

StEAM - Sector transformation in the Energy system: Analysis and Modelling of possible hydrogen strategies

Final project report

November 2025

Supported by:



Federal Ministry
for Economic Affairs
and Climate Action

on the basis of a decision
by the German Bundestag

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Acknowledgment

The research for this study was conducted within the project “StEAM” (Sector transformation in the energy system: Analysis and modelling of possible hydrogen strategies) supported by the German Federal Ministry of economic affairs and climate action. Research grant number 03El1043A and 03El1043B.

The authors thank the colleagues from the chair of energy systems and energy economics and the research partners from the house of energy, climate and finance for the collaboration on the research project. A special thanks also to the former colleagues Christopher Jahns, David Hückebrink, Dennis Schneider, Leonie Plaga and Benjamin Böcker for their contributions and guidance during the project work as well as to the developers of Spine and Backbone for the provision of the framework and technical support.

Abstract

The project "Sector transformation in the Energy system: Analysis and Modelling of possible hydrogen strategies" (StEAM) aims at investigating future global hydrogen production and transport systems under different scenarios. The project addresses the main questions: Where can we produce which quantities of hydrogen at which prices? Where is it needed and how and in which form does it get there? To answer these questions an energy system model is developed that includes investment and dispatch decisions and covers the sectors electricity and hydrogen including sector coupling technologies, pipeline transport and multi-commodity shipping. Furthermore, the model includes additional features and methods to enable more advanced investigations and better insights into the system dynamics of a possible hydrogen economy. The scenarios take into account different CO₂ budgets, electricity and hydrogen demands, as well as technological progress. The results show global capacity expansion for electrolyzer and electricity production technologies, as well as hydrogen production volumes and transport flows. It can be seen, that the majority of hydrogen production is more localized and shows hydrogen flows mostly from neighboring regions to one another via pipelines. In long-term and high demand scenarios shipping transport in the form of ammonia occur more often. The long-term marginal hydrogen production costs may lie at around 92-116 €/MWh (2.75 - 3.5 €/t) in Germany, with a high import share and depending on the dynamics of capacity expansion. Policy implications for Germany include rapid scale-up of renewable and electrolyzer capacities to enable long-term lower marginal costs and therefore improved competitiveness of the domestic market. Additionally, securing sufficient hydrogen supply from partner countries considering strategic independence with a focus on European countries and neighboring regions is crucial to meet future energy demands in Germany.

Kurzfassung

Das Projekt “Sektortransformation im Energiesystem: Analyse und Modellierung möglicher Wasserstoffstrategien” (StEAM) zielt darauf ab, zukünftige globale Wasserstoffproduktions- und Transportsysteme unter verschiedenen Szenarien zu untersuchen. Das Projekt behandelt die Hauptfragen: Wo können wir welche Mengen an Wasserstoff zu welchen Preisen produzieren? Wo wird er benötigt und wie und in welcher Form gelangt er dorthin? Um diese Fragen zu beantworten, wird ein Energiesystemmodell entwickelt, das Investitions- und Dispatch-Entscheidungen umfasst und die Sektoren Strom und Wasserstoff einschließlich Sektorkopplungstechnologien, Pipeline-Transport und Schiffstransport mit verschiedenen Energieträgern abdeckt. Darüber hinaus umfasst das Modell zusätzliche Funktionen und Methoden, um fortgeschrittene Untersuchungen zu ermöglichen und bessere Einblicke in die Systemdynamik einer möglichen Wasserstoffwirtschaft zu gewinnen. Die Szenarien berücksichtigen unterschiedliche CO₂-Budgets, Strom- und Wasserstoffnachfrage sowie technologischen Fortschritt. Die Ergebnisse zeigen die globale Kapazitätserweiterung für Elektrolyseure und Stromerzeugungstechnologien sowie Wasserstoffproduktionsvolumina und Transportströme. Es zeigt sich, dass der Großteil der Wasserstoffproduktion lokal und regional ist und Wasserstoffströme hauptsächlich zwischen benachbarten Regionen über Pipelines stattfinden. In langfristigen und hochnachfrageorientierten Szenarien tritt der Transport per Schiff in Form von Ammoniak häufiger auf. Die langfristigen Grenzkosten der Wasserstoffproduktion können in Deutschland bei etwa 92-116 €/MWh (2,75 - 3,5 €/t) liegen, mit einem hohen Importanteil und abhängig von der Dynamik der Kapazitätserweiterung. Politische Implikationen für Deutschland umfassen die schnelle Ausweitung der Kapazitäten für erneuerbare Energien und Elektrolyseure, um langfristig niedrigere Grenzkosten zu ermöglichen und damit die Wettbewerbsfähigkeit des heimischen Marktes zu verbessern. Zusätzlich ist die Sicherstellung einer ausreichenden Wasserstoffversorgung aus Partnerländern unter Berücksichtigung strategischer Unabhängigkeit mit Fokus auf europäische Länder und benachbarte Regionen entscheidend, um die zukünftigen Energiebedarfe in Deutschland zu decken.

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List of Abbreviations

Abbreviations	Definition
APS	<u>A</u> nnounced <u>P</u> ledges <u>S</u> cenario
CC	<u>C</u> arbon <u>C</u> apturing
DA	<u>D</u> elegated <u>A</u> ct
fom	<u>f</u> ixed operation and <u>m</u> aintenance
GDP	<u>G</u> ross <u>D</u> omestic <u>P</u> roduct
GIS	<u>G</u> eographic <u>I</u> nformation <u>S</u> ystems
HRU	<u>H</u> ydrogen <u>R</u> un- <u>U</u> p
MGA	<u>M</u> odelling to <u>G</u> enerate <u>A</u> lternatives
NECP	<u>N</u> ational <u>E</u> nergy and <u>C</u> limate <u>P</u> lan
NHS	<u>N</u> ational <u>H</u> ydrogen <u>S</u> trategy
NZE	<u>N</u> et <u>Z</u> ero <u>E</u> mission
PHS	<u>P</u> umped <u>H</u> ydro <u>S</u> torage
RED	<u>R</u> enewable <u>E</u> nergy <u>D</u> irective
RES	<u>R</u> enewable <u>E</u> xpansion <u>S</u> cenario
RFNBO	<u>R</u> enewable <u>F</u> uel of <u>N</u> on- <u>B</u> iological <u>O</u> rigin
SMR	<u>S</u> team <u>M</u> ethane <u>R</u> eforming
StEAM	<u>S</u> ector <u>T</u> ransformation <u>E</u> nergy System <u>A</u> nalysis <u>M</u> odel
STEPS	<u>S</u> Tated <u>P</u> olicies <u>S</u> cenario
TSA	<u>T</u> ime <u>S</u> eries <u>A</u> ggregation
TSAM	<u>T</u> ime <u>S</u> eries <u>A</u> ggregation <u>M</u> odule
vom	<u>v</u> ariable operation and <u>m</u> aintenance
VRE	<u>V</u> ariable <u>R</u> enewable <u>E</u> nergies
WACC	<u>W</u> eighted <u>A</u> verage <u>C</u> ost of <u>C</u> apital

1. Introduction

In the past, different aspects of hydrogen have been investigated extensively through a large number of hydrogen studies and projects. Most of them cover individual sectors, regions or countries. This project aims to investigate hydrogen production and transport on a global scale. To facilitate this, a new freely available global sector-integrated energy system model is developed and applied.

1.1 Background

At the latest since the Paris agreement has been signed in 2015 (UNFCCC, 2015), the fight against climate change has been an unavoidable topic for societies all over the world. Yet the fight against climate change has been pursued with widely varying degrees of consistency. Regardless, the transition of the energy system must play a key role in every attempt to mitigate climate change. To mitigate the most important greenhouse gas CO₂, the global energy systems need to be transitioned towards renewable energy sources. This can be achieved by either direct electrification or by replacing fossil fuels with renewable alternatives. Scientific advances and economic developments contribute to progressively trace the separation line regarding which processes can and will be electrified. For some processes, especially the ones requiring high temperatures or including process-inherent emissions, alternatives to fossil fuels are often hydrogen or hydrogen derivatives. Hydrogen can be used for direct reduction of iron ore in steel production, replace fossil hydrogen in chemical processes or be used as fuel for high temperature processes like in the glass and cement industry.

The overall research goal of this project is to investigate a possible future global hydrogen production and transport system to answer the questions: Where can we produce which quantities of hydrogen at which prices? Where is it needed and how and in which form does it get there? To be able to answer these questions, a global energy system model that integrates the electricity and hydrogen sectors is developed. With the help of this model, Germany's national hydrogen strategy shall be assessed in an international context using consistent future scenarios.

The relevant outcomes of the study for policy and decision makers are to identify potential hydrogen export nations and to project the needed expansion of renewable energies. This can then be used to initiate and intensify hydrogen partnerships on the one hand and on

the other hand to investigate matters of strategic autonomy and diversification of import streams.

From a scientific and technological perspective, the developed model represents the electricity as well as the hydrogen sector on a global scale, including the transport sector. To enable the evaluation and determination of optimal hydrogen-based transformation strategies for the energy system, the model is built as energy system optimization model, that uses total cost minimization as objective function. The model framework used is the Backbone open-source model framework, which is flexible and can represent various energy sectors and conversion processes (Helistö et al., 2019). By combining the framework with the model information, optimization problems are generated and solved efficiently, making detailed analyses of subsystems possible. For these detailed analyses, multiple methods and features are deployed. Beyond the optimization itself, a scenario analysis and an Modelling to generate alternatives (MGA) approach are performed to explore various hydrogen transformation paths.

At the end of the research project, the developed model including the datasets and tools has been published open source, to enable the research community and companies to investigate trade-offs and optimize different regions independently.

Accompanying the project, a group of stakeholders from different companies and agencies along the whole hydrogen value chain has been involved and has been regularly updated on the current status and results, thereby ensuring the model's relevance and practical applicability.

1.2 Current State of Research

Currently, there are many energy system models already available, each with its own scope. The models. Some models use pre-calculated levelized costs and therefore only compare static or average behavior of different technologies. This applies to ERIKSSON (Moritz et al., 2025) or the PtX Atlas (Pfennig et al., 2022). This approach enables higher geographical resolutions and more detailed infrastructure planning, especially with regards to limited calculation capacities. Nevertheless, this approach has drawbacks, since dynamic system behavior cannot be considered. This has disadvantages for storage behavior, the calculation of marginal costs and the investigation of necessary system flexibilities. Hence, the model developed during this project includes dynamic time series. Other models

like agent-based models or simulation models usually focus on different aspects of energy system research and therefore are not being covered as comparison for this model. The models considered here are all energy system optimization models that focus to some extent on cost-minimization as objective function (see Table 1.1). Another aspect differing between models is the geographical scope. There are many models that focus on individual countries or regions like FINE (Welder et al., 2018). Other models cover multiple countries, or alliances like the European Union, e.g. Balmorel, PyPSA-Eur-Sec or TEMOA (Wiese et al., 2018; Hörsch et al., 2018; Lerede et al., 2024). Only very few models like PLEXOS, Global Gas Model or PyPSA-Earth cover the whole world (Brinkerink et al., 2018; Egging et al., 2019; Parzen et al., 2023). The scope of this project is building a global energy system model. Additionally to the geographical scope, the modeled commodities vary and whether the different commodities and sectors are integrated with one another. The models with a limited geographical scope like PyPSA-Eur-Sec, TEMOA and Balmorel usually also include sector coupling between individual sectors but do not comprehensively model the global hydrogen system (Schafer et al., 2000; Komiyama et al., 2014). The other global models do not cover sector integration. PLEXOS covers electricity, while the Global Gas Model only covers gas infrastructure. PyPSA-Earth is currently working on expanding its dataset. Another aspect in which the StEAM and PyPSA model stand out in comparison to PLEXOS, is the fact that those models are open-source and freely available.

	StEAM	PLEXOS	PyPSAEarth	PyPSA-Eur-Sec	Balmorel	FINE	TEMOA
System scope	Multi-energy	Multi-energy	Multi-energy	Multi-energy	Multi-energy	Multi-energy	Multi-energy
Geographical scope	Global	Global	Global	Europe	Europe	Germany	Europe
Geographical resolution	Country	Country	Sub-country	Sub-country	Sub-country	Sub-country	Country
Commodities	Electricity, Hydrogen, Open	Electricity, Gas	Electricity, Hydrogen, Heat, Mobility, Industry	Electricity, Hydrogen, Heat, Mobility, Industry	Electricity, Hydrogen, Open	Electricity, Hydrogen	Electricity, Final Energy Demands
Open source	Yes	No	Yes	Yes	Yes	Yes	Yes

Table 1.1: Overview of different large energy system models.

Since the openly available models are limited, the studies are subsequently limited as well. Many studies focus on individual sectors, transport systems or infrastructure or limited geographical scopes. The “European Hydrogen Backbone” study focuses on European gas infrastructure but does not provide a global perspective (van Rossum et al., 2022). Other studies (Ram et al., 2020) analyze synthetic fuels but do not explicitly include pipeline infrastructures and their impact on transport costs. Furthermore, many studies, especially

from agencies, consultancies and institutes close to business, rely on proprietary models such as PLEXOS and are not entirely transparent about their base data, methodologies and assumptions (IEA, 2022). Results from energy system models are highly sensitive to input data (Egli et al., 2019; Bogdanov et al., 2019), and there is a need for transparency and methods to address uncertainty and generate alternative solutions. Additionally, global energy system studies tend to take a bilateral perspective, examining imports from specific partner countries. Sometimes even they may focus on only some of the biggest economies in the world, subsuming the remaining countries as "Rest of the World". This overlooks not only huge parts of the world's economies and population, but also creates a bias in terms of scientific insights and therefore perspective. Hence, it is necessary to set the foundation for a comprehensive and coherent global dataset on the level of the individual countries to enable more detailed investigation also of often underrepresented regions. Subsequently, also the complexity of neighboring energy systems and international trade dynamics may be considered in detail.

In conclusion, a freely available dynamic global sector-integrated energy system optimization model is needed that transparently makes use of a comprehensive and coherent global dataset to investigate global hydrogen production and transport relations for future years. Therefore, the setup and composition of this model is explained in the following chapters. After explaining the model setup, the model is applied on the defined scenarios and the results of the optimization are presented, analyzed and discussed. Subsequently, conclusions are drawn from the discussion and synthesized with the initial research questions. Finally, limitations are discussed to give an outlook on potential research gaps for future research and development.

2. Methods and Modelling

In the following section, the methods and data sources for the different components of the model are explained. On the one hand, the setup of the datasets is presented, including the data sources, the methods to create and prepare the datasets as well as the configuration of the energy system. On the other hand, the methods to facilitate, modify and improve the modeling are explained. This includes basics for the model setup, as well as advanced modeling methods and features.

2.1 Methods to drive data generation

To induce an energy flow, first, a demand must be defined. Therefore, the electricity and hydrogen demands for the model are derived to begin with. This is followed by setting the foundation for the electricity system including the power plant fleet and the transmission grid. The variable renewable power plants are then discussed individually, since apart from the general techno-economic data, capacity potentials and the respective profiles need to be determined. To ensure compliance with decarbonization pathways, CO₂ emission budgets and pricing are defined. In parallel to the electricity system, the hydrogen transport system can be defined and integrated with the former using sector coupling. This basic setup is then complemented with a differentiated dataset for weighted average costs of capital.

1. Demands
 - (a) Electricity demands
 - (b) Hydrogen demands
2. Electricity
 - (a) Power plants
 - (b) Transmission grids
3. Variable renewable potentials
 - (a) Capacity potentials
 - (b) Renewable profiles
4. CO₂ budgets and pricing
 - (a) Current CO₂ emissions and decarbonization pathways

(b) CO₂-pricing

5. Hydrogen transport system
6. Sector coupling
7. Weighted Average Costs of capital

2.1.1 Demands

The demands are given exogenously and based on the World Energy Outlook 2022 (IEA, 2022). Here, the hydrogen demands and electricity demands can be drawn from the different scenarios Stated Policies Scenario (STEPS), Net Zero Emission (NZE) and Announced Pledges Scenario (APS). The electricity demand includes all direct electricity demands as well as the ones for electrification of the industry, mobility and heat sector according to each scenario and for each country. In the source, the electricity demand already contains the electricity demand for the hydrogen production. Therefore, the corresponding electricity demand to meet the hydrogen demand is deducted from the electricity demand. The source does not provide data for each country in the world. Sometimes individual countries are provided, sometimes regions are being aggregated. To be able to derive individual hydrogen demands for all countries, the demands are complemented by additional literature (WEC, 2020; Statista, 2022; Hydrogen Europe, 2022; Hydrogen Council, 2022; WEC, 2022) and the remaining data gaps are filled by scaling to the share of Gross Domestic Product (GDP). The resulting demands are shown in Figure 2.1.

The electricity load profiles from PLEXOS (Brinkerink et al., 2021) are used and rescaled to fit the determined total demands. The hydrogen load profiles are assumed as flat profiles. Investigations show that this is an adequate assumption, except for some transport applications, since the main applications are in steel industry, chemical industry and heavy industry with almost exclusively continuous production. A representative load profile for Germany in 2040 (APS) is shown in Figure 2.2

2.1.2 Electricity

The electricity system is composed of the national power plant park in each country and the international transmission lines in between. National electricity systems are modelled as copperplates with single nodes representing national electricity grids where electricity production and demand are matched independently of transmission restrictions.

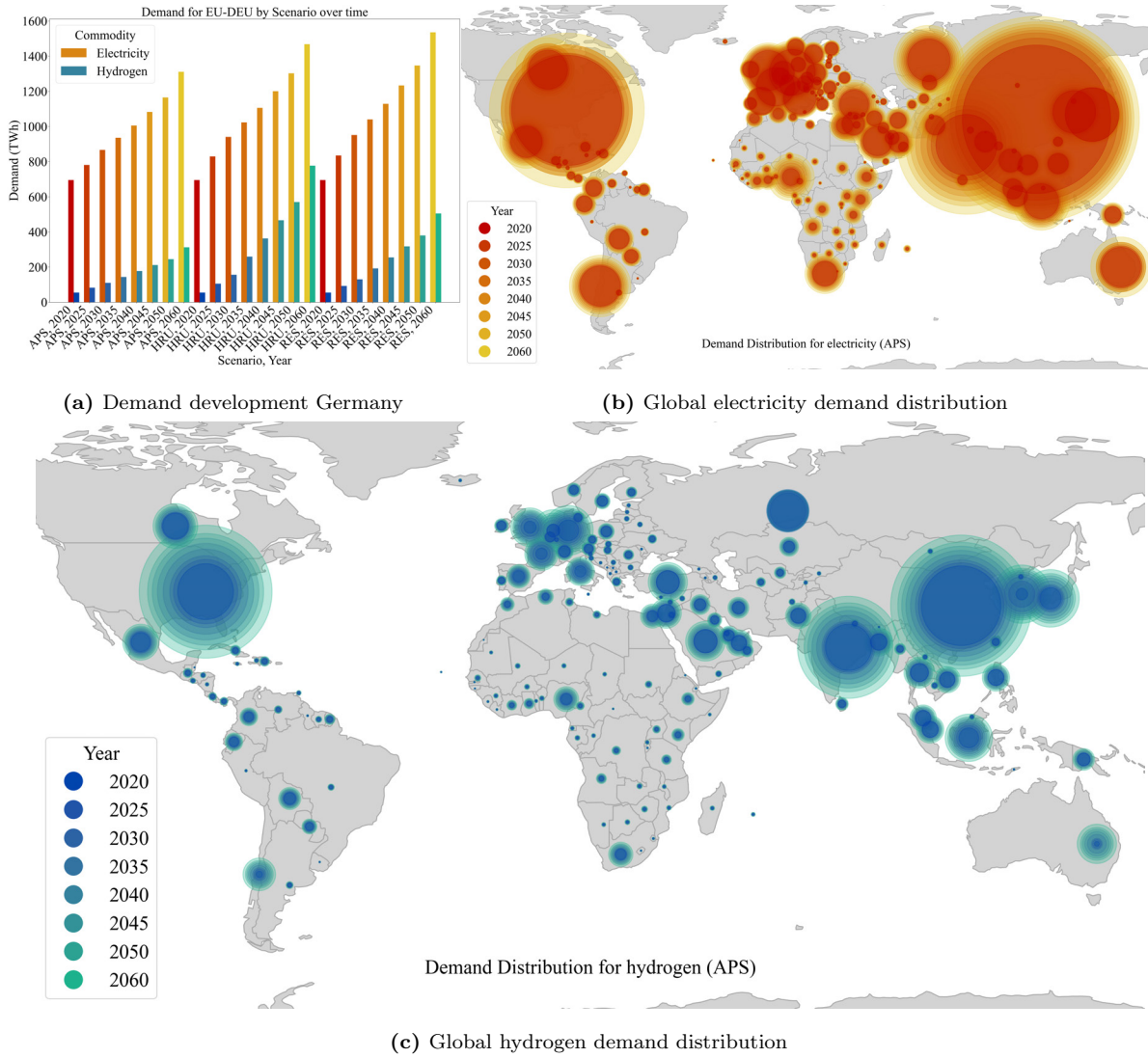


Figure 2.1: Find the complete demand dataset in <https://zenodo.org/records/15639823>

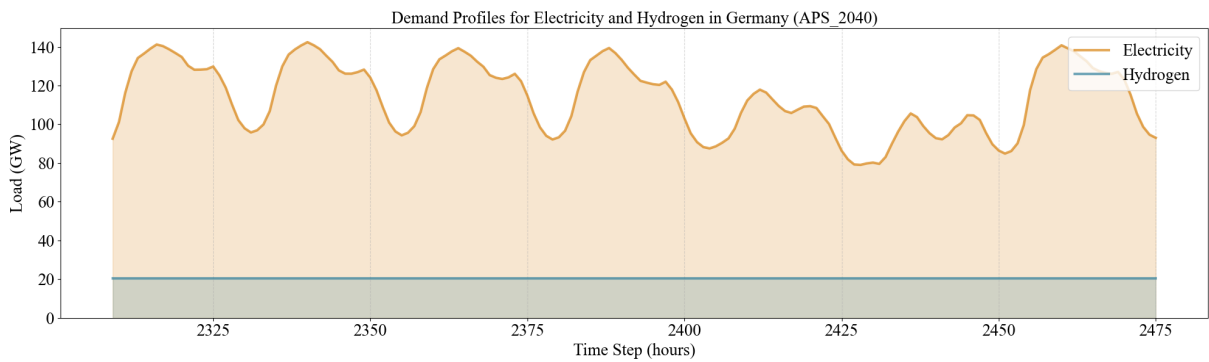


Figure 2.2: Representative demand profiles for electricity and hydrogen in Germany

Each element has techno-economic parameters like possible existing capacity, efficiencies, ramp-rates, lifetime, fuel costs, investment costs, fixed operation and maintenance (fom) and variable operation and maintenance (vom) cost. Additionally, the Weighted Average

Cost of Capital (WACC) (see chapter 2.1.7) and the cost of labor are varied between different regions and technologies (ILOSTAT, 2023; Schröder, 2019; SalaryExplorer, 2023). The existing power plant capacities have been updated to 2023 using IRENA (IRENA, 2023), Global Energy Monitor (GEM, 2024), Entso-E (Entso-E, 2024), Electricity Maps (Corradi, 2016) and are represented in Figure 2.3 showing the share of each technology as well as the total installed capacity. The data used in this study can be found on Zenodo¹.

