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Optimizing distributed flexibility provision in competitive wholesale markets considering local constraints in the distribution grid

Marion Pichoud

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THÈSE DE DOCTORAT

DE L'UNIVERSITÉ PSL

Préparée à l'Université Paris-Dauphine

**Optimizing distributed flexibility provision in competitive
wholesale markets considering local constraints in the
distribution grid**

Soutenue par

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Glossary of terms

ACER (Association for the Cooperation of Energy Regulators)
aFRR (automatic Frequency Restoration Reserve)
AM (Adjustment Mechanism)
ARENH (“Accès Régulé à l’Energie Nucléaire Historique”, french for regulated access to nuclear electricity)
ATC (Available Transfer Capacity)
ATLAS (Short-Term Market sequence model implemented on the PROMETHEUS platform)
BSP (Balance Responsible Party)
CCGT (Combined Cycle Gas Turbine)
CEE (“Certificats d’Economie d’Energie”, french for energy savings certificate)
CEER (Council of European Energy Regulators)
CEP (Clean Energy Package)

CRE (“Commissison de Régulation de l’Energie”, French regulator)
D – 1 (Day-Ahead)
DSO (Distribution System Operator)
EDF (“Electricité de France”, France most prominent historical supplier)
EDSO (European Distribution System Operators)
EJP (“Effacements Jours de Pointe”, french for load-shedding on peak days)
Enedis (French DSO)
ENTSO-E (European Network of Transmission System Operators for Electricity)
EPEX SPOT European electricity stock exchange
EV (Electric Vehicle)
FCR (Frequency Containment Reserve)
HV High Voltage)
ID (Intraday)
IGCC (International Grid Control Cooperation)
IPCC (Intergovernmental Panel on Climate Change)
LDC (Local Distribution Companies)
LV (Low Voltage)
MARI (Manually Activated Reserve Initiative)
mFRR (manual Frequency Restoration Reserve)
MPI (Maximum Power Indicator)
MV (Medium Voltage)
NEBEF (“Notification d’Echanges de Blocs d’Effacement”)
NOME (New Organization of the Electricity Market)
NS (No Signal)
NWE (North-Western Europe)
OTC (Over The Counter)
PICASSO (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation)
POS (Peak/Off-peak Signal)
PPE (“Planification Pluriannuelle de l’Energie”, french for Pluriannual Energy Plan)
PROMETHEUS (Prototyping integrated platform for the creation of energy system simulation models)
PSH (Pumped-Storage Hydroelectricity)
RE (Renewable Energy)
RES (Renewable Energy Sources)
RR (Replacement Reserve)
RTE (Réseau de Transport d’Electricité)
S3REnR (“Schémas Régionaux de Raccordement au Réseau des Énergies Renouvelables”)
STCS (Short-Term Controllability Signal)
TERRE (Trans European Replacement Reserve Exchange)
TRVE (“Tarif Régulé de Vente d’Electricité”, french for regulated electricity sales tariff)
TSO (Transmission System Operator)
TURPE (“Tarif d’Utilisation du Réseau Public d’Electricité”, french for cost of transmission)
V2G (Vehicle To Grid)
VOLL (Value of Lost Load)
VRES (Variable Renewable Energy Sources)
XBID (Cross-border Intraday Coupling)

Chapter 1: General introduction

This chapter introduces the scope of the thesis subject. This work is in line with the energy transition which disrupts the energy systems. This energy transition aims at reducing CO₂ emissions in order to tackle climate change. This transition involves, among other changes, an increase in the share of the variable renewable energy sources (VRES) that are solar and wind. They cause two major problems for the electricity system: a great variability, with high production spikes, and a production that does not automatically follow the load needs. Section 1 describes the fundamentals of the supply demand-balance and the network's infrastructure in Europe and identifies the challenges VRES entails for both.

Flexibility on both production and consumption can cope with this higher share of variable production. Section 2 describes the general concept of flexibility and introduces the flexibility assets that are focused on in this study, distributed demand flexibility.

Costly production curtailment can manage production spikes that are too high for the distribution grid's equipment. Flexible load can adapt to low production. At the same time, the distribution grid needs to undergo massive reinforcements to home this mostly distributed production as well as new flexible electric needs such as the EV charging. Section 3 details this issue of the need for the optimization of both costs of the reinforcement of the distribution grid and flexibility procurement for supply-demand balance. The use of flexible demand to minimize production costs by mostly taking advantage of RE (Renewable Energy) production and to minimize reinforcement costs are two flexibility uses that could be coordinated to achieve the highest gains for the electricity system.

The value of flexibility for the electric system, in the context of the energy transition is thus at the core of this work, as well as the impact of coordination of flexibility uses in this value. Section 4 introduces the problematic and the work of this thesis.

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1 General context

1.1 Decarbonization of the energy and electricity sector

The fight against global warming requires a significant reduction in GHG emissions from the various economic sectors (IPCC, 2014). This decarbonization is based on two major changes. On the one hand, the electrification of energy needs and on the other hand the decarbonization of electricity production.

As far as energy needs are concerned, energy efficiency and energy sobriety are the two levers for reducing energy consumption that will help achieve the objective of electrifying uses. Energy efficiency refers to the reduction of energy used for the same service. In particular, the energy performance of buildings was the subject of a European directive in 2010. Sobriety has been popularized more recently and aims to reduce energy consumption but this time by reducing also the underlying energy service provided, relying on changes in individual behavior (by heating less, for example). The use of these two levers, and in particular energy efficiency, could save 290 TWh of electricity consumption out of 845 TWh over the year in France, in the 2050 prospective scenario proposed by RTE (“Réseau de Transport d’Electricité”), the French TSO (Transmission System Operators), in “Futurs Energétiques 2050” (RTE, 2022).

As far as electricity production is concerned, the aim of the energy transition is to reduce the use of fossil fuels for electricity production, in order to reduce CO₂ emissions in accordance with IPCC recommendations, but also, in some European countries, such as Germany, to reduce the use of nuclear fuel, which is a low-carbon technology, but whose slow development and low acceptability compromise its development (Sonnberger & al, 2021) .

In Europe, the development of so-called Renewable Energies Sources (RES) is at the heart of the energy transition policy initiated in the 2000s. There are several definitions of RES, but here we will refer to those derived from naturally renewable resources. They include hydraulic energy, wind energy (land and sea), solar or photovoltaic energy, biomass and geothermal energy. Biomass has a relatively low potential when compared to the important and competing needs. In the energy sector, biogas seems to be often privileged to a use for electricity production (Scarlat, Dallemand, & Fahl, 2018). As far as geothermal energy is concerned, its development is for the moment not very advanced and geothermal energy is only economically interesting in a few places (Schilling & Esmundo, 2009). Moreover, as hydraulic deposits and their acceptability are limited, the decarbonization of energy production will rely to a large extent on electricity production sources, including wind, solar and nuclear.

As far as consumption is concerned, the European objective is to reduce final energy consumption by 36% by 2030, compared to 2007 in the European Union. However, this is accompanied by an increase in electrical energy consumption due to the electrification of uses, particularly in the transport sector. In France, RTE's “Futurs Energétiques 2050” scenario assumes a 40% decrease in energy consumption by 2050, but an increase of 30% of the share coming from electricity, for France (RTE, 2022). This consumption would be covered by a mix of nuclear, RES, hydro and decarbonized gas. Other

trajectories are envisaged for carbon neutrality in 2050. In particular, the "negaWatt" association proposes a 96% RE mix in 2050 and a lot of energy efficiency and sobriety aiming at dividing by three the current primary energy consumption (Association négaWatt, 2022). The scenarios proposed by ADEME for 2050 are also based on a strong decrease in demand, from 23 to 55% compared to 2015, and a high use of REs, at more than 70% (ADEME, 2021).

In Germany, the installed renewable capacity is more than twice as large as in France, with 138 GW versus 60 GW (Statista). This is due, on the one hand, to the desire to get rid of nuclear production entirely and, on the other hand, more recently, to get rid of dependence on Russian gas by accelerating the electrification of uses.

The war in Ukraine has accelerated European plans by bringing out politically an increased need for energy independence. The European Union has thus set itself the target, with the 2022 "REPowerEU" plan (European Commission, 2022), of 45% of energy produced from RES by 2030 (European Commission, 2022), which is equivalent to doubling the current share of renewable production (Figure 1- 1).

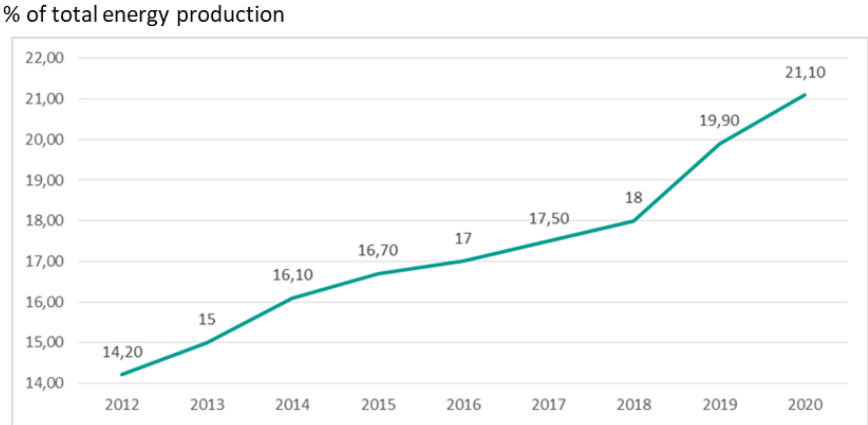


Figure 1- 1 Share of RE in European electricity consumption 2012 - 2021 (Statista)

1.2 Managing the supply-demand balance: a keystone of the European electricity system

To understand the impact of decarbonization on the electricity system, it is first necessary to understand the supply-demand balance and the fundamentals of the electricity markets. As electricity cannot be stored, the balance between production and consumption of electricity must be respected at all times. The European grid is interconnected at 50 Hz. This frequency must be stable to ensure the proper functioning of all rotating machines connected to the grid. If there is a discrepancy between production and consumption, the frequency of the grid deviates from 50 Hz, which leads to premature wear of the grid equipment and rotating machines (Rajan, Fernandez, & Yang, 2021), which therefore disconnect automatically in case of significant frequency deviations, with thresholds that vary according to the technology. The management of this balance between supply and demand in real

time is therefore crucial for the security of the power system. A deviation can go in two directions: it can be either too much production coupled with low demand, or on the contrary, high demand and a production deficit. If there is a gap, it must be filled by costly actions on production.

The role of the TSOs is to ensure the security of the power system in real-time and to coordinate generation and demand in order to avoid excessive frequency fluctuations (ENTSOE, 2013). System Services and manual actions on the balancing mechanism allow TSOs to continuously balance the frequency on the grid. System services are settings that are automatically activated in case of imbalance. A distinction is made between the FCR (Frequency Containment Reserve) and the aFRR (automatic Frequency Restoration Reserve).

The FCR is activated automatically in 30 seconds. It concerns all the European generators connected to the transmission network, with a total power of 3,000 MW, which makes it possible to respond to the simultaneous loss of the two largest generating units. France contributes 540 MW.

The aFRR, activated after the FCR, acts as a complement and allows the frequency of the network to be brought back to 50 Hz, as well as restoring the planned exchanges at the borders, in less than 15 minutes. In France, the aFRR is between 500 MW and 1180 MW, depending on the season, and all generating units over 120 MW must be able to provide it (CRE, 2020a).

Then, manual settings are activated, the mFRR (manual Frequency Restoration Reserve) which, by its fast activation (15 minutes), also contributes to bring the frequency back to balance and the RR (Replacement Reserve), a little slower (activation in 30 minutes), which allows to complete the FRR reserves (aFRR or mFRR) and to anticipate a future imbalance. Not all European TSOs have RR. These different actions and their impact on the frequency are presented in Figure 1- 2.

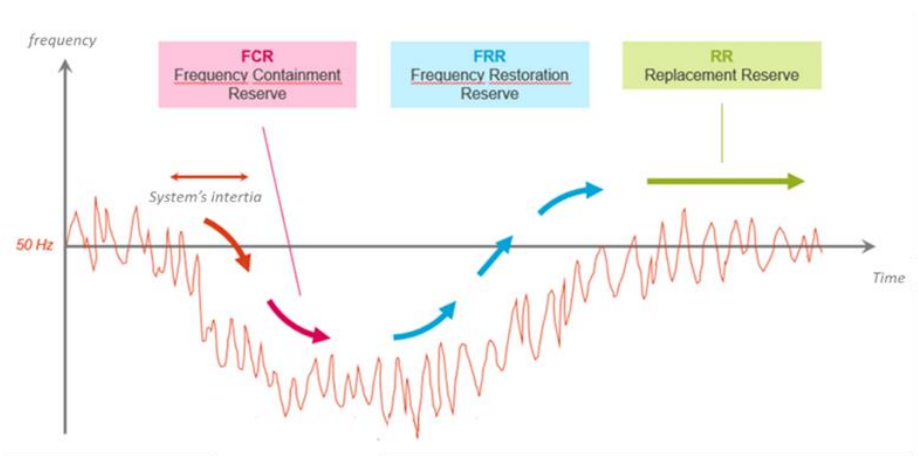


Figure 1- 2 Representation of the functioning of system services in Europe

The supply-demand balance is not only managed in the short term, but also in the longer term, by ensuring, through the necessary investments, that there is enough electricity generation capacity to meet future demand and guarantee security of supply. The long-term supply-demand balance relies

on investments in generation or storage capacity, the development of interconnections that allow for the pooling of intermittent generation, and actions on long-term demand, such as the renovation of buildings or the development of demand flexibility.

In theory, the markets send signals for these investments. It is generally assumed that generating units have an incentive to offer at their marginal cost, which is the additional cost of producing one MW (Soft, 2002). The production units have different technical and economic characteristics which are expressed through the prices of offers made by each of the units. First of all, installation and production costs are more or less high depending on the type of unit. The most capital-intensive means, with high installation costs, such as RES and nuclear power, have a low marginal cost, and therefore a low offer price. They thus come first in the economic precedence (also called “merit order”), which is illustrated in Figure 1- 3. Semi-base facilities, corresponding to CCGTs (Combined Cycle Gas Turbines) and coal-fired units, have a slightly higher marginal cost and a lower installation cost than nuclear and RES. These means are therefore next in order of economic precedence. Next come the peak power plants, i.e., combustion and fuel oil turbines, which have the highest marginal cost for a low installation cost.

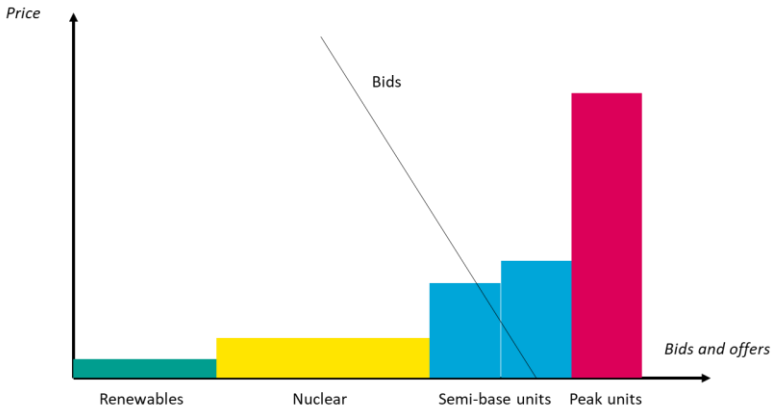


Figure 1- 3 Illustration of the merit order for the French electricity mix

Thermal power plants (excluding nuclear) also see their marginal cost increase with the price of CO₂. The producers (except for the last accepted offer) make a profit that covers their fixed costs. According to Boiteux, this profit encourages optimal investments in production units by allowing the convergence of long-term marginal costs with short-term marginal costs and therefore, it is the market price that guides virtuous investments (Boiteux M. , 1960). However, this theory is based on assumptions that are rarely all verified (Vassilopoulos, 2007) : that the installation time of new production units is negligible, that fuel costs are stable and that there is perfect competition between the players. Moreover, the last unit called has no incentive to offer at its marginal cost and has strong market power in case of shortage. These hypotheses are therefore not currently verified for the electricity system.

Decarbonization poses many challenges, some of which are related to managing the supply-demand balance and markets. These challenges are mainly related to Variable Renewable Energy Sources (VRES) such as wind and solar¹.

1.3 Electricity markets, a tool for coordinating dispatch on a European scale

Electricity markets can be divided into two main groups. First, the wholesale market is where electricity is traded to allow generators to sell their production as well as demand flexibility assets their consumption shedding or displacement, to cover the demand of large customers and suppliers. Second the retail market allows end customers to purchase electricity through suppliers.

1.3.1 Wholesale energy market

The various players in the electricity market exchange products defined by a power (in MW), a delivery period and a location (e.g. France). Europe is organized into several market areas, which generally correspond to national borders and within which internal congestion is ignored.

These exchanges can take place many years in advance and up to very close to real time. Most transactions involve multi-day products, with base products covering all hours of the day or peak products, which cover the hours between 8am and 8pm, only on weekdays.

These so-called “forward products” can be purchased up to several years in advance; the most traded are blocks for delivery over a whole year, a whole quarter or a whole month. They allow consumers (or producers) to secure the purchase (sale) price of the stable part of their consumption (production).

The “Day-ahead” (D-1) market is called the spot market and its prices are often used as a price reference for the zone. Indeed, it is close enough to real time for forecasts to be considered relatively reliable at that moment, and at the same time far enough away from it that the players still have room for maneuver with their production/consumption management means. This market therefore allows players to finely adapt their purchases and sales to daily circumstances.

These products are orders to buy and sell energy, submitted on D-1 for delivery on D-day. They are traded in France on the electricity exchanges. The market mechanism is based on the logic of economic precedence: offers are ranked in order of increasing price and requests in order of decreasing price². The order book closes at 12:00 each day and the exchange then calculates the supply and demand curves and the price at which they intersect (spot price) for each hour of the following day. This ensures that demand is met with the most economical supply available. The offers and demands selected are

¹ Conversely, hydro and biomass are renewable energies that can be controlled

² To hedge financially against spot price volatility, producers often sell a portion of their production on the futures markets. They then have an interest in bidding on the D-1 market to buy back the sold production if the price is below their marginal cost. The demand curve is therefore not only made up of consumption but also of these requests from producers.

at the spot price, which maximizes social welfare, i.e. the overall interest of all actors. Indeed, an actor who makes an offer whose price turns out to be lower than the market price will make a profit. The same is true for a seller who has made an offer whose price is lower than the market price. This surplus is maximized by retaining the most expensive buy orders and the least expensive sell orders (Figure 1-4). It is the market clearing and then the fixing that determine the volume of accepted orders and the spot price.

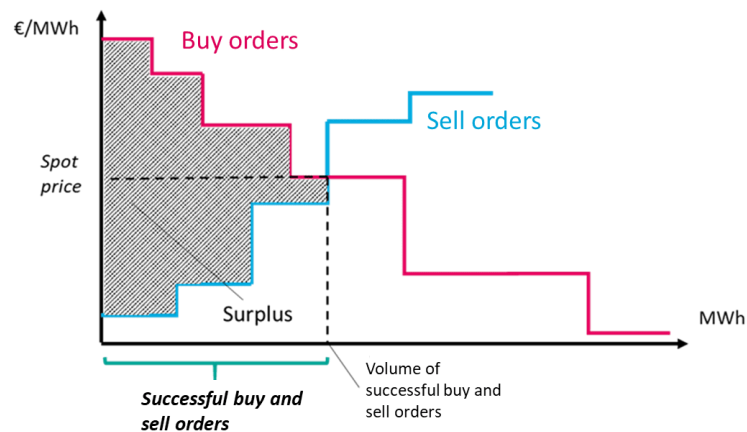


Figure 1- 4 Surplus of market players with the clearing of spot price offers

The European Union has promoted the creation of a single electricity market in Europe and the coupling of spot markets is an essential step in this process. Market coupling means that the products of each of these markets are traded as in a single market, but taking into account the limitation of trade imposed by the exchange capacities between market areas, areas that often correspond to countries. In 2014, the NWE (North-Western Europe) market coupling came into being. Currently, of all the market areas on the European continent, 19 form a coupled area, called Multi-Regional Coupling (MRC). The clearing of this coupled market is done via the "Euphemia" algorithm (NEMO Committee, 2019).

The trading limits taken into account in the market coupling are set by the TSOs. It was initially set for all countries in the form of a maximum trade flow per oriented border via the ATC (Available Transfer Capacity) method (ENTSO, 2000). However, since the European network is highly meshed, exchanges between countries are interdependent and flows that transit from country A to country B may transit the lines of country C. With the ATC method, the physical margins on the lines thus influenced by cross-border trade are distributed before the market. With the flow-based method, they are allocated directly in the market, thus providing more capacity where trade is more valuable (Sores, Divenyi, & Raisz, 2013). The flow-based method makes it possible to determine the exchange capacities on D-1 for 13 European countries.

After the results of the spot market on D-1, the intraday market allows the Balance Responsible Parties (BRPs) to buy or sell to adapt to changes in generation and consumption forecasts between day-ahead

and real-time, before the TSO takes over the balancing. This need for balancing can come from hazards on generation plants or from forecast errors. The production of intermittent energies is more difficult to forecast than for the thermal and hydraulic productions mainly used until now, and with their growth in the mix, forecasting errors are becoming increasingly high and the intraday market is therefore becoming increasingly important. It allows balancing up to about one hour before real time. This market is continuous, i.e. the order book is not closed and orders are taken into account as they are submitted: two compatible orders are immediately executed. 12 European intraday markets are currently integrated within the single intraday market coupling. Called “XBID”, the cross-border intraday coupling was implemented in 2018. Trades are made subject to sufficient capacity at the interconnections. “Explicit access” has been maintained at the France-Germany border, i.e., interconnection capacity can be acquired explicitly in a manner that is unbundled from the energy exchange (CRE, 2020b). The products exchanged can be on hourly, half-hourly or quarter-hourly time steps. The intraday market can also take place in an over-the-counter (OTC) transaction.

After the intraday market, balancing is in the hands of the TSO with system services and balancing. Balancing is a complementary market mechanism to the wholesale market, which will be developed in the following section.

The different market terms are summarized in Figure 1- 5.

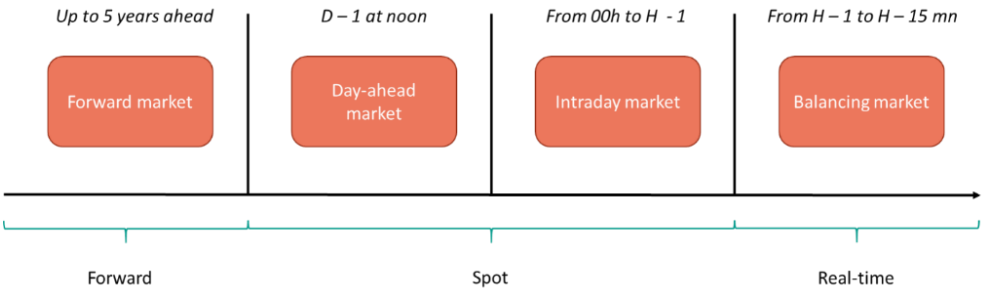


Figure 1- 5 Summary of wholesale energy market terms

1.3.2 Other market mechanisms fostering security of supply

Ideally, the hourly day-ahead market would be sufficient to ensure short- and long-term supply-demand balance by providing electricity generation according to demand. However, as we saw in 1.2, the market price is not necessarily a good signal for long-term investment, which threatens capacity adequacy. This problem is partly caused by the price cap in wholesale markets that prevents scarcity pricing and creates a remuneration deficit ("missing money") for peak plants that can't cover their investment costs, leading to the mothballing of peak units. The uncertainty on fuel prices intensifies this issue, notably for production means that do not depend on those fuels (Roques, Nuttal, Newbery, de Neufville, & Connors, 2006). Peak units are however crucial to the supply-demand balance because they provide flexible generation that can adapt to varying consumption patterns. This issue is also

enhanced by the increase of the share of VRES that decreases the market average price (Keppler, 2016). This poses a problem because these power plants are nevertheless necessary for the supply-demand balance and must exist for times when electricity demand is high, when there is little renewable production or when there are uncertainties in other production plants. Moreover, the wholesale market does not allow for contingencies or forecast errors on production and consumption. Therefore, other market mechanisms act as a complement to the wholesale market in order to guarantee the security of the system.

Capacity mechanisms were created to address this issue. By remunerating flexible production units or demand response for their available power, capacity mechanisms allow to encourage investments in production means and thus guarantee the long-term supply-demand balance. However demand flexibility should also be encouraged by complementary mechanisms. There is great heterogeneity in the way they are implemented in Europe. On the one hand, many countries simply do not have a capacity mechanism. Secondly, capacity mechanisms can take several forms: capacity auctions (capacities corresponding to an installed capacity target are chosen and remunerated for their installed capacity according to a merit order, several years in advance), strategic reserves (capacities are contracted to be used only in case of production shortage), or capacity obligations as is the case in France (Leonardo & Schittekatte, 2021).

In France, the capacity mechanism was created in 2017. In this mechanism, electricity suppliers have a capacity obligation, which is proportional to the consumption of all their customers during consumption peaks. They must purchase “capacity guarantees” to cover this obligation from producers and load-shedding operators. These capacity guarantees must be certified by RTE, which assesses the contribution of the generation plants during peak periods. They are sold to suppliers during capacity auctions organized by the EPEX SPOT exchange or via an OTC market. Penalties are applied to suppliers whose certificate volume does not correspond to their customers' consumption during peak periods, as well as to producers whose available capacity does not correspond to the capacity guarantees sold. With these capacity guarantees, the available production means, even if they are not used and therefore do not sell energy, obtain a remuneration complement. This mechanism encourages investment in peak capacity, despite the fact that this capacity is not used for many hours during the year and earns little money on the wholesale market, thus making it possible to meet demand during consumption peaks. It also encourages load shedding, which can either be certified and remunerated as such, or used to reduce the peak consumption of certain customers and thus reduce the obligation of the suppliers of these customers.

Short-term supply-demand balance is ensured by the TSOs as presented in 1.2, for which different market mechanisms are put in place. First of all, reserves for system services (FCR and FRR) are contracted with generation, consumption or storage units. As far as the FCR is concerned, it is constituted by a weekly cross-border call for tenders via the “FCR Cooperation”, which brings together the TSOs of Germany, Austria, the Netherlands and Switzerland (RTE, 2016). The mFRR and aFRR are currently contracted through national tenders.

The reserves, whether contracted or not, are activated in the event of a difference between generation and consumption in real time or close to real time. This activation is automatic for the aFRR and is done

in proportion to the reserved power. It is shared among several European countries thanks to IGCC, which allows to net upward and downward activations between countries. The activation of the mFRR and RR is done in each country concerned, with different mechanisms. The French balancing market, the Adjustment Mechanism (AM), which was set up in 2003, performs this task. This mechanism is based on the submission of bids by actors who wish to be remunerated for changing their production or consumption. There are two types of bids:

- « Upward » bids, giving the price at which the bidder wishes to be remunerated for each additional MW of energy injected into the network or for a decrease in withdrawals ;
- « Downward » bids, giving the price that the supplier agrees to pay for lowering its injections or increasing its withdrawals. This price may be negative.

The AM allows the activation of offers for balancing purposes, but also for managing congestion on the transmission network.

Actors in other countries can submit offers if their national processes allow it. This is the case for German and Swiss players, who actively participate in the French balancing mechanism³.

Following a European Commission regulation in 2017 (European Commission, 2017) and the Electrical Balancing regulation (European Commission, 2017), European platforms are or will be set up to improve cross-border exchanges. PICASSO will allow the activation of aFRR at merit-order shared over several European countries. MARI will enable mFRR exchanges. Finally, since 2020, a common platform for the exchange of RR (Replacement Reserve) called TERRE has been set up. The offers exchanged on this platform are standardized. This project concerns 6 European countries: England, Portugal, Spain, Switzerland, Italy and France, whose TSOs are respectively National Grid, REN, REE, Swissgrid, TERNA and RTE. Today, part of the balancing offers are activated on the European platforms and are no longer exchanged on the French AM.

In addition to these various market mechanisms, system services are used to control the voltage on the public transmission network in order to avoid voltage collapses. These system services have a very small scope of action and are not currently subject to market mechanisms in France, even though this may be the case elsewhere, for example in the USA.

1.3.3 Retail Market

The retail market is the intermediary between the wholesale market and the end-consumers. Like the wholesale markets it has undergone a lot of changes in the last decades. The retail market is a tool for consumer's incentive, through the tariff.

³ For balancing data, refer to [Equilibrage - RTE Portail Services \(services-rte.com\)](https://services-rte.com)

1.3.3.1 *Liberalization of the retail market*

The liberalization of the retail market in European Union countries was completed in 2007. Since then, consumers have been able to choose their own supplier, who no longer has to be a historical supplier (in France, this is EDF and the local distribution companies (LDC)). This introduction of competition required the dismantling of the vertically integrated monopolies that were the electricity industries, by separating the infrastructure activities (management of the transmission and distribution networks), which are necessarily monopolistic, from the production and supply of electricity (Chao, Oren, & Wilson, 2008). Its objective was economic efficiency, with the promise of lowering the price of electricity for the end consumer (Amenta, Aronica, & Stagnaro, 2022).

Three successive European directives imposed this opening to competition. First, in 1996, a first directive ("energy package") (European Commission, 1996) set the minimum thresholds for liberalization to be reached by member countries, which had to adapt their own laws to the opening to competition, and required the separation of infrastructure activities from production and supply. A second energy package was adopted in 2003. It allows industrial and residential consumers to freely choose their electricity supplier and requires the creation of national regulatory agencies, the CRE (Commission de Régulation de l'Energie) in France (European Commission, 2003). The third energy package, adopted in 2009 by the European Commission, reinforces the independence of TSOs and creates ACER (Association for the Cooperation of Energy Regulators) (European Commission, 2009a) as well as ENTSO-E (European Network of Transmission System Operators for Electricity) to consolidate cooperation between member states (European Commission, 2009b).

1.3.3.2 *History and scope of consumer tariffs in France*

In France, following this liberalization, consumers still eligible for the regulated electricity sales tariff (TRVE in french for "Tarif Régulé de Vente d'Electricité") can now choose between two offers for the supply of their electricity: market offers, the price of which is set by the chosen supplier (EDF, Engie, TotalEnergies, Eni...), and the TRVE which is set by the public authorities, and offered only by the historical suppliers, for residential and small non-residential sites. Today, about 40% of consumption sites are on market offers.

The TRVE is the heir to a history of tariff thinking that began in the 1950s with the work of Maurice Allais on maximizing social welfare (Yon, 2014) and inspired the work of Marcel Boiteux on electricity pricing. Following the nationalization of electricity production and distribution with the creation of EDF in 1946, the choice of a uniform tariff doctrine at the national level was necessary. For Marcel Boiteux, the tariff must allow rational consumers to make the most economical consumption choices for society, while guiding the investment policy. The solution found by Marcel Boiteux is marginal cost pricing (Boiteux, La vente au coût marginal, 1956). Marginal cost pricing consists of setting the price of the kWh at the production cost of the additional kWh, taking into account the long-term development costs that the production of this additional kWh would entail. There is therefore, on the one hand, the

short-term marginal cost, which is the cost of producing the additional kWh, in the case where the generating fleet and the network are fixed, and on the other hand, the long-term marginal cost, which is the cost of supplying the additional kWh in the case where the producers have been able to invest in new capacity. Marcel Boiteux shows that, in the case where the supply is a constant power over the year, the long-term marginal cost is equal to the short-term marginal cost for an adapted fleet, i.e. a fleet that satisfies the demand in the most economical way possible (Boiteux, *Le calcul économique dans l'entreprise électrique*, 1986). The means of production are thus used in such a way as to create maximum consumer satisfaction.

This theoretical approach is then adapted to integrate the specificities of electricity consumption, i.e. the peaks and dips of the load curve, and to create tariff options that are readable for consumers with different stakes and levels of understanding of the electricity system.

Thus, it is the daily consumption peaks and the winter consumption peak that alone define the need for capacity investment. With marginal cost pricing, only these periods will support investment costs. High prices will then cause consumption to shift to other time periods and the marginal cost tariff will lose its effectiveness in encouraging adequate investment. Thus, the marginal cost tariff has been adapted to the variability of demand during the day and to the disparities between peak and off-peak hours: peak hour tariffs are capped so as to allow demand to cover investments, while off-peak tariffs are reduced by the short-term marginal cost (Yon, 2014). Boiteux thus develops peak demand pricing.

Marcel Boiteux thus created a tariff system, based on marginal cost and peak demand pricing, which allows electricity consumption to be directed. A complex tariff was proposed to industrial customers, with eight tariff ranges (“tarif jaune”). A simple tariff is proposed for individual consumers, with a fixed power component and an average price per kWh consumed. The tariff system will then be enriched with a “double” tariff, which for a small increase in the fixed part allows to benefit from a cheaper off-peak price than in the simple tariff. Peak hour pricing has proven to be effective in guiding consumer choices since, with a uniform signal throughout the country, a new consumption peak was created at 11:00 p.m. (off-peak hour), corresponding to the activation of hot water tanks (Mougin, 2008). Indeed, this pricing system has encouraged the development of hot water storage tanks which are controlled by a peak/off-peak signal. In order to reduce this consumption peak, off-peak hours were decentralized, leaving this choice to the DSO (Distribution System Operator) (Ailleret, 1986).

Today, the TRVE is the “tarif bleu” of EDF. It has three options: basic, off-peak, and “Tempo”, which allow the consumer to be more or less involved in the management of his consumption. The basic option corresponds to the simple tariff, with a price of the kWh which is identical at any time of the day. The off-peak offer corresponds to the “double” tariff. The “Tempo” offer (formerly EJP for “Effacements Jour de Pointe” i.e load-shedding on peak days) is a tariff option created in the 1980s to encourage consumers to reduce their energy consumption during the periods when the electricity system is most strained. This option differentiates two different prices for the kWh, depending on the days of the year: a price for the so-called “normal” days, which correspond to 343 days of the year, where the price of the kWh is quite low, and a price for the so-called “EJP” days, which correspond to the 22 other days, between November 1 and March 31, where the price of the kWh is higher.

The market offers are proposed by alternative suppliers as well as by the historical suppliers. They can be fixed price or indexed and some suppliers also offer green offers, i.e. the supply of renewable energy certified by guarantees of origin. In France, these offers are composed of a “supply” part (cost of electricity supply), a “TURPE” part (cost of transmission, in French “Tarif d’Utilisation du Réseau Public d’Electricité”) and a tax part. TURPE covers the cost of operating, developing and maintaining the transmission and distribution networks. It guarantees solidarity between regions since, according to the principle of tariff equalization, its formula is identical for all individual customers, regardless of their distance from production plants (Enedis, 2021b). Finally, there are three taxes: the “contribution tarifaire d’acheminement” (CTA), which finances the pension insurance rights of employees under the electricity and gas industries regime, the domestic tax on final electricity consumption (TICFE in french) and VAT.

The final breakdown of the cost items covered by the regulated electricity sales tariff bill for a residential customer is shown in Figure 1- 6.

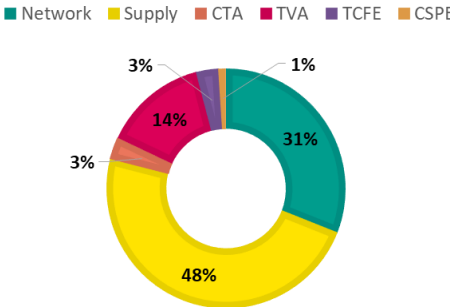


Figure 1- 6 Cost items covered by the regulated electricity sales tariff bill for a residential customer as of March 31, 2022 according to the CRE

The regulated sales tariff is calculated in such a way that alternative suppliers' offers are competitive. It is constructed as a stack of several components, some of which are the same as for market offers (transmission costs and taxes) and others that mimic the costs of an alternative supplier: the cost of regulated access to nuclear electricity (ARENH in French for “Accès Régulé à l’Energie Nucléaire Historique”) the cost of additional supply, the capacity guarantee and marketing costs (CRE, 2021).

The ARENH was created in 2010 with the NOME law (New Organization of the Electricity Market). Indeed, the historical supplier, EDF, owns all of the French nuclear power plants as well as a part of the hydroelectric dams. This makes it difficult for suppliers entering the market to compete with it, as EDF can supply these customers with cheap electricity instead of sourcing it on the markets. Access to nuclear base load electricity was therefore deemed necessary for the development of alternative suppliers and the establishment of real competition between suppliers. Alternative suppliers can, at a regulated price (currently 46.2€/MWh), access the electricity produced by EDF's nuclear power plants with a maximum of 100 TWh over the year (which corresponds to 25% of French nuclear production). In practice, alternative suppliers will therefore buy nuclear production from EDF when the wholesale

price on the markets exceeds the regulated price. When the ARENH ceiling is reached, the ARENH is “capped” and suppliers must compensate by purchasing on the markets. This capping is passed on in the TRVE. In return, alternative suppliers commit to increasing their production capacity, as the ARENH mechanism ends in 2025. The cost of the ARENH⁴ is the first component of the TRVE.

The second component of the TRVE is the cost to the supplier of supplying the market when customer consumption is no longer covered by the ARENH. Suppliers must then obtain supplies on the wholesale market and are therefore exposed to the market price of electricity.

The third component taken into account by the TRVE is the capacity guarantee. As explained earlier, electricity suppliers have to purchase capacity guarantees from generators, which is reflected in their costs and therefore must also be reflected in the TRVE.

Finally, marketing costs are the costs necessary to contract with customers. They also include the costs of energy saving certificates (CEE in French for “Certificats d’Economie d’Energie”) which are legal obligations of energy sellers, which certify that steps have been taken to save energy.

These components are then completed by the TURPE and the taxes and contributions to form the TRVE.

The opening up of the retail market to competition has given rise to much debate, particularly on the merits of the ARENH and the impact on consumer prices. The expected drop in prices due to competition did not take place, but this is also due to the current scarcity situation which increases prices on the markets. The ARENH is accused of being a positive discrimination in favor of new suppliers. Regulated tariffs may disappear in 2025, and all consumers will be subject to market offers.

1.3.3.3 Auto-consumption and prosumers and their impact on the tariff

In addition to being able to choose their supplier, some consumers can choose to produce electricity and consume it themselves⁵. There are two types of auto-consumption. With individual auto-consumption, a single building produces and consumes its own electricity. In France, in 2021, Enedis counts 100 000 consumers in individual auto-consumption. Collective auto-consumption corresponds to a group of self-consumers. It can have a different perimeter depending on the country. In some countries, including France, the use of the public electricity network is authorized for collective auto-consumption operations. In France, collective auto-consumption refers to multiple producers and consumers, with extraction and injection points located downstream of the same MV/LV substation and located less than 1 km apart in urban areas and 10 km apart in rural areas. In the rest of the

⁴ However, in this work, the cost of ARENH is not taken into account in the simulations. The cost of nuclear is always the same, at 5,02€/MWh.

⁵ In theory, this possibility is open to all consumers, but some do not have the practical means.

countries where collective auto-consumption is practiced, it is limited to a single building (Frieden, Tuerk, Neumann, d'Herbement, & Roberts, 2020). In France, collective auto-consumption concerns fewer customers, with 784 participants in 2021, but their number, as for individual auto-consumption, is increasing.

Auto-consumption is booming due to several factors. On the one hand, economic motivations. Indeed, it is an operation that can be financially profitable. The cost of solar panels is decreasing. The regulation is favorable to individual auto-consumption: the energy consumed is exempt from taxes and TURPE and can be sold to the energy supplier as surplus (CRE, 2018). This phenomenon is likely to be even more pronounced in the future as electricity prices increase, for example with the upcoming 15% increase in the regulated tariff in 2023. On the other hand, consumers are more and more interested in energy-related issues, due to the emphasis on the energy transition as the spearhead of the fight against global warming. Auto-consumption is done with energy considered as “clean”, solar energy, and the notion of “locally produced” energy resonates with the more general fashion of “local” applied to the more ecological consumption of food and consumer goods.

The benefit for the supply-demand balance brought by auto-consumption comes on the one hand from the additional means of production that the self-consumer represents and on the other hand from the involvement of this self-consumer, who passes from a passive customer to a “prosumer”, who will potentially seek to maximize his profit by changing his consumption habits. Indeed, the production of electricity via solar panels is very variable and is not in phase with a “classic” load curve. The daily consumption peaks are in the morning and evening, when the solar radiation is very low, and the production is at its maximum around noon, when the energy need is lower. A self-consumer will therefore potentially want to shift certain uses, such as the use of his washing machine or the recharging of his electric vehicle, to these hours when production is at its highest (Motlagh, Paevere, Hong, & Grozev, 2015). A self-consumer will try to maximize his self-generation rate, i.e. the ratio between the electricity consumed and the electricity produced by auto-consumption. This auto-consumption rate is around 20-30%. However, this rate can be greatly increased with the addition of a battery, which allows the electricity produced to be stored when it is greater than required [48]. Whether it is through the displacement of his uses, or through the addition of a battery, the self-consumer has many ways to maximize his profit through auto-consumption, as illustrated in Figure 1-7.

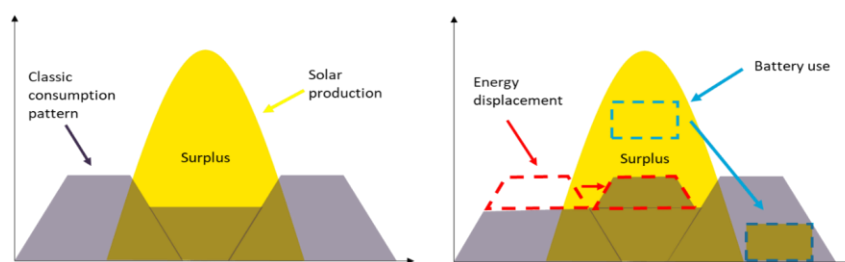


Figure 1- 7 Illustration of the increase of the auto-consumption rate by shifting some uses and adding a battery

The self-consumer will exchange up and down flows with the distribution network. On the one hand, the self-consumer draws energy from the grid to supplement his own production. On the other hand, the self-consumer can also sell his production to his energy supplier if he has one. Three options are possible for a consumer who produces electricity at home: either his production is sold in full to the energy supplier, at the feed-in tariff set by law, and the production is then entirely injected into the network, or only the surplus is sold, which is called partial auto-consumption, or the production is totally consumed on the spot and the self-consumer does not have a purchase contract with a supplier. Thus, in most cases, a self-producer remains dependent on the grid connection.

Auto-consumption has an impact on the financing of electrical networks. The TURPE is paid by all consumers to finance the management of the electricity network. It is composed of a power share and an energy share, proportional to the energy drawn. It generally represents about 30% of the electricity bill. For auto-consumption installations, less energy is extracted from the network than for a traditional consumer and therefore the TURPE paid is lower. However, it is mainly the power at the peak that influences network costs. Auto-consumption therefore induces cross-subsidies to the benefit of self-consumers (Borenstein, 2017) (Ansarin, Ghiassi-Farrokhfal, Ketter, & Collins, 2020). The issue of national solidarity is thus at the heart of the debate on the fair pricing of auto-consumption because then local initiatives challenge tariff equalization (Fonteneau, 2021). As far as collective auto-consumption is concerned, the regulation is different since collective auto-consumption flows through the Low Voltage (LV) network. Self-consumers in collective auto-consumption must therefore pay a specific TURPE, called "TURPE autoconsommation (auto-consumption)".

The profitability of collective auto-consumption compared to individual auto-consumption is still to be defined. Collective auto-consumption gives a consumer access to more production capacities, which are not all producing at the same time, with for example wind energy in addition to solar energy, which allows him to more easily maximize his self-production rate, and therefore his profit. However, the regulatory environment for collective auto-consumption is more complex than for individual auto-consumption and the TURPE auto-consumption may also make this model less attractive (Verderi, 2022).

Both the retail and wholesale markets have undergone profound changes in the 2000s: opening to competition and auto-consumption for the former, and European integration for the latter. These changes are still ongoing.

1.3.4 Mechanisms for valuing load shedding

Load-shedding is a demand response flexibility that is valued on various mechanisms for its participation to the supply-demand balance and capacity adequacy. It consists in curtailing a flexible load when market prices are high. It is different from load shifting for which the curtailed load is then deferred on other timeframes.

According to the definition of the French Energy Code, load shedding is: "the action of temporarily reducing the level of actual electricity consumption on the public transmission or distribution networks of one or more consumption sites, in relation to a forecasted consumption program or estimated consumption, upon a specific request sent to one or more final consumers by a load shedding operator or an electricity supplier" (Gilson Dranka, Ferreira, & Vaz, 2021) (Droit français, 2015).

