The Transition Institute 1.5
L'ambition d'une véritable transition

WORKING PAPER

#1 - septembre 2023

The demand-side flexibility in liberalised power market: a review of current market design and objectives

CLÉMENT CABOT
Mines Paris, PSL University, Centre for industrial economics (CERNA), i3 UMR CNRS, 60 Bd St Michel 75006 Paris, France , +33669011176, clement.cabot@mines-paristech.fr

MANUEL VILLAVICENCIO
Research associate, Chaire European Electricity Markets, PSL Research University, LEDa [CGEMP], Place du Maréchal de Lattre de Tassigny, 75775 Paris, France. +33666623523, manuel.villavicencio@dauphine.psl

DOI : 10.23646/tyjr-sv40

MINES PARIS | PSL | TT1.5° The Transition Institute

SOMMAIRE

Abstract

The recent energy crisis in Europe has brought the current electricity market design under scrutiny, highlighting the need for additional liquidity in forward markets, greater flexibility to mitigate peak prices and additional instruments to hedge consumer better again price risks. However, there is no consensus to date on the market design allowing the integration of demand as a source of flexibility, despite its critical role in complementing supply-side investments. This research presents a comparative analysis of current DR integration in different electricity markets, namely France, Germany, and Pennsylvania-New Jersey-Maryland (PJM) Interconnection in the US. The aim is to assess current trends, key differences, and the role of DR during recent power crises in Europe. The ongoing transformation of power systems calls for more active involvement of demand, necessitating improvements in existing tariffs and market design. This ranges from revising network tariff structure to ensure better incentives and fairness for prosumers and passive customers to introducing dynamic pricing schemes, which align consumer prices with wholesale market outcomes. However, despite efforts to facilitate consumer participation in different electricity markets, none of the existing DR schemes has achieved significant success. Moreover, the effectiveness of demand reduction during contingency events remains uncertain, raising questions about the level of reliability that can be achieved. However, DR also demonstrated its ability to fit in the existing wholesale market, notably during the 2021-2023 energy crisis in France, where its participation in the supply and demand equilibrium was demonstrated. While the market design that will emerge and the price signals used to coordinate decisions between customers, aggregators, and retailers remain unclear, there is a need for a more coordinated and robust approach toward integrating demand-side flexibility into electricity markets to achieve optimal outcomes for consumers and the grid.

Résumé en français

La récente crise énergétique en Europe a mis en évidence certaines lacunes dans l'architecture actuelle des marchés de l'électricité. Notamment, le besoin de liquidité sur les marchés à terme, d'une plus grande flexibilité pour atténuer les pics de prix et d'instruments additionnels afin de protéger les consommateurs du risque de prix ont été soulignés. Cependant, il n'existe pas à date de consensus sur l'architecture de marché permettant de faire émerger une meilleure intégration de la flexibilité de la demande, un levier pourtant nécessaire afin de compléter les investissements de côté de l'offre. Ce chapitre compare l'intégration actuelle des effacements de consommation dans différents marchés de l'électricité - la France, l'Allemagne et le marché Pennsylvanie-New Jersey-Maryland (PJM) aux États-Unis. Les tendances à l'œuvre, les différents paradigmes et le rôle de la demande dans la récente crise énergétique en Europe sont étudiés. Il ressort de l'analyse que l'ensemble des marches bénéficieraient d'un rôle plus actif de la demande, tant pour des besoins réseaux que pour améliorer l'efficacité des marchés de gros de l'électricité. Ces améliorations passent notamment par la refonte de la tarification de l'électricité, permettant d'améliorer les incitations fournies et l'équité entre consommateurs. Malgré l'ouverture progressive des marchés, aucun programme n'a permis jusqu'à présent de mobiliser de façon significative le potentiel de flexibilité identifié. De plus, le niveau d'effacement effectivement activé en situation de pointe n'atteint pas systématiquement les niveaux attendus, ce qui questionne les niveaux de fiabilité atteignables. Néanmoins, la capacité de la DR à s'intégrer au marché de gros existant et à participer à l'équilibre offre-demande a été soulignée lors de la crise énergétique de 2021-2023 en France. Plus généralement, il apparaît que des nombreux segments de l'architecture du marché restent à compléter afin de clarifier le rôle des différents acteurs, améliorer leur coordination tant spatiale que temporelle, et permettre de généraliser les gains de flexibilités à l'ensemble des segments, allant de la production au transport de l'électricité.

1. Introduction

Led by the energy policies fostering the energy transition, a whole new variety of power producers are emerging in the power sector thanks to the market unbundling and driven notably by the coal and nuclear phase-out happening in multiple European countries. The uptake comes mainly from renewable energy sources (RES), which accounted for more than 80% of capacity expansion worldwide in recent years (IRENA, 2021, 2020). However, demand-side resources have also sparked interest as a critical element of new power systems (IEA, 2016; IRENA, 2019). In addition, the 2021-2023 energy crisis in Europe has reinforced the interest in fostering demand response (DR), as an expected outcome would be to mitigate peak power prices. Regulatory speaking, the current market design, defined as both unbundling rules and auction design, has been criticised during the power crisis, and a new set of reforms is expected. In addition, electricity markets are still subject to multiple refinements, and the Clean Energy Package (European Commission, 2016a) indicates explicitly that all generation, storage and demand resources shall participate on a level playing field in the market. The European Commission, therefore, underlined again after the crisis the requirement for the power sector to accelerate the opening of electricity markets to DR, notably by providing dynamic prices to end-consumers.

From an economic point of view, electricity is a very particular good insofar as the demand has historically been considered almost inelastic, with no short-term price responsiveness (Stoft, 2002). In addition, electricity cannot yet be stored at scale at competitive prices, leading to production-centred top-down electricity market designs. This paradigm is reflected in the current flat tariff scheme favoured by utilities to recover the costs of the electricity purchased by consumers (Houthakker, 1951; Wilson, 2002). However, European power systems are increasingly called to rely on variable energy sources (vRES), such as wind turbines or solar PV, putting under question the existing paradigm. Indeed, vRES production fluctuates hour by hour, suffers from forecast deviations and can only partially provide ancillary services (AS) required for the stability, reliability, and resiliency of the electricity supply (Stram, 2016). As a result, several attributes of vRES impact both the operation and the corresponding market design put into place. As they are not dispatchable, their production cannot be adjusted upward, affecting the energy and reserves market conceived to balance system fluctuations. Additionally, vRES do not provide inertia to the grid, which means that a potential failure, such as the loss of a synchronous thermal power plant, might increase frequency deviations (Tielens and Van Hertem, 2016). In addition, it would impact ancillary services and require additional units capable of supplying reserves on short notice. They also provide little support for the yearly peaking hour (Boccard, 2009), raising the security of supply concerns and justifying, among others, the need for capacity mechanisms recently put into place to secure the profitability of peaking plants (Newbery, 2016). Finally, being much more distributed, they reverse the top-down approach usually adopted for delivering electricity (i.e., from the high-voltage grid to the low-voltage network). As the distribution grid accommodates a growing number of production units, it would require revamped grid management linked to reverse flows, especially for low-voltage levels. All those attributes must be taken care of, and increased flexibility from the demand is called to play a growing role in balancing all such system needs. As Wellinghoff et al. explain (2007), the demand part of the wholesale market has long been the missing block. Today, the promises of digitalisation are paving the way towards smart grids and transactive markets in order to support demand-side participation (Abrishambaf et al., 2019; Adeyemi et al., 2020). Distributed flexibility is seen as an opportunity for each market segment and has already been treated extensively in the literature (Eid et al., 2016b; Hussain and Gao, 2018; Lampropoulos et al., 2013; Meyabadi and Deihimi, 2017). The recent energy crisis in Europe has reignited interest in DR to achieve energy savings and lower electricity prices. Opening up electricity markets to all participants and implementing mechanisms that enable small-scale consumers and prosumers to participate actively in the market have been suggested by industry stakeholders as potential solutions (smartEn, 2022).

It is, therefore, essential to examine the ongoing integration of DR and its relevance to supporting Europe's energy transition. While this research gap has been addressed to some extent by Villar et al. (2018), our review focuses explicitly on the demand response market design, which implies specific market settlements and actors compared to flexibility as a whole. While previous studies have evaluated the integration of DR in the US (Cappers et al., 2010), Germany (Koliou et al., 2014), and Europe (Torriti et al., 2010), our research complements the existing literature by providing an updated economic assessment of DR market integration in France, which is at the forefront of demand integration in European electricity markets and has been subject to multiple changes in the last decade (Rious and Roques, 2014). A comparison is provided between the state of play of DR programs in France, Pennsylvania-New Jersey-Maryland Interconnection (PJM) in the US, which has a long-established program, and Germany, which has achieved high penetration of RES.

In addition, this research provides an ex-post analysis of the existing DR programs, notably by assessing the impact of the deployment of smart meters and their participation during the 2021-2023 energy crisis. Our research consists of a comprehensive literature review of academic work and empirical evidence for each topic and aims to clarify the following question for each market:

i. What is the current and future demand-side flexibility potential?

ii. Which are the different market designs in place to accommodate demand response?

iii. What are the potential inefficiencies still to be addressed?

This paper includes eight sections. Sections 1 and 2 provide specific context and present the proposed analysis framework. Section 3 reviews the potential for DR in the power systems studied. Section 4 describes the price-based approach towards DR. Section 5 discusses the existing incentive-based programs in the different electricity markets, while Section 6 discusses the additional market design envisaged. Finally, policy implications and conclusions are laid out in sections 7 and 8.

2. Demand-side integration in liberalised electricity markets

2.1 Flexibility requirements in power systems

There is no unique and consensual definition of flexibility in power system operations (Hillberg et al., 2019). The international energy agency defined it as "the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales, from ensuring instantaneous stability of the power system to supporting long-term security of supply" (IEA, 2016). While this definition captures the multifaceted nature of flexibility, it does not clarify the relevant timescale involved or the actors responsible for providing it. Historically, thermal and hydropower power plants have been the primary providers of balancing services. These units are expected to continue playing a major role in flexibility provision, notably in facilitating the integration of new vRES (Agora Energiewende, 2017). However, this article investigates behind-the-meter (BTM) flexibilities provided by the industrial, commercial, and residential sectors. These potential flexibilities remain largely untapped, as the prerequisites for active participation of the demand-side in electricity markets were not met until recently (Wellinghoff and Morenoff, 2007) and as end-use in these sectors are expected to be electrified.

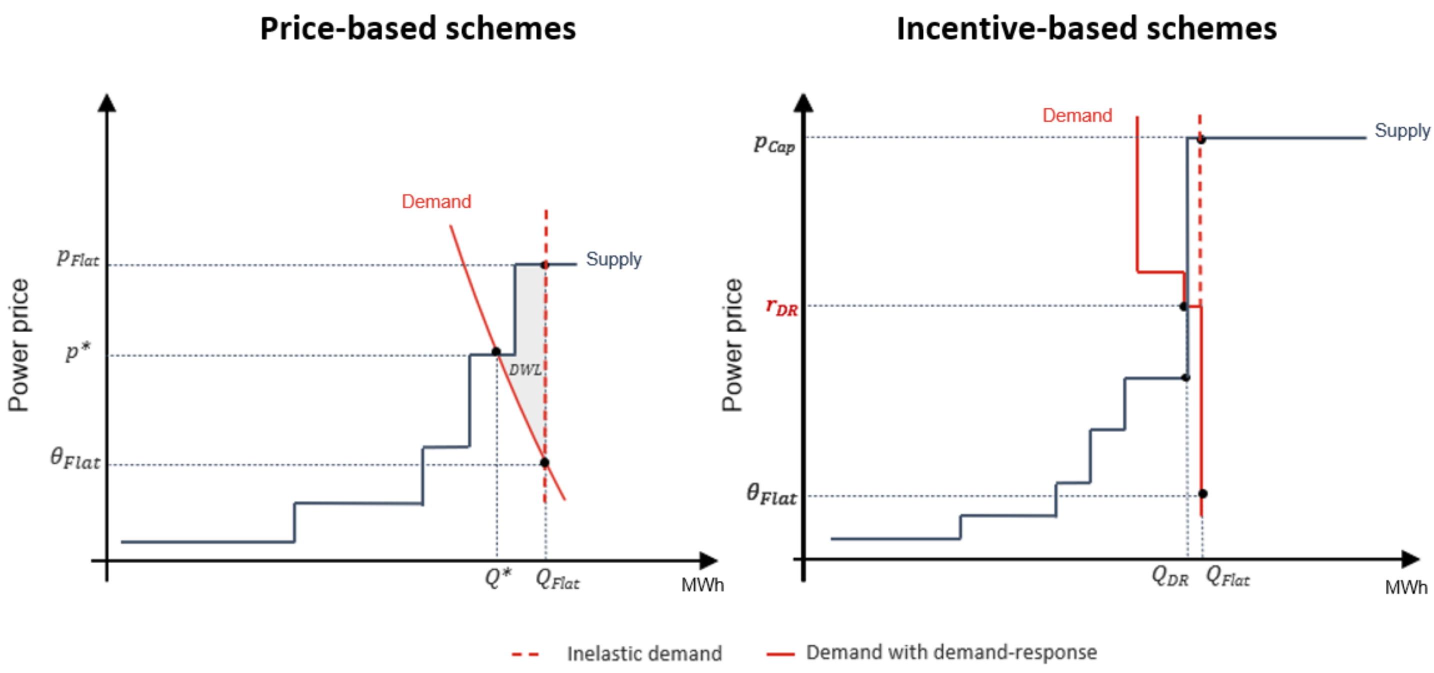
2.2 Approach towards DR

Disregarding the demand side of electricity markets has long been considered a severe failure of the current electricity market design (Bushnell et al., 2009). In the literature, a clear distinction is made between two approaches to leverage DR: the price-based and the incentive-based paradigm (Eid et al., 2016a). The first one also referred to as implicit demand response, relies upon the ability of customers to adjust their load based on price signals and, therefore, depends ultimately upon consumer behaviour. The second one also referred to as explicit DR, comprises a wide range of directly managed distributed sources (e.g. direct load control), such as water heaters, heat pumps, or electric vehicles that participate in the market through explicit contracts defining load interruptability or modulation clauses (Lund et al., 2015; Wang et al., 2017).

Even though both price-based and incentive-based programs rely on the same set of appliances, they represent distinct demand paradigms, as illustrated in Figure 1. In price-based DR, the objective is to reduce deadweight loss by conveying the electricity price information to the final consumer. In other words, moving away from a flat rate θ_{Flat} towards alternative pricing schemes where power prices would align with consumers' willingness to pay, referred to as p^*. This implies a different power demand Q^*, and a reduction of the deadweight loss DWL. Apart from the reduction in their electricity bills, no direct remuneration would be provided to the consumer. Alternatively, price signals conveyed to consumers through dynamic tariffs could be voluntarily inflated to achieve a more significant reduction during scarcity episodes.

In the case of incentive-based DR, the paradigm differs as it relies on an explicit remuneration r_{DR} to the demand (or a third party in charge) able to curtail power consumption under contractual conditions. Most consumers would eventually remain under a flat tariff, as the financial gains would stem from a reduction in the average power price, notably by reducing occurrences of reaching the price ceiling p_{cap}, and by the direct remuneration r_{DR}. In the illustration provided in Figure 1, the demand would be curtailed for electricity prices above a pre-determined strike price r_{DR} , shifting the demand from Q_{Flat} to Q_{DR}. In that case, the price would be set by the demand and aligned with the willingness to pay end-users as agreed upon in the contract[1].

Figure 1 - Illustration of price-based and incentives-based schemes paradigm impact on supply-demand equilibrium



1 The willingness to pay in this situation is also referred as the willingess to curtail (Cappers et al., 2010)

In addition to the different paradigms, it is important to underline that different objectives could be targeted by increasing DR. Faruqui (2011) distinguishes between five objectives: strategic load growth, load shaping, energy conservation, peak shaving and load shifting. Each objective relies upon different market designs to be effectively addressed. Therefore, it is essential to identify the objective targeted by a given market design to assess its effectiveness.

2.3. Demand response integration into electricity markets

A major factor shaping the DR integration in electricity markets lies in the market structure in place. Liberalised markets emerged in the late 1990s when incumbent vertically integrated utilities got restructured. The US has adopted an *integrated* market design consisting of a centrally optimised dispatch by the Independent System Operator (ISO). The unit commitment considers multiple operational characteristics, such as minimum power generation of units with the co-optimisation of energy supply and reserve (commonly referred to as a unit commitment approach). The physical feasibility of the resulting dispatch is paramount, even if only real-time dispatch is binding. A similar paradigm has been adopted in European countries since the 2000s. Transmission System Operators (TSO) and Distribution System Operators (DSO) own and operate the high-voltage and low-voltage grid, respectively. They are responsible for maintaining the supply/demand balance and for congestion management, grid reliability and network expansion, as well as for ensuring interoperability with other balancing areas within Europe. In addition to managing the physical grid, TSOs and DSOs also play a role in the market design, ensuring market monitoring and transparency, specifying network access charges, and organising the market for ancillary services, among others.

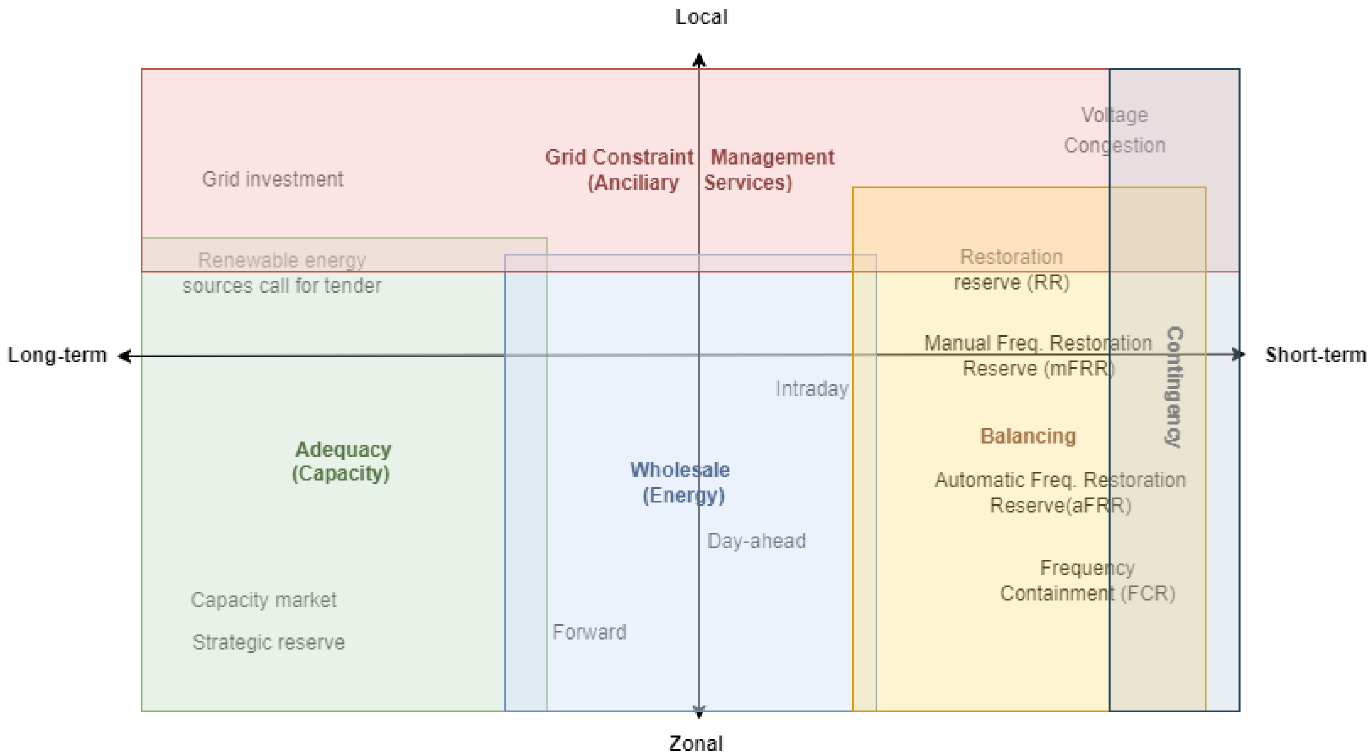
The European electricity market architecture differs from an integrated approach as settlements occur on consecutive markets. This approach is referred to as the *unbundled* market design (Klessmann et al., 2008; Wilson, 2002), where settlements are made successively, first on forward markets, then on day-ahead markets and finally during intra-day electricity markets. As the demand and generation forecasts gain accuracy when approaching delivery time, the market succession enables a balanced power system. Eventually, countries rely on ancillary services and balancing markets to adjust production and demand in real-time on a competitive basis to guarantee very short-term stability.

Nevertheless, market failures have emerged in recent years, justifying the implementation of additional markets and instruments. Arguably, due to the acknowledged missing-money problem peaking units are unable to recover their full costs (Joskow, 2008) and put investments in new capacities at risk. Capacity adequacy mechanisms were actively discussed in the 2010s, with some jurisdictions adopting adequacy mechanisms allowing additional remuneration streams to secure long-term capacities years ahead.

It is important to note that the distinction between integrated and unbundled market designs also affects the pricing mechanism adopted. The US has progressed towards locational marginal price LMP (PJM, 2020a), with each node having different market prices that reflect grid and production constraints. In contrast, Europe has adopted zonal pricing, where each bidding zone corresponds to a single price. This difference in pricing mechanisms has stark implications for the integration of DR, as LMP pricing provides more granular information to market participants regarding locational scarcity (Bertsch et al., 2017). European locational signals are usually addressed outside the market, using localised injection tariffs, regional targets for capacity expansion, or localised calls for tenders.