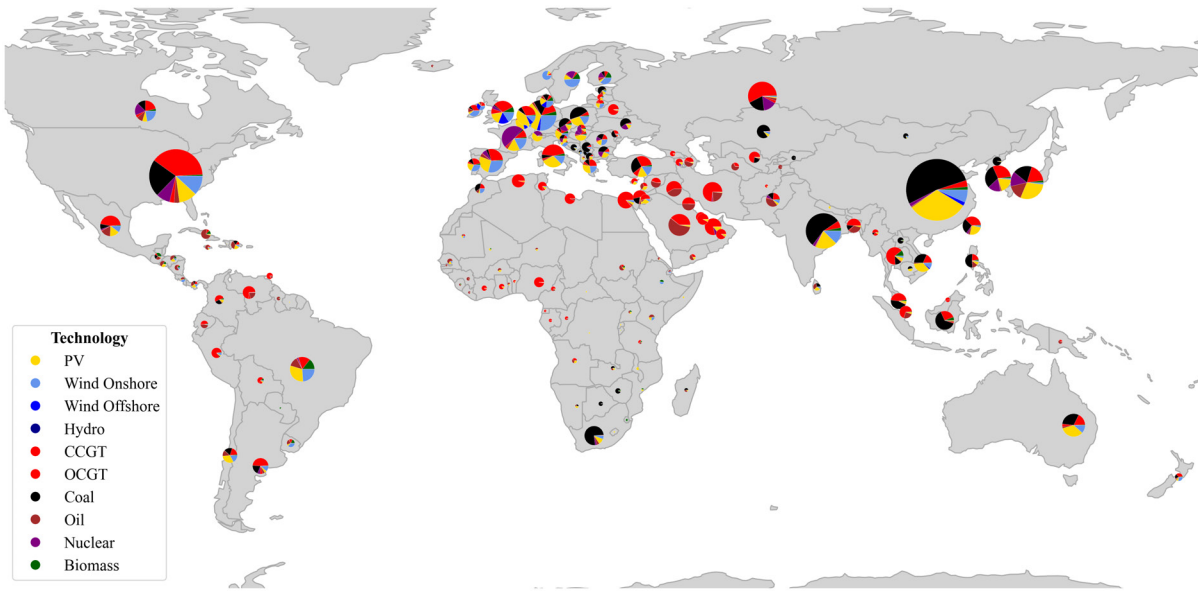


Figure 2.3: Global installed powerplant capacity distribution 2023

The existing interconnector capacities are based on Brinkerink et al. (2021) and have been partly updated through entsoe.eu (Entso-E, 2024) and electricitymaps (Corradi, 2016). The base dataset for the installed transmission lines is shown in Figure 2.4.

The electricity storages available to the model are Pumped Hydro Storage (PHS) and battery storages. PHS are currently implemented as installed capacity derived from Brinkerink et al. (2021) without the possibility to invest in additional capacities. Battery storages on the other hand are implemented as investable units, therefore enabling electricity storage expansion. Hydrogen storages are further described in chapter 2.1.5.

2.1.3 Variable Renewable Potentials

To realistically estimate renewable energy expansion pathways within decarbonization scenarios, it is necessary to introduce constraints that reflect physical and geographical

¹ This dataset can be found in <https://zenodo.org/records/15639823>.

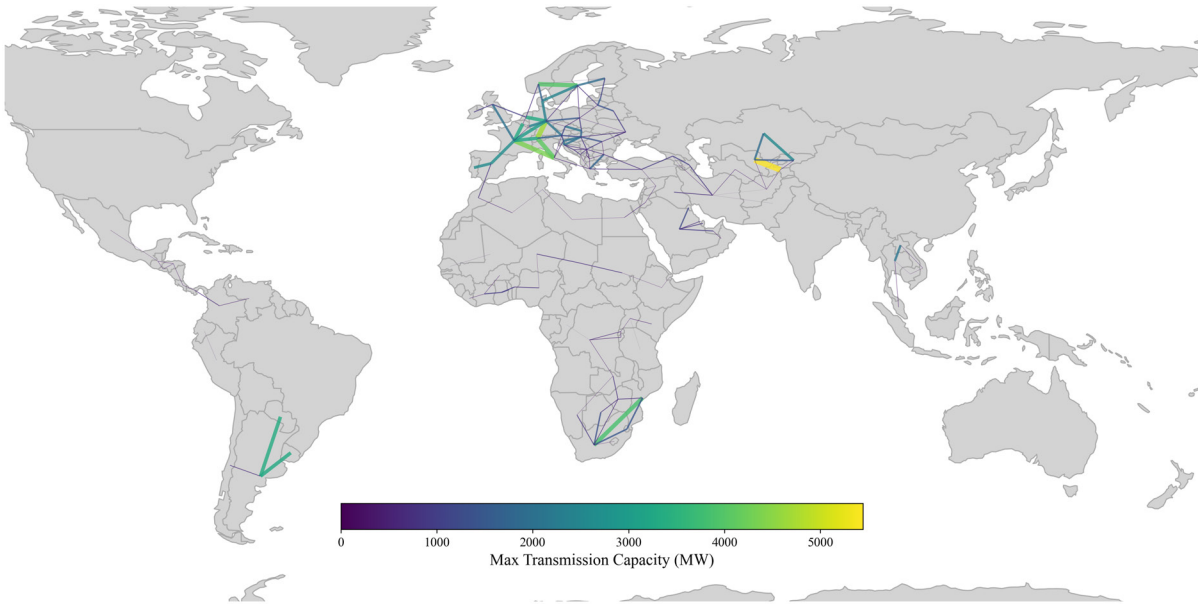


Figure 2.4: Global installed electricity interconnector capacities 2023

conditions. This is relevant both for meeting future electricity and hydrogen demand as well as for identifying potential export capacities on a global hydrogen market.

To this end, a GIS-based analysis was conducted in combination with the generation of renewable energy production profiles derived from climate data projections. This approach enables the identification of regions with both high land availability and favorable conditions for renewable power generation. In both cases, a global spatial resolution of $100 \text{ km} \times 100 \text{ km}$ was applied. The year 2050 was set as the target year for the climate projections.

To identify areas that are suitable for green hydrogen production, a land eligibility analysis has been conducted. Considered renewable energy sources are onshore and offshore wind and utility-scale PV. Based on (World Bank, 2020; World Bank, 2019; Bosch et al., 2017), eligible land areas for each technology were identified by applying exclusion criteria such as urbanized regions, protected areas, cropland, and complex terrain. Furthermore, areas with high water scarcity are deemed unsuitable for the production of green hydrogen (Hofste et al., 2019). For each spatial tile, the available area for each respective technology is determined and multiplied with a power density to assign a cap on the maximum installable capacity in this cell.

Since the energy system model has to find the cost-minimal composition, the results tend to accumulate installed capacities in individual countries, since initially the best possible locations for Variable Renewable Energies (VRE) are used. To consider this, two additional options were created to assess the effects of limiting the maximum installable

capacities for the VRE. This is achieved by combining the maximum installable potential derived from the aforementioned geographic information systems (GIS) analysis per country and a logistical extrapolation from historical VRE expansion. There are three possible model options available. The "Base_case" option again represents the model without any limitation, the "Cap_lim" option uses the logistic limitation and the "Kickstart" option applies a logistic limitation with increased expansion rate for countries with historically lower expansion. This option is explained in detail in Linsel et al. (2025).

The renewable energy capacity factor time series are based on climate projections of the Coupled Model Intercomparison Project (CMIP5). For this study, the Representative Concentration Pathway (RCP) 2.6 scenario for the year 2050 is used, providing variables such as wind speed, solar radiation, and temperature. To obtain the required spatial resolution, the projections are dynamically downscaled within the framework of the Coordinated Regional Climate Downscaling Experiment (CORDEX). In a subsequent step, the Python-based tool Cd2es converts the climate data into hourly capacity factor time series for wind (onshore and offshore) and photovoltaic (PV) technologies. Wind speed is translated into capacity factors using standardized turbine power curves for a given hub height. For PV, local temperature variations are used to calculate the PV cell temperature and thereby adjust conversion efficiency. Finally, a bias adjustment is performed by aligning the simulated time series with historical ERA5 reanalysis data. This approach is described in detail in (Plaga and Bertsch, 2023; Plaga and Bertsch, 2025)

2.1.4 CO₂ Budgets and Taxes

Country-specific CO₂ emissions and reduction pathways are incorporated into the model as exogenous parameters, shaping both the timing of carbon neutrality and the pace of decarbonization. A key challenge in defining these national reduction pathways lies in the heterogeneity of countries themselves, with respect to population size, current emissions, and GDP. This heterogeneity makes it impractical to derive consistent cross-country pathways based solely on a single base year and a uniform change rate. While this approach appeared to be reasonable for some countries, in others it resulted in carbon neutrality years that were considered far too early or far too late.

Therefore, in addition to a base year, a carbon neutrality target year was specified for each country. For countries that have announced climate goals published in the NECPs, the respective target year was set. This approach allows the construction of scenario-specific

pathways across countries, reflecting the individual decarbonization speeds of each country in line with their stated goals.

The year 2020 was chosen as the base year for all development pathways. Two central aspects must be considered in the specific design of the emission reduction pathways. First, the model primarily represents the energy sector. Therefore, based on (Crippa et al., 2023) and (Wolfsteiner and Wittmann, 2024), the share of the power sector in total greenhouse gas emissions is calculated and used as the starting point. Second, it is assumed that the electricity sector, as the foundation for the decarbonization of other energy sectors, must achieve full decarbonization earlier. Consequently, the target year has been moved forward by five years for all countries. Furthermore, the predefined reduction pathways correspond to each country's specific share of the electricity sector in the overall economy, and this share is set to remain constant over the modeling horizon.

Secondly, scenario-specific emission reduction pathways were defined to ensure a clear distinction between the Announced Pledges Scenario (APS) and the more ambitious Hydrogen Run-Up (Hydrogen Run-Up (HRU)) and Renewable-Electrification Scenario (Renewable Expansion Scenario (RES)), as described in section 2.2.1. In the APS scenario, a linear reduction pathway was employed to ensure a straightforward representation. In contrast, for the HRU and RES scenarios, a piecewise cubic polynomial interpolation was applied and parameterized according to the respective base and target years. Exemplary trajectories of these reduction pathways are illustrated for Germany and China in Figures 2.5a and 2.5. Figure 2.6 shows the country-specific reduction pathways aggregated at the continental level.

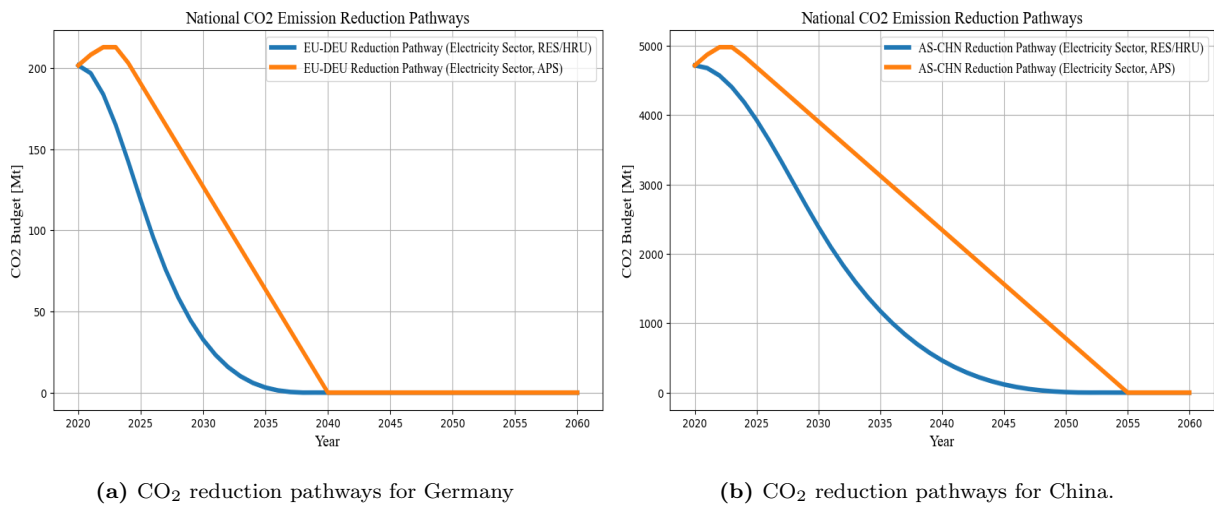


Figure 2.5: Exemplary CO₂ reduction pathways in the APS (red) vs. RES and HRU (blue) scenarios.

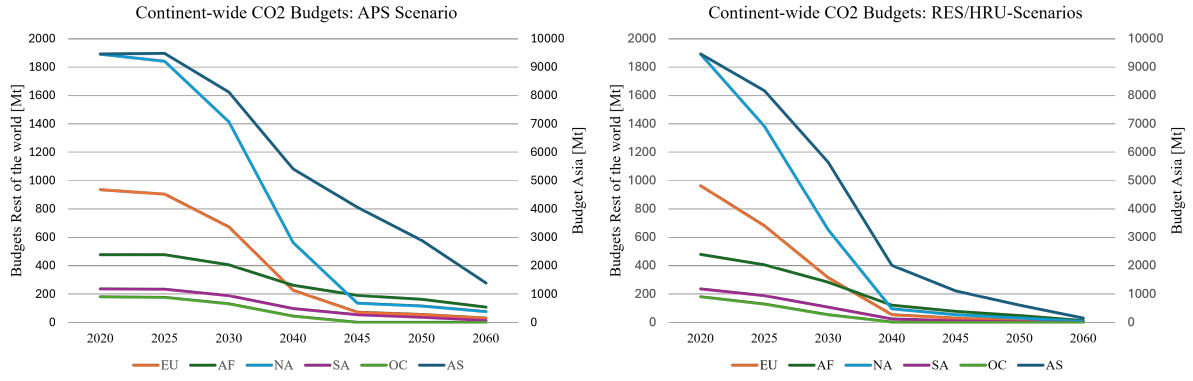


Figure 2.6: Spatially aggregated CO₂ reduction pathways by continent.

2.1.5 Hydrogen Transport System

The hydrogen transport system uses the given nodes and connects them via pipelines and shipping connections. The pipelines are determined through Delaunay triangulation to set up a potential grid between all nodes. These connections are then reassessed to get rid of unrealistically long connections or connections that cross water bodies that are too deep. The length of these pipelines is multiplied by an elongation factor of 1.3, that has been determined by evaluating existing pipelines, to take into account that in real world applications the topology does not allow perfect linear connections. For the shipping connections, dedicated terminals are predefined and connected to the respective country nodes. From these terminals, the shipping routes are defined to be able to connect each terminal with each other terminal. Since this is a quadratic relation, the number of available terminals in this dataset is limited to reduce the number of variables and therefore the computational intensity. The terminal dataset also includes different transport commodities such as liquefied hydrogen, ammonia and methanol. The datasets for the nodes and terminals can be easily expanded if needed. The complete and detailed documentation of the transport system is published in (Linsel and Bertsch, 2024). The potential hydrogen transport system including all country nodes and terminals is shown in Figure 2.7.

Hydrogen storages

The hydrogen storages available to the model are technical hydrogen storages in the form of gas tanks that can also be invested in. Additional investable bunker storages for hydrogen and its derivatives at the terminal sites as well as cavern storage potentials in each country are currently being implemented. Electricity storages are further described in chapter

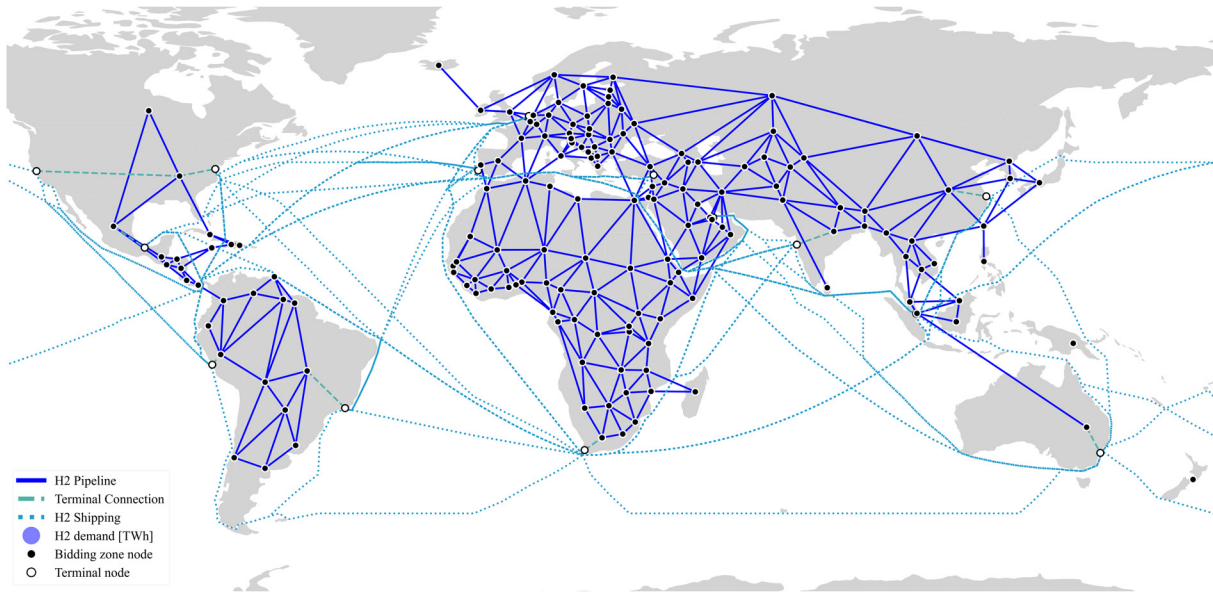


Figure 2.7: Potential hydrogen transport system

2.1.2.

