IMPACT ASSESSMENT OF THE FRENCH CAPACITY MARKET

A contribution to the European debate for a secure supply of electricity

SEPTEMBER 2018

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EXECUTIVE SUMMARY

Relevance of an impact assessment of the French capacity market

The gradual liberalisation of the European power sector, initiated during the 1990s, has been founded on the development of a European electricity market in which generators, demand response operators, suppliers and traders exchange energy blocks at different time horizons (futures, day-ahead, intraday). These trades take place within a same electricity price zone or from one price zone to another within the limit of interconnection capacities.

This design of energy markets has proven to be effective in ensuring that the use of generation and interconnection capacities is optimised across the European network. At every moment in time, the generation capacities with the lowest variable costs in Europe are used to meet the demand for electricity, within the limit of interconnection capacities.

However, the ability of energy markets to send relevant economic signals to trigger the investments required to maintain security of supply is being questioned. To help meet their security of supply requirements, most European countries have opted to introduce capacity mechanisms, which can take various forms.

France made this decision in 2010 based on in-depth parliamentary work. Technical and economic analyses were conducted to support the consultation processes on the evolution of the regulatory framework. These analyses have contributed to major design choices inherent in the implementation of such a system.

The French capacity market fully entered into force on the 1st of January 2017, after having been formally approved by the European Commission following an in-depth state aid investigation. However, while the debate held at the French level has helped in forming a relative consensus on the need for and the relevance of this type of mechanism, the debate remains open at European level today.

This situation is illustrated by the draft European legislative package known as the "Clean Energy Package", which, while recognizing the possibility for Member States to implement capacity mechanisms, proposes (i) to impose a number of constraints on their implementation (limited duration, annual assessment, national security of supply targets based on a European methodology for estimating the value of lost load, etc.) and (ii) to raise price caps on energy markets to the estimated value of lost load. Raising price caps is indeed presented as the key solution to solve current and future risks for the security of supply of Member States.

This is also demonstrated by the relative caution with which the Commission authorizes the creation of such mechanisms on a case by case basis. This cautious approach can be seen for example in the French case: while the mechanism has been approved, the clearance is valid only for a limited period of 10 years.

In view of this, RTE has conducted an economic impact assessment as part of the work carried out at the French level and to complement previous analyses, out of an ongoing concern to objectify the added value of the French capacity market and the choices guiding the construction of the regulatory framework and its future developments. Besides its interest for the French context, the conclusions of this analysis can also be used to guide the regulatory decisions made at European level, particularly within the framework of the development of the Clean Energy Package.

The limits of the energy-only market model to ensure security of supply

The work led by Ramsey and Boiteux in the 1950s on the relationship between financing of productive assets and marginal cost pricing[1] has been decisive for the understanding of the economy of the energy sector. This work is the academic backbone of the energy-only market organisation and provides a simplified model to describe the functioning of this type of market organisation. The reasons for the success of this theoretical representation lie both in the power of its results and the ease with which it can be modelled.

Under certain assumptions in this analytical framework, the functioning of the energy-only market would give rise to an identical result to what would be achieved under the watchful eye of a fair and omniscient central planner in charge of optimizing the operation of the power system. Several key assumptions must be met for this result to hold: (i) the operation of the market corresponds to a pure and perfect competition (perfectly rational players who do not have or do not use market power), (ii) the prices are set to the real degree of the loss of utility for consumers during periods of load shedding (definition of price caps at this level and no estimation error on the value of lost load) and (iii) when evaluating the expected profitability of their capacity investments, market participants only consider the expected income on energy markets, including the income obtained during periods of shortages, although these are very rare.

Analysing the impact of the implementation of a capacity mechanism requires an understanding of the limitations of this simplified representation of the functioning of energy markets, and a more realistic model taking better account of the way in which economic actors make their investment decisions. In particular, the lack of consideration for the profitability risk in the decision making process or on the cost of financing cannot be viewed as reflecting the real behaviour of market participants.

A review of existing impact assessments

With the emergence and implementation of different capacity mechanisms in Europe, numerous studies have been published to assess the impact of these mechanisms on the security of supply and to evaluate their consequences in terms of economic value created (or destroyed). These studies have revealed very varied and sometimes contradictory findings.

(i) To draw robust conclusions, RTE conducted a detailed analysis of published studies by focusing on identifying their scope of validity and the assumptions governing their findings. This review of the literature, already initiated in 2014[2], has been extended to include further studies. The scope of the studies considered, established in consultation with stakeholders, has focused on European studies which are (i) public, (ii) include a quantitative comparison with an energy-only market and (iii) cover a wide range of approaches, points of view and types of author (academic, consultants, institutions, etc.).

The seven studies which have been analysed are listed in Table 1.

The analysis framework defined by RTE has contributed to the identification of **essential properties required for the impact analysis of the capacity mechanism (the "must have"):**

- **The modelling of the decisions of market participants to invest, mothball or close capacities must be endogenous and based on the**

1. BOITEUX, Marcel. Sur la gestion des monopoles publics astreints à l'équilibre budgétaire. (On the management of public monopolies subject to budgetary constraints). Econometrica, 1956, Vol 24 (1), p22-40
2. French Capacity Market: Report accompanying the draft rules (RTE, 2014).

Table 1. List of impact studies analysed by RTE

Institution Organisation	Study	Year of publication
European Commission E3MLab/ICCS	*Impact assessment accompanying the proposals for the Clean Energy Package based on Modelling study contributing to the Impact Assessment of the European Commission of the Electricity Market Design Initiative (E3MLab/ICCS, 2017).*	2016
FTI-CL Energy	*Assessment of the impact of the French capacity mechanism on electricity markets*	2016
CEEM	*Ensuring capacity adequacy during energy transition in mature power markets and Effects of risk aversion on investment decisions in electricity generation: What consequences for market design?*	2016
UFE-BDEW	*Energy transition and capacity mechanism, A contribution to the European debate with a view to 2030*	2015
Frontier Economics – Consentec	*Impact Assessment of Capacity Mechanisms*	2014
Department of Energy and Climate Change	*Electricity Market Reform – Capacity Market – Impact assessment*	2014
Thema Consulting Group E3M Lab, COWI	*Capacity Mechanisms in Individual Markets within the Internal Energy Market*	2013

economic profitability of capacities. The Thema study, which assumes that the overall amount of investments is not altered by the establishment of a capacity mechanism, cannot therefore be regarded as a relevant impact assessment.

- **The modelling of the capacity mechanism must be compatible with the main design features of the French mechanism (i.e.: a market mechanism which is volume based, and to which all capacities are eligible).**
  The results of the Thema (on a selective capacity payment) and Frontier Economics - Consentec studies (for the sections on the analysis of a strategic reserve or a selective mechanism) cannot be transposed to the analysis of the French capacity market.

- **The modelled capacity mechanism must be configured in a manner consistent with the security of supply target.**
  Some studies (DECC, Frontier Economics - Consentec) consider a capacity mechanism configured to deliver substantial overcapacity in relation to what would be economically relevant. These studies do not assess the impact of a capacity mechanism in itself but rather the consequences of overcapacities, which could eventually negatively impact social welfare.

- **The uncertainties affecting the electricity system and inducing volatility in the revenues of capacity holders, as well as their impact on the cost of capital to finance new capacities, must be integrated in the quantitative studies.**
  The capacity mechanism reduces the financial risk of investment projects. Evaluation of the impact of the capacity mechanism on investments in generation capacity and on the cost of the power system for consumers requires representing the risk reduction resulting from the capacity mechanism and its influence on the decisions of the market participants and the cost of capital. The DECC, Frontier Economics-Consentec and Thema studies do not represent these uncertainties and while the European Commission study does account for these, it does not consider their effect on the decisions of investors.

Among the studies considered in the literature review, only three studies (UFE-BDEW, CEEM and FTI-CL Energy) meet these prerequisites and therefore bring a relevant contribution to the impact assessment of the capacity mechanism. They draw the following main conclusions:

- **In case of energy market failures, an energy-only market design cannot ensure security**

of supply over the long term, and leads to high loss-of-load expectations (of around 10 hours per year), incompatible with the standard set by the French public authorities. In this type of situation, a generation fleet complying with the public security of supply target (loss-of-load expectation of 3 hours/year) cannot be profitable (missing money).

- **Introducing a capacity mechanism to remedy energy market failures leads to net benefits in terms of social welfare, representing several hundred million euros a year.**
  These benefits stem from the reduced volume of unserved energy and the decreased cost of access to capital brought about by the implementation of a more secure framework for investment for market participants.

- **Attempting to correct energy market failures by increasing price caps may have undesirable side effects.** In fact, an energy only market in which price caps were raised to the value of lost load would pose substantial risks for the profitability of peak capacities (generation and demand response). These risks to the profitability of assets induce (i) a potential underinvestment and non-compliance with the security of supply target and (ii) additional costs for market participants, leading to a loss of social welfare which can be estimated up to several hundred million euros per year compared to a market design with a capacity mechanism, in which the risk to the profitability of the capacities is greatly reduced.

However, these studies do not represent the dynamics of the decisions relating to capacities (investments, decommissioning, mothballing) on a multi-year horizon. They underestimate the "long-term" uncertainties affecting the evolution of the macroeconomic and energy context (uncertainties regarding the evolution of demand, the development of renewable energies, fossil-fuel prices, etc.). Only "short-term" uncertainties (weather variability affecting consumption and generation from renewable sources, varying availability of power generation sources) are represented.

The UFE-BDEW study assumes a fixed capacity price over time and the FTI-CL Energy and CEEM studies consider a price which evolves over time but in a deterministic manner.

These studies may therefore tend to overestimate the benefits of the current French capacity market, which reduces the risk resulting from "short-term" uncertainties, but was not designed to protect investments against the risks associated with long-term uncertainties.

The risk associated with long-term uncertainties has become a major point of discussion between the French authorities and the European Commission, within the framework of the in-depth investigation into the French capacity market[3]. The fact that existing studies do not take into account this risk represents a significant flaw.

RTE's impact assessment to complement existing studies

RTE has itself conducted an impact assessment of the capacity mechanism in order to lift this main limitation. This study includes a fuller and more realistic representation of the risks actors are subject to in each of the market designs considered. It aims to compare several market designs combining whether or not energy market price caps are raised and whether or not a capacity mechanism is in place.

The approach consists in simulating [2016-2030] decisions (investment, mothballing, closure) taken by market participants concerning their generation and demand response capacities and their hourly dispatch. The modelling features decision making under uncertainty (not knowing which long-term scenario will occur), with the assumption that market participants behave in a manner which reflects pure and perfect competition. Lead times for building new power generation assets are taken into account.

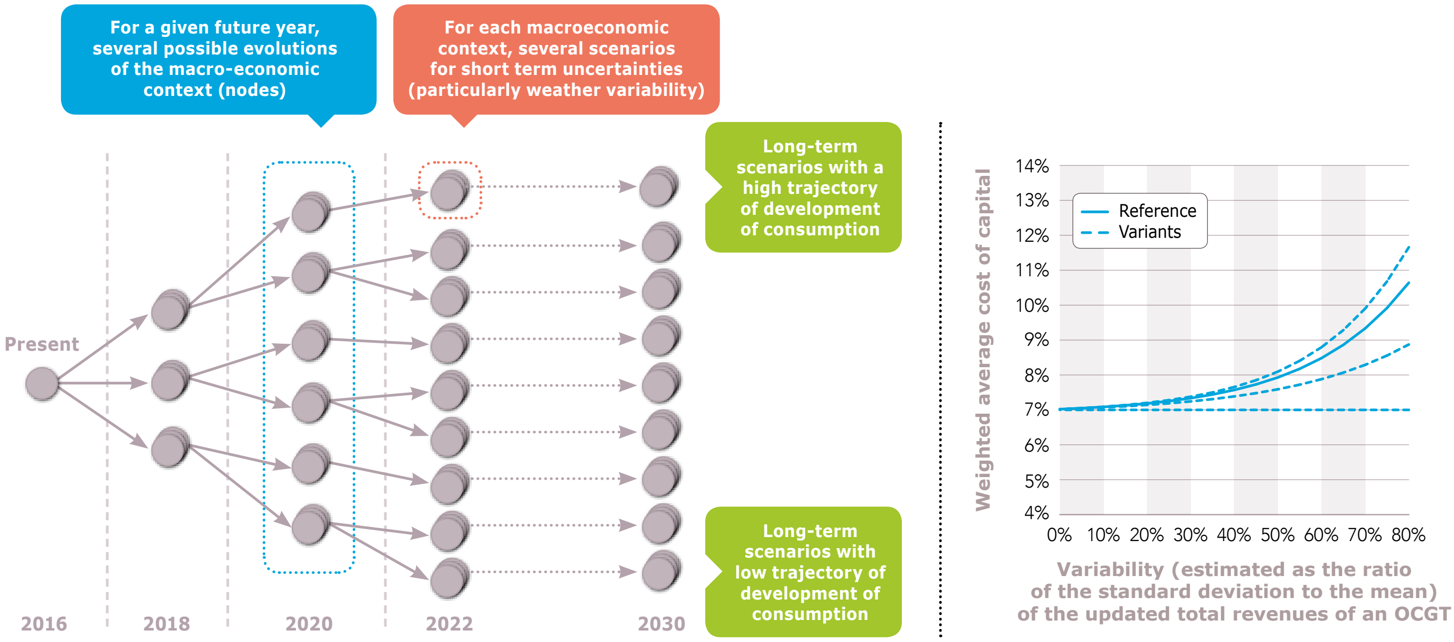
3. This issue was resolved by setting up a system for securing capacity revenues to build new capacities, so as to facilitate their emergence on the French market. This specific mechanism for new capacities will involve a system of Contracts for Difference to provide greater capacity revenue visibility for investors.

Table 2. Summary of the comparative analysis of impact studies

	RTE	(1) CE-E3MLab	(2) FTI-CL	(3) CEEM	(4) UFE-BDEW	(5) DECC	(6) Frontier Economics - Consentec	(7) Thema
Decisions based on a profitability calculation of assets (for technologies not subject to policy targets)	✓ Yes, except technologies driven by policy targets (RES, nuclear power)	✗ Yes, except for a part of the capacities	✓ Yes, except technologies driven by policy targets (RES, nuclear power)	✓	✓	✓	✓	✗ No
Type(s) of capacity mechanism modelled	✓ Market mechanism regulated by volumes and *market-wide*	✗ Stylized *Market-wide* capacity mechanism	✓ Market mechanism, based on a capacity obligation (or capacity demand curve), in which all capacities can participate (market-wide)	✓	✓	✓	✓ Various mechanisms studied: market-wide, targeted call for tender, strategic reserve	✗ Selective capacity payment
Parameters of the capacity mechanism	✓ LOLE of 3 h/y	? Reliability criteria not stated	✓ LOLE of 3h/y	✓	✓	✗ LOLE of 3h/y + 3 GW margin	✗ LOLE of 3h/y with no contribution of inter-connections	✗ Remuneration equal to missing money of OCGT
Representation of the effect of risk on the cost of capital and investment decisions	✓ Yes, endogenous risk aversion (cost of capital dependant on risk in terms of profitability of investments	✗ Exogenous (cost of capital differentiated arbitrarily depending on market design)	✓ Yes, endogenous risk aversion (cost of capital dependant on risk in terms of profitability of investments	✓ Yes, represented in the form of risk aversion without taking into account the effect of the risk on the cost of capital	✓	✗ No, no representation of the effects of the risk, either on the cost of capital or on investment decisions	✗	✗
Short-term uncertainties (weather, availability of assets, etc.) modelled and taken into account in the risk	✓ Yes, short-term uncertainties	✗ Short-term uncertainties represented but resulting risk not taken into account	✓ Yes, short-term uncertainties	✓	✓	✗ No, deterministic scenarios	✗	✗
Investment dynamics	✓ Yes, simulation of investments, mothballing and decommissioning on a multi-year horizon	✓	✓	✓	✗ No, representation of a single year (2030)	✓ Yes, simulation of investments, mothballing and decommissioning on a multi-year horizon	✓	✓
Long-term uncertainties (trajectories for RES, demand, energy context etc.) modelled and taken into account in the risk	✓ Yes, long-term uncertainties represented	✗ Long-term uncertainties represented but resulting risk not taken Into account	✗ No, no representation of long-term uncertainties	✗	✗	✗	✗	✗

✓ Representation adapted to the impact assessment of a capacity mechanism
✗ Representation which can be improved for a precise impact assessment of the capacity mechanism
✗ Representation not suited to an impact assessment of a capacity mechanism

Figure 1. Representation of uncertainties and effect of risk on the cost of capital in the modelling used for RTE's impact assessment



The study conducted by RTE is based on the modelling of energy and capacity markets. Energy market failures are represented, like in most other economic studies, by means of a price cap (of 3000 €/MWh). This modelling choice reflects the current predominance of the day-ahead market (in which price caps are set at 3000 €/MWh) on other time horizons (where different price caps may be in place) in terms of traded energy and therefore on price formation[4]. Similarly, the modelling of the capacity market accurately reflects the key market design features of the French mechanism: target of 3-hour loss of load expectation per year, participation of all capacities, technology neutrality approach, etc.

Two major types of uncertainties are taken into account, corresponding to the main explanatory factors of profitability of power generation assets. That is:

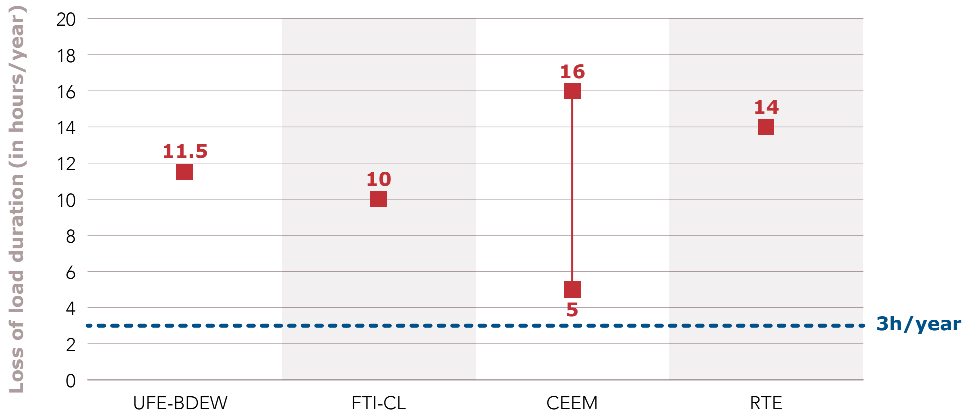
- long-term uncertainties in the development of the economic and energy context. These pertain to the structural developments affecting electricity consumption and the development of RES. These uncertainties are represented in the form of a "tree" of variables to account for increasing uncertainty the further the time horizon extends: uncertainties for the year 2018 are lower than uncertainties for the year 2030.
- Short-term uncertainties regarding weather conditions and availability of power generation assets. In practice, these are uncertainties in terms of electricity demand, renewable energy generation and availability of thermal and nuclear energy sources.

The cost of capital for market participants investing in power generation assets or demand response is represented as a function dependent on the profitability risk. The higher the risk, the greater the cost of capital. The profitability of investment projects is assessed according to potential price scenarios on energy markets (supposedly set at the marginal cost of generation) and capacity markets (supposedly set at the marginal cost of certificates[5]).

4. The main lessons from the assessment remain unchanged with an overall price cap equal to €10,000/MWh. Only the quantitative values would be modified.

5. In pure and perfect competition, the capacity price is established as the capacity remuneration required to secure the presence of the marginal unit of the generation capacity with respect to the policy target for security of supply (3 hours/year of loss of load expectation).

Figure 2 - Loss-of-load expectation in the energy-only market design capped at 3000 €/MWh. Comparison of the results of the different studies.



Conclusions

The study conducted by RTE supports the results of the three existing studies identified as relevant. It also enriches the scope of the conclusions (i) by analysing a market design incorporating higher energy market price caps as well as the introduction of a capacity mechanism, (ii) by analysing variants on the relationship between the risk borne by investors and the cost of capital, and (iii) by analysing variants on a possible price cap on the capacity market. Four main conclusions can be drawn from this economic analysis.

The effect of risk on the cost of capital is an essential feature in the analysis and comparison of the potential market designs for the electricity sector. Taking this effect into account, which some studies omit to do, significantly alters the respective merits of various market designs.

The literature review carried out in the context of this impact assessment has revealed that a number of economic studies focused on the security of supply issue consider that the cost of capital is independent

Figure 3. Loss-of-load expectation in each of the market designs studied

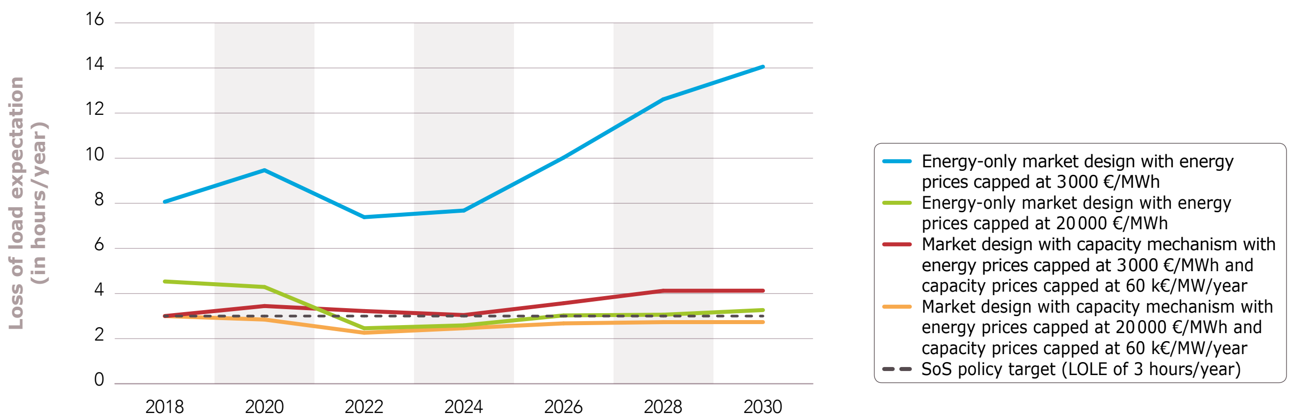
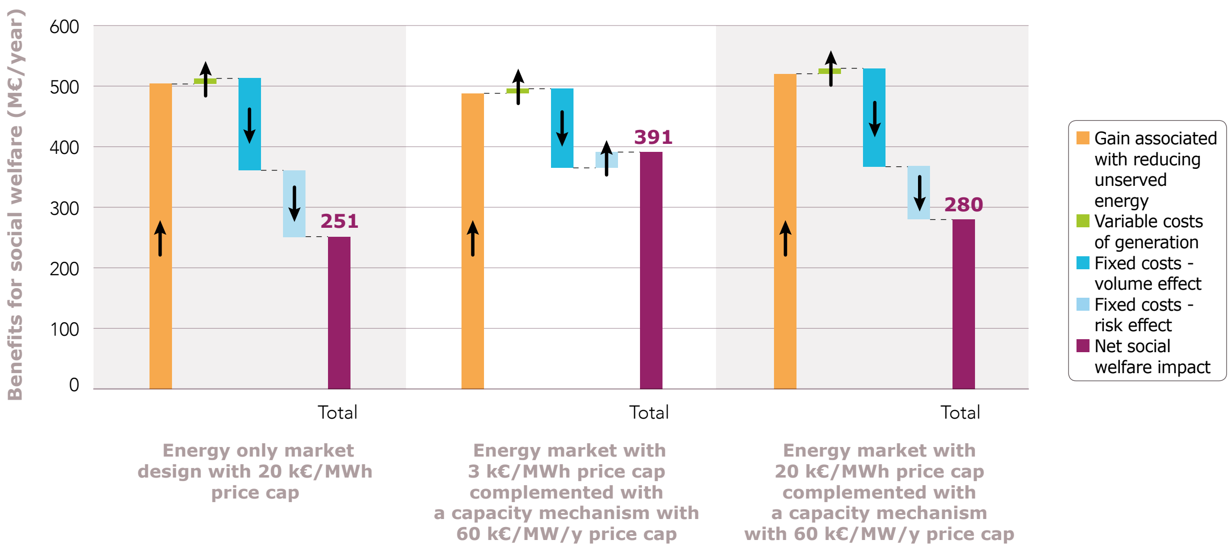


Figure 4. Breakdown of the social welfare improvement of different market designs, in comparison with the energy-only market design with energy price caps at 3 000 €/MWh

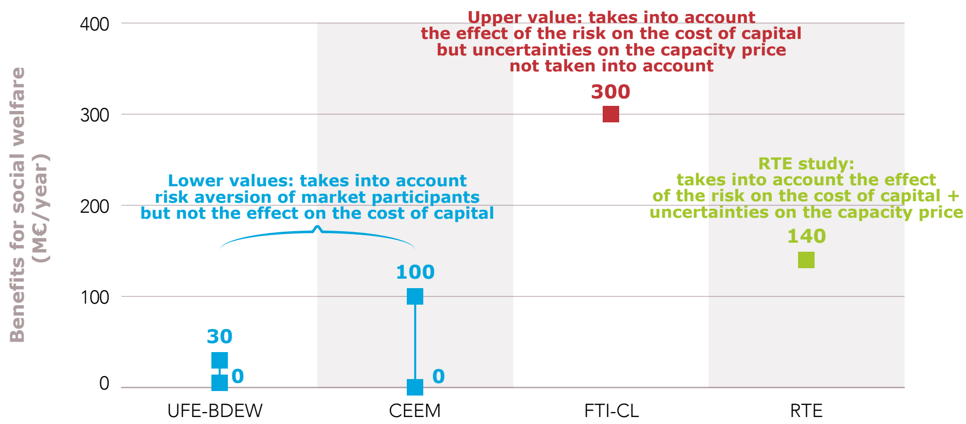


from the risk investors face. This means that these studies assume that the risk for investors is identical regardless of the market design in which they operate.

This hypothesis - crucial for the validity of the results of many studies discussed across Europe - is clearly incompatible with a precise analysis of the impact of the electricity market reforms. In other areas, such as the development of support mechanisms for renewable energies, the consensus is that the effect of the risk on the cost of capital is a key factor. It is therefore important to take this effect into account in the analysis of market designs and security of supply.

Most of the European studies published to date have not met this prerequisite. A few, however, have assumed a different cost of capital depending on the market design analysed. But these values, specific to each market organization, were sometimes exogenous and fixed in advance. They were not based on the

Figure 5. Benefits of a capacity mechanism for the social welfare in relation to an energy only market with high price caps. Comparison between the different studies.



outcome of the analysis of the results (calculated on the basis of uncertainties on the future income derived from the investments) but rather arose from an assumption (except in the case of the UFE-BDEW, FTI-CL and CEEM studies).

The contribution of RTE therefore aims to delve deeper by incorporating, in the representation of the business models of the investors, the risks to which they are exposed and the associated effects on the cost of capital. These risks are related to long-term uncertainties in the evolution of the energy context, as well as to short-term uncertainties (weather variability or asset availability) that can affect the revenues of a generation or demand response capacity from one year to another. These studies could be improved with additional analyses on the effect of risk on the cost of capital in the energy sector, on the impact of upstream-downstream integration (i.e.: generation-supply[6]) of certain utilities or on the influence of additional risks such as fluctuations in fossil fuel prices.

However, regardless of potential additional analyses, RTE's contribution has already emphasized that taking into consideration the influence of risk on the behaviour of market participants and their costs of financing changes the conclusions of studies comparing the merits of different market designs.

Regardless of whether there are market failures in energy markets, introducing a capacity mechanism is a no-regret option. A properly designed capacity mechanism not aiming for overcapacity systematically leads to social welfare improvement.

Energy market failures are generally modelled by the application of an energy price cap at a lower level than the value of lost load. Thus, without a capacity mechanism, an energy-only market capped at 3000 €/MWh leads to a loss of load expectation of up to 14 hours a year. This result is compliant with the findings of the other public studies.

In case of energy market failures, introducing a capacity mechanism ensures the security of supply target set by the French public authorities. The reduced risk of loss of load obtained from introducing a capacity mechanism leads to a significant improvement of the social welfare, which most studies, including RTE's, have evaluated at several hundred million euros a year over the long term. This result fully justifies the reform led by the French authorities to build a regulatory framework to achieve the security of supply target over time.

The interest of introducing a capacity mechanism is not justified solely by energy market failures. Indeed, assuming that the cost of unserved energy can be accurately estimated and that prices on energy markets can be set at this level, introducing a capacity mechanism would still be beneficial for social welfare. In fact, its implementation significantly reduces the cost of capital for investors by reducing uncertainty on the profitability of their investments, yet not fully de-risking them.

The magnitude of the gains associated with a capacity mechanism depends on the effect of the risk on the cost of capital: the more costly the risk, the greater the benefits of the insurance role of the capacity mechanism for the social welfare. Thus, even if there are no energy market failures, reasonable assumptions lead to a gain of around 140 M€/year and sensitivity analyses conducted in the context of this study have validated the robustness of this figure.

Therefore, the French capacity market will remain relevant regardless of future choices concerning the energy market reform, particularly with regard to price cap levels.

A reform of the energy-only market design based on higher price caps does not appear to be an efficient alternative to implementing a capacity mechanism.

6. Under certain configurations, upstream-downstream integration could reduce exposure to energy price volatility risk for capacity investments.

A reform of the energy-only market consisting of raising price caps to the level of the estimated value of lost load could theoretically resolve security of supply issues associated with energy market failures. However, this market design would expose capacity operators to a significant financial risk, much greater than in a design incorporating a capacity mechanism.

In fact, revenues from power generation assets and demand response would depend primarily on highly remunerative but rare and random events (typically once-in-a-decade cold spells). Such a design would raise the costs of financing investment projects compared to a market design based on an energy market capped at 3000 €/MWh and incorporating a capacity mechanism. The additional cost for society, as mentioned earlier, would be close to 140 M€/year.

This result is in line with other studies. Some studies (FTI-CL Energy) reported higher results, which can be explained by differences in the way long-term risks were accounted for. Other studies found lower results (UFE-BDEW and CEEM), because they did not consider the effect of risk on the cost of capital in the overall cost of the electricity system.

In a market design with a capacity mechanism implemented, setting higher energy market price caps would have a detrimental impact on the social welfare.

In a market design with a capacity mechanism, higher price caps would lead to increased incomes for capacity operators on energy markets, thus reducing missing money and lowering the revenues on the capacity market. As revenues from energy markets are more risky than revenues from the capacity market (since these are dependent on rare and random situations of shortage), such a measure would have the effect of replacing low risk revenues with much riskier revenues.

Thus, in a market design with a capacity mechanism implemented, higher energy market price caps would increase the cost of capital, which would decrease social welfare by around 110 M€ per year *(see Figure 4).*

In addition, a reasonably high cap on the capacity price is economically sound. This ensures that compliance with the security of supply target is not done at any price. In some situations there may be transitional needs for capacity that are particularly costly to meet, as they would imply the construction of peak generation assets for a need which is much shorter than the lifecycle of these assets.

