

# Seasonality impact in green hydrogen imports to Europe

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**Abstract**— Europe has been identified as a hydrogen importer due to renewable energy resources limitations. Hydrogen import demand may have seasonal fluctuations in Europe due to temperature and renewable energy availability. This seasonal demand creates the need for additional infrastructure in exporting countries to match the demand with the supply, impacting the cost. We evaluate the impact of including seasonality integration costs on the countries from which Europe could import hydrogen. Import costs were evaluated using an optimization model. These costs were then used as inputs to an energy system model to evaluate the effect on the European energy system. A sensitivity analysis was done considering two different storage costs both in Europe and MENA. The results show that seasonality has a large impact on the import costs with the variations in storage costs playing a smaller role. On the European system, higher storage costs lead to lower hydrogen imports.

**Index Terms** hydrogen production, renewable energy, hydrogen imports, hydrogen exports, storage

## I. INTRODUCTION

Hydrogen is recognized as a key energy carrier for a future decarbonized world. It is expected to play a critical role in sectors which are hard-to-electrify, such as chemical feedstock, steel production, long-distance transportation and long-term energy storage. Global demand for hydrogen is expected to grow from 3.2 PWh in 2023 to between 4 and 15 PWh in 2050 [1]. In addition to increasing demand, international hydrogen trade is expected to grow. Studies estimate that around 25-30% of hydrogen will be traded globally, with regions such as the Middle East and North Africa (MENA), South America and Australia emerging as major exporters, while Europe, Japan and South Korea are expected to be major importers [2].

In the case of Europe, hydrogen imports are expected to increase in the coming years. The REPowerEU strategy outlines plans to produce 333 TWh (10 Mt) of hydrogen domestically and import an additional 333 TWh (10 Mt) by 2030 [3, 4]. By 2050, hydrogen demand in Europe is estimated

to be between 697 and 2,897 TWh, with other studies suggesting a wider range of 300 to 3,000 TWh [1, 5].

To meet the expected demand for hydrogen, Europe will need a combination of domestic production and hydrogen imports from outside the continent. Several system studies have modeled the future European energy system and have determined the hydrogen import requirements [5, 6]. These studies suggest that imports from outside Europe could account for between 4% and 15% of the total hydrogen supply in 2050. In addition, long-term scenario analyses suggest that import requirements for Europe in 2045 could be between 0% and 8.5% [7]. However, other studies suggest that there could be significant import levels in 2045. Fraunhofer CINES has calculated that the technical potential for hydrogen imports from the MENA region could meet up to 42% of European hydrogen demand in 2045 [8]. Lux et al (2024) considered a scenario where low renewable energy capacity is installed in 2050 resulting in 59% of hydrogen provided by imports [9].

Alongside the total annual hydrogen imports that Europe will require, the timing of this demand is important. Seasonal effects on renewable energy production and storage have been studied [10–12]. Similarly, hydrogen imports needed in Europe have display seasonal patterns, with increased demand during the winter months [9]. In winter, the limited availability of renewable energy resources in Europe leads to higher costs and higher demands for hydrogen imports. However, the additional costs associated with imports considering the demand's seasonality have not been studied. Therefore, this paper aims to address the following research questions:

- A) How does demand seasonality influence the costs associated with hydrogen imports?
- B) What effect do increased hydrogen import costs have on the European energy system?

This paper is structured as follows: The introduction offers an overview of the research context, significance of the study, and the research questions. Section II, Data and Methods, details the approach, data sources, and models employed in this

analysis. Section III presents the scenarios utilized for the investigation. Section IV outlines the results obtained from these scenarios, while Section V discusses the findings and provides conclusions.

## II. DATA AND METHODS

This section is divided into three parts. The first part presents the data used in the system model, including demand data and renewable energy potentials. The second part explains the seasonal factors considered in the calculation of the storage profile for the exporting countries. Finally, the third part provides a detailed description of the two models used in this study.

