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OPTIMAL DSO/MARKET COORDINATION FOR THE ACTIVATION OF DISTRIBUTED FLEXIBILITY

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Optimal DSO/market coordination for the activation of distributed flexibility

Marion Pichoud[1], Virginie Dussartre[2], Maxime Lâasri[3], Jan-Horst Keppler[4]

Abstract

Optimally coordinating flexibility resources is an ever more critical element of ensuring the supply and demand balance at all hours in decarbonizing electricity systems with a high share of variable renewables. This paper estimates the value of coordinating local flexibility providers through competitive wholesale markets of Central Western Europe (Austria, Belgium, Switzerland, Deutschland, France, Spain, Great-Britain, Ireland, Italy, Luxembourg, Northern Ireland, Netherlands and Portugal) as well as the resulting investment needs at the level of the French distribution grid in 2030. It is based on detailed data of the electricity system, energy mix previsions from 2016 and consumption and production data for every 2000 substation of the French distribution network. A key result of this paper is that the economic welfare gains of coordinating multiple heterogeneous local flexibility resources are substantial while requiring only limited investments in the extension of local distribution grids. With a real-time activation signal, coordinating distributed flexibility in the wholesale market will generate a welfare gain of 1.4 billion Euros due to savings in both operational and fixed investment costs in comparison with a situation where no flexibility is offered. This gain can be realized at a cost increase for the reinforcement of distribution networks required by these flexibility activations of only 100 million Euros, mostly concentrated on urban stations with high EVs penetration. Subsequently, the paper offers several extensions such as, for instance, the impact of an easier to implement and predictable longer-term flexibility activation signal, for which the total gains are only 30% lower. Another extension studied is the implementation of a filtering by the DSO of flexibility activations with particularly high power swings with the help of a local "Maximum Power Indicator", which allows further welfare gains. Overall, the paper provides modelling evidence of the value of aggregating local flexibility resources at the level of the wholesale market, their limited costs in terms of required reinforcements and the benefits of a coordination between issues at local level (grid reinforcement) and European level (generation cost).

Keywords: flexibility; coordination; wholesale markets; distribution network; grid reinforcement; social welfare optimization; local; electric vehicle

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I. INTRODUCTION

1.1 Literature review

1.1.1 Development of distributed flexibility

Solar and wind are an interesting replacement of gas and coal units in the context of growing concerns about carbon emissions. However, unlike nuclear or hydraulics, renewables come with a distinctive, intrinsic uncertainty about their production and are not controllable. This eventually calls for more system "flexibility" (Mitchell, 2016). Flexibility is a multi-temporal asset of the electric system. It "reflects the power system's ability to adapt to variability and uncertainty in demand and generation, which occur on different timescales" (Heggarty, 2019).

Flexibility is a valuable asset for the electric system at 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. As illustrated in Figure 1, flexibility can be used in the long run to reduce investments, for the transmission and distribution network by reducing the loss-of-load without undertaking costly reinforcements (Boubert, 2015) (Shao, 2012) and for the production units by planning to use flexibility in replacement of new production units. Flexibility can also be used closer to real-time to alleviate congestions on transmission and distribution networks, to reduce operational costs of production units on wholesale markets, and to facilitate the balancing and reserves markets. All these issues must be coordinated.

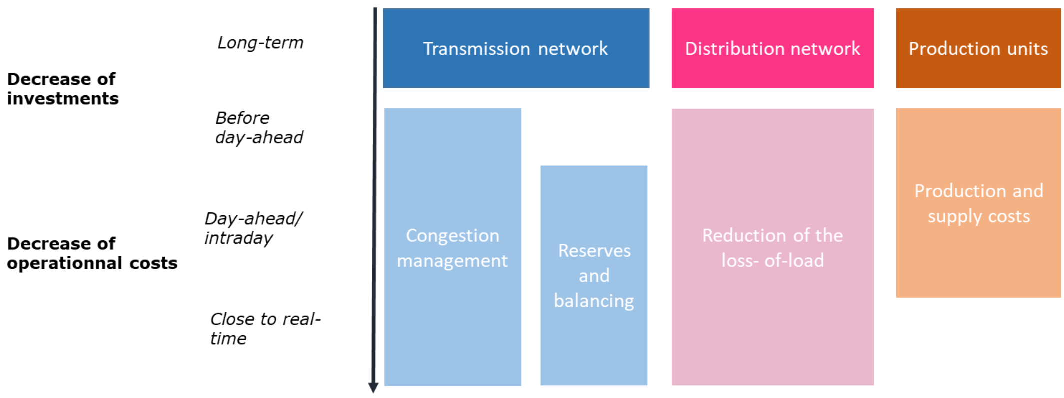


Figure 1 The possible distributed flexibility uses from long-term to real-time purposes for transmission network, distribution network, and production units

In France and the vast majority of countries with RES development, most of the solar and wind generation assets are connected to the distribution grid, defined as the part of the network that is not operated by the TSO[5]. In France, 92% of solar and wind assets are connected to the distribution grid, with about 20 GW of power. New flexible consumption sources like electric vehicle charging points are also connected to the distribution network. Thus, the distribution grid undergoes substantial transformation, and network reinforcements can be needed to maintain a sustainable quality of electricity distribution.

As a new valuable tool of the electric system, distributed flexibility use should be efficiently designed. 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

5 In France, the DSO operates the network up to 50 kV, which is low compared to the majority of other European countries.

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. Publications and positioning today mainly relate to coordination between TSOs and DSOs in the short term (Enedis, 2019a), (ACER, CEER, 2017), (CEDEC, EDSO, eurelectric, Geode, 2018), (CEDEC, EDSO, ENTSOE, EURELECTRIC, GEODE, 2019). Nevertheless, coordination between the DSO and with market actors is a crucial topic.

1.1.2 The new role of the DSOs

The DSO is at the core of the aforementioned issues concerning distributed flexibility, and his prerogatives are developing accordingly. The new role played by the distribution network in the energy transition is well stated by regulators. In 2017, the European Parliament, in the “Clean Energy Package”, entitles the DSOs to use the flexibility connected to their grid in a “market-based” approach and in coordination with the TSO for congestion management, following the recommendations of one of the most representative associations of European DSOs, EDSO. Indeed, EDSO claims that using flexibility for congestion management would provide benefits for the system as a whole and that flexibility services are a better alternative than grid reinforcement most times, whether from a long-term or short-term perspective (EDSO). The “market-based” procurement enables DSOs to explicitly activate distributed flexibility from long-term bilateral contracts or short-term markets. This approach is the “preferred option” for the regulator CEER among other access configurations, which are connection agreements, network tariffs, and a rules-based approach (CEER, 2018), provided that the market is liquid and unbundled. A “market-based” approach is not very specific and stakeholders have different views on how DSOs could deal with congestions.

1.1.3 Local flexibility market designs

The regulatory framework on market-based procurement of flexibility by the DSO is quite loose and mainly comprises recommendations. But these recommendations concerning the flexibility market design do not fit all needs and diverse local markets for congestion management experiments are carried out in Europe, to address specific local needs. The local flexibility markets should be distinguished from local energy communities, which are based on self-supply and decentralized energy management. While local flexibility markets’ purpose is to decrease network congestion costs with the use of decentralized flexibility, local energy communities aim at fostering consumer flexibility and promoting renewables insertion. Local energy collectives benefit from a European regulatory framework, with characterization in two different rules of the Clean Energy Package, as “Renewable Energy Communities” in Renewable Energy Directive (EU) 2018/2001 and « Citizen Energy Communities” in Internal Electricity Market Directive (EU) 2019/944. In contrast, local flexibility markets are at their experimental stage, with various designs being tested via local demonstrators.

According to (Dronne, 2020), classification of the design of the local markets can be done along three dimensions: timeframe (day-ahead, real-time…), external or third-party platform, and easiness of access. The design depends on local needs: for instance, in areas where congestion is increasing whereas flexibility sources are scarce, a long-term timeframe for the market design is well-suited to incentivize the development of new flexibility sources.

With this classification framework, (Dronne, 2020) has studied four European developing local markets which are GOPACS (Germany), ENERA (the Netherlands), UKPN (United-Kingdom), and a market developed by Enedis, Nice Smart Valley. Market designs proposed in the literature can be classified using the same framework. For the classification of these local markets in this paper, two of the three parameters of the framework described in (Dronne, 2020) are used: timeframe and the platform operators. Short-term or real-time local market designs are more often encountered but several countries, like France with Nice Smart Valley or the UK with UKPN, develop long-term congestion management with the use of flexibility.

Country	Local Market	Timeframe	Platform operator(s)
Germany	Enera (Dronne, 2020)	Day-ahead	Third-party (EPEX)
The Netherlands	GOPACS (Dronne, 2020)	Day-ahead	Third-party
	Interflex demonstrator (Interflex, 2019)	Long-term	The DSO
United-Kingdom	UKPN-Picloflex (Dronne, 2020)	Long-term (capacity remuneration)	Third-party (PicloFlex is a separate platform)
France	Nice Smart Valley (Interflex, 2019)	Long-term	The DSO
Several European countries	*The SmartNet project* described in (Migliavacca, 2017)	Real-time, clearing every 5 minutes	TSO, DSO, TSO&DSO, or independent market operator

Table 1 Example of local market designs classification

1.1.4 The economic value of flexibility control

European local flexibility markets, which still are in their infancy, tend to be operated by the DSO for congestion management purposes. However, the main economic value of flexibility does not always lie in congestion management. 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 (injection or load flexibility) and the location. According to (Enedis, 2017), the value of flexibility for the distribution network is up to €24/kW per year of postponement of the investment. Most of the value lies in the optimization of the distribution network expansion planning for the connection of renewable energy. This value is only for the medium voltage network; the value of flexibility for the low voltage is closed to zero (Enedis, 2017). These results are consolidated by another study carried on the French electricity network (E-cube, 2017) for the national regulator (CRE): first, the value of flexibility for the postponing of reinforcements on the distribution network is diverse and of the same order as Enedis evaluation (between 0 and €24/kW/year); second, E-Cube confirms there is no value for the use of flexibility to alleviate constraints on the low-voltage level.