A price cap on capacity certificates prevents the need for these costly investments, with minimal negative impact on the security of supply, for a net profit of around 165 M€ per year.

Outlook and extensions

The existing public impact assessments, supplemented by the study conducted by RTE provide a robust demonstration of the economic benefits of the French capacity market.

Still, the RTE study could be improved in several aspects. Firstly the modelling of long-term uncertainties could be refined, integrating additional variables that are risk factors for investors. In particular, uncertainties regarding fossil-fuel prices, CO_2 or public policy changes (nuclear power, interconnections, generation capacity abroad, etc.) could be considered. Secondly, an update of the results of the study could be considered, building on the latest scenarios from the 2017 publication of the RTE Generation Adequacy Report.

In the French context, this type of study could be used for the implementation of the contracts for difference regime for new capacities, due to come into effect in 2019. Contracts reduce financial risks for investments in new capacities by securing their capacity remuneration over the first 7 years of operation. The methodology for long-term simulation of investments developed in this impact study provides a framework of analysis to select the contracted capacities.

Beyond its interest for the French context, the purpose of this impact assessment is also to contribute to the debate in Europe and to guide future choices in terms of community regulation. It provides insights on issues such as the consequences of various market designs in terms of security of supply and the potential complementarity of these different approaches, as well as the long-term cost for the consumer of these different forms of market organization.

The conclusions of the study highlight the fact that the current preferred approach of the Clean Energy Package for guaranteeing security of electricity supply in the Union, based on an energy-only market design with very high price caps, is not the most economically efficient. Other forms of market organization, based on energy markets with reasonably high price caps and integrating national or regional market-wide capacity mechanisms, appear to be more effective. The choice of these alternative designs would ensure a secure supply of electricity at the least cost by limiting exposure to risk for market participants. Such market organizations would have the additional advantage of preserving the possibility for Member States to choose their target level of security of supply – a prerogative which could be called into question if the European energy market price cap level became the only determining factor of security of supply.

CONTENTS

1. CONTEXT AND ISSUES OF IMPACT ASSESSMENTS OF CAPACITY MECHANISMS

Based on in-depth parliamentary work, France made the decision in 2010 to put in place a capacity mechanism to complement the energy markets and ensure its security of electricity supply. Technical and economic analyses were then conducted to support each step within the regulatory framework, to guide the structural choices of the market design. Consultation between public authorities and stakeholders was central in this process, allowing the capacity mechanism to be launched on 1 January 2017. RTE has prepared this impact assessment as part of this work and to complement previous analyses, aimed at supporting regulatory choices with robust evidence.

1.1 An impact assessment in the continuity of the 2014 work on the limits of the "energy only" market design

At the request of the French authorities and prior to the implementation of the French capacity mechanism, RTE performed theoretical analyses on the soundness of introducing such a mechanism. The results of these qualitative analyses had previously been presented in the report accompanying the capacity market rules, published in 2014, on the submission of draft rules for the French capacity market to the Minister and to the regulator[7].

This analysis – based on substantial review of the literature, – helped to illustrate the close links between market design and the level of security of supply, and this more specifically in the framework of European regulation.

Indeed, a European electricity market has gradually been forged since the beginning of the liberalisation of the electricity sector started in the 1990s. This market relies on a decentralised model, in which generators, demand response operators, suppliers, traders or dealers trade energy blocks at different time horizons (futures, day-ahead, intraday). These trades take place within a same price zone or from one price zone to another within the limit of physical interconnection capacities.

This structure relies on the development of organised markets for purchase and sale of MWh of energy for different time horizons. The increased liquidity of organised markets occurs alongside an increasingly close coupling of various national markets, resulting in a very effective optimization of the European power system in the short term.

Among the different time horizons, the daily market today occupies a central place and the coupling of different price zones at this time interval is already very advanced, covering 19 countries and representing 85% of power consumption in Europe. In recent years, however, there has been an increase in volumes traded on intraday markets and over the next years these will be the greatest focus for integration at European level.

On these various energy markets, the price at which energy blocks are traded at each moment in time should be set at the marginal cost of the most expensive generation or demand response facility dispatched to meet the demand. All of the power generation or demand response sources with a lower marginal cost than this most expensive facility receive the market price and therefore benefit from an infra-marginal rent, corresponding to the difference between their variable costs and the market price.

7. RTE. Report to support the proposal for capacity mechanism rules. 2014

Box 1. A theoretical representation of the functioning of electricity markets with an energy-only design

The works led by Ramsey and Boiteux in the 1950s on the relationship between financing of generation assets and marginal cost pricing[8] have been decisive for the understanding and representation of the economy of the energy sector. This work is the academic backbone of the energy-only market organisation and provides a simplified model to describe the functioning of this type of market organisation. The reasons for the success of this theoretical representation lie both in the power of its results and the ease with which it can be modelled.

In this model, pure and perfect competition is assumed (atomicity and rationality of players, perfect information, free entry and exit of markets), as well as a number of simplifying assumptions (no externalities, no strategic behaviour and risk aversion of economic agents, non-discrete characteristic of the power generation sources, etc.). These assumptions are very strong and in practice rarely verified, under which, for example, players have perfect foresight and prices perfectly reflect fundamentals, potentially rising to substantial levels –reflecting the value of electricity as a good for consumers.

Under these assumptions, the free operation of the market would give rise to an identical result to what would be achieved under the watchful eye of a fair and omniscient central planner in charge of optimizing the operation of the power system. At each moment in time, power generation sources are called upon in order of economic precedence or merit order (from least expensive to most expensive) to meet the demand for electricity expressed by all of the consumers and the price is set at the marginal cost of the most expensive power plant that is required. All of the sources dispatched which have a lower marginal cost than the market price receive an infra-marginal rent.

When demand is too high to be fully satisfied, the supply-demand balance is established by adjusting prices: these increase to reach a level beyond which consumers prefer to see their power supply interrupted rather than pay for it

Figure 6. Infra-marginal rent

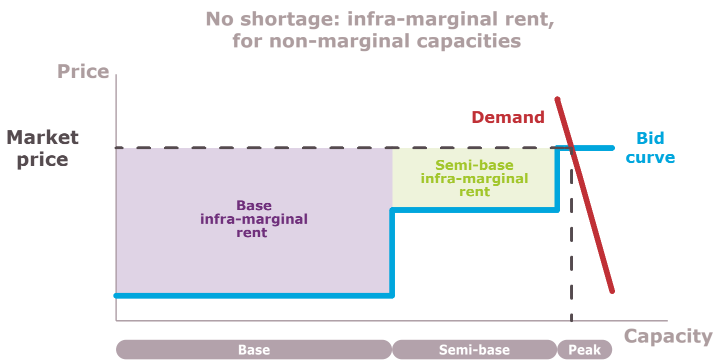
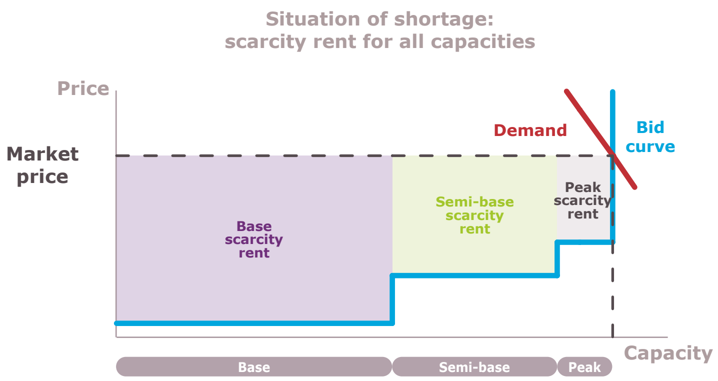


Figure 7. Scarcity rent



8. Boiteux M. (1949) La tarification des demandes en pointe: application de la théorie de la vente au coût marginal [Peak load pricing: application of the theory of marginal cost sales]. Revue générale de l'électricité

to be maintained. The cost of unserved energy or Value of Lost Load is used to determine this price level (CEND or VoLL in English). During such shortage situations all of the capacity plants receive a scarcity rent, which, in addition to the potential infra-marginal rent mentioned earlier, should cover the fixed costs of their facilities.

Important conclusions – greatly dependent on the simplifying assumptions mentioned above – can then be associated with the operation of the market. These can be summarised as follows:

- energy prices alone lead to a balanced situation in which the generating capacity is said to be adapted to meet the needs of consumers;
- in this balanced situation, loss-of-load expectation is economically optimal. This means it would be costly for the social welfare to develop further capacity sources to reduce it and that conversely it would be inefficient to increase the loss-of-load duration by removing a generation or demand response unit;
- all the power plants making up this adapted fleet earn revenue from the energy markets allowing them to recover the precise amount of their full costs, not more or less.
- Finally, under such a model, for a national consumption profile and a cost structure corresponding to the various generation and demand response sources, there is a very close link between average loss-of-load duration and the value of lost load.

Thus, for example, in a non-interconnected system, the loss-of-load expectation and the value of lost load are linked by a simple equation:

$$E_{loss\text{-}of\text{-}load} = \frac{Fixed\ costs_{peak}}{VoLL\ -\ Marginal\ cost_{peak}} \approx \frac{Fixed\ costs_{peak}}{VoLL}$$

Where:

- $E_{loss\text{-}of\text{-}load}$, the loss-of-load expectation of the power system in hours;
- $Fixed\ costs_{peak}$, the fixed costs of the peak generation or demand response capacity in euros per MW
- $Marginal\ cost_{peak}$, the marginal cost of the peak generation or demand response capacity in euros per MW
- $VoLL$, the value of lost load in euros per MWh ($\gg Marginal\ cost_{peak}$)

Forecasting energy market prices helps guide the investment or decommissioning decisions of stakeholders over the long term: (i) frequent periods of shortage lead to a greater level of remuneration of assets on the energy market, which stimulates the realization of new investments and the development of new capacities; (ii) conversely, a situation of long-term depressed energy prices is an indication for market players of an overcapacity situation and provides an incentive to close or mothball non-profitable or superfluous generation and demand response capacities.

At European level, the stakeholders of the electricity sector and the regulatory bodies are divided on the question of whether this signal for investment coming from energy markets is sufficient to ensure adequate capacity (i.e. a sizing of generation and demand response assets consistent with public objectives in terms of security of supply), or if on the contrary it only represents a component that must be supplemented by implementing mechanisms *ad hoc*. On the other hand, the debate that took place between 2010 and 2014 during the design process of the French capacity mechanism helped identify a relative consensus at the French level on the need for additional regulation aimed at ensuring this capacity adequacy.

Consequently, the bulk of the debates is now taking place at European level. The backdrop is an economic controversy on suitable representation of the functioning of energy markets by means of a theoretical model which is simplistic but fundamental for the analysis of the sector *(see box 1)*. It distinguishes on the one hand between stakeholders who favour a market that relies exclusively on energy block trades – upholders of the so-called "energy-only" market – and on the other hand defenders of an additional regulation to ensure security of supply.

Besides the theoretical considerations discussed below, this presentation of the state of play of the European debate raises two specific points at this stage. The first is that to date, in the various member states with liberalised electricity markets, there is no regulatory framework focused exclusively on the sale of energy blocks. All markets also include components linked to the balance of the system, in which TSOs contract reserves with market players, i.e.: a guarantee of availability over certain periods. This situation illustrates the extremely simplistic nature of the energy-only market model. Furthermore, it should be emphasised that recent European developments have brought to light the fact that most member states claiming an "energy-only" market design for electricity markets actually relied on implementing additional schemes in order to ensure their security of supply[9].

From a theoretical perspective, the academic literature reveals substantial developments concerning simplifications inherent to the energy-only model, and deviations between this modelling and the actual functioning of markets. These analyses were presented in the report published by RTE in 2014. These deviations between the theoretical model and the actual functioning of the markets are the reason behind the inefficiencies associated with an energy-only type electricity market, particularly in terms of security of supply. These inefficiencies justify implementing a corrective regulation in order to achieve the policy target for security of supply over time. The conclusions presented at the time are still fully valid, and a number of conceptual elements identified then are now at the heart of the debates between regulatory bodies and stakeholders in the sector.

1.1.1 The issue of price caps

Energy market price formation is central to coordinating decisions taken by market players, whether these decisions involve the use of generation and demand response capacities or the evolution of installed capacities (investments, closures, mothballing). Thus, in the long term, the process of price formation has a determining influence on the revenues of market players and on incentives to invest. Under certain strong assumptions, these price signals may alone allow the development of a suitable generation fleet and ensure an optimal level of security of supply.

This fundamental result strictly adheres to a set of assumptions that constitutes a significant simplification of the functioning of markets: setting the price at the level of utility loss during periods of shortages, assumption of pure and perfect competition, convexity of costs, non-discrete nature of investments in new capacities, lack of consideration of risk in investment decisions, etc.

Among these assumptions, one which considers that the energy price can be set, in situations of scarcity, at the level of utility loss for consumers in the event of a power outage, is particularly strong. One aspect of the issue of price levels during periods of scarcity relates to existing price caps on daily markets close to real time. This aspect has been the greatest subject of debate at the European level and the focus of attention of energy community regulatory boards. Such a focus can be explained both by the significant impact these price caps can have in a theoretical framework, as well as by the ease with which all energy market deficiencies can be modelled by this single parameter in economic studies *(see box 1 p. 17)*.

The theoretical analysis provides in effect that, when price caps are set below the value of lost load, the revenues of capacity operators during scarcity events (scarcity rents) are subsequently reduced, resulting in missing money when the security of supply criterion is respected. This term refers to the structural impossibility for the capacities required for security of supply (here understood as the optimal load shedding time) to recover their full costs.

Such price caps exist today on markets operated by Nominated Electricity Market Operators (NEMOs), (day-ahead and intraday) and on balancing markets managed by the TSOs; their establishment having been decided for technical reasons, in the interests of consumer protection and the prevention of potential anti-competitive practices. In light of their potential impact on investment and security of supply, raising

9. EC. Final Report of the Sector Inquiry on Capacity Mechanisms. 2016. COM(2016) 752.

Box 2. Price caps and missing money

The representation of the energy-only market discussed previously specifies that, in the event of introducing a price cap set lower than the VoLL, all of the capacities in the adapted fleet suffer from a missing money problem which is identical for all generation sources:

$$Missing\ money = P_{instal} \times E_{loss\text{-}of\text{-}load} \times (VoLL - price\ cap)$$

Where:

- P_{instal}, the installed power of the production unit considered in MW;
- $E_{loss\text{-}of\text{-}load}$, the loss-of-load expectation of the power system in hours;
- $VoLL$, the value of loss of load;
- Price ceiling, the energy market price cap, in euros per MWh.

price caps to a level reflecting the value of loss of load is currently being studied and is a proposal of the European Commission[10].

This reform proposal assumes, however, that the value of loss of load can be estimated with sufficient precision. Still, as the point was raised by a great number of market players during a consultation on the issue of price caps held by the CRE from April to May 2017, such an estimate is difficult and by nature uncertain. Assessing the value of this energy is – for example – likely to differ from one consumer to another: the value of a MWh not being the same for an industrial consumer as for a residential consumer. Moreover, this value may not be uniform and depend on the significance of the volume of lost load, on the period of time the power supply was interrupted, on the power, on the duration, etc.

Setting energy price caps at a level representative of the value of loss of load would therefore amount to defining a mean value, representative of the different individual valuations and the various possible situations. An error in the estimation of this value may be the cause of inefficiencies in the functioning of markets. In fact, as long as electricity consumption continues to present a low price elasticity, which is still the case despite considerable developments in demand response in markets in recent years, an overestimation of this value will result in over-procurement of capacity that is costly for the end consumer. Conversely, too low a value would result in an insufficient level of adequacy in view of collective preferences.

These risks are inherent to the regulation mechanism aimed at creating a collective good by controlling prices. Indeed, the definition of a price cap, supposed to represent the value of lost load, can be interpreted as a desire to steer the level of security of supply through prices. In doing so, such an approach tends to confer a political role to parameters which are fundamentally technical. There is a similar rationale in the positions of some regulators and industry experts who advocate to voluntarily introduce distortions in the energy price formation process when the system is nearing a scarcity situation.

From this perspective, it is paradoxical that some bodies, including the Commission, seem to favour such a price-based approach over a quantity-based approach, even while on a related topic, that of the good design of capacity mechanisms, they recommend avoiding capacity payment systems and focusing on volume-based systems.

> *Finally, with respect to 'capacity payments', the sector inquiry shows that these mechanisms are unlikely to set the right price for capacity since they do not allow the market to competitively set the right price, but rather depend on an administratively set price. They are therefore unlikely to correctly reflect the actual scarcity*

10. On this point, see article 9 of the draft revision of the regulation on the internal electricity market, sent by the Commission to the Parliament and Council

> *situation. They imply a high risk of under – or over-procurement of capacity – especially as such schemes tend to react slowly to changing market circumstances. […] The general presumption is therefore that price-based mechanisms are unlikely to be an appropriate measure regardless of the specific concern identified.*[11]

1.1.2 The common good aspect of security of supply

Energy market failures can also be addressed within the framework of the theory of common goods. Today security of supply still possesses the characteristics of such a common good, that is to say a good with characteristics of "rivalry": the consumption of this good by one agent reduces the possibilities of consumption by another, and "non-excludability": it is not possible to distinguish, based on economic considerations, consumers who should be able to benefit over others.

Indeed, the demands of various consumers during peak periods all add together and can only be met within the limit of the capacity of the system. In addition, and in spite of the substantial development of the demand response market, it is still not possible for all consumers to express – on an individual basis – the value they attach to uninterrupted electricity supply and therefore to reveal what they believe to be the value of lost load for them.

Thus, even if investments in additional capacities generate positive externalities on the security of supply (and therefore for all of the energy market players, end consumers included), the operators of these capacities are not guaranteed long-term remuneration for the level of service they provide for the community. There is a real risk of underinvestment and this has been the subject of significant documentation in the economic literature. The majority of stakeholders, including the European Commission, acknowledge this issue.

> *This means that in events of scarcity each consumer's likelihood of being disconnected is independent of his VoLL, making him unwilling to pay for reliability as much as he would otherwise be willing to. Economic theory thus suggests that in such circumstances a decentralised competitive [energy] market is likely to provide suboptimal incentives for generators to invest in generation capacity, which would therefore ultimately deliver suboptimal levels of system reliability compared to what consumers would have been willing to pay for if they were able to be individually disconnected on the basis of their individual VoLL.*[12]

The European Commission, along with other stakeholders, however, consider that the gradual deployment of smart meters could contribute to making the security of supply a private good in the long term. Each consumer could end up having their power supply interrupted or reduced when market prices exceed a predetermined level, chosen individually. This evolution would bring the actual operation of the power system closer to its theoretical representation. Such a logic, however, is not straightforward and raises some questions: from a social perspective particularly, since it amounts to considering that consumers willing to pay the highest price should be supplied first, to the detriment of the less well off. In the French power system, in which periods of higher consumption, and therefore of high prices, correspond to cold spells, this could lead to a situation where certain categories of consumers are deprived access to a basic necessity at the very moment they would have the greatest need for it, such as for heating needs.

This evolution would, to a certain extent, call into question the public service aspect of electric power supply[13]. A notion of French law to which correspond, in part, in European law, the concepts of services of general economic interest and universal service, which guarantee right of access to this type of service to any resident of the European Union "at an affordable price" and that the "service quality is maintained and, where necessary, improved."[14] Such an evolution of public service sectors is not, in essence, impossible or undesirable, but it requires at least some debate and a clear political decision and cannot simply result from a technical decision.

11. EC. Final Report of the Sector Inquiry on Capacity Mechanisms. 2016. SWD(2016) 385. p166
12. EC. Final Report of the Sector Inquiry on Capacity Mechanisms. 2016. SWD(2016) 385. p39
13. Article L121-1 of the French Energy law actually states that: "The public electricity service aims to guarantee an electricity supply over the whole country, in line with public interest."
14. EC. Green paper on services of general interest. 2003. COM(2003) 270, final, p16-17

1.1.3 Investment dynamics in the electricity sector

An analysis of the actual functioning of energy markets and critical review of their theoretical modelling must also incorporate the phenomena of investment dynamics. Most theoretical models of the energy-only market design, for example, tend to consider perfect and somewhat quasi-instantaneous adaptability of the electricity mix to any changes in the economic context.

The energy market is, however, characterized by time constants (construction times, asset lifetimes) that make the electricity mix at any given moment dependent on the choices made over the previous years and decades, on the basis of past forecasts.

These expectations are by nature not perfect, and are related in particular to economic parameters (demand, fossil-fuel prices, etc.). Deviations between the actual value of these parameters and the initial forecasts are sometimes very significant. The wave of commissioning of new combined-cycle gas power plants in the 2000s is a prime example. These investments were carried out on the basis of an assumption of growth in consumption, of a high carbon price forecast and a relatively slow development of renewable energies. A stagnating electricity consumption, a substantial development of renewables[15] and a sluggish carbon price have negatively affected the economic profitability of these investments and led to significant impairment of assets.

All these factors contribute to the creation of investment cycles, or boom & bust cycles, which are not specific to the energy sector as they also affect the activity of other industrial sectors[16].

These cycles can be explained by a form of inertia in the entry and exit of new power generation facilities: investments are "triggered" (generally by several players at once) beyond a threshold of expected profitability and closures are decided when a threshold of loss is exceeded, by several players at the same time. Real power systems therefore oscillate around a long-term equilibrium, which itself can evolve with the level of consumption, the costs of the various technologies, etc.

The alternation of these investment cycles and closures is therefore likely to result in a marked succession of periods of overcapacity and periods of under-capacity, which from an economic perspective are detrimental for both the electricity system and the consumer. For instance, during periods of under-capacity, the risk of load shedding may be too great and imply a level of security of supply which is too low from an economic perspective. In addition, due to the shifts between periods of investment and closure, all other things being equal, power generation units remain on the market for a shorter than optimal time, the need for investment is greater and the cost for the end consumer increases accordingly.

1.1.4 The risk relating to profitability of capacity investments and its effect on the cost of capital and investment decisions

The investment dynamic also depends on the level of risk associated with a given market design and the behaviour of the market players in the face of this risk. This dimension is frequently absent from discussions relating to the interactions between market design and security of supply.

The lack of consideration of this issue – particularly in debates at the European level – is surprising, as it constitutes a key determinant in the choice of market design in areas other than security of supply. Most of the considerations regarding support mechanisms for renewable energy sources concern this issue, for example, and the ways and means of limiting market players' exposure to risk. A too high risk could deter investments in these new energy sources and thus prevent achievement of the European objectives. It could also lead to an increase in the cost of capital and thus ultimately in the cost of the energy transition.

> *On the one hand, investments in maturing, clean technologies have taken place thanks to public support, which reduced the capital and operating costs and the risks for investors. […]*

15. RUDINGER, Andreas. SPENCER, Thomas. SARTOR, Olivier. *et al.* Getting out of the perfect storm: towards coherence between electricity market policies and EU climate and Energy goals. 2014, IDDRI working paper No. 12/14, p8-9

16. This, for example, is the case of the aluminium production sector, which must deal with a highly variable demand.

> *The problem with this approach (scarcity pricing) is that it may lead to high price volatility, which increases the investment risk associated to the electricity market and the uncertainty – especially for peaking plants, but also for variables renewable plants – to recuperate their investments.*[17]

Indeed, given the capital intensity of the sector, the lifetime of investments and their near irreversible nature, the assumption of neutrality of the players in the face of risk does not seem valid. Intuitively, admitting such an assumption would mean considering that a project developer will have no trouble financing an asset in which profitability depends on very high but infrequent price spikes and during which its availability is not guaranteed. This concept does not seem in keeping with the specific issues facing the industrial and financial sectors.

A rigorous and realistic modelling of the functioning of energy markets therefore requires taking into account the effects of profitability risk on the cost of capital and on investment decisions. However, these effects are difficult to estimate with precision and econometric studies on this issue are still incomplete at this time. Such difficulties, which must not deter any modelling effort, require a careful approach and sensitivity analyses should be conducted to better identify the actual impact of this parameter.

1.1.5 The need to complement theoretical analyses with quantitative elements

The analysis and assessment, carried out in 2014, for which the main results have been recapped above, has helped identify the dimensions to take into account to analyse the need for introducing a capacity mechanism, and the consequences of such an introduction, in terms of security of supply but also of economic efficiency. It would seem essential, however, to complement this reflection with a quantitative analysis to clarify and discuss the relative importance of the various phenomena mentioned above and to apprehend the long-term dynamic impacts related to the introduction of this mechanism.

This is moreover a regulatory requirement for RTE, as the rules of the capacity mechanism adopted by the Minister provide that:

> *RTE conducts studies on the dynamic impact of implementing the capacity mechanism over the long term. […] This work is sent to the CRE, to the minister in charge of energy and to the market players.*

RTE is fulfilling this regulatory requirement in response to feedback from stakeholders who, during various consultations held by RTE in the last three years, have frequently requested that such works be carried out. RTE was therefore able to rely on the collective expertise of French market players during the course of a specific consultation organised in the second quarter of 2016.

Finally, this impact analysis is part of a growing and legitimate concern for assessing public policies; a concern expressed as much within France as on the European level, in a context of scarcity of public resources and questions raised regarding the appropriate scope of intervention by public authorities. The energy sector is no exception to this focus on rationalisation and critical analysis of public action and regulation.

On the national level, the Member States are increasingly focused on justifying their decisions in the energy field, drawing on economic studies, the findings of which are sometimes shared at European level. Community authorities, and in particular the Commission, are also subject to this imperative of assessing their proposals in terms of regulation[18].

The dissemination of these best practices to all bodies involved in the regulation is a positive step to which RTE is committed to contribute to. This logic of evaluation could be consolidated and enriched by strengthening the transparency of data, key assumptions and methodologies used to perform this analysis. In fact, the quality and the means allocated can vary greatly from one study to another and it is often as important to carefully consider the conditions in which these studies have been carried out and the underlying assumptions, as the results themselves.

17. EC. Investment Perspectives in electricity markets, 2015, Energy Economic Developments, Institutional Paper 003, p36

18. Based on a scheme similar to the existing scheme in France for all draft laws, all legislative proposals from the Commission must be subject to an impact assessment, itself subject to an assessment and opinion issued by a dedicated board: the regulatory scrutiny board.

1.2 A contribution to the current European debate on the regulatory framework to ensure security of supply

This impact assessment is being published by RTE at a time when a new wave of reforms of the European power system is taking place, with ongoing negotiations on the "Clean Energy for All Europeans" package. This set of texts, containing 8 legislative proposals (including 4 draft guidelines and 4 draft regulations) and 5 non-legislative acts, brought forward on 30 November 2016 by the European Commission, is in the course of examination by the European Parliament and the Council of the European Union within the context of the usual legislative procedure.

This package constitutes an overhaul of the main European texts governing the organisation of the electricity sector in the Union, for which previous changes led to substantial transformations of the sector. The first package, adopted in 1996, led to the gradual liberalisation of the sector and the accounting and managerial separation of transmission and competitive activities, such as the supply or the generation of electricity, eventually leading to the creation of RTE in 2000. The second package, adopted in 2004, continued the opening to competition of the sector, in particular with the launch of the retail market and the strengthening of the imperatives of separation for transmission activities, and the establishment of similar imperatives – although less stringent – for distribution activities, leading to the creation of ErDF (now ENEDIS). Finally, the third package, becoming effective in 2009, constituted a last step in the opening to competition by introducing new provisions on the unbundling of transmission system operators and the mandatory set up of energy regulators for each Member State with strengthened competences and independence. The third package moreover led to the creation of new institutional structures for cooperation in the area of energy at the European level: ENTSO-E, the European network representing TSOs, and ACER, the European Agency for the Cooperation of Energy Regulators, whose mission is to set standards and common rules for the management of the network and markets, network codes, and may also arbitrate certain cross-border decisions. Through their work, these institutional structures contribute greatly to the coordination of energy policies of the various EU states, particularly through the publishing of its Ten-Year Network Development Plan, and mid-term adequacy Forecast (MAF).

The transformations to be expected from the Energy Package itself will likely be equally determining. The goal of the European Commission in presenting these draft legislations is to adapt the European energy market rules and the principles of functioning of the electricity system to the new energy paradigm of the future by meeting the challenge of increasing the share of intermittent energy sources, while seizing the opportunities that are offered by new and innovative digital tools. This recast of the European regulation is also the opportunity for the European Commission to re-examine the respective roles the market must play, on the one hand, and public intervention, on the other hand, in the organisation of the sector in order to ensure optimal management of the system, to achieve public policy objectives and security of supply targets. The main focus of the debates at this stage is on the main themes around which the European Commission has centred the bulk of its proposals:

- **Conditions offered to consumers:** the Commission has proposed to provide incentives for consumers to become more active, by putting an end to regulated electricity tariffs and by giving access to dynamic prices, while developing the European regulatory framework for demand response, or facilitating access to new modes of consumption and energy generation (self-consumption, local energy communities).

- **The definition of new European objectives, to achieve the targets set out in the Paris Agreement to decarbonise the economy, and an appropriate governance framework:** through new binding targets at the European level, particularly in the field of renewable energies and energy efficiency by 2030, on the basis of the conclusions of the European Council in 2014; through the implementation of a governance framework to monitor national targets (presented in national energy and climate plans) and verification to ensure European targets are met (through a mandatory contribution, in the event objectives are not met, to finance renewable energy projects), as well as through the establishment of a mandatory minimum cross-border opening of national support schemes for renewable energy.

- **Continuing integration of the European market, in particular with regards to close to real-time markets, along with establishing common rules and principles** relating to the operation of the system (congestion management, terms for integrating intermittent energy sources into the power grid), the establishment of market rules (capacity markets, balancing markets) or the new uses and practices which could provide services to the power system (electricity storage for example).

Finally, the Clean Energy Package negotiations notably involve the ongoing European debate on the regulatory framework to ensure national security of supply targets, on the appropriate level of intervention and on the terms for coordinating national, regional and European initiatives.

A majority of stakeholders now agree on the necessity to develop the existing framework to ensure a secure supply of electricity to all European citizens. However, there is no consensus on the solutions that need to be implemented to counteract the shortcomings of the current organisation of markets; particularly as the economic debate is coupled with a policy issue on the respective prerogatives of the Union and the Member States in terms of security of supply.

At the heart of these exchanges are the means by which the price formation process can be reformed, particularly through key policy measures such as the raising of energy market price caps. Linking these measures with the capacity mechanisms, which now form an integral part of the framework of European regulation, represents a significant part of the agenda in the discussions.

1.2.1 Review the functioning of energy markets by reforming the price formation process

The energy market price formation is a key element in the series of incentives provided for market players. Real time decisions on whether or not to activate the various power generation or demand response sources are made on the basis of these price signals. These price signals also direct energy flows between bidding zones. They therefore play a central role in optimising the short-term functioning of the electricity system. In the longer term, they also play a key role in encouraging market participants to invest in new capacities or on the contrary to close or mothball some of those that they operate, on the basis of income expectations on the energy markets.