2.1.6 Sector Coupling

The electricity and hydrogen sector are coupled to be able to investigate dynamic interactions. Electrolyzers are used to transform electricity to hydrogen, while hydrogen fuels cells, gas turbines and engines are possible technologies for the system to allow for reelectrification of hydrogen to electricity. The system may invest in capacity for each of these technologies individually for each region to enable optimal co-location of VRE capacities, electrolyzers and demands. The system configuration including the sector coupling is shown in Figure 2.8.

After preparing all techno-economic parameters, the dataset for WACCs needs to be compiled, to get a better representation of the cost differences between different countries and technologies while financing and developing projects.

2.1.7 Weighted Average Costs of Capital

While regional differences in the potentials and capacity factors of VRE are considered in chapter 2.1.3, an additional factor that varies between different regions and technologies is the cost of capital. In this section, the background, method and data of the implemented cost of capital rates are explained.

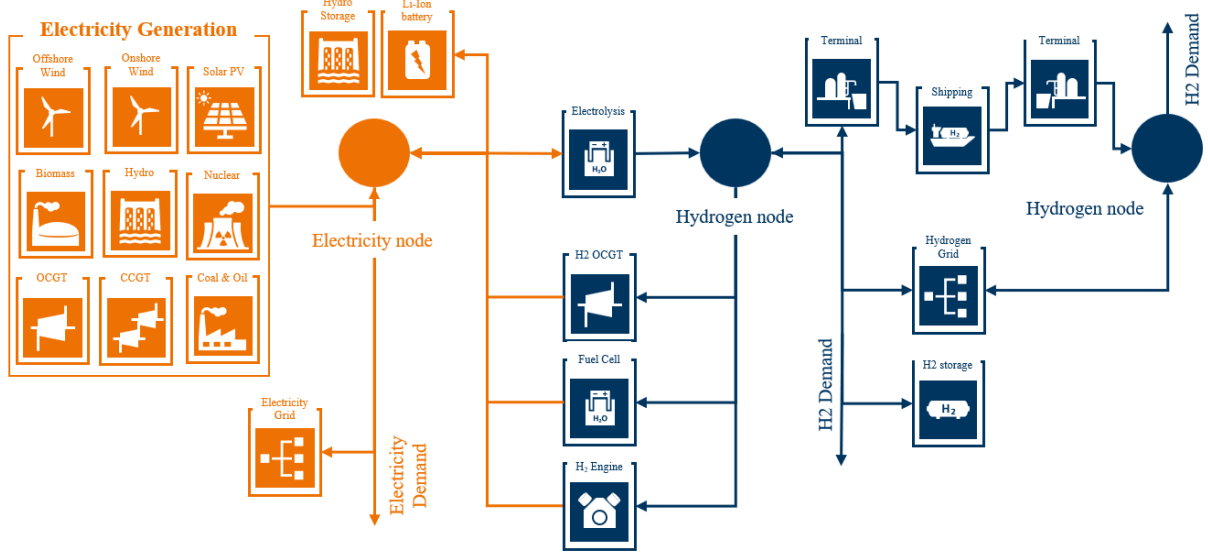


Figure 2.8: Energy system configuration

Definition and application

The weighted average cost of capital (WACC) is the weighted average of the cost of equity c_e and the cost of debt c_d as shown in equation (2.1):

$$WACC = c_e \frac{E}{D + E} + c_d(1 - t) \frac{D}{D + E} \quad (2.1)$$

where:

c_e = cost of equity

c_d = cost of debt

E = equity share

D = debt share

t = marginal tax rate

While the concept of WACC stems from corporate financing, we approximate the unknown project specific financing conditions of real world assets by assigning aggregated country- and technology specific risk premia in the form of an average WACC for a technology t in a country c as shown in equation (2.2):

$$invCosts_{t,c} = CAPEX_t * invCap_{t,c} * WACC_{t,c} \frac{(1 + WACC_{t,c})^n}{(1 + WACC_{t,c})^n - 1} \quad (2.2)$$

where:

- $invCosts_{t,c}$ = realized investment costs for technology t in country c [€]
 $CAPEX_t$ = specific capital expenditure of technology t [€/MW]
 $invCap_{t,c}$ = invested capacity variable of technology t in country c [MW]
 $WACC_{t,c}$ = WACC of technology t for country c [-]
 n_t = economic lifetime of an asset of technology t [a]

Method and results

Equity- and debt shares E and D are based on global averages of relevant industrial groupings such as "Green & Renewable Energy" for PV, wind and biomass power plant investments. The costs of equity and debt c_e and c_d are derived from market volatility indices of industrial groupings, national creditworthiness ratings and the inflation adjusted risk-free rate based on (Damodaran, 2024).

During model configuration, users can choose which year of financial data should be implemented with data available from 2013 to 2024. The resulting geographical WACC distribution is shown with technological averages for the year 2023 in Figure 2.9.

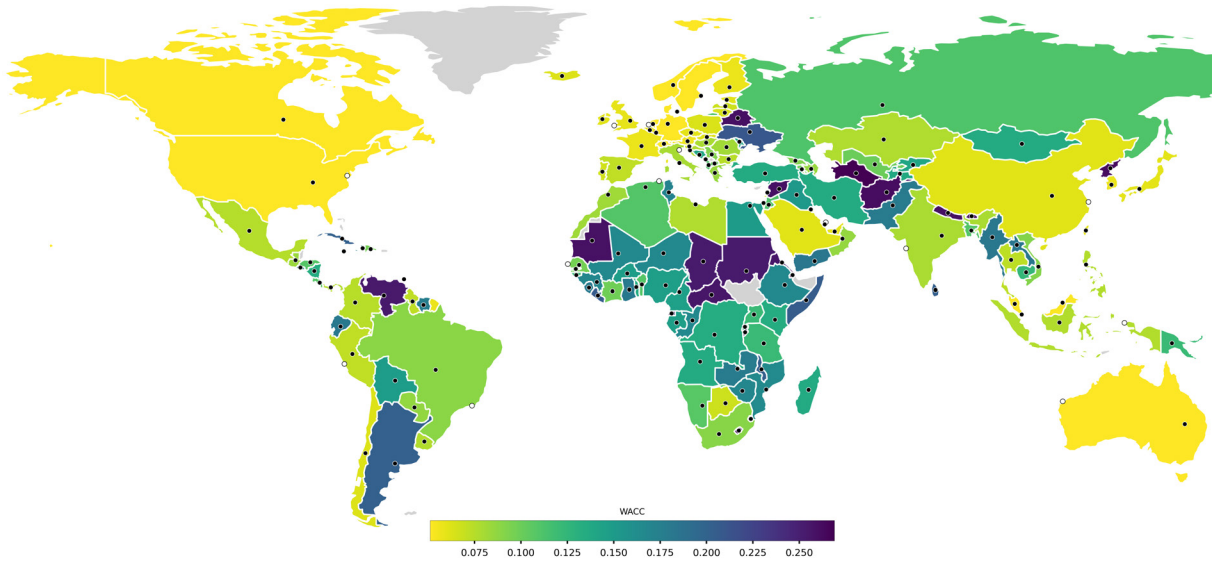


Figure 2.9: Global average WACC distribution of the year 2023

The complete process of data preparation and WACC calculations is accessible in an open source python script in the GitHub repository² of the Sector Transformation Energy System Analysis Model (StEAM) model. An additional standalone version³ that can be

² StEAM model repository: https://github.com/OliverLinsel/StEAM_model/blob/main/PythonScripts/WACC.py.

³ Standalone version: https://github.com/kTelaar/StEAM_WACC.

used independently for future projects and other modelers is available as well.

Data sources

All utilized datasets are free of charge and publicly available. Data for industrial groupings and national creditworthiness ratings is retrieved from Damodaran (2025a) and Damodaran (2025b). The inflation adjusted risk-free rate is implemented as the difference between the market yield on 10-year US treasury bonds and the 10-year inflation rate retrieved from St. Louis Federal Reserve (FRED, 2025a; FRED, 2025b). Marginal tax rates are retrieved from Enache (2024).

2.2 Methods to drive Modelling

Following the setup of the base model, basic model configurations, advanced methods and features are implemented and applied to the model, in order to increase the applicability and functionality. At first, the main scenarios and the subsequent changes in the main dataset are described and complemented by the method for dynamic recursive computations to enable long-term investigations. To increase the flexibility and mathematical feasibility, the geographic as well as the time resolution are being aggregated. Additionally, for better mathematical feasibility, possible decomposition approaches are discussed. To increase the practical applicability of the model, additional features and configurations have been implemented. These include, MGA, the option to enable different hydrogen production options that comply with the Delegated Act (DA) on Renewable Fuels of Non-Biological Origin (RFNBO), capacity expansion limitations to achieve more realistic capacity expansion for VRE and multiple minor features.

1. Scenarios
2. Dynamic recursive development
3. Flexible geographical aggregation
4. Time Series aggregation
5. Decomposition
6. Modeling to Generate Alternatives
7. Renewable Fuels of Non-Biological Origin
8. Capacity expansion limitation

9. Additional features

2.2.1 Scenarios

The model distinguishes three qualitatively different futures for the global energy system. Each scenario is built on a distinct set of policy assumptions, technology pathways, and hydrogen-demand trajectories. The main characteristics are summarized below. Fundamentally, the changes in the datasets concern the demands, the investment costs, the fuel costs, the CO₂-budgets, the lifetime and the WACCs.

Announced Pledges Scenario

This scenario follows the World Energy Outlook 2021 (WEO21) (IEA, 2021) “Announced Pledges” storyline and assumes full implementation of all existing climate commitments (e.g., Nationally Determined Contributions, the European Green Deal). Key features are:

- **Policy base:** Directly inherits the quantitative targets of the WEO21 “Announced Pledges” scenario.
- **Climate ambition:** 100% compliance with current pledges (NDCs, EU Green Deal, etc.).
- **European driver:** The European Green Deal is the dominant policy lever in Europe, shaping investment and decarbonisation pathways.
- **Hydrogen demand:** A relatively late surge in hydrogen consumption.

Renewable Electrification Scenario

The Renewable Electrification Scenario is constructed to be consistent with a **1.5°C pathway by 2050** and respects a globally allocated CO₂ budget. Decarbonisation is pursued primarily through the expansion of renewable electricity and complementary low-carbon technologies.

- **Climate target:** 1.5°C limit by 2050, enforced through a strict CO₂ budget.
- **Technology mix:** Aggressive deployment of renewable electricity, bioenergy, transmission-grid reinforcement, and carbon capture, utilisation and storage (CCUS) where electrification is infeasible.

- **Hydrogen role:** Hydrogen is introduced only in sectors where deep decarbonisation cannot be achieved by direct electrification (e.g., high-temperature industry, aviation, shipping).
- **System integration:** Strong emphasis on the integration of variable renewables (e.g., storage, demand-side response) to maintain reliability.

Hydrogen Run-Up Scenario

The Hydrogen Run-Up scenario explores a world in which **hydrogen becomes the cornerstone technology** for meeting the 1.5°C climate goal. An exogenous CO₂ budget for 2050 is imposed, and the model is allowed to meet it by scaling up both renewable electricity and *green* hydrogen production.

- **Policy driver:** Global commitment to the 1.5°C target, with an explicit CO₂ budget for 2050.
- **Technology focus:** Massive expansion of renewable generation together with large-scale production of *green* hydrogen (electrolysis powered by renewables); blue hydrogen plays a secondary, bridging role.
- **Demand outlook:** Very high hydrogen demand across all energy sectors (power, industry, transport, heating), reflecting an assumption that hydrogen will be the primary low-carbon carrier where direct electrification is impractical.
- **System implications:** Requires extensive grid reinforcement, large storage capacities, and robust CCUS infrastructure to manage residual emissions.

2.2.2 Aggregation

The following section explains the two different dimensions of aggregation used to manage the size and complexity of the model. Firstly, geographical aggregation that is used to manage the geographical scope and resolution of the model. Secondly, the temporal aggregation that is used to manage the temporal resolution of the model.

Geographical aggregation

Geographical aggregation refers to the possibilities of the model to flexibly change the the resolution of the model. The maximum resolution possible are the 160 individual country nodes (see Appendix A). There is a full set of data for each country available

in the complete model dataset⁴. These countries can be freely combined into regions, customized to the wishes of the modeler. The minimum amount of nodes modeled to successfully solve the model are three nodes, since this is the minimum amount to carry out the Delaunay triangulation for the hydrogen transport system.

Figure 2.10 (a) shows the maximum resolution of the model. One possible aggregation is shown in Figure 2.10 (b). It shows different sub-regions and also individual countries.

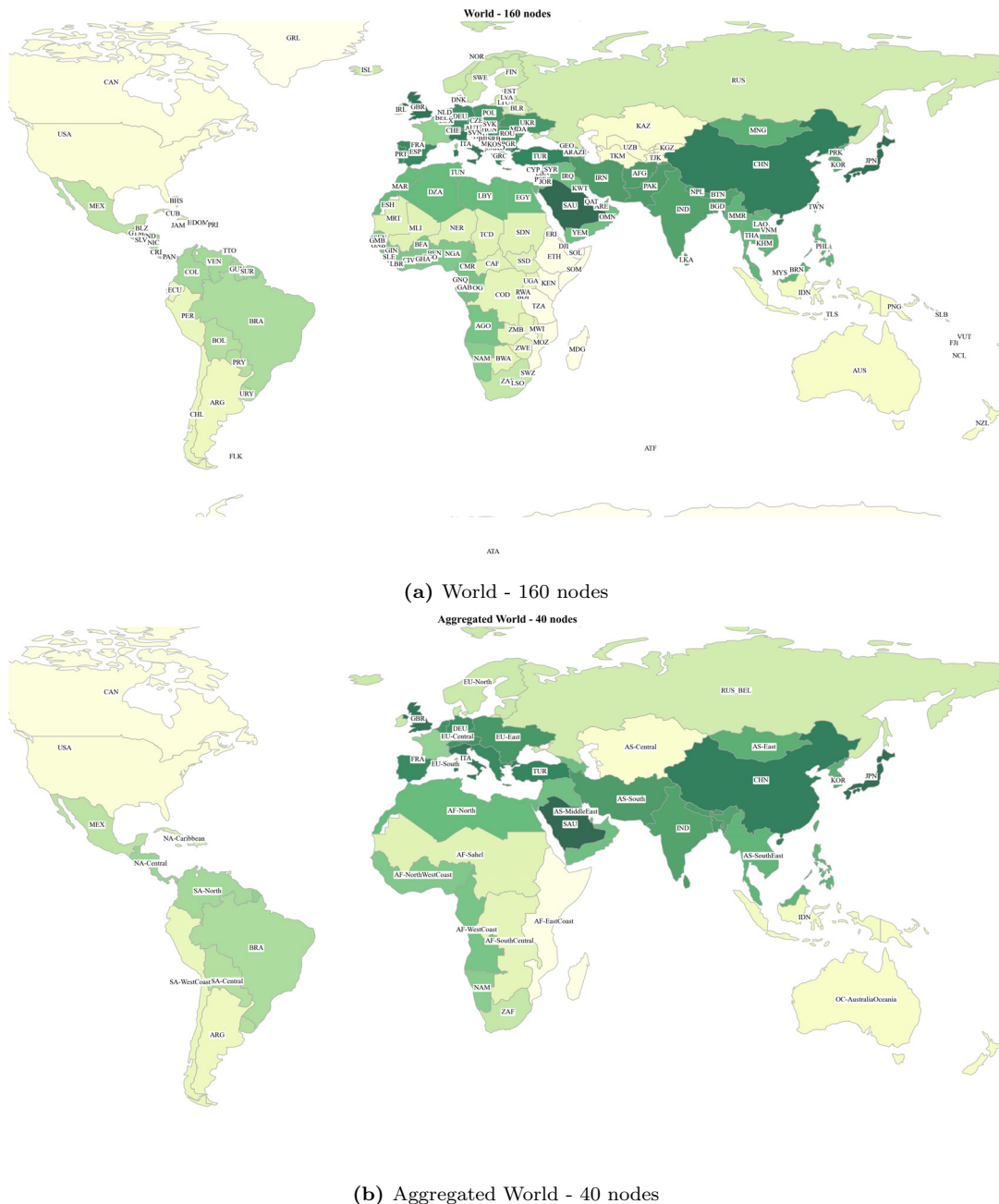


Figure 2.10: World with different geographical resolutions

Furthermore, it is not only possible to change the resolution of the global model, but

⁴ This dataset can be found in <https://zenodo.org/records/15639823>.

also to create sub-models with a more limited scope of countries or regions. Exemplary, this is shown in Figure 2.11 with a South-American scope and two different degrees of aggregation. Other sub-scopes to facilitate region specific case studies are possible as well.

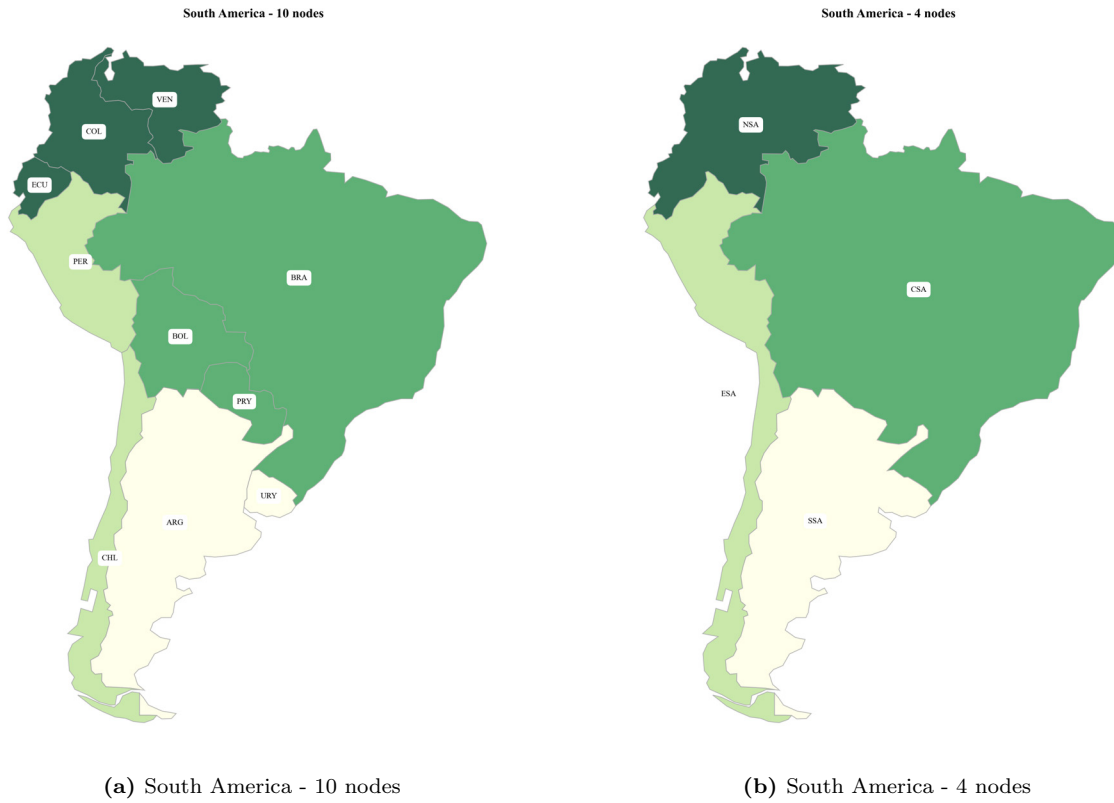


Figure 2.11: South America subset with aggregation

Temporal aggregation

Another way to reduce the computational complexity and thereby solving time is temporal aggregation. Temporal aggregation determines representative time periods that are used to represent the whole time series. This applies to the VRE profiles as well as the electricity and hydrogen demand profiles. Methodologically, the time span that has to be optimized is effectively shortened to shorter representative periods. These periods are chosen by different cluster methods to fit the original time series as good as possible. After the optimization, the results are rescaled by using the weights of each period to achieve valid results for a whole year. Nevertheless, it has to be considered, that Time Series Aggregation (TSA) is a simplification of the profiles and therefore produces errors by for example neglecting extreme situations. Also, long-term storages tend to be underrepresented, despite matching border conditions. This has to be considered especially when conducting scheduling runs as explained in chapter 2.2.7. The package used to conduct TSA is called Time Series Aggregation Module (TSAM) and the methods are explained and published

in (Hoffmann et al., 2020). The TSA resolution can be adjusted in the SpineToolbox tool. Possible settings are the cluster method, the number of periods as well as the length of each period.

