MANOEUVRE

Energy System Modelling for Transition to a net-Zero 2050 for EU via REPowerEU

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Executive Summaries of Case Studies

Final Version 1.0

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List of Acronyms and Abbreviations

Term	Explanation
ABM	Agent-Based Modelling
IAMs	Integrated Assessment Models
BECCS	Bioenergy with Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
CDP	Communication and Dissemination Plan
CETP	Clean Energy Transition Partnership
CHP	Combined Heat and Power
CS	Case Study
CST	Concentrated Solar Thermal
DMP	Data Management Plan
ECEMF	European Climate and Energy Modelling Forum
EERA	European Energy Research Alliance
ESMs	Energy System Models
EU	European Union
FEC	Final Energy Consumption
IEA-ETSAP	International Energy Agency - Energy Technology Systems Analysis Program
MIBEL	Iberian electricity market
NEP	National Energy Plan
NECP	National Energy and Climate Plan
PHS	Pump Hydro Storage
PPA	Power Purchase Agreements

PtX	Power-to-X
REPowerEU	European Commission plan to phase out Russian fossil fuel imports
TES	Thermal Energy Storage
UC	Unit Commitment
VRE	Variable Renewable Energy
vRES	Variable Renewable Energy Sources
WP	Work Package

Executive Summary

Based on our preliminary findings, European energy systems across the case studies collectively show that Europe can become both self-reliant and an exporter of low-carbon energy carriers if policies and investments unlock regional strengths and the right flexibility instruments are put in place. Southern states with abundant solar energy (e.g., Portugal, Spain, Greece, Turkey) can scale renewables and electrolysis. Scandinavia's hydropower offers system-scale flexibility that stabilises high variable renewable energy (VRE) penetration, and cross-model comparisons demonstrate that combining broad, cross-sectoral modelling with detailed power-system studies reveals complementary roles for exports, seasonal storage and short-term balancing. Studies of Germany and Hungary underline the critical role of dispatchable, negative-emission options—such as bioenergy with carbon capture and storage (BECCS)—to avoid reliance on fossil backstops, while agent-based macroeconomic results show that changing global energy factor prices will reshape (not necessarily hollow out) industrial activity.

To turn these preliminary findings into a resilient, independent, and clean European energy system, policymakers should pursue a coordinated, portfolio-based strategy: **(1)** accelerate large-scale renewables and electrolyser deployment, especially in resource-rich regions in south, while simultaneously investing in export infrastructure (ports, pipelines, long-duration storage and interconnectors) and harmonised certification for renewable hydrogen and synthetic fuels; **(2)** enhance market designs and revenue-support to reduce revenue cannibalisation and ensure sufficient incentives for both generation and diverse flexibility providers; **(3)** prioritise flexibility across timescales (by leveraging hydropower, thermal storage, batteries and demand response through explicit procurement and market signals) and integrate sector coupling so surplus VRE can be stored as hydrogen or synthetic fuels; **(4)** protect and scale dispatchable low-carbon options such as sustainably sourced BECCS to preserve system security during low wind and solar periods; **(5)** align industrial policy and labour measures to capture *renewable-pull* opportunities so Europe retains value-added production; and finally **(6)** fund research and development, pilots and EU-level coordination to manage infrastructure risks and ensure equitable, timely deployment. Together, these actions would maximise renewable integration, secure clean industrial competitiveness, and strengthen European energy independence. In this report, some case studies shared their preliminary results, which are expected to be finalised in the second version of the executive summary during the first quarter of 2026. The details of each case study are as follows:

> **CS1**: This case study assesses Spain's potential to contribute to European energy self-sufficiency across three key dimensions: green hydrogen production, thermal energy storage, and industrial decarbonisation. Using the *TIMES-Sinergia* model, four energy transition

scenarios (GoRes, NECP Essentials, REPower++, and TrinityEU) were developed and compared with the *GENeSYS-MOD* model and the Spanish NECP.

Results demonstrate that Spain can become a net exporter of green hydrogen, with a positive balance of approximately 240 PJ by 2050, leveraging abundant renewable resources and an electrolysis-focused strategy. Infrastructures will play a crucial role and can constrain exports. Regarding concentrated solar thermal with thermal energy storage, modest but increasing penetration is observed in industrial sectors including construction, pharmaceuticals, and food processing. Thermal storage proves essential for extending operating hours beyond peak solar availability and reducing fossil fuel backup requirements.

CS2 (preliminary results): This case study investigates the potential of the Scandinavian energy system to contribute to the European energy transition. The case study comprises two separate analyses: one using the energy system model *TIMES* for a dataset consisting of Norway and Sweden, and another using the power system model *FanSi* with a Northern European dataset, with a particular focus on Norway. Through the energy system analysis, the study evaluates the system-wide capability for energy export from Norway and Sweden, encompassing various energy carriers and sectors. The power system analysis evaluates how different flexibility sources influence the power system, with particular emphasis on how hydropower as a stochastic energy storage solution supports VRE, and which other flexibility sources could provide this service. The findings offer new insights into the challenges of transitioning from broad, cross-sectoral models to more detailed, sector-specific analyses, and highlight how these approaches can complement and reinforce one another.

CS3 (preliminary results): This case study investigates how shifts in global energy cost structures affect the competitiveness and energy demand of Europe's energy-intensive industries. Using an agent-based macroeconomic simulation model, we explore how the transition from fossil to renewable energy inputs changes relative energy factor endowments, production costs, and industrial location patterns, a mechanism known as *renewable pulls*. Current results indicate that while energy endowment shocks alter energy prices and trigger firm relocation, these dynamics can also lead to a reorganization rather than a decline of industrial activity. Some countries experience renewed competitiveness as changing factor prices attract new production. These non-linear feedback interactions highlight that Europe's industrial landscape may adapt through specialization and restructuring rather than uniform migration. The findings underscore the need to reflect such endogenous industrial responses when estimating future energy demand trajectories in national and European energy transition scenarios.

CS4 (preliminary results): Case study 4 analyses the effect of an increasingly flexible power demand on the refinancing conditions of renewable generators in the German power sector. First results indicate that higher degrees of flexibility can contribute to the stabilisation of market values for renewable energy sources. The effect in the simulations considered so far is rather small due to revenue cannibalization among flexibility options. We find a dependency of renewable market values on the scenario and the corresponding deployment of flexibility options. However, the issue of whether sufficient investment in flexibility options is stimulated in the face of mutual revenue cannibalisation is beyond the scope of the prevailing analysis as investments are not explicitly modelled. These are taken from the capacity mix of the EU EnVis-2060 scenarios. In an updated version of the existing deliverable, we plan to extend our analyses by including further flexibility sources, scenarios and snapshot years.

CS5: In this case study, we model the German bioenergy system within the European energy system. Our analysis using *BENOPTex* shows that the expansion of renewable energy sources may lead to system instability without the presence of dispatchable energy. Because bioenergy can both generate power and remove atmospheric emissions through carbon capture and storage, it represents a promising option that should be actively promoted. In the absence of bioenergy, risk-averse policymakers may rely on fossil fuels, jeopardizing the achievement of climate targets. We also find that under conditions of low solar and wind availability, bioenergy becomes more attractive from a cost-optimality perspective, with total system costs increasing by less than 10%. Comparing the NECP and REPowerEU++ scenarios for Germany from the EU EnVis 2060 shows higher capacities of variable renewables in the NECP scenario, reflecting efforts to meet the targets. We also examine the Hungarian energy system and observe that the current National Energy and Climate Plan does not fully exploit the available bioenergy potential (as well as wind energy) and is relatively lenient in its approach to renewable integration.

CS6 (preliminary results): The aim is to examine how hydrogen-based energy storage and power conversion can support Turkey's transition to a cleaner and more flexible energy system, while also contributing to Europe's long-term climate and energy goals. The study evaluates how hydrogen can link electricity and gas networks, provide seasonal storage, and supply energy for transport, residential heating, and electric vehicle demand through integrated modelling of Turkey and Europe. Our results show that by 2050, renewable electricity supported by hydrogen systems can supply more than 60% of Turkey's total final energy use. Surplus solar and wind generation is converted into hydrogen, stored for long periods, and then used to produce electricity during winter or periods of low renewable output. This reduces fossil fuel consumption by approximately 35% compared with 2020 levels. Electrolyser capacity increases to about five gigawatts in 2035, in line with national targets, and continues toward seventy gigawatts by 2053. With this scale of clean hydrogen production, Turkey can begin exporting up to half a million tonnes (16.67 TWh) of renewable hydrogen each year to European markets. Through these outcomes, case study 6 demonstrates how integrated hydrogen pathways can strengthen energy security, reduce emissions, and deepen cooperation between Turkey and Europe.

CS7: Case study 7 examines Greece's potential to become a medium- and longer-term renewable energy hub within the European-MENA region. In this study, Greece's potential for domestic production, transportation, and (re-)export of various energy carriers, including renewable electricity, green hydrogen, synthetic fuels, and green ammonia, was assessed using the *PRIMES* model. The EnVis scenarios were used as the basis for electricity final energy demand, while hydrogen and synthetic fuel demand were endogenously calculated. Variants of the GoRES scenario were then developed, examining the impact of different levels of implementation of hydrogen and synthetic fuels (domestic use and export) and infrastructure on the total energy system. The potential of hydrogen and synthetic fuels to become critical elements of the energy system beyond 2030 was evident across all scenarios, especially in hard-to-abate sectors such as aviation, maritime transport, and certain industries. The use of synthetic fuels, particularly in scenarios where strong export is assumed, drives a significant increase in electricity demand and necessitates additional renewable capacities. This underlines Greece's capability of capitalizing on its strong renewable resources potential and solidifying its position as a major regional player in renewable fuels. The outcomes of the analysis can be considered as complimentary to the Greek NECP, emphasizing long-term strategies that are interconnected with market evolution and infrastructure developments, such as investment requirements, renewable capacity expansion and flexibility needs, planning for electrolysers, synthetic fuel production, and export infrastructure. This shift to a highly renewable-based, hydrogen-enabled energy mix is also tied to and influencing a reshaping of electricity pricing and market design, as renewable energy dominance causes a significant drop in marginal generation costs, and electricity prices are expected to significantly drop accordingly.

CS8 (preliminary results): In this case study, the last version of the French NECP has been analysed in detail and compared with the EnVis-2060 NECP Essentials v1.2 scenario. Although the total final energy values are consistent, the disaggregation per energy vectors and energy sectors shows significant deviations, in particular: (i) The consumption of the industry, residential and transport sectors are underestimated, while the power consumption for specific uses of electricity is over-estimated in EnVis; (ii) Gas consumption is overestimated, particularly in the buildings sector, until 2035 but underestimated afterwards; (iii) Coal consumption is overestimated; (iv) The power sector displays some deviations: the coal phase-out appears too late in EnVis, and the gas and oil use is overestimated. Regarding renewables, there is too much wind power and not enough PV in EnVis, compared to the NECP; (v) Finally, electrification efforts are far less ambitious in EnVis than in the NECP. Updates to the GENeSYS-MOD input dataset have been proposed and discussed. The power system *plan4res* model has then been used to simulate in depth the EnVis NECP Essentials scenario for the year 2030.

CS9 (preliminary results): In this case study, the last version of the Portuguese NECP 2030 is analysed in detail and a series of simulations was carried out to assess the impact of different flexibility solutions. Using the *Dispa-SET* dispatch model, simulations were performed to evaluate the hourly operation of the power system, capturing demand variations, renewable generation profiles, and the role of stationary storage, sector-coupling and demand-side flexibility. The results highlight that demand flexibility is the most effective measure for maximising renewable integration, enabling renewable penetration up to 97.8% and significantly reducing curtailment. The increase of battery storage provides only limited gains and rigid hydrogen demand can reduce system efficiency. Reliability and system costs are closely related with the type of flexibility and scale. Batteries reduce frequent small deficits, hydrogen electrolysers reduce curtailment if sufficiently large, and demand flexibility lowers the costs, although deficits can occur. These deficit events occurred during the evening peak, emphasizing the need to enhance the flexible solutions with predictable daily demand and, in practice, to allow conventional power plants to operate outside optimal dispatch conditions as assumed in the simulations to ensure system security. These insights show that achieving the ambitious 2030 NECP renewable targets is technically feasible if the system flexibility is carefully planned and deployed.

Content

Introduction

This report includes nine case studies from various countries. Each case study addresses a question from a regional perspective while considering the general assumptions of the consortium through established scenarios. Although the case studies provide detailed insights within their respective regions, they have limited visibility of systems outside their boundaries. To address this, monthly "jour fixe" meetings were held, during which partners exchanged information, shared their results, and integrated regional findings into the European energy optimisation model (GENeSYS-MOD). We follow a consistent reporting format across all case studies, allowing readers who are interested in a specific region or question to skip other cases without losing essential context.

Iberian Region:

Case study 1: Feasibility assessment of green H_2 and thermal energy storage in Spain.
Case study 9: Power market modelling of Spain and Portugal

Nordic Region:

Case study 2A: Modelling Norwegian and Swedish energy export to facilitate the European low-carbon transition.

Case study 2B: Stochastic modelling of the Nordic power system.

Central Europe:

Case study 3: Global competitiveness and the energy demand of the energy-intensive industry

Case study 4: The role of growing demand in refinancing renewables.

Case study 5: Soft-linking BENOPTex and GENeSYS-MOD (Germany)

Case study 8: Green transition in France

Mediterranean Region:

Case study 6: Integrating electricity and gas network supported by energy storage and power conversion processes

Case study 7: Greece as a renewable energy hub

Case study 1: Feasibility assessment of green H_2 and thermal energy storage in Spain

Case Study 1 explores Spain's energy potential across three key dimensions with the aim of contributing to Europe's energy self-sufficiency. First, it assesses **whether Spain can ensure a sufficient supply of renewable resources**—particularly solar and wind energy—to produce large volumes of green hydrogen and become a net exporter to Europe. **Second, it analyses the role of Spain's current thermal storage capacity**—6.7 GWh in its concentrated solar thermal power plant fleet, with plans to expand to 60 GWh by 2030—as a long-term energy storage solution. **Third, it investigates the potential of using heat from concentrated solar thermal energy to decarbonize the industrial sector**, while considering current limitations such as high investment costs and low achievable solar fractions. All these assessments are carried out using the **TIMES-Sinergia** model to identify cost-efficient solutions for the production, storage, and export of renewable energy.

1.1. Accomplished Tasks

Task 1.1 – Improvement of Technology Modelling in the TIMES-Sinergia Framework. This task has focused on enhancing the modelling of technologies within the TIMES-Sinergia model via a thorough review of industrial sector demands for heat and hydrogen, updating the model accordingly, and introducing and characterizing new technologies that were previously not included, in order to realistically and accurately represent the Spanish energy system. For the solar heat and thermal storage component, the company SOLATOM provided valuable data and technical insights to support the modelling of solar thermal technologies and heat storage

Task 1.2 – Adaptation of the Man0EUvRE Project Input Data to the TIMES-Sinergia Model. This task has entailed adapting the input data from the Man0EUvRE project to the structure and requirements of the TIMES-Sinergia model. We conducted an in-depth review and developed a methodology to manage and integrate the data provided by WP2, both in IAMC format and in its native form—the latter being more suitable for integration into TIMES. An Excel-based script was developed to map the technologies and facilitate the adaptation of the dataset to the TIMES-Sinergia framework.

Task 1.3 – Analysis of GENeSYS-MOD Results and Comparison with the Spanish NECP. In this task, we analysed the output of the GENeSYS-MOD model and compared it with the objectives and projections outlined in Spain’s National Energy and Climate Plan (NECP). The goal was to assess how well the modelled pathways align with national targets for emissions reduction, renewable energy deployment, and sectoral transformation. Insights from this comparison were used to refine input data and adjust modelling assumptions, particularly in key sectors such as industry, transport, and power generation. This feedback loop has improved consistency with policy frameworks and increased the reliability of subsequent scenario analyses.

Task 1.4 – Scenario Development. In this task, we designed and created a set of energy transition scenarios within the TIMES-Sinergia model using the latest version of the input data and GENeSYS-MOD results provided by WP2. The four Man0EUvRE scenarios were created: GoRes, NECP Essentials, REPower++ and TrinityEU, reaching the project objectives. These scenarios reflect different pathways for the Spanish energy system, based on varying assumptions related to technology deployment, policy frameworks, renewable resource availability, and investment costs. They are aligned with the overarching goals of the Man0EUvRE project, exploring Spain’s potential role in contributing to a decarbonized and energy-independent Europe.

Task 1.5 – Scenario Analysis. This task focused on analysing the scenarios developed in Task 1.4, with an emphasis on evaluating the techno-economic feasibility and system-wide impacts of various decarbonisation strategies, particularly those involving green hydrogen production, thermal energy storage, and industrial sector decarbonisation. The analysis identified key trade-offs, synergies, and policy implications, offering insights into the most effective pathways for Spain's energy transition.

Task 1.6 – Comparison with GENeSYS-MOD Results. Finally, in the last task of CS1 in WP3, we conducted a comparative analysis between the results generated by the TIMES-Sinergia model and those obtained from the GENeSYS-MOD model. The comparison focused on key indicators such as electricity generation and renewable energy deployment, hydrogen production and exports, storage capacity utilisation, and emissions reduction. The goal was to identify consistencies and divergences between the two modelling approaches and to improve the robustness and credibility of the overall findings through cross-model validation.

1.2. Planned impact

Spain has the potential to play a strategic role in the future European energy system, not only as a leader in renewable electricity production but also as a key exporter of green hydrogen and provider of long-duration thermal storage solutions. With abundant solar and wind resources, as well as a growing fleet of concentrated solar thermal plants with storage capabilities, Spain could become a central hub for clean energy generation and cross-border energy support. However, realizing this potential requires a deep understanding of national dynamics—such as industrial energy demand, infrastructure limitations, storage capacity, and technology deployment strategies—that are often oversimplified in broader European energy models.

This case study aims to deliver a more realistic and granular representation of the Spanish energy system under multiple transition scenarios, considering detailed modelling of the industrial sector, hydrogen production, and thermal energy storage. By combining the strengths of the TIMES-Sinergia and GENeSYS-MOD models and aligning the outputs with Spain's NECP, this CS helps identify robust and cost-effective pathways toward decarbonisation.

The results of this research will be highly valuable to stakeholders and decision makers involved in the development of national strategic plans, including NECPs, long-term energy strategies, and sector-specific roadmaps. The insights generated will support evidence-based policy design, inform investment priorities in infrastructure and innovation, and contribute to a more coordinated and resilient European energy transition. Furthermore, the case study will highlight the importance of Spain's role in the regional energy landscape, particularly in enabling energy independence and climate neutrality goals at the European level.

1.3. Implementation

1.3.1. Challenges

One of the main challenges in this project arises from the structural differences between the GENeSYS-MOD and TIMES-Sinergia models, which make direct data exchange unfeasible. As a result, input and output data must undergo a thorough aggregation or disaggregation process to match the format and resolution required by each model. This issue is particularly pronounced in the industrial sector, where TIMES-Sinergia provides a much more detailed and technology-specific representation compared to GENeSYS-MOD.

In addition, the complexity and inherent assumptions of both models mean that not all parameters can be fully harmonised. This may lead to discrepancies in results and requires careful interpretation when comparing outcomes across scenarios. Last version of the input dataset, version 1.2, has been used to run the Spanish model, and the last version of GENeSYS-MOD result, version 1.2, have been used both as input and for scenario comparison.

1.3.2. Mitigation Measures

Efforts have been made to align the most influential parameters—such as technology costs, fuel prices, and emissions factors—to ensure a meaningful and consistent comparison. Another layer of complexity is added by differences in temporal resolution, which must be addressed through a consistent mapping methodology. A demand adjustment was made to reflect the different narratives of the scenarios, since TIMES-Sinergia has very detailed demand curves, and the input data had low resolution in that respect. Ultimately, the aforementioned challenges highlight the importance of developing robust methodologies for cross-model integration and validation to strengthen the reliability of the project's findings. Therefore, to guarantee consistency, an Excel script was used to do the mapping between TIMES-Sinergia and Man0EUvRE input data to build the four Man0EUvRE scenarios: GoRes, NECP Essentials, RePower++ and TrinityEU.

1.4. Results

1.4.1. Outcomes

In this section we present the results of the four energy transition scenarios developed using the TIMES-Sinergia model compared with the results generated by the GENeSYS-MOD model for Spain and some key insights in the research questions of this case study: whether Spain can ensure a sufficient supply of renewable resources to produce large volumes of green hydrogen and become a net exporter to Europe, and the potential of using heat from concentrated solar thermal energy an thermal storage to decarbonize the industrial sector.

Electricity production

The evolution of the Spanish power sector composition from 2025 to 2050 across the four energy transition scenarios is illustrated in Figure 1.1, comparing the outputs of TIMES-SINERGIA, GENeSYS-MOD and the Spanish NECP (PNIEC). Overall, the two models display a consistent picture regarding the long-term role of renewable energy technologies and the gradual phase-out of fossil and nuclear-based generation. This convergence indicates a robust agreement on the main structural trends of the Spanish power system transformation.

In addition, both models are in broad agreement regarding the total amount of electricity generated over the period, showing similar trajectories of increasing electricity demand and supply up to 2050. This consistency in overall electricity production levels further supports the robustness of the modelling results, indicating that the main differences arise not from the scale of power generation, but rather from the technology mix chosen to meet this growing demand.

Both models also agree on the overall balance between variable renewable generation (i.e., wind and PV) and dispatchable capacity, ensuring system reliability in the long-term. However, their technological preferences within the dispatchable portfolio diverge: GENeSYS-MOD tends to prioritise biomass and hydropower, whereas TIMES-SINERGIA assigns a more prominent role to concentrated solar power (CSP) and natural gas.

These differences highlight the importance of cross-model comparisons, as they reveal the uncertainties associated not only with the scale of variable renewable deployment but also with the choice of complementary dispatchable technologies under alternative transition pathways.

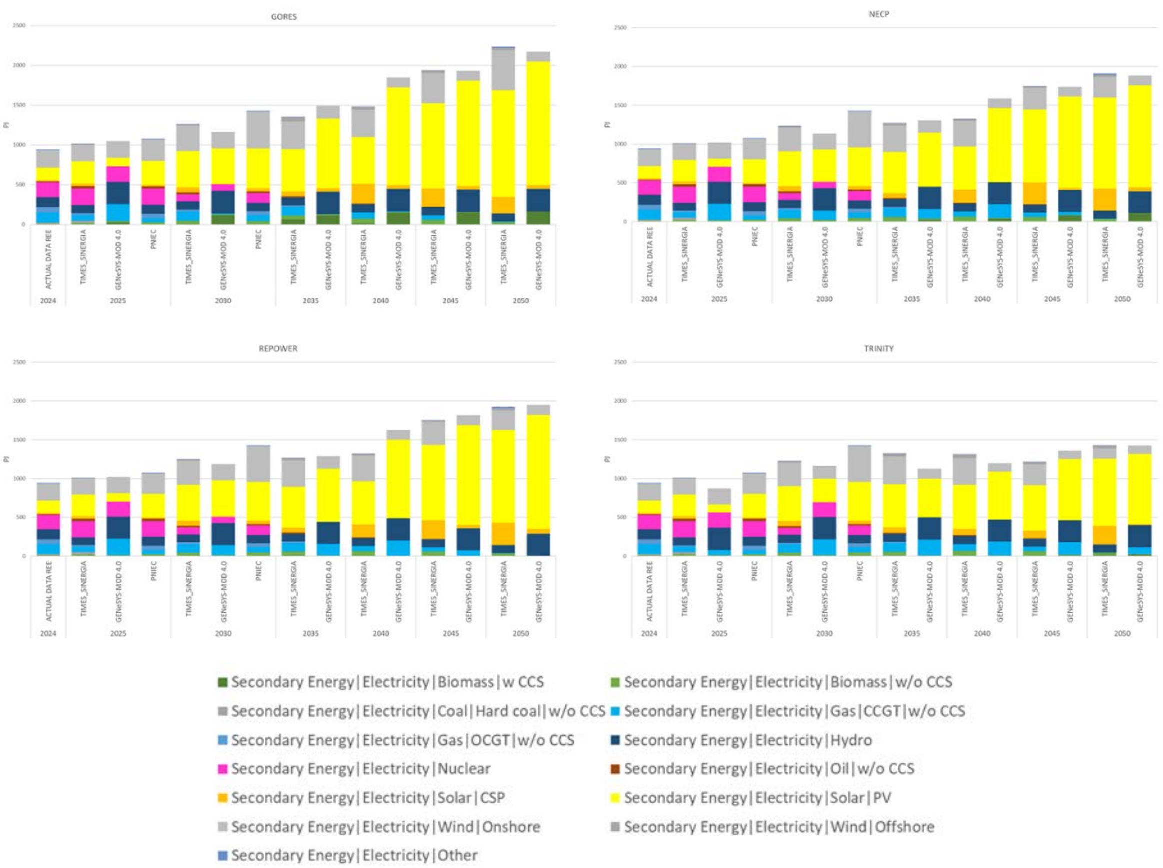


Figure 1.1. Evolution of the Spanish power sector composition from 2025 to 2050.

Hydrogen production and export potential

Figure 1.2 shows the balance of hydrogen production and consumption in Spain from 2030 to 2050 under the four Man0EUvRE transition scenarios in TIME comes from power generation, refineries, and residential uses, blended into demand grows steadily, driven primarily by the industry and transport sectors, while additional contributions appear from power generation, refineries and residential uses, blended in the gas grid. On the supply side, electrolysis dominates the production mix, complemented by SMR and solar SMR. A common feature across all scenarios is the increasing reliance on hydrogen to provide flexibility and decarbonisation across sectors, confirming its role as a central energy vector in the Spanish transition.

Despite differences in ambition and technological detail, the four scenarios display a broadly similar evolution, with TRINITY showing lower ambitions. By 2050, all pathways converge towards substantial net hydrogen production, with a positive balance of around 240 PJ. This indicates that domestic supply systematically exceeds internal demand, and positions Spain as a potential exporter of green hydrogen. The convergence across scenarios highlights the robustness of this result: regardless of the specific policy or market pathway, Spain's abundant renewable resources provide favourable conditions for competitive large-scale hydrogen production through electrolysis.

However, this export potential is not unlimited: the effective volumes are constrained by the planned H_2med corridor, which by 2030 is expected to reach a maximum capacity of around two million tonnes of hydrogen per year. This underlines the crucial role of infrastructure development in determining the scale of Spain's contribution to the European hydrogen market.

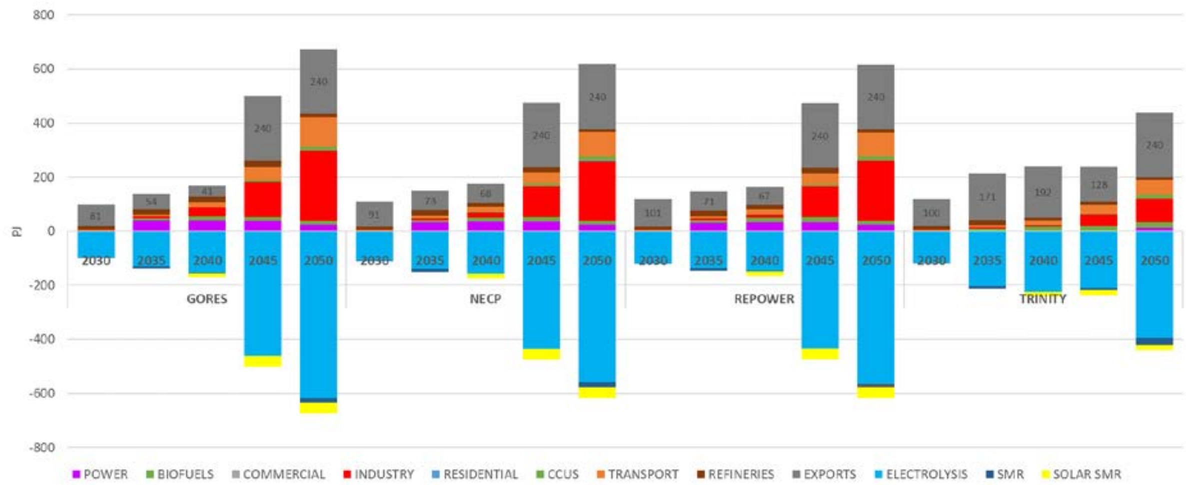


Figure 1.2. Hydrogen production and consumption in Spain (2030–2050) across the four TIMES-SINERGIA transition scenarios. Bars above zero show end-use demand by sector; bars below zero show domestic production by technology.

Based on Figure 1.3, results from TIMES-SINERGIA and GENeSYS-MOD differ in the ambition and technology with regards to H_2 production. Compared with GENeSYS-MOD v1.2, TIMES-SINERGIA reproduces the scenario ranking but diverges in the timing and scale of hydrogen deployment. GENeSYS-MOD projects substantially higher volumes in 2040, notably in NECP and REPOWER (≈3–4 times TIMES-SINERGIA), reflecting more target-driven pathways and lower adoption frictions. By 2050, trajectories converge: TIMES-SINERGIA matches or exceeds GENeSYS-MOD in GORES, NECP, and REPOWER, while TRINITY remains lower. Overall, Spain's hydrogen potential appears robust, while the pace of deployment can vary.

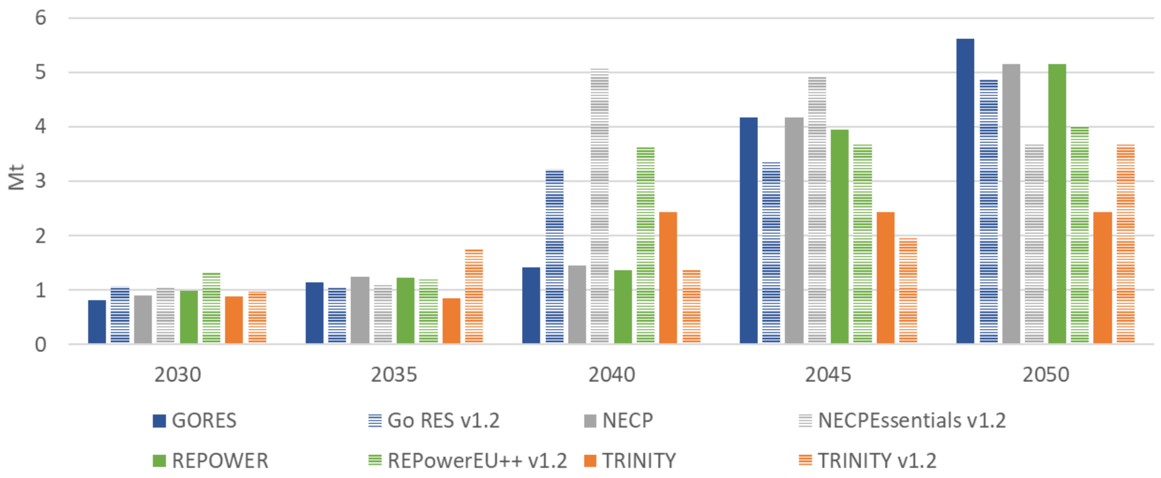


Figure 1.3. Domestic hydrogen production in Spain (2030–2050) by scenario and model. Solid bars show TIMES-SINERGIA results (GORES, NECP, REPOWER, TRINITY); striped bars show the corresponding GENeSYS-MOD v1.2 benchmarks (GoRES, NECPEssentials, REPowerEU++, TRINITY v1.2).

As shown in Figure 1.4, in terms of technology selection and in all scenarios, GENeSYS-MOD uses a broader technology mix (including SMR/ATR+CCS). In contrast, TIMES-SINERGIA concentrates supply in electrolysis tightly coupled to variable renewables.

Figure 1.4. Hydrogen balance by technology (production, <0) and end uses (≥0), 2030–2050. Stacks below zero show production by technology (Electrolysis, SMR), while stacks above zero show uses (Exports, Power, CCUS, Other uses).

In scenario GORES, GENeSYS-MOD shows a higher net balance already by 2040, supported by a mixed supply (electrolysis plus some ATR/CCS). TIMES-SINERGIA accelerates after 2040 and becomes clearly larger by 2045–2050, almost entirely electrolysis-led. This is consistent with the capacity chart: ~73 GW electrolyzers in TIMES vs ~45 GW in GENeSYS by 2050 as shown in Figure 1.5.

The same pattern holds in scenario NECP with slightly lower ambition: GENeSYS-MOD is ahead in 2040, whereas TIMES-SINERGIA overtakes by 2050, driven by electrolysis. Implied capacities: ~64 GW (TIMES) vs ~17 GW (GENeSYS) in 2050 as shown in Figure 1.5.

With the highest ambition, GENeSYS-MOD's REPOWER scenario again ramps earlier (notable exports by 2040 with support from SMR/ATR-CCS), while TIMES-SINERGIA concentrates growth after 2040 and dominates by 2050 on an electrolysis-only pathway. Electrolyzer capacities in 2050: ~69 GW (TIMES) vs ~24 GW (GENeSYS-MOD) as shown in Figure 1.5.

Under lower ambition, in TRINITY scenario, both models yield smaller volumes, but the technology split differs most: GENeSYS-MOD maintains a visible SMR/ATR-CCS role through 2050 and therefore needs ~24 GW of electrolysis, whereas TIMES-SINERGIA, relying mainly on electrolysis, requires ~44 GW to meet its end-period balance.

