Economic considerations on the demand-side of electricity markets in a context of energy transition

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Economic considerations on the demand-side of electricity markets in a context of energy transition

Considérations économiques sur la demande des marchés de l'électricité dans un contexte de transition énergétique

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Abstract

The ongoing energy transition requires a radical reallocation of capital to reduce the carbon intensity of economies, still vastly relying on oil, gas and coal. For the power sector, the deployment of renewable energy sources is underway and represents a major prerequisite for embarking all sectors in decarbonisation pathways. Simultaneously, the process of liberalising wholesale electricity markets in Europe adds an additional transformative aspect to the ongoing reconfiguration of the electricity sector. Nonetheless, the focus of both the liberalisation and the decarbonisation objectives has been so far on the supply side of the energy systems, while the demand has received little attention. Typically, the electricity markets in place have been built under the premise of inelastic power demand, notably due to the persistent challenge of conveying price signals to consumers. The extent of the ongoing economic transformation compels policymakers to reconsider the importance of the demand side, notably to ease the integration of renewable energy and further reduce the role of fossil-fuel-based generation. This shift in paradigm entails a revision of the current electricity market design, significant investments in infrastructure, and a regulatory overhaul. As an example, smart meters have been widely enforced in many countries, and electricity markets have gradually opened to the active participation of consumers, paving the way towards a revamped operational context of power systems. However, tariff innovations and integration into electricity markets are still lagging despite empirical evidence that demand response would benefit the functioning of the electricity market, a conclusion reasserted during the 2021-2023 global energy crisis.

This thesis complements the existing literature on electricity market design and decarbonised power systems by focusing on three major issues: (i) understanding to what extent the existing electricity market designs have fostered demand-side flexibility, (ii) analysing the preferred price signals to be conveyed towards consumers in the evolving electricity markets and (iii) assessing the welfare loss due to imperfect information and pace asymmetry between the supply and the demand in a context of accelerated electrification.

During this thesis, multiple models have been developed to represent each stakeholder of the power sector to account for the investment in power generation, the consumer's price elasticity or the electrification of industrial end-uses. Both the short-term price variability and the long-term impact of renewable energy sources on the power sector are therefore assessed from a system and a consumer standpoint. The main results are outlined below.

First, electricity markets entail different geographical and temporal realities depending on the sub-market considered. Demand-side integration could improve the economic efficiency of the power system by reducing investments in peak power plants or grid reinforcement and providing additional flexibility to accommodate variable renewable energy sources. However, depending

on the specific objectives pursued, different market designs must be settled and deployed. The case of France, Germany and Pennsylvania-New Jersey-Maryland shows that none of the current programs has successfully established a steady framework for integrating the demand side in electricity markets. This lag in adoption contrasts with the significant potential capacity and value found in the literature and the numerous empirical evidence underlining the price elasticity of consumers. Eventually, existing programs only partially provide the conditions necessary for managing prolonged power crisis episodes or accommodating the intra-day variability of variable renewable energy sources (vRES).

Second, existing dynamic tariffs in France are no longer expected to provide adequate price signals in decarbonising electricity markets. In a situation where renewables production determines price patterns, fixed schedules will no longer be the most relevant tariff design compared to more flexible dynamic pricing. Conversely, peak pricing performs well in reducing deadweight loss by signalling scarcity episodes. While an increasing gap between on-peak and off-peak power prices increases the strength of price signals conveyed to consumers, it might negatively impact the adoption rate of consumers if those are not provided with sufficient flexibility or hedging possibilities.

Third, the industrial electrification pace requires proper anticipation of forward power prices to ensure timely supply-side decarbonisation through electrification. An accelerated electrification scenario that would not factor in the achievable pace of power generation increase would lead to welfare losses. While electrification strategies shift the emissions burden from the downstream sector towards the power production, adverse effects could arise if investments are uncoordinated, leading to potential power price surges or increased greenhouse gas (GHG) emissions from the power sector. Policymakers should also consider the appropriate pace of carbon price increase while monitoring its effectiveness.

Keywords: Electricity market design, Dynamic tariff, Demand response, End-use electrification, Optimisation, Industrial decarbonisation.

Résumé

Le contexte de décarbonation dans lequel s'inscrit l'Union européenne implique des investissements massifs dans les décennies à venir, afin de réduire la dépendance aux sources d'énergies fossiles que sont le pétrole, le gaz et le charbon. Dans le cas particulier du secteur de l'électricité, les énergies renouvelables sont en train d'être déployées à grande échelle, et constituent le socle de la stratégie consistant à électrifier des segments importants de l'économie, du transport à la fourniture de chaleur industrielle. Le processus de libéralisation des marchés de gros de l'électricité en Europe mené au cours des dernières décennies est un autre aspect majeur de la transformation en cours au sein du secteur électrique. Néanmoins, ces deux processus ont été avant tout conçus comme un changement de paradigme du côté de l'offre, sans nécessairement impliquer une place et un rôle différents du côté de la demande. Ainsi, l'hypothèse d'une faible élasticité-prix pour les consommateurs a été historiquement retenue lors de la création des marchés libéralisés. Néanmoins, l'ampleur de la transformation économique en cours astreint les décideurs à reconsidérer l'importance de la demande dans les marchés de l'électricité, notamment pour faciliter l'intégration des énergies renouvelables et réduire le recours aux combustibles fossiles en période de pointe de consommation. Le déploiement des compteurs intelligents témoigne de ce changement de paradigme, et ouvre désormais la voie à une participation plus active de la demande. Cependant, malgré des résultats empiriques montrant les bénéfices associés à la modulation de la consommation, les innovations tarifaires et l'intégration de la demande aux marchés de l'électricité restent faibles. La crise énergétique mondiale de 2021-2023 a cependant réaffirmé l'importance de la participation des consommateurs à l'équilibre offre-demande.

Cette thèse complète la littérature existante sur la conception des marchés de l'électricité en se concentrant sur trois aspects majeurs : (i) analyser dans quelle mesure les conceptions actuelles des marchés de l'électricité ont permis l'émergence de la flexibilité de la demande, (ii) étudier les signaux prix à transmettre aux consommateurs dans un système électrique en voie de décarbonation et (iii) évaluer la perte de bien-être due à une coordination imparfaite entre l'offre et la demande dans un contexte d'électrification rapide.

Au cours de cette thèse, plusieurs modèles d'optimisation et de simulation ont été développés afin de représenter chaque acteur du secteur électrique. Les travaux effectués s'appuient principalement sur un modèle d'optimisation, nommé DEEM, permettant d'effectuer des analyses sur le *dispatch* économique des centrales de productions électriques et les investissements permettant de répondre à la demande à moindre coût. Par la suite, ce modèle a été complété par des modèles portant sur l'élasticité-prix des consommateurs et les investissements requis dans des technologies bas-carbone dans les secteurs industriels. La volatilité des prix à court et long terme sont ainsi évalués, tant du point de vue du système que de celui du consommateur. Les principaux résultats sont présentés ci-dessous.

Premièrement, chaque sous-marché de l'électricité témoigne des contraintes géographiques et temporelles différentes. Si l'intégration de la demande améliore l'efficacité économique de l'ensemble des sous-marchés considérés, chacun nécessite une architecture de marché différente en fonction des objectifs poursuivis. Les cas de la France, de l'Allemagne et de la Pennsylvanie-New Jersey-Maryland, soulignent ainsi que les programmes actuels n'ont pas réussi à établir un cadre stable pour l'intégration de la demande dans les marchés de l'électricité. En outre, bien que le gisement de flexibilité de la demande identifié soit important, son intégration actuelle dans les marchés de l'électricité ne fournit que partiellement les services permettant à terme l'intégration des énergies renouvelables, ou la gestion de crise similaire à celle subie en 2021-2023.

Deuxièmement, les tarifs dynamiques existants en France ne fournissent pas des signaux prix adéquats dans un contexte de croissance des énergies renouvelables. En effet, dans la mesure où la production d'énergies renouvelables va déterminer le profil des prix de l'électricité, les tarifs ayant une segmentation horaire fixe perdent progressivement de leur intérêt par rapport aux tarifs plus dynamiques. De fait, les tarifs à pointe mobile constituent une alternative à privilégier afin de réduire les pertes sèches pour les consommateurs. Leur adoption plus large nécessite cependant une flexibilité accrue et des possibilités de couverture de risques pour les consommateurs, sous peine de réduire leur taux d'adoption. En effet, le différentiel de prix entre période de pointe et période creuse est croissant dans les scénarios considérés, augmentant la perception du risque encouru.

Troisièmement, le rythme d'électrification industrielle nécessaire pour atteindre les objectifs de décarbonation nécessite une bonne anticipation des volumes et prix à terme de l'électricité pour permettre aussi bien l'électrification de la demande que la décarbonation effective de l'offre. En effet, un scénario d'électrification accélérée qui ne tiendrait pas compte du rythme réalisable de l'augmentation de la production d'électricité risque d'entraîner une perte sèche de bien-être social. En faisant reposer la charge de la décarbonation sur la production d'électricité, la réduction des émissions des industries pourrait engendrer des effets adverses sur le secteur électrique si les investissements ne sont pas coordonnés, résultant en une hausse des prix de l'électricité ou un accroissement temporaire des émissions de gaz à effet de serre (GES) liées à la production d'électricité

Mots-clés : Architecture des marchés de l'électricité, Flexibilité de la demande, Electrification des usages, Optimisation, Décarbonation industrielle.

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List of Acronyms

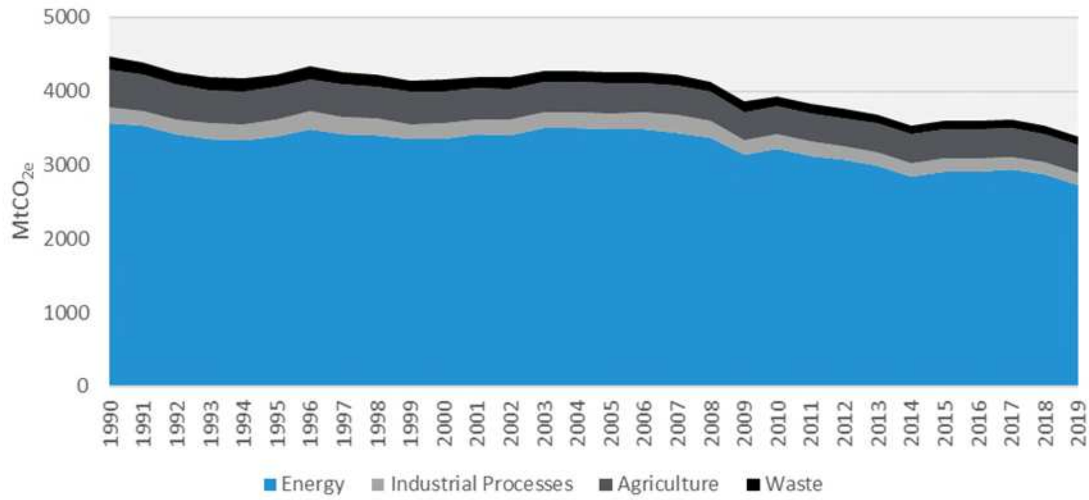
aFRR	automated Frequency Restoration Reserves
AS	Ancillary Services
AMI	Advanced metering infrastructure
AMR	Automated Meter Reading
BRP	Balance Responsible Party
BTM	Behind-the-meter
BTX	Benzene-Toluene-Xylene (Aromatics)
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Usage
CCUS	Carbon Capture, Utilisation and Storage
CfD	Contract for Difference
CPP	Critical peak pricing rates
CSP	Curtailment Service Provider
DAC	Direct Air Capture
DR	Demand response
DSO	Distribution System Operator
ETO	Ethylene Oxide
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicles
FERC	Federal Energy Regulatory Commission
FCR	Frequency Containment Reserves
GHG	Greenhouse gases
HVCs	High-Value Chemicals
ISO	Independent system operator
IT	Iterative
LPG	Liquefied petroleum gas
LSE	Load Serving Entity
MILP	Mixed-integer Linear Programming

MEG	Mono ethylene glycol
MS	Member States
mFRR	manual Frequency Restoration Reserves
NG	Natural gas
NGL	Natural gas liquids
OTC	Over-the-counter
PET	Polyethylene terephthalate
PJM	*Pennsylvania-New Jersey-Maryland* Interconnection
PPA	Power Purchase Agreement
PTA	Purified Terephthalic Acid
PTR	Peak-time rebate rates
PV	Photovoltaics
PVC	Polyvinyl Chloride
RES	Renewable energy sources
RR	Replacement Reserves
RTP	Real-time pricing
SC	Sector coupling
SMR	Steam methane reforming
SRMC	Short-run marginal cost
ToU	Time-of-use rates
TSO	Transmission system operator
UC	Unit commitment
US	United States of America
vRES	Variable renewable energy sources

I - General Introduction

The Sixth Assessment Report of the Intergovernmental Panel on Climate Change (Mukherji et al., 2023) recognises that human influence is unequivocally responsible for the ongoing alteration of the global climate system. This anthropogenic influence severely harms natural and human systems, resulting in the international community pledging to limit global warming to 2°C, and preferably 1.5°C, above pre-industrial levels during the 21st session of the Conferences Of the Parties (COP). As energy consumption has historically been responsible for around 75% of yearly European Union greenhouse gas (GHG) emissions (Mukherji et al., 2023), there is a clear mandate to undertake a sweeping energy transition in the coming decades. Nonetheless, GHG emissions reductions in the European Union (EU) have been slow to materialise, as illustrated in Figure 1. Hence, the pace of transformations required to meet climate plans is gradually becoming more drastic with each passing day.

Figure 1 - GHG emissions by sector in the European Union from 1990 to 2019 (EEA, 2023a)



While electricity represents 27% of the 2019 final energy consumption in the European Union (Eurostat, 2023a), the associated GHG emissions represent a much lower share of the emissions, reaching 14% as of 2019 (EEA, 2023b). Renewable electricity is one of the privileged energy sources for significantly reducing the carbon intensity of the energy supply and is a *de facto* enabler for reaching system-wide decarbonisation. As a result, multiple countries have prioritised investments in renewable energy sources (RES), translating into a significant reframing of the power supply in the forthcoming decades. All segments of power systems are expected to evolve, ranging from the need to expand the power grid (Egerer et al., 2016) to the challenge of meeting the growing power demand on time and the necessity to phase out most existing fossil-fuel power plants on the supply-side (IEA, 2021).

Today, a lingering two-thirds of the world's existing power plants are powered by coal, natural gas, and oil, compared with the 7% share for wind and 4% for solar photovoltaic (PV) (IEA, 2022a). However, the supply-side paradigm shift cannot be disentangled from the demand-side, which also faces a meaningful transformation moving away from fossil fuels. Examples of this shift include the electrification of heat supply in the industrial and building sectors and the increasing adoption of electric vehicles in the transport sector (IEA, 2021; RTE, 2021). Therefore, a significant capital stock change is required throughout the energy transition, requiring states' support to promote decarbonised technology adoption and ensure sufficient social acceptance, as consumers will ultimately bear the cost of the ongoing transition. However, risk aversion from private investors or lack of incentives could hamper the energy transition (Kraan et al., 2019). Breakthroughs are still expected in many sectors so that low-carbon alternatives reach cost-parity with current technologies. Notably, the energy transition entails an important operational challenge to integrate vRES into the existing energy system (Stram, 2016). Indeed, the variability in their power production result in additional hurdles to ensure the power system stability, reliability and resiliency. Implementing flexibility options, such as demand response and storage, is thus crucial for reaching a stable and cost-efficient energy system (Koolen et al., 2022; Wellinghoff and Morenoff, 2007). The IEA (2022b) notably estimates that more than 20% of power system flexibility will be provided by demand response in 2030 in advanced economies, while it only accounts for 4% in current systems. The role of the electricity market in providing adequate short and long-term incentives will therefore be critical to foster the ongoing transformation. The following sections provide an overview of the European power system and electricity markets and present the challenges associated with the ongoing energy transition, setting the ground for this dissertation.

1.1. Evolution of European electricity markets

1.1.1. Navigating amid a trilemma

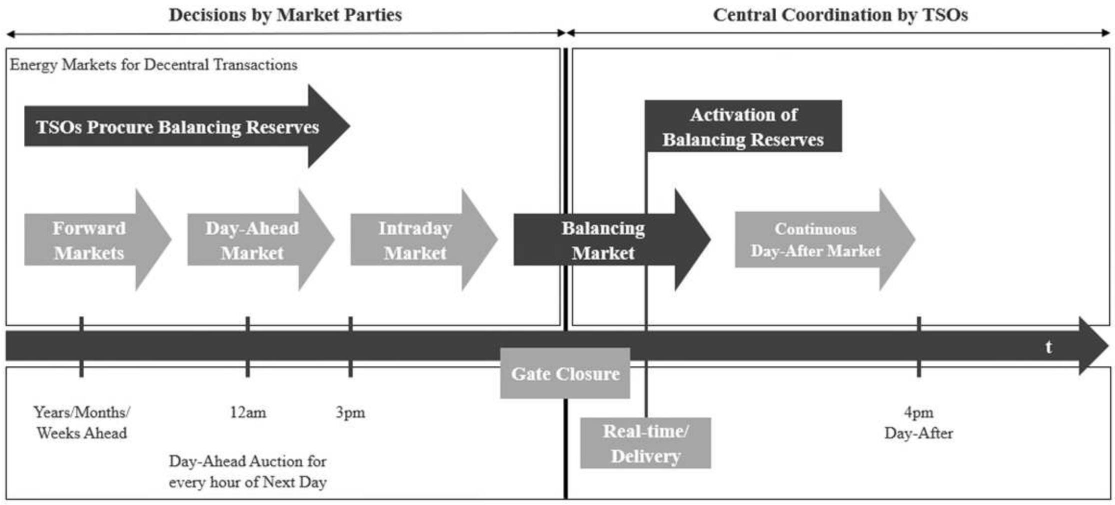
The World Energy Council (2021) introduced the world energy trilemma concept to underscore the challenges the energy sector should overcome in forthcoming decades. Stakeholders in charge of designing the energy transition and associated markets should gauge the ability to (i) provide sufficient energy security while (ii) ensuring energy affordability and (iii) achieving environmental sustainability. Due to the peculiar nature of electricity, the power sector is particularly prone to challenges in meeting those three conditions. Indeed, the supply between demand and production should be ensured in real-time, as electricity cannot be stored cost-effectively for now. As such, in the event of the loss of a power plant, spare capacities must instantaneously increase production, or an equivalent amount of demand must be reduced. As a result, deploying renewable energy sources poses a need for adaptation, as their production depends upon variable weather conditions. Notably, handling variable renewable energy sources (vRES) requires backup capacities capable of ramping at short notice. Historically, thermal units have provided those system services and are now complemented by energy storage (e.g., batteries, power-to-hydrogen) and demand response (DR). In addition, increased interconnection capacity should allow to take advantage of the different wind regimes across a region. While the continuous balance between supply and demand should be guaranteed, affordable access to electricity for consumers and industries is also critical in current societies. Given that power plants have a lifetime that ranges between fifteen to more than sixty years (RTE, 2021), the long-term assessment of costs (fuel cost, CO_2 price) and market conditions (demand level, capacity remuneration, generation, etc.) is prone to many uncertainties, impacting, therefore, the long-term affordability. The 2021-2023 energy and power crisis underscored the need for additional levers to soften peak price periods, as gas power plants have seen a ten to twenty-fold increase in production cost. Finally, energy security and affordability should be balanced with the overarching long-term sustainability goals to ensure climate ambitions are met. Those would require, among others, the deployment of low-carbon energy sources timely and at scale. Regular revisions of the objectives targeting the power sector are therefore included in the European policies to ensure the progress of the energy transition and adjust the instruments accordingly. The "Fit for 55" announcement (European Council, 2022) is the last regulatory piece on this matter in which renewable energy shares and carbon reduction targets were revised. It enacts a net emission reduction of at least 55% by 2030 compared to 1990 levels and a target of 40% renewable energy share in overall energy consumption by 2030, a doubling compared to current levels.

The context of a sweeping liberalisation of electricity markets, enforced since the early 2000s in Europe, adds a particular transformative aspect to the energy trilemma faced in the power sector. Indeed, the progressive opening to competition led to a steady increase in the number of wholesale and retail actors, resulting in complex financial flows and unexpected market failures (CRE, 2023). Although the literature has proposed multiple alternatives to tackling market failures, ranging from new market creation (capacity market, local flexibility market, local marginal pricing) to integrating new actors in existing markets (aggregators, prosumers), not all of them have gained sufficient traction to be effectively implemented in liberalised electricity markets so far (CRE, 2023; Hawker et al., 2017; Rebenaque et al., 2023). In addition, each alternative should be gauged against the energy trilemma to minimise potential negative impacts. For instance, a capacity market that focuses solely on ensuring the security of supply may lead to higher energy costs for consumers, thereby jeopardising energy affordability. Similarly, a market design that primarily incentivises the deployment of renewable energy sources without ensuring energy security may result in grid instability and blackouts, thereby compromising the objective of energy security. Therefore, one of the key challenges for the coming decade is to ensure all objectives of the trilemma are addressed by the market design in place, both in the wholesale and retail markets. One may wonder whether the existing design of both markets is able to accommodate the required change to orchestrate the energy transition. As a matter of fact, those have not been conceived in a context where the operation of power systems with high shares of low-carbon technologies was a particular concern.

1.1.2. Wholesale electricity market design

As previously stated, the central operation and planning performed historically by state-owned monopolies have been abandoned in favour of a market-based structure, with the European Union gradually setting the foundations of a common internal energy market (Ciucci, 2023). Joskow (2008), Concettini and Creti (2013), Newberry (2017), and Wolak (2021) discuss the functioning of the liberalised electricity market and the main lessons learnt since its inception. The energy-only market design, developed based on the seminal work of Boiteux (1951), is a cornerstone of the liberalised wholesale electricity market. In theory, assuming perfect competition, power producers under uniform pricing are better off by submitting bids at their short-term marginal cost. The marginal unit would then set the price based on the short-term variable costs of producing the next unit of electricity. This paradigm would foster efficiency gains stemming from a more efficient allocation of resources based on competitive pressure. In the long-term equilibrium, units are exactly recovering their capital expenditures by collecting inframarginal rents during their operations (Boiteux, 1951) and would invest based on private anticipations of future profitability, converging towards an adequate level of capacity (Stoft, 2002). The liberalised electricity market in Europe is not made of a single and homogenous energy-only market but is based on a succession of sub-markets, as illustrated in Figure 2.

Figure 2 - Overview of different timeframes of the wholesale and balancing in European electricity markets (Amprion, 2023)



Electricity is priced differently depending on the time horizons, namely on forward, day-ahead, intra-day, and balancing markets. For example, in forward markets, price levels are primarily determined based on anticipations of supply and demand equilibrium from market actors rather than relying on the cost of producing and storing electricity, departing from the premises of storable commodities (Prevot et al., 2004). While the succession of markets ensures that the power system operates reliably and efficiently, additional challenges are introduced, such as possible market power abuse, lack of transparency, or market failures that ought to be monitored and settled by the regulator (Hirth and Schlecht, 2018; Joskow and Kahn, 2001). In practice, the opening to competition in electricity markets enabled actors to pursue different strategies relative to price, shape or quantity risk exposure. However, those strategies mostly relate to competition among supply-side production units but have historically disregarded the role that the demand side could play in ensuring the supply and demand equilibrium.

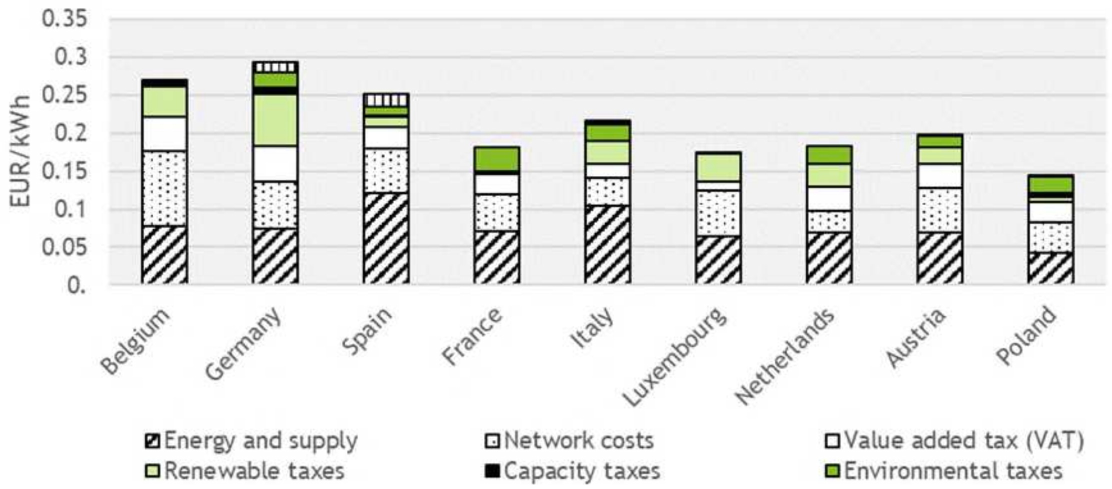
Zooming into the regulatory context, the electricity market liberalisation is framed under multiple *Energy Packages*, the first enforcing the gradual opening of national electricity markets to competition (European Parliament, 1996). Then, the subsequent *Energy Packages* have aimed to improve cross-border exchanges, correct market failures, and align the targeted energy mix of the European Union with the regularly revised climate ambitions (European Parliament, 2021; Nouicer et al., 2020). As a result, a progressive effort of harmonising the different national energy codes has been pursued, aligning operation and market design across all Member States (MS). Despite the convergence in market design and operation, significant differences in power systems across MS remain in keeping with the principle of subsidiarity. Country differences in the power generation mix or in the participation of the demand side still exist – although common marketplaces and reinforcement in interconnections have resulted in an increasing degree of convergence. The regular occurrence of common prices across Europe is a testament to the functioning of the single European electricity market and its ability to secure the power supply (Blume-Werry et al., 2019). For example, monthly full-price convergence in Central-Western Europe (CWE) systematically reached between 30% and 70% in 2021 (European Commission, 2022). Nonetheless, failures of liberalised electricity markets have been identified in the 2000s, notably fears of their practical incapability to ensure capacity adequacy. Hence, capacity payments have been introduced to address the missing money and part of the missing market problem (Newbery, 2016). Indeed, wholesale energy markets feature price caps to safeguard consumers against price spikes. Those directly impact the profits of peaking units, notably if the caps are poorly designed and prevent those from collecting sufficient scarcity rents (CRE, 2023). In addition to the price cap, the volatility in current and medium-term day-ahead power prices refrains private investors from engaging in new capital-intensive power plants. Under those premises, the security of supply in electricity markets has grown under concern, with looming boom-and-burst cycles resulting from structural over- and under-capacity. An option privileged by policymakers was to introduce capacity remuneration mechanisms, which could open both to the supply and demand participants able to react in situation of scarcity. The objective is to supplement energy revenue with capacity payments (Hancher et al., 2015). The introduction of capacity mechanism could, however, distort the functioning of electricity markets due to the lumpiness of the capacity invested, volatility of revenues, and intrinsic uncertainty in capacity or scarcity prices (de Vries and Heijnen, 2008; Ousman Abani et al., 2018). The 2021-2023 energy crisis has reignited the need to enhance and complete the functioning of wholesale electricity markets. Indeed, the security of supply and affordability have grown a major concern for MS, opening the door for a revamp of current market design. A revised approach toward electricity markets also represent an opportunity to address additional decade-long shortcomings. As an example, the lack of participation of the demand side in electricity markets have long been identified as a major market failure, as stated by Bushnell et al. (2009): "A major cause for many of the problems that have afflicted wholesale electricity markets is the unrealised potential for the demand-side to be a full participant." The conventional paradigm governing electricity markets remains heavily focused on a top-down system, historically due to the technological limits set by the metering infrastructure in place. As technical barriers are progressively removed, revising the role of the demand side in the wholesale market is regularly discussed as a means to bolster the efficacy of electricity markets and accompany the deployment of vRES.

1.1.3. Retail electricity market

The demand side of power markets cannot be disentangled from the retail electricity market, which is the main interface between final consumers and electricity producers. While consumer prices have been historically subject to administratively regulated tariffs, the introduction of price and non-price competition is expected to foster efficiency and spur innovation for the benefit of final consumers. As a result, the importance of a competitive retail electricity market is regularly reaffirmed, as in the European Directive 944/2019 (European Parliament, 2019) on common rules for the internal market for electricity, stating that "promoting fair competition and easy access for different suppliers is of the utmost importance for Member States in order to allow consumers to take full advantage of the opportunities of a liberalised internal market for electricity". Such considerations relies on the premises that a "fully liberalised, well-functioning retail electricity market would stimulate price and non-price competition among existing suppliers and provide incentives to new market entrants, thereby improving consumer choice and satisfaction". As a result, new actors have emerged in the European retail electricity markets in the past two decades, consisting of both historical MS incumbents, independent power producers and market-oriented players who do not own facilities.

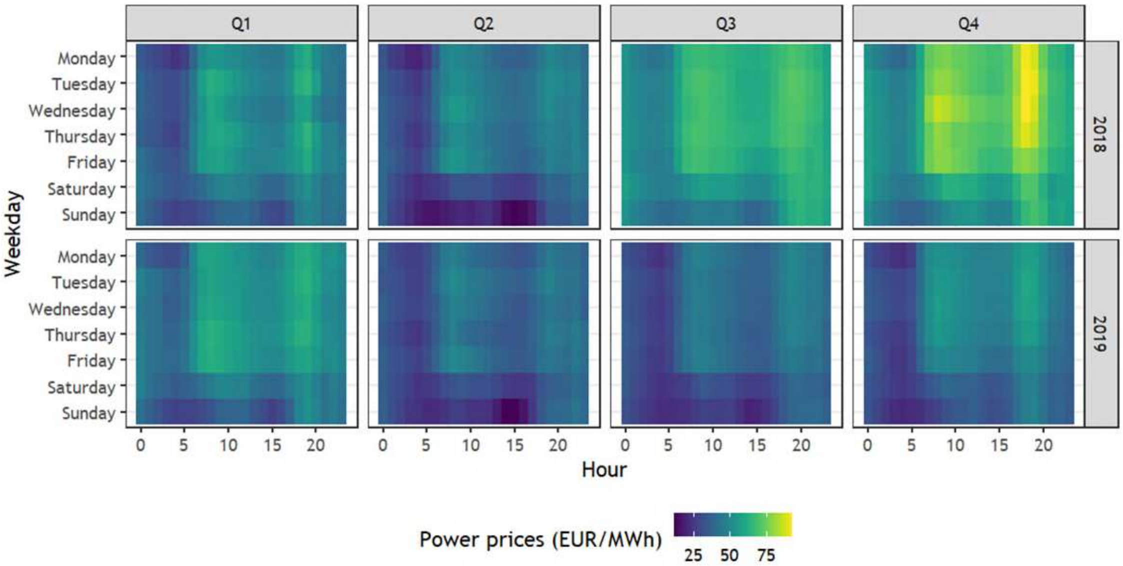
A rich literature discusses the European experience of retail electricity liberalisation and the required conditions to deliver welfare improvements (Amenta et al., 2022; Borenstein and Bushnell, 2015; Poudineh, 2019; Taber et al., 2005). Empirical pieces of evidence of downward price pressure resulting from the introduction of competitive forces are not conclusive in all geographies and for all segments, resulting in legitimate concern about the welfare gain of retail electricity market liberalisation. Notably, liberalisation's benefits are regularly questioned in light of the gradual price increase in the electricity delivered and the lack of incentives provided to foster consumer engagement (CRE, 2023). However, the observed increase in electricity prices over the past two decades can be attributed to the efforts to correct market failures and promote decarbonisation (Moreno et al., 2012), resulting in additional cost component stacking. Indeed, taxes and levies currently represent a third of electricity prices and are instrumental in the deployment of low-carbon energy sources. The case is salient in Germany, where the Energiewende has relied upon significant renewables support schemes framed in the successive *Erneuerbare-Energien-Gesetz* (Büsgen and Dürrschmidt, 2009). While all MS faces similar requirements in performing the energy transition, disparities in their power mix and tax regime result in a heterogenous electricity tariff structure, highlighted in the case of households in Figure 3 for a selection of European countries. It underlines the importance of renewable, capacity and environmental taxes in place in the final electricity tariff.

Figure 3 - Differences in electricity tariff structure in a selection of European countries in 2021 (Eurostat, 2023b)



According to the literature, one of the major hurdles faced during the retail electricity market liberalisation lies in the absence of all the requirements that would enable undertaking this endeavour successfully (Poudineh, 2019). As stated by Joskow and Tirole (2006), final consumers have not necessarily been able to react to power price fluctuations so far due to the lack of smart metering infrastructure, the significant transaction costs associated with power price monitoring and the inability to adjust their consumption freely. As a result, the lack of engagement in markets from the demand side is a persistent weakness of the current market design. A favoured option discussed in the literature lies in the introduction of dynamic tariffs for the energy and the network cost components of the electricity bills. They would allow to wedge the gap between the price faced by consumers and the costs incurred to deliver them the electricity. Advocates of dynamic prices in the retail market emphasise the welfare gain stemming from more active participation from a share of consumers (Allcott, 2011; Borenstein, 2005; Holland and Mansur, 2006; Jessoe and Rapson, 2014; Wolak, 2011). Notably, dynamic prices reflecting the short-run marginal cost of electricity production are expected to increase welfare by conveying scarcity prices and price volatility to consumers. Figure 4 illustrates the recent variations in electricity prices across years, seasons and days in the case of France, where the average daily price of electricity fluctuates by more than 75€/MWh between working days in winter and weekends in the summer. This becomes increasingly relevant as electricity price volatility could be exacerbated with the deployment of vRES and carbon pricing, notably in cases where battery storage and demand-side management are insufficiently developed (Rintamäki et al., 2017).

Figure 4 - Heat maps of average day-ahead power prices in France in 2018-2019 (ENTSO-E, 2020)



On the other side, legitimate concerns exist about whether the benefits of demand-side management are significant enough to justify the equipment of small consumers with dynamic tariffs and the associated smart metering infrastructure (Léautier, 2012). So far, retailers have not been successful in fostering the adoption of dynamic pricing, with less than 25% of households in almost all European countries, with the exception of Italy, Netherlands and the Scandinavian Peninsula (ACER, 2015). However, the undergoing paradigm change in electricity markets will likely reinforce the value provided by dynamic pricing and the need to foster demand response (IEA, 2022b; Léautier, 2012). Similar welfare gains are expected by the adoption of dynamic network tariffs in order to signal grid congestion (Schittekatte, 2018; Schittekatte and Meeus, 2018).

Overall, the welfare gain associated with DR primarily consists of reduced grid investments and operational redispatch costs, which have been continuously increasing with the deployment of renewable energy sources (Hirth and Schlecht, 2018). As a result, existing flat tariffs, charging a simple volumetric rate independently of time considered, would benefit from being revised in order to foster innovation and convey the seasonal and hourly price volatility, provided that consumers are able and willing to react to marginal prices (Ito, 2014). While economic efficiency is a prevailing consideration of the process of retail electricity market liberalisation, it is, however, not the only objective. Bonbright (1961) established guiding principles for rate making, including its understandability, acceptability and stability, among others. The retailers should gauge the balance between the economic efficacy of revised electricity tariffs and their social acceptance (Rábago, 2018). Indeed, one of the downsides of dynamic prices lies in the fact that risks are being shifted to consumers, who have fewer hedging opportunities than retailers in case of volatile wholesale markets. This contrasts with the capacity mechanisms discussed in Section 1.1.2, which enable power producers to secure a share of their revenues to reduce the risks associated with market volatility. Therefore, a key focus of the evolution of retail markets lies in the emergence of long-term supply contracts, securing a price and a share of the consumer's electricity provisions. Proponents argue that forward contracts prevent from benefitting from market opportunities and, from a regulatory perspective, create entry barriers for new entrants (De Hautecloque and Glachant, 2009; Reverdy, 2014). Advocates underline the importance of long-term contracting, notably for electro-intensive industries exposed to international trade, such as chlorine, hydrogen, or aluminium industries (Prevot et al., 2004). The ability to anticipate and hedge the electricity price level is critical to determine the economic viability of the activity. As a result, research is ongoing to reframe the functioning of the existing liberalised retail market to ensure its ability to (i) meet the objectives of affordability and security of supply for consumers and (ii) cope with an increasing share of low-carbon energy sources (CRE, 2023; Newbery, 2017; Wolak, 2021).

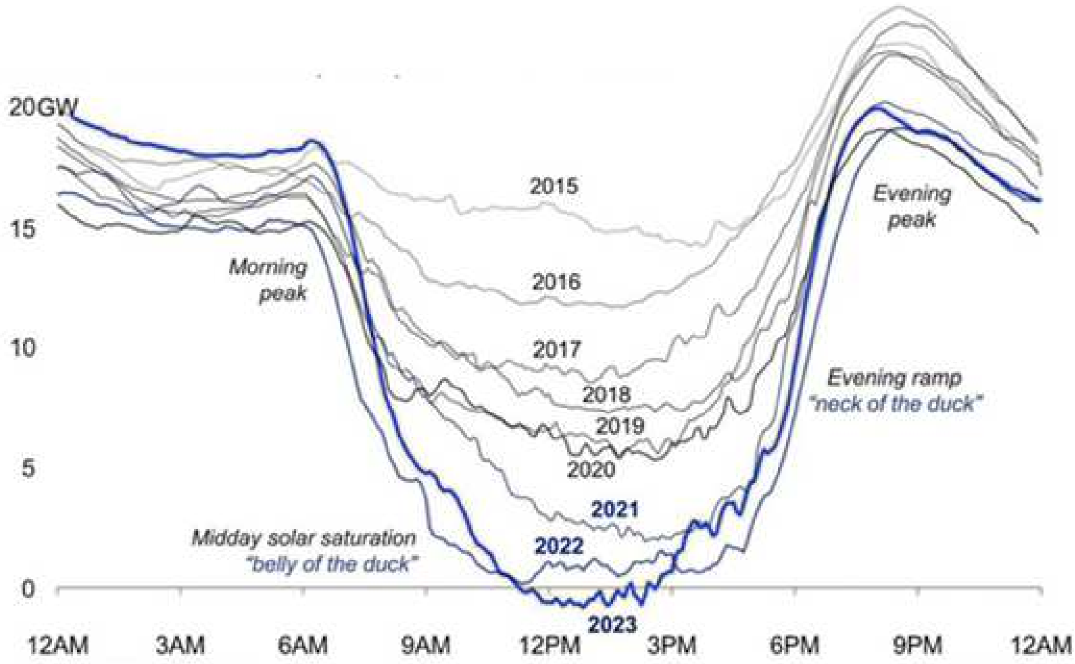
1.2. Current challenges in the European power system

The operation of European power systems is heavily impacted by the integration of vRES. As referred to in the previous section, further integrating the demand in electricity markets would present multiple advantages, ranging from (i) financial benefits from a consumer perspective (bill savings, payments), (ii) financial benefits from a market perspective, both on the short-term (during scarcity events) and in the long-term (avoiding capacity and grid reinforcement costs), (iii) operational benefits, thanks to diversified levers to ensure supply/demand in adverse market situations, as during the 2021-2023 energy crisis in Europe and (iv) environmental benefits expected thanks to demand response, able to reduce the utilisation of emission-intensive peaking plants (U.S. Department of Energy, 2006). The following section illustrates some of the shortfalls faced in existing electricity markets and the uncertainties related to their correction thanks to DR.

1.2.1. Integration of variable renewable energy sources

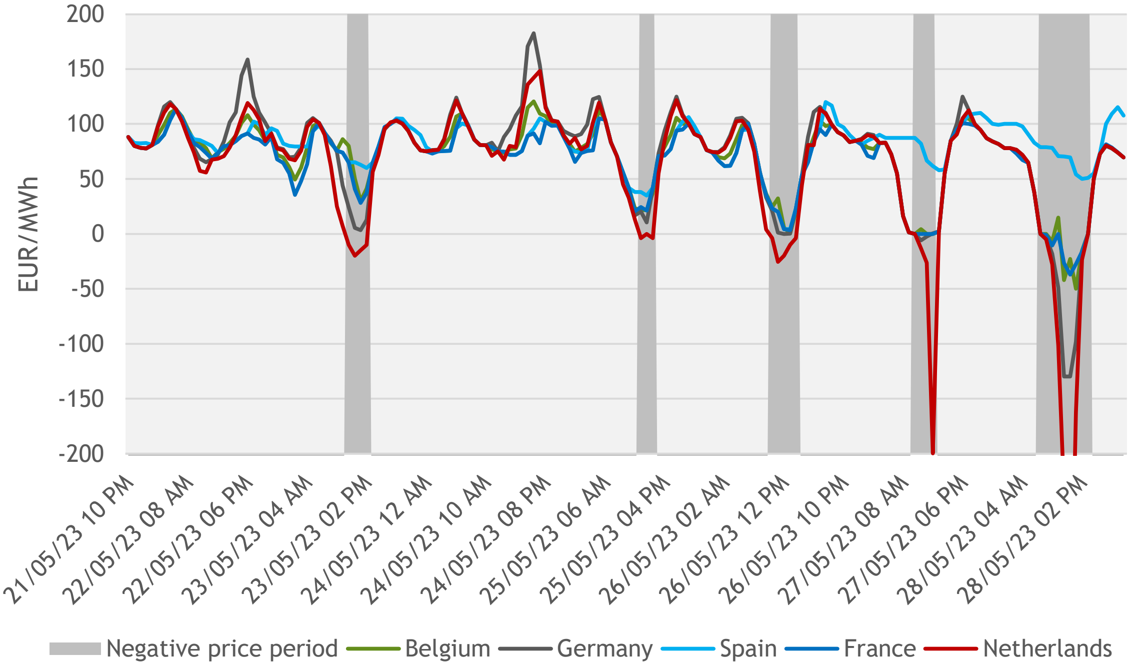
The impact of wind variability and solar PV ramp-up is already dimensioning in many electricity markets, notably in those that have already reached a significant share of vRES. Situations arise during midday hours when the entirety of power demand is met by variable renewable energy sources, resulting in the so-called "duck curve" of net load (IEA, 2020). As an example, Figure 5 illustrates the recent evolution of the net power demand in California, a region that has witnessed substantial deployment of Solar PV installation. While an excess of renewable energy production is not problematic *per se*, this net load pattern requires the availability of backup capacities to supplement renewables when those are not producing and to ensure the equilibrium at times of rapid vRES fluctuations, notably during the morning and evening ramps provoked by solar PV systems (CAISO, 2016). In addition, the market design must ensure that the prices emerging from the electricity market provide the signals required for the investments to arise and permit all market participants to recover their variable costs. Indeed, with power prices being cleared mostly on an hourly basis in Europe, occurrences of midday price drops arise and lead to a detrimental price cannibalisation effect for the installed solar PV (López Prol et al., 2020).

Figure 5 - California net power demand evolution (Bartholomew, 2023; CAISO, 2023)



Given the variability of vRES production and the widening short-run marginal cost (SRMC) gap between near-zero marginal plant and fossil-fuel-based power plants subject to the carbon price, the volatility of electricity prices is expected to increase. In such scenarios, it would be advantageous for both consumers and the grid operator to shift the power consumption to coincide with peak solar PV production while encouraging the deployment of battery storage systems and flexible thermal units to enhance system flexibility and reliability. Typically, the flexibility provided by batteries and demand response could benefit from periods of low power prices and, thereby, contribute to softening price volatility. Those considerations appear relevant as negative price periods have started to arise in European day-ahead electricity markets, as illustrated in Figure 6, with prices on the day-ahead wholesale market reaching -400€/MWh in the Netherlands and weekly price spread reaching more than 100 €/MWh in all countries.

Figure 6 – Power price in selected countries in Central-West Europe on week 31 in 2023 (Fraunhofer ISE, 2023)

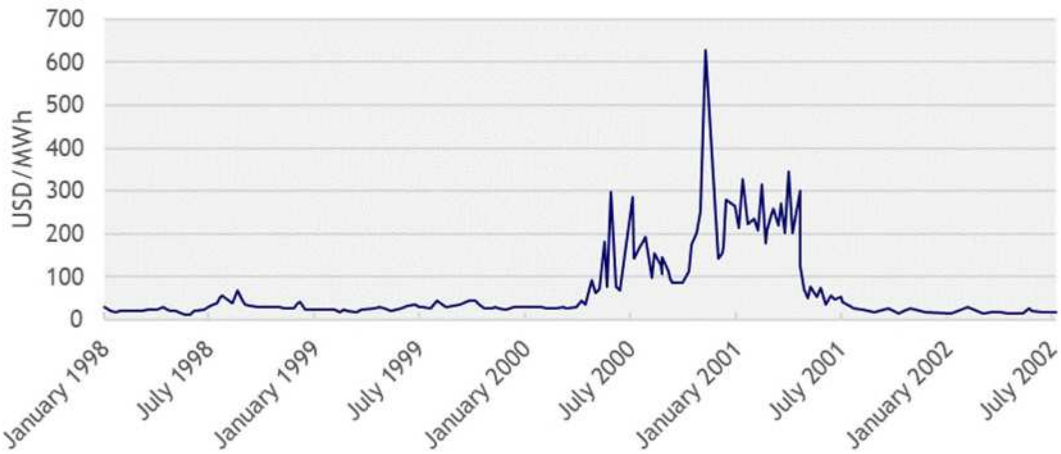


More generally, investing in DR potential is expected to (i) decrease the deadweight loss of consumers by conveying price information, (ii) reduce costly investments in low-carbon peak power plants and grid reinforcement by providing load-shedding capabilities, and (iii) increase the potential of variable renewable energy sources by providing load-shifting capabilities, among other. The recent 2021-2023 power crisis in Europe illustrated the benefits stemming from demand-side reduction, as the French TSO estimates that an average of 7-10% reduction in power demand has been triggered throughout 2023 in reaction to power prices (RTE, 2022). Zooming into the future operations of power systems, the importance of demand-side measures is even more salient. The majority of prospective scenarios in the literature include significant shares of DR to balance supply and demand in future low-carbon power systems (Després et al., 2017; IEA, 2022b; RTE, 2021; Seck et al., 2020). Therefore, enabling DR is considered essential in achieving deep decarbonisation in the power sector and facilitating the integration of wind and solar production (Bataille et al., 2018). However, socio-economic transformations are still required for consumers to become more responsive and active in the electricity market. Today, DR encounters similar challenges as peak power plants in terms of financial viability (Rious et al., 2015), and its current deployment is still far from the estimated potential.

