyser. There is a plateau in between which is set by hydrogen storage. The electrolyser can always sell its hydrogen on the mix hydrogen market, which sets a lower price for the green hydrogen market. Storage is able to buy hydrogen for lower prices and sell for higher prices and can set the price in between.

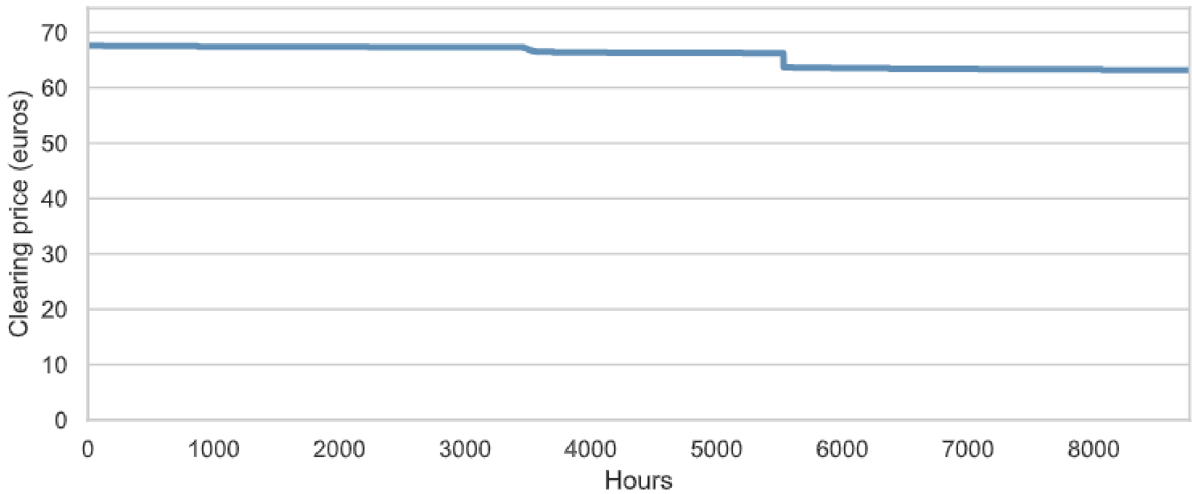


Figure 32 – Price duration curve for the green H2 spot market for green H2 spot trading.

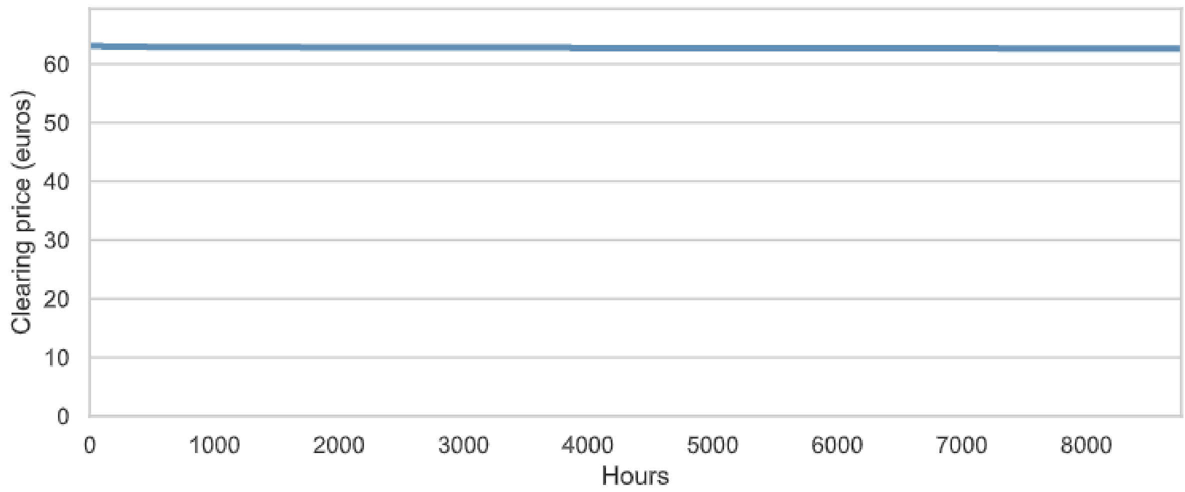


Figure 33 - Price duration curve for the mix H2 spot market for green H2 spot trading.

Figure 34 shows a load duration curve for an electrolyser without PPA on the green H2 market and mix H2 market. When the price on the electricity market is lower than 36% of the CO2 price the electrolyser demands electricity and supplies green hydrogen. The supply of green hydrogen can exceed the green hydrogen demand for that hour. In these hours hydrogen storage demands green hydrogen to be sold at a later moment.

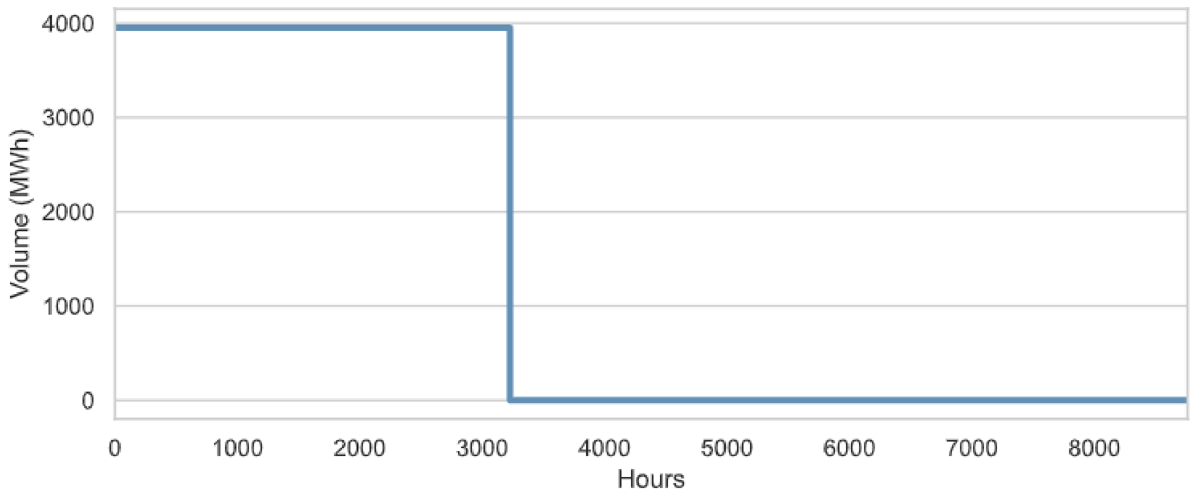


Figure 34 - Load duration curve of an electrolyser without PPA in case of a green H2 spot trading for the green hydrogen spot market.

Figure 35 shows total hydrogen supply for each asset. On the mix H2 market the ATR is running full load as it has the lowest marginal costs. Blue import is next and provides the majority of the hydrogen. SMR is not utilized as it has the highest marginal costs and is never needed to satisfy demand.

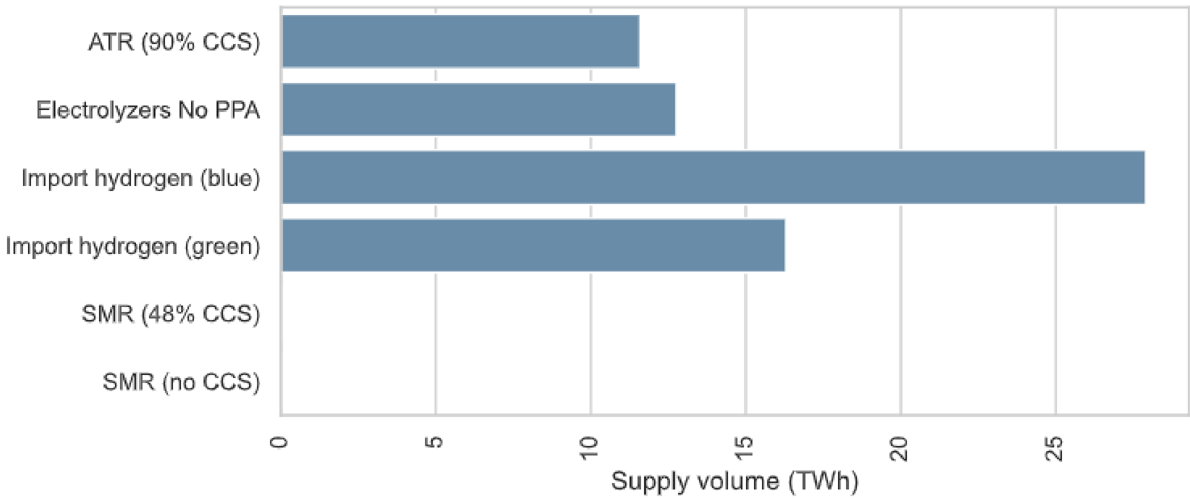


Figure 35 - Total hydrogen supply of each asset for in case of a green H2 spot trading.

Figure 36 shows the hydrogen supply throughout the year for the second case. In this case there is a no optimization via the market. As a result there is some demand with an overshoot of green hydrogen supply. In total 43% of the hydrogen supplied is green.

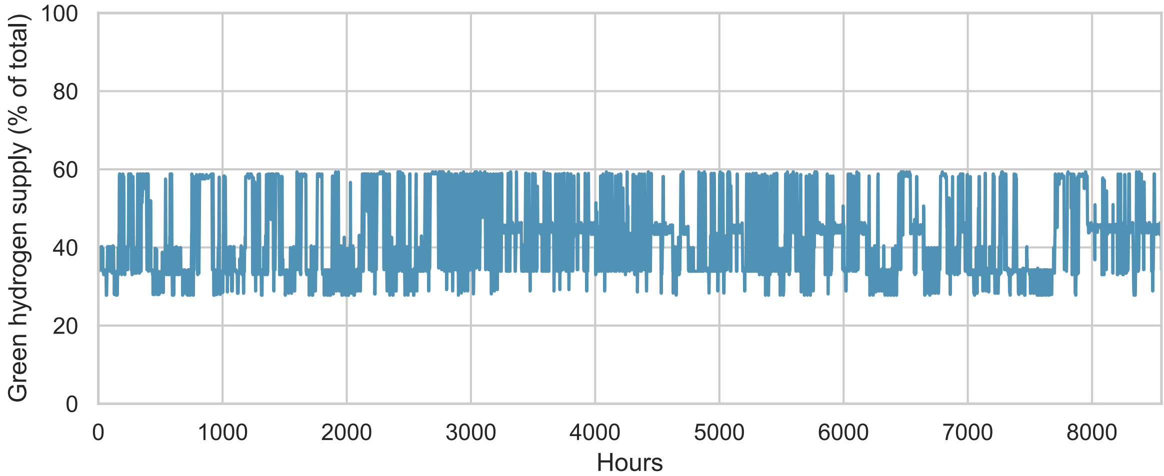


Figure 36 - Green hydrogen supply for each hour throughout the year for green H2 contracting.

The results for the two cases are very similar. Figure 37 shows the proportion of hydrogen supply for both cases. There is a slightly higher supply of hydrogen by electrolysers in the first case.