Among flexibilities, RES curtailment is at the center of interest for networks because of its high value to avoid reinforcement costs. The value of spillage could represent 250M€ of benefits per year for both the distribution and the transmission network (Enedis, 2019a). RTE evaluated the benefits of curtailment for the French transmissions network to 9 B€ for the 2012-2035 period (RTE, 2019b).

On the other hand, consumption management doesn't have much value for networks but much more for production costs. For instance, the gains of controlling electric vehicles' charging regarding the power system's needs could be up to 1bn€/year, by charging during periods where production costs are the lowest (RTE, 2019a). Deployment of smart-grids could represent 400M€/year of benefits, mostly in the production unit's capacity investment (RTE, 2017b). The comparison of the benefit of consumption management for the network or the production costs has been carried out on the scale of a French demonstrator, Greenlys. The optimization of production costs only compared to the optimization of both network and production costs shows the value of flexibility rather lies in the minimization of production 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).

The different estimated flexibility values are summarized in Table 2.

Study	Flexibilities	Value for the network	Value for the production
(Enedis, 2019b)	Renewable energy connection	Up to 250M€ to 2035 (distribution network)	Not addressed
(Battegay, 2015)	Consumption curtailment in the Greenlys demonstrator	500k€/year	7500k€/year
(E-cube, 2017)	Connection agreements, market-based procurement.	24€/kW/year	Not addressed
(RTE, 2017b)	RES curtailment and smart-grids	25M€/year	400M€/year
(RTE, 2019a)	EV	Not addressed	1bn€/year (>100M€/year for ancillary services)
(RTE, 2019b)	RES curtailment	1bn€/year (transmission network)	Not addressed

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

The comparison of these studies point out that the value of RES curtailment for the network reinforcement is relatively high (up to 1bn€/year according to (RTE, 2019b) but that for consumption flexibility, the value rather lies in production 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. Less than 2% of total production is for ancillary services (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-intense. The study emphasizes the variability of the value of flexibility with the energy mix and carbon policy: the value of storage increase with emission-intensive generation costs.

Demand response flexibility also represents a great value for the Danish regulating power market and that confirms the French studies. With this flexibility, the reduction in regulation costs, which are balancing costs at the expense of the BRP (Balance Responsible Party), could be up to 49%, which represents 2-3 million euros per year (Neupane). Indeed, the demand-response flexibility is a cost-effective lever to counteract the variability of RES.

1.1.5 Historical consumption flexibility control through tariff signal

The design of a local flexibility market must also consider the flexibility means, and as far as the demand is concerned, how and to what extent the demand flexibility is controlled. Full controllability of flexible resources is unnecessary to capture an important share of the value of flexible resources. There are two standards regarding the control scheme for demand-side response: short-term demand response and tariff signal. Short-term demand response is the short-term activation of flexibility (day-ahead to real-time) directly via the retailer for big industrial sites or via aggregators for low voltage consumers. Short-term demand response is adapted to the need and can be quickly activated but represents little volumes as few consumers accept this load control. A tariff signal is a long-term pricing incitation signal for retail consumers, for instance, the "peak/off-peak" hours pricing for electric water heaters that can be viewed also as load shedding (Poignant, 2010).

Historically, the purpose of retail consumer tariffs is to put in place long-term planning that relies on market prices to direct consumers. At the time of the nationalization of electricity production and transportation in France in 1946, tariffs were very heterogeneous across the territory. Different models attempted to unify these tariffs, and marginal pricing was eventually adopted for its technical and economic efficiency. Being based on development costs, marginal pricing enabled a long-term vision of the electric system, which was important as demand was increasing. This "marginal cost pricing" enables optimal coordination between production and consumption decisions (Boiteux, 1960). The marginal cost as computed by Boiteux takes not only into account the production cost of the additional MWh but also the long-term generation system development costs this additional MWh would require, provided that the developed electric system is the most cost-efficient system that meets the demand (Yon, 2014). As the daily consumption peaks and the winter month's consumption peaks single-handedly define the need for capacity investment, with the long-term marginal costs approach, only these periods will support development costs. Thus, the high prices will defer flexible consumption to other timeframes with lower prices, and the marginal cost tariff will lose its efficiency at fostering adequate investments. So, in France, this marginal cost tariff has been adapted to the variability of the demand during the day and the disparities between peak and off-peak hours. Peak-hour tariffs are caped in a way that enables the demand to cover capacity investments needed to match the accepted criterion for the security of supply, while off-peak hour tariffs are minored by the short-term marginal cost (Yon, 2014).

"Peak/off-peak" tariffs have resulted in the smoothing of peak hours, as consumers, especially professionals and manufacturers who were subject to the "tarif jaune" that directly derives from this marginal cost pricing, adapt their consumption to these prices. (Mougin, 2008). This smoothing of the load curve fosters adequate investments with minimum involvement of the consumer (Poupeau, 2017). When "Peak/off-peak" tariffs were born, he can choose between two tariff systems, a "simple" tariff or a "double" tariff, with cheaper off-peak hour's prices.

The signal sent for off-peak hours gives an interesting historical example of successful coordination between national and local levels. At first "off-peak" hours were the same for all the country (from 11 pm to 7 am, which corresponds to hours with the lowest national consumption). This tariff had increasing success but caused side effects, among which a new consumption peak at

11 pm. To reduce this peak, off-peak hours had to be differentiated by consumers. The opportunity was taken 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 national peak hours (8-12 am, 5-8 pm). Decentralization of the "peak/off-peak hours" reduces both the national night consumption peak and distribution network costs, giving a good example of coordination between local and national levels. This tariff is made of 8 h of peak hours per day, which can be spread over one, two, or three time slots, the time slots differing from one municipality to another (Ailleret, 1986). "Peak/off-peak" tariff has enabled the creation of water-heaters with storage, enabling massive energy storage. Nowadays, consumption cut-off services are being even further facilitated by automated meter management (like Linky in France) (Urvoas, 2009).

1.1.6 The interest of tariff signal

Nowadays, adequate pricing through tariff for the final customer is still a solution to be considered. First, for social acceptance: 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). 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). Third, the emergence of Electric Vehicles (EV) can considerably increase the energy controllable by tariff signal. Last but not least, 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. Thus, in (RTE, 2019a), the gain of the use of a tariff signal to control the EV charging is about 900M€/year. This represents 75% of the 1,2bn€/year of gains with dynamic controllability. The charging of EVs according to the "peak/off-peak" tariff could represent an economy of €320/year on the household electricity bill compared to a "natural" charging for residential vehicles (Enedis, 2020b). Using a tariff signal can capture 60 to 75% of the residential demand response controllability total value for the whole electric system (RTE, 2017b). But to our knowledge, no peer-reviewed study quantifies the share of flexibility value captured by a long-term tariff signal.

1.1.7 Contributions of the paper

The value of the flexibility for production costs and wholesale markets has been studied in specific markets or case studies. The major contribution of this paper is to assess a cost-benefits analysis of French demand flexibility for production and distribution costs. Long-term and operational production costs are evaluated in a probabilistic way, with a simulation of a day-ahead market for all of central Europe. The distribution costs considered in this paper are the reinforcement costs on nearly 2000 substations[6]: those costs can increase or decrease depending on the activation of flexibilities[7]. The paper will make this analysis for 3 different degrees of flexibility: no activation, long-term tariff signal, and short-term demand management. Indeed, as exposed in the literature review, short-term demand management is not the only way to capture demand flexibility value.

1.2 The context of the study

In a first step, a study simulates the activation of four types of flexibility sources in 2030, namely

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.
7 In this study, we consider there is no flexibility activation cost.

RES curtailment, EV charging stations, water heaters, and electric heating. The study is carried out on 10 meteorological years and on day-ahead market conditions extrapolated to 2030 (in particular as far as production and consumption assumptions are concerned). The aim is to assess the value of flexibility activation for long-term and operational production costs and to compare it to the cost of these activations for the distribution network in terms of reinforcement costs. This valuation is based on assumptions of a perfect market and perfect anticipation over one week. To reduce complexity, we focus on the DSO/market coordination, though flexibility also concerns the TSO.

In a second step, the distribution network reinforcement costs resulting from the flexibility activation are then considered in the flexibility activation process, reducing the overall cost of the system. These adjustments of the flexibility activations are a way of calculating if reinforcements are to be carried or not on substations with a given flexibility mix by arbitrating between minimizing production costs or avoiding reinforcement costs.

1.3 Different signals for flexibility control

Flexibility activation can be done with short-term activation, via aggregators for instance, or with a tariff signal similar to the French "peak/off-peak hours". In this paper, these two processes for flexibility activation are investigated, as well as the impact of their nature on the value of flexibility for production costs and on the need for distribution network reinforcement. For comparison, these two activation processes are complemented 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 production costs.
- Peak/off-peak signal (POS): this signal only concerns the flexibility from EV charging stations and water heaters; indeed an identical signal every day makes little sense for RES curtailment or heating shifting. The flexibility is activated following hourly ratios 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". The daily energy of EV charging and water heaters change each day following the calendar and the weather condition and is spread over each day according to the hourly ratio of the typical day.
- Those hourly ratios for typical days have been optimized to reduce the global production cost in the 10 meteorological years. 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.

