CONTRIBUTION OF THE FRENCH ELECTRICITY SECTOR TO THE PUBLIC CONSULTATION ON A NEW ENERGY MARKET DESIGN

About the UFE:

The UFE (Union Française de l'Électricité) is the professional association of the French electricity sector. It represents the employers in the electricity and gas industry sector, as well as the interests of its members, producers, suppliers, and transmission and distribution system operators, in matters economic, industrial or social. The UFE is a member of MEDEF (the French employers' association) and of EURELECTRIC, the European association of the electricity industry. The UFE brings together, directly or indirectly, over 500 companies, gathering in France about 150,000 people, and generating over €40 billion of benefits per year. The following are members of the UFE: BKW, CNR, Direct Energie, EDF, ENEL France, E.ON, ERDF, France Hydro-Electricité, GDF SUEZ, RTE, SHEM-GDFSUEZ, Syndicate for Renewable energies (SER), UNELEG. The UFE is a not-for-profit association under French law.

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KEY MESSAGES

Ongoing ambitious energy transitions in most of European Member States are questioning the current electricity market design. UFE welcomes this consultation on "a new Energy Market Design" as an opportunity to lead the way into a secure, affordable and climate-friendly electricity in a forward-looking and global approach.

UFE acknowledges that:

- **A fully integrated and well-functioning Internal Energy Market is one of main instruments to achieve the objective of competitiveness for energy consumers.** Today, the current market design unquestionably fulfils fundamental roles. First, it effectively provides for short-term optimization of the balance between supply and demand. Second, it shows the value of energy in the short term at every moment. By fostering competition between market parties and between technologies, it ensures that consumer's needs are satisfied in the short term in the most economical way. Recently, a lot of efforts have been dedicated to improve its efficiency. These efforts have been rewarded by significant progress among which the go live of the flow based method is certainly the most important. French actors (NRA, markets parties, TSO) have played a key role in these achievements. In years to come, improvements can still be brought: UFE welcomes and supports all evolutions, based on a positive cost-benefit analysis, that could make the energy market more efficient.
  However, further market integration and improvement of the functioning of the energy market will not be sufficient to achieve, on a cost-efficient way, the main European Energy Union's objectives: "affordable energy" target, "secure energy" target and "climate-friendly energy" target.

Thus, to this end, UFE recommends to:

- **Ensure a cost-efficient decarbonation of European economies, through a reformed and reinforced European Trading Scheme (ETS):**

  - **A reformed EU ETS is the central tool to reveal a unique carbon price signal at European level.** It is market based, technology neutral, and enables a cost-efficient CO_2 emission reduction.

  - In the long term, **the EU ETS carbon price has to be the main driver for investments enabling a transition to a low-carbon economy**, including investments in renewable energy sources. **To this end, in the target model, RES investments should only be triggered by market signals, without any support.** However, support schemes may temporarily be maintained in the short and medium term. In that case, they have to guarantee the RES integration in the market and in the system. The State Aid guidelines for energy and environment over the period 2014-2020 constitute a solid basis for a gradual harmonization of support schemes, at a EU level.

- **Secure ongoing energy transitions in Europe and ensure security of electricity supply, on a cost-efficient way, by complementing the energy market:**

  - The energy only market (EOM) fulfills the essential role of optimizing the short-term use of assets at the European level. But with an Internal Energy market relying exclusively on an EOM, member States have no guarantee that the level of security of supply that they are targeting will be met in the medium run. A recent study (see Annex) performed by UFE and BDEW illustrates this phenomenon: if France were to rely, in 2030, exclusively on an uncapped energy only market, the level of security of supply would be 50% lower than the one targeted by French authorities, resulting in significant economic losses and putting at risk the electricity supply.

  - **Capacity mechanisms secure current European energy transitions by providing incentives for essential investments in generation and demand response capacities and fostering innovation.** Moreover, contrary to a common belief, adding a well-designed[1] capacity mechanism leads to cost reductions in the long term.

  - **Coordinated approaches at a regional level should be promoted:**
    - All Members states would benefit greatly from discussing the methods they use to assess security of supply, in order to converge towards a harmonized method. A high level of coordination between Member States at least at regional level is crucial to ensure a coherent analysis of cross-border exchanges contribution when assessing the capacity needs for Europe and for the calculation of the necessary capacity to be procured to ensure adequacy. It would also be a positive evolution if all European countries were to define security of supply by using volume based security of supply criteria.
    - UFE welcomes the will of the European Commission to define reference models for capacity mechanisms, and recalls the importance of a competitive and sustainable approach, focused on cost-efficiency.

- **Incentivize efficient behaviors of consumers through relevant signals:**

  - **Simultaneously, the signals sent to end users through market prices, regulated tariffs, or taxes must be improved**, to incentivize efficient behaviors: an energy and/or capacity price reflecting the scarcity and tension on the system, can be used as an incentive to reduce peak day energy consumption.

[1] Technology neutral, market based, and market wide

Energy Union Summer Package:

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« A NEW ENERGY MARKET DESIGN »

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1. DELIVERING THE NEW ELECTRICITY MARKET FOR THE EUROPEAN UNION

Q1) *Would prices which reflect actual scarcity (in terms of time and location) be an important ingredient to the future market design? Would this also include the need for prices to reflect scarcity of available transmission capacity?*

UFE believes that prices on electricity markets should only be determined by the matching between aggregated supply and demand curves. Especially, in situation of stress, prices should be able to reflect the actual level of scarcity of the power system. UFE shares the analysis of the European Commission that current restrictions impacting the price formation process in short term energy markets may create market distortions.

Nevertheless, UFE identifies two main restrictions preventing the occurrence of scarcity prices: (i) existing limits that are de facto capping prices in short term energy markets, and (ii) doubts regarding the social and political acceptability of price spikes. To remove these two restrictions, serious difficulties will have to be overcome. For the UFE, the question whether this is feasible or not is still uncertain.

- ⇨ Existing limits on day ahead and intraday markets are preventing market clearing at a price above 3000€/MWh for D-1 and 10,000€/MWh for intraday. These technical limits are shared by many countries. As national markets are now coupled, removing these technical limits will most probably require an intergovernmental agreement. One could therefore expect the process to be rather long and complex, since some countries may remain convinced by the need of such technical limits.
- ⇨ Uncertainty regarding social and political acceptability. Even if the aforementioned difficulty has been successfully managed, free pricing will also require trust from market parties in the fact that public authorities will not intervene during scarcity periods which is note ensured. One must bear in mind that all previous price spikes have given rise to public concerns.

European Member States should not only rely on the future role of scarcity prices to ensure security of supply. Indeed, there is no indubitable evidence that an energy only market will ensure that national security of supply criteria will be met. As a matter of fact, a recent study conjointly performed by the UFE and the BDEW comes to the opposite conclusion (see annexed report; Annex 2): free pricing is not sufficient to ensure a secure electricity supply (see answer to question 2).

Q2) *Which challenges and opportunities could arise from prices which reflect actual scarcity? How can the challenges be addressed? Could these prices make capacity mechanisms redundant?*

A- Challenges and opportunities of steps towards free pricing

UFE supports the removal of technical limits that are currently capping short term energy markets. However, serious challenges associated with such an evolution should be anticipated.

First, volatile and potentially high scarcity prices could penalize small market actors, this type of actors being more impacted by imbalance settlements. For instance, if a small producer has taken a commitment to produce during a scarcity period but that he fails to do so because of an unplanned outage, this incident may have dire economic consequences on its P&L.

Second, a direct exposure of final customers, industrial, SMEs and domestic customers to scarcity prices should be carefully examined. Of course, this exposure is an opportunity for developing direct participation of some consumers to electricity markets, by critical peak pricing or through demand response explicit mechanism.
Nevertheless, being exposed to scarcity prices is a risk that is not easily manageable by all type of final customers especially for most SMEs or domestic customers, for which this risk is usually managed by their suppliers. That is why they should have to be able to choose within price lists contracts with or without exposure to scarcity prices.

B- <u>Scarcity prices and capacity mechanisms</u>

Although benefic, removing technical limits on energy markets will not be sufficient: with an electricity market framework relying exclusively on an EOM, Member States have no guarantee that the level of security of supply that they are targeting will be met in the medium run.
This is true not only for France, but also for many other EU Member States. Spain and Italy decided to implement a capacity payment, and from last year, the United Kingdom has introduced a capacity auction. At the same time, Germany put in place an administrative control for plant closures, which considers a capacity payment for some units (a mechanism that will evolve very likely towards a strategic reserve). Finally, Belgium is considering the opportunity to evolve the current strategic reserve scheme into a more comprehensive capacity mechanism. All these mechanisms share a similar objective: ensuring security of supply. However, they do not rely on the same key principles. Some mechanisms rely on a design consistent with principles exposed in European State Aid Guidelines while the others do not.

A recent study performed by UFE and BDEW with Artelys illustrates the sector's concerns about the EOM capability to ensure the required level of security of supply in the medium run (see annexed report). The study concludes that if France were to rely, in 2030, exclusively on an uncapped energy only market, security of supply will not be ensured since the LOLE would be 50% higher than the one targeted by French public authorities (LOLE of 3 hours), resulting in significant economic losses. The limits of the EOM to ensure the required level of electricity supply in the medium run can be explained by multiple elements:

- ⇨ **Risk is inadequately dealt within in EOM.** This is mainly due to the fact that revenues of market actors are highly connected to weather conditions, because of:
    - o <u>The thermal sensitivity of national electrical systems</u>: In France for instance, during

winter, a drop of 1°C results in an increase of electrical demand up to 2,400MW. Peak demand can vary up to 20 GW from one year to another.

- The growing part of RES in the electrical mix: depending on the actual production of RES during peak period, the level of net demand, and thus the level of electricity price, can differ importantly.

⇨ **As a consequence, to find sufficient incentives to invest in an energy-only market framework, market parties shall rely on a few very critical years with very high scarcity prices**. But the question of whether these years will actually materialize, or if these prices would be accepted by consumers, is critical. The UFE/BDEW study on security of supply shows that this uncertainty could result in significant underinvestment and in a failure of the market to ensure security of supply. Besides, in an EOM framework, baseload assets will be favored compared to peakload assets and DR, because they would be seen as less risky investments by market parties. Thus, the resulting power mix will not be optimal, neither in terms of overall capacity, nor regarding its composition.

⇨ **A CM –provided it has been well designed[2]- acts as insurance mechanism. It ensures security of supply by imposing capacity procurement and by providing a greater visibility on long term revenues because it reduces uncertainty by smoothing revenues.**

Besides, UFE is convinced that other elements that haven't been taken into account in the UFE-BDEW study will reinforce these results:

⇨ If any scarcity periods were to occur in a near future, market parties will likely have to face strong political pressures to maintain energy prices artificially low during such periods.

⇨ Second, as other industrial sectors, the electricity sector is subject to boom and bust investments cycles, led by specific dynamics: investments are "triggered" (usually by several stakeholders at once) beyond a certain level of projected profitability, and retirement decisions are made below a loss threshold, here again by various stakeholders at once. Real-life power systems thus oscillate around the long-term equilibrium. So, in a pure and well-functioning energy only market, decision making will be amplified and concentrated.

⇨ The risk dimension could be even more impacting. Considering that many decisions regarding national energy policy are taken at a high political level (such as nuclear phase-out or RES development rhythm), the political risk may be actually even greater than weather uncertainty. As a consequence, the underinvestment phenomenon expected in an EOM would be even higer than the one underlined by the results of the UFE/BDEW study.

It is fundamental to stress that scarcity prices will not make capacity mechanism redundant: a capacity scheme remains necessary to ensure that the level of security of supply targeted by public authorities will be met.

Q3) *Progress in aligning the fragmented balancing markets remains slow; should the EU try to accelerate the process, if need be through legal measures?*

[2] Technology neutral, market-based and capacity wide

UFE is in favor of the gradual alignment of balancing markets in Europe as a necessary lever to maximize the efficiency in the management of the European electricity system. Nevertheless, it is crucial to ensure that further integration of balancing markets is not implemented at all costs.

Currently, national balancing market designs differ across Europe and are operated differently according to local specificities. This differentiation justifies a particular attention to the costs and benefits related to each market integration and harmonization solution being included in the Network Code.

Therefore, a solid and robust cost-benefit analysis (CBA) should be conducted with the aim to identify a clear case for a pan-European harmonization of some aspects of balancing markets while a sufficient implementation period should be allowed when harmonization turns out to be necessary. The CBA should consider the result at the European level – and not on a country by country basis.

Depending on the subject studied, the consequence may differ greatly from one country to the other. However, the overall result is the one that should matter. The study should also consider precisely the consequences, positive and negative (i.e. distribution of costs and benefits), for each of the countries. Finally, UFE believes that the development of the Electricity Balancing Network Code and the implementation of the regional pilot projects, when leading to a step forward towards the target model, are the right instruments to progressively align European balancing markets. Before the entry into force of the Network Code Electricity Balancing and its full implementation, any additional legal intervention seems untimely and weakly justified.

Q4) *What can be done to provide for the smooth implementation of the agreed EU wide intraday platform?*

UFE considers that the integration of intraday markets is necessary to make the most cost-efficient use of the European power system, and supports therefore the deployment of the cross-border intraday (XBID) platform

Although the flow-based (FB) market coupling implementation has strongly improved the market integration in the day ahead (DA) market timeframe, part of the gain in social welfare gets lost in the intraday market timeframe. A general analysis shows that the market coupling algorithm finds an optimal solution that is maximising the flows in the day ahead, but no cross-border capacity is left anymore for intraday trading in both directions of the border. As a consequence, the possible cross-border exchanges during the intraday are blocked for about one fifth of the time.

As interim short term solution, UFE requests that ACER, NRAs and the Commission require TSOs to recalculate FB domain after DA clearing and to review the possible intraday domain based on this outcome.

For the further implementation of intraday trading, we would also strongly recommend to clarify further the target model:

- How/whether auctions should be integrated in the intraday trading target model?
- How FB ID should be eventually developed?

To ensure for a smooth transition, all TSOs, regulators and PXs should work on local implementation plans in parallel to the ongoing XBID solution development. For practical reasons, these plans should be designed on a regional basis. In the meantime, current solutions proved to be efficient in allowing intraday cross border exchanges such as the mixed implicit-explicit allocation of available transfer capacity on the German-Swiss-French platform should be maintained until liquidity in those markets will be sufficient to value complex block offers, which depends on the economic value of intraday exchanges. Like already in place on FR/GE and FR/CH borders.

Q5) *Are long-term contracts between generators and consumers required to provide investment certainty for new generation capacity? What barriers, if any, prevent such long-term hedging products from emerging? Is there any role for the public sector in enabling markets for long term contracts?*

UFE considers that long term contracts do have a role to play in electricity markets in three different ways:

- Co-investment projects where risks are shared between producers and users, with prices based on long-term economics and costs. They can be efficient solutions to give visibility for large consumers and to support investment to different technologies with high capital intensity

- Co-investment projects between producers to foster competition and create opportunities for market players to diversify their generation investment between complementary technologies and helps tend towards the optimal technology mix.

- Decarbonizing the European electricity industry while maintaining security of supply, will require significant investment in both clean generation technologies and fossil-fuel peak equipment. But electricity markets is based on marginal cost pricing, a market paradigm which worked well to induce competition between technologies with significant variables costs, such as gas fired plants. It does not help to secure investment in large CAPEX equipment as they are in the whole set of low carbon technologies. Long-term contracts could be a way to maintain incentives to invest in all the technology mix by helping risk management and risk sharing. This converges with the objectives of European and national policies combining supply security and reduction of carbon emissions.

- Moreover legislation should allow operators and consumers to conclude different kinds of long term contract (e.g contract for difference, several counterpart, public or private)

Q6) To what extent do you think that the divergence of taxes and charges10 levied on electricity in different Member States creates distortions in terms of directing investments efficiently or hamper the free flow of energy?

A- <u>Distortions to drive efficient investments</u>

Electricity bills are no longer driven primarily by the cost to generate and transport the electricity – but by the taxes and levies which are added on top. In this context, it is crucial to ensure that taxes do not distort competition between different energy sources, and that they reflect and drive cost-efficiently the investments needs. However, and as taxes are mainly driven by national policies, UFE underlines that a single taxation rate at a European Level would be inappropriate.

B- Distortions on the functioning of the IEM

Power plants are located in a regionally interconnected electricity markets, but are subject to different national taxes. This will worsen with the further integration of the European electricity markets (both energy and capacity). The more interconnected the markets are (both physically and operationally), the more sensitive they become to distortions in cost structure and pricing. As the further integration of electricity markets is a key European objective, the removal of these distortions should be a parallel priority.

Q7) *What needs to be done to allow investment in renewables to be increasingly driven by market signals?*

First of all, **contrary to the current situation, in the long term, the carbon price signal should be the main driver for investments** enabling a transition to a low-carbon economy, including investments in renewable energy sources, without any support. To be effective, the EU ETS should provide an adequate level of incentive to invest in low or non-carbon assets; it should also provide this incentive in the long term, because investments in the electricity sector, notably in renewables, are highly capital intensive and arise from long-term choices.

However, in the short and medium term, as carbon price cannot ensure the competitiveness of renewable energy on the market, a support mechanism, even for deployed technologies, may temporarily be maintained, while carbon price signal is reinforced. Nevertheless, support schemes have to guarantee the RES integration in the market and in the system, capable of making the transition to the target system (market system) as easy and as seamless as possible. At the very least, all support schemes have to be market-based, in line with the state aid Guidelines.

Concerning self-generation, market signals should be simple and easy to control. Grid charges should reflect costs and services induced by generation and self-generation according to the related services performed by the grid (frequency/voltage stability / continuity of supply). If any support is needed for (residential) PV, then it is preferable to make it "explicit" and not implicit.

Q8) *Which obstacles, if any, would you see to fully integrating renewable energy generators into the market, including into the balancing and intraday markets, as well as regarding dispatch based on the merit order?*

1) **Move towards placing operational market responsibilities on all generation, either directly or indirectly through a service provider.** Balancing obligations are necessary for all generation plants – existing and new ones (universal balancing). Further integrating RES into the market by giving them balancing responsibility should provide them with additional economic incentives to develop better generation forecasts and put in place improved control systems, thereby reducing system imbalances and flexibility needs. In the long run, full market integration should remain the target.

2) **Enable commercial parties to offer balancing and/or commercialization services to balance**

responsible RES generation. Placing balancing obligations on RES generators will naturally create a demand for balancing services, which will be offered by the market. The introduction of balancing obligations on RES would further improve the functioning of the power market, create new opportunities including for RES, and put an end to 'produce and forget' approaches.

3) **Improve the functioning of day-ahead, intraday and cross-border markets and gate closure in order to give RES producers all (short-term) opportunities to trade their imbalances.** In order to set up a level playing field for balancing between controllable and variable generation, gate closures of national and cross-border intraday markets should be moved closer to real time: a shorter forecasting horizon makes the generation more predictable and long or short positions can be managed via the intraday power market. Consequently, the need for ancillary services would be less pronounced and the costs of running the power system would be lower.

4) **RES generation should bear the same technical requirements and charges for grid connection and network use as other generators.** Connection arrangements should always ensure a level playing field for all generation types.

5) **Last but not least remove the incentives to produce when market prices are below variable costs.** Otherwise, support schemes may – depending on the circumstances – lead to inefficient re-dispatch at high costs for society.

Q9) *Should there be a more coordinated approach across Member States for renewables support schemes? What are the main barriers to regional support schemes and how could these barriers be removed (e.g. through legislation)?*

The State Aid guidelines for energy and environment over the period 2014-2020 constitute a solid basis for a gradual harmonization.

A progressive harmonization of national support schemes in this framework should be preferred to a unique support scheme or to open schemes with complex cross-border participation. Such an approach would prepare transition to a more efficient scheme, promoting cost-efficient development renewables in optimal geographic locations.

Q10) *Where do you see the main obstacles that should be tackled to kick-start demand response (e.g. insufficient flexible prices, (regulatory) barriers for aggregators / customers, lack of access to smart home technologies, no obligation to offer the possibility for end customers to participate in the balancing market through a demand response scheme, etc.)?*

UFE is deeply convinced that DR will play a key role in the upcoming years. As it should be the case for all technologies, DR should compete with other assets on a level playing field and development of DR should only be triggered by market incentives.

UFE believes that the main economic driver of DR will be the introduction of capacity mechanisms (capacity wide). Such a development has been observed in several countries where a capacity market has been introduced. For instance, in PJM, where a capacity market was introduced in 2007, the available DR has been multiplied by six within the last five years. This empirical evidence is confirmed by findings form the UFE-BDEW study (see annexed report). The study illustrates that peak assets and DR will be comparatively disadvantaged in an EOM without price cap because these types of assets will be perceived by market parties as too risky assets. In this context, the introduction of a capacity mechanism supports the development of DR and peak plants, by reducing the risks linked to such investments, compared to baseload assets.

As underlined in the European Commission communication "Delivering a New Deal for Energy Consumers", there are two complementary approaches to tap the DR potential. First, consumers should be proposed appropriate price signals. Second, consumers should be able to take part in electricity markets either directly or indirectly through intermediation of an aggregator. Both of these approaches have their own advantages.

⇨ Appropriate price signals

This approach have several advantages:

- It doesn't require any adaptation of the current market design and can be performed thanks to rather simple technology (not need to use sophisticated steering mechanisms).
- The efficiency of this approach has been clearly demonstrated. For instance, it has been successfully used in France for 20 years with offers such as EJP or TEMPO.
- Last, consumers may use steering mechanisms for the management of their household appliances to maximize their benefits. Future progresses of smart home will reinforce these potential benefits.

⇨ Consumers' participation to electricity market either directly or through intermediation of aggregators.

This approach for DR is also a promising one. It allows for instance very fast responses of consumers who can react to short term supply/demand imbalances.

The development of this type of DR often requires a reform of the power market design since **market rules should be adapted to remove existing barriers preventing the active participation of DR to all markets**. In the French market framework, such adaptations have already been made. More precisely, the market reform implemented in France:

- Addresses the competitive position of independent aggregators vs. suppliers and implements a regulated access of aggregators to the consumer base of every supplier;
- allows independent aggregators to bid directly on all markets, and thus addresses the means to allow "curtailed energy" to be sold as "energy";
- Regulates the financial interface between suppliers and independent aggregators in the case they cannot/ do not want to agree on financial settlement.
- Addresses all technical barriers to aggregation though the concept of single point of contact. It refers to the possibility for a DR operator to have a single point of contact and hence to aggregate capacities, regardless of the BRP, the supplier, the size and/or the connection grid of the consumers.

All these reforms have led the Smart Energy Demand Coalition to rank France as leader regarding the integration of DR in markets in Europe.

UFE believes that the gradual deployment of smart grids and smart meters will facilitate the development of this type of DR. As neutral market facilitators, DSO's can indeed foster the development of Demand response: in France the roll out of ERDF "Linky" smart meters (35 million meters for 5 billion Euros) starting this year, so as the "digital DSO" program launched in 2014 (with data management, access rights, data protection, and cybersecurity among others), is a step forward to enable a better Demand Response.

2. STEPPING UP REGIONAL COOPERATION IN AN INTEGRATED ELECTRICITY SYSTEM

Q11) *While electricity markets are coupled within the EU and linked to its neighbours, system operation is still carried out by national Transmission System Operators (TSOs). Regional Security Coordination Initiatives ("RSCIs") such as CORESO or TSC have a purely advisory role today. Should the RSCIs be gradually strengthened also including decision making responsibilities when necessary? Is the current national responsibility for system security an obstacle to cross-border cooperation? Would a regional responsibility for system security be better suited to the realities of the integrated market?*

UFE considers that a high degree of regional cooperation between TSOs is an important tool for a secure and well-functioning electricity market.

UFE supports therefore the swift and full implementation of the pan-European plan published in 2014 by ENTSO-E ("Future TSO coordination for Europe"), in order to enhance regional cooperation between TSOs through the establishment of Regional Security Cooperation Initiatives (RSCI's). UFE has taken note with satisfaction of the commitment of all European TSOs to participate in at least one RSCI.

UFE considers nevertheless that the national responsibility in system security is not an obstacle to cross-border cooperation, and that TSOs must, while benefitting from the regional support of the RSCI's, remain unique clear responsible for the decision. It could be considered to broaden the scope of their advisory role which is today limited to security issues and is not concerned with economic efficiency. In particular, their advisory role should be extended to the following areas: regional capacity calculation, cross-border redispatch, HVDC and phase shifter settings. In essence, UFE considers that coordination should focus on power system operation, regional adequacy studies, and assessment of projects of common interest.

Conversely, the establishment of regional control centers with decision-making responsibilities could bring more risks than benefits to consumers. Such a shift would neither be proportionate, nor efficient. It would not be proportionate, as it would require changing all the existing and well-functioning technical and operational practice, and would increase complexity of the processes. It would bring no advantage in terms of efficiency, and could even introduce significant operational risks: since the management of cross-border electricity flows can neither be isolated from management of intra-TSO electricity flows, nor from system balancing, transfer of decision making power implying responsibility shift from TSOs to RSCIs would mean a major centralization of tasks and therefore an increased impact of potential failure of the responsible entity.

Moreover, UFE highlights that such a centralized regional operation of the system would not solve the issue of divergent national regulatory incentives, which remains a major obstacle for concrete cooperation in operation. UFE considers that a much more important step forward should be expected from the implementation of CACM guidelines, which will harmonize and clarify costs sharing when cross-border redispatching is needed, suppressing one of these divergences.

Q12) *Fragmented national regulatory oversight seems to be inefficient for harmonised parts of the electricity system (e.g. market coupling). Would you see benefits in strengthening ACER's role?*

ACER, as the Agency for cooperation of NRAs, is the appropriate body for European national regulators to fully work together and cooperate in order to discuss and build a coherent and integrated European vision on consistent energy regulation to accompany the evolution of the internal electricity market.

⇨ **ACER should first and foremost use the mandate it has got with the Third Package to its full extent.**

- ACER has to act more proactively and firmly as a facilitator among NRAs for any kind of cross-border projects and take faster decisions in case of disagreement between the NRAs.

- In case of NRA disagreement on cross border issues (related to markets or infrastructure), ACER should be allowed to initiate action and a possibility should be open for other parties than NRAs to call upon ACER (right to initiate).

- Proper implementation of NC and Guidelines provisions shall be monitored by ACER in cooperation with ENTSO-E while respecting proper role and responsibilities of both organisations. Assessment should avoid any bureaucratic approach and focus on the effective results of the implementation regarding the objectives of security of supply, market integration and sustainability.

- ACER needs also to focus more on regional projects with multiple MS involvement.

⇨ **ACER should promote best practices (benchmarking of national systems) among NRAs**.

Q13) *Would you see benefits in strengthening the role of the ENTSOs? How could this best be achieved? What regulatory oversight is needed?*

In order to implement the Energy Union, ENTSO-E could play the following roles:

- Assess in a European and social welfare perspective, the concrete **impacts of any policy evolution on the power system**;
- **Elaborate the TYNDP,** in full transparency with the stakeholders, as the basis for the identification of projects of common interest;
- Draft the **Network Codes**, with guidance from ACER, and play a formal role in their amendment process, involving closely industry stakeholders and consumers; Coordinate **innovation** in electricity networks through R&D roadmaps and plans;
- Develop a **regional and a European system adequacy assessment** and the application of the corresponding methodology; such an approach would contribute to improve the consistency

between MS decisions on SoS;

- Play a major role in **regional cooperation of TSOs**, notably by coordinating the development of RSCIs, organizing the mandatory participation of all TSOs, and ensuring that regional structures deliver in due time**.**

Some of these tasks are already due under the 3rd energy package.

Q14) *What should be the future role and governance rules for distribution system operators? How should access to metering data be adapted (data handling and ensuring data privacy etc.) in light of market and technological developments? Are additional provisions on management of and access by the relevant parties (endcustomers, distribution system operators, transmission system operators, suppliers, third party service providers and regulators) to the metering data required?*

As neutral market facilitators, DSO's play a key role in an evolving electricity sector, increasingly decentralized.

Key principles to rule metering data management should be :

- Standardization of data formats and exchanges;
- Transparency in the definition of data handling procedure;
- Economic efficiency in its organisation;
- Protection of customer data privacy.

When a national market define metering activities as DSOs obligations, the existing rules, because they include those of the 3rd Energy Package, provide sufficient guarantees of non-discriminatory and transparency conditions for market participants.

Data privacy should be of primary concern at the European level. European specifications, by ensuring sufficient guarantees to protect privacy and therefore fostering customers trust, would allow worthwhile relevant data exchanges between market players.

Q15) *Shall there be a European approach to distribution tariffs? If yes, what aspects should be covered; for example tariff structure and/or, tariff components (fixed, capacity vs. energy, timely or locational differentiation) and treatment of self-generation?*

Tariffs structures among European Member States differ greatly, impacted by the specificities of each national energy market: it makes the definition of network tariffs an undeniable national matter.

A European approach to distribution tariffs would go against the subsidiarity principle. Nevertheless, as advocated by Eurelectric and EDSO a common understanding of best practices in the design of network tariffs could be profitable. Tariffs structures have to reveal the real costs of the network, and it is important to find the right balance between the variable and fixed components. It is also valid for the pricing schemes applied to self-consumption: regulation must evolve to ensure that every consumer shares equitably the costs of the services they benefit from, and the potential constraints they generate on the networks.

