HY3+

Enabling and balancing the hydrogen infrastructure in North Western Europe

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Enabling and balancing the hydrogen infrastructure in North Western Europe

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This report constitutes the results of the Hy3+ project. The project sponsors in the consortium support the general thrust of the arguments made, but should not be taken as agreeing with every finding or recommendation. Project Sponsors have not been asked to formally endorse the report.

Summary

North-West Europe, and in particular the Netherlands, Belgium and Germany, hosts large, energy intensive industrial clusters that contain steel factories, refineries, ammonia plants, steam crackers, chemical industrial plants, and others. These energy-intensive sectors are hard to abate, typically molecule based and all have hydrogen prominently on their decarbonization roadmaps. The region also contains a complete potential hydrogen value chain, from production and import to consumers and large scale storage possibilities. Almost all large multinational companies of the basic industry have one or more significant assets in this region.

The decarbonization of this energy and feedstock is high on the agendas of governments and companies that are based in this region. The use of hydrogen is one of the key enablers to decarbonize the region and can complement electricity as an energy source. It allows the large amounts of foreseen wind energy that is to be produced in the North Sea to be transported far into the hinterlands of the Netherlands, Belgium and Germany. A hydrogen network can be used to transport large quantities of hydrogen energy over large distances, potentially re-using existing natural gas pipelines. This can be complemented with imported hydrogen (-carriers) from other parts of the world. Hydrogen carriers (e.g. ammonia) can then be converted to hydrogen and fed into the hydrogen network. In addition, pilots are currently ongoing to confirm the potential to store hydrogen at large capacities in salt caverns.

There is currently no public hydrogen infrastructure to facilitate the transport of hydrogen between the Netherlands, Belgium and Germany. The Transmission System Operators (TSOs) of the countries have specified cross-border roll-out plans for this infrastructure.

The production of renewable hydrogen from solar and wind energy is more variable than the production of natural gas, as it depends on weather conditions according to current definitions. This variability has to be managed, as security of supply is crucial for companies to transition to hydrogen. The hydrogen infrastructure and storage play a pivoting role in the success of the hydrogen economy.

An independent view on the security of supply and demand that can be provided by the combined national roll-out plans , in combination with storage possibilities, is essential for companies to rely on. For that reason, the HY3+ project was initiated by TNO and Arcadis. The objective of HY3+ was to provide an independent analysis on prioritization in the roll-out of the envisioned hydrogen networks in Belgium, the Netherlands and Germany. This was done by evaluating the security of supply and demand of the planned networks.

To do so, a detailed model was generated of the technical hydrogen infrastructure in Belgium, the Netherlands and Germany. The Global Ambition scenario based on the 10-year network development plan (TNYDP) (adapted by North Sea Wind Power Hub) is used as basis for demand projections in demand clusters. This was complemented with an extensive dataset based on announced projects and strategies that provides location specific estimates for low-emissions hydrogen production (low carbon hydrogen and renewable hydrogen), import and storage assets. The compiled dataset is based on information available in 2024 and will likely be different in reality in 2030 and 2035. Sensitivity analyses have been performed on the geographical distribution of feed-in locations of hydrogen to the system. Recent

developments also indicate that delays are expected in the timelines for large scale hydrogen production assets to be in operation. For that reason, the results for the 2030 scenarios are indicated as 2030/2033 results.

The model is able to compute the hydrogen flows in the network on an hourly basis, based on the intermittent supply & demand of hydrogen to the system. The network model was coupled to a dynamic underground gas storage model, to have a realistic physical model that simulates the dynamic operation of the storage facilities in these countries. The combination of the models gives insight into the balance in the hydrogen network on an hourly basis, during a year. More importantly, it shows at each location and at each timestep what local pressures and flow velocities can be expected. By comparing these pressures and flow velocities to their allowable values, detailed insights into the security of supply and security of demand were obtained as well as the required storage capacities. To achieve these results, many alternative scenarios were tested to assess robustness of the outcomes and impact of varying assumptions regarding critical assets in the value chain: demand, supply, transport and storage.

The HY3+ study draws conclusions on:
1. the ability of the hydrogen infrastructure to facilitate the transport of hydrogen within physical and technical limitations;
2. the ability of storage facilities to balance both a temporal surplus and shortage of hydrogen production, to provide security of supply in the value chain. This includes not only the foreseen storage volumes, but also the limitations in injection rates and production rates from these storage sites;
3. the likelihood of a successful realization of the value chain in 2030/2033 and 2035.

1. **An interconnected hydrogen infrastructure for North Western Europe offers great value and mutual benefits and is crucial for developing a hydrogen value chain that supports industrial decarbonization. (East-West) Connections between the large hydrogen supply, demand and storage clusters are essential to provide security of supply and demand.**
   - Throughout the course of this study, there have been several updates on the infrastructure plans. Delays in specific sections of the network can create isolated clusters and disconnections between supply, demand and storage. This can have consequences on the developments of the value chain, in local clusters and also in the whole North West European region.
   - If the network will be rolled out as planned[1] by the TSOs in the three countries, then there is no connected network between the largest clusters in the three countries by 2030. Connections between main clusters will take shape in the years after, from 2032 onwards.
   - This, in contrast to the information available at the start of the project, which served as the basis for the simulations. If the network will be rolled out as was planned[1] by the TSOs in the three countries, then the pipe network itself will not have physical bottlenecks in terms of pressure, pressure loss or flow velocities, based on demand capacities according to the 'Global Ambition' scenario from the Ten Year Network Development Plan (TYNDP), the production and import clusters and the storage sites. The TYNDP-scenarios for 2030 and 2035 will result in high pressures, but will not exceed network limits.

[1] Based on the rollout plans that were available in Dec 2024.

- The planned network under the studied scenario balances demand and supply of hydrogen for industry in North Western Europe and it unlocks storage potential for three countries and large demand and supply clusters. The foreseen storage sites play a critical role in providing the flexibility that is required to balance the system. It is therefore essential to connect larger clusters of hydrogen supply (production/import) and demand clusters to the underground hydrogen storage sites.

It is therefore recommended to:

- **Connect the key clusters;** connect the larger clusters of hydrogen supply (production/import) and demand clusters to the underground hydrogen storage sites, by means of essential East-West connections in the countries.
- **Sustain cross border cooperation** and alignment on codes, standards and tariffs to assure effective use of cross-border connections to exploit the potential of the three countries jointly.

2. **The currently foreseen underground hydrogen storage development is insufficient to avoid curtailment in supply and demand of hydrogen. To achieve a balanced system, the hydrogen value chain of these three countries needs additional increased storage capacity or more flexible production and/ or consumption strategies.**
   - The study shows that flexibility from the currently foreseen storage sites is insufficient to assure security of supply/demand, even with an optimal cross border storage strategy. As a result, curtailment of supply and demand will therefore take place.
   - The curtailment takes place because of insufficient volume, as well as insufficient injection and withdrawal rates from these caverns. Over a year, the curtailed hydrogen production and demand is in the order of 1 percent. However, this is calculated using:
     - A centrally managed storage strategy that controls storage facilities according to a merit order, which results in an optimal utilization of the storage infrastructure and avoidance of bottlenecks. In reality, this will be initially determined by long-term storage agreements between producers and storage operators and curtailment will be larger.
     - A flat demand rate over all sectors. Dynamic demand rates can influence the total curtailment in the system, e.g. when introducing hydrogen fired power plants with dynamic demand profiles.
   - The currently estimated volumes and production/injection rates for underground hydrogen storage (UHS) are not enough for strategic storage purposes or to balance the system in prolonged extreme weather periods or significant supply chain disruptions.
   - A delay in the rollout of underground storage sites results in significantly larger amounts of curtailed production or demand.
   - Added flexibility in ports (local storage of hydrogen(carriers), in combination with flexible operation of e.g. ammonia crackers) can minimize curtailment when underground hydrogen storage facilities cannot deliver.
   - Effective implementation of flexibility in the system mitigates the risk on curtailment.

   It is therefore recommended to design the hydrogen value chain to account for weather variability and supply chain disruptions to manage intermittent green hydrogen production from solar and wind sources, by means of the following:
   - **Advance Underground Hydrogen Storage in time;** Advance the availability of underground hydrogen storage sites as much as possible to be ready for use in a very early phase of the hydrogen network.
   - **Establish storage facilities in ports with high and flexible discharge capacities**; This improves flexibility at ports and thus balances the system.

- **Value flexible operation;** evaluate how flexible operation of assets (supply and demand) can be valued, monetized or incentivized, such that impact on the dependency of storage sites is mitigated.
- **Evaluate alternatives;** Developing and realizing Underground hydrogen storage sites requires several years of development time. Considering the pace of the rollout of the network this articulates the need for alternative methods to provide flexibility. Evaluate (in terms of technology and policy) other means to add storage capacity and flexibility to the hydrogen value chain, in the form of:
    - Electricity storage before hydrogen production (batteries)
    - Variable hydrogen conversion at ports (e.g. cracking of ammonia)
    - Surface level storage options (i.e. other means of storage for hydrogen or hydrogen derivatives)

3. **In parallel to the technical analysis, a PESTLE deep dive was performed on the state of affairs regarding the hydrogen value chain in the three countries. Based on that work, it can be concluded that it is unlikely that the demand estimates from the Global Ambition scenario of TYNDP for 2030 can be met in time.**
    - The current level of investment plans in the hydrogen value chain is lagging behind ambitions.
    - Final Investment Decisions (FIDs) in electrolyzer capacity are insufficient to meet with required levels for establishing a hydrogen economy.
    - Announced hydrogen import capacity is lagging behind 2030/2033 targets, even if all projects are realized.

Robustness of the conclusions:

- Although the study focused on the time projections for 2030/2033 and 2035, the related demand/supply capacities determine the outcomes of the study. Should the network and capacities be delayed by a number of years, yet still materialize in the way described in the report, then the conclusions remain valid.
- The conclusions of this work are not dependent on the exact routing of the networks, as long as diameters are unchanged and the total pipe lengths between production, demand and storage locations remain within reasonable ranges.

Abbreviation

Abbreviation	Definition
BE	Belgium
DE	Germany
EHB	European Hydrogen Backbone
ENTSOG	The European Network of Transmission System Operators for Gas
FID	Final Investment Decision
IEA	International Energy Agency
IPCEI	Important Project of Common European Interest
KPI	Key Performance Indicator
NL	The Netherlands
NSWPH	North Sea Wind Power Hub
NUTS	Nomenclature of Territorial Units for Statistics
NW-EU	North West Europe
P2G	Power to Gas
PESTLE	political, economic, societal, technological, legislative, environmental
TSO	Transmission System Operator
TWh	TeraWatt hour (based on LHV)
TYNDP	10-year network development plan
TYNDP-GA	10-year network development plan Global Ambition scenario
UHS	Underground Hydrogen Storage

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1 Introduction

1.1 Role NW-EU in hydrogen economy

North-West Europe (NW-EU) is an energy intensive area, both in terms of energy production and energy consumption. It hosts large, energy intensive industrial clusters that contain steel factories, refineries, steam crackers, chemical industrial plants, and others. The decarbonization of this energy is high on the agendas of governments and the companies that are based in this region. The use of hydrogen is one of the key enablers to decarbonize the region, as hydrogen has four key functions that are particularly relevant to the region:

1. It can be used as a means to **capture and store renewable electricity** through the process of water electrolysis. Water electrolysis plants can be used as a flexible form of electricity demand, that can be controlled such that it supports the integration of renewable electricity to the energy system, without further congestion of the grid.
2. It can be used as a **fuel**. Typical applications are high temperature heat in industrial sectors, electricity production, road or rail transport, aviation and potentially in the built environment for sutainable heating.
3. It can be used as a **feedstock or industrial gas** for chemical processes to produce e.g. sustainable/synthetic fuels, steel, fertilizer and other chemicals.
4. Finally, it can be used as an **energy carrier to transport energy** from one place to another, either in bulk or through pipelines.

The combination of the four functions above and particularly the fact that energy is transported easily in molecular form, make hydrogen an attractive means to decarbonize this region. The use of hydrogen is one of the key enablers to decarbonize the region and can complement electricity as an energy source. It allows the large amounts of foreseen wind energy that is to be produced in the North Sea to be transported far into the hinterlands of the Netherlands, Belgium and Germany. A hydrogen network can be used to transport large quantities of hydrogen energy over large distances, potentially re-using existing natural gas pipelines. This can be complemented with imported hydrogen (-carriers) from other parts of the world. Hydrogen carriers (e.g. ammonia) can then be converted to hydrogen and fed into the hydrogen network. In addition, pilots are currently ongoing to confirm the potential to store hydrogen at large capacities in salt caverns.

Although privately owned hydrogen-infrastructure is already available, there is currently no public hydrogen infrastructure to facilitate the transport of hydrogen within the Netherlands, Belgium and Germany. The countries have presented roll-out plans for their infrastructure infrastructure, taking the infrastructures of neighbouring countries into account. The sizing of this network is typically done based on the accommodation of severe transport scenarios, derived from numerous supply and demand combinations. In contrast to the current natural gas production in our energy system, the production of hydrogen from renewable sources is less predictable and controllable. Security of supply is crucial for companies to transition to hydrogen. The hydrogen infrastructure and storage play a pivoting role in the succes of the hydrogen economy.

An independent assessment to evaluate the security of supply and -demand of the infrastructure combined with storage possiblities is valuable for companies in the complete value chain. For that reason, the HY3+ project was initiated by TNO and Arcadis.

1.2 The HY3+ project

In the preceding HY3 project [1], conducted in 2020, the potential, boundary conditions and overall feasibility for green hydrogen production in the Dutch and German offshore and coastal regions from 2025 to 2050 were assessed. The project identified significant opportunities between the Netherlands and Germany for a common hydrogen market and infrastructure. The HY3 project provided many answers, yet new questions also raised from the performed work and the presented final results.

For that reason, TNO and Arcadis now aim to focus on remaining questions from HY3 that are top of mind for different stakeholders in the hydrogen value chain:

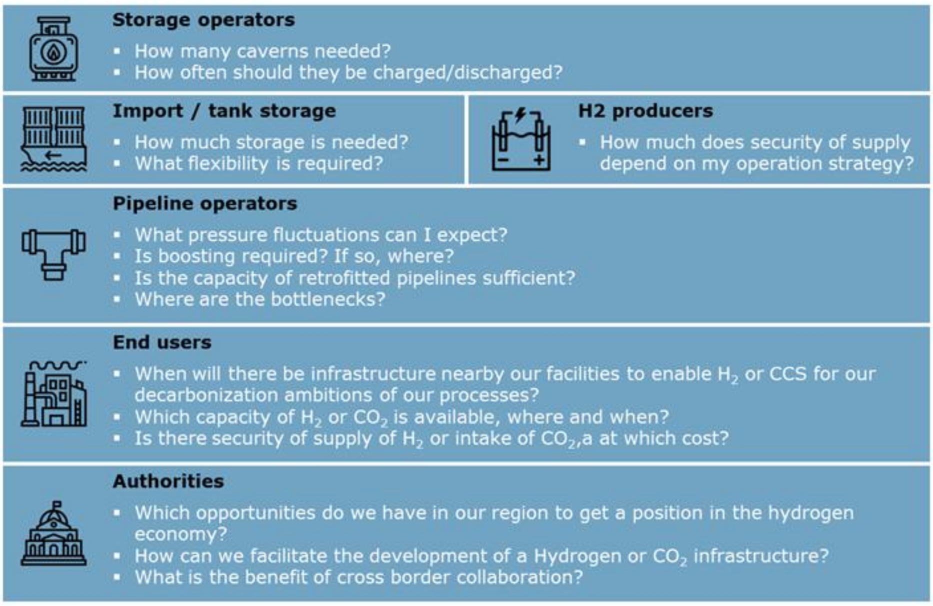

Figure 1.1: Examples of follow-up research questions resulting from the HY3-study.

The HY3+ study aims to provide more insight to answer these questions. Several studies on hydrogen transport and storage are performed with (quasi) static flow solvers based on yearly capacity rates for supply & demand of hydrogen. Within a year however, the dynamics in the operation of the hydrogen network (pressure, flowrates) may become a bottleneck for security-of-supply or demand as well. Dynamic modelling allows for early debottlenecking, based on the evaluation of the overall architecture of the currently planned hydrogen infrastructure. Therefore, next to industrial partners, this will require close collaboration between grid operators and governmental parties.

In addition to these questions, multiple developments in the hydrogen economy have taken place, such as the approval of European IPCEI (Important Project of Common European Interest) subsidies around large hydrogen production projects (e.g.Holland Hydrogen 1). Moreover, infrastructural plans have become more concrete (e.g. HyStock [2], the Kernnetz in Germany [3] and the start of the Hydrogen Network Netherlands [4]) and offtake plans of green hydrogen (e.g. steel producers) [5] have become more certain. Also in terms of policy and regulation, there have been further developments in the definition of green hydrogen and the importance of timely production and consumption of hydrogen to meet these requirements. As a result, supply of hydrogen at the right time and mitigating potential infrastructural bottlenecks become increasingly important.

Ultimately, HY3+ aimed to:
1. Provide independent advice on priorization in the cross-border roll-out of the currently envisioned hydrogen backbones in Belgium, the Netherlands and Germany.
2. Provide a platform to bring different parties in the hydrogen value chain together with the goal to learn about each others experiences, projects and individual and shared risks/bottlenecks, and thereby to pursue a common objective: governmwents (national, regional) producers, importers, storage parties, Transmission System operators (TSOs) and ports as energy HUBs and switch modalities

The above questions and developments all boil down to the following research questions:
1. Will the foreseen hydrogen infrastructural system be able to realize security of supply across the entire hydrogen value-chain in 2030 and 2035 with intermittent hydrogen production, fluctuating demand and the options for storage and import?
2. If not, what activities will be required to ensure the security of supply and to enable the hydrogen economy?

In line with these main research questions, several studies are exploring hydrogen infrastructure, via different approaches. Examples are the ENTSOG[2] TYNDP publications, such as its Infrastructure Report [6] or the European Hydrogen backbone (EHB) publications [7], such as the ‘EHB initiative to provide insights on infrastructure development by 2030’. Building upon these important studies, the HY3+ programme aims to create and add value, by means of the following differentiators:
1. **Joining forces** with (International) key players in the hydrogen economy / value-chain (TSOs, storage operators, industrial parties, governments).
2. Providing **cross-border insights** around security –of supply, **combined with dynamic modelling**. After all, many hydrogen system players are not solely operating in one country. Therefore, a complete and integrated picture around all potential risks and opportunities from a cross-border perspective is needed.
3. Providing insight into the behaviour of the physics in the network on an **hourly basis**, modelling **intermittent supply** of hydrogen
4. Combining both **technical and non-technical components**:
5. Dynamic modelling, rather than static, in combination with cross border insights. The modelling applied within HY3+ includes both time-specific as well as location-specific components, to validate that the system is able to handle not only the average capacities over the year, but also the fluctuations that may be expected from the intermittent production and consumption of hydrogen.
   a. Relevant non-technical dimensions, such as political, economic, societal, technological, legislative, environmental (PESTLE). This allows to analyse the bottlenecks within the surroundings, which in current studies remain underexposed.
6. Concrete **debottlenecking** and **providing early mitigations** for determined infrastructure bottlenecks, which is needed for a robust & mature infrastructure and allowing companies to complete the business-case around hydrogen.
7. HY3+ is a study performed by two **independent organizations** (TNO and Arcadis).

[2] The European Network of Transmission System Operators for Gas

1.3 The Structure of this report

This report contains a summary of the most relevant results from the HY3+ study, combined with an elaborate interpretation on the consequences of these results and the necessary steps towards a hydrogen infrastructure in the Netherlands, Belgium, and Germany.

In chapter 2, the starting points of the study are specified, as well as the key assumptions that led to our conclusions. In chapter 3, the scenarios that were evaluated are listed and the results of those scenarios are described. Chapter 4 contains the conclusions of the report, and a further elaboration on the impact and consequences of these results. The final conclusions and recommendations are outlined in chapter 5.

2 Main assumptions

Within the HY3+ study, the dynamics in hydrogen production, demand, transport, and storage are modelled in detail. This requires proper modelling of the complete hydrogen system. The major blocks that build the value chain, and thereby encompass the model scenarios are:

1. Demand (section 2.2)
2. Supply (section 2.3)
3. Transport (section 2.4)
4. Network control (section 2.5)
5. Storage (section 2.6)

In each of the sections indicated above, the overall sections describe the starting points and main assumptions of the project. Having the scope of the study formulated, the research questions are translated to models, assuming certain starting points. These starting points have key assumptions tied to them and are discussed in following sections, classifying them based on different blocks that build towards the scenario lookouts.

The discussions in this chapter primarily address how we model these blocks to steer from qualitative to quantitative information considering important assumptions to build a scenario.

2.1 Core assumptions

The most important and overall assumptions considered in this study across different themes are listed in the following:

1. **Control of network is not economy driven:**
   The production, consumption and use of storage is based on physical constraints rather than economical constraints. In reality, production and off-take of hydrogen will be based on contracts between parties in the value chain and the economy of the market. Due to the unavailability of such specific information, economic control of the market is not modelled. This means that there is a free flow of gas within the boundaries of the HY3+ regions, and consumption of hydrogen will not be contract specific.
2. **Import assures an equilibrium on an annual basis:**
   The total annual domestic production and demand of hydrogen over the three countries are not well matched; there is a bigger demand than domestic production. To compensate for the mismatch, import of hydrogen (carriers) is assumed whose annual quantity balances out the deficit in annual supply. The type of import carrier is not relevant within the study, as the gaseous hydrogen feed into the hydrogen network is the boundary condition to the model.
3. **Modelling on an hourly basis:**
   The system is modelled to operate on an hourly basis. This means that the flow quantities (pressure, flow rate, velocities) in the network are calculated every hour based on hourly supply & demand, throughout the entire network. Unless specified in specific scenarios, any hourly mismatch in supply & demand is handled by storage sites in the network that bring the system to equilibrium, such that the total hydrogen mass in the

network remains constant. Linepack volume (i.e. storage of hydrogen in the pipeline) is not allowed for market/strategic purposes. The system is balanced for every hour. Moreover, since the study is modelled on an hourly basis, we assume a fast system response (i.e. on the same hourly basis) of all components in the system. Moreover no downtimes of the assets in the system is included.

4. **Differences in the intermittency in the supply & demand vectors:**
   The hydrogen demand is assumed to be dominated by the industrial sector that typically requires a stable operation and thus is kept constant throughout the year having no intermittency. We also assume the blue hydrogen (henceforth addressed as low carbon hydrogen in this document) factories (running SMR/ATR) and import ports (ammonia storage tanks in combination with cracking terminals) to have a constant throughput of hydrogen into the system. The source of green/renewable hydrogen production is from the technology of electrolysis, that runs on variable load from wind power and solar power. Unless specified differently in specific scenarios, this is the only intermittent source of hydrogen in the system.
5. **NSWPH and TYNDP datasets for hydrogen demand and newly scoped HY3+ database for hydrogen production:**
   The granularity of work involves studying the network at a TSO level, that requires a relatively coarse model of supply & demand that is to be aggregated per region. Demand data is extracted from the North Sea Wind Power Hub (NSWPH) datasets [8] that classify information per Nomenclature of Territorial Units for Statistics (NUTS) region. Generally, within the NSWPH dataset, we choose the Ten Year Network Development plan's – Global ambition (TYNDP – GA) scenario, as this provides a consistent dataset for all three countries in a rather ambitious hydrogen roll-out scenario. As level of detail we choose NUTS level 2 for demand in specific regions.
   Due to the unavailability of detailed data of projects representing location specific supply of hydrogen carriers considered in the HY3+ study (such as Import and low carbon hydrogen), we have updated the supply dataset with location specific estimates for H2 production and import based on announced projects and import strategies. Individual hydrogen projects that are announced are sourced from various databases and are aggregated together to represent a certain capacity of hydrogen produced from that NUTS region.
6. **No cross-border flow outside HY3+ countries.**
   The scope of the study is the Netherlands, Belgium, and Germany. We assumed there is no cross-border hydrogen flow from/to Luxemburg, France, Switzerland, Austria, Czech, and Poland.
7. **The use of storage facilities is optimized on system performance**
   Storage is used in a manner that optimizes the balance of the system as a whole, and not the individual parties in the value chain.

2.2 Demand

The hydrogen demand for the HY3+ countries is obtained directly from the dataset of NSWPH. The dataset consists of the demand breakdown across different sectors. However, NSWPH does not distinguish or categorize demand per sector, but instead takes total demand across all sectors into account. The dataset is also classified per NUTS localization. Thus, similar to the aggregation performed for the production database, we use the data that is provided at the NUTS 2 level which represents demand from the respective provinces of each country. Figure 2.1 shows the total hydrogen demand (TWh/year) for the year 2035 following the TYNDP-GA scenario within the NSWPH dataset.

The total annual demand for the HY3+ regions in the year 2035 is 332 TWh/year, with Germany consuming vast majority (approximately 70%) of it. Figure 2.2 shows the distribution of the off-taker locations. The color gradient indicates the intensity of the demand at the node, scaling between dark reds for high magnitudes and light yellow for low magnitudes. Based on the NUTS classification, 35 different off-takers are considered for Germany, with high demands peaking in the region of Rhine-Ruhr where high concentration of industrial off-take is expected. The Netherlands is assumed to constitute 20% of the total demand across 6 different clusters (the 5 industrial clusters and one distributed cluster (cluster 6)). The remaining 10% of the demand is from Belgium which is consumed across 5 regions, with the highest off-take in Antwerp. The nature of demand is assumed to represent the operations of industrial clusters which require continuous baseload operations. Thus, we model the hourly demand to take a constant rate throughout the year.

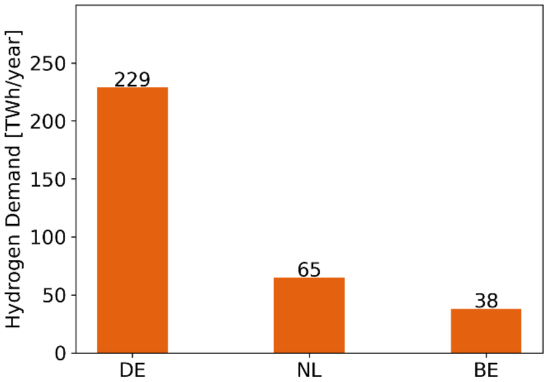

Figure 2.1: Hydrogen demand [TWh/year] (in 2035) in the HY3+ countries.