1.2.2. Power price crisis episodes

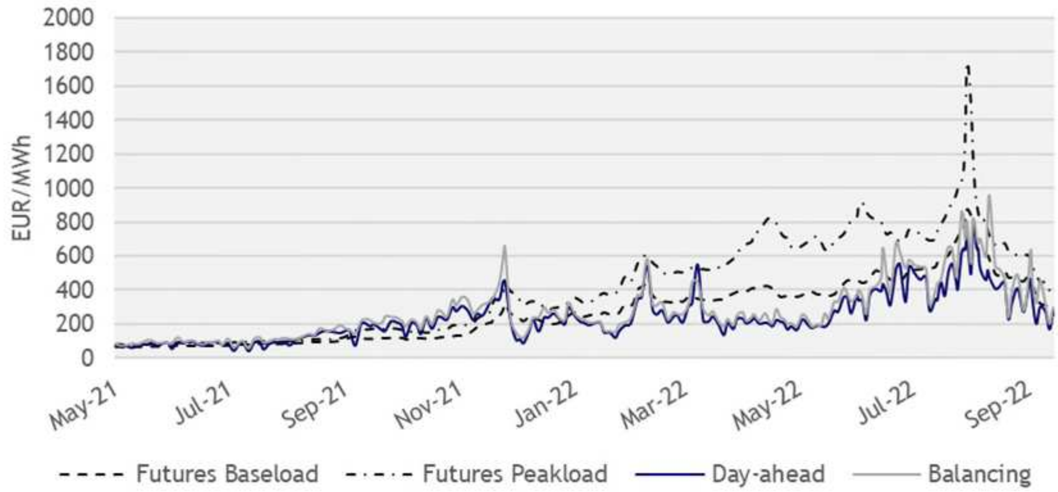
Not only does demand response appear beneficial in future power systems operation, but its slow-paced integration has already exacerbated the power crises that have arisen in the past decades, as demonstrated in the Californian energy markets crisis of 2000-2001. The impact of this crisis is depicted in Figure 7, which shows a ten-fold increase in on-peak power prices and resulted in a doubling of day-ahead power prices over a year. The investigations performed by the United States (US) Federal Energy Regulatory Commission (FERC) revealed that 'significant supply shortfalls and a fatally flawed market design were the root causes of the Californian market meltdown" (FERC, 2003).

Figure 7 - Weekly average on-peak prices in West Coast spot markets (Hanak, 2007)



Three market design flaws have been then identified as the primary causes: (i) the preclusion of utilities to engage in forward contracting, (ii) the lack of demand responsiveness, exacerbating supply shortfalls, and (iii) the under-scheduling of load. Subsequently, in 2008, the FERC issued Order No. 719 (FERC, 2008) to improve the wholesale energy markets incrementally and notably aimed at removing existing demand response barriers. In the wake of the crisis, policymakers have additionally implemented measures to shield consumers and limit the volatility of power prices by introducing price caps in electricity markets. The objective was to (i) prevent gaming and (ii) prevent excessive market power, which can further increase power prices in situations of supply scarcity. Interestingly, the Californian crisis also underlined the extent to which "markets for natural gas and electricity [..] are inextricably linked, and that dysfunctions in each fed off one another during the crisis". This analysis strongly resonates with the 2021-2023 energy crisis in Europe, where electricity markets faced an unprecedented rise in power prices depicted in Figure 8. The crisis directly stems from record-high gas prices and significant supply shortfalls due to the loss of nuclear and hydropower plant outputs. Designed price caps in the electricity market adopted in both the Californian and the European context have been effectively reached multiple times during the 2021-2023 energy crisis.

Figure 8 - Evolution of French power futures, day-ahead and balancing prices in 2021-2022 (EEX, 2022; ENTSO-E, 2023)[1]



Due to the severity of the financial burden associated with the power crisis, policymakers have called explicitly for additional electricity demand reduction measures (European Commission, 2023a). Nonetheless, as identified already in the 2000-2001 Californian crisis, the current retail market lacked the means to signal scarcity towards consumers. Consequently, none of the targeted demand-side reductions has been achieved, neither in terms of overall power demand reduction (-10% target) nor in terms of peak demand reduction (–5% target) (Wood Mackenzie, 2023). Therefore, policymakers and academics have responded to the power crisis by advocating for additional electricity market revision, including (i) improving liquidity in forward markets, (ii) enforcing sufficient hedging from retailers, and (iii) providing consumers more opportunities to participate actively in electricity markets (CRE, 2023). The outcome is similar to what occurred after the Californian episodes. The third market failure identified - the lack of demand response - is the central focus of this dissertation. To effectively enable DR's market participation, three prerequisites have been identified by Wolak (2021): (i) a rollout of the required technology to access hourly-based metering, (ii) the reception of actionable information to alter their consumption, and (iii) the alignment between economic incentives and the actionable information provided. With the advent of smart metering and the easiness of conveying information to consumers, two of the three conditions required for demand-side participation in electricity markets have been met recently. However, economic incentives are still lacking in most liberalised electricity markets. The European Commission has long been trying to improve the electricity market's completeness by enabling the demand to play a more active role, notably outlined in the COM(2015) 339 entitled 'Delivering a new deal for energy consumers' (European

[1] Balancing price depicted refers to the price of activated upward manual Frequency Restoration Reservers (mFRR).

Commission, 2015). The communication builds on Third Energy Package provisions and outlines a new framework for retail electricity markets. Notably, the lack of appropriate information on consumers' costs and consumption is acknowledged, as the insufficiently developed markets and services around residential energy generation and demand response. Subsequently, the European Parliament enacted the directive (EU) 2019/944 on the internal market for electricity (2019), which notably enforced for all MS "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.". The rationale lies in the slow adoption of advanced pricing, where a strong information asymmetry still exists for consumers and dampens their ability to benefit from the low power prices period emerging from electricity markets, which are called to increase in the future. However, their social acceptance is still uncertain, as their adoption have been lukewarm in the past two decades, questioning the potential of DR in the future.

1.2.3. Long-term uncertainties on the demand side

While the two aforementioned aspects of power systems' shortfalls relate to short-term market equilibrium, many uncertainties relate to longer-term changes. On the supply side, those consist of changes in the market design in place, the number of investments realised and their availability in the medium and longer term. Capacity mechanisms address part of those by providing long-term incentives to invest in generation capacities, although the economic context in which capacities will operate is subject to many uncertainties depending on the evolution of commodity price or approach towards environmental externalities. On the demand side, uncertainties remain salient and would mostly depend on the evolution of (i) the incentives in place to decarbonise the final demand for energy and (ii) the long-run price elasticity of demand for electricity, which are critical to assess the impact of energy policies. Regarding the latter, evidence indicates that consumers are more responsive in the long run than in the short term (Auray et al., 2020; Buchsbaum, 2022; Deryugina et al., 2018; Feehan, 2018), underlining the importance of electricity price level in the future trend of power demand, an aspect scarcely discussed in the prospective scenarios.

Most of the incentives in place to achieve the long-term objectives are targeting the supply side based on a combination of taxes and subsidies. Those incentives typically aim at distorting the merit order in energy-only electricity markets (Newbery, 2021) to favour the production of vRES and are primarily based on a cap-and-trade approach to limit GHG emissions since 2005. Regulating the quantity of GHG emissions is attractive to policymakers, as it provides certainty on the allocated emissions for a given trading period and ensures an optimal outcome by letting the carbon price reach alignment with the marginal abatement cost, for example, representative of the current coal-to-gas switch in the power sector (Aatola et al., 2013). Limits compared to a Pigouvian tax lie in the limited forward price information provided to investors (Pigou, 1920; Zhunussova, 2022) and the volatility that could arise in the market. While implementing a carbon tax provides more stable price signals to consumers, it requires an estimate of marginal abatement cost or social welfare disutility of GHG emissions, which are both prone to major assumptions on time preference, equity concerns or the impact of climate change. Therefore, the European Union enforced the EU Emissions Trading System (EU ETS), covering 43% of European emissions and all power plants (European Commission, 2023b). The resulting carbon price has been subject to many swings since its inception, mostly due to excess allowances in its infancy and increasing since that time to a level reaching more than 80 EUR/tCO2e in 2023. It is expected to reach higher levels in the coming decades and should be gauged against the social cost of carbon (Nordhaus, 2017; Pezzey, 2019; Tol, 2011). However, many uncertainties stem from the feasible and desirable rate of decarbonisation of the sector subject to the EU-ETS (Victoria et al., 2020). In addition, many industries depend upon research and development to deploy low-carbon alternatives, notably in the case of energy-intensive industries such as the iron and steel, cement, or the chemical sector. As a result, significant discrepancies in the future power demand stem from the existing foresight scenario (IEA, 2021; RTE, 2021; Sfen, 2020), shading legitimate concern about the amount of power plant that needs to be invested. The electrification level at a given time will ultimately result from the market conditions, the infrastructure in place and the level of carbon pricing in place. As for the electricity markets, the EU ETS mechanisms have been prone to multiple revisions, aiming to correct initial market failures and adjusting the pace of emissions cuts depending on the climate policies in place. A significant concern associated with the EU ETS lies in the risks of carbon leakage for energy-intensive industries exposed to trade, wherein price competition would be detrimental to Europe compared to regions with lower environmental taxation. However, power plants are not concerned as strongly as industries, given that electricity is, first and foremost, a local good with no long-distance freight feasible economically. While this dissertation will not discuss support schemes or the EU-ETS, the short-term and long-term decarbonisation incentives are central to the research questions presented in the following section.

1.3. Research questions and methodology

1.3.1. Research questions

The aforementioned uncertainties have been addressed by numerous research, establishing both the technical foundations of decarbonised power systems and the associated market design required to foster investments compatible with the overarching climate objectives. While the technical feasibility of decarbonised power systems has been demonstrated (IEA, 2021; RTE, 2021; Zappa et al., 2019), all studies underline the significant shares of flexibility required to compensate for the intrinsic variability of renewables, which ultimately depends on factors such as precipitation, wind or solar irradiation. Therefore, fostering the short-term elasticity of power demand is essential to ensure sufficient flexibility provisions in future power systems. Furthermore, significant uncertainties relate to the future electricity demand, which depends on economic growth or the adoption rate of new electric appliances. Those uncertainties also relate to the long-term price elasticity of power consumers, which determines the pace and extent of the electrification of the final energy demand and the associated power capacities in the coming decades. This dissertation builds upon existing literature on market design and decarbonised power systems by focusing on three major issues related to the demand side of future electricity markets: (i) understanding the extent to which existing market designs have encouraged demand-side flexibility, (ii) analysing the adequate short-term price signals to be conveyed towards consumers in decarbonising power systems and (iii) assessing possible welfare losses due to imperfect long-term price expectations between supply and demand in a context energy transition.

Under which paradigm has the demand-side response been integrated into power markets?

As highlighted in this introductory chapter, extensive literature has examined the market designs necessary to foster DR, which has long been recognised as a crucial missing component in liberalised electricity markets (Bushnell et al., 2009; CRE, 2023; Eid et al., 2016). This topic is gaining momentum as smart meters are being deployed in numerous countries. Nonetheless, no universal market design has emerged for fully enabling demand responsiveness, and the effectiveness of existing programs is still to be demonstrated (ACER and CEER, 2022). The first chapter of this dissertation sheds light on the recent experience of integrating demand response in different electricity markets and the paradigm that governed their implementation. It presents a comprehensive literature and empirical review, highlighting the potential benefits of demand response and discussing the programs currently in place across various regions.

Are existing electricity tariffs conveying adequate price incentives towards consumers in evolving power systems?

Following the discussion of the first chapter, the second chapter dives into the current state of electricity tariffs in France. A quantitative assessment of the current tariff's performance is realised, both historically and in the near term. France offers diverse dynamic tariffs, such as Time-of-Use (ToU) and Critical Peak Pricing (CPP), which have come under scrutiny as power systems evolved, sparking debates about their relevance and the savings actually achieved by consumers. The smart meter rollout performed in France and the associated reduction in transaction costs should foster the adoption of dynamic prices in the next decade. However, while the literature has underlined the effectiveness of each tariff design, there is no consensus on the most relevant price signals to convey in power systems with a higher share of renewables and the deadweight loss associated with each tariff design. Notably, the 2021-2023 energy crisis provides insights into the efficiency of the second-best electricity pricing in volatile electricity markets. Following a four-stage methodology, the adequacy and stability of the different dynamic tariffs over time are assessed, considering multiple weather scenarios in forthcoming years.

What are the losses associated with imperfect price expectations of the demand side when planning for system-wide decarbonisation pathways?

Although increasing the amount of short-term DR is essential to improve the economic efficiency of electricity markets, the long-term dynamics of the power systems are prone to many uncertainties, as previously underlined. While most studies have assessed the techno-economic feasibility of decarbonised power system and investigated optimal power generation mix, a significant uncertainty stem from the prospects of the demand side. Indeed, both the future power demand level and the hourly load consumption shape remain highly uncertain. In addition, the long-term price elasticity of the power demand is often overlooked as most studies consider a perfectly inelastic power demand. There is a research gap in understanding the interactions between the transformation of the electricity mix, the electrification of end-uses, and the underlying future power prices affordability. The third chapter addresses this gap by assessing the coordination issues between new electricity uses and the deployment of new power plants. Welfare losses associated with imperfect price and demand expectations are estimated considering the joint transformation of the chemical and the power sectors.

1.3.2. Methodological approach

Optimisation models have long been used to study energy systems. From their inception, models have been used to evaluate preferred technological options, with the objective of minimising primary energy demand, emissions of pollutants or monetary costs (Bruckner et al., 1997; Groscurth et al., 1995). Those models are used to support investment decisions at national, municipal or industrial scale. As a result, those models have been regularly used in assessing preferred pathways for decarbonisation and studying cost-effective abatement options with great technical details (Connolly et al., 2010; Jebaraj and Iniyan, 2006; Pfenninger et al., 2014). Notably, as optimisation models enable a bottom-up approach, this class of model is well-suited to incorporate a detailed description of a given sector based on individual technology representations. However, due to their computationally demanding level of detail, bottom-up models usually adopt a partial-equilibrium approach, relying on exogenous assumptions for demand and prices (Paltsev, 2017) and minimising (maximising) system costs (social welfare), considering investments or operations. Examples of such models in the energy sector exist in all fields: institutional (Kavvadias et al., 2018; Loulou, 2016), academic (Hirth et al., 2021; Leuthold et al., 2008; Maïzi and Assoumou, 2014; Schill et al., 2017; Villavicencio, 2018), and industrial (RTE, 2021; Sfen, 2020). Further distinctions exist among energy-system models based on the time horizon considered. Unit Commitment (UC) models focus on the short-term dispatch of power plants (Pavičević et al., 2019), considering technical constraints and operation of power plants, adopting an hourly or sub-hourly resolution. Conversely, investment models (Dreier and Howells, 2019) focus on the long-term planning of power systems, adopting a less detailed technical and temporal granularity but granting the possibility to consider a broader geographical resolution to account for investment dynamics in neighbouring countries over long periods of time.

To address the research questions of this thesis, outlined in Section 1.3.1, a similar optimisation approach has been developed. Indeed, deriving electricity price patterns and investment dynamics based on a foresight approach requires simulating future investments and dispatch, both in the power system and on the demand side (e.g. for the chemical sector). Therefore, the core model developed in the context of this thesis consists of an electricity market model based on the existing literature and referred to as DEEM (Deloitte European Electricity Market Model). This model is able to perform UC and long-term investment planning depending on the scope considered. The version used in the context of this thesis has been made available online (Cabot, 2023). Therefore, a significant undertaking of this thesis consisted of developing and populating the model with an up-to-date dataset of the power sector and an appropriate level of detail to answer the research questions identified. The model has been jointly initiated and developed with Johannes Brauer. The model has been written in GAMS and solved with the commercial CPLEX solver.

Nevertheless, most optimisation models imperfectly account for multiple aspects related to liberalised electricity markets. They commonly adopt a social planner and system perspective, cyclical tendency, where agents' behaviours and information asymmetry are not adequately factored in (Ousman Abani et al., 2018). Notably, the demand side is usually considered exogenous, with no consideration of the consumer’s price elasticity. As a result, increasing (decreasing) electricity prices would not result in short or long-term demand upward (downward) adjustments. As a consequence, results stemming from optimisation models lack the possibility to depict realistic demand response dynamics. Therefore, different approaches towards DR have been developed in the literature, either by adjusting the formulation of optimisation models or by using additional system dynamic models. While optimisation models outline the least-cost operation of electric appliances (e.g. electric vehicle charging), the price elasticity and willingness to pay from consumers considered in an optimisation model would not depend upon the absolute or relative electricity price level. As a result, a dynamic simulation method has been privileged in this thesis to represent consumer reaction to dynamic prices. This model enables the evaluation of the effects of different tariff designs over demand levels within a framework close to the day-ahead (DA) market. The model, anchored in existing literature (Doostizadeh and Ghasemi, 2012), has been adapted to the French perimeter and linked with DEEM (Cabot, 2023).

Finally, a detailed supply-chain model has been developed to study the optimal decarbonisation pathways for hard-to-abate industries for which direct and indirect electrification (i.e. hydrogen end-uses) are expected to be instrumental. This framework has been deployed on the assessments of the European chemical sector, a sector markedly affected by environmental policies due to the extensive use of oil and gas as feedstock and energy. This model has been coupled with DEEM to assess the impact of considering explicitly an end-use sector and its decarbonisation options, therefore revising the common assumption of exogenous and price-inelastic electricity demand. The model anchors in existing literature (Groscurth et al., 1995; Sahinidis et al., 1989; You et al., 2011) and has been expanded to account for investment dynamics and low-carbon technologies available in the chemical sector.

1.3.3. Organisation of the thesis

This dissertation is structured around three chapters corresponding to each of the topics introduced above.

Chapter I consist of a literature review of DR integration in electricity markets. It is organised into six sections. Section 2.1 provides more background on the open questions related to demand response. Section 2.2 discusses the flexibility required in the different electricity markets. Section 2.3 presents a literature review of DR potential. Sections 2.4, 2.5 and 2.6 present the empirical evidence of demand-side integration in electricity markets under three different paradigms. Section 2.7 discusses the results and their implications. Finally, Section 2.8 summarises the conclusions.

Chapter II builds on Chapter I and proposes an assessment of the performance of possible second-best electricity tariffs in France by estimating their associated welfare deadweight losses. The assessment is conducted both for historical years and using a forward-looking approach up to 2030. The chapter is structured around six sections. Section 3.1 sets up the background and the motivation behind the research question. Section 3.2 presents the methodology introduced to study dynamic tariffs. Section 3.3 describes the approach for simulations. Section 3.4 discusses the results across different dimensions, while section 3.5 discusses the policy implications and concludes.

In Chapter III, a longer-term perspective is adopted, studying the possible welfare losses incurred due to imperfect electricity price anticipation with the electrification of end-uses in the industry. The Chapter builds on the previous electricity market models, completed by a long-range investment planning representative of the chemical sector. Once again, the chapter includes six sections. Section 4.1 introduces the research question and its context. Section 4.2 provides an overview of the European chemical sector, while section 4.3 presents a literature review. Section 0 describes the methodology proposed, in particular, the modelling of the chemical sector decarbonisation pathways. Section 4.5 describes the case study used for the assessment. The results are presented in section 4.6. Section 4.7 provides a discussion of the results. Section 4.8 concludes the chapter.

A general conclusion, gathering the findings of all the chapters, including potential directions for further research, is proposed at the end of the manuscript.

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CHAPTER II

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

"Il faut savoir ce que l'on veut. Quand on le sait, il faut avoir le courage de le dire ; quand on le dit, il faut avoir le courage de le faire." Georges Clemenceau

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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 consumers against 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.

This chapter includes eight sections. Sections 2.1 and 2.2 provide specific context and present the framework of the analysis proposed. Section 2.3 reviews the potential for DR in the power systems studied. Section 2.4 describes the price-based approach towards DR. Section 2.5 discusses the incentive-based programs existing in the different electricity markets, while Section 2.6 discusses the additional market design envisaged. Policy implications and conclusions are laid out in sections 2.7 and 2.8.

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.

Ce chapitre est constitué de huit sections. Les sections 2.1 et 2.2 présentent le contexte et le cadre d’analyse du chapitre. La section 2.3 examine le gisement de flexibilité de la demande dans les systèmes électriques étudiés. La section 2.4 décrit l’approche par signaux prix de la réponse à la demande, tandis que la section 2.5 analyse la tarification fondée sur des incitations. La section 2.6 décrit des architectures de marché additionnelles. Enfin, les implications en matière de politique publique sont discutées en section 2.7, avant de conclure en section 2.8.

Contents of Chapter II

2.1. Introduction

Led by the energy policies fostering the energy transition, a whole new variety of power producers are emerging in the power sector since its 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 peak load 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.

2.2. Demand-side integration in liberalised electricity markets

2.2.1. 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.

2.2.2. 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).

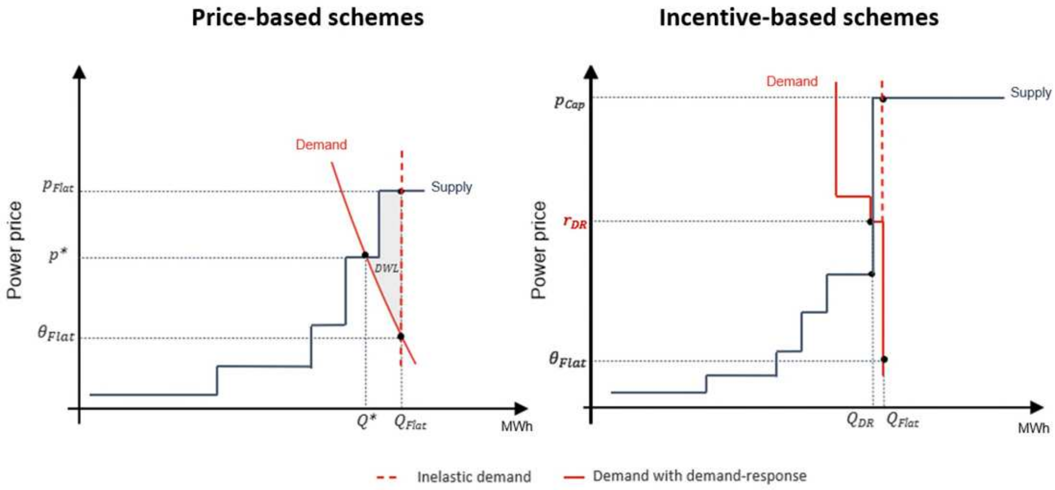
Even though both price-based and incentive-based programs rely on the same set of appliances, they represent distinct demand paradigms, as illustrated in Figure 1. In price-based DR, the objective is to reduce deadweight loss by conveying the electricity price information to the final consumer. In other 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 9, 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[2].

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

Figure 9 - Illustration of price-based and incentives-based schemes paradigm impact on supply-demand equilibrium



2.2.3. 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 were 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.

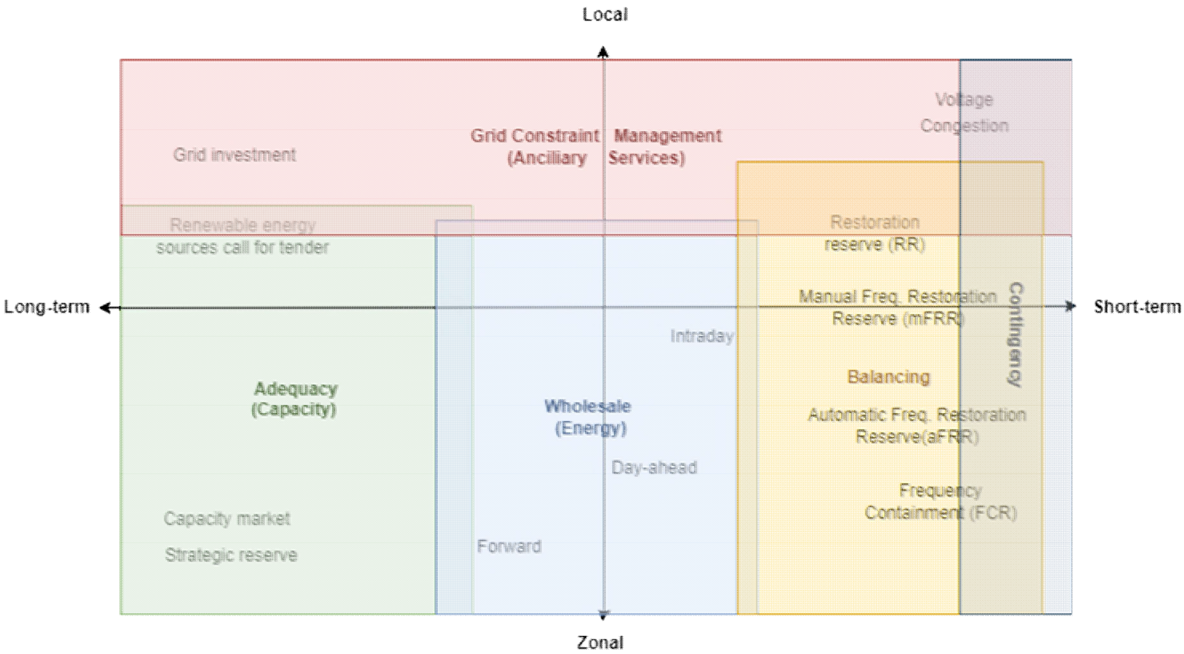
The European electricity market architecture differs from an integrated approach as settlements occur on consecutive markets. This approach is referred to as the *unbundled* market design (Klessmann et al., 2008; Wilson, 2002), where settlements are made successively, first on forward markets, then on 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 10 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 10 - Type of services that could be fulfilled by demand response within this analysis framework[3]



2.3. Current and future demand response potential

2.3.1. 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. 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

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

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 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.

Table 1 - Electricity market characteristics in France, Germany and PJM[4]

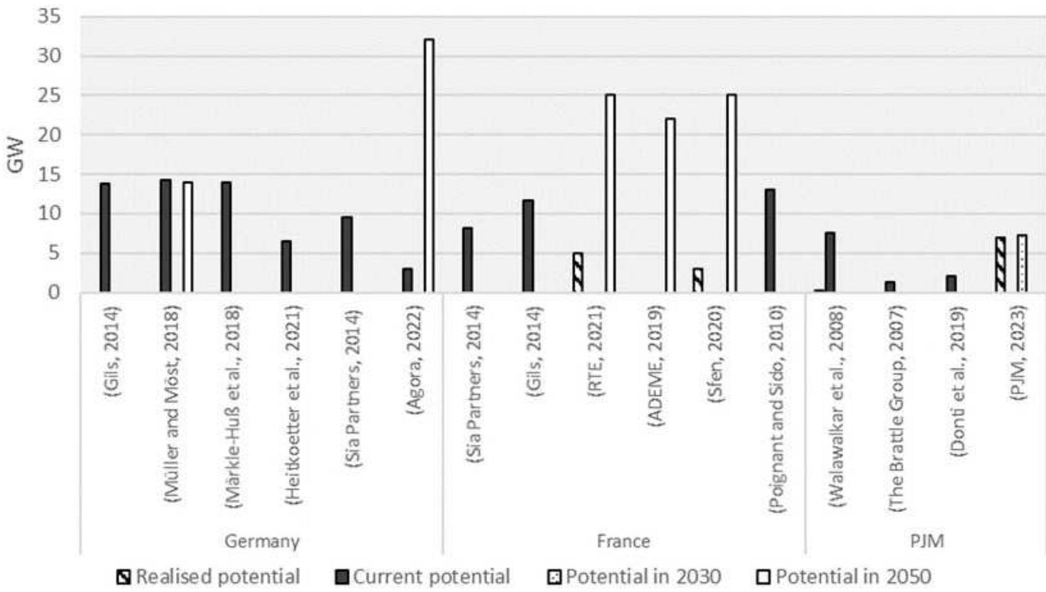
	2018		
	France	**Germany**	**PJM**
Yearly consumption (A) in TWh	478.3	520	806.55
Peak Load (B) in GW	94.5	79.6	165.49
Peak-Consumption Ratio (C = B/A)	0.197	0.153	0.205
Share of RES in annual energy production	21.2%	34.9%	5.4%
Share vRES[5] in annual energy production y	7%	24.2 %	-
Average residential 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%

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 11 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

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

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 11 - Demand-side reduction potential in France, Germany, and PJM from the literature review



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[6] and higher

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

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).

2.3.2. 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 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, and 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).

2.4. Market integration of price-based demand response

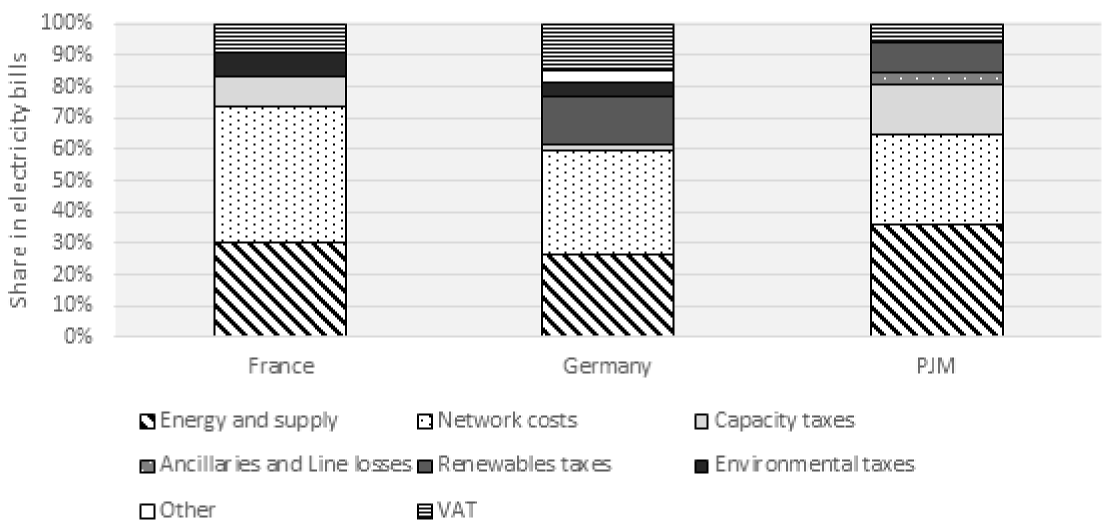
2.4.1. Principles of price-based DR

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). 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 12, with the difference that Germany has around 15% of the bill supporting the Energiewende and the sustained pace of deployment of renewables.

Figure 12 - 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.

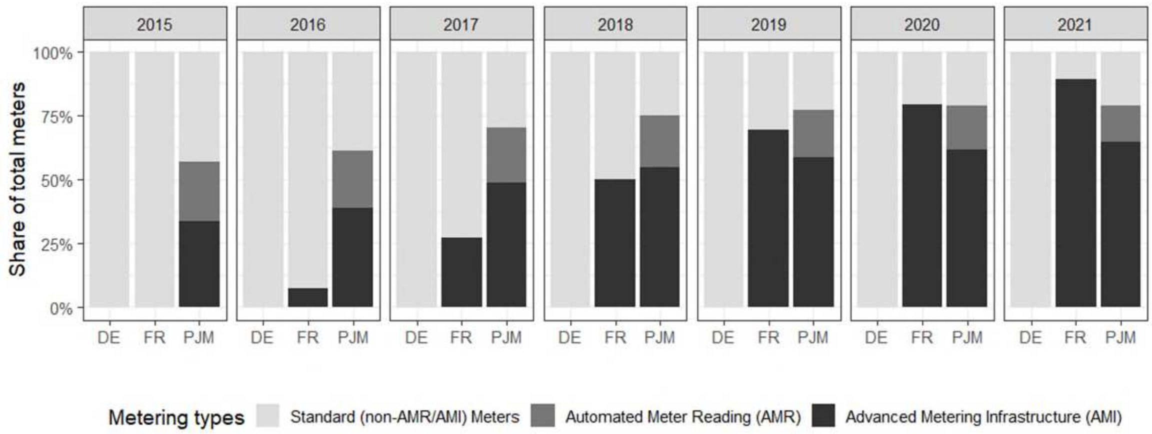
2.4.2. Overview of price-based schemes adoption

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, based on the cost-benefit analyses performed (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 13. 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 did not perform 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-benefit analysis 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 13 - Metering infrastructure in considered electricity markets (BSI, 2022; EIA, 2022; Enedis, 2023)

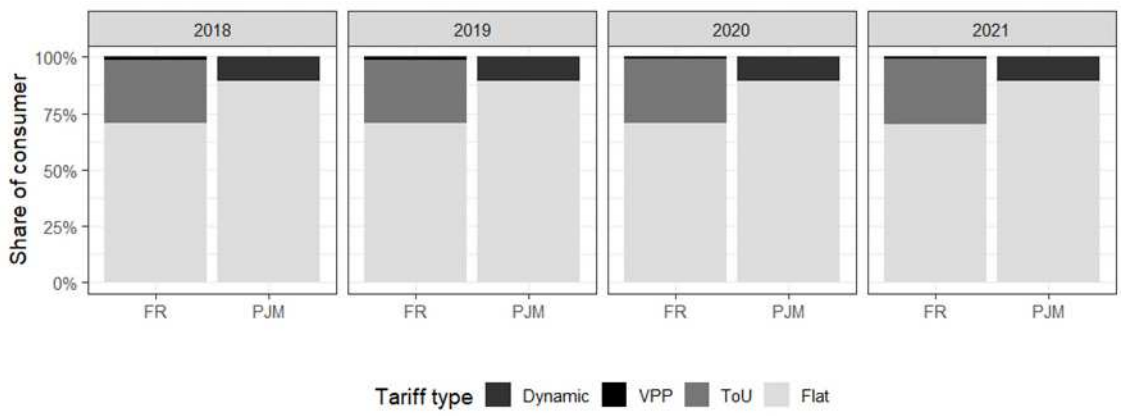


The deployment of smart meters has often been justified based on anticipated efficiency gains, prompting policies aimed at increasing their numbers, albeit with varying degrees of scale across countries. However, the effectiveness of such policies in enrolling customers in dynamic pricing programs is 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 14 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 14 - Share of consumers under dynamic tariff in France and PJM (EIA, 2022; Enedis, 2023)



2.4.3. 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 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[7]. 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[8]. 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, combining 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

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[7] An example of the related capacity reduction considered in the French capacity market is provided in Appendix A2, Figure A.1

[8] The literature review is provided in Appendix A2, Table A.3.

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 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 consists of the measured reduction in peak load 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 are not required 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.

2.4.4. 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 consumers 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 renewable 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 solar 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 solar PV installation. Such considerations are critical for DSOs, as many end-users are investing in batteries and rooftop solar 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.

2.5. Incentive-based schemes market integration

2.5.1. Principles of incentive-based DR

As underlined in section 2.2.2, the fundamental distinction between incentive-based and price-based approaches lies in the existence, within 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

	France	PJM (US)	Germany
Types of DR programs offered	Adequacy (CM, AOE), Contingency (IL) Wholesale (NEBEF), Balancing (FCR, aFRR, mFRR, RR)[9]	Adequacy (CP), Wholesale (Economic, PRD), Ancillary Services (Economic)	Contingency (AbLav), Balancing (FCR, aFRR, mFRR, RR)[9]
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

2.5.2. 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 10) 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-users, 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[10] 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

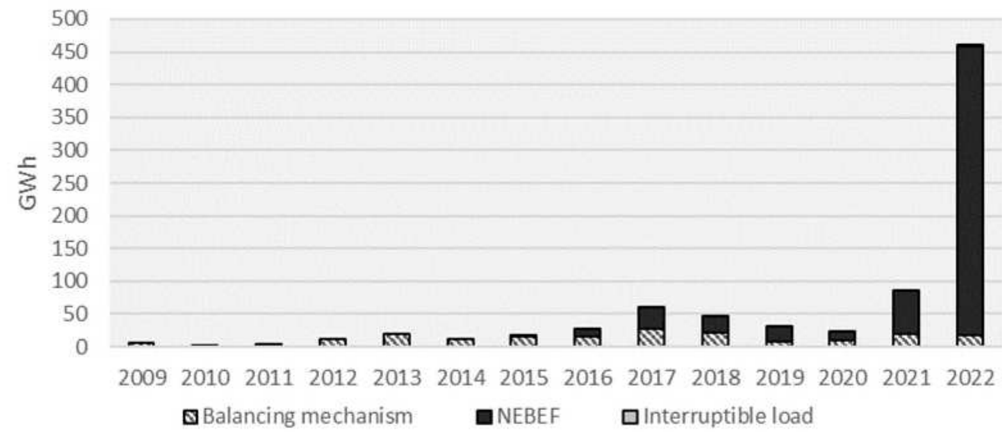
[9] Frequency Containment Reserve (FCR), automatic/manual Frequency Restoration Reserve (aFRR/mFRR), Replacement Reserve (RR). While balancing market are open to DR participation in France and Germany, no targetted DR program or support are implemented to date.

[10] Through participation in NEBEF hereafter described

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 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 15. 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 15 - 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 only 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, whose 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 behind-the-meter diesel generators have not been 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 fostering 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 5 seconds for a minimum duration of 5 minutes (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 11). 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.

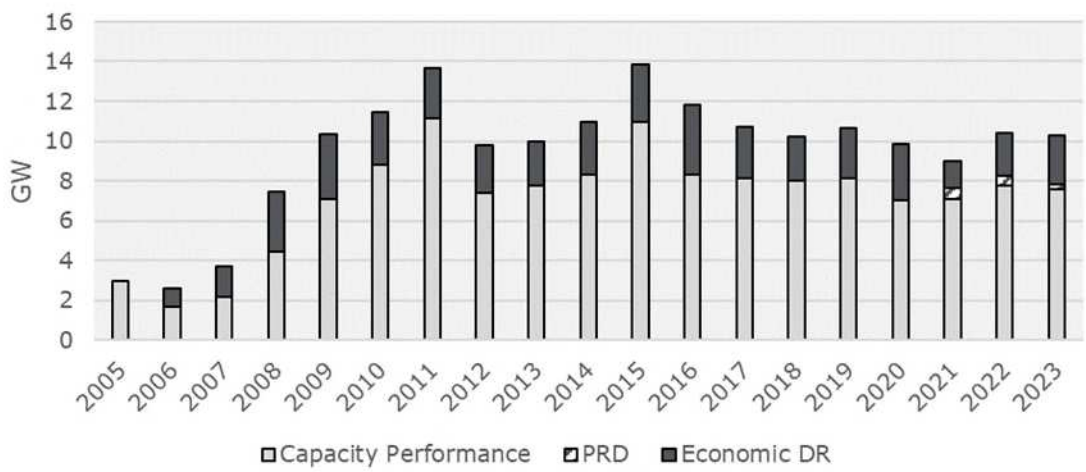
2.5.3. Incentive-based program in the PJM electricity market

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 means 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 16, 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 10).

Figure 16 - Historical PJM incentive-based demand-side enrolled capacity[11] (McAnany, 2023)



[11] 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).

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 120 minutes to 30 minutes 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 should react depends on the season or month to account for a different peak hour. Overall, the current distributed flexibility implementation in PJM focuses on load curtailment and long-term capacity adequacy. Therefore, demand 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, including 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[12] (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

[12] Heating, ventilation and air-conditioning

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). 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 programs studied, bids in Economic DR are flexible and voluntary as no capacity payments are provided.

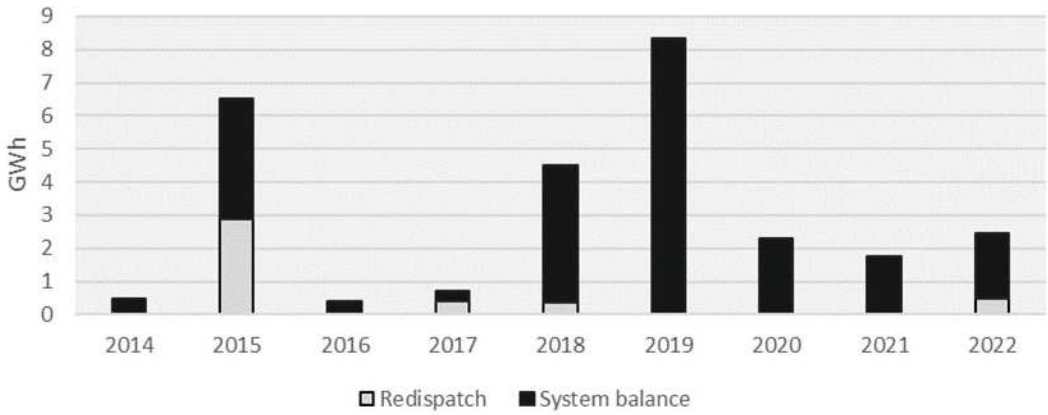
Given their activation price level, the current incentive-based DR programs in place in PJM target discrete events representative of load-shedding capabilities rather than load shaping and load-shifting objectives. Accordingly, the capacity mechanisms provided the predominant revenues of distributed 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 that 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.

2.5.4. 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 17. 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 17 - Historical German AbLav activation (50Hertz et al., 2019)



2.5.5. 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. As the European Commission progresses towards reaching an 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 party 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.

2.6. Alternative market designs in place: the case of local flexibility markets

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[13] 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.

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 harness customer flexibilities and offer 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 day-to-day congestion management but rather valorised for peak shaving opportunities 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

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

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 reaching 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.

2.7. Discussion and recommendations

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.

2.7.1. 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 objectives 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 that allows 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.

2.7.2. 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.

2.7.3. Coherence across the geographical dimension

The research framework, illustrated in Figure 10, 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.

2.7.4. 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 peak load 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 blackout 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	-		+	

2.8. 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 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.

