Research Square

Preprints are preliminary reports that have not undergone peer review.
They should not be considered conclusive, used to inform clinical practice,
or referenced by the media as validated information.

Assessing uncertainty space for long-term flexibility needs in future European sector-coupled energy system

Rasmus Bramstoft

rabpe@dtu.dk

Technical University of Denmark https://orcid.org/0000-0002-8875-8718

Théo Balanza

Technical University of Denmark

Marie Münster

Technical University of Denmark https://orcid.org/0000-0002-5543-547X

Article

Keywords: Flexibility, Sector coupling, Energy system modelling, Uncertainty space, Multiple weather year

Posted Date: September 17th, 2026

DOI: https://doi.org/10.21203/rs.3.rs-10999591/v1

License: This work is licensed under a Creative Commons Attribution 4.0 International License.
Read Full License

Additional Declarations: Yes there is potential Competing Interest. This research was supported through the DTU-TotalEnergies Excellence Centre for Clean Energy (DTEC) research project, related to GRid Enhancement for Ancillaries in Tomorrow's power systems (GREAT.

Assessing uncertainty space for long-term flexibility needs in future European sector-coupled energy system

Théo Balanza[1], Rasmus Bramstoft[1*], Marie Münster[1]
[1]Technical University of Denmark, Department of Wind and Energy Systems, Risø, 4000 Roskilde, Denmark.

* Corresponding author:
E-mail address: rapbe@dtu.dk (Rasmus Bramstoft)

Key words: Flexibility, Sector coupling, Energy system modelling, Uncertainty space, Multiple weather year

Abstract

Future energy systems increasingly relying on variable renewable sources will require flexibility, yet the role and competition of different flexibility providers remain uncertain. We use a pan-European sector-coupled energy system model to quantify flexibility needs across sectors, regions, and timescales in a Net-Zero energy system. We explore uncertainty spaces for flexibility portfolios using 33 weather years and Monte Carlo simulations.

Sector coupling unlocks flexibility opportunities, through electrified heating, electric vehicles and hydrogen production. Daily and weekly flexibility are provided by electric heating, electric vehicles, transmission and batteries, whereas annual flexibility relies on hydropower, electrolyzers, electricity transmission -nearly doubled by 2050- and peak gas. Peak gas capacity remains necessary as a low-capacity-factor backup, transitioning from natural gas to biomethane, with a 212 GW median capacity. Uncertainty in electric vehicles and hydrogen deployment impacts the flexibility mix. Our study highlights the need for diverse, cross-sectoral flexibility portfolios across regions and timescales.

1 Introduction

Flexibility will be required to integrate growing shares of variable renewable energy (VRE) in the future [1–4]. Flexibility options [5, 6], including transmission, energy storage, flexible generation and flexible consumption, can be unlocked through sector coupling [7] and are required across multiple timescales [8]. Several definitions and quantification methods for flexibility exist [9, 10]. ENTSO-E defines long-duration flexibility as the capacity of the energy system to respond to variability of supply and demand over daily, weekly and seasonal timeframes [11].

Flexibility needs are expected to rise towards 2050. The International Energy Agency (IEA) sees daily and weekly flexibility needs increasing by 50% by 2030 and doubling by 2050 compared to 2022 levels [6], while seasonal flexibility needs are projected to increase by around two-third by 2050 [6]. Based on a residual load curve methodology, the Joint research Center (JRC) [12] projects that the total flexibility requirement across daily, weekly, and monthly timescales will increase from 11 % of the annual EU electricity demand in 2021 to 30 % by 2050. Despite increasing recognition of flexibility to ensure adequate energy systems in the future, the role and competition of long-term flexibility options considering the inherent uncertainties remain under discussion.

Existing studies have often focus on the role of one flexibility type e.g. electric vehicles (EV) [13, 14], demand response [15], hydrogen [16], thereby ignoring potential competition and synergies, despite its importance, as highlighted by Sinsel et al. [3]. Other studies include multiple flexibility options but model only the power system [8, 17, 18], thereby overlooking the benefits of sector coupling [12, 19]. Some studies assessed flexibility needs for sector coupled system at regional or country scale [9, 20] or represent Europe with only a few nodes [6], which ignore the potentially large deployment of transmission. A growing body of studies considers multiple weather years when investigating future energy systems to assess how the system is impacted by differences across weather years [5, 6, 21, 22]. However, Grochowicz et al. [21] considers only the European power system, IEA [6] mainly focuses on power systems and performs dispatch rather than investment optimisation and Gøtske et al. [22] focuses on the dispatch with greater emphasis on the impact of weather years than on the role of flexibility options. Finally, uncertainty in flexibility provision has mainly been explored through scenario analysis or by activating and deactivating selected flexibility options to assess their individual impact on the system [23–25]. Although these approaches provide valuable insights, uncertainty in flexibility options remains insufficiently explored, using methods to explore the structural uncertainty, such as Modelling-to-Generate-Alternatives (MGA) [26, 27], or parametric uncertainty through Monte Carlo analysis [28, 29].

Despite the urgent need for flexibility in the future, there is a lack of a comprehensive energy transition pathway analysis that: 1) consider sector-coupling across power, heat, hydrogen, and electrified transport, 2) model all main flexibility options, 3) cover entire pan-Europe, 4) combine investment optimisation (capacity expansion) with hourly dispatch, 5) include multiple weather years, and 6) explore parametric uncertainty space for flexibility providers.

Here, we address these gaps, and investigate the role and competition of flexibility options in a sector-coupled, pan-European energy system, while considering multiple weather years and Monte Carlo simulations to explore the uncertainty space and identify key drivers for the deployment of the different flexibility options. We do so by extending and applying the pan-European sector coupled energy system model, Balmorel [30, 31], which determines the least-cost investments and operation across energy supply, transmission and storage to satisfy energy demands (see Methods). Balmorel represents all main flexibility options within the power system, heat sector (electric heating and heat storage) [32], hydrogen sector (production, transmission and storage) [31], and electric mobility (smart charging and Vehicle-to-grid (V2G))) [33]. To quantify flexibility needs across annual, weekly and daily timescales, while considering hourly results, we use the Fourier-based frequency filtering approach outlined in Heggarty et al. [8]. While the reference year is 2012 for the baseline results, we conduct a multiple weather year simulations relying on 33 historic profiles extracted from CorRES [34–36]. Finally, we explore the uncertainty space by running 100 Monte Carlo simulations, identified as the minimum sample size for robust results by Frey et al. [28], and use Spearman rank correlation coefficients to indicate the most influential parameters for each flexibility provider.

The overall objectives of this study are therefore to i) assess the needs for, and competition between, long-duration flexibility provision in future European sector-coupled energy systems, ii) identify the main flexibility providers and the main drivers of deployment of flexibility options, and iii) investigate the uncertainty spaces for the main flexibility providers.