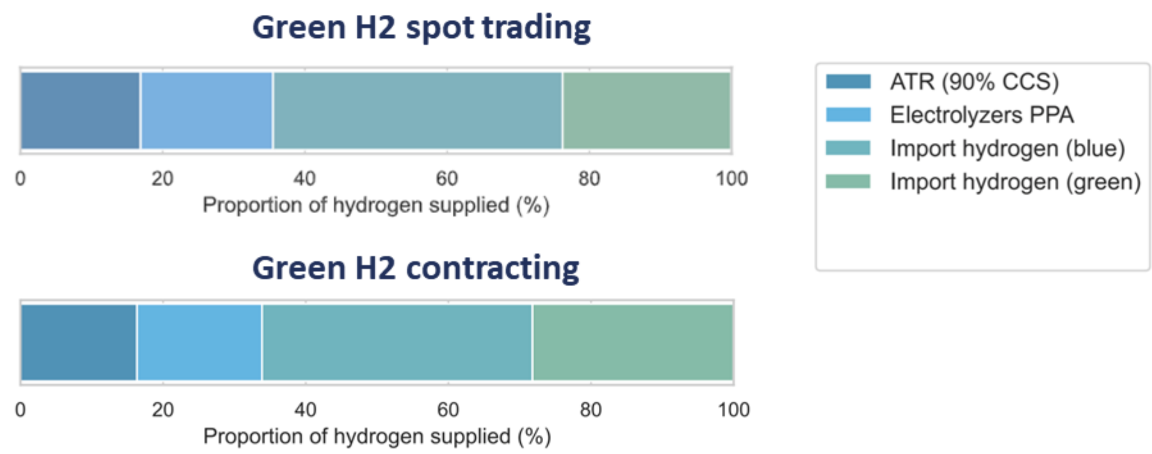


Figure 37 - Proportion of supplied hydrogen for the two cases.

In both cases naïve strategies have been used, especially for how demand will satisfy the green hydrogen target. This is a good first-order method, however it can cause an overshoot in green hydrogen consumption. Further optimization by the demand assets is required.

Based on these two cases we can conclude that the dynamics of the hydrogen market can change significantly due to how industry will satisfy its green hydrogen targets in 2030. We find that if industry relies on a dedicated spot market to reach its targets, then this will result in a close-to optimal dispatch as well as investments. If industry meets its targets via long term contracts, then this might give individual guarantees regarding price and volume risk, but it will also limit the benefits of a hydrogen spot market.

4. CEHIM - IMBALANCE MARKET SIMULATION

To better understand the system imbalance a new simulation model has been developed upon specific request of participating market parties as part of this project. This model allows for technical and financial analysis of the coupling between the electricity imbalance market and the hydrogen imbalance market. The imbalance model (CEHIM) is applied to the situation in 2030.

4.1 Description of the model, key assumptions and limitations

Description of the model

Originally the market simulation solely targets a spot market simulation. However, on request of market parties, a high-level investigation on the imbalance market has been performed. Market parties were especially interested in the coupling between the electricity imbalance market and the hydrogen imbalance market.

Modelling the imbalance market with CEHIM

We use historical data for prices (TenneT, 2019) on the electricity imbalance market and electricity day ahead market. Next, we rescale the imbalance prices based on the spot market prices from a spot market simulation performed with the EYE model. For example, if the simulated price is €40/MWh and the historical day ahead price for the same hour is €50/MWh, then we multiply the imbalance price by 0.8 (=40/50). The imbalance market is cleared for a 15-minute period, whereas the day ahead market is cleared for an hour period, so we multiply the four 15 minutes for that hour by 0.8.

Strategies and response on other markets

There are two ways in which the electrolyser can trade on the imbalance market. If a bid to produce is cleared on the day ahead market for hydrogen, then the producer can decide to 'supply' electricity on the imbalance market for electricity while falling short on its commitments for hydrogen production. If it is not cleared, then it can consider to buy low-cost electricity on the imbalance market for electricity in order to produce hydrogen, inducing imbalances on the hydrogen market (i.e. stored as linepack). If the electrolyser is cleared partly, then it can perform both actions, by supplying its cleared volume and demanding its remaining capacity.

By trading on the electricity imbalance market, the operator of an electrolyser causes an imbalance on the hydrogen market. We assume that it can use linepack for this imbalance. This provides a limitation to how much the electrolyser can do, namely the linepack capacity which is available. When the electrolyser demands electricity on the imbalance market, then it supplies more hydrogen than originally cleared, causing imbalances on the hydrogen balancing mechanism resulting in increasing linepack. When the linepack is full, this is not possible anymore, so the electrolyser cannot solve this imbalance on the electricity market. When the electrolyser supplies electricity on the imbalance market, then it supplies less hydrogen than originally cleared. In this case the linepack will supply hydrogen. When the linepack is depleted, this is not possible anymore, so the electrolyser cannot solve this imbalance on the electricity market. In reality the grid operator will monitor the pressure and when this gets into a critical range it will restore the balance through high imbalance prices. We assume that these price signals are strong enough for the linepack capacity to be a hard limit which is not exceeded.

Assumptions

This approach assumes that an electrolyser can always capture the full benefits of arbitrage between the imbalance market for electricity and imbalance mechanism for hydrogen. In the real market there will be competing bids, which can deplete this arbitrage opportunity. Multiple assets are looking at the imbalance market for their business cases, attracted by the high prices. However, the volumes that are traded on this market are relatively small. As such, these calculations indicate the best attainable capture rate.

Another assumption is how much of the linepack will be available for the electrolysers. We will model two cases: 10% and 50% of 14,000 MWh. The 10% and 50% are arbitrary numbers to give an indication of the additional revenue which might be captured on the imbalance market.

Next, the cost of linepack is assumed to follow the current status for linepack for natural gas. The end-of-day imbalance has a cost of 0.4% of the hydrogen spot market price. So if an electrolyser has an imbalance of 100 MWh and the hydrogen price is €70/MWh, then the cost of imbalance is €28 (= 0.4% * 100 MWh * €70/MWh). Of course the actual costs can be much higher, however we assume that we remain within an acceptable zone in which the prices for imbalance are 0.4% of the hydrogen spot market price. For the data we use 2019 data from TenneT for the imbalance and day ahead market.

Limitations

This imbalance model is a first order approach, illustrating orders of magnitude of imbalance arbitrage revenues, respective of hydrogen production revenues. It should not be considered as an accurate simulation of the imbalance market for 2030. The first order results give an indication of additional revenues attainable from imbalance arbitrage and potential imbalance volumes on the electricity market than can be solved by the hydrogen market via the electrolysers.

4.2 Scenario's imbalance analysis

Upon on request of market parties, a high-level investigation on the imbalance market has been performed and a new imbalance model has been developed (excel, available upon request).

Market parties were especially interested in the coupling between the electricity imbalance market and the hydrogen imbalance market, and the effect of two uncertainties, namely: i) how much linepack is available for the electrolyser; and ii) the imbalance volume of the electricity market w.r.t. 2019.

To evaluate the effects of these two uncertainties, five different scenarios have been analysed, the scenarios and the key parameters used are presented in the table below.

Table 15 - Imbalance analysis scenario description and results

Imbalance scenario's	Key parameters
I: Base linepack available, base imbalance volume	Linepack capacity: 1400 MWh Imbalance volume w.r.t 2019: 100%
II: Base linepack available, doubled imbalance volume	Linepack capacity: 1400 MWh Imbalance volume w.r.t 2019: 200%
III: Increased linepack available, base imbalance volume	Linepack capacity: 7000 MWh Imbalance volume w.r.t 2019: 100%
IV: Increased linepack available, doubled imbalance volume	Linepack capacity: 7000 MWh Imbalance volume w.r.t 2019: 200%
V: Unlimited linepack available, same imbalance volume	Linepack capacity: unlimited Imbalance volume w.r.t 2019: 100%

4.3 Results imbalance analysis 2030

This section shows the results from the imbalance analysis for each of the five scenario's. For each scenario the resulting graph and key findings are presented. Furthermore, Table shows financial parameters from the imbalance model for the four cases in which we alter the linepack capacity and imbalance volume. It shows the total revenue, which is calculated by multiplying the imbalance volume cleared by the electrolyser and the imbalance prices of these periods and summing this for all periods. This revenue is compared with the revenue which the electrolyser has on the hydrogen spot market.

Results scenario's: change in linepack state

I: Base linepack available, base imbalance volume

Figure 38 shows the state of linepack for a linepack capacity of 1400 MWh (ranging from -700 MWh to +700 MWh) and the same imbalance volume as in 2019. We see plateaus for which the linepack is full or depleted with regular switches between these two.

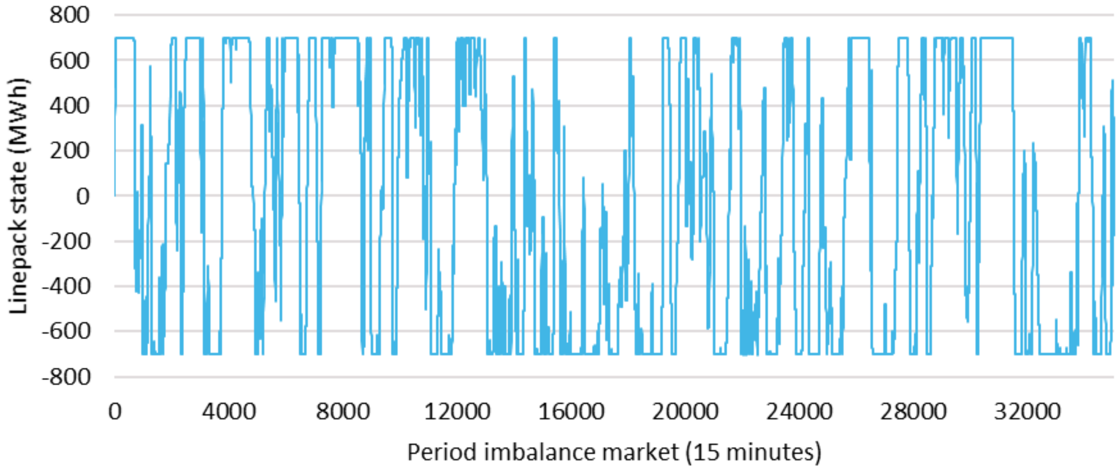


Figure 38 - State of the linepack for a linepack capacity of 1400 MWh and with the imbalance volume same as in 2019.

II: Base linepack available, doubled imbalance volume

In Figure 39 the imbalance volume is doubled. As a result the switching becomes more regular w.r.t. Figure 38.

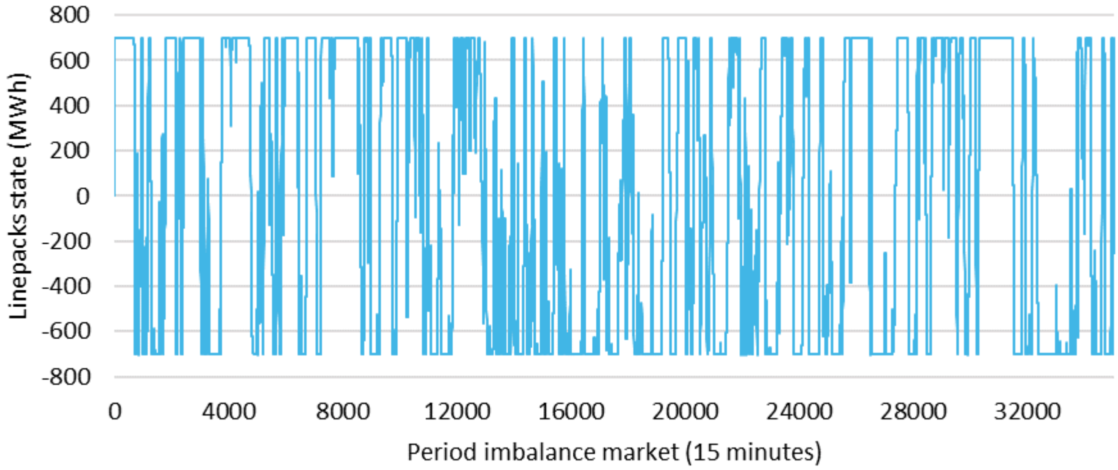


Figure 39 - State of the linepack for a linepack capacity of 1400 MWh and with the imbalance volume doubled w.r.t. 2019.