Load shedding is therefore a crucial means of achieving a supply-demand balance in a system increasingly dominated by intermittent energy sources. The share of RE in the European electricity consumption is around 20% (see Figure 1- 1) and is expected to jump to 45% in 2030 if the REPowerEU plan targets are met (European Commission, 2022). Since they do not require additional generation capacity, they can be an economically relevant solution.

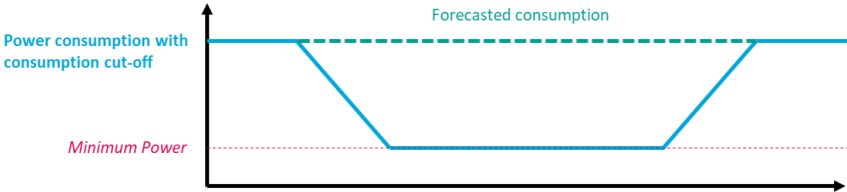


Figure 1- 8 Illustration of load shedding.

Accurate baselines are important to determine the likely level of demand from which load shedding capacity can be drawn. It enables efficient demand-supply balance in the short-term but also right system capacity sizing in the long-term.

Load shedding deposit is not very extensible because the electric consumption is not so malleable and the inflexible need in energy is nevertheless important. However, with the development of precise means of measuring consumption and the possibility of differentiating electrical uses, particularly with the "Linky" meter in France, load shedding can bring significant benefits to both the electrical system and the consumer.

There are two types of load shedding: so-called "industrial" load shedding, which concerns large consumers (industrial sites), and so-called "diffuse" load shedding, which mainly concerns tertiary consumers or individuals. They can be valued by many market mechanisms, by integrating them into the various electricity markets through specific rules or through specific mechanisms. The level of inclusion of load shedding in these mechanisms varies greatly in Europe, even if it is fairly consolidated for some (the FCR for example) and more uneven for others (wholesale markets, where only France has a mechanism that allows independent aggregators to value load shedding) (USEF, 2021). We will therefore focus on the French mechanisms, starting with the earliest timeframes and moving towards real time, as shown in Figure 1- 9.

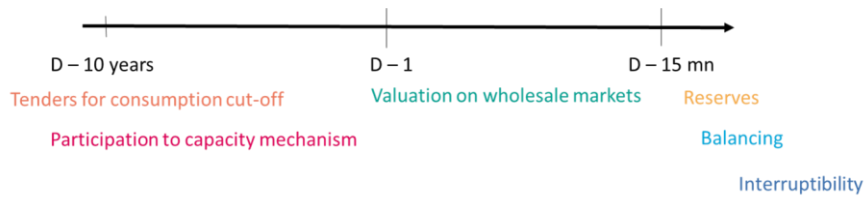


Figure 1- 9 Positioning of the different French mechanisms for the valuation of load shedding according to the deadline

Since 2018, load shedding has been promoted via the load shedding call for tenders⁶, which is open to all withdrawal sites that can carry out load shedding, excluding sites with conventional self-generation and those with an interruptibility contract. These are annual calls for tenders to support the load shedding sector, until 2023. This call for tenders allows the consumer to be remunerated for the provision of load-shedding capacity that can be activated by RTE or the aggregator.

They can also be valued via the capacity mechanism. This mechanism, described in 1.3.2, provides additional remuneration for so-called peak generation resources, which are essential to the supply-demand balance but struggle to cover their fixed costs via the wholesale market. Since 2019, the capacity mechanism has been enriched with a “long-term call for tenders” for new load-shedding and battery storage capacities. Long-term tenders ensure a stable remuneration for these new capacities for a period of 7 years. For the period 2021 - 2027, for example, 93 MW of batteries and 58.1 MW of load shedding have been selected through this mechanism (RTE, 2020a).

Load shedding can be valued on the wholesale market in many European countries, but often only via the energy supplier and not via an independent aggregator. In France, since 2014, the valuation of load shedding via independent aggregators is regulated via the “NEBEF” mechanism. Aggregators can be independent of the electricity supplier and the mechanism is designed to effectively enable this independence. Indeed, if the consumer chooses to value his load shedding through a load shedding operator who is not his electricity supplier, the load shedding operator is not required to obtain the supplier's authorization to sell the energy shed on the markets. However, the electricity supplier provides energy to the consumer for which it must be compensated. Financially, this compensation is done at a price corresponding to the “energy” part of the supply price of the erased energy. In terms of volume, this translates into the equivalent of a block exchange between the balancing perimeter of the load shedding operator and that of the supplier for the volume of energy shed. This mechanism requires precise control of the shed consumption. This requires the estimation of a reference curve, which can be done using several methods. An illustration of this mechanism is shown in Figure 1- 10.

⁶ [Bénéficiaire d'un soutien aux effacements - RTE Portail Services \(services-rte.com\)](https://services-rte.com)

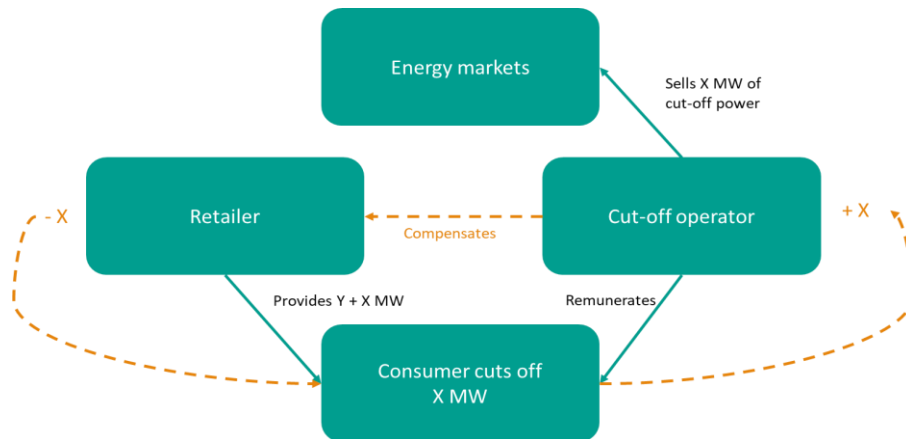


Figure 1- 10 Scheme of operation of the "NEBEF" mechanism

In most European countries, load shedding can participate in the supply of reserves. This concerns both automatic settings and contracted manual reserves. In France, for example, diffuse and industrial load shedding accounted for 18% of the FCR and 45% of contracted manual reserves in 2020.

Load shedding can be valued on the balancing mechanism; for contracted reserves, the aim is to remunerate their activation, but load shedding not included in the reserves can also participate. The overall volume of load shedding, on the balancing mechanism and via NEBEF, amounted to 21.7 GWh.

Finally, for large industrial sites, directly connected to the electricity transmission network (known as "electro-intensive") and willing to participate, an "interruptibility" contract can be signed with RTE. Their consumption can be immediately interrupted in case of risk on the supply-demand balance.

Thus, for both industrial sites and diffuse load shedding, the valuation of load shedding in national market structures has been gradually extended since 2003. Load shedding is now an important part of the management of the country's supply-demand balance.

Thus, market mechanisms evolved and also gradually integrated demand management. These various exchanges are made possible by the transmission and distribution networks.

1.4 The physical support of the supply-demand balance and the market: Large electricity transmission network, sub-transmission network and distribution network in France and in Europe

1.4.1 Structure of transmission and distribution networks

Historically, the electrical network has been used to transport electrical energy from production plants to consumers. The distinction between voltage levels varies between European countries, but in France, this network can be broken down into 3 parts, as shown in Figure 1- 11: the large transmission network, which corresponds to voltages 400kV and 220kV, the sub-transmission network, in 225 kV,

90 kV or 63 kV to which are connected the distribution network and large industrial customers, and the distribution network, connected to the sub-transmission network through substations, supplies consumers with medium voltage MV (20 kV) or low voltage LV (400 or 220 V). The low voltage is connected to the medium voltage by HV/LV transformers.

The large transmission network allows large quantities of energy to be transmitted over long distances with a low level of losses. In Europe, it is interconnected at 50 Hz. The large transmission network has a meshed architecture: the network nodes are connected to each other by several lines forming loops, which provides a high level of security of supply.

The large transmission network respects the N-1 or simple contingency criterion (Power, 2014): the loss of a network element (line, transformer, busbar section, etc.) has no impact on the final consumer, i.e. the loss of this element will not cause the technical limits of the equipment to be exceeded or the network to become unstable. In the case of a hazard, there is a load transfer and the flows that should transit on the lost equipment transit on the remaining equipment, sized to accommodate this additional load without exceeding their technical constraints.

The sub-transmission network ensures the supply of electricity on a regional scale. In France, it is also owned by RTE, but in other European countries, such as Germany, it is managed by the DSO. Energy is injected into the grid via the main transmission network or via medium power generation plants. The sub-transmission network is operated in a tree structure and is not looped like the main transmission network, but the MV consumers are connected to two HV/MV transformer stations, which allows, in case of a problem or a maintenance on a station, the withdrawal to be carried over to the other one, by activating a switch.

In the following, what we will call distribution networks includes medium voltage MV (20 kV) and low voltage LV (400 or 230 V). After the HV/MV transformer (substation), one or more MV busbars supply the MV customers and the MV/LV substations, which supply the lines that serve LV customers. In France, the management, delegated by the municipalities that own the network, is entrusted to the DSOs, i.e. Enedis for 95% of the territory and about 160 other DSOs for the rest of the territory. In Europe, the voltage levels concerned by the different network operators can be different and there are many different configurations. For example, in Germany, there are up to 5 layers of grid operators. The distribution network is much longer than the transmission network because it connects many more withdrawal points than the transmission network. It has a total of 1.3 million kilometers of lines, including 600,000 kilometers of MV lines, and 700,000 MV/LV substations.

The structure of distribution networks is very heterogeneous (Enedis, 2017a) (E-cube, 2017), depending on population density. For an urban network, the length of the lines is much shorter than for a rural network. Thus, the cost of urban networks is lower than that of rural networks. The constraints are also different. Thus, they are mainly transit constraints in urban networks and voltage constraints in rural networks.

For LV networks, no looping is done and they are generally oversized in terms of transit capacity. The main constraint on this network is the imbalance between phases, because the low number of

differentiated withdrawals at this voltage level. The length of LV feeders is limited by the admissible current and voltage drops.

Thus, the networks, depending on their voltage level, have very different characteristics and constraints. The economic fundamentals are therefore different for these networks.

The management of the networks by RTE and the DSOs in France is financed by the TURPE, which represents about 30% of the electricity bill of a private customer. The distribution part of the TURPE is much larger than the transmission part, about four times larger, given the larger size of the distribution network (CRE, 2022).

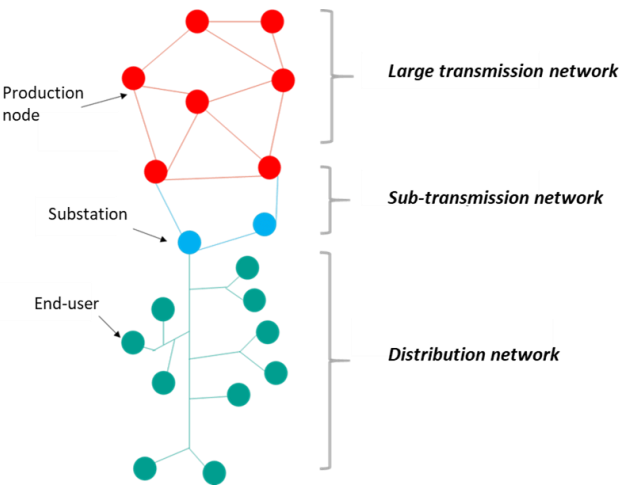


Figure 1- 11 Topology of the large transmission network, the sub-transmission network and the distribution network

1.4.2 Evolution of the distribution network

Before the insertion of REs, the distribution networks functioned passively: electricity flows were only drawn from the distribution network to be injected into the homes of individual consumers, by transiting the distribution network. The arrival of REs, which are largely connected to the distribution network (at 92%⁷) is changing the flows on the network. It will therefore undergo major transformations in order to integrate these new flows, but this impact is differentiated. Indeed, the insertion of REs does not have the same consequences depending on the location, in particular the urban or rural character and the size of the installation, which largely defines at which voltage level the REs are connected (Enedis, 2017b). These impacts are summarized in Figure 1- 12:

⁷ [Accueil RTE Bilan électrique 2020 \(rte-france.com\)](http://www.rte-france.com)

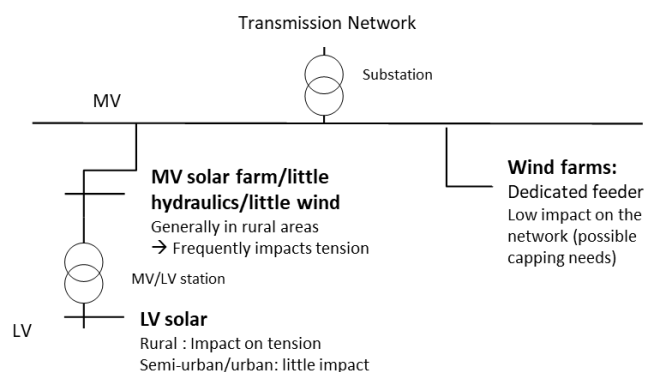


Figure 1- 12 Impact of RE on the distribution network

Large installations (>1MW⁸) are connected by dedicated feeder to the nearest MV source station. Apart from the creation of this substation, they generate few constraints on the MV networks (they do, however, generate constraints on higher voltage networks). This concerns almost all wind power and large solar parks.

Medium-sized installations (between 250 kVA and 1 MW), connected to MV/LV substations, can pose voltage management difficulties, especially in rural areas, where the vast majority of them are installed. These are generally small solar parks, small hydro, etc... In the absence of production, LV networks have a high voltage at the MV/LV station, which decreases according to the distance of the load from the MV/LV station. The voltage drop is more marked in rural networks, which are longer (Carvahlo, Correiea, & Ferreira, 2008) (Petinrin & Shaaban, 2016). The insertion of RES in these rural networks may lead to the desire to impose lower voltages at the MV/LV substation to be able to absorb the connected energy, but this is not necessarily compatible with maintaining the quality of electricity to consumers, because the voltage must be within a certain acceptable range.

LV installations (<250 kVA) can pose voltage management difficulties in rural areas. They generally have little impact in denser areas. Most of them are rooftop solar systems. In rural areas, the energy is generally not consumed on site and generates constraints similar to those described above for medium-sized installations. In denser areas, the energy is generally consumed by the site where it is generated or a nearby site. Moreover, the structure of the network induces less voltage constraints (networks are shorter and mostly underground).

Several solutions currently exist to facilitate the integration of RES into the grid and reduce its cost:

Coordination of connections and sharing of their costs: connection requests are numerous and costly because the network equipment must be reinforced to accommodate the new generation capacity or must be supplemented by new equipment. In France, the S3REnR (Schémas Régionaux de

⁸ The French thresholds for differentiation are given here, but this typology is valid in general in Europe, with more or less importance given to the different configurations according to the mix and densities of the different countries.

Raccordement au Réseau des Énergies Renouvelables) (FNCCR, 2018) is a good example of coordination and fair cost sharing between new generation capacities.

The principle of these connection schemes is threefold: to choose the least costly locations for the installation of RES, which is important to minimize their impact (Zahedi, 2011) ; to plan the right level of network reinforcement; and to share the cost. Indeed, if a new RES requires, for example, the creation of a new feeder on the distribution network, this new feeder will not only be used for this installation but also for future installations that will be located at the same place and for which the feeder will then already be installed. Therefore, these regional plans allow for the proper sizing of these reinforcements and for the installation costs of this new feeder to be shared among the future generation capacities located at this location. The S3REnR determine which works and therefore which costs are to be shared between the producers who connect to the network at a given point. Within the framework of the S3REnR, a producer wishing to connect his installation will therefore pay, in addition to the cost of the equipment that will concern his installations only, a share, which corresponds to the pro rata of the power, the costs of the works to be shared between the producers. The mutualized and non-mutualized network elements are shown in Figure 1- 13.

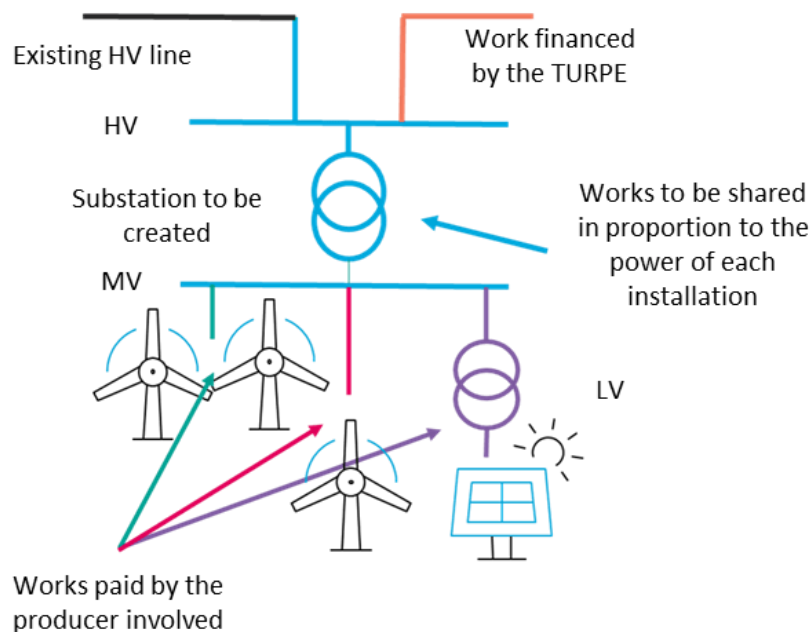


Figure 1- 13 Distribution of costs in the S3REnR (according to CRE)

- **The possibility of capping part of the injected production can reduce investment costs.** For example, in France, Enedis proposes alternative connection offers to RE producers, which are cheaper or faster than traditional connection offers, where part of the injection can be capped within the limits of what has been contracted in advance.
- **In some cases, the installation of storage units or the use of distributed demand flexibility can also help manage constraints** without losing production. The impact of demand flexibilities varies according to the location and, in particular, the presence or absence of RES.

The integration of VRES has led to significant changes in recent years and will lead to even more changes with the strong increase in VRES expected in all European countries. But future developments will also be driven by the electrification of uses. Thus, the final demand for electricity will become more important following the rise of the electric vehicle. This additional demand will require network reinforcements and/or the use of the flexibility of these new uses to minimize their impact. Flexibility could save up to 24€/kW in network reinforcements (Enedis, 2017b) (E-cube, 2017). Thus, the use of the flexibility of the electric vehicle to manage congestion on the distribution network benefits from a substantial literature (Knezovic, Marinelli, Codani, & Perez, 2015) (Deilami & Muyeen, 2020) (Nimalsiri, et al., 2020).

The integration of VRES into the distribution network, which has historically been unidirectional, as well as the increase in electrical demand, therefore pose major technical challenges in terms of accommodating these new production capacities, their impact on network stability and congestion management. These challenges are partly the responsibility of the DSO, whose role is becoming increasingly central to the energy transition.

1.5 Challenges of integrating VRES to the electric system

The management of the supply-demand balance is a first challenge posed by VRES (Chen, Mcelroy, Wu, Shu, & Xue, 2019). These non-controllable sources are both variable and uncertain, as both means of production depend on weather conditions. Variable, because their production can change considerably from one hour to the next depending on variations in sunshine and wind speed (Graabak & Korpas, 2016). Uncertain because their production is as difficult to predict as the weather (Widén & al, 2015). However, reliable forecasting of consumption and production as far in advance as possible of real time is necessary to balance the electrical system. If the wind and solar production suddenly drops, for example, and this in an unforeseen way, it will be necessary to increase the load of thermal means, or even to start up other ones, which takes time. Moreover, this production is not always correlated with the moments of highest demand. In case of unfavorable weather conditions (little wind, grey weather), wind or solar production (sometimes both at the same time) can be very low on a large scale. This intermittent generation is therefore dependent on either additional non-intermittent installed generation (Farhat & Salvini, 2022) or on additional means such as demand side management (Balasubramanian & Balachandra, 2021) or storage (Zsiborács, et al., 2019).

The second challenge of integrating VRES is the integration into the electricity grid (Chen, Mcelroy, Wu, Shu, & Xue, 2019). A significant part of the RES is connected to the distribution network, which implies a reinforcement of the network equipment. Indeed, the distribution network is originally supposed to lead power flows from the transmission network to the final consumer. With this new production connected to the grid, bi-directional flows have to be taken into account in addition to the increase in distributed capacity. The network reinforcements are costly and this cost can be reduced by replacing network investments by means enabling a discharge of the network when necessary, like demand flexibility or distributed production curtailment.

Finally, the third challenge concerns the profitability of conventional power plants. If the market is in equilibrium and RES are introduced with out-of-market financing, e.g., feed-in-tariffs, this can pose a problem for the long-term profitability of conventional power plants, based on fossil fuels, especially if coupled with carbon pricing (Nuno Carvalho Figueiredo & Patrícia Pereira da Silva, 2019). Indeed, the economic precedence implies that REs and nuclear, with the lowest marginal cost, are called first, shifting the call of technologies with higher marginal cost, notably semi-base and peak technologies, to times of higher demand. This is problematic because it would lead to a decrease in investment in conventional means, which become less profitable, but are nevertheless necessary for the supply-demand balance. In this context demand response becomes even more relevant to tackle the VRES variability and take part in the supply-demand balance.

VRES therefore generate significant technical challenges for the power system, requiring new tools. However, decarbonization also provides opportunities: via the electrification of uses, it takes us out of dependence on fossil fuels, allowing greater energy independence and bringing flexibility to the power system.

The general context of this thesis is therefore the one of a changing European electricity system, with a strong impact on market mechanisms. Strongly marked by the need for decarbonization, the evolution of the energy mix towards more RE impacts the management of the supply-demand balance and the market mechanisms. The latter are adapting to the change in fundamentals, for example the implementation of the capacity mechanism becomes even more necessary with VRES and increased uncertainty on fuel prices. They are also gradually integrating demand management. Indeed, the demand for electricity is evolving towards uses that can benefit the power system and partly compensate for this evolution of the energy mix towards more variable and uncertain production. These various exchanges are made possible by the transmission and distribution networks, whose capacities are decisive in allowing security of supply.

2 Flexibility

2.1 Definition and scope

The energy transition, by increasing the share of VRES in the electricity production, has made the supply-demand balance more complex. More flexibility is needed in order to cope with the variability of production while maintaining security of supply. « *Flexibility in power systems is the ability to provide supply-demand balance, to maintain continuity in unexpected situations, and to cope with supply-demand uncertainty* » (Impram, Nese, & Oral, 2020). This definition expresses the usefulness of flexibility from the point of view of the power system. Indeed, the need for flexibility comes from the constraint “ $P = C$ ” (production equals consumption) which must be verified at each moment and at each location. Variations in consumption as well as in non-controllable production imply that controllable means can react to these more or less rapid and random variations. With the increasing

share of VRES in the electricity mix, flexibility is an increasingly valuable asset as it allows to compensate for this increased variability.

More specifically, flexibility is defined on different time scales, from network planning and the determination of investments in long-term generation capacities (several decades before real time), to the triggering of protections on the network (a few seconds before real time), to short-term balancing operations (a few hours to a few minutes before real time) (IRENA, 2018), and on different geographical scales, from local flexibility markets (still very underdeveloped) for the management of congestion to the European wholesale markets (Heggarty, Bourmaud, Girard, & Kariniotakis, 2019). Therefore, on the one hand, there is flexibility for the network, to cope with congestion and hazards on the network, and on the other hand, there is flexibility for the supply-demand balance, so that consumption is covered by production at each moment. The challenge is to combine these two flexibility uses in a least-cost optimal manner for the electricity system.

Another definition of flexibility is given by (Heggarty, Techno-economic optimisation of the mix of power system flexibility solutions, 202) : “the power system's ability to cope with variability and uncertainty”. It insists on an important differentiation in the need for flexibility: variability, represented by cyclical variations in net consumption, typically on annual, weekly and daily timeframes, and uncertainty, which also plays a role on various timeframes, but whose importance in relation to variability is typically seen in the long term, with the possible evolutions of consumption and of the European production assets, and in the very short term on an intraday basis, due to forecast errors.

In concrete terms, what can be called “flexible means”, i.e. the technical means of providing flexibility to the power system, can be classified into four categories (Lund & al, 2015) :

- Generation means: all generation means bring flexibility to the power system, whether for the network (with redispatching) or for the supply-demand balance. Most of the generation resources participate in the reserves and the balancing mechanism, and can be modulated upwards or downwards more or less quickly. The most flexible generation resources will be the peaking resources, i.e. gas turbines and generators: they are characterized by fast and low-cost start-ups and the possibility to modulate their power rapidly. The least flexible means are the base means, nuclear and coal.
- Demand: consumption can be modulated upwards or downwards, at least to a certain extent, by tariff incentives or more direct control (see 2.2).
- Storage: the characteristics are different according to the technologies, which can therefore meet different needs. Thus, some storage systems are adapted to daily cycles (typically batteries) while others can be used for seasonal storage (PSH (Pumped-Storage Hydroelectricity) in some countries, Power-to-gas-to power). This is accompanied by different efficiencies (and therefore different cycle costs) as well as other characteristics such as a faster mobilization time for batteries than for thermal storage or compressed air energy storage for example (Alizadeh, Moghaddam, Amjady, Siano, & Sheikh-El-Eslami, 2016), which will affect their ability to participate in system services.

- Network elements: whether it is the interconnections between border countries, which reduce the need for national capacity, or equipment such as phase-shifting transformers or circuit breakers, which protect the network in case of contingencies and manage congestion, the network elements also contribute to the flexibility of the power system.

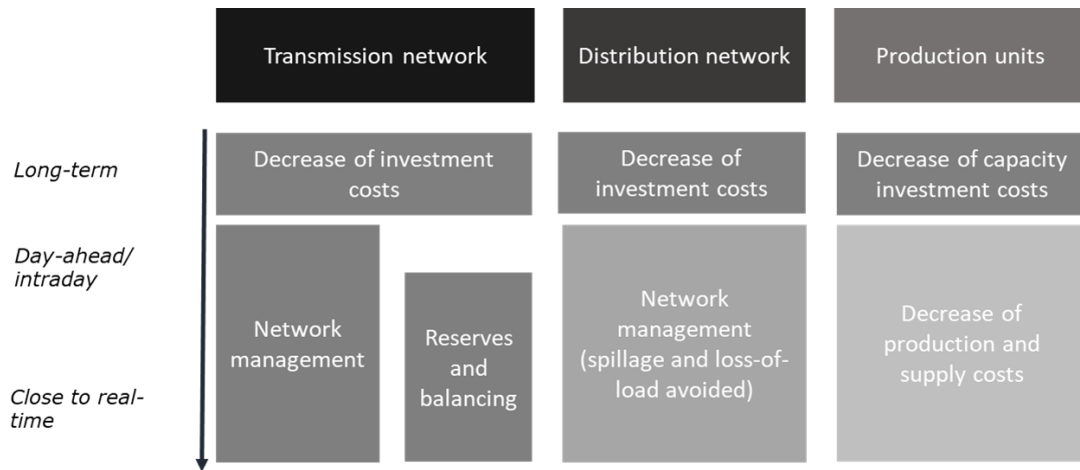


Figure 1- 14 The possible uses of flexibility for the network and for production in the more or less long term

In this manuscript, we focus on flexible demand side means, which is the one developed most recently (Rinaldi, Yilmaz, Patel, & Parra, 2022), with a more precise view of the contributions and impacts on generation costs, distribution networks and adjustment.

An overview of the applications of demand side flexibility for both the grid (transmission and distribution) and production is presented in Figure 1- 14, according to the time frame of the need covered by the use of flexibility.

In the long term, flexibility can reduce investments, whether in grid reinforcement or in generation capacity. For example, interconnections between European countries can be considered as flexibility that decreases the need for investment in generation capacity, because by allowing the pooling of generation from neighboring countries that do not have the same needs at the same time, it decreases the level of generation capacity needed in each country individually (Maeder, Weiss, & Boulouchos, 2021). Load shedding also replaces generation capacity if consumption is repeatedly shed at peak. For network investments, instead of reinforcing network equipment to absorb higher consumption, load shedding can be used on punctually during congestion situations.

In the short term, flexibility allows better integration of VRES by adapting to its variability, either with resources that can quickly modulate their production, or again with demand management or storage. In the very short term, flexible means also contribute to reserves and balancing. For the transmission and distribution networks, flexibility allows to manage congestion, for example with wind generation capping, redispatching or demand management. For the distribution network, local markets that use flexibility to manage congestion are developing in Europe and mainly concern wind capping (e.g. Enera). Some experiments are focusing on demand-side flexibilities, but do not concern the same types

of congestion. As there is no alternative to the use of this flexibility at the moment, congestion on the distribution network leads to loss-of-load, so the use of demand-side flexibility here mainly allows to avoid loss-of-load.

2.2 Demand flexibility

Demand flexibility can be distinguished according to the type of use: industrial, residential and tertiary.

2.2.1 Industrial demand flexibility

Industrial demand flexibility concerns large volumes of demand linked to industrial processes. Load shedding by industrial operators directly connected to the transmission system is a first part of this industrial demand flexibility. In France, for example, such load shedding is carried out within the framework of interruptibility contracts or directly via an industrial load shedding contract with a load shedding operator.

Electrolysis is a form of industrial demand flexibility that is currently the subject of growing interest and could develop significantly. European industrialists envisage a production capacity of 25 GW in 2025 (Hydrogen Europe, 2022). With electrolysis, electrical energy is transformed into hydrogen. The electrolyzers break down the water molecules with the help of electric current to obtain oxygen on one side and hydrogen on the other. This gas can then either be used directly as a source of energy, particularly in the transport sector, or be used as a storage medium and then converted back into energy. (RTE, 2020b) presents two ways of using electrolysis for decarbonation:

- On the one hand, decarbonizing existing uses: the current uses of hydrogen in industry but potentially also heavy mobility. In the medium term, hydrogen could also supply the existing gas network in substitution of fossil gas (within a certain limit) (Andrade, Selosse, & Maïzi, 2022).
- On the other hand, hydrogen could contribute, under certain conditions, to the balance of the electrical system by providing a storage and de-storage solution (RTE, 2022) (Association négaWatt, 2020) (power-to-gas-to-power principle).

By 2030-2035, the challenge of developing low-carbon hydrogen is part of a decarbonization process which is in line with the first way of using electrolysis. By this time, the use of hydrogen as a storage medium is not necessary to diversify the electricity mix and to accommodate the volumes of REs planned by the PPE (Pluriannual Energy Plan, in French “Planification Pluriannuelle de l’Energie”). However, the development of electrolysis could be significant in the future if green hydrogen benefits from a support mechanism. In this case, the flexibility provided would be that of consumption shedding.

The electrolysis units are small installations that could be connected to the distribution network, but they can be aggregated into larger units to achieve economies of scale. This is the case for the current projects. For now, the two electrolyser connection projects in France (Dunkirk and Port Jérôme) will be made to the 225kV transmission grid.

2.2.2 Residential/Tertiary Demand Flexibility

The flexibility of residential and tertiary demand corresponds to distributed flexibility, i.e. flexible means connected to the distribution network.

2.2.2.1 *Flexibility with low impact on the consumer: displaceable consumption*

The literature differentiates implicit demand flexibility from explicit demand flexibility (Freire-Barcelo, Martin-Martinez, & Sanchez-Millares, 2022) (Zenebe Degef, Bakken Sperstad, & Sæle, 2021). Implicit flexibility corresponds to consumption that can be shifted by pricing incentives. Thus, an adequate tariff, as developed previously, already allows the consumer to act on his electricity consumption in order to save on his bill if he chooses a tariff option that allows him to do so. For example, domestic hot water heated in hot water tanks controlled by the peak/off-peak signal is an implicit demand flexibility. Explicit flexibility corresponds to consumption that can be moved more directly, via a more targeted signal, as is the case in some EV (Electric Vehicle) experiments (Degefa, Sperstad, & Sæle, 2021).

The displaceable consumption corresponds on the one hand to the means of storage: water heaters, charging of electric vehicles and to a certain extent heating, thanks to thermal inertia. For these uses, the energy drawn from the network is not immediately useful for its use and is stored. The time at which the energy is drawn from the grid is therefore not completely dictated by the consumer's needs, because the time at which the energy is drawn from the grid does not correspond to the time at which it is actually used. This is what allows flexibility. Flexibility is therefore limited by the user's needs: for example, the user needs to have enough energy in the battery of his vehicle when he undertakes a journey, but does not need his vehicle to recharge as soon as he connects it to the grid. All these uses can therefore be moved within the constraints of effective use without the consumer noticing any significant difference in the service provided. It does not matter whether the vehicle has finished its recharge at 10 am or at 5 pm for a journey at 6 pm. A storage water heater delivers hot water when the consumer needs it. In a well-insulated room, turning down the heat by one degree for one hour can be done without impacting the consumer's well-being. Of course, these uses can only be shifted to a certain extent, which must be respected so that the quality of the service provided is indeed the same as without shifting consumption.

On the other hand, uses for which the need is not immediate can also be displaced by the consumer (washing machine, dishwasher). For these uses, the time of energy withdrawal from the network corresponds to the time of actual use of this energy. Flexibility is enabled by the consumer's action, who chooses the right time to take advantage of the service. The impact on consumer's well-being is therefore already greater, since an action by the consumer is necessary.

These different displaceable uses have been identified for a long time since they are one of the driving forces behind the implementation of the peak/off-peak tariffs in 1960. A finer control or a larger share of consumption responding to tariff signals would in theory be possible thanks to the deployment of the Linky meter in France and more generally to the possibilities offered by digitalization. However, these models are struggling to develop, for reasons that seem to be both economic and societal: the current gains do not seem to be sufficient to overcome consumer reluctance to these models. The growth of flexible demand for these uses may therefore come from: greater economic interest, greater acceptance of driving, or an increase in the uses in question. Thus, EV is very promising because this use is still not very developed but is growing rapidly, which justifies the particular interest that we will give to it in this manuscript.

According to RTE projections, more than 50% of individual vehicles in France will be electric in 2035 (the date set by the European Commission for banning the sale of combustion engine vehicles), compared with about 10% today (RTE, 2019a). Most of the prospective scenarios envisage a significant increase in this technology, with the lowest scenario, the "RTE low" scenario, being positioned around 7 million EVs by 2035 and the highest, "Green growth" of the PFA (car manufacturers' lobby, "Plateforme Automobile"), slightly below 17 million (Figure 1- 15).

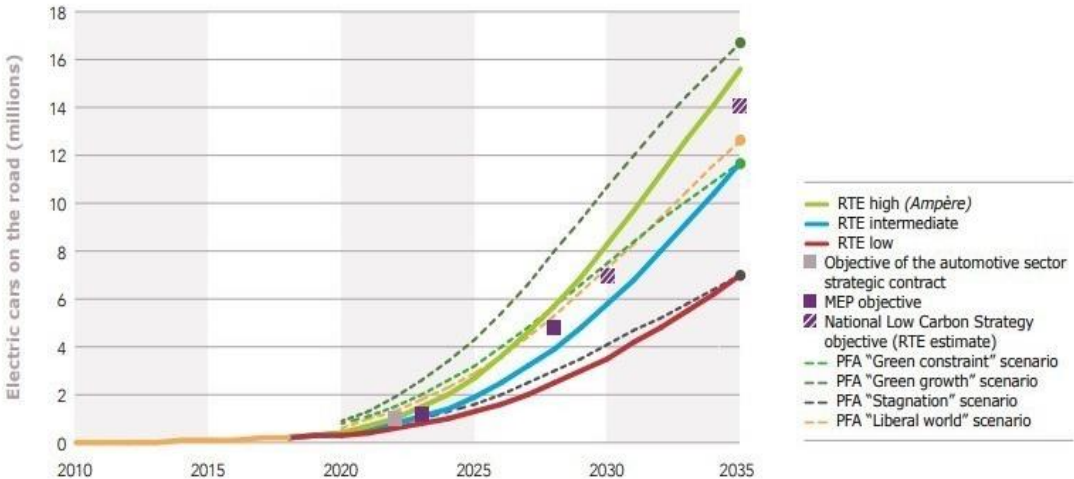


Figure 1- 15 Projections of the number of electric vehicles (100% electric and hybrid) by 2035 according to several scenarios (RTE, 2019)

The impact of replacing combustion vehicles with EVs on greenhouse gas emissions is significant, even taking into account the complete analysis of the vehicle's life cycle, from the construction of the batteries to their recycling: RTE estimates that the carbon footprint of an EV in France is four times smaller than that of a combustion vehicle. It should be noted that this carbon footprint is very specific to France, however, as it is highly dependent on the energy mix. France has one of the most carbon-free electricity mixes in Europe, thanks to the combination of nuclear and REs, and the EV will have a much smaller impact on CO2 emissions in countries like Germany or Poland. The development of EVs is therefore an important issue, and this sector is supported in France by purchase subsidies to

compensate for the high cost of access, as an EV is on average €10k more expensive than a combustion vehicle of the same model. However, this access cost is offset by a much lower consumption cost. The EV is therefore an economic and ecological technology in France and an important asset for the energy transition.

This storage medium can both draw and inject energy into the electrical grid. The EV thus allows for a double flexibility. On the one hand, the EV allows flexibility in the choice of the time of recharging. On the other hand, the EV can function as a storage medium and the energy stored in the battery can be re-injected into the grid, this is the "Vehicle-to-Grid" (V2G). Consumers can use the flexibility of their vehicles directly or via an aggregator by offering several services: on the one hand, to manage congestion on the distribution network, which they themselves can contribute to worsening (Gonzalez Venegas, Petit, & Perez, 2021) (Knezović, Marinelli, Codani, & Perez, 2015), or on the transmission network (Staudt, Schmidt, Gärttner, & Weinhardt) but also to participate in balancing services (Peng, Zou, & Lian, 2017) or markets (Papadaskalopoulos, Strbac, Mancarella, Aunedi, & Stanojevic, 2013). The amount of flexibility that this could represent is rather uncertain, since on the one hand it depends on the growth opportunities of electric vehicles and on the other hand on the willingness of drivers to participate in these mechanisms of control and valuation of their charging (Kubli, Loock, & Wüstenhagen, 2018). While control would a priori allow gains on the consumer's electricity bill (a few tens of euros per year (Gadea, Marinelli, & Zecchino, 2018) (FRED project, 2021)) for the consumer, the lack of confidence in this technology and thus the fear of not having one's car charged at the time one wishes to use it can be a major brake on the development of flexibility services offered by the EV. Thus, at present, only 37% of French people who own an electric vehicle have a system for controlling the charging of their vehicle (Enedis, 2020).

2.2.2.2 Consumption flexibility with a significant impact on the consumer

A significant part of the consumption is not displaceable, in any case not without impact on the well-being of the consumer. This is the case, for example, for lighting, cooking and a large part of heating. The impact on the consumer can be compensated via a cost, with paid load shedding. This so-called "diffuse" load shedding can be valued and managed by load shedding operators. In France, the capacity of diffuse load shedding is estimated at 3.3 GW (RTE, 2020a).

In cases of great tension on the electricity network, particularly when there is a shortage of production correlated with a high consumption peak, differentiated load shedding may be considered. This involves temporarily cutting off the power supply to electrical uses that are not considered to be a priority by consumers, and connected to differentiated outlets. The fact of consuming less during high voltage periods would result in a more favorable tariff, for example with a lower cost of the power share. The characteristics of the different means of demand flexibility are presented in Table 1- 1.

	Fixed costs ⁹	Variable costs	Location	Development
Industrial load shedding	Interruption facility	Process interruption	Transmission	Fairly high
Electrolysis	-	H ₂ not produced	Both	Low, very high prospects
EV	Smart terminal for control	Low if constraint taken into account	Distribution	Low, high prospects (tariff signals or control)
Heating	Box, if control	Low if limited	Distribution	Low when controlled, higher with tempo tariff
Water heaters	Equipped tank, box, if control	Low if constraint taken into account	Distribution	High in peak/off-peak hours
Other displaceable domestic uses	-	Displacements by consumers	Distribution	Average in peak/off-peak hours
Paid load-shedding	Box	Loss of comfort	Distribution	Low
Differentiated load-shedding	Sockets differentiating uses	Loss of comfort	Distribution	Only experiments

Table 1- 1 The different means of demand flexibility in France

A large part of the demand flexibility means is located on the distribution network. This distributed flexibility can create additional constraints but is also a way to manage congestion in a changing network.

3 Taking into account local network constraints in the overall European supply-balance optimization

Distributed flexibility is located on the distribution network and therefore seems to be an interesting tool for managing distribution network constraints. These constraints can be caused by high production inflows or by high consumption, the flexible part of which can be displaced or cancelled. The management of these constraints with distributed flexibility might be more economically efficient than straight-up network reinforcements.

Distributed demand flexibility can also serve a supply-demand balance purpose. By taking advantage of moments of low-cost production, it can decrease the cost of demand supply.

These two aims of distributed flexibility can be contradictory and therefore, an economical optimization of its use for the electricity system is necessary.

This section focuses more specifically on the distribution network. Its evolution in the context of the insertion of VRES is described (1.4). This evolution will make the need to manage congestion on this network more imperative, and this issue is therefore explained next (3.1). This evolution is also accompanied by a new regulatory framework for the DSO (Distribution System Operator), which is

⁹ Here we consider the fixed costs required to enable demand flexibility. Sometimes, the same use can have several types of flexibility, for example hot water tanks can have tariff signals or be controlled. The tariff signals only require a tank receiving the signal whereas the control requires a specific control box.

described in the next section (3.2). Demand flexibility is at the heart of this evolution since, while it increases the constraints on the distribution network, it can also be a way to limit them. The relevance of using distributed flexibility for congestion management on the distribution network is therefore discussed next (3.3). This use of distributed flexibility for congestion management is finally explored in the last section (3.4).

This section describes in a general way the networks and their constraints, but focuses on the French case when necessary.

3.1 Congestion management by the DSO

From a technical point of view, congestion on the transmission or distribution network occurs when a line or a transformer is overloaded due to an excessive current flowing through it (Bachtar Nappu, Arief, & Bansal, 2014). An equipment can withstand an overload, but it must be limited in amplitude and duration (the greater the amplitude of an overload, the shorter it must be). To avoid these overloads, which can then cause incidents on the network due to the deterioration of the equipment and pose a risk to safety because of the expansion of the lines due to heat, there are several mechanisms which are historically mainly in the hands of the TSO (Hith & Glismann, 2018).

The first way to manage these congestions is re-dispatching (Hith & Glismann, 2018). It is historically used by the TSOs: the TSO will modify the generation schedule of some units, upwards (increase generation) and downwards (decrease generation) to modify the network load plan, while maintaining the same overall generation level. This re-dispatching therefore impacts the generating units connected to the transmission system. This approach is costly because then the TSO will compensate the units whose action plan is thus modified.

There are also less costly ways for the TSO to manage congestion on the transmission system. For example, topological modifications can also be used by TSOs, as the extensive looping of the transmission network allows the path of power flows to be modified to some extent. Similarly, transmission system equipment such as phase-shifting transformers can also manage congestion by increasing or decreasing the power flow through them (Little, 2022).

Historically, DSOs have had few means of managing network congestion. As the distribution network is not or only slightly looped and the means of flexibility on the distribution network are historically almost non-existent, the consequences of congestion are outages at the end consumer, i.e. loss-of-load. Thus, the only lever available to the DSOs for managing congestion on the distribution network was the so-called “it and forget” approach (Ruester, Schwenen, Batlle, & Pérez-Arriaga, 2014), i.e., network reinforcements. The network must adapt to the growth of uses in normal and degraded situations, i.e. with the loss of a major equipment.

With the connection of more and more decentralized generation to the distribution network and the increase in demand for electricity, particularly from recharging electric vehicles, new constraints are appearing on the distribution network as well as new perspectives for congestion management.

Distributed RES can cause overloads or power variations beyond the authorized limits on equipment. Increased withdrawals may require costly reinforcements to the distribution system. Congestion management by the DSO is then considered more actively in order to manage increasing constraints while using the flexibility potential (eurelectric, 2013). Demand-side flexibilities are still very little used for congestion management on the distribution network. In France, the call for tenders experimented by Enedis would allow both to reduce investments in the distribution network and to manage congestion on it. Currently, in Europe, local flexibility markets for congestion management on the distribution network are being tested in limited areas.

3.2 The new role of the DSO: status of the regulations

The traditional roles of the DSO are twofold and have been described in the previous sections: planning the development of the distribution network and managing the network (Nouicer & Meeus, 2019). These roles are not performed in the same way in all member states, and the technical diversity that we mentioned earlier is combined with regulatory diversity in Europe. However, the trend is towards a form of regulatory harmonization with the increase in European regulation.