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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 the Impact of Electric Vehicles on peak load 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)[14]	(Schill and Gerbaulet, 2015)

[14] 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	Peak days ("PP2") Nov. - March: 7 AM-15 PM (CET) 18PM -20 PM (CET)	Peak days ("PP2") Nov. - March: 7 AM-15 PM (CET) 18PM -20 PM (CET) or	All	All	All, on TSO request	All, on TSO request	Weekly availability > 138 hours

				Available 20 days among "MiDic" days					
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[15] 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)

[15] 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)

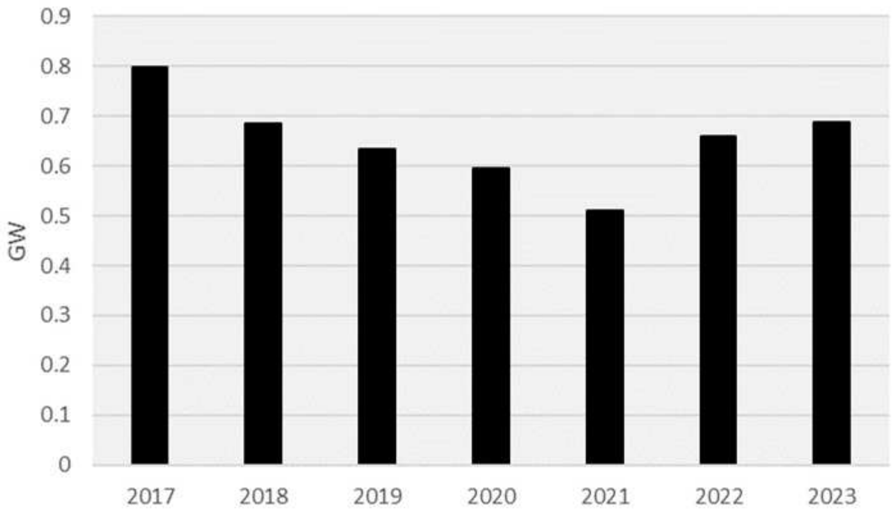


Figure A.2 - French incentive-based DR capacity resulting from the capacity call for tenders (RTE, 2023c)

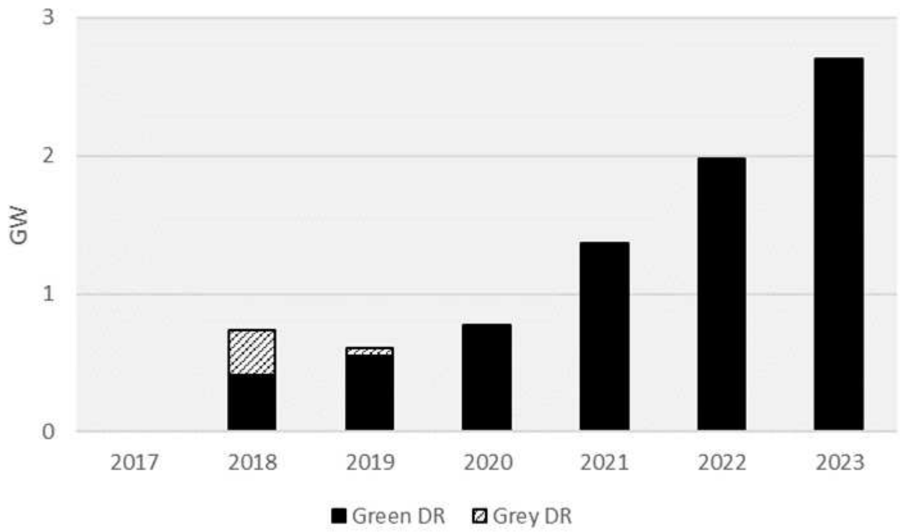


Figure A.3 - Capacity remuneration in France for conventional generators and DR (RTE, 2023c)

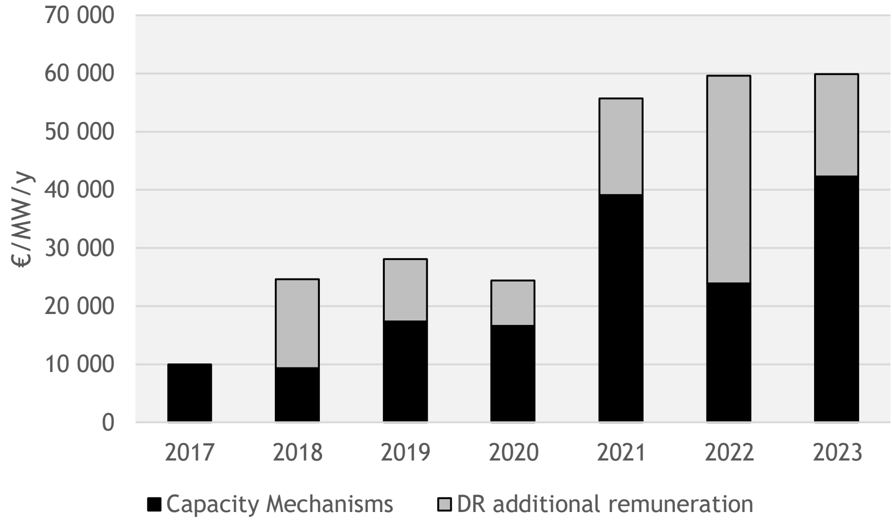


Figure A.4 - Historical PJM incentive-based demand-side and PRD performance (McAnany, 2023)

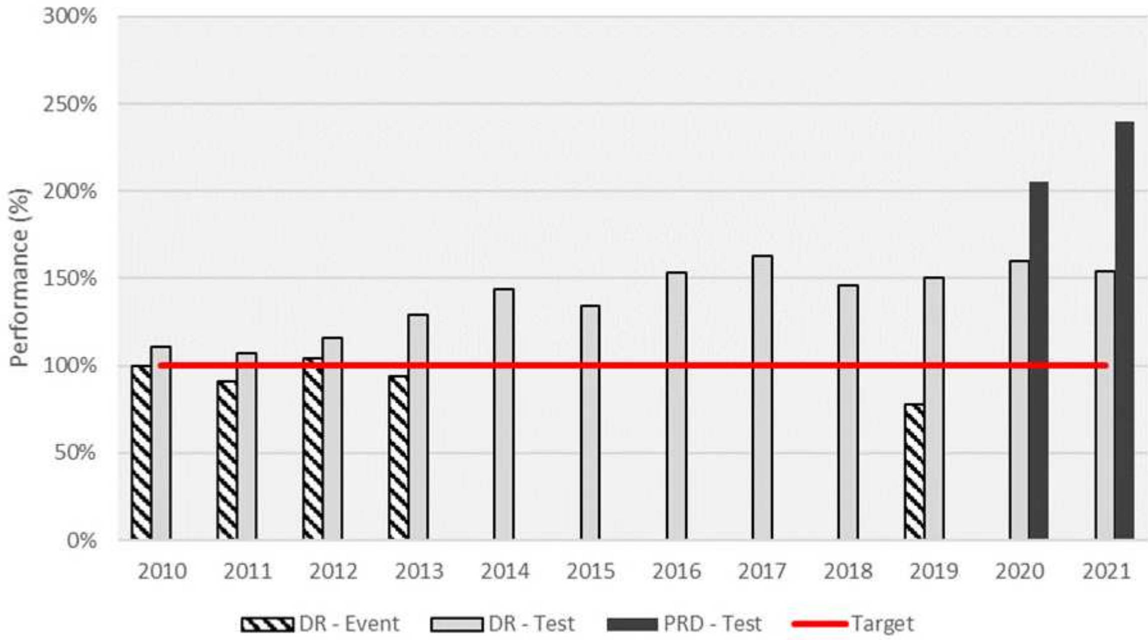
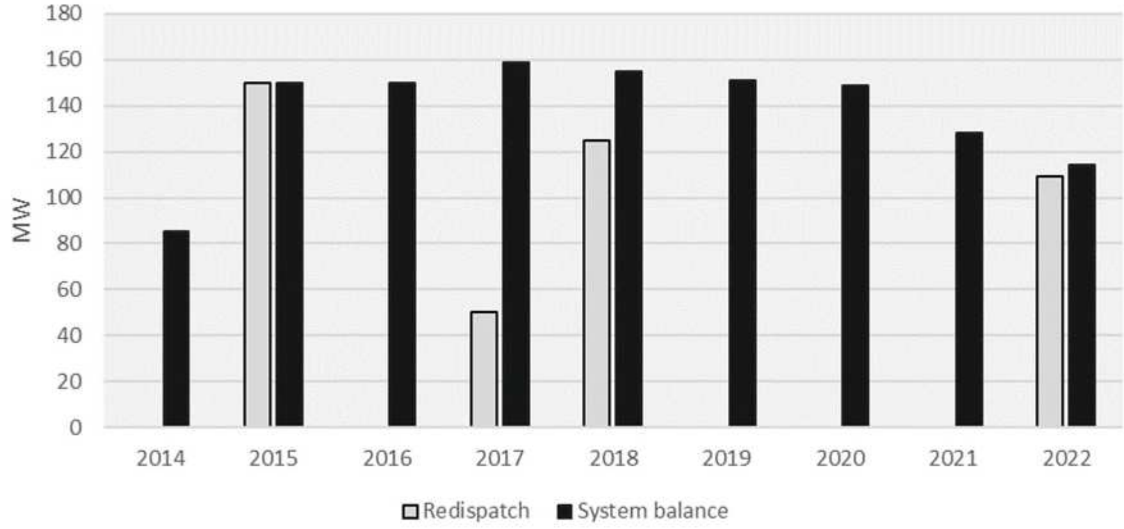


Figure A.5 - Historical German AbLav capacity enrolled (50Hertz et al., 2019)*[16]



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

CHAPTER III

Second-best electricity pricing in France: effectiveness of existing tariffs in evolving power systems

"Les tarifs sont faits pour dire les coûts comme les horloges pour dire l'heure" Marcel Boiteux

A preliminary version of this chapter has been published as a working paper: C. Cabot and M. Villavicencio, "Ensuring distributed demand response through future-proof tariff design," 2022, CEEM Working Paper.

The paper has been submitted to Energy Economics and is under review.

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Abstract

The adoption of dynamic tariffs in the French electricity market has been historically low despite their availability to consumers well before the deployment of smart metering. However, as the share of variable renewable electricity increases and carbon prices grow, the demand-side response will become increasingly important to achieve efficiency gains. Relying on the historical hourly consumption of French electricity consumers and multiple prospective weather years, we study the gain allowed by the broader adoption of dynamic electricity tariffs in low-carbon power systems.

We develop a four-stage methodology to assess the efficiency and stability of tariffs in France for historical and prospective years. Our analysis demonstrates that peak pricing schemes have increasing interest in the context of further deployment of renewable capacity, capturing 25% to 50% of the welfare gain reached under the theoretical first best of real-time prices. The corresponding deadweight loss of second-best tariffs represents 1 to 1.2 bn EUR per year in 2030 compared to the first-best of real-time prices. Conversely, welfare gains achieved by current time-of-use tariffs decrease over time and do not provide adequate incentives in future power systems. Besides the tariff efficiency, the results underlined an increasing price difference between on-peak and off-peak rates. This questions the social acceptance of dynamic tariffs for consumers unable to hedge against peak prices. By analysing the effectiveness and limitations of dynamic tariffs, our findings underline the importance and value of price-based DR in future power systems in general. Our results highlight the need to revise the end-user tariff design in the French power system, notably with regard to the conveyed price signals.

The chapter includes five sections. Section 3.1 and Section 3.2 sets up the motivation and the context behind the research question. Section 3.3 presents the methodology introduced to study dynamic tariffs. Section 3.4 discusses the results across different dimensions and discusses the policy implications. Conclusions are summarised in section 3.5.

Résumé en Francais

L'adoption de tarifs dynamiques sur le marché français de l'électricité a été historiquement faible, malgré leur disponibilité pour les consommateurs bien avant le déploiement des compteurs intelligents. Cependant, à mesure que la part de l'électricité d'origine renouvelable augmente et que les quotas d'émissions de GES diminuent, la flexibilité de la demande permet de réaliser des gains d'efficacité croissant. Ce chapitre s'appuie sur la consommation horaire historique des consommateurs français d'électricité, et sur plusieurs années météorologiques, afin d'étudier les gains liés à l'adoption de tarifs d'électricité dynamiques.

Une méthodologie en quatre étapes est développée afin d'évaluer l'efficacité et la stabilité des tarifs en France pour les années historiques et prospectives. Notre analyse démontre que les systèmes de tarification de pointe présentent un intérêt croissant dans le contexte d'un déploiement des capacités renouvelable, en capturant 25 à 50 % du gain net de bien-être atteint par la tarification en temps réel, optimum de premier rang. La perte sèche associée aux tarifs de second rang représente 1 à 1.2 milliard d'euros par an en 2030 relativement à l'optimum de premier rang d'une tarification en temps réel. En outre, le chapitre démontre que les gains nets de bien-être obtenus par les tarifs heures pleines/heures creuses actuels diminuent avec le temps et ne fournissent pas d'incitations adéquates dans les systèmes électriques à fortes proportions d'énergies renouvelables. Outre l'efficacité des tarifs, une différence de prix croissante entre les tarifs des heures pleines et des heures creuses est constatée. Cela questionne l'acceptation des tarifs dynamiques pour les consommateurs dans l'impossibilité de se couvrir contre les tarifs de pointe.

Plus généralement, les résultats soulignent l'importance et la valeur de la modulation de la consommation dans les futurs marchés de l'électricité. Néanmoins, il est nécessaire de revoir la conception actuelle des tarifs sur le marché français et les signaux prix transmis aux consommateurs.

Ce chapitre est constitué de cinq sections. Les sections 3.1 et 3.2 exposent la motivation et le contexte de la question de recherche. La section 3.3 présente la méthodologie utilisée pour étudier les tarifs dynamiques. La section 3.4 analyse les résultats selon différentes dimensions et discute de leurs implications. Les conclusions sont résumées dans la section 3.5.

Contents of Chapter III

3.1. Introduction

In the wake of the liberalisation of electricity markets, the introduction of competition in retail activities has provided consumers with multiple possible suppliers. However, despite the unbundling of the electricity market, there has been a lack of diversification in billing schemes with regard to tariff design, as most consumers are still charged a flat tariff based on their energy consumption. This historical choice was partially due to the limited metering capabilities, as the infrastructure deployed only allowed for annual or bi-annual readings and the inexistence of smart appliances.

Both the literature and fields experiment have, however, demonstrated tangible welfare gains from switching to dynamic pricing schemes to enable a direct cost pass-through from wholesale market prices to end-users (Allcott, 2011; Faruqui and Sergici, 2010; Wolak, 2011). Consumers were proved in those pilot projects to be statistically significantly price elastic, with peak load reduction achieving between 10 and 50% depending on the incentives, which comes to challenge the common assumption of inelastic consumers in the short-term. There is, therefore, the opportunity to send price incentives to end-users that would better reflect the market situation and notably enable them to manage their load to respond to grid congestion or scarcity on the supply side. Furthermore, even if short-term benefits might be low, literature has demonstrated non-negligible welfare gains in the long run by delaying or reducing investments in peaking capacity and network expansion (Borenstein, 2005; De Jonghe et al., 2012).

Those benefits are expected to be even more tangible now that most countries are completing their national plans to roll out smart meters and that system variability starts to be supply-side driven due to the increase in wind and solar generation. The European Commission indicates an annual saving of 22-70% of the energy supply component in the annual bill for small consumers (European Commission, 2019). Notwithstanding, concerns exist as dynamic pricing results in a pass-through of risks linked to price volatility towards end-users, who are less able than retailers to hedge against price volatility. During the 2021 winter events in ERCOT, existing spot-index-based tariffs have led to a considerable increase in consumer bills (Blumsack, 2021). Mitigation options include second-best pricing schemes such as Time-Of-Use[17] or Critical Peak Pricing. However, the European Parliament directive 2019/944 (European Parliament, 2019) states that "[All consumers] should therefore have the possibility of benefiting from the full deployment of smart metering systems and, where such deployment has been negatively assessed, of choosing

[17] Time-of-use rates adjust the rate depending on a pre-defined time period. It usually incentivises electricity consumption at a time of low demand (price), during the night. Critical Peak Pricing defines a fixed annual number of days where the electricity rate is higher.

to have a smart metering system and a dynamic electricity price contract. This should allow them to adjust their consumption according to real-time price signals that reflect the value and cost of electricity or transportation in different periods, while the Member States should ensure the reasonable exposure of consumers to wholesale price risk." According to the same directive, such dynamic offers will be mandatory for suppliers with more than 200,000 final customers. There is, therefore, a need to assess to what extent the demand response will represent an opportunity for responsive consumers.

This paper contributes to the literature by exploring the welfare gains of different time-differentiated electricity tariffs in both the historical and prospective French power systems. With the joint increase of near-zero marginal price capacities of renewable power and the rise of the short-run marginal cost of remaining thermal units due to the increasing price of emissions allowances, power prices are called to face increasing volatility in the near future. Therefore, the perpetuation of legacy rate structures to provide price signals to consumers may result in a loss of welfare if incentives are not aligned with the evolving needs of the power system. In contrast, new rate designs would be increasingly relevant due to the anticipated increased volatility.

In the first step, we investigate how existing tariffs have performed based on historical load consumption per profile from 2018 to 2022. The period studied has the specificity to include two successive crises impacting the power sector: the first relates to Covid-19, and the subsequent relates to the Russo-Ukrainian conflict. In the second step, we assess to what extent the rising carbon price and deployment of renewable energy sources impact existing schemes' benefits and volatility.

We find that the welfare gain of tariffs with peak pricing features increases over time, capturing between 25% to 50% of the welfare gain of the theoretical first-best of real-time prices. As the peak prices increase over time, due to the combined effect of carbon prices with a reduction in dispatchable power plants and the increased reliance on interruptible load, the welfare gain of fostering such tariffs increases. Conversely, the power price pattern will correlate with the net load, decreasing the correlation of the existing time-of-use rate with power prices. This phenomenon holds for most tariffs with fixed partitioning of hours and week. Nonetheless, we find that significant power price reductions are achievable by increasing the share of dynamic tariffs. However, the on-peak-to-off-peak ratio will likely increase in the coming years, raising questions about the social acceptance of such tariffs.

3.2. Literature review and contribution

Evaluating consumer price elasticity within the power sector has been a persistent topic of interest for both the industry and academics. One of the primary motivations for increasing consumers' price elasticity in the power sector is to mitigate the need for costly energy infrastructure and power plants, such as peak units and transmission lines. Furthermore, augmenting the price elasticity of demand can also contribute to more effectively balancing the supply and demand of electricity, thereby enhancing the efficiency of the power grid and reducing the likelihood of blackouts or brownouts. This is of increasing significance as supply becomes increasingly volatile due to the deployment of renewable energy sources. Consequently, numerous studies have been conducted over the years to gauge power price elasticity for various types of consumers in different countries. A primary distinction is between price-based and incentive-based schemes, both of which are utilised to curb energy consumption and promote energy efficiency. Price-based schemes leverage tariffs to induce changes in energy consumption by adjusting the price of electricity based on time or demand. In contrast, incentive-based schemes motivate consumers to reduce their energy consumption by offering financial rewards, often through contractual agreements. These two approaches represent distinct strategies for promoting energy conservation. Understanding their relative effectiveness is critical to designing successful energy policies. Our research focuses on price-based incentives, for which econometric modelling has been widely employed to estimate price elasticity in this context. Numerous studies have been conducted since the 1970s on the topic. Labandeira et al. (2017) perform a meta-analysis of recent and sizeable empirical studies to estimate short and long-term elasticity for various energy goods. In the case of electricity, short-term elasticity averaged out at -0.126 in the empirical literature. Andruszkiewicz et al. (2019) performed a literature review focusing on electricity price elasticity and found a relatively large range of self-elasticity, depending on the methodology deployed and the geographies considered. More importantly, they highlight that a common assumption is that short-term price elasticity is usually considered constant when it should be determined as a time variable. Additional research by Fan and Hyndman (2011) and Knau and Paulus (2016) provided the first estimates of hourly price elasticity of demand in South Australia and Germany, respectively, to support this idea. Specifically, they found that the price sensitivity is higher in the early morning and the afternoon. We posit that this is important when estimating the future welfare gain from having price-reactive consumers, as renewable power production will be much more volatile. The available literature on French electricity consumption and pricing is limited. Auray et al. (2020) estimate short- and long-term elasticities of French power consumption. Aubin et al. (1995) examine the impact of the "Tempo" tariff structure, which features six different pricing levels based on peak days and on-peak/off-peak hours. Their analysis finds that consumers are responsive to price changes, demonstrating price elasticity and that a majority of consumers benefited from the tariff structure. This highlights as well the relative dearth of data and studies conducted in France, where a relative overcapacity resulting from the extensive nuclear program diminishes the interest in costly demand-side management. However, the temperature sensitivity of power demand justified the offering of dynamic tariffs to different consumer segments, and the deployment of smart metering has been performed for all consumers. Further research is needed, given that the French nuclear fleet is ageing and that renewable energy sources are expected to provide a significant share of future power production (RTE, 2021). With the widespread implementation of smart meter technology, the ability to contract and measure consumers' power consumption under new tariffs has become increasingly feasible. As such, a notable segment of research in the realm of power price elasticity focuses on utilising field or natural experiments to empirically evaluate the responsiveness of consumers to various forms of dynamic pricing. These field experiments, such as those conducted by Allcott (2011) and Faruqui and Sergici (2010), have demonstrated the effectiveness of dynamic pricing despite the commonly observed low price elasticity of demand. One of the major hurdles for dynamic pricing adoption and effectiveness lies in the transaction cost associated with (i) changing electricity contracts and (ii) monitoring electricity price variations. In addition, consumer preferences are heterogeneous, as underlined in studies evaluating the relevance of behavioural factors such as patience, trust, risk and complexity aversion (Ziegler, 2020). While consumers prefer simple tariffs (defined as flat or two-part tariffs), providing them with adequate information or monetary incentives can overcome risk aversion or status quo bias for a share of consumers, although marginally (Dütschke and Paetz, 2013; Mayol and Staropoli, 2021). Although representing additional deployment costs, automation technology could ultimately reduce the impact of limiting behavioural factors and increase demand response (Buckley, 2020; Harding and Sexton, 2017). While those studies provide a better understanding of the factor at play in fostering dynamic electricity contracts and of the share of consumers who are likely to engage in those, it does not inform on the relevance of the dynamic tariffs concerning the operation of the power systems.

Recently, new insights have been given utilising simulation models to evaluate the welfare implications of departing from flat rates. Researchers such as De Jonghe et al. (2012), Gambardella and Pahle (2018) and Wolak (2019) have developed model-based methodologies to assess welfare gains from real-time pricing (*RTP*) implementation, primarily stemming from a reduction in the required investment in peaking generation capacity. Conversely, only a slight change is expected in consumers' electricity bills, raising the question of whether financial incentives are sufficient. Regarding the impact of increasing renewable energy generation, Anasarin et al. (2020) estimated the impact of five different tariff schemes over 144 households in the USA. The results underline how novel tariffs increase fairness and efficiency but focus on prosumers' and consumers' differences. An assessment of the stability of different tariff schemes in a system with increasing shares of renewables is lacking in the literature.

Schittekatte et al. (2022) suggest that dynamic tariffs are more socially valuable than previously estimated when considering changing generation mix. They notably introduce a new metric: the realised cost reduction potential (RCRP) of *ToU* and *CPP* rates using historical data from CAISO, ERCOT and ISO-NE. Based on two numerical models, the results indicate that the correlation between *ToU* and *RTP* prices is low (0.3-0.5) but can be significantly improved when complemented by *CPP* at times of high scarcity. Our research follows these attempts to study tariff design in forward-looking power systems but has a different geographical focus and derives insights from recent events in Europe.

Focusing on easily applicable heat pump load management, Nolting and Praktiknjo (2019) concur with the existing literature, denoting that current *ToU* and *RTP* incentives are insufficient to result in financial gains, especially when considering efficiency losses. However, medium-term scenarios with higher penetration of renewable energy sources result in increased financial interest. Ambec and Crampes (2021) show that increasing the share of reactive consumers reduces overall costs and emissions and would require some form of redistribution for non-reactive ones. In addition, the social welfare gains decrease with the shares of reactive consumers, pointing out that smart meters should not necessarily be deployed for all consumers. Essentially, there is a point at which increasing further consumer reactivity results in minimal additional welfare gains. Finally, our research anchors in the more general analysis of imperfect pricing policies. Jacobsen et al. (2020) demonstrate that standard output from a regression could be used to characterise the welfare gains achieved by imperfect pricing policies. Notably, they applied their approach to time-of-use electricity tariffs in the PJM wholesale electricity market and found little efficiency in the commonly used tariff structures. The coefficient of determination (R^2) of the regression is found to be a reliable indicator of the efficiency gains of constrained policies. Building on their demonstration, we use this metric to compare the model-based welfare assessment in the case of France.

Our research builds upon the last two methodological approaches to perform, to the best of our knowledge, the first assessment of the existing tariffs in France. The country's power demand is highly electrified for heat provision, thus subject to significant deviations driven by its temperature sensitivity of load. By adopting a system-level assessment of the country, we bring more general insights into the value of price-based DR in advanced electrification of the energy supply. In addition, we note the lack of explicit research on how integrating renewable energy sources (RES) impacts economic efficiency for various tariff schemes over time, as most studies and pilot projects revolve around a single year. Therefore, our research aims to fill this gap by analysing the impact of changing power system conditions on the economic efficiency of different tariff schemes in the context of the French power system. More specifically, we address the following research questions:

i. Have existing French dynamic tariffs efficiently incentivised power consumption?
ii. How will these tariff schemes perform over time with increasing renewable energy sources, and what are the consequences on social welfare?

In addition, we complement the literature by including in the assessment the recent Covid-19 crisis, which led to record-low power demand, and the subsequent power crisis with unprecedented power price volatility. This unprecedented situation allows us to study to what extent rate stability continued to deliver the right incentive in periods that might be representative of higher volatility. Finally, we contribute to the literature from the methodological standpoint by revisiting another crucial assumption when estimating the benefits of dynamic tariffs: we account for the impact of price-responsiveness on the power system thanks to a four-stage modelling approach.

3.3. Tariff consideration and mathematical formulation

This section is split up into four subsections. The first one describes the current tariff structure in France. The second describes the derived modelling approach and the related metrics to evaluate the tariff efficiency and stability over time. The third one provides the mathematical formulation of each model. Finally, the fourth one describes the data used.

3.3.1. French tariffs: structure and existing dynamic tariffs

Tariffs offered by French retailers to consumers are primarily composed of three separate components. The first component is the consumers' monthly fixed subscription fee to cover commercialisation, billing, and invoicing costs. While this cost may vary depending on the number of consumers per retailer, it is independent of individual consumers’ power consumption. The second cost component covers the costs incurred by transportation and distribution operators for maintaining and expanding the electricity network. This is typically based on each consumer's contracted power capacity. Those two first components make up half of French consumers' electricity bills and are usually not subject to variations over the year. Therefore, our research focuses on the third component, which relates to the cost of purchasing the electricity consumed. Retailers have been proposing different designs when charging this component in France, with already several dynamic tariffs proposed. Those are presented in Table 4. The first tariff type provides hourly incentives to reduce consumption during the daily morning and evening peak. The price signal is typically based on off-peak and on-peak hours, eventually complemented by a weekend or a seasonal differentiation (ToU_2, ToU_3 , ToU_4 respectively). As different timetables coexist in France, a distinction is made between tariffs based on their respective timetables (ToU_2^{night},ToU_2^{PV}). A second type of tariff aims to reduce consumption for a given number of days in the year during episodes of supply scarcity. Those are usually referred to as Critical Peak Pricing (CPP) schemes. Finally, more complex tariffs combine both hourly and daily quadrants (ToU_6, $ToU - CPP$). In practice, dynamic tariffs could be even more nuanced, depending on the specific location of the consumer. Besides those dynamic rates, consumers can also be charged a flat volumetric basis ($Flat$). Descriptive statistics for each segment are provided in Appendix, Table B.1.

Table 4 - Description of existing French electricity tariffs by segment

Segment	Tariffs	Description	Symbol
Residential	Flat-rate tariffs	-	$Flat$
	Two-tier time-of-use	Off-peak/On-peak hour	ToU_2
	Three-tier time-of-use	Off-peak/On-peak hour Weekend days	ToU_3
	Six-tier time-of-use	Off-peak/On-peak hour Peak/Mid-peak/Valley days	ToU_6
	Critical Peak Pricing	Peak days	CPP
Professional	Flat-rate tariffs	-	$Flat$
	Two-tier time-of-use	Off-peak/On-peak hour	ToU_2
	Six-tier time-of-use	Off-peak/On-peak hour Peak/Mid-peak/Valley days	ToU_6
	Critical Peak Pricing	Peak days	CPP
Industrial	Four-tier time-of-use	Off-peak/On-peak hour Summer/Winter days	ToU_4
	Four-tier time-of-use rate with critical peak pricing	Off-peak/On-peak hour Summer/Winter days Peak days	$ToU - CPP$

3.3.2. Modelling approach and metrics

To evaluate the stability and efficiency of the tariff schemes over time, two complementary methodological setups have been developed. The first approach is a backwards-looking assessment of historical data on tariffs in France provided by the system operators. In this case, an Ordinary Least Squares (OLS) model is used to derive a cost-representative rate for each consumer segment to evaluate the performance of dynamic tariffs over time in terms of efficiency gains. We distinguish between two cases: (i) the first one where historical prices (hereafter, historical) are considered, and (ii) a case where a partial equilibrium model of the day-ahead wholesale electricity market, formulated as a relaxed version of the mixed-integer linear programming (MILP) problem is used to estimate power price (hereafter, model-based). This enables to establish the baseline for the forward-looking approach in which the evolution of the electricity mix is considered.

This second approach adopt a four-stage methodology to analyse the influence of a growing share of renewable energy production on the stability and effectiveness of tariffs. The aim is to reproduce both the key players and the succession of markets performed in the current power sector.

i. Stage One involves the partial equilibrium model of the day-ahead wholesale electricity market. The optimisation process considers fixed power generation capacity and optimises the power dispatch, enabling us to determine a proxy for the hourly marginal price of electricity.
ii. In Stage Two, the prices derived from Stage One are used to establish cost-reflective tariffs from the retailer's perspective. This is accomplished through a constrained least-squared problem, ensuring that the retailer fully recovers electricity costs. This, in turn, allows us to calculate a price schedule for each type of tariff. More details on the year partitioning required for this step are provided in Appendix B, Method B2.2.
iii. In Stage Three, price-elastic consumers per segment are considered, and their response to hourly prices is simulated for each tariff scheme considered.
iv. Finally, in Stage Four, the impact of the updated price-reactive load on the power prices is determined using Stage One's model.

The methodology followed for both the historical and the prospective setup is illustrated in Figure 18 and Figure 19.

Figure 18 - Modelling approach in the historical case: two-stage setup (Historical & Model-based)

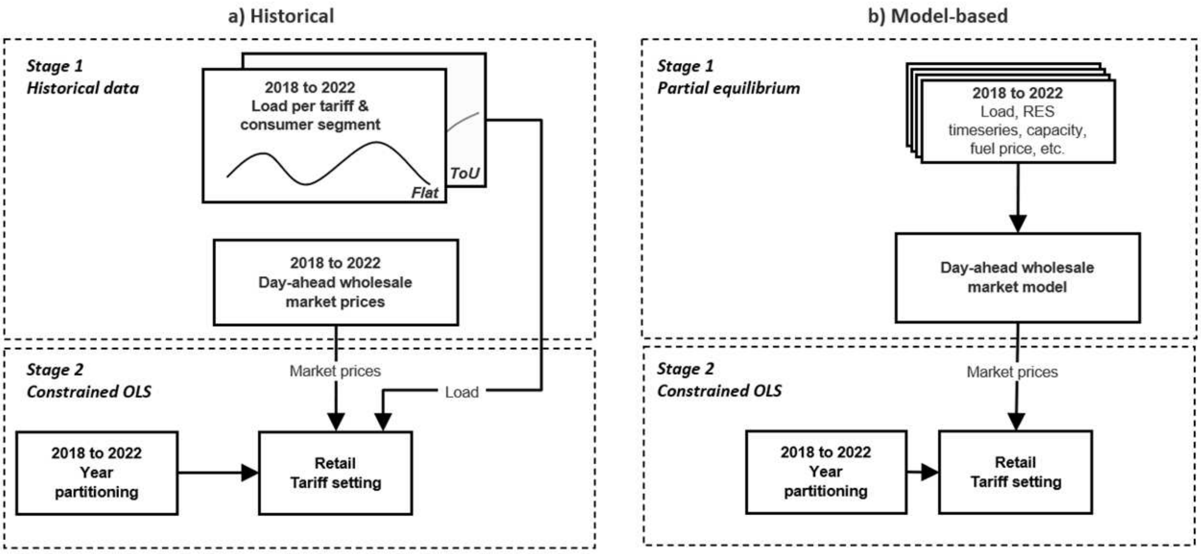
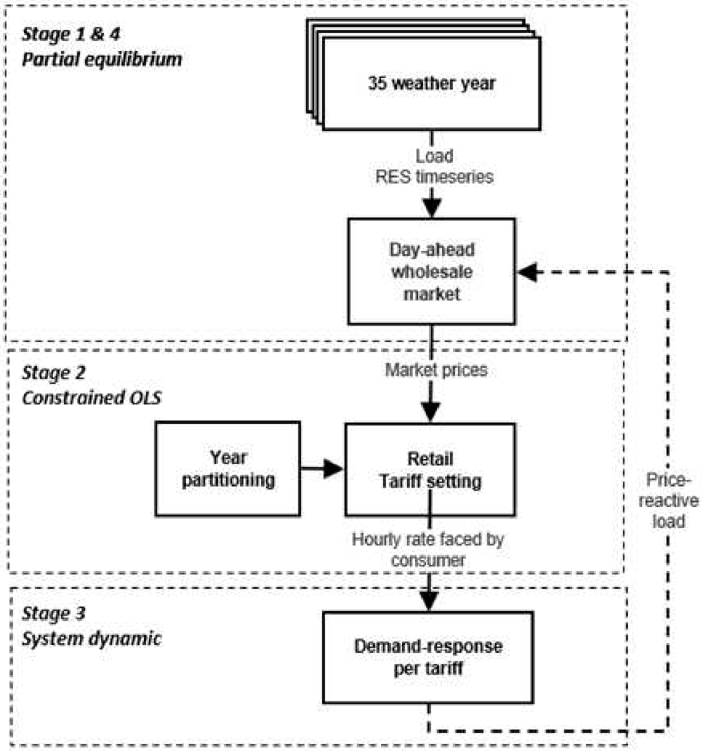


Figure 19 - Modelling approach in the prospective case: four-stage setup (Model-based)



Four different metrics are derived from the methodological setup developed. Our objective is to evaluate the effectiveness of the rates, that is, the degree to which they provide the right price signals to consumers. Therefore, the first metric to examine is the load-weighted average price of electricity for each consumer (or captured price), denoted as $\pi_{y,c,t}$, and the associated captured price ratio (*CPR*), which is the ratio of the captured price to the average power price, denoted as $\pi_{y,system}$, and corresponding to the total load-weighted average power price for a given year:

$$\pi_{y,c,tt} = \frac{\sum_h p_{y,h} * d_{y,c,tt,h}}{\sum_h d_{y,c,tt,h}} \qquad \forall y,\ c,\ tt \qquad \text{(Eq. 1)}$$

$$CPR_{y,c,tt} = \frac{\pi_{y,c,tt-}\ \pi_{y,system}}{\pi_{y,system}} \qquad \forall y,\ c,\ tt \qquad \text{(Eq. 2)}$$

Dynamic rates are designed to encourage consumers to gauge power prices at their true production cost. Therefore, tariffs should incentivise them to shift their load during low power price hours, resulting in lower captured prices, which should be reflected in the *CPR*. It is essential to acknowledge that the effectiveness of the CPR may be compromised by selection bias, whereby consumers select rates that align with their consumption patterns. To mitigate this bias, the analysis is completed by the Spearman correlation of the rates constructed using the Stage Two constrained least-squares approach for historical and future scenarios. This correlation is computed annually to provide a complementary perspective on the efficiency of the rates. Besides the Spearman correlation, the in-sample coefficient of determination or R^2 is made available online (Cabot, 2023). This adds to the analysis by assessing the extent to which the proportion of variance in the day-ahead prices is reflected in the calculated rates from the OLS. Similar approaches have been applied in the literature (Jacobsen et al., 2020; Schittekatte et al., 2022), notably in the case of the United States.

As our assessment is based on multiple historical and future weather years, additional metrics are used to evaluate the robustness and stability of dynamic rates over time, in line with the principle of rate design underlined by Bonbright (1961). These principles consist of three fundamental concepts: revenue requirement, fair apportionment of costs among customers, and optimal efficiency. In addition, Bonbright emphasised that rates must meet several key characteristics, including simplicity, transparency, stability, and non-discrimination. The stability of peak pricing features tariff is evaluated by analysing the monthly distribution of peak periods, representative of the year partitioning stability over time. In addition, the on-peak-to-off-peak price ratio (*PeakR*) evolution is assessed and is considered representative of the absolute rate level stability over time. However, Additional insights on the ratio considered for more complex pricing structures beyond the two-tier rate design are provided in Appendix B, Method B2.3. Complex pricing also comes with additional transaction costs for the consumer that are not considered when assessing only the cost-reflectiveness of tariffs.

$$PeakR_{y,c,tt} = \frac{\theta_{y,c,tt}^{onpeak}}{\theta_{y,c,tt}^{offpeak}} \qquad \forall y,\ c,\ tt \qquad \text{(Eq. 3)}$$

The power price reduction (*PPR*) achieved by increasing the share of price-reactive consumers is assessed using Stage One and Four of the methodological setups. This metric is calculated based on the difference between the two stages in the yearly average power price $\pi_{y,system}$. The only difference between the two stages stems from the load considered. Stage One (S1) considers a perfectly inelastic load, even in times of scarcity[18], while Stage Four (S4) accounts for the price-reactive load resulting from the system dynamic model of Stage Three.

$$PPR_{y,tt} = \frac{\pi_{y,tt,system}^{S4} - \pi_{y,system}^{S1}}{\pi_{y,system}^{S1}} \qquad \forall y,\ tt \qquad \text{(Eq. 4)}$$

Following Jacobsen (2020), the welfare gains are compared with the correlation found in order to corroborate the sufficient statistical approach outlined by Jacobsen over multiple years and in the

[18] At the exception of interruptible load and demand-side management measures (*DSM*), as defined by the French TSO and valued at 350 EUR/MWh.

case of France for different pricing regimes. We base the analysis on an estimate of the deadweight Loss (DWL), which will be further described in the discussion.

3.3.3. Mathematical formulation

3.3.3.1. The wholesale market model

The model consists of a MILP partial equilibrium model of the electricity market, usually referred to as a unit commitment (UC) model. Unit commitment models represent the day-ahead commitment of each power plant unit based on their short-run marginal costs and technical constraints. This model is based on existing literature and mathematical description from Quoilin (2015) and Palmintier (2011). The complete formulation is provided in Appendix B, Method B2.4. The model is written in GAMS and solved using the CPLEX solver. The cost minimisation objective function is subject to constraints to capture the specificities of each technology cluster. Technology clusters comprise a triplet of fuel used, technology, and vintage class[19]. Additional constraints are considered for renewables-based technology (wind, solar, or hydropower), limiting the availability of natural resources and are based on 2018 historical production. Those are modelled as an hourly availability factor multiplied by the installed capacities. Thermal units are also described with operational constraints reflecting their technical capabilities, as in Palmintier (2011). Those are ramping capability constraints, minimum up and down times, and minimum power generation. Finally, hydropower and battery behaviour are constrained by their operating range, storage capacities, and charging/discharging behaviour.

The market price resulting from the model is deduced from the marginal value of the supply and demand constraint:

$$\sum_{k \in K} G_{y,\,h,\,k,\,z} + \sum_{z' \in \zeta} I_{y,\,h,\,z,\,z'} = d_{y,\,h,\,z} + \sum_{z' \in \zeta} E_{y,\,h,\,z,\,z'} + \sum_{s \in ST} S_{y,\,h\,s,\,z} \qquad \forall y \in Y \quad \forall h \in \Theta \quad \forall z \in \zeta \qquad \text{(Eq. 5)}$$

Where:

[19] Fuel considered are coal, lignite, gas, nuclear, and renewables power. Technology is mostly used to distinguish between OCGT and CCGT gas power plants. Vintage classes are representative of the commissioning year of the power plant, linked to efficiency values considered for SRMC calculation.

$d_{y,h,z}$	Hourly electricity demand	$S_{y,hs,z}$	Charging/discharging power flows of storage technologies;
$I_{y,h,z,z'}$	Power imports of a given zone	$E_{y,h,z,z'}$	Power exports of a given zone

A marginal increase of an exogenous parameter, in this case, the load, would lead to an increase in the production of the marginal production unit and, thereby, translate into an increase in the system cost considered in the objective function. The marginal increase would equal the short-run marginal cost of the marginal unit available. Such value can be used as a proxy for the outcome of a day-ahead electricity market under perfect competition as for the unit commitment performed by the TSO[20] (Brent Eldridge et al., 2018). The marginal cost is used to determine rates in Stage Two of the modelling setup, corresponding to the retail model.

3.3.3.2. The retail model

The marginal price determined in Stage One is the basis for rate setting in Stage Two of the modelling setup. We posit a zero-profit condition for the electricity retailer, meaning the cost of purchasing power on the wholesale market for a given consumer should be entirely recovered. Therefore, free entry into the retail market is assumed. In other words, the load-weighted cost of the electricity purchased at the day-ahead price should equal the revenue collected by the retailer. As the rates are fixed for each tariff before the consumer faces them, a wedge to be recovered should be considered. For simplification purposes, we assume this would be recovered by a linear translation of rates proposed and, therefore, would not impact the demand-side response considered. The mathematical formulation of each tariff considered is provided in Appendix B, Method B2.1. In practice, retailers would offer different prices depending on their hedging strategy, resulting in different rates compared to the in-sample fit of day-ahead prices performed here. In addition, yearly rate adjustments are assumed to be performed in January each year. In practice, more regular price adjustments could be made by retailers, usually on a bi-annual basis.

The optimal tariff setting is solved using an Ordinary Least Square for each tariff. Given that additional constraints are investigated, representative of regulators trying to incentivise more important demand reduction at the expense of cost-reflectivity, we expressed it as a constrained OLS model. The model is written in GAMS and solved using the IPOPT solver. The objective is to minimise the sum of squared errors ε between the determined rates θ and the realised wholesale

[20] Transmission system operator, in charge of the coordination and monitoring of the power system.

power price $p_{y,h}$, under the condition of cost recovery for the retailer, based on the electricity consumption pattern d. We distinguish the electricity rates per consumer type *c*, per tariff type *tt* and for each sub-tariff's hourly segmentation *st*. The constraints defined by the regulator are presented in Appendix B, Method B2.2, alongside the methodology followed for setting the partitioning of the year Δ.

$$\text{Minimise } sse = \sum_h \left(\varepsilon_{y,h,c,tt}\right)^2 \qquad \forall y, c, tt \qquad \text{(Eq. 6)}$$

s.t.:

$$\theta^{we}_{y,h,c,tt} = \alpha_{y,c,tt} + \sum_{st} \beta^{st}_{y,c,tt} \cdot \Delta^{st}_{y,h,c,tt} + \varepsilon_{y,h,c,tt} \qquad \forall y, h, c, tt \qquad \text{(Eq. 7)}$$

$$\sum_h \theta_{y,h,c,tt} \cdot d_{y,c,tt,h} = \sum_h p_{y,h} \cdot d_{y,c,tt,h} \qquad \forall y, c, tt \qquad \text{(Eq. 8)}$$

$$\theta^{we}_{y,h,c,tt} = p_{y,h} \qquad \forall y, c, tt \qquad \text{(Eq. 9)}$$

The resulting tariffs in each hour are expressed as a fixed component α and one depending on the partitioning of the year β:

$$\theta_{y,h,c,tt} = \alpha_{y,c,tt} + \sum_{st} \beta^{st}_{y,c,tt} \cdot \Delta^{st}_{y,h,c,tt} \qquad \forall y, h, c, tt \qquad \text{(Eq. 10)}$$

The resulting R² and the Spearman correlation are then compared for each tariff, considering the yearly average electricity price $\overline{p_{y,c,tt}}$ faced by a consumer.

$$R^2_{\ y,c,tt} = 1 - \frac{\sum_h \left(\varepsilon_{y,h,c,tt}\right)^2}{\sum_h \left(p_{y,h} - \overline{p_{y,c,tt}}\right)^2} \qquad \forall y, c, tt \qquad \text{(Eq. 11)}$$

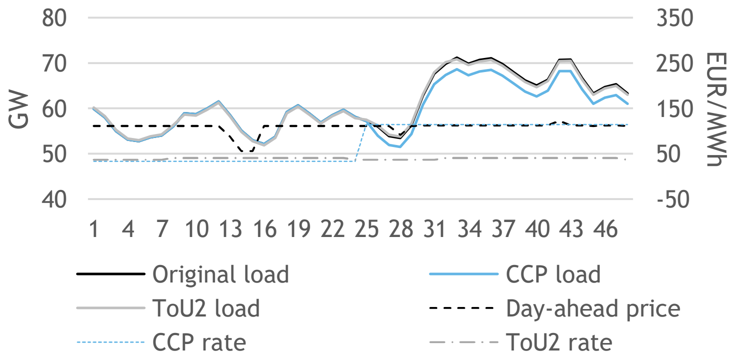
3.3.3.3. The demand-side model

The model represents price-reactive end-users that arbitrate their hourly power consumption based on the hourly rate faced. The demand response model follows formulation based on a linear demand function (Aalami et al., 2010; Borenstein, 2005; Doostizadeh and Ghasemi, 2012; Schittekatte et al., 2022), where the end-user responds to the differences between the rates offered and a base rate, representative of the consumer willingness to pay. The model is written in R and solved using the deSolve package. A common demand function for all consumers is assumed, who all faced a similar retail price depending on the tariffs selected fixed for each calendar year. Ultimately, each consumer would have a different price elasticity and willingness to pay. We consider d^0 the inelastic demand, ε the self-elasticity of the consumer considered, θ the tariffs faced by consumers, p^{bc} the base rate considered for each tariff. The cross-elasticity[21] ε^{cross} has not been considered as no reliable data have been found, and that pilot projects show little evidence of energy shifting in the case of peak pricing (Allcott, 2011; Borenstein, 2005):

$$d_{y,h,c,tt} = d^0_{y,h,c,tt} * \left(1 + \varepsilon_{c,tt} * \frac{\theta_{y,h,c,tt} - p^{bc}_{y,h,c,tt}}{p^{bc}_{y,h,c,tt}} + \sum_{h' \neq h}^{h'=h-x \dots h+x} \varepsilon^{cross}_{c,tt,h',h} * \frac{\theta_{y,h',c,tt} - \theta_{y,h\,c,tt}}{\theta_{y,h,c,tt}} \right) \quad \forall y,\ c,\ tt,\ h \qquad \text{(Eq. 12)}$$

An illustration of the load deviation resulting from the price incentive provided to consumers is provided in Figure 20. Given the assumed price elasticity, the load deviation observed during peak days is substantial for consumers under the *CPP* tariffs. On the other hand, consumers under the *ToU* tariffs exhibit minimal changes in their consumption behaviour, mainly due to the relatively small disparity between on-peak and off-peak rates and the lack of price signals that indicate peak days.

