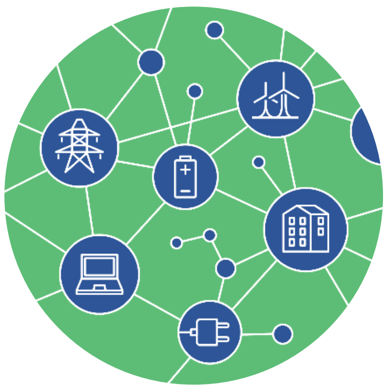
OSMOSE

OPTIMAL SYSTEM-MIX OF FLEXIBILITY SOLUTIONS FOR EUROPEAN ELECTRICITY

D1.3: Optimal Mix of Flexibility



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1 Executive summary

The OSMOSE project addresses the question of power system flexibility, understood as its ability to cope with variability and uncertainty in demand, generation and grid, over different timescales. Work-package 1 (WP1) of the project aims to find a flexibility mix that maximizes the European social welfare, taking into account all relevant technical constraints and associated costs. Given the variety of technologies and actors, interactions between the entities that require or provide flexibility must be accurately modelled in time and space to assess the real value of flexibility. WP1 focused primarily on addressing methodological issues and developing a general-purpose toolkit suitable for addressing these issues in the context of the European system. Within WP1, Task 1.1 builds scenarios with varying levels of compliance with the CO2 emission reduction commitments of the Paris Agreement, from today to 2050 and Task T1.2 aims to optimise the mix of flexibility associated with these scenarios at a "TSO-centric" level to ensure that the power mixes can match the security of supply criteria in force in Europe. This report describes the methodology developed by Task T1.2 and presents the main findings, which are summarised below.

Innovative flexibility quantification metrics are needed to address the question of who provides flexibility and how flexibility sources actually interact

The existing literature on flexibility metrics, while rich, does not address the question of who provides flexibility and how flexibility sources actually interact. Two indicators were therefore created to address this gap, covering annual, weekly and daily time horizons:

- Flexibility Solution Modulation Stack (FSMS) that expresses how each flexibility solution behaves to match supply to demand over the three time horizons.
- Flexibility Solution Contribution Distribution (FSCD) that evaluates the relative contribution of each flexibility solution for the different time horizons.

Coupling Capacity Expansion Models with shorter-term production cost models allows to better account for flexibility in investment plans while complying with security of supply targets. In addition, addressing this weakness greatly improves the reliability of CO_2 emission calculations.

Capacity Expansion Models like GENeSYS-MOD or OSeMOSYS are key in power system planning and energy policy. However, due to size and tractability issues, they rely on time slices, which are known to greatly impair the representation of variability and flexibility needs. One way to solve the limited flexibility representation in capacity expansion models is to couple them with production cost models providing a more accurate hourly dispatch. T1.2 pursued this idea using two soft-linking approaches:

- Heuristic soft-linking, where capacity adjustments were performed "heuristically". This approach helped frame and understand the typical problems with the capacity expansion model results.
- Automated bi-directional soft linking, where results from the production cost model are automatically fed back to the capacity expansion model to signal under- and over-investment in order to adjust the investment pathway in the next iteration. Two variants of the feedback scheme were successfully tested: a first one based on reserve margin feedback and a second one based on flexibility contribution metrics (which produced better results).

The assertion that established Capacity Expansion Models significantly underestimate flexibility value was experimentally confirmed in the automated soft-linking process, leading to a 10% increase in TOTEX, and notable changes to the generation mix (balance between base and peak units installed capacity), dispatch and subsequently CO_2 emissions.

Industrial capacity and infrastructure development rate is a critical parameter to be considered in capacity expansion planning, especially to meet ambitious CO2 emission targets

Results show that the political and industrial capacity considerations like industries' ability to roll-out new infrastructure fast enough significantly impact the model results, and especially the achievement of our current CO2 emission reduction targets.

In the studied scenarios, the flexibility requirements at the European level increase slightly until 2030 and then more significantly between 2030 and 2050. These studies demonstrate the value of new flexibility solutions (in particular short and long term storage), but confirm that interconnections will still have a major role to play.

Results show a shift from a scheme where annual modulations are linked to consumption and generation maintenance patterns to a new one driven by annual generation patterns of VRES which are irregular throughout the year. Although the situation is country dependant, the following key points were highlighted in the considered scenarios:

- In 2030 and 2050, interconnectors remain one of the main sources of flexibility on all time scales
- When there is a significant deployment of electrolysis[1], they become a major source of flexibility for all timescales (annual to hourly), potentially replacing hydro. This highlights the need for coordinated management of long-term storages, which has not been done in this simulation.
- In 2050, batteries provide significant flexibility, limited to the daily scale due to their energy rating.
- In 2050, gas turbines, ideally powered by green gas, are an important flexibility provider.
- RES curtailment appears in 2050 on several timescales despite significant storage capacity and RES generation could be curtailed on a regular basis for up to several weeks in a row.

A valuable collaboration effect between electrolysers and short-term flexibility sources (batteries, pump storage plants) may take place, provided that suitable market designs encourage the participation of all flexibility levers in the day-ahead and intraday markets

In 2050 simulations, during some sunny summer peaks, generation is exceeding both the demand and the electrolyser capacities. Then other shorter-term stock-based flexibility providers (such as batteries and pump storage plants) can charge before discharging a couple of hours later, when PV generation decreases, keeping electrolysers running outside sunny (or windy) hours. This optimal collaboration effect could be translated into operational reality by market designs that foster the participation of all flexibility levers in the day-ahead and intraday markets.

Considering sector coupling in capacity expansion model is key but requires modelling adaptations to keep the problem tractable

A limited scope of cross sectorial modelling was performed, ensuring that the power system will be able to fully run in 2050 on domestic green gas produced via electrolysis. It reveals additional linkages between flexibility requirements and provision capabilities and highlights how crucial it is to take these linkage into account when studying flexibility:

- In 2030, marginal costs (usually deemed as an acceptable proxy for the market clearing price) exhibit the usual pattern and are mainly driven by generation costs.
- In 2050, though the power system is mostly powered via VRES whose proportional cost is zero, marginal costs are driven by flexible demand. Indeed, electrolysers could significantly increase prices during scarcity periods, drastically limiting the time steps with a market price of zero.

[1] The merit order of decarbonisation solutions depends on the list of options considered to meet the European pledges of the Paris Agreement. This list is the combined result of technological maturity trajectories and political decisions. It has not been discussed in detail in this work, which focuses on methodological aspects.

In order to accurately reflect prices, other energy carriers (methane, hydrogen or even heat) should be modelled in detail, taking into account their price sensitivity their own demand. This would also require modelling inter-annual storage and alternative means of producing or importing each carrier.

Increasing the geographic resolution of the study highlights the sensitivity of overall system flexibility to internal grid constraints and the important role of the grid as a flexibility lever.

Dispatch simulations with a resolution of 99 zones for Europe lead to contrasted results: internal grid constraints increase both spillages, loss-of-load duration and energy not supplied. This analysis points to a reduction of system flexibility due to grid constraints and the significant role of the grid as the flexibility lever (in the 2050 study case, alleviating the internal grid constraints implies an increase in power-to-gas utilisation). Further analysis would be required to assess whether the optimal solution for mitigating this congestion is redispatch, which can represent an additional revenue stream for flexible units or rather more internal grid developments instead.

Reserve management processes should be harmonized, in particular to explicitly account for the Europe-wide temporal variability of VRES in reserve sizing. Access to interconnections by reserve providers should be fostered through appropriate market design (co-optimisation of reserves and energy in day-ahead and intraday markets).

A proof-of-concept study for integrating forecast errors effects and analysing the impact of reserve procurement has been run. Though results are obviously highly dependent on the underlying hypothesis of the scenarios, they give some general hints:

- Reserve requirements are dependent on VRES uncertainty and increase with the share of VRES.
- Grid is a mean to share VRES but also flexibility sources on all timescales, including reserves.

Fully efficient use of interconnection for reserve procurement implicitly assumes a co-optimisation of energy and reserve, which will require adaptation of market design to become operational reality.

The OSMOSE dataset is made publicly available to foster transparency on the assumptions, constructive criticism and reuse as a benchmark

Data collection and model development represented more than 90% of the work and is a common barrier for such studies. To build upon this work and facilitate additional studies, the full dataset developed by RTE, EKC and TUB is publicly available.

2 List of acronyms and abbreviations

aFRR	Automated Frequency Restoration Reserves
AT	Accelerated Transformation
BESS	Battery Energy Storage System
CAPEX	Capital expenditures
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CExM	Capacity Expansion Model
CGA	Current Goals Achieved
DC	Discrete current
DSM	Demand-side management
DSO	Distribution System Operator
ENS	Energy not served
EV	Electric vehicle
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves
FSCD	Flexibility Solution Contribution Distribution
FSMS	Flexibility Solution Modulation Stack
GTC	Grid Transfer Capability
IAM	Integrated Assessment Model
LCA	Life-cycle analysis
LOLD	Loss-of-load duration
LOLE	Loss-of-load expectation
MAF	Mid-Term Adequacy Forecast
mFRR	Manual Frequency Restoration Reserves
NCA	Neglected Climate Act
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
OPEX	Operational expenditure
OPF	Optimal power flow
P2G	Power-to-gas
PCM	Production Cost Models
PECD	Pan-European Climate Database
PEM	Polymer electrolyte membrane (electrolysis)
PSP	Pump storage plant
PV	Photo-voltaic
RES	Renewable energy source
RoR	Run-of-river (hydro unit)
TOTEX	Total expenditure
TSO	Transmission System Operator
TYNDP	Ten-year network development plan
VRES	Variable Renewable Energy Source

3 Introduction

The OSMOSE project addresses the question of power system flexibility. Beyond a mere buzzword, literature converges to define flexibility as the ability to cope with variability and uncertainty in demand, generation and grid. System operators have always had to cope with variability and uncertainty. The final goal being an optimal dispatch of the generation, demand, and storage in real-time.

However the energy transition is changing the flexibility landscape:

- Variable Renewable Energy Sources reshape the variability and uncertainty in the system,
- The switch from synchronous to inverter-based generation challenges its stability,
- The electrification of end uses - heating, mobility, power-to-gas - brings new types of loads in the system,
- Large storage solutions are becoming more competitive,
- Advanced automation and control technologies enable smarter and faster operations.

These changes represent both threats and opportunities for the power system: while flexibility requirements tend to increase, new flexibility sources are appearing, that can actually help tackle such challenges. Aware of the importance of evaluating the long-term effect of these transformations, the OSMOSE partners have planned in their answer to the H2020 call LCE-04-2017 to complement the demonstrators with prospective studies aimed at:

- Enhancing common understanding of future flexibility requirements and sources by analyzing the evolution until 2050 of prospective mixes targeting compliance with the European commitments of the Paris Agreement,
- Proposing a comprehensive methodology for designing and operating an optimal mix of flexibility.

Flexibility is fundamentally a question of time: what are the actions that can be taken? Which uncertainty and variability are they meant to address? All the time horizons are tightly interrelated which makes a global understanding very challenging.

Furthermore, given the variety of technologies and actors, most interactions between the entities that require or provide flexibility must be accurately modelled in time and space to assess the real value of flexibility. The project focused primarily on addressing methodological issues and developing a general-purpose toolkit suitable for addressing these issues in the context of the European system, rather than providing scenarios.

The purpose of this report is to present the methodology developed by Task T1.2 to answer these questions, as well as the reasoning behind the design decisions. Each brick of the methodology is illustrated by numerical results obtained on prospective scenarios developed to match the current energy transition strategy. At each stage, this report summarizes the main findings of the studies conducted, highlights the points that appear most robust and opens up future research questions.

4 Definition of flexibility used in the present research

4.1 A concept requiring clarification

A viable definition of flexibility should go beyond a mere buzzword into a workable concept for prospective studies. On top of that, such a definition has some fundamental implications on the methodology and tools one should use in prospective studies dealing with flexibility.

Flexibility can refer to many different ideas. Since the 1990's, several definitions of flexibility have been successively proposed:

- In the uncertain context of power sector unbundling and liberalisation, flexibility was a long-term investment issue, as planners worried their system would not be able to adapt to changing legislation.
- As renewables started integrating the system, the term flexibility took on a new meaning, linked to concerns for short-term operation.
- As renewable shares increased, challenges began to appear on longer timescales, and the multi-timescale nature of flexibility has often been stated explicitly.

This short historical summary illustrates the need for a broader and more robust definition of flexibility, encompassing the above elements. Furthermore, the definition of flexibility is a matter of point of view:

- Owners of flexibility solutions are concerned by the optimal design of their device, which maximises their revenue for a given level of risk.
- At the opposite end of the spectrum, a system operator understands flexibility through the lens of its main missions, namely load-supply balancing and congestion management. This approach applies to the short term (efficient operation of available flexibility sources), but affects long term perspectives as well (flexibility sources needed to operate the system in the future).

In the present document flexibility is defined, according to [Heggarty 2021], as "**the power system's ability to cope with variability and uncertainty**".

This definition is underpinned by the notion of common interest. As such, flexibility cannot be clearly distinguished from the ability to securely operate the power system by matching supply with demand, managing grid congestions, and ensuring electricity quality expected by industrial and domestic customers. In practice, this has been a key concern for system operators for decades, even before the word flexibility became popular.

To fully understand what is at stake with flexibility, a clear distinction needs to be made between variability and uncertainty, according to the level of predictability of the observed variations: uncertainty relates to a variation of a stochastic nature, while variability is used to describe deterministic fluctuations or events[2].

4.2 Basic classification for flexibility solutions

One can classify flexibility solutions according to different relevant perspectives.

First of all, there are many ways of providing flexibility in power systems, to cope with variability and uncertainty.

- One can modulate generation output, including variable renewable energy sources (VRES).
- Load can be modulated as well, including new uses like Electric Vehicles and other emerging uses like electrolysers (sector-coupling)[3].

[2] It should be noted that actual signals very often contain both. Furthermore this distinction largely depends on the look ahead time (e.g. installed capacity is uncertain 20 years ahead, but goes down to zero for the current month).

[3] It should be noted that some flexibility solutions like electric vehicles, batteries and sector-coupling shall play a specific role in that picture, introducing new flexibility sources but also inducing new flexibility requirements.

- By matching load and generation on a wide geographical scale, the grid smoothes out variations through space allowing locational load-generation discrepancies, within the limits of grid capacities.
- Or energy can be stored in a different form (including electrochemical storage in batteries) to smooth variations through time.

Secondly, variability in demand and generation occurs on several time-scales, but matching supply and demand is made all the more difficult when uncertainty comes into play:

- On the long-term, power system operation is made uncertain by the difficulty to predict energy policy, the evolution of consumer habits, economic growth etc.
- On the medium term, power system operators must face cyclical variations in demand and renewable generation as well as manage planned outages.
- On the short term, power system operation is constrained by incidents and forecastability of weather dependant demand and renewable generation.

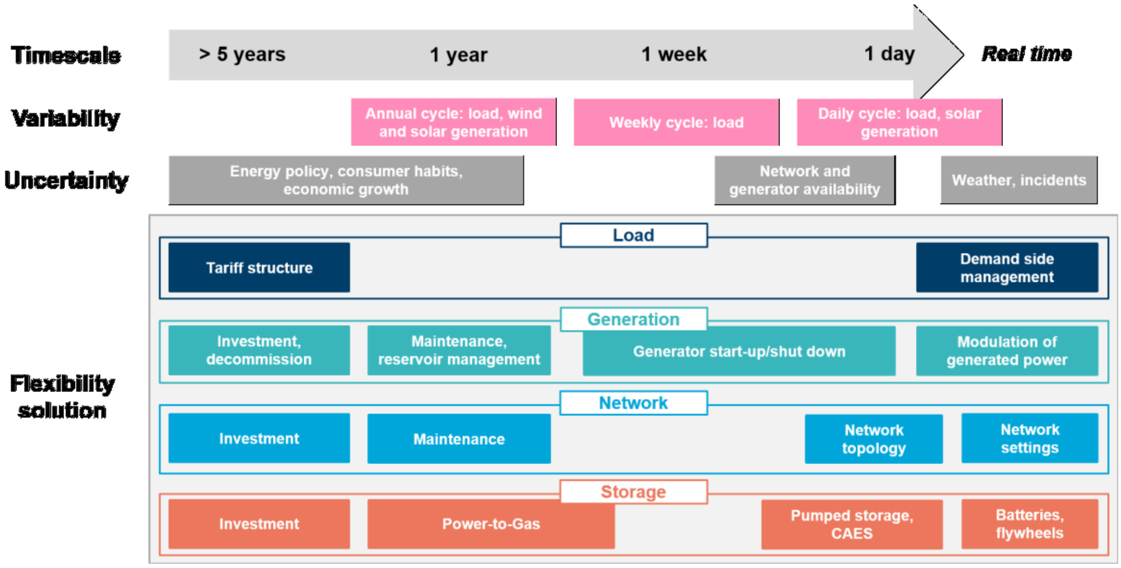

Figure 1: time-scale for flexibility

On the other hand, flexibility may be analysed in terms of the system operator's missions (load-supply balancing, congestion management and electricity quality), which depend to a greater or lesser extent on the exact location of flexibility solutions:

- The "balancing" flexibility (also called arbitrage) focuses on the ability of the system to maintain the balance between load and generation. Its value is frequently deemed to represent a significant part of the total value of flexibility. According to the current design of European power markets, flexibility is managed within each geographical bidding zone.
- However, flexibility solutions can often provide several services at the same time
    - Stability[4]
    - Reserves (Frequency Containment Reserves –FCR- & Frequency Restoration Reserves - FRR)
    - Grid management (grid congestion, reactive power provision…)

[4] [[Hatziargyriou et al 2020] has published an updated definition of stability, which encompasses rotor angle stability, voltage stability, frequency stability, resonance stability and converter-driven stability.

A deep understanding of multi-service (benefits and constraints) is key to fully grasping the economy of flexibility and properly sizing flexibility solution, in particular with respect to capital (CAPEX) and operational expenditure (OPEX). Given the diversity of flexibility sources, a holistic view of flexibility is necessary and leads to the notion of mix of flexibility.

Operating a power system involves a series of decisions taken at different time horizons, based on the forecasts available at that time. Uncertainty generally tends to be reduced when approaching real time. At the same time, the ability to adapt to changes is reduced as some levers become unavailable (implementation times). In order to determine the balance that results from these two opposing movements, it is necessary to explicitly take into account the forecast horizons. The look ahead factor is essential when dealing with flexibility levers:

- Several years ahead of real time, one can choose to invest or decommission flexibility solutions
- Conversely, on shorter timescales, only existing infrastructure can be activated.

4.3 Flexibility in the Energy Transition – a changing landscape

System operators have always had to cope with variability and uncertainty, but the energy transition is changing this flexibility landscape. On the one hand, renewable development is increasing flexibility requirement. On the other, historically dominant flexibility solutions like thermal power plants are being phased out, while new solutions like batteries or power-to-gas are emerging.

One major lever put forward to solve the environmental crisis is to drastically increase the share of renewables in the energy system, and in particular wind and solar generation, as their direct CO2 emissions amount to zero[5]. These two technologies are variable and share two common challenging features: they are weather dependant and non-dispatchable sources of supply. In systems with very high shares of Variable Renewable Energy Sources (VRES), flexibility becomes more crucial than ever.

The first step to implementing an optimal flexibility mix is therefore to improve our understanding of flexibility in the context of power system planning, i.e. in a quantitative manner that can serve as a basis for deriving an optimization process. This topic is addressed in Section 5, Flexibility metrics.

4.4 Which criterion to judge the Optimality of a mix of flexibility?

Once the concept of flexibility and the issues related to it in the context of the energy transition have been clarified, the question remains as to what is meant by an optimal flexibility mix. In a first analysis, designing an optimal mix of flexibility involves determining some kind of technical-economic merit order for flexibility. Given the variety of technologies that can be used to provide flexibility, this ranking cannot reasonably be done without adopting a holistic view[6]. This approach emphasizes our need to describe and model all types of technologies that can provide flexibility with sufficient detail to accurately reflect their interactions with the rest of the mix (their dynamic constraints, fixed and proportional costs, etc…)

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[5] When the full life cycle of these technologies ("cradle to grave" analysis) is considered, their CO2 emissions are not equal to zero: like for other technologies, one should account for indirect emissions related to the mining of raw materials, components manufacturing, installation building, maintenance and dismantling.

[6] In a vertically integrated power system, this task is achieved by utilities. In Europe, this responsibility has drifted to Transmission System Operators, who have no responsibility for generation planning and must therefore interact effectively with policy makers and stakeholders to enable optimal decision making.

However, the use of a technical-economic optimum (total costs[7] minimization, and more generally social welfare maximisation) as a proxy for “common good” clearly points to a top down vision of energy policies. The underlying assumption is that the goal of economics is to rationally allocate resources, in a general equilibrium paradigm. To do this, externalities (in particular environmental and social ones) must be explicitly and accurately integrated, and individual utility functions are assumed to be well-known and translatable into an aggregated utility curve.

These assumptions were already highly questionable in the context of monopolies[8], but the shift to a decentralized world tends to exacerbate the criticisms: a local decision-making paradigm is far from a rational central planner one; the environmental crisis illustrates how difficult it is to address sustainability. For instance, maximising social welfare tends to favour commercial exchanges at the expense of sufficiency. Therefore the traditional vision of the “common good” used by system planners may conflict with the ambitions of the energy transition (e.g., pillars of the energy trilemma - energy security, energy equity, environmental sustainability). No doubt flexibility sources are affected by this trend as are other elements of the energy system.

In other words, an investment decision is often the result of a multi-criteria choice. In addition, these criteria are often complex to take into account: eagerness to take part in the energy transition, to reduce one’s environmental footprint, to be more independent from the grid, to control the evolution of their electricity bill, etc. From this perspective, the practical problem is to know if this choice can be rationally modelled, and if so, what weight to give to each criterion to obtain a global ranking of the solutions.

On the other hand, Transmission System Operators (TSOs) in accordance with their mission, have to ensure that the various collective and individual initiatives will not make the whole system less optimal in technical and financial terms. Therefore, the decision was taken in WP1 to still use the criterion of cost minimisation to discriminate between options, but to complement it with other numerical indicators from the field of the Environmental Analysis (e.g., critical impact on water, depletion of rare minerals, human health…), in order to try to conciliate the different perspectives.

It is worth noting that the OSMOSE project aims to address the methodological aspects: to identify which assumptions play a leading role in scenarios with high VRES shares in the power mix, and based on this analysis, to set up a system modelling approach, which can capture the main interactions and the practical consequences. Scenarios are not a goal in themselves, but will be necessary to test the proposed methodology.

5 Flexibility metrics[9]

Quantifying is a convenient way of condensing large amounts of power system data to provide a quick understanding of a complex situation and set the basis for a rational discussion. Many flexibility metrics have been proposed in the literature: they either try to answer the question “how much flexibility does my system need?”, “how flexible is my flexibility solution?” or “how flexible is my full power system?”

The approach applied in WP1 is based on the observation that different flexibility solutions behave in different ways depending on the timescale, thus fulfilling different roles in the power system. In this

[7] Total costs are composed of Capital Expenditures (CAPEX) and Operational Expenditures (OPEX).

[8] For instance, consider Arrow’s impossibility theorem in [Arrow 1950], stating that ranked preferences of individuals cannot be converted into a complete and transitive community-wide ranking.

[9] Unless otherwise stated, the source for results and illustrations presented in the present section is [Heggarty 2021]

respect, two gaps identified in the existing metrics were of critical importance to fulfilling the mandate of feeding an optimization process. One of them is related to flexibility requirement on timescales beyond a few hours which existing metrics concentrated on. The other is the question of what technology actually provides flexibility in a given system.

We will now briefly describe quantification methods proposed by the OSMOSE project, and mention a few example applications.

The proposed approach for quantifying flexibility focuses on the behaviour of different flexibility solutions depending on the timescale. A Fourier analysis of historical hourly time series of load and VRES generation has shown that three different time scales are sufficient in a first approach to characterize flexibility requirement and provision: the annual, weekly and daily scales[10].

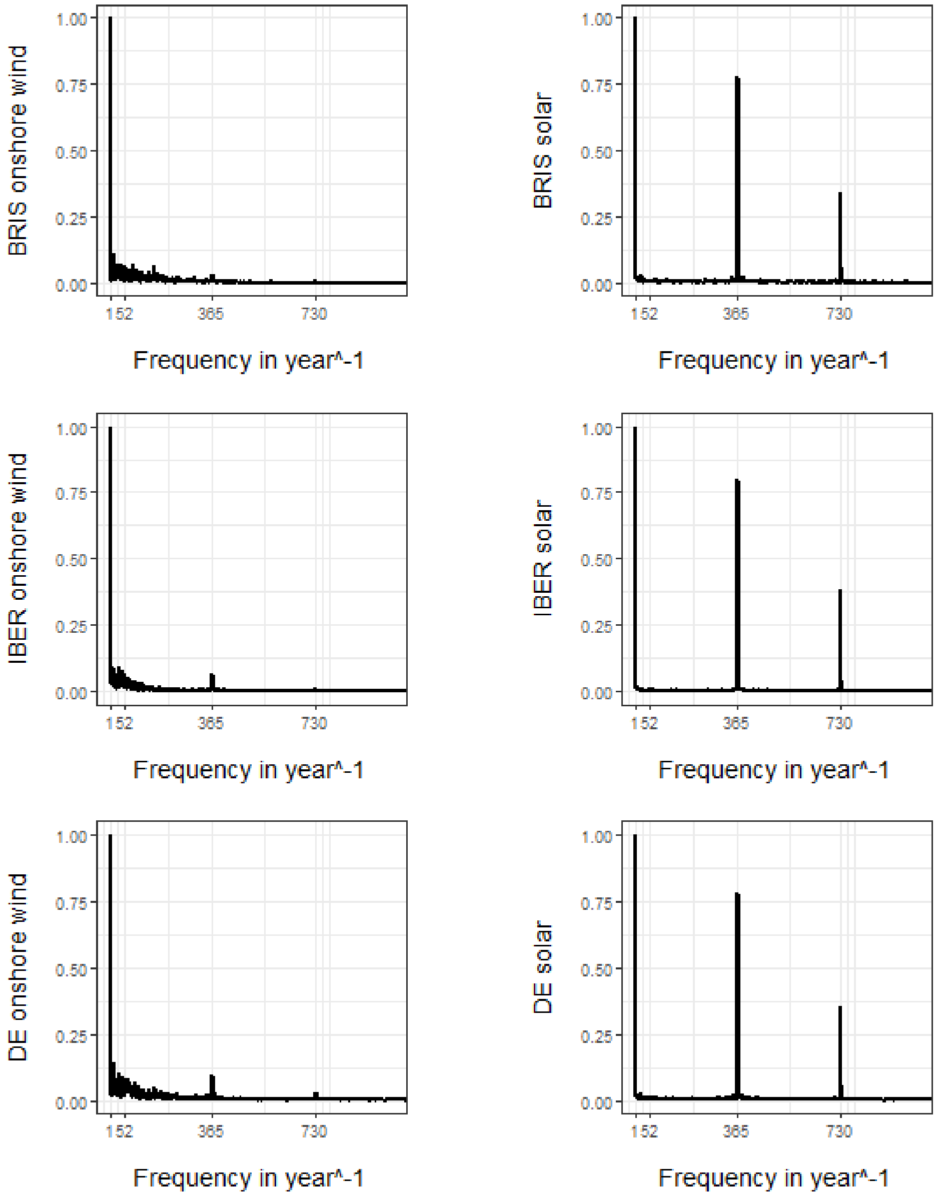

Figure 2: frequency analysis on a typical VRES generation time series for the British Isles (BRIT), the Iberian Peninsula (IBER) and Germany (DE) [source Heggarty_2021]

[10] By construction, the use of hourly time series prevents any taking into account of sub-hourly phenomenon.

5.1 Flexibility analysis over different timescales

The process of determining flexibility requirements takes net load as an input, i.e. load minus non-dispatchable generation, which mainly consists of variable generation from renewable energy sources. The hourly time series of net load can be obtained either from real system data or from simulations. The annual, weekly and daily components of each time series are then separated using frequency filters.

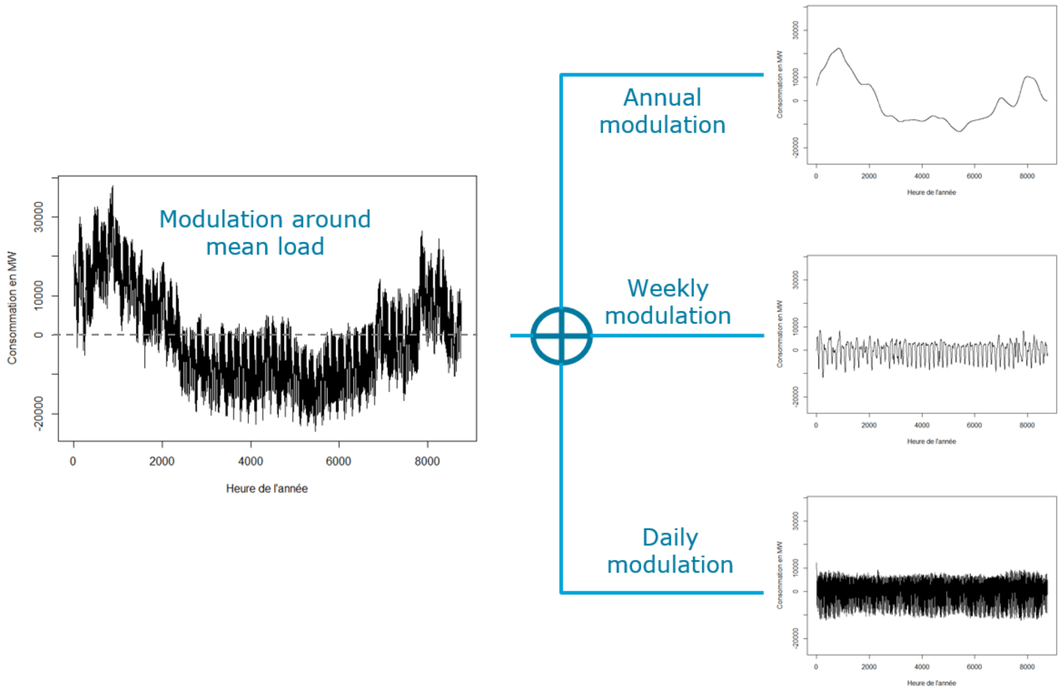

Figure 3: current situation in France (2018) [source Heggarty_2021]

Then, the proposed method quantifies the contribution of each flexibility solution to the total system effort. The same kind of Fourier analysis proved that the annual, weekly and daily timescales decomposition was relevant for dispatchable sources as well (including demand response).

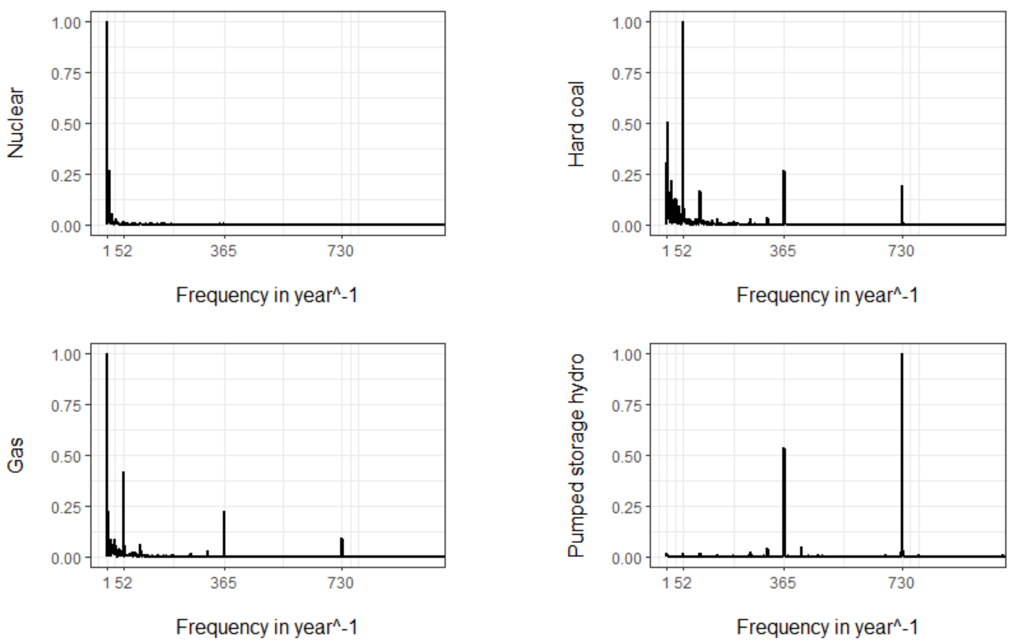

Figure 4: frequency analysis on a typical dispatchable generation time series [source Heggarty_2021]

5.2 Flexibility Solution Modulation Stack

The process of determining flexibility provision by technology takes the generation time series of each technology as an input (in the specific case of demand response, the time series of activated volume is used instead). For each timescale, the resulting modulations are stacked to produce a graphical tool, the **Flexibility Solution Modulation Stack** (FSMS)[11].

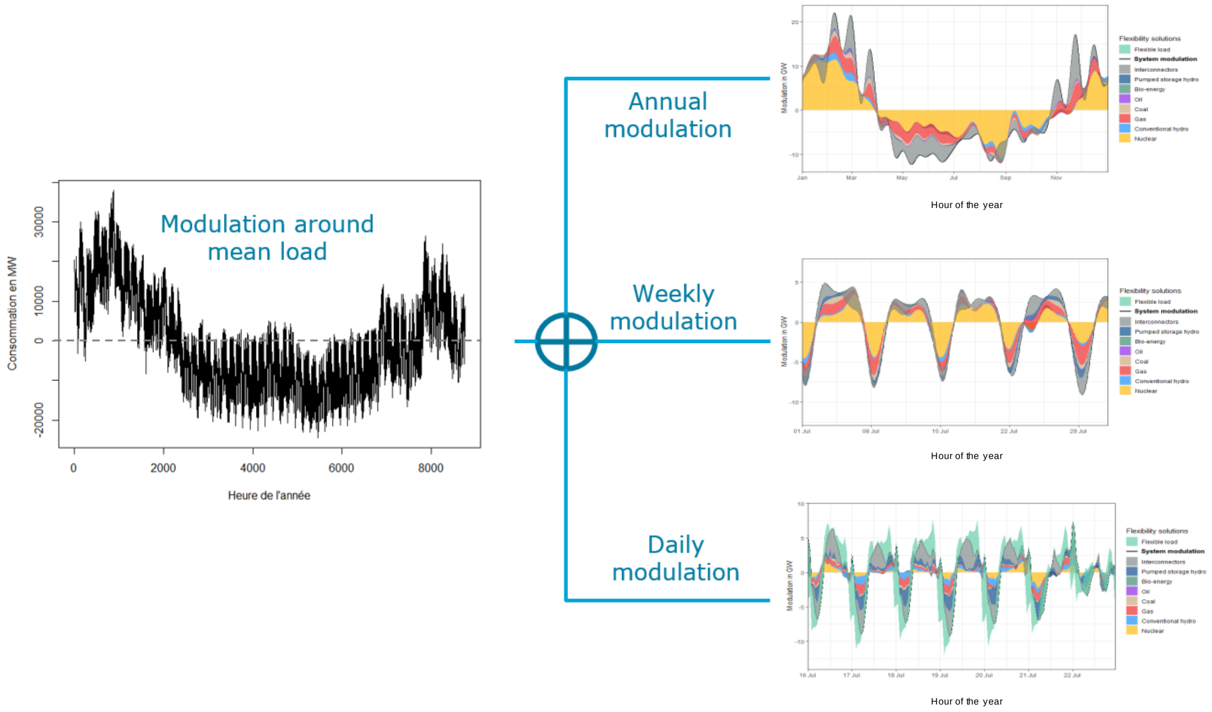

Figure 5 flexibility analysis for the French power system (2018) [source Heggarty_2021]

Each ribbon shows the extent to which a flexibility provider generates more or less than it does on average[12].