Q16) *As power exchanges are an integral part of market coupling – should governance rules for power exchanges be considered?*

The definition of requirements and obligations at European level to elect a set of compliant power exchanges (NEMOs) and temporary derogations, could be justified

3. A EUROPEAN DIMENSION TO SECURITY OF SUPPLY

Q17) *Is there a need for a harmonised methodology to assess power system adequacy?*

Within the EU, there is no more isolated country and all Members States rely, to a certain extent, on neighboring countries to ensure their offer/demand balance. In this context, each state needs to a have a clear view on adequacy situations in neighboring countries. Unfortunately, appropriateness of adequacy studies can vary greatly from one country to another. This is mainly due to the fact that various methods for adequacy assessment are being used in different Members states.

In some countries, rather rough deterministic methods are employed. In this type of methods, an estimation of the probable peak demand is made to compute a capacity margin level. Depending of the expected size of this margin, TSOs conclude that security of supply will or will not be ensured. In such approaches, the potential contribution of neighboring countries to national security of supply is taken into account in a very elementary way, if at all. In other Member States, like France for instance, TSOs use stochastic methods which rely on a great number of supply-demand balance simulations realized on hourly basis. These simulations often include an explicit modeling of the power system of neighboring countries (the power systems of 12 interconnected countries are explicitly modeled in the national adequacy assessment performed by RTE). Thanks to the outcome of these numerous simulations, TSO can compute several quantitative indicators (such as LOLE, LOLP, or ENS) for the upcoming years.

UFE believes that all Members states would benefit greatly to discuss about the methods they use to asses security of supply, in order to converge towards a harmonized method. A high level of coordination between Member States at least at regional level is crucial to ensure a coherent analysis of cross-border contribution when assessing the capacity needs for Europe and for the calculation of the necessary capacity to be procured to ensure adequacy.

Therefore, UFE recommends that the European Commission, in close collaboration with member states, defines minimum quality standard for adequacy assessment (compulsory use of stochastic method, time step used, explicit modelling of neighboring countries, etc.) and enforces the obligation for each member states to perform an annual stochastic adequacy assessment. Any methodology should include an economic assessment whether the plants are economically viable. If they are not viable with an energy only market, the introduction of a capacity mechanism guaranteeing that the required capacity will remain in the system and contribute to adequacy should be considered.

Q18) *What would be the appropriate geographic scope of a harmonised adequacy methodology and assessment (e.g. EU-wide, regional or national as well as neighbouring countries)?*

To foster convergence on methodology used and to deliver a better knowledge of European adequacy situation, UFE also encourages the achievement on regular basis of regional adequacy assessments, supported by national input. These regional adequacy assessments should be done in addition to national ones.

Thanks to some regional initiatives, progresses have recently been made in this regard. In particular, the Adequacy Assessment realized at the PLEF level has been a major breakthrough. UFE believes that this exercise should continue and be done on regular basis (for instance every two years), each exercise being an opportunity to improve the methodology used. Among the improvements that can still be brought to the methodology used by the PLEF, UFE underlines that the modeling of hydropower plants could be refined and that the economic situation could be taken into account to anticipate decommissioning or mothballing of capacities.

Q19) *Would an alignment of the currently different system adequacy standards across the EU be useful to build an efficient single market?*

Alongside encouraging convergence on methodologies used for assessing generation adequacy, UFE believes that the EU should promote the elaboration of convergent definitions of security of supply. Many Member States are currently aiming at an expected level of LOLE. France, Belgium, the United Kingdom and the Netherlands are doing so for instance. UFE believes it would be a positive evolution if all European countries were to define security of supply by using volume based security of supply criteria, such as LOLE, LOLP or EUE for instance. Each Member State should be free to choose the indicator(s) and the target(s) which are the most suited to the specificities of its power system and the associated shortfall risk.

Q20) *Would there be a benefit in a common European framework for cross-border participation in capacity mechanisms? If yes, what should be the elements of such a framework? Would there be benefit in providing reference models for capacity mechanisms? If so, what should they look like?*

A- Benefits of reference models for capacity mechanisms and key features of such models

As more and more Member States are introducing capacity mechanisms, UFE welcomes the will of the European Commission to define reference models for capacity mechanisms, and recalls the importance of a competitive and sustainable approach, focused on cost-efficiency. Nevertheless due to the specific characteristic of each national power system it seems not possible, nor desirable to define detailed blueprint capacity schemes. Instead, it would be more useful to define a framework that would enforce a set of main principles to be respected by all mechanisms. This framework should ensure that all implemented mechanisms are sustainable, cost efficient and consistent between each other. Moreover, these principles should protect all the progresses made towards the completion of the Internal Energy market.

In this regard, in line with the Eurelectric position, UFE believes that the European Commission should promote: market-wide, market-based and technology neutral mechanisms. UFE is also convinced that the commitment taken by capacity providers should be a commitment of availability performance. Otherwise, a feed-in commitment could have an impact on the functioning of the energy market and on intra-EU trade.

B- Benefits of a common European framework for cross-border participation and key elements of such a framework

UFE supports the idea of a common European framework to take into account cross border interactions provided that some fundamental principles are respected (see below). The UFE believes that this framework should apply to any kind of capacity mechanisms: decentralized obligation, centralized auction, strategic reserve, etc. Member states and TSOs should be closely involved in the development of this framework.

UFE is convinced that XB contribution should be taken into account as long as it provides the same service as domestic resources. All resources (national or foreign) participating explicitly in the same mechanism should be subject to the same obligations, same rules of certification, same control and penalties.

In any case, the contribution to security of supply of foreign resources in one region is limited by:

i) Their own availability at critical periods for the region. Only resources that are not committed to support SoS in another region at the same time, according to XB agreement on the management of common scarcity periods, can be proposed for XB participation;

ii) The availability of the interconnection capacity at critical periods. The participation of XB resources requires therefore a strong involvement of foreign TSOs and clear rules for the management of common scarcity situations.

The most efficient way to take into account XB interactions would be to couple regional capacity mechanisms based on a common assessment of the system needs to fulfill the expectations of each Member State with respect to security of supply. This applies to both centralized and decentralized[3] capacity mechanism but can hardly be derived for countries relying on strategic reserves to enforce security of supply. Anyway, if regional CMs share key features (products, delivery/availability modes, timing, etc.), the achievement of an economically efficient procurement of the required capacity would be facilitated.

While interim solutions are currently being discussed at the European level, several main issues will have to be carefully handled:

- Specific agreements between the involved member States and TSOs (validated by NRAs) to specify the conditions under which XB resources are not committed to ensure security of supply in their own region (in particular during common scarcity situations), and can effectively participate in the considered CM;
- Identification of resources that are not committed to fulfills the needs of their own region according to this agreement;
- Certification of available capacity margins (i.e. the capacity that is not engaged elsewhere to cope with simultaneous scarcity issues) according to the same rules as domestic resources.

[3] In the French decentralized markets, the shared capacity could be procured by the TSO when assessing the security coefficient.

- The way “the reciprocity principle” should be taken into account

Q21) *Should the decision to introduce capacity mechanisms be based on a harmonised methodology to assess power system adequacy?*

As previously explained (see question 17), UFE is strongly supporting convergence towards a shared methodology for assessing security of supply at the European level. However, the elaboration of a harmonized method will require time. If Member States judge that, meanwhile, a CM is needed to ensure their security of supply, they should not be impeded from introducing one.

Adequacy assessment provides essential information for the coming years, such as the expected level of electricity demand (energy and peak demand) or the contribution from cross border exchanges to national security of supply. In that respect, the existence of a robust methodology to assess power system adequacy is fundamental for the introduction of capacity mechanism since it allows identifying the volume and the location of the capacity necessary to efficiently ensure the desired level of security of supply.

However, UFE doesn’t believe that the decision to introduce or to maintain a capacity mechanism should be limited to situation of forecasted adequacy shortfalls.

First, in countries where a CM has already been implemented, UFE is convinced that it would be a mistake to believe that capacity mechanisms are not needed anymore because no immediate shortfall risk is anticipated in adequacy assessment. In a room where temperature is kept at 21°C thanks to a thermostat, the idea to remove this thermostat because the room is at the good temperature would not come into anyone’s mind. Similarly, it may be because of the existing capacity mechanism that no shortfall risk is anticipated. Likewise, in a country where no capacity mechanism exists, a CM may be needed even if the national adequacy assessment doesn’t foresee shortfall episodes. Indeed, adequacy assessments are prospective exercises that should always be read cautiously. Especially, insights regarding generation or demand side capacities are technical anticipations that do not take into account the full economic environment. Therefore, adequacy assessments might be inadequate instruments to anticipate adequacy shortfall due to economic downturn or take-off.

More generally, UFE is convinced that capacity mechanisms should be introduced to complement the actual European target model in order to ensure security of supply. Capacity markets are not temporary measures to remedy a given shortfall risk.

In an Energy Only Market, even an improved one (without price caps), generators, in particular peak generators, as well as demand response, need to rely on a few years with high scarcity rents for their plants to recover their costs. The simulations performed by UFE/BDEW (see annexed report) in regard of the ever-growing climatic hazard reveals that the current energy market framework is maladjusted, as investors will evolve in an even more risky environment. For instance, in 2030, if France were to rely exclusively on an EOM, peak plants needed to ensure SoS would have 25% chances to recover less than half of the initial investment and would have 40% chances to recover less than 75% of it. This level of risk is unbearable for investors and the study concludes that it will result in an overall underinvestment situation and failing to ensure security of supply. As a matter of fact, with an EOM, the level of Sos reached in France will be 50% lower than the one targeted by French public authorities. Moreover, in addition to this under-capacity situation, market parties will tend to prefer comparatively less risky investment such as baseload assets rather than more risky assets such as DR and peak plants. Because of this, DR would lack incentives to develop and there would be a structural baseload over-capacity, while flexible and peaking plants will be conversely under-developed. Thus, in the absence of capacity mechanisms, **the resulting power mix will not be optimal, neither in terms of overall capacity nor in terms of its composition**

ANNEXE 1 :

FRANCE - GERMANY STUDY ON ENERGY TRANSITION AND CAPACITY MECHANISMS

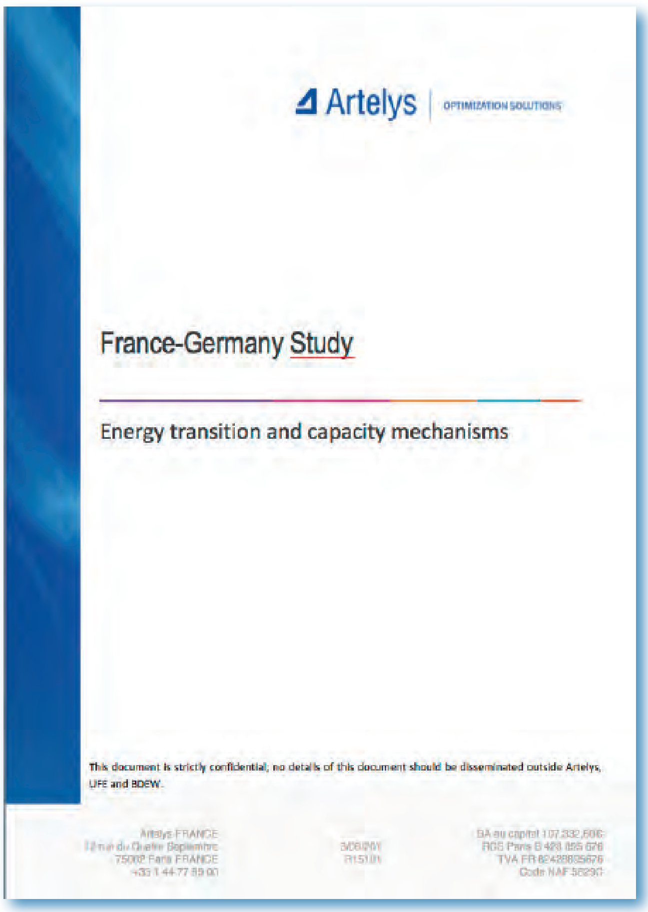
EXECUTIVE SUMMARY

France-Germany Study

Energy transition and capacity mechanisms

A contribution to the European debate with a view to 2030

Executive Summary



Artelys | OPTIMIZATION SOLUTIONS

France-Germany Study

Energy transition and capacity mechanisms

This document is strictly confidential, no details of this document should be disseminated outside Artelys, UFE and BDEW.

A FRANCO-GERMAN INDUSTRIAL PARTNERSHIP TO PREPARE TODAY FOR TOMORROW'S SECURITY OF ELECTRICITY SUPPLY

Ongoing ambitious and necessary energy transitions in Europe are questioning the security of electricity supply. With the steady growth of intermittent renewable energies, weather will play an increasingly important role being itself a source of uncertainty.

Aware of this change, UFE and BDEW, professional associations of the **two largest power markets in Europe, together representing over a third of the electricity consumed and produced in the European Union,** have decided to join their efforts to carry out a study on security of supply in a 2030 energy transition context.

Industrials from either side of the Rhine share two strong convictions that have deeply shaped the work performed in this study. First, in years to come, security of supply will be tackled more and more transnationally at the regional level and France and Germany will have a key part to play in this regard. Indeed, the two countries are at the core of the European Energy Union. Because of their central geographical situation, they are a bridge between Western and Eastern European countries and between Southern and Northern Europe. Assessing the level of security of supply reached in 2030 at the Franco-German level – as it is done in this study - is therefore a meaningful approach. Second, in today's liberalized power sector, security of supply issues cannot be discussed without considering market incentives. In the past, the level of installed capacities and their technical lifespan have been considered as key indicators for security of electricity supply. From now on, the level of security of supply delivered to European citizens will be more and more the result of decentralized investments and decommissioning decisions taken by market parties. These decisions are very much impacted by the power market design.

In this context, this **quantitative study** aims at answering two essential questions at the Franco-German level :

- **In 2030, will security of supply in an energy transition context be ensured at the desired level, by an energy only market - even an improved one (=without price cap[1])? What will be the effects of introducing a capacity mechanism, from the investor's point of view? From the community's point of view?**
- **What will be the consequences of a coordinated introduction of similar capacity mechanisms in France and Germany?**

Proactive hypothesis have been taken for 2030 in order to reflect a low carbon electricity system and a major part for demand side management (DSM):

- **40% renewables in both countries**
- **50% nuclear in France**
- **An important DSM volume: 11 GW in France (= 4 times the current volume) ; 7,5 GW in Germany (= 5 times[2] the current volume)**
- **An optimized France-Germany interconnection: 7GW (=doubling of 2015 capacity)**

Thus, by modelling the investment behavior of market parties in several market frameworks and by assessing what would be the consequences of such market designs in terms of security of supply for the two countries, this study delivers unique insight for the current European debate on the electricity market design reform.

1. Today, in France and in Germany, prices in the electricity day ahead market cannot exceed 3000 €/MWh.
2. The current DSM volume in Germany is supposed to be 1.3 GW.

2030: WEATHER RISKS CHALLENGE INVESTMENT DECISIONS

In 2030 and beyond, investments in conventional generation and DSM will still be needed but investment conditions will be uncertain. With the growing importance of renewable energies (RES) in European electricity mixes, weather uncertainties will play an even greater role than today for the power sector. Not only will demand continue to highly depend on temperatures, particularly in France, but generation from renewable assets will also vary greatly because of the variability of wind and solar resources. As a consequence, the net demand to be satisfied by conventional plants and DSM will show very random evolutions. From one year to another, the net peak demand will be very different. Similarly, the number of hours during which back-up assets will be needed and scarcity prices occur will also fluctuate significantly. Many capacities will not be used to their full extent or not at all in ordinary years, thus playing an insurance role.

Unfortunately, the majority of studies performed on market-design and security of supply issues neglects this fundamental weather dimension and therefore come to incorrect conclusions. To avoid this pitfall, this weather dimension has been fully integrated in this study and 50 representative weather scenarios have been used (referring to 30 years of historical data). Each of these scenarios represents possible demand and RES generation time series for all the hours of a given year. They illustrate the link between temperature, wind and solar radiation, and therefore the link between consumption and RES production. They clearly show that, in 2030, weather uncertainties would be one of the main stakes that the power system will have to cope with.

By integrating this weather uncertainty, the study evaluates whether actors are rather willing or reluctant to invest, depending on the market design studied :

- **Energy only market[3] (EOM) with de facto price cap**
- **Energy only market (EOM) without price cap**
- **Energy market (with or without price cap) + capacity mechanism only in France**
- **Energy market (with or without price cap) + capacity mechanisms in France and in Germany**

For each market design scenario, the model simulates investors' behaviors resulting into a new power mix with specific characteristics, namely:

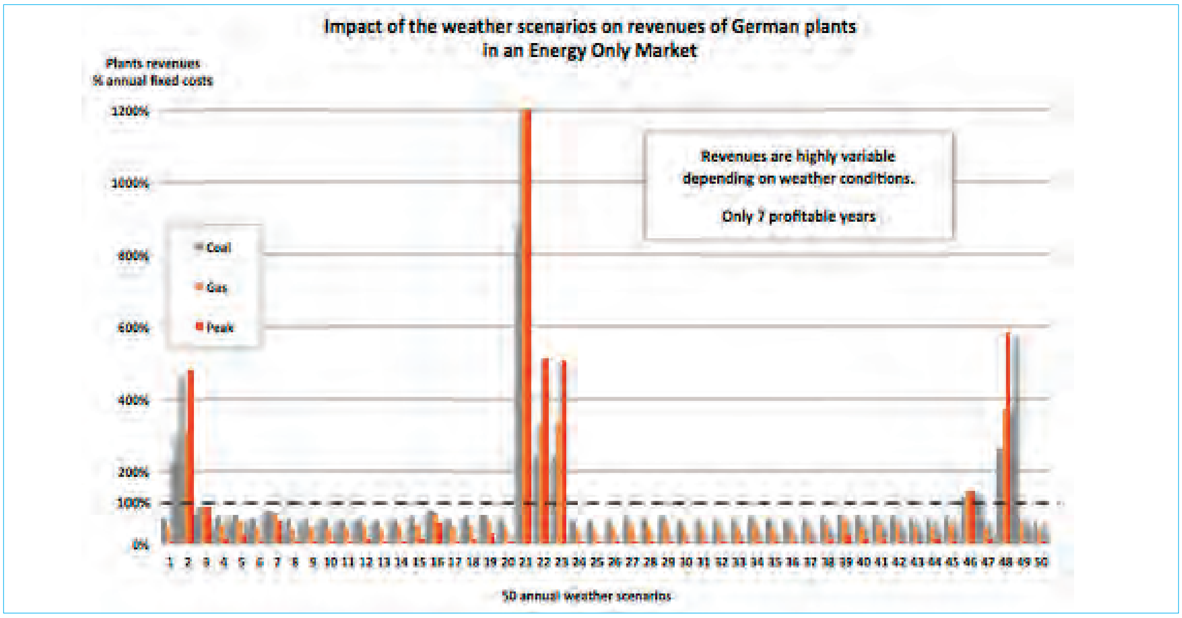
- **the level of security of supply**
- **the overall economic efficiency**
- **the cost for consumers**

FREE PRICING IN AN EOM (=WITHOUT PRICE CAP) UNABLE TO ENSURE SECURITY OF SUPPLY

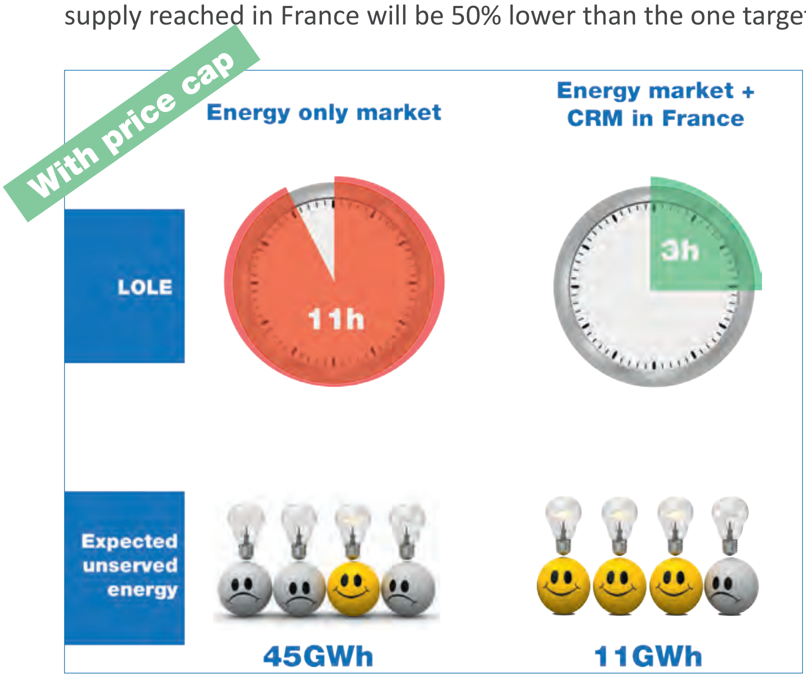
With regard to these ever-growing weather uncertainties, the results of the simulations performed in the study underline that the current energy market framework appears to be maladjusted.

In an Energy Only Market, with or without price cap, generators, in particular peak generators, as well as demand response, need to rely on a few years with high scarcity rents for their plants to recover their costs.

3. The model does not simulate the current market organization since some existing additional schemes haven't been modelled, such as the current reserves in Germany.



Indeed, among the 50 possible climatic years modelled in the study, benefits for market parties would arise in only seven years which would be very profitable. Even if one assumes that price spikes will be socially and politically accepted, this gives rise to two main uncertainties for investors. First: will these tense climatic - and thus profitable - years actually materialize during the lifetime of their assets? Second: when will these years occur? Will it be during the first years following their investments or will it be later? The study demonstrates that because of these uncertainties, investors will find themselves in a very risky environment. For instance, if France and Germany were to rely exclusively on an EOM, peak plants needed to ensure security of supply would bear a risk of 25 % in France and 23% in Germany to recover less than half of the initial investment and a risk of 40 % in France and 39 % in Germany to recover less than 75% of it. This level of risk is unbearable for investors and the study demonstrates that it will result in an overall underinvestment situation and failing to ensure security of supply. As a matter of fact, with just an EOM (free pricing scenario), the level of security of supply reached in France will be 50% lower than the one targeted by French public authorities



Moreover, in addition to this under-capacity situation, market parties will tend to prefer comparatively less risky investments such as baseload assets rather than more risky assets such as DSM and peak plants. DSM would then lack incentives to develop. Thus, **the resulting power mix will not be optimal, neither in terms of overall capacity nor in terms of its composition.**

A CAPACITY MECHANISM SECURES THE ENERGY TRANSITION

By contrast, the introduction of a (market-wide) capacity mechanism reduces the exposure of investors to the uncertainty associated to weather conditions and consequently remedies the underinvestment shortfall associated with an EOM framework.

Indeed, **by balancing the risks linked to variability of wind and PV production, and to thermo-sensitivity of demand, such a capacity mechanism acts as an insurance mechanism.**

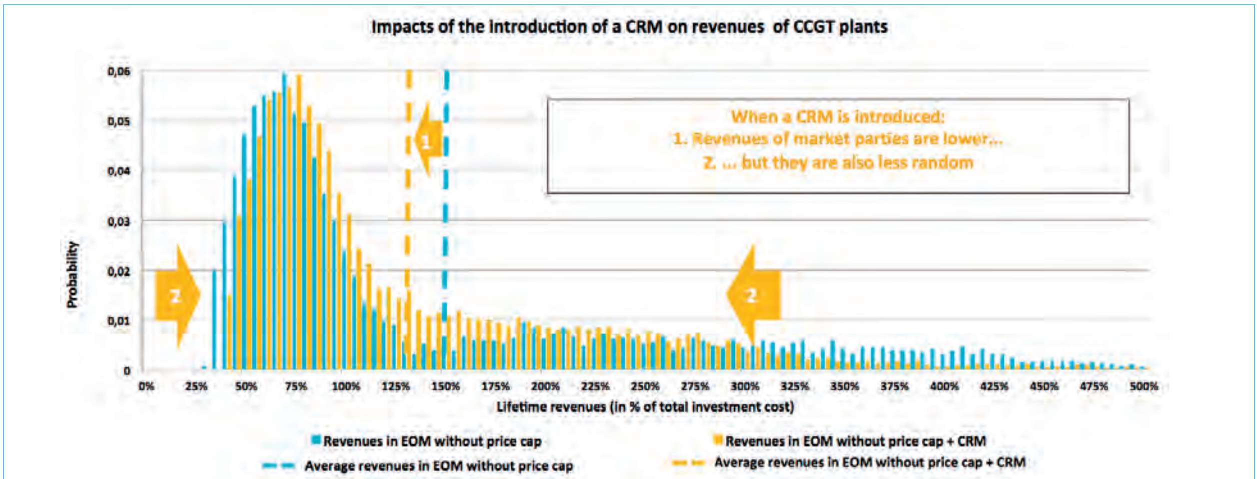
The capacity mechanism provides greater predictability on long term revenues and therefore spurs on investment in generation and in demand response, without discrimination. In doing so, **a capacity mechanism allows to achieve the required level of security of supply** even with a high level of renewable energy. It therefore ensures a safe and sustainable energy transition.

However, such a capacity mechanism does not eliminate the uncertainty on revenues: this mechanism is neither a subsidy nor a long-term income guarantee. Market parties still have to face price and volume risks.

A CAPACITY MECHANISM SECURES THE ENERGY TRANSITION AT A LOWER COST

Contrary to a common belief, adding a capacity mechanism to the energy market leads to cost reductions in the long term:

- **As security of supply is improved, the cost of loss of load is reduced**
- **In comparison with an EOM framework, the investment risk premium is lower with a capacity mechanism. Indeed, producers earn less in average but their incomes are also less random (reduction of the mathematical revenues expectation together with a reduction of their variance – see graphic)**
- **Eventually, in a market design with a capacity mechanism, the electricity mix will be more adjusted and DSM will find new incentives to develop**



The capacity mechanism thus reduces the loss of load expectation and provides security of supply without overcompensating assets.

Introducing a capacity mechanism leads to an improvement of the social welfare in the best case scenario. For instance, **an increase in social welfare of 370 m€ per year can be achieved thanks to the implementation of a capacity mechanism in France, by comparison with an EOM with price cap.** Furthermore, costs do not differ much, regardless of whether the market design is complemented by a capacity mechanism or consists in an EOM without any price cap.

Besides, a capacity mechanism in France leads French consumers to save[4] around 87 M€ on their electricity bills, in comparison to free pricing in the energy only market scenario. The introduction of such a mechanism also benefits to German consumers who save around 82 M€ per year. If Germany were to introduce also a capacity mechanism, French and German consumers would respectively realize additional savings around 180 M€ for French consumers and 225 M€ for German consumers

As a consequence and contrary to conventional wisdom, the introduction of a capacity mechanism brings about a higher level of security of supply thus benefiting consumers without inflicting additional costs and even resulting in gains.

A CAPACITY MECHANISM SECURES THE ENERGY TRANSITION AND FOSTERS FLEXIBILITY AND DEMAND RESPONSE

Our study also shows that a capacity mechanism makes the transformation of the energy system easier. Indeed, complementing the market design with such a tool leads to a mix which better meets the future needs of consumers and issues of the electric system. In particular:

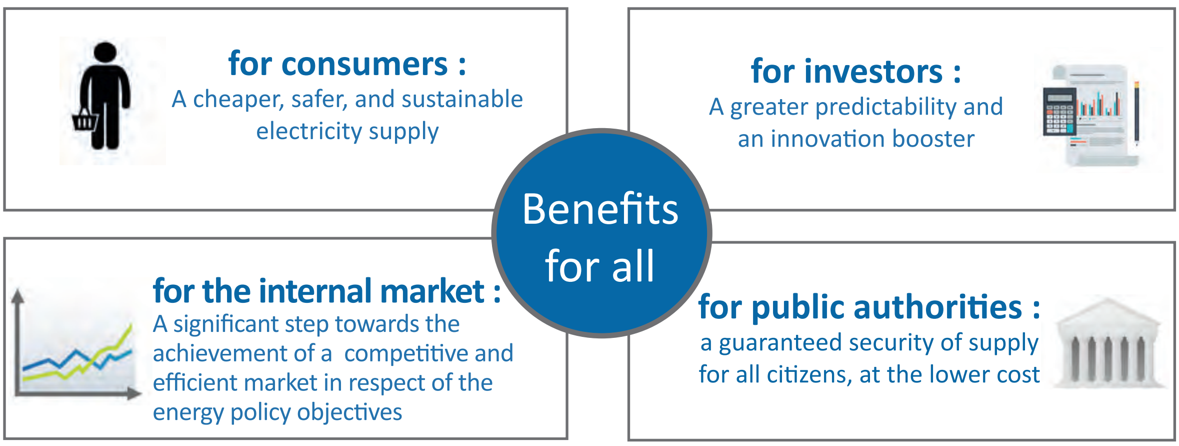
- **a capacity mechanism ensures security of supply of a renewable and low-carbon mix**
- **a capacity mechanism provides incentives for demand response**
- **a capacity mechanism provides incentives for flexible assets**

A REGIONAL COORDINATED APPROACH ON CAPACITY MECHANISMS ENHANCES BENEFITS FOR ALL

A simultaneous introduction of similar capacity mechanisms in France and Germany would result in efficiency benefits for all. It is by far more efficient to deliver security of supply on a bilateral and regional basis rather than on a purely national basis: the total capacity is optimized to ensure security of supply, the structure of the mix evolves as a result of the reduced risk, and last, the global welfare is increased across the whole zone.