2.2.3 Decomposition

The model is composed of 160 countries, two integrated energy sectors, full year hourly resolution, five profiles per VRE technology, many other technologies and hundreds of transport connections. Hence, it can be considered as a big and complex model. This size and complexity is mirrored in the number of optimization variables and therefore poses a considerable problem to solve mathematically. As mentioned in chapter 2.2.2 aggregation can reduce the complexity and size of the model. Still, solving the model is a challenge. Another possibility to improve solving performance is decomposing the mathematical problem into multiple problems and solving them individually while retaining result integrity through interface variables. The Benders Decomposition approach is a well-established method for solving large-scale optimization problems by decomposing them into a master problem and sub-problems solved iteratively until convergence. Originating with J.F. Benders in 1962 (Benders, 1962), the method is particularly suitable for large mixed-integer linear programming or stochastic programming tasks when a block-angular structure can be exploited.

Our data experiments with the decomposition approach have demonstrated that the optimization framework and GAMS, as an algebraic modeling language, already possess a high degree of maturity in terms of "built-in" mathematical decomposition. Consequently, we have explored a geographic decomposition approach on a trial basis, combining the results thereafter. While this method allows for an increased geographic resolution, the additional computational time required is substantial and disproportionate to the benefits obtained.

In parallel, we evaluated an alternative Dantzig–Wolfe (DW) decomposition algorithm as published by Kwon (2013). The original MATLAB implementation provided in the reference was used as starting point to create a prototype Python demo model based on 2 regions. For validation, the same model was directly solved. With reference to the model structure, we assessed whether the global hydrogen market model (which couples multiple energy system components) could be "wrapped" into a decomposition-friendly interface. That is, whether its monolithic GAMS-based formulation could be relaxed so as

to produce a balanced multiplicity of sub-problems suitable for a DW scheme.

This investigation involved tracing constraint dependencies, identifying candidate linking constraints, and assessing the feasibility of exposing block-angular structure without breaking the existing scenario modeling workflow. While several conceptual approaches were explored, no practical decomposition strategy was identified that could be implemented without extensive and disruptive refactoring of the core framework code and data-flows. As a result, the DW prototype remained at a validated test-case level rather than being applied to the operational hydrogen market simulation.

Project resources were subsequently reallocated to the operational integration of myopic optimization into the simulation framework. Nevertheless, both the prototype implementation and the model-structure analysis provide a clear technical foundation and road map for any future incorporation of advanced decomposition methods into large-scale energy system and market simulations. The prototype demo is available in the GitHub repository⁵.

2.2.4 Dynamic - Recursive Optimization

Recursive-Dynamic Optimization is a method for solving an optimization problem over multiple periods, considering how current decisions affect future outcomes.

The term dynamic implies the consideration of developments and changes of a system over time. The term recursive indicates the stepwise decision-making process, based on prior outcomes.

Thus, decisions made at a certain point in time (e.g., whether to invest in renewable energy or use fossil fuels) impacts future costs and the dynamics of the system.

As future technologies, market conditions and political decisions are difficult to foresee for decision makers, the assumption of myopic expectations is implemented in the StEAM model: The considered years are optimized in isolation, whereby the optimization makes decisions based only on the present situation, ignoring potential future changes. In a recursive-dynamic myopic framework, capacity expansion is based on the current demand of the reference year without anticipating potential future demand or cost adjustments. Investments made in previous years must then be treated as sunk costs. These represent fixed expenditures that have already been incurred and cannot be recovered. From an economic perspective, such costs are considered irretrievable and therefore should not

⁵ Standalone version: <https://github.com/ude-ewl/ewl-h2-dw-decomposition-demo>.

influence decisions regarding future investments. Since the initial investment is depreciated over the entire lifespan of the asset, sunk costs must be accounted for in each simulation year.

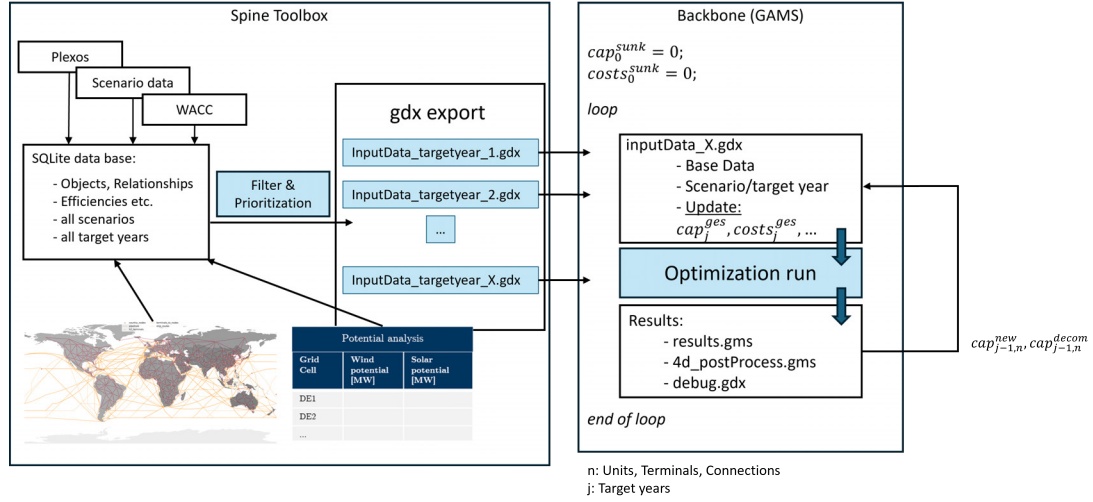


Figure 2.12: Scheme of Data Processing for Recursive-Dynamic Optimization

Figure 2.12 illustrates the data processing procedure. Starting with the loading of the input data for the initial run for the first model year, the algorithm checks for decommissioning based on lifetimes and calculates the sunk costs of prior investments. The input data for the next optimization loop is then updated and Backbone starts the optimization. Finally the output of the concurrent optimization is stored and the input data for the next target year is loaded. After that, all steps are repeated until all target years are optimized.

2.2.5 Modelling to Generate Alternatives

Additionally to solving the objective function towards a pareto-optimal total cost minimum, possible alternative developments of a future global hydrogen economy could be revealed by investigating the near-optimal solution space.

MGA is a group of methods that can be used to generate near-optimal alternatives that differ in system characteristics (Finke et al., 2024). Normally, the cost-minimal system composition represents the optimal solution for a given problem. Now, by opening a margin on the cost-minimal result, multiple near-optimal results with as varied system characteristics as possible are determined. Thereby, opening the range of possible alternatives aims to enable decision makers to get a better understanding of possible system designs (DeCarolus, 2011). We implemented MGA as a process that follows up on the

regular cost-minimal optimization of the energy system as the baseline model setup step shown in Figure 2.13.

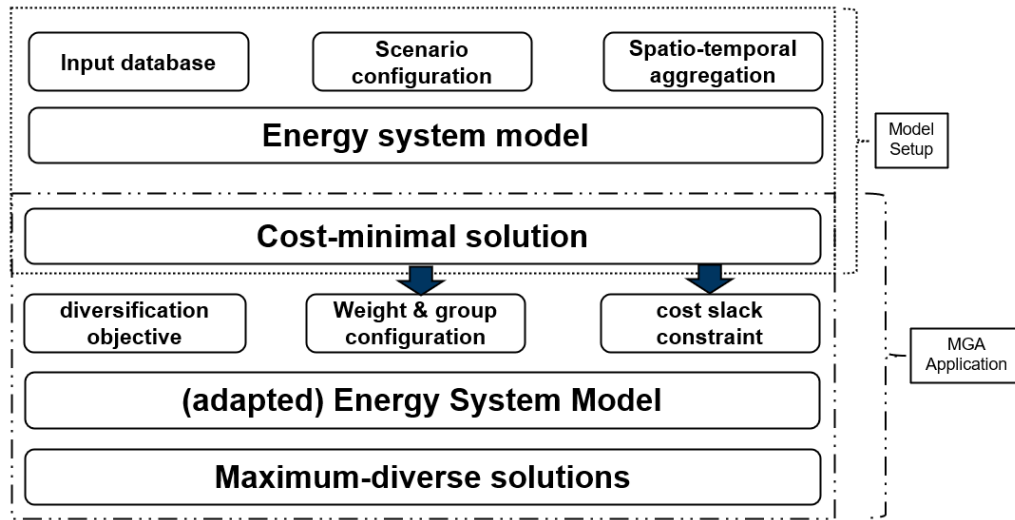


Figure 2.13: Process of the Modelling to Generate Alternatives method

The cost minimizing objective function is thereby exchanged for a new diversification objective function. The previously minimized cost objective is then instead implemented as a cost constraint. The cost constraint is expressed with the so-called cost slack which is typically set as a percentage of additional maximum costs cost slack in a system with a baseline cost minimal solution of 1M€ would mean the cost constraint in the MGA model would be implemented as up to 1.05M€. The user then selects which decision variables should be considered in the new diversification objective with the configuration of variable groups and weights. Typical diversification variables could be to explore the maximum and minimum technology deployment under a given cost slack e.g. maximum or minimum global PV investments with e.g. 1 - 5% additional costs.

2.2.6 Renewable Fuels of Non-Biological Origin

The DA on RFNBO defines the european standard for the production of green hydrogen. To allow investigations into the different options of the regulation, different system configurations can be chosen. The "Vanilla" configuration connects the sector coupling technologies directly to the mixed electricity grid. This represents the model default. To also be able to distinctly differentiate between renewable electricity and the remaining electricity mix, the "No_reg" option differentiates the electricity system into a renewable electricity node and a mixed electricity node (see Figure 2.14). The renewable electricity

generators are as defined in the Renewable Energy Directive (RED). After having these very rudimentary options between the yellow (mixed grid) and green (renewable electricity) production of hydrogen, the different options for the RFNBO regulation can also be applied. These options include production in Island Grids, in sufficiently defossilized grids and the base conditions of additionality, temporal correlation and geographical correlation. A detailed description of these model configurations is being prepared (Linsel and Bertsch, 2026).

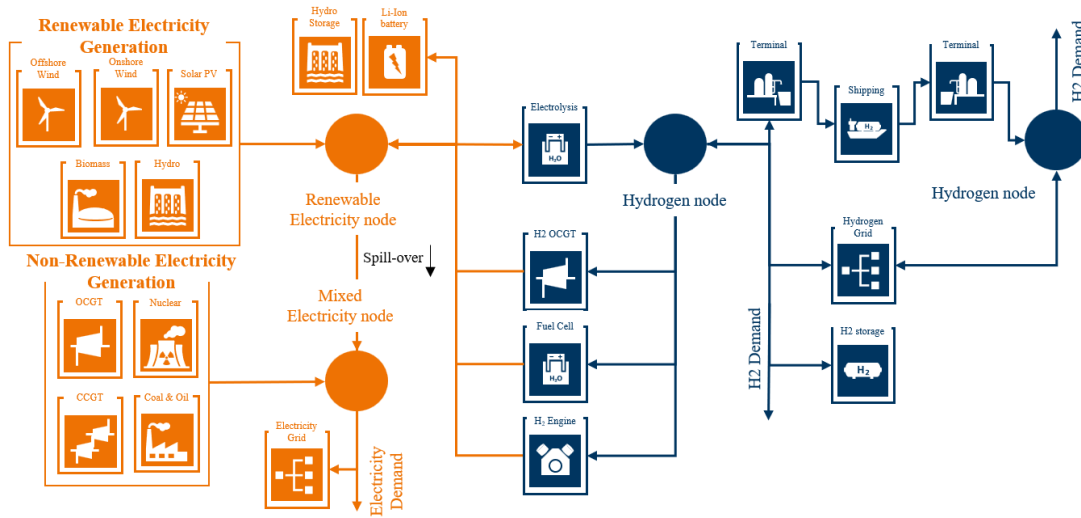


Figure 2.14: Energy system configuration for renewable hydrogen

2.2.7 Additional Features

There are a few additional features that can be used to customize certain configurations, constraints or parameters.

Blue and grey hydrogen

The options for blue and grey hydrogen have been included, by implementing Steam Methane Reforming (SMR) plants (see Figure 2.15), that consume natural gas and have varying degrees of CO₂ emissions. Here, the grey hydrogen production through SMR has unabated CO₂ emissions, while the blue hydrogen production abates CO₂ emissions through Carbon Capturing (CC). These options can be enabled (1) or disabled (0) in the model.config file.

Scheduling runs and capacity margins

Due to its complexity and size, the model is usually optimized with a representative set of weeks (see chapter 2.2.2) through TSAM to conduct the investment run. Since using

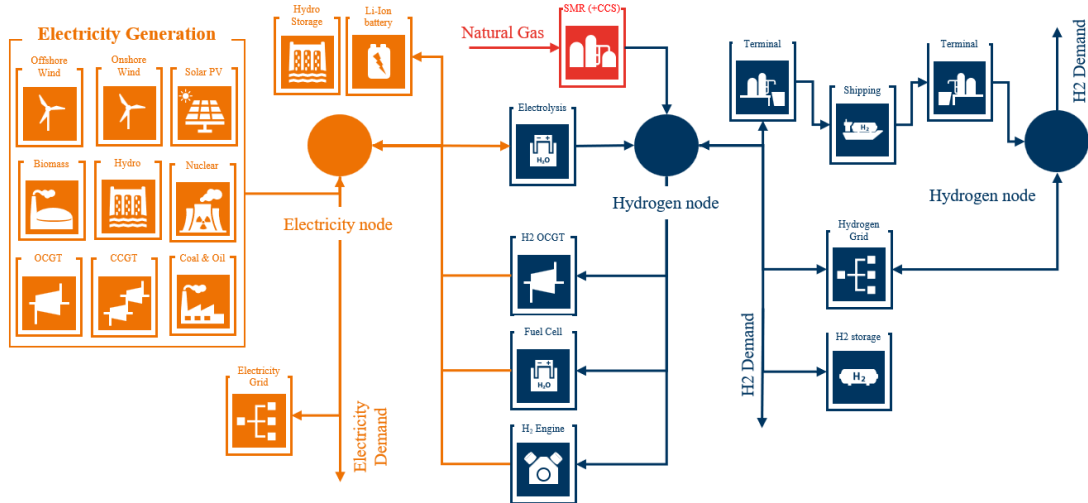


Figure 2.15: Energy system configuration including SMR

representative weeks covers the mayor characteristic of the yearly timeseries, but not the more rare occurrences, this may lead to the cost-minimal system being inadequate to supply the complete demand each day of the whole year. In these cases the system is being supplied with an emergency "dummy" generation that is prohibitively expensive in the normal optimization run, but can be used to enable mathematical feasibility. This can become a problem, if the so-optimized system should be used to for example generate a full-year time series with an hourly resolution in a scheduling run, because it drastically increases the marginal costs at some points in time and therefore disfigures the results time series. To address this problem, a capacity margin can be added to the investment calculation. Thereby, the installed capacity is increased by the given margin. This increases the total system costs, but gives the system additional reserve capacities for the scheduling run. The `model_config` allows to individually set a capacity margin on either hydrogen and electricity assets.

Maximum transmission capacities

In some circumstances, if corresponding degrees of freedom are available, the optimization can result in some countries being exclusively supplied by imported electricity from neighboring countries. Since, in general, this is an unwanted behavior, the transport capacities between different countries can be restricted by the parameter `cross_border_transmission_cap` in the `model_config` file. Transmission caps for individual bilateral connections can be defined in the source dataset.

System integration factor

In comparison to dispatchable electricity generators, VRE induce additional system costs through additional grid expansion and stabilization. Since the geographical and temporal resolution of the model does not allow to account for these aspects in the model, an auxiliary assumption is made. To include these additional costs, mostly in auxiliary infrastructure capacities, the fom costs for VRE are multiplied with a system integration factor. As default value this factor is set to 1.4 which is loosely based on Ueckerdt et al. (2013) and Hirth et al. (2015). Nevertheless, it can easily be modified by the modeler through the `model_config` file.

Simplifying VRE profiles

Some investigations require a higher geographic resolution, rather than a detailed temporal resolution. By default, the model has five individual time series for different grades of VRE for each of the three technologies solar, wind onshore and wind offshore. To be able to increase the model size in other regards, such as geographic resolution, these five grades of profiles can be reduced to one. Thereby, the number of investable units is reduced, which relieves the solver by limiting the number of similar profiles.

3. Results

In the following, the modeling results will be presented and explained. This includes the results for the scenario analysis and MGA analysis.

3.1 Scenario Results

In this chapter, we present the results of the three scenario frameworks: Announced Pledges, Hydrogen Run-Up and Renewable Electrification. The discussion focuses on the key outcomes with respect to capacity expansions, cross-border trade flows, and the resulting system-level effects. By comparing these scenarios, we aim to highlight the structural implications of different transition pathways for the energy system, providing insights into both regional and overall market dynamics. The results are shown for the years 2030 and 2040. For all scenarios the following potential hydrogen transport system is available.

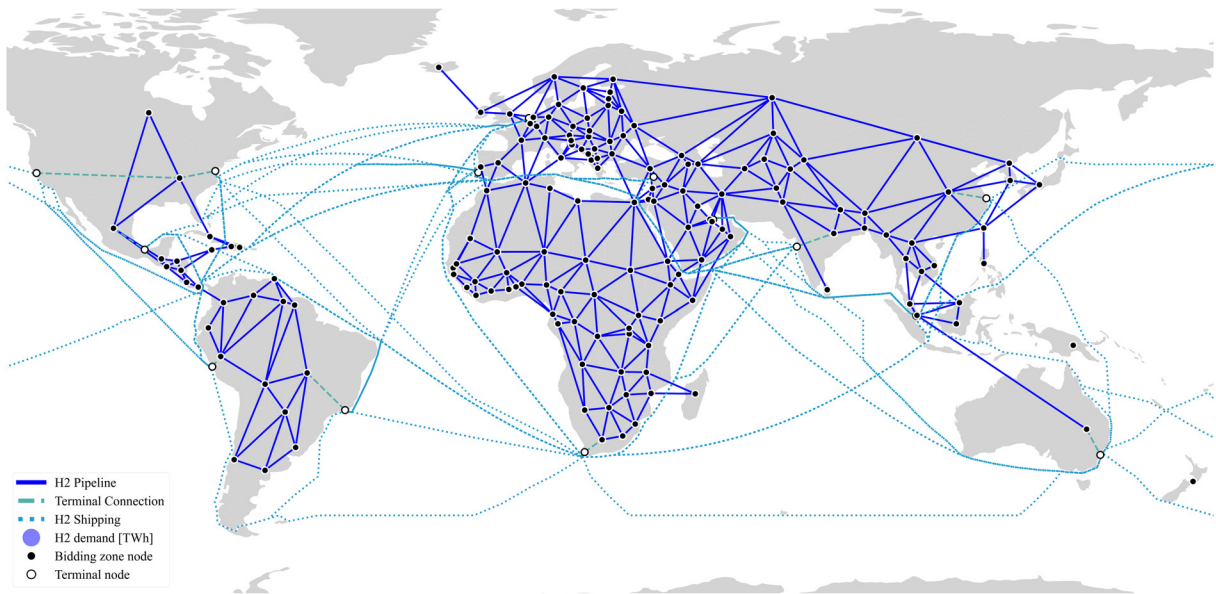
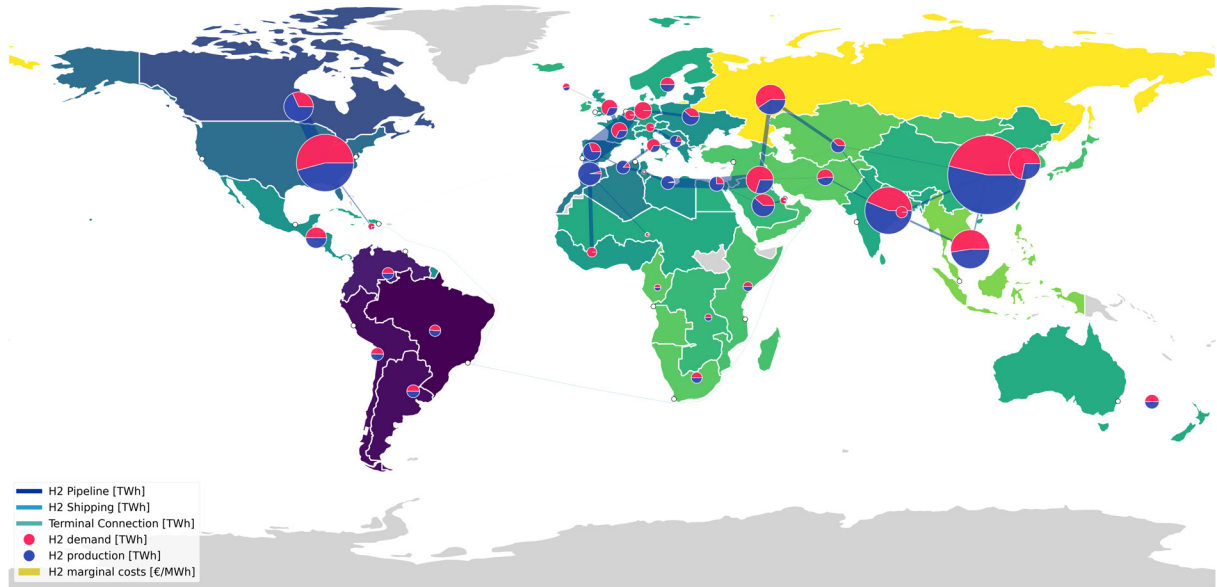