- In Figure 6, the red ribbon is stacked above other ribbons in February, meaning that gas plants generate more than they do on average. Conversely, it is below other ribbons in May, revealing that gas plants generate less.
- For interconnectors, depending on a system's annual exporting or importing status, a ribbon stacked above the others may refer to higher export or lower import than on average. In

[11] To better understand what the different time scales represent in the FSMS, it should be noted that the Fourier filtering can be roughly understood by referring to the notion of moving average:

- For the yearly horizon, the initial time series is smoothed over a typical period of 18 days.
- Then, for the weekly horizon, the annual signal is subtracted from the original time series, and a moving average is performed again, smoothing over a typical period of 2 days, then disregarding any variation with a period greater than 18 days or less than 2 days.
- Finally, for the daily horizon, the original time series is subtracted from the annual and weekly signals. The resulting signal only contains the variations whose period is less than 2 days.

[12] For a given source of flexibility and a given time scale, it appears as positive if it contributes more than the average for this time scale, and as negative if it contributes less. Occasionally, the stacking may reveal moments when two sources contribute in an opposite direction. In this case, the counteracting source is represented in faded colour.

February, interconnectors mainly contribute to the French flexibility provision on par with other sources. In January, on the other hand, interconnectors have a negative contribution to the French flexibility requirement, although the latter is quite high. This expresses the fact that the French system provides flexibility to its neighbours thanks to its interconnections.

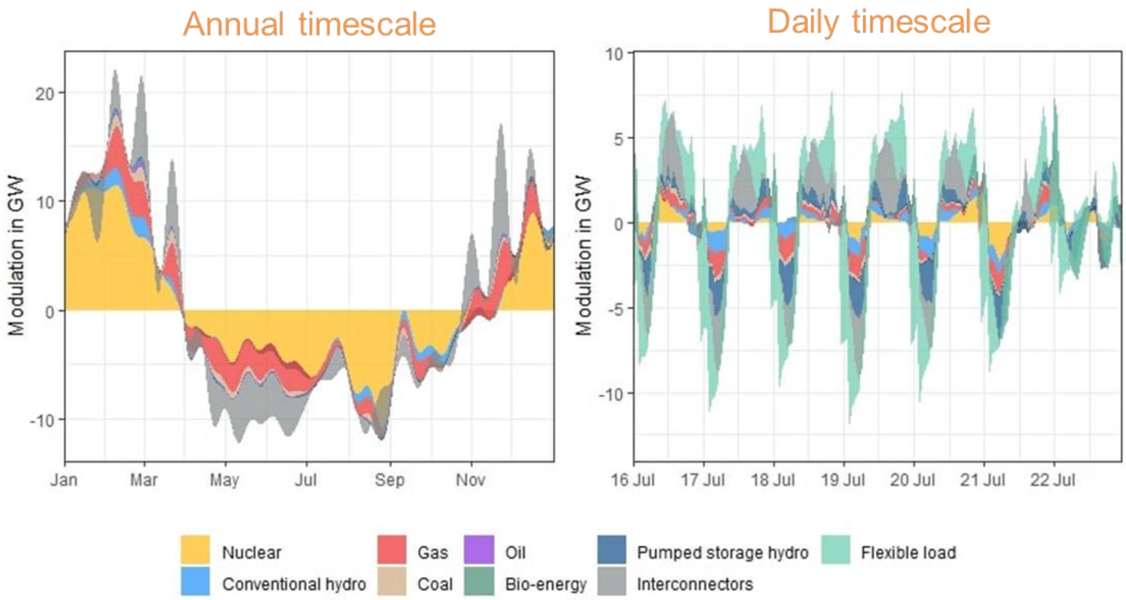

Figure 6 current situation in France (2018) [source Heggarty_2021]

If we compare timescales, it is very clear that the solutions providing flexibility in 2018 on the French system are very different. On the annual timescale, nuclear is a major contributor, while on the daily timescale, interconnectors, pumped storage hydro and flexible load play a more important role. Note that here, flexible load consists of hot water boilers.

5.3 Flexibility Solution Contribution Distribution

To summarise this information further, for each hour of the time series, we can calculate the individual contributions of each flexibility solution to total system modulation (including initial dispatch and up-to-real-time activations performed by system operators). This leads to a distribution for each solution and each timescale, which we can then represent graphically using a boxplot. This tool is referred to as the **Flexibility Solution Contribution Distribution** (FSCD)[13].

[13] Time steps where the absolute value of this total system modulation is smaller than 20% of its maximum are removed, to avoid spuriously giving credit to a flexibility solution because of asymptotic behaviour when net load modulation is close to zero.

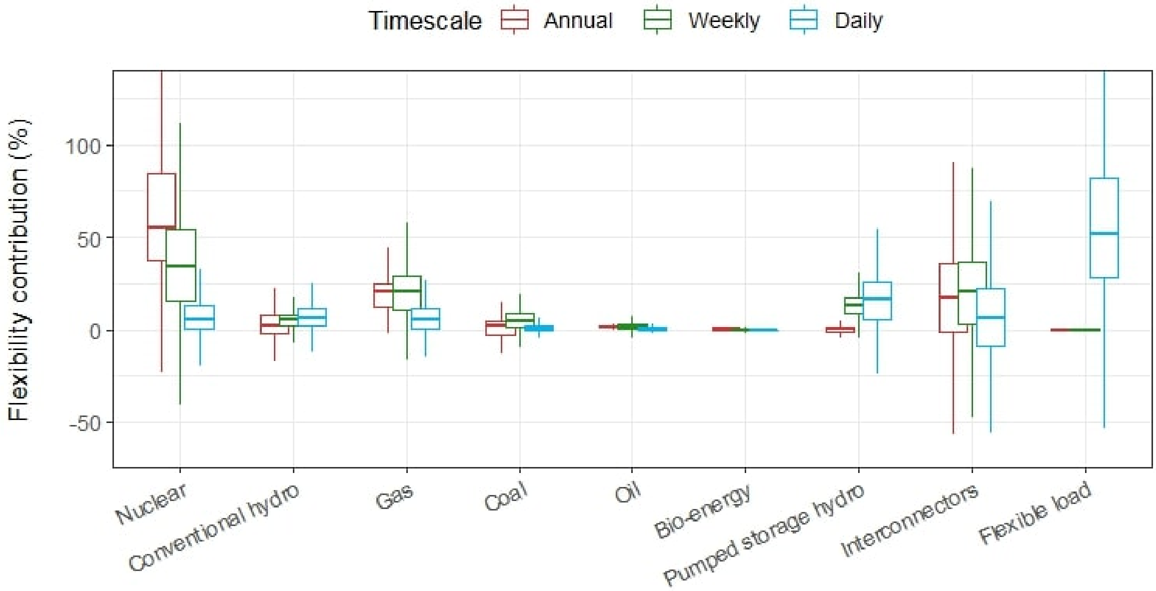

Figure 7 : FSCD for France – Current system (2018)

As we had the intuition on the FSMS graphical representation, nuclear is currently the main provider of long term flexibility in the French system, while flexible load plays a fundamental role in terms of daily flexibility.

As mentioned earlier, these indicators are also suitable for prospective studies, in order to better understand the potential future role of new flexibility solutions. We have applied these tools to systems with contrasting characteristics, showing how flexibility provision changes with system structure and size.

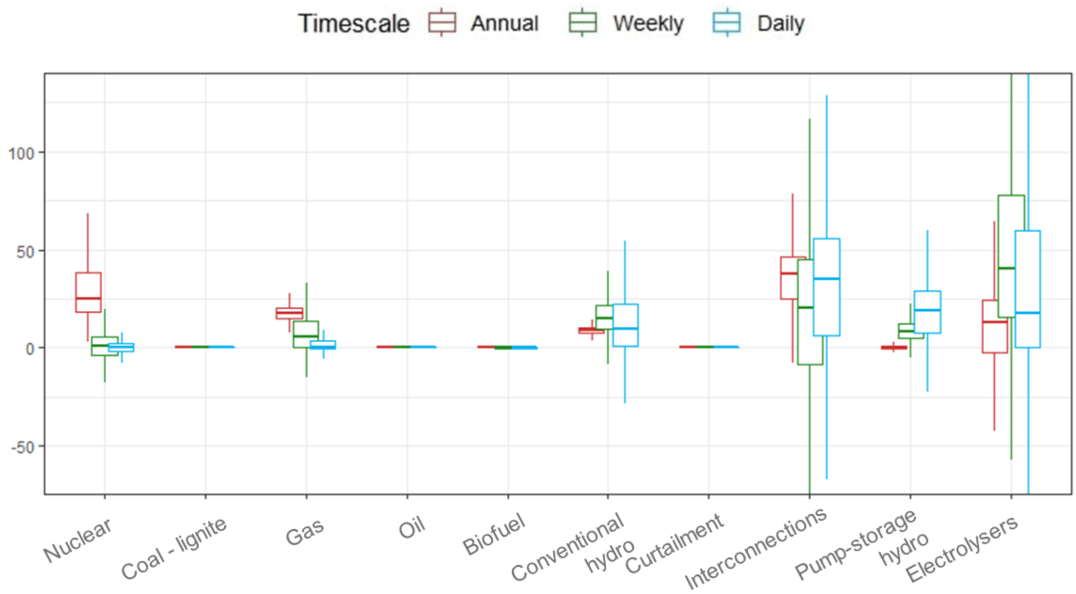

Figure 8 : FSCD for France – Prospective study (2035)

In this example looking at a scenario for 2035, we can see the trickle-down effects of electrolysers competing with nuclear for the long term flexibility, but also with short-term flexibility solutions like pump storage hydro and batteries, although electrolysers were not built for that purpose.

6 Requirements for building an Optimal Mix of flexibility

6.1 Context

In such a changing context as the energy transition, the question of what technologies should be used to best manage variability and uncertainty is rather open. Among all flexibility sources, which are competing for positions in the flexibility market, a holistic modelling is required to take into account various costs, overlapping time scales and contrasted efficiency levels.

As flexibility requirements range from long-term to near real-time, the optimal solution will in most cases be a combination of several flexibility sources. Additionally, some intertemporal competition effects may exist if long-term flexibility sources with high capital expenditures and low operational costs (such as power-to-gas units installed to match long term needs) are flexible enough to cannibalize near-real time sources (such as grid batteries).

Any cost-benefit assessment of flexibility sources strongly depends on the considered power mix, with its own characteristics. In addition, trajectories are essential in times of transition. In a nutshell, prospective studies on power system flexibility must be based on scenarios and pathways.

Although the objective of OSMOSE is to build a robust methodology, not to provide future-proof figures quantifying the economic space open to each flexibility source, contrasted trajectories will be necessary to check the robustness and validity of the proposed methodology.

6.2 A geographical and technical scope covering the full European energy system

As the power system is balanced on a continental scale, Europe is the relevant geographical scope for a study on flexibility needs, from very high voltage to low voltage levels. In addition, one should target the full energy system to capture cross-sectorial effects of flexibility and to take into account that flexibility sources in future mixes are deemed to be connected to the distribution grid.

Unfortunately, such a detailed and extensive modelling of all this is currently out of reach, and will probably remain so. The purpose of the following sections is to discuss the type of modelling that has proven relevant in the context of the OSMOSE project to address this issue, as well as present the tooling suitable for such a modelling.

6.3 Existing tools

Many tools already exist to simulate or optimize different aspects of the energy system. This section aims to illustrate the wide variety of topics they cover, in order to provide the reader with the conceptual building blocks and tools that were available to the OSMOSE partners at the beginning of the project. This section is broadly organised from the most general to the most specific models and tools.

6.3.1 Capacity Expansion Models

Prospective studies performed in the energy sector usually rely on Capacity Expansion Models (CExPM) such as TIMES or OSeMOSYS. These tools are usually considered as a subset of the Integrated Assessment Models (IAM) family, focussed on energy vectors and able to take into account local to global geographical scales.

The goal of Integrated Assessment Models is to provide a global modelling of the economy or some of its subsets. Some IAMs are extensive enough to integrate the representation of economic, energy and climate systems. This wide coverage must be put into perspective of the many general limitations that still exist in IAMs, as shown in [Hache et al. 2019]:

- Most models are based on a general macroeconomic equilibrium, which optimises the allocation of available resources (capital, labor) to satisfy consumer needs. Waste of resources and unused production capacities are hardly taken into account. Neither is the role of individual actors in the process.
- Equations and parameters are often determined from historical data rather than being endogenous to the modelling, which is not well suited to the analysis of abrupt transitions. This is particularly the case for consumer habits, which determine their needs, and for commodity prices (fossil fuels, metallic and non-metallic materials....), which are highly dependent on geopolitical conditions.
- Conversely, when product prices are endogenous, quantity-price laws are inferred for products, without clear evidence from real life (e.g., price elasticity of oil).
- The value of the discount rate has a first order influence on the results, for instance the respective performances of candidate technologies in the long term.
- Finally, the financial system is not represented due to its inherent complexity.

Most of these general criticisms directly apply to CExMs. However, focussing on the energy system reduces the overall complexity and nullifies the possible cross-sectorial effects across the economy. In addition, commodity and fuel price are purely exogenous input parameters in CExMs, and entirely under the control of those conducting the study, which is both an advantage in terms of transparency and a challenge because numerical values must be determined anyway.

Let us now examine the technical ability of CExMs to accurately handle flexibility, which is the key concern of OSMOSE. Since they deal with long-term evolutions, CExMs seem to be promising options to capture long-term flexibility. Unfortunately, these tools are known to underestimate short-term flexibility requirements, while they overestimate the short-term flexibility provided by flexibility solutions.

- Variability is typically expressed in CExM by aggregating each time series into time steps (called timeslices) that are intended to capture variations in load and VRES generation. Seasonal, weekday vs. weekend, and night vs. day variations are typically considered (e.g. for a total of 4*2*3 = 24 time slices). Then, the hourly time series of load and VRES generation are summarised for each time slice by applying a statistical index (average, quantile…) over the respective sections, which inevitably smoothens their fluctuation.
- Technical constraints (like ramps, minimum up and down-times, storage level…) strongly affect the operational behaviour of flexibility solutions. Unfortunately, the low temporal resolution and the lack of chronological linkage between timeslices prevent any accurate implementation of these constraints in CExMs. As a result, flexibility solutions are often more flexible in simulations than in reality.
- Crucially, these two phenomena are exacerbated as the share of RE increases.

Researchers have tried to determine the optimal number of timeslices to capture sufficient variability. Without VRE, about 10 timeslices was a satisfactory compromise, but, once VRES were added to the system, this number increased to the order of 1000, jeopardizing the tractability of the optimization problem. Since VRES capacities are endogenous variables in CExMs, solving the question of how to represent flexibility by finding the right number of time slices is a puzzle that fails to escape their tendency to underestimate the value of flexibility.

Another timeslice limitation is the inability to accurately reflect geographical aspects of variability in multi-region studies: relevant timeslice choice in a region with high wind resource will be very different to that of a region with high solar resource. Besides, expressing geographical correlations in VRES profiles is potentially feasible, but may require so many timeslices that the computational advantage of timeslices over original time series is offset.

This inherent underestimation of the value of flexibility in turn leads to an underestimation of the need for flexibility solutions compared to the installed capacity of base-load generation (medium merit and peak generation, storage, interconnection or demand response). As a consequence, relying only on CExM cannot be an option for OSMOSE.

6.3.2 Production Cost Models

Production Cost Models (PCMs), such as AntaresSimulator, simulate the hourly operation of a power systems, minimizing only the overall operating cost, while taking into account proportional and non-proportional generation costs, and valuing the energy not supplied (generation shortage) or, conversely, the spilled energy (generation in excess). The hourly time resolution allows for the fine modelling of a wide variety of technical constraints related to the generation units or the network.

PCMs are typically used to perform generation adequacy studies, a key requirement here is to study a large number of scenarios that appropriately represent the uncertainties that can affect the balance between load and generation. Therefore, PCMs are very powerful in assessing the actual behaviour of flexibility solutions, and deriving the total operational costs of the power system.

PCMs generally focus on the electricity network, but some extensions to modelling gas and heat networks have been developed, taking advantage of modelling similarities. Conversely, they take installed capacities by technology and by zone as an input, and are not designed to perform investment planning or ensure economic profitability. PCMs can be an interesting building block for OSMOSE as a complement to tools dedicated to set up relevant investment paths.

6.3.3 Life Cycle Analysis tools

A life-cycle analysis (LCA) approach enables the implementation of a multi-factorial assessment of energy system scenarios (e.g.: CO2 emissions, resources consumption and depletion, biodiversity impact…), which would largely help inform the project on the consequences of the flexibility options. The major drawback of multi-criteria modelling is its limited compatibility with optimization methods:

- Provided that acceptable limits can be set for each environmental indicator, it allows the definition of an accessible domain, but once the limits are reached, it does not provide the decision-maker with obvious means of arbitration between factors.
- A practical alternative is to internalize externalities by defining a synthetic criterion. In environmental assessment, it has the downside of introducing a weighting factor between criteria of very diverse origins, with uncertainties of different orders of magnitude. This option is therefore not suitable for truly transparent decision making.

The use of LCA requires very precise modelling of each technology, generally provided by databases like EcoInvent, fed from various practical case studies (e.g.: thorough analysis of a solar farm in Spain, of a nuclear power plant in Switzerland). Of course, the more numerous, recent and geographically relevant the cases studied, the more representative the description of a technology.

The distinction traditionally made in LCA between the foreground (which describes the general context of the study, such as the raw material supply chain and the manufacture of components) and the background (the system studied by the LCA), although still relevant for energy and electricity production, needs to be adapted: the environmental impacts of almost all products and services are highly dependent on energy and electricity, generating a kind of chicken and egg cycle, which is of particular interest for studies assessing the impacts of changes in energy and power mixes.

In terms of tools, companies conducting LCAs generally prefer all-in-one software with a user-friendly graphical interface, but these tools often lack the flexibility to programmatically navigate the extensive hierarchy of involved industrial processes and effectively adapt the background (e.g.: monitor and alter the energy mix used to manufacture photovoltaic cells). More programming-oriented open-source tools have recently appeared, like Brigthway 2 and LCA algebraic, which would better suit the needs of OSMOSE (see [Brigthway] and [LCA_Alg]).

6.3.4 Market Equilibrium models

Equilibrium Market models seek to integrate the effect of market participant behaviour into energy system analysis, in order to assess not only the value created but also its partition among actors (individuals, companies, countries...). However, they still assume some sort of equilibrium.

A very common type of equilibrium assumes conditions of perfect competition. Perfect competition implies, among other things, the absolute rationality of actors, a large number of buyers and sellers, homogeneous products, perfect and complete information[14], and perfect mobility of production factors. This approach is known to be questionable for general reasons:

- Perfect information while information has a cost and a propagation speed
- A catalogue of product references of gigantic size to guarantee the homogeneity of the products
- Extreme centralization of the market, requiring an intermediary ("auctioneer") to organize the market and "shout the prices”
- A convex aggregate utility function, although Arrow proved the general impossibility of constructing a collective preference consistent with the individual ones.

When applied to the power system, perfect competition assumptions induce additional deviations with observations from the real world:

- Since electricity cannot be stored, demand is largely inflexible and “short-term" competition does not easily come from consumers.
- In real time, it is impossible to distinguish the defaulting actors in order to physically impute to them the deviation from the contract[15].

Some ad hoc modifications have been introduced in market equilibrium models to mitigate these deviations: taking into account the strategies of price makers, and modelling more than one market round (usually day-ahead and intraday). Each company then adapts to what it "sees" as it goes along, and information can become imperfect and based on "beliefs". Modelling reality, which is a purely continuous process, may require a large number of rounds. However, introducing “inefficiencies” (via additional constraints or costs) to match the real-world behaviour is complicated and arbitrary, especially for OSMOSE’s long-term scenarios where almost everything could change with respect to the present.

Strictly speaking, the “benevolent monopoly” approach is equivalent to the “perfect competition” allocation. This equivalence allows a relatively simple modelling of the system by an optimization program maximising the social welfare, as do CExMs and PCMs (although on partial energy or

[14] Perfect information: perfect and instantaneous knowledge of all market prices, their own utility, and own cost functions.
Complete information: knowledge about other market participants or players is available to all participants.

[15] The load-generation balance is therefore not guaranteed by the conforming execution of the contracts between actors, a “supplier of last resort” is needed (in Europe the TSO)

electricity markets). Of course, the “benevolent monopoly” approach shares the same difficulties as perfect competition when it comes to dealing with "inefficiencies". However, as it maximizes the social welfare, this assessment will show the highest possible gain, which can be of high interest in projects like OSMOSE as a “corner stone” reference for further studies.

6.3.5 Agent-based Market models

Agent-based models generally assume strict rationality: Agents are individualistic entities with clear goals and simple interactions with other agents[16]. Agents are rational, in the sense of calculating, strictly maximizing the achievement of objectives, knowing how to weigh present and future stakes, and not affected by emotions or by supposedly insignificant facts.

In these models, the main focus is on simulating the interactions between agents. Each agent tries to maximise its own benefit. This modelling is much more complicated than Market Equilibrium models: the more agents there are, the better the simulation is expected to be. Different levels of information for different actors may be modelled. Some irrational behaviours (e.g., analysis bias, confirmation bias…) may be added as well, if deemed relevant. In addition, this approach is suitable for measuring the impact of decisions taken one after the other.

Agent-based models are built upon individual preferences. A downside to it is that its results are determined by a sum of individual criteria, which in no way guarantees that social welfare is actually maximized.

Agent-based modelling requires a very detailed and flexible modelling. Results validation is therefore essential: one must be aware of the many approximations made, compare with historical observations, if any, and make the model even more complex where relevant (accuracy is a matter of goal and perspective). Using agent-based model is therefore very demanding in terms of computation time, calibration and resources, even for small systems. However, it has already been introduced in Power System Analysis as a way to deal with sequential analysis in the context of the FP7 project OPTIMATE (see [Maenhoudt 2010]). PROMETHEUS/ATLAS used in OSMOSE/WP2 is a direct offspring of this initiative.

6.3.6 Load flows

Load flows (or power flow analysis tools) are numerical algorithms designed to compute the steady state of a power system network knowing the net active and reactive power injected at each bus, as well as the characteristics of the lines and transformers (bus topology and equipment impedances).

It requires the resolution of a system of non-linear equations, Kirchhoff’s voltage and current laws. The complexity is increased by the fact that we are interested in the solutions of the system, if any, located in a restricted domain compatible with its operation (thermal limits of the lines, voltage ranges...). The presence of many automated systems (protection devices) can make the modelling even more complicated.

In meshed grids (such as the transmission network), load flows are typically used to simulate the effects of faults (contingency analysis), in order to check in real time the robustness of the current grid state to the tripping of any line or power transformer (“N-1” rule[17]). A high execution speed is therefore essential, as a very large number of problems must be solved in a very short time.

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[16] This kind of rational individual is usually referred to as “homo-economicus”, and used in many economic models.

[17] As the transmission network is meshed, it provides several electrical paths between the injection and the load bus. The energy flows are distributed between these different paths according to the Kirchhoff’s laws. This

In general, load flows require a very precise modelling of the network to provide accurate results. When only active power flows are of interest, the system can be approximated as a linear system (DC approximation), which reduces the numerical load and data requirements, at the cost of a loss of accuracy, especially in poorly-meshed grids.

In essence, load flows focus on a specific time step. As far as OSMOSE is concerned, load flows can only be used to check the operational grid state, once all other macro-assumptions have been determined. In addition, their high sensitivity to input data should limit their practical use to those areas of the European network where feedback and expertise from project members is available.

6.3.7 Optimal Power flows

An optimal power flow (OPF) uses the same set of equations as a load flow to model the grid, but optimizes the dispatch (and possibly the topology of the grid) to ensure that the power flows remain within both the thermal limits and the voltage stability constraints.

The OPF constraints can include the modelling of contingencies (security-constrained optimal power flow) to reflect the conditions imposed by the “N-1” rule. The OPF cost function takes different forms depending on the active or reactive power quantities that we wish to either minimise (e.g.: dispatch cost, losses) or maximise (e.g.: overall voltage setting as a proxy for voltage stability). The option of shedding load or generation in excess is usually taken into account to ensure the widest possible convergence of the optimization problem.

As with load flows, the Kirchhoff’s laws can be approximated as a linear system when the focus is on active power (DC approximation).

Limits to the use of OPF within OSMOSE are similar to the ones mentioned above for load flows. It is worth mentioning that OPF might be useful in the OMSOSE context as an aid to locally adapt assumptions (generation, grid capacity) resulting from the downscaling of investment pathways.

6.3.8 Dynamic and transient analysis

Dynamic and transient analysis techniques are used to study stability (frequency, inertia, voltage…). As the response of the full system is very sensitive to input data, these tools require extremely accurate modelling, much more demanding than that required for load flows.

In the OSMOSE context, the high share of VRES targeted by the scenarios largely calls into question the stability of pan-European system. However, the level of uncertainties is extremely high (especially for the 2050 horizon), and the project’s ability to provide reliable conclusions from dynamic and transient analyses is a major challenge.

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operating mode aims to maintain the power supply in case of a single fault located on any of these electrical paths.

However, the initial fault leads to a power transfer to the other electrical paths, which may in turn exceed their operational limits, trigger their own protection devices and trip. This type of incident is called "cascade of overloads", and can lead to the total collapse of system. On a transmission system network, the purpose of the “N-1” rule is to prevent such a collapse.

7 OSMOSE three-step approach toward an optimal mix of flexibility

In order to answer the methodological and practical issues mentioned in sections 5 and 6, the OSMOSE project opted for a three-step approach, which attempts to make “the best of both worlds”, but implies an additional step of reconciliation:

1. **Assessment based on the analysis of the fundamentals of power system economics**

   At this stage, the project aims to take into account all relevant technical constraints and associated costs (technology, potentials, “natural” loads…), and tries to maximize the social welfare of the area under consideration, establishing an upper bound that will then serve as a reference. The main bricks for this assessment are CExMs, PCMs and load flows. At this stage, particular attention should be paid to sensitivity analyses, to ensure sufficient robustness and to distinguish fundamental from circumstantial effects (e.g., nearly “flat” cost function giving rise to many equivalent solutions).

2. **Introduction of imperfections**

   Agent-based simulations act as a “fact checker” for the plausibility of the “behavioural” assumptions made in step 1 (impact of acceptability on VRES potential, on Demand-side management –DSM–…). Economic inefficiencies such as forecast uncertainty, market players and their strategies, market rules…) will result in lower social welfare than that of the “benevolent monopoly” approach. At this stage, the way the added value is shared will also come into play, which is an essential criterion to identify individual stakes and efficiently promote the needed adaptations of rules.

The present deliverable mainly touches upon the first step of this process.

7.1 Organisation of WP1 to perform the assessment based on fundamentals

The multi-scale modelling introduced above has been translated into the organization of WP1 into subtasks. This paper summarizes the results of Task T1.2, "Optimal Flexibility Combination", in interaction with other WP1 subtasks and WP2.

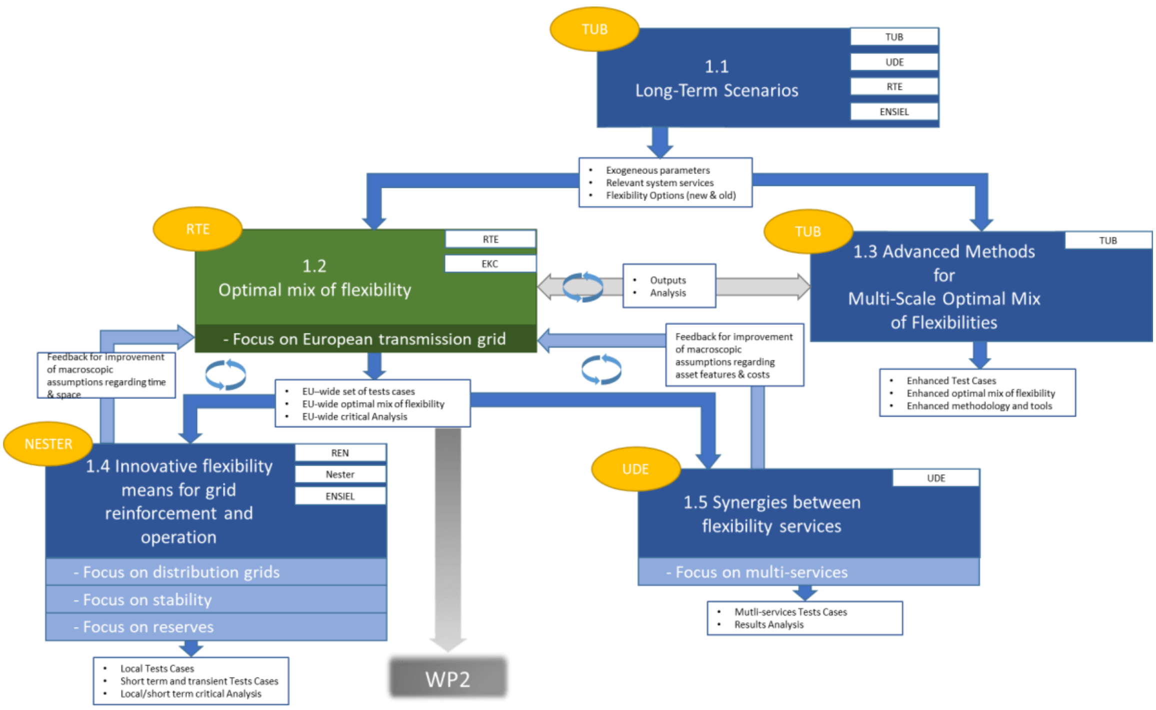

Figure 9: multi-scale structure of the study

The organisation of WP1 can be summarised as follow:

- The scenarios used are created by T1.1 ("Long term scenarios"), under the constraint that the energy system respects precise CO2 emission constraints from today to 2050. T.1.1's functional scope is larger than the power system.
- T1.2 ("Optimal mix of flexibility") performs security of supply assessment of the European power mixes produced by T1.1, with clear interfaces with other sectors and vectors, and scope of modelling focused on the transmission grid ("TSO-centric modelling"). Given the conclusion of this analysis, T.1.2 adapts the power mixes to try to match the security of supply criteria in force in Europe.
- T1.3 ("Advanced methods for multi-scale Optimal Mix of Flexiblity") deals with the impact on the other sectors and vectors of the modifications performed by T1.2 to better integrate the flexibility requirements and procurement.
- A geographical and temporal downscaling is performed in T1.4 ("Innovative flexibility means for grid reinforcement and operation"), to address distribution grid issues, focus on reserve procurement, and verify stability. For reasons of resource and data availability, the downscaling is limited to some parts of the European grid.
- T1.5 ("Synergy between flexibility services") tries to model the synergies between flexibility services, with their impacts on the costs and lifetime of flexibility solutions.
- T1.2 supplies the other tasks with generation programs reflecting the behaviour of each technology in a holistic view of the power system, and in turn collects feed-back from the other to improve its own modelling, thus materializing a rough decomposition-coordination scheme.

As shown by the circular arrows in Figure 9, the initial idea was then to formally integrate all sub-tasks at a high level of feedback: a description of the additional costs and constraints induced by geographical and temporal downsizing, as well as cross-sectorial modelling and the assessment of multiservice effects. All of this is really necessary to fully understand the economics of flexibility and to size flexibility solutions appropriately.

However, doing so in our modelling would have added a new layer of complexity to an already complex problem. For reasons of efficiency and time limitation, it was decided to investigate the different strategies in parallel. Therefore, the final analysis would have to take into account the individual effects measured in each of these strategies.

7.2 Selected tools

In addition to organization, the tools needed to conduct the studies are a key question. As presented in Section 6, when the OSMOSE project was initiated, there existed mature and widely-used tools to study most of the aspects enlisted in Figure 9 (e.g., load flows for studying the local impact of flexibility citing and sizing, transient analysis tools for studying stability). However, none of these tools was able to answer all the questions on its own. In addition, some areas were not covered.

In the timeframe of OSMOSE (a 4-year project), developing a full-fledged ad hoc tool from scratch was not an option, and the following plan was put in place:

- Identify existing methodologies/tools suitable for each subtask,
- Try to couple these methodologies/tools in order to benefit from the best experience in each category, and more specifically specify functional interfaces to be able to efficiently share modelling and data between subtasks.

The multi-annual optimisation of the flexibility mix is the core of T1.2. Unfortunately, no standard tool was deemed able to compute a cost-effective investment path while accurately capturing flexibility at all its time scales. Developing a new tool, even one with this limited scope, again seemed too risky. Fortunately, an efficient way to solve this problem is identified in the literature. The guiding idea was to implement a soft-linking between a Capacity Expansion Model (CExM) and a Production Cost Model (PCM). Such an architecture makes it possible to take into account the investment trajectory over decades and, at the same time, to benefit from a precise hourly generation programming, which is essential to accurately capture flexibility requirements and provision:

- The first step of this approach is to perform a one-way soft-linking, to assess the security of supply of the proposed scenarios for each year of the investment path. The validation typically involves refining the operational cost assessment, as well as capturing detailed information on security of supply. Such a link is called "unidirectional".
- The second step is to set-up an iterative scheme, to adapt the generation capacity by technologies and by zones, to better capture true value of load balancing flexibility and to cost-effectively improve the security of supply. While the transfer from the CExM to the PCM model is quite straight forward (it comes down to using the capacities by technology estimated by the CExM in PCM simulations), we will see that the kind of information to provide back to the CExM (feed-back loop) to ensure (and if possible, speed up) the “convergence”, is much more complex to determine.

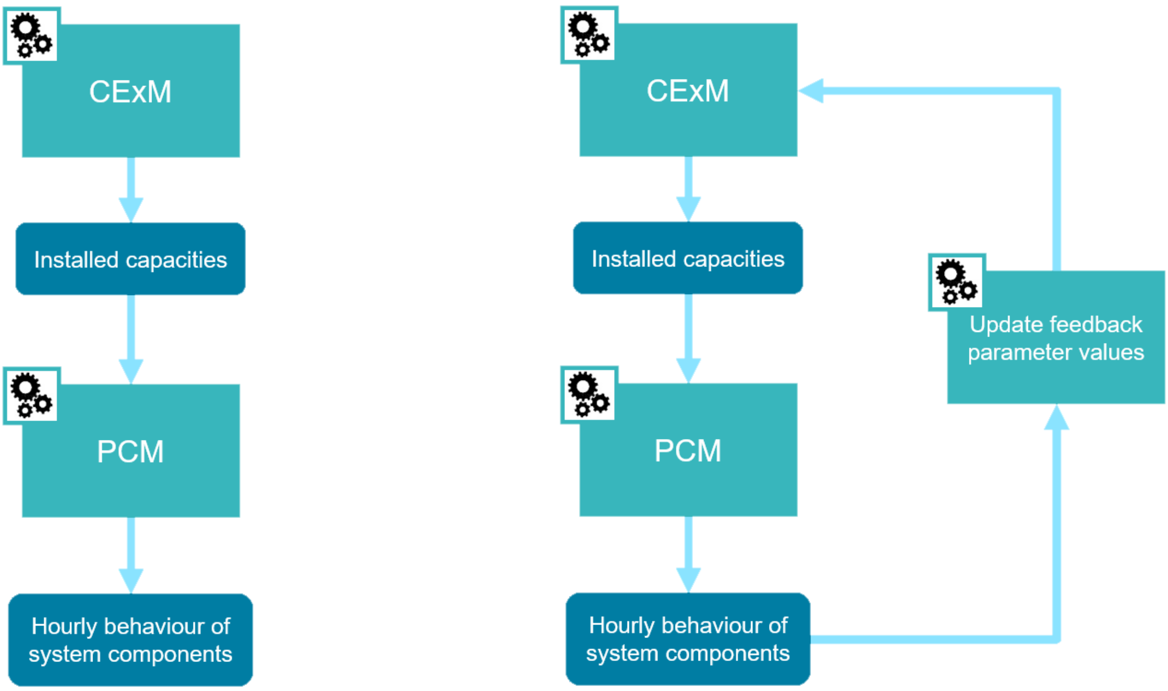

Figure 10: unidirectional (left) vs bidirectional (right) soft-coupling between Capacity Expansion and Production Cost Models

7.3 Study cases map

To facilitate the reading of the present document, a graphical summary of the dependency between the study cases within WP1 (as well as the data links to WP2) is displayed in Figure 10.