For the European Commission, the functioning of energy markets must be reformed in order to improve the price formation process:

> *Prices that reflect the true value of electricity can provide signals for new investment in the reliable and flexible capacity needed to deliver secure electricity supplies. […]*
>
> *A second important market reform concerns the participation of demand response providers in the market. Increasing the responsiveness of demand to prices in real time is of crucial importance because it can flatten demand peaks and thus reduce the need for additional generation capacity. […]*
>
> *Finally, the sector inquiry demonstrates that delineation of bidding zones should be examined and revisited so that appropriate local prices can form to stimulate investment in capacity in those places where it is lacking as well as in the transmission infrastructure needed to move electricity from producers to consumers.*[19]

This agenda of reforms is set out in the proposals for directives and regulations unveiled in November 2016. Three major measures have been put forward: (i) increasing flexibility of consumption through the establishment of a European regulatory framework to facilitate the emergence of demand response, (ii) implementing a methodology and governance framework aimed at redefining relevant bidding zones and, finally, (iii) raising price caps on energy markets to a level reflecting consumers' willingness to pay to ensure uninterrupted electricity supply.

To promote the development of new demand response capacities, and thus make the consumption of electricity more flexible, the Commission proposes to establish a European regulatory framework for demand response, requiring, on the one hand, suppliers to offer their

19. EC. Final Report of the Sector Inquiry on Capacity Mechanisms. 2016, COM (2016) 752, final, p6-8

customers at least one supply offer at prices indexed to spot markets and, on the other hand, allowing the free activity of independent demand response aggregators. This model of the independent aggregator is indeed a no regret measure which has featured in the French regulations since 2013. The initial proposal of the Commission does not seem, however, to be compatible with the fundamental principles of the market design implemented in France. It raises questions in particular about the possibility of providing a system of payment between demand response operators and suppliers. Such a system would be essential for maintaining relevant economic incentives and preserving ownership rights of market players.[20]

Furthermore, to improve the representativeness of the price signal, and in particular its local dimension, the Commission advocates a regular review of bidding zones, following a procedure conferring a substantial power of decision-making to community institutions (in particular to the ACER and the Commission itself), whose prerogatives would thereby be strengthened in relation to the current framework defined in the Network Code on Capacity Allocation and Congestion Management (CACM).

The configuration of bidding zones plays an important role in the energy price formation process. Specifically, their delineation must achieve a delicate compromise between moderately sized bidding zones, which identify and develop capacities that are locally limiting (network or generation and demand response capacities) and larger bidding zones, which increase liquidity of the markets and reduce the complexity of their coupling. These bidding zones must also be stable in order to allow market players and TSOs to value their investments over the long term. Although technical, this topic also has a strong political dimension, as a revision of these bidding zones may lead to the splitting of a country into different geographical areas, within which prices are not the same and for which the supply-demand balance is managed independently.

Finally, the last major axis of reform put forward by the Commission is the raising of price caps on daily, intraday and balancing markets to a level reflecting the Value of Lost Load. The draft regulation of the internal market in electricity thus proposes implementing a methodology to determine this pricing, which would be developed by ENTSO-E, and which would then be applied by each Member State, at a minimum every five years. The price caps of the various markets for the different bidding zones would then be aligned with the values calculated by the Member States.

These proposals from the Commission were made public in 2016 and are being discussed within the framework of the ordinary legislative procedure and of the interinstitutional dialogue between the European Parliament and the Council of the European Union.

Without knowledge of the final outcome of the discussions on the *Clean Energy Package,* it is likely that these proposals – and in particular those relating to increasing price caps – will evolve to take into account the position of Member States, particularly on the subject of security of supply. The Commission's proposals raise a certain number of questions that members of the European Parliament or the Member States may wish to study further.

Firstly there is a subsidiarity topic. While it is true that the approach proposed by the Commission formally preserves the Member States competence to set security of supply targets, Member States' freedom of choice will de facto be very limited by technical provisions. Indeed, the Clean Energy Package provides binding methodologies to be applied by Member States when determining their reliability standard, including how to set the main values taken into account in the calculation (value of lost load, cost of new entry etc.). This approach leads to a form of window-dressing subsidiarity, in which methodologies are decided at European level (in this case proposed by ENTSOE and approved by ACER), and the prerogatives of Member States will be limited to the application of those methodologies. A question of credibility follows, linked to the potential increase of energy price caps to the level of the value of lost load. While the Commission seems to encourage a stronger involvement of the Union on social issues[21], and that it has made consumer protection a major axis of this fourth package[22], it is fair

20. The revised version amended by the Council fixes this issue.

21. Jean-Claude JUNCKER. Speech by the President of the European Commission on the state of the Union. 14 September 2016

22. EC. Memorandum, "New electricity market design: a fair deal for consumers." 2016, available at: https://ec.europa.eu/energy/sites/ener/files/documents/technical_memo_marketsconsumers.pdf to question how public opinion would react to very high price peaks on energy markets. These reactions could be even stronger if a significant share of residential consumers have opted for a spot market indexed price offer, as the Commission intends to require suppliers to propose. A peak price of 20,000 €/MWh for five hours, for example, would result in a direct cost of 1,000 € for a small consumer consuming 10 kW over this period. This issue of social acceptability is important for investors, as acceptability issues undermine the stability of the regulatory framework. Following periods of scarcity marked by high prices on the energy markets, price caps could be reinstated in response to consumer demands, which would erode a large part of the reform envisaged in this fourth package.

These considerations instil doubt as to the credibility of the proposed reform over the long term, even though it is an essential parameter for its effectiveness. Indeed, potential investors need to be convinced that the rules of the game will not be challenged once their investments have been made. However, in light of the history of the sector, the focus on consumer protection and more generally the strong political involvement of public authorities – which is particularly justified in view of the climate imperative – the emergence of such a conviction is a real challenge.

Finally, ensuring security of supply by increasing energy market price caps raises the question of effectiveness. There is no guarantee that the measure will be sufficient, given the other market imperfections identified *(see Parts 1.1, 1.2, 1.3 and 1.4).* Will price peaks, which are by nature uncertain and during which the availability of a given asset cannot be guaranteed, convince potentially risk-averse investors from investing in new electricity generation sources? The text originally proposed is based largely on this premise, which has never been proven other than in purposefully simplified theoretical representations of the market, and which a large share of the market players, and even some regulators, do not seem to believe in.

> *CRE believes that the risks associated with the European Commission's proposal outweigh the expected benefits, and is therefore unfavourable to it.*
>
> *In the short-term, CRE has expressed reservations concerning the fact that an increase in price caps, during the periods of strain between the supply and the demand can, in practice, effectively allow access to additional generation capacities. It remains unproven that it is necessary to attain the price caps so that all the means of generation and demand side management are mobilized.*
>
> *In the medium/long-term, the economic reasoning of investors does not seem to be compatible with the principle of covering the fixed costs during events characterized by a low probability of occurrence, and whether the price caps are fixed at 3,000€/MWh as it is currently the case, or raised to a level equal to the VoLL. CRE considers that it remains unproven that an increase in price caps alone can be conducive to the investments necessary for the security of supply (particularly for the means required for extreme peak demand times) and prevent capacity shutdowns. […]*
>
> *While this proposal relates to uniquely theoretical benefits, as previously stated, it nevertheless raises a number of practical problems such as:*
>
> - *The difficulty of correctly estimating the VoLL: a unique value for representing a significant number of diverse willingnesses to pay among different categories of consumers;*
> - *The exposure of market participants to unnecessarily high financial guarantees. Since the cost of risk hedging is higher for a small producer or supplier, any increase in price caps, in particular for the day-ahead market, will expose them to greater financial risks, making their entry in the market and development more difficult. In addition, the current price caps are likely to limit the impacts of operational risks that may arise in the context of a fixing auction, as used for the day-ahead market.*[23]

On the contrary, several market participants, and in particular new entrants, consider that an approach based on increasing energy caps would have adverse

23. CRE. Memorandum of 13 documents containing observations from the regulator on the European Commission proposals for the package entitled "Clean Energy for all Europeans". 2016, Document 13, p1-2

effects from a competition standpoint, by significantly increasing the level of risk they would face. While price peaks constitute an opportunity for additional revenue, they are also synonymous with increased risks: a stakeholder defaulting during a period of scarcity despite having committed to delivering a given amount of energy would incur a substantial increase in penalties. The cost of the financing would probably be affected and could reach levels that would be prohibitively high for the most fragile market participants.

The impact of this approach on competition leads us to consider the overall interest of such a measure for the consumer. Similarly, the increase in the cost of capital – due to increased risk – could also lead to higher energy prices to cover the risk premiums expected by investors. Price caps also play a role in the protection of market participants, and more specifically of consumers, against potential anti-competitive practices. Their removal or increase would mean reduced protection for market players and consumers. This problem is even more complicated by the fact that during price peak episodes it may be difficult to distinguish the share of these events that result from proven situations of scarcity from those which result from a strategy of players aimed at influencing the functioning of the market.

1.2.2 Capacity mechanisms, an additional insurance which is now an integral part of the European regulatory framework

While the European Commission continues to favour a target design for the internal energy market based on the implementation of integrated markets on which energy blocks are exchanged at different time horizons, it has nevertheless evolved its doctrine on capacity mechanisms over the course of the last few years. It now recognizes that these mechanisms are an integral part of the European regulatory framework, whether for capacity markets[24] or for more administered schemes, such as strategic reserves[25].

This evolution can be explained by the taking into account of imperfections in energy markets, by the willingness for a constructive dialogue with Member States seeking to guarantee their security of supply, and by the recognition of the actual situation. This has led the Commission to recognize that the introduction of capacity mechanisms – in addition to short term reforms of the market – could be legitimate in certain situations.

> *Some analysts indicate that there is practical evidence that an energy-only market design can realise sufficient investment without the need for mechanisms that make separate capacity revenues available to generators and/or demand response. However, other authors stress that such reforms alone may not completely solve the missing-money problem. Either because market reforms may take time to be fully implemented or because they may be insufficient to fully address the generation adequacy problem generated by the lack of optimal incentives to invest in generation capacity, Member States may want to establish additional measures to address a residual missing money problem and ensure generation adequacy.*[26]

The Commission recognizes the fact that, out of the eleven Member States covered by the sector inquiry, none of them rely on an energy-only market design and that examples of such a design in liberalised markets are rare.

> *However, none of the countries in this inquiry have chosen to rely on an energy-only electricity market, and examples of liberalised 'energy-only' markets outside the enquiry are relatively rare.*[27]

The Commission considers, however, that all these mechanisms, regardless of their design, are state aid measures and this interpretation – while it may be discussed from a legal perspective- seems generally agreed upon.

> *The designs of the mechanisms vary widely, but all have in common the underlying principle of enabling revenues for capacity providers and*

24. Like those established or being established in the United Kingdom, France, Ireland, Italy and Poland
25. Introduced or being introduced into Germany, Sweden, Poland and Belgium in particular.
26. EC. Final Report of the Sector Inquiry on Capacity Mechanisms. 2016, SWD(2016) 385, p47-48
27. EC. Final Report of the Sector Inquiry on Capacity Mechanisms, 2016, SWD(2016) 385, p162

> *thus they may fall within the category of state aid measures. They can therefore be subject to the Union's rules on state aid and their compatibility with these rules may have to be assessed by the Commission.*[27]

Considering capacity mechanisms as State Aids confers on the Commission a predominant role in the design and approval of capacity mechanisms. The analytical framework proposed by the Commission is thus broadly structured around the concepts of competition law. Specifically, the Commission must verify whether the fact of introducing such a mechanism could lead to historical or key players maintaining or strengthening their dominant positions[29].

The publication by the Commission of its proposals for the Energy Package marks an important step in the development of this framework, including the sector inquiry's findings on capacity mechanisms and the addition of specific provisions for capacity mechanisms in the proposal for a regulation on the internal market for electricity. These texts complement the general principles previously outlined in the Guidelines on State aid for environmental protection and energy for 2014-2020[30]. This suggests community regulation will include provisions on capacity mechanisms, which were previously only covered by elements of soft law.

While this framework has not yet been set, with changes still ongoing, we can still retain the classification proposed by the Commission that distinguishes between mechanisms aimed at dealing with transitional issues from those which deal with the more structural issues of adequacy. This approach in terms of objectives allows the Commission to distinguish the good characteristics that the capacity mechanisms implemented must display.

1.2.2.1 Assessment of strategic reserves for the management of temporary risks affecting capacity adequacy

In the case where national public authorities consider that energy market reform will be sufficient to guide investments, but that they will take time before producing all their effects, the commission considers that the risks to security of supply are temporary. These risks are also temporary when there is a need to control the transition from a situation of overcapacity to a situation of capacity adequacy, by controlling the pace and closure of surplus generation installations. To deal with these types of issues, the Commission advocates the use of strategic reserves or targeted capacity auctions.

> *Strategic reserves can be used where there are good reasons that the market does not (yet) deliver appropriate exit signals, to manage market exit of conventional generation in a gradual way and prevent too many closures leading to temporary local or general shortages. In market areas where market reforms are still in the early stages of their implementation and market participants are hesitant to invest on the basis of price signals alone, a strategic reserve can provide an effective transitional measure on the road to market-based new investment inspired by market reforms.*[31]

The main guideline to follow when designing strategic reserves are the following:

- to be temporary, with a clear end date, and to rely on short-term commitments only (for example one year renewable contracts) to limit "incentives to wait" for market participants;
- to be as small as possible and activated as much as possible outside the market[32], that is to say after the closure of the daily, intraday and balancing markets, in order to minimize distortions to the functioning of the market;
- to be open only to the existing capacities, and not to new capacities, to avoid distorting investment incentives.

For the Commission, these temporary mechanisms have the advantage of being easily implemented with potentially low direct costs. They do however present disadvantages identified by the Commission:

28. EC. Final Report of the Sector Inquiry on Capacity Mechanisms, 2016, SWD(2016) 385, p48
29. RTE, a revised capacity mechanism to improve security of supply and maintain electrical competition, 2017, p17-18
30. EC, Communication of the European Commission on Guidelines on State aid for environmental protection and energy 2014-2020, 2014, (2014/C 200/01), p38-40
31. EC. Final Report of the Sector Inquiry on Capacity Mechanisms, 2016, SWD(2016) 385, p146
32. Nevertheless, distortions seem inevitable insofar as the full activation times for power stations do not enable real-time activation.

A strategic reserve affects market structure if it creates incentives for plants to announce closures that would not otherwise have taken place, because the expected profitability for a certain plant is higher within the strategic reserve scheme than outside the scheme. As a result, the strategic reserve can in this case accelerate exit from the market. [...] Moreover, in particular gas-fired power plants [...] risk being drawn into the growing reserve. This can have additional impacts on the competitiveness of the underlying electricity market, where the exit of plants into the reserve risks increasing market power.

Another source of concern arises from the potential ability and incentive of an incumbent with presence in the strategic reserve to withhold capacity in the market to trigger a price increase and the activation of the strategic reserve, provided that its profits from activating the reserve outweigh the cost of withholding capacity. Finally, an additional source of concern can relate to the exercise of market power when the candidates to be integrated into a strategic reserve are very few. In this case, it can be that the tender for the reserve is not sufficiently competitive, which would reduce the ability of a strategic reserve to cost effectively address a transitional generation adequacy problem.[33]

1.2.2.2 Assessment of mechanisms covering the entire capacity for the management of structural risks affecting the capacity adequacy

In its report, the Commission underlines that strategic reserves are not a means to overcome more structural adequacy issues. To address this, the Commission recommends implementing capacity markets covering the entire system, whether centralised or decentralised.

In the first of the four cases, i.e. where a general missing money problem is identified and confirmed by way of an adequacy assessment, the appropriate response consists of a longer term intervention in the market that ensures new investments and maintains existing capacity providers in the market to the extent they are necessary to ensure security of supply.

In contrast, market-wide mechanisms can, if well-designed, create the confidence existing and aspirant market participants need.[34]

These mechanisms must respect the design principles set out by the Commission in its report. These principles relate to eligibility, the terms and conditions for the selection of capacities retained, and obligations imposed on capacity providers.

- As far as possible, mechanisms must be as open to new capacities as to existing ones (market-wide mechanism) and to all generation and demand response technologies (technology neutral mechanism). Such an opening increases competitive pressure, thus reducing the cost of the mechanism for the consumer, while limiting the risks of a slippery slope effect;

- The selection of capacities retained must be done with the help of a market mechanism as this selection method is a better alternative to administrative mechanisms, the latter being "unlikely to reveal the true capacity value and are therefore unlikely to be cost-effective". They may "risk providing too much or too little capacity".

- Obligations imposed on capacity providers must be measurable, limited, and with penalties providing enough incentives to encourage the capacities retained to fulfil their commitments. These penalties should not however be a substitute to energy price signals and distort cross-border energy trade between Member States.

The analytical framework proposed by the Commission presents the advantage of being flexible and adapted to the diversity of existing situations within the different Member States. Moreover, the Commission analyses, on a case by case basis, the utility and good design of the capacity mechanisms by conducting in-depth investigations. Such a systematic approach aims to ensure equity of treatment between the different capacity mechanisms implemented. The French

33. EC. Final Report of the Sector Inquiry on Capacity Mechanisms, 2016, SWD(2016) 385, p148
34. EC. Final Report of the Sector Inquiry on Capacity Mechanisms, 2016, SWD(2016) 385, p163

mechanism was one of the first mechanisms, along with the British mechanism, to be the subject of such an investigation. Similar assessment of other mechanisms have followed[35], and others are in progress or will follow.

The review of the French mechanism has led the French authorities to engage in a constructive dialogue with the Commission. This cooperation has helped maintain the benefits of the French system, as it was designed in 2014, whilst improving on it and making it compatible with the new requirements of the Commission.

> *The French capacity mechanism will be open to all capacity providers, including those located across the border, and allow new players to enter the market. This ensures that the measure is cost-effective and competitive. Today's approval ensures that electricity prices are kept in check for consumers. We have worked constructively with the French authorities to bring the planned French mechanism into line with EU state aid rules.*[36]

1.2.2.3 Elements of the regulatory framework to clarify

Draw the consequences of the distinction between long-term mechanisms and short-term mechanisms

In spite of these recent advances, several topics could still require clarification in the European regulations relating to capacity mechanisms. Firstly, the distinction between long-term mechanisms and transitional mechanisms should be clarified. This relevant distinction translates in effect into different recommendations in terms of design, but it has few consequences on the regulatory durability of the mechanisms.

In addition, the periods for approval of some mechanisms, although qualified as structural by the Commission, are relatively limited in view of the time constants of the sector[37] and are essentially fairly close to those assigned to transitional mechanisms. Similarly, in the draft regulation of the internal market, the Commission proposes an annual review of the need for capacity mechanisms, which is relevant for transitional mechanisms but is unsuited to more elaborate mechanisms undertaken over the long term. Such a provision would in effect imply instability in the regulatory framework which could potentially lessen the benefits associated with this type of mechanism. The examination of the texts by the Parliament and the Council would thus be an opportunity to ensure the future European legislation is consistent with this distinction made by the Commission.

Cross-border participation: an issue of equity and reciprocity

The issue of cross-border participation in capacity mechanisms is another area in which improvements appear possible. The most recent works carried out by TSOs through the Pentalateral Energy Forum (PLEF)[38] have brought to light the fact that cross-border participation in capacity mechanisms is essentially a redistributive issue: regardless of the mechanism considered, a direct participation from cross-border capacities will have no influence on the level of security of supply obtained.

There is therefore no reason to distinguish between mechanisms, those which should be open to this type of participation from those which could be free of such an obligation. It is a question of equity and reciprocity, which cannot be based on technical considerations.

A link with the raising of price caps to be examined and clarified

Finally, the link between capacity mechanisms and the increase in price caps should be the subject of careful examination. The question arises as to whether these two measures constitute competing and incompatible alternatives or if, on the contrary, they are complementary options.

From a theoretical perspective, it is clear that these two measures have a same objective: to ensure security of supply. The coexistence of the two measures does

35. For example, see the following cases in the State aid register held by the European Commission: Interruptibility scheme (SA.43735), German Network Reserve (SA.42955), Greece Transitory electricity flexibility remuneration mechanism (SA.38968)

36. Margrethe VESTAGER, Press conference of the Commissioner for competition on the approval of the French capacity mechanism by the European Commission, 8 November 2016

37. The British and French mechanisms have therefore been authorised for a 10-year period.

38. The Pentalateral Energy Forum is an intergovernmental cooperation board including the ministers for energy, regulators, transmission system operators and market players from Benelux, Germany, France, Austria and Switzerland.

not necessarily mean they are redundant. Under the assumption that the cost of financing is independent of the level of risk borne by the stakeholder, the simplified model of pure and perfect competition predicts, for example, mitigation effects between capacity revenues and energy revenues, ensuring on average identical remuneration for the stakeholders. In practice, however, the impact of the risk on the cost of capital as well as the existence of energy market failures call into question the validity of this result.

Quantitative studies are therefore likely to shed light on the possible interactions between the raising of price caps and the introduction of a capacity mechanism.

This impact assessment- beyond its interest for the French framework – also contributes to the European debate and future choices in terms of regulation, providing insights on issues such as the consequences in terms of security of supply of different market designs and the potential complementarity of these different approaches. It also features insights on the long-term cost for the consumer of these different forms of market organisation.

1.3 Consolidate and supplement the analysis tools related to the investment framework and security of supply

To conduct this impact assessment, an inventory and critical analysis of existing studies was firstly made, considering in particular of the assumptions put forward and the modelling tools used *(Part 2)*. This review of the literature revealed areas of analysis to be further developed and led to a complementary study *(part 3).* Based on these insights, it was eventually possible to identify a base of shared findings in these different studies and to reconcile certain conclusions which could initially appear to be contradictory *(Part 4).*

The approach followed in this analysis is part of a process of consultation and objectivity, insofar as the scope of the studies considered was established in a concerted manner with the stakeholders. It brings together European studies which are (i) public, (ii) incorporating a component of quantitative comparison with an energy-only market design and (iii) covering a wide range of approaches, points of view and types of author (academic, consultants, institutions, etc.). All of these were analysed *via* a common evaluation framework, considering solely their intrinsic technical qualities.

This approach is in line with a logic of transparency, since particular care has been devoted to researching the underlying assumptions of each of the studies analysed and that these assumptions (and in particular those used by RTE) have been clearly highlighted. This desire for transparency is also evident in the conscious choice made to systematically discuss the impact of different assumptions on the results obtained. Such an approach allows each player to draw their own conclusions, depending on the set of assumptions that it seems reasonable to adopt. Indeed, a number of assumptions frequently made in this type of study are subject to debate and could not be completely justified.

Finally, this approach is a prudent one, and aims to set out the findings and the conditions of their validity. Extrapolations outside of these conditions are limited, or at the very least discussed and put into perspective.

2. REVIEW OF EXISTING IMPACT ASSESSMENTS IN THE LITERATURE

With the emergence and implementation of various capacity mechanisms in Europe (e.g.: capacity market in the United Kingdom or strategic reserve in Germany), numerous studies have been published over the past few years analysing their impacts.

All of these studies have revealed heterogeneous findings with respect to the impacts associated with implementing these mechanisms. Some results even appear contradictory across the various studies. It was therefore necessary to go beyond the specific framework in which each of the studies had been conducted and to broadly explore the modelling, the scope and assumptions related to each of them, in order to be able to reconcile each finding with its assumptions and methodology, and thus reach robust overarching conclusions.

This review of the literature also aimed to identify potential gaps in the existing studies and modelling frameworks, in order to propose additional studies to build a consolidated outlook on capacity mechanisms.

The review of the literature, which had already started in 2014 with RTE's publication of its analysis of the report accompanying the European Commission "guidance on public interventions", has since been expanded on to cover a larger number of studies.

Among the existing studies, RTE has therefore identified a number of impact assessments which deals with implementation of capacity mechanisms. The impact assessments that are considered and described below are not a comprehensive list. The review of the literature is focused on the most relevant publications which have been examined in detail. The selection of aforementioned studies hinges on the following criteria:

(i) Studies needed to be public, so that the conclusions of the critical analysis could be shared with all stakeholders;

(ii) They had to include a quantitative segment, and in particular a quantitative analysis of the impacts of a capacity mechanism in comparison with an energy-only market design;

(iii) All of the selected studies cover a wide range of points of view and approaches, while all remaining relevant to the European case. These studies were conducted by various types of stakeholders (academic, consultant firms, businesses, institutions, etc.) and from different countries (France, Germany, United Kingdom).

Lastly, the studies selected by RTE to be included in the review of the literature presented here, and which have been the subject of a detailed critical analysis, are listed below:

- **European Commission,** 2016, Impact assessment accompanying the proposals for the Clean Energy Package based on the research of E3MLab/ICCS, 2017, Modelling study contributing to the Impact Assessment of the European Commission of the Electricity Market Design Initiative.
- **FTI-CL Energy,** 2016, Assessment of the impact of the French capacity mechanism on electricity markets
- **CEEM,** 2016, Ensuring capacity adequacy during energy transition in mature power markets and Effects of risk aversion on investment decisions in electricity generation: What consequences for market design?
- **UFE-BDEW,** 2015, Energy transition and capacity mechanism, A contribution to the European debate with a view to 2030
- **Frontier Economics – Consentec,** 2014, Impact Assessment of Capacity Mechanisms
- **DECC,** 2014, Electricity Market Reform – Capacity Market – Impact assessment
- **Thema Consulting Group,** E3M Lab, COWI, 2013, Capacity Mechanisms in Individual Markets within the IEM.

This scope of study was decided in consultation with the stakeholders of the French electricity market[39].

The remainder of this part is intended to provide an overview of the results of these impact studies, putting the specificities of the various modelling choices into perspective.

2.1 Evaluation framework for assessing capacity mechanisms

In order to contrast and compare the different studies listed above, RTE developed an evaluation framework to analyse all of the studies considered objectively, on the basis of the same criteria.

This evaluation framework is divided into 5 main parts:

1. A "Context" section to specify what were the objectives of each study, in which framework it was carried out and finally who were the parties who ordered/carried out this study;

2. A "Modelling" section, detailing all of the modelling choices made in each of the studies. This modelling analysis section is crucial for the proper understanding and interpretation of the results from each of the studies. It addresses several distinct aspects:
   - The modelling choices in terms of competition, information, and behaviour of the market participants faced with capacity investment decisions;
   - The modelling choices in terms of the effect of revenue risk on the cost of capital and/or on investment decisions;
   - The time horizons and uncertainties modelled: deterministic approach (1 scenario only) *vs* probabilistic approach using Monte Carlo simulation;
   - The modelling choices representing the energy market and short-term market mechanisms;
   - The modelling choices representing the capacity mechanism;
   - The different market designs studied;

3. A "Perimeter, Assumptions and Data" part detailing the choice of geographical scope, time horizon as well as the energy scenario data (evolution of demand, generation, fuel prices, etc.) used;

4. A "Main Results" part to analyse the results obtained from each of the studies;

5. A last "Critical Analysis" part providing an opinion on the interpretation of the results obtained with regard to the choice of modelling made.

This analysis grid was shared with all of the stakeholders in the framework of the "economic studies on the impact of the capacity mechanism" working group, derived from CURTE's Market Access Committee. It was unanimously supported.

A summary is provided on the following page.

This evaluation framework was applied separately to each of the studies identified. Detailed fact sheets describing each study are presented in annex 1. In the rest of this section, a comparative analysis is given in the form of a table to identify commonalities, differences and specificities of the seven modelling approaches considered.

39. GT *Economic studies on the impact of the capacity mechanism* of the electricity transmission network users committee [CURTE] dated May 11, 2016

Figure 8. Overview of the analysis grid of impact assessments of the capacity mechanism

1. Context

2. Modelling

Competition, behaviour and information of players in investment decisions	• Pure competition or exercise of market power? • Perfect or imperfect completion? • Exogenous investment decisions?
Effect of risk	Representation of the effect of risk on the cost of capital and investment decisions?
Horizon and uncertainties modelled	• Static or dynamic context? • Short-term uncertainties (weather variability, availability of sources, etc.)? • Long-term uncertainties (on the evolution of the energy context)?
Representation of the energy market and short-term mechanisms	• Assumption of competition and behaviour of market players? • Modelling of hydraulic power units? • Modelled mechanisms (day-ahead only or intraday and balancing mechanisms included)? • Revenues taken into account (energy market revenues only or reserve and balancing mechanism revenues included)?
Representation of the capacity mechanism	• Market-wide mechanism? Or selective mechanism? • Price-based or volume based capacity mechanism?
Market designs represented	Do the market designs studies include: • Energy-only market? With low or high price cap? • Energy market associated with a capacity mechanism?

3. Scope, assumptions and data

4. Principal results

5. Critical analysis

2.2 Comparative analysis and limitations of existing studies

The impact assessments described above reveal a number of differences in terms of choice and perimeters of modelling. The summary table below presents all of these choices using the characteristics of the evaluation framework applied for the comparative analysis.

The properties of the models implemented are genuinely decisive for the interpretation of the results obtained. It is therefore essential to be able to analyse the various models used and their parameters with precision to determine the validation conditions of the results. Specifically, aspects of the modelling that are critical to analyse the impact of the French capacity mechanism should be distinguished from those which bring added value but appear to be rather secondary to the analysis.

✓ ✗ ✗ ?

Firstly, some modelling elements are essential prerequisites to draw conclusions on the economic interest of a capacity mechanism with the characteristics of the French mechanism ("must have"). These are listed below and are presented in the summary table using green ticks and yellow or red crosses. Studies which do not include a satisfactory representation of these elements (hence represented with a red cross in the summary table) are therefore not suited to assess the impact of the French capacity mechanism.

- A representation of investment, mothball and closure decisions is endogenous and based on the criterion of economic profitability of capacities. In the framework of the liberalized electricity markets, it is indeed the economic profitability criterion that guides players' decisions on whether to keep generation and demand response assets in operation or whether to invest in new assets. In addition, the capacity mechanism has the effect of bringing additional remuneration to the capacities required for security of supply, and therefore to ensure their economic viability and existence in the energy mix (continued operation or new investment), whereas a market design based solely on the energy market is likely to fail to maintain a good level of security of supply. The assumption that investments will remain unchanged regardless of the market design thus disqualifies any impact assessment which deals with the effects of implementing a capacity mechanism;

- A modelling of the capacity mechanism which is compatible with the French mechanism design, i.e. a market mechanism, regulated by quantities (capacity obligation), and to which all capacities can participate (market-wide). If the capacity mechanism considered is very different from the French mechanism, for example regulated by prices and based on selective capacity payments, and therefore providing stakeholders with very disparate economic incentives, the study does not specifically analyse the impacts of the French mechanism;

- Relevant parameters for the capacity mechanism. For this reason in some studies the target volume of capacities is purposefully oversized. In this case, the studies considered do not assess the economic interest of a capacity mechanism per se, but rather assess the loss of value related to the existence of a capacity mechanism which is poorly designed;

- A representation of short-term uncertainties (weather variability and the availability of power generation and demand response sources) and their influence on the cost of capital and investment decisions. As discussed in part 1.1.4, taking this risk into account appears essential, in particular to compare the impacts of a capacity mechanism with those of an energy-only market design.