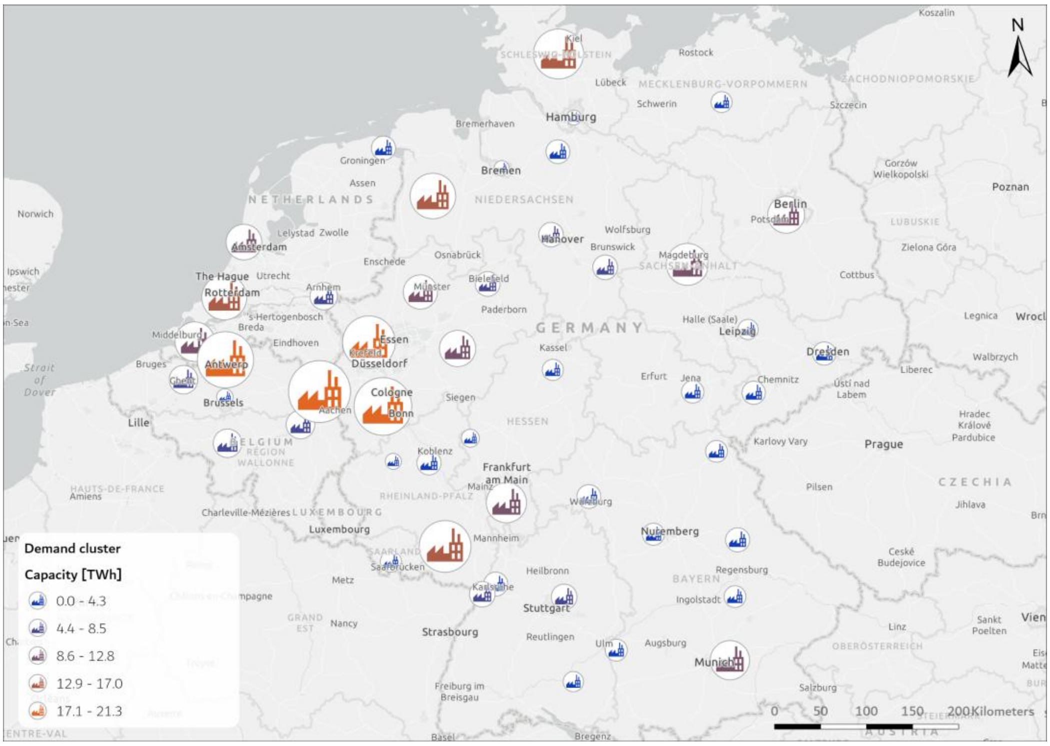

Figure 2.2: Distribution of offtake (demand) clusters in the HY3+ countries

2.3 Supply

The hydrogen database was scoped based on an initial survey of projects across the HY3+ regions. Different resources such as the International Energy Agency (IEA) hydrogen production database, news articles, official documents (announced up to February 2024) were gathered and referred to further classify these projects based on their project lifecycle (feasibility study, FID, construction, commissioned, and operational). All projects that are scheduled to be operational by 2030 and 2035 were filtered and considered in the database to contribute to their respective scenarios.

To make the system robust, hydrogen feed-in from different carriers (derivatives) were considered. All existing and planned:

- green hydrogen production plans from onshore electrolysis,
- green hydrogen production plans from offshore electrolysis,
- Low carbon hydrogen production plans at facilities equipped with Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) technologies,
- hydrogen production plans from Ammonia import terminals via cracking

were considered and incorporated in the total supply in the system.
The study is primarily aimed at evaluating the hydrogen system (network of the HY3+ countries) at the transmission level. Considering this scope and the level of granularity needed for the study, individual production projects were geographically aggregated together to represent a capacity of hydrogen production from a certain NUTS region.

2.3.1 Onshore and offshore Electrolysis

All documented individual onshore electrolysis projects were geo-spatially placed across the HY3+ regions. A rule-based clustering algorithm was designed in a GIS software that accumulated several projects into clusters. Figure 2.3 shows the distribution of the Power to Gas (P2G) (electrolyzer) cluster nodes considered in the study. We can see that most of the electrolysis clusters are situated along the coastal locations where the offshore wind power is expected to land, making it well suited for onshore P2G. The clusterization algorithm resulted in a total of 4 clusters in The Netherlands, 2 clusters in Belgium and 12 clusters in Germany. The breakdown of total capacities per country is shown in Figure 2.4 for the year 2035. A total of 11 GWe was assigned for The Netherlands, with more than 55% (6.3 GWe) of the capacity found in the Eemshaven area, and approximately 20% (2.2 GWe) of the green produced being transported from the Rotterdam area. The Ghent-Antwerp region is also a concentrated production area in Belgium with similar capacities of 2.5 GWe. Large production clusters are also seen in the north-western part of Germany (in the area of Wilhelmshaven carrying capacity of 3.4 GWe).

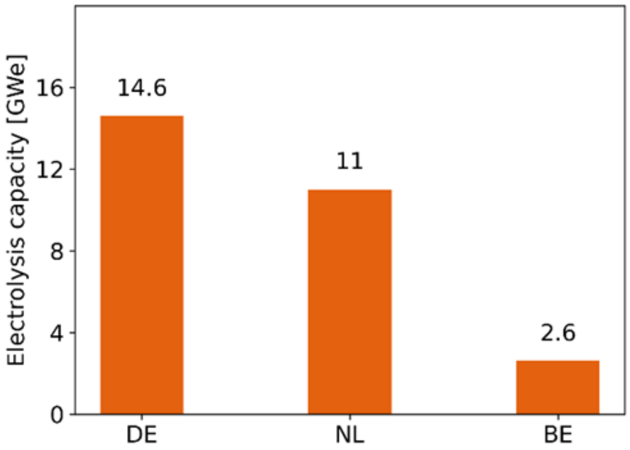

Figure 2.3: Total electrolysis capacity [GWe] (offshore and onshore) assumed for each HY3+ country for the year 2035

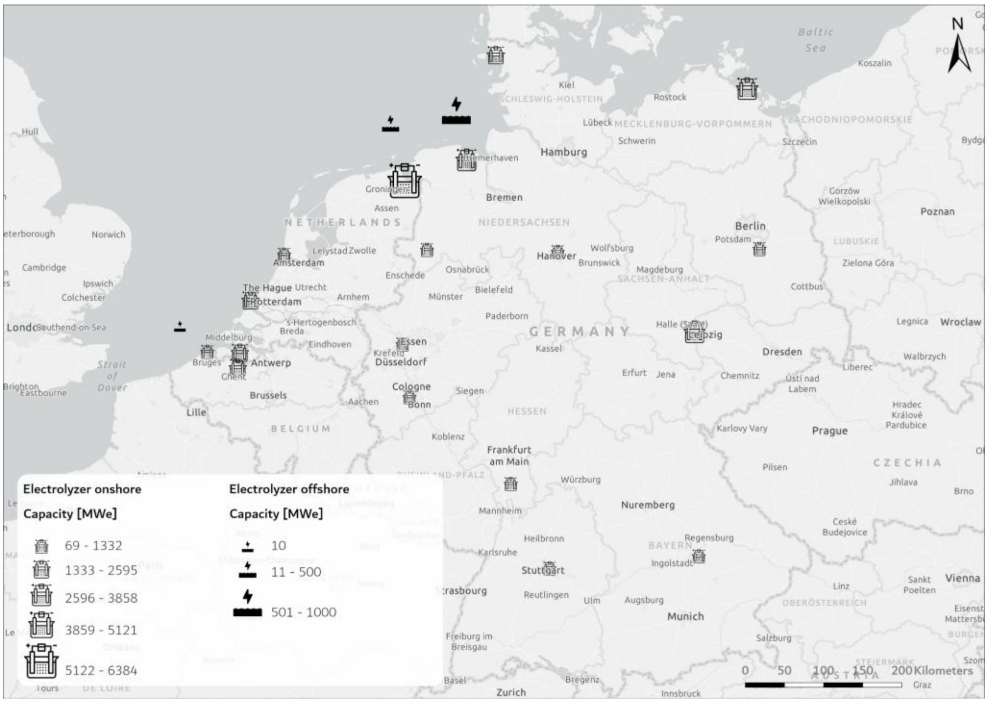

Figure 2.4: Distribution of offshore and onshore electrolysis clusters

Regarding the offshore hydrogen production facilities, these were not modelled at their expected locations of offshore platforms, but at the foreseen landing points close to the shore, thereby directly feeding-in to the network.
The assigned feeding in locations are:

- 500 MWe electrolyzer, feeding in at Eemshaven, The Netherlands (DEMO-1)
- 10 MWe electrolyzer, feeding in at Zeebrugge, Belgium (HOPE)
- 1000 MWe electrolyzer, feeding in at Brunsbuttel, Germany (SEN-1)

2.3.2 Low carbon Hydrogen

The low carbon hydrogen feed in locations were also geographically aggregated, resulting in (ref Figure 2.5):

- 3 clusters in The Netherlands, summing up to 665 ktpa H2.
- 1 cluster in Belgium, summing up to 365 ktpa H2.
- 2 clusters in Germany, summing up to 405 ktpa H2.

The hourly flowrate of low carbon hydrogen is assumed constant and is based on the yearly value above.

2.3.3 Import

To compensate for the annual mismatch of production and demand, import of hydrogen is incorporated into the model. The hydrogen is foreseen to be transported globally in various forms: liquid hydrogen or packaged in ammonia, methanol or specially developed hydrogen carriers, known as Liquid Organic Hydrogen Carriers (LOHC). For the study, the type of hydrogen carrier is not considered relevant, as the boundary to the model is the gaseous hydrogen feed-in at the terminal location. At this stage, the hydrogen is already converted or cracked and compressed to the gaseous hydrogen at the desired pressure.

The required import across all ports are calculated on an annual basis, depending on the deficit in annual supply to match the annual demand as totals across all HY3+ countries. The amount of hydrogen that is imported at each port scales according to the announced (national) ambition at that port. Inland ports are assumed to import via barges from larger ports. The share of import is shown in Figure 2.6 and the distribution of the locations shown in Figure 2.5. The port of Rotterdam contains the highest share of import due to the large import ambitions.

Figure 2.5: Distribution of Import terminals and low carbon hydrogen production facilities

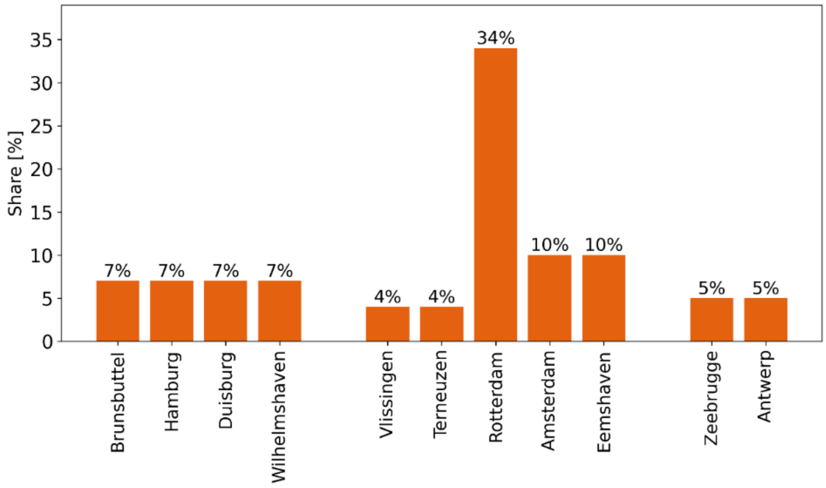

Figure 2.6: Distribution of capacities among the port locations where imports (of hydrogen) are assumed.

The hourly flowrate of import is assumed constant and is based on the yearly value (deficit in annual supply to match annual demand) and then distributed based on share per port.

The system is modelled to have a constant flow of imported hydrogen in the network. This implies the presence of hydrogen (-carrier) storage at the ports. There should be sufficient storage capacity and cracker capacity in the ports to provide for this. For comparison: for LNG ports storage capacity in the ports is typically 2-4% of annual throughput [9].

2.3.4 Energy supply and conversions

All electrolyzers are operated under dynamic load subjected to power input between minimum load (20% assumed) and its capacity. The power is assumed to be generated from a combination of renewable energy sources: wind and solar farms. Note that the power required to generate baseload electrolysis (20%) is assumed to be available readily from the grid, and is not quantified by the source. Figure 2.7 shows the distribution of the assumed wind farms (in red) and the solar farms (in yellow). These combined (scaled) power sources are supplied to their corresponding cluster of electrolyzers.

Figure 2.7: Assumed wind farm and solar farm locations in the HY3+ countries.

Meteorological datasets along the locations placed in the WF (wind farm) markers of Figure 2.7 were extracted from the New European Wind Atlas (NEWA [10]) and used to generate wind power profiles using open source wind farm models. A photovoltaic geographical information system [11] was used to generate solar power profiles along the locations shown in the PV panel marker. The combined wind and solar profiles are scaled three times the size of the electrolyzer's capacity. The electrolyzers are assumed to use the bottom third of the (power) load duration curve (Figure 2.8).

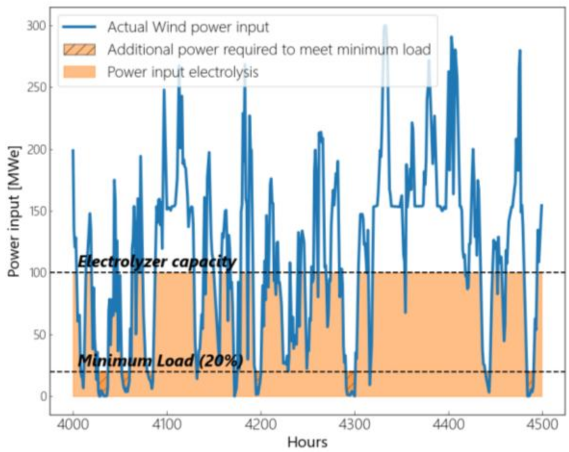

Figure 2.8: Combined power input from wind and solar source (blue), and power sent in for electrolysis (orange) for an electrolyzer having a capacity of 100 MWe.

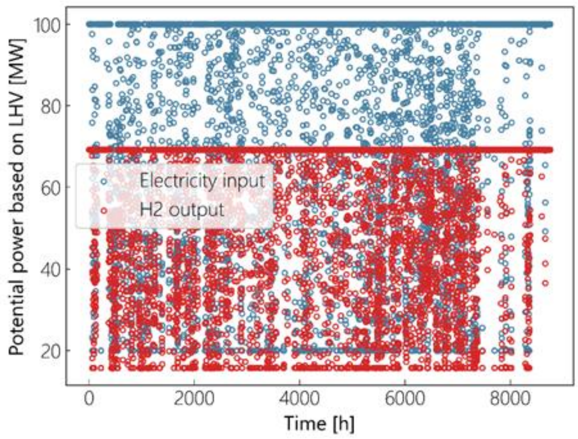

Figure 2.9: Scattered plot of electricity power input (blue) and hydrogen power output (red) based on LHV conversion for an Alkaline electrolyzer having a capacity of 100 MWe.

A dynamic model of an electrolyzer is used to compute the hydrogen production. Given the design and operational conditions of an electrolyzer, the electrochemical model computes the hourly amount of hydrogen produced (Figure 2.9). To already address the suitability of technologies between offshore and onshore electrolysis, we use Alkaline Water Electrolysis (AWE) technology for onshore P2G systems and Proton Exchange Membrane Electrolysis (PEME) technology for offshore P2G systems. To make the system uniform, the same design and operational parameters are used within the specific technology of electrolysis. We use such methodology to generate hourly hydrogen production profiles for all electrolyzers depending on their specific (input) wind patterns to be able to use it as supply data.

2.4 Transport

To boost the hydrogen economy, the national ambitions across the whole value chain are ramping up. The network operators along with the government have laid out essential infrastructure development plans to commence the transport of the commodity over long distance in high pressure pipelines as early as 2030. Current visions and mature plans of the network build up for transportation have been published individually by each of the TSOs (in the HY3+ regions). Iterations of the rollout plans have been continuously shared by the TSOs, Gasunie from The Netherlands, Fluxys from Belgium, and FNB, a consortium of TSOs in Germany. With the individual pieces of the puzzle and the information as of February 2024, the high-pressure network from each of the TSOs have been put together to represent the transmission backbone within the HY3+ countries, as seen in Figure 2.10 - representing year 2030 and Figure 2.11 - representing the year 2035. The showcased networks were modelled and used as a basis for the evaluation for the studies in HY3+.

The figure shows how the network is aimed to build up in terms on complexity, connecting more elements in the value chain. The fundamental growth in the network during the 5-year period is marked by its ability to connect more hydrogen production facilities and off-taker clusters. The main developments are in the regions north-western Netherlands, Wallonia in Belgium and North Rhine-Westphalia, Bavaria and Rhineland-Palatinate in Germany.

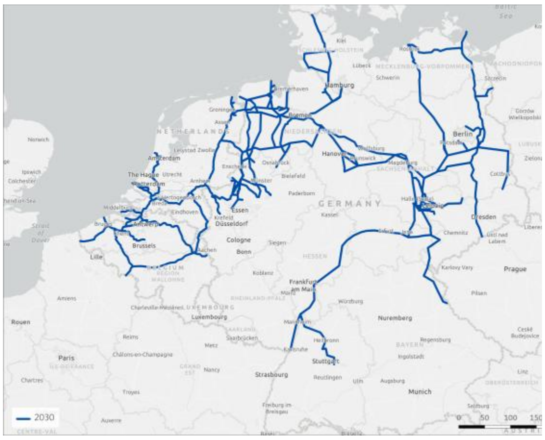

Figure 2.10: The modelled HY3+ hydrogen network in year 2030/2033.

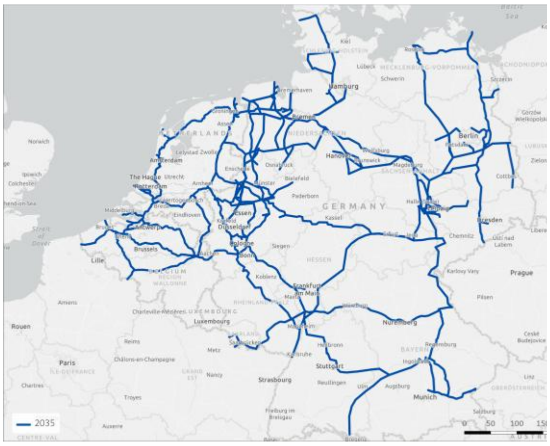

Figure 2.11: The modelled HY3+ hydrogen network in year 2035.

Necessary design properties of pipes such as the diameter, roughness and wall-thickness have been used wherever these specifications where known but have been assumed if not. Such geometrical and spatial information about pipes of the core German network were published by FNB and re-used for the study. For The Netherlands uniform pipeline diameters of DN1050 (42 inch) with a roughness of 15 µm were assumed, except for the line between Maasvlakte and Pernis, which uses a diameter of DN600 (24 inch). We assume similar 42 inch pipelines for Belgium.

The technical standard for the exact operational pressure range per section of the network is not known in all locations, thus we assume the maximum and minimum operable pressures to be 66 barg and 30 barg for both three countries. It is known in Germany there are pipeline sections that have maximum operable pressures up to 85 barg. The minimum allowed pressure values are based on assumptions on minimum required pressures at end users. Within these pressure ranges, the hydrogen is allowed to flow freely between the borders (at the interconnection points) without any booster compression. We also assume no compressors within the national networks. The gas is also contained within the HY3+ countries for the reference cases, thus no import/export is allowed from or to any bordered foreign countries. The physical inherent nature of the network to 'linepack' is not modelled in this study. We restrict the transient and unsteady behavior of the network that has the ability to 'store' gas, and thus it is assumed to be operated in a quasi-steady state where the network is required to be balanced by supply & demand on an hourly basis.

The networks are modelled based on the information available in February 2024. In the meantime several developments have taken place. The impact of these developments are described in section 2.8. As a consequence of these developments, it is considered more likely that the network and results that were foreseen for 2030 will be delayed in time to approximately 2033. Therefore the network and results in this report are labelled as 2030/2033 results.

2.5 Network Control

Different hydrogen energy carriers are incorporated for modelling the total production of the gas in the system. The system's production and consumption were discussed to be balanced on an annual basis, however, they require close management to account for fluctuations that occur on an hourly basis to maintain equilibrium. Given that the production from P2G assets is dynamic in nature, the total supply of hydrogen varies on an hourly basis. Since we assume the demand to be at flat rate, there is a possibility of mismatch every hour, leading to a surplus or a deficit of hydrogen production.

The surplus or deficit in production are primarily handled by the storage sites (salt caverns) in the system. The excess (surplus) in the system is stored across the storage sites, by injecting hydrogen into salt caverns within their limits. Similarly, the deficit in production is handled by producing (withdrawing) hydrogen from the storages within their limits. A storage site's limits are restricted either by its maximum injection and production rates or the state of charge. To ensure the safe operation of the storage sites, strict adherence to constraints is essential. Therefore, the surplus or deficit cannot be addressed at times, and needs to be handled outside the storage system. At these instances, imbalances are corrected either by curtailing the supply or demand at instances of surplus or deficit of hydrogen, respectively.

In case of a deficit, when the production of hydrogen (including the production from storage) cannot meet the demand,, we reduce/curtail the total demand in the system to match total production during that hour. Similarly, at an instance of overproduction (that cannot be injected into the storage), we curtail the supply of hydrogen from the system. Due to the availability of multiple producer assets in the system, we define a (merit) order from which the production must be curtailed.

The priority order is assumed to be based on the ability of an asset to ramp up or ramp down and based on the color to match the total demand, and is listed as:

1. Import, the first to curtail in case of surplus
2. Low carbon hydrogen, the second to curtail if there is still an excess in the system
3. Onshore electrolyzer assets, the third to curtail if there is still an excess
4. Offshore electrolyzer assets, the fourth to curtail.

Such a merit order is implemented to curtail the hourly excess to maintain equilibrium in the system.

2.6 Storage

Following the collaborative plans between the network and storage operators, we filter out all the announced projects that are expected to be operational by 2035. We do not consider surface (tank) storages for the reference cases, and only model underground (subsurface) storage sites. Six underground storage sites (5 in Germany, 1 in the Netherlands) are selected across the HY3+ region, all of which are salt caverns (ref Figure 2.13). The associated working volumes of each of the storage site is shown in Figure 2.12, that accounts to a total working volume of 1.15 TWh in the year 2030 and 3.8 TWh in the year 2035. In the Netherlands, Zuidwending is chosen as the only storage location. In Belgium, we do not have any storage location considering the maturity and the projections.

For all the simulations performed in this study, the initial fill level of a storage site is assumed to be at 50% of the working volume (thus half-full). However, this might not be the case in reality as the first year of operation of a storage site, will have an initial fill level of 0% (thus empty), and be mainly dependent on booking of contracts of a customer. As indicated, no such economic control of the market is performed, and thus such an assumption of the initial fill level is made.

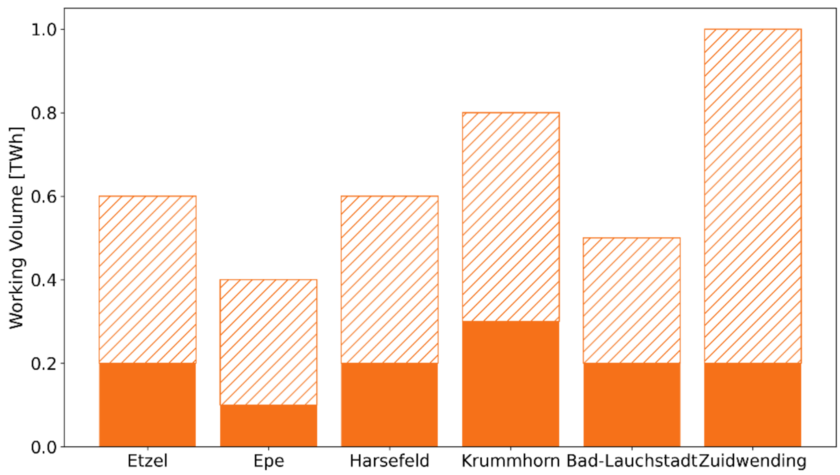

Figure 2.12: Working volumes of considered storage sites in the year 2030 (filled) and the growth in the working volume towards 2035 (hatched). The total bar height represents the working volume in 2035.

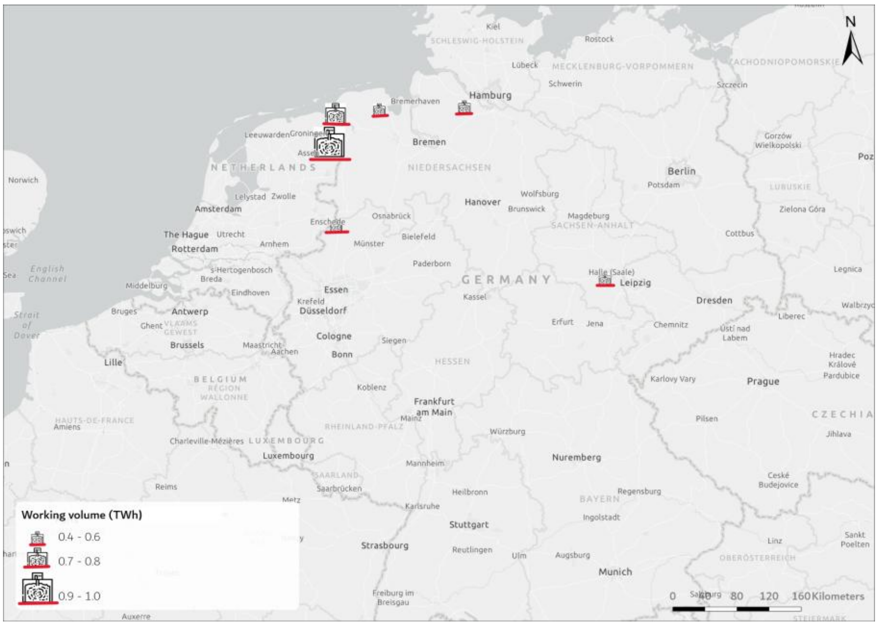

Figure 2.13: Distribution of storage locations in the HY3+ regions

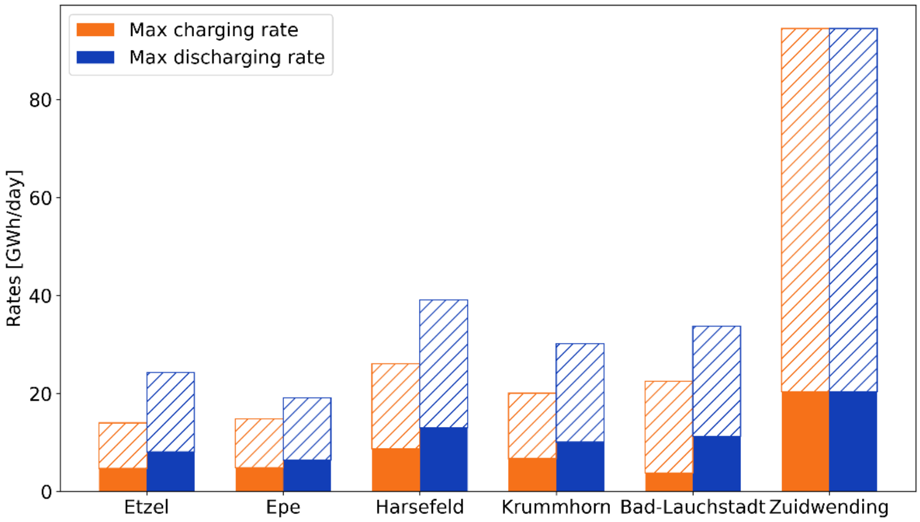

Figure 2.14: Maximum charging and discharging rates of storage sites in the year 2030 (filled) and the growth in the rates towards 2035 (hatched). The total bar height represents the maximum charging and discharging rates in 2035

The maximum charging/discharging rates directly represent the latest information following the plans if known. They are represented in the Figure 2.14 and shows what the expected rates in 2030 and 2035 are. In the absence of such information, a conversion factor (estimation for hydrogen vs. natural gas) is used to arrive at respective parameters considering the design and operational constraints such as well parameters, maximum pressure variations etc.