2 Results

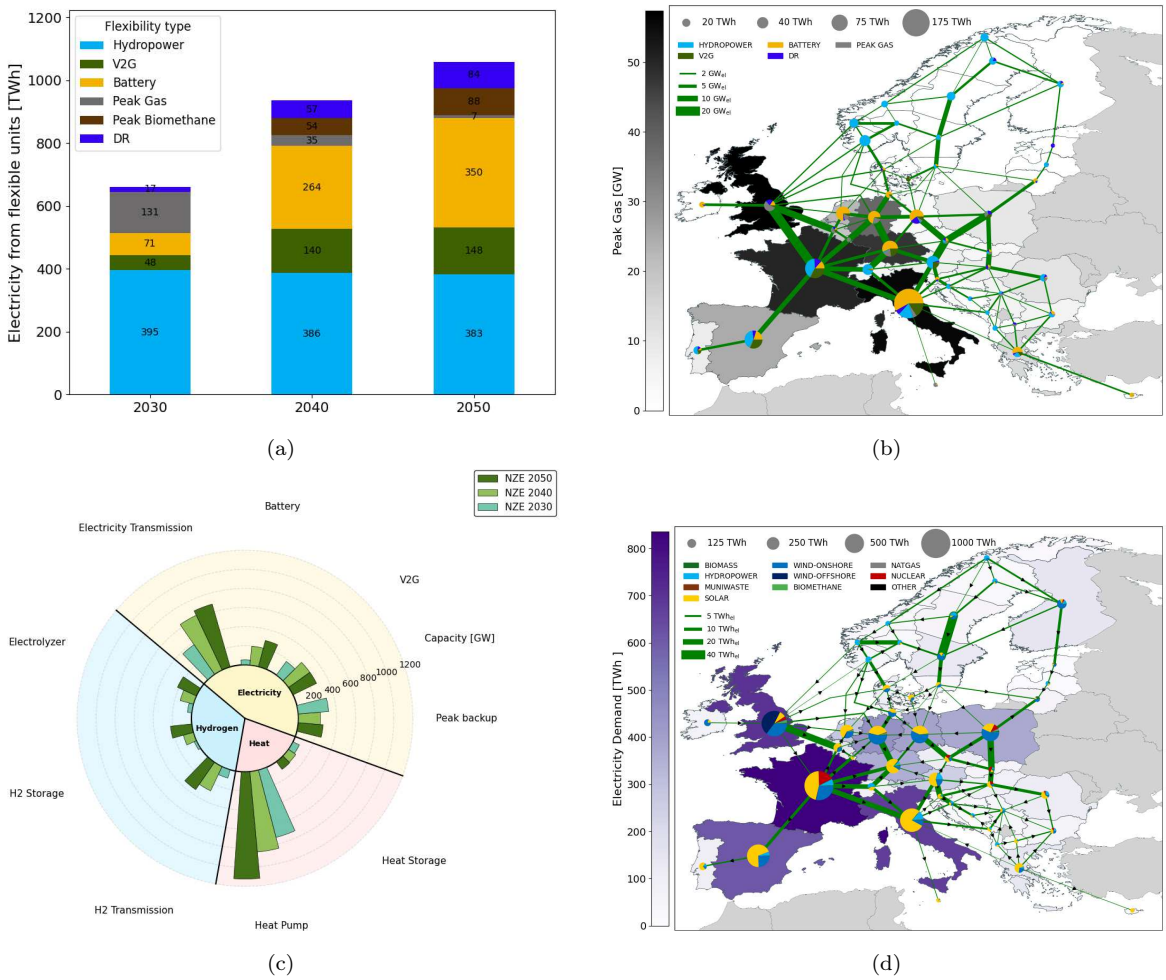


Figure 1: a) EU electricity production evolution, from 2030 to 2050, from flexible assets in the power sector. b) EU power grid expansion and electricity production mix from flexible assets in 2050. Pie charts indicate the distribution of electricity flexibility, per technology in each region. The line width represent the size of the electricity transmission capacity. Background shows the peak gas capacity per country, regardless of the fuel used (natural gas or biomethane). c) EU installed capacity of assets providing flexibility in electricity, heat and hydrogen sectors. d) EU yearly power grid flow and electricity production mix in 2050. Pie charts indicate the distribution of electricity production, per technology in each region. The line width represent the flow of electricity in the transmission per year. Background shows the yearly electricity demand per country. Results are shown for the weather year 2012, used as baseline.

2.1 Flexibility needs increase over time shifting towards new flexibility options

An increasing share of VRE is occurring in the electricity mix which raises the yearly electricity production from flexible assets from 662 TWh by 2030 to 936 TWh by 2040, reaching 1060 TWh by 2050 (Fig. 1a).

The expansion of electricity transmission infrastructure is the largest electricity flexibility option in terms of capacity, with transmission capacity projected to nearly

double from current levels to approximately 690 GW (Fig. 1c), allowing increased trade between electricity price zones (Fig. 1b and d).

While hydropower contribution to flexibility remains stable as no new projects are assumed, the additional flexibility requirements are increasingly met through a combination of electricity transmission, battery storage, EV smart charging, V2G, and demand response (Figure 1b).

The assumed role-out of EV's reaching 225 million cars in Europe by 2050 (Tab.1) unlocks a remarkable flexibility option for the electricity sector, with high deployment of smart charging. Our findings illustrate that V2G, if realised, can become a key provider of flexibility, delivering an average of 0.63 MWh of flexibility per EV annually in 2050, equivalent to approximately 12 additional full battery discharge cycles per vehicle.

In our study, we exogenously constrain minimum batteries deployment levels set out by ENTSO-E [37], with thresholds of 52 GW by 2030, 198 GW by 2040, and 216 GW by 2050, enabling batteries to provide flexibility at hourly level. While binding in 2030 and 2040, the model endogenously invests in additional capacity in 2050, reaching 282 GW.

Peak backup shifts from natural gas to biomethane from 2040, driven by the CO_2 tax and net-zero constraint (Fig. 1a). Electricity generation from natural gas declines to 7 TWh by 2050, compared with 550 TWh in 2023 [38], while biomethane-based generation increases to 88 TWh. Indeed, natural gas is almost phased out by 2050, contributing only to 0.1% and 0.4% of total electricity and heat generation, respectively. However, a sufficient level of peak gas capacity - around 262 GW in 2050- needs to be maintained to ensure sufficient peak-load flexibility (Fig. 1c), particularly during prolonged winter stress periods.

Demand response (DR) is mainly provided by residential space and water heating. From 2040 onward, DR from the tertiary sector, particularly space and water heating, ventilation, and cooling, also becomes a main contributor to deliver demand response (Supplementary Fig.6).

2.2 Cross-sectoral flexibility becomes essential in a future sector-coupled European energy system

Flexibility increasingly originates from interactions between the electricity, heat, and hydrogen sectors in the future rather than from the power sector alone (Fig. 1c). The results indicate a significant deployment of heat pumps and electric heating, reaching up to 1126 GW by 2050 and supplying approximately 69% of total heat demand. Heat pumps act as a flexible asset, by shifting electricity consumption when combined with heat storage and dispatchable heat sources such as biomass. District heating in combination with large-scale heat pumps and heat storage further enhance cross-sectoral flexibility provision for countries such as Denmark and Germany.

Assuming a hydrogen demand of 1000 TWh by 2050 (Tab.1) for the decarbonization of hard-to-abate sectors such as heavy long-distance transport and parts of the industry, leads to the deployment of electrolyzers, hydrogen storage and hydrogen transmission infrastructure, which enables the hydrogen sector to become a key flexibility provider, acting as a flexible electricity demand (Fig. 1c).

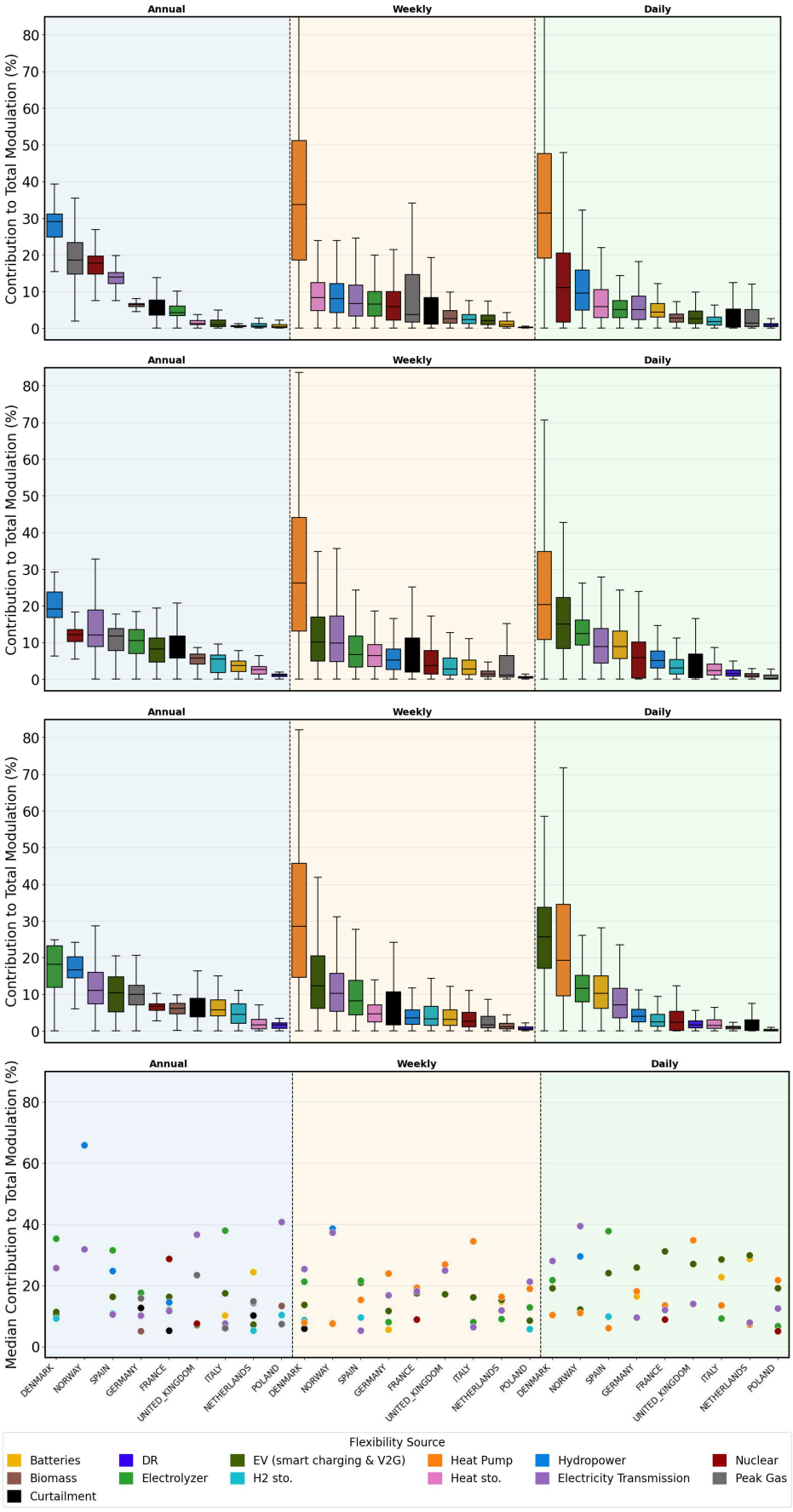


Figure 2: Frequency-based approach of flexibility provision (see Method 4.5): Flexibility contribution distributions on annual, weekly and daily timescales for the European energy system in a) 2030, b) 2040 and c) 2050. d) Country specific flexibility contribution median value in 2050.

2.3 Different countries rely on different flexibility options

Flexibility portfolios varies substantially across Europe, reflecting differences in the electricity mix, demand levels, hydropower availability and geographical characteristics (Fig. 1b and 2d).

Hydropower-rich countries, including Norway, Sweden, Austria and Switzerland, primarily rely on reservoir hydropower to provide system flexibility. In Norway, this is complemented by extensive electricity interconnections and widespread electrification of heating. In contrast, countries with high hydrogen production, such as Spain, Italy, and Denmark benefit from the flexibility of electrolyzers (Fig. 2d and Supplementary Fig.5).