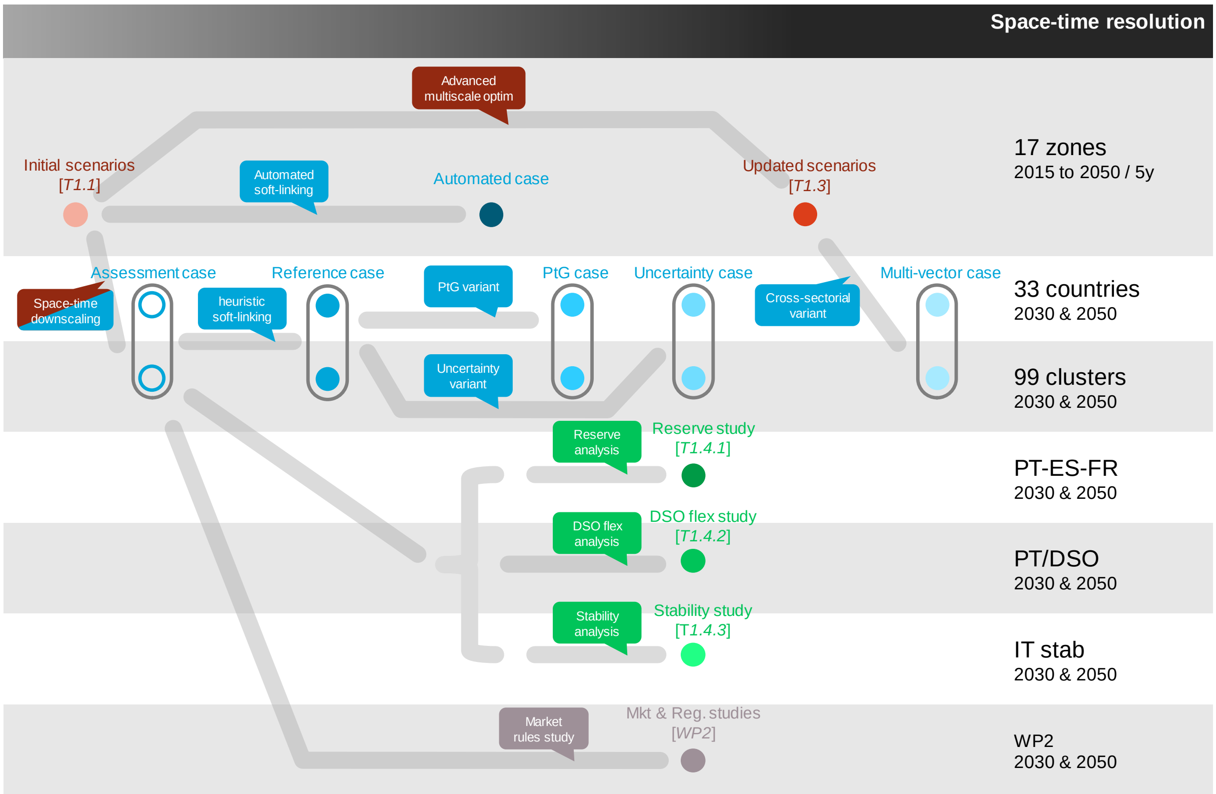

Figure 11: map of studies

8 Heuristic-based soft-linking

8.1 Initial scenarios and space-time downscaling

Subtask T1.1 produced three scenarios named "Current Goals Achieved" (CGA), "Accelerated Transformation" (AT), and "Neglected Climate Action" (NCA). These scenarios have been set up, in order to respect:

- Varying carbon emission budgets over the period 2015-2050[18], split over the main industrial sectors (energy, industry, agriculture, waste management),
- Varying levels of final energy demand,
- Cost trajectories assumptions for all generation technologies, as well as for CO_2-emitting fuels[19],
- A preference for low emission energy sources, reflected in mandatory phase out schedules for coal units.

[18] The CO_2 budget for CGA is in line with the Nationally Determined Contributions (NCDs) of European countries ratified by the EU in October 2016, whereas the CO2 budget for AT is lower (more constraining) and the CO2 budget for NCA is higher (more lax)

[19] Fuel prices are based on the corresponding scenarios of the World Energy Outlook 2017 until 2040 and held constant afterwards.

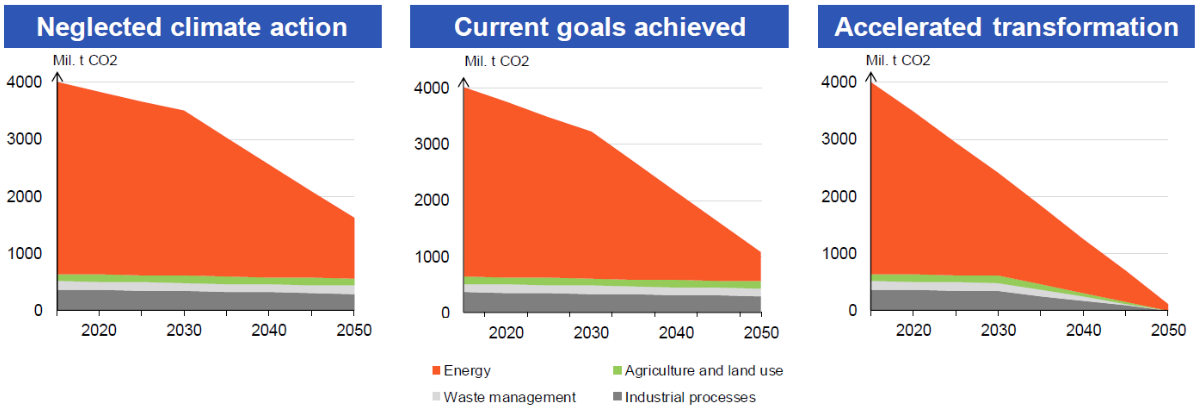

Figure 12: emissions across scenarios (source D1.1.)

In the subtask T1.1, final energy demand consists of:

- Original electricity uses that are traditionally supplied by electricity (e.g., lighting, household appliances),
- Final demand for heat (in MW_{heat}), which is subdivided into low temperature heat (water and room heating and cooling) and high temperature heat (mostly industrial process over 100 °C) [D1.1],
- Final demand for passenger transport (in passenger.km) and freight transport (in Tonne.km), which is distributed among the different types of transport (rail, road) by modal split (see [Loeffler 2017] and [D1.1] section 3.3).

The candidate technologies (including storage of electricity, gas and heat) considered by the optimization to meet the energy and mobility demand on the investment path are shown in Figure 12.

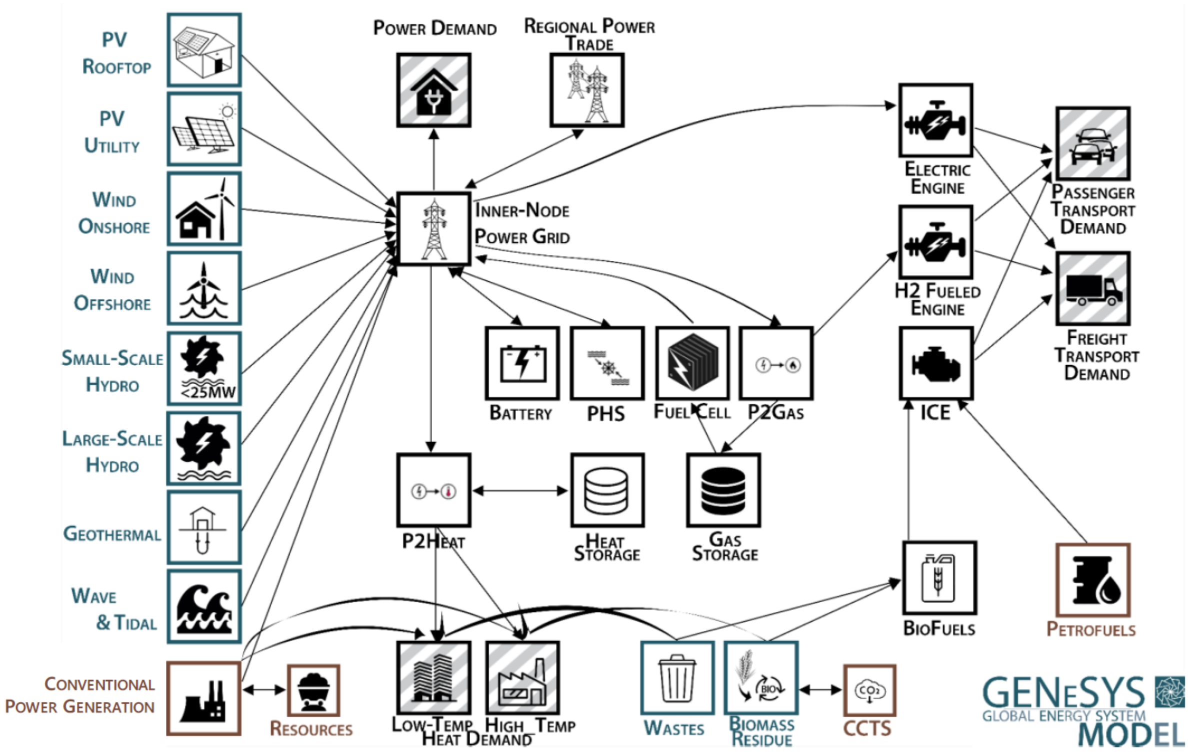

Figure 13: final energy demand considered in T1.1 (source [D1.1])

Model calculations determine, for each scenario, the development of the overall energy system and detailed power system supply and demand:

1. The process is based on a cost minimizing optimisation (GENeSYS-MOD) performed at the scale of the full European energy system[20] (33 countries aggregated into 17 European macro regions).
    - It computes a cost efficient pathway from 2015 to 2050 in 5-year steps.
    - Each representative year is modelled via 16 time slices.
    - The investment and dispatch decisions are determined to minimize the total cost of covering the demand in original electricity, heat and transport in each macro region and for each representative year of the considered time interval.
    - This step implies in particular to determine the optimal share of heat and mobility demand addressed to electricity in each region.
    - Investment decisions affect capacities in power generation (VRES and conventional technologies) and power storage (batteries, pumped hydro storage), power transfer capacities between macro-regions (modelled as NTCs), sector-coupling devices (power-to-gas, fuel cells, and power-to-gas units), heat and methane storage capacities[21], and transportation technologies (engines).
    - Additional constraints limit the grid and renewable generation expansion par year[22].
2. Then, the results are refined by a cost minimization performed over 2020-2050 in 10-year steps, for the power system only (DYNELMOD), at a higher geographical resolution[23] (downscaling from 17 European regions to 99 nodes).
    - Each representative year is modelled via 351 time steps (reduction technique) in the investment optimization stage and 8760 time steps in the dispatch simulation stage.
    - The downscaling from 17 macro-regions to 99 nodes is performed by using distribution keys.
    - Investment decisions affect power generation and storage technologies capacities (batteries, pumped hydro storage), power network capacities between nodes (modelled as net transfer capacity –NTC-) and combined heat and power units.
    - Technology-specific efficiency ratios are used to translate heat and mobility demand into mere power demand.
    - Remaining potentials for biomass and rooftop photovoltaic (PV) generation after step 1 are made available to the optimizer.
    - Demand Side Management is considered as an additional flexibility lever.

[20] This step used GENeSYS-MOD, a rewrite by TU Berlin of the open source tool OSeMOSYS. See [OSsMOSYS]

[21] Heat grids in each macro-regions are not interconnected, while congestion over the European methane grid as well as potential limitations in access to CO2 sources for methanation are neglected.

[22] They are assessed on a per scenario basis, based on TSOs' feedback on pragmatic limits for grid expansion.

[23] This step involved DynELMOD, developped by TU Berlin. See [dynELMOD]

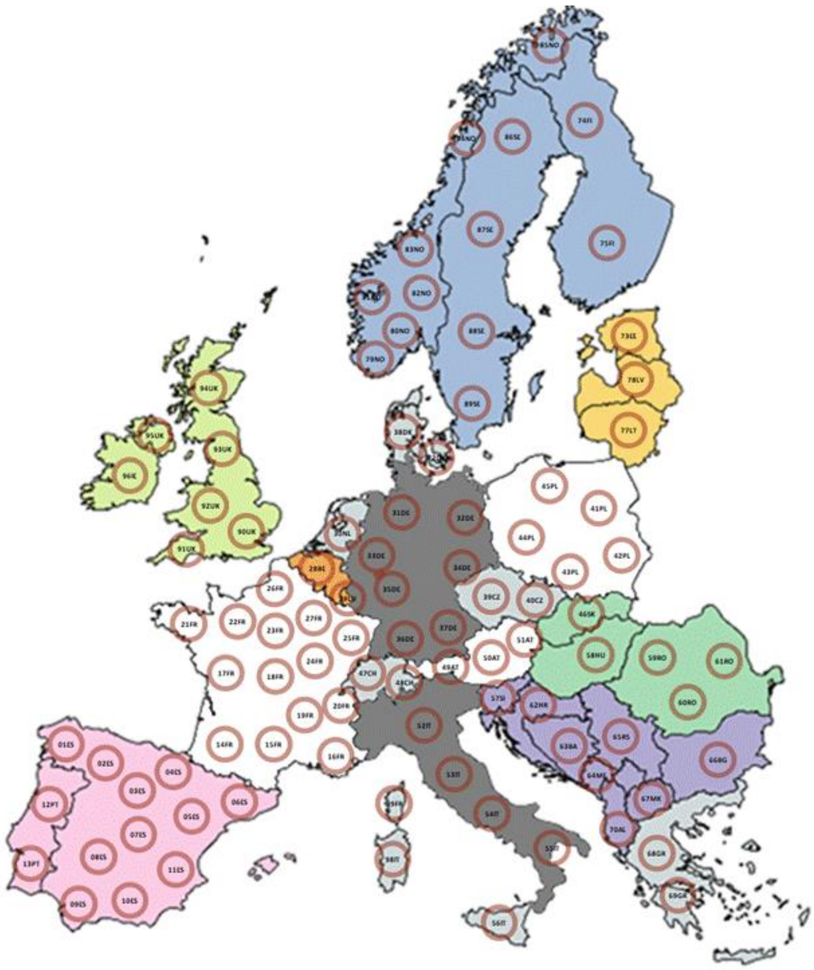

Figure 14 : geographical downscaling from 17 macro-regions to 99 clusters.

The share of energy demand addressed to the power sector globally increases, showing a clear trend to electrification of the economy.

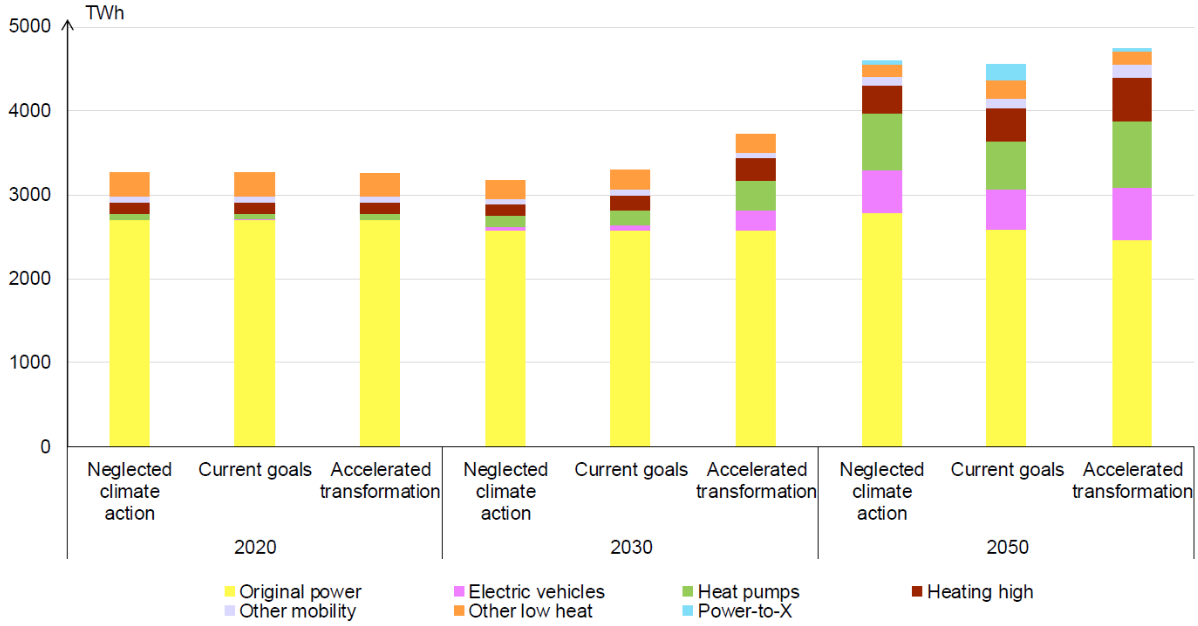

Figure 15: total electricity demand across scenarios (source D1.1.)

In terms of total installed capacity, the trend is clearly towards a very strong increase in VRES production (visible in a more moderate way even for NCA,). This trend is coupled with a strong development of power-to-gas, batteries and flexible demand.

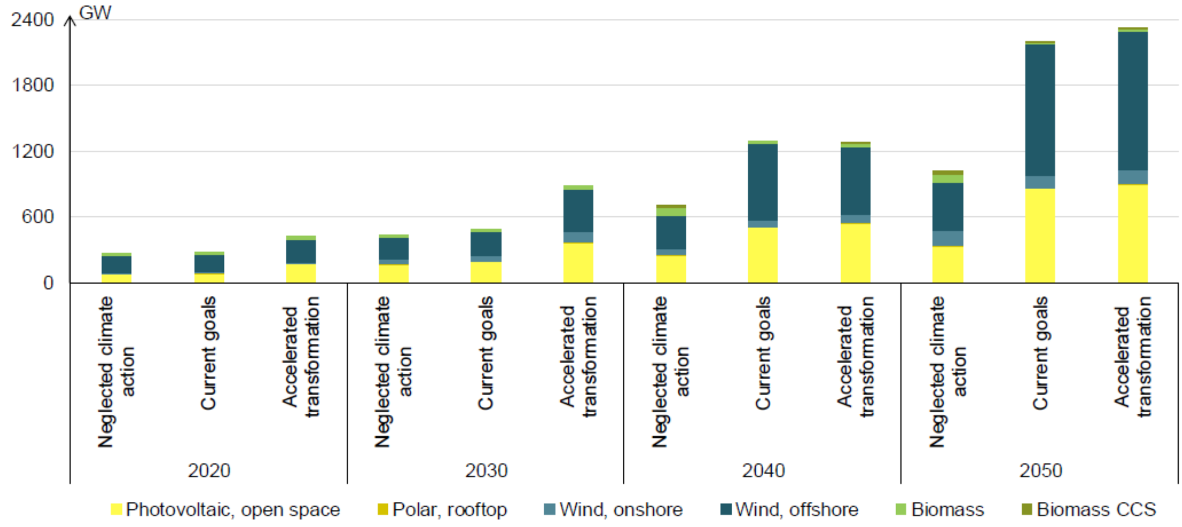

Figure 16: total installed capacity of VRES across scenarios (source D1.1.)

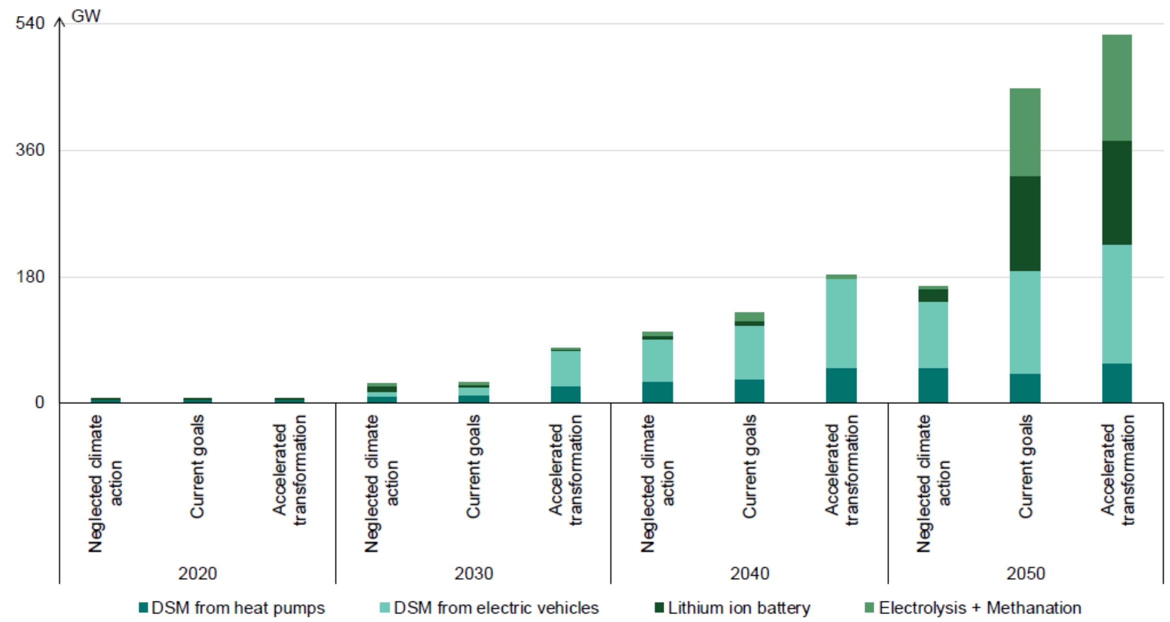

Figure 17: total installed capacity of storage units and flexible demand across scenarios (source D1.1.)

The CExM combines this massive growth of variable renewable technologies with a significant volume of dispatchable resources ensuring backup. Obviously, the CO_2 budget constraint and the mandatory coal phase-out schedule lead to a shift towards thermal units running on renewable gas.

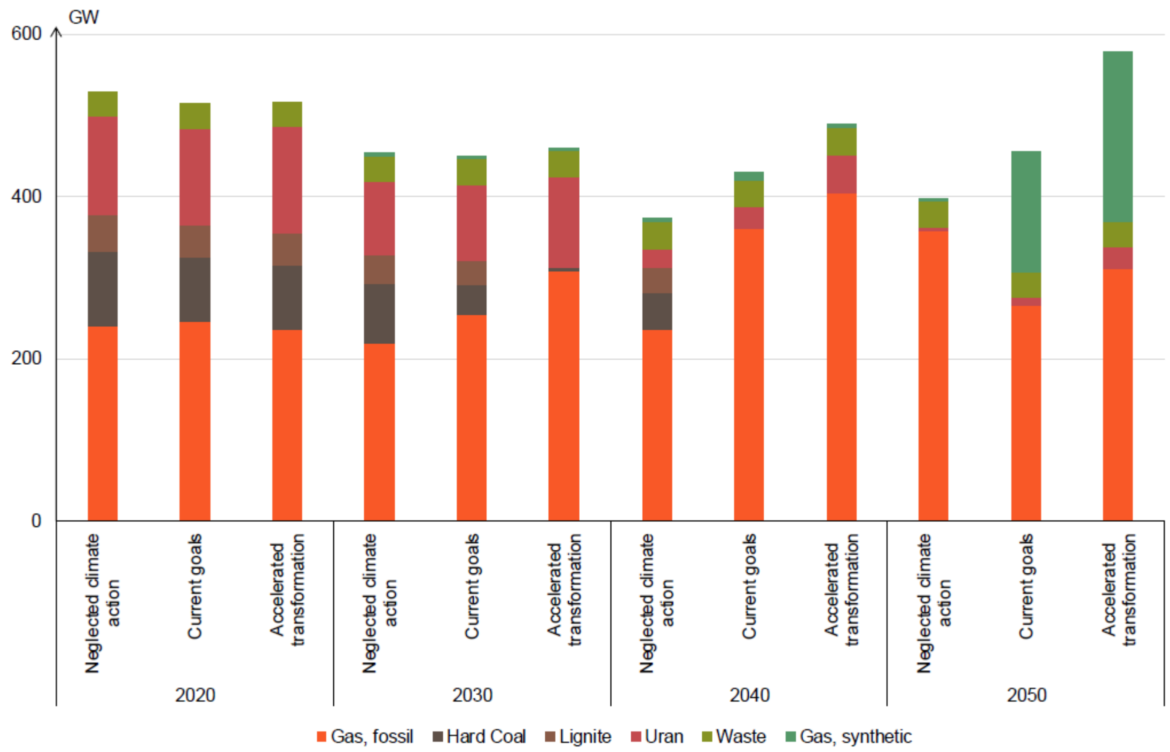

Figure 18: total installed capacities of thermal units across scenarios (source D1.1.)

Similarly, CExM invests substantially in the network. It is worth noting that the grid expansion rate is primarily driven by a constraint modelling a maximum investment allowance per period (ensuring plausibility of planning schedules), not because of the relative cost of the network with respect to other technologies.

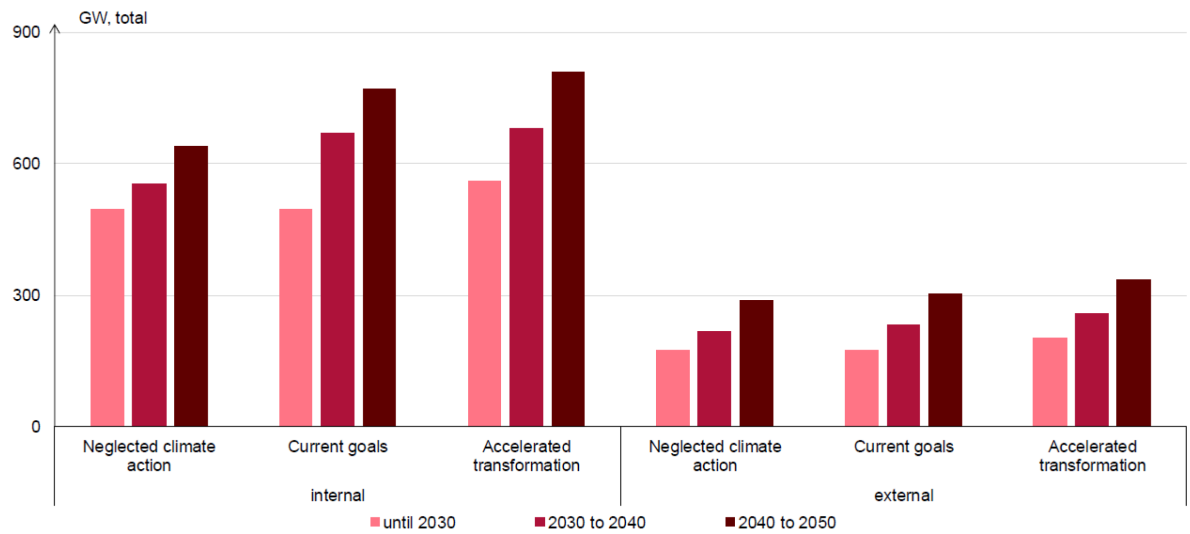

Figure 19: total grid capacities (internal and cross-border) across scenarios (source D1.1.)

8.2 Monte-Carlo modelling

In OSMOSE WP1, the Loss Of Load Expectation (LOLE) is used as the criterion for measuring Security of Supply. The use of such a criterion implies a stochastic approach to the different uncertainties that the power system faces. In PCMs, the classical way to implement this statistical approach is to use Monte-Carlo modelling. Hence, the three scenarios produced in Task 1.2 must first be complemented by a sufficient number of Monte-Carlo years for the variables that are deemed the most affected by annual-to-hourly uncertainties.

The three scenarios produced by Task 1.1 have been validated in Task 1.2 via the open-source PCM *AntaresSimulator* software (see [AntaresSimulator]). This tool is a power system simulator that aims to quantify the adequacy (or the economic performance) of interconnected energy systems. As such it performs several probabilistic simulations of energy consumption, generation and transmission throughout year-long periods made of 8760 hourly time-frames each. More specifically, *AntaresSimulator* performs weekly adequacy optimisations in order to minimise the overall cost of the system, considering unit commitment for thermal generation based on a perfect foresight hypothesis over the coming week. Conversely, the long-term foresight (in particular how reservoirs and other storages are managed) is modelled in a way which prevents anticipativity[24], by the use of Bellman values or heuristics achieving the same goal.

The power system model and dataset used in the OSMOSE simulations have been taken from the *e-Highway2050* EU-project (see [e-Highway 2050]). This dataset consisted of 3 years of electricity consumption profiles, 3 years of hydrological data and 11 years of solar and wind capacity factors for 99 clusters representing the European power system (see Figure 14). In the first OSMOSE simulations, 1 year of load, 1 year of hydrological data and the 11 years of VRES profiles have been used. For computation efficiency purposes two models have been set up, each with their own geographical resolution. A first one using the 99 initial nodes and a second one aggregating the nodes at the country level, resulting in 33 areas/countries. Each model has then been run with 2030 and 2050 scenario data.

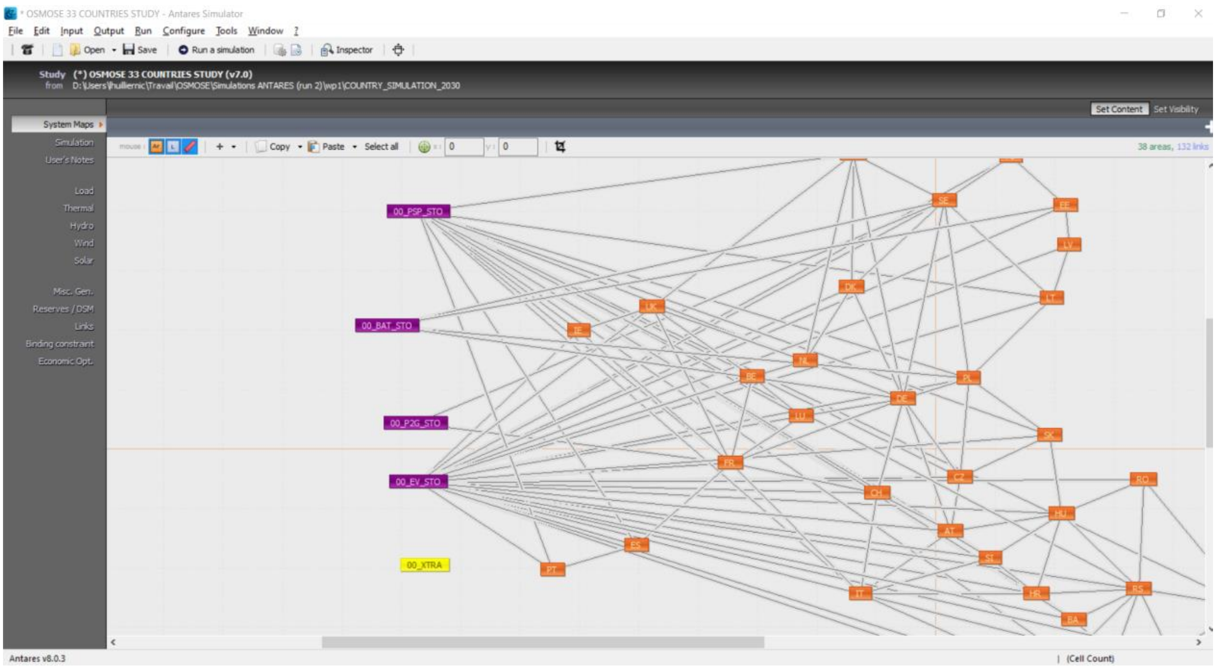

Figure 20: screenshot of OSMOSE country model in AntaresSimulator

For each OSMOSE scenario, installed capacities of generation, electricity consumption volumes and network capacities have been transposed in the model:

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[24] The concept of non-anticipativity depicts the fact that the optimizer should not use at a given moment in time information that it is only revealed later on in the process one wants to mimick.

- In order to take the capacity pathways defined in T1.1 scenarios into account, transfer capacities between nodes (both between countries and between country internal nodes) are modelled via grid transfer capacity (GTC) used as NTC. Equivalent impedances of links and Kirchhoff laws are not taken into account, which tends to overestimate actual exchanges.
- Generation from variable renewable sources is modelled by multiplying the installed capacity in each area by its corresponding capacity-factor profile which varies year on year.
- Thermal generation is modelled using technology-specific clusters, with technology-dependent parameters (ex. maximum power, minimum power, minimum stable power, market bid, outage probability, etc.).
- Run-of-river and bioenergy generation is modelled via explicit generation time-series.
- Hydro-reservoir generation is optimised weekly once the annual energy corresponding to the sum of the inflow time-series has been distributed per week thanks to a heuristic[25].

For hydro reservoir and run-of-river, generation capacities and time-series computed by T1.1 have not been considered relevant. In ANTARES simulations, this data has been replaced by one (average) time-series and generation capacity data coming from the *e-Highway2050* scenario Big&market (see [e-Highway 2050]).

In addition to these standard generation technologies, five types of flexibilities have been added in the initial system model: pumped storage plants (PSP), battery energy storage systems (BESS), electrolysers (also called power-to-gas units -P2G), electric vehicle smart charging[26] (EV) and heat-pump cut-offs (DSM):

- PSP can store and generate electricity following a weekly cycle with an efficiency ratio of 75%. Like other hydro capacities, PSP capacities come from Ten-year Network Development Plan (TYNDP). However, since reservoir volumes are not available in TYNDP data, reservoir volumes from *e-Highway2050* have been used once rescaled based on generation capacities.
- BESS can store and generate electricity following a daily cycle with an efficiency ratio of 90%.
- Regarding EV, a percentage of the overall daily load corresponding to the charging of the electrical vehicles can be optimally positioned within a day by the optimisation process.
- DSM are modelled as last resort generators which are available +/- 2 hours around the evening load peak.
- P2G represents the energy that is pulled out the power system as gas (H2 or CH4) in order either to be used in other industrial processes[27] or to fuel gas-based power generators (ex. open cycle gas turbines –OCGT-, combined cycle gas turbine -CCGT- or even fuel cells). The overall efficiency of this latter is only controlled in post processing. Since gas storage and transport facilities are considered large enough not to be constraining, P2G is modelled via a common reservoir.

Details of the flexibility modelling are available in [Appendix A].

Finally, an option of *AntaresSimulator* called “Day-ahead reserve” is used to take the balancing reserves that are required to ensure the security of the system into account. This modelling consists in fictively increasing the load as seen by the model during the unit commitment phase of thermal

[25] See [AntaresSimulator RefGuide] for details about this heuristic

[26] Only smart charging is considered in these simulations. Vehicle to grid solutions are out of scope.

[27] For instance in the 2050 CGA scenario, it is assumed that 175 TWh of energy shall annually leave the power system for other industrial usages.

generators[28]. This functionality therefore indifferently models some kind of FCR, automated (aFRR) and manual FRR (mFRR), i.e. all generation available in less than 30 min.

8.3 Security of supply assessment

Results of these first simulations are shown in the table below for the 3 scenarios on the 2 time horizons.

Average annual results	CGA 2030	NCA 2030	AT 2030
Overall costs[29] (B. Eur)	101	129	75
Load (TWh)	3281	3164	3714
Generation wind (TWh)	682	594	1245
Generation solar (TWh)	247	206	437
Generation nuclear (TWh)	670	629	734
Generation waste and bioenergy (TWh)	225	259	270
Generation fossil (TWh)	916	932	528
Generation from P2G (TWh)	~0	~0	~0
Generation from battery (TWh)	1	2	1
Generation from PSP (TWh)	13	8	41
Generation from DSM (TWh)	~0	~0	~0
P2G storage (TWh)	2	~0	13
P2G2P observ. ratio[30]	N/A	N/A	N/A
Spilled energy (TWh)	~0	2	20
Unsupplied energy (TWh)	0.8	3.7	0.7
CO2 emissions (Gt CO2 eq)	504	614	183

Table 1: Security assessment of initial scenarios for 2030

Average annual results	CGA 2050	NCA 2050	AT 2050
Overall costs (B. Eur)	35	501	31
Load (TWh)	4361	4540	4703
Generation wind (TWh)	3072	1417	3236
Generation solar (TWh)	1013	417	1053
Generation nuclear (TWh)	54	22	179
Generation waste and bioenergy (TWh)	205	603	265
Generation fossil (TWh)	75	1492	35
Generation from P2G (TWh)	200	9	246
Generation from battery (TWh)	134	10	139
Generation from PSP (TWh)	81	29	75
Generation from DSM (TWh)	~0	19	0
P2G storage (TWh)	668	1	690

[28] The optimal dispatch phase on the other hand is performed on the initial load values.

[29] These only include fuel costs and loss of load (curtailment costs being assumed to be zero). See section 6.3.2.

[30] Total generation from gas-to-power units divided by total energy consumed by power-to-gas units.
This ratio estimates the efficiency of the power-to-gas-to-power cycle when a methanation step follows the electrolysis. The maximum theoretical ratio, deduced from an efficiency of ~80% électrolysers and ~45% for CCGT, is expected to lie below 40%.