Figure 3.1: Potential Hydrogen Transport System

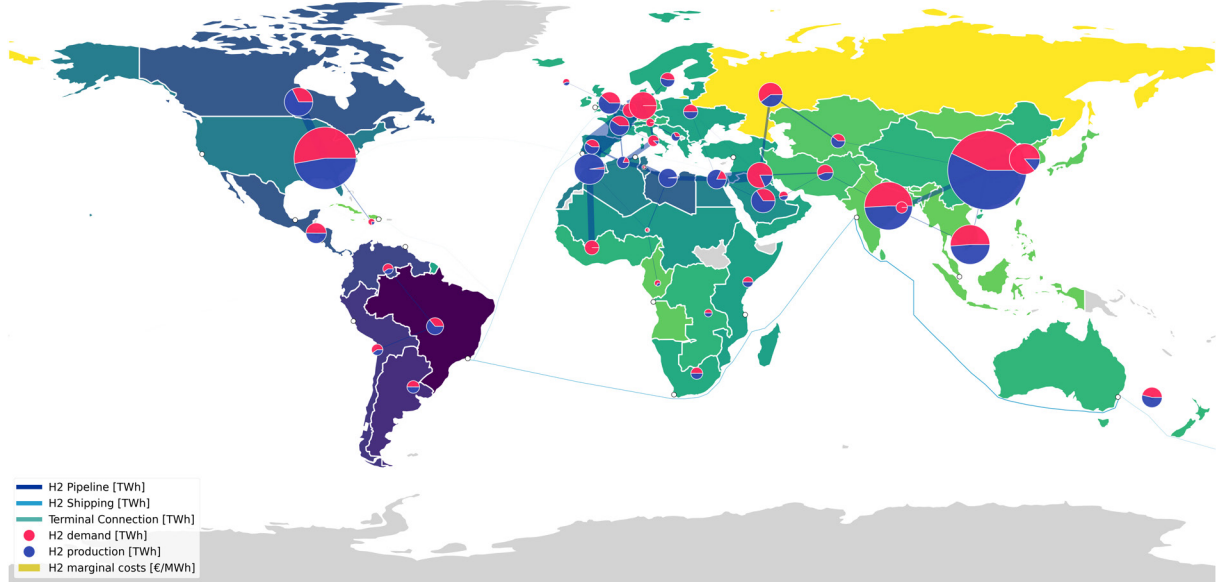
Announced Pledges Scenario

The APS scenario illustrates a transformation pathway derived from the current National Energy and Climate Plan (NECP)s and their respective climate neutrality targets. This includes, among other things, a linearly declining CO_2 budget and a moderately increasing electricity and CO_2 budget. Consequently, this scenario is the least ambitious of the proposed three. Figure 3.2 reveals rather localized solutions for each continent or subregion.

We observe a high level of pipeline transport within Europe and North Africa. The Middle East, Asia, North America and South America represent further integrated hydrogen systems. The transport via ships is negligible in 2030 and slightly emerges in 2040 from Australia and South America towards India.



(a) Hydrogen Transport - 2030

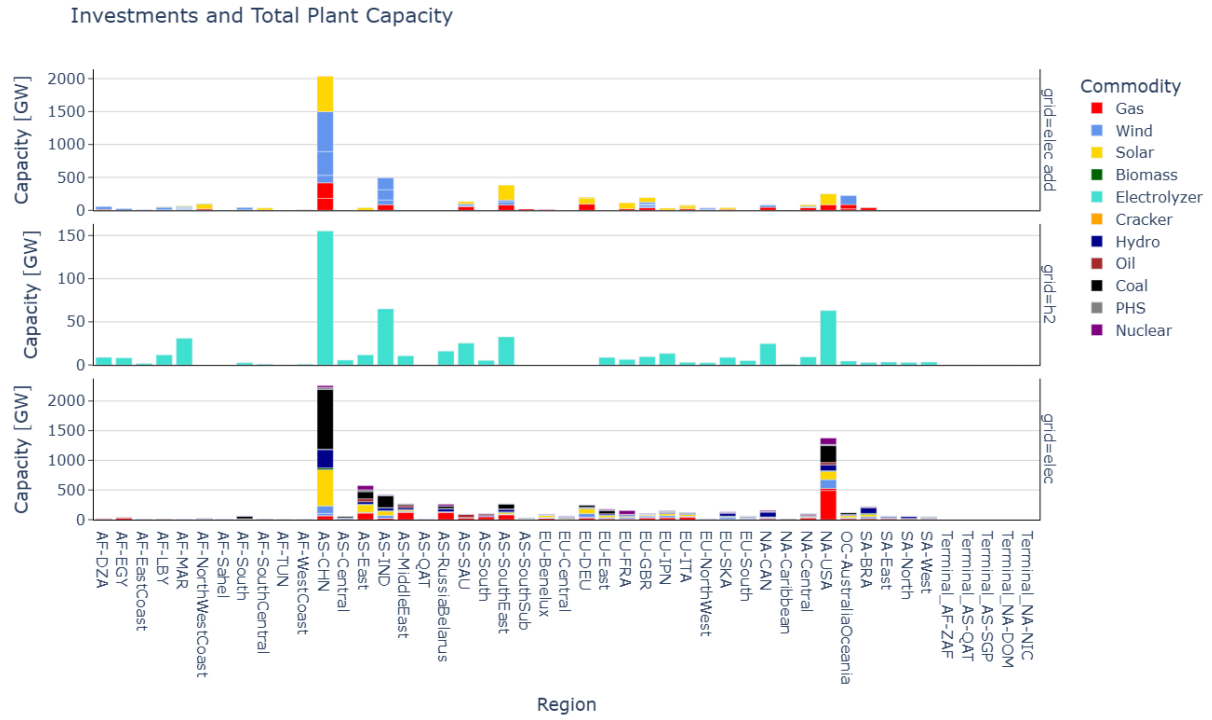


(b) Hydrogen Transport - 2040

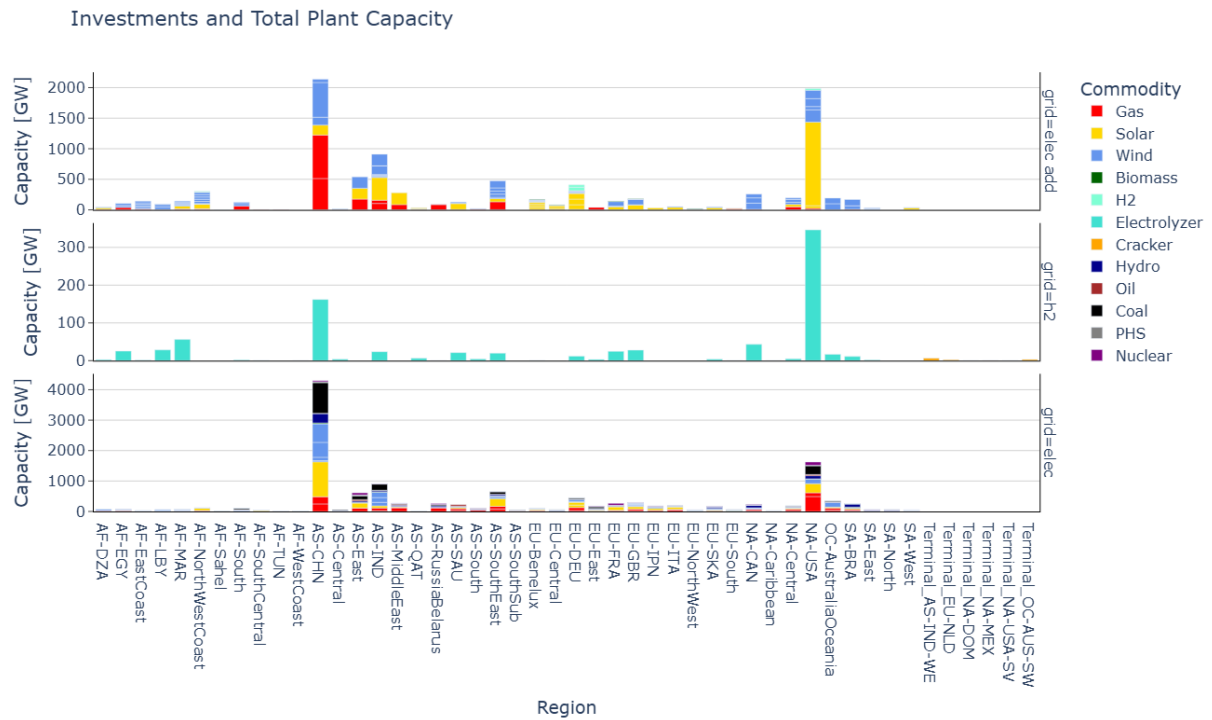
Figure 3.2: Hydrogen Transport System Geoplot (APS)

Figure 3.3 illustrates the capacities and investments in each simulated year. Globally, wind and solar dominate investments. This is related to the strict pathways to decarbonize, i.e., decreasing CO₂ budgets. As a transitional technology, gas is also of high relevance to meet

increasing energy demands, specifically in 2040.



(a) Capacity Expansion and Power Plant Portfolio - 2030

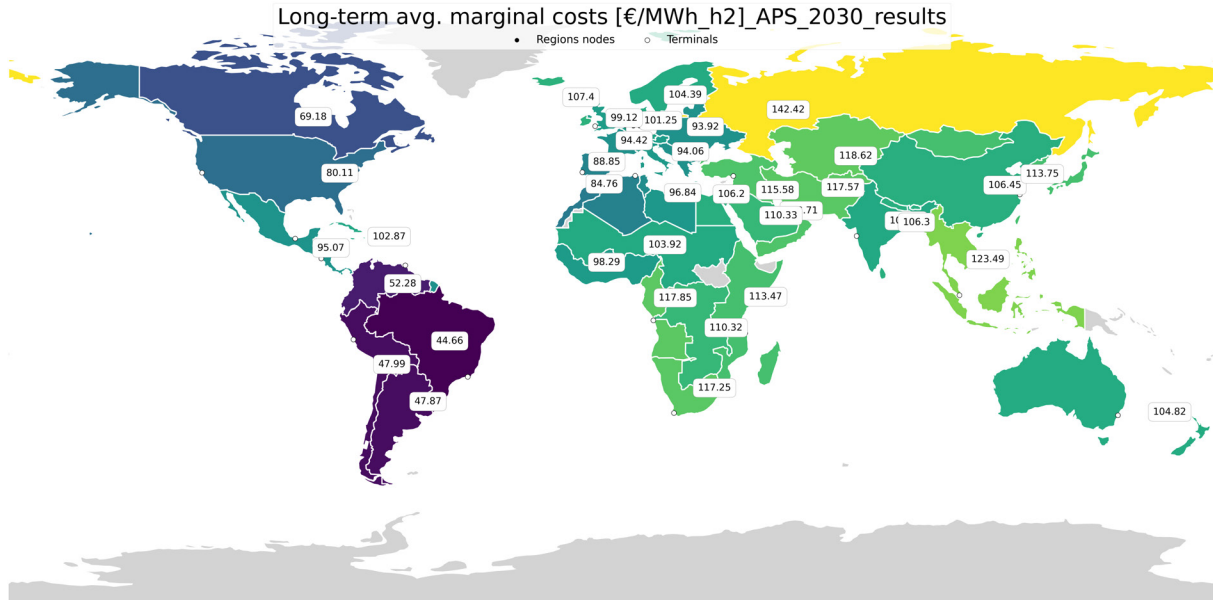


(b) Capacity Expansion and Power Plant Portfolio - 2040

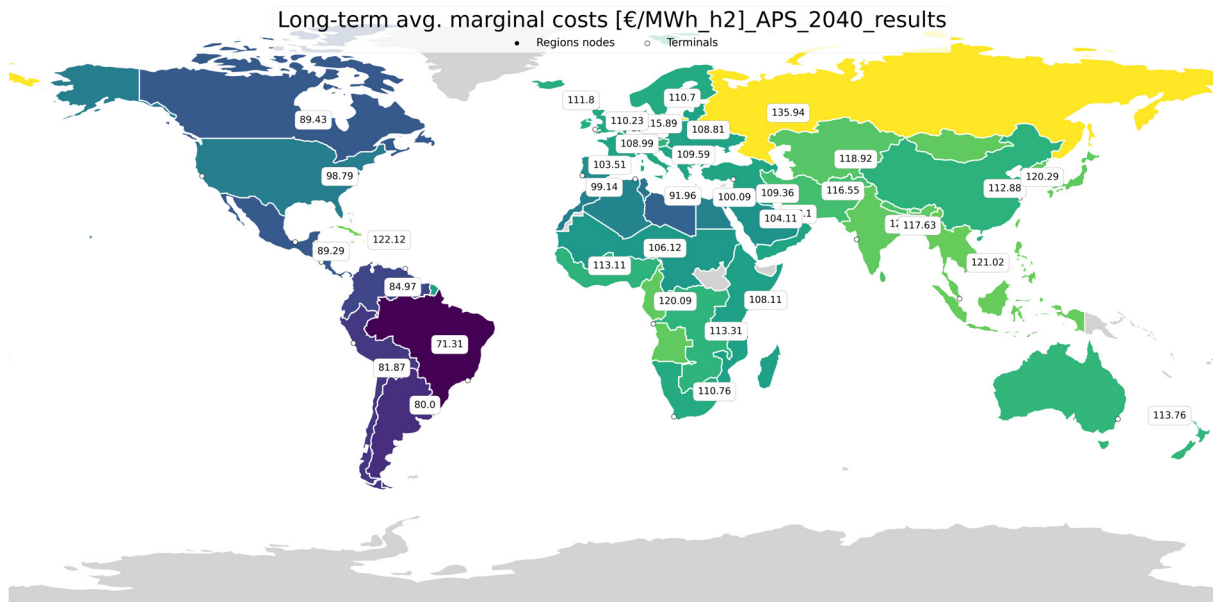
Figure 3.3: Capacity Expansion (APS)

The long-term marginal costs represent a weighted yearly average cost for the hydrogen production. These marginals for hydrogen are shown in Figure 3.4. They further underline

the direction of transport flows. In 2030 most regions show costs roughly around 100 EUR/MWh or even higher while America, except for the Caribbean, has advantageous conditions. In 2040 this effect remains strong. Even though, the difference between the American continent and Europe is not high enough to make large-scale shipping volumes economically viable.



(a) Hydrogen long-term Marginal Costs - 2030



(b) Hydrogen long-term Marginal Costs - 2040

Figure 3.4: Hydrogen long-term Marginal Costs Geoplot (APS)

Hydrogen Run-Up

Like the RES scenario, the HRU scenario is designed to be compatible with the Paris

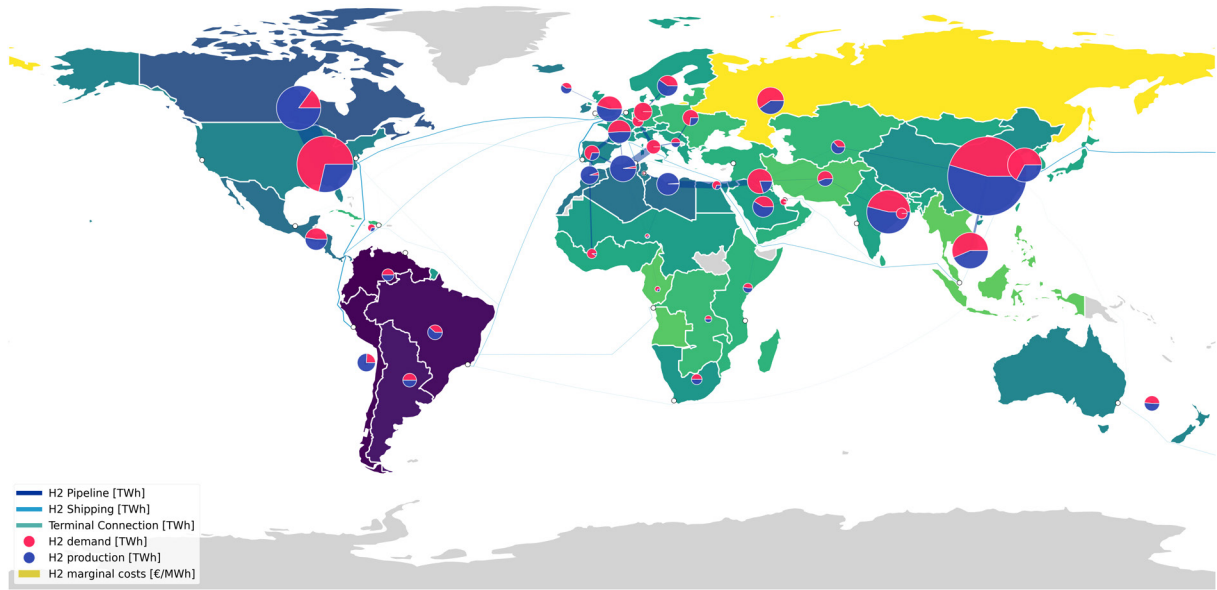
Climate Agreement's 1.5 °C target. Compared to the APS scenario, both scenarios have a significantly tighter CO₂ budget across the modelling period. Additionally, the HRU scenario represents the greatest increase in H₂ demand due to accelerated sector coupling, as well as more pronounced cost reductions in investment costs along the H₂ value chain. In the HRU setting, Figure 3.5 reveals a high level of shipping. While in 2030 Europe imports hydrogen mainly through pipeline transport, in 2040 high quantities are imported from America via shipping routes. The trade between regions in the Middle East, Asia and Africa basically relies on pipeline transports. The biggest economies, the US and China are net exporters in 2040, while India and Europe, except for the UK, are net importers. Due to their profitable renewable potentials, the Northern African countries export not only to Europe but also to Western and Eastern African countries.

Figure 3.6 illustrates the Capacities and Investments in each simulated year. Similarly to the APS setting, wind and solar dominate in investments. This is related to the strict pathways to decarbonize, i.e., decreasing CO₂ Budgets. In contrast to the APS pathway, gas is of less relevance for the transition towards a decarbonized system.

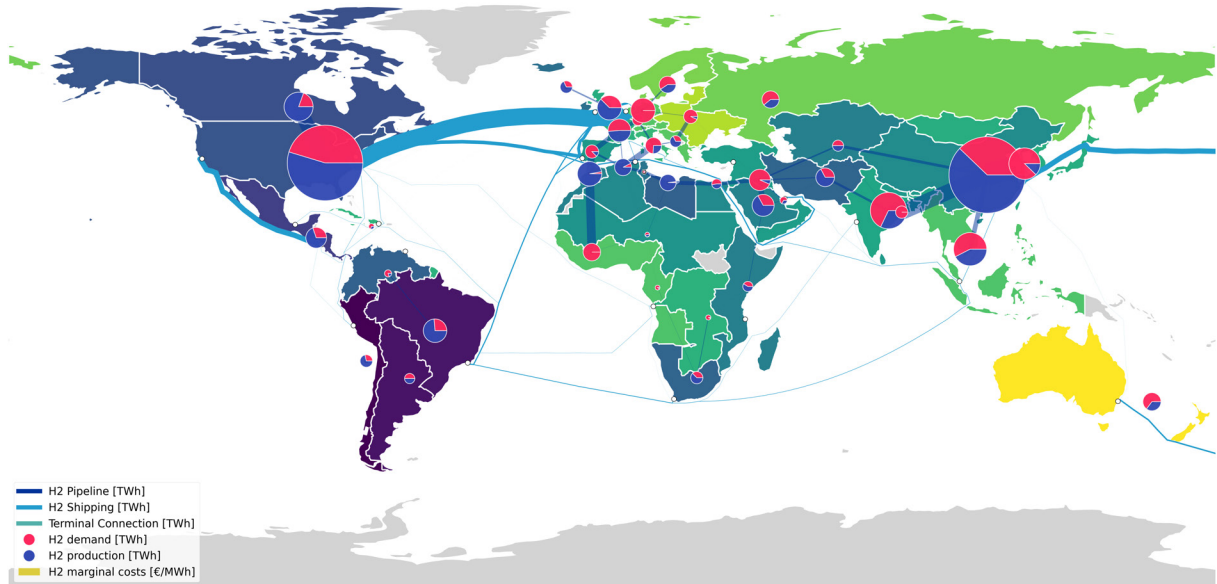
Similar to the APS setting the long-term average marginal hydrogen costs in Figure 3.7 show lowest levels in America, except for the Caribbean. In 2040 this effect remains strong. Exports from the US Hub towards Europe are beneficial in 2040 on, which results in a massive increase in shipping volume to Central Europe.