Countries with high solar PV deployment, including Germany, Italy, France and the Netherlands, rely more on smart charging and V2G or batteries, depending on the amount of EVs, to balance the daily variations. This highlights the complementarity between solar PV and daily flexibility options such as smart charging, V2G and batteries.

Despite the deployment of other flexibility assets, peak gas remains necessary in most regions. Peak capacity requirements are higher in countries with high peak electricity demand e.g. Germany, United Kingdom, France and in regions with a greater reliance on one technology to generate electricity e.g. Italy compared to Spain (Fig. 1b). Since the optimisation is performed for an interconnected European system, these capacity requirements account for the possibility of sharing peak generation through cross-border electricity transmission.

2.4 Different flexibility options provides flexibility at different timescales

Using the frequency-based approach framework defined in Heggarty et al. [8] (see Methods 4.5), we quantify the flexibility provision at daily, weekly and annual timeframes to reveal and quantify the role of different flexibility options.

Daily flexibility is primarily provided by heat pumps from 2030 onwards, while EV through smart charging and V2G, electrolyzers and batteries become increasingly important toward 2050. Together, these technologies provide two-thirds of daily flexibility by 2050, emphasising the opportunities for unlocking the demand-side and storage flexibility in balancing hourly and daily variations in renewable generation (Fig. 2).

Our results reveal a shift from the conventional generation based flexibility provision in 2030 towards demand side flexibility, storage and transmission over time. For example, peak gas generators transition from baseload generation to rare winter stress periods, operating only 144 hours on average per country in 2050 (Fig. 2).

Weekly flexibility is delivered through a combination of assets across multiple energy sectors. Heat pumps, electric heating and thermal storage provide significant flexibility from the heating sector, followed by EV, while electrolysers and hydrogen storage become increasingly important as hydrogen demand increases. Electricity transmissions are the third largest contributor to weekly flexibility by 2040 and 2050, enabling the

power system to exploit spatial weather differences across Europe and thereby improve the integration of VRE.

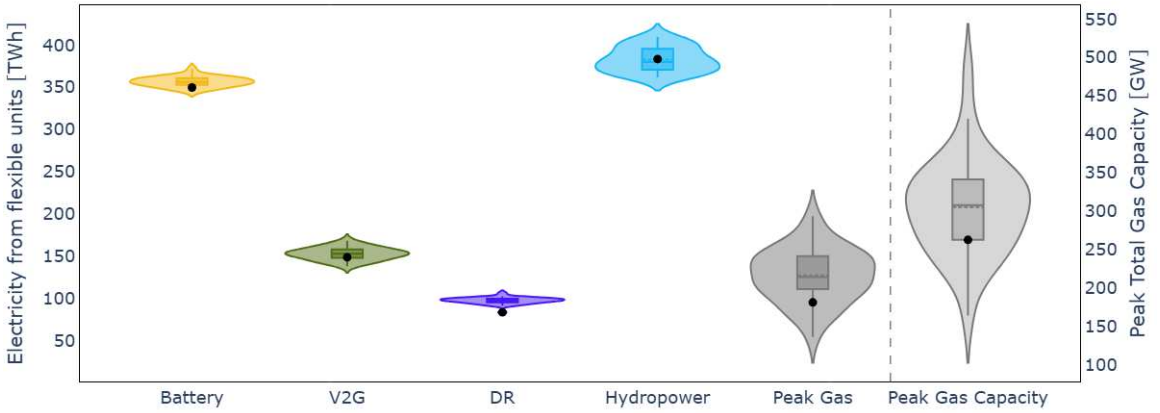
Annual flexibility, typically across months, is provided by hydropower, although this remains highly country specific (Fig. 2d), as well as by electrolyzer and electricity transmission, while peak generators are mostly operated in Dunkelflaute periods.

Across all timescales, electricity transmission and electrolyzers emerge as key flexibility providers. Overall, our results confirm that ensuring system adequacy relies on a combination of complementary flexibility assets operating over different timescales. These findings also highlight the importance of coordinated investments across sectors, to unlock demand side flexibility and storage opportunities, together with cross-border coordination to efficiently harvest and use the location specific VRE generation.

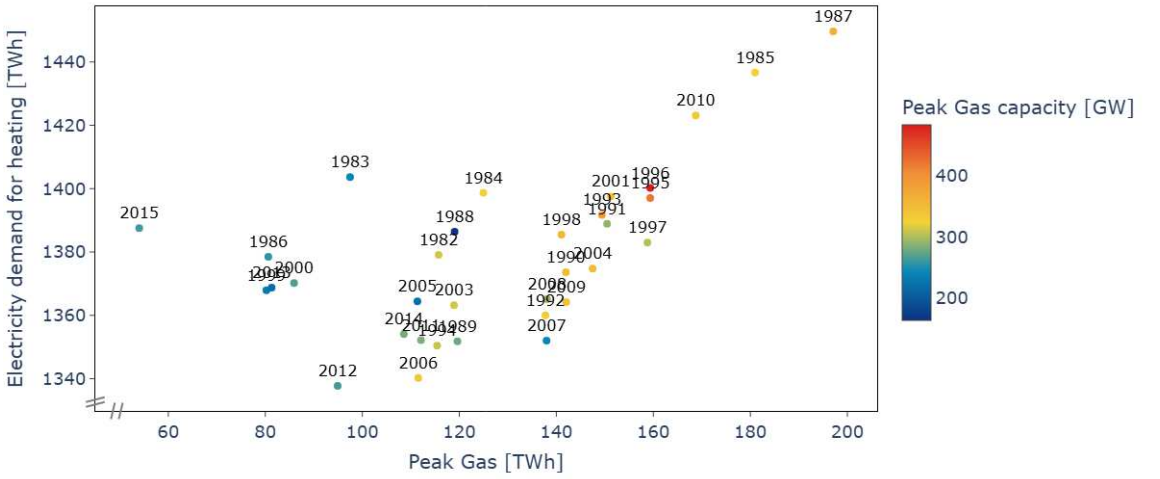
2.5 Multiple weather years reveal higher peak gas capacity requirements

Our analysis across 33 historical weather years (see Methods 4.6) reveal that peak gas generation and capacity highly depend on the weather year (Fig. 4). The capacity expansion is fixed to the 2050 solution obtained using the 2012 weather year, consistent with the baseline scenario, while only the dispatch is re-optimised using each of the 33 historical weather years.

The overall flexibility provision and capacity deployment of peak gas units are positively correlated with the level of electricity demand for heating in the selected weather year (Fig. 3b). A median value of 308 GW of peak gas capacity in 2050 is observed across the different weather years dispatch simulations (Fig. 3a). In 2050, peak gas units operate, on average per country, between 43 hours (2005, low heat demand year) and 419 hours (1987, high heat demand year), with a mean of 197 hours across all weather years. Thus, the role of peak gas generators remains largely unchanged across weather years, with operation limited to rare system stress periods during winter. Beyond the impacts on solar and wind (Supplementary Fig.10), weather-year selection also affects hydropower generation through interannual variability in inflows.



(a)



(b)

Figure 3: (a) Distribution of electricity production from flexible assets provided by different flexibility providers across various weather years in 2050. Black points indicate the baseline values for the 2012 weather year. (b) Relation between electricity demand for heating, peak gas electricity generation, and peak gas electricity capacity across different weather years.

2.6 Solar PV investment cost is a key driver of V2G and batteries output

Monte Carlo simulations using the 2012 weather year generate 100 scenarios to quantify uncertainty in flexibility and system outcomes (see Methods 4.7) and results are presented in Figures 4 and 5.

V2G contribution to flexibility remains significant across scenarios, contributing at least to a level of 105 TWh in 2050, with a median value of 216 TWh (Fig. 4). V2G output increases with higher solar PV deployment, greater EV uptake, lower charging infrastructure costs and higher charger capacity, which enable higher V2G peak capacities. Solar PV installed capacity shows higher uncertainty than onshore and offshore wind (Supplementary Fig.13). Higher solar PV production is correlated with an increased use of both V2G and batteries (Figures 4 and Supplementary Fig.14).

Overall, demand response and hydropower contributions remain stable across scenarios, whereas V2G, peak gas capacity, electrolyzers, electricity and hydrogen transmission are identified as more uncertain flexible assets (Fig. 4).

2.7 Uncertainty in peak gas requirements

Peak gas generation and capacity decrease with increasing CO_2 tax, natural gas price and greater deployment of onshore wind (Fig. 5). Additionally, higher CO_2 tax incentivise greater electrification of heating.

Peak gas generation and capacity increase when hydrogen storage deployment is limited, as reduced storage flexibility requires more dispatchable generation to meet periods of peak demand (Fig. 5). Similarly, peak gas capacity increases as electricity transmission deployment decreases.

Across all Monte Carlo scenarios, peak gas generation ranges from 14 to 306 TWh, with a median value of 37 TWh, consistent with the baseline scenario, and is predominantly fuelled by biomethane (Fig. 4). Peak gas capacity ranges from 167 to 275 GW, with a median value of 212 GW, also aligned with the baseline results. Despite uncertainty on peak gas capacities amount needed, their role remain largely unchanged across scenario.

2.8 Cross-sectoral trade-offs shape future flexibility mix

Flexibility deployment is influenced not only by uncertainty within individual technologies but also by interactions between energy sectors, highlighting the importance of considering sector-coupling when assessing flexibility needs.

