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MODELLING A CLEAN AND RESILIENT EUROPEAN ENERGY SYSTEM UNDER PHYSICAL, ECONOMIC, AND GEOPOLITICAL RISKS

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Abstract

Europe has committed to achieving climate neutrality by 2050, placing the transformation of the energy system at the centre of its climate, industrial, and economic strategy. While a large body of research has demonstrated the technical feasibility of deep decarbonisation pathways, it has mostly ignored mounting physical and geo-economic risks. Several structural factors challenge the assumption that cost-optimal solutions identified under idealised conditions are robust. Climate-induced weather extremes affect energy systems, European energy-intensive industry faces growing global competitiveness pressures, and geopolitical tensions and trade fragmentation reshape the environment in which the transition unfolds. This doctoral thesis investigates the resilience of European decarbonisation pathways under multiple, compounding risks. The thesis adopts state of the art energy, economic and climate modelling from a resilience perspective, analysing three key sources of risks: physical climate risks affecting power system adequacy, economic risks related to the competitiveness of energy-intensive industries, and geopolitical risks arising from trade policy disruptions. Methodologically, the thesis builds on high-resolution energy system modelling and extends existing frameworks to incorporate climate impacts, endogenous industrial production decisions, and macroeconomic feedbacks through soft coupling with a computable general equilibrium model. The results indicate that European climate targets are achievable, but that transition pathways are sensitive to climate-induced stress, industrial production scale decisions, and trade fragmentation. These findings suggest that effective decarbonisation under increasing uncertainty requires careful coordination between mitigation and adaptation, prudent industrial policy design, and a critical assessment of the extent to which trade tariffs contribute to climate objectives. The thesis demonstrates that resilience should be treated as a core objective of climate policy, alongside emissions reduction and economic efficiency, and highlights the need for integrated energy, industrial, and trade policy design to support a robust European energy transition.

Abstract in lingua italiana

L'Europa si è impegnata a raggiungere la neutralità climatica entro il 2050, ponendo la trasformazione del sistema energetico al centro della sua strategia climatica, industriale ed economica. Sebbene un'ampia letteratura scientifica abbia dimostrato la fattibilità tecnica di percorsi di decarbonizzazione profonda, essa ha in gran parte ignorato i crescenti rischi fisici e geo-economici. Diversi fattori strutturali mettono in discussione l'assunzione che le soluzioni ottimali in termini di costi identificate in condizioni idealizzate siano robuste. Gli eventi meteorologici estremi indotti dal cambiamento climatico influenzano i sistemi energetici, l'industria europea ad alta intensità energetica affronta pressioni competitive globali crescenti, e le tensioni geopolitiche e la frammentazione commerciale ridefiniscono l'ambiente in cui si svolge la transizione. Questa tesi di dottorato indaga la resilienza dei percorsi di decarbonizzazione europei sotto molteplici rischi che si sommano tra loro. La tesi adotta modelli energetici, economici e climatici allo stato dell'arte da una prospettiva di resilienza, analizzando tre fonti chiave di rischio: i rischi climatici fisici che influenzano l'adeguatezza del sistema elettrico, i rischi economici legati alla competitività delle industrie ad alta intensità energetica, e i rischi geopolitici derivanti dalle perturbazioni delle politiche commerciali. Dal punto di vista metodologico, la tesi si basa sulla modellizzazione ad alta risoluzione dei sistemi energetici ed estende i quadri esistenti per incorporare gli impatti climatici, le decisioni di produzione industriale endogene e i feedback macroeconomici attraverso l'accoppiamento debole con un modello di equilibrio generale computabile. I risultati indicano che gli obiettivi climatici europei rimangono raggiungibili, ma che i percorsi di transizione sono sensibili allo stress indotto dal clima, alle decisioni sulla scala di produzione industriale e alla frammentazione commerciale. Questi risultati suggeriscono che una decarbonizzazione efficace in un contesto di crescente incertezza richiede un'attenta coordinazione tra mitigazione e adattamento, una progettazione prudente delle politiche industriali e una valutazione critica della misura in cui le tariffe commerciali contribuiscono agli obiettivi climatici. La tesi dimostra che la resilienza dovrebbe essere trattata come un obiettivo centrale della politica climatica, insieme alla riduzione delle emissioni e all'efficienza economica, e sottolinea la necessità di una progettazione integrata delle politiche energetiche, industriali e commerciali per sostenere una transizione energetica europea robusta.

Summary

Europe has committed to achieving climate neutrality by 2050, positioning the transformation of the energy system at the centre of its climate, industrial, and economic strategy. This transition is often framed as a cost minimization problem under stable conditions: identifying low-carbon technologies and deploying them at scale to meet emissions targets at minimum expected system cost. A complete cost accounting requires incorporating additional risk dimensions. Climate change is already affecting energy demand and supply, industrial decarbonisation raises concerns about global competitiveness, and geopolitical tensions together with trade fragmentation reshape the external conditions under which the transition unfolds. Taken together, these dynamics suggest that minimizing the true expected costs of the European energy transition depends not only on optimizing under static assumptions, but also on accounting for the costs associated with vulnerability to multiple, interacting risks.

This doctoral thesis investigates how advanced energy system models can be used to identify decarbonisation pathways that remain resilient under climate stress, competitiveness pressures, and geopolitical disruption. Rather than focusing exclusively on cost-optimal solutions under idealised assumptions, where technology costs, supply chains, and climate conditions remain stable, the thesis adopts a risk-oriented perspective to identify robust decarbonisation strategies. This approach analyses how different sources of vulnerability may affect the transition: physical risks from climate impacts on energy systems, economic risks from competitiveness pressures and carbon leakage, and geopolitical risks from supply depen-

dencies and trade fragmentation. By examining these vulnerabilities and their interactions, the analysis identifies which strategies maintain cost-effectiveness across plausible disruptions and which policy interventions can enhance resilience. Three dimensions of risk are examined in particular: physical climate risks affecting energy system adequacy, economic risks related to industrial competitiveness, and geopolitical risks arising from international trade and policy fragmentation. Each of these risks is analysed through a dedicated modelling study, collectively forming a coherent assessment of how to strengthen European decarbonisation pathways against sources of uncertainty.

Research objectives and approach

Building on this risk-oriented framework, the overarching objective of this thesis is to identify the conditions under which the European energy transition can remain both technically feasible and socio-economically resilient when exposed to physical and geo-economic risks. The analysis focuses on three critical dimensions where these risks intersect with decarbonisation pathways. Each dimension corresponds to a distinct but interconnected source of vulnerability: the physical impacts of climate change on energy infrastructure and operations, the economic pressures facing energy-intensive industries in a fragmented global market, and the geopolitical forces reshaping international cooperation and trade. These dimensions are explored through the following research questions:

- How do climate-induced changes in future weather patterns affect the operation, adequacy, and investment needs of decarbonised power systems?
- Under which conditions can the decarbonisation of European energy-intensive industries remain globally competitive?
- How do international trade policies and geopolitical fragmentation interact with climate policies and energy system outcomes?

Methodologically, the thesis employs a progressive modelling strategy with increasing sectoral scope and economic comprehensiveness. The first research question uses an electricity-only system model (Oemof) to analyse climate impacts on power generation, transmission, and electricity demand. The second and third research questions employ PyPSA-Eur as a sector-coupled energy system model, endogenously representing electricity, heating, road transport, aviation, shipping, and industry. For the second research question, the industrial module is extended to include plant-level technology choices, existing capital stock, and production-level decisions. For the third research question, the sector-coupled model is soft-linked with a computable general equilibrium model to capture macroeconomic feedbacks and trade dynamics. A central methodological contribution of the thesis lies in the systematic coupling of power and energy system models with complementary modelling frameworks to capture the multidimensional nature of transition risks. To address the first research question, a power system model is coupled with regional climate models to incorporate climate-induced changes in weather patterns and their impacts on electricity supply and demand. For the second research question, an energy system modelling framework is extended to explicitly represent energy-intensive industrial production processes. For the third research question, the energy system model is soft-coupled with a computable general equilibrium model to capture macroeconomic feedbacks and international trade dynamics. Across all three studies, scenario analysis is employed to explore alternative futures and to stress-test decarbonisation pathways under adverse conditions.

Summary of the included articles

The first article examines climate change as a direct physical risk to power system operation and planning. While climate policy is typically motivated by the need to mitigate future climate change, this study shows that climate change itself can undermine the reliability of decarbonised power systems if its impacts are not explicitly accounted for.

Using the Italian power system as a case study, the article integrates empirically estimated climate impacts on electricity demand, thermal power plant availability, and hydropower production into a high-resolution capacity expansion and dispatch model. The results show that for this case study climate change significantly increases summer peak demand and exacerbates system stress during extreme weather events. Importantly, the study demonstrates that mitigation and adaptation strategies can be complementary: investments in solar photovoltaics and short-term storage, traditionally considered mitigation measures, simultaneously serve as adaptation by improving system adequacy under climate stress. By meeting increased cooling demand during hot periods when solar generation peaks, PV capacity provides resilience against the very climate impacts that decarbonisation aims to prevent. This article establishes that mitigation strategies must explicitly consider adaptation co-benefits, as certain technologies like solar photovoltaics can simultaneously reduce emissions and enhance resilience to climate impacts.

The second article focuses on the decarbonisation of European energy-intensive industries and the associated risks to global competitiveness.

Extending the sector-coupled energy system model to represent plant-level industrial production across five energy-intensive sectors (steel, cement, ammonia, methanol, plastics), the study explores alternative industrial trajectories, such as continued decline, stabilisation, and reindustrialization. The analysis shows that deep industrial decarbonisation in Europe for these sectors is technically feasible by mid-century, primarily through electrification and green hydrogen. However, maintaining competitiveness is highly sensitive to production scale. Aggressive reindustrialization leads to sharply increasing costs and unprecedented subsidy requirements, while more moderate pathways allow decarbonisation and competitiveness to co-exist within a narrow policy corridor. The study further evaluates strategies such as intra-European industrial relocation, imports of low-carbon intermediates, and targeted subsidies, highlighting the importance of extra-EU trade openness and sector-specific policy support that maintains production of globally competitive final goods while sourcing green intermediates from regions with lower renewable energy costs.

The third article addresses the interaction between climate policy and international trade in an increasingly fragmented geopolitical environment. The study employs a bidirectional coupling between a high-resolution energy system model and a macroeconomic trade model. Energy costs and low-carbon technology investments from the energy model feed into production costs and trade flows in the economic model, determining industrial competitiveness. Conversely, resulting changes in production and demand volumes feed back into energy and industrial demand patterns in the energy system model. This integrated approach evaluates the combined effects of European climate policies and trade measures such as USA tariffs on steel, revealing interdependencies that would remain hidden when analysing energy systems or trade policies in isolation. The results show that climate targets remain technically achievable and are driven primarily by internal climate ambition rather than by external trade policies, though this finding is specific to the moderate-scale USA steel tariffs examined and may not hold under more severe trade disruptions or supply-side shocks. Economic impacts of steel decarbonization are heterogeneous across regions, with Eastern Europe experiencing the largest relative output losses. This article highlights that safeguarding EU industrial competitiveness depends less on defensive trade measures and more on accompanying climate ambition with targeted industrial support, and region-specific transition policies that align climate, industrial, and social objectives.

Overall contribution and policy relevance

Taken together, the three articles in this doctoral thesis demonstrate that the European energy transition is achievable and can be made resilient through strategic policy design. From a policy perspective, the findings indicate that building a robust European energy transition requires integrated strategies that explicitly account for sources of risk. Climate adaptation must be embedded in energy infrastructure planning, recognising that certain mitigation technologies provide dual benefits. Industrial decarbonisation strategies must acknowledge competitiveness constraints and leverage international trade in low-carbon intermediates, rather than pursuing aggressive reindustrialization targets that prove economically unsustainable. Trade policy, in turn, should prioritise openness and targeted support over defensive protectionism, which generates costs without delivering lasting competitiveness gains and exacerbates regional disparities.

More broadly, the thesis demonstrates that resilience should be treated as a core design principle of European energy transition planning, alongside emissions reduction and cost minimization. From a methodological perspective, it shows how high-resolution energy system models are well suited to support this shift, as they explicitly represent infrastructure constraints, technology portfolios, and long-term investment decisions that shape system feasibility under stress. By extending these models beyond least-cost optimisation under idealised assumptions, through the integration of climate impacts, industrial dynamics, and macroeconomic feedbacks, and by using them to stress-test decarbonisation pathways, the analysis illustrates how energy system modelling can better inform policy design under real-world conditions of uncertainty. In this way, the thesis contributes to a more policy-relevant understanding of how Europe can pursue decarbonisation while maintaining economic viability and system robustness in an increasingly volatile global context.

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CHAPTER 1

General introduction and state of the art

1.1 Context and motivation

Energy systems constitute a foundational pillar of modern societies. They underpin economic activity, enable industrial production and mobility, support communication and digital services, and shape patterns of social welfare and development. Reliable and affordable access to energy has historically been associated with productivity growth, economic stability, and improvements in living standards, while disruptions to energy supply have repeatedly produced far-reaching economic and political consequences. As such, the organisation and transformation of energy systems is not merely a technical challenge, but a central concern for public policy, economic governance, and geopolitical strategy.

Over the past century, energy systems have evolved in close interaction with technological change, economic development, and political priorities. Fossil fuels have played a dominant role in enabling industrialisation and economic expansion, but their widespread use has also generated significant environmental externalities. Among these, anthropogenic climate change has become a central factor shaping contemporary energy policy, altering the objectives and constraints under which energy systems increasingly operate.

Anthropogenic climate change is firmly established in the scientific evidence base. The Sixth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) concludes that it is unequivocal that human activities have caused widespread warming of the atmosphere, ocean, and land, primarily through the combustion of fossil fuels, land-use change, and industrial processes [1, 2]. This assessment is supported by multiple independent lines of evidence, including attribution studies, observed trends in greenhouse gas (GHG) concentrations, and physical understanding of the climate system [3–5]. The recognition of human-driven climate change provides the fundamental scientific justification for climate mitigation policies and places energy systems, currently responsible for around 75% of global GHG emissions [6], at the centre of the transition challenge.

Climate change is already generating significant impacts on natural systems, human societies, and economic activity. Observed and projected impacts include sea level rise, increasing frequency and intensity of heatwaves, droughts, floods, and other extreme weather events, as well as long-term shifts in temperature and precipitation patterns [7]. These physical changes affect ecosystems, water availability, food production, human health, and infrastructure, leading to measurable economic losses and rising adaptation costs [8, 9]. Climate extremes such as heatwaves and droughts have direct implications for energy systems by altering electricity demand profiles, constraining thermal generation, reducing hydropower availability, and affecting the performance of renewable energy technologies [10–12]. As climate change intensifies, the interaction between climate impacts and energy system performance becomes increasingly critical for planning and policy.

Climate action is commonly framed around two complementary strategies: mitigation and adaptation. Adaptation refers to adjustments in natural or human systems in response to actual or expected climate impacts, with the aim of moderating harm or exploiting beneficial opportunities [7]. Mitigation seeks to limit the magnitude of future warming through rapid reductions in GHG emissions and enhanced carbon sinks, thereby reducing long-term climate risks [13, 14]. However, because a substantial degree of warming is already locked in due to historical emissions, adaptation is unavoidable and must proceed in parallel with mitigation efforts. Delayed mitigation increases both the scale of future impacts and challenges for adaptation, underscoring the importance of near-term action [15, 16]. For energy systems, this dual challenge implies not only decarbonising supply and demand, but also ensuring that future infrastructure remains resilient under evolving climatic conditions.

Within this global context, the European Union has positioned itself as a frontrunner in climate mitigation policy. The European Climate Law makes climate neutrality by 2050 legally binding and establishes an intermediate target of at least 55% net greenhouse gas (GHG) emissions reductions by 2030 relative to 1990 levels [17]. These objectives are operationalised through the Fit-for-55 legislative package, which updates the EU's climate and energy framework across key sectors [18]. Core instruments include the EU Emissions Trading System (EU ETS), which remains the central pillar of EU climate policy for power generation and energy-intensive industry [19], and the Carbon Border Adjustment Mechanism (CBAM), designed to address carbon leakage risks and align trade with climate objectives [20]. Looking beyond 2030, the European Commission has proposed a net GHG emissions reduction target of 90% by 2040, reflecting the need for a credible and continuous pathway between near-term action and climate neutrality [21].

Together, these policy packages translate long-term climate objectives into a set of interacting instruments and sectoral constraints whose combined effects are difficult to assess using qualitative reasoning alone. This complexity has made quantitative modelling indispensable for ex ante evaluation, enabling analysts and policymakers to explore feasible technology portfolios, infrastructure requirements, and cost and price implications under consistent assumptions and constraints.

This thesis employs a progression of modelling frameworks with increasing sectoral scope. The first research question uses an electricity-only system model, focusing on power generation, transmission networks, and electricity demand. The second and third research questions use a sector-coupled energy system model that endogenously represents electricity, heating, transport, and industry, accounting for energy carrier demands (electricity, hydrogen, and other fuels) across all major consuming sectors. However, because the industrial module in standard implementations primarily captures energy demand for industrial processes rather than production-level decisions, it was extended to explicitly represent industrial production volumes, technology choices, capital stock, and competitiveness constraints. The third research question further augments this extended energy system model by coupling it with a computable general equilibrium framework to capture macroeconomic feedbacks, international trade flows, and economy-wide distributional effects. This progressive approach allows each research question to be addressed with the appropriate level of sectoral and economic detail.

Energy system models have played a central role in assessing these policies and in exploring long-term decarbonisation pathways. They are formulated as optimisation-based representations that identify least-cost (or welfare-maximising) configurations of investments and operations subject to engineering, resource, and policy constraints, such as energy balance, network limits, operational feasibility, and emissions caps or carbon prices. The scope of these models ranges from electricity-focused frameworks to comprehensive multi-sector representations covering heat, transport, industry, and feedstocks. Many contemporary models adopt a modular approach, building outward from a high-resolution electricity system core to incorporate sector-coupling dynamics where relevant. To make these problems tractable, models typically rely on stylised behavioural and market assumptions (e.g., perfect foresight or myopic decision-making, representative agents, and equilibrium or cost-minimising dispatch), while treating key drivers such as technology costs, demand trajectories, and policy parameters as exogenous scenario inputs.

Since the oil crises of the 1970s, energy system modelling has been used to support energy security and strategic planning, gradually expanding to include environmental and climate dimensions [22, 23]. In this context, real-world experimentation with energy systems at continental scale is impossible, thus modelling provides a structured way to explore counterfactual futures, assess trade-offs, and evaluate the robustness of policy strategies under uncertainty. Over time, energy system models have increased in temporal and spatial resolution to better represent variable renewable energy, system flexibility, and infrastructure constraints [24, 25]. High-resolution frameworks now enable hourly simulations of power systems, detailed network representations, and sector coupling across electricity, heat, transport, and industry [26–28]. These advances have strengthened the policy relevance of modelling, while also raising questions about uncertainty, transparency, and the robustness of model-based insights [29].

Despite ambitious policy commitments, Europe's energy transition is increasingly exposed to multiple sources of risk. Climate change is no longer only a motivation for mitigation policy, but an active stressor of energy systems through its impacts on demand, generation, and system adequacy. At the same time, the decarbonisation of energy-intensive industries raises economic risks related to competitiveness, employment, and public finance. These challenges are further compounded by geopolitical tensions, trade fragmentation, and strategic competition over clean technologies and critical raw materials, which undermine assumptions of open markets and stable international trade. Under these conditions, the success of the energy transition depends not only on achieving emissions reductions at least cost, but on designing decarbonisation pathways that remain resilient to interacting physical, economic, and geopolitical risks.

A substantial body of literature has explored pathways towards deep decarbonisation of European energy systems, highlighting both the technical feasibility of large-scale emissions reductions and the complexity of system transformation [2, 30]. At the same time, Europe faces multiple obstacles in its transition towards a climate-neutral energy system and economy. Achieving Net-Zero requires large upfront investment in renewable generation, grid expansion, and industrial retrofitting, placing significant demands on public and private capital. Infrastructure bottlenecks, particularly in electricity transmission and emerging hydrogen networks, risk delaying the deployment of clean technologies [31, 32].

Importantly, these investments also generate system-wide benefits. Accelerating grid development can reduce renewable curtailment and congestion costs, dampen wholesale price volatility, and enhance security of supply in a more electrified energy system [33]. EU grid policy debates emphasise that insufficient grid capacity already leads to avoidable costs and lost clean generation, while targeted investments and improved permitting can deliver net system savings and support competitiveness, electrification, and energy security [34, 35]. Beyond infrastructure, the transition also raises social and distributional challenges, as costs and benefits are unevenly distributed across regions and income groups [36–38]. Uncertainty remains around the scalability and cost-competitiveness of emerging technologies such as green hydrogen and carbon capture [39–42], while coordination failures across Member States and sectors can fragment policy implementation and undermine efficiency within the single market [43–45].

Taken together, these challenges suggest that the European energy transition cannot be assessed solely in terms of cost-optimal decarbonisation pathways, but must also be evaluated in terms of its vulnerability to multiple sources of risk and uncertainty. It is within this broader context that this thesis focuses on three interacting risk dimensions shaping the resilience of the transition.

The first of these concerns climate change impacts on power systems, which can directly undermine the performance and reliability of electricity production and affect power demand. While climate change affects all energy vectors, its impacts are most directly observable in the electricity sector through effects on temperature-driven demand, renewable generation potential, and thermal plant efficiency. Rising temperatures, changing precipitation patterns, and the increasing frequency of extreme weather events affect both electricity demand profiles and the availability of renewable and conventional generation, with implications for power system adequacy, infrastructure planning, and operational costs [10, 11, 46]. As decarbonised energy systems increasingly rely on weather-dependent power sources and electrified end uses, these climate-driven stresses become more pronounced, raising concerns about whether electricity system designs based on historical climate conditions remain robust under future climatic regimes [7].

The second risk dimension concerns the competitiveness of energy-intensive industries during the decarbonisation process. Beyond the power sector, hard-to-abate industries such as steel, cement, and chemicals face particularly acute challenges due to their reliance on high-temperature processes, large energy inputs, and, in some cases, unavoidable process emissions [47, 48]. Transitioning these sectors to low-carbon production routes often requires capital-intensive technologies such as electrification, green hydrogen, or carbon capture, which can substantially increase production costs relative to incumbent processes. In an open economy such as the European Union, these cost increases translate into heightened exposure to international competition, potentially widening cost differentials with producers operating under less stringent climate policies. If not accompanied by appropriate policy measures, these dynamics can incentivise the relocation of production outside the EU (carbon leakage) or lead to a contraction of domestic industrial activity, thereby undermining both the economic viability and political sustainability of ambitious decarbonisation strategies [20, 49].

The third risk dimension arises from geopolitical developments and evolving trade dynamics that shape the external conditions under which the energy transition unfolds. Increasing trade fragmentation, strategic competition over clean energy technologies and critical raw materials, and the growing use of trade policy as a geopolitical instrument introduce uncertainty into global markets and supply chains [50, 51]. Energy price shocks and supply disruptions have demonstrated how geopolitical events can propagate rapidly through energy systems, affecting fuel availability, investment decisions, and production costs across sectors. For a transition that relies on internationally traded energy carriers, industrial inputs, and clean technologies, such disruptions can materially alter decarbonisation pathways and their economic outcomes.

Despite these realities, many energy system modelling studies continue to rely on simplifying assumptions, including the use of historical weather years, stable international trade relations, and exogenously specified industrial production levels. As a result, potential vulnerabilities arising from climate change impacts, trade policy shocks, and geopolitical fragmentation are often understated, limiting the ability of conventional modelling approaches to fully assess the resilience of European decarbonisation strategies under non-idealised physical, economic, and political conditions.

Together, these three perspectives narrow attention to specific dimensions of vulnerability within the European energy transition, allowing for a more focused assessment of how climate, economic, and geopolitical risks may affect the feasibility and stability of decarbonisation pathways. By leveraging advanced energy system modelling, augmented with climate impact data, industry-specific representations, and economic and trade linkages, this thesis explores how European decarbonisation pathways respond to selected climate, economic, and geopolitical stressors. Rather than aiming to comprehensively redefine the energy transition, the analysis isolates and evaluates particular vulnerabilities that are often abstracted from in conventional modelling approaches. The objective is to contribute targeted, policy-relevant insights on how robustness considerations can be more systematically incorporated into the assessment of European energy transition strategies.

1.2 Energy system modelling for policy analysis

Energy system models have become essential tools for climate and energy policy analysis in Europe, providing quantitative insights into the costs and implications of decarbonisation pathways. Since the 1970s energy crises, these models have evolved from supporting energy security assessments to addressing climate mitigation, environmental constraints, and economic interactions [22, 24]. Over the past two decades, this evolution has accelerated as the European Union has adopted increasingly ambitious climate targets, culminating in the legally binding objective of climate neutrality by 2050.

A large body of literature employs bottom-up energy system models to assess European climate policy scenarios. These models explicitly represent energy technologies, infrastructure, and operational constraints, allowing for detailed analysis of renewable integration, electrification, sector coupling, and system adequacy. Comprehensive studies demonstrated that deep decarbonisation of the European energy system is technically feasible using a combination of renewable electricity, electrification, and complementary low-carbon options [52]. Subsequent analyses refined these insights by quantifying the pace and scale of transformation required under different climate targets. Victoria et al. [53] show that achieving stringent climate goals implies historically unprecedented rates of deployment for renewables, grids, and storage, highlighting the importance of early action. Similarly, Pickering et al. [54] emphasise the diversity of technology portfolios capable of delivering climate neutrality, underlining that multiple pathways exist but each entails distinct trade-offs.

High-resolution modelling frameworks have played a central role in this literature. The PyPSA-Eur model, introduced by Horsch et al. [26], is an open-source framework that has evolved from power system model into a comprehensive sector-coupled energy system model. It enables continent-wide optimisation with explicit spatial and temporal detail, representing electricity generation and transmission networks alongside endogenous representation of heating demand (heat pumps, resistive heaters, district heating), aviation, shipping and road transport, and industrial energy demands for electricity, hydrogen, and other energy carriers. The model optimises investment and operation across these sectors jointly, capturing substitution effects and infrastructure requirements for sector coupling. As an open-source framework, PyPSA-Eur has fostered a growing collaborative research community, enabling transparent model development, methodological scrutiny, and rapid extension of the modelling framework to address emerging policy questions. A growing number of studies have applied PyPSA-Eur and related open-source frameworks to assess transmission expansion needs, flexibility requirements, and the interaction between power, transport, and heating sectors under European climate policies [52, 55, 56]. These analyses have been influential in shaping debates on infrastructure planning, system integration, and the feasibility of renewables-dominated power systems.

Comparable insights have been generated using alternative high-resolution modelling frameworks. As an example, the Calliope model has been widely used to analyse low-carbon energy systems, with Pickering et al. [54] demonstrating that modelling assumptions strongly shape conclusions on system diversity and resilience. Together, these frameworks underline the importance of detailed, open-source, and community-driven models in advancing evidence-based debates on European energy system transformation.

Energy system modelling is widely applied beyond Europe to assess decarbonisation strategies under diverse institutional, economic, and development contexts. In the United States, coupled energy-economy modelling frameworks are increasingly used to evaluate net-zero pathways and their distributional implications, showing that technology choices and revenue recycling mechanisms can significantly shape welfare outcomes across income groups [57]. In Latin America, open-source optimisation models such as OSeMOSYS have been applied to national transition planning, demonstrating that deep emissions reductions can be achieved alongside substantial socio-economic benefits through electrification, low-emission fuels, and efficiency improvements [58]. In sub-Saharan Africa, academic contributions emphasise that the policy relevance of energy system models depends not only on technical detail, but also on their ability to reflect political economy constraints, governance structures, and institutional feasibility [59]. Across Asia, integrated energy-economy modelling studies show that combining carbon pricing with targeted renewable investment can accelerate coal phase-out while mitigating adverse macroeconomic impacts, particularly in rapidly industrialising regions [60]. Similarly, applications to India highlight that rapid demand growth can offset gains from low-cost renewables, implying that deep decarbonisation requires coordinated policy measures beyond technology deployment alone, including regulatory constraints on fossil capacity and demand-side interventions [61]. Taken together, these studies illustrate that while modelling approaches and policy questions vary across regions, energy system models have become central tools for evaluating decarbonisation pathways, distributional effects, and policy trade-offs under region-specific constraints. This growing literature reinforces the relevance of extending energy system modelling beyond idealised least-cost transitions toward analyses that explicitly engage with economic, institutional, and political dimensions of the energy transition.

An increasingly important strand of the literature focuses on integrating climate model outputs into energy system modelling to assess the physical impacts of climate change on energy supply and demand. Rather than relying on historical weather data, these studies use bias-corrected climate projections to generate future time series for temperature, wind, solar irradiance, and hydrological variables, thereby enabling the evaluation of power system performance under non-stationary climate conditions. Applications at the European level show that climate change can materially affect electricity demand profiles, renewable generation patterns, and system adequacy, with implications for investment needs and operational flexibility [11,62,63]. By explicitly accounting for changing climate conditions and extreme events, this line of research highlights that decarbonisation pathways optimised under historical climate assumptions may underestimate future system costs and vulnerability.

In parallel, energy system models have increasingly been extended through the implementation of sector-specific modules to provide more detailed representations of key components of the transition. Examples include explicit modelling of energy-intensive industrial processes, transport technologies, hydrogen production and storage, and negative-emissions options. Such modular extensions allow researchers to capture sector-specific constraints, technology choices, and infrastructure requirements while retaining a system-wide perspective [64]. This approach has proven particularly valuable for analysing hard-to-abate sectors, where simplified representations risk overlooking critical feasibility and competitiveness issues. By embedding detailed sectoral modules within integrated frameworks, these studies improve the relevance of modelling results for policy design, especially when evaluating targeted interventions such as industrial subsidies, infrastructure planning, or sector-specific regulations.

Parallel to bottom-up analyses, integrated assessment models and macroeconomic frameworks have been widely used to evaluate EU climate policies from an economy-wide perspective. Fragkos et al. [65] analyse the implications of the EU's intended nationally determined contribution using the PRIMES model, quantifying energy system transformation and associated policy impacts. Weitzel et al. [66], using the JRC-GEM-E3 model, provide a detailed socio-economic assessment of EU climate policy pathways, highlighting distributional and labour market effects. These analyses underline the importance of capturing price signals, trade dynamics, and income effects when evaluating climate policies.

Hybrid and soft-coupled modelling approaches have emerged to better capture interactions between energy systems, the economy, and international trade. Academic applications demonstrate that linking computable general equilibrium models with detailed energy system models can substantially affect projections of energy demand, investment, and macroeconomic outcomes under climate policy scenarios [67]. Iterative coupling frameworks further show that feedbacks between long-term decarbonisation targets and short-term system operation influence price formation and infrastructure deployment in high-renewables systems [68]. Integrated computable general equilibrium-energy system modelling has been applied to regional climate mitigation analysis, revealing systematic differences in macroeconomic impacts compared to standalone economic models [69].

Building on this applied literature, this thesis positions energy system modelling as a tool not only for identifying cost-optimal decarbonisation pathways under idealised assumptions, but also for systematically stress-testing European climate strategies against a range of emerging risks. Energy system models are particularly well suited for this purpose because they enable internally consistent exploration of long-term infrastructure investments, technology portfolios, and system-wide constraints under explicit policy targets. In the context of deep decarbonisation, where capital stock turnover, network expansion, and technology deployment unfold over decades, such models provide a coherent framework for analysing feasibility and trade-offs that are difficult to capture through short-term or partial-equilibrium perspectives.

The results of this thesis are intended primarily for policymakers, system planners, and analysts involved in the design and evaluation of European climate, energy, industrial, and trade policies. Rather than prescribing specific actions, the analysis aims to inform strategic decision-making by identifying vulnerabilities, trade-offs, and boundary conditions under which policy objectives may conflict or reinforce one another. Accordingly, the findings should not be interpreted as forecasts of future prices, investment decisions, or market outcomes. Instead, they provide conditional insights into system behaviour under explicitly defined scenarios and assumptions, with the aim of supporting robust policy design rather than predicting realised transition pathways.

Optimisation-based energy system models embody a specific analytical paradigm. They typically represent a central planner who minimises total system costs subject to technical, policy, and environmental constraints. This abstraction facilitates transparent comparison of alternative system configurations and policy scenarios, but it also entails important limitations. In particular, these models do not explicitly represent decentralised market behaviour, strategic interaction among heterogeneous actors, imperfect information, or institutional frictions. As a result, critics from more market-oriented or behavioural traditions have argued that central-planning optimisation models may overstate coordination efficiency and underrepresent transition dynamics driven by investment risk, path dependence, and bounded rationality [70, 71].

Alternative modelling approaches have been proposed to address these limitations. Agent-based and behavioural models explicitly represent heterogeneous actors, such as firms, consumers, and investors, whose interactions generate emergent system outcomes without assuming global optimisation. Different works demonstrate that such approaches can capture diffusion dynamics, coordination failures, and distributional effects that are often abstracted from in optimisation-based frameworks [72, 73]. However, agent-based models typically operate at lower spatial or technological resolution and face challenges in representing large-scale infrastructure systems, network constraints, and long-term capacity planning in a computationally tractable way.

Rather than viewing these approaches as substitutes, this thesis adopts the position that different modelling paradigms are complementary and suited to different analytical questions. High-resolution optimisation-based energy system models are particularly valuable for assessing system feasibility, infrastructure adequacy, and long-term investment needs under binding climate constraints. By extending these models to explicitly incorporate climate impacts, industrial competitiveness considerations, and macroeconomic feedbacks through model coupling, this thesis leverages their strengths while partially addressing some of their known limitations. Accordingly, the results of this thesis should not be interpreted as forecasts of future prices, investment decisions, or market outcomes, but as conditional system-level insights under explicitly defined assumptions and constraints.

By focusing on climate change impacts on power system operation and planning, competitiveness constraints in the decarbonisation of energy-intensive industries, and disruptions to international trade and policy environments, the thesis extends existing modelling practice towards a more risk-aware and policy-relevant assessment of Europe's energy transition. This approach allows for the identification of vulnerabilities and trade-offs that may not be apparent in conventional cost-optimal analyses, while remaining grounded in quantitative, system-level modelling. In doing so, the thesis aims to support the design of climate and energy policies that are robust not only to cost uncertainty, but also to physical, economic, and geopolitical shocks that are increasingly shaping the European energy landscape.

1.3 Climate change as a risk to the energy transition

Climate change is commonly framed as the primary motivation for decarbonising energy systems, with mitigation policies typically represented in energy system models as exogenous constraints on GHG emissions. In many long-term transition analyses, however, the physical characteristics of the energy system, such as weather-dependent demand patterns and renewable resource availability, are assumed to remain broadly stable over time. This implicit assumption of climatic stationarity contrasts with a growing empirical literature documenting that climate change is already affecting energy systems and is likely to do so more strongly in the future. As a result, the physical impacts of climate change constitute an additional source of risk that is often insufficiently reflected in electricity decarbonisation pathways [10, 74, 75].

One of the most extensively studied channels through which climate change affects energy systems is temperature-driven changes in electricity demand. Empirical analyses across multiple regions consistently show that rising temperatures increase electricity demand for cooling, while reductions in heating demand during milder winters only partially offset this effect [12, 76]. Importantly, these relationships are highly non-linear, with demand responses increasing sharply at temperature extremes [77]. As a consequence, climate change can substantially raise peak electricity loads even when average annual demand changes are modest, with direct implications for capacity adequacy, network sizing, and system costs [46].

Climate change also affects electricity supply through multiple pathways. Hydropower generation is particularly sensitive to changes in precipitation patterns, snowmelt dynamics, and drought frequency, leading to shifts in seasonal availability and increased interannual variability [78, 79]. Thermal power plants can experience reduced efficiency or forced outages during periods of high ambient temperatures and water scarcity, especially in regions reliant on once-through cooling systems [63]. In addition, extreme weather events, including heatwaves, droughts, floods, and storms, pose direct risks to generation assets, transmission infrastructure, and fuel supply chains, increasing the likelihood of correlated system stress events [75, 80].

Despite this expanding evidence base, the explicit integration of climate impacts into energy system modelling remains limited. Many long-term decarbonisation studies continue to rely on historical weather data to represent renewable generation profiles and electricity demand, thereby neglecting projected changes in climate variability and extremes [81, 82]. Moreover, most modelling efforts focus on average climate trends, while tail risks and compound extreme events, which are particularly relevant for system adequacy and resilience, are less frequently explored. These modelling gaps are especially consequential for highly decarbonised power systems that rely heavily on variable renewable energy sources and electrified end uses. In such systems, adequacy and flexibility margins are typically tighter, and correlated climate-driven stresses on demand and supply can amplify system vulnerability. Ignoring climate impacts therefore risks underestimating both total system costs and the probability of adverse outcomes under future conditions [11]. Furthermore, mitigation and adaptation are often treated as separate policy domains, obscuring potential synergies between investments that simultaneously reduce emissions and enhance system robustness, such as grid reinforcement, storage deployment, and diversified renewable portfolios [75].

The first article included in this thesis contributes to this literature by explicitly modelling climate change as a physical risk to power system operation and planning. It integrates empirically estimated climate impacts on electricity demand and renewable generation into a high-resolution European power system model, and explicitly considers the role of extreme events in shaping investment and adequacy outcomes. The associated climate-energy dataset underpinning this analysis is documented by Di Bella et al. [83] and the article, on which I am the first author, has been published on *Environmental Research Infrastructure and Sustainability* [84].

1.4 Industrial decarbonisation and competitiveness

The decarbonisation of energy-intensive industries is widely recognised as one of the most challenging dimensions of the European energy transition. In the EU27, industrial activities emitted around 600 Mt of CO_2 in 2021, corresponding to approximately 20% of total EU greenhouse gas emissions [85]. These emissions are highly concentrated in certain sectors, with iron and steel accounting for about 22%, chemicals for 21%, and non-metallic minerals, including cement and glass, for roughly 32% of industrial CO_2 emissions [86]. These sectors are characterised by long-lived capital assets, high energy and process-related emissions, and strong exposure to international markets. As a result, their transition raises not only questions of technological feasibility and system costs, but also concerns related to international competitiveness, relocation incentives, and the coherence of European industrial policy.

A growing body of applied modelling literature has examined technological pathways for industrial decarbonisation in Europe, focusing on options such as electrification of heat, hydrogen-based processes, carbon capture and storage (CCS), reduced input consumption, and the use of low-carbon intermediates. Comprehensive assessments emphasise that decarbonisation strategies are highly sector-specific and depend strongly on energy prices, infrastructure availability, and regional context [47, 48]. Hydrogen-based production routes, in particular, appear prominently in European decarbonisation roadmaps, reflecting their potential role in steelmaking, chemicals, and fuel synthesis, but their competitiveness remains contingent on access to low-cost renewable electricity and large-scale hydrogen infrastructure [87–89].

Several studies embed industrial decarbonisation directly within energy system modelling frameworks to assess system-level implications under European climate policies. Neumann et al. [64] analyse hydrogen-based primary steel production using a high-resolution European energy system model, showing that while green steel is technically feasible at scale, its competitiveness is highly sensitive to electricity prices, renewable deployment, and system flexibility. This highlights the need to assess industrial decarbonisation jointly with power system expansion rather than as an exogenous demand. Raillard and Cazanove [90] examine European industrial transition pathways through a techno-economic framework that captures interactions between industrial technologies, energy carriers, and climate policy. Their results show that competitiveness outcomes depend strongly on trade assumptions, carbon pricing, and infrastructure availability, underscoring the interdependence of industrial strategy, trade, and energy system design. Complementary insights are provided by Madeddu et al. [91], who represent energy-intensive industries within an integrated European energy system model. Their analysis highlights the substantial electricity demand and infrastructure requirements associated with industrial electrification and hydrogen pathways, demonstrating that costs and feasibility depend critically on coordinated cross-sectoral planning and access to low-cost renewable electricity.

Despite these advances, a key limitation of many industrial decarbonisation modelling exercises is the assumption of fixed or exogenously specified industrial output. While this simplification is often appropriate for assessing technological feasibility and system costs, it constrains the ability to analyse competitiveness dynamics, relocation incentives, and structural change. In practice, industrial production volumes respond to relative production costs, policy incentives, and international market conditions, making the analysis of different production levels relevant for understanding system dynamics [92,93]. Moreover, the high production costs imposed by decarbonisation can undermine industrial competitiveness, necessitating alternative strategies to maintain Europe's industrial base. These include relocation within Europe to exploit regional cost advantages, imports of low-carbon intermediates to preserve downstream value chains, and targeted subsidies to support critical sectors. However, these options are frequently analysed in isolation rather than within a unified framework that captures their interactions and trade-offs under binding decarbonisation constraints.

Methodologically, this work builds upon and extends the PyPSA-Eur framework developed by Neumann et al. [64], shifting the analytical focus from system-level infrastructure requirements to the industrial sector itself. A novel contribution is the explicit representation of existing industrial plants, including their technology type, geographical location, and construction year, which allows the analysis to capture path dependencies and lock-in effects associated with the current industrial capital stock. In addition, the transition towards climate neutrality is analysed along the full pathway to Net-Zero within a myopic modelling framework, rather than being restricted to a single future target year. In contrast to previous studies that primarily emphasise transmission expansion, storage deployment, or least-cost system design, the second article in this PhD thesis explicitly focuses on policy-relevant strategies for industrial decarbonisation under competitiveness constraints. By comparing European production costs with global benchmarks and evaluating alternative strategies, including relocation within Europe, imports of low-carbon intermediates, and targeted subsidies, the study moves beyond standard cost optimisation. It provides a quantitative assessment of the conditions under which industrial decarbonisation and international competitiveness can coexist in Europe, rather than assuming production levels are preserved by construction. The full study, with myself as first author, is available on ArXiv as Di Bella et al. [94].

1.5 Trade, geopolitics, and policy fragmentation

The third article included in this thesis examines the interaction between climate policy, trade policy, and macroeconomic feedbacks by soft-linking a high-resolution European energy system model with a computable general equilibrium (CGE) model. A large body of literature has analysed European decarbonisation pathways using energy system models, providing detailed insights into technology deployment, infrastructure requirements, and system costs under increasingly stringent climate targets. Studies such as Seck et al. [95] and Löffler et al. [96] demonstrate the technical feasibility of deep decarbonisation based on electrification, renewable energy, and low-carbon fuels, while Victoria et al. [55] quantify the implications of early and coordinated action for system costs and investment needs. However, these analyses typically rely on exogenously specified demand trajectories and assume stable trade environments, thereby abstracting from macroeconomic adjustments and international competitiveness effects.

In parallel, a rich economic literature has explored the interaction between climate policy and international trade using macroeconomic and trade-focused frameworks. General equilibrium analyses have been widely used to assess carbon pricing, border carbon adjustments, and trade-related climate instruments, highlighting their implications for competitiveness, carbon leakage, and welfare distribution. For example, Böhringer et al. [20] evaluate the effectiveness and distributional consequences of carbon border adjustment mechanisms, while Shapiro [97] and Bellora et al. [98]

show that trade policies and tariff structures can implicitly subsidise or penalise carbon-intensive production, shaping global emissions outcomes. Although these studies capture economy-wide and trade-mediated effects, they generally rely on highly aggregated representations of the energy system, limiting their ability to assess technological constraints, system adequacy, and infrastructure bottlenecks associated with decarbonisation.