The storage sites work together as one collective storage portfolio in order to balance the network. This means that no storage is given a sole preferential treatment for meeting a mismatch. Thus in case of a surplus, all storage sites inject and in an event of a deficit, all storage sites produce, unless violated by the constraint. The gas allotment per storage site is based on its state of charge compared to all other storage sites, and thus the distribution follows a merit order. The merit order is as follows:

1. In case of a surplus, a storage site with the lowest state of charge will be injected with the most gas, and vice versa for a site with highest state of charge.
2. In case of a deficit, a storage site with the highest state of charge will be producing the most gas, and vice versa for a site with the lowest state of charge.

If the allocated injection or production rates cannot be handled by a storage site due to constraints (either their maximum rates or full/depleted storage volume) the deficit in the assigned flow is passed on to the next storage site in the merit order (and so on, unless the site is limited by constraints). In this way, we ensure a shared distribution of handling the hourly mismatch between the storage sites to bring the system to a balanced state.

This method was chosen since no market price behavior is included in this study and thus the centralized method will give optimal allocation for each storage site.

Additionally, we do not enforce constraints or optimal control for the storage systems to be self-sufficient. This is because, the strategies of import, green, low carbon hydrogen and demand are not altered in any way for the storage systems to react and achieve self-sustainability, thus leaving the network and its assets to react purely based on the given set of inputs and configurations. Hence, this could result in a fill level (state of charge) of storage at the end of the year, different compared to how we begin with at the start of the year. Note: The curtailment to balance the overall network control still applies as explained in Section 2.5.

2.7 Key performance indicators

Upon simulating various scenarios, it is crucial to inspect a few key performance indicators (KPIs) associated to gas networks, to learn and gain insights into the system's overall safety and reliability. It is deemed to be necessary not only to maintain a safe operation, but also check the compliance with regulatory standards and limits established for the transport of gas within high pressure pipelines. To do so, we analyze the results and mainly study the pressure and velocity in the pipelines, and assess the storage availability and flexibility in ensuring security of supply. We define six key KPIs that will be assessed for every scenario demonstrated in this work, which are stated in table 2.1:

Table 2.1: KPIs considered in this study.

KPI	explanation	Observed variable in HY3+ model	Limit
Security of Supply	Minimum pressure for consumers shall be guaranteed.	Minimum guaranteed pressure: p_{min}	30 barg (assumed)
Security of Demand	Ability to produce hydrogen whenever desired. Maximum operational pressure shall not be exceeded.	Maximum operational pressure: p_{max}	DE: 85 barg (depends on pipeline) NL: 66 barg BE: 66, 70, 80 barg (depends on pipeline)
Operational limitations	Maximum operational pressure shall not be exceeded.	Maximum operational pressure: p_{max}	DE: 85 barg (depends on pipeline) NL: 66 barg BE 66, 70, 80 barg (depends on pipeline)
Flow velocities	High flow velocities may cause undesired friction losses and erosion in pipelines if not properly purified	Flow velocity: v_{max}	For NG: 20m/s For H_2: 60m/s
Input for material analyses	Pressure fluctuations lead to cyclic stress levels in pipes, fittings and welds. Their magnitude and frequency are computed and provided, so they can be used for insights on fatigue loading.	Pressure fluctuations: p'	Depends on material
Curtailment due to Storage SOC and maximum injection/ production rates		Curtailment of H_2 due to storage SOC	No limit, but expressed as percentage (%) of demand
		Curtailment of H_2 due to Max Injection & Production rates: $Q_{max, inj}$, $Q_{max, prod}$	No limit, but expressed as percentage (%) of demand

The observed variables are explained below.

1. Maximum pressures in the network, p_{max}
   - The maximum pressures are typically experienced at locations of maximum flow injection/feed-ins onto the network. These maximum pressures are important to monitor for a safe operation of the pipelines, so as to be compliant with the design standards such as the maximum allowable operating pressure (MAOP)
   - Apart from the design perspective, the maximum pressures are also crucial for a connected part (i.e. a producer that is directly injecting onto the grid). The effective pressure at a connection point depends on the distance from the pressure-regulation or a compressor station. Thus when the system reaches high pressures near the limits (shown in Table 2), additional injection of gas might not be always possible.
2. Minimum pressures in the network , p_{min} :
   - Maintaining pressure in the grid is crucial for its stable operation. This means that the downstream pressure in the network cannot be too low which may result in a higher overall pressure loss in the system. To mitigate this, compression can be employed to maintain the required pressure levels. Thus the pressure levels/pressure drops and

minimum pressures are monitored throughout the network to highlight the necessity of compression, if required.
- Overall low system pressure can also influence the off-takes. A low delivery pressure at the off-taker (typically large-scale industries) can lead to unstable operation, disrupt processes, and lead to inability in securing the demand. Additionally, low pressures in the high pressure transmission line can also affect the junctions to regional transmission line (typically operated at lower pressures) networks where the mismatch between and pressures levels can be a problem.

3. Pressure fluctuations in the network, p' :
   - The network is subjected to different instantaneous pressures resulting from intermittent supply of hydrogen. Pressure fluctuations lead to cyclic stress levels in the pipe walls, fittings and the welds. Depending on the magnitude and the frequencies of these pressure fluctuations, these stresses could lead to crack growth, leaks and failures. Pipelines are designed to be able to cope with these pressure fluctuations. In this report, we only provide the peak-to-peak fluctuations in pipelines at maximum fluctuating locations and record the history of cycles (against pressure ranges) through the method of rainflow counting, to inform on the dynamic loading of these pipelines. No judgement is made on the fatigue life of pipelines; this requires detailed mechanical analysis which is out of scope of this work.
4. Maximum velocities in the network, $v_{\max}$:
   - Maximum velocities is a key KPI that is studied in this work. Higher velocities are undesirable in transmission as they correspond to additional frictional losses in the pipelines, leading to more energy dissipation. Additional associated risks such as pipeline erosion could lead to more wear and degradation on the inner walls of the pipelines or noise problem. Any technical standard on the maximum velocities of hydrogen transport in pipelines is not established at this moment. Although, studies [12] address the limitations by adhering to the specific energy and the energy density compared to Natural gas (NG) pipelines. For the same energy to be transported as NG at similar pressures, hydrogen flows 3x faster, thus is considered to also be a ‘rule of thumb’ in this study, setting the assumption of maximum velocity to be 60 m/s.
5. Curtailment (Imbalances; H_2 curtailed) due to storage state of charge (SOC_{storage}), and storage inflexibility (maximum production/injection rates - $Q_{\text{max, inj}}$, $Q_{\text{max, prod}}$):
   - The amount of working volume available in a storage acts as a buffer to balance the hourly mismatch in supply & demand. For a given supply demand matching, any shortage in the availability of storage is undesirable, as the primary goal would be to store it in the system for long-term usage. Additionally, in the view of operations, storage usage is also monitored regarding the maximum and minimum fill levels as this corresponds to the pressure levels inside the storage well, and thus is needed to be ensured to stay within the pressure regimes. The storage’s state of charge (fill level %) is continuously monitored and reported. Any violations in the maximum and minimum pressures will lead to a situation where the system cannot store and thus leading to curtailment of production or demand.
   - The ability of the storage to react, ramp up or ramp down for different flow rates and directions is important in balancing the system on an hourly basis. Due to the variability in production, momentary/sustained severe overproduction and/or underproduction could occur, for which storages should be resilient to undergo such stresses in the system to achieve balance of the network. If the storage cannot undergo high production/injection rates (i.e., beyond their maximum limits), production/demand needs to be curtailed from the system to balance the network. In this work, we study the performance of these KPIs under various scenarios and address their impact and relevance.

2.8 Developments during the project

Throughout the project the hydrogen infrastructure rollout plans have been adjusted. Key assumptions in the study, such as the network layout used in the analysis for 2030 and 2035, were frozen in March 2024. In the meantime, there have been updates regarding hydrogen policies and plans.

- In June 2024 the Dutch government announced the news of the delay of construction of the DRC (Delta Rhine corridor) [13], the east-west hydrogen pipeline, connecting the ports in the west of the Netherlands with the demand clusters in Germany. Completion would not be expected before 2032.
- In October 2024, the German Federal Network Agency (BNetzA) approved Kernnetz, the hydrogen transport project through Germany [14].
- In November 2024, Fluxys started a market consultation related to the east west connection in Belgium [15].
- In December 2024, the Dutch government decided to accelerate the planning-process of the DRC, pronouncing the expectation that it can be operational in 2031-2033. HyNetworks also updated the roll-out plans of the hydrogen networks in the Netherlands [16].

The **Delta Rhine Corridor** (DRC) is an infrastructure initiative aimed at facilitating the transportation of hydrogen and carbon dioxide (CO_2) and other commodities between the Netherlands and Germany. The DRC will connect industrial clusters in the Netherlands, particularly around Rotterdam and Chemelot, to regions in North Rhine-Westphalia. Initiated by a consortium that includes major players such as BASF, Gasunie, OGE, and Shell, the DRC seeks to construct multiple underground pipelines and HVDC cables. It was officially recognized in November 2021 when it was included in the Dutch government's Multi-year Program Infrastructure Energy and Climate (MIEK), highlighting its importance for achieving national climate goals. In this phase, the lead of the project has been transferred from private parties to public parties, Gasunie (the Dutch natural gas network TSO) and TenneT (the Dutch high voltage network TSO).
The primary commodities targeted for transport through this corridor include:

- Hydrogen
- CO_2
- Ammonia
- HVDC

In December 2024, the Dutch government announced that Ammonia and a HVDC cable will no longer be part of the DRC.

The planned hydrogen pipeline in the network is part of the Dutch hydrogen grid of HyNetwork. Hynetwork, a subsidiary of Gasunie, has the task to construct the hydrogen network in the Netherlands.

Germany's hydrogen core network, known as ***Wasserstoff-Kernnetz***, is an initiative aimed to establish a nationwide hydrogen transport system. The network will span approximately 9,040 kilometers, with around 60% of its pipelines converted from existing natural gas pipelines. Initial sections of the network are expected to become operational by mid-2025, with priority given to projects receiving EU funding under the Important Projects of Common European Interest (IPCEI) framework. The transmission system operators (TSOs) responsible for the German hydrogen core network are organized under the Association of Gas Transmission System Operators, known as FNB Gas.

Fluxys hydrogen, a subsidiary of Fluxys Belgium, has been appointed on 26 April 2024 as the hydrogen network operator by the Belgian government. In close collaboration with market players and neighbouring operators, Fluxys intends to roll out a hydrogen transmission network (midstream) with open, transparent, and non-discriminatory access to link hydrogen supply (upstream) and demand (downstream) in the most economical and efficient manner. Fluxys aims to offer 30 TWh of transport capacity by 2030.
Fluxys wants to build a hydrogen network in different phases, starting development by 2026. The hydrogen transmission infrastructure will connect industrial clusters located in the port of Antwerp Bruges, North Sea Port, Hainaut and Liège. Also, cross border interconnection between Belgium and adjacent countries (Germany, The Netherlands and France) are foreseen.

Taking into consideration the updated as mentioned above, then a difference can be observed to the network that was modelled for the study. The network for 2030 will be less developed than modelled in this study. Isolated clusters are observed that will not be connected to large underground hydrogen storage sites yet, particularly in West Netherlands and West Belgium. Large developments are planned between 2030 and 2035, which indicate that by 2035 the network will be better connected and more in line with the model used for that year (Figure 2.11).

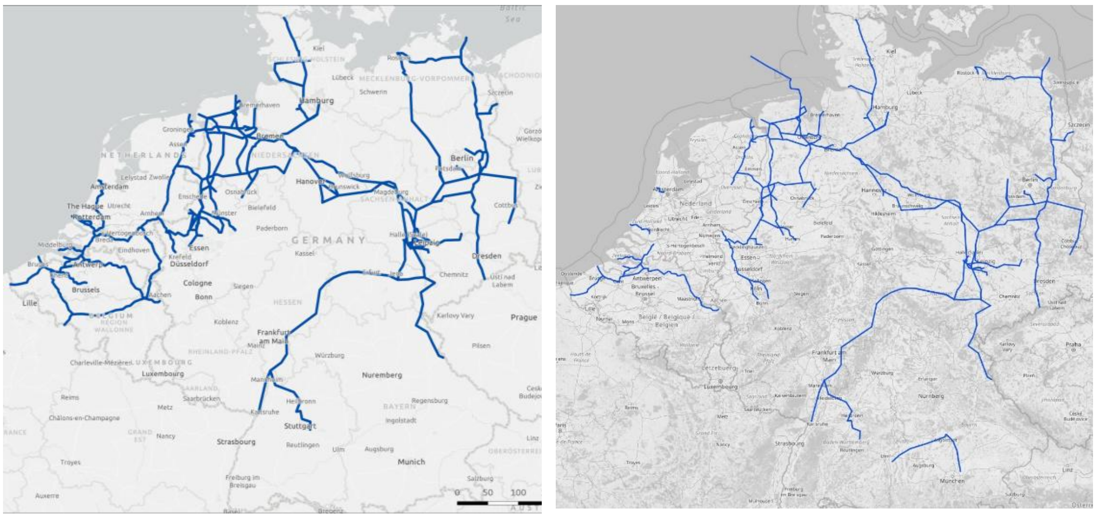

Figure 2.15: the modelled network in the study (left) compared to the most recent rollout plans for 2030, in-accordance with the published information as of Nov, 2024 (right), .

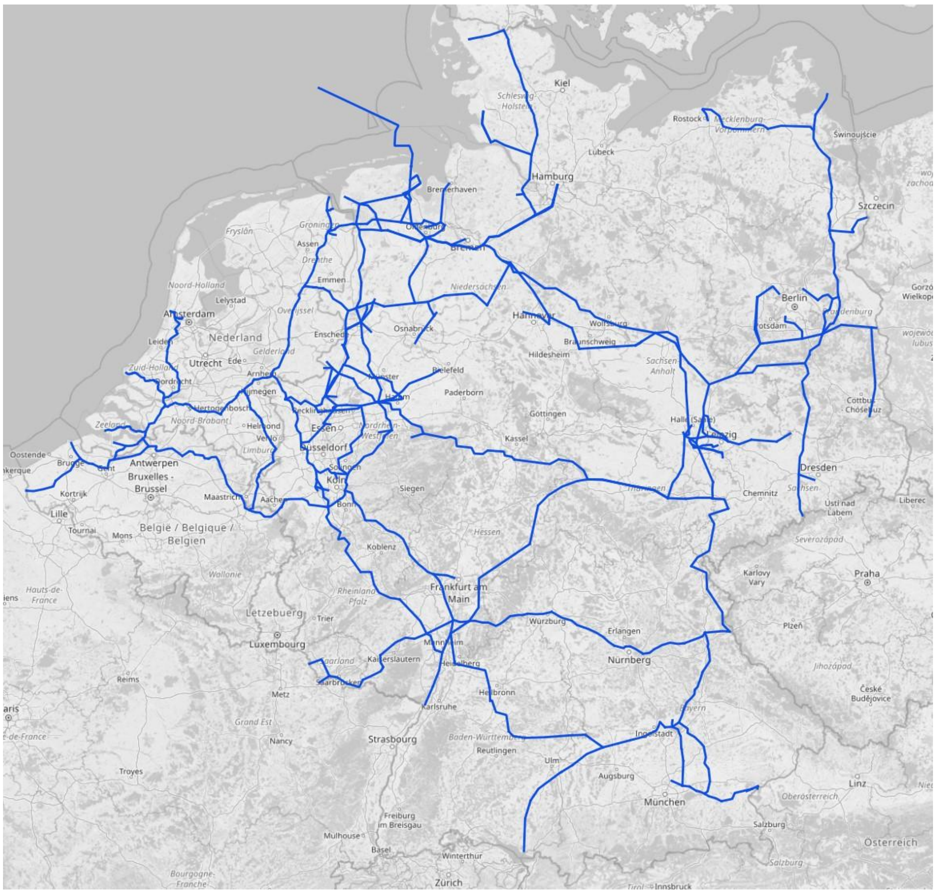

Figure 2.16: Evolution of the network in the year 2033 according to the revised 2030 network in-accordance with the published information as of Nov, 2024.

3 Results

This chapter provides a summary of the results that were obtained from the dynamic network and storage modelling. The chapters starts with section 3.1 that describes the different scenarios that were computed, following by a section of the results for 2035 (section 3.2) and for 2030 (section 0).

3.1 Scenario description

This first section provides a summary of the descriptors for each scenario that is discussed to generate the results. The descriptors are the key elements that form the hydrogen value chain, such as production, off-take, transport, storage, and operations. In Chapter 2, the assumptions were outlined that formed the basis (starting points) for analyses. These assumptions are put together to represent the ambitious Reference cases of 2030 and 2035, which is summarized first. Then different scenarios are formulated using the elements in the value chain as 'levers', that fall under 'Thematic scenarios' under each reference case year.

3.1.1 Year 2035

Reference case
The starting point of the study encompasses the network development plans envisioned for the year 2035. Thus, we gathered data to compile information across the whole value chain as discussed in Chapter 2.

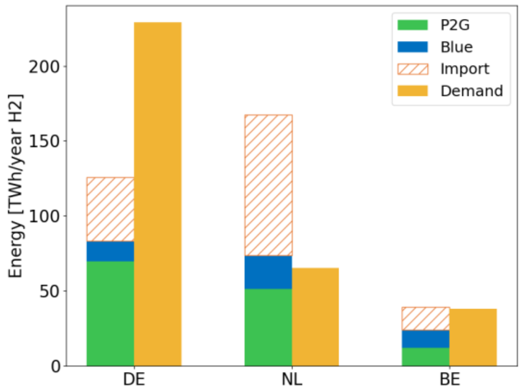

Figure 3.1: Breakdown of hydrogen energy supply & demand per country. Note that the amount of Import presented in each case is a calculation as described in 2.3.3

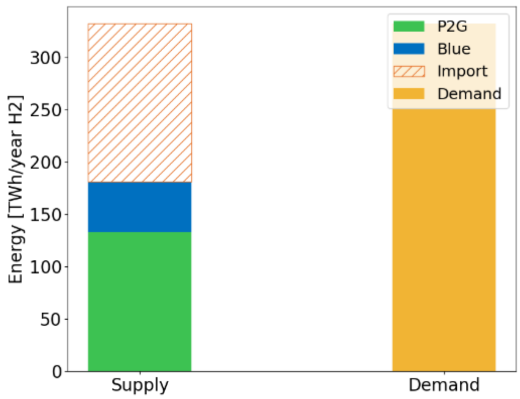

Figure 3.2: Hydrogen energy breakdown in annual supply and corresponding total annual demand of three countries for the reference case year 2035.

- Figure 3.1 and Figure 3.2 shows the annual energy mix of this reference case, broken down per country and by totals respectively.
- The total quantities of supply and demand vary per country. Among the HY3+ countries, Belgium seems to be balanced on an annual basis, whereas Germany is supply deficient, and The Netherlands is surplus in supply.
- We see that a total of 332 TWh/year of demand in the HY3+ region is balanced by different mixes of energy supply. Energy from electrolysis (offshore and onshore) contributes to 40% of the mix, whereas roughly 15% is provided by low carbon hydrogen. The remaining 45% is supplied by imports to fill the gap.. Both the supply feed-in and demand off-take is regionalized (location specific) as discussed in the previous chapter.
- Transmission is assumed via the HY3+ backbone illustrated in Figure 2.11.
- Storage sites across the network are considered at the locations with the assumed volumes and rates as described in Chapter 2.6.

Thematic Scenario –weather dependency hydrogen production
This scenario evaluates the outcomes of the KPIs upon modelling the system based on a different energy input relative to the reference case scenario. Chapter 2.3.4 highlights the steps taken in order to compute the green hydrogen production based on wind and solar energy yield subjected to conditions in the year 2016. The annual load factor is computed for different years, among which 2016 was identified as the median value (Figure 3.3). Thus we choose 2016 as the refence year.

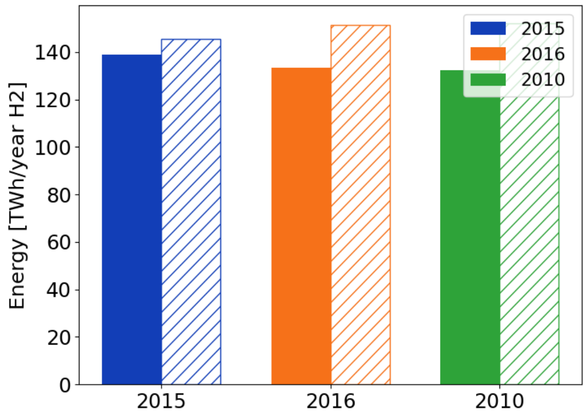

Figure 3.3: Total green hydrogen production in the system for different weather years (filled), and the resulting import calculated, shown in a hatched bar for the corresponding years.

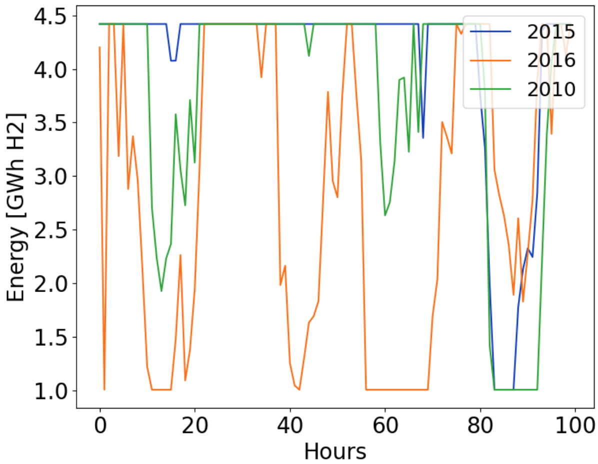

Figure 3.4: Time series snippet of hydrogen production from different wind power profiles.

The energy yield is highly variable both on an hourly scale and an annual scale (Figure 3.3 and Figure 3.4). Note that, the import (hatched bar in Figure 3.3) which is a 'gap filler' also varies as a result of having different yields per year. The difference in the hourly scale can lead to a different production of hydrogen from electrolysis, resulting in different dynamics of transport. On an annual scale, the storage operation and curtailment may vary. To study this, we investigate the effects of choosing different weather years (2015 and 2010) for the computations of wind profiles compared to the reference case. They are chosen appropriately so as to result in a different annual green hydrogen production. Weather year 2015 results in a higher production and weather year 2010 leads to a low production. Note that higher/lower annual yield does not always necessarily lead to more hourly production. Thus, by keeping all other levers unchanged we study the impact of different weather profiles on the KPIs under the theme/lever ‘supply’.

Thematic Scenario – Unavailability in storage sites
The evaluation of this thematic reflects the impacts of risks associated with the initiation plans or operational failures of underground storage sites within the system. Such situations could lead to scenarios where one or more storage site(s) might be non-operational, intrinsically stressing other storage sites in the system. To model such scenario, we omit storage (only) one at a time to simulate the outcome on an annual basis. The result is then several sub-scenarios over which different KPIs are assessed that fall under the theme/lever ‘storage’.

Thematic Scenario – Delay in storage capacity
This scenario entails a situation where a delay in the upscaling of storage sites is expected. We model a condition where a 5 year delay is assumed, that roughly contains only 25% of the storage volumes and rates planned for 2035. By preserving other levers of supply, demand, and network, we only modify storage sites by scaling them down, and evaluate the outcome on the system.

Thematic Scenario – Additional storage at ports
The idea of this thematic scenario is to make the storage system and the hourly balancing in the network more robust and flexible. This is brought by incorporating more surface tank storage capabilities additionally to help balancing the network. We assume both additional storage tanks are available and that more conversion (ammonia cracker capacity) is present at every import (port) location in the network, with properties and rules:

- Additional volume of the tank storage is equivalent to 1% or 5% (2 subscenarios) of the throughput of the annual import volume at the respective port locations
- Maximum charging and discharging rate depends on the capacity of the cracker and increases with added storage volumes

We also assign the priority to these tank storages for hourly balancing within their limits and constraints. Thus this takes the first place in the dispatch merit order, thereby de-stressing the sub-surface storages.

Thematic Scenario – Equal offshore and onshore imports
The theme of this scenario is to change the lever of supply, that involves and reflects the reality of having imports via neighboring countries. Thus we split and modify the import strategy equally between offshore (at ports) and onshore (neighboring countries of Hy3+ regions) locations:

- Offshore imports (at ports). This takes 50% of the deficit in annual supply and annual demand, with the ports operating with shares as listed in Figure 2.6.
- Onshore imports. This takes the rest 50%. Onshore imports are realized with pipelines that connects other neighboring countries, where in the import volumes are based on relative pipe capacities.