✓ ✗

Secondly, other modelling elements seem interesting but not necessarily essential ("nice to have") for a fine evaluation of the impact of capacity mechanisms. They are indicated in the table as green ticks or yellow crosses. The fact of not taking these into account is problematic and could potentially lead to bias in the results but does not on its own disqualify a study of the French mechanism:

- Representation of the investment dynamic over a multi-year horizon.
- A representation of the long-term uncertainties on the evolution of the macro-economic and energy contexts (uncertainties in demand trends,

Table 3. Summary of the comparative analysis of existing studies

	(1) CE-E3MLab	(2) FTI-CL	(3) CEEM	(4) UFE-BDEW	(5) DECC	(6) Frontier Economics - Consentec	(7) Thema
Decisions based on a calculation of the asset profitability (for sources not managed by public authorities)	✗ Yes, except for part of the capacities	✓ Yes, except sources resulting from a public choice perspective (RE, nuclear)	✓	✓	✓	✓	✗ No
Type(s) of capacity mechanism modelled	✗ Stylized market-wide capacity mechanism	✓ Market mechanism, based on a capacity obligation (or capacity demand curve), where all capacities can participate (market-wide)	✓	✓	✓	✓ Various mechanisms studied: market-wide, targeted call for proposals, strategic reserve	✗ Selective capacity payment
Parameters of the capacity mechanism	? Margin criterion not stated	✓ LOLE of 3h	✓	✓	✗ LOLE of 3h + margin 3 GW	✗ LOLE of 3h without -contribution of interconnections	✗ Remuneration equal to the missing money of CTs
Representation of the effect of risk on the cost of capital and investment decisions	✗ Exogenous (cost of capital arbitrarily differentiated according to market design)	✓ Yes, endogenous risk aversion (cost of capital dependent on risk on the profitability of investments	✓ Yes, representation in the form of risk aversion, without taking into account the effect of risk on the cost of capital	✓	✗ No, no representation of the effects of risk either on the cost of capital, or on investment decisions	✗	✗
Short-term uncertainties (weather, availability of plants, etc.) and taking into account risk	✗ Short-term uncertainties represented but resulting risk not taken into account	✓ Yes, short-term uncertainties	✓	✓	✗ No, deterministic scenarios	✗	✗
Investment dynamic	✓ Yes, simulation of investments, mothballing and decommissioning over a multi-year horizon	✓	✓	✗ No, photo 2030	✓ Yes, simulation of investments, mothballing and decommissioning over a multi-year horizon	✓	✓
Long-term uncertainties (RE trajectories, demand, energy context, etc.) and taken into account for risk	✗ Long-term uncertainties represented but not taking resulting risk into account	✗ No, no representation of long-term uncertainties	✗	✗	✗	✗	✗
Market power on the capacity market	✗ No, pure competition	✗	✗	✗	✗	✗	✗ Not applicable (no market)
Market power on the energy market	✓ Yes, mark-ups (varying in degree, depending on the presence of a capacity mechanism)	✓ Yes, mark up on the bid price	✗ No, pure competition	✗	✓ Yes, mark up on the bid price	✗ No, pure competition	✗ Various types of competition
Rationality of players	✗ Rationality and perfect information	✗	✓ Rationality and imperfect information	✗ Rationality and perfect information	✗	✗	✗

penetration of renewable energy sources, fuel prices, etc.) and their influence on the decisions of players.

✓ ✗

Lastly, certain modelling features provide additional insight but appear to be of secondary importance, and even likely to complicate the analysis and interpretation of results (marked in grey in the table). In practice, these secondary characteristics correspond to assumptions that deviate from the framework of pure and perfect competition:

- A representation of the strategic behaviour of players in a situation of imperfect competition (use of market power on energy markets and capacity). The modelling of strategic behaviours is a complex task which requires representing both profit optimisation for stakeholders (which in itself can technically be modelled) and the limits imposed by the regulatory framework and the detection capabilities of regulatory authorities[40];
- A representation of the actual decision processes of players facing imperfect information and rationality.

The list of characteristics outlined above, and transcribed in the summary table, is by no means comprehensive to describe the scope of the studies conducted. There are additional aspects of modelling or other parameters which may differentiate the studies (for example, the geographical scope chosen, whether or not issues of European harmonisation or participation of cross-border capacities are represented, whether or not reserve mechanisms and mechanisms for balancing the system are represented, the comparison of economic impacts

Box 3: The difference between marginal costs and prices offered on energy prices and their impacts on the economic profitability of capacities and the need for capacity mechanisms

In the economic literature, a certain number of studies put forward the assumption that capacity operators submit bids on the energy market at prices above their marginal costs, particularly in a situation of tension on the supply-demand balance. This discrepancy is most often referred to as mark-up. This type of bid strategy deviates from what is expected in the framework of pure and perfect competition and depends on the exercising of market power. Indeed, when the equilibrium between supply and demand tightens or in other words when capacity margins are low, all of the capacity operators become essential to the balance and are said to be "pivotal" (in the sense of the pivotal supplier index). They can then increase their bid prices without fear of being driven out by a competitor and thus ensure an increase in their infra-marginal rent. Taking into account and modelling this type of strategic behaviour – in theory prohibited by competition law – leads to an improvement in the economic assessment of generation and demand response capacities, especially when their sole income is derived from the energy market.

In the public debate at European level, some suggest that these mark-ups constitute a legitimate exercise of market power that should be authorised in order to ensure the economic profitability of the required capacity for security of supply. In fact, for this to be the case, the increase in bid prices would need to exactly compensate for the missing money of the capacities required to ensure security of supply. The issue would likely be referred to the regulator who would be responsible for defining the limits between reasonable and legitimate exercise of market power to ensure security of supply and abuse of market power, harmful for the competitive operation of electricity markets. This exercise, which appears very delicate, would involve heavily regulating the energy price setting process on electricity markets.

40. In practice, due to the initial design choices and thanks to the changes introduced further to the in-depth inquiry by the European Commission, the French capacity mechanism currently includes a set of measures to limit the risk of players using market power.

with other energy policy interventions, etc.) and these are described more specifically in the detailed fact sheets given in appendix. However, these elements are less important to assess the relevance of each of the capacity mechanism impact assessments.

As indicated previously, the items indicated with a red cross in the table highlight modelling choices that are incompatible with the analysis of specific impacts of the French capacity mechanism. This is particularly the case for studies in which:

- investment decisions are not always simulated on the profitability criteria of generation and demand response assets (Thema study);
- the impact of risk on the cost of capital is not systematically modelled endogenously to differentiate the market designs (CE-E3MLab, DECC, Frontier Economics, Thema studies);
- the representation of the capacity mechanism in the modelling is different from the choices of market design made for the French mechanism (Thema and to a lesser extent CE-E3MLab studies);
- represents a poorly-designed capacity mechanism in terms of size, thus heading to a situation of overcapacity in terms of the economic optimum (DECC, Frontier Economics, THEMA).

Among the seven studies listed, four of them present models that are too restrictive to draw robust conclusions on the impact of the French capacity mechanism.

- The Thema study accumulates a number of instances of bias in the modelling that prevents drawing conclusions on the impact of the French capacity mechanism: risk aversion and short-term uncertainties are not represented, the capacity mechanism considered is entirely the opposite of the French mechanism design and is moreover poorly sized. Finally, the total volume of capacity investments is determined exogenously and is not supposed to be influenced by market design[41] and associated economic incentives.
- A second set of studies, DECC and Frontier Economics, present fairly close modelling approaches, both allowing a modelling of the capacity mechanism which is representative of the French model. However, they both have a two-fold limitation: on the one hand, they do not represent short-term uncertainties (particularly weather variabilities) and thus the influence of these on financial risk and decisions of players; and on the other hand, the capacity mechanism considered is assumed to be oversized in relation to the reference criterion of security of supply. These studies tend to show that capacity mechanisms that are poorly designed in terms of size (i.e.: aiming for a greater than optimum capacity target) would be less beneficial, or even likely to generate a significant amount of additional costs to the electricity system. They thus serve to reinforce the idea that proper sizing of capacity mechanisms is a key determinant of their effectiveness.
- Finally, the recent impact assessment of the European Commission is rather difficult to classify. Some aspects of the modelling technique reflect a desire to represent the essential characteristics of the functioning of electricity markets, but their representation appears significantly flawed. For example, the effect of risk on investment decisions of market players is mentioned in the qualitative analysis and represented in the model as a differentiated cost of capital, but this cost of capital differentiation is exogenous and fixed independently of the risk identified. The study therefore does not provide an answer to questions regarding the degree of risk perceived by capacity operators in the various market designs. Another example: the capacity mechanism modelled is indeed a market-wide capacity mechanism and based on a demand curve and a criterion of security of supply but (i) the mechanism is simplified and does not actually represent a market in which generation and demand response sources sell at their marginal costs of capacity[42] and (ii) the capacity margin criterion used for sizing the mechanism is not specified. Finally, while decisions on whether or not to maintain capacities in the market are indeed based on a criterion of economic profitability, it is important to note that the analysis assumes the existence, irrespective of the market design considered, of a specific reserve contracted by the TSO to ensure a total volume of capacity per country equal to what is needed to ensure adequate security of supply (i.e.:, the level of capacities

41. Only the allocation of investments between countries or industries is potentially modified based on the remuneration conditions set out by introducing a capacity remuneration mechanism in one or more countries.

42. More specifically, the capacity balance price is determined as being based on the ratio between the supplied capacity and the demanded capacity.

Box 4. Price caps: the only grounds for capacity mechanisms historically represented in the models?

As discussed in Part 1, the real functioning of energy markets can deviate from the theoretical model of the energy-only design, due to certain specific characteristics of the markets and decision-making processes (market failures, behaviour of market players, etc.). One of the well-known and widely documented characteristics is the existence of price caps, which are generally set at levels considered to be lower than the value of loss of load. In the case of an energy-only market, these price caps can therefore lead to generation and demand response capacities being undercompensated in relation to their actual contribution to reducing the number and duration of situations of scarcity, and consequently to underinvestments in relation to the optimal level of capacity.

The impact of these price caps on the energy market can easily be modelled in the investment and dispatch optimization models normally used to assess the evolution of the mix over the long term. The apparent value of lost load simply needs to be modified in these unit commitment models to assess the effects on the profitability of generation and demand response capacities. As a result, the modelling of price caps and their impact on security of supply has been widely analysed in many studies, including those designed to inform the public debate around the potential developments for electricity market design.

However, this is not the only deviation between the theoretical model of the energy-only market and the actual functioning of the market. It would thus seem inappropriate to develop recommendations on the evolution of market design based on findings from studies which deal solely with the effect of price caps. Indeed, while increasing energy market price caps appears to be the perfect solution to resolving investment problems in these studies, this is primarily due to the choice of modelling and to simplifications in the representation of the market. There are in fact a number of reasons to doubt that such raising of price caps could effectively ensure adequate security of supply, particularly as price peaks remain a rare phenomenon and the question of the impact of the amplitude of the peak on the investment decision depends on (i) the ability of players to represent their occurrence (difficult to estimate the probability of a rare phenomenon) and (ii) of risk aversion.

Moreover, once we assume there is a risk aversion of investors and thus an impact of risk on the cost of capital (i.e.: cost of financing projects), a mechanism which can reduce risk (such as a capacity mechanism) adds value even if security of supply remains unchanged. However, the modelling approaches, particularly in the older studies, sometimes omit this aspect of the functioning of electricity markets, even though it appears a determining factor in evaluating the relevance of various market designs, and especially to compare the impacts of a capacity mechanism with an energy-only design.

obtained in the reference scenario EUCO27 of the European Commission). In reality, the design labelled EOM in the study is not an energy-only market since it incorporates a specific reserve mechanism to meet a defined level of security of supply. The study cannot therefore assess the impact of the market design on the respect of a security of supply criterion. On the other hand, it highlights once again the fact that many of the capacities required for the security of supply fail to cover their fixed costs with the revenues of the energy market alone. The authors of the modelling study conducted for the European Commission seem aware of the methodological limitations of the study and the conclusions that can be drawn:

> *"Despite the sophisticated approach of the PRIMES-OM model, we take a clear position that the model is not able to answer the question whether an energy-only market is a better design than a market with a capacity mechanism. The modelling difficulties and the impossibility of verifying the modelling assumptions lead us to this statement."*

Finally, the four studies mentioned above do not allow us to draw conclusions on the impacts of and the value brought by implementing a capacity mechanism in France.

Conversely, the approaches used in the three other studies (FTI-CL, UFE-BDEW, CEEM) are relevant and suited to the impact assessment of the French capacity mechanism. They rely on a representation of the decisions of players based on economic criteria, taking into account uncertainties (or at least some of these) and the effects of risk on the player' decision-making (risk aversion and/or effect on the cost of capital). The specific modelling choices differ between these three studies. The modelling differences relate to (i) representation of the geographical scope (taking into account cross-border capacity contributions to the security of supply vs. the isolated France approach), (ii) the temporal and multi-annual dynamics of decisions for investment in new capacities (dynamic approach vs. representation of an annual cross section) or (iii) the information available to market players and their economic rationale in the decision making. As these studies rely on a common and relevant modelling basis (investment and decommissioning decisions based on a criteria of rationality, effect of risk on the decision/cost of capital), differences in modelling make these studies complementary and thus provide consolidated findings on the impacts on the French capacity mechanism.

They draw the following main conclusions:

- Due to imperfections in the operation of energy markets, an energy-only market design cannot ensure security of supply over the long term, and leads to high loss-of-load expectations (of around 10 hours per year), incompatible with the standard set by the public authorities. In this type of situation, a generation fleet sized on the basis of the public security of supply criterion (loss-of-load expectation of 3 hours/year) cannot be profitable (missing money).
- Introducing a capacity mechanism to remedy the imperfections of energy markets leads to net benefits for social welfare representing several hundred million euros a year. These benefits stem from the reduced volume of unserved energy and the decreased cost of access to capital brought about by the implementation of a more secure investment framework for market players.
- Attempting to correct imperfections of the energy markets by increasing price caps may have undesirable effects. In fact, an energy-only market design in which price caps were raised to the level of the value of lost load would pose substantial risks to the profitability of peak capacities (generation and demand response). These risks affecting the profitability of assets are reflected (i) by a potential underinvestment and non-compliance with the criterion of security of supply[43] and (ii) by additional costs for the players, due to the loss of social welfare. This can be estimated at several hundred million euros per year compared to a market design with a capacity mechanism, in which the risk affecting the profitability of the capacities is greatly reduced.

On the other hand, the summary table presented above reveals modelling aspects which do not feature in any existing study, notably:

- **the modelling of long-term uncertainties on the evolution of the energy context.** In fact, in each of the studies analysed, the long-term evolution of the economic and energy context of reference is assumed to be perfectly known and anticipated by all market players and investors. They therefore do not bear the financial risk resulting from uncertainties in the long-term evolution of energy prices and capacity. The capacity mechanism would therefore appear to be particularly de-risking. One of the objectives of the RTE impact assessment is to exceed this limit. The analysis is outlined in Part 3.
- **the effects of market power (imperfect competition) on the capacity market.** While the issues relating to market competition have already been the subject of analysis in the report accompanying the 2014 rules and while certain behaviours of market players have more recently been studied by RTE in order to shed light on the issues related to the development of the rules proposed to the European Commission by the French authorities, no modelling approach has as yet fully analysed the behaviour of players in terms of exercising market power on the capacity mechanism. Beyond the complexity of conducting

43. More specifically, it would be possible to guarantee security of supply with an energy-only market, but according to the player risk aversion hypothesis, this could require setting the price cap at a level higher than the cost of lost load.

this type of study, representing both the market power and the limits and potential controls from regulatory authorities, the interest, specifically for analysing the French mechanism, is debatable, given all of the transparency measures and binding decisions imposed upon players (notably the compulsory capacity bidding via the organised market for "integrated" operators) which have been introduced, particularly following the in-depth European Commission investigation.

3. AN ADDITIONAL ECONOMIC ANALYSIS CONDUCTED BY RTE ON THE IMPACT OF THE FRENCH CAPACITY MARKET

3.1 Objectives of the study

The aim of the study conducted by RTE is to complement pre-existing public studies with a more accurate representation of markets operation and stakeholders' behaviour. The study attempts to complete the representation of risks having an impact on profitability of investment in generation (and demand response) capacities and the representation of investment decision-making under uncertainty, including with "long-term" uncertainties as regard to the energy context (uncertainties on the growth of demand, the pace of development of renewables, etc.).

Indeed, as detailed above, studies that exist in the literature do not take account of "long-term" risks on investment decisions. The resulting representations of capacity mechanisms lead to the simulation of mechanisms that significantly reduce risks, a great deal more than what is likely to happen. This results in a capacity price with no uncertainty or volatility for investors. For example, the UFE-BDEW study strives to calculate a fleet suited to the market design conditions until 2030, which implies a fixed and guaranteed capacity price for the entire service life of the power plants. The FTI-CL study assumes perfectly accurate predictions of the trajectories of energy prices and long-term capacity in investment decisions. In these conditions, the capacity mechanism is likely to appear particularly risk-reducing, and thus allow the criterion of loss-of-load expectation of 3 hours per year to be met, in all cases. If there are uncertainties on the fluctuation development of supply and demand, and for example if there is an unexpected demand shock, it is possible that the timeframes for building new plants do not allow to build the generation systems needed in time to meet the 3-hour criterion.

In practice, investors wishing to invest in capacity projects must face a number of uncertainties about the development of long-term market conditions (change in demand, change in fossil-fuel prices, energy and capacity prices, possible development of new technologies, etc.) that may affect the profitability of their projects.

The capacity mechanism must guarantee the capacity operators compensation for their contribution to reducing the risk of loss of load (i.e. for their availability at peak), which is independent of weather incidents. Therefore in a market design with a capacity mechanism, annual income for production and demand response systems, and in particular those of peak and hyper-peak capacities are less dependent on the occurrence of cold spells. This helps reduce the financial risk weighing on the revenue of these capacities.

However, in its initial design, the capacity mechanism was not intended to eliminate the risk component corresponding to long-term variables that may affect the economic and energy context. Since the capacity certificates provided by the French mechanism are annual contracts, to date there is no institutionalised framework for capacity operators to sell their certificates at a guaranteed price in the long term[44]. However, the question of long-term risk has become a major issue in discussions between the French authorities and the European Commission, as part of the in-depth investigation of the French capacity mechanism. This issue was resolved by setting up a system for securing capacity revenues of new capacity investors, so as to facilitate their emergence in the French market. This specific mechanism for new capacities will involve a system of Contracts for Difference, which will provide greater visibility for investors on their capacity revenue.

44. This is different to the British capacity mechanism, which enables new capacities to benefit from guaranteed remuneration for a period of up to 15 years.

The purpose of the study presented hereafter in this section is to bridge a gap in existing studies, by providing a more precise representation of the long-term risk in investment decisions. The modelling developed thus helps represent the uncertain nature of the context in which market participants take investment decisions, and notably it takes into account the timeframes that may exist between the decision to invest in a new capacity and the actual arrival of this capacity in the market.

The analysis also led to a more detailed representation of the risk, including a modelling of its impact on investments financing costs (i.e. the average weighted cost of capital), and also a more exhaustive representation of short-term variables that can affect the supply-demand balance and thus capacity revenues (weather, variables on hydraulic stocks and on unscheduled and scheduled outages of generation capacities).

Furthermore, the modelling designed enabled the study of additional questions on the market design, particularly the impact of different combinations in terms of energy and capacity market price caps. For example, the impacts (in particular on the risk perceived by the players) of a market design combining an energy market with high price cap and a capacity mechanism were studied, whereas other studies did not consider such a design.

Lastly, the methodology for simulating long-term investments developed in this impact assessment will establish an analysis framework that can later be used to provide quantification and clarify the upcoming dialogue process on the specific mechanism to support investments in new capacities, which will come into force in 2019 in accordance with the commitments made by the French authorities during the negotiation with the European Commission.

3.2 Methodology, modelling and assumptions

3.2.1 General methodology principles

The methodological approach and the model chosen to carry out this study will meet the above-mentioned goals. They are based on the following guidelines:

- The methodological approach will enable long-term representation (around fifteen years) of the decisions of market participants in terms of investments, maintenance, mothballing or closure of capacities, according to the market design, profitability of all capacities in the energy mix, and price signals from the energy and capacity markets. This means the functioning of the energy market needs to be modelled through which the generation and demand response capacities achieve a large proportion of their revenues and the operation of any capacity mechanism. To facilitate the interpretation of results and take account of existing measures in terms of transparency and strategic behaviour prevention, market power and information asymmetry between players are not represented; the behaviour of market participants is assumed to reflect the assumption of pure and perfect competition.
- The risk on the economic profitability of projects and its influence on the cost of access to capital and on the investment decisions must also be considered. In particular, the various uncertainties that affect the revenues of a capacity through market prices need to be represented; whether these are "short-term" uncertainties (weather variables, availability of the generation facilities, etc.) or "long-term" uncertainties (such as demand trends, development pace of renewable energies); the risk borne by market participants investing in generation (or demand response) capacities leading to higher or lower capital costs.
- The model must include the constraints on the plants in terms of construction timeframes, to reflect the possible change in the macro-economic context between a decision to invest and the commissioning of the capacity in question. Decisions to invest in new plants are generally taken several years before commissioning, based on information at the time of the decision, and plants might not be actually relevant at the time they are commissioned. The timeframes must be differentiated for each technology, particularly between generation capacities and demand response capacities, since the latter are considered quicker to implement.
- The model developed must allow the assessment of a diverse range of market designs, which are differentiated by the possible existence of a capacity mechanism, and according to the level of price caps in the energy and capacity markets. In particular four specific market designs were assessed. Their abbreviated names are given in the table below.

Table 4. Assessed market designs

Energy market \ Capacity mechanism	No capacity mechanism	With capacity mechanism and price cap of €60,000/MWh
Price cap of €3,000/MWh	EOM 3k	EM 3k + CM 60k
High price cap of €20,000/MWh	EOM 20k	EM 20k + CM 60k

- Lastly, the impact assessment conducted involves comparing all costs related to the founctionning of the power system, as well as investment and dispatch decisions, in the different market designs considered. The analysis must underline the effects of the market design on security of supply (loss-of-load expectation), on the evolution of the energy mix or the social welfare.

The following sections present the modelling, solving techniques and all the assumptions made to conduct the impact assessment.

3.2.2 Implementing the modelling approach

The analysis conducted was based on the simulation of market participants' decisions in terms of investments, mothballing, closure and hourly dispatch of generation and demand response means. The decisions concerning the evolution of the fleet are taken in a uncertain future context. The hypothesis was made that (i) participants behave in a manner which reflects pure and perfect competition and that (ii) the cost of financing their investments depends on the related financial risk.

The modelling aims to simulate the optimum decisions of market participants, taken under uncertainty, while taking into account the effect of risk on the cost of access to capital. This is a stochastic optimisation problem which has the specific feature of representing dependency between investment costs and the financial risk of projects (a risk which results among other things from the investment decisions).

Solving this optimisation problem is based on two main modelling components that are used iteratively, to determine market participants decisions taking into account the effect of the risk on cost of capital.

1. A model for optimising investments and dispatch allowing simulation of biennal decisions of market participants in terms of investment, keeping capacities in service (every two years) and dispatch at hourly intervals, for several scenarii and according to the market design (possible existence of a capacity mechanism, level price caps in the energy and capacity markets). In this model, market participants are investing in new generation capacities provided that their expectated revenues covers all of their fixed costs.
2. A retroactive loop which, on the basis of the revenue distribution wich results from a previous calculation carried out with the previously described simulation model, adapts the capital cost assumptions associated with investments in new generation and demand response capacities, as input for the next calculation in the optimisation model described above. The cost of capital corresponding to each possible investment is calculated based on the revenue distribution associated with this investment, and this revenue is itself obtained as an output from the previous calculation carried out using the investment and dispatch optimisation model.

A balance between the simulated investment decisions and the cost of capital assumptions is sought via successive iterations.

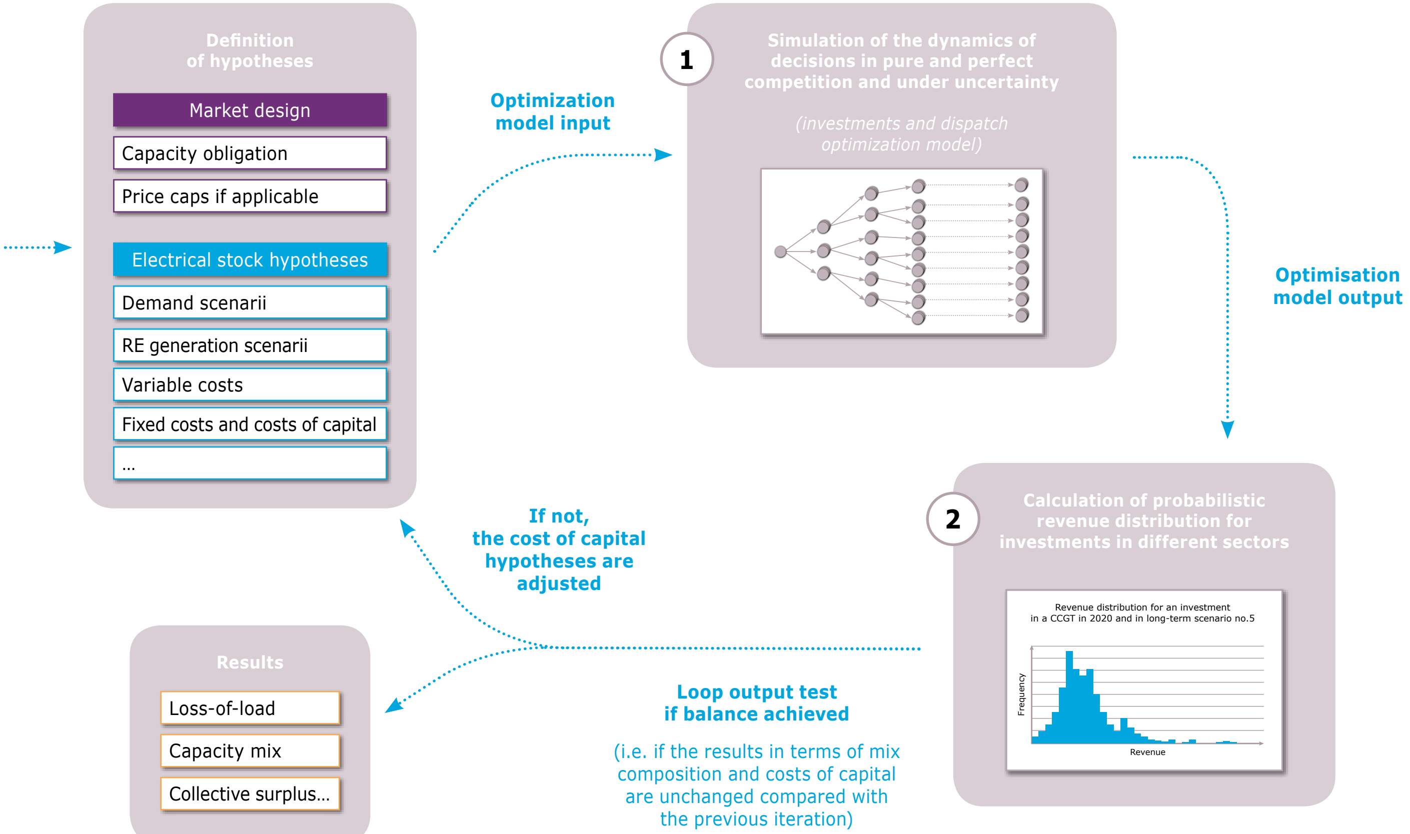
3.2.3 Model for intertemporal optimisation of investments and dispatch

Under the hypothesis that the participants' behaviour reflects the conditions of pure and perfect competition, the decisions (in terms of investment and dispatch) must lead to the minimisation of costs for the community[45]. As a result, these decisions are simulated through an optimization model that aims to minimise the total operating costs of the power system, and whose operation includes the following cost components:

- Fixed costs investment, operation, maintenance and mothballing;
- Costs of capital, dependent on the financial risk involved with investments in new generation and demand response capacities;

45. Strictly speaking, in the presence of risk aversion, the decisions of players aim to maximise the utility of their revenue, which may result in minimising costs, taking account of a cost component associated with the risk.

Figure 9. Methodology deployed to simulate investments and dispatch under uncertainty and with risk-averse players.



- Variable costs: generation and activation of demand response;
- Shadow costs for non-compliance with the supply-demand balance constraint at any time: in the model this fictitious cost is set at the price cap that may exist in the energy market (typically €3,000/MWh assuming a price cap equal to that which exists today on the organized EPEX SPOT market, or €20,000/ MWh in the case where the price cap is increased), in order to reflect the economic incentives of this energy market. These shadow costs are introduced so that the simulated decisions are decisions that would be taken by the market participants, in consideration of the existing incentives. But failure comply with the supply-demand balance constraint results in lost load, which is included in the socio-economic cost of lost load, which is €20,000/MWh for the community. Thus "re-processing" is carried out after the optimization model;
- Cost of failure to respect the capacity obligation constraint (when a capacity mechanism is assumed to exist): as for the energy market, this cost may be set at the level of the price cap that may exist in the capacity market, in order to reflect the maximum compensation that the capacity operators may expect in this market. This cost component is comprised in the model, so that the simulated decisions of the market participants reflect their incentives, but is not included in the social welfare, since the cost of loss-of-load is already included in the value of lost load.

The constraints represented in this optimisation model are supply-demand balance constraints represented in hourly increments, maximum power constraints of generation and demand response units, constraints related to the evolution of the energy mix according to investment, closure and mothballing decisions, constraints of construction timeframes, as well as constraints related to any capacity obligation.

The modelling is thus focused on elements that appear essential for providing clarification on the impact of the French capacity mechanism, namely a representation of the financial risk and of the time dynamics of investment decisions made under uncertainty, marked by short and long-term uncertainties. These modelling choices are made at the expense of very accurate representation for the technical constraints that exist on the generation units. Thus the starting costs, the constraints in terms of ramp, threshold and minimum operation and outage durations of thermal units, as well as stock constraints, are not modelled. However, the placement of hydraulic generation as well as border exchanges (imports/exports of power and their contribution to security of supply) are taken into account but are set exogenously, using the results of simulations carried out as part of the generation adequacy report.

3.2.4 Representation of long-term uncertainties related to variables in the unpredictable development of the economic and energy context

Long-term uncertainties related to development of the economic and energy context are represented using a "hazard tree", an illustration of which is given in Figure 3. Each node of this hazard tree represents a possible future and each branch of the tree is associated with a possibility of change in the energy context between year Y and year Y+2. Moreover, as described in the figure, different scenarii and short-term variables are associated with each node of the hazard tree (in particular weather variables), the definition of which is given in the next section.

This hazard tree enables to simulate decision-making (on investments, mothballing, closure or maintenance in service) under uncertainty.