P2G2P observ. ratio[30]	0.4	0	0.37
Spilled energy (TWh)	92	2	125
Unsupplied energy (MWh)	~0	20.9	~0
CO2 emissions (Gt CO2 eq)	27	529	11

Table 2: Security assessment of initial scenarios for 2050

The use of fossil generators, which are much more expensive than RES explains the significantly higher cost of the NCA 2050 scenario. With 21 TWh of unsupplied energy, this scenario also appears much more unbalanced than the two others, which on the other hand may be over-capacitive.

The surprisingly high level of CO2 emissions for the AT 2050 scenario is due to the observed ratio of the power-to-gas-to-power cycle[30], which is above 40%. CO2 emissions had therefore been corrected to reflect the fact that not all P2G generation can actually be provided by domestic “green” gas.

Considering the CGA scenario only, there is a clear shift from a landscape in 2030 in which generation from fossil gas and coal is majority to a new one in 2050 where generation from renewables (solar and wind) is majority and generation from green gas, which is produced throughout the year, is used in winter with a little support from fossil gas.

Beware that cost results must only be used to compare scenarios and shall not be interpreted as projections of actual system costs.

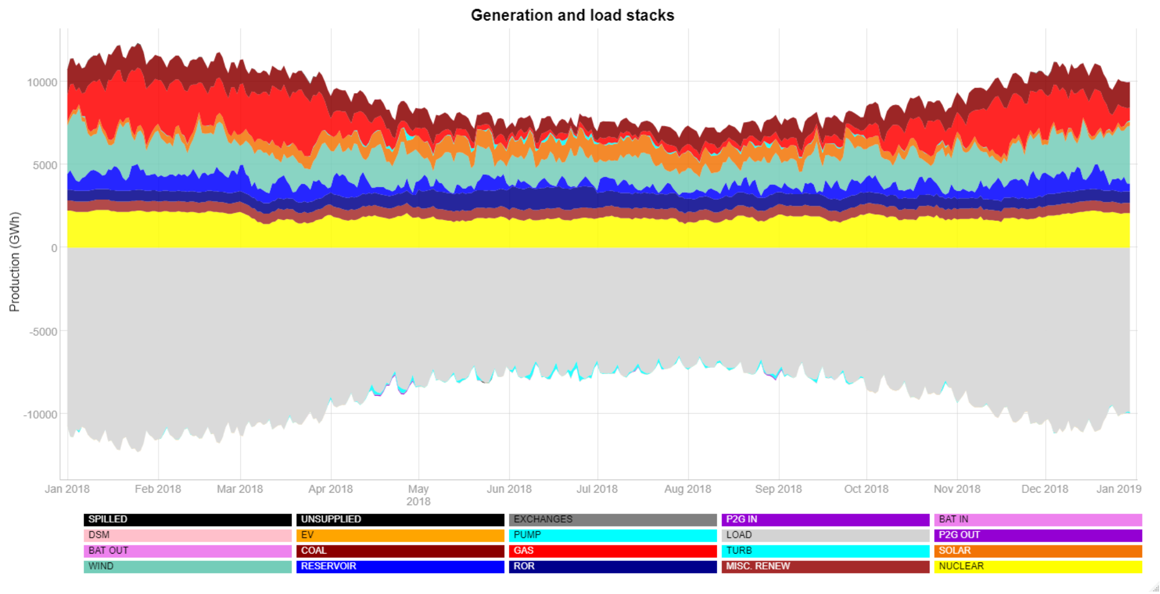


Figure 21: Annual generation (above) and load (below) stacks for all Europe in 2030 CGA scenario

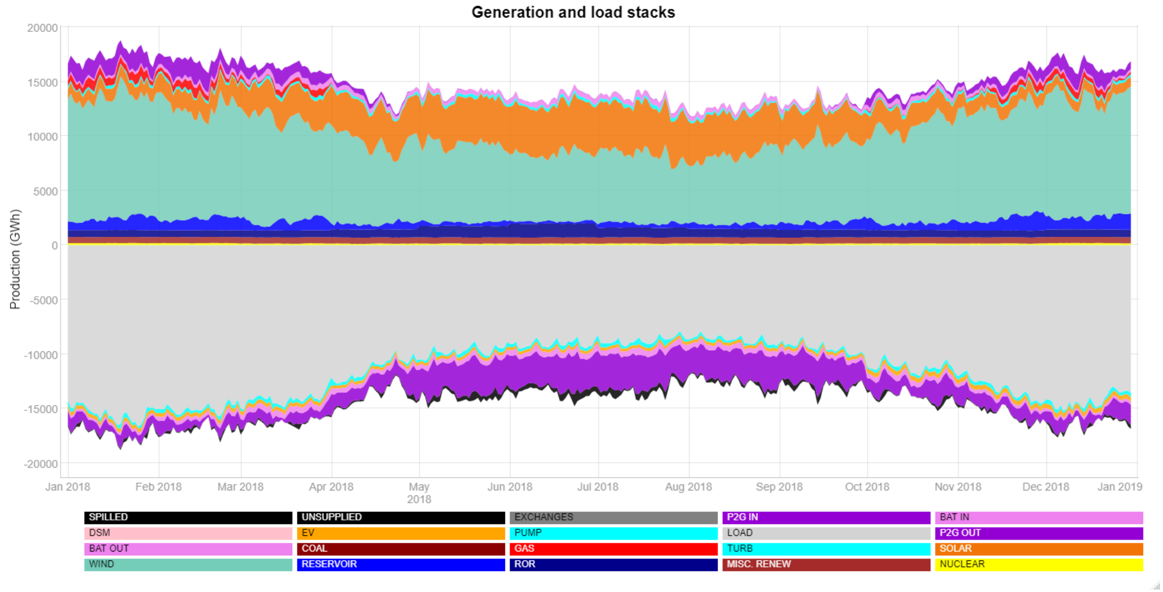


Figure 22: Annual generation and load stacks for all Europe in 2050 CGA scenario

8.4 Feedback on scenarios

Although the 3 scenarios have been initially modelled, NCA results have been considered incompliant with CO2 emissions objectives, whereas AT outcomes by technology appear to be very close to CGA ones despite significant increases in VRES installed capacities. Therefore the initial CGA results have been chosen to feed Task 1.4. Feedback on this scenario has been collected from WP1 members, which is presented in this section.

T1.1 invested in *power-to-gas-out* units which are explicitly dedicated to using green gas generated by *power-to-gas-in* units (electrolysis and methanation). The technical characteristics of power-to-gas as defined in GENeSYS-MOD are distinct from those of conventional OCGT or CCGT. In practice, existing CCGTs and OCGTs are perfectly capable of burning green gas; dedicated power-to-gas-out units turn out to be an unnecessary use of CAPEX. In ANTARES simulations, technical characteristics for power-to-gas-out units have been aligned with OCGTs'. This leads to a European thermal fleet that seems over capacitive. Capacities in France and Germany in particular seem overestimated, while Italy or Finland rely on capacity in other countries. Indeed, all countries but Finland have a LOLE[31] of 0. A better option seems to directly locate additional thermal capacity in the country with lack of generation.

Regarding reserves, these initial results show reserve requirements are satisfied. As a consequence, there is no need for specific capacity constraints in the expansion model to handle reserves. Nevertheless, this conclusion should be re-examined once the sizing issue of the gas power fleet is addressed.

Italian partners working on Task 1.4 noticed for instance that Italian imports in 2050 sometimes peak at more than 70% of the overall domestic load, which seems unrealistic. This may be explained by exchange capacities being overestimated (actually twice more than what is planned in TYNDP scenarios), though in T1.1 optimisation model, yearly limits on interconnection expansion volume had

[31] Loss Of Load Expectation

been set. Additionally, in CGA 2050 (final year of the simulation period), one can notice large reinforcements of more than 2 GW, which mainly concern internal links[32].

Though optimisation results of T1.1 are not intended to accurately reflect national planned decisions reported in TYNDP, assumptions on grid costs should be checked, as well as total costs of grid expansion resulting from DYNELMOD (see [dynELMOD]). The limit on yearly interconnection expansion rate also has an impact on the results. It could be advantageously replaced by a minimal level of domestic generation per country.

Onshore wind investments are scarce in some countries with an important wind energy potential, although these countries have a high energy dependence toward the rest of Europe (UK, IE, SE). The model also seems to strongly favour wind power over solar PV in France.

Offshore wind has been invested in only one cluster per country. In some cases wind generation in those clusters is 5-6 times higher than the annual load. In particular, most wind offshore investment concentrates in NL (51 GW).

Storage capacity seems to be highly correlated with countries' RES capacities, what seems quite reasonable. There is however an inexplicable preference of the optimization for power to gas in France and batteries in Germany, although T1.1 computed similar RES capacities for these two countries.

Finally, neither the currently built nuclear power plants (Flamanville in France and Olkiluoto in Finland) nor the planned units in the UK (Hinkley Point) are present in T1.1 results.

Due to time constraints, in parallel to the automated soft-linking exercise further described in section 9 of this report and scenario improvement performed by Task 1.3, a first manual adaptation of the feedback loop has been tackled by T1.2 in order to create a reference CGA study addressing the above-mentioned drawbacks.

8.5 New reference simulation

In the first simulation run, only 1 time-series of hydro and load data and 11 time-series of renewables hourly capacity-factors have been used[33]. There was therefore no suitable correlation between the load and the meteorological conditions driving VRES generation. In order to improve on this facet, a dataset produced by the *Plan4Res*[34] EU project has been used in the second run. This dataset relies on the PECD v3 (Pan-European Climate Database), which has also been used in ENTSO-E Mid-Term Adequacy Forecast (MAF) 2019 and 2020. The PECD provides 42 years of temperatures, RES capacity-factors (onshore and offshore wind and solar) and hydro time-series (both run-of-river –RoR- and inflows) which are correlated from the geographical and meteorological point of view. This data is available at the geographical resolution of the OSMOSE 99 clusters. It is however based on a reanalysis of years 1981-2016 and therefore does not account for climate change. Additionally, the *Plan4Res* project released demand data for most of the 33 EU countries modelled in OSMOSE. This demand data provides a single profile for the non-thermo-sensitive usages and the charging of electric vehicles, in

[32] Attention must be paid to the fact that internal reinforcements only take place in the second step of T1.1 process, during the downscaling to the 99 clusters.

[33] These 11 scenarios of renewables power-factor as well as the hydropower time series are reused from the dataset made publicly available by the FP7 project e-Highway 2050 (see [e-Highway 2050]).
As a reminder, these hourly time series were based on reanalysis weather data, and express some geographical and temporal correlations. However, load, VRES generation and hydro time series have been generated independently and present no inter-variable correlations.

[34] https://www.plan4res.eu

addition to weather-dependant profiles for heating and air-conditioning. Whilst the non-thermo-sensitive data has been reused without modifications in OSMOSE, the thermo-sensitive profiles have been reprocessed after some inconsistencies were discovered (ex. peak load in Italy being twice the one of France for 1985). New electric vehicle charging profiles have also been created by OSMOSE to better reflect the expected natural charging patterns as found in the literature and to include thermo-sensitivity, which may account for up to 35% of the consumption of the vehicle in winter. Air-conditioning profiles have been discarded due to lack of information to accurately build them. Details of the building of these profiles are available in [appendix B]. Removing incomplete years, the OSMOSE data finally comprises 35 years of consistent data. This number may still not be seen ideal for an adequacy assessment but is already a significant step forward.

It is worth noting that the new wind capacity-factors appear to be smaller than the previous ones, hence they tend on average to lower the annual VRES generation, which falls in 2050 from 4126 TWh to 3853 TWh.

Besides, hydro is modelled using more time series (35 instead of 1). Also, hydro parameters in 2030 and 2050 have been updated based on TYNDP2020:

- Run-of-river generation capacities from TYNDP2020 for 2040 have been taken as expected in 2050. Generation capacities in 2030 have been scaled between current values and the ones expected in 2050. Daily generation from PECD have been scaled with respect to capacities.
- Pumped storages and corresponding reservoir capacities (volumes in GWh) have been modelled as closed cycle with same generation capacities in 2030 and 2050 based on data from *e-Highway2050* scenario Big&market (see [e-Highway 2050]) which are the same as data from the initial CGA scenario.
- Reservoir generation capacities took into account the total hydro capacities from TYNDP2020 and run-of-river and PSP capacities determined as described above. Annual generation and reservoir capacities (volumes in GWh) have been taken from PECD (see [PECD]) and scaled to determined capacities.

In order to tackle the remarks on the thermal fleet in the CGA scenarios, the 2030 thermal fleet has been manually adjusted to reach a level of unsupplied energy that seems acceptable. In 2050, all gas and power-to-gas-out capacities have first been removed. Nuclear capacities have been aligned with their minimal values the TYNDP20 scenarios. Then a joint optimisation of gas units and exchange capacities has been performed to reach LOLE values that seem acceptable (see Figure 25). It is worth noting that internal grid capacities (capacities inside countries) have not been changed which has an impact on the results of the simulations on cluster level (see chapter 8.4.5).

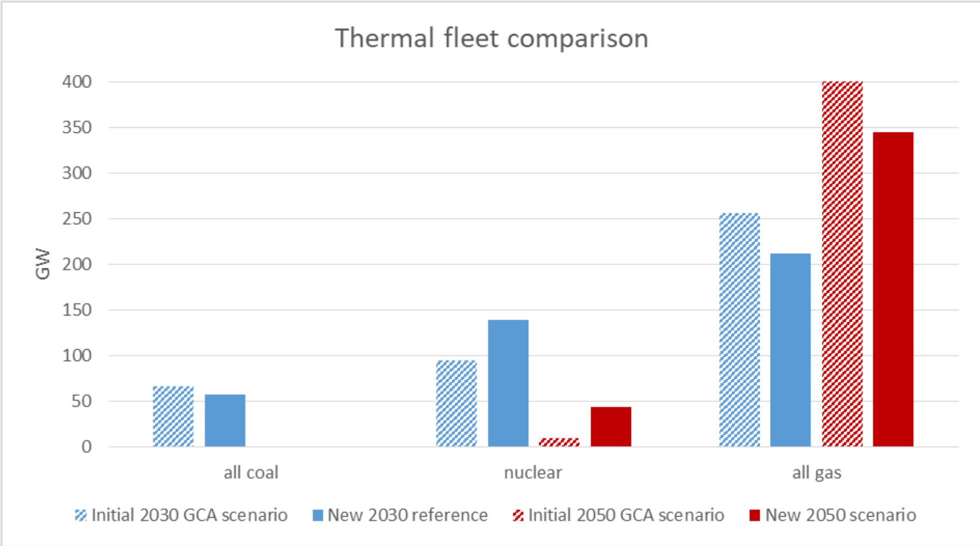


Figure 23: Adjustment of the thermal fleet in the 2030 and 2050 reference scenario

Investments performed in network transfer capacity by the *AntaresXpansion* optimisation is summarised in the following map (Figure 24).

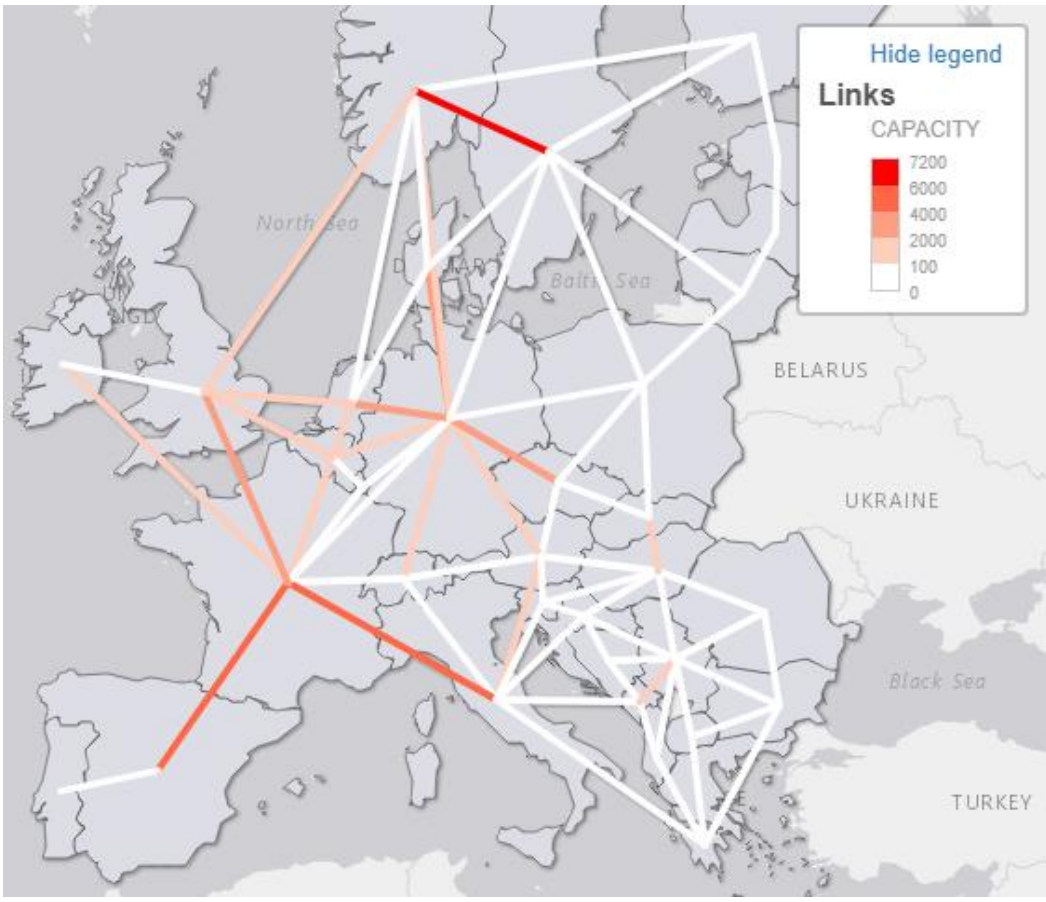


Figure 24: Transfer capacity increase between 2030 and 2050

Some additional minor adjustments to the ANTARES model were made:

- The parameters of the hydro reservoir management heuristic have been updated to ensure the reservoir is sufficiently filled when winter is coming.

- Charging capacities for electric vehicles have been reduced by 2/3 between 9am and 6pm to reflect the fact that some vehicles will not be able to charge at these times.
- Flexibility of nuclear power plants has been reduced.
- The planned outage rate has been slightly decreased in March and November to reduce energy no served (ENS) in these months.

All these changes lead to an annual number of load shedding hours (LOLE) which is lower than 3 hours on average (usual criteria for adequacy), but higher than 0 in order to prevent over capacity. The result is obviously not perfect as some countries experience a LOLE greater than 3. However, considering the balancing of a generation fleet is a complex and time-consuming problem, this result seems sufficient to analyse the contribution of the different flexibility providers.

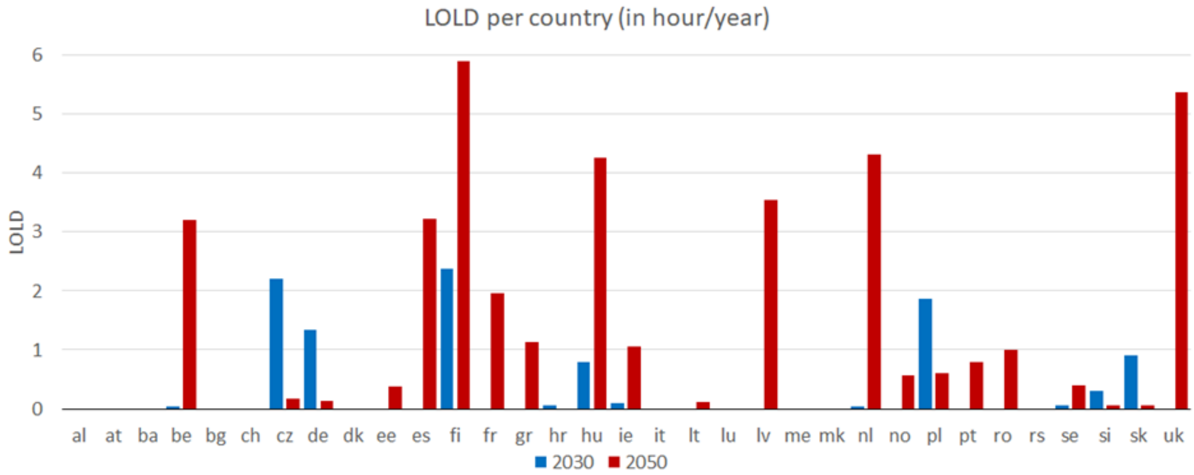


Figure 25: Average Loss-of-load duration (LOLD) in new reference scenario 2030 & 2050

8.6 Key findings and outcomes

In 2050 the demand is almost twice that of 2030 and it is also more irregular due to storage demand, in particular power-to-gas.

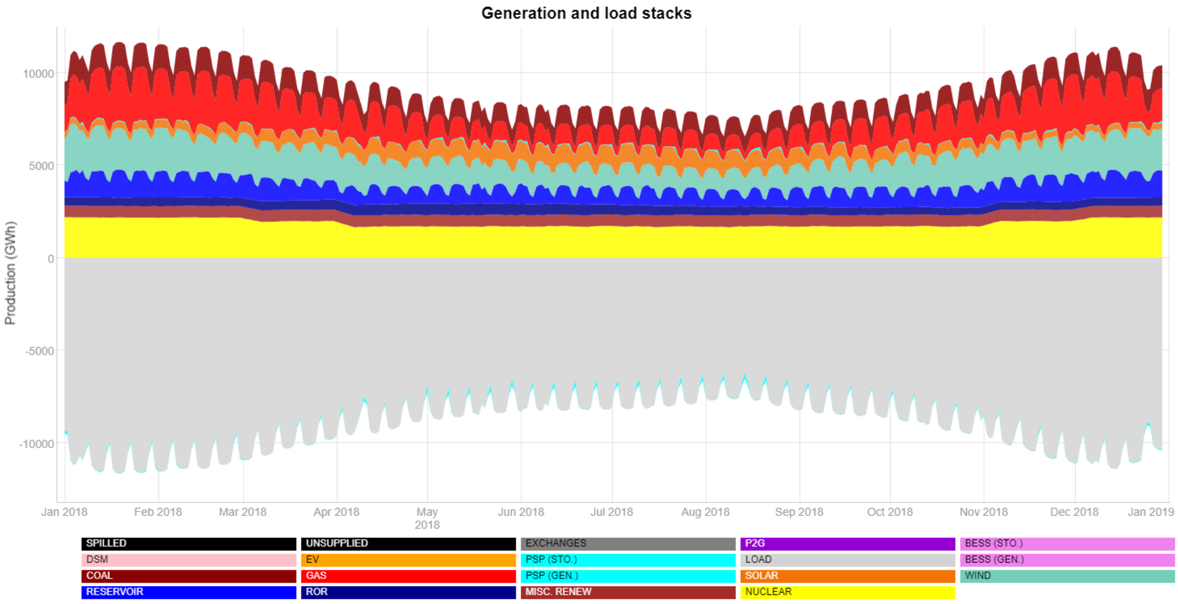


Figure 26: Daily average generation (above) and demand (below) for the simulated European power system in 2030

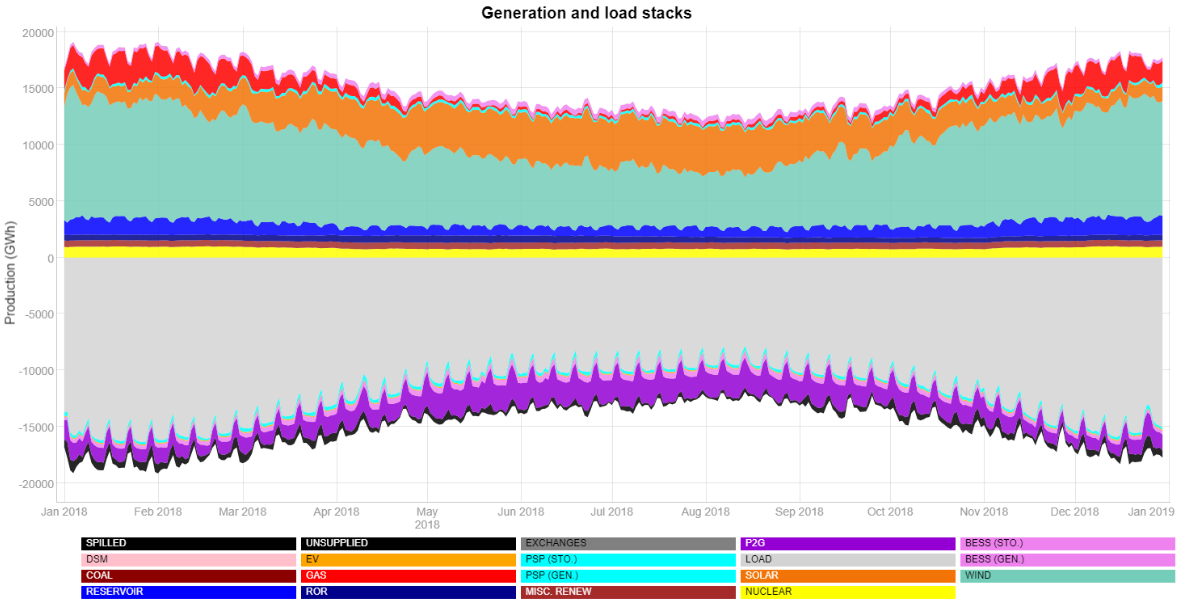


Figure 27: Daily average generation (above) and demand (below) for the simulated European system in 2050

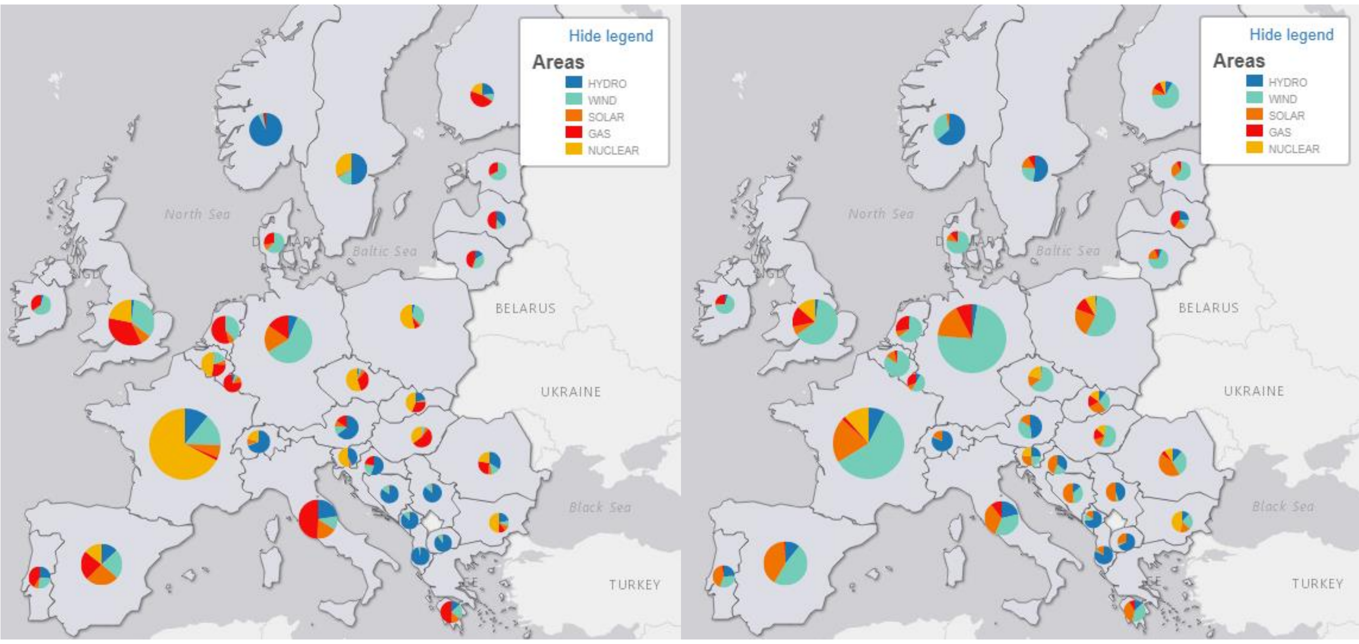


Figure 28: Annual energy generation mixes by country in 2030 (left) and 2050 (right)

	CGA 2030		CGA 2050	
Average annual results	**1st run**	**2nd run**	**1st run**	**2nd run**
Overall costs (B. Eur)	101	103	35	68
Demand (TWh)	3281	3283	4361	4400
Generation wind (TWh)	682	623	3072	2798
Generation solar (TWh)	247	255	1013	1055
Generation nuclear (TWh)	670	675	54	301
Generation hydro (TWh)	547	545	544	576
Generation waste and bioenergy (TWh)	225	225	205	205
Generation gas (TWh)	501	566	275	358
Generation coal (TWh)	414	401	-	-
Generation from battery (TWh)	1	1	134	138
Generation from PSP (TWh)	13	17	81	78
Generation from DSM (TWh)	~0	~0	~0	~0
P2G storage (TWh)	1.7	0.05	668	668
P2G2P observ. ratio[30]	N/A	N/A	0.4	0.7
Spilled energy (TWh)	~0	~0	92	184
Unsupplied energy (TWh)	0.8	~0	~0	0.1

Table 3: comparison of CGA scenario key figures before and after heuristic soft-linking

As illustrated in Figure 29, year-by-year results show there is a clear link between the net load (i.e. the part of the demand no being satisfied by VRES generation) and the amount of ENS (energy not supplied).

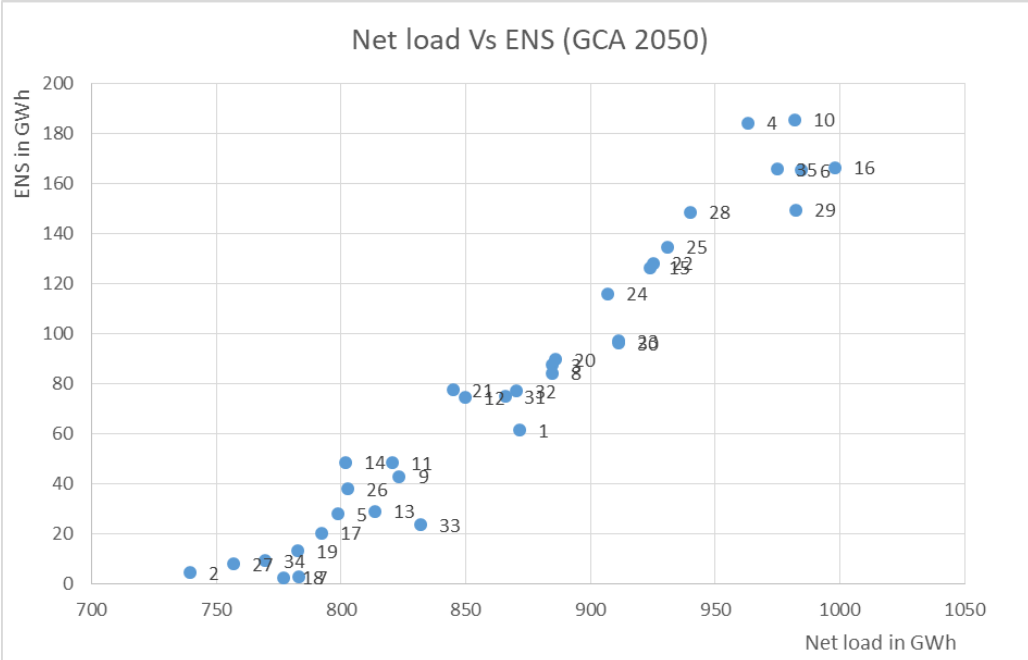


Figure 29: Netload vs net load for the 35 mc-years of the OSMOSE dataset

In the new reference simulation, there is no longer a distinction between gas power plant running on domestic "electro-green" gas (i.e. gas produced via electrolysis and methanation within the European power system) and ones running on fossil gas. Since the observed ratio of the power-to-gas-to-power cycle is above 40%, it means not all of these power plant can run on European "electro-green" gas. The additional gas provisioning may be fulfilled via other "green" gas production technologies (ex. anaerobic digestion), "green" gas imports or even fossil gas imports. The final CO2 emissions therefore depend on the origin of these additional gas provisioning. If the only alternative source is fossil gas, the CO2 emissions would peak at 79 Gt CO2 eq. Comparing these results with their corresponding values in the initial scenario show that they are somehow aligned, in particular if we consider that T1.1 scenarios included negative emissions factors for biomass which have not been modelled in T1.2.

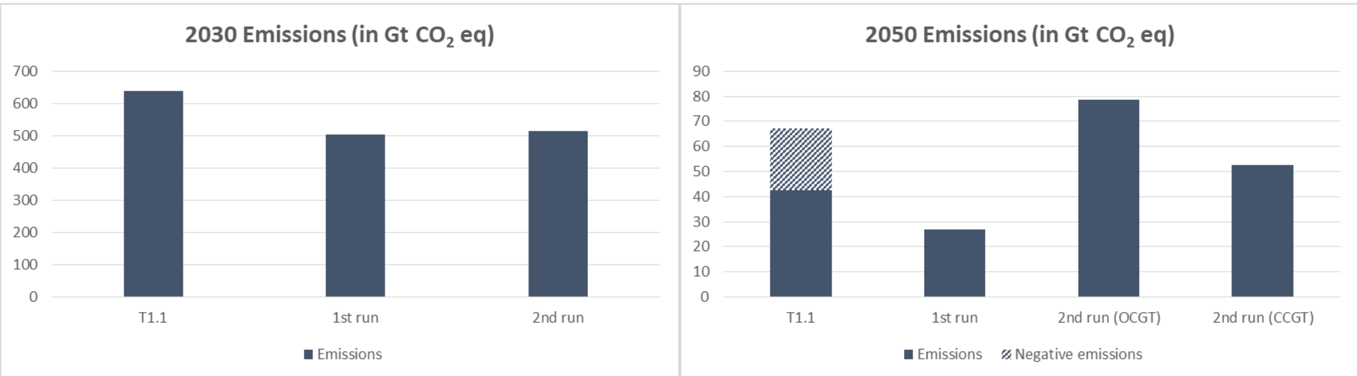


Figure 30: Comparison of CO2 emissions

8.6.1 Competition and collaboration between flexibility sources

8.6.1.1 Flexibility metrics

Building on the metrics defined in section 5, the graphs below illustrate the contribution of the various flexibility providers at the annual, weekly and daily scales for a given year (year 1) both in France and in Germany. Flexibility needs are notably higher in 2050 compared to 2030 and also appear to be twice as high in Germany compared to France (beware that graph scales are different). In France, there is a clear shift from nuclear and hydro in 2030 to power-to-gas and batteries in 2050 for France. Comparing 2030 and 2050, the shape of the annual flexibility modulations becomes much more irregular. This can be interpreted as a shift from a scheme where annual modulations are linked to consumption and generation maintenance patterns to a new scheme where annual modulations are linked to RES generation patterns which are irregular throughout the year (as in Germany). In Germany, gas remains an important flexibility provider, but power-to-gas and batteries also play a major role in 2050. In both cases, interconnectors remain a valuable source of flexibility. As for curtailment, it appears in 2050 at various timescales both in France and Germany.