As far as network planning is concerned, not all DSOs are required to publish regular development plans. In France, before the implementation of the European Directive 2019/944 of June 5, 2019 on the internal electricity market (European Commission, 2019) into French law, they were simply approved by the CRE (European Commission, 2015), while in other countries they were already regularly published.

On the grid management side, prior to the implementation of the Clean Energy Package (CEP), the regulations regarding the use of distributed flexibility for congestion management on the distribution grid were not standardized at the European level and there were no clear rules even at the national level. In any case, this use of flexibility by the DSO is still very marginal (Nouicer & Meeus, 2019).

In addition to these traditional roles, which are evolving with the decentralization of generation resources, the DSO now has new prerogatives: the installation of charging stations for electric vehicles, and the management of the data necessary for the operation of electricity markets in which demand-side flexibilities can participate (Nouicer & Meeus, 2019). Another important task for DSOs is to set up the information exchange with the TSO necessary for their coordination (CEDEC, E.DSO, ENTSOE, eurelectric, & Geode, 2021).

In order to supervise the evolution of the historical roles of DSOs and to allow the development of their new roles, the POC has given several guidelines for DSOs.

The development of the distribution network must be done in a transparent manner and in coordination with the TSOs (European Commission, 2019).

As far as congestion management is concerned, the DSO can use the flexibility present on its network in a market logic and in coordination with the TSOs. However, he can only use them for local congestion

and non-frequency system services. The TSOs remain the only ones who can manage balancing with frequency system services (reserves) (European Commission, 2019). The market design for the provision of these flexibilities to TSOs is the subject of a large literature and a variety of experiments have been conducted in Europe, with few concrete implementations (Centre on Regulation in Europe, 2021). For the TSO association ENTSO-E, the creation of local flexibilities markets may however “hinder the completion” of a European balancing market that takes into account distributed demand flexibilities (ENTSOE). According to this association, the development of grid digitization solutions should not be left to the DSO alone and in general the cooperation between the DSO and the TSO should remain a priority.

Regarding the new roles of the DSO, the CEP asks DSOs to promote the development of distributed flexibility. The DSO must be a facilitator of the valuation of distributed flexibility on the markets. However, it cannot itself own, develop or operate charging infrastructures or storage facilities.

This regulatory framework will probably evolve in the future, with the feedback from the TSOs and DSOs of the member states as well as from the regulators. The association of European DSOs “E.DSO” is in favor of a regulatory “sandbox” that would allow DSOs to experiment with market design and thus foster innovation (E.DSO, 2020). Experimentation in different European countries would also allow the regulatory framework to adapt to the multiplicity of local situations.

DSOs are therefore evolving in a framework that is still not well defined, but which allows for experimentation, complementing the existing literature, in order to progressively evolve this framework towards a more precise regulation adapted to the issues at stake.

3.3 The optimal trade-off between distributed flexibility provision and network reinforcement to ensure the demand and supply balance at least cost

Managing congestion on the distribution network and limiting reinforcement costs are only part of the possible value of distributed flexibility. Distributed flexibility has multiple interests for the system, and the services they can provide are sometimes in competition. The value of flexibility for the wholesale markets, i.e. to reduce production costs, is studied in the literature, especially by the energy industry, and compared to the value of flexibility for the distribution network.

First, the value of distributed flexible assets for the distribution network is not negligible, but is very heterogeneous. In France, various studies show that the value of flexibility depends highly on the type of flexibility and the location. As far as the location is concerned, according to Enedis and E-cube, the value of flexibility for the distribution network is up to €24/kW per year of postponement of the investment, but even (Enedis, 2017b) (E-cube, 2017).

Most of the value lies in the optimization of the distribution network expansion planning for the connection of RE. This value is only for the medium voltage network; the value of flexibility for the low voltage is close to zero. With regard to the type of flexibility, among different kinds of flexibilities, RES

curtailment is at the center of interest for networks because of its high value to avoid reinforcement costs.

Valuations may vary according to assumptions and time periods: the value of curtailment represents 250M€ of benefits per year for both the distribution and the transmission network according to Enedis (Enedis, 2021a). It is 500M€ for the transmission alone according to RTE (RTE, 2019b).

However, some reports find that distributed flexibility has even more value for the decrease of production operational costs. A French demonstrator, Greenlys shows the value of flexibility rather lies in the minimization of production operational costs i.e. the optimization of the supply-demand balance: the value of consumption curtailments in the Greenlys demonstrator is about 7500k€/year for production, whereas the value of consumption curtailments for avoiding reinforcements is about 500k€/year (Battegay, 2015).

The different estimated flexibility values are summarized in Table 1-2.

The value for the network entails all the gains that the considered flexibility (in the Scope column) has enabled in the management of the network (transmission or distribution), whether it is for the congestion management or in terms of avoided reinforcement costs. The value for supply-demand balance is the operational costs savings enabled by the use of the flexibility (in the Scope column).

Study	Scope	Value for the network	Value for supply-demand balance
(Enedis, 2021a)	RES connection in France	Up to 250M€ to 2035 (distribution network)	Not addressed
(Battegay, 2015)	Load shifting in the "Greenlys" demonstrator	500k€/year (distribution network)	7500k€/year
(E-cube, 2017)	Connection agreements, market-based procurement in France.	24€/kW/year (distribution network)	Not addressed
(RTE, 2017)	RES curtailment and smart-grids in France	48M€/year (transmission network congestion management)	756M€/year
(RTE, 2019b)	RES curtailment in France	500M€/year (transmission network reinforcement costs avoided)	Not addressed

Table 1- 2 Value of flexibility for the network reinforcement costs and generation costs according to various French studies

The comparison of these studies points out that the value of RES curtailment for the network reinforcement is relatively high (up to 500M€/year according to RTE (RTE, 2019b)) but that for consumption flexibility, the value rather lies in generation costs savings on the European wholesale

markets they are involved in. For ancillary services, the value of consumption flexibility is very high (€900/year for a single electric vehicle), however, there is very little need, as less than 2% of total production is for ancillary services, thus this would concern only a very small portion of the EV fleet (RTE, 2019a).

Thus, if distributed flexibility naturally tends to be used by the DSO, because of its location on the distribution network and because it tends to aggravate or create constraints on it, it can also be used in a more centralized way for gains from a global system point of view that may be higher.

Managing congestion on the distribution network by using distributed flexibilities requires coordination with market players such as flexibility aggregators, which can use flexibility in several ways, especially on the wholesale markets, and with the TSO, which can use flexibility to manage congestion on the distribution network and for system services and balancing.

3.4 Coordination of congestion management by the DSO

Coordination for flexibilities must be done at different timeframes: in the long term, i.e. from a few years to a few months in advance, it must allow distribution system operators to avoid reinforcements or schedule maintenance (Verzijlbergh, De Vries, & Lukszo, 2014) (Philipsen, de Weerd, & de Vries, 2016) while limiting the potential undistributed energy; in the short term, i.e. in D-1 or in D, it must allow arbitration between the use of flexibility for the network and other services.

Congestion management only on short-term can be costly and risky, as potentially a lot of energy must be displaced on short notice, or flexible capacities may be insufficient. Thus, in the short-term, congestion management can be inefficient and lead to loss-of-load. Long-term congestion management is sometimes necessary to reach the right level of investment or to give signals to less responsive flexibilities (responding to tariff signals but not to the spot price).

3.4.1 Long-term coordination for congestion management

Two long-term coordination for congestion management are studied in this section. Long-term local capacity allocation auctions are based on distribution grid congestion forecasts: it is easily applied to the distribution grid. Long-term localized pricing signals guide electricity use with local tariffs. We will focus on the long-term pricings that have a localized component, but not necessarily on the distribution network scale because such cases are rare.

There are two types of long-term local capacity allocation auctions, auctions for flexible capacity and auctions for distribution network capacity. With auctions for flexible capacity, the DSO pays flexibility aggregators for the long-term reservation of their flexible capacity. The DSO establishes contractual relations with flexibility producers to have access to their flexibility in case of need. The aggregators are the sellers and the DSO the buyer. Inversely, in auctions for distribution network capacity, the DSO announces the forecasted network capacity limitations far from real-time, and flexibility providers bid for the amount of capacity they need. Generally, it seems that auctions for distribution network

capacity target flexible demand and usually EVs, whereas auctions for flexible capacity target both flexible production and demand. The auctions for flexible capacity are actually experimented in Europe whereas auctions for distribution network capacities has no practical implementation.

Concerning experimentation, Enedis, the French DSO, experiments since March 2021 local auctions for long-term flexibility contracts (Enedis, 2021a). The winning tenders are paid a fixed share for the capacity reservation and a variable share when the flexible capacity is indeed used by the DSO. If the reserved flexible capacity is not available for the DSO, financial penalties are paid by the aggregator involved. In Denmark, a platform, Ecogrid 2.0, tests this coordination mode, with the DSO paying for flexibility owners to limit the use of the grid at time slots announced from 1 to 12 months before real-time (Heinrich, Ziras, Syrri, & al., 2020).

Concerning auctions for distribution network capacities, the literature mainly focuses on auctions design, particularly on temporal management of capacities (Verzijlbergh, De Vries, & Lukszo, 2014) (Philipsen, de Weerd, & de Vries, 2016).

Also, **long-term regulatory local pricing mechanisms** have been put in place in various countries to incentivize the siting of production means and consumption patterns across the transmission network, generally in case of structural congestion. Few of these mechanisms are also applied to the distribution network. Also, these signals usually concern injection, but can be extended in some cases to demand flexibilities, as in the case of the capacity mechanism. For the siting of production means, four different long-term local pricing mechanisms are currently in use in various countries: local capacity markets, localized network connection tariffs, localized renewable feed-in tariffs, and localized grid tariffs (Eicke, Khanna, & Hirth, 2020).

For capacity markets, few examples of localized component exist but they do not concern the distribution grid. In France, there is a local capacity mechanism for a unique CCGT plant under construction in Brittany, a region that is lacking production capacities (Marty & Reverdy, 2017).

Localized network connection tariffs are quite popular. In France, the S3REnR (see part 3.1) is an example of such a mechanism: a consultation of RES projects leaders allows to elaborate a vision of network reinforcement needs and costs; then, the connection tariff depends on the region where the plant is to be installed and the deep connection costs are equally shared between all RES projects connected to a same substation.

Renewable support mechanisms are rarely localized, but one example is the German system in which onshore wind adjustment factors for auctions depend on the wind speed of the region. In (Grashof, Berkhout, Cernusko, & Pfennig, 2020), these specific scheme is evaluated in the first years of deployment and the results are disappointing, as in 2018, bids have fallen below the auction volumes. There are a few applications of a grid injection tariff to the distribution network, as in Norway, where energy-based tariff for production feed-in is reduced in certain areas of both transmission and distribution networks for new productions, until the production capacity goal for this region is reached (Econ Pöyry, 2008).

The DSO can therefore use flexibility to avoid network reinforcements via long-term mechanisms. Today, the main mechanism tested is the flexible capacity auction. The adaptation of the long-term signals used for the transmission network could also be studied.

3.4.2 Short-term coordination

Short-term coordination is at the core of the work of this thesis. Chapter 2 explicates the fundamentals of the need for a coordination between the global short-term market flexibility activations and local constraints. The impact of a coordination mechanism on overall system gains is analyzed. Chapter 3 tests a coordination mechanism, filtering, in the short-term market sequence.

Short-term coordination, i.e. in D-1 or D, is an additional resource to optimize flexibility provision. This section proposes a classification of these coordination modes for the short-term operation of the distribution network with distributed flexibilities.

Short-term coordination mechanisms are happening from day-ahead to real-time. These mechanisms can be classified into two categories: price coordination and volume coordination. With price coordination, a price signal is sent to flexibility aggregators to prevent congestion. Volume coordination is the physical flexibility activation restriction, either because flexibility is activated by the DSO in local flexibility markets, or because the DSO filters flexibility activations that threaten network safety.

3.4.2.1 Price coordination

Price coordination is in theory a perfect coordination mode, allowing optimization both at short and long term. With price coordination, market actors pay a real-time congestion price, via a dynamic tariff. The literature that addresses price coordination relates to nodal network architectures. In this literature, in order to limit the demand which congests the distribution network, the DSO uses a localized price signal, by adding a congestion cost to the bids on the distribution network or subtracting this cost from the requests.

On the example of Figure 1- 16, we represent a market session with only one flexibility bid concerned by congestion (we assume this flexibility bid originates from the congested area). The congestion cost on the flexibility bid decrease the overall clearing price as well as the volume of accepted offers, which drops below the network capacity limitation. This congestion cost is equal to the cost of managing congestion by the DSO (by increasing local production or by cutting other flexible demands at this node via a local market, for example). The lack of flexible capacity at a node of the distribution network will often lead the DSO to put a cost corresponding to that of the loss-of-load. In practice, this cost will be such that the relevant bid or offer will have very little chance of being accepted. If liquidity is sufficient however, price coordination may allow the aggregator to maintain its bid, while allowing the induced congestion to be managed by other means.

This congestion cost can be the result of a co-optimization in a theoretical framework of extensive information exchange between stakeholders. Network constraints are directly taken into account in a global optimization problem, leading to intensive data exchange (SmartNet, 2016) (Le Cadre, Mezghani, & Papavasiliou, 2018). Of course, it is an ideal coordination mode that is not achieved otherwise than in theoretical cases. Intermediate variants are described in the literature with extensive DSO's involvement in the aggregators' planning, pushing towards co-optimization (O'Connell, et al., 2012) (Bach Andersen, Hu, & Heussen, 2021) (Verzijlbergh, De Vries, & Lukszo, 2014) (Askeland & Korpas, 2019).

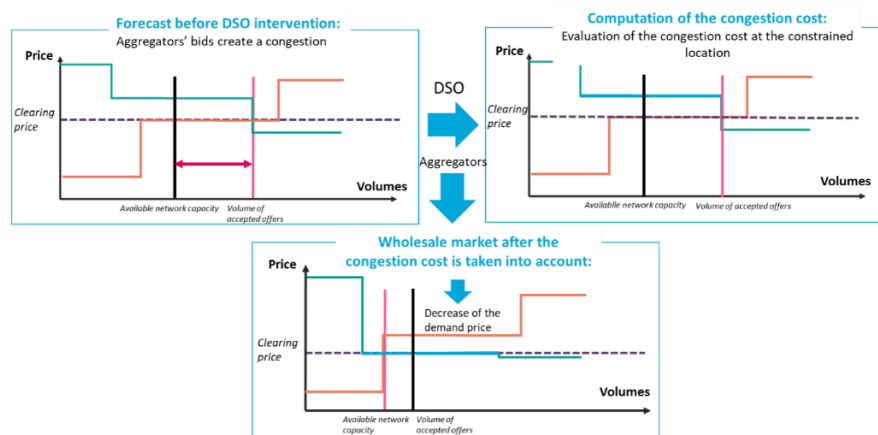


Figure 1- 16 Market operation of the price coordination mechanism

In general, the level of information exchange between DSO and aggregators to be expected for this mode is quite high, which makes the mechanism difficult to implement and sensitive to uncertainties. The reliability depends on the computation of the congestion cost by the DSO, based on the forecast of flexible demand. Thus, price coordination with DSO anticipation is not as reliable as capacity limits (volume coordination) as it does not guarantee the respect of the physical limitation. In the literature variations are proposed to cope with uncertainties, but add complexity (Hanif, Massier, Beng Gooi, Hamacher, & Reindl, 2017) (Shen & Wu, 2022) (Silva, et al., 2018). Price coordination is a short-term mechanism which is nevertheless valuable as a long-term localization signal. The short-term computation of a dynamic tariff leads in theory to a long-term optimization of the network reinforcement needs. However, if we compare price coordination for distribution network to its transmission network counterpart, nodal pricing, its long-term efficiency needs to be mitigated. Indeed, nodal pricing's long-term efficiency would be for instance insufficient without financial transmission rights (Petropoulos & Willems, 2020).

3.4.2.2 Volumes coordination

Volumes coordination encompasses both local flexibility markets and filtering, which is developed in 3.5.3. We consider local flexibility market as a volume coordination because the main signal of coordination is the volume of re-dispatching needed by the DSO to respect available network capacity.

The market operation of a local flexibility market is described in Figure 4. Aggregators submit their bids either to the wholesale market or to the local flexibility market. The DSO can then manage the congestion caused by the activation of constraining bids on the distribution network with the bids on the local flexibility market.

There are 18 European local flexibility market initiatives (Valarezo, et al., 2021) which configurations are different from one another, notably depending on the local needs (Dronne, Roques, & Sagan, 2020). However, root characteristics are the same across these markets. (Radecke, Hefele, & Hirth, 2019) lists them as follows :

- Its objective is distribution networks' congestion management;
- By impacting the dispatch of flexible assets;
- With voluntary participation;
- And a remuneration that is based on market participant's bids.

(Radecke, Hefele, & Hirth, 2019) insists price formation is often regulated, limiting the incentive for participation, and that these markets are a complement to other existing congestion management mechanisms. We can argue that it's the lack of incentive for participation that generates a lack of liquidity, making these markets not efficient enough to function on their own.

For example, in the SmartNet project, which aims at improving the coordination between the TSOs and the DSOs, a coordination mode between the TSO and the DSO for ancillary services (frequency and voltage control) is proposed, the "local AS market model" (SmartNet, 2016), that combines filtering and a local flexibility market. This market design is compared to three others of the SmartNet project in (Savvopoulos, Konstantinou, & Hatziaargyriou, 2019) and gets the best results.

Local flexibility markets are rather easy to implement and integrate into a variety of different local settings, and foster the valuation of local flexibilities. However, in the literature, various issues are raised regarding local flexibility markets. First, the flexibility market is a good option when congestion can be relieved via the market, but otherwise other mechanisms must be used, such as filtering (the "traffic light" concept, implemented in the Enera project). Liquidity is lacking in these markets which makes continuous designs more suitable (Schittekatte & Meeus, 2020). Then local flexibility market could be subject to inc-dec gaming (Hirt & Schlecht, 2019). Indeed, the local flexibility market is close to re-dispatching through market mechanisms. The ability to anticipate the need for re-dispatching, as is the case for flexibility providers, allows for strategic bids in the spot market.

3.4.3 Filtering

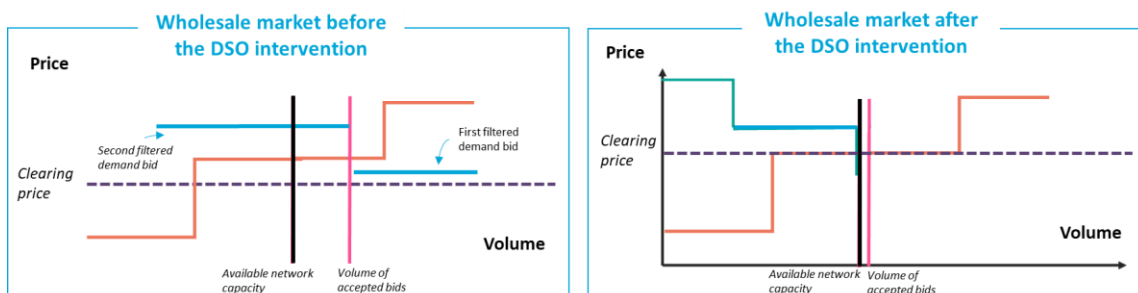


Figure 1- 17 Market operation of the merit-order filtering mechanism

“Filtering” is a volume coordination mechanism that gets a step closer in the integration of distributed, localized flexibility into wholesale markets. The market operation of filtering is described in Figure 1-17. Filtering is a mode close to price coordination. Simply, instead of congestion management being done indirectly, via a price signal to which the aggregators react, it is done directly via the cancellation of offers that will create a congestion on the network if they are activated. The DSO blocks the activations of certain flexibility offers after they have been formulated, because they place a strain on the distribution network. The bid is suppressed from the merit order. This mode has the advantage of being much less uncertain than price coordination, because it is directly the desired flexibility volume that is deleted. Depending on the market design, filtering can be implemented in different ways: pro rata of activated offers, first come first served or by “merit-order filtering”, ie filtering the most expensive offers (resp the cheapest requests). This last option (merit-order filtering) allow in theory similar economic efficiency as DSO activation on a local flexibility market. Indeed, when the DSO filters the most expensive offers to prevent a congestion, the last accepted offer’s price would have been the price offered by the DSO to activate a flexibility on a local market to cope with the same congestion.

Enera is a local flexibility platform that experiments this filtering concept with what is called the “traffic light” principle, the DSO giving direct instructions to generators and flexibility aggregators when the risk of congestion is high. Here, the coordination mode depends on the congestion status and a local flexibility market is supplemented with filtering when needed. Filtering is a mechanism well thought of for common European balancing markets (Meeus, Schittekatte, & Reif, 2020), for which system security is an important concern. To cope with uncertainties of activated bids, in (Guntermann, Gunderson, Lindeberg, & Håberg, 2018), the TSO forecasts a set of relevant power flows on the transmission system. It is used by the TSO on the European balancing platforms (TERRE and MARI).

Volume coordination is much simpler and direct to implement than price coordination. That is probably why different mechanisms for local flexibility provision (frequently referred to as “local energy markets”) are experimented with all over Europe. Moreover, these local flexibility markets operate outside of the wholesale markets sequence, independently. They do not necessitate a complex interaction protocol with wholesale markets, even though some local flexibility markets can be quite complex. For filtering however, the integration to wholesale markets complicates its implementation. Volume coordination is still more straightforward than price coordination, because it doesn’t rely on an intermediary signal between the DSO and aggregators.

3.4.4 Evaluation of the coordination mechanisms

These short-term coordination modes can be compared according to four indicators: efficacy of the congestion management, easiness of implementation, and gains for aggregators, and coordination preferred moment of coordination.

Thus the use of flexibility by the DSO to manage congestion on its network can be done in several ways. The local flexibility market solution is the simplest to implement and has been the subject of numerous and rather heterogeneous experiments in Europe. This mechanism allows a much decentralized dispatch of distributed flexibility. The insertion of local constraints in a centralized mechanism such as the wholesale market centralizes the use of distributed flexibility but can make it even more optimal, with the extreme and a priori unattainable case of co-optimization, given the current state of cooperation of market players. Filtering and coordination by prices (which is an indirect filtering, and therefore also more complex) can help to optimize the use of distributed flexibility by being more integrated into national market mechanisms.

Distributed flexibility is an interesting tool to manage not only congestion on the distribution network but also supply-demand balance at a national scale. The coordination of these two goals is therefore necessary for an optimal use of the flexibility. During more constrained moments on the distribution network especially, it raises the issue of the ability of the network to allow the use of all the distributed flexible capacities to satisfy the supply-demand balance.

4 Problematic of the thesis

In this introduction, we have seen that distributed demand flexibility can have a significant value for the power system. It can be valued through multiple mechanisms and for different and potentially contradictory purposes. In particular, it can be used to reduce production costs on wholesale markets or to manage local constraints on the distribution network. The coordination of these two objectives is at the heart of this thesis work. On the one hand, competition between them is not quantified in the literature on a large scale (on the scale of a country like France): most works focus on its local value. On the other hand, the value of demand flexibility at short-term timeframes, and more particularly at intraday timeframes, is generally little studied and explored in these works, in the context of the implementation of a concrete coordination mechanism. The research question that we will try to answer is therefore the following:

What impact does a coordination mechanism for the global and local use of distributed demand flexibility have on its value for the power system?

The work of this thesis begins with a study of the fundamentals of this local (distribution network) and global (production cost reduction) coordination. The coordination is considered here in a theoretical

way, but it allows us to apprehend its impact on a prospective electrical system, at the European scale. This first part answers the first question: **what is the value of distributed flexibility for the supply and for the distribution network in France?** This study is conducted by considering first that distributed flexibility is valued on the wholesale market, and that the possible constraints it generates on the distribution network are dealt with by reinforcing this network. Secondly, we measure the impact of a mechanism allowing to postpone flexibility activations on the wholesale market and the loss-of-load when they generate a constraint on the distribution network, called "filtering". This local constraint is expressed in the form of the exceeding of the "maximum power" of a source station. In this section, the use of RTE data concerning consumption and generation at the European level as well as at the local level will allow a precise quantification of this value for France.

However, this value is calculated within the framework of a perfect market, where there is only one market deadline and the players have a perfect view of prices. However, the impact of forecasting errors on the decisions of market participants can be significant. Indeed, these errors can give more value to the flexibility that would allow for the absorption of changes in forecasts, but also have an impact on the efficiency of coordination. This brings us to the second question of this manuscript: **What is the efficiency of short-term coordination and its impact on the value of flexibility?** To answer this question, we first look at the value of flexibility for wholesale markets, by considering the latter with a more operational view and by detailing the sequence of wholesale markets from D-1 to real time. This approach allows us to measure the impact of short-term forecast errors on the use of demand flexibility and the value captured at different short-term timeframes. This study was carried out with local forecast error data for France.

The complexity of setting up a coordination and its efficiency is then evaluated by inserting a coordination within the market sequence, on D-1, intraday or during the balancing. The analysis and discussion of these cases shows the constraints imposed by a short-term coordination inserted in the markets.

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Chapter 2: The value of distributed flexibility for reducing generation and network reinforcement costs.

Abstract: This flexible decentralized demand is the subject of study in this work. The first study of this thesis discusses the value of French demand flexibility for the European power system in 2030, considering two major valuation items: on the wholesale market, in order to minimize the production cost, and on the French distribution networks, in order to avoid reinforcement costs. In a first step, this study is conducted using a tool¹ that calculates an optimal dispatch on Western Europe, to value the contribution of distributed flexibility on the wholesale market, represented as a perfect market. The possible constraints generated on nearly 2000 French distribution networks are expressed in the form of exceeding the "maximum power" of a source station. They are treated by a simplified modeling of the reinforcement decisions of this network. This first step shows that the value of flexibility for the wholesale markets is all the more important the more fine-grained the control of flexibility is, but that fine-grained control also leads to high reinforcement costs on the distribution network, thus making a "time-of-use" control more interesting from the point of view of the power system as a whole. In a second step, we freeze the reinforcement of the network at its value without flexibility activation (thus lower than with a fine control) but we keep a fine control of the demand. We simulate a coordination between the distribution network and the wholesale market by moving the flexibility activations to the wholesale market when they generate a constraint on the distribution network. This coordination makes it possible to avoid almost entirely the extra costs of reinforcement, while only slightly reducing the gains on the wholesale market, so that the finer control becomes more interesting, with about 1 billion in total gains.

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¹ Antares, open-source model developed by RTE: <https://antares-simulator.org>

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1 Introduction

1.1 Development of distributed flexibility

All over the world, the share of VRES (Variable Renewable Energy Sources) such as wind and solar is expected to increase strongly in the coming years (IEA, 2021). This trend will be particularly pronounced in France, where their current contribution is small (11% for 2020)² but is expected to increase to 21%³ in 2030. However, unlike nuclear or hydroelectricity, VRES come with a distinctive, intrinsic uncertainty about their production and are not controllable. This eventually calls for more system flexibility, in particular on the demand side (Mitchell, 2016).

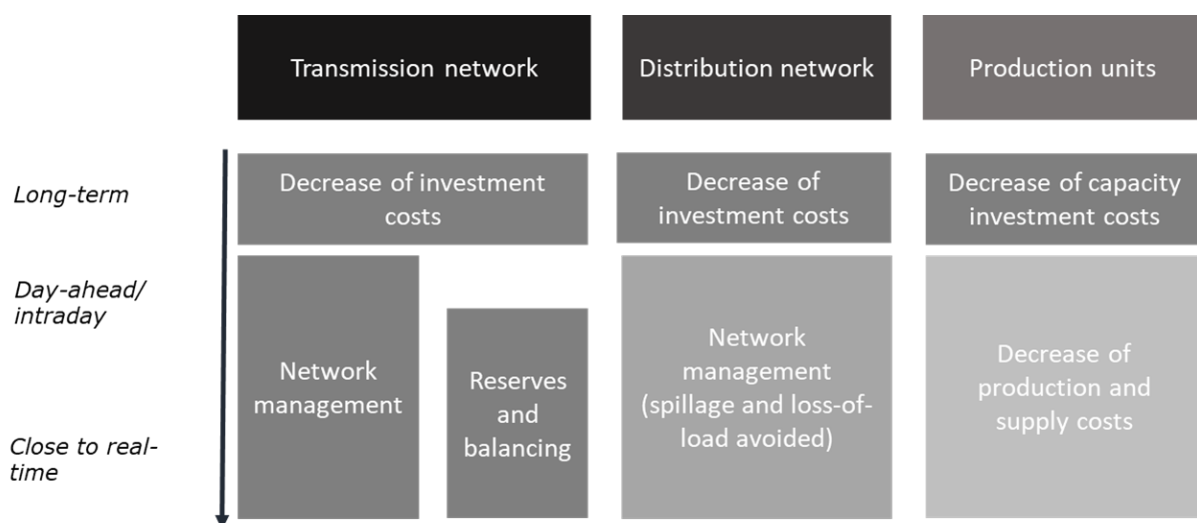


Figure 2- 1 The possible distributed flexibility uses from long-term to real-time purposes for transmission network, distribution network, and production units

Flexibility is thus an increasingly valuable asset in the electric system over different timescales, from long-term network planning to short-term balancing operations and at different geographic scales, from local flexibility markets for congestion management to European wholesale markets (Heggarty, 2019). As illustrated in Figure 2- , which shows the benefits of flexibility from a systemic point of view, flexibility can be used in the long run to reduce investments, by postponing or canceling network reinforcements and reducing the need for new production units (Smart Grid Task Force, 2015) (Villar, Bessa, & Matos, 2018). Flexibility can also be used closer to real-time to alleviate congestions or manage incidents on the transmission or distribution network (these services are gathered under the name “network management in (Enedis, 2019). For network management, demand flexibility can be used to reduce the demand (curtailment of demand) but flexibility in general also includes devices

² [Accueil RTE Bilan électrique 2020 \(rte-france.com\)](https://www.rte-france.com/fr/accueil-rte-bilan-electrique-2020)

³ According to the “VOLT” scenario of RTE’s “Bilan Prévisionnel 2017” for 2030 [bp2017 complet vf compressed.pdf \(rte-france.com\)](https://www.rte-france.com/fr/bilan-previsionnel-2017/bp2017-complet-vf-compressed.pdf)

such as on-load tap transformers for voltage control or compensators for reactive power control. It also reduces the operational costs of production units in wholesale markets and facilitates balancing for the TSO and reserves markets. There are many ways flexibility can benefit the system in the long- and short-term that must be economically evaluated in a system-wide approach.

In France in 2020, 92,9% of solar and wind assets (26 GW⁴ of power) were connected to the distribution grid. New flexible consumption sources like electric vehicle charging points were also connected to the distribution network. Thus, the distribution grid undergoes substantial transformation, and network reinforcements may be needed to maintain a sustainable quality of electricity distribution.

As a newly important element of the electric system, the use of distributed flexibility must be designed efficiently. This efficiency depends on the way market participants and operators coordinate their activities. Coordination can take place between the DSO and market players, the latter offering flexibility to interested buyers more or less independently of the DSO's constraints. It can also take place between the DSO and the TSO, through local flexibility markets.

In general, local flexibility markets are a tool for the DSO to solve congestion management using flexible bids from distributed resources, like in the Enera or GOPACS flexibility markets (Valarezo, et al., 2021). Publications and position papers today mainly relate to short-term coordination between TSOs and DSOs (Enedis, 2019), (ACER, CEER, 2017), (CEDEC, EDSO, EURELECTRIC, & GEODE, 2018), (CEDEC, EDSO, ENTSOE, EURELECTRIC, & GEODE, 2019). Many projects study the TSO-DSO coordination schemes, and often a DSO "filtering" case study is presented, where the DSO restricts flexibility activations for distribution network congestion management purposes: the local flexibility market Dutch demo in the Interflex project (Interflex, 2019), "Local Market Model" in CoordiNet (CoordiNet, 2019), mandatory curtailment by the DSO in the INTERFACE project (Nouicer, Meeus, & Delarue, 2022), the "Local AS model" in the SmartNet project (SmartNet, 2019). Coordination between the DSO for network reinforcement cost minimization and flexible assets remains a crucial topic but is still less researched in the academic field. Indeed, TSO-DSO coordination for balancing benefits from country-wide studies focuses on re-dispatching costs without taking into account network needs (Pearson, Wellnitz, Crespo del Granado, & Hashemipour, 2022). Other articles focus more on the benefits of flexibility for reinforcement costs at the country/regional scale (Vallés, Reneses, Frias, & Mateo, 2016). No study has been found to encompass both the DSO's reinforcement costs/gains and the generation costs/gains resulting in the use of distributed flexibility.

1.2 A new role for DSOs

The DSO is at the core of the aforementioned issues concerning distributed flexibility, and his responsibilities are developing accordingly. The new role played by distribution networks in the energy transition is well recognized by regulators. In 2017, the European Parliament, in the "Clean Energy Package", thus entitles DSOs to use the flexibility connected to their grid via a "market-based"

⁴ [Accueil RTE Bilan électrique 2020 \(rte-france.com\)](https://www.rte-france.com/accueil-rte-bilan-electrique-2020)

approach as long as it is coordinated with the TSO for congestion management. Such “market-based” procurement enables DSOs to explicitly activate distributed flexibility through either long-term bilateral contracts or short-term markets. This approach is the preferred option for the Council of European Energy Regulators (CEER) before other options regulating access such as connection agreements, network tariffs, or rules-based approaches (CEER, 2018). However, also “market-based” approach is not very specific and stakeholders have different views on how DSOs could deal with congestion.

1.3 Historical consumption flexibility control through tariff signal

There are two standard ways for organizing demand-side response: explicit demand response and tariff signals (Nouicer, Meeus, & Delarue, 2022). Explicit demand response is the activation of flexibility directly via the retailer or aggregators. Explicit demand response is adapted to the need and can be quickly activated but represents low volumes as few consumers accept such load following. In this paper, we consider an explicit short-term signal for the activation of distributed flexibility. A tariff signal is a price incentive for retail consumers, based on regularly recurring needs such as, for instance, the “peak/off-peak” hours pricing for electric water heaters that can be viewed also as load shifting (Poignant, 2010).

“Peak/off-peak” tariffs have resulted in the smoothing of peak hours, as consumers, especially professionals and manufacturers who were subject to the French *tarif jaune* that directly derives from this form of long-run marginal cost pricing, adapt their consumption to these prices (Mougin, 2008). The smoothing of the load curve fosters adequate investments with minimum additional cost to consumers (Poupeau, 2017).

The signal sent for off-peak hours gives an interesting historical example of successful coordination between the national and the local level. At first, “off-peak” hours were the same for the whole country (from 11 pm to 7 am, when national consumption was lowest). With increasing success, this signal caused side effects, especially a consumption peak at 11 pm. To reduce this peak, off-peak hours had to be differentiated by consumers. This led to the decision to decentralize the definition of “peak/off-peak” hours: the DSOs were given the responsibility of setting off-peak hours to reduce their network reinforcement costs, as long as these hours did not overlap with national peak hours. Decentralization of the “peak/off-peak hours” reduced both the national night consumption peak and distribution network costs, giving a good example of coordination between local and national levels. The “Peak/off-peak” tariff has promoted the adoption of water heaters with storage, thus creating a significant amount of energy storage capacity. Nowadays, load shedding and load shifting are further facilitated by automated meter management, put in place by DSOs, such as the Linky smart meter in France. Indeed, in France, “peak/off-peak” tariffs are determined by the DSO⁵.

⁵ In the context of liberalization of retail markets, “peak/off-peak” tariffs are still relevant as each retailer can offer a “peak/off-peak” tariff based on the DSO’s peak/off-peak hours. However, in France, there is also a

1.4 The context of the study

This study simulates the activation of four types of flexibility sources in 2030, namely RES curtailment, EV charging stations, water heaters, and electric heating, in a unit commitment optimization. The study is carried out on 10 meteorological years extrapolated to 2030 (in particular as far as production and consumption assumptions are concerned). Appendix A describes the production and flexibility mix used in this study. The aim is to assess the value of flexibility activation for long-term and operational generation costs and to compare it to the cost of these activations for the distribution network in terms of reinforcement costs. Therefore, generation costs are minimized with a unit commitment.

The flexibility activations are designed for the minimization of production costs. However, those activations also have an impact on the distribution network. As they change the load distribution, they may lead to congestions on the distribution network and generate reinforcement costs. Two different situations are studied in this paper:

- Minimization of generation costs (1st situation): in this situation, generation costs only are minimized, regardless of the reinforcement costs they generate.
- Filtering (2nd situation): to approach an optimal activation of consumption flexibility, which minimizes both generation and distribution costs, the DSOs can filter the flexibility activations (for the STCS - Short-Term Controllability Signal- signal) that generate constraints in distribution networks. They can thus avoid some reinforcements. It means that constraints on maximum flexible consumption activation power are added to the technical constraints on consumption.

In this paper, these two processes for flexibility activation are investigated and compared with the “no signal” process, with no possibility of controlling demand. The detailed features of these three flexibility activation signals are:

- No signal (NS): the demand follows its natural course. Flexible capacities are not activated.
- Short-term controllability signal (STCS): the flexibility activations are decided the day-ahead to minimize generation costs.
- Peak/off-peak signal (POS): This signal is not a typical “peak/off-peak” binary signal but a daily activation profile resulting from the sum of individual reactions to different price signals by many consumers.

The three flexibility activation signals are summarized in Table 2- 1.

regulated tariff, other than the “peak/off-peak” tariff, that can be offered uniquely by the historical retailer, here EDF.

No Signal (NS)	Short-Term Controllability Signal (STCS)	Peak/Off-Peak Signal (POS)
Reference test case Flexible capacities are not activated (Test case 1)	Minimization of generation costs (Test case 2)	Minimization of generation costs (Test case 3)
	Filtering reaction (Test case 4)	-

Table 2- 1 The 5 test cases considering the 3 types of activation signals and the 2 different reactions to the flexibility activations by the wholesale market

In this work, the three flexibility activation signals are studied, each on its own. 100% of existing flexible assets, as described in Appendix A, are considered available, for each of these signals. In reality, in the future, flexibility activations will probably be a mix of these three signals.

In the following, section 2 summarizes the state of the art in assessing the economic value of flexibility based on the current literature. Section 3 provides the methodology for the minimization of overall costs of electricity provision through the use of distributed flexibility. Section 4 summarizes the results of the study. Section 5 concludes.

2 State of the art

2.1 Comparison of the flexibility values for the distribution network and generation costs

European local flexibility markets, which still are in their infancy, tend to be operated by the DSO for congestion management purposes and the literature focuses on this issue (T. Kornrumpf, 2016) (P. B. Andersen, 2012). However, the main economic value of distributed flexibility does not lie in congestion management. Various studies also acknowledge flexibility's value in reducing network investment costs. Distributed flexibility also has a potential value for cutting back on generation costs (Martinot, 2016). Attempts at costing the value of flexibility are mostly found in industrial reports from TSOs and DSOs. This value highly depends on network location, and coordination schemes should account for this heterogeneity.

In France, various studies show that the value of flexibility depends highly on the type of flexibility and the location. According to Enedis and E-cube, the value of flexibility for the distribution network is up to €24/kW per year of postponement of the investment (Enedis, 2017) (E-cube, 2017). Most of the value lies in the optimization of the distribution network expansion planning for the connection of RE. This value is only for the medium voltage network; the value of flexibility for the low voltage is close to zero.

Among different kinds of flexibilities, RES curtailment is at the center of interest for networks because of its high value to avoid reinforcement costs. Valuations may vary according to assumptions and time periods: the value of spillage represents 250M€ of benefits per year for both the distribution and the

transmission network according to Enedis (Enedis, 2019). It is 500M€ for the transmission alone according to RTE (RTE, 2019b).

Some reports find that distributed flexibility has even more value for the decrease of generation costs. A French demonstrator, Greenlys shows the value of flexibility rather lies in the minimization of generation costs: the value of consumption curtailments in the Greenlys demonstrator is about 7500k€/year, whereas the value of consumption curtailments for avoiding reinforcements is about 500k€/year (Battegay, 2015). This demonstrator gives an interesting insight into the value of flexibility for both the network and the generation costs for France as these two items are explicitly confronted, even though the scope of the study is quite narrow.

The different estimated flexibility values are summarized in Table 2- 2.

Study	Scope	Value for the network	Value for the generation costs
(Enedis, 2019)	RE connection <i>in France</i>	Up to 250M€ to 2035 (distribution network)	Not addressed
(Battegay, 2015)	Consumption curtailment <i>in the “Greenlys” demonstrator</i>	500k€/year (distribution network)	7500k€/year
(E-cube, 2017)	Connection agreements, market-based procurement <i>in France.</i>	24€/kW/year (distribution network)	Not addressed
(RTE, 2017b)	RES curtailment and smart-grids <i>in France</i>	48M€/year (transmission network congestion management)	756M€/year
(RTE, 2019b)	RES curtailment <i>in France</i>	500M€/year (transmission network reinforcement costs avoided)	Not addressed

Table 2- 2 Value of flexibility for the network reinforcement costs and generation costs according to various French studies

The comparison of these studies points out that the value of RES curtailment for the network reinforcement is relatively high (up to 500M€/year according to RTE (RTE, 2019b)) but that for consumption flexibility, the value rather lies in generation costs savings on the European wholesale markets they are involved in. For ancillary services, the value of consumption flexibility is very high (€900/year for a single electric vehicle), however, there is very little need, as less than 2% of total production is for ancillary services, thus this would concern only a very small portion of the EV fleet (RTE, 2019a).

In other countries, various studies show the value of flexible consumption for electricity markets. The storage value has been studied for the Australian wholesale market, which has a very high price cap and is very volatile (McConnell, 2015). Storage can provide similar flexibility services to peak generators while being far less carbon-intensive.

2.2 The interest of a tariff signal

Full controllability of flexible resources is unnecessary to capture an important share of the value of flexible resources. Nowadays, adequate pricing through tariffs for the final customer is still a solution to be considered. First, for social acceptance: for instance as far as EV charging is concerned, if the majority of car owners would have the recharge of their vehicle deferred to avoid consumption peaks, it is mostly to benefit from the peak/off-peak hours tariff (Enedis, 2020a). In France, water heaters with storage are already controlled by a “peak/off-peak” signal without alterations to the way of life of consumers, and with high efficacy, as explained in 1.3.

Second, the full controllability of available flexible resources cannot be accounted for as it asks for huge infrastructure investments. For instance, only 37% of French people who own an electric vehicle have a system for the control of the recharge of their vehicle (Enedis, 2020a). For water heaters, it would also require additional investments for a priori little efficiency gains compared to the current method. The emergence of Electric Vehicles (EVs) can considerably increase the energy controllable by tariff signal, adding to water heaters. From an economical perspective, many studies have been conducted on EVs. The economic benefit from 1MW of load responding to off-peak signal is lower but comparable to day-ahead controllability of the vehicles charging, according to reports made by the French TSO and the French main DSO. Using a tariff signal can capture 60 to 75% of the residential demand response controllability total value for the whole electric system (RTE, 2017b) (RTE, 2019a) (Enedis, 2020b). More theoretically, “peak/off-peak” tariffs could have an efficiency gain of up to 30% compared to a flat tariff (Astier, 2021). In (Lauvergne, Perez, Françon, & Tejada De La Cruz, 2022), a tariff signal for controlling EV charging makes up to 65% of the gains of a dynamic signal. However, a tariff signal is not suitable for heating shifting as heating energy is not stored (or at least, even if there is some inertia in heating thermodynamics, it is not stored with the same efficacy as EV and water heaters energy). Thus, even with a tariff signal, consumers would activate their heating system whenever needed, and this time can vary from day to day. What is possible, however, is to decrease the heating power (to an acceptable limit) when used, and report the missing energy on the following time steps, which is suited to a short-term control signal.

2.3 Contributions of the paper

This study aims at overcoming three gaps in the literature on the economic value of flexibility for the electric system.

First, the value of flexibility for the distribution network costs has been studied in the literature for specific markets or case studies. Thus, a major contribution of this paper is to assess the costs and benefits of demand flexibility as they reduce generation costs and investments in distribution network reinforcement for an entire European country, which is France in this case. The gains in terms of operational costs are evaluated with and without flexibility provision with the minimization of generation cost at the European scale for a given 2030 mix. In addition, distribution reinforcement

costs are evaluated over 1890 substations⁶, taking into account the flexibility activation simulated in the first step: these costs can increase or decrease for a given individual substation depending on the pattern of flexibility activation.

Second, this paper will make this analysis for 3 different levels of flexibility activation: no flexibility activation, a long-term tariff signal, and short-term demand management. Indeed, as indicated in the literature review, short-term demand management is not the only way to capture a decisive share of the value of demand flexibility. As an additional, case, this paper studies the provision of a filtering signal that indicates the system needs to market participants.

