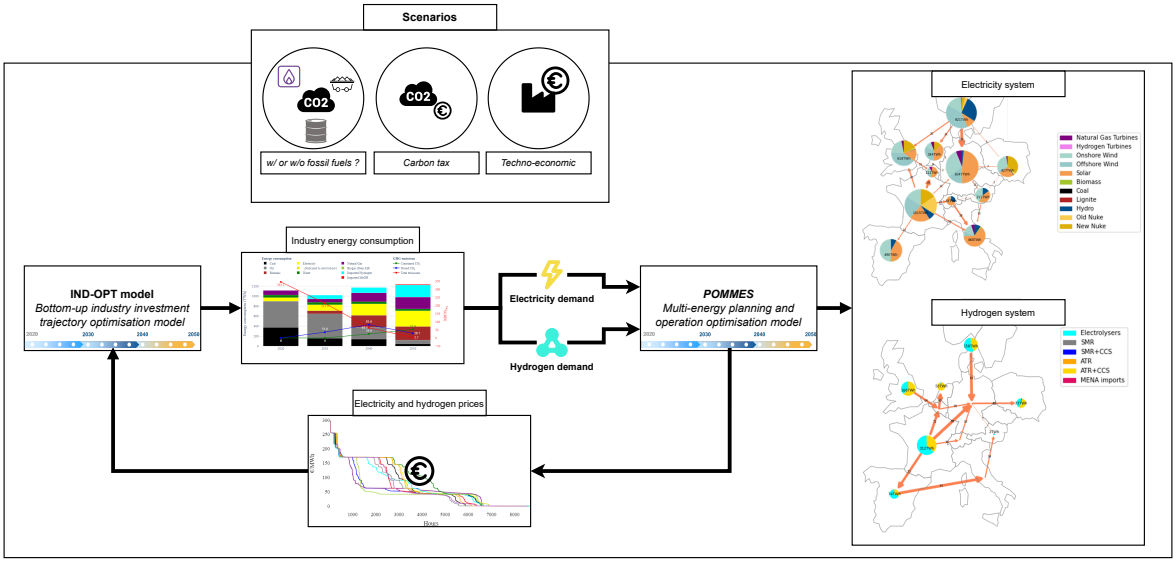
Decarbonisation of industry and the energy system: exploring mutual impacts and investment planning

Quentin Raillard–Cazanove, Thibaut Knibiehly, Robin Girard

Graphical Abstract

Decarbonisation of industry and the energy system: exploring mutual impacts and investment planning

Quentin Raillard--Cazanove, Thibaut Knibiehly, Robin Girard



Highlights

Decarbonisation of industry and the energy system: exploring mutual impacts and investment planning

Quentin Raillard--Cazanove, Thibaut Knibiehly, Robin Girard

- Industry decarbonisation significantly increase electricity and hydrogen demand
- Higher electricity and hydrogen prices emerge with notable regional disparities, worsened by a phase-out of fossil fuels
- Reducing carbon taxes lowers prices but makes fossil fuel usage more attractive, limiting decarbonisation progress
- Synergies between electrolytic and blue hydrogen help maintain competitive hydrogen prices, supporting cost-effective production

Decarbonisation of industry and the energy system: exploring mutual impacts and investment planning

Quentin Raillard--Cazanove[a,*], Thibaut Knibiehly[a], Robin Girard[a,*]

[a]*Mines Paris, PSL University, Centre for processes, renewable energy and energy systems (PERSEE), Sophia Antipolis, 06904, France*

Abstract

The decarbonisation of the energy system is crucial for achieving climate goals and is inherently linked to the decarbonisation of industry. Despite this, few studies explore the simultaneous impacts of decarbonising both sectors. This paper aims to examine how industrial decarbonisation in Europe affects the energy system and vice versa. To address this, an industry model incorporating key heavy industry sectors across six European countries is combined with an energy system model for electricity and hydrogen covering fifteen European regions, refered to as the EU-15, divided into eleven zones. The study evaluates various policy scenarios under different conditions.

The results demonstrate that industrial decarbonisation leads to a significant increase in electricity and hydrogen demand. This additional demand for electricity is largely met through renewable energy sources, while hydrogen supply is predominantly addressed by blue hydrogen production when fossil fuels are authorized and the system lacks renewable energy. This increased demand results in higher prices with considerable regional disparities. Furthermore, the findings reveal that, regardless of the scenario, the electricity mix in the EU-15 remains predominantly renewable, exceeding 85%.

A reduction in carbon taxes lowers the prices of electricity and hydrogen, but does not increase consumption, as the lower carbon tax makes the continued use of fossil fuels more attractive to industry. In scenarios that enforce a phase-out of fossil fuels, electricity prices rise, leading to a greater reliance on imports of low-carbon hydrogen and methanol. Results also suggest that domestic hydrogen production benefits from synergies between electrolytic hydrogen and blue hydrogen, helping to maintain competitive prices.

Keywords: Decarbonisation, Industry, Energy System, Renewable Energy, Synergies

Nomenclature

Acronyms

ATR	Autothermal Reforming
BF	Blast Furnace
BOF	Basic Oxygen Furnace
DAC	Direct Air Capture
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
GHG	Greenhouse Gas
MeOH	Methanol
MSR	Methanol Synthesis Reactor
MTO	Methanol to Olefins
NC	Naphtha Cracking

*Corresponding authors

Email addresses: quentin.raillard-cazanove@minesparis.psl.eu (Quentin Raillard--Cazanove), robin.girard@minesparis.psl.eu (Robin Girard)

OCM	Oxidative Coupling of Methane
PHS	Pumped Hydro Storage
PtXtP	Power-to-X-to-Power
RTE	Round Trip Efficiency
SMR	Steam Methane Reforming
TCR	Thermo-Chemical heat Recovery
WACC	Weighted Average Cost of Capital

1. Introduction

1.1. Background

Anthropogenic greenhouse gas emissions (GHG), the primary driver of global warming, are poised to inflict severe harm on ecosystems, compromise water availability, and jeopardise health, well-being, and economic stability [1]. It is, therefore, imperative that we reduce our GHG emissions to mitigate these adverse effects.

In 2019, approximately 48% of greenhouse gas emissions in Europe were attributable to industry and the production of electricity and heat [2]. It is therefore crucial to decarbonise these sectors to mitigate global warming, particularly as decarbonised electricity production can facilitate the decarbonisation of the residential and tertiary sectors, as well as transport (which accounted for 24% of emissions in Europe in 2019 [2]).

Indeed, the direct or indirect use of low-carbon electricity is crucial for the decarbonisation of transport [3–7] and industry [7–9]. Similarly, the decarbonisation of buildings is largely reliant on electricity usage [7, 10, 11].

1.2. Industry decarbonisation

Industry, particularly heavy industry, exhibits a high energy demand and is characterised by significant emissions, especially for processes heavily reliant on fossil fuels. Decarbonising industry thus necessitates substantial technological advancements leading to the adoption of low-carbon energy sources.

It should be noted that many decarbonisation options are nearing commercial maturity [12], and both direct and indirect electrification present significant potential for reducing emissions [8, 13]. Therefore, several prospective studies on industrial decarbonisation [14–16] found a profound shift in energy consumption patterns, which is expected to ultimately influence the dynamics of the energy system.

1.3. Energy supply decarbonisation

The decarbonisation of the electricity system, a cornerstone of the European energy transition, necessitates the increased deployment of renewable energy sources alongside flexibility measures [17–23]. Several studies and reports [17, 23, 24] explore the potential role of nuclear energy, while highlighting the significant advantages of an interconnected system that promotes cooperation between nations [23, 25, 26].

The production of low-carbon hydrogen presents a significant challenge for decarbonising aviation, shipping, and industry [7, 14]. In various prospective studies, hydrogen is predominantly produced via electrolysis [7, 27, 28], indicating that the electricity system must adapt to meet the corresponding demand. However, electrolysers can offer valuable flexibility for both hydrogen consumers [29] and the electricity system [7, 23]. Furthermore, solutions such as Power-to-X-to-Power (PtXtP) are poised to address the seasonal intermittency of renewable energy sources in the long term [23, 30]. Consequently, the integrated modelling of an electricity/hydrogen system highlights systemic economical advantages [31].

1.4. Interdependent dynamics

A cross-sectoral modelling approach allows for a better consideration of synergies and minimises trade-offs between sectors [32]. The various stakeholders in the energy transition exhibit interconnected responses to climate policies [33]. While urban and rural areas adopt a systemic approach with the automotive sector, the decarbonisation efforts of the energy and industrial sectors remain uncoordinated and lack a dynamic systemic perspective [33].

In most prospective studies modelling the European energy system, industry is treated merely as an exogenous demand parameter [19, 22, 23, 25, 31, 34]. Although Fleiter et al. [34] models industrial consumption within a dedicated model, it remains an exogenous parameter to the energy system under study. Papadaskalopoulos et al.

[35] also treats industrial consumption as an exogenous parameter but allows the energy system to make it flexible, demonstrating the associated economic and renewable energy deployment benefits.

To the authors' knowledge, only one study stands out, Manuel et al. [36], optimising the energy system of the Netherlands jointly with the technological deployment in the industrial sector. It then examines the impact of four industrial energy policies (Bio-based, CCUS-based, Electrification, Hydrogen-based) on the initial optimal system.

Nonetheless, changes in the electricity system, such as the availability of low-cost renewable energy can significantly impact industrial strategies, influencing decisions related to energy sourcing and investment in new technologies.

1.5. Research gap and objectives

Despite the evident interdependencies between the energy system and industry, limited research considers the bidirectional and simultaneous impact of decarbonisation in these sectors.

While Manuel et al. [36] investigates the impact of enforced technological choices in industry on the overall energy mix, we propose an approach, detailed in Section 2, that focuses on the implications of an economically optimised industrial decarbonisation pathway within different political and macroeconomic contexts, focusing on its effects on the electricity system and the resulting synergies.

Thus, this paper aims to investigate how the decarbonisation of industry in Europe affects the electricity system's planning and operation, and vice versa. To achieve this, we have coupled an industrial model, based on previous work [14], with an energy system model both incorporating investment planning frameworks.

By exploring the interactions between these two models, this study provides insight into the synergistic planning required to achieve our decarbonisation goals.

2. Methodology

2.1. Industry decarbonisation modelling

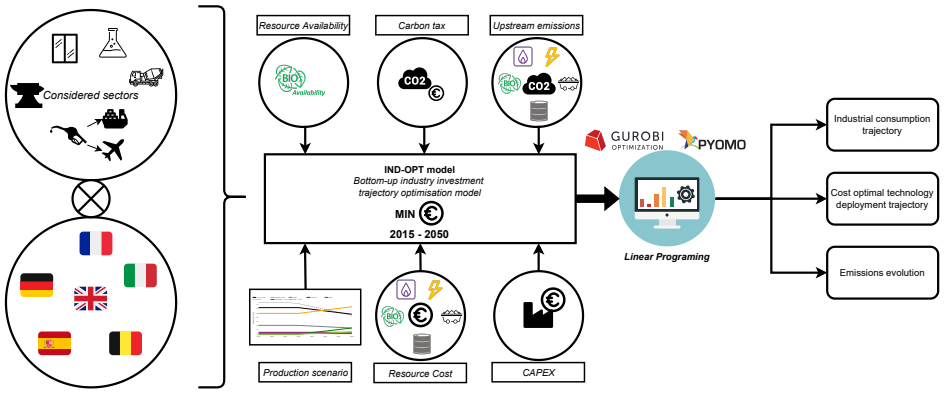


Fig. 1. IND-OPT model simplified scheme

The industry modelling builds upon prior research [14] that focuses on decarbonising the steel, chemical, cement, and glass sectors, along with e-fuel production in six European countries[1]. The IND-OPT model employs a bottom-up technological approach, taking into account numerous technologies detailed in Table 1.

[1] France, Germany, Great Britain, Italy, Spain and Belgium

Resource	Hydrogen	Ammonia	Olefins	MeOH	E-Kerosene	Clinker	Steel	Glass
Technologies	SMR/eSMR[a] ATR[a] Gasification[a] Electrolysis Pyrolysis	Haber-Bosch	NC/eNC[a] MTO OCM	SMR-MSR Gasification-MSR CO_2 to MeOH	Fischer-Tropsch	Reference Oxy-Ref[a] eC-pK[a] OC-HK[a] eC-OK[a] eC-HK[a]	BF-BOF[a] DRI-EAF[a] Electrowinning EAF (recycling)	Regenerative SP[a] Regenerative EP[a] Recuperative[a] Oxyfuel[a] TCR[a] Hybrid[a] Electric[a]

[a]Carbon capture compatible

Table 1
Production technologies considered in IND-OPT for the study based on [14]

2.2. *Energy system modelling*

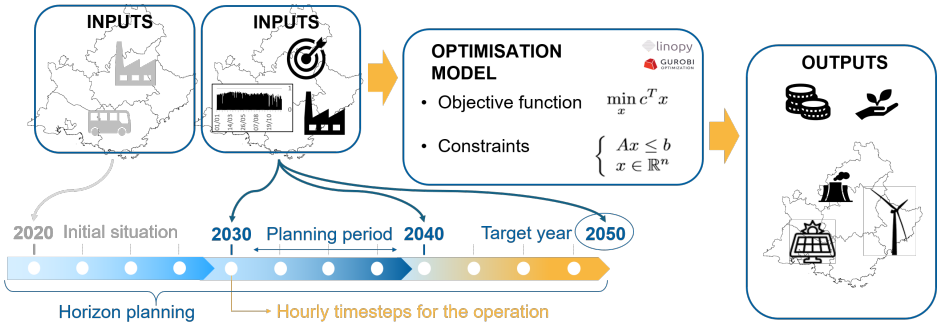


Fig. 2. POMMES framework scheme

POMMES (Planning and Operation Model for Multi-Energy Systems) is a framework adapted from the model developed by Jodry et al. [29], specifically designed for multi-horizon modelling of energy systems, with the primary objective of cost minimisation [37]. In this study, POMMES has been employed to model the electricity and hydrogen system of 15 countries (grouped into 11 nodes) up to the year 2050. The modelling process includes the optimisation of system operations on an hourly basis, alongside a planning horizon—also optimised—set at 10-year intervals. Interconnections between countries are incorporated into the model, with POMMES capable of optimising these as well. The equations underlying the model are detailed in the Supplementary Materials.

2.3. Models Coupling

2.3.1. Coupling method

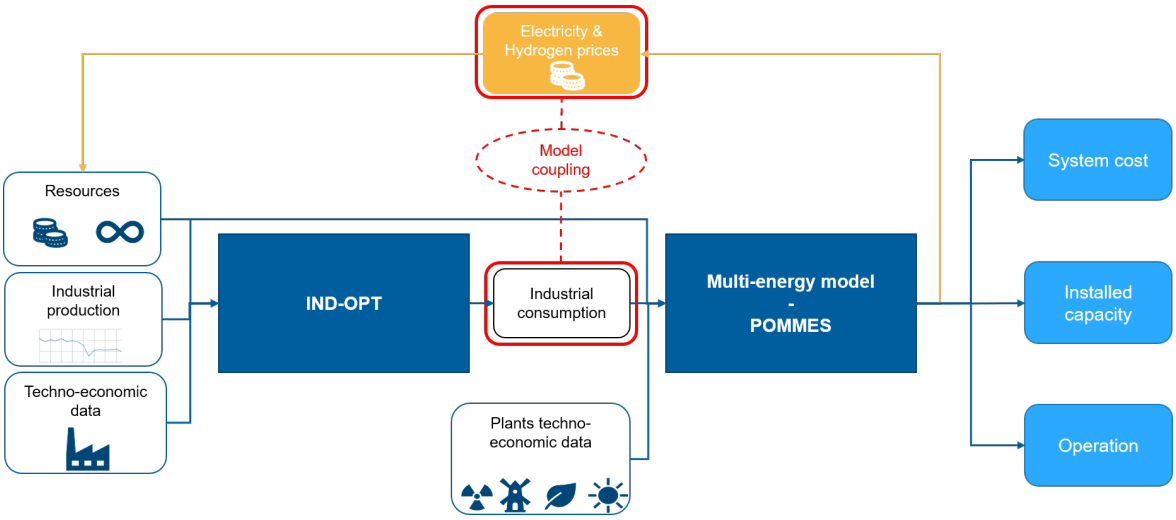


Fig. 3. Models coupling scheme

The models were integrated as depicted in Fig. 3, based on industrial consumption data from IND-OPT and hydrogen and electricity prices from POMMES. The iterative process involves alternating calculations between IND-OPT and POMMES until convergence of consumption and prices is achieved over two successive iterations. The stopping criteria are defined as follows:

$$Stopping\ criteria = \begin{cases} \left| \overline{P}_{€}^{elec,i} - \overline{P}_{€}^{elec,i-1} \right| < 0.1€/MWh \\ \left| \overline{P}_{€}^{hyrogen,i} - \overline{P}_{€}^{hyrogen,i-1} \right| < 0.01€/kg \\ \sum_{y \in Years} \left| C_{TWh}^{elec,y,i} - C_{TWh}^{elec,y,i-1} \right| < 1TWh * Nb\ of\ regions \\ \sum_{y \in Years} \left| C_{TWh}^{hydrogen,y,i} - C_{TWh}^{hydrogen,y,i-1} \right| < 1TWh * Nb\ of\ regions \end{cases}$$

with, at iteration i, $\overline{P}_{€}^{elec,i}/\overline{P}_{€}^{hydrogen,i}$ the average price over the modelled horizons (2030, 2040 and 2050) for respectively electricity/hydrogen, and $C_{TWh}^{elec,y,i}/C_{TWh}^{hydrogen,y,i}$ the industrial consumption form IND-OPT at year y.

2.3.2. Considered countries and data

The regions modelled are displayed in Fig. 4. As a reminder, IND-OPT models industry based on Raillard-Cazanove et al. [14] and therefore only includes the countries shown in yellow in Fig. 4, as well as the steel, cement, chemicals, glass, and e-fuel production sectors for air and sea transport. The associated consumption of electricity and hydrogen is thus used as an input parameter for POMMES. Consumption in other sectors (those not included in IND-OPT, such as residential, transport, etc.) is an exogenous parameter largely based on the Distributed Energy scenario in the TYNDP 2024 report [21]. Detailed consumption assumptions are provided in the Supplementary Materials.

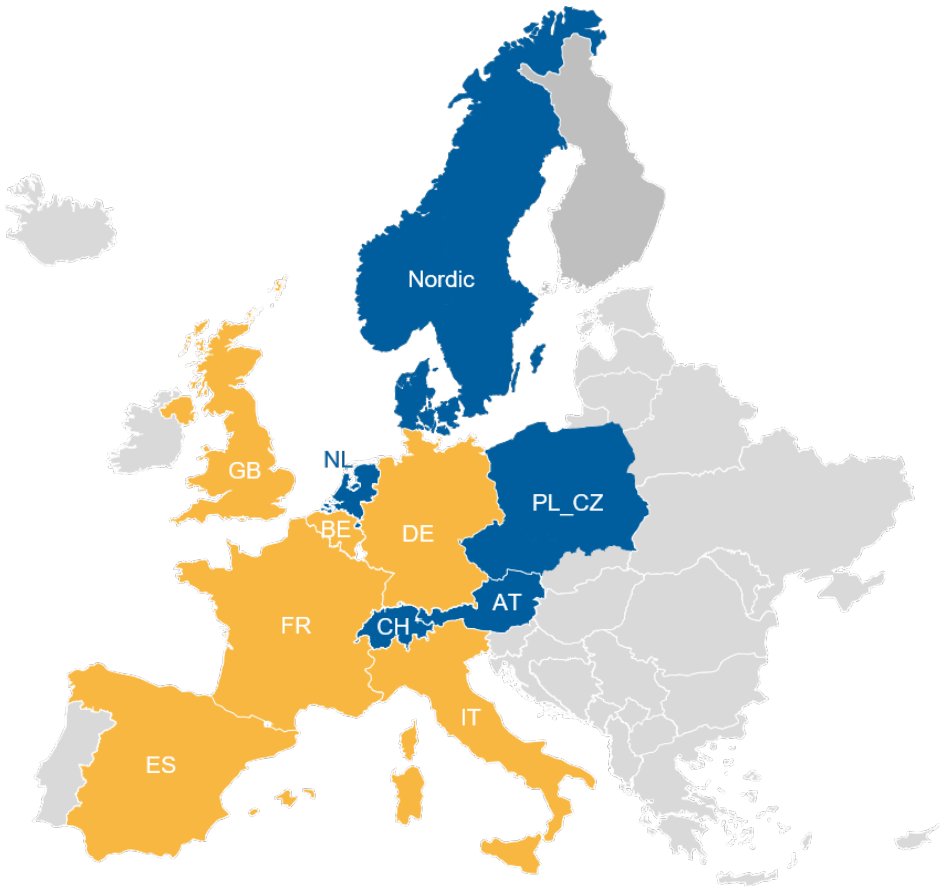


Fig. 4. Considered area nodes — Areas in blue are only considered in POMMES while areas in yellow are included in both models

The technologies for generating and storing electricity and hydrogen are detailed in Appendix B, along with their economic characteristics. For renewable and nuclear energy, the maximum deployment capacities are determined based on data from TYNDP 2024[21], as well as the FES [38] and BP2050[23] reports from ESO and RTE concerning nuclear energy in the UK and France.