Distributed flexibility is perceived as an opportunity for all the aforementioned power segments, although the grid components are regularly disregarded in the literature (Heggarty et al., 2020). Figure 2 illustrates the framework used to review the different segments requiring flexibility and the associated temporality and geographical scale. This market-based framework complements other approaches developed to assess the required flexibility from an operational point of view (Hillberg et al., 2019). The first axis of the framework is based on the geographical scale, which determines whether the market conveys a local signal, usually linked to grid management, or a zonal signal, representative of system-wide balance. This aspect is especially relevant in the European case, where most price signals are zonal. The second axis refers to the temporality of each market, from yearly procurement to real-time settlement. While this framework illustrates the most relevant quadrant for each market, in practice sequential markets are interconnected, offering trade-off opportunities and allowing for hedging positions. Short-run and long-run competitive equilibrium are part of the same market design, where changes in the day-ahead market design impact the long-run adequacy outcome.

Figure 2 - Type of services that could be fulfilled by demand response within this analysis framework[2]



2 The European nomenclature are used in the framework. An analysis of the differences is provided by Imran and Kockar (2014)

3. Current and future demand response potential

3.1. Assessment of DR potential

To assess the potential of DR and its prospects, it is essential to consider the specificities of a given electricity market and its trends. For illustration, we have selected three different mature electricity markets for discussion: France, Germany, and the Pennsylvania-New Jersey-Maryland Interconnection (PJM) area in the US. Further information on the key characteristics of each market is provided in Table 1.

Table 1 - Electricity market characteristics in France, Germany and PJM[3]

	2018		
	France	**Germany**	**PJM**
Yearly consumption (A) in TWh	478.3	520	806.55
Peak Load (B) in GW	94.5	79.6	165.49
Peak-Consumption Ratio (C = B/A)	0.197	0.153	0.205
Share of RES in annual energy production	21.2%	34.9%	5.4%
Share vRES[4] in annual energy production y	7%	24.2 %	-
Average residential household consumption in kWh	4,760	3,171	10,649
Residential end-use shares	36%	27%	37%
Commercial end-use shares	47%	28%	37%
Industrial end-use shares	17%	45%	26%

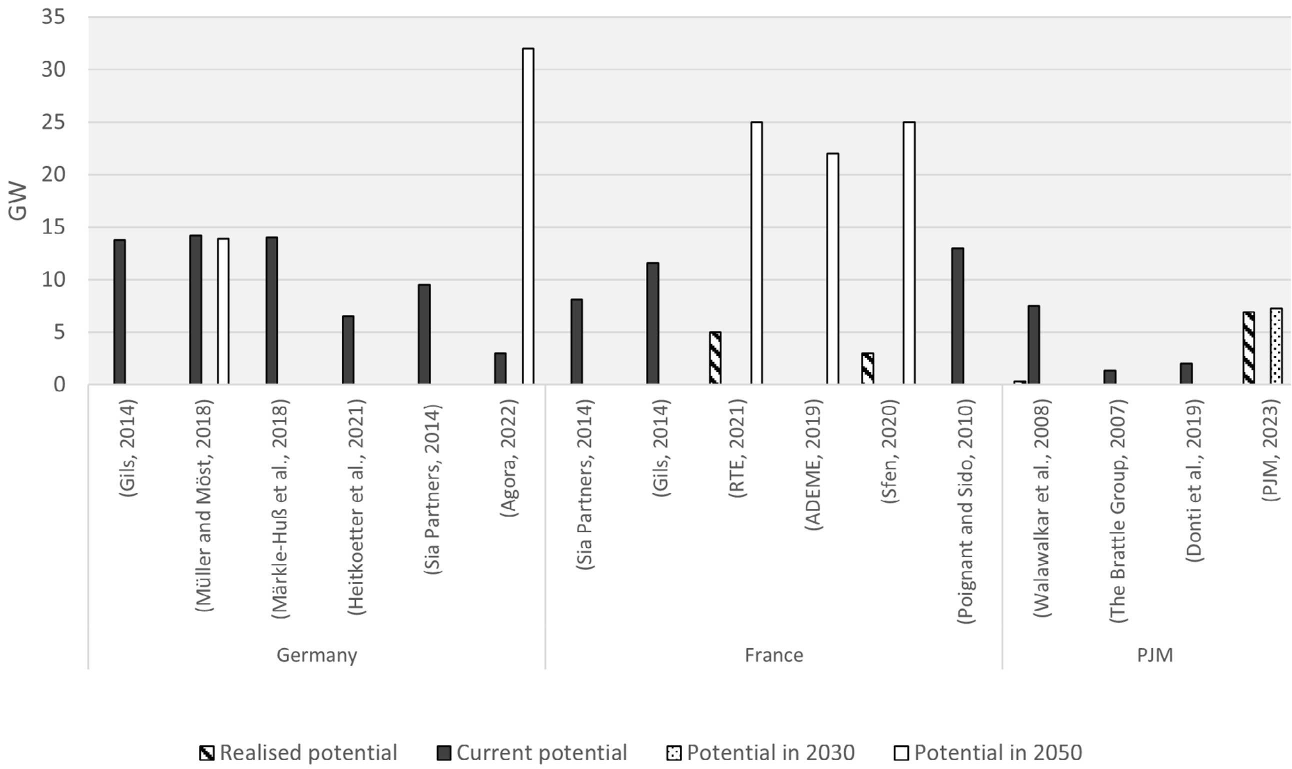
Germany is engaged in the “Energiewende”, targeting high shares of RES in the power mix (Renn and Marshall, 2016). Referring to the IEA Status of Power System Transformation (IEA, 2019), Germany is already facing high flexibility needs, being in a phase where vRES production determines the operation pattern of the system. The industrial sector mainly drives power consumption, representing 45% of total electricity consumption. Conversely, PJM is a market where households represent high shares of the total power demand, nearly 37% in 2018. The overall power demand is higher than Germany's and is met mainly by thermal units, with RES accounting for less than 10% of the power production in 2018. Moreover, even if the annual electricity consumption in Germany is higher than that of France, the favourable conditions for deploying electric heating in France due to nuclear power availability has led the French peak load to become higher than the German one. Those features are partially reflected in the development of DR programs, which are most advanced in France and PJM where the peak load is important relative to the average

3 (BDEW, 2019; EIA, 2020; ENTSO-E, 2020; PJM, 2023; RTE, 2019a)
4 Variable Renewables Energy Sources (vRES). Sum of onshore, offshore and solar PV.

consumption. On the other hand, higher flexibility needs are also expected in systems with high vRES shares, a situation becoming more and more prominent in Germany.

The broad potential of DR relies on the ability to alter end-users power consumption thanks to price signals or payments. Typically, the potential of DR relies on electrified appliances that can be shifted thanks to natural thermal latency (e.g., boilers, heat pumps, water heaters) or through an energy storage capacity such as electric vehicles (EV) (Eid et al., 2016a). Figure 3 displays each market's DR's historical and prospective potential. It is based on a literature review for each market, building on academic and grey literature. All references are provided in Appendix A1, Table A.1. While some references indicate DR potential as the achievable reduction in peak load, the figures display the available capacity expressed in gigawatts, considering temporal availability and industrial operation's seasonality. Regarding technical potential, Gils (2014) comprehensively assess Europe's theoretical demand response potential across all sectors. The findings revealed comparable potential in France and Germany in historical years, with an average of respectively 11.6 GW and 13.8 GW. Using historical peak values, these figures correspond to 10% and 15% potential reduction at peak load for both countries. In the US, the Federal Energy Regulatory Commission (FERC) provides an annual report on demand response and advanced metering, as required by section 1252(e)(3) of the Energy Policy Act of 2005 (U.S. Congress, 2005). In the case of PJM, the size of DR reached 10.2 GW in 2019, or 6.9% of the peak load. In practice, PJM has demonstrated a 5% peak capacity on average per year, corresponding to 6.9 GW, which is expected to increase slightly in the next decade, reaching 7.24 GW in 2032 (PJM, 2023).

Figure 3 - Demand-side reduction potential in France, Germany, and PJM from the



A commonality underlined in the literature for the future demand response lies in the deployment of EV and the load management possibility for charging batteries. EV undeniably has a significant potential for providing flexibility and for participation in grid congestion management and peak load reduction. In the three geographies considered, the impact of EV deployment will likely consist of a net peak load increase because of charging requirements. However, the French TSO RTE (2019b) has also considered cases of EV integration with favourable Vehicle-To-Grid (V2G) flexibility, leading to potential savings during peak hours thanks to the enhanced load management capabilities. Those flexibilities are considered a "*no-regret option*" for the grid, but the deployment phase should provide the foundations for harnessing the flexibility potential. As a matter of fact, residential charging points are becoming mandatory in many countries for new construction, such as in the U.K. (GOV.UK, 2021), and the design considered should decide whether reverse flow and separate metering are enforced. Conversely, if electric vehicles represent a net increase in peak load, they will increase peak capacity investments[5] and higher short-term grid management costs, as EV charging is particularly steep. Overall, Vehicle-To-Grid is an example of technology that could provide flexible services in numerous markets if well managed, resulting in cost savings for the customer (RTE, 2019b; Veldman and Verzijlbergh, 2015).

3.2. Limits of DR potential evaluation

Different assumptions or scopes explain most discrepancies between sources. First, a distinction should be made between DR's technical, economic, and socio-economic potential (Appendix A1, Table A.1). The technical potential of DR refers to the maximum amount of load reduction achievable based on the appliances' power consumption. The economic potential of DR focuses on the value and cost-effectiveness of implementing DR strategies. Lastly, the socio-economic potential of DR considers the broader societal implications of demand response. Indeed, the overall DR capacities recover a wide range of appliances associated with heterogenous utilities for consumers, resulting in different curtailment costs. As a result, the socio-economic potential, which should denote the historical activation of DR more accurately, is difficult to assess in a forward-looking methodology and is disregarded when assessing only the technical pool of appliances able to provide flexibility. In addition, prospective studies are also prone to methodological differences, notably between normative approaches that estimate the need for DR in prescribed power systems, compared to descriptive approaches, which are based on

5 The impact of EV on the yearly peak load in each market according to the TSOs is provided in Appendix A1, Table A.2.

historical trends (PJM, 2023).

While the total DR potential is distributed evenly between residential, tertiary, and industrial loads, the existing demand response programs are typically primarily implemented in the industrial sector. As industrial facilities are more energy-intensive than a single household, more comprehensive savings, greater stakeholder interest, and limited operating costs facilitate industrial enrolment in DR programs.

A second observation relates to the evolution of flexibility providers over time. Currently, the potential for load reduction comes primarily from refrigerators, ventilation, and heaters in the commercial and residential sectors (Gils, 2014). Focusing on Germany, Müller and Möst (2018) indicate that the potential mainly stems from electric arc furnaces in prospective years, contrasting with the current situation where most potential relies upon night storage heaters. Therefore, the assessment underlined that the DR potential should account for the dynamic nature of the end-users power consumption. Typically, the previous decade's reductions in the French industrial sector output have also reduced the former potential of demand response (Poignant and Sido, 2010). Conversely, electric vehicles are believed to provide most future flexibility requirements (RTE, 2019b). Therefore, the trajectories of end-user power consumption should be assessed and made transparent when providing estimates of flexibility potential. While energy efficiency measures will likely reduce some flexibility sources, the electrification of end-uses will provide many new opportunities. The prospective studies underlined the potential for DR likewise, but also its importance. Agora Energiewende (2023) estimates an increase of DR in Germany from 3 GW, lying in short-term industrial load shifting, to 32 GW in 2050, mostly thanks to the addition of vehicle-to-grid capabilities. Similarly, multiple studies have been performed in France, with DR hovering around 25 GW of demand-side flexibility in 2050 (ADEME, 2019; RTE, 2021a; Sfen, 2020). Given the criticality of those assumptions in the resulting power generation mix, assessing the feasibility and market design required to foster those DR capacities is essential. The ability of systems operators to rely on DR to balance the system will also determine the extent of the dispatchable capacities required to ensure the security of supply.

The third observation stems from the multiple temporal factors that should be considered to refine the technical potential found in the literature. Indeed, Müller (2018) distinguishes between the overall potential and the potential at peak load, which considers the temporal availabilities of appliances. The latter was only 50% of the overall potential, reducing it from 14 GW to 6.8 GW. The literature also distinguished between load-shedding potential, resulting in a net decrease in electricity consumption, with load-shifting potential, where the consumption is shifted over time. Märkle-Huß (2018) found a potential of 14 GW in Germany for load shedding compared to 32 GW for load shifting. The DR potential also varies significantly depending on the duration of the activation. Most of the technical industrial DR potential concerns short-term load reduction but would sharply decrease if an hour-long load reduction is envisaged. A survey and expert analysis conducted by Stahl (2014) in Germany estimates a 9 GW DR potential for 5 minutes of load shedding, while this potential reduces to 2.5 GW for a 1-hour load-shedding event and less than 1 GW for a timeframe exceeding 4 hours. Hence, it is crucial to relate the potential for load shedding with the duration of the events under consideration.

Finally, while a more active role for customers is expected to yield multiple benefits, such as greater efficiency and cost savings (Burger et al., 2019), the literature emphasises that customer-operated systems could likewise result in detrimental effects from a system perspective, notably if consumer's objectives are to maximise self-consumption (Green and Staffell, 2017). As a result, DR potential will not necessarily be available in electricity markets, depending on consumers' incentives and objectives. Eventually, it should be noted that the situation differs significantly across geographies, given past policies, existing appliances, and foreseen power mix. Therefore, the status and pace of transformation to increase DR are not comparable. Also, national policies toward energy savings might differ substantially, resulting in different priorities towards DR. Typically, the current German policies focus on energy efficiency rather than demand response (Kuzemko et al., 2017).

4. Market integration on price-based demand response

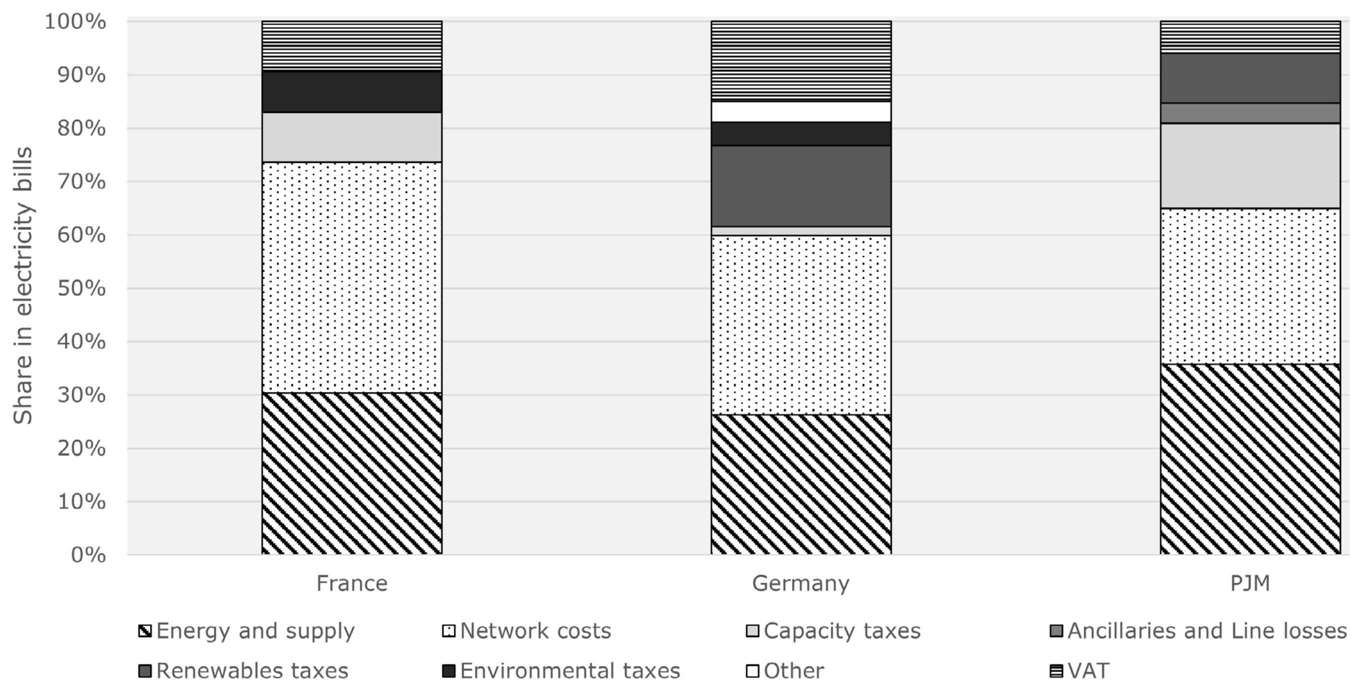
4.1. Principles of price-based DR

The price-based approach increases demand-side elasticity by conveying temporal market information to end-users. Those schemes were already discussed in the mid-20th, notably by Houthakker (1951), discussing retail electricity tariffs in place. Since then, it has been subject to almost no change from a customer perspective, set aside price fluctuations. Most cost structures and related tariff designs have been studied extensively in the literature, notably the interests of Time-Of-Use (ToU) pricing and peak-load network tariffs. The principle of such tariff is to distinguish power prices given the hour, day, or season to make end-users arbitrate between times of high and low prices known in advance. The "Clow Differential", one of the first trials of seasonal tariff set in the United Kingdom during the second world war, proved to be a failure and was soon abandoned after one year (Houthakker, 1951). Houthakker argues that the *seasonal* approach failed to reduce *hourly* peak demand and that such change would imply a lag in adoption that did not materialise given the short timeframe of the trial. One of the learnings from the experiment is that the price-based approach should be stable and active long enough to see its effect and effectively change consumer behaviour. In addition, if reducing peak load is the objective, conveying a price signal targeting single hours would be more efficient than conveying a seasonal price difference. Conversely, seasonal price distinction could incentivise long-term energy savings, favouring investments in building insulation or efficient heat appliances.

Following Bonbright's (1961) principles of public utility rate-making, the current tariff structures should fulfil multiple requirements, mainly recovering costs, ensuring simplicity and comprehensibility, fostering fairness in customer charging, and incentivising reasonable energy use. Easy-to-understand energy-based tariffs, consisting of a single price per kWh, have been a widespread approach, despite the poor cost-reflectivity and incentives such tariff schemes provide (Burger,2019). In an effort to mitigate peak loads, alternative tariff schemes with on-peak/off-peak differentiations have emerged. However, these schemes have not yet addressed the challenge of accommodating the variability of RES. This raises questions about their suitability for an electricity market that is influenced by substantial price deviations based on weather conditions rather than consumption habits. Moreover, consumers still face a significant information asymmetry when consuming electricity, impeding them from becoming more price-elastic. Indeed, the long-standing bi-annual or monthly meter reading illustrates the operational complexity of accounting for finer temporal resolution. However, such consideration has changed with the advent of smart metering infrastructures (Rábago, 2018). A variety of dynamics tariffs have been progressively available to consumers with different objectives, ranging from Time-Of-Use (ToU), Critical Peak Pricing (CPP), Variable Peak Pricing (VPP), Critical Peak Rebate (CPR or PTR), or the theoretical first best of Real-Time Pricing (RTP). A summary of the distinction between tariffs is treated in the literature (Eid et al., 2016a; Parrish et al., 2019).

Currently, simple two-part or three-part flat tariffs covering energy, capacity, and customer costs have persisted in numerous countries and are still perceived as a fair and accommodating way to collect necessary revenues. The most important components correspond to the energy supply components, reflecting the cost of purchasing and producing electricity. It is calculated considering wholesale power prices, future prices, power purchase agreements, or the nuclear price covered by the ARENH mechanisms in France. The second most significant share of the bills covers the network costs relative to the transportation and distribution grid investments. Finally, an association of taxes and levies usually represents another third of the bill. It consists of a capacity tax used to compensate for the missing money from peaking power plants, levies for fostering the development of RES, and taxes. The repartition is similar in the three markets studied, illustrated in Figure 4, with the difference that Germany has around 15% of the bill supporting the Energiewende and the sustained pace of deployment of renewables.

Figure 4 - Typical components of retail electricity bills in France, Germany and PJM (Eurostat, 2023; Price et al., 2021)



One crucial point to consider when transitioning to dynamic pricing for part of the component is its potential impact on the stability of the electric bill. However, it is worth noting that since the energy component of the bill typically only accounts for 30% of the total bill, the overall impact of dynamic pricing on bill stability may be limited. Although it reduces customer bill volatility, it also weakens the economic incentive for consumers to adjust their power consumption. For illustration, even a 20% variation in energy prices will likely result in a mere 6% impact on the total bill, which may not be substantial enough to trigger a significant consumer demand response. This effect is one of the first shortfalls to be considered when assessing price-based DR. In France, differences between on-peak and off-peak tariffs are regulated (CRE, 2022) to maximise price-based incentives.