In this work, the three flexibility activation signals are studied, each on their own. 100% of flexible capacities are activated for each signal. In reality, in the future, flexibility activations will probably be a mix of these three signals.

1.4 Coordination between wholesale market and DSOs to reduce reinforcement costs induced by flexibility activations

The flexibility activations are designed for the minimization of production costs. However, those activations have also 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:

- Non-coordination (1st situation): in this situation, production costs only are minimized: There is no coordination between the wholesale markets and the DSO. The flexibilities are used for the minimization of the production costs only, regardless of the reinforcement costs they generate.
- Filtering (2nd situation): to approach an optimal activation of consumption flexibility, which minimizes both production and distribution costs, the DSOs can filter the flexibility activations that generate constraints in distribution networks. They can thus avoid some reinforcements. For the STCS, it means that constraints on maximum flexible consumption activation power are added to the technical constraints on consumption. For the POS, it means that the hourly ratios for each typical day are marginally changed to meet maximum power constraints at each time slot for each substation.

- No Signal (NS)	Short-Term Controllability Signal (STCS)	Peak/Off-Peak Signal (POS)
Reference test case Flexible capacities are not activated (Test case 1)	No coordination (Test case 2)	No coordination (Test case 3)
	Filtering reaction (Test case 4)	Filtering reaction (Test case 5)

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

Following this introductory section, section 2 focuses on the first situation (no coordination). It describes the method and all the hypotheses regarding its implementation, the minimization of production costs with the use of distributed flexibility, and the computation of the induced reinforcement costs with the MPI. The results for this first situation, for test cases 1, 2, and 3, as classified in Table 3 are detailed and analyzed in section 4. Section 3 ends the paper with the second situation: the filtering by the DSO of constraining activations, and evaluates production and reinforcement costs for the two last test cases: test case 4 and test case 5.

II. SITUATION 1: NO COORDINATION

2.1 Method

2.1.1 *Method for production costs minimization*

Flexibility and production mix

Assumptions on generation and inflexible load for the European countries within the study's scope (at, be, ch, de, fr, es, gb, ie, it, lu, ni, nl, pt) in 2030 are made according to the VOLT scenario of the "Bilan Prévisionnel" of RTE (RTE, 2017a). They are summarized in Figure 2.

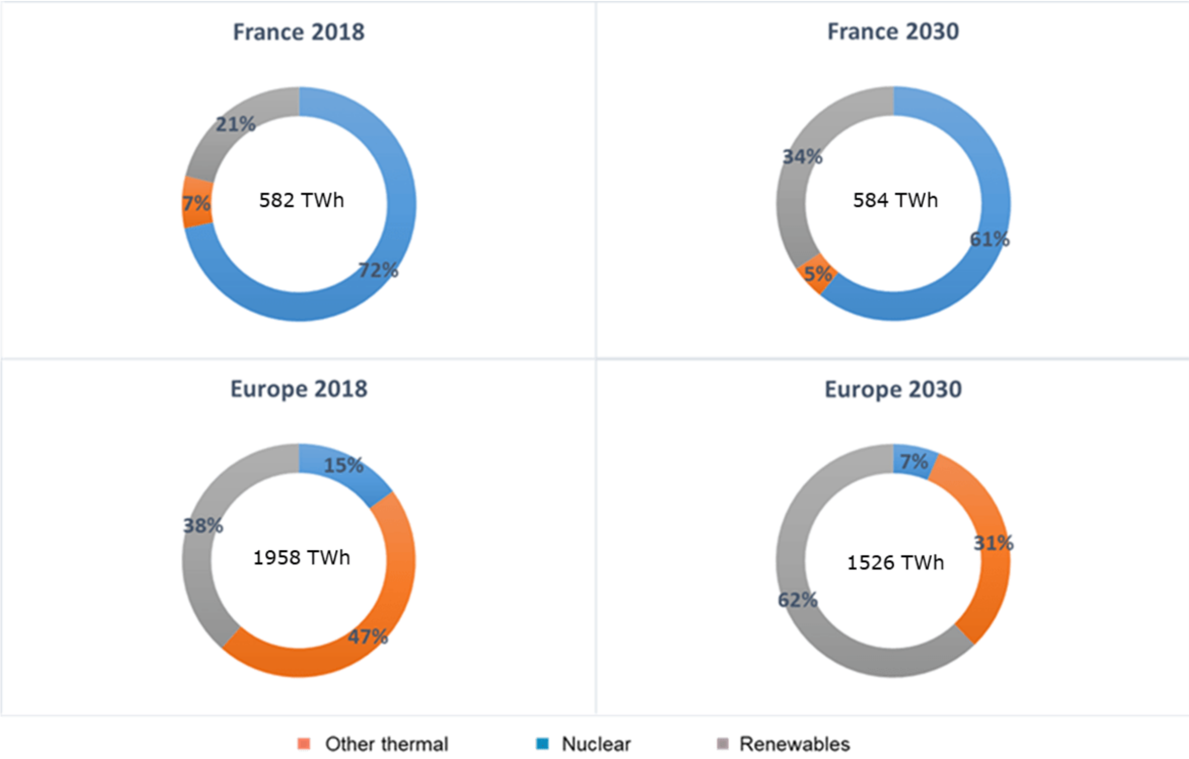


Figure 2 Distribution of production in France and the other European countries considered in the study

Inflexible load is as stated in Table 4:

Inflexible load (TWh)	2018	2030
France	480	425
Other European countries	1896	1680

Table 4 Inflexible load for France and the other European countries considered in the study for 2018 and under the VOLT scenario's assumptions for 2030

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 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 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 5 Assumptions for EV charging for the concerned EU countries

Tools and modeling

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-minimization problem that accounts for production costs, start-up costs, and loss-of-load costs[8]. Demand flexibility is implemented by the following equations:

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

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

$$\begin{cases} \sum_{h=(d-1)*24+1}^{d*24} WH_h = StorWH_d \ (1) \\ WH_h < WH_{max,h} \ (2) \end{cases}$$

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.

- 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 SimVE, another application developed by RTE.

$$\begin{cases} SoC_{max,h} > SoC_h > SoC_{min,h} \ (3) \\ SoC_h = SoC_{h-1} + 0{,}92 * EV_h + MobileStor_h \ (4) \\ EV_h < EV_{h,max} \ (5) \end{cases}$$

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 SimVE for the input number of electric vehicles considered in this study:

8 https://antares-simulator.org/

$SoC_{min,h}$ 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 $h-1$.
$EV_{max,h}$ the maximum national charging power at hour h.

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

$$\begin{cases} 0 \leq def_h \leq def_{max,h} \ (6) \\ heating_h = heating_h^0 - def_h + \sum_{k=1}^{24} coeff_k * def_{h-k} \ (7) \end{cases}$$

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 loss).

Frequency discontinuities resulting from flexibility activation are not modeled.

This modeling for the activation of distributed flexibility sources enables to compute market costs for the STCS only. For the POS, the flexibility activations are computed for EVs and water heaters. Heating deferral cannot be controlled via a tariff signal. Indeed, a tariff signal won't be precise enough to respect the deferral coefficients. Thus, there is no heating deferral for the POS. The activations of EVs and water heaters flexibility for POS are based on the mean of STCS activations for each hour of the day, considering four different types of days ("summer working day", "winter working day", "summer weekend day" and "winter weekend day"). Each typical day ends with its own daily energy distribution curve (the daily energy is the same as activated with the STCS). Then, the energy distribution for each typical day is then optimized using marginal prices. The distribution coefficients are lowered when the marginal price is higher than the daily mean marginal price and increased otherwise.

These market costs will be compared to the reinforcement costs induced by these flexibility activations, computed with the following method.

2.1.2 *Method for the computation of the reinforcement costs*

The proxy distribution network architecture used in this paper

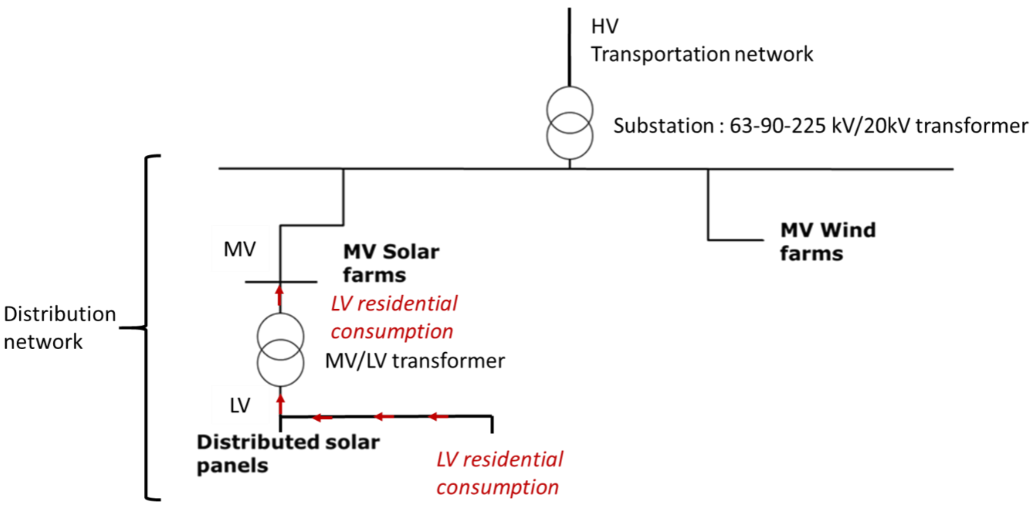


Figure 3 Reinforcement location depending on residential consumption and the considered renewable production type

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 3. 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.