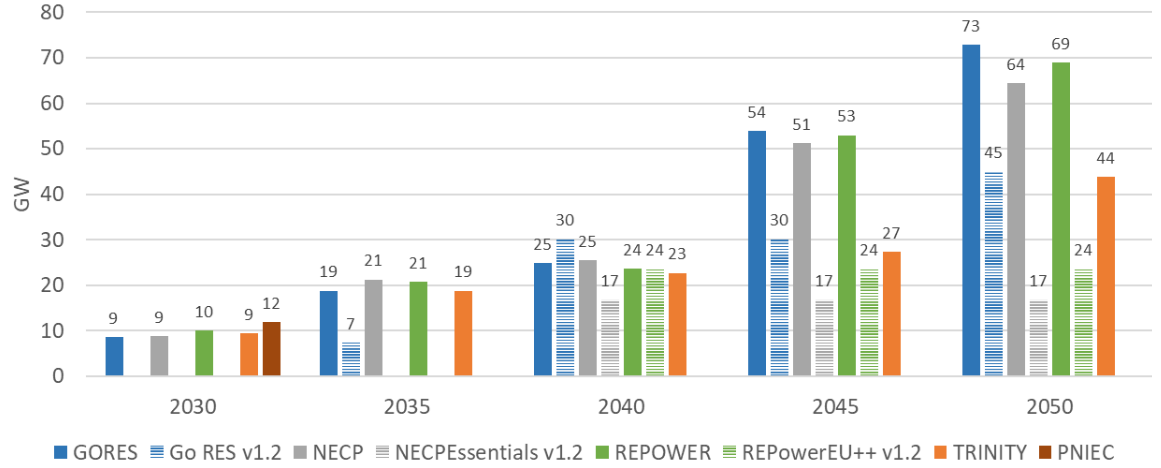


Figure 1.5. Electrolyser capacity in Spain (GW, installed), 2030–2050. Solid bars are TIMES-SINERGIA (GORES, NECP, REPOWER, TRINITY); hatched bars are the corresponding GENeSYS-MOD v1.2 benchmarks; the brown bar marks the PNIEC 2030 reference.

For Spain, ATR with CCS is not a strategic option: the country lacks domestic natural gas resources, and large-scale CO_2 capture, transport and storage is not a policy priority. By contrast, Spain's abundant renewable potential (wind and solar) makes electrolysis the natural cornerstone for low-cost, scalable hydrogen. An electrolysis-centric pathway also aligns better with power-system decarbonisation, enabling flexible absorption of variable renewables and reducing import dependence. The model comparison is therefore consistent with national strengths: TIMES-SINERGIA's electrolysis-heavy buildout reflects a pathway that is both technically coherent and strategically sound for Spain.

Potential of using solar heat to decarbonize the industrial sector

In collaboration with SOLATOM—manufacturer of Concentrated Solar Thermal (CST) heat and thermal energy storage (TES)—we assess the potential of medium-temperature solar heat (≈120–300 °C) in Spanish industry. We focus on pharma, construction, food, beverage & tobacco, and textile & leather, which exhibit the highest medium-temperature heat demand. The technology is represented with primary performance and cost data from SOLATOM. The solar field can either (i) deliver process heat directly or (ii) charge a TES unit for deferred use. The optimisation takes hourly industrial demand profiles and solar availability as inputs, allowing the model to decide when to produce or store heat to minimise system costs/emissions subject to operational constraints.

As shown in Figure 1.6, CST achieves modest but increasing penetration in the target sectors across all transition scenarios. Initial limited penetration reflects competition with dispatchable and non-variable options, such as coal and light fuel oil. As emission reduction targets become more stringent, solar heat increases its market share alongside the transformation of high-temperature heat (first from gas combined heat and power (CHP) systems and then from biomass CHP systems) into medium-temperature heat.

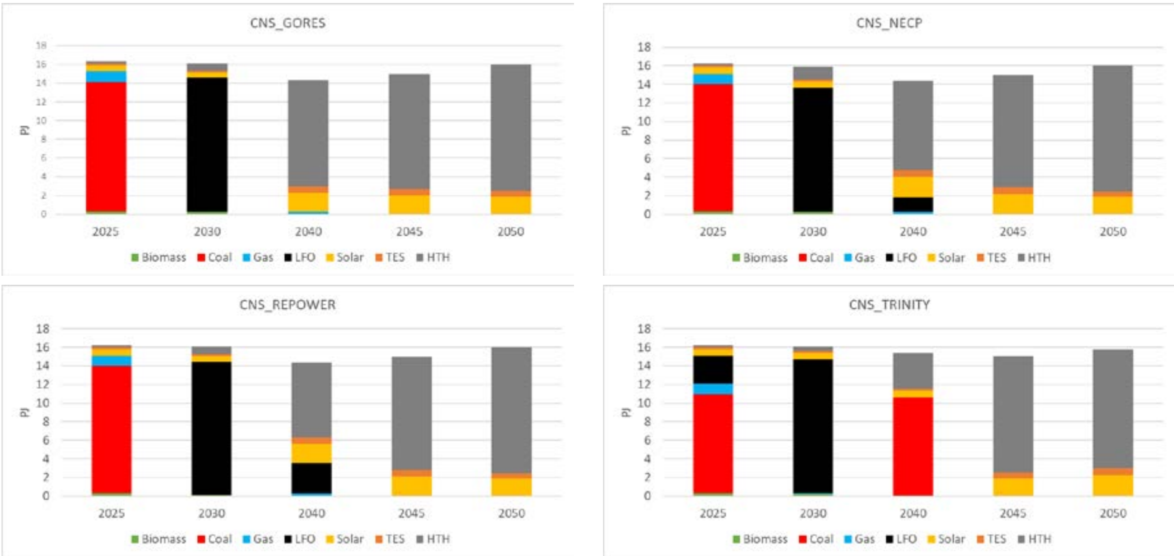


Figure 1.6. Penetration of CST with thermal storage in the construction sector across all the transition scenarios.

The role of the storage system is pivotal in the penetration of solar heat as it extends operating hours beyond sunset, smooths intraday variability, and reduces auxiliary fossil backup. Uptake is driven by (a) good coincidence between solar resources and daytime process loads, (b) the ability of TES to shift heat into late afternoon/evening hours.

Figure 1.7. illustrates the typical operating pattern of the system. As an example, we show the behaviour of the system in the construction sector in 2050 and in the GoRES scenario. Around midday (hours 10–14), the solar field reaches its production peak (yellow). Some part is directed to the TES unit (grey), which is mainly charged from late morning to early afternoon. As solar irradiance decreases towards the end of the day, the stored heat is progressively discharged (orange), allowing the system to continue supplying useful thermal energy during the late afternoon and evening hours, even after sunset.

The same operating pattern can be observed throughout the different seasons, although with variations in intensity. In winter, solar output peaks are lower and more concentrated around midday, limiting the amount of heat available for storage. By contrast, in summer the solar field produces higher and more sustained outputs, resulting in broader production plateaus that extend over several hours. During these periods, the thermal storage system plays a more active role: it is charged more frequently and discharged later in the day, enabling the system to shift solar heat production from the hours of maximum irradiance to the evening demand.

The consistent presence across scenarios indicates robustness to broader system assumptions. Priority use-cases are sites with (i) daytime-weighted loads, (ii) contiguous roof/ground area for collectors, (iii) tolerance for 120–300 °C heat integration, and (iv) space for TES tanks near points of use.

Figure 1.7. Typical operating pattern of the CST heat and TES systems.

1.4.2. NECPs

Electricity production in TIMES-SINERGIA aligns quite well with the NECP, with slightly lower shares on wind and PV and total electricity production of the system, as shown in Figure 1.1. In contrast, GENeSYS-MOD shows less electric production with a lower presence of PV al wind power.

Regarding hydrogen production, the Spanish NECP set an ambitious objective for electrolyser capacity (12 GW) in 2030, slightly higher than the results of TIMES-SINERGIA (10 G W). GENeSYS-MOD results show a capacity of 7 GW in 2030 and only in GORES scenario as shown in figure 1.5. For Solar heat and thermal storage, the Spanish NECP doesn't specify any minimum capacities or other objectives.

1.4.3. Supplementary Data

To incorporate GENeSYS-MOD parameters into our model, as a first step, we constructed a dictionary establishing the correspondence between the technology names used in GENeSYS-MOD and those included in the TIMES-SINERGIA model.

We developed four scenario files and included them in the model runs to generate results for the four Man0EUvRE scenarios. Each file contains input data from GENeSYS-MOD:

- Investment costs
- Fixed O&M costs
- Variable O&M costs
- Efficiencies

GENeSYS-MOD emission results were also used as inputs and embedded in the scenario files.

Three additional files were created to capture differences in energy-service demand across the Man0EUvRE scenarios by varying the GDP growth used to project the demands computed in TIMES-SINERGIA. NECP and REPOWER use the central GDP-growth case, while GORES and TRINITY use the high- and low-growth cases, respectively.

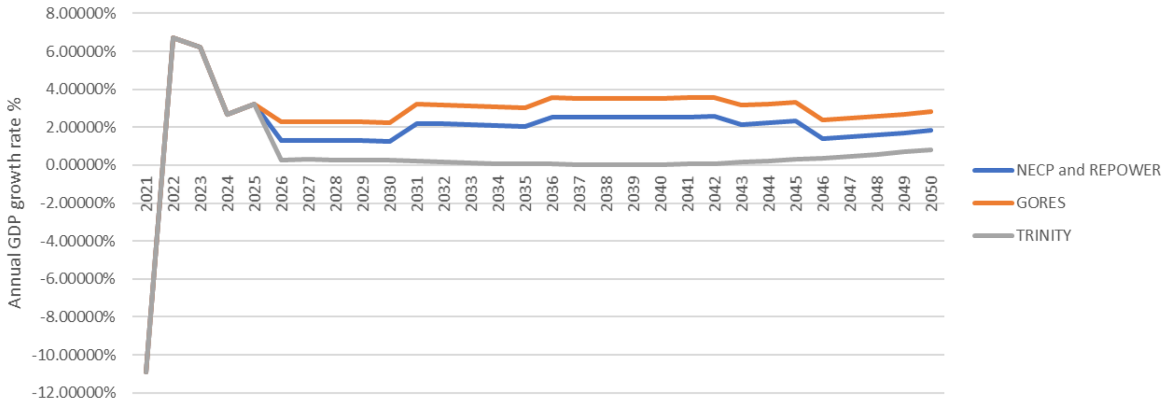


Figure 1.8. GDP growth evolution considered in the four MAN0EUvRE scenarios

The last version of GENeSYS-MOD results was used for scenario comparison and as input for TIMES-SINERGIA model. You can find them in: https://github.com/carlosmantillaciemat/Man0EUvRE.git

Case study 2: Modelling the ability for Norway and Sweden to support European low-carbon transition

This case study investigates the potential of the Scandinavian energy system to contribute to the European energy transition. The analysis is conducted in parallel with two models: TIMES-NOSE and FanSi. First (**Part A**), the study evaluates the system-wide capability, encompassing various energy carriers and sectors. Second (**Part B**), focuses on the power sector, with particular emphasis on hydropower as a stochastic energy storage solution supporting VRE. The findings offer new insights into the challenges of transitioning from broad, cross-sectoral models to more detailed, sector-specific analyses, and highlight how these approaches can complement and reinforce one another.

Part A: Modelling Norwegian and Swedish energy export to facilitate the European low-carbon transition using TIMES models

This case study quantifies the energy export opportunities from Norway and Sweden towards 2050 that are aligned with European needs. It includes the corresponding investments and operation of energy infrastructure, as well as implications for the energy system. The analysis examines various energy pathway scenarios, exploring how national industry development, shaped by technology maturity, policy frameworks, competitiveness and resource availability, affects export potentials. The scenarios range from high electrification and hydrogen production for new industries to large-scale energy exports supporting European decarbonisation. The supply of electricity large depends on uncertain factors, such as public acceptance of onshore wind and nuclear power, deployment of building applied PV and building mass upgrades, establishment of new energy-consuming industries (e.g., battery factories and data centres) and the pace of industrial electrification. The analysis explores the interplay between offshore wind power, hydrogen, new power intensive industries. For example, offshore wind can contribute to meet the REPowerEU target through electricity export directly to the European market, whereas another option is to use the electricity domestically to produce hydrogen or to serve new power intensive industry.

2A.1. Accomplished Tasks

Task 2A.1 – Industry scenarios: In this task, we developed various industry scenarios exploring how the green transition of energy-intensive industries in Norway and Sweden may unfold toward 2050. These scenarios capture uncertainties related to immature technologies, policy and regulatory frameworks, international competitiveness, and the availability of energy resources. They lay the foundation for the upcoming scenario analysis, which will provide deeper insights into different decarbonisation pathways for industry and their potential implications for the wider energy system. The scenarios are documented in a report (see Section 2A.4.3) that presents current energy use, future plans, and greenhouse gas emissions from industry, along with the storylines for future developments and the underlying rationales.

Task 2A.2 – Model extensions: In this task, the required model extensions are implemented to capture the necessary level of detail in the Norwegian and Swedish energy systems, with a particular focus on the industry sector and the modelling of hydrogen. This includes a more detailed spatial resolution for both countries, covering all price zones as well as potential offshore wind regions. The model structure for the industry sector will be enhanced to better represent different decarbonisation options. Furthermore, the hydrogen modelling is improved to include production technologies, compression, storage, trade, and end-use.

Task 2A.3 – Model coupling and parameterisation: To ensure consistency with the EU EnVis-2060 scenarios defined in the overall project, this task focuses on parameterization and alignment with the scenario data from WP2. Input parameters that have been harmonised and aligned includes technology parameters for renewable production technologies, e.g., onshore and offshore wind, building applied and utility PV, as well as parameters for hydrogen production. Additionally, assumptions regarding cross-border energy trade have been aligned with the storylines. Moreover, in the second version of this report, TIMES-NOSE uses scenario-specific energy prices for neighbouring countries from GENeSYS-MOD and EMPIRE, including prices for CO_2, electricity and hydrogen. Due to the different temporal resolutions of the models, the output data will be processed and adjusted to ensure compatibility with the TIMES-NOSE framework.

Task 2A.4 – Scenario analysis: In this task, the TIMES-NOSE model is applied. The scenario analyses are based on the industry scenarios developed in Task 2A.1, as well as the harmonisation with GENeSYS-MOD and EMPIRE from Task 2A.3. The analysis provides insights into the future development of industry in Norway and Sweden, and how both countries can contribute to the energy transition in Europe. The latter includes the trade of various energy commodities, such as electricity, hydrogen, and e-fuels. Task 2A.4 employs various industry pathways for the Norwegian and Swedish industry for two of the Energy vision scenarios, GoRES and Trinity. The selection of the scenarios is based on the criteria that they provide different European framework conditions, offering a larger range for energy requirements and technology developments. This diversity ensures that the case study captures the uncertainty and variability in future European energy system developments.

Task 2A.5 – Comparison with GENeSYS-MOD results: In order to strengthen the creditability of the findings, the results from the TIMES-NOSE model were compared to those from GENeSYS-MOD, for Norway and Sweden. The comparison focused on key indicators such as electricity and hydrogen production, demand and exports for the two scenarios: GoRES and Trinity. Emission reductions within Norway and Sweden were also compared. The aim was to reveal both converging trends and discrepancies, and to provide feedback to GENeSYS-MOD on representation of the Norwegian and Swedish energy system. The outcomes and methodology from the case study will be published in a separate peer-reviewed paper.

2A.2. Planned impact

Norway and Sweden both have a crucial role in providing clean and stable electricity to the European energy system. With vast hydropower resources, Norway and Sweden act as a green battery for Europe, being a net exporter of surplus electricity to stabilise European supply. However, both countries have ambitious transition plans and progressive pledges for new industry establishments, creating uncertainty related to future energy supply and infrastructure. While European models aim to capture the dynamics within Europe, they often lack the spatial, temporal and technological resolution needed to fully represent national dynamics, including energy infrastructure and demand, flexibility options, national policies and industrial transition plans. This case study therefore aims to provide better knowledge related to the role of energy supply from Norway and Sweden to the European energy system under different future transition pathways. Moreover, the case study further assesses the interaction between Norway and Sweden, as well as provides insights on wider energy system implications.

The generated results from our research provide insights to stakeholders and decision makers on how future energy systems in Norway and Sweden might unfold considering various industry development scenarios. By capturing key uncertainties and system dynamics, our findings support informed decision-making on energy policy, infrastructure investments, and resource allocation. Additionally, the research highlights the importance of cross-border interactions and collaboration between Norway, Sweden, and the broader European energy system.

2A.3. Implementation

2A.3.1. Challenges

Due to structural differences between GENeSYS-MOD and TIMES-NOSE, the data exchange was not one-to-one and required aggregation or disaggregation to match the respective model formats. This was particularly relevant for the industry sector, where TIMES-NOSE offers a significantly more detailed representation. Additionally, given the complexity of both models, not all parameters could be fully harmonised, which may affect the comparability of the results.

2A.3.2. Mitigation Measures

To minimise discrepancies between scenarios, we harmonised the parameters that have the greatest impact on the results.

2A.4. Results

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

2A.4.1. Outcomes

In this section, we present the results of four energy transition scenarios, including two different industrial demand scenarios for Norway and Sweden, within the scope of the two EU-EnVis 2060 scenarios: GoRES and Trinity. The results provide key insights into the central research questions of this case study: to what extent Norway and Sweden can supply energy exports to Europe, how different trajectories of industrial demand growth shape this potential, and the role of technology development (among other things) in enabling these outcomes.

In this section, four scenarios will be presented with the following abbreviations:

1. **LoTri:** Low demand projections within Trinity
2. **HiTri:** High demand projections within Trinity
3. **LoGo:** Low demand projections within GoRES
4. **HiGo:** High demand projections within GoRES

Electricity production and demand

Figure 2A.1 illustrates the development of electricity generation in Norway and Sweden from 2025 to 2050 across the four scenarios. In Norway, the main differences relate to onshore and offshore wind expansion. In the Trinity scenarios, offshore wind reaches 7 TWh (LoTri) and 16 TWh (HiTri) compared to 58 TWh in both GoRES scenarios, reflecting more conservative technology assumptions in Trinity. Onshore wind development is also impacted by the cost variations, as well as the energy demand levels, in which none of the low demand scenarios reach full expansion potential. Production ranges from 20 TWh to 39 TWh, in which southern parts of Norway is the most favourable region. Sweden has a similar trend in varying levels of wind development, but unlike Norway, utility-scale PV proves highly competitive, reaching maximum deployment of 50 TWh across all scenarios. Nuclear development is assumed to be a political decision and therefore has the same development across scenarios. Lastly, Trinity is a scenario subject to significant geopolitical tension both within and outside Europe, which is considered by assuming limited investments in new cross-border capacities. Electricity production for exports is therefore not as pronounced as in GoRES.

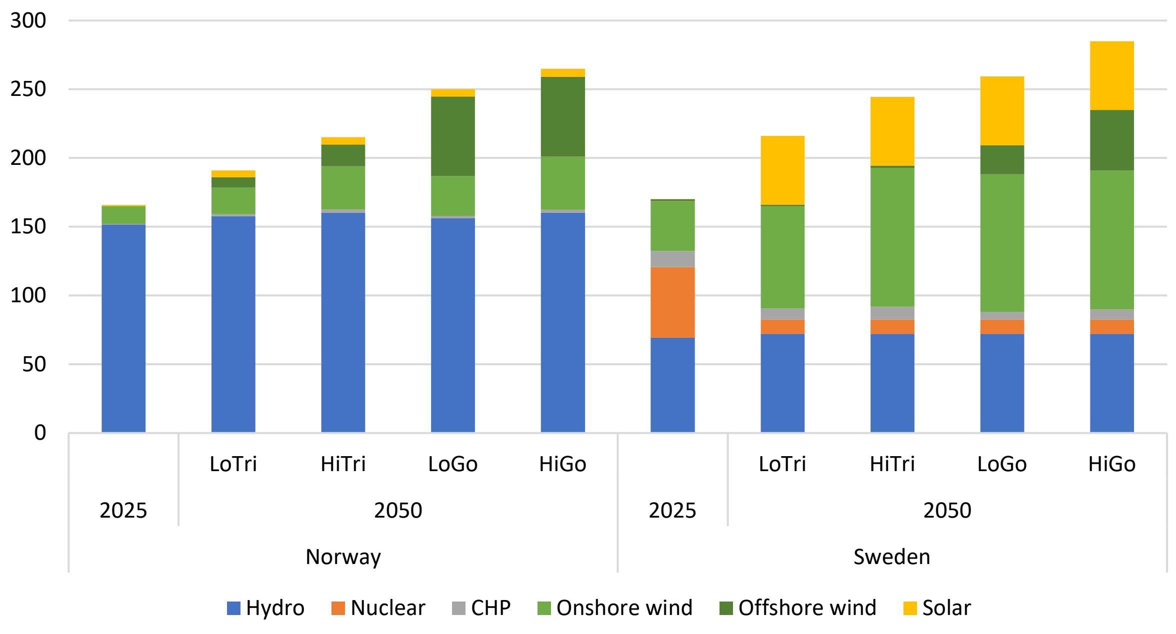


Figure 2A.1. Electricity generation mix in Norway and Sweden in 2025 and 2050 across the four scenarios.

In terms of electricity demand, the increase from 2025 to 2050 ranges between 22-121 TWh in Norway and 93-176 TWh in Sweden across the four scenarios (see Figure 2A.2). While electricity use for industry varies largely in Norway between low and high demand scenario (almost doubles), Sweden industry shows stable demand across all scenario variants.

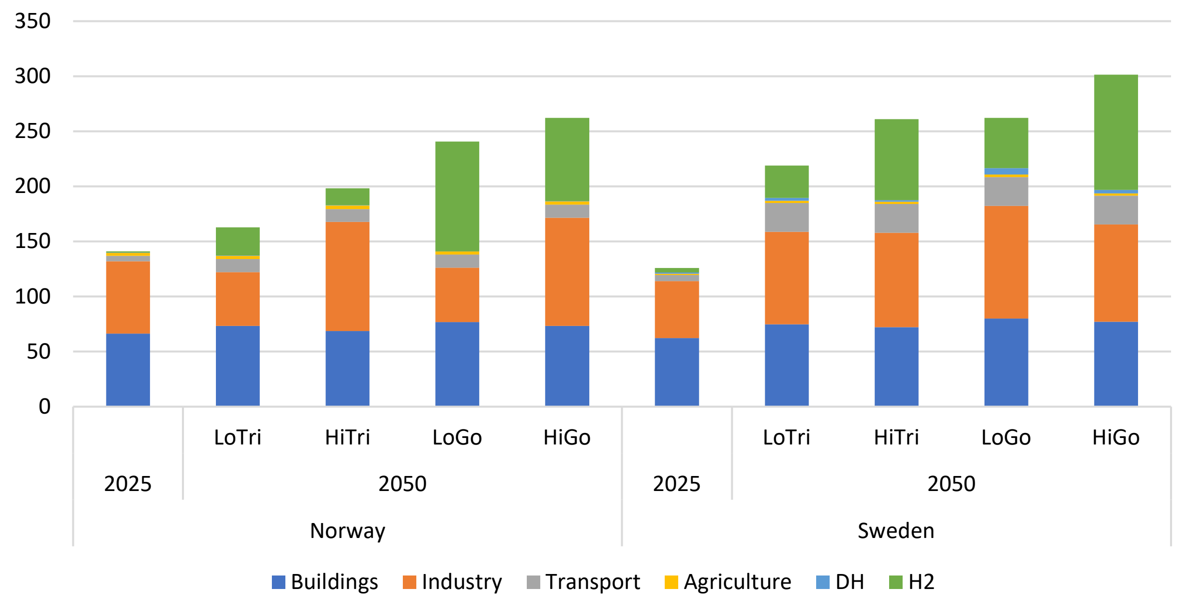


Figure 2A.2. Electricity demand in Norway and Sweden across sectors and scenarios in 2025 and 2050.

2A.4.2. NECPs

This section entails the NECP-related discussions from Part A and Part B, as both focus on the same region. Norway is not obliged to send updated NECP's to the commission. Norway did send an NECP in 2019 but has now adapted the work in a separate process through the Norwegian climate plan[1]. This plan indicates the policy priorities within different sectors, and for CS2, it is of interest to look for policies and ambitions with direct impact on the power system. This can be policies that changes demand or policies that changes the energy mix in the system or leads to significant changes in the transmission and medium voltage distribution system. The text in ***bold italic*** is how we have responded to the information in CS2 Part B.

The Climate plan states that the Norwegian government will pursue an energy policy based on the premise that access to renewable power should be a competitive advantage for Norwegian industry. This involves increased power production, enhanced domestic transmission capacity in the grid, and more efficient use of energy in the system. ***The increased transmission capacity of the sensitivity scenarios is not in line with this policy, which requires that the power system Norway should remain a surplus area compared to neighbouring countries.***

Huge step-up in offshore wind and a concrete action is to build 30GW offshore wind before 2040: ***This is a system change which we have considered in our modelling.***

To enable transition relevant energy projects, more resources will be given to concession processes: ***This is in line with the REPowerEU pointing to wind as a growing technology in the energy mix and argues that the transition in NECP-Essentials is possible to achieve also for Norway.***

[1] See https://www.regjeringen.no/contentassets/1b2fd715fe494bd886a4756a49737670/no/pdfs/regjeringens-klimastatus-og-plan.pdf

Improved efficient energy use: ***This aspect is explored in the case study through: (Part A) by adjusting relevant TIMES parameters., (Part B) modelling of different principles for demand flexibility as load shifting or modelling of price sensitivity demand.***

No sector specific reduction targets are or will be developed, but the climate plan has a long list of suggested policy actions, and a couple of them are mentioned below:

> E.g. CO_2 tax is set to 1400 NOK/Ton in 2025: ***In our calculation this is not directly relevant as there is no thermal power generation in land-based Norway. On the other hand, the tax impacts on electrification rate of the industry, which is included in our studies, as increased electricity demand.***
>
> E.g. support to charging infrastructure for zero-emission heavy transport 3,7 BNOK: ***Our calculations consider growth in electricity demand, which includes the increase in electric transport***.

The governing concept of the Climate Plan (see Figure 2A.3) is that the progress in emission reduction will be assessed and the plan updated and revised yearly according to the calendar of the Norwegian Government.

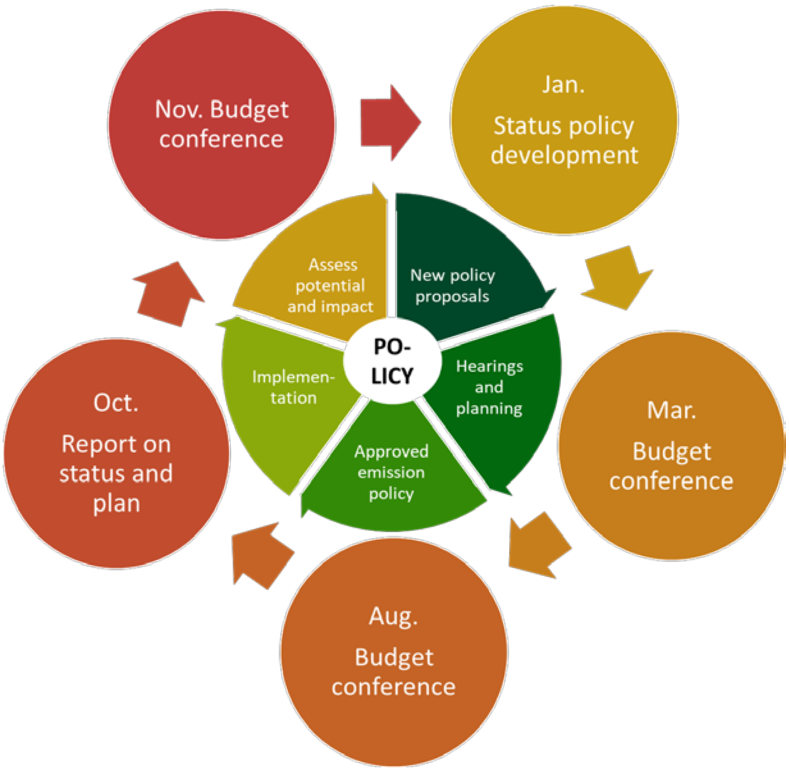


Figure 2A.3. Norwegian Climate Plan management.

Considering the actual progress towards the climate goal, this should show whether the existing measures are effective, or if additional measures are needed.

The status at the release of the climate plan was that emissions have been reduced with 9% compared to 1990 level while GDP has doubled and the population has increased with 1.3 million.

Looking forward, the climate plan indicates emission reduction in selected sectors towards 2030 (check Figure 2A.4), meaning that our calculations need to extrapolate or adopt the same development towards 2050. The short horizon is a limiting factor, as investments in the energy transition policies need to have a longer perspective to justify and give direction to the required investments.

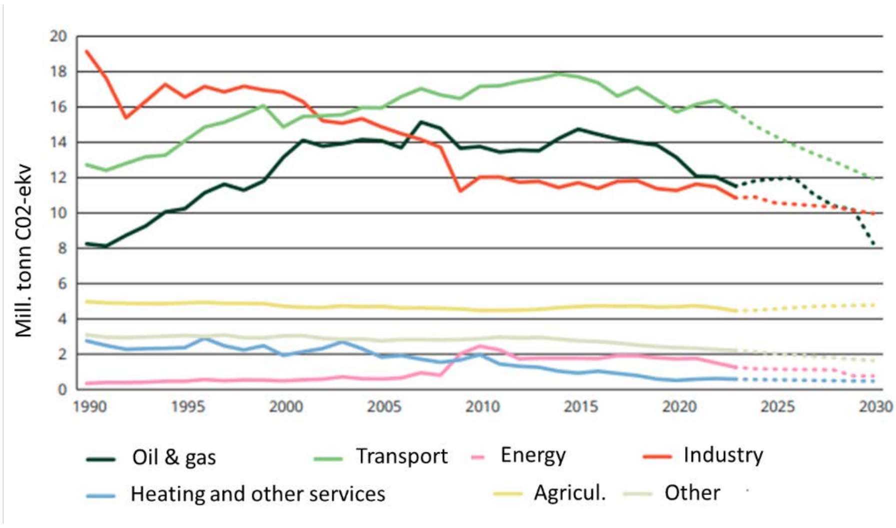


Figure 2A.4. Sector wise reductions in Norway towards 2030 (Norwegian climate plan[2]).

The Norwegian Climate Plan does not consider the benefits across the Nordic countries of joint actions or collaboration towards the EU policies on emission reduction. The Nordic power market shares regulation and the Nordic region is strongly interconnected through the power grid. Changes in the Norwegian power sector will impact the other Nordic countries and vice versa – this must be included in and accounted for in the respective NECPs. Therefore, while the Nordic power system development varies in terms of policy, the actual integration level is already quite high.

2A.4.3. Supplementary Data

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

Part B: Stochastic Modelling of the Nordic power system

With the increasing importance of electrification in mind, this study analyses how the power sector in Norway interacts with demand flexibility internally and externally with the European power system. Of particular interest is how hydropower, as a renewable energy source with 78,3 TWh storage capacity in Norway, can play a pivotal role in European VRE integration, especially if the power sector can utilise internal demand flexibility to release more capacity to interact with Europe.

In the definition and planning of the power system study, our researchers have worked closely with the Norwegian industrial Man0EUvRE partners: Statkraft, Hafslund og Equinor. Initially, three different angles on the analysis were discussed:

- **Research Idea 1**: The potential future value of offshore wind power in Northern Norway and Sweden

[2] See https://www.regjeringen.no/contentassets/1b2fd715fe494bd886a4756a49737670/no/pdfs/regjeringens-klimastatus-og-plan.pdf

- **Research Idea 2**: The future value of increased industrial demand-side flexibility and hydropower flexibility
- **Research Idea 3**: Investigate the inter-annual variability of future Norway-Sweden electricity exchange

In the dialog with the industry, a series of bilateral meetings was arranged for discussing the alternatives and find common ground for the Nordic power system analyses. In this co-creation process, a modified version of **Research Idea 2** with focus on power system flexibility was formulated, motivated by the following challenges:

- Managing the variability of wind and solar poses challenges across the Nordic power systems
- With growing deployment of wind and solar power, flexibility solutions become increasingly important
- Investments in demand-side flexibility and hydropower (generation) flexibility are two strategies to revenues while helping mitigate adverse system effects of variability
- As a stochastic model, FanSi is well-suited for analysing flexibility solutions in power systems with high VRE shares and various flexibility sources, including that of demand.

The discussions resulted in the definition of the following objective:

- Investigate the potential future value of industrial demand-side flexibility and hydropower flexibility within the frame of the Man0EUvRE scenarios.

This work uses the stochastic optimization power market model FanSi, which is designed for hydropower-rich systems and applicable to a broad Northern European setting. FanSi maximizes expected socioeconomic surplus by optimally dispatching generation and transmission capacity while explicitly representing hydropower reservoir dynamics and other temporal couplings. Approximately 1300 individual hydropower modules are represented in the FanSi dataset. In this work, simulations are performed for thirty historical weather years (1991-2020) based on detailed weather data for precipitation, temperature, and production from wind and solar. This allows the model to provide the solution space spanned by weather variability. Thus, findings from FanSi will include variability in the simulated revenues for power producers and costs for consumers, as well as power prices and power exchange between regions. A particularly relevant opportunity is to investigate long-duration flexibility: Intraday flexibility to balance variations in solar input, multi-day or multi-week to balance "*Dunkelflaute*" events or even balance seasonal variation.