As a result, energy system and macroeconomic analyses of climate and trade policy have largely evolved in parallel, with limited integration between the two approaches. This separation risks overlooking important feedbacks whereby climate policies reshape energy prices and technology choices, influencing industrial costs, trade flows, and economic activity, which in turn feed back into energy demand and system configuration. The third article addresses this gap by combining the technological realism of high-resolution energy system modelling with the economy-wide perspective of CGE analysis, enabling a more comprehensive assessment of how climate and trade policies jointly shape Europe's decarbonisation pathways under conditions of increasing geopolitical and economic uncertainty. Different studies have advanced the coupling of energy system and economic models for climate policy analysis. Gong et al. [99] develop a bidirectional framework linking integrated assessment models with high-resolution power sector models, capturing feedbacks between long-term investment decisions and short-term system operation. Fattahi et al. [67] apply a soft-linking approach between a CGE model and a detailed energy system model to evaluate macroeconomic and energy system interactions under climate policy scenarios. Odenweller et al. [68] propose an iterative coupling between REMIND and PyPSA-Eur, enabling a consistent assessment of European decarbonisation pathways across temporal and spatial scales. Beyond Europe, Nishiura et al. [69] demonstrate the applicability of integrated modelling frameworks for regional and global mitigation analysis. Building on these advances, the present study develops a two-way soft-coupling framework linking the European energy system model PyPSA-Eur, extended to represent energy-intensive industries, with the CGE model FIDELIO [100]. FIDELIO is a multi-sector, multi-region CGE model developed by the Joint Research Centre of the European Commission to analyse the European economy within a consistent representation of production, consumption, trade, and factor markets. It captures interactions across sectors and Member States, international trade linkages, and the economy-wide effects of policy interventions, making it particularly suitable for assessing climate, industrial, and trade policies in the EU context. The coupling framework enables the consistent evaluation of climate and trade policies by capturing how changes in energy prices, carbon costs, and technology deployment feed back into economic activity, trade flows, and sectoral production, and vice versa. In contrast to one-way linking approaches, bidirectional coupling allows macroeconomic responses, such as changes in output, demand, and trade patterns, to influence energy demand and, in turn, the overall system configuration, thereby improving the policy relevance of the analysis.

Empirically, the article situates European climate policy within an increasingly fragmented international trade environment characterised by the use of tariffs, subsidies, and strategic trade measures. Using 2025 USA tariffs on steel [101] as a case study, the analysis quantifies how trade disruptions propagate through energy-intensive industrial sectors and interact with climate instruments such as the EU Emissions Trading System and the Carbon Border Adjustment Mechanism. By explicitly representing both energy system constraints and trade-induced economic adjustments, the study shows that trade policy can materially affect decarbonisation pathways, system costs, and competitiveness outcomes, even when climate targets remain unchanged.

The main contribution of the third article is therefore twofold. Methodologically, it extends the emerging literature on energy–economy model coupling by applying a bidirectional soft-linking approach at the European level, whereas previous studies have largely focused on individual Member States. Substantively, it provides a quantitative assessment of how climate policy outcomes are shaped by geopolitical and trade-related risks, highlighting that decarbonisation strategies that appear robust under assumptions of stable and open markets may be significantly altered under conditions of trade fragmentation. The complete study, on which I am first author, is currently under preparation for submission.

1.6 Research questions, contributions, and thesis structure

Building on the preceding review of the state of the art, the central research question of this doctoral thesis concerns identifying the conditions under which the European energy transition can achieve deep emissions reductions while remaining robust to climate-related, economic, and geopolitical disruptions. This overarching topic is addressed through three interrelated research questions, each examining a distinct but interconnected dimension of risk that shapes the feasibility and resilience of European decarbonisation pathways.

- **RQ1: Physical climate risks.** How do climate change impacts and extreme weather events influence power system operation and infrastructure investment in the transition to Net-Zero emissions? What synergies emerge when mitigation and adaptation strategies are jointly considered within electricity systems?

- **RQ2: Economic and competitiveness risks.** To what extent does industrial decarbonisation exacerbate or alleviate international competitiveness challenges faced by European energy-intensive industries? How effective are alternative policy strategies, such as intra-European industrial relocation, imports of low-carbon intermediate goods, and targeted subsidies, in reconciling climate ambition with industrial viability?

- **RQ3: Geopolitical and trade-related risks.** How do evolving trade policies, such as tariffs on steel imports, interact with European climate instruments to shape decarbonisation pathways? What are the resulting implications for industrial production, trade flows, and broader macroeconomic outcomes under conditions of geopolitical fragmentation?

These research questions employ a progressive modelling strategy that increases in sectoral scope and economic comprehensiveness. The first research question (RQ1) uses an electricity-only system model to analyse climate change impacts on power generation, transmission infrastructure, and electricity demand, isolating physical climate risks within the electricity sector. The second and third research questions (RQ2 and RQ3) employ PyPSA-Eur in its sector-coupled configuration, which endogenously represents energy demand and technology choices across different sectors. For RQ2, we extend the industrial module beyond its standard implementation, which primarily captures aggregate industrial energy demand, to explicitly represent production volumes, plant-level technology choices, existing capital stock, and competitiveness dynamics for energy-intensive sectors such as steel, cement, and chemicals. This extension enables the analysis of industrial decarbonisation strategies under economic constraints, including production relocation, imports of intermediates, and targeted subsidies. For RQ3, the extended sector-coupled energy system model is further augmented through soft-coupling with the FIDELIO computable general equilibrium model, allowing the analysis to capture macroeconomic feedbacks, international trade adjustments, sectoral output changes, and distributional effects across EU Member States. This three-stage progression, from electricity-only, to sector-coupled energy system with detailed industrial representation, to energy-economy coupling, reflects a deliberate analytical strategy in which each research question is addressed using the modelling scope appropriate to the specific risk dimension under investigation.

The thesis makes two main contributions. First, it delivers a methodological contribution by advancing the use of high-resolution, open-source energy system models as tools for analysing transition robustness under risk. This includes the integration of climate impacts into power system optimisation, the endogenous representation of industrial production decisions, and the coupling of energy system models with macroeconomic frameworks to capture economy-wide and trade-related feedbacks. Together, these modelling extensions enable the systematic stress-testing of European decarbonisation pathways against multiple, interacting sources of disruption.

Second, the thesis provides a policy-relevant contribution by generating insights directly applicable to the design of coherent European climate, industrial, and trade policies. By explicitly accounting for physical climate risks, competitiveness constraints, and geopolitical uncertainty, the analysis informs strategies aligned with the objectives of Fit for 55 and related instruments such as the Carbon Border Adjustment Mechanism. By building on transparent and community-developed modelling frameworks, the thesis further contributes to reproducibility, methodological scrutiny, and cumulative model development within the energy modelling community.

The remainder of this thesis is organised as follows. Chapter 2 provides an overview of the three articles that constitute this compilation thesis and outlines their individual contributions within a coherent research framework. Chapter 3 synthesises the findings of the first article, which examines the impacts of climate change on power system supply, demand, and adequacy. Chapter 4 presents the second article, focusing on the decarbonisation of energy-intensive industries in the European Union and analysing how increased production costs affect the international competitiveness of industrial goods. Chapter 5 is devoted to the third article, which investigates the interaction between trade policies and decarbonisation outcomes through the coupling of a high-resolution energy system model with a macroeconomic model. Finally, Chapter 6 concludes the thesis by summarising the main insights, discussing their policy implications, and outlining directions for future research. Separate appendices are provided for each article.

CHAPTER 2

Overview of the included articles

This doctoral thesis is structured as a compilation of three peer-reviewed, submitted or close to submission articles that collectively investigate the robustness of European energy transition pathways under different sources of risk. While each article addresses a distinct research question and policy domain, all three share a common methodological foundation based on advanced energy system modelling and scenario analysis. The leitmotif gluing them together is the progressive enhancement of energy system models through coupling with complementary modelling tools: in the first article through climate model outputs with a power system model, in the second article through an extended industrial processes module in an energy system model, and in the third article through soft-coupling of this final model with a CGE model. Together, they form a coherent body of work that examines the feasibility, competitiveness, and resilience of decarbonisation pathways in the European context.

The three articles differ in geographical scope (Italy vs EU27), modelling structure (electricity-only vs sector-coupled vs energy-economy coupling), and analytical focus. These differences reflect the specific requirements of each research question: climate impacts on power systems can be rigorously assessed at national level using electricity models, whereas industrial competitiveness and trade policy require continental-scale analysis with sectoral representation and macroeconomic feedbacks. This section clarifies the scope and methodology for each article and discusses how their findings can be integrated.

2.1 Article I: Climate change impacts on power system adequacy

The first article, *"Mitigation strategies can alleviate power system vulnerability to climate change and extreme weather: a case study on the Italian grid"*, investigates climate change as a direct physical risk to power system operation and planning. The study is motivated by the observation that many decarbonisation scenarios assume historical climate conditions, despite strong empirical evidence on temperature-driven demand changes and climate impacts on generation availability [10, 46, 78, 102]. This article focuses on Italy using an electricity-only system model, representing power generation technologies, electricity demand, and interconnections with neighbouring countries. Climate impacts on power systems operate primarily through temperature-driven electricity demand and weather-dependent generation, which can be assessed using high-resolution electricity models without requiring full energy system representation.

The analysis integrates empirically estimated climate impacts into a high-resolution capacity expansion and dispatch model, with explicit attention to extreme events. The results for the case study of Italy show that climate change substantially increases summer peak electricity demand and exacerbates system stress during extreme events. The study further demonstrates that mitigation and adaptation strategies can be complementary, as investments in solar photovoltaics and short-term storage can simultaneously reduce emissions and improve adequacy under climate stress. The supporting dataset is documented in Zenodo [83] and the full articled is published in *Environmental Research Infrastructure and Sustainability* [84]

2.2 Article II: Industrial decarbonisation and global competitiveness

The second article, *"Decarbonisation without deindustrialisation: assessing future pathways for European industry"*, focuses on the decarbonisation of European energy-intensive industries and associated competitiveness risks. It builds on literature reviewing industrial mitigation options and sectoral constraints [47, 48, 64] and investigates the policy conditions under which industrial decarbonisation can coexist with international competitiveness.

This article operates at the European scale using PyPSA-Eur as a sector-coupled energy system model, endogenously representing electricity, heating, shipping, aviation, road transport, and industrial energy demands across multiple carriers. Methodologically, the article extends PyPSA-Eur [103] to represent industrial production at plant and technology level. The study explores alternative industrial production level trajectories and evaluates strategies including intra-European relocation, imports of low-carbon intermediates, and targeted subsidies. A non-peer reviewed version of the paper is provided in ArXiv [94].

2.3 Article III: Trade policy, macroeconomic feedbacks, and transition resilience

The third article, *"Climate policy, steel decarbonisation, and trade fragmentation: a coupled energy-macroeconomic analysis for Europe"* examines how international trade policies interact with European climate policy in an increasingly fragmented geopolitical environment. It builds on the literature discussing border carbon adjustments and trade-climate interactions [97, 104, 105] and addresses the limitation that many energy system studies abstract from trade frictions and macroeconomic feedbacks.

This article uses the same European-scale sector-coupled configuration as Article II, including the extended industrial module. The key extension is soft-coupling with FIDELIO, a multi-region, multi-sector computable general equilibrium model representing 43 economic sectors across EU Member States and trading partners. The coupling is bidirectional: energy system results (electricity prices, hydrogen costs, carbon prices) update production costs in FIDELIO, while FIDELIO returns adjusted industrial output levels and trade patterns that feed back into the energy model iteratively until convergence. This integrated framework allows the joint assessment of climate and trade policies, consistent with recent developments in model coupling approaches [67–69]. The paper is close to finalisation.

CHAPTER 3

Mitigation strategies can alleviate power system vulnerability to climate change and extreme weather: a case study on the Italian grid

Abstract

This study explores compounding impacts of climate change on power system's load and generation, emphasising the need to integrate adaptation and mitigation strategies into investment planning. We combine existing and novel empirical evidence to model impacts on: i) air-conditioning demand; ii) thermal power outages; iii) hydro-power generation shortages. Using a power dispatch and capacity expansion model, we analyse the Italian power system's response to these climate impacts in 2030, integrating mitigation targets and optimising for cost-efficiency at an hourly resolution. We outline different meteorological scenarios to explore the impacts of both average climatic changes and the intensification of extreme weather events. We find that addressing extreme weather in power system planning will require an extra 5-8 GW of photovoltaic (PV) capacity, on top of the 50 GW

of the additional solar PV capacity required by the mitigation target alone. Despite the higher initial investments, we find that the adoption of renewable technologies, especially PV, alleviates the power system's vulnerability to climate change and extreme weather events. In fact, renewable energy sources are generally less vulnerable to the impacts of climate change, such as rising temperatures and shifting precipitation patterns, compared to thermal power and hydropower generation. Furthermore, enhancing short-term storage with lithium-ion batteries is crucial to counterbalance the reduced availability of dispatchable hydro generation.

3.1 Introduction

The complex and urgent challenge posed by climate change, including more frequent and severe windstorms, heavy precipitation, droughts, and wildfires, can significantly increase risks to power infrastructure and energy systems [106]. At the same time, nations are increasingly committing to fundamentally reshape energy infrastructures, transitioning them towards low-carbon solutions to mitigate the adverse effects of climate change [107]. Nevertheless, the impacts of climate change are already evident in daily life, with projections indicating that these effects will intensify [108]. As a result, it is imperative to design and plan future energy and power systems with a dual focus: not only on mitigating climate change but also on ensuring adaptation to the impacts that will arise. The need for planning with a focus on both climate change mitigation and adaptation is particularly crucial when considering the electricity sector. Firstly, future power infrastructure will increasingly depend on variable renewable energy sources (VREs), which are far more weather-dependent than traditional fossil-based thermal plants [109]. Secondly, a widely recommended strategy for decarbonising other sectors of the economy is the electrification of final demand [110]. This shift will require significant increases in electricity production, which may be more susceptible to weather-related risks due to the higher penetration of VREs. Consequently, careful planning is essential to ensure that future power systems are both sustainable and resilient in the face of these challenges. In the case of the European Union (EU), power systems are already undergoing significant transformations, with nearly one-third of the region's electricity now generated from renewable sources such as hydropower, solar, and onshore wind [111]. As electrification progresses and the integration of RES deepens, European energy systems are becoming increasingly dependent on weather conditions.

Climate change impacts every stage of the electricity generation process:

supply side, transmission and distribution networks, and load patterns. On the demand side, elevated temperatures can lead to increased electricity consumption for air conditioning during the summer, while warmer winters may reduce demand for heating: these changes affect not only the overall electricity demand but also result in higher load peaks and alterations in the power load profile [46,102,112–116]. As populations adapt to climate change, analyses on the influence of demand-side shocks on power systems are crucial for planning resilient systems. Some studies consider aggregated timespans, seasonal parameters or daily peaks for the electricity load [116–118], while others reach an hourly resolution for temperatures and power demand [115, 119]. Having estimates at a fine detail appears critical to enhance the resilience of the power sector, which could suffer during hours of high demand and low availability of supply [120]. Most of the literature has provided evidence of the short-term, intensive margin adjustments, examining how immediate changes in temperature influence electricity demand on a day-to-day or hour-by-hour basis [46,117,121,122], disregarding instead long-run extensive margin adjustments. Over the past two decades, AC usage has increased rapidly in both developed and developing regions [123], highlighting the critical need for novel analyses to better understand the implications of AC adoption on power system planning [102].

As previously introduced, climate change also has significant impacts on the generation side of the power infrastructure. Higher air and water temperatures can reduce the cooling efficiency of thermal power plants, leading to reduced power output. Coal and nuclear plants, which operate using steam-turbine processes, can experience significant operational challenges during droughts. Variations in stream flow levels and elevated temperatures can substantially impact the availability of cooling water required for these plants to function at full capacity [62]. Gas-fired power plants, operating though combustion-turbine processes that require little or no water for cooling, can be affected by a reduction in the efficiency of turbines due to extreme ambient temperatures, ultimately leading to power output reductions [120]. Recent work has underscored that climate change has already increased curtailment of thermal power plants [63].

Climate change can increase the frequency of prolonged droughts, which can reduce water availability for hydropower. A large body of literature has focused on how water scarcity due to climate change can undermine power generation of hydroelectric dams [79, 124–127]. van Vliet et al. observe that climate change is projected to lead to significant regional variations in hydropower potential: some areas are expected to experience substantial increases in potential, while others may face considerable decreases, such as the United States and southern Europe [124]. Turner et al. corroborate these findings, highlighting the pronounced regional variability in hydropower impacts and emphasising the considerable investment required to adapt to anticipated changes in water availability [79]. Climate change also significantly impacts renewable power generation. Heatwaves and high temperatures can reduce the efficiency of solar panels, while altered wind patterns can affect wind turbine output [106, 128]. Evaluating these effects is complex, and there is limited consensus on the magnitude and direction of climate-induced impacts on variable RES, particularly when addressing issues at the country level [10, 81, 128–132].

Finally, weather-related impacts on transmission and distribution systems are expected to be amplified by climate change. Increased frequency and severity of extreme weather events, such as storms and high winds, can cause physical damage to infrastructure, leading to outages and disruptions [133]. Additionally, higher temperatures can affect the efficiency and capacity of transmission lines, increasing the risk of overheating and reducing performances [129, 134, 135]. Transmission capacity, crucial for the integration of the future electricity grid, might be significantly reduced during summertime due to increased peak temperatures [120].

To provide policymakers with strategies for enhancing the resilience of power systems, integrating climate change impacts on both supply and demand into a comprehensive modelling framework is essential. Weather and climate effects can disrupt electricity operations, leading to increased costs, load shedding, or outages if demand exceeds forecasts or power capacities are compromised. Only a few studies incorporate high-frequency supply and demand forecasts under climate change, enabling an evaluation of effective responses. Tobin et al. [136] assess climate impacts on European electricity production and suggest increasing resilient RES like wind and solar. Bloomfield et al. [81] highlight substantial climate-induced variability in Europe's energy balance by 2050, stressing the need for better integration of climate uncertainty in planning.

Optimisation models are traditionally employed to develop strategies for power capacity planning, especially when incorporating future mitigation goals [24], while the integration of empirically-estimated climate change impacts in energy models is more limited (country-level studies include [76] and [137]). IAM-based projections provide valuable insights; however, their findings tend to be aggregated in both space and time due to the broad nature of aggregated energy demand [138]. In contrast, high-resolution bottom-up power system models offer more detailed analysis, making them better suited for understanding the complexities of the interplay between mitigation and adaptation within the power system. Bottom-up models might advance our vision on the hourly and local consequences of future climate, since they generally have a larger spatial and temporal resolution compared to IAMs [139]. In a few cases, regional versions of leading IAMs have been coupled with power-system models with the aim of assessing climate change impacts on peak load and generation ([140], [141], [142]). To the best of our knowledge, Handayani et al. is one of the few research articles that thoroughly explores the intricate relationship between optimising mitigation and adaptation strategies in power sector planning [142].

In this context, this paper makes two significant contributions to both academic literature and power system investment planning. First, it stands out as one of the few studies that simultaneously addresses decarbonization goals and the impacts of climate change on various power generation technologies and electricity demand while modelling power system expansions. Unlike existing research that typically focuses on long-term pathways (e.g. [142]), this paper examines the operation and optimal capacity requirements for a specific year. This approach provides high temporal (hourly) and spatial (market zones) resolution, which is crucial given that climate change effects can be highly localised and may vary significantly at different times of the day. As a second contribution, by delineating various scenarios, this paper addresses the inherent uncertainties associated with climate change. Our goal is not only to assess the optimal investment strategy under average future weather conditions but also to evaluate the requirements for extreme weather scenarios. This approach enables a comprehensive understanding of how investment strategies might need to adapt to both typical and atypical climatic conditions. In this paper, we explore the implications of both demand and supply side shocks on energy system planning using a bottom-up capacity expansion model, focusing on the power system planning for Italy in 2030. In this study, we build upon previous work by employing an integrated modelling approach to provide a more complete and rigorous analysis. We optimise the least-cost electricity system across various weather scenarios to account for potential future climatic conditions. By defining various weather scenarios for 2030, we can evaluate the impacts of both average near-future climate shifts and more extreme weather conditions. We combine existing and new empirical evidence to expand the understanding of power demand shocks and supply impairments under future climate change, with a focus on the implication of increased temperatures on air-conditioning demand, thermal power outages and hydropower generation.

The remaining sections of this paper are organised as follows. Section 3.2 outlines the methodology used, including the empirical evaluation of climate change impacts on power supply and demand, as well as the development of the bottom-up model for the Italian power system. Section 3.3 presents the findings of the study, while Section 4.4 provides a discussion of these results. Finally, Section 5.5 outlines the possible implications for policy-making, and addresses the study's limitations along with recommendations for future research.

3.2 Materials and methods

3.2.1 Italian power system

In order to evaluate the effects of climate change on the Italian power sector in 2030 we adopt a power system modelling framework developed based on the open source model *oemof*, which consistently represents electricity dispatch and optimisation (the model is described in details in Appendix A.3). A version of the power system model is available on *GitHub* at [143] and was already employed in peer-reviewed studies [144, 145]. The Italian power system is described with an hourly resolution, divided into the seven market zones defined by the transmission system operator Terna [146, 147]. The model includes the existing power generation capacities up until the year 2021, then the optimiser is able to install new power plants to minimise the total system costs within the limits of model constraints (outlined in Appendix A.3). In the majority of the outcomes, the optimisation is performed assuming the implementation of the mitigation policies for Italy, which are legally binding according to the European Climate Law [148]. The European decarbonization goal for 2030 is to decrease carbon dioxide released in the atmosphere by 55%, in line with the *Fit-for-55* policy package [18]. A larger effort is expected from sectors in the EU Emission Trading Scheme (which are electricity and heat generation, energy-intensive industry sectors, aviation and maritime transport) reaching a 62% decrease in CO_2 emissions [149, 150]. In particular, the power sector can count on more mature technologies than other energy sectors and it is a fundamental enabler of the transition of other energy sectors through electrification [151]. Therefore, in this model we impose to the Italian power system in 2030 a reduction of CO_2 emissions of 65% of electricity emissions with respect to their value in 1990 (they were 124.6 Mton of CO_2 [152]). Additionally, in Section 3.3.3, we present scenarios in which no mitigation policies are applied (denoted as $NonMitigated$ cases) to evaluate the implications of adapting the power system for climate resilience compared to the $Mitigated$ cases.

The various elements of the power system necessary to shape the Italian electricity system are delineated in the Appendix A. Key features include: i) multiple market zones linked in the model through high-voltage transmission lines; ii) power production resources including natural gas, rooftop and utility scale photovoltaic, wind onshore and offshore, run-off-river, reservoir hydro, biomass and geothermal generation and imported electricity; iii) the possibility to add storage capacity for lithium-ion batteries and hydrogen storage technology, composed of electrolysers, fuel cells and hydrogen tanks. The model outcome has been validated with the data from the Transmission System Operator for the baseline year of 2019 [153].

3.2.2 Climate variables

Data

Historical weather patterns are derived from weather reanalysis data for the forty years from 1981 to 2020 (following a method from [154]), available from ERA5 and ERA5-Land [155]. We chose a time period of several decades centred around 2000 to strike a balance between - from the one side - evaluating weather conditions close to recent years and - from the other side - including several decades of weather data in order to derive reliable distributions of weather patterns. Nevertheless, we show that the impacts we estimate are largely unchanged if we restrict the time span of our historical weather scenario to the two decades of 2001-2020 (see Supplementary Information and Supplementary Figure A.7).
The future climate projections derive from one CMIP5 EUROCORDEX Global and Regional Climate Model (GCM and RCM) (the GCM ICHEC-EC-EARTH and the RCM KNMI-RACMO22E). This data was preferred over CMIP6 climate projections because the former has hourly resolution, allowing us to conduct an assessment of climate change impacts retaining the high temporal frequency of the historical reanalysis ERA5 data. We consider as main future emission scenarios the RCP 4.5 (we find that no substantial differences arise with respect to hotter climate scenarios, e.g. RCP 8.5, in the time horizon of our analysis, centred around 2030, see Supplementary Figure A.8). We match the historical period to the ERA5 reanalysis baseline period (1981-2020) and consider as future period the two decades around 2030 (2021-2040). In this way, our climate change im-

pact projections should be considered as medium-term shifts in the climate occurring over three decades. While mean climate changes over only three decades might lead to negligible shifts in the mean climate conditions, the focus of this work is on both the mean and the tails of the weather distribution, allowing to test if power system planning will be impacted by climate change even in the next few decades, due to an amplification in extreme weather conditions. Both historical ERA5 reanalysis and future CORDEX projections data are taken from the population-weighted dataset of [156], available for Italy at the NUT3 level.

Definition of scenarios

The impacts of weather patterns on the supply- and demand-side of the electricity system are included in the paper by considering four alternative scenarios developed separately for each impact category: demand for power, hydropower supply, thermal power supply and VREs power supply.

We start by considering a number j of weather variables (W^j) - such as daily maximum temperatures - at the NUTS3 level (n) for each hour (h), calendar day (d) and year (y). From each weather variable $W^j_{n,h,d,y}$ we derive the power system impacts based on different methodological approaches depending on the impact type (described in detail in Section 3.2.3 and Appendix A.2.2). Regardless of the specific approach, we can generalise the method adopted for the computation of impacts as follows. Consider the location- and time-specific impacts $\Upsilon_{n,h,d,y}$ computed from the weather variable W^j through a damage function $f()$:

$$\Upsilon_{n,h,d,y} = f(W^j_{n,h,d,y}) \tag{3.1}$$

First, we compute the impact of mean historical weather on the power generation variables (scenario *Historical Mean,* HM) by taking the average over all years y of $f(\hat{W}^j_{n,h,d,y})$ for a given location, hour and calendar day, where $\hat{W}^j_{n,h,d,y}$ is a weather variable of the ERA5 weather reanalysis spanning from 1981 to 2020:

$$\Upsilon^{HM}_{n,h,d} = \frac{\sum_y f(\hat{W}^j_{n,h,d,y})}{y} \tag{3.2}$$

Second, we use the delta change-method, adopted extensively in the climate impact literature (see for instance [157–159]) to calculate the impact due to the shift from the mean historical weather to the mean weather around 2030 (scenario *Future Mean*, FM). More in detail, we compute the climate change amplification (Δ) as the difference between the future and historical EUROCORDEX projections of each weather variable $Z^{j}_{n,h,d,j}$ for n, h and d, where means are computed over 20 years around 2010 k (2001-2020)[1] and 20 years around 2030 (2021-2040) m:

$$\Delta^{j}_{n,h,d} = \frac{\sum_m Z_{n,h,d,j}}{m} - \frac{\sum_k (Z_{n,h,d,k})}{k} \tag{3.3}$$

To identify the impact of the scenario *Future Mean*, we add the amplification Δ to $\hat{W}^{j}_{n,h,d,y}$ and, similarly to equation 3.2.2, we take the average impact over the years y (note that Δ is common across all years):

$$\Upsilon^{FM}_{n,h,d} = \frac{\sum_y f(\hat{W}^{j}_{n,h,d,y} + \Delta^{j}_{n,h,d})}{y} \tag{3.4}$$

The implementation of $\Upsilon^{HM}_{n,h,d}$ and $\Upsilon^{FM}_{n,h,d}$ on a power system model allows to compare how slowly moving climatic changes in the mean weather conditions can affect the optimisation of power system capacity planning. Then, we evaluate the implications of weather-related impacts that occur in the tails of the historical and future simulated weather distributions, respectively. The two alternative extreme weather scenarios (HE and FE) are constructed by considering the tail of the distribution of possible weather impacts resulting from $f(\hat{W}^{j}_{n,h,d,y})$, based on a quantile function $Q^{\chi}()$ and a quantile threshold χ. We consider as alternative values for χ the 75th and 95th percentile of impacts. While the impacts in the model are identified at the regional and hourly level, the computation of the percentile is done by ranking each possible weather simulation at the annual and country level. In other words, we rank each of the possible weather realisations based on their aggregated country-level impact. We then select the 10 and 2 years which have the highest simulated impact for the 75th and 95th quantile thresholds respectively. Finally, we take the average the hour- and calendar-day specific impact in the subset of selected years, with the aim of reconstructing the simulated extreme weather conditions while at the same time maintaining a plausible inter-annual variability deriving directly from the observed reanalysis data characterising the selected years.

Note that when we evaluate each impact category in isolation we simulate shocks occurring once every four years (75th percentile) or once every twenty years (95th percentile). On the other hand, the model run that

[1] We test two different historical periods baselines, alternatively 1981-2020 and 2001-2020. We find negligible differences in the amplification effect of climate change, as reported in Figure A.7.

combines extreme weather shocks of all impact categories (demand, hydropower and thermal generation) has a different implied probability given that some years in our distribution exhibit a pattern of co-occurrence of extreme weather impacts across multiple categories (as reported in Table 3.1).

In the case of the *Future Extreme*, the amplification of climate change is accounted for by adding the Δ amplification as in Eq. 3.2.2.

$$\Upsilon^{HE,\chi}_{n,h,d} = \frac{\sum_{p(y)^\chi} f(\hat{W}^j_{n,h,d,p(y)^\chi})}{p(y)^\chi} \tag{3.5}$$

$$\Upsilon^{FE,\chi}_{n,h,d} = \frac{\sum_{z(y)^\chi} f(\hat{W}^j_{n,h,d,z(y)^\chi} + \Delta^j_{n,h,d})}{z(y)^\chi} \tag{3.6}$$

Where $p(y)^\chi$ and $z(y)^\chi$ are the subset of years among the historical and future simulations selected, respectively, depending on the given percentile threshold χ.

Table 3.1 presents a summary of the method used to compute the different weather impact scenarios:

Table 3.1: *Computation of alternative weather impact scenarios*

Acronym	Period	N. years	Statistic	Equation
HM	Historical	40	Mean of all years	$\frac{\sum_y f(\hat{W}^j_{n,h,d,y})}{y}$
HE	Historical	10	Mean of years above 75th percentile	$\frac{\sum_{p^{75}} f(\hat{W}^j_{n,h,d,p^{75}})}{p^{75}}$
HE	Historical	2	Mean of years above 95th percentile	$\frac{\sum_{p^{95}} f(\hat{W}^j_{n,h,d,p^{95}})}{p^{95}}$
FM	Future	40	Mean of all years	$\frac{\sum_y f(\hat{W}^j_{n,h,d,y}+\Delta^j_{n,h,d})}{y}$
FE	Future	10	Mean of years above 75th percentile	$\frac{\sum_{z^{75}} f(\hat{W}^j_{n,h,d,z^{75}}+\Delta^j_{n,h,d})}{z^{75}}$
FE	Future	2	Mean of years above 95th percentile	$\frac{\sum_{z^{95}} f(\hat{W}^j_{n,h,d,z^{75}}+\Delta^j_{n,h,d})}{z^{95}}$

3.2.3 Impacts on electricity demand

The response of the hourly electric load to temperature is computed taking into account two aspects: the short-run co-variation between load and weather as well as the long-run amplification in the short-run load-weather relationship due to the growth in the adoption of air-conditioning appliances in the residential sector. First, in order to identify the increase in electricity demand related to the growth in AC uptake across Italian households we use an empirically estimated response function that provides a generalised functional relationship between daily maximum temperatures, AC market saturation and peak load demand, provided by [102]. We project the prevalence of residential AC ownership rates in Italy at the regional (NUTS 2) level by associating for each location and year the probability of AC ownership in households based on the adoption function of [102] (the detailed equation used by this study are shown in the Supplementary Information).

Historical AC ownership rates at the regional level are taken from the Italian Budget Survey published by ISTAT for the year 2019 [160]. The projected regional AC share is shown in the Supplementary Figure A.6. In general, the average AC ownership rate in Italy goes from 33% in 2019 to 47%-55% in 2030 under RCP 4.5-8.5. The regions with the highest current as well as future AC share are the ones characterised by higher annual CDDs (Sardegna, Sicilia, Puglia) or by higher income per capita levels (Veneto, Emilia-Romagna, Lombardia).

Second, we couple the future NUTS3-level hourly temperature projections provided by [156] and the NUTS2 AC prevalence levels to estimate the amplification of hourly electricity demand due to climate change, based on the temperature-load coefficients ($\widehat{\beta}$) resulting in the non-linear function $h()$ estimated in [102] (taking the form shown in the Supplementary Methods), and the projected hourly temperatures provided by [156]. As in [138] the non-linear temperature-load function $h()$ is defined based on the population-weighted temperatures binned into k intervals of 3°C width, $B_k = [\underline{T}_k, \overline{T}_k)$, here we construct a k-vector of indicators that track whether each hour's mean temperature falls within a given interval:

$$T^k = 1 \cdot \{T \in B_k\} + 0 \cdot \{\text{Otherwise}\}$$

.

The observed historical binned hourly temperature for each location (n) for each hour (h), calendar day (d) and year (y), $\widehat{T^k_{n,h,d,y}}$ and the difference in the EUROCORDEX climate series for the historical and future epochs $\Delta(T^k_{n,h,d})$ are used to project the impact on the hourly load based on the historical and future AC prevalence levels, respectively, in each scenario, based on the equations presented in 3.2.2. An important note has to be done on the impacts of meteorological variables on electricity demand for heating, visible in Figure 3.1 panel a for the winter months. The correlation for the effects of temperature on power load for heating are produced using the whole Europe as a sample, thus they include various levels of heating electrification. In Italy, currently, the final consumption for space heating met with electricity is 1 TWh [161]; projections assume that the number and capacity of heat pumps in Italy will double by 2030 [162], we can assume to also double the consumption, thus 2 TWh would be around 2%

of the winter consumption of electricity. This value will be used to cap the reduction during winter months in order to offer plausible results.

Figure 3.1 Panel a shows how the mean temperatures vary in each season depending on the scenario. A large increase is observable in mean temperatures during summer but also a higher frequency of warm temperatures in winter. Panel b shows the resulting amplification of the hourly load in the summer around 2030, with respect to the *Historical Mean* scenario, averaged for all bidding zone. Maximum and mean amplifications of the hourly load at the national level reach over 30% and 20% in the central hours of summer months, respectively.

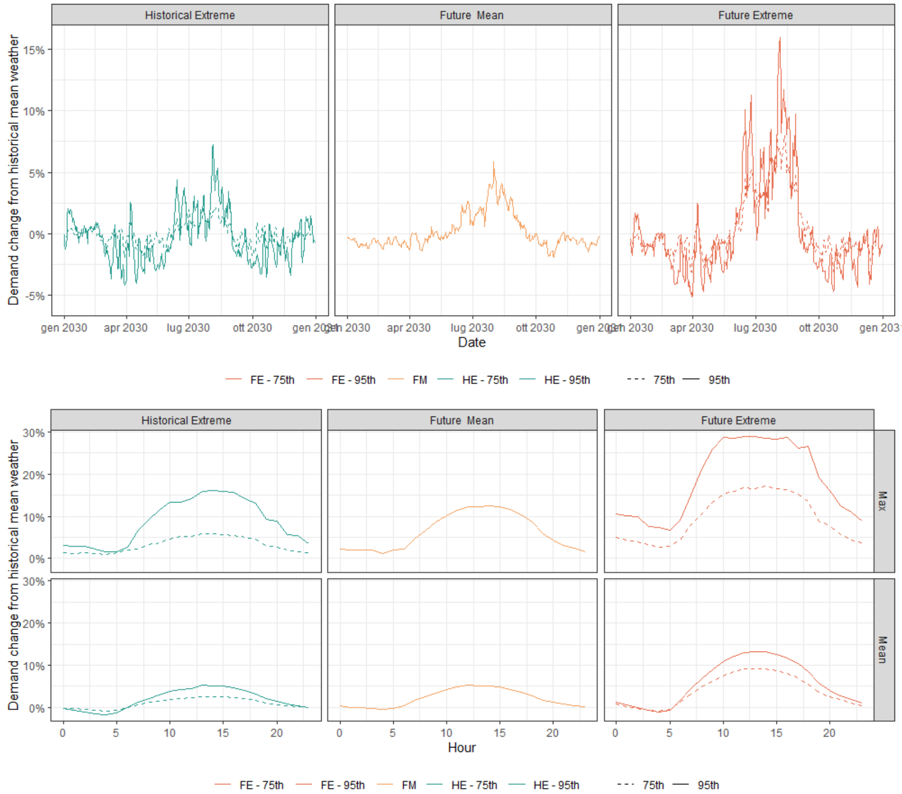

Figure 3.1: *Climate change impacts on electricity demand. Panel above: Changes in daily load with respect to the mean weather scenario, in each alternative climate scenario. Panel below: Changes in hourly load n the summer with respect to the mean weather scenario, in each alternative climate scenario. Solid lines show the change of the 95th percentile, while dashed lines of the 75th percentile.*

3.2.4 Impacts on power generation

In this work we take into account the potential impact of long-run climate change and short-run weather variability on power generation in several dimensions.

First, we develop a set of projections on the changes in hydro-power generation by exploiting the daily time series of hydro-power potential at the NUTS3 level developed in [156], distinguishing between run-off-river and reservoir. The potential hydro-power generation is combined with the installed production capacity of hydro-power plants. We emphasise that this analysis does not incorporate changes in the management of water demand for human needs, as they fall outside the study's scope. However, it is worth noting that such changes could potentially mitigate the impact of decreased water availability on hydro-power production [163, 164]. We compute both daily and weekly power generation levels in each scenario (*Historical Mean*, *Future Mean*, *Historical Extreme*, *Future Extreme*) for each Italian macro-zone (see Figure 3.2 Panel a for the projected value of the country-level total hydropower generation).

Second, we develop a statistical analysis to investigate the impacts of daily maximum temperatures and water runoff anomalies on the availability of thermal power generation. More in detail, we generate a regression model based on unexpected outages data collected from 2018 to 2022 in Italy. The dataset [165] includes information of over 4000 outages, of which 2352 of gas- and 1887 of coal-fired generation units. The method adopted partially follows a previous analysis [63], but expands from the literature by providing country-specific and fuel-specific responses. In the most detailed specification, we identify fuel-specific impacts by including a set of interaction terms between temperature and runoff anomalies and a character variable representing the power plant type. Comprehensive information on the methods employed is provided in Appendix A.2. We find that the likelihood of occurrence of an outage for coal-fired generation increases considerably when daily maximum temperatures surpass 35°C, reaching 10-50% at 40°C, depending on the water runoff anomaly. Gas-fired generation is less sensitive to high temperature and low water runoff levels, but the likelihood of an outage is non-negligible and between 5-25% at 40°C. Since in our power model optimisations coal generation is phased out from the mix, we focus on the projections of impacts for gas-fired generation. We use the estimated outage occurrence function in conjunction with daily maximum temperature anomalies at the location of the gas-power plants to simulate daily thermal outage occurrence. Finally, we aggregate the resulting projections of power plant outages at the bidding-zone level to obtain an indicator of power generation availability changes around 2030 in the four scenarios identified in section 3.2.2 (see Figure 3.2 Panel b).

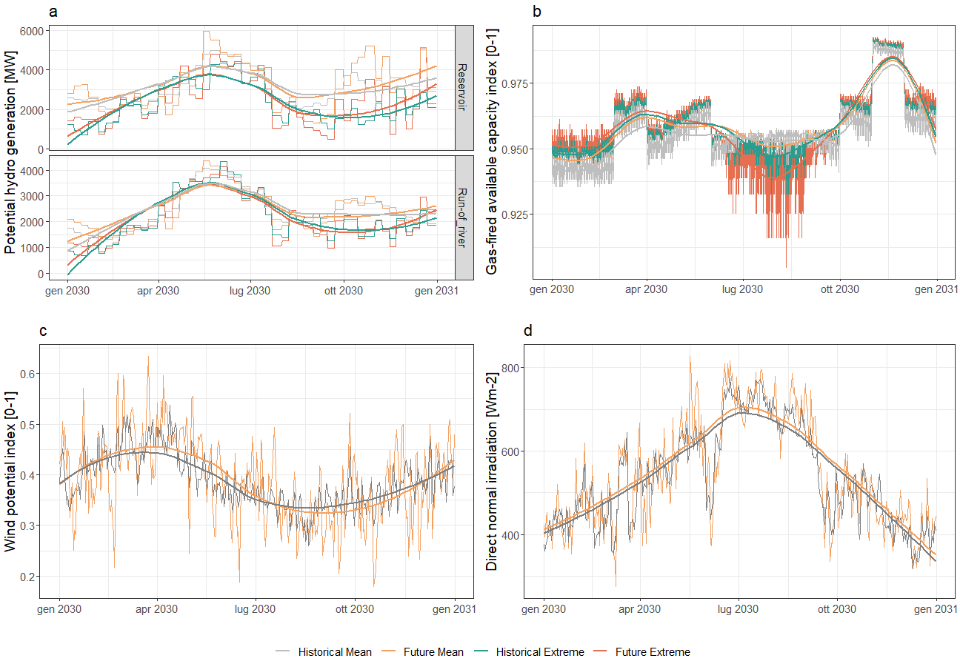

Figure 3.2: *Climate change impacts on power generation. Panel a: national-level potential hydro-power generation across the four climate scenarios; Panel b: Normalised availability of gas-fired generation after accounting for the occurrence of unplanned outages, across the four climate scenarios; Panel c: Normalised wind power potential at the national level, in the two selected scenarios; Panel d: BNI averaged at the national level, in the two selected scenarios. Impacts shown in Panel a, c and d are computed using as input data the SECURES-Met database. Impacts shown in Panel b are developed based on the econometric analysis presented in Appendix A.2.1. The values used as input data to the model are shown as thin lines, while thick lines show the smoothed time series for enhancing the inspection of trends in the data.*

Our model has a deterministic approach in the quantification of the available supply of power generation sources. As noted by [166], the main problems of this method relate to its unique economic objective function and the absence of uncertainties in its formulation. Other works (e.g. [167]) have proposed a stochastic model where long-term uncertainty in the VREs resources is introduced by using multiple scenarios consisting of weekly time series of hourly wind power output data. We leave the adoption of a stochastic approach to future studies, and we partially address this limitation by observing the outcomes of two alternative set of model runs: one with no impact of climate change on VREs and one where the generation profiles of VREs in the four different scenarios are included - although through the deterministic approach. We observe negligible differences when incorporating the effects of meteorological variables on VREs (see Appendix A.2.3). However, as this approach is not ideal for capturing VREs' uncertainty in capacity expansion analyses, we have chosen to present our main findings without these considerations.

3.3 Results

3.3.1 Installed capacity

We identify considerable impacts of mitigation policy goals and climate impacts on the optimal generation capacity. The installed capacities for the 2030 Italian power system, determined through investment optimisation, meet hourly load requirements while enforcing a 65% reduction in power sector emissions. We consider as "added capacity" the additional one optimised by the solver on top of the existing one in the 2019 reference case, detailed in Table A.4. The effects of mitigation (grey bars) and of climate change and extreme weather (coloured bars) on generation and storage capacity are displayed in Figure 3.3, for the different climate scenarios and generation technology.

In Figure 3.3, the panel on the left shows the changes in installed capacity resulting from the *Historical Mean* scenario: in this case, the added capacity is driven only by mitigation policies. Around 50 GW of photovoltaic panels, mostly in large scale fields, are required to reach 2030 decarbonization targets for power generation in Italy in a cost optimal system. The alternative climate scenarios take into account the effects of long-term climatic changes and extreme weather variability on electricity demand, thermal power plants and hydro-power. We performed various optimisation accounting for these effects separately to grasp which has more consequences on the installed capacities. Despite increasing the likelihood of unplanned outages, the impact of climate change on gas-fired plants does not affect optimal installed capacity, thanks to the ample unused natural gas power capacity available in both the 2019 reference and mitigation scenarios[2]. As a side note, changes in the availability of solar and wind en-

[2] Note that such results depends on the modelling framework, which assumes perfect foresight of the reduction in available capacity from unplanned power outages. More detailed assessment of the impacts on short-term market operations when unplanned outages occur fall out of the scope of this analysis.