The general framework for calculating reinforcement cost induce by flexibility activation

The computation of reinforcement costs is a three-step process:

1. National inflexible load, renewable generation, and flexibility activations are spread over the nearly 2000 substations of the French territory.
2. Once the local net consumption and generation curves are obtained, 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 comparison of 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 signal. If the 2030 MPI obtained after flexibility activation is higher than the "historical" MPI, a reinforcement of the substation is needed. Reinforcement costs are a function of this MPI gap.

The method for the computation of reinforcement costs is simplified: the aim is to get an order of magnitude of the reinforcement costs that enables a comparison between the three flexibility activation signals (NS, STCS and POS) and the two coordination situations. The computed reinforcement costs are to be viewed from the perspective of the accuracy of this method.

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 2000 substations of the French distribution network to assess the need for local network reinforcement. 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. See Appendix 1 for the details of the breakdown method for each item.

The maximum power indicator (MPI)

Each substation can handle a maximum power, beyond which the load is curtailed. If this maximum power is exceeded too often, a reinforcement could become economically preferable to bearing very high load curtailment costs (usually referred to as Value Of Lost Load - VOLL).

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

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

Using this method enables the authors to model the impact of congestion on the need for investment in the distribution network without going into detail about the grid elements (MV and LV).

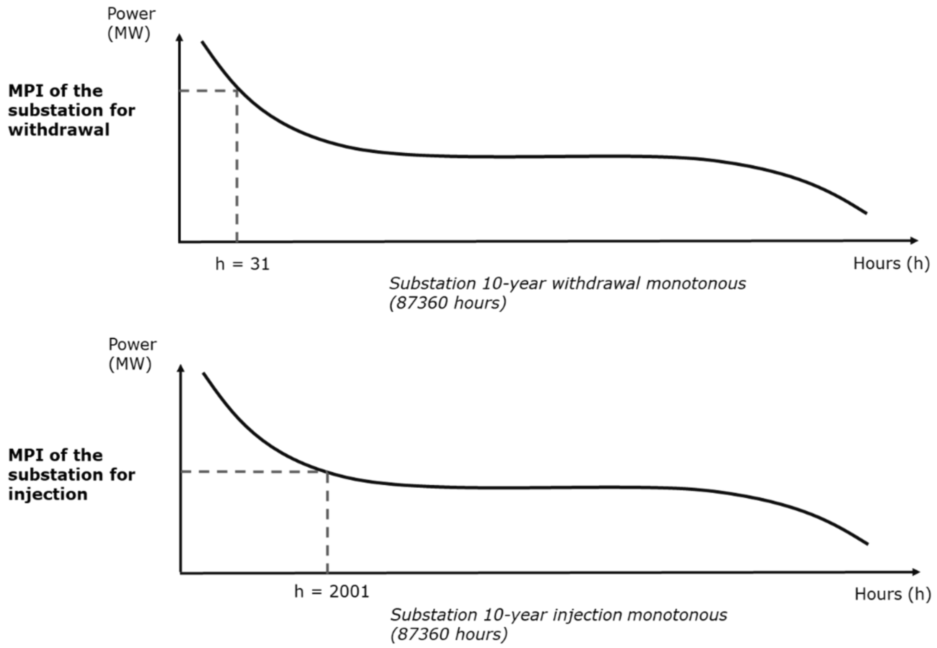


Figure 4 Method for the computation of the MPIs of injection and withdrawal at each substation

The method for the computation of reinforcement costs

Reinforcement cost depends on the difference between historical and future MPIs. In this paper, the lack of a precise description of the distribution network allows the authors to estimate only the order of magnitude of these reinforcement costs.

Reinforcement costs induced by an increase in the load are evaluated by Enedis at €30/kW/year (C.Gaudin/M.Krotova, 2012). 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). According to (Nadaud, 2008), to consider these cost inequalities, the reinforcement costs for LV and MV networks were adjusted by EDF with an adjustment coefficient. These coefficients, exposed in Table 6, will be used for the computation of reinforcement costs induced by LV and MV load increase.

Regarding injection, the average cost of renewables insertion on the distribution network is 300M€/GW for solar and 100M€/GW for wind (C.Gaudin/A.Minaud, 2012). 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 urban area mainly because of voltage issues caused by consumption located far from injection.

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

Table 6 Adjustment coefficients for reinforcement costs for the different area types

2.2 Results

The results of the modeling concerning the first situation (no coordination) in terms of system costs are divided into three parts. First, the market gains resulting in the flexibility activations are detailed and explained. Then the evolution of the reinforcement needs is exposed for each flexibility activation signal with the MPI. The reinforcement costs resulting from the evolution of the MPI are finally compared to the national market gains in a final summary of the system gains.

2.2.1 *Minimization of production costs at the national level*

With the assumptions stated in 2.1.1, we calculate the production and loss-of-load costs for the three degrees of flexibility control: NS, STCS, and POS. The first important result is that the production costs are the lowest with the STCS (Figure 5). This was expected, as the activation of flexibility with this signal allows more levers to minimize production costs.

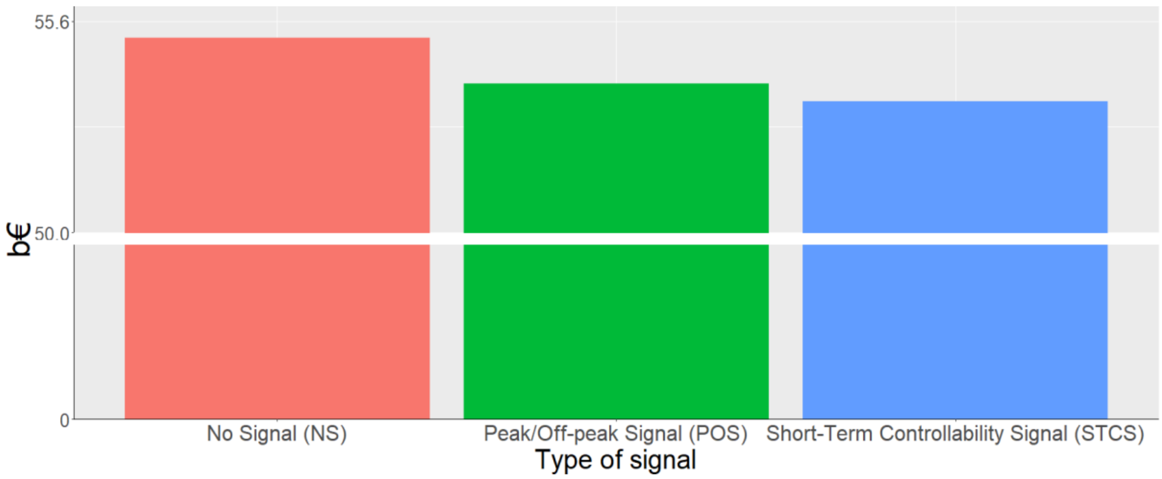


Figure 5 Mean for the 10 meteorological years of 2030 of Europe (at, be, ch, de, es, fr, gb, ie, it, lu, ni, nl, pt) total operational costs for the 3 flexibility signals

Production unit type	NS relative to STCS	POS relative to STCS
Nuclear	- 7,5 TWh	- 1,4 TWh
Lignite	- 0,9 TWh	- 0,3 TWh
Coal	- 2,1 TWh	- 0,6 TWh
Gas – CCGT	11,8 TWh	3,8 TWh
Gas – CT	3,0 TWh	0,7 TWh
Oil	65,4 GWh	30,1 GWh
RES curtailment	2,7 TWh	1,0 TWh

Table 7 Mean for the 10 meteorological years of 2030 of the energy produced in France per unit type, for both NS and POS compared to the STCS. A positive value indicates more production than in the STCS case.

Table 7 shows that the energy produced by all low-cost production units (nuclear, lignite, and coal) 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 7). The POS is just a little less efficient to avoid spillage than the STCS.