It would theoretically be possible to represent various long-term scenarii that may differ in terms of demand trends, development of the installed capacity in RE or nuclear power plants, or in terms of fluctuation in fuel and CO2 prices. However in order to control the size of the hazard tree considered, only the uncertainties about demand trends and the pace of RE development (through representation of the demand reduced from renewable generation, refered to as "net demand") were represented within the context of this study. This choice is justified by the fact that these uncertainties particularly affect how thermal power plants are called during peak periods, and thus the capacity volume needed to ensure that the security of supply criterion is met.

The long-term hazard tree includes three branches every two years: one central branch (showing the 2016-2030 trajectory of the "Diversification" scenario of the generation adequacy reports published by RTE in 2014) and upper and lower branches. These three branches are assumed to be equally probable.

The possible trajectories for development of consumption in France in the long term are set to comply with the following principles:

(i) (i) Uncertainty about the development of net consumption in France between year Y and year Y+2 ranges from -12 TWh to +12 TWh around a reference value, in accordance with the uncertainties observed on the net demand forecast for the same year between two generation adequacy reports two years apart;

(ii) The levels of demand obtained by 2030 are compatible with the four long-term scenarii in the 2014 generation adequacy report.

With three branches every two years between 2016 and 2030 representing possible futures, the number of possible trajectories in the long-term hazard tree is 3^7 = 2,187.

These consumption and RE penetration pace trajectories were established based on the generation adequacy report published in 2014, the latest publication of RTE clarifying this timeframe at the time the analysis was conducted.

Figure 10. Description of the "hazard tree"

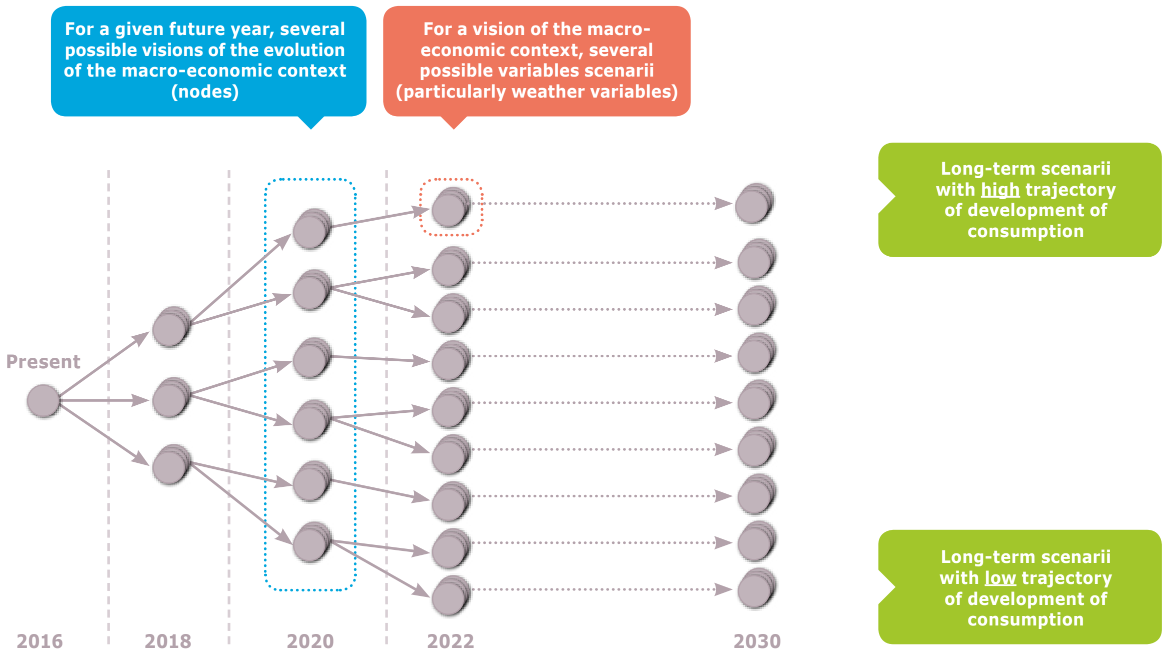
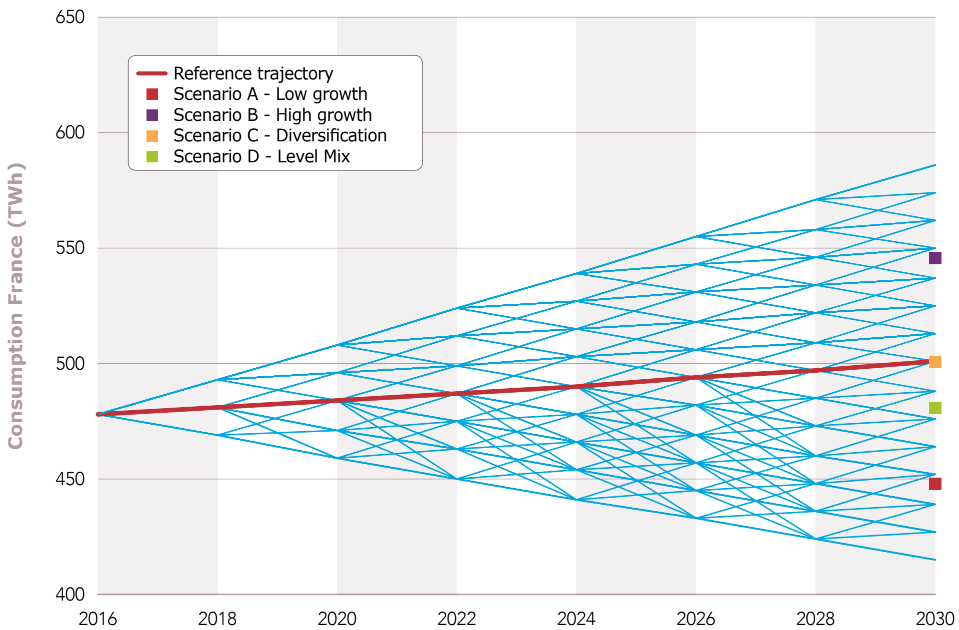


Figure 11. Scenarii regarding long-term consumption trends in France



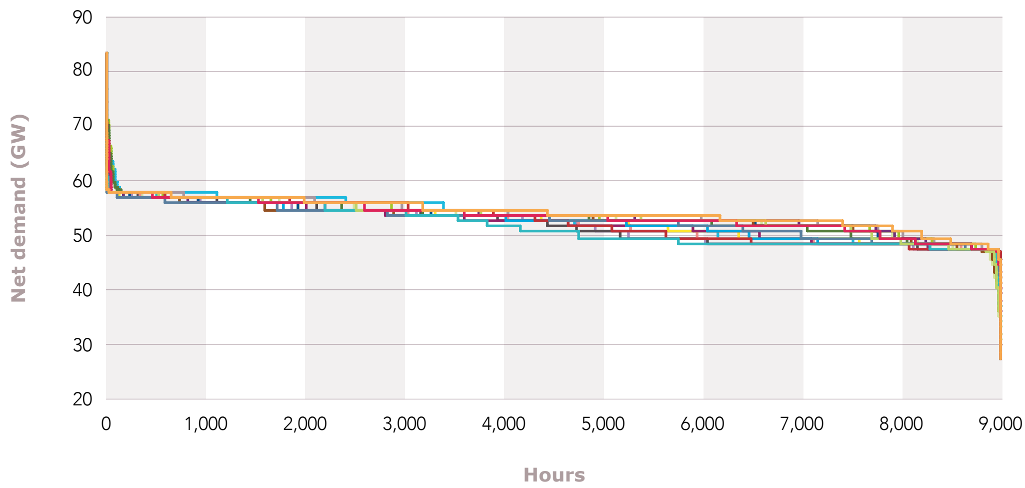
3.2.5 Representation of short-term uncertainties, related to weather features

The short-term uncertainties related to weather features (in particular cold spells), and the availability of generation capacities are represented using 100 short-term variable measurements (i.e. 100 monotone) for each node of the variables tree. These weather variable measurements are from the assumptions of the generation adequacy report published in 2014.

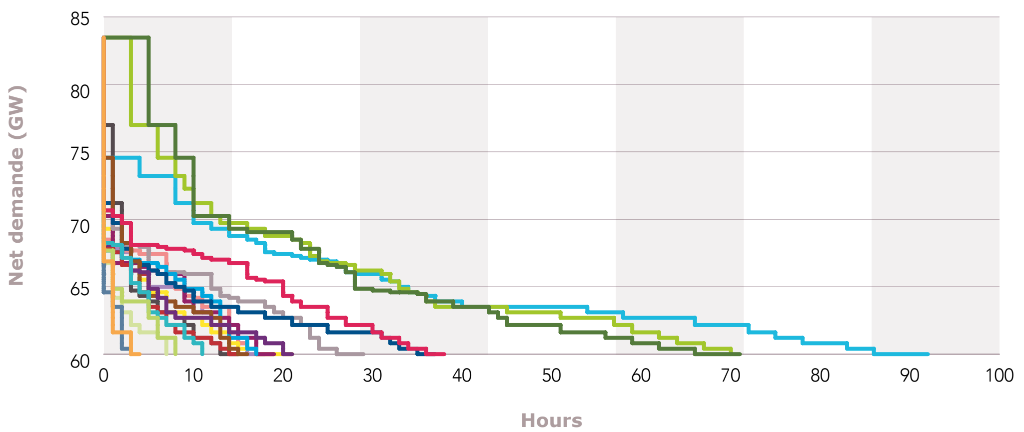
Figure 12 shows an example of net demand monotones (i.e. demand reduced from renewable generation and imports/exports), for different short-term variable measurements associated with one only node in the tree (in this instance the node corresponding to the mean scenario in 2030). To ensure legibility, only 20 measurements (of the 100 used) are shown here on these graphs.

These 100 short-term variable measurements are combined with long-term scenarii on the structural change in demand (2,187 trajectories).

Figure 12. Sample of 20 yearly net demand monotones (i.e. demand minus renewable generation and imports/exports) associated with the different weather variable measurements (out of 100)



Focus on the 100 hours of highest net demand



Box 5. Risk perception by all market participants on the electricity markets (investors, operators, suppliers, consumers) and financial

Capacity operators and investors in new capacities bear a financial risk regarding the economic profitability of their means because, among other things, of the existence of uncertainties on the levels of energy and capacity prices and their fluctuation. This risk results in an increase of the cost of capital for projects.

Other market participants, and in particular electricity consumers and suppliers, may also be affected by risks related to uncertain energy prices. However, the economic challenge associated with the risk borne by these market participants is less significant, since the timescales and the amounts corresponding to coverage of their power purchases are respectively closer together and lower than those associated with developing new capacities. In this modelling approach, the reduction in risk for consumers or suppliers is not expected to generate any profit.

Note that capacity operators and consumers/suppliers[46] bear risks on the variability of energy prices which are symmetrical. This encourages generators and suppliers (or consumers directly) to implement strategies to neutralize their mutual risks.

Opposite risks may be neutralized through exchange of hedging products (forward products, options, etc.). Exchange of forward products is a widespread practice but hedging is generally over relatively short periods of time (often between 1 and 3 years), corresponding to the term of supply contracts (suppliers seek to cover risk related to sourcing of their customer portfolio).

Opposite risks may also be neutralized via vertical integration ("upstream-downstream") of companies through generation and electricity supply activity. The effect of vertical integration will likely be to reduce short-term risks but not long-term ones. This vertical integration is a reality in the French power system although the upstream and downstream portfolios of the main French companies are not in practice fully "balanced".

The finding (i) of the existence of hedging strategies via exchange of forward products between the players and (ii) of the fact that the generators/suppliers are integrated, even partially, is evidence of a challenge for companies in controlling their risk.

The capacity mechanism makes a contribution to reducing risks borne by the players, which produces a benefit for the power system by reducing the costs of financing investments in generation (or demand response) capacities.

In the analysis performed by RTE (as well as in existing studies assessed), this benefit is assessed without considering the effects of risk control strategies such as vertical integration. Their consideration could lead to the modulation of the value provided by a capacity mechanism.

46. The bearer of the risk on price variability depends on the type of supply contract (fixed price, market price indexing, etc.) and the type of risk. The "short-term" volatility of market spot prices is generally, for most consumers, borne by their suppliers (via fixed-price contracts, contracts adjusted based on time of day or seasons or otherwise). Long-term variations, however, are generally borne by the consumers. The supply contracts proposed by suppliers to consumers, generally established for one to two years, reflect market conditions (forward prices) on the date the contract is signed.

3.2.6 Financial risk considerations regarding the cost of capital

Considering the risk impact actually results in adjusting the cost of capital of projects. The higher the risk regarding the project profitability, the higher its financing cost (i.e. weighted average cost of capital).

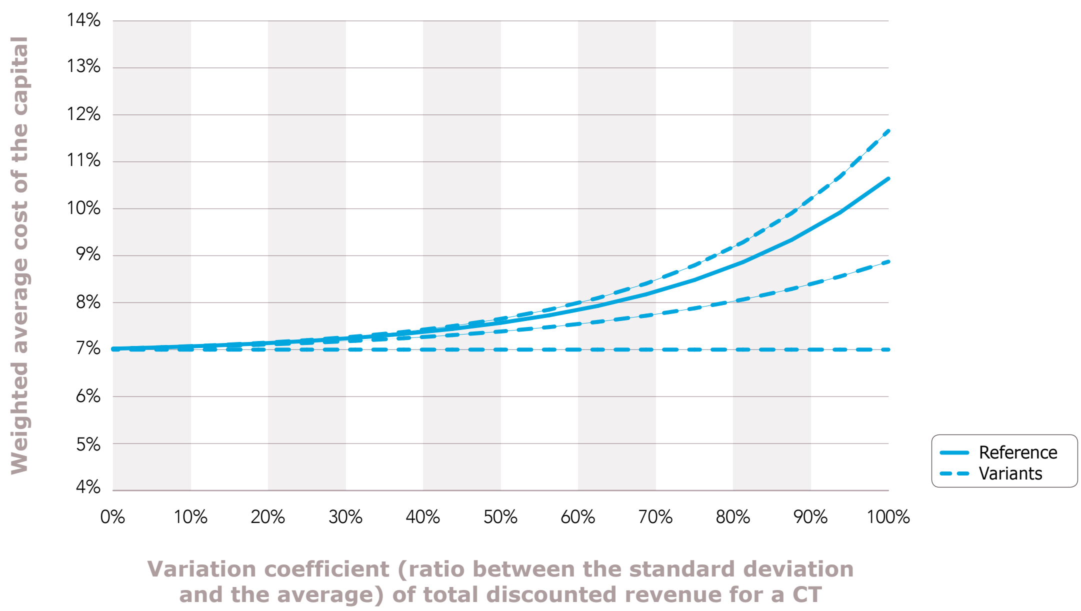
In this modelling approach, the hypothesis on the cost of capital is therefore adapted (via successive iterations) to correspond to the risk profile of each possible investment. This adaptation of the cost of capital is based on the application of a utility function that is concave to the revenue distribution, which is common a technique for many academic structures[47].

The utility function chosen for this study is an exponential concave function whose formula and properties are detailed in the appendix of this report. Applied to revenue distribution, this allows calculation of the risk premiums, or what is equivalent, for the costs of capital differentiated according to the type of capacity investment (i.e. the power source in which the investment is made) and according to the year when the investment was initiated. As an illustration, Figure 13 shows the change in the cost of capital for a CCGT project according to the variation coefficient (ratio between the standard deviation and the expectation) of its revenue distribution.

Moreover, note that the cost of capital here is assumed to directly affect fixed investment costs for projects and thus that these excess financing costs represent a real cost for the community. This finding differs from the assumptions used in other studies, in particular UFE-BDEW and CEEM analyses, in which it is assumed that the excess financing costs associated with the risk only have a de-optimization effect but do not affect the social welfare.

This modelling of risk which affects investment decisions was discussed between RTE and the stakeholders of the French power market in a dedicated working group. RTE is currently working to further develop this modelling and will continue to work with the interested parties to

Figure 13. Illustration of the change in cost of capital according to revenue distribution of a CT



47. AID, R. A review of optimal investment rules in electricity generation. *In Quantitative Energy Finance,* Springer, 2014. p3-40.

Box 6. Is the utility function considered an "optimistic" representation of risk aversion?

Modelling of the risk by the concave utility function described in the appendix represents the effect of projects risk on financing costs. Moreover, it is assumed that the assumptions of perfect rationality and information of parties have been verified.

This results in the fact that the model developed within this study implicitly assumes that the market participants and investors providing funding are able to calculate the profitability of their assets for a large number of distinct scenarii, and thus assess the variability of this profitability to determine the relevant cost of capital.

In practice, the perception of risk by investors and its impact on the actual decisions may diverge from this theoretical model. On the one hand, the market players and investors providing funding are likely to be unable to estimate the capacity revenue for all possible scenarii, or to exclude the least probable extreme scenarii.

A different risk aversion function could therefore realistically be used to represent the fact that investors are likely to not take into account revenues with very low probability of happening, even if they are very lucrative. With this type of representation of how uncertainties affect the decision-making process of market participants, funding of peak capacities, most of the revenue of which is achieved during statistically infrequent cold spells, would be particularly costly in an energy-only market design. With these hypotheses, the gains associated with introducing a capacity mechanism would be higher than those evaluated in the analysis presented here.

improve alignment between the risk modelling in the simulations and the actual decision criteria.

3.2.7 Representating various market designs

Different market designs are assessed, in which there is a capacity mechanism or not, and in which there can be different levels of price caps in the energy and capacity markets. For greater clarity, the names of the simulations corresponding to each of the market designs are abbreviated and indicated in the table below. The analysis focuses on the comparison of four specific market designs combining on the one hand two possibilities of price caps on the energy market, and on the other hand the existence or otherwise of a capacity mechanism ("EOM3k", "EOM 20k", "EM 3k + CM 60k" and "EM 20k + CM 60k" designs). When there is a capacity mechanism, it is assumed to be sized to meet a criterion of loss-of-load expectation of 3 hours per year. It is also assumed that the capacity price cap is set at €60,000/MW; in practice, this price cap is liable to lead to situations in which the 3-hour criterion is occasionally not met (obligated parties prefer to pay the €60,000/MW penalty rather that acquire capacity certificates at higher prices, for example when there is a temporary need for new capacity).

To assess the impact of a capacity mechanism with a price cap set very high, a sensitivity analysis is proposed in section 3.3.5.2.

In terms of modelling, the capacity mechanism is represented in the investment and dispatch optimization model by a capacity obligation constraint concerning the total volume of capacities available at peak demand. In accordance with the design of the French capacity mechanism, this level of capacity obligation is set to meet the security of supply criterion of loss-of-load expectation of 3 hours per year. Furthermore, when it is assumed that there is a price cap on the capacity mechanism, the capacity obligation constraint may be removed at a cost equal to the price cap in question.

This modelling of the capacity mechanism is in line with the basics of the French capacity mechanism design; it is a mechanism based on volumes, with the loss-of-load expectation of 3 hours per year, and in which all technologies can participate to the extent of their contribution to security of supply (i.e. availability at peak demand).

Table 5. Market designs studied and sensitivity analyses

	Reference designs		Designs presented in sensitivity analysis (part 3.3.5.2)
Capacity mechanism / Energy market	No capacity mechanism	With capacity mechanism and price cap at €60,000/MW	With capacity mechanism and infinite penalty system (i.e. without price cap)
Price cap at €3,000/MWh	"EOM 3k"	"EM 3k + CM 60k"	"EM 3k + CM without cap"
High price cap at €20,000/MWh	"EOM 20k"	"EM 20k + CM 60k"	"EM 20k + CM without cap"

Furthermore, note that energy and capacity prices are modelled assuming that parties' behaviour reflects pure and perfect competition. In particular, in the energy market, capacity operators are assumed to offer at their marginal cost, whereas suppliers/consumers cover their consumption at each time period by purchasing energy at any price. In the modelling used, the price is assumed to be at the level of the cap (thus €20,000/MWh in certain market designs studied) when there is a loss-of-load (lack of supply), which ensures a high level of remuneration for capacities available during these price peak periods.

3.2.8 Representation of imports/exports and consideration of the contribution of cross-border capacities to security of supply

Although the simulation of the development of the fleet and its activation (dispatch) are focused on France, imports/exports are taken into account in the analysis. They are considered statically, meaning that they are not assumed to be impacted by development of the fleet. In practice, they come from simulations conducted as part of the generation adequacy report (the 2015 publication for the first five years over the period of the analysis and the 2014 publication for the period to 2030). These import/export logs allow the consideration of the contribution of cross-border capacities to security of supply.

3.2.9 Assumptions on the generation capacity

Installed capacities in RE, hydraulic, nuclear and coal segments are assumed to adhere to public guidelines and their development over time is represented as being exogenous and is not modelled as being governed by a profitability logic. Thus only installed capacities in the CCGT, CT (gas) and demand response segments are assumed to be governed by their economic profitability for the 2016-2030 period.

The trajectories of installed capacities corresponding to the sectors governed exogenously come from data and projections in the generation adequacy reports from 2014 (for the long term) and from 2015 (for the medium term) and are represented on the graph above. These trajectories in this fixed portion of the generating capacity are assumed to be identical for all long-term scenarii, except for RE[48] capacities.

As indicated previously, the long-term scenario used as a reference for this analysis corresponds to the 2030 Diversification scenario in the 2014 generation adequacy report. This is characterized by a slight increase in consumption compared with today (between +0.2% and +0.3% average annual growth rate), a development of renewable generation systems (30 GW wind and 16 GW photovoltaic in 2030) and decommissioning of a significant number of nuclear power units (17 units decommissioned between 2020 and 2030).

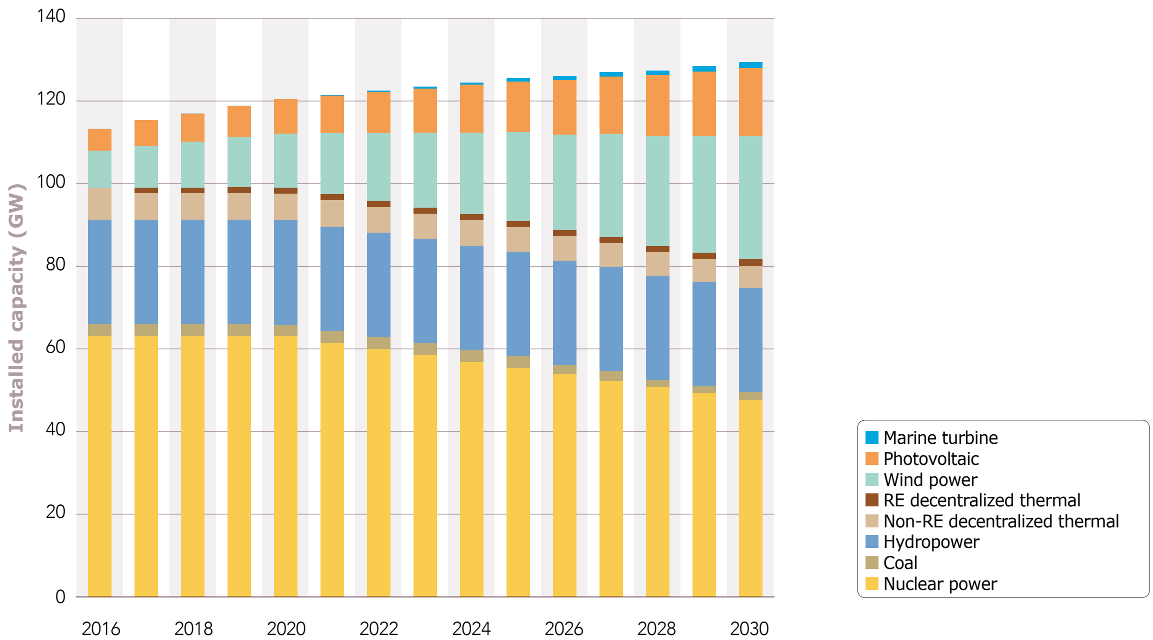
48. Uncertainty on the capacity of renewable energies is represented via the remaining demand in the uncertainties tree.

However, it is important to note that although these hypotheses reveal an increase in the total installed capacity of the sectors mentioned above, the capacity available at national peak demand is on a downward trend. Indeed, although the installed capacity in wind and solar power generation systems is increasing more rapidly than the installed capacity in nuclear units is decreasing, renewable generation systems have an availability rate (or load factor) at winter peak that is much lower than that of nuclear[49] generation systems.

As a result, these change hypotheses outside the mix, associated with an assumption of slight growth at peak demand, reveal a need for investment in new capacity, to ensure that the long-term security of supply criterion is met. More specifically, the analysis of the new capacity volume to cover the capacity obligation reveals two separate periods within the 2016-2030 period:

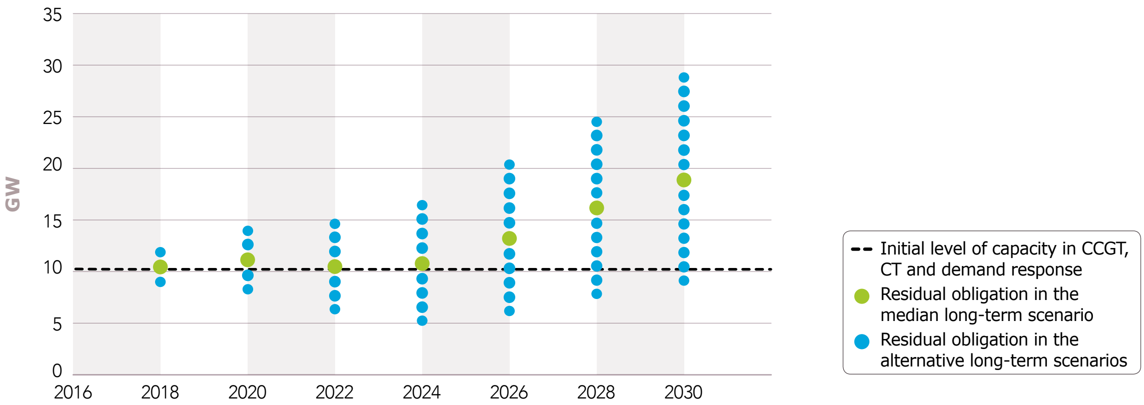
- Between 2016 and the start of the 2020s, power demand is stable in the reference scenario, as is the level of installed capacities in the nuclear sector, whereas installed capacities in renewable generation systems are increasing. There is therefore no need for new capacity to ensure security of supply, aside from the scenarii with a higher consumption growth than expected on average.
- From the point at which nuclear decommissioning is initiated (around 2022 to 2024 in the political scenario in question), there is a need for new capacity, the level of which varies according to the long-term scenarii in the hazard tree, except for the scenarii with the lowest demand.

Figure 14. Trajectories of installed capacities in sectors that are governed exogenously (RE, nuclear, coal)



49. For more details, in particular see the report on the coefficients $C_{industry}$ and C_{AL} for the capacity mechanism, published by RTE in 2016 and available on the customer website.

Figure 15. Residual capacity obligation to be covered by new capacity (excluding RE trajectories regulated by public authority) to ensure that the security of supply criterion is met (expectation of 3 hours per year)



The cost assumptions established, corresponding to sources with optimized capacities, are taken from data of the JRC[50] and AIE[51] reports.

To facilitate interpretation of the results, the fuel and CO_2 costs are assumed to be constant during the period 2016-2030. They correspond to those of the Diversification 2030 scenario in the 2014 generation adequacy report. In particular, the cost of CO_2 is taken as €33/t.

Table 6. Assumptions relative to the costs of the various generation and demand response sectors

	"Exogenous" capacities, where development is controlled by public choices (excluding RE)		"Optimized" capacities development is governed by economic profitability		
	Nuclear power	Coal	CCGT	CT	Demand response
Fixed investment costs (€k/MW)	-	-	850	550	
Fixed operation and maintenance costs (€k/MW/year)	-	-	25	15	
Total fixed annualized costs[52] (k€/MW/year) for a low level of risk	-	-	98	60	From 5 to 40, according to the reserve employed[53]
Variable costs of generation and activation (€/MWh)	10	56	71	110	200
Construction timeframe	-	-	2 years	2 years	Insignificant
Reserve	-	-	-	-	6,000 MW
Initial capacity (2016)	63.1 GW	2.9 GW	5.4 GW	1.5 GW	3.3 GW

50. JRC, *Energy Technology Reference Indicator projections for 2010-2050.* 2014.
51. International Energy Agency & Nuclear Energy Agency, *Projected Costs of generating electricity.* 2015.
52. Annuities given here for information, assuming there is a very long life cycle for the generation units and a discount rate of 8%.
53. To simplify and take account of the shorter investment periods than in the generation industries, the sizing of demand-response capacities is reassessed every two years. The costs of the industry are represented as annualised fixed costs, with no specific distinction between the fixed investment costs (CAPEX) and the fixed operating and maintenance costs (OPEX).

3.3. Results and analysis

3.3.1. Impacts on security of supply

In an energy-only market design with a price cap of €3,000/MWh in the energy market, the loss-of-load expectation is high (~8 h/year) from the first years simulated, as since a certain number of capacities that are not profitable without capacity remuneration (in particular demand response) are decommissioned. The level of security of supply drops even further from 2024 (loss-of-load expectation at 14 h/year in 2030), when nuclear plant decommissioning requires new capacity investments. The economic profitability of new generation sources, especially peak sources, is thus not guaranteed with this kind of market design.

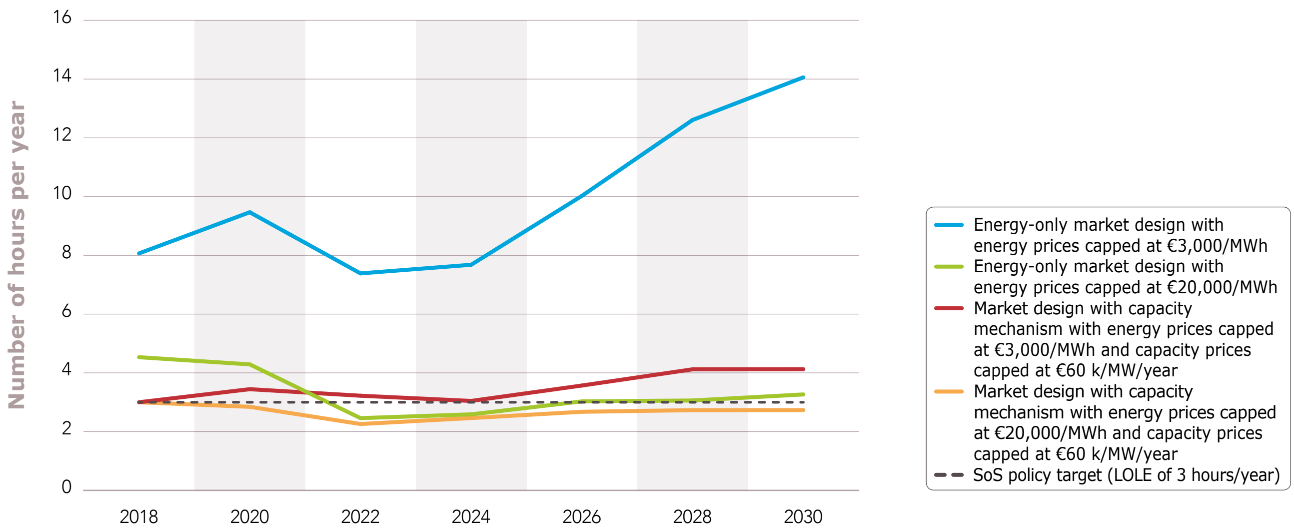
However, if the price cap of the energy market is high at a level consistent with the value of lost load (i.e. €20,000/MWh) and/or a capacity mechanism exists, the loss-of-load expectation remains close to the reference criterion of 3 hours loss-of-load per year.