The time series used for demand and availability of generation resources are based on 2018 data from the ENTSOE Transparency Plateform[2] and Renewables.ninja[3] (for renewables in particular).

Electricity market prices are obtained from POMMES, derived from the Lagrangians of the adequacy constraint between electricity production and consumption. Country-specific network costs are incorporated during the post-processing stage before implementation in IND-OPT. These network costs, sourced from Eurostat [4] data, are detailed in Table B.4. This electricity network tax is also applied within POMMES to hydrogen production technologies in the form of variable costs weighted by the amount of electricity consumed.

The models can also import hydrogen and methanol (MeOH) from the MENA region, which are treated as exogenous parameters. Building on the work of Lux et al. [39], it is assumed that hydrogen imported from MENA is produced through electrolysis powered by renewable energy. The corresponding import prices are provided in Table 2. Methanol is assumed to be produced using DAC units, with the technical and economic data drawn from Raillard-Cazanove et al. [14], in conjunction with electrolysers.

[2] https://transparency.entsoe.eu/
[3] https://www.renewables.ninja/
[4] https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_205_c__custom_12113170/default/table?lang=en

	2030	2040	2050
Hydrogen (€/kg)	5.1	4.2	3.3
MeOH (€/kg)	0.86	0.72	0.59

Table 2
Hydrogen and MeOH imports from MENA cost assumptions

From the perspective of allocating limited resources, it is assumed that bioenergy is reserved for industry and transport. Consequently, only IND-OPT can utilise it, within the limits defined in Raillard-Cazanove et al. [14], while the SMR/ATR and CCGT/TAC in POMMES rely on natural gas.

2.4. Studied frameworks

2.4.1. Policy scenarios

Three policy scenarios were developed for this study to assess their impact on the industry and the energy system synergies:

- **Reference:** This scenario is based on the Raillard-Cazanove et al. [14] reference scenario, specifically the 300€/tCO_2 in 2050 carbon tax case, which was established as a zero direct emission threshold for the modelled industries.
- **No Fossil 2050:** A variation of the Reference scenario where the models are constrained to achieve a fossil-free system by 2050. This scenario imposes a reduction in fossil fuel consumption starting in 2045, with the requirement that fossil fuel use shall not exceed 10% of 2015 levels. Raillard-Cazanove et al. [14] demonstrated that a complete fossil phase-out driven solely by economic factors is challenging for the industry without the enforcement of additional policies.
- **Low Carbon Tax:** This scenario modifies the Reference scenario by applying a 150€/tCO_2 carbon tax, aligning with the Raillard-Cazanove et al. [14] reference scenario.

2.4.2. Technical and economical variations

In addition to the policy scenarios, we explored techno-economic variations within the energy system. Our analysis begins with a reference case, termed **Central**, which is comprehensively detailed in Section 2.3.2 and Appendix B. A crucial assumption in the Central case is that hydrogen production is treated as a domestic activity for each country, with no cross-border hydrogen exchange. Several other techno-economic scenarios are explored to assess different potential futures:

- **Nuke_Plus:** This scenario assumes that governments increase their equity stakes in nuclear projects, resulting in a reduction of the weighted average cost of capital (WACC) to 4%. Additionally, it considers, as installable by POMMES, 8 GW of new nuclear capacity in Italy and 6 GW in Belgium by 2050. The United Kingdom is allowed to maintain its current nuclear capacity until 2050. The assumptions for Italy and the UK are based on recent political commitments, whereas the assumptions for Belgium are derived from the Electrification scenario of the PATHS2050 project by EnergyVille.
- **Exch_Plus:** This scenario involves doubling the electric interconnection capacities that can be installed by 2050, enhancing cross-border electricity exchanges.
- **ENR_Plus:** In this scenario, the renewable energy capacities that can be installed by 2050 are adjusted to reflect the highest deployment rates observed between 2030 and 2050. This adjustment addresses the observed decline in deployment rates in many countries between 2040 and 2050, as documented in the TYNDP 2024 dataset.
- **ENR_Plus_Plus:** Building on the ENR_Plus scenario, this scenario assumes a WACC of 2% for renewable energy projects, compared to the standard 4%.
- **ENR_Exch_Plus:** This scenario combines the assumptions of ENR_Plus with the enhanced electric interconnection capacities from the Exch_Plus scenario, allowing for both increased renewable energy deployment and greater cross-border electricity exchange.

- **H_2_Exch_Plus:** In this scenario, hydrogen interconnections between countries are allowed, following the projects outlined in the TYNDP 2024 report, facilitating cross-border hydrogen trade.

3. Results

3.1. Energy System Standalone Analysis

The energy system was initially modelled without coupling, meaning industrial consumption from IND-OPT was not considered. The results indicate substantial differences when varying policy scenarios, though less so when considering technical and economic variations. Therefore, in this section, only the "Central" cases are considered across various policy scenarios.

The results (Fig. 5) reveal an electricity system predominantly powered by renewable energy, accounting for at least 85% of total production (storage not included), with a relatively stable nuclear share at 10-11%. Fossil fuel contributions, specifically from gas-fired power plants, account for 3% and 5% of electricity generation in the Reference and Low Carbon Tax scenarios, respectively. In contrast, fossil fuels constituted approximately 37% of electricity production in 2015.

For hydrogen production (Fig. 5), in the Reference scenario the distribution between electrolysis and ATR+CCS technologies is relatively balanced. A transition away from fossil fuels assigns a significant role to imports in ensuring supply. Naturally, a fossil-free approach implies the exclusion of ATR and SMR processes in POMMES results, which would necessitate a greater emphasis on storage capacity to manage the variable output from electrolysis. Similarly, in a fossil-free scenario, the electricity system replaces natural gas power plants with hydrogen-powered ones, significantly increasing the required hydrogen production to meet approximately 2% of Europe's electricity demand.

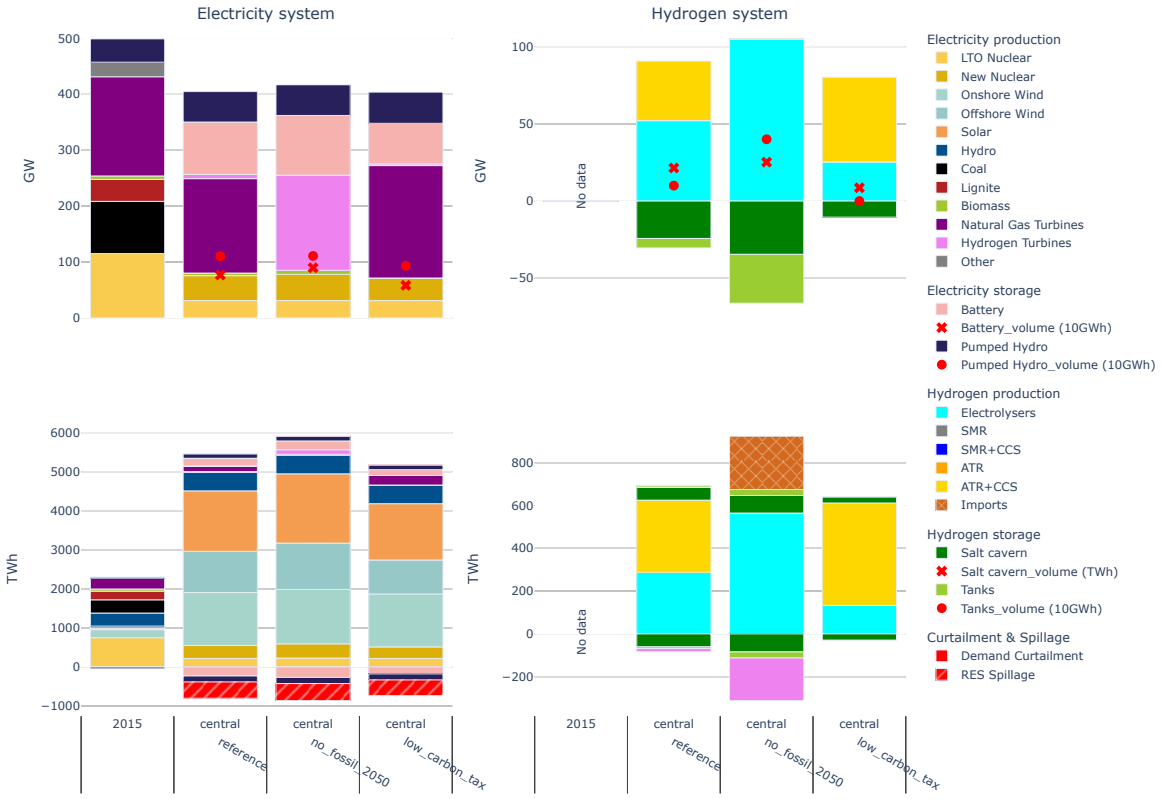


Fig. 5. POMMES Standalone - Electricity and hydrogen system installed capacity (only distpatchables for electricity) and production per technology in 2050

Concerning electricity and hydrogen prices, the results presented in Fig. 6 reveal significant territorial disparities, with Spain and France consistently benefiting from lower prices. In contrast, Italy and Germany exhibit prices above the EU-15 average.

However, these prices are notably affected by carbon taxes. For most countries, a reduction by 50% in the carbon tax leads to a decrease in electricity prices of around 5-6€/MWh. It is also noteworthy that a system devoid of fossil fuels results in higher prices—approximately 3€/MWh for electricity and 0.32€/kg for hydrogen at the EU-15 level. This increase can be attributed to the No Fossil 2050 scenario leading to a replacement of gas-fired power plants by hydrogen-fired power plants and an increased reliance on hydrogen imports, thereby driving up costs.

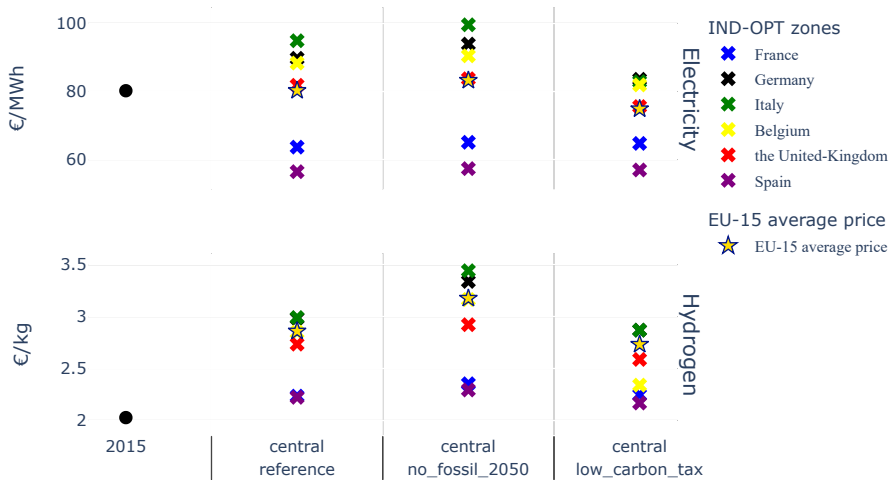


Fig. 6. POMMES Standalone - Average electricity and hydrogen price in 2050

3.2. Impact of additional industrial energy consumption

When IND-OPT is integrated with POMMES, it results in additional electricity and hydrogen consumption that POMMES must address. As shown in Fig. 7, the increased electricity demand requires a 5-8% rise in electricity generation, primarily met through wind, solar, and nuclear energy sources.

Regarding hydrogen production for Central scenarios, the demand driven by IND-OPT necessitates a 29-41% increase in hydrogen generation. In scenarios excluding "No Fossil 2050", more than 74% of this additional production is supplied by ATR+CCS technologies. If we look at how the additional hydrogen demand is met when more renewable energies are authorised, we can see that electrolysis plays a much greater role in meeting this additional demand.

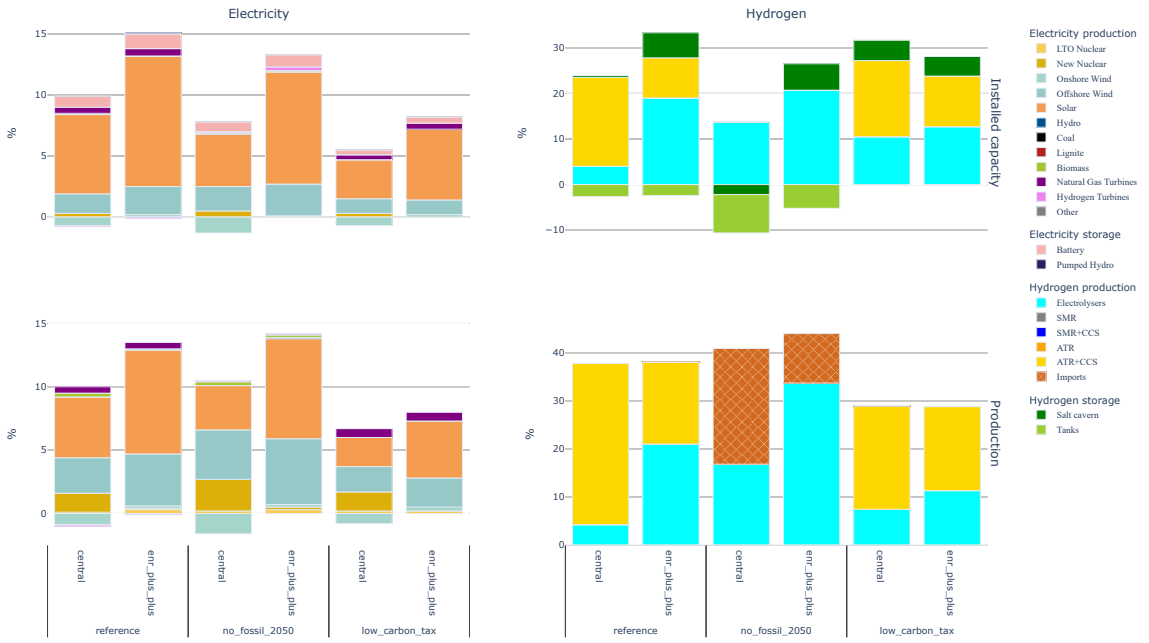


Fig. 7. Impact of POMMES-IND-OPT coupling on POMMES Standalone installed capacity and production results in 2050

Regarding prices (Fig. 8), the additional demand from the countries modelled in IND-OPT leads to an increase in both electricity and hydrogen prices in these countries, with varying impacts depending on the nation. Consequently, the average price in the EU-15 rises by 3-5€/MWh for electricity and 0.08-0.14€/kg for hydrogen. Spain appears as the most affected, experiencing an increase of up to 14€/MWh for electricity and 0.66€/kg for hydrogen. However, it seems that Spain's ability to install more low-cost renewable energy is significantly limiting the rise in prices.

This greater increase in costs observed in Spain can be explained by several factors. Firstly, the onshore wind potential had already been fully exploited before the coupling of the models. As a result (see Fig. A.20), it is primarily solar energy, combined with batteries and a higher reliance on imports from France, that meets the additional electricity demand. This leads to a rise in electricity prices, which causes the additional hydrogen demand to be met by ATR+CCS, provided fossil fuels are allowed by the scenario. However, if Spain has the opportunity to install additional low-cost renewable energy (mainly solar, as the potential had not been fully reached), the increase in electricity prices is less significant. Consequently, the share of hydrogen production from electrolysers increases, which helps limit the rise in costs within the country.

However, these increases in prices should be viewed in context, as Spain, along with France, continues to have the lowest prices among the countries modelled by IND-OPT, as illustrated in Fig. 14.

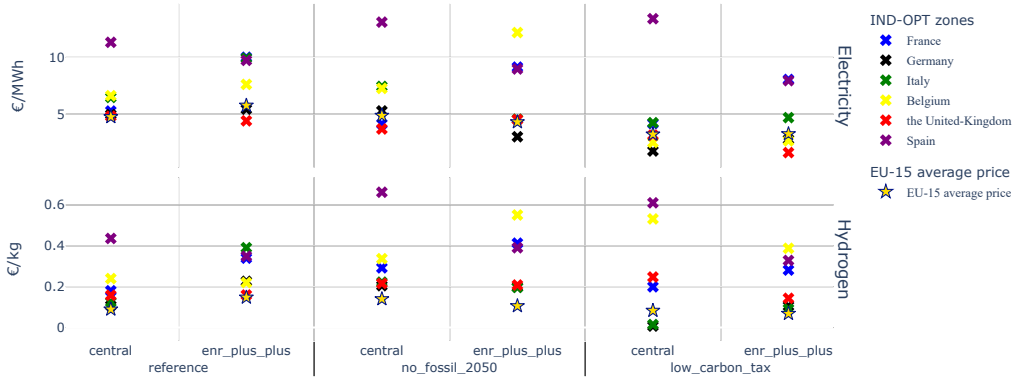


Fig. 8. Impact of POMMES-IND-OPT coupling on POMMES Standalone electricity and hydrogen prices in 2050

3.3. Coupled Models: Integrated Results

The impact of policy scenarios on industrial consumption is more significant than that of the techno-economic scenarios, which lead to only marginal changes. Therefore, Fig. 9 presents the heavy industry consumption modelled by IND-OPT for the central case only across the three policy scenarios. Detailed information regarding the techno-economic scenarios impact is provided in Fig. A.16.

A general increase in natural gas consumption is observed in scenarios permitting fossil fuel use, particularly for the production of MeOH in the chemical sector. Naturally, a reduction in the carbon tax leads to a higher share of fossil fuels in industrial consumption. However, it is noted that phasing out fossil fuels, as in the ”No Fossil 2050” scenario, requires an increased reliance on methanol imports.

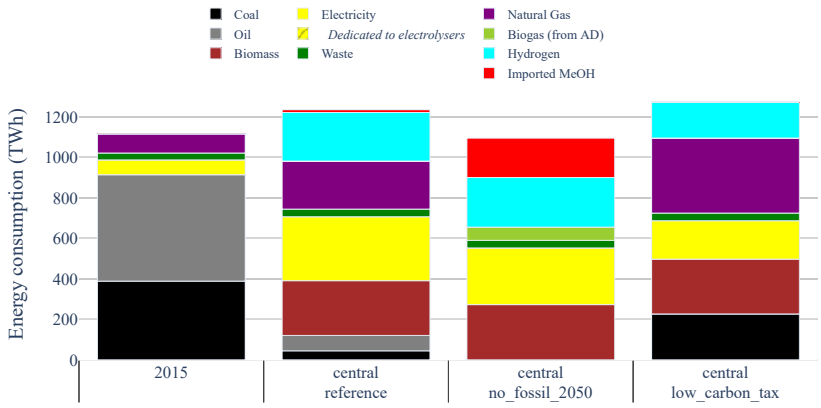


Fig. 9. Heavy industry consumption in EU-5+1 from IND-OPT in 2050 — Electricity and hydrogen demands are met by POMMES

While Fig. 14 shows that a lower carbon tax results in electricity and hydrogen prices being reduced by 5-7 €/MWh and approximately 0.1 €/kg, respectively, these reductions are insufficient to drive an increase in electricity and hydrogen consumption compared to the Reference scenario. Indeed, the carbon tax of 150 €/tCO2, as opposed to 300 €/tCO2 in the Reference scenario, has a more significant impact on consumption.