Compared to the scenario were a capacity mechanism would be introduced only in France, in complement to the electricity market without price cap, the introduction of coordinated capacity mechanisms in 2030 in France and in Germany (provided they respect some fundamental principles: market-wide, market-based and technology neutral) would reduce the expected unserved energy by 35% for the two countries and would increase additional savings by €405 million per year for both German and French consumers.

To open up this bilateral approach within a wider regional scope and to give a new European dimension to security of supply will definitely enhance these benefit



4. These results were computed by comparing risk premiums reduction costs calculated for investments on optimized capacity, to which security of supply improvement gains/losses are added.

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Septembre 2015

ANNEXE 2 :

FRANCE - GERMANY STUDY ON ENERGY TRANSITION AND CAPACITY MECHANISMS

FULL REPORT

France-Germany Study

Energy transition and capacity mechanisms

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1 Introduction

In most countries of the world, the electricity sector is undergoing a structural transition, driven by requirements of efficiency and sustainability: renewable capacity is witnessing a continuous growth, making the need of flexibility increase, while electricity market prices tend to decrease.

In the medium-term, the power system will have to deal with increasing levels of risk, which will take different forms in France and Germany, which are the two countries this study focuses on. In France, the risk is related to the thermo-sensitive power demand, whereas in Germany the risks are related to the high penetration of intermittent renewable power generation. Both of these facets of risk lead to a high volatility of the residual demand from one hour to the next, and therefore require the power system to be more flexible. In this context, the question of whether the current market design will be able to ensure a satisfactory level of security of supply through an adequate remuneration of it actors is open.

Market design is therefore a crucial point whose appropriate treatment could ensure the sustainability of the current and future power systems. An inadequate market design could in contrast lead to a massive decommissioning of power plants, including the most flexible ones, which will directly impact the security of supply in both France and Germany. The security of supply at the European level could also be at risk since France and Germany host the two largest power systems in Europe.

To face these new challenges, several solutions are being planned or implemented in different countries. These solutions all involve combinations of the following ingredients:

- improvements of the **energy-only markets**, without price caps and with higher demand-response capacities, to let the system send more accurate price signals during times of scarcity,
- **capacity reliability mechanisms**, among them capacity mechanisms based on a targeted level of security of supply at a national level, or other mechanisms such as strategic / capacity reserves where the system operator puts aside some capacity to ensure security of supply in exceptional circumstances.

As will be discussed in this study, a crucial ingredient that highly influences the effectiveness of mechanisms aimed at ensuring security of supply is the level of international coordination.

In this context, this study focuses on assessing the impacts in 2030 of different market designs in France and Germany on the security of supply and on social welfare, evaluated through a modeling of the investment behavior of market participants. This study has been commissioned by UFE and BDEW, two major European institutions bringing together the main actors of the Franco-German power system.

Section 2 is devoted to the description of the power system model for France and Germany. Section 3 analyses investment risks in new capacity for the different studied market designs. Actor behavior modeling, along with the resulting supply mixes are presented in Section 4.

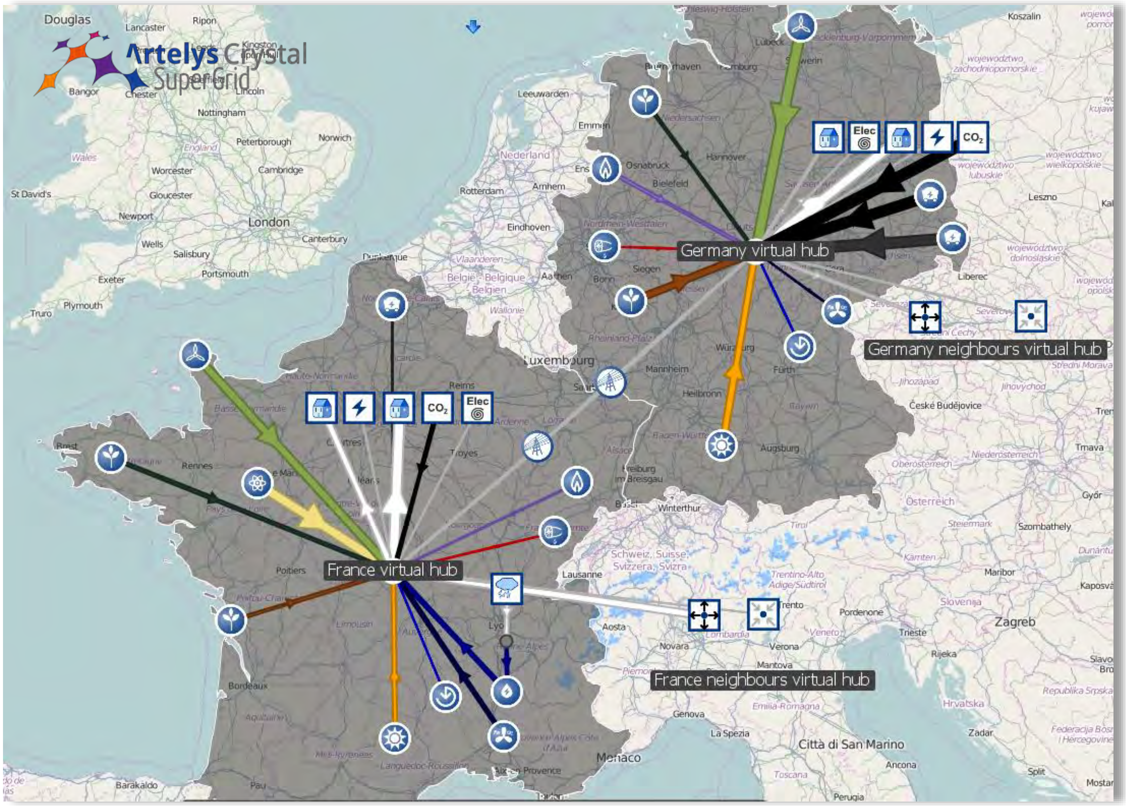

Figure 1: Franco-German power system in Artelys Crystal SuperGrid

2 Power system modelling

This section is devoted to presenting the key methodological choices of this work, along with the reasons these choices were made, in order to be fully equipped to interpret the results.

2.1 A cost-based approach

For a given generating mix, the electric system operations are supposed to be cost-minimizing. This means that at all times, a power plant is brought online only if the remaining power plants have higher or equal variable costs. In other words, available power plants are ranked based on ascending order of variable costs, which defines the order – the *merit order* – in which plants are to be brought online.

The following graph shows how the 2030 French production is dispatched between production fleets to meet the demand. One can refer to section 2.4 for more details regarding the assumptions underlying the construction of the 2030 power system.

Each color stands for a given production fleet, fleets' productions are stacked in accordance with the merit order, and demand is represented by the black line. Differences between supply and demand correspond to imports and exports.

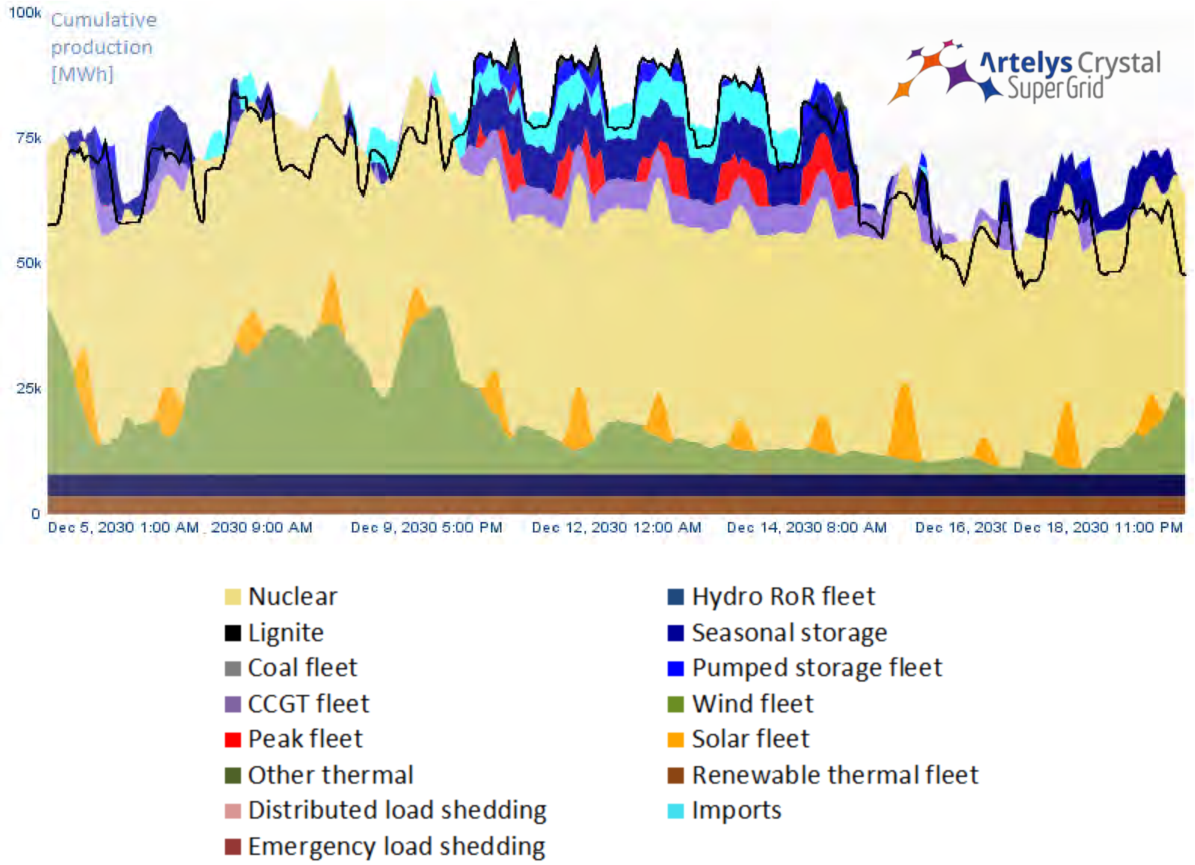

Figure 2: Cumulative production in France, extracted from power management simulations
Climatic scenario 23 - Dec, 5th to Dec, 19th 2030

This graph exhibits the fact that expensive peaking plants (represented in red) or emergency demand response (represented in grey) are only called when cheaper production plants are not able to meet the demand by themselves. The period between December 12 and December 14 is characterized by small wind (represented in green) and solar (in orange) productions. During this period, nuclear (in light yellow) and gas (in purple) power plants are not able to complement the intermittent production to reach the demand. By contrast, from December 6 to December 9 wind power plants' production is such that nuclear power plants do not need to run at full capacity to satisfy the French demand. Since German base fleets' costs (coal and lignite) are higher than the ones of French nuclear units, the extra available nuclear capacity in France is used to meet Germany's needs, which is why French cumulative production is greater than the national demand.

One of the main difficulties of power management lies in the variability of the demand on every time scale, since production dispatch has to be adjusted "in real-time" to meet the demand. This variability is all the more intense when an important share of intermittent power generation is integrated into the mix, since its variability is added to the demand's one. An appropriate representation of the variability of both the demand and of renewable production has to be included in the modeling effort in order to identify periods during which the most expensive power plants are to be taken online, and thereby the effects of variability on marginal costs and on producers' revenues.

The time step used in the simulation has therefore to be selected in such a way as to allow for a proper depiction of the power plants' operations and to capture the variability of both the demand and intermittent productions. Since yearly, monthly and daily time steps do not fulfil these requirements, it has been decided to establish the supply-demand equilibrium on an hourly time-step. In this way, it is ensured that variability is well captured, leading to realistic economic outcomes in terms of production costs and producers' revenues.

Finally, since storage is an important player in the considered energy mixes, working on a demand monotone (as is sometimes the case for economic analyses) would not allow for a suitable representation of the links between time steps. Indeed, storage relates time steps between them in an asymmetrical way, different order of appearance being nonequivalent. A chronological representation has therefore been used in this study.

2.2 A model of the generation mix

The power model which is used in this study has been designed to fulfil two requirements:

- First, it has to be able to simulate the operations of the French and German energy mixes over a range of climatic scenarios by minimizing the average global welfare, and thereby to dimension their capacities.
- Second, it has to embed a depiction of the actors' dynamics, which permits to assess the producers' production and revenues according to a range of different market designs.

The French and German power mixes are each represented by a node to which the respective production fleets (aggregated by type of power plant) and demand-response programs are associated. The electric interconnection between France and Germany is linking the two aforementioned nodes and permits power exchange.

The detailed list of the production fleets which are considered in this study is provided in Appendix A, together with their operational constraints. Both distributed load shedding (from domestic consumers) and emergency load shedding (from industrial consumers willing to reduce their consumption during periods of high prices) programs are implemented in the model.

A simplified model of imports-exports with the rest of Europe is implemented in order to ensure the study is based on a realistic picture of the European power system. The loss of load is modeled by adding a virtual plant running at a very high variable cost (15k€ per MWh).

Finally, operational constraints such as power gradients, minimum and maximum loads, energy conservation, etc. are modeled in a detailed way.

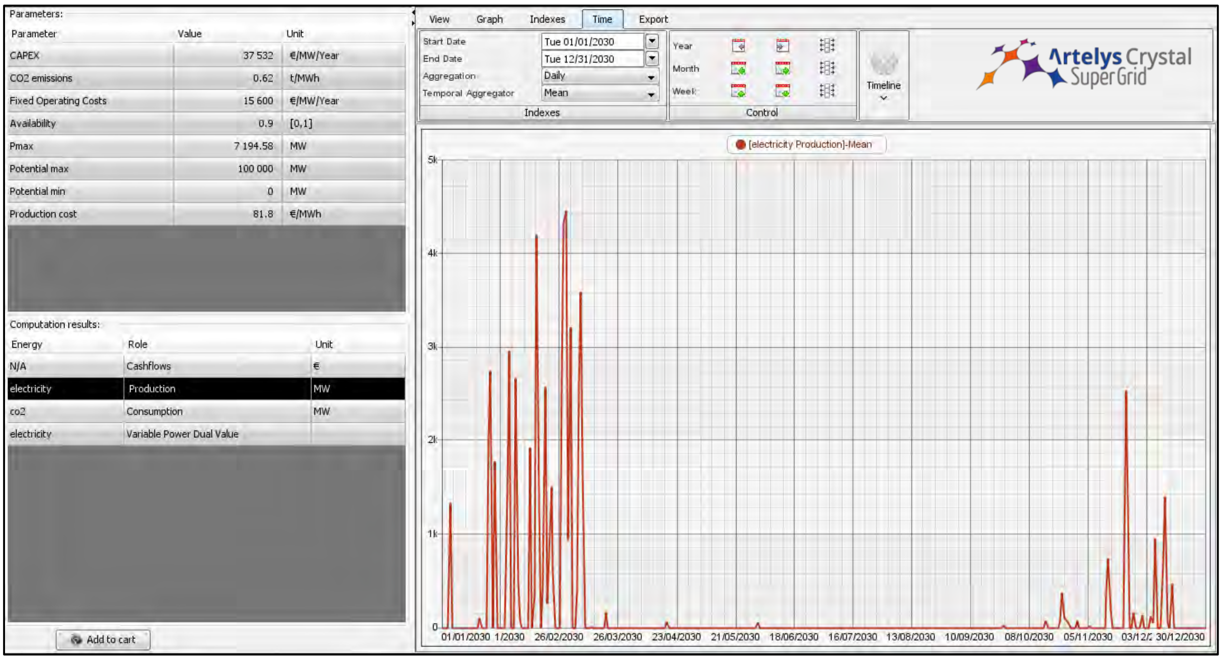

Figure 3: Asset view of 'France peak fleet' within Artelys Crystal Supergrid

The resulting model is able to dimension the capacities of conventional thermal assets and of the Franco-German interconnection by minimizing the overall costs under operational constraints for a range of climatic scenarios.

Moreover, the operations of both the power plants and the interconnection are optimized with an hourly time resolution, for 50 climatic scenarios. One thereby gets access to the production of each of the fleets and the marginal costs for both France and Germany.

The model is therefore well-suited to assess the influence of market design on the security of supply on the producers' revenues.

2.3 Uncertainties modelling

Since security of supply is the prime interest of this study, a key factor that has to be taken into account is the climatic conditions' variability. The latter can be translated into risks for the security of supply of both France and Germany, which turn out to be of different nature and importance. Indeed, in France, the main risk related to the security of supply is coming from the consumption peak occurring in winter, due to the high share of electrical heating in France. In Germany, the risk is related to the structure of its generation mix, and in particular to the importance of its share of intermittent wind and solar power. The intrinsic variability of these sources may be critical for the security of the German power system.

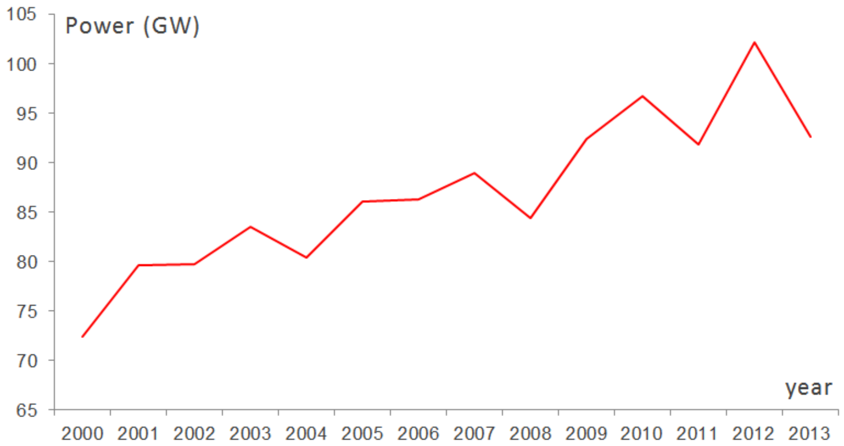

Figure 4: Annual consumption peak power in France from year 2000 to year 2013 (source: RTE)

These uncertainties also have a high incidence on the short-term price levels in an energy-only market, and therefore an impact on producers' revenues. For a given generation mix, the average price will be higher in cold winters than in warm winters. Climatic variability therefore translates into an uncertainty for producers regarding their revenues. This effect is even higher for production plants that are used only for peak hours, as they only get revenues (short-term price minus variable costs of production) when a more expensive unit (or load shedding) is called at the same time.

50 climatic scenarios were built to depict the variability of both demand and production by renewables. These scenarios are based on realized generation and consumption data in both countries in order to take into account the correlation of these different time series and to be able to assess adequately the security of supply at the Franco-German level. In particular, a close attention has been paid to the correlation between renewables generation in Germany and temperatures in France as these two parameters have the most significant impact on the security of supply. See Appendix A for more details.

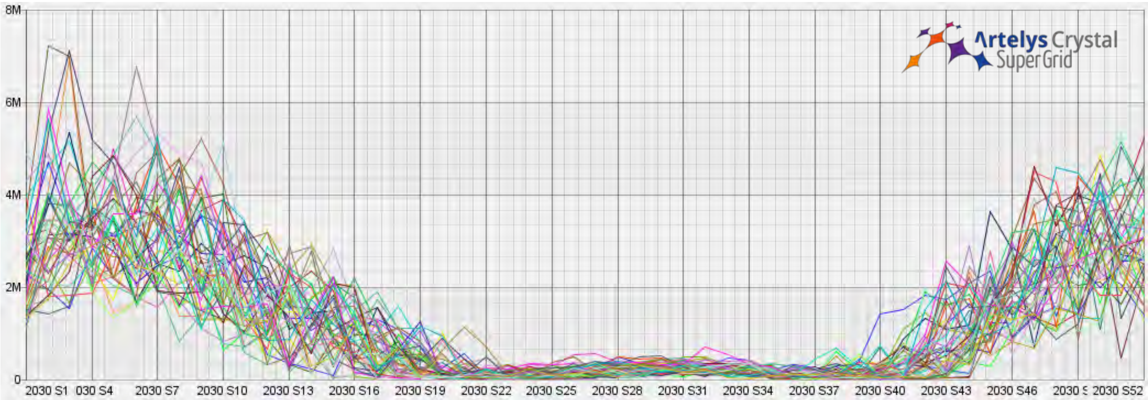

Figure 5: Scenarios of French thermo-sensitive consumption within Artelys Crystal Supergrid scenario view

These scenarios are used to assess the security of supply for a range of market designs, as explained in section 3, and will allow to measure the risk for producers in terms of profitability of their investments.

2.4 A virtual reference 2030 mix

In this section the design and computation of the reference 2030 energy mixes is described. The virtual reference mix satisfies the following two requirements:

- First, they take assumptions regarding the evolution between the present situation and 2030 into account, in particular the strong increase of renewables in both France and Germany and the projections regarding the evolution of installed nuclear and lignite capacities are depicted.
- Second, the 2030 generation mixes avoid structural dis-adaptation, in order to ensure the observed effects can entirely be attributed to market designs.

To answer these two requirements, public national and international forecasts data were used for storage facilities, demand-side management, consumption, imports/exports balance and installed capacities for Renewable Energy Sources (RES) as well as nuclear and lignite power plants[1]. Conventional thermal power plants (namely: coal, CCGT and peak fleets) and France-Germany interconnection installed capacities were optimized, using a welfare-maximizing capacity expansion model to get a reasonable starting point for the study.

The resulting virtual reference mix is close to ENTSO-E's forecasts, and coherent with the different scenarios considered by the French TSO, RTE[2], on one hand, and the German Federal Ministry for Economic Affairs and Energy (BMWi) on the other hand. The remainder of the section presents, first, the main assumptions used to produce the 2030 generation mixes, and secondly, the resulting thermal generation mixes. Detailed information can be found in Appendix A.

One must bear in mind that this virtual reference mix is a virtual optimum which is not reachable in real economic conditions since investors tend to display a certain level of risk aversion.

[1] Sources: ENTSO-E TYNDP 2014, RTE Bilan prévisionnel 2014, EWI / GWS / Prognos, Study commissioned by the German Federal Ministry of Economic Affairs and Economy; In particular, RES hypothesis were taken from the average of two ENTSO-E scenarios for France, and from EWI/GWS/Prognos for Germany.

[2] In particular, assumptions of nuclear installed capacity, demand, and exports in France are close to the "diversification" scenario of RTE.

2.4.1 Main assumptions

INSTALLED CAPACITIES

The 2030 installed capacities in the virtual reference mix are presented in the following table:

	Installed capacities (MW)	
Technology	France	Germany
Nuclear	48 000	0
Lignite	0	17 000
Hydro run-of-river	13 100	4 000
Seasonal hydro storage	9 300	0
Pumped hydro storage	4 300	8 000
Other thermal	4 200	2 880
Solar	30 800	68 000
Wind	36 200	59 000
Renewable thermal	5 800	7 000

Table 1: Generating power plants' installed capacities

POWER DEMAND

The demand is assumed to consist of two parts: a fixed non-thermo-sensitive part and a thermo-sensitive part.

The thermo-sensitive component mainly represents electric heating and air conditioning. It has been generated for each of the 50 climatic scenarios, based on historical data. It has further been adapted to take into account climate change and the evolution of electricity used for appliances and consumer electronics. France has a higher thermo-sensitivity than Germany, as shown on the graph below, which results in more acute and more intense winter peaks.

The fixed non-thermo-sensitive component represents other domestic and tertiary usages (such as electric appliances), industrial consumption and transports.

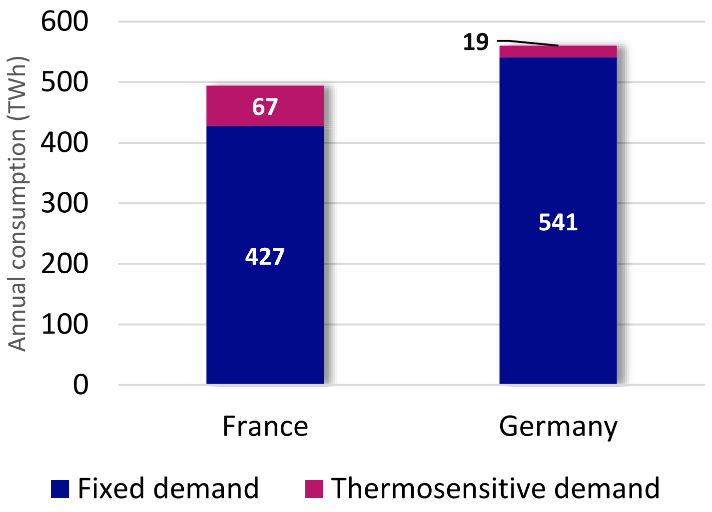

Figure 6: Assumptions of demand in France and Germany by 2030, averaged over 50 climatic scenarios

With this model, for the most unfavorable climatic scenarios, peaks of residual demand (national demand minus solar and wind electricity generation) can reach up to 113 GW in France and 99 GW in Germany[3].

DEMAND-SIDE MANAGEMENT

Demand-side management capacities are expected to significantly increase during the two next decades, thanks to new technologies (such as smart and connected equipment) and new habits, making demand more responsive to price levels.

Demand-side management mechanisms are broken down in the following two categories:

- **Distributed load shedding**, representing the capacities of domestic demand-response. They are modelled as having a nil marginal cost and can be used up to 100 equivalent hours per year. While it has no cost of use, it is in practice only activated during peak time since the total available volume is limited.
- **Emergency load shedding**, activated when the price goes above 400€/MWh corresponding to industrial load shedding. Since it is about four times as expensive as peak fleets, this demand-response capacity is only used as a last resort to avoid loss of load.

[3] In France, the impact of extremely poor weather conditions is high due to the significant share of electric heating in the domestic sector combined to extremely low temperatures. In Germany, the impact of extreme weather conditions is increased compared to the current situation due to the planned growth of the share of heat pumps in domestic heating combined with the global increase of consumption. In addition, the increasing use of electricity in the transport sector will impact on overall electricity consumption.

	Demand-side management capacities (MW)	
	France	Germany
Distributed load shedding	7 000	2 500
Emergency load shedding (400€/MWh)	4 000	5 000

Table 2: Demand-side management capacities.

Note that these assumptions have a relatively low impact on the analysis made in this study as a lower share of DSM will simply result on a higher peak fleet optimized capacity in the virtual reference mix.

IMPORTS AND EXPORTS WITH THE REST OF EUROPE

While the Franco-German interconnection is explicitly modelled and optimized, imports and exports with other countries are also represented within the model.

To be coherent with the relatively high assumption on nuclear installed capacity in France, France's export balance with neighboring countries other than Germany is considered to keep being significantly positive: the average yearly balance over the climatic scenarios is assumed to be 50 TWh. On the other hand, Germany's imports and exports are supposed to be balanced. Note that since installed capacities of the conventional thermal fleet are optimized for the virtual reference mix, a different assumption on import/export balance would not alter significantly the results of the study.

VARIABLE COSTS OF PRODUCTION

The following table presents the assumptions regarding the variable costs of production. They are composed of fuel costs on the one hand, and CO_2 emissions' costs on the other hand, **the price of CO_2 being set at 33 €/t**.

Variable costs of Production			
Technology	Fuel costs (€/MWh)	CO_2 emissions (t/MWh)	Total variable cost (€/MWh)
Nuclear	6.4	0	6.4
Coal	25	0.89	54
Lignite	15	0.99	48
CCGT	52	0.40	65
Peak fleet	82	0.62	100
Other thermal	82	0.62	100

Table 3: Variable production costs

These assumptions are based on projections carried out by the International Energy Agency (*World Energy Outlook 2013* and *CO_2 Emissions from Fuel Combustion*).

2.4.2 Optimizing thermal and interconnection capacities

CONVENTIONAL THERMAL INSTALLED CAPACITIES

Conventional thermal power plants' capacities being optimized via a cost-minimizing approach, assumptions regarding their fixed costs also have to be provided. Two types of fixed costs are considered: annualized investment costs, which correspond to annual capital costs, and fixed operating costs, which are typically wages paid to employees. An actualization rate of 7.25%[4] is used throughout this study, over the scheduled lifetime of investments.

[4] This actualization rate is for instance used by the French authority on energy regulation (Commission de régulation de l'énergie – CRE).

Fixed costs – optimized fleets			
Technology	Annualized total fixed cost (€/MW.year)	Lifetime (years)	Total fixed cost (€/MW)
Coal	150 000	25	1 700 000
CCGT	95 000	20	980 000
Peak fleet	53 000	20	550 000

Table 4: Optimized fleets' fixed costs

The obtained installed capacities are presented below.

	Installed capacities (MW)	
Technology	France	Germany
Coal	0	17 500
CCGT	6 300	27 200
Peak fleet	8 300	5 300

Table 5: Conventional thermal optimized capacities

INTERCONNECTION

The France-Germany interconnection is also optimized simultaneously to conventional thermal fleets using a cost of 40 000€/MW/year. The result of this optimization is presented in the following table:

FR-DE Transmission	Installed Capacity (MW)	Average annual flows (TWh)
France to Germany	6 900	20,5
Germany to France	6 900	5,5

Table 6: Power transmission lines capacities obtained via the optimization procedure

The installed capacity obtained by the uncapped optimization is 6900 GW. The current net transfer capacity is 4400 MW from Germany to France, and 2450 MW from France to Germany.

This shows the economic value of having well interconnected systems:

- The interconnection allows for a better management of generation fleets across the whole zone

- A high capacity of interconnection allows for a better use of generation during peak hours and therefore results in a reduction of the necessary capacity to face difficult situations, which reduces investment costs.