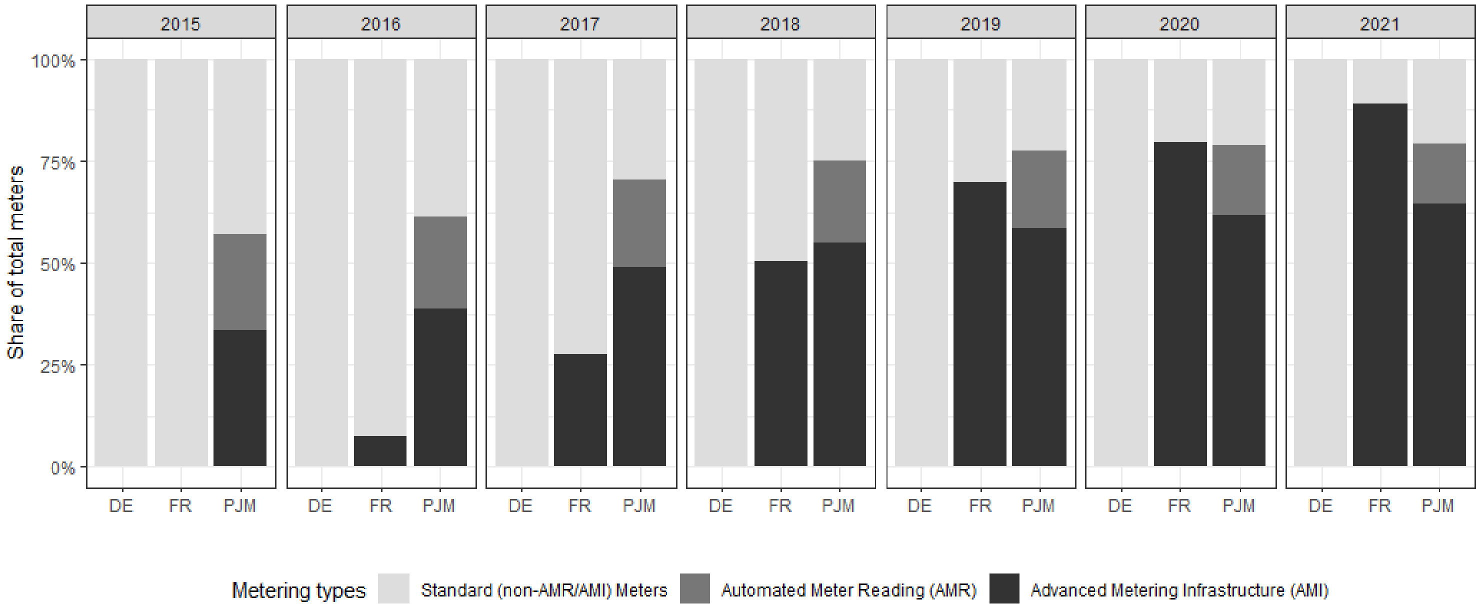
4.2. Overview of price-based schemes adoption

Although a new infrastructure is being developed, allowing for broader adoption of price-based DR, it should be underlined that similar programs have been deployed without advanced metering infrastructure (AMI) or Automated Meter Reading (AMR). On-peak/off-peak tariff schemes were used before smart meters were deployed. More time-differentiated schemes have emerged, notably in France, with a Tempo tariff that combines time-of-use and critical peak pricing features, distinguishing between six time periods (Crossley, 2007). Recent AMIs have the significant advantage of avoiding physical intervention to change pricing schemes and more freedom for setting the year partitioning, reducing the operational cost of the metering operator (usually the DSO or the retailer). Thanks to the enhanced connectivity of appliances, new opportunities are given for energy savings through digitalisation. Therefore, AMI rollout has been imposed in numerous countries.

In the US, the Energy Policy Act of 2005 (U.S. Congress, 2005) can be traced back as the first step, stating that "it is the policy of the United States that time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit by responding to them, shall be encouraged, the deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary service markets shall be eliminated.". This view is shared with the European Parliament (2019), stating that: "Member States shall ensure that the national regulatory framework enables suppliers to offer dynamic electricity price contracts. Member States shall ensure that final customers with a smart meter installed can request to conclude a dynamic electricity price contract with at least one supplier and with every supplier with more than 200 000 final customers.”. It is mentioned that the European Union (EU) aimed to replace at least 80% of electricity meters with smart meters by 2020, wherever it is cost-effective, with multiple Cost-Benefits Analyses performed to assess performance (Commission, 2014). Dynamic pricing is then transposed into national law, such as the German one, where energy savings are enforced, partly thanks to time-of-use tariffs (Dütschke and Paetz, 2013; EnGW, 2021). The French power regulators initially defined dynamic offers as schemes providing hourly incentives, indexed for at least 50% on the day-ahead or intraday wholesale markets. Following the power crisis, the decision was recently revised to include tariffs based on more straightforward peak pricing signals to increase short-term adoption (CRE, 2022).

As smart metering infrastructure has been enforced only recently, the deployment is still ongoing in the geographies considered, as illustrated in Figure 5. In the US, the Energy Information Administration (EIA) provides an annual electric power industry report (2022) consisting of a survey of all electric utilities. It provides notably a vision of the number of existing DR programs, the dynamic tariff offered and the level of deployment of advanced metering infrastructure. In recent years, AMI has been deployed on over 75% of metered points in France and PJM. Interestingly, Germany has not performed a widespread smart meter deployment in the 2010s and did not consider it an essential tool to support vRES integration until recently. Indeed, the Cost-Benefits Analyse concludes that a wide rollout was not cost-effective and decided to enforce it only for customers above 6000 kWh/year (IEA, 2020). The threshold is, therefore, above the average household consumption, averaging 3500 kWh/year (Table 1). Kuzemko (2017) discusses the German transition strategy and underlines that those potentials are mainly untapped as smart metering has not been perceived as a critical resource for providing flexibility. It could partly be explained by the ambitious energy efficiency measures that aim to reduce overall consumption and peak load. In addition, Germany can rely on its flexible thermal fleet, based on coal, lignite, and gas, which remains a significant flexibility provider until the phase-out of fossil fuels becomes fully effective. In contrast, France relies predominantly on its nuclear fleet, which should limit significant hourly fluctuations. In addition, the importance of the energy-intensive industries in the German economy represents a significant flexibility potential, justifying the strong focus on heavy consumers. Following the 2021-2023 energy crisis, a new law has been proposed, committing Germany to deploy smart meters more rapidly across all segments from 2025 onward, although it will remain optional for small consumers (BSI, 2022).

Figure 5 - Metering infrastructure in considered electricity markets (BSI, 2022; EIA, 2022; Enedis, 2023)

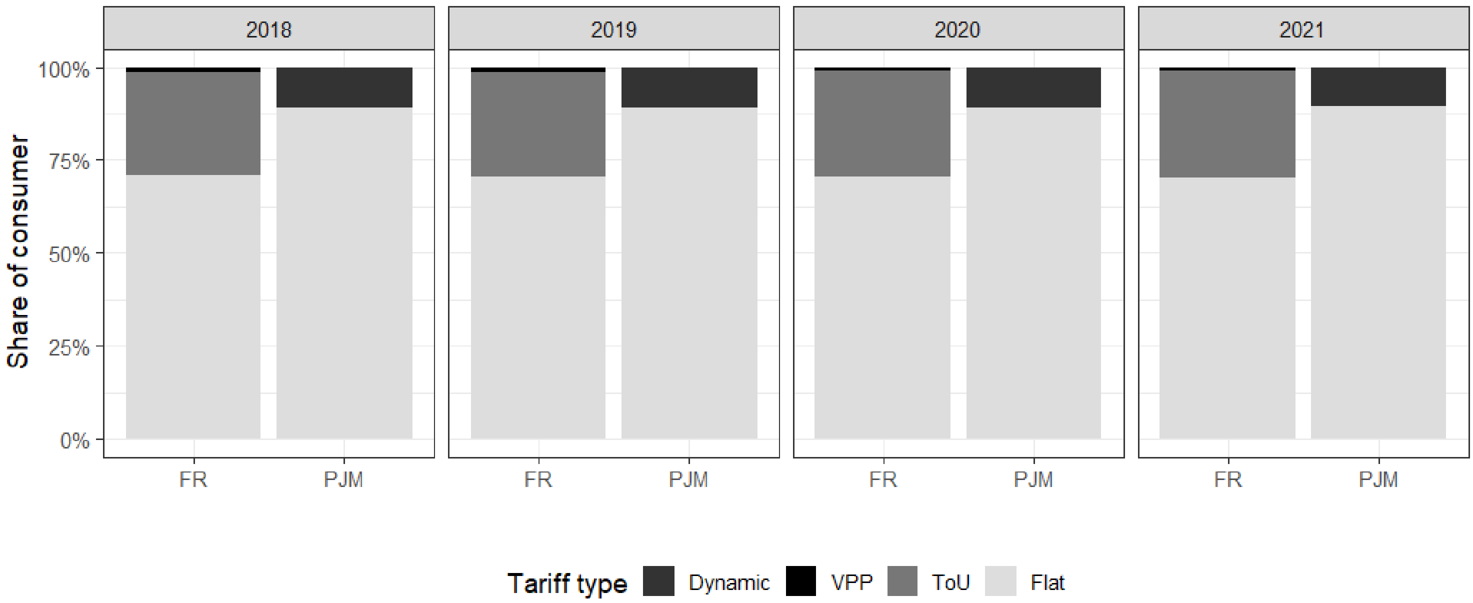


The deployment of smart meters has often been justified based on anticipated efficiency gains, prompting policies aimed at increasing their numbers, albeit with varying degrees of scale across countries. However, the effectiveness of such policies in enrolling customers in dynamic pricing programs is questionable. Despite the deployment of smart metering infrastructure, the adoption rate of dynamic pricing has not followed in most European countries, with adoption rates below 25% since 2015. Even then, the adoption mainly consisted of on-peak/off-peak dynamic schemes when enforced (ACER, 2015). Figure 6 illustrates the results for France and PJM. Although France had a significant share of customers enrolled in time-of-use pricing (more than 25%), only a minority were enrolled in variable peak pricing tariffs, which offered hourly or seasonal price differentiation. The number of meter points enrolled in time-of-use tariffs has progressed over the last three years with a growth rate of 1.5% to 2.4%, slightly higher than the flat tariff (+0.5%), which still represents almost 80% of the residential market share. The number of clients under tariffs with peak pricing components has gradually decreased, indicating a lack of immediate acceptance, information, or financial interest in switching to more dynamic tariffs in France despite the smart metering infrastructure.

Another recent initiative that deserves mention in the case of France is the voluntary-based program “écoWatt” (RTE, 2021b). This pilot program has been deployed to decrease peak load and was expanded during the power crisis, with no monetary incentive but relying instead on increasing public awareness of the importance of energy savings measures. Similar concepts could be used for dynamic tariffs to increase demand response. Indeed, digital solutions can increase consumer awareness, and the 'écoWatt" program, depicted as the "weather of electricity", is based on voluntary load shifting with no financial retributions.

On the other hand, in Germany, the situation differs, with almost no dynamic pricing in place due to a lack of familiarity among customers and the unavailability of smart metering infrastructure (Agora Energiewende, 2023). As a result, no data is provided at the country level, preventing the assessment of trends and savings enabled by dynamic tariffs. Meanwhile, in the United States, the number of customers enrolled in dynamic pricing programs has remained stable in PJM, hovering around 10% of total consumers despite the annual growth rate of advanced metering infrastructure (AMI).

Figure 6 - Share of consumers under dynamic tariff in France and PJM (EIA, 2022; Enedis, 2023)



4.3. Price-based scheme literature review

Ceteris paribus, price-reactive consumers lead to a decrease in average power prices. This principle should apply similarly to real-time pricing schemes and any type of dynamic tariffs. Those are often deemed second-best alternatives due to their lower reflectiveness of real-time electricity market conditions given their fixed features (such as on-peak/off-peak hours, weekends, and winter/summer periods). Consequently, the provision of balancing and contingency services is unlikely due to the absence of sub-hourly granularity in the economic incentives provided. In addition, the cognitive burden imposed on consumers with shorter-term price fluctuations reduces the adoption rate of such schemes (Layer et al., 2017).

Those considerations are reflected in the way electricity markets have integrated price-based DR. In France and PJM, reactive consumers in the retailer's portfolio are reducing the utility's capacity payments linked to long-term capacity adequacy[6]. The current market approach of price-based DR is aligned with the evidence in the literature insofar as the focus is on peak-shaving capabilities[7]. Indeed, significant peak load reductions are demonstrated at the system level by Faruqui (2016) for all dynamic tariffs assessed (ToU, VPP, PTR, and CPP), always reaching more than 10% peak savings. Parrish et al. (2019) systematically review peak reduction potential depending on the dynamic tariff considered. Likewise, their results underlined that a 10% load reduction is reached for most tariffs. More generally, a consensus emerged on the benefits of moving away from flat retail tariffs towards time-differencing schemes. Borenstein (2005a), studying RTP in the US, found that ToU captures 20% of the potential gains of RTP, which implementation is attractive even when considering customers with low price elasticity. He also points out that the benefits of including small customers might not be justified, a conclusion shared with the German Cost-Benefit analysis concerning smart meter rollout (dena, 2014). From the consumer's side, Dupont et al. (2011) found a short-term welfare increase for customers' bills when adopting dynamic prices, with an average of 2% reduction in the electricity bill. Only one reference on dynamic pricing in France was found, where Aubin et al. (1995) propose an analysis of the French Tempo tariff, consisting of a six-price tariff, combing peak days and on-peak/off-peak hours. The results demonstrate the price elasticity of consumers and their welfare gain under this price scheme, although the longer-term effects were not assessed. An important consideration for the success of the price-based experiment lies in the estimated price elasticity of consumers. Faruqui and Malko (1983) provide empirical evidence from twelve programs. The price elasticity is limited, from null to -0.4, and little evidence is found concerning load shifting from on-peak to off-peak, implying a low cross-elasticity in time. More recently, Lijesen (2007) has provided an overview of flexibility from the demand side. Results indicate a lower elasticity for households than for industries, with overall values ranging from -0.04 to -1.113. In addition, elasticities are susceptible to change, given the season and the time of day. In the case of France, Auray (2018) reports elasticities in winter between -1.45 and -1.85, which slightly increase in summer to -1.61 and -2.08.

Overall, the literature aligns on low price elasticities, with lower short-term price elasticities than long-term elasticities when assessed. Interestingly, no clear geographical effect has been underlined in our review showing a relatively homogenous price-elasticity

6 An example of the related capacity reduction considered in the French capacity market is provided in Appendix A2, Figure A.1
7 The literature review is provided in Appendix A2, Table A.3.

across consumers in the different geographies considered. Overall, the literature underlines that the majority of welfare gains achievable by price-based programs lie in the capacity quadrant, allowing for long-term efficiency gains thanks to reduced peak energy consumption. Consequently, the metric studied in most programs and academic papers refer to the peak load reduction when assessing the efficiency of price-based approaches (Allcott, 2011; Faruqui and Malko, 1983). However, the grid quadrant also appears relevant insofar that peak-shaving results in lower grid investment needs, mainly driven by coincident power consumption (Allcott, 2012). However, dynamic tariffs usually concern the energy procurement part of the electricity bills, with no consideration for the temporal dimension of network cost incurred. Therefore, additional savings by alleviating grid congestion are unlikely achievable with price-based DR without Locational Marginal Pricing (LMP). Likewise, voltage or frequency regulation is hampered by the geographical granularity of incentives provided. Finally, no savings are achievable in balancing markets, as price signals of current tariffs are provided hourly at most.

From a system perspective, price-based DR easily fits into the current market structure, consistent with the current top-down market design approach: consumers react to price signals but do not require to submit bids in electricity markets. The drawback lies in the absence of short notice reaction and the limited financial streams involved in the absence of value stacking. Consequently, price-based incentives are mostly valued in the existing electricity markets for their capacity value, resulting in long-term savings by reducing the need for peaking units or grid reinforcement linked to the coincident peak load. In addition, price-based programmes are also valued in the energy quadrant, as dynamic tariffs convey price signals aligned with the day-ahead market outcome. Finally, from a consumer perspective, dynamic tariffs enable them to improve their welfare by reducing consumption in on-peak hours, thereby reducing the average price of the electricity purchased.

4.4. Remaining barriers to price-based DR programs

Despite the welfare gain achievable with price-based DR, some barriers and shortfalls are underlined in the literature. While the existing market programs have proved their ability to trigger a demand response, they have also underlined a significant heterogeneity of consumer responses (Gyamfi et al., 2013). As a result, their potential elasticity to price-based incentives differs widely, both in time and in extent. More recently, the Low Carbon London pilot (J. Schofield, R. Carmichael, S. Tindemans, M. Woolf, M. Bilton, G. Strbac, 2014) shows that demand response differs significantly between households, with the top 25% reacting three times more than the average households. Those empirical findings underline mainly two drawbacks of price-based schemes.

First, in the short term, the presence of reactive consumer increases the unpredictability of the demand in a context where solar and wind conditions are already variable. Even if demand response becomes more stable through the aggregation of consumers, it is counterintuitive to rely on the uncertain behaviour of end-users to provide the necessary flexibility to the system. Then, in the long term, the reliance on an expectation of consumers' peak shaving capabilities to avoid investments should be compared to the firm capacities that peak generators offer. Conversely, Germany's focus on energy efficiency is a viable alternative to price-based DR if the objective is primarily to reduce customer peak consumption. Another barrier faced by price-based DR relates to the achievable cost-efficiency of its deployment. The analysis of the Chicago Energy-Smart Pricing Plan pilot (Alcott, 2011) indicates that DR benefits do not appear to recover the gross costs of advanced metering infrastructure required to observe hourly consumption. However, longer-term and diverse scenarios should be considered, as the demand side has alleviated costs incurred in the electricity sector during Europe's 2021-2023 energy crisis. In addition, this shortfall could be overcome if consumers' price elasticity increases over time. For instance, the use of information technology increases efficiency, as highlighted by Jessoe and Rapson (2014). Informed households are more responsive to temporary price increases, and transaction costs are lower for consumers. Eventually, the social acceptance of increasing volatility in the electricity bill resulting from increased exposure to dynamic prices hamper the adoption of price-based DR. This caveat has been underlined by Borenstein (2007), who demonstrates, however, that simple hedging through forward contracts could avoid 80% of the bill volatility. Nonetheless, he underlines one of the significant shortfalls of price-based DR: if consumers are hedged against peak spikes, little incentives are provided to modulate demand. On the other hand, stable and predictable electricity bills are deemed required to shield consumers, a priority highlighted by the 2021-2023 energy crisis. The adequate balance between those two opposite effects still needs to be overcome.

Another shortfall arises when consumers are expected to purchase their baseline power consumption, notably in the case of PTR pricing. Indeed, information asymmetry might lead consumers to inflate the baseline and benefit from a more significant rebate (Astier and Léautier, 2021). In addition, the rebound effect should also be considered when assessing the benefits of such tariff schemes (Turner, 2013). The response to dynamic prices can create additional, unexpected consumption peaks if consumers uniformly shift their load. Allcott (2011) also demonstrates, building on a PJM program, that RTP might increase and create peak load episodes even though its implementation would still increase welfare by delaying investment. Eventually, the stability of day-head price patterns, allowing for stable and predictable demand reduction in existing programs (Wolak, 2011), will not necessarily hold as renewables energy generation expands. As the stability of rates in time is essential, as underlined by Bonbright (1961), assessing tariff designs under a broader timeframe and market conditions is paramount to ensure that the current tariff structure is "future-proof".

Finally, the existing literature underlines the need to consider not only the incentives provided by the energy component of the electricity bill but also that of moving towards more cost-reflective network tariffs. A privileged option is to charge the network component on a capacity basis rather than an energy basis and to remove the net-metering scheme used for PV owners. Indeed, the literature underlines the existing cross-subsidies between active and passive consumers thanks to the net-metering schemes enforced for private-PV installations and the designed network tariffs (Burger, 2019; Neuteleers et al., 2017; Schittekatte et al., 2018). However, moving away from net metering would *de facto* reduce the savings made and potentially slow down the development of household PV installation. Such considerations are critical for DSOs, as many end-users are investing in batteries and rooftop PV. As a result, utilities might face what is commonly referred to as a "death spiral" (Athawale and Felder, 2022). Other things equal, the lower the consumption, the lower the DSO revenue that still faces similar costs linked to grid maintenance and development. If the operator enforces a price increase to recover the cost, the incentives for installing self-generation will increase, further decreasing the collected revenue to recover network costs. This phenomenon, long expected, might be, however, overestimated according to the literature (Castaneda et al., 2017; Costello, 2014; Hledik, 2018). As underlined by Schreiber (2015), it is essential to anticipate the power and energy tariff components interaction, which might create unforeseeable demand peaks, hindering price and grid stability if not carefully designed.

5. Incentive-based schemes market integration

5.1. Principles of incentive-based DR

As underlined in section 2.2, the fundamental distinction between incentive-based and price-based approaches lies in the existence for the former of an explicit contract or bid offering between the flexibility provider (the consumer or a mandated third party) and the flexibility purchaser (market participants or grid operator). This paradigm effectively reduces the dependence on the voluntary choices of consumers to adjust their energy consumption patterns based on price signals (Khajavi et al., 2011). While a widely adopted market architecture for this arrangement has yet to materialise, several electricity market segments have gradually been opened to incentive-based DR, and multiple programs have been conceived. In practice, third-party entities such as aggregators in Europe and Curtailment Service Providers (CSP) in the US handle the bidding process and aggregate end-user load to attain a critical size of their flexibility pool, particularly relevant within the residential segment. Direct load control possibilities, where third parties can interrupt part of the consumer's electricity demand, or tariff-based control systems deployed on appliances, are already implemented in Europe and the US. While these approaches are being considered for recent appliances, such as EVs (RTE, 2019b), the first trials date back to 2007 in liberalised electricity markets.

After examining the status of incentive-based programs in PJM, France, and Germany, the main insights gained from the past decade's initiatives are discussed in the following section. Since third-party entities oversee decision-making and operations, such mechanisms are expected to be less uncertain than price-based programs in terms of reliability and are able to participate in all quadrants of the framework of analysis. An overview of each market where the demand side can participate is provided in Table 2 and will be discussed in each geography. A more comprehensive of specifications of each market is provided in Appendix A1, Table A.4 and Table A. 5.

Table 2 - Summary comparison of existing DR incentive-based programs enrollments

	France	PJM (US)	Germany
Types of DR programs offered	Adequacy (CM, AOE), Contingency (IL) Wholesale (NEBEF), Balancing (FCR, aFRR, mFRR, RR)[8]	Adequacy (CP), Wholesale (Economic, PRD), Ancillary Services (Economic)	Contingency (AbLav), Balancing (FCR, aFRR, mFRR, RR)[8]
Mechanisms	Call for tender, Market offer	Contract, Market offer	Call for tender
Minimum bidding size	1 MW	100 kW	5 MW
Registered capacity	3.9 GW	8.3 GW	894 MW

5.2. Incentive-based program in France

In France, explicit market integration of demand-side resources has been progressively implemented since the end of the 2010s. The existing program targets both the industrial and the residential flexibility potential (Eid et al., 2015) and involves aggregators within the residential customers to reach a critical size. Twenty-one actors have been certified to date and can participate in electricity markets like any power generation plant (RTE, 2023a). All quadrants of the analysis framework (Figure 2) have gradually opened to demand response, including the day-ahead market in 2014. Such progressive openness made France the first European country to open all national electricity markets to end-user, including those at the distribution grid level.