3 Methodology

The methodology entails three steps. First, the optimal dispatch for cost minimization is computed with the Antares software for the three test cases STCS (Short-Term Controllability Signal), POS (Peak/Off-peak Signal) and NS (No Signal) (the STCS case being the only one in which the EV and water heaters activations are not fixed before the optimization). Then, the national flexibility activations for these three cases are broken down on each substation in order to compute the reinforcement costs. These two first steps generate a first result: the cost-benefit analysis of the valuation of flexibility on wholesale markets without filtering. Finally, the filtering process is simulated for the STCS case to obtain the second result, the cost-benefit analysis with a DSO filtering signal.

3.1 General method for generation costs minimization

This study is based on a unit commitment model that minimizes the operational generation costs. Such cost minimization entails a displacement of flexible load according to its opportunity cost but no direct activation pricing, as required within the current European Regulatory context. The objective is not to look at the impact on the investments in production means but the evolution of the unsupplied energy will give us an estimate of the capacity value of the demand flexibility, in the context of the study.

While modeling results may coincide under certain conditions with the results of perfectly operating markets at the local and the national level, the methodology itself is not based on exchanges between decentralized actors and thus cannot be considered the study of a specific “market design”. Nevertheless, the results provide insights that may be put to good use in the development of future market designs at the European level.

The system’s hourly dispatch is computed with Antares, an open-source application developed by RTE that simulates large power systems’ operations. Antares’ simulation engine is based on a cost-

⁶ The substations are the level of detail chosen in this study to represent the distribution grid. They can be seen as an approximation of the part of the distribution grid served by each substation.

minimization problem that accounts for generation costs, start-up costs, and loss-of-load costs in 52 weekly optimization of the whole system. Antares represents an interconnected system and is thus especially useful for studying the integrated European electricity market. Each node represents a region of the system or a bidding zone. The links represent the interconnection capacities between the regions. Each node is defined by assumptions on its electrical demand and its generation fleet, with technical and economical characteristics.

For a given horizon and mixes, 10 scenarios are studied, with different possible meteorological realization of the same year, which affect temperature-sensitive load and wind and solar production, and different thermal availabilities. For each scenario studied, Antares optimizes the unit commitment to meet the demand at the lowest cost.

3.2. Method for distributed flexibilities optimization

In this study, three demand flexibility uses are modeled: water heaters, EV charging, and heating power. Three different simulations are made with different flexibility activations.

In “No signal” case, no flexibility are activated, which means water heaters, EV charging, and heating power are used without any energy displacement. For water heaters and heating, the load curves are entailed in the consumption hypothesis of the VOLT scenario presented in Appendix A. For EVs there is few historical data available. The methodology for the computation of EV load curves is taken from (Lauvergne, Perez, Françon, & Tejada De La Cruz, 2022) . It takes into account weekly trip patterns and several range of recharge modes.

For the Short-Term Controllability Signal (STCS), EV, water heaters and heating deferral activations are planned within the optimal dispatch for cost minimization with Antares. These activations are however subjected to some constraints. Water heaters are subjected to a maximum power and daily energy target constraint. Heating deferral must be energy conservative over the 24 consecutive time steps following the curtailment and is also limited by a maximum curtailment power. For EVs, the constraints are mainly about the charging level of the vehicles. It must be over 30% of the battery maximum capacity at all times. The energy lost by the consumer use of the vehicle is taken into account in a constraint inspired by the functioning of a battery. A maximum charging power also constrains EV charging activations. The constraints are further described in Appendix - B. The optimization is done week by week, for the 52 weeks of the 10 meteorological years. For each week, the assets are dispatched to minimize the generation costs (while keeping the same energy). Therefore, flexible consumption is dispatched on the timeframes where the marginal cost is the lowest, within the limits of the technical constraints⁷. Frequency discontinuities resulting from flexibility activation are not modeled.

⁷ Which for EVs ensures they are charged when necessary, for heating limits the consecutive hours of shedding to 2h and for water heaters limits their activation power.

For the Peak/Off-peak Signal (POS), flexibility activations are computed for EVs and water heaters. Heating deferral cannot be controlled via a tariff signal. Indeed, a tariff signal will not be precise enough to respect the deferral coefficients. The flexibility is activated following hourly ratios⁸ differentiated by the type of day and season, considering that the signal activation is different on “summer working day”, “winter working day”, “summer weekend day” and “winter weekend day”. Therefore, the POS is considered to be a peak/off-peak signal as the hourly ratios are fixed (though different for each type of day) before the market time, and their value is an indication of the preferred moment for flexibility activation, even though no tariff is attached to each hour of the day but directly a daily energy volume ratio. Those hourly ratios for typical days have been optimized to reduce the global production cost over 10 meteorological years. The methodology for the optimization of POS hourly ratios entails three steps:

1. The primary hourly ratios are computed as the mean of the STCS activations (as a proportion of the total activation energy for the day) for each of the four typical days.
2. The EV and water heaters POS load curves computed with these hourly ratios (by multiplying the ratios of the relevant typical day, with the energy of the considered day, for each day). These load curves are fixed in the Antares simulation in order to compute the corresponding marginal prices.
3. The POS ratios are then marginally modified by hand with the information given by the marginal costs: the ratios are lowered on the time steps where the marginal costs is higher than the mean marginal cost for the typical day and increased otherwise. Step 2 and 3 are then repeated with these new ratios until the difference in the ratios from two successive is sufficiently close to 0. In these case five iterations were needed. The EV ratio iterations are presented Figure 2- 2.

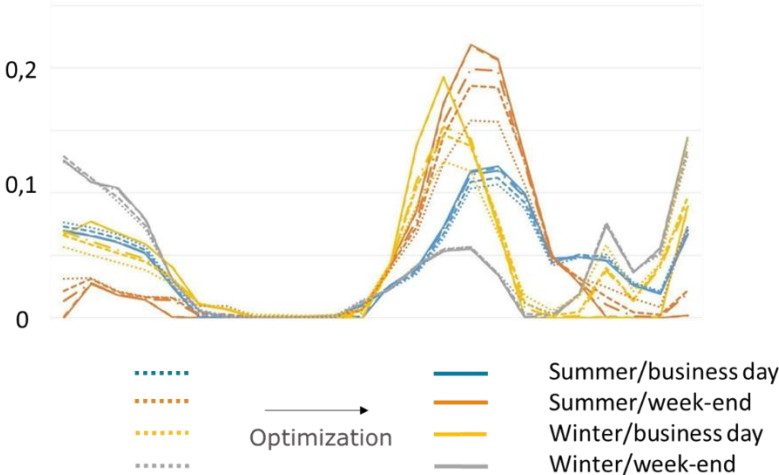


Figure 2- 2 EV peak/off-peak ratios evolution with the optimization process

⁸ Hourly ratios are used instead of hourly energy as the daily energy change each day following the calendar and the weather condition.

These generation costs will be compared to the costs for distribution network reinforcement computed with the method presented below.

3.2 Method for the computation of the reinforcement costs

3.2.1 The proxy distribution network architecture used in this paper

As seen in Chapter 1, the substation is the interconnection point between the transmission network and the distribution network. The impact of an increase in consumption or production is considered at different levels of the distribution network, as shown in Figure 14. An increase in LV residential consumption affects both LV and MV levels, whereas MV solar farms are connected to the MV level and the MV wind farms are directly connected to the substation feeder (see Figure 2- 3).

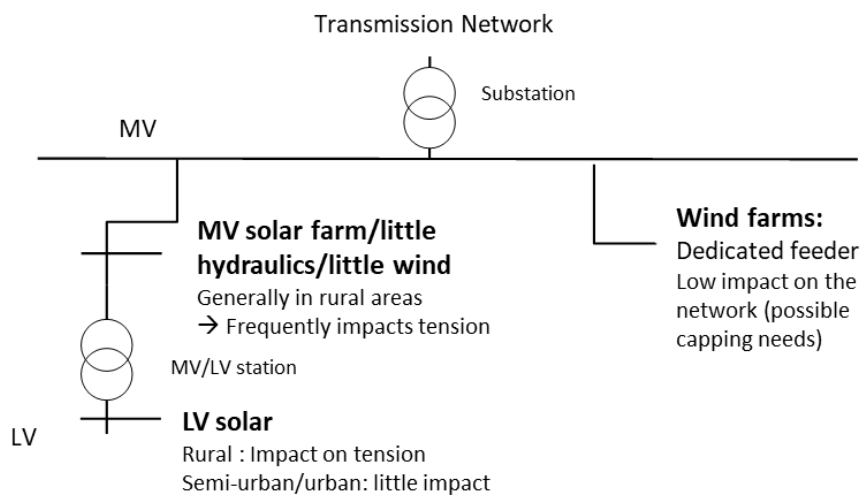


Figure 2- 3 Impact of RE on the distribution network

3.2.2 The general framework for calculating reinforcement cost induced by flexibility activation

The computation of reinforcement costs takes place in a three-step process:

1. Given national load, RE, and flexibility activations are spread over 1890 substations of the French territory.
2. The Maximum Power Indicator (MPI) is computed for each substation. It shows the maximum of power reached by the net consumption curve: peak on withdrawal and peak on injection. The MPIs are computed for the 2018 and 2030 load curves for the three flexibility activation signals.

3. The gap between the MPIs obtained with the 2030 net consumption curves for each flexibility activation signal and the “historical” MPI, computed on 2018 net consumption curves, shows the reinforcement need for each substation and the underlying network, for the three signals. Reinforcement costs are a function of this MPI gap if positive.

Thus, this methodology estimates the reinforcement costs of an entire distribution network from the magnitudes at its source station. This methodology aims to get an order of magnitude that enables a comparison between the three flexibility activation signals (no signal, STCS, and POS). The computed reinforcement costs are to be viewed from the perspective of the accuracy of this method.

3.2.3 Local load and generation calculation: breakdown of the national power over the substations

Once flexibility activations are calculated on a national level with Antares, they need to be distributed over the 1890 substations of the French distribution network to assess the need for local network reinforcement. Indeed, the flexibility activations made at the national level can create a congestion at the local level (here, the substation level). The congestion arises at a substation when the activated power at the national level exceeds the maximum power this substation can endure.

The breakdown is executed independently for each consumption item (inflexible consumption, water heaters, EV charging, heating) and renewable production, and over the 10 meteorological years simulated with Antares, using methodologies developed by RTE. For the inflexible load, the breakdown is computed by multiplying the national inflexible load curve by hourly coefficients for each substation (extracted from historical inflexible load curves). For EV and water heaters the coefficients for the breakdown are the same for every hour and only differentiated along substations. See Appendix C for the detailed method used for each item. The breakdown retains the national dynamics of flexibility activations. At the local level, flexibility activations are supposed to be more differentiated. This impacts in particular the peak/off-peak signal, as in France, this signal is supposed to be locally differentiated.

3.2.4 The maximum power indicator (MPI)

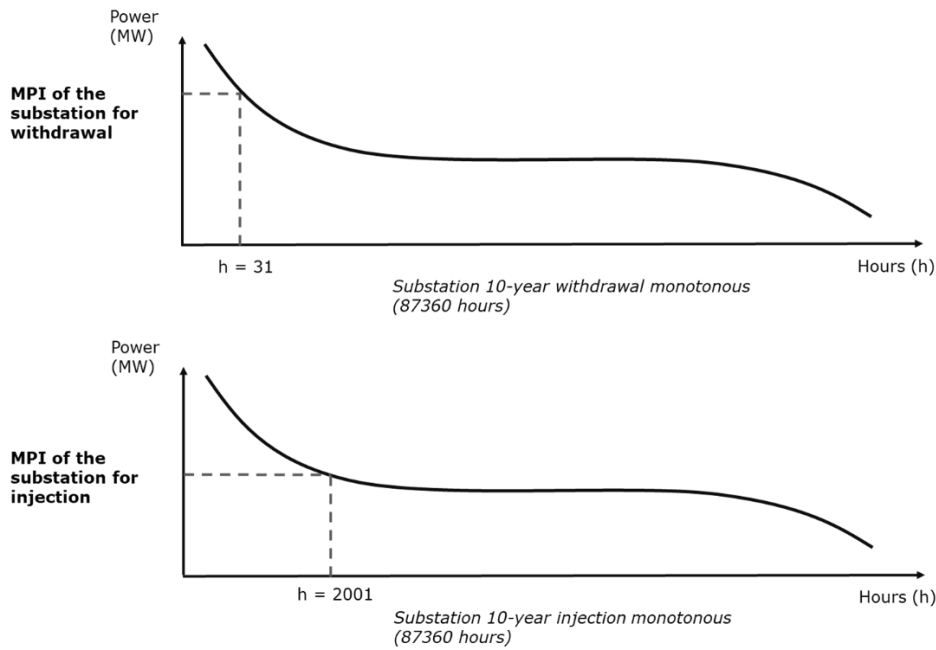


Figure 2- 4 Method for the computation of the MPIs of injection and withdrawal at each substation

Each substation can handle a maximum power level, beyond which the load is curtailed. If this maximum level is exceeded too often, network reinforcement becomes economically preferable to the increasing costs of load curtailment (usually referred to as Value of Lost Load - VOLL).

In this paper, maximum power levels are computed separately for each substation for load, solar generation, and wind generation, as the costs of reinforcement are different for these items that, in this model, affect different levels of the distribution network.

The method used for the computation of this indicator is the probabilistic method described in Enedis' documentation (Enedis, 2017). It relies on monotonous load duration curves (power values over a long period ranked in decreasing order). The MPI of a given substation is the maximum of the 31st highest value of its 10-year monotonous load duration curve (which corresponds to an average of 3 hours of load curtailment per year) and the 2001st highest value for 10-year monotonous injection curves - which corresponds to 200 hours of permitted spillage per year at each substation feeding a distribution network.

In this method, we model the impact of congestion on the need for investment in the distribution network without going into detail about the grid elements located at the medium and low voltage below the substation. Those elements are taken into account through hypothesis on costs.

3.2.5 The method for the computation of reinforcement costs

Reinforcement costs depend on the difference between historical and future MPIs.

Reinforcement costs induced by an increase in the load are evaluated by Enedis at €30/kW/year (internal data). These €30/kW/year of distribution network reinforcement investments are shared between 1/3 for the MV (Medium Voltage, from 50 kV to 1kV) network and 2/3 for the LV network (Low Voltage, up to 1kV). We will use those values for this work. As the localization of the substation has a major impact on the reinforcement costs, the method takes into account a multiplicative coefficient depending on the area of the substation: urban, semi-urban, or rural. Rural network reinforcements are more costly than urban network reinforcements since the length of the electric lines is higher in rural areas (population density is lower). To consider these cost inequalities, the reinforcement costs for LV and MV networks were adjusted by EDF with an adjustment coefficient (Nadaud, 2008). These coefficients, exposed in Table 2- 3, will be used for the computation of reinforcement costs induced by LV and MV load increase.

Regarding injection, the average cost of RES insertion on the distribution network is 300M€/GW for solar and 100M€/GW for wind (internal data). The difference is to account for cost scale effects, as wind farms can produce more power than solar farms on average. These costs depend a lot on the voltage level where the connection to the network occurs and on the density of the population. In rural areas, reinforcement for renewable costs on average 3 times as much as reinforcement in an urban area mainly because of voltage issues caused by consumption located far from the injection.

Type of area	Adjustment coefficient
Rural	1,55
Semi-urban	1
Urban	0,75

Table 2- 3 Adjustment coefficients for reinforcement costs for the different area types

A key element to reproducing heterogeneity between substations is to make discrete reinforcements. For each substation, the number of years an investment can be deferred, and thus the benefits or costs induced by flexibilities, depends on the margin from the substation’s computed MPI to the next reinforcement and on the consumption growth at this substation. The value is highest for low growth and margin before reinforcement: the weaker the growth, the more reinforcements are reported in time. Postponing an imminent reinforcement (low margin) means postponing it to a distant future, infinity in the extreme case.

Conversely, in the case of higher margins, the investment is sufficiently distant, its present value is therefore low and the postponement of the investment is of little economic interest.

The distance to the next reinforcement checkpoint is randomly generated for each substation considering a maximum distance to the next reinforcement MPI. The detailed methodology for the computation of reinforcement costs is presented in Appendix D.

So in this model, we use published mean data on reinforcement costs heterogeneity but we however manage to introduce heterogeneity with margin. This does not allow us to provide a good prediction of the cost of reinforcement at each substation, but it does provide a good representation of both the average cost and its heterogeneity.

3.3 Assessing DSO network reinforcement costs in the presence of a filtering signal

Once the reinforcement costs are computed for the first case described above, a second case aims to evaluate the gains that could be brought by the activation of a filtering signal. As a few peak hours often play a decisive role in network dimensioning, it can be expected that limiting activations during those hours will have little impact on overall generation costs while diminishing network reinforcement costs⁹. As for the previous case, the methodology is based on dispatch optimization and not on explicit market simulation.

In this second case, we choose to cap the MPI of the substations at the MPI computed for the No Signal case (NS MPI). As we will see on the results this is both ambitious in term of reinforcement cost saving and accessible because the NS (No Signal) case is at least a possible solution for flexibility activations.

The method for filtering with STCS (Short-Term Controllability Signal) is broken down into two steps: first, the evaluation of generation costs with a DSO filtering, with a national view taking into account aggregation of local constraints and then, the transposition of these national constraints to the local level. A method has also been applied to POS, with less interest because only 6 substations are concerned with congestions in this case. This method is explained in Appendix E.

3.3.1 Evaluating production cost for STCS with a DSO filtering signal

The filtering simulation is performed with Antares, using the following process.

First, each week, substations are classified into two categories: constrained and unconstrained substations. A substation s is called *constrained* for the week w (520 weeks for this 10-year study) if, and only if the following inequality holds:

$$\max(WH_{s|w} + heating_{s|w} + EV_{s|w} + Inflexible_{s|w} - DS_{s|w}) > P_{max,s}^* \quad (1)$$

$WH_{s|w}$ the 10-year water heaters consumption of the substation s restricted to the week w

$heating_{s|w}$ the 10-year heating consumption of the substation s restricted to the week w

$EV_{s|w}$ the 10-year charging stations consumption of the substation s restricted to the week w

$Inflexible_{s|w}$ the 10-year inflexible consumption of the substation s restricted to the week w

$DS_{s|w}$ the 10-year distributed solar production of the substation s restricted to the week w

$P_{max,s}^*$ the MPI of the substation s

It is called *unconstrained* otherwise.

⁹ This limitation (which consists in displacing the flexibility activations causing the congestion to other timeframes) does not lead to a remuneration of the limited flexibility provider. Here, we only assess the social welfare corresponding to the displacement of flexibility activations for network management purposes.

Constraints are then added to Antares' optimization problem, to simulate filtering by DSOs. The three flexible demand uses are now modelled twice, with initial constraints on flexible consumption attributed to constrained and unconstrained substations proportionally to the weekly distribution of the substations in these two categories. The total consumption of constrained substations is limited by the sum of the MPI of these substations. For each week w , each substation s belonging to the set of constrained substations of the week $Constrained_w$ and each hour h of the week w :

$$\sum_{s \in Constrained_w} WH_{s|w,h} + heating_{s|w,h} + EV_{s|w,h} + Inflexible_{s|w,h} - DS_{s|w,h} < \sum_{s \in Constrained_w} P_{max,s}^* \quad (2)$$

This constraint is much more computationally efficient than having one constraint per substation, but it does not ensure that each substation is individually constrained at its MPI.

3.3.2 Optimized decomposition of the flexibility activations on each substation

After the Antares optimization including the constraint (2) is performed, another optimization verifies that a decomposition of the obtained flexibility activations complies with the MPI of each substation exists and, if not, how far we are beyond the individual MPIs. Indeed, the national flexibility activation constraint does not ensure that each substation is individually constrained at its NS (No Signal) MPI. The distribution of the national flexibility activations is not satisfactory as various substations overrun their NS MPI. The following method for the distribution of the national activations on every substation enables energy exchange between substations to verify there is a national flexibility activation breakdown that satisfies the individual NS MPI at each substation. If this breakdown does not exist, the optimization finds the breakdown that minimizes total NS MPIs excesses.

This optimization problem aims to minimize the total energy exceeding the MPI on all the substations (the loss-of-load). The objective function is as follows:

$$\sum_{h=0}^{167} \sum_{s \in Substations} (\max (WH_{s,h} + EV_{s,h} + heating_{s,h} + Inflexible_{0,s,h} - DS_{0,s,h} - P_{max,s}^*; 0)) \quad (3)$$

$WH_{s,h}$ the water heaters consumption for the substation s at hour h (optimization variable)

$EV_{s,h}$ the charging stations consumption for the substation s at hour h (optimization variable)

$heating_{s,h}$ the heating consumption for the substation s at hour h (optimization variable)

$Inflexible_{0,s,h}$ the inflexible consumption for the substation s at hour h

$DS_{0,s,h}$ the distributed solar production for the substation s at hour h

$P_{max,s}^*$ the chosen MPI of the substation s

The constraints applied to the optimization variables are the breakdown on substations of the constraints applied to the flexible activations with Antares in optimal dispatch simulation. Other constraints entail the conservation of energy at each substation for each flexibility asset and the

conservation of the total power as computed with Antares for the evaluation of the production costs with filtering.

The constraints are detailed in Appendix F.

4 Results

The results section follows is divided in four parts. First, the result of the Antares economical dispatch for the three test cases is presented. Then we carry an analysis of the costs generated on the substations by this dispatch. These costs are then added to the gains from the Antares dispatch to present the cost-benefit analysis of the use of flexibility for the minimization of production costs. Finally, the modifications of this cost-benefit summary made by the filtering process on the STCS (Short-Term Controllability Signal) test case are shown.

4.1 Minimization of generation costs at the national level

Under the assumptions stated in 3.1, generation and loss-of-load costs for the three degrees of flexibility control NS (No Signal), STCS (Short-Term Controllability Signal), and POS (Peak/Off-peak Signal) were computed. The first important result is that the generation costs are the lowest with the STCS (Figure 2- 5). This was expected, as the activation of flexibility with this signal allows more leveraging of a greater number of flexibility providers to minimize generation costs

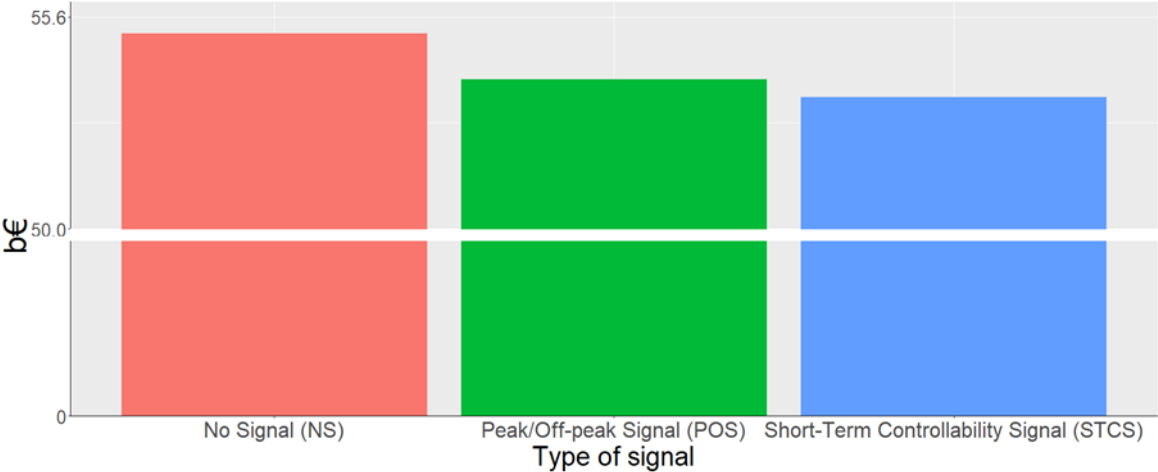


Figure 2- 5 Annual costs for different degrees of flexibility control: Mean for the 10 meteorological years of 2030 of Europe (at, be, ch, de, es, fr, gb, ie, it, lu, ni, nl, pt) total operational generation costs for the 3 flexibility signals

Production unit type	STCS relative to NS	POS relative to NS
Nuclear	7,5 TWh	6,1 TWh
Lignite	0,9 TWh	0,6 TWh
Coal	2,1 TWh	1,5 TWh
Gas – CCGT	- 11,8 TWh	- 8,0 TWh
Gas – CT	- 3,0 TWh	- 2,3 TWh
Oil	- 65,4 GWh	- 35,3 GWh
RES curtailment	- 2,7 TWh	- 1,7 TWh

Table 2- 4 Changes in the generation mix: Mean for the 10 meteorological years of 2030 of the energy produced in France per unit type, for both STCS (Short-Term Controllability Signal) and POS (Peak/Off-peak Signal) compared to the NS (No Signal) test case. A positive value indicates more production than in the NS case.

Table 2- 4 shows that the energy produced by all low-cost production units (nuclear, lignite, and coal)¹⁰ is higher for the STCS and is the lowest when there is no flexible consumption with the NS test case. Thus, flexible consumption is shifted to time slots with the lowest generation costs. Flexible consumption can also coincide with wind production periods. As a result, there is far less spillage with short-term controllability of flexible load than with no flexibility (Table 2- 4). The POS is just a little less efficient to avoid spillage than the STCS.

Figure 2- 7 confirms that the controllability of flexible consumption focuses its activation timeframes on hours where marginal costs are the lowest. This is the cause of congestion at the local scale which is assessed in 4.2 with the reinforcement costs. In comparison, flexible consumption in Figure 2- 6 is much more evenly spread when no signal is used. These marginal costs are computed by the Antares software. They correspond to the market price (cost of the last unit called). However, Antares computes a unit commitment, using overall optimization variables and not explicit market bids, which can lead to slight differences in the result with a market. For instance, on the markets, paradoxically accepted bids are forbidden and the start-up costs are not considered.

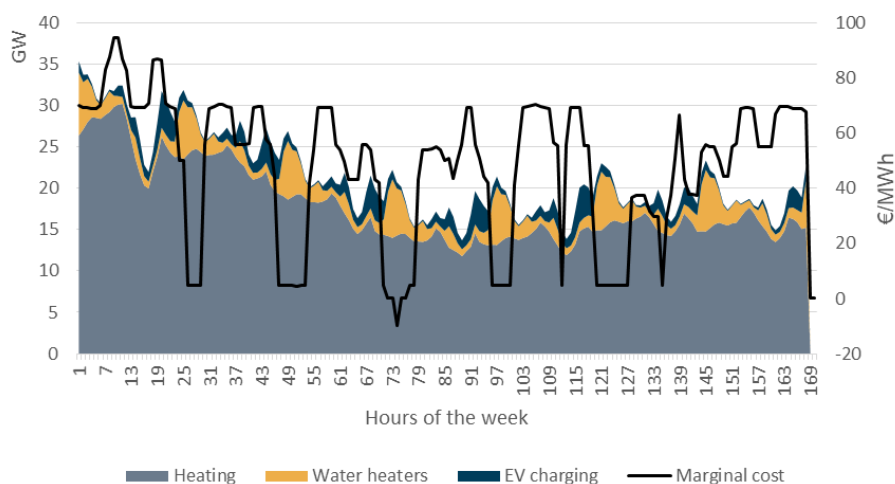


Figure 2- 6 NS (No Signal) flexibility layout - Winter week

¹⁰ The cost of CO₂ is embedded in the marginal cost of the production units. In this study it is at 32€/t which is far below actual values (90€/t).

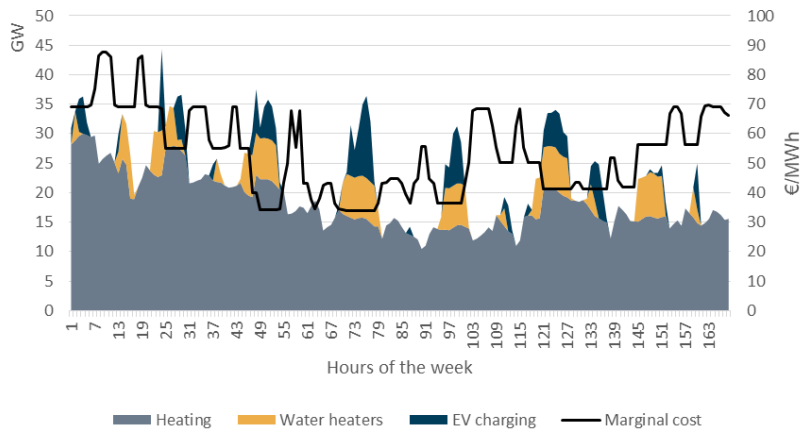


Figure 2- 7 STCS (Short-Term Controllability Signal) flexibility layout -Winter week

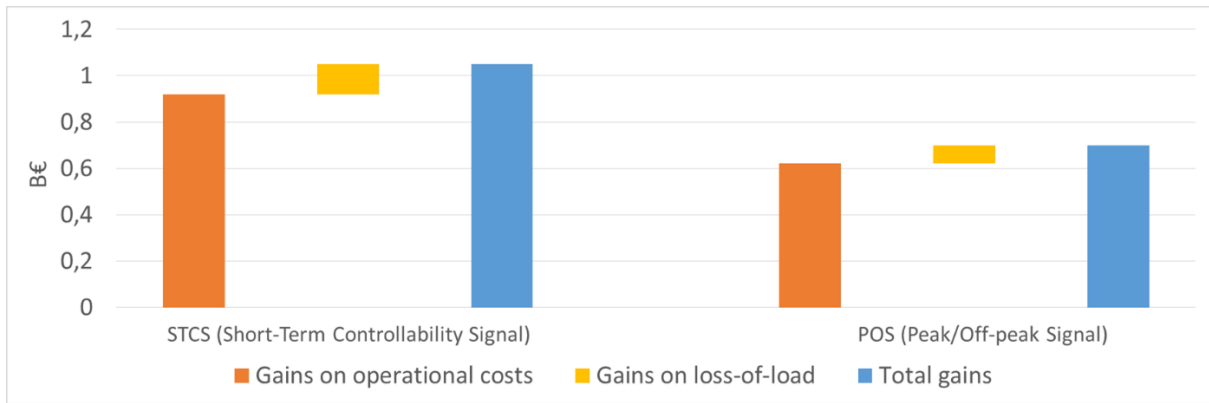


Figure 2- 8 Mean for the 10 meteorological years of 2030 of total gains for France only for both STCS (Short-Term Controllability Signal) and POS (Peak/Off-peak Signal) cases against the NS (No Signal) case

The short-term controllability of the load has a lot of value for the generation costs and loss-of-load costs¹¹ (Figure 2- 8). The high level of controllability of the STCS enables a gain of approximately 1B€ for France regarding the NS test case, which represents 2% of the total system costs. This is above the 756M€ found in (RTE, 2017b) because we take into account the flexibility of other European countries that can contribute to decreasing the generation costs in France thanks to the interconnections. At this point of the economic evaluation of the different signals, the POS achieves 65% of STCs gains.

4.2 MPis and reinforcement costs

To complete the benefits analysis of flexibilities activation, reinforcement needs have been calculated through Maximal Power Indicator (MPis) calculation. Figure 2- 9 shows the MPis for 2030 with the three different flexibility signals compared with the MPis calculated on historical data, with the same

¹¹ The decreased loss-of-load regarding the NS test case (with a value of 10k€/MWh for loss-of-load) represents about 200 M€.

method (described in 3.2). If the MPI for the NS (No Signal), POS (Peak/Off-peak Signal), or STCS (Short-Term Controllability Signal) case is below the historical MPI for a substation, the MPI takes the value of the historical MPI as the network cannot be uninstalled. It can be seen that the greatest gains accrue at a comparatively small number of substations.

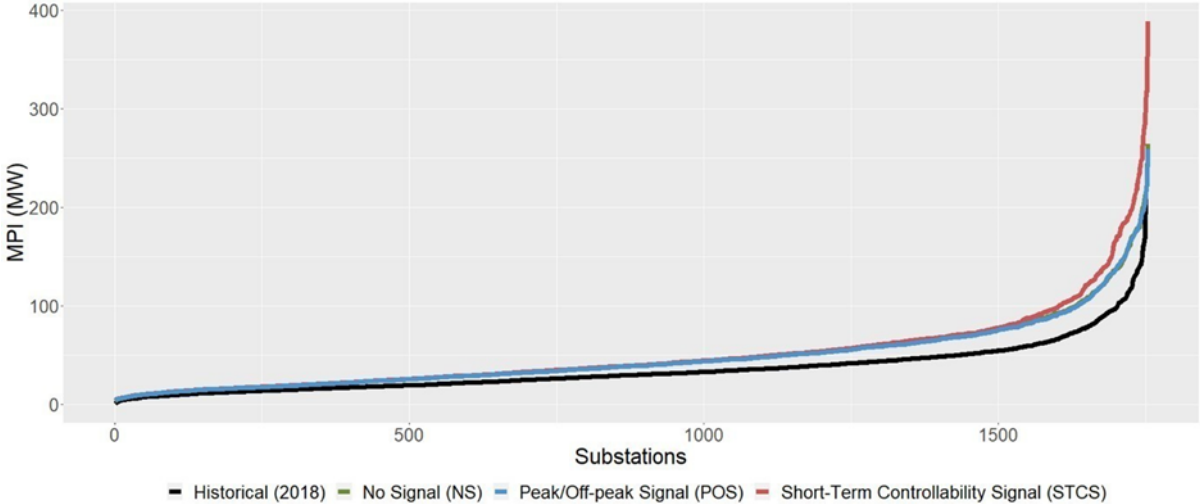


Figure 2- 9 MPIs for the different degrees of flexibility activation and historical MPIs: Mean for the 10 meteorological years of the load maximum power indicator over the 1890 substations of the French distribution network, historical and for the 3 flexibility degrees.

Figure 2- 10 shows the impact on a substation with a lot of EVs of each of the test cases. With the STCS test case, the EV load notably is narrowed on a few time steps creating high consumption spikes. This explains why the MPIs are the highest for the STCS test case. The POS test case and NS test case have both a smoother load curve, at the origin of lower MPIs.

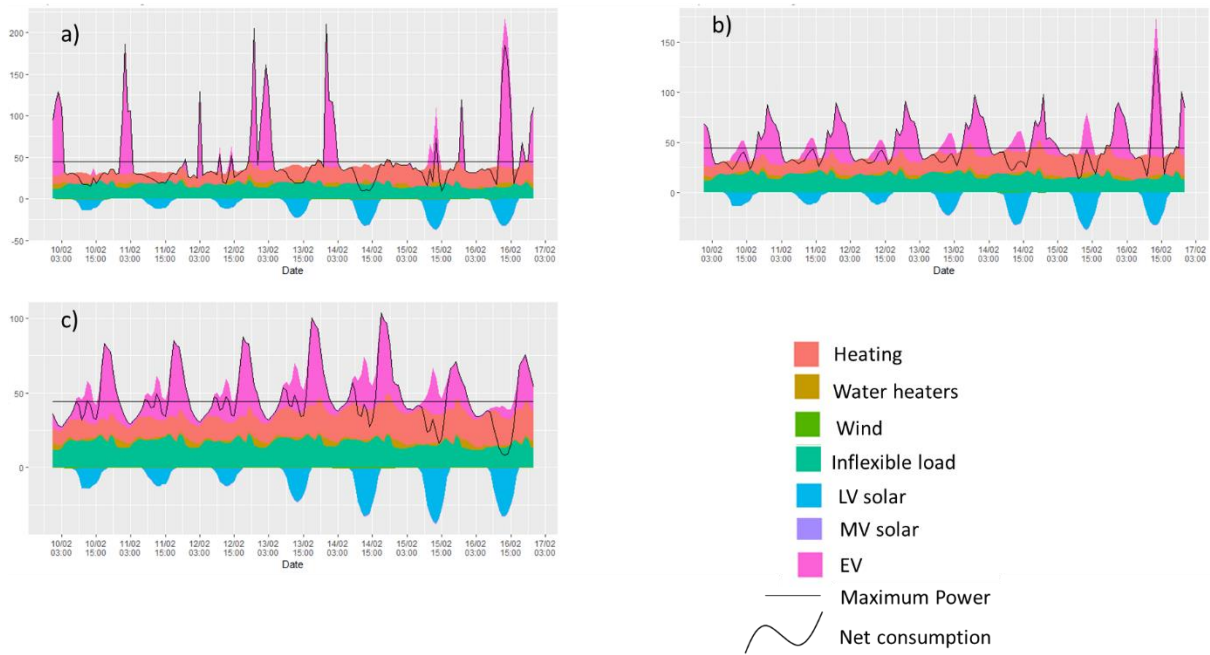


Figure 2- 10 Breakdown of the national load and renewable production curve on a substation for a) STCS (Short-Term Controllability Signal), b) POS (Peak/Off-peak Signal) and c) NS (No Signal) test cases, with the indication of the historical Maximum Power for the substation and the net consumption.

The evolution of the MPIs lead to the reinforcement costs presented in Figure 2- 11. These costs are higher for the STCS test case which is linked to the higher MPIs for this case. The monotonous can be divided in four category for further analysis in Figure 2- 12.

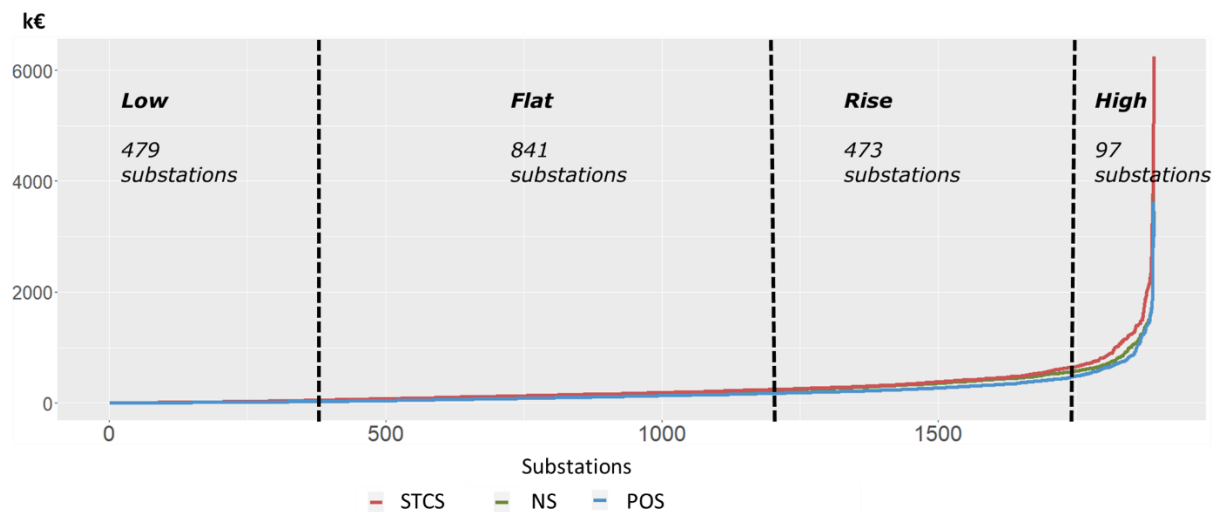


Figure 2- 11 Monotonous of the reinforcement costs of the substations: the monotonous is divided in three parts. The “low” part contains 479 substations with very low reinforcement costs. The “flat” part contains 841 substations with relatively low reinforcement costs. The “rise” part contains 43 substations with higher reinforcement costs. And the “high” part contains the 97 substations with the highest reinforcement costs.

Figure 2- 12 analyzes the causes of the reinforcement costs for the four categories depicted in Figure 2- 11. It shows that it is mostly the load that cause reinforcement costs, for all the three test cases. The higher the costs, the greater the cost difference between STCS and other studies. The difference

between reinforcement costs for the “high” category is explained by the EV flexibility activations, as shown in Table 2- 5.

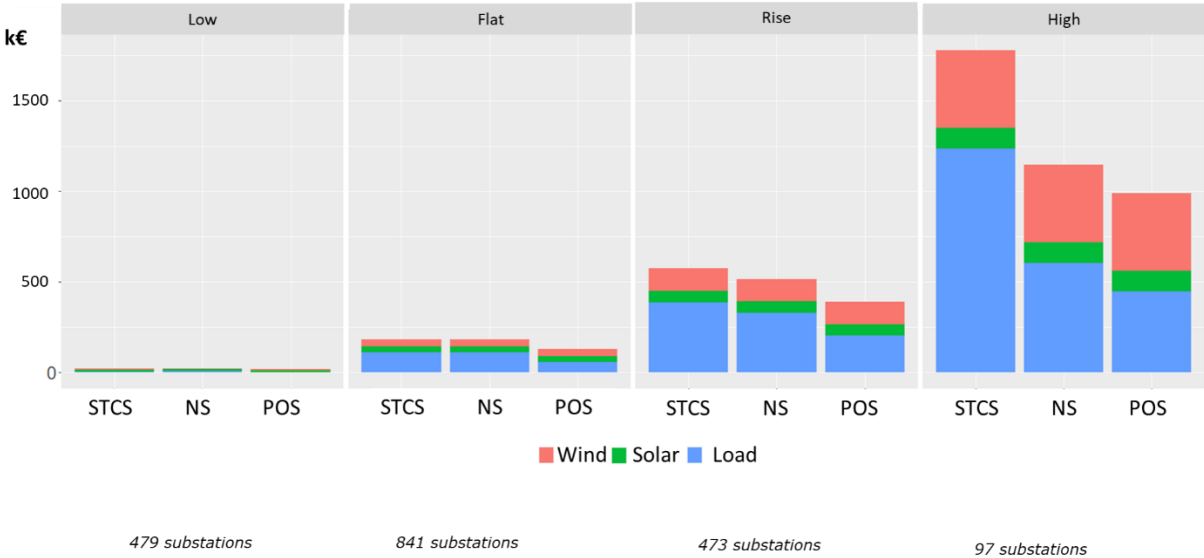


Figure 2- 12 Repartition of the reinforcement costs between their three causes: wind, solar or load, for NS (No Signal), POS (Peak/Off-peak Signal) and STCS (Short-Term Controllability Signal) cases. The repartition costs are analyzed for four categories of substations corresponding to the categories from the monotonous of Figure 2- 11

The MPI increase compared to the historical (2012-2016) value is higher for the STCS than the other signals for 36% of all substations. Table 2- 5 shows these substations are those where EV charging stations are concentrated and EV flexible consumption creates the highest spikes in load, i.e., the share of EVs in the load at the peak is high. The higher the consumption spikes, the higher the reinforcement costs: the 10% substations with the highest MPI, which are the substations with the highest number of EVs on average, account for 36% of network reinforcement costs.

% of highest STCS MPIs	Average number of EVs per substation	Mean share of EVs in load at peak (%)	Share of total reinforcement costs (%)
10	38445	24,3	35,7
25	19526	13,0	57,0
100	6321	4,7	100

Table 2- 5 The average number of EVs, the average maximum ratio between EV power and the rest of the consumption, and the share of total reinforcement costs for substations being respectively in the 65, 35, 25, and 10 % highest STCS (Short-Term Controllability Signal) MPIs.

Figure 2- 11 shows that for POS and STCS consumption management, the MPIs are rather similar. The incitement of flexible consumption via a long-term tariff signal thus seems an interesting compromise between implementation costs and the reduction of the overall costs of electricity provision in the presence of load spikes due to the effects of EV utilization.

4.3 Cost-benefit analysis without a DSO filtering signal

Once the reinforcement costs for France’s 1890 substations are computed, they are combined with the operational and loss-of-load gains of Figure 2- 8 to provide a cost-benefit analysis of both the STCS (Short-Term Controllability Signal) case and the POS (Peak/Off-peak Signal) case compared to the absence of any incentive for flexibility activation (NS (No Signal) case).

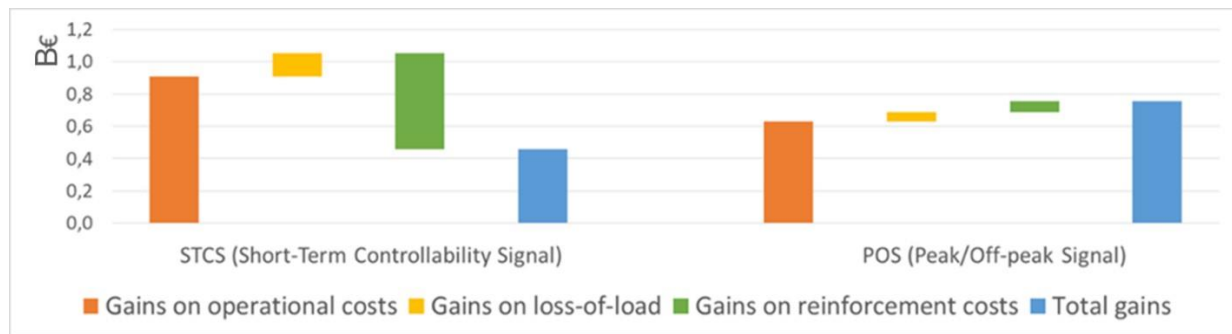


Figure 2- 13 Mean of total gains for France over the 10 meteorological years of STCS (Short-Term Controllability Signal) and POS (Peak/Off-peak Signal) against the NS (No Signal) consumption for 2030

Flexibility thus enables substantial gains for the entire system whenever it is activated with a short-term signal or with a long-term “peak/off-peak” signal (Figure 2- 13). The POS is the flexibility control signal that has the highest total gains compared to the NS test case (about 800 M€). With the use of a peak/off-peak (POS) signal to control the flexibility, production and loss-of-load gains are lower than for the STCS case, representing about 600M€, but network reinforcement gains are positive, meaning network reinforcements are less than in the NS case. This makes the POS more interesting than the STCS in terms of total gains, which are 67% higher for the POS. This result is obtained with a peak/off-peak signal that is not locally differentiated, which differs from current practices.