3.1.2 Year 2030/2033

Reference case

The second part of the study encompasses the network development plans envisioned for the year 2030. Thus, we gathered data to compile information across the whole value chain as discussed in Chapter 2.

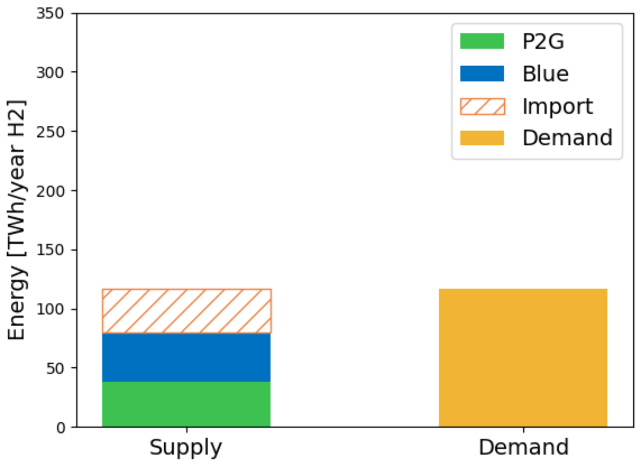

Figure 3.5: Hydrogen energy breakdown in annual supply and corresponding total annual demand of three countries for the reference case year 2030.

- Figure 3.5 shows a similar breakdown of energy mix that is assumed for the early phase development of the network, i.e., for the year 2030. We see that the market will still be developing, already comprising more than 1/3rd of the demand envisioned for 2035.
    - It is assumed that the annual throughput (absolute value) of low carbon hydrogen in 2030 is the same as in 2035. Compared to renewable (green) hydrogen production, it is assumed that low carbon hydrogen will play a larger relative contribution in the first years of the hydrogen economy.
    - This makes all 3 vectors (green hydrogen, low carbon and import) have similar contributions in matching the demand.
- The network backbone assumed for this scenario is illustrated in Figure 2.10.
- Storage sites assumed with volumes and rates are described in Chapter 2.6.

Thematic Scenario – Delayed East West connections

From the geographical distribution of supply & demand illustrated in Chapter 2, we see that the west of The Netherlands is a crucial region for hydrogen production. This puts the pipelines within this region that connect to the rest of the network in a pivoting position for ensuring security of supply. Additionally, with the news of delay in the DRC (Delta Rhine corridor) we investigate this scenario by modelling it, and further investigating the relative importance of similar the east-west connections under the theme of the network lever. Thus the goal of this scenario is to test the resilience of the network to transport the gas from the east to the west. We devise 3 sub-scenarios:

- Reference network without the DRC connection

- Reference network without the North Belgium East-West connection
- Reference network without the South Belgium East-West connection

and compare the network KPIs against the reference case.

3.2 2035 Results

In this section the results of the most relevant scenarios that were run in the HY3+ project are listed. First, the reference case results are presented (section 3.2.1) in detail. Then the other scenarios are presented, highlighting the main differences with the reference case:

- Weather dependency hydrogen production: section 3.2.2;
- Unavailability in storage sites: section 3.2.3;
- Delay in storage capacity: section 3.2.4;
- Flexible operation of import locations: section 3.2.5;
- Onshore import connections: section: section 3.2.6.

3.2.1 Reference case

The results in the reference case section will cover the main physical parameters that result from the scenario inputs. First the mean pressure distribution over the network is provided, as well as the impact of the intermittent supply of hydrogen on the local pressure over time. Similarly the flow distribution is presented. The final parts of the section show the results of the utilization of the storage sites, indicating the fill levels and the required injection and withdrawal rates. The sections concludes with the curtailment that is observed from the scenario.

Pressure distribution and fluctuations

This section discusses the results related to the pressure distribution and fluctuations throughout the 2035 network along an entire year. Emphasis is placed on the hour of maximum flow in the whole network. Since demand and imports have a constant rate throughout the year, the moment of maximum flow corresponds to the moment where green hydrogen production (from solar and wind) is at its maximum.

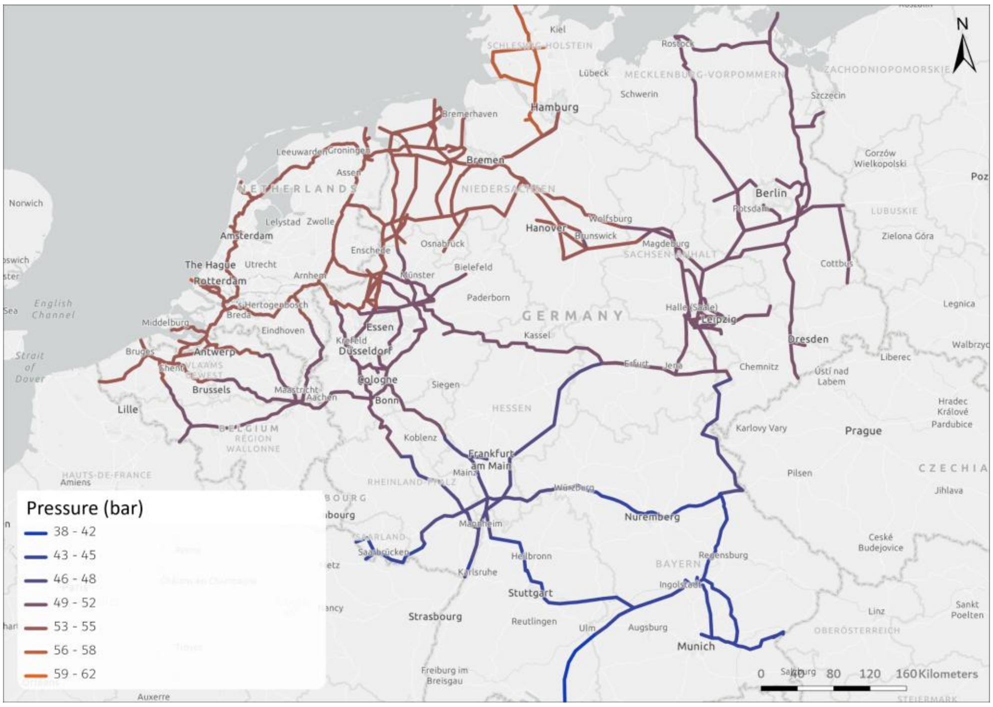

Figure 3.6. Pressure distribution of the 2035 reference case network at the moment of maximum flow.

Figure 3.6 shows the pressure distribution throughout the network at the moment of maximum pressure drop. The maximum pressure areas can be found in the Western part of the Netherlands and it steadily decreases moving to the East and South of Germany. The minimum pressure regions are found in the South of Germany. The maximum peak to peak difference between the high and low pressure locations reaches a maximum of 24bar. Most of the production is located in the West and Northwest of the network, where most of the hydrogen is injected. As the gas is transported to the other regions of the network its pressure level gradually decreases as it arrives to demand cluster and experiences pressure losses throughout the pipelines.

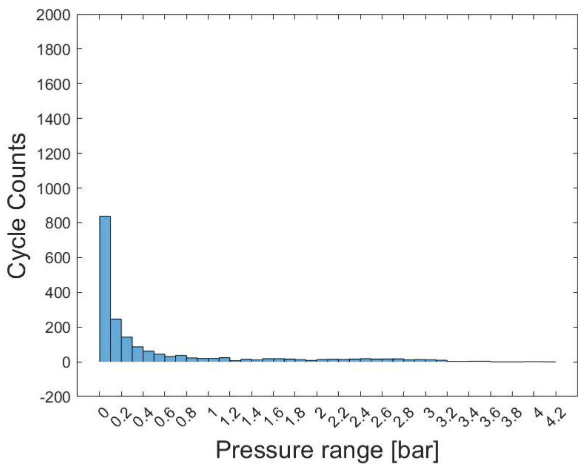

Figure 3.7 Rainflow count (occurrence of pressure fluctuations) at maximum pressure location.

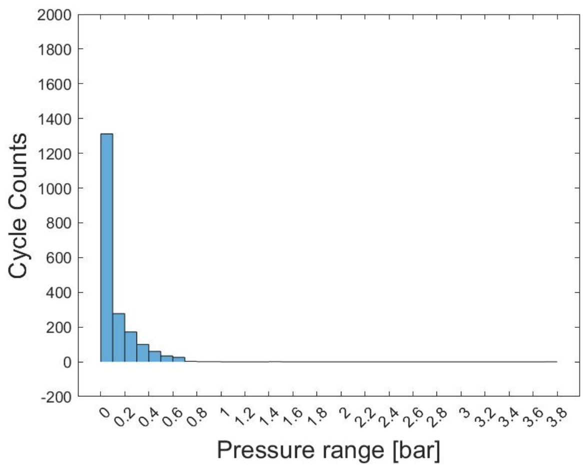

Figure 3.8 Rainflow count (occurrence of pressure fluctuations) at minimum pressure location.

The maximum pressure location, can be found in the vicinity of the Port of Rotterdam. The pressure oscillations throughout the year there can be seen in Figure 3.7. The amplitude of the oscillations is fairly consistent throughout the year, with a maximum peak to peak difference between peaks of approximately 4 bar. Figure 3.8 shows the same plot for the minimum pressure location, at the network's Southernmost point in Germany. As can be seen, the pressure oscillations remain very stable, with an amplitude of about 0.5 bar. There is an exception towards the end of the year, where the pressure suddenly increases about 4 bar. As later explained in the section 'Curtailment', this is caused by a brief period of demand curtailment.

These pressure results show that there are is no bottlenecks in the 2035 hydrogen network. Since the pressure distribution remains always between the minimum of 30 bar and maximums of 66 bar and 85 bar throughout the year.

Velocity and flow distribution

The two figures above showcase the velocity and flow distributions through the 2035 network at the moment of maximum flow. Both plots show a similar pattern as their pressure counterpart, with the maximum values reached in the West of the Netherlands and its lowest towards the East and South. An important point to note is the high velocity peak near the Port of Rotterdam which can be caused by the way the simulated network lumps all of the supply in Rotterdam into a single pipeline. Aside from this anomaly, there appear to be no other obvious bottlenecks, with the velocity in the whole network well below the expected limit of 60m/s, even in this extreme case of maximum flow hour.

Figure 3.9: Velocity distribution throughout the 2035 network at the moment of maximum flow

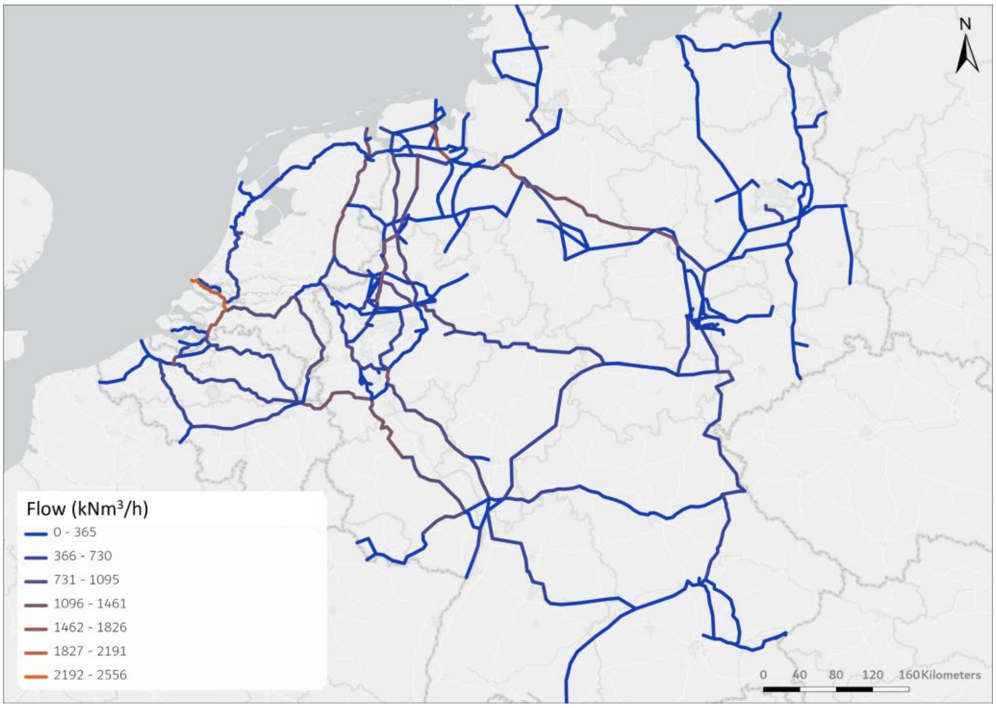

Figure 3.10: Flow distribution throughout the 2035 network at the moment of maximum flow

Storage

Figure 3.11 shows the fill level of all storage sites in 2035. As seen in the 2035 reference scenario, assuming a year start fill level of 50%, the storage system reaches both its maximum and minimum fill levels at several points within the year. This is an indication that the assumed storage capacity (ref. Figure 2.12) is insufficient under this scenario. When the storage volume is depleted, there is a curtailment of demand. An insufficient storage volume capacity has a significant impact on demand curtailment. This can be seen towards the end of the year in Figure 3.15.

Another important observation is that the system does not recover to the initial 50% fill level at the end of the year. Under these settings, the system is not self-sustainable. As discussed in section 2.6, no strategy to achieve a self-sustainable storage was implemented, so as to keep the system unbound. Although not shown or demonstrated here, an ideal storage to balance the system for an entire year (weather year 2015) would have 4.1 TWh of storage capacity with a required injection capacity of 5.4 GW and production of 10.5 GW. This also would allow for a storage fill at the beginning and end of the year that is balanced.
It is important to note that the storage fill level profile is highly dependent on the weather scenario chosen for this simulation. This aspect is later discussed in section 3.2.2.

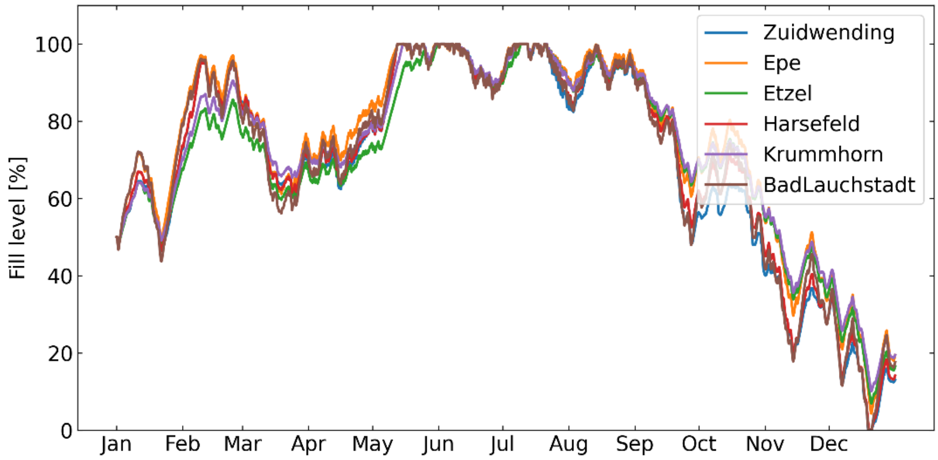

Figure 3.11 Fill level at every storage location for the 2035 reference case.

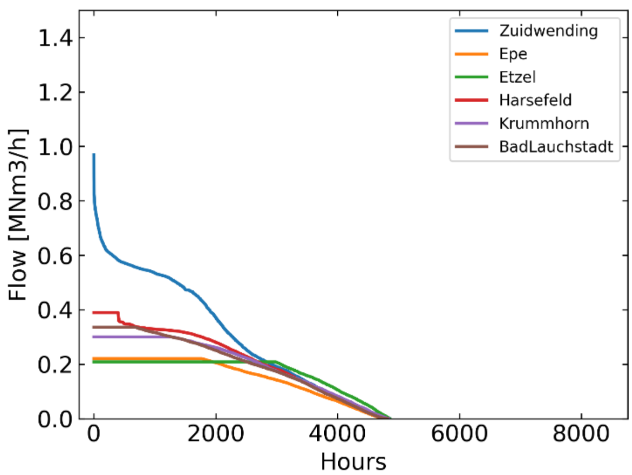

Figure 3.12 Injection rate-duration curve for all the storage sites during the 2035 reference case.

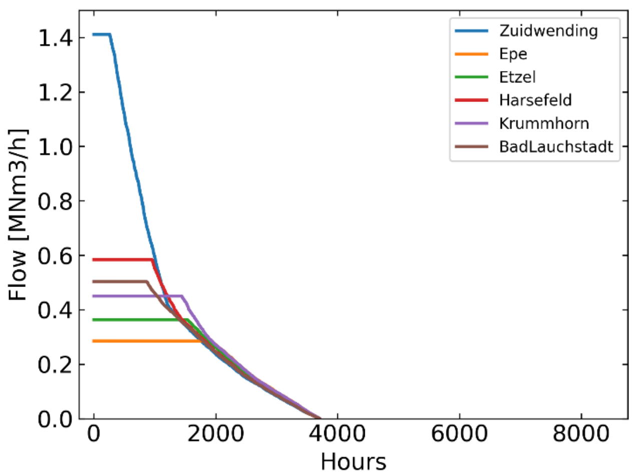

Figure 3.13 Discharge rate-duration curve for all storage sites during the 2035 reference case.

Figure 3.12 and Figure 3.13 show the injection and discharge rate duration curves of every storage site through the year (arranged from high to low). The injection rate of Zuidwending never reaches its limit, meaning that the system can accommodate the required injection rates. At certain time instances in the year, however, the fill level of the cavern has reached its maximum. This results curtailment of production nonetheless. The other sites all reach their maximum production rates for a number of hours. This is an indication that the maximum production rates in the storage system are too low and more production capacity might be necessary. This insufficient storage production rate results in demand curtailment. The magnitude of this curtailment is lower than in the case of insufficient storage volume. It can be seen in the small demand curtailment peaks throughout the year in Figure 3.15. This bottleneck can result in moments where the system is incapable of satisfying the required demand rates creating this demand curtailment.

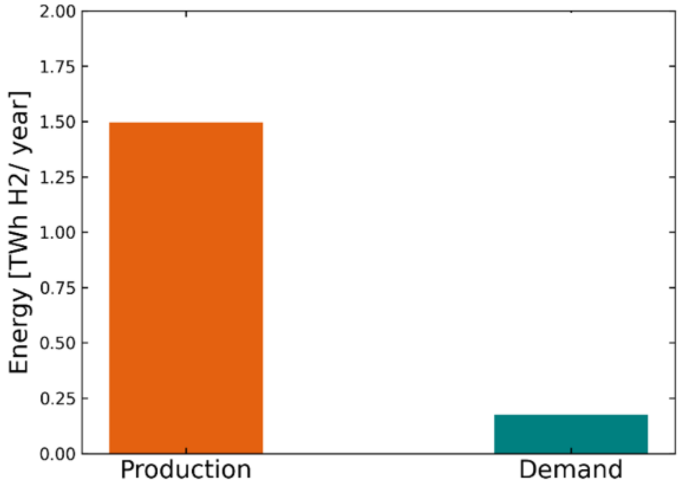

Figure 3.14 Total hydrogen production and demand curtailed during the 2035 reference scenario in a stacked bar chart (Production is stacked with different sources : Import, low carbon hydrogen, Onshore and Offshore P2G)

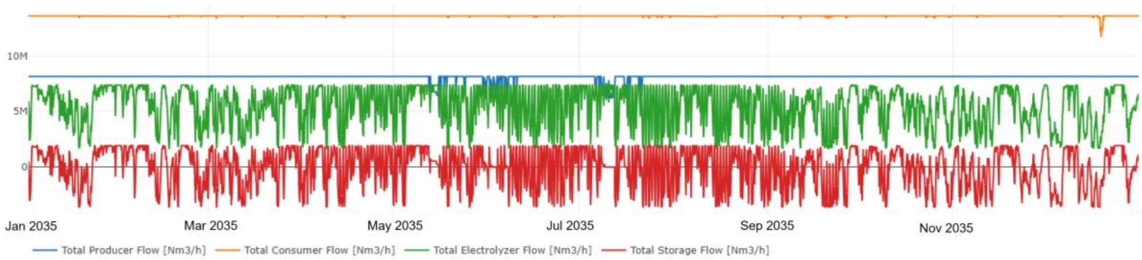

Figure 3.15 Exploded view of total producer (Import and low carbon Hydrogen) in Blue, total consumer (Orange), total electrolyzer (Green) and total storage (Red) flow rates throughout the year in the 2035 reference scenario. Negative storage flow rates are instances of production and positive flow rates are instances of injection.

Figure 3.14 shows the amount of energy curtailed during the 2035 scenario from a production and a demand point of view. As seen, all curtailment is applied to import of hydrogen, and a globally distributed over demand. A curtailment in production indicates a forced stop in the amount of hydrogen being produced and a demand curtailment shows a cut on the uptake of that hydrogen. They are both indications of imbalances of the system. In the case of production, there is an observed curtailment of 427 hours with 0.45% of the total yearly production. This is caused by the previously mentioned insufficient storage capacity. With a constant demand rate, if the system's fill level reaches 100%, the system needs to rebalance itself by curtailing production.

Demand curtailment is caused by an inability of the system to generate a high enough production rate to satisfy demand. If the hydrogen generation from imports and other sources is too low, this must be compensated by storage production. The fact that the system is uncapable of achieving this for 285 hours, is another indication of the previously mentioned insufficient storage maximum production rate. This could also be solved with storage sites with a higher maximum production rate, to avoid the system hitting 0% fill level and possible demand curtailment.

Over a year, the curtailed hydrogen production and demand is in the order of 1 percent. However, this is calculated using an optimal, cross border storage strategy which is very unlikely to be realized. In addition a flat demand rate over all sectors, which can influence the total curtailment in the system.

2035 reference case conclusions
The 2035 reference case conclusions are as follows.
- No critical bottlenecks are observed in transporting hydrogen safely within maximum operational pressures and minimum guaranteed pressure.
- Pressure fluctuations in the pipeline network can be around 3-4 bar peak-to-peak.
- Velocities up to 45 m/s occur in the Rotterdam area.
- The volumes and production rates of storage sites are insufficient to avoid curtailment completely.

3.2.2 Weather dependency hydrogen production

In both reference cases, the green hydrogen production is directly dependent on the weather profile used. The production rate at every hour is dependent on the amount of solar and wind energy production at that given hour. By this reasoning, it is obvious that the production profile of a given year will directly depend on the weather profile used. For the previous reference cases, the weather profile for 2016 was used. The goal of the scenario discussed in this section was to analyze the impact of the weather profile selected on the results. At the same time, it will be evaluated whether it is possible to improve the storage profile by correlating the results obtained for different weather years. To do this, two additional weather profiles, 2010 and 2015, will be used as an input and the results will be analyzed. All of the simulations in these scenarios were performed on the 2035 network.

The differences between the scenarios presented here and the reference case are the power production profiles used as inputs for the P2G producers (electrolyzers). Instead of the reference case year (2016), the 2010 and 2015 weather years were used. 2010 corresponds to what is referred to as a 'low wind' year and 2015 as a high wind year, but also a year with a “Dunkelflaute”. It is important to note that a year is labelled as low, medium or high based on the total yearly power production coming from wind. To build these weather profiles, the wind data from the three countries is used, in combination with solar data.

Table 3.1 Main network parameters for the different weather profiles scenarios.

Weather profile year	Δp_{max} [bar]	V_{max} [m/s]
2010	24.6	43.7
2015	24.3	42.3
2016 (reference)	23.5	45.2

Table 3.1 shows the network high level results for the different weather profiles. The highest pressure drop happens during the low wind year. The reason for this is that the import rate is calculated taking into account the total green hydrogen produced in that year. A low wind year will result in a low green production, and the import rate is increased to compensate this. Despite this, as can be seen, the maximum pressure over the network is quite small for different weather inputs. The same conclusion applies for the maximum velocity values.

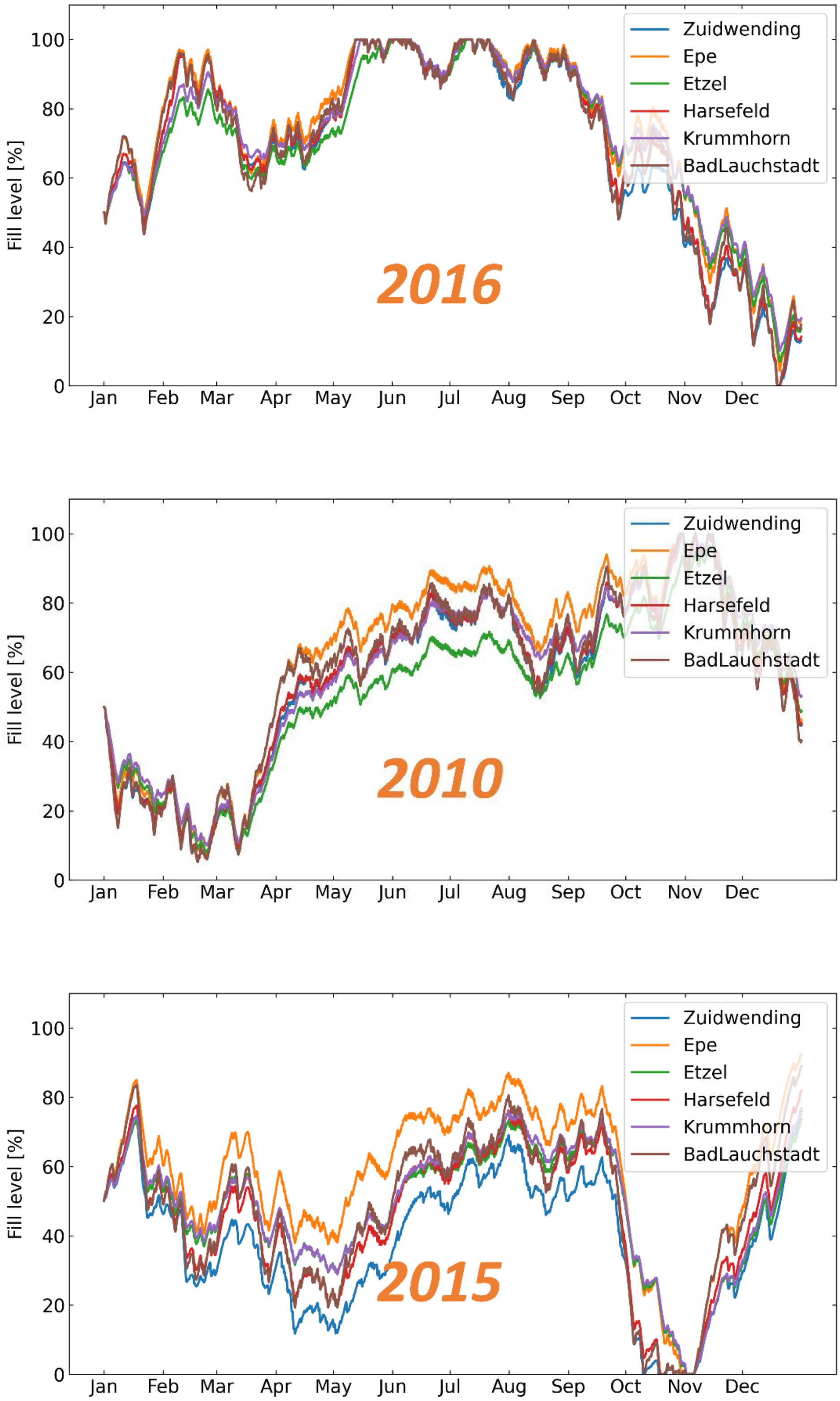

Figure 3.16 Storage fill level throughout the year for all storage sites for different weather profile inputs. NOTE: the years labelled correspond to the weather year used as an input. All the simulations were performed on the 2035 network.