Figure 20 - Illustration of price-reactive load under *CPP* and *ToU₂* tariffs



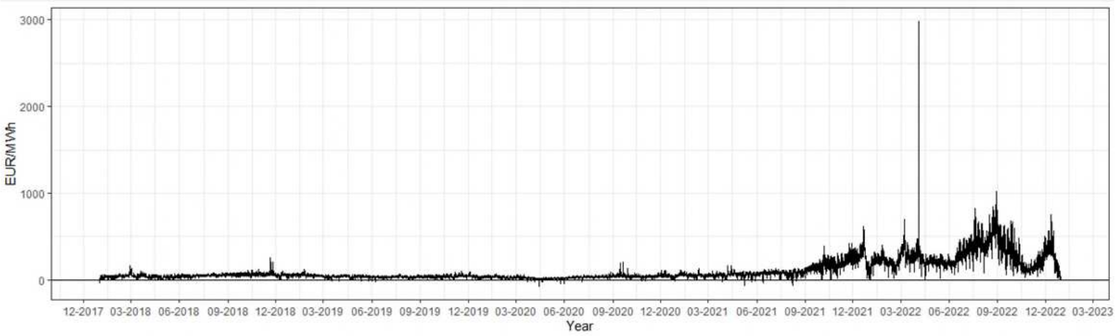
3.3.3.4. *Data used for the numerical example*

Two data sources are used in this paper: market data for historical years and synthetic data from model outputs for prospective years. The historical data for this research was obtained from the French distribution grid operator, Enedis, which provides half-hourly data on French power demand from 2018 to 2023. Although this data does not allow for the estimation of the price elasticity of individual households, it captures the daily, weekly, and seasonal variations of consumption patterns for each tariff scheme, which is sufficient for the historical analysis. The

[21] Cross-elasticity refers to inter-period elasticity of demand. In other words, price-reactive demand will consider for each timestep not only the distance to the average electricity price but also the relative distance of the neighbouring hours.

partitioning of hours for each tariff is based on the historical calendar provided by the transmission and distribution system operators, while day-ahead prices are taken from the ENTSO-e transparency platform. In addition, the data covers the Covid-19 crisis period, which led to record-low power consumption and the energy crisis following the Russo-Ukrainian conflict, providing additional insights into tariff robustness. The evolution of day-ahead market prices in France is displayed in Figure 21, where the power crisis in 2022 is visible from December 2022 to February 2023, with average prices reaching more than 200 EUR/MWh for several months.

Figure 21 - Day-ahead electricity prices in France (2018-2022)



For the prospective setup described, we use the publicly available EERAA dataset (ENTSO-E, 2022). It provides hourly data for load, renewables hourly capacity factor, and power generation capacities for each European market area. We complement it with various sources from the literature and from the national transmission system operator. All data sources are presented in Appendix B, Method B2.4. In addition, the code and data used for the two setups are available online[22].

3.4. Results and discussion

The results obtained answer the two following research questions posed in the introduction:

i. Have existing French dynamic tariffs efficiently incentivised power consumption?

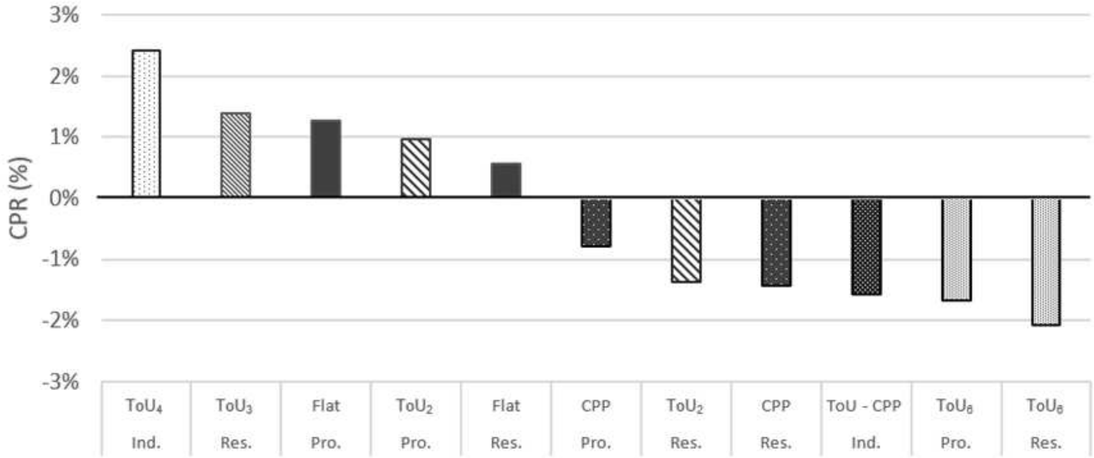
ii. How will these tariff schemes perform over time with increasing renewable energy sources, and what are the consequences for social welfare?

3.4.1. Historical captured price per consumer segment

The first metric to consider when assessing to what extent the rates have been efficient in incentivising consumers to shift their consumption at a time of low power prices is the *CPR* metric introduced in section 3.3.2. Figure 22 displays the average *CPR* per tariff type from 2018 to 2022.

[22] (Cabot, 2023), available online: https://zenodo.org/record/7824519#.ZDfj6HZBzx6

Figure 22 - Average Captured Price Ratio per tariff and consumer segment (Historical, 2018-2022)



In general, the more complex and dynamic the tariffs are, the lower their captured power prices tend to be. The tariffs that include peak pricing features (*CPP*, *ToU-CPP* and ToU_6) result in a 1 to 2% lower captured price than the system average. On the other hand, consumers who are under flat tariffs tend to consume more during expensive hours, resulting in 0.5 to 1% higher *CPR* compared to the system average. However, this result should be nuanced. First, some time-of-use tariffs result in higher-than-average power price consumption than the consumer under a flat rate. The first reason could stem from the price incentive's triggers being misaligned with the hourly power price fluctuations. This will be discussed in the next section when assessing the correlation between rates and day-ahead market prices. A second reason is that the *CPR* metric is subject to selection bias: consumers engage in a given tariff if they are better off in gross surplus. Some consumers with electric vehicles (EVs) might favour the ToU_3 scheme to charge EVs during the weekend, but it would also result in more electricity consumed in winter due to increasing car usage. For this segment, the ratio between winter and summer power consumption reaches more than two (Appendix B, Figure B.2), translating into a higher CPR than the system's average. In addition, the *CPR* is also highly sensitive to power consumption during scarcity hours. This would necessarily improve the case of peak pricing tariffs compared to those providing only seasonal or daily price signals, such as time-of-use tariffs (ToU_2, ToU_3, ToU_4).

Finally, additional dynamics are highlighted by looking at the yearly evolution of tariffs (Appendix B**,** Figure B.3). Indeed, two peculiar periods are part of the underlying data. The first one corresponds to the Covid-19 crisis, mainly being reflected during 2020 due to the severe lockdowns. No significant difference in the captured price per segment is found in this case. On the contrary, a switch in tariff performance is observed during the 2021-2023 energy crisis. In this unique situation lasting for several months, tariffs with peak pricing features appear less efficient in providing price signals. Indeed, as the system operator must select a fixed number of days, incentives will likely be less efficient as demand reduction would have been required for a sustained period and not for isolated days. Reducing the daily evening peak might prove more important compared to reducing consumption for a given number of days.

An important distinction is therefore highlighted between tariffs, as some provide price signals reflecting intraday, weekly, or seasonal fluctuations, while others focus on peak pricing days, either exclusively or in addition. The *CPR* points out higher efficiency for tariffs with peak pricing features in France. The analysis is completed by assessing the correlation of each tariff with the day-ahead prices.

3.4.2. Efficiency of current dynamic tariffs

The Spearman correlation between the different tariffs and the French day-ahead prices is studied to gain deeper insights into tariff performance. As explained in section 3.2, the constrained OLS model is used to estimate the different rates for each tariff.[23] Correlation performance is measured by the quality of the fit between the hourly rates and the day-ahead prices: if day-ahead prices increase (respectively decrease), the rate is expected to increase (respectively decrease) accordingly. The Spearman correlation is more suited than the standard Pearson correlation when the relationships are non-linear, which is likely the case given the significant volatility observed in market prices. In addition, the Spearman correlation is more stable against price levels that were exceptionally low and high during 2020 and 2022, respectively. The Spearman correlation measure is considered more appropriate than the commonly used Pearson correlation (Schittekatte et al., 2022).

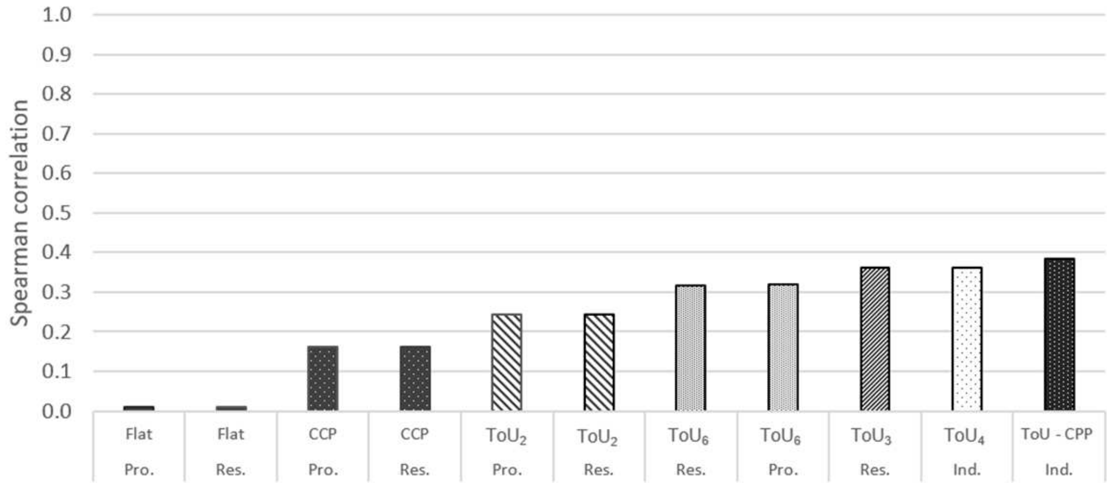
The average from 2018 to 2022 is displayed in Figure 23 for each tariff. Our analysis shows that tariffs with more complex dynamics features have a higher Spearman correlation with the French day-ahead prices. This result is in line with the increased granularity of dynamic tariffs. However, it contrasts with the previously analysed captured price. Indeed, tariffs with weekly (ToU_3) and seasonal (ToU_4) features correlate better with day-ahead prices, despite finding that consumers under those tariffs depict higher captured prices than the system's average. However, when analysing the results over the full period (Appendix B, Figure B.4), results are more nuanced, notably due to the impact of the 2022 power crisis. Tariffs with peak pricing features have underperformed in the last two years due to the fixed number of peak pricing days.

On the other hand, tariffs such as ToU_4 had a better correlation due to the seasonality of these tariffs, which allowed them to match better the sustained period of high prices experienced during the crisis. Finally, by capturing weekend variability, ToU_3 resulted in a higher correlation with

[23] The resulting rates are provided in the online repository (Cabot, 2023)

day-ahead prices than ToU_6 during the crisis. This suggests a more substantial distinction between working days and weekends compared to the differences between peak, mid-peak, and valley days, which became less pronounced during the crisis.

Figure 23 - Average Spearman correlation of designed tariffs with day-ahead prices (Historical, 2018-2022)



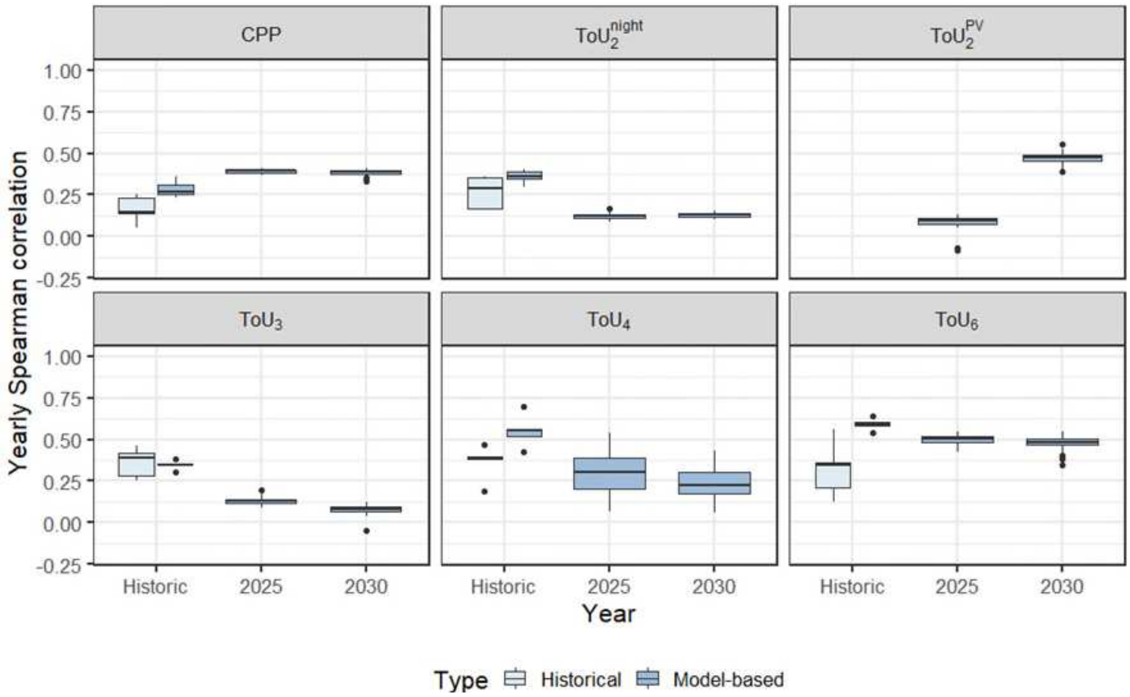
Generally, all tariffs experienced a decrease in their Spearman correlation with day-ahead prices due to increased power price volatility during the 2022 power crisis (Figure 21). This decrease is particularly evident in the case of tariffs with peak pricing features (*CPP*, ToU_6), which saw their correlation drop from over 0.25 to less than 0.1 during the power crisis (Appendix B, Figure B.4). The extreme power price occurrences were not captured by the fixed number of peak pricing days imposed by such tariffs. Similarly, time-of-use tariffs decreased in correlation, with both ToU_2 and ToU_3 having their Spearman correlation index reduced respectively by 45% and 35%, compared to the average between 2018 and 2020. Only two tariffs were resilient to the power crisis: ToU_4 and *ToU-CPP*. Those two tariffs, intended for industries, distinguish between winter and summer. Given the relative seasonality of prices during the 2022 crisis, they performed better in capturing price deviations than the other tariffs.

Overall, the results indicate that the captured price per consumer depends mostly on consumption patterns, given the discrepancy between ToU_4 and ToU_3 captured price and correlation. As expected, the results indicate that complex tariffs are better correlated with day-ahead prices, with weekly and seasonal variations still being more prominent than peak hours in France. Two main factors could explain such a pattern: first due to the significant thermosensitivity of demand in France due to the electric heaters in the building sector, and second by the significant role of hydropower and nuclear power fleet, accounting currently for 80% of the power generation, which availability depicts more seasonal variation than fossil-fuel-based power generation mix. However, the Spearman correlation of two-tier tariffs (ToU_2) is relatively close to or above *CPP* tariffs (0.25 compared to an average of 0.35), which underlines the almost equal importance of the intraday price pattern compared to yearly patterns, mostly driven by peak pricing days. However, this factor will likely be heavily impacted by the increasing share of renewable power generation, as their production is more variable, which will be discussed in the next section.

3.4.3. Evolution of tariffs efficiency over time

The evolution of the Spearman correlation is assessed over time based on the results of the 35 weather years studied as part of the prospective setup presented in section 3.3.2. Using the modelled wholesale power prices, optimal tariff rates are derived based on an ex-ante partitioning of the year (Appendix B, Method B2.2). The Tukey boxplot of the Spearman correlation between tariffs and day-ahead prices is presented in Figure 24. The focus is made on five different tariffs, each representative of a given price variability: *ToU_2* for daily variability, *ToU_3* for weekly variability, *ToU_4* for seasonal variability, *CPP and ToU_6* for peak pricing. All other tariffs are displayed in Appendix B, Figure B.5. In addition, differences between historical and model-based approaches for historical years are presented. Due to the simplification made in the day-ahead wholesale electricity market model, model-based prices are not capturing the full extent of power price volatility. Therefore, model-based Spearman correlations reflect the alignment of rates with the fundamentals of power prices captured by the model, rather than with day-ahead power prices. As one could expect, it falls on the high side when compared with historical correlation. We provide in appendix further details on the representativeness of the model-based rates calculated (Appendix B, Figure B.8).

Figure 24 - Tukey boxplot of yearly Spearman correlation between tariffs and day-ahead prices (2018-2022, 2025, 2030)

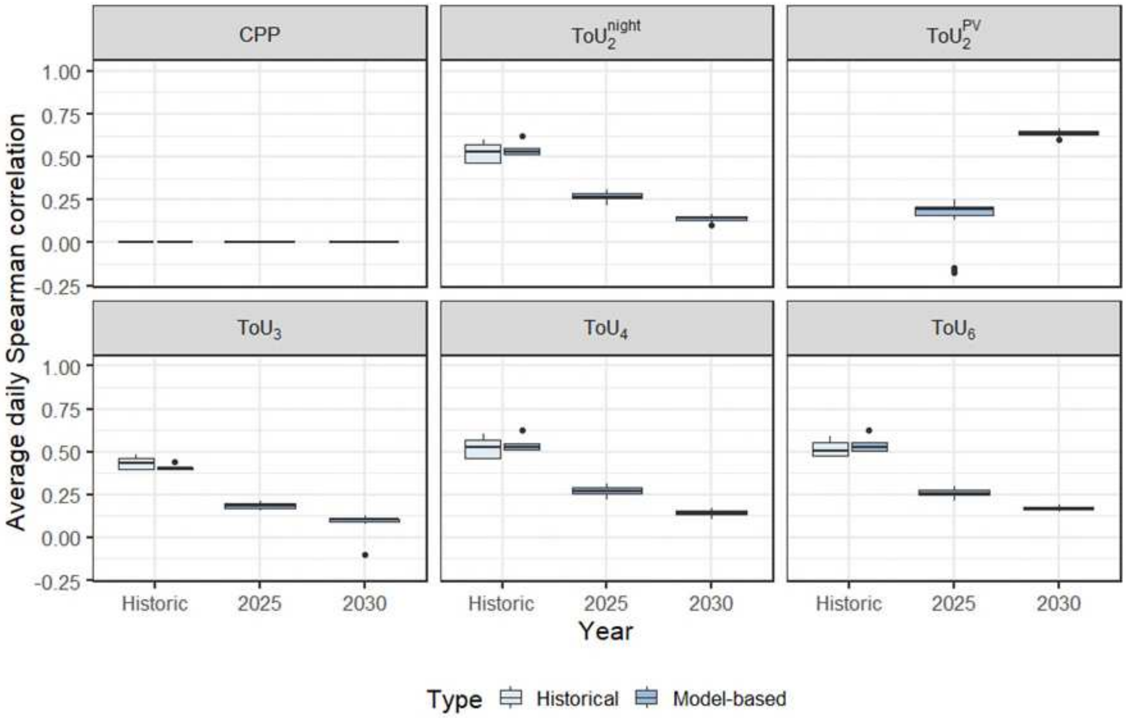


Four observations can be made: first, the benefits of the historical daily, weekly and seasonal partitioning sharply decrease over time. With increasing shares of renewable energy generation, the price difference between day and night becomes less relevant, as seen in the case of ToU_2^{night} for which the correlation figure drops to 0.1 and is even negative for some weather years in 2025. On the contrary, while the value in matching solar PV production is still not significant in 2025, it increases over time, placing the ToU_2^{PV} tariff among the ones with the highest correlations in 2030 (at 0.4). Likewise, the price difference between working days and weekends will decrease substantially, becoming negative for some weather years in 2030. While the day-ahead prices have historically been correlated with the load, implying a difference in the weekend due to the reduced industrial and professional activities, this does not hold when the system variability is dominated by the power supply of renewables. As price correlates with the net load, the relative importance of demand swings on power prices is reduced. The same reasoning applies to the seasonal cycle and explains the progressive reduction of ToU_4's correlation factor. A second observation can be made here: contrary to all other tariffs, ToU_4 is the only one that exhibits a significant spread in its correlation. We attribute this to the fact that while fixed daily and weekly schedules remain relatively similar across different weather years, the seasonal component presents a distinct situation. Indeed, the seasonality of hydropower, wind, and solar electricity supply becomes a key determining factor and might significantly influence the winter/summer electricity price spread. As such, despite an overall decrease in the correlation factor over time, the tariffs perform well for multiple weather years.

Finally, the last observation concerns the tariffs with peak pricing features, for which the correlation remains constant over the year. As those tariffs target only a reduced number of days, the correlation factors are close to the historical level. Such tariffs could better reflect changing three market situations: one where low renewables output might result in generation scarcity, requiring the use of expensive interruptible load, while mid-peak and valley days would better reflect a situation where fossil-fuel-based power plants and renewable energy sources would be marginal.

To conclude, we contrast the yearly Spearman correlation with the average daily Spearman correlation in Figure 24. Tariffs with peak pricing features exhibit no correlation, as they do not capture the daily price patterns. Conversely, the significance of ToU_2^{PV} is underscored, with a correlation above 0.5 in 2030. In contrast, since all other tariffs are based on the ToU_2^{night}segmentation, their average daily and weekly correlations decline over time (Appendix B, Figure B.6 and Figure B.7).

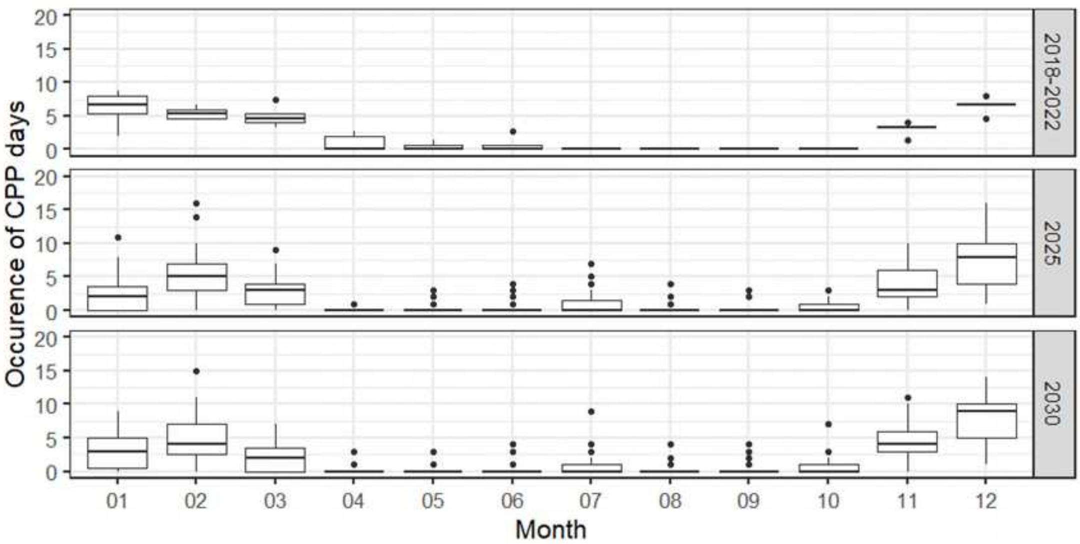
Figure 25 - Tukey boxplot of daily Spearman correlation between tariffs and day-ahead prices (2018-2022, 2025, 2030)



3.4.4. Evolution of tariffs stability over time

Bonbright (1961) underlines that rate setting should not only target efficiency and fairness but also remain stable to improve predictability and acceptance of dynamic tariffs for consumers. Acknowledging the importance of the stability aspect, the change in rate schedules is assessed over time. As dynamic tariff adoption rates are currently very low in France, fluctuating partitioning of the year can impact the likely adoption rate. Typically, for a consumer to reduce its power consumption during peak days, alternatives might be required to keep the consumer's utility unaffected (e.g. comfort level). For example, in wintertime, this might consist of alternative heat supply sources, also referred to as grey load shedding, replacing or completing electric heat supply (e.g. electric heaters or heat pumps) with other fuels such as wood or gas. Nevertheless, such peak days might imply different alternatives and acceptability for consumers if those are concentrated in the summer period, where a consumer would require a different alternative to using electricity. Figure 26 illustrates the evolution of the occurrence of peak pricing days over time. Additional insights are provided for similar peak and mid-peak days features of the ToU_6 tariffs in Appendix B, Figure B.9 and Figure B.10.

Figure 26 - Monthly distribution of peak pricing days (2018-2022, 2025, 2030)

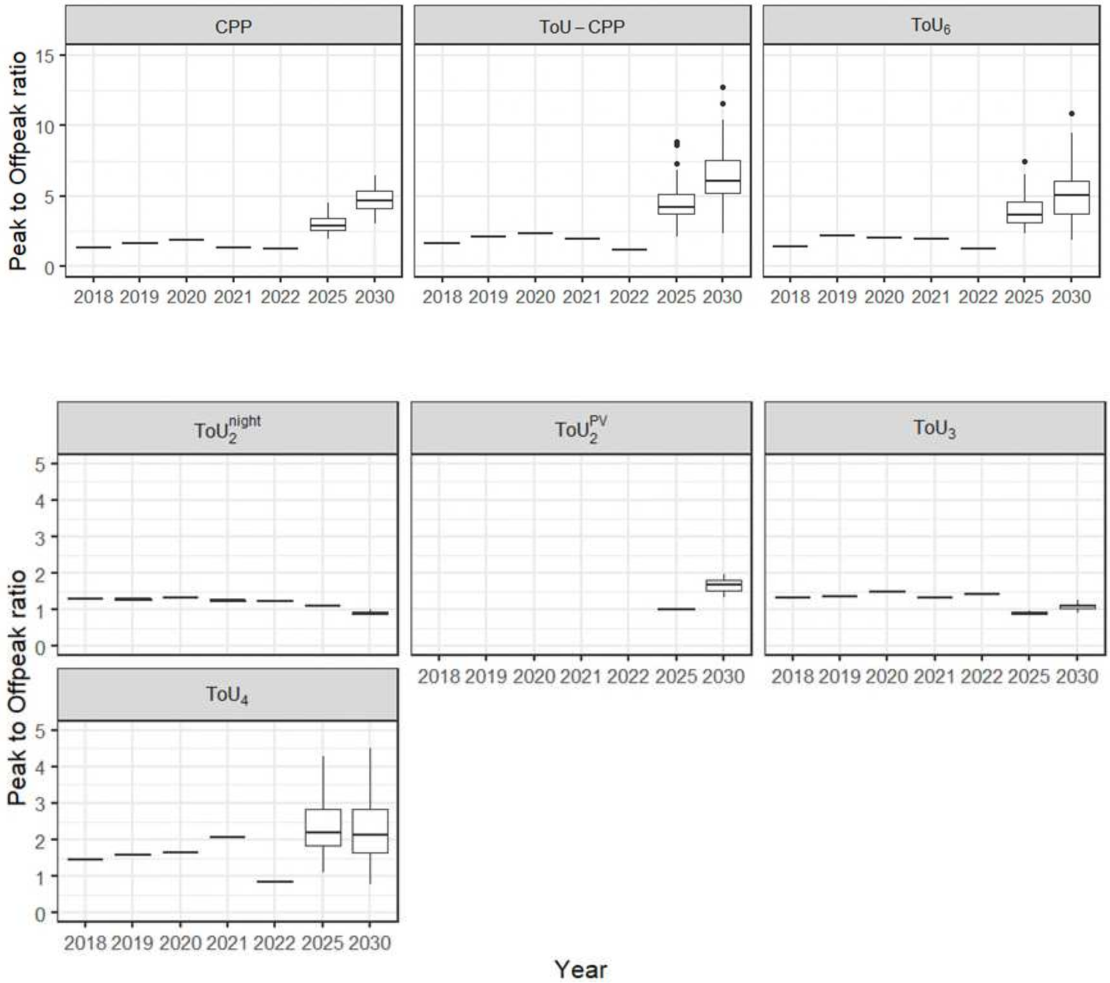


The results underline that although there is a slight shift from a predominance of peak prices from January towards February, most of the high price occurrences will remain in the winter period. Although some peak prices also occur in July, they remain exceptional in 2025 and 2030. The time stability of rates, therefore, appears untouched towards 2030. This is, however, not the case for mid-peak days in the case of ToU_6, where a shift towards the summer arises (Appendix B, Figure B.9).

The rate stability over time applies not only to the partitioning of the year but also to the price level of the rate itself, which could evolve from one year to another to reflect the evolving market conditions. For example, a rapid increase in the on-peak rate compared to the off-peak rate could be perceived negatively by consumers, which factors in the relative difference between the two rates. While some consumers might see advantages in having an increasing gap between the different rates, it could also negatively impact those unable to hedge against long-lasting peak periods. As presented in section 3.3.2, the evolution of the on-peak-to-off-peak rate ratio is assessed and presented in Figure 27. The focus is made on typical tariffs representative of the different time variability. Additional results are provided in Appendix B, Figure B.11 and Figure B.12.

We observe peak rates shifting upwards with the year, driven by the price of interruptible load and the increase in the carbon price. This is likely to discourage consumers from enrolling in tariffs with peak pricing components if they cannot hedge against those periods. The perceived risks will likely increase, even though the overall collected revenue compared to a flat tariff should be equal by design. Moreover, the opposite holds for the historical ToU_2 tariffs, for which the price deviations between on-peak and off-peak decrease until reaching parity, even having the night rate higher than the day rate in 2030. Such rate reversion should be anticipated by retailers and regulators, as the historical incentive provided will likely require adjustments for consumers, for which daily habits would be impacted. A similar situation is observed for ToU_3, confirming the Spearman correlation figures that progressively indicate a reduced interest in weekend tariffs with an increasing share of renewables. Finally, the virtue of rates matching solar PV production is confirmed, with a median peak ratio reaching 1.8 between off-peak hours (matching solar PV production) and the rest of the day. Such tariffs could be particularly well-suited to incentivise consumers but should be evaluated against social acceptance.

Figure 27 - Evolution of the on-peak-to-off-peak ratio over time (2018-2022, 2025, 2030)



3.4.5. Welfare gains of dynamic tariffs

This section sheds light on the extent of welfare gains achievable through the wider adoption of dynamic tariffs in the French power system. As presented in section 3.3.2, the demand-side model is used in combination with the wholesale electricity market model for this assessment. Notably, our approach accounts for the rebound effect, which could occur under on-peak/off-peak schemes and reduce welfare gains if the effect is significant. Two cases are considered. The first one corresponds to a situation where all consumers of the load under consideration (i.e. at the distribution grid level) would adopt the same tariff scheme. Based on the historical data, this would correspond to 60% of the French domestic demand, reacting uniformly to the various price incentives. While this is not representative of a likely situation, it allows for estimating the welfare gain ceiling in the context of a widespread deployment of dynamic tariffs. In contrast, a second case is considered, aligned with the current distribution of dynamic tariffs (hereafter, “Current”) in the French retail market. Therefore, it corresponds to a situation where consumers would remain under the same tariff as today. Table 5 presents the base case assumption for each tariff regarding the price elasticity and the base rate, following the formulation presented in section 3.3.3. A range of price-elasticities has been considered, enabling to account for uncertainties on the achievable level of demand response. Notably, the price elasticity would likely differ between tariffs, as the differences between on-peak and off-peak rates are significantly lower under ToU_2 rates than under tariffs with peak pricing features. In addition, the willingness to pay p^{bc} is distinguished for each tariff. Under the current formulation, consumers will not react to tariffs if a rate is aligned with their willingness to pay. As such, assumptions have been made on the rate at which the consumer will not change its initial load consumption. The resulting load deviation remains in the range envisaged by the French transmission system operators (RTE, 2021), aligning with the current and foreseen demand-side response potential, although depending on the price elasticity considered (Appendix B, Figure B.13). Moreover, the range of price-elasticity considered aligns with the existing literature (Auray et al., 2020; De Jonghe et al., 2012; Gambardella and Pahle, 2018; Wolak, 2019).

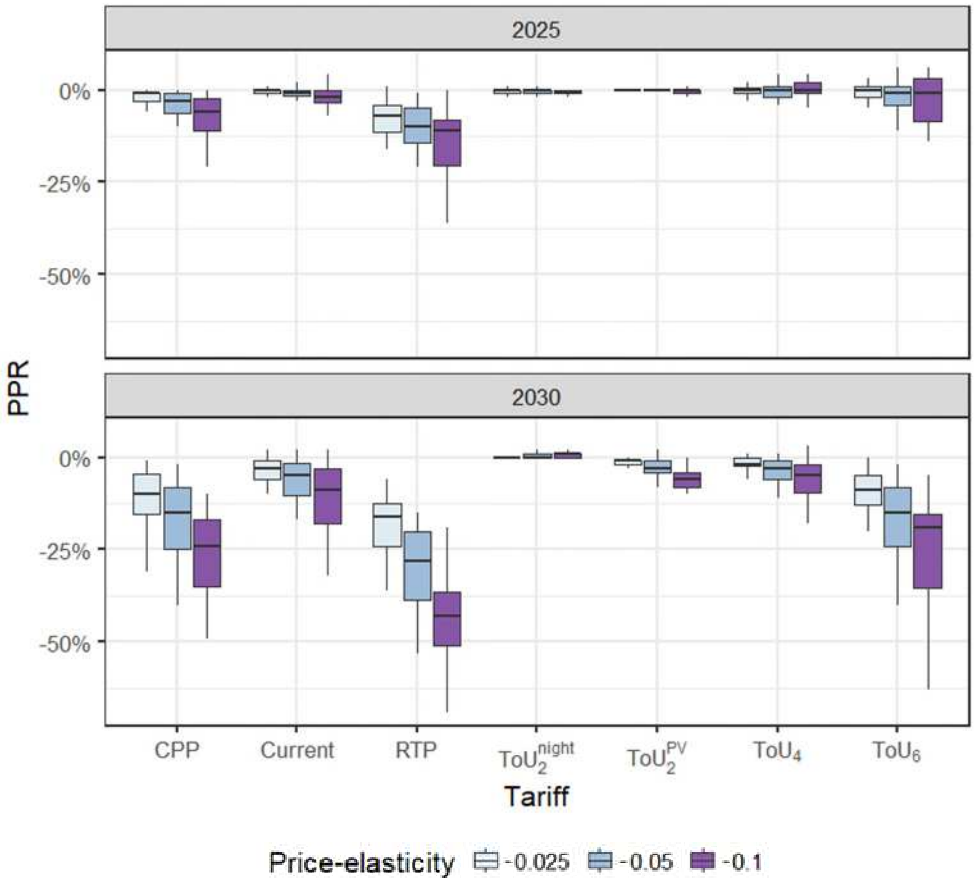
Table 5 - Price elasticity and base rate considered in the dynamic setup per tariff[24]

Type	**Tariffs**	$\boldsymbol{\varepsilon_c}$	$\boldsymbol{p^{bc}}$
Daily	ToU_2	[-0.025, -0.05, -0.1]	θ_{Flat}
Seasonal	ToU_4	[-0.025, -0.05, -0.1]	θ_{Flat}
Real-time pricing	RTP	[-0.025, -0.05, -0.1]	θ_{Flat}
Critical Peak pricing	ToU_6	[-0.025, -0.05, -0.1]	$\theta_{ToU6}^{onpeak,V}$
Critical Peak pricing	ToU-CPP	[-0.025, -0.05, -0.1]	$\theta_{ToU-CPP}^{onpeak,S}$
Critical Peak pricing	CPP	[-0.025, -0.05, -0.1]	$\theta_{CPP}^{offpeak}$

[24] Due to the instability of the base rate for the tariff ToU_3, this tariff is not considered for the welfare analysis.

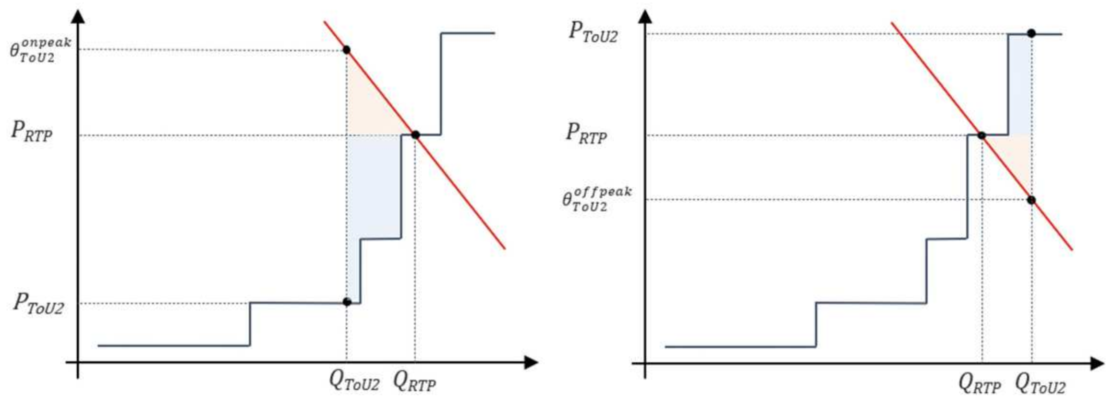
The resulting power price reductions are presented in Figure 28. First, as expected, higher savings are reached under the *RTP* tariff. The power price reduction reaches a median value of -7 to -11% in 2025, depending on the price elasticity considered. The reduction increases further to reach a median value of 16% to 43% in 2030. Second, the existing dynamic tariffs, such as ToU_6 and *CPP,* capture around 50% of the *RTP* power price reduction. The interests of such tariffs, which convey best the generation scarcity, are confirmed over time. Third, while ToU_2^{night} results in a price increase in 2030, this is not the case for ToU_2^{PV}, which PPR increases over time to reach a median value of -6%, thereby underscoring its relevance compared to historical schedules. Apart from ToU_2^{night}, the trends of larger power price reduction over time are common across all dynamic tariffs. This trend is mainly driven by the increasing marginal cost of producing electricity, with more expensive unabated natural gas units and interruptible load setting the price. As a result, more granular tariffs such as ToU_6 perform better in reducing average power prices, even without a time schedule matching the solar PV production. While this effect is significant, it is also important to underline that the results are also linked with the net reduction in power demand that some tariffs entail (Appendix B, Figure B.14). Those demand reductions directly stem from the assumption used on the willingness to pay p^{bc}.

Figure 28 - Evolution of the power price reduction achieved by second-best dynamic tariffs



However, reducing power prices does not necessarily translate into welfare gains. In the case where consumers value electricity consumption at 70 EUR/MWh, while it could be produced at a lower cost, it is welfare optimal to increase consumption at this time. As such, the effectiveness of dynamic tariffs in reducing the Deadweight Loss (DWL) is assessed and compared to the theoretical optimum of real-time prices with the highest price elasticity of -0.1. To estimate the deadweight loss achieved, a linear demand curve is assumed. The hourly deadweight loss for consumers is calculated based on Harberger's triangle, defined by the difference between the rate charged and the real-time price and the width of the load deviations. On the supply side, we use the merit order curve of our perimeter based on the short-run marginal cost of producing electricity. The resulting deadweight loss is the area between the real-time prices and the marginal price of the technology whose production has been affected by the same quantity as the load deviations[25]. This calculation is illustrated in Figure 29.

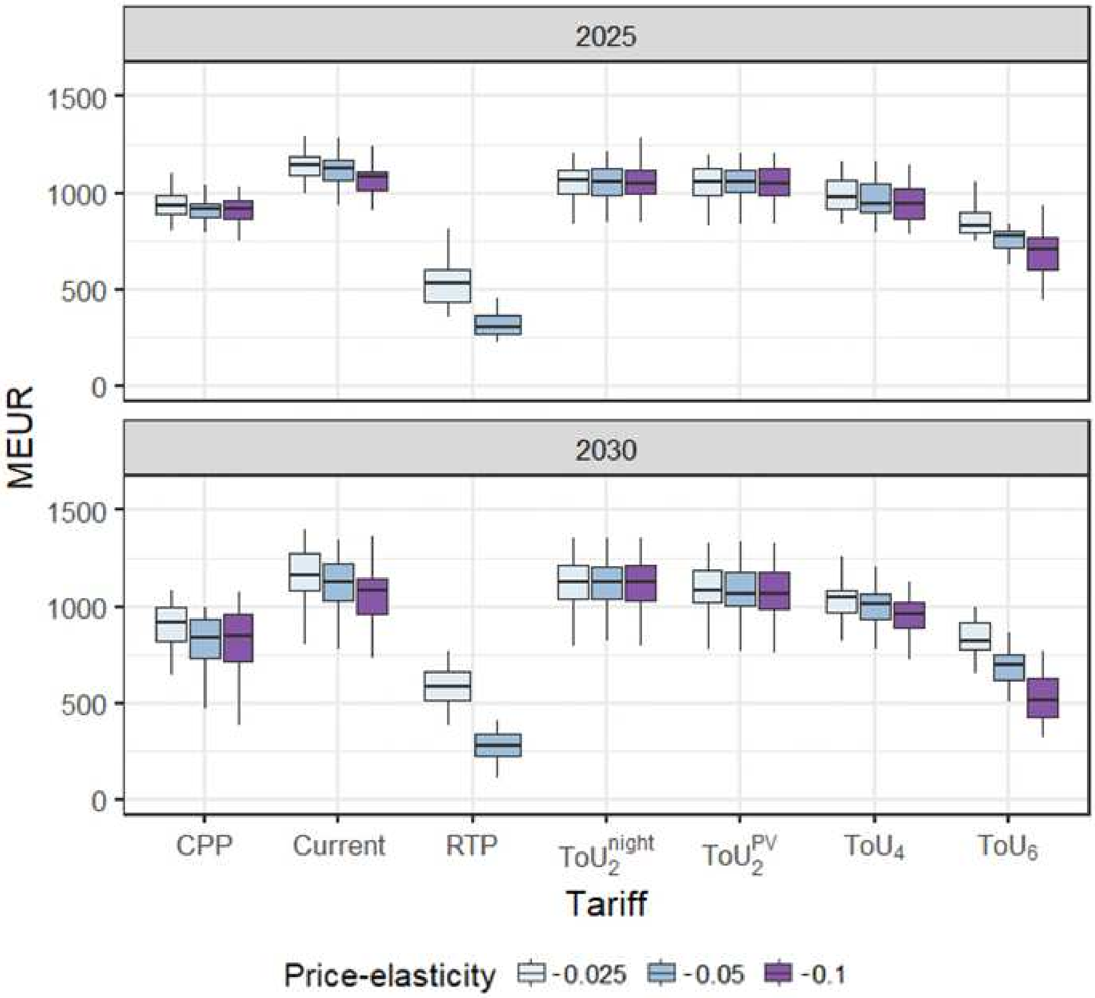
Figure 29 - Deadweight Loss calculations illustration compared to *RTP*



In the cases when demand exceeds the merit order, therefore resulting in non-voluntary load shedding, the deadweight loss is not defined. Even though it is considered in the modelling framework and valued at 8000 EUR/MWh, based on ERAA assumptions, adjustments are made to the calculations of the deadweight loss in that situation. We stretched out the supply to meet the demand in those cases, considering additional imports would be available and setting power prices at the marginal cost, which is an interruptible load. In Appendix B, Figure B.15, we further illustrate this case. Figure 30 presents the results of the deadweight loss for each second-best dynamic tariff relative to the real-time price outcome, considering the higher price elasticity of the demand. The focus is made on a selection of tariffs, with all results provided in Appendix B, Figure B.16.

[25] Additional deviations could occur due to the presence of storage technologies.

Figure 30 - Deadweight Loss of second-best dynamic tariffs compared to real-time pricing



First, the importance of deadweight loss for each dynamic tariff is relatively aligned with the analysis of the Spearman correlation. The results, however, temper the case for the ToU_2^{PV} tariff. As underlined in section 3.4.3, this tariff depicts an increasing Spearman correlation over time, reaching slightly less than 0.4 in 2030. Similarly, the power price reduction reached 6% in 2030, similar to the level reached under the current dynamic tariff adoption. However, its deadweight loss is relatively stable at around 1.05 bn EUR in both 2025 and 2030, far from tariffs with peak-pricing components for which the deadweight loss is significantly below, around 0.5 to 0.8 bn EUR. This directly stems from the relatively low price gap between on-peak and off-peak rates for the ToU_2^{PV} tariff, reducing the potential for demand response. In addition, the effect is reinforced by the lack of consumer response during scarcity events, where consumers are provided with regular off-peak and on-peak periods price signals. As the deadweight loss is significant during those events (Appendix B, Figure B.15), the absence of demand response is detrimental to all static electricity tariffs. Nonetheless, it remains beneficial to favour ToU_2^{PV} compared to ToU_2^{night} based on the results, although the reduction of DWL are limited.

In addition, increasing consumer price elasticity would allow for higher savings only in cases where incentives are well-aligned with the wholesale market prices but would otherwise yield higher losses when tariff variations are negatively correlated with power price variations. As a result, static tariffs do not reduce deadweight loss significantly more when price elasticity is increasing. Indeed, the deadweight loss remains stable at around 1 to 1.2 billion EUR for static tariffs. In contrast, for tariffs incorporating peak pricing features, the deadweight loss is projected to be between 0.5 and 1 billion EUR annually by 2030 compared to the first-best *RTP* tariff. Even considering the lowest price elasticity for tariffs that integrate peak-pricing components yields a lower deadweight loss than static tariffs, regardless of the price elasticity level. Similarly, the results underline the relevance of the first-best *RTP* tariff from an economic standpoint, which outperforms all other dynamic tariffs even at low elasticity values. Focusing on the current distribution of dynamic tariffs, the results demonstrate a reduction of the deadweight loss by 0.1 bn EUR between the lowest and the highest price elasticity considered. Fostering consumer price elasticity or automation of appliances would, therefore, deliver some benefits. However, the level remains far from the gain achievable thanks to a higher share of consumers reacting to a tariff with peak pricing components.