For STCS, the very high gains in terms of generation costs (operational costs + loss-of-load), accounting for about 1B€, are counteracted by the 0.6B€ of extra distribution network reinforcement costs mainly caused by the EV charging spikes. The gains in generation costs are slightly optimistic as flexibility activations are not constrained by frequency regulation issues. Flexibility activations also do not consider possible power limitations because of customer contracts with fixed maximum power, which is not adapted to EV peak charging. Taking into account those limitations would tend to smooth flexibility activation over time with probably lower gains on generation costs but also lower reinforcement costs.

Thus, this study leads to two major conclusions on flexibility value in the French context of historically well-developed networks. First, flexibility activation has significant value for reducing the overall costs of electricity provision in the presence of large amounts of VRES, whether controlled with a short-term signal or with a peak/off-peak signal by acting on operational costs and the need for curtailment. Second, a peak/off-peak signal (POS) appears to constitute at this stage the best signal as while being

easier to implement and more transparent for the consumer, it allows the greatest overall economic gains by inducing less network reinforcement costs than the Short-Term Controllability Signal (STCS).

4.4 Cost-benefit analysis with a DSO filtering signal

An additional filtering signal to constrain activations has little effect on the gains in production costs. Indeed, constraining the sum of the MPIs of the constrained substations to the sum of their NS (No Signal) MPI with the DSO national filtering (« Filtered STCS ») only increases the costs by 2,4 M€ (Figure 2- 14), which represents only 0,004% of total costs. In particular, it should be noticed that the filtering has few effect on loss-of-load, and thus maintains the capacity value of the demand-side flexibility. One might have feared that during the very cold winter weeks, which are both dimensioning events for the networks and for the supply-demand balance, the constraints linked to filtering would deteriorate the situation at the national level. This effect seems very small, either because the dimensioning events at the local level are sufficiently distinct from those at the national level, or on the contrary because they are well aligned and the demand shift is both favorable to the networks and to the supply-demand balance. It is likely that both types of situations occur locally.

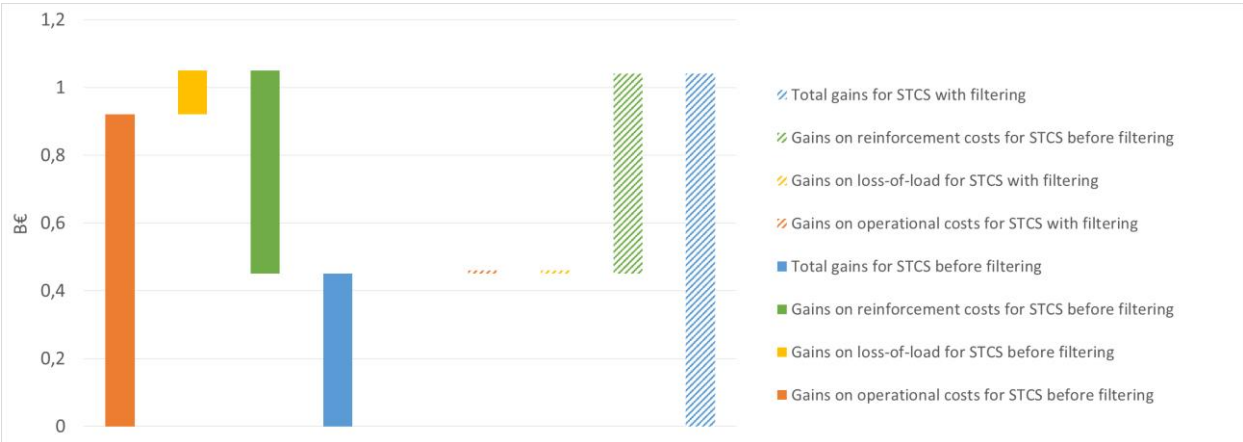


Figure 2- 14 Comparison of costs difference for the STCS (Short-Term Controllability Signal) before filtering and the “Filtered STCS”, with the NS (No Signal) test case

However, filtering of activations enables a large decrease in reinforcement costs for the STCS (Short-Term Controllability Signal) case. After filtering, the distribution of activations by substations has been optimized for the most constrained week over the 10 meteorological years (week 27 of year 10, Figure 2- 16), with about 1500 constrained substations. For this week, 480 substations have exceeded their no signal MPI of 4591 MWh. This represents about a 95% overload decrease compared to an average activation of flexibilities per substation. The decrease enabled by the optimization is assumed to be the same for each week of the simulation, even if in our case only one week has been tested. For all weeks, the residual constraints are slight and can be accommodated with reinforcement costs of only

5,2M€. This implies that from the 595M€ of reinforcement costs caused by the STCS without filtering, only 5,2M€ remain after filtering, which is less than 1%.

The lowering of reinforcements cost in « Filtered STCS » compared with STCS allowing significant benefits of 590M€, shows that the implementation of filtering would be a very interesting improvement of the STCS. This is twice as much as the value of flexibility for the distribution network stated in Enedis’ documentation, which only accounted for RES connection flexibility (Enedis, 2019). The “Filtered STCS” becomes economically more interesting than the POS (Peak/Off-peak Signal) with 1B€ of gains compared to the NS signal, while the POS achieves almost 0.8B€ of gains. However this 0.2B€ of additional gains for the “Filtered STCS” should be put in perspective with the additional complexity this signal requires, induced by both the short-term controllability and the filtering process. The gains on reinforcement costs are concentrated on very few substations that account for most of the filtering gains on reinforcement costs (Figure 2- 15). More than 90% of total reinforcement cost gains accrue in only 3% of substations (57 substations). The maximum gains, reached for substation “J.BRU” are of 37,4€/kW/year, which is somewhat above the estimate of 24€/kW/year provided in (Enedis, 2017) and (E-cube, 2017).

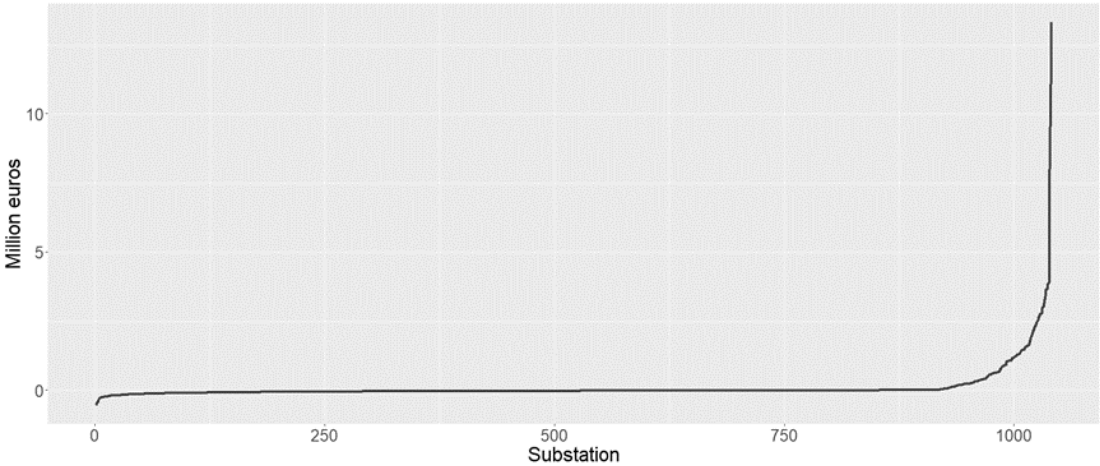


Figure 2- 15 Monotonous of the gains on reinforcement costs per substation with filtering compared to the STCS (Short-Term Controllability Signal) costs

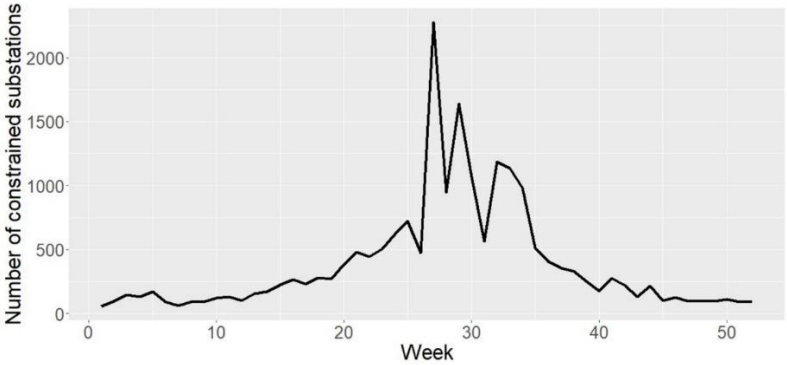


Figure 2- 16 Sum of constrained substations for each week over the 10 meteorological years

5 Conclusions

This chapter focuses on the value of flexibility for reducing both generation costs and distribution network reinforcement costs from a system-wide perspective. In the first case, the value of flexible load displacement compared to a situation where the load is fixed is assessed in terms of capital investments at the level of the distribution grid, operational gains in electricity generation, and curtailment costs. In a second case, activations are limited by the provision of a filtering signal to avoid excessive power surges on the distribution grid. Comprehensive microdata regarding flexibility resources and network operations available at the French TSO RTE-France is used. Two key results emerge from this work.

First, flexibility is valuable. This study shows that the benefits of activating flexibility assets through the Short-Term Controllability Signal (STCS) are important in terms of the combined savings on operational costs and curtailment costs. Indeed, the distributed flexibility activated through the SCTS allows a 1.1B€ gain in terms of operational costs and curtailment costs in comparison with a situation, in which no flexibility is activated. However, reinforcement costs at the level of the distribution network required by flexibility activations through STCS (Short-Term Controllability Signal) represent 0.6B€, which counterbalance the aforementioned savings resulting in a reduced overall gain of 0.4B€. We also studies the impact of a long-term, rather than a short-term, flexibility activation signal, a Peak/Off-peak Signal (POS) for which the total gains are 67% higher than in the Short-Term Controllability Signal (STCS) case. While the POS (Peak/Off-peak Signal) has lower operational and curtailment gains than the STCS (Short-Term Controllability Signal), the reinforcement costs are lower than the NS (No Signal) case for this signal, resulting in higher overall gains. This result is obtained with a peak/off-peak signal that is not locally differentiated, however it is not currently the case.

Second, this study has simulated the advanced transmission of a filtering signal constraining activations that would exceed the capacity of the distribution grid. Filtering the flexibility activations under the STCS (Short-Term Controllability Signal) ensures that net consumption power peaks at each substation do not exceed the Maximum Power Indicator (MPI). While the savings in operational and curtailment costs for filtering are slight, there are considerable reductions in DSO network reinforcement costs. For the STCS (Short-Term Controllability Signal) such filtering nearly eliminates the need for reinforcing distribution networks reducing reinforcement costs by 590M€. Thus, STCS (Short-Term Controllability Signal) with filtering reaches more overall gains than the POS (Peak/Off-peak Signal), with 0.2B€ additional overall gains. This might have advantages in particular institutional settings or under specific distributional arrangements. These gains are concentrated on a subset (3%) of substations. However, while the STCS (Short-Term Controllability Signal) provides the greatest amount of economic benefits in the case of a filtering process minimizing reinforcement costs, it has some shortcomings of its own: it is less acceptable to consumers as it entails a precise tracking of their consumption. Such tracking is necessary due to the uncertainty concerning consumption. It is not necessary, however, with a predictable POS (Peak/Off-peak Signal). The filtering process for the filtered STCS (Short-Term Controllability Signal) adds a layer of complexity.

The work presented in this study is concerned with system-wide cost minimization through one centralized optimizing algorithm. Future work will concentrate on adding more institutional structure to the activation of flexibility and its impacts on system operations. This will extend to the study of real-time activation schemes in short-term markets including day-ahead and balancing markets. The analysis will thereby move progressively closer from general considerations of minimizing the overall costs of electricity provision to the analysis of the functioning of real-world markets for flexibility provision.

Résumé en français : La première étude de cette thèse discute la valeur de la flexibilité de la demande française pour le système électrique européen en 2030, en considérant deux postes de valorisation majeurs : sur le marché de gros, afin de minimiser le coût de production, et sur les réseaux de distribution français, afin de d'éviter des coûts de renforcements. Dans un premier temps, cette étude est menée en utilisant un outil calculant un dispatch optimal sur l'Europe de l'Ouest, pour valoriser l'apport de la flexibilité distribuée sur le marché de gros, représenté comme un marché parfait. Les éventuelles contraintes générées sur près de 2000 réseaux de distribution français s'expriment sous la forme d'un dépassement de la « puissance maximale » d'un poste source. Elles sont traitées par une modélisation simplifiée des décisions de renforcements de ce réseau. Cette première étape montre que la valeur de la flexibilité pour les marchés de gros est d'autant plus importante que le pilotage est fin, mais qu'un pilotage fin engendre également des coûts de renforcement élevés sur le réseau de distribution, rendant ainsi un pilotage de type heures-pleines/heures creuses plus intéressant du point de vue du système électrique dans son ensemble. Dans un second temps, on fige le renforcement du réseau à sa valeur sans activation de flexibilité (donc plus basse qu'avec un pilotage fin) et mais on garde un pilotage fin de la demande. On simule une coordination entre réseau de distribution et marché de gros en déplaçant les activations de flexibilité sur le marché de gros quand celles-ci génèrent une contrainte sur le réseau de distribution. Cette coordination permet de s'affranchir presque entièrement des surcoûts de renforcement, tout en ne diminuant que très peu les gains sur le marché de gros, le pilotage plus fin devient alors plus intéressant, avec environ 1 milliard de gains totaux.

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Conclusions

This thesis focuses on the value of distributed demand flexibility in the context of the energy transition, with in particular the development of electric vehicles. This value is considered in the context of wholesale markets, in coordination with local constraints at the distribution network level. This work has been carried out with tools developed at RTE, allowing a fine modeling of the European electrical system for Chapter 2, and of the short-term market sequence for Chapter 3, each time with precise prospective data at both local and global scales. It allowed both to estimate the value of flexibility at the level of France and to explore the interest and operating conditions of a coordination within the wholesale markets to manage local congestion on the distribution network, while valuing the flexibility distributed on the markets.

Chapter 1:

This first chapter allows us to contextualize this thesis work. It describes a power system in mutation, whether it is at the physical level (impact of renewable energy on the networks), the economic level (transformation of the markets) or the institutional level (evolution of the role of the DSO). It presents flexibility as a means to cope with these changes, as it is defined as "the power system's ability to cope with variability and uncertainty". The value of flexibility for the power system is understood through the explanation of the mechanisms that allow to valorize the flexibility of the demand, which currently concerns mainly load shedding, and by giving elements of literature on the local and global valorization of this flexibility.

This general context being established, the scope of the flexibility studied in this manuscript are then defined. The flexibility of distributed demand concerns the possibility to reschedule flexible uses of consumers connected to the distribution network. The electric vehicle in particular could be a distributed demand flexibility that represents a significant displaceable volume. The flexibility on which this work focuses, i.e., EVs, domestic hot water and the postponement of heating, falls into the category of storable, displaceable means with a low impact on the consumer. Distributed demand flexibility is still not very valued in market mechanisms because it represents little power, but its growing impact on the distribution network and its potential value for supply-demand balance and congestion management could change the game. A literature review focusing on these two value items, i.e. avoided network reinforcement costs and minimization of generation costs, shows a fairly high gain from using flexibility to reduce generation costs compared to using it to reduce network reinforcement costs, which gives an initial insight into the results of the study in the next chapter. This introduction also presents the state of the art of congestion management on the distribution network with distributed flexibility. This review gives an overview of the merits and feasibility of several long- and short-term coordination modes between the wholesale market and the DSO that are currently being considered or even experimented for the use of flexibility.

Chapter 2:

This chapter focuses on the fundamentals of the value of flexibility for the power system by considering two main valuation items: valuation at the global level, on the wholesale markets, to minimize production costs and valuation at the local level, via the DSO, to reduce the reinforcement costs of the distribution network.

This chapter allows us to draw several conclusions on the value of flexibility for the power system. This value is not negligible in terms of reducing the cost of supplying demand via the wholesale markets, including a reduction of operational generation cost and unsupplied energy¹ but the network impact of this flexibility leads to significant reinforcement costs in the case of a controlled signal applied without paying attention to its impacts on the distribution grid.

In the study, the gains from the use of flexibility for the electric system are the most important in the framework of a controlled signal with short-term coordination. Indeed, a coordination avoids most of the additional reinforcement costs of centralized management with little impact on wholesale markets and on avoided unsupplied energy. The tariff signal comes second and the signal without filtering comes last. Thus, it seems that in order to make the controlled signal more interesting than the tariff signal, which is simpler to implement and has a higher acceptability, it is necessary to couple it to a coordination mechanism with the distribution network, which is a priori complex to implement. The gains for the power system as a whole from the use of flexibility achieved by the time-of-use tariff signal, which represent about $\frac{3}{4}$ of the gains achieved by the (near real time) controlled signal with filtering, do not necessarily justify the choice of a controlled signal given the additional complexity that this would imply. This first study does not allow us to draw any conclusions regarding the actual implementation of a filtering mechanism in the wholesale markets, but it already allows us to give a quantification, at the scale of France, of the value of flexibility for the power system.

Chapter 3:

In this chapter, the impact of short-term forecast errors on the value of flexibility, on the one hand, and on a short-term coordination mechanism, on the other hand, is studied. Short-term forecast errors are the most important in day-ahead and then decrease in intraday and up to real time. Thus, demand-side flexibilities, whose rescheduling cost is low, benefit from the updating of consumption and production forecasts for solar and wind power at these times by submitting new offers to the market to ensure the new predicted supply-demand balance. The cumulative gains of these flexibilities in intraday and balancing represent more than half of the gains made by the flexibilities on day-ahead.

¹ As it was difficult to evaluate the gains in terms of investments in means of production or storage, we preferred to evaluate the gain in terms of avoided unsupplied energy.

This reinforces the interest of the controlled signal assessed in Chapter 2, which was only studied for a single representative time frame of the wholesale market. Indeed, for the tariff signal, the profiles of use of the flexible capacities are fixed before $D - 1$, without the possibility of making intraday offers and on balancing.

As far as filtering is concerned, it has little effect on the operational costs and earnings of the aggregators, which is consistent with the results of Chapter 2, in which filtering was found to have very little effect on operational costs compared to the case of the controlled signal alone. Even if this result could vary according to the strategies actually implemented by the actors, it suggests that a more complex coordination than filtering would provide little additional benefit. However, the analysis also shows that filtering is only effective in balancing, as demand-side flexibilities are heavily used in balancing and their schedule therefore varies greatly, making coordination in day-ahead and intraday ineffective. The feasibility of such a mechanism at the balancing timeframe is questionable due to the practical constraints they impose. Firstly, offers must be localized, which is not the case in all balancing mechanisms today, and makes the implementation of aggregated offers more complex. Secondly, to manage congestion, filtering must be able to enforce submission of upward and downward offers (in practice to cancel flexible consumption on certain time steps) and this is only possible if the flexibilities have been offered on the balancing market. Thus, coordination would only work well with an obligation for distributed flexibilities to participate in balancing. Third, the balancing process has become extremely complex with the go-live of European balancing platforms, with a need for high automation on the part of the network operators but also of the players to make offers. Compulsory participation in these mechanisms would therefore constitute a barrier to entry that would significantly slow down the emergence of a controlled distributed demand.

General Conclusion

The need for mechanisms ensuring the relevant use of demand response assets by the electricity system is explored in this work. Demand response can on the one hand facilitate the demand-supply balance, which is becoming more complex with the increase in the share of VREs in the European electricity mix. On the other hand, it can be a lever enabling the alleviation of distribution network constraints that are increasing due to new electricity uses. This work shows that distributed demand flexibility has a significant value for the power system, that this value would come mainly from a valuation of flexibility on the wholesale markets, by facilitating the demand-supply balance, but that a coordination between the DSO (for the alleviation of distribution network constraints) and the wholesale market would be more efficient from the point of view of the power system. This thesis thus provides interesting insights on the value of a mechanism coordinating the use of distributed demand flexibility to facilitate the supply-demand balance and to optimize the management of constraints on the distribution network. On the one hand, it proposes a quantification of this value under different hypotheses, with and without a coordination mechanism and for different types of flexibility activation signals. This allows to measure the positive economic impact of a coordination mechanism, with

concrete and realistic prospective values. On the other hand, this thesis also focuses on the operational implementation of such a coordination mechanism. This step is necessary because the operational complexity does not show up in fundamental market analyses. Here, it has been possible to highlight the temporal difficulties of the filtering mechanism, linked to important forecast errors, especially on the demand side, and an algorithmic complexity linked to the location of the market offers of the flexible units on the distribution network. The coordination is currently done in Europe through local flexibility markets, which are decoupled from the wholesale market and mainly deal with distributed generation. However, this work shows some differences between distributed demand flexibilities and distributed generation flexibilities. In particular, demand-side flexibilities have an interest in modifying their schedule until close to real time. This thesis therefore explores short-term coordination through a coordination mechanism called “filtering”, which consists in shifting the flexible demand activations made by the wholesale market in order to avoid congestion on the distribution network. This mechanism theoretically gives interesting results by allowing to increase the value of flexibility for the system, but its real implementation seems to be difficult because of the need to implement it on the balancing. More generally, all short-term coordination schemes seems very difficult to implement because of the high value of shifting consumption in time on an intraday basis and for balancing. Thus, several solutions need to be further analyzed.

The first solution could be to encourage time-of-use tariff signal for activation of demand-side flexibilities. It generates very little additional network cost and allows significant gains by shifting demand to the cheapest periods of the day. This solution does not provide the intraday and balancing gains identified in our study.

The second solution would be to encourage full control of demand-side flexibility and to reinforce the network without considering demand-side opportunities when sizing the grid. With the assumptions taken in our studies, this solution would be more economically interesting than the first one, with more reinforcement cost but also more important gains on the markets. This solution is in practice difficult to implement because an optimal reinforcement of the network need to foresee not only the number of electric vehicles that will connect but also which share of the electric vehicle fleet will actually implement controlled charging management.

The third solution would be to encourage full control of demand-side flexibility and to find another coordination mode. We have investigated on short-term coordination but long-term coordination could be cheaper and easier to implement and allow some benefits compared to the previous solutions.

The choice between these solutions will depend on the level of demand-side full controllability that can be achieved, the short-term needs due to the level of integration of renewable energies and the development of other flexibility solutions. In particular, batteries, electrolysis and heat networks are solutions that can be connected to higher voltage levels and for which the coordination issues between local and national constraints are therefore a little less strong.

Perspectives

First, there are some limitations to the assumptions and methodologies used in this work that could help frame other studies.

- Distributed demand flexibilities are restricted here to EV charging, domestic hot water and heating deferral. Other flexibilities could be added, such as electrolysers, which is generally present in prospective studies. This would make it possible to observe the impact of stronger competition between flexible means on the value of flexibility.
- The political issue of the transparency of filtering actions taken by the DSO has to be furthered analyzed in order to better frame the involved actors and the feasibility of such a mechanism. Regulatory authorities, as well as the TSO in the case of balancing filtering, should probably be able to audit the DSO's filtering decisions, and be jointly held accountable for it.
- On the network side, the calculation of reinforcement costs on the distribution network is very simplified and is based on the assumption that wholesale market have priorities on the use of flexibilities. The modelling could be refined and it would be interesting to determine an optimal reinforcement level, using flexibilities.
- The valuations of the demand flexibilities at different short term timeframes have been done on a single week of simulation (in November), on a given mix and with a low fuel cost assumption. This work shows that under the conditions of the study, the value of adapting the use of distributed flexibility to short-term uncertainties on the intraday and balancing is far from being negligible, whereas it is often omitted in studies that value adaptation to the variability of RES and participation in frequency control. The dependence of this valuation on other periods and other assumptions of energy mix, flexibility and costs should therefore be studied, for example with more solar and wind, or higher fuel prices that would be closer to the current situation, or with more competition between flexibilities (flexibilities in other countries). Mixes with more RES would result in lower prices but probably more value from flexibility in the short term. Indeed, such mixes would increase the short-term forecast errors with potentially more value for flexibility at intraday timeframes.
- The consequences of these findings in terms of optimal mix should also be investigated, with a vision of the gains and costs of implementing large-scale distributed flexible demand management, taking into account uncertainties. This exercise should provide elements to guide the design of a consistent and cost-effective architecture for distributed demand management.

Finally, it would be interesting to study an alternative to the short-term coordination modes described. One alternative could be the adaptation of a long-term coordination mode presented in the introduction and called "long-term capacity reservation". In this mechanism, the DSO announces the forecasted network capacity limitations far from real-time (several month in advance), and flexibility providers bid for the amount of capacity they need.

In order to have a fine management of the available capacity, this mechanism could also be applied on day-ahead. This is because a very early determination of capacities is not well adapted to a context of inflexible and very thermo-sensitive demand, as it is the case in France and increasingly in the rest of

Europe with massive electrification of energy use. Indeed, in this case, the power of the inflexible consumption, and thus the power available for the flexible capacities, varies very significantly according to the temperature and can only be reliably estimated in day-ahead. Our proposal is therefore to set an hourly power limit of the flexible demand per substation² on day-ahead. This limit would correspond to the margin between the inflexible consumption forecast on day-ahead and the maximum power of the substation. It should probably be slightly lower than this margin in order to compensate for possible errors in forecasting inflexible consumption at times closer to real time. Initially, the limitation could be applied in proportion to the flexible demand on that substation, which would make the mechanism less cumbersome than holding auctions.

This mechanism would ensure that flexible demand would not cause congestion, but time-shifting opportunities for flexibility sources would be more limited. There would be a loss of revenue for market participants compared to the filtering mechanism simulated in Chapter 3. It would be interesting to estimate this loss, but the small revenue losses in the case of filtering at all timeframes suggest that it would likely be limited. Indeed, the filtering at all market phases that we evaluated is quite close to this mechanism with two differences: it applies once the offers have been placed and therefore offers less visibility to the actors, and it does not take into account a margin to compensate for unfavorable changes in inflexible consumption.

This mechanism introduces a differentiation that disadvantages flexible demand compared to inflexible demand. It could therefore be complemented with more favorable grid access tariffs. For example, flexibilities participating in this mechanism could be subject to lower access fees for capacity (relative to access fees for consumed energy volume); this would be consistent with the costs of network reinforcements avoided by this mechanism.

² This assumes that providers or aggregators have knowledge of the substations to which their customers are linked, which may vary. An alternative would be to define stable geographical zones, at a granularity very close to that of the substations.

Chapter 3: Proposition of a coordination mechanism integrated to wholesale markets operating under uncertainty, to make better use of distributed flexibility resources: the filtering mechanism

Abstract: The second part of the thesis revisits these conclusions by integrating short-term uncertainties into the approach, which will affect both the valuation of flexibilities on the wholesale markets and the coordination mechanism. The wholesale market is no longer modeled as a perfect market with a single deadline and the sequence of short-term markets, from D-1 to real time, is detailed with the modeling of short-term uncertainties in the "ATLAS" market model. In addition, a coordination mechanism by filtering is inserted at each market deadline, between the moment of the formulation of the offers and the moment of the market clearing. This filtering corresponds to the simplest coordination that can be implemented in short-term markets, but would already significantly modify the current principles: it involves a decrease or cancellation of the volume of offers creating constraints on the distribution networks. This very complex modeling could only be used for one week in 2030, but it has allowed us to highlight interesting conclusions on the gains of flexibilities at different market timelines and on coordination mechanisms. Since the cost of controlled demand shifts is very low, provided that the constraints corresponding to user needs are respected, flexible demand can perform a lot of intraday arbitrage and the associated gains are significant. In the simulations, they represent more than half of the total gains. This result can modify the conclusions of prospective studies, which rarely take these timeframes into account. In particular, real-time control would be much more interesting than "time-of-use" control, since these gains are only possible with fine-grained control. As far as filtering is concerned, it could only manage congestion close to real time and on the condition that the flexibilities offered at the previous deadlines are obliged to offer again, and with a precise location, which raises questions as to the possibility of a concrete implementation, especially in terms of the complexity of processing so close to real time for both network operators and aggregators.

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1. Introduction

Some electricity uses, such as electric vehicle charging, or thermic uses are considered flexible as their power curve can be changed to a certain extent, and this flexibility is very valuable for the electric system. In chapter 2, we have shown that the use of demand flexibility at its full potential, in a perfectly anticipated market setting, enables 1b€ of production gains per year for France. This work also explored the consequences of these production gains for the distribution system operator (DSO), as the flexibility uses are connected to the distribution grid. Indeed, the need for reinforcement of the distribution network is about 0.6b€ higher when flexibilities are used to minimize production cost, which leads to a 0.4b€ of cost-benefits balance for the electricity system. To decrease this cost, a compromise has been reached between the use of flexibility to minimize production and network reinforcement costs, by avoiding the activation of flexibility when networks are constrained, enabling a 0.5b€ decrease in reinforcement costs, while only marginally decreasing production gains. Thus, a mechanism that would prevent market flexibility activations when these activations are constraining for the distribution network, could increase the cost-benefice balance to 0.4b€ to 0.9b€.

This work shows that the coordination of flexibility activations between DSO and other market actors (producers, aggregators) is a key element in the optimization of social welfare and congestion management. But this work was based on a perfect market assumption and particularly with perfect information. In reality, a process enabling market actors to use and value flexibility on wholesale markets under the distribution network's constraints is needed. Such a process is called a coordination mechanism.

Distributed flexibility being a quite new and growing asset, distribution congestion management literature is less abundant than for transmission networks, where current mechanisms are based on widely implemented and heavily tested methodologies (whether it is nodal prices or re-dispatching). Coordination between DSO/TSO and market actors for distribution network's congestion management is difficult to put in place and the regulatory framework around this issue is quite loose. Moreover, distributed demand flexibility is not very developed yet and the existing mechanisms focus more on decentralized production. The electric vehicle expanding significantly (50% of electric vehicles in France by 2035, date ending the sale of combustion engine vehicles, or about 10 millions (RTE, 2019)), it is now considered an interesting asset in such mechanisms. A coordination mechanism for the use of distributed demand flexibility seems very important as the consequences of non-coordination can be both non-economically efficient and dangerous for the security of the system.

In this article, we aim at answering the following question: What are the economic stakes of coordination for activation of demand flexibility at the different market closure times (day-ahead, intraday, and balancing) taking into account imperfect information and particularly local forecast errors? Constraining flexibility activations that create congestion on the distribution network, as implemented in the previous work in the setting of a perfect market, will be here tested with realistic modeling of the short-term market sequence, from day-ahead to real-time with the evolution of consumption and production forecasts along this sequence.

To do so, we will first look at the literature about error forecast for load and renewables and then determine the particularities of the coordination modes to be taken into account in our simulations, with a special focus on the constraints on the moment of coordination. Next, we will present the simulation methodology, which is based on the use of the ATLAS process for simulating short-term markets. To make our simulation we have implemented in ATLAS distributed flexibilities offers and an offer filtering process. Then, the results will first present elements on the valuation of distributed flexibilities before focusing on the filtering results. Finally, these results will be discussed and in particular the conditions for the success of a short-term coordination mode will be clarified.

2. State of the art

Short-term coordination for congestion management benefits from a growing interest in the literature. This literature proposes several coordination modes. However, it rarely takes into account practical difficulties that could arise in the implementation of these coordination modes. This section focuses on these aspects. First, in section 2.1, the modelling of short-term forecast errors for short-term coordination is studied. Section 2.2 then describes the coordination modes that can be found in the literature, with a particular emphasis on their implementation complexity. Section 2.3 explains a possible limitation for the practical establishment of a coordination too close to real-time. Finally, section 2.4 analyzes the preferential moment for coordination for each mode.

2.1. Local and national forecast error for load and renewables

In this chapter, we study a coordination mechanism between the DSO and market actors at different moments ahead of real-time. The forecasts on the real-time wind and solar production, as well as the consumption power, vary with the chosen moment, and therefore the actors' decisions vary as well. The accuracy of forecast errors for different moments ahead of real-time is thus an important aspect of the relevance of this work. The study of the coordination between the market and local constraints requires looking at both local and national forecast error.

At the local level, we are interested in constraints related to distributed flexible demands. We will therefore focus on the forecast errors on consumption and on distributed solar, which concern the same lines, while as recalled in Chapter 1, the other RES are generally installed on dedicated feeders.

At the national level, the main uncertainties between D-1 and real time are the consumption error, the wind and solar production errors and the forced outages on the generators. Since we are interested in the coordination process at several points in time, the dynamic of these contingencies are particularly important. For consumption and solar and wind production, this dynamic is continuous while it is discrete for generators outage.

As the complexity of the process to be simulated requires us to restrict the period of time concerned to one week, we have chosen not to insert any group loss because there would have been statistically

only a few events over the week for a country like France and the choice of the moments when this happens would have had an important impact on the results without being statistically relevant.

To visualize this dynamic of decreasing errors by approaching real time, we used forecast data for French solar and wind generation and for load calculated by RTE for each hour of the year 2018, for 36 different time frames (from H-35 to H). The errors were then extrapolated to the installed VRES capacities used in the study in Chapter 2 and which will also be used for this chapter. Forecasts errors decrease as real-time approaches as shown in Figure 3- 1, elaborates with RTE data. Notably, thanks to the observability, enabling to have real-time measurement of RE production, forecasts are improved in the following hours. Observability enables mean forecast errors to be very low a few hours before real-time.

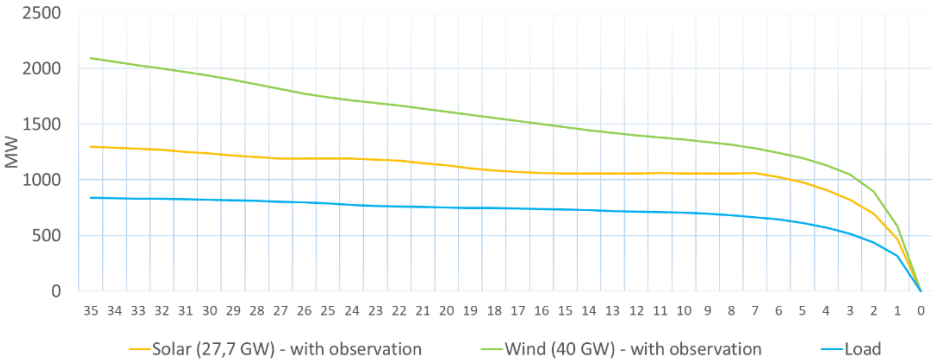


Figure 3- 1 Average of the absolute error values according to the number of hours before real-time for solar, wind and load.

Local forecast errors are rarely taken into account for the modeling of flexible loads. However, it is important to capture the DSO’s risk when procuring flexibility in day-ahead or intraday. When forecast errors are modeled, it is usually made with the randomization of a reference local load curve (Esmat, Usola, & Moreno, 2018) (Diekerhof, Peterssen, & Monti, 2018). A more complex methodology is used by (Zhang, Shen, & Mathieu, 2017), with randomized transition matrixes for the loads. The uncertainty is considered for loads in general, but also renewable production and reserves (Zhang, Shen, & Mathieu, 2017). Local forecasts can be aggregated at a feeder (Esmat, Usola, & Moreno, 2018) or computed for each load (Diekerhof, Peterssen, & Monti, 2018) (Zhang, Shen, & Mathieu, 2017). In (Esmat, Usola, & Moreno, 2018), forecasts are computed for the day-ahead market, to compute congestion probabilities. In (Diekerhof, Peterssen, & Monti, 2018), demand response services can be procured in both day-ahead and intra-day markets but the randomization process stays the same for both terms without taking into account the convergence to real-time.

In the examples found, only the local load curve is accounted for and the resulting aggregated national forecast error is not mentioned. Yet, this resulting error could be very different from the usual national load forecasting error. Having local forecasting errors which are consistent with the national forecasting error is necessary for this study, as both local and national process are simulated. We

choose to use RTE's historical data, which are both realistic and coherent between scales, with the drawbacks of being non-public. This implies also that the quality of forecasts does not improve beyond the improvement of observability.

2.2. Coordination modes

As explained in chapter 1, proposals for coordination mechanisms for the congestion management on the distribution network with flexible assets are plenty in the literature (Valarezo, et al., 2021) (Dronne, Roques, & Saguan, 2020) (Interflex, 2019) (CoordiNet, 2019) (Nouicer, Meeus, & Delarue, 2022) (SmartNet, 2016) (Le Cadre, Mezghani, & Papavasiliou, 2018) (O'Connell, et al., 2012) (Andersen, Hu, & Heussen, 2021) (Verzijlbergh, De Vries, & Lukszo, 2014) (Askeland & Korpas, 2019) and there is no consensus on a most efficient one.

Those coordination mechanisms are classified in our analysis considering the signal of coordination: volume coordination, that directly impact flexibilities power, and price coordination, that impact their prices. In addition, we consider the volumes coordination category entails two different coordination mechanisms: local flexibility markets and filtering. Moreover, the price coordination category entails two other coordination mechanisms: internalization of the price of the congestion on the distribution network and co-optimization.

Local flexibility markets are the most developed coordination mechanism. There are 18 European local flexibility market initiatives (Valarezo, et al., 2021), like GOPACS, NODES, Enera, whose configurations are different from one another, notably depending on the local needs (Dronne, Roques, & Saguan, 2020). Of the four coordination mechanisms local flexibility markets are the easiest mechanism to implement as they are implemented separately from the wholesale markets' sequence. These markets enable to locally manage congestions by using flexible local assets, mainly wind curtailment. This is a first positive step towards the integration of flexible demand and variable production into the distribution network. Currently, this implies that either suppliers choose one of the markets, and therefore reduce liquidity on the intraday or flexibility market, or they choose both but are at risk of not being able to follow two commitments made on both platforms.

Filtering is the easiest way to integrate the distribution network's constraints into the wholesale markets¹ and thus to avoid the drawback of local flexibility markets but it is still much more complex to implement than local flexibility markets. Congestion management with filtering is done via the suppression, by the DSO, of the most expensive offers (resp the cheapest requests) that would create some congestion on the network. This mechanism can be implemented in various short-term markets (day-ahead, intraday, and balancing) and its complexity may depend on the market in which it is inserted. In particular, this mechanism works with localized bids, which is generally not the case in

¹ The filtering process is modeled in different ways in four demonstrators across Europe (Interflex, 2019), (CoordiNet, 2019), (Nouicer, Meeus, & Delarue, 2022), (SmartNet, 2019). All these examples are local flexibility market designs with DSO at the origin of the filtering for congestion management purposes. But, filtering could also be integrated in wholesale markets.

Europe for the day-ahead and intraday markets² and only the case in some countries for balancing. With perfect market hypothesis, merit-order filtering allows at least similar economic efficiency as DSO activation on a local flexibility market. Indeed, when the DSO filters the most expensive offers to prevent congestion, the last accepted offer's price would have been the price offered by the DSO to activate flexibility on a local market to cope with the same congestion, if the flexibility assets were the same in both cases.

With price coordination, complexity goes up along with economical optimality. With internalization of the price of the congestion on the distribution network, to limit the demand which congests the distribution network, the DSO uses a localized price signal, by adding a congestion cost to the bids on the distribution network or subtracting this cost from the requests. Therefore, the DSO must be able to compute these congestion costs, in a short delay, between the moment the bids are submitted to the market and the moment the market is cleared. This mechanism is often associated with nodal pricing (Patnam & Pindoriya, 2021) (Bai, Wang, Wang, Chen, & Li, 2018) (Faqiry, Wang, & Wu, 2019) but this principle can be applied to the zonal model with localized bids.

With co-optimization, this congestion cost can be the result of a co-optimization in a theoretical framework of extensive information exchange between stakeholders. Network constraints are directly taken into account in a global optimization problem, leading to intensive data exchange (SmartNet, 2016) (Le Cadre, Mezghani, & Papavasiliou, 2018). Of course, it is an ideal coordination mode that is not achieved otherwise than in theoretical cases. Intermediate variants are described in the literature with extensive DSO involvement in the aggregators' planning, pushing towards co-optimization (O'Connell, et al., 2012) (Andersen, Hu, & Heussen, 2021) (Verzijlbergh, De Vries, & Lukszo, 2014) (Askeland & Korpas, 2019).

This short description shows a fairly strong gradation in terms of implementation difficulties, with many local flexibility markets already in place but potentially significant difficulty in inserting coordination into the market through screening. Then, the price coordination and co-optimization modes present even more implementation difficulties, with in particular a question of calculation time more or less dimensioning according to the moment of the coordination. Before focusing on this topic, we will focus on temporal constraint specific to balancing market.

2.3. Temporal constraint in a balancing coordination

The specific case and timing of the existing balancing markets is explained in this section. The currently ongoing integration of balancing electricity markets is based on common balancing platforms. These are expected to reduce balancing costs across Europe and help deploy REs. The resulting implementation projects are ambitious and impose very time constrained processes. We illustrate that

² Italy for example has localized bids in day-ahead and intraday but is an exception.

with TERRE process, knowing that this is only the first of the balancing platforms set up, several other platforms should arrive soon, notably MARI and PICASSO, and have parallel processes³.

TERRE process is bound to evolve over time. Today, it is an hourly auction covering four quarter, with a half hour delay between clearing and full activation (targeting products with mobilization times of 30 minutes or less). It is planned to evolve to an auction every fifteen minutes, over two quarters of an hour, keeping the 30 minutes for activation to respect an operational window size⁴ of 1h15. Sequencing of actions is described in Figure 3- 2 for two auctions and a zoom on the first 20 minutes are given in Figure 3- 3.

Example of possible TERRE process with clearing every 15 minutes

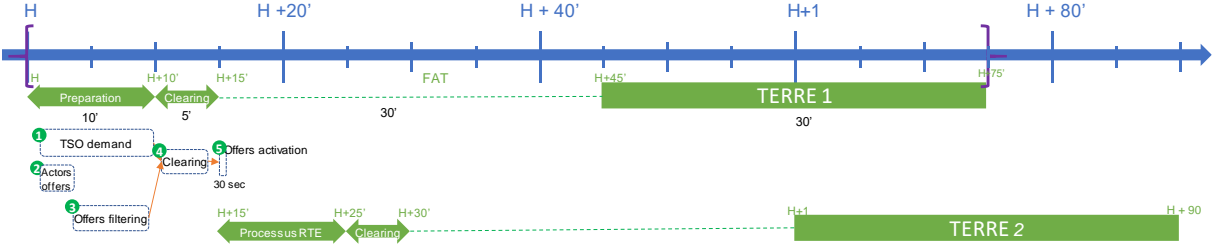


Figure 3- 2 Example of possible TERRE process with clearing every 15 minutes, general view on two auctions (FAT = Full Activation Time)



Figure 3- 3 Example of possible TERRE process with clearing every 15 minutes, zoom on first 20 minutes

The time constraints for the preparatory phase and clearing are given by the size of the operational window on which the platforms are supposed to be able to act (here 1h15), by the product mobilization time (here 30 minutes) and by the maximum activation time (here 30 minutes, corresponding to the two quarters). This leaves 15 minutes for the preparation and clearing processes. Clearing in 5 minutes is accessible, though challenging, and therefore leaves 10 minutes for offers and requests from TSOs.

In 10 minutes the offers must therefore be made and transmitted by the players to their TSOs, who must then examine those that may jeopardize the grid security. These two processes can therefore

³ See https://www.entsoe.eu/network_codes/eb/ for more information.

⁴ Duration of the moment during which the TSO can take operational measures

only take a few minutes each, which is very constraining for market players, who have just received the results of the previous clearing, and for TSOs, who must check that the bids do not pose a threat to safety in a few minutes. A coordination between TSOs and DSOs in the market would therefore take place within these few minutes.