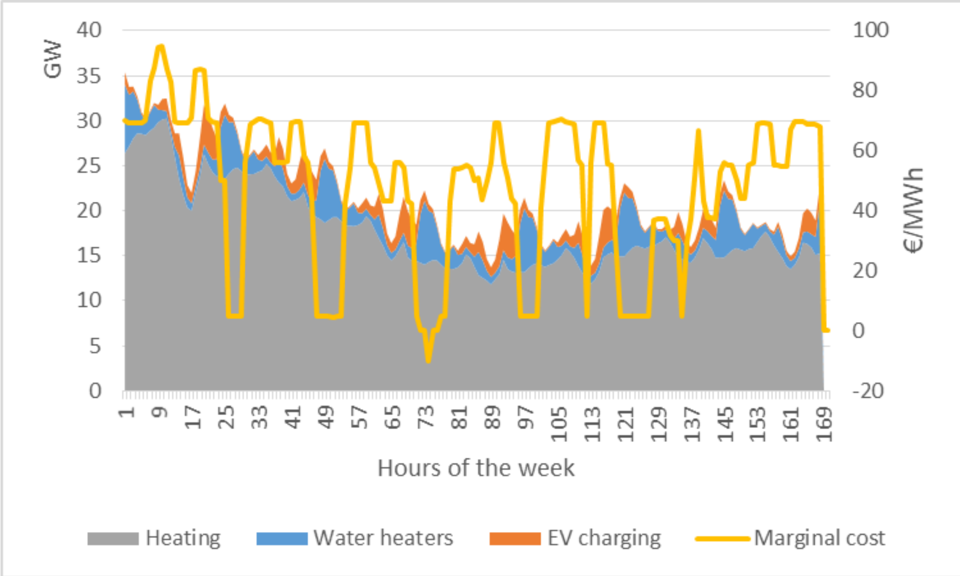


Figure 6 NS flexibility layout - Winter week

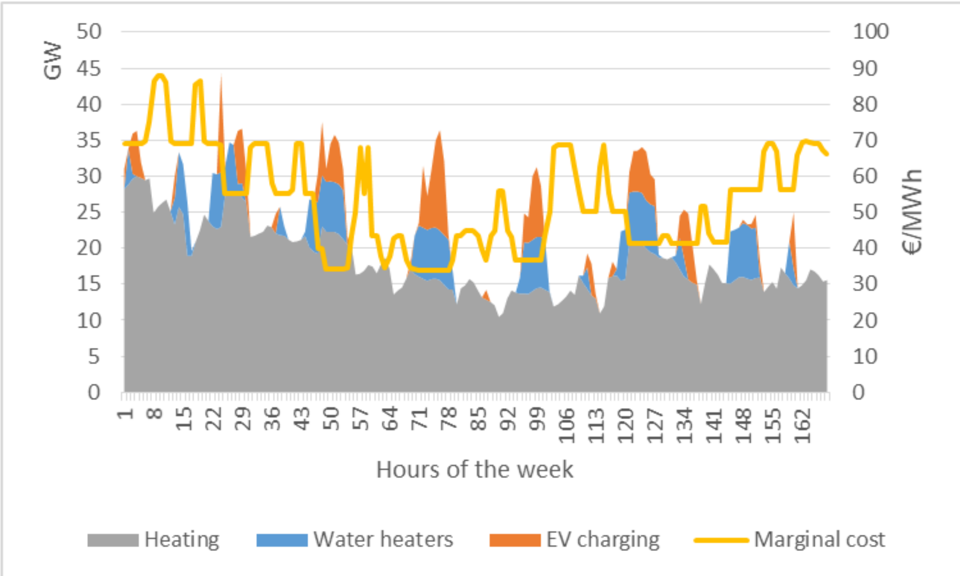


Figure 7 STCS flexibility layout -Winter week

Figure 7 confirms that the controllability of flexible consumption focuses its activation timeframes to hours where marginal costs are the lowest. In comparison, flexible consumption in Figure 6 is much more evenly spread when no signal is used. This energy concentration results in new or accentuated consumption peaks.

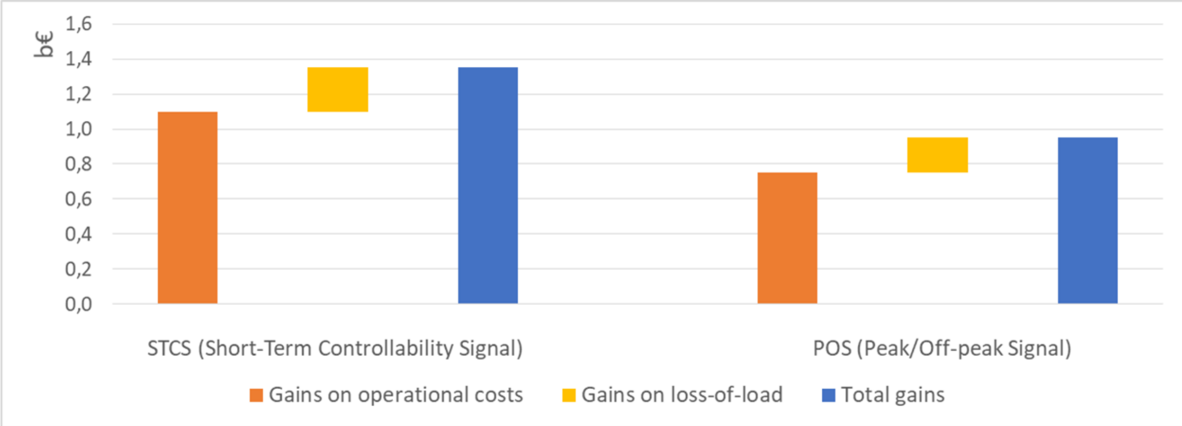


Figure 8 Mean for the 10 meteorological years of 2030 of total gains for both STCS and POS cases with respect to the NS case

The short-term controllability of the load has a lot of value for the production costs and loss-of-load costs (Figure 8). The gains on loss-of-load are the savings related to the decreased loss-of-load regarding the NS test case. The loss-of-load costs are evaluated at 10k€/MWh[9]. The high level of controllability of the STCS enables a gain of approximately 1.3 b€ regarding the NS test case, which represents 2% of the total system costs. A large share of this value, 70%, is captured by the POS. This is an interesting result, as controlling the load with a POS could be easier to implement in practice than direct short-term management.

2.2.2 *MPIs and reinforcement costs*

To complete the benefits analysis of flexibilities activation, reinforcement needs have been calculated through Maximal Power Indicator (MPIs) calculation. Figure 9 shows the MPIs for 2030 with the three different flexibility signals compared with the MPI calculated on historical data, with the same method (described in 2.1.2). The MPI for the NS, POS, and STCS is minored by the historical MPI (the distribution network cannot be uninstalled).

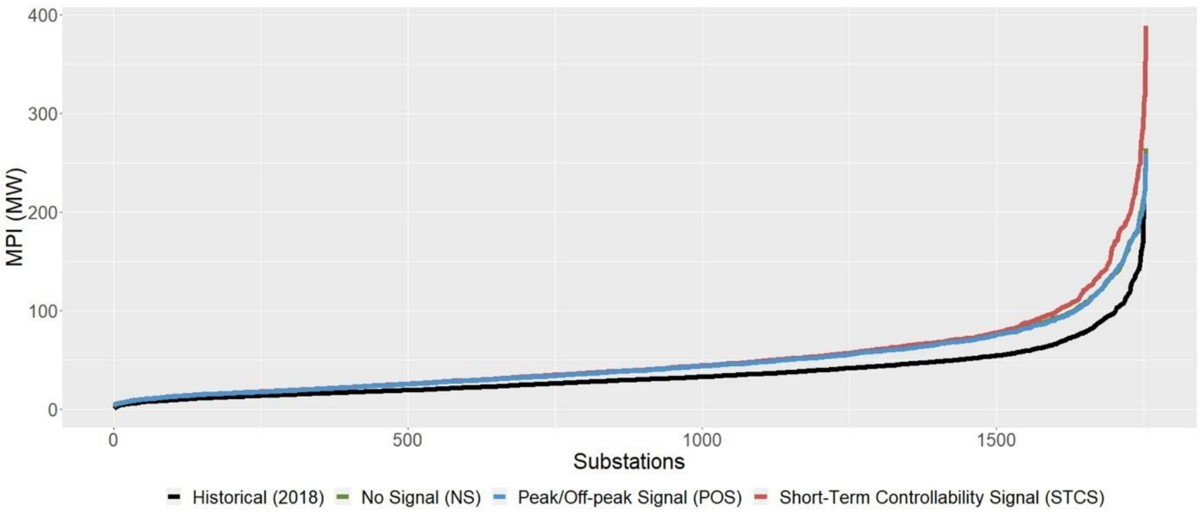


Figure 9 Mean for the 10 meteorological years of the load maximum power indicator over the 1890 substations of the French distribution network, historical and for the 3 flexibility degrees of the 2030 study

9 Capacity valuation for a peak generator.

% highest STCS MPIs	Average number of EVs	Average maximum ratio: EV power to rest of consumption	% of total reinforcement costs
65	9331	1.1	89%
35	14722	1.8	69%
25	19526	2.4	57%
10	38445	5.4	36%

Table 8 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 MPIs.

The MPI is the highest for the STCS because of the consumption spikes created by the flexible consumption. These spikes are uncorrelated with inflexible consumption. The MPI increase compared to the historical (2012-2016) value is higher for the STCS than the other signals for 36% of all substations. These substations are those where consumption flexibility creates the most consumption spikes and are the substations where EV charging stations are many (Table 8). It is observed that the higher the consumption spikes, the higher the reinforcement costs. The 10% substations with the highest MPI, who are the substations with the highest number of EVs on average, account for 36% of network reinforcement costs. For POS and NS consumption management, MPIs are almost the same. The control of flexible consumption via a tariff signal seems at this stage an interesting compromise between production cost gains and the height of the consumption spikes.

2.2.3 *Cost-benefits analysis for Situation 1*

Once the reinforcement costs are computed, they are put in perspective with the operational and loss-of-load gains of Figure 8 to provide a cost-benefit analysis of both test case 2 (STCS with no coordination) and test case 3 (POS with no coordination) compared to the test case 1 (NS).

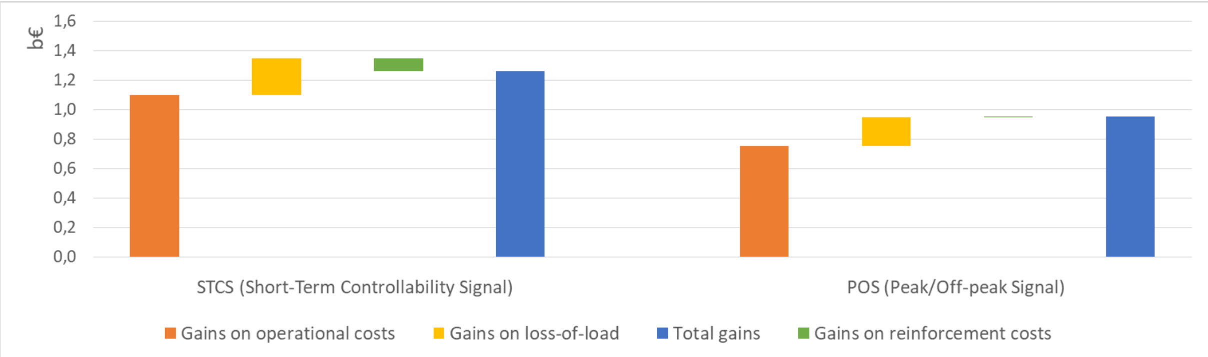


Figure 10 Mean of total gains over the 10 meteorological years of STCS and POS with respect to the NS consumption for 2030

Flexibility 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 10). The STCS is the flexibility control signal that has the highest total gains compared to the NS test case (about 1.3b€). The very high gains on production costs (operational costs + loss-of-load), accounting for 1.4 b€, are timidly counteracted by the 0.1 b€ of extra distribution network reinforcement costs mainly caused by the EV charging spikes. These gains are a little optimistic as flexibility activations are not constrained by frequency regulation issues that would require smoothing of flexibility activations over time. The flexibility activations also do not consider possible power limitations because of customer limited power subscription[10] not adapted to EV peak charging. With the use of a "peak/off-peak" signal to control the flexibility, production costs are 30% lower, representing about 1b€, but network reinforcement costs are about ten times lower.