Renewable Electrification

The focus of the cross-sectoral decarbonization strategy in this scenario is on direct electrification, which is reflected in a higher electricity demand compared to the HRU scenario. In contrast, both hydrogen demand and the cost degression along the hydrogen value chain are assumed to be lower, although they remain significantly higher than in the APS scenario. In the RES scenario, we observe minor changes compared to the HRU scenario (cf. Figure 3.8). In 2040 high quantities are exported from America to Europe via shipping routes. Saudi Arabia is reducing its production and will be replaced as an exporter to the Middle East by supplies via the Mediterranean. Australia becomes a net exporter compared to the HRU setting. The biggest economies, the US and China are net exporters in 2040, while India and Europe, except for the UK, are net importer. The American Continent has the lowest costs.



(a) Hydrogen Transport - 2030

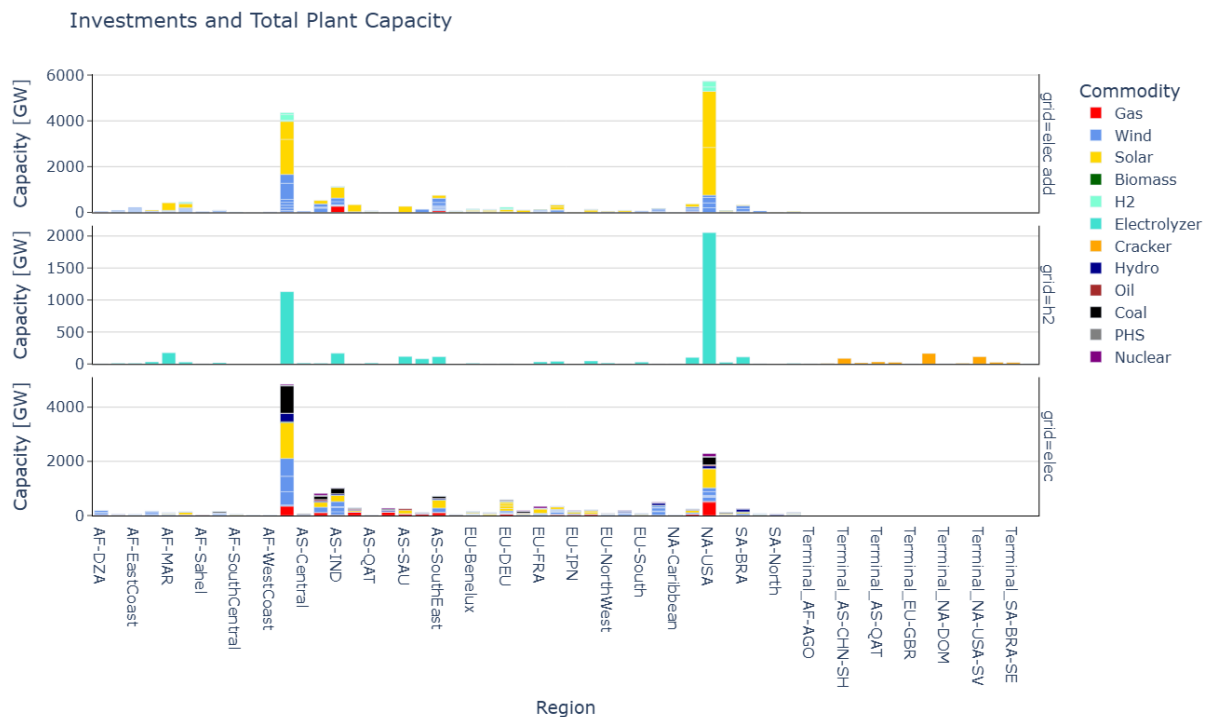
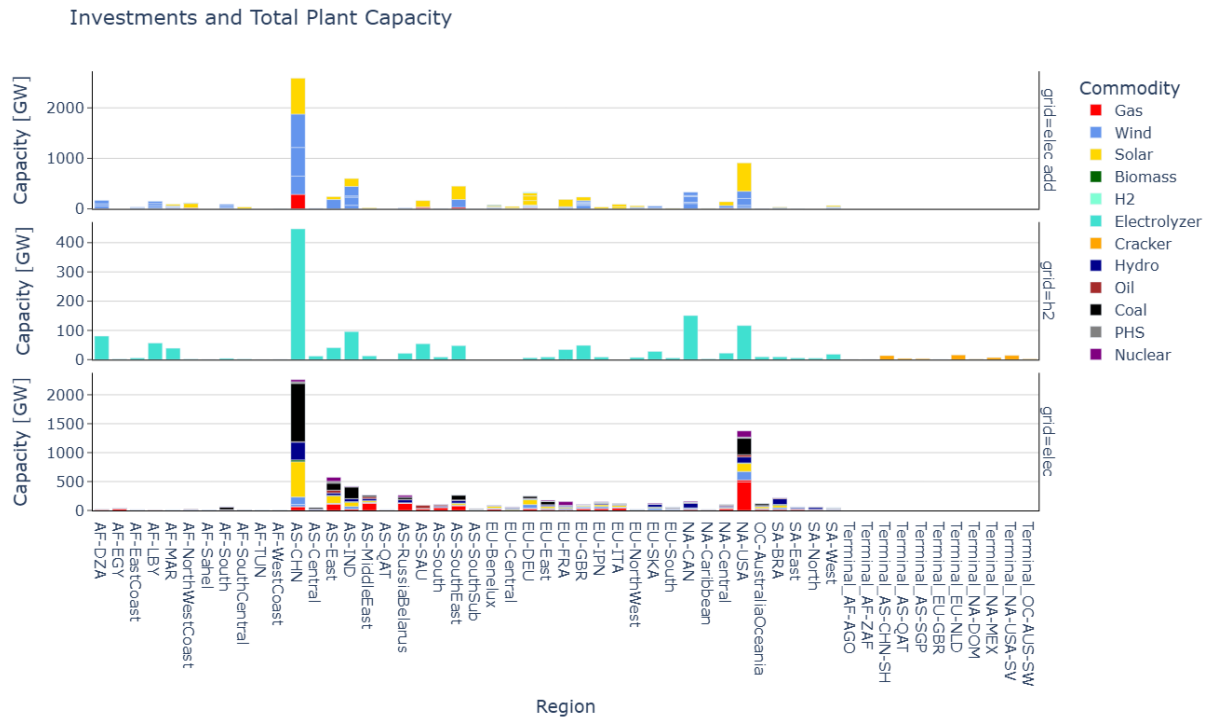


(b) Hydrogen Transport - 2040

Figure 3.5: Hydrogen Transport System Geoplot (HRU)

Figure 3.9 illustrates the Capacities and Investments in each simulated year. Similar to the HRU scenario, wind and solar dominate in investments. In 2040, the electrolyzer capacities are highest in the US and China. In contrast to the HRU pathway, the investments are in the electrification scenario much higher, i.e. around 4000 GW in China and more than 4000 GW in the US in 2040.

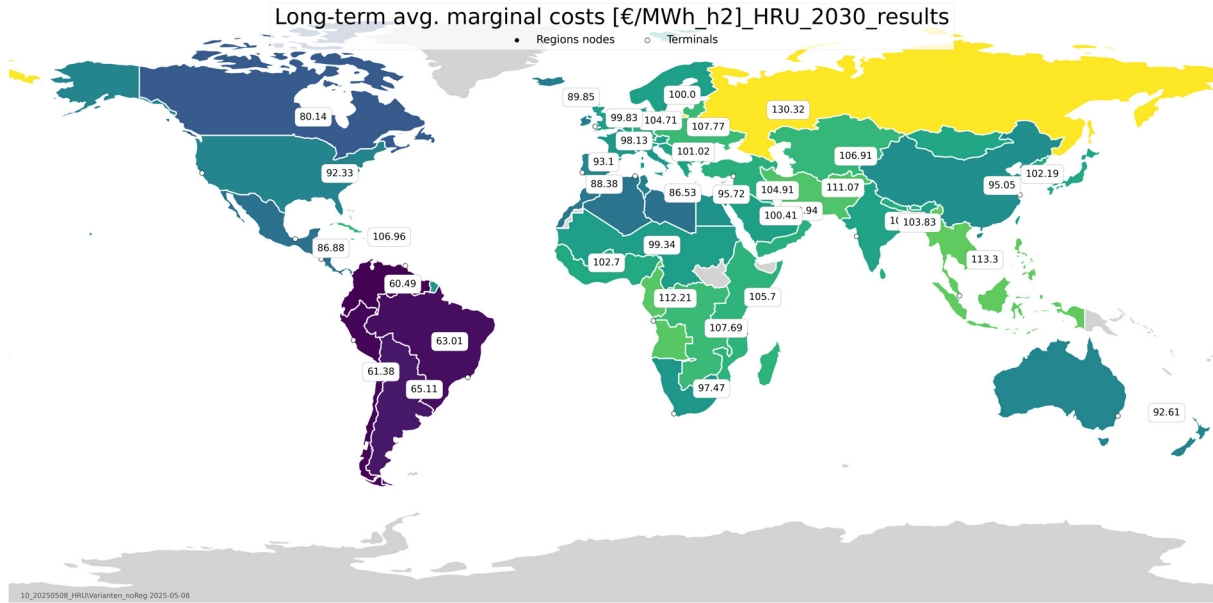
The RES long-term average marginal hydrogen costs in Figure 3.10 show similar conditions as in the HRU setting. While the American Continent shows low costs due to their



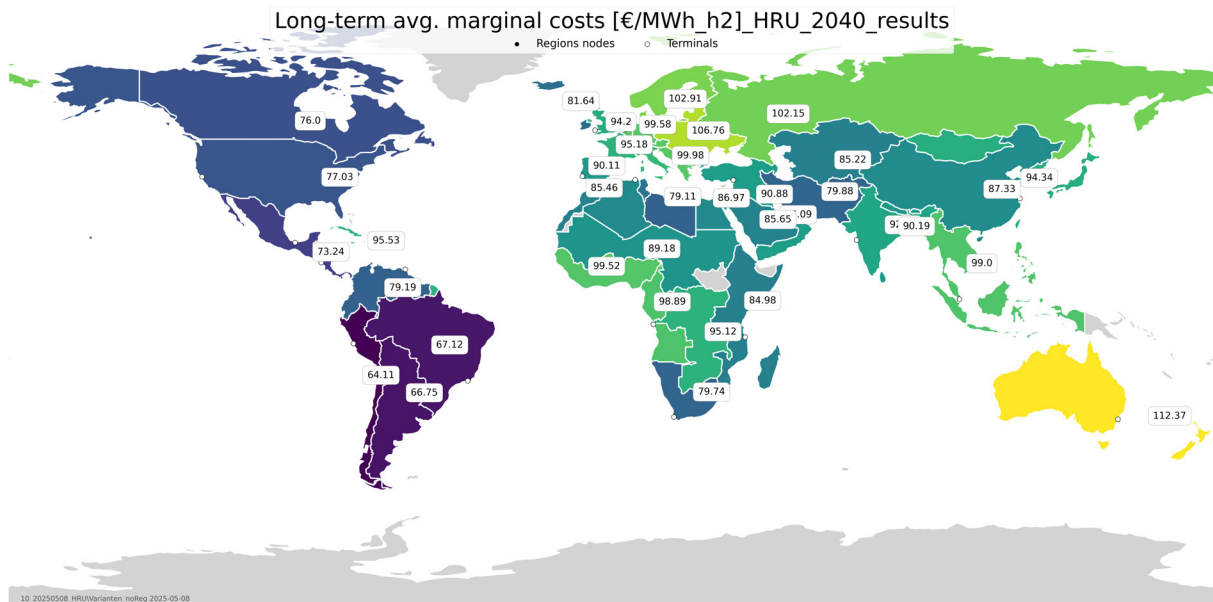
(b) Capacity Expansion and Power Plant Portfolio - 2040

Figure 3.6: Capacity Expansion (HRU)

beneficial renewable conditions, Europe and Central as well as Southern Africa show higher costs. In Asia the picture is mixed as China has lower costs, while Russia and South Asia face highest cost in this continent.



(a) Hydrogen long-term Marginal Costs - 2030

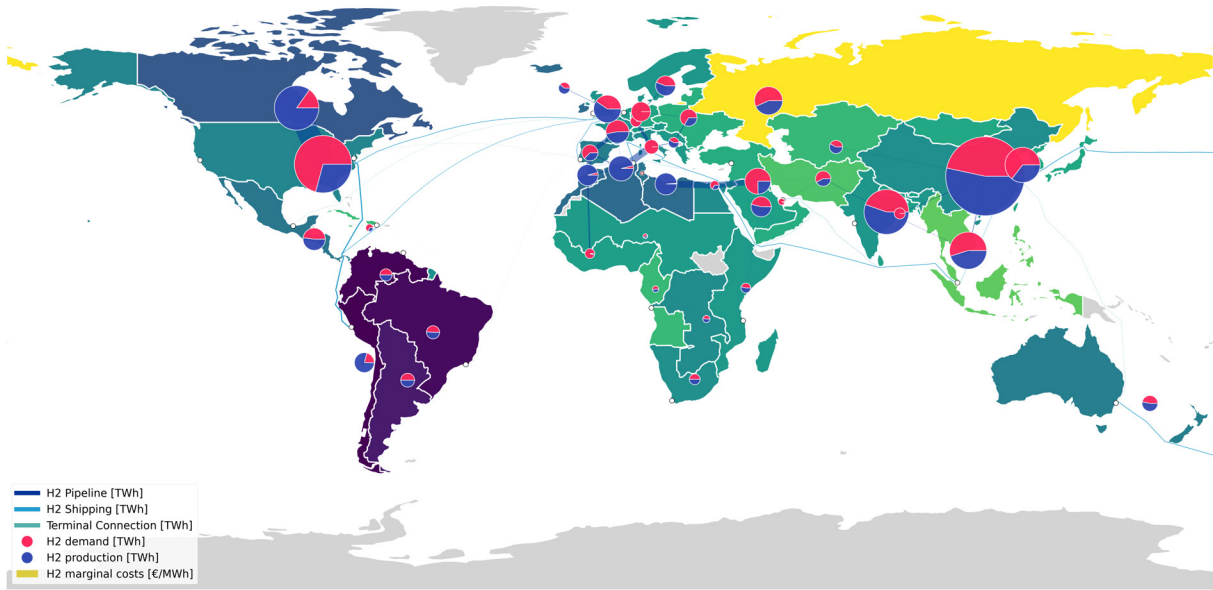


(b) Hydrogen long-term Marginal Costs - 2040

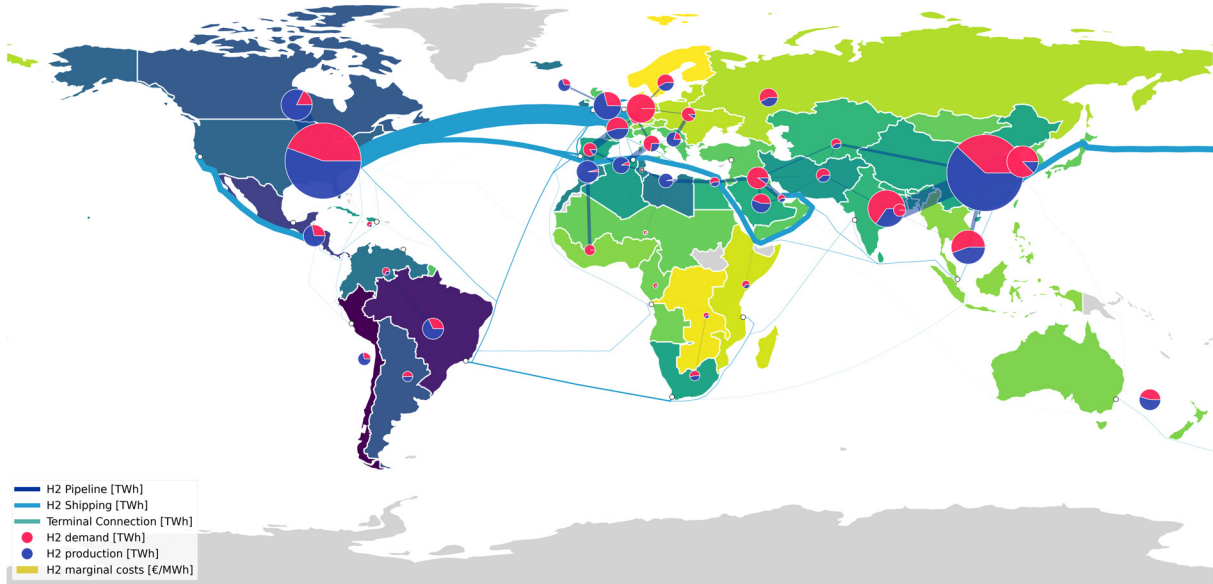
Figure 3.7: Hydrogen long-term Marginal Costs Geoplot (HRU)

3.2 MGA Results

Additionally, to the results of the cost-minimization of the model, the MGA results give complementary insights. The MGA calculations have been conducted with 1% cost slack that was added relative to the pre-calculated cost-minimum. The results are shown in Figure 3.11. Generally, changes in electricity production are relatively small (+/- up to 12 TWh between regions), which can be explained by already greatly expanded and diversified electricity systems, higher transmission losses over long distances in comparison



(a) Hydrogen Transport - 2030



(b) Hydrogen Transport - 2040

Figure 3.8: Hydrogen Transport System Geoplot (RES)

to hydrogen pipeline transport and thereby more localized electricity production. In comparison, the hydrogen production varies greatly (+/- up to 700 TWh between regions). The model was configured to emphasize seven different technology options by applying different weights in each of these MGA alternatives. By emphasizing shipping into the optimization, electricity production hardly changes, since electricity is not transported via ships. The distribution of hydrogen production on the other hand changes a lot and shifts production and therefore export further towards Chile and Peru and away from China