The co-generation process of the project activity together with the industry contributes to enhance the relevance of the case study results and simultaneously lead to more knowledge about the impact from energy transition among the industry and how model results can be translated to transition strategies.

2B.1 Accomplished Tasks

This section summarises the work and results in the case study that is described in greater detail in later sections.

Definition of Power System Scenarios

Table 2B.1 provides an overview of the scenarios that is analysed with FanSi. The starting point for these scenarios is given by the Man0EUvRE's NECP-Essentials scenario, and results from GENeSYS-

MOD provides the frame for the power system scenarios analysed in the case study. The power system, from which the Base scenario is developed, is the current system with the necessary updates to align the system with the GENeSYS-MOD results from the NECP-Essentials.

The Base scenario serves as the reference case. The other scenarios represent variations designed to explore four distinct dimensions of system flexibility:

- **+HydroTransFlex**: Expanding Norwegian hydropower generation and/or pumping capacity. Expanding Norway-Europe High-Voltage DC (HVDC) interconnections, improving cross-border exchange and enabling synergies with hydropower flexibility.
- **+TimeFlexDemandTransFlex**: Introducing demand-side flexibility in the *timing* of electricity use (e.g., via inertia provided by thermal energy storages or behind-the-meter batteries that shift electricity consumption across hours or days). Expanding Norway-Europe HVDC interconnections, improving cross-border exchange and enabling synergies with hydropower flexibility.
- **+VolumeFlexDemandTransFlex**: Introducing demand-side flexibility in the *volume* of electricity use, allowing loads to be scaled up or down depending on market prices. Expanding Norway-Europe HVDC interconnections, improving cross-border exchange and enabling synergies with hydropower flexibility.

Table 2B.1. Overview of potential FanSi scenarios. “flex” stands for “flexibility”.

Scenario name	Norwegian hydropower	Norwegian industry time flex	Norwegian industry volume flexibility	Norway-Europe transmission
Basecase	-	-	-	Increased capacity
+HydroTransFlex	Increased capacity	-	-	Increased capacity
+TimeFlexDemandTransFlex	-	Load shifting introduced	-	Increased capacity
+VolumeFlexDemandTransFlex	-	-	Price elasticity introduced	Increased capacity

While the geographical scope of FanSi is Northern Europe, the variations in flexibility assumptions across scenarios (see Table 2B.1) will focus on Norway. The purpose of the scenarios is to explore system-wide impacts, including impacts on peak prices, low prices, price volatility, price distribution, revenues for producers and costs for consumers.

Expansion of Norwegian hydropower

The +HydroFlex is based on the list of applicable hydropower flexibility projects from the CEDREN-HydroBalance project from 2013 until 2017 (Solvang et al., 2012) implemented in a FanSi dataset by the KSP HydroConnect project 2021-2024). Hydropower expansions must be located where there are hydropower potential and the results from 2017 is therefore still relevant. The list of projects is within the current regulation schemes and respect the recommended maximum water level change per hour, 13 cm/hour, as defined by CEDREN. All projects consider existing hydropower reservoirs only and no new reservoirs are added to the hydropower system. The proposed expansion is therefore realistic in terms of water level variability in the reservoirs.

Table 2B.2. Increases in hydropower generation and pumping capacity that can potentially be included in the +Hydroflex scenario.

Power plant	Lower reservoir	Upper reservoir	Increased generation (MW)	Increased pumping (MW)	FanSi area
Tonstad	Sirdalsvatn	Nesjen	1400	1400	NO-SOUTH
Holen	Botsvatn	Urarvatn	700	700	NO-SOUTH
Lysebotn	Lysefjorden	Lyngsvatn	1400	-	NO-SOUTH
Tysso	Ringedalsvatn	Langevatn	700	700	NO-WESTSOUTH
Jøsenfjord	Jøsenfjord	Blåsjø	1400	-	NO-WESTSOUTH
Oksla	Hardangerfjord	Ringedalsvatn	700	-	NO-WESTSOUTH
Tinnsjø	Tinnsjø	Møsvatn	1000	1000	NO-INLAND1
Mauranger	Hardangerfjord	Juklavatn	400	-	NO-WESTMID
Sy-Sima	Hardangerfjord	Sysenvatn	700	-	NO-WESTMID
Aurland	Aurlandsfjord	Viddalsvatn	700	-	NO-WESTMID
Tyin	Årdalsvatn	Tyin	700	-	NO-WESTMID
Kvilldal	Suldalsvatn	Blåsjø	1400	1400	NO-WESTMID

Relation of the scenarios to the project HydroConnect (2021-2024)[3]: HydroConnect already analysed power system impacts of implementing all twelve projects included in Table 2B.2 under a future European energy system scenario. The present Man0EUvRE analysis will be distinguished from the HydroConnect analysis by using GENeSYS-MOD scenarios as frameworks, which are different from the energy system scenarios used in HydroConnect (e.g., different electricity mixes in Europe).

2B.2. Planned impact

This work will increase the knowledge about the importance of stochastic modelling in RES-dominated power systems by accounting for both weather uncertainty, through stochastic optimization, and inter-annual variability, by simulating 30 historical weather years. This becomes increasingly important as the transition towards the low-emission power and energy system progresses and the RES share in the power system increases.

In this part of Case Study 2, we assess the impacts of the NECP-Essential scenario on the existing 87 TWh energy storage in the Norwegian power system. The effect of various flexibility scenarios on the utilisation of the hydropower energy storage is investigated, comparing how different flexibility types influence the Nordic power system and its ability to provide flexibility to the rest of Europe.

In addition to the system perspective on changes in energy storage use, the study also provides different socio-economic costs for power system operation in the four scenarios analysed. This includes assessment of market *power prices* and *capture prices for different producers and consumers* in the different regions in the model, and how the distribution of producer revenues and consumer costs might vary across scenarios and regions.

Finally, the study discusses how the obtained results are aligned with the framework provided by the results of the GENeSYS-MOD's NECP-Essential scenario. This includes the quality check of GENeSYS-MOD results when setting up data for the five calculations in the FanSi model and a discussion over the obtained values for the power system from GENeSYS-MOD.

[3] https://www.sintef.no/en/projects/2021/hydroconnect/

2B.3. Implementation

The implementation of the case study of the Nordic power system follows the approach sketched below:

- Based on the information on installed capacities and electricity demand from Man0EUvRE scenarios, GENeSYS-MOD results for industrial electricity demand flexibility and hydropower flexibility in 2050 are developed. The selected scenarios are implemented and analysed in the FanSi model (Bjørnerem et al., 2024; Helseth et al., 2018), using the dataset from KSP HydroConnect as a starting point to incorporate the aforementioned flexibility scenarios into the dataset:
    - The NECP-Essential scenario results from GENeSYS-MOD for the year 2050 serves as input to FanSi. During the implementation, it became clear that analysing more than one scenario and one year would probably not be feasible within the project constraints, and it was concluded to consider only the NECP Essentials stage 2050. Additional GENeSYS-MOD scenarios (i.e., the Trinity scenario) might be investigated under more relaxed resource conditions if possible.
    - For the NECP-Essential scenario, we generate a set of sensitivity scenarios to explore the impacts of various flexibility solutions. Hereafter, in this section, these sensitivity scenarios are referred to simply as *scenarios*.
- The results of different scenarios are compared with the results from CS2, part A. The results are also compared to those of GENeSYS-MOD in order to provide the revised inputs for the final GENeSYS-MOD run.
- Finally, future work on the FanSi model is suggested based on the experience from the work and to which extend the dataset or the optimisation model itself could benefit from further improvement.

2B.3.1. Challenges

The adaptation to the Man0EUvRE scenario includes many assumptions and decisions about how the single node results from GENeSYS-MOD for Norway and Sweden are translated to a power system model of the Nordic System with several nodes per country, see Figure 2B.1. As indicated above, the scenario study of the Nordic power system is based on individual modelling of all reservoirs and hydropower plants in the system group around the water courses with cascaded modelling in addition to their location in the different price zones.

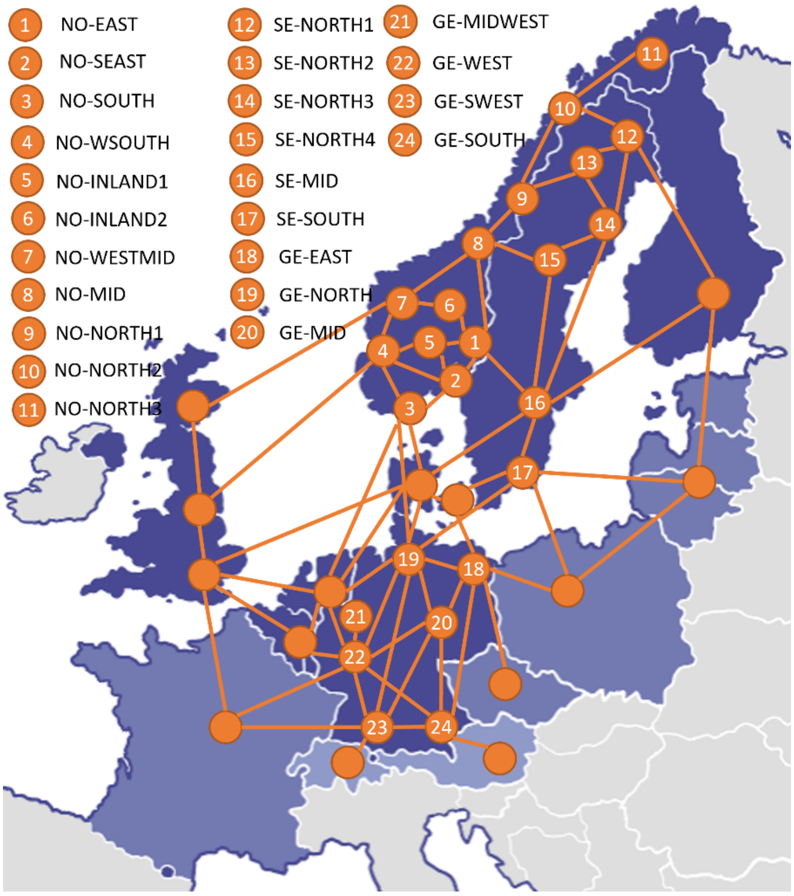


Figure 2B.1. Map of the power system modelled with FanSi. A translation between Norwegian and English names can be found in Table 2B.3. The circles represent the geographic regions included in the model. To streamline the figure, only the areas that are most relevant to the analysis or selected for results presentation are labelled, while other modelled areas, depicted with circles, remain unnamed. Darker blue shades indicate regions modelled with higher detail in terms of power demand and supply.

2B.3.2. Mitigation Measures

Our approach coherently links results from the cross-sectoral capacity expansion model GENeSYS-MOD with the detailed operational model FanSi, enabling a consistent representation of the 2050 European energy system and Nordic power system operation. The countries Norway, Sweden, Denmark, United Kingdom and Germany are divided into multiple price areas in FanSi, allowing for the representation of geographical variabilities in renewable energy inflow and internal transmission constraints within countries.

To disaggregate country-level results from GENeSYS-MOD into subnational areas defined in FanSi, a distribution algorithm has been designed using different distribution factors for different parameters. An example of distribution factors can be seen in Table 2B.3 (for onshore wind). The following parameters from GENeSYS-MOD are handled in a similar way in their adaptation to the more detailed geographical representation in the FanSi model. Demand categories include industry, buildings, transport and a residual category. Generation categories are onshore wind, offshore wind, solar power, thermal power from bio and gas, nuclear and battery energy storage systems.

Table 2B.3. Distribution factors for onshore wind. The relative shares of all areas in one country can be summarised to one.

Node	Native name	English name	Rel. share	Node	Native name	English name	Rel. Share
1	OSTLAND	NO-EAST	0.1	17	SVER-SYD	SW-SOUTH	0.17
2	SOROST	NO-SEAST	0.1	18	TYSK-OST	GE-EAST	0.14
3	SORLAND	NO-SOUTH	0.1	19	TYSK-NORD	GE-NORTH	0.09
4	VESTSYD	NO-WSOUTH	0.1	20	TYSK-MIDT	GE-MID	0.14
5	TELEMARK	NO-INLAND1	0.05	21	TYSK-IVEST	GE-MIDWEST	0.00
6	HALLINGDAL	NO-INLAND2	0.05	22	TYSK-VEST	GE-WEST	0.37
7	VESTMIDT	NO-WESTMID	0.1	23	TYSK-SVEST	GE-SWEST	0.17
8	NORGEMIDT	NO-MID	0.1	24	TYSK-SYD	GE-SOUTH	0.12
9	HELGELAND	NO-NORTH1	0.1	25	FINLAND	FINLAND	1.00
10	TROMS	NO-NORTH2	0.1	26	DANM-OST	DK-EAST	0.41
11	FINNMARK	NO-NORTH3	0.1	27	DANM-VEST	DK-WEST	0.59
12	SVER-ON1	SW-NORTH1	0.17	28	NEDERLAND	NETHERLANDS	1.00
13	SVER-ON2	SW-NORTH2	0.17	29	BELGIA	BELGIUM	1.00
14	SVER-NN1	SW-NORTH3	0.08	30	GB-SOUTH	UK-SOUTH	0.40
15	SVER-NN2	SW-NORTH4	0.08	31	GB-MID	UK-MID	0.40
16	SVER-MIDT	SW-MID	0.33	32	GB-NORTH	UK-NORTH	0.20

Electric Import/export capacities also need to be transferred from the GENeSYS-MOD results. The single value from GENeSYS-MOD is distributed relatively to the existing connections in the FanSi model. Similar electric losses as in the original dataset are used. Neither GENeSYS-MOD nor the FanSi model used here include internal losses in the nodes, which is a weakness as grid infrastructure build-up internal in each country or price zone is required to accommodate the increased import and export capacities found in GENeSYS-MOD.

Concerning GENeSYS-MOD results

In this process, we performed a check of the GENeSYS-MOD results and reported back to TU Berlin that the following values needed correction: Adjustment of electricity demand in Norway and Sweden to be approximately aligned with the national scenarios published by the national TSOs (Statnett and Svenska Kraftnät) and the Norwegian regulator (NVE).

Overall hydropower generation in Norway was set to a level aligned with the scenarios from the Norwegian regulator NVE.

These improvements were discussed with TU-Berlin and resulted in new results where demand and hydropower generation were more in line with the Nordic scenarios available from the TSOs and NVE. In the updated GENeSYS-MOD model runs, the changes in demand and hydropower resulted in a significant increase in renewable generation from wind in Norway compared to the original GENeSYS-MOD results.

Total installed battery capacity in the modelled countries is 165 GW in 2050. GENeSYS-MOD assumes 3-hours duration for the battery. Based on this, the installed battery capacity is approximately 500 GWh. Table 2B.4 shows the battery investment in the part of Europe SINTEF are analysing with the FanSi model.

Table 2B.4. Battery capacity (in GW) from GENeSYS-MOD for different years in NECP Essentials.

Area/Year	2035	2040	2045	2050
Belgium				1.6
Denmark			0.3	2.2
Finland	1.8	3.4	6.3	8.8
France		2.1	25.4	75.3
Germany			21.1	62.9
Netherlands			1.1	13.9
Norway			1.2	1.3
Sweden				
United Kingdom		2.8	12.3	30.6
Sum	1.8	5.5	55.4	164.4

Energy storage in hydropower reservoirs represent a possibility for long-term energy storage beyond what batteries can provide. Hydropower capacity in Norway, is 40 GW with 87 TWh of energy stored and therefore a theoretical duration of ~2000 hours. Energy content of the above battery capacity based on GENeSYS-Mod is estimated to 0.5 TWh, which is much lower compared to what was published in the HydroBalance project (Graabak et al., 2019) stating that 25 TWh of storage and 250 GW is needed in northern Europe to balance wind, solar and load variability in a 100% renewable northern Europe.

Setting up the sensitivity scenarios

This section describes in greater detail the scenarios and the work for setting up the scenarios that is analysed in the Nordic power system case study. The analysis has worked with four scenarios for power system development in a stochastic power system model for northern Europe: one base scenario, which should be as close to the EU-EnVis 2060-scenario *NECP Essentials* as possible, and three sensitivity scenarios:

- Sensitivity scenario #1: *TimeFlexDemand* includes modelling of flexibility in industrial demand.
- Sensitivity scenario #2: *VolumeFlexDemand* includes modelling of price sensitive demand
- Sensitivity scenario #3: *HydroFlex* increases the flexibility in the Norwegian hydropower fleet

All scenarios include expanded transmission capacity, domestically in Norway and between Norway and neighbouring countries. These scenarios define various strategies for increasing the flexibility in the Nordic power system and will provide more information about the system behaviour if the flexibility is realised with focus on the industry, in general for all demand, through transmission expansion or increase in the hydropower capabilities.

In all three sensitivity scenarios Norway's and Scandinavia's HVDC interconnections with Europe are expanded to strengthen transmission flexibility beyond that of the base case. In general, greater transmission capacity increases the system's ability to transfer electricity from regions with energy surpluses to regions facing tighter balances. Expanded transmission may also be crucial in combination with hydropower expansion (as in HydroFlex), since some hydropower upgrades may only become profitable if supported by stronger connections to the United Kingdom and/or continental Europe.

HydroFlex

This scenario focuses on expanded flexibility in hydropower by expanding generation and pumping capacity of already existing hydropower plants in Southern Norway. Energy inflows and reservoir storage volumes will be kept unchanged; the only changes will be to generation and/or pumping capacities.) The increase in hydropower flexibility is shown in Table 2B.2.

TimeFlexDemand

In this scenario, demand-side temporal flexibility is introduced, focusing on electricity demand in the industry sector. Compared to the base scenario, which assumes given electricity demand profiles and does not allow time-shiftable demand, this scenario allows part of the electricity consumption to be reallocated across time in response to market prices.

The flexibility could originate from different sources, such as industrial thermal processes with heat storage, behind-the-meter batteries or other shiftable loads. The key feature is that electricity demand is not rigidly tied to a given hour but can be adapted within defined limits. We will make assumptions on the timescale of the flexibility (e.g., intraday or across days or weeks).

This scenario differs from the HydroFlex scenario, which increases hydropower production and/or pumping capacity. Whereas HydroFlex expands supply-side flexibility and is subject to the detailed characteristics of hydropower systems, TimeFlexDemand represents demand-side flexibility in the form of a generic time-shiftable electricity use. It does not entail flexibility in the volume of electricity consumed, however.

VolumeFlexDemand

This scenario builds on the HydroFlex, but in this scenario, electricity demand is made more flexible by allowing the *volume* of electricity consumption to adjust according to price signals. Instead of shifting demand between hours, industry can scale electricity demand up during low-price periods or reduce it during high-price periods. A concrete implementation in FanSi could, for example, involve meeting a fixed heat demand with two technology options: an electrical boiler that is used when electricity prices are low, and an alternative boiler based on gas or biomass that is activated when prices are high. This setup represents a form of fuel switching or demand substitution.

2B.4 Results

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

2B.4.1. Outcomes

To be added later

2B.4.2. Supplementary data

Possible contributions from FanSi to European scenarios are listed below.

Climate variability data for each Fansi node:

- Inflow scenarios

- Wind speed scenarios
- Solar radiation scenarios
- Temperature dependent demand scenarios

In our work with aligning our analyses with the results from GENeSYS-MOD, results from the parallel studies with the TIMES and Empire models we have gone in depth with on the Man0EUvRE scenario results and contributed to the quality check of the Nordic results in the model for the NECP Essentials scenario.

Case study 3: Global competitiveness and the energy demand of the energy-intensive industry

The goal of this case study is to investigate how global energy cost structures in the production of energy-intensive goods influence industrial energy demand. With the ongoing transition from fossil to renewable energy inputs, the relative energy factor endowments of countries are expected to shift, thereby affecting production costs and energy prices – a mechanism often referred to as *renewable pulls* (cf. Samadi et al., 2023).

The model developed in this case study captures the migration of manufacturing activities both across industry branches (products) and between geographical production sites. To reflect sector- and product-specific heterogeneity, an agent-based modelling (ABM) framework is employed, enabling a bottom-up representation of firm behaviour and technological characteristics. In this framework, agents represent individual firms that decide what and where to produce based on expected profit calculations. These expectations are endogenously interlinked, as the decisions of one firm affect the profitability of others through production linkages, trade relations, and transport costs. This interaction captures the complex dynamics of global production networks and the emergence of industrial clusters or relocations. By explicitly modelling these interdependencies, the framework allows for the exploration of non-equilibrium adjustments in industrial energy demand within a globally integrated economy, thereby providing refined demand trajectories for energy systems modelling.

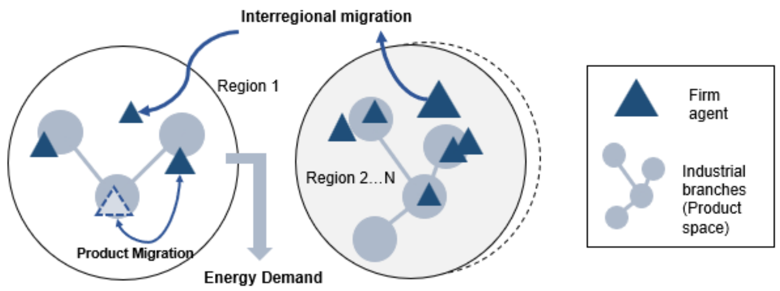


Figure 3.1. Overview of the model developed in case study 3.

3.1. Accomplished Tasks

Task 3.1 – Model set-up: In the first step, a stock-flow consistent agent-based macroeconomic simulation model was built using the open-source modelling package *sfctools* developed at DLR (Baldauf, 2023), which represents economic sectors (such as the steel and chemical industries) in a disaggregated way. In addition, all other major economic agents such as the state, banks, capital goods and *service goods* producers are considered aggregated at the sectoral level. The model takes sector- and country-specific knowledge and capital stocks into account and uses the product space method to parameterise the knowledge stock. The input data is sourced from the open-source *EXIOBASE* multiregional input–output database, providing a consistent representation of sectoral production, trade, and energy use across countries.

Task 3.2 – Model calibration: In this task, the calibration of the macroeconomic model was carried out alongside the testing of the base configuration. The objective was to achieve a stable dynamic baseline state in which production and trade decisions emerge endogenously based on country-specific factor endowments and technological capabilities. This ensures that the model reproduces an empirically consistent global production structure before applying any policy or cost shocks.

Task 3.3 – Scenario Analysis: In this task, the agent-based macroeconomic model was applied to explore how changes in renewable energy endowments influence industrial competitiveness and energy demand across Europe and globally. The scenario analyses are aligned with the overarching European scenarios used in the project and build upon empirical estimates of renewable electricity generation potentials. To reflect the changing relative energy factor endowments between countries, we introduced an exogenous endowment uplift, elaborated based on recent literature (Kan et al. 2025). These uplift factors modify the country-specific energy endowment parameters in the model, effectively representing the long-term competitiveness advantages associated with abundant renewable energy resources. The resulting changes in industrial location patterns, production structures, and final energy demand are then evaluated.

Task 3.4 – Processing of results and contribution to European scenarios: In this task, the data exchange between the European scenarios and the macroeconomic simulation is ensured and the results are processed. Furthermore, the utilised model is made open-source and prepared for applicability by third parties to other European countries (see Section 3.4.3).

3.2. Planned Impact

Our industry migration model can significantly enhance the framing assumptions used in system cost optimisation modelling for Europe's energy transition by improving the accuracy of energy demand projections and optimising infrastructure planning. As industries relocate due to factors, such as energy prices, policy incentives, and supply chain shifts, the energy demand landscape evolves dynamically. Understanding these shifts allows for more precise allocation of renewable energy resources, efficient grid expansion, and better sector integration (electricity, hydrogen, and heating). Our model might identify energy demand that may become obsolete due to declining industrial activity or vice versa pointing out increasing demand in other geographical regions or industrial sectors. Additionally, the insights will finally be the basis on which policymakers might design strategies that enhance the competitiveness of European industries while aligning with decarbonisation goals. It also supports risk assessment and resilience planning in the realm of energy system modelling, ensuring Europe's energy system remains robust against economic and geopolitical uncertainties.

3.3. Implementation

The industry migration patterns are provided at the resolution of the used product space and underlying geographical scope (the geographical energy system model scope plus additional geospatial entities in the global economy). The industrial demand is then aggregated from the energy demand estimated at the production site-level. The revealed changes in demand are compared to the assumptions made in GENeSYS-MOD.

3.3.1. Challenges

Due to the complex dynamics involved in the model, the model developments and data processing steps need to be well documented to ensure further usability and reproducibility.

3.3.2. Mitigation Measures

We adhere to standard documentation procedures throughout this work, enabling us to respond to any questions that may arise.

3.4. Results

3.4.1. Outcomes

At the time of preparing this version of the executive summary, we cannot yet provide robust quantified, country-level results regarding changes in industrial energy demand, due to the complex dynamic interactions within the model. Further analyses and validation are ongoing.

Nevertheless, preliminary explorations offer qualitative insights into the mechanisms at work. The model shows that a shock to national energy endowments — reflecting differences in renewable energy potential — leads to adjustments in energy prices, which in turn affect firms' production and location decisions. Firms may respond to higher energy costs either by shifting to less energy-intensive products within the same country or by relocating production to regions with more favourable energy endowments.

Through the production linkages embedded in the input–output network, the movement of one firm alters the cost structure of others, creating a complex web of interdependent reactions. A recurring pattern observed in several scenarios is that, although firms initially migrate away from countries with an unfavourable energy endowment shock, this outflow reduces domestic factor prices, particularly for labour. The resulting change in cost competitiveness can subsequently attract new production activities, sometimes leading to higher aggregate output after the shock than in the baseline scenario without it.

This counterintuitive outcome suggests that temporary shocks can trigger more efficient reorganizations of industrial structures, in line with insights from classical trade theory (cf. Heckscher–Ohlin–Samuelson). While these findings remain exploratory, they illustrate the non-linear and path-dependent nature of industrial adaptation under changing energy cost structures.

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

3.4.2. NECPs

The preliminary results highlight important implications for the NECPs of European countries. They suggest that energy cost differences and renewable resource availability could lead not only to industrial relocation but also to restructuring and specialization within Europe's production network.

A deeper understanding of these mechanisms will help assess:

- how comparative advantages in renewable energy resources affect industrial competitiveness,
- where energy demand trajectories may deviate from current NECP assumptions, and
- how industrial policy and infrastructure planning can mitigate unintended regional imbalances.

Further quantitative analysis will be necessary to link these qualitative observations to measurable changes in sectoral energy demand and to translate them into actionable insights for NECP implementation.

3.4.3. Supplementary Data

All datasets and configuration files used in this case study are based on open and reproducible data sources, primarily the *EXIOBASE* 3.9 multiregional input–output database and the renewable energy cost index published in Kan et al. (2025). The modelling framework, including pre-processing scripts, calibration routines, and scenario definitions, will be made available as open-access resources to ensure transparency, replicability, and further development by the research community.

The final results, together with the complete model code and documentation, will be published open access following internal validation, allowing other researchers to apply and extend the model to additional European countries and global contexts.

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

Case study 4: The role of growing demand in refinancing renewables

In this case study, the role of a growingly flexible power demand for refinancing renewable generators as well as flexibility options is analysed. For this purpose, the agent-based power market model *AMIRIS*[4] is applied for the Federal Republic of Germany. AMIRIS has been extended by a generic representation of competing flexibility options. The model has been soft-coupled with GENeSYS-MOD and uses input data from the EU EnVis-2060 scenarios. The results obtained are prepared to provide feedback to the German NECP.

4.1. Accomplished Tasks

Task 4.1 – Model extension/adaptation: In this task, necessary model extensions have been made to study the development of market values and the resulting market-based re-financeability of renewable generators and flexibility options. This includes the representation of competing flexible demand agents. In particular, a new generic approach to deal with competing flexibility and their price repercussions has been implemented in AMIRIS. At the beginning of the project, implementations already existed in AMIRIS for electric heat pumps and classical demand response. The controlled charging of electric vehicles and the flexible operation of electrolysers are added in this task, in part building on former work. The existing flexibility representations are transferred to the newly

[4] https://helmholtz.software/software/amiris

introduced approach to study competing flexibilities. Capabilities for studying regulatory framework conditions, such as the (dynamic) end customer electricity tariff design, are expanded.

Task 4.2 – Model coupling and parameterisation: To parameterise the actual simulations, in this task input data and results from the European EU EnVis-2060 scenarios calculated in GENeSYS-MOD have been prepared for the usage in AMIRIS using automated data workflows.

Task 4.3 – Model simulations: This task encapsulates all activities for the AMIRIS simulations. Different constellations of flexible demand agents as well as different regulatory framework conditions and their repercussions on flexible demand—and ultimately on the market-based refinancing of renewable generators—are analysed. Doing so requires repeated and reproducible simulation runs. To ensure this, an automated model workflow is developed, which comprises the parameterisation from the data converter developed in the previous task, runs an AMIRIS simulation with the data and processes the results. Thus, the possibility of a comparative evaluation is provided in the next task.

Task 4.4 – Processing of results and contribution of European scenarios: In the last task of CS4, the previously generated results have been processed and evaluated. For this purpose, various criteria and indicators are identified and analysed in an automated manner. In preparation for the feedback on the German NECP in WP4, the results are processed and visualised in tabular or graphic form. Conclusions are derived from the observed effects of a flexible demand towards the refinancing of capacities as well as potential mitigation options in case of insufficient cost recovery.

4.2. Planned impact

The outcomes of this case study shed light on whether, and to what extent, flexibility in the power sector and sector coupling technologies contribute to stabilizing the refinancing situation of renewable energy sources in Germany. This is a pivotal question to assess the necessity and extent of state-administered policy support for renewable generation technologies or flexibility options. In contrast to classical system cost minimisation approaches, our agent-based modelling approach allows to encapsulate business-oriented decision making as well as an anticipation of prognosed price repercussion and cannibalization effects from competing flexibility options under uncertainty. A stable refinancing situation and a reduction of potential income risks ultimately is crucial to incentivize investors to deploy renewable generation as well as flexibility technologies. This addresses the prospect of achieving renewable energy sources expansion targets as set out in the NECPs.

4.3. Implementation

AMIRIS has been extended by a generic representation of flexibility units within Task 4.1. It now allows for the simulation of competing flexibility sources with defined dispatch strategies, e.g. profit maximisation. To achieve this, the flexibility options consider both their own price repercussions, as well as those observed for competitors. This is realised by the utilisation of competition multipliers. The new implementation has been tested for storage units in the first place (Schimeczek et al., 2025). As of November 2025, it has been expanded to load shifting and electric vehicles. An implementation for heat pumps is to be added soon to allow for the simulation of a flexible target system.

For the parameterization of AMIRIS scenarios with data obtained from the EU EnVis-2060 scenarios a data conversion script has been developed in Task 4.2. The parameterisation is still refined within the automated workflow tool. Furthermore, a workflow to run AMIRIS is drafted in Task 4.3. Once finalised, it will allow to run all scenarios and snapshot years considered in the project as well as to calculate metrics concerning cost recovery.

4.3.1. Challenges

The representation of competing flexibility options proved to be a challenge, as there is no comparable implementation for agent-based models in the literature. There exist some black box approaches (Harder et al., 2025) or assessments of single flexibility options (Liu et al., 2025; Fahrani et al., 2023) that neglect the system context.

One major challenge the project team faces is the timeline. The first version of the deliverable (i.e., D3.1) only presents first indicative results and draws general conclusions. These should be rather seen as hypotheses whose robustness and generalisability are yet to be tested. In the updated version of the prevalent deliverable (version 2.0), the results of all scenarios as well as for a comprehensive representation of all flexibility options will be presented.

4.3.2. Mitigation Measures

The AMIRIS developers found a flexible way to model competing flexibility within an agent-based simulation environment. The agent that markets the flexibility is attributed with some information on how flexibility options have been dispatched in the past. The agent can use this to derive a sort of similarity factor for the dispatch. This allows for an assessment of how the own dispatch and the prognosed dispatch of competitors may impact prices. By considering a specific assessment function, the agent can choose suitable dispatch schedules.

4.4. Results

So far, only the NECP Essentials scenario has been studied for the year 2045. The results are presented in the following section. Results for the other scenarios and snapshot years will be added with the updated version of this deliverable.

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

4.4.1. Outcomes

2045 has been selected for further analyses, as Germany aims to reach the climate-neutrality goal by then. In order to gain insights into the effect of flexibilities on the perspectives of refinancing, the storage capacities and installed powers have been increased and decreased respectively by 50%. The cost recovery of renewable generators has been evaluated based on the investment expenses c^{inv}, fixed c^{fix} and variable costs c_t^{var} those generators face. The cost recovery rate cr is defined as

$$cr = \frac{TP}{TC} = \frac{\sum_{t=1}^{8760} p_t \cdot g_t}{\sum_{t=1}^{8760} c_t^{var} \cdot g_t + c^{fix} \cdot P + A(c^{inv}, P, i, n)}$$

Hereby TP denotes the total profit from the day ahead market, TC the total cost, p_t the current power price at hour t, g_t the current power output, P the installed capacity and $A\left(c^{inv}, P, i, n\right)$ the annuity of the investment expenses for an interest rate i as well as a lifetime n. In the first place, the interest rate has been taken over from GENeSYS-MOD and assumed to be 5% for all technologies. The lifetime has also been taken from GENeSYS-MOD, and is assumed to be 20 years for batteries, 27 years for wind onshore, 30 years for wind offshore, 35 years for PV and 50 years for pumped-storage. These assumptions have been varied to show the sensitivity and reflect an investors point of view, where calculatory lifetimes of assets may be shorter and interest demand higher, compared to an overall system point of view.