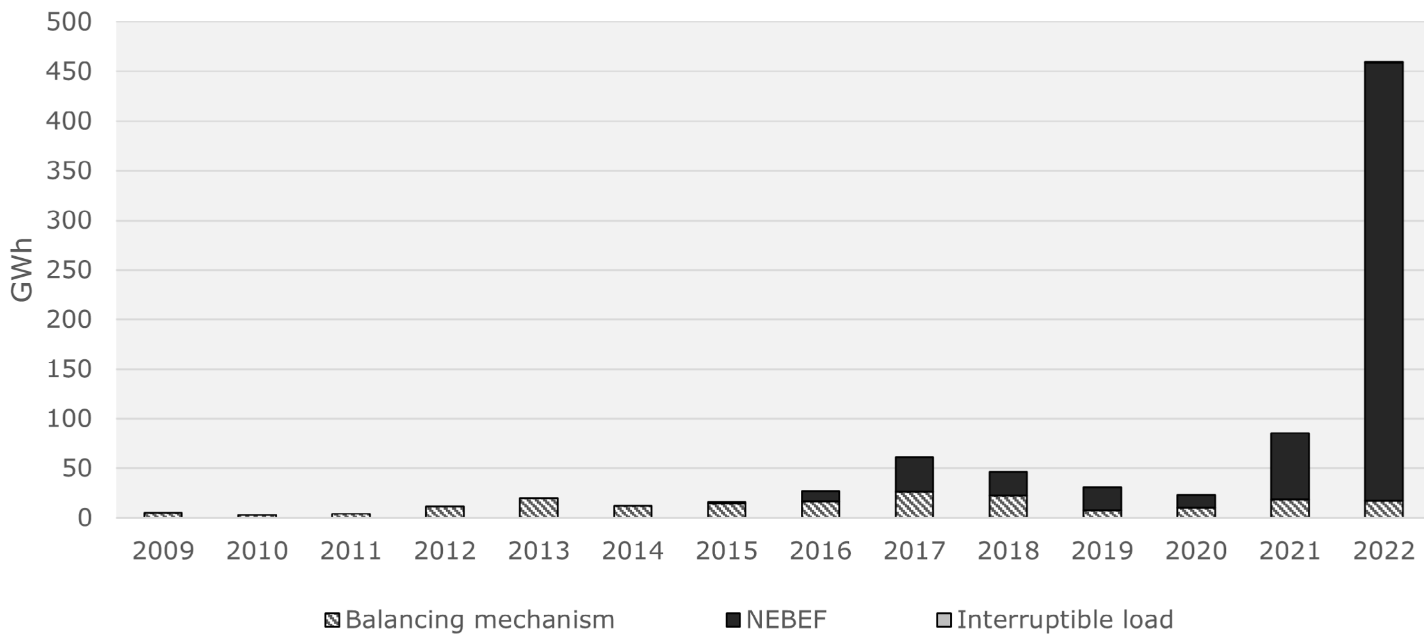
Incentive-based DR programs are principally remunerated through capacity mechanisms (CM) associated with mandatory balancing or wholesale market[9] participation for a specified number of days. More specifically, a call for tender for "green" demand response capacity (AOE) has been initiated in France, focusing on DR capacity provision. This programme has gradually gained traction (Appendix A2, Figure A.2) and provides a price premium to DR capacities. As a result, the remuneration is 70% higher than the price granted to generators, with the price ceiling at 60000 EUR/MWh/y being reached in the last years (RTE, 2020) (Appendix A2, Figure A.3). Consequently, demand response

8 Frequency Containment Reserve (FCR), automatic/manual Frequency Restoration Reserve (aFRR/mFRR), Replacement Reserve (RR). While balancing market are open to DR participation in France and Germany, no targetted DR program or support are implemented to date.
9 Through participation in NEBEF hereafter described

capacities have continuously increased its shares in the capacity market, reaching 2.7 GW of certified capacity in 2023 and representing 3% of the overall volume certified.

However, their activation in the energy markets remains scarce and volatile, as illustrated for balancing (FCR, aFRR, mFRR, RR), day-ahead energy markets (NEBEF) and interruptible load (IL) in Figure 7. The only exception was during the 2021-2023 energy crisis, where DR contributed more significantly to the supply-demand equilibrium. More generally, before the inception of the NEBEF mechanisms, distributed flexibility from the demand side was used only punctually, acting as a peaking unit for balancing purposes and emergencies rather than providing daily load shifting. Historically, the focus on capacity remuneration stems from aggregators being new entrants in the electricity markets, facing high entry costs to deploy direct load control on distributed resources, especially for those targeting residential customers. To deploy a viable business model, stable sources of revenue are required to recover costs, contrasting with the scarce activation of demand-side resources on the different energy markets in place. As a result, capacity remuneration associated with the balancing and contingency programs has been favoured at the expense of the energy-only paradigm, unable to provide sufficient revenue streams and actors.

Figure 7 - Historical French incentive-based demand-side participation in Energy, Balancing and contingency quadrant (RTE, 2023a)



Consequently, aggregators have increased their participation in the wholesale energy market recently. Notably, the unprecedented marginal cost of conventional units during the 2021-2023 energy crisis resulted in the extensive use of DR to ensure the balance between supply and demand in the wholesale energy market. Although the capacities enrolled remain low and never exceed 0.45 GW of coincident power, demand-side resources were used 82% of the time in 2022. The energy curtailed was up to 441 GWh in 2022 compared to an average of 13 GWh since the DR program's start. The power crisis demonstrated the potential role of DR, activated not in a situation of scarcity but also as a resource economically dispatched. The NEBEF framework has created a favourable environment for the participation of DR in the day-ahead market. The developed regulatory framework fostered DR in the current electricity market design, for which the financial flows between aggregators and retailers are critical to assess investment profitability. Under the current framework, aggregators compensate the consumer's retailer for the curtailed demand, accounting for the cost incurred by the open position created in the retailer's energy procurement (Burger et al., 2017). The financial compensation provided to the retailer is based on regulated prices determined by the TSO, which distinguishes between on-peak and off-peak prices. Given the sustained high prices in 2022, the interest to curtail demand has increased significantly as the spread between the day-ahead price and the compensation to the retailer increased. However, relying on regulated prices impacts the viability of the aggregator's revenue, which profitability depends upon the price level decided by the TSO and the frequency of its revision. In addition, the design has also been criticised by aggregators, which deemed that the consumer should be free to manage its load consumption, including shifting it at times of low prices thanks to third parties, especially as no prior baseline consumption has been contracted with the retailer.

Nonetheless, the explicit intervention of a third party shifts the responsibilities of imbalances and increases the balancing costs to the retailer. From a consumer perspective, no payments are received from the aggregators, and potential savings stem from lowered electricity bills resulting from lower electricity consumption. Therefore, the established market design should gauge costs incurred by retailers with the expected benefits allowed by integrating the demand in the wholesale market and ensure consumers are not charged additional costs. Given the multiplicity of actors involved and the volumes exchanged, incentive-based DR programs appear less straightforward in wholesale energy markets than in balancing markets or for dealing with contingency episodes.

Regarding the balancing mechanisms (FCR, aFRR, mFRR, RR), the TSO points out that demand response has mostly a capacity value, which resulted in limited activations in recent years. Indeed, the balancing offers have scarcely reached the price level of the submitted DR bids. Most of the balancing was performed by dispatchable capacities, required to participate in rapid and complementary reserve (RR), and by power exchanges with neighbouring countries (for around 40%). Nonetheless, since the opening of electricity markets to the demand side in 2014, industrial consumers have been able to participate in Frequency regulation (FCR) voluntarily and are meeting 14% of the Primary Reserve used for frequency regulation (CRE, 2018). Likewise, industrial actors represented more than 50% of rapid and complementary reserves (RR) in 2017 (CRE, 2018). The volumes activated for those reserves are, however, considerably lower than those exchanged on the wholesale energy market, as the total energy activated reached 120 TWh in 2021. In addition, eligibility to the balancing mechanisms has gradually tightened since offers from behind-the-meter diesel generation are not allowed to participate in demand-side programs since 2019.

Finally, a specific program for contingency measures called the interruptability mechanisms (IL) is also in place to foster DR, but impede industries from participating in the mechanisms mentioned above. Although value stacking is critical to foster demand response, capacities participating in balancing markets are not considered available for contingency measures, notably to avoid multiple counting. Enrolments in the interruptability mechanism provide the system operator with a capacity of 1.2 GW, which should react to signals in less than 5s for a minimum duration of 5min (Appendix A1, Table A.4). This DR program offers a tangible recognition of the value that DR have for the security of the system, reflected in the remuneration provided to the industrial participating in the program, above 70000 EUR/MW/y. This level should reflect the loss incurred by curtailing part of an industrial site. The willingness to curtail (or disutility of curtailment) is more challenging to assess for residential consumption. However, the remuneration lies essentially in the same order of magnitude for aggregators participating in the DR call for tender, despite less stringent performance expectations. It reveals the current utility for the TSO to increase the operating margin in a situation where both the availability of the nuclear fleet in France and the hydropower are subject to uncertainties for the coming years.

Overall, a pre-requisite for all demand-side activation is to ensure sufficient performance, which is currently slightly below the expected reduction and reached 88% efficiency in the last two years. Despite the progressive opening of electricity markets to the demand side, the capacity registered is still well below the 10 GW potential found on average in the literature (Figure 3). This raises the question of the actual costs of demand response and the measures that can best foster it, given the already attractive capacity remuneration provided to DR (Appendix A2, Figure A.3).

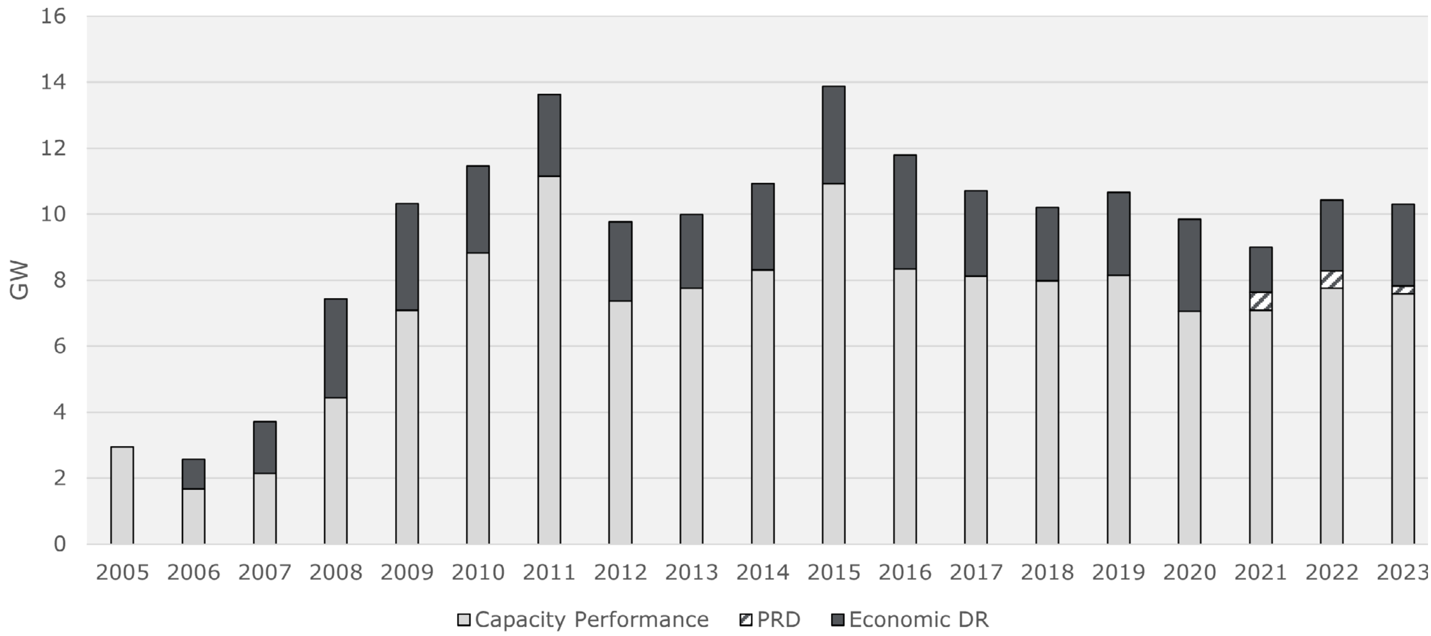
Regarding the objectives pursued by the French incentive-based integration, load shaping, peak shaving, load shifting, and reliability are all targeted, given the integration in the different markets. However, strategic load growth and energy conservation are not addressed by the current incentive-based DR, as consumers could remain unaffected by price spikes. Although the current French programs are already advanced, additional learnings stemming from the comparison with PJM and Germany are described in the following sections.

5.3. Incentive-based program in the PJM electricity market

The PJM market provides a notable example of the evolution of incentive-based schemes since their initial implementation. The demand-side flexibility is handled by Curtailment Service Providers (CSP), responsible for all demand response activities, acting as an intermediary between consumers and market actors or grid operators. While this role can theoretically be fulfilled by an existing Load Serving Entity (LSE) or Balancing Responsible Party (BRP), the current specialisation of CSP has been maintained and is regarded as the most effective mean of harnessing flexibility. CSP are believed to favour innovation and increase competition in the wholesale energy market, while retailers have limited motivations to reduce the power consumption of their consumers.

Historically, all quadrants of the framework of analysis have been opened to demand-side resources in PJM. Each CSP can develop its demand response program, which typically involves automatic communication and direct control of devices such as water heaters, pool pumps, heat pumps, and cooling systems, as well as bill rebates or tailored industrial implementations. Thanks to different programs deployed, the number of CSP has steadily increased over the past five years, with around 80 actors in 2015 to nearly 100 in 2021. While all markets have been opened to demand response, the participation and revenue primarily come from the capacity market program referred to as Capacity Performance (CP) in PJM and participating in the Reliability Pricing Model (RPM). The other two existing DR programs are the Price Responsive Demand (PRD) and the Economic DR program, which will both be further discussed below. Overall, the DR response participation in this capacity market has been stable since 2012, accounting on average for 5% of the total committed capacity, slightly more than the French participation rate. The evolution is displayed in Figure 8, where capacity enrolled represents around 8 GW in the latest years, which is aligned with the potential of 12% of the peak load found in the literature (Figure 2).

Figure 8 - Historical PJM incentive-based demand-side enrolled capacity[10] (McAnany, 2023)



However, incentive-based programs have been subject to regular amendments in the past decade. The number of programs implemented since the inception of these markets stands at nine, with each program being associated with different expectations in terms of capacity performance linked to the number of events, maximum duration, or the period of the year the DR should respond to system operator signals. Those frequent amendments are tightly linked to the RPM development process in recent years, favouring year-long capacity-based options compared to energy-only programs.

The current Capacity Performance design features unlimited events and has been enforced since 2020. The change of programs has not necessarily allowed for fostering more demand-side flexibility and even reduced the pool slightly by requiring yearly availability compared to previous programs that would allow for summer participation only. Regarding the remuneration scheme, the RPM includes a capacity-part payment, fixed per year, depending on each zone's capacity need. The energy-part remuneration depends on the event's lead times, increasing payment from 120min to 30min prior notice. Programs in place have privileged giving certainty to consumers regarding the hours required to respond as well as the maximum duration of the interruption. The time window when consumers react depends on the month to account for a different peaking hour and on the season. Overall, the current distributed flexibility implementation in PJM focuses on load curtailment and long-term capacity adequacy. Therefore, demand

10 Capacity performance entails previous capacity-based program. The expansion between 2005 and 2007 is partly due to utilities from the Midwest joining PJM (Cappers et al., 2010).

response is mainly considered as a peaking unit, available at a high cost, rather than a flexible unit used for balancing purposes that could behave like a short-term battery with load-shifting capacities (Rious et al., 2015). Even if those capacities are referred to as DR, part of the load-shedding potential is provided by behind-the-meter generation units consisting of diesel units. However, this share has decreased recently, pointing out that load reduction and smarter energy management of household appliances have increased during the last three years. From more than 20% in 2014, that share of behind-the-meter generation has decreased, accounting for 14% of load reduction in 2020. The decrease mainly comes from a more restrictive GHG emission cap for demand response (PJM, 2020b). Therefore, HVAC[11] (35% of the demand-side load reduction) and manufacturing (42% of the demand-side load reduction) represent the most important demand-side flexibility contributors

In addition, a hybrid DR program has been developed in PJM, referred to as Price-Responsive Demand (PRD). This program is similar to a price-based DR insofar as consumers face a dynamic retail rate structure. The difference stems from the supervisory control performed by the CSP relative to the dynamic incentives, allowing them to bid in both the energy and the balancing markets and remotely reduce the customer's load (PJM, 2020c). The CSP commits to lower consumption below a pre-determined level when location marginal pricing exceeds a threshold. While no revenues from the market are provided, the capacity requirement is reduced, and the electricity bill is lowered for the consumer, thanks to the lower capacity requirements and energy savings performed. The two actors could have a potential conflict of interest if the retailer does not provide the curtailment services. Indeed, a retailer could reduce the revenue stream of retailers and impact the volume secured as part of the hedging strategy. The capacity registered under PRD hovered around 200 to 500 MW in recent years. However, the high cost associated with demand-side activation lowers the activation opportunity, with a strike price above $1000/MWh. Although the increasing use of IoT could lower the cost of load management, the acceptability of remote control of power consumption compared to the expected price savings will determine the adoption rate of a similar program.

Finally, an Economic DR is also in place in PJM, allowing large consumers to directly submit bids in the wholesale energy market or provide ancillary services. Under this scheme, consumers are remunerated at the LMP for each hour awarded, similar to generators submitting production bids. Contrary to the other schemes, there are no yearly commitments to participate in the program, resulting in variable demand-side participation, between 1 to 3.5 GW depending on the months and year (McAnany, 2023).

11 Heating, ventilation and air-conditioning

However, the revenues for the ancillary services and the energy market have been low compared to the capacity remuneration program. The demand-side reduction in the energy market reached 103 GWh in 2022 and 21 GWh in balancing markets, with performance ranging between 98% to 132%. Contrary to the other incentive-based program studied, bids in Economic DR are flexible and voluntary as no capacity payments are provided.

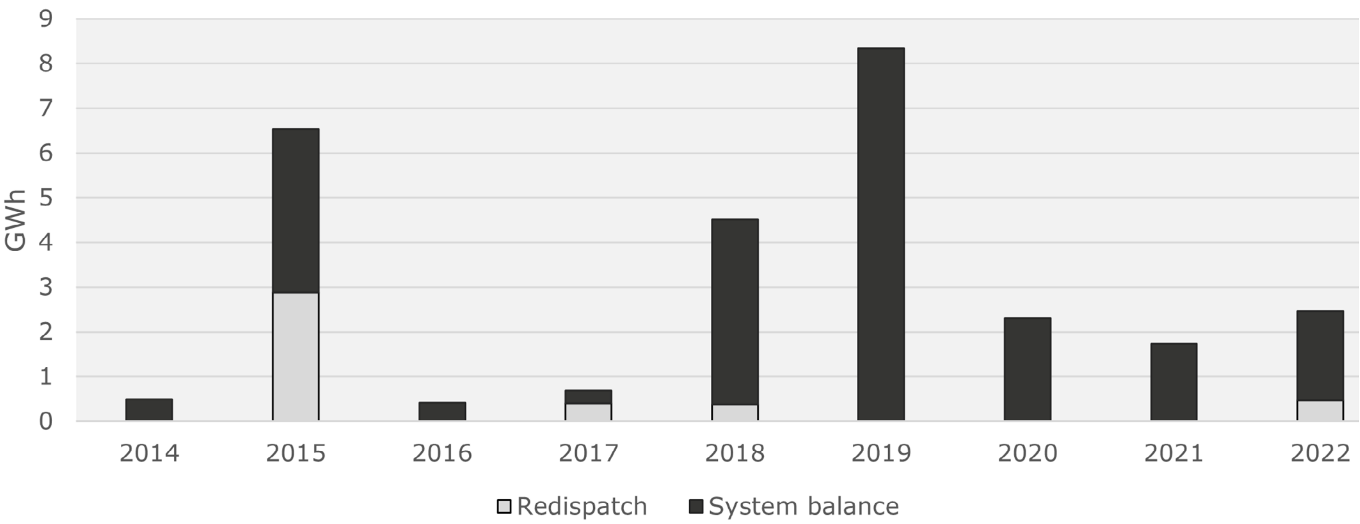
Given their activation price level, the current incentive-based DR programs in place in PJM target discrete events representative of load-shedding capabilities rather than load shaping and load-shifting objectives. Accordingly, the capacity mechanisms provided the predominant revenues of distributed flexibility since the program's implementation (McAnany, 2023). Regarding the performance level of demand response, neither of the two programs achieved a high level of reliability. According to the annual summary (Appendix A2, Figure A.4), the performances have been unpredictable, with test events repeatedly above the expected level and event performance notably lower than expected (PJM, 2020b). Assuming that the adequacy need is sized correctly, it is paramount that demand response activations are reliable. As those capacities are accounted for in the capacity market, part of the investments in peak generation is supposed to be avoided thanks to demand-side capabilities. While significant benefits are expected from peak shaving opportunities, it also implies that capacity should be effectively available during a contingency. In addition, the existence of multiple demand-side programs also raises the question of the paradigm which should be continued and the relationship between price-based programs only, hybrid options such as PRD, and direct load control, which differs in terms of involvement from consumers, remuneration provided and activation signals (market price or operator signals). While the PRD programs achieved higher responses in test events, those are triggered only when locational marginal prices are above a threshold. Although these activations can target both the congestion and the generation scarcity issue in the US, they cannot be transposed directly in the European zonal market.