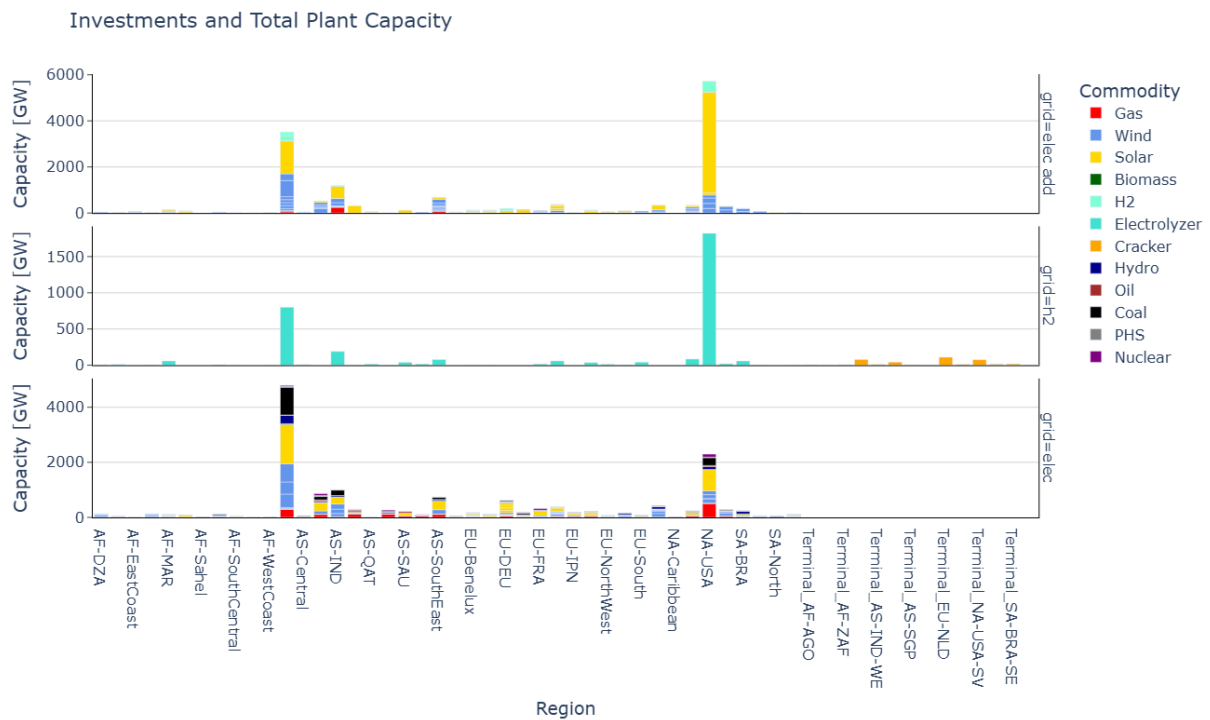
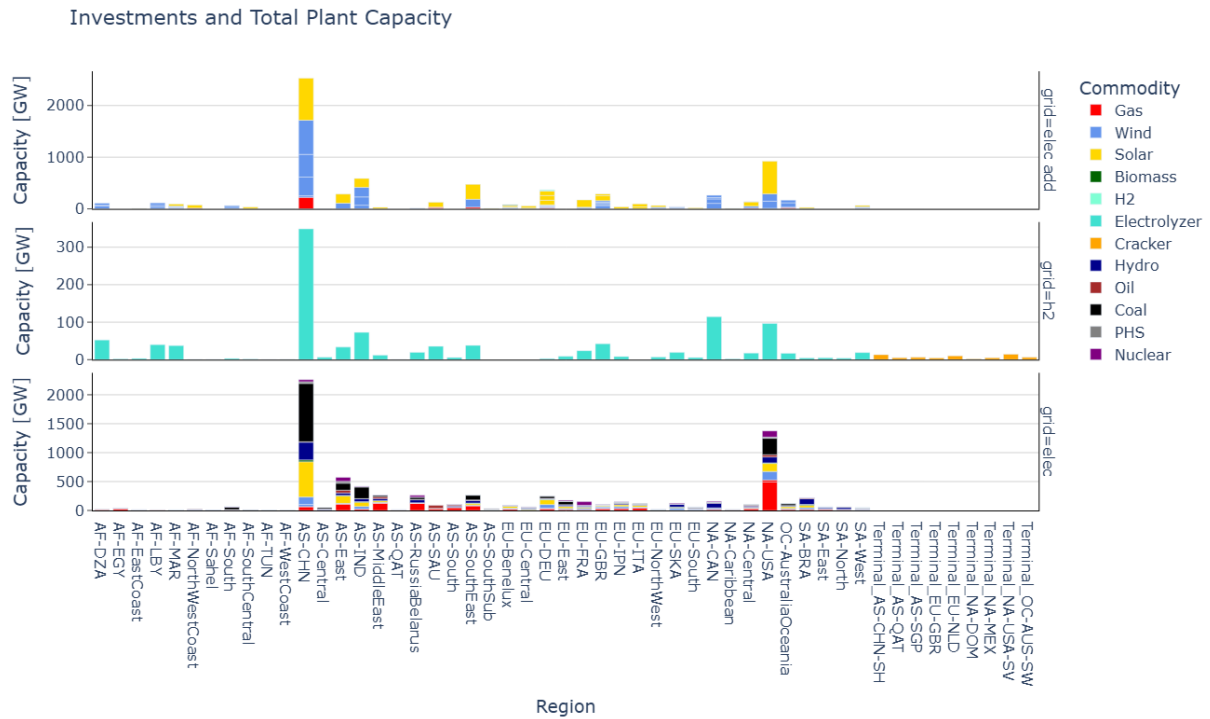
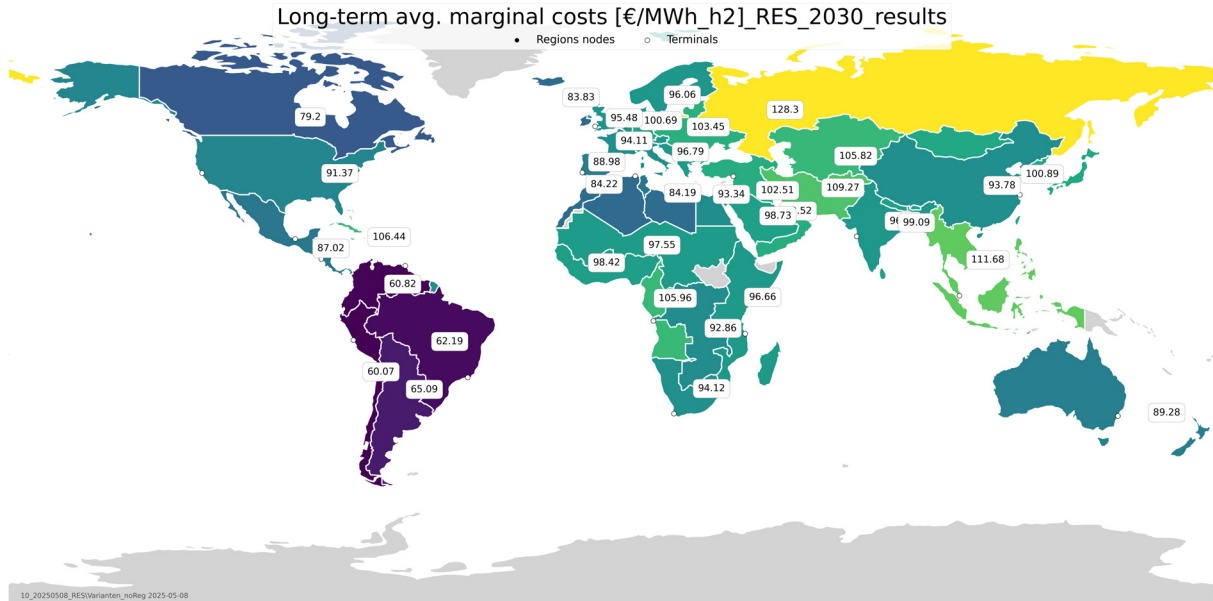
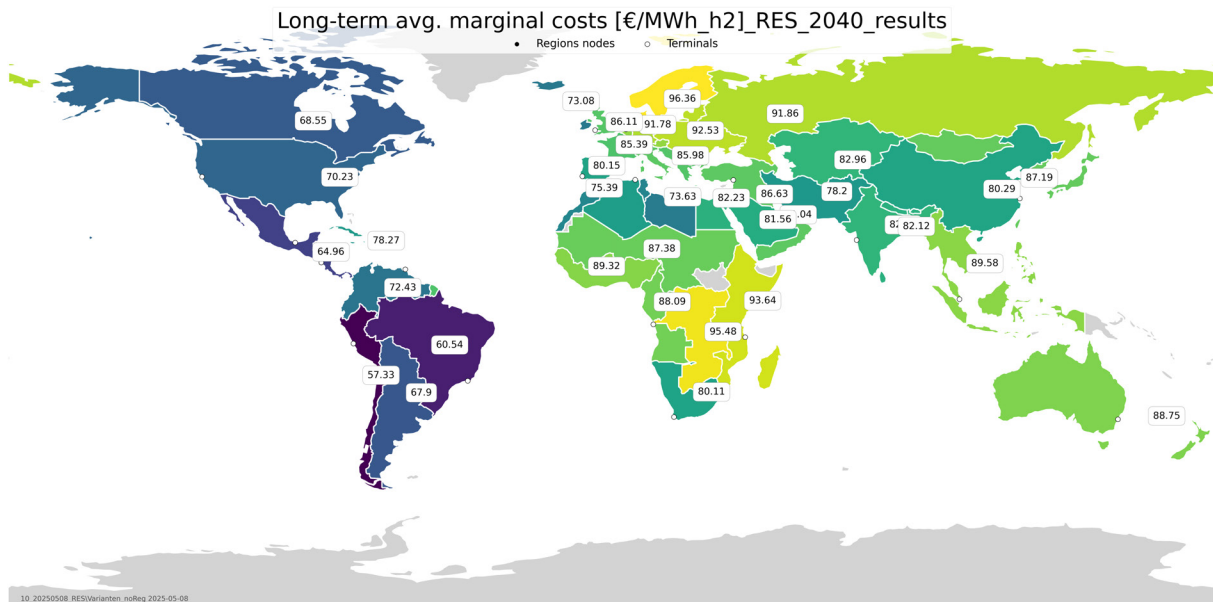


Figure 3.9: Capacity Expansion (RES)

and the rest of Asia. This shows, that already with a relatively small increase in total system costs, countries that are more remote, but possess more abundant VRE resources, may participate stronger in an international hydrogen economy. Reducing the selection



(a) Hydrogen long-term Marginal Costs - 2030



(b) Hydrogen long-term Marginal Costs - 2040

Figure 3.10: Hydrogen long-term Marginal Costs Geoplot (RES)

of batteries to push the system towards hydrogen energy storages hardly changes. This can be explained by batteries being used more as a short-term storages in comparison to hydrogen being used for medium to long-term storage, therefore serving another purpose in the system. Another strong impact can be seen in maximizing wind and solar usage, which shifts hydrogen production from the rest of Asia towards China. This may be explained through Chinas good VRE abundance, favorable geographic location, making it easier to build pipeline infrastructure between one another, and advantageous financing conditions

compared to some of the neighboring countries (as shown in Figure 2.9).

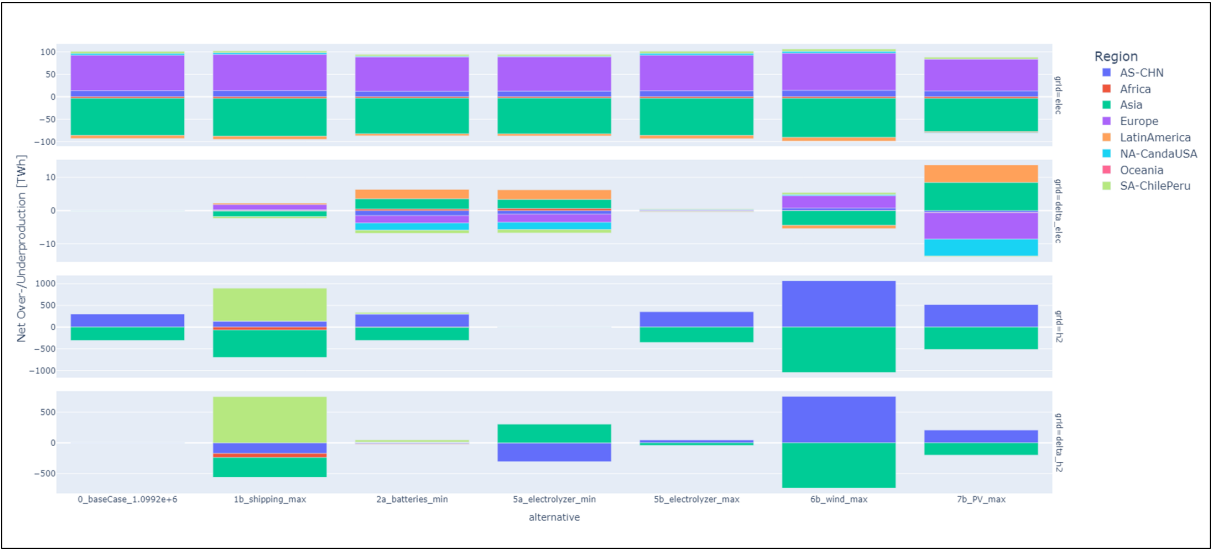


Figure 3.11: MGA production variation with 1% cost slack

4. Discussion

Although all scenario results show quite substantial differences in marginal hydrogen production costs, which in turn would imply mayor transport streams, the actual degree of global hydrogen transport differs widely between the scenarios. The APS scenario shows almost exclusively pipeline transport, which is mostly between North-Africa to Europa, Canada to the USA and China to southeast Asia. Compared to the APS scenario, the HRU scenario shows much more ship transport, especially in 2040. Countries that export hydrogen via ship include the USA, China and Brazil. The pipeline connections also increase in number. Lastly, the RES scenario shows again a lot more transport, both in shipping and pipeline transport.

4.1 Scenario Discussion

The comparative assessment of the three modeled scenarios—Announced Pledges (APS), Hydrogen Run-Up (HRU), and Renewable Electrification (RES)—highlights the diverging pathways that global energy systems may take toward decarbonisation under varying policy and technology assumptions. Figure 4.1 provides a direct comparison of the exogenously specified CO₂ budgets and the model-based CO₂ emissions derived from the power plant dispatch. The results are shown aggregated for all continents and for all scenarios for the reference year 2040. As depicted in the figure, all CO₂ budgets except for Asia in the APS scenario are fully exhausted. They thus establish a binding CO₂ constraint that is essential for achieving the decarbonization of the global energy system. While this constraint ensures substantial emission reductions, the underlying mechanisms, investment structures, and trade dynamics differ markedly.

System transformation and investment patterns

Across all scenarios, the electricity sector emerges as the backbone of decarbonisation, confirming its pivotal role as an enabler for subsequent emission reductions in other energy sectors. In both HRU and RES, the accelerated phase-out of fossil-based generation is compensated primarily by large-scale additions of renewable capacity, most notably solar PV and onshore wind. The dominance of these technologies is reflective of their rapidly declining costs and technological maturity, but it also underscores the growing need for system flexibility through grid reinforcement, storage expansion, and demand-side response. Investment trends differ substantially between the scenarios. The APS scenario, aligned

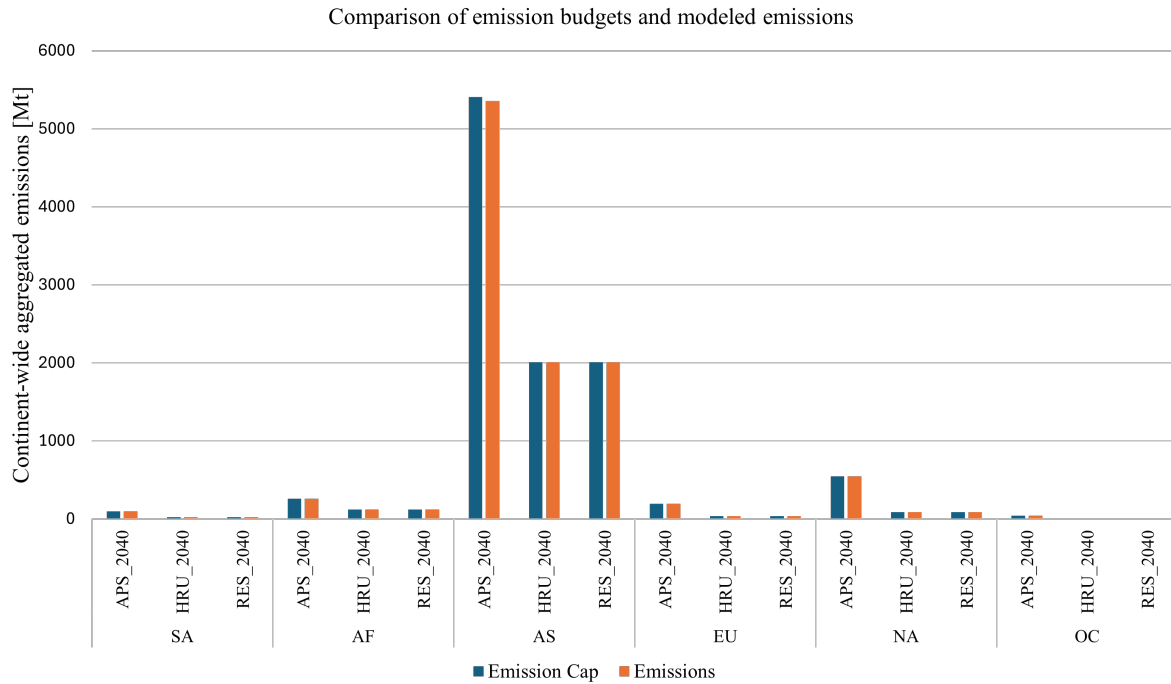


Figure 4.1: CO₂ Emission comparison across all continents and scenarios in 2040

with current national pledges, maintains a relatively balanced generation mix in 2030, with gas still serving as a transitional technology. In contrast, both HRU and RES exhibit a more rapid reallocation of capital toward renewables and electrification technologies. In the HRU pathway, electrolyzer capacities increase sharply after 2030, driven by the expanding role of green hydrogen as a cross-sectoral energy carrier. The RES scenario amplifies this trend further: total installed renewable capacities in 2040 reach about 4000 GW in China and more than 4000 GW in the United States, reflecting the aggressive pursuit of direct electrification and renewable integration consistent with a 1.5 °C trajectory.

Hydrogen deployment and cost dynamics

Hydrogen production, transport, and trade patterns differ considerably across the scenarios. In APS, globally interacting hydrogen markets play a modest role, with regional production largely satisfying domestic demand. Average marginal costs remain moderate, but the absence of large-scale trade flows indicates that hydrogen is not yet a globally traded commodity under this policy setting. The Hydrogen Run-Up scenario transforms this picture fundamentally. By 2040, global hydrogen trade becomes highly interconnected: Europe imports substantial volumes via shipping from the Americas, while intra-regional exchanges in the Middle East, Asia, and Africa are dominated by pipelines. The United States and China emerge as major net exporters, leveraging their vast renewable potentials

and cost advantages. Northern African countries benefit strongly from their solar resources, exporting hydrogen not only to Europe but also to neighbouring African regions. Marginal production costs are lowest in the Americas, enabling profitable transatlantic shipping even under high transport costs. The Renewable Electrification scenario yields a similar spatial pattern, yet with slightly higher total production and investment levels for electricity. Compared to HRU, Saudi Arabia's export role diminishes as Mediterranean suppliers gain relevance. Australia, conversely, strengthens its position as a global exporter. The long-term marginal costs of hydrogen in RES remain lowest in the Americas, while Europe and most parts of Africa face higher production costs due to more constrained renewable resource conditions. The heterogeneity of hydrogen costs across regions underscores the importance of global trade infrastructure for achieving cost-efficient decarbonisation.

CO₂ budgets and temporal decarbonisation

The imposed CO₂ budgets crucially shape the timing and intensity of the transition. In the APS scenario, a linear reduction trajectory reflects gradual progress toward announced targets, leading to slower structural changes and higher residual emissions in mid-term years. In contrast, the HRU and RES pathways—parameterised through piecewise polynomial reductions—induce accelerated emission declines, particularly in the electricity sector, which reaches carbon neutrality roughly five years earlier than the national average. This temporal frontloading of mitigation aligns with literature emphasising the power sector's leverage effect on the broader energy transition.

General implications and trade-offs

Overall, the model results suggest that pathways consistent with the 1.5 °C target (HRU and RES) entail significantly higher near-term investments. However, the two 1.5 °C-consistent pathways differ in their strategic emphasis: The HRU pathway relies on hydrogen as a unifying vector for sector coupling, requiring massive expansion of electrolyzer capacity and global trade infrastructure. The RES pathway prioritises direct electrification wherever possible, thereby reducing the system's dependence on hydrogen logistics but demanding even larger renewable capacity additions and stronger grid integration. Both approaches imply substantial coordination challenges at the international level, particularly regarding infrastructure development, CO₂ accounting, and technology standardisation. The APS scenario, though less ambitious, illustrates the limitations of current pledges in achieving deep decarbonisation, as residual fossil generation and limited hydrogen deployment persist beyond 2040.

Cost related implications

Figure 4.2 shows the marginal cost distribution for the different continents in APS 2040. Especially South America sees very low marginal hydrogen costs at around 80 €/MWh (2,40€/kg) in comparison to the other continents, where hydrogen costs of 90-120 €/MWh (2,7-3,6 €/kg) occur. This relation can be seen throughout all scenarios and years. Nevertheless, the amount of hydrogen exported to other parts of the world is limited. This can be explained by the additional costs and losses from transport, that pose as a comparatively high disadvantage when competing against pipeline transport from closer regions. Especially relevant are the retransformation losses back to hydrogen in the case of, e.g., ammonia. Therefore, the analyses indicate, that if pure hydrogen is needed, the transport distances will be more limited to nearer regions. If hydrogen derivatives are needed, such as ammonia, methanol or other synthetic fuels, regions like South America may profit from more competitive production costs in combination with ship transport with fewer losses and higher volumetric energy densities. Furthermore, from a perspective of countries with lower VRE abundance and but well-established base materials industry, e.g., for ammonia production and other chemicals, this implies the risk of long-term competitive disadvantage possibly leading to either relocation of these industries or needs for long-term subsidies.

Discussion of the MGA results

The MGA results clearly show, that even relatively small changes like 1% cost slack in total system costs, may strongly influence future hydrogen flows and thereby import and export relations between different regions. Especially for Chile and Peru, this can be seen as an opportunity, since although the cost-minimization calculations shows limited export to other continents due to remoteness and high shipping losses and costs, there are export opportunities if ship transport costs are reduced sufficiently.

4.2 Benchmarking

In the following, the demand assumptions and results are compared and classified with the national hydrogen strategy for Germany.