The values for 2045 have been used for c^{inv}, c^{fix} and c_t^{var}. This is equal to a situation where the system would have to be rebuilt in 2045. This forms a rather optimistic approximation as costs decrease over time. In an updated version, also other constellations shall be considered. Table 4.1 shows the resulting cost recovery for renewable generators.

Table 4.1. Cost recovery of renewable generators and storage technologies.

Cost Recovery Rate	PV	Wind Onshore	Wind Offshore	Pumped Storage	Lithium-Ion Batteries
BASE	111.7%	115.2%	86.6%	173.2%	310.4%
-50% Storages	107.7%	114.6%	84.9%	184.5%	393.9%
+50% Storages	111.5%	115.8%	87.6%	161.0%	243.0%

It can be observed that for renewable generators, the cost recovery does not change drastically among the scenarios. For storage operators, however, there is a strong dependency on the amount of storage capacity in the system. The effect of revenue cannibalization is clearly observable here as for the case with the lowest storage capacity, the cost recovery rate is highest. In the setting with profit-maximising strategies, storage operators dispatch less capacity compared to a system-cost minimising strategy in order not to further cannibalize their own revenues.

The small variations for renewable generators can be explained through the structure of the merit order. The merit order is not very granular and thus, it requires substantial amounts of capacities for a price change that affects the remuneration situation.

Cost recovery rates for wind offshore are lowest due to the comparatively high investment expenses assumed which cannot be offset by higher full load hours. Interestingly, for PV, cost recovery rates in the baseline case are slightly higher than in the case with increased capacity of storages. This is a contrast to the general finding that higher degrees of flexibility lead to a revenue stabilisation. Also, cost recovery rates for PV show the strongest variations between 107 and 112%. Cost recovery rates for wind onshore for the prevalent cases are around 115%.

As calculatory lifetimes of investors may diverge from the assumptions in GENeSYS-MOD, a sensitivity check has been conducted, in which the calculated lifetimes of renewable generators were set to 20 years. Furthermore, for wind offshore, an interest rate of 7% has been used. This is motivated by the higher technological risk and the interest demand of large investors. The interest rates for PV and wind onshore where not altered and left at 5% as these technologies are established and return rates are comparatively low. The results are given in Table 4.2.

Table 4.2. Cost recovery of renewable generators for modified lifetimes and interest rates.

Cost Recovery Rate	PV	Wind Onshore	Wind Offshore
BASE	91.5%	100.1%	63.8%
-50% Storages	88.2%	99.7%	62.6%
+50% Storages	91.3%	100.7%	64.6%

The sensitivity consideration shows, that for all cases, cost recovery rates for wind offshore and PV are well below 100%, while wind onshore has a cost recovery rate around 100%. Wind offshore shows cost recovery rates between 62.6 and 64.6% in this setting. The cost recovery rate for PV is between 88.2 and 91.5%.

However, further scenarios and parameter sensitivities need to be assessed to come to final conclusions. Also, the scenario parameterisation needs to be made more granular to better reflect the characteristics of the system. For instance, imports and exports have been neglected for the prevalent analysis but are to be included in the updated version of this deliverable.

4.4.2. NECPs

In case upcoming analyses support the finding of comparatively low-cost recovery rates below 100% for the case of calculatory lifetimes of 20 years, there is a need for policy support to ensure that the necessary renewable capacity expansion decisions are made. In case the cost recovery rate is below 100% only in some cases, this still raises the question whether some sort of investment de-risking is necessary. However, profound policy conclusions can only be drawn once other constellations have been analysed in sufficient level of detail.

4.4.3. Supplementary Data

The analyses have been conducted using AMIRIS v4.0.0 which is available on GitLab: https://gitlab.com/dlr-ve/esy/amiris/amiris/-/releases. For the parameterisation, v3.1 of the EU EnVis-2060 scenarios has been used: https://zenodo.org/records/13710869.

Case study 5: Soft-linking BENOPTex and GENeSYS-MOD

Energy System Models (ESMs) and Integrated Assessment Models (IAMs) are commonly employed for designing policy advice. While IAMs shed light on the interrelation between energy systems, the economy, land use, and climate, ESMs provide comprehensive and context-specific understandings of the technological transition needed to decarbonise the energy system with more temporal and spatial detail. Compared to single region models, Pan-European ESMs offer the advantage of covering a wider geographical scope, spanning multiple European countries, and capturing a more comprehensive view of the interconnectedness and interdependencies within the energy landscape. Doing so enables researchers to accurately model cross-border energy flows, market dynamics, and the EU policy (e.g. the REPowerEU plan), which assists them in studying the competition and synergy between technologies. However, covering a wider geographical scope means dealing with more computational complexity. To mitigate the computation time, researchers often decrease the sectoral coverage, technological, and temporospatial details of these pan-European models. To enrich mentioned dimensions of the selected pan-European model and consider the bio-based economy, we link a regional model with high technological and sectoral granularity (i.e. BENOPTex) to GENeSYS-MOD, which governs the energy flow between European countries.

BENOPTex is a perfect foresight model that optimises the allocation of limited bio-based materials and renewable energies to various transformative technology concepts, in order to satisfy the end-use energy/material demands in the transport, heat, and power sectors as well as the chemical industry. Figure 5.1 depicts the connection between BENOPTex and GENeSYS-MOD. The domestic production of biofuels and synthetic fuels can be generated by BENOPTex and used in the GENeSYS-MOD to satisfy the end-use demands.

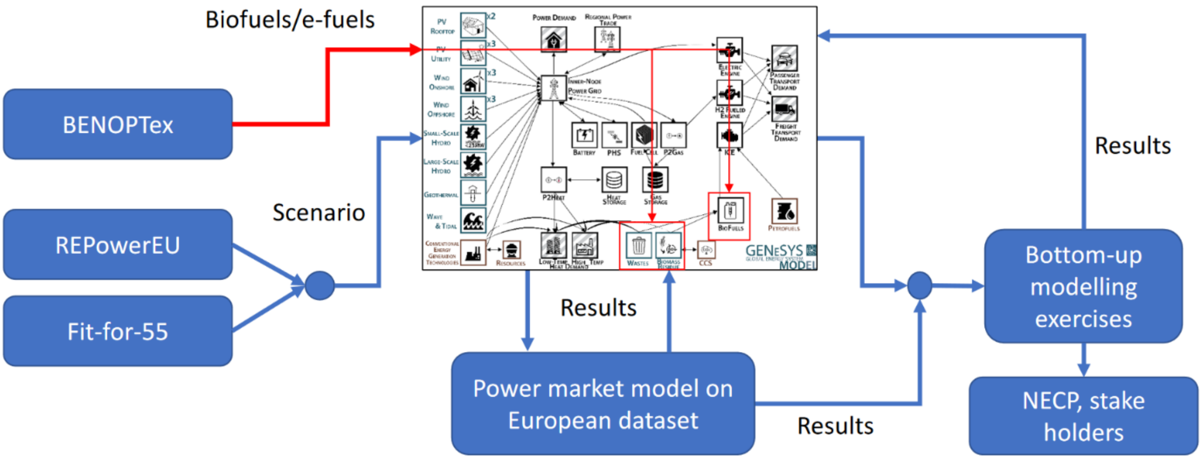


Figure 5.1. Connecting BENOPTex with GENeSYS-MOD.

5.1. Accomplished Tasks

Task 5.1 – Incorporating GENeSYS-MOD outputs in BENOPTex: In this task, we identify and formulate BENOPTex-related parameters within European scenarios. These parameters are translated into mathematical form, resulting in a stochastic optimisation model that is subsequently optimised.

Task 5.2 – Collecting data for selected EU countries to expand BENOPTex: While the main model was still under development, the required data for the selected countries have been acquired. The technical and political frameworks of these countries have been considered to the best of our abilities. Additionally, the energy exchange between neighbouring countries is taken into account, either implicitly (via scenarios) or explicitly (from/to Germany).

Task 5.3 – Extending the BENOPTex model to include selected countries: The knowledge and data collected in Task 5.2 have been incorporated into the optimisation model developed in Task 5.1. The results have been verified in close collaboration with experts. Various statistical experiments and sensitivity analyses have been conducted in this task to shed light on the impact of political instruments on the future of the bioenergy supply chain. The outputs of this task have been used in Task 5.4.

Tasks 5.4 – 5.5 Publishing outcomes in the scientific journals: This task can be divided into two sections within WP3 and WP5. In the first section, under the umbrella of WP3, most the necessary analyses (from Task 5.3) with the corresponding storylines are collected for publication. The draft of the first manuscript has been finalised during the fourth quarter of the second year.

5.2. Planned impact

Our research activities in the Man0EUvRE project hold tremendous promise as they centre on the intricate synchronisation of diverse energy system models at two levels (i.e. regional and pan-European), leading to the attainment of consistent solutions on a continent-wide scale. The developed tools and the generated outcomes through our research are made available to the relevant stakeholders at the end of the project. Policymakers can benefit immensely from the provided insights, as our results will equip them with the means to analyse and anticipate forthcoming events and gauge their ramifications within regional and interregional systems.

While many continent-wide models predominantly concentrate on the power and gas sectors, we take a bold step forward in this case study. We extend our purview to encompass the bioenergy supply chain, a critical yet mostly overlooked facet. By considering not only the power and gas sectors in the GENeSYS-MOD model but also the interplay of the bioenergy supply chain by linking with the BENOPTex model, we enhance the comprehensiveness and relevance of our findings at the European level. Furthermore, BENOPTex accounts for the intricate interplay between future climate scenarios and available lands. This forward-looking approach enables us to provide insights that are attuned to the evolving dynamics of our environment, ensuring the utmost accuracy and applicability of our results for a future resilient system.

5.3. Implementation

First, the output from GENeSYS-MOD is imported into BENOPTex and converted to standard units. For selected scenarios, relevant decision variables are identified for inclusion in BENOPTex. Considering the technological resolution of each model, a permissible range is defined within which the BENOPTex optimal solution may diverge from that of GENeSYS-MOD. This allows for targeted adjustments to GENeSYS-MOD results in the subsequent iteration within WP2. Finally, for the selected sectors and technologies, BENOPTex results are aggregated back into the original format and transferred to GENeSYS-MOD.

5.3.1. Challenges

Due to limitations in defining new technologies within the IAMC format, the detailed pathways of biomass use across different technologies in BENOPTex must be aggregated. Moreover, as the connected models evolve to better capture the interplay between synthetic fuels and bioenergy, they must also incorporate the variability of intermittent renewable resources. This necessitates the development of a stochastic model, which is often computationally demanding.

Expanding the model to additional countries has also proven challenging, as it requires in-depth knowledge of each country's energy system and policy landscape.

5.3.2. Mitigation Measures

Although the IAMC format is less detailed than BENOPTex in representing bioenergy technologies, we provide the necessary data for model expansion in a format that can later be integrated into GENeSYS-MOD.

To capture the intermittency of renewable energy sources for Power-to-X (PtX), we first integrated intermittent renewable technologies into BENOPTex and then used historical weather data to represent their variability. To enhance the model in this regard, we developed a parallelised approach in which each scenario is solved independently using a dedicated solver.

While the model has been successfully extended to Hungary, solving it with a linear programming (LP) solver proved infeasible due to its bi-level structure. To overcome this, the model was further enhanced to incorporate decision variables across multiple levels within an equilibrium solution framework (T. Szabó et al., 2025).

5.4. Results

5.4.1. Outcomes

In this section, we present the results of our case study on the optimal deployment of bioenergy in selected European countries using BENOPTex. Two European countries are selected for this purpose: Germany and Hungary. The Hungarian model has been developed considering national geographical resolution, whereas the German model is detailed to the federal state.

5.4.1.1. Hungarian Case Study

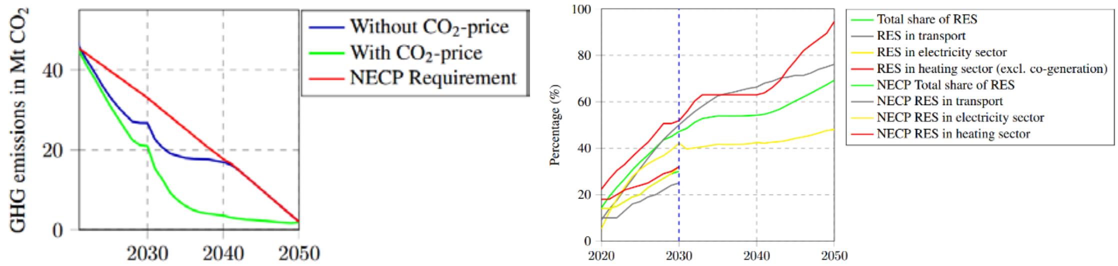
As a first step, we implemented a deterministic model of the Hungarian energy system, focusing on the integration of renewable energy sources (T. Szabó et al., 2025). To this end, the status quo and planned targets for Hungary are collected. The latest Hungarian NECP is studied, and major targets are identified, which are as follows:

- Achieve a share of at least 30% renewable energy sources in gross final energy consumption by 2030.
- Increasing the share of renewable energy in heating and cooling by at least 1 percentage point between 2021 and 2025 and by at least 1.3 percentage point per year between 2026 and 2030.
- Increase the renewable energy share in DH on average by 2.2 percentage points per year until 2030.
- Reducing the share of natural gas to 50% by 2030 in DH, by increasing the share of municipal solid waste and waste heat technologies.

These regulations were modelled endogenously and solved using an iterative optimisation algorithm. The results show that the targets in the NECP of Hungary are not tight enough, and a cost-optimal solution can even improve these targets by using bioenergy more efficiently. Figure 5.2 (a) depicts that the GHG emissions of Hungary's energy sector will decrease from an initial value of approximately 46.7 Mt in 2019 to less than 2 Mt in 2050, thanks to the expansion of nuclear and renewable energy in various sectors. Based on the blue trend denoting a scenario without CO_2-price, it is evident that our model selects production pathways with lower emissions, thus reaching lower GHG emissions than the amounts prescribed by NECP's climate neutral WAM[5] scenario for the energy sector. This can be due to economic advantage of the technologies, or due to the final maximum emission limit in 2050 that unfolds effect on the evolution of cost-optimal GHG emissions in the whole period. All in all, the NECP requirement seems not bold enough until 2040. After 2041, the scenario without CO_2-price aligns with the NECP's maximum emission requirements. The green trend denoting the scenario with CO_2-price shows a substantially higher system capacity to reduce GHG emissions, by reaching to only 3.6 Mt CO_2eq by 2040 – around 14 Mt CO_2eq lower than required.

Figure 5.2 (b) depicts the overall NECP renewable energy target of 30% in FEC by 2030, its sectoral sub-targets, and the renewable energy shares. The renewable shares in the scenario without CO_2-price also substantially exceed the NECP target for every sector. The reason for overachieving the 2030 targets is that the distribution of GHG-abatement achieved with higher shares of renewables in 2030 is cheaper since reaching to 2 Mt CO_2eq by 2050 remains an overarching target in 2030 as well.

[5] WAM: With Additional Measures



(a) GHG trends under the cost-optimal solutions.

(b) Share of total final energy consumption from RES in various sectors in the scenario without CO_2-price (%).

Figure 5.2. Results of modelling Hungarian NECP via the bioenergy optimisation model.

Our findings underscore the important role of geothermal energy (both in heating and power generation), biomass in the heating and cooling sector, and biomethane and second-generation biofuels in the transport sector. The substantial role of bioenergy is evident in the growth of biomass feedstock utilisation in the optimal solution, as both scenarios increase the consumption of energy crops and residues from around 160 PJ in 2020 to around 400 PJ in 2050 (T. Szabó et al., 2025).

5.4.1.2. German Case Study

To endogenously model the generation of renewable electricity from solar and wind, as well as its competition with bioenergy, we extended the deterministic BENOPTex model into a stochastic version (Gutjahr et al., 2025) using 40 years of weather data. Risk sensitivity was incorporated into the objective function through the inclusion of Value-at-Risk (VaR) and Conditional Value-at-Risk (CVaR) measures. The results, in Figure 5.3, show that when solar and wind energy are abundant, the overall system cost is at a minimum, whereas during shortages, flexible bioenergy can support meeting electricity demand, albeit at approximately 10% higher total system cost. Moreover, our findings suggest that excessive risk sensitivity may drive greater dependence on dispatchable fossil energy, which poses a serious threat to achieving climate targets.

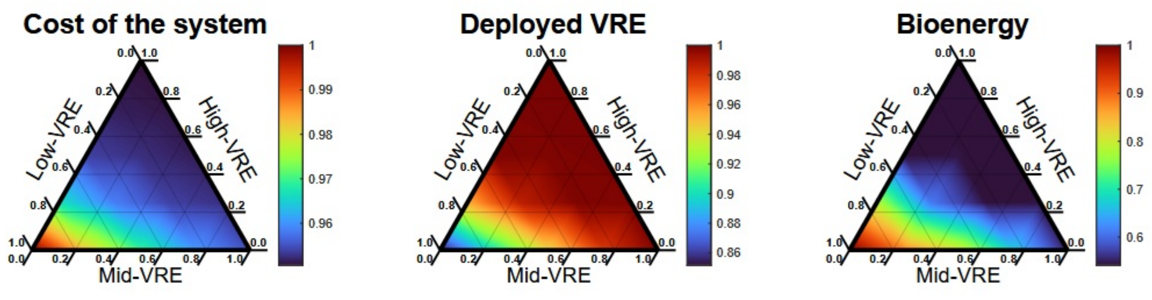


Figure 5.3. Results of risk-neutral stochastic model for German energy system.

As shown in Figure 5.4, under the high availability of variable renewables, the model invests in solar and wind energy more uniformly across states, primarily due to the widespread availability of solar energy. In contrast, under the low availability of VREs, northern states focus more on wind energy and southern states prioritise solar energy, while states located in the central region invest less overall compared to those in the north or south. This results in Bavaria in a capacity multiple times higher than the average of all states under low-VRE scenario in comparison to high-VRE scenario, reflecting patterns similar to the current situation (Gutjahr et al., 2025).

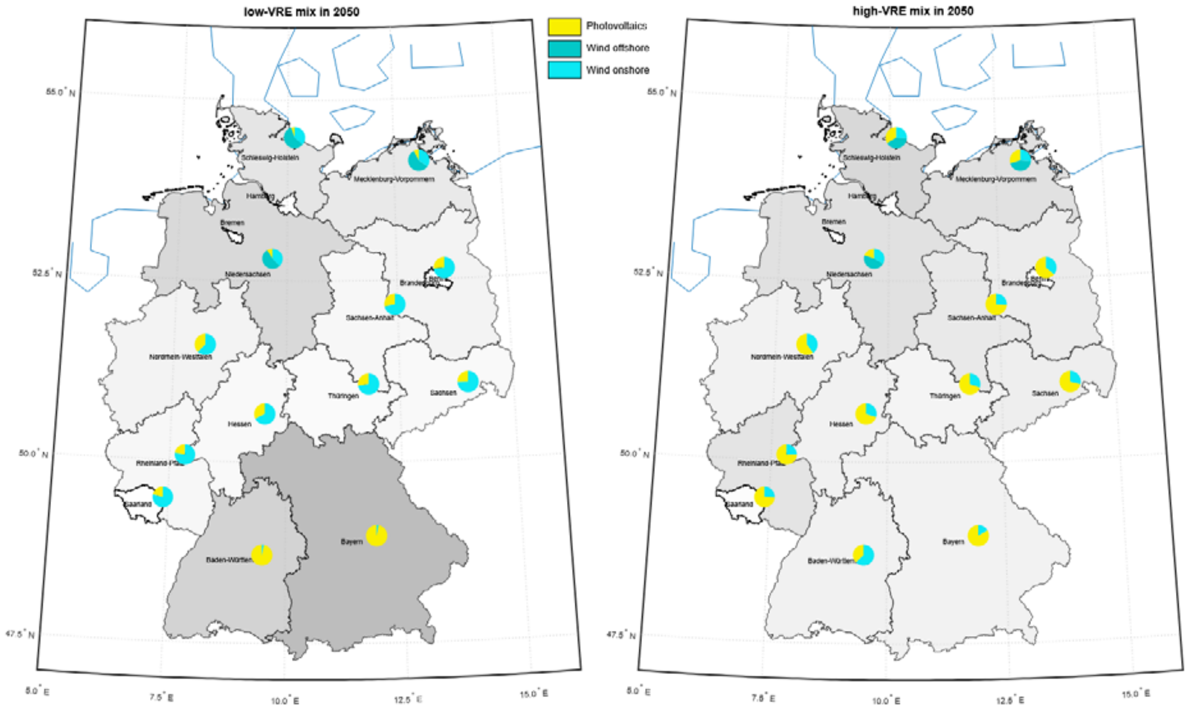
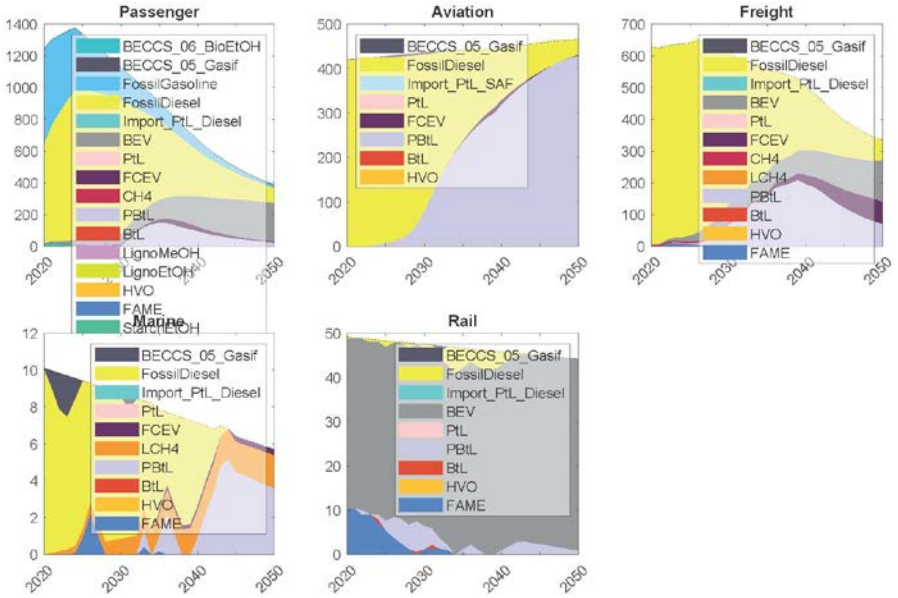


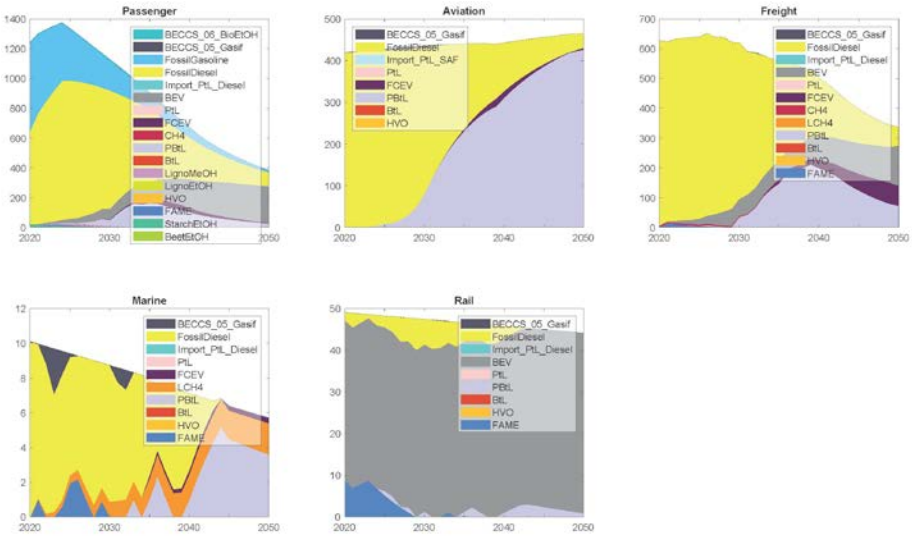
Figure 5.4. A risk-sensitive (i.e., VaR with α = 99%) mixture of VREs (installed capacities in GW) in different German states in 2050.

The BENOPTex model is utilised to model selected scenarios that are provided by GENeSYS-MOD. Selected variables are kept feasible within a window based on the level of detail; therefore, the selected BENOPTex technology variables were aggregated to the level of detail provided by GENeSYS-MOD. In the evaluation of the results, we present the dominant technologies for the different sectors of the energy system until 2050 in comparison for two analysed scenarios. The size of the windows depends on the scenario. For comparison, the REPowerEU++ and NECP scenarios were selected, utilising GENeSYS-MOD data Version 1.2. The following results are broken down by sector.

The analysed transport sector consists of the passenger, the aviation, the freight, the marine and the rail subsector. We identify a decline in energy demand for passenger vehicles, freight, and the marine sector. In 2050, the dominating technologies will be BEV and PBtL. Fossil diesel and gasoline is still used in 2050 in both scenarios but overall, a decline in fossil diesel is shown in Figure 5.5. Besides BEV, an increase in PBtL, especially in the freight and marine sectors, is detected from 2030. Finally, in the marine sector, the usage of liquid methane increases until 2050.

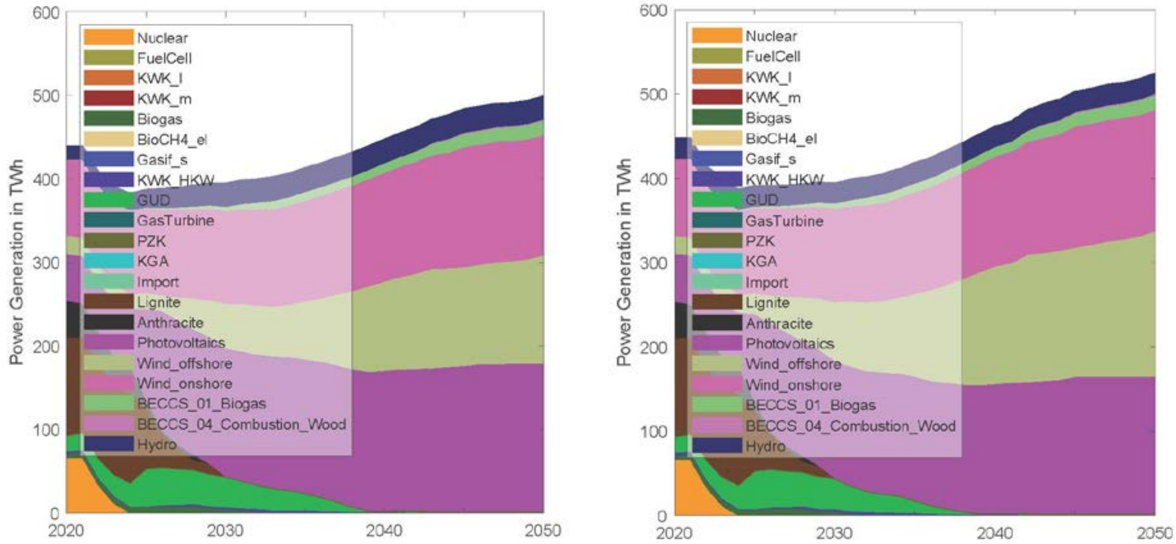


(a): REPowerEU++ Scenario.



(b) NECP Scenario.

Figure 5.5. Technologies in Transport Sector until 2050 in REPowerEU++ Scenario.



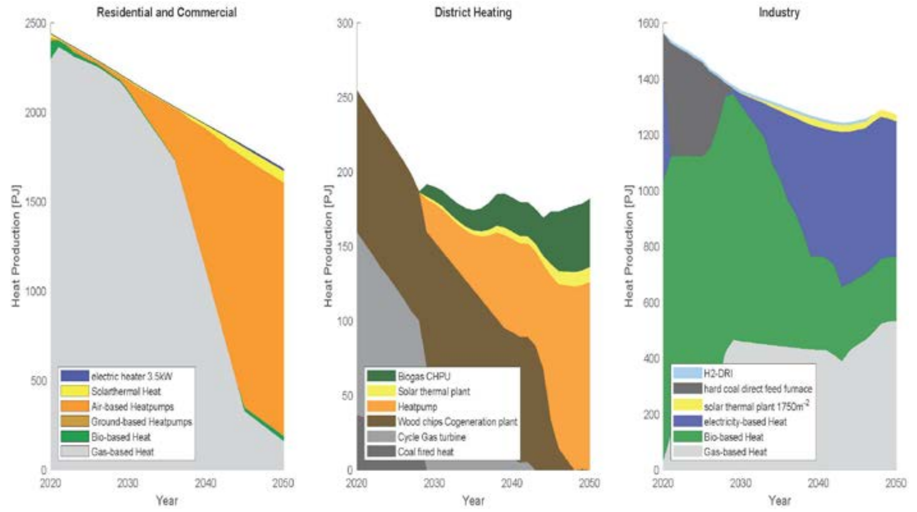
(a) REPowerEU++ Scenario (b) NECP Scenario

Figure 5.6. Technologies in the power sector until 2050 in REPowerEU++ Scenario.

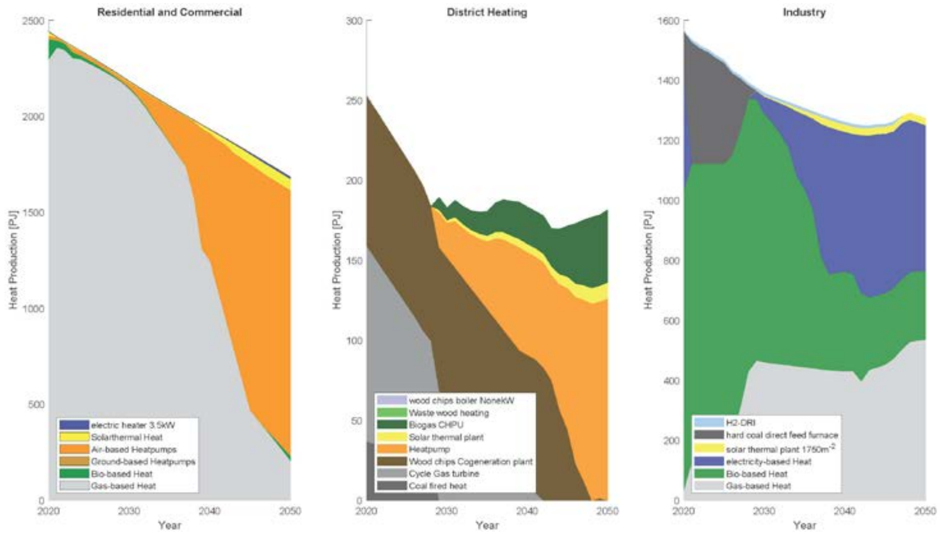
The analysis of the power sector, in Figure 5.6, reveals that under the REPowerEU++ scenario, solar PV will be the dominant technology in 2050. Germany's nuclear phase-out until 2023 is also visible from the figure. Additionally, lignite will be used until 2030 for power production. Figure 5.6(b) shows the electricity production until 2050 under the NECP scenario, and an increase in power generation is visible. To fulfil Germany's NECP targets, the capacities of onshore wind and offshore wind increase until 2050. However, the capacity targets as defined in the NECP will not be reached. BECCS technology will also assist Germany in removing atmospheric CO_2 to compensate for emissions from the hard-to-abate sectors.

For the analysis of the heating sector, three subsectors were identified, and the technologies are aggregated for better visualisation (see Figure 5.7). We analyse heating technologies in the residential and commercial sector, district heating and industry heating. While technologies based on gas decrease in the residential use, as in district heating applications, the industry will rely more on gas in 2050. Bio-based heating technologies are mostly used in the industry subsector. The share of air-based heat pumps will increase for residential and commercial applications and in district heating.

The NECP sets the target for large-scale heat pumps with more than 500kW per year for 2030 to 86TWh, which is not reached in our results. However, as stated in the NECP more than 23.5% of energy in heating and cooling will be generated from renewable sources, the Germany specific goal of 32% is not reached. The goal to implement 500.000 new heat pumps per year is not implemented into the model.



(a) REPowerEU ++ Scenario.