Regarding the electricity system, the results reveal, as in Section 3.1, an electricity system predominantly driven by renewable energy sources and, to a lesser extent, nuclear power. The total installed capacity of dispatchable power and storage, shown in Fig. 10, decreases slightly compared to 2015, despite electricity production being 2 to 3 times higher (Fig. 11). While scenarios with increased interconnections or nuclear energy show a reduction in thermal capacities (gas or hydrogen), scenarios with higher shares of renewable energy lead to a decline in nuclear power, with thermal plants used to compensate for intermittency. Naturally, the Nuke_Plus scenarios result in an additional 35 to 48 GW of installed nuclear capacity.

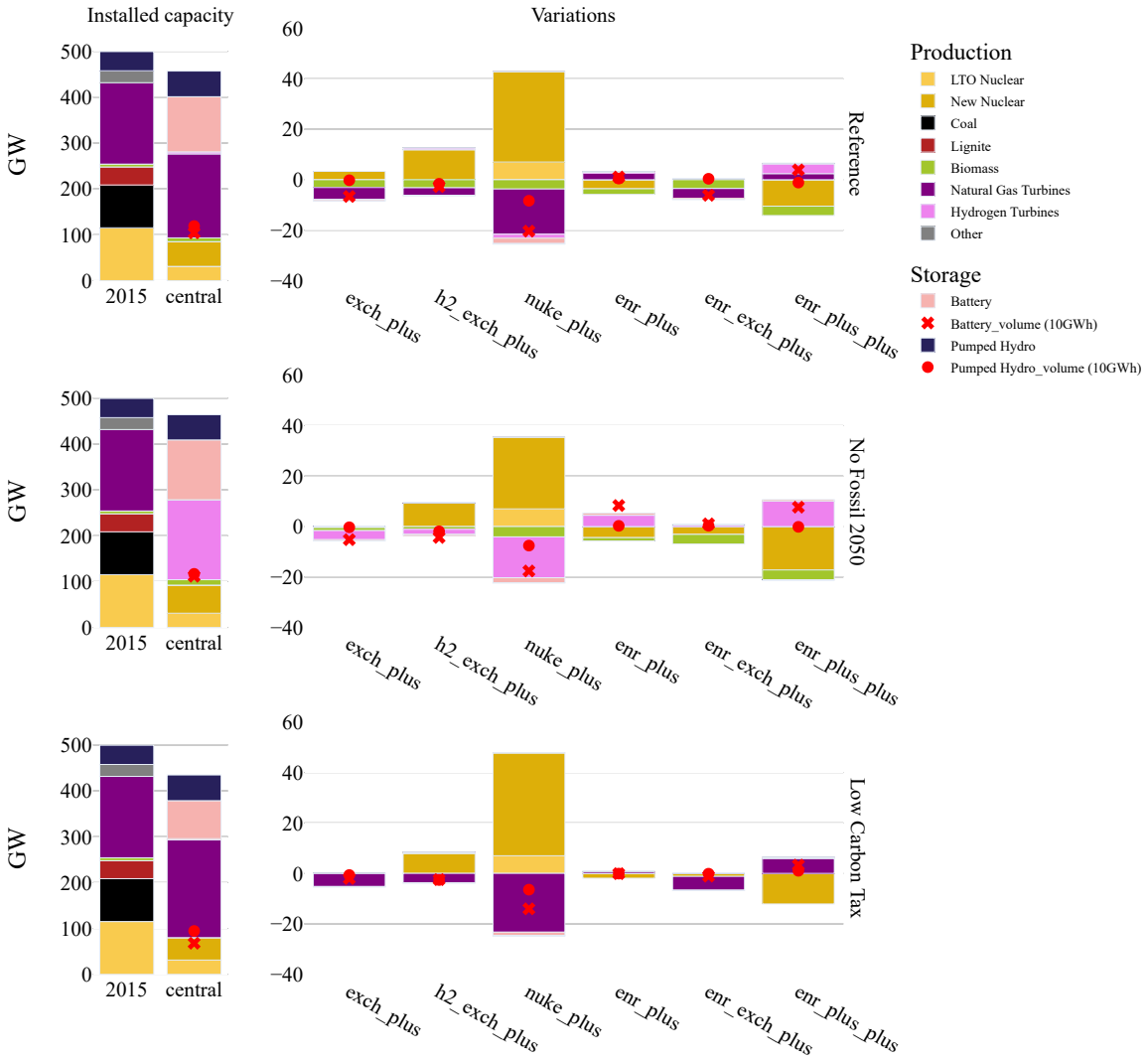


Fig. 10. EU-15 electricity dispatchable installed capacity and variations in 2050

As depicted in Fig. 11, these outcomes also impact electricity generation, where nuclear energy substitutes renewable energy generation (as well as their spillage) and vice versa. In the ENR_Plus_Plus scenario (with a lower capital

cost for renewable energy), new nuclear power becomes significantly less competitive, reducing both its installation and production. This, however, leads to an increase in spillage, although a slight reduction in fossil fuel production is also observed. Nonetheless, the H_2_Exch_Plus scenario, which facilitate hydrogen interconnections, benefit both nuclear and renewable energy sources.

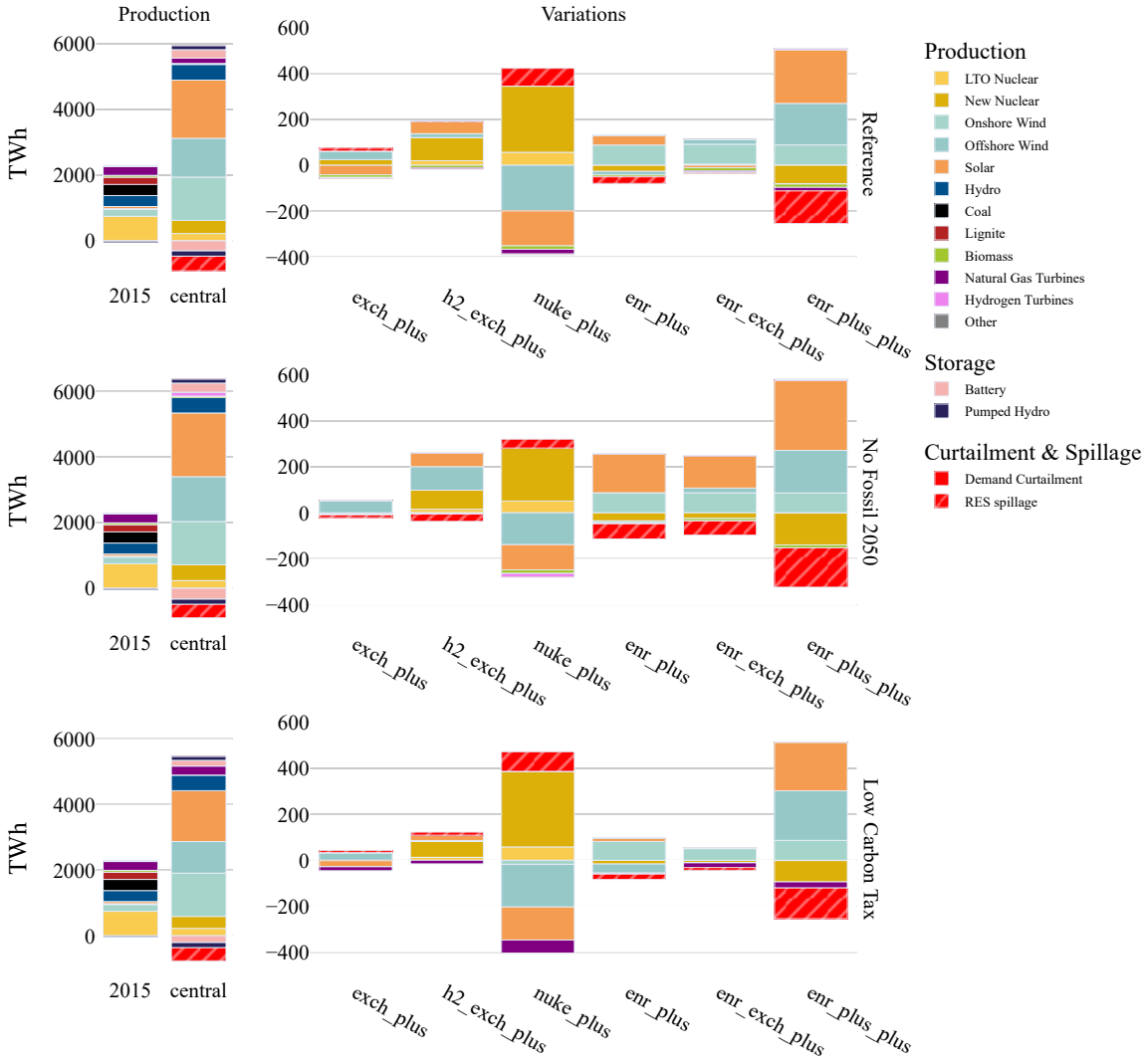


Fig. 11. EU-15 electricity production and variations in 2050

For hydrogen production, Fig. 12 shows that electrolyser capacities in the "Central" cases range between 35 and 128 GW. The installation of electrolysers appears to be correlated with the deployment of storage facilities. Fig. 13 highlights a substantial reliance on hydrogen imports in the No Fossil 2050 scenarios. However, most techno-economic scenarios help reduce both fossil-based hydrogen production and imports.

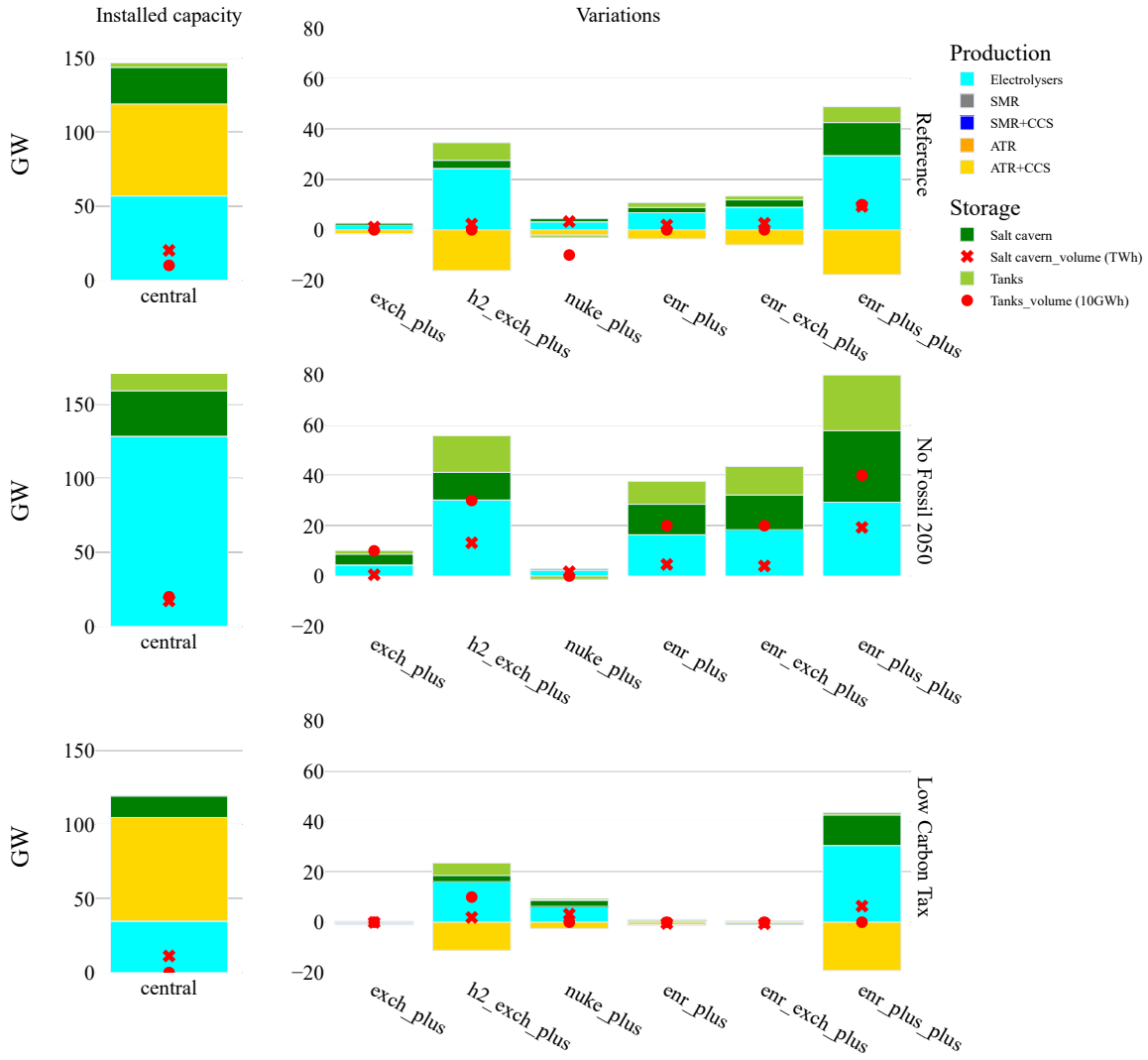


Fig. 12. EU-15 hydrogen installed capacity and variations in 2050

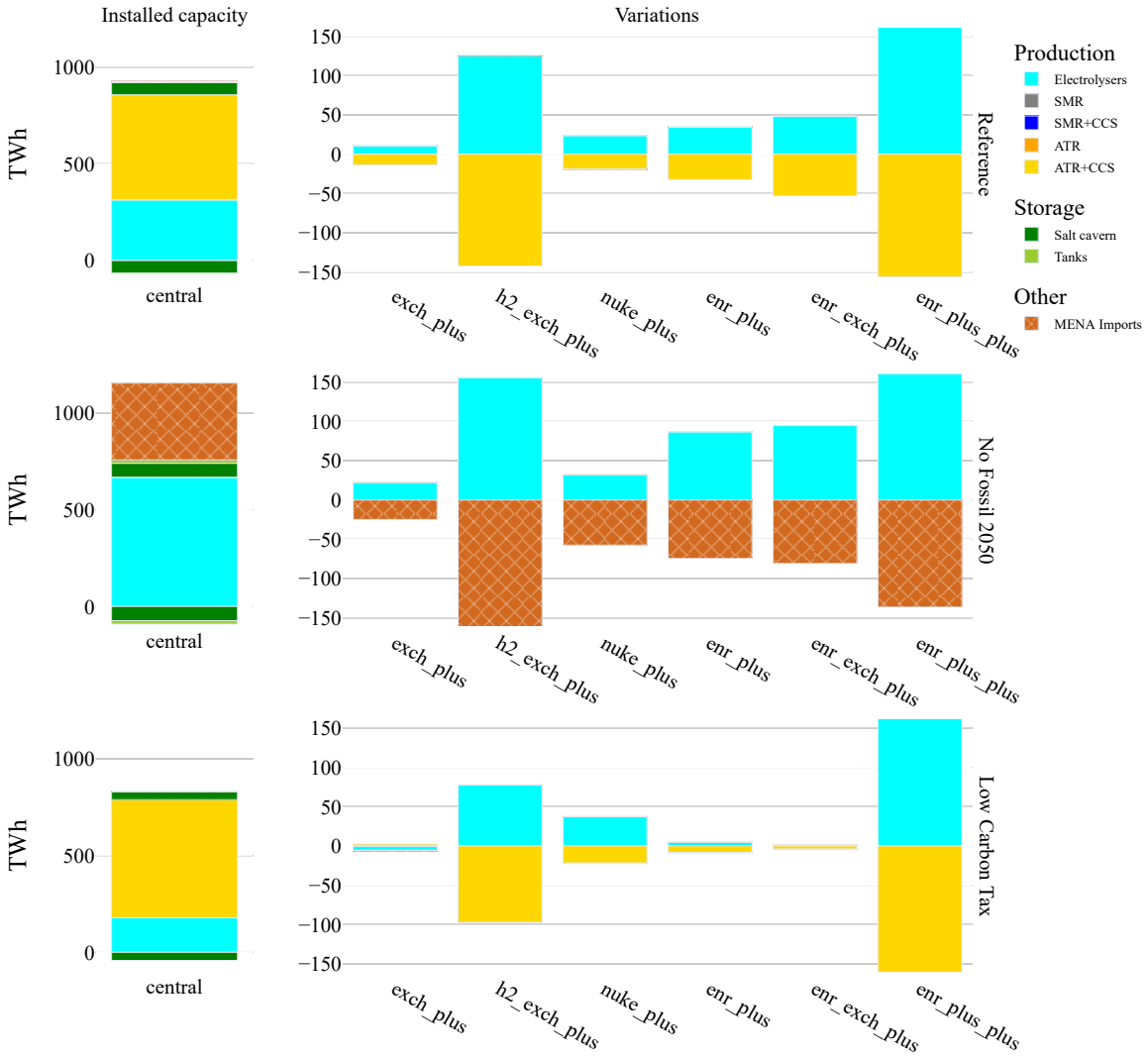


Fig. 13. EU-15 hydrogen production and variations in 2050

Similar to Section 3.1, electricity and hydrogen prices, illustrated in Fig. 14, exhibit significant variation depending on the country. The Nuke_Plus and ENR_Plus_Plus scenarios result in the lowest prices. The results indicate that, with the exception of the No Fossil 2050 scenario, blue hydrogen constitutes a substantial proportion of production (Fig. 13). Regional disparities in production (Fig. A.18) are mirrored in hydrogen prices and are a direct consequence of differences in regional electricity prices (Fig. 14).

The addition of a hydrogen network in the H_2_Exch_Plus techno-economic scenario slightly reduces hydrogen prices but, more importantly, brings the prices across countries closer to a common value. For instance, in the Reference scenario, countries such as France and Spain, with hydrogen prices of 2.41€ and 2.66€/kg respectively, see prices increase to 2.83€ and 2.88€/kg.

While Fig. 6 indicates that, in the Central cases, a system without fossil fuels results in an increase of approxi-

mately 3€/MWh for electricity and 0.32€/kg for hydrogen, Fig. 14 demonstrates that these values remain unchanged when the additional industrial consumption is accounted for.

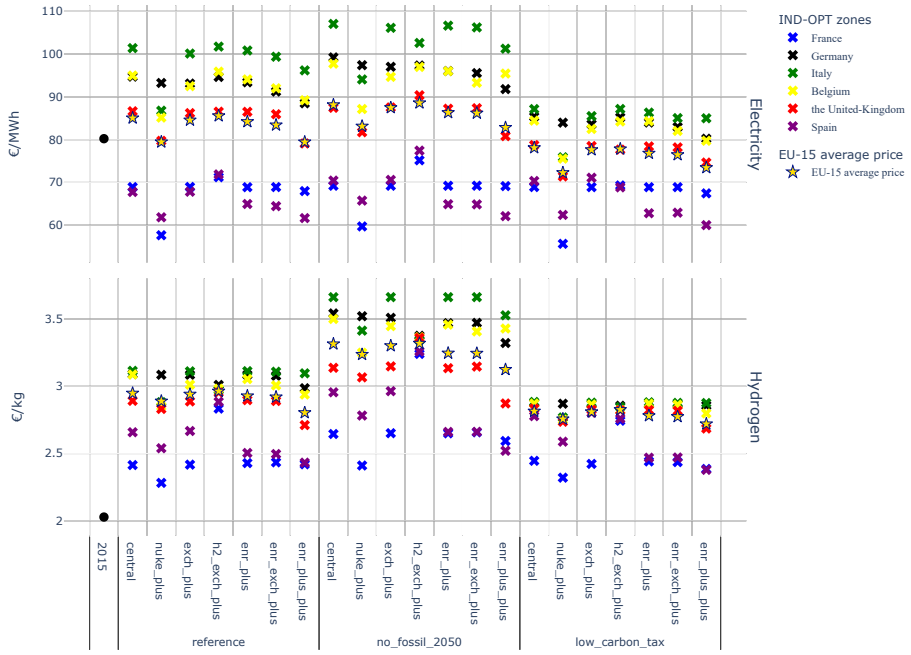


Fig. 14. Average electricity and hydrogen price in 2050

Fig. 15 illustrates the costs of the electricity and hydrogen system modelled by POMMES for 2050, according to the different scenarios and their impact on demand. It is evident that demand for electricity and hydrogen from IND-OPT varies significantly across both the policy scenarios and their respective techno-economic variation scenarios. The techno-economic scenarios that achieve the greatest cost reductions are those that lower the weighted average cost of capital (WACC) for nuclear energy (Nuke_Plus) and renewable energy (ENR_Plus_Plus) to 4% and 2%, respectively. Although the No Fossil 2050 scenarios tend to be more expensive than others, the Nuke_Plus and ENR_Plus_Plus scenarios still result in system costs that are considerably lower than in the Reference Central scenario.