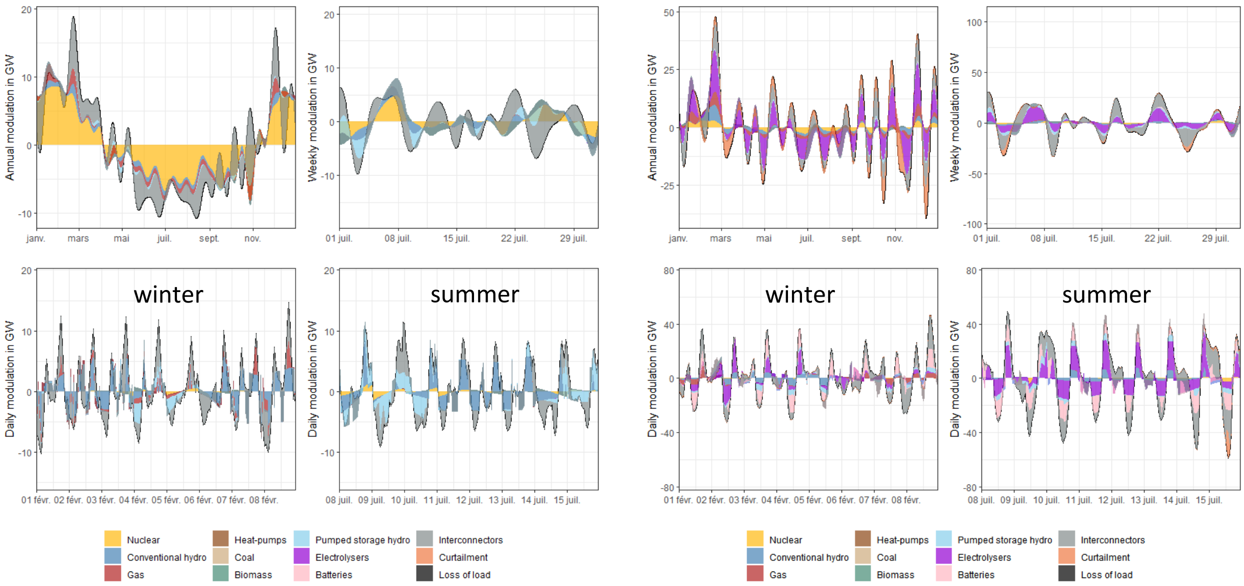


Figure 31: Flexibility providers in 2030 (left) and 2050 (right) for year 1 in France

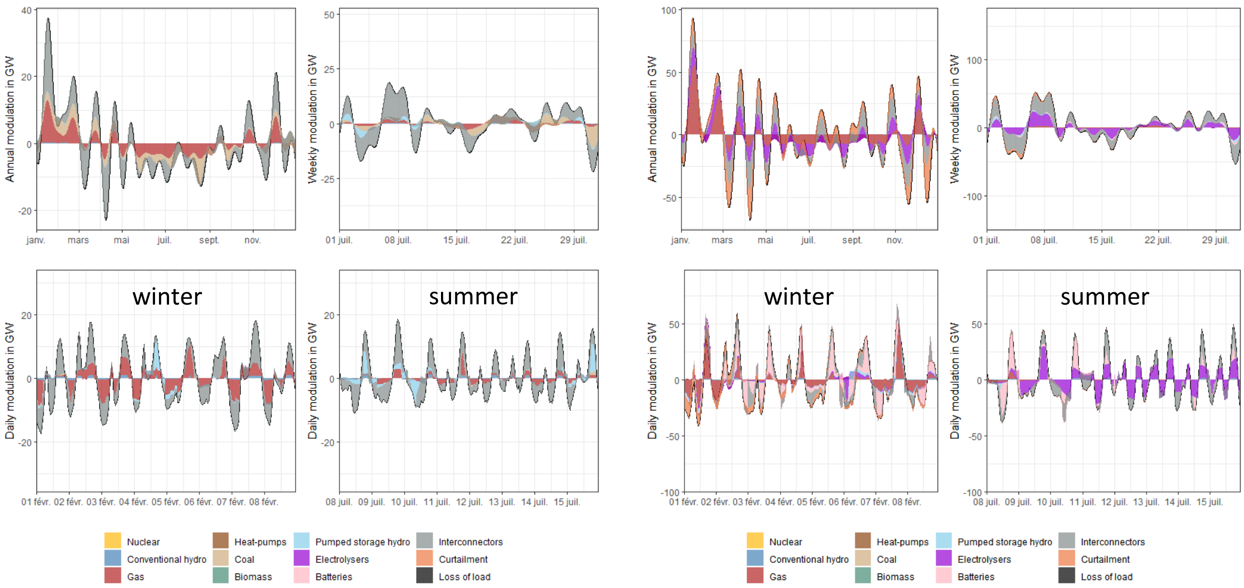


Figure 32: Flexibility providers in 2030 (left) and 2050 (right) for year 1 in Germany

The FSCD[35] indicator for France in 2050, unsurprisingly illustrates that electrolysers become one of the two main flexibility providers for all timescales. This may partly be linked to the fact that in our simulations electrolysers are considered as highly flexible at short-term, though it should be noted that this actually depends on the technology used (alkaline vs polymer electrolyte membrane electrolysis - PEM). Interconnectors continue to play an important role. In particular, electrolysers substitute nuclear at the annual scale. The indicator also shows the growing role of curtailment and batteries at the daily timescale.

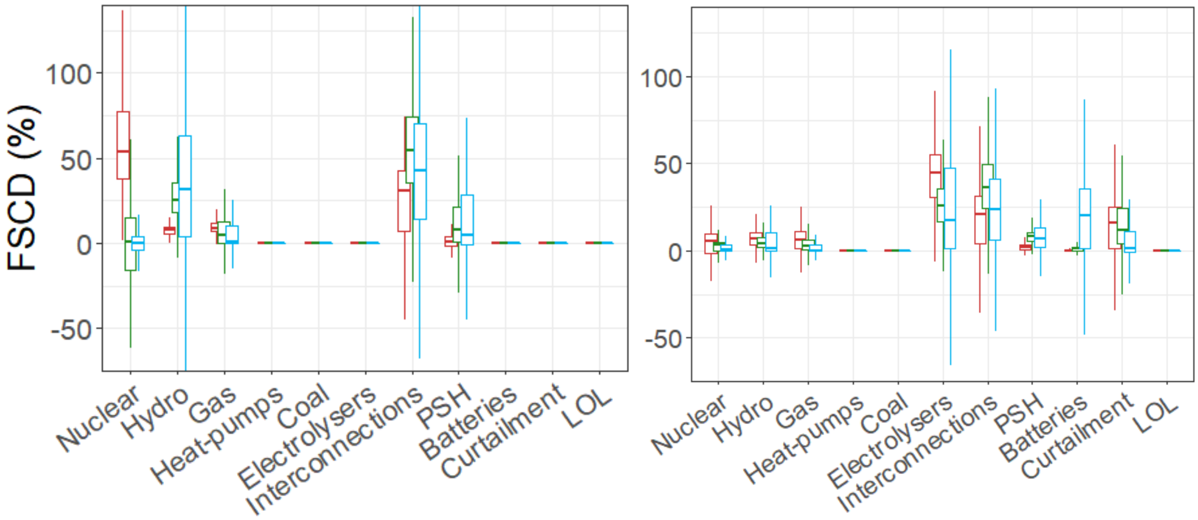


Figure 33: FSCD indicators for France, year1 in 2030 (left) and 2050 (right) (red: annual, green: weekly, blue: daily)

In Germany the situation appears mode balanced between gas, electrolysers and curtailment.

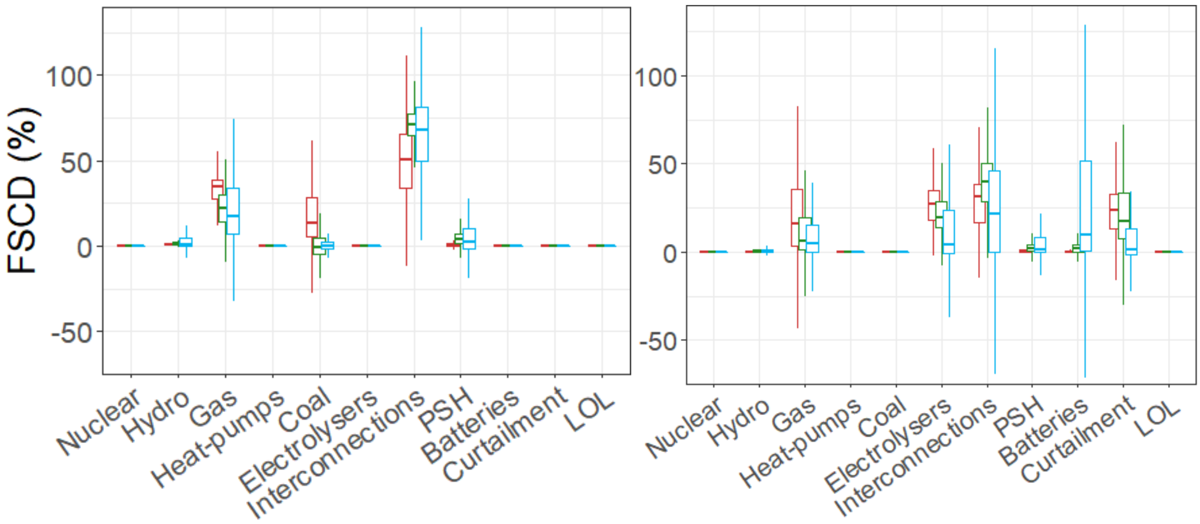


Figure 34: FSCD indicator for Germany, year1 in 2030 (left) and 2050 (right) (red: annual, green: weekly, blue: daily)

[35] Flexibility Solution Contribution Distribution (see section 5 for definition)

8.6.1.2 "Trickledown" effect

Looking more closely at the daily scale, an interesting cooperative effect between flexibility providers has been noticed in 2050 simulations. This effect, which had not been highlighted previously to our knowledge, allows to lengthen the activity time of electrolysers.

In the CGA 2050 scenarios, during sunny summer peaks, generation is exceeding both the demand and the electrolyser capacities. As shown in the right-hand side figure, other shorter-term stock-based flexibility providers (such as batteries and PSP) can charge (1) then discharge a couple of hours later, when PV generation decreases (2). This behaviour allows electrolysers to remain running outside sunny (or windy) hours (3). As such it increases their charge factor and therefore their profitability.

This trickle-down effect is obviously a consequence of the optimisation performed within *AntaresSimulator*, but it could be encouraged by market designs.

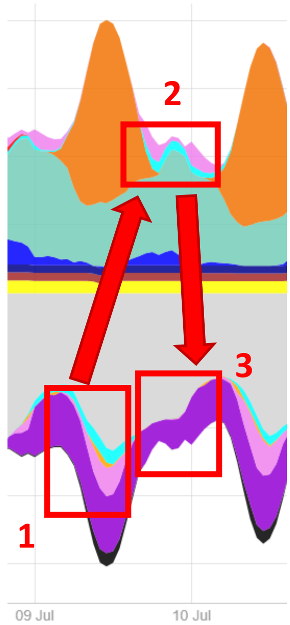


Figure 35: trickle-down effect

8.6.2 Impact of geographical resolution

Simplified simulations in the 2nd run have been carried out for representation of the power systems at country level (33 countries) and additional sensitivity has been made for more dispersed representation, with 99 clusters.

Results point to the impact of the country's capacity distribution to regions (clusters) but also to the impact of the internal grid connections. As previously mentioned, although in this 2nd run exchange capacities between some of the countries are increased, no changes of the internal grid capacities (capacities inside countries) were performed.

The results show that internal grid constraints increase both spillages and ENS, again pointing to the significant role of the grid as the flexibility lever. In 2050, the mitigation of internal grid constraints implies an increase in P2G utilisation.

	CGA 2030		CGA 2050	
Average annual results	**2nd run - COUNTRY**	**2nd run - CLUSTER**	**2nd run - COUNTRY**	**2nd run – CLUSTER**
Overall costs (B. Eur)	103	106	68	147
Demand (TWh)	3283	3283	4400	4400
Generation wind (TWh)	623	632	2798	2844
Generation solar (TWh)	255	257	1055	1054
Generation nuclear (TWh)	675	662	301	287
Generation hydro (TWh)	545	545	576	577
Generation waste and bioenergy (TWh)	225	225	205	205
Generation gas (TWh)	566	586	358	527
Generation coal (TWh)	401	393	-	0
Generation from battery (TWh)	1	1	138	119
Generation from PSP (TWh)	17	20	78	61
Generation from DSM (TWh)	~0	~0	~0	3
P2G storage (TWh)	0.05	0.12	668	916

P2G2P observ. ratio[30]	N/A	N/A	0.7	0.7
Spilled energy (TWh)	~0	11	184	153
Unsupplied energy (TWh)	~0	0.1	0.1	5.2

Table 4: comparison between country and cluster-level simulations

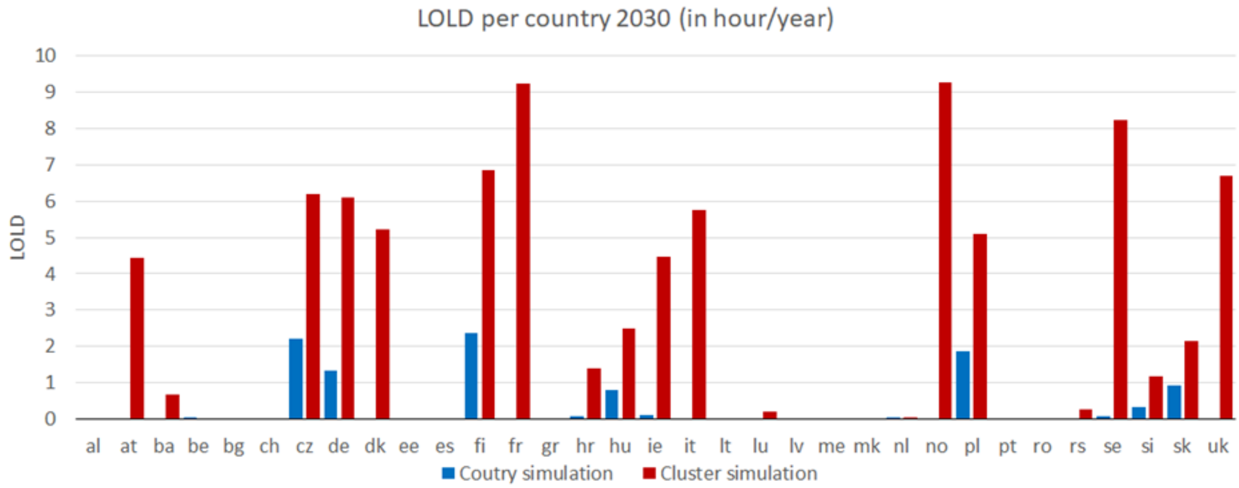


Figure 36: Average LOLD in new reference scenario 2030

It is worth noting that in 2050 grid constraints increase the need for P2G engagement. P2G provides required flexibility when it is reduced due to grid constraints.

Cluster simulations in the new reference scenario in 2050 show unacceptably high levels of loss-of-load duration (LOLD) conversely to the country simulation showing that grid constraints significantly reduce the system flexibility. As an additional sensitivity run, a 2050 simulation without internal grid constraints has been carried out and results are summarized in the following Table. The results are similar to the results of country simulations but there are still some differences. Wind and solar generation is different due to differences in capacity factors per clusters and at country level. In addition, presentation of PSPs and batteries with different granularity in country and cluster simulations also present the reason for small differences in the results. Differences in LOLD are presented in the following Figure.

	CGA 2050		
Average annual results	**2nd run - COUNTRY**	**2nd run - CLUSTER**	**2nd run – CLUSTER Without internal grid constraints**
Overall costs (B. Eur)	68	147	74
Demand (TWh)	4400	4400	4400
Generation wind (TWh)	2798	2844	2844
Generation solar (TWh)	1055	1054	1054
Generation nuclear (TWh)	301	287	304
Generation hydro (TWh)	576	577	577
Generation waste and bioenergy (TWh)	205	205	205
Generation gas (TWh)	358	527	395
Generation coal (TWh)	-	0	0
Generation from battery (TWh)	138	119	116
Generation from PSP (TWh)	78	61	59

Generation from DSM (TWh)	~0	3	0
P2G storage (TWh) P2G2P observ. ratio[30]	668 0.7	916 0.7	860 0.6
Spilled energy (TWh) Unsupplied energy (TWh)	184 0.1	153 5.2	86 0.2

Table 5: identification of effects of internal grid constraints

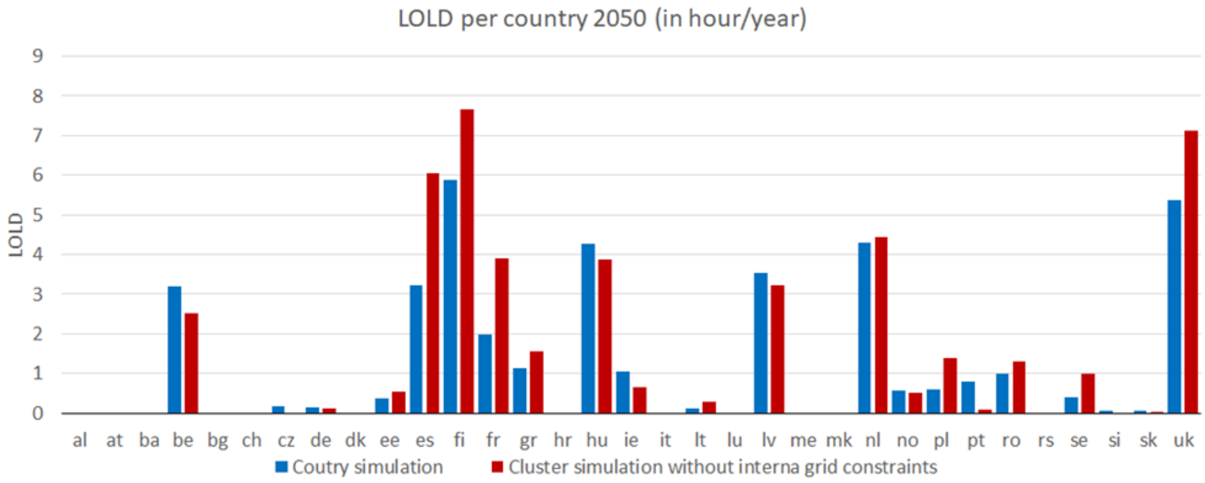


Figure 37: LOLD comparison in 2050 between country and cluster without internal constraints

Results of the simulations without internal grid constraints provide rough information about needed internal grid reinforcement. Reinforcement is mainly needed in France, Germany, Italy, Romania and Norway, as presented in the following Figure.

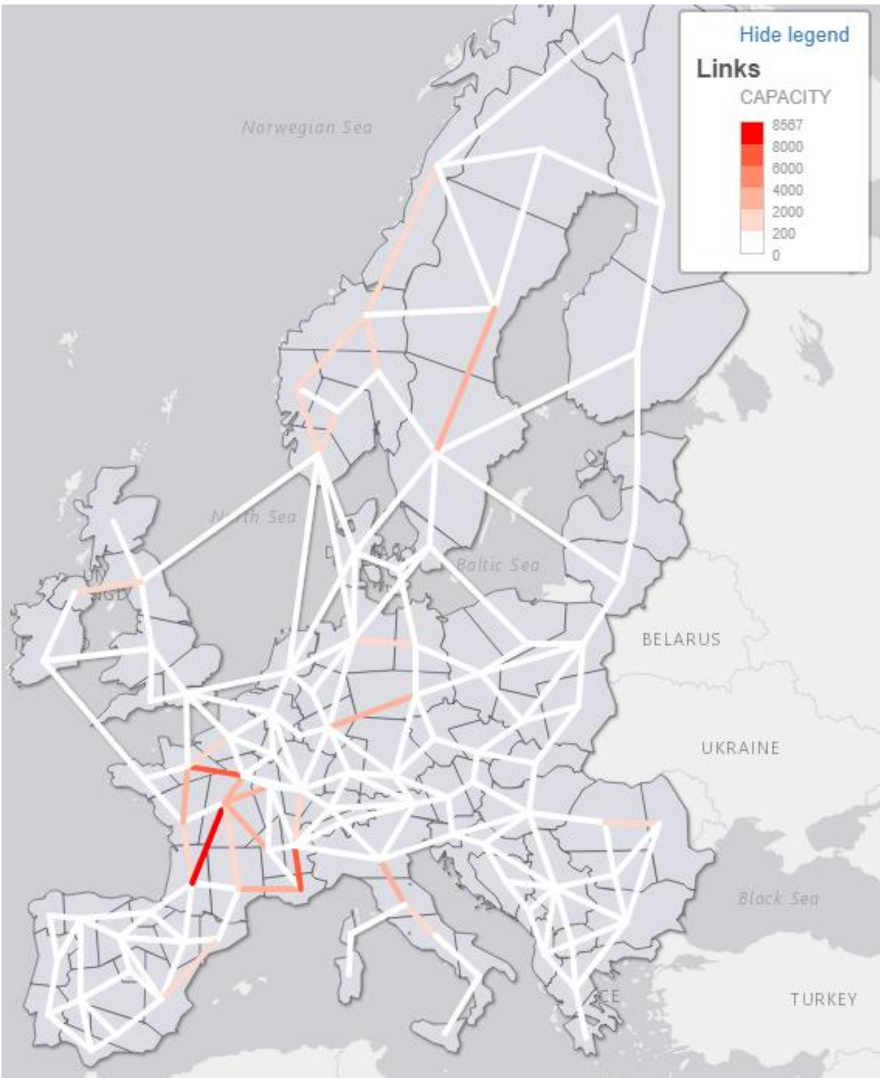


Figure 38: Required internal reinforcements between 2030 and 2050

8.6.3 Effect of sector-coupling on prices

AntaresSimulator does not provide results on market prices. However, marginal cost, which is an optimisation outcome corresponding roughly to the cost of an additional 1 MW of demand, is usually deemed as an acceptable proxy for the market clearing price. In 2030, marginal costs exhibit the usual pattern and are mainly driven by generation costs (see Figure 58 below, left hand side).

In 2050 the power system being mostly powered via renewable energy sources whose market cost is zero, one could expect the marginal cost of the system being often close to zero. Actually, as this has already been described[36], in such scenarios, prices are also driven by demand (in particular the electrolysis). This is illustrated in Figure 58below (right hand side), where two simulations have been performed with two different electrolysis costs (40€ in blue and 100€ in red). One can clearly identify a step in the cost curve corresponding to electrolysis, which last about half of the year.

[36] https://iaee2021online.org/download/contribution/presentation/1301/1301_presentation_20210602_153536.pdf

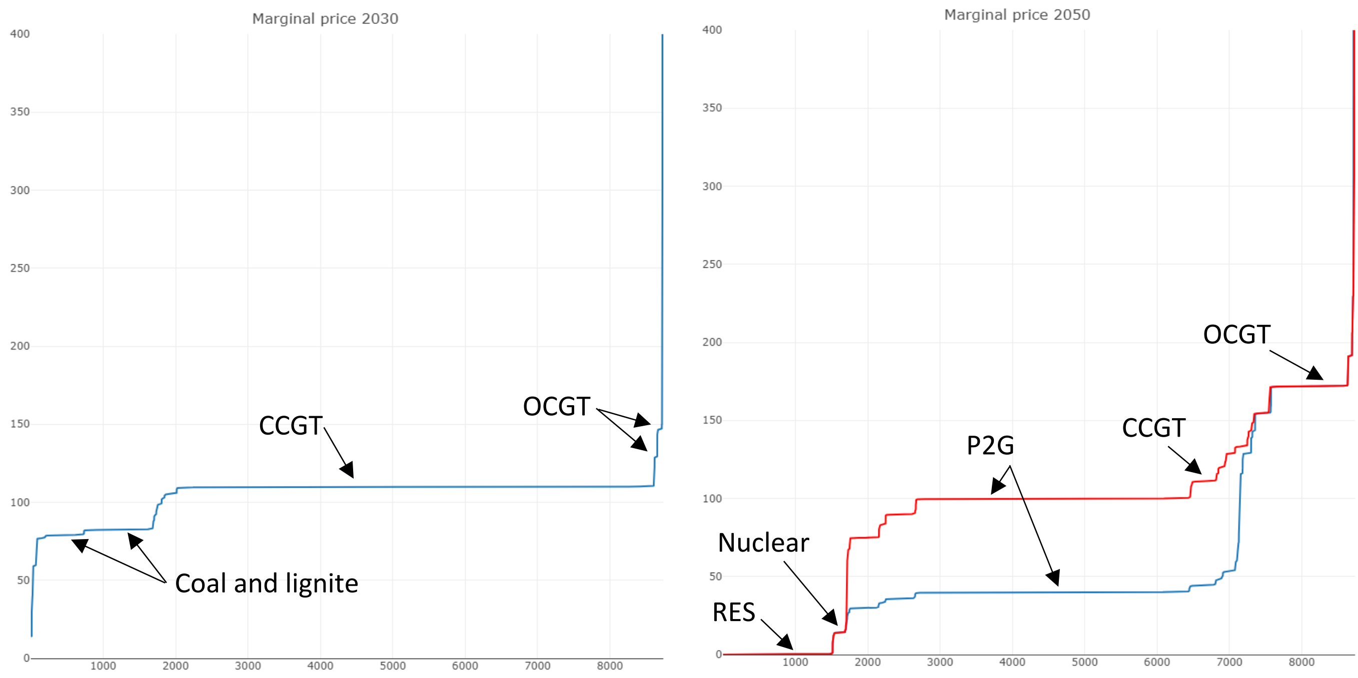


Figure 39: Marginal cost duration curves in 2030 and 2050 reference simulations

8.6.4 Reserve requirement and procurement

In order to take reserve considerations into account in the simulations, there was a need to compute reserve provisioning requirements. Note that these requirements concentrate on upwards reserve which is considered as the most acute aspect. Downward margins are assumed to represent a second-order problem thanks to last-resort curtailment in case of high VRES generation or thanks to modulation of thermal generation if VRES generation is contrarily significantly low.

In order to compute reserve requirements, we used MAF2018 dataset as a basis for the impact analysis of renewables on control power (reserve that presents the sum of FCR and FRR). MAF2019 was used only for data that are missing in MAF2018. In both cases data related to reserve values for each country in 2025 are used.

We have also collected preliminary FCR participation coefficients from ENTSO-e for year 2019 and have calculated FCR part of the total reserve presented in MAF2018 study (FCR+FRR) assuming that FCR will remain the same. Suspicious values (that are significantly less than max unit capacity) are replaced with values that take into account capacity of the biggest unit in the system.

With the aim to separate 2025 reserve values into two parts: a part that depends on the peak load or biggest unit in the system and a part that depends on RES capacities, we assumed that part of reserve needed to control the RES is 3% of installed capacities in RES. By applying this assumption, we calculated the part of reserve non-dependent on RES.

Based on this, we calculated the reserve values for 2030 and 2050 by scaling the RES dependent part of reserve with RES capacities in corresponding years. This scaling is made with the same 3% assumption which can be considered as conservative. These values are then increased for the part of reserve that is RES non-dependent.

With this approach, total reserve values for 2030 and 2050 that are applied in all Antares simulations are presented in the following table:

Country	RESERVE (MW) in 2050 – Current goals achieved	RESERVE (MW) in 2050 – Current goals achieved
AL	266	309
AT	472	1276
BA	329	1050
BE	1186	2580
BG	332	678
CH	964	1111
CZ	1214	2840
DE	4726	12740
DK	1112	1742
EE	253	718
ES	1082	5035
FI	1605	3448
FR	2514	12511
GR	1040	1576
HR	243	550
HU	1087	2003
IE	378	433
IT	3980	6329
LT	697	1290
LU	59	102
LV	259	325
ME	55	73
MK	161	188
NL	719	2455
NO	1537	2673
PL	1120	7021
PT	223	833
RO	1311	3221
RS	607	949
SE	1197	1985
SI	416	665
SK	930	1764
UK	5213	8087

Table 6: total reserve values for 2030 and 2050

For modeling purposes in cluster model, we assumed uniformly distribution of reserve by clusters.

Reserve values determined in the above described way we modeled as "day-ahead' reserve forcing Antares to keep the required reserve values as "operating reserve". With this approach, cross-border cooperation in provision of reserve is assumed and with the aim to minimize the costs, system will keep reserve at the cheapest cluster.

We believe that, for our consideration of flexibility needs, this approach is acceptable.

The following flexibility sources are expected to provide the reserve:

- **CCGT**
- **OCGT (P2G-gen)**
- **COAL (in 2030)**
- **Batteries**
- **PSP**

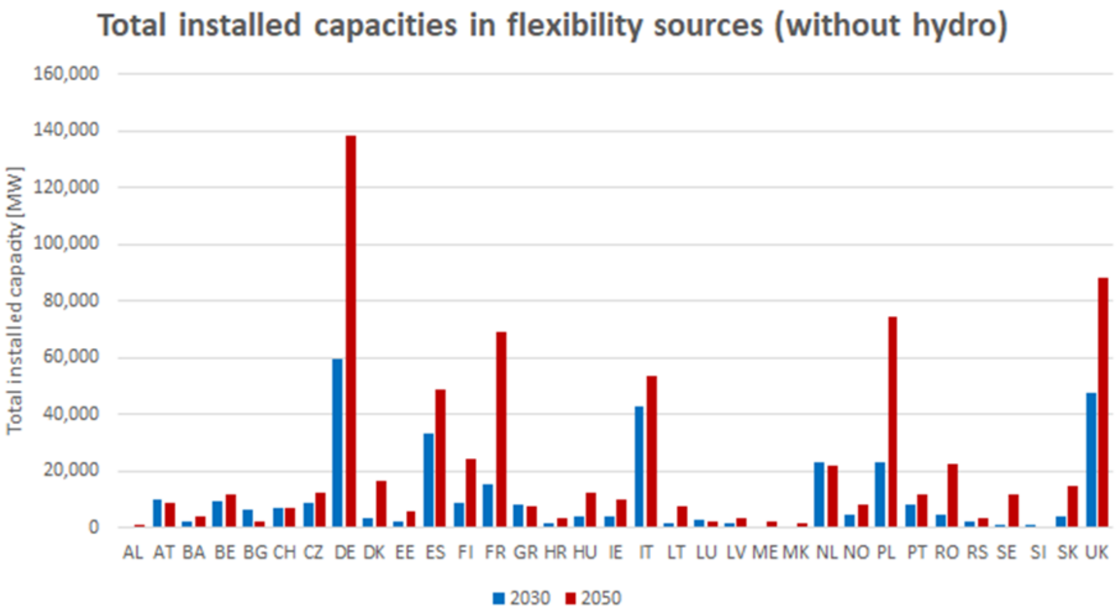


Figure 40: Total installed capacities in flexibility sources (without hydro)

The above list does not include HPPs (RoR and reservoir) that present relevant providers of the reserve and due to this fact, the following analyses can be considered as conservative. On the other side, inclusion of HPPs in the sources of reserve, when all HPPs per cluster are modelled as one HPP, could lead to overestimation of the reserve capacities.

Only batteries are considered as the sources that can provide the reserve from 0 MW (i.e. even when not initially generating).

Ex-post analyses of the results of the country simulations in 2030 and 2050 has been carried out for one MC year (MC1) with two objectives:

1. To check the provision of reserve when it is provided by spinning units only
2. To check the provision of reserve when it is provided by spinning and non-spinning units (e.g. BESS).

The real situation likely lies between these two cases.
Total capacities in flexibility sources are higher in 2050 mainly due to higher capacities in P2G and batteries.

With low level of flexibility sources in 2030 reserve provision by all capacities except hydro is rather low and there are a lot of countries in which there is a high number of hours in which reserve is not satisfied.

In 2050, with more P2G capacities and more batteries (batteries increase from 5.5 GW in 2030 to 288 GW in 2050), reserve provision is significantly better. It should be noted that in 2030 provision of reserve by hydro power plants and provision of reserve from the neighbouring systems will be of high importance.

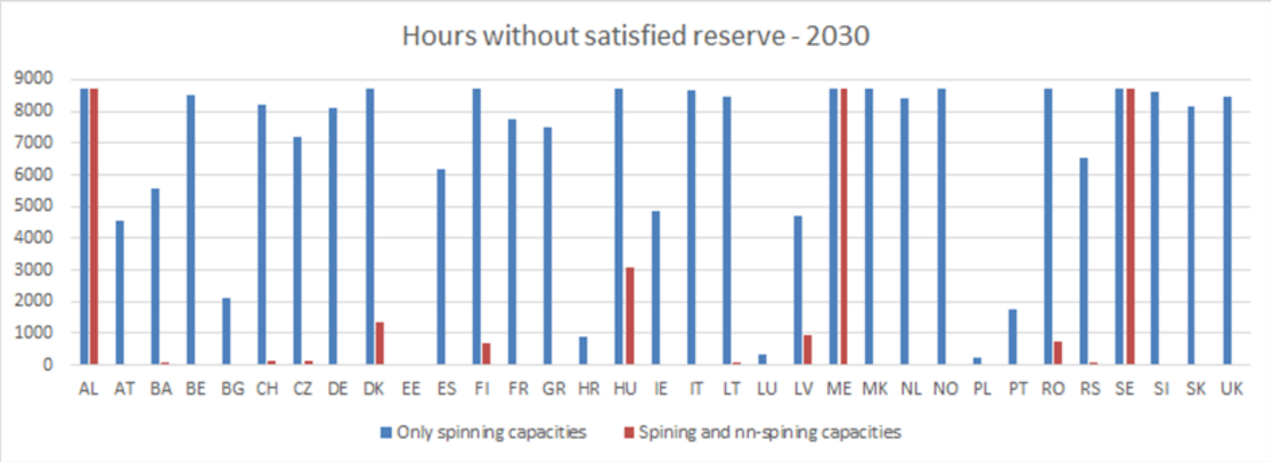


Figure 41: Hours where reserve provision is not satisfied in 2030

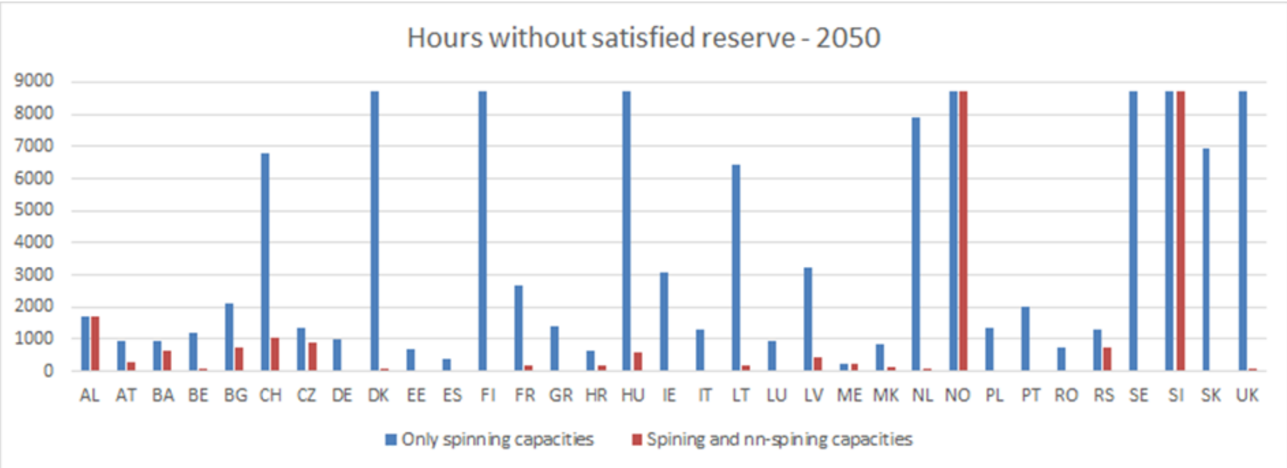


Figure 42: Hours where reserve provision is not satisfied in 2050

8.6.5 Publication of OSMOSE dataset to foster transparency and reuse as a benchmark

The OSMOSE dataset used in the second simulation run is composed of 35 years of data which are spatially and meteorologically coherent:

- RES capacity factors (onshore wind, offshore wind and solar PV)
- Load profiles (non-thermosensitive, heating and electric vehicles)
- Hydro time-series (run-of-river generation and reservoir inflows)

Note that thermo-sensitive load profiles average to 1 over the 35 years but not individually, meaning that some years (ex. year 10) are more stressed than some others.

Data is available at two geographical scales: 33 countries and 99 clusters. This dataset will be made publicly available at the end of the project.

9 Automated soft-linking[37]

As mentioned earlier, the heuristic approach has the shortcoming of relying heavily on expertise. Moreover, its outcomes may be very specific to the cases studied. A solution based on a bi-directional automated soft-linking was considered a promising option to improve the robustness of the results.