Higher hydrogen storage costs shift flexibility provision towards the power sector, increasing electricity transmission, peak backup, battery and V2G, while reducing electrolyzers and hydrogen transmission deployment. Similarly, higher electrolyzer costs increase V2G deployment. This highlights competition between electricity and hydrogen sector.

Higher offshore wind investment cost shifts renewable production from offshore to onshore wind, more geographically distributed, therefore reducing electricity transmission flows. This creates a cross-sectoral trade-off, with increased deployment of hydrogen transmission (Fig. 5).

Considering a sector-coupled system allows these cross-sectoral flexibility synergies to emerge, enabling the system to provide flexibility across sectors rather than relying solely on power-sector flexibility solutions. Other examples are described in Supplementary material.

2.9 Uncertainty in flexibility assets is country-dependent and significantly depends on hydrogen and EV assumed deployment

Uncertainty in flexibility assets is more pronounced in countries with large population, which are associated with high peak demands and high EV deployment, as well as in solar-rich countries and regions with high hydrogen demand or production. For instance, peak gas generation is highly uncertain in Italy and Germany, while V2G is most uncertain in Italy, Spain and Germany (Supplementary Fig.16). Spain's flexibility mix uncertainty is further driven by potential hydrogen production, whereas in Germany it is impacted by uncertainty on hydrogen demand. Therefore, uncertainty in hydrogen and EV deployment significantly impacts the contribution of flexible assets of these sectors.

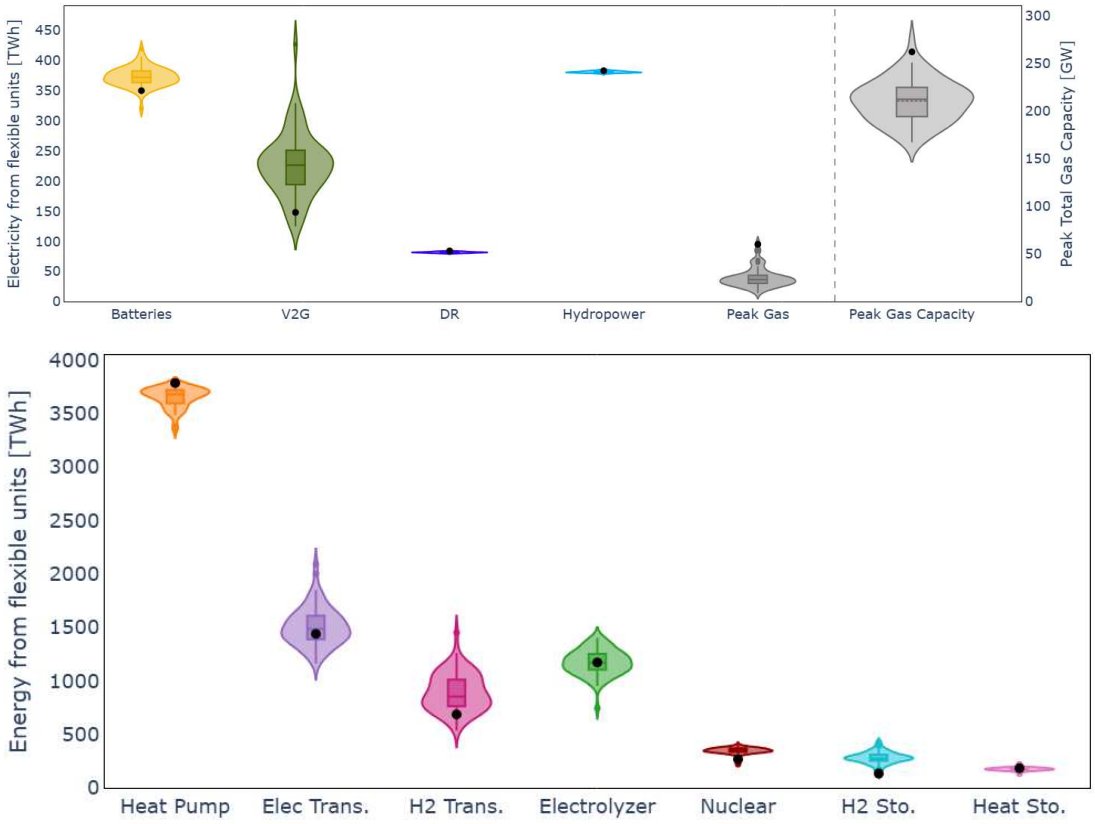


Figure 4: (a) Distribution of electricity production from flexible assets provided by different flexibility providers across 100 Monte Carlo simulation scenarios in 2050. Black points indicate the baseline values from the 2050 Net Zero scenario shown in Fig. 1. (b) Distribution of other flexibility assets across the same 100 Monte Carlo simulation scenarios in 2050.

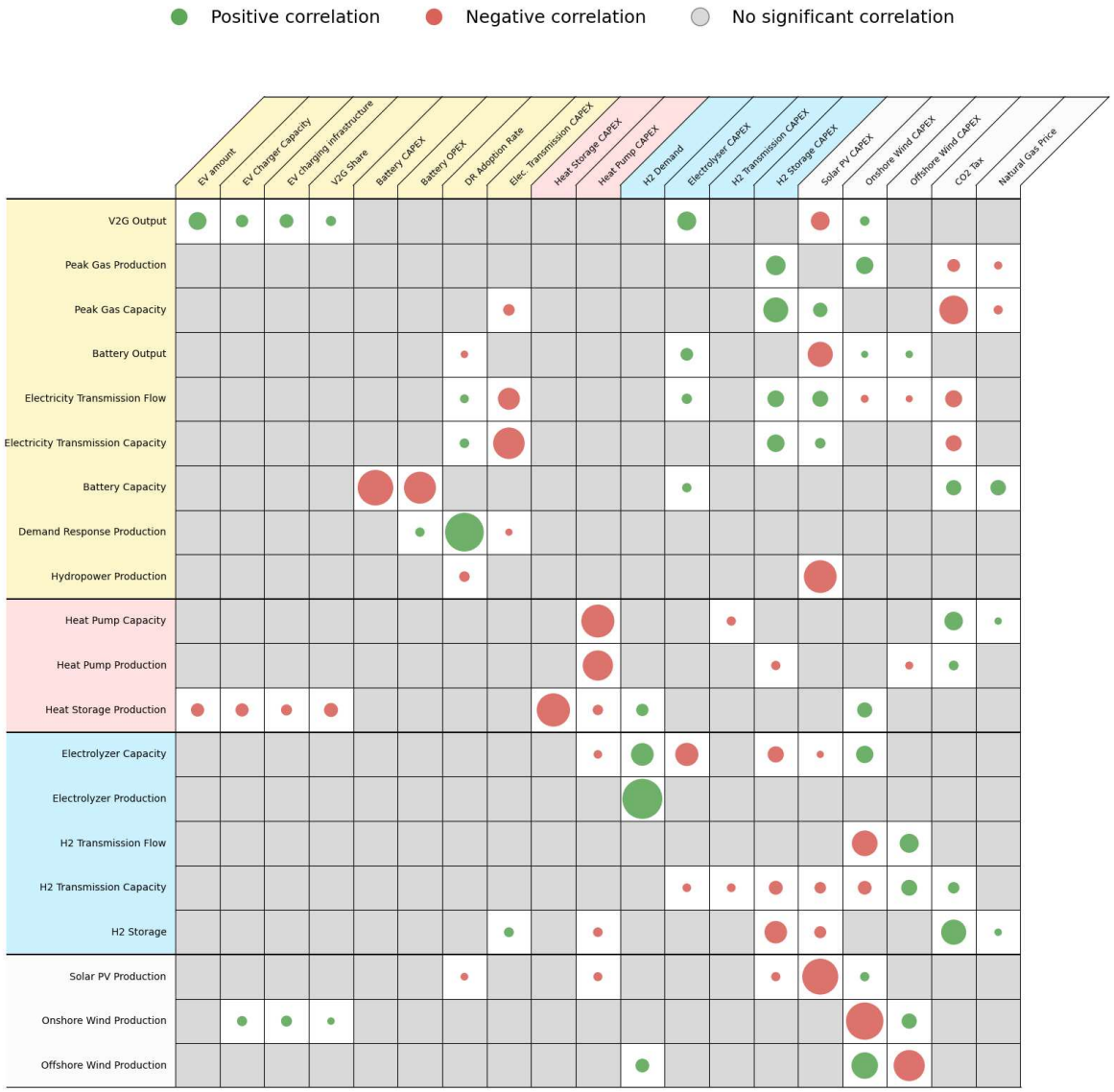


Figure 5: Spearman rank correlation coefficients calculated from 100 Monte Carlo simulation scenarios in 2050. The Spearman rank correlation coefficient (ρ) is a non-parametric statistical measure that quantifies the strength and direction of the monotonic relationship between two variables. The x-axis shows the input parameters modified in the Monte Carlo simulations, while the y-axis shows the key model outputs, grouped per category (electricity flexibility, heat flexibility, hydrogen flexibility and renewable production). Green circles indicate positive correlations, whereas red circles indicate negative correlations between the corresponding input and output variables. The size of each circle is proportional to the absolute value of the Spearman correlation coefficient (ρ). Grey boxes indicate correlations that are not statistically significant.