It is worth noting that, although Fig. 14 demonstrates that the addition of a hydrogen network using the H_2_Exch_Plus scenario has no effect on average prices at the European level, Fig. 15 shows a reduction in the weighted system cost of between 0.4% and 1.9% compared to the Central cases.

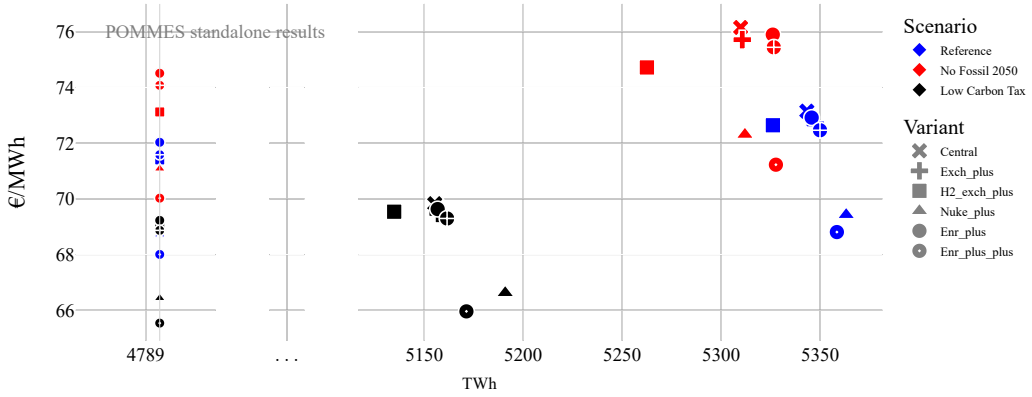


Fig. 15. Electricity and hydrogen system overall cost in EU-15 in 2050 versus demand per scenario

4. Discussion

4.1. Results implication

The results of this study provide important insights into potential future compositions of the European energy and hydrogen systems, particularly in the context of increased industrial low-carbon energy consumption. The analysis emphasises the substantial role of renewable energy, accounting for at least 85% of electricity production in 2050, and nuclear energy providing 10-11% of the supply. These findings reflect a significant shift from the 2015 energy mix, where fossil fuels made up 37% of electricity generation in EU-15, highlighting the potential for a highly decarbonised system. However, the industrial sector's energy demands pose significant challenges to achieving this transition cost-effectively.

The integration of additional industrial energy consumption (from the IND-OPT model) represents a critical factors affecting future energy systems. When IND-OPT is incorporated, electricity demand in EU-15 increases by 5-8%, and hydrogen demand rises dramatically by 29-41%, depending on the scenario, although IND-OPT only considers 6 countries. This significant increase in consumption has major implications for both energy generation and infrastructure. To meet this growing demand, the system must rely heavily on renewable and nuclear generation, requiring further expansion of wind and solar capacities alongside hydrogen production technologies. The costs associated with these adjustments vary considerably across different scenarios, with some scenarios achieving notable cost reductions by lowering the WACC for nuclear and renewable energy, while others, particularly those phasing out fossil fuels, tend to be more expensive.

The impact of industrial consumption is not limited to energy generation but extends to energy prices, particularly in electricity and hydrogen markets. The increased demand driven by industries leads to higher prices, with notable variations across regions. For instance, Spain and France, while continuing to enjoy some of the lowest prices, experience sharp increases in electricity prices. In Spain, prices rise by as much as 14€/MWh, while hydrogen prices increase by 0.66€/kg due to the industrial sector's growing demand. This shows that even countries traditionally benefiting from lower prices are not insulated from the pressures of increased industrial consumption.

These results underscore the vital role of industry in shaping energy system outcomes and highlight the challenges of balancing decarbonisation goals with the energy needs of a changing industrial sector. The findings suggest that policymakers must address the industrial sector's future energy needs through targeted interventions, expanding renewable capacities, and ensuring sufficient hydrogen infrastructure to meet demand. Without careful planning, the energy-intensive demands of industry could threaten the cost-effectiveness of the transition and exacerbate regional price disparities. Indeed, the results also show that the policy scenarios have a much greater impact on the industry and the energy systems than the techno-economic scenarios.

In scenarios such as No Fossil 2050, where fossil fuels are phased out entirely, industrial demand significantly increases the reliance on electrolytic hydrogen production and imports. The transition away from fossil fuels would necessitate a shift to electrolysis-based hydrogen production, raising concerns about the availability of sufficient storage and infrastructure to handle the variability in renewable electricity generation. Additionally, the required expansion in hydrogen production capacity, particularly from ATR+CCS technologies, underscores the technical and economic hurdles that must be addressed to meet industrial demand.

The analysis of hydrogen networks, such as in the H_2_Exch_Plus scenario, reveals important insights into how industrial consumption impacts regional price dynamics. While hydrogen networks can help reduce price disparities between countries, not all nations benefit equally. The price convergence observed in the H_2_Exch_Plus scenario results in rising hydrogen prices for countries like France and Spain, which in the Central techno-economic scenario case had lower prices. This demonstrates that while hydrogen networks promote integration, they can also diminish the competitive advantage for countries with lower energy costs, potentially leading to increased costs for industrial consumers in these regions.

Overall, the results indicate that the industrial sector's growing energy demands can be a crucial determinant in the success of Europe's energy transition. Achieving a sustainable, low-carbon energy system will require not only an expansion of renewable and hydrogen technologies but also a clear strategy for managing the energy-intensive demands of industries. The trade-offs between decarbonisation, affordability, and regional price disparities will need to be carefully balanced, particularly in regions with substantial industrial activity. Policymakers must consider these factors as they design strategies for the energy transition, ensuring that both the energy and industrial sectors can adapt to the challenges of a decarbonised future.

4.2. Comparison with literature

While our study gives an economically driven substantial role to renewable energy, accounting for at least 85% of electricity production in 2050, Fleiter et al. [34] finds a share of 87-88%.

Regarding hydrogen demand, our results range from 22 to 30 Mt, depending on the scenario, which aligns with the lower end of the range reported by Tarvydas [7], varying between 19 and 60 Mt. The difference with the upper range can be explained by the inclusion of hydrogen use in buildings in some scenarios, which we do not account for, as well as the fact that Tarvydas [7] considers the whole of Europe, while we focus on only 15 countries.

The inclusion of a hydrogen network in our analysis results in a reduction in weighted system costs of between 0.4% and 1.9%. In comparison, Neumann et al. [31] report a decrease in total system costs ranging from 1.6% to 3.4%. This difference could stem from several factors. Firstly, Neumann et al. [31] do not account for extra-European imports. Secondly, their hydrogen network design differs from ours; for instance while they allow for an interconnection between France and Italy, our model, based on TYNDP data, allows the construction of a pipeline between Spain and Italy, which Neumann et al. [31] do not consider. Finally, they exclude nuclear energy from their analysis, which we have seen substantially impacts electricity and hydrogen prices.

Similar to our study, Kountouris et al. [28] emphasise the synergies between SMR/ATR with carbon capture and electrolysers. However, in their reference scenario H2E, electrolysers produce the majority of hydrogen, nearly 60%, whereas our study finds the opposite. This discrepancy is due to different techno-economic assumptions. Specifically, Kountouris et al. [28] use higher electrolyser efficiency assumptions (74% in 2050) compared to ours (65%). It appears they employed higher heating value (HHV) efficiency, while we used lower heating value (LHV). Moreover, their 2020 efficiency figure of 65.6% differs from their source's 57.7%, suggesting they might not have included Balance of Plant consumption.

Additionally, the efficiencies for fossil-based hydrogen in Kountouris et al. [28] are closer to our assumptions for SMRs than for ATRs. However, ATRs with carbon capture are ultimately less costly than their SMR counterparts. Despite these differences, both studies highlight the presence of synergies between electrolysers and SMRs/ATRs.

Another result that can be linked to existing literature is the impact of a hydrogen network on the spatial distribution of hydrogen production facilities, as illustrated in Fig. A.18. Similarly to the findings of Fleiter et al. [34], our study shows Germany and Belgium importing all of their hydrogen, significantly affecting their neighbouring countries. The main difference between Fleiter et al. [34] and our study lies in the broader range of countries included in their analysis, as well as their assumption that hydrogen production is entirely based on electrolysis. In contrast, we allow for blue hydrogen production, and even grey hydrogen if economically viable.

The case study by Fleiter et al. [34] aligns with our "No Fossil 2050" policy scenario in its H2_Exch_Plus variation. Although Fleiter et al. [34] does not provide an economic analysis, their scenario leads, in our study, to an increase of 2.9% in weighted system costs, 3.5% in electricity prices, and 12.1% in hydrogen prices compared to the Reference scenario, which permits the use of fossil fuels.

4.3. Limitations and perspectives

A limitation of this study pertains to the POMMES model, for which only a single weather time series (2018) was utilised. While incorporating multiple weather time series through a stochastic approach would offer more robust estimations, it would significantly increase computational demands and time. Future work could explore such an approach. Additionally, as a perspective, a comparison between the IND-OPT-POMMES model results, which integrate both industrial and energy systems, and a full POMMES model could be conducted. The full POMMES model would remove the intermediary layer that links electricity and hydrogen prices between the energy system and industry, allowing industry to be modelled as an integrated component of the overall system. This contrasts with the current approach, where industry is optimised for its own benefit rather than as part of a holistic energy system, and would require further modifications to POMMES.

Regarding the hydrogen network and imports from the MENA region, the imports are treated as exogenous, without considering ramping or capacity constraints. In this model, a country like Poland is assumed to import hydrogen directly from MENA, while in reality, such imports would likely flow through France, Spain, and Italy via pipelines. A more accurate representation would model MENA as a node that produces and transmits hydrogen to Europe, respecting pipeline capacity constraints.

Another limitation of this study is that the POMMES model only allows for the consumption of natural gas in SMR/ATR and even CCGT/TAC processes. This choice stems from the default allocation of biogas production to the industrial sector. Consequently, the IND-OPT model allows the use of biogas in its industrial processes and for the portion of hydrogen production that it manages internally. Future research could explore how the results evolve, particularly in the No Fossil 2050 policy scenario, when the use of biogas is permitted within the POMMES framework.

A potential improvement in modelling could involve modifying POMMES to allow for the flexibility of demand from future electric vehicles. Indeed, the integration of electric vehicles into the power system appears to be a well-researched topic [40–46], with TSO reports, such as those from RTE [22, 23], even incorporating Vehicle-to-Grid (V2G) technology in their prospective studies.

Finally, this study does not account for the potential negative impact of decarbonising heavy industry on competitiveness, particularly with regard to the associated costs. Cooper et al. [47] demonstrated that decarbonisation in the UK could raise the prices of manufactured goods by 10-15%. In such a scenario, two outcomes are possible: either industries relocate, leading to a reduction in domestic energy consumption, or competitiveness is maintained through some form of external support [47]. However, this issue lies beyond the scope of the present study.

5. Conclusion

A model of key heavy industry sectors in six major European countries was coupled with a model of the European energy system. The aim of this coupling was to assess the impact of electricity and hydrogen consumption by these key industrial sectors on the energy system under various policy and techno-economic scenarios. The findings show that policy scenarios lead to the greatest differences in the results. The study highlights synergies between energy system planning and heavy industry. Specifically, the inclusion of industrial electricity and hydrogen consumption leads to an increase in electricity and hydrogen prices, with significant disparities between countries. Additionally, phasing out fossil fuels results in greater price increases and a higher reliance on hydrogen and methanol imports.

While scenarios with lower carbon taxes lead to lower electricity and hydrogen prices, these reductions are not sufficient to increase industrial consumption. In fact, lower carbon taxes make continued use of fossil fuels more attractive to industries.

The results also show that introducing a hydrogen network helps to reduce price disparities between countries but diminishes the competitiveness of countries that would otherwise benefit from lower prices in the absence of such a network.

As well, the additional electricity and hydrogen consumption in the energy system is primarily met by increased renewable energy installations in the power sector. In the hydrogen sector, except in scenarios involving the complete phase-out of fossil fuels, most of the additional consumption is met through fossil-based hydrogen production with carbon capture. The study thus demonstrates synergies between electrolytic hydrogen and blue hydrogen, which help to reduce overall hydrogen prices. These synergies appear as essential for achieving competitive hydrogen production prices.

CRediT author statement

Quentin Raillard--Cazanove: Conceptualization, Methodology, Software, Writing – original draft. **Robin Girard:** Supervision, Conceptualization, Writing - Review & Editing. **Thibaut Knibiehly:** Software, Writing - Review & Editing.

Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work the authors used ChatGPT-4 in order to improve readability and language. After using this tool/service, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

Appendix A. Supplementary results

Appendix A.1. Industry consumption results

Fig. A.16 shows the impact of the techno-economic scenarios on the central scenarios presented in Fig. 9. As stated in Section 3.3, the variations due to the techno-economic scenarios on the final consumption of the sectors modelled by IND-OPT are marginal, of the order of 3% maximum. The policy scenarios, on the other hand, have a huge impact on technological choices and therefore on consumption.

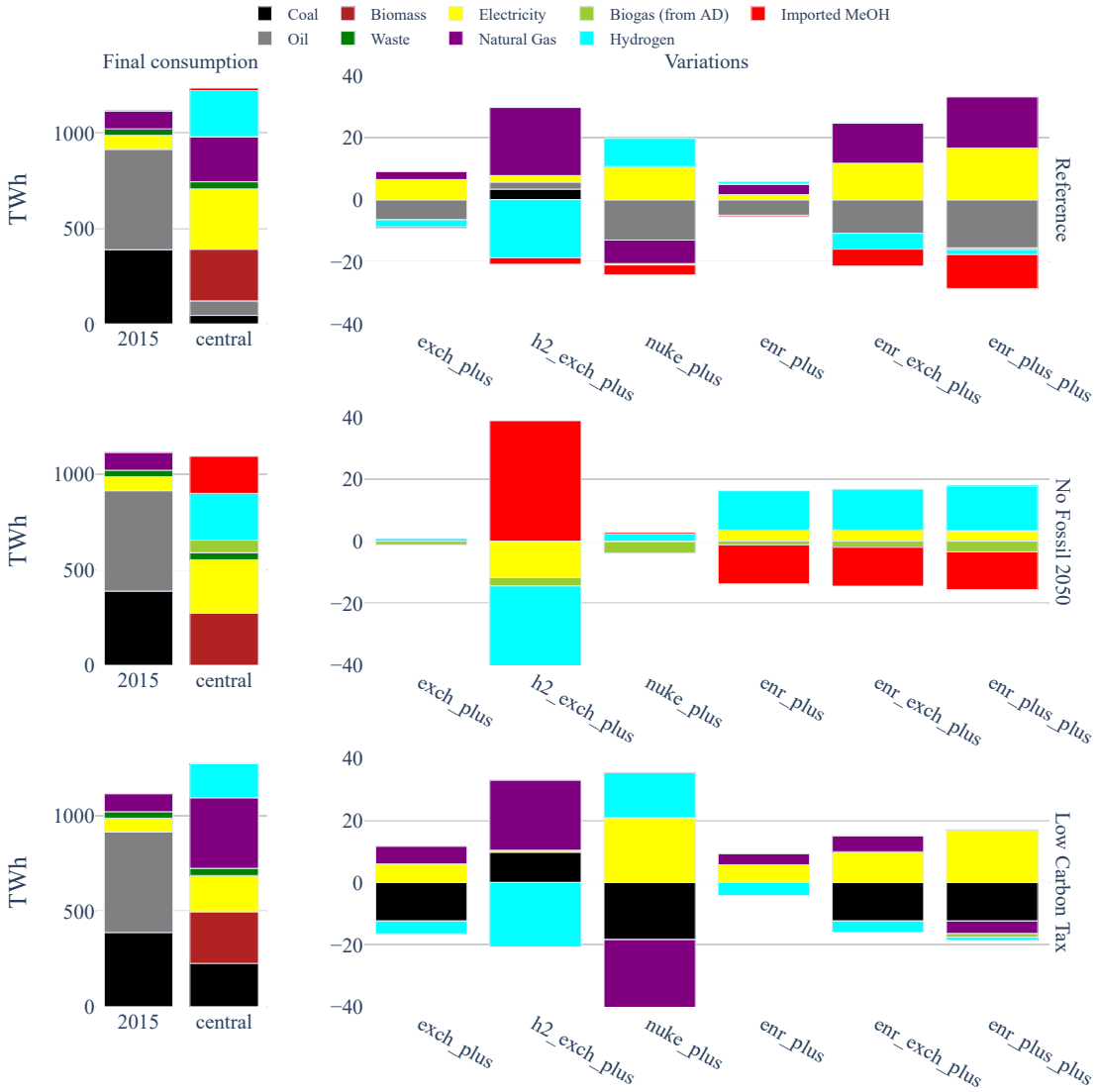


Fig. A.16. Heavy industry consumption and variations in EU-5+1 from IND-OPT in 2050 — Electricity and hydrogen demands are met by POMMES

Fig. A.17 illustrates the origin of hydrogen consumed in the sectors modelled by IND-OPT. To construct this figure, data from hydrogen production in POMMES and production managed by IND-OPT (notably for gasification or MeOH production) are cross-referenced. Additionally, IND-OPT can operate some ATR+CCS plants, which can also consume biogas produced from biomass gasification. In the No Fossil 2050 scenario, the ATR+CCS units operate entirely on biogas. The figure compares results in a scenario where IND-OPT entirely manages hydrogen production, based on electricity prices derived from the results presented in Section 3.1 (partial coupling).

Similar to Fig. 13, under coupled models, nearly all scenarios lead to a reduction in ATR+CCS production as well as a decrease in imports. In the EU-5+1 case, hydrogen imports, which typically come from the MENA region, can also come from neighbouring countries like Norway in the H_2_Exch_Plus scenario. Likewise, except for the No

Fossil 2050 scenario, the techno-economic variations largely replace SMRs for MeOH production with eSMRs that consume electricity rather than gas for heat production. This is due to the significant impact on electricity prices of the techno-economic scenarios.

The difference between partial and full coupling is explained by the fact that IND-OPT, with its annual time step, does not manage supply-demand balance at the hourly level, a function that POMMES handles. This leads to higher costs in POMMES due to the inclusion of storage solutions. As a result, when operated independently, IND-OPT overestimates the competitiveness of electrolysers. This is a known limitation of IND-OPT, as identified in Raillard-Cazanove et al. [14], further emphasising the benefits of coupling IND-OPT with POMMES, as showed in this study.