Thus, this study leads to two major conclusions on flexibility value in the French context of historically well-developed networks. First, the value of flexibility for production costs, whether this flexibility is controlled with a short-term signal or with a peak/off-peak signal, far exceeds the value of avoided network reinforcement when flexibility is not activated. However, reinforcement costs are not evenly distributed across substations, and flexibilities (EV in particular) lead to important reinforcement costs on some substations. Indeed, as shown in Table 8, the 10% of substations with the highest 2030 STCS MPI represents 36% of the total needed reinforcement costs and are the substations with the highest average number of EVs. Second, a peak/off-peak pricing is a satisfactory compromise between easiness of implementation, acceptability (the peak/off-peak signal has been adopted by 50% of French consumers for water heating), and economic benefits.

III. SITUATION 2: LIMITATIONS OF THE FLEXIBILITY ACTIVATIONS BY DSOS

3.1 Taking into account the reinforcement costs through a DSO filtering

Flexibility activations could generate reinforcement costs on distribution networks since they are at low voltage levels. Although these reinforcement costs are quite low compared to the gains in production costs, they could be lowered further through better coordination between activation for market needs and network distribution's costs limitation. As few dimensioning hours play a role in network dimensioning, we expect that limiting activations on those hours will have little impact on production costs while avoiding network costs.

To evaluate the impact of such coordination on flexibility market gains and reinforcement costs, we will study distribution network dimensioning with activation of flexibilities filtered by DSOs. Thus, the MPI of the substations is capped at their NS MPI.

For the STCS, the method for filtering is broken down into two subsections: first, the evaluation of production costs, and second, the evaluation of reinforcement costs. Then the third subsection describes the computation of both production and reinforcement costs for the POS filtering.

3.1.1 Evaluation of production cost for STCS with a DSO filtering

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:

$$\max\left(WH_{s|w} + heating_{s|w} + EV_{s|w} + Inflexible_{s|w} - DS_{s|w}\right) > P^*_{max,s} \quad (17)$$

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

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

10 However, a market model where the augmentation of power subscription is not billed to the customers because of the value of EV flexibility for the electric system is not a far-fetched hypothesis.

$EV_{s|w}$ 10-year charging stations consumption of substation s restricted to the week w
$Inflexible_{s|w}$ 10-year inflexible consumption of substation s restricted to the week w
$DS_{s|w}$ 10-year distributed solar production of substation s restricted to the week w
$P^*_{max,s}$ the MPI of the substation s

It is called *unconstrained* otherwise.

Constraints are then added to Antares' optimization problem, to simulate a filtering by DSOs. Initial constraints on flexible consumption exposed in section 2.1 are attributed to constrained and unconstrained substations proportionally to the weekly distribution of the substations in these two categories. The total load 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:

$$\sum_{s\in Constrained_w} WH_{s|w,h} + heating_{s|w,h} + EV_{s|w,h} + Inflexible_{s|w,h} - DS_{s|w,h} < \sum_{s\in Constrained_w} P^*_{max,s} \quad (18)$$

This constraint is much more computationally efficient than having one constraint per substation, but it does not insure that each substation is individually constrained at its MPI. Another less permissive variant has been studied and is described in Appendix 3 – *Variant with additional constraint on flexibility activations*, and the conclusions are very similar.

3.1.2 Decomposition of the flexibility activations on each substation

Then, an 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 as explained in section 3 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.

The aim of this optimization problem is to minimize the total energy exceeding the MPI on all the substations (the loss-of-load). The constraints are detailed in Appendix 2.

$$\sum_{h=0}^{167} \sum_{s\in Substations} (\max\,(WH_{s,h} + EV_{s,h} + heating_{s,h} + Inflexible_{0,s,h} - DS_{0,s,h} - P^*_{max,s};\,0)\,) \quad (20)$$

$WH_{s,h}$ the water heaters consumption for substation s at hour h (optimization variable)
$EV_{s,h}$ the charging stations consumption for substation s at hour h (optimization variable)
$heating_{s,h}$ the heating consumption for substation s at hour h (optimization variable)
$Inflexible_{0,s,h}$ the inflexible consumption for substation s at hour h
$DS_{0,s,h}$ the distributed solar production for substation s at hour h
$P^*_{max,s}$ the chosen MPI of substation s

3.1.3 Evaluation of production costs for the Peak/Off-peak Signal with a DSO filtering

POS filtering is based on the differentiation of the national hourly ratios that characterize the POS along substations (see 2.1.1). These hourly ratios are originally the same for every substation. To deal with NS MPIs overruns of substations constrained with the POS, these distribution coefficients are adapted to each constrained substation with the POS filtering.

Practically, the computation of the new constrained substation energy hourly ratios is done for the most constrained day of each typical timeframe for the constrained substation. If no overrun occurs in a typical timeframe of a constrained substation, the daily distribution of energy is kept to the national distribution for this timeframe. Otherwise, a post-processing step is added to shift flexibility activation spikes that create overruns of the NS MPI to time slots where the NS MPI is not reached for this most constrained day.

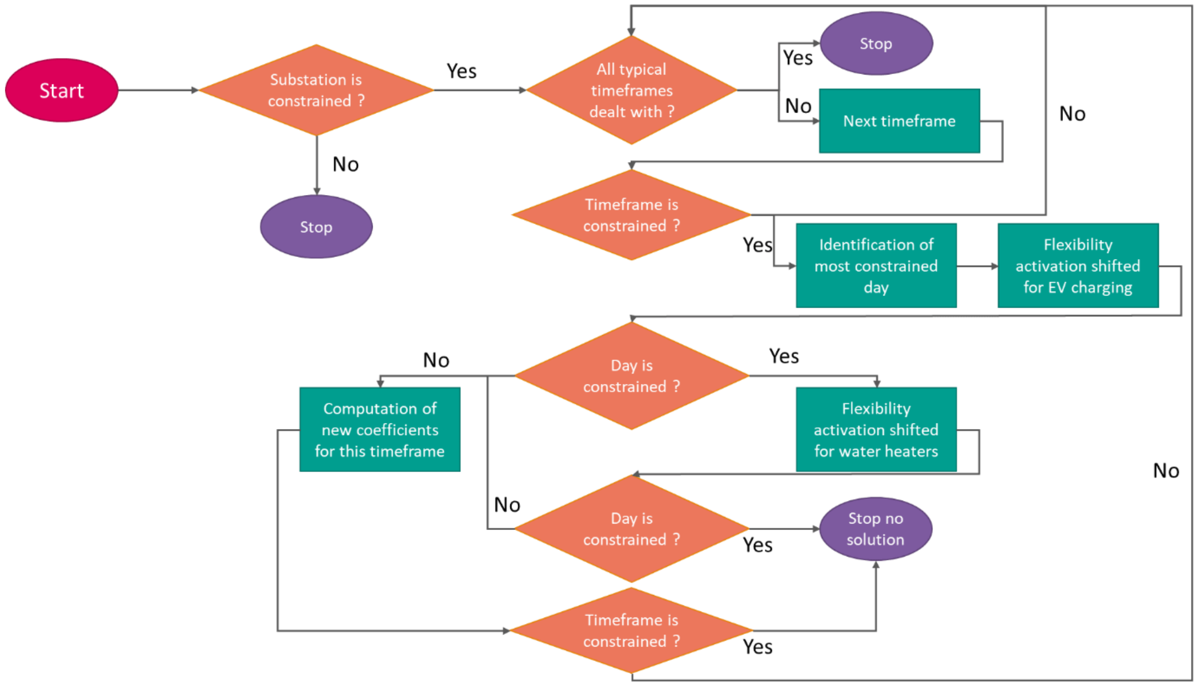


Figure 11 POS filtering algorithm, for each constrained substation

Once the new energy hourly ratios have been computed for each substation that is constrained compared to the NS with the POS, the new market costs are computed. The flexibility activations are established as the sum of the flexibility activations generated by the new differentiated energy hourly ratios of each substation.