3 Discussions

Our study explores flexibility requirement in a future European energy system and how this need can be met through different flexibility assets across sectors, regions and timescales. We assess the role of these flexibility assets at European and country levels within a sector-coupled Net-Zero energy system. By considering multiple weather year and Monte Carlo simulations, our study goes beyond existing literature by quantifying the uncertainty space of future flexible assets deployment.

Following previous studies [5, 12], our results highlight the need for substantial flexibility investments, particularly in electricity transmission and storage. Electricity transmission expands to around 690 GW, nearly doubling from 2030 plans, while batteries reach around 282 GW, both aligned with ENTSO-E projections [5]. Existing hydropower infrastructure also remains an important flexibility source. Our results further identify smart charging and V2G as important flexibility options. While consistent with Aliasghari et al. [13], our V2G contribution exceeds ENTSO-E projections [5] of around 85 TWh in 2050, highlighting uncertainty in this emerging flexibility option. Our study confirms a need for peak gas capacity throughout the entire period towards 2050, aligning with previous European assessments [5, 21]. However, gas use declines substantially across power and heat sectors. The role of gas in the electricity sector fundamentally changes, shifting from baseload generation to low-capacity-factor peak units, consistent with findings from the literature [5, 6, 12]. We also observe a shift from natural gas to biomethane, driven by ambitious fossil phase-out targets. Similarly, Gøtske et al. [22] argued that peak gas generation could shift from fossil fuels to synthetic green fuels, as only limited energy volumes are required to provide backup. This translates in a median value of 212 GW of peak gas capacity by 2050, predominantly fueled by biomethane. Although this exceeds estimates from ENTSO-E [5] (185 GW) and Grochowicz et al. [21] (77 GW in a power sector only model), the overall requirement for peak gas capacity is consistent across studies.

Our findings are aligned with ENTSO-E's assessment that flexibility solutions are both country and timescale dependent [11]. Increasing shares of renewables in the power system require greater volumes and a diverse combination of flexibility assets across sectors, as pointed out by ENTSO-E and IEA [5, 6]. In line with IEA study, we find that demand-side flexibility from EVs and electrified heating, together with batteries provides most of the daily flexibility. The IEA similarly highlights that these resources could supply up to two-thirds of daily flexibility by 2050 [6]. Hydropower, electricity transmission and electrolyzers emerge as key flexibility providers of annual flexibility, consistent with previous assessments in the literature [6, 12].

The higher contribution of peak gas and batteries to flexibility in the JRC assessment may result from limited sector coupling, which overlooks cross-sectoral interactions [12]. This highlights the importance of sector-coupled modelling, as power-sector-only approaches may misestimate the flexibility levels needed [39]. Key contributors to cross-sectoral flexibility include the electrification of transport, heating, and e-fuel production. The Monte Carlo simulations further highlight that changes in one sector can impact the deployment of flexibility assets in other sectors, reinforcing the importance for a sector-coupled energy system perspective even when assessing electricity system flexibility.

While the main flexibility assets remain consistent across weather years and Monte Carlo simulations, the deployment pathways of hydrogen and electric vehicles introduce substantial uncertainty into the 2050 flexibility landscape. Countries with greater reliance on these emerging technologies, as well as solar-rich countries, exhibit the largest uncertainty in their future flexibility mix.

The comparison with the literature underscores several limitations of our study. First, capacity expansion is optimized using representative time slices, which may affect dispatch outcomes. Second, the model does not capture flexibility needs associated with balancing services or forecast errors, although ongoing work is addressing this limitation [40]. Third, distribution grid constraints on EV charging are not represented [14], potentially overestimating V2G flexibility contribution [13, 14, 33]. Furthermore, alternative solutions to peak gas capacity to resolve potential infeasibilities, such as additional renewable capacity or batteries, are not explicitly assessed during dispatch. Consequently, the observed increase in peak gas capacity under multiple weather years should be interpreted as a model-dependent outcome rather than an indication of an optimal system requirement. We also do not evaluate the economic viability of keeping peak gas units for the operators. In addition, our results may reflect overly fast deployment rates for emerging technologies. Finally, because the model does not represent the complete energy system (Section 4.2), residual energy demand may be supplied through fossil fuels. These limitations should therefore be considered when interpreting the estimated flexibility mix and the implications for achieving net zero.

Our findings have policy implications for the deployment of flexibility to support renewable integration, emphasizing the importance of considering flexibility needs across sectors and timescales. Policies should therefore promote a diverse portfolio of flexibility options, including demand-side flexibility, sector coupling solutions, transmission expansion and storage. In addition, maintaining operational peak gas capacity, fueled by green fuels, will be essential to ensure security of supply during periods of prolonged system stress, particularly in winter. Our results show a transition from conventional generation-based flexibility in combination with transmission towards a more diverse flexibility landscape with increasing contribution from demand-side flexibility and storage across sectors.

Several open questions should still be addressed regarding flexibility needs in future highly renewable energy systems. First, integrated modelling frameworks are needed to capture flexibility requirements across multiple timescales, including day-ahead operation, balancing markets, and ancillary services, enabling a more comprehensive assessment of future system flexibility. Secondly, private economic feasibility and willingness to participate in V2G services as well as the feasibility of deploying smart charging strategies at scale need to be further analyzed.

4 Methods (2420 words)

4.1 Overall methodology framework

The overall methodological framework used to assess flexibility needs in future energy systems is presented in Fig. 6. The study applies the large-scale, sector-coupled energy system model, Balmorel, which considers long term investment decisions followed by hourly dispatch. Balmorel is extended to model all flexibility options, while representing the electricity, heating, hydrogen and parts of the transport sector. In this study, the modelling framework enables simulations of 33 multiple weather years and explore the parametric uncertainty space using 100 Monte Carlo simulations. The Spearman rank correlation coefficient is used on the 100 Monte Carlo simulations to identify the most influential parameters of specific output results. The flexibility contribution is assessed through a frequency based post-analysis, following the methodology of Heggarty et al. [8].

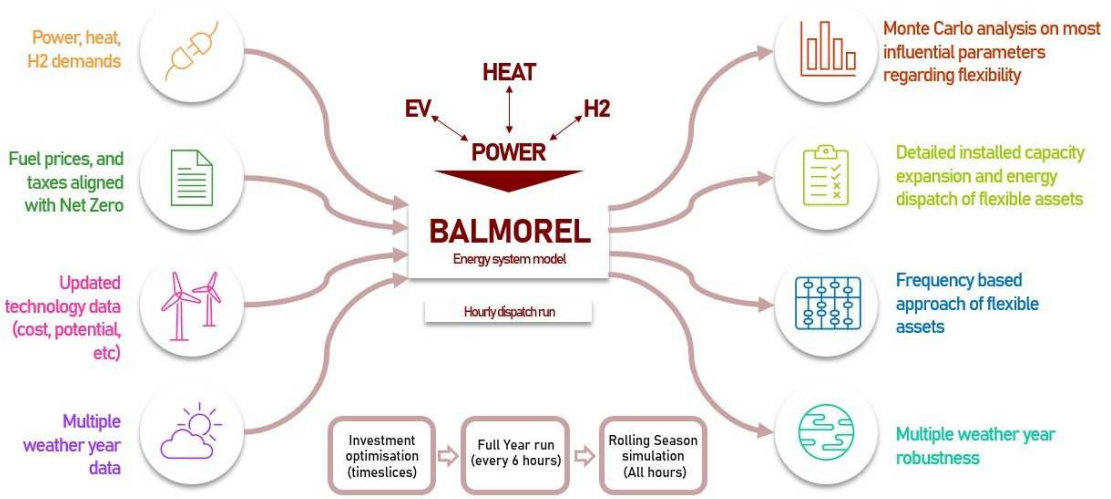


Figure 6: Methodological framework to assess flexibility needs using the sector-coupled energy system Balmorel. Hourly results are obtained through a three steps approach, combining investment optimisation and dispatch runs.

4.2 Scenario description

The scenario *Net Zero* considers an ambitious net zero energy system in 2050 with a large electrification of the transport sectors including EV as well as an hydrogen demand of 1000 TWh in 2050. CO_2 tax is taken from the Net Zero scenario of the IEA World Energy Outlook for Europe [41]. The scenario considers the years 2030, 2040 and 2050. A few main input data are gathered in Tab.1. It should be noted that the energy system considered in this study achieves net-zero emissions only for the sectors explicitly modelled, which are electricity, heat, transport electrification, and the production of 1000 TWh of hydrogen. Thus, the overall energy system may not be fully net zero if additional energy demands from hard-to-abate sectors are needed, which might be fulfilled by fossil fuels. Hydrogen demand is aligned with the CLEVER scenario [42] which projects a hydrogen demand around 1000 TWh

in 2050. This scenario is consistent with the European net-zero target and follows a Sufficiency–Efficiency–Renewables framework, which assesses the level of energy required for all to meet societal needs and combines it with technological improvements and renewable energy deployment. The projected hydrogen demand is close to the median value across published scenarios [43]. It should be noted that the ENTSO-E TYNDP 2024 scenarios [37] project hydrogen demand between 2,500 and 3,000 TWh in 2050, substantially exceeding the demand assumed in this study. Furthermore, these scenarios account for hydrogen imports, which are not considered in this study.

Year	Unit	2030	2040	2050
CO_2 tax [41]	$[e/ton_{CO_2}]$	120	175	213
Natural gas price[11]	$[e/MWh]$	20.9	20.9	20.9
Hydrogen demand	[TWh]	200	670	1000
Minimum battery capacity [37]	[GW]	52	198	216
$EV_y^{Smartcharging,share}$ [44]	[%]	95	99	99.9
$EV_y^{V2G,share}$ [11]	[%]	21	31	41
$EV_{EU,y}^{available}$ [5]	[Million of EV]	26.7	115.7	225.1

Table 1: Input data for the Net Zero scenario.