5.4. Incentive-based program in Germany

The electricity market integration of demand response is much less developed in Germany than in France and PJM. Even if all markets are accessible to the demand side (Valdes et al., 2019), in practice, there are low participation rates because of entry barriers, notably linked to the restrictive reaction time for reserve supply (Bayer, 2015). Spot market demand response participation has therefore been restricted to industries that own their generation sources (Valdes et al., 2019), and demand response in the reserve market accounts for 2-3% of total capacity (Appendix A2, Figure A.5). Consequently, it reaches a lower level of activation compared to France, as depicted in Figure 9. Kuzemko (2017) explains this low penetration rate as a consequence of the strict pre-qualification rules, which are hard to be met by distributed flexibility, even in large industries. Germany's main initiative towards demand integration is the Ordinance on Interruptible Load Agreements (AbLav), settled in 2012. It allows the interruptible load to participate in German balancing mechanisms, providing secondary and tertiary reserves. As of 2020, twenty agreements have been found for 2.5 GW, with 0.8 GW under the immediately interruptible loads (Tennet et al., 2020). Nonetheless, the ordinance expired on July 1, 2022, and has not been replaced to date. The TSOs were able to use the responsive loads to perform frequency regulation and resolve grid congestion. Given the focus of demand response on balancing markets, no effect stemming from the energy crisis has been identified in Germany, contrasting with France. This is directly linked to the lower participation rate and the absence of integration to wholesale energy markets that benefitted aggregators in France. Nonetheless, because of the initially low participation rates, the condition has been relaxed on the voltage levels of consumers participating, lowered to medium voltage levels. Similarly, a revision has been performed to lower the minimum bid size of load curtailment from 50 MW to 5 MW.

As Koliou (2014) explains, the current design has not seen a rise in load participation or aggregation in Germany, with still very little demand-side participation today. Instead, the focus of policies in place has been directed to energy efficiency and virtual power plant that pools distributed generation. Such design allows aggregating multiple renewables and grid-connected batteries to bid on the markets but does not rely on demand-side resources. As a result, demand responses have not been considered a major element of the energy transition, even if DR programs could have reinforced the incentives to save energy.

Figure 9 - Historical German AbLav activation (50Hertz et al., 2019)



5.5. Remaining barriers to incentive-based DR programs

While all electricity markets have progressively been opened to demand-side participation in most geographies studied, the value of demand response has been mostly confined to its capacity and contingency value, corresponding to the peak shaving objective. However, France demonstrated that demand response could be activated on a daily basis, underlining its ability to act as an effective load-shaping instrument during the recent energy crisis. Nonetheless, several barriers are still faced by incentive-based DR programs. Those have been identified in each country and consist of (i) a significant strike price required to foster DR, (ii) unstable DR specifications, and (iii) unsettled ownership of the curtailed energy.

Second, the strike price of DR is significant in all markets, with its deployment in France relying upon specific calls for tenders which provide a significant premium compared to conventional generation capacity. Indeed, the order of magnitude between French capacity remuneration differs significantly from the one provided in PJM and Germany. Although this explains the recent take-off in France's capacities, it also results in potential non-competitive capacity market outcomes, as the demand side does not compete in the same market as power generation and has systematically reached the price ceiling in recent years.

Given the cost incurred and the low participation rate, the competitiveness of demand response relying on direct load control to provide peak-shaving capacities is questionable, notably compared to other flexibility options (batteries, peak capacity). In addition, there are limited incentives for consumers to engage with aggregators as benefits are not directly accessible to them apart from consumption savings. In addition, other barriers, such as transaction costs, might still represent a major barrier to incentive-based DR. More importantly, the level of reliability has still to be demonstrated to justify the capacity payments in place and to ensure long-term adequacy, as neither the programs in France nor those in the US have achieved stable performance in load reduction committed.

Looking at the different market designs implemented in France and Germany, significant discrepancies exist in DR market integration, partly due to the different stages of infrastructure deployments. Insofar as the European Commission's ambition progress towards the integrated European electricity market, and while balancing and wholesale energy markets have been harmonised, the adequacy (capacity) and part of the balancing markets still need to be amended to ensure full market coupling, including the accomplishment of a level-playing field for all relevant actors with harmonised pricing rules. Currently, neither the bid specification nor the level of performance expected by demand response is similar in France and Germany (Appendix A1, Table A.4). For example, the minimum biz size in Germany is fixed at 5MW, while France enabled the bid to reach 1 MW, and sets different mandatory duration within the product specifications. Similarly, neither the frequency of calls for tender nor the required availability are comparable. While each country has a different set of appliances and interests in demand response, market participants in a given geography have consequences for neighbouring countries. Indeed, as the wholesale electricity market reaches a higher level of interconnection and price convergence, the insufficient capacity margin in a given country, or intrinsic lack of flexibility of a given generation mix, would also impact interconnected countries.

Third, comparing the French market design with the one implemented in PJM, similarities are underlined in the adequacy quadrant, focusing on providing capacity and energy remuneration for being available in case of contingency or balancing requirements (Rious et al., 2015). Given the lack of locational marginal pricing, the existing DR program in PJM would not be perfectly adapted to the European context. However, France's current wholesale market design has not perfectly settled the question of the ownership of the energy curtailed. Indeed, the retailer is expected to hedge the power consumption of the consumer, bearing the load-shape risk. When the retailer acts as a curtailment service provider, arbitrage between delivering the energy purchased and curtailing the demand to sell the flexibility on energy or balancing markets is feasible. In the case where a third-parties is involved, inefficiencies and gaming opportunities are introduced, as they would be granted the right to sell energy consumption they do not own (Chao, 2011; Clastres and Geoffron, 2020). In order to overcome those inefficiencies, the French mechanisms settled on a second-best option to foster DR programs, consisting of transferring the ownership from the retailer to the aggregator by a financial compensation exchanged at a regulated price, granting him the ability to bid the flexibility in electricity markets. Although those situations have been envisaged in the literature, none of the current market designs studied follow the first-best option consisting of "buy-the-baseline" schemes. Under this paradigm, consumer would procure the electricity to the retailer (the baseline) before selling it in wholesale energy markets or to aggregators in case when the power prices exceed the agreed baseline price, and that the consumer is willing to be curtailed. While engaging in two-sided contractual costumer baseline is deemed more efficient, its implementation is also unpractical and subject to consumer acceptance. As a result, the baseline allowing to estimate of the realised load reduction is administratively determined in France and PJM, with several methodologies considered based on representative historical days or neighbouring hours (Lee, 2019).

Eventually, the current integration has underlined the technical feasibility and effectiveness of incentive-based DR programs, notably during the energy crisis in France. Moreover, further electrification efforts aligned with Europe's net-zero carbon emission target might foster future demand response deployment if ease of implementation is considered early in the deployment phase, notably for EV. More generally, none of the current incentive-based approaches developed here requires a profound change of the current market design since settlements are primarily handled through third parties in existing markets. The dispatch remains centralised, and arbitration between markets is performed by third parties, with the TSO able to access the flexibility option for balancing purposes. One of the limitations in the current European market design relates to the fact that local and short-term constraints DSO faces are not explicit, although grid congestion is part of the balancing and contingency mechanisms.

6. Alternative market designs in place: the case of local flexibility markets based schemes market integration

Contrary to European electricity markets, PJM relies on Locational Marginal Prices (LMP) that give each node power prices based on congestion level and supply and demand balance. To foster the development of flexibility at a local level, European TSOs and DSOs have encouraged several pilots of local flexibility markets. Creating local pools of actors would address the lack of grid management flexibility, which is not the focus of current price-based and incentive-based DR programs developed in Europe, as discussed previously. Increasing flexibility is highly relevant as the local grid must accommodate more vRES and EVs in the following decades. Indeed, although their deployment might have a limited impact on the *zonal* coincident peak load, it will translate into a significant *local* increase in peak load (Putrus et al., 2009; Verzijlbergh et al., 2014). In addition, as Vicente-Pastor et al. (2019) indicate, local flexibility activations could be required on the distribution grid level if TSO flexibility activation creates congestion on the distribution grid. Therefore, a recent development in the electricity market consists of enabling local distributed flexibility capabilities (Ramos et al., 2016). Such an approach leads to a broader discussion about the roles of the different actors in the future market design and implies changing the current bid structure[12] to allow more information to flow between DSO, TSO, consumers, retailers, and aggregators. The main advantage of the local flexibility market is the addition of a geographical dimension to the zonal pricing paradigm without requiring the implementation of LMP. Additional price incentives could be conveyed in the local market, where DR flexibility has been deemed required. The most significant projects are part of the Horizon 2020 initiative from the EU: Smartnet evaluates different market designs (Migliavacca, 2019), while Interflex focuses more on DSO and grid relief (Interflex, 2019). Enera is part of the German SINTEG initiative (Enera, 2020) and plans to assess how digital technologies benefit the electricity grid, markets, and actors. A consensus from the pilot project is that active congestion management should be based on market-based mechanisms.

12 The case of Local Energy markets will not be discussed (P2P trading, Energy community, Virtual Power plant among others)

Current research focuses on the market design that would enable the activation of local and short-term flexibility for the benefit of one actor, DSO, TSO, or BRP, without creating externalities to the others. To achieve this, Vicente-Pastor et al. (2019) envisage three options for short-term settlement: sequential clearing, cooperation between Retailer-TSO-DSO, and cooperation between TSO-DSO (with Shapley value pays-off), the latest increasing the most the total welfare. Gerard et al. (2018), referring to the Smart-Net project, envisaged five different market structures (Appendix A1, Table A. 6)

Those would need to be sorted before being widely deployed, especially if local flexibility resources are expected to participate in system-wide flexibility provision in addition to the local flexibility activation. Notably, proposals have been made for DSOs to have priority whenever congestion arises. It is referred to as the traffic light concept proposed by the BDEW. It allows the DSO to overrule the market if necessary (Zacharias, 2015). Another non-market approach towards local flexibility has been proposed by USEF (2015), with a prominent role for aggregators that harnesses customer flexibility and offers it to the different actors through flexibility contracts with DSO and BRP. One of the conclusions of Interflex is that, even if functioning, the business case is not yet present, as traditional fit-and-forget actions are sufficient to accommodate current load growth (Interflex, 2019). The demand response would, therefore, not be leveraged as a day-to-day congestion management but rather valorised for peak-shaving to defer grid reinforcement or accommodate more renewables. However, it is noteworthy that for both USEF and SmartNet projects, the advantage of flexible market platforms comes from the possibility of revenue stacking, as multiple products can be offered to a whole range of actors, notably retailers, TSO, or DSO. The current literature emphasises that without value stacking, the potential is often too little to justify the investment in distributed flexibility. All those pilots demonstrate an interest in DSOs using flexible BTM resources to defer long-term investments and potentially for congestion management to complement the existing ancillary services market. Multiple proposals have been made to set DSOs with the highest priority regarding the use of BTM flexibility when grid congestion occurs. The review performed by Schittekatte and Meeus (2020) points out that TSO-DSO coordination and integration of flexibility markets into the current sequence of electricity markets are not the only debate around flexibility markets, but only two out of six identified. The remaining controversies lie in the standardisation of products, the inter-DSO coordination, as Germany counts more than 900 DSOs, the existence of a reservation payment and whether a third party operates the flexibility market. One of the challenges in coordinating those flexibility resources is that the resulting market liquidity is expected to be relatively low (Migliavacca, 2019), and the benefits for participants are not significant. Moreover, a market failure in those local markets is caused by the inherent market concentration due to the small number of actors participating, which can lead to undesirable market power issues and strategic gaming (IEA, 2019).

Since 2018, the French DSO has open calls for tenders for local flexibility. While building a local market is not the target, the DSO offers contracts for demand response in the identified local grid. The bids are relatively similar to other French DR programs, notably the minimum DR size or the performance expectations. Nonetheless, a significant difference with the incentive-based DR programs discussed in the last section stems from the diversity in the call for tender.

A broad spectrum of flexibility products has been commercialised in France (Enedis, 2022, 2021). First, on the type of settlements, some contracts awarded granting rights to capacity remuneration, while others are remunerated only for the energy curtailed or produced. Second, on the DR event duration. Depending on the local situation, flexibility could require day-long activation, while some calls for tender expect seven hours of continuous activation to carry out work on the grid. Conversely, some tenders for local flexibility target temporary grid congestion management and require only thirty minutes of activation. The period where the flexibility should be available is also a component of the call for tender, usually targeting precise months of a given year. This specification diversity underlines the multiple benefits of demand-side resources for the DSO and the intrinsic lack of standardisation of flexibility products and objectives. Creating local flexibility pools could be relevant to reach sufficient liquidity to address all flexibility needs. Regarding the market design, DSOs send an activation signal, units being free to answer in programs where no capacity remuneration for availability has been settled. A similar paradigm to NEBEF is implemented insofar that the flexibility provider should compensate the retailers for the curtailed energy. A remaining issue lies in the ex-post assessment of realised load shedding, which requires a reference to be benchmarked. Eventually, the success has been limited in past years, with low participation in the call for tender. Overall, the local flexibility markets are often considered not yet mature. Moreover, the competition between different flexibility investments (*e.g.* batteries, interconnection or DR) and the competition between state support for energy efficiency, distributed generation, and distributed flexibility is another reason why the progress of those additional markets is slow and uncertain.

7. Discussion and recommandations

In the aftermath of the 2021-2023 energy crisis, the electricity market design in Europe has been extensively commented on, with multiple actors acknowledging the role of DR in a period of crisis. This research performs a literature review of empirical evidence to identify the current integration of DR into electricity markets. Overall, the results suggest a relative increase in the capacity enrolled in DR programs over the past decade and underline the willingness to include those as flexibility providers in power systems. A framework is proposed to identify likely shortfalls based on the temporal and geographical dimensions of the different electricity markets in place.

7.1. Directionality of DR programs

Initial attempts to include DR in electricity markets have been made in all the geographies considered. While both the incentive-based and the price-based approaches are usually considered alternatives, we underlined that the objectives and the associated consumer's role differ significantly between the two. On one side, price-based DR program values lie in the long-term reduction in peak units and the completion of the wholesale energy market, uplifting the price elasticity of power consumers. The remuneration consists of reduced capacity procurements and bill savings consumers realise when reducing or shifting consumption towards less expensive hours. On the other side, incentive-based DR programs have relied on third parties, targeting balancing and contingency markets and being remunerated primarily on a capacity basis for their availability. Table 3 summarises the main strengths and weaknesses of the different approaches to DR and the variety of the objective targeted. In both paradigms, the short and long-term peak shaving capabilities have been a strong focus of DR programs. Consequently, a high Peak-Consumption Ratio (PCR) in PJM and France explains why they are among the earliest adopters of DR programs.

In contrast, the potential of DR to shape and shift load has not been the primary objective, despite its theoretical relevance in power systems with high shares of vRES while flexible thermal units are progressively phased-out. Price-based programs have, in theory, the potential to leverage such flexibility, as illustrated by ToU or RTP tariffs.

In contrast, incentive-based DR programs have historically not aimed at modulating power consumption due to the high transaction costs consumers face to enrol in such activities. However, some programs developed in the wholesale market since 2015 have addressed load-shaping objectives, as illustrated by the PRD program in PJM and the NEBEF programs in France. However, uncertainties remain concerning the methodology to use for assessing DR performance. Indeed, difficulties arise when establishing a reference baseline for consumers, as those have no ex-ante contractual basis for their energy consumption profile. Additional difficulties stem from the multiple objectives that DR is targeting. More attention should be given to the framework allowing for value stacking when multiple DR programs co-exist. Conversely, DR programs targeting precise segments and objectives facilitate the enrolment but miss some opportunities to valorise flexibility.

7.2. Socio-economic implication of DR programs

From a system perspective, if the primary objective is to foster contingency peak-shaving capacities, enforcing tariffs with peak pricing components and deploying direct-load control are the main levers implemented. However, one of the prerequisites to delay investment lies in identifying the long-term socio-economic potential of DR and the share of investments in peaking units DR can substitute. Improper planning could lead to stranded assets or insufficient capacity provision. Consequently, the value of DR should be gauged against alternative solutions, especially since the current incentives required to foster its development in France highlight the difficulties in establishing a competitive ground between generators and DR and question the effective cost-savings realised. For example, energy savings programs or building renovation in the residential sector reduce peak demand without requiring DR. Similarly, batteries or the retrofit of existing thermal units provide the intra-day flexibility required in future wholesale energy markets without incurring the cost for distributed activation of DR. Nonetheless, the advent of electric vehicles with vehicle-to-grid capabilities presents a promising DR opportunity that should be anticipated in the future market design, impacting the way EV charging is deployed. Lastly, the efficiency of DR based on consumer reaction still needs to be demonstrated, given the historical performance in the regions considered. Delaying investments in peak units is only valuable if DR can effectively supplement them when generation scarcity occurs. Importantly, the potential for DR differs significantly depending on the types of flexibility needed, from very short-term to hour-long activation. Overestimating the flexibility potential by disregarding the duration of events in which DR is expected to play a role or the activation time required for DR poses significant risks.

7.3. Coherence across the geographical dimension

The research framework, illustrated in Figure 2, exposes additional coherence gaps and spillover risks among the three types of DR programs assessed. The first risk is primarily related to the local *vs* zonal dimension, represented in the vertical axis of the analysis framework proposed. European DR architectures have been based so far on a zonal approach. Consequently, the zonal approach is the basis of all price-based DR programs linked to the wholesale energy market and balancing markets, resulting in a lack of local flexibility signals. However, the ongoing trends in local flexibility pilots indicate growing concerns about the local impact of the widespread installation of vRES and EV chargers. Although the existing grids are resilient enough to accommodate those in the short term, the rapidly increasing penetration of EV and the electrification of end uses are expected to enhance the local flexibility provision's value. It would therefore be essential to align the different markets and refine the interaction between actors, notably TSO, DSO, retailers, and aggregators. The pilot proposals have underlined the possible market design to be implemented and likely issues between local and zonal coordination. Those issues have been targeted by workable concepts like the "light traffic" or by setting activation priorities when different actors require managing these flexibilities. However, no evidence of those settlements has been found in existing programs, at the risk of harming the power system efficiency.

Geographical coherence is also necessary among European countries, which are gradually moving towards common balancing markets but have not yet harmonised their position regarding DR integration. Similarly, the lack of harmonised adequacy mechanisms results in disparities among countries.

7.4. Coherence across the temporal dimension

A second spillover lies in the coexistence of implicit and explicit mechanisms, and more precisely, between their different timeframe, corresponding to the horizontal axis of the analysis framework proposed. Indeed, Faruqui and Malko (1983) acknowledge the need to quantify the interactions between ToU rates, direct load controls, and energy conservation programs to avoid multiple-counting errors. We can argue that there are potential inefficiencies in developing price- and incentive-based DR simultaneously. The interactions between both are scarcely discussed, while those are already being implemented. Potential spillovers are expected since all programs intend to modify customers' energy consumption. For instance, a household engaged in a DR program with an aggregator while their retailer or DSO settles a dynamic tariff to limit peaking hours creates an operational risk or could lower the incentives to shift consumption. The DR potential should not be double-counted when assessing the volume that the aggregator offers to the DSO and the retailer. Establishing a flexibility pool to improve coordination between TSOs, DSOs, retailers, and aggregators could foster demand response while avoiding parallel activation. Achievable welfare gains would, however, also be reduced by the misalignment of second-best dynamic tariffs with real-time system operation. An attempt to align the two paradigms has been made with PJM's PRD program, using locational marginal prices (LMPs) as a price signal for direct load control to overcome the issue. However, providing frequent price signals to modify consumers' electricity consumption patterns may hamper acceptance or effectiveness if signals are too frequent. In addition, it is essential to assess for consumer, TSO, and DSO the impact of dynamic pricing in terms of bills, volatility and risk, which is a significant barrier to acceptability, especially as the recent energy crisis in Europe underlined the importance of hedging consumers from price spikes. Simple hedging consisting of a contract baseline is privileged in the literature studied. More recently, alternative bill stability options have been suggested by Battle et al. (2022) in the aftermath of the 2021-2023 energy crisis. Regulatory-driven centralised auctions of “affordability options” are proposed to protect vulnerable consumers based on long-duration Asian call options. The core objective is to limit the impact of price spikes on monthly electricity bills while maintaining the short-term market incentives- which are critically lacking with vanilla options. While the authors acknowledge the importance of fostering demand response, more research would be required on the possible distortion of short-term signals for power prices above the strike price.

Table 3 - Synthesis of strengths and weaknesses of current DR programs

		Price-based		Incentive-based	
		Strengths	**Weaknesses**	**Strengths**	**Weaknesses**
Quadrant	**Grid constraint management**	Delay grid investments, reduce coincident peak load	No short-term incentive for congestion management in the absence of Locational Marginal Pricing (LMP), more complex grid cost recovery for TSO/DSO, divergent price signal with wholesale market	Delay grid investments, reduce coincident peak load, flexibility pool available to TSO/DSO activation	Potential not evenly distributed for congestion management, friction between DSO/TSO flexibility need
	Adequacy	Delay or reduce peak generation capacity, incentivise long-term energy savings	Uncertainty in the effective DR activation	Delay or reduce peak generation capacity	Uncertainty in the effective DR activation, difficulties in setting a baseline
	Wholesale	Reduce peak load and marginal prices, shift daily consumption to off-peak hours	Additional uncertainty in supply/demand balance, limited hedging possibility for consumers, divergent price signal with grid management	Reduce peak load and marginal prices, shift daily consumption to off-peak hours	Friction between aggregators/CSP and retailer business model, difficulties in setting a baseline
	Balancing	✗	✗	Provide reserves, rapid activation, reduce blackouts risks	Uncertainty in the effective DR activation, difficulties in setting a baseline
Objectives	**Strategic load growth**	+		-	
	Load shaping	++		-	
	Energy conservation	+		-	
	Peak shaving	+		++	
	Load shifting	++		++	
	Reliability	-		+	

8. Conclusion

The above discussion and analysis provide an overview of the potential for DR in France, PJM and Germany, the welfare gain found in the literature and the existing programs developed based on those premises.