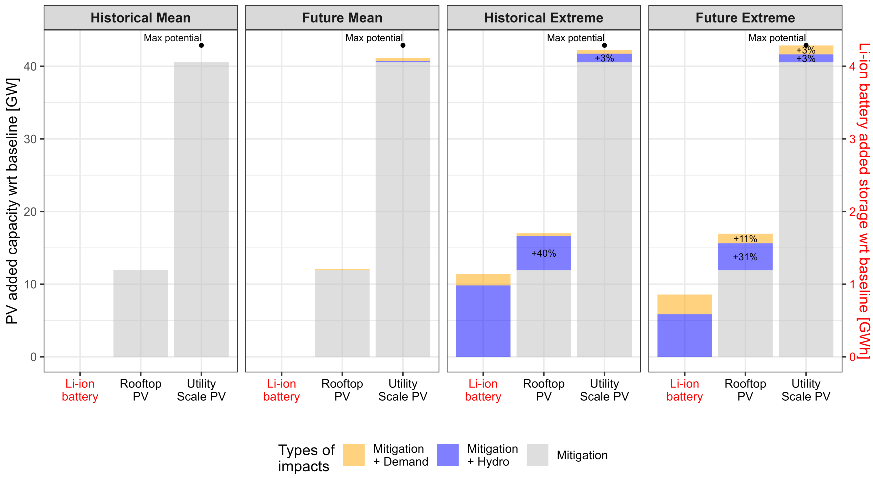

Figure 3.3: *Added capacity for PV power (utility scale and rooftop) and for lithium-ion storage with respect to the 2019 Italian power system baseline (described in Table A.4 for the four scenarios. The different colours highlight the climate driver behind each capacity expansions. Grey bars show the added capacity when the only effect is the push to reach decarbonization goals, while in the others each weather variable is evaluated on top of the mitigation. In addition to the impact of mitigation measures, the purple bars encompass the marginal effect of weather variables on hydroelectric generation, while the yellow bars on power demand.*

ergy from the *Historical Mean* to the *Future Mean* climate scenarios are negligible when aggregating across time and space, and point to a modest increase in rooftop solar generation and curtailment to account for an increase in seasonal weather variability of wind generation (results are presented in the Appendix). In the *Future Mean* scenario, considering only the effects of climate change from a shift in the mean climatic conditions, the additional installed capacity is minimal with respect to the *Historical* scenario. This indicates that the photovoltaic power installed for mitigation purposes would be sufficient to ensure the system's resilience to an average year of weather under climate change conditions occurring by 2030. In fact, solar electricity is significantly correlated with power demand driven by AC appliances, since they are both relevant in the middle of the day (the contribution of solar PV on hourly power generation during summer months is shown more in detail in the next section, particularly in Figure 3.5). When considering historical extreme weather (*Historical Extreme* panel), changes in the availability of hydropower have a relevant role in increasing the need for solar capacity (plus $\approx$ 5GW). Solar electricity is produced during the day, substituting the reduced run-off-river generation and shifting the use of reservoir hydro during night-time, instead of employing natural gas-fired plants. This mechanism allows the system also to stay compliant with the emission reduction target by reducing the use of fossil-based electricity. Furthermore, climate-induced changes in hydropower availability have remarkable effects in driving the uptake of short term storage. Indeed, when the availability of hydro power generation is reduced, the need for flexibility in the system is satisfied with li-ion batteries. In this *Historical Extreme* case the storage capacity is relatively small ($\approx$ 1GWh), but for higher degrees of decarbonization a larger volume will be needed. To provide a comparison, Terna, as published in the 2022 Future Energy Scenarios document, foresees approximately 71 GWh of new utility-scale storage capacity will need to be developed by 2030 to meet the requirements of the *Fit-for-55* scenario[3]. Finally, the *Future Extreme* scenario presents a stronger impact of the increase in demand for AC utilization. Utility Scale PV installation reach the maximum potential, taken from Trondle et al. [168], which considers social and technical constraints to fields installations. The optimisation algorithm tends to prioritise Utility Scale panels over rooftop PV, since they are more costs efficient due to their lower price for economies of scale, but land availability, protected areas and

[3]The optimisation does not install extra storage technologies in the *Future Mean* case since it works in perfect foresight and thus acts to minimize the costs, but it is not able to foresee market dynamics and future decarbonization of the system.

social constraints limit strongly their potential. A sensitivity analysis on the value for its maximum potential might enlarge the use of this technological option, given its price competitiveness. In the *Future Extreme* scenario, the effect of reduced hydro generation on installed capacity is lower than in the *Historical Extreme* scenario because of the balancing between summer and winter water inflows, observed in the mean climate change weather analysis (Figure 3.2). As the impact on hydro electricity production goes down, also the necessity for substitute li-ion batteries decreases (half of the need in the *Historical Extreme* case driven by hydro power).

Table 3.2: *Investments related to the additional installed capacities for generation and storage technologies in the four weather scenarios [M€]. In brackets we show the percentage change with respect to the investments in the Historical Mean scenario.*

Technology	Historical Mean	Future Mean	Historical Extreme	Future Extreme
Utility Scale PV	2312.7	2346.6 (+1.5%)	2414.9 (+4.4%)	2455.1 (+6.2%)
Rooftop PV	1115.6	1135.8 (+1.8%)	1595.5 (+43.0%)	1589.9 (+42.5%)
Li-ion battery	0.0	0.0	16.5	11.6

In Table 3.2 we display the values of annualised investments related to the extra installed capacities represented in Figure 3.3. These values reflect the compound effect of all the weather variables in the optimisation (AC demand, hydro and thermal power). The investment values reflect the results already observed in the figure: in the *Future Mean* scenario, there is a negligible increase in costs compared to the *Historical Mean*. Given that all scenarios assume a 65% reduction in CO_2 emissions from power generation, this indicates that decarbonising the energy system may yield significant synergies with adaptation strategies to climate change. This is largely attributed to the integration of climate-resilient technologies, particularly rooftop PV systems and utility-scale PV installations. In the extreme weather cases (*Historical* and *Future*), the primary increase in system expenses is attributable to rooftop PV installations. These technologies are more costly compared to Utility-Scale solar panel fields; however, rooftop PV installations are essential due to the larger availability of potential spaces for their installations and their ability to reduce centralised load demands. Indeed, rooftop PV is a form of distributed energy production and plays a crucial role in mitigating stress on the high-voltage grid by generating electricity locally. This becomes particularly advantageous under increased electricity demand scenarios due to climate change or extreme weather conditions, as it diminishes the dependency on centralised power sources, as demonstrated in Figure A.1 in Appendix A.1.1.

3.3.2 Electricity generation

As a consequence of the changes in the power capacity mix induced by mitigation policies[4], the generation mix is substantially different in 2030 with respect to the reference generation of 2019[5] (panel a of Figure 3.4).

Despite the cap on carbon dioxide emissions, natural gas still plays a significant role in 2030 power mix: 54 TWh less mean that 121 TWh of electricity are still gas-generated, one third of the total annual value. Solar electricity production has a relevant increase in all the scenarios. In the *Historical Mean* case this is due to the abatement target for CO_2 that forces the model to install and use more solar panels. Instead, the marginal increase in solar power generation in the other weather scenarios is driven by the effect of climate change and more frequent severe weather events. Another crucial point is curtailment: in the case of extreme weather in both historical and future climate, excess electricity would be 5 TWh. Although curtailed power constitutes only about 1.5% of the total demand, it requires attention as it presents both challenges and opportunities. This surplus cheap energy can be used within hard-to-abate sectors, reducing overall costs for mitigation solutions. On the other hand, excess power could be accounted for by load shifts, moving the request of electricity for certain services or appliances to hours of peak generation.

The total annual electricity demand (shown with a red dot in Figure 3.4) grows from 320 TWh in 2019 to 331-334 depending on the climate scenario. In the *Historical Mean* case, the additional electrical load is based on exogenous projections for the year 2030 [171], which consider the electrification of end-uses, particularly for passenger transport, industry and heating. The projections of [171] also take into account the simultaneous reduction driven by investments in energy efficiency. The change in demand with respect to the *Historical Mean* case is driven by the change in hourly demand for heating and cooling devices projected based on the method presented in section 3.2.3. Changes in annual aggregate demand mask considerably higher impacts occurring at the hourly level in the summer.

Figure 3.5 shows an example of hourly generation and demand in the four weather scenarios for a representative summer week (going from Monday to Sunday) in Sardinia. We chose this power market zone since, in the

[4]As a reminder, all the expansion capacity optimisations are performed with the underlying assumption of coal phase-out [169] and an abatement of CO_2 emissions in line with European policies [170].

[5]The model outcome for the 2019 reference year has been validated with the data from the Transmission System Operator [153].

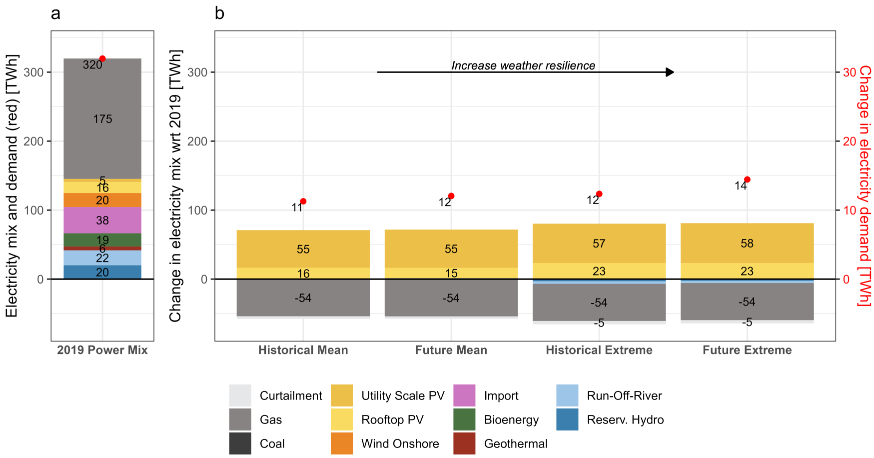

Figure 3.4: *Panel a: Model output of the electricity mix in Italy for the year 2019, different colour for each power technology. The red dot indicates the annual load in TWh; Panel b: Variation in the Italian electricity generation for year 2030 in the presented weather scenarios. Going from left to right, each output provides a stronger resilience to extreme weather conditions. In this panel the red dot precises the variation of national annual power load with respect to the 2019 baseline.*

two extreme weather scenarios, it is where the majority of li-ion battery capacity is installed to take advantage of the excess renewable generation (the impact of solar PV on the net load of all the Italian regions during the summer is shown in Supplementary Figure A.1). Inspecting the hourly behaviour of demand and production in each weather scenario confirms the capability of PV panels to produce a large amount of electricity during the central hours of the day, precisely when the demand for cooling is projected to peak. Additionally, it is noteworthy to notice the interactions with neighbouring regions (*To other regions* and *From other regions* in the legend, representing Centre-North, Centre-South and Sicily) and the utilisation of storage mechanisms, specifically the charging and discharging processes of PHS and batteries. This strategy involves charging the storage system with excess solar generation during midday, followed by discharging to supply power in the evening, reducing the use of natural gas.

3.3.3 Mitigation vs adaptation: trade-offs and synergies

While the main objective of this work is to investigate climate change impacts in a power system which is compliant with the legally binding Eu-

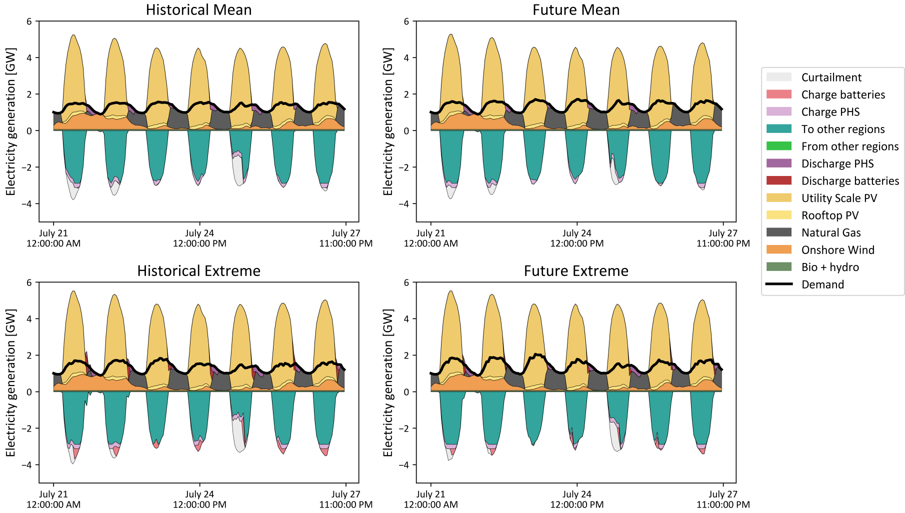

Figure 3.5: *Hourly generation and demand for Sardinia region during a summer week, considering the four different weather cases. The generation from Biomass, Run Off River and Reservoir Hydro is aggregated, as well as the one from and to other regions. Sardinia as a market zone in the Italian power system is connected to Centre-North, Centre-South and Sicily.*

ropean mitigation laws by 2030, in this section we compare those results with an alternative case in which climate change affects the Italian power sector when no stringent mitigation target is enforced. We undertake this analysis to determine whether achieving mitigation goals entails a trade-off with adaptation goals, meaning planning a system resilient to climate change and extreme weather conditions. To this aim, we run each climate impact scenario (*Historical Mean*, *Future Mean*, *Historical Extreme* and *Future Extreme*) assuming that the Italian power system faces no mitigation target in 2030 ($NonMitigated$ scenario). The results in terms of costs are outlined in Figure A.2, showing the total annual system cost in 2030 for a $NonMitigated$ power system in the column on the left, then that cost for a $Mitigated$ system in the right column. The waterfall bars represent the cost differences due to the achievement of the mitigation targets, always including the adaption to the impacts of the specific weather scenario.

As expected, the cost to purchase natural gas is always negative; instead, installation costs for solar technologies and batteries increase, even if the increase of the latter is negligible. The crucial difference is that the expenses for the acquisition of fuels is an operational cost, while the others are initial investment costs. This means that installing renewable technologies has

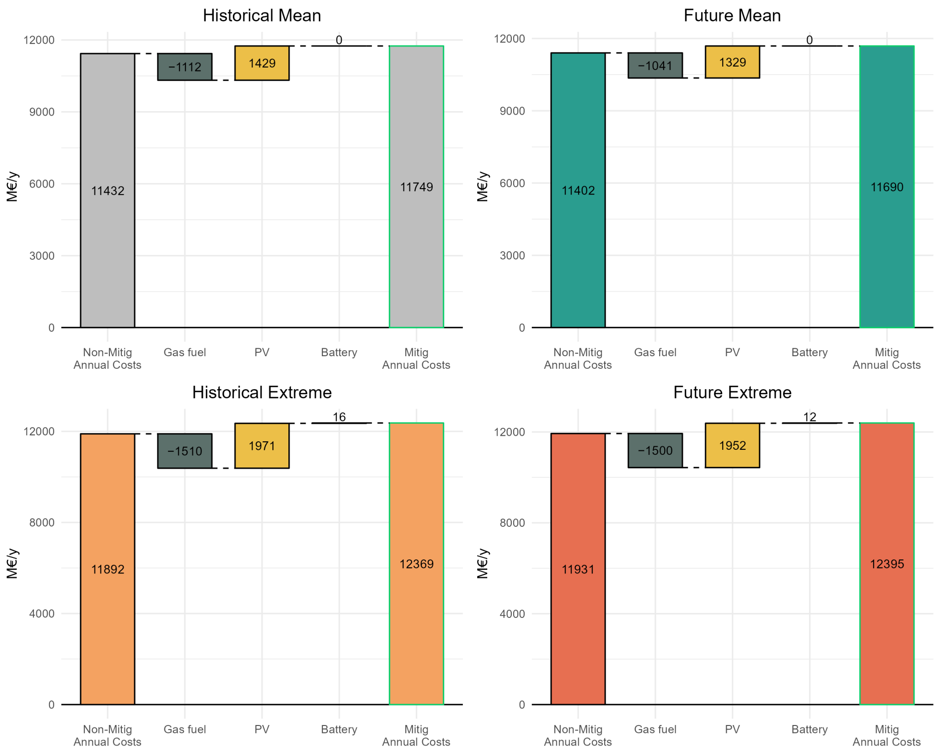

Figure 3.6: *Waterfall charts going from the total annual system cost for the $NonMitigated$ case to the $Mitigated$ case (with green borders) in the four different weather scenarios analysed in the paper. The values on the bar between the one on the left and the on on the right in each graph describe the costs items differences to achieve a mitigated Italian power system starting from the $NonMitigated$ but resilient one.*

a higher initial expenditure but significantly enhances the energy independence of the country and its resilience to geopolitical tensions and volatility of prices. In both the $NonMitigated$ and the $Mitigated$ scenarios, total annual system costs increase when going to Extreme weather cases (upper vs lower graphs). When moving to the scenario resilent to the effects of climate change (upper left vs upper right graphs), the expenditures decrease in the $Meanweather$ cases. The key message is that adapting to changing average weather patterns, particularly with regard to air conditioning demand and the unavailability of thermal and hydro power generation, reduces mitigation costs. Solar panels play a crucial role in this trade-off, as they not only represent an environmentally sustainable technology but also enhance the system's resilience to increasing temperatures. When considering extreme weather conditions, the effects of climate change result in a rise in expenditures (lower left vs lower right graphs). A pivotal aspect is that extreme weather events, which will become more frequent even under the RCP 4.5 scenario around 2030, pose a relevant threat and a possible increase in expenses for the power system. Importantly, the differences between total annual system costs in the $NonMitigated$ and $Mitigated$ cases are quite negligible, highlighting the advantages of planning for a system concurrently decarbonized and adapted to a changed climate.

3.4 Discussion

In this study, we employ a capacity expansion model of the Italian power system projected for 2030 to assess the necessary investments in power generation capacity quantitatively. This analysis is conducted with the dual objective of meeting mitigation targets and addressing the impacts of climate change on both power demand and generation while maintaining a high temporal resolution. The European decarbonization goal for 2030 is outlined in the *Fit-for-55* policy package and mandates a 55% reduction in CO_2 emissions [18]. The power sector, leveraging its advanced technologies, is expected to achieve more considerable emission reductions. Thus we assumed a 65% decrease in Italian electricity CO_2 emissions compared to 1990 levels, capping them at 44 Mton of CO_2 in the year 2030. We develop four alternative meteorological scenarios to thoroughly decompose the effects of climate change, distinguishing between shifts in the mean and the extremes of the weather distribution while assuming the implementation of decarbonization policies.

Overall, we find that transitioning towards a low-carbon power system capable of meeting demand under extreme weather patterns - both as occurred in the past and amplified by climate change - necessitates a substantial increase in installed capacity, specifically in solar generation and short-term storage. Around 5-8 GW of additional PV capacity and 0.8-1.1 GWh of li-ion batteries are required at increasing weather stress on the 2030 Italian power system. These expansion requirements serve to withstand, at the same time, higher future AC-induced peaks in the load as well as lower hydropower generation. Given the pivotal role that electricity is expected to play in driving the decarbonization efforts of hard-to-abate energy sectors, it becomes imperative to prioritise the ability of the power sector to address such concerns. While demand-side measures related to electricity and water use in agriculture and other end-use sectors could help alleviate stress on the electrical grid, they are outside the focus of this research.

A valuable feature of this work is that it examines the adequacy of the power sector while at the same time ensuring that decarbonization policies are implemented, therefore allowing to identify of potential trade-offs or co-benefits between adaptation and mitigation. The outcomes of the optimisations find that the largest installation of new generation technologies is of Utility Scale PV (40-42 GW) since this is the most cost efficient in the Italian peninsula (see Figure 3.3). Rooftop PV requires an addition of 12 GW to meet decarbonization goals, and extra 5 GWs are needed in the most extreme weather cases. This decentralised technology is crucial in reducing the stress on the electric grid and satisfying the power load locally. Furthermore, we find robust evidence that accounting for extreme weather events (both in the *Historical* and *Future Extreme* scenarios) affects the optimal capacity mix: a power system resilient to extreme events requires storage to help balance the water scarcity and thus hydropower unavailability. Climate change and extreme weather might hinder the availability of programmable reservoir hydropower plants and non-dispatchable RES might not be sufficient to meet the hourly load. Investments in storage capacity could be fundamental to alleviate the burden on the system and to mitigate the volatility and unpredictability in power generation. In this study, two storage options are available for the power system model: a short term storage with li-ion batteries and a long-term one with hydrogen tanks, electrolysers and fuel cells. Given the short-term nature of meteorological impacts, lithium-ion batteries are preferred over hydrogen storage for energy management. Chemical batteries, such as lithium-ion, are particularly well-suited for daily and short-term energy storage due to their minimal energy losses during charge and discharge cycles [172], making them an effective alternative to weather-dependent hydro power. Moreover, installing electrolysers, pressurised tanks and fuel cells has a high cost, which becomes viable only in more severe abatement scenarios.

The generation mix is markedly different from the reference generation of 2019, with solar electricity production showing substantial increases across all scenarios. This rise is attributed to the stringent CO2 abatement targets and the effects of climate change, which include more frequent severe weather events. Despite the cap on carbon emissions, natural gas remains a crucial component in the transition of the power mix, providing 121 TWh of electricity, one-third of the total annual power supply. Our analysis underscores the importance of addressing curtailment, particularly in extreme weather scenarios where excess electricity generation reaches 5 TWh. Although this constitutes a small fraction of total demand, it presents opportunities for integration into hard-to-abate sectors. It highlights the potential for load shifts to manage electricity demand more efficiently. The projected increase in annual electricity demand, from 320 TWh in 2019 to 331-334 TWh in 2030, reflects the anticipated electrification of end-uses, balanced by investments in energy efficiency. However, this aggregate increase masks significant hourly variations, especially during summer peaks. Finally, this study underscores the vital interplay between mitigation and adaptation in the power sector. The analysis reveals critical insights into the costs and benefits associated with achieving mitigation goals in the context of climate change impacts on the Italian power system. We compare scenarios with and without stringent mitigation targets (denominated $NonMitigated$ and $Mitigated$ cases), considering the set of different meteorological scenarios deployed. In the $Mitigated$ cases, we demonstrate that, while initial investments in renewable technologies are higher, they significantly reduce operational costs associated with fuel purchases. This shift from operational to capital expenditures enhances energy independence and resilience to geopolitical frictions and price volatility. The increase in capital investments and the decrease in operational and fuel purchase expenditures requires a careful evaluation of the financial aspects linked to this shift, which falls out of the scope of this work. We leave for further analysis the assessment of how the change in these financial flows affects the actors of the supply chain, as well as the possible regulatory incentives for the new capital investments; both aspects are crucial for achieving an effective energy transition. Solar panels emerge as a pivotal technology in the trade-off between adaptation and mitigation of the power system, contributing to environmental sustainability and bolstering system resilience against rising temperatures. Notably, the study highlights that the total annual system costs remain relatively stable between the $NonMitigated$ and $Mitigated$ scenarios, underscoring the feasibility and advantages of concurrently pursuing decarbonization and climate adaptation strategies. These findings underscore the critical importance of integrating renewable energy investments into long-term planning to develop a robust, sustainable, and climate-resilient power system.

To conclude, it is important to clarify which findings are likely generalizable beyond Italy and which are context-specific. The core methodological contribution, integrating climate model outputs with empirically estimated demand and supply impacts into high-resolution power system optimization, is broadly transferable to other regions and can be applied at larger geographical scales. The qualitative finding that solar PV generation exhibits strong synergies with temperature-driven cooling demand, thereby supporting both mitigation and adaptation objectives, holds across regions with significant air conditioning loads and solar resources. Similarly, the result that climate change reduces hydropower availability and thermal plant efficiency, necessitating compensating investments in storage and flexible generation, reflects physical mechanisms applicable beyond Italy. However, the quantitative magnitudes are highly context-specific. Italy's high summer cooling demand, significant hydropower dependence, limited winter heating electrification, and Mediterranean climate exposure shape the specific numerical results. In northern European countries with lower cooling needs, higher heating electrification, and different hydrological regimes, the balance between demand and supply impacts would differ substantially. Likewise, the relative cost-effectiveness of utility-scale versus rooftop PV, and the specific storage requirements, depend on land availability constraints, grid topology, and regulatory frameworks that vary across countries. The quantitative values of capacity requirement under extreme weather should therefore be interpreted as illustrative of the Italian case rather than a transferable benchmark for other systems.

3.5 Conclusions

Our findings indicate that transitioning to a low-carbon power system in Italy by 2030, capable of meeting demand under increasingly extreme weather conditions, requires substantial investments in PV generation and storage capacity. While the specific quantitative results reflect the Italian context, characterized by high solar resources, significant hydropower dependence, Mediterranean climate exposure, and moderate heating electrification, the broader methodological approach and qualitative insights are applicable to other power systems facing similar climate-energy interactions. Utility-scale PV is identified as the most cost-efficient option, with rooftop PV playing a crucial role in alleviating grid stress. Furthermore, resilience to extreme weather events necessitates a robust storage strategy, with lithium-ion batteries preferred for short-term energy management due to their round-trip efficiency. Moreover, our results display the projected generation mix for 2030, showing solar electricity production increasing substantially due to stringent CO_2 abatement targets and adaptation to impacts of climate change. Despite the emphasis on renewable energy, natural gas still supplies one-third of total annual electricity, while managing curtailment is crucial for redirecting excess generation to hard-to-abate sectors. Finally, this study highlights the crucial interaction between mitigation and adaptation strategies in the power sector, demonstrating that while initial investments in renewable technologies are higher under stringent mitigation scenarios, they lead to significant reductions in operational costs and enhance the robustness of the system to climate change impacts. Importantly, the findings indicate that total annual system costs remain stable between scenarios with and without stringent mitigation targets, affirming the feasibility of simultaneously pursuing decarbonization and climate adaptation. These results underscore the necessity of integrating renewable energy investments, particularly on solar panels, within long-term planning to develop a sustainable and climate-resilient power system, given their low dependence on meteorological conditions.

This analysis is not without caveats. The impacts of mean climate shifts and extreme events on transmission lines (e.g., due to overheating of cables) are not included. In addition, we do not perform sensitivity analyses on economic variables, which could shift technical choices on different options. This can be a crucial consideration for the resilience of transition scenarios; however, it does not constitute the primary focus of this study. Furthermore, the quantitative findings are specific to the Italian power system context and should not be directly extrapolated to other countries without accounting for differences in climate conditions, energy system structure, hydropower dependence, heating and cooling demand patterns, land availability for renewable deployment, and grid characteristics. Qualitative insights regarding synergies between solar PV deployment and adaptation to temperature-driven demand changes, and the need for storage to compensate for reduced hydropower availability, are more broadly applicable, though their magnitudes will vary by regional context.

Future research can expand the evidence provided in this work in several directions. A more detailed power dispatch model could investigate options to strengthen the resilience of power systems not only through changes in the dispatch mix, but also by exploiting balancing services, cross-border trade and demand-side management. Furthermore, given that conventional generation technologies play a dominant role in setting wholesale prices as they meet the net-load, i.e. residual demand not satisfied by renewable sources, extreme weather events may result in wholesale price fluctuations. Understanding the characteristics of power markets' operations during extreme weather may bring to the surface possible limitations of the current power systems, leading not only to volatility in power prices but possibly also to higher costs for managing the grid. Models with a detailed representation of the use of electric appliances and of the behavioural aspects of consumption can be adopted to investigate the demand-side potentials for reducing the peak-load during extreme events.

CHAPTER 4

Decarbonisation without deindustrialisation: assessing future pathways for European industry

Abstract

Decarbonising the industrial sector while maintaining international competitiveness are two central objectives of European Union policy, yet they may conflict. This study investigates the trade-offs between these goals under alternative pathways for European industrial development, ranging from a continued decline in production to a policy-driven resurgence of industrial activity. Focusing on the most energy- and emission-intensive sectors, iron and steel, cement, methanol, ammonia, and high-value chemicals (mainly plastics), we assess how emissions reductions affect production costs and competitive positioning relative to low-carbon imports from regions with abundant renewable resources. Using an energy system model extended with a detailed representation of industrial processes, we compare domestic production costs of low-carbon industrial goods with those of imported alternatives and evaluate three policy-relevant strategies: intra-European relocation of industrial activity, selective imports of green inter-

mediate goods, and targeted government subsidies. The results show that deep industrial decarbonisation in Europe is technically feasible, with electrification playing a central role. However, cost competitiveness is highly sensitive to policy choices and peaks during the investment-intensive phase of the transition. Intra-European relocation delivers only limited cost reductions and is constrained by economic, social, and infrastructural considerations. By contrast, strategic imports of green intermediate goods substantially reduce system costs and carbon prices while allowing Europe to retain downstream industrial activity, employment, and value creation. Subsidies can mitigate competitiveness losses but become fiscally unsustainable under strong reindustrialization. Overall, the findings suggest that European industrial policy should prioritise decarbonisation and the retention of existing industrial capacity, supported by targeted, time-limited public support, rather than pursuing broad-scale expansion of energy-intensive production.

4.1 Introduction

The European Union (EU) has committed to achieving climate neutrality by 2050, requiring rapid and substantial reductions in greenhouse gas (GHG) emissions across all economic sectors [17]. Industry plays a central role in this transition, as many existing industrial processes remain incompatible with deep decarbonisation pathways [173]. In response, the EU has introduced a range of policy initiatives, including the Net-Zero Industry Act and the Clean Industrial Deal, aimed at accelerating clean technology deployment while strengthening industrial resilience and strategic autonomy [174, 175]. At the same time, concerns over high energy prices, regulatory complexity, and slower innovation have raised questions about Europe's ability to maintain industrial competitiveness during the transition [176]. European industrial products are already facing structural cost disadvantages in global markets, with energy-intensive goods often priced above international competitors, reinforcing fears of deindustrialisation and carbon leakage. Recent policy discourse increasingly frames decarbonisation not only as a climate imperative, but also as a potential driver of long-term competitiveness and economic security [175].

In 2021, the EU27 industrial sector emitted approximately 600 Mt of CO_2, accounting for around 20% of total EU GHG emissions [85, 86]. Emissions are concentrated in a small number of energy- and material-intensive sectors, notably iron and steel, chemicals, and non-metallic minerals, which together account for more than two-thirds of industrial emissions. These so-called hard-to-abate sectors face structural challenges due to their reliance on fossil fuels for high-temperature heat and carbon feedstocks, as well as the limited maturity of low-carbon alternatives. Electrification, green hydrogen, and carbon capture and storage (CCS) are widely recognised as key technological pillars of industrial decarbonisation. Recent reviews emphasise that industrial decarbonisation requires coordinated technological portfolios, long investment cycles, and supportive policy frameworks to address both technical and economic barriers [16,48,177–179].

A growing body of applied literature has employed energy system models (ESMs) to explore pathways for industrial decarbonisation, assessing technology deployment, sectoral interactions, and emissions reductions [88,90,91,180]. These studies have provided important insights into the technical feasibility of electrification, hydrogen use, and CCS, while also highlighting persistent uncertainties related to costs, data availability, and technology performance [181–183]. In parallel, several analyses suggest that Europe could reduce system-wide decarbonisation costs by increasing imports of energy carriers or energy-intensive goods from regions with abundant renewable resources, including green hydrogen, synthetic fuels, electricity, and steel [184–186]. Beyond technical feasibility, recent policy-oriented contributions emphasise that industrial decarbonisation entails significant economic and distributional risks, highlighting the need for pathways that align emissions reductions with competitiveness, investment incentives, and regulatory stability, and thus for policy-relevant assessments that go beyond technology cost optimisation [48,187,188].

Neumann et al. [64] combine a global energy supply chain model with the PyPSA-Eur framework to show that importing renewable energy and steel can reduce Europe's infrastructure requirements and overall system costs. While such strategies may improve cost efficiency, they also raise concerns regarding deindustrialisation, employment losses, innovation capacity, and increased dependence on external suppliers. These trade-offs are particularly relevant in the current policy context, where industrial policy, energy security, and climate objectives are increasingly intertwined.

Despite extensive modelling work on industrial decarbonisation and growing attention to policy risks and competitiveness concerns, an important gap remains. Existing studies tend to emphasise either system-level cost optimisation or sector-specific technology pathways, while paying limited attention to how decarbonisation strategies interact with industrial competitiveness and policy instruments such as subsidies. This paper advances the literature by providing an integrated assessment that combines a detailed, process-level representation of key industrial sectors with economy-wide energy system dynamics, enabling an explicit evaluation of competitiveness trade-offs and policy-relevant transition strategies over the full pathway to Net-Zero.

This study addresses this gap by extending the PyPSA-Eur framework to analyse European industrial decarbonisation through a competitiveness-oriented lens. We include a plant-level representation of key industrial sectors, accounting for the type, location, and age of existing facilities, and assess alternative transition strategies within a myopic optimisation framework covering the full transition period. Beyond technology deployment, the analysis explicitly considers three policy-relevant mechanisms: (i) intra-European relocation of industrial activity to optimise production and infrastructure use; (ii) selective imports of green intermediate goods, such as Hot Briquetted Iron (HBI), methanol, and ammonia; and (iii) targeted government subsidies aimed at closing cost gaps with regions benefiting from lower renewable energy costs.

By analysing how these strategies affect production costs, emissions, and trade-offs between domestic production and imports, the paper provides new insights into how deep decarbonisation can be reconciled with industrial competitiveness under realistic policy constraints. In doing so, it complements existing system-level analyses by shifting the focus toward industrial structure, policy design, and transition feasibility.

The paper addresses the following research questions:

- **RQ1:** How can European industries reduce emissions while preserving competitiveness in global markets?

- **RQ2:** What role do intra-European relocation and imports of green intermediate goods play in shaping less disruptive transition pathways to Net-Zero?

- **RQ3:** To what extent can targeted subsidies support the retention of green industrial production in Europe?

The remainder of the paper is structured as follows. Section 4.2 describes the modelling framework and key assumptions. Section 3.3 presents the results of the scenario analysis. Finally, Section 4.4 discusses the implications for industrial and climate policy.

4.2 Methods

4.2.1 Model development

The ESM employed in this study is PyPSA-Eur, an open-source, high-resolution modelling tool developed to explore cost-optimal decarbonisation pathways for the European energy system. For a comprehensive description, readers are referred to the official model documentation [189], and the GitHub repository [103]. PyPSA-Eur, open-source and widely used [32, 53, 190], enables integrated analyses of electricity, heating, transport, industry, agriculture, shipping, and aviation. It was chosen for its detailed power grid representation and ability to capture inter-sector interactions. The model performs high-resolution linear optimization to minimize system costs, optimizing investments and operations across generation, storage, conversion, and transmission.

While PyPSA-Eur has been extensively documented in the official documentation [189], we summarise here its key features as used in this study to improve readability and self-containment of the manuscript. The model formulates the European energy system as a linear optimisation problem that minimises total system costs subject to demand satisfaction, technical constraints, and policy targets. Investment and dispatch decisions are optimised jointly across electricity generation, storage, and end-use sectors including industry, heating, and transport, allowing for endogenous trade-offs between sectors. This structure makes PyPSA-Eur particularly suitable for analysing interactions between industrial decarbonisation pathways, energy infrastructure, and policy constraints.

Industrial modelling in PyPSA-Eur, detailed in Victoria et al. [53], uses JRC-IDEES data [86] to estimate energy demands and process emissions per unit output, with exogenous assumptions on low-carbon technology uptake. Production volumes are held constant until 2050, yielding predetermined electricity, hydrogen, biomass, and oil demands. Neumann et al. [64] extended the model to include material imports and Electric Arc Furnaces (EAF) for steel, but their greenfield 2050 optimization ignores the spatial distribution and operational status of existing plants.

While the current framework of PyPSA-Eur is able to capture industrial energy demand, this study requires a more detailed representation of sectors and technologies. By modelling specific processes and techno-economic parameters, the model endogenously determines least-cost technology and fuel mixes, optimizes production levels, and achieves economy-wide Net-Zero emissions cost-effectively. If decarbonization of a sector is costly, mitigation can shift to other sectors or use negative emissions without prior assumptions. To this end, PyPSA-Eur was extended to represent five key sectors, iron and steel, cement, ammonia, methanol, and High Value Chemicals (HVCs), which account for nearly two-thirds of EU27 industrial CO_2 emissions [86]. Due to space constraints, a detailed description of the industrial process representations, technology options, and techno-economic assumptions is provided in Supplementary Section B.1, which documents the modelling choices underlying each industrial sector in full detail.

Additionally, this study integrates climate-adjusted weather projections into PyPSA-Eur. Standard PyPSA-Eur uses ERA5 (2013) and SARAH-3 data for wind and solar generation [155], but climate change affects renewable generation, demand, and infrastructure. We use a dataset from Antonini et al. [12], which combines historical ERA5 data (1940-2023) with CMIP5 EURO-CORDEX projections (2006-2100) under RCP 2.6, 4.5, and 8.5. It provides country-level time series for wind, solar, and hydropower across the EU27 (excluding Cyprus and Malta), UK, Norway, Switzerland, and Serbia, incorporating multiple climate models to capture uncertainty.

4.2.2 Parameters and assumptions

Common assumptions

A consistent set of parameters is applied across all scenarios. The PyPSA-Eur model is operated in myopic mode with a three-hourly temporal resolution for the years 2030, 2040, and 2050 using Gurobi solver. The model spans 39 nodes across 34 European countries, covering all EU27 Member States (excluding Cyprus and Malta), United Kingdom, Switzerland, Norway, Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, Serbia, and Kosovo. Each country is represented by at least one node. The modelling framework follows a brownfield approach, incorporating existing power and heating generation, transmission infrastructure, industrial hubs, enhanced in this study with data on existing plants added to the original PyPSA-Eur model. Renewable generation from onshore and offshore wind, and solar PV can expand based on land eligibility via *atlite*, while hydropower is fixed and nuclear may increase if cost-optimal. Electricity storage includes pumped hydro, batteries, and hydrogen systems (electrolysers, tanks, fuel cells). Power and methane grids use SciGRID_gas [191] and OpenStreetMap [192]. Grid expansion is allowed, but line use is capped at 70% to approximate N-1 security. Due to delays in hydrogen pipeline deployment [193, 194], H_2 infrastructure is excluded, and each node meets demand via local production. A robustness analysis considers repurposing existing gas pipelines or investing in new ones (Supplementary Fig. B.3). Technology costs are updated for each optimisation year using the Technology-Data package [195]. Weather-dependent resources are derived from year- and country-specific climate projections developed by Antonini et al. [12], from CNRM-CERFACS-CM5 global model and downscaled with th CNRM-ALADIN63 regional model, based on the RCP 4.5 scenario. Sustainable biomass is capped at 1,372 TWh/a (JRC-ENSPRESO [196]), with no imports. CO_2 removal via Bio-Energy CCS (BECCS) and Direct Air Capture (DAC) is limited to 50 $MtCO_2$/a in 2030, 250 $MtCO_2$/a in 2040, and 400 $MtCO_2$/a in 2050, in line with EU targets and IAM projections [197, 198].

Scenarios framework

	Climate Target		**Relocation**	**Intermediate Imports**
Industrial Production	**No Climate Policy** **Continued Decline** No Relocation No Interm. Imports	**Climate Policy** **Continued Decline** No Relocation No Interm. Imports	Climate Policy Continued Decline **Relocation within Europe** No Interm. Imports	Climate Policy Continued Decline No Relocation **Intermediate Imports**
	No Climate Policy **Stabilization** No Relocation No Interm. Imports	**Climate Policy** **Stabilization** No Relocation No Interm. Imports		
	No Climate Policy **Reindustrial** No Relocation No Interm. Imports	**Climate Policy** **Reindustrial** No Relocation No Interm. Imports	Climate Policy Reindustrial **Relocation within Europe** No Interm. Imports	Climate Policy Reindustrial No Relocation **Intermediate Imports**

Table 4.1: *Scenario matrix combining climate targets and industrial production trends, relocation within Europe and intermediate imports.*

Different scenarios are illustrated in Table 4.1. In *No Climate Policy* scenarios, the system is cost-optimized without GHG targets, though renewable investments may occur if economically advantageous. *Climate Policy* scenarios implement EU targets: 55% GHG reduction by 2030, 90% by 2040, and Net-Zero by 2050 [18, 21, 199], with all GHG expressed in CO_2 equivalents. Sectoral assumptions differ: land transport is fully electrified, methanol meets 50% of shipping demand (boosting industrial methanol production), and aviation uses synthetic kerosene via Fischer-Tropsch synthesis.

The second scenario differentiation concerns industrial production. European industry has declined due to high energy costs, ageing infrastructure, and global competition [176, 200, 201], prompting policies like RePowerEU [202], the Clean Industrial Deal [175], and the CBAM [203] to support competitiveness and the green transition. To capture uncertainty, three trajectories are considered: *Continued Decline* (continued decline), *Reindustrialization* (annual growth), and *Stabilization* (stable output). These scenarios refer to domestic production; in *Continued Decline*, reduced output is assumed offset by imports, raising questions about the carbon intensity of foreign goods, while *Reindustrialization* may reduce import reliance and create exports. Changes in domestic consumption are not explicitly modelled, and a full assessment of trade-related emissions is beyond this study's scope.

To model the rate of change in industrial production, historical trends are extrapolated by replicating each sector's annual absolute change, based on linear interpolation between the earliest and latest available data (2023 for most sectors, 2022 for cement and plastics, 2021 for methanol) as shown in Eq. 4.1.

$$\Delta P = \frac{|P_{\text{latest}} - P_{\text{first}}|}{t_{\text{latest}} - t_{\text{first}}} \tag{4.1}$$

Table 4.2: *Historical annual production changes for each subsector*

Subsector	Annual production change ΔP [Mt/year]	Source
Iron and steel	2.6	Word Steel Association [204]
Cement	1.9	Cembureau [205]
Ammonia	0.32	Eurostat [206]
Methanol	0.09	Eurostat [206]
Plastics	0.63	Plastics Europe [207]

In Table 4.2 values for each sector are detailed. Figure 4.1 shows historical production (dots) and projected trajectories for each sector under the three production scenarios. Here, methanol values reflect industrial demand only, but under *Climate Policy*, the model has an additional shipping demand of 7 Mt in 2030, 16 Mt in 2040, and 23 Mt in 2050.

The analysis also explores two additional scenario dimensions under *Climate Policy* for both *Continued Decline* and *Reindustrialization*. The first examines intra-European relocation of industrial production. In *No Relocation* scenarios, production remains fixed, reflecting inertia due to infrastructure, labour, supply chains, and regional policies. In *Relocation within Europe* scenarios, the model optimizes plant locations for cost-effectiveness, capturing a potential "renewables pull" where industries move to regions with abundant low-cost renewable energy [208, 209].

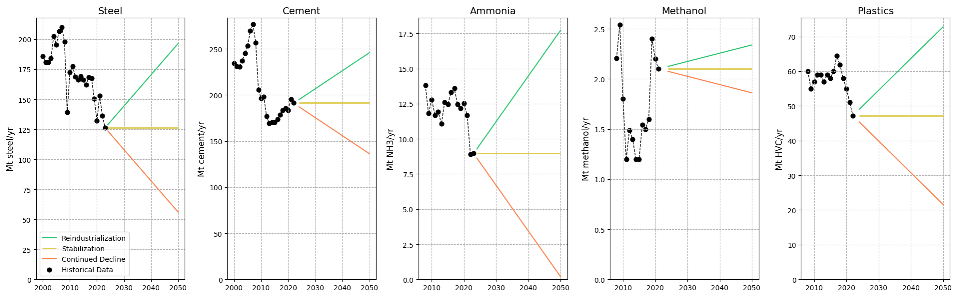

Figure 4.1: *Industrial production trajectory within the geographical scope of the model, EU27 (without Cyprus and Malta), UK, Switzerland, Norway, Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, Serbia, and Kosovo, for the five industrial goods considered in the study, in the Continued Decline, Stabilization, and Reindustrialization scenarios. Note that methanol production data exhibit an irregular trend, which may be attributable to inconsistencies or gaps in reporting rather than to underlying structural changes in the sector.*

The second dimension examines imports of intermediate green goods under *Climate Policy* for both *Continued Decline* and *Reindustrialization*. This strategy retains high-value industrial segments in Europe while outsourcing energy-intensive stages to regions with lower renewable costs [64,208,210]. Imports considered include green methanol and ammonia for 2040 and 2050, using literature-based average prices [64, 211], and green Hot Briquetted Iron for EAF at 395 EUR/ton [185]. These feedstocks also serve as low-carbon fuels in other sectors.

Government subsidies calculations

Subsidies are modelled in this study as an analytical device to quantify the competitiveness gap between domestic low-carbon production and imported green alternatives, rather than as normative policy recommendations. The resulting subsidy levels should therefore be interpreted as indicative magnitudes of the cost differential that would need to be bridged to retain industrial activity within Europe under different transition pathways. Importantly, the analysis does not assume that such subsidies would be fully implementable under existing EU competition law or state aid rules. Instead, the subsidy estimates serve to highlight the scale of the challenge faced by industrial policy and to inform discussions on feasible combinations of trade, regulation, and targeted support instruments.