2.4. Moment of the coordination

In the literature, mechanisms are generally studied at one specific moment of the wholesale market’s sequence, whether it is day-ahead, intraday or balancing (for DSO/TSO coordination). For each short-term coordination mode, we are looking at the moments at which the literature have studied them preferentially and, for balancing, confront it with the temporal constraints mentioned in 2.3. In Figure 3- 4, some coordination mechanisms, whether they are theoretical or real implementations, are represented considering their moment of coordination with the wholesale market. It is to be noted that real implementations are in the vast majority local flexibility markets that take place in intraday.

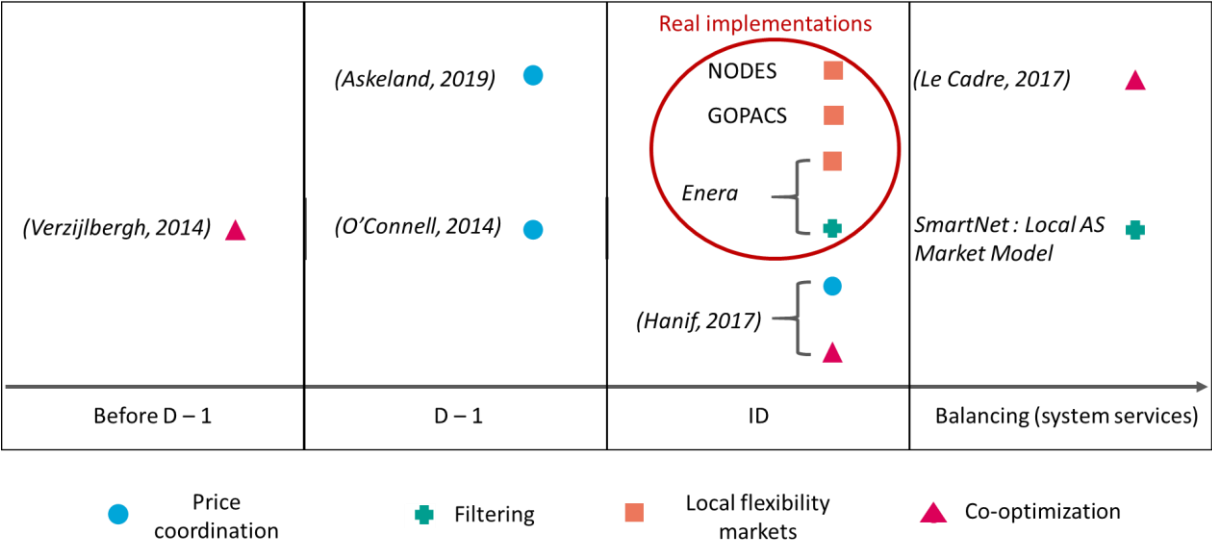


Figure 3- 4 Representation of the moment of coordination for different existing coordination mechanisms or mechanisms presented in the literature.

Co-optimization is the only mode for which there is no preferential timeframe in the literature. It is mainly because co-optimization is theoretical and is mainly used as a benchmark for the other modes and therefore compared to them in their own timeframes.

For short-term price coordination most articles describe day-ahead computation of the congestion cost. This is also noted in (Christensen, Ma, & Jorgensen, 2021). There are some exceptions, as (Hanif, Massier, Beng Gooi, Hamacher, & Reindl, 2017) that describes an intraday price coordination. Coordination through prices on balancing does not seem at all realistic, as it would require DSOs to be

able to receive bids, make OPFs on the scale of all potentially constrained stations in order to bring out excess costs and transmit them to the TSOs in a few minutes.

Local markets are mainly in intraday also: the DSO turns to them whenever day-ahead settlement can create a constraint on the distribution network. On an intraday basis, not coordinating flexibility activations with the wholesale markets seems to have little impact. Indeed, the simultaneous activation of offers is unlikely. For near-real-time use however, the lack of coordination with balancing can lead to different risks depending on the design and the quantities concerned. The simultaneous activation of offers, becomes quite likely during balancing since the time span is much shorter and could thus jeopardize the supply-demand balance. Also, if the re-dispatching is unbalanced (i.e., for example, a single upward offer without having activated a downward offer to compensate), this will have consequences on the supply-demand balance that are more or less troublesome depending on the volume concerned and the general trend of the supply-demand balance.

For filtering, coordination is envisaged either in intraday or in real-time (balancing). Indeed, filtering doesn't request complex computations and is therefore more adapted than price coordination to closer to real-time timeframes. For instance, in the Enea project, the estimation of the state of the network is carried out every 15 minutes, in intraday. Filtering offers from distributed demand on balancing is more realistic than other modes, but remains very challenging. DSOs can calculate a maximal power and an inflexible demand forecast before receiving orders. They will have to compare demand quantities to the difference between maximal power and inflexible demand forecast to determine if a filtering is needed. In this case, the flexible demand must be ranked by merit to determine which offers have to be filtered. This process must be performed on many locations but it can be parallelized.

Thus, this survey shows the implementation constraints of different coordination modes.

The local flexibility market is not coordinated with the other markets taking place simultaneously. This point can be more or less troublesome depending on the time frame. On an intraday basis, this induces little risk, whereas close to real time, it can lead to loss-of-load as there is little time left to take corrective actions whenever an offer is simultaneously activated on both the wholesale market and the local market. As VRES forecast errors decrease significantly a few hours before real time, intraday local flexibility markets seem to be adapted for preventive VRES management. However, this solution is not necessarily adapted to demand side flexibilities, for which forecast errors can follow a different pattern. The adaptation of an intraday management for demand side flexibility needs to be tested.

Filtering is the easiest way to integrate the distribution network's constraints into the wholesale markets but is much more complex to implement than local flexibility markets. In particular, it requires localized bids. In balancing, its implementation would be challenging due to high temporal constraint.

Finally, price coordination and co-optimization are theoretically more efficient but have additional operational constraints compared with filtering, notably due to a need for more information exchange and a need of time consuming algorithm. The implementation on balancing appears as unrealistic and implementation on others time frame raises question.

Those implementation issues can have a determinant impact on economic efficiency. On particular, the best solution will be found knowing the impact of coordination on both efficiency of coordination to reduce congestions and valorization of demand response flexibilities. Our methodology will thus be focused on those evaluations.

3. Methodology

3.1. Principle and variants studied

To evaluate the impact of coordination on both efficiency of coordination to reduce congestions and valorization of demand response flexibilities, we will focus on a coordination mechanism and one of the conditions of its implementation, the coordination timing. It actually seems to be a weakness in the literature surrounding coordination mechanisms for congestion management, as, if multiple examples of local coordination exist, at multiple timeframes, the choice of the best coordination decision timing is rarely justified. Indeed with forecast errors, decisions in the day-ahead timeframe can be inaccurate but the real-time decision can threaten the security of supply.

We will quantify the impact of coordination moment on efficiency of coordination to reduce congestions and valorization of demand response flexibilities for a filtering mechanism. Indeed, it is both an interesting mode of coordination as the most simple to integrate into wholesale markets and the easiest mode to model. The impacts of others mode of coordination will be discussed.

To achieve this, a short-term market sequence is simulated, from day-ahead to balancing including an intraday session. Regarding balancing, this study will focus on manual activations and common market platforms and will not look at the activation of automatic settings (FCR and aFRR), which follows a different logic. A filtering coordination mechanism is included at different moments of the wholesale markets sequence, resulting in five different case studies, and two others with a methodological variants on the filtering process. The study focuses on two flexible means which activations can be filtered: EV charging and water heaters. Both are storage facilities so their use can be displaced to some extent (with maximum and minimum power and stored energy constraints). EV is a rapidly growing flexible asset that is prone to causing constraints on the distribution network because of the new load it adds on network's equipment that is not necessarily sized for this load volume. Water heaters have in France been controlled to a certain extent in order to minimize load curve peaks.

Table 3- 1 shows every filtering case studied in this article:

- The “no filtering” case where there is no filtering at any time;
- The “balancing filtering only” where filtering only occurs during balancing.
- The “intraday filtering only” where filtering only occurs during intraday.
- The “day-ahead filtering only” where filtering only occurs during day-ahead.
- The “filtering at every market stage” where filtering occurs during day-ahead, intraday, and balancing.

	Day-Ahead	Intraday	Balancing
no filtering	-	-	-
day-ahead filtering only	Filtering	-	-
intraday filtering only	-	Filtering	-
balancing filtering only	-	-	Filtering
filtering at every market stage	Filtering	Filtering	Filtering
balancing filtering and fostering	-	-	Filtering with fostering of upward bids
Filtering and fostering at every market stage	-	-	Filtering with fostering of upward bids

Table 3- 1 Summary of the seven filtering variations

Filtering is a one-sided process: it can curtail but cannot foster offers or demands. Therefore, if a demand planning creates an exceeding of the maximum power, there are three possibilities. Either a local upward balancing bid is accepted by the balancing clearing, local demand decrease and the exceeding is diminished or cancelled; or no local upward balancing bid is accepted, and the exceeding remains. Thus, the filtering process doesn't foster the acceptance of upward bids and can therefore fail to prevent exceeding caused by day-ahead and intraday downward activations.

Another process is then tested instead of the balancing filtering in the balancing market: the filtering with fostering of upward bids. The filtering process remains the same for downward bids, but a supplementary possibility is added: the price of upward bids needed to counteract the exceeding are set to the market minimum price (-3000 €/MWh). This ensures the upward bid are accepted by the clearing, except if the minimum price is reached which is not the case in our simulations.

This adds two supplementary variations to the five above, as shown in Table 3- 1:

- The “balancing filtering and fostering” where filtering only occurs during balancing, with fostering of upward bids.
- The “filtering and fostering at every market stage” where filtering occurs during day-ahead, intraday, and balancing, with fostering of upward bids in balancing.

This section then describes the methodology for the implementation of these seven variations. First, the data for wind, solar and load forecast errors in day-ahead and intraday is described (3.2). Then, the modelling platform and the short-term market sequence model used in this study are presented (3.3). Finally, the filtering process implemented for this work is detailed (3.4).

3.2. Local and national Forecast

The first step of the methodology is to compute local and national forecast. Three versions exist for each time-series of the load, solar and wind production: Day-ahead (at 11 AM the day before) and intraday (at midnight the same day) forecasts and real-time load or production. Filtering process will be simulated for France only, as local data are only available for France. Thus, only national/zonal times-series are computed for European countries apart from France, through a multivariate formulation of the distribution function, using a copula approach and taking into account intra- and inter-forecast correlations. This methodology is described in (Kolkmann, Fortin, Böcker, & Weber, 2019).

For France, more localized forecast data is used, at the scale of the substation. This data is extracted from historical operational records of RTE and extrapolated to the 2030 scenario of this study. This extrapolation is made by increasing/decreasing the historical records' power in proportion to the ratio of the 2030's energy to the historical energy.

The studied week from the 28th of October to the 3rd of November is chosen to stall on the availability of this data.

The aggregated local forecasts for load, solar, and wind for France are in Figure 3- 5 and Figure 3- 6.

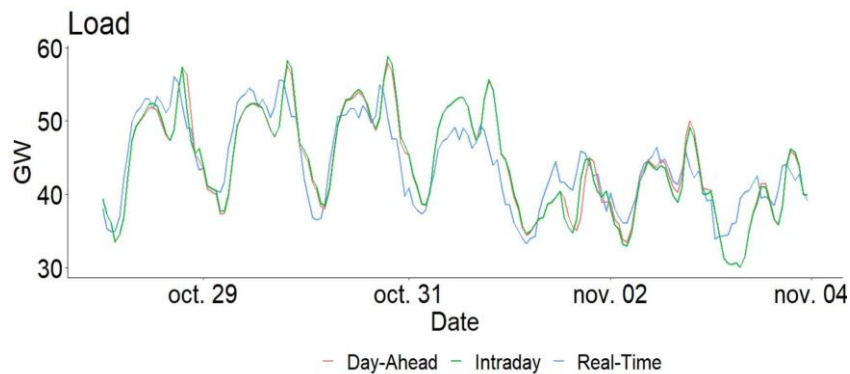


Figure 3- 5 Day-ahead, intraday, and real-time load for France

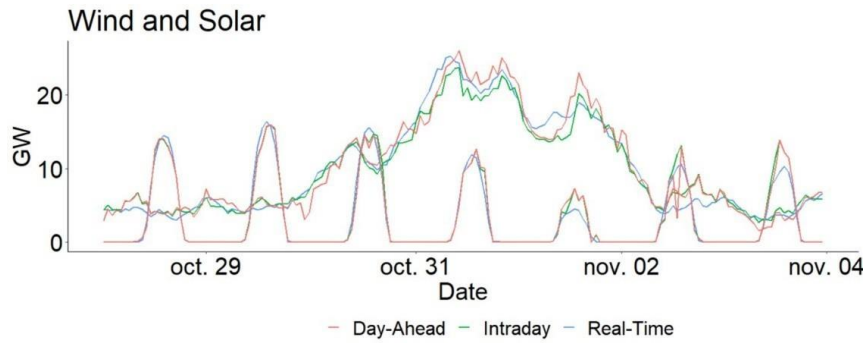


Figure 3- 6 Day-ahead, intraday, and real-time wind and solar production for France.

The forecast errors in day-ahead are shown in Figure 3- 7. They are relatively high, with a mean absolute value of 3,4 GW for the net load.

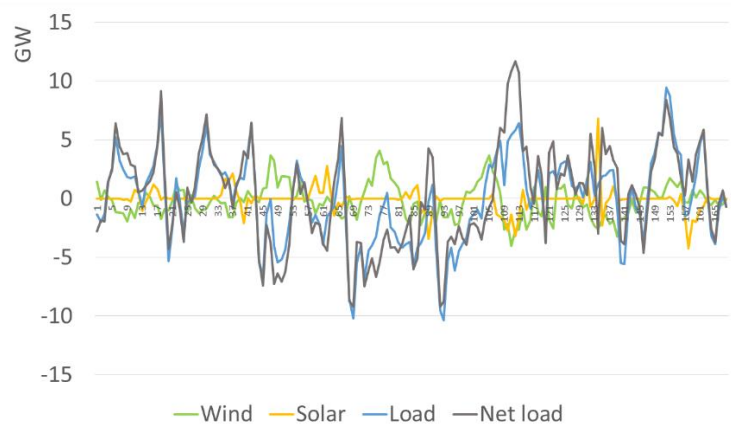


Figure 3- 7 Forecast error over the week of the study (28th of October to 3rd of November), for wind, solar, load and net load.

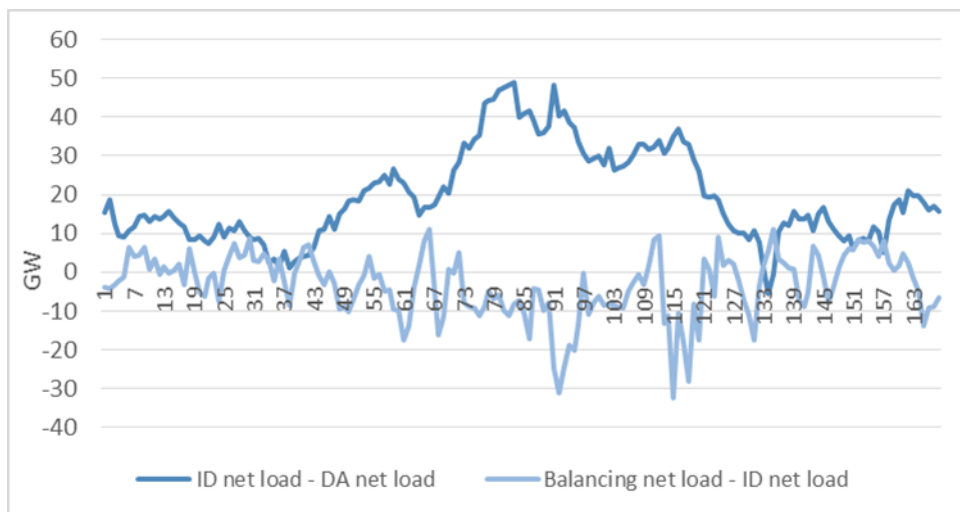


Figure 3- 8 Europe net consumption forecast differences between intraday and day-ahead and between balancing and intraday

Figure 3- 8 shows the differences in net consumption forecasts in intraday compared to day-ahead and in balancing compared to intraday. It shows that net consumption is sometimes higher than anticipated in intraday and that balancing net consumption is lower on average than the day-ahead and intraday forecasts.

3.3. PROMETHEUS and ATLAS

After their calculation, the forecast are integrated into an integrated platform PROMETHEUS. It has been designed by RTE to simplify the creation of energy system simulation models. It is particularly intended for the study of the economic or environmental consequences of the introduction of new regulations or new technologies in the energy mix.

Our study use ATLAS, a market model run on PROMETHEUS which simulates in the same sequence:

- The formulation of offers by market participants the day before and intraday. This formulation is based on estimated marked prices;
- European market coupling (ATC and flow-based) for the different products traded by the players;
- The optimization of the players' production within their portfolio of assets following the results of the various markets;
- The balancing mechanism that models supply-demand equilibrium actions in real-time.

The ATLAS data structure entails:

- An “Equipment” class, comprised of all the hydraulic, storage, thermic, photovoltaic, and wind units as well as “Load” units representing the load of each bidding zone. Each unit has various attributes, some specific to the unit type (minimum time on for thermic units for instance) and others shared by all unit types, among which a maximum and minimum power time series.
- A “Market” class that contains all market data: the market areas (bidding zones), with the market prices time series and price forecasts, the market borders with their maximal flows, the formulated orders, and their constraints.
- A “Market Agent” class with the agent’s portfolios.

This simulation enables the inclusion of the national forecasts at every market stage, day-ahead, intraday terms, and balancing.

The market sequence is composed of different modules. The modules can be classified according to the market stage they correspond to, whether it is “Day-Ahead”, “Intraday” or “Balancing”. In the following sections, we give a short description on those modules, focusing more on the modeling of EVs and water heaters, specific to this study. A more detailed description is given in (Cogen, et al., 2022).

3.3.1. Day-ahead modules

The day-ahead process consists of four steps, described in Figure 3- 9.



Figure 3- 9 Day-ahead primary process.

The first step is an optimization taking into account day-ahead price forecasting, for each bidding zone. Those day-ahead price forecast are the marginal cost calculated on the case study by Antares, the tool used in Chapter 2. This estimated price is not the day-ahead market price, but enables bidders to formulate their bids and notably to place the start-up moments for semi-base and peak units. Then for each unit, the hourly optimal planning is identified considering the price forecast of the relevant bidding zone. This planning is computed over the next 36 hours, in order to give hints on the future economic context to the units with high temporal constraints. As flexibility is the focus of this study, the constraints taken into account for the computation of this optimal planning are further detailed compared to most models in the literature: for each unit, maximum and minimum powers, maximum gradient, minimum stable power duration, minimum times on and off and startup and shutdown durations.

Second, the day-ahead orders are formulated for each unit with the “Day-Ahead Orders” module. Trading commitments of actors prior to the day-ahead market are considered to be zero. Thus, for most units, offers quantities are based on the aforementioned optimal planning, allowing the most adequate repartition of start-up cost for thermal units. All the power available is offered for peak units (start-up cost are thus recovered on only one hour) and for hydraulic whose stock is operated based on water value. The price of the order is set considering the production cost, which is computed differently whether the unit is load or a thermic, hydraulic, storage, or non-dispatchable unit. The orders are placed to maximize the profit of the equipment with the assumption that the equipment is price-taker, preventing gaming. Each order is defined on a unique time step, but orders can be coupled to model potential activation constraints between orders. Not all the technical constraints can be reflected when placing the order and only the maximum and minimum power constraints and the start-up delay are effectively taken into account in this model.

Dispatchable flexible units EV and water heaters order creation process has been developed for this study, also with the hypothesis of profit maximization for price-taker actors. Concerning the quantities, they are based on the possibility to let the market choose the optimal timestep for flexible demand consumption⁵. We choose a compromise between full time-step optimization (which makes the problem more complex) and a simple determination of quantities based on price forecast, which may be sub-optimal if prices are different from the forecast. An optimal planning is computed entailing the same constraints as in Chapter 2, expressed in Appendix B, but the targeted total daily energy artificially increased by a coefficient of 1.5. Purchase bids represent thus 50% more volume than

⁵Indeed, bids constrained with a maximum power and linked with a targeted volume of activation over the day, are enabled in the Euphemia price-coupling algorithm.

necessary and quantities are offered on more timestep than needed. To respect the target energy, the orders of flexible demand units include an energy constraint: the volume of activated orders (determined with the following “Clearing” module) on the considered day is equal to the targeted total daily energy. The surplus of energy in the formulated orders enables the clearing to choose the timestep when the demand is the cheapest. This bidding strategy for flexible assets both takes into account the complexity of the constraints on EV and water heaters and enables a trade-off margin in case of price forecast error.

Third, the orders are “cleared” (accepted or rejected) by the “Clearing” module according to the merit order, thus providing a market clearing price for each bidding zone. The market clearing process is close to the Euphemia price-coupling algorithm⁶, with a stage for maximizing the social welfare distinct from the stage of price fixing. The social welfare optimization stage includes the energy constraint for the activation of the targeted amount of daily energy for EV and water heater units.

Fourth, the portfolio optimization process optimizes each agent’s production schedule to maximize their profit, subject to their technical constraints (for EV and water heaters, these constraints are the ones defined in Appendix B) and taking into account their commitments and anticipation of imbalance penalty. The results of this optimization can therefore lead to programs that do not strictly match the day-ahead computed market commitments of the portfolio.

For the day-ahead market time, the process without filtering entails these three elements i.e the formulation of the day-ahead orders, followed by the market clearing, and then the portfolio optimization.

3.3.2. Intraday modules

In Intraday, the forecast for load, solar, and wind are updated (see 3.2 for details on forecasts data) and a new price forecast is computed, taking into account the forecast updates and a price sensitivity calculated with Day-ahead forecast price scenarios.

Today, the intraday market is mostly continuous but auctions with clearing exist in some countries (for example Germany) and will be extended to whole CORE region in 2023, with three intraday auctions. In this study, started before the implementation details of intraday auctions was known, we represent a single clearing at midnight. This hypothesis will concentrate more liquidity and allow more exchange on this auction, but will probably result in less intraday trading in total. In addition, the near real time imbalance is likely to be a little over-estimated in our simulation. The simulated intraday process is very similar to Day-ahead process and has also four steps, described in Figure 3- 10:

⁶ https://www.nemo-committee.eu/assets/files/190410_Euphemia%20Public%20Description%20version%20NEMO%20Committee.pdf



Figure 3- 10 Intraday primary process

First, a new planning optimization is carried out. This optimization is the same as in day-ahead but takes into account the day-ahead commitments and new forecast: load, wind, solar, and intraday price forecast. Flexible units (storage and dispatchable generation) will adapt their schedule to take into account new volumes (changes in forecasts may generate a need to rebalance the portfolio) and new prices (that can create new opportunities).

Second, the intraday's order are formulated, with strategies depending on the unit. As well as for Day-ahead order's formulation, optimization results and day-ahead commitments are used to formulate orders on the intraday market for units that regularly start up and stop. For those units, the orders will be made from the difference between the optimization results (which is used for scheduling the unit commitment, i.e. when each unit is expected to be on or off) and the day-ahead commitments. For units with no start-up issues (storage units, peak thermal units, most of the time base units), all the remaining available power is offered in intraday, upward and downward. Specifically, for storage EV and water heaters units, we bid all the available power given, upward and downward, as shown in Figure 3- 11, with an additional storage constraint⁷. Bidding all the available power is optimistic in terms of intraday liquidity. All the EVs and water heaters dispatched in day-ahead can be re-dispatched in intraday. This is a major assumption as therefore EV and water heaters planning can be completely changed between day-ahead and intraday timeframes. This hypothesis has in particular an impact on the "filtering and fostering" variant, as it allows to have sell bid available to reduce congestions by fostering in case of local constraints.

⁷ This strategy is a little different from the one done in D-1 because the clearing problem is less complex, so there is less value to preselect time-step as done for day-ahead.

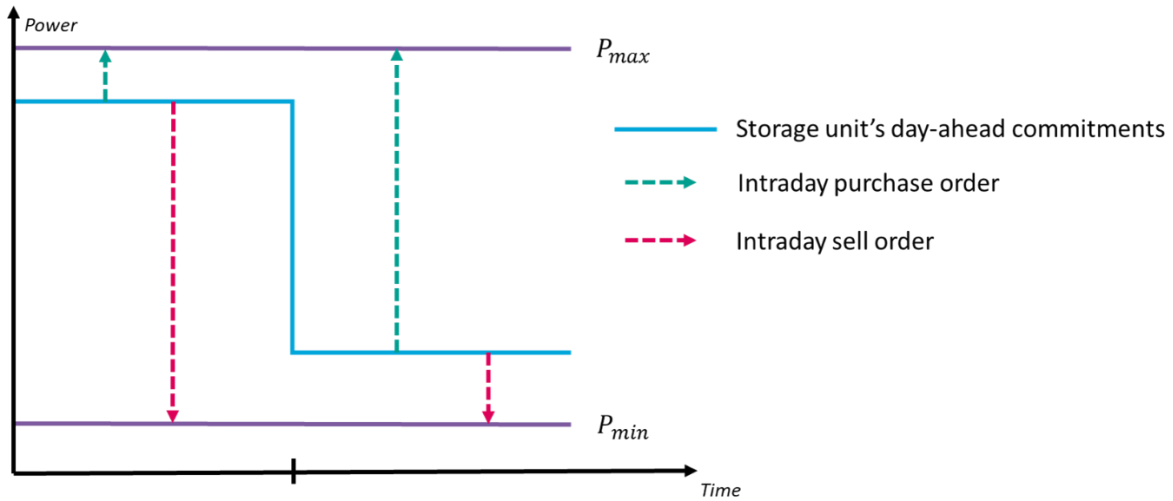


Figure 3- 11 Principle of intraday storage bidding (demands and offers are linked by an energy constraints)

Finally, clearing and portfolio optimization have the same functioning as in day-ahead. In the clearing module, a constraint is added to ensure that the sum of the intraday activated powers of both the EV unit and the water heaters unit is the same as in day-ahead, and thus respect consumer's needs. Thus, for these units, the quantity of offers and demands accepted in intraday are equals.

3.3.3. Balancing modules

For balancing, the load, solar, and wind forecasts are updated once again, with real-time data. The process has also four steps but differs somewhat from day-ahead and intraday processes (mainly due to the short-time horizon and the active role of the TSOs in this market). It is shown in Figure 3- 12.



Figure 3- 12 Balancing primary process

The orders formulation is separated into two steps:

- The Balance Responsible Parties' (BSP) orders formulation, which offers the remaining power for all production units. All the upward and downward power remaining from the intraday commitment is offered whenever allowed by technical constraints. The available power of every unit is computed using a heuristic method, even for thermal units contrary to day-ahead and intraday.

- The TSO's orders formulation, which places "load" orders (buying or selling resp. the shortage or surplus of load compared to the intraday load forecast). This is done by computing the imbalance in each area between the power level of production units and the power level of load units. For wind, solar and load units, the new real-time forecast is used for this computation.

Concerning EVs and water heaters, the bidding strategy is quite different from day-ahead and intraday. Indeed, contrary to day-ahead and intraday processes, which are repeated once a day on 24 hours, the balancing process is repeated every hour on one hour. Therefore, it is not possible to have an energy constraint in the clearing module to ensure the EVs and water heaters' daily energy is respected. To keep the daily energy on balancing as close as possible to its target⁸, we are assuming the actors modify their bids prices. Every three hours, the activated volume for EVs and water heaters is checked. If the total balancing activated volume so far, upward and downward, is close to zero, no action is taken. If the activated volume so far deviates from 0 too much (at least 100 MWh), the order's formulation for the following time step is modified. If there are too many upward (resp. downward) activations:

- the upward (resp. downward) orders' price for the considered unit (EV, water heaters, or both) is increased (resp. decreased), to make them less likely to be accepted by the clearing,
- and similarly, the downward (resp. upward) orders' price is decreased (resp. increased) to foster their acceptance by the clearing.

Then the market clearing module performs the same computation as for the day-ahead and intraday clearing, with the balancing orders. The portfolio optimization module is also similar to previous optimization, but with balancing view on forecast and balancing commitments.

3.4. The filtering process at each stage of the market sequence

The ATLAS process has been simulated as described in the previous section and give results for the "no filtering" case. We have added filtering process at different stages of the process. We will described first the pre-calculation of a maximum power for each substation and then how this allows to filter in day-ahead, intraday and balancing.

3.4.1. Definition of a Maximum Power for each substation

The Maximum Power for each substation is a key parameter as the filtering by the DSO is based on the trespassing, for each substation, of this limit. Figure 3- 13 indicates the extent of the Maximum Power across the nearly 2000 substations of the French distribution network.

⁸ Which is zero, because as in intraday, we want to keep the same daily energy for flexible units as in day-ahead.

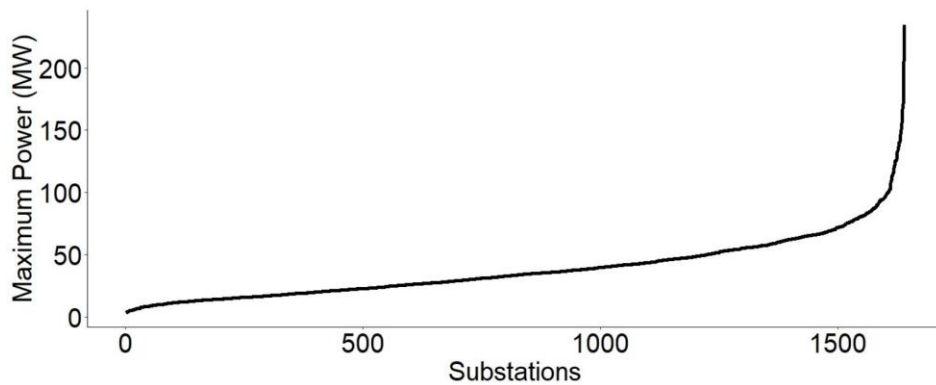


Figure 3- 13 Maximum Power of the 1790 substations

This maximum power curve was computed in Chapter 2 by simplifying the DSO’s dimensioning practice. The Maximum Power reference in this study is the “No Signal” Maximum Power of Chapter 2. In this test case, the Maximum Power was overall lower than in a case where flexible capacity was controlled (“STCS” test case) allowing significant reductions of reinforcement costs. We show in Chapter 2 that filtering could manage most of the residual constraints caused by the control of the flexibility.

These Maximum Powers are used in this study to limit local demand. They stay constant during the study which means that we do not consider any incident on the network, although they are relatively frequent at the scale of a whole country. How this limitation is implemented is described in 3.4.2 for day-ahead and 3.4.3 for intraday and balancing.

3.4.2. Day-ahead filtering

The filtering step is added between the day-ahead orders formulation and the market clearing module. The whole process is shown in Figure 3- 14.

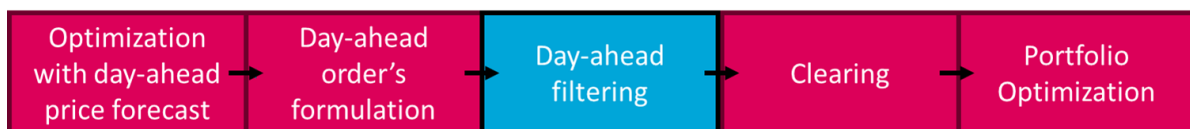


Figure 3- 14 Day-ahead process with filtering.

The objective of the filtering process is to alter maximum activation power of the distributed demand orders generated by the order formulation stage so that the risk of trespassing on the power limit of a substation is minimized, whenever the orders are activated totally.

- The first step is to move from national to local data. for this, we assume that activations are made locally in proportion to national activations, depending on the number of EVs connected

to each station. First, for each day d , two hourly potential flexible load curves are created, one for EVs, EV_{max}^d and one for water heaters, WH_{max}^d . At each time step, those potential flexible load are defined as the maximum activation power of the order of the unit formulated for this time step. The modeling of EV and water heaters and their associated constraints are described in Annex 1.

EV_{max}^d and WH_{max}^d are then broken down on each substation and added to the substation's day-ahead forecast inflexible load curve, resulting in the total hourly demand for the substation $Dem_{DA,s}$ given by (1).

For every substation:

$$Dem_{DA,s} = EV_{max}^d * coeffEV_s + WH_{max}^d * coeffWH_s + Load_{inflex,s}^{DA} \quad (1)$$

With:

$coeffEV_s$ the share of overall EV power connected at the substation s

$coeffWH_s$ the share of overall water heaters power connected at the substation s

$Load_{inflex,s}^{DA}$ the hourly day-ahead forecast inflexible demand at the substation s

- The second step is the filtering process. Filtering consists in removing the most expensive offers from the merit order. For each substation s , the maximum activable power for the day d , $\max(Dem_{DA,s})$ at each substation is compared to the maximum power the substation can sustain $MaxP_s$.

If $\max(Dem_{DA,s}) > MaxP_s$, then at least for one hour of the day the maximum activable power exceeds the maximum power for the substation. For this substation, at every hour where the maximum activable power exceeds the maximum power of the substation, the orders for EVs and water heaters formulated need to be capped.

For every substation s that exceeds its maximum power, at every hour h where it is the case, is computed $p_{s,h}$ the excess compared with $MaxP_s$, with (2) :

$$p_{s,h} = \max(Dem_{DA,s}[h] - MaxP_s; 0) \quad (2)$$

Thus, the EV and water heater orders will be iteratively capped until the sum of excess or the flexible demand's at the substation is equal to 0, which is expressed by (3).

$$p_h = \sum_s p_{s,h} \quad (3)$$

For every hour h , the EV and water heaters orders formulated for this hour are gathered in o_h . The most expensive order $o_{max,h} \in o_h$ is capped first. Its maximum power is decreased by the power quantity exceeding the substation's maximum power (each order impacts every substation but to a different extent).

If $Q_{max,o_{max,h}} > p_h$, the most expensive order has sufficient power for its limitation to overcome the excess at hour h . $Q_{max,o_{max,h}}$ is capped at $Q_{max,o_{max,h}} - p_h$ and $p_h = 0$.

If $Q_{max,o_{max,h}} < p_h$, the most expensive order doesn't have sufficient power for its limitation to overcome the excess at hour h . $o_{max,h}$ is completely removed from the merit order and $p_h = p_h - Q_{max,o_{max,h}} > 0$. The process is repeated with the next most expensive order in o_h , until either $p_h = 0$, in what case the filtering at hour h is successful as every substation s that would initially exceed its maximum power, does not exceed its $MaxP_s$ at hour h , or there are no more EV or water heaters orders available at hour h to cancel the totality of the exceeding power. In this case, the filtering can still be successful for some part of the substations s . In this study, the day-ahead filtering is successful for every hour h and therefore $p_h = 0$ for every hour h .

This process is quite straightforward but raises some questions about equity and transparency from the flexibility providers' point of view. However, first, the filtering process filters the most expensive bids first. Thus, the selection of filtered bids is not a random process and it follows a certain logic. Second, while the filtering process does not offer a remuneration to the filtered flexibility providers, this can be explained by the fact that this could lead to gaming behaviors. Indeed, flexibility providers could be tempted to bid at prices higher than they would without compensation for filtering. Moreover, considering that locally, there are only a few bids that can manage a local congestion, in a lot of cases, there is no choice for the DSO when it comes to which bid to filter.

3.4.3. Intraday and balancing filtering

The intraday filtering step is added between the intraday orders' formulation and the market clearing module. The resulting process is shown Figure 3- 15.

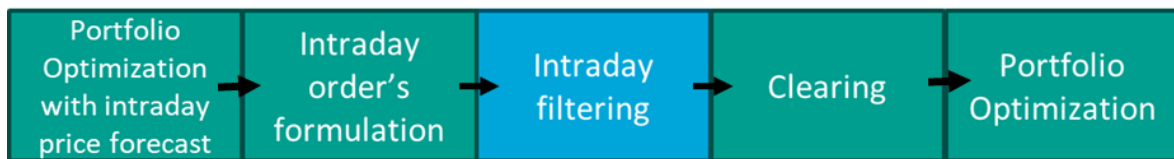


Figure 3- 15 Intraday process with filtering

Similarly, the balancing filtering step is added after the BSP and the TSO order's formulation and before the market-clearing module. The resulting process is shown in Figure 3- 16.



Figure 3- 16 Balancing process with filtering

As a reminder, following the optimization of units' planning with intraday price, and wind and solar new forecasts, the intraday orders are formulated. As explained in 3.3.2, the remaining downward and upward power of all EVs and water heaters dispatched in day-ahead is offered in intraday. The same goes for the balancing timeframe with the intraday EVs and water heaters planning.

Therefore, intraday (resp. balancing) filtering is a little different from day-ahead filtering as intraday (resp. balancing) bids are taken into account relative to the day-ahead cleared quantity (resp. day-ahead and intraday cleared quantity) can be upward or downward. Filtering is carried out the same way as for day-ahead bid filtering, except that $EV_{max,h}^d$ and $WH_{max,h}^d$ include orders to be filtered and previously activated orders.

4. Study case

For this study, the mix and geographic perimeter of the study are similar to those in Chapter 2.

The study is set in 2030's Western Europe. Assumptions on generation and inflexible load for the European countries of Central Western Europe: France (fr), Austria (at), Belgium (be), Switzerland (ch), Germany (de), Spain (es), Great-Britain (gb), Ireland (ie), Italy (it), Luxembourg (lu), Northern Ireland (ni), Netherlands (nl) and Portugal (pt) in 2030 are made according to the "VOLT" scenario of the French adequacy forecast ("Bilan Prévisionnel") of RTE (RTE, 2017). The French adequacy forecast is a prospective adequacy report for France that RTE is legally obliged to produce every year, covering a period from 5 to 15 years. In these reports, various scenarios for consumption, installed capacity, and production are explored. The "VOLT" scenario describes the case of intensive development of renewables alongside economically optimal nuclear production. The assumptions made by this report for this scenario are summarized in Figure 3- 17.

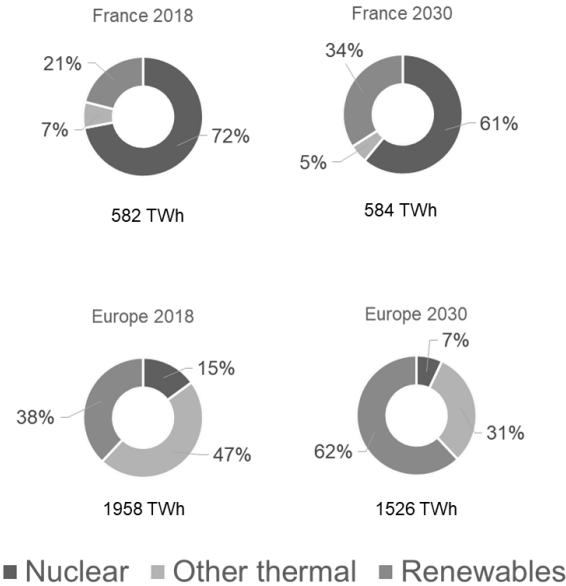


Figure 3- 17 Distribution of production in France and the other European countries considered in the study

In this study, nuclear variable price is at 5.02 €/MWh, for new CCGT it is 69.32 €/MWh, and for conventional gas units it is between 90 and 120 €/MWh.

Inflexible load is as stated in Table 3- 2:

Inflexible load (TWh)	2018	2030
France	481,0	447,8
Other European countries	1896	1680

Table 3- 2 Inflexible load for France and the other European countries considered in the study for 2018 and under the VOLT scenario's assumptions for 2030

The study focuses on the week from the 28th of October to the 3rd of November.

The assumptions considering flexible load (EV charging and water heaters) are different from Chapter 2:

- To limit complexity, postponement of heating hasn't been considered, as it was found to be the least used flexibility in Chapter 2 and it needed another modelling, whereas EV and water heating modelling are similar.
- The number of EVs in France is similar to Chapter 2: 5.8 million EVs, representing about 10 TWh of annual consumption. Chapter 2 compares impact of different types of flexibility activation (no activation, tariff signal, fully controllable), but in reality, these different types of activation will co-exist. We consider 20% of EV charging are controlled via tariff signal and 20% of EV charging is fully controllable (representing 960 MW of flexible power with 37,6 GWh of flexible EV charging load on the week). See Chapter 2 for the explanation of EV modelling.
- For others counties, the number of EVs is similar to Chapter 2 but their charging is not controllable.
- Annual consumption of water heaters of 17 TWh in France, with a capacity of 7.6 GW (RTE, 2017). It is less than the actual 19 TWh because the new regulation requires new storage water heaters to be more efficient than the older ones. These new water heaters, whose load cannot be controlled, are gradually replacing thermodynamic water heaters. However, the share of controllable water heaters will remain sufficiently important in the future to include them in this study. Water heaters' flexibility is accounted for only in France because the control of water heaters (via the in-feed of a modulated 175Hz signal) currently only exists in France. The assumption on controllability are similar to EVs: 20% of water heaters consumption is fully controllable, what means a flexible power of about 1 GW with 68 GWh of load on the week.

All these assumptions (mix, one week of simulation, 20% of the theoretical flexibility controlled, no controlled demand capacities in the other countries, low prices on combustibles and CO₂) will obviously have an important impact on the results and will be discussed in the following. A variant for this 20% piloted flexibility is also studied: 100% of flexible capacity controlled, but on 1/5th of the substations. The volume of controlled flexibility remains the same, but the share of flexible capacity that is controlled is not the same for every substation (with here the extreme case of 1/5th of the substations at 100% of flexible capacity that is controlled and 4/5th of the substations with uncontrolled flexible capacity).

5. Results

The results will be presented in two parts. First, the gains of demand flexibilities and their underlying causes are presented in the case of no filtering. Second, the impact of the different filtering timeframes on the gains and the congestion management is explored.

5.1. Demand-side flexibilities gains

We consider demand-side flexibilities gains on a market horizon as the difference between the benefits of the new commitments made at this market horizon and the benefits that the flexibilities would have made with their prior commitment at the new market horizon price. This is given by the following equations.

- In day-ahead:

$$gain_{DA} = \sum_h ((volume_{DA}[h] - volume_{nat}[h]) * price_{DA}[h]) \quad (4)$$

- In intraday:

$$gain_{ID} = \sum_h ((volume_{ID}[h] - volume_{DA}[h]) * price_{ID}[h]) \quad (5)$$

- In balancing:

$$gain_{Bal} = \sum_h ((volume_{Bal}[h] - volume_{ID}[h]) * price_{Bal}[h]) \quad (6)$$

With:

$volume_{DA(or ID, or Bal)}$ the hourly volume of total activated flexibility for the considered market time.

$volume_{nat}$ the hourly volume of activated volume for flexible assets in the case of no flexibility control.

$price_{DA (or ID, or Bal)}$ the hourly day-ahead (or intraday, or balancing) market price.

Thus, the gains at the different time frames are the result of both the market price and the timing of flexibility activation.

5.1.1. Results on prices

The range of the market prices over the considered week for the European country in the scope of the study and for the three different timeframes is shown Figure 3- 18.

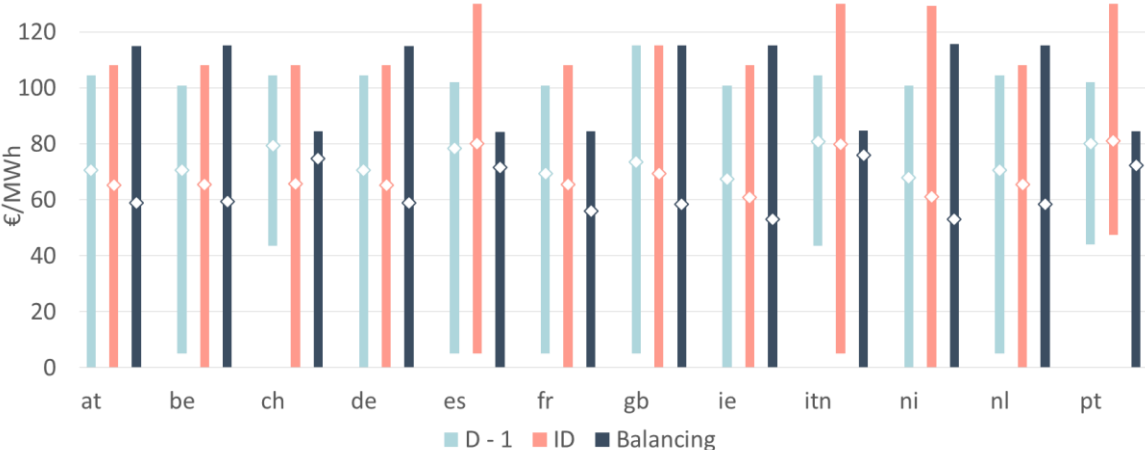


Figure 3- 18 Range of the day-ahead, intraday and balancing prices, and their mean value, for the considered week for the countries of the scope of the study

The intraday⁹ price is the most variable price over the week and the day-ahead price the least variable. The day-ahead price is overall higher than both the intraday and balancing prices and the balancing price is overall lower. This can be explained by Figure 3- 8 in 3.2, showing that balancing net consumption is often lower than the day-ahead and intraday forecasts. This explains why balancing prices are the lowest. It also shows that the intraday net consumption forecast is higher sometimes higher in intraday, which explains the intraday price peaks.