### A. Demand data and renewable potentials

The demand data used in this paper comes from the TransHyDE-Sys project. The scenario selected for evaluation is S2\_ChemSteel, which assumes that the European hydrogen demand comes mainly from the industrial sector, with a particular focus on chemical feedstock, steel production, and high-temperature industrial processes. Other sectors, such as transport and buildings, have minimal hydrogen demand. In addition, PtL products for long-distance transportation are not included in the hydrogen demand. A more detailed description of the demand data can be found in [5, 13].

The renewable electricity generation potential used in the PyPSA-EUR model were calculated using the Renewable Potential Calculator 2.0 of the EnerTile model. This calculator estimates the electricity generation potential for utility-scale photovoltaic (PV), rooftop PV, onshore wind, offshore wind, and concentrated solar power (CSP) with high geographical (6.5 x 6.5 km<sup>2</sup>) and temporal (hourly) resolution. More details about this calculation can be found in the literature [14, 15]. All models consider an interest rate of 2.0%.

### B. Seasonality in import demand

Hydrogen imports in the S2\_ChemSteel exhibit seasonal variations (Figure 1) as reported in the literature [9]. These variations are due to changes in the availability of renewable resources and demand throughout the year. PV production dominates in the spring and summer months, resulting in lower hydrogen production costs in Europe. In winter, the lack of solar resources, the volatility of wind production and the higher demand lead to higher hydrogen production costs within Europe and an increased need for hydrogen imports from outside Europe. Seasonality is then included into the hydrogen import cost model considering different levels of integration as described in the following section.

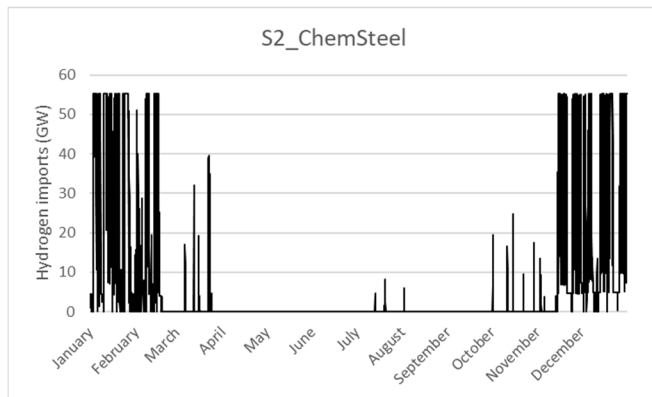


Figure 1. Hourly distribution of hydrogen imports to Europe in 2050

### C. Model description

A soft coupling was made between an optimization model for import calculations and the PyPSA-EUR system model. The models are described below.

#### 1) Import Model

A linear optimization import model has been developed to minimize the total supply costs associated with delivering gaseous and liquid hydrogen from production sites to the European border. The model accounts for all cost components related to hydrogen production, storage, and transportation. Country-specific assumptions are incorporated using detailed techno-economic data and transport distances. The model integrates hydrogen energy infrastructure, including production facilities powered by renewable energy (photovoltaic, onshore and offshore wind), liquefaction plants, underground storage caverns, and transportation networks (pipelines and shipping terminals).

Model parameters are set within a temporal resolution framework using annual modeling with daily time steps. Weather dependent renewable energy variability is captured using 2018 meteorological data, while hydrogen import demand, as a fraction of the total European demand, is based on optimized import quantities to Europe in the PyPSA-EUR model, with socio-economic constraints on hydrogen production to reflect local resource availability.

The objective function of our linear import model is to minimize total costs, including investment, production, conversion, and storage costs. It achieves this by representing multiple processes: renewable electricity generation with time-varying capacity factors; hydrogen production via electrolysis that converts electricity into hydrogen; conversion processes that transform hydrogen into a commodity; and storage operations that manage underground hydrogen caverns. Additionally, the model incorporates geographic differentiation by dividing exporting countries into subregions, taking into account factors such as distance from the coast and renewable resource quality, and supports various import strategies, including pipeline imports (e.g., from Morocco to Spain and Tunisia to Italy) and ship imports to Central Europe. The open

source model, along with all underlying data and assumptions, is available on GitHub<sup>1</sup>.