3 Investment risks for different market designs

The revenues of a given producer are influenced by a broad range of factors, such as the total demand, climatic conditions, the capacities and production costs of all other actors, the availability of its assets, etc. The aim of this study is to identify and quantify the influence of market design on producers' revenues.

Two types of energy-only markets are considered: an energy-only market with price cap at 3k€/MWh, and an energy-only market without price cap. In the second case, the market price can attain 15k€/MWh which is the value of loss of load in the model. Capacity reliability mechanisms are also considered.

This section is devoted to computing the producers' revenues for the different market designs. In particular, the influence of the risks felt by producers in energy-only markets and in capacity markets, in particular the risks related to weather uncertainties, will be assessed.

3.1 Impact of market design upon annual revenues distribution

For a given power supply mix and a given climatic scenario (influencing both the thermo-sensitive demand and renewables production – more details are provided in Appendix A), assets' revenues are evaluated by optimally dispatching the production with an hourly time resolution on a one-year time horizon. The optimal planning results in production curves for each fleet as well as in marginal costs of electricity for both countries, which, together with the market design, are used to evaluate the producers' revenues[5].

3.1.1 Revenues assessment methodology for energy-only markets

ENERGY-ONLY MARKET WITHOUT PRICE CAP

In energy-only markets without price cap, as well as in all other market designs studied below, it is assumed that the production is dispatched between the fleets according to the merit order: the fleets are taken online in the order of increasing variable production costs. (Technical constraints which may slightly modify a strictly economic dispatch have been taken into account).

The hourly electricity prices are obtained through the optimal dispatch marginal costs. These values correspond to the cost of producing one more MWh and are computed as the dual values of the supply-demand equilibrium constraint at each time step. Since the capacity of the interconnection linking France and Germany is limited, marginal costs do not necessarily converge across the whole

[5] When assuming perfectly competitive markets and perfect foresight, market prices are found to be given by the marginal production costs. Therefore, using a cost-based approach is entirely justified in the context of this study. However, this modeling approach does not simulate the actual trading of power, and therefore does not give an exact representation of the revenues derived from the actual market.

zone, therefore the **marginal cost of production may be different in France and in Germany**. According to the results of our power system simulations, marginal costs are the same in France and Germany during 85% of the time steps.

For a given climatic scenario, the annual remuneration consists of the product between the vector of hourly production (in MWh) and the vector of marginal costs (in € per MWh)[6]:

$$\mathrm{AnnualRemuneration} = \sum_{\mathrm{t}} \mathrm{generatedEnergy_t} \cdot \mathrm{marginalCost_t}$$

To obtain producers' annual revenues, one has to subtract production costs from the annual remunerations:

$$\mathrm{AnnualRevenuesInEOM} = \sum_{\mathrm{t}} \mathrm{generatedEnergy_t} \cdot (\mathrm{marginalCost_t} - \mathrm{variableCost})$$

The variableCost parameter represents the cost of production per MWh, including fuel costs and CO_2 emission costs. Note that this parameter is assumed not to depend on time.

This revenue is called the **infra-marginal rent**.

ENERGY-ONLY MARKET WITH A PRICE CAP

During peak hours, the power system might not be able to meet the power demand, even if emergency demand-response is used. In this case, the marginal cost of the system strongly increases and reaches the value of loss of load.

In a perfect market, setting a high value of loss of load is required to ensure peaking units obtain satisfactory revenues, and thereby that the mix remains stable in the long run. However a price cap[7] is often applied, as is the case today in the day-ahead market in the power exchange covering France and Germany.

To compute revenues in this market design, marginal costs are simply to be capped compared to the previous situation. Annual revenues are given by the following formula:

$$\mathrm{AnnualRevenuesInEOM} = \sum_{\mathrm{t}} \mathrm{generatedEnergy_t} \cdot (\min(\mathrm{marginalCost_t}, \mathrm{priceCap}) - \mathrm{variableCost})$$

[6] For the sake of readability, the climatic scenario index has been suppressed.
[7] Technical or political limit

Variability of the infra-marginal rent

In a perfect market, producers only receive revenues when the marginal cost of production is higher than their own variable cost. Since the value of loss of load is usually much higher than any variable production cost, some assets may rely on scarcity situations to be remunerated, as is shown in the following graphs.

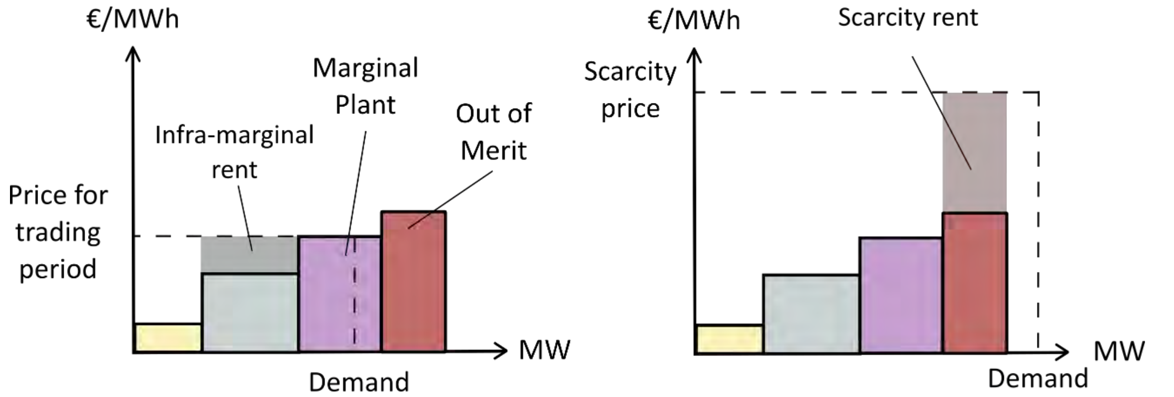

Figure 7: Merit order, marginal costs, infra-marginal and scarcity rent.

The two graphs on Figure 7 *illustrate the basics of price formation in a perfect market. When the demand is lower than the available capacity (left), the price is set by the variable cost of the marginal power plant. The other generating assets (grey and yellow) receive an infra-marginal rent. When the demand is higher than the available capacity (right), the EOM price corresponds to a scarcity price, which is either given by the value of loss of load, or set to a technically- or politically-fixed limit. In this case, all generating assets receive a scarcity rent.*

One may notice that the occurrence of scarcity prices is also dependent on actual bidding restrictions in the wholesale market and the public and political acceptance of price spikes which are not taken into account in the model.

This highlights the structural problem for peak producers and DSM: their only revenues originate from periods during which expensive demand-response is activated or when there is some demand curtailment. Base producers are relatively less impacted by this phenomenon than peak producers, since their revenues are generated over a greater set of hours, i.e. those when more expensive assets are producing. For instance, coal fleets perceive a revenue during at least 2000 hours, which is when the CCGT are brought online.

3.1.2 Simulation results

Revenues of actors of the virtual reference mix without price cap

Assets' revenues are computed for the generating fleets composing the virtual reference mix. A large dispersion of annual revenues over the climatic scenarios can be witnessed: climatic scenarios with very cold periods and low wind have long periods of high prices, while the marginal costs remain low for other scenarios.

To illustrate these points, the revenues in an energy-only market without price cap are presented below, for thermal fleets in Germany and in France, for the 50 climatic yearly scenarios.

Figures are given in percentage of the annual fixed costs.

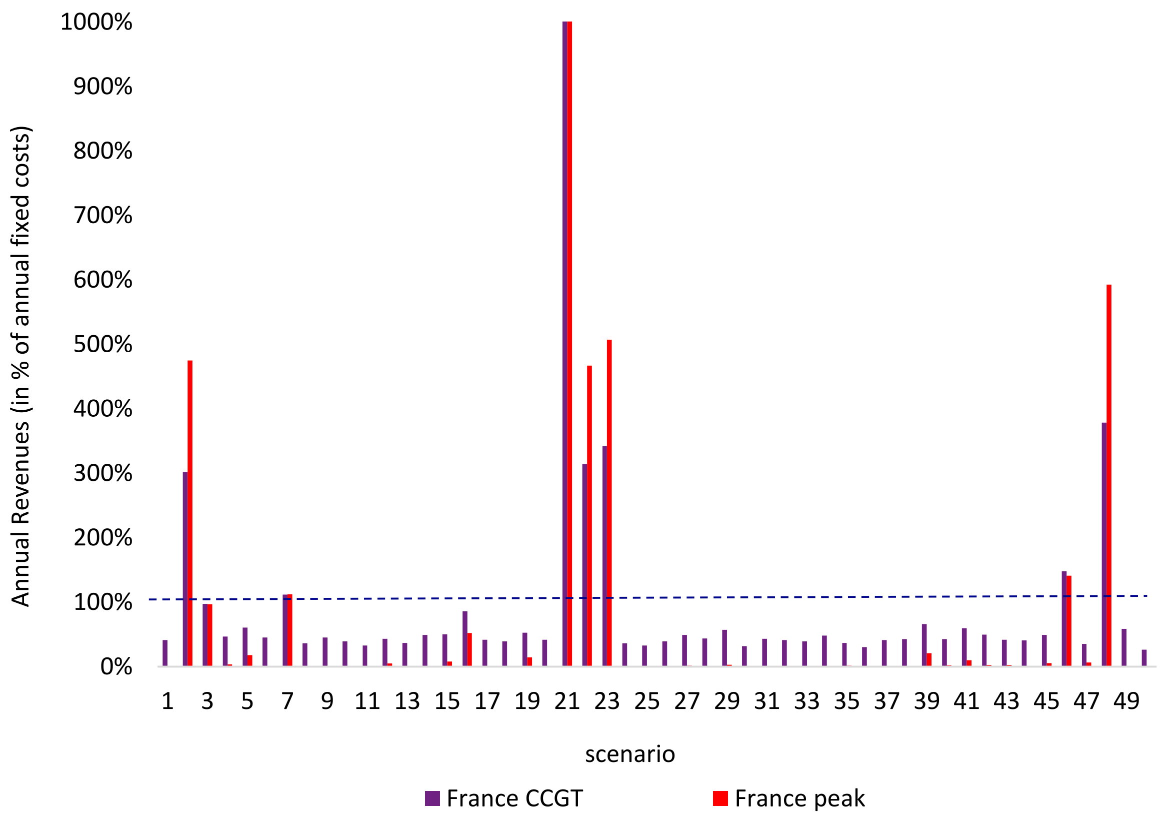

Figure 8: French assets' annual revenues without price cap

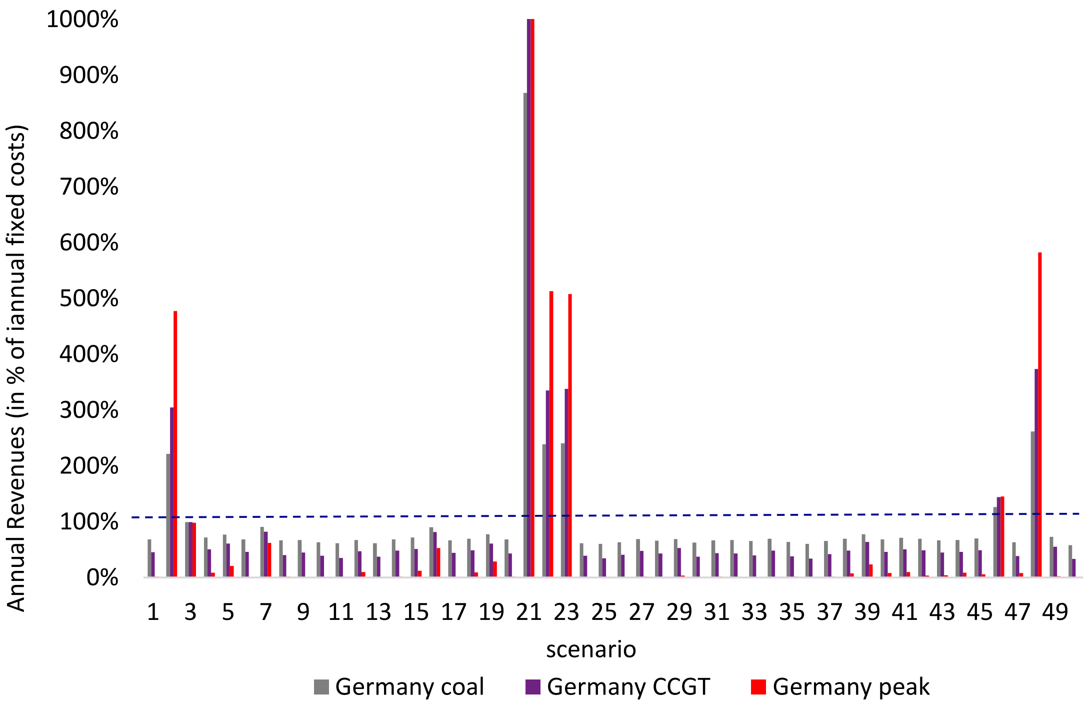

Figure 9: German assets' annual revenues without price cap

As shown in the previous graphs, peaking fleets' revenues can attain up to 25 times their annual fixed costs, but only for a limited number of scenarios in which temperatures are low and peaks of consumption coincide with a drop of wind and solar generation. For the majority of the scenarios, they do not get any revenue since marginal costs never exceed peaking unit variable costs. This phenomenon is also present for coal and CCGT fleets, but the revenues dispersion is lower, since they benefit from more regular revenues (when peaking units are called) even during warm scenarios.

Note that, in this virtual and riskless reference mix, since (i) the generation mixes are adapted (i.e. they are obtained according to the procedure presented in section 2.4) and (ii) the market is assumed to be perfect, the average revenues of each of the optimized thermal fleet exactly amounts to its annual fixed costs[8].

Revenues of actors of the virtual reference mix with price cap at 3k€/MWh

In an energy market with a lower price cap of 3k€/MWh, the dispersion of revenues is slightly lower, but since the level of revenues also decreases, the level of risk remains high. To illustrate this point, the annual revenues for French assets for the 50 climatic scenarios are presented below.

[8] To get further information on these microeconomics results, one can refer – for instance – to *Energie, Economie et politiques*, J-P. Hansen, J. Percebois.

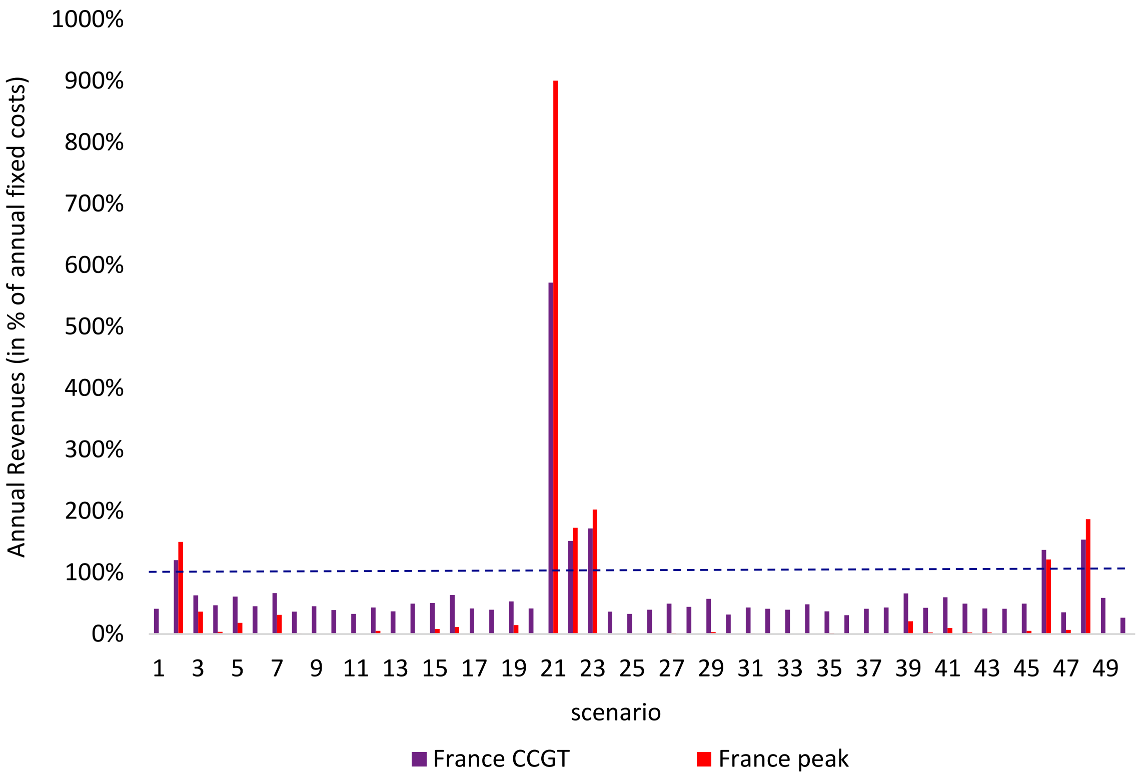

Figure 10: French assets' annual revenues with a 3k€/MWh price cap

The exact same effect can be observed on German assets' annual remunerations.

Note that in the case of a 3k€/MWh price cap, which is lower than the value of loss of load (15k€/MWh in the model), the average revenues of each thermal fleet does not allow them to cover their annual fixed costs. The difference of revenues between EOM with and without price cap finds its origin in times when the marginal cost is at least 3k€/MWh, that is only when there is some loss of load (since there are no units with variable costs higher than 3k€/MWh). During these time steps, revenues are limited by the price cap and therefore the annual revenues are insufficient to cover fixed costs. For instance, in this virtual reference mix, peak fleets only cover 40% of their fixed costs if price is capped at 3k€/MWh.

3.1.3 Revenues assessment for capacity reliability mechanism

In order to ensure security of supply, several countries have studied or implemented capacity reliability mechanisms of different forms. This study focuses on a capacity market in which, to meet a security of supply criterion, capacity providers are remunerated. In particular, the capacity price is not set a priori, but is the result of the market clearing. The methodology used to compute capacity prices can be found in section 4.1.3.

REVENUES' DEFINITION WITH A CAPACITY RELIABILITY MECHANISM

When introducing a capacity mechanism, capacity providers receive a remuneration which depends on the market price of capacity. Capacity providers therefore earn revenues from the energy market and from the CRM.

The annual revenues for a given producer is then given by:

$$\text{AnnualRevenues} = \text{AnnualRevenuesInEOM} + \text{Capacity} \cdot \text{capacityPrice}$$

It should be noted that the remuneration obtained in a capacity reliability mechanism (CRM) is independent of the climatic scenario. Indeed, each producer is remunerated for the capacity that he could deliver during peak hours[9]. The remuneration is therefore independent of the actual production of the asset. If their capacities are needed to ensure security of supply, all capacity providers are thereby granted a remuneration even in unfavorable climatic conditions (leading to no energy market revenues). This mechanism therefore reduces the investment risks as can be read from the following graph.

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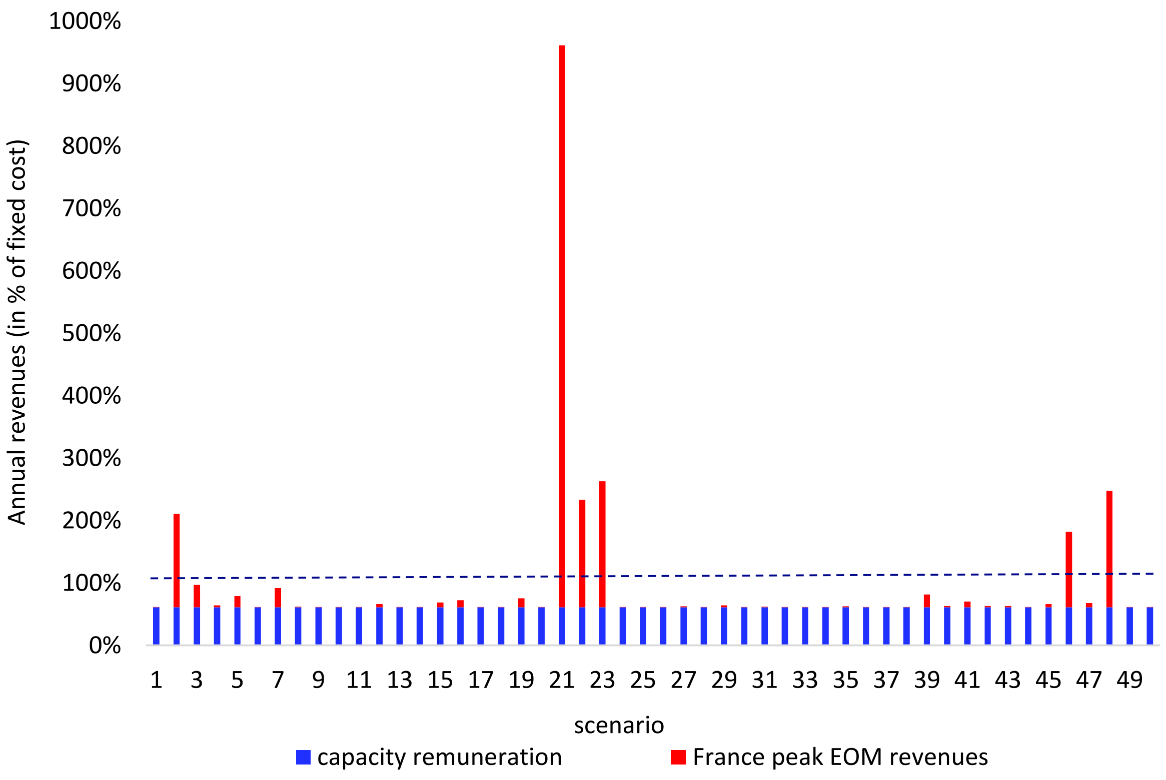


Figure 11: French peak fleets annual remunerations with a price cap of 3k€/MWh and a capacity reliability mechanism

[9] For instance, the average available capacity for peak fleets is 90% of their installed capacities.

In the previous graph, an arbitrary capacity price has been chosen to highlight the effect of a CRM remuneration on capacity providers' revenues structure. The methodology used to compute capacity prices is explained in section 4.1.3.

3.2 Investment risk assessment over asset lifetime

3.2.1 Methodology

As exhibited in section 3.1, annual revenues are highly dependent on the climatic conditions. From an investor point of view, it is the revenues over the whole lifetime of an asset that matters. As one does not know in advance the climatic conditions for the next 25 years, only a distribution of these revenues can be given. The methodology to generate these distributions of revenues over the asset lifetime is described below.

Revenues distribution over assets' lifetime

As shown in 3.1, annual revenues are concentrated in specific yearly climatic scenarios in which temperatures are low and peaks of consumption coincide with a drop of wind and solar generation. The two main factors that will therefore impact lifetime revenues are first the frequency of occurrence of this type of years and secondly the point in time when this type of years take place. Indeed, a high revenue in year one matters more than a high revenue in the last year of the operational lifetime of the asset [10].

In order to take these particularities into account, the assessment of lifetime revenues of the asset is based on a computation of its net present value. For a given order of climatic scenarios, one scenario being picked for each year in the lifetime of the asset, the lifetime revenues are then:

$$\text{lifetimeRevenues} = \sum_{\substack{\text{t in} \\ \text{lifetime}}} \frac{1}{(1+\text{r})^{\text{t}}} \text{annualRevenues}_t$$

An actualization rate of $r = 7.25\%$ is used throughout this study.

To assess a distribution of these revenues, we compute this value for 10000 orders of T years where T is the scheduled lifetime of the asset. This is done by randomly picking T climatic scenarios from the previously introduced set of 50 yearly climatic scenarios. Successive years are assumed to be independent: 50^T different possible sequences can be generated for an asset of lifetime T. The computation of lifetime revenues is then done for each one of the 10000 draws, which gives us a distribution of revenues.

Risk Premium

From an investor's point of view, the attractiveness of an investment is usually determined by comparing the expected revenues to the fixed costs. However investors commonly show a certain

[10] This phenomenon is generally called *preference for the present.*

degree of risk aversion. This is a rational approach which is due to the fact that in reality investors do not have perfect foresight. To take risk aversion into account, the value assigned to a potential investment is given by the expected revenues from which a risk premium is subtracted.

$$\text{investmentValue} = \text{E}[\text{lifetimeRevenue}] - \alpha \cdot \text{riskPremium}$$

The α parameter weighs the relative importance given to risk by investors.

The risk premium is often assumed to depend on the distribution of the expected revenues. If revenues are dispersed, the risk premium will be high and the value attributed to the investment will be lowered. The risk premium is defined as follows:

$$\text{riskPremium} = \frac{\text{semiVariance}(\text{lifetimeRevenue})}{2 \cdot \text{E}[\text{lifetimeRevenue}]}$$

Usually, for a symmetric distribution, the risk premium is computed using the variance instead of the semi-variance[11]. From an investor's standpoint, the risk consists in getting a revenue that is less than the fixed cost: it is therefore only the left part of the curve that matters, which is why the semi-variance is preferred to the variance in the case of non-symmetric distributions.

Note that the risk premium is homogeneous to a revenue. In the following, it is therefore expressed in % of the total fixed costs of the investment.

This framework is derived from the utility theory and risk aversion formulation originally exposed by von Neumann and Morgenstern, in their seminal book: Theory of Games and Economic Behavior, Princeton University Press, 1953. The above formula corresponds to further developments by Arrow (Essays in the Theory of Risk Bearing, North-Holland Amsterdam, 1971). The following paper provides some insight into the experimental and empirical issues: Holt and Laury, Risk aversion and Incentive Effects, American Economic Review, 2002.

3.2.2 Results analyses

As seen in part 3.1, the variability of the EOM-derived annual revenues' distribution over the 50 annual scenarios are higher in the case without price cap. Indeed since the market price can take higher values during scarcity periods, revenues obtained for difficult climatic scenarios are higher, which induces a greater dispersion of revenues. The same results are obtained for lifetime revenues, as is illustrated below in the following curves which present the distributions of lifetime revenues in EOM without price cap for coal fleet, and in EOM without price cap, EOM with price cap at 3k€/MWh and in the case of a CRM for peak fleets.

Looking at revenues dispersion in Figure 12, it is clear that coal fleet revenues are much more stable than peak fleet revenues (and DSM). Indeed, even though revenues expectations without price cap is exactly 100% of the fixed costs for both assets, peak fleets' revenues may vary by over 300% of their

[11] In this case semi-variance and variance are equal.

fixed costs depending on the climatic scenarios, since annual revenues of peak fleets can vary from 0 to 30 times their annual fixed costs. Coal fleet's revenue, on the other hand, have a global dispersion of about 120% of their fixed costs since the variation of their annual revenues is lower: even for difficult scenarios, annual revenues cover around 60% of their annual fixed costs. Overall results show that, in general, base fleets' risks are smaller than peak fleets' one.

These results stay true with a price cap, even if the revenues and risks are lower.

Finally, a CRM decreases significantly the revenue dispersion. Indeed, the CRM replaces an uncertain revenue from the EOM, depending on the climatic conditions, by a stable revenue. Another illustration of this phenomenon can be seen in the following table (Table 7) providing risk premiums for French fleets in the different market designs: energy market with and without price cap, with or without a CRM in France or Germany.

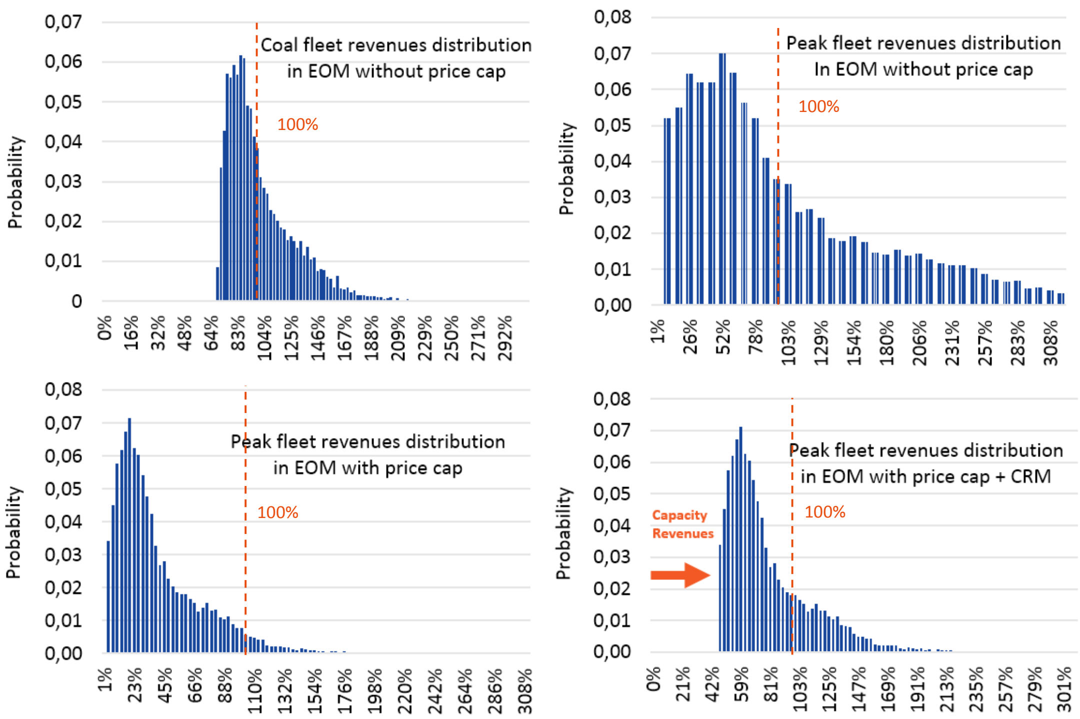


Figure 12: Impact of market design and technology type and lifetime revenues

Risk premiums (in % of lifetime fixed costs)		
	France CCGT fleet	**France peak fleet**
EOM without price cap	22.1%	50.7%
Energy market without price cap + CRM in France	12.6%	30.5%
Energy market without price cap + CRM in France and Germany	4.7%	14.0%
EOM with price cap at 3k€/MWh	5.5%	14.3%
Energy market with price cap at 3k€/MWh + CRM in France	2.9%	9.5%
Energy market with price cap at 3k€/MWh + CRM in France and Germany	0.9%	4.2%

Table 7: Impact of the market design on risk premium

As seen in Figure 12, the variability of revenues in an energy market without price cap is significant. The risk premiums are therefore very high. With a price cap, the variability is reduced, so the risk premium is lowered. With a CRM, the risk premiums decrease in both cases since the risk is lowered and more bearable.