Overall, in-sample correlation and R^2 should not be the only metric used to assess the welfare gains of dynamic tariffs. Fostering social acceptance toward tariffs with peak pricing components becomes increasingly relevant in the context of the current energy transition as the peak prices are expected to increase in the future power markets. However, it should be underlined that the deadweight loss presented corresponds to a situation where all consumers at the distribution grid level are enrolled on the same tariff and react homogeneously to the price signals over time. Therefore, it is likely overestimated, depending on the price elasticity assumption considered.

3.5. Conclusion

In this paper, we applied a novel modelling approach to analyse the efficiency and stability of the French electricity tariffs, considering historical and prospective years. Each model is representative of a different actor in the electricity markets, ranging from firms competing in the wholesale market to the end-user consumers reacting to the different rates proposed by the retailer. In addition, multiple weather years have been considered to assess the robustness of the findings.

First, our analysis suggests that current tariffs have been effective in incentivising behaviour in the French electricity market. More specifically, we find that complex tariffs incorporating peak pricing features have been more effective in capturing lower power prices compared to simpler tariffs. The Spearman correlation analysis also supports this finding, showing stronger correlations with day-ahead prices for these types of tariffs. However, the 2021-2023 energy crisis has highlighted the limitations of such tariffs to provide sustained incentives during periods of high prices. In these situations, tariffs that target daily load patterns, such as on-peak/off-peak schemes, may be more effective in reducing power prices by targeting all evening peak loads equally. Despite their effectiveness in the current French electricity market, the efficiency of existing tariffs is not expected to persist in the near term. Notably, the efficiency of currently designed on-peak/off-peak schemes is not demonstrated with an increasing share of renewables, as the current partitioning of the day and year is not adapted to future power price patterns, notably linked to solar PV production. If this comes with no surprise, our results show that even in 2025, with relatively low penetration of renewables, the incentives provided are misaligned with power prices for multiple weather years considered. This finding has some direct policy implications, as future tariff design must be flexible enough to adapt to changing market conditions and technological advancements. Consumers able to shift consumption at night will not necessarily be capable of shifting it during the day, which also suggests the need for anticipation to foster a timely adoption of new hour partitioning and progressively remove price signals to shift consumption at night. Similar conclusions hold for more complex tariffs, for example, in the case of ToU_6. The critical peak periods (including mid-peak days) should also be subject to amendments in the determination rules and the number of days of activation. Although we find that the distribution of peak days is relatively stable over time, mainly concentrated in the winter, a shift towards the summer is also underlined in our results, requiring anticipation and communication to consumers enrolled. In addition, tariffs with peak pricing features have performed poorly during the power crisis, underlining their intrinsic inability to pass through correct incentives when sustained periods of high prices are faced. Although we do not expect such extraordinary situations to be common, the tariff design should consider periods of low renewables output that might arise in the future (also referred to as cold dark doldrums). Compared to the results from the literature in the United States, which exhibit a Spearman correlation between 0.5 and 0.8 for *ToU* and *ToU-CPP* (Jacobsen et al., 2020; Schittekatte et al., 2022), our study finds that the French tariffs exhibit relatively lower correlation levels. This result could be attributed to the lower granularity of French tariffs, which contain only two periods per day, compared to the three or four periods per day in US tariffs. It suggests that future tariff design in the French electricity market may benefit from increasing the granularity of tariffs to better align with market conditions and achieve higher correlation levels with day-ahead prices.

Our second finding relates to the evolution of the rate differences between the on-peak and off-peak periods for dynamic tariffs. With the increasing carbon price, the costly natural gas used in peaking units, and the progressive phase-out of conventional thermal capacities (coal, lignite), we expect the ratio between off-peak and on-peak hours to increase gradually. If this might be beneficial for fostering consumer demand response, thanks to the increased incentives to shift consumption, it would also likely impact the adoption rate of such dynamic tariffs. Indeed, consumers might be reluctant to engage in such tariffs if the ratio is deemed too high, notably if consumers cannot hedge or substitute their consumption during peak periods. Therefore, more empirical evidence is required on the French adoption rate based on the relative difference between on-peak and off-peak periods. In addition, more research would be beneficial on the short-term price elasticity depending on the tariff schemes. This is highly important as renewable power production starts reaching a significant share in most countries, and demand response is expected to play a more prominent role in the future for industrial, professional, and residential segments.

A third finding relates to the use of Spearman correlation and R^2 in assessing the welfare gain achieved by second-best electricity tariffs. We highlight the importance of peak pricing features in future power markets compared to fixed on-peak/off-peak schedules, whose interests gradually decrease despite being the most widely adopted scheme. Adjusting the schedules to match the solar PV production does not significantly reduce the deadweight loss compared to the more complex tariff, although it depicts a relatively high correlation with day-ahead prices. Indeed, the deadweight loss is estimated between 0.5 and 1 bn EUR per year in 2030 for tariffs with peak pricing features, while it is between 1 and 1.2 bn EUR for less complex tariff designs. More widespread adoption of tariffs with peak pricing features would likely benefit the future power system while benefitting consumers, as the achieved power price reduction reaches 10% for most dynamic tariff adoption in our framework.

Finally, our research also suggests that bill savings allowed by dynamic pricing are overestimated. When comparing the results to the bill reduction envisaged by the European Commission (2019) for *RTP* schemes of 22-70% of the energy supply component in the annual bill, the demand response would need to deliver more than six times the savings found. Indeed, the yearly average price difference compared to the case of an inelastic load never exceeds 25% in our study, except in the case where 50% of consumers would adopt *RTP* pricing with a significant price elasticity. We believe the result of the European Commission would likely go along with a significant price elasticity or a net decrease in electricity consumption for the end users and would concern only a reduced share of consumers. In addition, pilot projects do not evaluate the utility function or transaction costs associated with monitoring electricity consumption and reacting to price incentives. While we have considered a stable yearly consumption for most tariffs under our demand-side response formulation, we did not assess long-term price elasticity in relation to electricity price level or to dynamic tariff adoption. If our results would hold when considering hourly cross-elasticities or load-shifting potential, changing the willingness to pay a consumer to lower values would allow for more benefits by lowering the annual energy consumption.

It is essential to note that our methodology has some caveats. Primarily, the prices derived from the model (in Stage One) may not fully reflect day-ahead market settlements, notably in price volatility. Notably, relaxations of the unit commitment have been required to reduce computation time due to the multiple weather years considered. In addition, while we align with the existing literature for which a common assumption is that all firms participate in the day-ahead market, transactions occur mainly over the counter in France. This assumption could impact the rate level found in our methodological approach. Similarly, we consider the marginal price stemming from the unit commitment model to determine each rate, while French regulations such as ARENH should also be considered in the rates setting. Additional uncertainty on the wholesale market stems from France's considered power generation capacity up until 2030. However, given the relatively short-term period considered in the prospective case and that the lead time in the power sector is typically over ten years for nuclear power stations, this is unlikely to affect the considered figures significantly. Concerning Stage Two and Three of the methodology, the prospective years' assessment relies on the total load profile, adjusted based on fixed price elasticity for each consumer segment and tariffs. This assumption likely leads to overestimated demand response and does not account for consumer heterogeneity.

We believe that further research is also required to understand to what extent grid and generation scarcity would require different signals to be conveyed to the end-users and might conflict with each other. This issue relates to the TSO-DSO coordination research stream, where country-wide signals from the wholesale market might go against local grid congestion flexibility requirements or investment needs. In addition, a ceiling effect is expected for a given deployment rate of dynamic tariffs, implying decreasing marginal value in additional price reactivity. In other words, once a reactivity level is reached, for example once a certain amount of peak-load reduction is achievable, there are few welfare gains from increasing the reactivity further. Determining such an optimal share of reactive consumers would be of interest. In addition, more research would be required to estimate hourly price elasticity over a large pool of consumers depending on the season, day types, and rate faced. Indeed, field experiment has demonstrated the heterogeneity of consumers' preferences in terms of electricity tariffs, whose acceptance are subject to status quo bias and risk aversion, thereby impacting the features of dynamic tariffs, such as the price spread.

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Appendix B

B1. Supplementary Tables

Table B.1 - Description of tariffs segmentation and aggregation performed

c	Tariffs	Description	Tariff symbol
Residential	RES1 (+ RES1WE)	Flat-rate tariffs (≤ 6 kVA)	θ^{R}_{flat}
	RES11 (+ RES11WE)	Flat-rate tariffs (> 6 kVA)	
	RES2 (+ RES5)	Two-tier time-of-use rate	θ^{R}_{ToU-2}
	RES2WE	Three-tier time-of-use rate	θ^{R}_{ToU-3}
	RES3	Six-tier time-of-use rate	θ^{R}_{ToU-6}
	RES4	Critical Peak Pricing	θ^{R}_{CPP}
Professional	PRO1 (+ PRO1WE)	Flat-rate tariffs	θ^{P}_{flat}
	PRO2 (+ PRO2WE + PRO6)	Two-tier time-of-use rate	θ^{P}_{ToU-2}
	PRO3	Six-tier time-of-use rate	θ^{P}_{ToU-6}
	PRO4	Critical Peak Pricing	θ^{P}_{CPP}
	PRO5	Flat-rate tariffs (Public lighting only)	$\theta^{P}_{flat_l}$
Industrial	ENT1 (+ ENT2)	Four-tier time-of-use rate	θ^{I}_{ToU-4}
	ENT3 (+ ENT4 + ENT5 + ENT7)	Four-tier time-of-use rate with critical peak pricing	$\theta^{I}_{ToU+CPP}$

Table B.2 - Descriptive statistics of consumer segment and tariffs considered

Segment	Name	Average yearly consumption (TWh)	Average yearly consumption (%)	Draw-off points ('000)	Draw-off points (%)
Residential	$Flat$	47.0	*10.8%*	7 622	*74.9%*
	ToU_2	88.7	*20.2%*	1 736	*17.1%*
	ToU_3	1.0	*0.2%*	38	*0.4%*
	ToU_6	1.8	*0.4%*	37	*0.4%*
	CPP	2.6	*0.6%*	82	*0.8%*
Professional	$Flat$	23.3	*5.4%*	387	*3.8%*
	ToU_2	12.6	*2.9%*	105	*1.0%*
	ToU_6	1.2	*0.3%*	9	*0.1%*
	CPP	0.8	*0.2%*	18	*0.2%*
Industrial	ToU_4	33.9	*7.8%*	107	*1.0%*
	$ToU - CPP$	57.4	*13.2%*	35	*0.3%*
Total		*436.2*	*62.0%*	*10 176*	*100.0%*

Note: This table shows the average yearly consumption in TWh and the average number of draw-off points for the period 2018 to 2022. Only consumers on the distribution grid are considered, apart from the average yearly consumption, which is expressed as the percentage of the total power demand.

Table B.3 - Symbols and sets used for the retail tariff model

Element	Set	Description
y	$\in$ Y	Year
c	$\in$ C	Consumer segment {R, P, I}
tt	$\in$ T	Tariffs
st	$\in$ S	Sub-tariffs
h	$\in \Theta$	Hour of the year
z	$\in \zeta$	Country
d	$\in \Lambda$	Day of the year
s	$\in \Upsilon$	Season of the year

Table B.4 - Metrics and notations used

Element	Unit	Description
$\pi_{y,c,tt}$	[EUR/MWh]	Captured price per consumer type, tariff and year
$CPR_{y,c,t}$	[%]	Captured price ratio per consumer type, tariff and year
$PeakR_{y,c,tt}$	[%]	On-peak to off-peak ratio per consumer type, tariff and year
$R^2{}_{c,tt}$	[-]	Coefficient of determination
$PPR_{y,tt}$	[%]	Yearly power price reduction achieved for a given tariffs
$d_{y,c,tt,h}$	[MWh]	Demand per consumer type, tariff, year and hour
$p_{y,h}$	[EUR/MWh]	Hourly power price
$\theta_{y,c,tt}$	[EUR/MWh]	Rate of a given consumer type, tariff and year

B2. Supplementary Methods

B2.1 Formulation of dynamic tariff considered

Flat tariff

The flat-rate tariffs assume a homogenous price of electricity throughout the year. As such, the flat-rate tariff offered to consumers is determined based on the load-weighted average of the wholesale prices. It is considered as the reference load profile, i.e., representative of consumers facing no price-based incentive to manage their load.

$$\theta_{Flat} = \frac{\sum_{h,s} p_{y,h} * d_{y,c,flat,h}}{\sum_{h,s} d_{y,c,flat,h}} \qquad \text{(Eq. B. 1)}$$

Time-of-use (*ToU*) tariff

Time-of-use tariffs discriminate power prices considering hourly, monthly, or seasonal fixed effects. As depicted in Table 1, multiple time-of-use rates have been implemented in France. The more widespread tariffs in France consist of two-tier tariffs based on the hour of the day, although additional distinctions between working days and weekends or between the different seasons have been implemented.

(Eq. B. 2)

$$\theta_{ToU2} = \begin{cases} \theta_{ToU2}^{onpeak} & \forall h \epsilon \{\Theta_{onpeak}\} \\ \theta_{ToU2}^{offpeak} & \forall h \epsilon \{\Theta_{offpeak}\} \end{cases}$$

$$\theta_{ToU3} = \begin{cases} \theta_{ToU3}^{onpeak} & \forall (h,d) \epsilon \{\Theta_{onpeak} \cap \Lambda_{weekday}\} \\ \theta_{ToU3}^{offpeak} & \forall (h,d) \epsilon \{\Theta_{offpeak} \cap \Lambda_{weekday}\} \\ \theta_{ToU3}^{weekend} & \forall d \notin \{\Lambda_{weekday}\} \end{cases} \quad \text{(Eq. B. 3)}$$

$$\theta_{ToU4} = \begin{cases} \theta_{ToU4}^{onpeak,W} & \forall (h,s) \epsilon \{\Theta_{onpeak} \cap \Upsilon_{onpeak}\} \\ \theta_{ToU4}^{offpeak,W} & \forall (h,s) \epsilon \{\Theta_{offpeak} \cap \Upsilon_{onpeak}\} \\ \theta_{ToU4}^{onpeak,S} & \forall (h,s) \epsilon \{\Theta_{onpeak} \cap \Upsilon_{offpeak}\} \\ \theta_{ToU4}^{offpeak,S} & \forall (h,s) \epsilon \{\Theta_{offpeak} \cap \Upsilon_{offpeak}\} \end{cases} \quad \text{(Eq. B. 4)}$$

Critical Peak Pricing (*CPP*) tariff

An additional tariff in France consists of critical peak pricing. For a given number of days, the power price is significantly higher than the flat rate. Conversely, the rate offered the rest of the days' benefits of a relative discount compared to the peak pricing days.

$$\theta_{CPP} = \begin{cases} \theta_{CPP}^{onpeak} & \forall d \epsilon \{\Lambda_{peakday}\} \\ \theta_{CPP}^{offpeak} & \forall d \notin \{\Lambda_{peakday}\} \end{cases} \quad \text{(Eq. B. 5)}$$

Tempo tariff (*ToU_6*)

The rate can be combined with on-peak and off-peak hours, resulting in the "Tempo" tariffs in France and distinguishing between three types of days:

- Peak, for 22 days per year, called "Red" day.
- Mid-peak, called "White" days. They are defined for 43 days per year. The rate offered is higher than the valley rate but below "Red" days.
- Finally, valley days, called "Blue", made up for the rest of the year.

$$\theta_{ToU6} = \begin{cases} \theta_{ToU6}^{onpeak,P} & \forall(h,d)\epsilon\left\{\Omega_{onpeak} \cap \Lambda_{peakday}\right\} \\ \theta_{ToU6}^{offpeak,P} & \forall(h,d)\epsilon\left\{\Omega_{offpeak} \cap \Lambda_{peakday}\right\} \\ \theta_{ToU6}^{onpeak,MP} & \forall(h,d)\epsilon\left\{\Omega_{onpeak} \cap \Lambda_{midpeakday}\right\} \\ \theta_{ToU6}^{offpeak,MP} & \forall(h,d)\epsilon\left\{\Omega_{offpeak} \cap \Lambda_{midpeakday}\right\} \\ \theta_{ToU6}^{onpeak,V} & \forall(h,d)\epsilon\left\{\Omega_{offpeak} \cap \Lambda_{valleyday}\right\} \\ \theta_{ToU6}^{offpeak,V} & \forall(h,d)\epsilon\left\{\Omega_{offpeak} \cap \Lambda_{valleyday}\right\} \end{cases} \quad \text{(Eq. B. 6)}$$

$$\theta_{ToU-CPP} = \begin{cases} \theta_{ToU-CPP}^{onpeak,W} & \forall(h,s,d)\epsilon\left\{\Theta_{onpeak} \cap \Upsilon_{onpeak} \backslash \Lambda_{peakday}\right\} \\ \theta_{ToU-CPP}^{offpeak,W} & \forall(h,s,d)\epsilon\left\{\Theta_{offpeak} \cap \Upsilon_{onpeak} \backslash \Lambda_{peakday}\right\} \\ \theta_{ToU-CPP}^{onpeak,S} & \forall(h,s,d)\epsilon\left\{\Theta_{onpeak} \cap \Upsilon_{offpeak} \backslash \Lambda_{peakday}\right\} \\ \theta_{ToU-CPP}^{offpeak,S} & \forall(h,s,d)\epsilon\left\{\Theta_{offpeak} \cap \Upsilon_{offpeak} \backslash \Lambda_{peakday}\right\} \\ \theta_{ToU-CPP}^{onpeak} & \forall d\epsilon\left\{\Lambda_{peakday}\right\} \end{cases} \quad \text{(Eq. B. 7)}$$

Real-time prices tariff (*RTP*)

Finally, an additional tariff is considered, recently offered by some retailers in France and for which the availability to consumers is enforced by the regulator. This tariff consists of a direct pass-through of the wholesale power price to end consumers:

$$\theta_{RTP} = p_{y,h} \quad \forall h \quad \text{(Eq. B. 8)}$$

B2.2 Partitioning algorithm considered for the OLS

An additional input required for rate setting with the constrained OLS model consists of the partition of hours for each year. While methodologies have been deployed (Astier, 2021; Yang et al., 2019) to determine optimal partitioning, we instead relied on an approach tailored to our methodological set-up.

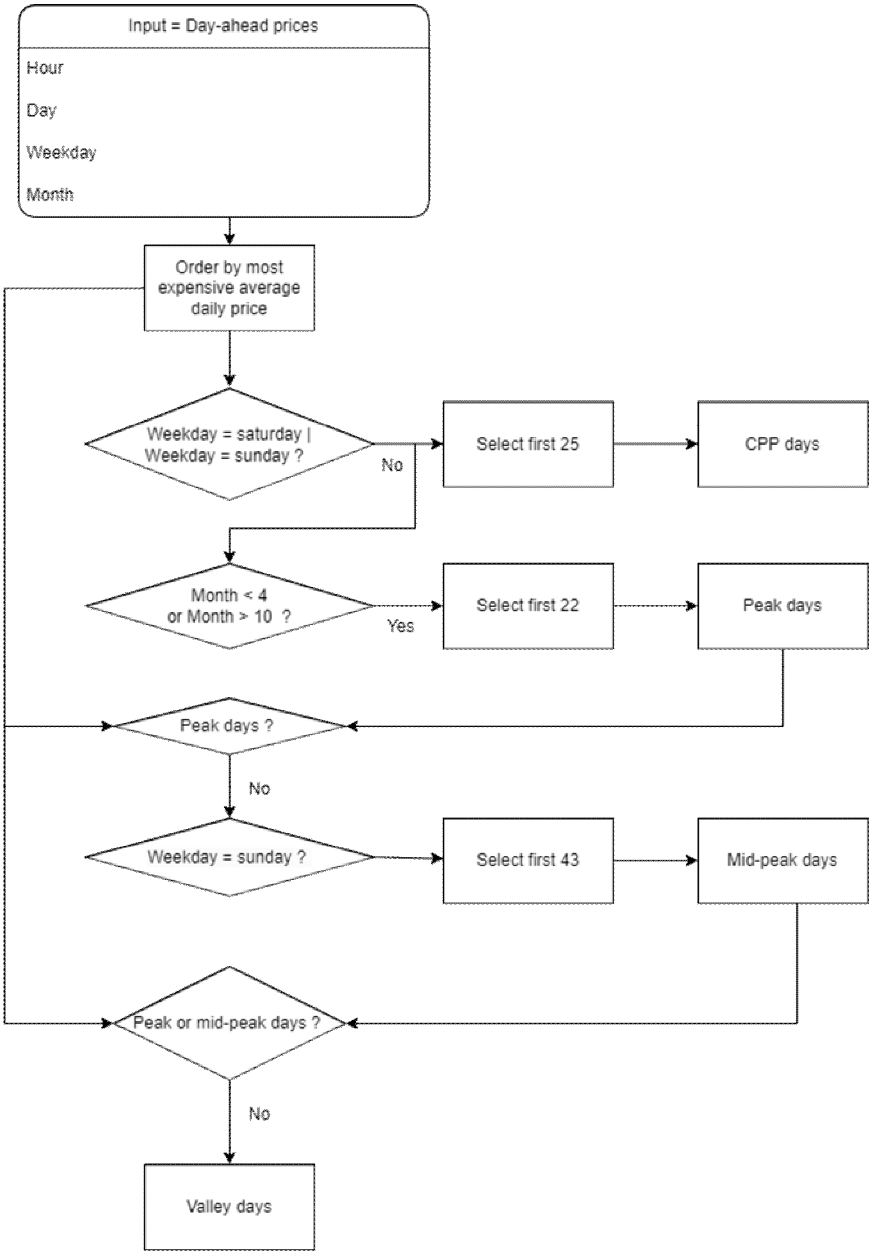
The first step consists of setting the rules that will be applied for each tariff, presented in Table A.5. To this end, we based our assessment on existing tariffs and time schedules, as provided by the public operator (Mourlon and Beaumeunier, 2020; RTE, 2023a, 2023b). Therefore, we relied on the historical partitioning of hours based on the information publicly available. Additional sensitivities for some tariffs were considered to account for the differences between the simplified set-up provided and existing tariffs. Therefore, three different two-tier time-of-use rates (ToU_2) have been considered depending on the hourly segmentation considered for off-peak hours. Similarly, two different six-tier time-of-use rates (ToU_6) were considered to assess the impact of fixing the ratio between on-peak and off-peak rates. Given the absence of significant differences, results for ToU_2^{nd} and ToU_6^{b} are not presented.

Table B.5– Rules and timetable considered for each tariff

Tariff	Rules considered
$\boldsymbol{Flat}$	-
$\boldsymbol{ToU_2^{night}}$	Off-peak from 11 pm to 6 am
$\boldsymbol{ToU_2^{PV}}$	Off-peak from 11 am to 5 pm
$\boldsymbol{ToU_3}$	Off-peak from 11 pm to 6 am Weekends days
$\boldsymbol{ToU_6}$	Off-peak from 11 pm to 6 am 22 peak days (“Red”) 43 mid-peak days (“White”) 300 off-peak days (“Blue”)
$\boldsymbol{ToU_6^b}$	Off-peak from 11 pm to 6 am 22 peak days (“Red”) 43 mid-peak days (“White”) 300 off-peak days (“Blue”) Minimum ratio of 7 between the valley and the on-peak rates
$\boldsymbol{CPP}$	22 CPP days
$\boldsymbol{ToU_4}$	Off-peak from 11 pm to 6 am Q1-Q4 winter period Q2-Q3 summer period
$\boldsymbol{ToU - CPP}$	Off-peak from 11 pm to 6 am Q1-Q4 winter period Q2-Q3 summer period 22 CPP days

For the prospective set-up, we could not rely on historical partitioning of the year. Therefore, we determine CPP days, as well as peak and mid-peak days for ToU_6. To do so, we rely on the outcome of Stage One to determine the peak pricing days. Additional rules have been implemented, following the methodology described by the French TSOs (RTE, 2016). The steps performed are described in Figure M.1. A key distinction with the TSOs methodology described comes from the deterministic nature of our algorithm based on the modelling results, as both load and the production of the renewable are fixed for each weather year. We estimate the peak pricing days based on the resulting power price outcome in this context. We, therefore, consider that the main objective is to reduce consumption when power prices are the highest, but abstract from the grid congestion management objective.

Figure B.1 - Schematic representation of the year partitioning used for CPP, Peak and Mid-peak days



B2.3 Definition of the on-peak-to-off-peak ratio

France has a variety of dynamic tariffs in place. While some consist of two-tier tariffs, distinguishing between on-peak and off-peak periods, others have more complex schemes. Therefore, we define for each tariff the considered ratio used for the *PeakR* metric introduced in section 3.3.2

Table B.6 - Peak and Mid-valley ratio considered for each tariff

Tariff name	Peak ratio considered	Mid-valley ratio considered
$\boldsymbol{Flat}$	-	-
$\boldsymbol{ToU_2}$	$\frac{\theta_{ToU2}^{offpeak}}{\theta_{ToU2}^{onpeak}}$	-
$\boldsymbol{ToU_3}$	$\frac{\theta_{ToU3}^{weekend}}{\theta_{ToU3}^{onpeak}}$	$\frac{\theta_{ToU3}^{offpeak}}{\theta_{ToU3}^{onpeak}}$
$\boldsymbol{ToU_6}$	$\frac{\theta_{ToU6}^{offpeak,V}}{\theta_{ToU6}^{onpeak,P}}$	$\frac{\theta_{ToU6}^{offpeak,MP}}{\theta_{ToU6}^{onpeak,P}}$
$\boldsymbol{CPP}$	$\frac{\theta_{CPP}^{offpeak}}{\theta_{CPP}^{onpeak}}$	-
$\boldsymbol{ToU_4}$	$\frac{\theta_{ToU4}^{offpeak,S}}{\theta_{ToU4}^{onpeak,W}}$	$\frac{\theta_{ToU4}^{offpeak,W}}{\theta_{ToU4}^{onpeak,W}}$
$\boldsymbol{ToU-CPP}$	$\frac{\theta_{ToU-CPP}^{offpeak,S}}{\theta_{ToU-CPP}^{onpeak}}$	$\frac{\theta_{ToU-CPP}^{offpeak,W}}{\theta_{ToU-CPP}^{onpeak}}$

B2.4 Wholesale market model formulation and data considered

A complete formulation of the core wholesale electricity market model developed in this dissertation is given below. The model and data are available online. Note that all parameters and constraints are not relevant to this chapter's research question considered and that intermediate calculations are not depicted. The mathematical formulation and the data are similar for Stage One and Stage Four.

Sets

Element	Description	Set	Example
y	Year	$\in$ Y	*2018, 2025…2050*
z, z'	Country or zone considered	$\in \zeta$	*CWE; FR, DE…*
h	Hour of the year	$\in \Theta$	*1, 2, 3,…, 8760*
d	Day of the year	$\in \Lambda$	*1, 2, …, 365*
w	Week	$\in W$	*1, 2, 3, …, 53*
wh	Hour of the week	$\in WH$	*1, 2, …, 168*
e	Energy sources	$\in$ E	*Natural gas, Hard coal, Lignite, …*
t	Technology	$\in$ TECH	*CCGT, OCGT, …*
v	Vintage class, based on the year of installation	$\in$ V	*V1, V2, V3, …*
k, k'	Technology considered. Triplet of fuel used, turbine installed, and vintage class	$\in$ K	*(Natural gas, CCGT, V4)...*
vres, vres'	Renewable energy sources	$\in$ vRES $\subseteq$ E	*Wind onshore, Solar PV, …*
therm	Thermal power plants	$\in$ THERM $\subseteq$ E	*Nuclear, Natural gas, …,*
s	Storage technologies	$\in$ ST $\subseteq$ E	*Battery, PS, Dam…*
b	Battery-type storage	$\in$ B $\subseteq$ B	*Battery, PS, …*
dm	Dam-type storage	$\in$ DM $\subseteq$ B	*Dam, Mixed-Pumped storage*
ror	Run-of-river power plant	$\in$ ROR $\subseteq$ E	*Run-of-river*

Parameters

The first term of the objective function is the total cost of producing electricity, considering only the variable and operational expenditures:

Parameter	Description	Unit
$n_{k,z}^{0}$	Initial installed capacity of a given technology in a given zone	[MW]
$d_{y,\,h,\,z}$	Hourly electricity demand	[MWh]
$c_{y,\,k,z}^{v}$	Short-run marginal cost of a unit, composed of fuel price and variable O&M	[EUR/MWh]
ef_k	Emission factor of a given technology	[tCO_{2e}/MWh]
$c_{y,z}^{CO2}$	Market price of the carbon emission allowances	[EUR/tCO_{2e}]
$c_{k,z}^{ie}$	Yearly capital expenditures of a given technology	[EUR/MW]
c_{z}^{ll}	Value of Lost Load, associated with the market price cap in the electricity market	[EUR/MWh]
$c_{z,z'}^{i}$	Cost of importing power from neighbouring countries	[EUR/MWh]
$c_{k,z}^{start}$	Starting cost of a unit	[EUR/MWh]
$e_{y,\,h,\,z,\,z'}^{0}$	Historical power exports of a given zone;	[MWh]
$i_{y,\,h,\,z,\,z'}^{0}$	Historical power imports of a given zone;	[MWh]
$\alpha_{y,k,z}$	Market share of a given vRES technology	[%]
$avail_{y,h,k,z}$	Hourly availability factor for a given technology	[%]
$must_{y,h,k,z}$	Must-run factor for a given technology	[%]
$NTC_{y,d,z,z'}$	Net Transmission Capacity between zones	[MW]
$inflow_{y,h,d,z}$	Hourly water inflows	[MWh]
SoC^{h}	Hourly storage level of storage	[MWh]
$link_{w,h}$	Link between week and hour	[-]
$\eta_{b}^{in/out}$	Storage efficiency factor (charging/discharging)	[%]
dd_s	Energy storage capacity	[MWh]
$cf_{y,h,k,z}$	Hourly availability factor	[%]
$uc_{y,k,z}^{0}$	Number of existing units	[-]
$MinP_k$	Minimum power output for a given unit	[%]
$MinP_k$	Maximum power output for a given unit	[%]
$Ramp_{k}^{down}$	Downward ramping factor for a given unit	[%]
$Ramp_{k}^{up}$	Upward ramping factor for a given unit	[%]

Variable

Variable	Description	Unit
$Total_{cost}$	Total cost	[EUR]
$N_{y,k,z}$	Yearly installed capacity of a given technology in a given zone;	[MW]
$N_{y,k,z}^{closed}$	Closure of capacity for a given year and technology;	[MW]
$G_{y,h,k,z}$	Hourly production of a given technology cluster of a zone;	[MWh]
$LL_{y,h,z}$	Lost load, energy not served in a zone;	[MWh]
$I_{y,h,z,z'}$	Power imports between two zones	[MWh]
$S_{y,h,s,z}$	Hourly storage level of storage	[MWh]
$C_{y,h,s,z}$	Hourly charging of storage technologies	[MWh]
$UC_{y,h,k,z}$	Number of activated units	[-]
$UC_{y,h,k,z}^{up}$	Number of units started	[-]
$UC_{y,h,k,z}^{down}$	Number of units shut down	[-]

Objective function

The first term of the objective function is the total cost of producing electricity, considering only the variable and operational expenditures:

$$Total_{cost} = \Big(\sum_{y,h,k,z} G_{y,h,k,z} * \left(c_{y,k,z}^{v} + ef_k * c_{y,z}^{CO2}\right) + \sum_{y,h,z} LL_{y,h,z} * c^{ll} + \sum_{y,h,z,z'} I_{y,h,z,z'} * c_{z,z'}^{i} + \sum_{y,h,k,z} UC_{y,h,k,z}^{up} * MinP_k * c_{k,z}^{Start}\Big) \quad \text{(Eq. B. 9)}$$

The cost minimisation objective function is subject to constraints to capture the specificities of each technology cluster.

Adequacy equation

The market price resulting from the model is deduced from the marginal value of the supply and demand constraint. A marginal increase of exogenous parameters, here the load, would result in an increase of the production variable and the objective function by an amount equal to the short-run marginal cost of the last unit called. Such value can be used as a proxy for the price of the day-ahead electricity market under perfect competition to render the dispatch performed by the system operator[26] (Brent Eldridge et al., 2018).

$$\sum_{k \in K} G_{y,\ h,\ k,\ z} + \sum\nolimits_{z' \in \zeta,\ \ z' \neq z} I_{y,\ h, z,\ z'} = d_{y, h,\ z} + \sum\nolimits_{z' \in \zeta,\ \ z' \neq z} e^0_{y, h, z,\ z'} + \sum\nolimits_{s} C_{y, h\, s,\ z} \qquad \forall y,\ h,\ z \qquad \text{(Eq. B. 10)}$$

Power production

The first constraint for production units relates to their initialisation and availability. We consider historical hourly availabilities to limit production based on historical factors. Conversely, some cogeneration units should provide baseload power independently of the economic dispatch for heat generation, for example.

$$N_{y,k,z} = \mathrm{n}^0_{y,k,z} \qquad \forall y,\ k,\ z \qquad \text{(Eq. B. 11)}$$

$$G_{y,\ h, k, z} \leq avail_{y,h,k,z} * N_{y,k,z} \qquad \forall y,\ h,\ k,\ z \qquad \text{(Eq. B. 12)}$$

$$G_{y,\ h, k, z} \geq must_{y,h,k,z} * avail_{y,h,k,z} * N_{y,k,z} \qquad \forall y,\ h,\ k,\ z \qquad \text{(Eq. B. 13)}$$

Power exchange

We consider historical power import and export to determine the power exchange for each hour. Power imports being eventually the price-setter, the assumption has been taken that the import price is aligned with the marginal cost of production of natural gas CCGT unit. In addition, power exchanges are symmetrical.

$$I_{y,\ h, z,\ z'} \leq i^0_{y,\ h, z,\ z'} \qquad \forall y,\ h,\ k,\ z \qquad \text{(Eq. B. 14)}$$

$$I_{y,\ h, z,\ z'} = E_{y, h, z',\ z} \qquad \forall y,\ h,\ k,\ z \qquad \text{(Eq. B. 15)}$$

Renewable power production

Several constraints are considered for renewables-based technology (wind, solar, or run-of-river hydropower), limiting the availability of natural resources. Those are based on 2018 historical production and consist of an hourly availability factor $cf_{y,h,vRES}$, in percentage, multiplied by the

[26] Independent system operator in charge of the coordination and monitoring of the power system. We do not distinguish it from the European terms Transmission System Operator (TSO).

installed capacities. We let the possibility of curtailment in case of excess generation. The formulation is slightly different, as ERAA provide daily run-of-river production factors, which have been uniformly allocated to individual hours.

$$G_{y,\,h,\,vRES,z} \leq cf_{y,h,vRES,z} * N_{y,vRES,z} \qquad \forall y,\, h,\, vRES, z \qquad \text{(Eq. B. 16)}$$

$$G_{y,\,h,\,ror,z} \leq ror_{y,d,ror,z}/24 \qquad \forall y,\, h,\, z \qquad \text{(Eq. B. 17)}$$

Storage-related constraint

Hourly charging and discharging of storage technologies must be limited to their installed capacities. An additional nominal charging capacity is considered by applying a scaling factor α_k, to the nameplate (discharging) capacity.

$$C_{y,\,h,\,s,z} \leq \alpha_s \times N_{y,s,z} \qquad \forall y,\, h,\, s,\, z \qquad \text{(Eq. B. 18)}$$

Storage technologies have different energy storage capacity dd_k, expressed in hours. This discharge duration induces a limit in the hourly state of charge of the storage option.

$$S_{y,\,h,\,s,z} \leq N_{y,s,z} * dd_s \qquad \forall y,\, h,\, s,\, z \qquad \text{(Eq. B. 19)}$$

Storage technologies face limitations due to the current state of charge. The state of charge is initialized and finalized at the same level, which imposes constraints on storage systems.

$$G_{y,\,h,\,s,z} \leq S_{y,\,h,\,s,z} \qquad \forall y,\, h,\, s,\, z \qquad \text{(Eq. B. 20)}$$

$$S_{y,\,0,\,s,z} = SoC^{0} * N_{y,s,z} \qquad \forall y,\, s,\, z \qquad \text{(Eq. B. 21)}$$

$$S_{y,\,8760,\,s,z} = SoC^{8760} * N_{y,s,z} \qquad \forall y,\, s,\, z \qquad \text{(Eq. B. 22)}$$

Hydropower-related constraint

The storage level of lakes (dams and reservoirs) depends on the water inflow (by rivers or rain) to the considered reservoir or lake that is blocked by the dams. Weekly available energy for the hydroelectricity generated by lakes and reservoirs is defined with regard to the weekly water inflows (Eq. B. 24).

$$S_{y,\,h,\,dm,z} = S_{y,\,h-1,\,dm,z} + inflow_{y,h-1,dm,z} - G_{y,\,h-1,\,dm,z} \qquad \forall y,\, h,\, d,\, z \qquad \text{(Eq. B. 23)}$$

$$\textstyle\sum_{h|link_{w,h}} G_{y,\,h,\,dm,z} \leq \sum_{h|link_{w,h}} inflow_{y,h,dm,z} \qquad \forall y,\, w,\, dm,\, z \qquad \text{(Eq. B. 24)}$$

Batterie-related constraint

Storage technologies are charged when there is excess electricity production and are discharged when there is a lack on the supply side. The operation of storage technologies must be optimal based on their costs. We apply the energy conservation law to the operation of storage technologies.

$$S_{y,\,h,\,b,z} = S_{y,\,h-1,\,b,z} + C_{y,\,h-1,\,b,z} \;*\eta_k^{in} - \;G_{y,\,h-1,\,b,z}\,/\eta_b^{out} \quad \forall y,\,h,\,b,\,z \qquad \text{(Eq. B. 25)}$$

Unit commitment constraint

Unit commitment is performed for each unit of dispatchable power plants. The number of activated units at each timestep UC is limited by the number of existing units uc^0 each year.

$$UC_{y,\,h,\,k,z} \;\leq\; uc^0_{y,k,z} \qquad \forall y,\,h,\,k,\,z \qquad \text{(Eq. B. 26)}$$

The number of activated units is also constrained by the previous state of each unit, completed by the number of units shut down UC^{down}, and the number of units started UC^{up} .

$$UC_{y,\,h,\,k,z} = \;\; UC_{y,\,h-1,\,k,z} + \;UC^{up}_{y,\,h,\,k,z} - \;UC^{down}_{y,\,h,\,k,z} \qquad \forall y,\,h,\,k,\,z \qquad \text{(Eq. B. 27)}$$

We consider a minimum ($MinP$) and a maximum (Max) power output for each unit. The hourly generation for a given technology cluster is, therefore, limited by the number of active units and their technical range of operation.

$$G_{y,\,h,\,k,z} \;\;\geq\;\; UC_{y,\,h,\,k,z} * MinP_k \qquad \forall y,\,h,\,k,\,z \qquad \text{(Eq. B. 28)}$$

$$G_{y,\,h,\,k,z} \;\;\leq\;\; UC_{y,\,h,\,k,z} * MaxP_k \qquad \forall y,\,h,\,k,\,z \qquad \text{(Eq. B. 29)}$$

Ramping constraints are defined upward and downward. The decrease (respectively increase) in the hourly production of a given cluster is limited by the downward (respectively upward) ramping factor $\mathrm{Ramp}^{\mathrm{down}}$ (resp. $\mathrm{Ramp}^{\mathrm{up}}$) applied to all active units that are not being started. We deduce from it the number of units started, as well as the unit being shut down, to apply the constraint only to the unit remaining active.

$$\begin{aligned} G_{y,\,h-1,\,k,z} \;-\; G_{y,\,h\,k,z} & \qquad \forall y,\,h,\,k,\,z \qquad \text{(Eq. B. 30)} \\ \leq\;\; & \left(UC_{y,\,h,\,k,z} - \;UC^{up}_{y,\,h,\,k,z}\right) * \;Ramp_k^{down} \\ - \;& UC^{up}_{y,\,h,\,k,z} * \;Min_k \\ + \;& \mathbf{max}\left(Min_k, Ramp_k^{down}\right) * \;UC^{down}_{y,\,h,\,k,z} \end{aligned}$$

$$G_{y,h,k,z} - G_{y,h-1,k,z} \leq \left(UC_{y,h,k,z} - UC^{up}_{y,h,k,z}\right) * Ramp^{up}_{k} - UC^{down}_{y,h,k,z} * Min_{k} + \mathbf{max}\left(Min_{k}, Ramp^{up}_{k}\right) * UC^{up}_{y,h,k,z} \quad \forall y, h, k, z \quad \text{(Eq. B. 31)}$$

Finally, minimum up and down times are defined within sliding time windows for each technology cluster.

$$UC_{y,h,k,z} \geq \sum_{h'}^{h'=h-\min_{up}\ldots h} UC^{up}_{y,h',k,z} \quad \forall y, h, k, z \quad \text{(Eq. B. 32)}$$

$$uc^{0}_{y,k,z} - UC_{y,h,k,z} \geq \sum_{h'}^{h'=h-\min_{down}\ldots h} UC^{down}_{y,h',k,z} \quad \forall y, h, k, z \quad \text{(Eq. B. 33)}$$

B3. Supplementary Data

Table B.7 - Considered capacity in 2025 and 2030 for France ((ENTSO-E, 2022)

		Nominal capacity (MW)	
Country	**Energy**	**2025**	**2030**
FR	Nuclear	61 761	58 213
FR	Hard Coal	0	0
FR	Gas	7 189	7 189
FR	Oil	1 331	971
FR	Hydro - Run of River and Pondage	13 600	13 600
FR	Hydro - Reservoir	9 539	9 847
FR	Hydro - Pump Storage	3 800	3 800
FR	Batteries	253	253
FR	Wind Onshore	24 059	35 929
FR	Wind Offshore	2 500	5 500
FR	Solar PV	18 185	43 441
FR	Others renewable	2 250	2 375
FR	Other non-renewable	5 665	4 223
FR	DSR	3 900	6 500

Table B.8 - Considered cost assumptions (ENTSO-E, 2022; RTE, 2021)

Fuel price

		Fuel	
Fuel	**Unit**	**2025**	**2030**
Nuclear	[EUR/MWh]	1.69	1.69
Hard Coal	[EUR/MWh]	10.76	10.98
Gas	[EUR/MWh]	46.62	43.92
Oil	[EUR/MWh]	56.84	56.84
Others renewable	[EUR/MWh]	19.06	19.06
Other non-renewable	[EUR/MWh]	9.81	9.81
DSR	[EUR/MWh]	350	350

Carbon price

		EU ETS	
	Unit	**2025**	**2030**
EU ETS	[EUR/tCO_{2e}]	93.75	110

Variable operation and maintenance cost

		Variable Operation and Maintenance (VOM)	
Fuel	**Unit**	**2025**	**2030**
Nuclear	[EUR/MWh]	4	4
Hard Coal	[EUR/MWh]	3.95	3.95
Gas	[EUR/MWh]	2	2
Oil	[EUR/MWh]	2.76	2.76
Others renewable	[EUR/MWh]	5.85	5.85
Other non-renewable	[EUR/MWh]	6.9	6.9
DSR	[EUR/MWh]	-	-

Table B.9 - Considered fuel emissions

Energy	Value	Reference
Hard coal	0.34	(Wilke, 2013)
Lignite	0.36	(Wilke, 2013)
Natural gas	0.20	(Wilke, 2013)

Other energy sources are assumed to be zero if based on renewable input (Biomass, Wind, Solar).