III: Increased linepack available, base imbalance volume

In Figure 40 the imbalance volume is the same as in 2019 and the linepack capacity is increased to 7000 MWh (ranging from -3500 MWh to +3500 MWh). This increase in linepack capacity causes a sharp decrease in switching between full and depleted linepack. We can observe that during the winter the linepack is full, while in the summer it is depleted. The behavior has become more seasonal due to the increase in linepack capacity.

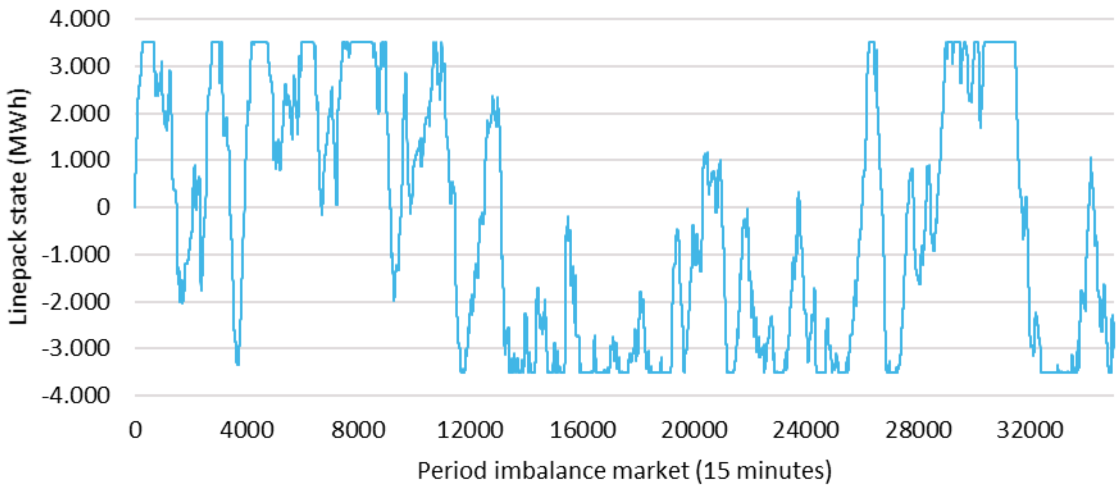


Figure 40 - State of the linepack for a linepack capacity of 7000 MWh and with the imbalance volume same as in 2019.

IV: Increased linepack available, doubled imbalance volume

In Figure 41 we double the imbalance volume again, which causes the behavior of the linepack to become more short-cyclical.

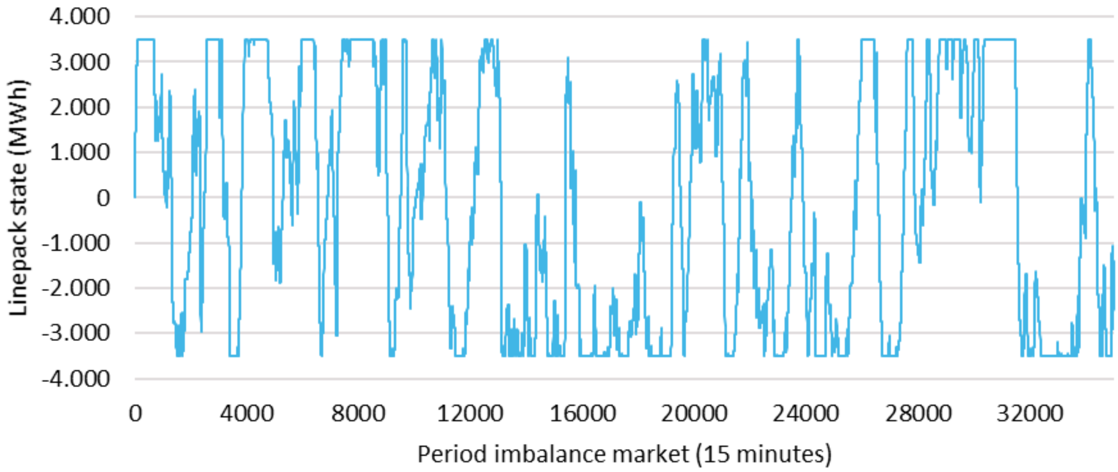


Figure 41 - State of the linepack for a linepack capacity of 7000 MWh and with the imbalance volume doubled w.r.t. 2019.

V: Unlimited linepack available, same imbalance volume

Finally in Figure 42 we remove the linepack capacity constraint. We observe the same seasonal behavior as before, in its most extreme. The required linepack capacity would be 70,000-80,000 MWh. This is of course not possible for linepack, but it does show that there is also a role for hydrogen storage. This will mainly be the case when additional hydrogen is produced. In these cases the additional hydrogen can later be sold on the hydrogen spot market for a high price. The case in which less hydrogen is produced will only occur for very high imbalance prices. It is likely that other assets, such as E-storage will fix this imbalance, instead of electrolysers.

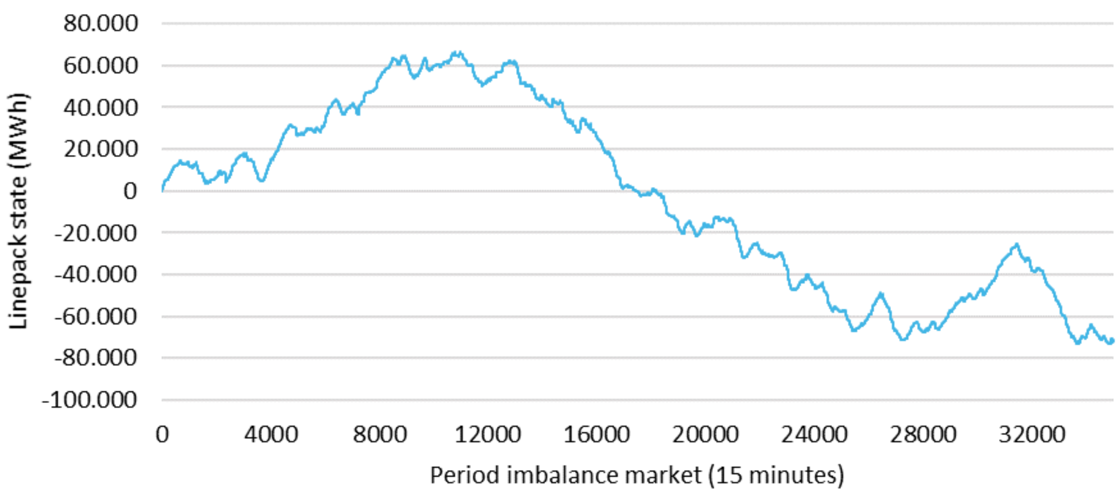


Figure 42 - State of the linepack for an unlimited linepack capacity MWh and with the imbalance volume same as in 2019.

Results scenario's: financial impact

Table 19 shows financial parameters from the imbalance model for the four cases in which we alter the linepack capacity and imbalance volume. It shows the total revenue, which is calculated by multiplying the imbalance volume cleared by the electrolyser and the imbalance prices of these periods and summing this for all periods. This revenue is compared with the revenue which the electrolyser has on the hydrogen spot market.

We find that both linepack capacity and imbalance volume have a positive influence on the revenue which the electrolyser can obtain on the electricity imbalance market. However, doubling the imbalance volume does not cause a doubling in revenue. This is caused by the linepack capacity constraint: the electrolyser is not able to utilize all the imbalance volume when the linepack is either full or depleted.

The revenue on the imbalance market w.r.t. the hydrogen spot market ranges from 0.5% to 1.3%. It is important to repeat the assumption that the electrolysers are able to clear all the volume on the electricity imbalance market. In practice there will be competition with other assets, such as E-storage.

Table 16 - Financial parameters from the imbalance model.

Scenario	Linepack capacity for electrolysers	Imbalance volume in 2030 w.r.t 2019	Total revenue	Revenue on E-imbalance market w.r.t H2 spot market
I	1400 MWh	Same	4.7 M€	0.5%
II	1400 MWh	Double	7.8 M€	0.8%
III	7000 MWh	Same	7.0 M€	0.7%
IV	7000 MWh	Double	13.0 M€	1.3%

Bibliography

B. den Ouden. (2020). *A Hydrogen Exchange for the Climate.* Utrecht: B. den Ouden.

Berenschot & Kalavasta. (2020). *Klimaatneutrale energiescenario's 2050.* Utrecht: Berenschot.

Berenschot & TNO. (2017). *CO2-vrije waterstofproductie uit gas.* Utrecht: Berenschot & TNO. Opgehaald van https://projecten.topsectorenergie.nl/storage/app/uploads/public/5be/057/6e7/5be0576e7f09a133717726.pdf

Carlo Arnaiz del Pozo, S. C. (2022). Techno-economic assessment of blue and green ammonia as energy carriers in a low-carbon future. *Energy Conversion and Management, 255*. doi:https://doi.org/10.1016/j.enconman.2022.115312

CE Delft. (2018). *Waterstofroutes Nederland - blauw, groen en import.*

CE Delft. (2018). *Waterstofroutes Nederland - Blauw, groen en import.* Delft: CE Delft. Opgehaald van https://ce.nl/wp-content/uploads/2021/03/CE_Delft_3K37_Waterstofroutes_Nederland_def.pdf

Fernleitungsnetzbetreiber [FNB] Gas. (2022). *(Interim) Network Development Plan 2022.* Berlin: FNB Gas. Opgehaald van https://fnb-gas.de/wp-content/uploads/2022/07/2022_07_06_NEP-Gas-2022-2032-Zwischenstand.pdf

Fraunhofer-Institut für Produktionstechnologie und Automatisierung [Fraunhofer IPA]. (2018). *Industrialisierung der Wasserelektrolyse in Deutschland: Chancen und Herausforderungen für nachhaltigen Wasserstoff für Verkehr, Strom und Wärme.* Stuttgart: Fraunhofer IPA. Opgehaald van https://www.ipa.fraunhofer.de/content/dam/ipa/de/documents/Publikationen/Studien/Studie-IndWEDe.pdf

Gasunie & TenneT. (2019). *Infrastructure Outlook 2050.* Groningen: Gasunie.

H2 Gateway. (2020). *Poort naar een CO2-vrije waterstofeconomie.* Opgehaald van https://portofdenhelder.nl/files/documents/Poort%20naar%20een%20CO2-vrije%20waterstofeconomie%20-%20H2%20Gateway.pdf

H-Vision. (2019). *Blue hydrogen as accelerator and pioneer for energy transition in the industry.* Rotterdam: H-Vision. Opgehaald van https://www.deltalinqs.nl/stream/h-vision-bijlagen-bij-het-eindrapport

HyStock. (2023, April). *About Hystock - the Project*. Opgehaald van Hystock.nl: https://www.hystock.nl/en/about-hystock/the-project

IEA. (2019). *The Future of Hydrogen - Assumptions Annex.* Opgehaald van https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf

International Energy Agency Greenhouse Gas R&D Programme [IEAGHG]. (2017). *Techno-economic evaluation of SMR based standalone (merchant) hydrogen plant with CCS.* Cheltenham: IEAGHG. Opgehaald van https://ieaghg.org/exco_docs/2017-02.pdf

Matheus de Groot, J. K. (2022). Optimal operating parameters for advanced alkaline water electrolysis. *International Journal of Hydrogen Energy*, 34773-34783. doi:https://doi.org/10.1016/j.ijhydene.2022.08.075

NEA. (2023). *Tarieven CO2-heffing*. Opgehaald van Nederlandse Emissieautoriteit: https://www.emissieautoriteit.nl/onderwerpen/tarieven-co2-heffing

Port of Rotterdam. (2022). Grootschalige ammoniakkraker moet 1 mln ton waterstofimport mogelijk maken via Rotterdamse haven. Opgehaald van https://www.portofrotterdam.com/nl/nieuws-en-persberichten/grootschalige-ammoniakkraker-moet-1-miljoen-ton-waterstofimport-mogelijk

PwC/Strategy&. (2021). *HyWay 27: waterstoftransport via het bestaande gasnetwerk?* Amsterdam: PwC.