Figure 3.16 shows the fill level throughout the year for every storage site in the 2035 networks, using different weather year information as inputs. Regarding storage strategies, with wind profile year 2010 and 2016, it would be reasonable to aim for maximum storage fill levels in November, in order to accommodate for the low production months after it. On the other hand, using this strategy wind profile year 2015 would lead to curtailment situations after November, due to the increase in production after that month. This shows that no clear storage strategy can be extracted by studying patterns in the weather profiles.

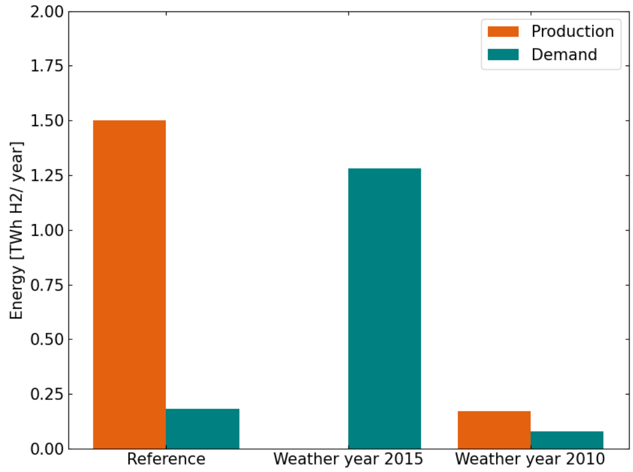

Figure 3.17 Total energy curtailed in the 2035 network by using different weather profiles as an input in a stacked bar chart (Production = orange, demand = blue)

Table 3.2 Total energy curtailed values in the 2035 network for different weather profiles used as an input.

Year	Curtailed production [TWh H2]	Curtailed demand [TWh H2]
2010	0.17	0.08
2015	0	1.28
2016 (reference)	1.50	0.18

Figure 3.17 and Table 3.2 show the total energy curtailment that was necessary during the simulations using different weather profiles as an input. As it can be seen, the total curtailment, both in production and demand, is highly sensitive to the weather profile used. In the 2010 case, the curtailment is very low. In this scenario, the bottleneck is not the total storage volume, but the maximum production rates from the storage sites. The only asset type to curtail from the production (following the merit order) was import, accounting to only 0.1% of the total volume. The curtailment of demand was observed to be only 0.02% of the total amount.. For the weather year 2015, we see that only demand is curtailed (roughly accounting to 0.35% of the total amount). This is due to the occurrence of the “Dunkelflaute” (a long period of time with no or almost no wind or sun). During this phenomenon, the production rates are too low creating a sharp imbalance between the demand and production available at that time. In the case of 2016, the curtailment is significant for production and there is also a noticeable curtailment on the demand side.

All of the previous results show that there is no correlation between the results across different weather years. While there are no significant impacts on the maximum pressures and velocities through the network, there is a big influence of the weather on the curtailment values. As concluded also in the reference cases, there are bottlenecks arising due to insufficient storage volumes and limiting storage production rates.

3.2.3 Unavailability in storage sites

The goal of this scenario is to study the impact of eliminating single storage sites from the 2035 network. This was modelled by removing each storage site individually and simulating a full year for each case.

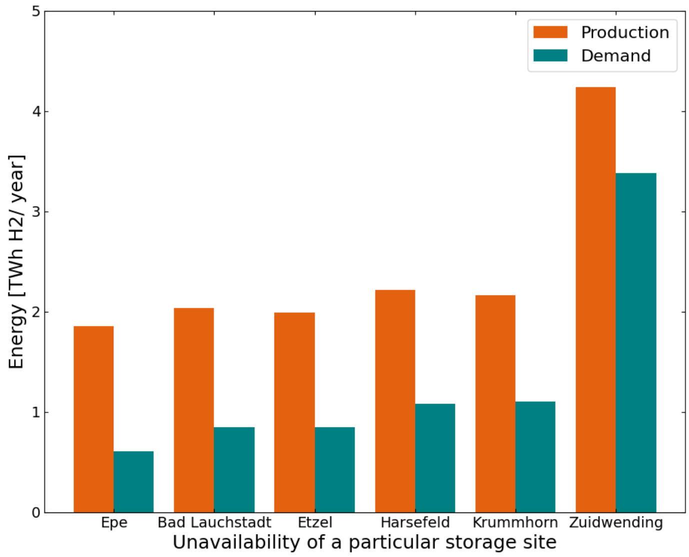

Figure 3.18 Curtailment levels resulting from eliminating single storage sites as part of the omittance in storage sites scenario (production = orange, demand = blue).

Figure 3.18 shows the curtailment incurred during the simulations of these sub scenarios. Compared to Figure 3.14 it can be seen that, by removing a storage site, there is always an increase in curtailment compared to the reference case, both from the production and demand side. Figure 2.12 and Figure 2.14 show the storage volumes of each site, together with their maximum injection and production rates. By comparing these figures with Figure 3.18, it becomes clear that the increase in curtailment is driven by the removal of high injection and production rate sites, not by their total volume.

3.2.4 Delay in storage capacity

The goal of this scenario was to study the impact that delays in the available storage capacity would have on the system. To achieve this, the 2035 network was modelled using the storage sites and volumes of the 2030 reference case.

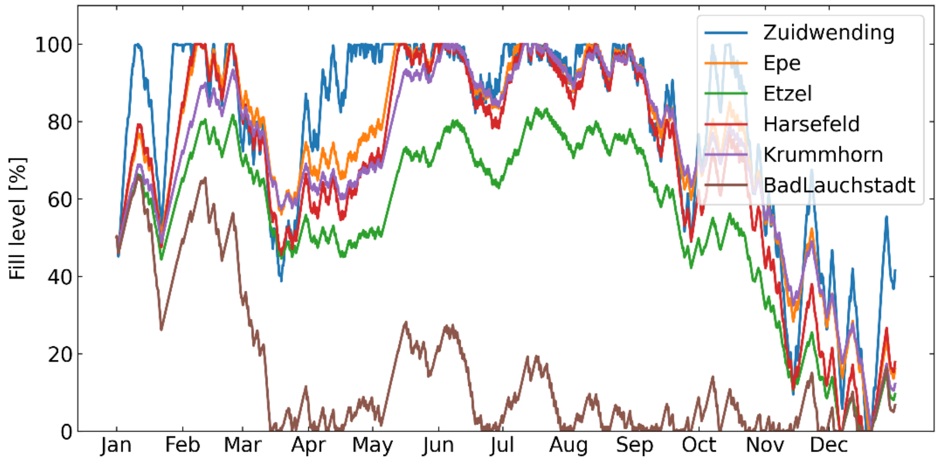

Figure 3.19 Storage fill level at every storage site throughout the year in the delay in storage capacity scenario.

Figure 3.19 shows the fill level at every storage site throughout the year in this scenario. It can be clearly seen that the storage capacity is insufficient, with almost every site reaching its 100% fill level during extensive periods of the year. This results in curtailment, both in production and demand, as seen in Figure 3.20. The asset type that is curtailed from is import, accounting to approximately 7% of its total volume, whereas demand accounting to 3%. By comparing this result with Figure 3.14 it becomes clear that the curtailment values are greater than in the 2035 reference case. This is to be expected, since it was already established that the reference case already had insufficient storage capacity. It is also important to note how the Bad Lauchstadt location is almost always depleted. The reason for this is a combination of a low storage volume and a high maximum production rate. In order to avoid demand curtailment, the production rates of storage sites is quickly maxed out. When this is applied to a storage with a high maximum rate and a low storage volume, it results in a fast depletion.

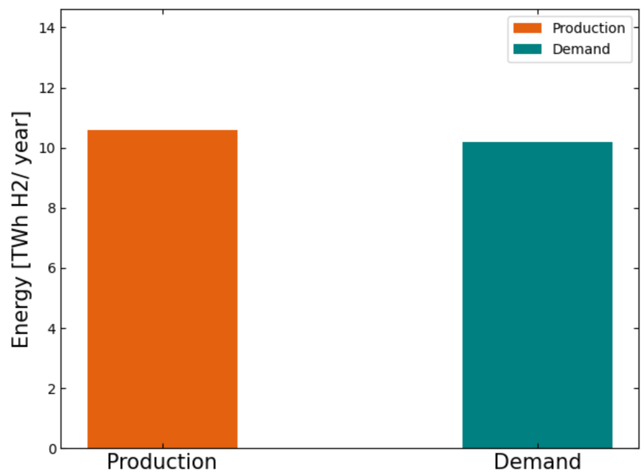

Figure 3.20 Total demand and production energy curtailed during the delay in storage capacity scenario in a stacked bar chart (Production is stacked with different sources : Import, low carbon hydrogen, Onshore and Offshore P2G) .

3.2.5 Additional storage at ports

The goal of this scenario was to explore the impact of adding additional storage capacity at the import harbors in the form of surface storage tanks. The main question that this analysis aims to answer is whether this additional storage, in combination with the assumed underground storage sites, can enhance security of supply & demand. This analysis was performed on the 2035 network.

In the reference case it was assumed that the storage at the import would be designed in such a way so that a flat rate supply of hydrogen to the pipeline infrastructure from import locations throughout the year could be achieved. Depending on the vessels frequency and sizes of storage capacity is assumed to be in the same range as that for LNG import.

The main difference in this additional scenario compared to the 2035 reference case is the addition of extra storage tanks at each port. Two cases were set up, one with an additional storage capacity at each port of +1% of the total import volume and the other bookend scenario at +5%. This results in a total additional storage capacity of 1.5 TWh in the 1% case and 7.5 TWh in the 5% scenario. For both cases, topside surface storage is assumed, with the charge and discharge rates set at a maximum of double the import rates at each port.

Without considering the cost optimum, it is assumed that additional surface storage tanks at the import locations are developed. These storages are comparable to sizes of large, refrigerated ammonia storage tanks [17]. These capacities are assumed at roughly 330 GWh ~ 10kt/y H2 (based on LHV), leading to 12 tanks totally installed and distributed across all port locations for the case of 1% throughput and 28 tanks for the case of 5% throughput[3].

[3] Note that the ENTEC report cited here quotes "The total installed costs for 55,000 t NH_3 tanks are estimated at roughly 64 M€, which is equivalent to a specific cost of ~1,164 €/t NH_3 (or ~ 6,500 €/t H_2) " this would imply that adding 12 tanks would cost at least 750 Meuro of investments excluding the costs of the required cracker capacity. According to the ENTEC report ammonia tank storage and CAPEX requirements for UHS in caverns is in the same order of magnitude.

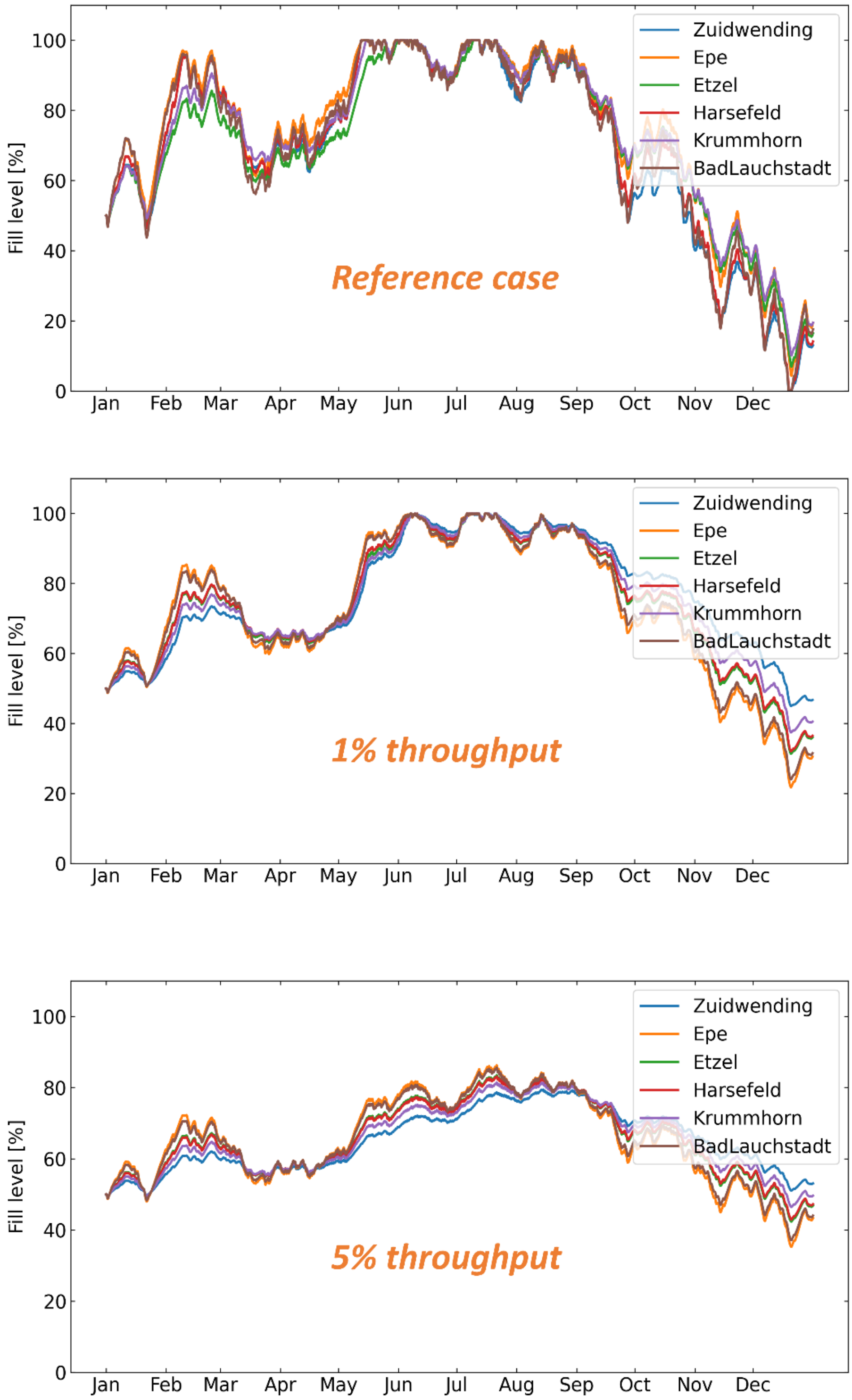

Figure 3.21 Storage fill levels throughout the year at every underground storage site for the 2035 reference case (top), the 1% import storage capacity (middle) and 5% import storage capacity (bottom) scenarios.

Figure 3.21 shows the storage fill level at every underground storage throughout the year. Adding storage capacity at the ports relieves some of the total volume stress on the underground system. In the 1% case, the additional port storage capacity is enough to avoid complete depletion of the underground storage portfolio, although it does reach its maximum fill level several times. In the case of the 5% additional storage scenario, the extra capacity is enough to avoid maxing out or depleting the underground storage at any point throughout the year.

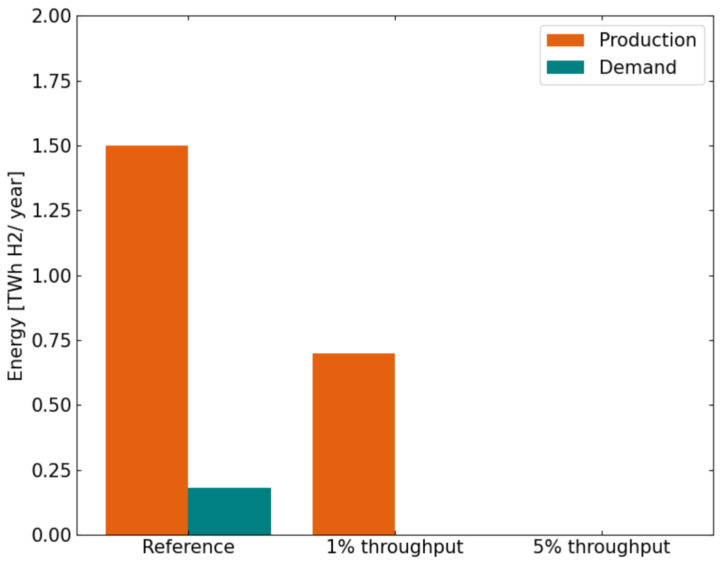

Figure 3.22 Comparison of the total curtailed energy in production and demand for the 2035 reference case (middle), and the two port storage scenarios (left - 1% throughput; right – 5% throughput).

Figure 3.22 shows the total energy curtailed for the 2035 reference case and the two scenarios studied here. As expected, the curtailment level decreases with the added storage capacity at the ports. In the 1% scenario, some production curtailment is still necessary. This is caused by the previously mentioned times when the maximum underground fill level is reached. In the case of the 5% port storage capacity, no curtailment is needed at any point throughout the year. This suggests that adding this storage capacity at the import locations could alleviate the need for additional underground storage capacity.

3.2.6 Equal offshore and onshore imports

This scenario is scoped around the scenario of alternative supply routes. The main difference is that we have a different import strategy, that is not only entirely routed via port locations, but considering in-land imports too, where the annual volume is split equally between in-lands (50%) and port locations (50%). In-land imports are assumed to be brought in via the pipelines connecting to other countries neighboring all HY3+ regions (France, Switzerland, Austria, Czechia and Poland).

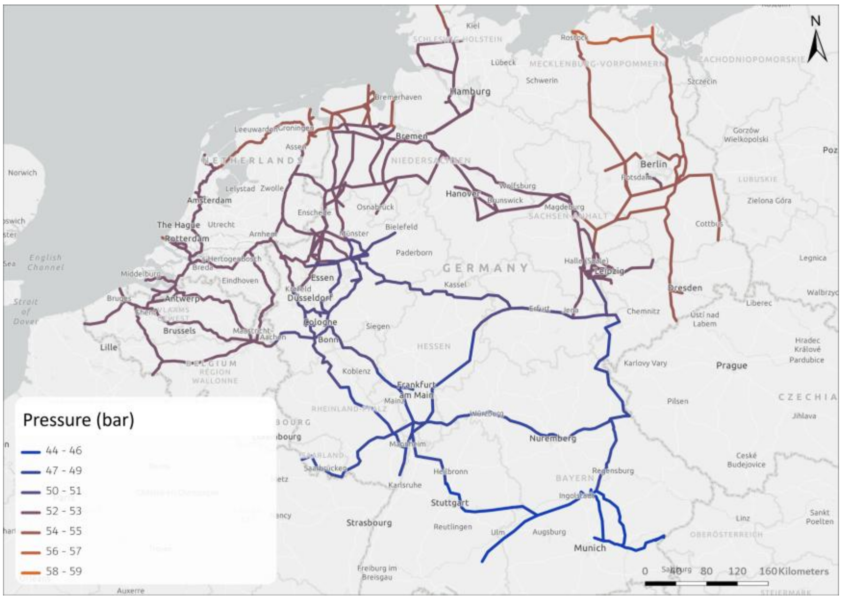

Figure 3.23: Pressure distribution through the network at an instant of maximum flow

Figure 3.23 shows the pressure throughout the network at instant of maximum flow (due to maximum production from electrolyzers, which are the only variable asset). Initially, we see similar trend of pressure distributions, of having higher pressures in the coastal regions, gradually reducing towards the south-east part of the network. Although, we see a significant difference in the magnitudes of the pressure in the network. The overall pressure drop across the network is minimal (compared to the reference case ; Figure 3.6) due to additional supply sources via onshore imports.

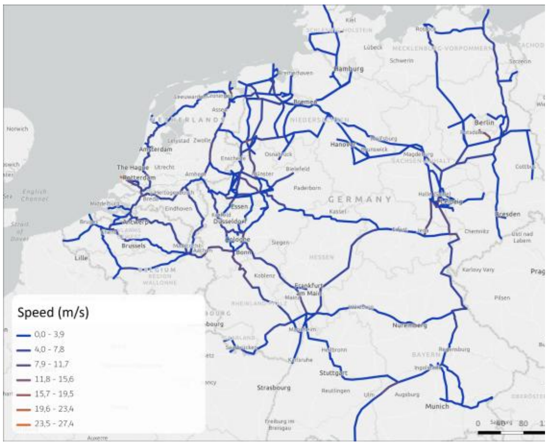

Figure 3.24: Velocity distribution through the network at a maximum flow instance.

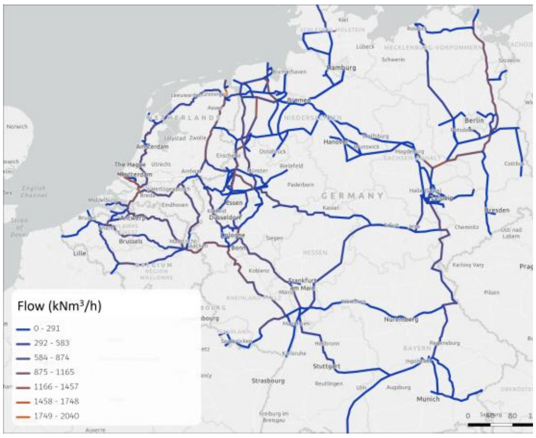

Figure 3.25: Flow distribution through the network at a maximum flow instance.

Without any in-land imports, the system experiences high pressure drops that is required to drive the flow produced in the coastal regions to the off-take clusters in the middle and south of Germany. With the presence of in-land imports, we have additional (constant) flow from the pipes connecting the neighboring countries ranging between 0.08MNm^3/h - 0.3MNm^3/h. This makes the total supply of hydrogen in those bordering regions higher, requiring less hydrogen to be transported from the coastal regions, making the total network pressure drop lower (to 14 bar on a maximum flow interval). Consequently, the total velocities in the pipeline are also lower than the reference; no more than 27 m/s due to the difference in the flow distribution.

3.3 2030/2033 Results

The scenarios discussed in this section are all the simulations performed on the 2030/2033 hydrogen network. First, the reference case results are presented in detail (section 3.3.1). Then one other specific scenario is detailed further, which shows the impact of delayed East-West connections (section 3.3.2).

3.3.1 Reference case results

Similar to the 2035 results, the reference case section will cover the main physical parameters that result from the scenario inputs. Hence, first the mean pressure distribution and pressure fluctuations are presented, followed by the flow distribution and local flow fluctuations. The final parts of the section show the results of the utilization of the storage sites, indicating the fill levels and the required injection and withdrawal rates. The sections concludes with the curtailment that is observed from the scenario.

Pressure distribution and fluctuations

After simulating the 2030 hydrogen distribution network for an entire year, the pressure distribution throughout the network was analyzed. This section presents the results and observations related to this network pressure distribution. The moment of maximum flow is given special emphasis. This moment is identified on September 24th of 2030. Since the demand of the simulation is set as a constant, the maximum flow instant is a result of the selected yearly wind profile.

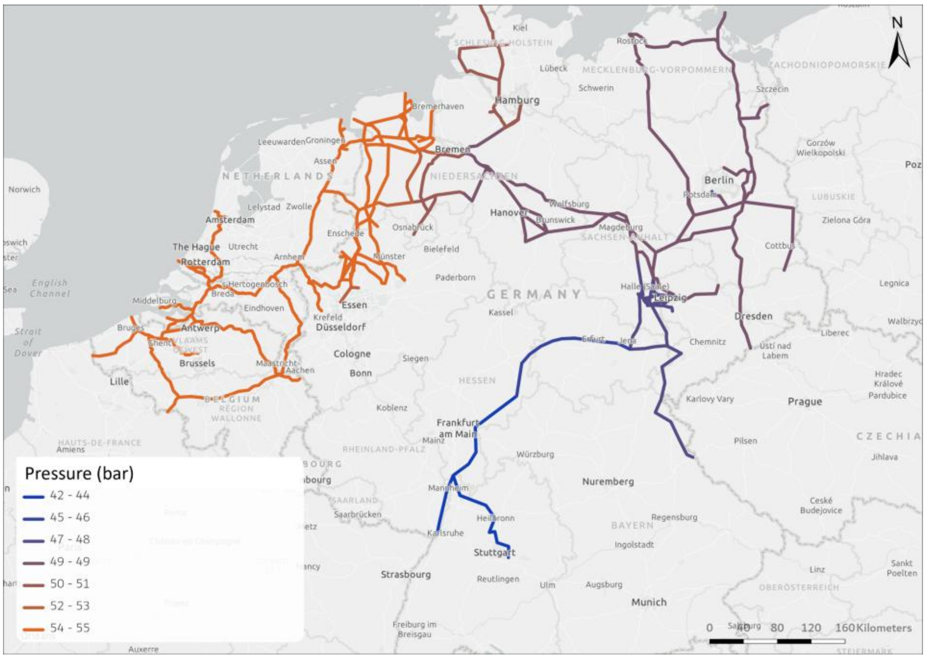

Figure 3.26 Pressure distribution of the 2030/2033 reference case network at the moment of maximum flow.

Figure 3.26 displays the pressure distribution in the hydrogen network during the 2030 reference case scenario. The date selected for this map corresponds to the maximum flow instance throughout the year. As can be seen in the figure, the map shows a pressure distribution with its maximum at the Western part of the Netherlands and a decrease towards the East and West, to reach its minimum in Southern Germany. The is because the major import and production points of the network are in the vicinity of the Port of Rotterdam. Since there are no booster stations in the studied network, the pressure of the gas gradually decreases as it travels through the network to the East and then South. It is important to remember that, in this model, no physical connections to neighboring countries (aside from the three studied) are present.