## 2) European Model

PyPSA-EUR is an open-source European energy system model built using the PyPSA (Python for Power System Analysis) software toolbox [16]. The model covers the entire ENTSO-E region and integrates electricity, transport, heating, and industry to analyze sector coupling and decarbonization strategies. The model follows a techno-economic optimization approach to meet energy demand with the most cost-efficient solution, while adhering to the technical boundaries of the system. With high spatial and temporal resolution, the model captures detailed grid dynamics and demand variations. It also takes into account flexibility solutions like power-to-X, electric mobility, and long-term storage, including hydrogen caverns and thermal storage [17].

The model’s hydrogen network starts with the German core-network as a seed and optimizes the rest of the network in a green field approach. Two main import corridors from the MENA region are then added in the model, based on the European Hydrogen Backbone supply corridors report [18]; Corridor “A - North Africa Southern Europe” through Italy and Corridor “B - Southwest Europe North Africa” through Spain. The capacities, location, and operation schedule of other hydrogen system components, including electrolyzers, hydrogen power plants, and storage facilities, are endogenously optimized within the model.

For the purpose of this study, the European model was run for the year 2045 with a 12-hour timestep and a 300-node resolution, 47 of which are in Germany. Both hydrogen storage costs and import costs from the MENA region were varied for the sensitivity analysis, based on input from the import model described in the previous subsection.

## III. SCENARIOS

Eight different scenarios were evaluated, taking into account different demand seasonality integration levels. They are summarized in TABLE I.

TABLE I. Modeling scenarios analyzed in this study

Scenario	Demand seasonality integration
S2_1200_0	Zero
S2_550_0	
S2_1200_100	Full
S2_550_100	
S2_1200_75	Medium
S2_550_75	
S2_1200_50	Low
S2_550_50	

The scenarios consider three different cases to evaluate the impact of demand seasonality integration (Figure 1) on the exports side. Zero integration, where the import model does not consider seasonal effects (scenarios with suffix 0). Full seasonality integration (scenarios with suffix 100), where the import model is fully aligned with the seasonal profile of demand shown in Figure 1. Two intermediate cases (scenarios

with suffix 50 and 75), where we assume that the domestic demand for PtX products helps to reduce the infrastructure needs at the import point. This leads to a partial integration of seasonality. In order to validate the results, for both the import and the European model, as indicated in the scenario name, two different storage costs were used, low and base: 0.55 and 1.25 €/kWh\_H2 respectively.

## IV. RESULTS

This section is divided into two parts. First, we present the results of the optimization model at the export nodes. Second, we present the results of the PyPSA-EUR optimization model showing the impact on the European system in 2045.

### A. Import costs results

This section examines eight import cost scenarios for gaseous and liquid hydrogen, which differ according to base and low cavern costs as well as the degree seasonality integration.

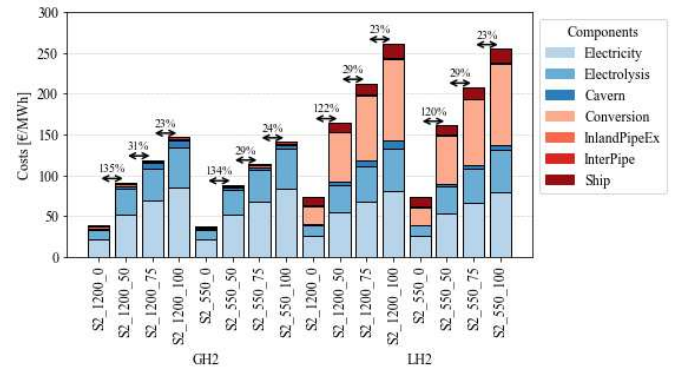


Figure 2. Import costs for cavern cost and flexibility scenarios

As illustrated in Figure 2, the results indicate that import costs vary by a factor of seven, ranging from 38 to 261 €/MWh, across the scenarios. Notably, gaseous hydrogen is on average 45% more cost-effective than liquid hydrogen.