3.2 Results

3.2.1 *POS with a DSO filtering*

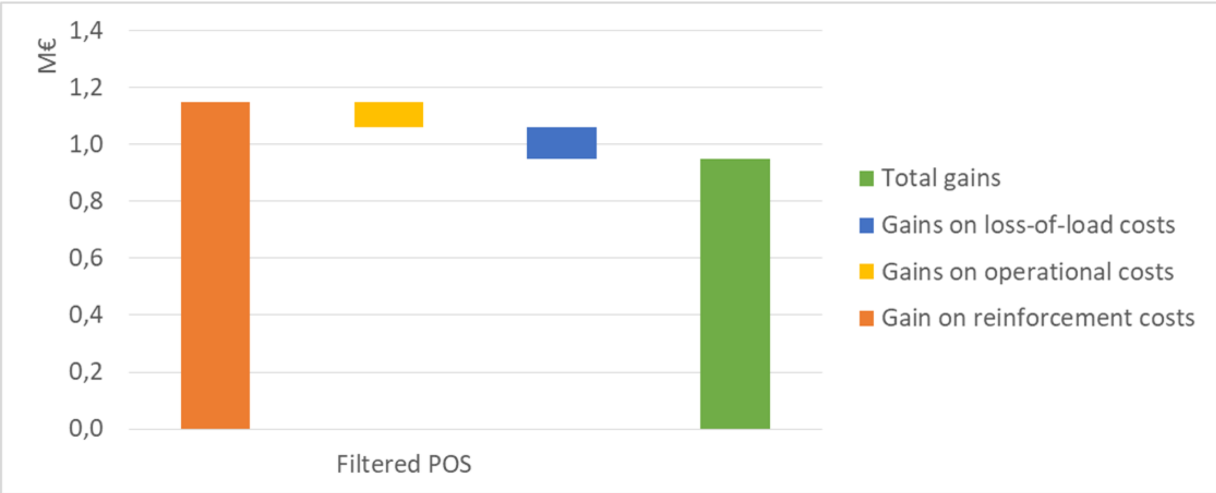


Figure 12 Gains on reinforcement costs, operational costs, and loss-of load costs of the POS filtering compared with the POS

The POS filtering at the NS MPI has little effect on total gains. Indeed, only 6 substations were overcoming the NS MPI with the POS. The gain of reinforcement cost after filtering compared with the POS without filtering is 1,1M€ (Figure 12).

3.2.2 *STCS with a DSO filtering*

The filtering of constrained activations has little effect on the gains on production costs. Indeed, constraining the sum of the MPIs of the constrained substations to the sum of their NS MPI with the DSO national filtering (« Filtered STCS ») only increases the costs by 2,4 M€ (Figure 13 – « Filtered STCS »), which represents 0,004% of total costs.

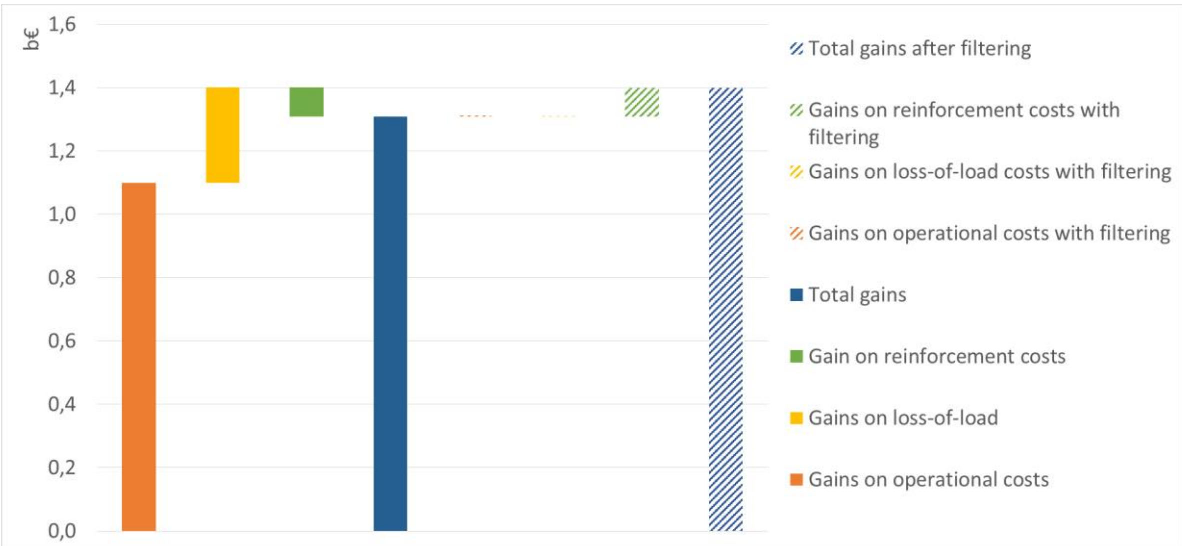


Figure 13 Difference of the costs of the "Filtered STCS" with the STCS compared with the NS test case

The simplification used to simulate « Filtered STCS » implies some unsolved distribution network constraints. Indeed, the optimization of the distribution of activations by substations has been run for the most constrained week over the 10 meteorological years (week 27 of year 10, Figure 15), with about 1500 constrained substations. For this week, 480 substations have exceeded their NS MPI of 4591 MWh. This represents about a 95% overload decrease compared to an average activation of flexibilities per substations. Those residual constraints are tight and can be solved by reinforcement costs of 123k€.

The lowering of reinforcements cost in « Filtered STCS » compared with STCS allows significant benefits of 90M€, showing that implementation of filtering would be an interesting improvement of the STCS. The gains on reinforcement costs are concentrated on very few substations that account for most of the filtering gains on reinforcement costs. 90% of total reinforcement cost gains are to account for 3% of the substations.

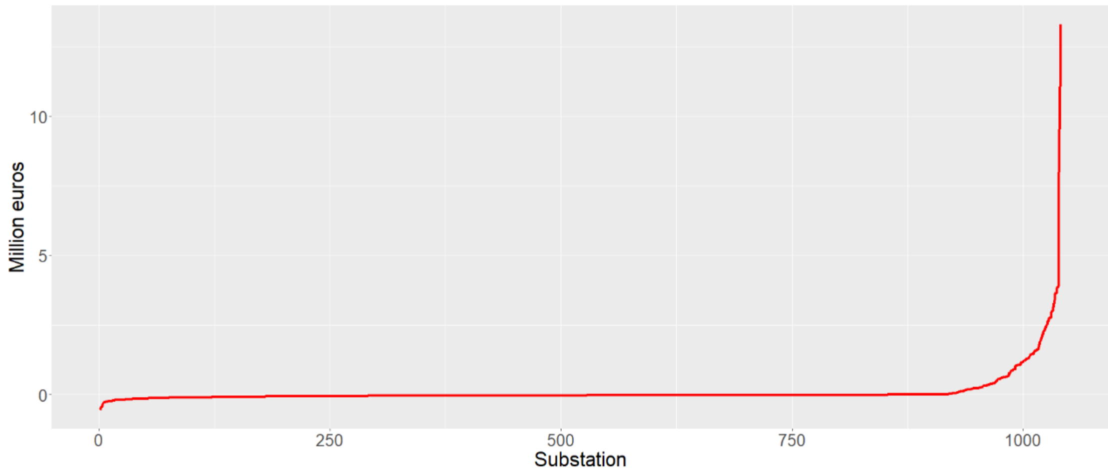
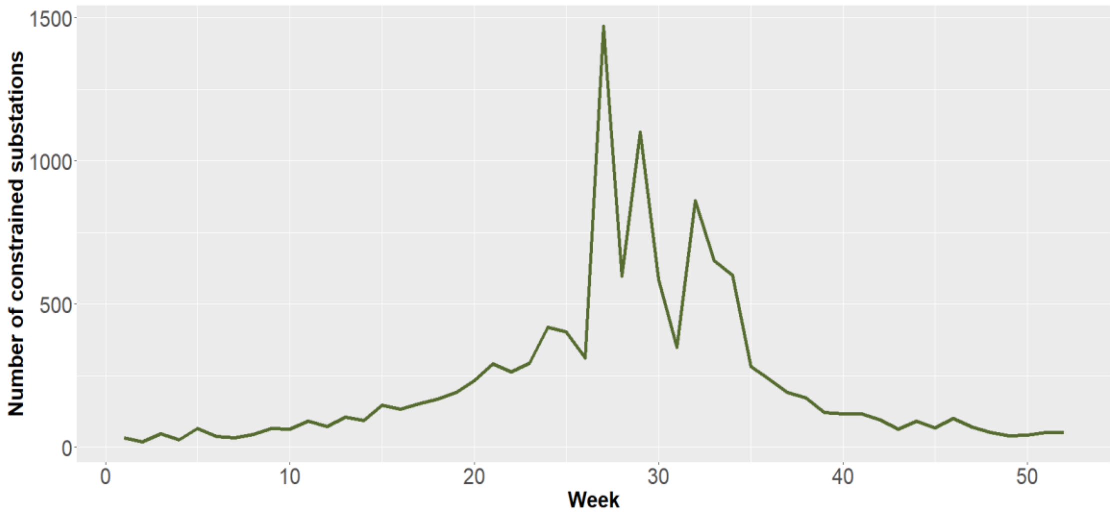


Figure 14 Monotonous of the gains on reinforcement costs per substation with filtering compared to the STCS costs



IV.

Figure 15 Sum of constrained substations for each week over the 10 meteorological years

V. CONCLUSION

In this paper, we focus on the coordination between the use of distributed flexibility to postpone or avoid network investments and the use of distributed flexibility as a production means on the wholesale market. The goal of such coordination is to use this flexibility at its maximum potential, enabling the maximum gains for both the DSO and the market.

In a first draft of coordination scheme, enabling distributed flexibility activation with the only objective to reduce production costs, we show that the gains of using flexibility sources far overcome the costs for the distribution network in terms of reinforcement needs. Indeed, with a short-term activation signal, the use of distributed flexibility for the wholesale market enables a 1.4b€ gain in comparison with a situation where no flexibility is offered. The distribution network reinforcement costs involved by these flexibility activations only represent 0.1 b€. The paper also studies the impact of a long-term flexibility activation signal, for which the total gains are only 30% lower. This long-term flexibility activation signal is easier to implement as it is computed once and for all and does not vary every day along with the day-ahead production and consumption forecasts. For consumers, this flexibility activation signal also seems less intrusive and easier to apprehend thanks to its predictability.