For practical and timing reasons, it was deeded preferable to focus on proving that the convergence process could be automated and accelerated, rather than taking full advantage of the feedback gathered in the manual iteration scheme in terms of data accuracy. As a result, the following deviations from the assumptions used in the heuristic approach described above were implemented:

- To accelerate the mastering of the CExM code by RTE, the automated soft-linking has been based on OSeMOSYS (see [OSsMOSYS]), instead of its derivative GENeSYS-MOD[38]. Nevertheless, this switch does not affect the equations used by the CExM under the hood, but only their implementations. In addition, it ensures adaptability and full open-sourcing of the final code. One distinctive features of GENeSYS-MOD compared to OSeMOSYS was the power transmission module developed by TU Berlin, which was expected to play an essential role in enabling the sharing of flexibility provisions between countries and market zones. OSMOSE contributed to the back-porting of this module into OSeMOSYS, in order to match the performance of GENeSYS in this respect and to allow the whole OSeMOSYS community to benefit from it.
- The automated soft-linking subtask focussed on the conception of the coupling algorithm design. In particular, the number of zones was limited to the initial GENeSYS-MOD spatial resolution[39], in order to allow for a more thorough sensitivity analysis by greatly speeding up the optimisation. In addition, this saved the project from having to use DynELMOD (see [dynELMOD]) to scale the system down to 99 nodes. This reduction in complexity helped understand in a comprehensive manner the factors with the largest influence on the results. It was assumed that this difference in spatial scale would have effects of the same order and nature as those observed in the heuristic approach between the 33-country and 99-cluster modelling.

In order to run an automated process, the signal to be sent as well as an explicit stopping criterion have to be specified beforehand, whereas in a manual soft-linking they can be adapted at each iteration on a case-by-case basis.

In the WP1 approach, a system is considered underinvested if it leads to more than 3 hours of LOLE, and conversely, overinvested if it leads to less than 2.5 hours of LOLE[40]. As we will illustrate in the results section of this chapter, the actual performance of the coupling is highly dependent on how effectively this signal is summarized and fed back from the cost minimization module to the capacity expansion module. After a direct application the methodology developed by [Alimou et al. 2020], two alternative approaches were considered to improve the behaviour of the coupling in this regard. Their

[37] Unless otherwise stated, the source for results and illustration presented in the present section is [Heggarty 2021]

[38] [GENeSYS-MOD] is written in GAMS, which requires very specific programming skills and a commercial license, while [OSeMOSYS] is fully python-based, open-sourced and well documented.

[39] The OSMOSE data transmitted to GENeSYS depicts Europe in 17 macro-zones.

[40] This "dead band" of 0.5 h is intended to prevent over-refinement of the mix with respect to the long-term uncertainties (costs of technologies, annual demand, but also fluctuations of weather dependent variables which are depicted by a limited number of Monte Carlo years).

advantages and drawbacks will be examined in the sections below, which summarise the modelling work carried out to improve the representation of flexibility in power system planning.

The main steps of the soft-linking process, common to these three approaches, can be summarised as follows:

- After having set initial values for feedback parameter, OSeMOSYS is run, proposing a first investment pathway from 2015 to 2050, in five year investment steps (“Investment years”).
- The results, consisting in installed capacities for all generation technologies, interconnection and storage can be directly translated into Antares inputs, in a fairly straightforward manner[41].
- Next, for every decade in the investment pathway (2020, 2030, 2040 and 2050 are referred to as “Soft-linked years”), an AntaresSimulator simulation is run on the full Weather years dataset.
- For each Soft-linked year, Antares outputs hourly time series describing the behaviour of all system components (generation, interconnection and storage).
- These outputs are then used to compute new values for the feedback parameters of each Soft-linked year[42].
- The process is then repeated for a new iteration, with OSeMOSYS proposing a new investment pathway based on the new feedback parameter values, until the defined stopping criterion is reached.

Investment year	OSeMOSYS invesment step. Range from 2015 to 2050 in 5-year steps.
Soft-linked year	Subset of investment year for which Antares simulations are run. Range from 2020 to 2050 in 10-year steps
Weather year	11 Antares realisations of the same soft-linked year (source: e-Highway 2050)

Table 7: Summary of the several time periods used by the coupling

In a soft-linking scheme, the feedback process has two key roles:

1. Reporting to OSeMOSYS underinvestments and overinvestments,
2. Telling OSeMOSYS how to adjust the investment path in the next iteration.

The first point is a general requirement for all considered options. How the second point is implemented will differ in each feedback technique.

[41] A specific approach is required to obtain the number of thermal units to be modelled in Antares, as their economic dispatch and unit commitment are significantly influenced by the size and number of units.

[42] Parameters calculated based on Soft-linked year 2020 are also applied to Investment years 2015 and 2025, those on Soft-linked year 2030 to Investment years 2035 etc.

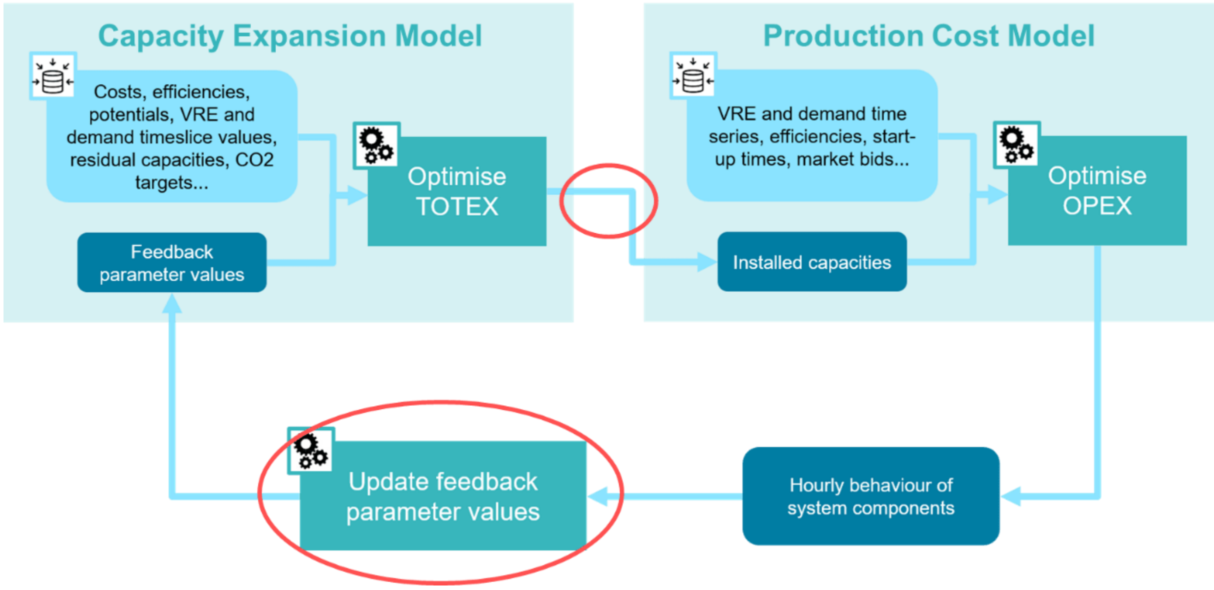


Figure 43: soft-coupling between Capacity Expansion Model and Production Cost Model

It is worth noting that all soft-linked years are optimized and assessed simultaneously, assuming perfect vision in the investment problem. No claim of proven optimality can be made for the solution provided by soft-linking a CExM with a PCM. However, proving the strict optimality of a capacity expansion solution seems in general a questionable goal, given the modelling simplifications, the input data uncertainties, and the limited ability to take into account non-technical but essential constraints (e.g., social or environmental). In this respect, the approach adopted puts more emphasis on a heuristic evaluation of the robustness of the solution: in particular, the ability of the final solution to match supply and demand with acceptable Security of Supply levels is validated over a full hourly resolution for many weather years, which is much more stringent than the levels exhibited by the original CExM solution.

The most natural stopping criterion for this feedback loop would be to check whether the agreed Security of Supply criterion has been reached, ensuring feasibility[43]. But since the solution proposed by a soft-linking exercise cannot guarantee to be optimal, this can lead to a system with an unreasonably high level of reliability. Instead, monitoring the subsequent behaviour of the total expenditures (TOTEX) was deemed relevant, putting the focus more on a TOTEX convergence perspective: the soft-coupling was run for 10 iterations; within solutions leading to LOLE below 3h, the one with the lowest TOTEX (CAPEX+OPEX) seen by the CExM was kept[44].

9.1 Initial scenarios complemented by Weather dependent data

The scenarios used to put the coupling under testing were based on modified TUB scenarios, with 17 zones. The "standard" budget, based on TUB OSMOSE scenario data, is used as a reference. Budgets are allocated among regions according to their share in European annual demand.

[43] This criterion was used in [Alimou et al. 2020] who soft-linked the CExM TIMES to the PCM Antares, on a single-node representation of the French power system, for a single Soft-linked year and considering investment only in generation.

[44] In most cases, 10 iterations were sufficient to observe a significant decrease in the TOTEX variation from one iteration to the next, indicating a stabilization tendency. In the opposite case, a few more iterations were added.

Technology	Pmax (MW)	Pmin (MW)	Min up time (h)	Min down time (h)	Market bid (€)	CO2 emissions (tCO2e/MWh)
Nuclear	1600	800	168	168	14	0
Coal	800	320	6	6	79	0.75
CCGT	500	150	3	3	118	0.327
OCGT	250	120	0	0	172	0.488
Oil	250	120	3	3	190	0.65

Table 8: Thermal generation Antares parameters (bio-energy modelled as must-run)

Because of its importance in relation to flexibility, a special effort has been made to define the structure of the time slices to be used in the CExM. An analysis on a dedicated use case to assess the impact of different timeslice structures and number on the model outcome shows that improving the representation of solar and wind variability indeed impacts the final installed capacity, but to different degrees depending on the freedom given to the model. If the modeler adopts a greenfield approach and does not limit investment rates in technologies, this impact will be a lot more significant.

Following this analysis, a single structure consisting of 16 timeslices[45] was selected and applied to all bilateral soft-linking schemes. Since the CPM will provide a much more detailed description of the operational behaviour, this structure was considered an appropriate trade-off between computational time and accuracy. The timeslice values for VRES and load were obtained based on a set of 35 years of hourly time series data, derived from reanalysis historical weather data. For VRES, the factor value for a given timeslice is set as the average power output relative to installed capacity over the group of hourly time steps matching the time slice definition. The principle for load timeslice values is the same.

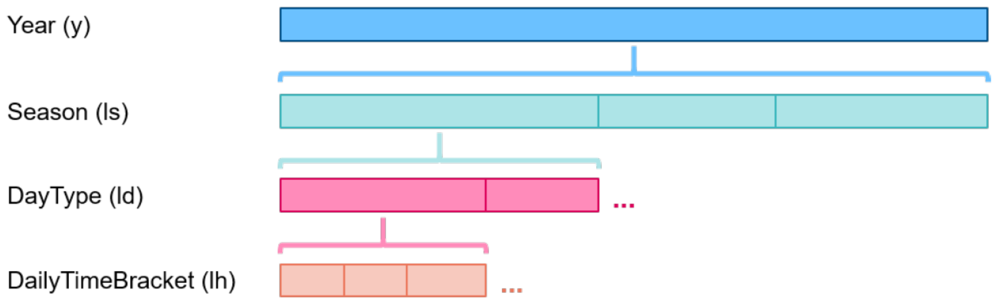


Figure 44: hierarchical timeslice structure

As with heuristic coupling, the use of stochastic methods adapted to the assessment of security of supply by the CPM requires supplementing these scenarios with Monte Carlo years, in order to model uncertainties related to load and fatal generation (hydro and VRES). When the automated soft-linking was launched, only the 11 scenarios from the e-Highway 2050 dataset were available (cf. section 8.5). For reasons of internal consistency, the choice was made to use them as is in this section, without trying to update them once the new Monte Carlo datasets would be available.

[45] 16 timeslices , resulting from the ,combination of 4 seasons (Summer, Autumn, Winter, Spring), 1 day-type and 4 daily-time-brackets (Night, Morning, Afternoon, Evening).

9.2 Automated iterative soft-linking – Reference feedback loop approach

As previously mentioned, this first approach is built upon the methodology developed by Alimou et al., with the following key features:

- The feedback loop is designed around an ad hoc constraint present in the CExM and imposing that the sum of installed capacities weighted by their capacity credits[46] must exceed peak timeslice demand multiplied by a reserve margin (referred to as "CExM Adequacy Constraint").
- This constraint is a proxy for system adequacy, correcting for the fact that, due to averaging, peak demand over timeslices may be significantly lower than the actual hourly peak demand.
- Capacity credits are updated after each iteration on the basis of Antares outputs.
- Conversely, the reserve margin, which is obviously a key parameter, is fixed for the entire run[47].

NB: in Alimou et al., the methodology is limited to one target year. In the OSMOSE context, it was adapted in a straightforward way to take into account a multi-year investment path.

In Figure 45, total system costs over iterations for a single-node German power system, and for different reserve margin, are displayed. The colour and shape of the corresponding dots reflect the status of a given iteration on the investment path, in terms of Security of Supply (green being the "target" colour):

- In accordance with the main findings of the study by [Alimou et al. 2020], a generation mix provided by a CExM frequently leads to unacceptable LOLE levels due to insufficient operational details (iteration 1). This is true even for very high reserve margin levels.
- Situation leading to more than 3 hours of LOLE (red and, for some Soft-linked years, pink and orange dots) mostly tend to be adjusted as desired, i.e. investment is increased in the subsequent iteration.

Situations leading to less than 3 hours of LOLE per node (yellow, green and, for some Soft-linked years, pink and orange dots) should be adjusted by reducing investment in the next iteration. However, the exact opposite is happening. Investment is systematically increased, until the optimizer cannot respect the maximum annual capacity investment constraint[48] (triangles).

[46] Capacity credits are intended to express how each generation technology contributes to meet hourly peak demand. See [Alimou et al. 2020] for details.

[47] In [Alimou et al. 2020] the reserve margin is set to 1.28 throughout the softlinking process.

[48] Maximum annual capacity investment constraint reflect political and industrial considerations with an impact on the deployment rate of technologies, such as the ability of industry to develop onshore wind and solar capacity fast enough.

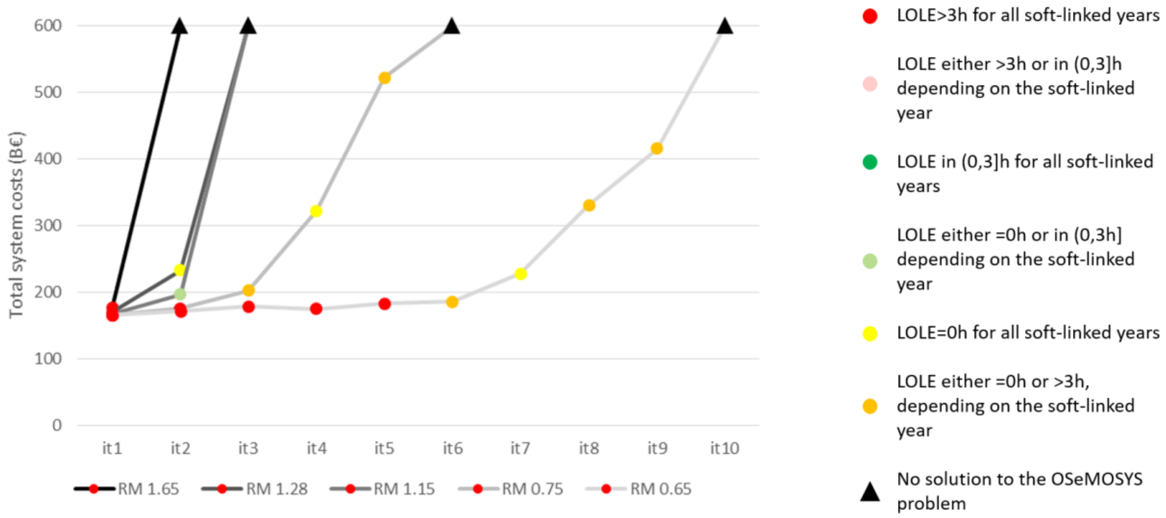


Figure 45: Evolution of OSeMOSYS total system costs over iterations,
for a single-node German power system and for different reserve margin

This feedback technique fails to differentiate under and over-invested situations, always generating positive feedback as iterations progress. Let us explain this behaviour from a theoretical perspective. The left hand side of the CExM Adequacy Constraint (demand multiplied by a reserve margin) is held constant over iterations. A change in investment then requires a change in capacity credits. Signalling over-investment would hence involve an overall increase in capacity credit values when LOLE drops below 3 hours. We can see in Figure 46 that on the contrary, dropping LOLE levels lead to an overall collapse in capacity credit values, which will cause investment to increase in an already over-invested system.

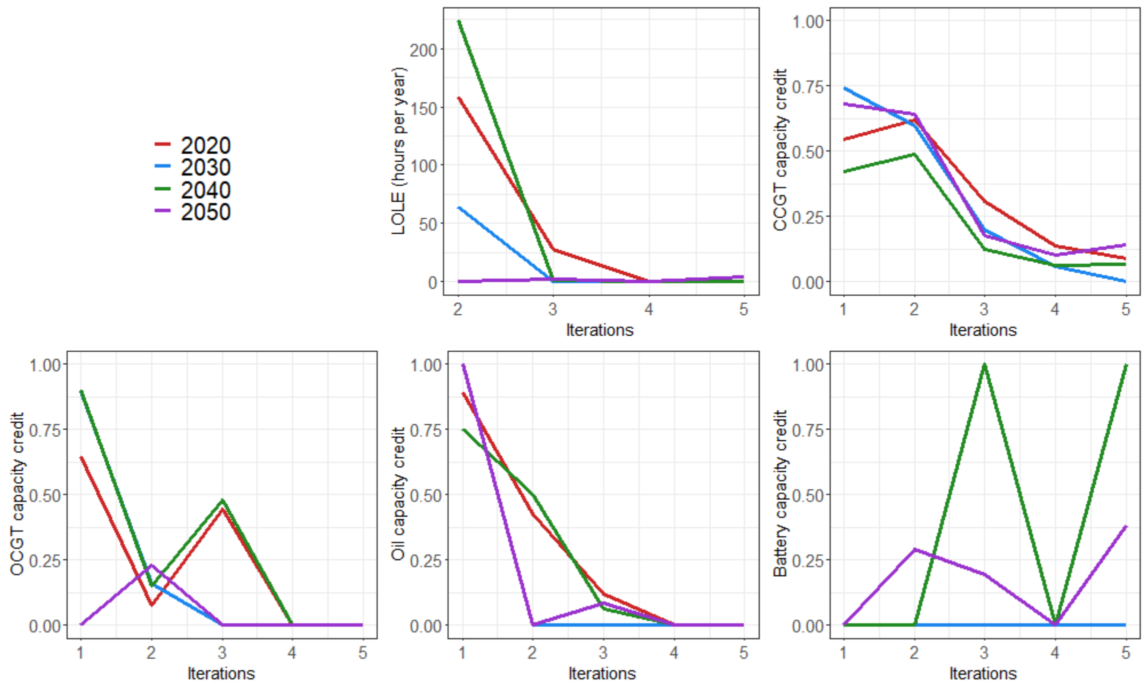


Figure 46: Evolution of OSeMOSYS total system costs over iterations for dispatchable technologies

There is clearly a gap between what we intuitively expect from capacity credits and what we actually get. Capacity credits as defined above express to what extent each generation technology contributes to meeting hourly peak demand in a given situation. Whereas the feedback information we are looking for to properly guide the CExM is the degree to which a technology could be used to meet peak net load if needed[49], which may notably differ from the observed participation. While these two notions are equivalent for VRES, they are not for dispatchable generation.

Because of the fundamental issues described above, the reference feedback technique was not considered suitable for use in the OSMOSE project, and no attempt was made to adapt this technique to a multi-node context. However, the general idea behind this feedback technique is of significant value. After extensive exploration, a new feedback technique was derived, which is presented in the next section.

9.3 Automated iterative soft-linking– Reserve margin based feedback

In the CExM Adequacy Constraint, the reserve margin parameter expresses the degree to which a generation mix sized on timeslices deviates from being able to guarantee adequacy. This proxy has no direct link to power system physical quantities, and a reserve margin value derived for a given system has no reason to be appropriate for another. Therefore, it seems to be a very appropriate tool to signal under- and over-investment.

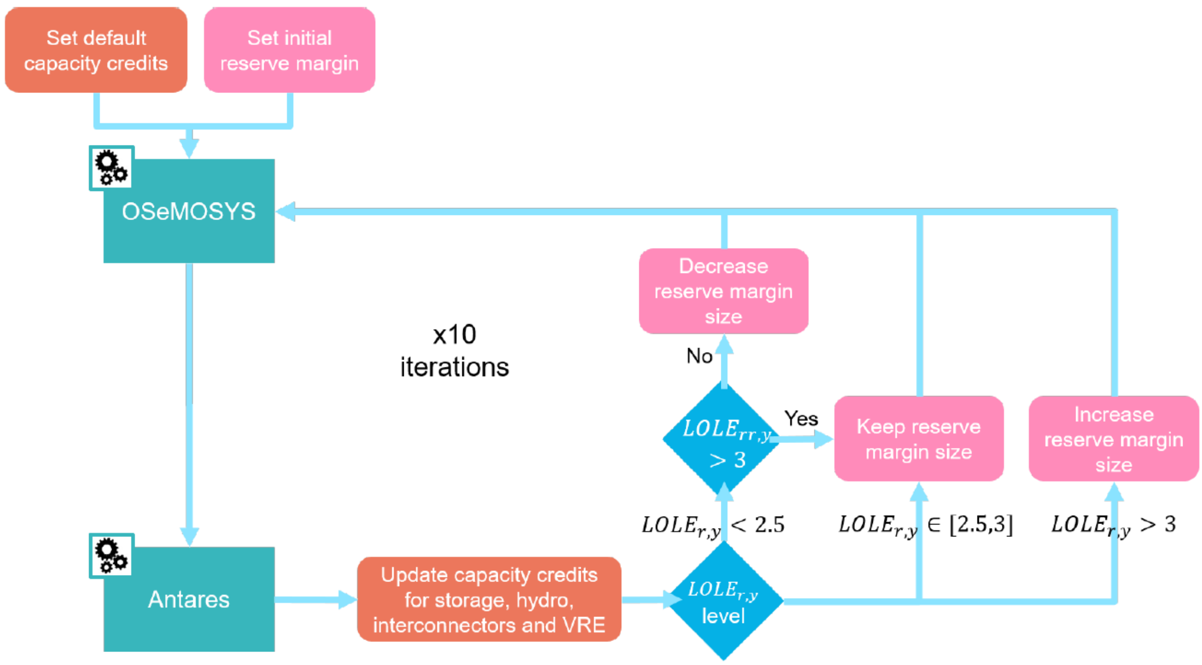


Figure 47: Evolution of OSeMOSYS total system costs over iterations for dispatchable technologies

There are many potential ways of implementing the details of this adjustment principle. Extensive testing showed that, to ensure a preferable strategy for reserve margin adjustment was to first obtain an adequate solution (LOLE <3h) and then reduce investment. The main idea of the present technique is therefore to link reserve margin to LOLE level: it defines the relative adjustment to be made on the reserve margin used at last iteration, depending on the LOLE computed by the PCM. This monotonically increasing function is referred to as "Reserve Adjustment function" and is "neutral" around the 3h target level (to conform to some fixed-point theorem logic). No analytical solution could be derived for

[49] For instance, its ability to be used as a back-up, in case of a sudden drop in RES generation or a dispatchable unit contingency.

the Reserve Adjustment function: the proposed strategies are the result of experimental trade-offs between robustness and speed.

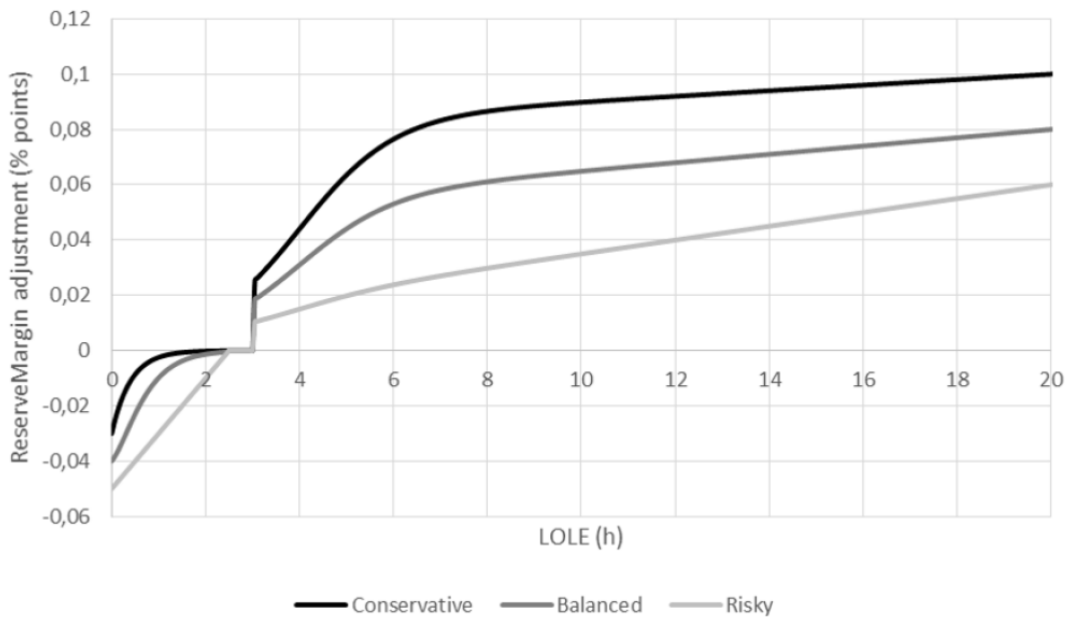


Figure 48: Possible designs of the Reserve Adjustment function, depending on the speed/robustness compromise

In multi-node situations, the reserve margin adjustment defined above requires an additional rule: a region's reserve margin can only be reduced if, for the same soft-linked year, none of its neighbouring regions have a LOLE level above 3h. Without the inclusion of this rule, the location of new generation investment may switch over iterations, between neighbouring regions, failing to bring LOLE levels below 3 hours in both regions simultaneously.

Finally, besides the logic of adjusting the reserve margin, some questions regarding the capacity credits were still pending: The switch to multi-node systems entails defining capacity credits for interconnectors to signal to the CExM their flexibility value. Each link is assigned a pair of capacity credit values, based on the mean flow during the 100 hours of highest net load in each of the two connected regions. Note that this may lead to a negative value.

Initial (and default) values were derived in a way to ensure that they truly measure the ability of each asset to be online when it is really needed. With this in mind, The CExM computes an investment pathway without any reserve margin constraint, which is then submitted to the PCM with a 33% load increase. In the PCM, residual capacity may be sufficient to ensure adequacy at the start of the model period, but this process will lead to high levels of LOLE at the end of it, and will hence provide asset behaviour under tense conditions.

As for capacity credits update, extensive research was conducted on both the single-node German system and the multi-mode system, and ultimately showed that updating capacity credit values over iterations provides limited value to the process[50]: the comparison of TOTEX trajectories presented in Figure 49 shows that successively updating capacity credits leads to more instability, particularly in the first few iterations, while the cheapest adequate systems proposed have TOTEX cheaper by 0.1% at most. Surprisingly, updating the reserve margin provides the CExM with sufficient leverage to signal under and over-investment and adjust the investment path in the next iteration.

[50] Provided that initial capacity credit values are set to reflect assets' ability to be online when it is really needed.

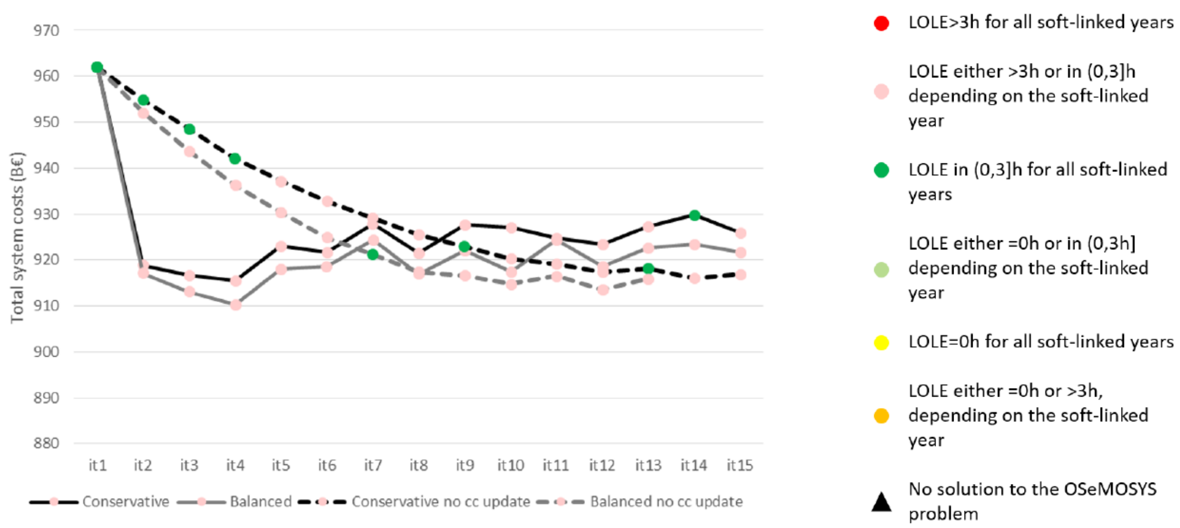


Figure 49: Evolution of total system costs over 10-iteration runs for the17-node European system with (solid) or without capacity credit updates (dashed lines) - initial reserve margin size of 1.28

The view provided by Figure 49 is too geographically aggregated to study how investments are adjusted over iterations. Figure 50 provides more detailed insight into the evolution of LOLE, and explains why investment may decrease despite some nodes exhibited a LOLE greater than 3 hours in the previous iteration: in the vast majority of combinations of regions and soft-linked years, LOLE is below 3 hours. With decreasing investment as iterations go by, there are fewer situations with 0h of LOLE and more situations with LOLE levels in the]0,3] hours interval. This suggests that the soft-linking process is successfully reducing investment in over-invested regions. However, it struggles to keep all LOLE values below 3 hours, and the process seems rather unstable. It should be noted that LOLE in excess of 3 hours remains at reasonable low levels.

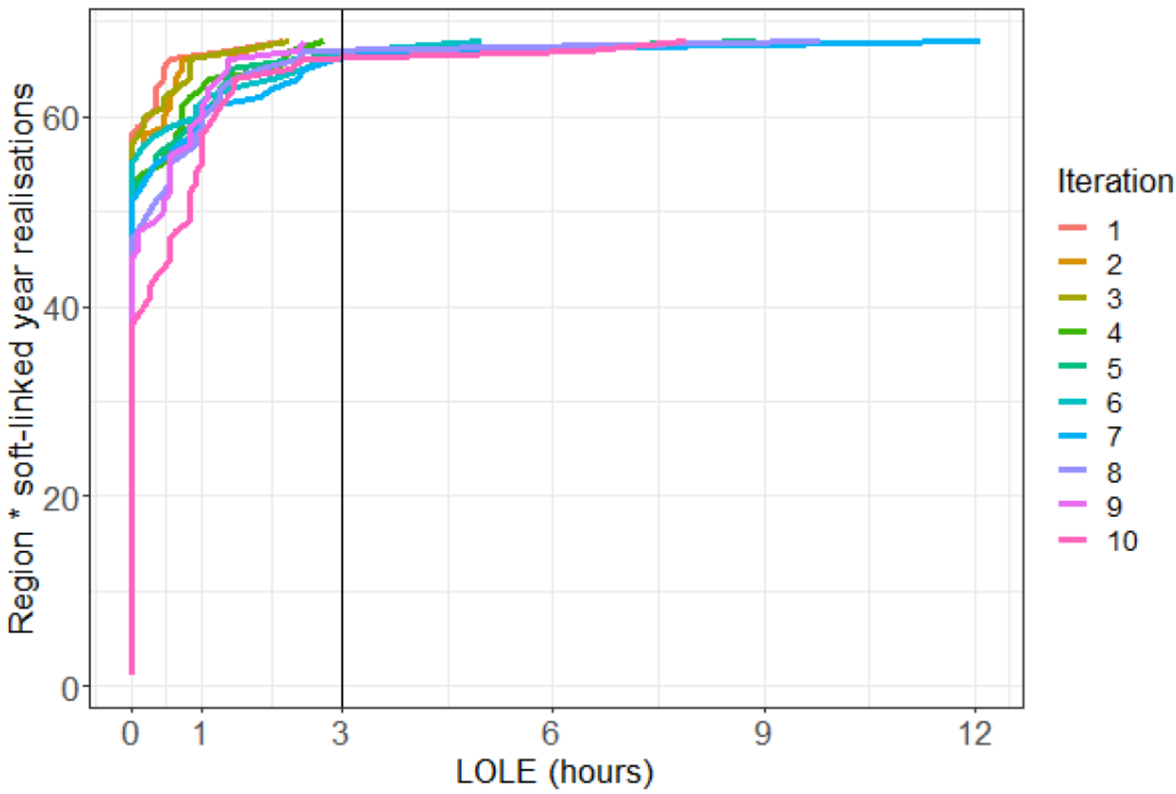


Figure 50: Evolution of LOLE distribution over iterations, in the 17-node system for the whole investment path

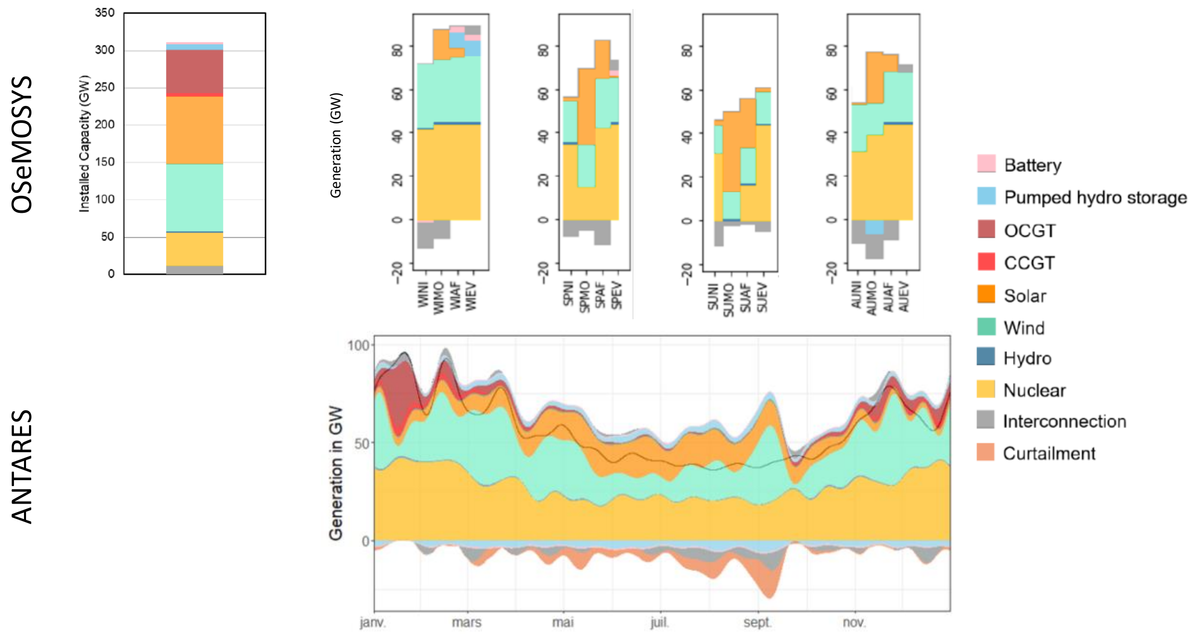
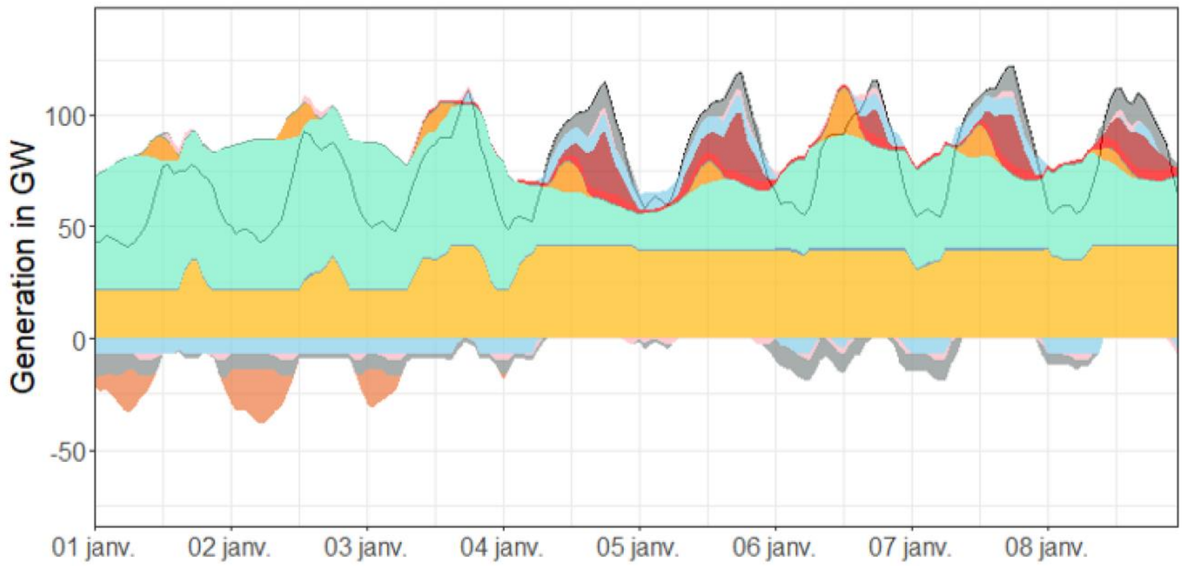


Figure 51: Comparison between dispatch computed by the CExM and the PCM
reserve margin feedback method applied to the 17 node case study - British Isles region
NI: night, MO: morning, AF: afternoon, EV: evening



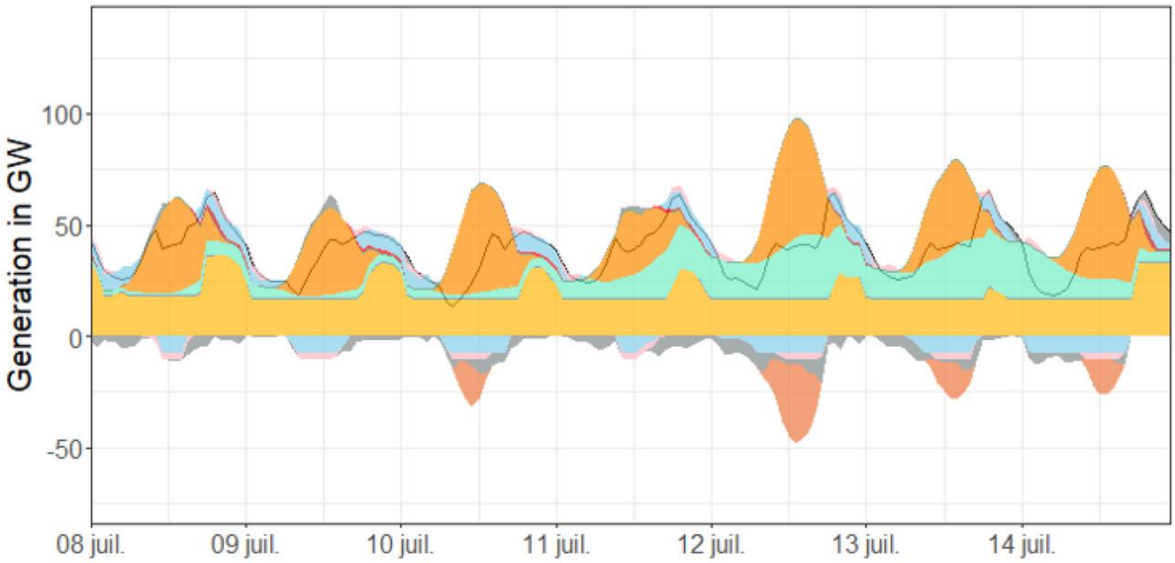


Figure 52: PCM dispatch – zoom on a winter (upper) and summer week (lower) for a given Weather year reserve margin feedback method applied to the 17 node case study - British Isles region

9.4 Automated iterative soft-linking– Flexibility contribution based feedback

By considering only the ability of a technology to contribute to peak net load, capacity credits overlook the value this technology may have for other purposes, especially flexibility. However, the value brought by a flexibility source varies significantly with the considered timescale. Being able to express this information in the soft-linking framework should help us find adequate investment plans at lower TOTEX. This intuition led to the flexibility contribution based feedback technique, to which this section is devoted.