4.3 Energy system model, Balmorel

The energy system model Balmorel is considered to quantify the flexibility in future European energy systems. Additional material about the Balmorel model is available in the Balmorel Community Github [45] and in Supplementary material (Supplementary Tab.4). The specific model used in this study is available on Zenodo [46].

4.3.1 Balmorel

Balmorel is a bottom-up, partial equilibrium, open source optimisation model that assumes perfect markets and perfect foresight for the simulated year. It optimises for the least-cost investments and operation of generation and transmission of a sector-coupled energy system, to meet specific demands. An overview of the structure of Balmorel is presented in Fig. 6.

The model validity has been assessed through various comparisons with other models [47, 48]. Balmorel is commonly used to assess transition pathways in Europe for sector-coupled energy system, e.g. to identify the role of hydrogen in future European energy system [31], or the impacts of considering Planetary Boundaries when designing an energy system [49].

4.3.2 Capacity development and dispatch run

The scenario considers hourly resolution dispatch runs. This is done in 3 steps (Fig. 6). The model is run for 2030, 2040 and 2050 with myopic vision. For computational complexity, the capacity development expansion step considers 8 weeks spread over the year and one every three hours used as representative timestep for the optimization. The capacity development results are then used for a two steps dispatch simulation. 1)

a full year simulation establishes storage levels at the end of every week, 2) a rolling, week-by-week optimisation is performed.

To avoid infeasibility, peak backup with a maximum installable capacity of 1000 GW per region is introduced. This upper bound is intentionally set at a sufficiently high level to remain non-binding in all modelled scenarios, while variable operating costs discourage its use except when necessary. Peak backup capacity requirements are derived from the dispatch results of the backup generation technology. At the European level, it is assumed that countries can support each other through electricity trade and interconnection. Consequently, the required backup capacity is defined as the maximum fuel consumption of the backup technology observed across all seasons and timesteps during the simulated year, representing the simultaneous peak requirement for the interconnected system. At the country level, the required backup capacity is calculated as the maximum backup fuel consumption for each region across all seasons and timesteps. Since these national peak values do not necessarily occur simultaneously, summing them overestimates the total European backup capacity requirement. Therefore, country-level estimates should be interpreted as indicative of national backup needs rather than as capacities that can be directly aggregated to the European level (Fig. 1b).

4.4 Balmorel, sectors modelling

The power sector representation includes electricity generation technologies, electricity demand, and cross-border electricity exchanges. Final electricity consumption data are obtained from Eurostat. Electricity transmission flows are modelled through net transfer capacities, allowing electricity exchanges between regions.

The heat sector is categorized into individual users areas for residential and tertiary sectors, temperature requirements areas for industry (low, medium and high) and district heating areas [31].

The hydrogen sector is based on the modelling framework developed by Kountouris et al. [31]. Country-level hydrogen demand projections for industry and transport are derived from the European Hydrogen Backbone assumptions [50] and subsequently adjusted to align with the hydrogen demand levels defined in the CLEVER scenario. Hydrogen demand is exogenously specified in Balmorel for power-to-X applications, transport, and industrial uses, while additional electricity-related hydrogen demand can be endogenously determined by the optimisation model. Investments in hydrogen transmission infrastructure are enabled from 2030 onwards. The model allows hydrogen production from grey, blue, and green hydrogen pathways. This study does not include offshore energy hubs which, however, has been modelled in previous papers [51, 52].

The rest of the transport sector, including bus, passenger cars, light commercial vehicles and rail are decarbonized through electrification towards 2050. There are represented as additional electricity demand profiles in Balmorel. Country level demand projections for electrifying the transport sector are extracted from ENTSO-E projections for EVs (Tab.1) and the EU Reference Scenario 2020 [53] for the remaining modes.

The model accounts for cross-sectoral interactions and sector coupling between electricity, heat, hydrogen, transport, and fuels [7]. Synergies arising from the integration of different sectors are represented, such as the use of excess heat from electrolyzers and industrial processes for heat supply [54]. The coupling between sectors also enables additional flexibility options beyond the electricity sector. The electrification of transport introduces flexibility through smart charging and V2G [33]. Similarly, the electrification of heating through heat pumps provides demand-side flexibility by enabling temporal shifts in electricity consumption while maintaining heat supply. In addition to electricity storage, the model represents storage options across other energy carriers, including heat storage and hydrogen storage, allowing flexibility to be provided through multiple sectors [32].

4.4.1 Balmorel, geographical scope and data developments

This study focuses on pan-European countries, which will be referred as EU, including the 27 member states of European Union, the United Kingdom, Norway, Switzerland and the Balkans countries. The energy system considered includes electricity, individual and industrial heat demand, hydrogen and electrification of transport e.g. electrified rail, trucks and EVs and hydrogen. Yearly hydrogen demand is exogenously defined (Tab.1). Key technology data are summarised in Supplementary Tab.4. Electricity transmission expansion is aligned with the most recent pan-European electricity infrastructure development plan from ENTSO-E up to 2030 [37]. Beyond 2030, investments in new transmission is allowed.

The model used in this study incorporates several updates compared with previous model versions. Renewable energy potentials for solar PV, onshore and offshore wind have been updated based on the assumptions from ENTSO-E TYNDP 2024 scenarios [55]. The maximum renewable potentials are defined according to the installed capacity projected in the Distributed Energy scenario for 2050, which assumes a higher hydrogen demand of 2500 TWh. Minimum deployment level of batteries are aligned with ENTSO-E minimum potentials [55].

EV modelling follows the work of Balanza et al. [33], using the charging profile for vehicles aligned with ENTSO-E TYNDP 2024 (referred as PR_{Middle} in Balanza et al. [33]) and includes charging infrastructure costs [14]. The modelling of demand response in Balmorel from Kirkerud et al. [15] has been expanded for this study to cover the entire European region. Several new modelling capabilities have also been introduced. Peak gas power and heat units can operate using either natural gas or biomethane fuel. Furthermore, biogenic carbon capture and storage technologies have been included in the model, with negative operational emissions resulting from the sequestration of biogenic carbon. Solar PV tracking technology has also been included. However, direct air capture and hydrogen imports from outside Europe are not allowed in this study. Finally, the techno-economic assumptions have been updated using the latest technology catalogue (Supplementary Tab.4) [56]. In particular, investment costs for offshore wind, onshore wind, and solar PV have been revised to reflect recent market developments, including the significant cost increases observed in the offshore wind supply chain. In addition, multiple historical weather years have been incorporated into the modelling framework to better capture interannual climate variability (Section

4.6).

4.5 Flexibility quantification across different timeframes

As highlighted by the IEA, flexibility requirements differ fundamentally across timescales: daily flexibility is driven by solar PV generation cycles and daily demand patterns, weekly variations reflect multi-day wind variability and weekday–weekend demand differences, while annual fluctuations are associated with seasonal heating demand. Analysing flexibility across all three timescales is therefore essential for a comprehensive assessment.

Following the frequency-based approach framework of Heggarty et al. [8], flexibility contributions of different technologies are quantified separately across three timescales: daily (periods shorter than 2 days), weekly (from 2 to 60 days), and annual (periods longer than 60 days).

To distinguish these different timescales of flexibility provision, Fourier-based frequency filtering is applied to the simulated time series of each flexibility asset. The input data consist of hourly time series obtained from the energy system model, representing the operation of each flexibility technology throughout the simulation year. The times series are decomposed into the three frequency bands previously stated. For each timescale and at every simulation timestep, the modulation provided by an individual flexibility asset is expressed as a percentage of the total modulation supplied by all flexibility assets within the timescale. Then, these contributions are aggregated over all the timesteps of the considered year for a specific timescale to obtain a statistical distribution for each flexible type of asset and timescale. The resulting Flexibility Solution Contribution Distribution are presented as box plots showing the median, interquartile range, minimum and maximum. This methodology from Heggarty [8] provides a comprehensive assessment of flexibility provision by identifying the relative importance of different technologies across daily, weekly, and annual timescales. Therefore, it offers a framework to compare flexibility portfolios between scenarios, countries and years across different timescales.

4.6 Assessment of flexibility needs under different weather years

As highlighted by Grochowicz et al. [21] and Gøtske et al. [22], interannual weather variability significantly impacts energy system model assessments. Thus, to demonstrate greater robustness in assessing flexibility needs, the analysis is conducted across multiple weather years.
The optimal energy system configuration based on the capacity expansion step (Section 4.3.2) obtained using the reference weather year 2012, is evaluated under alternative historical weather years ranging from 1982 to 2015 [34–36], generated with CorRES. This is achieved by running the dispatch steps of the framework (Section 4.3.2) for each weather year. This approach captures interannual variability in both energy demand and renewable energy generation, therefore enabling the assessment of flexibility assets under different meteorological conditions. For each weather year, the input data are updated to reflect weather year specific yearly full load hours and hourly generation

profiles for wind, solar PV and hydropower as well as annual and hourly demand profiles for electricity and heat demands.