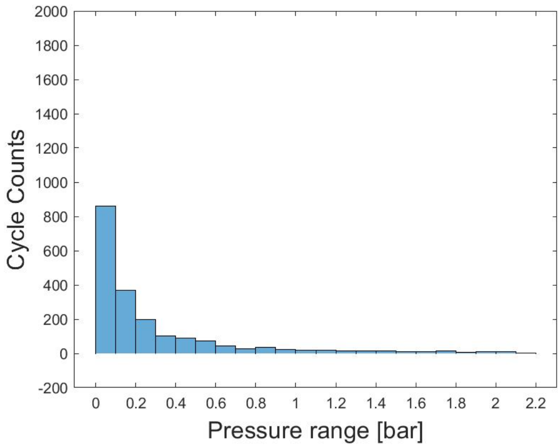

Figure 3.27 Rainflow count at the maximum pressure location.

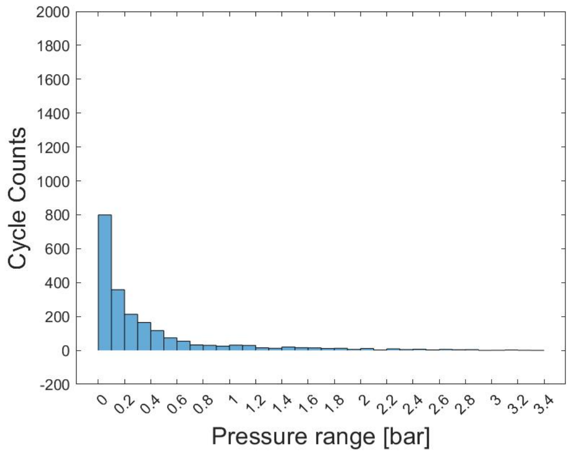

Figure 3.28 Rainflow count at the minimum pressure location.

The maximum pressure location can be found at the Port of Rotterdam, reaching a value of almost 55 bar. The pressure fluctuates throughout the year as the production profile changes with time. These fluctuations can be seen Figure 3.27. As displayed in this graph, most of the oscillations have a range of 0.6bar or less, with a maximum difference between peaks of approximately 2 bar. The minimum pressure location can be found around the demand cluster of Stuttgart (Southern-West Germany). The pressure fluctuations at this location during the maximum flow instant can be seen in Figure 3.28. These oscillations also show a typical amplitude of 0.6 bar or less throughout the year, with a maximum difference between peaks of about 3.5 bar.

The pressure analysis shows that no bottlenecks can be observed for the safe transport of hydrogen throughout the network in 2030/2033. This is shown by the fact that the envisioned minimum (30 bar) and maximum pressure limits (66 bar for the Netherlands, 85 bar for Germany) are not exceeded throughout the year.

Velocity and flow distribution

Figure 3.29 and Figure 3.30 show the velocity and flow rate distribution throughout the network at the maximum flow instant. The highest velocities and flow rates are observed among the DRC pipeline in the Netherlands and the lines near Hannover in Germany. A similar pattern was observed following the pressure distribution analysis. Aside from this observation, no clear bottlenecks can be found in the network from a velocity and flow rate point of view. Even at the maximum flow instant, shown in the figures discussed, the maximum velocity is well below the expected maximum limit of 60m/s.

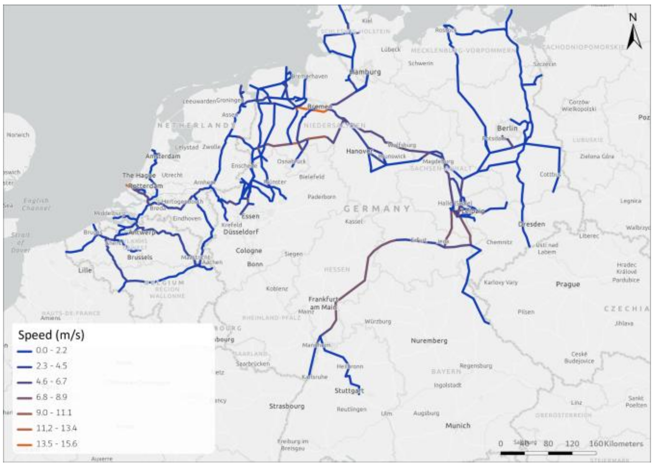

Figure 3.29 Velocity distribution throughout the 2030 network at the moment of maximum flow.

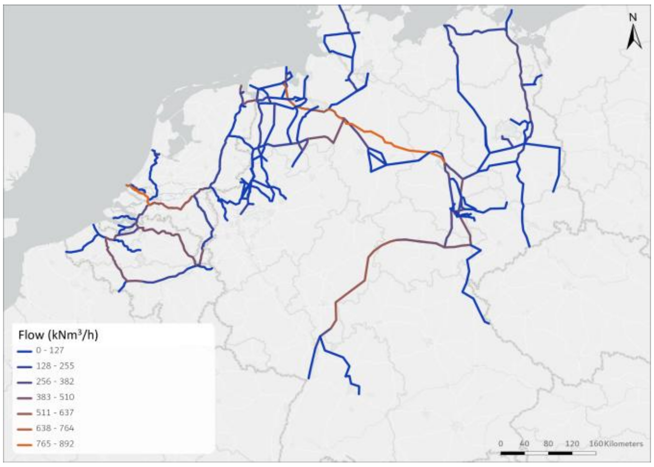

Figure 3.30 Flow distribution throughout the 2030 network at the moment of maximum flow.

Storage

Figure 3.31 above shows the storage fill level at every storage in the network throughout the 2030 reference year. As it can be seen, all sites start at a level of 50% on the 1st of January. After that, their fill level oscillates throughout the year, increasing when production is higher than demand, depleting in the opposite situations. It is important to notice that all storage sites reach maximum capacity several times throughout the year, with some instances in July where all sites reach a 100% fill level simultaneously.

Figure 3.32 and Figure 3.33 show the injection and production rate duration curves for all sites. For almost every site, both production and injection duration curves flatline for a significant number of hours. Every site has a maximum injection and production rate, dictated by technical and physical limitations. These flat lines in the duration curves indicate that the sites are hitting these maximum rates for a certain time duration. This is an important observation, since it indicates that the sites cannot accommodate higher charge or discharge rates during those times, even if production or demand require it.

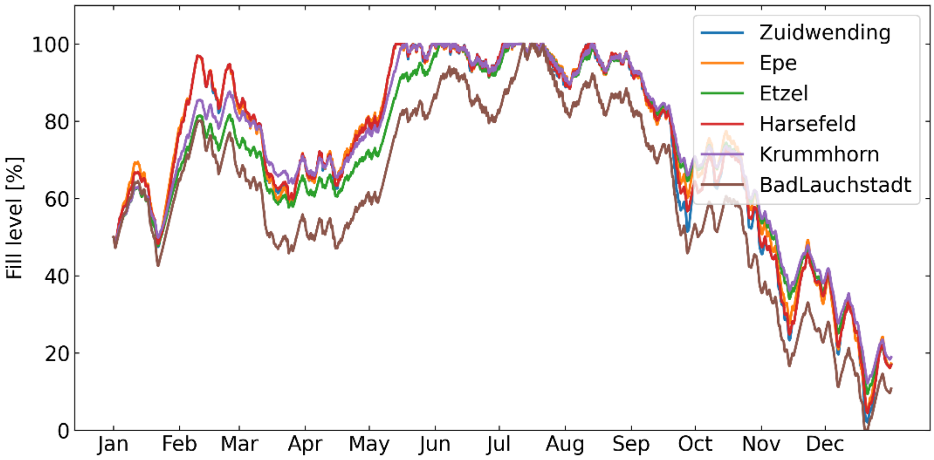

Figure 3.31 Fill level at every storage location throughout the year for the 2030 reference case.

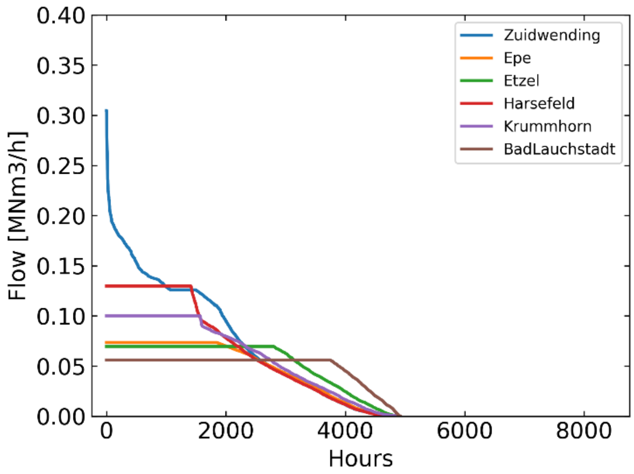

Figure 3.32 Injection rate-duration curve for all storage sites throughout the year during the 2030 reference case.

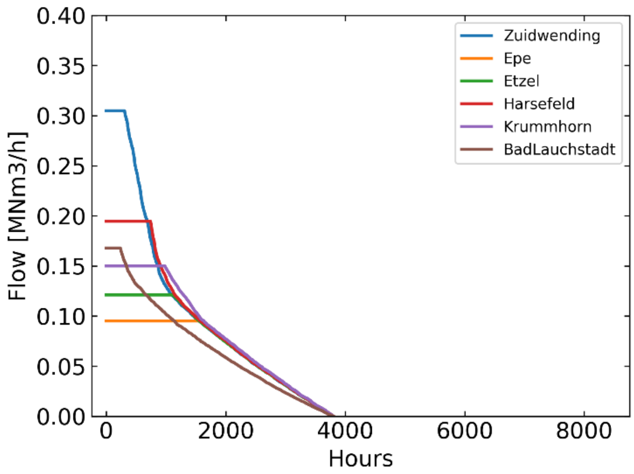

Figure 3.33 Production rate-duration curve for all storage sites throughout the year for the 2030 reference case.

These two results, with the storage sites reaching their maximum fill level and maximum production and injection rates, are an important limitation for the network. This is a clear indication that the current proposed network storage capacity is insufficient for the 2030 hydrogen network and chosen demand & supply scenario. Additionally, these observations, together with the selected storage strategy, are responsible for the storage levels not reaching their initial 50% level at the end of the year.

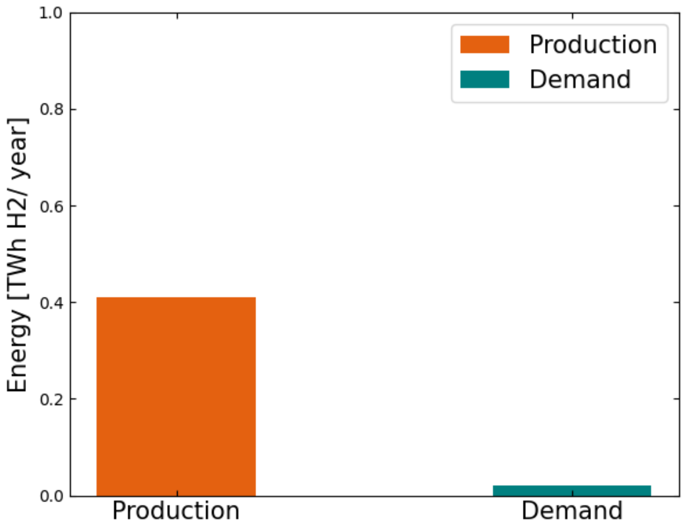

Figure 3.34 Production and demand of hydrogen curtailed throughout the year during the 2030 reference scenario in a stacked bar chart (Production is stacked with different sources : Import, low carbon hydrogen, Onshore and Offshore P2G) .

Figure 3.34 shows the amount of curtailment performed throughout the year in the 2030 case. Curtailment occurs when the network cannot accommodate the hydrogen being produced (production curtailment), or when the network cannot satisfy demand at a given moment (demand curtailment). As seen in the figure, there is a noticeable amount of production curtailment (0.35% of the total production over a span of 457 hours) and a small level of demand curtailment (0.015% of the total demand over 222 hours). Both situations are a sign of the system being unable to accommodate the full required hydrogen flow.

Both situations are caused by the storage limitations previously described. In the production case, the storage sites cannot accommodate all of the produced hydrogen. During periods of high production, supply exceeds demand, so the difference must be stored. During these periods, the storage sites eventually hit their 100% fill level, becoming unable to absorb this excess supply. This is a sign of insufficient storage capacity in the network. During periods of low production, demand may exceed production. This deficit needs to be covered by gas produced from the storage sites. If the storage sites reach 0% fill level or the required outward flow exceeds its maximum production rate, demand must be curtailed. These two situations were seen when analyzing the storage results, indicating again that the storage capacity in the 2030 case is insufficient.

2030 reference case conclusions

The 2030 reference case conclusions are as follows.

- No critical bottlenecks are observed in transporting hydrogen safely within maximum and minimum operational pressures.
- Pressure fluctuations are experienced in the pipeline network around Rotterdam and South Germany around 3-4 bar peak-to-peak.
- The production rates of storage are insufficient. Storage volumes (capacity) and injection rates are sufficient.

Sensitivity analysis lower network pressure

In order to assess the robustness of the simulations performed, a short sensitivity analysis was conducted. Most of the simulations in this study start with a network pressure of 50 bar. If the demand in 2030 is lower than expected, running the network at a lower pressure of 40 bar could be possible. This could lead to higher flow velocities and pressure drops. The goal of this simulation at 40 bar is to check if new bottlenecks emerge under these conditions. The pressure, velocity and flow distributions throughout the network are shown in Figure 3.35, Figure 3.36 and Figure 3.37.

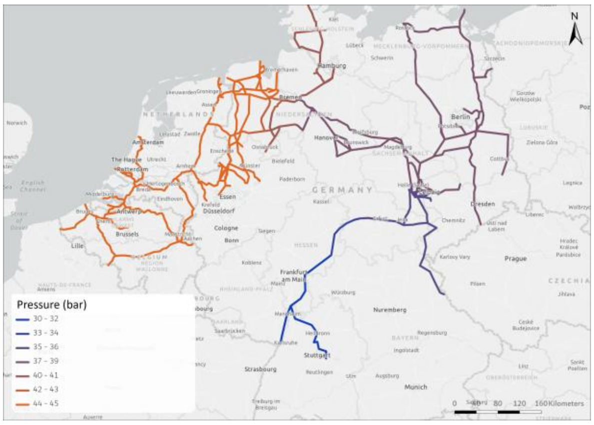

Figure 3.35 Pressure distribution throughout the network for a base network pressure of 40 bar and the 2030 reference scenario.

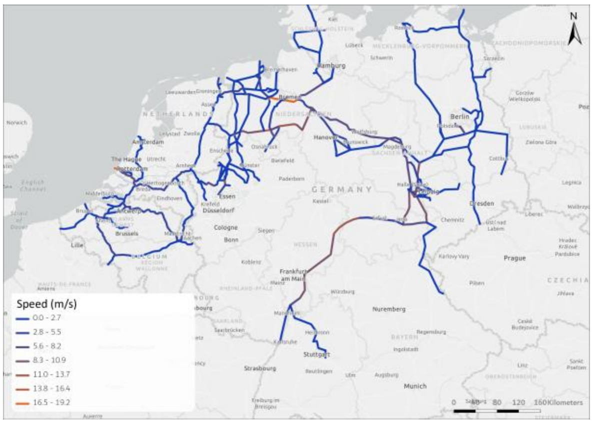

Figure 3.36 Velocity distribution throughout the network for a base network pressure of 40 bar and the 2030 reference scenario.

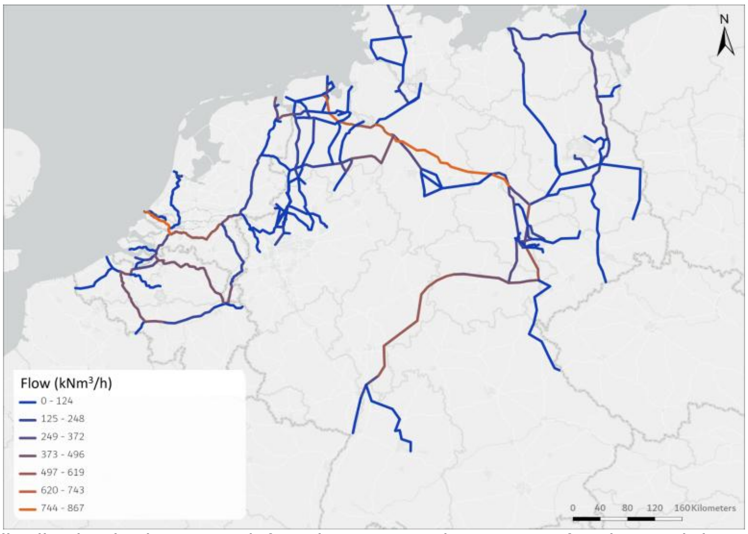

Figure 3.37 Flow distribution in the network for a base network pressure of 40 bar and the 2030 reference scenario.

It was observed that the overall pressure distribution throughout the network decreases about 10 bar, as would be expected after initializing it with a 10 bar lower pressure. At the same time, the maximum velocity has increased approximately 23% from 15.6 m/s, in the original reference case, to 19.2 m/s in this sensitivity study. With a decrease in pressure of 20%, a corresponding decrease in density of approximately the same magnitude is anticipated. The simulation is set with the constraint of mass flow demand matching. This means that if the density is decreased by 25%, the velocity of the gas needs to increase by the same amount, as observed. The difference between the maximum and minimum pressures detected is 15.6 bar (about 28% higher than in the reference simulations). The increased pressure difference can be attributed to differences in local pressure. All of these observations support the belief that the simulations are robust enough and the physical conclusions reliable.

3.3.2 Delayed East West connections

The goal of this scenario is to study the impact of a delay in the implementation of the Delta-Rhine Corridor pipeline (DRC), especially in the area of security of supply & demand. This was modelled by removing this pipeline from the 2030 reference network. Three sub scenarios were simulated: one without just the DRC, one with one East-West line in Belgium and one without any East-West lines in Belgium. The main results to be expected here are a higher pressure drop through the network and a rerouting of the flow through the system.

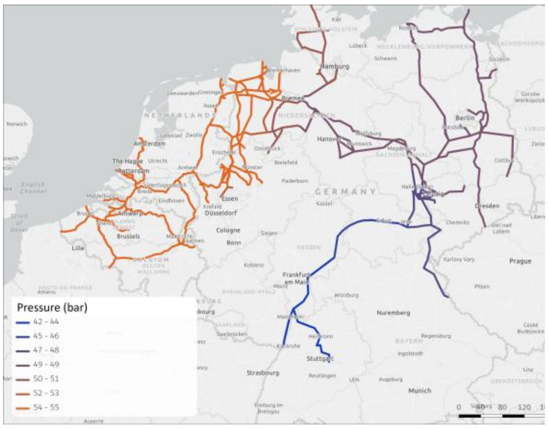

Figure 3.38 Pressure distribution in the 2030 reference case at the hour of maximum flow.

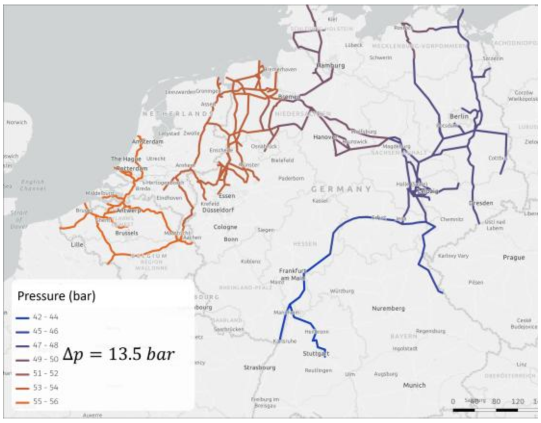

Figure 3.39 Pressure distribution in the 2030 reference case without DRC and with two East-West lines in Belgium at the hour of maximum flow.

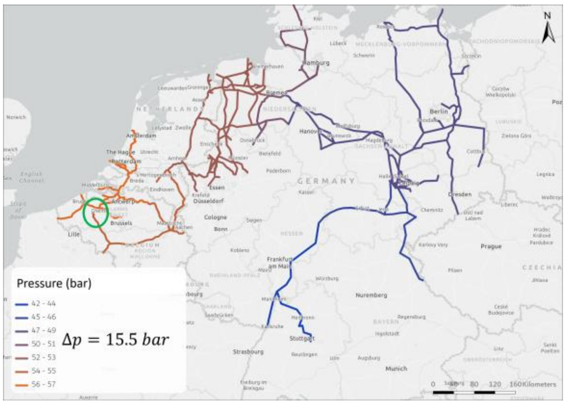

Figure 3.40 Pressure distribution in the 2030 reference case without DRC and with one East-West line in Belgium at the hour of maximum flow.

Table 3.3 Maximum pressure drop, velocity and flow rate at a given reference point resulting from the DRC delay scenario.

Case	Δp_{Max} [bar]	V_{Max} [m/s]	Q_{Max} [MNm^3/h] in Albertkanaal
Reference: DRC + 2 Belgium E/W connections	12	15.6	0.86
No DRC, 2 Belgium E/W connections	13.5	15.7	1.02
No DRC, 1 Belgium E/W connection	15.5	15.5	1.54

Figure 3.38, Figure 3.39 and Figure 3.40 show the pressure distribution throughout the network in the three sub scenarios at the moment of maximum flow. As seen, the pressure configuration shows a similar structure as in the reference case, with high pressures in the West and the lowest in the South-East.

Table 3.3 summarizes the maximum pressure drops and velocities in each case, together with the maximum flow at an arbitrary location.

The delay of the DRC, or the elimination of the Belgian pipelines does not have a noticeable impact on the maximum velocity. On the other hand, the elimination of these lines seems to have an important impact on the maximum gas flow through Belgium. Nonetheless, the most important impact on the network is noticed in the maximum pressure drop. Compared to the reference case, removing the DRC and the South pipeline of East-West Belgian connections, results in an increase in pressure drop of 3.5bar. This would have a direct impact on the required discharge pressure, increasing it by the same amount. These sub scenarios do not run into any of the physical limitations of the network (pressure, flow or velocity), but they would have an economic impact on the network, caused by the increase in required feed-in pressure.

3.4 Summary of results

A summary of the results of all the scenarios and simulations run in the current study is shown in Table 3.4. This covers the cases discussed in the previous sections. The parameter for each KPI is extracted from Table 2.1. The thresholds used to assess whether the KPI has been met can also be found in that table. A green tick indicates that the value is below the threshold.

Table 3.4 KPI interpretation at every simulated scenario.

Scenario	P_{Min}	P_{Max}	V_{Max}	Production curtailment [% of total production]	Demand curtailment [%of total demand]
2035					
Reference case	✓	✓	✓	0.4%	< 0.1%
Weather dependency	✓	✓	✓	Max. 0.4%	<0.1%
Unavailability of storage sites	✓	✓	✓	Max. 1.5 %	Max. 1%
Delay in storage	✓	✓	✓	3.2%	3%
Flexible operation of import locations	✓	✓	✓	Max 0.2%	0
Equal offshore and onshore imports	✓	✓	✓	0.4%	<0.1%
2030					
Reference case	✓	✓	✓	0.3%	0.17%
40bar network (sensitivity)	✓	✓	✓	0.3%	0.17%
Delayed East-West connections	✓	✓	✓	0.3%	0.17%

What can be observed is that the pressures and velocities remain within their allowable limits for the network.

- The foreseen hydrogen infrastructure[4] for Belgium, Netherlands and Germany is sufficient to facilitate the hydrogen transport between the clusters, and the storage locations.
    - It balances demand and supply of hydrogen for critical industry in North Western Europe
    - It unlocks storage potential for three countries and large demand and supply clusters
- If the network will be rolled out as planned by the TSOs in the three countries, then the pipe network itself will not have physical bottlenecks in terms of pressure, pressure loss or flow velocities, based on demand capacities according to the 'Global Ambition' scenario from the Ten Year Network Development Plan (TYNDP). The TYNDP-

[4] Based on the rollout plans that were available in Feb 2024.

scenarios for 2030 and 2035 will result in high pressures but will not exceed critical limits.
- The foreseen storage sites play a critical role in providing the flexibility that is required to balance the system. It is therefore essential to connect larger clusters of hydrogen supply (production/import) and demand clusters to the underground hydrogen storage sites.

The results show that flexibility from the currently foreseen storage sites is insufficient to assure security of supply/demand, even with an optimal cross border storage strategy. As a result, curtailment of supply and demand will therefore take place.
- The curtailment takes place because of insufficient volume, as well as insufficient injection and withdrawal rates from these caverns. Over a year, the curtailed hydrogen production and demand is typically in the order of 1 percent or lower. However, this is calculated using:
    - An optimal, cross border storage strategy which is very unlikely to be realized, resulting in significantly larger curtailment rates.
    - A flat demand rate over all sectors. Dynamic demand rates can influence the total curtailment in the system.
- The currently estimated volumes and production/injection rates for underground hydrogen storage (UHS) are not enough for strategic storage purposes or to balance the system in prolonged extreme weather periods or significant supply chain disruptions.
- A delay in the rollout of underground storage sites results in significantly larger amounts of curtailed production or demand.
- Added flexibility in ports (local storage of hydrogen(carriers), in combination with flexible operation of e.g. ammonia crackers) can minimize curtailment when underground hydrogen storage facilities cannot deliver.

Consequences of these results are elaborated further in the next chapter.

4 Discussion and outlook

The subsequent sections delve deeper into interpreting the model outcomes and their implications. This includes scrutinizing the model assumptions and contrasting them with prevailing market conditions using the PESTLE framework. Additionally, the PESTLE prerequisites for establishing a functional cross-border infrastructure are outlined. Where relevant, the analysis evaluates, through a PESTLE lens, the prerequisites for establishing a hydrogen market compared to the current situation. Although price formation is not extensively explored, as it is the focus of other studies, the discussion incorporates PESTLE aspects essential for shaping recommendations and relevant to the model's findings.

From the outcomes of the simulations, it is evident that, the hydrogen network in the scenarios for 2030 and 2035 has been engineered with sufficient capacity to meet the anticipated demands and production levels outlined in the TYNDP 2030 and 2035 scenarios. This assertion holds true under the presumption that there exists a minimum of one pipeline connection linking production/import facilities, storage units, and end-user locations. However, there are situations possible where the network can get out of balance, such as:

Based on the currently available information, **a deficiency in west-east connectivity** could be occurring by 2030, challenging the aforementioned assumption. At the same time, demand and supply figures in 2030 could prove to be optimistic too. The simulation's findings also reveal that, the **storage capabilities may not always align** with requirements in terms of demand and supply.
Furthermore, the **allocation of import capacities** among seaports could potentially result in localized pressure bottlenecks in specific scenarios, although this could be a resolution error as a result of model input based on specific locations of the infrastructure assets.