Table B.10- Electrical Efficiency (net) in optimal load operation in percentage

Energy	Type	Value	Reference
Biomass	-	36-38	(Commission et al., 2021; Lacal Arantegui, 2014)
Natural gas	CCGT	59	(Commission et al., 2021; Lacal Arantegui, 2014)
Natural gas	OCGT	42	(Commission et al., 2021; Lacal Arantegui, 2014)
Nuclear	-	40	(Commission et al., 2021; Lacal Arantegui, 2014)
Offshore	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
Onshore	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
PV	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
Battery	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)

Table B.11- Considered discharge duration of electrical storage units (own assumptions)

Energy	Value (h)
Battery	4
Hydro – Pump storage	12

Table B.12 - Considered round-trip efficiency of electrical storage units (own assumptions)

Energy	Value (%)
Battery	87%
Hydro – Pump storage	80%

Table B.13- Considered technical parameters used for the Unit Commitment (Schill et al., (2017)

	Minimum uptime	Minimum downtime	Max. ramp up rate	Max. ramp down rate
	(h)	(h)	(%)	(%)
Nuclear	10	10	27%	27%
Hard Coal	7	7	40%	40%
Gas	1	1	65%	65%
Oil	2	2	40%	40%
Others renewable	0	0	40%	40%
Other non-renewable	0	0	40%	40%
DSR	0	0	100%	100%

B4. Supplementary Results

Figure B.2 - Ratio of average power consumption per quarter compared to the minimum (2018-2022)

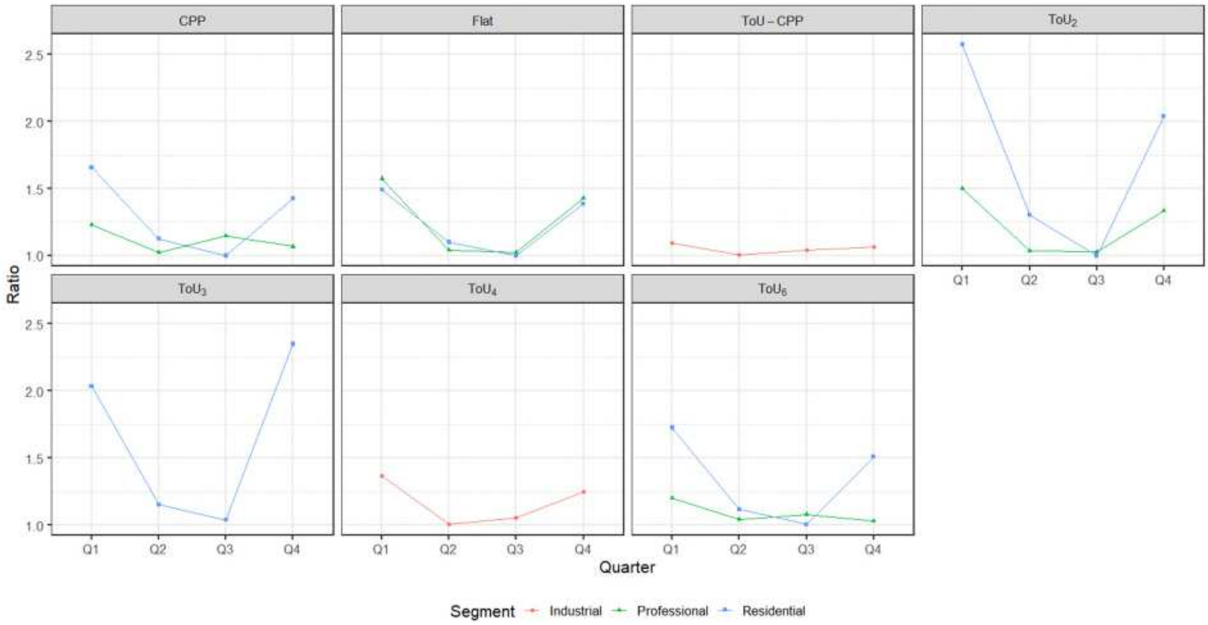


Figure B.3 - Captured Price Ratio per tariff and consumer segment from 2018 to 2022

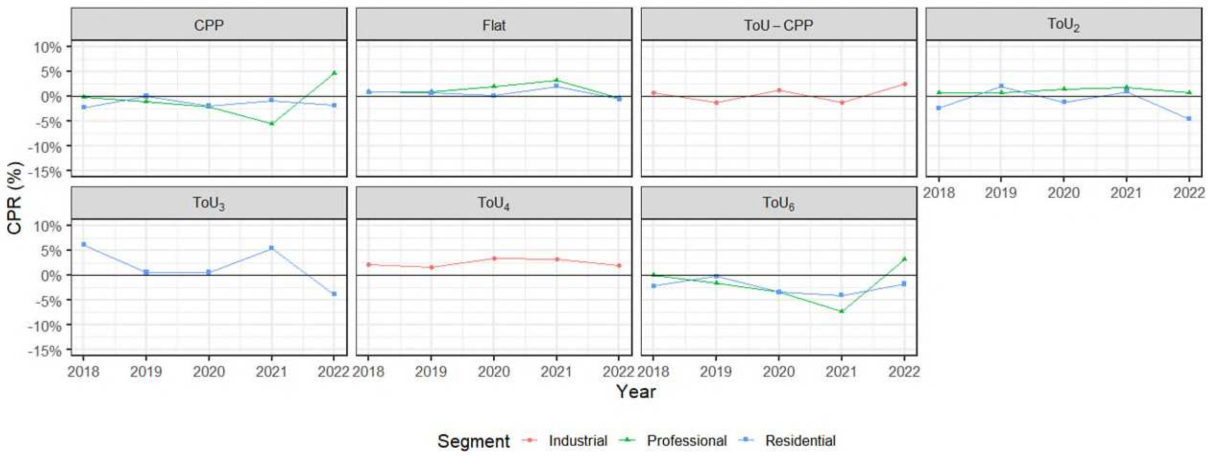


Figure B.4 - Spearman correlation of designed rate with day-ahead prices from 2018 to 2022

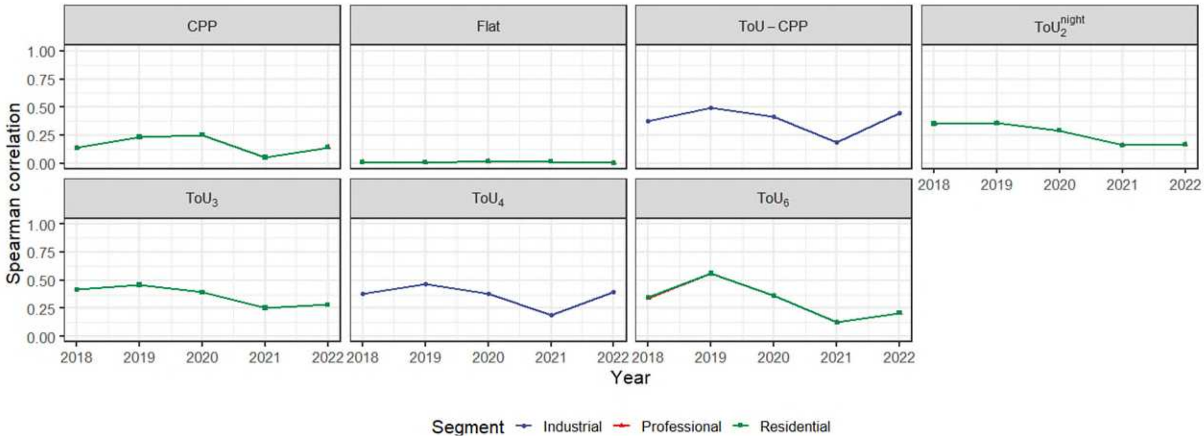


Figure B.5 - Tukey boxplot of yearly Spearman correlation between tariffs and day-ahead prices

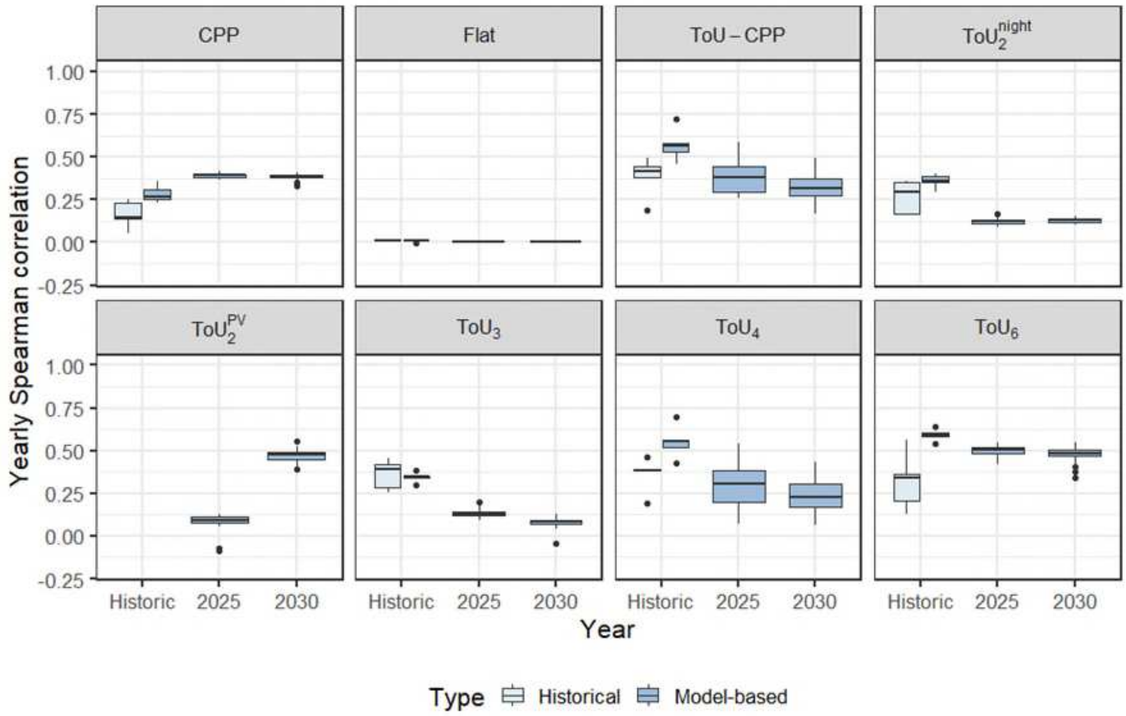


Figure B.6 - Tukey boxplot of average weekly Spearman correlation between tariffs and day-ahead prices

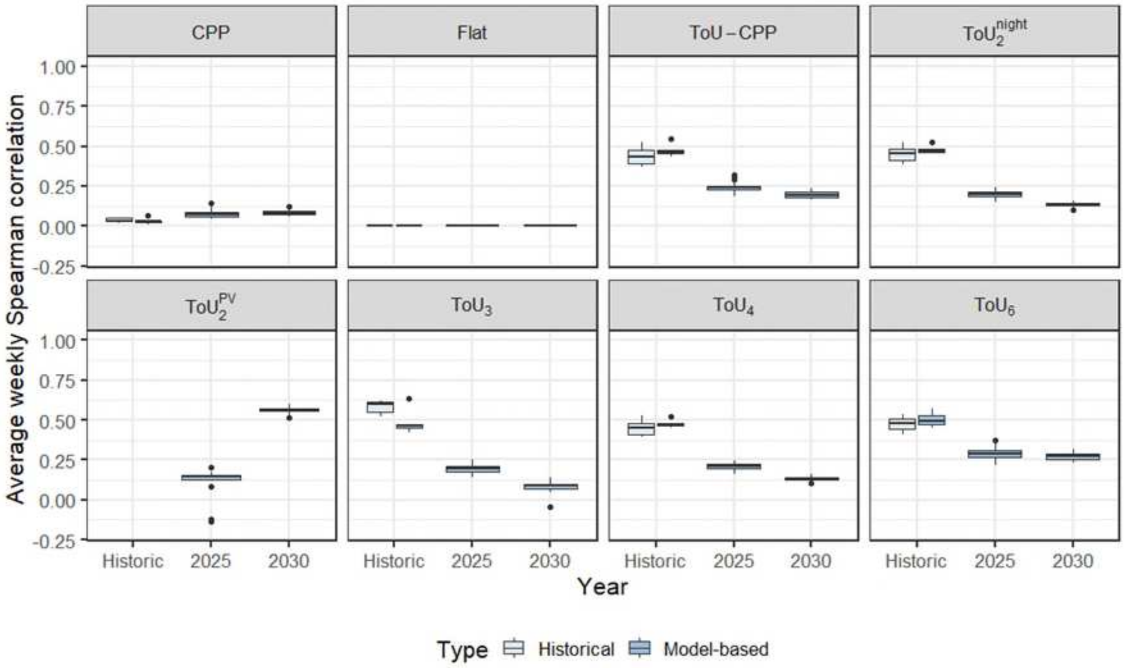


Figure B.7 - Tukey boxplot of average daily Spearman correlation between tariffs and day-ahead prices

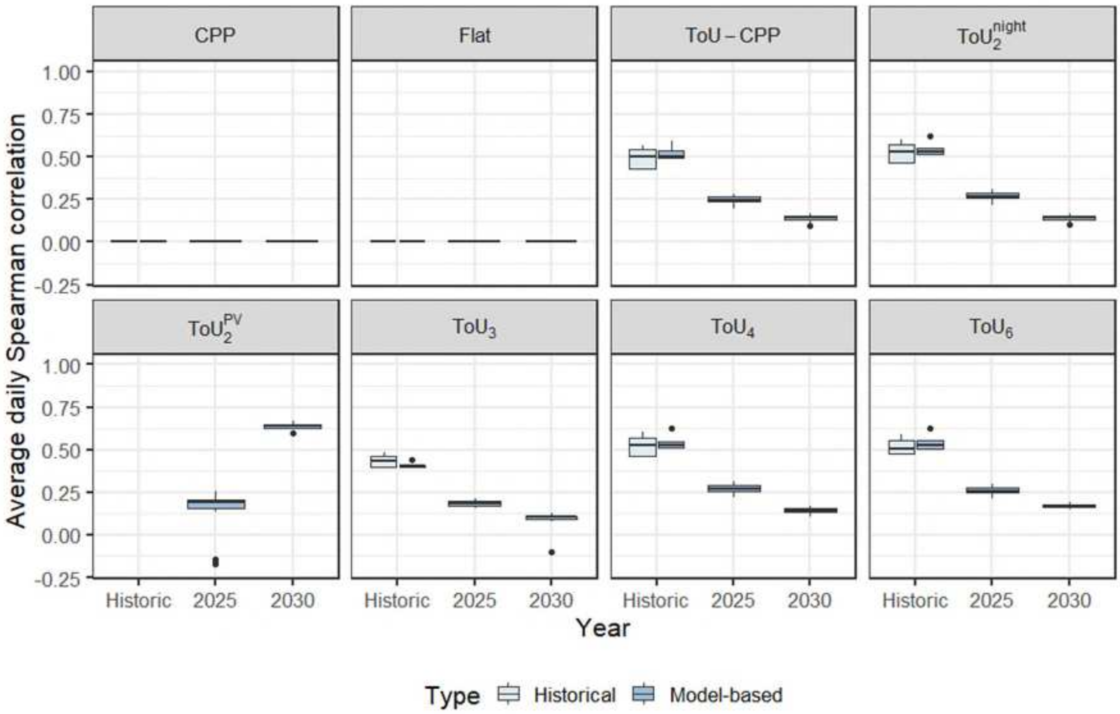
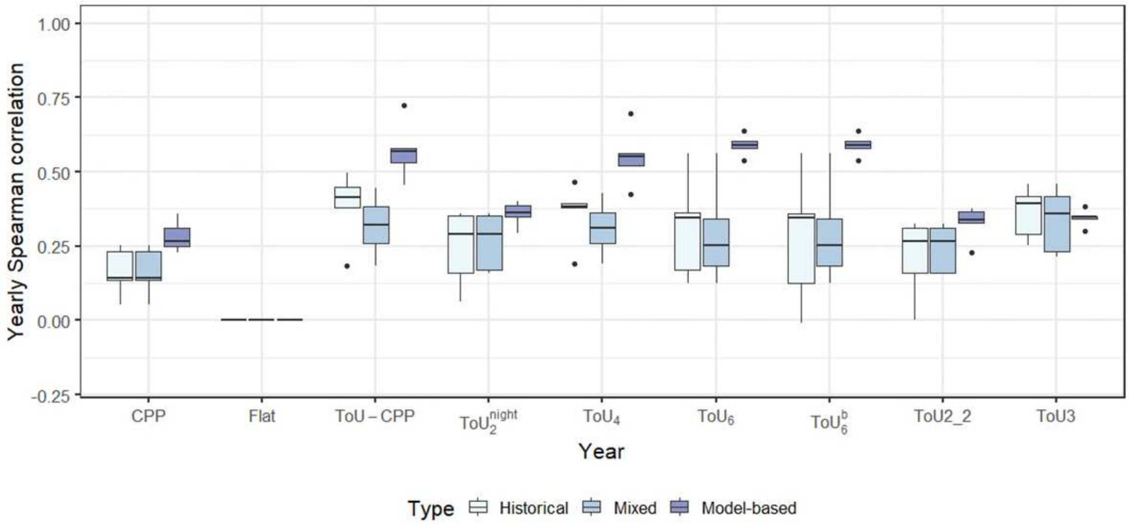


Figure B.8 - Tukey boxplot of yearly Spearman correlation between tariffs and day-ahead prices in the different set-up considered for historical years



"Historical" corresponds to the Spearman correlation of historical power prices with rates determined with the OLS based on historical power prices.

"Model-based" corresponds to the Spearman correlation of model-based power price rates with rates determined with the OLS based on model-based power prices.

"Model-based" corresponds to the Spearman correlation of model-based power prices rates with rates determined with the OLS based on model-based power prices.

Figure B.9 - Monthly distribution of peak day ("Red") defined for the ToU_6 tariff

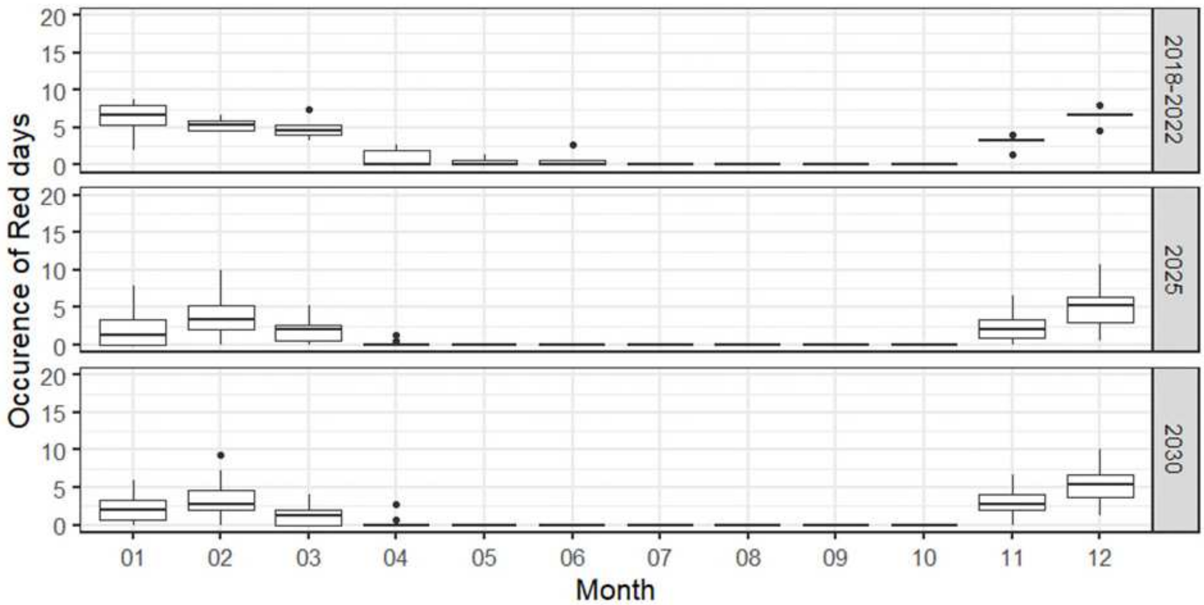


Figure B.10 - Monthly distribution of mid-peak days ("White") defined for the ToU$_6$ tariff

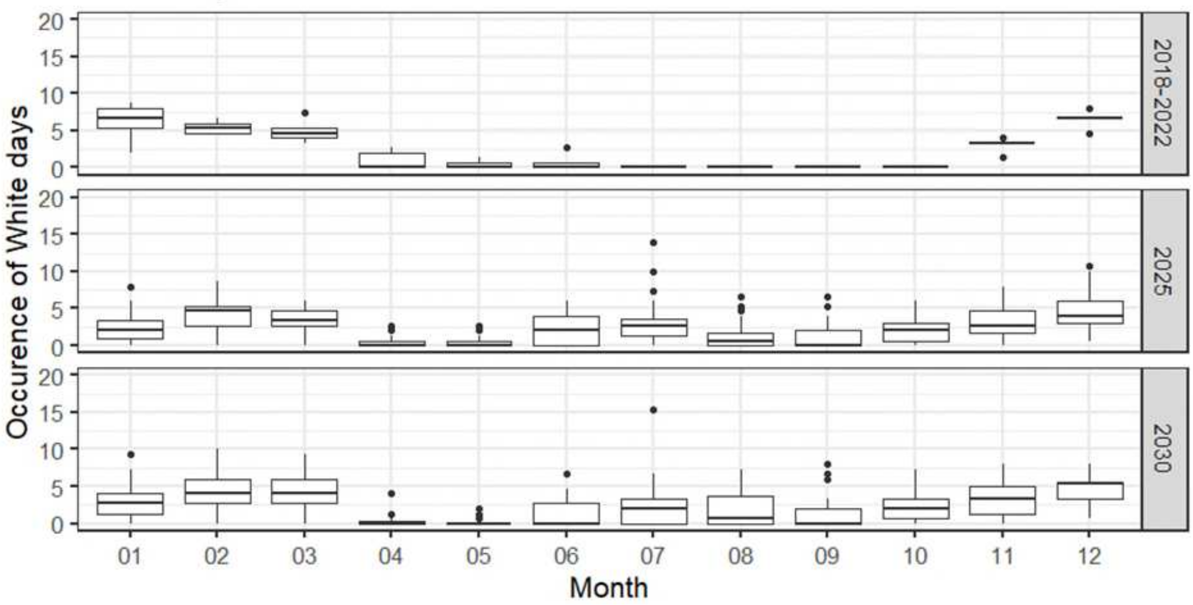


Figure B.11 - Evolution of the peak ratio per tariff

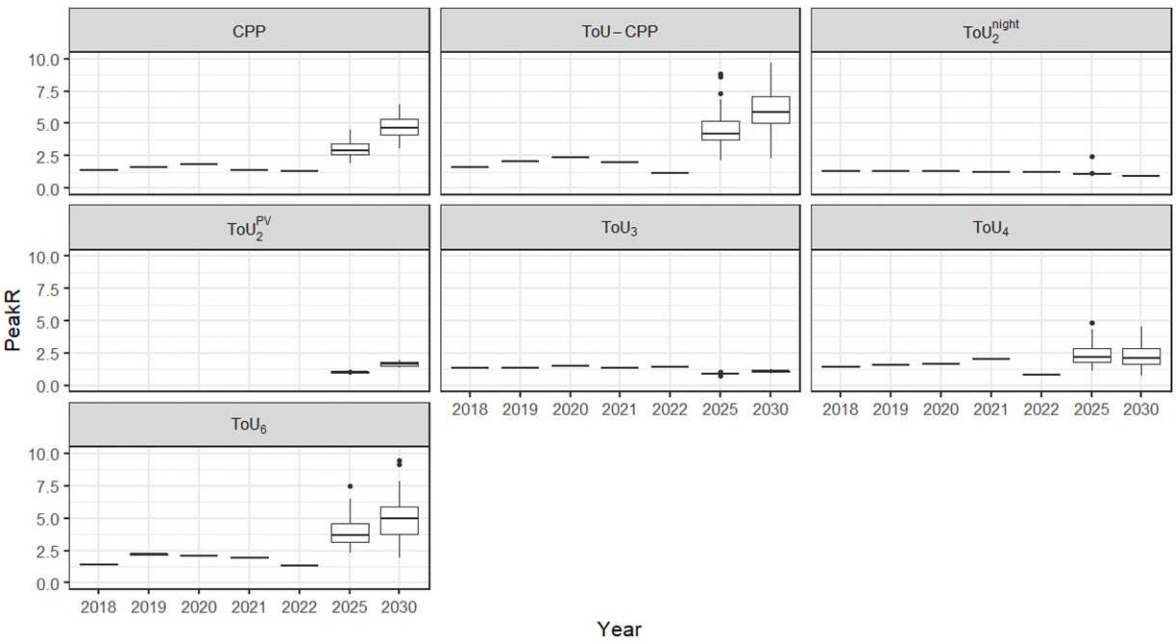


Figure B.12 - Evolution of the mid-valley ratio per tariff

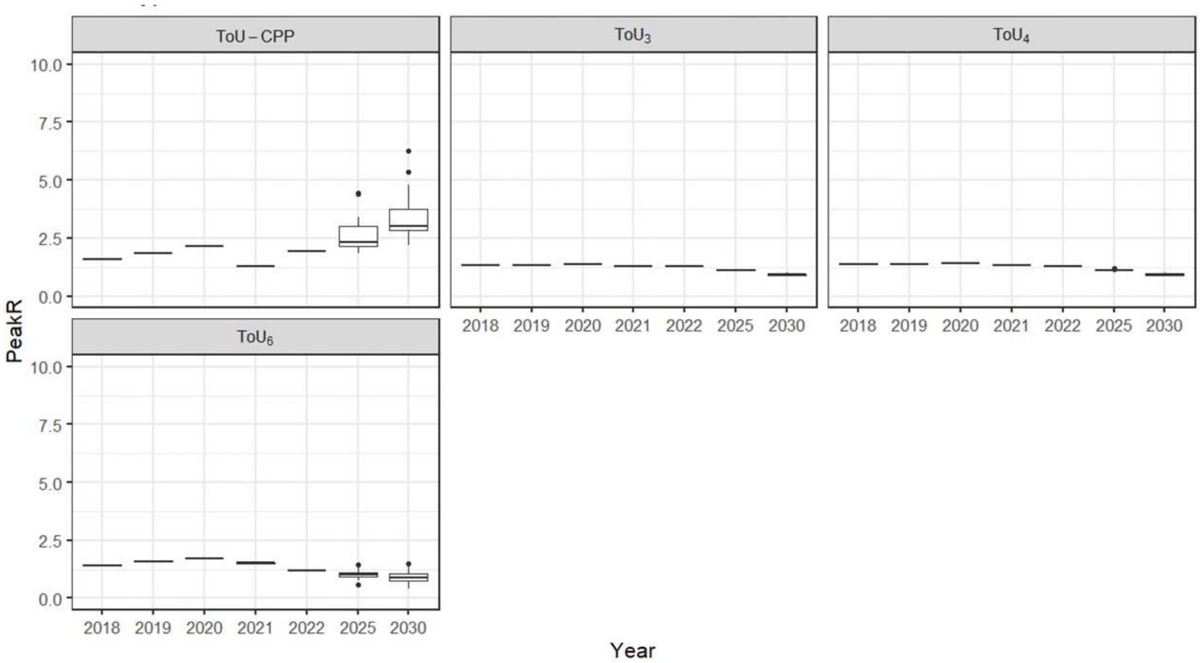
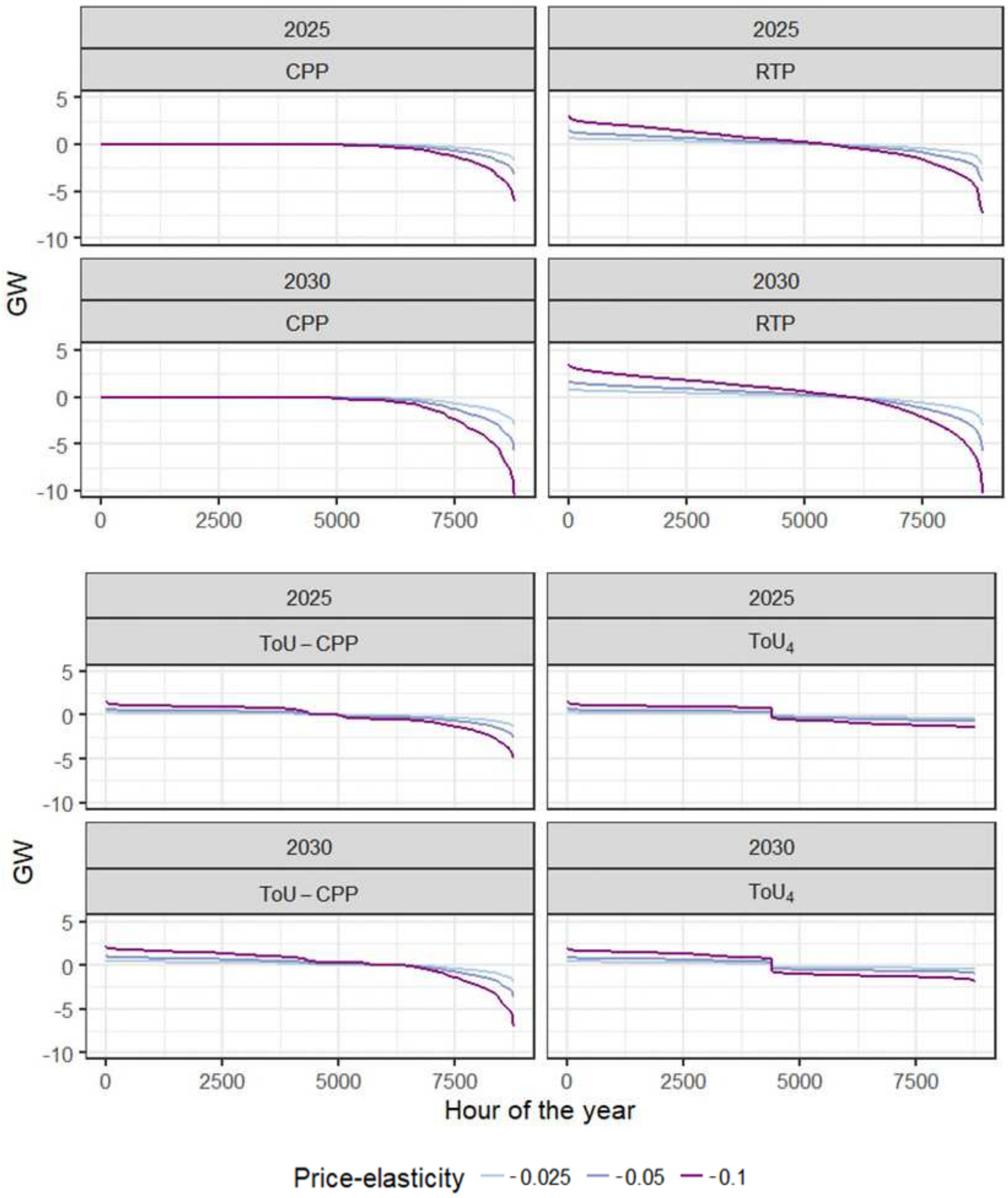
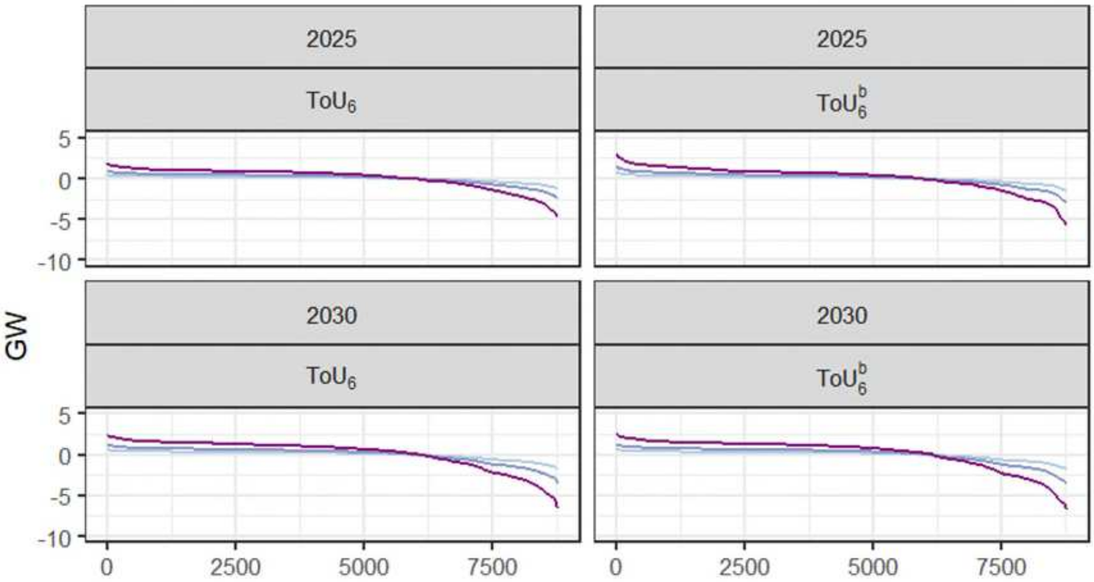
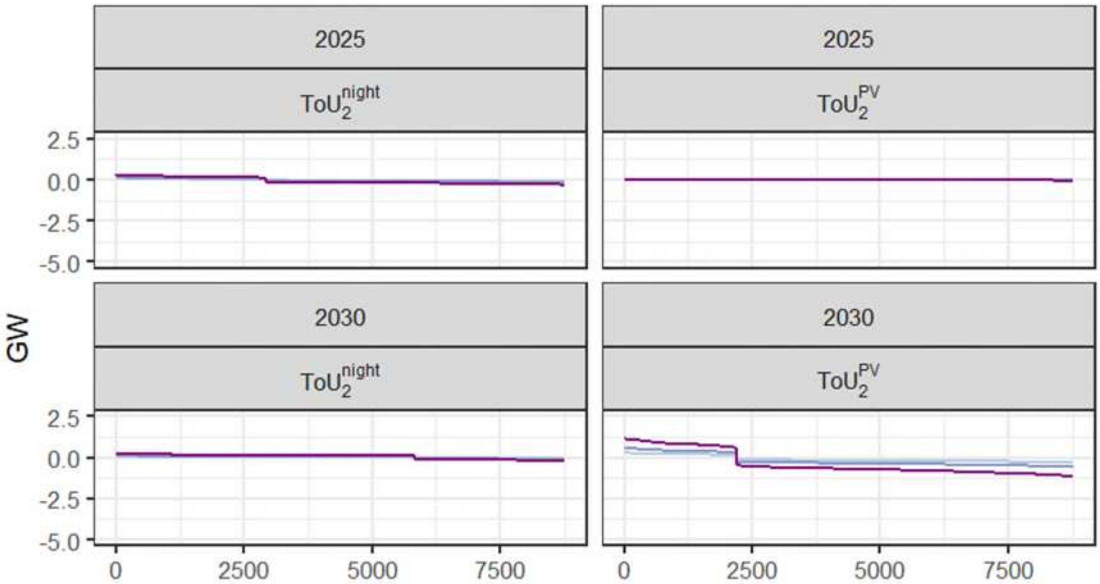


Figure B.13 - Annual load deviations per tariff (2025, 2030)




2025
ToU_6
2025
ToU_6^b
2030
ToU_6
2030
ToU_6^b
GW
5
0
-5
-10
0
2500
5000
7500


2025
ToU_2^{night}
2025
ToU_2^{PV}
2030
ToU_2^{night}
2030
ToU_2^{PV}
GW
2.5
0.0
-2.5
-5.0
0
2500
5000
7500

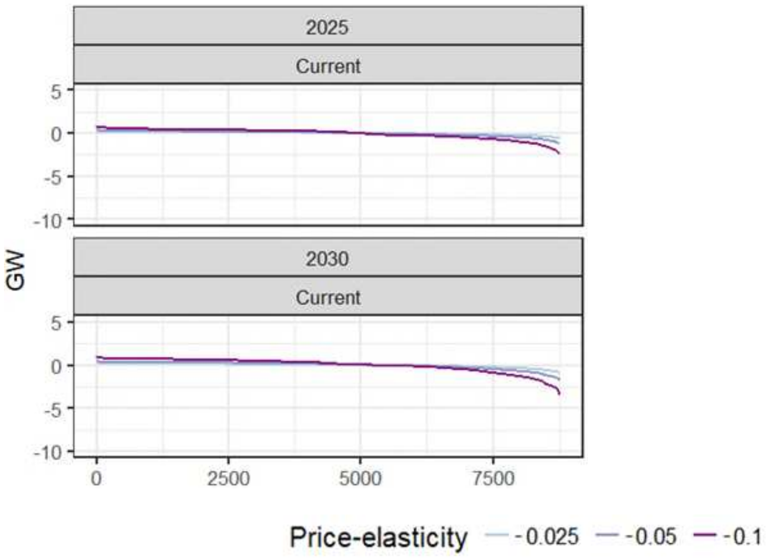

2025
Current
2030
Current
GW
5
0
-5
-10
0
2500
5000
7500
Price-elasticity
-0.025
-0.05
-0.1

Figure B.14 - Power price reduction per tariff (2025, 2030)

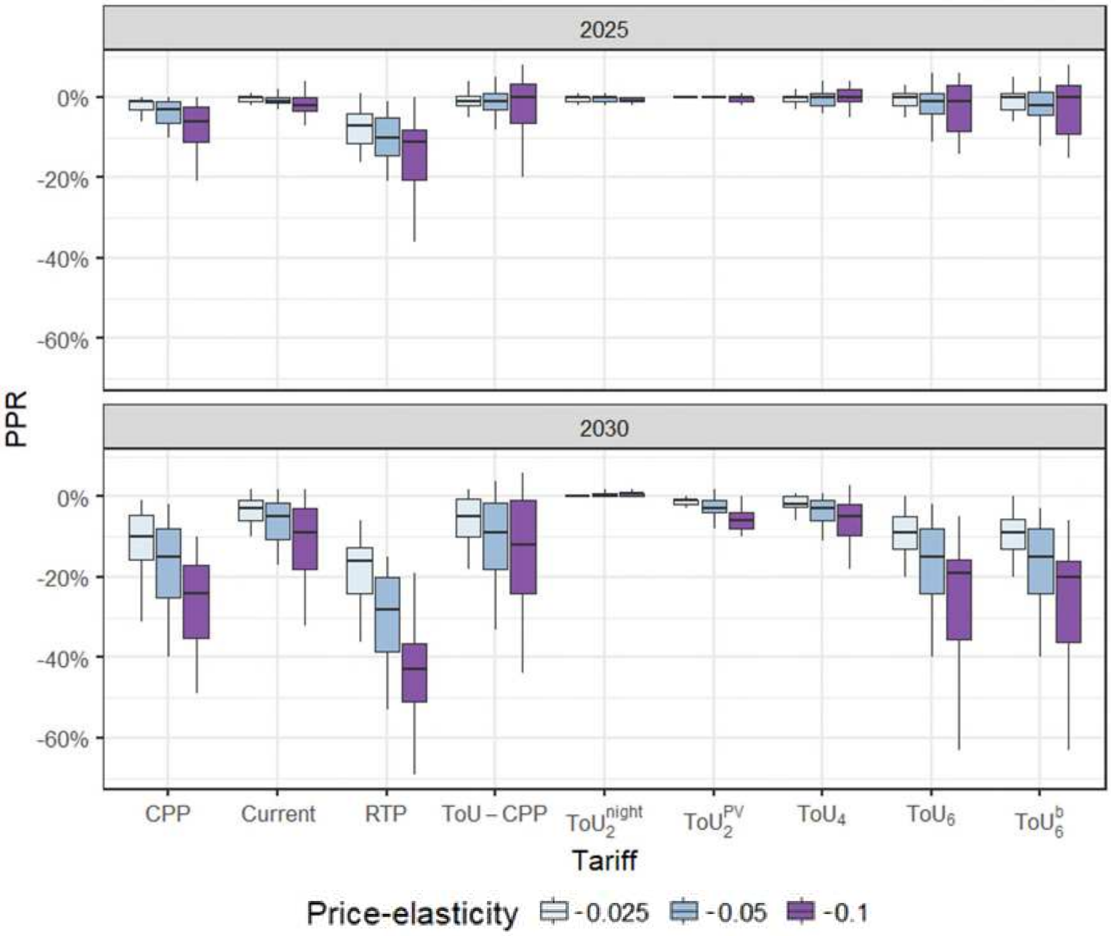


Figure B.15 - Deadweight Loss considered in the case of load shedding

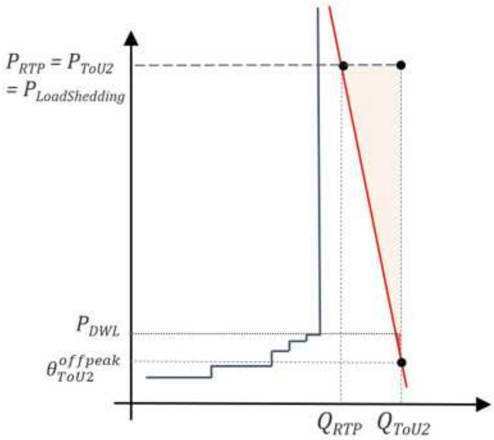
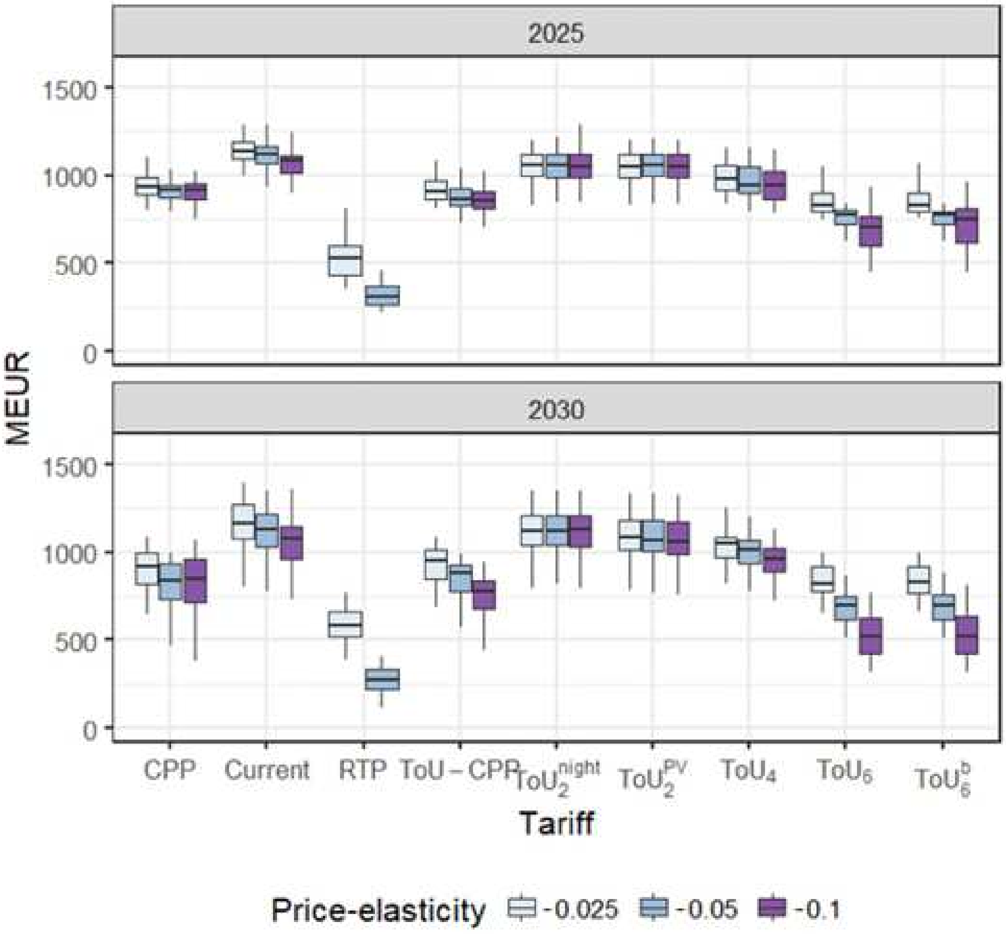


Figure B.16 - Share of Deadweight Loss reduction achieved relative to RTP



CHAPTER IV

What pace for electrification? Co-optimised pathways for the European chemical and power sector

> *"Bien qu'on ait du coeur à l'ouvrage*
> *L'art est long et le temps est court."*
> *Charles Baudelaire*

A paper based on the chapter has been published as a conference proceeding: C. Cabot and M. Villavicencio, "Electrification of the hard-to-abate sectors: implication for Net-Zero power systems in Europe," 2022 18th International Conference on the European Energy Market (EEM), Ljubljana, Slovenia, 2022, pp. 1-5, doi: 10.1109/EEM54602.2022.9921125.

The paper will be resubmitted to Applied Energy after a "Revise and resubmit" decision in September 2023.

The research was presented at the 6th AIEE Energy Symposium of the AIEE, 2021 (online), the 43rd international conference of the International Association of Energy Economists (IAEE), 2022, Tokyo (Japan), at the 40th International Energy Workshop (IEW), 2022, Freiburg (Germany), at the 18th International Conference on the European Energy Market (EEM), 2022, Ljubljana (Slovenia), and at the 30th Young Energy Economists and Engineers Seminar (YEES), 2022, Copenhagen (Denmark). I am extremely thankful to all participants for their helpful comments and discussions. All errors are my own.

Abstract

Decision makers and private investors impacted by the evolution of the carbon price should limit risks associated with investments performed in decarbonised options, notably for electrified options. This chapter demonstrates that considering only future power prices and carbon content might be insufficient in situations where accelerated sectoral electrification effort is foreseen. To illustrate the phenomenon, this chapter focuses on the conditions and the extent of electrification in decarbonising the chemical sector in Central-West Europe. Specifically, we consider energy transition pathways until 2050 for the power and the chemical sectors using a novel co-optimisation model, minimising the net present cost of both sectors and considering different carbon price scenarios and deployment rates. The results demonstrate that electrification is a crucial factor in reducing CO_2 emissions, with different scenarios ranging from a 13% reduction to a 110% increase in the current chemical sector's electricity consumption, impacting the type and pace of investments required in the power sector. Our findings indicate that not accounting for constraints in the power sector when assessing the chemical sector's transition pathways overestimates GHG reduction potential and underestimates the net present cost by 3 to 10% in some scenarios. Our results hold true in scenarios considering carbon capture technologies. Overall, the findings highlight the importance of upstream power sector investments in evaluating preferred pathways for GHG reduction in downstream sectors. Potential welfare losses are found in the case of transition pace asymmetry between the two sectors or resulting from imperfect anticipation of the respective decarbonisation trajectory of each sector.

The chapter is organised as follow: Section 4.1 and 4.2 introduce the chapter and provide an overview of the European chemical sector. Section 4.3 presents the literature review. Section 0 describes the methodology introduced to study decarbonisation pathways, while section 4.5 describes the scenario considered and the data used. Section 4.6 presents the modelling results, while section 4.7 discusses their policy implications. These sections also discuss the sensitivity analyses performed. Conclusions are summarised in section 4.8.