In particular, besides a potential effect of the price cap on the capacity market, the capacity mechanism provides the means to comply with the 3-hour criterion.

If there is a price cap at €60,000/MWh in the capacity mechanism, the annual loss-of-load expectation could reach a level slightly higher than 3 hours/year given the uncertainties on the evolution of capacity demand. With a price cap, security of supply is no longer achievable at any cost. As an example, for a sustained need new capacities, the annualized fixed costs of a CT for its entire service life (around €60,000/MW under low-risk assumptions) justify compliance with the security of supply criterion (loss-of-load expectation of 3 hours/year). However, when the capacity requirement is temporary and the CT is useful only for a few years, its fixed costs annualized over these few years (and not over the service life) could be much higher than the price cap of the capacity market, and the CT will probably not be built.

The graph below illustrates the level of security of supply achieved in the medium and long term in the different market designs, indicating the loss-of-load expectation achieved on average on all scenarios in the same year. The level of loss-of-load may however vary between the different nodes associated with the same year, in particular according to how strong the growth in demand has been compared with the average trend.

Figure 16. Loss-of-load expectation in each of the market designs studied



3.3.2. Impacts on the installed capacities mix

The results in terms of installed CCGT, CT and demand response sectors, for the four market designs in question, are represented on the graph below. The values displayed correspond to the average installed capacities for each year (average on all scenarios associated with a given year), the installed capacities for each scenario in the same year can in reality vary according to the level of demand.

These results reveal a clear difference between the total volume of installed capacities in the "EOM3k" market design on the one hand, and the other three market designs on the other.

In accordance with the analysis conducted in 3.2.7, for the three market designs guaranteeing long-term security of supply ("EOM20k", "EM3k+CM60k" and "EM20k+CM60k"), the volume of installed capacities in CCGT, CT and demand response goes from 10 GW in 2020 to more than 18 GW by 2030, allowing offset of the decrease in nuclear capacity and ensuring that the criterion of loss-of-load expectation of 3 hours per year is met. The increase of installed capacities affects the CCGT, CT and demand response sectors.

However, the energy-only market design with price cap of €3,000/MWh does not provide incentives for as many investments: the volume of installed capacities in CCGT, CT and demand response does not exceed 13 GW in 2030, or around 5 GW less than in the other market designs. This capacity deficit is due essentially to missing money for capacities during periods of shortages, due to the price cap being set at €3,000/MWh, assumed to be lower than the value of lost

Figure 17. Average trajectories of installed capacities in optimized sectors for the four market designs studied and illustration of the comparisons studied

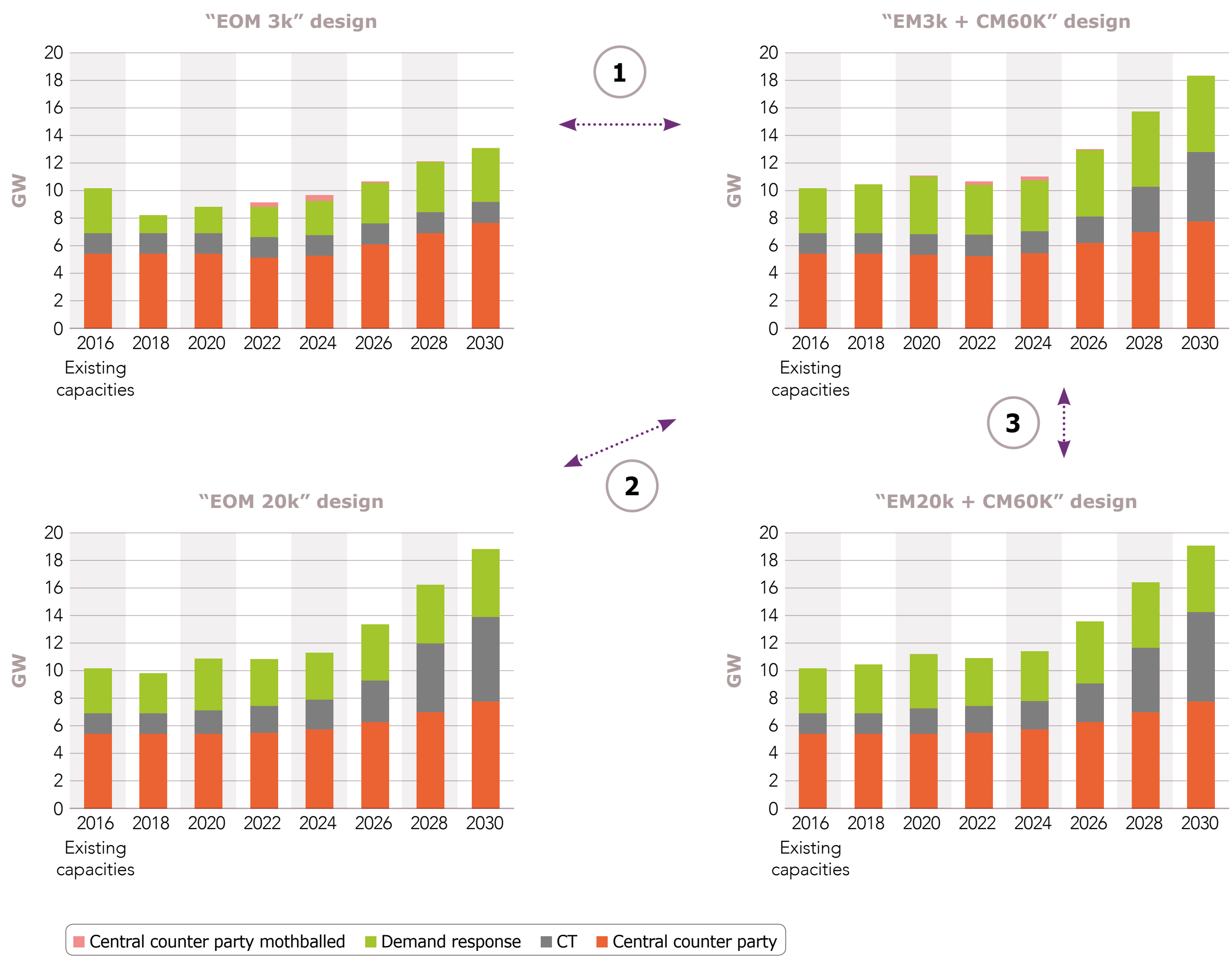
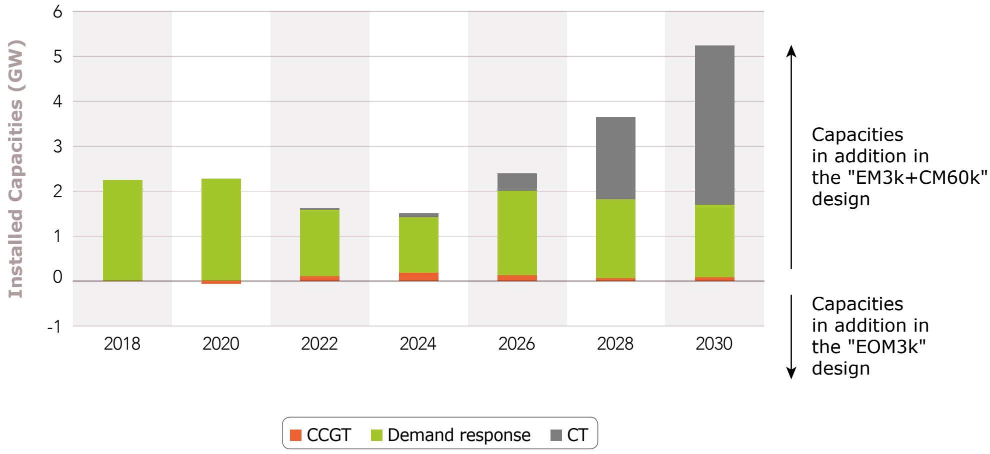


Figure 18. Difference in installed capacities between "EM3k+CM60k" and "EOM 3k" designs



load (here taken as equal to €20,000/MWh). This missing money leads to under-investment in capacity and thus to deterioration in the level of long-term security of supply in this market design, as underlined in section 3.3.1. More specifically, in the medium term (2018-2022), in the absence of a mechanism for remunerating the capacity to produce[54], the demand response capacity implemented each year will decrease to reach between 1.5 and 2 GW on average (compared with around 3 GW currently). In the longer term (2024-2030), the available demand response capacity will increase slightly, and new investments in CCGT may be made.

The differences in terms of change in installed capacities in the other three market designs ("EOM20k", "EM3k+CM60k" and "EM20k+CM60k") are more subtle. To analyse them, the results between two market designs are presented differentially further on in this section. The comparisons made are indicated with arrows on figure 17.

1) Comparison between "EM3k+CM60k" and "EOM 3k" designs:

Figure 18 above represents the differential between the two market designs mentioned. The introduction of a capacity mechanism has an effect on the installed capacities, essentially on the CT and demand response sectors.

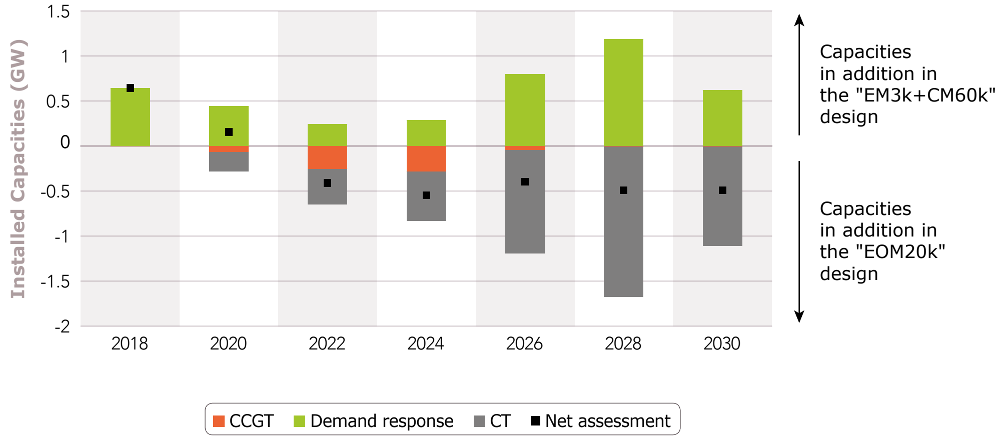
2) Comparison between "EM3k+CM60k" and "EOM20k" designs:

In the medium term (2018-2020) an energy-only market design with a high "EOM20k" price cap will not encourage development of demand response capacities, whose revenue based only on the energy market will be uncertain, since highly dependent on the occurrence of cold spells. In the long term however, the total installed capacities in the three sectors considered will increase. In particular, the development of intermittent renewables is likely to change the electrical loss-of-load landscape and the frequency of price peaks. These high price peak periods will be shorter through 2030 but more frequent (statistically 1 year in 2). As a result, the uncertainty in peak system energy revenue will fall, thus improving the economic outlook for this type of capacity project, even in an energy-only market design.

However, the make-up of new capacity investments between the two market designs "EM3k+CM60k" and "EOM20k" is relatively different. The design with capacity mechanism promotes the development of extreme peak capacities, namely demand response, in relation to the energy-only market design with high price cap. Indeed, in an energy-only market design, demand response systems are the means with the riskiest remuneration (since they depend only on price peaks on the energy market) and risk-averse market

54. In this assessment, we assume that the demand response capacities have no support measure for power that can be mobilised, such as using the demand supply invitation to tender.

Figure 19. Difference in installed capacities between "EM3k+CM60k" and "EOM20k" design



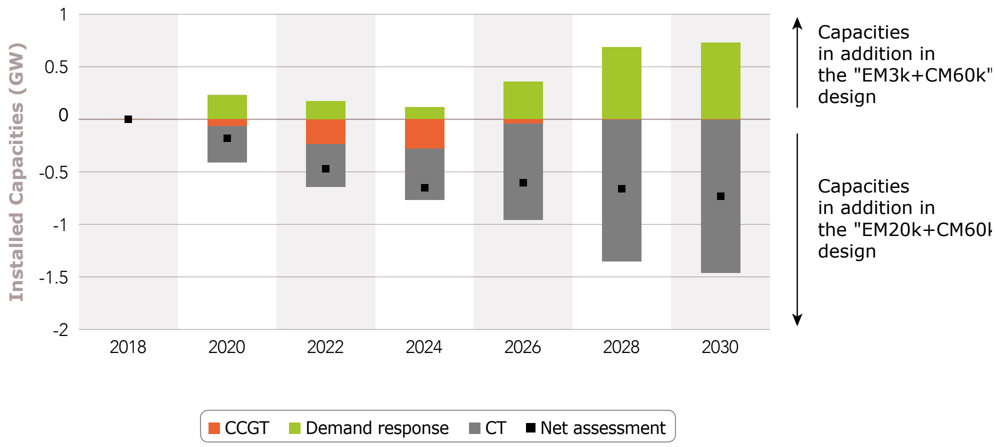
participants will thus prefer development of capacities with lower risk such as CT or CCGT.

Furthermore note that the total level of installed capacities in the energy-only design is around 500 WM higher than that achieved in the capacity mechanism design. This result is due to the fact that the two security of supply goal formulations (on the one hand the security of supply criterion set at a loss-of-load expectation of 3 hours/year and, on the other hand, valuation of the loss-of-load at €20,000/MWh) are not strictly equivalent.

3) Comparison between "EM3k+CM60k" and "CM60k" designs:

A comparison largely similar to the previous one is observed between the two market designs with capacity mechanisms. Indeed, despite the existence of a capacity mechanism, the "EM20k+CM60k" design in which the price cap of the energy market is raised involves greater risk for investors than the "EM3k+CM60k" design. An increase in price caps in the energy market increase the expectation of remuneration in the energy market and thus reduce the market price of the capacity. This leads to transfer the revenue achieved on the capacity market, which is low-risk (revenue defined annually,

Figure 20. Difference in installed capacities between "EM3k+CM60k" and "EOM20k+CM60k" designs



Box 7. Loss-of-load metrics and relevance of the 3-hour criterion

In the majority of quantitative analyses conducted on the effect of long-term capacity mechanisms, the impact in terms of security of supply is valued (when it is quantified) by reducing lost load, assuming that the loss of utility associated with this lost load is accurately known. According to the level of the value of lost load chosen, the security of supply criterion defined in number of hours of loss-of-load (in particular the criterion of expected loss-of-load of 3 hours per year, on which the French capacity mechanism is based), may appear more or less economically relevant.

The precise value allocated to the lost load seems to be somewhat uncertain, as shown by the various figures used in studies in the literature (€15,000/MWh in the UFE-BDEW study, - €20,000/MWh in the CEEM study, €26,000/MWh in the FTI-CL study and £17,000/MWh in the DECC study on the British capacity mechanism). Another approach could have been to consider that the correct value to be considered for lost load is the one that makes this criterion of 3 hours of loss-of-load per year optimal. According to this hypothesis, the consistency between the value of lost load and the sizing of the capacity mechanism would lead to a benefit for social welfare regarding the implementation of the capacity mechanism, which would be higher than that estimated in this study.

Lastly, it seems important to mention here that the economic relevance of the security of supply criterion must be the subject of dedicated studies in the coming years. Public authorities have expressed their desire to study this issue and consider revising the security of electricity supply criterion, as part of the multi-annual energy programme (PPE):

> *"By 2018 conduct an assessment on the cost of loss-of-load and examine the opportunity to revise the level of the loss-of-load criterion, in conjunction with European deliberations on the standardization of national criteria."*

independently of weather variables), to revenue achieved in the energy market, which is higher risk. If there is a capacity mechanism, the increase in energy price caps penalizes the demand response capacities (where revenue on the energy market is particularly uncertain) to the benefit of CT.

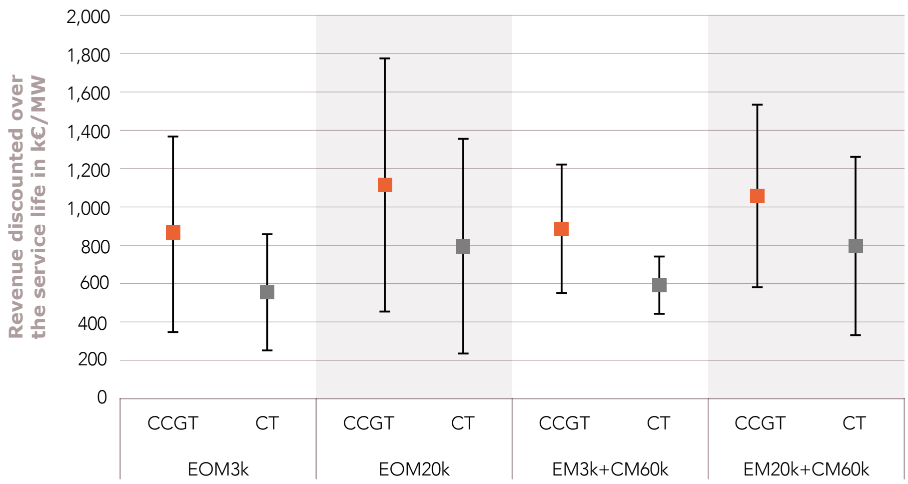
3.3.3. Risk on profitability

Figure 21 hereafter illustrates risk differences on the profitability of generation capacity investments according to the market design, by representing the average and standard deviation of revenue distribution for an investment decision made in 2016.

The market design including a capacity mechanism is the one that gives the lowest uncertainty on revenue in comparison with energy-only market designs, which leads to a risk reduction and thus a reduction in cost of capital for such investments.

It is important to note, however, that the capacity mechanism does not neutralize all risks on the profitability of generation capacities. On the one hand, the revenue of capacities from the energy market remains dependent on the occurrence of price peaks and thus dependent on weather variables and/or variables in terms of capacity availability. In particular these risks appear higher if the price caps in the energy market are set at high levels. On the other hand, the revenue on long-term energy and capacity markets is subject to variability in the development of the economic and energy context. One of the advantages of this study here is that it considers and quantifies this risk. Remuneration of capacities for their contribution to security of supply guarantees an annual basis remuneration that is independent of weather variables.

Figure 21. Average and standard deviations of total revenue updated for generation capacity investments decided in 2016

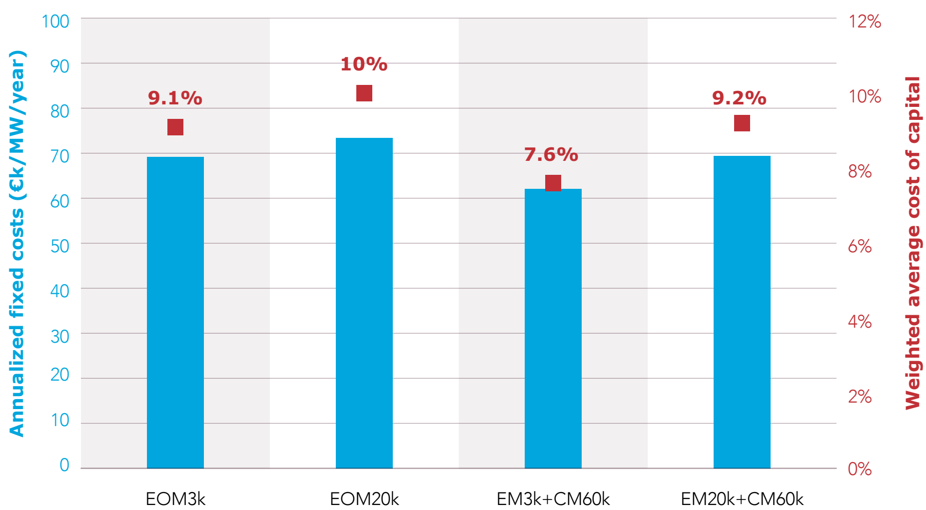


Moreover, the system for securing investments to be introduced in France beginning in 2019 is not taken into account in this analysis, since the precise parameters of this system are not as yet determined.

In the modelling used, the distribution of possible revenue for each of the capacities has a direct impact on the cost of capital of the projects concerned. Figure 22 shows this effect (in the form of an annualized cost) for an investment in a CT at the start of the period considered, for different market designs.

In a symmetrical fashion, the reduction of uncertainties applies also to uncertainties on the final price of power paid by consumers. As detailed in box 5, this risk reduction for consumers is however not highlighted in this analysis (unlike the risk for capacity operators).

Figure 22. Illustration of the simulated cost of capital for an investment in a CT in 2018 and the corresponding annualized fixed costs according to market design



3.3.4. Impacts on social welfare

The various market designs studied are therefore likely to lead to different generation and demand response capacities (total volume of installed capacities and distribution between the different sectors), and to different risk profiles and financing costs for investors in these type of capacities. The various electrical power generation fleets resulting from the market designs studied result in different social welfare levels. As indicated in section 3.2.2, the costs to be considered are of three types: (i) fixed costs (CAPEX and OPEX) of generation and demand response capacities (including financing costs that may be higher or lower depending on the profitability of projects), (ii) variable costs of generating and activating demand response and (iii) loss of load costs.

The results in terms of social welfare are illustrated on the graph below, in the form of gains compared with the energy-only market design with price cap of €3,000/MWh, which is the most costly for social welfare.

Overall, the impact of the market design on variable costs is limited (less than €10 M per year variation).

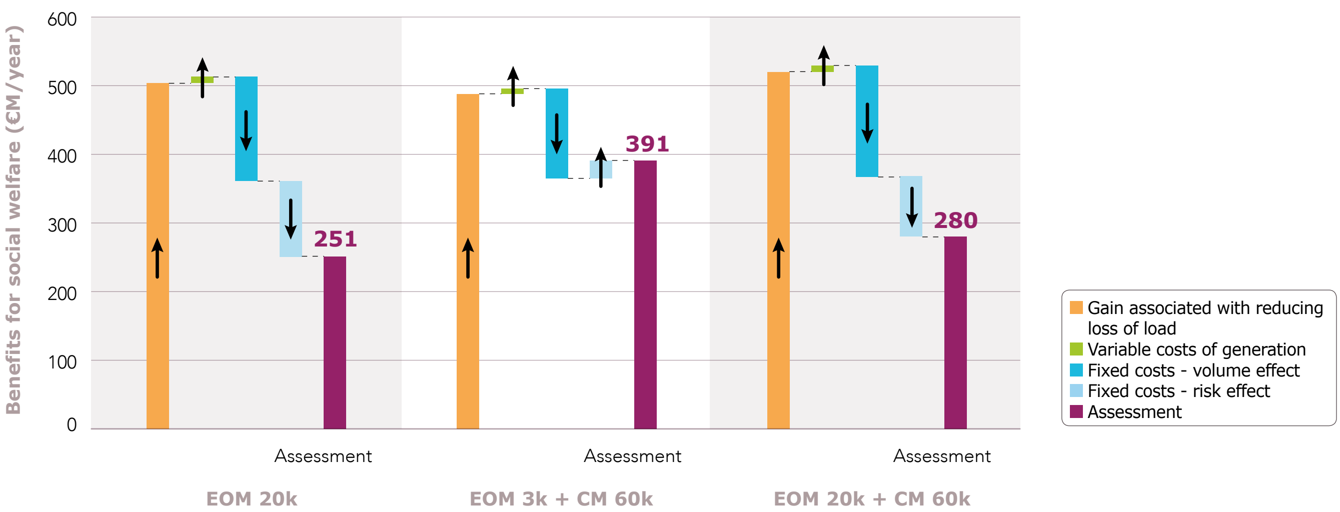
In addition, as detailed in 3.3.1, the "EOM3k" market design is the only one that leads to a very much lowered level of security of supply. All three other designs shown in figure 23 allow considerable reduction of the volume of lost load compared with the "EOM3k" market design, leading to a related gain of around €500 to €520 M per year.

However, this reduction in lost load comes at the expense of additional capacity investments, whose fixed costs may vary widely from one market design to another, due in particular to the existence of financial risks on profitability of generation and demand response assets. Indeed, if the price cap on the energy market is raised to €20,000/MWh ("EOM20k" et "EM20k+CM60k" market designs), the generation and demand response capacities achieve a large proportion of their revenue from extreme events that are very lucrative (i.e. when the energy price rises to €20,000/MWh), but nonetheless very infrequent (with expectation of 2 to 4 hours per year) and very uncertain (occurrence statistically between 1 year in 2 and 1 year in 10). This helps increase the cost of capital of capacity investments.

More specifically, compared with "EOM3k", the additional fixed costs resulting from the different market designs can be broken down as follows:

- In the "EOM20k" market design, additional fixed costs are €250 M/year, including an excess cost of €150 M/year resulting from a "volume" effect (higher installed power) and an excess cost of around €110 M/year resulting from a "risk" effect (i.e. increase in the unit cost of financing investments

Figure 23. Benefits for the social welfare compared with an energy-only market design with price cap of €3,000/MWh



in new generation and demand response capacities related to increase in the financial risk);
- In the "EM20k+CM60k" market design, the additional fixed costs are around €250 M/year, still including an excess cost of around €160 M resulting from the "volume" effect and an excess cost of around €90 M resulting from the "risk" effect;
- In the "EM3k+CM60k" market design, the additional fixed costs are limited to around €110 M/year, an amount broken down into an excess cost of around €140 M resulting from a "volume" effect (higher installed power) and a gain of around €30 M resulting from the "risk" effect. The "EM3k+CM60k" design is thus the only one that allows for a risk reduction compared with the "EOM3k" design.

These observations allow us to draw the following conclusions:
- The "EM3k+CM60k" market design is the most efficient economically and leads to a gain for the social welfare of around €140 M/year compared with EOM20k and a gain of €390 M/year compared with EOM3k.
- In a system with a capacity mechanism, raising price caps of the energy market does not seem to be economically relevant. Indeed, the resulting increased risk for capacity operators leads to extra costs for the community of around €110 M/year.
- Lastly, the capacity mechanism is a no-regret option: its use leads to a gain for the social welfare of €390 M/year if the price cap on the energy market is set at €3,000/MWh, and €30 M/year if the price cap on the energy market is €20,000/MWh.

3.3.5. Sensitivity analysis

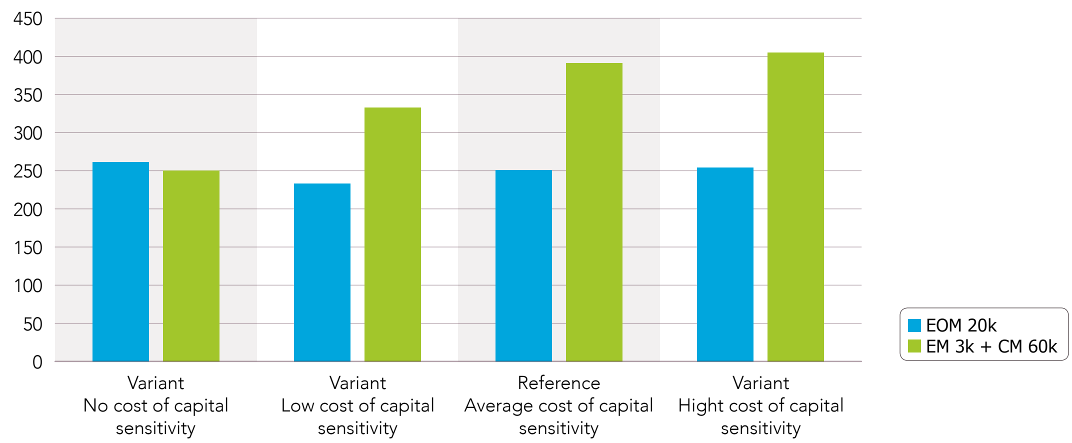
3.3.5.1. Sensitivity to representation of the risk effect on the cost of capital

To check the sensitivity of results to the parameters used for modelling the risk effect on the cost of capital, simulations similar to those described above were carried out for varying levels of dependency of the cost of capital on profitability risks[55], which are represented in figure 13.

The results of this sensitivity study are shown in figure 24.

If the risk effect on the cost of financing is not considered, the gains related to the "EOM20k" and "EM3k+CRM60k" designs are almost equal. Indeed in this case, the two market models are theoretically equivalent in leading to the emergence of an optimum stock which will ensure security of supply.

Figure 24. Sensitivity of benefits for the social welfare provided by a capacity mechanism according to the dependency of the cost of capital on the risk (assessed in relation to an energy-only market design with raised price cap)



55. In practice, these variants on the sensitivity of the cost of capital for the risk correspond to different values from the alpha coefficient present in the utility function *(see appendix 2 for more details)*.

However, when the effect of the risk on the cost of capital is taken into account, the solution with capacity mechanism appears to create greater value than the energy-only market. Whereas the gains with a market design with increased price caps do not exceed €250 M per year compared with an energy-only market design without raised caps - and regardless of the assumption on the effect of the risk on financing costs - the gains associated with a capacity mechanism are €350 M to €400 M per year; the extent of the gains depends on the representation of the risk effect on financing costs.

3.3.5.2. Sensitivity to the level of the price cap in the capacity market

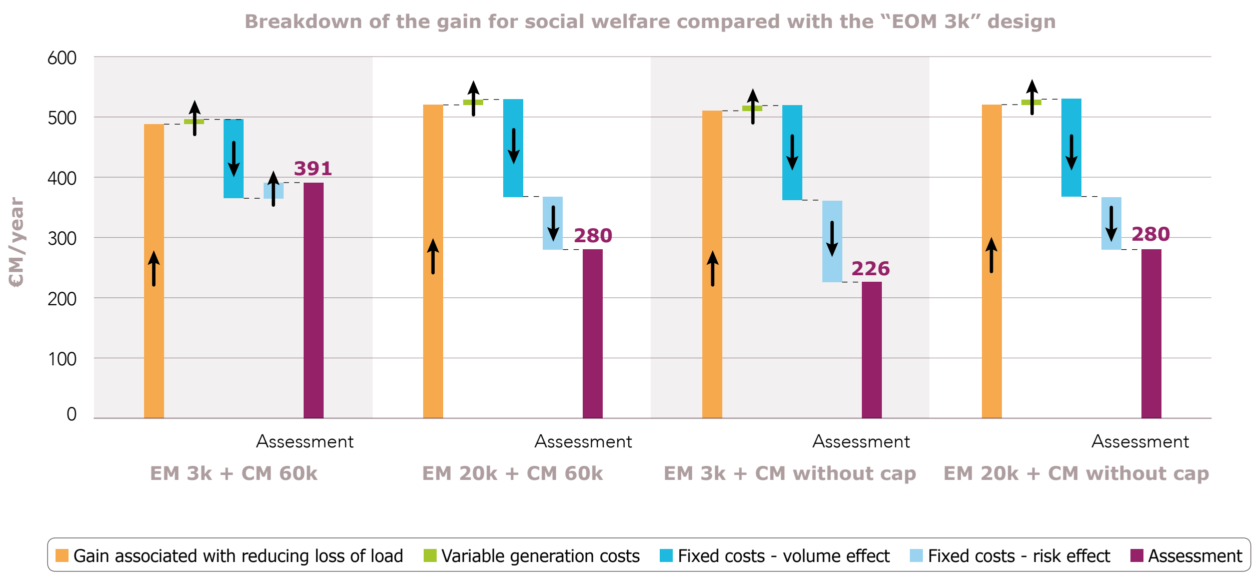
Moreover it is possible to compare the gains for the social welfare obtained by market designs with capacity mechanism, according to the level of the price caps on the energy and capacity markets. In particular, the case of a capacity mechanism with no price caps (in other words a mechanism in which the imbalance price in capacity is infinite) was studied in a sensitivity analysis.