Roland Berger. (2021). *Haalbaarheidsstudie klimaatneutrale paden TSN IJmuiden.* Amsterdam: Roland Berger. Opgehaald van https://www.fnv.nl/getmedia/91110cd9-b455-4025-96e6-5387dbb8f98d/Eindrapport-klimaatneutrale-paden-Tata-Steel-Nederland-211118.pdf

TenneT. (2019). *Data systeem & transport*. Opgehaald van Exporteer data: https://www.tennet.org/bedrijfsvoering/ExporteerData.aspx

TenneT, G. (2019). *Infrastructure Outlook 2050.*

TKI nieuw gas 2018. (2018). *Contouren van een Routekaart Waterstof.* Amersfoort: TKI nieuw gas 2018. Opgehaald van https://topsectorenergie.nl/documents/67/TKI_Nieuw_Gas-20180307_Routekaart_Waterstof_TKI_Nieuw_Gas_maart_2018_-_180301.pdf

TKI nieuw gas. (2018). *Contouren van een routekaart waterstof.* Amersfoort: TKI nieuw gas.

TNO. (2021). Integrated electricity, hydrogen and methane system modelling framework: Application to the Dutch Infrastructure Outlook 2050. *Applied Energy, Volume 289*, 1-19. Retrieved from https://publications.tno.nl/publication/34638376/g1Wevs/koirala-2021-integrated.pdf

A.I: SENSITIVITY ANALYSIS DISPATCH MODEL

Introduction

The I-ELGAS model is a is a full dispatch model that takes renewability conditions for hydrogen production only indirectly into account. As is it a spot market optimalization model, hydrogen is assumed to be produced when the electricity price is at its lowest, something to occur in 2030 during hours of high shares of renewable production. The model however does not have renewable electricity as a fixed criteria (the model does not allow for this functionality). From sustainability perspective as well as in reality because of the EU criteria for green hydrogen, it is expected and desirable that electrolysers operate only if the produced hydrogen is fully renewable. Therefore a sensitivity analysis to test the hourly correlation between renewable electricity production and electrolyser dispatch is conducted. This sensitivity analysis aims to validate to what extent the electrolyser dispatch hours in the 2030 simulation are in line with the hourly correlation requirement of the Delegated Act on conditions of renewable hydrogen production.

This hypothesis is validated using the following research questions:

a) How do low electricity prices, and therefore electrolyser activity, correlate with renewable electricity production?
b) How many renewable hours are excluded by the electrolyser dispatch and how can these so-called 'missed opportunities' be explained?
c) How much non-renewable hydrogen production occurs and how can it be explained?

Correlation between renewable energy production and electricity price

To evaluate this correlation, the production of wind and solar power is compared to the electricity demand for all hours. The electricity demand assumed in this evaluation is the basic national electricity demand, excluding the electricity demand for electrolysers, charging battery storages and import/export. Figure 43 shows how often a certain share of renewables occurs and what the average electricity price is during these times. We find that in 49% of all hours the renewables production exceeds the basic national electricity demand, as expected the electricity price is the lowest during these hours.

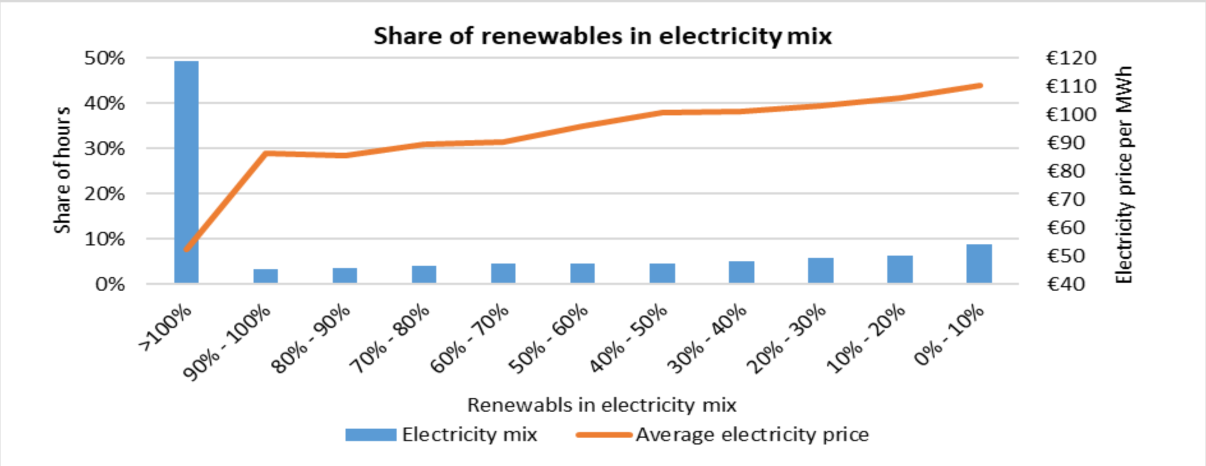


Figure 43 - Share of renewables in electricity mix

For each hours in which the electrolysers have electricity demand, the production of wind and solar power was compared to the total electricity demand (including the demand for electrolysers). Figure 44 shows what the share of renewables in the mix is during electrolyser activity.

Figure 44 shows that that all of the eight scenario's for the 2030 system perform similar and that during most of the hours with electrolyser activity (+- 72%)there is a surplus of wind and solar power. Only the market based dispatch scenario's produce a 'better' result, achieving between 78% and 81% of renewable electricity production shares. This results fits our hypothesis that the market-based scenario's perform better as the absence of an FLH constraint causes the electrolysers to run less hours, and these additional hours will be less optimal (more expensive and have a lower share of renewability).

Comparing Figure 44 to Figure 43 shows further that the hours with electrolyser activity are more renewable than randomly picked hours; the hypothesis behind I-ELGAS that hydrogen production takes place during hours of low electricity price and that this coincides with a high share of renewable electricity productions holds true.

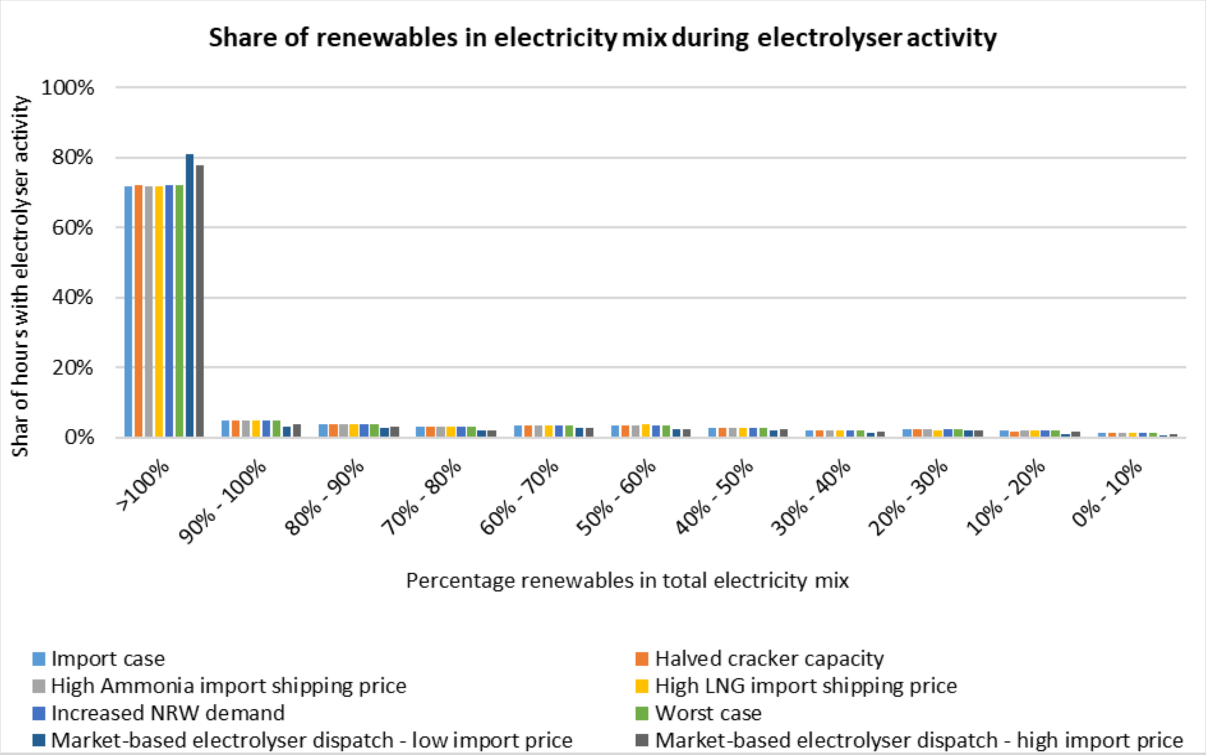


Figure 44 - Percentage of renewables in electricity mix during electrolyser activity

Missed opportunities for electrolysis with renewable energy

There are also hours with a surplus of wind and solar power that have no electrolyser activity, these hours will be called 'missed opportunities'. We find that 15% of all hours with a surplus of renewables is a missed opportunity hour in the first 6 scenarios. For the market based electrolyser dispatches this is about 38% with a low ammonia import price and 31% with a high ammonia import price.

The exclusion of these renewable hours in the electrolyser dispatches is counterintuitive as it would be expected that electricity prices are low when there is an electricity surplus, making it profitable to dispatch electrolysers. However, the electricity prices during these hours are in fact not low. Figure 45 shows how many hours electrolysers run on a certain electricity price and what the electricity prices are during missed opportunities. There are three price ranges that are of interest in this figure:

- €0 - €93
  - Most electrolyser activity (82%) occurs in this price range
  - No missed opportunities occur in this price range
- €93 - €95
  - Some electrolyser activity (18%) occurs in this price range
  - Part of the missed opportunities (4%) occur in this price range
- > €95
  - 0% of electrolyser activity occurs in this price range.
  - Most of the missed opportunities (96%) occur in this price range

To conclude, these missed opportunities are excluded because the prices are high. Prices above €95 will always be excluded while prices between €93 and €95 will sometimes be excluded, depending on other factors varying per day or hour.

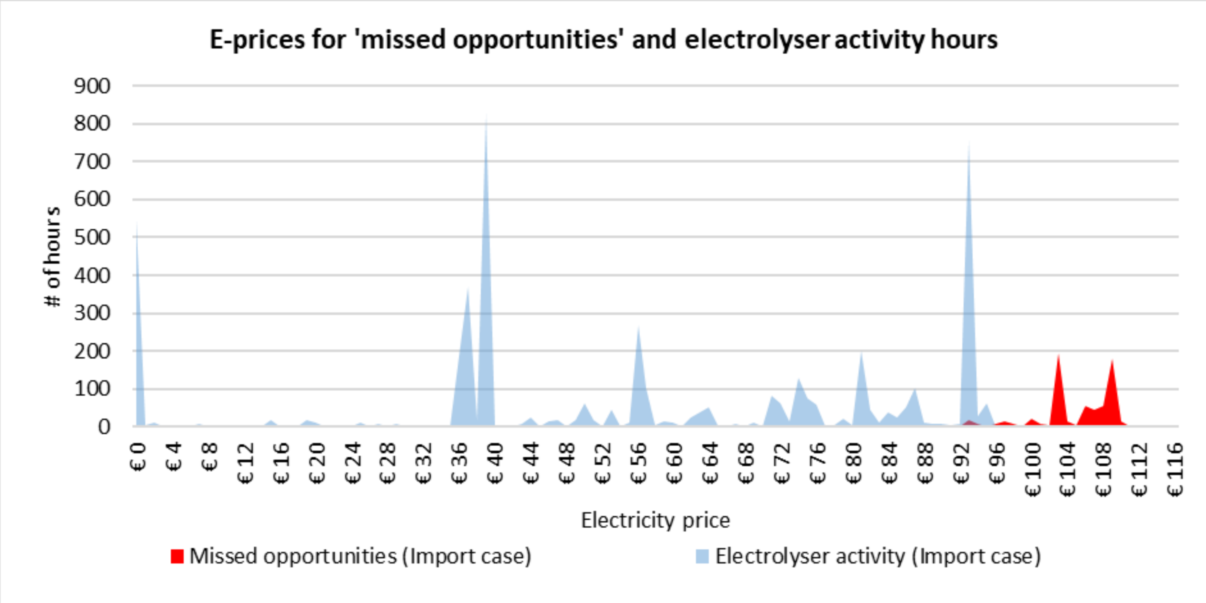


Figure 45 - E-prices for 'missed opportunities' and electrolyser activity hours

These 'missed opportunities' are hours in which renewable hydrogen could have been produced due to the abundance of renewable electricity in the Netherlands. However, the fact that renewable production exceeds national demand does not mean that electricity is curtailed. Mostly there is a net export of electricity during these hours. In fact there are even natural gas power plants active during a lot of the missed opportunity hours to accommodate the large foreign demand. This explains the high prices during these hours and why they should not be counted as actually missed opportunities. In reality, some hydrogen production might occur in these hours, depending on the PPAs that are in place.