In the next paragraphs the following will be discussed:
Flexibility (Section 4.1**):**The necessity of flexibility to manage demand, supply, and avoid curtailment, alongside strategies for optimizing storage to balance the system.
Interconnections (Section 4.2**)**: The critical role of cross-border network connectivity and the implications of delays in network development.
Supply Chain Risks (Section 4.3**)**: Assessing the readiness of the supply chain and identifying measures to ensure timely delivery of required components.

4.1 Flexibility in the emerging hydrogen system

Main takeaways of this section: Flexibility is essential to balance the network and prevent curtailment. In the model, all flexibility comes from storage which turns out to be insufficient in almost all scenarios. To balance the system more flexibility is required. Flexibility is driven by price mechanisms opposed to how storage is handled in the model. In the model storage can be controlled and optimized to suit the network. In practice, storage will be driven by market mechanisms, making it less predictable and controllable.

The simulation results of the reference cases indicate that during periods of surplus production, the storage injection rate may struggle to match the supply of hydrogen. Similarly, during times of excess demand, the storage withdrawal rate may not always align with the hydrogen demand. This may lead to **imbalances in the system and will lead to curtailment of supply & demand**. To solve the imbalances, more flexibility in the system is required.

Why flexibility is essential in the network
Due to the intermittent and uncertain availability of renewable energy sources like solar and wind energy, the production of green hydrogen is also intermittent and uncertain. Industrial consumers on the other hand have a stable demand and are often dependent on continuous supply. Supply & demand in the network should match on a short time basis to prevent large pressure fluctuations and keep the network stable. Flexibility in the system helps to match supply & demand and minimizes curtailment on the supply & demand side. This way flexibility helps to stabilize the hydrogen network.

Methods to increase flexibility in the system:
- Increase storage capacity and increase injection and withdrawal rates.
- Shift demand in time, driven by market prices.
- Make production of low carbon hydrogen flexible.
- increase the terminal size and/or flexible operation of the ammonia cracker (cracking ammonia to H_2) (See the results of section 3.2.5)
- Increase the capacity of interconnections to neighboring countries.
- Increase flexibility of intermittent renewables by using batteries or allowing to use increased integration of grid power.
- Consumers use different (renewable)fuels such as ammonia, methanol, synthetic fuels etc.
- Curtail supply or demand of hydrogen.

Since underground storage of hydrogen is already considered, an obvious solution to this challenge would be to **increase storage capacity**, consequently increasing injection and withdrawal rates. This could be achieved by building more caverns per site, building additional sites or enlarging the planned caverns and installations. The results of the 2035 scenario where extra (terminal) storage in the ports is considered (Section 3.2.5) show that with approximately double the storage capacity the underground storage is less stressed. As a result, demand is no longer curtailed and the curtailed supply halved compared to the reference case.

The storage is capable to compensate for small term fluctuations (several months). The storage capacity installed is more limited when foreseen to be used as a strategic storage or compensate for extreme weather conditions (section 3.2.2) and large seasonal fluctuations. Storage of hydrogen in depleted natural gas fields with typical large capacities could complement cavern storage, but the practical feasibility still needs to be proven and tested with feasibility studies and demonstration projects (section 4.3.3).

In this model's premise, hydrogen import and low carbon hydrogen production are assumed to occur at a constant rate, akin to H2 consumption. The only variable considered is the local green hydrogen production, which fluctuates based on renewable energy availability. Given these assumptions, additional mitigation strategies include introducing **more flexibility in both import and low carbon hydrogen production, as well as in end-user consumption**, to align with the variability of green hydrogen production.

In contrast to the modelled situation, **the amount of flexibility in the future system is expected to be driven by price mechanisms that value demand for flexibility in the value chain**. It is a challenge to provide enough flexibility on a system level for the system to function without making the system too costly. How much are consumers willing to pay for security of supply? When consumers also have other fuel options, they might not be willing to pay for a premium when supply is low and switch to an alternative fuel, reducing the demand for flexibility. For example, consumers who have a continuous process that depends on hydrogen or need to achieve RFNBO targets are willing to pay more for hydrogen which affords flexibility options like underground or terminal storage.

In the 2035 scenario, approximately half of the assumed import capacity at ports (combined port ambitions) for hydrogen import will be utilized. If all port ambitions are met, this overcapacity could be an opportunity to **create significantly more storage capacity at ports.** As explained before, this could significantly reduce curtailment (see section 3.2.5). However, this storage cannot absorb hydrogen from the grid and is only capable of releasing hydrogen, since the hydrogen is stored in derivatives such as ammonia. In reality, not all port ambitions related to import will be met if only half of the import capacity is required. Overcapacity at storage terminals will result in low utilization factors of cracking facilities. Market instruments should be in place to compensate for this lower utilization. Ultimately, the costs for flexibility will determine how large the import and storage capacity in the port will actually be. When there is demand for storage and the ability to provide flexibility contracts to compensate for intermittent suply, capacity may be created and the need for flexible supply can be met.

Local storage at ports of imported hydrogen could also fulfill a similar role as that of the current role of LNG, in the way that it provides a way for countries to diversify their energy supply mix, reducing reliance on piped natural gas or domestic production. It allows importers to source fuels globally, mitigating risks related to supply disruptions in specific regions. Unlike pipeline gas, LNG can be traded on spot markets and redirected during transit, offering supply flexibility to respond to price fluctuations or supply shortages. This flexibility has helped develop a more liquid, globally interconnected gas market with price benchmarks, such as Japan-Korea Marker (JKM) and Dutch TTF, which influence pricing for both long-term contracts and spot transactions globally. Some countries maintain strategic gas reserves, using LNG storage to balance supply & demand in emergencies.

When the size of the strategic hydrogen reserves is smaller than the one for natural gas, the role of stored hydrogen at (im)port locations can be larger than the one of LNG. This presents both an opportunity from the perspective of transhipper and terminal companies, as well as a challenge when it comes to, for example, spatial planning. It is recommended to make a deeper analysis on a larger role for storage at ports.

4.1.1 Impact of storage in the model vs. reality

Since the model results of almost all scenarios show that storage is not sufficient to balance the network and prevent curtailment, it is critical to **analyze the variances between the model assumptions and real-world market operations**.
While a comprehensive **regulatory framework for hydrogen storage** is not yet fully established, it is anticipated that there will be **similarities and disparities compared to natural gas storage regulations**.

The simulations are conducted under the assumption that storage injection and withdrawal are solely based on the requirements of the hydrogen network, following an hourly balancing rule. Furthermore, all storages will be operated equally, acting in theory as one large storage. All storages are either charging or discharging. No provision for strategic use of linepack[5] (as a means to be used as additional storage capacity) is made in compliance with market regulations.

It should be noted that **storage injection and withdrawal methods in the natural gas market differ from those in the model, as observed in natural gas storage practices**. Hydrogen storage contracts are likely to adopt firm and interruptible service models, similar to those in natural gas storage. For firm service, customers pay a fee to reserve a certain storage capacity, irrespective of whether they fully use it or not. Firm contracts will guarantee access to storage capacity, while interruptible services will provide more flexible but less secure access.

In highly dynamic markets like the Netherlands and Germany, **storage contracts often include flexibility provisions**, allowing customers to adjust their withdrawal and injection rates based on market conditions. Moreover, natural gas storage contracts often allow customers to **trade storage rights** or swap capacities with other market participants, providing additional flexibility and liquidity.

This underscores that the accessibility of hydrogen storage will likely be subject to more constraints and stakeholders than depicted in the model. There is no central party which manages storage, but the injection and withdrawal of hydrogen is decided by market participants. Therefore, storage is not fully predictable and controllable. It could not be concluded if any bottlenecks identified in the simulations will be intensified by market mechanics. The use of storage will be driven by the value of flexibility.

Example: Party A has a capacity of storage X available. He doesn't momentarily need this so leaves it in storage. Party B urgently needs 0.5X hydrogen and is willing to pay €10/kg. Party A will then sell and withdraw 0.5X from the storage if he knows that he can turn on the electrolyzer tomorrow to produce for €5/kg. In this situation the market enables flexibility.

4.1.2 Curtailment of supply & demand

When flexibility measures cannot keep up with the market needs, curtailment on either the production or the demand side will take place. This curtailment will be driven by the market mechanisms that will get in place in a newly to be established hydrogen market. In the emerging hydrogen market, curtailment will likely draw on principles from both the electricity and natural gas markets but with specific modifications to suit hydrogen's unique characteristics.

[5] Linepack in a gas network refers to the volume of gas that is stored within the pipelines.

EU2024/1789 Hydrogen and Decarbonised Gas Market package
The EU adopted the Hydrogen and Decarbonised Gas Market Package on may 21, 2024. The Directive and Regulation revise existing legislation from 2009 (Gas Directive and Gas Regulation) to align with the goals of the EU Green Deal. This includes separating hydrogen network operators from energy production and supply activities, ensuring independent management of hydrogen infrastructure. Moreover, the regulation enshrines the establishment of an independent body for hydrogen networks - the **European Network for Network Operators of Hydrogen (ENNOH)**. The package lays down the common rules for the transport, supply, and storage of hydrogen. Furthermore, the rules on the organisation and functioning of the sector, including market design, main regulatory principles, such as unbundling and third-party access.
In general, the enshrined internal market rules for hydrogen are similar to the existing ones for the natural gas and electricity sectors. Yet, they also establish a degree of flexibility to ramp-up the development of the hydrogen market.

Regulators may prioritize curtailment protocols that **favor green hydrogen production** over hydrogen derived from fossil fuels. This would align with the EU's environmental goals, especially the European Green Deal, which emphasizes prioritizing renewable energy sources. From a consumers side it's also favorable to curtail low carbon hydrogen over green hydrogen to meet RFNBO targets. Incentives and priority access rules may ensure that production curtailment only applies to green hydrogen as a last resort, thus supporting the sustainability and investment in renewable hydrogen.

Similar to both the electricity and gas markets, regulators may consider **market-based mechanisms, such as auctions**, where producers can bid on compensation for curtailment. The auction determines both the allocation and the price, promoting market efficiency as this would allow the market to determine where curtailment is most economically viable, reducing the impact on production while ensuring network stability.

4.2 A connected cross border network

A connected cross-border network is essential for a balanced hydrogen network. This is particularly the case because of dependency on centralized locations for storage and the substantial dependency of Germany on imports. If the network is not connected in time, isolated clusters could occur, leading to great imbalances in the system. This has disadvantages for the balance of the network as a whole. A base network should be realized in time to connect the main supply clusters to demand clusters and storage.

4.2.1 A connected network to kickstart the hydrogen economy.

The presence of infrastructure that connects supply, demand and storage is an important condition for developing the hydrogen value chain that supports the decarbonization of industry. A developed and cross-border network is desirable for suppliers because it gives them access to more consumers. Consumers also have the option to choose from more suppliers.

The ports in the West of Belgium and the Netherlands have ambitious hydrogen import ambitions and aim to act as hydrogen import hubs for North-Western Europe. The Port of Rotterdam has the ambition to import up to 40% of the total REPowerEU import target by

2030. Several Memorandum of Understandings (MoU's) are signed with countries across the globe to import hydrogen and hydrogen derivatives to these ports.

Figure 3.1 indicates that The Netherlands and Belgium have a surplus of hydrogen supply while in Germany the demand for hydrogen is higher than domestic production and import both in the 2030 and 2035 reference case. Therefore, an interconnected network is essential to supply hydrogen from the producers and import terminals in Belgium and the Netherlands to demand centers in Germany to balance supply & demand on all three countries. In line with EU regulations, member states lacking underground storage facilities are encouraged to engage in agreements with neighboring states possessing such storage capabilities. This collaborative approach helps ensure a more resilient and interconnected energy network, allowing countries like Belgium to leverage storage facilities in other nations to optimize their energy resources and enhance energy security. An interconnected network allows countries to utilize storage capacity in neighboring countries.

4.2.2 The impact of delays in network development

Over the course of the HY3+ study, there have been updates regarding the rollout of the networks in the countries. To illustrate the impact of network delays, in this section we will go through three crucial network rollout plans in this section and assess the impact of the DRC in the Netherlands, Kernnetz in Germany and Fluxys in Belgium. In Section 2.8 the difference between the modelled network and the currently foreseen network is depicted.

DRC in the Netherlands
In June 2024 the then Dutch minister of Climate and Energy announced that the completion of the DRC has been delayed from 2028 to at least 2032. As a consequence, a large part of the Dutch hydrogen network will not be ready in 2030. According to the latest information provided by Hynetwork [18], it is unlikely that an East-West connection is realized by 2030. More specifically, a delay of the DRC means that at least the Rotterdam and Amsterdam cluster in the Netherlands are isolated until 2032 at least. Also, a connection between Rotterdam Maasvlakte and Moerdijk is absent. The Smart Delta Region network (including North Sea Port) will be ready by 2030 and will be connected to Belgium. The Chemelot cluster will also not be connected to the Dutch network by 2030. In December 2024, it was confirmed that the hydrogen pipeline of the DRC will in operation in or before 2033 [19].

Kernnetz in Germany
On October 22, 2024, the Federal Network Agency (Bundesnetzagentur, BNetzA) approved the final draft of the hydrogen infrastructure plan of the German Kernnetz. The network should be completed by 2032 while some parts of the network should be ready by 2027. In previous versions of the rollout plan the network would've been finished by 2030.

Fluxys network in Belgium
Although Fluxys has the aim to start the development of the hydrogen network in 2026, a rollout plan of the network is still unknown. Fluxys hydrogen is currently launching call for market interests for several parts of the network. The hydrogen network of Fluxys is still unconfirmed by 2030.

Impact of unconfirmed connections
With the delay of the hydrogen pipeline in the DRC and the Fluxys network in Belgium that is unconfirmed, there are no confirmed pipelines that connect the west of the Netherlands and Belgium to their hinterlands and Germany, before 2030. Furthermore, the clusters in the west of the Netherlands and Belgium are not connected to any storage facility.

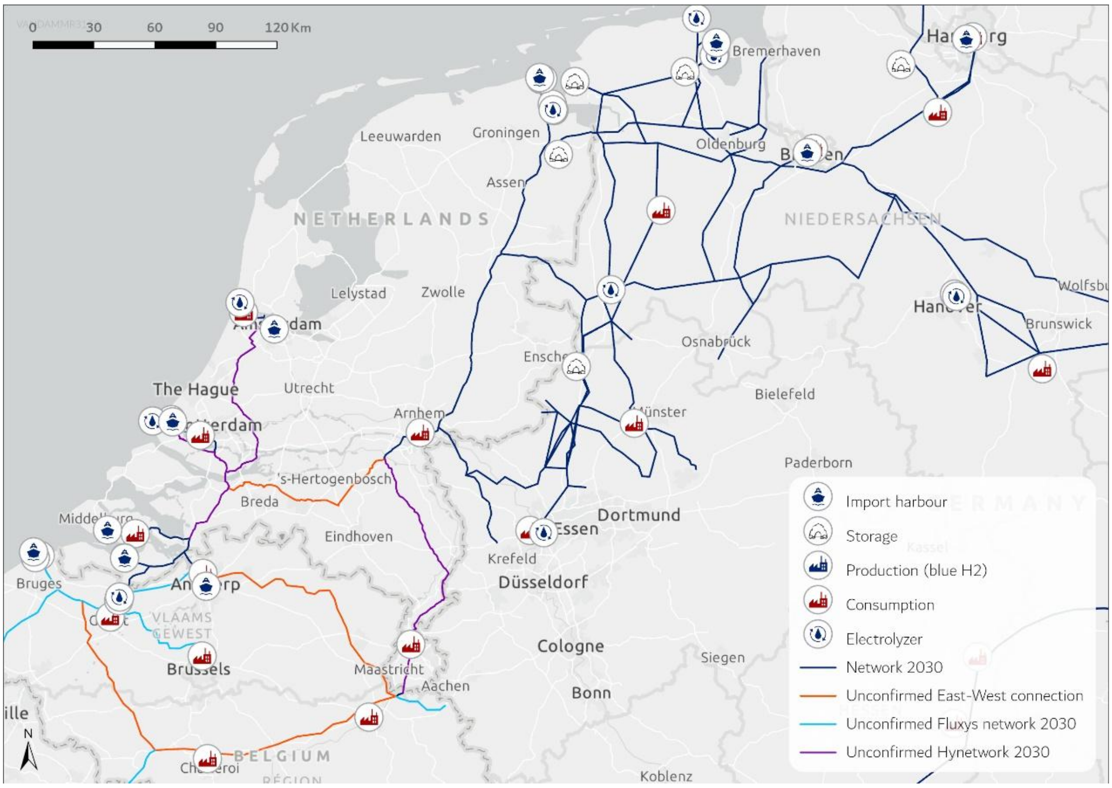

Figure 4.1 Impact of the delay of the network developments in the Netherlands and the unconfirmed connections by 2030.

Absence of at least one East-West connection means under current assumptions a significant oversupply in the West of the Netherlands and Belgium and a deficit of hydrogen supply in the remainder of the network. In case of an absence of an East-West connection, additional hydrogen can be produced and/or imported in the north of the Netherlands and North-West Germany, and then transported via the planned infrastructure from Kernnetz and Hynetwork. However, based on the scenarios in the study, the western clusters in the Netherlands and Belgium have a large hydrogen demand. Intensified import/production in the North of the Netherlands and Germany will play a limited role in achieving the 2030 decarbonization targets of the Netherlands and/or Belgium.

Furthermore, it is questionable whether the infrastructure to compensate for the ports in the West will be available on time. As discussed in section 4.3.4 the number of announced projects for the import of hydrogen(carriers) is limited and needs to speed up rapidly to meet the targets for the reference scenario and port ambitions. If such a shift from the West to the North would take place, clarity about the network is needed and parties have to act quickly.

Isolated clusters without storage

Without one of the (orange marked) East-West connections in Figure 4.1 available in 2030 (and in the years after) the demand of western industrial clusters in the Netherlands and Belgium is not connected to the main storage capacity that will be located in the northeast of the Netherlands and in the north of Germany. The clusters in the west have a high potential demand for renewable hydrogen and can make a significant contribution to the decarbonization of industry in the Netherlands and Belgium. Furthermore, the majority of landing points of offshore wind energy for production of intermittent green hydrogen is located in the west.

Storage is required to balance the intermittent supply with the foreseen continuous demand of hydrogen. Section 4.1 described why flexibility in the system is an essential element in the network. The results of the 2030 base case (section 3.3.1) and the weather dependency analysis (section 3.2.2) show the significance of having sufficient storage to balance the system and mitigate curtailment of supply & demand of hydrogen. Not having sufficient storage is a risk for the stability in the systems and it is questionable whether other means of flexibility as opposed in section 4.1 are sufficient to balance the system with the assumed supply & demand.

4.2.3 Realizing a base network to connect supply, demand and storage

A base network is required that connects supply clusters, demand clusters and storage. Without a confirmed connection between the West and the East of the network, it is necessary to find other routes to connect the West of the Netherlands and Belgium to the whole network. The scenario discussed in section 3.3.2 shows that **one** East-West connection in the network is sufficient from a network point of view.
In this scenario the clusters in the West of the Netherlands are connected to Antwerp, assuming that the Hollands Diep crossing[6] in the DRC is not delayed and the network in the west of the Netherlands (Amsterdam, Rotterdam, Zeeland) with the connection to Antwerp is ready by 2030. Furthermore, at least one East-West connection should be available in Belgium in 2030. Under these circumstances the network is able to transport excess volumes in the Western part of the network to storage and consumers in the Eastern part of the network. Thus at least **one** East-West connection could be sufficient to meet demand in the East according to the simulations.

To achieve a well-functioning interconnected network, it is important that, besides the physical infrastructure being in place, there is 1) a clear overarching legal framework, 2) cooperation between TSOs and 3) that there is alignment on quality standards in the network.

Alignment on legal framework and Cooperation between TSOs
With the adoption of the EU 2024/1789 Hydrogen and Decarbonized Gas Market Package [19](see section 4.1.2) the EU set its first step towards a hydrogen infrastructure. By initiating the European Network for Operators of Hydrogen (ENNOH) the EU established a network for cooperation between TSOs. The package mandates the unbundling of hydrogen transmission network operators from other energy activities to prevent conflicts of interest and promote fair competition. This includes both horizontal and vertical unbundling measures similar to those applied in the natural gas sector. In this respect, full integration of transmission system operators is pursued by promoting the interoperability of EU transmission grids.

[6] The water crossing northwest of Breda in Figure 4.1.

European Network for Operators of Hydrogen (ENNOH), is an initiative established by the European Union aimed at enhancing the operational efficiency of the hydrogen market across Europe. Set to be operational by 2025, ENNOH's primary goals include:

- **Facilitating Efficient Market Operations**: ENNOH is tasked with promoting the development and proper functioning of the internal hydrogen market and cross-border trade.
- **Developing Network Codes**: The organization will create technical recommendations and network codes to ensure effective market and system operations.
- **Regional Cooperation**: ENNOH aims to foster collaboration among member states to enhance the integration of hydrogen with other renewable energy sources, thereby improving overall grid stability and efficiency.

The adoption of the EU 2024/1789 is an important step towards establishing a well-functioning cross-border hydrogen network. Nevertheless, current network delays shows that commitment is required from all involved parties to realize this network. While hydrogen is a critical enabler of the energy transition, it is not the only infrastructure that needs development. High-voltage (HV) grids also need significant upgrades, and new energy carriers will also play a role in the future energy mix. Broader collaboration can accelerate the development of the hydrogen network as well as other commodities, ultimately advancing the energy transition as a whole.

Example of the complexity to realize a cross-border network: The Delta Rhine Corridor (DRC)

One of the causes of the delay of the DRC is the complicated governance around the project. It is a project with a cross-border connection, with a consortium of several private parties and multiple different ministries. All parties have their own interests and are in different phases in the decision making. The hydrogen pipeline for example is required earlier and further developed in the decision making process than the HVDC cable. However, it is important to keep all the stakeholders aboard, as the combination of purposes (hydrogen, CO2, HVDC) is a strength of the project. If one is left out, local stakeholders will not be likely to endorse the project anymore. Therefore, it is not realistic to just leave other purposes out.

On top of that there are technical challenges. On some locations along the route the space is limited to accommodate all commodities. Furthermore, a hydrogen pipeline has much more flexibility and can be installed quicker than a CO_2 pipeline for example. Other unknowns such as the effects of a HVDC cable on surrounding (steel) pipelines need to be solved.

To prevent further delays it is important to embrace the planning that presented to Dutch parliament on June 2024 and set the scope and commit to it with all parties. When all parties are aligned and fully committed, a strong and robust governance needs to be setup with a project board that has the right mandate, so the project can proceed to the next phase. It is not a solution to only install the hydrogen pipeline in an earlier stage, because that will reduce support and is not convenient because it hinders the other commodities due to the limited available space. There has been extensive contact with all stakeholders and there is a lot of support for combined construction. This is mainly because excavation is limited and the ground only needs to be open to a limited extent.

For an interconnected network it is required that the codes and standards, and the transmission and border fees are harmonized between the three countries in the first place. Since parts of the hydrogen network are expected to be operational before 2030 and the first interconnectors are planned for 2030 **or before,** it is important that the network codes will be established well before 2030.

The longer term goal of the EU is to have an interconnected European hydrogen network. For a well functioning European hydrogen network it is important that not only the three discussed countries reach alignment but that codes and standards will be harmonized on an European level.

Alignment on purity

In the Netherlands and Germany, construction work has already begun on establishing a hydrogen network, and Belgium is expected to follow soon. One of the prerequisites for a well-functioning cross-border network is reaching an agreement on the network's quality standards.
No alignment on purity could lead to limited flow through interconnectors, a significant amount of purifying (and re-purifying), losses of hydrogen and increased energy consumption.

It is not within the scope of the HY3+ study to set the quality standard of the cross-border network, but agreement on purity in the network can help to prevent these bottlenecks. Currently, discussions are ongoing within and between the three countries (Belgium, Germany, and the Netherlands) on what the network's quality requirements should be. Hynetwork states the following on their website [20]:

"In neighboring countries, there is increasing support for a minimum purity requirement of 99.5%. The European Commission expects to start a European standardization process for hydrogen, which is likely to take around 3 years. In the Netherlands, Belgium and Germany, hydrogen flows into the grid are coming on stream earlier. Therefore, a number of transport companies in Germany, Belgium and the Netherlands, including Gasunie, have started working on a joint specification based on 99.5% purity."

Although the quality standards are not set, support is increasing for a universal purity standard avoiding a possible bottleneck to interconnect national hydrogen networks. For a well functioning European hydrogen network it is important that not only the three discussed countries reach alignment but that the purity will be standardized on a European level.

Hydrogen serves various purposes as both feedstock and fuel, with distinct quality requirements for different applications. Three main quality categories include:

1. **Fuel Cell Quality:** This type demands pure hydrogen with a minimum amount of impurities like CO, essential for fuel cell operations. The minimum purity is 99.97%.
2. **Industrial Grade:** Characterized by a purity level exceeding 99.95%, meeting the standards set by companies like Air Liquide and Air Products. Primarily utilized as feedstock in the chemical industry and refineries.
3. **Energy Production Grade:** Encompasses hydrogen mixtures with purity levels greater than 95%. Typically produced through steam-reforming processes, this grade is commonly used for energy production applications.

Opting for low-purity hydrogen is relevant when many network consumers use hydrogen solely for energy production, where high purity is not critical. Contamination within the network can make maintaining strict quality standards challenging. Lower purity thresholds reduce entry barriers for suppliers; for example, SMR with CCUS produces hydrogen at ~95% purity.

However, lower standards require consumers needing high-purity hydrogen to invest in purification, increasing energy consumption and hydrogen losses. Electrolyzed hydrogen, typically > 99.9% pure, loses its quality advantage when mixed in low-purity networks, leading to inefficiencies. High-purity networks (e.g., 99.5%) minimize purification needs for consumers, lowering their costs.

KIWA N.V. and DNV [26] recommend a 99.5% purity standard for the Dutch hydrogen network, concluding that contamination from retrofitted gas pipelines and salt cavern storage is minimal. According to their study, this standard balances cost efficiency across the hydrogen chain. Over time, the need for high purity may decrease as export and energy markets (requiring lower purity) grow relative to industrial applications by 2050.