Subsidy requirements are quantified, for each commodity c in scenario s and year y, by multiplying its production volume $Q_{c,s,y}$ by the difference between PyPSA-Eur weighted average marginal prices and green import prices from the literature [64, 211] (Eq. 4.2).

$$S_{c,s,y} = \left(p_{c,s,y}^{\textit{PyPSA-Eur}} - p_{c,s,y}^{\textit{Green Imports}}\right) \cdot Q_{c,s,y} \tag{4.2}$$

Green industrial products from outside Europe are assumed to be available from 2040 (also as in Figure 4.3); thus, subsidies are not applied in 2030. The average annual subsidy for commodity c in scenario s (2035-2055) is computed as the weighted mean over representative years, with each year representing a decade, yielding Eq. 4.3.

$$\overline{S}_{c,s} = \frac{10}{20} \sum_{y \in \{2040, 2050\}} S_{c,s,y}, \tag{4.3}$$

4.3 Results

To guide the interpretation of the results, Table 4.3 provides an overview of how the model outputs presented in this section relate to the research questions and policy mechanisms analysed in the study. We first assess technology choices and cost competitiveness under the scenarios with climate policy and different industrial production levels (RQ1), then evaluate relocation and intermediate imports as alternative strategies (RQ2), and finally quantify the implied subsidy requirements to retain production within Europe (RQ3).

Table 4.3: *Link between research questions, analysed mechanisms, and results presented in the paper*

Research question	Analysed mechanisms	Results section	Key figures
RQ1	Technology portfolios, production costs, and competitiveness of domestic green industrial goods	Section 4.3.1	Figures 4.2, 4.3, B.1
RQ2	Intra-European relocation of industrial activity and imports of green intermediate goods	Section 4.3.2	Figures 4.4, 4.5
RQ3	Targeted government subsidies and competitiveness gaps relative to green imports	Section 4.3.3	Figure 4.6

4.3.1 Decarbonisation and competitiveness

Technology portfolios

Figure 4.2 presents the cost-optimal technological pathways identified by PyPSA-Eur across scenarios. The first column shows the *No Climate Policy* scenario under *Stabilization* of industrial production, while the remaining columns depict *Climate Policy* scenarios under *Continued Decline*, *Stabilization*, and *Reindustrialization*. Methanol production increases in all the *Climate Policy* scenarios to meet growing maritime fuel demand. All optimisations assume *No Relocation* within Europe and *No Intermediate Goods* imports.

Across scenarios, industrial decarbonisation is primarily driven by electrification and green hydrogen deployment (Figure B.1), while CCS plays a limited role. For steel, ammonia, and methanol, green hydrogen-based production becomes dominant from 2040 onward under stringent decarbonisation targets (-90% GHG). Steelmaking relies heavily on scrap-based EAF due to their cost and emissions advantages, reaching the imposed cap of 75%, which reflects quality constraints that still require some primary steel. SMR with CCS remains relevant in 2030, as captured CO_2 can be utilised in other industrial processes. In the *Reindustrialization* scenario, plastics increasingly rely on sequestered CO_2 for Fischer-Tropsch synthesis, reaching approximately 25% of output by 2050, while biomass use remains constrained by competing demands. Cement emissions are mitigated primarily through DAC and BECCS rather than conventional CCS, reflecting the availability of atmospheric carbon removal options within the model.

Prices of industrial goods

Figure 4.3 reports production-weighted average European industrial commodity prices for *Climate Policy* scenarios at various production levels. Prices are derived from Karush-Kuhn-Tucker multipliers, representing marginal production costs by region and time. Historical price ranges and recent European prices are included for reference.

Decarbonisation leads to higher industrial production costs, with a pronounced peak around 2040, followed by a decline by 2050 as major investment phases are completed. Cost increases are driven primarily by capital-intensive investments in low-carbon technologies, particularly electrolysers, and higher electricity consumption. For fully decarbonised sectors such as steel, ammonia, and methanol, green hydrogen becomes the dominant cost driver. In harder-to-abate sectors, including cement and plastics, carbon pricing plays a larger role.

Comparisons with literature-based cost ranges for imported low-carbon goods from renewable-rich regions indicate that plastics remain competitive across scenarios, while steel competitiveness is maintained only under

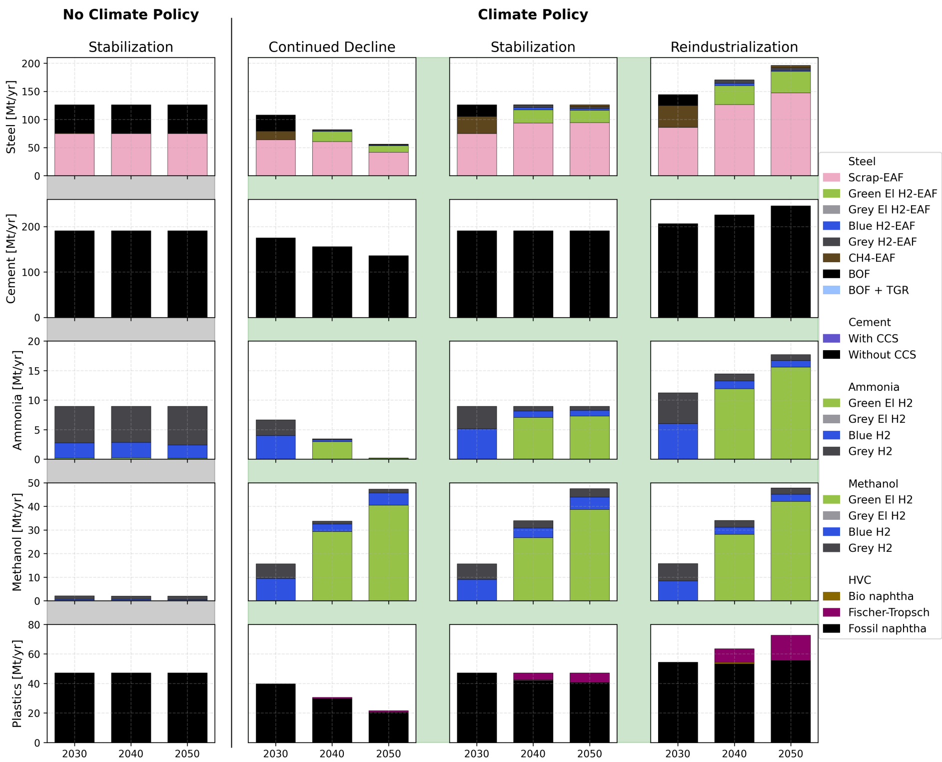

Figure 4.2: *Production of industrial goods in four scenarios: the first column represent the scenario with No Climate Policy and Stabilization of industrial production, the other three columns show scenarios implementing the EU Climate Policies, spanning from Continued Decline, to Stabilization and then Reindustrialization. Rows indicate the different industrial sectors and the technologies available in the model are depicted in the legend.*

Continued Decline. Ammonia and methanol remain competitive under both *Continued Decline* and *Stabilization*, reflecting lower marginal cost pressures at reduced production volumes. Overall competitiveness outcomes depend on domestic production trajectories and uncertainties surrounding green import costs.

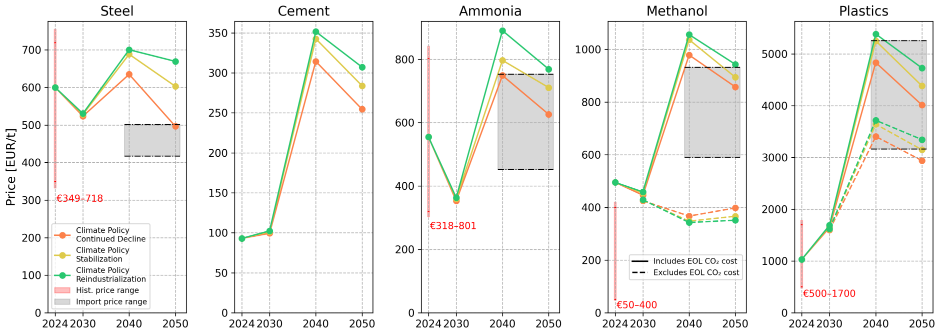

Figure 4.3: *Prices of industrial goods, average across European countries and time steps, for different scenarios. Dotted lines for methanol and plastics represent a price when no carbon price on End Of Life (EOL) emissions is applied. The red line indicates historical price ranges while the grey bar represents the costs for green products from outside the EU's borders.*

4.3.2 Industrial relocation and green intermediates trade

To moderate cost increases under deep decarbonisation while limiting carbon leakage, we evaluate two strategies: (i) relocation of industrial activity within Europe toward regions with favourable renewable potentials, and (ii) selective imports of green intermediate goods from outside Europe.

Relocation within Europe

Allowing full relocation of industrial activity within Europe leads to a pronounced concentration of production in regions with abundant and low-cost renewable resources, notably Spain, the Nordic countries, and the United Kingdom (Figure 4.4). This spatial reallocation reflects a strong "renewables pull" effect [209] and results in lower industrial electricity expenditures across all scenarios, as shown in panel (c) of Figure 4.4.

However, these results reflect a cost-optimal outcome that abstracts from social, economic, and infrastructural constraints. The model does not account for relocation costs, employment impacts, regional economic disruption, or the additional infrastructure investments required to support large-scale industrial shifts. Consequently, while intra-European relocation yields measurable reductions in energy expenditures, the magnitude of these benefits alone would be unlikely to justify substantial restructuring of existing industrial value chains.

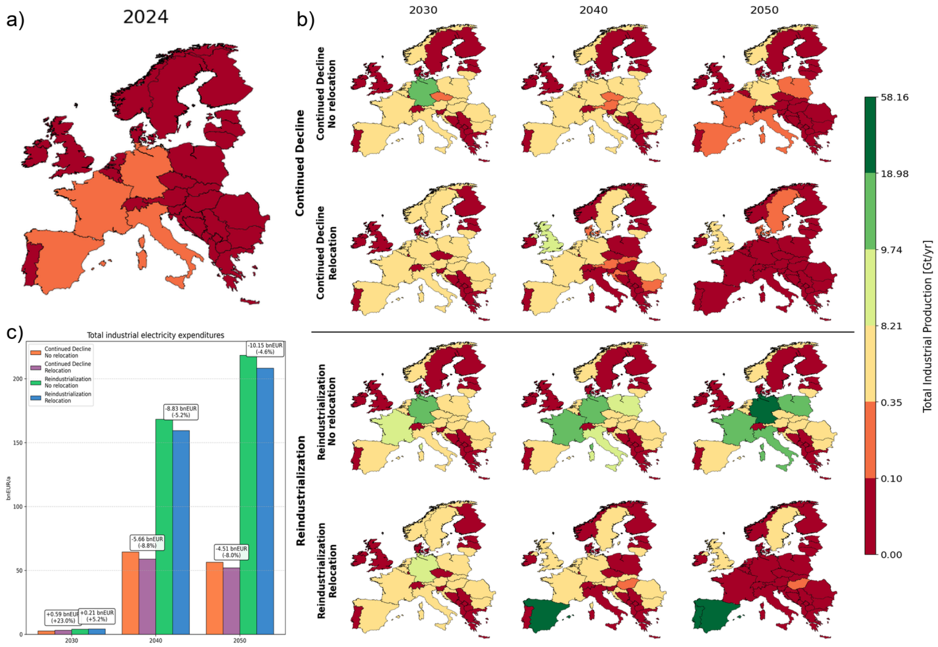

Figure 4.4: *(a) Total industrial production levels across European countries in 2024, showing current capacity distribution. (b) Projected industrial production trajectories for 2030, 2040, and 2050 under four scenarios: Continued Decline (two top rows) with No relocation within Europe and with Relocation within Europe, and Reindustrialization (two bottom rows), again with and without relocation. Color scale represents total industrial production in Gtons/a. (c) Industry expenditures for electricity across scenarios and years, in billion euros per year. Boxes report absolute and percentage differences relative to the No Relocation case.*

Imports of green intermediate goods

As an alternative to large-scale relocation, we assess the impact of importing green intermediate goods, HBI, ammonia, and methanol, from outside Europe starting in 2040. This strategy aims to reduce exposure to high domestic production costs while preserving downstream industrial activity within Europe. Figure 4.5 presents the resulting technology shares and system-level cost outcomes for the *Continued Decline* and *Reindustrialization* scenarios. Imports of green intermediates substantially reshape the European industrial technology mix from 2040 onward. Steel production increasingly combines imported HBI with domestic EAF, while ammonia and methanol production shift almost entirely toward imports by 2050.

This transition reduces domestic green hydrogen demand by approximately 25% and leads to a significant reduction in annual system costs and carbon prices, particularly under the *Reindustrialization* scenario. Compared to intra-European relocation, the import of green intermediates achieves larger cost reductions while limiting structural disruption to existing industrial capacity. By retaining final-stage processing within Europe and outsourcing the most energy-intensive production steps, this strategy emerges as a more effective mechanism for reconciling industrial decarbonisation with competitiveness under stringent climate targets.

4.3.3 Government subsidies

Figure 4.6 shows the average annual subsidies required to retain industrial production within Europe between 2035 and 2055. Subsidy needs vary significantly across sectors and scenarios.

The highest subsidy requirements arise under *Reindustrialization* without intermediate imports, reaching approximately 235 bnEUR/year. Plastics exhibit high total subsidy needs primarily due to large production volumes rather than lack of price competitiveness. Ammonia, methanol and steel require more moderate support, particularly when intermediate imports are allowed.

4.4 Discussion and policy implications

This study has the goal to examine whether deep industrial decarbonisation in Europe can be achieved while preserving cost competitiveness and industrial capacity. This tension is increasingly central in EU climate and industrial policy discussions, where Net-Zero targets are pursued alongside competitiveness and resilience objectives [18,175]. Beyond identifying this tension, the analysis explicitly evaluates which combinations of industrial policy instruments, subsidies, trade in intermediates, and spatial reallocation, remain fiscally, legally, and politically feasible under EU institutional constraints.

At high level, the results confirm a central tension already highlighted in the literature: although low-carbon strategies, particularly electrification and green hydrogen use, enable substantial emissions reductions, their large-scale deployment increases production costs relative to regions with abundant and inexpensive renewable resources [64,185].

The analysis provides additional insights. One is the temporal dimension of the trade-off. Cost pressures peak around 2040, when capital-intensive investments in electrolysers, low-carbon process technologies,

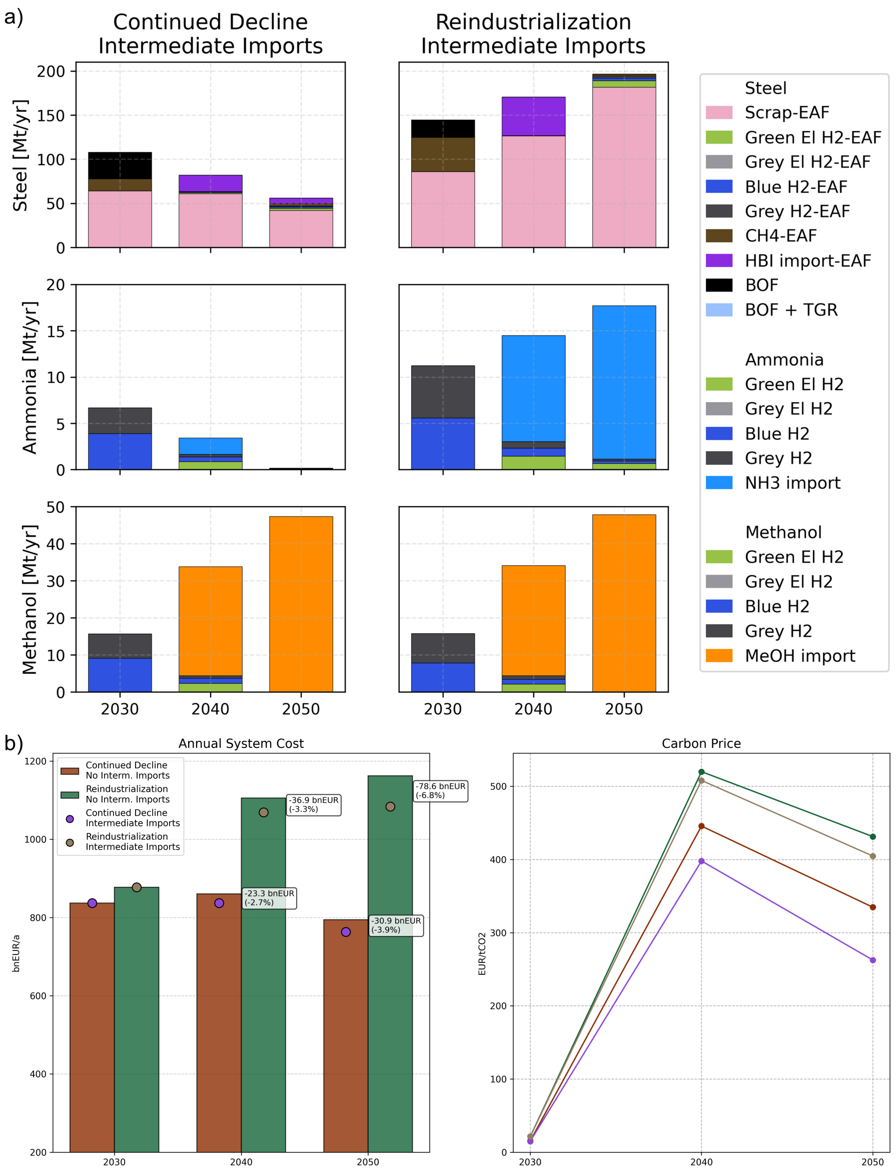

Figure 4.5: *(a) Projected industrial production trajectories for 2030, 2040, and 2050 under two scenarios with Intermediate Imports: Continued Decline and Reindustrialization. (b) Annual system costs (bnEUR/a) and carbon prices (EUR/tCO$_2$), compared to the corresponding No Intermediate Imports cases. Boxes report absolute and percentage differences relative to the No Intermediate Imports scenario.*

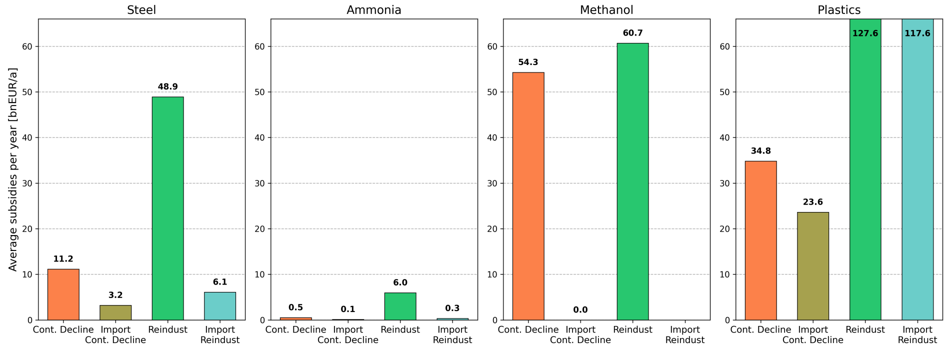

Figure 4.6: *Average annual subsidy requirements [bnEUR/a] for the five industrial sectors under four policy scenarios: Continued Decline, with and without Intermediate Imports, Reindustrialization with and with No Intermediate Imports.*

and supporting infrastructure coincide with stringent emissions constraints. By 2050, costs decline as capital stock turnover is completed, though price differentials with renewable-rich regions persist. This dynamic perspective complements previous system-level studies by showing that competitiveness challenges are not static, but concentrated in specific phases of the transition, specifically during the coming decade [55, 90, 212].

From an industrial policy perspective, the results suggest that strategies centred on large-scale reindustrialization under climate targets would require substantial and sustained public support. In the most ambitious scenarios, annual subsidy requirements exceed 200 bnEUR, far surpassing historical EU renewable energy subsidies (around 80 bnEUR/year in 2021 [213]) and current funding ambitions under initiatives such as the Clean Industrial Deal (approximately 100 bnEUR [175]). Such magnitudes raise concerns regarding fiscal feasibility and compatibility with EU competition law and state aid rules. State aid that distorts competition and affects trade within the internal market is in principle prohibited and may only be authorised under strict conditions. While recent frameworks allow support for decarbonisation and clean technologies [214], public support must be necessary, proportionate, and time-limited, and cannot permanently offset structural cost disadvantages. The subsidy levels needed for a major reindustrialization would therefore face legal and institutional barriers, particularly if concentrated in a small number of energy-intensive sectors or Member States, and risk exacerbating fragmentation of the internal market. These findings imply that subsidies can only play a transitional and selective role, rather than forming the backbone of a long-term European reindustrialization strategy under Net-Zero constraints.

By contrast, more moderate industrial strategies emerge as comparatively robust and policy-relevant. Allowing selective imports of green intermediate goods, such as hot briquetted iron, ammonia, and methanol, reduces system costs while preserving downstream industrial activity within Europe. This approach enables Europe to retain value-added stages of production, limit exposure to volatile energy prices, and reduce the scale of public subsidies required to maintain competitiveness. Importantly, these findings align with recent arguments that partial internationalisation of energy-intensive production may be preferable to either full offshoring or costly domestic self-sufficiency [64, 184, 185]. From a policy perspective, this suggests a shift from protecting entire value chains toward selectively safeguarding high value-added stages, while allowing energy-intensive upstream processes to partially internationalise under controlled trade and carbon pricing regimes.

Intra-European relocation of industrial activity can reduce production costs by shifting energy-intensive processes toward regions with abundant and lower-cost renewable electricity, reflecting a clear "renewables pull." However, the results also confirm that relocation alone offers limited savings relative to the scale of the transition. While energy expenditures decline, the model abstracts from broader social, economic, and political frictions associated with relocation, including employment effects, regional disparities, supply-chain reconfiguration, and infrastructure constraints. Consistent with previous assessments, these factors suggest that relocation within Europe is unlikely to constitute a dominant or sufficient decarbonisation strategy on its own, and that trading green intermediate products may achieve comparable or larger cost reductions while preserving value creation in renewable-scarce regions [208].

Taken together, the results point toward a pragmatic policy direction in which European industrial policy prioritises the decarbonisation and retention of existing capacity rather than aggressive expansion. Strategic use of intermediate imports, combined with targeted, time-limited subsidies, appears more compatible with fiscal and institutional constraints than broad-based support for full domestic production of all energy-intensive intermediates. In this context, revenues from the EU Emissions Trading System and the Carbon Border Adjustment Mechanism could help finance transitional support, provided distributional impacts are carefully managed through instruments such as the Social Climate Fund.

More broadly, the analysis underscores that industrial decarbonisation cannot be assessed solely through a technological or cost-optimisation lens. Trade-offs between emissions reductions, competitiveness, fiscal capacity, and political feasibility are intrinsic to the transition. By explicitly modelling these interactions over the full pathway to Net-Zero, this study contributes to a more policy-relevant understanding of how Europe might navigate the industrial transformation ahead.

Limitations and future research directions

This study provides a comprehensive representation of five energy-intensive industrial sectors (steel, cement, ammonia, methanol, plastics) within a sector-coupled European energy system model. However, other energy carriers and end-use sectors are treated in a simplified manner. Heat demand for industry outside the five analysed sectors is represented through aggregated profiles, synthetic fuel production for aviation and maritime transport is modelled using fixed technology assumptions, and biomass availability is subject to exogenous constraints. These simplifications reflect deliberate modelling choices to maintain tractability while focusing analytical detail on the industrial sectors most critical for decarbonization feasibility and competitiveness. The competitiveness dynamics, subsidy requirements, and trade strategies identified in this study are specific to the five analysed sectors and may differ for other industrial activities with different energy intensities, capital requirements, value-chain structures, or exposure to international competition. Similarly, the results are sensitive to assumptions about the availability and cost of green imports from renewable-rich regions, which remain highly uncertain and subject to future geopolitical and technological developments. The finding that selective imports of green intermediates can substantially reduce system costs and competitiveness pressures should therefore be interpreted within the bounds of the assumed import price ranges, which reflect current literature estimates but may not capture the full spectrum of future market conditions. Future research could address these limitations by extending the sectoral coverage, incorporating alternative assumptions on import availability and costs, and exploring how results vary under different configurations of the broader energy system. In this paper, we do not consider the possibility to replace today's plastics primary production with higher recycling rates and we omit biomass-based methanol, to maintain tractable CO_2 accounting and for the sake of simplicity. Including these pathways in future analyses would expand decarbonization options, and enable a more comprehensive assessment of interactions with other low-carbon strategies. This study's technology portfolio is not fully comprehensive, omitting CCS at NG-DRI-EAF steel plants, clinker-to-output improvements in cement, and other measures requiring more detailed modelling. It also excludes CO_2 transport and storage infrastructure, which could affect CCS and CDR adoption, while costs for emerging CDR and DAC technologies remain highly uncertain. Despite these gaps, major low-carbon options are captured, and future work incorporating sensitivities and CO_2 infrastructure could refine assessments of industrial decarbonization pathways. The analysis also omits potential geopolitical shocks and their effects on commodity and technology costs, particularly for clean energy technologies dependent on concentrated critical raw materials. Future work incorporating cost sensitivities and supply chain risks would help evaluate the robustness of decarbonization pathways under market and geopolitical uncertainties.

CHAPTER 5

Climate policy, steel decarbonisation, and trade fragmentation: a coupled energy-macroeconomic analysis for Europe

Abstract

This paper examines the interaction between European Union (EU) climate ambition and recent trade policies affecting energy-intensive industries, with a particular focus on steel. It assesses the extent to which EU climate policy outcomes are influenced by an increasingly fragmented global trade environment. By coupling a high-resolution European energy system model with a global computable general equilibrium framework, the analysis captures both technological feasibility and economy-wide adjustment mechanisms along the transition pathway. Two main results emerge. First, the paper quantifies economy-wide feedbacks associated with steel decarbonisation under EU climate policy. EU steel production declines, by around 10% on average by 2040, and exhibits a pronounced regional heterogeneity, whereas aggregate macroeconomic impacts remain limited, with EU-wide GDP losses below 0.5%. Second, the analysis shows that trade fragmentation plays a secondary role relative to domestic climate pol-

icy. While EU decarbonisation targets remain technically achievable, USA steel tariffs have only marginal additional effects on production, trade, and GDP, reflecting the limited exposure of EU steel-intensive sectors to the USA market and leaving transition pathways unchanged. Overall, the results indicate that internal climate policy design, rather than external trade measures, is the primary driver of economic and industrial outcomes during the transition. From a policy perspective, this suggests that climate ambition should be accompanied by targeted industrial and regional support measures. In contexts where trade measures are unilateral and limited in scale, assessing the effective exposure of the domestic economy is a necessary prerequisite before considering retaliatory actions.

5.1 Introduction

The European Union (EU) has established itself as a forerunner in the fight against climate change with the implementation in 2020 of the European Green Deal [199], aiming to transform the EU economy for sustainability and prosperity. The path from European Green Deal's objectives to practical realization has been marked by two significant developments. The first is the European Climate Law [17], which legally binds EU Member States to achieve climate neutrality by 2050. The second is the Fit-For-55 (FF55) package [18], that combines revisions to existing legislation with the introduction of new policy instruments, with the aim to reduce EU's greenhouse gas emissions by 55% by 2030. Key policies within the package include amendments to directives governing the EU Emissions Trading System (EU ETS), targets for renewable energy deployment, energy efficiency standards, and CO_2 emissions regulations for vehicles. In addition to these changes, the FF55 package introduces novel mechanisms such as the Carbon Border Adjustment Mechanism (CBAM) and the Social Climate Fund.

Over the past decade, global economic governance has shown a tendency to move away from the liberalisation paradigm. Governments are adopting interventionist measures, such as subsidies and selective tariffs, to strengthen domestic competitiveness and strategic autonomy, a trend partially driven by rising geopolitical instability. In the United States, policies like the Inflation Reduction Act [215], together with renewed tariffs and trade renegotiations, aim to re-shore clean-tech production and reduce import dependence. The European Union has taken a similar path, combining trade and industrial instruments such as the CBAM, targeted trade defences, and subsidy schemes to sustain low-carbon manufacturing.

Emerging economies, including China and India, have likewise expanded domestic production mandates in key low-carbon sectors [216, 217]. These developments redefine the context for Europe's decarbonisation efforts, reshaping the global conditions under which energy and industrial transitions unfold.

Given this framework, the scope of the paper is to situate European climate policies within an evolving landscape of economic and geopolitical uncertainty, and to assess how they interact. Through this lens, we evaluate their combined implications for both the energy system and the wider economy. In particular, we focus on the energy system and steel industry. Decarbonising energy-intensive industries hinges on the availability and cost of low-carbon electricity, hydrogen, and other clean energy carriers. Focusing on the energy system thus allows us to capture how European climate policies, by altering the energy mix and carbon prices, reshape production costs, while trade shocks feed back into energy demand. We dedicate particular attention to the steel industry, a hard-to-abate sector that sits at the intersection of decarbonisation challenges and trade policy tensions. Steel production's energy-intensive nature and its strategic economic importance make it a critical lens through which to examine how trade policies affect industrial decarbonisation pathways. We use the 2025 USA tariffs on European steel as a case study to investigate to what extent trade barriers in this sector can affect production systems and influence Europe's industrial decarbonisation strategy.

Classical analyses of trade-environment linkages emphasise the roles of scale, composition, and technique effects in shaping environmental outcomes [218, 219]. More recent work extends this perspective by showing that trade regimes and policy architectures themselves can embed environmental distortions, for example by shifting emissions across borders, altering relative competitiveness, or weakening incentives for low-carbon investment under asymmetric regulation [97, 98]. Empirical evidence on pollution-haven and carbon-leakage dynamics remains mixed [220–222], yet it underscores the sensitivity of energy-intensive sectors to asymmetric regulation and trade costs. A growing literature has assessed policy instruments that seek to align trade with climate objectives, most notably carbon border adjustment mechanisms and climate clubs [20, 223–225]. At the same time, heterogeneous-firm and innovation-focused analyses reveal that protectionist measures can dampen productivity and slow clean-technology diffusion [226], while open, rule-based regimes tend to favour innovation spillovers [227]. Recent modelling work further explores how trade measures influence decarbonisation pathways in transport and industry [228, 229]. Overall, these studies suggest that the climate impact of protectionism is context-dependent, varying with sectoral structure, technology availability, and policy design, making integrated assessments that capture energy-industry-trade interactions increasingly necessary.

Previous research has explored potential decarbonization pathways for the European economy, with a substantial body of literature utilizing Energy System Models (ESMs) to evaluate climate policy targets [55, 95, 96]. Mikropoulos et al. [230] conduct a comprehensive multi-model comparison of integrated assessment and energy system models to assess EU climate policy pathways to 2050, finding broad consensus on reduced energy demand driven by electrification, increased renewables, and divergent technology choices that underscore the value of model diversity for robust policy insights under climate-neutral scenarios. Fragkos et al. [65] evaluated on the previous EU's target of reducing GHG emissions by 40% through simulations using the PRIMES energy-system model. Beyond the energy modelling perspective, economics research has addressed the economic, social and distributional impacts of energy policies [231–234]. One of the most relevant studies is the European Commission's Impact Assessment, which shows that achieving the EU's Fit-for-55 climate targets would strengthen energy security, reduce dependence on imported fossil fuels, and create jobs by redirecting investments from fossil fuels to clean energy technologies [235]. Another crucial analysis in the economic assessment literature is Weitzel et al. [66], which employ the JRC-GEM-E3 Computable General Equilibrium (CGE) model, with inputs from energy system models, to assess policy scenarios combining regulations and carbon pricing, downscaling results to analyse household-level distributional and labour market impacts.

ESMs provide rigorous analytical frameworks to explore transition pathways, technological investments, and the feasibility of alternative energy strategies [24]. CGE models offer a comprehensive tool to assess climate change mitigation policies by capturing multi-sectoral interactions, economic agents' behaviour, and international trade dynamics [236, 237]. Energy models typically fail to account for the economic implications of changes in the energy system, such as variations in energy demand, with outcomes often influenced by externally defined assumptions about load levels [238, 239]. In contrast, CGE models do not typically capture the detailed representation of supply technologies and technical constraints that ESMs offer as an advantage. Integrating different model types can expand the scope of analysis and enable a more nuanced examination of individual sectors [240].

Building on previous research advocating the integration of CGE and ESM frameworks, this study develops a coupled modelling approach linking an energy system model and a CGE to coherently assess the combined impacts of energy and trade policies. We develop an integrated framework that couples the ESM PyPSA-Eur (with industrial extensions) and the CGE model FIDELIO through a two-way soft link. This enables us to assess policy-driven decarbonisation pathways from technical feasibility to macroeconomic feedbacks, and analyse the implications of trade policies, specifically, steel tariffs, on Europe's energy and industrial transitions.

According to the literature, models can be linked through either hard or soft coupling. Hard coupling fully integrates models and typically involves joint solution of a simplified hybrid system, while soft coupling keeps models separate, using the output of one as input to the other. When information flows in both directions, the approach is referred to as two-way soft coupling; otherwise, it is one-way coupling.

Recent studies have advanced the integration of economic models with energy system models to better assess climate and energy policies. Gong et al. [99] develop a bidirectional soft-coupling between the integrated assessment model REMIND and the hourly power sector model DIETER to jointly solve for investments and operational details, improving representation of variable renewables and price signals in decarbonisation pathways for Germany. Fattahi et al. [67] illustrate a soft-linking approach between the CGE model ThreeME and the detailed energy system model IESA-Opt for the Netherlands, showing how linking models that represent macroeconomic feedbacks and energy technology detail can alter projections of energy demand and GDP under climate policy scenarios. Odenweller et al. [68] integrate REMIND with the European energy system model PyPSA-Eur through iterative, price-based soft coupling, enabling the combined evaluation of long-term investment decisions for Germany to assess technically feasible, economically viable pathways to climate neutrality and the role of demand-side flexibility. Collectively, these studies demonstrate how model coupling can provide detailed, policy-relevant insights by integrating macroeconomic and energy system dynamics, allowing evaluation of technology, market, and carbon pricing interventions under realistic system constraints.

The present study enriches the literature in different directions:

1. We assess how steel industries respond to economy-wide decarbonisation dynamics, addressing a gap highlighted by Gillingham et al. [183].

2. We evaluate the influence of recent trade policies on European climate policy outcomes, a timely and understudied topic.
3. We implement a soft coupling between a global CGE and a detailed European energy system model, applied at the EU level, a methodological advance, as previous soft-linking studies focused only on individual EU countries.

The paper is organized as follows. Section 5.2 describes the methodological framework, summarising the model coupling approach, expanded in C.1, and detailing the policy modelling strategy adopted in this study. Section 3 describes the main results. Finally, Section 4 discusses the outcomes and Section 5 draws some policy implications and conclusions.

5.2 Methods

To describe the methodology implemented, this Section provides first an overview of the two models employed (Subsection 5.2.1) and the methods used to couple them (Subsection 5.2.2). Second, we describe the policy context, looking at both the EU climate targets and then the USA tariffs on imported steel (Subsection 5.2.3). Finally, Subsection 5.2.4 details how these policies are implemented within the modelling framework, while Subsection 5.2.5 presents the scenario design used to address the research questions.

5.2.1 Models description

This analysis soft-couples a detailed energy system model, PyPSA-Eur with a macroeconomic CGE model, FIDELIO, to capture both economy-wide adjustments and technology-specific decarbonisation pathways.

PyPSA-Eur is an open-source techno-economic optimisation model of the European energy system that determines cost-minimising investment and dispatch decisions subject to technical, spatial and policy constraints. For a detailed description of the model, the reader is referred to Brown et al. [103]. The model endogenously determines technology mix, energy prices, and investment requirements consistent with emissions constraints, minimizing system costs. PyPSA-Eur represents electricity generation, heat production, industry, transport, and transmission networks at high spatial and temporal resolution. For this study, it has been extended to include energy-intensive industrial processes, particularly steel production, following Di Bella et al. [94]. In this paper industrial production is assumed to remain geographically fixed, relying on the existing stock of industrial plants. No relocation of production capacity across regions is permitted within the modelling framework.

The model is run in myopic mode for 2030, 2040, and 2050 at three-hourly resolution, with 31 country-level nodes covering the EU27 (excluding Cyprus and Malta) and the United Kingdom. Throughout this paper, the geographical aggregation for Europe derived from PyPSA-Eur is referred to as "EU26+UK". A brownfield setup is used, with endogenous expansion of renewables, storage, and selected technologies. Climate impacts on renewable generation are represented using climate-adjusted ERA5 and EURO-CORDEX projections under RCP 4.5. Electricity and methane networks are based on existing infrastructure with limited grid expansion allowed, while technology costs follow PyPSA Technology-Data assumptions [195]. Biomass and CO_2 removal options are constrained in line with EU long-term strategies. Current power grid is included and the expansion of transmission lines is constrained to a maximum of 20% of existing installed capacity, weighted by individual line lengths.

FIDELIO is a recursive-dynamic, multi-region, multi-sector CGE model built on global multi-regional input-output data; a detailed documentation is provided in Rocchi et al. [100]. It represents international trade through bilateral flows and Armington differentiation, and captures interactions between production, consumption, investment, government behaviour and foreign trade across countries and sectors. A key feature of FIDELIO is the explicit modelling of short-term rigidities and adjustment frictions, which allow transitional dynamics and policy-induced adjustment costs to be analysed rather than assuming instantaneous long-run equilibrium outcomes. The model solves sequentially over time, with each period depending on the previous one, making it suitable for analysing medium-term transition pathways under climate and trade policies.

The choice of these models reflects the need to jointly capture detailed energy system transformation within Europe and economy-wide trade and macroeconomic interactions at the global level. PyPSA-Eur offers a high-resolution, open-source representation of the European energy system, with detailed spatial and temporal resolution, a well-maintained and transparent database, and an extended formulation that endogenises steelmaking technologies through vintage plant modelling [94]. Complementing this, FIDELIO provides a global, multi-regional macroeconomic framework with detailed sectoral and bilateral trade representations, allowing the analysis of demand responses, trade reallocation, and adjustment frictions across regions. Its structure is especially suited to evaluating trade-related policy shocks and their economy-wide spillovers, which are central to understanding the interaction between climate ambition and trade fragmentation. The integrated modelling framework combines PyPSA-Eur and FIDELIO through a two-way soft coupling. The full implementation is available in an open-source repository (https://github.com/cerealice/pypsa-fidelio), which provides the shell framework coordinating data exchange, iteration control, and convergence between the two models.

5.2.2 Models coupling

The two models are linked through a two-way, iterative soft-coupling framework designed to combine their respective strengths while preserving their internal consistency. Information is exchanged iteratively between them until convergence is achieved for a predefined set of variables. This approach allows each model to operate within its structure while capturing feedbacks between the energy system and the broader economy. The coupling follows a sequential logic, illustrated in Figure 5.1.

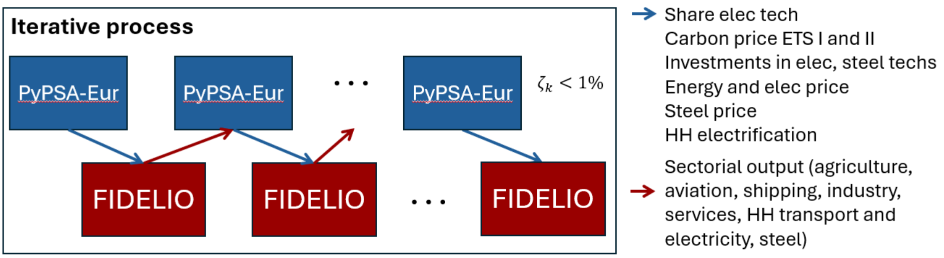

Figure 5.1: *Iterative framework scheme. ζ_k denotes the convergence indicator; convergence is assumed when ζ_k falls below 1%.*

For each scenario, PyPSA-Eur is solved first to determine the energy-system and industrial transformation implied by the climate policy, including power-sector deployment, electricity and energy prices, steel production costs, investment levels, household electrification rates, and carbon price signals. This sequencing reflects the fact that several of these variables are endogenously determined within the energy system model and are not available or cannot be resolved with sufficient technological detail in FIDELIO. These outputs are then translated into a set of harmonised shocks and parameters that are passed to FIDELIO. In FIDELIO, these inputs affect production costs, final demand, investment behaviour and trade flows, generating economy-wide adjustments in sectoral output and household demand. The CGE returns updated demand trajectories to PyPSA-Eur, meaning aggregate and sector-specific activity levels, as well as demand shifts for energy-intensive products and transport and energy services. PyPSA-Eur then re-optimises the energy system under these updated demand conditions. This exchange is repeated iteratively, until changes in the exchanged variables fall below a predefined convergence threshold.

Since the two models differ in temporal and spatial resolution, the coupling involves a number of harmonisation steps. PyPSA-Eur outputs, which are generated at high temporal resolution and for discrete milestone years, are aggregated and interpolated to match the annual time structure of FIDELIO. Conversely, economy-wide demand changes computed by FIDELIO are mapped onto the sectoral and service categories required by PyPSA-Eur. Detailed documentation of the data mappings, convergence metrics, and implementation of the coupling is provided in C.1.

5.2.3 Climate and trade policy framework

The analysis considers the interaction between European climate policy and evolving international trade conditions. More in detail, this Section provides a description of the two specific policy tools assessed: (i) the implementation of the European Union's climate policy architecture under the Fit-for-55 package, and (ii) recent USA steel tariffs on imports.

The Fit-for-55 package constitutes the core instrument through which the European Union operationalises the objectives of the European Green Deal and the European Climate Law, namely a reduction of greenhouse gas emissions by at least 55% by 2030 relative to 1990 levels and the achievement of climate neutrality by 2050. FF55 is a comprehensive and integrated framework combining market-based instruments, regulatory standards, and supporting measures across energy, industry, transport, and households. At the centre of the package is the reform of the EU Emissions Trading System, which introduces a tighter emissions cap, a higher linear reduction factor, and a gradual phase-out of free allowances for energy-intensive sectors. The scope of emissions trading is expanded to maritime transport, while a new ETS (ETS2) applies to emissions from buildings and road transport. Complementary regulatory instruments include revised targets under the Renewable Energy Directive (RED) and the Energy Efficiency Directive, stricter CO_2 performance standards for road transport, and fuel-specific regulations for aviation and maritime transport. Additional provisions address hydrogen and gas markets, infrastructure deployment, and social compensation mechanisms, notably through the Social Climate Fund. Taken together, these measures influence technology choices, investment patterns, and energy-system configuration, while also generating economy-wide adjustment pressures. A distinctive element of the FF55 architecture is the Carbon Border Adjustment Mechanism, which links climate policy directly to international trade. CBAM aims to reduce carbon leakage risks by aligning the carbon cost of selected imports with that faced by EU producers under the ETS, and is closely connected to the progressive removal of free allowances in covered sectors, including steel.

Alongside climate policy, the analysis explicitly considers trade policy shocks reflecting a renewed use of tariffs and trade restrictions. The applied analysis focuses on recent USA tariffs on steel imports as a case study of trade measures affecting key hard-to-abate sectors. In early 2025, the USA administration announced a 50% tariff on steel imports, prompting the European Commission to impose retaliatory duties worth 26 bnEUR [241, 242]. These tariffs alter relative prices, competitiveness, and trade flows independently of climate policy objectives, yet interact strongly with decarbonisation efforts by reshaping market conditions for energy-intensive industries.

For context, we report descriptive trade statistics from the 2015 benchmark underlying the FIDELIO model. While not intended to represent current trade patterns, these figures characterise the initial trade structure from which the policy simulations depart. As shown in Table 5.1, the United States absorbs around 11% of total EU exports in steel-related value-chain sectors, suggesting a meaningful but not dominant exposure of European producers to USA steel tariffs.

Table 5.1: *EU26+UK (EU27 excluding Cyprus and Malta, plus UK) exports of steel value-chain sectors by top 10 destinations in 2015.*

Destination	Share (%)
China	17.9
USA	11.4
Russia	6.3
Switzerland	6.1
Turkiye	6.0
Norway	3.2
Saudi Arabia	3.1
Mexico	3.0
South Korea	2.6
Australia	2.4

5.2.4 Policies implementation

Climate and trade policies are implemented within the coupled PyPSA-Eur-FIDELIO framework according to the scope and modelling strengths of each model. Policies that directly affect the energy system, technology choices, and emissions constraints are primarily represented in PyPSA-Eur, while policies that operate through trade costs, income redistribution, and macroeconomic channels are implemented in FIDELIO. Through the two-way coupling, the effects of these policies propagate across both models.

The Fit-for-55 climate policy package is implemented as a coherent set of constraints consistent with the EU's emissions reduction objectives for 2030, 2040, and 2050. In PyPSA-Eur, these objectives are operationalised through sector-specific greenhouse-gas emission caps, technology and fuel-mix requirements, and performance standards that guide investment and dispatch decisions in the power system, transport, and selected industrial sectors. An overarching emissions trajectory ensures a 55% reduction by 2030, a 90% reduction by 2040, and Net-Zero emissions by 2050 at the EU level. Instruments such as the Carbon Border Adjustment Mechanism and the recycling of climate-policy revenues are implemented directly in the macroeconomic model. Trade policy shocks are implemented in FIDELIO as changes in bilateral trade costs affecting energy-intensive sectors, with a particular focus on steel.