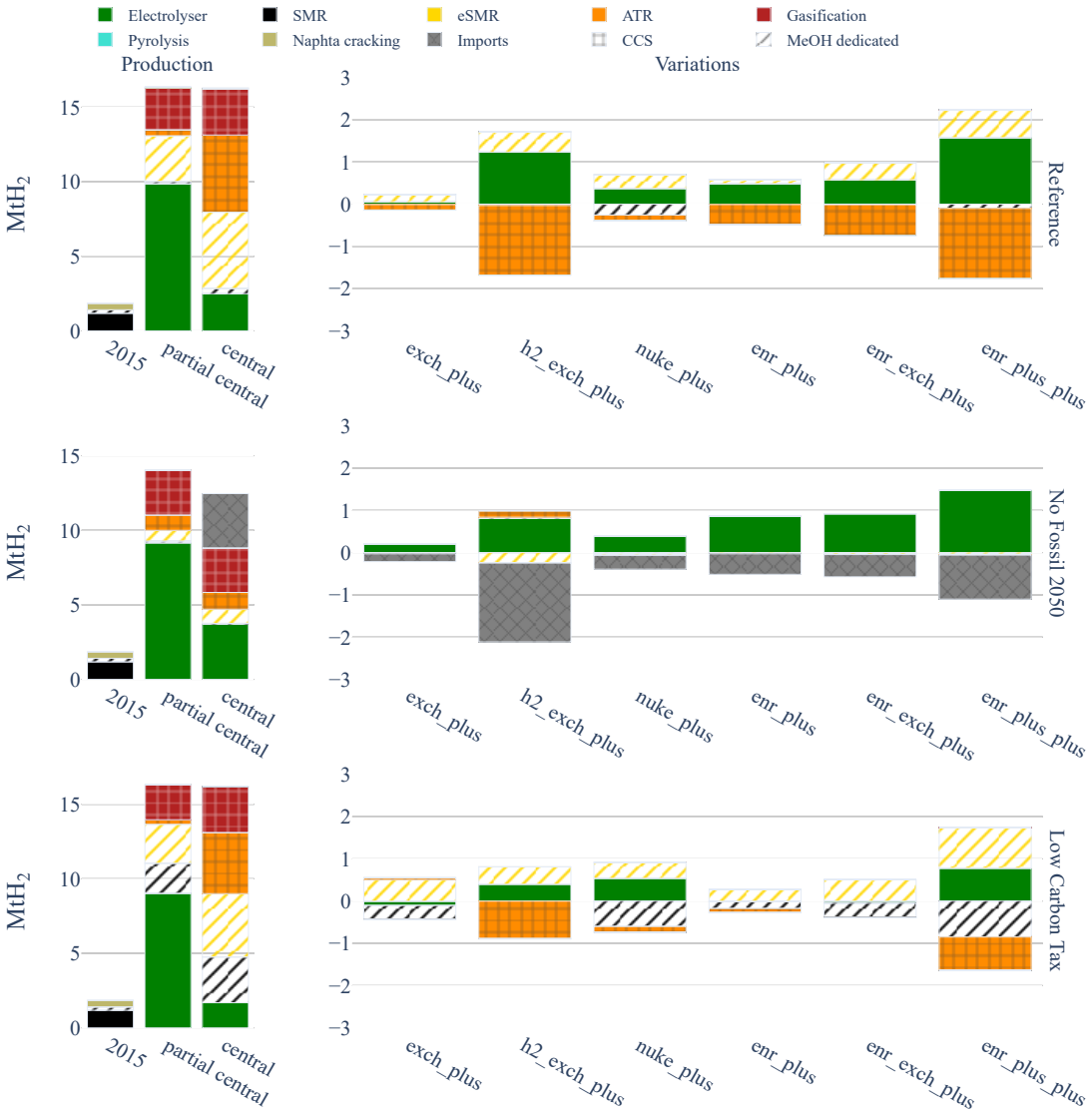


Fig. A.17. Heavy industry hydrogen origin in EU-5+1 from IND-OPT in 2050

Appendix A.2. Hydrogen network impact

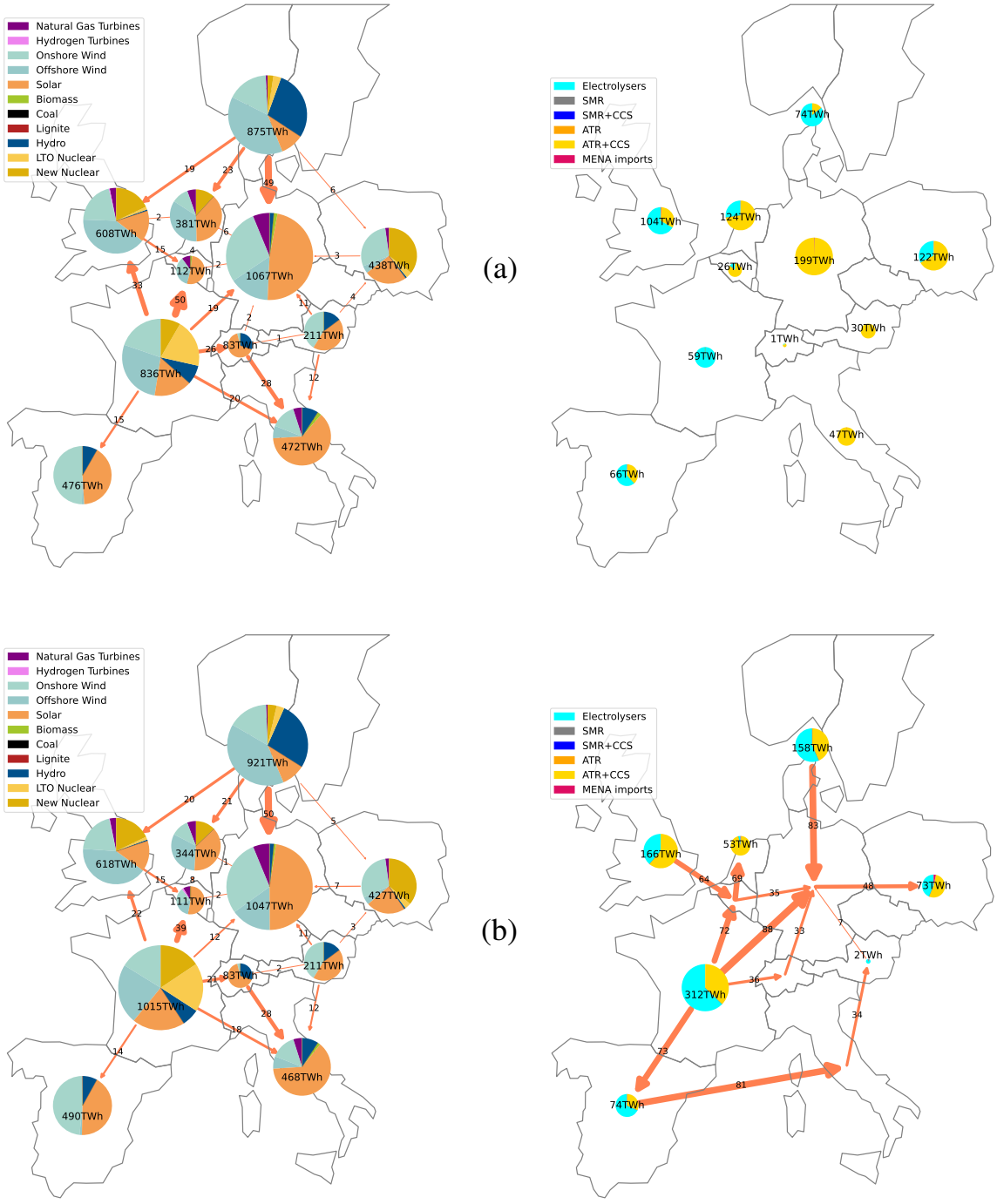


Fig. A.18. Reference Central (a) and H_2_Exch_Plus (b) scenarios electricity and hydrogen systems in 2050

Appendix A.3. Model coupling impact

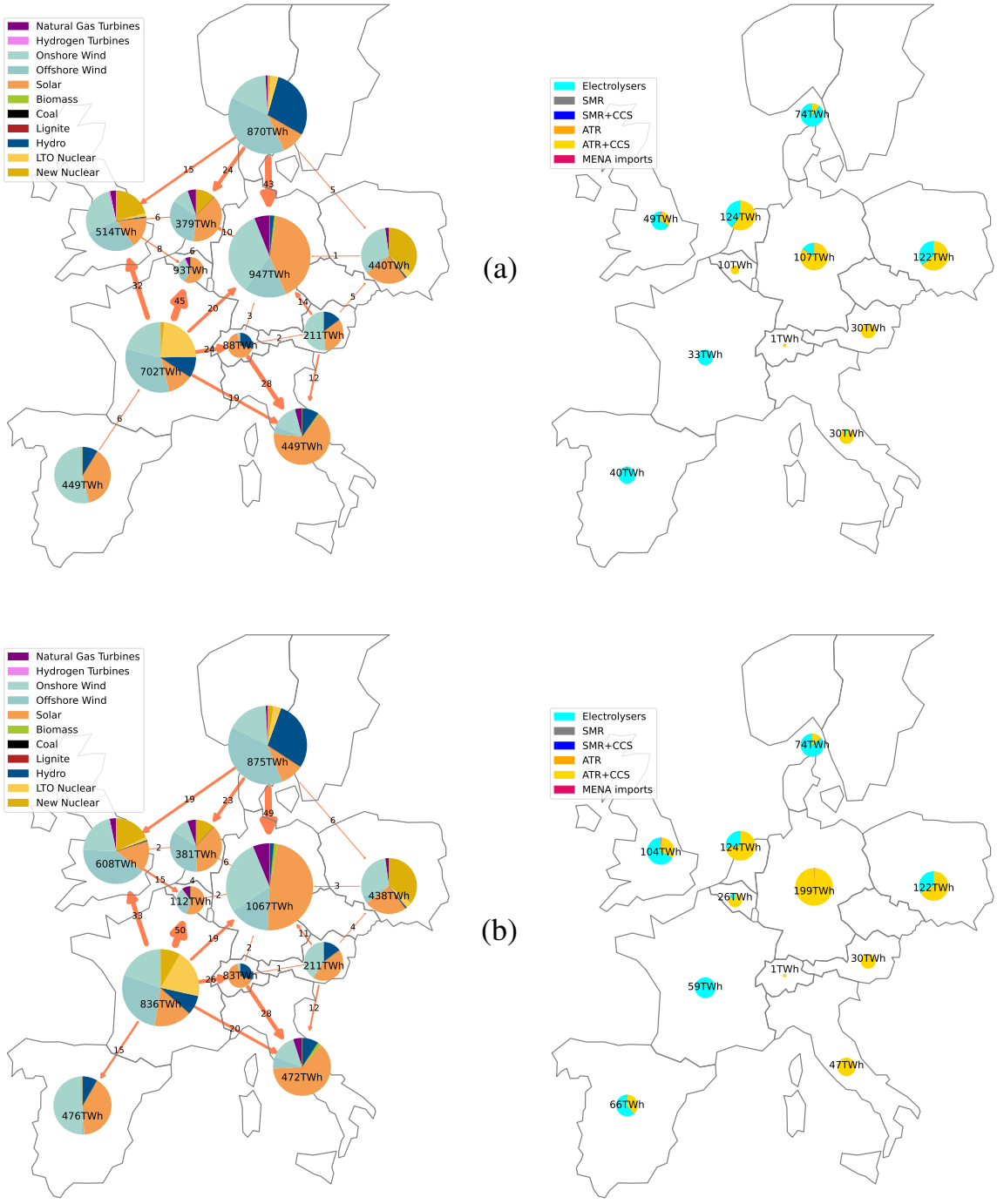


Fig. A.19. Reference Central scenario electricity and hydrogen systems in 2050 for POMMES standalone (a) and model coupling (b)

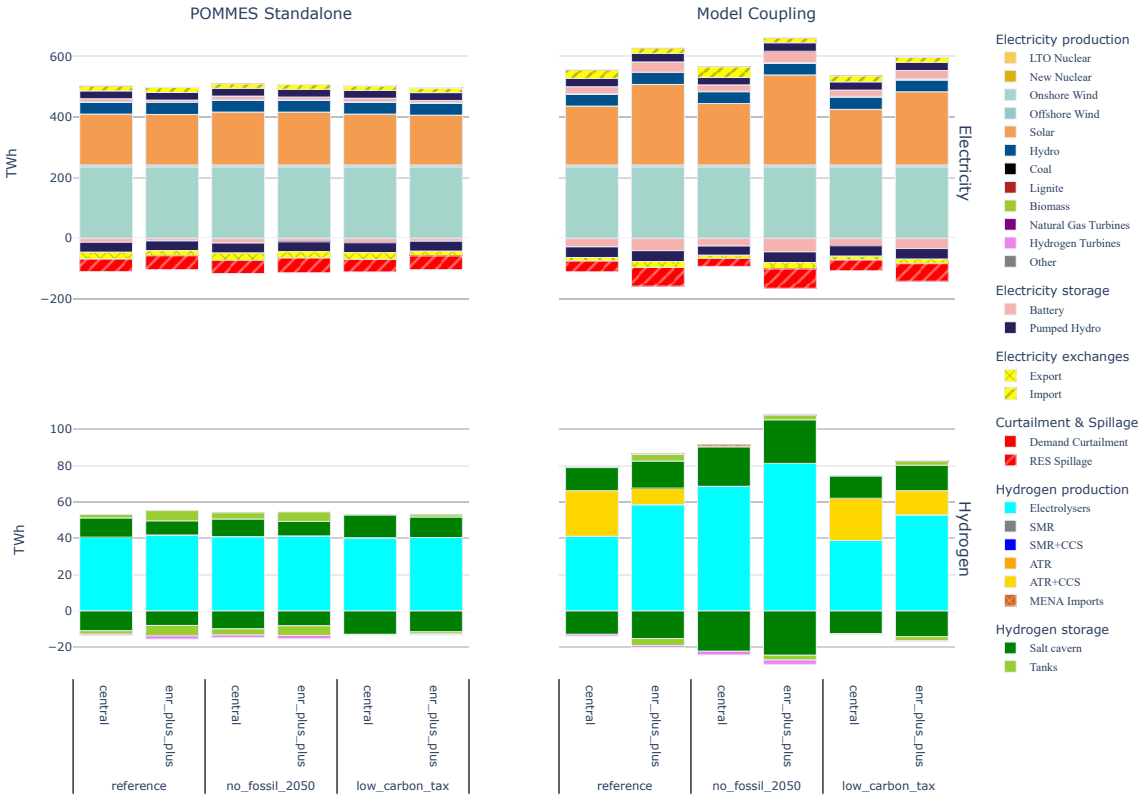


Fig. A.20. Electricity and hydrogen production in Spain — POMMES standalone vs model coupling comparison

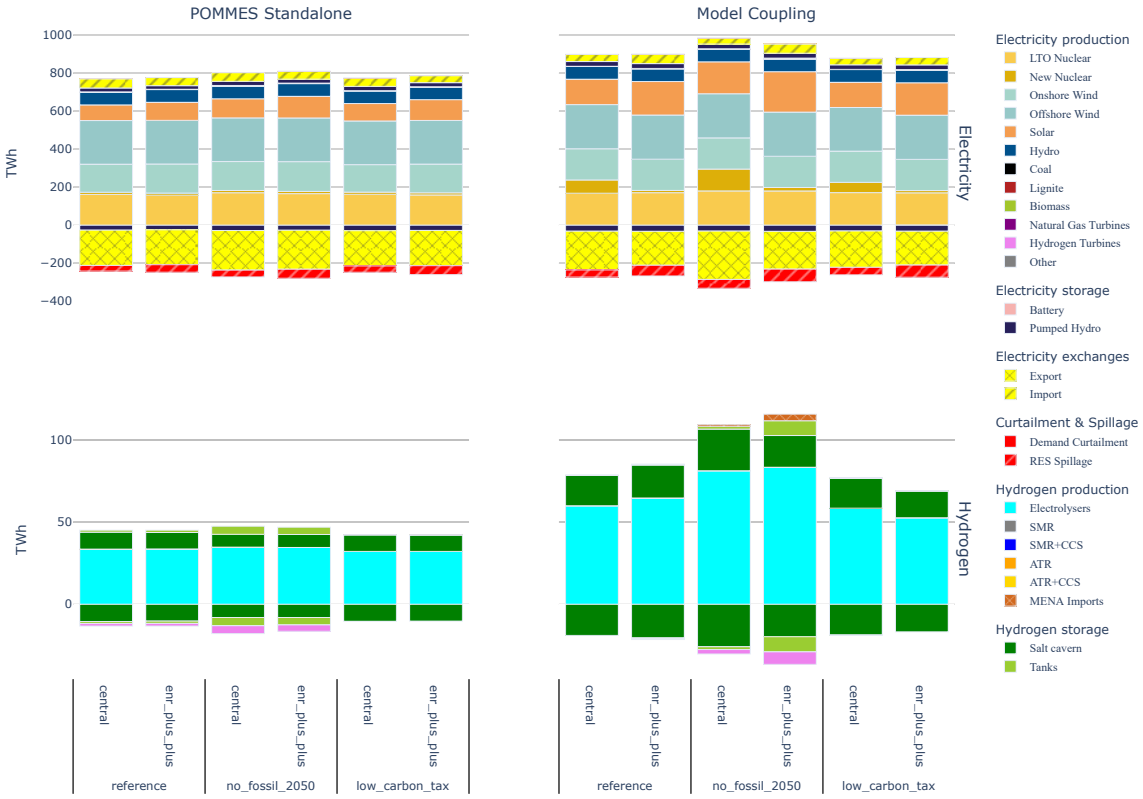


Fig. A.21. Electricity and hydrogen production in France — POMMES standalone vs model coupling comparison

Appendix B. Techno-economic data for POMMES

Appendix B.1. Prices and tax

	Policy scenario	2030	2040	2050
Carbon tax [€/tCO2]	Reference	100	200	300
	No Fossil 2050	100	200	300
	Low Carbon Tax	50	100	150
Natural gas [€/MWh]		35	35	35
Hydrogen imports [€/MWh]		170	140	110

Table B.3
Carbon tax and import prices

Zone	FR	DE	ES	IT	BE	GB	CH	NL	AT	Nordic	PL_CZ
Network tax (€/MWh)	8.9	15.3	7	7.5	7.8	10.3	11.2	10.6	16.7	9.87	15.2

Table B.4
Electricity network tax per area

Appendix B.2. Electricity production

The characteristics of electricity generation technologies are presented in Table B.5. The data for wind and solar are sourced from ENTSOE and ENTSOG [21], while the data for nuclear, hydro, and gas and hydrogen power plants are drawn from RTE [23]. Information for coal, lignite, and biomass power plants is obtained from Kost et al. [48].

Based on RTE BP2050, all WACCs have been established at 4%, with the exception of new nuclear, which has been set at 8%. These WACCs are the focus of sensitivity analyses in the study, particularly for the ENR_Plus_Plus and Nuke_Plus scenarios.

	Direct emissions	Overnight Invesment Costs [€/kW]			Fixed Costs	Lifetime
Technologies	[tCO_2/MWh]	2030	2040	2050	[€/kW/yr]	[yr]
Wind Onshore		1040	990	970	1.2% CAPEX	30
Wind Offshore		1800	1650	1640	3% CAPEX	30
Solar PV		380	330	290	2.5% CAPEX	40
Biomass	0.150	3000	3000	3000	33	20
LTO Nuclear					186	10
New Nuclear		11900	5035	4505	100	60
Hydro River					121	70
Hydro Lake					121	70
Coal	0.855	1500	1500	1500	22	30
Lignite	0.933	1800	1800	1800	22	30
OCGT	0.534	600	600	600	20	30
CCGT	0.356	900	900	900	40	40
OCGT-H_2		800	800	800	20	30
CCGT-H_2		1100	1100	1100	40	40

Table B.5
Economic characteristics in POMMES for electricity production technologies

Appendix B.3. Hydrogen production

The modelled hydrogen production technologies characteristics are described Table B.6 and Table B.7. Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) reactors data were adapted from Oni et al. [49] and Raillard-Cazanove et al. [14]. Electrolyser costs were taken from RTE [23] with an efficiency and lifetime adapted from Brissaud et al. [50], assuming alkaline electrolysis. The initial electrolyser's efficiency (including balance of plant) is 54%[50] which we assume to increase linearly up to 65% in 2050.