4.7 Monte Carlo Simulation

Uncertainty is addressed using Monte Carlo sampling. Parameters are sampled using normal distributions, summarized in Supplementary Tab.3. Latin Hypercube Sampling is applied to explore the parameter space and generate multiple scenarios. This approach enables the identification of a solution space for each flexibility type rather than a single outcome solution, allowing the robustness of flexibility contributions to be assessed under different scenarios. 100 scenarios are considered, representing a compromise between computational time and accuracy of the results. Frey et al. [28] highlights that robust energy system analyses should consider a sufficiently large number of scenarios, typically exceeding 100, to adequately capture uncertainty. The Monte Carlo scenarios are generated based on the Net Zero reference scenario (Section 4.2) for 2050 only, following the three-step approach described in Section 4.3.2.

The uncertain input parameters are selected to represent key drivers of future energy system development and flexibility provision. They are grouped into several categories. First, macroeconomic drivers of the Net Zero transition are considered, including the CO_2 price and natural gas price. Second, investment costs of key technologies are varied, including renewable generation technologies (solar PV, onshore wind, and offshore wind) and flexibility providers across sectors: batteries in the power sector, heat pumps and thermal storage in the heating sector, and electrolysers and hydrogen storage in the hydrogen sector. Transmission infrastructure uncertainties are represented through variations in electricity and hydrogen transmission investment costs. The role of EVs as flexibility providers is assessed through variations in key parameters identified by Balanza et al. [33], including the amount of EVs deployed in Europe, technical characteristics affecting flexibility potential, such as charging capacity and the share of EVs participating in V2G as well as the charging infrastructure investments costs for both unidirectional and bidirectional charging. Hydrogen demand is also varied between 500 and 1500 TWh to capture uncertainty in future hydrogen system development. Finally, the adoption rate of demand response is included, as it has been identified as a key factor influencing the deployment and contribution of demand response.

The influence of uncertain input parameters on key energy system outputs is quantified using the Spearman rank correlation coefficient (SRCC), a non-parametric measure that evaluates the strength and direction of relationships between variables. The SRCC is calculated between each parameter varied in the Monte Carlo simulation and each selected output, indicating whether increases in input parameters are associated with increases or decreases in model outputs. Correlations are considered significant when the p-value is below 0.2 and the absolute SRCC value exceeds 0.1. The results are presented in Figure 5 as correlation matrices, where colour indicates the direction of correlation and the magnitude of the coefficient reflects its strength. This analysis identifies the main drivers of uncertainty in flexibility provision and highlights the parameters influencing the role of different flexibility providers.

5 Data availability statement

The full model and all associated data are publicly available via GitHub and Zenodo [46]. Details of the underlying modelling framework are provided in the Balmorel Community.
Github :

- Balmorel (great_NetZero branch)
- Balmorel_data (great_NetZero branch)

High performance computer is required to run the scenarios of this study. The computational requirements depend on the type of simulation performed. The baseline Net Zero scenario capacity development for the years 2030, 2040, and 2050, requires approximately 10 hours of computation. A full-year dispatch simulation for a single representative year requires around 6 hours, while the rolling dispatch approach over one year requires approximately 10 hours. For these two steps, the runs for different years can be parallelized. The 100 Monte Carlo simulations using the three-steps approach requires approximately 15 days of computation. The total computation time is primarily determined by the number of scenarios that can be executed simultaneously through parallelization.

6 Acknowledgments

This research was supported through the DTU-TotalEnergies Excellence Centre for Clean Energy (DTEC) research project, related to GRid Enhancement for Ancillaries in Tomorrow's power systems (GREAT).

7 Authorship contribution statement

Théo Balanza: Conceptualization of this study, Data Curation, Methodology, Software, Formal Analysis and Investigation, Validation, Visualization, Writing – original draft, Writing – review and editing.
Rasmus Bramstoft: Conceptualization of this study, Formal analysis and Investigation, Methodology, Supervision, Validation, Writing – original draft, Writing – review and editing.
Marie Münster: Conceptualization of this study, Writing – review and editing.

8 References

[1] ENTSOE. *ENTSOE_position paper*. Technical report. 2025. URL: https://www.entsoe.eu/2025/11/18/entso-e-position-paper-on-flexibility-from-renewable-energy-sources-res/.

[2] O. M. Babatunde, J. L. Munda, and Y. Hamam. "Power system flexibility: A review". In: *Energy Reports*. Volume 6. Elsevier Ltd, February 2020, pages 101–106. DOI: 10.1016/j.egyr.2019.11.048.

[3] Simon R. Sinsel, Rhea L. Riemke, and Volker H. Hoffmann. *Challenges and solution technologies for the integration of variable renewable energy sources—a review*. January 2020. DOI: 10.1016/j.renene.2019.06.147.

[4] Eamonn Lannoye, Damian Flynn, and Mark O'Malley. "The role of power system flexibility in generation planning". In: *IEEE Power and Energy Society General Meeting*. 2011. ISBN: 9781457710018. DOI: 10.1109/PES.2011.6039009.

[5] ENTSOE and Entsog. *TYNDP 2024 // Scenarios Report – Final Version January 2025*. Technical report. 2024. URL: https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2025/01/TYNDP_2024_Scenarios_Report_FInal_Version_250128_web.pdf.

[6] International Energy Agency. *Managing the Seasonal Variability of Electricity Demand and Supply*. Technical report. 2023. URL: https://www.iea.org/reports/managing-the-seasonal-variability-of-electricity-demand-and-supply.

[7] Juan Gea-Bermúdez, Ida Græsted Jensen, Marie Münster, Matti Koivisto, Jon Gustav Kirkerud, Yi kuang Chen, and Hans Ravn. "The role of sector coupling in the green transition: A least-cost energy system development in Northern-central Europe towards 2050". In: *Applied Energy* 289 (May 2021). ISSN: 03062619. DOI: 10.1016/j.apenergy.2021.116685.

[8] Thomas Heggarty, Jean Yves Bourmaud, Robin Girard, and Georges Kariniotakis. "Quantifying power system flexibility provision". In: *Applied Energy* 279 (December 2020). ISSN: 03062619. DOI: 10.1016/j.apenergy.2020.115852.

[9] Julian Geis, Michael Lindner, and Tom Brown. "Managing the Mismatch: The Role of Flexibility on the Path to a Carbon-Neutral Energy System". In: (April 2026). URL: http://arxiv.org/abs/2604.00674.

[10] Peter D. Lund, Juuso Lindgren, Jani Mikkola, and Jyri Salpakari. *Review of energy system flexibility measures to enable high levels of variable renewable electricity*. 2015. DOI: 10.1016/j.rser.2015.01.057.

[11] ENTSOE. *ENTSO-E Report System Flexibility Needs for the Energy Transition*. Technical report. 2024. URL: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/System_Needs/entso-e_System_Needs_Energy_Transition_v10.pdf.

[12] Koolen D., De Felice M., and Bush S. *Flexibility requirements and the role of storage in future European power systems*. Technical report. JRC, 2023. URL: https://publications.jrc.ec.europa.eu/repository/handle/JRC130519.

[13] Parinaz Aliasghari, Leonard Göke, and Ruud Egging-Bratseth. "The potential of electrified transport for enhancing flexibility in integrated renewable energy systems". In: *Energy Reports* 13 (June 2025), pages 3379–3401. ISSN: 23524847. DOI: 10.1016/j.egyr.2025.03.002.

[14] Francesco Sanvito, Francesco Lombardi, and Stefan Pfenninger-Lee. "Coordinated planning of European charging infrastructure and energy system for optimal V1G and V2G deployment". In: *Nature Energy* (July 2026). ISSN: 2058-7546. DOI: 10.1038/s41560-026-02107-5. URL: https://www.nature.com/articles/s41560-026-02107-5.

[15] J. G. Kirkerud, N. O. Nagel, and T. F. Bolkesjø. "The role of demand response in the future renewable northern European energy system". In: *Energy* 235 (November 2021). ISSN: 03605442. DOI: 10.1016/j.energy.2021.121336.

[16] Dai Wang, Matteo Muratori, Joshua Eichman, Max Wei, Samveg Saxena, and Cong Zhang. "Quantifying the flexibility of hydrogen production systems to support large-scale renewable energy integration". In: *Journal of Power Sources* 399 (September 2018), pages 383–391. ISSN: 03787753. DOI: 10.1016/j.jpowsour.2018.07.101.

[17] Siavash Khalili, Gabriel Lopez, and Christian Breyer. *Role and trends of flexibility options in 100% renewable energy system analyses towards the Power-to-X Economy*. April 2025. DOI: 10.1016/j.rser.2025.115383.

[18] Christoph Brunner, Gerda Deac, Sebastian Braun, and Christoph Zöphel. *The future need for flexibility and the impact of fluctuating renewable power generation*. April 2020. DOI: 10.1016/j.renene.2019.10.128.

[19] Niels Oliver Nagel, Jon Gustav Kirkerud, and Torjus Folsland Bolkesjø. "The economic competitiveness of flexibility options: A model study of the European energy transition". In: *Journal of Cleaner Production* 350 (May 2022). ISSN: 09596526. DOI: 10.1016/j.jclepro.2022.131534.

[20] Pandu Prianto, Lisa Göransson, and Filip Johnsson. "Roles of flexibility measures in a regional electricity power system: Stationary batteries, V2G, and flexible hydrogen". In: *Advances in Applied Energy* 22 (June 2026). ISSN: 26667924. DOI: 10.1016/j.adapen.2026.100276.

[21] Aleksander Grochowicz, Hannah C. Bloomfield, and Marta Victoria. "Resilience metrics to guide back-up investments in the power system during extreme weather". In: (June 2026). URL: http://arxiv.org/abs/2508.05163.