The results, illustrated on the graph below, show that the market design in which the price caps are kept relatively low (i.e. at €3,000/MWh in the energy market and at €60,000/MWh in the capacity market) creates the most value for the social welfare. Although the "EM3k+CM60k" design provides benefits for the social welfare of around €390 M/year compared with the "EOM20k" design, the gain from other designs with capacity mechanism compared with the same reference does not exceed €280 M/year.

This can be explained by the fact that, without a price cap on the capacity market, the capacity prices can be very high in some configurations where there is a need for temporary capacity. It is particularly costly to meet temporary capacity requirements as this would imply the construction of peak generation assets for a need for a period much shorter than the lifecycle of these assets. The capacity price may therefore be at the level of the costs of these peak assets, annualized for the duration of the capacity requirement and not the lifecycle of these assets. A price cap on capacity certificates avoids this type of situation, at the expense of decreased security of supply, which is shown by the analysis to be minimal.

Furthermore, when there are potential high capacity price scenarii, the revenue from generation and demand response capacities is highly dependent on these price peaks, even though they are very uncertain. This increases the risk for investments in new capacities and thus increases their financing costs significantly.

Figure 25. Benefits for the social welfare obtained in different market designs with capacity mechanism compared with an energy-only market design with price cap of €3,000/MWh



This sensitivity analysis shows the economic relevance of having a price cap in the capacity market. This price cap help prevent security of supply from being too costly for consumers in certain temporary transitional situations where strict compliance with the criterion would cause economically unwise decisions to be made (construction of systems which would be used for only a few years).

3.4. Conclusions and limits of the RTE impact analysis

3.4.1 Conclusions on the results obtained

The results of the impact analysis conducted by RTE adds a new contribution to the body of existing studies by providing a representation of long-term uncertainties in the simulation of investment decisions, and thus a more in-depth representation of the impact of the capacity mechanism on the financial risks faced by capacity operators. The results obtained from this analysis support the results already shown in the external environmental impact assessments presented in section 2.

This impact analysis supports the results of previous studies on the level of security of supply achieved with an energy-only market design with a price cap of €3,000/MWh. This level of security of supply would fall rapidly from the medium term, with a loss-of-load expectation of around 10 hours per year or even more. However, all the other market designs studied, namely market designs that include a capacity mechanism, as well as the one based on an energy-only market with high price caps at VoLL, ensure a level of security of supply close to the criterion of loss-of-load expectation of 3 hours per year.

The difference, shown by this study, between an energy-only market design with increased price caps and a market design that includes a capacity mechanism, lies mainly in the level of risk involved in the profitability of generation and demand response capacities and thus in the costs of financing these capacities.

The analysis conducted by RTE attempted to represent the "long-term" uncertainties (concerning trends in demand and penetration of RE) and investment decision-making under this uncertainty, taking into account the effect of uncertainties on the cost to finance new capacities. It is a substantial input compared with all the existing studies, which allows us to realistically quantify the actual risk borne by investors in generation capacity. Indeed, the other studies consider only short-term uncertainties (availability, weather variables affecting demand and generation of RE) and assume that the energy context is entirely deterministic in terms of duration of investments.

Compared with the existing analyses, the study conducted by RTE showed that, even taking into account long-term uncertainties expressed in the evolution of energy prices and long-term capacity (and even without a capacity price securing mechanism), the introduction of a capacity mechanism helps reduce uncertainties on the profitability of capacities, compared with an energy-only market design. This risk reduction helps reduce financing costs (reduction of cost of capital) for generation and demand response capacity projects, which leads in the end to a benefit for the social welfare of several hundred million euros per year.

Lastly, the study shows the benefit of price caps on both the energy and capacity markets.

With a capacity mechanism, keeping the price cap relatively "low" in the energy market prevents a mechanical switch of revenue of the capacity market to "raised" revenue from the energy market, which would generate an additional risk for capacities and higher financing costs.

The price cap of the capacity mechanism serves, in certain configurations where there are temporary capacity needs, to prevent the security of supply criterion from being respected at any cost, and lead to the construction of peak systems that would be needed for a period of time much shorter than their service life.

3.4.2. Extensions

Note that this impact analysis comes with certain limits as mentioned previously, and which could be extended:

- The representation used does not take into account the specific contracts for difference regime for new generation capacities, which will be introduced in 2019. This system will lead to reduction of the financial risk for investments in new capacities to the extent that these investments could benefit from a secure capacity remuneration during the first 7 years of operation. However, the methodological

Table 7. Summary of the comparative analysis of impact studies

	RTE	(1) CE-E3MLab	(2) FTI-CL	(3) CEEM	(4) UFE-BDEW	(5) DECC	(6) Frontier Economics - Consentec	(7) Thema
Decisions based on calculation of profitability of assets (for sectors not controlled by public authority)	✓ Yes, except sources resulting from a public choice perspective (RE, nuclear)	✗ Yes, except for a part of the capacities	✓ Yes, except sources resulting from a public choice perspective (RE, nuclear)	✓	✓	✓	✓	✗ No
Type(s) of capacity mechanism modelled	✓ Regulated demand response mechanisms by volumes and market-wide	✗ Stylized market-wide capacity mechanism	✓ Demand response mechanisms, based on a capacity obligation (or capacity demand curve), where all capacities may participate (market-wide)	✓	✓	✓	✓ Various mechanisms studied: market-wide, targeted call for tender, strategic reserve	✗ Selective capacity payment
Parameters of the capacity mechanism	✓ LOLE at 3h	? Unexplained margin criterion	✓ LOLE at 3h	✓	✓	✗ LOLE at 3h + margin 3 GW	✗ LOLE at 3h without contribution of interconnections	✗ Remuneration equal to missing money of a SCCT
Representation of the risk effect on the cost of capital and the investment decisions	✓ Yes, endogenous risk aversion (cost of capital dependent on risk in terms of profitability of investments)	✗ Exogenous (cost of capital differentiated arbitrarily depending on market design)	✓ Yes, endogenous risk aversion (cost of capital dependent on risk in terms of profitability of investments)	✓ Yes, represented in the form of risk aversion, without taking into account the effect of the risk on the cost of capital	✓	✗ No, deterministic scenarios	✗	✗
Short-term uncertainties (weather, availability of assets, etc.) and taken into account in the risk	✓ Yes, short-term uncertainties	✗ Short-term uncertainties represented but resulting risk not taken into account	✓ Yes, vagaries of the short term	✓	✓	✗ No, deterministic scenarios	✗	✗
Investment dynamics	✓ Yes, simulation of investments, mothballing and decommissioning on a multi-year horizon	✓	✓	✓	✗ No, photo 2030	✓ Yes, simulation of investments, mothballing and decommissioning on a multi-year horizon	✓	✓
Short-term uncertainties (trajectories on RE, demand, the energy context, etc.) and consideration in the risk	✓ Yes, long-term uncertainties represented	✗ Long-term uncertainties represented but the resulting risk not taken into account	✗ No, no representation of long-term uncertainties	✗	✗	✗	✗	✗
Market power on the capacity market	✗ No, pure competition	✗	✗	✗	✗	✗	✗	✗ Not applicable (no market)
Market power on the energy market	✗ No, pure competition	✓ Yes, mark-ups (level according to existence of a capacity mechanism)	✓ Yes, existence of a mark-up on offer prices	✗ No, pure competition	✗	✓ Yes, existence of a mark-up on offer prices	✗ No, pure competition	✗ Various competition regimes
Rationality of players	✗ Rationality and perfect information	✗	✗	✓ Rationality and imperfect information	✗ Rationality and perfect information	✗	✗	✗

framework developed could lend itself to such a mechanism, to the extent that it allows investment decisions subject to long-term uncertainties to be represented. This methodological framework could help define the specific parameters of this system that would be the most economically relevant for the power system.

- The long-term uncertainties represented are assumed to apply only to net demand, whereas in reality there are many other uncertainties that may affect remuneration of capacities in the long term: uncertainties in the price of fuel, in the trajectories of installed capacity of nuclear sectors, coal, etc. The modelling developed may allow these uncertainties to be represented in future studies, but the fact that the problem has multiple dimensions may pose a problem from a calculation standpoint.
- The methodology used falls under the framework of pure and perfect competition, and the analyses performed do not allow the effects of imperfect competition on the capacity market to be represented. This type of analysis would in fact require a very different methodological framework and could complicate the interpretation of results.

4. GENERAL CONCLUSIONS OF THE IMPACT ASSESSMENT OF THE FRENCH CAPACITY MARKET

The studies that seem the most relevant for assessing the long-term economic impacts of the capacity mechanism, in particular compared with an energy-only market design, have helped identify some robust conclusions and figures.

► **The capacity mechanism constitutes a significant improvement in the overall market design:**

- **The capacity mechanism is an economically effective solution in terms of costs for society and in particular costs for the consumer, to guarantee security of supply.** Its introduction by nature leads to compliance with the security of supply target set by public authorities (expectation of 3 hours of loss-of-load per year), whereas an energy-only market with a price cap of €3,000/MWh would lead in the long term to a significant deterioration in security of supply, which would result in an expected loss-of-load of 10 hours per year.

- **The capacity mechanism creates value for the social welfare in the amount of several million euros per year, compared with the capped energy-only market design.** By decreasing the volume of lost load on the one hand and reducing the financial risk on capacity revenue and thus improving financing conditions for investors on the other, the capacity mechanism increases social welfare by several hundreds of millions of euros per year, which essentially benefits the end user.

- **The capacity mechanism is a no-regret option.** Even in a case where price caps on the energy market are raised to €20,000/MWh, the analysis performed by RTE shows that the introduction of a capacity mechanism leads to an estimated gain of around €30 M/year for the social welfare.

Figure 26. Expected loss-of-load duration by 2030 in an energy-only market design with price cap of €3,000/MWh. Comparison between the different studies

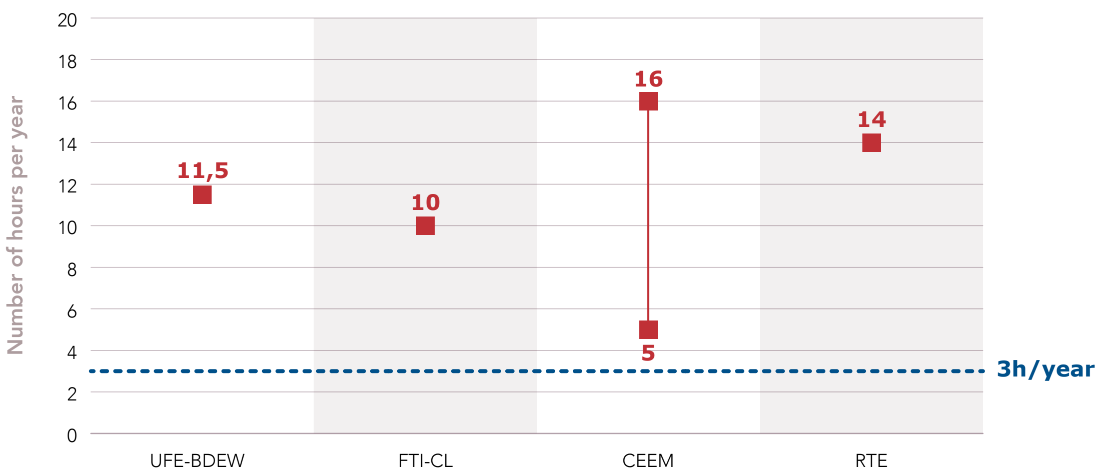
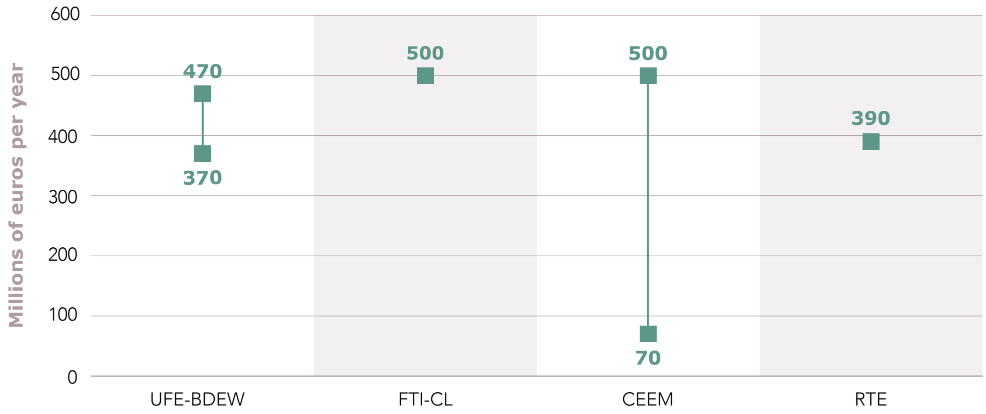
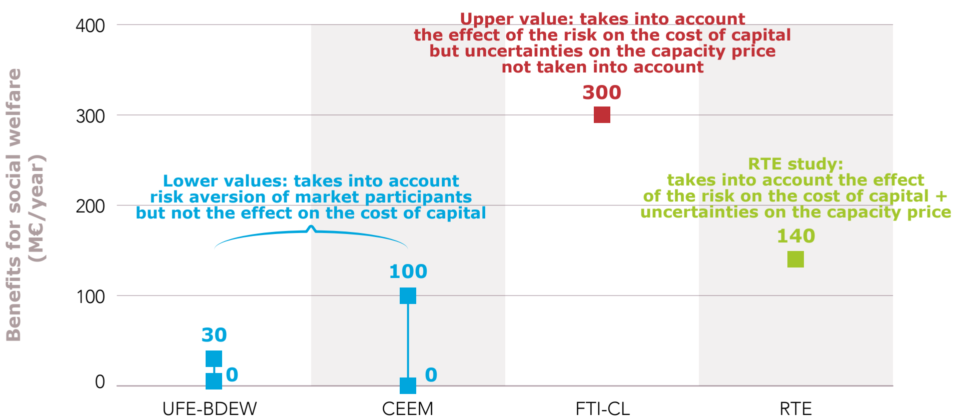


Figure 27. Benefits of a capacity mechanism for the social welfare compared with an energy-only market design with price cap of €3,000/MWh. Comparison between the different studies



► **A theoretical energy-only market design does not seem to be an effective alternative to the capacity mechanism.** Indeed the current energy-only market does not appear able to ensure security of supply and leads to levels of load shedding that are incompatible with public targets. A reform of the energy market focused on raising price caps could improve the level of security of supply, but would not guarantee that the level of security of supply required by public authorities would be met. Indeed, in this type of market design, the market participants would be exposed to a high financial risk (much higher than in a design with a capacity mechanism) since generation and demand response revenues would depend largely on the occurrence of extreme events (typically cold spells). This increase in the risk leads to an increase in the cost of capital of capacity investments and thus costs for the social welfare: compared with the capacity mechanism, this type of design generates an additional cost for the social welfare of several tens or hundreds of millions of euros a year, given the impact of the risk on financing costs.

Figure 28. Benefits of a capacity mechanism for the social welfare in relation to a raise in energy market price caps. Comparison between the different studies



The different results between the UFE-BDEW and CEEM studies on the one hand, and the FTI-CL and RTE studies on the other hand, stem mainly from the fact that in the UFE-BDEW and CEEM studies, the risk of profitability of investments does not impact their financing costs but only the decision (market participants are risk-averse but their financing cost is not impacted by the risk), whereas the FTI-CL and RTE studies take into account the effect of investment profitability risk on their financing cost.

- **The benefits and the effects related to the introduction of the capacity mechanism are not dependent on the hypotheses on the scope of the study and on the static or dynamic representation of investments.** The compared studies use different approaches and hypotheses but all produce similar results in terms of benefits for the social welfare resulting from the introduction of the capacity mechanism.
The impact assesment of the French capacity mechanism demonstrate its economic efficiency, particularly in comparison with other theoretical solutions that involve for example raising price caps on the energy market.

- **When a capacity mechanism exists, increasing price caps on the energy market does not seem to be economically relevant.** Indeed, this raising of price caps leads to an increase in the financial risk on the profitability of generation and demand response capacities, and results in social welfare loss of several tens of millions of euros a year.

APPENDIX 1: DESCRIPTION AND ANALYSIS OF EXISTING IMPACT ASSESSMENTS

Description and analysis of the European Commission's impact assessment on the proposals for the Clean Energy Package (2016)

Context

This impact assessment supports the legislative proposals from the European Commission in the context of the publication of the winter package or Clean Energy Package. The assessment aims to analyse the impact of the various measures with regard to three major issues for electricity markets. One of these issues is entitled *"Problem Area II: Uncertainty about sufficient future generation investments and uncoordinated capacity mechanisms"* and is therefore focused on the ability of the various market designs to guarantee security of supply.

The impact assessment report is available online on the Commission's website:
https://ec.europa.eu/energy/sites/ener/files/documents/mdi_impact_assessment_main_report_for_publication.pdf

This report, however, refers to other publications from which it uses certain results. These other publications therefore need to be analysed to sufficiently understand the economic outputs published in the impact assessment: *Modelling study contributing to the Impact Assessment of the European Commission of the Electricity Market Design Initiative (https://ec.europa.eu/energy/sites/ener/files/documents/ntua_publication_mdi.pdf)* provides specifics on modelling.

Modelling

Competition, players' behaviour and level of information: investment, decommissioning and dispatch decisions from the players are endogenous to the model. In particular, investment and decommissioning decisions are based on a pure and perfect competition hypothesis, where the players are assumed to be rational and omniscient.

Risk aversion: The players' risk aversion is mentioned. However, assumptions in terms of the impact of the risk on the cost of capital (or hurdle rates) are exogenous to the model. More accurately, the cost of capital, for projects on existing capacity retention or investment in new capacities, is assumed to be lower in the presence of a capacity mechanism than for an energy-only market (as revenue is less uncertain here), and even lower where the capacity mechanism enables explicit participation from cross-border capacities (the argument put forward is that competition is supposed to increase and lower the return expectations from investors). However, the exact figures for the cost of capital used in the assessment are not explained.

Time horizon and uncertainties section: in this assessment, the investment decisions are simulated through a dynamic economic and energy model, covering a 30-year period. This makes it possible to take account of the demand growth rate, roll-out of renewable energies, planned power station closures and fluctuation in energy prices and capacity over time. Long-term uncertainties as regards carbon pricing, the price of gas and the roll-out of renewable energies are represented. Short-term uncertainties (demand, availability rate and hydraulic supply) are also represented by various logs but their impact on the project risks is not taken into account.

Representation of the energy market and short-term mechanisms: behaviour of the energy market players is assumed to be different based on whether or not there is a capacity mechanism in the country considered. Thus, in the presence of a capacity mechanism, the behaviour of the energy market players reflects a pure and perfect competition hypothesis (the players are supplying on the market at marginal cost) while, in the absence of a capacity mechanism, they are assumed to apply a mark-up on the price of their supply, depending on the tension in the supply-demand balance, which ultimately helps them to cover their fixed costs.

Representation of the capacity mechanism: the modelled capacity mechanism corresponds to a design where all capacities can participate (market-wide). The most competitive capacities are selected by cross-referencing the capacity supply with a demand curve, made up of a minimum demand volume (requested at a price equal to the price cap) and a maximum demand volume point (for which the requested price would therefore be close to zero). The methodology used to accurately create this curve is not explained (or hardly at all). The few explanations published, however, suggest that the maximum volume point requested corresponds to the peak in demand and that the minimum volume point is constructed based on a margin criteria (reserve margin ratio), which is not explained.

Market designs studied: four main market designs were studied:

(i) "imperfect" energy-only market, notably with a price cap of €3,000/MWh, assumed to reflect the current market measures;

(ii) "improved" energy-only market, notably with a high price cap at VoLL level (in practice, other measures such as the participation of market demand responses or improvement in short-term mechanisms also differentiate the two energy-only market designs mentioned above);

(iii) improved energy market supplemented by a capacity mechanism with implicit consideration of the foreign capacity contribution in four countries (France, Italy, UK and Ireland);

(iv) improved energy market supplemented by a capacity mechanism with explicit participation of foreign capacities in the same four countries.

Scope, hypotheses and data

Geographical scope and time horizon: the energy markets and decisions on investment or retaining existing capacity are simulated at the scale of the 28 European Union Member States for the 2021-2050 period.

Data on demand and generation: context assumptions (demand, fuel prices, installed capacities of renewable industries, etc.) are based on the PRIMES EUCO27 scenario from the European Commission. To represent short-term uncertainties, the PRIMES-IEM model takes 52 demand and generation logs as inputs.

Main results

Within the second case, which deals with security of supply and future investments in generation and demand response capacities, the Commission's impact assessment seems to conclude from quantitative analysis that the improved energy-only market design is the most cost-efficient option for guaranteeing security of supply.

More specifically, with respect to the current situation (energy market with fairly low price caps and the existence of injection priority rules for certain industries), the increase in price caps in the context of an energy-only market with high price caps, associated with setting up a level-playing field between all capacities[1], would enable savings of approximately €5bn/year for the entire European Union[2] (with gains therefore not only being linked to the increase in price caps).

On the other hand, if a capacity mechanism is established in four countries, with implicit consideration of the contribution of foreign capacities (respectively, an explicit participation of foreign capacities), the total annual cost estimation for

1. A level playing field would involve stopping the use of existing rules in terms of injection priority for renewable energies (notably sun, wind and biomass).
2. Supposing that these profits are proportional to the energy consumed in each country, savings for France would be around €830m/year.

the consumer is €4bn higher (respectively, €500m higher) when compared to an energy-only market with high price caps. The analysis also specifies that the distribution of these extra costs is not even over Europe: the four countries that are supposed to introduce a capacity mechanism are deemed to be subject to high extra costs while the other countries benefit from significant cost decreases.

Critical analysis and result validity conditions

The European Commission's impact assessment is used to assess the impact of a number of different measures relative to the energy market design, using different models depending on the issues studied. The assessment is accompanied by various appendices and different publications containing hundreds of pages setting out these different models. Nevertheless, some information and hypotheses are insufficient to obtain a consolidated interpretation of the results.

Certain modelling aspects demonstrate a desire to represent the main operating characteristics of the electricity markets, but their representation appears very debatable and contains little detail. For example, the players' risk aversion is mentioned in the qualitative analysis and represented in the model by a differentiated cost of capital, but this differentiation of costs of capital remains exogenous and therefore fixed in principle. The assessment does not, therefore, address the issue of the level of risk perceived by the capacity operators in the various market designs. Another example: the modelled capacity mechanism design does correspond to a market-wide mechanism based on a demand curve and a security of supply criterion but (i) the mechanism design does not in fact represent a market in which the generation and demand response sources are supplying at their marginal capacity costs[3] and (ii) the margin criterion used to size the mechanism is not specified. Lastly, although decisions on whether or not to retain capacities in the market are based on a financial profitability criterion, it is important to note that the assessment assumes the existence of a specific reserve, regardless of the market design in question, subject to contracts by the transmission system operator to ensure a total volume of capacities per country equal to the volume required to guarantee security of supply (i.e., the capacity level obtained in the Commission's EUCO27 reference scenario). Strictly speaking, even the design labelled EOM in the assessment is not really energy-only as it includes a specific reserve mechanism used to obtain a given security of supply level. The assessment does not, therefore, answer the question about how the various market designs compared can affect compliance with security of supply criteria. However, it once again highlights the fact that many capacities required for security of supply are not able to cover their fixed costs with revenue from the energy-only market. The authors of the assessment conducted for the European Commission also seem to be aware of the methodological limitations of the assessment and the conclusions that may be drawn from it:

> *"Despite the sophisticated approach of the PRIMES-OM model, we take a clear position that the model is not able to answer the question of whether an energy-only market is a better design than a market with a capacity mechanism. The modelling difficulties and the impossibility of verifying the modelling assumptions lead us to this statement."*

Therefore, upon reading this assessment, it is not possible to clearly identify how introducing a capacity mechanism would become an additional cost for the community, compared to an energy-only market design based on price peaks. It is likely that this extra cost is inherent to the hypotheses used, insofar as they seem to assume ineffective sizing for the capacity mechanisms represented.

3. More specifically, the capacity balance price is determined as being based on the ratio between the supplied capacity and the demanded capacity.

Description and analysis of the FTI-CL Energy assessment (2016)

Context

This assessment was conducted by FTI-CL upon a request from RTE. There were two reasons for this:

1) to assess the impacts of the French capacity mechanism (with respect to an energy-only market design capped at €3,000/MWh) for different indicators, notably including security of supply, energy prices and the cost for consumers;

2) to compare these impacts with those of other public interventions in terms of European electricity market regulations (support mechanisms for renewable energies, the moratorium on nuclear power and the strategic reserve in Germany, or even the carbon floor price in the United Kingdom).

The assessment report was published in July 2016 and is available on the FTI-CL Energy website at the following address:
http://www.fticonsulting.com/fti-intelligence/research/eu-power-markets/the-french-capacity-mechanism

Modelling

Competition and behaviour/information on players: Investment, mothballing, decommissioning and dispatch decisions of the players are endogenous to the modelling. In particular, investment, mothballing and decommissioning decisions are based on a pure and perfect competition hypothesis, according to which the players are fully rational and omniscient (however they cannot plan for short-term uncertainties).

Risk aversion: the players' risk aversion is represented via a modification to the cost of capital for the investment projects, based on an estimation of the variability of the revenue. The cost of the risk is assumed to be a real cost for the social welfare[4] (in other words, an increase in the cost of capital results in extra costs in terms of social welfare).

Time horizon and uncertainties: in this assessment, the investment decisions are simulated for a dynamic economic and energy-based context, covering a 25-year period. This makes it possible to take account of the demand growth rate, availability rate, roll-out of renewables, planned power station closures and fluctuation in energy prices and capacity over time. The "short-term" uncertainties (on demand, the availability of means and hydraulic facilities) are modelled. However the "long-term" uncertainties (in the economic and energy-based context5) are not represented.

Representation of the energy market and short-term mechanisms: the energy market is supposed to operate with pure and perfect competition behaviour, except in situations of tension and shortages in the supply-demand balance in which the players are likely to apply a mark-up on the price of their offers. The hydraulic stocks are represented and their use is optimised in the energy market. The operation of short-term mechanisms such as intra-day exchanges, the creation of reserves, the adjustment mechanism and the system services are not modelled. However, any remuneration from these mechanisms is taken into account on a flat-rate basis in investment or decommissioning decisions by the players.

Representation of the capacity mechanism: the modelled capacity mechanism corresponds to (i) a capacity obligation, set to the criteria of 3 hours of loss of load expectation per year (ii) a market mechanism where all capacities can participate.

Assessed market designs: the assessment compares the effects of an energy-only market design (with a price cap at €3,000/MWh in the reference scenario) with the effects of a design including a capacity mechanism in France. A sensitivity analysis also provides elements on the impact of an energy-only market solution with higher price caps. Lastly, other European public policies are assessed, notably the German strategic reserve or the carbon floor price in the United Kingdom.

4. See section 3.2.5.2 for more details.

5. Change in renewable energy or nuclear capacities, trends as regards demand, fuel prices, etc.

Scope, hypotheses and data

Geographical scope and time scale: the electricity markets are simulated on a scale of 15 European countries, whilst investment and decommissioning decisions are simulated only at French level, all of which over the 2017-2040 period.

Data on demand and generation: the representation of adverse weather events is based on a set of 11 annual measurements on uncertainties as regards demand and intermittent energy sources. These are from the "2030 Diversification" scenario of the 2014 forecast plan from RTE, as are the economy and energy-based context forecasts (growth hypotheses for the demand in renewables, planned closures of specific sources, etc.).

Main results

The analysis shows that the French capacity mechanism, compared to the energy-only market with a price cap at €3,000 MWh, (i) Allows in the mid-term the retention of several capacities which are essential for security of supply and (ii) fosters new investments in generation and demand response in the long term. This therefore results in reducing the loss of load expectation to a level compliant with the public security of supply criterion. The capacity mechanism is also used to reduce the financial risk resulting from adverse weather events and their volatility and therefore reduce the cost of capital associated with the generation and demand response sources. Both of these effects finally result in savings for the social welfare of around €500m/year on average for the period considered, of which around €400m/year benefits the consumer.

The results of this assessment also quantify the impact of the mechanism on energy market prices. Although the mechanism has no impact on the supply behaviour of the players and therefore the energy markets, in the long term it leads the mix towards a situation that satisfies the security of supply criterion. The French capacity mechanism therefore tends to lower the occurrence of shortage situations and therefore the occurrence of episodes of peaks in prices in energy markets compared to a design based on an energy-only market capped at €3,000/MWh. This impact on energy market prices remains limited to a reduced number of time intervals and a magnitude lower than that linked to other public policies assessed.

Critical analysis and result validity conditions

This impact assessment therefore provides the basic quantitative items as regards the effects of the capacity mechanism on long-term investment dynamics, taking account of the players' risk aversion by modifying the cost of capital based on the risk faced by these players. The analysis confirms an improvement in security of supply and a reduction in the costs for the community linked to setting up the capacity mechanism in France, compared to an energy-only market design.

However, the lack of representation of long-term uncertainties in changes to the context, demand, use of renewables, etc. does not take account of all uncertainties when simulating investment, mothballing or closure decisions and can therefore make the capacity mechanism appear to be particularly risk reducing.

Description and analysis of the CEEM assessment (2016)

Context

This academic assessment, conducted in the context of a thesis within the CEEM chair and in partnership with RTE, aims to assess the impact of the capacity mechanism on investment dynamics, by simulating decisions made based on the investment decision criteria representing (i) imperfect information for the players and (ii) a simulation of decision-making by a private investor, moving away from the decision-making of an omniscient, fully rational player. Compared to other assessments set out in this document, the analysis therefore sheds light on the effects of the capacity mechanism in a context where the players' behaviour is based on a limited rationality.