A detailed overview of the individual policy instruments and their specific representation within each model is provided in Table 5.2.

Table 5.2: *Overview of Fit-for-55 policy measures and their implementation in the modelling framework.*

Measure	**Details**	**Model implementation**
Revision of EU ETS	Power, energy-intensive industry, and aviation (+maritime): -63% GHG emissions in 2030 relative to 2005.	PyPSA-Eur, imposing a cap on GHG emissions from the respective sectors.
ETS2	Buildings (commercial and residential) and road transport: -43% GHG emissions in 2030 relative to 2005.	*PyPSA-Eur*, imposing a cap on GHG emissions from the relative sectors.
CBAM	Industrial products from countries without ETS pay CBAM certificates.	FIDELIO: CBAM is modelled as an additional import tariff on EU imports of CBAM-covered goods, calculated as the EU ETS carbon price multiplied by the embedded CO_2 intensity of exporter production (sector-weighted and time-updated) and adjusted for the progressive phase-out of free allowances. The mechanism is applied to all CBAM-covered industrial sectors, while electricity imports are excluded, reflecting their physical transmission constraints.

Continued on next page

Table 5.2 – *Continued from previous page*

Measure	Details	Model implementation
Revision of ESR	National emission reduction targets for buildings, road transport, agriculture, waste, and small industries to achieve -40% GHG emissions in 2030 relative to 2005.	PyPSA-Eur, imposing a cap on GHG emissions from non-ETS sectors.
Performance standards for Internal Combustion Engine (ICE)	Ban on internal combustion engine sales after 2035	PyPSA-Eur, adjusting Electric Vehicles (EVs) shares to meet performance targets, detailed in C.2.1.
FuelEU Maritime	Annual carbon intensity reduction with respect to 2020: -6% (2030), -38% (2040), -80% (2050) [CO_2/t-mile]. Reference value: 91.16 gCO_2e/MJ.	PyPSA-Eur, adjusting maritime fuel mix to meet carbon intensity targets, detailed in C.2.2.
Refuel EU Aviation	SAF (Sustainable Aviation Fuels) shares: 6% (2030), 34% (2040), 70% (2050); e-fuels: 1.2% (2030), 15% (2040), 35% (2050).	PyPSA-Eur, adjusting aviation fuel mix to meet SAF and e-fuel targets, detailed in C.2.3.
Social Climate Fund	ETS revenues earmarked for vulnerable households, microenterprises, and transport users.	FIDELIO: ETS revenues are recycled through the Social Climate Fund by reallocating 50% of carbon tax revenues to public consumption, representing transfers and support measures for households and vulnerable users, while the remaining 50% is redistributed through other government channels.
Gas markets	Development of a hydrogen backbone network.	PyPSA-Eur, enabling hydrogen grid expansion and utilisation.
Revision of Energy Efficiency Directive	-39% primary and -36% final EU energy consumption by 2030 (this translated in no more than 1023 Mtoe for primary, 787 for final [243]).	PyPSA-Eur, validated ex-post through resulting primary energy consumption in C.3.1.
Revision of Energy Performance of Buildings	-16% average primary energy in residential buildings by 2030, -20% by 2035; phase-out of fossil boilers by 2040.	PyPSA-Eur, oil boilers are not included, energy performance is validated ex-post through resulting building energy demand in C.3.1.
REPowerEU (Revision RED)	Renewable energy share target: 42.5-45% in final energy.	PyPSA-Eur, validated ex-post through resulting RES shares in C.3.1.
Regulation on methane	Common standards for methane emissions; mandatory leak detection and repair; ban on venting/flaring.	Not implemented (methane leaks not represented in models).
Alternative Fuels Infrastructure Regulation	EV recharge stations every 60 km by 2026; H_2 refuelling every 100 km by 2028.	Not implemented (specific infrastructures not included).
New LULUCF rules	-310 MtCO_2 target in 2030.	Sector not adequately represented in either model.
Market Stability Reserve (ETS)	Adjustment of allowance supply in EU ETS.	Not explicitly modelled.
Revision of Energy Taxation Directive	Restructuring of energy taxation based on carbon content and energy efficiency.	Not explicitly modelled.

The EU ETS2 and the ESR partially overlap in buildings and road transport, combining national emission targets with a market-based carbon price. From 2027, both apply simultaneously, requiring coordination to ensure policy coherence, while the ESR remains relevant for uncovered sectors such as agriculture and waste. ETS2 also includes a price stabilization mechanism, with allowance releases if prices exceed EUR 45/tCO_2 before 2029; accordingly, this price cap is imposed until 2030 [234]. For transport sectors, policies usually refer to emission or performance standards. Designing those in PyPSA-Eur requires some calculations, that are shown in

C.2.

5.2.5 Scenarios design

Three scenarios are analysed to disentangle the effects of climate policies and trade tariffs. The *Baseline* scenario represents a counterfactual pathway without climate policy, providing the reference trajectory against which all policy impacts are evaluated. The *EU ClimPol* scenario implements the full Fit-for-55 policy package and the European Climate Law objectives. The *EU ClimPol + Tariffs* scenario builds on the climate-policy scenario by introducing trade policies in the form of the 50% tariffs on steel imports in the US. This scenario allows the assessment of how rising protectionism and geopolitical fragmentation interact with climate policy, particularly in hard-to-abate sectors. Across all scenarios, policies are applied consistently over time, and results are reported for the milestone years 2030, 2040, and 2050. By comparing outcomes across scenarios, the analysis isolates the macroeconomic, trade, and energy-system effects of climate policy alone and in combination with trade shocks.

5.3 Results

Results are presented separately for the energy-system outcomes generated by PyPSA-Eur (Subsections 5.3.1 and 5.3.2) and the macroeconomic outcomes produced by FIDELIO (Subsections 5.3.3 and 5.3.4). To facilitate interpretation, EU countries are grouped into three macro-regions: Southern Europe (SEU), comprising Spain, Greece, Italy, and Portugal; Eastern Europe (EEU), including Bulgaria, Czech Republic, Estonia, Croatia, Hungary, Lithuania, Latvia, Poland, Romania, Slovenia, and Slovakia; and Northwestern Europe (NWEU), covering Austria, Belgium, Germany, Denmark, Finland, France, the United Kingdom, Ireland, Luxembourg, the Netherlands, and Sweden.

5.3.1 Electricity production

Figure 5.2 shows electricity production and consumption per capita by macro-region and total electricity generation and demand at the EU26+UK level across the three scenarios. Relative to the *Baseline*, both climate-policy scenarios (*EU ClimPol* and *EU ClimPol + Tariffs*) exhibit a pronounced increase in electricity demand over time, reaching the total value of around 8200 TWh in 2050. This reflects the central role of electrification in decarbonization, as power increasingly substitutes for fossil fuels across industry, transport, and other end-use sectors. The PyPSA-Eur-FIDELIO

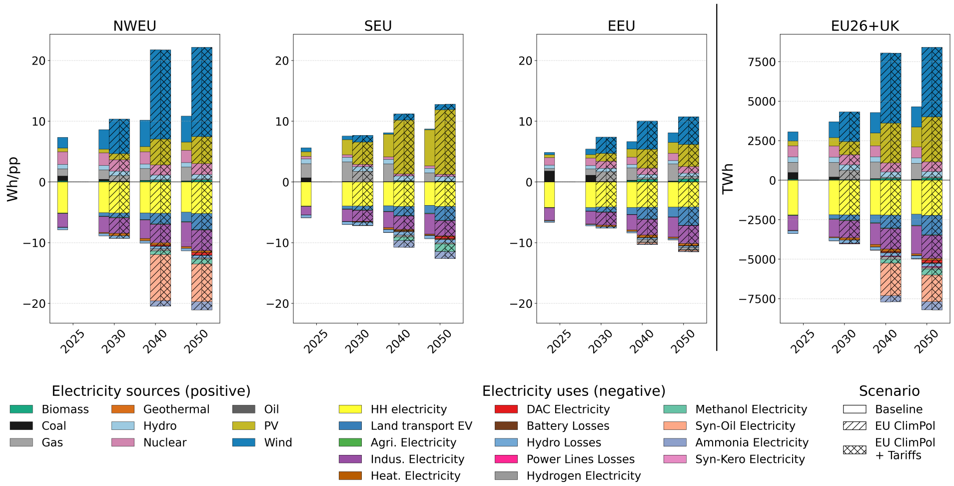

Figure 5.2: *Electricity production and demand per capita by macro-region (left panels) and total electricity production and demand at the EU level (right panel) under the Baseline, EU ClimPol, and EU ClimPol + Tariffs scenarios. Positive values represent power generation per different technologies, while the negative values show how this electricity is consumed by end-use sector. Results are shown for 2030, 2040, and 2050. Electricity production reflects the combined effects of electrification, renewable deployment, and synthetic fuel production in the coupled modelling framework.*

coupling allows electricity demand to respond endogenously to structural economic changes, providing additional flexibility and robustness to the results. In comparison, the uncoupled PyPSA-Eur model yields electricity demand that is, on average, 12.3 TWh higher, corresponding to less than 0.2% of total demand in 2050. This limited divergence suggests that, for this variable, long-term electricity demand trajectories are only weakly affected by economy-wide feedbacks, and appear largely driven by the structural features and constraints of the electricity system representation.

The expansion of power generation is broadly consistent with findings from other European decarbonisation assessments, including recent analyses by the Joint Research Centre [244]. While their standard projections estimate EU gross electricity generation will range between 3850 and 6400 TWh by 2050, the Low-Carbon Energy Observatory outlines a significantly higher scenario reaching 10548 TWh, driven by the energy intensity of hydrogen and e-fuel production.

In our results, NWEU displays the highest per-capita electricity production, driven by extensive wind deployment, while SEU relies more strongly on solar generation. EEU shows lower overall production levels and a more balanced renewable mix. In addition to the existing European power grid, transmission expansion is limited to a maximum increase of 20% of existing capacity, reflecting a conservative assumption on cross-border coordination. This allows for moderate EU power market integration, while potentially understating the benefits of deeper grid expansion. The power generation mix remain similar across the two climate-policy scenarios, indicating that trade measures have limited influence on the electricity system compared to the scale of electrification and decarbonization. A major driver of electricity demand growth in the climate-policy scenarios is the production of electro-based fuels, in particular synthetic oil produced via Fischer-Tropsch processes. These fuels contribute significantly to total electricity consumption, accounting for 26.7% of all power use in 2040 across climate policy scenarios. This reflects the central role of syn-fuels in decarbonising hard-to-electrify sectors such as aviation and maritime transport. The magnitude of this effect is also influenced by a modelling assumption in PyPSA-Eur, where all synthetic fuels are produced domestically; allowing for imports could potentially alleviate pressure on the electricity system and reduce overall costs.

5.3.2 Steel production

Figure 5.3 illustrates the evolution of steel production and prices across EU macro-regions under climate and trade policy scenarios. In the *Baseline* scenario, steel production follows historical spatial patterns, with output concentrated in NWEU (71.2 Mt/yr) and lower production levels in SEU (39.9 Mt/yr) and EEU (15.0 Mt/yr).

In 2030, climate policy has little impact on steel output, as the transition is still in its early stages and production structures remain largely unchanged, whereas 2040 represents the most disruptive phase, marked by deep emissions reductions and peak investment and restructuring in the steel sector. EU26+UK steel production declines sharply in 2040, by 11.7% under *EU ClimPol* and 10.3% under *EU ClimPol + Tariffs*, before partially recovering by 2050, when output remains 5.0% and 3.8% below the *Baseline*, respectively. The slightly smaller production losses under the tariff scenario suggest that USA tariffs on steel import marginally improves the competitive position of EU steel overall, although this effect remains secondary to the dominant influence of climate policy.

Eastern European countries experience the largest relative reductions in steel output, reaching around 25% by 2040. However, EU steel production is largely concentrated in NWEU and SEU, where relative declines are more limited, so sizeable percentage losses in the EEU translate into a smaller contribution to aggregate EU output changes. This pattern reflects

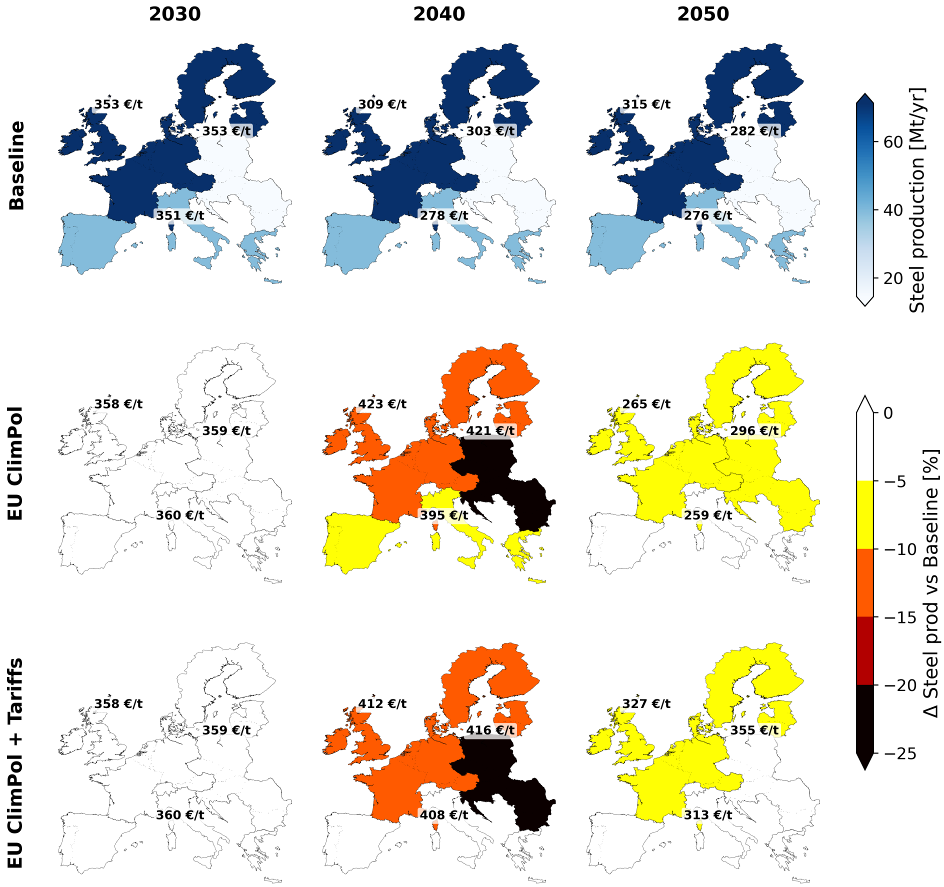

Figure 5.3: *Spatial distribution of steel production and production-weighted steel prices across EU macro-regions in 2030, 2040, and 2050 under the Baseline, EU ClimPol, and EU ClimPol + Tariffs scenarios. The top row shows absolute steel production levels (Mt/yr) in the Baseline. The middle and bottom rows report percentage deviations in steel production relative to the Baseline under climate policy alone and with additional trade tariffs, respectively. Annotated values indicate average production-weighted steel prices (€/t) by macro-region.*

the assumption that industrial production capacity is geographically fixed and cannot be relocated. Changes in steel output occur within the countries where production is historically located and cannot be offset through spatial reallocation.

Steel prices increase substantially under climate policy scenarios, most notably in 2040, reflecting higher production costs associated with low-carbon technology investments, before stabilising by 2050 as major capital adjustments are completed. By comparison, the uncoupled PyPSA-Eur model yields a production-weighted average steel price of about 487 EUR/t for EU26+UK in 2040. When the macroeconomic feedbacks captured by FIDELIO are taken into account, steel prices are around 14.5% lower, indicating that price formation is substantially influenced by the coupling.

5.3.3 Macroeconomic results

Figure 5.4 shows GDP deviations relative to the *Baseline* for EU macro-regions under the *EU ClimPol* and *EU ClimPol + Tariffs* scenarios, computed as five-year averages for 2030, 2040, and 2050.

Overall, aggregate GDP impacts for the EU26+UK remain limited, indicating moderate system-wide transition costs, as higher production costs are partly offset by increased low-carbon investment. GDP effects are slightly positive in 2030, reflecting the early transition phase with moderate investment needs and less stringent emissions constraints. By 2040, GDP impacts turn clearly negative, coinciding with the most demanding phase of the transition, marked by deep emissions reductions (-90%) and peak investment and restructuring requirements. In 2050, GDP deviations partially recover as major transition investments have largely been completed and the system enters a more stable phase. Impacts are uneven across regions: Eastern Europe experiences the largest GDP losses, reaching up to -0.9%, while NWEU and SEU are less affected, reflecting differences in industrial structure and renewable resource availability, with more limited renewable potential in the EEU compared to strong wind resources in the NWEU and solar potential in the SEU. Finally, the introduction of USA steel tariffs does not significantly alter the GDP trajectory relative to the climate policy scenario alone. This limited effect is primarily attributable to two factors: steel production represents only 1.3% of EU GDP [245], and steel-intensive products exported to the USA account for less than 2% of total EU production in these sectors[1] [246].

[1] According to the FIGARO input-output database (2015), around 11% of EU exports of steel-intensive products are destined to the United States, and extra-EU exports represent approximately 17% of total EU production of these goods. Combining these shares implies that US-bound exports correspond to roughly 2% of overall EU

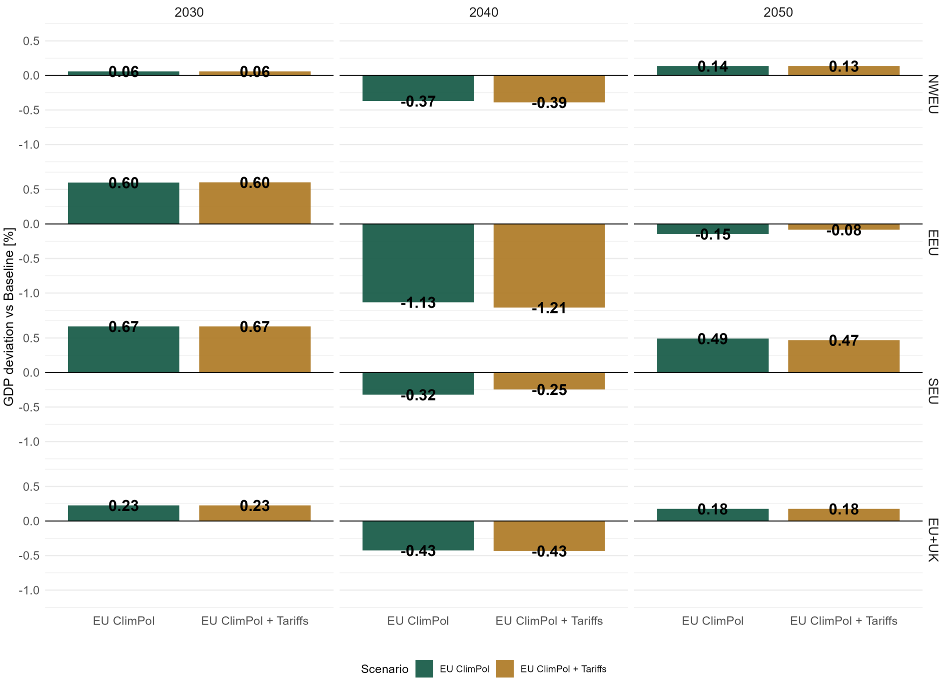

Figure 5.4: *Variation in GDP relative to the Baseline scenario, expressed in percentage points, for NWEU, EEU, SEU, and the EU26+UK aggregate. Results are shown for the EU ClimPol and EU ClimPol + Tariffs scenarios and for the milestone years 2030, 2040, and 2050, averaging for 5 years around the corresponding one.*

5.3.4 Trade implications

Figure 5.5 reports the variation in export volumes, excluding intra-EU trade, by macro-region and year (2030, 2040, and 2050) for the aggregated steel-intensive sectors, as percentage deviations relative to the *Baseline*.

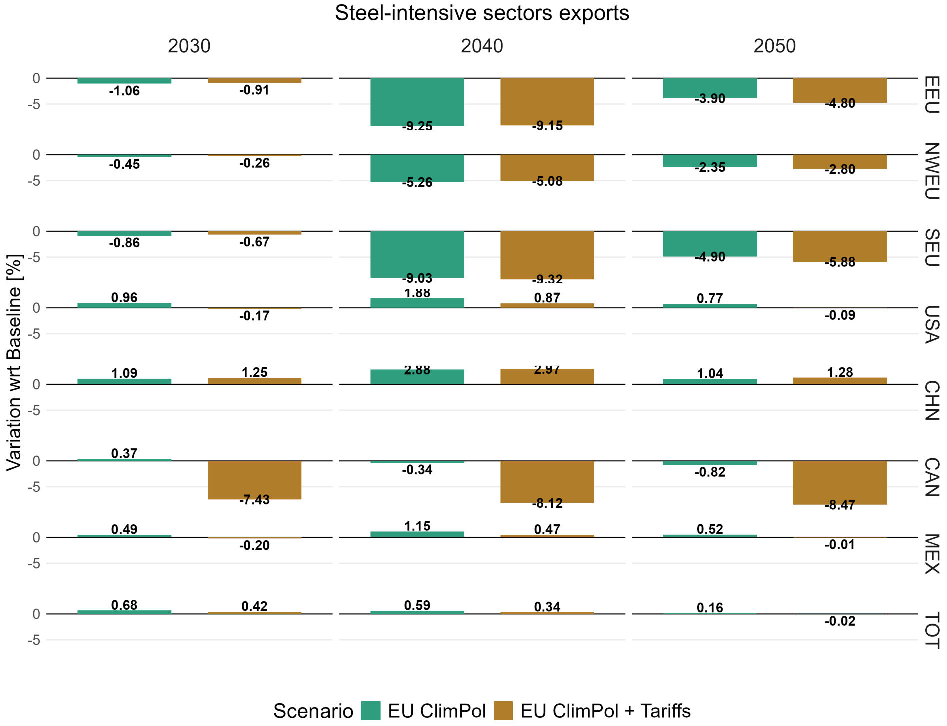

Figure 5.5: *Variation in total exports of steel-intensive sectors by macro-region relative to the Baseline, for EU ClimPol and EU ClimPol + Tariffs. Values are computed as 5-year averages and exclude intra-EU macro-regional trade flows. The steel-intensive sectors sectors includes primary steel production, non-ferrous basic metals, fabricated metal products, machinery and equipment, electrical equipment, and motor vehicles and transport equipment.*

All values represent five-year averages before the target years, smoothing short-term fluctuations. The steel-intensive sectors encompass primary steel production (Classification of Products by Activity code CPA_C24_S) as well as downstream steel-intensive manufacturing sectors: fabricated metal products (CPA_C25), machinery and equipment (CPA_C28), motor vehicles, trailers and semi-trailers (CPA_C29), and other transport equipment (CPA_C30). This classification is adopted to capture not only di-

steel-intensive production.

rect trade effects in raw steel but also indirect adjustments transmitted through vertically integrated industrial activities. Regional aggregation distinguishes the three chosen European macro-regions and selected non-EU economies that play a central role in global steel trade.

Across all European macro-regions, climate policy implementation leads to a reduction in exports from 2040, reflecting a broadly homogeneous response across Eastern, Southern, and Northwestern Europe. The reduction in exports is reduced for EU regions when intra-European trade is included, as shown in C.3.2 (e.g., in Figure C.4 for 2040, *EU ClimPol*: EEU -5.93%, NWEU -3.03%, SEU -5.02%). This reflects the fact that intra-EU trade is both less affected by transition-related price increases and constitutes a substantial share of total EU trade (around 70% [246]). The introduction of USA tariffs has a negligible additional effect on EU exports, indicating that the dominant driver of the export contraction is domestic decarbonisation rather than external trade measures. In contrast, the United States experiences an increase in exports under *EU ClimPol* scenario, up to 1.88% in 2040, consistent with a competitiveness-driven reallocation of steel and steel-intensive production towards regions facing weaker climate constraints. This export expansion is reduced when tariffs are introduced, highlighting the role of trade tariffs in dampening competitiveness gains associated with asymmetric climate ambition. China exhibits a larger increase in export with respect to US, within the *EU ClimPol* up to 2.88%, marginally more when tariffs are applied. Finally, Canada shows a pronounced sensitivity to USA trade measures: while EU climate policy alone has a limited effect on Canadian exports, the introduction of tariffs leads to a marked reduction, reflecting Canada's strong trade integration with the US.

Figure 5.6 presents the variation in import volumes, excluding the intra-EU trade, by macro-region and year (2030, 2040, and 2050), measured as percentage deviations from the *Baseline* for the aggregated steel-intensive sectors.

Import responses differ across EU macro-regions and over time. While imports increase across all regions in 2030 under the *EU ClimPol* scenario, reflecting an early adjustment phase in which rising domestic costs require greater reliance on foreign supply, this effect diminishes by 2040. In particular, NWEU exhibits a slight decline in imports in 2040, as domestic steel production contracts but remains sufficient to meet reduced internal demand, lowering the need for imports. The introduction of USA tariffs leads to only marginal additional changes, confirming that EU import dynamics are primarily shaped by internal climate policy rather than external trade

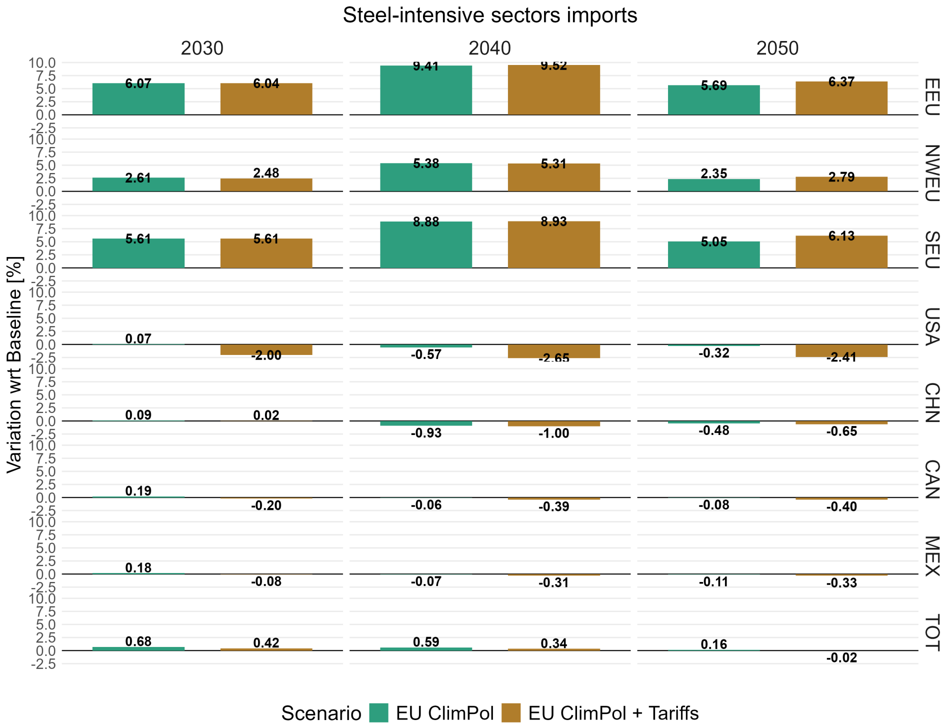

Figure 5.6: *Variation in total imports of steel-intensive sectors by macro-region relative to the Baseline, for EU ClimPol and EU ClimPol + Tariffs. Values are computed as 5-year averages and exclude intra-EU macro-regional trade flows. The steel-intensive sectors sectors includes primary steel production, fabricated metal products, machinery and equipment, electrical equipment), and motor vehicles and transport equipment.*

measures. The United States experiences a moderate reduction in imports, which becomes more pronounced when tariffs are introduced (-2.65% in 2040). China shows a decline in imports under the *EU ClimPol* scenario, while USA tariffs further amplify this contraction. For both countries, the observed reduction in imports is predominantly attributable to decreased procurement from EU member states, partially offset by the substitution of products sourced from other countries and the expansion of domestic manufacturing within steel-intensive sectors (as in Figure C.8 (2040): *EU ClimPol* yields +0.61% USA and +1.14% China; *EU ClimPol + Tariffs* yields +0.54% and +1.19% respectively). Canada and Mexico, by comparison, exhibit minor change in import volumes under *EU ClimPol* alone, and both nations record slightly stronger reductions of imports once USA tariffs are applied.

5.4 Discussion

This study integrates a high-resolution European energy system model with a global macroeconomic trade model to assess how climate ambition and trade fragmentation jointly shape energy, industrial, and economic outcomes. By coupling PyPSA-Eur and FIDELIO in a two-way iterative framework, the analysis captures feedbacks between technology deployment, energy prices, industrial costs, trade flows, and aggregate economic activity that are typically examined in isolation.

Before interpreting the substantive results, it is important to clarify the scope and representativeness of the trade shock analysed. The USA steel tariffs examined in this study represent a specific, unilateral, and sector-focused trade measure affecting a limited share of EU steel-intensive exports (approximately 11% of total EU exports in these sectors). The finding that this tariff has minimal impact on EU climate policy outcomes should therefore be understood as context-specific rather than universally generalizable to all forms of trade fragmentation or geopolitical disruption. More aggressive trade scenarios, such as coordinated retaliatory tariff escalation, broader sectoral coverage (e.g., extending to chemicals, cement, or critical raw materials), or multilateral trade disruptions affecting major EU export markets like China, could produce substantially different outcomes. Similarly, supply-side shocks, such as restrictions on critical raw materials (rare earths, lithium, cobalt) or fuel imports, would affect the energy system and industrial competitiveness through different transmission channels and with potentially larger magnitude effects. The analytical framework developed here is well-suited to assess such alternative scenarios, and the limited impact observed for USA steel tariffs should not be interpreted as implying that all forms of trade fragmentation are inconsequential for the European energy transition. Rather, it underscores the importance of assessing the effective exposure of the domestic economy to specific trade measures before designing policy responses.

Across all scenarios, changes in production, trade, and economic outcomes for EU26+UK are shaped predominantly by EU climate policy itself, while the specific trade measure examined (USA steel tariffs) plays a secondary role and does not materially alter the direction or timing of the decarbonisation pathway. However, this result holds within the scope of the trade policies examined here and may differ under more aggressive or coordinated retaliation frameworks. From a policy perspective, this suggests that retaliatory measures, that potentially introduce additional distortions without clear economic or climate benefits, should be evaluated with caution, as moderate tariffs appear to have limited effectiveness in shaping transition and economic outcomes.

The electricity system emerges as the backbone of the transition, with rapid electrification and the expansion of renewable generation underpinning emissions reductions across sectors. Synthetic fuel production for aviation and maritime transport substantially amplifies electricity demand. Also in the steel sector, results show that production adjustments are governed mainly by the stringency of climate policy. The reduction in steel output around 2040 coincides when emissions targets tighten sharply and a large share of existing steelmaking capacity must be replaced or retrofitted with low-carbon technologies, increasing adjustment costs and temporarily constraining production.

At the macroeconomic level, GDP impacts remain moderate for overall EU26+UK but are unevenly distributed across regions, with Eastern Europe experiencing the largest relative losses due to differences in industrial structure and more limited renewable resource availability. This highlights the importance of accompanying climate policy with targeted support measures, such as enhanced investment subsidies, expanded use of the Social Climate Fund, and region-specific industrial transition assistance, to mitigate adjustment costs and ensure a more balanced and inclusive decarbonisation pathway. Trade tariffs on steel contribute little to aggregate GDP effects compared to the scale of adjustment induced by climate policy, underscoring that decarbonisation, rather than trade fragmentation, is the dominant driver of long-term economic outcomes in the EU context.

Trade results indicate a consistent reorientation of steel-intensive trade flows under asymmetric climate ambition. For the EU, decarbonisation increases imports and reduces exports, reflecting higher domestic production costs and reduced international competitiveness. However, the additional effect of USA steel tariffs on EU trade flows is limited. Instead, tariffs generate more pronounced distortions for the United States and for closely integrated partners such as Canada and Mexico, reducing both imports and exports and reinforcing inward-oriented production patterns. These findings suggest that trade protection dampens international competitiveness without delivering sustained export gains, while producing negative spillovers for highly connected economies.

The trade results indicate that the primary driver of adjustment in steel-intensive trade flows for EU is domestic climate policy rather than external trade measures. EU decarbonisation leads to higher production costs and prices in steel and downstream sectors, reducing export competitiveness and increasing reliance on imports. By contrast, the introduction of USA steel tariffs generates only marginal additional effects on EU trade flows, reflecting both the limited exposure of EU steel-intensive production to the USA market and the dominance of internal policy-driven cost pressures. Outside the EU, asymmetric climate ambition creates temporary competitiveness gains for regions with weaker climate constraints, notably the United States and China, while tariffs primarily reallocate trade away from closely integrated partners such as Canada rather than delivering sustained export gains for the tariff-imposing country. From a policy perspective, these findings suggest that concerns over large trade distortions from unilateral steel tariffs may be overstated in the EU context, while competitiveness impacts of climate policy are more effectively addressed through targeted industrial support and coordinated climate-trade instruments than through defensive trade measures.

The two-way coupling between PyPSA-Eur and FIDELIO highlights an important asymmetry in cross-model feedbacks. On the energy-system side, electricity demand levels adjust endogenously to macroeconomic changes, but these variations do not substantially alter the optimal technology mix or the spatial structure of generation, which remains primarily driven by resource availability and system constraints. By contrast, price signals transmitted from the energy system to the macroeconomic model play a much stronger role. In particular, changes in energy and steel prices generated by PyPSA-Eur significantly affect production costs, trade flows, and demand responses in FIDELIO. Steel prices are especially sensitive to the coupling, as endogenous demand adjustments and economy-wide feedbacks lead to systematically lower prices than in the uncoupled energy-system representation. Overall, these results suggest that coupling is most critical for capturing price- and demand-mediated adjustment mechanisms, while the core technological configuration of the energy system remains relatively robust to macroeconomic feedbacks.

5.5 Conclusions

This paper addresses two closely related research questions: whether recent trade measures materially affect European climate policy outcomes, and how steel decarbonisation interacts with broader economic and trade dynamics. The results indicate that, for the EU26+UK and for the specific trade shock examined, climate outcomes are driven by internal climate ambition rather than by external trade policies. Recent USA steel tariffs, while relevant for specific bilateral trade relations, do not significantly alter the timing, direction, or feasibility of the decarbonisation pathway, nor do they meaningfully affect aggregate economic outcomes. Instead, their impacts are concentrated outside the EU, generating distortions for highly integrated trading partners without delivering sustained competitiveness gains for the tariff-imposing country. This finding reflects both the limited direct exposure of EU steel-intensive sectors to the USA market (around 11% of extra-EU exports) and the dominant role of domestic climate policy in shaping production costs and competitiveness. However, this result should not be generalized to all forms of geopolitical or trade-related uncertainty. More severe or coordinated trade disruptions, broader sectoral coverage, or supply-side restrictions on critical materials and energy imports could produce substantially different impacts on the European energy transition.

At the same time, the analysis shows that steel decarbonisation in the EU is driven by economy-wide adjustment processes rather than sector-specific technological constraints alone. Steel production, prices, and trade outcomes respond to the interaction of climate policy stringency and endogenous demand adjustments captured in the coupled PyPSA-Eur-FIDELIO framework. The sharp contraction in 2040 reflects the alignment of deep emissions reductions with peak investment and restructuring needs, while the partial recovery by 2050 indicates easing adjustment pressures after major capital turnover. Strong regional heterogeneity persists, with Eastern Europe experiencing the largest relative output losses, reinforcing the need to analyse industrial decarbonisation within an integrated economic framework. From a policy perspective, the findings suggest that safeguarding EU industrial competitiveness is less a matter of defensive trade measures and more a question of accompanying climate ambition with targeted industrial support, coordinated climate-trade instruments, and region-specific transition policies. Aligning climate, industrial, and social policies therefore emerges as a prerequisite for delivering an economically resilient and politically sustainable decarbonisation pathway.

From a modelling perspective, the results highlight the added value of integrated energy-economy frameworks for analysing industrial decarbonisation. While energy-system models capture technological feasibility, coupling with a macroeconomic model is crucial to represent price formation, demand responses, and trade adjustments that materially affect sectoral and economic outcomes. Given the additional complexity and computational cost, such coupling is most appropriate when research questions focus on global trade and economy-wide adjustments. For studies centred on power-system technologies or operational detail, the benefits of full energy-economy coupling are more limited.

Limitations and future research

This analysis relies on a number of simplifying assumptions that suggest avenues for future research. In the macroeconomic model, investments related to steel are aggregated within the broader "Manufacture of Basic Metals sector" (C24 in CPA codes), which encompasses iron and steel, ferroalloys, and non-ferrous basic metals, potentially obscuring upstream and downstream value-chain interactions. In addition, trade measures are assumed to persist over the entire projection horizon, climate policy is implemented only in the European Union, and synthetic fuel demand is fully satisfied by domestic production. Importantly, the analysis focuses on a single, unilateral trade shock (USA steel tariffs) affecting a limited share of EU exports. Alternative trade scenarios, including coordinated tariff escalation, broader sectoral coverage, multilateral trade disruptions, or supply-side restrictions on critical raw materials and energy carriers, may produce substantially different outcomes and warrant dedicated assessment. Relaxing these assumptions would allow future work to better capture global decarbonisation dynamics, evolving trade regimes, international energy and fuel supply chains, and a wider spectrum of geopolitical risks affecting the European energy transition.

CHAPTER 6

Conclusions

6.1 Risk-proofing the European energy transition

This thesis set out to investigate the European energy transition at a moment when the energy transition is facing internal and external challenges. Over the past decade, European climate policy has been guided by a significant body of modelling evidence showing that deep decarbonisation is technically feasible and economically manageable under coordinated policy action. However, recent developments, including accelerating climate impacts, renewed industrial competition, energy price shocks, and rising geopolitical tensions, require a renewed assessment of transition pathways beyond idealised conditions.

Against this backdrop, the central contribution of this thesis is to reframe decarbonisation not only as a mitigation challenge, but as a problem of systemic resilience. Rather than identifying a single cost-optimal pathway to climate neutrality, this thesis examines how European energy and industrial transition strategies remain viable under physical climate risks, competitiveness pressures, and trade disruptions. In doing so, it shows that policy-relevant analysis must account not only for cost efficiency, but also for robustness under risks.

This reframing is particularly timely. The European Green Deal, the European Climate Law, and the Fit-for-55 package establish ambitious and legally binding targets, yet their implementation unfolds in a context fundamentally different from that assumed in many pre-2020 modelling exercises. Climate change is no longer an external motivation but an active stressor of energy systems; industrial decarbonisation has become inseparable from questions of strategic autonomy and reindustrialization; and trade policy has re-emerged as a core instrument of climate and industrial strategy. This thesis directly engages with this fast-evolving policy landscape by providing an analytical framework capable of assessing European decarbonisation strategies under the physical, economic, and geopolitical conditions in which they are now being implemented.

6.2 Synthesis of the three articles

The three articles composing this thesis jointly address the overarching question of how to assess viable European decarbonisation pathways under multiple, interacting sources of risk. Each paper focuses on a specific dimension: climate impacts, industrial competitiveness, and trade disruptions. Overall, the articles provide policymakers with evidence-based insights into how decarbonisation pathways can be designed to remain resilient under different sources of risk.

The first article demonstrates that climate change affects energy systems not only through long-term trends, but through non-linear impacts on demand, renewable generation, and system adequacy. Rising temperatures, altered hydrological regimes, and increasing frequency of extreme events materially affect both electricity supply and demand. Importantly, the analysis shows that power system designs optimised using historical climate data can underestimate future costs and adequacy challenges, particularly in renewables-dominated systems. This finding challenges the widespread assumption of climatic stationarity in energy system modelling and highlights the need to integrate climate impacts endogenously into planning frameworks.

The second article addresses the decarbonisation of energy-intensive industries as a key competitiveness constraint of the European energy transition. By examining different levels of industrial production, the analysis challenges the common assumption of fixed output and evaluates how alternative industrial trajectories interact with climate ambition. The results show that decarbonisation outcomes depend not only on technology availability, but critically on Europe's cost position relative to global competitors. Within this framework, selective imports of low-carbon intermediates, and targeted, time-bound subsidies emerge as complementary policy instruments for reconciling emissions reductions with industrial viability.

The third article investigates how European decarbonisation pathways interact with international trade dynamics in an increasingly fragmented geopolitical context. Focusing on USA trade tariffs affecting steel, the analysis shows that European climate outcomes are driven primarily by internal climate ambition rather than by external trade policies. While trade measures do not significantly alter the timing or feasibility of decarbonisation, they do reshape production patterns, and trade flows. These findings highlight that trade policy influences the distributional and economic consequences of decarbonisation rather than its technical viability, underscoring the importance of analysing climate policy within an integrated economic and geopolitical framework.

The three articles demonstrate that the resilience of European decarbonisation pathways depends on the extent to which physical, economic, and geopolitical risks are jointly incorporated into their design and evaluation. Climate impacts, competitiveness pressures, and trade disruptions do not act independently, but interact through energy prices, infrastructure constraints, and investment dynamics, shaping the conditions under which decarbonisation strategies remain viable. By explicitly examining these interactions, the thesis shows how transition pathways can be structured to preserve effectiveness under multiple sources of risk.

6.3 Implications for energy system modelling practice

The findings of this thesis carry several implications for how energy system models are developed and used to support climate and energy policy. Energy system modelling has made substantial progress in representing technological detail, spatial resolution, and sectoral integration. However, the analyses presented here suggest that prevailing modelling practices remain insufficiently equipped to assess transition robustness under real-world conditions of uncertainty and disruption.

A first implication concerns the widespread reliance on stationary assumptions in long-term decarbonisation modelling. Many studies implicitly assume that historical climate conditions are a sufficient proxy for future system operation, that industrial activity follows fixed trajectories, and that international trade remains stable and frictionless. While such assumptions were reasonable simplifications in earlier phases of modelling, when the primary aim was to demonstrate the technical feasibility of deep decarbonisation, they are increasingly misaligned with the conditions under which climate policy is now being implemented. The results of the first article show that neglecting climate change impacts on energy demand and supply leads to a systematic underestimation of system costs, adequacy risks, and infrastructure needs. Climate impacts can therefore no longer be treated as an external sensitivity or a post-processing exercise. Instead, they need to be integrated directly into energy system optimisation. Incorporating climate model outputs, through modified demand profiles, renewable resource availability, or explicit stress tests of extreme events, allows the system to adjust endogenously via investment and operational decisions.

A second implication concerns the representation of industry within energy system models. Traditionally, industry has often been modelled as an exogenous demand sector, with fixed production volumes and limited spatial or technological differentiation. While suitable for analysing power system expansion or sector coupling in aggregate terms, this abstraction limits the ability of models to engage with one of the most pressing policy questions facing Europe: whether industrial decarbonisation can proceed without eroding global competitiveness. The second article shows that allowing industrial production to respond to relative costs fundamentally changes model outcomes and policy conclusions. Endogenising industrial output reveals trade-offs between domestic production, relocation, and imports that remain invisible under fixed-demand assumptions.

A second implication concerns how industry is represented within energy system models. Industry is often treated as an exogenous demand sector, with fixed production levels and limited spatial or technological differentiation. While this abstraction may be sufficient for analysing aggregate power system expansion, it constrains the ability of models to address one of the most consequential policy questions facing Europe: whether industrial decarbonisation can be achieved without undermining international competitiveness. The second article shows that allowing industrial production to respond endogenously to relative cost differentials fundamentally alters both model outcomes and policy interpretations. The analysis highlights the limits of large-scale reindustrialization strategies that rely on sustained public subsidies. By contrast, more moderate approaches, combining selective imports of low-carbon intermediates with targeted, time-limited support, emerge as comparatively robust options for preserving industrial capacity under Net-Zero objectives.

A third implication concerns the treatment of international trade and macroeconomic feedbacks. Energy system models have traditionally abstracted from trade dynamics or represented imports and exports through fixed price assumptions, while macroeconomic and trade models typically rely on highly aggregated representations of energy technologies. The third article shows that this separation hides important interactions between trade policy, energy prices, and decarbonisation outcomes. When energy systems and trade dynamics are analysed jointly, trade disruptions are found to propagate through energy-intensive sectors and feed back into energy demand, industrial output, and investment decisions, even when climate targets themselves remain unchanged.