Ramp-up/down characteristics are taken from Jodry et al. [29] and electrolysis minimum power rate is as reported by Brissaud et al. [50]. Regarding SMR/ATR, minimum power rates assumptions were made following discussions with industry stakeholders such as Air Liquide.

	Direct emissions	Overnight Invesment Costs [€/kW]			Fixed Costs	Lifetime
Technologies	[tCO_2/MWh]	2030	2040	2050	[€/kW/yr]	[yr]
Electrolysis		641	574	507	12	10
SMR	0.28	850	850	850	144	25
SMR + partial CCS	0.169	950	950	950	199	25
SMR + CCS	0.059	1150	1150	1150	302	25
ATR	0.25	1300	1300	1300	89	25
ATR + CCS	0.023	1600	1600	1600	108	25

Table B.6
Economic characteristics in POMMES for hydrogen production technologies

Although some prospective studies model the ATR technology [51], it is still often not represented [25, 29, 31, 34, 36]. Autothermal reforming of methane is a variant of SMR in which the gas is burnt directly in the reformer to provide heat. Oxygen is injected into the reformer to partially oxidise the CH_4, leading to greater reaction energy efficiency [49]. Even though ATR is essentially more expensive than SMR (see Table B.6), thanks to the partial oxidation of

methane, syngas and flue gases are not mixed with N_2. So capturing CO_2 is easier (and cheaper) with ATR than with SMR [52]. One key characteristic is the substantially lower energy consumption for ATR+CCS compared to SMR+CCS as depicted Table B.7.

		Consumption [kWh/kWh$_{H_2}$]		Ramp up/down	Minimum power rate
Technologies	Year	Electricity	Methane	[hr]	[%]
Electrolysis	2030	1.73		<1	20
	2040	1.63		<1	20
	2050	1.53		<1	20
SMR		0.017	1.31	3.5	15
SMR + partial CCS		0.028	1.34	3.5	50
SMR + CCS		0.121	1.37	3.5	50
ATR		0.071	1.25	3.5	15
ATR + CCS		0.108	1.25	3.5	50

Table B.7
Technical characteristics in POMMES for hydrogen production technologies

Appendix B.4. Storage

The storage technologies characteristics used in POMMES are described Table B.8. Pumped Hydro Storage (PHS) data was taken from Schmidt et al. [53] with 80% round trip efficiency (RTE). Battery costs were derived from Cole and Karmakar [54] and RTE [23] and a 0.04%/hr self-discharge was assumed for a 85% RTE[54]. As for salt cavern and hydrogen tanks, the data was taken from Jodry et al. [29] with a 98% RTE.

			Overnight Invesment Costs		Fixed Costs	Lifetime
Technologies	Resource	Year	Power [€/kW]	Volume [€/kWh]	Power [€/kW/yr]	[yr]
Pumped Hydro Storage	electricity		1130	80	8	50
Battery	electricity	2030	315	240	30	15
		2040	300	200	30	15
		2050	285	155	30	15
Salt Cavern	hydrogen		545	0.28	2	40
Tank	hydrogen		12.6	5.4	2	20

Table B.8
Economic characteristics in POMMES for storage technologies

References

[1] Intergovernmental Panel on Climate Change (IPCC), Climate Change 2022 – Impacts, Adaptation and Vulnerability, Cambridge University Press, 2023. URL: https://www.cambridge.org/core/product/identifier/9781009325844/type/book. doi:10.1017/9781009325844.

[2] H. Ritchie, P. Rosado, M. Roser, Breakdown of carbon dioxide, methane and nitrous oxide emissions by sector, Our World in Data (2024). URL: https://ourworldindata.org/emissions-by-sector.

[3] B. Shirizadeh, A. Ailleret, C. Cartry, S. Douguet, T. Gehring, S. Maden, B. Mais, L. Mross, J. Theis, C. Cabot, M. Villavicencio, J. Trüby, Climate neutrality in European heavy-duty road transport: How to decarbonise trucks and buses in less than 30 years?, Energy Conversion and Management 309 (2024) 118438. doi:10.1016/J.ENCONMAN.2024.118438.

[4] O. Ruhnau, S. Bannik, S. Otten, A. Praktiknjo, M. Robinius, Direct or indirect electrification? A review of heat generation and road transport decarbonisation scenarios for Germany 2050, Energy 166 (2019) 989–999. doi:10.1016/J.ENERGY.2018.10.114.

[5] European Environment Agency, Decarbonising road transport, Technical Report, Publications Office of the European Union, 2022. URL: https://data.europa.eu/doi/10.2800/68902. doi:10.2800/68902.

[6] P. Jaramillo, S. Kahn Ribeiro, P. Newman, S. Dhar, O. E. Diemuodeke, T. Kajino, D. S. Lee, S. B. Nugroho, X. Ou, A. Hammer Strømman, J. Whitehead, Transport, Climate Change 2022 - Mitigation of Climate Change (2023) 1049–1160. URL: https://www.cambridge.org/core/books/climate-change-2022-mitigation-of-climate-change/transport/90D9E570DA9236EB0C8A2BFE38AEF454. doi:10.1017/9781009157926.012.

[7] D. Tarvydas, The role of hydrogen in energy decarbonisation scenarios, Technical Report, Publications Office of the European Union, Luxembourg, 2022. URL: https://publications.jrc.ec.europa.eu/repository/handle/JRC131299. doi:10.2760/899528.

[8] M. Wei, C. A. McMillan, S. de la Rue du Can, Electrification of Industry: Potential, Challenges and Outlook, Current Sustainable/Renewable Energy Reports 2019 6 (2019) 140–148. URL: https://link.springer.com/article/10.1007/s40518-019-00136-1. doi:10.1007/S40518-019-00136-1.

[9] I. A. Bashmakov, L. J. Nilsson, A. Acquaye, C. Bataille, J. M. Cullen, S. de la Rue du Can, M. Fischedick, Y. Geng, K. Tanaka, Industry, in: Climate Change 2022 - Mitigation of Climate Change, Cambridge University Press, 2022, pp. 1161–1244. URL: https://www.cambridge.org/core/product/identifier/9781009157926%23c11/type/book_part. doi:10.1017/9781009157926.013.

[10] L. F. Cabeza, Q. Bai, P. Bertoldi, J. M. Kihila, A. F. Lucena, E. Mata, S. Mirasgedis, A. Novikova, Y. Saheb, Buildings, in: Climate Change 2022 - Mitigation of Climate Change, Cambridge University Press, 2023, pp. 953–1048. URL: https://www.cambridge.org/core/product/identifier/9781009157926%23c9/type/book_part. doi:10.1017/9781009157926.011.

[11] M. Santamouris, K. Vasilakopoulou, Present and future energy consumption of buildings: Challenges and opportunities towards decarbonisation, e-Prime - Advances in Electrical Engineering, Electronics and Energy 1 (2021) 100002. doi:10.1016/J.PRIME.2021.100002.

[12] A. Gailani, S. Cooper, S. Allen, A. Pimm, P. Taylor, R. Gross, Assessing the potential of decarbonization options for industrial sectors, Joule 8 (2024) 576–603. URL: http://www.cell.com/article/S2542435124000266/fulltexthttp://www.cell.com/article/S2542435124000266/abstracthttps://www.cell.com/joule/abstract/S2542-4351(24)00026-6. doi:10.1016/J.JOULE.2024.01.007/ATTACHMENT/CB655E58-8851-4924-8569-96DC47813B58/MMC1.XLSX.

[13] S. Madeddu, F. Ueckerdt, M. Pehl, J. Peterseim, M. Lord, K. A. Kumar, C. Krüger, G. Luderer, The CO2 reduction potential for the European industry via direct electrification of heat supply (power-to-heat), Environmental Research Letters 15 (2020) 124004. URL: https://iopscience.iop.org/article/10.1088/1748-9326/abbd02. doi:10.1088/1748-9326/ABBD02.

[14] Q. Raillard-Cazanove, A. Rogeau, R. Girard, Industry Decarbonisation Bottom-Up Modelling in a Cost Optimised Trajectory, SSRN (2024). URL: https://ssrn.com/abstract=4761874. doi:10.2139/SSRN.4761874.

[15] T. Fleiter, A. Herbst, M. Rehfeldt, M. Arens, Industrial Innovation: Pathways to deep decarbonisation of Industry - Part 2: Scenario analysis and pathways to deep decarbonisation, Technical Report, Fraunhofer ISI, 2019. URL: https://www.isi.fraunhofer.de/de/competence-center/energietechnologien-energiesysteme/projekte/pathways.html#3.

[16] E. Sandberg, A. Krook-Riekkola, The impact of technology availability on the transition to net-zero industry in Sweden, Journal of Cleaner Production 363 (2022) 132594. URL: https://linkinghub.elsevier.com/retrieve/pii/S095965262202193X. doi:10.1016/j.jclepro.2022.132594.

[17] B. Shirizadeh, P. Quirion, Low-carbon options for the French power sector: What role for renewables, nuclear energy and carbon capture and storage?, Energy Economics 95 (2021) 105004. doi:10.1016/J.ENECO.2020.105004.

[18] L. M. Pastore, D. Groppi, F. Feijoo, G. Lo Basso, D. Astiaso Garcia, L. de Santoli, Optimal decarbonisation pathways for the Italian energy system: Modelling a long-term energy transition to achieve zero emission by 2050, Applied Energy 367 (2024) 123358. doi:10.1016/J.APENERGY.2024.123358.

[19] S. L. Luxembourg, S. S. Salim, K. Smekens, F. D. Longa, B. van der Zwaan, TIMES-Europe: An Integrated Energy System Model for Analyzing Europe's Energy and Climate Challenges, Environmental Modeling and Assessment (2024) 1–19. URL: https://link.springer.com/article/10.1007/s10666-024-09976-8. doi:10.1007/S10666-024-09976-8/FIGURES/9.

[20] P. Colbertaldo, F. Parolin, S. Campanari, A comprehensive multi-node multi-vector multi-sector modelling framework to investigate integrated energy systems and assess decarbonisation needs, Energy Conversion and Management 291 (2023) 117168. doi:10.1016/J.ENCONMAN.2023.117168.

[21] ENTSOE, ENTSOG, TYNDP 2024 Draft Scenarios Report, Technical Report, 2024. URL: https://2024.entsos-tyndp-scenarios.eu/.

[22] RTE, Bilan prévisionnel 2023-2035, Technical Report, RTE, 2024. URL: https://www.rte-france.com/analyses-tendances-et-prospectives/les-bilans-previsionnels#Lesdocuments.

[23] RTE, Futurs énergétiques 2050 : les chemins vers la neutralité carbone à horizon 2050, Technical Report, RTE, 2021. URL: https://www.rte-france.com/analyses-tendances-et-prospectives/bilan-previsionnel-2050-futurs-energetiques#Lesresultatsdeletude.

[24] A. Aszódi, B. Biró, L. Adorján, Á. Csaba Dobos, G. Illés, N. Krisztián Tóth, D. Zagyi, Z. Tas Zsiborás, The effect of the future of nuclear energy on the decarbonization pathways and continuous supply of electricity in the European Union, Nuclear Engineering and Design 415 (2023) 112688. doi:10.1016/J.NUCENGDES.2023.112688.

[25] T. Brown, D. Schlachtberger, A. Kies, S. Schramm, M. Greiner, Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system, Energy 160 (2018) 720–739. URL: https://linkinghub.elsevier.com/retrieve/pii/S036054421831288X. doi:10.1016/j.energy.2018.06.222.

[26] D. Schlachtberger, T. Brown, S. Schramm, M. Greiner, The benefits of cooperation in a highly renewable European electricity network, Energy 134 (2017) 469–481. URL: https://linkinghub.elsevier.com/retrieve/pii/S0360544217309969. doi:10.1016/j.energy.2017.06.004.

[27] M. Münster, R. Bramstoft, I. Kountouris, L. Langer, D. Keles, R. Schlautmann, F. Mörs, C. Saccani, A. Guzzini, M. Pellegrini, A. Zauner, H. Böhm, D. Markova, S. You, M. Pumpa, F. Fischer, F. Sergi, G. Brunaccini, D. Aloisio, M. Ferraro, M. Mulder, H. Rasmusson, Perspectives on green hydrogen in Europe—during an energy crisis and towards future climate neutrality, Oxford Open Energy 3 (2024). URL: https://dx.doi.org/10.1093/ooenergy/oiae001. doi:10.1093/OOENERGY/OIAE001.

[28] I. Kountouris, R. Bramstoft, T. Madsen, J. Gea-Bermúdez, M. Münster, D. Keles, A unified European hydrogen infrastructure planning to support the rapid scale-up of hydrogen production, Nature Communications 15 (2024) 1–13. URL: https://www.nature.com/articles/s41467-024-49867-w. doi:10.1038/s41467-024-49867-w.

[29] A. Jodry, R. Girard, P. H. A. Nóbrega, R. Molinier, M. D. El Alaoui Faris, Industrial hydrogen hub planning and operation with multi-scale optimisation, Journal of Cleaner Production 426 (2023) 138750. doi:10.1016/J.JCLEPRO.2023.138750.

[30] M. Victoria, K. Zhu, T. Brown, G. B. Andresen, M. Greiner, The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system, Energy Conversion and Management 201 (2019) 111977. doi:10.1016/J.ENCONMAN.2019.111977.

[31] F. Neumann, E. Zeyen, M. Victoria, T. Brown, The potential role of a hydrogen network in Europe, Joule 7 (2023) 1793–1817. URL:

https://linkinghub.elsevier.com/retrieve/pii/S2542435123002660. doi:10.1016/j.joule.2023.06.016.
[32] M. Babiker, G. Berndes, K. Blok, B. Cohen, A. Cowie, O. Geden, V. Ginzburg, A. Leip, P. Smith, M. Sugiyama, F. Yamba, Cross-sectoral Perspectives, in: Climate Change 2022 - Mitigation of Climate Change, Cambridge University Press, 2023, pp. 1245–1354. URL: https://www.cambridge.org/core/product/identifier/9781009157926%23c12/type/book_part. doi:10.1017/9781009157926.014.
[33] I. B. Boa Morte, O. d. Q. F. Araújo, C. R. Morgado, J. L. de Medeiros, Electrification and decarbonization: a critical review of interconnected sectors, policies, and sustainable development goals, Energy Storage and Saving 2 (2023) 615–630. URL: https://linkinghub.elsevier.com/retrieve/pii/S2772683523000456. doi:10.1016/j.enss.2023.08.004.
[34] T. Fleiter, K. Al-Dabbas, A. Clement, M. Rehfeldt, METIS 3, study S5 : the impact of industry transition on a CO2-neutral European energy system., Technical Report, European Commission, 2023. URL: https://data.europa.eu/doi/10.2833/094502. doi:10.2833/094502.
[35] D. Papadaskalopoulos, R. Moreira, G. Strbac, D. Pudjianto, P. Djapic, F. Teng, M. Papapetrou, Quantifying the potential economic benefits of flexible industrial demand in the european power system, IEEE Transactions on Industrial Informatics 14 (2018) 5123–5132. doi:10.1109/TII.2018.2811734.
[36] S. D. Manuel, T. Floris, W. Kira, S. Jos, F. André, High technical and temporal resolution integrated energy system modelling of industrial decarbonisation, Advances in Applied Energy 7 (2022) 100105. doi:10.1016/J.ADAPEN.2022.100105.
[37] T. Knibiehly, A. Jodry, Q. Raillard-Cazanove, R. Girard, Planning and Operation Model for Multi-Energy Systems (POMMES) · GitLab, 2024. URL: https://git.persee.mines-paristech.fr/energy-alternatives/pommes.
[38] ESO, Future Energy Scenarios 2024, Technical Report, 2024. URL: https://www.nationalgrideso.com/future-energy/future-energy-scenarios.
[39] B. Lux, J. Gegenheimer, K. Franke, F. Sensfuß, B. Pfluger, Supply curves of electricity-based gaseous fuels in the MENA region, Computers & Industrial Engineering 162 (2021) 107647. doi:10.1016/J.CIE.2021.107647.
[40] M. Taljegard, L. Göransson, M. Odenberger, F. Johnsson, Electric Vehicles as Flexibility Management Strategy for the Electricity System—A Comparison between Different Regions of Europe, Energies 2019, Vol. 12, Page 2597 12 (2019) 2597. URL: https://www.mdpi.com/1996-1073/12/13/2597/htmhttps://www.mdpi.com/1996-1073/12/13/2597. doi:10.3390/EN12132597.
[41] C. Loschan, D. Schwabeneder, G. Lettner, H. Auer, Flexibility potential of aggregated electric vehicle fleets to reduce transmission congestions and redispatch needs: A case study in Austria, International Journal of Electrical Power & Energy Systems 146 (2023) 108802. doi:10.1016/J.IJEPES.2022.108802.
[42] A. Colmenar-Santos, A. M. Muñoz-Gómez, E. Rosales-Asensio, A. Lopez-Rey, Electric vehicle charging strategy to support renewable energy sources in Europe 2050 low-carbon scenario, Energy 183 (2019) 61–74. doi:10.1016/J.ENERGY.2019.06.118.
[43] M. Cañigueral, J. Meléndez, Flexibility management of electric vehicles based on user profiles: The Arnhem case study, International Journal of Electrical Power & Energy Systems 133 (2021) 107195. doi:10.1016/J.IJEPES.2021.107195.
[44] A. Nikoobakht, J. Aghaei, T. Niknam, H. Farahmand, M. Korpås, Electric vehicle mobility and optimal grid reconfiguration as flexibility tools in wind integrated power systems, International Journal of Electrical Power & Energy Systems 110 (2019) 83–94. doi:10.1016/J.IJEPES.2019.03.005.
[45] H. Zhao, X. Yan, H. Ren, Quantifying flexibility of residential electric vehicle charging loads using non-intrusive load extracting algorithm in demand response, Sustainable Cities and Society 50 (2019) 101664. doi:10.1016/J.SCS.2019.101664.
[46] M. K. Gerritsma, T. A. Al Skaif, H. A. Fidder, W. G. van Sark, Flexibility of Electric Vehicle Demand: Analysis of Measured Charging Data and Simulation for the Future, World Electric Vehicle Journal 2019, Vol. 10, Page 14 10 (2019) 14. URL: https://www.mdpi.com/2032-6653/10/1/14/htmhttps://www.mdpi.com/2032-6653/10/1/14. doi:10.3390/WEVJ10010014.
[47] S. J. Cooper, S. R. Allen, A. Gailani, J. B. Norman, A. Owen, J. Barrett, P. Taylor, Meeting the costs of decarbonising industry – The potential effects on prices and competitiveness (a case study of the UK), Energy Policy 184 (2024) 113904. doi:10.1016/J.ENPOL.2023.113904.
[48] C. Kost, S. Shammugam, V. Fluri, D. Peper, A. D. Memar, T. Schlegl, Levelized Cost of Electricity - Renewable Energy Technologies, Technical Report, Fraunhofer ISE, 2021. URL: https://www.ise.fraunhofer.de/en/press-media/press-releases/2021/levelized-cost-of-electricity-renewables-clearly-superior-to-conventional-power-plants-due-to-rising-co2-prices.html.
[49] A. O. Oni, K. Anaya, T. Giwa, G. Di Lullo, A. Kumar, Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions, Energy Conversion and Management 254 (2022) 115245. doi:10.1016/J.ENCONMAN.2022.115245.
[50] F. Brissaud, A. Chaise, K. Gault, S. Soual, Lessons learned from Jupiter 1000, an industrial demonstrator of Power-to-Gas, International Journal of Hydrogen Energy 49 (2024) 925–932. doi:10.1016/J.IJHYDENE.2023.10.003.
[51] G. S. Seck, E. Hache, J. Sabathier, F. Guedes, G. A. Reigstad, J. Straus, O. Wolfgang, J. A. Ouassou, M. Askeland, I. Hjorth, H. I. Skjelbred, L. E. Andersson, S. Douguet, M. Villavicencio, J. Trüby, J. Brauer, C. Cabot, Hydrogen and the decarbonization of the energy system in europe in 2050: A detailed model-based analysis, Renewable and Sustainable Energy Reviews 167 (2022) 112779. URL: https://linkinghub.elsevier.com/retrieve/pii/S1364032122006633. doi:10.1016/j.rser.2022.112779.
[52] Y. Khojasteh Salkuyeh, B. A. Saville, H. L. MacLean, Techno-economic analysis and life cycle assessment of hydrogen production from natural gas using current and emerging technologies, International Journal of Hydrogen Energy 42 (2017) 18894–18909. doi:10.1016/J.IJHYDENE.2017.05.219.
[53] O. Schmidt, S. Melchior, A. Hawkes, I. Staffell, Projecting the Future Levelized Cost of Electricity Storage Technologies, Joule 3 (2019) 81–100. doi:10.1016/J.JOULE.2018.12.008.
[54] W. Cole, A. Karmakar, Cost Projections for Utility-Scale Battery Storage: 2023 Update, Technical Report, National Renewable Energy Laboratory, 2023. URL: https://www.nrel.gov/docs/fy23osti/85332.pdf.