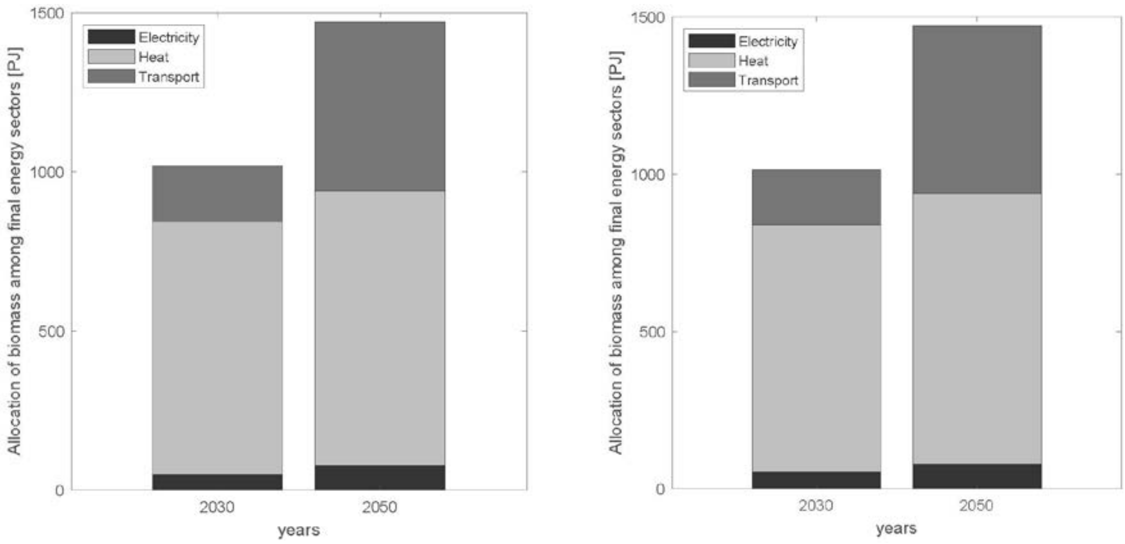


(b) NECP scenario.

Figure 5.7. Technologies in Heating sector until 2050.

In conclusion, it can be stated that the NECP scenario leads to approximately 0.6 % higher total costs compared to the REPowerEU++ scenario.

Comparing the allocation of biomass in different sectors for the two scenarios shows less biomass usage in 2030 under the NECP scenario. In both scenarios, an increase in biomass usage in the transport sector from 2030 to 2050 can be detected. Most biomass is used in the heating sector, and only a small amount for electricity production as indicated by Figures 5.8 (a) and (b).



(a) REPowerEU++ scenario (b) NECP scenario.

Figure 5.8. Allocation of biomass in different sectors in 2030 and 2050.

5.4.2. NECPs

Germany has set ambitious renewable energy targets. In its NECP, clear goals are outlined for solar (215 GW), onshore wind (115 GW), and offshore wind (30 GW) capacity by 2030. However, the plan does not specify targets for other renewable sources and emphasizes that electricity generation from biomass and hydropower is not expected to increase. This means 600 TWh electricity generation from renewables in 2030, accounting for 80% of gross electricity consumption of 750 TWh.

For the heating and cooling sector, the share of renewables must be at least 23.5% by 2030; however, Germany is aiming for an overall share of 32%.

Table 5.1. Final energy demand by sector in Germany

Final Energy Demand in PJ (2030)	NECP (2030)	NECP Essential (v1.2)
Heating and Cooling	5040	4144
Industry	1872	1465
Trade, commerce and households	2520	2952
Transport	2120	1852
Total	11552	10414

5.4.3. Supplementary Data

Incorporating GENeSYS-MOD outputs into case study models, formats as data tables circulated to case study partners (see WP2).

The developed RAG system as well as CADNN system can be found in the GitLab link of Forootani et al. (2025). Some papers linked to these datasets are under review in various journals and are subject to change.

- RAG System: https://github.com/ElsevierSoftwareX/SOFTX-D-25-00122
- CADNN: https://github.com/Ali-Forootani/neural_wind_model
- RE-LLM: https://doi.org/10.5281/zenodo.17311775 (under review)

Additional implementations and data can be found in the repositories listed below.

- HU-BENOPT: https://git.ufz.de/esmaeili/hu-benopt (under review)
- Output of Stochastic BENOPTex: https://git.ufz.de/esmaeili/sto-benoptex.git (under review)

Case study 6: Integrating electricity and gas network supported by energy storage and power conversion processes

ESMs are indispensable for exploring pathways towards deep decarbonisation, particularly when analysing the coupling of electricity and gas infrastructures with emerging hydrogen technologies. While pan-European models, such as GENeSYS-MOD-Europe, provide an integrated view of cross-border energy flows, market interactions, and policy impacts, their spatial and technological granularity is often limited by computational complexity. National-level extensions, such as *GENeSYS-MOD-Turkey*, address this limitation by offering more detailed representations of local technologies, sectoral interlinkages, and region-specific energy strategies.

In CS 6, we focus on Turkey as both a critical consumer and potential supplier of hydrogen within the European energy system. Turkey's strategic position as an energy hub, combined with its domestic renewable potential and recently announced national hydrogen strategy, provides a unique opportunity to examine the role of hydrogen in bridging electricity and gas networks. By incorporating hydrogen storage, electrolysis, and fuel cell technologies into GENeSYS-MOD-Turkey, we aim to capture their contribution to system flexibility, seasonal balancing, and sectoral decarbonisation.

The case study investigates scenarios where locally produced hydrogen is stored and subsequently utilised across multiple end-use sectors, including residential heating, transportation, and electric vehicle demand. This integration highlights the dual role of hydrogen: as a vector for decarbonizing hard-to-abate sectors and as a balancing mechanism supporting large-scale deployment of variable renewable energy sources. By aligning Turkish and pan-European results, CS 6 not only provides insights into Turkey's domestic energy transition but also its potential role in supplying hydrogen to European markets under REPowerEU and related strategies.

6.1. Accomplished Tasks

Task 6.1 – Incorporating GENeSYS-MOD outputs in Genesys-Mod-Turkey: In this task, we identified and formulated GENeSYS-MOD-Turkey–specific parameters within the broader European scenarios. These parameters were conserved, resulting in an optimisation framework capable of capturing the interaction between Turkey and the European energy system. This formulation provides the foundation for integrating hydrogen-related pathways, including electrolysis, storage, and conversion technologies, into the national model.

Task 6.2 – Collecting data for Turkey to be used in Genesys-Mod-Turkey: While the national model was under development, we gathered the required datasets for Turkey. This included energy demand projections, renewable energy potentials, and infrastructure data, as well as newly published policy frameworks, such as the *Hydrogen Strategy Paper* and the *National Energy Plan* (NEP). The technical and political contexts of Turkey have been considered to ensure that the model outcomes reflect both domestic transition priorities and Turkey's potential role in European hydrogen supply.

Task 6.3 – Running GENeSYS-MOD-Turkey to produce results: The knowledge and data collected in Task 6.2 have been incorporated into the GENeSYS-MOD-Turkey framework developed in Task 6.1. Initial model runs have been conducted to test the integration of hydrogen technologies across electricity, transport, and residential sectors. These simulations are ongoing, with preliminary results highlighting the role of hydrogen as a seasonal storage medium and a decarbonisation vector in hard-to-abate sectors. Sensitivity analyses and scenario comparisons are also being prepared to assess the robustness of the results.

Task 6.4 – Publishing outcomes in the scientific journals: This task can be divided into two components within WP3 and WP5. In the first component, under the umbrella of WP3, analyses from Task 6.3 with their associated storylines will be consolidated for publication in peer-reviewed journals. The draft of the first manuscript is scheduled to be finalised during the fourth quarter of the second year. In the second component, linked to WP5, dissemination and communication activities will continue, with a MSc student preparing further publications under the advisory guidance of the postdoctoral researcher.

6.2. Planned impact

The integration of hydrogen-based storage and conversion systems in the GENeSYS-MOD models is expected to yield significant benefits both locally for Turkey and at the broader European scale. Locally, incorporating hydrogen into Turkey's energy mix will help decarbonise hard-to-abate sectors (such as heavy industry, heating, and long-haul transport) by replacing fossil fuels with green hydrogen. This is crucial for meeting Turkey's climate goals (including net-zero emissions by 2053) and reducing dependence on imported natural gas. In scenario analyses, introducing hydrogen (e.g. via power-to-gas and blending) led to substantial reductions in CO_2 emissions and lowered natural gas demand, thereby cutting import dependency. Moreover, using hydrogen as a storage medium enhances flexibility and resilience in the energy system: Surplus renewable electricity can be converted to hydrogen and stored, then converted back to power during peak demand or low renewable periods. This long-term storage capability (far beyond battery timescales) provides seasonal balancing and backup, improving the reliability of a renewable-based grid. It also strengthens energy security by enabling domestic renewable energy to substitute for fossil fuels.

EU-wide, the hydrogen integration in Turkey's model has positive spillover effects aligned with European decarbonisation initiatives. The EU's REPowerEU plan, for instance, targets 20 million tonnes of renewable hydrogen by 2030 (10 Mt domestic production and 10 Mt imports) to both decarbonise and diversify Europe's energy supply. Turkey's capacity to produce green hydrogen at scale can contribute to this goal by exporting renewable hydrogen or synthetic methane to European markets, leveraging its abundant solar/wind resources and strategic location. This supports EU efforts to replace natural gas (especially Russian imports) with clean alternatives, enhancing overall system resilience. At the same time, domestic benefits in Turkey (reduced emissions and improved flexibility) complement EU climate objectives – both aim for net-zero emissions around mid-century. In line with REPowerEU and Turkey's own NEP, the project's modelling of hydrogen systems is expected to accelerate electrification and sector coupling. By enabling higher renewable penetration and electrification of end-uses, it addresses goals such as increasing the share of electricity in final energy (to ~25% by 2035) and expanding clean hydrogen capacity. For example, Turkey's NEP calls for deploying 5 GW of electrolysis capacity by 2035 to produce green hydrogen, as a stepping stone to 70 GW by 2053. Integrating hydrogen storage in the model directly contributes to these targets, demonstrating pathways to achieve them. In summary, the planned impact includes faster decarbonisation of multiple sectors, strengthened energy security through hydrogen-based flexibility, and concrete contributions to the REPowerEU strategy and Turkey's NEP objectives (renewables integration, electrolyser deployment, and electrification of demand).

6.3. Implementation

To realise the above vision, a phased implementation approach has been undertaken for Case Study 6. The GENeSYS-MOD-Europe results provide a high-level pathway, which is being downscaled and refined for Turkey using GENeSYS-MOD-Turkey, ensuring consistency between EU-wide trends and national specifics. The implementation steps are summarized as follows:

- **Incorporating EU Scenario Outputs:** First, outputs from the European model (GENeSYS-MOD for Europe) were integrated as boundary conditions and benchmarks for the Turkish model. This included using European decarbonisation scenarios (with hydrogen deployment) to inform Turkey's model inputs. Key parameters such as carbon prices, fuel import prices, and overall hydrogen demand/supply levels from the EU scenario were mapped onto the Turkey model to ensure alignment with the broader EU pathway.
- **Collecting National Data and Model Extension:** Next, the team gathered up-to-date national data and adapted the model to Turkey's context. This involved assembling detailed Turkish energy data: demand projections by sector, renewable energy potentials, technology costs, and policy targets (from sources like Turkey's NEP and Climate Strategy). The GENeSYS-MOD-Turkey model was then extended with new modules to represent hydrogen pathways at a finer resolution. For instance, local electrolysis, hydrogen storage, and fuel cell technologies were added or parameterised based on Turkey-specific conditions. Infrastructure for hydrogen – such as potential pipeline transport and storage facilities – was approximated within the model's framework. Throughout this phase, care was taken to validate that imported EU-level assumptions (from the first step) were consistent with Turkey's data (e.g. adjusting Europe-wide parameters to match Turkey's demand scale and resource availability).
- **Running Local Simulations (Ongoing):** With the data and model updates in place, scenario simulations for Turkey are being executed. The model is currently solving for least-cost energy system pathways for Turkey through 2050, now with hydrogen storage and conversion options enabled. These runs explore multiple scenarios (e.g. varying hydrogen demand in transport, different electrolyser cost trajectories, and policy constraints like emission caps aligned with net-zero 2053). The simulation phase is *ongoing* – preliminary results are being generated, and the model is iteratively validated. As the runs complete, the outcomes will feed into analysis of how hydrogen can optimally be deployed in Turkey's energy mix under different conditions. The current status is that the core model runs are under way, and subsequent steps will involve result processing, stakeholder review, and integration of any feedback into final scenario runs.

6.3.1. Challenges

Implementing this integrated modelling approach has presented several **technical and logistical challenges**:

- **Data Integration and Consistency:** One challenge is harmonising data and assumptions between the EU-wide model and the Turkish model. The European scenario operates at an aggregated level, so downscaling its results to disaggregated Turkish model (and combining them with detailed local data) requires careful calibration. Ensuring consistency in input parameters (e.g. technology costs, efficiencies, and demand projections) is non-trivial – discrepancies could lead to misaligned outcomes.
- **Adapting EU-Level Constraints to Turkish Context:** The EU scenario provides overarching targets and limits (e.g. EU-wide CO_2 budgets, hydrogen import/export targets, renewable deployment goals), which are not directly applicable at the national level without adjustments. A challenge has been translating these high-level constraints into the Turkey model. For example, if the European model assumed a certain availability of hydrogen imports or a uniform carbon price, the Turkish model must adapt this to local policy context (Turkey's own emissions targets, trade possibilities, etc.).
- **Multi-Sector Coupling and Model Complexity:** Incorporating hydrogen affects multiple sectors (power, transport, industry, buildings), which increases the complexity of the model. Capturing sector coupling – for example, linking surplus renewable electricity in the power sector to hydrogen production for transport or heating – means the model must handle new interactions and possibly finer time resolution. This multi-sector integration is computationally demanding and can lead to larger solution spaces for the optimisation. Balancing detail and tractability are a challenge: Too much detail could make the model intractable, while too little could miss important dynamics of hydrogen use across sectors.
- While national data for Turkey's electricity system are well-established, hydrogen-specific datasets—such as techno-economic parameters for domestic production, storage, and transport—remain scarce. Aligning these with policy frameworks, including the Hydrogen Strategy Paper, NEP, and Climate Change Mitigation Strategy, requires careful harmonisation.

6.3.2. Mitigation Measures

Several measures have been implemented to address the above challenges and ensure a robust modelling framework:

- **Parameter Validation and Harmonisation:** To tackle data integration issues, a thorough validation of input parameters was conducted. We cross-checked European model outputs with Turkish statistics and adjusted inputs accordingly. For instance, if the EU model projected a certain hydrogen demand in Turkey by 2030, we compared it with Turkey's own plans and modified demand profiles to avoid unrealistic gaps. Additionally, the team performed test runs and sensitivity analyses to ensure that the integrated dataset yields stable and credible results for Turkey (e.g. checking that energy balances and emissions in the base year match known values).

- **Model Enhancements with Modular Design:** The GENeSYS-MOD framework's open, modular structure has been used to incorporate hydrogen-related technologies as plug-in modules. The team added new functionality for electrolysers, hydrogen storage, and fuel cells in a stepwise manner, verifying each addition against simple test scenarios. By designing these components modularly, we maintained flexibility to activate or deactivate parts of the hydrogen supply chain as needed. For instance, a module for **local electrolysis and storage** was developed (reflecting a PV–electrolyser–H_2–fuel cell system) and integrated into GENeSYS-MOD-Turkey. This modular approach mitigates complexity: We can isolate the hydrogen sub-model for debugging, and ensure it interfaces correctly with the power, transport, and gas sectors. It also allows adapting EU-level hydrogen constraints (like blending limits or import availability) by toggling parameters in the module without overhauling the whole model.
- **Use of Open-Source Tools and Data Standards:** The project leverages open-source modelling tools and **harmonised data sets** to ease integration. GENeSYS-MOD itself is open-source, which allowed the team to modify the code for new hydrogen functionality without proprietary barriers.

Data gaps for hydrogen in Turkey are mitigated through triangulation of sources: published government strategies (Hydrogen Strategy Paper, NEP, Climate Change Mitigation Strategy), and international technology cost databases.

To deal with uncertainties around Turkey's export role, we are planning to construct multiple scenarios with differing assumptions about infrastructure investments and policy harmonisation with Europe. This approach enabled us to bound the potential range of Turkey's contribution to the European hydrogen system, while remaining consistent with both national NECPs and EU decarbonisation pathways.

6.4. Results

The preliminary results from the GENeSYS-MOD-Turkey simulations with hydrogen integration are promising, illustrating how hydrogen can bolster Turkey's energy transition while interacting with the broader European system. Overall, the model suggests that introducing hydrogen technologies leads to a more flexible, low-carbon energy system by 2050.

Hydrogen emerges as a key energy carrier that connects sectors: It enables excess renewable power to be stored and later used across electricity, transport, and heating applications, thereby smoothing out intermittency and aligning energy supply with demand patterns. The presence of hydrogen-based storage improves the resilience of the system – Turkey can maintain energy supply during peak demand or low renewable periods by tapping into hydrogen reserves, reducing the risk of outages or reliance on emergency fossil backup. Importantly, the results indicate these benefits can be achieved while pursuing Turkey's and Europe's long-term climate targets.

The integrated scenario meets stringent decarbonisation goals (consistent with net-zero emissions by 2053 for Turkey) and even allows Turkey to contribute to EU climate objectives by exporting clean energy in the form of hydrogen or derived fuels. In the following subsections, we will detail the outcomes of the case study, discuss how they align with policy targets, and outline the supplementary data that will accompany this report.

Place holder for ES v2.0
The results in this section are initial findings; final quantitative figures will be incorporated once the ongoing simulations are completed. The narrative highlights expected trends and contributions, with placeholders for figures from the model runs. This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

6.4.1. Outcomes

The initial model outcomes reveal several qualitative trends about hydrogen's role, as well as indicative quantitative impacts on Turkey's energy mix:

- **Hydrogen Uptake in Transport and Residential Sectors:** The simulations show hydrogen being substantially utilised in transportation, particularly for modes less suited to direct electrification. By 2040–2050, a notable fraction of Turkey's heavy-duty transport energy is supplied by hydrogen (fuel-cell trucks, buses, and possibly trains), reducing diesel use and cutting emissions. Lighter vehicles are largely electric, but hydrogen fuel-cell vehicles complement battery EVs for long-range needs. In the residential and commercial sectors, the model anticipates hydrogen playing a strategic role. Rather than widespread direct hydrogen heating, the optimal pathway is to blend hydrogen into existing natural gas networks for heating and cooking, especially post-2040, to decarbonize those end-uses. By 2050, the hydrogen blending rate in gas could reach the technical limits (on the order of 15–20% by energy, as a placeholder), which abates a corresponding share of emissions from buildings. Additionally, small-scale fuel cells appear in some scenarios for combined heat and power in buildings or distributed generation, supporting residential loads and providing backup power using hydrogen – these further underlines hydrogen's versatility alongside electrification.
- **Seasonal Balancing and Energy Storage:** A critical outcome is the utilisation of hydrogen for seasonal energy storage. The model's least-cost solution leverages Turkey's summer surplus of solar and wind generation to produce hydrogen via electrolysis, which is stored for later use. During winter months or prolonged low-renewable periods, this stored hydrogen is converted back to electricity (through fuel cells) to meet demand peaks. This pattern confirms the expected role of hydrogen as a seasonal battery for the energy system. Quantitatively, the storage capacity (hydrogen tanks or underground caverns) in 2050 is on the order of several TWh of energy, enabling a significant shift of energy from high-output periods to months with deficits. The presence of this storage smooths out the renewable supply curve and reduces curtailment of solar/wind – the model results show a reduction in renewable curtailment by a substantial margin thanks to hydrogen conversion. Moreover, the resilience benefit is evident: even in stress-test simulations (e.g. a cold winter with low wind), the hydrogen buffer ensures electricity supply adequacy and reduces reliance on imported fuels or costly peaking plants.
- **Integration with PV/Wind Generation:** The hydrogen pathway significantly enhances the integration of renewable energy in Turkey. By providing an outlet for excess generation, it allows the model to install more solar and wind capacity without the usual constraints of curtailment or grid instability. In scenarios without hydrogen, renewable expansion was limited by the need for balance, but with hydrogen, the 2050 renewable installed capacity is higher. The hourly dispatch profiles from the model show that midday solar peaks, which would overshoot demand, are absorbed by flexible electrolysers ramping up to convert

electricity to hydrogen. Wind generation at night or in windy seasons is similarly utilised to produce hydrogen when it exceeds immediate demand. This flexible load from electrolysis effectively acts as a grid-balancing resource, consuming power when prices are low or when the grid needs to shed load. Conversely, during peak demand or low renewable periods, the stored hydrogen is used to generate power, feeding electricity back into the grid. This two-way interaction (power-to-hydrogen and hydrogen-to-power) improves overall system efficiency and economics: it reduces the curtailment losses and provides a form of arbitrage that flattens the demand-supply mismatch. The model results thus expect higher renewable penetration – by 2050, renewables could contribute over 60% of Turkey's total final energy consumption (up from ~20% today, based on our preliminary calculations), facilitated by hydrogen storage and conversion. In summary, the outcomes highlight hydrogen as a linchpin for integrating renewables and decarbonising challenging sectors, with tangible benefits in terms of emissions reduced, fossil fuel imports avoided, and system flexibility gained.

6.4.2. NECPs

The findings and assumptions of this case study are closely aligned with Turkey's climate and energy plans and related strategic documents, ensuring that the modelled pathway supports national priorities. Firstly, the net-zero 2053 target is explicitly built into the scenario – the model meets an emissions trajectory that reaches carbon neutrality by 2053, echoing Turkey's official commitment. This means all sectors contribute to deep decarbonisation, with hydrogen playing the role outlined by national strategy (replacing fossil fuels where electrification is difficult). The scenario's hydrogen development is also consistent with the **Turkey Hydrogen Strategy and Roadmap**: the model results achieve approximately 5 GW of electrolyser capacity by 2035, matching the NEP's interim target and then scale up hydrogen production further to approach the **70 GW by 2053 vision.** In doing so, the scenario supports Turkey's goal of becoming a regional hydrogen exporter and technology leader.

Additionally, the integrated model assumes ambitious improvements in energy efficiency and electrification in line with Turkey's NECP expectations. By 2035, primary energy intensity improves by around 35%, which mirrors the NEP's target of a 35.3% reduction in energy intensity (versus 2020) through efficiency measures across all sectors. This reduction is achieved in the model via measures like industrial process optimisation, building insulation, and efficient appliances – all exogenous inputs consistent with Turkey's Climate Change Mitigation Action Plan.

Electrification of demand is another pillar: the scenario reflects the NEP projection that the share of electricity in final energy consumption rises from about 22% in 2020 to ~25% by 2035 and continues further to exceed 50% by 2053 as Turkey's energy system transforms. Such high electrification (over half of final energy by mid-century) aligns with both the NECP and the EU's broader decarbonisation scenarios, indicating consistency between national efforts and European trends. The electrification is driven by the uptake of electric vehicles, heat pumps, and electric industrial processes in our model – all assumptions cross-checked with Turkey's national plans (e.g. EV deployment targets and industrial electrification goals in the 2024–2030 Climate Action Plan). Meanwhile, hydrogen serves to decarbonise the remaining energy uses that are not easily electrified, alleviating also the transmission lines' congestion, which is exactly the role envisaged in Turkey's climate strategy (e.g. using hydrogen for heavy industry and blending into gas networks by 2053). Lastly, the scenario's renewable energy expansion is aligned with NECP targets, such as reaching ~65% renewable share in power generation by 2035 and beyond, ensuring our model does not wildly exceed or undershoot official expectations.

In conclusion, the case study's modelling outcomes are not only technically and economically optimised but also **policy-coherent** – they support Turkey's NECP objectives of net-zero emissions, enhanced efficiency, large-scale electrification, and strategic hydrogen development, thereby providing a plausible pathway for real-world policy implementation.

6.4.3. Supplementary Data

To support transparency and allow replication, a comprehensive set of supplementary data and scenario details will be provided in the appendices. This will include **scenario parameters** (all key inputs and assumptions used in the model runs), such as technology cost trajectories, fuel price projections, demand growth rates, and policy targets for each scenario variant. We will also supply the specific **hydrogen-related assumptions** – for example, electrolyser capital costs, efficiency and lifetime assumptions, hydrogen storage costs and capacities, and fuel cell performance characteristics – that underpin the hydrogen integration analysis. These assumptions are drawn from open sources and aligned with both EU and Turkish references and will be tabulated for clarity. Furthermore, details on the **spatial and temporal resolution** of the model are provided: the appendices document how Turkey is regionally represented in GENeSYS-MOD (if applicable) and the time-slice structure used to capture daily/seasonal variations for renewables and hydrogen operations. Maps or tables may illustrate the regional breakdown or resource distribution used. Finally, we include an overview of the **scenario definitions** (storylines) analysed in this case study (e.g. baseline vs. hydrogen-boost scenario), and any deviations from default GENeSYS-MOD configurations. All supplementary information follows the project's open-data ethos, enabling interested stakeholders to review the assumptions and even run the model themselves.

This additional data is intended to provide full context for the results, ensure reproducibility of the findings, and offer granular insights that could not be exhaustively covered in the main report.

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

Case study 7: Greece as a renewable energy hub

The purpose of the seventh case study is the examination of Greece's potential to become a medium- and longer-term renewable energy hub within the European-MENA region. In this study, we examined and compared Greece's potential for domestic production, transportation, and re-export of various energy carriers, including renewable electricity, green hydrogen, synthetic fuels, and green ammonia. The aim was to identify the interrelationships among these carriers and determine the optimal combination of resources, infrastructure, and technical and economic conditions required to make this potential a reality. To this end, we performed simulation analyses of the Greek energy market and its interconnections with neighbouring countries using the PRIMES energy system model. An energy system analysis was then conducted to evaluate emissions, costs, and investments in line with the targets of the net-zero greenhouse gas strategy, which also assessed the impact of available infrastructure (e.g., new electrical interconnections with Egypt and Israel, which could enable further exports either to Italy and Germany or to the South-East European market).

7.1. Accomplished Tasks

Task 7.1 – Model enhancement & calibration: In this task, the Electricity, Heat/Steam, and Clean Fuels modules of PRIMES were expanded to better align with the targets of this case study. Following a significant update to the technoeconomic data used, the PRIMES hydrogen and synthetic fuels module was further enhanced, including the addition of production technologies, transportation options, and interlinkages with other modules. Further improvements to the power and heat supply modules were made in conjunction with an update to the input calibration databases, including existing power plant capacities. Following the completion of these enhancements, some initial simulations based on existing PRIMES scenarios were run for testing purposes, including assumptions on future interconnection infrastructure of electricity and hydrogen.

Task 7.2 – Data updates to include the latest information and data from final NECPs 2024: This task focused on gathering and implementing NECP data related to the targets and policies submitted by the member states of the EU and the rest of the countries that may impact this case study's results (e.g. non-EU Balkan states). This task was delayed in its conclusion, mainly because not all NECPs were submitted on time.

Task 7.3 – Model simulations: Following the implementation of the targets of the final Greek NECP, and in conjunction with the model testing started in Task 7.1, the scenario designing and simulation phase was initiated. As a first step, a detailed evaluation of Greece's sectoral demand for electricity, hydrogen and synthetic fuels, focusing on the latter, which is an ongoing research topic with little to no actual data to calibrate on, was conducted. A reference scenario, not based on the EU-EnVis data, was created. Subsequent scenarios have been developed to assess the impact of several factors, the most important of which is expected to be variations in export demand, since the aforementioned analysis indicated that domestic demand is not likely to vary significantly.

Task 7.4 – Results analysis and impact assessment: In this final task, the evaluation of the simulation process's outputs per scenario and a comparison between them on fuel consumption, power generation by plant type, emissions, fuel prices, imports/exports, etc., are conducted.

7.2. Planned impact

The results of the case study provide policymakers, investors, and infrastructure authorities with a deeper understanding of how Greece's energy system could evolve under different hydrogen and synthetic-fuel deployment pathways. By comparing scenarios that examine delayed hydrogen infrastructure, export-oriented synthetic-fuel production and domestic self-reliance, the analysis offers complementary insights to those in the Greek NECP. It highlights how Greece's substantial renewable resources could support a future role as an energy and green-fuels hub in the wider European–MENA region.

The scenario outcomes, covering the evolution of the electricity mix, the scale of renewable deployment, the role of hydrogen and e-fuels, and the resulting import–export configurations, can support strategic decision-making for long-term energy planning, infrastructure prioritisation and regional cooperation. They also highlight the system implications of different strategic orientations, including the renewable capacity, storage needs and hydrogen infrastructure required to enable domestic decarbonisation and, where relevant, potential export activity.

In doing so, the case study does not seek to replace or critique the roadmap set out in the NECP, but rather to enrich it by illustrating the broader set of possibilities that could arise as hydrogen and synthetic-fuel markets develop across Europe and neighbouring regions.

7.3. Implementation

Following the finalisation of PRIMES' modelling enhancements, calibration, and testing, a routine for data import from the IAMC format used in the EU EnVis scenarios, with appropriate implementation and mapping to the PRIMES model, was designed. To guide the determination of crucial parameters (such as demand and prices), a more detailed elaboration was employed to represent better the specific case study in the final scenario design. The PRIMES model was used for each case, and a total energy system analysis, comparison, and impact assessment have been conducted for all of them.

7.3.1. Challenges

The primary challenge in Case Study 7 was aligning the GENeSYS-MOD data outputs with those of the PRIMES model. There are possible discrepancies in assumptions about efficiencies and capacities, as well as variations in the availability of necessary parameters in the GENeSYS-MOD outputs. Additionally, differences in the structural modelling approaches, such as how sectoral demand is modelled, make achieving full compatibility quite complex.

7.3.2. Mitigation Measures

To navigate the challenges in Section 7.3.1 effectively, we have chosen to focus on specific outputs, particularly electricity demand, capacity levels, and pricing. This strategy facilitates the implementation of distinct storylines for each EU-EnVis scenario while incorporating the necessary assumptions about missing data already established in the PRIMES model. EnVis scenarios version 1.2 was used in all simulations.

A baseline scenario, based on the EU member states' NECPs and assumed to achieve the targets set at the European level, mainly, was designed to address data and assumption gaps related to the structural differences between GENeSYS-MOD and PRIMES. The scenario was extensively tested and serves as the underlying assumption whenever discrepancies arise between the two models.

The total final energy demand and power plant cost data of GENeSYS-MOD was used across all countries represented, while for the rest, the PRIMES baseline scenario values were used. Due to PRIMES having a much more disaggregated sectoral allocation, and achieving targets is closely associated with sectoral behaviour, the demand sectoral allocation of the baseline scenario was applied to the total final energy demand of the EnVis scenarios, instead of a mapping between the models. Hydrogen and synthetic fuel demand are either too low or non-existent in the EnVis scenarios. This was incompatible with the case study's target of evaluating the effects of different energy carriers on Greece's potential as an energy hub, as well as with Greece's NECP, which explicitly includes projections of synthetic fuels demand. As such, the baseline scenario projections were used as the associated demand for each EnVis scenario in the four initial simulations. In these projections, Greece is a net exporter of hydrogen, but a net importer of synthetic fuels. The underlying assumption is that Greece's hydrogen production benefits from a strong RES potential and, as such, lower prices and demand from central Europe are the main drivers for exports, given a pipeline network as predicted by the European Hydrogen Backbone. Synthetic fuel production is assumed to be consistent with refinery activity at the European level; this reflects an assumed business shift of refinery activity from the production of fossil fuels to the production of synthetic fuels, given the accumulated knowledge in fuel production, land and infrastructure availability etc. The cost data assumed for hydrogen and synthetic fuels production do not follow the EnVis scenarios, as a variety of production technologies (PEM, Alkaline, SOEC electrolysers for hydrogen, Fischer Tropsch, Methanol-to-X for synthetic fuels, etc.) are modelled and the costs are a result of the technology mix, which is a model decision.

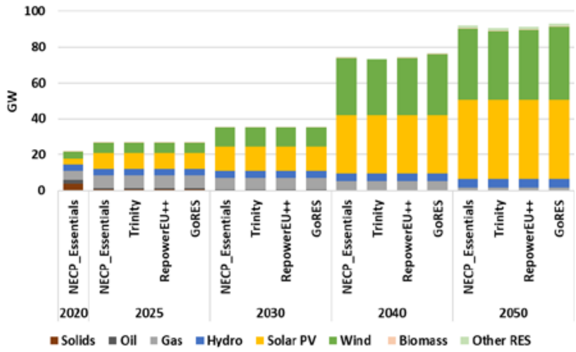
A sensitivity analysis was then conducted, using the GoRES scenario as its basis, exploring variants in hydrogen and synthetic fuel production and trade. GoRES was selected for this purpose as its assumptions of higher social acceptance, technological growth, and favourable geopolitical conditions would make the more sense as the basis for experimentation with new technologies based on conversion of electricity. It would also make more sense to quantify such effects on a scenario where electrification of the energy system is more thorough, to examine its impact on an already high-RES deployment electricity market. The following variants were explored: **a)** A scenario in which hydrogen infrastructure had a slower uptake, with the planned Bulgaria-Greece pipeline being commissioned in 2040 instead of 2030; **b)** A scenario in which Greece became a net exporter of synthetic fuels, reflecting substantial investment in synthetic fuels production that surpassed current refinery activity; and **c)** A scenario of total self-reliance in hydrogen and synthetic fuel demand that is also accompanied by a lack of demand for exports.

7.4. Results

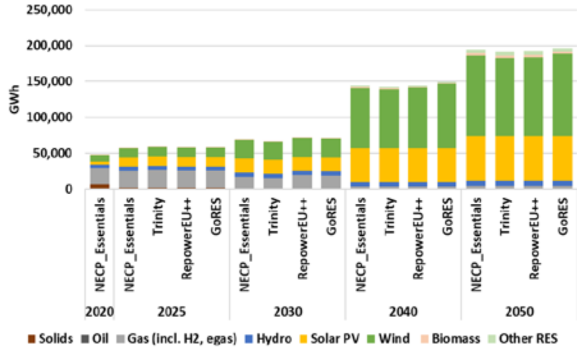
7.4.1. Outcomes

Greece is rapidly transforming its energy system to meet EU climate goals and achieve neutrality by 2050, with the updated NECP targeting over 80% renewable electricity by 2030, supported by grid upgrades, island interconnections, and large-scale storage. Rising electricity demand from electrification, hydrogen, and synthetic fuels will drive further investment. While the NECP focuses on domestic decarbonisation, cross-border projects like HVDC links to Egypt, Cyprus, Israel, and the Balkans could position Greece as a regional energy hub, though timelines and market dynamics remain uncertain. This analysis complements the NECP by exploring how such infrastructure could expand Greece's role in regional renewable and synthetic fuel exchanges.