Non-renewable electrolyser use

There are also hours with electrolyser activity even though there is no surplus of renewable electricity generation. Most of this production however still occurs during hours with a large share of renewables. In fact, none of the electrolyser activity coincides with power production from natural gas. It does, however, coincide with nuclear power, bio power plants, waste energy, green gas power, discharging battery storages and (net) imports.

Mostly, the electrolyser activity correlates with a large share of solar and wind generation. For all cases (except the market based dispatches) only 17% of hydrogen production by electrolysis occurs when the national wind and solar power can meet less than 70% of the national demand. It does mean that during these hours the dispatch of electrolysers could work against achieving the climate agreement goal of 70% renewables in the electricity mix by 2030. Still, the production is in practise likely fully renewable through Power Purchase Agreements (PPAs). We viewed the I-ELGAS results and found that a substantial portion of electrolyser dispatches in the I-ELGAS model align with conditions for renewable hydrogen (upside of 90%-98%[10]), because:

- Hydrogen production through electrolysis is anticipated to predominantly involve (PPAs) with offshore wind farms. Depending on the agreed upon terms, renewable hydrogen can be generated whenever there is sufficient offshore wind availability. However we find that, depending on the scenario, in 8% to 15% of operational hours the electrolyser demand exceeds offshore wind supply and hence electricity is from other sources (such as solar).

[10] We note that hydrogen production that is not considered to be green/renewable would realistically not occur due to the lower value of non-renewable hydrogen.

- During 4% to 7% of hydrogen production, offshore wind generation falls short, but grid electricity is priced below €48.96 (0.36 times the ETS price of €136), this means that produced hydrogen is labelled fully renewable according to current Commission guidelines.
- In 2% to 10% of hydrogen production hours, offshore wind is inadequate, and no price exception applies. Hydrogen producers could potentially have reached agreements with additional installations, such as onshore wind or solar parks, meaning that some of this production can still be renewable.
- In 1% to 3% of all hydrogen production hours, the combined wind and solar power is insufficient to meet electrolyser demand, rendering the electricity used and hydrogen produced non-renewable under the Delegated Act conditions. With the only exceptions being the yearly share of renewables in the bidding zone exceeding 90% or the average emission factor of the bidding zone being below 18 g CO_2 / MJ.

While specific compliance cannot be tested due to a lack of insight in contracts between renewable electricity and electrolysers, this analysis suggests that a significant portion of electrolysis in the model aligns with the terms for green hydrogen in the Delegated Act.

Conclusion and discussion

Even though renewability is not a condition of the model the electrolyser dispatches are mostly renewable due to the correlation between electricity prices and renewable generation. Especially the market based dispatches without FLH constraints perform well as they exclude the less favourable hours.

This sensitivity analysis showed that the I-ELGAS resulting dispatches are renewable by the fact that there is a surplus of wind and solar power compared to the national demand during most of the electrolyser activity. This does not mean however, that this electricity would otherwise be curtailed as it might also be used for charging battery storages or export.

This analysis also showed that a small share of the dispatches does not meet the renewable criteria as set out in the Delegated Act and therefore will in practise likely not occur. During these hours the main energy source for the Netherlands is import. Even if the imported energy would be renewable it would not meet the geographical correlation condition making it undesirable to produce hydrogen in these hours as it lacks the green ‘mark-up’.

A.II: EYE VARIANTS

There are four strategy sets:

1. Demand & SMR/Import;
2. Demand & SMR/Import & Electrolyser;
3. Demand & Electrolyser & Hydrogen storage;
4. Market

Each strategy requires input, namely: strategy for each asset; total volume and price; for each market; and allow for multiple bids. The assets can be distributed over these strategy sets to research the influence of these strategies on the market dynamics. There are two merit orders: one with all assets in the strategy set 2027-D and one with demand and SMR in strategy set 2027-A.

In the first case electrolysers and SMR can fulfil the demand and the clearing price is equal to the bidding price of the SMRs. When demand and SMR are taken off the market, both the SMR capacity and demand on the market decrease, however not necessarily with the same amount. As the SMR is scaled to the maximum demand, more SMR capacity is taken off the market than demand. Consequently, in this situation, import is needed to fulfil the remaining demand on the hydrogen market, resulting in a higher clearing price.

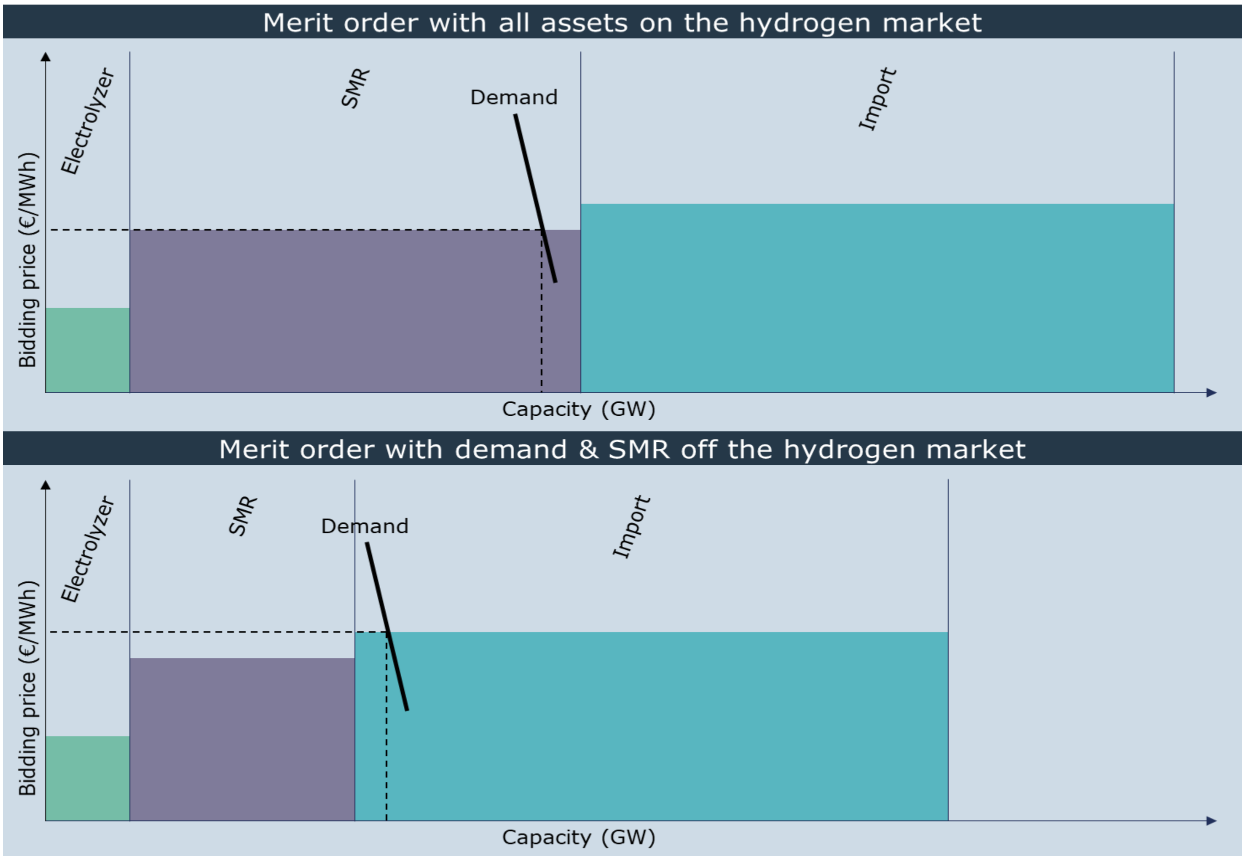


Figure 46 - Merit order for two situations: upper merit order with all assets on the hydrogen market and lower merit order with demand and SMR off the hydrogen market. As the demand and SMR are off the market, import is needed to fulfil the remaining demand on the market, resulting in a higher clearing price.

1. Demand & SMR/Import

There are two assets present in this strategy set: a hydrogen demand and either SMR or import. We have only modelled the demand and SMR combination. In this strategy we create a local market with only the demand and SMR.

The demand has an hourly demand profile which is yearly normalized: the sum over all hours over the year equals 1. This profile is multiplied by the yearly hydrogen demand, e.g. 8 TWh, to obtain the hydrogen demand for each hour. The demand bids this volume for the maximum price, as it is a static demand. The SMR bids its capacity as a volume, e.g. 1 GW of hydrogen production (for an hour, so 1 GWh of hydrogen production for a certain hour) and with the production cost as price. The production costs consists of the fuel costs and CO2 costs:

- SMR production costs = Fuel costs + CO2 costs;
- Fuel costs = natural gas costs / SMR efficiency;
- CO2 costs = CO2 price * CO2 emission natural gas / SMR efficiency.

In the case of a two-sided SMR, it can also bid on the hydrogen market to generate additional revenue. On this market it will bid again its production cost (marginal cost). The volume is equal to the remaining capacity after supplying the hourly hydrogen demand.

These strategies are summarized in Table 20.

Table 17 - Strategies for the Demand & SMR strategy set.

<table>
<tr><th colspan="2">Asset</th><th>Market</th><th>Volume</th><th>Price</th></tr>
<tr><td colspan="2">Demand</td><td>Demand & SMR</td><td>Hourly demand</td><td>Maximum (static)</td></tr>
<tr><td rowspan="3">SMR</td><td rowspan="2">Two-sided</td><td>Demand & SMR</td><td>Capacity</td><td>SMR production costs</td></tr>
<tr><td>Hydrogen market</td><td>Remaining capacity</td><td>SMR production costs</td></tr>
<tr><td>One-sided</td><td>Demand & SMR</td><td>Capacity</td><td>SMR production costs</td></tr>
</table>

2. Demand & SMR/Import & Electrolyser

There are three assets present in this strategy set: a hydrogen demand, either SMR or import, and an electrolyser. We have only modelled the demand, SMR and electrolyser combination. We create a local market with the demand, SMR and electrolyser.

The demand and SMR operate as in the Demand & SMR strategy set. The electrolyser receives electricity from a PPA with offshore wind and the electricity market when the prices are low. It bids the produced hydrogen for an artificial price of zero. On the electricity market it bids using the SMR as a reference price. When it can produce hydrogen cheaper than the SMR can, then it will demand electricity on the electricity market.