First, the potential found is relatively homogenous across markets and consists mainly of industrial DR willing to curtail under contractual conditions. The review demonstrates a future shift in DR potential based on the assumption of a broad EV adoption and the heat provision's electrification. As a result, DR potential is expected to quadruple by 2050. Most of the assessment, however, does not explicitly consider the cost associated with each potential nor the socio-economic consequences for consumers involved. More study would be required, notably if future investments in firm capacities rely upon the assumption of the future availability of a significant flexibility pool in renewable-heavy power systems.

Second, empirical evidence and economic literature underline that liberalised electricity markets would benefit from allowing DR to participate in markets on a competitive basis. The uptake in DR would, however, require: (i) clarifying actors responsible for providing DR, (ii) increasing transparency for consumers on market activities, and (iii) ensuring clarity on the objectives and the nature of the DR activities. Overall, the three geographies studied have successfully established the first frameworks enabling DR activities. Nonetheless, none of the existing programs depicted a significant uptake of DR, despite the smart meters rollout in France and PJM. In addition, the current objectives of DR primarily lie in the contingency quadrant, with most DR resources being absent from day-ahead activities to ease the deployment of RES and provide flexibility on a more regular basis. When both energy and contingency activations are expected, efforts to foster coordination across the supply chain will be required to avoid spillovers, such as parallel activation. In addition, improving the reliability of the DR capacity enrolled is critical. Indeed, reaching the required level of reliance expected is critical before relying to some extent on DR for both short-term activation and long-term adequacy.

From a policymaker's perspective, the market design should anticipate further electricity market development. Distributed flexibility is only one part of the electricity market transformation that also entails the increasing interconnection between countries and the coupling between sectors and energy carriers, which will all require a standardisation of products and settlement types. Furthermore, electricity demand and associated price patterns are called to evolve rapidly with the ambitious targets of reaching Net Zero emissions by 2050 in Europe. While policies incentivise all flexibility options, it is still unclear which potential and needs lie in those solutions and if price-based DR should be considered a substitute or a component of incentive-based DR programs. Some facts that might hold in the current perimeter might fall short with a higher share of renewables with near-zero marginal costs, while the electricity tariffs structure should depict stability over time to ensure public acceptance. It is paramount not to forget that those resources have, first and foremost, a utility value for the end user, notably in the case of EVs. In addition, a gradual decrease in the cost of DR should be fostered thanks to smart appliances to reduce transaction costs and ultimately reflect the consumer's willingness to curtail depending on the timing considered.

The aforementioned uncertainties make long-term planning more uncertain in the presence of DR compared to traditional supply-side architecture and increase the complexity of the optimisation performed on an integrated market model. Those interaction calls for further quantitative studies to assess to what extent multiple approaches towards flexibility coexist and which objectives of the DR will be relevant with more RES. Furthermore, given the ambition to revisit electricity market design in Europe, it is essential to foster efforts on DR, as it has been a central element in overcoming the 2021-2023 energy crisis and has a role to play in lowering GHG emissions in future power systems.

References

50Hertz, Amprion, Tennet, Transnet BW, 2019. Prequalified Capacity in Germany.

Abrishambaf, O., Lezama, F., Faria, P., Vale, Z., 2019. Towards transactive energy systems: An analysis on current trends. Energy Strategy Reviews 26, 100418. https://doi.org/10.1016/j.esr.2019.100418

ACER, 2015. Market Monitoring Report - Electricity and Gas retail markets.

ADEME, Laurent, 2019. Trajectoires d'évolution du mix électrique 2020-2060.

Adeyemi, A., Yan, M., Shahidehpour, M., Bahramirad, S., Paaso, A., 2020. Transactive energy markets for managing energy exchanges in power distribution systems. The Electricity Journal, Special Issue: The Future Electricity Market Summit 33, 106868. https://doi.org/10.1016/j.tej.2020.106868

Agora Energiewende, 2023. Klimaneutrales Stromsystem 2035 [WWW Document]. URL https://static.agora-energiewende.de/fileadmin/Projekte/2021/2021_11_DE_KNStrom2035/A-EW_264_KNStrom2035_WEB.pdf (accessed 3.6.23).

Agora Energiewende, 2017. Flexibility in thermal power plants.

Allcott, H., 2011. Rethinking real-time electricity pricing. Resource and Energy Economics, Special section: Sustainable Resource Use and Economic Dynamics 33, 820-842. https://doi.org/10.1016/j.reseneeco.2011.06.003

Astier, N., Léautier, T.-O., 2021. Demand Response: Smart Market Designs for Smart Consumers. EJ 42. https://doi.org/10.5547/01956574.42.3.nast

Athawale, R., Felder, F.A., 2022. Electric utility death spiral: Revisited in the context of tariff design. The Electricity Journal 35, 107062. https://doi.org/10.1016/j.tej.2021.107062

Aubin, C., Fougère, D., Husson, E., Ivaldi, M., 1995. Real-time pricing of electricity for residential customers: Econometric analysis of an experiment. Journal of Applied Econometrics 10, S171–S191. https://doi.org/10.1002/jae.3950100510

Auray, S., Caponi, V., Ravel, B., 2018. Price Elasticity of Electricity Demand in France. CREST-Ensai.

Battle, C., Schittekatte, T., Knittel, C.R., 2022. Power Price Crisis in the EU: Unveiling Current Policy Responses and Proposing a Balanced Regulatory Remedy by Carlos Batlle, Tim Schittekatte, Christopher R. Knittel :: SSRN [WWW Document]. URL https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4044848 (accessed 5.27.23).

Bayer, B., 2015. Current Practice and Thinking with Integrating Demand Response for Power System Flexibility in the Electricity Markets in the USA and Germany. Curr Sustainable Renewable Energy Rep 2, 55–62. https://doi.org/10.1007/s40518-015-0028-7

BDEW, 2019. Entwicklung des Nettostromverbrauchs in Deutschland [WWW Document]. URL https://www.bdew.de/service/daten-und-grafiken/entwicklung-nettostromverbrauch-deutschland/ (accessed 5.26.23).

Bertsch, J., Brown, T., Hagspiel, S., Just, L., 2017. The relevance of grid expansion under zonal markets. EJ 38. https://doi.org/10.5547/01956574.38.5.jber

Boccard, N., 2009. Capacity factor of wind power realized values vs. estimates. Energy Policy 37, 2679–2688. https://doi.org/10.1016/j.enpol.2009.02.046

Bonbright, J.C., 1961. Principles of Public Utility Rates. Columbia University Press.

Borenstein, S., 2007. Customer Risk from Real-Time Retail Electricity Pricing: Bill Volatility and Hedgability. The Energy Journal 28, 111–130.

Borenstein, S., 2005. The Long-Run Efficiency of Real-Time Electricity Pricing. The Energy Journal 26, 93–116.

BSI, 2022. Act on Metering Point Operation and Data Communication in Smart Energy Networks [WWW Document]. URL https://www.bsi.bund.de/EN/Das-BSI/Auftrag/Gesetze-und-Verordungen/Smart-Metering-GDEW-MsbG/smart-metering-gdew-msbg.html?nn=907610 (accessed 3.17.23).

Bundesrecht, 2022. § 4 AbLaV Vergütung abschaltbarer Lasten Verordnung zu abschaltbaren Lasten [WWW Document]. URL https://www.buzer.de/s1.htm?g=AbLaV&a=4 (accessed 3.7.23).

Burger, S., Chaves-Ávila, J.P., Batlle, C., Pérez-Arriaga, I.J., 2017. A review of the value of aggregators in electricity systems. Renewable and Sustainable Energy Reviews 77, 395–405. https://doi.org/10.1016/j.rser.2017.04.014

Burger, S.P., 2019. Rate Design for the 21st Century: Improving Economic Efficiency and Distributional Equity in Electricity Rate Design 257.

Burger, S.P., Jenkins, J.D., Huntington, S.C., Perez-Arriaga, I.J., 2019. Why Distributed?: A Critical Review of the Tradeoffs Between Centralized and Decentralized Resources. IEEE Power and Energy Magazine 17, 16–24. https://doi.org/10.1109/MPE.2018.2885203

Bushnell, J., Hobbs, B.F., Wolak, F.A., 2009. When It Comes to Demand Response, Is FERC Its Own Worst Enemy? The Electricity Journal 22, 9–18. https://doi.org/10.1016/j.tej.2009.08.004

Cappers, P., Goldman, C., Kathan, D., 2010. Demand response in U.S. electricity markets: Empirical evidence. Energy 35, 1526–1535. https://doi.org/10.1016/j.energy.2009.06.029

Castaneda, M., Jimenez, M., Zapata, S., Franco, C.J., Dyner, I., 2017. Myths and facts of the utility death spiral. Energy Policy 110, 105–116. https://doi.org/10.1016/j.enpol.2017.07.063

Chao, H., 2011. Demand response in wholesale electricity markets: the choice of customer baseline. J Regul Econ 39, 68–88. https://doi.org/10.1007/s11149-010-9135-y

Clastres, C., Geoffron, P., 2020. Les effacements de consommation électrique et le surplus des acteurs énergétiques. Revue d'économie industrielle 171, 9–46. https://doi.org/10.4000/rei.9176

Commission, 2014. Report from the Commission Benchmarking smart metering deployment [WWW Document]. URL https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52014SC0188&from=EN (accessed 4.5.20).

Costello, K.W., 2014. Electric Utilities' 'Death Spiral': Hyperbole or Reality? The Electricity Journal 27, 20.

CRE, 2022. Délibération de la CRE du 27 juillet 2022 portant décision relative aux modalités selon lesquelles l'offre à tarification dynamique prévue au II de l'article L. 332-7 du code de l'énergie prend en compte les variations des prix de marché et modifiant la délibération n°2021-135 du 20 mai 2021 [WWW Document]. URL https://www.cre.fr/Documents/Deliberations/Decision/offre-a-tarification-dynamique (accessed 3.3.23).

CRE, 2018. Effacements [WWW Document]. URL https://www.cre.fr/Electricite/Reseaux-d-electricite/Effacements (accessed 4.8.20).

Crossley, D., 2007. Evaluation and Acquisition of Network-driven DSM Resources 41.

dena, 2014. Analyse von Rolloutszenarien und ihrer regulatorischen Implikationen.

DIRECTIVE (EU) 2019/ 944 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL - of 5 June 2019 - on common rules for the internal market for electricity and amending

Directive 2012/ 27/ EU, 2019. 75.

Donti, P.L., Kolter, J.Z., Azevedo, I.L., 2019. How Much Are We Saving after All? Characterizing the Effects of Commonly Varying Assumptions on Emissions and Damage Estimates in PJM. Environ. Sci. Technol. 53, 9905–9914. https://doi.org/10.1021/acs.est.8b06586

Dupont, B., De Jonghe, C., Kessels, K., Belmans, R., 2011. Short-term consumer benefits of dynamic pricing, in: 2011 8th International Conference on the European Energy Market (EEM). Presented at the 2011 8th International Conference on the European Energy Market (EEM), pp. 216–221. https://doi.org/10.1109/EEM.2011.5953011

Dütschke, E., Paetz, A.-G., 2013. Dynamic electricity pricing—Which programs do consumers prefer? Energy Policy 59, 226–234. https://doi.org/10.1016/j.enpol.2013.03.025

EIA, 2022. Annual Electric Power Industry Report, Form EIA-861 detailed data files [WWW Document]. URL https://www.eia.gov/electricity/data/eia861/ (accessed 4.5.23).

EIA, 2020. Use of electricity [WWW Document]. URL https://www.eia.gov/energyexplained/electricity/use-of-electricity.php (accessed 5.26.23).

Eid, C., Codani, P., Chen, Y., Perez, Y., Hakvoort, R., 2015. Aggregation of demand side flexibility in a smart grid: A review for European market design, in: 2015 12th International Conference on the European Energy Market (EEM). Presented at the 2015 12th International Conference on the European Energy Market (EEM), pp. 1–5. https://doi.org/10.1109/EEM.2015.7216712

Eid, C., Codani, P., Perez, Y., Reneses, J., Hakvoort, R., 2016a. Managing electric flexibility from Distributed Energy Resources: A review of incentives for market design. Renewable and Sustainable Energy Reviews 64, 237–247. https://doi.org/10.1016/j.rser.2016.06.008

Eid, C., Koliou, E., Valles, M., Reneses, J., Hakvoort, R., 2016b. Time-based pricing and electricity demand response: Existing barriers and next steps. Utilities Policy 40, 15–25. https://doi.org/10.1016/j.jup.2016.04.001

Enedis, 2023. Enedis : Agrégats segmentés de consommation et production électriques au pas 1/2 h [WWW Document]. URL /agregats-segmentes-de-consommation-et-production-electriques-au-pas-12-h (accessed 3.30.21).

Enedis, 2022. Résultats des appels d'Offres de flexibilités locales 2022.

Enedis, 2021. Résultats des appels d'Offres de flexibilités locales 2021.

Enera, E., 2020. Energy future with enera [WWW Document]. EWE AG. URL https://www.ewe.com/en/shaping-the-future/digitalisierung/enera (accessed 9.29.21).

EnGW, 2021. § 41a EnWG [WWW Document]. URL https://www.gesetze-im-internet.de/enwg_2005/__41a.html (accessed 3.3.23).

ENTSO-E, 2020. Transparency Platform [WWW Document]. URL https://transparency.entsoe.eu/ (accessed 7.10.20).

European Commission, 2016a. Clean Energy Package [WWW Document]. URL https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:52016PC0861R(01)&from=EN (accessed 3.30.23).

European Commission, 2016b. ABLAV Interruptibility Scheme [WWW Document]. URL https://ec.europa.eu/competition/state_aid/cases/264060/264060_1841480_86_2.pdf (accessed 3.6.23).

Eurostat, 2023. Electricity prices components for household consumers [WWW Document]. URL https://ec.europa.eu/eurostat/databrowser/view/NRG_PC_204_C__custom_5758880/default/table?lang=en (accessed 4.13.23).

Faruqui, A., 2016. Brattle Group, IPU's Annual Regulatory Studies Program: The Fundamentals Course Lansing, Michigan 67.

Faruqui, A., 2011. The Costs and Benefits of Smart Meters for Residential Customers [WWW Document]. URL https://www.edisonfoundation.net/iee/Documents/IEE_BenefitsofSmartMeters_Final.pdf (accessed 5.7.20).

Faruqui, A., Malko, J.R., 1983. The residential demand for electricity by time-of-use: A survey of twelve experiments with peak load pricing. Energy 8, 781–795. https://doi.org/10.1016/0360-5442(83)90052-X

Faruqui, A., Sergici, S., 2010. Household response to dynamic pricing of electricity: a survey of 15 experiments. J Regul Econ 38, 193–225. https://doi.org/10.1007/s11149-010-9127-y

Gerard, H., Rivero Puente, E.I., Six, D., 2018. Coordination between transmission and distribution system operators in the electricity sector: A conceptual framework. Utilities Policy 50, 40–48. https://doi.org/10.1016/j.jup.2017.09.011

Gils, H.C., 2014. Assessment of the theoretical demand response potential in Europe. Energy 67, 1–18. https://doi.org/10.1016/j.energy.2014.02.019

GOV.UK, 2021. Electric vehicle chargepoints in residential and non-residential buildings [WWW Document]. GOV.UK. URL https://www.gov.uk/government/consultations/electric-vehicle-chargepoints-in-residential-and-non-residential-buildings (accessed 9.22.21).

Green, R., Staffell, I., 2017. "Prosumage" and the British Electricity Market. EEEP 6. https://doi.org/10.5547/2160-5890.6.1.rgre

Gyamfi, S., Krumdieck, S., Urmee, T., 2013. Residential peak electricity demand response—Highlights of some behavioural issues. Renewable and Sustainable Energy Reviews 25, 71–77. https://doi.org/10.1016/j.rser.2013.04.006

Heggarty, T., Bourmaud, J.-Y., Girard, R., Kariniotakis, G., 2020. Quantifying power system flexibility provision. Applied Energy 279, 115852. https://doi.org/10.1016/j.apenergy.2020.115852

Heitkoetter, W., Schyska, B.U., Schmidt, D., Medjroubi, W., Vogt, T., Agert, C., 2021. Assessment of the regionalised demand response potential in Germany using an open source tool and dataset. Advances in Applied Energy 1, 100001. https://doi.org/10.1016/j.adapen.2020.100001

Hillberg, E., Zegers, A., Herndler, B., Wong, S., Pompee, J., Bourmaud, J.-Y., Lehnhoff, S., Migliavacca, G., Uhlen, K., Oleinikova, I., Pihl, H., Norström, M., Persson, M., Rossi, J., Beccuti, G., 2019. Flexibility needs in the future power system 48.

Hledik, R., 2018. Storage-oriented rate design_ Stacked benefits or the next death spiral? The Electricity Journal 5.

Holland, S.P., Mansur, E.T., 2006. The Short-Run Effects of Time-Varying Prices in Competitive Electricity Markets. The Energy Journal 27, 127–155.

Houthakker, H.S., 1951. Electricity Tariffs in Theory and Practice. The Economic Journal 61, 1–25. https://doi.org/10.2307/2226608

Hussain, M., Gao, Y., 2018. A review of demand response in an efficient smart grid environment. The Electricity Journal 31, 55–63. https://doi.org/10.1016/j.tej.2018.06.003

IEA, 2020. Germany 2020 - Energy Policy Review 229.

IEA, 2019. Status of Power System Transformation 32.

IEA, 2016. Tapping the Potential of Commercial Prosumers [WWW Document]. URL http://iea-retd.org/wp-content/uploads/2016/04/RE-COM-PROSUMERS-Report.pdf (accessed 12.3.19).

Imran, K., Kockar, I., 2014. A technical comparison of wholesale electricity markets in North

America and Europe. Electric Power Systems Research 108, 59–67. https://doi.org/10.1016/j.epsr.2013.10.016

Interflex, 2019. Interflex Project Summary [WWW Document]. URL https://interflex-h2020.com/wp-content/uploads/2019/11/Interflex-Summary-report-2017-2019.pdf (accessed 4.7.20).

IRENA, 2021. Renewable capacity highlights.

IRENA, 2020. Renewable capacity highlights.

IRENA (Ed.), 2019. Demand-side flexibility for power sector transformation.

J. Schofield, R. Carmichael, S. Tindemans, M. Woolf, M. Bilton, G. Strbac, 2014. Residential consumer responsiveness to time-varying pricing [WWW Document]. URL https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2019/05/LCL-Learning-Report-A3-Residential-consumer-responsiveness-to-time-varying-pricing.pdf (accessed 9.25.21).

Joskow, P.L., 2008. Capacity payments in imperfect electricity markets: Need and design. Utilities Policy, Capacity Mechanisms in Imperfect Electricity Markets 16, 159–170. https://doi.org/10.1016/j.jup.2007.10.003

Khajavi, P., Abniki, H., Arani, A.B., 2011. The role of incentive based Demand Response programs in smart grid, in: 2011 10th International Conference on Environment and Electrical Engineering. Presented at the 2011 10th International Conference on Environment and Electrical Engineering, pp. 1–4. https://doi.org/10.1109/EEEIC.2011.5874702

Klessmann, C., Nabe, C., Burges, K., 2008. Pros and cons of exposing renewables to electricity market risks—A comparison of the market integration approaches in Germany, Spain, and the UK. Energy Policy 36, 3646–3661. https://doi.org/10.1016/j.enpol.2008.06.022

Koliou, E., Eid, C., Chaves-Ávila, J.P., Hakvoort, R.A., 2014. Demand response in liberalized electricity markets: Analysis of aggregated load participation in the German balancing mechanism. Energy 71, 245–254. https://doi.org/10.1016/j.energy.2014.04.067

Kuzemko, C., Mitchell, C., Lockwood, M., Hoggett, R., 2017. Policies, politics and demand side innovations: The untold story of Germany's energy transition. Energy Research & Social Science 28, 58–67. https://doi.org/10.1016/j.erss.2017.03.013

Lampropoulos, I., Kling, W.L., Ribeiro, P.F., van den Berg, J., 2013. History of demand side management and classification of demand response control schemes, in: 2013 IEEE Power Energy Society General Meeting. Presented at the 2013 IEEE Power Energy Society General Meeting, pp. 1–5. https://doi.org/10.1109/PESMG.2013.6672715

Layer, P., Feurer, S., Jochem, P., 2017. Perceived price complexity of dynamic energy tariffs: An investigation of antecedents and consequences. Energy Policy 106, 244–254. https://doi.org/10.1016/j.enpol.2017.02.051

Lee, S., 2019. Comparing methods for customer baseline load estimation for residential demand response in south korea and france: predictive power and policy implications. CEEM Working paper.

Lijesen, M.G., 2007. The real-time price elasticity of electricity. Energy Economics 29, 249–258. https://doi.org/10.1016/j.eneco.2006.08.008

Lund, P.D., Lindgren, J., Mikkola, J., Salpakari, J., 2015. Review of energy system flexibility measures to enable high levels of variable renewable electricity. Renewable and Sustainable Energy Reviews 45, 785–807. https://doi.org/10.1016/j.rser.2015.01.057

Märkle-Huß, J., Feuerriegel, S., Neumann, D., 2018. Large-scale demand response and its implications for spot prices, load and policies: Insights from the German-Austrian electricity market. Applied Energy 210, 1290–1298. https://doi.org/10.1016/j.apenergy.2017.08.039

McAnany, J., 2023. 2023 Demand Response Operations Markets Activity Report: February 2023.

Meyabadi, A.F., Deihimi, M.H., 2017. A review of demand-side management: Reconsidering theoretical framework. Renewable and Sustainable Energy Reviews 80, 367–379. https://doi.org/10.1016/j.rser.2017.05.207

Migliavacca, 2019. Smartnet Project exploitation and impact [WWW Document]. URL http://smartnet-project.eu/wp-content/uploads/2019/07/Migliavacca-Project-exploitation-and-impact.pdf (accessed 4.7.20).