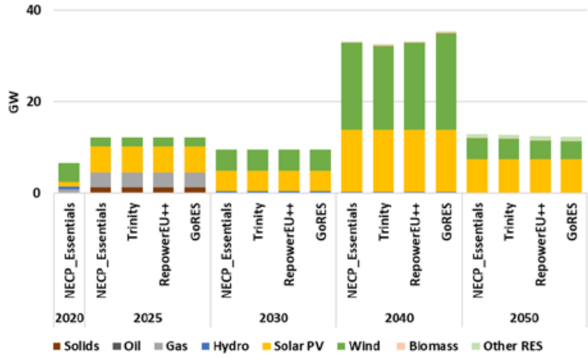
The initial four simulation runs implemented each of the EnVis scenarios' electricity final energy consumption in conjunction with the endogenously calculated demand for hydrogen and synthetic fuels. The results exhibited little variation in both generation quantities and technology mix. As depicted in Figure 7.1(a), the installed power capacity for each of the scenarios is very similar in the whole timeseries. Figure 7.1(b) shows that net electricity generation closely follows the data presented in Figure 7.1(c). This is an expected outcome, as in the case of Greece and its neighbouring countries, electrification and deeper RES penetration results both from their NECPs and their trajectory up until now. As such, the absence of significant hydrogen and synthetic fuels demand projections from the EnVis scenarios becomes more evident in the case of Greece, as these could have a much more significant impact on the whole of the power system depending on their level of deployment. That was the main reasoning behind the sensitivity analysis conducted around it, the results of which will be further discussed next.



(a) Net installed power capacity



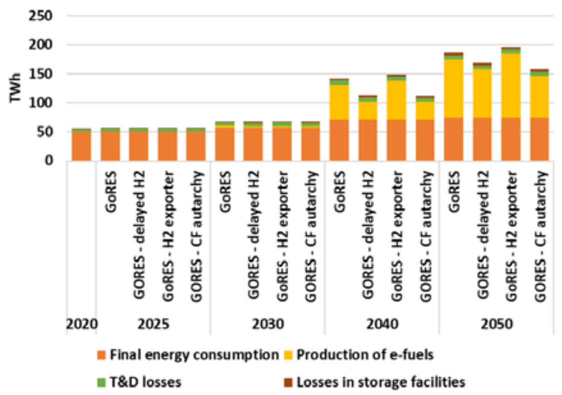
(b) Net electricity generation



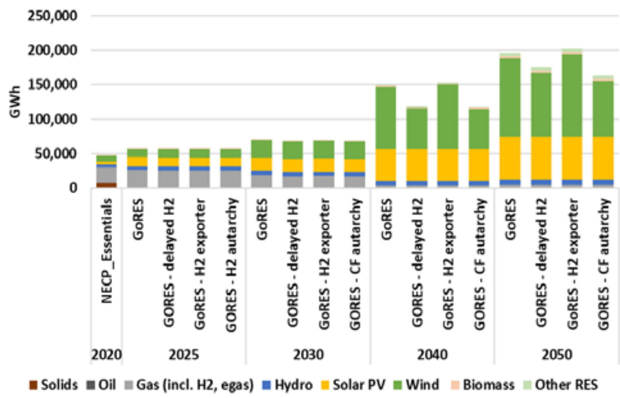
(c) Capacity addition (Investments)

Figure 7.1: Results by fuel type across EnVis scenarios.

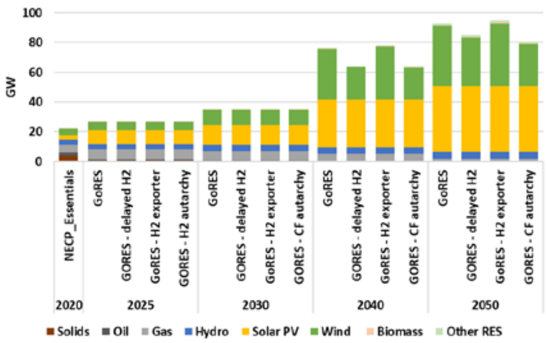
In the subsequent simulations, the PRIMES model was applied to the Go-RES scenario family by running the reference Go-RES pathway alongside three sensitivity variants, each reflecting different assumptions about hydrogen and synthetic-fuel production and trade. These variants included: a delayed-infrastructure case, in which the planned Greece–Bulgaria hydrogen pipeline is commissioned in 2040 instead of 2030; an export-oriented case, assuming Greece becomes a net exporter of synthetic fuels through substantial investment in production capacity; and a self-reliance case, in which hydrogen and synthetic-fuel production meet domestic needs only, with no demand for exports. In all simulations, the final electricity consumption from Go-RES was introduced as an exogenous input to PRIMES. At the same time, hydrogen and synthetic-fuel demand were calculated endogenously and kept consistent within each respective variant.



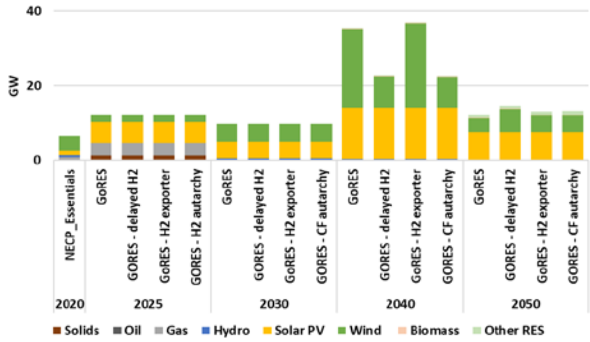
(a) Electricity demand in Greece



(b) Net electricity generation by fuel type



(c) Net installed power capacities



(d) Capacity investments

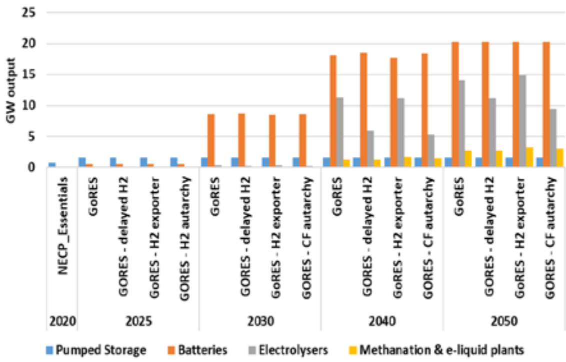
Figure 7.2. Results by fuel type in Greece for the Go-RES scenario family.

The results show that electricity demand across the Go-RES scenario family remains relatively stable up to 2030, ranging from 55 to 70 TWh, as shown in Figure 7.2(a), in close alignment with the NECP projection of 56.3 TWh for that year. This similarity reflects the fact that the near-term electrification of buildings, transport and industry is broadly consistent across scenarios and remains the primary driver of consumption by 2030. After this point, however, demand diverges significantly due to differences in hydrogen and synthetic-fuel production, the timing of hydrogen infrastructure availability, and the presence or absence of export markets.

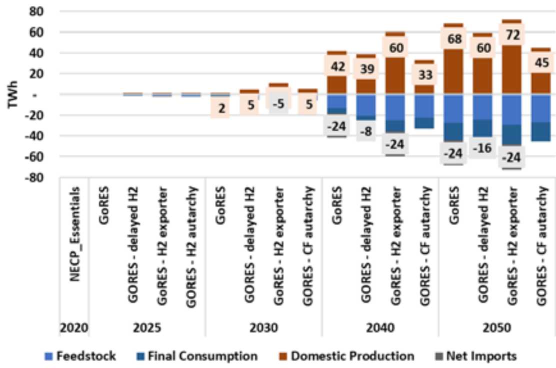
Electricity demand in Greece is projected to rise sharply under all Go-RES scenarios, driven primarily by hydrogen and e-fuel production. In the baseline case, demand grows steadily after 2030, reaching 110–130 TWh by 2040 and nearly 170 TWh by 2050—well above the NECP's 122.5 TWh projection. This reflects the substantial power requirements of electrolysis and synthetic-fuel synthesis, even without exports. The H_2-exporter scenario shows the most pronounced growth, with demand approaching 200 TWh by mid-century as Greece becomes a major producer and exporter of synthetic fuels, revealing a structural gap between current NECP planning and export-oriented pathways. By contrast, the delayed-H_2 scenario sees slower growth until 2040, when commissioning of the Greece–Bulgaria hydrogen pipeline triggers rapid expansion, compressing system development into a shorter timeframe and intensifying integration challenges. The CF-autarchy scenario, assuming self-sufficiency and no exports, results in more moderate growth to around 150 TWh by 2050, yet still exceeds NECP levels. Across all cases, even modest hydrogen and e-fuel deployment significantly amplifies electricity needs, underscoring that any future with meaningful PtX penetration will require a far larger power system than current policy anticipates.

The composition of electricity generation shifts rapidly toward renewables in all Go-RES variants, as presented in Figure 7.2(b). By 2030, coal and oil will have been almost completely phased out, and natural gas supplies will only account for a limited share of the generation mix, mainly as a balancing resource. Solar PV and wind dominate electricity production, bringing the power system close to the NECP's 81% renewable energy target by that year.

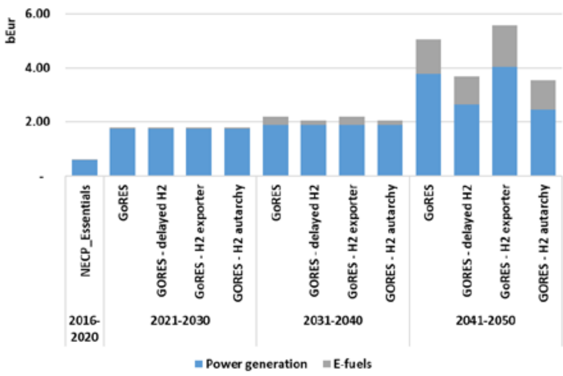
Two distinct investment waves emerge: the first, up to 2030, reflects the decarbonisation and electrification measures already anticipated in policy, while the second, larger wave between 2030 and 2040 corresponds to the rapid build-out required to support hydrogen and synthetic-fuel production. The timing of this second wave is sensitive to the availability of infrastructure. In the delayed-H_2 scenario, the commissioning of the hydrogen pipeline in 2040 compresses the expansion of renewable capacity into a shorter period, creating more concentrated investment pressures. By contrast, the exporter scenario spreads investment over a longer period but requires a larger overall scale. These dynamics highlight the importance of infrastructure and market timing in shaping long-term investment needs.



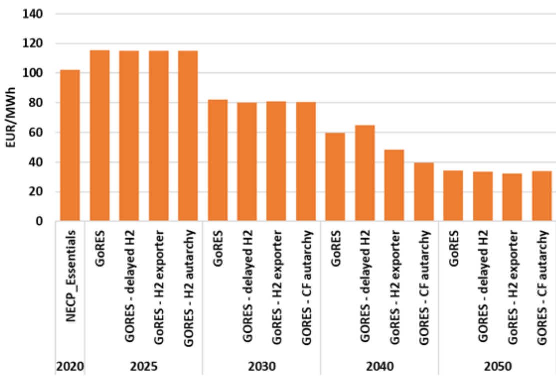
(a) Capacity of energy storage and e-fuel production facilities



(b) Hydrogen balance in Greece



(c) Annual investment expenditures



(d) System marginal price for electricity

Figure 7.3. Sensitivity analysis of outcomes for the Go-RES scenario family.

Storage and e-fuel production evolve in tandem with rising renewable penetration and PtX deployment. As shown in Figure 7.3(a), pumped storage remains limited by geographic constraints, while battery capacity expands rapidly—reaching 8–9 GW by 2030, 18–20 GW by 2040, and over 20 GW by 2050—well above NECP projections and highlighting the need for fast-response flexibility. Electrolysers become a defining feature post-2030, with 10–12 GW installed by 2050 in the baseline and delayed-H_2 scenarios, and nearly 15 GW in the H_2-exporter pathway to support large-scale hydrogen and synthetic-fuel production. Even the autarchy scenario, despite lower electrolyser capacity, requires significant synthetic methane and e-fuels production to meet domestic demand. Across all cases, electrolysers and e-fuel facilities shift from peripheral to central system components, with deployment timing shaped by infrastructure and export strategies. As illustrated in Figure 7.3(b), hydrogen production grows from negligible levels to 40–45 TWh by 2040 in most scenarios and up to 75 TWh by 2050 in export-oriented pathways, far exceeding domestic demand and creating substantial export surpluses. Consumption rises to 37–50 TWh by mid-century, driven mainly by aviation and maritime sectors, while industrial use remains limited. Trade patterns diverge sharply, as exporter scenarios achieve large surpluses, delayed-H_2 sees later, smaller exports, and autarchy remains self-reliant. These dynamics reveal a strategic gap in the Greek NECP, which omits hydrogen exports and underestimates related infrastructure needs. Even moderate export activity significantly scales up renewable capacity, storage, and system integration needs beyond current national planning.

Investment needs remain modest until 2030, at €1.7–1.9 billion annually across all scenarios, reflecting common constraints such as permitting and grid reinforcement, as shown in Figure 7.3(c). These figures align with NECP expectations and show that near-term investment intensity is shaped more by delivery limits than hydrogen strategy. After 2030, trajectories diverge: the baseline rises gradually to €3.5–4 billion per year in the 2040s, while the H_2-exporter scenario exceeds €5 billion as export-driven infrastructure accelerates deployment. The delayed-H_2 pathway compresses expansion into a shorter window, amplifying late-period investment intensity, whereas the autarchy scenario peaks below €3 billion due to its domestic-only focus. These patterns underscore three insights: infrastructure timing strongly influences investment profiles; export-oriented strategies demand earlier, larger commitments to renewables and PtX; and limiting hydrogen to domestic needs reduces capital intensity but constrains Greece's regional role. Alignment with NECP before 2030 highlights the importance of stable policy, faster permitting, and grid upgrades to keep long-term options open.

Finally, as illustrated in Figure 7.3(d), system marginal electricity prices decline sharply across all Go-RES scenarios as renewables and zero-marginal-cost generation dominate supply. Prices remain around €100–115/MWh in 2020–2025, falling to about €80/MWh by 2030 with fossil displacement and growing storage, which is consistent with NECP expectations. After 2030, prices drop further: by 2040 they range from €50–65/MWh, slightly higher in exporter and delayed-H_2 scenarios due to greater demand, and as low as €40/MWh in autarchy. By 2050, all scenarios converge at €32–34/MWh, reflecting near-zero marginal costs and extensive storage mitigating scarcity pricing. These results contrast with NECP's moderate decline outlook, showing that hydrogen and e-fuel pathways drive a structural shift toward very low prices, moving system economics from operational costs to capital investment and flexibility services. A hydrogen-enabled future would thus imply a need to rethink market design and investment incentives.

In conclusion, we developed the Go-RES scenario family, based on the EnVis 2060 Go-RES scenario, to examine how Greece's energy system could evolve under varying assumptions about hydrogen infrastructure, synthetic-fuel production, and export potential. The analysis complements the NECP by assessing system-level implications of PtX and cross-border integration. Results show hydrogen and e-fuels become essential after 2030, driving higher electricity demand and renewable capacity even without exports, while export-oriented pathways reveal opportunities for Greece to take advantage of its renewable resources as a regional green-fuel supplier. Investment, storage, and flexibility need rise with hydrogen deployment, underscoring the importance of planning for electrolysers, e-fuel facilities, and export infrastructure. The transition to a high-renewable, hydrogen-enabled system also reshapes electricity pricing, pushing marginal costs toward very low levels and shifting value to flexibility and integration services. The Go-RES scenarios act as enrichments of the NECP by illustrating strategic options related to hydrogen and e-fuel deployment that could define Greece's role in an interconnected, decarbonised energy future.

7.4.2. NECPs

The revised Greek NECP provides a comprehensive vision for the energy transition up to 2050, focusing on rapid deployment of renewable energy, electrification, grid reinforcement, and the gradual emergence of renewable gases and synthetic fuels. It sets ambitious targets, including 35.5 GW of installed electricity capacity by 2030 and 70.7 GW by 2050; the near-complete phase-out of lignite by 2028, significant expansion of photovoltaic and wind capacity and the development of initial commercial green-hydrogen production lines, primarily linked to refineries. The NECP also recognises the importance of major interconnections, such as island interconnections and planned grid reinforcements, to support high-RES penetration and system flexibility.

While the NECP's modelling concentrates on domestic decarbonisation and security of supply, it also acknowledges the strategic potential of Greece's geographical position and the transformation of regional gas flows, including the prospect of renewable gases and cross-border exchange evolving in the longer term.

The present study builds on this foundation by exploring how emerging hydrogen and synthetic-fuel markets, in combination with future interconnections, could influence Greece's longer-term role in the wider South-East European and Mediterranean energy systems. In doing so, the analysis complements the NECP by shedding additional light on how Greece's strong renewable potential and forthcoming infrastructure projects might support alternative pathways, including scenarios where the country could act as a producer or exporter of renewable-based energy carriers.

7.4.3. Supplementary Data

The following data from GENeSYS-MoD and the EnVis scenarios[6] were used:

- Capital Costs of Power Plants
- Fixed O&M Costs of Power Plants
- Variable Non-Fuel Costs of Power Plants
- Electricity Final Energy (all countries simulated in GENESYS-MoD)

Other input data, including hydrogen and synthetic fuels production technology costs, conversion efficiencies etc, can be made available in a temporary version upon request, and will be publicly available as open access resources in the near future.

Case study 8: Green transition in France

The objective of this case study is to analyse the potential for electrification of disaggregated consuming sectors. The study focuses on France but will include simulation of the whole Europe. It

[6] https://zenodo.org/records/17079324

investigates the four EnVis-2060 scenarios on selected years, looking at long-term energy policies and realistic development potentials of low-carbon generation and storage, and the massive electrification planned for France. This case study evaluates the potentials for electrification of consuming sectors, renewable electricity generation expansion, reduction of final uses coming from energy efficiency and sobriety, and for other energy vectors such as hydrogen or biofuels, accounting for variable renewable profiles and short-term storage needs.

The French NECP and French strategy regarding the energy system states that achieving carbon neutrality will require **i)** vast electrification of uses, in particular transportation and industry **ii)** reduction of the final energy consumption mainly from energy efficiency (including electrification) and sobriety, and **iii)** significant acceleration in the rate of development of decarbonized electricity generation.

The case study uses the *plan4res* power system model for simulating the power system operation based on the scenarios produced by GENeSYS-MOD.

8.1. Accomplished Tasks

Task 8.1 – adapt the GENeSYS-MOD input data and assumptions for France: The first step was to conduct a comparison of the EnVis-2060 NECP Essentials scenario with the actual NECP for France, with the objective of adapting the inputs of GENeSYS-MOD so that its outputs, regarding the NECP Essentials scenario, are in line with the French NECP. This comparison allowed to identify the main divergences and to propose measures to mitigate them:

- The sectoral consumption as modelled in GENeSYS-MOD needs to be adapted
- The weight of the different energy vectors needs to be adapted
- The electricity generation mix needs to be adapted
- Electrification of uses is underestimated in all sectors, but particularly in the industry sector, where it is "*replaced*" by coal and gas

Task 8.2 – GENeSYS-Mod / plan4res coupling: The objective is to compute "*Flexibility need*" indicators out of plan4res simulation results. These indicators will be fed back to GENeSYS-MOD in order to help GENeSYS-MOD evaluate the need for flexibility. An analysis of the GENeSYS-MOD algorithm, in particular of the time series reduction methodology has been conducted and a set of indicators, together with the specifications of the way to feed them into GENeSYS-MOD.

Task 8.3 – Scenario analysis and sensitivities run: Plan4res has been linked with the inputs and outputs of GENeSYS-MOD via the IAMC data format and nomenclature, and plan4res simulations have been conducted for the case of the scenario NECP Essentials v1.2 and the year 2030.

8.2. Planned impact

- CS8 includes two main expected results:
    - **Methodological result:** implement a feedback loop for feeding GENeSYS-MOD with information from plan4res simulation. The objective is to provide GENeSYS-MOD feedback about the variability of both power demand and variable power potential generation. The objective is to allow GENeSYS-MOD to produce scenarios accounting for the variability of uncertain parameters (such as temperature, wind, sun, water inflows) without using stochastic optimisation.
    - **Case study results:** insights about the French power mix in future years (e.g. 2030, 2050) for the four EnVis-2060 scenarios

8.3. Implementation

The simulations were conducted with the plan4res model. plan4res is an electricity system optimisation and simulation tool, composed of the following three models:

1. **A Capacity Expansion Model (CEM)** aimed at adapting the electricity mix.
2. **A Seasonal Storage Valuation model (SSV)** aimed at optimising the management of seasonal storages. It computes the Bellman values (= cost-to-go functions) that represent the future expected economic value of the seasonal storages' levels at time stages. This is necessary to know when to best use a "*free*" but limited and uncertain resource such as water inflows to large hydropower reservoirs: should the hydropower plant produce now and discharge part of its stored water, for example to avoid starting up a costly coal plant to meet demand, or should water be kept for a latter use, for example because present demand is low and RES generation is sufficient?
3. **A Simulation Model (SIM)** aimed at optimising the short-term operation of the system. The simulation is run on every scenario using a Unit Commitment (UC) model sequentially for the entire period. The cost-to-go functions computed by the SSV are used as a variable cost for the generation of seasonal storages.

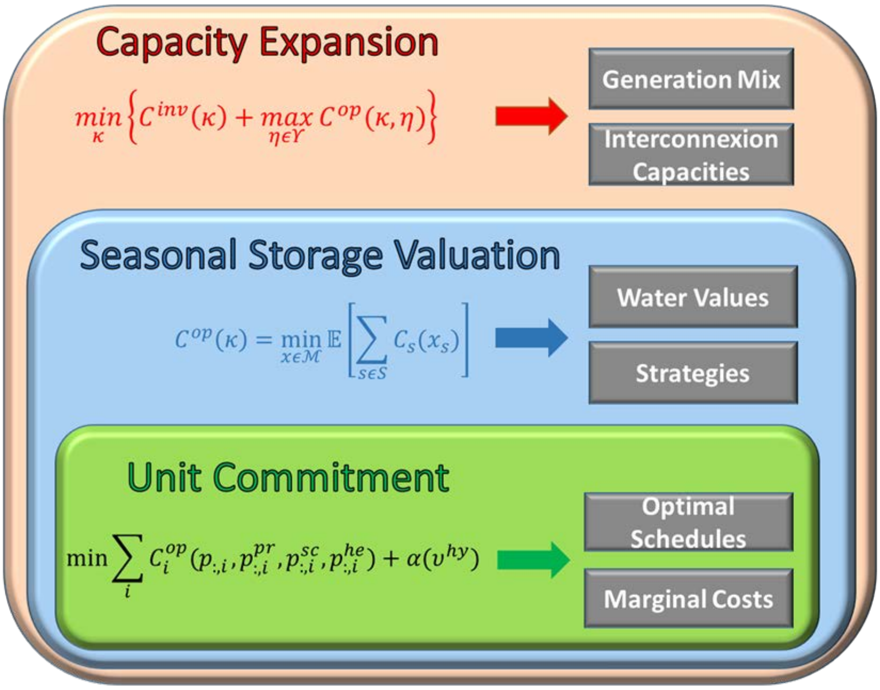


Figure 8.1. the plan4res embedded models.

The aforementioned three models cannot be described independently as:

- The CEM uses the SSV model for the evaluation of its operation cost function, which include the economic values and opportunities offered by seasonal storages.
- The SSV model itself uses the UC model for solving its inner transition problem. Indeed, to assess the value of storages on the long run, the model sequentially computes future cost-to-go functions that represent how much a given amount of energy storage can reduce future operation costs (e.g., by using hydropower to save on expansive fuel costs). To do so, a lot of UC problems are solved recursively using an algorithm called dynamic programming.

All models share the exact same set of data, as summarized in Figure 8.2.

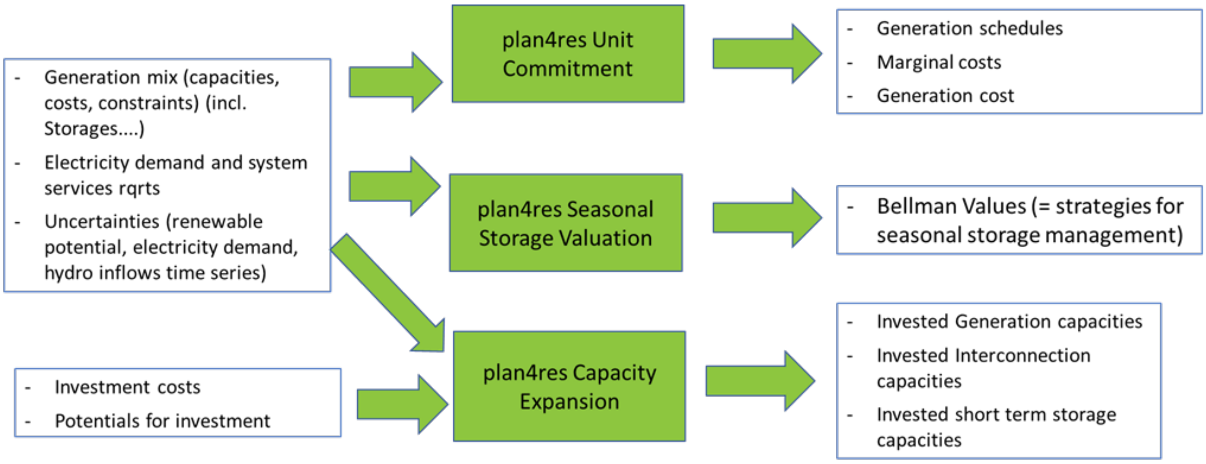


Figure 8.2. plan4res Inputs and outputs.

8.3.1. Challenges

The main challenges consisted in

- Comparing the NECP Scenario with the real NECP, where the main difficulty lies in identifying the correspondence between the different variables and recalculating equivalent ones.
- Computation of the necessary variables for feeding plan4res out of the inputs and outputs of GENeSYS-MOD. For this, we implemented a "*linkage*" script, which converts GENeSYS-MOD inputs/outputs in native format into a dataset in the IAMC format, only focusing on electricity variables. Some difficulties lie in computing the installed capacities with relation to the fuel used.

8.3.2. Mitigation Measures

The following data are required for conducting the plan4res runs:

- Electricity demand projections for all EU countries, separated into uses (heating, cooling, transport, other)
- Electricity generation technologies costs (OPEX and CAPEX)
- Electricity generation technologies characteristics (installed capacities, constraints….)
- Electricity storages characteristics
- Renewables potentials and profiles
- Demand flexibility potentials for each day of a representative year. (from DATACELLAR)
- Transmission grid

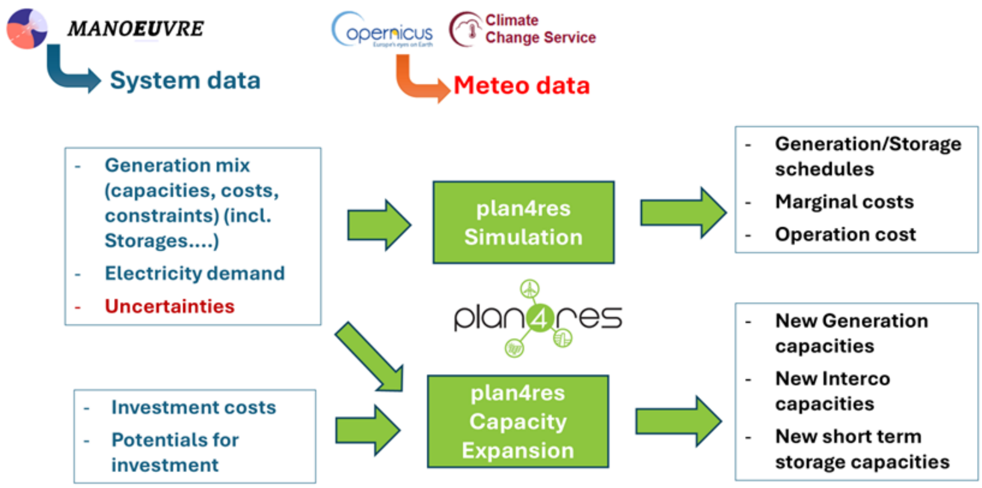


Figure 8.3. plan4res inputs and outputs and where they come from

The following subsections detail the input data per data source.

Data from ENVIS Scenarios:

The following variables are required (following the open ENTRANCE nomenclature). They have been created out of GENeSYS-MOD raw inputs and outputs by using a linkage script for converting the data and computing variables, which are not available in the scenarios.

The following countries were used: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Non-EU-Balkans, North Macedonia, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, The Netherlands, Turkey, United Kingdom.

The following countries are aggregated in regions:

- Belgium, Luxembourg, Netherlands → Benelux
- Estonia, Latvia, Lithuania → Baltics
- Non-EU-Balkans, Bulgaria, Croatia, Greece, Romania, Slovenia, North Macedonia → Balkans
- Austria, Czech Republic, Hungary, Poland, Slovakia → Eastern Europe

The list of variables is the following:

- **For creating the electricity demand: yearly electricity demand per uses; in TWh**
    - Final Energy|Electricity,
    - Final Energy|Electricity|Heat,
    - Final Energy|Electricity|Transportation
- **For describing the transmission grid: interconnection capacities between countries (in MW)**
    - Network|Electricity|Maximum Flow
- **For creating the generation mix, definition of all generation technologies**
    - *Thermal generation, including the following technologies:*
        - Electricity|Biomass|w/o CCS
        - Electricity|Coal|Hard coal|w/o CCS
        - Electricity|Coal|Lignite|w/o CCS
        - Electricity|Gas|Fossil|CCGT|w/o CCS
        - Electricity|Gas|Biomethane|CCGT|w/o CCS
        - Electricity|Nuclear

    - Electricity|Oil|w/o CCS
    - Combined Heat and Power|Biomass|w/o CCS
    - Combined Heat and Power|Biomass|w/ CCS
    - Combined Heat and Power|Coal|Hard coal|w/o CCS
    - Combined Heat and Power|Coal|Lignite|w/o CCS
    - Combined Heat and Power|Gas|Fossil|CCGT|w/o CCS

  The following variables are uses for thermal generation:

    - Capacity|<technology> → installed capacity (GW)
    - Maximum Capacity| <technology> → maximum potential for new capacity (GW)
    - Maximum Utilization|<technology> → average availability in %
    - Lifetime|<technology> → life duration (number of years)
    - Emission|CO_2|<technology> → emission in tons of CO_2 per MWh generated
    - Variable Cost|<technology> → variable operation cost in €/MWh
    - Fixed Cost|<technology> → fixed operation cost in €/MW
    - Capital Cost|<technology> → CAPEX in €/MW

- *Hydraulic generation, including reservoirs (= large lakes), pumped storage and run-of river.*

The following variables are used:

    - Capacity|Electricity|Hydro|Reservoir: installed capacity of hydro reservoir generation (GW)
    - Secondary Energy|Electricity|Hydro|Reservoir for computing the hydraulic inflows to the reservoirs (TWh);
    - Maximum Storage|Electricity|Hydro|Reservoir: size of the reservoir storages (TWh)
    - Maximum Utilization|Electricity|Hydro|Reservoir: average availability (%)
    - Capacity|Electricity|Hydro|Pumped Storage: installed capacity of pumped storage generation
    - Maximum Storage|Electricity|Hydro|Pumped Storage: size of storages (TWh)
    - Maximum Capacity|Electricity|Hydro|Pumped Storage: maximum potential for new generation capacities (GW)
    - Capital Cost|Electricity|Hydro|Pumped Storage: CAPEX (€/GW)
    - Fixed Cost|Electricity|Hydro|Pumped Storage: Fixed operation cost (€/GW)
    - Lifetime|Electricity|Hydro|Pumped Storage: life duration (# of years)
    - Pumping Efficiency|Electricity|Hydro|Pumped Storage: efficiency of the pumped storage
    - Capacity|Electricity|Hydro|Run of river: installed capacity of run of river generation
    - Maximum Capacity|Electricity|Hydro|Run of river: maximum potential for new generation capacities (GW)
    - Capital Cost|Electricity|Hydro| Run of river: CAPEX (€/GW)
    - Fixed Cost|Electricity|Hydro| Run of river: Fixed operation cost (€/GW)
    - Lifetime|Electricity|Hydro|Run of river: life duration (# of years)
    - Pumping Efficiency|Electricity|Hydro| Run of river: efficiency of the pumped storage

- *Renewable Energy Sources, including photovoltaic and wind power generation:*

- Solar|CSP
- Solar|PV|Rooftop
- Solar|PV|Utility
- Wind|Onshore
- Wind|Offshore

The following variables are used:

- Capacity|Electricity|<technology>: installed capacity of run of river generation
- Maximum Capacity|Electricity|<technology>: maximum potential for new generation capacities (GW)
- Capital Cost|Electricity|<technology>: CAPEX (€/GW)
- Fixed Cost|Electricity|<technology> Fixed operation cost (€/GW)
- Lifetime|Electricity|<technology>: life duration (# of years)

Data representing the uncertainties:

We used timeseries from the Horizon Europe CROSSEU[7] project, where hourly scenarised profiles are available. These chronicles correspond to 37 climatic years.