From a modelling perspective, the analysis points to three key implications for the use of energy system models in industrial and trade policy assessment. First, energy system models intended to inform industrial policy require a more granular representation of industry, including production processes, existing capital stock, and spatial heterogeneity. Aggregate or fixed-demand representations are insufficient when policy questions concern competitiveness, carbon leakage, and the retention of industrial capacity under Net-Zero constraints. Second, modelling frameworks need to move beyond purely cost-minimising behaviour under fixed constraints and allow for strategic responses to policy-induced cost differentials. This does not imply that all energy system models should evolve into full economic equilibrium models. It suggests that the boundary between energy system modelling and industrial or economic modelling must be reconsidered when analysing policies that directly affect production decisions, relocation incentives, and trade exposure. Third, the results underscore the value of coupled modelling approaches when analysing policies that simultaneously affect energy systems, industry, and international trade. Soft coupling preserves the strengths of specialised models while enabling the feedbacks necessary for policy relevance. In this context, one-way linkages, where energy system outputs are passed to economic models without feedback, risk systematically misrepresenting adjustment dynamics.

More broadly, the thesis highlights a shift in the role of energy system modelling from identifying optimal pathways under idealised conditions to stress-testing strategies under plausible adverse scenarios. This does not diminish the value of cost-optimal modelling; rather, it complements it by recognising that policy decisions must perform acceptably across a range of futures rather than excel in a single projected outcome. Scenario diversity, explicit treatment of risks, and transparency about assumptions become as important as optimisation precision.

Finally, these implications point to an evolving relationship between modelling and policy. As climate policy becomes more tightly intertwined with industrial strategy, trade policy, and adaptation planning, energy system models are increasingly called upon to inform decisions under uncertainty rather than provide definitive forecasts. The contributions of this thesis suggest that enhancing model realism-through climate integration, endogenous industrial behaviour, and economic coupling-can improve the credibility and usefulness of modelling outputs for policymakers navigating an increasingly complex transition landscape.

6.4 Policy relevance in the European context

The policy relevance of this thesis derives from the structural challenges inherent to large-scale energy system change. Transitions toward low-carbon energy systems require long-term investment decisions to be taken under conditions of technological uncertainty, economic competition, and evolving political constraints. These challenges are articulated in Europe through binding climate targets and sector-specific regulations, but they are neither unique to the European Union nor confined to the present decade. Climate impacts on energy systems, competitive pressures on industry, and disruptions to trade and supply chains are persistent features of contemporary energy systems.

This thesis addresses this challenge by reframing decarbonisation as a problem of robustness rather than optimisation under idealised conditions. European climate policy instruments, including emissions pricing, renewable energy targets, and sectoral regulations, are increasingly intertwined with industrial policy objectives, trade measures, and adaptation requirements. The analyses presented here demonstrate that policy coherence across these domains is not optional: policies designed in isolation may appear effective ex ante, but can generate unintended and potentially destabilising outcomes once exposed to climate impacts, competitiveness pressures, or trade disruptions.

In the power sector, the findings show that treating climate adaptation as separate from mitigation is no longer justifiable. Climate change already affects electricity demand, renewable generation profiles, and system adequacy, with direct implications for infrastructure planning and investment. Integrating climate risks into energy system planning, through network development plans, capacity mechanisms, and renewable deployment strategies, reduces the likelihood of costly retrofits and supply disruptions later in the transition. More broadly, the results support a closer alignment between climate risk assessment and the institutions responsible for energy system planning at national and European levels.

For energy-intensive industries, the analysis highlights the limits of decarbonisation strategies that rely on uniform policy instruments or large-scale reindustrialization supported by sustained public subsidies. More nuanced approaches, focused on preserving and decarbonising existing industrial capacity, particularly in downstream activities, while allowing selective imports of low-carbon intermediates, emerge as more robust under institutional and budgetary constraints. Targeted instruments such as contracts for difference, selective state aid, and infrastructure investment can help bridge cost gaps in strategically important sectors, while avoiding permanent dependency on public support. These insights directly inform ongoing debates around the Clean Industrial Deal and the role of EU-level funding in industrial transformation.

The interaction between climate policy and international trade further reinforces the need for integrated policy assessment. Trade measures and geopolitical developments can materially affect production patterns, investment decisions, and regional economic outcomes. Mechanisms such as the Carbon Border Adjustment Mechanism are intended to reconcile climate ambition with competitiveness, yet their effectiveness depends on broader economic feedbacks, including downstream impacts, responses from trade partners, and changes in energy demand. The results underscore that trade instruments cannot be evaluated in isolation, but must be assessed in conjunction with climate and industrial policies within a coherent analytical framework.

Overall, the contributions of this thesis support a shift in European climate and energy policy thinking. Rather than pursuing narrowly defined least-cost pathways, policymakers must increasingly navigate trade-offs between emissions reduction, competitiveness, resilience, and political feasibility. Energy system models, when extended to incorporate climate impacts, industrial dynamics, and economic feedbacks, provide a critical basis for informing such decisions. By explicitly analysing how decarbonisation strategies perform under stress, this thesis contributes to a more realistic and policy-relevant evidence base for governing the energy transition.

In the European context, the question is no longer whether decarbonisation is achievable, but whether it can be pursued while maintaining economic vitality and social cohesion. The analyses presented here indicate that this balance is attainable, but only if climate policy is designed with an explicit awareness of risk, interdependence, and uncertainty.

6.5 Limitations and directions for future research

While this thesis advances the analysis of decarbonisation pathways by explicitly incorporating physical, economic, and geopolitical risks, several limitations remain and point toward important directions for future research. These limitations do not undermine the core findings, but reflect deliberate modelling choices made to balance analytical scope, tractability, and policy relevance.

One set of limitations concerns the representation of climate change impacts on energy systems. Although the first article in this thesis integrates empirically estimated climate effects on electricity demand and renewable generation, the range of physical impacts considered remains partial. Important channels, such as infrastructure damage from extreme events and compound risks arising from the interaction of multiple hazards, are not explicitly modelled. In addition, climate impacts are represented through a limited set of deterministic scenarios, which cannot fully capture deep uncertainty in future climate trajectories. Future research could address these limitations by more tightly coupling energy system models with climate and impact assessment frameworks, and by explicitly incorporating uncertainty quantification into the modelling process. Ensemble-based, probabilistic, or stochastic modelling approaches would allow system robustness to be evaluated across distributions of climate outcomes rather than discrete scenarios.

Further limitations arise from the scope of industrial sectors and decarbonisation options represented. While the thesis focuses on several key energy-intensive industries, other sectors with substantial emissions and transition challenges, such as refining, non-ferrous metals, and parts of manufacturing, are not explicitly included. Moreover, demand-side strategies such as material efficiency, circular economy practices, and large-scale recycling are treated only implicitly in order to preserve model tractability. Expanding industrial coverage and incorporating demand-reduction and circularity strategies would allow future work to explore a wider set of transition pathways and trade-offs, and to assess how reductions in material demand interact with energy system transformation and industrial competitiveness.

Limitations are also present in the representation of economic feedbacks and behavioural responses. Although the coupling between the energy system model and the CGE framework captures price and demand adjustments at the macroeconomic level, it does not explicitly represent firm-level behaviour, investment uncertainty, or strategic responses to policy signals. Labour market dynamics, skills constraints, and regional distributional effects are only partially captured. Future research could build on this work by integrating more granular representations of firms, households, and labour markets, potentially through agent-based or microsimulation approaches. Such extensions would enhance the ability of models to assess social and political feasibility alongside economic efficiency, particularly in the context of industrial transformation and just transition concerns.

Trade and geopolitical uncertainty represent an additional area where modelling remains stylised. In this thesis, trade and geopolitical risks are explored through policy shocks and scenario assumptions that allow for systematic comparison across regimes. However, such approaches cannot fully capture the strategic and endogenous nature of geopolitical interactions, including retaliation, alliance formation, and competition over critical technologies and raw materials. Future research could draw more explicitly on insights from international political economy and security studies, using scenario-based approaches that reflect alternative geopolitical futures and institutional arrangements.

An overarching limitation concerns the generalizability and representativeness of the case studies analysed across the three articles. The first article focuses on Italy as a case study for climate impacts on power systems. While the methodological approach and qualitative findings regarding synergies between solar PV and adaptation are broadly applicable, the quantitative results are context-specific and reflect Italian characteristics including high cooling demand, significant hydropower dependence, Mediterranean climate exposure, and limited heating electrification. Direct extrapolation to other European countries without accounting for differences in climate regimes, energy system structure, and demand patterns would be inappropriate. The second article provides a comprehensive European-level assessment, but results are sensitive to assumptions about the availability and cost of green imports from renewable-rich regions, which remain highly uncertain and subject to geopolitical and technological developments. Moreover, the analysis focuses on five energy-intensive sectors (steel, cement, ammonia, methanol, plastics) that account for a large share of industrial emissions but do not represent the full industrial landscape. The competitiveness dynamics, subsidy requirements, and trade strategies identified may differ for other industrial sectors with different energy intensities, value-chain structures, or exposure to international competition. The third article examines USA steel tariffs as a case study of trade fragmentation. The finding that these tariffs have limited impact on EU climate policy outcomes reflects both the specific exposure structure and the unilateral, sector-focused nature of the measure. More severe or coordinated trade disruptions, broader sectoral coverage, multilateral trade restrictions affecting major markets, or supply-side shocks could produce substantially different outcomes through different transmission channels. Future research extending these analyses to other countries, climate zones, or trade scenarios would help establish the boundary conditions under which the qualitative insights of this thesis remain valid.

Although the thesis analyses full transition pathways to climate neutrality, it relies on a myopic optimisation framework that does not fully capture expectations, learning effects, or path dependency. Investment decisions are therefore optimised within each period without perfect foresight of future conditions. While this choice enhances realism relative to perfect-foresight models, it may still underestimate coordination challenges and lock-in effects. Future research could explore alternative decision-making paradigms, including adaptive or stochastic optimisation, to better represent learning, uncertainty, and irreversible investments. Such approaches would be particularly valuable for analysing infrastructure planning and industrial policy under uncertain technology costs and climate impacts.

6.6 Towards risk-aware and policy-relevant energy system modelling

Overall, the limitations of this thesis point to a broader research agenda for energy system modelling. As climate policy moves from target-setting to implementation, models must increasingly engage with uncertainty, risk, and institutional constraints. This thesis demonstrates that extending energy system models beyond least-cost optimisation, by incorporating climate impacts, industrial dynamics, and economic feedbacks, can substantially improve their policy relevance. Future research should continue this trajectory by developing modelling frameworks that are not only technically detailed, but also capable of informing decisions in complex, contested, and uncertain policy environments. By situating decarbonisation within a broader risk landscape, future modelling efforts can better support the design of climate and energy policies that are resilient, adaptive, and socially sustainable.

Within this broader agenda, this doctoral thesis offers a concrete and constructive contribution. By systematically integrating climate impacts, industrial dynamics, and economic feedbacks into high-resolution energy system modelling, it demonstrates how decarbonisation pathways can be analysed not only for technical feasibility, but for their capacity to remain effective under stress. The results provide both methodological advances and policy-relevant insights that help bridge the gap between abstract transition targets and the complex conditions under which they must be implemented. In doing so, the thesis contributes to a growing body of work that seeks to make energy system modelling more responsive to real-world risks and constraints.

More broadly, the analyses presented here point toward a shared responsibility for the research and policy communities. For researchers, they underline the importance of developing modelling tools that engage explicitly with uncertainty, distributional impacts, and institutional feasibility. For policymakers, they highlight the value of evidence-based strategies that prioritise robustness, coherence, and adaptability over narrow optimisation. By strengthening the dialogue between modelling practice and policy design, this thesis aims to support energy transitions that are not only low-carbon, but also durable, inclusive, and capable of withstanding the challenges ahead.

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APPENDIX A

Appendix to Article I: Mitigation strategies can alleviate power system vulnerability to climate change and extreme weather: A case study on the Italian grid

A.1 Supplementary Results

A.1.1 Effects of rooftop PV generation on centralised power demand

Rooftop PV generation is a form of distributed power generation, thus it has the advantage of reliving tension from the high voltage grid by producing locally and decreasing the centralised electricity load. In this sense, even if the overall electricity demand increases due to climate change or severe weather conditions, the remaining power request from centralised technologies is reduced, as illustrated in Figure A.1). In the two Extreme scenarios the power load is almost halved by the large presence and generation provided by rooftop PV panels. This technology represents a pivotal resource within mitigation strategies, not only to address increased household electricity consumption, particularly for air conditioning, stemming from climate change-induced warmer climates, but also to alleviate strain over centralised power generation and transmission.

A.1.2 Mitigation and adaptation trade-off

Figure A.2 represents the additional (if positive) or reduced (if negative) costs that the system incurs under increased weather stress in the mitigated scenarios compared to the scenario without any

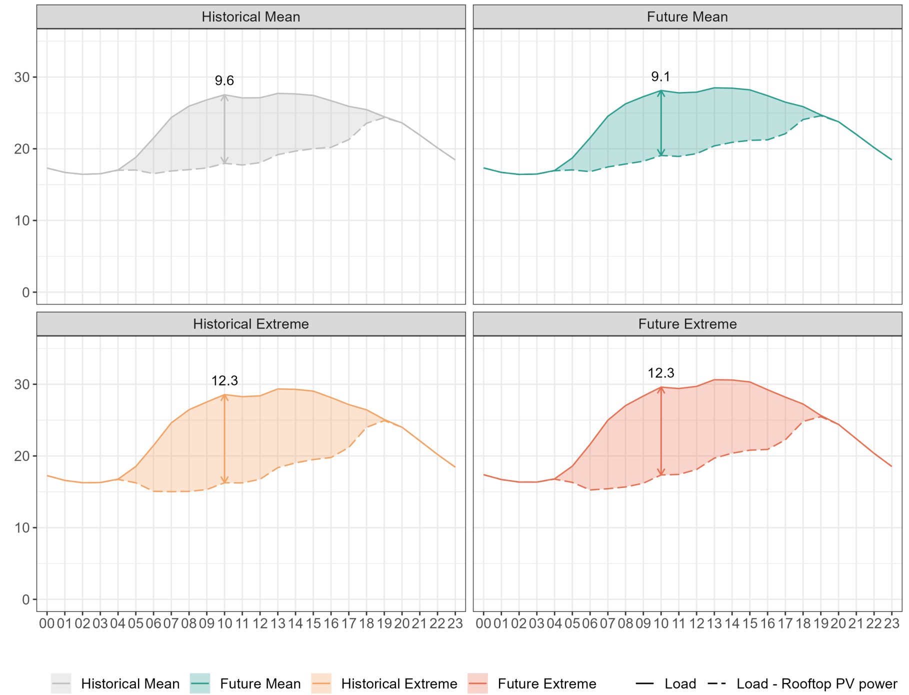

Figure A.1: *Net electricity demand after the one supplied by the distributed generation through rooftop photovoltaic panels, for the four scenarios. The values are for an average of all the Italian regions during the summer season*

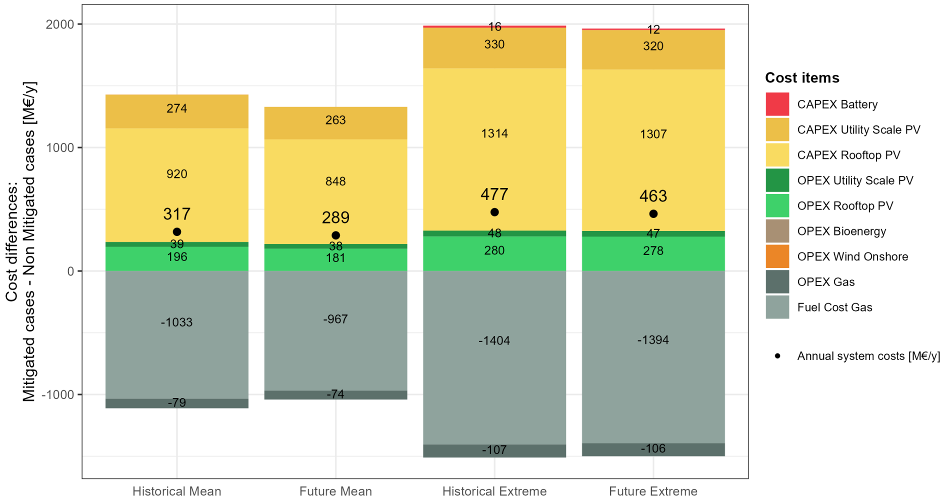

Figure A.2: *Cost items differences in the total balance of the annual system costs for the Italian power system in 2030, $Mitigated$ cases with respect to $NonMitigated$ cases. Bars represent cost items differences between $Mitigated$ cases and $NonMitigated$ cases. The black dots indicates the total annual system cost difference between $Mitigated$ cases and $NonMitigated$ cases.*

imposed climate goals. The black dots represent the difference in total annual system costs between the $Mitigated$ and $NonMitigated$ scenarios. Their presence on the positive side of the graph highlights that achieving both adaptation resilience and decarbonization goals leads to a greater increase in annual power system costs compared to a system addressing only adaptation constraints. The delta in annual system expenditures decreases when looking at the corresponding Future cases (*Future Mean* with respect to *Historical Mean*, *Future Extreme* with respect to *Historical Extreme*). This indicates that adapting to a changing weather in terms of AC demand, thermal and hydro power generation unavailability, reduces the mitigation costs. Solar panels play a key role in this trade-off, as they not only represent an environmentally friendly technology but also enhance system resilience to rising temperatures.

Another critical observation from Figure A.2 is that, as anticipated, all the mitigated scenarios exhibit higher expenditures for PV panels and batteries, while reducing costs associated with natural gas acquisition. This has relevant implications in terms of energy security: in fact, the Italian power system in all mitigated cases would be more independent from energy imports.

Another graph the we deem important to show is Figure A.3. It offers a comprehensive overview of the cost items embedded in the different total annual system costs, allowing to really get the idea of how the expenditures for the Italian power sector in 2030 would be allocated. A notable point it the absence of CAPEX expenses for rooftop PV in the $NonMitigated$ cases. This distributed technology has a larger cost with respect to Utility Scale solar generation since it lacks economies of scale. It becomes critical though, when achieving mitigation goals, to enhance the production of renewable electricity and ensure the operation of the power system when higher temperatures have an impact on hourly AC demand.

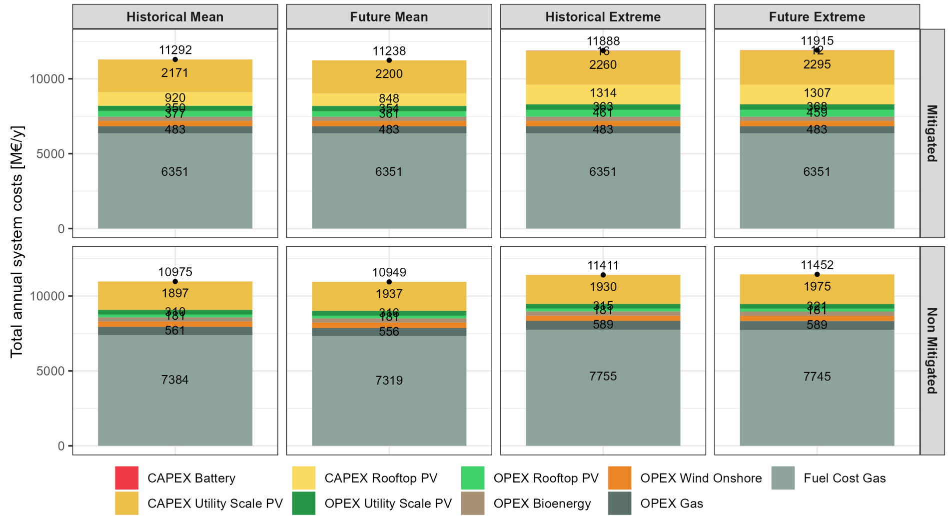

Figure A.3: *Bars represent cost items differences between $Mitigated$ cases and $NonMitigated$ cases. The black dots indicates the total annual system cost difference between $Mitigated$ cases and $NonMitigated$ cases.*

A.2 Supplementary Methods for Climate Impacts

A.2.1 Air Conditioning load estimation

Coefficients are estimated by [102] though a pooled cross section-time series regression with a logit link function, Λ [247]. The variables used to identify the level of AC adoption are the 10-year moving average CDD24s ($\mathcal{C}$), the logarithm of the 10-year moving average annual per capita income (y) and the logarithm of the 10-year moving average annual urbanization rate (u):

$$\begin{aligned}\Lambda(s_{i,t}) &= \log\left(\frac{s_{i,t}}{1-s_{i,t}}\right) = \boldsymbol{Z\alpha} \\ &= \alpha_i^0 + \alpha^Y y_{i,t} + \alpha^C \mathcal{C}_{i,t} + \alpha^{YC}(y_{i,t}\cdot\mathcal{C}_{i,t}) + \alpha^U u_{i,t} \qquad \text{(A.1)}\end{aligned}$$

with location fixed effects α^0, and estimated parameters α^Y and α^C that capture the direct effects of income and heat exposure, and α^{YC} that captures their interaction. The functional form yields nonlinear effects of the linear predictors, governed by the logistic transformation.

The non-linear temperature-load function is estimated with a fixed effect models of per capita daily electric load, q, at the European member state level in each day from 2015 to 2019. Population-weighted temperatures are binned into k intervals of 3°C width, $B_k = [\underline{T}_k, \overline{T}_k)$ to construct a k-vector of indicators that track whether each day's maximum temperature falls within a given interval:

$$\mathcal{T}_k = 1\cdot\{T \in B_k\} + 0\cdot\{\text{Otherwise}\}$$

Suppressing location and time subscripts, the empirical specification estimated by [102] is:

$$\mathbb{E}[\ln q] = \textstyle\sum_k \beta_{k,v}^T \mathcal{T}_k + \sum_k \beta_{k,v}^{TAC}(\mathcal{T}_k\cdot s) + \beta_v^Y y + \text{controls} \qquad \text{(A.2)}$$

where controls include state or country fixed effects that absorb variation associated with unobserved temporally-invariant confounders, and day-of-week, season and year fixed effects that control for idiosyncratic time-varying influences that are unrelated to temperature. The elements of $\boldsymbol{\beta}^T$ account for consumers' adjustments of stocks of energy-using durables, explicitly captured by the vector of interaction coefficients, $\boldsymbol{\beta}^{TAC}$. The fitted coefficient vectors $\widehat{\boldsymbol{\beta}}^T$ and $\widehat{\boldsymbol{\beta}}^{TAC}$ provide flexible piece-wise linear spline representations of macro-regions' distinct nonlinear temperature response functions (see Supplementary Information).

A.2.2 Impacts on thermal generation outages

We study the potential unavailability of thermal power generation units due to extreme temperatures by developing a regression model based on outage information collected from 2018 to 2022 in Italy. The dataset [165] includes information of over 4000 outages, of which 2352 of gas- and 1887 of coal-fired generation units. The method adopted partially follows previous analysis [63], but expands from the literature by providing country-specific and fuel-specific responses. We consider as key dependent variable the occurrence of an outage in each power-plant, represented by a dichotomous variable alternatively 0 or 1 (c), and identify the influence of daily maximum temperatures (t) and water runoff anomalies (r), controlling for month (m) and location (p) fixed effects. Since temperature and runoff anomalies can have non-linear impacts on the operations of thermal generators, non-linear effects are captured by adding a quadratic or alternatively a cubic term to each. Furthermore, in the most detailed specification, we identify fuel-specific impacts by including a set of interaction terms between temperature and runoff anomalies and a character variable representing the power plant fuel k. We estimate the following equation though a logistic regression, so that the log odds of the outcome are modelled as a combination of the predictor variables:

$$\Lambda(c_{i,t}) = \log\left(\frac{c_{i,t}}{1-c_{i,t}}\right) = f(t_{i,t}) \cdot k + z(r_{i,t}) \cdot k + \psi k + \mu p + \nu m + \varepsilon \tag{A.3}$$

$$\tag{A.4}$$

We compare the different polynomial specifications based on standard performance metrics, and select the model with a fuel-specific cubic response to temperatures (Figure A.4).

We find that the likelyhood of occurrence of an outage for coal-fired generation increases considerably when daily maximum temperatures surpass 35°C, reaching 10-50% at 40°C and 50-90% at 45°C, depending on the water runoff anomaly. Gas-fired generation is less sensitive to high temperature and low water runoff levels, but the likelihood of an outage is non-negligible and between 5-25% at 40°C. Regression results are shown in the Table A.1. We use the estimated available capacity function in conjunction with future daily maximum temperature anomalies to simulate daily thermal power generation availability around 2030 and apply the results to the oemof Italian power system model optimisations.

A.2.3 Impact on variable renewable sources

We describe here the methodology for assessing the impacts of climate change on variable renewable generation production. We only evaluate these impacts in the two scenarios *Historical Mean* and *Future Mean*, since the optimization of power system capacity expansion is not be based on extreme low- or high- wind and solar generation occurrences, which are typically dealt with by transmission system operators though ancillary services and balancing energy markets. In other words, we only consider how climate change may alter the solar and wind production patterns by taking into account the hour-, calendar day- and region- specific mean production value across the historical and future year period. For both wind and solar power potential generation, we exploit the projections

Table A.1: *Outage regression results*

	Dependent variable:		
	Likelihood of outage		
	(1)	(2)	(3)
technology-Gas	−1.760***	−2.471***	−0.973***
	(0.050)	(0.073)	(0.123)
tmax	−0.037***	−0.244***	0.103***
	(0.002)	(0.006)	(0.019)
tmaxˆ2		0.005***	−0.015***
		(0.0001)	(0.001)
tmaxˆ3			0.0003***
			(0.00002)
runoff_anomaly	−0.758***	−0.482***	−0.370***
	(0.065)	(0.065)	(0.066)
runoff_anomalyˆ2	4.059***	3.638***	3.536***
	(0.074)	(0.075)	(0.075)
technology-Gas:tmax	0.063***	0.155***	−0.129***
	(0.001)	(0.006)	(0.020)
technology-Gas:tmaxˆ2		−0.002***	0.013***
		(0.0002)	(0.001)
technology-Gas:tmaxˆ3			−0.0003***
			(0.00002)
Constant	−4.036***	−2.552***	−4.271***
	(0.075)	(0.085)	(0.125)
month	Y	Y	Y
year	Y	Y	Y
province	Y	Y	Y
Observations	1,353,432	1,353,432	1,353,432
Log Likelihood	−170,880.300	−170,056.200	−169,796.300
Akaike Inf. Crit.	341,854.700	340,210.400	339,694.600
Note:			*p<0.1; **p<0.05; ***p<0.01

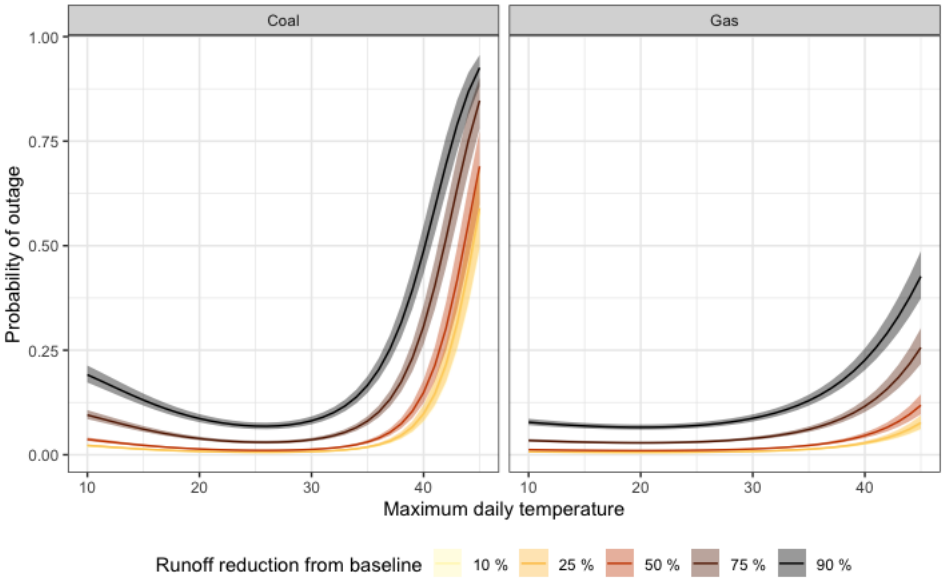

Figure A.4: *Outage probability based on temperature and water runoff anomalies levels, based on the selected logit model. Shades show the 95th confidence interval.*

developed by [156]. For wind generation, we retrieve the time-series of normalised with potential at the NUTS3 level directly from the database, then we aggregate at the bidding-zone level. As for solar, we consider the time-series of hourly population-weighted direct normal irradiation (DNI), the amount of solar radiation per unit area [W/m^2] by a surface perpendicular to the sun rays. Temperature is also included into the analysis, since the power output that a solar panel *p* is able to produce at each hour *h* in its location *n* is dependent on ambient temperature. The following formula, taken from [248] shows the correlation, where T$_{n,h}$ is expressed in degree Celsius and DNI$_{n,h}$ is the DNI value, in location *n* and hour *h*:

$$P_{n,h} = \eta_p S_p DNI_{n,h}(1 - 0.005(T_{n,h} - 25)) \tag{A.5}$$

The parameters η_p and S_p represent the conversion coefficient [%] and the surface area [m^2] specific to the photovoltaic unit *p*. These values are not relevant for the calculation since $P_{n,h}$ is then normalised to a time-series, accounting for the maximum values in each scenario and region, to obtain the solar potential. η_p itself is dependent on temperature, as explained by Evans [249], following the equation:

$$\eta_{p,T} = \eta_{p,Tref} * (1 - \beta_{ref} * (T - Tref)) \tag{A.6}$$

$\eta_{p,Tref}$ refers to the panel efficiency at Tref, the reference temperature (which is commonly 25°C) and solar radiation of 1000 W/m^2. β_{ref} is the temperature coefficient and it is generally assumed to be 0.0004 K^{-1} [250, 251]. Thanks to these equations we can coherently consider the impact of the change of DNI and temperature in the future climate scenarios on PV panels power output.

In Figure A.5 we evaluate the variation in electricity generation and additional installed capacities for the Italian case study in 2030 in the *Future Mean* weather scenario with respect to the

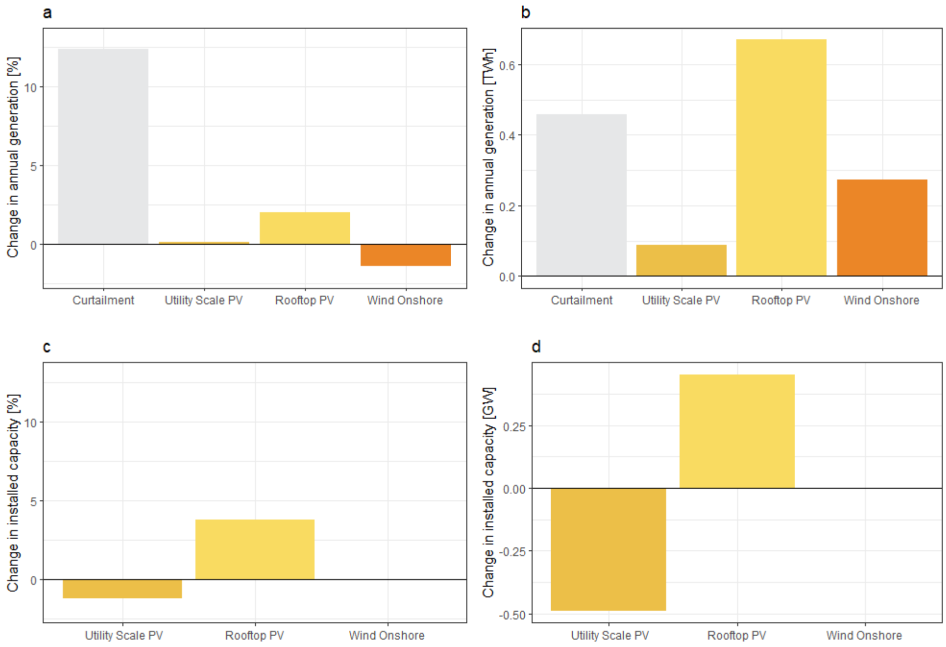

Figure A.5: *Change in the generation (panels a-b) and capacity (panels c-d) in the $FutureMean$ climate scenario when including the mean climate change impacts on the hourly wind and solar generation.*

Historical Mean one. Again, we do not focus on the *Historical Extreme* and *Future Extreme* scenario because the high variability of renewable sources to weather is informative for dispatch optimisation problems, while it is not a key driver for power system investment planning. The input shocks included in the model, namely the mean level of the normalised wind power potential and the BNI, used to project future impacts for wind and solar, respectively, are presented in Figure 3.2, Panels c and d. As you can see in Figure A.5, the changes

A.2.4 Additional figures

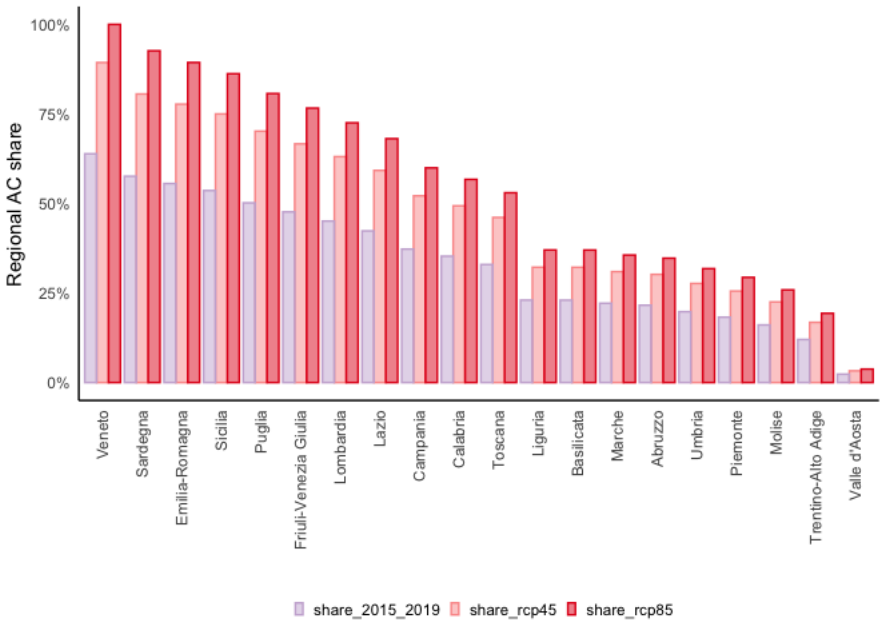

Figure A.6: *AC prevalence in households in Italian regions, observed average of 2015-2019, and future in 2030 under RCP 4.5 and RCP8.5.*

Figure A.7 shows that no substantial difference can be found in the value of the input projections of hydro production and electricity demand change by changing historical base year period of CMIP6 model output from 1981-2020 to 2001-2020.

Figure A.8 shows that no substantial difference can be found in the value of the input projections of hydro production and electricity demand change from RCP 4.5 and RCP 8.5 in 2030.

A.3 Supplementary Methods for Power System Modelling

We employ a power system model of the Italian electricity system [143], developed with Oemof (Open Energy MOdelling Framework), an open-source energy modelling tool in Python [252]. This framework enables the creation of an energy network and then uses a solver to determine the energy balances (in this case, the one utilized was Gurobi, but Oemof is able to work with other open-source

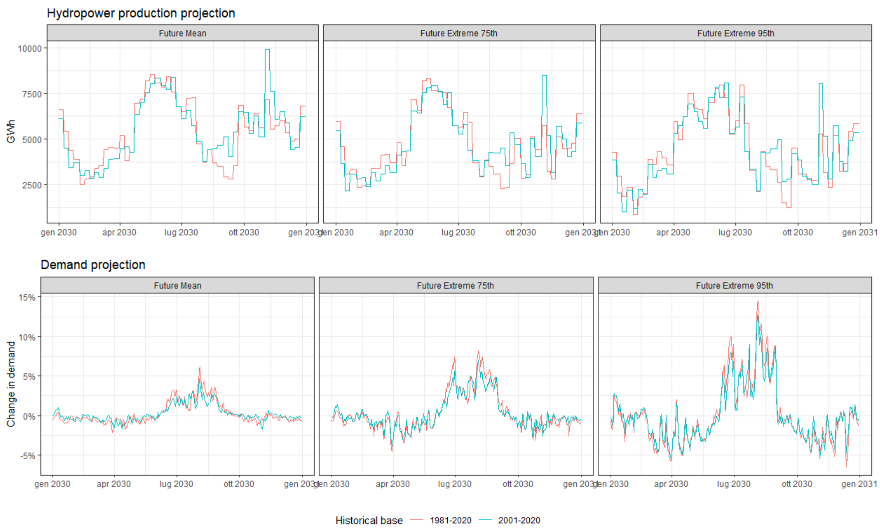

Figure A.7: *Comparison of input projections of hydro production and electricity demand change, by choice of historical base year period*

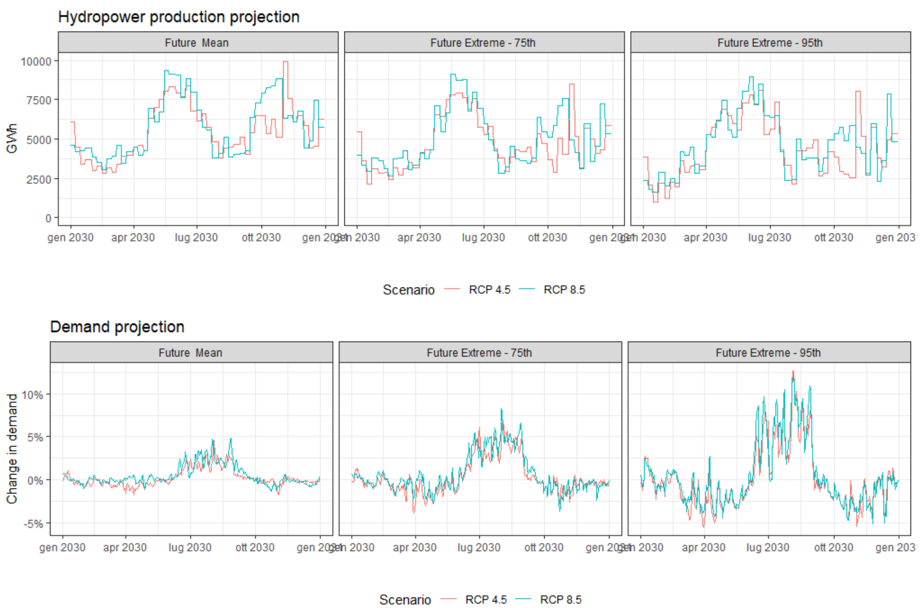

Figure A.8: *Comparison of input projections of hydro production and electricity demand change, by RCP* solvers). The same power system model for Italy has been used in previous works [144, 145]. To be able to run simulations and investment optimizations, Oemof expansion capacity script requires the following inputs, provided through an Excel file. The spatial resolution of the model is based on the Italian electricity market zones, which, since year 2021, consist of 7 different areas [146, 147], organized as shown in Table A.2. Building from the subsection in the paper discussing briefly the main elements of the model, Table A.2 shows the break-down in regions of each model node, while Table A.3 outlines the powerlines capacity.

Table A.2: *Italian electricity market zones composition*

Market zone	Regions
North	Emilia-Romagna, Friuli Venezia-Giulia, Liguria, Lombardia, Piemonte, Trentino-Alto Adige, Valle D'Aosta, Veneto
Centre-North	Marche, Toscana, Umbria
Centre-South	Abruzzo, Campania, Lazio
South	Basilicata, Calabria, Molise, Puglia
Sardinia	Sardinia
Sicily	Sicily
Calabria	Calabria

Table A.3: *Transmission lines capacity*

Line	Capacity [MW]
North → Centre-North	4300
North ← Centre-North	3100
Centre-North → Centre-South	2900
Centre-North ← Centre-South	2800
Centre-South → South	2000
Centre-South ← South	5550
Centre-South → Sardinia	720
Centre-South ← Sardinia	900
Centre-North → Sardinia	1095
Centre-North ← Sardinia	1015
Sicily → Sardinia	800
Sicily ← Sardinia	800
Centre-South → Sicily	700
Centre-South ← Sicily	700
South → Calabria	1100
South ← Calabria	2350
Calabria → Sicily	1750
Calabria ← Sicily	1200

A.3.1 Key features

Transmission lines. Market zones are linked in the model through high-voltage transmission lines. Capacity data are taken from Terna Development Plan in 2019 [253] and updated according to the 2021 Plan [254] and the National Energy and Climate Plan (PNIEC *Piano Nazionale Integrato per l'Energia e il Clima* [169]), assuming the transmission capacities targets for 2026 completely achieved in 2030. The spatial subdivision and the values for exchangeable GWs between zones are visualised in Figure A.9.

Demand. For each region, a time series of the hourly power load is considered, obtained from Terna *Download Center* web page, taking data for the year 2021 [253]. Terna projects an annual national electricity demand of 331 TWh by 2030, taking into account the ongoing electrification of the transportation, heating, and industrial sectors [254]. The distribution of this demand into market zones in 2030 is assumed to mirror that of 2021. Consequently, for 2030, we maintain the same hourly demand profiles, adjusting them upward to align with the anticipated national load of 331 TWh for the year.

Commodity sources. For power production, the resources considered in this case study are natural gas, water and imported electricity. Nowadays Italy still has some coal-fired power plants

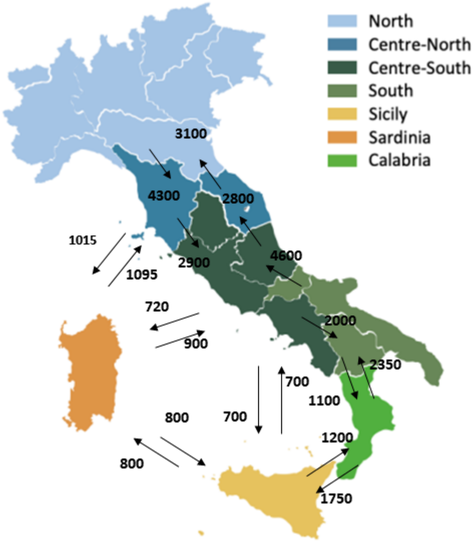

Figure A.9: *Representation of the spatial resolution of the Italian power model. The seven nodes of the model aggregate different Italian regions, according to the colours in the picture. The zones are linked through high-voltage power lines, whose transmission capacity is indicated with the values in the graph [GW]. The capacity values assume that the already announced grid expansion projects up until 2026 are built.*

running [255], but according to the Italian climate and energy strategy [169], the phase-out from this polluting source will be in 2025. Therefore, this work assumes that in 2030 there will be no coal power plant working. Import refers to the net electricity imported from other countries and it has been designed as a source of generation. Italy exchanges electricity with France, Switzerland, Austria, Slovenia, Greece, Malta and Montenegro, but the main importer is France [147]. For this reason we assumed to model import as a source of generation only for the *North* market zone and with a negligible emission factor [256], thanks to the large fraction of French electricity produced with nuclear power. For commodity sources, variable costs are specified; for import and hydro costs are set to zero. Natural gas prices for 2030 are derived from World Energy Outlook 2022 [30], assuming the Stated Policy case, thus 29 €/MWh of thermal energy. Specific emissions factors are adopted from technical specifications in [256].

Power plants transformers. For natural gas-fired plants, total installed capacities are imposed at 2021 values [153], with no possibility to expand. Import power derives from the assumption of constant import throughout the whole year, so a total amount of 42.8 TWh [153] reduced by 4.75 TWh due to transmission and distribution losses, results in 4.34 GW in each hour. For hydro power plants, efficiencies for the conversion to electricity are offered by [195], import has no efficiency and for gas-fired plants efficiency is evaluated as an average of the whole Italian gas power plants park (55.1%) [257]. For gas plants cost of operation is also specified, set at 4 €/MWh [195].