The flexibility contribution based feedback technique follows a similar general structure to that of the CExM Adequacy Constraint used previously:

- A flexibility target is defined for each time scale (annual, weekly and daily), each region and each investment year. The flexibility target must be met by a sum of installed flexibility solution capacity, weighted by a parameter expressing the ability of each solution to provide flexibility for that time scale ("flexibility balancing")[51].
- For each time scale, the ability of each solution to provide flexibility is represented by a flexibility proxy, whose value is determined based on Antares outputs. The design of the flexibility proxies is largely influenced by the flexibility metrics derived in section 5.

The information carried by flexibility proxies should play a role similar to that of capacity credits in the CExM Adequacy Constraint. Therefore, we face the same dilemma: should flexibility proxies express the degree of flexibility of a flexibility source in the current situation, or the degree of flexibility it could provide if needed? The review of flexibility metrics suggested that the information necessary for the second option could be expressed with reasonable ease for timescales ranging from minutes to hours

[51] To simplify the validation of the feedback technique's behaviour, flexibility constraints were treated as a replacement for the CExM Adequacy Constraint.

NB: CExM and flexibility constraints are not intrinsically mutually exclusive: the validity of a solution is exogenously confirmed based on Antares outputs, which in turn modify the CExM parameters for the next iteration. Therefore, the concatenated problem is not necessarily more constrained than the original one.

but would be much more complicated to assess over longer time scales. The first option was therefore selected.

For obvious reasons of consistency in the context of the project, the decision was made to base the flexibility proxies on the FSCD tool which evaluates a flexibility source's modulation relative to the total modulation of the flexibility mix:

- A first necessary adaptation was related to the fact that the CExM requires a single value per timescale. A quantile of each distribution was therefore taken, after having checked that the impact of quantile choice on the soft-linking behaviour was limited.
- The second adaptation worth mentioning was related to the nature of the FSCD. Since it assesses each flexibility source's contribution to total system modulation, a high FSCD value may simply be due to a high installed capacity. In order not to reward technologies only because they were already present in the mix, the contribution to flexibility of each technology must be normalized by its relative capacity share in the system.

Another design decision had to be made regarding the way flexibility targets were to be defined. Neither VRES nor load varies over iterations. Therefore a net load based flexibility target could not be expected to reflect the evolution of the flexibility requirement over iterations. Flexibility targets were hence treated in a similar way to the reserve margin, increased or decreased from one iteration to the next depending on LOLE levels.

This LOLE-dependent update raises the question that loss-of-load may have more to do with one timescale than another. To express this idea, LOLE is first characterised on the annual, weekly and daily timescales, providing a quantitative indication of the timescales that are challenging to manage from an adequacy perspective.

An adjustment budget is then defined based on LOLE levels, just as was done for the reserve margin in Section 9.3. Several adjustment functions, described in Figure 5.11, were implemented, giving different soft-linking behaviours. The adjustment budget derived using these functions can then be shared among the annual, weekly and daily timescales according to the previously defined LOLE characterisation.

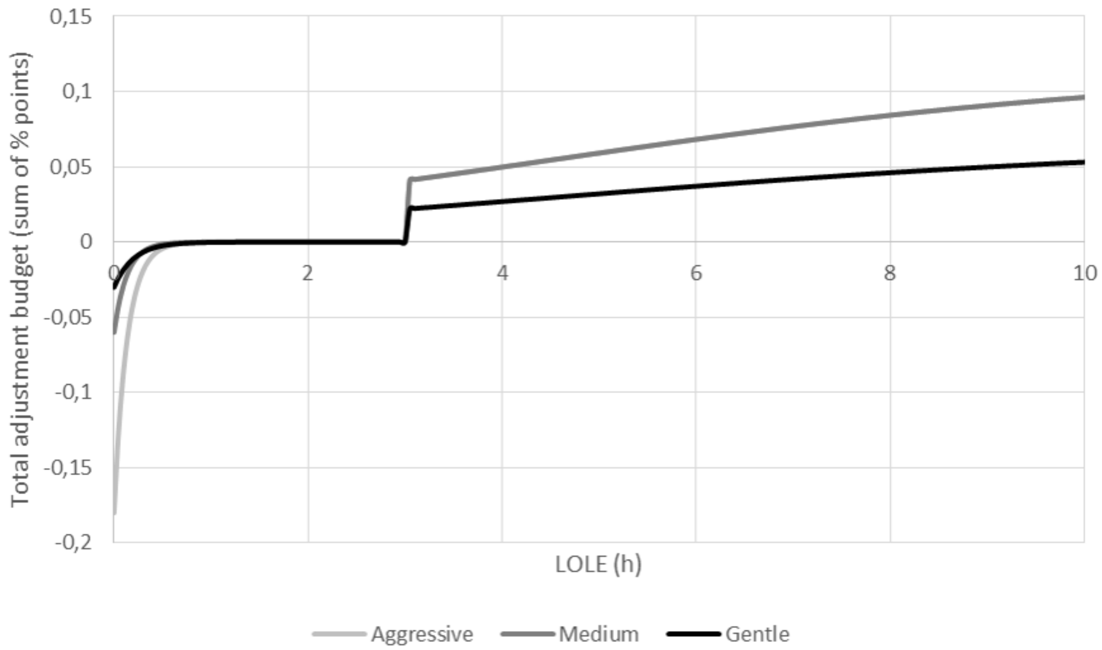


Figure 53: Three examples of flexibility target adjustment budget functions

The values derived for the flexibility proxies can vary significantly from one iteration to the next, and as flexibility targets are also updated to signal under- and over-investment, this can send conflicting signals to the CExM, jeopardizing the process convergence. In order to ensure stability, lower extremes in adjustment budget functions were used to update flexibility targets. For flexibility proxies, inertia was introduced in the updating process.

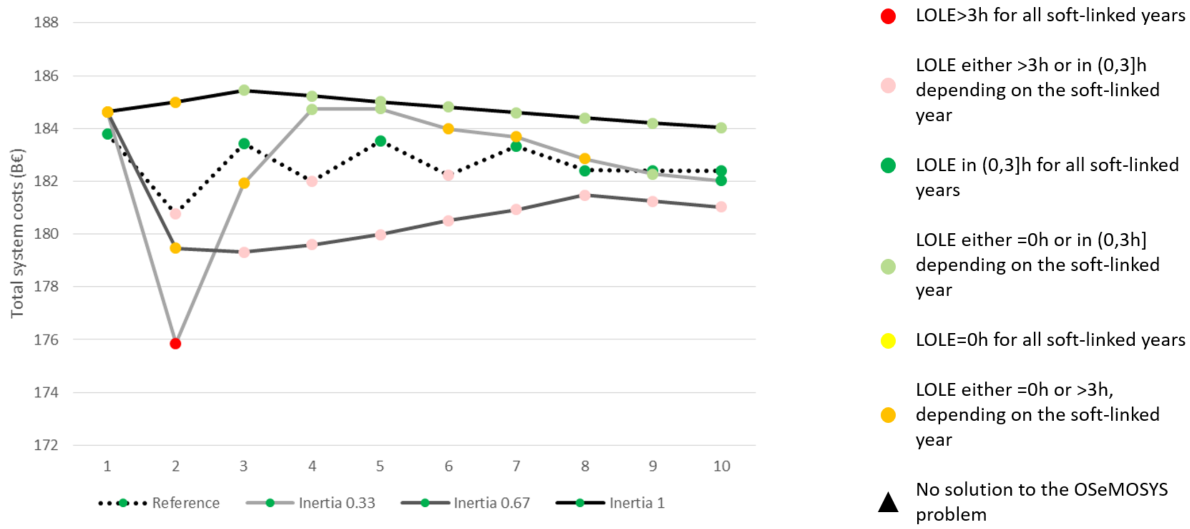


Figure 54: Evolution of total system costs over 10-iteration runs for the single-node German system, using the "gentle" flexibility target adjustment budget function

Thanks to these modelling refinements, the behaviour of the flexibility contribution based feedback technique have been validated on a single-node system. The next crucial observation to make is that it has proposed cheaper adequate investment pathways than the reserve margin based feedback technique, albeit not by much (0.8%). This is true for all three flexibility target adjustment functions.

Due to time constraints, the flexibility contribution based feedback method was not applied to multi-node case studies. As with for the reserve margin based feedback method, we can expect a struggle to ensure our adequacy criterion is respected in every region and every soft-linked year. However, the results would likely be better than for the reserve margin as flexibility contributions can be expected to provide a better indication of the value of interconnection than capacity credits.

9.5 Key findings

Capacity Expansion Models tend to underestimate the value of flexibility and CO2 emissions, a more accurate representation of RES variability has a significant impact on the final investment plan

As Capacity Expansion Models cannot use hourly time series of load and renewable generation due to size and tractability issues, they typically use timeslices designed to capture variations in load and variable renewable energy generation. A typical modelling setup may use 24 timeslices reflecting seasonal, intra-week and intra-day variations, thus offering a limited representation of variability and flexibility needs.
Within WP1, RTE used the open-source modelling framework OSeMOSYS on a dedicated use case to assess the impact of different timeslice structures and number on the model outcome. Results show that improving the representation of solar and wind variability indeed impacts the final installed capacity, but to different degrees depending on the freedom given to the model. If the modeler adopts a greenfield approach and does not limit investment rates in technologies, this impact will be a lot more significant.

Industrial capacity and infrastructure development rate is a critical parameter to be considered in such models

The same study also explored the impact of the political and industrial capacity considerations on the Capacity Expansion Model outcomes, e.g. the ability of industry to develop onshore wind and solar capacity fast enough. Results show that industrial capacity constraints significantly impact the model outcomes. This conclusion highlights two points:

- The extent to which our ability to meet our CO2 emission reduction targets hold on the industries' ability to roll-out new infrastructure fast enough,
- The importance of taking this limiting factor into account in planning

The power grid plays an essential role in enabling the sharing of flexibility provisions between countries and market zones. It is therefore essential to model it in an accurate manner in studies dealing with flexibility.

One of the most distinctive features of GENeSYSMOD compared to OSeMOSYS was the power transmission module developed by TU Berlin. OSMOSE contributed to the back-porting of this module into OSeMOSYS, in order to match the performance of GENeSYS in this respect and to allow the whole OSeMOSYS community to benefit from it.

Coupling Capacity Expansion Models with shorter-term production cost models allows to better account for flexibility in investment plans while complying with security of supply targets

One way to solve the issue of poor flexibility representation in capacity expansion models is to couple them with shorter-term production cost models, obtaining an investment strategy built upon a detailed consideration of operational costs.

RTE pursued this idea by coupling the capacity expansion model OSeMOSYS (see above) with the production cost model AntaresSimulator (open-source tool) through a bi-directional soft linking. The critical point in such a soft linking framework is the way information is fed back from the production cost model to the capacity expansion model to signal under- and over-investment and instruct how the investment pathway should be adjusted in the next iteration.

RTE tested different feedback techniques on a multi-node and a single-node case study, setting up a security-of-supply constraint of LOLE <3 hours region per year (common good practice target in Europe):

- The reference feedback technique therefore fails to fulfil its two roles: it is unable to signal both under- and over-investment to OSeMOSYS. Increased investment does not necessarily reduce LOLE levels, the second role is therefore not fulfilled either.
- The technique based on reserve margin feedback allowed the proposition of long-term investment pathways on a large, multi-node system considering not only investment in generation, but also storage and interconnection.
- The technique based on a flexibility contribution metrics produced better results, i.e. cheaper adequate solutions compliant with security constraint, however limited at the time of writing to a promising proof-of-concept study on a single-node system.

		Uni-directional link		2nd feedback technique		3rd feedback technique	
OSeMOSYS TOTEX (B€)		166,33		182,4		180,88	
Antares LOLE (h/y)	2020	3598,45		3		1,18	
	2050	1963,91		2,45		0,73	
		OSeMOSYS	Antares	OSeMOSYS	Antares	OSeMOSYS	Antares
Emissions (Mt/y)	2020	152,58	123,34	129,73	126,59	145,80	133,14
	2050	1,56	16,50	1,87	53,07	1,39	49,25

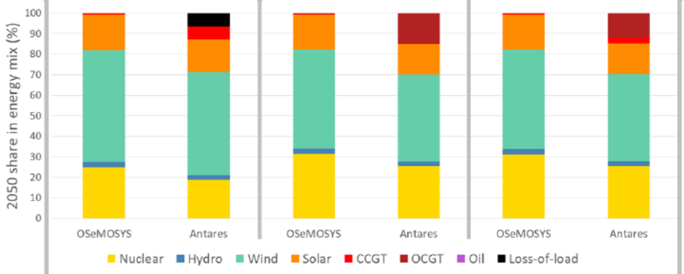


Figure 55 - Comparison of a selection of OSeMOSYS and Antares outputs, for a uni-directional soft link and for the best adequate solutions proposed by the second and third feedback technique

- These results underline just how crucial it is to simulate the detailed operation of a system proposed by a capacity expansion model, as LOLE can reach a few thousand hours per year when no security constraint is set in the model. This can therefore be successfully corrected by the proposed soft-linking techniques, leading to a 10% increase in TOTEX and notable changes to the generation mix.

10 Power-to-gas variant

The objective of this variant of the reference simulation is to evaluate the impact on results of a power system in which all gas power plants would be fuelled with "green" gas produced via electrolysis and methanation within the European power system.

10.1 Initial scenario

Starting from the reference scenario described in section 8, an additional "P2G efficiency" constraint has been included to the model in order to limit the annual power generated by gas power plant to 40% of the annual energy stored via electrolysers[52]. However, since *AntaresSimulator* only performs weekly optimisations, additional information is required to efficiently model seasonal storage patterns. One solution is to use the heuristic which distributes the annual hydro reservoir energy. Another option, more in line with storage management theory, is to use shadow price values. This management method is based on the attribution of a value to the gas, expressed in €/MWh. This value corresponds to the expected future gain from the use of this stock. Thus, at each time step t, the optimisation will choose between:

- Using a part of the energy stock in t, which will be valued on the market at Price(t) if Price(t) is higher than the use value, since the current earning is greater than the future one.
- Conserving gas: if the use value is higher than Price(t).

The use value depends in theory on the day of the year and the level of the reservoir:

- When the storage is almost empty, the remaining energy will be placed only on hours with very high prices,
- When the storage is full, the energy will be used more often, which will result in the energy being used on hours with lower prices.

[52] This constraint is actually applied on average over the 35 years as the size of gas storages enables supply between years.

In the absence of means for calculating use values suited to our problem, the use values were calculated by assuming a linear relationship with the reservoir level. Successive iterations on the directing coefficient and the y-intercept of the line allowed to reach an average final filling level equivalent to the initial filling level. This process does not allow to differentiate the use values according to the day of the year, contrary to the calculations usually used in the energy world which are based on dynamic stochastic optimization.

Results with the P2G efficiency constraint see a reduction in power generation from gas units from 358 to 203 TWh. P2G storage on the other hand slightly increases from 668 to 685 TWh, whilst unsupplied energy jumps to 80 TWh. Spilled energy remains at 184 TWh and it appears to be located in 13 countries which electrolyser's charge factor is already relatively high (see Figure 56). However, even though all the spilled energy could be converted into power via the power-to-gas-to-power cycle, the system would still lack around 6 TWh of energy due to the 60% losses assumed for this process.

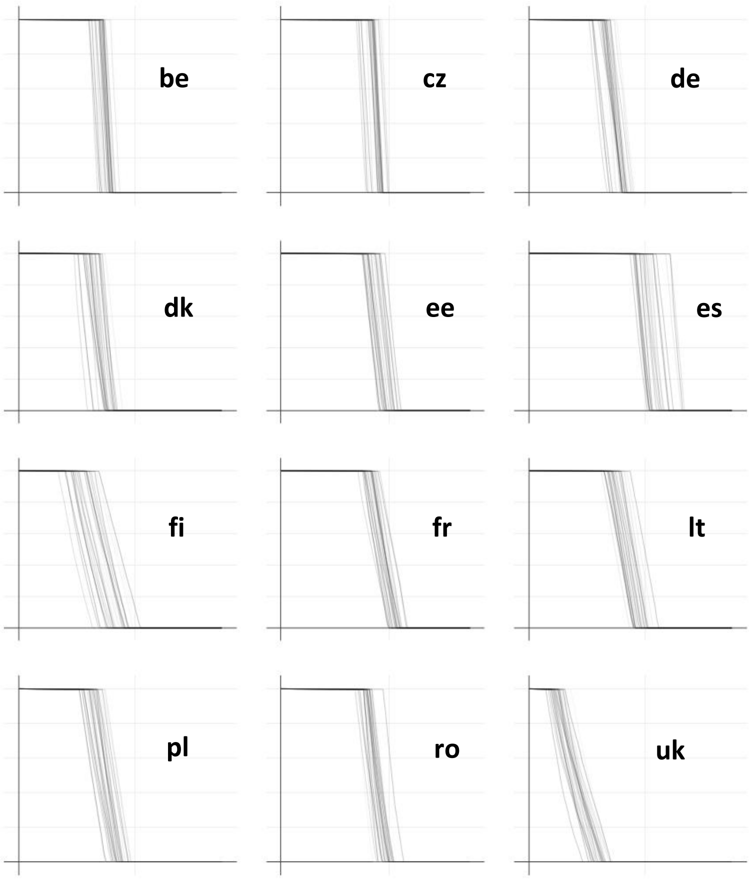


Figure 56: Duration curves of charge factor of electrolysers for all years and some countries

10.2 Investment re-optimization

Considering the level of unsupplied energy, the objective is therefore to rebalance the system. Since LOLE levels in the reference simulation are deemed as acceptable, it is assumed that the thermal fleet does not require adjustments. The missing part is green gas to feed these thermal units. A simultaneous optimisation of electrolyser and VRES capacities would then be the correct approach. Unfortunately, the modelling of the P2G efficient constraint does not work with our tools and a two-step approach is use instead (first investing in power-to-gas units, then in VRES).

The first investment step is meant to capture as much spilled energy as possible by increasing the electrolyser capacities in country exhibiting spilled energy. This is performed using *antaresXpansion*[53], an expansion planning tool built on top of *AntaresSimulator*. Results of the electrolyser capacity expansion are shown on Figure 57. Interestingly, most countries experience an increase in electrolysis capacities, but UK and IT.

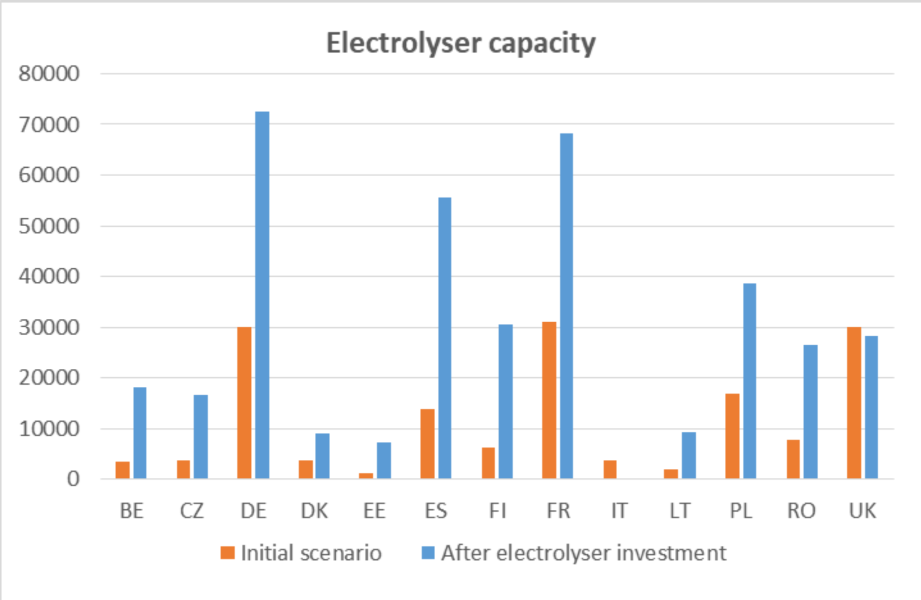


Figure 57: Comparison of electrolyser capacities in reference scenario and after investment (CGA 2050)

Taking these new capacities into account, spillage in simulation results falls from 184 to 35 TWh and P2G storage increases from 684 to 804 TWh (+120). Unsupplied energy is further reduced from 80 to 37 TWh (43), what more or less corresponds to the additional stored energy multiplied by the efficiency constraint (40%).

The second step consists in increasing RES capacities (wind onshore and solar PV) by a constant percentage throughout Europe to reduce the amount of unsupplied energy. It appears that a 5% increase is sufficient from the security of supply point of view. P2G storage greatly increases (+37% compared to the reference simulation) and gas generation retrieves the same level as in the reference simulation. This requires a significant usage of DSM though compared to the reference simulation.

	CGA 2050	
Average annual results	**Reference simulation**	**P2G efficiency variant**
Overall costs (B. Eur)	68	63
Demand (TWh)	4400	4400
Generation wind (TWh)	2798	2918
Generation solar (TWh)	1055	1107
Generation nuclear (TWh)	301	306
Generation gas (TWh)	358	358
Generation from battery (TWh)	138	126
Generation from PSP (TWh)	78	65
Generation from DSM (TWh)	~0	27
P2G storage (TWh)	668	918

[53] https://github.com/rte-antares-rpackage/antaresXpansion

P2G2P observ. ratio[30]	0.7	0.4
Spilled energy (TWh)	184	72
Unsupplied energy (MWh)	142 951	120 848

Table 9: comparison of mix key figures for the reference simulation and the P2G efficiency variant

10.2.1 Effect of sector-coupling on prices

Looking back at marginal prices, the electrolysis step vanishes in this variant as there is no longer a fixed price to arbitrate over. We can however consider that the electrolysis sets the price for 3/4 of the year (see Figure 58, in which, for sake of comparison, curves corresponding to a fixed electrolysis price of 40€ (blue) and 100€ (red) have been added).

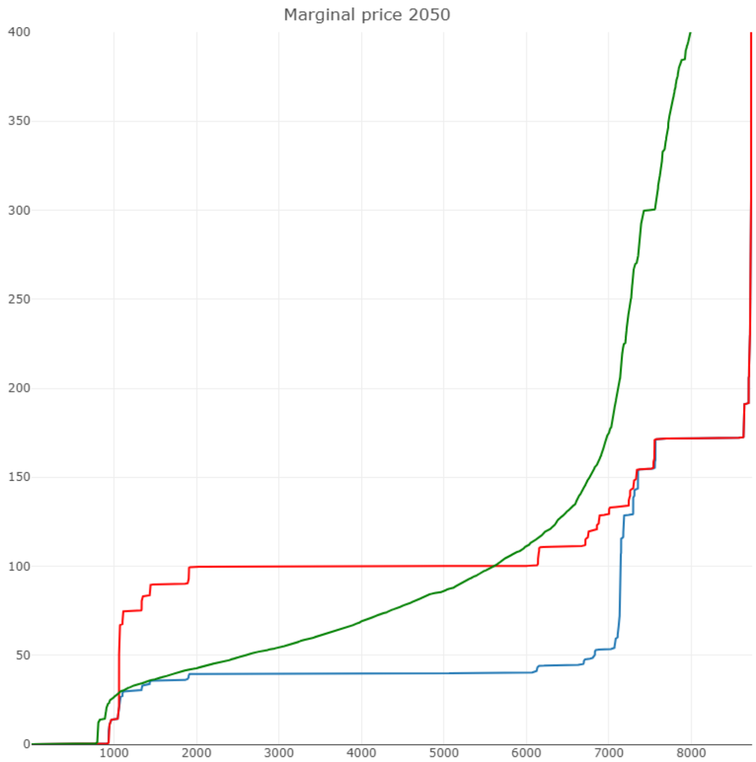


Figure 58: comparison of prices in the variant and the reference simulations

10.3 Key findings

Ensuring that the power system will be able to fully run in 2005 on domestic green gas produced via electrolysis requires to increase both the electrolysis capacity and the VRES installed capacity from the initial scenario. Such a joint optimisation is out of reach of current models, but the 2-step heuristic we performed tend to indicate that it could significantly increase electricity prices during scarcity periods. This would also require inter-annual gas storage capacities. Other means to produce or import green gas do exist, but their impact on prices has not been investigated in this variant.

Note however that in order to efficiently reflect prices, a volume-based modelling of non-electric vectors is insufficient. Vectors (methane, hydrogen or even heat) should be modelled in detail, taking into account the price sensitivity of each to its own demand. This would also require modelling inter-annual storage capacities and alternative means of producing or importing each vector.

11 Uncertainty variant

In order to analyse the impact of reserve procurement on results, a second variant of the reference simulation has been run. As already explained in §8.6.4, it must be recalled that the modelling of reserves in the T1.2 simulations both covers FCR and FRR via a single value. This reserves provision is aimed at coping with uncertainties arising once the unit commitment has been fixed.

11.1 Reserve provisioning adjustment

The first modification performed is to better adapt the flat reserve requirements to the actual RES generation and corresponding deviations. It is indeed unnecessary to provide reserve for solar PV generation during unlit hours. On the other hand, PV generation, which is more distributed than wind by nature, is therefore less observable and consequently more subject to forecast errors. Reserve provisioning corresponding to PV generation shall therefore been greater than wind power one. Keeping the same value for the reserve requirement, it has been redistributed in order to place the reserve related to PV during the sunny hours. This mathematically increases the percentage of the PV installed capacity that correspond to reserve procurement from 3% to 5-6%. At the European level, the reserve requirements move from a constant hourly value of 37 GW in 2030 to a more crenelated shape with lows at 31 GW and highs at 42 GW. In 2050 these values become 62 GW for lows and 109 GW for highs (to compare with the initial 89 GW constant value).

Re-running the reference simulations with these new reserve requirements does not noticeably alter general results. This is likely explained by the overall reserve requirements remaining the same. The two metrics introduced in §8.6.4 have been recomputed to highlight differences. Note that in order to take into account in these metrics that reserve would be provided by neighbouring countries, metrics have been computed at the European levels, assuming transmission capacities will not be limiting.

The first metrics computes the average number of hours for which the reserve requirements cannot be fulfilled by spinning units only (thermal and reservoir). Note that in 2050 this is completed with cut-off of electrolysers which are deemed to be highly flexible.

The second metrics computes the average number of hours for which the reserve requirements cannot be fulfilled considering all flexibility sources available (i.e. adding support from PSP and batteries). Note that these two latter can provide upwards margin via direct generation or cut-off of storage/charging.

These metrics are supplemented by the average annual number of loss of load hours (LOLE) at the European level.

2030	**Reference**	**New reserve**
Metrics1 (h)	144,0	135,4
Metrics1 (%)	2%	2%
Metrics2 (h)	101,8	88,7
Metrics2 (%)	1%	1%
LOLE (h)	5,7	5,7

2050	**Reference**	**New reserve**
Metrics1 (h)	362,3	341,5
Metrics1 (%)	4%	4%
Metrics2 (h)	17,3	14,7
Metrics2 (%)	0,2%	0,2%

LOLE (h)	26,2	30,5

Metrics1 and Metrics2 improve both in 2030 and 2050 with the new reserve provisioning. This observation is somehow expected as the new reserve shapes require more margin when there is usually more generation available and lesser demand. On the other hand, the new reserve requirements increase the LOLE by 15%, which may be explained via a worst optimisation of the thermal or hydro generation plan.

11.2 Assessment of reserve provisioning

The next step of this variant is to evaluate the ability of the provision of reserve to cope with forecast errors which can lead suboptimal decisions in thermal unit commitment. This validation is similar to the analysis performed in WP2 (Deliverable 2.4), though it is more theoretical as it does not include intraday adjustments of both the forecast and the generation. Neither does it model individual behaviours of the different actors (benevolent monopoly optimisation).

In order to perform this validation, it was required to obtain forecast data for load, wind generation and PV generation. This has been performed by adding errors to the actual data using the principle defined by UDE [deliverable 2.1] and used in WP2. Forecast data have been additionally smoothed based on 2020 ENTSOE transparency reference data (see figures below), then rescaled so their RMSE is adjusted to 2030 and 2050 horizons.

Thanks to WP2, a module for generating forecast error times series (for wind and solar generation, and for load) was available. However this module was designed by WP2 for market studies focused on Central Western Europe around 2035. Adaptations were necessary to use it for the 33 countries belonging to the geographical scope of WP1 over the whole 2020-2050 horizon, characterized by a strong increase in the share of VRES in all the considered countries. A methodology was therefore set up, for load, and for onshore-wind and PV generation, to match the general behaviour observed in the realised and day-ahead forecast data published on the ENTSOE transparency web site:

- Recalibration of the error times series to match a target RMSE,
- Recalibration of the temporal autocorrelation.

Next, rules for assessing the evolution of each country's RMSE[54] were derived, especially for countries that currently have little installed VRES capacity, or low thermo-sensitive part in their load. It should be noted that a thorough analysis of ENTSOE data led us to the conclusion that the country-to-country correlation for the day-ahead forecast errors are currently too low to be accounted for in the methodology. For similar reason, inter-variable correlations for a given country (i.e. correlations between load and wind, load and solar and wind and solar forecast errors) were neglected. Details of the building of these forecast time series are available in [appendix B].

Figure 59 to Figure 64 present the graphical comparison of ENTSOE forecast data and WP1 simulated data for 2020 and France, showing how the proposed methodology is able to reproduce the general behaviour of forecast time series.

[54] Root mean square of error, an indicator usually used to measure the accuracy of a forecast.