- Hourly demand profiles are generated by multiplying the overall yearly demand by hourly rate profiles from CROSSEU (hourly profiles electricity demand for heating; electricity demand for electric mobility; (deterministic) electricity demand for other uses);
- hourly maximum generation profiles for PV, offshore/onshore wind-power and run of river hydropower are computed by multiplying CROSSEU scenarised profiles by the installed capacity.
- Inflows to reservoir profiles are generated by multiplying the overall yearly energy produced by Reservoir hydro by hourly rate profiles from CROSSEU.

8.4. Results

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026. Results presented here preliminary results only, and will be extended one the final version of the EnVis 2060 scenarios will be available.

8.4.1. Outcomes

The Inputs for the installed capacities and demands: Figure 8.4 shows the power installed capacities in all the regions in the case study, for the year 2030, while Figure 8.5 displays the same data on a map of Europe. The installed capacities are directly derived from GENeSYS-MOD results and served as inputs to plan4res.

[7] The Horizon Europe CROSSEU project: [CROSSEU - Advancing climate resilience]

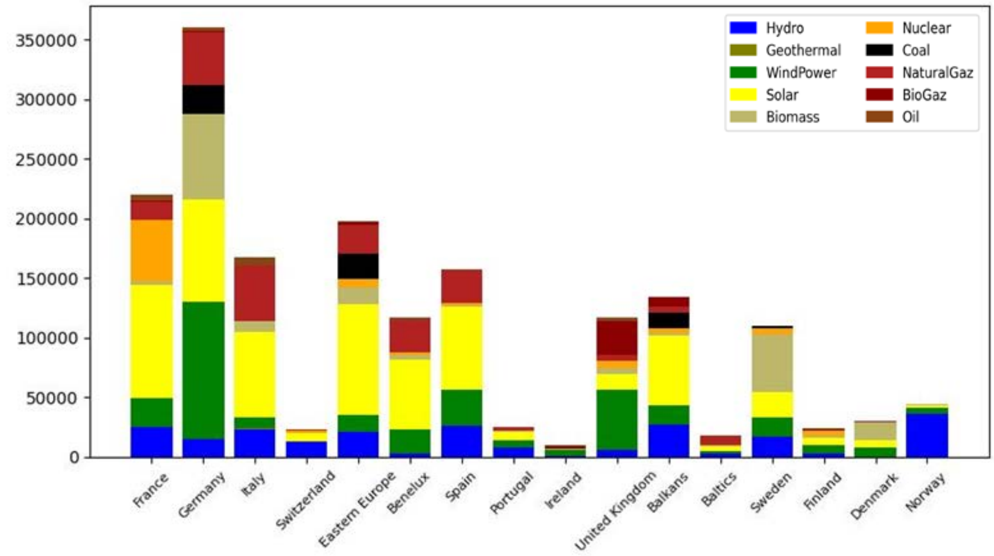


Figure 8.4. Power generation installed Capacity in NECP Essentials v1.2, 2030 (in MW)

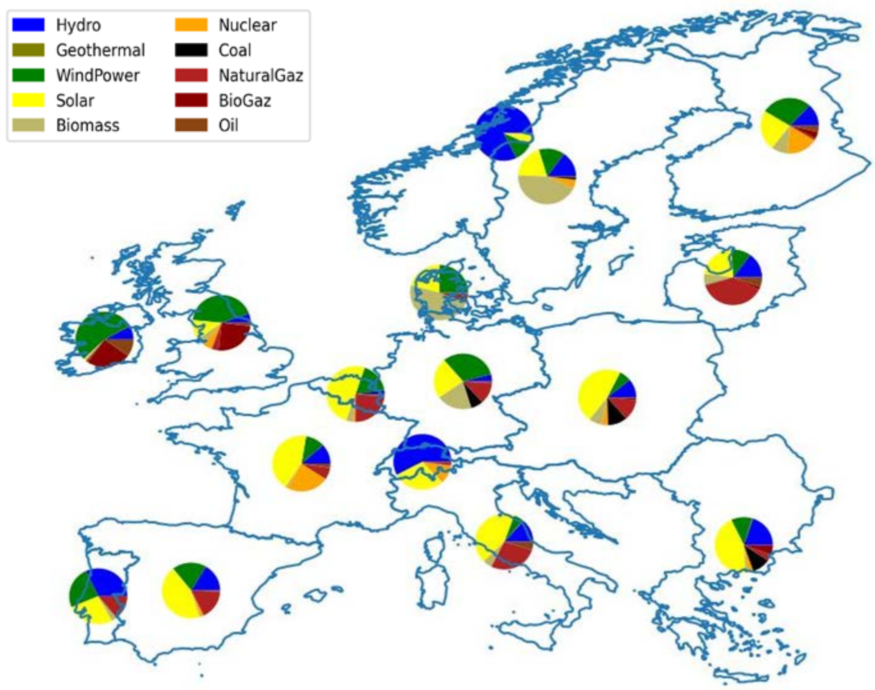


Figure 8.5. Power generation installed Capacity in NECP Essentials v1.2, 2030 (shares).

Figures 8.6 and 8.7 show the interconnection capacities, which are also a result of GENeSYS-MOD and inputs to plan4res.

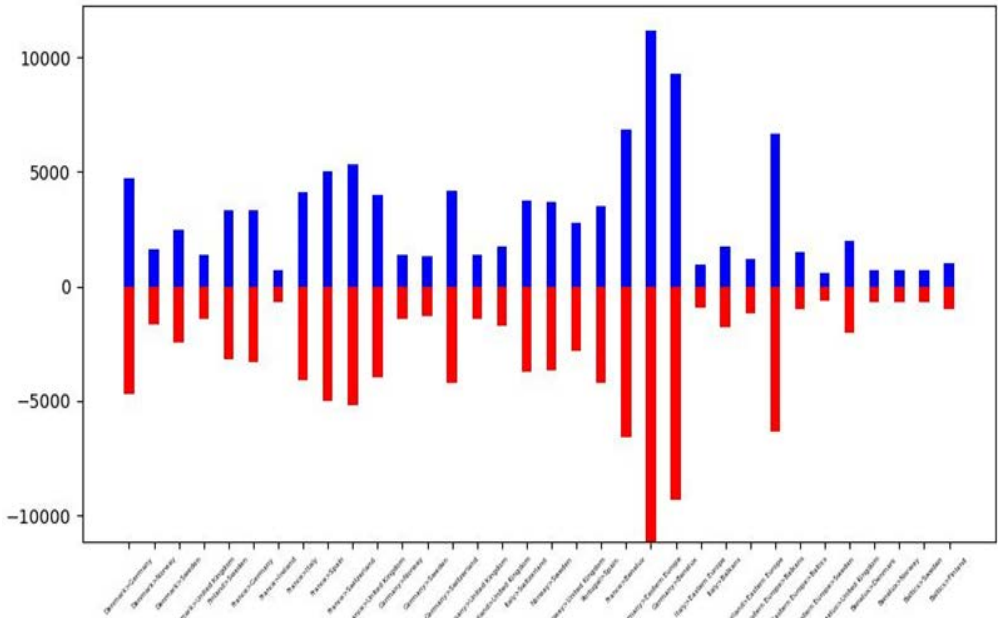


Figure 8.6. Interconnection capacities between regions (in MW)

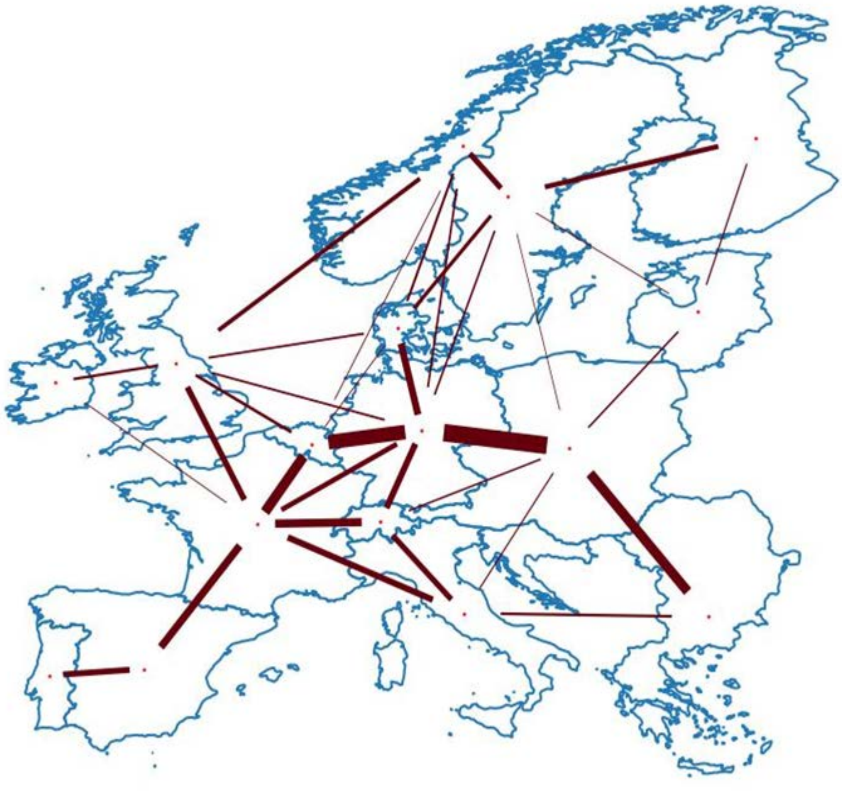


Figure 8.7. Map of interconnection capacities

Figure 8.8 depicts the power demand timeseries, which were computed by multiplying the total power demand (i.e., Final Energy|Electricity) for the year 2030 from GENeSYS-MOD by scenarised hourly profiles of the power demand from the CROSSEU project, based on ERA5 climate projections. In the case study, 105 timeseries (for each region) are employed. Those timeseries, which are also correlated with timeseries for the load factors of renewable generation and inflows to hydro reservoirs, represent climate variabilities.

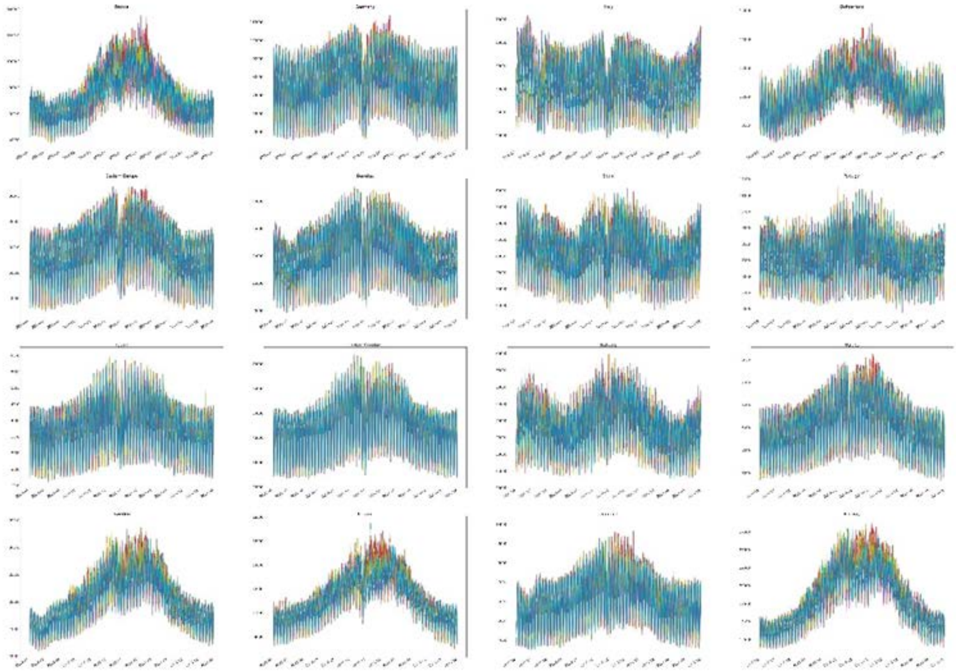


Figure 8.8. Scenarised power demand timeseries between Jul1,2030 and June30, 2030 (in MWh).

Analyses on the whole year 2030: Figures 8.9 and 8.10 show the average yearly power production, which is computed by plan4res, as an average over the 105 climatic scenarios.

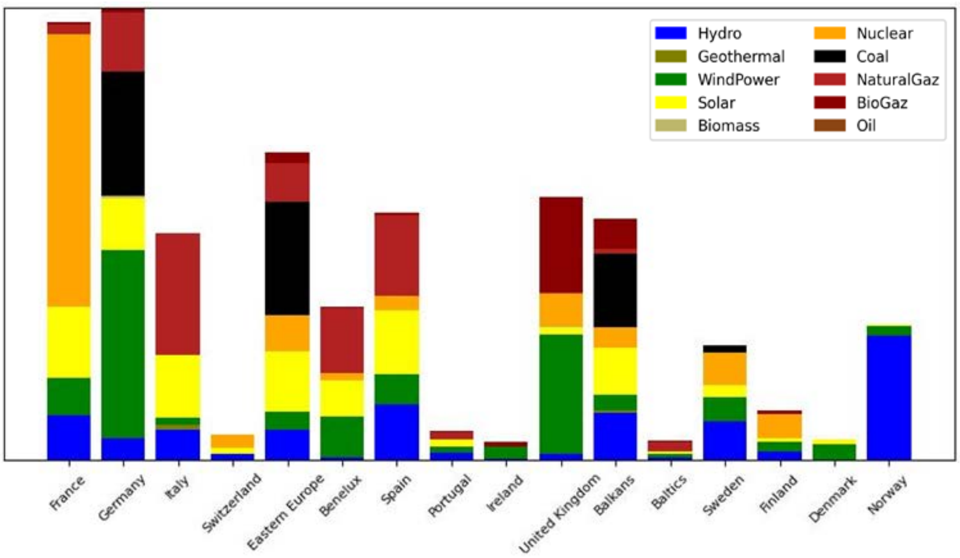


Figure 8.9. Average yearly power production per technology (in MWh).

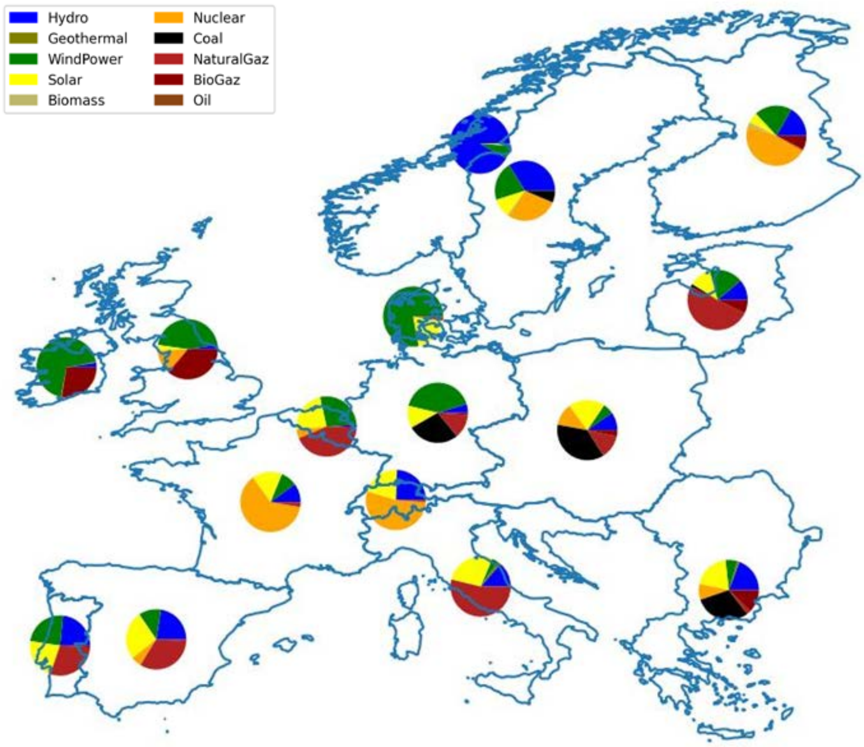


Figure 8.10. Map of the shares of power production per technology.

Figure 8.11 shows the average yearly power flows between the different regions.

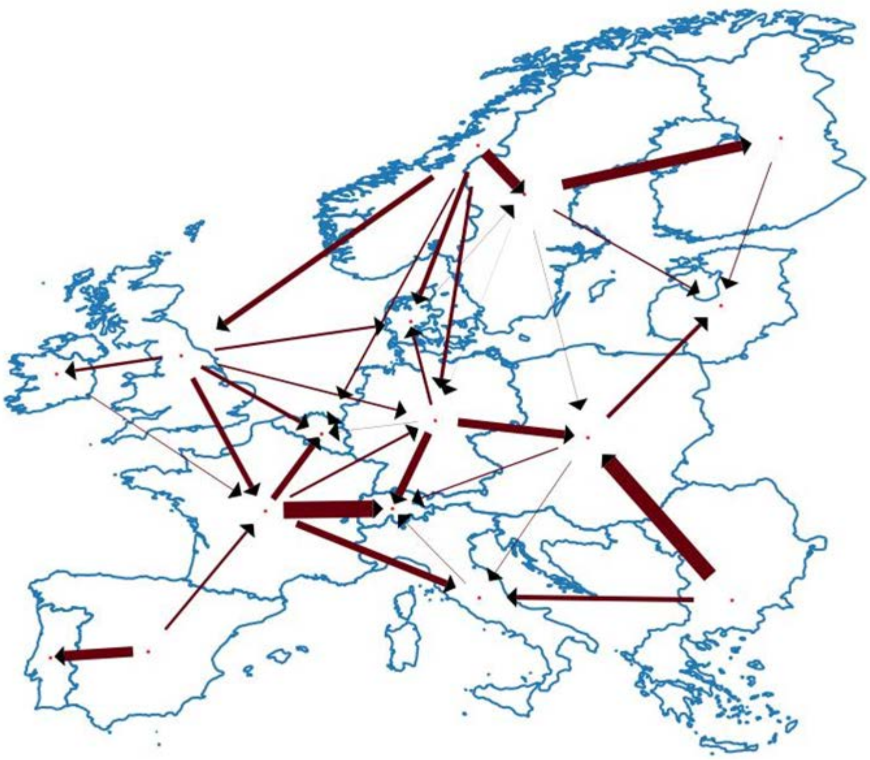


Figure 8.11. Average power flows between regions.

Figure 8.12 shows the marginal costs of electricity in each region, for all scenarios. Those marginal costs have been ordered (biggest first) for helping the reader to visualize.

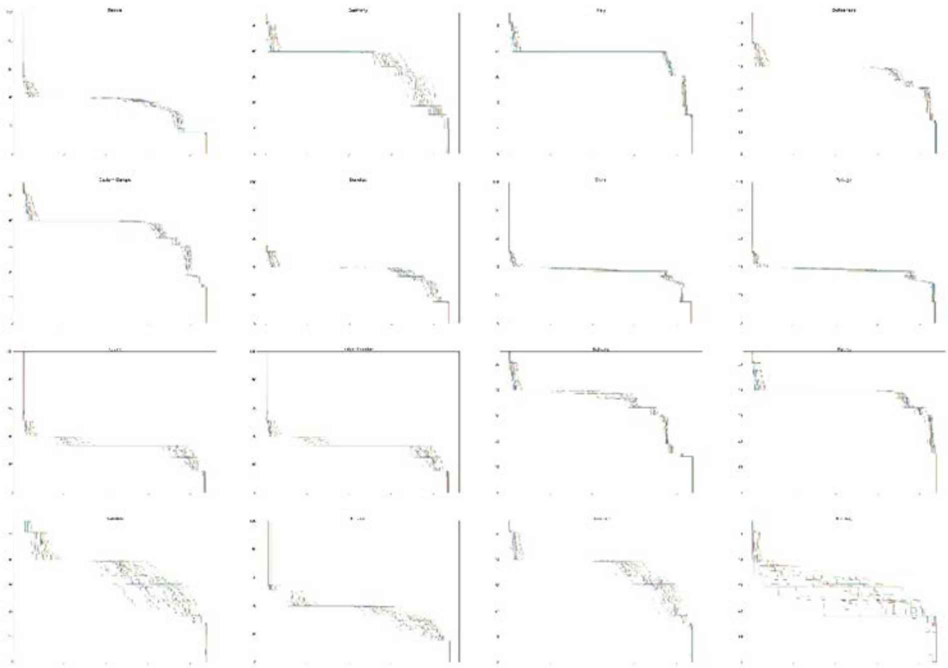


Figure 8.12. Histogram of the scenarised marginal costs of electricity (€/MWh).

Figure 8.13 shows the scenarised schedules of non-served electricity, only for the region where non-served electricity occurs, while Figure 8.14 shows the average number of hours in the year with non-served electricity as well as the maximum (corresponding to the scenario with the biggest number of hours).

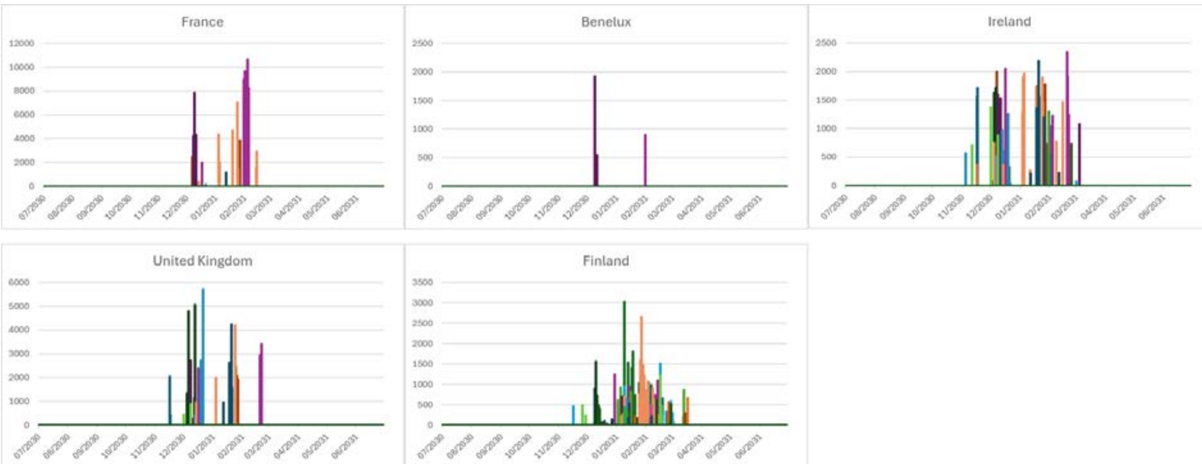


Figure 8.13. Scenarised schedules of non-served electricity (MWh).

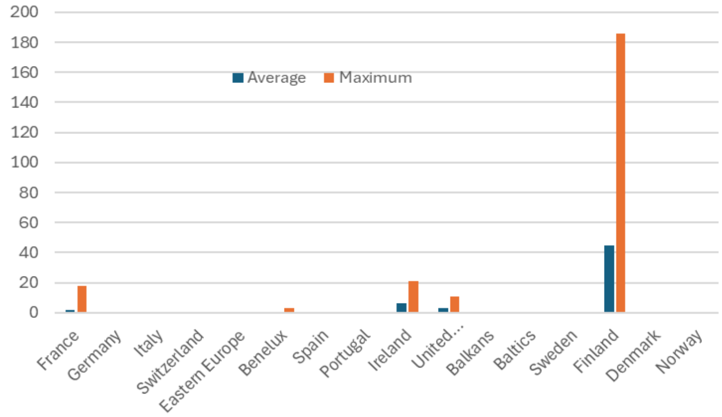


Figure 8.14. Maximum and average number of hours with non-served electricity.

Figure 8.15 shows the power generation from the available technologies during the whole year (from July to June). The graph on the top represents the climatic Scenario 4, with a very high demand peak (the black line corresponds to the power demand), while the graph on the bottom represents the climatic Scenario 1 (remind that all simulations are done for the EnVis scenario NECP Essentials, and climatic uncertainties are described by 105 climatic scenarios, all of them applied to the EnVis Scenario NECP Essentials). We can see not only the difference in the demands but also the difference in the renewable generation, linked to their availability due to the climatic conditions.

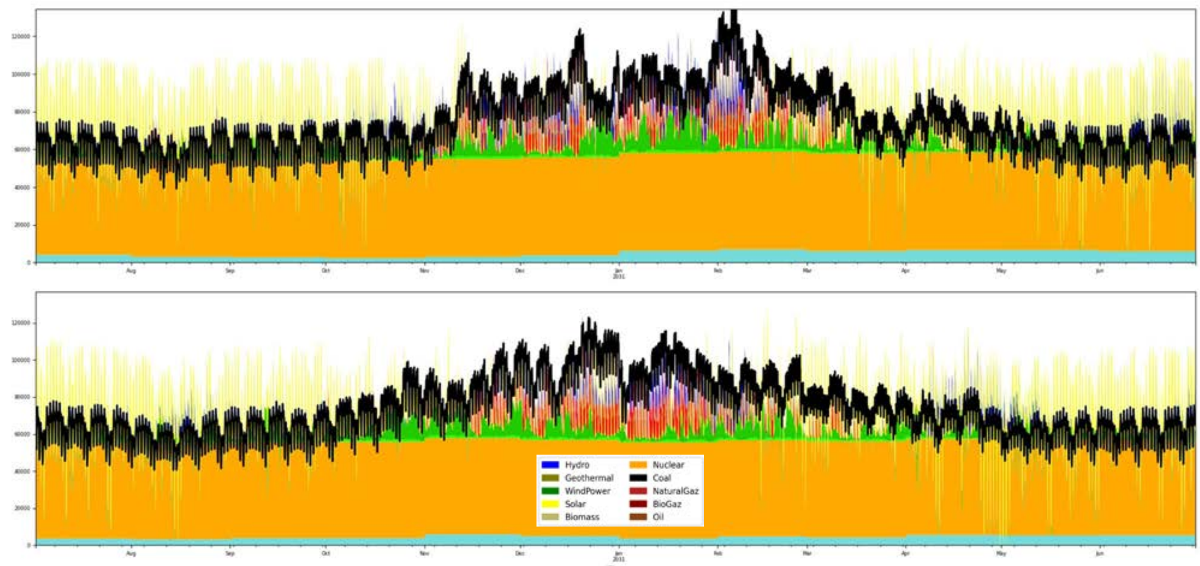


Figure 8.15. Stacked power generation in France 2030, for two different uncertainty scenarios

Focus on a difficult winter period: Figure 8.16 zooms on the power demands between January 31 and February 13. The first week is the one when the periods with the highest non-served electricity occur (as shown in Figure 8.18).

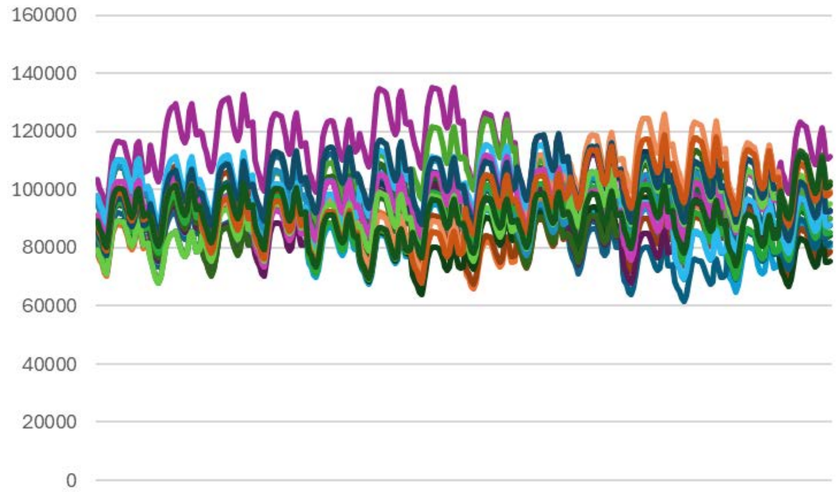


Figure 8.16: Scenarised demands in France from Jan 31 to Feb 13.

In the following, we are analysing the optimized power generation schedules and marginal cost for two "*scenarios*": Scenario 4, which is the most difficult scenario, corresponding to the highest non-served electricity and highest demand (in purple in Figure 8.16), and Scenario 1 (light blue), which is an average scenario.

Figures 8.17 and 8.18 depict the stacked schedules of power generation and the related marginal costs for two consecutive weeks, in France. Figure 8.17 displays Scenario 4, while Figure 8.18 displays Scenario 1. The left side corresponds to the week with non-served electricity, and the right side to the following week. On the bottom are the corresponding marginal costs for the same week, same scenario. We can see that the power demand is very high, higher during the first week due to the combined impacts of a low temperatures and reduced availability of wind energy. During the second week, there is much more wind, and even if there is less sun, the import capacity is enough to avoid non-served hours.

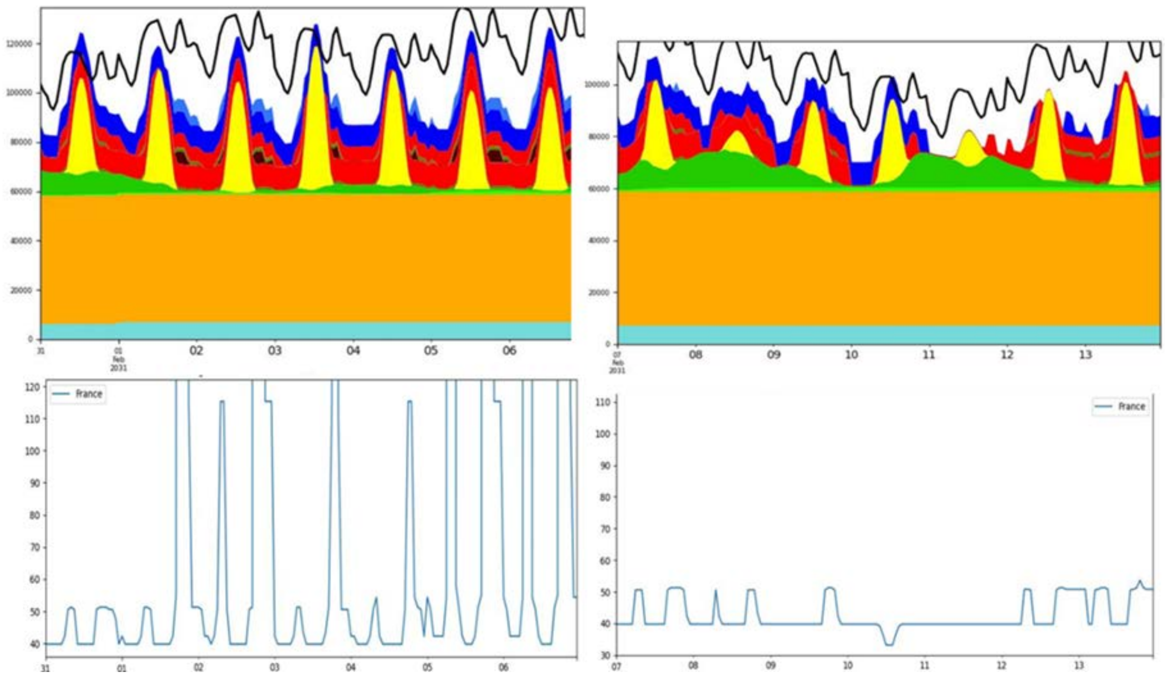


Figure 8.17. First row shows the power generation (in MWh), and second row depicts marginal costs for two consecutive winter weeks in France, Scenario 4.

Within Scenario 1, there is no no-served electricity. The demand is lower than in Scenario 4, and there is more wind, which limits the use of gas power (shown in red) to only demand peaks, when solar energy is not available.

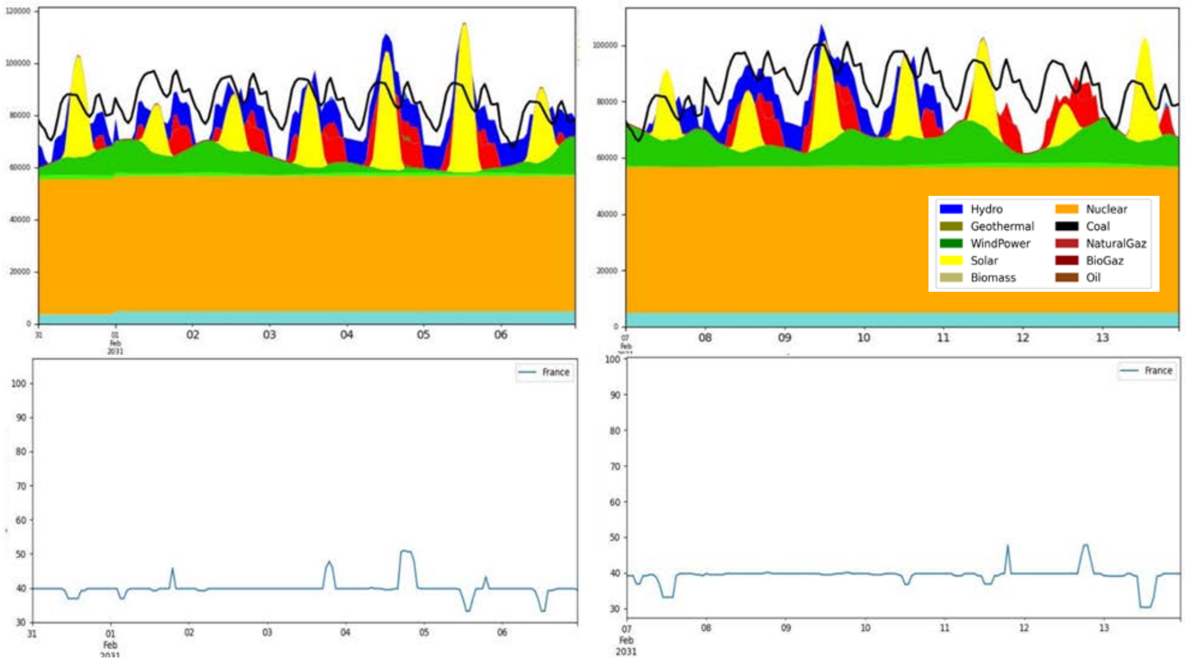


Figure 8.18. Power generation (in MWh) and marginal costs for two consecutive winter weeks in France, Scenario 1.