A key determinant is the integration of seasonality. Scenarios with lower seasonality integration result in lower costs, while scenarios with higher seasonality integration result in significantly higher costs. Specifically, when comparing the zero seasonality scenarios to the low seasonality scenarios, costs increase by 120-135%. When considering higher seasonality integration (medium scenarios), costs increase by 29-31%, while considering the full seasonality integration results in a more modest increase of 23-24%. These cost escalations are due to the increased production capacity, such as renewables, electrolysis and liquefaction facilities, needed to meet winter demand, which are often underutilized during the summer months.

Moving from zero seasonality to low seasonality integration requires a staggering 244% increase in production capacity. Moving from low seasonality to medium seasonality integration requires an additional 130% increase, while moving from medium to full seasonality integration requires an additional 124% increase. For example, the S2\_1200\_0 gaseous

<sup>1</sup> [https://github.com/BTU-EnerEcon/Seasonal\\_Import\\_Model](https://github.com/BTU-EnerEcon/Seasonal_Import_Model)

hydrogen scenario requires 142 GW of renewable capacity and 28 GW of electrolysers in 2045, while the S2\_1200\_100 scenario requires 560 GW of renewables and 113 GW of electrolysers. This highlights the significant infrastructure investment required to meet the varying seasonal demands.

Despite the significant impact of seasonality integration in the costs for export, variations in storage costs have a comparatively minor effect on import costs, resulting in an average cost reduction of only around 4 €/MWh (−4%). These findings underscore the relatively modest influence of storage infrastructure expenses compared to the broader effects of production capacity adjustments and demand flexibility.

### B. Impact in Europe

The results of the zero, full, and low seasonality integration scenarios were evaluated using the PyPSA-EUR model. Figure 3 shows the hydrogen balance for these scenarios in 2045. The S2\_1200\_0 scenario shows the highest hydrogen imports, which can be attributed to the low import costs resulting from the absence of seasonality integration. These low import costs are further reflected in a greater amount of hydrogen used in the conversion sector, primarily for electricity generation.

In contrast, the full seasonality integration scenarios (suffix\_100) show almost negligible hydrogen imports. This is due to the significantly higher import costs. For the low scenarios (suffix\_50), the different storage costs for hydrogen in the European system lead to a significant difference in the import volumes. This occurs even though the import costs are similar between the two scenarios, as shown in Figure 2. Consequently, the costs associated with storage within the European system play a critical role, as higher storage costs lead to higher domestic production costs. All the hydrogen imports occur through the pipeline connections in the system, as the cost of importing hydrogen via pipeline is significantly lower (Figure 2).

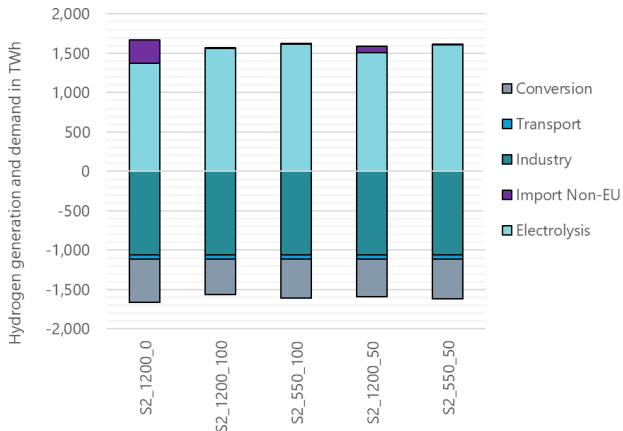


Figure 3. Hydrogen balance in Europe in 2045 for the different scenarios

Figure 4 depicts the differences in electricity generation from onshore wind, offshore wind, and solar in the scenarios compared to S2\_1200\_0. All scenarios show higher levels of electricity generation because a portion of the hydrogen imports in S2\_1200\_0 are used for electricity generation, resulting in lower generation from these sources for S2\_1200\_0 itself. The scenarios with low storage costs, S2\_550\_100 and S2\_550\_50