What will happen is that based on the wind volumes and electricity prices the electrolyser will produce a certain amount of hydrogen, which suffices a certain part of the hydrogen demand. SMR will supply the remaining hydrogen demand and bid its remaining capacity on the hydrogen market for additional revenue.

Table 18 - Strategies for the Demand & SMR & Electrolyser strategy set.

<table>
<tr><th colspan="2">Asset</th><th>Market</th><th>Volume</th><th>Price</th></tr>
<tr><td colspan="2">Demand</td><td>Demand & SMR & Electrolyser</td><td>Hourly demand</td><td>Maximum (static)</td></tr>
<tr><td rowspan="3">SMR</td><td rowspan="2">Two-sided</td><td>Demand & SMR & Electrolyser</td><td>Capacity</td><td>SMR production costs</td></tr>
<tr><td>Hydrogen market</td><td>Remaining capacity</td><td>SMR production costs</td></tr>
<tr><td>One-sided</td><td>Demand & SMR</td><td>Capacity</td><td>SMR production costs</td></tr>
<tr><td colspan="2" rowspan="3">Electrolyser</td><td>PPA offshore wind</td><td>Capacity</td><td>Artificial price >0</td></tr>
<tr><td>Electricity market</td><td>Remaining capacity</td><td>SMR price * Electrolyser efficiency</td></tr>
<tr><td>Demand & SMR & Electrolyser</td><td>Cleared volume * Electrolyser efficiency</td><td>Artificial price 0</td></tr>
</table>

3. Demand & Electrolyser & Hydrogen storage

In the Demand & SMR & Electrolyser strategy set, an SMR is used to provide the flexibility to match the production profile of an electrolyser and demand profile. In this strategy set hydrogen storage is used to provide this flexibility.

We assume that this is only done with a flexible demand asset, as it can also be possible that there is no hydrogen supply, due to a lack of renewable energy. If this were to be done with a static demand, then the electrolyser will have to perform must-run bids on the electricity market. This is also possible, but is not how it has been modelled. The demand again uses a profile for an hourly demand. The price is equal to the SMR price. The electrolyser operates in the same manner as in the Demand & SMR & Electrolyser strategy. Hydrogen storage is used to balance the hydrogen demand and supply. To accomplish this it places a demand bid for a price slightly lower than the demand price and a supply bid for a price slightly higher than the electrolyser price. Consequently, it will demand hydrogen when there is an abundance of hydrogen production from the electrolyser, and supply hydrogen when there is a shortage. The volumes are determined by the (dis)charge rate and the fill level. From the demand side it is how much hydrogen can still be added to the storage and from the supply side it is how much hydrogen is present in the storage.

Table 19 - Strategies for the Demand & Electrolyser & Hydrogen storage strategy set.

Asset		Market	Volume	Price
Demand		Demand & Electrolyser & Hydrogen storage	Hourly demand	SMR production costs
Electrolyser		PPA offshore wind	Capacity	Artificial price >0
		Electricity market	Remaining capacity	SMR price * Electrolyser efficiency
		Demand & Electrolyser & Hydrogen storage	Cleared volume * Electrolyser efficiency	Artificial price 0
Hydrogen storage	Demand	Demand & Electrolyser & Hydrogen storage	Minimum of charge rate and remaining capacity	Price slightly lower than demand price
	Supply	Demand & Electrolyser & Hydrogen storage	Minimum of discharge rate and fill level	Price slightly higher than electrolyser price

4. Market

In this strategy set each asset bids on the hydrogen market. Demand can have both a static part which must be satisfied at any cost and a flexible part which will only be cleared at lower prices, e.g. SMR production costs.

Asset		Market	Volume	Price
Demand		Demand & Electrolyser & Hydrogen storage	Hourly demand	SMR production costs
Electrolyser		PPA offshore wind	Capacity	Artificial price >0
		Electricity market	Remaining capacity	SMR price * Electrolyser efficiency
		Demand & Electrolyser & Hydrogen storage	Cleared volume * Electrolyser efficiency	Artificial price 0
Hydrogen storage	Demand	Demand & Electrolyser & Hydrogen storage	Minimum of charge rate and remaining capacity	Price slightly lower than demand price
	Supply	Demand & Electrolyser & Hydrogen storage	Minimum of discharge rate and fill level	Price slightly higher than electrolyser price

In these strategies the electrolyser has a PPA with offshore wind. A choice is made for the ratio of offshore wind and electrolyser capacity. By increasing the offshore wind capacity w.r.t. the electrolyser capacity, the full load hours of the electrolyser increase. This is illustrated Figure 47, presenting load duration curves (LDCs) of an electrolyser with a PPA with offshore wind.

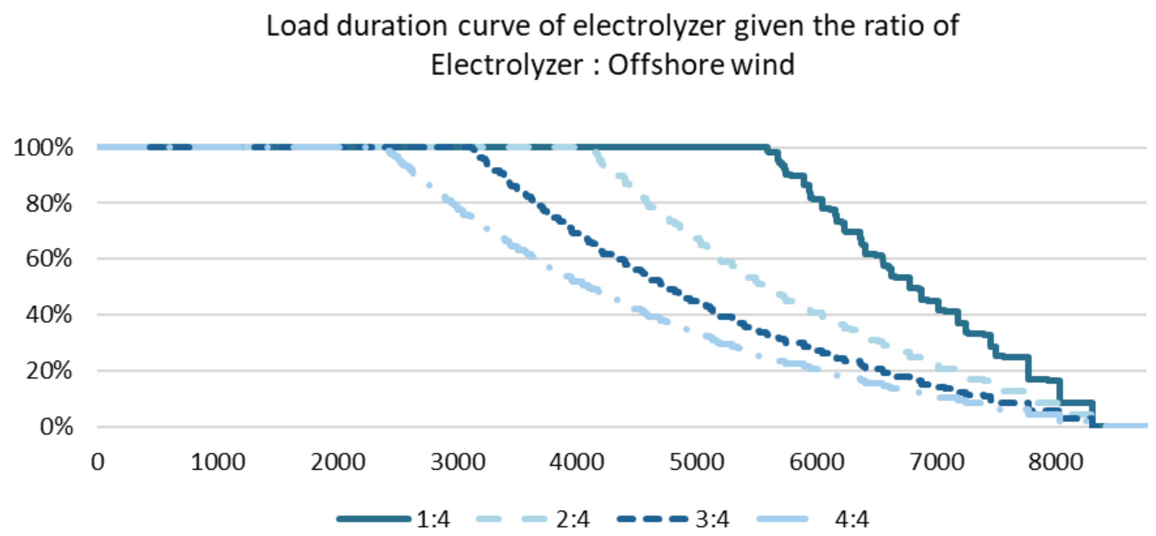


Figure 47 - Load duration curves of an electrolyser with a PPA with offshore wind for several ratios of electrolyser capacity : offshore wind capacity. In the simulations we use a ratio of 1:2, so an electrolyser with capacity 1 GW will have a PPA with an offshore wind park with a capacity of 2 GW. The ratio of electrolyser and offshore wind capacities is shifted from curve to curve as indicated in the legend. An electrolyser of 1 GW and offshore wind of 4 GW has a ratio of 1:4. For a ratio of 4:4 the LDC of the electrolyser is equal to the LDC of offshore wind. For higher ratios the LDC of the electrolyser lies above the LDC of offshore wind.

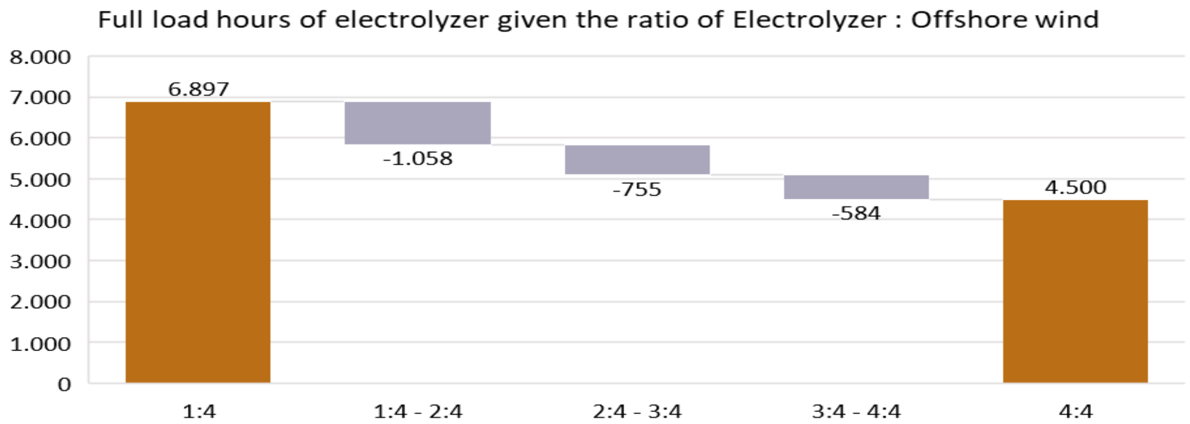


Figure 48 - Full load hours of an electrolyser with a PPA with offshore wind for several ratios of electrolyser capacity : offshore wind capacity. Figure 48 shows the full load hours (FLHs) for the same ratios as in Figure 47. The highest FLH – 6.897 – is for a ratio of 1:4 and it decreases to exactly 4.500 for a ratio of 4:4. For the ratios in between the decreases in FLHs is shown. The highest decreases occur at the beginning, going from 1:4 to 2:4.

A.III: ROLES AND INPUT FROM (MARKET) PARTICIPANTS

Market parties and infrastructure providers were actively involved in the spot market simulation project. This is organized at different levels, which are explained below. Additionally, there were many bilateral consultations if such coordination was desired or necessary.

Steering Committee

The HyXchange steering committee meets every 1.5 months to discuss the progress and next steps of HyXchange Initiative projects, among which the H2SMS project. Her members are representatives of the H2SMS project partners. The members are therefore well-informed about the choices and progress of this study and assist where possible through their networks.

Simulation Committee

The Simulation Committee, consisting of 8 market parties, is consulted on a regular basis. The Simulation committee provides the researchers working on H2SMS with feedback on draft findings and key inputs. The participants in this committee have a different background, and together compass key areas of the hydrogen value-chain. Throughout the entirety of the study, this group was involved at regular intervals.

Regional workshops (3)

In the first months of the study market parties were consulted per region about the intended developments regarding hydrogen demand, supply, and network in their respective regions. In these workshops, they were invited to actively participate in the design of the simulation by taking part in the Simulation Committee. There were a total of 3 regional workshops in Zeeland, Rotterdam and Groningen (North), ranging from 10 to 20 participants.

Live simulation sessions (2)

In total two game simulation sessions were held, where TNO presented its EYE-model framework and explained and showed how a range of producer and consumer strategies would impact the hydrogen system, the spot price and the balance of the backbone. In total 25 participants joined these meetings to discuss (draft) findings and increase researchers and participants understanding of the future hydrogen market.