Note that in this approach, risks related to long-term variations of the demand, variable costs and mix structure, such as a higher than planned rate of penetration of renewables, are not taken into account in the computation of the dispersion of revenues in the energy market nor in the computation of the capacity price[12].

[12] Capacity pricing methodology is given in section 4.1.3.

4 Investments and security of supply: the impacts of market designs

As seen in the previous section, market design has a high impact on risk levels pertaining to the lifetime revenues of assets. Since investors usually have to take into account risk to assess the economic feasibility of an investment, a market design generating a high level of risk for actors might lead to a global trend of underinvestment. Since the revenues of the different fleets are not impacted in the same way, risk is likely to modify the structure of the generation mix in the long run. This section aims at quantifying these structural changes.

4.1 Methodology

In order to compare the considered market designs, an iterative process allowing the conventional thermal fleets to adapt their installed capacities has been implemented. Starting from the virtual reference mix, the revenues of each actor, which depend on the market design, are computed for the 50 climatic scenarios. Depending on the assets' estimated revenues over their lifetime, the installed capacity is increased or decreased. After a number of iterations, the process leads to a new generation mix where every asset is at the financial equilibrium.

In this process, investors are assumed to be risk averse, meaning that in order to be at the financial balance, the total revenues need not only to cover the costs but also an additional risk premium related to the dispersion of the revenues. The value of an investment is therefore lowered by the risks on its revenues. For the same average revenue and investment cost, a risky investment might then be unprofitable while a non-risky investment will be profitable.

This process allows to take into account the volatility of the investments' performances due to climatic variability. Risks related to the long-term evolution of the demand, to national political decisions regarding the mix structure, to primary energy import prices, and to CO_2 costs, which impact both capacity and energy market prices, have not been considered in this study. Note that these additional risks would reinforce the risk dimension and thus the underinvestment trend in all cases.

In this part, for both types of energy markets, the following market designs were considered:

- **EOM** in both France and Germany - A coordinated Franco-German energy-only market (EOM) with a shared price cap,
- **Energy market + CRM** in France and **EOM** in Germany - The French capacity market is modelled according to the objective of the French capacity obligation: ensuring a LOLE of 3 hours (on average over the 50 climatic scenarios). Germany's market remains an energy-only market, both markets have the same price cap,
- **Energy market + coordinated CRM** in France and in Germany – In this case, system adequacy calculations are made in common in order to deliver the level of security of supply reached with the virtual reference mix. Both energy markets share the same price cap.

Note that only hard coal, gas and peak fleets were considered in the re-adaptation of the mix.

4.1.1 Risk criteria for investment evolution

The rules used to adjust the capacity of coal, CCGT and peak fleets are given below:

- **If**:

  $$\mathrm{E[lifetimeRevenues]} > \mathrm{fixedCosts} + 2.5 \cdot \mathrm{riskPremium}$$

  Then, the asset is considered as profitable and the installed capacity is increased.

- **If**:

  $$\mathrm{fixedCosts} + 2 \cdot \mathrm{riskPremium} > \mathrm{E[lifetimeRevenues]}$$

  Then, the asset is considered non-profitable and its installed capacity is decreased.

- Between these two limits, the asset is considered to be at financial equilibrium and its capacity remains unchanged. Its revenues are sufficient to cover the fixed cost of the investor while taking into account the risk.

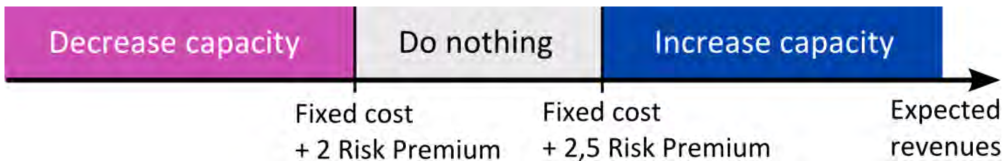


Figure 13: Capacity adjustment mechanism

Risk premium multiplicative coefficients (2 and 2.5) have been chosen to correspond to a moderately risk averse actor. A particularly risk averse actor may be modelled through larger coefficients while an actor less sensitive to risk may use lower coefficients. One may refer to *Holt and Laury, Risk aversion and Incentive Effects, American Economic Review, 2002*, for additional insight into these choices. Note that considering a more (respectively less) risk averse behavior of the actors will increase (decrease) the difference of risks between base and peak fleets, but the main tendencies in the evolution of mixes presented below will remain the same.

The capacity step by which fleets are increased or decreased is chosen so that the algorithm presented in the next section converges satisfactorily.

4.1.2 Simulation process for an energy-only market

Depending on the chosen market design, individual calculations of investors and the decision to increase, to keep or to decrease their installed capacity accumulate to a macro-economic result: a new generation mix. The following iterative process is used to adapt the generation according to the risk felt by investors. The algorithm presented below is valid for energy-only market designs with or without price cap.

1. Start from the virtual reference mix (see section 2.5)
2. Simulate the power system management over the 50 climatic scenarios
3. Compute actualized revenues' distribution using simulations' outputs (in particular production by fleet and the marginal costs of electricity)
4. Assess risk premiums and investors' decisions.
5. Update the mix in consequence, by increasing the capacity of profitable fleets and decreasing capacity of non-profitable fleets using previously described rules.
6. When every asset is at its financial balance, the process ends. Else, go to step 2.

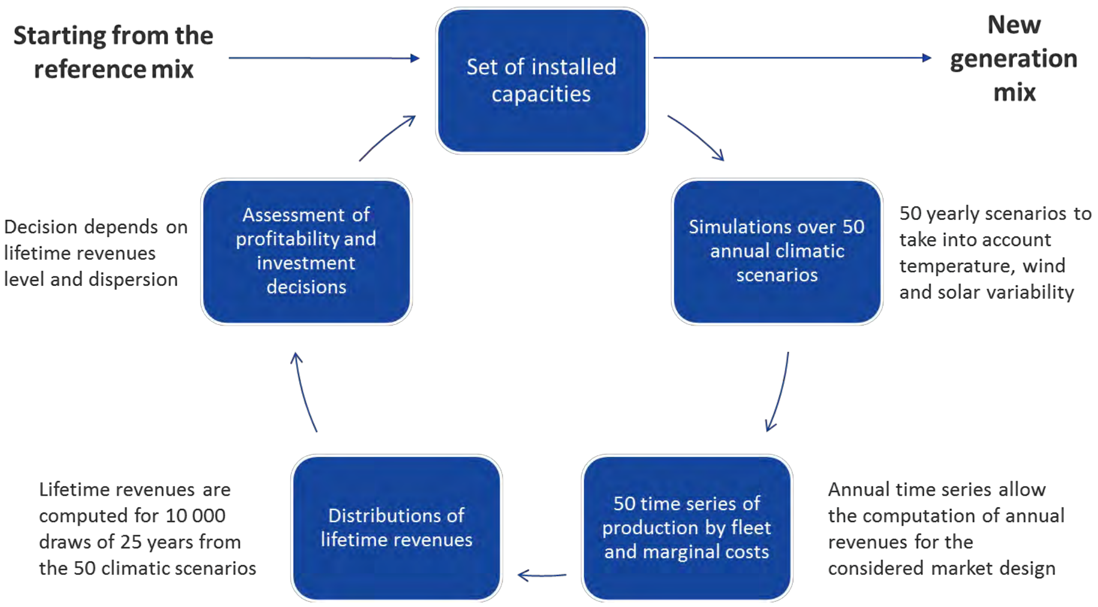


Figure 14: Generation mix adjustment with regard to investors' behavior

The result of this approach is a re-adapted generation mix, depending on the market design, where every asset is at its financial equilibrium.

4.1.3 Simulation process with a capacity reliability mechanism

The previously described process has been adapted to handle capacity mechanisms.

The capacity price is computed independently for France and Germany, for given criteria on the level of security of supply. In the case of the French capacity mechanism, as defined by the French authorities, the capacity price is set to ensure the average loss of load duration over the climatic scenarios is no more than 3 hours. In the case of coordinated capacity mechanisms, a target of minimal installed capacity, defined conjointly for France and Germany, is chosen instead[13].

In each case, the capacity price is common for all fleets within the country and is the minimum incentive to ensure the security of supply target is met.

Since an iterative process is used to adjust the mix, the capacity price evolves at each step of the process following the rules described below:

- If the security of supply is not sufficient, the price is set to the minimal level that would induce an increase of at least one asset's installed capacity.
- If the security of supply is more than required, the price is set to the minimal level that would induce a decrease of at least one asset's installed capacity.

The complete algorithm aiming at adapting the generation mix in the case a capacity mechanism is implemented is given below:

1. Start from the virtual reference mix (see section 2.5) and a capacity price of 0
2. Simulate the power system management over the 50 climatic scenarios
3. Compute actualized revenues' distributions using simulations' outputs (in particular production by fleet and marginal costs of electricity)
4. Assess risk premiums and investor decisions with the current capacity price.
5. If necessary, update the capacity price according to the targets so that capacity evolves in the right direction. Assess risk premiums and investor decisions.
6. Update the mix in consequence, by increasing the capacity of profitable fleets and decreasing capacity of non-profitable fleets using previously described rules.
7. If every asset is at its financial balance, the process ends. Else, go to step 2.

This methodology allows to reach a new generation mix where every asset participates to the CRM: offer of capacity is equal to the demand of capacity defined by the security of supply target (which is therefore met). Additionally, each asset is at its financial equilibrium: its remuneration in the energy market and in the CRM is just enough to cover its fixed costs and the risk premium.

4.2 A CRM in France to ensure security of supply

The simulation results demonstrate that the security of supply is greatly improved by the implementation of a CRM in France. Indeed, compared to a situation of a pure EOM, the CRM in France ensures structurally that loss of load will not go above 3 hours in average.

In a situation of an energy market with price cap at 3k€/MWh, the price of the French capacity market converges at 33600€/MW, which is sufficient to maintain enough capacity to ensure less than 3 hours of curtailment in France. In France, the average annual loss of load, measured in GWh, is reduced by a factor 4. Across the whole France-Germany zone, the reduction factor is 2.5.

[13] This capacity target is based on the capacity in both countries in the virtual and risk-free generation mix.

	EOM with price cap at 3k€/MWh	Energy market with price cap at 3k€/MWh + CRM in France
Loss of load volume in France (GWh)	46	11
Loss of load volume in Germany (GWh)	9	10

Table 8: Loss of load volumes in an energy market with price cap at 3k€/MWh, with or without CRM in France

The re-adapted generation mixes obtained in this case are presented below.

Figure 15: Coal, CGGT and Peak capacities for an energy market with price cap at 3k€/MWh, with or without a CRM in France

From this graph, one can see that the CRM in France has the following effects:

- **The total capacity increases to ensure security:** the global capacity increases (+3GW). The CRM ensures more stable revenues which decrease risks for investors.
- **The structure of the mix is changed because of the reduced risk:** New investments primarily concern peak capacity (+3.5 GW) and CCGT (+1GW). Coal capacity decreases by 1.5GW. As explained in Section 3.2, reducing investment risks with stable revenues first benefits peak capacities (and DSM, in an equivalent manner). Their capacity increases and comes closer to the reference risk-free mix.

- **Since capacity decreases in Germany, a new equilibrium has to be found to reach the required level of security of supply in France:** Investments are made in France (+5GW in France, versus -2GW in Germany in an energy market with price cap). Investments in France benefit from more stable revenues, while German capacity suffers from a high risk and insufficient remuneration as explained in section 3.1 due to the 3k€/MWh price cap. It should however be stressed that this phenomenon is likely be reduced if the interconnection capacity between France and Germany does not increase to the optimized level of 6,9GW[14].

Because of the improvement of the mix structure and of the reduction of loss of load duration, introducing CRM in France in addition to an energy market with price cap leads to a reduction of 370M€ of the annual total costs.

Costs difference w.r.t energy market with price cap at 3k€/MWh	**Impact of a CRM in France**
Operational Costs (M€/year)	70
Loss of load costs (M€/year)	-510
Fixed annual costs (M€/year)	70
Total Cost (M€/year)	**-370**

Table 9: Impact in terms of costs of a CRM in France in an energy market with price cap

Even if the global capacity increases by 3GW, the additional CAPEX costs remain limited as the generation mix is closer to the virtual reference mix (with more peak units and less coal). Operational costs slightly increase, as more energy is generated by peak units and CCGT (with higher variable costs). On the other hand, costs related to loss of load highly decrease.

When considering an energy market without price cap, one may notice that the capacity transfer from France to Germany is lower (less than 1GW). Moreover, the security of supply is in this case also improved by the introduction of a CRM in France and the global welfare is not decreased.

Note that in Germany, a strategic reserve is being implemented, complementing the electricity market. It is designed to exist on a stand-alone basis, separated from the electricity market. It is important to note that the strategic reserve therefore does not solve the risk issues for units in the energy market, as energy market revenues remain equally volatile and uncertain.

4.3 A coordinated CRM to improve the security of supply and secure investments in both France and Germany

As presented in section 4.1.3, the market design studied in this section assumes a CRM in both France and Germany with targets driven from the reference case (optimal supply mix without risk constraints).

[14] In the study, the interconnection capacity between France and Germany has been optimized. Resulting capacity is 6,9 GW, a level which is higher than its current capacity.

In the case of an energy market with price cap at 3k€/MWh, the capacity market price converges at around 44300€/MW in Germany and 45300€/MW in France. It is not surprising that prices are very similar in French and German capacity markets even if they are not directly linked. Indeed, since France and Germany are very well interconnected (almost 7GW of interconnection), revenues per unit of installed capacity in the energy market are almost the same for thermal fleets in both countries. Therefore, the capacity prices needed to ensure that fleets stay/develop in the market are similar for the two countries. With this level of capacity price, around 80% of the fixed costs of peak power plants is covered by the capacity remuneration[15].

The obtained generation mixes with an energy market with price cap at 3k€/MWh are presented below.

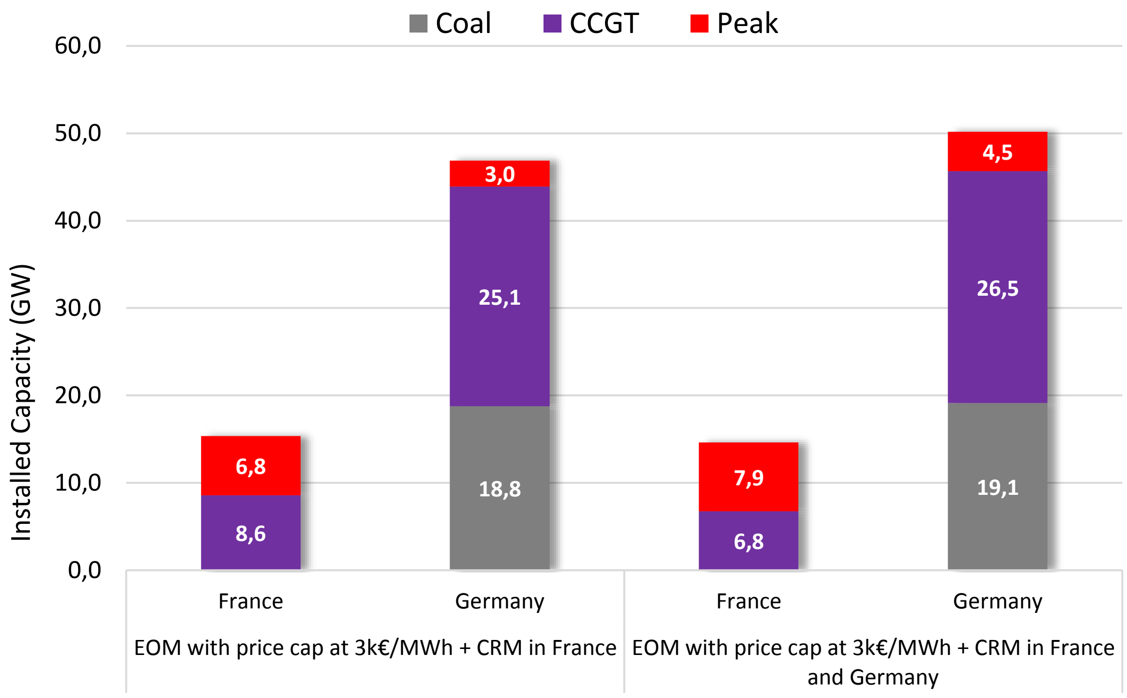
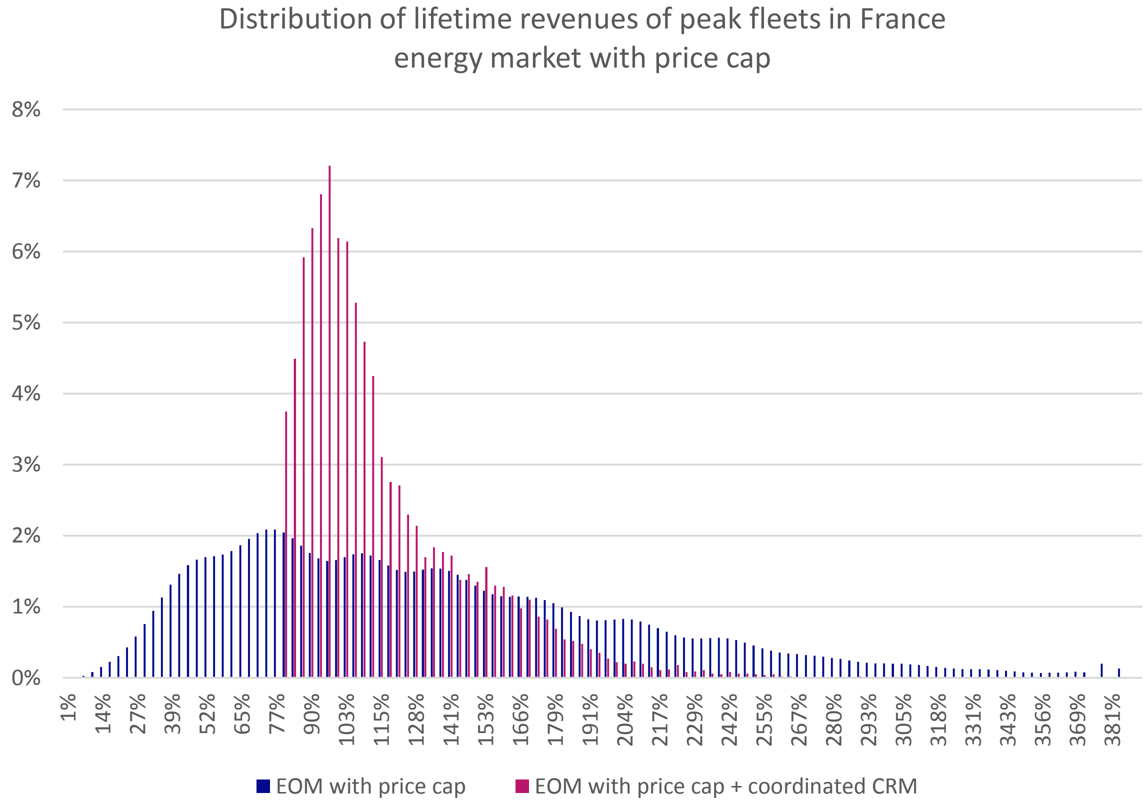


Figure 16: Generation mix for the market designs in an energy market with price cap

Note that in this case, the implementation of a coordinated CRM prevents a transfer of capacity from one country to another. Indeed, when a CRM is implemented in both countries, the risk levels for producers in both France and Germany are similar and cross-border effects on capacity investments are therefore limited.

[15] Indeed, since it is available at 90% of the time during peak hours, it will earn 40500€/MW for its capacity, which is roughly 80% of the fixed costs of 53k€/MW.

Moreover, with a coordinated CRM, the resulting supply mix is closer to the risk-free virtual reference mix[16]: revenues are more stable and the risk levels for producers are lowers, in particular for peak units as illustrated in the following lifetime revenue distribution curves.



Overall, due to the risk being reduced in France and Germany in a similar way, the global cost is lower for a coordinated CRM than for all the other studied cases (an EOM in France and Germany, or a CRM only in France).

Costs difference w.r.t energy market with price cap at 3k€/MWh	Energy market with price cap + CRM in France	Energy market with price cap + coordinated CRM in France and Germany
Operational Costs (M€/year)	70	< 5
Loss of load costs (M€/year)	- 510	- 700
Fixed annual costs (M€/year)	70	230
Total (M€/year)	**- 370**	**- 470**

Table 10: Difference of total costs with an energy market with price cap

[16] The difference in terms of annual costs is less than the numerical precision of the model.

Finally, a coordinated CRM allows to highly decrease the loss of load volume across the whole zone, as the notion of security of supply is inherent to this market design: as long as the target of capacity is chosen adequately, security of supply targets are met.

	EOM with price cap	Energy market with price cap + coordinated CRM
Loss of load volume in Germany (GWh)	9	1.9
Loss of load volume in France (GWh)	46	6.7

Table 11: Loss of load volumes in an energy market without price cap and with a coordinated CRM

In the case of an energy market without price cap, results of an implementation of a coordinated CRM are fairly similar. The obtained capacity market price is however lower since revenues in the energy market are higher than in the case with a price cap. The price converges at 26100€/MW in Germany and 24500€/MW in France. As a consequence, peak unit revenues are more volatile (since more than half the remuneration still comes from the energy market).

The obtained generation mixes are presented below.

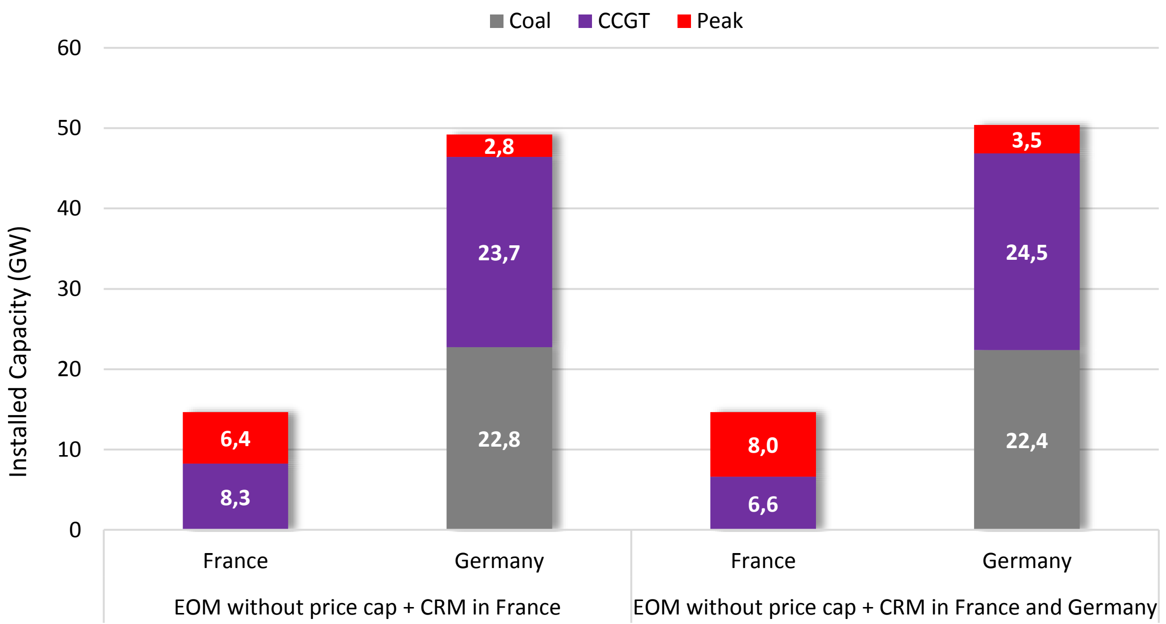
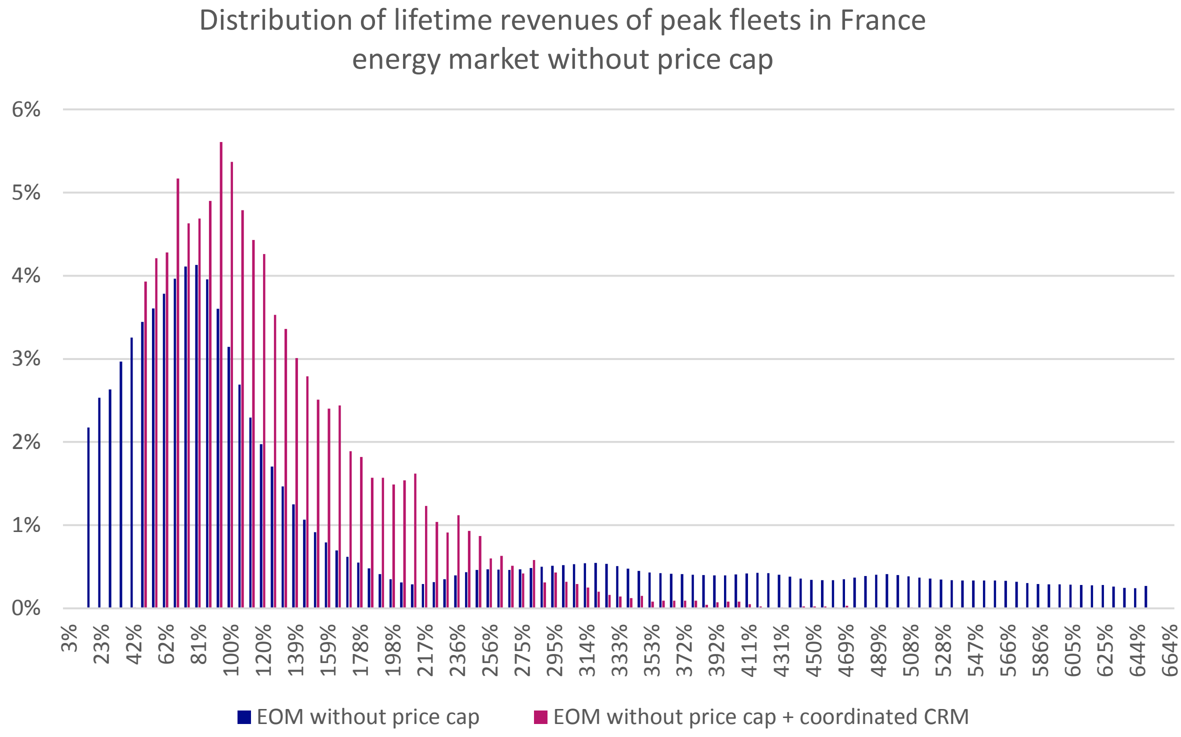


Figure 17: Generation mixes in an energy market without price cap with CRM and coordinated CRM

Note that in this case (energy market without price cap), the coordinated CRM also prevents the transfer of capacity from Germany to France. Indeed, as seen previously, this is due to the risk levels for production assets being lower and similar in France and Germany.

The obtained generation mix is therefore closer to the virtual risk-free mix due to the reduction of the risk. Lifetime revenues are indeed more stable, in particular for peak fleets, as can be seen in the following distribution curves.



The total annual costs are also reduced compared to a situation with no CRM, or with a CRM only in France, as one can see in the following table.

Costs difference w.r.t energy market without price cap	Energy market without price cap + CRM in France	Energy market without price cap + CRM in France and Germany
Operational Costs (M€/year)	-20	30
Loss of load costs (M€/year)	< 5	-70
Fixed annual costs (M€/year)	20	10
Total Cost (M€/year)	**< 5**	**-30**

Table 12: Difference of costs with the virtual reference mix in an energy market without price cap

One can note that the reduction of costs is mainly centered on the reduction of loss of load through an increase of capacity (and thus investment and operational costs). While the implementation of a coordinated CRM has a relatively modest impact on the annual costs of the power system, it allows a significant reduction of the loss of load volume across the whole zone, even with an energy market without price cap.

	EOM without price cap	Energy market without price cap + coordinated CRM
Loss of load volume in Germany (GWh)	3.5	1.9
Loss of load volume in France (GWh)	9.9	6.7

Table 13: Loss of load volumes in an energy market without price cap and with a coordinated CRM

5 Appendix A – Description of the Model and of Data Source

5.1 Description of the Model

5.1.1 Production Side

Section 2.4 contains the description of the assumptions related to the structure of the 2030 generation mixes in France and Germany. This section provides additional elements regarding the parameters characterizing each of the technologies entering these mixes.