Supplementary Materials — Decarbonisation of industry and the energy system: exploring mutual impacts and investment planning

Quentin Raillard--Cazanove[1], Thibaut Knibiehly[1], and Robin Girard[1]

[1]Mines Paris, PSL University, Centre for processes, renewable energy and energy systems (PERSEE), Sophia Antipolis, 06904, France

Nomenclature

Indices and index sets

$a \in \mathcal{A}$ areas
$i \in \mathcal{Y}^{inv}$ investment years
$y \in \mathcal{Y}^{op}$ operation years
$y \in \mathcal{Y}^{dec}$ decommissioning years
$t \in \mathcal{T}$ operation snapshots
$r \in \mathcal{R}$ resources
$c \in \mathcal{C}^{tech}$ conversion technologies
$s \in \mathcal{S}^{tech}$ storage technologies
$w \in \mathcal{W}^{tech}$ transport technologies
$\mathcal{R}_a$ resources considered in area a
$\mathcal{C}^{tech}_{a,i}$ conversion technologies which can be installed in area a for investment year i
$\mathcal{S}^{tech}_{a,i}$ storage technologies which can be installed in area a for investment year i
$\mathcal{W}^{tech}_{^\circ a,a^\circ,i}$ transport technologies which can be installed from area $^\circ a$ to area a° for investment year i
$\mathcal{W}^{tech}_{a,i}$ transport technologies which connect area a, $\mathcal{W}^{tech}_{a,i} = \bigcup_{b\in\mathcal{A}} \left(\mathcal{W}^{tech}_{b,a,i} \cup \mathcal{W}^{tech}_{a,b,i}\right)$

General parameters

$d_{r,t,y}$ exogenous demand of r in y at t [MWh]
$\lambda^{shed}_{r,y}$ load shedding cost [€/MWh]
$\lambda^{spill}_{r,y}$ resource spillage cost [€/MWh]
$g^{CO_2}_{a,y}$ maximum total CO_2 emission in y [kgCO_2]
$t^{CO_2}_{a,y}$ carbon tax value in y [€/kgCO_2]
τ discount rate [%]
y_0 reference year for actualisation [year]
$\phi_1(\tau, y, y_0)$ discount factor to bring back values from year y to actualised value in year y_0 [%]
$\phi_2(\alpha, n)$ capital recovery factor [%]
$\Delta i = \Delta j = \Delta y$ investment/decommissioning/operation year time step [year]
$(\Delta T)_t$ snapshot length [hour]

Conversion parameters

α_c conversion technologies finance rate [%]
β_c specific overnight cost of c [€/MW]
ω_c fixed OPEX of c [€/MW/yr]
λ_c variable OPEX of c [€/MWh]
$a_{y,t,c}$ availability of c in operation year y at t [$\in [0,1]$]
$k_{c,r}$ conversion factor of c, $k_{c,r} \leq 0$ (resp. ≥ 0) for consumption (resp. emission) of r [%]
$\varepsilon^{CO_2}_c$ CO_2 emission rate for c invested for year i [kgCO_2/MWh]
l_c life length of c invested for year i [year]
$p^{c,min}_c$ minimum capacity that must be invested in c [MW]
$p^{c,max}_c$ maximum capacity that can be invested in c [MW]

Storage parameters

α_s storage technologies finance rate [%]
β_s power capacity specific overnight cost of technology s [€/MW]
σ_s energy capacity specific overnight cost of technology s [€/MWh]

ω_s fixed OPEX of technology s [€/MW/yr]
η_s Dissipation losses in s over 1 hour [%]
$k^{in}_{s,r}$ Charging factor to load 1 MWh into s, $k^{in}_{s,r} \leq 0$ (resp. ≥ 0) for consumption (resp. emission) of r [%]
$k^{keep}_{s,r}$ Consumption factor to keep 1 MWh during 1 hour in s (not taking into account dissipation), $k^{keep}_{s,r} \leq 0$ (resp. ≥ 0) for consumption (resp. collecting or emission) of r [h^{-1}]
$k^{out}_{s,r}$ Discharging factor, $k^{out}_{s,r} \leq 0$ (resp. ≥ 0) for consumption (resp. collecting or emission) of r [%]
res_s main resource stored by s
l_s life length of s [year]
$p^{s,min}_s$ minimum storage power capacity that must be invested in s [MW]
$p^{s,max}_s$ maximum storage power capacity that can be invested in s [MW]
$s^{s,min}_s$ minimum storage energy capacity that must be invested in s [MWh]
$s^{s,max}_s$ maximum storage energy capacity that can be invested in s [MWh]

Transport parameters

β_w specific overnight cost of w [€/MW]
ω_w fixed OPEX of w [€/MW/yr]
λ_w variable OPEX of w [€/MWh]
$a_{y,t,w}$ availability of w in operation year y at t [$\in [0,1]$]
$k_{w,r}$ conversion factor of w, $k_{w,r} \leq 0$ (resp. ≥ 0) for consumption (resp. emission) of r [%]
$\varepsilon^{CO_2}_w$ CO_2 emission rate for w [$kgCO_2$/MWh]
l_w life length of w [year]
$p^{w,min}_w$ minimum capacity that must be invested in w [MW]
$p^{w,max}_w$ maximum capacity that can be invested in w [MW]

Exchange with ROW parameters

$\gamma_{y,r,t}$ importation cost of r in y at t from ROW [€/MWh]
$\varepsilon^{CO_2}_{y,r,t}$ importation emission rate of r in y at t from ROW [kg/MWh]
$\pi^{max,imp}_{y,r,t}$ max importation volume of r in y at t from ROW [MWh]
$\pi^{max,exp}_{y,r,t}$ max exportation volume of r in y at $t$to ROW [MWh]

Investment variables

$\mathbf{P}^{c,inv}_{c,d}$ capacity of $c \in \mathcal{C}^{tech}_{a,i}$ decommissioned for year d [MW]
$\mathbf{P}^{s,inv}_{s,d}$ storage power capacity of $s \in \mathcal{S}^{tech}_{a,i}$ decommissioned for year d [MW]
$\mathbf{P}^{w,inv}_{w,d}$ capacity of $w \in \mathcal{W}^{tech}_{\circ a,a^\circ,i}$ decommissioned for year d [MWh]
$\mathbf{S}^{inv}_{s,d}$ storage energy capacity of $s \in \mathcal{S}^{tech}_{a,i}$ decommissioned for year d [MWh]
$\bar{P}^c_{y,c}$ total capacity of c in operation in year y [MW]
$\bar{P}^s_{y,s}$ total storage power capacity of s in operation in year y [MW]
$\bar{S}_{y,s}$ total storage energy capacity of s in operation in year y [MWh]
$\bar{P}^w_{y,w}$ total capacity of w invested in operation in year y [MW]

Operation Variables

$\mathbf{P}^c_{y,t}$ power of c in y at t [MW]
$U^{net,c}_{y,t,r}$ resource r net generation from conversion technologies in y at t [MWh]
$\mathbf{P}^{s,in}_{y,t,s}$ storage charging power of s in y at t [MW]
$\mathbf{P}^{s,out}_{y,t,s}$ storage discharging power of s in y at t [MW]
$\mathbf{S}_{y,t,s}$ amount of energy in s in y at t [MWh]
$U^{net,s}_{y,t,r}$ resource r net generation from storage technologies in y at t [MWh]
$\mathbf{P}^w_{y,t}$ power of w in y at t [MW]
$U^{net,w}_{y,t,r}$ resource r net generation from transport technologies in y at t [MWh]
$\mathbf{U}^{shed}_{y,t,r}$ load shedding for resource r in$y$ at t [MWh]
$U^{spill}_{y,t,r}$ resource spillage for r in y at t [MWh]
$\mathbf{I}_{y,t,r}$ importation of r in y at t from ROW [MWh]
$\mathbf{E}_{y,t,r}$ exportation of r in y at t to ROW [MWh]
$I^{net}_{y,t,r}$ net imports from ROW [MWh]

Intermediate cost variables

$\mathcal{CAP}_{a,y}$ annualised cost of capital of the system in y
$\mathcal{FIX}_{a,y}$ fixed operation costs of the system in y
$\mathcal{VAR}_{a,y}$ variable (proportional) operation costs of the system in y
$\mathcal{A}^{var}_{a,y}$ adequacy (load shedding and spillage) costs in y
$\mathcal{C}^{cap}_{a,y}$ conversion annualised capital cost in y
$\mathcal{C}^{fix}_{a,y}$ conversion fixed operation cost in y
$\mathcal{C}^{var}_{a,y}$ conversion variable operation cost in y

$\mathcal{S}^{cap}_{a,y}$ storage annualised capital cost in y
$\mathcal{S}^{fix}_{a,y}$ storage fixed operation cost in y
$\mathcal{W}^{cap}_{a,y}$ transport annualised capital cost in y
$\mathcal{W}^{fix}_{a,y}$ transport fixed operation cost in y
$\mathcal{W}^{var}_{a,y}$ transport variable operation cost in y
$\mathcal{I}^{net,var}_{a,y}$ Net imports from ROW variable costs in y

1 POMMES equations

1.1 Objective

The objective function of the problem is given by the minimisation of the actualised costs in equations (1). All variables are continuous and positive.

$$\min_{\mathbf{P}^{inv},\mathbf{P},\mathbf{S}^{inv},\mathbf{S},\mathbf{I},\mathbf{E},\mathbf{U}} \sum_{a,y} \left[\phi_1 \left(\tau, y + \frac{\Delta y}{2}, y_0 \right) \left(\mathcal{CAP}_{a,y} + \mathcal{FIX}_{a,y} + \mathcal{VAR}_{a,y} \right) \right] \tag{1}$$

Where $\phi_1(\tau, y, y_0)$ is the discount factor to actualise all the costs to reference year y_0 (2).

$$\phi_1(\tau, y, y_0) = (1+\tau)^{-(y-y_0)} \tag{2}$$

1.2 Costs definition

1.2.1 Annualised capital costs

Annualised capital costs are given in equation (3), and details are given in (4), (5), and (6).

$$\mathcal{CAP}_{a,y} = \mathcal{C}^{cap}_{a,y} + \mathcal{S}^{cap}_{a,y} + \mathcal{W}^{cap}_{a,y} \quad \forall\, a, y \tag{3}$$

Where

$$\mathcal{C}^{cap}_{a,y} = \sum_{i \leq y} \sum_{c \in \mathcal{C}^{tech}_{a,i}} \phi_2(\alpha_c, l_c)\, \beta_c \sum_d \mathbf{P}^{c,inv}_{c,d} \quad \forall\, a, y \tag{4}$$

$$\mathcal{S}^{cap}_{a,y} = \sum_{i \leq y} \sum_{s \in \mathcal{S}^{tech}_{a,i}} \phi_2(\alpha_s, l_s) \left(\beta_s \sum_d \mathbf{P}^{s,inv}_{s,d} + \sigma_s \sum_d \mathbf{S}^{inv}_{s,d} \right) \quad \forall\, a, y \tag{5}$$

$$\mathcal{W}^{cap}_{a,y} = \frac{1}{2} \sum_{i \leq y} \sum_{w \in \mathcal{W}^{tech}_{a,i}} \phi_2(\alpha_w, l_w)\, \beta_w \sum_d \mathbf{P}^{w,inv}_{w,d} \quad \forall\, a, y \tag{6}$$

The coefficient $\phi_2(\alpha, n)$ represents the capital recovery factor in annualising the costs with a finance rate of α during n years with one term per year (equation (7)). Payments occur at the end of the year.

$$\phi_2(\alpha, n) = \frac{\alpha}{1 - (1+\alpha)^{-n}} \tag{7}$$

The annualisation of the CAPEX is done on the whole life length of the technologies, even if they can be early decommissioned.

1.2.2 Fixed operation costs

Fixed operation costs are given in equation (8) and details are provided in (9), (10) and (11).

$$\mathcal{FIX}_{a,y} = \mathcal{C}^{fix}_{a,y} + \mathcal{S}^{fix}_{a,y} + \mathcal{W}^{fix}_{a,y} \quad \forall\, a, y \tag{8}$$

Where

$$\mathcal{C}^{fix}_{a,y} = \sum_{i \leq y} \sum_{c \in \mathcal{C}^{tech}_{a,i}} \omega_c \bar{P}^c_{y,c} \quad \forall\, a, y \tag{9}$$

$$\mathcal{S}^{fix}_{a,y} = \sum_{i \leq y} \sum_{s \in \mathcal{S}^{tech}_{a,i}} \omega_s \bar{P}^s_{y,s} \quad \forall\, a, y \tag{10}$$

$$\mathcal{W}^{fix}_{a,y} = \frac{1}{2} \sum_{i \leq y} \sum_{w \in \mathcal{W}^{tech}_{a,i}} \omega_c \bar{P}^c_{y,c,i} \quad \forall\, a, y \tag{11}$$

Moreover, storage fixed costs are only proportional to installed power capacity, not energy capacity.

1.2.3 Variable operation costs

Variable operation costs are given in equation (12) and details are given in (13), (14), (15) and (16).

$$\mathcal{VAR}_{a,y} = \mathcal{C}^{var}_{a,y} + \mathcal{I}^{net,var}_{a,y} + \mathcal{W}^{var}_{a,y} + \mathcal{A}^{var}_{a,y} \quad \forall\, a, y \tag{12}$$

Where

$$\mathcal{C}^{var}_{a,y} = \sum_{i \leq y,t} \sum_{c \in \mathcal{C}^{tech}_{a,i}} (\Delta T)_t \times \left(t^{CO_2}_{a,y} \varepsilon^{CO_2}_c + \lambda_c \right) \mathbf{P}^c_{y,t,c} \quad \forall\, a, y \tag{13}$$

$$\mathcal{I}^{net,var}_{a,y} = \sum_{t,r} \left(t^{CO_2}_{a,y} \varepsilon^{CO_2}_{y,r,t} + \gamma_{y,r,t} \right) I^{net}_{y,r,t} \quad \forall\, a, y \tag{14}$$

$$\mathcal{W}^{var}_{a,y} = \frac{1}{2} \sum_{i \leq y,t} \sum_{w \in \mathcal{W}^{tech}_{a,i}} (\Delta T)_t \times \left(t^{CO_2}_{a,y} \varepsilon^{CO_2}_w + \lambda_w \right) \mathbf{P}^w_{y,t,w} \quad \forall\, a, y \tag{15}$$

The model has no proportional power capacity or energy capacity costs for storage.

$$\mathcal{A}^{var}_{a,y} = \sum_{t, r \in \mathcal{R}_a} \left(\lambda^{shed}_{r,y} \mathbf{U}^{shed}_{y,t,r} + \lambda^{spill}_{r,y} U^{spill}_{y,t,r} \right) \quad \forall\, a, y \tag{16}$$

1.3 Adequacy constraint

The adequacy is met for each resource at each operation time (17). The net generation of the conversion (resp. storage) technologies are aggregated for each time step in the $U^{net,c}_{y,t,r}$ (resp. $U^{net,s}_{y,t,r}$) variable defined in equation (18) (resp. (19)).

$$\boxed{d_{r,t,y} + U^{spill}_{y,t,r} = U^{net,c}_{y,t,r} + U^{net,s}_{y,t,r} + U^{net,w}_{y,t,r} + I^{net}_{y,t,r} + \mathbf{U}^{shed}_{y,t,r} \quad \forall\, a, y, t, \quad \forall\, r \in \mathcal{R}_a} \tag{17}$$

$$U^{net,c}_{y,t,r} = (\Delta T)_t \times \sum_{i \leq y} \sum_{c \in \mathcal{C}^{tech}_{a,i}} k_{c,r} \mathbf{P}^c_{y,t,c} \quad \forall\, a, y, t, \quad \forall\, r \in \mathcal{R}_a \tag{18}$$

$$U^{net,s}_{y,t,r} = (\Delta T)_t \times \sum_{i \leq y} \sum_{s \in \mathcal{S}^{tech}_{a,i}} \left(k^{in}_{s,r} \mathbf{P}^{s,in}_{y,t,s} + k^{keep}_{s,r} \mathbf{S}_{y,t,s} + k^{out}_{s,r} \mathbf{P}^{s,out}_{y,t,s} \right) \quad \forall\, a, y, t, \quad \forall\, r \in \mathcal{R}_a \tag{19}$$

$$U^{net,w}_{y,t,r} = (\Delta T)_t \times \sum_{i \leq y} \sum_{(^\circ a, a^\circ) \in \mathcal{A}^2} \sum_{w \in \mathcal{W}^{tech}_{^\circ a, a^\circ, i}} (\delta_{^\circ a, a} - \delta_{a, a^\circ}) \times k_{w,r} \mathbf{P}^w_{y,t,w} \quad \forall\, a, y, t, \quad \forall\, r \in \mathcal{R}_a \tag{20}$$

Remark

One could be surprised by the addition of the $\eta^{in}_{s,i,r}\, P^{s,in}_{y,t,s}$ term to the resource production as the resource r is supposed to be consumed if loaded into storage, or at least, that the signs before the *out* and *in* are the same in the storage part of the equation. However, this approach comes from single energy carrier modelling. The storage does not store electricity or gas. It stores energy in MWh. Let's consider low-temperature storage, for example. It consumes electricity when loading (thus $\eta^{in}_{elec} < 0$) and consumes electricity when discharging ($\eta^{out}_{elec} < 0$ with the heat pumps consumption) and discharge low-temperature heat ($\eta^{out}_{heat} > 0$).