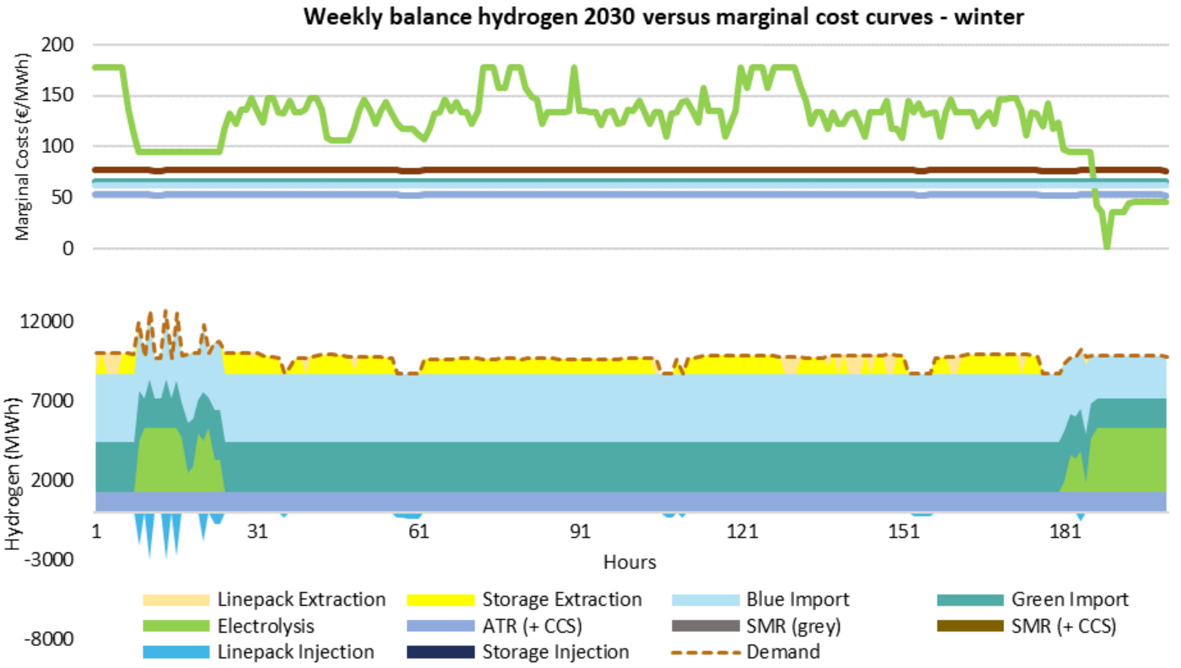
General meetings HyXchange initiative and conferences

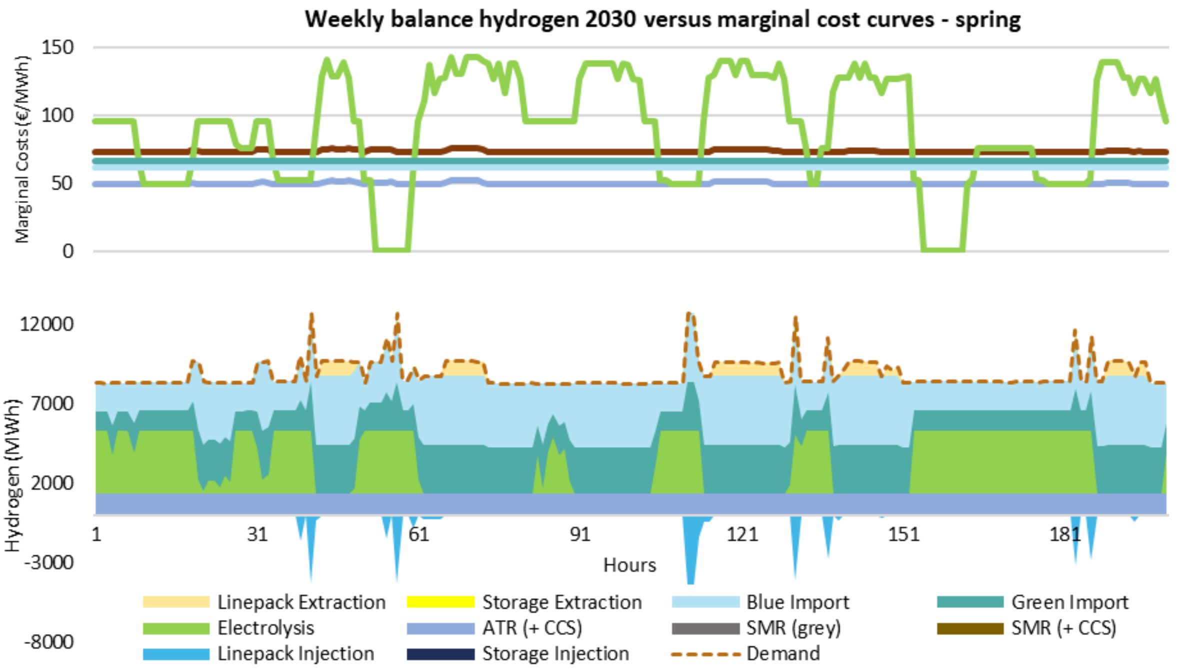
Finally, the spot market simulation project is also discussed at the quarterly general meetings organized by the HyXchange initiative, which is overarching for various projects such as the spot market simulation project, but also the certificate project. Individuals from among the approximately 100 stakeholders (market parties) are invited to these (digital) sessions. These sessions are generally well-attended by 40-70+ participants.

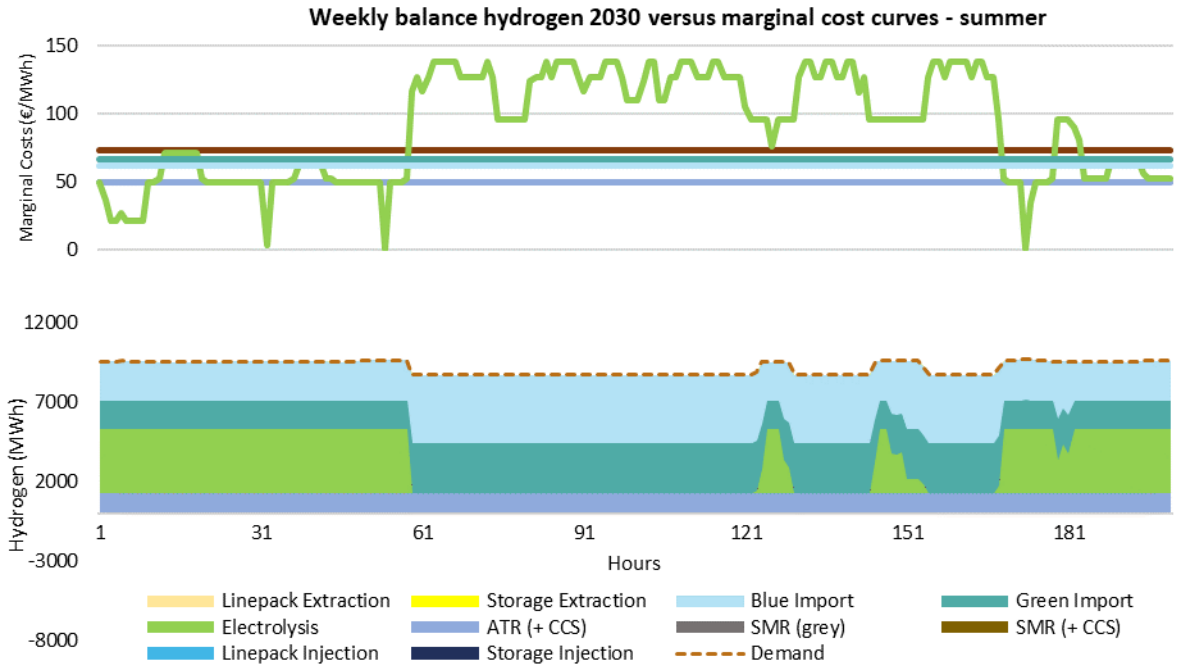
A.IV: WEEKLY BALANCES DISPATCH

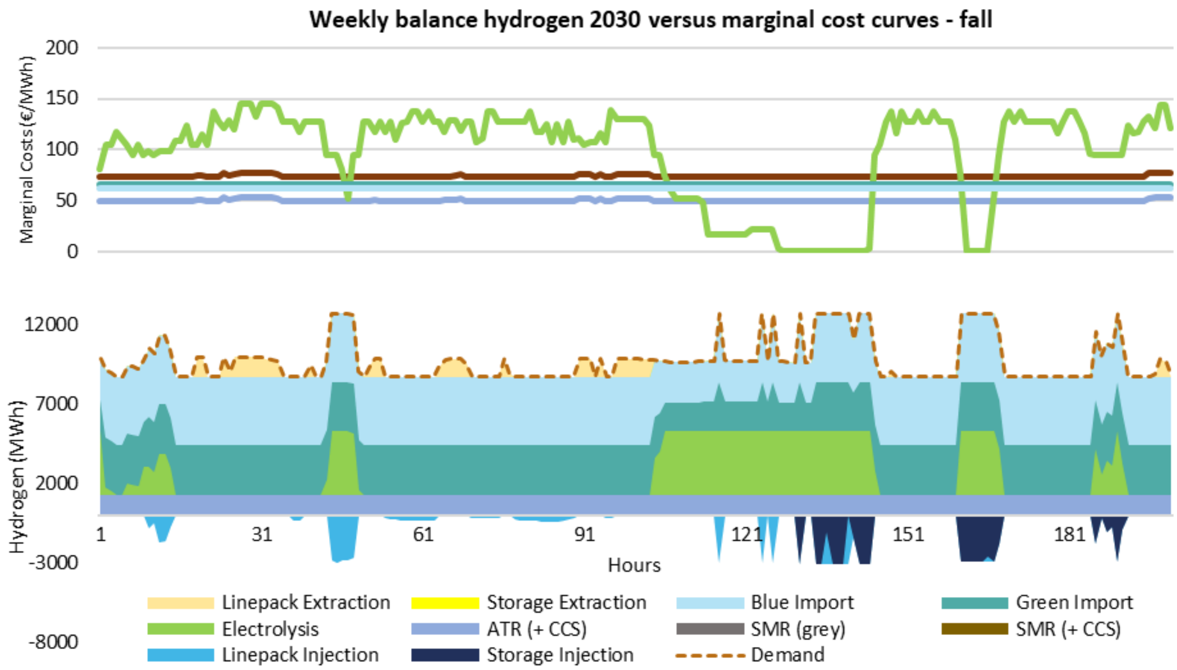
1. Import Case 2030

In addition to the weekly balances shown for a week in autumn, for the 2030 simulations, weekly balances are shown here for all seasons (starting on hours 1.000, 3.000, 5.000 and 7.000 of the year) of the import case results.