Secondly, a filtering step of network constraining activations has been simulated and allows complimentary benefits. The Short-Term Controllability Signal (STCS) and Peak/Off-peak Signal (POS) of the first situation (test cases 2 and 3) are filtered considering that net consumption power peaks at each substation can't exceed the Maximum Power Indicator of the substation obtained with the No Signal (NS) test case. This filtering almost cancels the additional reinforcement costs of the Short-Term Controllability Signal compared to the No Signal test case observed in the first situation. Thus, the filtering enables a 90M€ supplementary gain to the first situation. For the Peak/Off-peak Signal, the filtering at the No Signal Maximum Power Indicator enables a supplementary gain of almost 1M€, filtering at a lower Maximum Power Indicator might have allowed a greater gain.

These results support the use of at least a substantial share of distributed flexibility for the wholesale market, via aggregators for instance, instead of reserving it exclusively for the DSO's activities. This share can be decided in coordination with the DSO via the use of the Maximum Power Indicators to approach a global optimization of the system costs.

The potential benefits of coordination using the Maximum Power Indicators between market activations and network reinforcements have been prospectively studied in this paper, for 2030. The details of practical implementation have been excluded from the analysis, although they can have a significant impact, especially for short-term coordination. In future work, this coordination scheme will be studied as a real-time activation scheme on short-term markets from day-ahead to balancing, considering uncertainties on load and renewable generation.

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Appendix

Appendix 1 - Breakdown of the national power over the substations

- 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:

$$\text{For every substation } s,\ Inflexible_s = Inflexible_{tot} \times \frac{med(Inflexible_{historical,s})}{\sum_{t \in Substations} med(Inflexible_{historical,t})} \quad (8)$$

$Inflexible_s$ the 10-year inflexible consumption time-series of the substation s
$Inflexible_{tot}$ the 10-year national inflexible consumption time-series
$Inflexible_{historical,s}$ the 2012- 2016 consumption of the substation s

- 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,

$$Solar_s = Solar_{tot} \times \frac{LFS_a}{LFS_{tot}} \times \frac{CapaS_s}{\sum_{t \in a} CapaS_t} \quad (9)$$

$$Wind_s = Wind_{tot} \times \frac{LFW_a}{LFW_{tot}} \times \frac{CapaW_s}{\sum_{t \in a} CapaW_t} \quad (10)$$

$Solar_s$ 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

- 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.

$$WH_s = WH_{tot} \times \frac{enerWH_{s,hist}}{\sum_{t \in Substations} enerWH_{t,hist}} \quad (11)$$

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

- For the EV local load curves, the breakdown model takes into account population density[11], median income[12], and current car ownership level[13] 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:

$$coeff_m = \frac{1}{3} \times \left(\frac{Pop_m}{\sum_{t \in M} Pop_t} + \frac{Inc_m}{\sum_{t \in M} Inc_t} + \frac{Car_m}{\sum_{t \in M} Car_t} \right) (12)$$

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.

$$coeff_{m,adapted} = \frac{coeff_m}{nbSub_m} (13)$$

$coeff_{m,adapted}$ 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

$$coeff_s = \sum_{m \in s} coeff_{m,adapted} (14)$$

$coeff_s$ the downscaling coefficient of the substation s

$$EV_s = EV_{tot} \times coeff_s (15)$$

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

- 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.

$$heating_s = heating_{tot} \times \frac{heating_{s,2030}}{\sum_{t \in Substations} heating_{t,2030}} (16)$$

$heating_{tot}$ 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.

11https://www.insee.fr/fr/statistiques/4515503?sommaire=4515944&q=m%C3%A9nages+par+commune
12 https://www.insee.fr/fr/statistiques/1893185
13 https://www.data.gouv.fr/fr/datasets/taux-de-motorisation-des-menages/

Appendix 2 - Decomposition of the flexibility activations on each substation

For each substation s the total energy of each flexibility must remain the same:

$$\forall s \in Substations, \forall d \in [1;364], \sum_{h=24*(d-1)}^{24*d-1} WH_{s,h} = WH_{s,d} \quad (21)$$

(the energy of water heaters is constrained daily)
$WH_{s,d}$ the water heaters energy consumption of substation s for day d

$$\forall s \in Substations , \sum_{h=0}^{167} EV_{s,h} = \sum_{h=0}^{167} EV_{0,s,h} \quad (22)$$

$EV_{0,s,h}$ the initial charging stations consumption of substation s for hour h

$$\forall s \in Substations , \sum_{h=0}^{167} heating_{s,h} = \sum_{h=0}^{167} heating_{0,s,h} \quad (23)$$

$heating_{0,s,h}$ the initial heating consumption of substation s for hour h
The total activation power must remain the same:

$$\forall h \in [0;167],$$
$$WH_{tot,h} = \sum_{s \in Substations} WH_{s,h} \quad (24)$$
$$heating_{tot,h} = \sum_{s \in Substations} heating_{s,h} \quad (25)$$
$$EV_{tot,h} = \sum_{s \in Substations} EV_{s,h} \quad (26)$$

$WH_{tot,h}$ 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 (2) leads to:

$$\forall s , \forall h \in [0;167] , WH_{s,h} < WH_{max,h} \quad (27)$$

$WH_{s,max,h}$ the downscaling of the maximum national water heater power activation for substation s and hour h

The downscaling of (3), (4) and (5) leads to:

$$\forall s , \forall h \in [0;167] ,$$
$$SoC_{max,s,h} \geq SoC_{s,h} \geq SoC_{min,s,h} \quad (28)$$
$$SoC_{s,h} = SoC_{s,h-1} + 0{,}923 * EV_{s,h} + MobileStor_{s,h} \quad (29)$$
$$0 \leq EV_{s,h} \leq EV_{max,s,h} \quad (30)$$

$SoC_{max,s,h}$ 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 (6) and (7) leads to:

$$\forall h \in [0; 167], \forall s, 0 \leq def_{s,h} \leq def_{max,s,h} \text{ (31)}$$

$$\forall h \in [0; 167], \forall s,$$

$$heating_{s,h} = heating_{NS,s,h} - def_{s,h} + \sum_{k=1}^{23} coeff_k \times def_{s,h-k\,[168]} \text{ (32)}$$

$def_{s,h}$ 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

Appendix 3 – Variant with additional constraint on flexibility activations

A variant (called "Filtered STCS +") is made with artificial reinforcement of the constraints of 5.5 MW per constrained substation. Constraint (18) is changed to:

$$\sum_{s \in Constrained_w} WH_{s|w,h} + heating_{s|w,h} + EV_{s|w,h} < \sum_{s \in Constrained_w} P^*_{max,s} - Inflexible_{s|w,h} + DS_{s|w,h} - 5{,}5 \text{ (19)}$$

Figure 16 shows how lowering the constraint limits the national flexibility activation.

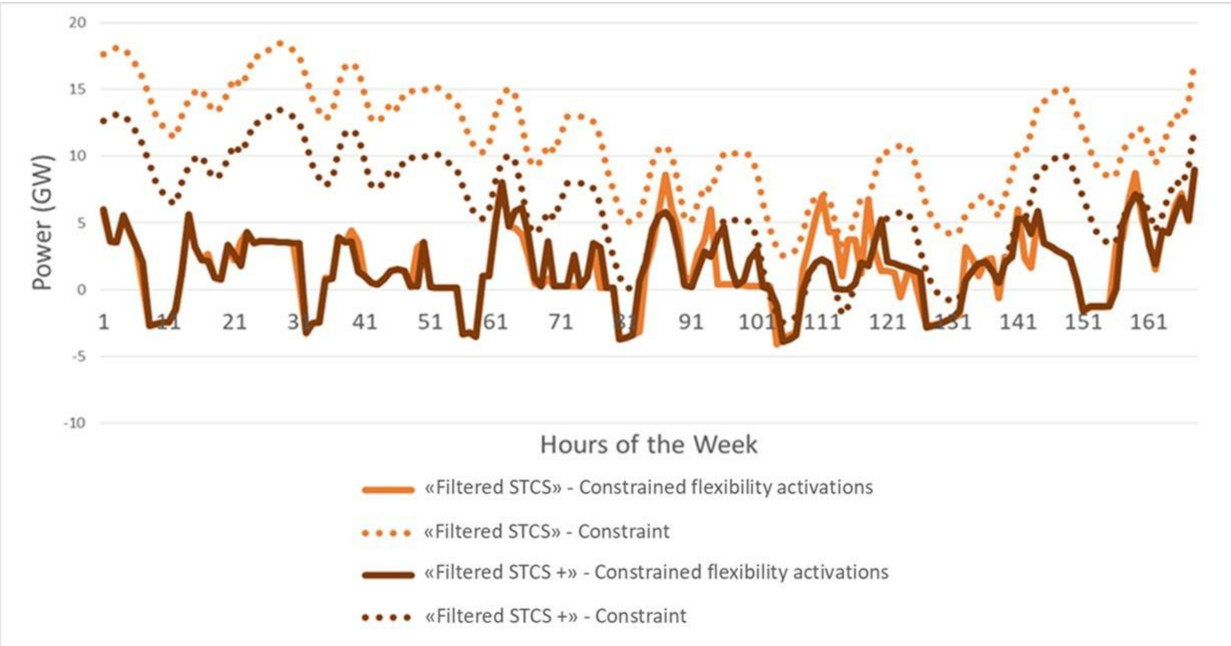

Figure 16 Filtering of the most constrained week (week 27 of year 10) with an added 5 GW margin
For the « Filtered STCS +», production costs increase is only a little higher than "Filtered STCS", close to 2,5M€.

As « Filtered STCS », « Filtered STCS +» do not solve every distribution network constraints. The minimum reached by « Filtered STCS +» after the optimization is 3994 MWh, only a bit lower than « Filtered STCS », for week 27 of year 10.
This residual constraints can be solved by reinforcement costs of 60k€.