Power plants have been clustered into so-called **fleets** according to the power plants' primary energy. As a result, the following fleets compose the generation mixes:

- non-renewable thermal fleets:
    - nuclear fleet,
    - lignite fleet,
    - coal fleet,
    - CCGT fleet,
    - peak fleet.
- intermittent renewable fleets:
    - wind fleet,
    - solar PV fleet,
    - renewable thermal fleet,
    - run-off-river hydro fleet,
    - hydro pondage fleet.
- hydro with storage fleets:
    - seasonal hydro storage fleet,
    - pumped hydro storage fleet.

NON-RENEWABLE THERMAL FLEETS

The non-renewable thermal fleets that enter the 2030 generation mixes are nuclear fleets (in France), lignite fleet (in Germany), coal fleet, CCGT fleet, peak fleets and other non-renewable thermal fleet.

Each thermal asset is characterized by:

- The installed capacity (in MW),
- The variable cost (in €/MWh), including both fuel and CO_2 emissions costs,
- The availability profile (in %) based on historical values.

For example, the France nuclear fleet average availability profile is presented below, along with some historical profiles.

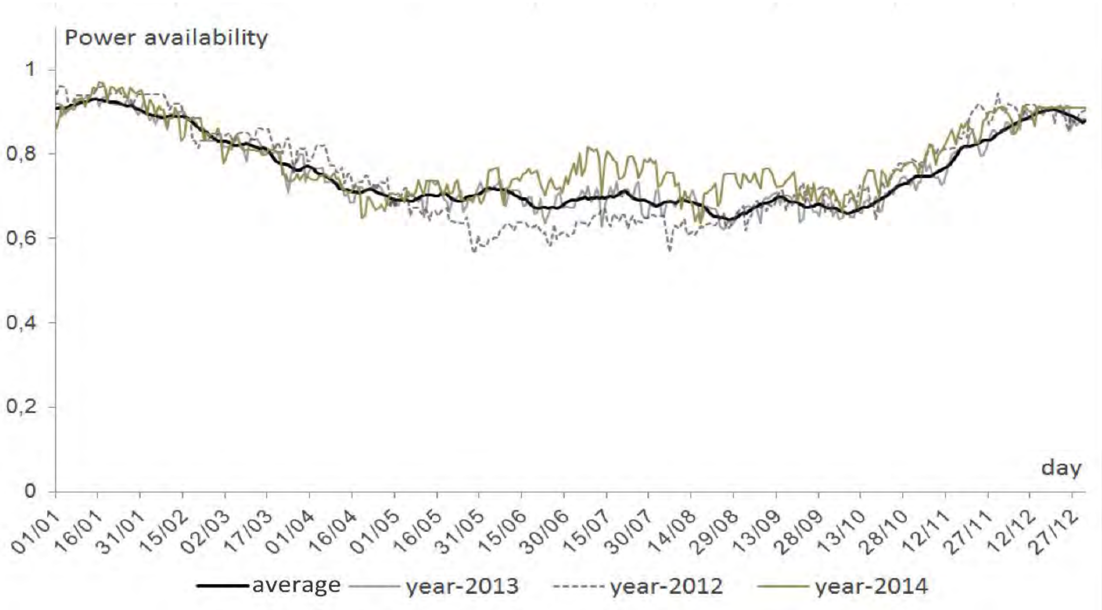


Figure 18: France nuclear fleet power availability average and historical profiles (data source: http://clients.rte-france.com/)

The previous figure clearly displays the seasonality of the French nuclear power availability. Indeed, to fulfill maintenance requirements while minimizing generation shortfalls risks, maintenance is mainly performed in summer, when less generation capacity is needed.

Parameters entering operational constraints such as minimum load (nuclear) and power gradients (coal, nuclear) constraints are also provided.

Additionally, since coal, CCGT and peak fleets capacities are optimized in our simulations (see section 2.4), these assets are also characterized by annual investment and fixed OPEX costs.

Intermittent renewable energy sources

Intermittent renewable energy sources taken into account are wind fleet, solar PV fleet, renewable thermal fleet, run-off-river hydro fleet and hydro pondage fleet.

Since the production delivered by these assets is intrinsically intermittent, both their installed capacity and power generation profiles enter the model.

- Average profiles based on historical values are provided by RTE for hydro pondage, run-off-river and renewable thermal fleets,
- Generation profiles for wind and solar PV are generated based on 50 climatic scenarios, see Section 5.2.3.

HYDRO STORAGE TECHNOLOGIES

Two types of hydro storage facilities are taken into account in this study: a seasonal hydro storage fleet and a pumped hydro storage fleet.

By definition, pumped hydro storage facilities are assumed to control the amount of energy stored in their reservoirs. They are characterized by an installed capacity, a storage capacity and a storage efficiency of 80%.

Seasonal hydro storage facilities correspond to dams that are used to store energy from one season to another. They usually are equipped with large storage capacities, whose operations depend on water inflow. Seasonal hydro storage facilities are characterized by an installed capacity, a storage capacity, a minimum storage level and a water inflow profile, which are calibrated on historical data. The following figure shows the average France hydro seasonal storage level as well as historical profiles.

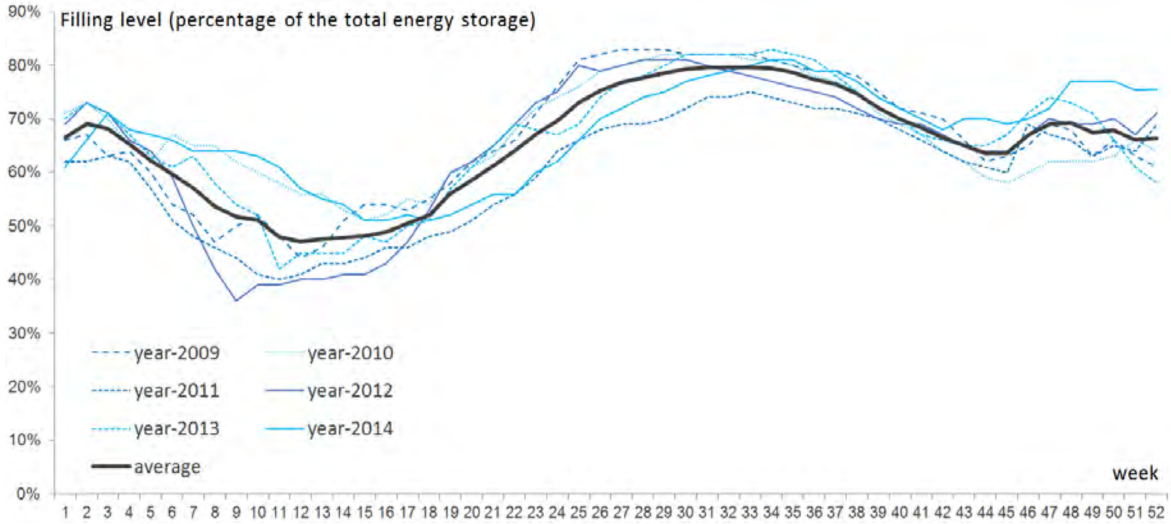


Figure 19: France hydro seasonal storage filling level average and historical profiles (data source: http://clients.rte-france.com/)

The following table provides the technical characteristics of the two types of hydro storage technologies considered in France and Germany.

	Storage Capacities in 2030	
	Maximal Stock Volume (GWh)	Maximal Generating Power (MW)
France Hydro storage	3 700	9 300
France Pumped storage	160	4 300
German Pumped Storage	60	8 000

Table 14: Storage capacities in France and Germany

5.1.2 Demand Side

The overall demand has been divided into a thermo-sensitive part and a fixed part. The thermo-sensitive part corresponds to heating and air conditioning, whose profiles vary according to climatic conditions. All the other uses are aggregated into the fixed part of the demand except for the domestic hot water, whose significant contribution to the French demand called for a specific representation. Additional information regarding the construction of demand profiles is available in section 5.2.

The cumulative consumption in October 2030 for a particular climatic scenario is shown on the following figure for France:

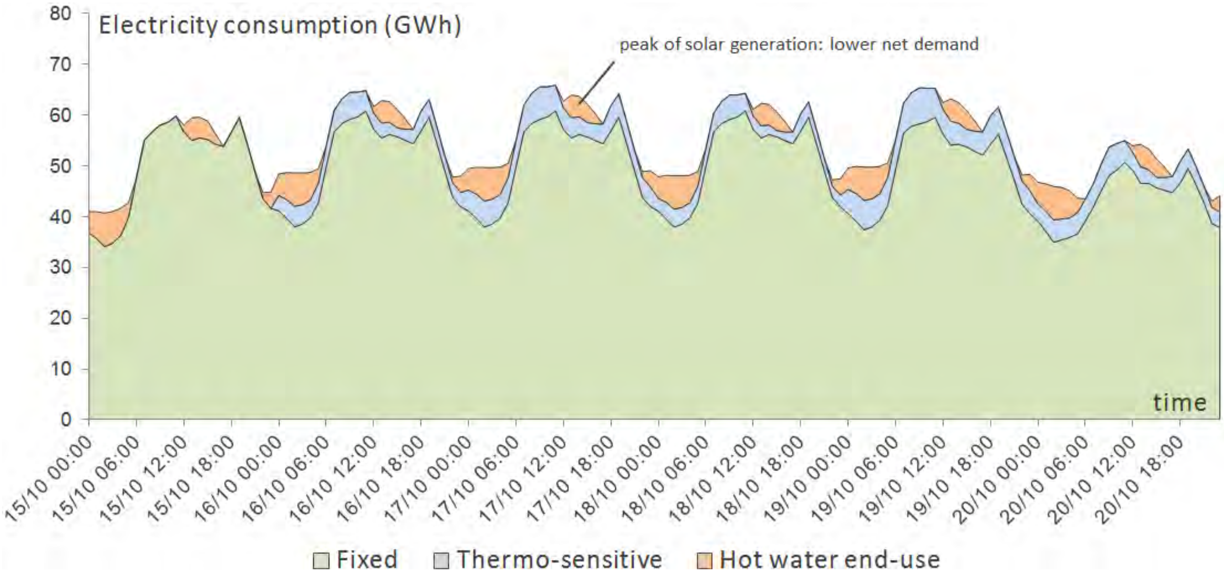


Figure 20: French cumulative consumptions in October 2030

5.1.3 Demand-side management capacities

Demand-side management is taken into account in the model. Two types of assets have been considered.

The first one represents distributed load shedding in the residential sector. It takes the form of an additional energy reserve with a limited power capacity. The energy reserve is supposed to be brought online for a maximum of 100 hours.

The second one represents the industrial demand-response program, and is only limited in power capacity for a cost of 400€ per MWh. The following table gives installed capacities in France and Germany in 2030.

	Demand-side management capacities (MW)	
	France	Germany
Distributed load shedding	7 000	2 500
Emergency load shedding (400€/MWh)	4 000	5 000

Table 15: Details on DSM installed capacities

5.1.4 Interconnection and exchanges with the rest of Europe

The interconnection between France and Germany is explicitly modeled. Its capacity is optimized during the construction of the energy mixes, see section 2.4 . The hourly power flow then results from the subsequent operations optimization.

Exchanges with the rest of Europe are modeled as import and export contracts. The import and export volumes are calibrated using a model based on considerations regarding the residual demand in both France and Germany.

5.2 Construction of the climatic scenarios

5.2.1 Climatic scenarios

The key parameters driving both the demand and intermittent power generation are related to climatic conditions. Due to the volatility of the latter, 50 climatic scenarios are constructed to handle the uncertainty pertaining to temperatures, and to wind and solar power availabilities. A climatic scenario consists of (i) hourly temperatures, (ii) hourly wind availability, and (iii) hourly solar radiation. A particular effort has been devoted to taking correlations between temperature, wind and solar irradiation into account.

Taking correlations into account may indeed be crucial. Indeed, whether or not residual demand peaks simultaneously in France and Germany may have a significant impact on optimal installed capacities, power management, and hence on investors' revenues and capacity prices.

First, the correlations between historical time series have been analyzed. For instance, the following graphs show that days that are both sunny and windy Germany are not frequent, and that windy days in Germany are neither very cold nor very warm in France. These empirical considerations prove to be useful to determine if a generated climatic scenario has to should better be rejected or not.

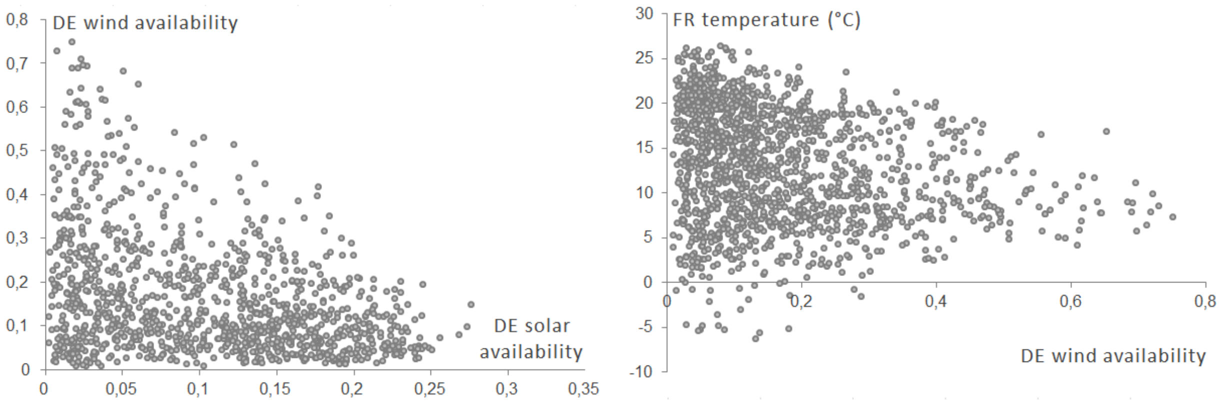


Figure 21: France temperature and Germany wind power availability and Germany wind and solar power availabilities correlations

Another important point when generating climatic scenarios, is to take into account the seasonality of temperatures, wind and solar time series. As shown in Figure 22, wind power availability profiles exhibits a short-term periodicity, which is not the case for solar profiles. Finally, mean solar and wind power plants' generating levels are related to seasons (see Figure 23).

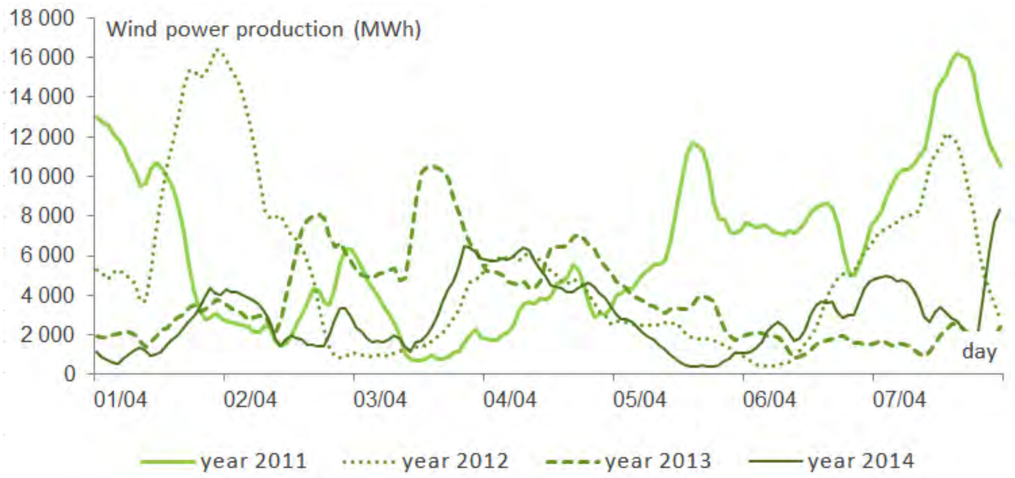


Figure 22: Wind power production in Germany during the first week of April for years 2011 to 2014

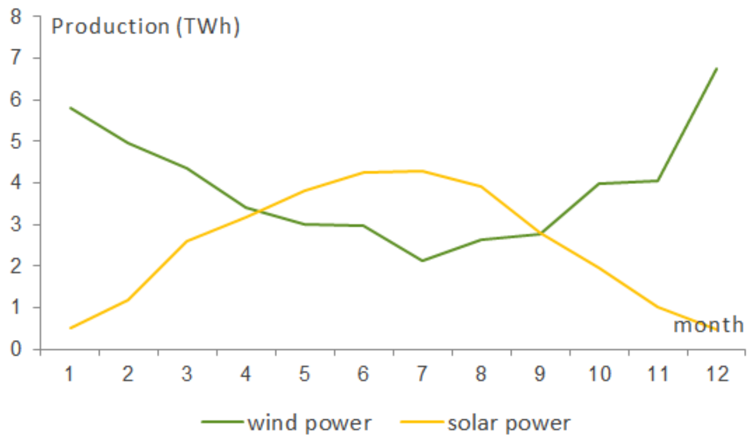


Figure 23: Germany wind and solar average monthly productions over 2012-2014

Finally, temperature also depends on seasons. Hourly temperature are generated using a statistical regression method over historical values. As a result, 50 scenarios of temperature have been obtained. These scenarios can be seen in the following figures.

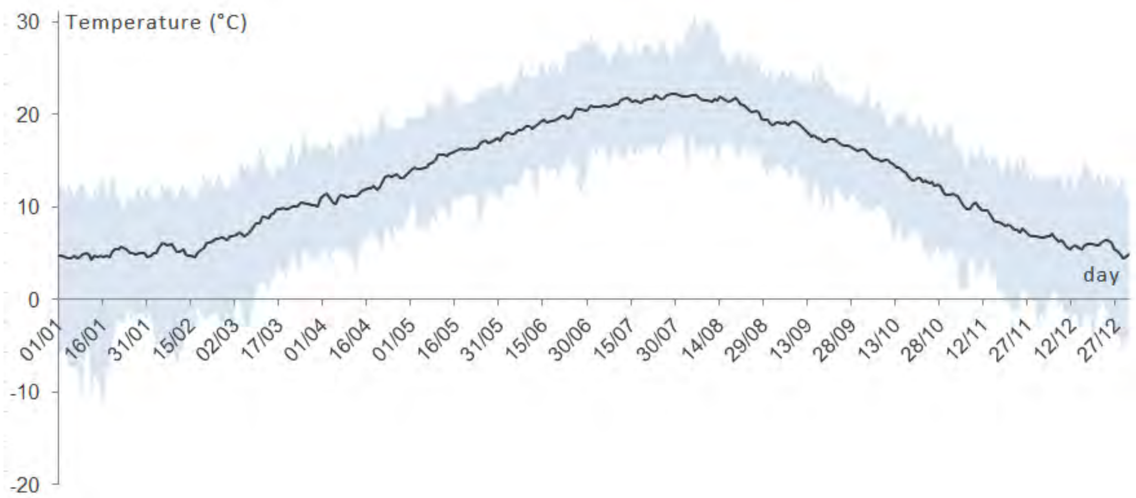


Figure 24: Overview of French year-2030 temperature forecasts

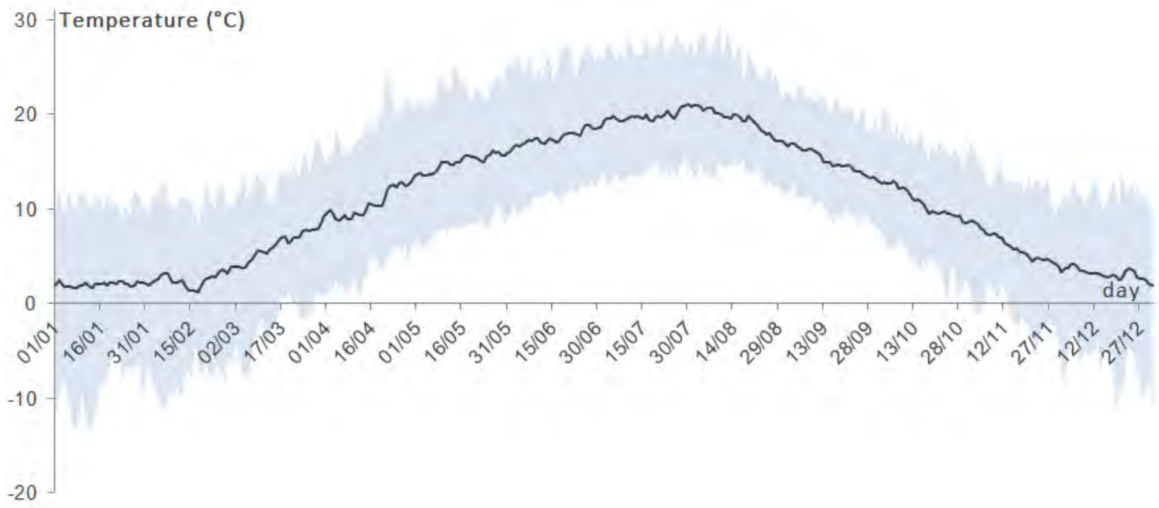


Figure 25: Overview of German year-2030 temperature forecasts

5.2.2 Demand Scenarios

As presented in 2.4, demand is divided in two parts for Germany (fixed non thermo-sensitive and thermo-sensitive parts) and in three parts for France (fixed non thermo-sensitive, thermo-sensitive and domestic hot water parts). The fixed non thermo-sensitive part of the load is generated by using forecasts that are based on historical values. The thermo-sensitive parts depend on the 50 previously generated climatic scenarios through the implementation of a thermal gradient method. For France, the hourly thermal gradient in winter is taken at -2040 MW per °C: a decrease of one degree results in an increase of the power demand by 2040 MW[17]. Air conditioning is also taken into account in France, with a gradient of 320MW per °C. In Germany, the average winter gradient is 460 MW per °C.

Finally, the French domestic hot water demand is distributed over the year by assuming the daily amount of hot water is produced when prices are at their lowest. The French and German 2030 daily demand are presented on Figure 26 to Figure 28. The colored area in figure 27 and figure 28 represents the area spanned by all 50 realizations and illustrates the scenarios' dispersion.

[17] Note that this gradient is lower than the current value of 2400MW. Main causes for this reduction are energy efficiency measures (including change of supply mix for domestic heating).

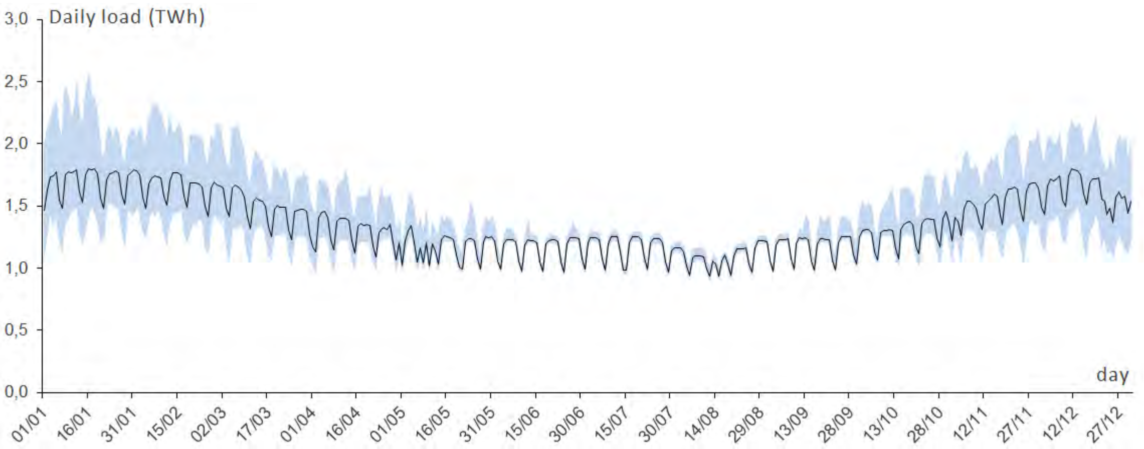


Figure 26: Overview of French 2030 daily load (blue area) and related average profile (black curve)

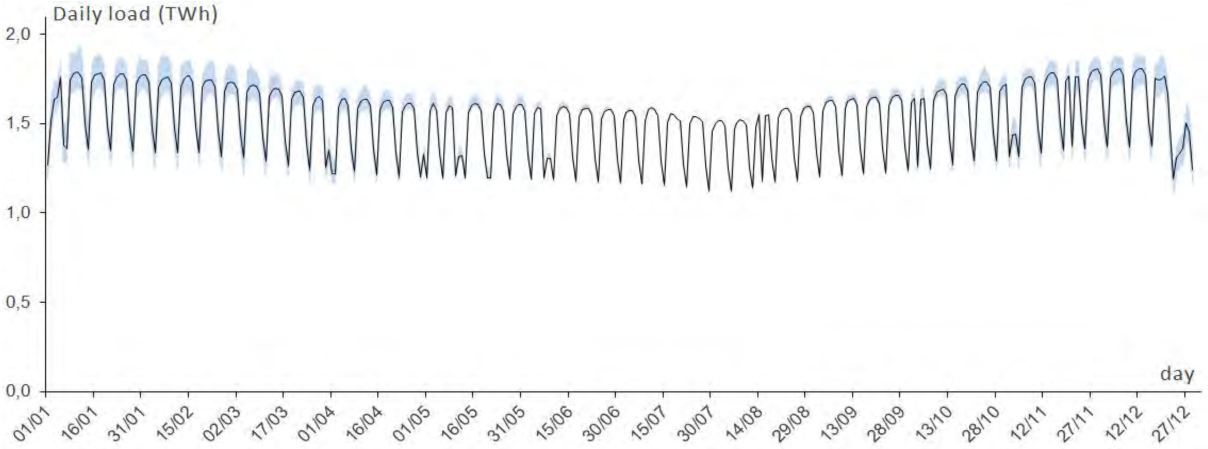


Figure 27: Overview of German year-2030 daily load (blue area) and related average profile (black curve)

As can be noticed, the demand scenarios comply with the main typical structures which have to be observed: seasonality, magnitude, holidays, thermo-sensitivity (Figure 26 and Figure 27) and the daily dispatch of the France hot water consumption (Figure 20).

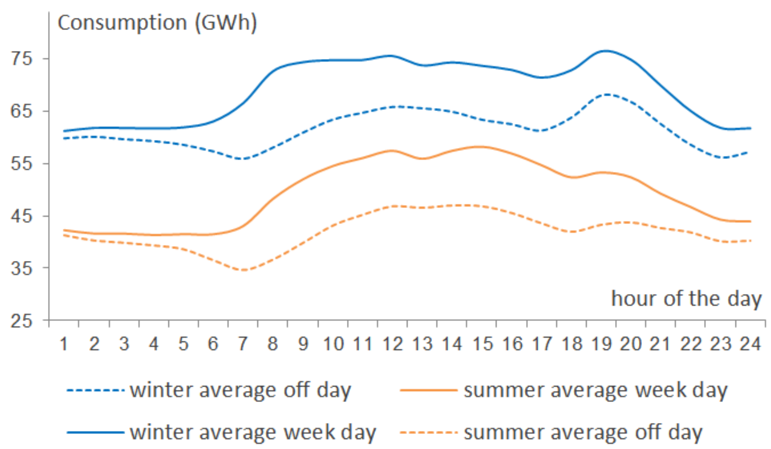


Figure 28: Average days of France consumption

5.2.3 Renewable Production

The construction of the renewables power scenarios is based on a monitored[18] crossover of the historical availabilities profiles and on a sample rejection mechanism based on correlation considerations (such as those which are described in Section 5.2.1). A sample of the generated scenarios are displayed in Figure 29, Figure 30 and Figure 31.

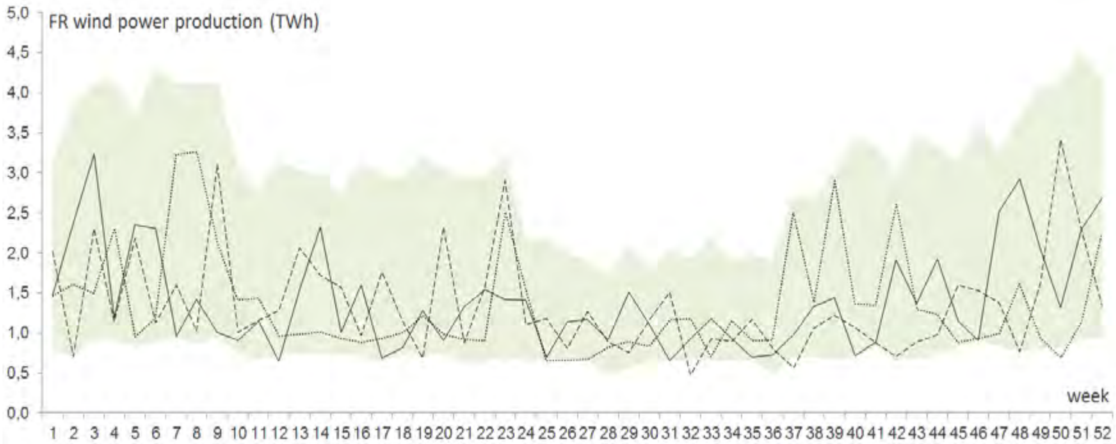


Figure 29: Overview of year-2030 wind power production in France

The 50 wind scenarios of wind power production in France span the colored area shown on Figure 30. In addition, three randomly picked curves are displayed to highlight the variability of wind production. The corresponding graph for Germany is shown in Figure 31.