Müller, T., Möst, D., 2018. Demand Response Potential: Available when Needed? Energy Policy 115, 181–198. https://doi.org/10.1016/j.enpol.2017.12.025

Neuteleers, S., Mulder, M., Hindriks, F., 2017. Assessing fairness of dynamic grid tariffs. Energy Policy 108, 111–120. https://doi.org/10.1016/j.enpol.2017.05.028

Newbery, D., 2016. Missing money and missing markets: Reliability, capacity auctions and interconnectors. Energy Policy 94, 401–410. https://doi.org/10.1016/j.enpol.2015.10.028

Next Kraftwerke, 2017. Abschaltverordnung (AbLaV) – Was ist das? [WWW Document]. URL https://www.next-kraftwerke.de/wissen/abschaltverordnung (accessed 3.7.23).

Parrish, B., Gross, R., Heptonstall, P., 2019. On demand: Can demand response live up to expectations in managing electricity systems? Energy Research & Social Science 51, 107–118. https://doi.org/10.1016/j.erss.2018.11.018

PJM, 2023. Load forecast report.

PJM, 2020a. Locational Marginal Pricing [WWW Document]. URL https://learn.pjm.com/three-priorities/buying-and-selling-energy/lmp (accessed 9.20.21).

PJM, 2020b. 2019 Distributed Energy Resources (DER) that participate in PJM Markets as Demand Response.

PJM, 2020c. Price Responsive Demand Overview.

Poignant, S., Sido, B., 2010. Rapport Poignant-Sido.

Price, C., Botts, A., Sundaramoorthy, S., Chaudhari, S., Wenning, T., 2021. Understanding Your Utility Bills: Electricity (No. ORNL/SPR-2021/1839, 1833978). https://doi.org/10.2172/1833978

Putrus, G.A., Suwanapingkarl, P., Johnston, D., Bentley, E.C., Narayana, M., 2009. Impact of electric vehicles on power distribution networks, in: 2009 IEEE Vehicle Power and Propulsion Conference. Presented at the 2009 IEEE Vehicle Power and Propulsion Conference, pp. 827–831. https://doi.org/10.1109/VPPC.2009.5289760

Rábago, K.R., 2018. Revisiting Bonbright's principles of public utility rates in a DER world. The Electricity Journal 5.

Ramos, A., De Jonghe, C., Gómez, V., Belmans, R., 2016. Realizing the smart grid's potential: Defining local markets for flexibility. Utilities Policy 40, 26–35. https://doi.org/10.1016/j.jup.2016.03.006

Renn, O., Marshall, J.P., 2016. Coal, nuclear and renewable energy policies in Germany: From the 1950s to the "Energiewende." Energy Policy 99, 224–232. https://doi.org/10.1016/j.enpol.2016.05.004

Rious, V., Perez, Y., Roques, F., 2015. Which electricity market design to encourage the development of demand response? Economic Analysis and Policy, Energy 48, 128–138. https://doi.org/10.1016/j.eap.2015.11.006

Rious, V., Roques, F., 2014. Architecture de marché et gestion de la demande électrique. Revue d'économie industrielle 161–192. https://doi.org/10.4000/rei.5967

RTE, 2023a. Valoriser vos flexibilités [WWW Document]. Portail Services RTE. URL https://www.

services-rte.com/fr/decouvrez-nos-offres-de-services/valorisez-vos-flexibilites.html (accessed 9.28.21).

RTE, 2023b. Participer au mécanisme de capacité - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/decouvrez-nos-offres-de-services/participez-au-mecanisme-de-capacite.html (accessed 3.7.23).

RTE, 2023c. Rapport de synthèse analyse des offres AOE 2023 [WWW Document]. URL https://www.services-rte.com/files/live/sites/services-rte/files/pdf/effacements/Rapport%20de%20synth%c3%a8se%20analyse%20des%20offres%20AOE%202023.pdf (accessed 3.7.23).

RTE, 2023d. Bénéficier d'un soutien aux effacements - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/decouvrez-nos-offres-de-services/beneficiez-d-un-soutien-aux-effacements.html (accessed 3.7.23).

RTE, 2023e. Participer au mécanisme d'ajustement - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/decouvrez-nos-offres-de-services/participer-au-mecanisme-d-ajustement.html (accessed 3.8.23).

RTE, 2023f. Réserves Rapide et Complémentaire : résultats de l'appel d'offres 2023 - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/actualites/reserves-rapide-et-complementaire-resultats-appel-offres-2023.html (accessed 3.8.23).

RTE, 2023g. L'appel d'offres interruptibilité - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/decouvrez-nos-offres-de-services/l-appel-d-offres-interruptibilite.html (accessed 3.7.23).

RTE, 2023h. Paramètres et acteurs du mécanisme de capacité - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/visualisez-les-donnees-publiees-par-rte/parametres-et-acteurs-du-mecanisme-de-capacite.html (accessed 3.6.23).

RTE, 2022. Réserves rapide et complémentaire : résultats de l'appel d'offres 2022 - RTE Portail Services [WWW Document]. URL https://www.services-rte.com/fr/actualites/reserves-rapide-et-complementaire-resultats-de-l-appel-d-offres-2022.html (accessed 3.8.23).

RTE, 2021a. Futures énergétiques 2050 - Production [WWW Document]. URL https://assets.rte-france.com/prod/public/2021-12/BP2050_rapport-complet_chapitre4_production-electricite.pdf (accessed 1.14.22).

RTE, 2021b. Ecowatt [WWW Document]. URL https://www.rte-france.com/accelerer-transition-energetique/eclairer-les-consommateurs (accessed 10.1.21).

RTE, 2020. Résultat Appel d'Offre Effacement 2021 [WWW Document]. URL https://www.services-rte.com/files/live/sites/services-rte/files/pdf/actualites/Resultats-AOE-2021.pdf (accessed 9.27.21).

RTE, 2019a. Bilans électriques 2018 [WWW Document]. URL https://www.rte-france.com/analyses-tendances-et-prospectives/bilans-electriques-nationaux-et-regionaux (accessed 5.26.23).

RTE, 2019b. Enjeux du développement de l'électromobilité pour le système électrique.

Schill, W.-P., Gerbaulet, C., 2015. Power System Impacts of Electric Vehicles in Germany: Charging with Coal or Renewables?

Schittekatte, T., Meeus, L., 2020. Flexibility markets: Q&A with project pioneers. Utilities Policy 63, 101017. https://doi.org/10.1016/j.jup.2020.101017

Schittekatte, T., Momber, I., Meeus, L., 2018. Future-proof tariff design: Recovering sunk grid costs in a world where consumers are pushing back. Energy Economics 70, 484–498. https://doi.org/10.1016/j.eneco.2018.01.028

Schreiber, M., Wainstein, M.E., Hochloff, P., Dargaville, R., 2015. Flexible electricity tariffs: Power and energy price signals designed for a smarter grid. Energy 93, 2568–2581. https://doi.org/10.1016/j.energy.2015.10.067

Sfen, 2020. Scénarios 2050 – Etude de la contribution du parc nucléaire français à la transition énergétique européenne [WWW Document]. URL https://www.sfen.org/wp-content/uploads/2020/06/Etude-Compass-Lexecon-SFEN-2020.pdf (accessed 2.28.23).

Sia Partners, 2014. Demand Response: a study of its potential in Europe. [WWW Document]. URL https://energy.sia-partners.com/wpfiles/2015/02/20141218_Article_DR-potential-in-Europe-1.pdf (accessed 4.2.20).

smartEn, 2022. The implementation of the Electricity Market Design to drive demand-side flexibility [WWW Document]. URL https://smarten.eu/wp-content/uploads/2022/03/The_implementation_of_the_Electricity_Market_Design_2022_DIGITAL.pdf (accessed 2.28.23).

Spees, K., Lave, L., 2008. Impacts of Responsive Load in PJM: Load Shifting and Real Time Pricing. The Energy Journal 29, 101–121.

Stahl, O., 2014. Demand Response Experiences from Germany.

Stoft, S., 2002. Power System Economics: Designing Markets for Electricity.

Stram, B.N., 2016. Key challenges to expanding renewable energy. Energy Policy 96, 728–734. https://doi.org/10.1016/j.enpol.2016.05.034

Tennet, Amprion, 50Hertz, Transnet BW, 2020. Abschaltbare Lasten Daten [WWW Document]. URL https://www.regelleistung.net/ext/static/abla (accessed 9.29.21).

The Brattle Group, 2007. Quantifying Demand Response Benefits in PJM [WWW Document]. URL http://www.ces-us.com/download/Reports_and_Publications/Quantifying_Demand_Response_Benefits_in_PJM_Jan_29_2007.pdf (accessed 3.1.23).

Tielens, P., Van Hertem, D., 2016. The relevance of inertia in power systems. Renewable and Sustainable Energy Reviews 55, 999–1009. https://doi.org/10.1016/j.rser.2015.11.016

Torriti, J., Hassan, M.G., Leach, M., 2010. Demand response experience in Europe: Policies, programmes and implementation. Energy, Demand Response Resources: the US and International Experience 35, 1575–1583. https://doi.org/10.1016/j.energy.2009.05.021

Transnet BW, 50Hertz, Tennet, Amprion, 2023. Regelleistung [WWW Document]. URL https://www.regelleistung.net/ext/ (accessed 4.7.20).

Turner, K., 2013. "Rebound" Effects from Increased Energy Efficiency: A Time to Pause and Reflect. The Energy Journal 34, 25–42.

U.S. Congress, 2005. Energy Policy Act of 2005 [WWW Document]. URL https://www.congress.gov/109/plaws/publ58/PLAW-109publ58.pdf (accessed 3.3.23).

USEF, 2015. USEF Framework.

Valdes, J., Poque González, A.B., Ramirez Camargo, L., Valin Fenández, M., Masip Macia, Y., Dorner, W., 2019. Industry, flexibility, and demand response: Applying German energy transition lessons in Chile. Energy Research & Social Science 54, 12–25. https://doi.org/10.1016/j.erss.2019.03.003

Veldman, E., Verzijlbergh, R.A., 2015. Distribution Grid Impacts of Smart Electric Vehicle Charging From Different Perspectives. IEEE Transactions on Smart Grid 6, 333–342. https://doi.org/10.1109/TSG.2014.2355494

Verzijlbergh, R., Brancucci Martínez-Anido, C., Lukszo, Z., de Vries, L., 2014. Does controlled electric vehicle charging substitute cross-border transmission capacity? Applied Energy 120, 169–180. https://doi.org/10.1016/j.apenergy.2013.08.020

Vicente-Pastor, A., Nieto-Martin, J., Bunn, D.W., Laur, A., 2019. Evaluation of Flexibility Markets for Retailer–DSO–TSO Coordination. IEEE Transactions on Power Systems 34, 2003–2012. https://doi.org/10.1109/TPWRS.2018.2880123

Villar, J., Bessa, R., Matos, M., 2018. Flexibility products and markets: Literature review. Electric Power Systems Research 154, 329–340. https://doi.org/10.1016/j.epsr.2017.09.005

Walawalkar, R., Blumsack, S., Apt, J., Fernands, S., 2008. An economic welfare analysis of demand response in the PJM electricity market. Energy Policy 36, 3692–3702. https://doi.org/10.1016/j.enpol.2008.06.036

Wang, F., Xu, H., Xu, T., Li, K., Shafie-khah, M., Catalão, João.P.S., 2017. The values of market-based demand response on improving power system reliability under extreme circumstances. Applied Energy 193, 220–231. https://doi.org/10.1016/j.apenergy.2017.01.103

Wellinghoff, J., Morenoff, D.L., 2007. Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation. Energy L.J. 28, 389.

Wilson, R., 2002. Architecture of Power Markets. Econometrica 70, 1299–1340.

Wolak, F.A., 2011. Do Residential Customers Respond to Hourly Prices? Evidence from a Dynamic Pricing Experiment. American Economic Review 101, 83–87. https://doi.org/10.1257/aer.101.3.83

Zacharias, J., 2015. Smart Grid Traffic Light Concept 14.

Appendix A

A1. Supplementary Tables

Table A.1 - References on demand-side flexibility potential in the French, German and PJM electricity markets

Reference	Type	Geography	Methods	Perimeter	Potential/ Socio-technical/ Economic potential	Year	Load reduction potential (GW)	Description	Main source of flexibility
(Gils, 2014)	Ac.	France (Europe)	BU	I/T/R	✓/×/×	H	11.6	Average load reduction by shedding or shifting	Commercial ventilation, Refrigerators
(Gils, 2014)	Ac.	Germany (Europe)	BU	I/T/R	✓/×/×	H	13.8	Average load reduction by shedding or shifting	Refrigerators
(Müller and Möst, 2018)	Ac.	Germany	BU	I	✓/×/×	H	14.2	At highest potential	Night storage heater
(Müller and Möst, 2018)	Ac.	Germany	BU	I	✓/×/×	P	13.9	At highest potential	Electric Arc furnace
(Müller and Möst, 2018)	Ac.	Germany	BU	I	✓/×/×	H	3.9	At peak load	Heat Pump
(Müller and Möst, 2018)	Ac.	Germany	BU	I	✓/×/×	P	6.8	At peak load	Heat Pump
(Märkle-Huß et al., 2018)	Ac.	Germany-Austria	LR	T/R	✓/×/×	H	14	Assumption based on (Gils, 2014)	Refrigerators
(Agora Energiewende, 2023)	Ind.	Germany	-	I/T/R	-	H	3	Demand-side management =short-term load-shifting potential in industry	Demand-side management
(Agora Energiewende, 2023)	Ind.	Germany	-	I/T/R	-	P	32		EV (V2G)
(Heitkoetter et al., 2021)	Ac.	Germany	BU	I/T/R	✓/ ✓/ ✓	H	6.5	Socio-technical potential	Residential
(Heitkoetter et al., 2021)	Ac.	Germany	BU	I/T/R	✓/×/×	H	19	Technical potential	Residential
(Heitkoetter et al., 2021)	Ac.	Germany	LR	I/T/R	✓/×/×	H	(15.5/32.5)	Technical potential	Residential
(Sia Partners, 2014)	Ind.	France (Europe)	BU	I/T/R	✓/×/×	H	8.1	At peak load	Heating system/ electric boiler

(Sia Partners, 2014)	Ind.	Germany (Europe)	BU	I/T/R	✓/×/×	H	9.5	At peak load	Heating system/ electric boiler
(RTE, 2021a)	Ind.	France	BU	I/T/R	✓/ ✓ / -	H	5	Average load reduction in 2019	Water heating
(RTE, 2021a)	Ind.	France	BU	I/T/R	✓/ ✓ / -	P	(9/25/44)	Average load reduction in 2050, three scenarios considered	Vehicle-to-grid
(ADEME, 2019)	Ind.	France	BU	I/T/R	✓/ - / -	P	22	Max. capacity in 2050, two scenarios	Industrial process
(Sfen, 2020)	Ind.	France	BU	I/T/R	✓/ - / -	H	3	Capacity in 2020	Industrial process
(Sfen, 2020)	Ind.	France	BU	I/T/R	✓/ - / -	P	(25/30)	Capacity in 2050, two scenario	Electrolysers
(Poignant and Sido, 2010)	Ind.	France	BU	T/R	✓/ ✓/ ✓	H	13	Estimated potential	Thermal use of electricity
(Walawalkar et al., 2008)	Ac.	PJM	TP	I/T/R	× /×/✓	H	0.3	0.2% of DR cleared at peak demand (150GW)	-
(Walawalkar et al., 2008)	Ac.	PJM	TP	I/T/R	× /×/×	P	7.5	5% of peak demand (150GW)	-
(The Brattle Group, 2007)	Ind.	PJM	TP	I/T/R	× /×/×	H	1.35	0.9% of PJM peak demand (150GW). 3% inside a target zones	-
(Donti et al., 2019)	Ac.	PJM	TP	-	× /×/✓	H	2	Expressed in GWh, assumed monthly load shift	-
(Donti et al., 2019)	Ac.	PJM	TP	-	× /×/✓	H	9	Expressed in GWh, assumed monthly load shift	-
(PJM, 2023)	Ind.	PJM	-	I/T/R	× /×/✓	H	6.9	PJM RTO, contractually interruptible (2022)	-
(PJM, 2023)	Ind.	PJM	-	I/T/R	× /×/✓	P	7.24	PJM RTO, contractually interruptible (2032)	-

Legend: (BU)-Bottom-Up, (TD)-Top-Down, (LR)-Literature review, (I)-Industry, (R)-Residential, (T)-Tertiary, (H)-Historical, (P)-Prospective

Table A.2 - References on demand-side flexibility potential in the French, German and PJM electricity markets

	PJM	France	Germany
2020 EV consumption	0.17 GW	-	-
2035 EV consumption	+1.5 GW	-5.2 GW / +8 GW	+1.6 GW / +3.5 GW
2035 peak load estimate	163.1 GW	94.5 GW	83.5 GW
EV impact on peak load	+0.92%	-5.3% / +9.3%	+2% / +4.4%
Reference	(PJM, 2023)	(RTE, 2019b)[13]	(Schill and Gerbaulet, 2015)

13 The intermediary trajectory 3 has been considered.

Table A.3- References on the economic value of price-based demand response in France, Germany and PJM

References	Time horizon	Methods	Market	Tariffs considered	Elasticity considered	Total welfare gain	Consumer surplus	Grid impact	Environ. impact	Note
(Borenstein, 2005)	ST/LT	Mod.	-	RTP	[-0.025/-0.5]	×	+3%/12%	×	×	100% adoption rate. Total Surplus change as a percentage of original electricity bill
(Borenstein, 2005)	ST/LT	Mod.	-	ToU	[-0.025/-0.5]	×	+0.2%/1%	×	×	-
(Allcott, 2011)	ST	Econ.	PJM	RTP	-	×	[-1%/-2%]*	×	-4.4%	*Reduction in electricity bill
(Holland and Mansur, 2006)	ST	Mod.	PJM	RTP	-0.1	0.24%	2.5%	×	-0.16%	100% adoption rate
(Holland and Mansur, 2006)	ST	Mod.	PJM	ToU	-0.1	0.21%	1.17%	×	×	100% adoption rate
(Holland and Mansur, 2006)	ST	Mod.	PJM	S	-0.1	0.17%	1%	×	×	100% adoption rate
(Faruqui and Sergici, 2010)	ST	Emp.	-	ToU/PTR/CPP/ RTP	-	×	×	×	×	Peak load reduction estimate
(Wolak, 2011)	ST	Econ.	PJM (Columbia)	RTP	-0.03 (R)/ -0.175 (AE)	×	×	×	×	Distinguish between regular (R) and all-electric (AE) consumer
(Wolak, 2011)	ST	Econ.	PJM (Columbia)	CPP	-0.09 (R)/ -0.162 (AE)	×	×	×	×	Distinguish between regular (R) and all-electric (AE) consumer
(Spees and Lave, 2008)	ST	Mod.	PJM	RTP	[-0.05/-0.4]	-	[1.89%/ 4.57%]	×	×	-
(Spees and Lave, 2008)	ST	Mod.	PJM	ToU	[-0.05/-0.4]	[1.28%- 3.60%]*	[0.39%/ 1%]	×	×	*Deadweight Loss reduction compared to RTP
(Aubin et al., 1995)	ST	Econ.	FR	Tempo (ToU-CPP)	-0.12/-0.82	×	7.96%*	×	×	Six-price Tempo tariff analysed. *Comparison between consumers' present discounted value of electricity expenditures

Table A.4 - Incentive-based demand response integration in studied electricity markets (Capacity component)

	PJM		France						Germany
	CP	**PRD**	**Capacity mechanisms (CM)**	**Demand response (AOE)**	**FCR**	**aFRR**	**mFRR-RR**	**Interruptible load (IL)**	**AbLaV**
Adequacy/ Wholesale/ Balancing/ Grid management	✓/×/×/✓	✓/✓/×/(✓)	✓/(✓)/(✓)/(✓)	✓/(✓)/(✓)/(✓)	×/×/✓/✓	×/×/✓/✓	×/×/✓/✓	×/×/✓/✓	×/×/✓/✓
Settlement	Contract	Contract	Market (EPEX) Contract (OTC)	Annual call for tenders	Daily call for tender	Daily call for tender	Annual and daily call for tender	Annual call for tender	Weekly call for tender
Reserved to demand-side	✓	✓	×	✓	×	×	×	✓	✓
Bid time granularity	Annual	Annual	Annual	Annual	4h	4h	Annual/Daily	Annual	Weekly
Activation	TSO signal	Locational Marginal Price	Depends on the market	Depends on the market	Automatic, frequency deviation	Automatic, TSO signals	TSO signal	TSO/DSO signals	Automatic TSO signals
Activation time	<30min <60min <120min	<15min	Depends on the market	Depends on the market	<2s	<300s	Rapid: <13min, Complementary: <30min	< 5s	SOL < 350ms SNL < 15min
Min/Max. bid size	-	-	1 MW / -		1 MW /150 MW	1 MW /150 MW	10 MW / -	10 MW / -	5 MW / 200 MW
Maximum number of interruptions	Unlimited	Unlimited	Between 15 and 25 days per year	Between 15 and 25 days per year	-	-	Rapid: 4 per day Complementary: 4 per day	5 to 10 per year	-
Hours of day required to respond	June - Oct. & May: 10 AM - 10 PM (EPT) Nov. - April: 6 AM- 9 PM (EPT)	June - May	Peaking days ("PP2") Nov. - March: 7 AM-15 PM (CET) 18PM -20 PM (CET)	Peaking days ("PP2") Nov. - March: 7 AM-15 PM (CET) 18PM -20 PM (CET) or Available 20 days among "MiDic" days	All	All	All, on TSO request	All, on TSO request	Weekly availability > 138 hours