Renewables. The Renewable Energy Sources RES embedded in this study are rooftop and utility scale photovoltaic, wind onshore and offshore, run-off-river, reservoir hydro, biomass and geothermal generation (actually present only in Tuscany, thus with 771.8 MW in Centre-North). Existing offshore capacity is set to zero and the model can expand generation capacity of the two types of solar and the two categories of wind power. In each node the existing installed power in April 2022 is the starting point, aggregated in market zones. Data are taken from Terna [258], assuming that Utility Scale photovoltaic (PV) has a size larger than 1 MW, and from the European Commission's *Joint Research Centre* (JRC) [259] for run-off-river and reservoir hydro. PV panels in large fields or on rooftops are distinguished in the model by different existing capacities, investments and operational costs and maximum potential for available land. The existing capacity for each power generation technology in each region is represented in Table A.4.

Table A.4: *Renewable energy sources and fossil fuels power plants capacity per Italian market zone in 2021 [MW]*

Capacities in MW	Rooftop PV	Ut. Sc. PV	Wind onshore	Biomass	Run-off-river	Reservoir hydro	Gas-fired power plant
North	9397	1465	172	2304	4399	4352	27712
Centre-North	1864	287	162	452.0	368	80	2587
Centre-South	2687	1299	2189	529	1117	201	7485
South	2718	900	4760	490	23	122	4882
Sardinia	504	603	1112	125	20	88	1088
Sicily	1088	601	2039	104	8	65	5394
Calabria	456	149	1174	219	121	589	3630

Storages. In 2021, in the Italian power system only Pumped Hydro Storage (PHS) power plants can store electricity, since there are no batteries or hydrogen storage connected to the grid. Values for PHS pumping and generation power capacities and the nominal retainable energy are provided by JRC database [259], with a national storage value of 560 GWh. Other parameters supplied are a capacity loss of $8.33 \cdot 10^{-6}$ [260] (referred to the stored energy), inflow and outflow efficiencies, choosing respectively of 85% and 90% to get a Round Trip Efficiency (RTE) of 76.5% [259]. The optimisation can expand the storage capacity for lithium-ion batteries and hydrogen storage technology, composed of electrolysers, fuel cells and hydrogen tanks. Further details can be found in Appendix A.3.

A.3.2 Dispatch optimization

In this work we deploy both dispatch and expansion capacity optimizations, based on the chosen scenario. The main goal of a dispatch optimization is to find the generation mix which meets the demand at the lowest operational cost. The solver will start using the cheapest sources per MWh until the energy needed is provided. The objective function developed for this work can be expressed by Eq. A.1, describing the minimum of the cost to operate the system $\mathrm{C}^{\text{operation}}$.

$$\text{Min}\ \mathrm{C}^{\text{operation}} = \text{Min}(\sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{s=1}^{S}\mathrm{E}_{t,n,s}\cdot \mathrm{vc}_{t,n,s}) \tag{A.1}$$

where:
t = analysed time step, from 1 to T
n = node considered, from 1 to N
s = generation source, from 1 to S
$\mathrm{E}_{t,n,s}$ = energy generated by the source s, located in the node n at the time step t.
$\mathrm{vc}_{t,n,s}$ = variable costs of generation for the energy source $\mathrm{E}_{t,n,s}$

This main objective function must respect a series of constraints. They will be explained and analysed further, following Prina et al. work [260]. The major constraint is to meet the energy demand, considering also the charge and discharge energy of the storages and the transmission losses. This has to be valid for every time step and it is possible to have an excess of generation.

$$\sum_{s=1}^{S}(\mathrm{E}_{t,n,s} + \mathrm{E}_{t,n,st}^{\text{charge}} - \mathrm{E}_{t,n,st}^{\text{discharge}} - \mathrm{E}_{t,p}^{\text{transmission loss}}) = \mathrm{D}_{t,n} + \mathrm{E}_{t,n}^{\text{excess}} \tag{A.2}$$

$E^{\text{charge}}_{t,n,st}$ = energy employed for charging storage technology *st* at time *t* in node *n*
$E^{\text{discharge}}_{t,n,st}$ = energy employed for discharging storage technology *st* at time *t* in node *n*
$E^{\text{transmission loss}}_{t,p}$ = energy lost due to transport losses at time *t* in powerline *p* for node *n*
$D_{t,n}$ = load demand at time *t* for node *n*
$E^{\text{excess}}_{t,n}$ = surplus of generated energy at time *t* for node *n*

Another restriction is the respect of the maximum power given as input for each generator unit. Non-dispatchable renewable units *s* in node *n* can supply up to their nominal capacity $P^{\text{non-dispatchable}}_{n,s}$ according to the source profile throughout the year. Fossil fuel and dispatchable renewable plants (such as reservoir hydroelectric), instead, can always provide power up until their stated capacity, $P^{\text{dispatchable}}_{n,s}$ for node *n* and source *s*.

$$0 \leq P_{t,n,s} \leq P^{\text{dispatchable}}_{n,s} \tag{A.3}$$

$$0 \leq P_{t,n,s} \leq P^{\text{non-dispatchable}}_{n,s} \cdot a_{t,n,s} \tag{A.4}$$

$P_{t,n,s}$ = power provided by the source s (can be dispatchable or not) at time *t* in node *n*
$a_{t,n,s}$ = availability of the renewable source *s* at time *t* in node *n*. It can be a number between 0 and 1 (0 being no obtainable energy and 1 being maximum power available).

In addition, for dispatchable generators, an efficiency is presented to calculate the amount of resource exploited, according to the following equation. $P^{\text{dispatchable}}_{t,n,s}$ in this case is referred only to dispatchable generation units.

$$E^{\text{resource}}_{t,n,s} = \frac{P_{t,n,s}}{\eta_{n,s}} \tag{A.5}$$

$E^{\text{resource}}_{t,n,s}$ = quantity of commodity source employed by resource *s* at time *t* in node *n*.
$\eta_{n,s}$ = efficiency of the generation source *s* in node *n*.

Energy can be exchanged between two nodes, passing through transmission lines that have a nominal capacity value. $P^{\text{powerline}}_{p}$ represents the maximum exchangeable power in the transmission line *p*, which goes from one node to another. Each powerline *p* has losses related to the exchange of power, taken into account by the efficiency $\eta^{\text{transmission losses}}_{p}$. The energy that can pass through powerline *p* at timestep *t* is $E^{\text{exchanged}}_{t,p}$.

$$E^{\text{exchanged}}_{t,p} \leq P^{\text{powerline}}_{p} \cdot \eta^{\text{transmission losses}}_{p} \cdot \Delta t \tag{A.6}$$

Δt = timestep (in this case one hour)
st = storage technology, from 1 to ST;

Finally, storage technologies need to respect constraints and balances for the daily dispatch, bearing in mind also self-discharging. The first crucial restriction is that the storage content $SC_{t,st}$ of the storage technology *st* at the time step *t* can not exceed the maximum storage content SC^{nominal}_{st} for each technology *st*. In this work, Oemof has been set to maintain the same storage content at the beginning and the end of the time frame considered, thus energy stored describes a mean to achieve flexibility in the system.

$$SC_{t,st} \leq SC^{\text{nominal}}_{st} \tag{A.7}$$

Storage units have to observe another limitation, regarding the storage balance: the equation takes into account the power to charge the storage *st* at time *t* in node *n*, $P^{\text{charge}}_{t,n,st}$, and the power to discharge it, $P^{\text{discharge}}_{t,n,st}$, with their respective efficiencies, $\eta^{\text{charge}}_{st}$ and $\eta^{\text{discharge}}_{st}$. The storage unit undergoes through a self-discharging process, contemplated with the efficiency η_{st}^{self} applied to the stored energy. Eventually, the exchanged power modifies the storage content of the unit from one time step to another.

$$(\mathrm{P}_{t,n,st}^{\text{charge}} \cdot \eta_{st}^{\text{charge}} - \frac{\mathrm{P}_{t,n,st}^{\text{discharge}}}{\eta_{st}^{\text{discharge}}}) \cdot \Delta t - (\mathrm{SC}_{t,st} - \mathrm{SC}_{t-1,st}) \cdot \eta_{st}^{\text{self}} = \mathrm{SC}_{t,st} - \mathrm{SC}_{t-1,st} \tag{A.8}$$

$\mathrm{SC}_{t,st} - \mathrm{SC}_{t-1,st}$ = stored energy at time *t* in storage technology *st*, given by the difference of the storage content from one time step to another.

A.3.3 Expansion capacity investment

Oemof framework is suitable for investment optimisation analyses: the solver can decide how to invest in order to expand the technologies capacities if this can help to satisfy the energy demand with an overall lower cost. In general, all Oemof components can be expanded introducing the investment option in the code. In this paper the generation technologies that have the possibility to be expanded are rooftop photovoltaic, Utility Scale photovoltaic, on-shore wind and off-shore wind. The chosen RES generation technologies are in line with National Development Plans for Italy [169], while others are excluded for different reasons: for example nuclear plants can not be added in the electricity mix due to political choices in the country. The expandable storage options are lithium ion batteries, hydrogen tanks, electrolysers and fuel cells. Energy storage is already provided in the current system by PHS, but in the model it cannot be increased since the exploitation limit has been already reached and there is no further space to build this type of power plants, which require a large amount of constructions and affect the environment [261]. Li-ion batteries were detected in the electro-chemical storage panorama as the biggest market player [262], while many studies suggest that hydrogen can be an interesting option for power systems adequacy, since its cost can be reduced by exploiting it as an energy carrier in other hard-to-abate sectors [263–265]. The model thus can provides short-term storage with batteries and long term one with hydrogen, offering a comprehensive solution to store electricity produced.

Oemof offers an annuity function that provides the *Energy Periodical Cost* (Ep cost) for each technology, which is the essential variable to choose if an investment is convenient. The Ep cost is calculated according to Eq. A.9. Some inputs are needed for each technology in order to compute the ep cost: capital expenditure (capex) in euros per unit of installed capacity, lifetime in years and a Weighted Averaged Cost of Capital (WACC) to consider the credit for the investment.

$$\begin{aligned}\text{Ep cost} &= \text{oemof.tools.economics.annuity(capex, lifetime, wacc)} \\ &= \text{capex} \cdot \frac{\text{wacc} \cdot (1+\text{wacc})^{\text{lifetime}}}{(1+\text{wacc})^{\text{lifetime}-1}}\end{aligned} \tag{A.9}$$

Besides the economic parameters, the solver requires as inputs the existing technology capacity of the technology (which can be *None*) and its maximum potential foreseen for the future year to which the study is referring to. In the expansion capacity optimisation the objective function has been modified, adding also the investment made on the various technologies and minimising the total cost C^{tot}.

$$\text{Min } \mathrm{C}^{\text{tot}} = \text{Min}\Big(\mathrm{C}^{\text{op}} + \sum_{n=1}^{N}(\sum_{s=1}^{S} \mathrm{C}_s \cdot \mathrm{P}_{n,s}^{\text{added}} + \sum_{st=1}^{ST} \mathrm{C}_{st} \cdot \mathrm{E}_{n,st}^{\text{added}} + \sum_{p=1}^{P} \mathrm{C}_p \cdot \mathrm{P}_p^{\text{added}})\Big) \tag{A.10}$$

C_s = capital cost for the expansion of the resource *s*

C_{st}^{added} = capital cost for the expansion of storage technology *st*
C_p = capital cost for the expansion of power lines
$P_{n,s}^{added}$ = power capacity added for source *s* in node *n*
$E_{n,st}^{added}$ = storage capacity for storage *st* in node *n*
P_p^{added} = power capacity added for power line *p*

The output of this function is the total annual cost for operation and optimization of the system. Insights are also given about the amount of power installed for each technology in each node; this is a very helpful information for policy makers, to understand which should be the aim of the incentives to introduce.

Oemof framework allows to introduce a constraint on emissions of the system, modifying the main expansion capacity script. To bring about it correctly, it is necessary to bestow emission factors for the polluting commodity sources, in quantity of contaminants per unit of energy supplied. The total amount of emissions, CO_2^{total} is calculated as follows.

$$CO_2^{total} = \sum_{t=1}^{T} \sum_{n=1}^{N} \sum_{s=1}^{S} P_{t,n,s}^{\text{fossil source}} \cdot co2_s^{factor} \tag{A.11}$$

$P_{t,n,s}^{\text{fossil source}}$ = thermal power at time *t* in node *n* from the fossil commodity source *s*
$co2_s^{factor}$ = emission factor specific to the commodity source *s* in $[\frac{\text{ton of } CO_2}{MWh_{th}}]$

APPENDIX $\mathcal{B}$

Appendix to Article II: Decarbonisation without deindustrialisation: assessing future pathways for European industry

B.1 Industrial sectors modelling

Here, we provide a detailed description of the implementation of various industrial sectors within PyPSA-Eur. It is important to note that all these industrial technologies operate at generally high temperatures. Consequently, a minimum partial load constraint, specific to each technology, is incorporated to account for their limited operational flexibility. This constraint influences the model outcomes, as these plants are required to operate continuously, even at low output levels and at times with high electricity prices.

Iron and steel

The predominant methods for steel production today are primary production from iron ore and secondary production from recycled scrap. The Blast Furnace–Basic Oxygen Furnace (BF-BOF) process, commonly referred to as Integrated Steelmaking, involves the reduction of iron ore using coke and coal, resulting in substantial CO_2 emissions. A more energy-efficient and less carbon-intensive alternative is the Direct Reduced Iron-Electric Arc Furnace (DRI-EAF) process, where iron ore is reduced using natural gas before being melted in an EAF. Hydrogen has the potential to serve as a reducing agent in the DRI process, but it is currently not used industrially due to its higher cost compared to natural gas. The secondary production route, based on scrap-fed electric arc furnaces, melts recycled steel scrap using electricity and thereby achieves substantially lower emissions than primary steelmaking, as it avoids the direct reduction stage. Recent EU policy developments underscore the strategic importance of steel scrap, with measures to retain greater volumes within Europe [266], yet current data on EU27 availability, around 112 Mt in 2018, remain limited in their resolution by quality class, which is essential for aligning scrap supply with specific steel product requirements [267]. In our model, the scrap-EAF route is represented using the market price of steel scrap in Europe of 302.5 EUR/ton [268]. Due to both its economic attractiveness and its environmental benefits, the share of scrap-based production is expected to increase to the maximum technically feasible level. To capture this dynamic, we impose an upper bound on scrap use as a percentage of total steel production. Estimates in the literature diverge on this limit, with some studies adopting more conservative assumptions (e.g., 75% by 2050 in Transition Asia [269]) and others suggesting higher potential (e.g., 90% by 2050 in Pehl et al. [270]). The constraint reflects the fact that scrap availability and quality limit full substitution, as recycled steel may contain impurities that restrict its use in high-grade applications. We base the growth in scrap use in EAFs on historical trends in Europe, where the share of scrap in total steel production increased from 52% in 2014 to 58% in 2022 [199]. Extrapolating this trajectory yields an upper limit of 83% by 2050, which we cap at 75% to stay conservative, which is reached around 2040. Incorporating steel scrap utilization as a decarbonization pathway is highly relevant, as previous studies show it can directly affect the demand for green hydrogen in steel production [271, 272].

Other steel-making processes exist but are less commonly used. The Smelting Reduction (SR) process converts iron ore directly into liquid iron using coal in a single-step process. Open Hearth Furnaces (OHF), which have largely been phased out in most regions, still account for 19% of steel production in Ukraine [273]. Biomass-based reduction, utilizing charcoal as a substitute for fossil-based coke, is also employed, particularly in Brazil [274]. An emerging technology in steel production is Molten Oxide Electrolysis (MOE), which directly converts iron ore into molten iron through electrolysis, eliminating the need for carbon-based reducing agents; however, this method remains in early research and development stages. In 2023, Europe's steel production reached approximately 170 million tonnes (126 inside EU), using for around 55% the BF-BOF route and for 45% the Electric Arc Route. Of the latter, only 1% of the production of iron employs DRI, while the rest uses scrap as a feedstock to the electric arc [273, 275, 276]. The most effective strategies for decarbonizing the steel sector involve transitioning from BF-BOF production to either Scrap-EAF or Hydrogen-based DRI-EAF (H_2-DRI-EAF), both of which relying on renewable electricity, either for direct use in the electric arc furnace and for hydrogen production via electrolysis. An alternative approach is the implementation of carbon capture technologies, such as Top Gas Recycling (TGR), within existing BF-BOF plants, retrofitting facilities to capture and sequester carbon emissions. To summarize, the steel-making processes included in the model are BF-BOF, DRI-EAF fuelled with natural gas or hydrogen, scrap-EAF and retrofitting BF-BOF plants with TGR.

Cement

Cement production is a highly energy-intensive process and a major contributor to global CO_2 emissions, primarily due to both fuel combustion and the chemical decomposition of limestone (calcination). The predominant method of cement manufacturing (80% worldwide) is the dry clinker production process, in which limestone and other raw materials are heated in a rotary kiln at temperatures exceeding 1400°C to form clinker, the key binding agent in cement [277]. The wet process, now largely phased out due to its larger energy demands, was initially developed for its simpler pre-processing, especially for raw materials with high moisture content. EU27 cement production reached approximately 161 million tonnes in 2023, with the vast majority manufactured using the dry clinker route [278]. Several strategies have been proposed to mitigate CO_2 emissions in cement production, including reducing the cement-to-clinker ratio by using supplementary cementitious materials (SCMs) like fly ash or calcined clay, improving energy efficiency in clinker production, implementing CCS, and electrifying the clinker production process with renewable electricity [279, 280]. The cement production process considered in the model is limited to traditional dry clinker production, with the potential for retrofitting with CCS. The electrification of cement production processes currently depends on plasma technologies or indirect electrification via hydrogen [281]. However, due to the low maturity of these technologies, they are excluded from the scope of this study.

Chemicals

The chemical sectors developed in PyPSA-Eur include methanol, ammonia, and ethylene, the latter serving as a proxy for production of all types of plastics. Currently, methanol is mainly produced through a methanol synthesis process, employing syngas generated via steam methane reforming (SMR). Ammonia production, predominantly via the Haber-Bosch process, also relies on natural gas for hydrogen production, while ethylene is produced via steam cracking of hydrocarbons, which is a highly energy-intensive process that involves the decomposition of naphtha.

Efforts to reduce emissions in these sectors focus on several strategies. For ammonia synthesis, the electrification of hydrogen production for the Haber-Bosch process is considered the most viable solution, as it would allow keeping existing production capacities. Similarly, methanol can be synthesized from green hydrogen, but achieving a fully renewable process requires CO_2 inputs derived from carbon capture and utilization (CCU) or from biomass. In this study, the biomass pathway is omitted for simplicity, as the sustainable biomass potential within Europe [196] is largely allocated to BECCS and biomass Combined Heat and Power (CHP) generation. Ethylene and other HVCs can be produced from naphtha of various origins, all serving as feedstock for steam cracking facilities. The model considers fossil-derived naphtha, biomass-to-liquid naphtha, and synthetic naphtha generated via CCU through the Fischer–Tropsch process. Another pathway for HVCs synthesis is the conversion of methanol to olefins, which is not included for simplicity.

The model accounts for emissions from methanol utilization and the end-of-life degradation of HVCs in landfills, thereby incentivize process decarbonization. These emissions are also incorporated into the commodity price through the application of the carbon price. Plastic recycling represents another possible mitigation pathway; however, it has not been included in the model, both to maintain simplicity in the accounting of CO_2 emissions, since recycling alters the timing and location of carbon release, and because recycling is inherently limited by material degradation and cannot be sustained indefinitely [282]. Nevertheless, its importance is acknowledged, with 8.7 Mt of plastics recycled in Europe in 2022 [283], and it should be incorporated in future analyses.

Data on the location, type, and age of existing plants are obtained from the Global Energy Monitor [284], the Spatial Finance Initiative [285], and the Supplementary Materials of Neuwirth et al. [88]. Iron ore cost assumptions are detailed in [286], while the cost of limestone is taken from [287] and set at 35 million EUR per kilotonne of limestone. Table B.1 in Supplementary Material provides an overview of the technical parameters included in this extension of PyPSA-Eur. These comprehend energy inputs, emission factors, capital expenditure (CAPEX), operational expenditure (OPEX) where available, and assumed lifetimes. The table also indicates the sources for each parameter, which were cross-checked against values reported in the literature to ensure consistency within typical ranges. While the majority of parameters are drawn from Technology Data [195], more specific sources are specified when available.

Table B.1: *Detailed technical and cost parameters for steel and cement sectors by technology.*

Sector	Technology	Parameter	Value (year)	Unit	Reference
Steel	BF-BOF	Iron input	1.8	kt iron/kt steel	[90]
		Coal input	6342	MWh_{th}/kt steel	[90]
		Electricity input	194	MWh/kt steel	[90]
		Emission factor	1760	tCO_2/kt of steel	[90]
		CAPEX	871.85	milEUR/kt steel	[286]
		OPEX	123.67	milEUR/kt steel	[286]
		Lifetime	25	years	[90]
	NG DRI-EAF	Iron input	1.36	kt iron/kt steel	[288]
		NG input	2803	MWh_{th}/kt steel	[288]
		Electricity input	554	MWh/kt steel	[288]
		Emission factor	565	tCO_2/kt steel	[288]
		CAPEX	698.34	milEUR/kt steel/a	[286]
		OPEX	118.27	milEUR/kt steel/a	[286]

		Lifetime	40	years	[286]
	H_2 DRI-EAF	Iron input	1.39	kt iron/kt steel	[288]
		H_2 input	2211	MWh_{th}/kt steel	[288]
		Electricity input	611	MWh/kt steel	[288]
		Emission factor	76	tCO_2/kt steel	[288]
		CAPEX	698.34	milEUR/kt steel/a	[286]
		OPEX	118.27	milEUR/kt steel/a	[286]
		Lifetime	40	years	[286]
	Scrap-EAF	Scrap price	280	milEUR/kt scrap	[288]
		Electricity input	640	MWh/kt steel	[286]
		Direct emission factor	0	tCO_2/kt steel	
		CAPEX	210	milEUR/kt steel/a	[286]
		OPEX	63	milEUR/kt steel/a	[286]
		Lifetime	40	years	[286]
	Retrofit TGR on BF-BOF	Electricity input	0.107 (2030), 0.095 (2040), 0.093 (2050)	MWh/tCO_2	[195]
		Capture rate	90 (2030), 95 (2040, 2050)	%	[195]
		CAPEX	297 (2030), 251 (2040), 205 (2050)	EUR/tCO_2	[195]
		Lifetime	25	years	[195]
Cement	Cement Plant	Limestone input	1.28	kt limestone/kt cement	[289]
		NG input	1900	MWh_{th}/kt cement	[289]
		Emission factor	500	tCO_2/kt cement	[289]
		CAPEX	263	milEUR/kt cement	ETSAP
		Lifetime	25	years	[90]
	Retrofit TGR on cement plant	Electricity input	0.107 (2030), 0.095 (2040), 0.093 (2050)	MWh/tCO_2	[195]
		Capture rate	90 (2030), 95 (2040, 2050)	%	[195]
		CAPEX	297 (2030), 251 (2040), 205 (2050)	EUR/tCO_2	[195]
		Lifetime	25	years	[195]
Ammonia	Haber-Bosch	Electricity input	0.2473	MWh_{el}/MWh NH_3	[195]
		H_2 input	1.1484	MWh_{th}/MWh NH_3	[195]
		CAPEX	166.67 (2030), 136.32 (2040), 104.51 (2050)	EUR/MWh NH_3/a	[195]
		OPEX	0.0225	EUR/MWh NH_3	[195]
		Lifetime	30	years	[195]
Methanol	Methanolisation	Electricity input	0.271	MWh_{el}/MWh methanol	[195]
		H_2 input	1.138	MWh_{th}/MWh methanol	[195]
		EOL emissions	0.248	t CO_2/MWh methanol	[195]
		CAPEX	80.33 (2030), 69.83 (2040), 59.33 (2050)	EUR/MWh methanol/a	[195]
		Lifetime	20	years	[195]
HVCs	Naphtha steam cracker	Naphtha input	28806	MWh naphtha/kt HVC	[90]
		Electricity input	135	MWh_{el}/kt HVC	[90]
		H_2 output	0.699	MWh H_2/kt HVC	[90]
		EOL emissions	0.2571	t CO_2/MWh naphtha	[195]
		CAPEX	1817	milEUR/kt HVC	[290]
		Lifetime	30	years	[90]
	Bio-naphtha production	Biomass input	0.3833 (2030), 0.4167 (2040), 0.45 (2050)	MWh biomass/MWh naphtha	[291]
		CO_2 in biomass	0.0979 (2030), 0.1072 (2040), 0.1157 (2050)	t CO_2/MWh biomass	[291]
		CAPEX	3118.43	milEUR/MW	[292]
		Lifetime	25	years	[195]
	Fischer-Tropsch	H_2 input	1.252	MWh H_2/MWh naphtha	[293]
		CO_2 input	0.2571	t CO_2/MWh naphtha	[195]
		CAPEX	703.726	milEUR/MW	[293]
		Lifetime	20	years	[195]
Hydrogen	Electrolysers	Electricity input	0.6217 (2030), 0.6532 (2040), 0.6994 (2050)	MWh_{el}/MWh H_2	[195]
		CAPEX	1500 (2030), 1200 (2040), 1000 (2050)	milEUR/MW	[195]
		Lifetime	25	years	[195]
	Steam Methane Reformer	NG input	0.76	MWh NG/MWh H_2	[294]
		Emission factor	0.198	t CO_2/MWh NG	[195]
		CAPEX	396.87	milEUR/MW H_2	[195]
		Lifetime	30	years	[294]
	Steam Methane Reformer + CC	NG input	0.69	MWh NG/MWh H_2	[294]
		CO_2 out	10	%	[195]
		CO_2 captured	90	%	[195]
		CAPEX	417.97	milEUR/MW H_2	[195]
		Lifetime	30	years	[294]

B.2 Extra indicators for energy sectors

To complement Figure 4.2 and Figure 4.5, we examine the role of hydrogen production across the scenarios. Hydrogen produced via electrolysis is classified as either green or grey, depending on the carbon intensity of the electricity used: it is considered grey when generated using electricity from CO_2-emitting sources, and green when produced from low-carbon electricity. From 2040 onwards, green hydrogen becomes a key element of the industrial decarbonisation pathway. In the *Reindustrialization* scenarios, our estimates reach almost twice the level projected by Hydrogen Europe (35 Mtons by 2040 [295]), but production is reduced if *Intermediates Imports* are allowed. The *Continued Decline* scenarios maintain a more comparable European hydrogen generation. As a reference, the European Commission has set a target of 10 Mtons by 2030 [201].

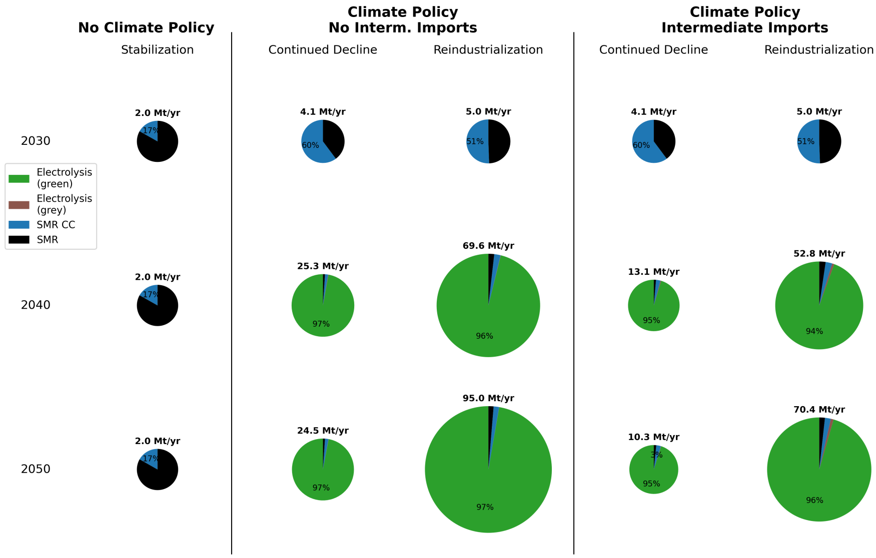

Figure B.1: *Hydrogen production in five scenarios: the first column represents the scenario with No Climate Policy and Stabilization of industrial production; the two columns in the middle show scenarios implementing the EU Climate Policies for Continued Decline and Reindustrialization, with No Intermediate Imports; the two columns on the right represent Climate Policies for Continued Decline and Reindustrialization, with Intermediate Imports. The radius of each pie chart is proportional to the total quantity indicated above it, while the segment shares represent the contribution of each production technology.*

In Figure B.2, we present key energy system indicators to provide insight into the underlying dynamics of the modelled scenarios. The panel on the left displays the average electricity price, represented by the Lagrange multipliers $\lambda_{n,t}$, which correspond to the marginal cost of producing electricity in region n at time step t. We report the annual European average electricity price for each future year in the pathway (2030, 2040, and 2050), denoted as $elprice_{EU,year}$. This value is computed as a weighted average over all regions and time steps, as defined in Equation B.1, where $elprice_{n,t}$ and $P_{n,t}$ are respectively the Lagrange multiplier for electricity and the power production in nation n and timestep t, with Δt is the timestep, in this case of 3 hours.

$$\overline{elprice}_{EU,year} = \frac{\sum_n^N \sum_t^T elprice_{n,t} \cdot P_{n,t} \cdot \Delta t}{\sum_n^N \sum_t^T P_{n,t} \cdot \Delta t} \tag{B.1}$$

The central panel illustrates the share of electricity generated from low-carbon sources for each simulated year. In this context, "green electricity" refers to electricity produced from technologies that do not emit CO_2 during operation. These include reservoir hydro, Run-of-River (RoR), solar PV , on- and off- shore wind, biomass, and nuclear technologies, as modelled in the system.

The share of green electricity, denoted as $s^{\text{green}}_{\text{elec},y}$ in year y, is defined as the ratio of total electricity generated by green sources to the total electricity generation:

$$EUshare_{greenelec} = \sum_t^T \frac{\sum\limits_{g \in G_{\text{green}}} P_{g,t} \cdot \Delta t}{\sum\limits_{g \in G} P_{g,t} \cdot \Delta t} \tag{B.2}$$

Where:
$P_{g,t}$ is the power output of generator g at time t
G_{green} is the set of green (non-emitting) generators
G is the set of all generators
T_y is the set of time steps in year y
Δt is the duration of each time step (can be omitted if uniform)

The panel on the right displays the CO_2 price, which, in a linear energy system optimisation model, arises as the *shadow price* (or dual variable) associated with the constraint on total allowable CO_2 emissions. The model seeks to minimize total system costs subject to technical, economic, and environmental constraints, including a cap on cumulative CO_2 emissions. For a detailed description of the objective function and the implementation of the CO_2 constraint in `PyPSA-Eur`, refer to [53]. From an economic perspective, the CO_2 price μ_{CO_2Limit} represents the marginal cost of tightening the CO_2 emissions constraint. It quantifies the increase in total system cost resulting from a one-unit decrease (e.g., one tonne) in the permissible CO_2 emissions:

$$\mu_{CO_2Limit} = \frac{\partial \text{System Cost}}{\partial CO_2Limit} \tag{B.3}$$

Electricity prices do not increase significantly in the *Climate Policy* scenarios (as in Figure B.2). This is primarily because the decarbonization of the power sector remains relatively consistent even in the *No Climate Policy* cases, driven by the projected low costs of solar PV and wind turbines in the coming decades. The graphs present only the average price across time and model nodes, as we found the inclusion of price volatility to add limited additional insights. Indeed, the variation in volatility across scenarios is negligible, likely reflecting the consistently high penetration of renewable energy technologies in each case. In the *Climate Policy* scenarios, electricity generation is almost entirely based on renewable sources by 2030. In contrast, under the *No Climate Policy*, the share of renewable electricity stabilizes around 85%, meaning that fossil-fuel-based generation is still required during peak demand periods. The third graphs reports the carbon prices, representing the required cost of CO_2 emissions to achieve the emission reduction targets in an economically efficient manner. In practice, they reflect the price level necessary to increase the marginal costs of emitting technologies sufficiently to incentivize the adoption and deployment of zero-emission alternatives.

B.3 Robustness check on hydrogen infrastructure

Figure B.3 shows that the presence or absence of a hydrogen transmission grid has only a modest effect on time-averaged European prices for industrial commodities. In 2040, a slight reduction in

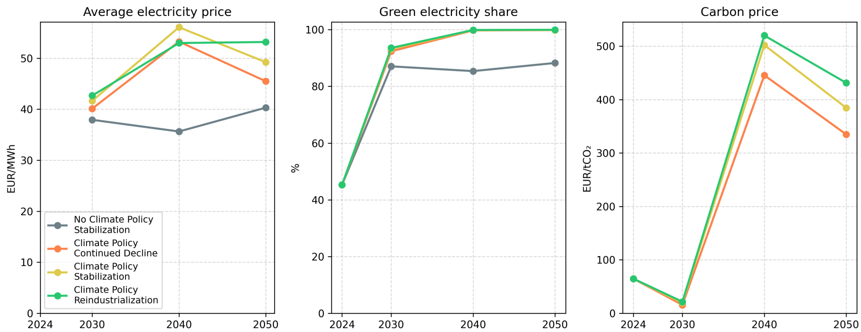

Figure B.2: *Evolution of key energy system indicators under different policy and industrialization scenarios. Left: electricity price, averaged across regions and timesteps [EUR/MWh]. Center: Share of green electricity in total supply [%]. Right: CO_2 price [EUR/ton of CO_2] (note that scenarios with No Climate Policy have no carbon price). The scenarios compare pathways with and without Climate Policy, as well as differing industrialization trends (Continued Decline vs. Reindustrialization).*

production costs is observed for hydrogen-intensive products such as ammonia, methanol, and steel. The average cost of hydrogen itself remains largely unchanged, as lower electricity expenditures when using the grid are offset by the capital costs of pipeline infrastructure. While the grid could provide marginal benefits for hydrogen-dependent commodities, the pace and uncertainty of hydrogen market and infrastructure development make it a challenging option to rely upon for industrial decarbonisation strategies.

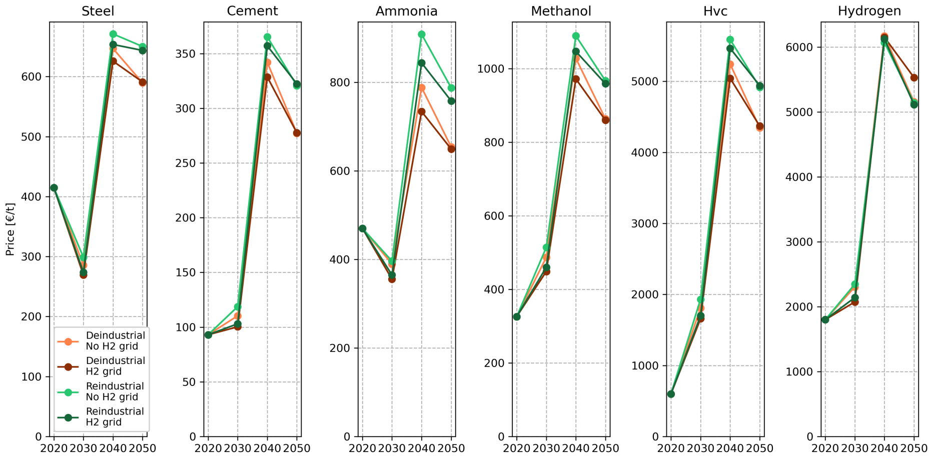

Figure B.3: *Prices of industrial goods, average across European countries and time steps, for different scenarios: Continued Decline with No H_2 Grid and with H_2 Grid, Reindustrialization with No H_2 Grid and with H_2 Grid. The scenarios with No H_2 Grid are the part of the Main Scenarios, the others are compared for a robustness check.*

APPENDIX C

Appendix to Article III: Climate policy, steel decarbonisation, and trade fragmentation in Europe: a coupled energy-macroeconomic analysis

C.1 Methodology for models' coupling

C.1.1 Qualitative description of the coupling

The coupling between PyPSA-Eur and FIDELIO requires the definition of a *Baseline* scenario, as several variables are introduced as shocks relative to baseline values and a counterfactual is needed for comparative analysis. Accordingly, the first stage of the coupling consists of iteratively running the two models until convergence is achieved in the *Baseline* scenario.

PyPSA-Eur is executed first, as FIDELIO relies on a number of exogenous inputs derived from the energy system model and does not explicitly represent electricity and energy system dynamics. Prior to this step, FIDELIO is run in a *Pre-Baseline* configuration that excludes inputs from PyPSA-Eur. This preliminary simulation is necessary because baseline variables in FIDELIO are defined as deviations relative to the *Pre-Baseline* scenario.

The variables transferred from PyPSA-Eur to FIDELIO include:

- Shares of electricity generation technologies in the electricity mix;
- Average electricity and energy prices (PyPSA-Eur operates at hourly resolution; averages are computed using hourly consumption as weights);

- Average steel and aluminium production costs (PyPSA-Eur operates at hourly resolution; averages are computed using hourly consumption as weights);
- Investments in electricity generation technologies;
- Investments in steel and aluminium production technologies;
- Household-level electricity and non-electricity consumption shares, particularly for passenger transport and residential heating (which are not endogenously modelled in FIDELIO);
- Carbon prices at the European level for ETS1 and ETS2.

A series of Python and R scripts is used to process and transform the outputs of PyPSA-Eur into the input format required by FIDELIO. FIDELIO is then executed with the corresponding input interface activated and the relevant scenario specification selected.

Following the FIDELIO simulations, the outputs are processed into a format compatible with PyPSA-Eur to initiate the first iteration of the coupled modelling framework. The corresponding script computes shock values capturing changes in key economic indicators under the *EU ClimPol* and *EU ClimPol + Tariffs* scenarios relative to the *Baseline*, as well as changes in the *Baseline* relative to the *Pre-Baseline* scenario. The variables transferred from FIDELIO to PyPSA-Eur consist of variations in:

- Industrial production;
- Agricultural output;
- Service-sector activity;
- Household consumption of electricity and heat;
- Household demand for land-based transport;
- Demand for maritime transport services;
- Demand for aviation services;
- Steel and aluminium production levels.

Once these shock values are prepared, PyPSA-Eur is rerun to complete Iteration 1, now incorporating the economic feedbacks derived from FIDELIO. This iterative process is repeated until a predefined convergence threshold is reached, at which point the final simulations of each model are taken as the converged results of the coupled framework.

The two models differ along multiple dimensions, necessitating harmonization of variables to ensure consistent interactions. First, regarding temporal resolution, PyPSA-Eur operates with a three-hourly time step for a single year in 2020, 2030, 2040, and 2050, whereas FIDELIO has annual resolution and runs continuously from 2015 to 2050. To transfer variables from PyPSA-Eur to FIDELIO, values for non-simulated years are obtained through linear interpolation, while historical values for 2015 are derived from FIDELIO's source data. Conversely, when transferring variables from FIDELIO to PyPSA-Eur, only values corresponding to years simulated in PyPSA-Eur (2030, 2040, 2050) are used, as 2020 is treated as historical and fixed. Second, with respect to spatial resolution, PyPSA-Eur represents most countries at a single-node country level, with additional nodes for geographically complex countries (e.g., Italy: one node for the peninsula and Sicily, one node for Sardinia). FIDELIO provides country-level values for the EU, as well as for selected non-EU countries (e.g., USA, China, India) and a "Rest of the World" category. For countries outside the EU, model inputs are held constant during the coupling, though FIDELIO's internal trade mechanisms allow them to interact with EU economies. A core assumption of the coupled framework is that non-EU countries do not implement climate policies, consistent with the study's focus on the European Union.

C.1.2 Variables exchanged from PyPSA-Eur to FIDELIO

A python script converts PyPSA-Eur variables into a standardized nomenclature, then an R-based data processing workflow harmonizes PyPSA-Eur outputs for FIDELIO. The script standardizes regional identifiers, filters relevant countries and technologies, and maps PyPSA technology codes to a consistent nomenclature. FIDELIO adopts 2015 as its baseline year, whereas PyPSA-Eur simulations begin in 2020. However, as the analysis focuses on future developments rather than historical dynamics, values for years prior to 2020 are assumed to remain constant and identical across both models to ensure consistency in the coupling framework. The variables exchanged and details about the processes are described below. For the *Baseline* scenario, only electricity generation shares and carbon price are exchanged. All other variables are expressed as deviations from the corresponding PyPSA-Eur values in the policy scenarios, relative to the *Baseline*.

Electricity generation shares

PyPSA-Eur electricity generation results are post-processed through a dedicated data harmonisation pipeline, spatially aggregated at the country level and mapped to FIDELIO's electricity subsectors of the NACE D35 code which is "Electricity, gas, steam and air conditioning supply". For each scenario, country, and model year, electricity production is converted into technology-specific shares. To align the differing temporal resolutions of the models, PyPSA-Eur outputs available for the years 2020, 2030, 2040, and 2050 are interpolated to annual values over the 2015-2050 horizon, using linear or exponential interpolation where required to ensure numerical stability and convergence of the coupled framework. To ensure compatibility with the FIDELIO base-year calibration, electricity technology shares are rebased on observed 2015 input-output production structures from the FIDELIO database. Specifically, PyPSA-Eur derived shares are scaled such that total electricity output by country and year matches the corresponding D35 aggregate, while preserving the relative technology composition implied by the energy system optimisation. This ensures that D35 continues to represent the same share of output in monetary terms in the economy. The rebasing is performed according to Eq. C.1.

$$s^{\text{FID}}_{c,t,y} = \frac{s^{\text{PyPSA}}_{c,t,y}}{\sum_t s^{\text{PyPSA}}_{c,t,y}} \cdot S^{\text{D35}}_{c,y}\,, \tag{C.1}$$

where $s^{\text{PyPSA}}_{c,t,y}$ denotes the PyPSA-Eur electricity share of technology t in country c and year y, and $S^{\text{D35}}_{c,y}$ is total electricity production in the FIDELIO input-output database.

Finally, the processed variables are exported as exogenous shares of electricity production as variation with respect to values in 2015.

Carbon price trajectories for ETS1 and ETS2

CO_2 price trajectories produced by PyPSA-Eur correspond to the shadow prices of the CO_2 emissions constraints applied to the sectors covered by ETS1 and ETS2, respectively. In the *Baseline* scenario, these prices are zero, reflecting the absence of binding emissions constraints. PyPSA outputs are available only at milestone years (2020, 2030, 2040, and 2050); therefore, the time series are harmonized by introducing a zero-price reference in 2015 and constructing annual values through piecewise linear interpolation. For the *Baseline* scenario, ETS1 prices are entirely replaced by an exogenous projection based on IEA assumptions [296], ensuring consistency with the reference pathway adopted in FIDELIO. ETS2 prices are set to zero prior to the system's introduction and capped at an upper bound of 45 EUR/tCO_2 in 2030 to prevent unrealistically steep short-term price increases [297]. Finally, ETS1 prices over the initial period (2015-2020) are harmonized across scenarios in order to isolate policy-induced price differentials in subsequent years.

Average electricity and energy prices

Electricity and energy price signals from PyPSA-Eur are transferred to FIDELIO in the form of country-level relative price variations with respect to PyPSA-Eur *Baseline*. PyPSA-Eur provides electricity prices as shadow prices of the electricity balance constraint, and aggregate energy prices as shadow prices of the secondary energy balance constraint, both reported at optimized years (2030, 2040, and 2050). Prices are defined on each timestep and are therefore calculated as weighted averages, with weights corresponding to electricity generation and energy production, respectively. Changes in prices induced in the Climate Policy scenarios are expressed as proportional deviations from the corresponding *Baseline* values at the country-year level. For each price type $x \in \{\text{elec}, \text{ener}\}$, the price shock applied in FIDELIO is computed as Eq. C.2

$$\Delta p^{x}_{c,t} = \frac{p^{x,\text{policy}}_{c,t} - p^{x,\text{baseline}}_{c,t}}{p^{x,\text{baseline}}_{c,t}} \tag{C.2}$$

where $p^{x,\text{policy}}_{c,t}$ and $p^{x,\text{baseline}}_{c,t}$ denote, respectively, electricity or aggregate energy prices in country c and year t under the policy and *Baseline* scenarios. To ensure consistency with FIDELIO's annual temporal resolution, the resulting relative price shocks are extended over the period 2015-2050 using piecewise linear interpolation between milestone years, with a zero-deviation reference imposed in 2015. The final country-specific electricity and energy price deviation profiles are implemented as exogenous price shifters of the endogenous prices of the macroeconomic model.