Previously, the national targets for hydrogen demand in 2030 have been changed from between 90 and 110 TWh in the 2020 strategy (BMW_i, 2020) to 95 and 130 TWh in the 2023 strategy update (BMW_K, 2023). Those target ranges are shown in comparison to the

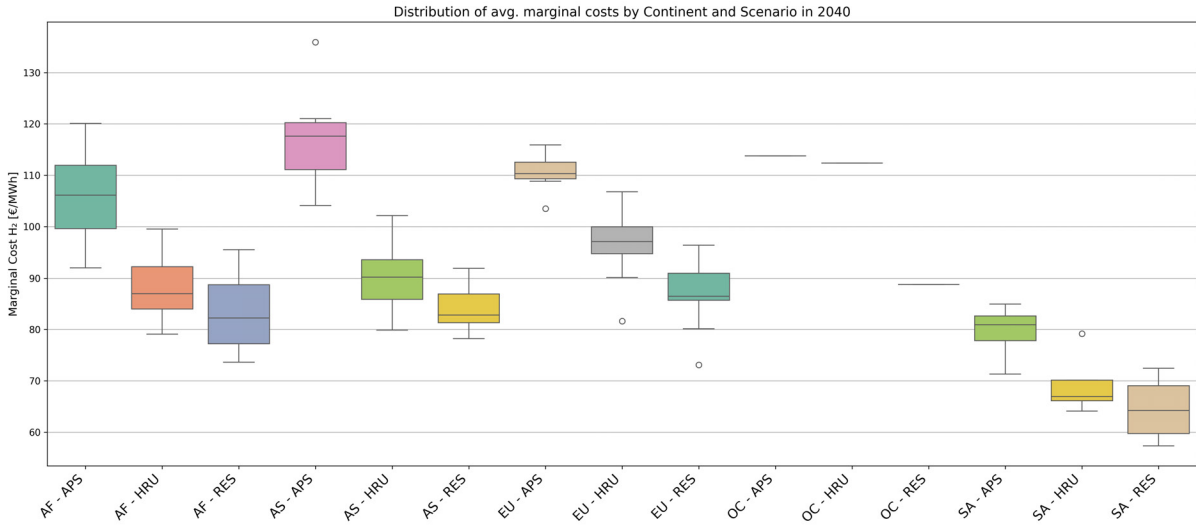


Figure 4.2: Green hydrogen long-term marginal cost comparison between scenarios and continents in 2040

hydrogen demands in the model scenarios in figure 4.3. While the APS scenario lies at 110 TWh and thereby inside of both demand ranges, the RES scenario lies on the upper bound of the updated demand at 130 TWh and beyond the original strategy. The HRU demand lies at 156 TWh and thereby far beyond the maximum targets in the national strategy. Since the APS scenario represents the announced targets, it is consistent that demand in this scenario lies in the announced range. Nevertheless, more ambitious scenarios like the HRU scenario represent higher rates of system defossilization and thereby higher hydrogen demands.

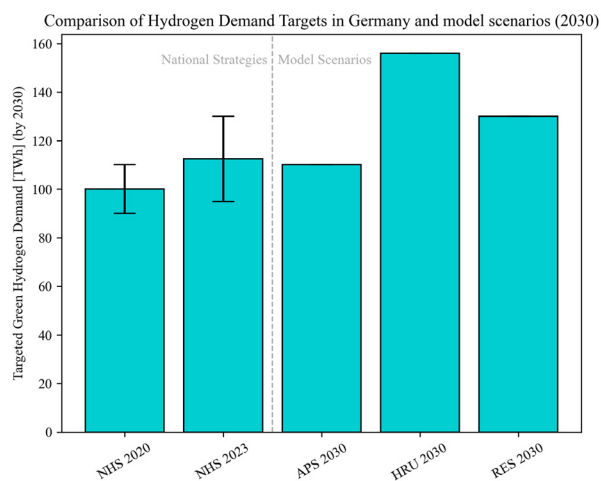


Figure 4.3: Comparison of Hydrogen Demand Targets in Germany and model scenarios (2030)

Figure 4.4 shows the assumed hydrogen demands over time in Germany in the different model scenario results and different strategies and studies. This includes the national

import strategy (BMWK, 2024), the BNetzA scenario frame (abbreviated with SF) for the German federal grid development plan (BNetzA, 2025) as well as the demands assumed in the Ariadne project (Luderer et al., 2025b). These newer scenarios start at a lower level in 2030 and then see a strong increase in projected hydrogen demand over time, overtaking most of the other scenarios. Similarly, the Ariadne scenarios start at an updated lower initial demand and develop in parallel to the original strategy scenarios, shifted down by almost 100 TWh (Luderer et al., 2025a).

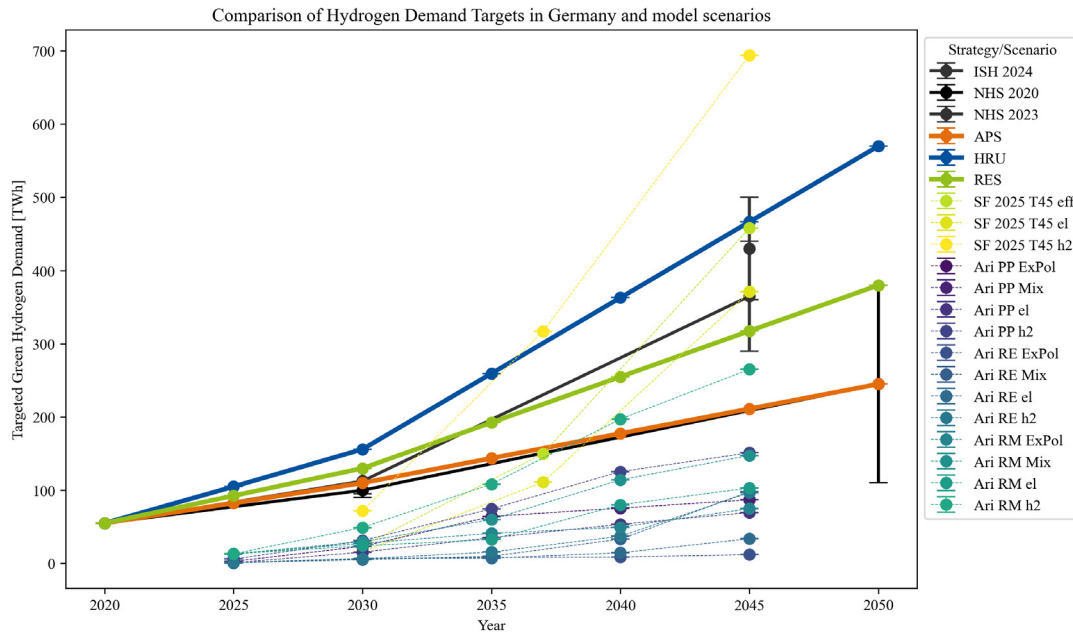


Figure 4.4: Comparison of Hydrogen Demand Targets in Germany and model scenarios over time

The results of the different scenarios regarding the installed electrolyzer capacity in comparison to the National Hydrogen Strategy (NHS) show less installed capacities than the national targets. The original 2020 NHS target of 5 GW installed electrolyzer capacity in 2030 was raised to 10 GW. The model results show no installed electrolyzer capacity in Germany by 2030 in the APS scenario, 6.2 GW in the HRU scenario and 2.8 GW in the RES scenario. The model results for 2040 show 12 GW installed electrolyzer capacity in Germany in the APS scenario, 9.6 GW in the HRU scenario and 2.8 GW in the RES scenario. Although the model resolution is relatively rough, it can be seen that with less ambitious targets like in the APS scenario, the development of hydrogen demand and subsequently domestic electrolyzer capacity requirement shifts further into the future in comparison to the more ambitious scenarios. With regard to the actual hydrogen import in the different scenarios, the demand in the APS scenario in 2030 is completely covered by hydrogen imports. The other scenarios show between 90 and 99 % import share for 2030

as well as for 2040. In contrast the 2023 NHS envisages an import share between 50 and 70 %. These results must be critically evaluated. Optimization models generally tend to lean towards individual extrema and less to diverse and balanced results. Especially with the relatively rough geographical resolution at hand, the comparison of individual countries with whole regions will differ from real world developments with more granular project development. Therefore, these results can be used to get an orientation towards which direction the system will develop. In this regard, the developments in reality show, that there are electrolyzer capacities being built in Germany and that therefore the no capacity results in the APS 2030 scenario is not realistic at all. Nevertheless, seeing a very high import share over all three scenarios and in both years indicates that domestic hydrogen production in Germany is not a sure thing and depends on the dynamic of the run-up of the hydrogen economy. A high dynamic scenario as shown in HRU and RES does create a favorable environment for domestic electrolyzer capacity expansion as explained earlier.

4.3 Conclusions

In summary, the comparative scenario analysis reveals that achieving a climate-neutral power and H₂ system by mid-century is technically feasible but highly contingent on early policy commitment and infrastructure scaling. While the APS scenario reflects the pursuit of current national energy and climate plans (NECP), both HRU and RES demonstrate that accelerated transitions—though capital-intensive—are necessary to align with global temperature goals. The contrasting reliance on hydrogen versus direct electrification highlights a fundamental strategic choice for policymakers: whether to pursue a diversified, hydrogen-centred transition or to prioritise electrification as the dominant decarbonisation pathway.

In conclusion, the findings emphasise that meeting global climate targets will depend not only on the pace of decarbonisation but also on coherent strategic choices between electrification and hydrogen deployment. Strong, early policy intervention, cross-sectoral coordination, and international cooperation on infrastructure and standards are essential to ensure that the global energy system can transition effectively toward a sustainable and climate-neutral future.

With regard to the benchmarking of the model results with the NHS in chapter 4.2 it can be concluded that higher ambitions with more dynamic hydrogen demands lead to faster domestic electrolyzer capacity increases. If we add the results from chapter 4 it also

shows that a more dynamic increase of hydrogen demand will result in higher investment cost earlier, but lower marginal costs in the long-term. Using the marginal costs as price proxies, it can be concluded that for a more competitive hydrogen price in the future, a fast increase in VRE and electrolyzer capacities is desirable.

Policy relevant conclusions

The following policy implications can be drawn from the study:

- **Ensure Rapid Scale-Up to Enable Long-Term Low Marginal Costs and Prices**
 - Implement policies that facilitate the quick deployment of hydrogen technologies to achieve economies of scale.
 - Support research and development to continuously reduce production and operational costs.
 - Aim for medium to long-term hydrogen marginal costs of 92-116 €/MWh (2.75 - 3.5 €/t) in Germany, depending on the dynamics of capacity expansion.
- **Secure Supply Given High Import Share**
 - Develop strategies to ensure a stable and reliable supply of hydrogen, considering the significant portion that will be imported.
 - Establish robust infrastructure and logistics to handle large-scale hydrogen imports.
- **Prioritize Attractive Import Partners, Primarily within the EU and Neighboring States**
 - Foster strong trade relationships and agreements with EU member states and neighboring countries to secure hydrogen supplies.
 - Encourage regional cooperation and joint infrastructure projects to enhance supply chain resilience.
- **Consider Long-Term Implications of Lower Marginal Costs for Hydrogen Derivatives in South America**
 - Analyze the potential impact of lower production costs for hydrogen derivatives in South America on the global market.
 - Develop policies that address competitive dynamics and ensure a level playing field for domestic and international hydrogen markets.
 - Explore opportunities for collaboration and investment in South American hydrogen production to leverage cost advantages.

4.4 Outlook

This study provides an overview of three potential development scenarios for a future global hydrogen economy. In order to further elaborate on these investigations and improve their significance and level of detail, we recommend conducting further research and refining the model.

Since this model does not differentiate into different demands for hydrogen and its derivatives, the conclusions may differ for derivatives with a higher energy density and therefore more favorable transport conditions. Especially continents like South America may benefit from producing higher value commodities themselves and shipping them to import regions. Hence, it is desirable to extend the model to more demand sectors and commodities, enabling more detailed analysis. Additionally, including demand flexibility may increase the realism of the demand assumptions. This could also be improved by incorporating methods to better investigate path dependencies. Furthermore, the results are limited by the calculation capacity available. A long-term goal would be to increase the geographical and temporal resolution to gain more adequate and detailed insights. Overall, long-term maintenance of model data may enable long-term investigation of the development and therefore yielding the maximum use of the now available model. Considering the outcomes in chapter 4.2 and the MGA method results established in chapter 3.2 investigating the near-optimal behavior of domestic electrolyzer capacity expansion in Germany may reveal the robustness of the results. Thus, providing an interesting starting point for extended detailed investigations.

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Appendix

Table A.1 contains the complete set of countries included in the model as mentioned in chapter 2.2.2 as well as an exemplary assignment to certain regions and the full name of the country for better understanding. The datasets for all of these countries can be found on Zenodo¹.

Region	Subregion	Country
AF-AGO	AF-WestCoast	Angola
AF-BDI	AF-SouthCentral	Burundi
AF-BEN	AF-NorthWestCoast	Benin
AF-BFA	AF-NorthWestCoast	Burkina Faso
AF-BWA	AF-SouthCentral	Botswana
AF-CAF	AF-Sahel	Central African Republic
AF-CIV	AF-NorthWestCoast	Côte d'Ivoire
AF-CMR	AF-WestCoast	Cameroon
AF-COD	AF-SouthCentral	Democratic Republic of the Congo
AF-COG	AF-WestCoast	Republic of the Congo
AF-DJI	AF-EastCoast	Djibouti
AF-DZA	AF-North	Algeria
AF-EGY	EGY	Egypt
AF-ERI	AF-EastCoast	Eritrea
AF-ETH	AF-EastCoast	Ethiopia
AF-GAB	AF-WestCoast	Gabon
AF-GHA	AF-NorthWestCoast	Ghana
AF-GIN	AF-NorthWestCoast	Guinea
AF-GMB	AF-NorthWestCoast	Gambia
AF-GNB	AF-NorthWestCoast	Guinea-Bissau
AF-GNQ	AF-WestCoast	Equatorial Guinea
AF-KEN	KEN	Kenya
AF-LBR	AF-NorthWestCoast	Liberia
AF-LBY	LBY	Libya
Continued on next page		

¹ Complete StEAM model dataset: <https://zenodo.org/records/15639823>.

Table A.1 – continued from previous page

Region	Subregion	Country
AF-LSO	AF-South	Lesotho
AF-MAR	MAR	Morocco
AF-MDG	AF-EastCoast	Madagascar
AF-MLI	AF-Sahel	Mali
AF-MOZ	AF-EastCoast	Mozambique
AF-MRT	AF-Sahel	Mauritania
AF-MWI	AF-SouthCentral	Malawi
AF-NAM	NAM	Namibia
AF-NER	AF-Sahel	Niger
AF-NGA	NGA	Nigeria
AF-RWA	AF-SouthCentral	Rwanda
AF-SDN	AF-Sahel	Sudan
AF-SEN	AF-NorthWestCoast	Senegal
AF-SLE	AF-NorthWestCoast	Sierra Leone
AF-SOM	AF-EastCoast	Somalia
AF-SWZ	AF-South	Eswatini
AF-TCD	AF-NorthWestCoast	Chad
AF-TGO	AF-NorthWestCoast	Togo
AF-TZA	TZA	Tanzania
AF-UGA	AF-SouthCentral	Uganda
AF-ZAF	ZAF	South Africa
AF-ZMB	AF-SouthCentral	Zambia
AF-ZWE	AF-SouthCentral	Zimbabwe
AS-AFG	AFG	Afghanistan
AS-ARE	AS-MiddleEast	United Arab Emirates
AS-BGD	AS-South	Bangladesh
AS-BHR	AS-MiddleEast	Bahrain
AS-BRN	AS-SouthEast	Brunei
AS-BTN	AS-South	Bhutan
Continued on next page		

Table A.1 – continued from previous page

Region	Subregion	Country
AS-CHN	CHN	China
AS-IDN	IDN	Indonesia
AS-IND	IND	India
AS-IRN	IRN	Iran
AS-IRQ	AS-MiddleEast	Iraq
AS-ISR	AS-MiddleEast	Israel
AS-JOR	AS-MiddleEast	Jordan
AS-JPN	JPN	Japan
AS-KAZ	AS-Central	Kazakhstan
AS-KGZ	AS-Central	Kyrgyzstan
AS-KHM	AS-SouthEast	Cambodia
AS-KOR	KOR	South Korea
AS-KWT	AS-MiddleEast	Kuwait
AS-LAO	AS-SouthEast	Laos
AS-LBN	AS-MiddleEast	Lebanon
AS-LKA	AS-South	Sri Lanka
AS-MMR	AS-SouthEast	Myanmar
AS-MNG	AS-South	Mongolia
AS-MYS	AS-SouthEast	Malaysia
AS-NPL	AS-South	Nepal
AS-OMN	AS-MiddleEast	Oman
AS-PAK	AS-South	Pakistan
AS-PHL	AS-SouthEast	Philippines
AS-PRK	AS-East	North Korea
AS-QAT	QAT	Qatar
AS-RUS	RUS_BEL	Russia
AS-SAU	SAU	Saudi Arabia
AS-SGP	AS-SouthEast	Singapore
AS-SYR	AS-MiddleEast	Syria
Continued on next page		

Table A.1 – continued from previous page

Region	Subregion	Country
AS-THA	AS-SouthEast	Thailand
AS-TJK	AS-Central	Tajikistan
AS-TKM	AS-Central	Turkmenistan
AS-TUR	TUR	Turkey
AS-TWN	AS-East	Taiwan
AS-UZB	AS-Central	Uzbekistan
AS-VNM	VNM	Vietnam
AS-YEM	AS-MiddleEast	Yemen
EU-ALB	EU-South	Albania
EU-ARM	AS-MiddleEast	Armenia
EU-AUT	EU-Central	Austria
EU-AZE	AS-MiddleEast	Azerbaijan
EU-BEL	EU-Central	Belgium
EU-BGR	EU-East	Bulgaria
EU-BIH	EU-South	Bosnia and Herzegovina
EU-BLR	RUS_BEL	Belarus
EU-CHE	EU-Central	Switzerland
EU-CZE	EU-Central	Czech Republic
EU-DEU	DEU	Germany
EU-DNK	EU-North	Denmark
EU-ESP	IBER	Spain
EU-EST	EU-North	Estonia
EU-FIN	EU-North	Finland
EU-FRA	FRA	France
EU-GBR	GBR	United Kingdom
EU-GEO	AS-MiddleEast	Georgia
EU-GRC	EU-South	Greece
EU-HRV	EU-South	Croatia
EU-HUN	EU-Central	Hungary
Continued on next page		

Table A.1 – continued from previous page

Region	Subregion	Country
EU-IRL	EU-North	Ireland
EU-ISL	EU-North	Iceland
EU-ITA	ITA	Italy
EU-LTU	EU-North	Lithuania
EU-LUX	EU-Central	Luxembourg
EU-LVA	EU-North	Latvia
EU-MDA	EU-East	Moldova
EU-MKD	EU-South	North Macedonia
EU-MNE	EU-South	Montenegro
EU-NLD	EU-Central	Netherlands
EU-NOR	NOR	Norway
EU-POL	POL	Poland
EU-PRT	IBER	Portugal
EU-ROU	EU-East	Romania
EU-SRB	EU-South	Serbia
EU-SVK	EU-Central	Slovakia
EU-SVN	EU-South	Slovenia
EU-SWE	EU-North	Sweden
EU-UKR	UKR	Ukraine
NA-CAN	CAN	Canada
NA-CRI	NA-Caribbean	Costa Rica
NA-CUB	NA-Caribbean	Cuba
NA-DOM	NA-Caribbean	Dominican Republic
NA-GTM	NA-Central	Guatemala
NA-HND	NA-Central	Honduras
NA-HTI	NA-Caribbean	Haiti
NA-JAM	NA-Caribbean	Jamaica
NA-MEX	MEX	Mexico
NA-NIC	NA-Central	Nicaragua
Continued on next page		

Table A.1 – continued from previous page

Region	Subregion	Country
NA-PAN	NA-Central	Panama
NA-SLV	NA-Caribbean	El Salvador
NA-TTO	NA-Caribbean	Trinidad and Tobago
NA-USA	USA	United States
OC-AUS	AUS	Australia
OC-NZL	NZL	New Zealand
OC-PNG	PNG	Papua New Guinea
SA-ARG	ARG	Argentina
SA-BOL	SA-EastCoast	Bolivia
SA-BRA	BRA	Brazil
SA-CHL	CHL	Chile
SA-COL	SA-North	Colombia
SA-ECU	ECU	Ecuador
SA-GUY	SA-North	Guyana
SA-PER	PER	Peru
SA-PRY	SA-EastCoast	Paraguay
SA-SUR	SA-North	Suriname
SA-URY	SA-EastCoast	Uruguay
SA-VEN	SA-North	Venezuela

Table A.1: List of all countries included in the model