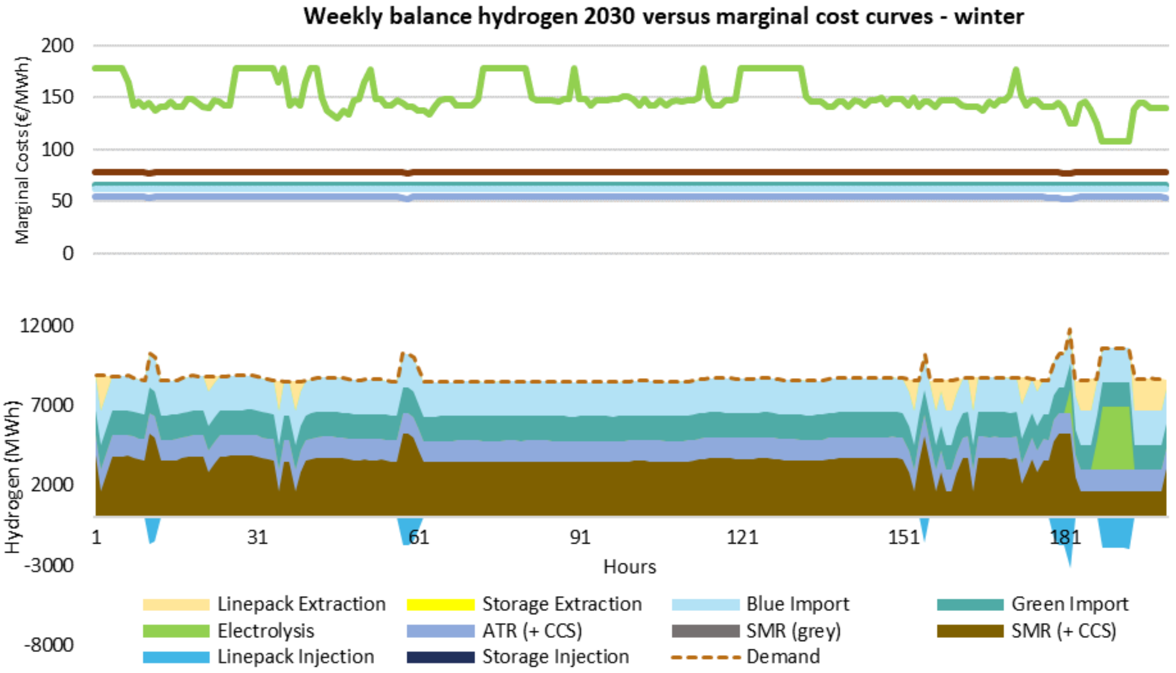


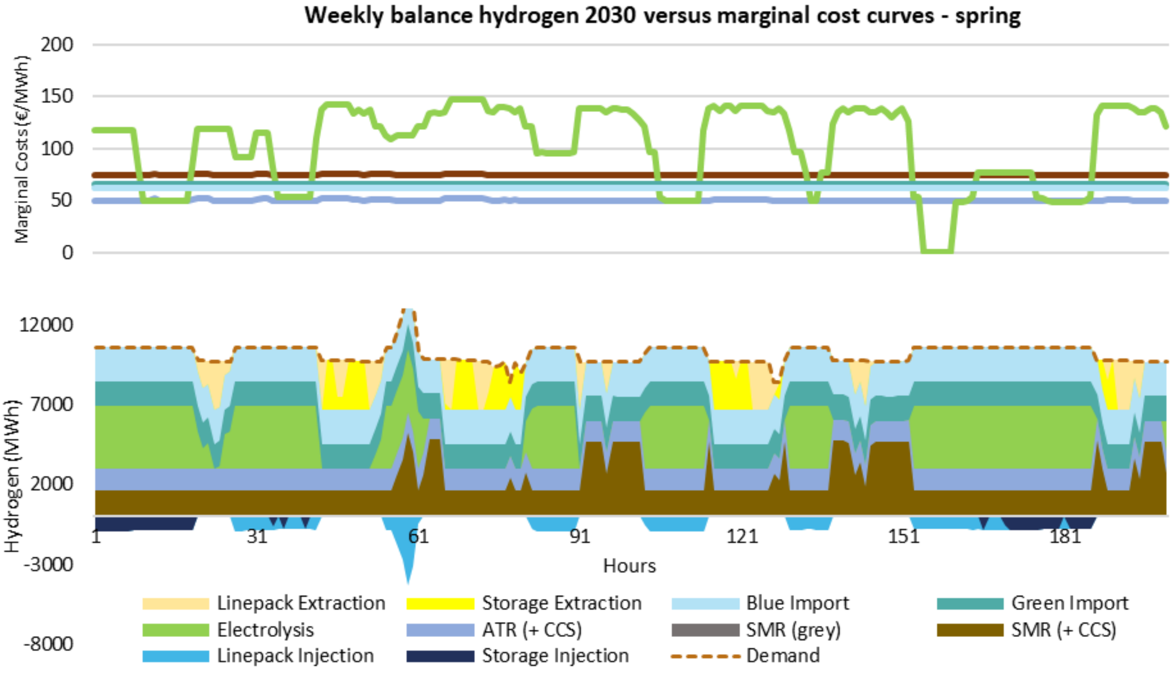

Weekly balance hydrogen 2030 versus marginal cost curves - summer
Marginal Costs (€/MWh)
150
100
50
0
Hydrogen (MWh)
12000
7000
2000
-3000
-8000
1
31
61
91
121
151
181
Hours
Linepack Extraction
Storage Extraction
Blue Import
Green Import
Electrolysis
ATR (+ CCS)
SMR (grey)
SMR (+ CCS)
Linepack Injection
Storage Injection
Demand

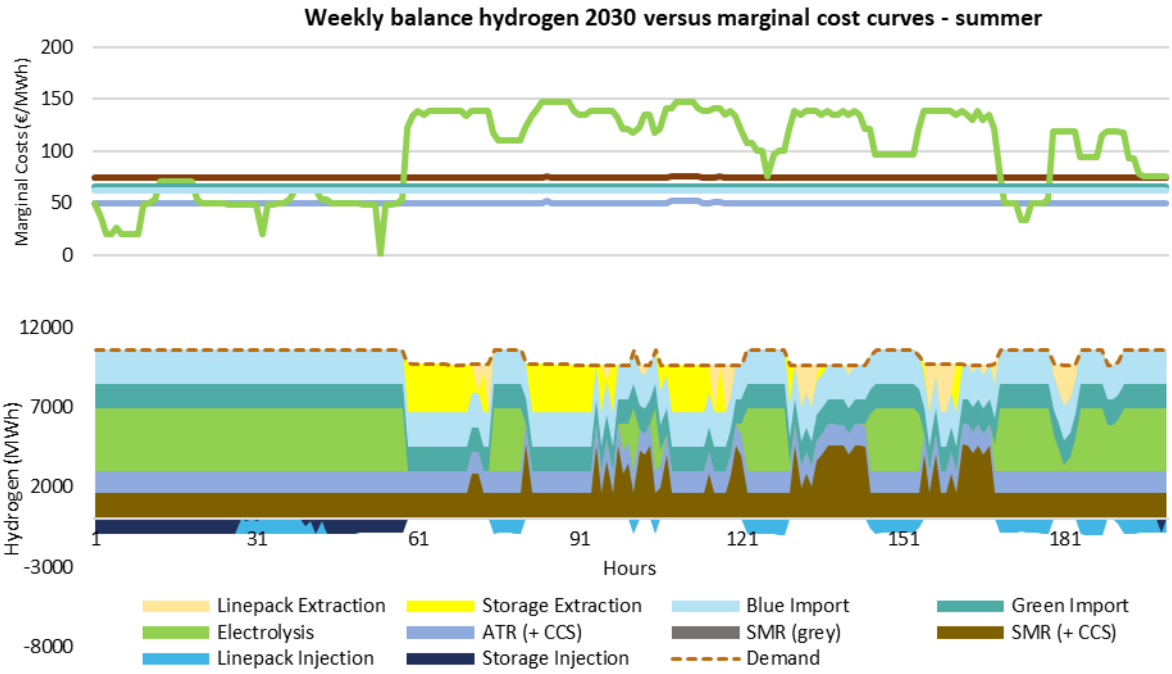

Weekly balance hydrogen 2030 versus marginal cost curves - fall
Marginal Costs (€/MWh)
200
150
100
50
0
Hydrogen (MWh)
12000
7000
2000
-3000
-8000
1
31
61
91
121
151
181
Hours
Linepack Extraction
Storage Extraction
Blue Import
Green Import
Electrolysis
ATR (+ CCS)
SMR (grey)
SMR (+ CCS)
Linepack Injection
Storage Injection
Demand

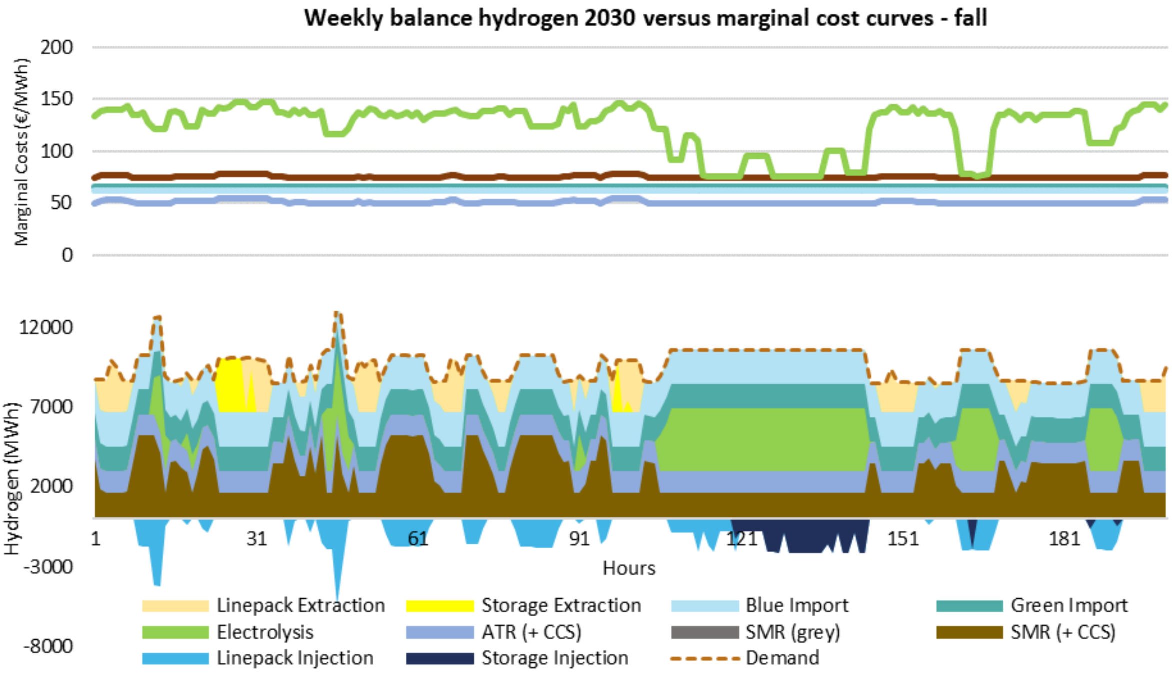
2. Worst case 2030

Finally, weekly balances are shown for four seasons of the Worst case simulation results of 2030.






Weekly balance hydrogen 2030 versus marginal cost curves - summer
Marginal Costs (€/MWh)
200
150
100
50
0
Hydrogen (MWh)
12000
7000
2000
-3000
-8000
1
31
61
91
121
151
181
Hours
Linepack Extraction
Storage Extraction
Blue Import
Green Import
Electrolysis
ATR (+ CCS)
SMR (grey)
SMR (+ CCS)
Linepack Injection
Storage Injection
Demand


Weekly balance hydrogen 2030 versus marginal cost curves - fall
Marginal Costs (€/MWh)
200
150
100
50
0
Hydrogen (MWh)
12000
7000
2000
-3000
-8000
1
31
61
91
121
151
181
Hours
Linepack Extraction
Storage Extraction
Blue Import
Green Import
Electrolysis
ATR (+ CCS)
SMR (grey)
SMR (+ CCS)
Linepack Injection
Storage Injection
Demand

ABOUT THE HYXCHANGE INITATIVE: HYXCHANGE AIMS TO REALIZE A TRADING PLATFORM FOR HYDROGEN ON THE MAIN DUTCH HYDROGEN INFRASTRUCTURE.

Introduction: Hydrogen is increasingly attracting interest as an important part of the energy transition. Due to the position that hydrogen will occupy in the future and the many ways in which it can be produced and used, with a variety of producers and users, the development of the trade in hydrogen will become important. As a result, parties from the sector have started the "HyXchange" initiative. HyXchange is supported by Gasunie, Port of Rotterdam, Port of Amsterdam, Groningen Seaports, North Sea Ports and a large, growing number of interested market parties.

Key objectives: For the functioning of a hydrogen exchange it is important that the underlying conditions for market forces in hydrogen are met. Firstly, an openly accessible transport infrastructure for hydrogen is important condition; this will be facilitated with the establishment of the backbone that allows storage and independent management. Secondly a diverse supply of hydrogen is important, in which, in addition to the electrolysis of Dutch sustainable electricity, other sources also play a role, in particular the import of (green) hydrogen from other countries and continents, and low-carbon hydrogen from industrial processes. This also contributes to the security of supply. Thirdly, a dependable and transparent trading platform greatly enhances market access, pools liquidity and reduces transaction costs and trading risks.