(0.55 €/kWh<sub>H2</sub>), show a significant increase of more than 5% in electricity generation from solar sources (including utility-scale PV and rooftop PV) compared to the scenarios with base storage costs. In contrast, scenario S2\_1200\_50 shows the smallest change compared to S2\_1200\_0. This is because this scenario has the second highest volume of hydrogen imports into Europe. Notably, S2\_1200\_100 has the largest increase in electricity generation from wind, including both onshore and offshore. It also has the highest storage costs, and the highest hydrogen import costs.

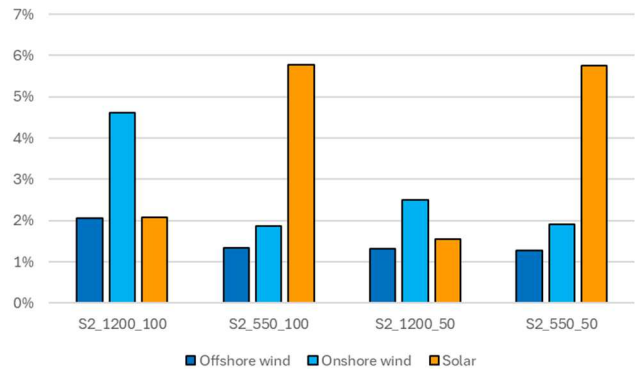


Figure 4. Variations in generation in 2045 for different renewable energy sources in the scenarios compared to S2\_1200\_0.

TABLE II shows the maximum storage capacities in Europe for the different scenarios in 2045. The two scenarios with lower storage costs (0.55 €/kWh<sub>H2</sub>) exhibit the highest storage capacities. S2\_1200\_100, which has high hydrogen import and storage costs, exhibits the lowest storage capacity.

TABLE II. Maximum storage capacities in Europe for the different scenarios

Scenario	Storage cap in TWh
S2_1200_0	436
S2_1200_100	578
S2_550_100	635
S2_1200_50	536
S2_550_50	632

## V. DISCUSSION AND CONCLUSIONS

In this paper, we investigated the impact of seasonality integration on hydrogen import costs. We calculated eight different scenarios with varying levels of seasonality integration on the import side. The results were integrated into the energy system model PyPSA-EUR to evaluate their impact on the European energy system.

The results show that the cost of importing hydrogen varies widely between the scenarios, ranging from 38 to 261 €/MWh. These variations are highly dependent on the transport method chosen, with pipeline transport generally being more cost effective as hydrogen does not need to be reconverted for use. In contrast, shipping hydrogen can result in higher costs due to the need for liquefaction and subsequent reconversion. However, existing pipeline links between Europe and MENA are currently used for the transport of natural gas. The future use of these pipelines for hydrogen will depend on several

factors, including a significant reduction in demand for natural gas and the need to reconfigure the infrastructure for hydrogen transport.

The total import volume calculated by PYPASA-EUR is mainly delivered to Europe by pipeline. However, the discussion on hydrogen imports also takes into account the important role of maritime transport. Although shipping may be more costly than pipeline transport, it plays a critical role in diversifying sources of supply, thereby increasing overall security of supply [19]. Other PtX products, such as ammonia, have a large advantage for long-distance transport through ships. It was determined that the import of ammonia for Finland and Germany will be more cost-efficient than domestic production in 2030 and 2050 [20].