This assessment was presented at the 13th international conference of the European Energy Markets (EEM). A description of the methodology used and the results are set out in two articles published in 2016 and available online:

- Petitet, M., Finon, D., Janssen, T., 2016. Ensuring capacity adequacy during energy transition in mature power markets: *A social efficiency comparison of scarcity pricing and capacity mechanism. CEEM Working Paper No. 20* http://www.ceem-dauphine.org/working/en/ENSURING-CAPACITY-ADEQUACY-DURING-ENERGY-TRANSITION-IN-MATURE-POWER-MARKETS-A-Social-Efficiency-Comparison-of-Scarcity-Pricing-a

- Petitet, M., 2016. Effects of risk aversion on investment decisions in electricity generation: *What consequences for market design? 13th International Conference on the European Energy Market (EEM), IEEE.* https://www.researchgate.net/publication/303370642_Effects_of_risk_aversion_on_investment_decisions_in_electricity_generation_What_consequences_for_market_design

Modelling

Competition and behaviour/information on players: the simulated decisions reflect a pure competition behaviour but the players have imperfect information and make decisions moving away from the framework of perfect rationality. Therefore, the modelled investment criteria can result in decisions moving away from economic optimality. This is because the investment decisions are simulated assuming that the players maximise the ratio between their revenue and their investment costs, only assessing the change in their revenue for a time scale limited to 5 years ("short-sighted" hypothesis).

Risk aversion: the players' risk aversion is represented via a utility function, which tends to penalise decisions that result in uncertain revenue. The risk is supposed to modify investment decisions from the players (deoptimisation compared to the case with no risk aversion). Nevertheless, the cost of this risk for capacity operators is not accounted for in the social welfare costs[6] (it is assumed that the cost of the risk is redistributed and represents a gain for other players in the social welfare, notably the finance sector, which has to fund projects that are riskier but also more profitable).

Time horizon and uncertainties: the analysis consists in simulating a series of investment and/or decommissioning decisions over a time horizon of several years, by using a "system dynamics" model. The decisions are simulated year after year, based on partial anticipations on changes to the electricity mix and energy and capacity prices, more specifically for a limited time horizon of 5 years, thereby conveying myopic foresight of the players. Short-term uncertainties (on demand, availability rate and hydraulic supply) are modelled. Long-term uncertainties (on changes to the energy context, notably uncertainties on changes to the renewable energy or nuclear capacities, demand trends, fuel price trends, etc.) are not represented.

6. See section 3.2.5.2 for more details.

Representation of the energy market and short-term mechanisms: the energy market is supposed to operate with pure and perfect competition behaviours. The hydraulic stocks are represented and are triggered in the energy market when the residual consumption is the highest. The short-term mechanisms such as intra-day exchanges, the creation of reserves, the adjustment mechanism and system services are not taken into consideration in the decisions of the players.

Representation of the capacity mechanism: the modelled capacity mechanism corresponds to (i) a capacity obligation, generally set to the criterion of 3 hours of loss of load expectation per year (other restrictive criteria were also tested) and (ii) a market mechanism where all capacities can participate and technological neutrality.

Assessed market designs: the dynamics of the investment decisions are simulated for three different market designs, to compare their impacts: energy-only market with a price cap at €3,000/MWh, energy-only market with price cap at €20,000/MWh and lastly the capacity mechanism associated with an energy market with a price cap at €3,000/MWh.

Scope, hypotheses and data

Geographical scope and time horizon: the energy market and the investment decisions are simulated at French level over the 2015-2035 period. The contribution of interconnections is not modelled.

Data on demand and generation: the representation of adverse weather events is based on a set of 11 annual random sets of demand and intermittent energy sources, based on historical records. For economic and energy forecasts (demand growth rate, roll-out of renewables, planned closure of specific sources, etc.), the choice was made to use illustrative data, not data from the referenced forward-facing scenarios.

Main results

The assessment highlights the energy market's inability to guarantee security of supply in France with a price cap at €3,000/MWh. The introduction of a capacity mechanism guarantees the 3-hour annual loss of load expectation criterion and therefore results in savings for the social welfare of around €70m to €500m (depending on whether the market players are deemed more or less risk averse) mainly corresponding to a reduction in loss of load costs.

The removal of price caps in the energy market can only result in positive effects similar to those of establishing a capacity mechanism under the assumption of there being no risk aversion. When players' risk aversion is taken into account, an increase in price caps – at the level of the value of loss of load considered – results in lower social welfare than that resulting from setting up a capacity mechanism.

Critical analysis and result validity conditions

This assessment therefore sheds more light than the other assessments mentioned in this document, by introducing a model on the limited rationality of the players. The results, similar to those of the two other assessments (profits created by setting up a capacity mechanism linked to the decrease in the volume of lost load and a reduction in the financial risk for generation assets) confirm that the benefit of a capacity mechanism is consistent with the player behaviour modelling assumptions.

Description and analysis of the UFE-BDEW assessment (2015)

Context

This assessment, jointly directed by UFE and BDEW and conducted by Artelys, compares:

1) the impacts associated with a change of market design towards a market with a capacity obligation mechanism, (i) in France only or (ii) in France and Germany at once;

2) the impacts associated with a change towards an energy-only market in which price caps would be raised to a level reflecting the cost of lost load for the whole France/Germany area (in which the power markets are coupled).

However, this assessment specifically addresses the importance of coordinating designs among several interconnected European countries, focusing on the France/Germany area.

The assessment report and its summary were published in September 2015 on the UFE site: *http://ufe-electricite.fr/publications/etudes/article/etude-ufe-bdew-energy-transition*

Modelling

The selected approach consists in modelling the decisions of market participants in terms of generation capacity and demand response investments for two interconnected countries (France and Germany) in distinct market designs.

Competition and players' behaviour and level of information: investment and dispatch decisions by players are endogenous to the model and hinge on pure and perfect competition behaviours, where the market participants are fully rational and omniscient (though unable to plan for short-term uncertainties).

Risk aversion: the players' risk aversion affecting investment decisions is represented through an endogenous calculation of a risk premium to be assigned to investors based on revenue fluctuation. The risk premiums are supposed to affect players' investment decisions (suboptimal fleet compared to the no-risk-aversion framework). Nevertheless, the cost of this risk for capacity operators is not accounted for in the costs of the community[7] (it is assumed that the cost of the risk is redistributed and represents a benefit for other stakeholders, notably the finance sector which finances projects that are riskier but also more profitable).

Time horizon and uncertainties: the approach is based on a "static" vision that does not represent the dynamic evolution of the energy mix and demand, or long-term uncertainties. The short-term uncertainties (on demand, the availability rate and hydraulic supply) are represented.

Representation of the energy market and short-term mechanisms: the energy market (coupled between the two modelled countries) is assumed to operate with pure and perfect competition behaviours. The hydraulic stocks are represented and optimally called on by the energy market. The short-term mechanisms such as intra-day exchanges, the frequency containment reserve, the adjustment mechanism and the automatic frequency restoration reserve are not represented and no remuneration is taken into consideration in the players' decisions.

Representation of the capacity mechanism: the modelled capacity mechanism corresponds to (i) a capacity obligation, set to the criteria of 3 hours of loss of load expectation per year and (ii) a market mechanism where all capacities can participate, without technological discrimination (market-wide).

Market designs studied: the study covers the impact assessment of six possible market designs based both on the perimeter for setting up a capacity mechanism (in France only, or in France and Germany or neither zone for an energy-only market model) and the price cap on the energy market (set at €3,000/MWh or €15,000/MWh, with the latter value corresponding to the assumption on the cost of lost load in this assessment).

7. See section 3.2.5.2 for more details.

Scope, hypotheses and data

Geographical scope and time scale: the electricity markets and the investment/decommissioning decisions are simulated for the France-Germany area (exchanges with neighbouring countries are taken into account exogenously) and in 2030.

Data on demand and generation: the representation of adverse weather events is based on 50 annual random sets of demand and intermittent energy generation, consisent with those of RTE's Diversification scenario from the 2014 generation adequacy report.

Main results

The assessment highlights the current energy market's inability (with a price cap of €3,000/MWh) to guarantee security of supply in France. The introduction of a capacity mechanism in France structurally guarantees compliance with the public security of supply criterion in France and reduces the volume of lost load in Germany. This kind of capacity mechanism, when set up in France only, thus results in a reduction of costs for the social welfare, at a France/Germany level, of around €370m per year, mainly due to the reduction in the costs related to lost load. When the capacity mechanism is introduced both in France and Germany, these benefits increase and amount to €470m per year.

However, the increase of the current price cap on the spot market to a level equivalent to the cost of lost load (i.e. a theoretical energy-only market solution with higher price caps) is not enough to meet the desired level of security of supply, as the annual loss-of-load expectation in France is higher than 3 hours in such a market design. In the energy-only market, revenue from generation and demand response sources is very sensitive to adverse weather events, which introduces a risk as regards the profitability of these assets. Removing the price caps in the energy-only market increases this risk and therefore (i) limits investments in capacities to a sub-optimal level compared to the level set by the public security of supply criterion, and (ii) increases the costs for the community and the consumer in particular (due to the increased risk premium required to fund new investments).

Lastly, this assessment shows that additional benefits for the social welfare could be obtained by coordinating the establishment of capacity mechanisms at European level.

Critical analysis and result validity conditions

This noteworthy methodological approach sheds real light on the effects of the French capacity mechanism on the energy mix and potential benefits for consumers, as it includes a representation of the interactions between several countries and a risk aversion model. Although the approach does not represent the dynamic evolution of the energy mix as it is based on a static vision, it stresses the theoretical balance resulting from the various market designs. The assessment therefore quantifies the impact of the increase in price caps by including their effect on the level of risk.

Description and analysis of the DECC assessment (2014)

Context

This assessment was conducted by the British DECC (Department of Energy and Climate Change) in the context of its consultation on the reform of electricity markets, so as to analyse the economic impact of the implementation of a capacity mechanism in Great Britain.

The latest version of the British capacity mechanism impact assessment (excluding transitory measures) dates back to 2014 and is available online on the website of the *Electricity Market Reform:*

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/354677/CM_-_revised_IA_and_front_page__September_2014__pdf_-_Adobe_Acrobat.pdf

The previous versions of the impact assessment are also accessible on the British ministry's website, on the page dedicated to the electricity market reform.

Modelling

The DECC's impact assessment on multi-annual modelling of investments and the dispatch of power generation sources was conducted using a dedicated optimisation tool called the *Dynamic Dispatch Model* (DDM).

Competition and market participants' behaviour and level of information: investment decisions are endogenous to the model and reflect pure and perfect competition behaviours, where the players are fully rational and omniscient (though unable to plan for short-term uncertainties).

Risk aversion: risk aversion of the market participants is not represented.

Time horizon and uncertainties: investment decisions are simulated through a dynamic economic and energy model, covering a period of around twenty years. This makes it possible to take account of the pace of growth of demand, evolution in the roll-out of renewable energy sources, planned power station closures and fluctuation in energy and capacity prices over time. Short-term uncertainties (demand, availability rate and hydraulic supply) and long-term uncertainties (changes in the financial and energy context) are not represented here.

Representation of the energy market and short-term mechanisms: the energy market is supposed to operate with pure and perfect competition behaviours, except in situations of tension and shortages in the supply/demand balance, during which the players are likely to introduce mark-ups on their pricing. The hydraulic stocks are represented and optimally called on in the energy market. The operation of short-term mechanisms such as intra-day exchanges, the creation of reserves, short-term adjustment and system services are not modelled.

Representation of the capacity mechanism: the modelled capacity mechanism corresponds to (i) a capacity obligation and (ii) a market mechanism where all capacities can participate, without technological discrimination (market-wide). The capacity obligation level is based on the level of capacities required to meet the 3-hour loss of load expectation criterion, and the safety margin of 3 GW is added, so as to limit the risk of reaching a sub-capacity situation.

Assessed market designs: the assessment compares the effects of an energy-only market design (with a price cap at £6,000/MWh in this reference scenario) with the effects of a design including a capacity mechanism in the United Kingdom.

Scope, hypotheses and data

Geographical scope and time scale: the electricity markets and the investment/decommissioning decisions are simulated over 2012-2030 and the stage of the United Kingdom (cross-border exchanges with neighbouring countries are taken into account exogenously).

Data on demand and generation: the determinants for the electricity demand and supply used as inputs come from the set of assumptions annually established by DECC, and more precisely the 2013 Updated Energy Projections (UEP).

Main results

The quantitative impact assessment conducted by the DECC shows that setting up the capacity mechanism considered provides savings of tens of millions of pounds a year compared to an energy-only market design with a price cap at £6,000/MWh (£760 m of discounted savings for the community over the 2012-2035 period), mainly linked to the reduction of the loss of load expectation. The analysis also tends to show that the transaction costs linked to setting up the capacity mechanism may account for a significant proportion of the costs and have an effect on the cost-benefit analysis.

Critical analysis and validity conditions of results

This impact assessment conducted by the DECC provides a vision on the impacts of a capacity mechanism in a different context than the French electricity system and therefore highlights that the benefit provided by setting up such a mechanism is not specific to the French system but also applies to other situations.

The modelling and sizing hypotheses are set out transparently in the successive DECC publications, and thus provide the means to identify the effects associated with setting up the capacity mechanism.

Nevertheless, the results of this assessment do not take account of (i) the uncertainties in capacity revenues and consecutively the associated financial risk that could be reduced with the introduction of the capacity mechanism and (ii) extra gains that may arise with a properly-sized capacity mechanism. Indeed, the modelled capacity obligation appears oversized as it includes an additional safety margin of 3 GW with respect to the obligation required to meet the 3-hour loss-of-load expectation criterion.

Lastly, the assessment makes no comparison between the impacts relate to the capacity mechanism and those linked to a change towards an energy-only market design in which the price caps on the energy market would be raised to the VoLL level.

Finally, the gains for setting up the capacity mechanism that are calculated in this assessment come from the improved security of supply with respect to an energy-only market design with price caps. They are however undervalued by both the oversizing of the capacity mechanism considered and not considering gains related to reducing the cost of risk.

Description and analysis of the Frontier Economics – Consentec assessment (2014)

Context

This assessment was conducted by the firms Frontier Economics and Consentec for the BMWi (German Federal Ministry for Economic Affairs and Energy) in the context of its consultation on the overhaul of the electricity markets (Green Paper).

The aim of this assessment was to evaluate the performance of various capacity mechanism designs (strategic reserve, centralised or decentralised market-wide mechanisms, selective mechanisms, etc.) based on several indicators (security of supply, economic effectiveness, etc.) to provide recommendations on the market designs to be favoured.

The summary (available in English) and the full report (in German) are available on the Frontier Economics website:

Summary: *http://www.frontier-economics.com/documents/2014/09/security-of-supply-in-the-electricity-sector-impact-assessment-of-potential-capacity-reliability-mechanisms-for-germany.pdf*

Report: *http://www.frontier-economics.com/de/documents/2014/07/folgenabschatzung-kapazitats-mechanismen-frontier-report.pdf*

Modelling

Competition and market participants' behaviour and information level: investment decisions are endogenous to the model and reflect pure and perfect competition behaviours, where the market participants are fully rational and omniscient (though unable to forecast short-term uncertainties).

Risk aversion: risk aversion of the players is not represented.

Time horizon and uncertainties: investment decisions are simulated through a dynamic economic and energy model, covering a 25-year period. This makes it possible to take account of the demand growth rate, roll-out of renewable energies, planned power station closures and fluctuation of the energy and capacity prices over time. However, neither short-term uncertainties on demand, the availability rate and hydraulic supply nor long-term uncertainties on the economic and energy-based context are represented.

Representation of the energy market and short-term mechanisms: the energy market is supposed to operate with pure and perfect competition behaviours. The hydraulic stocks are represented and optimally called on in the energy market. The price cap for the energy market is assumed to be equal to €15,000/MWh in all simulations. The operation of short-term mechanisms such as intra-day exchanges, short-term adjustment, the frequency containment reserve and the automatic frequency restoration reserve are not modelled.

Representation of capacity mechanisms: three different models are applied based on the type of mechanism studied: (i) strategic reserve, (ii) selective mechanism (tender) and (iii) market-wide[8] mechanism. The mechanism in which all capacities can participate (especially interesting for the French case) is represented using a capacity obligation set to a 3-hour loss-of-load expectation criterion, but using a very conservative hypothesis of zero contribution from peak demand interconnection capacities.

Studied market designs: as indicated above, various market designs were studied, at least qualitatively: energy-only markets (notably with "EOM 2.0" in which the price caps would be raised to VoLL level) or with different types of capacity mechanism (strategic reserve, selective capacity mechanism or even centralised or decentralised capacity mechanisms).

8. The centralised and decentralised market-wide capacity mechanisms are represented in the same way in the quantitative analysis. Modelling does not enable the designs to be distinguished from one another.

Scope, hypotheses and data

Geographical scope and time scale: the energy market and the investment decisions are simulated for an area of about ten countries, over the 2015-2039 period.

Data on demand and generation: the data used and notably the consumption data, renewable generation, fixed costs and fuel costs are based on hypotheses belonging to Frontier Economics.

Main results

The results of the quantitative study conducted by Frontier Economics and Consentec tend to show that all capacity mechanism designs would result in significant extra costs for the community compared to "EOM 2.0" (notably with a price cap equal to the VoLL in the energy market). Indeed, EOM 2.0 is modelled as a perfect mechanism, in which the market participants make the best decisions as they have no risk aversion, while all the capacity mechanisms modelled are only additional constraints on the capacity level to be reached and therefore leads to suboptimal investment decisions.

In addition, the assessment also seems to show that certain mechanisms result in higher extra costs than others: the selective mechanism appear more costly than the market-wide mechanisms, which themselves appear to be more costly than strategic reserves.

Critical analysis and result validity conditions

This analysis provides a broad comparison between the various types of capacity mechanism compared to an energy-only market design, qualitatively and quantitatively.

However, with this modelling approach, the various capacity mechanisms are not similarly sized and the discrepancy in terms of extra costs for the community are mainly representative of the sizing quality of each mechanism. For example, the market-wide capacity mechanism is sized based on a very conservative hypothesis of zero contribution of peak demand interconnection capacities. In reality, as the interconnections do not have zero contribution at peak demand, such an assumption results in oversizing the capacity obligation, to the extent that the loss-of-load expectation finally obtained with a capacity mechanism is close to zero and certain capacities present in the mix are in fact superfluous and therefore costly for the social welfare.

In addition, in the quantitative study, the market participants are supposed to be risk neutral. Thus, with no risk aversion and supposing that the optimal level of security of supply for the facilities is determined by the cost of lost load, the energy-only market design, with increased price caps, is considered under optimal assumptions and the other market designs can therefore only result in sub-optimal mixes.

Finally, it seems that the quantitative part of the Frontier Economics and Consentec assessment only demonstrates that in a system where the players are not risk averse, poorly sized capacity mechanisms (take.g.: no account of interconnection contributions to security of supply) with overcapacity targets result in significant extra costs for the social welfare (discounted extra cost of several billion euros for the 2015-2039 period).

Description and analysis of the Thema assessment (2013)

Context

This report was prepared by Thema Consulting Group, E3M-Lab and COWI, and published by the European Commission in 2013, at the time of the public consultation on generation adequacy, capacity mechanisms, and the internal market. In chapter 7.6, it includes an impact assessment on setting up a capacity mechanism referred to as "asymmetrical", i.e. set up in a single country (either only in France or only in Germany). This study aimed to assess the possible impacts on the electricity market entailed the implementation of capacity mechanisms in Europe.

A critical analysis conducted by RTE was published in April 2014 for the accompanying report on the rules of the capacity mechanism. This analysis has been rehashed to complement this comparison of impact assessments in light of the same analysis table.

The assessment report is available on the DG Energy website:
https://ec.europa.eu/energy/sites/ener/files/documents/20130207_generation_adequacy_study.pdf

Modelling

Competition and market participants' behaviour and level of information: in the scenario used as a reference (2013 EU Reference scenario[9]), investment or decommissioning decisions are simulated to minimise the total costs for the system, thus reflecting a theoretically perfect market, operating under pure and perfect competition assumptions. The assessment does not really specify the market design required to reach this ideal dynamic for the evolution of the energy mix. It however considers, via its set of assumptions, that the design would be similar to a perfect energy-only market in which demand is elastic[10] and the producers cover their investment costs thanks to "contracts for difference" (this hypothesis therefore hides the existence of missing money with an energy-only market design in which the price would not be the value of lost load in a scarcity situation). The investment dynamics obtained are also used as a point of reference for simulating the impacts of the various market designs, notably:

(i) In the energy-only market design: this best dynamic for the mix is deemed fixed in the dispatch simulations. Investment decisions are not questioned despite a potential lack of profitability.

(ii) In a market design with a capacity mechanism: the overall capacity volume, including all industries and countries, is deemed invariable; only the allocation of investments between countries or industries is potentially modified based on the remuneration conditions set out by introducing a capacity payment.

As a result, the assessment does not simulate investment dynamics so to speak that are based on a profitability criterion for capacity projects based on the various market designs.

Risk aversion: risk aversion of the players is not represented.

Time horizon and uncertainties: investments in generation capacities are simulated in a dynamic context, covering a multi-year period. The economic and energy contexts are assumed to be perfectly known and long-term uncertainties are therefore not represented. Short-term uncertainties on demand and the availability of generation sources are not modelled either.

Representation of the energy market and short-term mechanisms: three different competition hypotheses are used to simulate the energy market: pure and perfect competition (marginal cost bidding), supply function equilibrium and Cournot competition. The short-term mechanisms such as intra-day exchanges, the creation of reserves, the adjustment mechanism and the system services are not represented and no remuneration is taken into consideration in the decisions of market participants.

9. EC, *EU energy, transport and GHG emissions – Trends to 2050 – Reference scenario 2013, 2013*
10. This kind of hypothesis on the elasticity of the demand represents voluntary demand responses from consumers, but not load shedding.

Representation of the capacity mechanism: the capacity mechanism modelled in this assessment corresponds to a selective capacity payment for new combined cycle gas and gas turbine type power stations only. It is set up either in France or in Germany, with a level of payment set to €40,000/MW/year, independently of the existing level of security of supply.

Scope, hypotheses and data

Geographical scope and time scale: the energy market is simulated at the scale of the European Union Member States over the 2011-2030 period.

Data on demand and generation: the representation of energy market operation is based on the simulation of nine typical days for each annual period. The long-term forecasts and generation of renewables are based on the "2013 EU Reference Scenario" from the European Commission.

Main results

Firstly, the assessment demonstrates that a high number of power stations of the ideal mix are not profitable with the only revenue from the energy market. Thus, the missing money for the new peak generation power stations, resulting from the existence of price caps in the energy market lower than the value of lost load, is evaluated at between €35,000 and €50,000/MW/year on average for the whole European Union, based on the competition hypotheses.

Secondly, the assessment attempts to analyse the impact of setting up a selective capacity payment in an isolated European country. The assessment therefore highlights a transfer of generation capacity investments of around several dozen GW (from countries with an energy-only market design to the country that sets up a capacity mechanism), as well as a distortion in the mix structure (reduction in basic capacities and increase in combined cycle gas and gas turbine power stations) due to the technological discrimination caused by this kind of market design. This distortion to the mix also results in an increased cost for the consumer, estimated at over €4.5bn/year when the capacity payment is applied only in France.

Critical analysis and result validity conditions

The model used in this assessment is not appropriate for the French capacity mechanism impact assessment. On the one hand, the assumptions for representing the capacity mechanism are inconsistent with the choices made in the French mechanism. The French capacity mechanism design is based on volumes via a decentralised and market-wide mechanism and may not be represented by a selective capacity payment. This kind of selective payment measure could create distortions in the investment decisions insofar as it favours certain industries (that are remunerated for their capacity) over others. On the other hand, the lack of accounting for loss-of-load costs hinder the assessment of the benefits linked to setting up a capacity mechanism. Lastly, the impacts of market designs on capacity profitability and therefore on the development of the mix do not seem to be correctly represented: the volume of capacities present in Europe is indeed supposed to be set exogenously (and is not therefore estimated based on a profitability calculation) and only the geographical distribution of capacities is assumed to be affected.

APPENDIX 2: UTILITY FUNCTION USED TO REPRESENT THE EFFECT OF THE RISK ON THE COST OF ACCESS TO CAPITAL

The effect of the risk on the cost of funding new power capacities is represented with a utility function (concave). The risk premium from this utility function corresponds to the extra cost of capital resulting from the risk.

The utility function used in the context of this assessment is a modelling solution to represent the effect of risk on the cost of capital and is not a model which aims to represent market participants' risk aversion. This means that the players are not modelled as being risk averse insofar as they are assumed to have a preference for a low risk economic balance sheet, but they are modelled as seeking to optimise their expected economic balance sheet, taking account of the effects of the risk on their funding costs. Although the notion of risk aversion is used in the rest of this section, it actually only represents the effect of the risk on the cost of capital.

A utility function is an approach frequently used in the models representing risk aversion for market participants[11,12]. This type of approach is generally based on the idea that the decisions of market participants[13] maximise the expected utility associated with their revenue and not simply their expected revenue.

For a risk-averse player, the general idea consists in using a concave utility function that therefore checks the following property: the expected utility is lower than the utility of expectation.

$$E[U(x)] \leq U(E[x])$$

Based on this logic, a player will therefore obtain greater utility from an investment resulting in guaranteed revenue, rather than from an investment that would result in the same expected revenue but with more variable (and therefore more uncertain) revenue.

To give a concrete example, in the case of an investment decision in a generation power plants, resulting in uncertain revenue that could take the values (discounted) R_1 or R_2, in an equiprobable way. In the absence of risk aversion, the player in question will then invest when the total discounted costs of the project are lower than the discounted expected revenue $(R_1+R_2)/2$. However, when the player is risk averse, the utility expectation is lower than the mean revenue utility and economic arbitration may be modified. Thus, the risk-averse player will invest if the project costs are lower than "the certain equivalent", associated with the probabilistic distribution, which is defined as the certain revenue guaranteeing the same utility as the expectation of the utility of probabilistic revenue distribution, i.e.:

$$CE \text{ defined as: } U(CE) = \frac{U(R_1) + U(R_2)}{2} < U\left[\frac{R_1 + R_2}{2}\right]$$

(Note: U being a strictly increasing function,

$$CE < \frac{R_1 + R_2}{2})$$

and investment decision criterion: $Costs_{\text{with no risk}} \leq CE$

Lastly, the risk bonus may be defined as the difference between the revenue expectation and the certain equivalent of the possible revenue distribution for a given investment, i.e.:

$$CE + RiskBonus = E[Revenue] = \frac{R_1 + R_2}{2}$$

and investment decision criterion:

$$Costs_{\text{with no risk}} + RiskBonus \leq \frac{R_1 + R_2}{2}$$

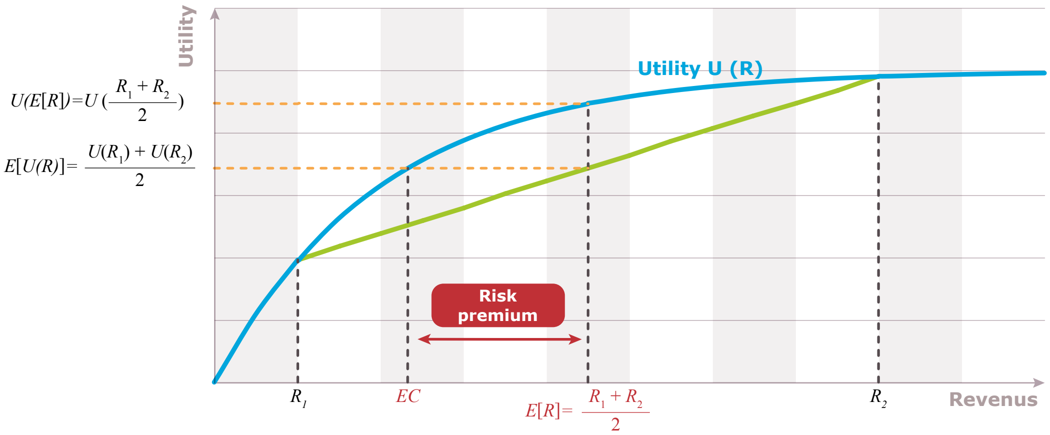
Finally, the investment criterion may be formulated in two equivalent ways:

11. For instance, Petitet, 2016, *Long-term dynamics of investment decisions in electricity markets with variable renewables development and adequacy objectives*, thesis presented on November 29, 2016

12. The modelling approachs of the CEEM study and of the study considered in this section differ on some issues, particularly in terms of information modelling and market participants' rationality.

13. VON NEUMANN, J. et MORGENSTERN, O., Theory of games and economic behavior. Princeton university press, 1947.

Figure 29. Illustration of the utility function applied to incomes and suggesting a risk representation



(i) "The investor funds the project when the discounted costs (or no risk discount rates) of the project are lower than the certain equivalent of probabilistic revenue distribution";

(ii) Or: "the investor funds the project when the sum of the discounted costs for the no risk rate and the risk bonus is lower than the revenue expectation".

The notions defined above and the economic arbitration resulting from the risk aversion are illustrated in figure 29.

Economic publications suggest different utility functions to represent agent aversion. In particular, there are two classic types of utility function : i) the CARA (constant absolute risk aversion) function, which assumes that the absolute risk aversion level does not increase with the initial wealth of the agents, and ii) the CRRA (constant relative risk aversion) function, which, on the contrary, assumes that the absolute risk aversion level varies with the initial wealth of the agents. These utility functions were historically proposed and discussed by Arrow and Pratt in a series of works and articles published in 1964 and 1970[14]. The utility function chosen in this assessment is a concave exponential function specified below, which preserve the mathematical property of the CARA function separability and introduces normalisation with the expectation, thus conciliating with the properties of CRRA functions.

$$U(Revenue) = 1 - \exp\left(-\alpha.\frac{Revenue}{Esp[Revenue]}\right)$$

Coefficient α, normalised with the expected revenue associated with each project ***Exp[Revenue]***, corresponds to the Arrow-Pratt absolute risk aversion measurement. The higher this coefficient, the more curved the utility function, which conveys higher sensitivity of the cost of capital to the risk. The assessment presented here keeps a coefficient $\alpha = 2$, in line with the magnitude of the coefficients used in other similar studies[15]. A sensitivity analysis with the value of this criterion[16] is also proposed in part 3.3.5.

Modelling the financial impact of the risk on the cost of capital that was chosen in this assessment is therefore based on the use of a concave utility function, which is a conventional method, used in various academic works and recommended by several economists[17].

14. ARROW, K. J., Aspects of the theory of risk-bearing. Yrjö Jahnssonin Säätiö. 1965.
ARROW, K. J., Essays in the theory of risk-bearing. Amsterdam, London : North-Holland. 1970.
Pratt, J. W., Risk aversion in the small and in the large. Econometrica : Journal of the Econometric Society, 1964. pages 122-136.

15. PETITET, M. Effects of risk aversion on investment decisions in electricity generation : What consequences for market design? Proceedings of the 13th International Conference on the European Energy Market (EEM), IEEE. 2016.

16. As an example, for a risk aversion coefficient α = 2 and an investment equiprobably leading to incomes equal to € 10M or € 20M, the risk premium will amount to 10% of the average value of the incomes, corresponding to € 1.5M.

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A contribution to the European debate for a secure supply of electricity

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