4.3 Supply chain risks

Main takeaway of this section: The number of FIDs is far behind on the announced projects throughout the value chain. If we want the hydrogen economy to succeed by 2030 and meet the RED III ambitions, FIDs should follow rapidly. If market parties behave expectantly, it is likely that the entire value chain will be delayed, and that we lose sight of these targets.

The inputs and results of the simulations outline the conditions that must be met to achieve security of supply, demand, and storage in the system. Assumptions regarding the amount of domestic production, imports, and hydrogen storage have been made based on the TYNDP scenarios, NSWPH data and announced projects.

The question centers on the likelihood of all necessary assets being ready on time to establish the complete supply chain to fulfill demand. At the moment, many projects are still in the feasibility phase, and the percentage of projects with a Final Investment Decision (FID) remains low. This could lead to risks in the supply chain. Market parties are reluctant to make FIDs, because the hydrogen network relies heavily on cooperation between stakeholders in the supply chain. Also uncertainty of the network rollout plans further complicates the situation.

In the next sections, supply chain risks are identified for electrolyzers, the readiness of export (and import) projects, underground hydrogen storage and ammonia import terminals and crackers.

4.3.1 Electrolyzer capacity

The FIDs in electrolyzer capacity lag behind the planned and required levels to establish a hydrogen economy. While 520 GW of electrolysis projects are announced globally, only 20 GW have reached FID [21]. Of this, just 5 GW is expected to be operational by the end of 2024, with about 70% located in China. In Europe a meager 1 GW is expected to be operational by the end of 2024.

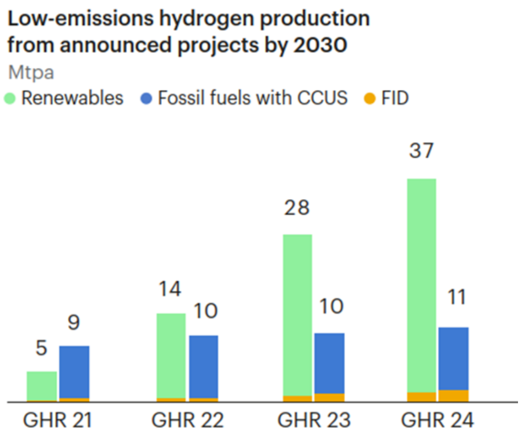

Figure 4.2: Annual low-emission hydrogen production from announced projects by 2030 [21].

Globally, 3.4 Mtpa (Megatonne per annum) of hydrogen production has reached FID, including 1.9 Mtpa via electrolysis. For comparison, the EU's REPowerEU target aims for 10 Mtpa of domestic production and 10 Mtpa of imports by 2030. The IEA highlights the need for faster growth. The IEA stated the following in their 2024 Global Hydrogen Review [21]:

"*Overall, there is noteworthy progress, but most of the potential production is still in planning or at even earlier stages. For the full project pipeline to materialize, the sector would need to grow at a compound annual growth rate of over 90% from 2024 until 2030, well above the growth experienced by solar PV during its fastest expansion phases. Several projects have faced delays and cancellations, which are putting at risk a significant part of the project pipeline.* ***The main reasons include unclear demand signals, financing hurdles, delays to incentives, regulatory uncertainties, licensing and permitting issues and operational challenges.***

To realize the project pipeline, electrolyzer capacity addition must scale faster than the exponential growth of solar PV. In the TYNDP global ambition scenario, Belgium, Germany, and the Netherlands target 17.4 GW of electrolysis capacity by 2030 and 30 GW by 2035. Achieving these goals demands rapid FIDs in the coming years, as large-scale electrolyzer projects require at least five years to complete.

Recent projects reaching FID in July 2024 aim for operation by 2027, demonstrating a 3-year timeline from FID to commissioning. Currently, only 1.7 GW of the announced 54 GW capacity in these countries has reached FID, is under construction, or is operational. **To stay on track for the 2030 target, 15.7 GW must secure FID by 2027.**

In order to materialize the electrolysis projects sufficient manufacturing capacity should be available. From Figure 4.3 can be seen that by the end of 2023, 25 GW/yr of manufacturing capacity was available. This capacity is significantly underutilized with an estimated electrolyzer production of only 2.5 GW in 2023. Europe has approximately 5 GW/y of electrolyzer manufacturing capacity available by the end of 2024. **These numbers suggest that the electrolyzer manufacturing capacity itself is not a bottleneck for the coming years.**

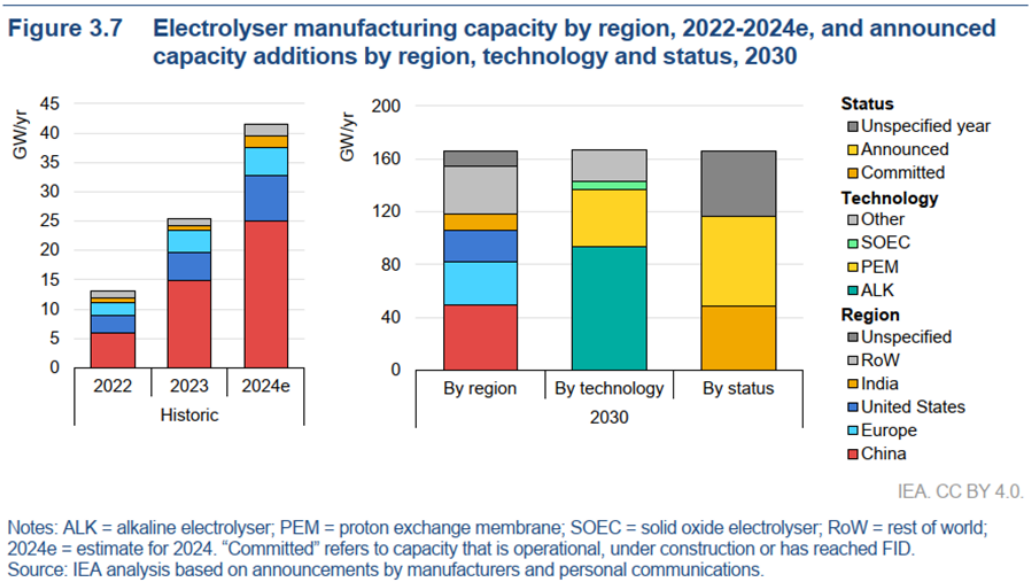

Figure 4.3: Electrolyzer manufacturing capacity and announced capacity by region. [21]

4.3.2 Hydrogen import

For the EU, and in this case the Netherlands, Germany and Belgium, to import green hydrogen, the supply chain for exporting countries should be operational on time as well. In the 2030 and 2035 reference case, 1.2 Mtpa and 4.5 Mtpa of hydrogen equivalent needs to be imported to cover the gap between domestic production and demand. But equally to what is observed for electrolyzer capacity FID or projects under construction in the HY3+ countries, these projects in exporting countries are lagging compared to the high ambitions.

To be able to export green hydrogen overseas to Europe the following needs to be operational:

- Renewable electricity generation for green hydrogen production
- Hydrogen production capacity (electrolysis)
- Hydrogen conversion to derivatives (e.g. ammonia)
- Export terminals and ships

If all export oriented projects come to completion, all projects could account for 16 Mtpa $H_{2,eq}$ by 2030 [21]. From Figure 4.4 can be concluded that only 5 Mtpa is currently targeted for Europe if these projects materialize. Which is half of the REPowerEU import target for

Europe. This could double if the distribution of the not defined projects is the same as the defined projects. Still all projects need to materialize to achieve the REPowerEU target.

It also means that the targeted regions should not change. Although the projects are set-up with a specific offtaker or country in mind, the actual destination of the hydrogen(derivatives) will be dependent on market conditions and geopolitical developments.

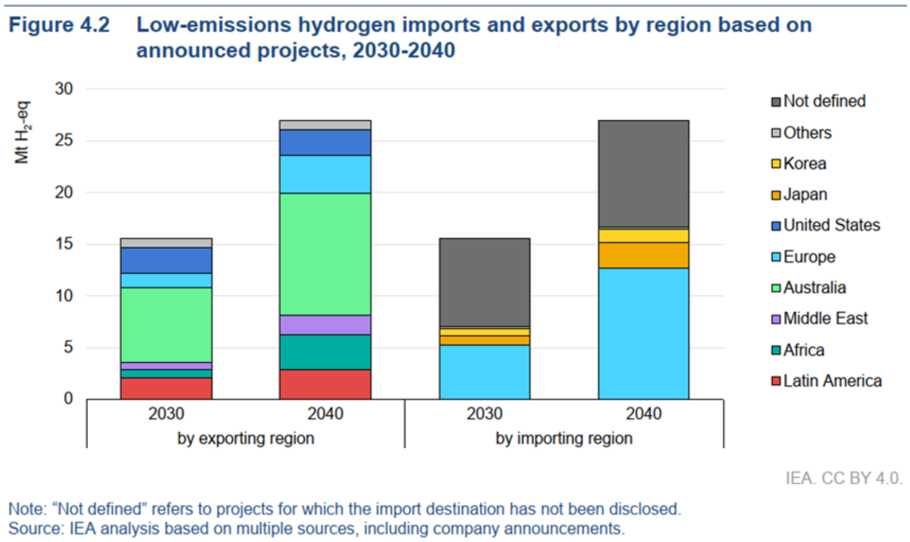

Figure 4.4 Low emissions hydrogen imports based on announced projects [21].

4.3.3 Storage

The model results show that the storage capacity and injection and withdrawal rates are bottlenecks in several scenarios, which is under optimistic assumptions, namely that storages are developed in time and at a high ambition level for the sites. Therefore, it’s crucial that at least the already announced storage projects are completed in time. Expanded storage capacity could reduce the identified bottlenecks. If the permitting process for the announced sites has already started this could be achieved on time.

Up to 2035, only plans for newly built underground storage in salt caverns are announced in the assessed countries. Current natural gas storages (some of which are salt caverns) are still in use and are not expected to be available by 2030 and 2035 [22]. Therefore, in the simulations only new salt caverns (and no porous reservoirs) are considered for underground storage of hydrogen.

To construct a salt cavern, first permits are required for salt exploration, salt mining and storage of hydrogen, before the exploration and mining of the salt can start. For new storage sites, a solution will have to be found to connect to the salt processing industry to discharge or process the brine. When the mining of salt is completed the storage facility can be constructed. Construction on sites which already have a permit for exploration such as Zuidwending in the Netherlands could take significantly shorter.

Hydrogen can be stored in large volumes underground in salt caverns, depleted natural gas field or aquifers. Large scale underground hydrogen storage can be utilized for:

- Balancing of supply & demand for systems with fluctuating renewable energy sources
- Adding reserves for extreme weather situations
- Strategic reserves for long term disruption of supply
- Act on trade markets to utilize price differences (arbitrage).

Salt caverns are typically used for fast cycle storage and are designed to have multiple cycles per year. This is comparable to how it is currently used for natural gas storage. Empty natural gas fields on the other hand are more suitable for seasonal storage. Currently, storage in salt caverns is the only type of underground storage of hydrogen which is currently operational; in the UK and Texas for example. There is no commercial experience yet with hydrogen storage in empty natural gas fields and there is still a knowledge gap. Earlier work from TNO and EBN [27] assumes that hydrogen storage in empty natural gas fields is a technically feasible option, although this still needs to be proven with feasibility studies and demonstration projects.

The construction of one cavern of 1 million m^3 takes approximately three years, calculated from the moment that leaching can be started (details are provided in the former Hy3 study [1]). For new sites where there is no brine extraction, this can take longer. This excludes the time required for the application for permits, location search, construction of surface level infrastructure, etc. In a 1 million m^3 cavern approximately 0.25 TWh of hydrogen could be stored. In the 2030 reference case a total storage capacity (working volume) of 1.2 TWh is assumed. This would require a total of 5 caverns of 1 million m^3 to be operational. In terms of capacity this should be feasible when projects have already started. This also means that the timeline for the permitting and realization of caverns and surface storage installation including commissioning is already tight.

For the 2035 reference case 3.9 TWh of storage capacity is assumed to be operational in the Netherlands and Germany. This means a threefold increase in storage capacity requiring additional caverns to be realized or to be repurposed (from use for natural gas storage). This also requires timely planning of permitting and realization schedules so that commissioning can start in time.

4.3.4 Cracker capacity and Import terminals

To meet the import needs in this study, large and fast implementation of ammonia import and storage terminals with cracker capacity are required at very large scale and with high flexibility. This is very optimistic considering the state of the technology and typical project duration for implementing such large projects.

Import of hydrogen is expected to mainly take place via international shipping of hydrogen carriers such as Ammonia, Methanol and LOHCs. The advantage of Ammonia and Methanol is that it could also be used as feedstock replacing feedstock derived from fossil fuels. Methanol and Ammonia are already traded globally as feedstock. The infrastructure is already present albeit at a much smaller scale. In the reference scenarios only import through deep water ports and to Duisburg via Rotterdam with barges is assumed as import. Since Ammonia is the most chosen carrier for import & exports projects, the focus of this subsection is on development of ammonia infrastructure.

The reference case in 2030 assumes a total terminal capacity of 330 TWh of $H_{2,eq}$ throughput per year based on national and port ambitions but only a small portion of the capacity is used in the reference case (~40 TWh). In the 2035 reference case almost half of this import capacity is required (151 TWh).

The majority of all announced ammonia import projects in Europe are located in Belgium, the Netherlands and Germany. According to data from the IEA global hydrogen review just over 8 Mt ammonia import capacity is announced in the three countries in 2030. Where only the existing OCI terminal expansion in the port of Rotterdam reached FID. The data might also include double counting of the OCI terminal expansion. On top of that, it is likely that not all ammonia import will be converted to hydrogen since ammonia is also used as feedstock and could contribute to RFNBO targets by replacing ammonia derived from fossil fuels.

The announced hydrogen import capacity is far behind the combined port ambitions and is also insufficient for the 2030 reference case if all projects are realized.

The cracking technology to crack ammonia to hydrogen (and nitrogen) is integrated into the import terminal for several announced projects. The capacity of almost all projects is unknown and therefore it is not possible to determine if the capacity will be sufficient. The facts that the terminal capacity is insufficient, none of these projects passed the feasibility phase and that the cracking technology is not yet proven on a commercial scale, would suggest that a significant uptake of projects is required to meet the hydrogen demand in the reference scenarios.

4.3.5 Maturity of the supply chain

With the current state of affairs, it is unlikely that the supply chain will be ready in time or that it will be there at all. Final Investment Decisions (FIDs) are lagging on announced projects with long lead times. Rapid project scale-up and swift investment decisions are crucial to meet targets. Market parties require certainty about the timing and location of infrastructure and demand, which national governments must provide through consistent, long-term policies.

The uncertainty related to the completion of infrastructure projects is likely to lead to delays in investment decisions of industrial parties on when and how to decarbonize, regardless of whether the infrastructure delays are the direct cause. Without an interconnected network supply & demand could also shift geographically. Large international consumers may prioritize new projects at sites in the West near import and production hubs, while domestic green hydrogen production could move inland where renewable energy is abundant. Western ports, aiming to become hydrogen import hubs for North-West Europe, risk losing their first-mover advantage without a connected network by 2030. Production and import facilities could be realized elsewhere where there is access to storage and consumers can be reached.

Another reason of delays of FIDs is the uncertainty about the future of their industry activities in North-Western Europe. The energy-intensive industry has, among other factors, settled in North-Western Europe because of cheap and easy to use natural gas. To comply

with EU Energy regulation and to achieve climate goals a cleaner alternative such as hydrogen is required. These alternatives are currently expensive, and renewable energy can be produced at lower costs in other regions of the world. As a result, North West Europe may not be the most cost-effective location for hydrogen production.
This trend can be seen in recent announcements on the demand side. In October Thyssenkrupp announced it will review its green steel production plans [23]. Thyssenkrupp would be one of the main offtakers in the German hydrogen network. In November ArcelorMittal announced to postpone the 1 billion FID for 'hydrogen-ready' DRI-EAF facilities for green steel production in Ghent [24].

Given the network delays and lack of FIDs it is likely that the development of the entire value chain will be delayed or only come to maturity in a reduced form. This means that the EU climate targets for 2030 become even more out of sight.

Actors across the value chain must embrace calculated risk-taking to unlock investments, breaking the current stalemate where governments, TSOs, producers, and consumers are waiting on each other to act. Stakeholders are standing around the pool with their hands tied waiting to see 'who will jump first'. Jumping together along the value chain enables the uptake of hydrogen and could reduce risk and share risk in a fair way across the value chain.

One option to break this cycle, is to perform a regional market assessment and scenario planning which is approved by all National Regulatory Authorities (NRAs) before moving forward with FIDs. An example of such a process are the Dutch "maatwerkafspraken".

Next, the necessary capacity could be put out for tender and secured through Contracts for Difference. Such as the European Hydrogen bank is offering, for example. It is essential that all NRAs are actively involved to ensure that the regulatory model and market design are aligned.

Additionally, it is important that the costs for the required infrastructure are distributed in such a way that TSOs can recoup their costs and that first movers do not pay the highest price for a connection.

4.4 Recommendations

From this chapter, the following recommendations can be drawn.
1. Organize flexibility in the network. Because of the intermittency of green hydrogen production, a balanced hydrogen network needs flexibility. This flexibility can be organized by, among others, optimizing underground storage volumes in combination with the needed injection and withdrawal rates, shifting demand and production of hydrogen driven by market pricing, making production of low carbon hydrogen flexible, increasing above ground storage options for hydrogen (e.g. ammonia) and needed conversion installations, increase size and flexibility of ammonia crackers.. This needs a cross-border and coordinated action combined with sustainable market incentives for investors to place large investments in these flexibility measures ahead and in pace with the growing hydrogen market.

2. Make sure the network is well connected. Having a cross-border and connected hydrogen network in place and in time is essential to connect supply, demand and storage. In its absence there will be great imbalances in the system with detrimental effects on the roll-out and market growth, due to isolated clusters and poor market access for actors in the value chain. It is important that there is a clear overarching legal framework, cooperation between TSOs and alignment on quality standards. This includes the need for consistency on border tariffs, and exemptions to pay double fees when crossing border just to use storage. Ultimately alignment on tariffs and codes and standards should be achieved on an European level to achieve an interconnected European Hydrogen network in the long term.

3. All value chain parties have to move at the same time. Building the hydrogen value chain is a big industrial transition. This can only be done in coordination with all parties involved. There has to be enough mutual confidence to make it work, as it demands risk-taking and handling uncertainty. If the majority of parties is not willing to “jump”, investments will be delayed, parties will adopt a ‘wait-and-see' attitude, and the transition will be delayed.

4.5 Recommendations for future work

Although the HY3+ study has given valuable insights, further research is still needed. Recommendations for future work regarding the dynamic simulations and modelling activities are:

- Update the HY3+ simulations with the latest insights of network developments.
- Simulate of smaller local clusters; this can give insights in the network dynamics on a local scale in earlier phases of the network development.
- Simulate of flexible demand; in the HY3+ study, demand has been assumed flat rate to keep the scope manageable, in reality demand will vary over time depending on the demand sector.
- Investigate the impact of market dynamics; the effect of pricing on the shifting of demand, availability of supply and the use of storage.

Other recommendations for future work related to the hydrogen value chain are:

- The business cases of the various roles in the hydrogen economy; what the main incentives are to step in for different parties.
- The role of private hydrogen networks; how they may impact the development of the interconnected hydrogen backbone.
- The EU gas package: modelling scenarios for the entire EU Hydrogen backbone.
- A study of the feasibility of storage options; this can help to assess the possible obstacles to realise the needed storage in time.

5 HY3+ conclusions

HY3+ aimed to provide independent advice on priorization in the cross-border roll-out of the envisioned hydrogen backbones in Belgium, Netherlands and Germany. This was done by evaluating the security of supply and demand of the envisioned networks.

Therefore, HY3+ tries to answer the following research questions:
The above questions and developments all boil down to the following research questions:

1. Will the foreseen hydrogen infrastructural system be able to realize security of supply across the entire hydrogen value-chain in 2030 and 2035 with intermittent hydrogen production, fluctuating demand and the options for storage and import?
2. If not, what activities will be required to ensure the security of supply and to enable the hydrogen economy?

To do so, the HY3+ project generated a detailed model of the hydrogen value chain of the Belgian, Dutch and German hydrogen network. The model is able to compute the hydrogen flows in the network on an hourly basis, based on the intermittent supply & demand of hydrogen to the system. The network model was coupled to a dynamic underground gas storage model, to have a realistic physical model that simulates the storage capabilities in these countries. The combination of the models gives insight into the balance in the value chain on an hourly basis, for one year. More importantly, it shows at each location and at each timestep what local pressures and flow velocities can be expected. By comparing these pressures and flow velocities to their allowable values, detailed insights into the security of supply or security of demand were obtained.

The main conclusions of the HY3+ study have been drawn from 1) technical simulations and 2) the PESTLE analysis. The conclusions drawn from the technical simulations are as follows:

1. An interconnected hydrogen infrastructure for North Western Europe offers great value and mutual benefits and is crucial for developing a hydrogen value chain that supports industrial decarbonization. (East-West) Connections between the large hydrogen supply, demand and storage clusters are essential to provide security of supply and demand.

- Throughout the course of this study, there have been several updates on the infrastructure plans. Delays in specific sections of the network can create isolated clusters and disconnections between supply, demand and storage. This can have consequences on the developments of the value chain, in local clusters and also in the whole North West European region.
- If the network will be rolled out as planned by the TSOs in the three countries, then there is no connected network between the largest clusters in the three countries by 2030. Connections between main clusters will take shape in the years after, from 2032 onwards.
- This, in contrast to the information available at the start of the project, which served as the basis for the simulations. If the network will be rolled out as was planned by the TSOs in the three countries, then the pipe network itself will not have physical bottlenecks in terms of pressure, pressure loss or flow velocities, based on demand capacities according to the ‘Global Ambition’ scenario from the Ten Year Network

Development Plan (TYNDP), the production and import clusters and the storage sites. The TYNDP-scenarios for 2030 and 2035 will result in high pressures, but will not exceed network limits.
- The planned network under the studied scenario balances demand and supply of hydrogen for industry in North Western Europe and it unlocks storage potential for three countries and large demand and supply clusters. The foreseen storage sites play a critical role in providing the flexibility that is required to balance the system. It is therefore essential to connect larger clusters of hydrogen supply (production/import) and demand clusters to the underground hydrogen storage sites.

It is therefore recommended to:
- **Connect the key clusters;** connect the larger clusters of hydrogen supply (production/import) and demand clusters to the underground hydrogen storage sites, by means of essential East-West connections in the countries.
- **Sustain cross border cooperation** and alignment on codes, standards and tarrifs to assure effective use of cross-border connections to exploit the potential of the three countries jointly.

2. The currently foreseen underground hydrogen storage development is insufficient to avoid curtailment in supply and demand of hydrogen. To achieve a balanced system, the hydrogen value chain of these three countries needs additional increased storage capacity or more flexible production and/ or consumption strategies.
- The study shows that flexibility from the currently foreseen storage sites is insufficient to assure security of supply/demand, even with an optimal cross border storage strategy. As a result, curtailment of supply and demand will therefore take place.
- The curtailment takes place because of insufficient volume, as well as insufficient injection and withdrawal rates from these caverns. Over a year, the curtailed hydrogen production and demand is in the order of 1 percent. However, this is calculated using:
  - A centrally managed storage strategy that controls storage facilities according to a merit order, which results in an optimal utilization of the storage infrastructure and avoidance of bottlenecks. In reality, this will be initially determined by long-term storage agreements between producers and storage operators and curtailment will be larger.
  - A flat demand rate over all sectors. Dynamic demand rates can influence the total curtailment in the system, e.g. when introducing hydrogen fired power plants with dynamic demand profiles.
- The currently estimated volumes and production/injection rates for underground hydrogen storage (UHS) are not enough for strategic storage purposes or to balance the system in prolonged extreme weather periods or significant supply chain disruptions.
- A delay in the rollout of underground storage sites results in significantly larger amounts of curtailed production or demand.
- Added flexibility in ports (local storage of hydrogen(carriers), in combination with flexible operation of e.g. ammonia crackers) can minimize curtailment when underground hydrogen storage facilities cannot deliver.
- Effective implementation of flexibility in the system mitigates the risk on curtailment.

It is therefore recommended to design the hydrogen value chain to account for weather variability and supply chain disruptions to manage intermittent green hydrogen production from solar and wind sources, by means of the following:

- **Advance Underground Hydrogen Storage in time;** Advance the availability of underground hydrogen storage sites as much as possible to be ready for use in a very early phase of the hydrogen network.
- **Establish storage facilities in ports with high and flexible discharge capacities**; This improves flexibility at ports and thus balances the system.
- **Value flexible operation;** evaluate how flexible operation of assets (supply and demand) can be valued, monetized or incentivized, such that impact on the dependency of storage sites is mitigated.
- **Evaluate alternatives;** Developing and realizing Underground hydrogen storage sites requires several years of development time. Considering the pace of the rollout of the network this articulates the need for alternative methods to provide flexibility. Evaluate (in terms of technology and policy) other means to add storage capacity and flexibility to the hydrogen value chain, in the form of
    - Electricity storage before hydrogen production (batteries)
    - Variable hydrogen conversion at ports (e.g. cracking of ammonia)
    - Surface level storage options (i.e. other means of storage for hydrogen or hydrogen derivatives)

3. In parallel to the technical analysis, a PESTLE deep dive was performed on the state of affairs regarding the hydrogen value chain in the three countries. Based on that work, it can be concluded that **it is unlikely that the demand estimates from the Global Ambition scenario of TYNDP for 2030 can be met in time.**

- The current level of investment plans in the hydrogen value chain is lagging behind ambitions.
- Final Investment Decisions (FIDs) in electrolyzer capacity are insufficient to meet with required levels for establishing a hydrogen economy.
- Announced hydrogen import capacity is lagging behind 2030/2033 targets, even if all projects are realized.

Robustness of the conclusions:

- Although the study focused on the time projections for 2030/2033 and 2035, the related demand/supply capacities determine the outcomes of the study. Should the network and capacities be delayed by a number of years, yet still materialize in the way described in the report, then the conclusions remain valid.
- The conclusions of this work are not dependent on the exact routing of the networks, as long as diameters are unchanged and the total pipe lengths between production, demand and storage locations remain within reasonable ranges.

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