Another important cost factor is seasonality integration. Assuming that the infrastructure is used to meet the seasonal demand for hydrogen imports in Europe, this leads to a need for increased production capacity in the summer months, which may remain underutilized in the winter. To avoid infrastructure stagnation, it is important for exporting countries to focus not only on hydrogen production for export, but also to move up the value chain by producing higher value products such as ammonia or steel [21]. In addition, while storage contributes to cost increases, it only accounts for 4% of the cost increase, making it a relevant factor but not as significant as the cost increases driven by seasonality fluctuations. Therefore, addressing seasonality and promoting value-added production will be critical to optimizing hydrogen infrastructure and costs.

All our scenarios have a low level of hydrogen imports except S2\_1200\_0 that has low import costs and does not consider seasonality impact. To have low imports of hydrogen into Europe a large capacity of PV, wind onshore and wind offshore shall be installed. However, public acceptance is a key factor that may hinder this installation. The phenomenon known as "not in my backyard" has been extensively studied in various regions, including Europe [22, 23], the United States [24] and China [25], and highlights the challenges that arise when local communities resist the development of renewable energy projects. If this phenomenon is considered, it may pose greater challenges to the installation of renewable energy sources, potentially delaying or limiting their deployment. As a result, these challenges could lead to increased reliance on hydrogen imports to meet energy needs as shown in [9].

Blue hydrogen produced within Europe may also reduce the demand of green hydrogen imports into Europe. Blue hydrogen is recognized as a low-carbon alternative and may be more cost-competitive than the green hydrogen options discussed in this paper [26]. The establishment of blue hydrogen production in Europe could significantly reduce the need for green hydrogen imports. It is considered that blue and green hydrogen will both have a role in the future European energy system [27].

Storage costs play an important role in determining the level of hydrogen imports to Europe. In the S2\_550\_50 scenario, low storage costs (0.55 €/kWh<sub>H2</sub>) lead to reduced hydrogen production in Europe and very low imports. In contrast, the S2\_1200\_50 scenario involves higher import costs (1.25 €/kWh<sub>H2</sub>), but the increased storage costs lead to increased domestic production costs. Consequently, this

scenario is associated with higher hydrogen imports from outside Europe, highlighting the complex interplay between storage costs and import dynamics.

In addition, the scenarios that consider lower storage cost tend to have a higher number of installed PV systems. These increased PV installations are used for hydrogen production. However, it is important to note that PV systems experience significant annual production fluctuations. Therefore, the successful deployment of a larger number of PV systems depends on the presence of lower storage costs, which facilitates the necessary storage capacity within the European energy system. The results from the long-term scenarios show a similar correlation as their T45-PV scenario +(with a higher PV installed capacity) requires 380 TWh of hydrogen storage in Europe, significantly higher than T45-Strom\* that requires only 278 TWh [7]. Finally, the scenarios with higher storage costs (1.2 €/kWh<sub>H2</sub>) have lower solar reliability in solar and have higher wind onshore and offshore generation and lower storage needs.

We have identified the significant impact of seasonality on European hydrogen import demand, with higher levels of seasonality leading to higher hydrogen import costs. Introducing flexibility in exporting countries can help mitigate these effects and significantly reduce costs. Another key factor is the mode of transport, where pipelines emerge as the least expensive option and are predominantly selected by the energy system model PYPASA-EUR. In addition, we observed that a reduction of storage costs to 0.55 €/kWh<sub>H2</sub> leads to a higher installed capacity of photovoltaic (PV) systems compared to the baseline scenario. Storage costs also influence import dynamics, as higher storage costs within the European system led to increased hydrogen imports. While the energy system model optimizes for cost efficiency, it does not take into account broader considerations such as energy security or social acceptance, which should be included in future research. We focused our research on the MENA region and other countries in the southern hemisphere. The seasonality effect may be different, as the peak of supply, the summer in the southern hemisphere, coincides with the high demand in the European winter. Ultimately, seasonality of demand and storage costs are critical factors in shaping the future of the European hydrogen infrastructure, highlighting the need for strategic planning and policy intervention.

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