Minimum duration of min/max DR activation	1h/-	Offer	Depends on the market	Depends on the market	-/15min	-/30 min	Rapid: -/120min Complementary: -/90min	15min/1h	>4h per week
Maximum duration of event	May - Oct : 12 hours Nov - April: 15 hours	Unlimited	Depends on the market	Depends on the market	Contractual basis	Contractual basis, Accepted bid	Rapid: <4h per day Complementary: < 3h per day	Contractual basis, Accepted bid	8 hours
Capacity remuneration	$18 000 MW/y	(Cost savings)	>15 000 €/ MW/y	Marginal price >50 000 €/ MW/y <60 000 €/ MW/y	Bid price (secondary market) or fixed price ~100 000€/ MW/y	Bid price (secondary market) or fixed price 150 000€/MW/y	Rapid: 330 300 €/MW/y (2022) Complementary: 238 700 €/MW/y (2022)	<70 000€/MW/y	Contractual price. < 26 000 €/MW/y (500€/MW per week)
Market size	~8 GW (2022)	~0.3 GW	83.5 GW (2021)	2.7 GW	0.5 GW	0.5 GW	Rapid: 1 GW Complementary: 0.5 GW	1.2 GW	0.75 GW (SOL) + 0.75 GW (SNL)
Status	✓	✓	✓	✓	✓	✓	✓	✓	× Discontinued in 2022
Eligibility	-	-	CO2 emission factor < 550 gCO_2/kWh	Diesel generator not allowed. IL forbidden	-	-	-	AOE forbidden	-
References	(Cappers et al., 2010; McAnany, 2023)	(McAnany, 2023; PJM, 2020c)	(RTE, 2023b)	(RTE, 2023c, 2023d, 2020)	(RTE, 2023e; Transnet BW et al., 2023)	(RTE, 2023e; Transnet BW et al., 2023)	(RTE, 2023f, 2022)	(RTE, 2023g)	(Bundesrecht, 2022; European Commission, 2016b; Koliou et al., 2014; Next Kraftwerke, 2017)

Table A.5 - Incentive-based demand response integration in studied electricity markets (Energy component)

	PJM	PJM	France				Germany
	CP	Economic DR	NEBEF	FCR	aFRR	mFRR-RR	Ablav
Market	Balancing	Energy, Balancing	Energy	Balancing	Balancing	Balancing	Balancing
Availability	Signal from the clearing operator	Bid offer	Signal from the clearing operator	Automatic, frequency deviation	Continuous activation based on the N level.	Signal from the TSO.	Automatic, frequency deviation or TSO signals
Settlement	Annual	Market (day-ahead, real-time, ancillary services)	Market (day-ahead) or contractual basis	Annual and daily call for tenders	Daily call for tenders in D-1	Daily prescription to obliged players or participation via secondary market	Weekly call for tenders
Remuneration	Marginal price <$2000/MWh	Marginal price	Marginal price	Marginal price	Marginal price	Marginal price 19 €/MWh, offer price	< 400 €/MWh
Note	-	-	Payment due to suppliers of curtailed demand	-	-	-	-

Table A.6 – Market design envisaged for local flexibility management

Market design	Description	Buyer	References
Centralised AS[14] market model	Common market for flexible resources used for balancing	TSO responsible for balancing DSO not included	(Gerard et al., 2018)
Local AS market model	Local market for DSO for congestion + Balancing market for TSO	DSO Priority on local resources transmitted to TSO after clearing. DSO responsible for congestion.	(Gerard et al., 2018; Interflex, 2019; Schittekatte and Meeus, 2020; Vicente-Pastor et al., 2019)
Shared Balancing Responsibility	Local Market for DSO for congestion and balancing + Balancing market for TSO	DSO responsible for local congestion and balancing.	(Gerard et al., 2018)
Common TSO-DSO AS market model	Common market for flexible resources	Both TSO and DSO Allocated to highest need (lowest system cost).	(Enera, 2020; Gerard et al., 2018; Schittekatte and Meeus, 2020; Vicente-Pastor et al., 2019)
Integrated Flexibility market model	Common market for flexible resources	TSO, DSO and Retailer Allocated to highest need (lowest system cost)	(Gerard et al., 2018; Vicente-Pastor et al., 2019)

14 Ancillary Services (AS) refer to a range of services crititcal to ensure the reliablity of the power systems, such as frequency regulation, voltage control, or congestion management;

A2. Supplementary Figures

Figure A.1 - Peak load energy savings values considered by the French TSO (RTE, 2023h)

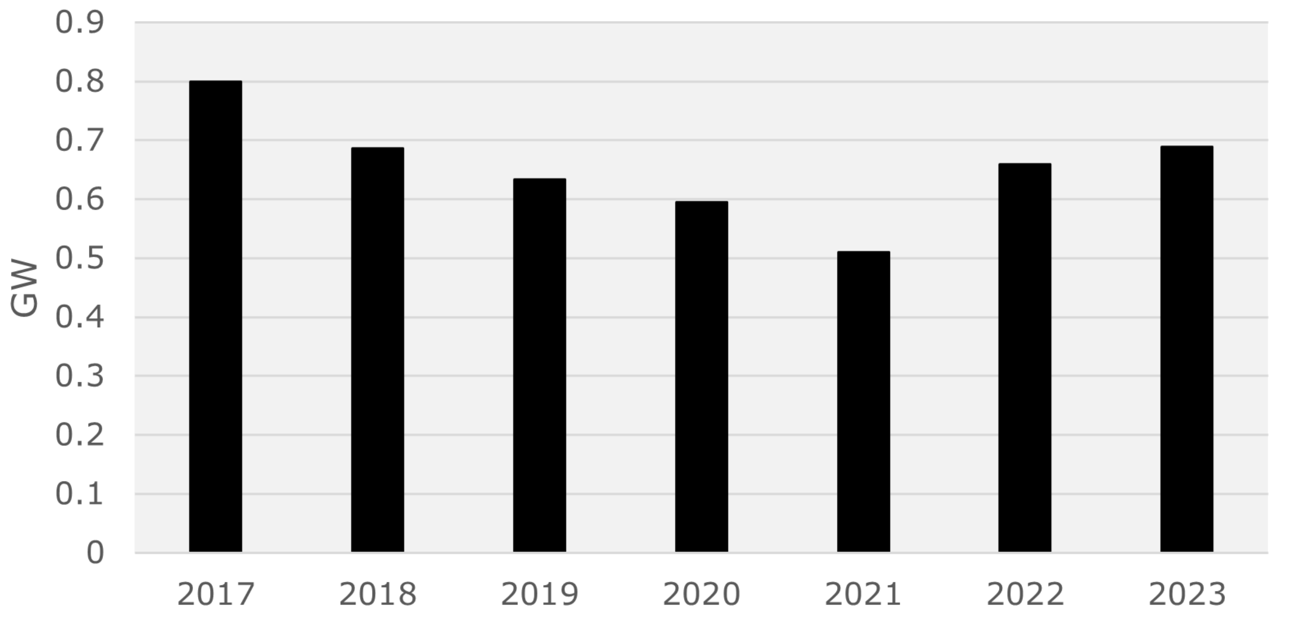


Figure A.2 - French incentive-based DR capacity resulting from the capacity call for tenders (RTE, 2023c)

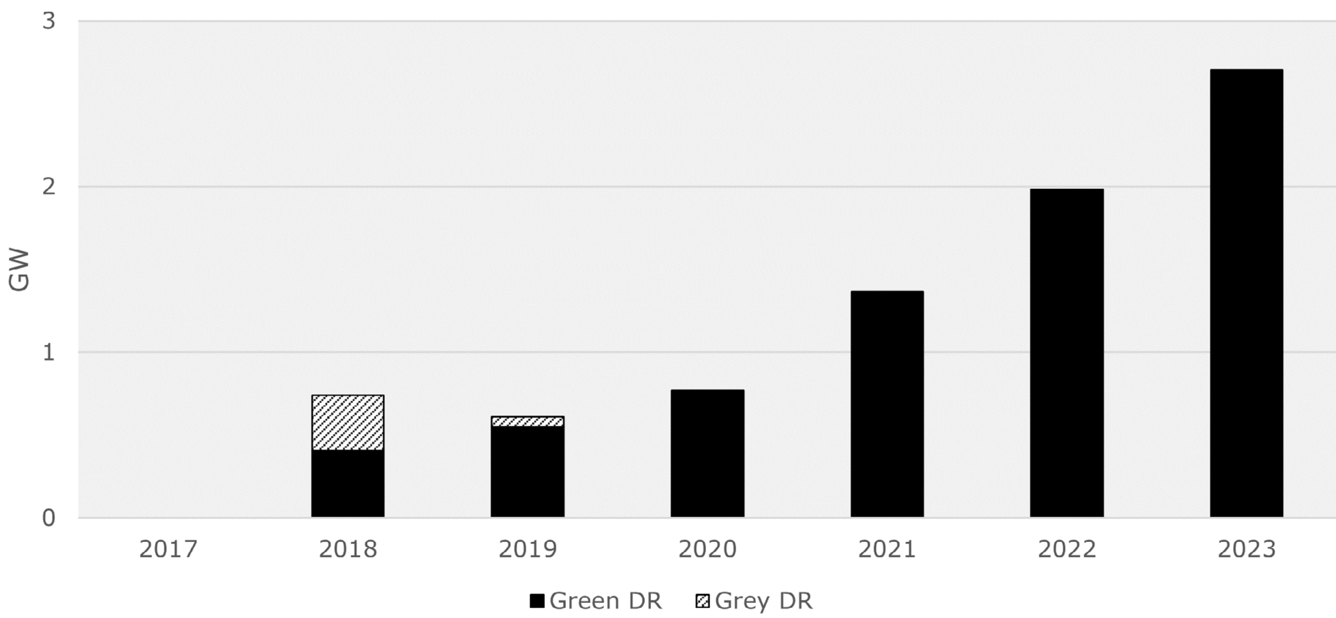


Figure A.3 - Capacity remuneration in France for conventional generators and DR (RTE, 2023c)

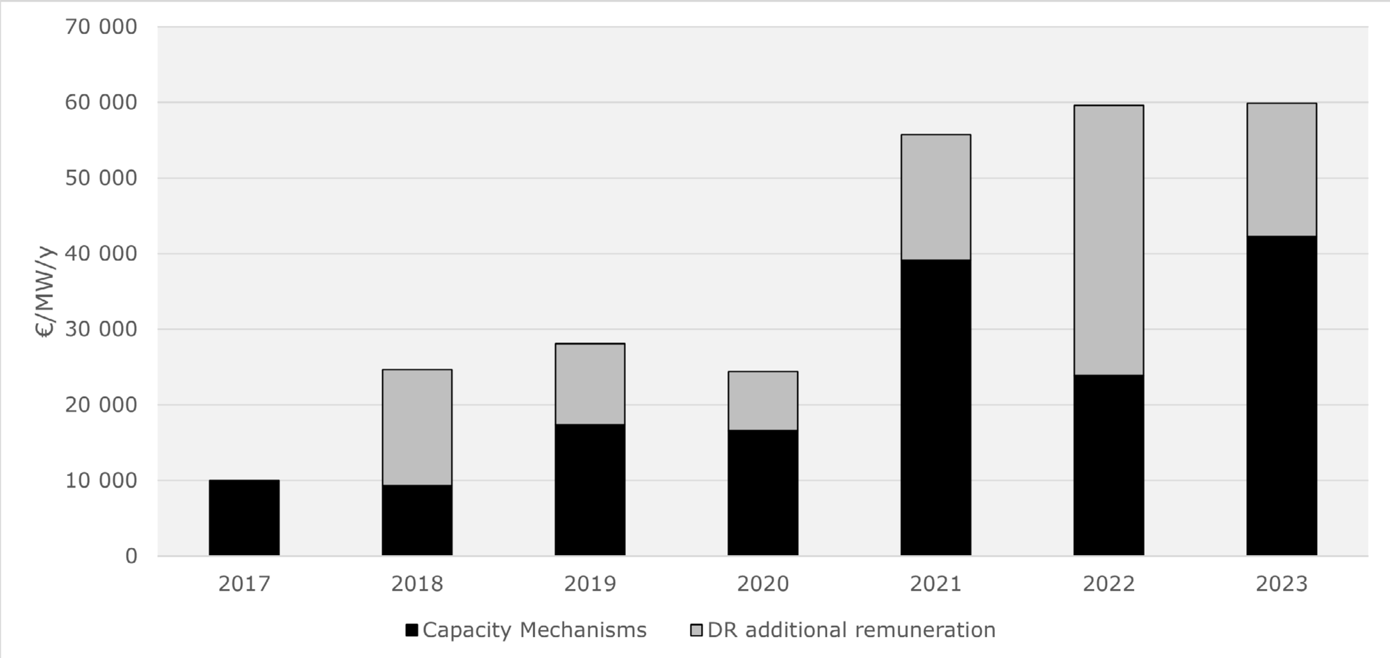


Figure A.4 - Historical PJM incentive-based demand-side and PRD performance (McAnany, 2023)

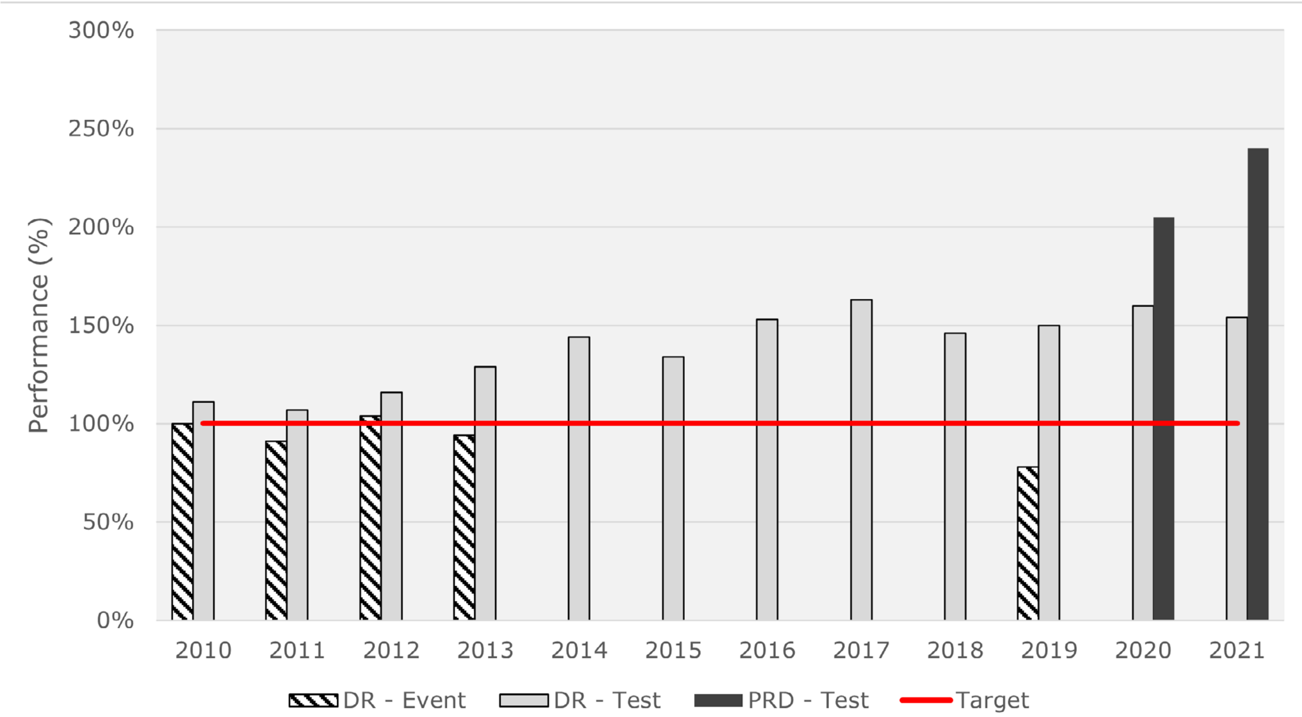
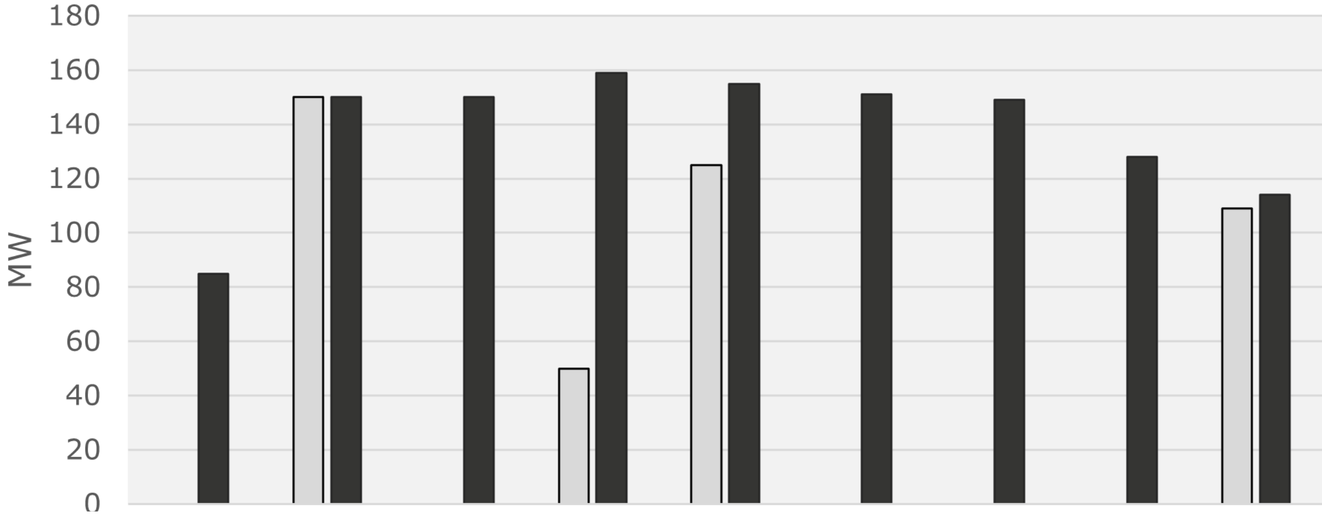
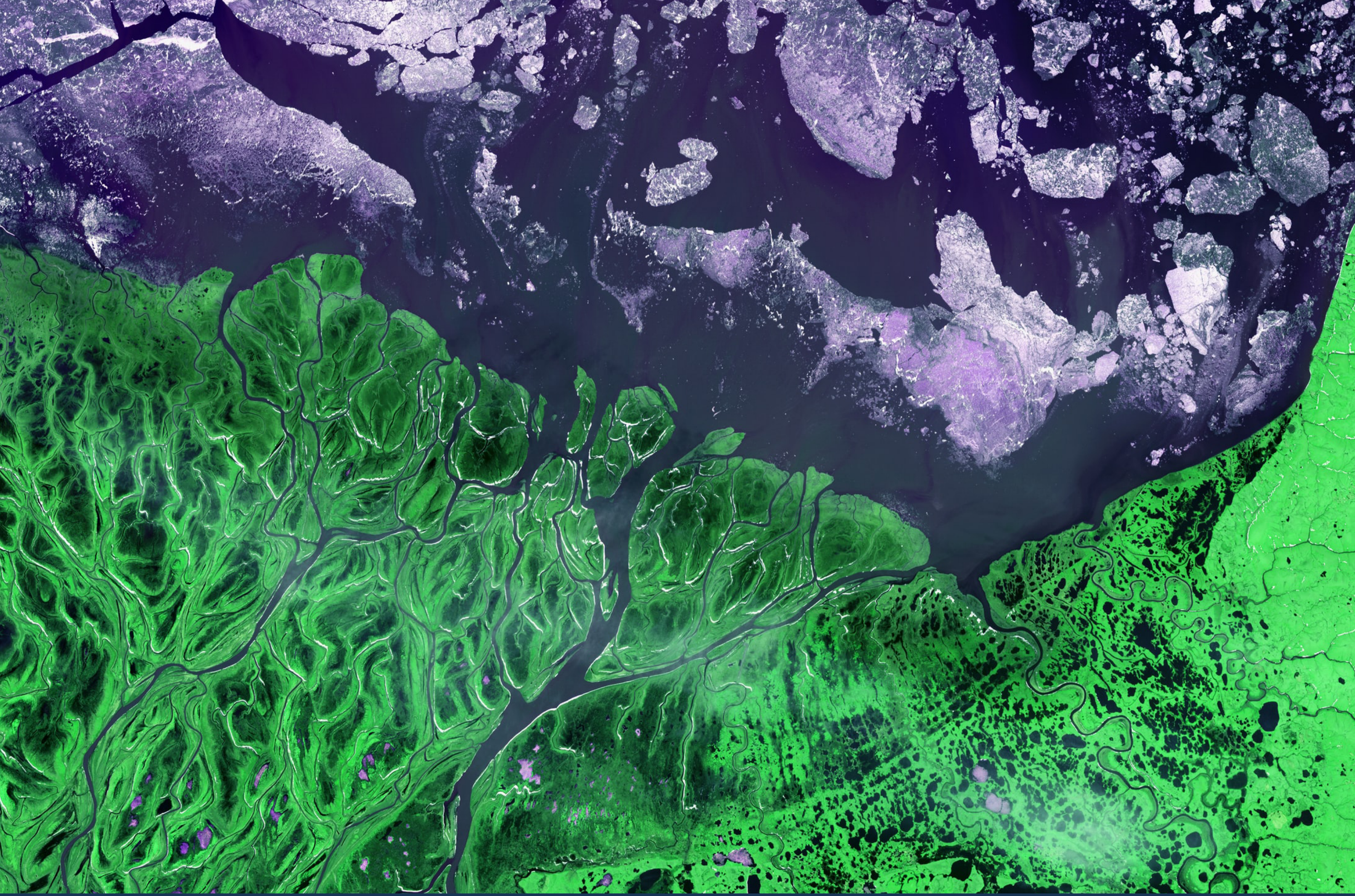


Figure A.5 - Historical German AbLav capacity enrolled (50Hertz et al., 2019)*[15]



15 System balance corresponds to the balancing quadrant while redispatch corresponds TSO activation for grid managements purposes.



Ce travail a été réalisé dans le cadre du parcours doctoral de The Transition Institute 1.5 (TTI.5)

TTI.5 est un institut de recherche de Mines Paris - PSL dédié à la transition bas carbone

CONTACT

the-transition-institute.minesparis.psl.eu

tti.5@minesparis.psl.eu

WORKING PAPER #1