Focusing on France, Figure 3- 19 shows the hourly market price at each timeframe. The variability of the intraday and balancing prices is visible, with frequent occurrences of low prices and even zero prices.

⁹ In this study, the intraday is not modelled as a continuous market. It is cleared at 00h, once. The intraday market price is the price resulting from this clearing.

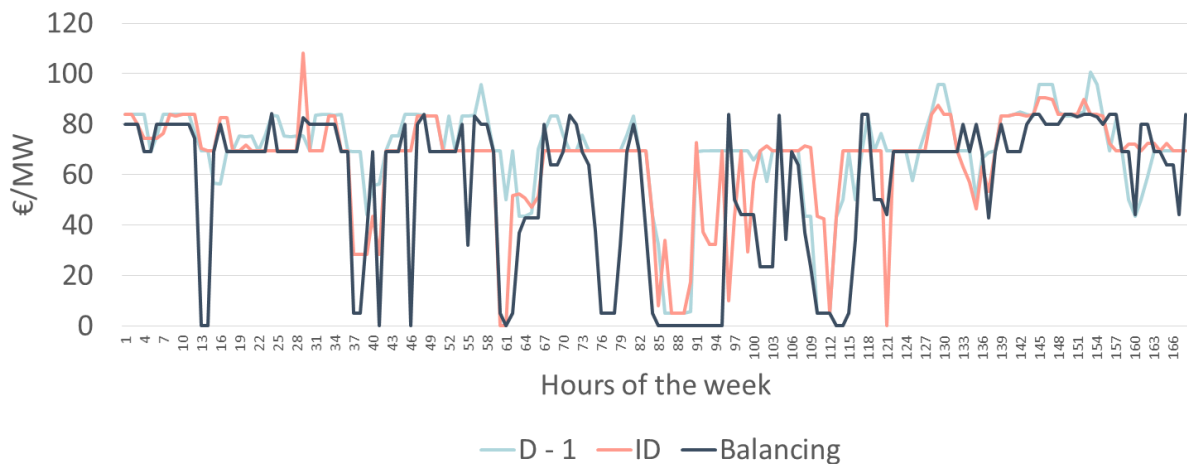


Figure 3- 19 Day-ahead, intraday and balancing prices for France for each hour over the considered week

Those results depends on the many assumptions made in this study that we will discuss.

First, it depends on marginal cost of generation units and on underlying assumptions of fuel and CO₂ prices. Those hypothesis are quite low in our study. With higher fuel and CO₂ prices, prices would be higher but prices volatility would also increases, as low prices are not dependent on fuel and CO₂ prices.

Second, the prices differential between hours also depend, on the one hand, on the bidding strategy, and on the other hand on the assumptions regarding controlled capacities and more generally other flexibilities in the study. The larger the flexibilities are, the less each one can gain from being controlled. Here, the controlled capacities in France are rather low (around 2 GW) and there are none in the rest of the countries modeled. However, while the depth of flexibility that can be valued is limited, it does appear to be far greater than our assumptions on controlled capacities, given the forecast errors outlined in 2.1.

5.1.2. Results on engagements

The market price is a key element in understanding the flexibility gains. Indeed, in order to optimize its gains, a flexible demand assets will place the more possible demand on the timeframes where the prices are the lowest. Therefore, it will follow the price fluctuations across timeframes and accommodate by modifying its planning. Figure 3- 20 and Figure 3- 21 show the different market placement of the demand of respectively EVs and water heaters, for the day-ahead, intraday and balancing timeframes for one day of the considered week, the 29th of October. The placement is quite different from the day-ahead initial placement to the balancing final one. The intraday placement resembles in both cases the balancing placement.

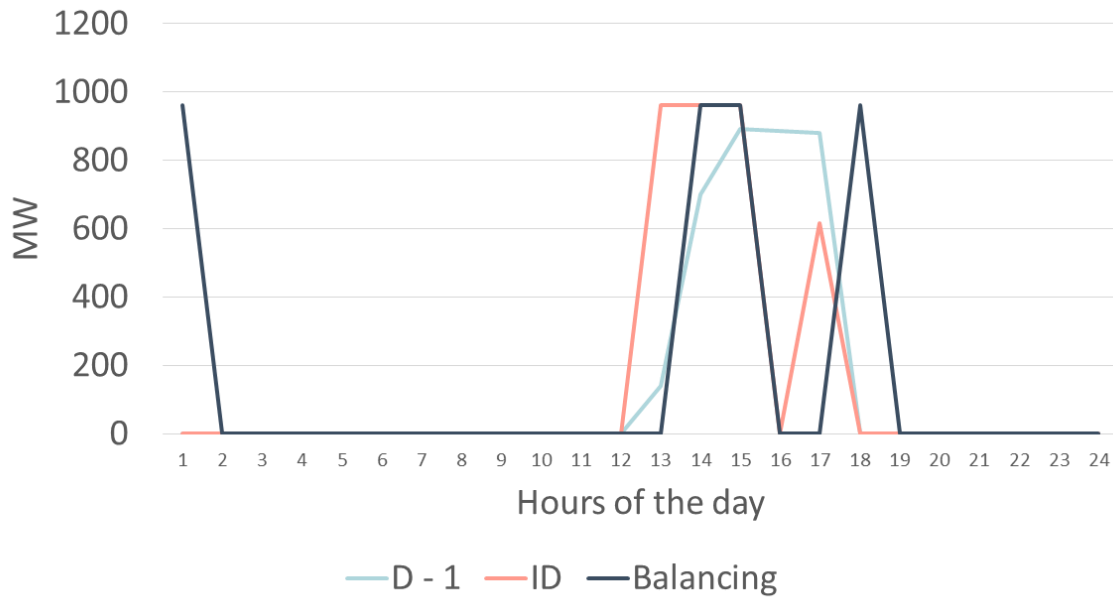


Figure 3- 20 EVs planning resulting of market activations in day-ahead, intraday and balancing for the 29th of October

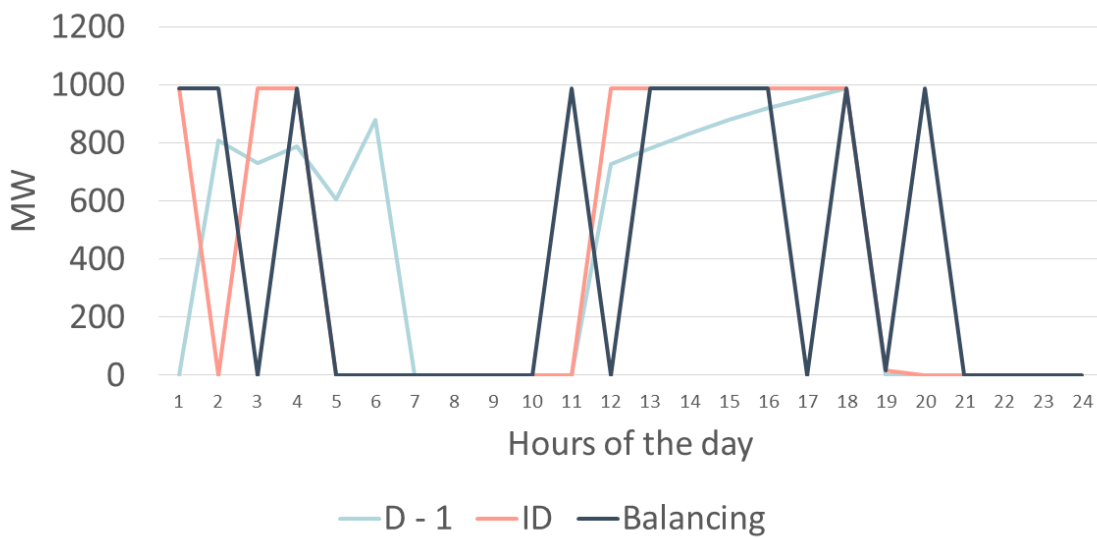


Figure 3- 21 Water heaters planning resulting of market activations in day-ahead, intraday and balancing for the 29th of October

Figure 3- 22 shows the displaced volumes of different flexible means in intraday compared to the day-ahead and in balancing compared to the intraday. The EV and water heaters are the most rescheduled flexible means relatively to their maximum capacity. This explains the major changes in their commitments from one market stage to another and the gains earned by these means in intraday and balancing.

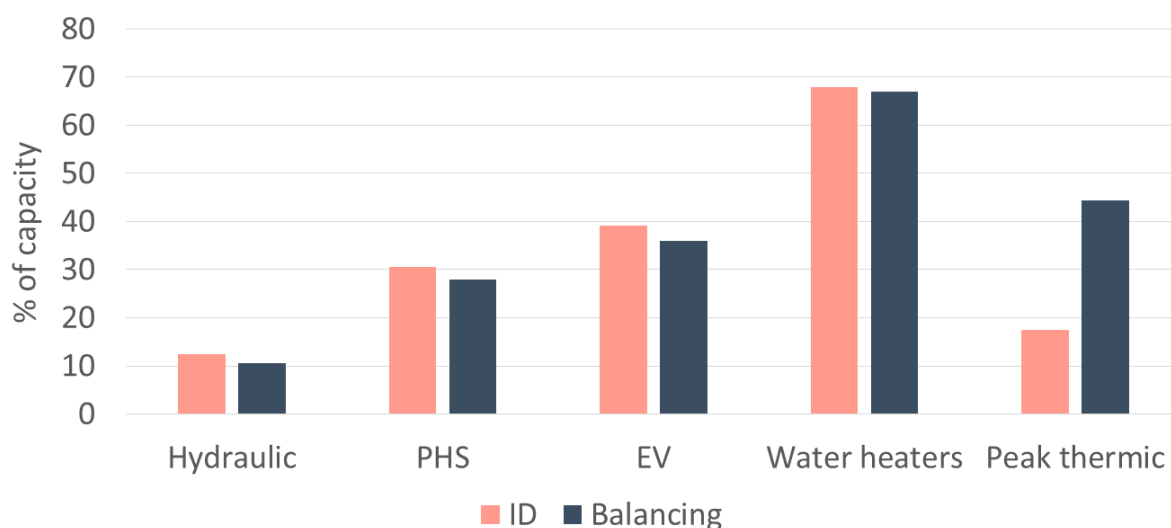


Figure 3- 22 Absolute value of the commitment gap with the previous market time in intraday and balancing relative to the capacity for different flexible means

In our hypothesis, flexible assets like EVs or water heaters can be rescheduled at a zero marginal cost once users' needs are taken into account. Therefore, these assets are often rescheduled to take advantage of price opportunities and are an important means of flexibility in intraday.

These results on the rescheduling of demand flexibilities depend on the volumes of adjustments needed, and therefore on many assumptions made in this study.

Concerning the forecast error, the choice of the week to be analyzed has an impact: in winter, wind production and thus wind error forecast is higher than the rest of the year. It is also a week with a public holiday and therefore prone to a high forecast error on consumption. Obviously, the mix has also an impact: for France the chosen mix has more than twice as much wind and solar¹⁰ as today and is in line with actual official targets, but the actual mix may be different in practice. Finally, the error calculation assumes that the quality of forecasts does not improve by 2030, which is pessimistic both because observability and models can improve, but also because the quality of national forecasts per installed MW improves with the increase in installed capacity thanks to the multiple capacities whose fluctuations are smoothed out between them.

Concerning the rebalancing of the players, the fact that there is only one auction on intraday increases the imbalance, but the fact that the players systematically rebalance is conversely an optimistic assumption. Thus, intraday volumes are probably underestimated and the volumes in balancing overestimated.

¹⁰ In 2023, the capacity installed in France were 13,8 GW for PV and 19 GW for Wind. In our hypothesis for 2030, they are respectively 27.7 GW and 40.2 GW.

To assess the impact of these assumptions on balancing volumes, we analyzed the balancing volume data made available by RTE on its website for 2022¹¹. Figure 3- 23 illustrates the average daily volumes of offers activated for French balancing, distinguishing between upward and downward activations. We can see the volatility of the activation is high.

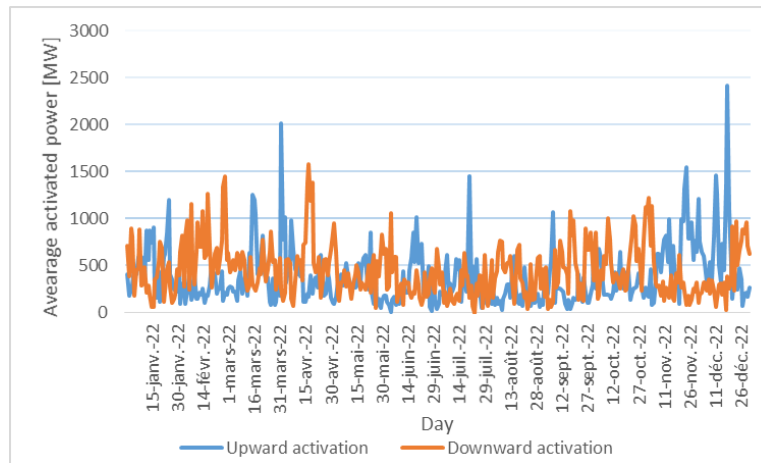


Figure 3- 23 Average daily volumes of offers activated for french balancing (source RTE)

The average volume activated in our simulations is about 3.4 GW, while it is 0.9 GW in the year 2022 (summing upward and downward activation). The volume of adjustment in our week thus seems to correspond to a week with a lot of adjustment in 2030 rather than to a representative week, but is realistic given the doubling of RES capacities.

Since the intraday is expected to experience significant changes, the comparison with the realized data is of little meaning. We will just note that the volumes are probably underestimated due to the fact that only one auction is simulated.

Finally, the percentage of demand-side capacities used in intraday and balancing also depend on the bidding strategy, the assumptions regarding controlled capacities (and more generally other flexibilities in the study), as well as prices differential between hours.

These preliminary results on demand-side flexibility planning are important to better understand how flexible activations across timeframes can result in significant gains for flexibility assets.

5.1.3. Consequences on demand-side flexibility gains

Figure 3- 24 shows that the gains on the intraday and balancing stages represent about 58,5% of total remuneration gains. As previously discussed for prices and quantities, this gain is very dependent on

¹¹ Available at https://www.services-rte.com/fr/telechargez-les-donnees-publiees-par-rte.html?category=market&type=balancing_energy&subType=volumes_per_reason

various study assumptions, but its result indicates that, when forecast errors are accounted for, intraday and balancing terms may become very important for the valuation of flexible assets.

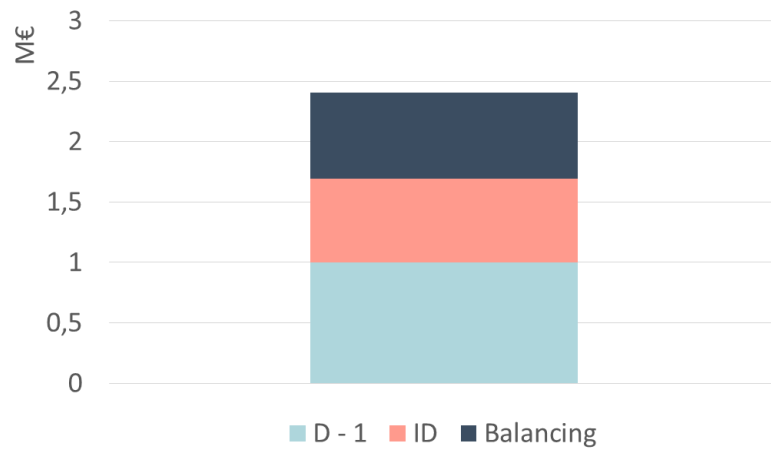


Figure 3- 24 Day-ahead, intraday and balancing flexibility gains

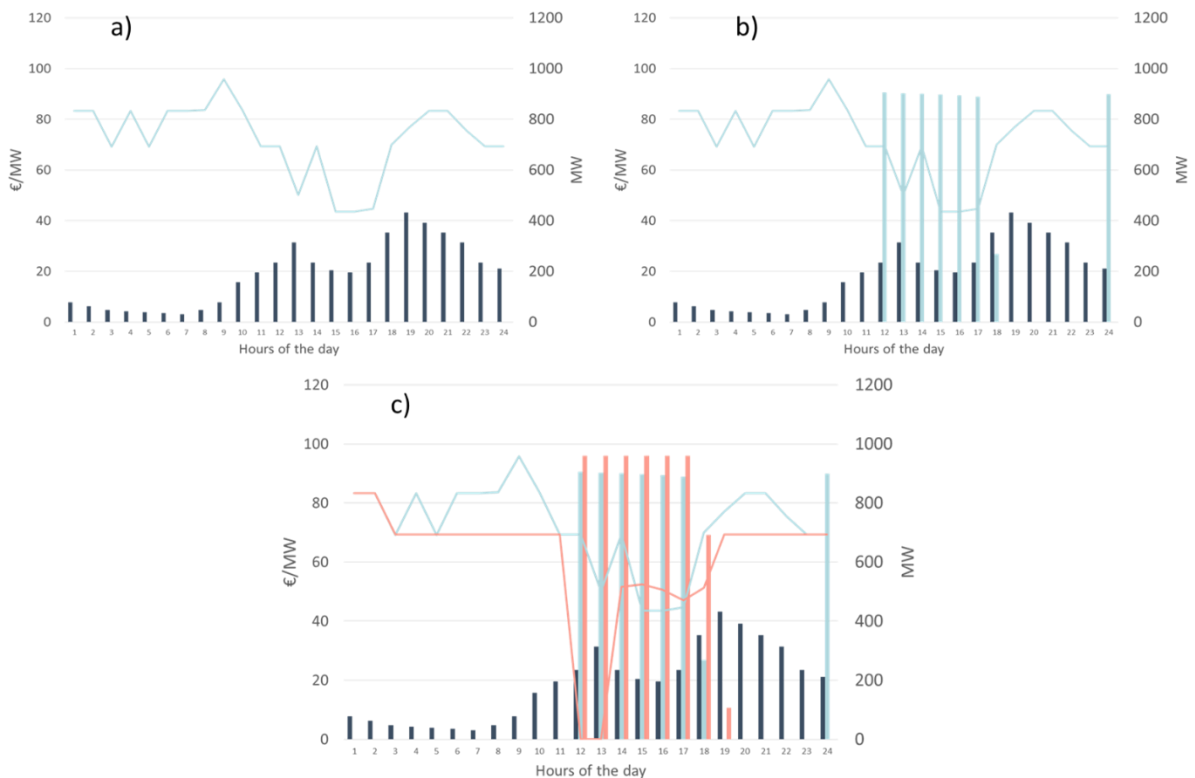


Figure 3- 25 Explanation of the flexibility gains in day-ahead and intraday : a) EV placement without taking into account day-ahead price and day-ahead market-price; b) Addition to a) of the EV placement after day-ahead price acknowledgement : placement focuses on timeframes when the day-ahead price is the lowest; c) Addition to b) of the intraday market price and the new intraday EV planning following the acknowledgement of the intraday market-price; displacement of EV to match the lowest intraday prices (within the scope of the constraints on the flexibility). The curves are shown for the 30th of October

It can be explained by the high variability of market prices, notably in intraday. Figure 3- 25 shows that first, taking into account the day-ahead price for flexible assets generates a rescheduling of EV charging on the timeframes when the market prices are the lowest. This first rescheduling enables the day-ahead gain for flexible assets compared with a previous scheduling where the flexible capacities are not dispatched considering the day-ahead price but as if demand was not flexible. Then the intraday market-price generates another opportunity for flexible assets. With the new prices being particularly low, high gains can be generated by rescheduling flexible consumption on the time frames when the prices are zero or close to zero.

In the following section, the impact of filtering is presented. The seven case studies are computed for the week of the 28th of October to the 3rd of November.

5.2. Impact of filtering

5.2.1. Visualization of filtering on a single substation

The filtering coordination mechanism is a global mechanism that takes into account a local constraint, the Maximum Power at a substation, to alter the flexible dispatch optimized in the wholesale market. On Figure 3- 26 and Figure 3- 27, the local constraint is represented on a substation (an urban substation to which many EV charging points are connected), without and with day-ahead filtering. Without filtering, the Maximum Power of the substation is sometimes exceeding. This exceeding has high consequences as there is no other means than load curtailment to manage it. His cost is thus very high. With day-ahead filtering, the congestions are cancelled. The flexible energy that has been shed is reported in this case in the hours before the surge in total consumption.

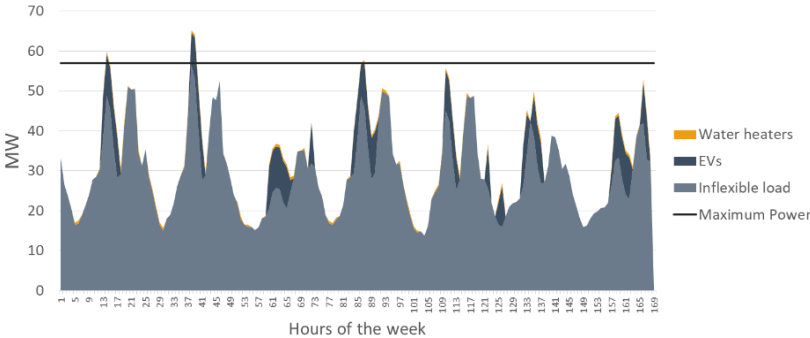


Figure 3- 26 Day-ahead dispatch for inflexible load, EV and water heaters for the "J.BRU" substation without filtering

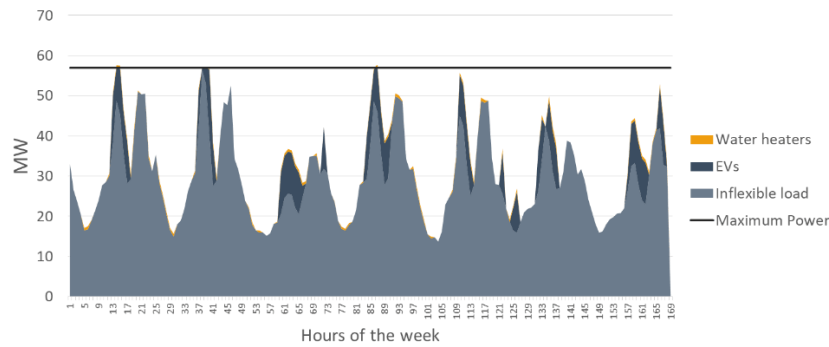


Figure 3- 27 Day-ahead dispatch for inflexible load, EV and water heaters for the "J.BRU" substation with filtering

For this substation, it seems quite clear that EVs are a major reason for congestion. However, EV surges where the congestion occurs always coincides with also an inflexible load peak.

5.2.2. Filtering impacts on production costs and flexibility gains

First, the total generation costs for the seven cases studied are compared in Figure 3- 28. The generation costs for the six cases with at least one filtering are above the generation costs without any filtering. The timing of filtering, whether day-ahead, intraday, or balancing market time, does not have much impact on the generation costs. The filtering, whether it is effective in managing congestion (balancing filtering) or not (day-ahead filtering) seems to impose the same level of constraint on the dispatch whatever the timing, so that we obtain such similar generation costs outputs.

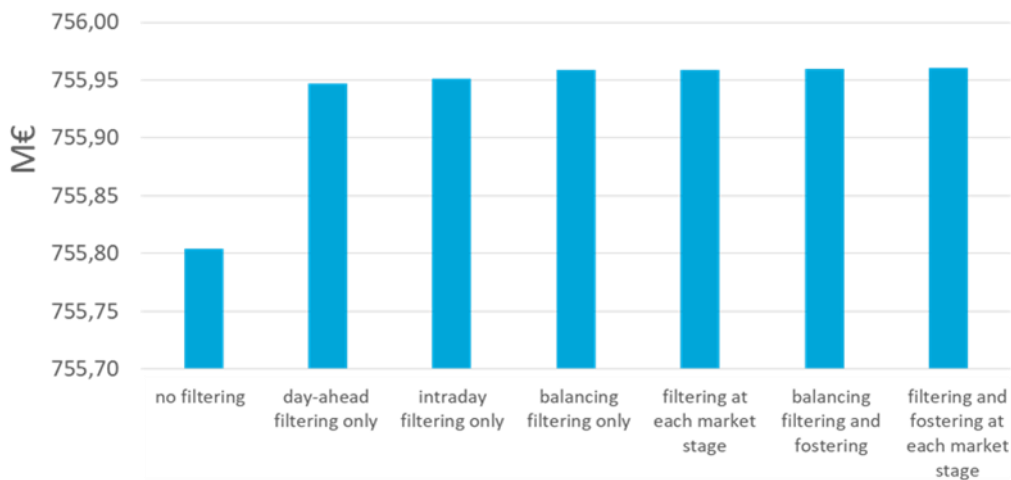


Figure 3- 28 Comparison of the generation costs of the seven case studies

The flexibilities gains for each variant are computed with respect to the remuneration of the same amount of flexibility, which placement is fixed in the day-ahead timeframe, without any optimization of this placement concerning the forecasted price are shown Figure 3- 29.

Similarly to generation costs, there is not much variation from one test case to another. The filtering mechanism, by re-arranging EV and water heater’s unit activation planning, does not cause much loss for these aggregators. It would imply that the “second best” optimal placement for flexibility, that is

to say in this case the optimal placement provided there are no congestion detected on the distribution network at each market stage ahead of real-time, is ultimately close, in terms of the objective's function value, to the optimal placement without considering the distribution network's constraints. This goes in line with (Pichou, Dussartre, Lâasri, & Keppler, 2023), where the authors found that a filtering mechanism like the one proposed in this paper (though computed at only one market time) could almost cancel the reinforcement costs induced with flexibility activations without changing much the gains on generation costs.

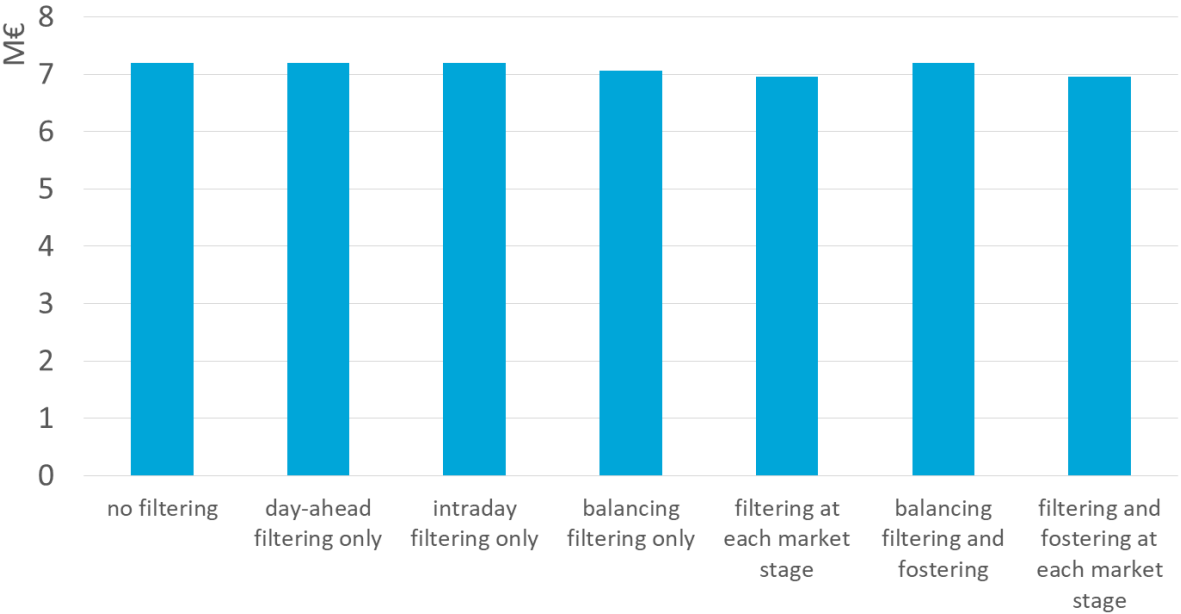


Figure 3- 29 Remuneration gain of flexible optimal placement for each variant over the considered week at each market stage

These results insist on the low impact a remuneration for a filtered flexibility provider would have. The loss is limited for the flexibility providers, thus the equity problem is not as important as it would be if the loss was consequential.

5.2.3. Filtering efficiency by timeframe with equal percentage of controllable flexibilities

The congestion of maximum power is computed over the considered week for every substation in the variant with 20% demand response flexibility activation at each substation. An example is given in Figure 3- 30 on the same substation as Figure 3- 26. It compares the flexibility activations to the margin between Maximum Power and inflexible power with D-1, intraday and balancing view. The congestions occurs when flexibility is placed at a low margin point. On this substation, we can see that flexibility activations changed a lot between timeframes, which can lead to inefficiency of day-ahead filtering.

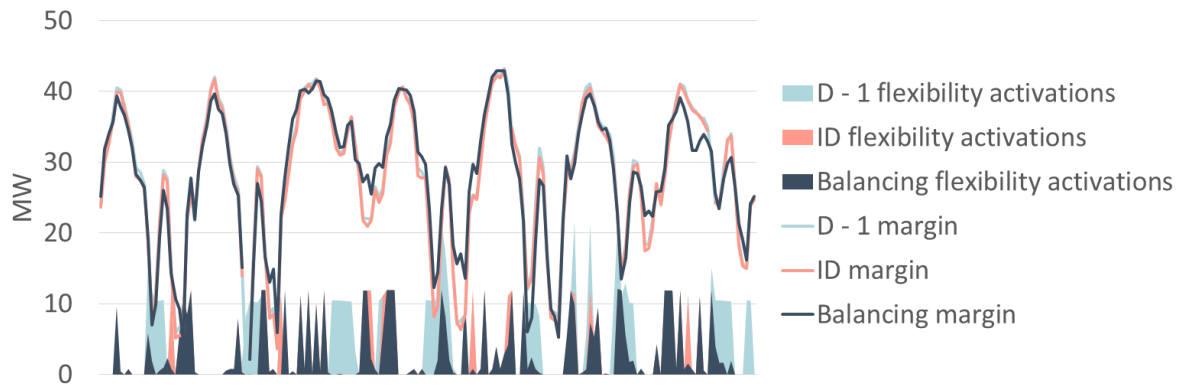


Figure 3- 30 Comparison of flexibility activations with the remaining margin to Maximum Power for day-ahead, intraday and balancing

To conclude on efficiency of filtering by timeframes, result has been synthesized in Figure 3- 31 (efficiency of filtering to reduce congestion) and Figure 3- 32 (economic efficiency). The results by time frame show that the closer the filtering takes place to real-time, the more effective it is in dealing with congestion as shown. Three important remarks can be made.

First, it is remarkable that, with the level of uncertainty represented, filtering in day-ahead only marginally reduces congestion. The day-ahead filtering seems very inefficient. It is inefficient to reduce congestions but also more generally less economically efficient than other filtering as stated in Figure 3- 32, which shows the economic balance of each of the filtering variants.

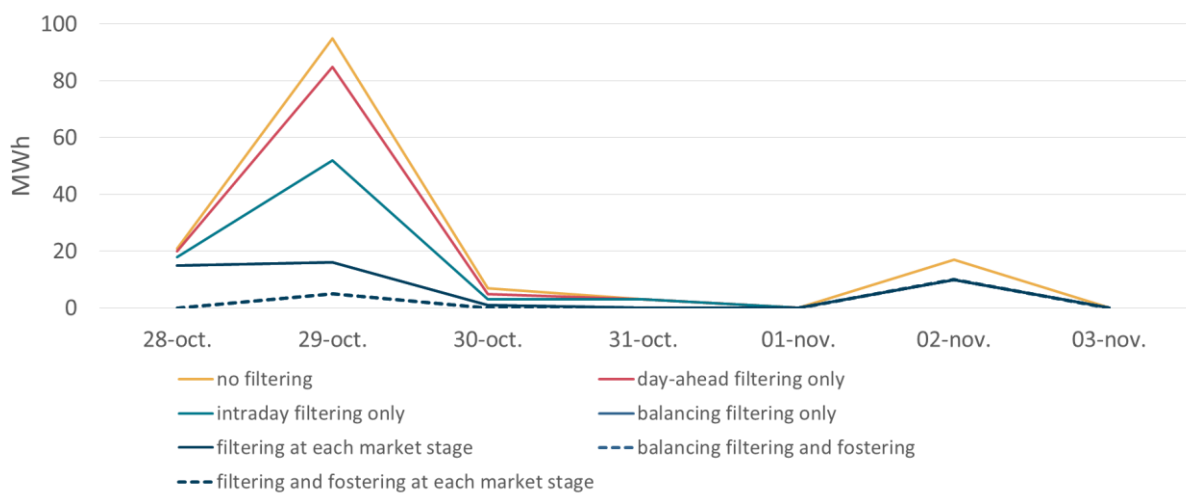


Figure 3- 31 Energy of the congestion for each day of the week for the seven variations

Second, similarly, filtering at all deadlines has no contribution compared to filtering only in balancing. With forecast errors, filtering the closest to real-time seems to be the most efficient solution to avoid network constraints and ultimately loss-of-load caused by the distribution network's failure.

Third, filtering at each market stage is not sufficient to avoid congestion.

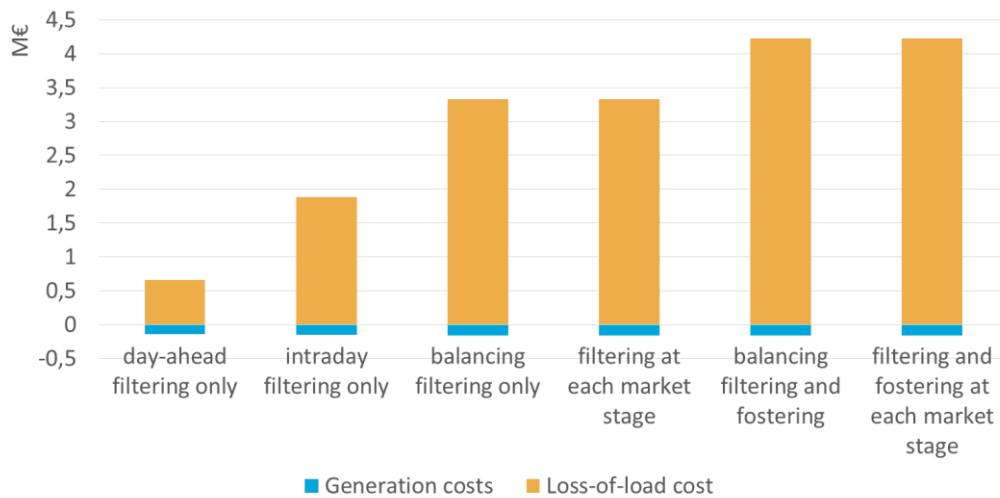


Figure 3- 32 Cost-benefit balance of the different filtering variants compared to the case without filtering. This balance sheet includes the impact in terms of production costs and in terms of unsupplied energy related to unresolved congestion but does not include the implementation costs.

To explain these findings, we are then investigating on causes for congestions. When there is an excessive load on a substation and a time-step, there are three possible causes: inflexible load, EVs, or water heaters. The excess is considered as caused by inflexible load, whenever, at this hour, the inflexible load alone exceeds the maximum power of the substation. If this is not the case, the excess is considered caused by EVs or water heaters, at the prorata of their total activation power. We choose this convention to see the displacements that could have been avoided by shifting demand from EVs and water heaters. This convention will be used throughout the analysis below, keeping in mind that it is only a convention.

Those causes of congestion are shown on Figure 3- 33 for each variant of filtering and for “no filtering variant” only, but with more details on the causes in Table 3- 3. Those six cases are exhaustive and exclusive. They allows to understand the conditions of well-functioning of filtering, and more generally of short-term coordination.

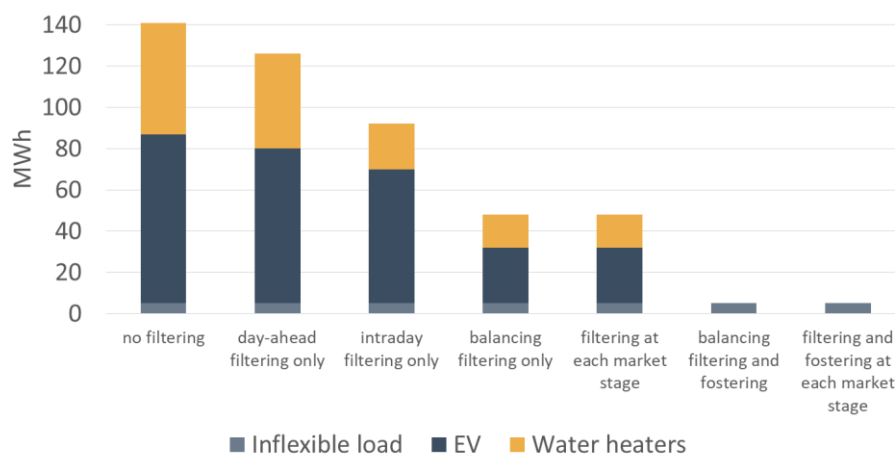


Figure 3- 33 Cause of the congestion remaining after filtering for each variant over the considered week

Cases	Main causes	Precisions	Part in % ¹²
1	Inflexible demand only	No flexibility activation	3,5
2	Day-ahead flexible demand placement	Congestion known in day-ahead (no adverse variation of inflexible load)	11,3
3	Day-ahead flexible demand placement	Congestion unknown in day-ahead	6,4
4	Intraday flexible demand placement	Congestion known in Intraday (no adverse variation of inflexible load)	22,9
5	Intraday flexible demand placement	Congestion unknown in Intraday	25,6
6	Balancing flexible demand placement	In our modeling, all congestion are supposed to be known at this time	30,2

Table 3- 3 Part of congestion in no filtering variant for six causes

Case 1 correspond to congestion with no flexible demand consumption. It represent few part of congestion as network dimensioning has been made to have congestion only a few hours by years with inflexible years and no activation of flexible demand¹³. No variants of filtering, and more generally no short-term coordination could solve the congestion with the flexibilities we modeled. It could be the case with vehicle-to-grid. In our modelling, incident on the network are not taking into account. In practice, they would reduce the maximal power that the network can transmit and have a similar effect as inflexible load increase.

¹² Congestion volume caused by each case compared to the volume of the “no filtering” variant. For case 1, the congestion volume is the “filtering and fostering” one. For case 2, it is the difference between the “no filtering” volume and the “day-ahead filtering only” volume. The congestion volume for case 3 is computed on its own: it is the volume of EV and water heaters placed in day-ahead, which creates a congestion in intraday. For case 4, the congestion volume is the difference between “no filtering” and “intraday filtering only” to which is subtracted the congestion volume of case 3. For case 5, the congestion volume is also computed on its own, it is the volume of EV and water heaters placed in intraday, which creates a congestion in day-ahead. For case 6, it is the difference between the “no filtering” volume and the “balancing filtering only” volume to which is subtracted the congestion volume of case 5.

¹³ This means that there is the same weekly demand for EVs and water but the charge is not scheduled, it is made directly when connected.

In case 2, demand from EVs or water heaters in day-ahead, added to inflexible demand, causes congestion known in day-ahead. Among six cases, those congestion are the only that can be cancelled by day-ahead filtering. In our simulations, these cases represent a small volume because flexible demand is very frequently modified in intraday or balancing markets. This behavior of flexibilities and thus the limited interest of Day-ahead filtering, observed thanks to the simulations, seems logical in a context of development of controlled demands and VRES - and thus of short-term uncertainties. However, it could be less pronounced in a context with a much higher share of solar than wind power. Indeed, in this case, on the one hand, there would be a stronger interest in day-ahead scheduling, to consume more at the time of high solar production, and on the other hand, there would be fewer changes in the price trend between spot and intraday with prices still very low in the middle of the day, and therefore less interest in moving flexible demands. Thus, the simulation on a summer week would probably have given more favorable results to day-ahead filtering than the week of November chosen. But given the very small share of congestion that can be cancelled by day-ahead filtering in simulations and the fact that congestion must be treated the whole year and not only in summer, day-ahead filtering seems unsuitable for the European context, which mixes a large share of wind and solar production.

In case 3, congestion is caused by a demand from EVs or water heaters scheduled in day-ahead and an inflexible demand higher than anticipated in Day-ahead. The congestion is therefore not anticipated in day-ahead. In this case, to alleviate the congestion when it is known, the flexible demand must be moved to another time step, and therefore a market order lowering the demand must be accepted. But as we have seen, filtering allows orders to be refused but not accepted, this is why even filtering at each market time cannot solve congestion. This problem can be solved by a filtering and fostering mechanism solves or by the other short-term coordination mechanisms presented, as none of which presents this dissymmetry problem. But the cancellation of the charging of EVs or water-heaters near real-time can be a problem for the consumer.

Case 4 is very similar to case 2 but in intraday. Those case could represent in reality a more important part than in our simulations with several intraday clearing. Thus, our results probably under-estimate the efficiency of intraday filtering in reduction of congestions if intraday filtering was put in place in each intraday session and in intraday continuous process. However, it would be insufficient to treat all the congestions, because of case 5 and 6.

Case 5 is very similar to case 3 but in intraday.

Finally, **case 6** is very frequent in our simulations, because distributed flexible demand is a low cost balancing means with very interesting technical characteristics (very fast response time, no minimum stable power duration). Balancing is the last market time we simulate but in reality, flexible demand can change closer to real-time if it participates in frequency regulation.

Thus, most of the local constraints are due to a flexible demand placement that occurs in intraday or during balancing. As we saw in 5.1.2, those placements are quite different from Day-ahead placements, which explains that short-term coordination can only be efficient to reduce congestions

near real-time. This short-term coordination must be symmetrical, i.e. it must be able to impose a lowering in consumption.

5.2.4. Filtering efficiency by timeframe with controllable flexibilities concentrated on one fifth of substations

A variant for the computation of the congestion volume is tested, with the use of 100% of flexible capacities distributed over 1/5th of the substations (instead of the use of 1/5th of flexible capacities distributed over 100% of the substations).

With this variant the remaining congestion volume has more than doubled for each variant as shown in Figure 3- 34. The increase in congestions on substations with 100% controllable flexibilities is therefore such that it more than compensates for the fact that there are 5 times fewer posts concerned. This can be explained by the threshold effect, illustrated in Figure 3- 35. Indeed, in the case of 20% controllable flexibilities, most of the exceeding is lower than the flexible power at the substations. In other words, without flexible power, there is a margin between the maximum power and the inflexible consumption. For these substations, with 100% controllable flexibilities, the volume of exceeding volume over the week overrun is therefore more than multiplied by 5 compared to 20% of controlled flexibilities spread over all substations.

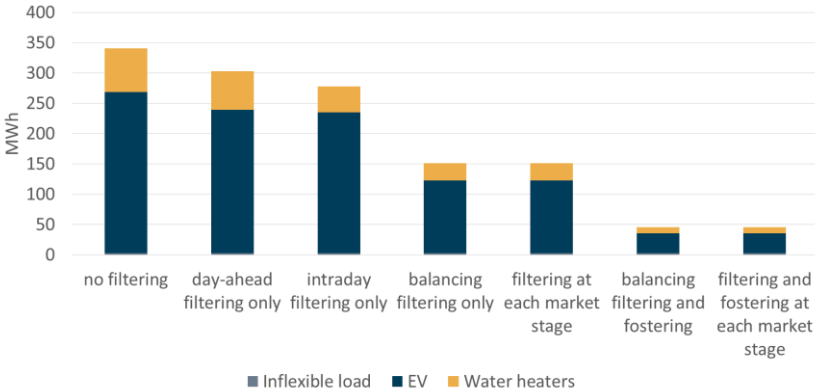


Figure 3- 34 Cause of the congestion remaining after filtering for each variant over the considered week with 100% of flexible capacities restricted to 1/5th of the substations

These results confirm the previous analyses on efficiency of filtering with a new contribution: there are still flexible demands during congestion in the cases with bid fostering. Indeed, in our model, flexible demands can only offer to cancel their consumption at a time step if the consumption can be carried forward, i.e. if the energy stored in the vehicles’ batteries is sufficient for future trips. Thus, with 100% use of flexible capacity, the energy constraint makes it harder to favor a congestion-free flexibility scheduling, which explains this increase in total congestion volume in filtering and fostering cases.