Résumé en français

Les décideurs publics et investisseurs privés doivent estimer les risques associés à l'allocation de capitaux dans des procédés bas carbone, notamment dans un contexte d'électrification impactant l'ensemble des secteurs. Le chapitre démontre les pertes liées à la seule considération des prix à terme de l'électricité et de son contenu carbone future dans le cas de trajectoires d'électrification à l'échelle d'un secteur. Ce chapitre illustre notamment les conditions et l'étendue de l'électrification du secteur chimique en Europe du centre-ouest. Des trajectoires de décarbonation conjointes avec le secteur électrique sont ainsi évaluées à horizon 2050 à l'aide d'un modèle d'optimisation à moindre coût. Plusieurs trajectoires d'évolutions du prix du carbone et différentes hypothèses du rythme d'investissement atteignable sont considérées, et démontrent la criticité de l'électrification dans l'atteinte des objectifs de décarbonation. Les résultats soulignent notamment l'impact de la tarification du carbone sur la consommation d'électricité du secteur chimique, allant d'une réduction de 13% à une augmentation de 110% de sa consommation actuelle. Ce rythme d'électrification a des conséquences sur le type et le rythme d'investissements requis dans le secteur électrique. En outre, une approche découplée de la transition de chaque secteur mène à une surestimation du potentiel de réduction des émissions de GES et à une sous-estimation du coût net actualisé, de l'ordre de 3 à 10% dans certains scénarios. Plus généralement, les résultats mettent en évidence l'importance des investissements dans le secteur amont de l'électricité pour évaluer les trajectoires optimales de décarbonation dans les secteurs avals. Des pertes sèches de bien-être sont ainsi possibles dans le cas d'une asymétrie dans les rythmes d'investissements, ou d'une mauvaise anticipation des trajectoires respectives entre les secteurs.

Ce chapitre est constitué de huit sections. La section 4.1 présente la question de recherche et son contexte. La section 4.2 présente le secteur chimique européen. La section 4.3 présente la revue de littérature effectuée. La section 0 décrit la méthodologie développée afin d'étudier les scénarios de décarbonation, tandis que la section 4.5 présente les scénarios considérés et les données utilisées. La section 4.6 présente les principaux résultats de la modélisation effectuée, la section 4.7 discutant de leurs implications. Les études de sensibilités effectuées sont également discutées dans ces sections. Enfin, la section 4.8 résume les principales conclusions.

Contents of Chapter IV

4.1. Introduction

The European Union has enforced a net zero greenhouse gas (GHG) emissions target by 2050 to limit global warming in line with the Paris Agreement (European Commission, 2018a). This objective requires significant GHG emissions reductions within three decades and across all sectors. The required investments are particularly important for hard-to-abate sectors, which refer to energy-intensive uses currently relying on fossil fuels, such as heavy industry (cement, iron and steel, chemicals, and aluminium) and heavy-duty transport (shipping, trucking, and aviation). However, the pathways to net zero emissions in those sectors are still unclear. Most scenarios consider electrification, carbon capture and storage (CCS), low-carbon hydrogen and sustainable biomass as the critical enablers to reaching climate neutrality in those sectors. However, each alternative would require significant upstream investments to meet the growing demand, potentially years before they can deliver clean energy. Indeed, investment decisions, permitting, and construction lead time, among others, take several years before facilities operate. Typically, the more the decarbonisation strategies rely on electrification, the harder it gets for the power system to decarbonise current power production while meeting a rapidly increasing demand. As an example, deploying electric vehicles is usually considered a cornerstone of a net zero emission economy. However, it would typically increase the need for carbon-free and affordable electricity, which shifts the burden of decarbonisation to the power sector and might be risky if renewables are not deployed fast enough.

In this chapter, we study the case of attaining low-carbon emissions in the chemical sector, (downstream sector) and the impact this would entail on the power sector (upstream sector). Currently, the use of sustainable feedstocks and the low-carbon heat provision would depend upon technological and economic improvements, as the low-carbon alternatives are either not demonstrated at scale or not cost-effective. The detailed transition to low-carbon emissions is an important challenge for the chemical sector that is overlooked in most top-down transition models (Gerres et al., 2019). The direct emissions of the EU chemical sector were 128 $MtCO_{2(e)}$ in 2018, corresponding to 16% of EU industrial emissions. Worldwide, the chemical sector emits 6.3% of global GHG emissions, making it one of the most important sub-sector emitters (Ge et al., 2020). While the European chemical industry's direct greenhouse gas (GHG) emissions have decreased substantially since the 1990s, with a reduction of more than half between 1990 and 2019, the production increased by more than 47% (Cefic, 2022). Despite this recent reduction in GHG emissions, CO_2 emissions have been mostly stable over the past decades, and further reduction should be achieved in a shorter period to meet the 2050 ambition. However, there is no consensus on how reductions could be achieved, to what extent electrification will be required for the chemical sector, and under which conditions. In other words, GHG reduction in the chemical sector through electrification is not yet well understood, and the conditions for it to materialise are still blurred. Furthermore, Joskow (2022) underlined that forecasting system power demand is paramount when planning for the evolution of generation capacity, as construction time might take years for some technologies, such as nuclear, before being operational.

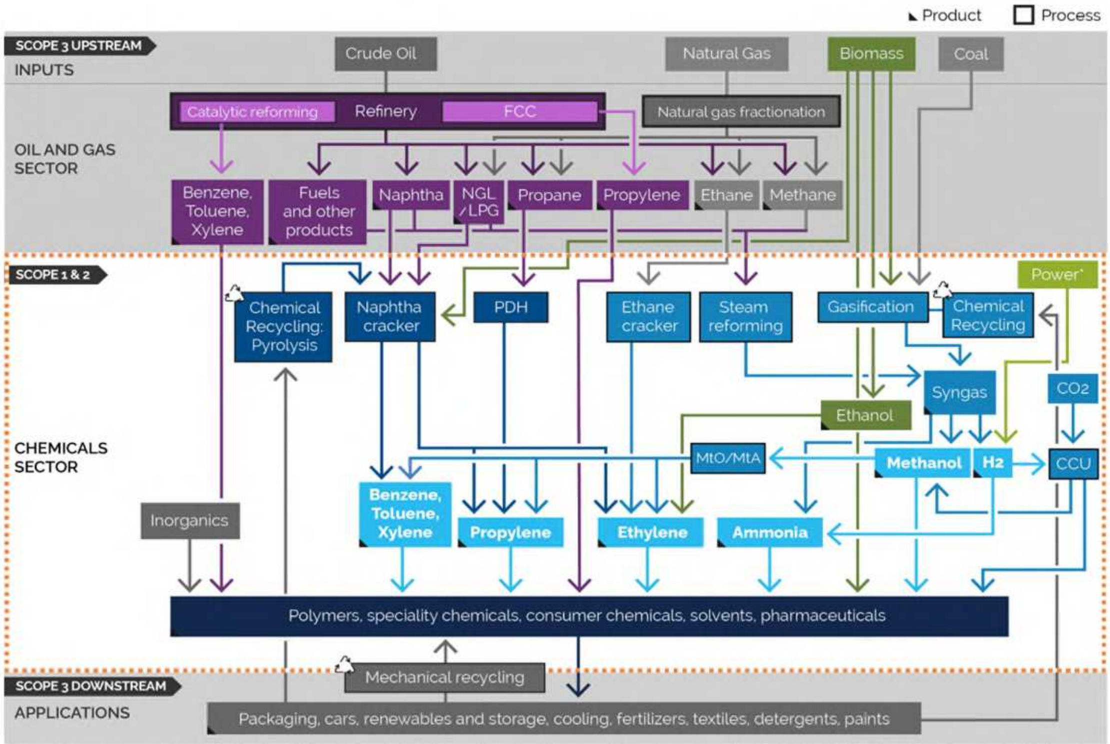
We address this research gap by examining the long-term industrial transformation required to accomplish low-GHG emissions ambitions of the European chemical industry by including the challenges and complementarities induced in the power sector. This chapter notably expands the literature by quantifying a low-emission pathway for both sectors and comparing it with a situation where each sector would undertake its energy transition in isolation. We determine the least-cost options for the hard-to-abate chemical sector while considering the required upstream investment for the power system. In addition, we estimate the long-term GHG emissions reduction in the chemical sector through direct and indirect electrification of industrial uses (e.g. adoption of electric boilers and production of hydrogen from electrolysis). We developed a novel formulation of a capacity expansion problem for the supply chains of the chemical sector based on Sahinidis et al. (1989) and You et al. (2011) combined with a long-term capacity expansion model of the power sector based on Palmintier and Webster (2011). Our analysis focuses on the Central-West Europe (CWE) region, currently producing nearly 60% of the EU chemical supply.

4.2. Overview of the European chemical sector

The chemical sector encompasses multiple value chains that primarily rely on oil and gas feedstocks to produce a particularly broad range of consumer goods. Instead of being a single, homogenous sector like the power sector, the chemical sector is a collection of industries where multiple actors compete in different markets (Griffin et al., 2018). A representative overview of the chemical sector is presented in Figure 31 and serves as the basis of the value chain model developed[27].

[27] Additional Sankey diagrams are presented in Appendix C

Figure 31 - Illustration of chemicals sector components and boundaries (SBTi, 2020)



Notes: CCU = Carbon capture and utilization; FCC = Fluidized catalytic cracking; H_2 = Hydrogen; NGL = Natural gas liquids; LPG = Liquified Petroleum Gas; MtO = Methanol to olefins; MtA = Methanol to aromatics; PDH = Propane dehydrogenation. *Power denotes selected electricity use. Note discussion below on classification of chemical recycling.
Source: SBTi.

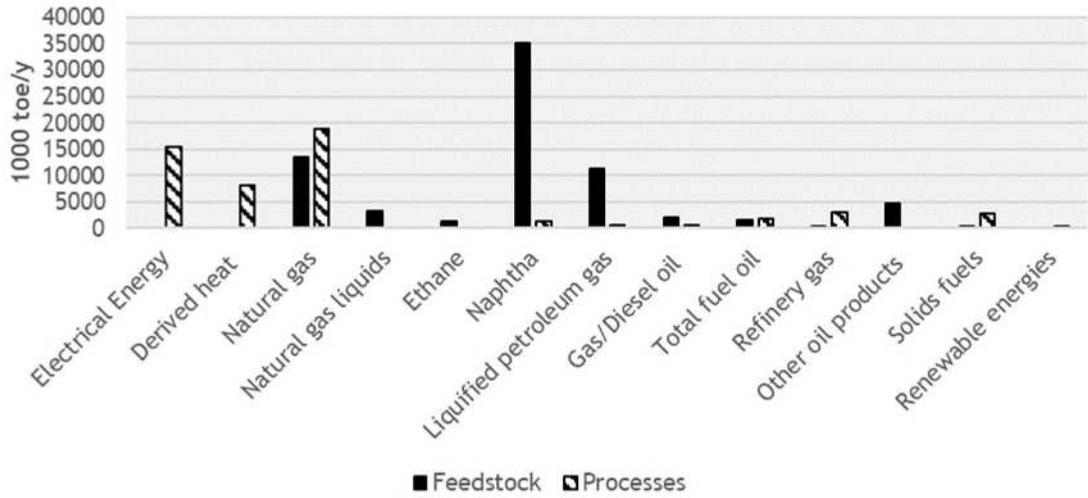
Given the variety of products inside the petrochemical sector, many interlinked value chains must be considered. A brief overview of the most significant product and the associated processes is presented below:

- **High-Value Chemicals (HVCs)**: HVCs are composed of **ethylene** (C_2H_4), **propylene** (C_3H_6), **butadiene** (C_4H_6), and pyrolysis gasoline containing **benzene** (C_6H_6), **toluene** ($C_6H_5CH_3$), and **xylene** (C_8H_{10}) also referred as aromatics. All those are essential raw materials for manufacturing goods, such as packaging, transportation, and construction materials. As described in Figure 31, HVCs are produced in steam cracking facilities, a central process of the chemical sector accounting for 40% of the energy consumption of the entire petrochemical industry and about 25% of the GHG emissions of the chemical industry (JRC, 2017). Steam cracking is a versatile process, able to crack a variety of hydrocarbons. Indeed, the primary feedstock used for steam cracking in Europe is naphtha (for around 70%), followed by natural gas liquids (NGL), in which propane and butane account for 18% and ethane for 4% (Petrochemicals Europe, 2023). The arbitration between feedstock is done based on the market conditions and the steam cracker's flexibility to accommodate different feedstocks. The respective HVCs yields depend likewise on the market conditions for the end product, the feedstock use and the operational cracking conditions. In addition to HVCs, hydrogen and methane-rich gases are by-products of steam crackers, eventually recycled/used on-site.

- **Ammonia**: Ammonia (NH_3) production represents the second-largest source of GHG emissions in the chemical sector, accounting for approximately 20% of total emissions (JRC, 2017). Being at the basis of nitrogen fertiliser production, ammonia is expected to grow between 37% and 165% by 2050, according to the IEA (2022). The Haber-Bosch process, which relies on steam methane reforming (SMR) to synthesize hydrogen, is the most widely employed method for ammonia production and a major GHG emitter.
- **Hydrogen production:** Hydrogen (H_2) production for purposes other than ammonia accounts for another 9% of total GHG emissions of the chemical sector (JRC, 2017). As mentioned above, steam methane reforming is the predominant process for hydrogen production in current industrial operations, representing 48% of the hydrogen production. Alternative processes based on liquid hydrocarbons (30%) or coal (18%) exist, while alkaline water electrolysis – a lower emission alternative process in cases where low-carbon intensity electricity is used - is still in its infancy at the industrial scale. In addition to ammonia production (representing 32% of the hydrogen demand), the majority (50%) is directly employed in refineries for crude oil upgrading, with additional volumes being used for methanol production (JRC, 2017),
- **Chlorine**: Finally, chlorine (Cl) is a major segment of the chemical sector, likewise used in a diverse range of applications, particularly in the production of polyvinyl chloride resins (PVC) and as a solvent (JRC, 2017). Unlike the other products, chlorine production entails almost no direct emissions but requires substantial electricity consumption to perform the chloralkali process, consisting of the electrolysis of brine. Consequently, reducing GHG emissions from chlorine production primarily entails energy efficiency gain and, more importantly, a transition to low-carbon intensity electricity sources.

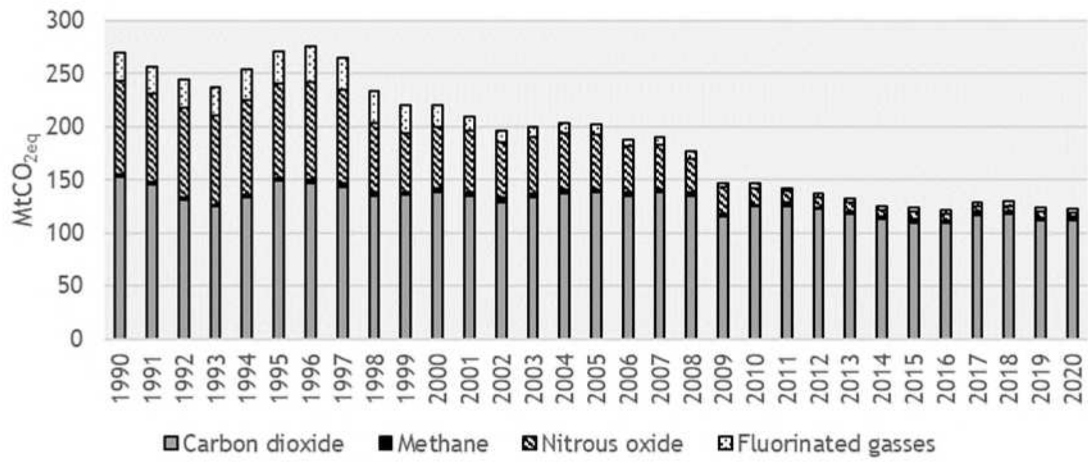
Those four products and categories account for more than 65% of the overall GHG emissions of the chemical sector, 50% of the sectorial power consumption and 30% of the fossil fuel and steam provision (JRC, 2017). As mentioned above, the specificity of the sector stems from the use of oil and gas as both feedstock and fuels, as illustrated in Figure 32. Due to the reliance on fossil fuel and feedstock, the sector has long been a significant contributor to GHG emissions, accounting for around 6% of global GHG emissions (Ritchie et al., 2020). As the chemical sector is tightly linked with the refineries, significant investments are expected in the next decade to comply with climate neutrality goals by 2050, especially as the sector is currently the largest driver of global oil demand (IEA, 2018). In addition to transitioning the energy provision of the sector towards low-emitting energy sources, it is crucial to explore alternative carbon sources as well. Bio-based carbon, recycled carbon streams, and direct air capture (DAC) present promising avenues for the chemical sector to reduce its fossil carbon footprint (IEA, 2018). Bio-based carbon refers to utilising carbon derived from biomass, offering a renewable and potentially carbon-neutral feedstock option. Recycled carbon streams involve capturing and reusing carbon from waste or by-product streams, reducing the reliance on virgin feedstocks. DAC technologies have the potential to extract carbon dioxide directly from the atmosphere, enabling its utilisation as a feedstock for chemical processes.

Figure 32 - Fuels consumed by the European chemical industry as feedstock and in the processes (JRC, 2017)



Considering the current trend of GHG emissions in the chemical sector, an acceleration is required to meet the climate objectives. The overall GHG emissions halved since 1990 thanks to improvements in process and energy efficiency, the adoption of new technology and stricter regulation, as for the hydrofluorocarbons (Montreal Protocol). However, CO_2 emissions reductions have stagnated above 100 $MtCO_{2e}$/year for the last decade, as described in Figure 33.

Figure 33 – Total Scope 1 GHG emissions in the EU27 chemical industry (Cefic, 2022)



4.3. Literature review

Many streams of the literature have provided insights on decarbonisation pathways, both at a regional and national energy system level or at sectorial levels. However, the industrial sector has regularly been aggregated, with simplified substitution options compared with the numerous process alternatives and materials inherent to the industrial sector (Bataille et al., 2021; Johannsen et al., 2023). As a result, the focus of most decarbonisation pathways has been on the supply side, adopting an exogenous power demand evolution based on sectorial assumptions on the demand side. Conversely, detailed-oriented bottom-up approaches on the demand side have been developed for the industrial and chemical sectors but consist of partial equilibrium models, which usually do not account for the impact of the decarbonisation path on the upstream energy sector. Both streams of the literature have been reviewed for the purpose of this research.

The first stream of the literature review focuses on decarbonisation options for the chemical sector and, more broadly, the hard-to-abate sectors. As a starting point, Levi and Cullen (2018) have mapped the feedstock flow for the chemical industry, underlining the importance of petroleum products and natural gas as raw materials. Focusing on decarbonisation options, most are already well-identified to reach a net zero decarbonised global industry (Mortensen et al., 2020; Rissman et al., 2020). On the supply side, the importance of electrifying the heat provision, notably for steam crackers, is highlighted for the chemical industry. In addition, one of the most critical levers for the chemical sector lies in the use of bio-based feedstocks to reduce the reliance on fossil feedstocks. Similarly, fostering carbon circularity and recycling plastic would add low-emission carbon feedstock to be processed. As such, the possibility for the chemical industry to sequester more carbon than the volume emitted is envisaged, despite the significant energy demand associated with such an option. Finally, the use of carbon capture, utilisation and storage (CCUS) appears as a requirement to reach the climate ambition timely and would allow for significant cost savings (Gerres et al., 2019; Greig and Uden, 2021; Paltsev et al., 2021; Saygin and Gielen, 2021). Therefore, researchers call for policy support to de-risk investments and target commercial availability at scale before 2030. However, Wesseling et al. (2017) and Zibunas et al. (2022) underline many other likely bottlenecks, notably in the case of the chemical sector. For instance, most low-carbon innovations are critically linked to the availability of clean energy composed of renewable electricity, hydrogen, and biomass. However, those availabilities are not considered explicitly in most methodologies. Indeed, Saygin and Gielen (2021) consider, for example, assumption-based technology penetration, and the impact of those assumptions on the upstream power sector is not considered. Consequently, the electrification share does not depend on the power mix decarbonisation, although the required renewable power by 2050 for the chemical equals roughly the current global power generation capacity. The same approach is used by Lechtenböhmer et al. (2016), which considers a "what-if" scenario where everything would be electrified, resulting in industrial electricity consumption increasing from 125 TWh to 1713 TWh, without assessing the impact on the power sector. A similar methodology is employed by Zibunas et al. (2022) and based on an exogenous assumption for electricity price and carbon content, resulting in a power consumption increase of 9,000 TWh worldwide, or 31% of the currently estimated global power consumption increase by the International Energy Agency (IEA). Similarly, Griffin et al. (2018) propose a hybrid top-down/bottom-up approach for assessing the decarbonisation pathways for the chemical sector. However, they consider the future of the power sector by making exogenous assumptions, such as a reduction of carbon intensity of grid electricity of 85% in 2050. Therefore, the implications of the chemical sector electrification over the power sector are not discussed, which might challenge the cost-optimality of the trajectories described or even their likelihood. Additional bottom-up models have been developed to assess industrial pathways, such as the one described in Gabrielli et al. (2023), which provide an overview of the different net zero pathways of the chemical sector and assess the required energy, land and water requirements for each. While the authors underlined that all routes (e.g. biobased, CCS, electrified) are aligned with the climate objectives, further research is needed to assess the optimal combination between alternatives, and determine the optimal "co-evolution of the chemical and energy sectors". The likelyhood of benefiting from a decarbonised energy is therefore not assessed in this stream of research, neither the cost of each pathway. Finally, the FORECAST model and the IndustryPLAN model provide additional insight on the Best Available Technologies (Fleiter et al., 2018; Johannsen et al., 2023). While those two provide insights into the abatement measures, they primarily rely on energy savings and abatement cost estimates per product. As such, the interlinkage between HVCs production streams is disregarded when considering only Ethylene, Methanol, Ammonia, Soda ash and Carbon Black in the IndusryPLAN model. Conversely, the FORECAST model is much more extensive in its description of the chemical sector but also lacks the coupling with the electricity sector, which has been identified as critical limiting factors.

Similar techno-economic pathways for the chemical sector exist as well in the grey literature. The German Society for Chemical Engineering and Biotechnology, Dechema (2017) considers a range of future electricity consumption for the chemical industry alone from 960 TWh to more than 4900 TWh, with a central assumption of 1900 TWh. The Fraunhofer Institute (2019) also considered low-carbon pathways for the industry and estimated that the chemical industry would consume more than 1000 TWh in 2050, about the same amount as the 2015 total industry sector electricity consumption. It is well above the current electricity consumption levels of the chemical industry, which is close to 170 TWh (Cefic, 2021). Regarding techno-economics data and grey literature, the Joint Research Center (JRC) (2017) performs a complete overview of the chemical processes and assesses the potential for GHG reduction. It describes the entire sector's Best

Available Technics (BAT) and Innovative Technology (IT). However, the scenarios considered do not reach significant emissions reductions, leading to a 36% reduction when accounting only for retrofits. Overall, the interlinkage between deep electrification of the chemical industry and the power system's energy transition is insufficiently studied in the literature focusing on industrial decarbonisation, and bottom-up co-optimisation of both sectors has not been performed to assess the welfare loss of disregarding the upstream impact.

The second stream of the literature reviewed relates to energy system models, which allow for a comprehensive assessment of energy demand across all sectors. However, those usually rely on simplified aggregations of industrial sectors. Indeed, extensive research has been undertaken on low-carbon power systems modelling in recent years, as their feasibility is a pre-requisite to reaching the climate objectives (Bataille et al., 2021, 2018; Bistline and Blanford, 2021; Howells et al., 2011). The resulting decarbonisation scenarios of the power sector typically provide pathways and first-best policies for reaching low-carbon power systems and have been studied both in the scientific literature (Després et al., 2017; Pavičević et al., 2019; Pedersen et al., 2021) and in the institutional (IEA, 2021; RTE, 2021). However, there is no consensus regarding the demand-side evolution and the associated level of future end-use electrification. While the current electricity consumption in the EU28 is around 2900 TWh (Eurostat, 2021), the estimates found in the literature for 2050 vary widely depending on the underlying assumption and scenario (ENTSO-E and ENTSOG, 2022; IAEA, 2019; IEA, 2021; McKinsey&Company, 2010). Typically, it ranges between 3200 TWh (IAEA, 2019) and 5500 TWh (ENTSO-E and ENTSOG, 2022) when accounting for electricity demand for electrolyser and transmission and distribution losses. Nonetheless, detailed assumptions per sector are not provided (Johannsen et al., 2023), and the industry's final energy consumption is regularly considered as a whole, estimated with a compound annual growth rate (CAGR), an efficiency factor and rates of adoption of electricity-based technology. Indeed, energy system models usually consider a final energy demand by sector and fuel type without considering the downstream technology arbitrage (Howells et al., 2011). The scale of the effort to reach net zero is, therefore, very different from one scenario to the other. As an example, Victoria et al. (2022) assume a switch towards methane for high temperatures, while the lower heat grades are assumed to electrify. Such approaches do not allow for providing detailed transitions in industrial sectors. As highlighted by Bataille (2021), "Progress can and is started to be made towards a much more detailed representation in system models of industrial decarbonisation options".

Our research lies in these early attempts to include more detailed industrial decarbonisation pathways, starting with the chemical sector. Notably, our research aims to clarify the extent to which individual sector transition pathways depart from the social welfare optimum when disregarding the required investments upstream. While we focus on the power and the chemical sector, the findings are relevant for all modelling exercises adopting a partial-equilibrium approach. This framework informs on the synergies between both sectors and the trade-off between the electrification of end-uses and other options to decarbonise the industry supply chains.

4.4. Mathematical formulation

We adopt a social planner perspective, for which the capacity and the dispatch are endogenously optimised for both sectors. A brown-field approach is adopted, meaning pathways start with the existing production capacities as of 2018. We consider a 5-year timestep, running to 2050, while the power and chemical sectors face common carbon price trajectories. The following section will provide the formulation of the two models used.

4.4.1. Electricity market model

We represent the power system with a partial equilibrium model, usually referred to as an investment and dispatch model. It is based on Quoilin (2015) and Palmintier (2011) formulations, presented in section 3.3.3.1 and extended with investment decisions. For parsimony, only the most dimensioning equations are presented in this section, while the complete model formulation is provided in Appendix C. Investment models study the long-term development of power generation capacity based on their day-ahead dispatch resulting from their short-run marginal costs. The model minimises total costs over the entire horizon, considering capital expenditures and variable costs per year. Technologies available to the model encompass hydrogen turbines, natural gas turbines with CCS, onshore and offshore wind, solar PV, nuclear power plants and batteries. The power demand is considered price-inelastic except for the chemical industry, which can endogenously invest in electrified processes and, therefore, is elastic to price and sensitive to the carbon intensity of the electricity mix. The optimisation model considers multiple constraints, notably on the supply-demand equilibrium and the hourly availabilities of power plants. In addition, the capacity expansion is limited for nuclear, coal and gas to capture the current policies in place in the EU. Finally, a limit in the feasible installation pace for each technology is considered for wind offshore, wind onshore, solar PV, batteries and CCGT-CCS. Those are implemented to consider construction lead time, lack of financing or lack of social acceptance. The weather reference year used is 2018, translating into the hourly generation of wind, solar and hydropower production. We assume perfect foresight and solve the model using representative weeks for 2025, 2030, 2040 and 2050. As we focus on the long-term CWE region, we abstract from a detailed grid representation, although we acknowledge that resulting market prices could diverge due to cross-border congestions. Clearing price divergences compared to historical could also be explained by the absence of combined heat and power plants (CHP), the lack of unit commitment based on technical data, or non-competitive bidding in existing markets.

The first term of the objective function is the total net present cost of producing electricity, considering the sum of capital and operational expenditures (Eq. 13).

$$NPC_{Power} = \sum_{y} (1+r)^{-(y-Y_0)} * \Big(\sum_{h,k,z} G_{y,h,k,z} * \left(c^{v}_{y,k,z} + ef_{k} * c^{CO2}_{y,z}\right) + \sum_{k,z} N_{y,k,z} * c^{ie}_{k} + \sum_{y,h,z,z'} I_{y,h,z,z'} * c^{i}_{z,z'} + \sum_{y,h,z} LL_{y,h,z} * c^{ll} \Big) \quad \text{(Eq. 13)}$$

Where:

$G_{y,h,k,z}$	Hourly production of a given technology cluster of a zone;	$N_{y,k,z}$	Yearly installed capacity of a given technology in a given zone;
$c^{v}_{y,k,z}$	Short-run marginal cost of a unit, composed of fuel price and variable O&M;	c^{ie}_{k}	Yearly capital expenditures of a given technology;
ef_{k}	Emission factor in $tCO_{2(e)}$ of a given technology cluster;	$LL_{y,h,z}$	Lost load, energy not served in a zone;
$c^{CO2}_{y,z}$	Market price of the carbon emission allowances. We assume a complete pass-through of the carbon price;	c^{ll}	Value of lost load, associated with the market price cap in the day-ahead market, set at 3000 EUR/MWh;
$I_{y,h,z,z'}$	Power imports between zones	$c^{i}_{z,z'}$	Cost of importing power from neighbouring countries
r	Discount rate;		

Adequacy equation

The market price resulting from the model is deduced from the marginal value of the supply and demand balance constraint (Eq. 14). A marginal increase of exogenous parameters, here the load, would result in an increase of the production variable and the objective function by an amount equal to the short-run marginal cost of the last unit called. Such value can be used as a proxy for the price of the day-ahead electricity market under perfect competition to render the dispatch performed by the system operator[28] (Brent Eldridge et al., 2018).

$$\sum_{k\in K} G_{y,\ h,\ k,\ z} + \sum_{z'\in \zeta,\ z'\neq z} I_{y,\ h,z,\ z'} = d_{y,h,\ z} + D_{chem\ y,h,z} + \sum_{z'\in \zeta,\ z'\neq z} e^{0}_{y,h,z,\ z'} + \sum_{s} C_{y,h\,s,\ z} \qquad \forall y,\ h,\ z \qquad \text{(Eq. 14)}$$

Where:

$d_{y,h,\ z}$	Hourly electricity demand;	$D_{chem\ y,h,\ z}$	Hourly electricity demand of the chemical sector;
$I_{y,\ h,z,\ z'}$	Power imports of a given zone;	$e^{0}_{y,h,z,\ z'}$	Power exports of a given zone;
$C_{y,\ h,s,z}$	Charging/discharging power flows of storage technologies;		

We consider that the power sector entirely provides the power demand of the chemical sector. In practice, actors might engage in a corporate power purchase agreement (PPA) to secure both the price and the carbon intensity of the electricity purchased (BloombergNEF, 2022). In this research, we assume that all power generators are connected to the grid and that industries do not have priority access to clean and affordable electricity compared to other sectors. In our cases, capacities were aggregated at the region level, as we disregard congestion inside the Central-Western European region.

Power production constraint

The first constraint for production units relates to their availability (Eq. 15). We consider historical hourly and annual availabilities to determine the full load hour each technology can reach. In addition, invested capacity per year cannot exceed a given value, based on historical yearly capacity addition in Central-Western Europe. Conversely, some technologies have planned phase-outs, for example, nuclear or coal power plants in Germany. The modelling accounts for such policy-driven early closure in (Eq. 17. We do not consider a minimum share of power produced from renewables, even though some governments have already announced targets. However, we loosely restrict the feasible year-on-year installation rate of renewables and natural gas to account

[28] Independent system operator in charge of the coordination and monitoring of the power system. We do not distinguish it from the European terms Transmission System Operator (TSO).

for market rigidities (e.g. local resistance due to permitting and NIMBY[29] effects) and project lead time based on (Eq. 16).

$$G_{y,h,k,z} \leq avail_{y,h,k,z} * N_{y,k,z} \qquad \forall y, h, k, z \qquad \text{(Eq. 15)}$$

$$N^{new}_{y,k,z} \leq \gamma_{y,k,z} \qquad \forall y, k, z \qquad \text{(Eq. 16)}$$

$$N^{closed}_{y,k,z} \geq \delta_{y,k,z} \qquad \forall y, k, z \qquad \text{(Eq. 17)}$$

Where:

$\gamma_{y,k,z}$	Yearly installation rate for a given technology;	$\delta_{y,k,z}$	Planned phase-out for a given technology;
$N^{new}_{y,k,z}$	Invested capacity for a given year and technology;	$N^{closed}_{y,k,z}$	Closure of capacity for a given year and technology;
$avail_{y,h,k,z}$	Hourly availability factor for a given technology;		

4.4.2. Presentation of the chemical supply chain model

The chemical processes are considered in a bottom-up supply chain model, allowing for capacity expansion. Investment decisions in chemical production capacity and operational decisions are optimised to satisfy the demand while minimising the cost of producing chemical products. Investment decisions are based on the net present costs of investments required for meeting future demand, assuming perfect foresight from industrial actors. The formulation is based on Sahinidis (1989) and You (2011), adjusted with a carbon price and expanded to consider investment in low-carbon technologies and abatement options[30] (i.e. low-carbon heat technologies, CCUS). It includes a detailed representation of the key chemical products' production routes and their interactions (Table 6). Other chemical products are aggregated and referred to as the "rest of chemicals"[31]. Based on 2018 sector-level data, the "rest of chemicals" feedstock, energy demand, and emissions per ton of products were estimated. Existing processes' energy, emissions and installed capacities are based on the JRC assessment (JRC, 2017), supplemented by product-specific available information (Cefic, 2022; Fertilizers Europe, 2023; Petrochemicals Europe, 2023). Due to the commercial confidentiality inherent to the sector, standard values for energy, yields and investment figures have been considered for each process based on the available

[29] Not In My Backyards (NIMBY) effect depict a situation where local resistance prevent distributed energy sources to be deployed.

[30] A complete list of considered options is provided in Appendix C, Table C.3 and Table C.4

[31] The results of the "rest of the industry" are not considered in detail in this research. This segment is mainly composed by third tier chemicals for which decarbonisation entails mostly fuel switch and energy efficiency improvements.

literature. While this chapter identifies transition risks and evaluates the order of magnitude of the transition to be performed based on existing data, this research does not intend to provide an accurate representation of the current sector's operation nor to provide a forecast of the chemical sector's future evolution. For each scenario and case, we study the resulting carbon intensity of the electricity produced, the chemical sector's electricity consumption, and its resulting direct and indirect emissions. We consider only scope 1 (direct emissions) and scope 2 (energy consumption) emissions, which are calculated based on the evolution of the electricity mix resulting from the electricity market model, as referred to in section 4.4.1. The chemical value chain model distinguishes between biogenic and non-biogenic CO_2 emissions. The same carbon price applies for both the power and the chemical sector, but is not applied to technologies relying on bio-based materials[32]. Carbon capture (CC) investments are considered as a sensivity, and further distinguished based on the purity of the CO_2 stream. The captured CO_2 can then be used in the chemical industry as a feedstock (Carbon Capture and Usage, or CCU) or stored underground (Carbon Capture and Storage, or CCS). Given the lack of consensus regarding the European chemical sector evolution, we have considered a constant demand towards 2050 for the tractability of the results, aligned with existing literature (Lechtenböhmer et al., 2016; Victoria et al., 2022). We performed a literature review to identify key low-emitting alternatives available for investments in the chemical sector and associated techno-economic data (Appendix C)

Table 6 - Product considered in detail within the chemical supply chain model

	Products
Organics	Ethylene, Propylene (Olefins)
	Benzene, Toluene, Xylene (BTX)
	Methanol
Inorganics	Ammonia
	Hydrogen
	Chlorine
Intermediates	Styrene
	Ethylene Oxide (ETO)
	Mono ethylene glycol (MEG)
	Purified Terephthalic Acid (PTA)

[32] CO_2 emissions from the exclusive use of bio-based fuels do not fall under current EU ETS regulation provided they are in line with a sustainability criterion defined in the EU Renewable Energy Directive II; hence it is not impacted by the emission allowance mechanism.

Polymers	Polyethylene
	Polypropylene
	Polystyrene
	Polyvinyl Chloride (PVC)
	Polyethylene terephthalate (PET)

The problem formulation represents the cost of running, expanding and transforming the CWE chemical industry towards 2050. All sets, parameters and equations are provided in Appendix C.

The model minimises the net present cost (NPC) to meet the demand and satisfy the additional constraints. The NPC is defined as the present value of all costs incurred until 2050: capital expenditures, operational expenditures, variable costs, and mitigation costs. The calculation is presented in (Eq. 18).

$$NPC_{Chem} = \sum_{y,z}(1+r)^{-(y-Y_0)} * \sum_{i}\left(c^{ie}_{y,\,i} * N^{c}_{y,\,i,z} + (c^{v}_{y,\,i} + ef_{y,\,i} * c^{CO2}_{y,z}\right) * P^{c}_{y,i,z} + CC^{cost}_{y,i,z} \quad \text{(Eq. 18)}$$

Where:

$N^{c}_{y,\,i,z}$	Yearly capacity of a given technology or process	$P^{c}_{y,i,z}$	Yearly production of a given technology for a given product
$c^{v}_{y,\,i}$	Yearly operational expenditure of a given technology or process	$c^{ie}_{y,\,i}$	Yearly capital expenditures of a given technology or process
$c^{CO2}_{y,z}$	Carbon price	$ef_{y,\,i}$	Emissions factor of a given process
$CC^{cost}_{y,i,z}$	Yearly carbon capture expenditure of a given technology		

A discount rate of 0.55% is assumed by default for both the chemical and the power sectors. It is based on the European Commission guidelines and calculated based on the Communication from the Commission on the revision of the method for setting the reference and discount rates (OJ C 14, 19.1.2008, p.6.)[33].

[33] Further information is available at: https://ec.europa.eu/competition-policy/state-aid/legislation/reference-discount-rates-and-recovery-interest-rates/reference-and-discount_en

Adequacy equation

The supply-demand equation (Eq. 19) implies that output should match net demand for each year and each product, considering the amount of mechanically recycled product $\nu_{y,z}^{c,mech}$, the trade balance $\omega_{y,z}^{c,in/out}$ and the yields of each process $\psi_{y,i}^{c,out}$. The demand and trade balances are fixed as of 2018 values and considered price-inelastic, meaning that the net demand remains constant regardless of the cost of production.

$$\sum_{z,p} P_{y,p,z}^{c} + \omega_{y,z}^{c,in} + \nu_{y,z}^{c,mech} + \sum_{i\epsilon\{\Pi\cup F\}} P_{y,i,z}^{c} * \psi_{y,i}^{c,out} = d_{y,z}^{c} + \omega_{y,z}^{c,out} + \sum_{p} P_{y,p,z}^{c} * \psi_{y,p}^{c,in} \quad \forall y,\, c \qquad \text{(Eq. 19)}$$

Where:

$\omega_{y,z}^{c,\frac{in}{out}}$	Yearly imports/exports of a given product	$d^{c}_{y,z}$	Yearly domestic demand for a given chemical product c
$\nu_{y,z}^{c,mech}$	Volume of mechanically recycled product	$\psi_{y,i}^{\frac{in}{out}}$	Material flow in/out of a given process

Heat-related constraint

An equivalent supply-demand constraint is written regarding the heat requirement of each process, both from chemical processes and carbon capture systems (Eq. 20).

$$\sum_{hh} P_{y,hh,i,z}^{h} = P_{y,i,z}^{c} * h_{y,i} \quad \forall y,\, i,\, z \qquad \text{(Eq. 20)}$$

Where:

$h_{y,i}$	Heat requirement for a given process

Feedstock constraint

Similarly, each process is associated with a feedstock need that can be either produced endogenously, from a different process or purchased from the market exogenously. We distinguish between the case of processes taking only bio-based feedstock (Eq. 21) and the case of processes taking fossil feedstock but eventually able to diversify towards bio-based feedstock (Eq. 22).

$$Q_{y,i,z}^{bio} = P_{y,i,z}^{c} * \psi_{y,i,z}^{bio,in} - \sum_{k\epsilon\{Z\}} P_{y,k,z}^{fd} * \psi_{y,k}^{bio,out} \quad \forall y,\, i,\, z \qquad \text{(Eq. 21)}$$

$$Q^{fossil}_{y,i,z} = P^{c}_{y,i,z} * \psi^{fossil,in}_{y,i} - \sum_{bio\epsilon\{S_{bio-fossil}\}} Q^{bio}_{y,i,z} - \sum_{k\epsilon Z, bio\epsilon\{S_{bio-fossil}\}} P^{fd}_{y,k,z} * \psi^{bio,out}_{y,k} \quad \forall y,\ i,\ z \qquad \text{(Eq. 22)}$$

$Q^{bio}_{y,i,z}$	Feedstock flow for a given process, bio-based	$S_{bio-fossil}$	Linkage between fossil feedstock and their bio-based substitute
$Q^{fossil}_{y,i,z}$	Feedstock flow for a given process, fossil-based		

Production-related constraint

As for the power sector, facilities are constrained by their typical utilisation factor (Eq. 23). The feasible year-on-year installation rate of new processes is constrained to account for market rigidities and avoid penny-switching effects, considered in (Eq. 24) and (Eq. 25)

$$P^{c}_{y,i,z} \leq uf_{y,i} * N^{c}_{y,\, i,z} \quad \forall y,\ i,\ z \qquad \text{(Eq. 23)}$$

$$N^{c,new}_{y,i,z} \leq \gamma^{c}_{y,i} \times N^{c}_{y-1,\, i,z} \quad \forall y,\ i,\ z \qquad \text{(Eq. 24)}$$

$$N^{c,closed}_{y,i,z} \leq \delta^{c}_{y,i} * \mathrm{n}^{c,0}_{i,z} \quad \forall y,\ i,\ z \qquad \text{(Eq. 25)}$$

Where:

$uf_{y,i}$	Yearly utilisation factor of a given process	$N^{c,new}_{y,i,z}$	Invested capacity for a given year and technology
$\gamma^{c}_{y,i}$	Yearly installation rate for a given process	$N^{c,closed}_{y,i,z}$	Phased-out capacity for a given year and technology
$\delta^{c}_{y,i}$	Yearly phase-out rate for a given process	$N^{c}_{y,\, i,z}$	Capacity for a given year and technology
$\mathrm{n}^{c,0}_{i,z}$	Initial capacity of a technology		

4.4.3. The coupling between the power and the chemical sector

As the electricity market model is solved on an hourly basis, the annual value of electricity consumption resulting from the chemical models is spread to hourly electricity consumption using an hourly load profile representative of the industry (Priesmann et al., 2021). We considered the German industry's time series as representative of the CWE region, accounting for lightning, heat and cold supply, and mechanical energy supply (e.g. pumps, compressors, etc.).

$$D_{chem\ y,\, h,z} = \sum_i P_{y,\, i,z} * e_{y,\, i} * p_{h,\, i} \quad \forall y,\ h,\ i,\ z \qquad \text{(Eq. 26)}$$

Where:

$e_{y,\, i}$	Electricity consumption per production unit of a given chemical process	$p_{h,\, i}$	Industrial hourly power demand profile

Two formulations are implemented to consider the possibility of joint optimisation of the two sectors. While a sector coupling approach accounts for the electricity production costs endogenously, it is not the case in approaches where the power and the chemical sectors are disconnected. Likewise, the electricity demand considered in the power sector model differs between the two approaches, being perfectly inelastic in the case where sector coupling is not considered. Operational expenditure of the chemical process $c^{v}_{y,\,i}$ and power demand $D_{y,\,h,\,z}$ formulations are presented in Table 7.

Table 7 - Mathematical formulation implied by the sector coupling approach

Case	Description	Formulation		
Coupling	Chemical sector operational expenditure	$c^{v}_{y,\,i} = \left(c^{feed}_{y,\,i} * \psi^{in}_{y,i} \right) * P^{c}_{y,i,z}$	$\forall y, i, z$	(Eq. 27)
	Power sector demand	$D_{y,\,h,\,z} = d_{y,\,h,\,z} + D_{chem\ y,\,h}$	$\forall y, h, z$	(Eq. 28)
No coupling	Chemical sector operational expenditure	$c^{v}_{y,\,i} = \left(c^{feed}_{y,\,i} * \psi^{in}_{y,i} + c^{power}_{y,\,i} * e_{y,\,i} \right) * P^{c}_{y,i,z}$	$\forall y, i, z$	(Eq. 29)
	Power sector demand	$D_{y,\,h,\,z} = d_{y,\,h,\,z}$	$\forall y, h, z$	(Eq. 30)

Where:

$c^{feed}_{y,\,i}$	Exogenous feedstock price	$c^{power}_{y,\,i}$	Exogenous electricity price
$d_{y,\,h,\,z}$	Exogenous hourly electricity demand		

4.5. Data and scenarios

We examine the impact of carbon pricing on the chemical and power sectors using 2018 as the reference year. Four scenarios of carbon price trajectories have been considered (Figure 34):

(i) The "**low**" scenario, where the carbon price reaches 200 EUR/t$CO_{2(e)}$ in 2050,

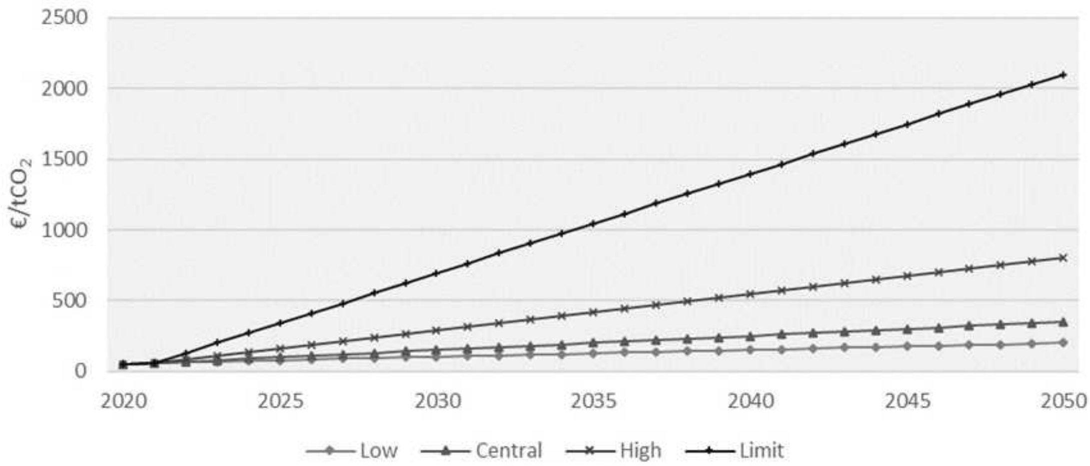
(ii) The "**central**" scenario reaches 350 EUR/t$CO_{2(e)}$ in 2050. This is aligned with scenarios considering the 1.5°C carbon budget, notably the European Commission's net zero emissions scenarios (European Commission, 2018b; Victoria et al., 2022).