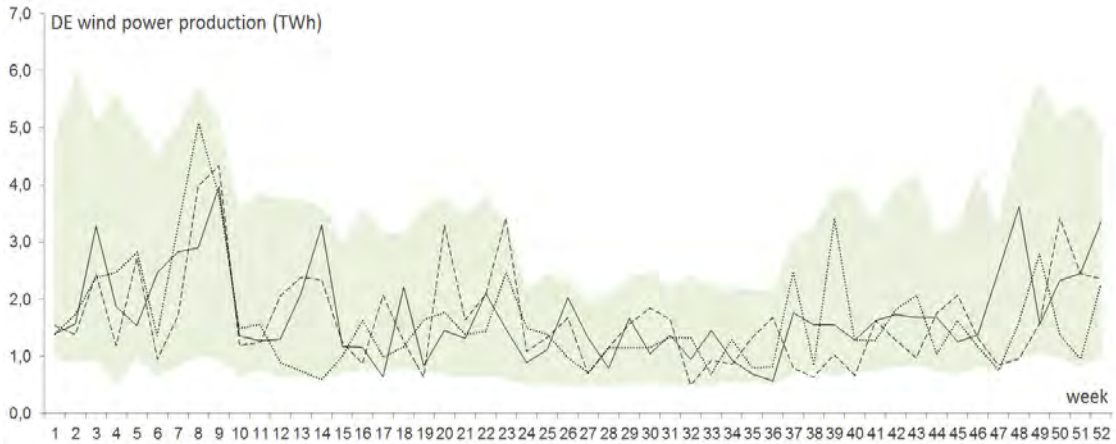


Figure 30: Overview of year-2030 wind power production in Germany

The areas spanned by solar winter and summer daily productions are represented in Figure 32 for France and Germany, along with their respective averages.

Thanks to the monitoring and rejection rules, the typical structures of renewable power production can be observed in the generated scenarios. Finally, it has successfully been checked that the

[18] Correlations and seasonality considerations which were made in section 5.2.1 are taken into account.

generated scenarios are compatible with the average frequency of windy days during winter and sunny during summer.

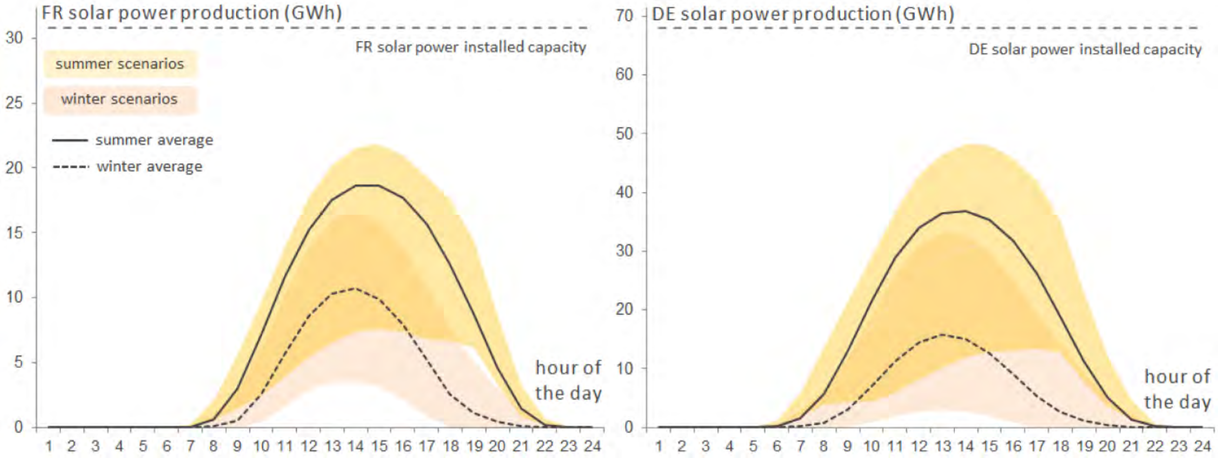


Figure 31: Overview of year-2030 solar power production in France and in Germany

6 Appendix B - France and Germany in 2030

The following graphs show the repartition of production during typical periods. Note that imports and exports with neighboring countries (other than France and Germany) do not appear in these graphs. When the demand curve (in black) is lower than the total production, it should be understood that power is being exported towards other countries and/or locally stored.

The different technologies are distinguished using the following color code:

- Nuclear
- Lignite
- Coal fleet
- CCGT fleet
- Peak fleet
- Other thermal
- Distributed load shedding
- Emergency load shedding
- Hydro RoR fleet
- Seasonal storage
- Pumped storage fleet
- Wind fleet
- Solar fleet
- Renewable thermal fleet
- Imports

6.1.1 Typical winter week: scenario 1 – January, 1st to January, 7th

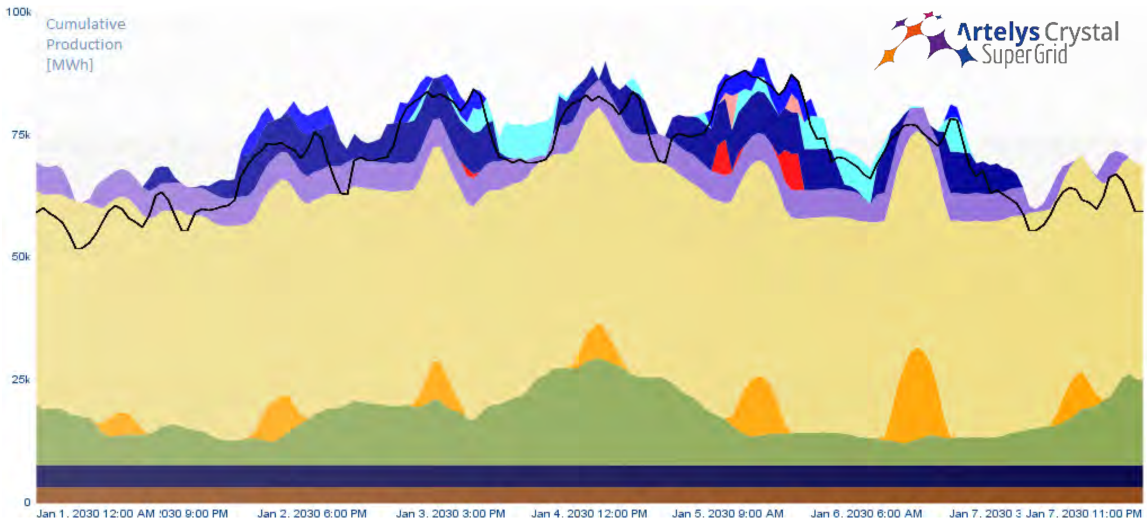


Figure 32: Cumulative production in France from January, 1st to January, 7th, for scenario 1

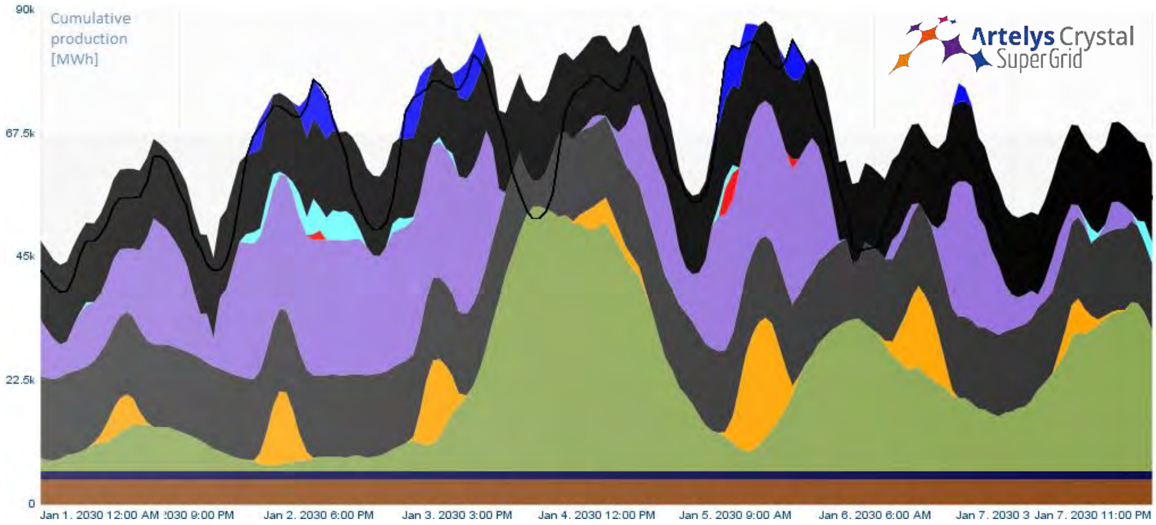


Figure 33: Cumulative production in Germany from January, 1st to January 7th, for scenario 1

6.1.2 Typical summer: Scenario 12 – June, 30th to July, 1st

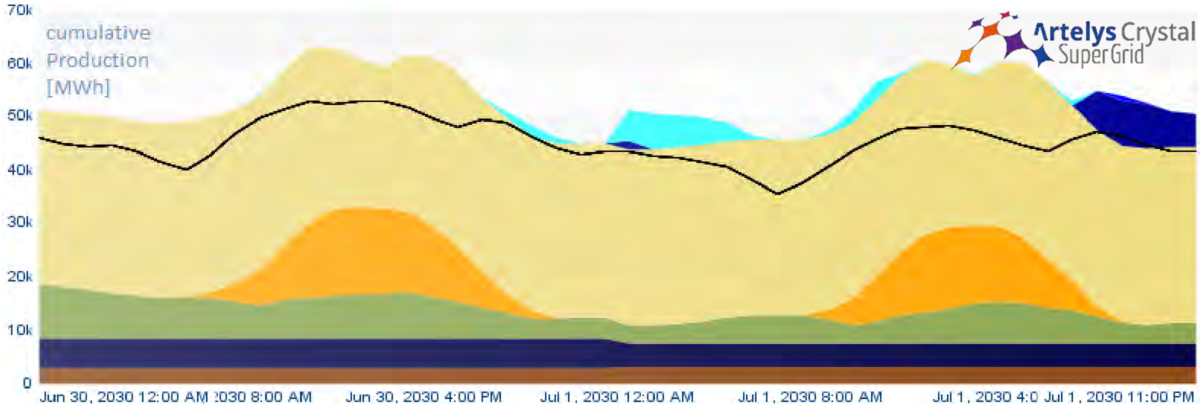


Figure 34: Cumulative production in France from June, 30th to July, 1st , for scenario 12

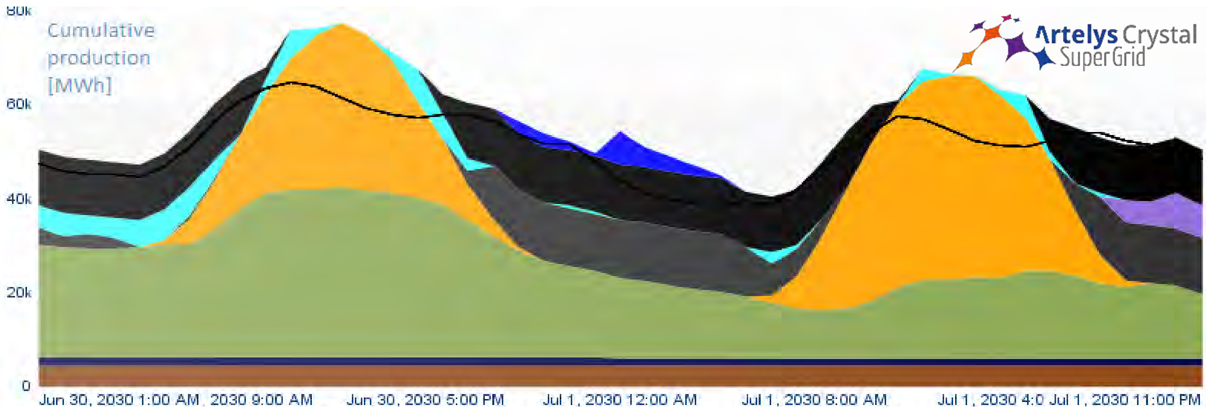


Figure 35: Cumulative production in Germany from June, 30th to July, 1st, for scenario 12

6.2 Production overview

This section gives an overview of the production dispatch in France and Germany over the 50 scenarios. The following charts provide an overview of the different technologies' average yearly production.

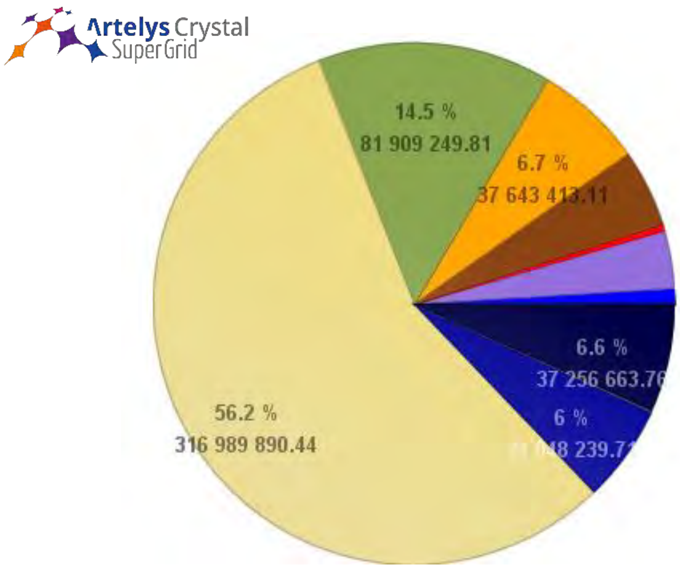


Figure 36: Production dispatch in France over 50 scenarios (in MWh)

	Average production dispatch in France	
Technology	**Average production [TWh]**	**Contribution in the total production**
Nuclear	317.0	56.2%
Coal	0.0	0.0%
Gas	20.1	3.6%
Peak fleet	2.6	0.5%
Other thermal	0.3	0.1%
Hydro seasonal storage	34.0	6.0%
Wind	81.9	14.5%
Solar	37.6	6.7%
Renewable thermal	26.9	4.8%
Hydro RoR	37.3	6.6%
Pumped storage	5.1	0.9%
Demand response	0.1	0.0%
Distributed load shedding	0.7	0.1%
Total	563.7	100%

Table 16: France average production dispatch over 50 scenarios

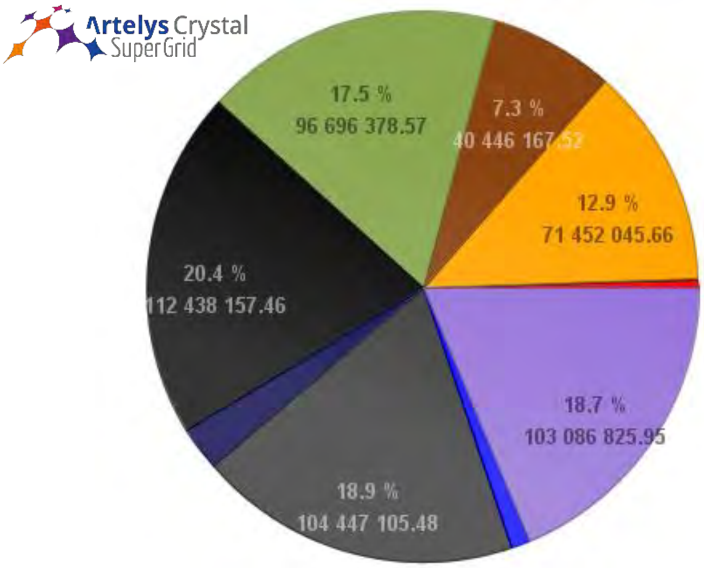


Figure 37: Production dispatch in Germany over 50 scenarios (in MWh)

	Average production dispatch in Germany	
Technology	Average production [TWh]	Contribution in the total production
Coal	104.4	18.9 %
Lignite	112.4	20.4 %
Gas	103.1	18.7 %
Peak fleet	2.5	0.5 %
Other thermal	0.4	0.1 %
Wind	96.7	17.5 %
Solar	71.5	12.9 %
Renewable thermal	40.4	7.3 %
Hydro RoR	14.3	2.6 %
Pumped storage	6.0	1.1 %
Demand response	0.1	0.0 %
Distributed load shedding	0.3	0.0 %
Total	552.1	100 %

Table 17: Germany average production dispatch over 50 scenarios

6.3 Interconnection utilisation

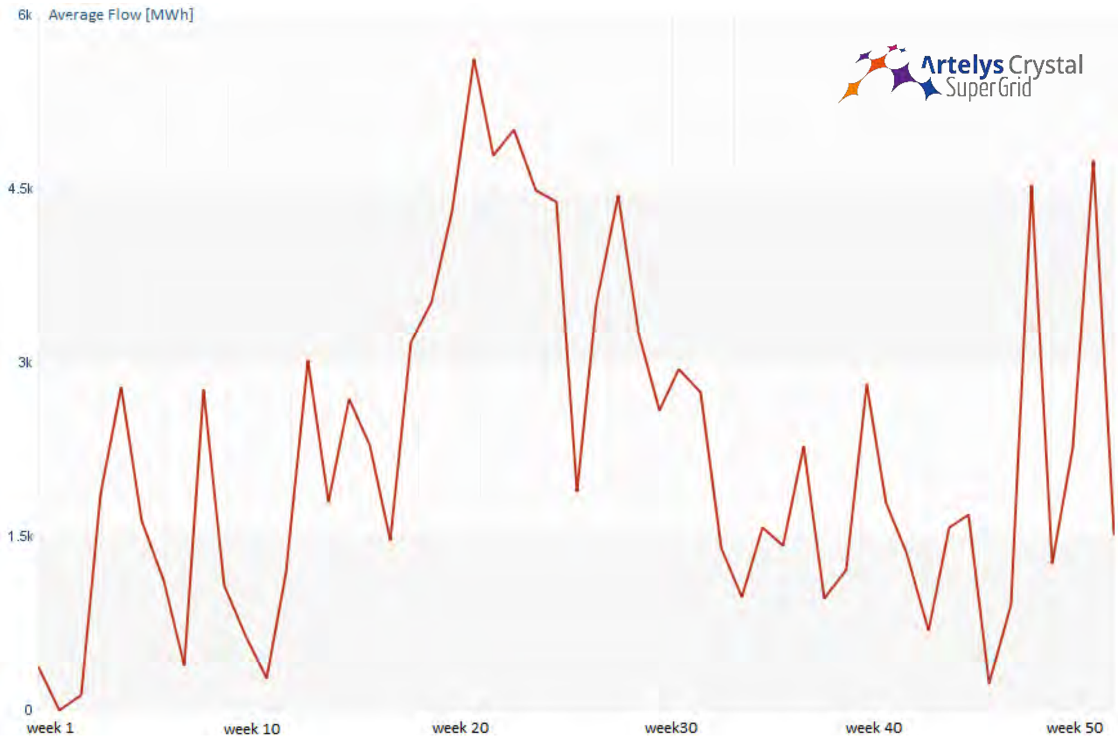


Figure 38: Weekly average flows from France to Germany in scenario 21

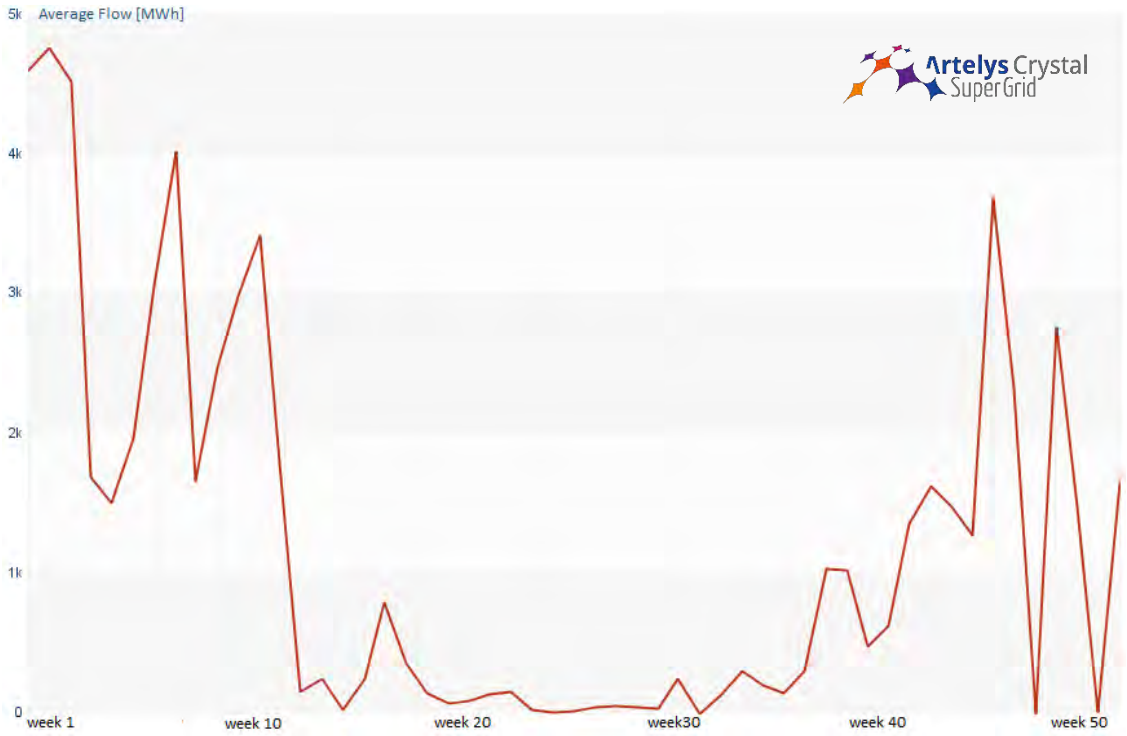


Figure 39: Weekly average flows from Germany to France in scenario 21

7 Appendix C - Market design and actors' revenues

This section provides graphics showing annual remuneration per fleet and per scenario, in EOM with and without price cap, for fleets of the virtual reference mix.

7.1 Annual remunerations

7.1.1 EOM without price cap

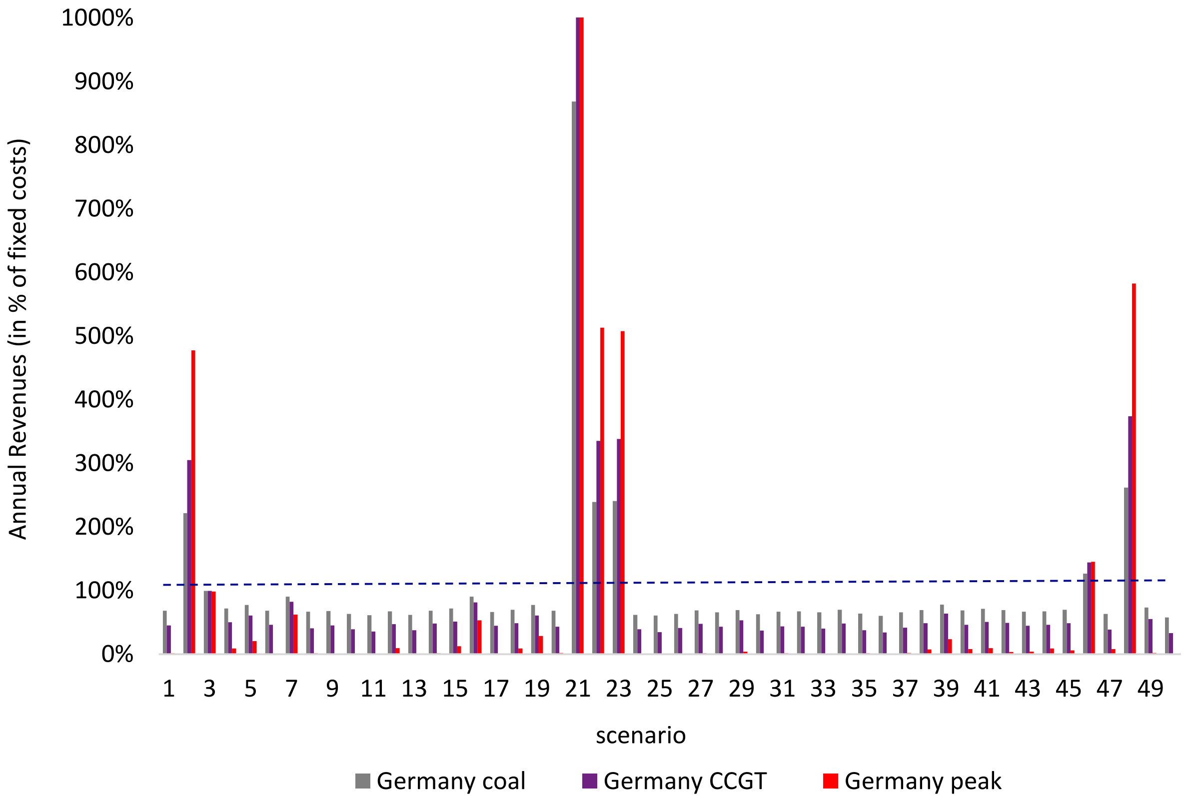


Figure 40: German assets' annual revenues without price cap

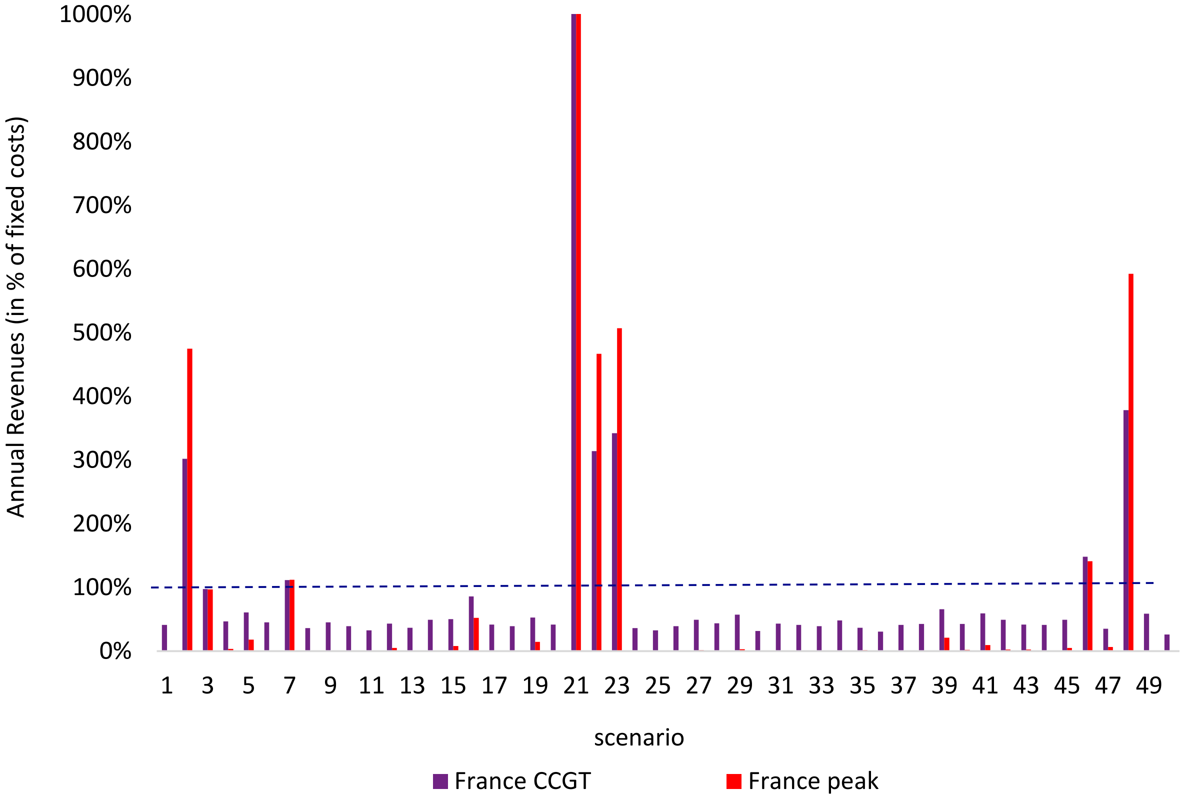


Figure 41: French assets' annual revenues without price cap

7.1.2 EOM with a price cap at 3 000 €/MWh

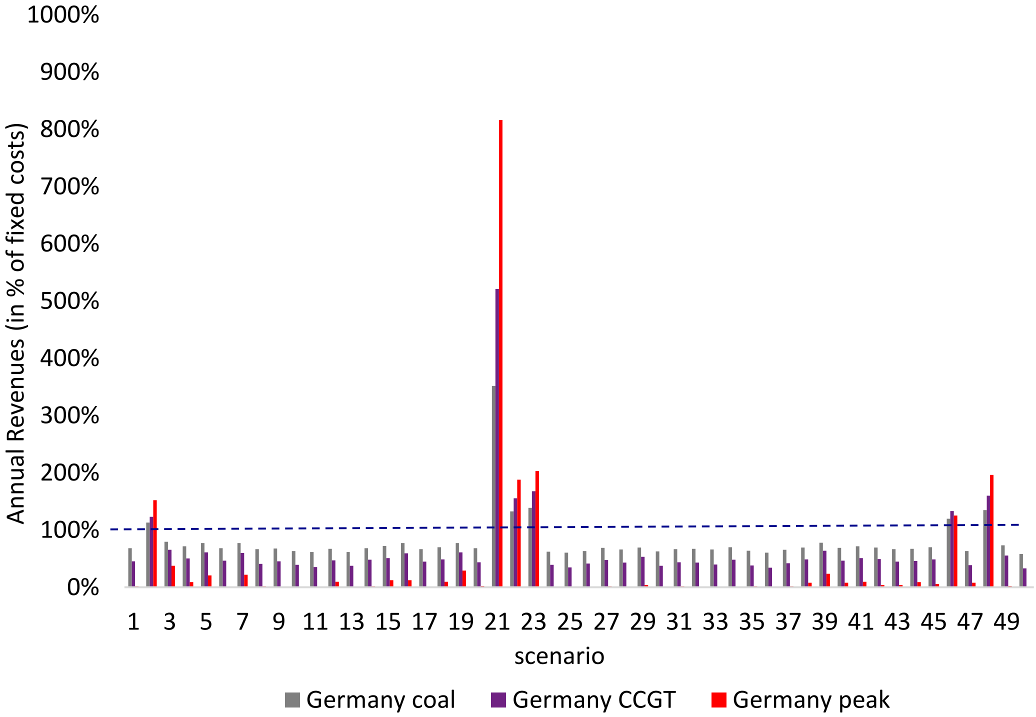


Figure 42: German assets' annual revenues with price capped at 3000€/MWh

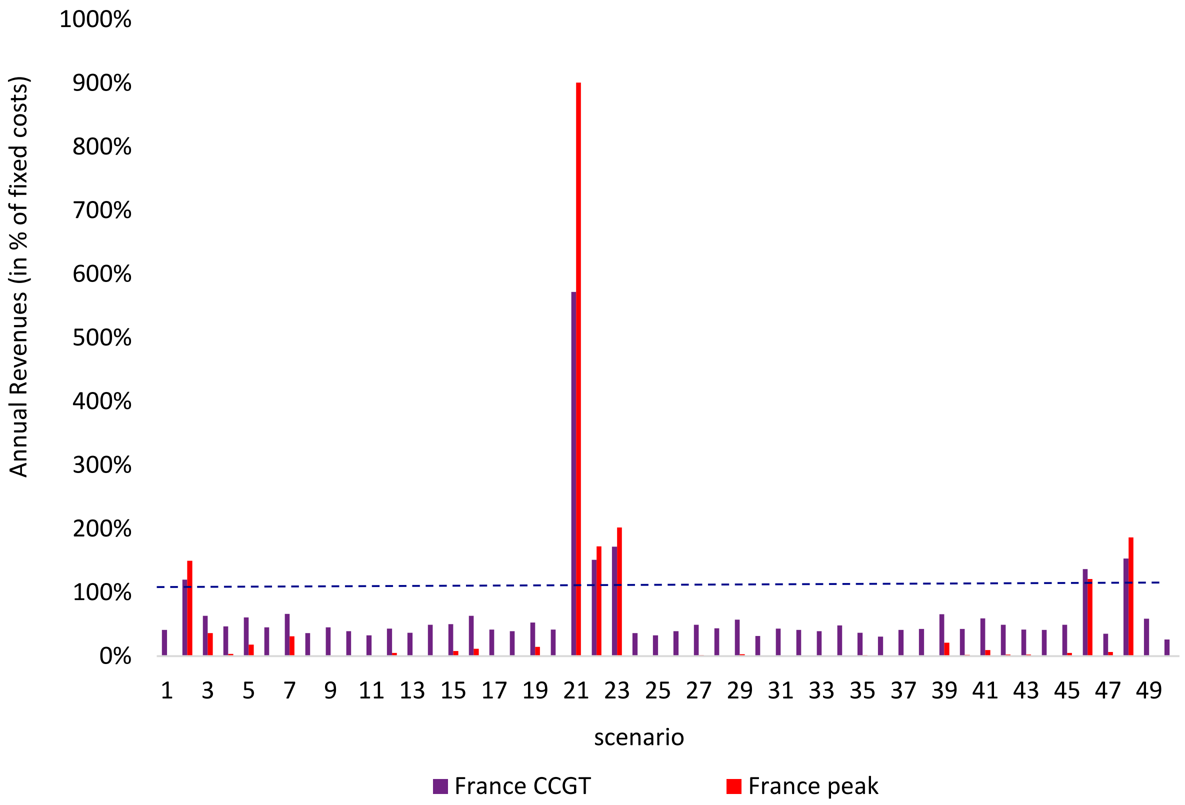


Figure 43: French assets' annual revenues with price capped at 3000€/MWh

7.1.3 Annual revenues' dispersion in EOM

The following tables provides the minimal and maximal revenues per asset over the scenarios, as percentages of the average remuneration, for the virtual reference mix.