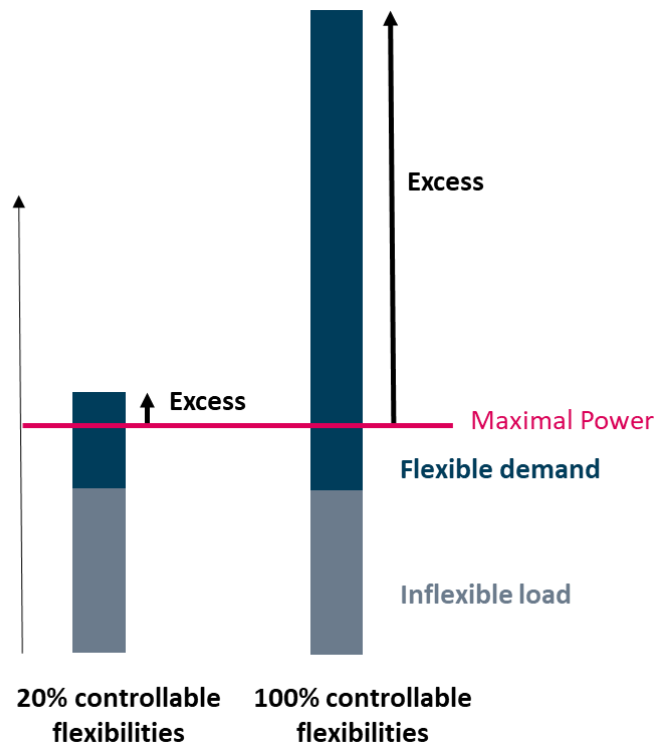


Figure 3- 35 Illustration of the threshold effect

6. Discussion and conclusions

This chapter focuses on the issue of coordinating the activation of distributed demand flexibility between the different short-term markets (day-ahead, intraday and balancing) and local constraints, by integrating the notion of uncertainties.

The literature analysis explained the implementation of different existing or theoretical coordination modes and evaluated the impact of these modes on both efficiency of coordination to reduce congestions on the one hand and valorization of demand response flexibilities on the other hand, depending on the coordination stages.

From this literature value, it is gathered that filtering is the most feasible next step from local flexibility markets towards the integration of local constraints into the wholesale markets.

This coordination mode for flexibility activations between the DSO, the TSO, and market actors is implemented and studied on the PROMETHEUS platform of RTE, with a model of market sequence, ATLAS. The filtering by the DSO of EV and water heaters activations, is set at different stages of the market sequence, namely day-ahead, intraday, and balancing, to measure the impact of forecast errors for load, solar, and wind on the efficiency of the coordination mechanism.

The quantitative results presented in section 5 are largely dependent on the assumptions and data used for this study. They are very dependent on the assumptions made on the volume of EVs and water

heaters consumption and the part of this volume that is controllable, the choice of the 2030 scenario for the electricity power mix, and the forecast error level. Moreover, this study has been carried out on a single week, which cannot be representative of the whole year. However, it is possible to draw key conclusions.

First, the gains for flexible demand assets in intraday and balancing is quite high compared to the day-ahead gains. These assets take advantage of short-term forecast errors on consumption and production and therefore the evolution of the market price at each timeframe. The rescheduling being cost-free for these assets, they are the first units whose commitment is modified to match an evolving forecast. This reinforces the interest of valuing flexible assets in these timeframes in order to get the most of their flexibility.

The second important result is that filtering does not impact system operational costs much nor the remuneration of flexible assets. This suggests a more complex coordination mode wouldn't have economical interest, as the additional benefits in term of operational cost would be low with a higher implementation cost.

The third important result is that the filtering the closest to real-time (balancing filtering) is the most effective in managing congestion, whereas the furthest from real-time (day-ahead filtering) is not effective at all. Indeed, forecast errors on the load in day-ahead are important and bids are filtered unnecessarily or on the contrary, some of the constraint causing bids are not filtered at this stage. This is caused by the significant modifications of the demand flexibility planning at each timeframe, to cope with the evolution of the forecasts on load, solar, and wind production. Inflexible load has for its part little impact on the exceeding volume at each timeframe.

Lastly, filtering is not sufficient to avoid all network constraints caused by flexibility activations. Indeed, the filtering is not symmetrical and can only cancel offers. To solve some constraints, flexible consumption reduction offers must be activated. This is only possible if these offers exist and therefore if the flexible demands participate in the intraday and balancing. Upward and downward bids should be mandatory when possible. Participation of aggregators¹⁴ in the balancing market must be mandatory to have an efficient short-term coordination, which is a very strong condition. Moreover, this obligation is not sufficient to avoid unmanaged constraints and hence load curtailment: indeed, EVs or water heaters consumption cannot always be postponed.

These results therefore do not lead to an implementation process for the filtering coordination mechanism, but completes the vision of each coordination mode given by the state of the art.

In theory, price coordination and co-optimization are more efficient, but have additional operational constraints compared with filtering, notably due to a need for more information exchange and a need of time consuming algorithm. Though their implementation on the balancing timeframe appears unrealistic in the next years, the question of their realization may arise later, in case of successful implementation of filtering and a need for further optimization of the coordination.

¹⁴ This concerns actual aggregators, therefore all of those who control an EV fleet. It might be needed to verify that EV are controlled or not for each aggregator.

The local flexibility markets are not coordinated with the other markets. This point can be more or less troublesome depending on the time frame. On an intraday basis, this induces little risk, whereas close to real time, it can be more critical as there is little time left to take corrective actions. As VRES forecast errors decrease significantly a few hours before real time, intraday local flexibility markets seem to be adapted for preventive renewable management. However, this solution appears unsuitable for demand side flexibilities. This raises the question of the possibility to have distinct mechanism for VRES and demand response.

Filtering is the easiest way to integrate the distribution network's constraints into the wholesale markets, but is much more complex to implement than local flexibility markets. In particular, it requires localized bids, and, as seen in our study, the requirement for distributed flexibility aggregators to participate in balancing. In balancing, its implementation would be challenging due to high temporal constraint. Those temporal constraint impose complex process also for actors. Thus, obligation to participate in balancing would be an important barrier to entry for aggregators.

This insight into the constraints related to the implementation of short-term coordination raises the question of a cost-benefit analysis of a large-scale deployment of distributed demand full controllability.

Résumé en français : Cette partie de la thèse réexamine ces conclusions en intégrant à la démarche les incertitudes de court terme, qui vont jouer à la fois sur la valorisation des flexibilités sur les marchés de gros et sur le mécanisme de coordination. Le marché de gros n'est plus modélisé comme un marché parfait avec une échéance unique et la séquence des marchés court-terme, du J – 1 au temps réel, est détaillée avec la modélisation des incertitudes de court-terme dans le modèle de marché « ATLAS ». De plus, un mécanisme de coordination par filtrage est intercalé à chaque échéance de marché, entre le moment de la formulation des offres et le moment du clearing de marché. Ce filtrage correspond à la coordination la plus simple pouvant être implémentée dans les marchés court terme, mais modifierait déjà significativement les principes actuels : il s'agit d'une baisse ou une annulation du volume des offres créant des contraintes sur les réseaux de distribution. Cette modélisation très complexe n'a pu être utilisée que sur une semaine de 2030, mais elle a permis de mettre en évidence des conclusions intéressantes sur les gains des flexibilités aux différences échéances de marché et sur les mécanismes de coordination. Les déplacements de demande pilotée ayant un très faible coût à condition de respecter les contraintes correspondant au respect des besoins des utilisateurs, la demande flexible peut réaliser beaucoup d'arbitrage en infra-journalier et les gains associés sont importants. Ils représentent dans les simulations plus de la moitié des gains totaux. Ce résultat peut modifier les conclusions d'études prospectives, qui prennent rarement en compte ces échéances. Notamment, le pilotage jusqu'en temps réel serait bien plus intéressant qu'un pilotage tarifaire puisque ces gains ne sont possibles que pour un pilotage fin. En ce qui concerne le filtrage, il ne pourrait gérer les congestions que proche du temps réel et à condition que les flexibilités offertes offerts aux échéances précédentes offrent obligatoirement (à la hausse et à la baisse si cela est techniquement faisable) et avec une localisation précise, ce qui pose question quant à la possibilité d'une mise en œuvre concrète, notamment en termes de complexité de traitement à une échéance si proche du temps réel à la fois pour les gestionnaires de réseaux et pour les agrégateurs.

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Appendix

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1 Appendix A - Case study for Chapter 2

Assumptions on generation and inflexible load for the European countries of Central Western Europe : France (fr), Austria (at), Belgium (be), Switzerland (ch), Germany (de), Spain (es), Great-Britain (gb), Ireland (ie), Italy (it), Luxembourg (lu), Northern Ireland (ni), Netherlands (nl) and Portugal (pt) in 2030 are made according to the “VOLT” scenario of the “Bilan Prévisionnel” (which could be translated as “Forecasts Summary”) of RTE (RTE, 2017a). The “Bilan Prévisionnel” is a prospective adequacy report for France that RTE is legally obliged to produce every year, covering a period from 5 to 15 years. In these reports, various scenarios for consumption, installed capacity and production are explored. The “VOLT” scenario of the 2017 “Bilan Prévisionnel” describes the case of an intensive development of renewables alongside an economically optimal nuclear production. The assumptions made by this report for this scenario are summarized in Figure Appendix - 1.

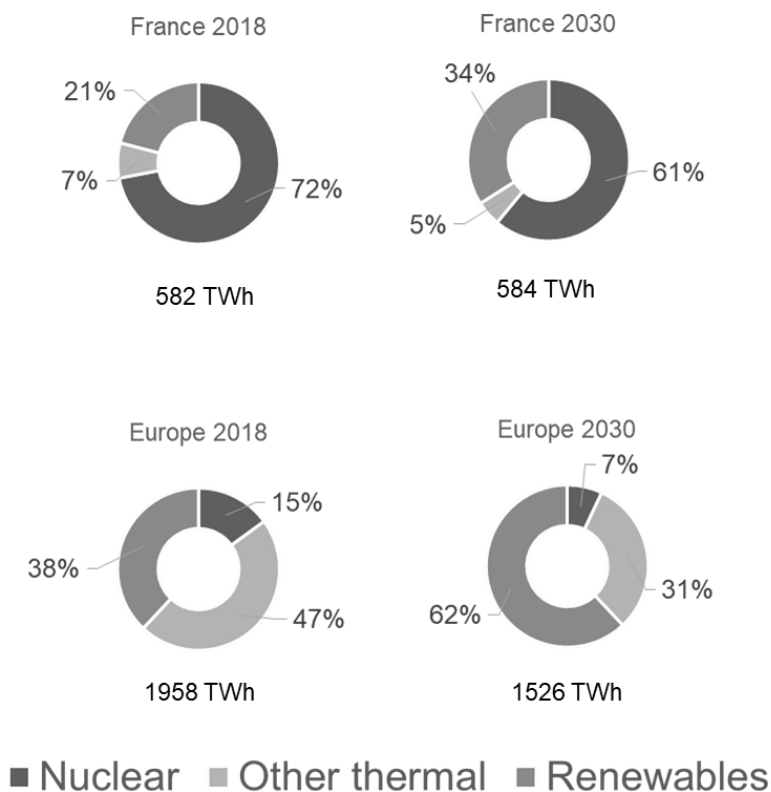


Figure Appendix - 1 Distribution of production in France and the other European countries considered in the study

Load is as stated in Table Appendix - 1:

Inflexible load (TWh)	2018	2030
France	481,0	447,8
Other European countries	1896	1680

Table Appendix - 1 Load for France and the other European countries considered in the study for 2018 and under the VOLT scenario's assumptions for 2030

The 2030 installed capacity for France is as stated in Table Appendix - 2.

Installed 2030 capacity	GW
Nuclear	57,6
Thermic	11,1
CCGT	6,7
Combustion turbines	1,6
Cogeneration	2,1
Other distributed thermic units	0,77
Renewables	97,2
Hydraulic	25,5
Including PHS	4,2
Wind	40,2
Including onshore wind	32,7
Including offshore wind	7,5
Solar	27,7
Bioenergies	3,1
Marine energies	0,6
Load-shedding	2,5
TOTAL	168,3

Table Appendix - 2 Installed 2030 production capacity in France according to (RTE, 2017a)

Table Appendix - 3 details the variable cost hypothesis for the different thermic unit types.

Thermic unit type	Variable cost hypothesis (€/MWh)
Nuclear	5,02
CCGT	69,32
Coal	57,31
CT gas	95,73
CT oil	229,14

Table Appendix - 3 Variable costs hypothesis for the different thermic unit types according to the "Bilan Prévisionnel"

The interconnections' capacity of France with its neighboring countries are summarized in Table Appendix - 4.

Interconnection with...	Import capacity (GW)	Export capacity (GW)
Germany	4,3	4,3
Belgium	3,9	5,2
United-Kingdom	6,7	6,7
Spain	4,5	4,5
Italy	1,9	3,7
Switzerland	1,6	4,2
Ireland	0,6	0,6

Table Appendix - 4 Interconnections capacity of France for 2030

For other countries, the data is derived from the "Bilan Prévisionnel", which considers the TYNDP (Ten-Year National Development Plan) at 2035.

This study only considers EV charging, water heaters and heating shifting which are the main demand response assets that are expected to be broadly used by end-users. A precise modelling is used for

each of these consumer uses, entailing technical characteristics proper to each use and therefore no general framework for demand response is used.

For flexible load, the assumptions made are:

- 5.8 million EVs in France in 2030. For other countries, the number of expected EVs in 2030 is evaluated from the TYNDP 2035 (Ten-Year National Development Plan) using a simple linear transform based on France's 2030 and 2035 forecasts (the TYNDP predicts the existence of 8.3 million electric vehicles for 2035 in France):

$$nbEV_c = nbEV_{c,TYNDP} \times \frac{5,8}{8,3}$$
with $nbEV_c$ the number of electric vehicles for the country c in the study and $nbEV_{c,TYNDP}$ the number of electric vehicles for the country c for 2035 in the TYNDP. These assumptions for EVs are detailed in Table Appendix - 5. Countries considered in the study which are not in the table do not have electric vehicles in the TYNDP.
- Annual consumption of water heaters of 17 TWh in France, with 7.6 GW of power (RTE, 2017a). It is less than the actual 19 TWh because the new regulation requires new storage water heaters to be more efficient than older ones. These new water heaters, whose load cannot be controlled, are gradually replacing thermodynamic water heaters. Water heaters' flexibility is accounted for only in France because the control of water heaters (via the in-feed of a modulated 175Hz signal) currently only exists in France.
- For heating shifting, the assumption made is that 20% of the whole heating consumption can be shifted in cold months (from October to March). The heating energy consumption shed during an hourly time slot is carried forward within the next 24 hours following the load-shedding.

	Millions of EVs	Power of EV charging (GW)	Annual EV charging energy (TWh)
Switzerland (ch)	0,55	2,6	1,0
Deutschland (de)	4,66	21,7	8,7
Spain (es)	2,33	10,8	4,3
France (fr)	5,80	27,0	10,8
Great-Britain (gb)	3,37	15,7	6,3
Italy (it)	3,77	17,5	7,0
Netherlands (nl)	0,84	3,9	1,6

Table Appendix - 5 Assumptions for EV charging for the concerned EU countries (no modelling of EV charging for be, ie, lu, ni and pt because of lack of data)

2 Appendix B – Constraints on the dispatch of demand flexibility in Antares

This appendix details the constraints in the optimization problem for dispatch cost minimization for water heaters, EVs and heating deferral.

2.1 Water heater's flexibilities

The water heaters' flexibility is constrained by a daily water heaters' energy and an hourly maximum power.

For each day of the year $\in [1; 364]$:

$$\left\{ \begin{array}{l} \sum_{h=(d-1)*24+1}^{d*24} WH_h = StorWH_d \quad (B.1) \\ WH_h < WH_{max,h} \quad (B.2) \end{array} \right.$$

WH_h is the volume of water heating power activated on hour $h \in [1; 8736]$.

$StorWH_d$ is the water heating storage to spread on day d .

$WH_{max,h}$ is the maximal water heater power that can be activated on hour h .

2.2 EVs flexibility

The charging of EVs is constrained by the minimum state of charge of the EVs connected to a charging station and by a storage constraint whose parameters are calculated by MoveRTE, another application developed by RTE. This calculation is described in (Lauvergne, Perez, Françon, & Tejada De La Cruz, 2022).

$$\left\{ \begin{array}{l} SoC_{max,h} > SoC_h > SoC_{min,h} \quad (B.3) \\ SoC_h = SoC_{h-1} + 0,92 * EV_h + MobileStor_h \quad (B.4) \\ EV_h < EV_{h,max} \quad (B.5) \end{array} \right.$$

EV_h the power activated for the EVs' recharge at hour h .

SoC_h the state of charge of the EVs connected to recharge stations at hour h .

The other components of the models are the parameters computed by the software MoveRTE for the input number of electric vehicles considered in this study:

$SoC_{min,h}$ the minimal state of charge of the EVs connected to recharge stations at hour h .

$SoC_{max,h}$ the maximal state of charge of the EVs connected to recharge stations at hour h .

$MobileStor_h$ the delta of the energy contained in batteries that are connected to a recharge station between hour h and hour $h - 1$. It can vary because of energy use or because of number of vehicles connected.

$EV_{max,h}$ the maximum national charging power at hour h .

2.3 Heating flexibility

The heating power is constrained by the deferrals. The shifted heating power is deferred in its entirety on the 24 following time slots. The deferral has four decreasing levels.

$$\left\{ \begin{array}{l} 0 \leq def_h \leq def_{max,h} \text{ (B.6)} \\ heating_h = heating_h^0 - def_h + \sum_{k=1}^{24} coeff_k * def_{h-k} \text{ (B.7)} \end{array} \right.$$

def_h the heating power deferral report at hour h .

$def_{max,h}$ the maximal deferral power at hour h

$heating_h$ the heating power at hour h .

$heating_h^0$ the heating power at hour h without deferral.

$coeff$ the deferral coefficients. The sum of the coefficients on the 24 time slots after the shifting is equal to 1 as all the power shifted is deferred (we assume there is no energy gain or loss).

3 Appendix C - Breakdown of the national power over the substations

This appendix describes the computation of the local loads (flexible and inflexible) and productions (solar and wind) from their national curve, at each substation of the scope of the study.

3.1 Inflexible load

The distribution of the inflexible load over the substations is proportional to the median of the historical consumption per substations over five years, as follows:

$$\text{For every substation } s, \text{Inflexible}_s = \text{Inflexible}_{tot} \times \frac{\text{med}(\text{Inflexible}_{\text{historical},s})}{\sum_{t \in \text{Substations}} \text{med}(\text{Inflexible}_{\text{historical},t})} \quad (C.1)$$

Inflexible_s the 10-year inflexible consumption time-series of the substation s

Inflexible_{tot} the 10-year national inflexible consumption time-series

$\text{Inflexible}_{\text{historical},s}$ the 2012- 2016 consumption of the substation s

3.2 Solar and wind

Renewable production is first broken down by area, to capture dependence on meteorological conditions. The French territory is divided into 26 areas which are considered coherent in terms of weather conditions and grid exploitation. The renewable production is spread over the 26 areas according to the load factors of each area. From this area-wide distribution, the injection curve on substations is allocated according to the 2030 installed capacity of the substation as forecasted by RTE.

For every area a and every s substation of a ,

$$\text{Solar}_s = \text{Solar}_{tot} \times \frac{\text{LFS}_a}{\text{LFS}_{tot}} \times \frac{\text{CapaS}_s}{\sum_{t \in a} \text{CapaS}_t} \quad (C.2)$$

$$\text{Wind}_s = \text{Wind}_{tot} \times \frac{\text{LFW}_a}{\text{LFW}_{tot}} \times \frac{\text{CapaW}_s}{\sum_{t \in a} \text{CapaW}_t} \quad (C.3)$$

Solar_s the 10-year solar production time-series of the substation s

Solar_{tot} the 10-year national solar production time-series

LFS_a the 10-year solar load factor of the area a

LFS_{tot} the national 10-year solar load factor

CapaS_s the installed solar capacity of the substation s

Wind_s the 10-year wind production time-series of the substation s

Wind_{tot} the 10-year national wind production time-series

LFW_a the 10-year wind load factor of the area a

LFW_{tot} the national 10-year wind load factor

$CapaW_s$ the installed wind capacity of the substation s

3.3 Water heaters

The breakdown of the water heaters load curve is calculated along with the historical breakdown of the water heaters load curve. This breakdown is calculated by country with PERSEE, a software developed by RTE.

$$WH_s = WH_{tot} \times \frac{enerWH_{s,hist}}{\sum_{t \in Substations} enerWH_{t,hist}} \quad (C.4)$$

WH_s the 10-year water-heater consumption time-series of the substation s

WH_{tot} the 10-year national water-heater consumption time-series

$enerWH_{s,hist}$ the mean of the yearly 2012-2016 water heaters consumption energy for the substation s .

3.4 EVs

For the EV local load curves, the breakdown model takes into account the population density¹, median income², and current car ownership level³ of the municipalities, from a public data provider, INSEE. The total number of EVs is fixed and spread over each municipality and the breakdown on each municipality is computed with a downscaling coefficient:

$$coeff_m = \frac{1}{3} \times \left(\frac{Pop_m}{\sum_{t \in M} Pop_t} + \frac{Inc_m}{\sum_{t \in M} Inc_t} + \frac{Car_m}{\sum_{t \in M} Car_t} \right) \quad (C.5)$$

M the set of municipalities of France

$coeff_m$ the downscaling coefficient of the municipality m

Pop_m the population density of the municipality m

Inc_m the median income of the municipality m

Car_m the average number of vehicle per household of the municipality m

For each substation s , the downscaling coefficient is the sum of the downscaling coefficients of each municipality serviced by the substation. If a municipality is serviced by more than one substation, its downscaling coefficient is divided by the number of substations that service the municipality first.

$$coeff_{m,adapted} = \frac{coeff_m}{nbSub_m} \quad (C.6)$$

¹<https://www.insee.fr/fr/statistiques/4515503?sommaire=4515944&q=m%C3%A9nages+par+commune>

²<https://www.insee.fr/fr/statistiques/1893185>

³<https://www.data.gouv.fr/fr/datasets/taux-de-motorisation-des-menages/>

$coeff_{m,adapted}$ the downscaling coefficient of the municipality m after adaptation to the number of substations of the municipality.

$nbSub_m$ the number of substations that services the municipality m

$$coeff_s = \sum_{m \in s} coeff_{m,adapted} \quad (C.7)$$

$coeff_s$ the downscaling coefficient of the substation s

$$EV_s = EV_{tot} \times coeff_s \quad (C.8)$$

EV_s the 10-year charging stations consumption time-series for the substation s

EV_{tot} the 10-year national charging stations consumption time-series

3.5 Heating

The breakdown of the heating load curve is made according to the historical share of the substation heating power within a region. The share of each region in the national heating load curve is forecasted in 2030 with ORPHEE a software developed by RTE.

$$heating_s = heating_{tot} \times \frac{heating_{s,2030}}{\sum_{t \in Substations} heating_{t,2030}} \quad (C.9)$$

$heating_{tot}$ the 10-year heating national consumption time-series

$heating_s$ the 10-year heating consumption time-series of the substation s

$heating_{r,2030}$ the 2030 heating total energy consumption of the substations s as forecasted by ORPHEE.

4 Appendix D: Computation of the reinforcement costs

The computation of reinforcement costs takes place in a three-step process:

1. Given national load, renewable generation, and flexibility activations are spread over 1890 substations of the French territory.
2. The Maximum Power Indicator (MPI) is computed for each substation. It shows the maximum of power reached by the net consumption curve: peak on withdrawal and peak on injection. The MPIs are computed for 2018 load curves and 2030 load curves for the three flexibility activation signals.
3. The gap between the MPIs obtained with the 2030 net consumption curves for each flexibility activation signal and the “historical” MPI, computed on 2018 net consumption curves, shows the reinforcement need for each substation, for the three signals. Reinforcement costs are a function of this MPI gap if positive.

The computation of the load curves for each substation constitutes another annex of the manuscript. This annex focuses on steps 2 and 3.

4.1 Computation of the MPIs for each substation

For each substation there are four MPIs: one for the load, one for the load minus the LV solar production, one for the MV solar production and one for the wind production. These four MPIs are necessary to the computation of reinforcement costs that take into account both MV and LV levels and both injection and withdrawal. The MPIs are computed for the year 2030 with the simulations’ outcomes and for the year 2018 with historical data.

For every substation s :

$$MPI_{s,2030}^{load} = TY_{load|10,2030}[3] \quad (D.1)$$

$$MPI_{s,2030}^{load-LV\ solar} = TY_{load-LV\ solar|10,2030}[3] \quad (D.2)$$

$$MPI_{s,2030}^{MV\ solar} = TY_{MV\ solar|10,2030}[200] \quad (D.3)$$

$$MPI_{s,2030}^{Wind} = TY_{Wind|10,2030}[200] \quad (D.4)$$

$$MPI_{s,2018}^{load} = TY_{load|10,2018}[3] \quad (D.5)$$

$$MPI_{s,2018}^{load-LV\ solar} = TY_{load-LV\ solar|10,2018}[3] \quad (D.6)$$

$$MPI_{s,2018}^{MV\ solar} = TY_{MV\ solar|10,2018}[200] \quad (D.7)$$

$$MPI_{s,2018}^{Wind} = TY_{Wind|10,2018}[200] \quad (D.8)$$

$MPI_{s,2030}^{load}$ the load MPI of the substation s for the year 2030

$MPI_{s,2030}^{load-LV solar}$ the load minus the LV solar MPI of the substation s for the year 2030

$MPI_{s,2030}^{MV solar}$ the MV solar MPI of the substation s for the year 2030

$MPI_{s,2030}^{Wind}$ the wind MPI of the substation s for the year 2030

$MPI_{s,2018}^{load}$ the load MPI of the substation s for the year 2018

$MPI_{s,2018}^{load-LV solar}$ the load minus the LV solar MPI of the substation s for the year 2018

$MPI_{s,2018}^{MV solar}$ the MV solar MPI of the substation s for the year 2018

$MPI_{s,2018}^{Wind}$ the wind MPI of the substation s for the year 2018

$TY_{load|10,2030}$ the ten-year monotonous for load at substation s sampled 1/10 for the year 2030

$TY_{load-LV solar|10,2030}$ the ten-year monotonous for load minus LV solar at substation s sampled 1/10 for the year 2030

$TY_{MV solar|10,2030}$ the ten-year monotonous for load at substation s sampled 1/10 for the year 2030

$TY_{Wind|10,2030}$ the ten-year monotonous for wind at substation s sampled 1/10 for the year 2030

$TY_{load|10,2018}$ the ten-year monotonous for load at substation s sampled 1/10 for the year 2018

$TY_{load-LV solar|10,2018}$ the ten-year monotonous for load minus LV solar at substation s sampled 1/10 for the year 2018

$TY_{MV solar|10,2018}$ the ten-year monotonous for load at substation s sampled 1/10 for the year 2018

$TY_{Wind|10,2018}$ the ten-year monotonous for wind at substation s sampled 1/10 for the year 2018

4.2 Computation of the reinforcement cost for each substation

4.2.1 MPI equivalent at the MV level

The reinforcement need at the MV level depends on the reinforcement need for load and MV solar and the localization of the substation. We assume that for rural substations the lines are not completely reversible and that only one third of the withdrawal maximum power can be injected. For urban and semi-urban areas, this is not the case and withdrawal and injection flows can be the same.

Thus, for rural areas, the MV MPIs $MPI_{s,2030}^{MV}$ and $MPI_{s,2018}^{MV}$ for the substation s could be written in such a way:

$$MPI_{s,2030}^{MV} = \max(MPI_{s,2030}^{load}, 3 * MPI_{s,2030}^{MV solar}) \quad (D.9)$$

$$MPI_{s,2018}^{MV} = \max(MPI_{s,2018}^{load}, 3 * MPI_{s,2018}^{MV solar}) \quad (D.10)$$

For urban and semi-urban areas, $MPI_{s,2030}^{MV}$ and $MPI_{s,2018}^{MV}$ are expressed in this way:

$$MPI_{s,2030}^{MV} = \max(MPI_{s,2030}^{load}, MPI_{s,2030}^{MV solar}) \quad (D.11)$$

$$MPI_{s,2018}^{MV} = \max(MPI_{s,2018}^{load}, MPI_{s,2018}^{MV solar}) \quad (D.12)$$

4.2.2 Randomization of reinforcement margins

The network is not reinforced continuously but in a discrete way. Indeed, a reinforcement is the installation of a new transformer, line or connection which increases the maximum power flow the substation can handle by a value that is inherent to the technical characteristics of the equipment. Thus, when a reinforcement is made, it exceeds the immediate need for reinforcement and there is a margin before the next reinforcement needs to be carried out. This margin is different for each substation and depends on previous reinforcements. This data is not available to us and therefore, the margin before the need for reinforcement is randomly drawn uniformly over the maximum margin between two reinforcements which depends on the substation's localization (Table Appendix - 6).

Localization	Urban	Semi-urban	Rural
Maximum margin $mr g_{MAX}$	48 MW	12.3 MW	6.7 MW

Table Appendix - 6 Maximum margin before the next reinforcement for a substation depending on its localization

We choose the reinforcement need at the MV level as an indicator because we assume the LV level is reinforced only if the MV level is reinforced, even if the reinforcement need is not the same.

Assuming a monotonous increase of the maximum power spread in the 12 years between 2018 and 2030 we can compute the yearly increase of the Maximum Power for MV and LV levels as follows:

$$ratio_{s,MV} = (MPI_{s,2030}^{MV} - MPI_{s,2018}^{MV})/12 \quad (D.13)$$

$$ratio_{s,LV} = \frac{MPI_{s,2030}^{load-LV solar} - MPI_{s,2018}^{load-LV solar}}{12} \quad (D.14)$$

The number of years before reinforcement is carried out is the number of years before the MPI reaches the next reinforcement milestone, in $mr g_{s,MV}$ MW for the MV level and $mr g_{s,LV}$ for the LV level. As the reinforcement is discretized, the margin $mr g_{s,MV}$ is reinforced at once if $MPI_{s,2030}^{MV} - MPI_{s,2018}^{MV} < mr g_{s,MV}$, and $mr g_{s,MV} + k_{s,MV} * mr g_{MAX}$ if $MPI_{s,2030}^{MV} - MPI_{s,2018}^{MV} > mr g_{s,MV}$ and for the LV level,

the margin $mr g_{s,LV}$ is reinforced at once if $MPI_{s,2030}^{load-LV solar} - MPI_{s,2018}^{load-LV solar} < mr g_{s,LV}$, and $mr g_{s,LV} + k_{s,LV} * mr g_{MAX}$ if $MPI_{s,2030}^{load-LV solar} - MPI_{s,2018}^{load-LV solar} > mr g_{s,LV}$, with:

$$k_{s,MV} = \left\lceil \frac{MPI_{s,2030}^{MV} - MPI_{s,2018}^{MV} - mr g_{s,MV}}{mr g_{MAX}} \right\rceil \quad (D.15)$$

$$k_{s,LV} = \left\lceil \frac{MPI_{s,2030}^{load-LV solar} - MPI_{s,2018}^{load-LV solar} - mr g_{s,LV}}{mr g_{MAX}} \right\rceil \quad (D.16)$$

$$n_{s,MV} = \max \left(\frac{\log \left(1 + \frac{mr g_{s,MV}}{MPI_{s,2018}^{MV}} \right)}{\log(ratio_{s,MV})} - 12,0 \right) \quad (D.17)$$

$$n_{s,LV} = \max \left(\frac{\log \left(1 + \frac{mr g_{s,LV}}{MPI_{s,2018}^{load-LV solar}} \right)}{\log(ratio_{s,LV})} - 12,0 \right) \quad (D.18)$$

4.2.3 Accounting for the localization

The localization of the substation is accounted for with a multiplicative adjustment coefficient Adj_s applied to the total reinforcement cost according to the localization of the substation (Table Appendix - 7).

Type of area	Adjustment coefficient
Rural	1,55
Semi-urban	1
Urban	0,75

Table Appendix - 7 Adjustment coefficients for reinforcement costs for the different area types

4.2.4 Reinforcement cost

We assume the different financial characteristics for the equipment:

$i = 4.5\%$ the discount rate

$T = 40$ the lifetime of the equipment

Reinforcement cost for a substation is the addition of the LV reinforcement cost, the MV reinforcement cost and the wind reinforcement cost.

At the LV level, the cost of a reinforcement is $c_{LV} = 20k\text{€}/\text{MW}/\text{year}$.

At the MV level, the cost of a reinforcement is $c_{MV} = 10\text{k€}/\text{MW}/\text{year}$.

For wind, the cost of a reinforcement is $c_{Wind} = 100\text{k€}/\text{MW}$

Thus, for each substation s :

$$C_{LV} = mrg_{s,LV} * c_{LV} * \frac{1}{(1+i)^{n_s}} * Adj_s \text{ if } n_{s,LV} > 0 \text{ (D.19)}$$

$$C_{LV} = (mrg_{s,LV} + k_{s,LV} * mrg_{MAX}) * c_{LV} * Adj_s \text{ if } n_{s,LV} > 0 \text{ (D.20)}$$

$$C_{MV} = mrg_{s,MV} * c_{MV} * \frac{1}{(1+i)^{n_s}} * Adj_s \text{ if } n_{s,MV} > 0 \text{ (D.21)}$$

$$C_{MV} = (mrg_{s,MV} + k_{s,MV} * mrg_{MAX}) * c_{MV} * Adj_s \text{ if } n_{s,MV} = 0 \text{ (D.22)}$$

$$C_{Wind} = ((MPI_{s,2030}^{Wind} - MPI_{s,2018}^{Wind}) * c_{Wind}) / T * Adj_s \text{ (D.23)}$$

The total annualized cost for substation is:

$$C_{tot,s} = C_{LV} + C_{MV} + C_{Wind} \text{ (D.24)}$$

5 Appendix E – “Peak/Off-peak” (POS) filtering

By symmetry with the analysis of a full control of flexibility with filtering, a similar exercise was conducted for a tariff signal. The approach is therefore to take reinforcement hypotheses corresponding to the case without activation of flexibilities and to modify the energy ratios⁴ in tariffs on the stations where overruns are created. As we have seen, the reinforcement costs in tariffs are close to those without activation of flexibilities, so there are very few substations concerned by overruns.

The result is therefore a small economic gain, but the methodology remains interesting and could be applied with lower levels of reinforcement. This is why we explain it in this appendix.

We call POS filtering this adaptation of the energy ratios for the four typical days to take into account local constraints. The energy ratios are differentiated for the 6 substations involved in this filtering.

For each of these substations, an iterative heuristic lowers the ratios on the hours where the NS MPI is exceeded and increases them on the time steps without constraints but with low average prices (in order to keep the same daily energy for the substation). At each iteration, we take care that the flexibility activations on these other time steps do not cause new exceeding of the NS MPI.

The results are presented on a substation for a winter week in Figure Appendix - 2. The daily pattern of EV and water heaters consumption are modified in order to cancel the exceeding caused by EV charging.



Figure Appendix - 2 Consumption curve for a substation before and after POS filtering

⁴ The energy ratios are the “peak/off-peak” signal hourly coefficients for the repartition of the daily energy over the 24 hours of the day. Their sum equals 1 over the day. There are four sets of energy ratios, for four typical days: summer/business day; summer/week-end; winter/business day; winter/week-end.

In Figure Appendix - 3 the gains of POS filtering compared with the POS. The local differentiation of energy ratios enables to reduce the costs of POS by approximately 1M€. The gains corresponding to the prevented reinforcement costs are about 1,1M€, and the operational and loss-of-load costs increase (negative gains) is approximately 0,1M€.

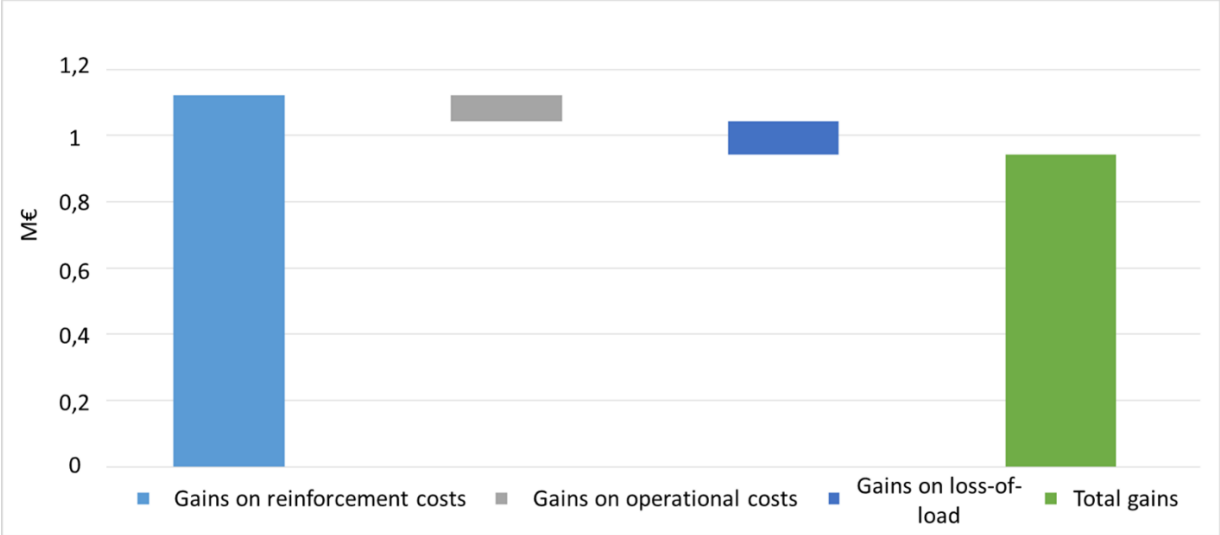


Figure Appendix - 3 POS filtering gains with respect to the POS

6 Appendix F – Optimized decomposition of the flexibility activations on each substation

After the Antares optimization including the constraint (9) is performed, another optimization verifies that a decomposition of the obtained flexibility activations complies with the MPI of each substation exists and, if not, how far we are beyond the individual MPIs. Indeed, the national flexibility activation constraint does not ensure that each substation is individually constrained at its NS MPI. The distribution of the national flexibility activations is not satisfactory as various substations overrun their NS MPI. The following method for the distribution of the national activations on every substation enables energy exchange between substations to verify there is a national flexibility activation breakdown that satisfies the individual NS MPI at each substation. If this breakdown does not exist, the optimization finds the breakdown that minimizes total NS MPIs excesses.

This optimization problem aims to minimize the total energy exceeding the MPI on all the substations (the loss-of-load).

6.1 Objective function

The objective function is as follows:

$$\sum_{h=0}^{167} \sum_{s \in \text{Substations}} (\max (WH_{s,h} + EV_{s,h} + heating_{s,h} + Inflexible_{0,s,h} - DS_{0,s,h} - P_{max,s}^*; 0)) (F. 1)$$

$WH_{s,h}$ the water heaters consumption for the substation s at hour h (optimization variable)

$EV_{s,h}$ the charging stations consumption for the substation s at hour h (optimization variable)

$heating_{s,h}$ the heating consumption for the substation s at hour h (optimization variable)

$Inflexible_{0,s,h}$ the inflexible consumption for the substation s at hour h

$DS_{0,s,h}$ the distributed solar production for the substation s at hour h

$P_{max,s}^*$ the chosen MPI of the substation s

6.2 Constraints

The constraints applied to the optimization variables are the breakdown on substations of the constraints applied to the flexible activations with Antares in optimal dispatch simulation. Other constraints entail the conservation of energy at each substation for each flexibility asset and the conservation of the total power as computed with Antares for the evaluation of the production costs with filtering.

For each substation s the total energy of each flexibility must remain the same:

$$\forall s \in \text{Substations}, \forall d \in [1; 364], \sum_{h=24*(d-1)}^{24*d-1} WH_{s,h} = WH_{s,d} \quad (F.2)$$

(the energy of water heaters is constrained daily)

$WH_{s,d}$ the water heaters energy consumption of substation s for day d

$$\forall s \in \text{Substations}, \sum_{h=0}^{167} EV_{s,h} = \sum_{h=0}^{167} EV_{0,s,h} \quad (F.3)$$

$EV_{0,s,h}$ the initial charging stations consumption of substation s for hour h

$$\forall s \in \text{Substations}, \sum_{h=0}^{167} heating_{s,h} = \sum_{h=0}^{167} heating_{0,s,h} \quad (F.4)$$

$heating_{0,s,h}$ the initial heating consumption of substation s for hour h

The total activation power must remain the same:

$$\forall h \in [0; 167],$$

$$WH_{tot,h} = \sum_{s \in \text{Substations}} WH_{s,h} \quad (F.5)$$

$$heating_{tot,h} = \sum_{s \in \text{Substations}} heating_{s,h} \quad (F.6)$$

$$EV_{tot,h} = \sum_{s \in \text{Substations}} EV_{s,h} \quad (F.7)$$

$WH_{tot,h}$ the total water heaters consumption for hour h

$heating_{tot,h}$ the total heating consumption for hour h

$EV_{tot,h}$ the total charging stations consumption for hour h

The flexibility activations for each substation must still comply with the national constraints. Thus, national constraints on flexibility activation are distributed on each substation, with the same methodology as the distribution of national flexibility activations.

The downscaling of (B. 2) leads to:

$$\forall s, \forall h \in [0; 167], WH_{s,h} < WH_{max,h} \quad (F.7)$$

$WH_{s,max,h}$ the downscaling of the maximum national water heater power activation for substation s and hour h

The downscaling of (B. 3), (B. 4) and (B. 5) leads to:

$$\forall s, \forall h \in [0; 167],$$

$$SoC_{max,s,h} \geq SoC_{s,h} \geq SoC_{min,s,h} \quad (F.8)$$

$$SoC_{s,h} = SoC_{s,h-1} + 0,923 * EV_{s,h} + MobileStor_{s,h} \quad (F. 9)$$

$$0 \leq EV_{s,h} \leq EV_{max,s,h} \quad (F. 10)$$

$SoC_{max,s,h}$ the downscaling of the maximum national state of charge for substation s and hour h

$SoC_{min,s,h}$ the downscaling of the minimum national state of charge for substation s and hour h

$SoC_{s,h}$ the state of charge for substation s and hour h (optimization variable)

$EV_{max,s,h}$ the downscaling of the maximum national charging power for substation s and hour h

$MobileStor_{s,h}$ the downscaling of $MobileStor_h$ on substation s .

The downscaling of (B. 6) and (B. 7) leads to:

$$\forall h \in [0; 167], \forall s, 0 \leq def_{s,h} \leq def_{max,s,h} \quad (F. 11)$$

$$\forall h \in [0; 167], \forall s,$$

$$heating_{s,h} = heating_{NS,s,h} - def_{s,h} + \sum_{k=1}^{23} coeff_k \times def_{s,h-k} \quad (F. 12)$$

$def_{s,h}$ the heating power deferral report for substation s at hour h .

$def_{max,s,h}$ the downscaling of the maximal deferral power for substation s at hour h

$heating_{NS,s,h}$ the downscaling of the national heating power without deferral for substation s at hour h

RÉSUMÉ

Ce travail étudie la pertinence de mécanismes de coordination des actifs de gestion de la demande par le système électrique. La flexibilité de la demande peut faciliter l'équilibre entre l'offre et la demande, qui devient plus complexe avec l'augmentation de la part des EnRs dans le mix électrique européen. Elle peut aussi être un levier permettant d'atténuer les contraintes du réseau de distribution qui augmentent en raison de nouveaux usages. Ce travail montre que la flexibilité de la demande a une valeur significative pour le système électrique, que cette valeur provient d'une valorisation de la flexibilité sur les marchés, mais qu'une coordination entre le GRD et le marché de gros serait plus efficace du point de vue du système électrique. Cette thèse fournit des indications sur la valeur d'un mécanisme coordonnant l'utilisation de la flexibilité de la demande distribuée pour faciliter l'équilibre offre-demande et optimiser la gestion des contraintes sur le réseau de distribution.

MOTS CLÉS

Flexibilités distribuées, Marchés de gros, Coordination local/global, Contraintes réseau

ABSTRACT

The need for mechanisms ensuring the relevant use of demand response assets by the electricity system is explored in this work. Demand response can facilitate the demand-supply balance, which is becoming more complex with the increase in the share of VREs in the European electricity mix. It can also be a lever enabling the alleviation of distribution network constraints that are increasing due to new electricity uses. This work shows that distributed demand flexibility has a significant value for the power system, that this value would come mainly from a valuation of flexibility on the wholesale markets, but that a coordination between the DSO and the wholesale market would be more efficient from the point of view of the power system. This thesis thus provides interesting insights on the value of a mechanism coordinating the use of distributed demand flexibility to facilitate the supply-demand balance and to optimize the management of constraints on the distribution network.

KEYWORDS

Distributed flexibility, Wholesale markets, local/global coordination, Network constraints