8.4.2. NECPs

We conduct a comparison of the EnVis-2060 NECP Essentials scenario with the actual NECP for France. The objective was to adapt the inputs of GENeSYS-MOD so that its outputs, regarding the NECP Essentials scenario, are in line with the French NECP. This comparison enabled us to identify the main divergences and to propose measures to mitigate them:

1. **The sectoral consumption as modelled in GENeSYS-MOD needs to be adapted (see Figure 8.19):**
    a. The consumption of the industry sector is under-estimated
    b. The consumption of the residential sector is under- estimated from 2030
    c. The consumption of the transportation sector is under- estimated from 2035
    d. The power consumption for specific uses of electricity is over-estimated

Figure 8.19. Final energy per sector (in TWh)

2. **The weight of the different energy vectors needs to be adapted (see Figure 8.21):**

a. The gas consumption is over-estimated, especially in the building sector (see Figure 8.20)

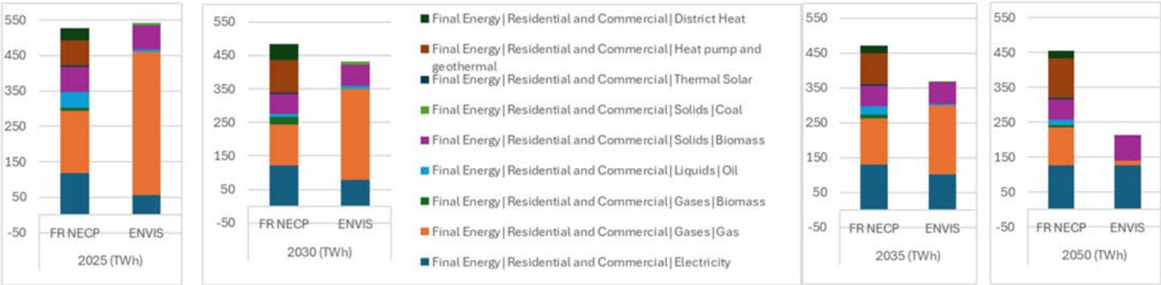


Figure 8.20. Final energy of the building sector, per energy vectors (in TWh)

b. The coal consumption is over-estimated
c. The gas consumption is under-estimated from 2035
d. Waste and Hydrogen are absent from the GENeSYS-MOD dataset, while they are used in the NECP

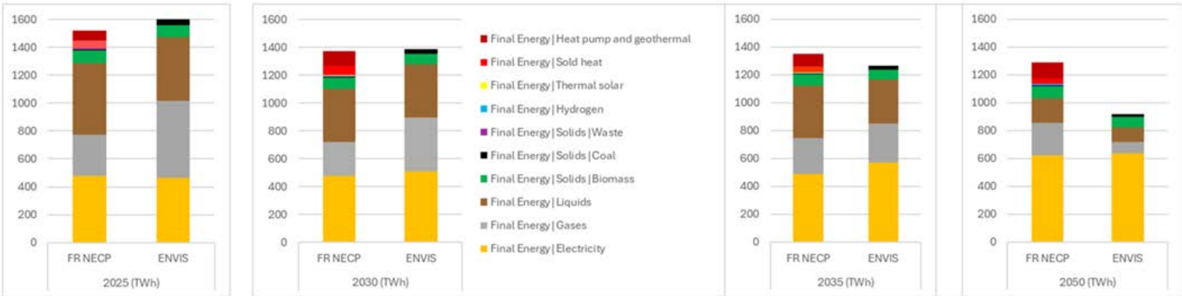


Figure 8.21. Final energy per energy vector (in TWh)

3. **The electricity generation mix needs to be adapted (see Figure 8.22)**:
   a. The French NECP foresee shutdown of coal fuelled generation in 2027, while it remains in GENeSYS-MOD until 2050
   b. Gas-fuelled generation is over-estimated in 2025, while underestimated at the end of the period
   c. Oil-fuelled generation is over-estimated in 2025 and should be decommitted from 2030
   d. Wind power is under-estimated
   e. Photovoltaic is over-estimated
   f. Interconnections capacities are over-estimated

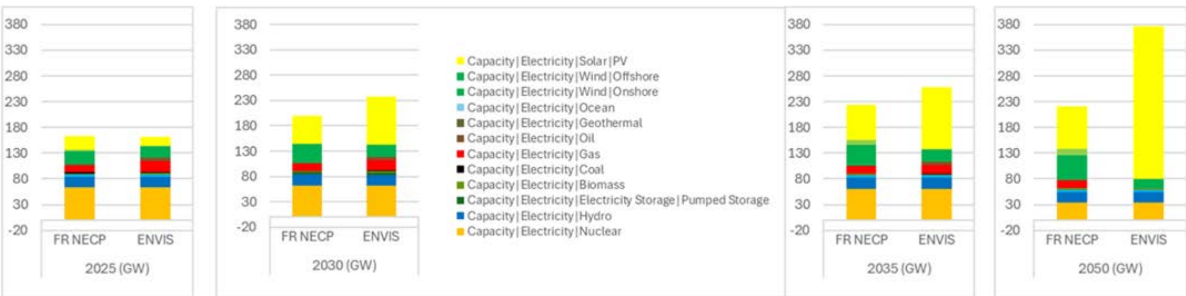


Figure 8.22. Electricity generation installed capacity (in GW)

4. Electrification of uses is under-estimated in all sectors, but particularly in the industry sector, where it is “replaced” by coal and gas (see Figure 8.23)

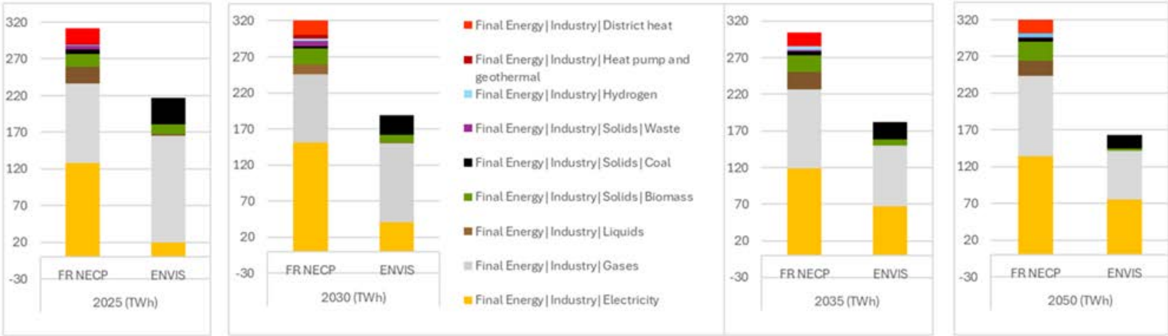


Figure 8.23. Final energy per energy vector in the industry sector.

8.4.3. Supplementary Data

The data used to compare the NECP with the EnVis-2060 NECP Essentials scenario are based on the modelling exercises published by the French Ministry for Ecological Transition, which also form the foundation for the NECP’s development. The details are available on the ministry’s web site[8].

The scenarised timeseries have been created by the CROSSEU project, based on the latest data available in the Pan-European Climate Database, which provides information on climate and renewable energy variables for both historical and future time periods. For historical data, the ERA5 global reanalysis serves as the underlying climate data, while future projections are based on selected CMIP6 global climate models. More details can be found on the Copernicus Climate Data Store[9].

Case study 9: Power Market Modelling: Spain and Portugal

This case study addresses in detail the 2030 NECP of Portugal, which has the ambitious goal of increasing the penetration of renewables in the electric sector to a share of 87% by 2030 (Lopes, F., 2018). That can be achieved by increasing the capacity of wind (to 9.3 GW), solar PV (to 9.0 GW), hydro (8.7 GW, of which 4.1 GW will be PHS – pump hydro storage), and biomass (to 0.5 GW). Combined Cycle Gas Turbine (CCGT) is already the only fossil-fuel technology in operation in Portugal since 2021, as all coal plants were decommissioned.

CS9 simulated the electric power/energy markets and since the Portuguese and Spanish electricity markets are integrated for the Iberian region, Spain NECP has also been addressed, in a more general form. Furthermore, both countries are expected to increase their cross-border transmission capacity from the actual 3.2 GW to 4.2 GW in 2030. Within the context of REPowerEU, Portugal is particularly focussed on accelerating variable Renewable Energy Source (vRES) power plants deployment via simplified permitting processes, exploring new concepts as RES hybrid power plants, and on implementing renewables gases generation and consumption (green hydrogen and biomethane). Case Study 9 have paid special attention to these factors, particularly by considering different types of Power Purchase Agreements (PPAs) and also considering their smooth integration into the energy

8 Scénarios prospectifs énergie-climat-air | Ministères Aménagement du territoire Transition écologique
9 Climate and energy related variables from the Pan-European Climate Database derived from reanalysis and climate projections

market by proposing solutions to mitigate bottlenecks of these trading contracts, allowing citizens and industry to access affordable and clean renewable-based generation.

It is also widely discussed how and why the traditional centralised top-down approach of electricity/energy markets has proven to be insufficient to gather the full potential of consumers, variable renewable energy sources, and the synergy with other energy vectors (Algarvio et al., 2024). The fact that future markets will drive and efficiently coordinate all elements of the power system (i.e., generation, consumption, storage and other flexibility options), from individual consumers to the wholesale level, results in a pressing need to study, implement and test new market models/designs and tools. Consequently, the investment in projects related to this subject is increasing significantly, particularly in Europe.

Case study 9 combined expertise on both power market modelling with energy system modelling, investigating synergies and antagonisms between these two analytical levels. It also considered mainly national level, but special attention has been paid to assess implications of power and hydrogen trade with other neighbouring countries for different NECP scenarios. Results of the simulation of power markets for different scenarios have been compared and analysed in order to identify the most beneficial energy mixes (and energy transition paths) for the Portuguese economy and society. Finally, in CS9, we assess the operation of the Iberian electricity market (i.e., MIBEL) and provide recommendations for the 2030 Portuguese NECP.

Figure 9.1 schematically presents the soft-linking approach of various tools used in CS9, highlighting the types of simulations and the objectives of each simulation.

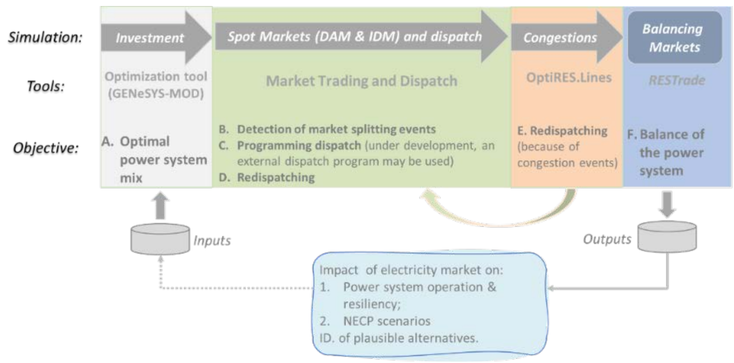


Figure 9.1. Overview of the soft-linking procedure of different models used in case study 9.

9.1. Accomplished Tasks

Task 9.1 – Collecting, analysing and selecting data: This task focuses on gathering and analysing data essential for accurately modelling the Iberian electricity market. A key objective is to ensure that the selected data has the appropriate temporal and spatial resolution to effectively replicate market behaviour, including electricity generation, demand patterns, cross-border exchanges, and pricing dynamics. The process started with the collection and analysis of relevant Iberian governmental plans, such as the Portuguese NECP (version released in 2024) and carbon-neutral roadmaps, to identify strategic targets, regulatory frameworks, and expected market developments. Based on this analysis, a careful selection of data has been made to ensure consistency and reliability in subsequent simulations.

Data from the WP2 scenarios is also considered to simulate various future energy mixes, where applicable and in alignment with established national commitments.

Task 9.2 – Modelling, parametrisation and simulation: The focus is on modelling and simulating the electric power sub-system, including the development and integration of dispatching capabilities and sub-models into existing electricity market models. This task involves parameterizing all necessary input data to simulate the most relevant Iberian/Portuguese scenarios defined within the project. The MATREM - *Multi-Agent TRading in Electricity Markets* (Lopes, F., 2018), RES.Trade (Algarvio et al., 2024), and *OptiRES.Lines - Optimal Power Flow and Dynamic Line Rating* (Algarvio et al., 2021) models have been enhanced to improve the accuracy and reliability of the studies. Additionally, the adoption of a dispatch programming model (e.g., Dispa-SET[10] or PyPSA[11]) were considered to simulate the hourly commitment of different power plants in Portugal, ensuring a more detailed representation of market operations.

Further system improvements have been implemented to optimise simulations, followed by initial analysis of results, which guides updates and refinements in the modelling approach. The enhancements support the comprehensive analysis of results, supporting updates in modelling and simulations that align with the project's objectives.

Task 9.3 – Recommendation to the Portuguese NECP: This task involves an in-depth analysis of the project results to develop and provide comprehensive recommendations for the Portuguese NECP, focusing particularly on the electric power sub-sector. The recommendations address key aspects of the electric power system, offering guidance on optimising its performance, aligning with national energy objectives, and supporting the transition to a sustainable and resilient energy future for Portugal. These findings also support the refinement of the models and simulations, ensuring that the recommendations are based on accurate, up-to-date data and models.

9.2. Planned impact

Given the ambitious renewable energy targets outlined in the recent version of the Portuguese 2030 NECP, understanding the operational feasibility of this scenario becomes crucial. While the long-term energy system models used to define these targets are fundamental for establishing pathways and investment needs, they often lack the temporal and technical resolution required to capture short-term system dynamics and operational constraints. To complement these strategic planning models, running a dispatch model, such as Dispa-SET, is therefore essential. This type of model simulates the hourly operation of the power system, taking into account generation profiles, demand variations, and flexibility solutions. Using this approach makes it possible to identify bottlenecks in system flexibility, evaluate the adequacy of storage and backup capacity, and estimate system costs and emissions with higher accuracy.

In this context, and assuming an isolated system without interconnection to Spain, the dispatch simulations serve as a feasibility check of the NECP ambitions, bridging the gap between the policy targets and the physical realities of power system operation. The insights obtained serve as a benchmark, to be later compared with the results from WP2, and will support policymakers and stakeholders in designing robust, cost-effective, and secure energy transition strategies, ensuring that the renewable integration goals are both technically feasible and economically sustainable.

[10] https://www.dispaset.eu

[11] https://pypsa.readthedocs.io/

9.3. Implementation

The implementation approach of this case study is illustrated in Figure 9.1. All tools required further development and adaptation for the project.

- The MATREM tool simulates the spot market to determine electricity marginal prices and support programmed power system dispatch.
- OptiRES.Lines identifies network congestions, curtailments, and re-dispatching needs.
- RESTrade focuses on final power system dispatch, curtailment management, and balancing price determination.

These models are fed by data from NECP and from the investment model from WP2 that provides key information, such as optimal capacities per power plant, power plant efficiency, fixed and variable costs, and potentially sector coupling capacities.

9.3.1. Challenges

Most of the data from the NECP and GENeSYS-MOD (from WP2) is only available at an aggregated national level, and with a coarse temporal resolution, limiting our ability to accurately replicate competitive market behaviour. This lack of granularity prevents a detailed representation of the different generation profiles of vRES and does not reflect the strategic behaviour of market participants. For example, WP2 results (for Portugal) indicate no installed electrolysers or battery systems and even the decommissioning of wind power capacity in the different scenarios for 2030, which contrasts with the NECP projections. These differences can be explained mainly by two factors:

i) the European-scale optimisation applied in WP2, which leads to a higher deployment of solar capacity in Portugal due to its highest capacity factors; and

ii) the assumed interconnection capacity, since the Portuguese NECP considers an isolated system without interconnection with Spain, while WP2 accounts for a fully interconnected European grid.

9.3.2. Mitigation Measures

To address this limitation, data from multiple wind and solar PV power plants in Portugal and Spain are used and proportionally upscaled to match the installed capacity in each scenario. This approach ensures the inclusion of vRES players with diverse generation profiles, enabling a more realistic representation of bidding strategies in the MIBEL electricity market.

At this stage, and given the significant discrepancies between the WP2 outcomes and the Portuguese NECP, the analysis focuses on the most recent version of the Portuguese NECP, namely, in the assessment of the impact of flexible solutions, such as hydrogen production, energy storage, and demand flexibility, in Portugal, which represent key components of the future MIBEL market.

9.4. Results

In this section, preliminary results using the Dispa-set model for Portugal are presented.

9.4.1. Outcomes

Table 9.1 provides the installed capacity according to the Portuguese NECP 2030. According with the table, the total installed capacity is expected to reach nearly 48 GW, with vRES, such as wind and solar PV, reaching 33.2 GW, representing a 69% share of the total installed capacity. Including hydro, biomass, and other renewables, renewable sources represent 89% of total capacity, highlighting a highly decarbonised and renewable-based power system.

Table 9.1. Technologies and installed capacity foreseen for 2030.

Technology	Installed capacity (GW)
Hydro (Pumped hydro storage)	8.1 (3.9)
Wind (onshore / offshore)	12.4 (10.4 / 2.0)
Solar PV (centralised/ decentralised)	20.8 (15.1 / 5.7)
Biomass, Biogas and Wast	1.3
Other renewables	0.3
Natural Gas	3.5
Batteries	2.0
Total	48.4

According to this last version, the total electricity consumption in Portugal is expected to reach approximately 90 TWh. This high demand is justified by two main factors: **i)** the additional electricity needs of the industrial sector due to digitalisation and energy transition, including adoption of low-carbon technologies and smart manufacturing processes. To account this increment, the consumption time series from (Helisto et al., 2024) was used; **ii)** the planned electrolysers installed capacity of around 3 GW, which alone will be an important consumption of electricity since to ensure economic viability this technology should have a capacity factor ideally equal to or above 75%. In the simulations, the electricity consumption of the electrolysers is not predefined. The model autonomously decides whether and when the electrolysers operate based on system conditions.

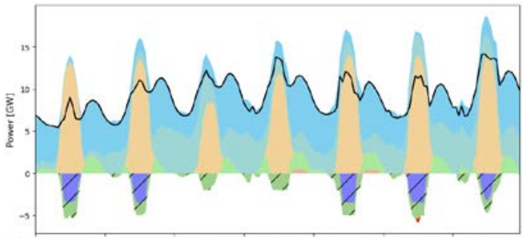
Based on the data presented in the Portuguese NECP, a series of simulations was carried out to assess the impact of different flexibility solutions. Table 9.2 summarises the simulation configurations performed with the Dispa-SET model, assuming the installed capacities from Table 9.1 and using typical operational efficiencies, constraints and cost parameters available in the literature for Portugal considering the data (renewable generation and demand) from 2019.

Table 9.2. Technologies and installed capacity foreseen for 2030.

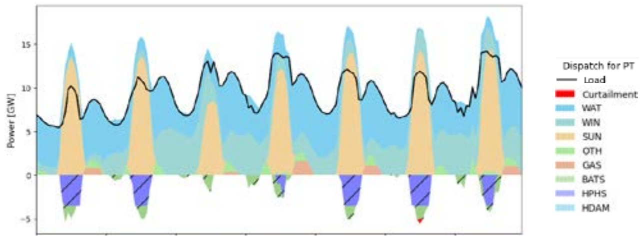
Scenario	Installed capacity (GW)		Batteries storage (h)	Demand flexibility (%)
	Batteries	Electrolysers		
Baseline	2	3	8	0
Bat_4h	2	3	**4**	0
Bat_2h	2	3	**2**	0
H2_1GW	2	**1**	8	0
H2_5GW	2	**5**	8	0
DemFl_5%	2	3	8	**5**
DemFl_10%	2	3	8	**10**

According to Table 9.2, the simulations designed to assess the impact of different flexibility options on the power system include a *baseline* scenario with 2 GW of batteries (comprising 4 units of 500 MW each in all scenarios) with 8 hours of storage and 3 GW of electrolyser capacity, and no demand flexibility. Battery storage scenarios (*Bat_4h* and *Bat_2h*) test shorter storage durations, while electrolyser scenarios (*H2_1GW* and *H2_5GW*) assess the effects of hydrogen consumption on system flexibility. Demand flexibility scenarios (*DemFl_5%* and *DemFl_10%*) evaluate the benefits of shifting 5% and 10% of consumption, respectively, to better align demand vRES generation.

Figure 9.2 shows the representative first week of simulation for the *Baseline* and *Bat_2h* scenarios. From this figure, it is possible to observe the role of battery storage in meeting electricity demand at the end of the day, which in the Bat_2h scenario largely replaces the generation that would otherwise be supplied by gas power plants.



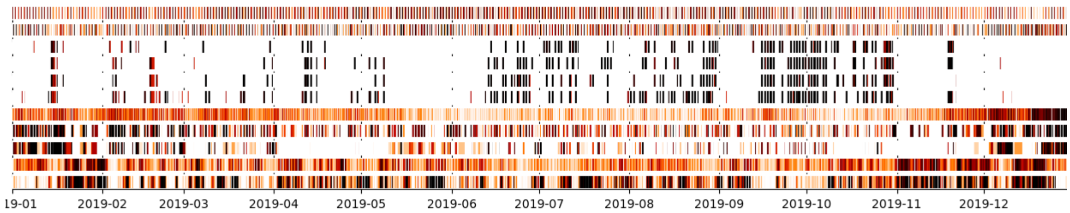
a) Baseline scenario



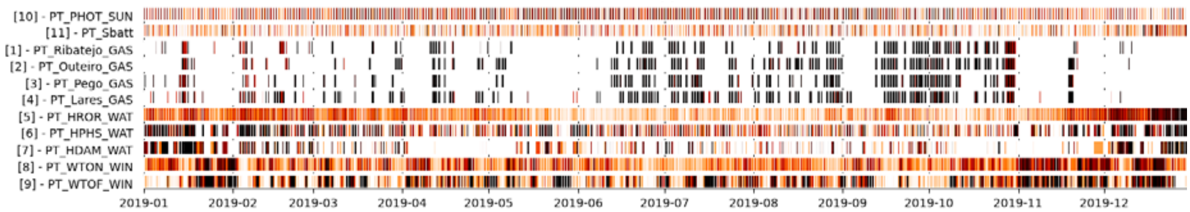
b) Bat_2h scenario

Figure 9.2. Representative first week of simulation.

To better understand the patterns of electricity generation and storage operation, Figure 9.3 presents an annual heatmap for the *Baseline* and *Bat_2h* scenarios, highlighting the contribution of each technology during the year.



(a) *Baseline* scenario



(b) *Bat_2h* scenario

Figure 9.3. Annual heatmap of hourly generation.

Renewable generation penetration and curtailment: The annual share of vRES and RES penetration in the final electricity consumption is depicted in Figure 9.4.

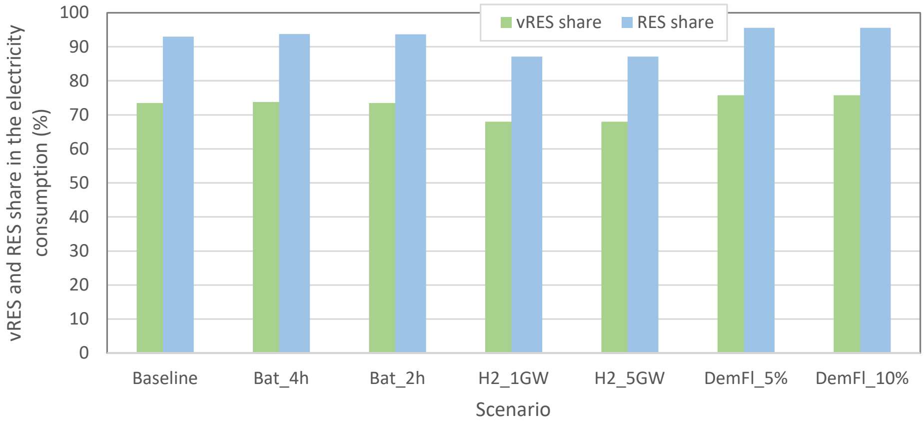


Figure 9.4. Annual share of vRES and RES penetration in the final electricity consumption.

Comparing to the *Baseline* scenario (vRES = 73.5%, RES = 93.0%), both battery storage and demand-side flexibility enable to increase the penetration of renewable-based generation in the final consumption, while the scenario that explores only hydrogen reduces the contribution of these technologies as expected. Adding 2-4 h of battery capacity leads to modest gains, increasing RES to around 93.7%, reflecting improved short-term balancing. The strongest improvement is observed with the demand flexibility: a 5% demand flexibility raises RES to 95.6%, while 10% flexibility achieves a nearly 100-RES power system (vRES = 77.6%, RES = 97.8%). These results highlight that demand flexibility is crucial to maximise renewable integration, whereas rigid hydrogen demand can undermine system decarbonisation benefits if not coupled with operational flexibility solutions.

Figure 9.5 presents the share of vRES generation that is curtailed, expressed relative to the total potential generation from these technologies. The purpose of this analysis is to assess the efficiency of renewable energy integration and to identify any significant mismatch between energy supply and demand.

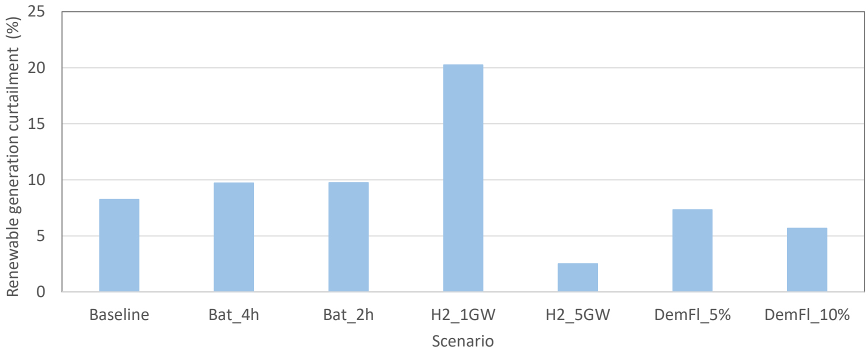


Figure 9.5. Share of vRES curtailment.

According to Figure 9.5, the curtailment in the *Baseline* scenario is 8.3%. The battery scenarios, despite adjustments in storage duration, show little effect on curtailment, suggesting that the installed capacity is insufficient to absorb the available renewable generation. This outcome can be explained by the strong mismatch between production and consumption, with excess generation occurring during periods of high solar output that exceed the nominal power of the batteries. The hydrogen scenarios highlight the strong influence of electrolyser capacity: 1 GW increases curtailment due to limited absorption of surplus renewables, while 5 GW substantially reduces it to 2.5%. Demand flexibility, increased from 5% to 10%, progressively lowers curtailment, confirming its effectiveness in balancing renewable variability. Hence, the results indicate that increasing the hydrogen capacity and enhancing demand flexibility are the most impactful strategies for reducing renewable curtailment by 2030.

Furthermore, the capacity factors of batteries and electrolysers provide additional insights regarding the power system performance (see Figure 9.6). Battery utilisation decreases with the reduction in the storage capacity to nearly 52% compared to the Baseline scenario (72.6%), highlighting the limited contribution to absorbing the surplus of renewable generation. In contrast, the *H_2 scenarios* cases show opposite behaviour: with 1 GW, the electrolyser utilisation factor increases to 57.9% due to full operation during surplus periods, while in the 5 GW case it decreases to 44.7%, reflecting the higher installed capacity and reduced operating hours. Nevertheless, these results indicate that, from an economic point-of-view, the expected hydrogen generation when RES surplus is available may not be sufficient to ensure the economic viability. The demand flexibility scenarios maintain high battery utilisation (around 75%) and moderate electrolyser use (about 47%), illustrating a more balanced and efficient system operation. These results reinforce that properly sizing flexible technologies and increasing demand flexibility are key to maximising renewable integration and minimising curtailment.

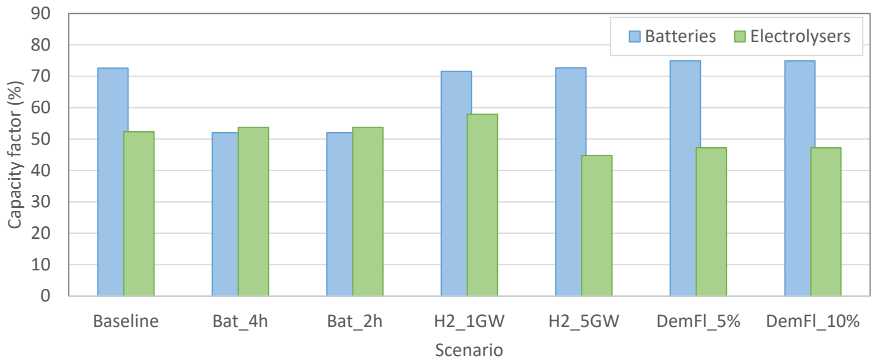


Figure 9.6. Annual capacity factor of batteries and electrolysers.

Power system reliability and economic assessment: Table 9.3 presents key metrics associated with the power system, including the Energy Not Served (ENS), Loss of Load Probability (LOLP), and the average electricity cost assuming in the model a maximum of load shedding of 5%. For ENS, two measures are analysed: the maximum 1-hour ENS, representing the highest energy deficit observed in a single hour, and the maximum event ENS, representing the total energy deficit over consecutive hours of a single supply shortfall. These indicators provide insights into both the frequency and magnitude of supply deficits.

Table 9.3. Energy Not Served (ENS), Loss of Load Probability (LOLP), and Average Electricity Cost.

Scenario	Max. ENS (MWh)	Max Event ENS (MWh)	LOLP (%)	Average electricity cost (€/MWh)
Baseline	134	262	0.10%	32.74
Bat_4h	87	114	0.08%	33.63
Bat_2h	413	466	0.08%	36.09
H2_1GW	107	152	0.13%	70.58
H2_5GW	173	262	0.11%	42.86
DemFl_5%	524	524	0.08%	29.33
DemFl_10%	523	1265	0.06%	28.50

In the *Baseline* scenario, the maximum 1-hour ENS is 134 MWh, the maximum event ENS is 262 MWh, and LOLP is 0.10%, with an average electricity cost of 32.74 €/MWh. Battery storage of 4 hours reduces frequent small deficits, lowering maximum ENS to 87 MWh and LOLP to 0.08%, while slightly increasing costs. Shorter 2-hour storage concentrates deficits in fewer but larger events, reflected in higher max ENS (413 MWh) and event ENS (466 MWh), with a slightly lower LOLP (0.08%). Hydrogen at 1 GW provides limited reliability improvement but results in very high electricity costs (70.58 €/MWh), whereas 5 GW hydrogen reduces curtailment and LOLP (0.11%) with moderate costs (42.86 €/MWh). The increase in the demand flexibility enables to reduce the costs and LOLP; nevertheless, in this scenario concentrates deficits into very large events.

Interestingly, all ENS events occur between 19:00 and 20:00, coinciding with the evening peak in domestic electricity consumption. In all scenarios, gas-fired power plants were not activated in the Dispa-SET simulations. This is consistent with the optimal technical and economic dispatch assumptions of the model, which prioritises renewable generation, and storage based on system cost minimisation. However, in a real system, dispatchable conventional power plants might deviate from the purely optimal economic dispatch to ensure system security covering short-term peaks and avoid ENS events. The concentration of deficits within a single period highlights a critical mismatch between peak demand and the available fast-response flexibility, suggesting that batteries, demand-side management, or flexible operation of conventional plants would be essential to maintain the power system reliability. Therefore, the results emphasise the importance of aligning flexible resources with predictable daily load peaks, while recognising that conventional thermal plants may need to deviate from purely optimal economic dispatch to ensure system security in practice.

9.4.2. NECP

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

9.4.3. Supplementary Data

All datasets and configuration files used in this case study are derived from open and reproducible data sources, primarily the TradeRES project database (Helistö et al., 2024) and complemented with information from the Portuguese NECP 2030. The modelling framework is based on the Dispa-SET model and includes all preprocessing scripts, calibration routines, and scenario definitions.

These materials will be made available as open-access resources in Gitlab/Zenodo to ensure transparency and traceability of the workflow, facilitate replication of the results, and support further use and development by the wider research community. Comprehensive documentation covering data processing steps, assumptions, version control, and software requirements will also be provided to ensure consistent and reliable reuse.

Place holder for ES v2.0
This section will be finalised in the second version of the Executive Summary, scheduled for release in Q1 2026.

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