Annual revenues dispersion over 50 scenarios					
	France CCGT	**France peak**	**Germany coal**	**Germany CCGT**	**Germany peak**
Minimal annual revenue (in % of investment cost)	26%	0%	58%	33%	0%
Average annual revenue (in % of investment cost)	100%	100%	100%	100%	100%
Maximal annual revenue (in % of investment cost)	1437%	2446%	869%	1387%	2363%

Table 18: Annual revenues' dispersion over scenarios without price cap

Annual revenues dispersion over 50 scenarios					
	France CCGT	France peak	Germany coal	Germany CCGT	Germany peak
Minimal annual revenue (in % of investment cost)	26%	0%	58%	33%	0%
Average annual revenue (in % of investment cost)	66%	38%	80%	66%	39%
Maximal annual revenue (in % of investment cost)	572%	901%	351%	521%	816%

Table 19: Annual revenues' dispersion over scenarios with a price cap at 3k€/MWh

7.2 Actualized revenues over assets' lifetimes

Lifetime revenues dispersion for assets of the virtual reference mix are given here in an EOM with price cap and without price cap.

7.2.1 EOM without price cap

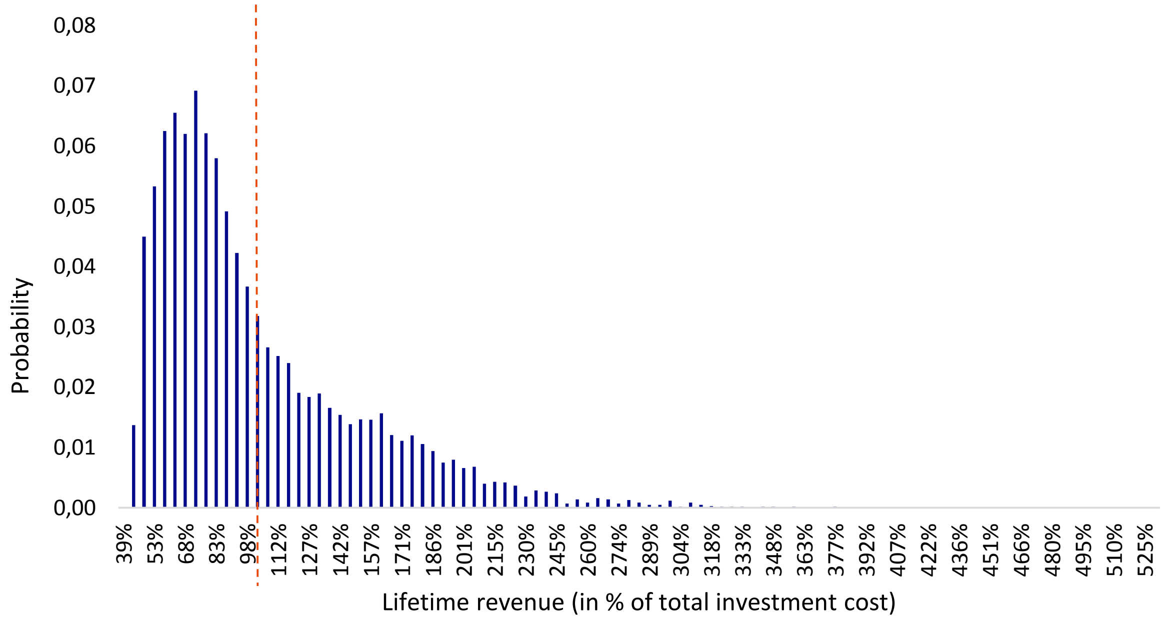


Figure 44: French CCGT fleet's revenue distribution without price cap

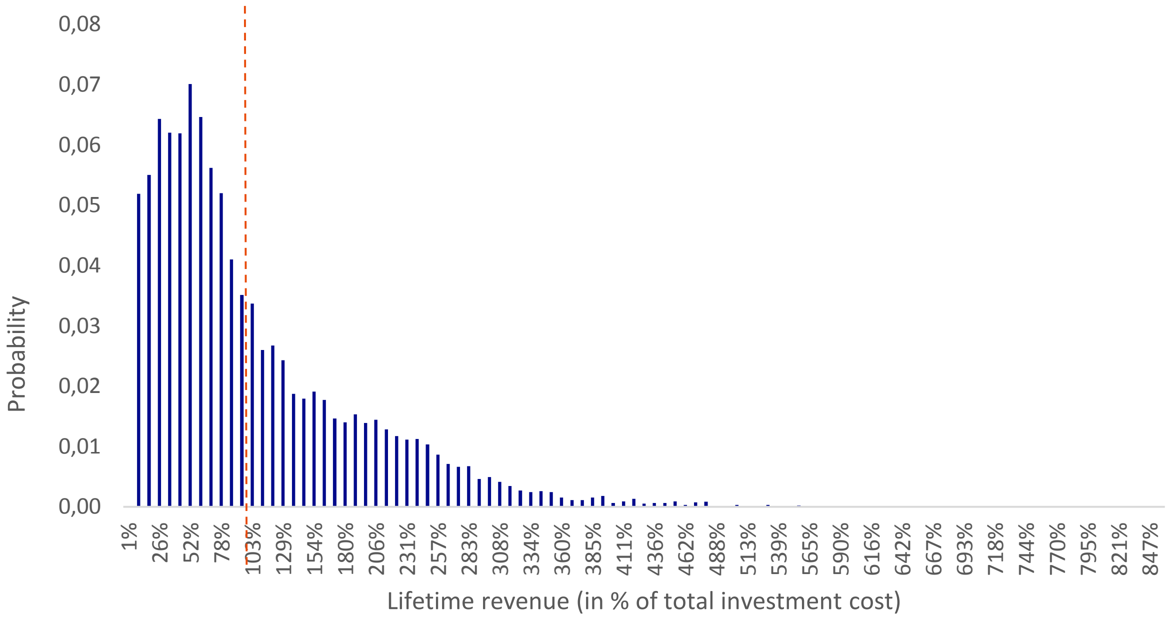


Figure 45: French peak fleet's revenue distribution without price cap

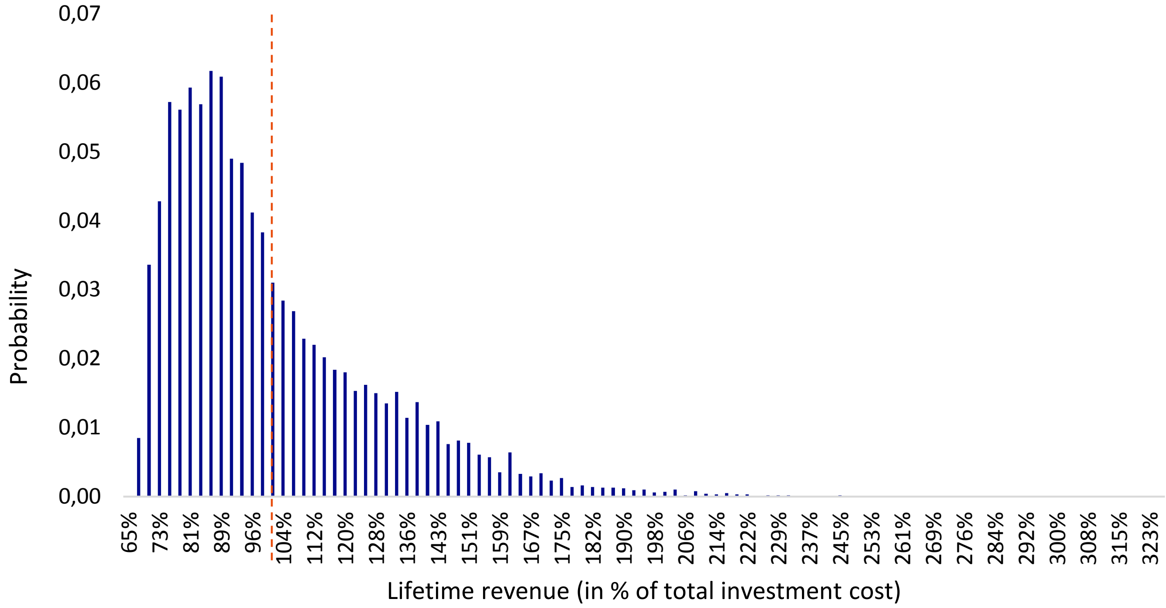


Figure 46: German coal fleet's revenue distribution without price cap

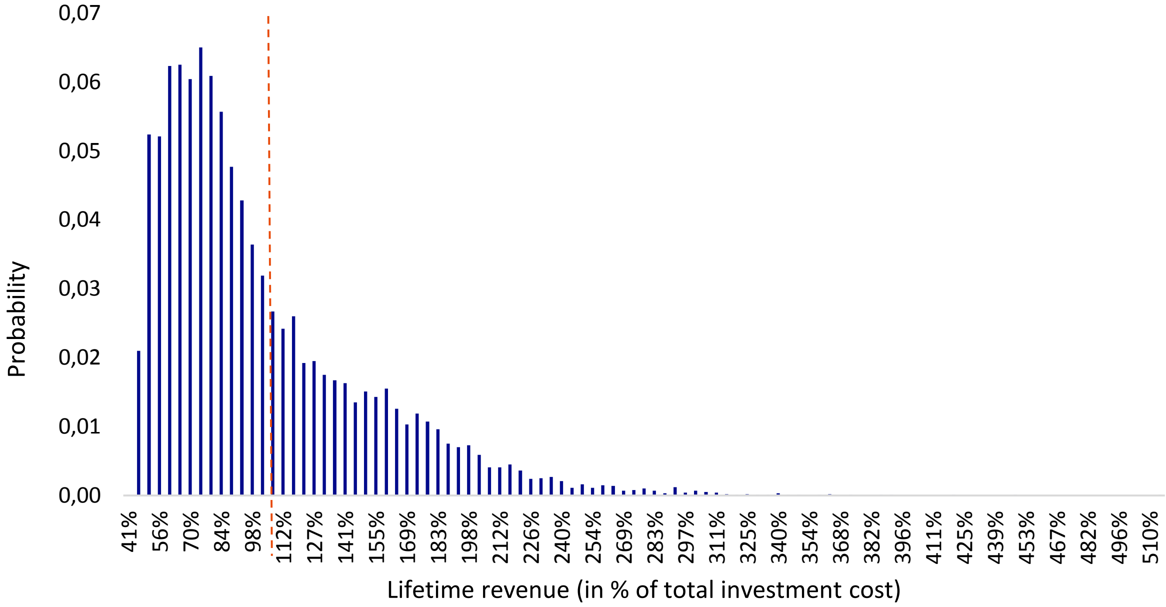


Figure 47: German CCGT fleet's revenue distribution without price cap

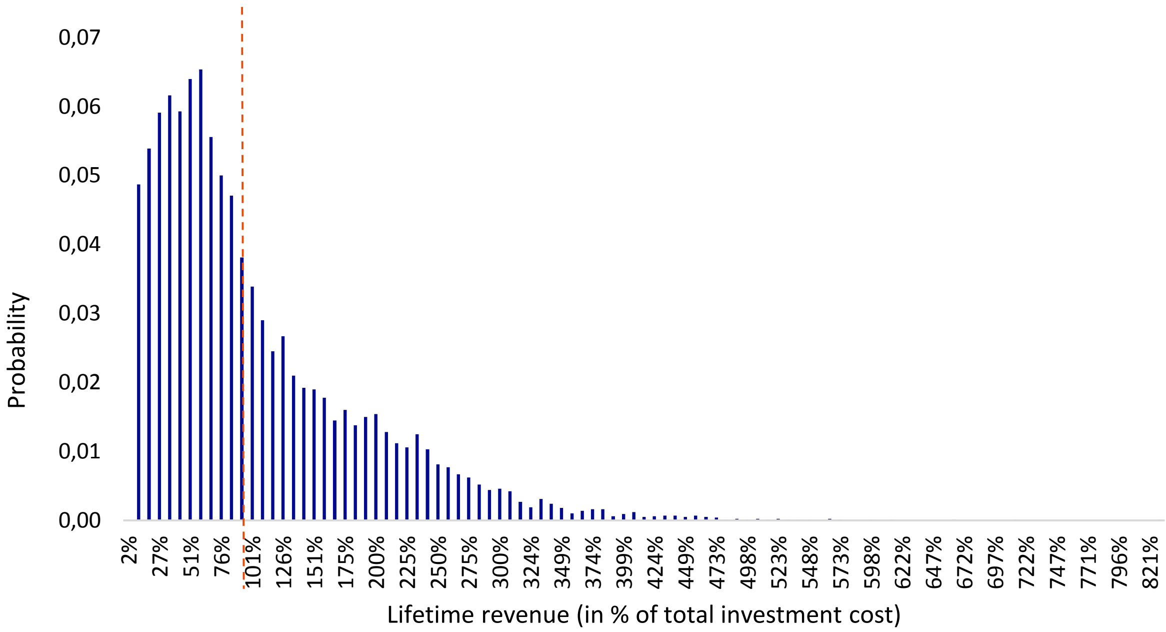


Figure 48: German peak fleet's revenue distribution without price cap

7.2.2 EOM with price cap at 3000€/MWh

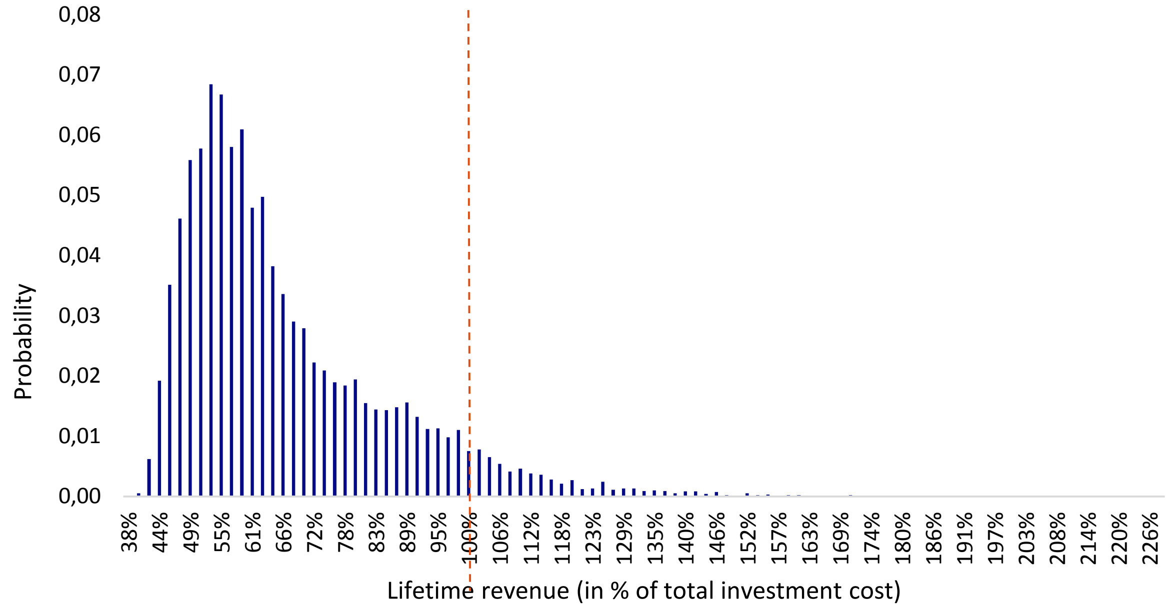


Figure 49: French CCGT fleet's revenue distribution with a price cap at 3k€/MWh

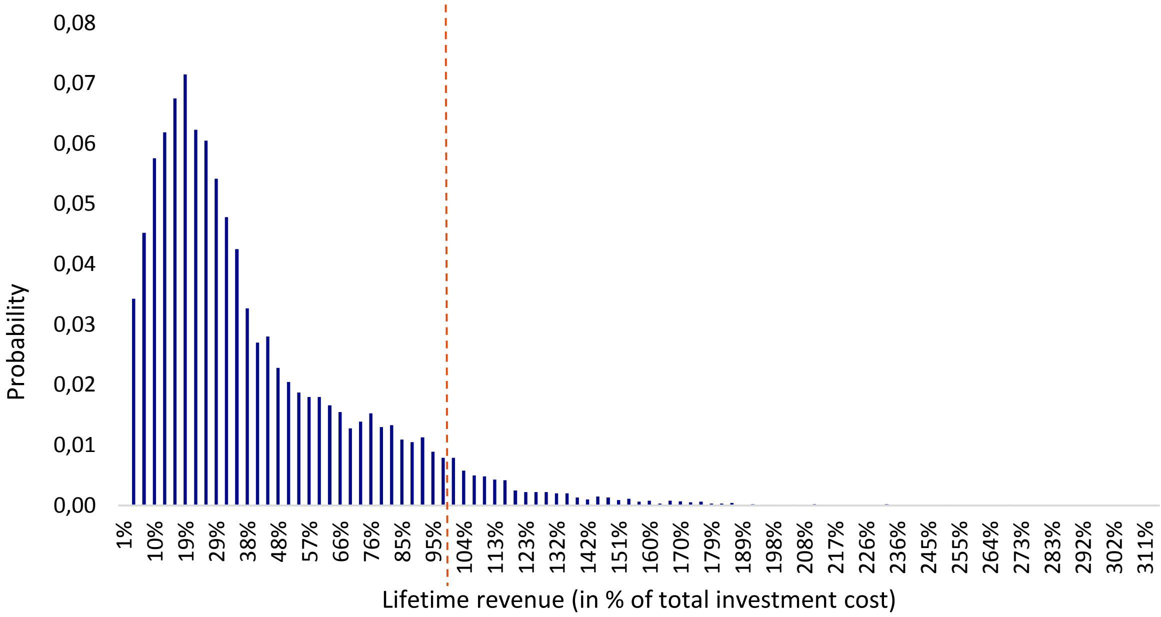


Figure 50: French peak fleet's revenue distribution with a price cap at 3k€/MWh

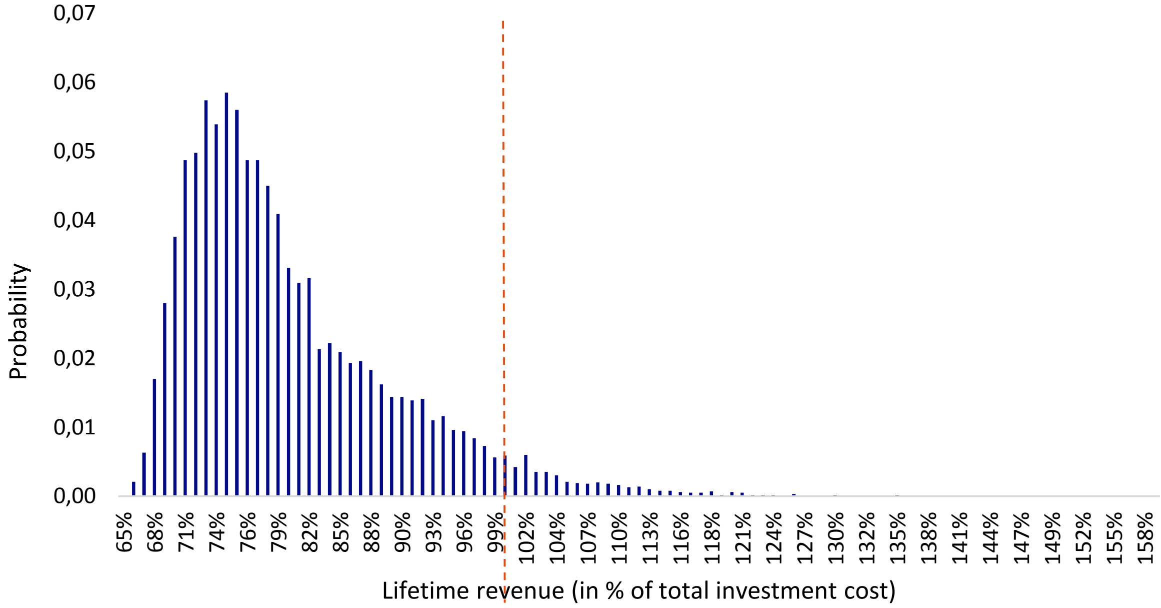


Figure 51: German coal fleet's revenue distribution with a price cap at 3k€/MWh

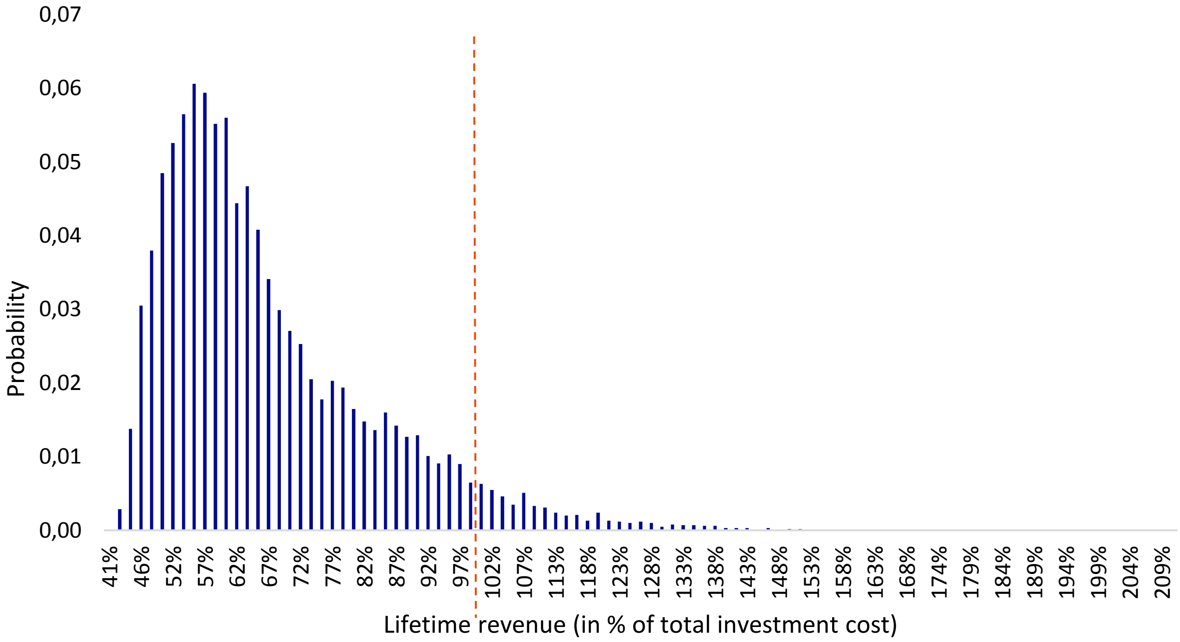


Figure 52: German CCGT fleet's revenue distribution with a price cap at 3k€/MWh

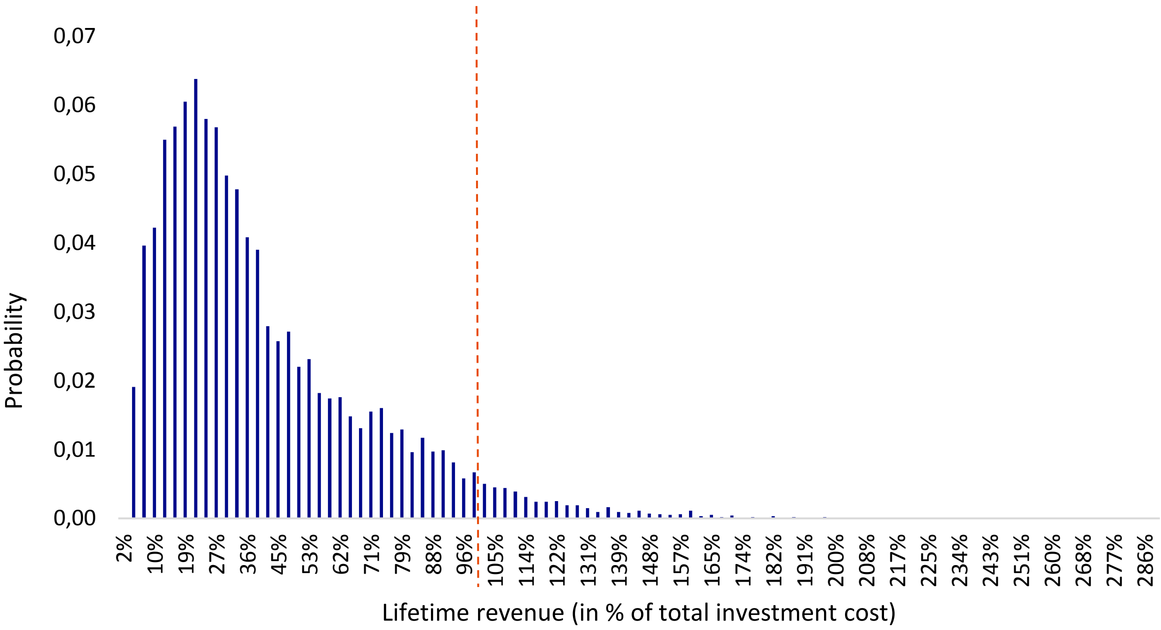


Figure 53: German peak fleet's revenue distribution with a price cap at 3k€/MWh