1.4 Capacity constraints

The instant power of the conversion technologies is lower than the available installed capacity (21).

$$\mathbf{P}^{c}_{y,t,c} \leq a_{y,t,c}\, \bar{P}^{c}_{y,c} \quad \forall a, y, t, \quad \forall i \leq y, \quad \forall c \in \mathcal{C}^{tech}_{a,i} \tag{21}$$

Considering this, the total installed capacity of c for operation year y ($\bar{P}^{c}_{y,c}$) is defined as the total installed capacity of technology c that is not yet decommissioned in y.

$$\bar{P}^{c}_{y,c} = \sum_{d>y} \mathbf{P}^{c,inv}_{c,d} \quad \forall a, y, \quad \forall i \leq y, \quad \forall c \in \mathcal{C}^{tech}_{a,i} \tag{22}$$

Moreover, decommissioning must happen strictly after investment and before the end of the technology life length (23).

$$P^{c,inv}_{c,d} = 0 \quad \forall a, i, \quad \forall c \in \mathcal{C}^{tech}_{a,i}, \quad \forall d \in \{d \mid d \leq i\} \cup \{d \mid d > i + l_c\} \tag{23}$$

The minimum bounds are the invested capacity and the maximum allowed each year by the decision maker (24). This constraint could be related to the deployment rate or to the limited space of the local area, for example.

$$p^{c,min}_{c} \leq \sum_{d} \mathbf{P}^{c,inv}_{c,d} \leq p^{c,max}_{c} \quad \forall a, i, \quad \forall c \in \mathcal{C}^{tech}_{a,i} \tag{24}$$

1.5 Storage constraints

The total storage power (resp. energy) capacity for operation year y is defined as the total power (resp. energy) capacity of (s, i) that is not yet decommissioned in y in equation (25) (resp. (26)).

$$\bar{P}^{s}_{y,s} = \sum_{d>y} \mathbf{P}^{s,inv}_{s,d} \quad \forall a, y, \quad \forall i \leq y, \quad \forall s \in \mathcal{S}^{tech}_{a,i} \tag{25}$$

$$\bar{S}_{y,s} = \sum_{d>y} \mathbf{S}^{inv}_{s,d} \quad \forall a, y, \quad \forall i \leq y, \quad \forall s \in \mathcal{S}^{tech}_{a,i} \tag{26}$$

Where as in (23) the decommissioning must happen strictly after investment and before end of life length (27).

$$P^{s,inv}_{s,d} = S^{inv}_{s,d} = 0 \quad \forall a, i, \quad \forall s \in \mathcal{S}^{tech}_{a,i}, \quad \forall d \in \{d \mid d \leq i\} \cup \{d \mid d > i + l_s\} \tag{27}$$

Any resource of the model can be stored in the right storage technology s is invested in. For all time steps t, the input rate of storage $P^{s,in/out}_{y,t,s}$ is bounded by the total invested power capacity $\bar{P}^{s}_{y,s}$:

$$\mathbf{P}^{s,in/out}_{y,t,s} \leq \bar{P}^{s}_{y,s} \quad \forall a, y, \quad \forall i \leq y, \quad \forall s \in \mathcal{S}^{tech}_{a,i} \tag{28}$$

The total amount of energy in storage $S_{y,t,s}$ should remain lower than the total invested energy capacity $\bar{S}_{y,s}$:

$$\mathbf{S}_{y,t,s} \leq \bar{S}_{y,s} \quad \forall a, y, \quad \forall i \leq y, \quad \forall s \in \mathcal{S}^{tech}_{a,i} \tag{29}$$

Invested power and energy capacities are bounded by the minimum and maximum allowed values in equations (30) and (31).

$$p_s^{s,min} \leq \sum_d \mathbf{P}_{s,d}^{s,inv} \leq p_s^{s,max} \quad \forall a, i \quad \forall s \in \mathcal{S}_{a,i}^{tech} \tag{30}$$

$$s_s^{s,min} \leq \sum_d \mathbf{S}_{s,d}^{inv} \leq s_s^{s,max} \quad \forall a, i \quad \forall s \in \mathcal{S}_{a,i}^{tech} \tag{31}$$

The total amount of energy in the storage at each time step $S_{y,t,s}$ is defined as the total amount of energy in the storage at the previous time step minus the dissipation plus the loaded energy minus the discharged energy (32). The constraint is cyclic to avoid side effects.

Note that $P_{y,t,s}^{s,in}$ is the power to load 1 MWh into the storage and $P_{y,t,s}^{s,out}$ is discharge power to lower the storage level of 1 MWh.

$$\mathbf{S}_{y,t,s} = (1-\eta_s)^{\frac{(\Delta T)_t}{1[h]}} \mathbf{S}_{y,t-1,s} + (\Delta T)_t \times (\mathbf{P}_{y,t,s}^{s,in} - \mathbf{P}_{y,t,s}^{s,out}) \quad \forall a, y, t, \quad \forall i \leq y, \quad \forall s \in \mathcal{S}_{a,i}^{tech} \tag{32}$$

1.6 Transport constraints

The instant power of the transport technologies is lower than the available installed capacity (33).

$$\mathbf{P}_{y,t,w}^{w} \leq a_{y,t,w} \bar{P}_{y,w}^{w} \quad \forall \circ a, a^{\circ}, y, t, \quad \forall i \leq y, \quad \forall w \in \mathcal{W}_{\circ a,a^{\circ},i}^{tech} \tag{33}$$

The total installed capacity of w for operation year y ($\bar{P}_{y,w}^{c}$) is defined as the total installed capacity of technology w that is not yet decommissioned in y (34).

$$\bar{P}_{y,w}^{w} = \sum_{d>y} \mathbf{P}_{w,d}^{w,inv} \quad \forall \circ a, a^{\circ}, y, \quad \forall i \leq y, \quad \forall w \in \mathcal{W}_{\circ a,a^{\circ},i}^{tech} \tag{34}$$

Moreover, decommissioning must happen strictly after investment and before the end of the technology life length (35).

$$P_{w,d}^{w,inv} = 0 \quad \forall \circ a, a^{\circ}, i, \quad \forall w \in \mathcal{W}_{\circ a,a^{\circ},i}^{tech}, \quad \forall d \in \{d \mid d \leq i\} \cup \{d \mid d > i + l_w\} \tag{35}$$

The minimum bounds are the invested capacity and the maximum allowed each year by the decision maker (36).

$$p_w^{w,min} \leq \sum_d \mathbf{P}_{w,d}^{w,inv} \leq p_w^{w,max} \quad \forall \circ a, a^{\circ}, y, \quad \forall i \leq y, \quad \forall w \in \mathcal{W}_{\circ a,a^{\circ},i}^{tech} \tag{36}$$

1.7 Carbon related constraints

Equation (37) defines the operation emission variable.

$$E_{a,y,t}^{\mathrm{CO_2}} = (\Delta T)_t \times \sum_{i \leq y} \sum_{c \in \mathcal{C}_{a,i}^{tech}} \varepsilon_c^{\mathrm{CO_2}} \mathbf{P}_{y,t,c}^{c} + \sum_{r \in \mathcal{R}_a} \varepsilon_{y,r,t}^{\mathrm{CO_2}} I_{y,r,t}^{net} \quad \forall a, y, t \tag{37}$$

The total emission constraint is in equation (38).

$$\sum_t E_{a,y,t}^{\mathrm{CO_2}} \leq g_{a,y}^{\mathrm{CO_2}} \quad \forall\, a, y \tag{38}$$

1.8 Imports constraints

Imports bound are defined in equation (40). Variables are in energy units (MWh).

$$I^{net}_{y,r,t} = \mathbf{I}_{y,r,t} - \mathbf{E}_{y,r,t} \quad \forall\, y, r, t \tag{39}$$

$$\mathbf{I}_{y,r,t} \leq \pi^{max,imp}_{y,r,t} \quad \forall\, y, r, t \tag{40}$$

$$\mathbf{E}_{y,r,t} \leq \pi^{max,exp}_{y,r,t} \quad \forall\, y, r, t \tag{41}$$

2 Supplementary results

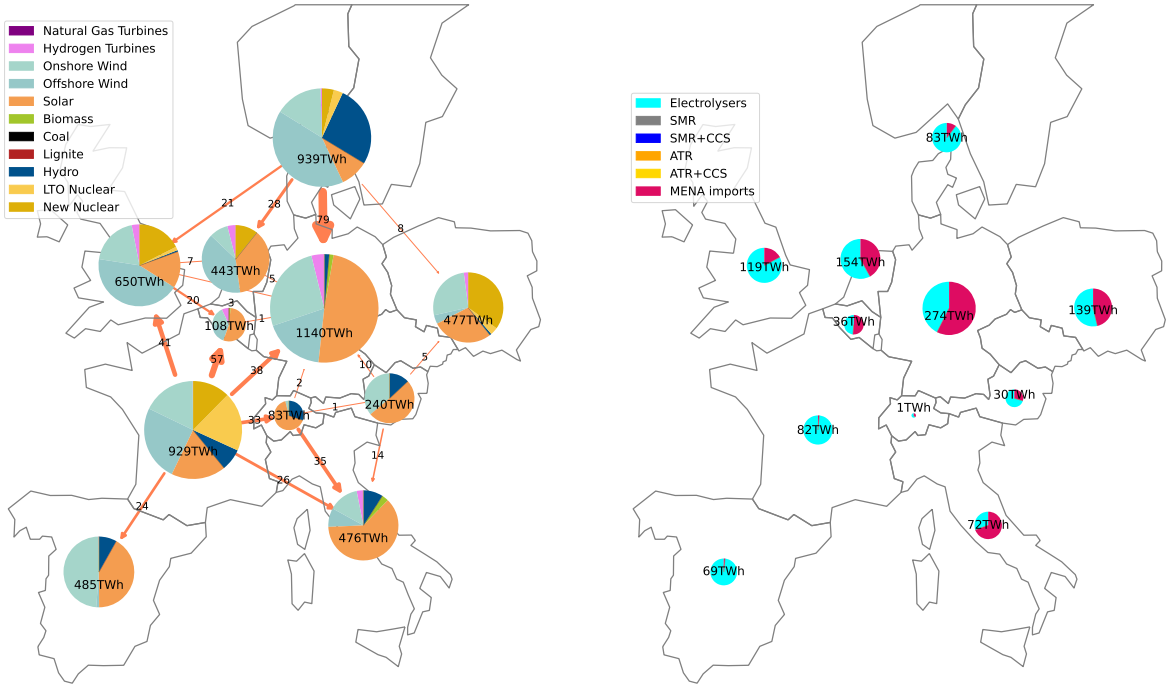


Fig. 1. No Fossil 2050 Central scenario electricity and hydrogen system in 2050 — from POMMES

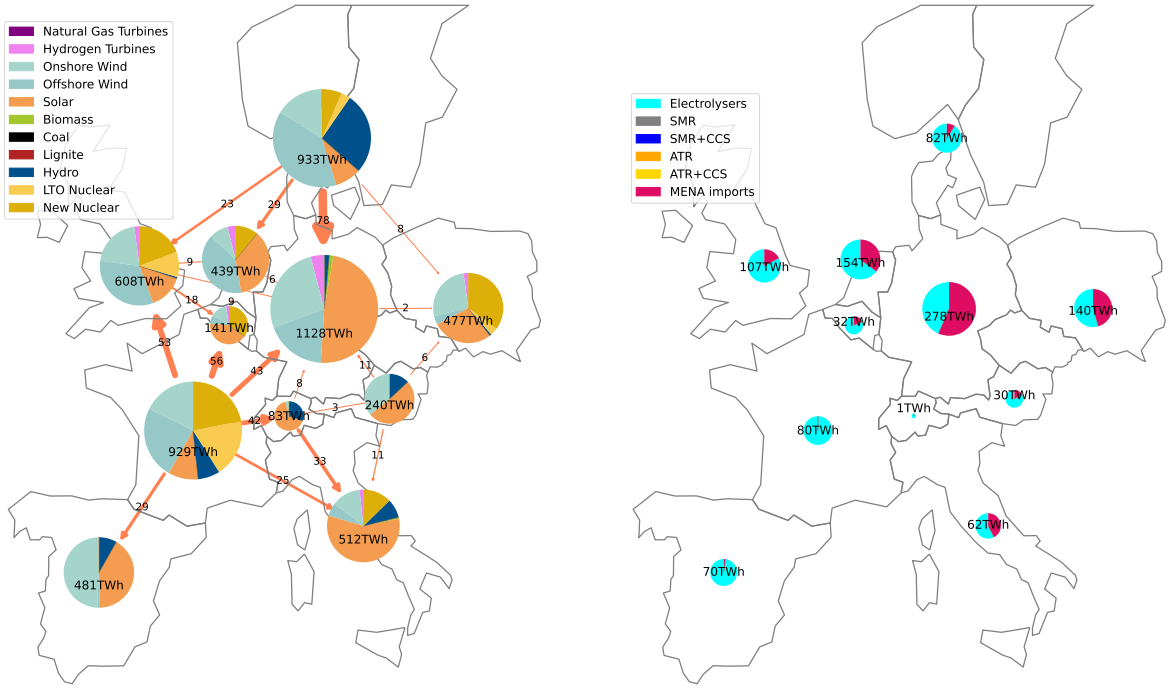


Fig. 2. No Fossil 2050 Nuke_Plus scenario electricity and hydrogen system in 2050 — from POMMES

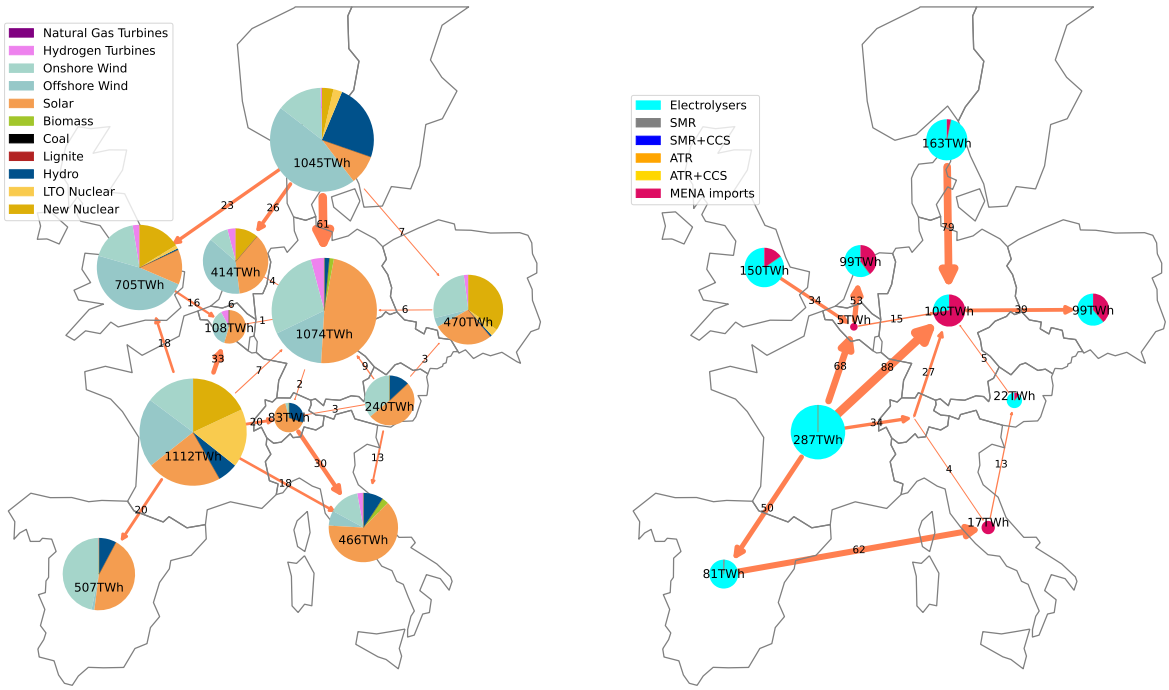


Fig. 3. No Fossil 2050 H_2_Exch_Plus scenario electricity and hydrogen system in 2050 — from POMMES

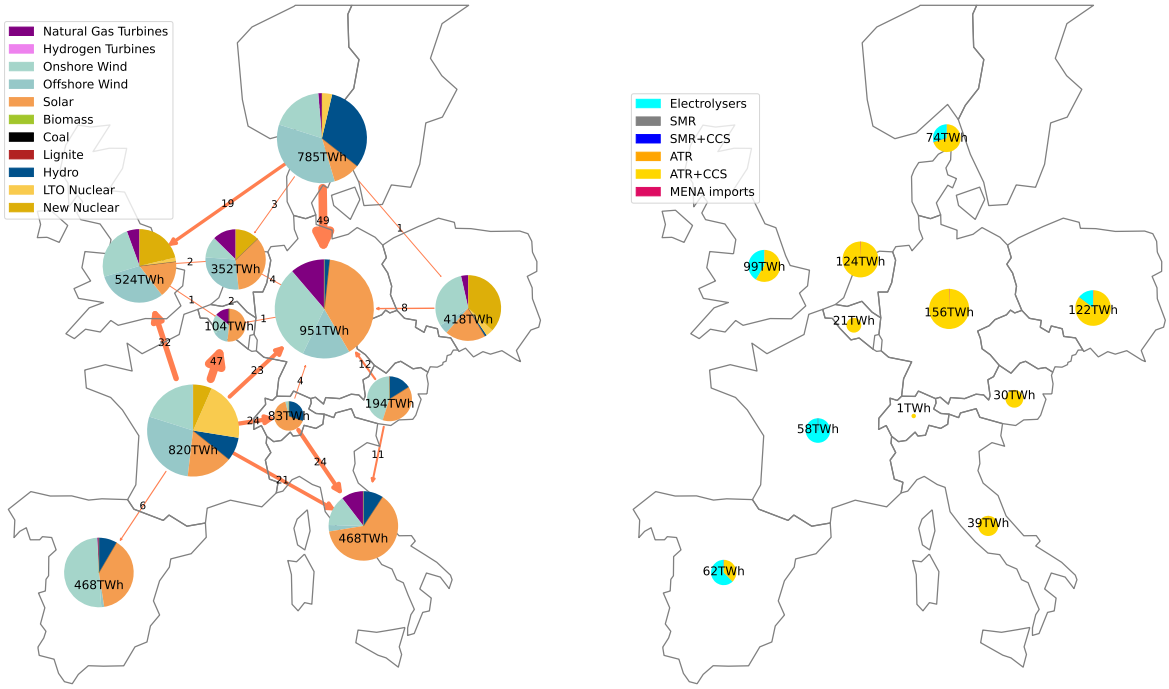


Fig. 4. Low Carbon Tax Central scenario electricity and hydrogen system in 2050 — from POMMES

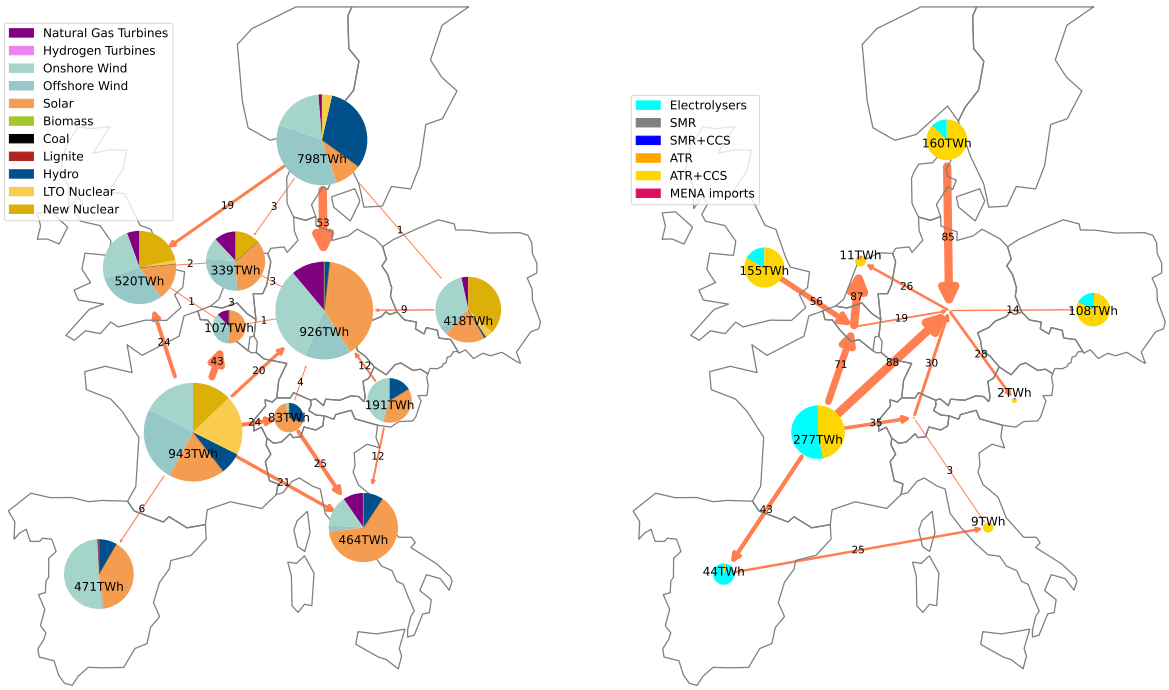


Fig. 5. Low Carbon Tax H_2_Exch_Plus scenario electricity and hydrogen system in 2050 — from POMMES