Soft-linking detailed energy system models (e.g., TIMES, PRIMES, PyPSA) with CGE models can generate unrealistically large macroeconomic impacts when high ESM-derived energy price increases are passed directly to the CGE. European studies show that strong decarbonization or supply shocks often produce price spikes that translate into implausible GDP losses (e.g., -5.5% for the Netherlands in Fattahi et al. [67]), partly due to inconsistencies between base-year CGE prices and future marginal prices in ESMs [298]. To avoid this, researchers commonly apply price-dampening methods, such as numerical scaling, elasticity adjustments, or iterative smoothing, to ensure that the transmitted price signals yield credible macroeconomic outcomes. The scaling is necessary because electricity prices in the two models reflect different underlying mechanisms: in PyPSA-Eur, prices are marginal-cost indicators shaped by network constraints, hourly dispatch, and the shadow value of carbon or system-integration requirements, whereas in FIDELIO they summarise average production costs within a CES-based, annually-aggregated equilibrium. Passing the full PyPSA-Eur price change into FIDELIO would therefore overstate the effective cost shock perceived at the macroeconomic level, conflating marginal scarcity signals with structural production costs. In this case we apply a price dampening coefficient of 50%. An additional methodological clarification is required regarding the interpretation of energy prices. In our modelling framework, electricity and energy prices are obtained as the dual variables of the respective demand-balance constraints. They therefore represent marginal system costs, that is, wholesale prices reflecting the short-run marginal cost of supplying an incremental unit of energy. As a consequence, these prices do not incorporate the recovery of capital expenditures made in previous optimisation periods, even though capacity built in earlier years is carried forward in the pathway simulations. In real-world energy systems, such costs are typically recouped through system charges or regulated tariffs. To ensure that the price signals passed from PyPSA-Eur to FIDELIO fully reflect the investment requirements of the system, we assume a uniform investment repayment period of ten years. Given that our pathway simulations advance in ten-year increments, this implies that all investments made in a given optimisation year are fully amortised by the time the next iteration is computed. Importantly, the technical lifetimes of assets remain unchanged and follow the values specified in the technology dataset. This approach guarantees that the investment costs associated with electricity supply technologies are consistently accounted for and ultimately embedded within the electricity prices faced by end-users in FIDELIO.

In coupled energy-economy frameworks, electricity price changes induced by climate policy reflect multiple underlying mechanisms. Decarbonisation policies simultaneously increase the capital intensity of electricity supply, through a shift toward low-carbon generation technologies, and raise the cost of residual fossil-based generation through carbon pricing and associated operating cost changes. When transmitting these effects from a detailed energy-system model to a macroeconomic model with distinct price channels for current production and investment, it is therefore necessary to distinguish between price changes linked to capital deepening in the power sector and price changes arising from carbon pricing and operational costs borne by non-decarbonised generation. Representing the electricity price shock as a composite of an investment price effect and an electricity output price effect provides a pragmatic way to preserve this distinction within a general equilibrium framework, while remaining consistent with the structure of both modelling approaches. We operationalise this decomposition by using the change in the low-carbon "green" electricity share as a proxy for the capital-intensity component of the electricity price shock. Specifically, we define the investment-driven share of the electricity price change as Eq. C.3.

$$from\_inv_{s,n,t} = \frac{green\_share_{s,n,t} - green\_share_{Baseline,n,t}}{1 - green\_share_{Baseline,n,t}} \tag{C.3}$$

where s indexes policy scenarios, n denotes countries, and t denotes model periods. This expression measures the scenario-induced increase in green generation relative to the maximum feasible increase from the baseline (i.e., up to a fully green electricity mix), yielding a normalised share in $[0, 1]$ under typical conditions. We allocate the fraction $from\_inv_{s,n,t}$ of the electricity price shock to the investment price channel, capturing the higher capital intensity associated with the shift toward low-carbon generation, and the remaining fraction $1 - from\_inv_{s,n,t}$ to the electricity output price channel, capturing price effects arising from carbon pricing on residual fossil-based generation as well as other short-run operating cost changes. This mapping allows the coupled framework to represent electricity-sector decarbonisation as both a contemporaneous cost shock faced by electricity users and a capital-deepening process with broader macroeconomic implications, while remaining consistent with system constraints embedded in the energy-system scenarios. Because this decomposition relies on a proxy rather than an accounting identity, it should be interpreted as a modelling assumption; future work could refine the split using explicit system cost decompositions (e.g., separating CAPEX, fixed O&M, fuel, and carbon components) directly from the energy-system results.

Average steel and aluminium prices

Steel and aluminium prices are treated analogously to electricity and energy prices. In PyPSA-Eur, price signals are obtained as shadow prices of the corresponding industrial production constraints. Annual country-level prices are computed as weighted averages over timestep, with weights given by steel and aluminium production, respectively. Policy-induced effects are expressed as proportional deviations from the *Baseline* scenario at the country-year level and are available for 2030, 2040, and 2050. These deviations are extended to annual trajectories over 2015-2050 via piecewise linear interpolation, imposing a zero-deviation reference in 2015-2020. The resulting country-specific price shock profiles are introduced in FIDELIO as exogenous shifters of endogenous industrial production costs. For the same reasons as the electricity and energy price a dampening coefficient is imposed to smooth the effect of these price shocks on the CGE structure.

Investments in power generation technologies

Electricity sector investment signals are extracted from PyPSA-Eur at the country- and technology-specific level and harmonized with FIDELIO's baseline investments. In PyPSA-Eur, investments are reported on an annual basis for each power generation technology and are annualized taking into account the assets lifetimes and a discount rate. Reported investments include not only new capacity additions for the given year but also ongoing expenditures from previous years that have not yet reached the end of their economic lifetime (e.g., investments recorded in 2040 also account for unexpired investments made in 2030). Policy-induced investment effects are expressed as proportional deviations from the *Baseline* scenario following Eq. C.4.

$$\Delta I_{c,t}^{tech} = \frac{I_{c,t}^{\text{policy}} - I_{c,t}^{\text{base}}}{I_{c,t}^{\text{base}}} \tag{C.4}$$

where $I_{c,t}^{\text{policy}}$ and $I_{c,t}^{\text{base}}$ are the PyPSA-Eur investment values for country c, technology $tech$, and year t under the policy and Baseline scenarios, respectively. In cases where both *Baseline* and policy investments are zero, deviations are set to zero. If the policy scenario shows zero investment while a baseline investment exists, the deviation is set to -1 with a small offset to prevent negative scaling issues. Conversely, if the *Baseline* is zero but policy investments are positive, the deviation is computed relative to the mean baseline investment of the country to ensure consistency with national investment levels. These deviations are then applied to FIDELIO's baseline investments anchored in 2015. The resulting trajectories are extended to a full yearly time series over 2015-2050 using piecewise linear interpolation and capped to avoid negative or implausibly large values. Finally, the processed country- and technology-specific investment paths are implemented in FIDELIO as exogenous shocks, driving the evolution of power system capacity.

Investments in steel and aluminium production technologies

Investments in industrial assets are calculated following the same methodology as for the electricity sector, at the country- and technology-specific level. Annual investment values are computed from PyPSA-Eur outputs and reflect annualized capital costs, including investments from previous optimization years that have not yet been fully amortized. Policy-induced effects are expressed as proportional deviations from the *Baseline* scenario. Cases where both *Baseline* and policy investments are zero are set to zero; if only the policy scenario is zero, the deviation is slightly adjusted to avoid negative scaling; if only the *Baseline* is zero, deviations are calculated relative to the country's mean baseline investment. These deviations are applied to FIDELIO's 2015 baseline investments, extended over 2015-2050 using linear interpolation, and capped to avoid negative or implausibly large values. The resulting country- and industry-specific investment trajectories are incorporated into FIDELIO as exogenous shocks driving industrial capacity evolution.

Electrification shares across households

For each scenario, annual sectoral shares of electricity required to satisfy energy service demand in the passenger transport and household sectors are extracted and normalized, checking that the upper bound is 100%. Values for intermediate years are determined via linear interpolation between the available data points, ensuring a temporally smooth trajectory. The relative change of electrification under policy scenarios compared to the *Baseline* is computed for each country n, sector s, and year t as Eq. C.5.

$$\text{pct\_diff}_{n,s,t} = \frac{\text{share}_{n,s,t}^{\text{policy}} - \text{share}_{n,s,t}^{\text{baseline}}}{\text{share}_{n,s,t}^{\text{baseline}}} \tag{C.5}$$

where $\text{share}_{n,s,t}^{\text{policy}}$ is the electrification share under the policy scenario, $\text{share}_{n,s,t}^{\text{baseline}}$ is the electrification share under the baseline scenario, and $\text{pct\_diff}_{n,s,t}$ represents the relative difference in electrification share between the policy and baseline scenarios. Missing or negative values set to zero for consistency.

C.1.3 Variables from FIDELIO to PyPSA-Eur

Economic feedbacks generated by the CGE model FIDELIO are transferred to PyPSA-Eur through a systematic comparison of policy and *Baseline* simulation outputs. The analysis focuses on sectoral output and household consumption variables evaluated at the optimized years in PyPSA-Eur, which are 2030, 2040, and 2050. At the sectoral level, production quantities are aggregated across detailed sectors belonging to a given macro-sector (industry, agriculture, shipping, aviation, and services) for each country n and year t. For a generic sector s, the relative policy-induced variation with respect to the baseline is computed as in Eq. C.6.

$$\Delta_{n,s,t} = \frac{Q^{\text{Policy}}_{n,s,t} - Q^{\text{Baseline}}_{n,s,t}}{Q^{\text{Baseline}}_{n,s,t}} \tag{C.6}$$

where $Q^{\text{Baseline}}_{n,s,t}$ and $Q^{\text{Policy}}_{n,s,t}$ denote total sectoral output in the *Baseline* and policy scenarios, respectively. Relative changes below a small threshold are set to zero to avoid the propagation of numerical noise. Household consumption effects are derived using a two-step procedure based on COICOP categories. First, total household consumption expenditure is reconstructed for each country and year by combining household purchasing power, an exogenous consumption bridge, and endogenous consumption shares. Household consumption in COICOP category c is computed in Eq. C.7.

$$H_{n,c,t} = B_{n,t} \cdot PP_{n,t} \cdot \sigma_{n,c,t} \tag{C.7}$$

where $PP_{n,t}$ denotes household purchasing power, $B_{n,t}$ is an exogenous scaling bridge, and $\sigma_{n,c,t}$ is the consumption share associated with COICOP category c. Policy-induced variations in household consumption are then computed analogously to the sectoral case. In addition to individual COICOP categories, transport-related consumption effects are obtained by aggregating COICOP categories associated with passenger transport services prior to computing relative changes. The resulting country- and year-specific relative change signals are exported as exogenous shocks and fed back into PyPSA-Eur, where they modify sectoral demand levels and household consumption patterns in subsequent energy system optimization runs.

C.1.4 Convergence algorithm

In each scenario, the modelling framework follows an iterative coupling between PyPSA-Eur and FIDELIO, as displayed in Figure 5.1, in order to ensure that the results of the two models are aligned.

Before initiating the integrated modelling process, FIDELIO is first executed independently (without inputs from PyPSA-Eur) to generate a set of parameters required for the *Baseline* scenario. These include electricity demand shares prior to the PyPSA-Eur optimisation, steel production levels, and historical input-output values for the year 2015, which serve as reference points for subsequent analyses. In the first step, PyPSA-Eur is run to produce detailed representations of the energy system, which then serve as inputs to FIDELIO. FIDELIO subsequently simulates the macroeconomic adjustments and generates updated demand for selected service sectors, which are fed back into PyPSA-Eur as shocks to corresponding energy services. This iterative exchange continues until both models converge on a consistent solution. This method is applied for all the three scenarios evaluated.

To evaluate if the coupled models reach a stable equilibrium, convergence between consecutive iterations is assessed using a Gauss-Seidel method, as commonly applied in similar soft-coupling frameworks [299]. At iteration k, the convergence criterion ζ_k quantifies the relative variation in the exchanged demand vectors between two successive iterations, aggregated over all years $y \in (2030, 2040, 2050)$.

Each demand vector $D_{y,i}$ represents the European-level aggregation of variables exchanged from FIDELIO to PyPSA-Eur (industry, steel, agriculture, water transport, air transport, and services output, and household consumption data for *COICOP4* and *COICOP8-10*), for a given year $y \in (2030, 2040, 2050)$.

The adjusted demand vector $D'_{y,k}$ is computed as a weighted sum of all previous demand vectors $D_{y,i}$ up to iteration k, following the recursive formulation in Eq. C.8:

$$D'_{y,k} = \frac{2}{(k+2)(k+3)} \cdot \sum_{i=0}^{k} (i+1) \cdot D_{y,i} \tag{C.8}$$

where i denotes the iteration index. This weighting scheme progressively smooths the convergence trajectory by assigning greater weight to more recent iterations. This process is repeated also to get $D'_{y,k-1}$, stopping at the previous iteration $k-1$

The convergence criterion ζ_k quantifies the relative change between consecutive iterations of the coupled model. It is defined as the ratio of the Euclidean distance between the two most recent adjusted demand vectors, $D'_{y,k}$ and $D'_{y,k-1}$, to the Euclidean norm of the latest demand vector $D'_{y,k}$, as in Eq. C.9

$$\zeta_k = \frac{\sqrt{\sum_y \left(D'_{y,k} - D'_{y,k-1}\right)^2}}{\sqrt{\sum_y \left(D'_{y,k}\right)^2}} \tag{C.9}$$

A small value of ζ_k indicates limited variation between iterations, suggesting that the coupled system has approached a steady-state equilibrium (we assume 1% as the threshold to be reached).

C.2 Modelling emission/performance standards from European policies

C.2.1 Passenger cars and vans

PyPSA-Eur requires, as an input, the distribution of Electric Vehicles (EVs), fuel cell electric vehicles (FCEVs), and internal combustion engine (ICE) cars within the total vehicle fleet for each investment year. In this study, we determine the share of EVs based on observed technological trends and current policy provisions, assuming no deployment of FCEVs for land-based passenger transport. Fuel cell vehicles are excluded due to their limited cost-competitiveness and low energy conversion efficiencies, which result in a financially unsustainable total cost of ownership [300]. EU Commission sets target for new registered cars, thus we need to translate these into fleet-wide average emission factors and subsequently into the projected EV share. As of 2021, the average emission factor of the EU vehicle fleet was 173.95 gCO_2/km, based on calculation from JRC-IDEES data [301]. The European car market replaces approximately 11.37 million vehicles per year out of a total fleet of 291 million (2019) [302], corresponding to an annual turnover of 4%. Starting from a 2021 baseline emission factor for newly sold cars of $EF_{\text{newcars,2021}} = 95$ gCO_2/km [243], the emission factor of new cars in each subsequent year y is calculated as Eq. C.10.

$$EF_{\text{newcars},y} = EF_{\text{newcars,2021}} \cdot (1-r)^{(y-2021)} \tag{C.10}$$

where r represents the annual reduction rate. In the *Baseline* scenario, the annual emission factor reduction rate r is set to 1.6%, corresponding to the historical average for light-duty vehicles [303]. Under the FF55 policy framework, the EU targets emission factors of 49.5 g CO_2/km for new passenger cars and 90.6 g CO_2/km for new vans by 2030, the latter accounting for approximately 11% of the light-duty vehicle (LDV) fleet [304]. From 2035 onward, new internal combustion engine (ICE) vehicle sales are to be fully phased out, with a target of 0 g CO_2/km for new vehicles [305].

The average emission factor of the entire fleet in a given year Y_{end} is then obtained recursively as Eq. C.11.

$$EF_{\text{allcars},Y_{\text{end}}} = \sum_{y=Y_{\text{start}}}^{Y_{\text{end}}} [s_{\text{new}} \cdot EF_{\text{newcars},y}] + (1 - s_{\text{new}})^{(Y_{\text{end}}-Y_{\text{start}})} \cdot EF_{\text{allcars},Y_{\text{start}}} \tag{C.11}$$

where $s_{\text{new}} = 11.37/291 = 4\%$ denotes the annual share of newly sold vehicles. In this analysis, EF_{allcars} is computed for 2030, 2040, and 2050, using $Y_{\text{start}} = 2021$ and the corresponding Y_{end}.

The share of FCEVs is assumed to remain at 0%, as hydrogen-powered cars and vans are generally more expensive than EVs for passenger applications, and the development of hydrogen refueling infrastructure continues to lag behind that of electric charging networks [306, 307]. The share of EVs in the total fleet is derived from the resulting fleet emission factor, assuming that EVs emit 0 gCO_2/km and that the initial share of EVs in 2021 was negligible (approximating 100% ICE LDV), as Eq. C.12:

$$EV_{\text{share}} \cdot 0 + (1 - EV_{\text{share}}) \cdot EF_{\text{allcars,2021}} = EF_{\text{allcars},Y_{\text{end}}} \tag{C.12}$$

Solving for EV_{share} yields the implied share of electric vehicles consistent with the FF55 performance standards. The shares are depicted in panel a and b of Figure C.1. Currently, PyPSA-Eur represents only passenger land transport within its framework. To enhance the scope of the analysis, future extensions will incorporate additional transport sectors, such as maritime and aviation, to provide a more comprehensive assessment of the decarbonization pathways in the European mobility system.

C.2.2 Shipping sector

The FuelEU Maritime Regulation, part of the Fit-for-55 package, establishes a progressive reduction in the GHG intensity of fuels used in maritime transport, aiming for a 6% decrease by 2030, 38% by 2040, and 80% by 2050, relative to the 2020 fleet-wide average GHG intensity of 91.16 gCO_2eq/MJ [308]. To achieve these targets, alternative fuels such as ammonia and methanol, both included in PyPSA-Eur, are expected to play a crucial role in decarbonising the maritime sector. Ammonia is a hydrogen-based fuel with a zero direct emission factor (0 gCO_2eq/MJ), whereas methanol has an emission intensity of 68.9 gCO_2eq/MJ). Given the lower thermal efficiency of methanol in internal combustion engines compared to oil, an efficiency value of 36% is assumed [309]. In the absence of policy intervention, the maritime sector is assumed to remain fully reliant on oil-based fuels. Under the FuelEU Maritime regulatory framework, however, the model must identify the optimal fuel mix among ammonia, methanol, and oil that satisfies the required GHG intensity constraints.

For 2030, this regulation overlaps with the International Maritime Organization (IMO) strategy on reducing GHG emissions from ships, which mandates that at least 5% of the energy used in international shipping come from zero-emission fuels [310]. Accordingly, we assume that 5% of the maritime energy demand in the EU is supplied by ammonia. The remaining shares of methanol and oil are computed using Eq. C.13.

$$\begin{split} MeOH_{share} \cdot GHG_{MeOH} + NH_3 share \cdot GHG_{NH_3} \\ + (1 - NH_3 share - MeOH_{share}) \cdot GHG_{Oil} = GHG_{target} \end{split} \tag{C.13}$$

where GHG$_{MeOH}$=68.9 gCO_2eq/MJ, GHG$_{NH_3}$=0 gCO_2eq/MJ, GHG$_{Oil}$=91.16 gCO_2eq/MJ, GHG$_{target,2030}$=85.69 gCO_2eq/MJ and $NH_3 share$=5%. Solving Equation C.13 yields a methanol share of 4.14% for 2030. By 2050, oil is assumed to be completely phased out from maritime fuel use, requiring an average GHG intensity of 18.23 gCO_2eq/MJ. Solving the same balance equation without the oil component results in a composition of 73.5% ammonia and 26.5% methanol. For 2040, we assume a linear increase in the methanol share of approximately 1.1% per year, leading to a 15.3% methanol share. To meet the 2040 target intensity of 56.5 gCO_2eq/MJ, the corresponding share of ammonia is 34.3%, with the remainder supplied by oil. Extending the same linear trend to 2050 implies a 26.3% methanol share; assuming conservatively that 25% of demand is still met by oil in 2050, the remaining 48.7% is supplied by ammonia. Results in terms of energy are shown in Figure C.1, panel c.

C.2.3 Aviation sector

PyPSA-Eur receives as input the shares of various fuels in a sector's energy consumption, enabling a straightforward application of policy measures. The model incorporates the use of synthetic fuels (synfuels) produced from CO_2 and hydrogen, initially synthesizing methanol and subsequently converting it into kerosene. Additionally, for Sustainable Aviation Fuels (SAF), PyPSA-Eur considers biofuels derived from sustainably sourced biomass. Under the ReFuel Aviation policy [311], a specific proportion of the SAF share is mandated to come from synfuels, while the remainder consists of biofuels. The model assumes that the efficiency of a turbofan engine powered by synfuels is equivalent to that of a kerosene-based engine, given that the chemical composition remains unchanged. In contrast, for biomass-fuelled engines, Akdeniz et al. [312] estimate an 18.18% increase in thermal efficiency compared to the conventional thermal efficiency of 50.084% [313]. The projected shares are depicted in Figure C.1, panel d.

C.3 Additional results

C.3.1 Consistency of model outcomes with Fit-for-55 directives

This section presents an assessment of model outcomes for the *EU ClimPol* scenario against EU 2030 energy policy targets that could not be directly implemented as model constraints. These include the revised Energy Efficiency Directive, the revised Energy Performance of Buildings Directive, and the revised Renewable Energy Directive. Since PyPSA-Eur treats energy service demands as exogenous inputs, simply reducing demand levels would not reveal the system-level challenges associated with achieving these targets. Similarly, for renewable energy shares, imposing them as constraints would not capture the difficulty or trade-offs the system faces in meeting such objectives.

First, total EU final energy consumption in 2030 reaches approximately 13000 TWh, corresponding to about 1116 Mtoe, which is around 9% above the reference value associated with the revised Energy Efficiency Directive target (1023 Mtoe). This indicates that, while the transition substantially reshapes the energy system, the simulated pathways do not fully achieve the required reduction in aggregate final energy consumption by 2030, suggesting either remaining demand rigidities or conservative assumptions on efficiency improvements in end-use sectors.

Second, the results show a markedly stronger performance for the buildings sector. Final energy use in residential and services buildings decreases by more than 23% relative to the 2020 reference level set by the directive, exceeding the revised Energy Performance of Buildings Directive target of a 16% reduction by 2030. This outcome reflects the strong penetration of electrification in buildings heating and indicates that the modelled transition is consistent with near-term policy ambitions in this sector.

Third, renewable electricity generation amounts to roughly 4160 TWh in 2030, corresponding to only about 32% of total final energy consumption, well below the RED target range of 42.5-45%. Even under a sensitivity case in which nuclear electricity is counted as renewable, the share rises

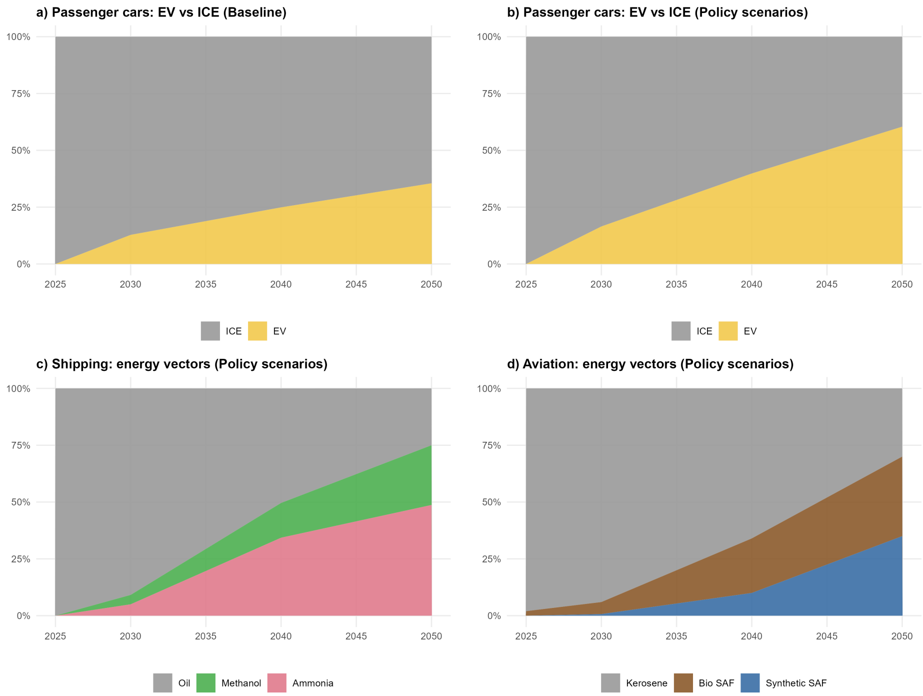

Figure C.1: *Assumed evolution of transport technology and energy carrier shares under Baseline and policy scenarios. (a) Passenger car drivetrain shares in the Baseline scenario. (b) Passenger car drivetrain shares under policy scenarios. (c) Shipping energy carrier shares under policy scenarios. (d) Aviation energy carrier shares under policy scenarios.*

only to around 37%, still short of the target. This gap is noteworthy when placed in context: in 2024, renewables accounted for approximately 25.4% of total final energy consumption [314], implying that while the modelled scenarios deliver a substantial increase relative to current levels, they fall short of the acceleration required to meet the revised RED targets by 2030. Importantly, nuclear energy is not considered renewable under EU legislation, and its inclusion here serves only as an illustrative upper bound, reinforcing the conclusion that achieving the 2030 renewable share target would require faster deployment of renewables beyond the power sector. Overall, these results suggest that the modelled transition is broadly aligned with sector-specific efficiency objectives, particularly in buildings, but that additional policy effort or more ambitious assumptions would be required to simultaneously meet economy-wide energy efficiency and renewable share targets by 2030.

C.3.2 Bilateral trade results

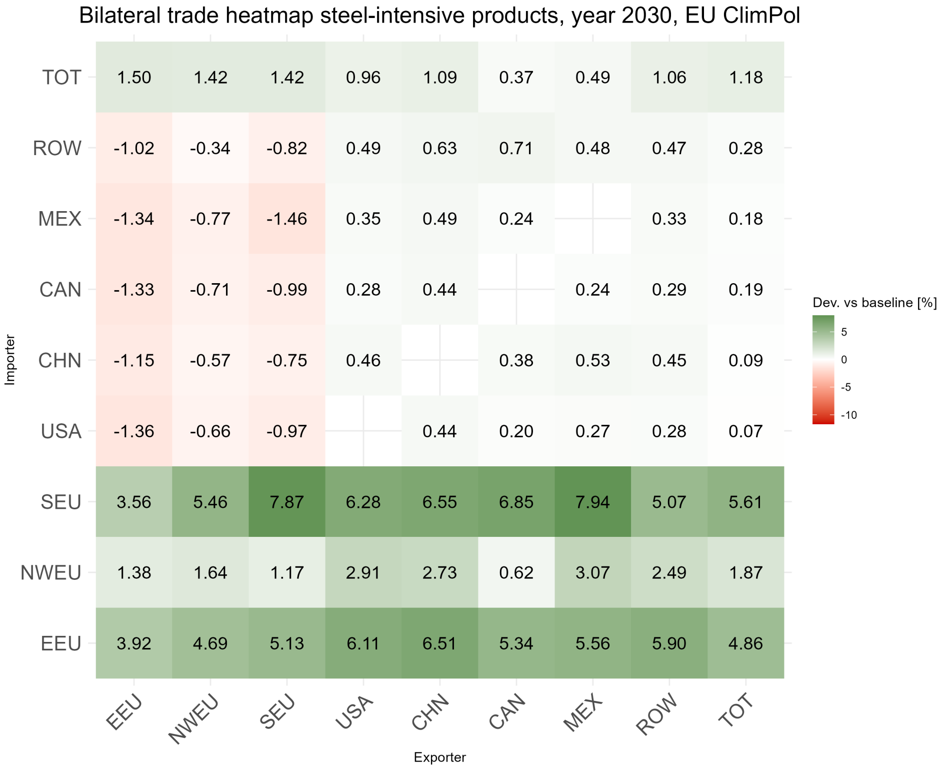

Figure C.2: *Bilateral trade deviations for steel-intensive products under EU climate policy (EU ClimPol), for year 2030, averaged over 2026-2030. The heatmap reports percentage deviations in bilateral trade flows relative to the Baseline for aggregated regions (EEU, NWEU, SEU, USA, CHN, CAN, MEX, ROW), including intra-EU macro-regional trade. Rows indicate importers and columns exporters; the final row and column ("TOT") show total imports and exports by region.*

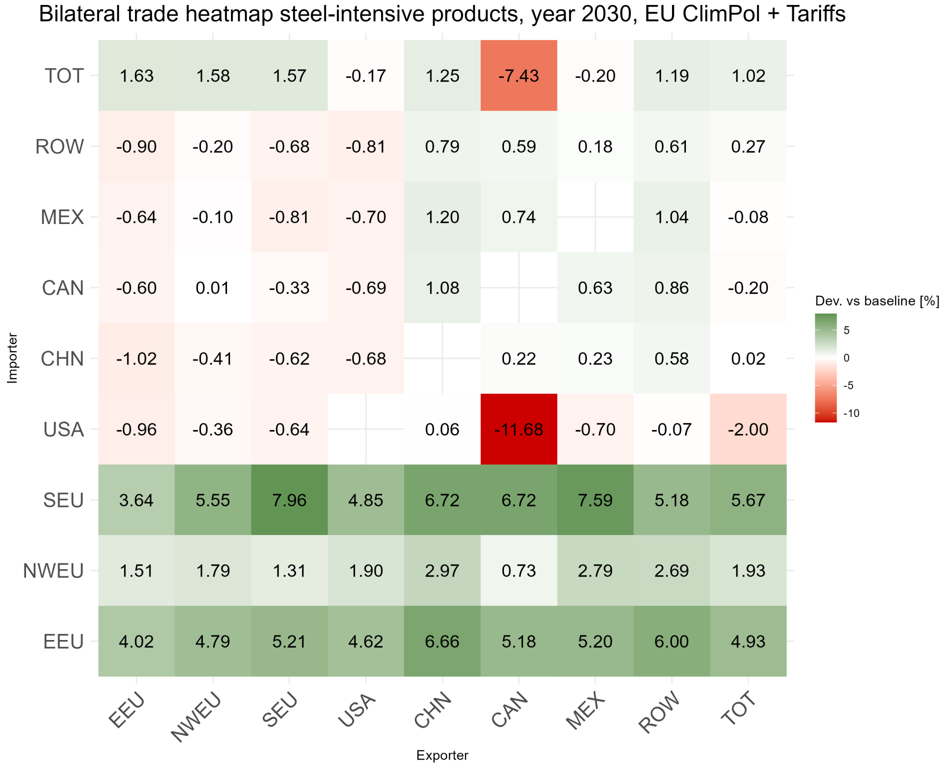

Figure C.3: *Bilateral trade deviations for steel-intensive products under EU climate policy and USA tariffs on steel implementation (EU ClimPol + Tariffs), for year 2030, averaged over 2026-2030. The heatmap reports percentage deviations in bilateral trade flows relative to the Baseline for aggregated regions (EEU, NWEU, SEU, USA, CHN, CAN, MEX, ROW), including intra-EU macro-regional trade. Rows indicate importers and columns exporters; the final row and column ("TOT") show total imports and exports by region.*

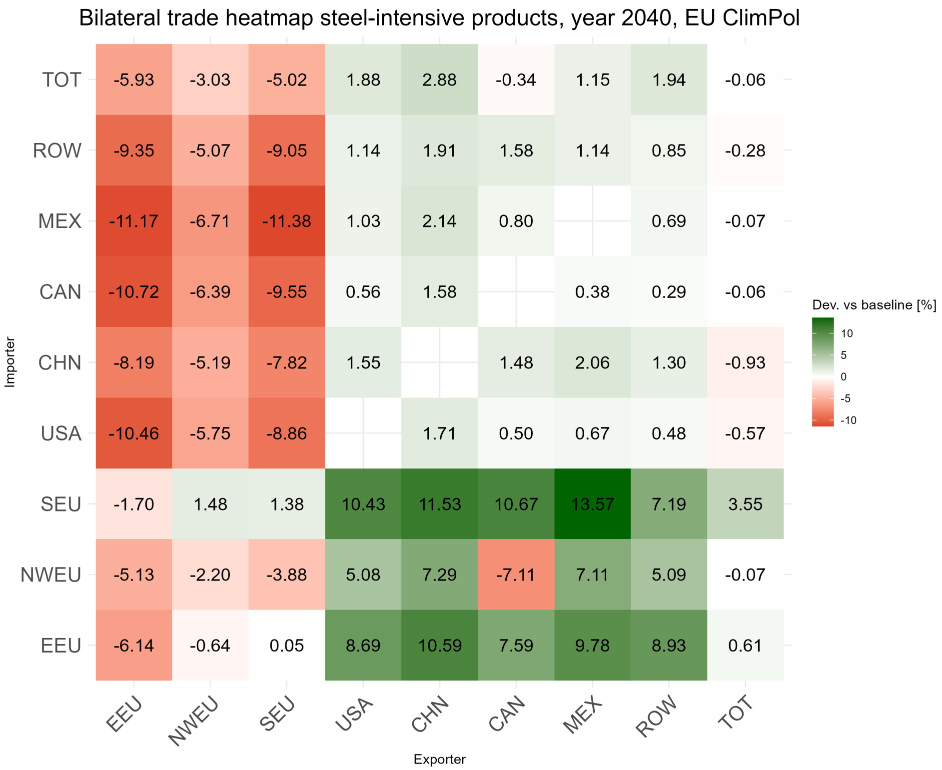

Figure C.4: *Bilateral trade deviations for steel-intensive products under EU climate policy (EU ClimPol), for year 2040, averaged over 2036-2040. The heatmap reports percentage deviations in bilateral trade flows relative to the Baseline for aggregated regions (EEU, NWEU, SEU, USA, CHN, CAN, MEX, ROW), including intra-EU macro-regional trade. Rows indicate importers and columns exporters; the final row and column ("TOT") show total imports and exports by region.*

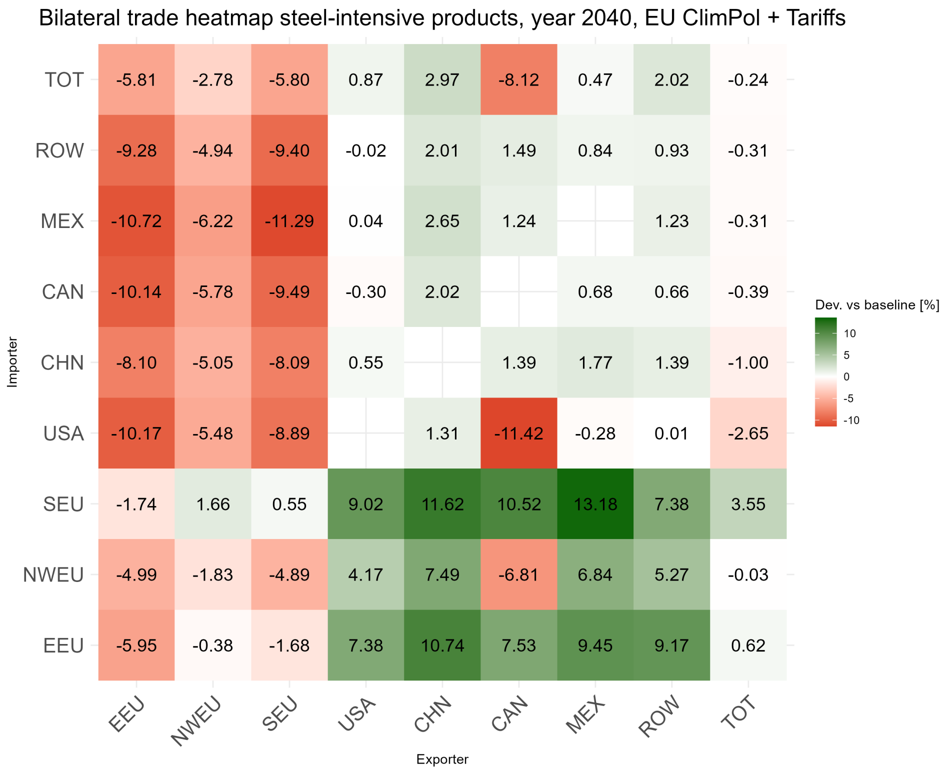

Figure C.5: *Bilateral trade deviations for steel-intensive products under EU climate policy and USA tariffs on steel implementation (EU ClimPol + Tariffs), for year 2040, averaged over 2036-2040. The heatmap reports percentage deviations in bilateral trade flows relative to the Baseline for aggregated regions (EEU, NWEU, SEU, USA, CHN, CAN, MEX, ROW), including intra-EU macro-regional trade. Rows indicate importers and columns exporters; the final row and column ("TOT") show total imports and exports by region.*

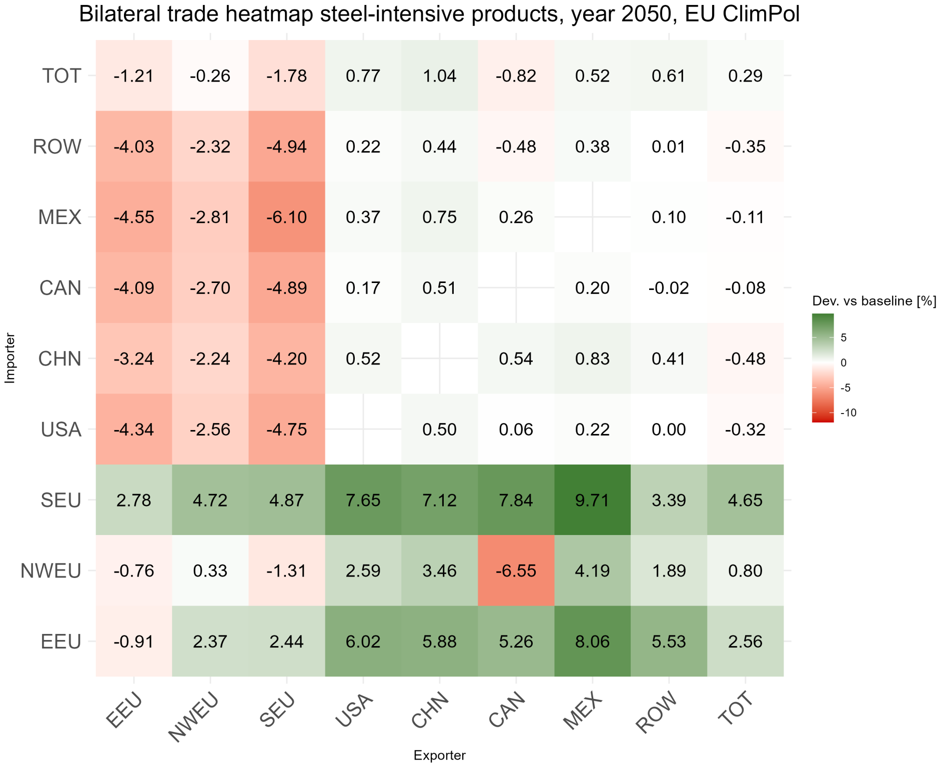

Figure C.6: *Bilateral trade deviations for steel-intensive products under EU climate policy (EU ClimPol), for year 2050, averaged over 2046-2050. The heatmap reports percentage deviations in bilateral trade flows relative to the Baseline for aggregated regions (EEU, NWEU, SEU, USA, CHN, CAN, MEX, ROW), including intra-EU macro-regional trade. Rows indicate importers and columns exporters; the final row and column ("TOT") show total imports and exports by region.*

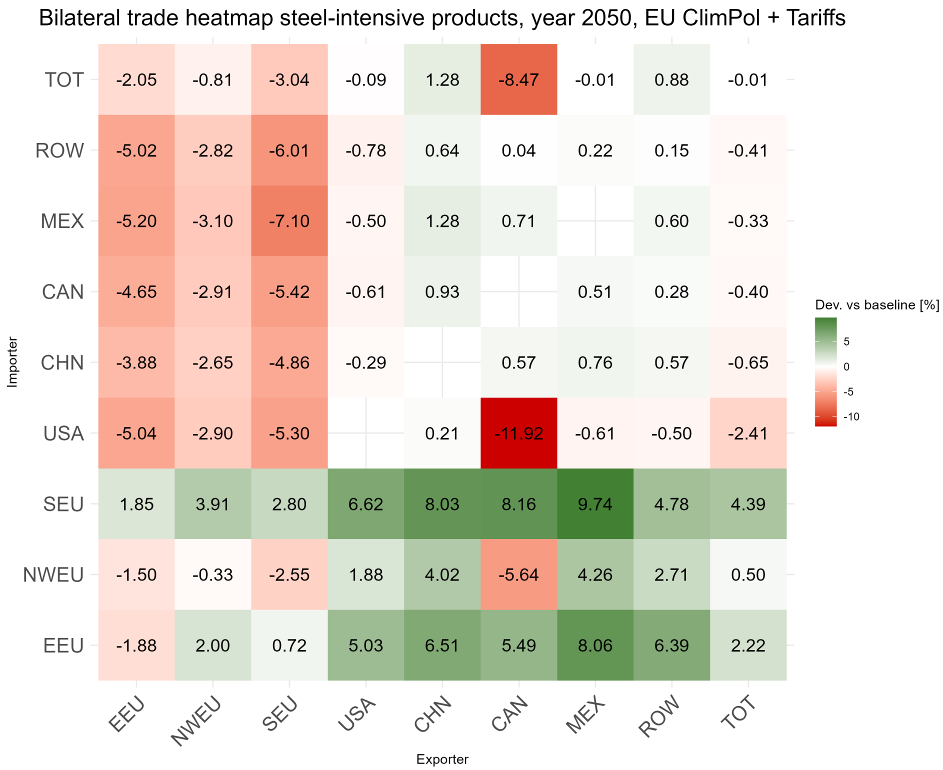

Figure C.7: *Bilateral trade deviations for steel-intensive products under EU climate policy and USA tariffs on steel implementation (EU ClimPol + Tariffs), for year 2050, averaged over 2046-2050. The heatmap reports percentage deviations in bilateral trade flows relative to the Baseline for aggregated regions (EEU, NWEU, SEU, USA, CHN, CAN, MEX, ROW), including intra-EU macro-regional trade. Rows indicate importers and columns exporters; the final row and column ("TOT") show total imports and exports by region.*

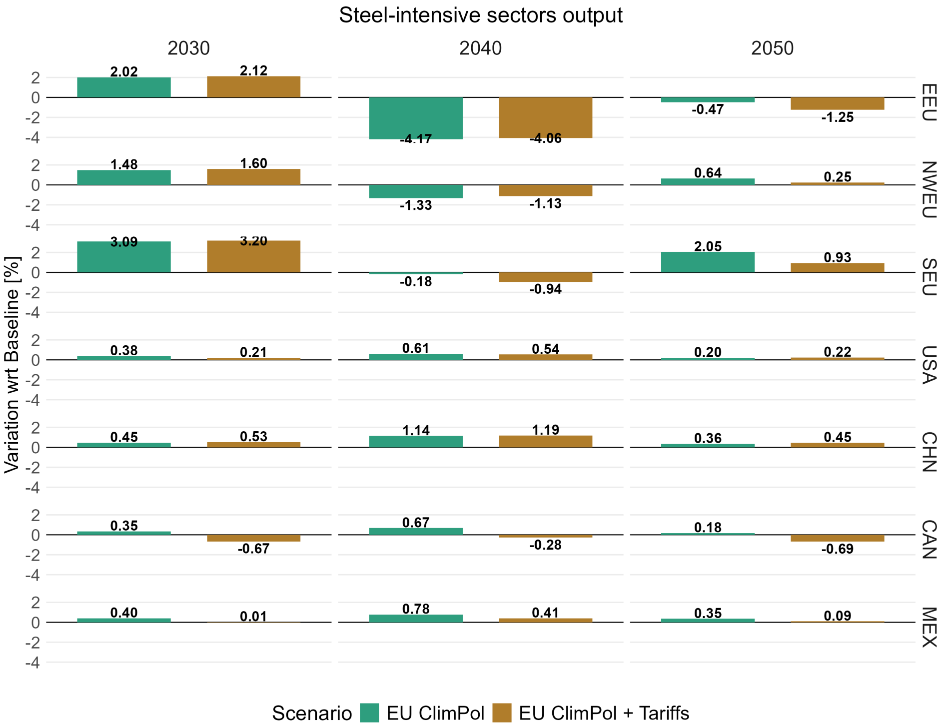

Figure C.8: *Percentage deviations in bilateral trade flows of steel-intensive products relative to the Baseline under the EU ClimPol + Tariffs scenario in 2050 (five-year average over 2046-2050). Rows denote importing regions and columns exporting regions; aggregated regions include EEU, NWEU, SEU, USA, China, Canada, and Mexico.*