[22] Ebbe Kyhl Gøtske, Gorm Bruun Andresen, Fabian Neumann, and Marta Victoria. "Designing a sector-coupled European energy system robust to 60 years of historical weather data". In: *Nature Communications* 15.1 (December 2024). ISSN: 20411723. DOI: 10.1038/s41467-024-54853-3.

[23] T. Brown, D. Schlachtberger, A. Kies, S. Schramm, and M. Greiner. "Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European energy system". In: *Energy* 160 (October 2018), pages 720–739. ISSN: 03605442. DOI: 10.1016/j.energy.2018.06.222.

[24] Matija Pavičević, Andrea Mangipinto, Wouter Nijs, Francesco Lombardi, Konstantinos Kavvadias, Juan Pablo Jiménez Navarro, Emanuela Colombo, and Sylvain Quoilin. "The potential of sector coupling in future European energy systems: Soft linking between the Dispa-SET and JRC-EU-TIMES models". In: *Applied Energy* 267 (June 2020). ISSN: 03062619. DOI: 10.1016/j.apenergy.2020.115100.

[25] H. Lund, P. A. Østergaard, M. Yuan, P. Sorknæs, and J. Z. Thellufsen. "Energy balancing and storage in climate-neutral smart energy systems". In: *Renewable and Sustainable Energy Reviews* 209 (March 2025). ISSN: 18790690. DOI: 10.1016/j.rser.2024.115141.

[26] Joseph F. DeCarolis. "Using modeling to generate alternatives (MGA) to expand our thinking on energy futures". In: *Energy Economics* 33.2 (March 2011), pages 145–152. ISSN: 01409883. DOI: 10.1016/j.eneco.2010.05.002.

[27] Fabian Neumann and Tom Brown. "The near-optimal feasible space of a renewable power system model". In: *Electric Power Systems Research* 190 (January 2021). ISSN: 03787796. DOI: 10.1016/j.epsr.2020.106690.

[28] Ulrich Joachim Frey, Karl-Kiên Cao, Shima Sasanpour, Jan Buschmann, and Thomas Breuer. "The benefits of exploring a large scenario space for future energy systems". In: *Nature Communications* (December 2025). ISSN: 20411723. DOI: 10.1038/s41467-025-67593-9.

[29] Amalia Pizarro-Alonso, Hans Ravn, and M. Münster. "Uncertainties towards a fossil-free system with high integration of wind energy in long-term planning". In: *Applied Energy* 253 (November 2019). ISSN: 03062619. DOI: 10.1016/j.apenergy.2019.113528.

[30] Frauke Wiese, Rasmus Bramstoft, Hardi Koduvere, Amalia Pizarro Alonso, Olexandr Balyk, Jon Gustav Kirkerud, Åsa Grytli Tveten, Torjus Folsland Bolkesjø, Marie Münster, and Hans Ravn. "Balmorel open source energy system model". In: *Energy Strategy Reviews* 20 (2018), pages 26–34. ISSN: 2211467X. DOI: 10.1016/j.esr.2018.01.003.

[31] Ioannis Kountouris, Rasmus Bramstoft, Theis Madsen, Juan Gea-Bermúdez, Marie Münster, and Dogan Keles. "A unified European hydrogen infrastructure planning to support the rapid scale-up of hydrogen production". In: *Nature Communications* 15.1 (December 2024). ISSN: 20411723. DOI: 10.1038/s41467-024-49867-w.

[32] Ioannis Sifnaios, Daniel Møller Sneum, Adam R. Jensen, Jianhua Fan, and Rasmus Bramstoft. "The impact of large-scale thermal energy storage in the energy system". In: *Applied Energy* 349 (November 2023). ISSN: 03062619. DOI: 10.1016/j.apenergy.2023.121663.

[33] Théo Balanza, Alexander Torp Jørgensen, and Rasmus Bramstoft. *The Role of Electric Vehicles and Vehicle-to-Grid in a Future Sector-Coupled European Energy System*. Technical report. URL: https://ssrn.com/abstract=6569982.

[34] Shubham Nayak, Ernestas Simutis, Juan Pablo Murcia Leon, Bjarke Tobias Olsen, and Matti Juhani Koivisto. "Validation of European wind generation time series simulation: Importance of wakes, micro-scale adjustments and stochastic simulations". In: *Applied Energy* 402 (December 2025). ISSN: 03062619. DOI: 10.1016/j.apenergy.2025.126882.

[35] Shubham Nayak, Matti Juhani Koivisto, and Polyneikis Kanellas. *Pan-European wind and solar generation time series*. Technical report. 2025.

[36] Shubham Nayak, Matti Juhani Koivisto, and Polyneikis Kanellas. *Pan-European weather dependent generation and demand time series for Balmorel Energy system modelling*. Technical report.

[37] ENTSOE. "TYNDP_2024_Scenarios_Report". In: (2024). URL: https://2024.entsos-tyndp-scenarios.eu/foreword/.

[38] *Electricity and heat statistics*. 2022. URL: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_and_heat_statistics&oldid=552866#Derived_heat_production.

[39] Nourelden Gaafar, Patrick Jürgens, Jael Sepúlveda Schweiger, and Christoph Kost. "System flexibility in the context of transition towards a net-zero sector-coupled renewable energy system—case study of Germany". In: *Environmental Research: Energy* 1.2 (June 2024), page 025007. DOI: 10.1088/2753-3751/ad5726.

[40] Mie H Bahl, Rujie Zhu, Rasmus Bramstoft, Matti Koivisto, Anouar Bouallaga, and Kaushik Das. "Assessing Balancing and Flexibility Needs in Future Power Systems: A Nordic Case Study for 2030". In: 2025. URL: https://findit.dtu.dk/en/catalog/699f0078a2c1fd2c4b34a234.

[41] International Energy Agency. *World Energy Outlook 2025*. Technical report. 2025. URL: www.iea.org/terms.

[42] Stephane Bourgeois, Nicolas Taillard, Emile Balembois, Adrien Toledano, Alexandre Gabert, Yves Marignac, Fabien Baudelet, Sébastien Teysset, and Stephane Larue-Bernard. *The CLEVER network Report drafting (négaWatt Association) Project coordination (négaWatt Association) Design (négaWatt Association)*. Technical report. 2023.

[43] European Hydrogen Observatory. *Explore and compare the leading scenarios for future hydrogen demand in Europe in 2030, 2040 and 2050 by sector*. URL: https://observatory.clean-hydrogen.europa.eu/tools-reports/scenarios-future-hydrogen-demand.

[44] International Energy Agency. *Global EV Outlook 2024 Moving towards increased affordability*. Technical report. 2024. URL: www.iea.org.

[45] *Balmorel community*. URL: https://github.com/balmorelcommunity.

[46] Balanza Theo and Bramstoft Rasmus. *The role of flexibility in future European sector-coupled energy system (model and data)*. DOI: 10.5281/zenodo.22304432.

[47] Emir Fejzic et al. *Planning for climate neutrality in the Nordic power sector: Insights from a non-harmonised comparison of eight energy system models Email addresses of all authors*. Technical report.

[48] Soner Candas et al. "Code exposed: Review of five open-source frameworks for modeling renewable energy systems". In: *Renewable and Sustainable Energy Reviews* 161 (June 2022). ISSN: 18790690. DOI: 10.1016/j.rser.2022.112272.

[49] Théo Balanza, Nicolas Campion, Mathias Berg Rosendal, Rasmus Bramstoft, and Anders Bjørn. "Exploring configurations of a European energy system within the planetary boundaries". In: *Environmental Research Letters* 20.7 (July 2025). ISSN: 17489326. DOI: 10.1088/1748-9326/ade26b.

[50] Anthony Wang, Jaro Jens, David Mavins, Marissa Moultak, Matthias Schimmel, Kees Van Der Leun, Daan Peters, and Maud Buseman. *Analysing future demand, supply, and transport of hydrogen EUROPEAN HYDROGEN BACKBONE Executive summary*. Technical report. European Hydrogen Backbone, 2021. URL: https://transparency.entsog.eu/.

[51] Juan Gea-Bermúdez, Rasmus Bramstoft, Matti Koivisto, Lena Kitzing, and Andrés Ramos. "Going offshore or not: Where to generate hydrogen in future integrated energy systems?" In: *Energy Policy* 174 (March 2023). ISSN: 03014215. DOI: 10.1016/j.enpol.2022.113382.

[52] Rasmus Bramstoft, Polyneikis Kanellas, Juan Pablo Murcia Leon, and Matti Koivisto. "The role of offshore wind energy hubs in the Baltic Sea energy system". In: *Energy* 348 (April 2026). ISSN: 18736785. DOI: 10.1016/j.energy.2026.140554.

[53] European Commission. *EU Reference Scenario 2020*. Technical report. 2020. URL: https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en.

[54] Rasmus Bramstoft, Amalia Pizarro-Alonso, Ida Græsted Jensen, Hans Ravn, and Marie Münster. "Modelling of renewable gas and renewable liquid fuels in future integrated energy systems". In: *Applied Energy* 268 (June 2020). ISSN: 03062619. DOI: 10.1016/j.apenergy.2020.114869.

[55] ENTSOE. *TYNDP ENTSOE 2024*. 2024. URL: https://2024.entsos-tyndp-scenarios.eu/visualisation-platform/.

[56] Danish Energy Agency. *Technology catalogue*. 2024.

Supplementary Files

This is a list of supplementary files associated with this preprint. Click to download.

- FlexibilityTheoBalanzaSupplementaryinformation.pdf