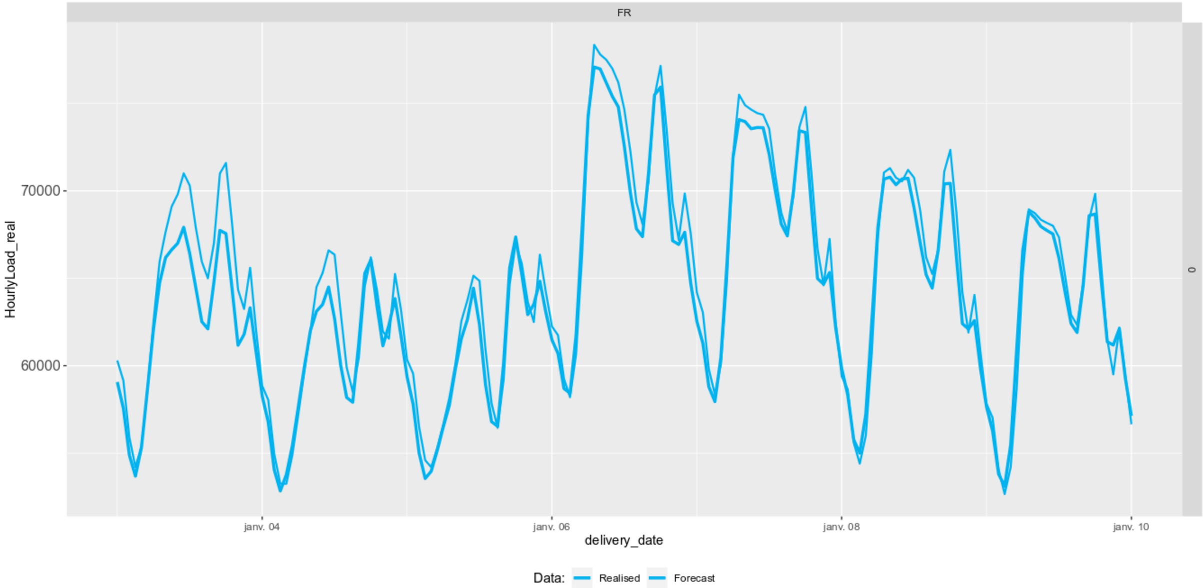


Figure 59: ENTSOE transparency day ahead load forecast time series – France in year 2020 realised data (bold) vs day-ahead forecast (solid)

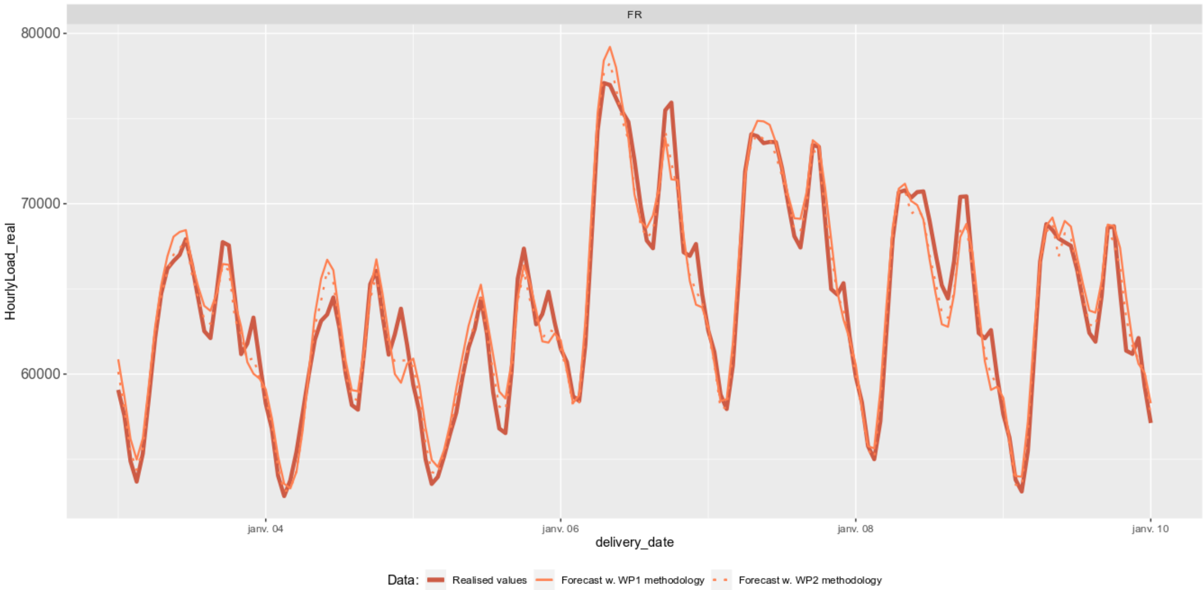


Figure 60: simulation of day ahead load forecast time series – France in year 2020 realised data (bold) vs day-ahead forecast in WP2 (dotted) vs adapted day-ahead forecast in WP1 (solid)

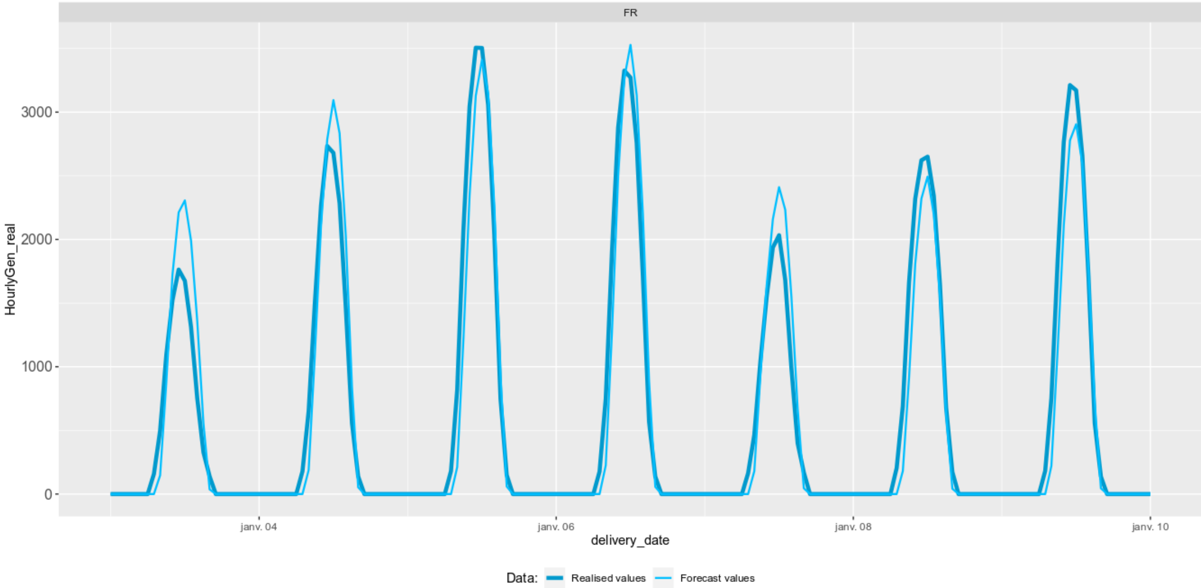


Figure 61: ENTSOE transparency day ahead solar generation forecast time series – France in year 2020 realised data (bold) vs day-ahead forecast (solid)

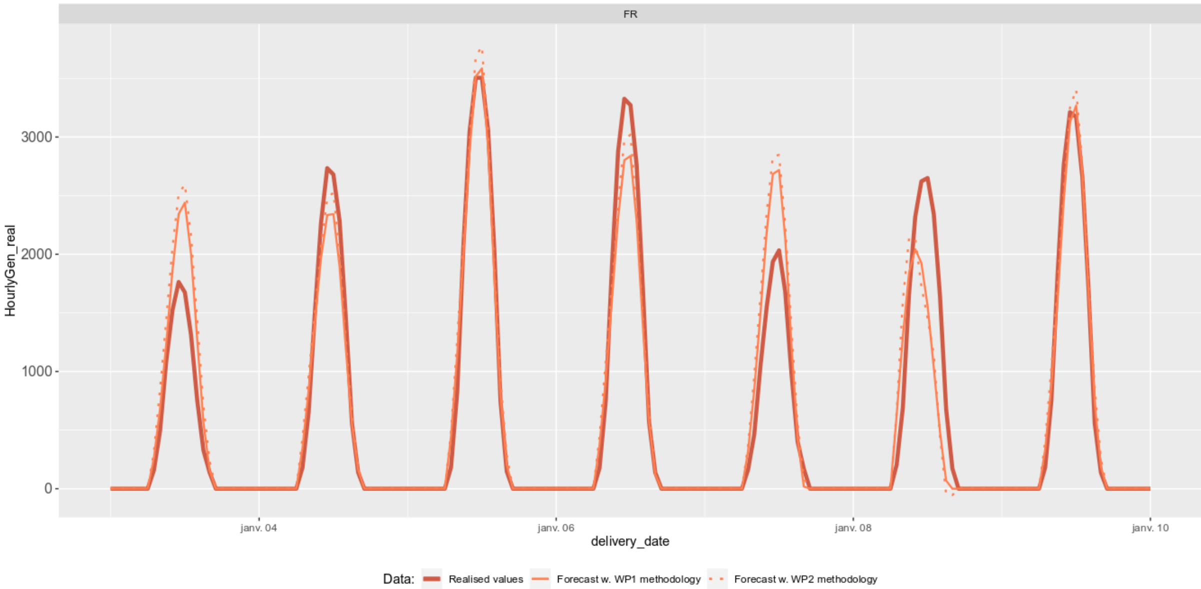


Figure 62: simulation of day ahead solar generation forecast time series – France in year 2020 realised data (bold) vs day-ahead forecast in WP2 (dotted) vs adapted day-ahead forecast in WP1 (solid)

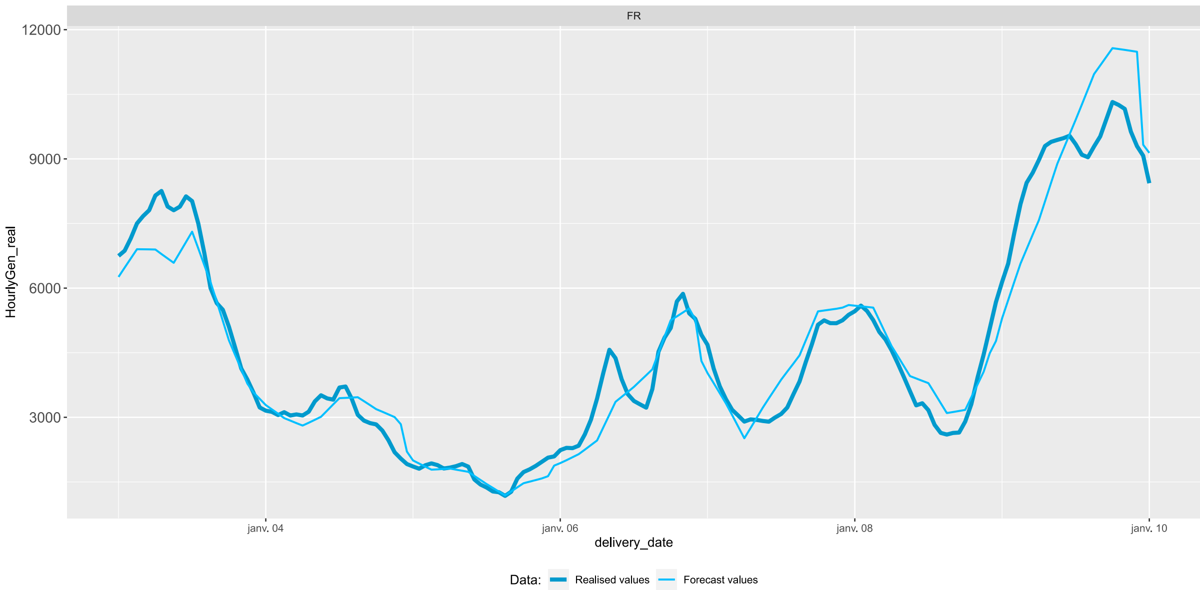


Figure 63: ENTSOE transparency day ahead wind generation forecast time series – France in year 2020 realised data (bold) vs day-ahead forecast (solid)

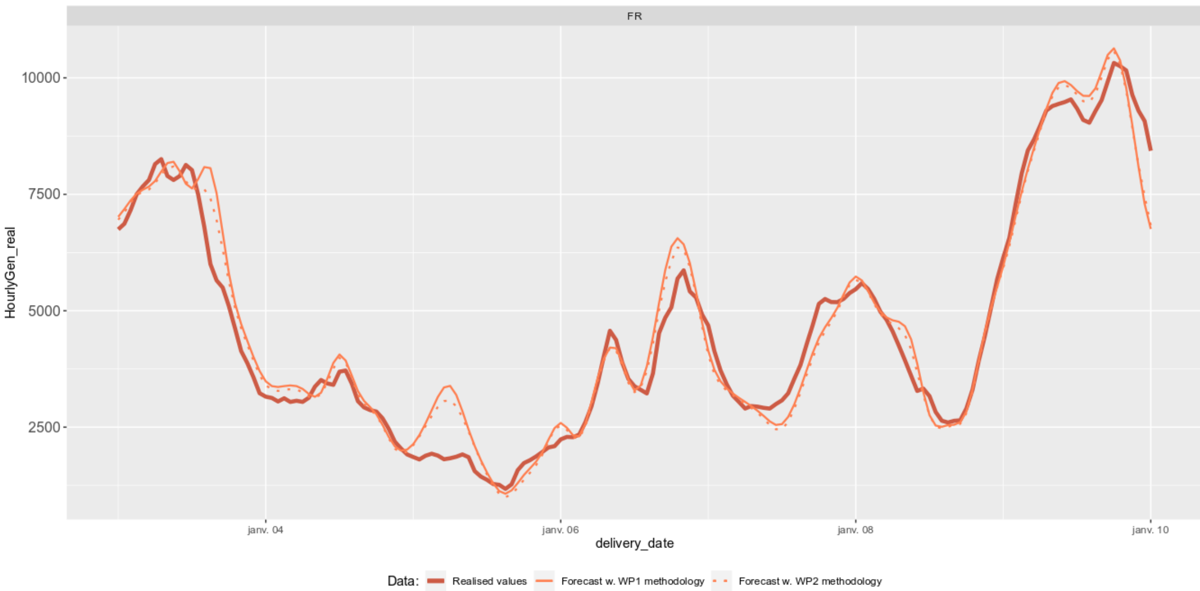


Figure 64: simulation of day ahead wind generation forecast time series – France in year 2020 realised data (bold) vs day-ahead forecast in WP2 (dotted) vs adapted day-ahead forecast in WP1 (solid)

In the following, data previously used in reference simulations are now considered as measured data (i.e. error free), whereas the newly produced forecast data are considered as their estimations. The term of the forecast data requires to be adjusted to the term of the reserve provisioning (e.g. minimum time notice for the modifications of thermal unit generation programs). The only source of publicly available forecast data accessible to adjust our forecast models being day-ahead data, the produced forecast data are equivalent to data available around 6pm the day before (what means from 6 to 30 hours before term). Note also that due to the computational complexity of producing suitable forecast data, only 10 mc-years of forecast data have been computed and used in the following simulations.

As already briefly mentioned in section 8.2, *AntaresSimulator* performs a two-step optimisation. The first step, dubbed “unit-commitment”, aims at identifying which thermal units are required to be running. In this step, demand can be increased by a fictive value (see section 8.6.4). The objective is ideally to start more thermal unit than required in order to increase the upwards margins. The second step consists in the actual optimisation with respect to the additional unit-commitment constraints of the first step results and using the original value for demand.

In this variant, we performed a first *AntaresSimulator* simulation based on the forecast data. This first simulation will therefore be referred to as “forecast”. Its results are used to set for each hour the number of running thermal units in a second simulation, referred to as “real”, as it is using the actual data. The “real” simulation consequently behaves as if its unit commitment step for all thermal generators had been performed on the forecast data and can no longer be changed in real-time operation. This can be seen as a rather conservative approach since thermal generators in 2050 are expected to be highly flexible. But additional constraints (e.g. congestions on the gas grid) could heavily restrict intraday modifications of their generation programs. Results from the “real” simulation are then compared to the results of a reference simulation (dubbed as “new reserve” in the previous section) in which the unit commitment phase had been performed on the actual data. The objective is therefore to assess the impact of uncertainties on results and in particular which reserves means are able to take over thermal generators and whether the provisioned amount of reserve are able to cope with forecast errors.

In 2030, overall results of the “real” simulation are very similar to the “new reserve” ones. There is only one additional hour with unsupplied energy (over the 10 mc-years). This takes place in year 6 in UK. The forecast wind generation is overestimated by 15 GW whereas the demand forecast is underestimated by 5 GW. As a consequence, gas generation is lower by 11 GW in the “real” simulation compared to the “new reserve” one. This lack of generation is partially offset via exchanges (1 GW), PSP (7 GW) and DSM (2 GW). In the end, there remains around 1 GW of ENS.

This single difference between the “real” and the “new reserve” simulations in 2030 tend to validate the reserve provisioning for this time horizon. Note however that the impact of forced generator outages, which is also meant to be supported by the reserve is not evaluated in this simulation since the unit commitment phase already includes planned and forced outages.

Results are more contrasted in 2050 as LOLE at the European level is double (from 24.5 up to 50.5). All new ENS hours being located in 3 countries only (UK, NL, IE). All hours with ENS in the “new reserves” simulation also experience ENS in the “real” simulation with identical or very close values.

Figure 65: ENS increase in 2050 in the “real” simulation (in dark, ENS related to new ENS hours)

All new hours with ENS in the “real” simulation are logically associated with important forecast errors. Fortunately, not all significant forecast errors link to an increase in ENS, as shown on figure below. This figure shows the distribution of differences in the net-load[55] between the “real” and the “forecast”

[55] net-load = demand – RES generation

simulation in UK. This forecast error on net-load, shall be understood as an aggregated view on all forecast errors.

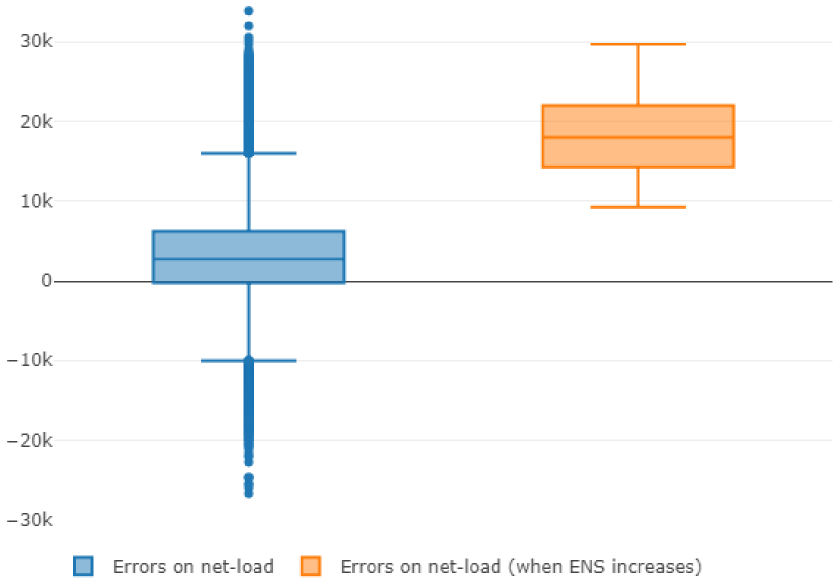


Figure 66: Errors on net-load in UK for all hours and hours which experience an increase in ENS

Errors on the net-load imply a suboptimal generation mix in the "real" simulation compared to the "new reserve" one, where the unit commitment step has been performed on error-free data. The gap induced by forecast errors will be bridged by reserve means. In particular, gas generation is higher on average in the "real" simulation as thermal generators are one of the primary reserve means. However, if the forecast net-load is much lower than the actual value, there may be not be enough thermal generators available in the "real" simulation. This lacking gas generation has then to be replaced by others reserve means. Looking at differences in the generation stack between the "new reserve" and "real" simulation helps to understand which reserve means actually contribute. As shown on the Figure 67, these reserve means are primarily exchanges, electrolysis cut-off or PSP:

- Left hand side: on average, the introduction of forecast errors has no specific impact on the dispatch. Gas generation may decrease or increase as well as exchanges and electrolysis.
- Right hand side : the negative value for gas generation highlights that gas generation was required in the "new reserve" simulation without error forecast but was not started up on time in the simulations with error forecast. New ENS hours occur when imports and electrolysis fail to substitute gas.

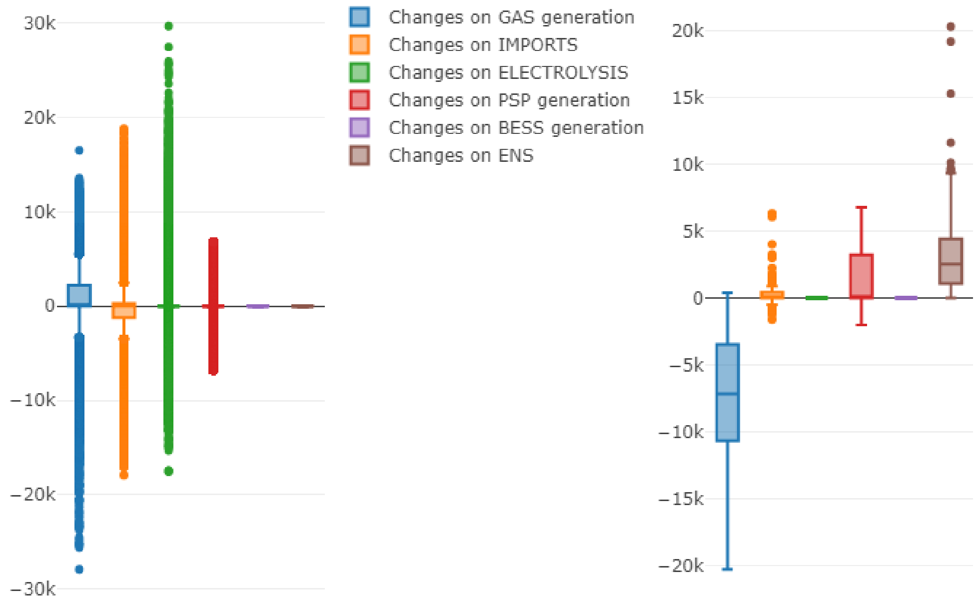


Figure 67: Differences between the "real" and the "new reserve" simulation results when ENS does not change (left) and when ENS increase (right).

It is indeed possible to visualise the impacts on the generation stack for UK. In the blue dotted box on the figure below, the gas generation (red) in the "real" simulation (right) is lower than in the "new reserve" simulation (left). This lack of gas generation is compensated by PSP (cyan), BESS (pink) and ENS (black), because exchanges are already used at the maximum capacity.

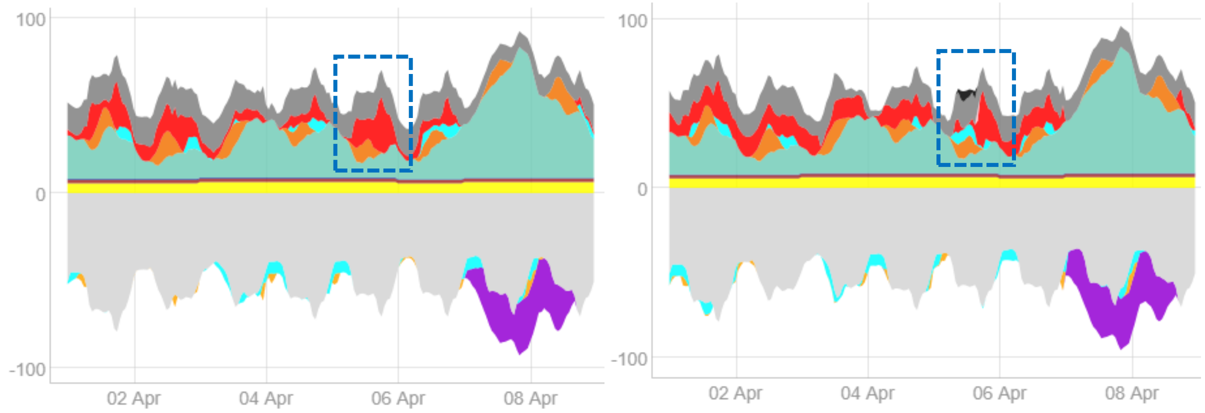


Figure 68: Comparison of generation stacks between the "new reserve" (left) and the "real" (right) simulations (UK, year 1)

In the figure below is further possible to see (in the blue box) the compensation of the gas generation by exchanges (grey) or (in the green box) by the reduction of the electrolysis (purple).

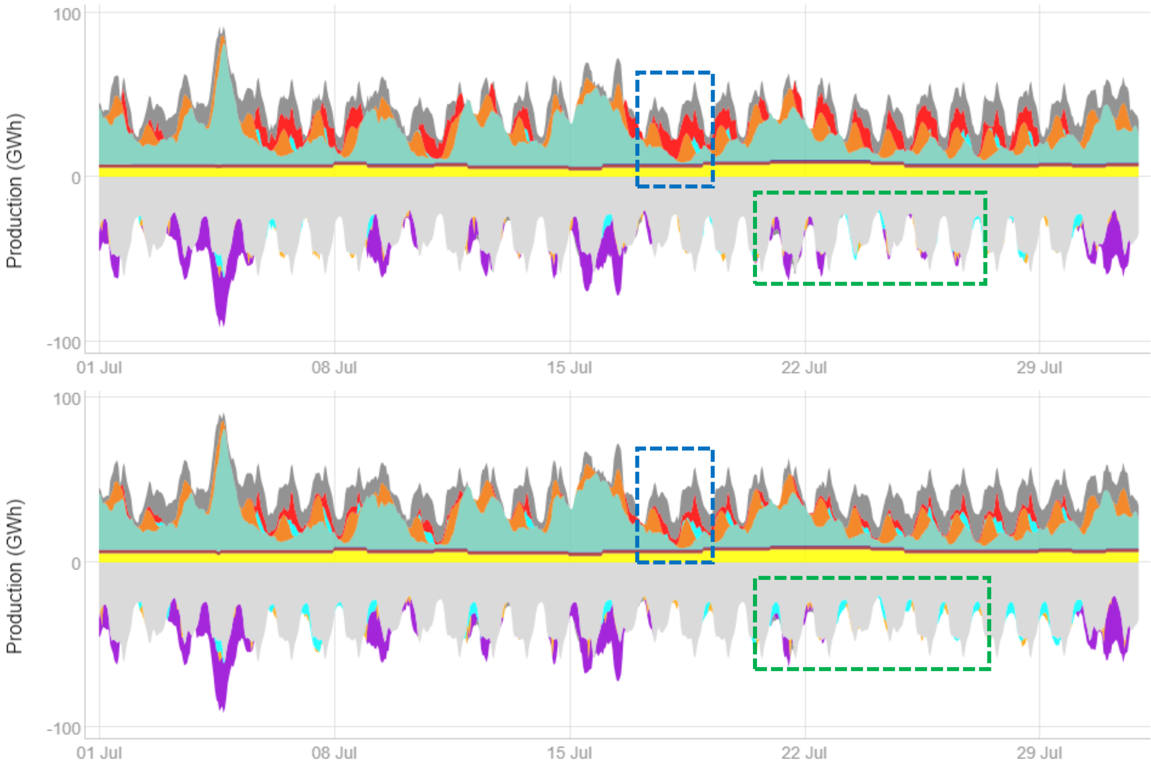


Figure 69: Comparison of generation stacks between the "new reserve" (top) and the "real" (bottom) simulations (UK, year 1)

Flexibility metrics introduced in section **Erreur ! Source du renvoi introuvable.** can also be applied to generation differences between the "real" and the "new reserve" simulation in order to illustrate the modulation pattern of the various reserve providers at all timescales. In the following graphs, the black line corresponds to the difference in gas generation between the two simulations.

Figure 70 below shows these metrics at the European level in 2050. It strengthens the major role of electrolysers and also tells that BESS only play a role at the weekly timescale, whilst curtailment does not appear to play a significant role.

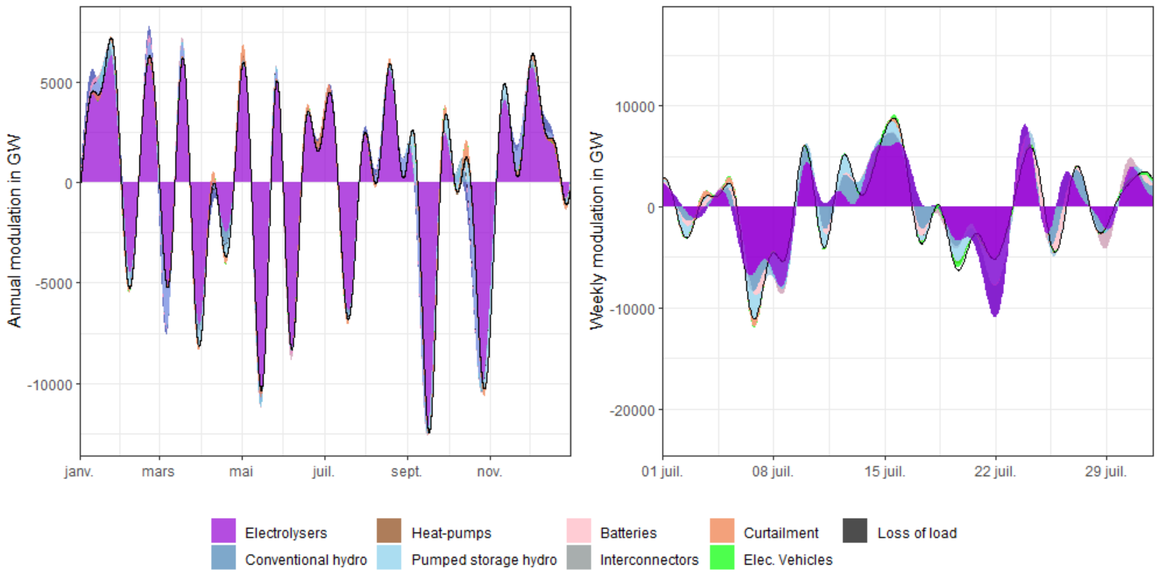


Figure 70: modulation of reserve means used to compensate differences in gas generation between the "real" and the "new reserve" simulations (EU, 2050, year 1)

By comparison, in 2030, the lack of thermal (gas + coal) generation is mainly replaced by hydro and also electrolysers, though their installed capacity is still relatively low.

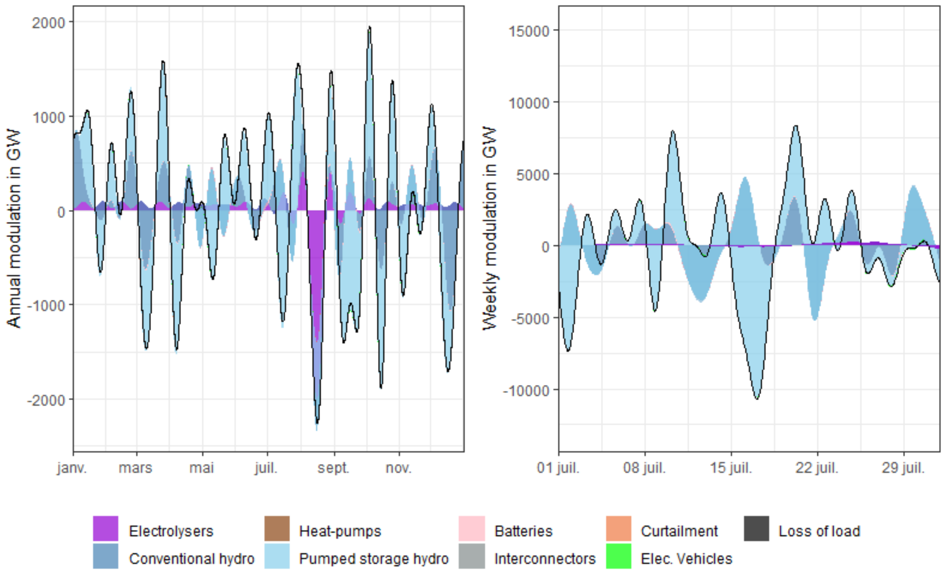


Figure 71: modulation of reserve means used to compensate differences in gas generation between the "real" and the "new reserve" simulations (EU, 2030, year 1)

Figure 72 below shows the flexibility metrics for UK in 2050 to highlight the role played by interconnectors, which cannot be seen at the overall EU level. It is worth noting the complementary role played by smart charging of electric vehicles, which in our simulations can be optimised at the daily basis by the tool.

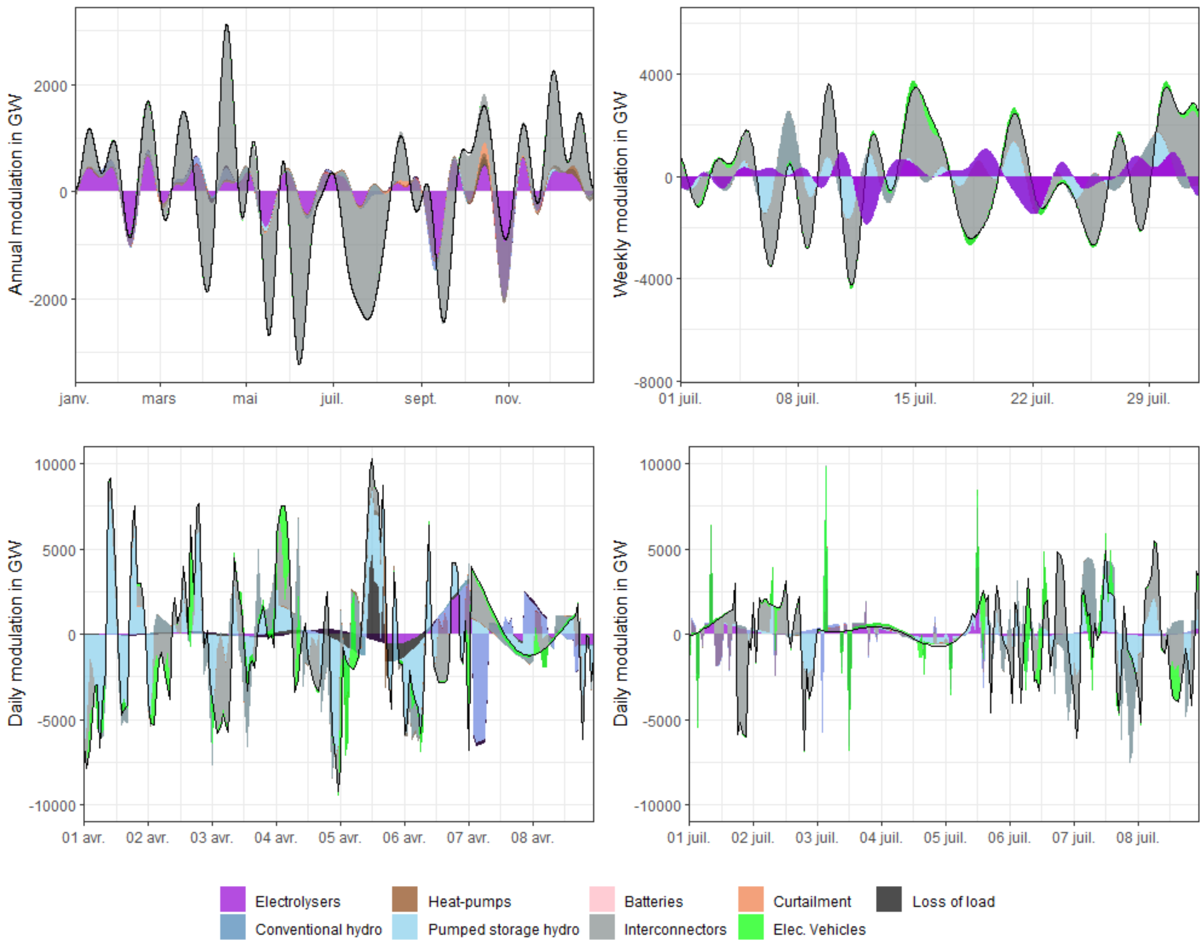


Figure 72 : modulation of reserve means used to compensate differences in gas generation between the "real" and the "new reserve" simulations (UK, year 1)

The last part of this variant is meant to investigate the actual reserve provisioning that would maintain LOLE in the "real" simulation at the same level as in the "new reserve" simulation. This has been achieved by iteratively increasing the reserve requirements in UK, IE and NL only from 3% to 10% of the wind installed capacities (other parameters remaining constant). The gain in LOLE however does not linearly grow with the reserve percentage of shown on Figure 73 below.

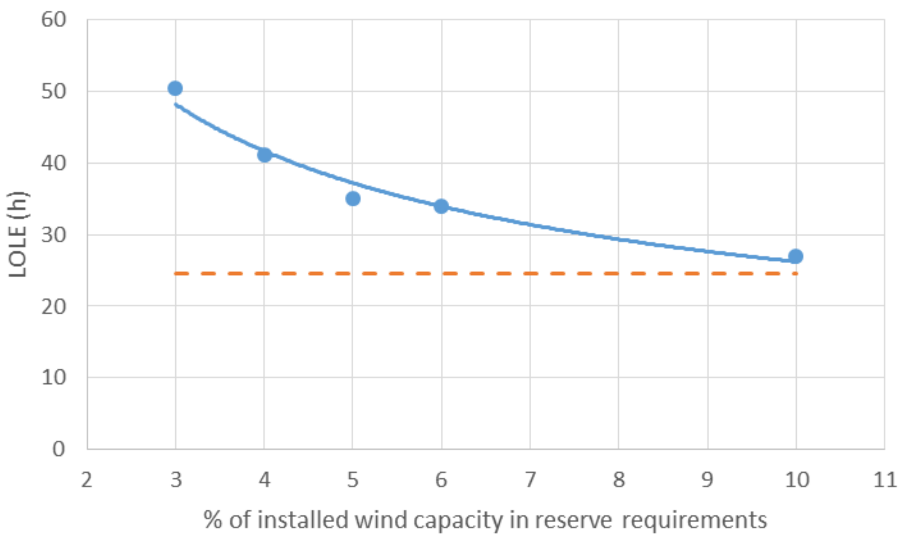


Figure 73: decrease of LOLE in the "real" simulation with increase of the wind capacity share in reserve requirements

11.3 Summary of key findings

Results presented in this variant are obviously highly dependent on the underlying hypothesis of the CGA 2050 scenario. In particular an important share of highly flexible electrolysers and substantial exchange capacities. They may nevertheless give a general signal. The simulation modelling assumed a co-optimisation of energy and reserve and an efficient use of interconnection for reserve procurement, which is not the case in current European market design. Hence, the lack of correlation in forecast errors between countries favours mutual cooperation. If the global forecast error level were to decrease at the European scale, thanks to improved cooperation between countries, reserves requirements would decrease accordingly, but maybe not as much as individual error reduction rates due to an increase in error correlation at the global scale.

More generally grid can be seen as a mean to share VRES but also flexibility sources. So grid is a flexibility provider in itself, but also a lever for other flexibilities. Conversely, constraints applied to enforce more local generation could deter grid expansion, and require more local flexibility sources. Grid value is a combination of a mere geographical smoothing effect and a more complex flexibility enabler.

12 Appendixes list

The appendices are provided as separated documents:

- Appendix A: AntaresSimulator modelling description
- Appendix B: Dataset and weather dependent variable generation
- Appendix C: Environmental impact indicators - proof-of-concept studies

13 References

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