(iii) The third scenario, "**high**", anchors in the trajectory from the Quinet report (2019), leading to a carbon price of 500 EUR/t$CO_{2(e)}$ in 2040 and 775 EUR/t$CO_{2(e)}$ in 2050, deemed required to reach cost-parity of hydrocarbon-based technologies and decarbonised alternatives.

(iv) Finally, an additional carbon price trajectory, "**limit**", has been considered to estimate if additional electrification would be triggered with an even higher carbon price or, on the contrary, if higher carbon prices would undermine the benefits of electrification due to further increasing power prices. Therefore, the scenario reaches 2100 EUR/t$CO_{2(e)}$ in 2050.

All trajectories are linearly interpolated between the starting point in 2018 set at 50 EUR/t$CO_{2(e)}$ and the 2050 final values retained. Carbon prices are applied to direct emissions from the chemical and the power sector, assuming that no free emission allowances are granted to the sectors.

Figure 34 - Carbon price trajectory considered.



Considering the four carbon price scenarios, we have analysed two approaches that reflect different considerations between the upstream power sector and the downstream chemical sector:

(i) First, the "**sector coupling**" approach (hereafter "**SC** " case) encompasses both sectors. We consider a social planner perspective, meaning investment decisions are realised to minimise the cost incurred in both sectors to supply the demand, with perfect coordination and information between the two sectors. As a result, any additional electricity demand from the chemical sector leads to further power production, which may require additional investments in the power sector. This approach serves as our base scenario.

(ii) The second approach corresponds to a phased optimisation performed without sector coupling, referred to as the "**iterative**" approach (hereafter, "**IT**" case). This approach considers that investment decisions depend upon investors' forecasts. First, we consider the forward electricity prices and electricity carbon intensity resulting from the SC case and optimise the investment in the downstream chemical sector (**IT-1**). This approach aligns with existing literature that assumes exogenous assumptions for electricity prices when investigating low-emissions pathways for the chemical sector. In the second step (**IT-2**), we perform a feedback loop to account for the resulting chemical sector electrification trajectory. This step allows us to estimate the impact of the IT-1 electrification trajectory on the power sector, notably on the power prices. We assume that the investors know how additional projects are commissioned in the chemical sector (IT-1), leaving them the ability to invest in additional power plants.

By comparing the outcomes of the SC and IT approaches, we can identify the resulting differences and trade-offs. A summary of the cases is provided in Figure 35. We consider, therefore, eight different outcomes made of the two approaches and the four carbon price trajectories considered.

Figure 35 - Illustration of the sector coupling and iterative approaches considered

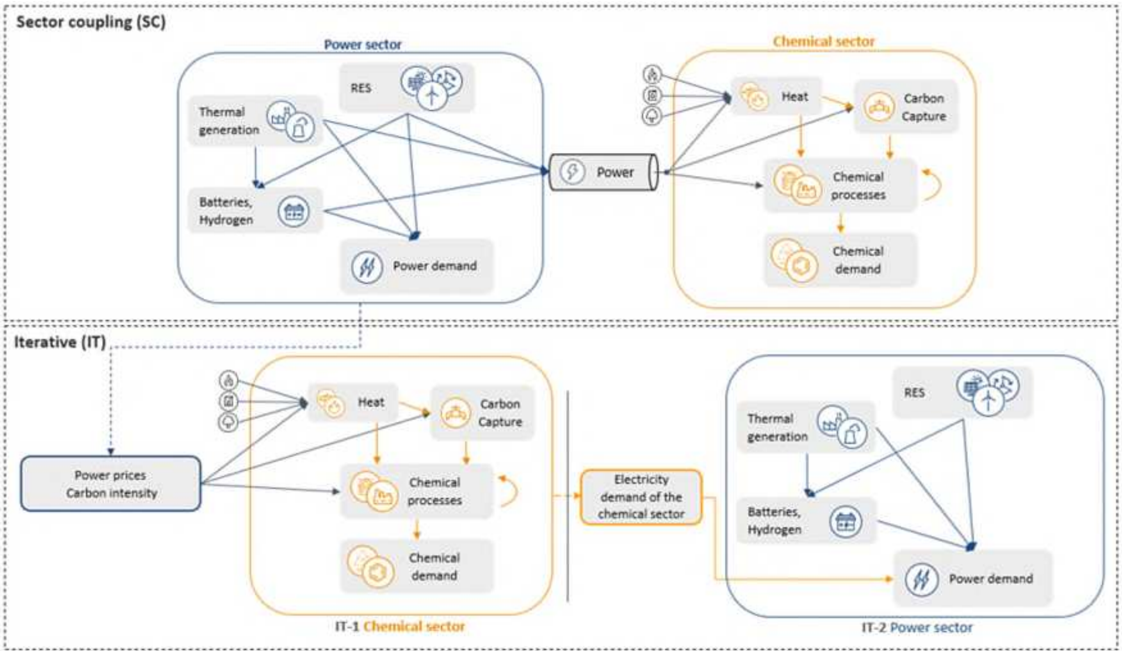


Table 8 summarises the key methodological differences between the SC and IT approaches used in the study. The results from the sector coupling scenario are used as an input assumption for the iterative case, both in terms of electricity price and carbon content. The dual variable of the supply and demand equilibrium constraint is considered to estimate the electricity price (Eq. 14). As a consequence, the SC and IT-1 cases share the same electricity price for the chemical sector, but any additional consumption in the chemical sector would not affect the electricity price or its carbon content. Finally, in the IT-2 step, we evaluated the impact of the differences in chemical electricity consumption on the power sector. Additional investments in the power sector are possible compared to the SC case, which implies that the chemical facilities would require construction time long enough for the power sector to adapt to the new demand.

s

Table 8 - Summary of the cases considered in the modelling framework

Cases	Sector modelled	Power prices	Power carbon intensity	Chemical power demand
SC	Power and Chemical	Endogenous	Endogenous	Endogenous
IT-1	Chemical	Exogenous based on the SC case	Exogenous based on the SC case	Endogenous
IT-2	Power	Endogenous	Endogenous	Exogenous based on the IT-1 case

Depending on the case considered, the formulation of the objective function differs. In the case of joint optimisation of both sectors (SC), the electricity provision for the chemical sector is handled endogenously. In the iterative cases (IT1 and IT2), as the provision of electricity is exogenous, the model minimises the net present cost of the chemical sector, considering power price as an input parameter. This leads to a slightly different formulation of the net present cost between the two cases. To be able to compare the net present cost difference stemming from the two formulations, we consider the following calculation:

$$\Delta NPC_{Power} = NPC_{Power}^{IT.2} - NPC_{Power}^{SC} \quad \text{(Eq. 31)}$$

$$\Delta NPC_{Chem} = NPC_{Chem}^{IT.1} - NPC_{Chem}^{SC} + \sum_y (1+r)^{-(y-Y_0)} * \left(\delta_y^{IT.2} * D_{chem,y}^{IT.2} - \delta_y^{SC} * D_{chem,y}^{SC}\right) \quad \text{(Eq. 32)}$$

$$\Delta NPC_{tot} = \Delta NPC_{Chem} + \Delta NPC_{Power} \quad \text{(Eq. 33)}$$

With:

δ_y power price stemming from the marginal value of (Eq. 14)

α_y ponderation of each year, including discounting

The results obtained include the cumulative electricity production, the cumulative greenhouse gas emissions, and the net present cost for each scenario and case. We extended the results of the five timesteps considered in the model by assuming stable operation in intermediate years. To ensure the validity and reliability of our results, we conduct sensitivity analyses to assess the impact of carbon capture technologies on reducing emissions. Additionally, the study examines the sensitivity of results to variations in natural gas prices and deployment rates in the power sector.

4.6. Results

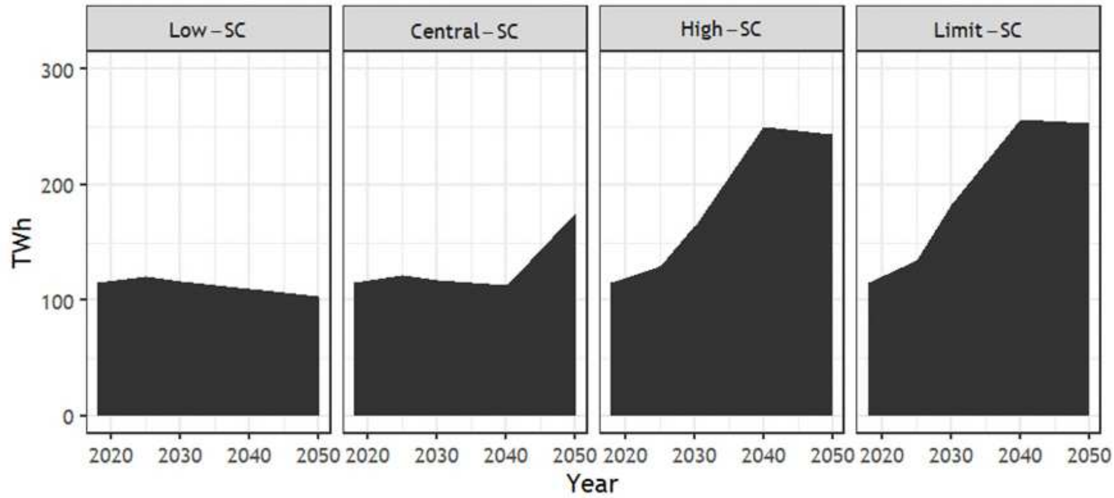
The proposed methodology allows us to quantify the extent to which the energy provision of the chemical sector is electrified under different carbon price trajectories and the loss associated with an iterative approach. First, we consider the electrification trajectory in the sector coupling approach (section 4.6.1) and the associated investments in the power sector (section 4.6.2).

Second, we look at the electrification trajectory of the iterative approach (section 4.6.3). Finally, we assess the welfare change associated with the difference between the SC and the IT case (section 4.6.4). In addition, we discuss the sensitivities performed on carbon capture, natural gas prices and deployment pace in the power sector (section 4.6.5).

4.6.1. Effect of carbon pricing on the pace of electrification

As illustrated in Figure 36, higher carbon price trajectories lead to higher endogenous electricity consumption in the chemical industry, thus incentivising end-use electrification.

Figure 36 - Electrification trajectories in the chemical sector - SC case



However, the impact of increasing carbon prices on electrification is constrained by the pace at which new clean electricity capacity can be deployed in the power sector and the availability of further electrification opportunities. As a result, the "limit" and "high" scenarios exhibit a similar electrification trajectory despite the gap in the carbon price. By 2050, the electricity consumption in the chemical sector reach 250 TWh, representing a 110% increase from the 2018 baseline after accounting for energy efficiency improvements over time. Given that no other low-carbon alternatives are invested between the two scenarios, it corresponds to a situation where all the electrification opportunities have been realised. However, reaching a threshold in carbon prices is a pre-requisite so that the electrified option reaches cost-parity with the fossil-based processes. This threshold is not reached in the "low" scenario, which reduces its electricity consumption over time driven by the energy efficiency gains. In contrast, the "central" scenario achieves the threshold carbon price only in the final year, resulting in lower electrification than in the "high" and "limit" scenarios, as the processes are not deployed at scale in 2050. It leads to a 52% increase in power consumption in the "central" scenario.

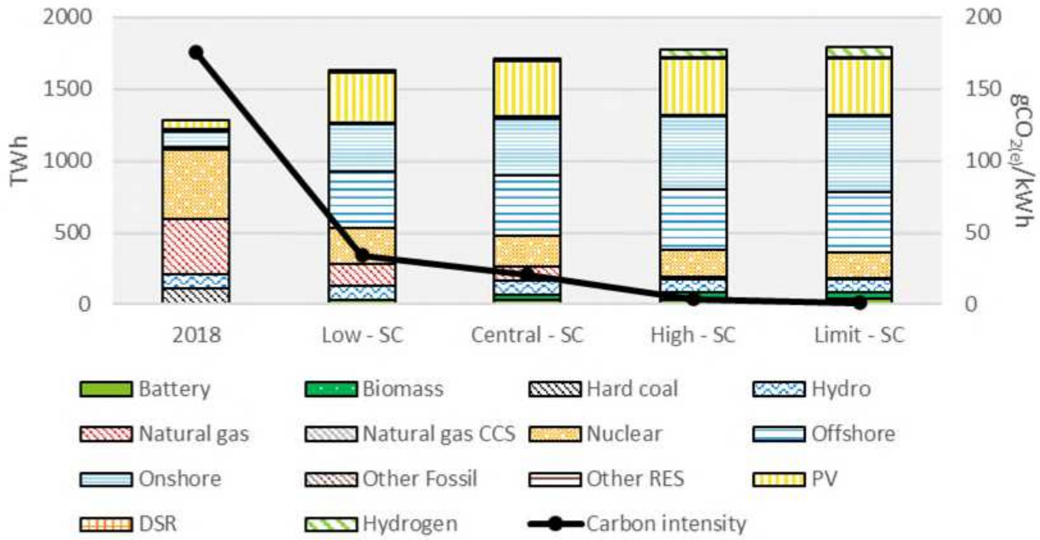
The electrification trajectory in the chemical sector is closely tied to the investment decisions made in the sector. Specifically, most of the increase in power demand can be attributed to the electrification of low-temperature heat supply within the chemical industry (Appendix C, Figure

C.8). Generally speaking, all trajectories reduce their low-temperature heat reliance on fossil fuels towards electricity. Driven by increasing CO_2 prices, there is a shift of scope one emission from the chemical industry towards much lower scope 2 emissions due to the availability of clean electricity. However, savings are also permitted by the energy efficiency gains of industrial end-uses (assumed to be 0.55% per annum), below historical rates (Cefic, 2022), reducing heat provision by 16% or 130 PJ by 2050. Then, technology switches triggered by the carbon pricing support the further deployment of biomethane and electrified boilers. As the carbon price increases, the proportion of electrified low-temperature heat provisions increases from 0% in the "low" scenario to 75% in the "high" and "limit" scenarios. It is not the case for the high-temperature heat provision, as some processes, such as the electrified steam crackers, would require carbon capture to be relevant. Indeed, electrifying the high-temperature heat supply implies having ways to dispose of the fuel gas resulting from the cracking that used to be recycled (Layritz et al., 2021). The carbon capture option will be further studied as part of the sensitivities performed. Regarding the pace of deployment, the results also point out that electrification starts at different points in time, depending on the scenario. Typically, we found that a carbon price above 250 EUR/$tCO_{2(e)}$ is required for the first investments to occur, a condition met only in 2050 in the "central" scenario.

4.6.2. Effect of carbon pricing on the pace of power generation decarbonisation

Regarding the optimal power generation mix in each scenario, our analysis finds that all scenarios rely on a significant share of renewable energy sources to meet the increasing electricity demand. Figure 37 depicts the differences in the 2050 generation mix and the associated carbon intensity of the sector coupling scenarios, where renewable energy sources represent between 66% and 80% of the power production in 2050. The higher the carbon price is, the more renewable energy sources develop. Hence, natural gas-based generation has a reduced market share compared to current levels, with its capacity being either stable or decreasing (between 45 and 90GW of installed capacity in 2050). Similarly, its load factor shrinks from a value above 60% in today's power mix to levels between 14-28% in "low" and "central" scenarios and lower than 3% in the others. This points out a need for capacity payments to guarantee the security of supply, as already underlined in the literature (Joskow, 2022). There is a persistent need for backup capacity for periods of low wind and solar PV infeed (Appendix C, Figure C.9 and Figure C.10), translating into a significant increase in the installed capacity.

Figure 37 - Power generation and carbon intensity of the electricity in 2050 per scenario, compared to the 2018 reference - SC case



The resulting carbon intensity of electricity follows a similar trend regardless of the carbon price. The additional decrease in the electricity production's carbon intensity between scenarios corresponds to the increased expansion of hydrogen turbines and increased reliance on renewable energy sources. This deployment comes, however, with increasing shares of curtailment (Appendix C, Figure C.11). This could likely be used for hydrogen production, for which the production is not considered in our modelling apart from the chemical sector. For the scenario "limit", almost no additional emissions savings are reached in 2050 compared to the "high"' scenario by further increasing carbon prices. It points out that the power sector decarbonisation attains a ceiling. Such a ceiling is likely due to the availability of renewable energy sources constrained by the weather year considered. It would require a significant and non-cost-efficient over-capacity of renewables or batteries to abate the last existing thermal units.

4.6.3. Impact of the IT approach on the pace of electrification

Figure 38 shows the differences in the electricity consumption of the chemical sector between the two cases by scenario. In the "low" scenario, it is observed that the electrification trajectory remains unchanged in the chemical sector, as the cost-parity threshold between electrified and fossil fuel boilers is not reached. However, compared to the sector coupling case, all other scenarios depict an increase in electricity consumption in the iterative case. It points out that fixed and exogenous assumptions taken on the evolution of the power price and carbon content led to an overestimation of the electrification pace of the chemical sector. Depending on the scenario and year, this adverse effect could reach 50% to 81%. In the "central" scenario, the electrification level reached in 2040 and 2050 is higher than when considering sector coupling. A similar effect is depicted in the scenario "limit", where the electrification takes place much earlier and faster, in

2025 and 2030, which points out again that early electrification is cost-effective from the standpoint of the downstream sector. The "high" scenario does not result in early electrification, pointing out that the power sector did not constrain the pace of the electrification in this scenario and that the threshold of electrification is not reached earlier.

Figure 38 - Electrification trajectories in the chemical sector in the IT case and percentage differences in the SC case

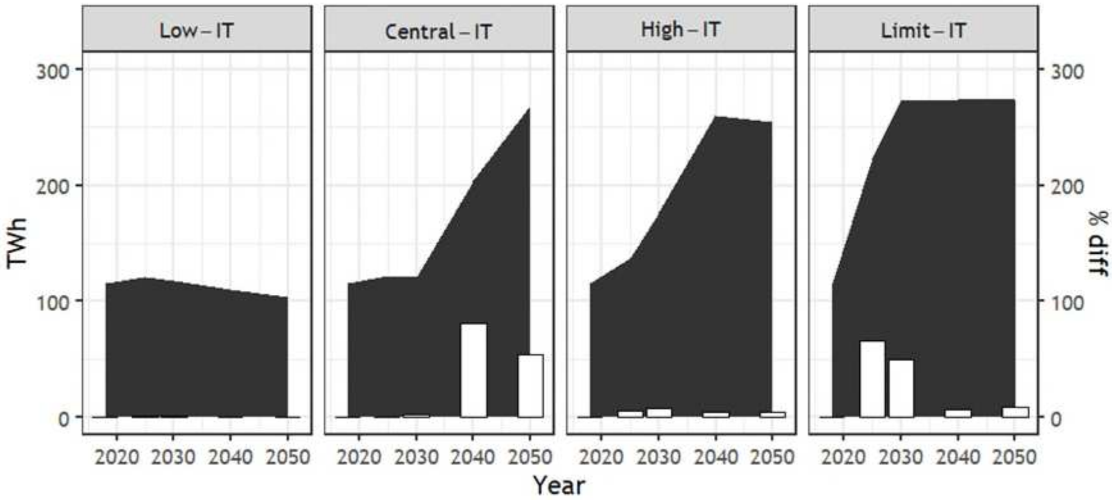
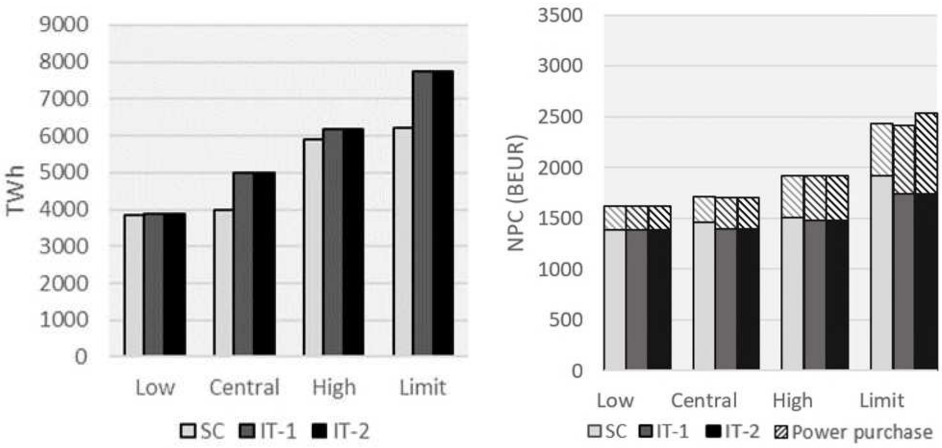


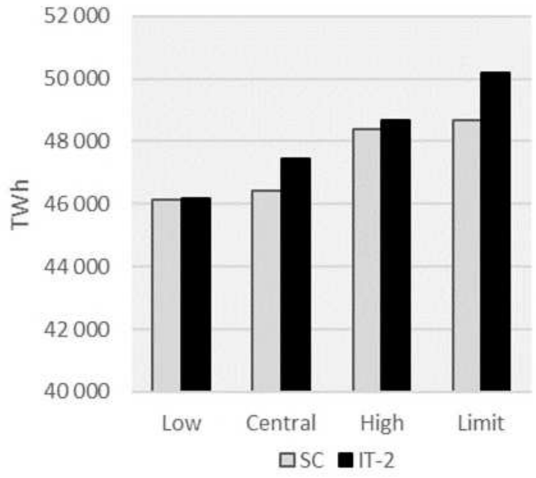
Figure 39 presents the differences incurred by the chemical sector in the sector coupling and the iterative cases. We display two metrics: the cumulated power consumption and the net present cost. Additional results on the cumulated GHG emission are provided in Appendix C, Figure C.12. The more pronounced differences are observed in the "central" and "limit" scenarios, where the cumulated electricity consumption diverges by 25% between the SC and the IT cases. This early electrification substantially reduces the cumulated emissions by 9% in the "central" scenario and by 17% in the "limit" scenario (Appendix C, Table C.16). A reduction in the net present cost is found between the SC and the IT-1 case in all scenarios, and notably in the “central” and “limit” scenarios where the differences are the most important, translating in an NPC difference of -0.5% and -0.6%. Nevertheless, the results from the IT-1 case relate to a situation where the impacts on the power sector are neglected. The higher electricity demand in the chemical sector would lead to increased electricity prices and carbon content. Therefore, the power price increase between IT-1 and IT-2 cases should be considered to assess the change in the net present cost of the chemical sector trajectory, as outlined in section 4.4.3. Considering those additional changes in the power purchase expenditures, all scenarios still result in net savings except for the “limit” scenario, where the 18% power price increase in the electricity purchase offsets the benefits from early electrification found in the IT-1 step. The resulting net present cost is increased by 4.3%. The results indicate that if a low-carbon and affordable power sector develops fast enough, it is optimal to electrify early downstream sectors. However, the savings in some scenarios do not account for the additional investments required in the power sector to supply the increased power demand.

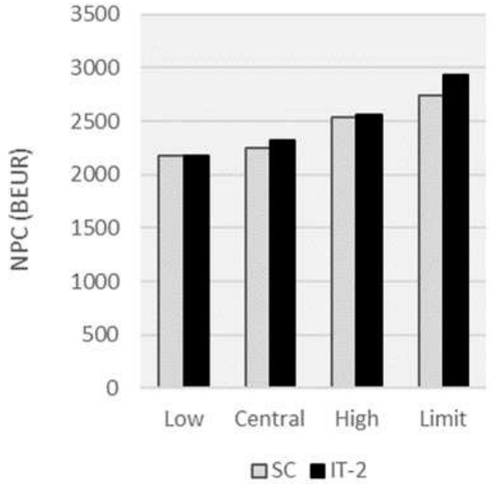
Figure 39 - Differences in the chemical sector cumulated power consumption and net present cost between SC and IT-1 for all scenarios



The net present cost for the power sector in each case is depicted in Figure 40. The increase ranges from 0% to 1% in the "low" and "high" scenarios. However, more substantial differences emerge in the "central" and "limit" scenarios, with net present cost variations reaching 3% and 7%, respectively. This observation is consistent with the higher demand for power production required in those scenarios. In addition, the results on GHG emissions indicate that although early electrification results in lower emissions in the chemical sector, this is not the case for the power sector. Specifically, we find that the additional electricity production comes not only from additional renewable energy sources but also from additional natural gas turbine production. This, in turn, leads to an increase in cumulated emissions of 0.1% in both the "low" and "central" scenarios and up to 8.5% in the "limit" case. Indeed, early electrification limits the power sector's ability to rely on substantially more renewable energy sources (Appendix C, Table C.17). A substitution strategy based primarily on renewable energy sources would have increased both the net present cost and the cumulated electricity production, but not the cumulated emissions.

Figure 40 - Differences in the power sector generation and net present cost between SC and IT-2 for all scenarios





4.6.4. Welfare gain of sector coupling

Finally, we assess the total net present cost between the SC and the IT cases. To do so, we account for the net present cost gain of the early electrification of the chemical sector, as presented in Figure 39. Next, we add the cost resulting from the increased electricity consumption in the power sector, corresponding to the IT-2 step of our modelling framework. The results are displayed in Figure 41. We find that the total effect on the net present cost is negative. While faster electrification of the chemical sector leads to some cost savings, these are offset by the power sector's resulting cost and price differences. In scenarios where the electrification differences are substantial, the losses are particularly significant, with a 3% difference in NPC for the "central" scenario and an 11% difference in the "high" scenario. However, accelerated electrification would save emissions in all scenarios but at a significant price premium. In particular, we find that the net present cost of abatement, obtained by dividing the net present cost difference between the two cases by the cumulated emissions savings, is much higher than the carbon price considered in 2050 for each trajectory (Appendix C, Table C.18).

Figure 41 - NPC differences between SC and IT cases for the power and chemical sectors for all scenarios

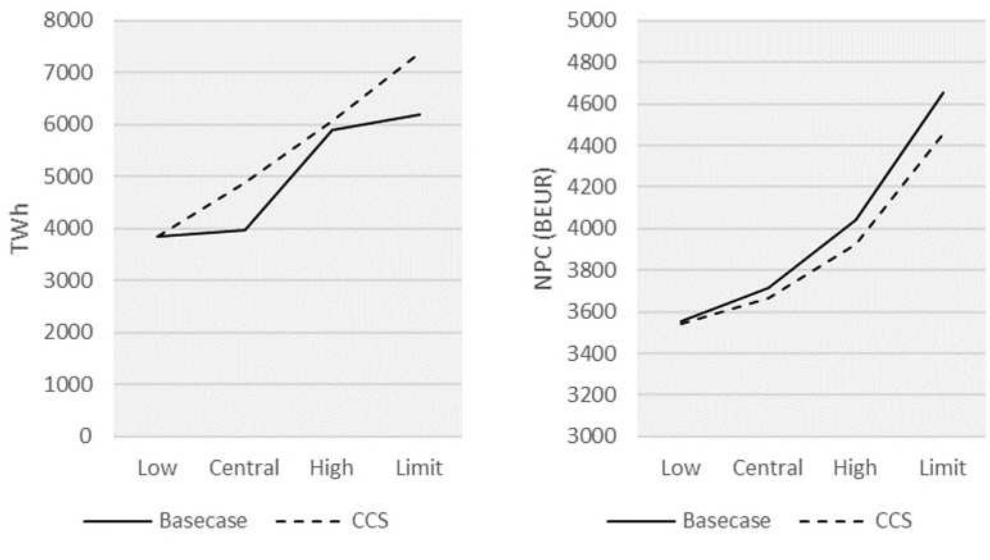
The observed results are contingent upon the ability of the power sector to increase its power generation capacity. Specifically, we found that the yearly installation rate of renewable energy sources varied by 1 to 5 GW/year between the "central" and "limit" scenarios. However, these differences remain within the deployment constraint outlined in Section 3.1. If the power sector cannot invest significantly or with additional lead time, the resulting power price differences between the initial trajectory in IT-2 and the outcome of IT-2 will likely be even more significant. This result underlines the risks linked to pace inconsistency between sectors under a common carbon price. The anticipated carbon and power prices are critical drivers for the chemical sector to invest. However, solely relying on prices will be detrimental for the downstream sector if the associated demand expansion due to electrification is not duly estimated. Our results, therefore, call for policymakers and industries to consider both aspects and look for appropriate hedging strategies to reduce the risks of bottlenecks and stranded assets.

4.6.5. Sensitivities

To assess the robustness of our results, we conducted several sensitivity analyses on the level of electrification in the sector coupling case for each carbon price trajectory. Specifically, we evaluated the impact of adding carbon capture technologies, variations in the deployment rate in the power sector, and natural gas price fluctuations. The last two sensitivities involved differences ranging from -20% to +20% compared to the base case.

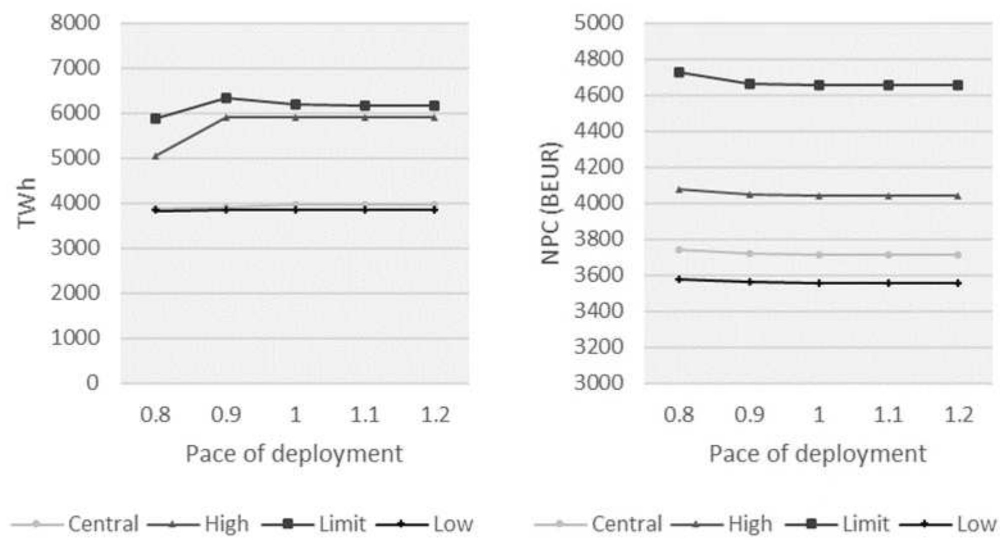
First, we assess the robustness of the electrification trajectory when allowing for carbon capture. As highlighted in the literature review, many studies suggest carbon capture will play a critical role in reducing emissions within the chemical sector. Therefore, we implemented two different carbon capture technologies depending on the purity of the CO_2 stream. The results are depicted in Figure 42, which shows the cumulated electricity consumption of the chemical sector and the evolution of the overall net present cost for each scenario. We find that carbon capture increases electricity consumption in all scenarios. We identify two primary drivers for this outcome. The first one is that enabling carbon capture for the power sector allows for lower electricity prices, as it mainly substitutes the hydrogen turbines with less expensive natural gas turbines equipped with CCS. The second driver is that carbon capture allows to abate additional direct emissions for the same carbon price but further increases electricity consumption due to its energy consumption. Therefore, it results in higher electrification levels in all scenarios, especially in the "central" and "limit", where the increase in cumulated power consumption is respectively 23% and 19%, driven by the earlier deployment of electricity-based heat supplies. Deploying carbon capture allows for an overall reduction of the net present cost. The reduction is 1% in the "central" scenario and around 3% in the "limit" scenario. The cumulative emissions savings reach 6 to 7% due to carbon capture mainly installed on conventional steam crackers and natural gas boilers that have not been electrified in the "central" scenario (Appendix C, Figure C.13). In addition, when carbon capture is allowed for both the power sector and the chemical industry, electrified steam crackers do not appear as a favoured option. It indicates that installing carbon capture on conventional steam crackers in the chemical industry would be more cost-effective than electrifying all their high-temperature heat demand. As already pointed out in the literature, the interests and economics of deploying electrified steam crackers must be carefully assessed (Layritz et al., 2021). Regarding the power sector, carbon capture leads to lower investments in renewable energy sources and hydrogen turbines.

Figure 42 - Differences in cumulated power consumption of the chemical sector and overall net present cost with and without carbon capture technologies



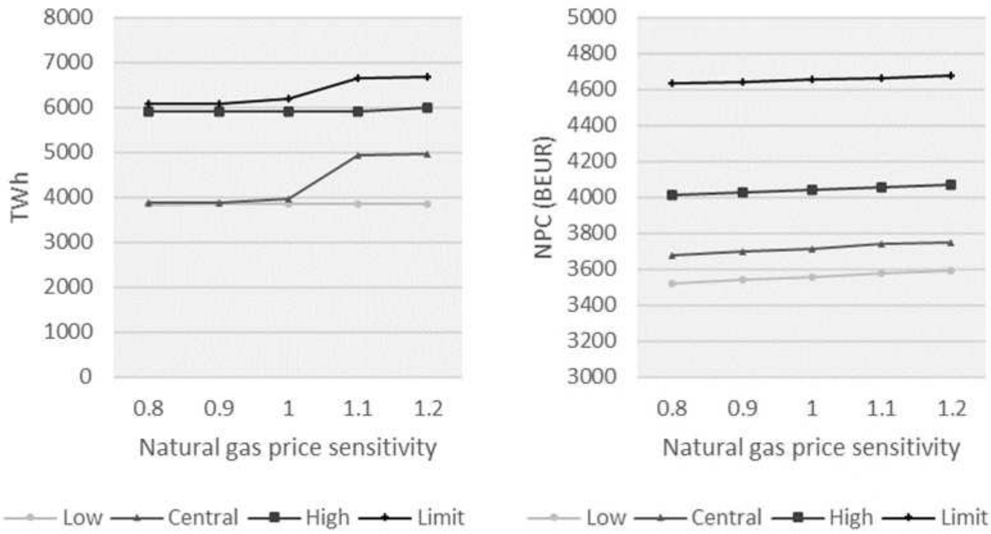
Then, we assess the consequences of delayed or accelerated deployment of new generation capacities by performing sensitivities on the deployment rates in the power sector (Eq. **16**). We varied the feasible pace of deployment for the new power capacity by +/- 20%. It stems from the modelling that such relaxation has a non-linear impact, as displayed in Figure 43. When considering a 20% lower deployment pace of power generation capacity or a maximum of 12% year-on-year growth for each technology, we find reduced electricity consumption for the chemical power sector. As a result, power becomes both more expensive and more carbon-intensive. As such, the deployment of electrified heat boilers is delayed in the "high" and "limit" scenarios. Accordingly, the net present cost increased by 0.9% and 1.5% in those scenarios. However, such a phenomenon is not observed when considering a 10% lower deployment rate in the power sector. Indeed, a lower deployment pace of power generation capacity resulted in an earlier deployment of electric boilers to achieve the same electrification level in 2050, partly due to the perfect foresight approach considered in the modelling framework. However, both the delayed and the early deployment results in a net present cost increase of 0.2% and 0.16%, respectively. The scenarios considering a higher feasible pace of deployment in the power sector does not results in different electrification level or significant cost savings. The demand-side deployment constraint interferes, as a similar year-on-year growth rate also constrains chemical processes: a joint evolution of the production capacity and the demand-side electrification pace results in lower costs.

Figure 43 - Differences in cumulated power consumption of the chemical sector and overall net present for different paces of deployment in the power sector



Finally, we have considered sensitivities on natural gas prices. The results presented in Figure 44 underline that an increase in natural gas prices leads to an increase in the cumulated electricity consumption, notably in the "central" and "limit" scenarios. The net present cost rises linearly for all scenarios, reaching between 0.4% and 1% higher for a natural gas price increase of 20%. The effect is less pronounced in the high scenarios as the cost-parity of electrified options is not reached earlier, even with increased natural gas prices. Overall, this shows how electrification can be considered a hedge against higher natural gas prices, provided that renewable energy sources and alternative clean energy power generation capacities are deployed fast enough.

Figure 44 - Differences in cumulated power consumption of the chemical sector and overall net present for different natural gas prices



4.7. Discussion

This research presents the results of a novel co-optimisation assessment of the power and chemical sectors subject to carbon pricing. The methodology allows us to estimate the importance of electrification for the chemical sector and the required carbon price to reach low GHG emissions levels. Our first finding is that the electrification of the heat supply in chemical processes is essential to reach low emissions, potentially leading to a doubling in electricity consumption by 2050 in the scenarios considered. Furthermore, the sensitivity analysis shows that the extent of electrification is not significantly affected by the availability of carbon capture and storage (CCS) or the deployment rate of renewable energy sources in the power sector, provided that these technologies can be rapidly deployed to meet the demand.

More generally, our findings highlight the need for rapid technology switches to reduce GHG emissions. This transition occurs in the power sector, where renewables expand rapidly and in the chemical sector, where incumbent heating technologies must phase out progressively. In addition, our results stress a risk associated with industrial dynamics in the energy transition. Undeniably, several abatement options require accelerated research and development to be commercially available at scale (e.g. carbon capture, hydrogen). Those technologies will require expanding the future transport and distribution infrastructure (electricity, hydrogen, CO_2), subject to further research and development efforts. Many system and industrial rigidities, such as financing constraints, lack of or too slow social acceptance, permitting and construction lead time, could prevent the transformation of the two sectors at the required pace to meet the 2050 objectives.

Even if low-emitting alternatives to avoid reliance on hypothetical carbon capture at scale by 2050 are underlined in this chapter, they represent an additional cost subject to public acceptance issues. Nevertheless, with the existing technologies considered, we have shown that reducing 80% of direct $CO_{2(e)}$ emissions is feasible. It is important to note that if the chemical sector expands, the transformation required could be more challenging, whereas it may be less difficult in the case of an output reduction, all other things equal. Likewise, the impact of a reindustrialisation effort in Europe is not assessed in the present research but will have consequences on the feasible pace and costs of electrification for each sector, as all are expected to electrify their operations, albeit to various extents. These considerations should be factored in within reindustrialisation policies to account for the investments required in the power system.

A second finding relates to the required carbon prices, as only trajectories reaching more than 250 EUR/$tCO_{2(e)}$ in 2050 would allow for large-scale emission abatements. Both sectors being subject to the same carbon price, our results indicate that end-products would face an additional cost burden in the case the growth rates of carbon prices are faster than the deployment pace the different sectors can achieve. Such a situation could increase consumer costs and lower production levels, depending on the demand's price elasticity and the competitiveness of the European industry. We believe a revision of the current design and operation of the EU ETS mechanism would be required to avoid such situations. In addition, further research would be required to estimate to what extent a volatile carbon price for different sectors can lead to economic losses due to dynamic constraints alongside the transition toward Net Zero GHG emissions and the different thresholds of carbon prices required to foster investments in low-emitting technologies. This is notably relevant as hard-to-abate sectors not considered in the present research could set the price of the EU ETS higher under the current cap and trade design.

Our results highlight the necessity of adopting an integrated approach to transition to a low-carbon economy. Specifically, we demonstrate that employing an iterative approach rather than a sector coupling one toward decarbonisation could lead to an overestimation of the pace of electrification of end-uses. Indeed, when exogenous price and carbon content trajectories are considered for the chemical sector transition, the power demand of the chemical sector increases by 50% to 80% for specific years compared to the sector coupling approach due to the earlier electrification of the chemical sector. These results shed light on the importance of considering upstream constraints in designing effective policies to promote decarbonisation through the electrification of end-uses and have important implications for policymakers, energy market regulators, and industry stakeholders. The impact on power generation should be cautiously estimated before advocating for extensive electrification strategies, as low-emitting power generation capacity would not only need to replace existing generation capacities but also meet the growing demand from new electrified end-uses. Disregarding the upstream impact of downstream investment decisions might result in adverse effects on power prices and associated carbon emissions. Specifically, disregarding these issues leads to a 3% to 11% higher net present cost in the scenarios considered for the chemical sector. Forward power prices should inform actors about the marginal cost of additional electrification to prevent welfare losses. Alternatively, Power Purchase Agreements (PPA) and Contract-for-Differences (CfD) would allow energy-intensive industries to secure baseload power production over the years, enabling industries to hedge price and volume risks underscored in the chapter. This result also underlines the importance of reducing information asymmetry between sectors when planning for the Net Zero emissions target in 2050.

This research has several limitations that could be the subject of further research. The first one stems from the fact that we disregard the long-term price elasticity of the chemical sector output to energy prices. Likewise, we do not consider the demand elasticity of chemical products. Nonetheless, as we have considered a fixed demand over time, and given the consumption growth expected, we believe the range of electrification resulting from our analysis would still hold. However, an important limitation to the estimated electrification trajectory lies in the uncertainty of the role and status of future hydrogen production. Indeed, its relevance for hard-to-abate sectors such as heavy transport or iron and steel production is not considered in our research. While we account for changes in hydrogen demand and processes, both its use as a feedstock (e.g. in ammonia and methanol production) or for heat provision within the chemical sector, we have not incorporated the potential additional hydrogen demand stemming from other sectors. Electrolytic hydrogen production stands out as a promising option, albeit one that requires additional electricity generation. The consideration of this aspect would, in turn, contribute to a further increase in electricity demand. However, its production and use in other sectors go beyond the scope of the present research, which focuses on the current chemical sector and associated end-products. Further research could extend the current framework to assess different paces of electricity demand increase, encompassing all other sectors and the potential inter-sectoral competition for low-carbon electricity.

Regarding the power sector, we use an exogenous assumption to account for the demand growth from electric vehicles and buildings, which might increase or reduce the pressure on the power sector's transition. This would directly impact the chemical sector, which investment decisions relate to both the power prices and the carbon content of electricity. We also abstract from some flexibility options from the demand side. Our results depict a situation where construction lead time, transaction costs, or financing availability are simplified using a single deployment rate parameter. Likewise, investment risk premiums are likely underestimated, as agents have perfect foresight on the evolution of the carbon price and other commodities. It results in a likely accelerated transition towards a low-emission system for the CWE region.

On the chemical sector side, simplifications have been made concerning the research and development cost required to make new low-carbon technologies commercially available, and energy efficiency improvement costs have not been considered. Therefore, we likely underestimate the total capital expenditures and the carbon price required to trigger emission reduction. Conversely, retrofit options have not been considered. Finally, we disregard geographical considerations in both sectors. The CWE region is considered a single node, likely underestimating the required power capacity and abstracting the chemical sector from different local resources and policy environments. These simplifications could result in alternative investment choices, fostering the integration of multiple supply chains into single industrial hubs and increasing interest in small-scale technologies on-site on sites with important renewable energy resources.

Eventually, an important aspect that could impact the results is the carbon accounting rule assumed. Understanding the extent to which the carbon accounting rules assumed could impact resulting technological choices, as well as accounting for other types of induced emissions (e.g. upstream emissions, end-of-life emissions), would be part of further research. By design, this research focuses on direct emissions targeted by the EU ETS in both sectors with the associated carbon price. As such, oil and gas are still used as feedstocks in 2050, as no emissions linked to the incineration of the final products were considered. Likewise, refineries and oil and gas extraction emissions were not considered. Therefore, aiming at sectoral emission reductions in an isolated manner without considering upstream and downstream emissions could lead to sub-optimal investments due to the limited view of the dynamics and challenges of feedstock extraction and final usage of products.

4.8. Conclusion

This research aims to inform the ongoing policy discussions on industrial energy transition pathways. We applied a novel co-optimisation model of the power and the chemical sector to conditions defining the incentives and the pace of the energy transition in the case of the CWE chemical sector. We stress that a twofold increase in electricity consumption from the chemical sector is required to attain significant GHG emissions reduction in the industry. Assuming the sector continues to grow in future decades, we estimate that a tripling of electricity demand is likely.

Two policy implications follow from the framework developed. First, providing the industrial sector with forward-looking electricity prices and quantities can enhance investment and climate perspectives by improving the security of supply and reducing welfare losses. Our analysis shows that constraints in the upstream power sector significantly impact the optimal pace of energy transition in the downstream chemical sector. Second, evaluating the carbon price trajectories that make energy transition operational and affordable for consumers is crucial. Specifically, the carbon price increase should not outpace the lead time required for changing conventional processes. Our results underscore the need for considering sector coupling when designing decarbonisation pathways. Future studies can investigate these policy implications by explicitly considering all industries subject to electrification to assess the potential competition to secure a clean and affordable electricity supply.

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Appendix C

C1. Supplementary Data

Table C.1 - Initial installed capacities considered for the chemical sector (JRC, 2017)

Zone	Product	Technology name	2013 Nameplate capacity (Mt)
CWE	Ammonia	Haber-Bosch	6.474
CWE	BTX	BTX (Reformate)	1.445
CWE	BTX	BTX (Pygas/Coke-oven)	2.538
CWE	BTX	BTX (HDA)	0.316
CWE	Chlorine	Chlorine -electrolysis (Membrane-100%)	3.566
CWE	Chlorine	Chlorine - electrolysis (Membrane-mix)	0.178
CWE	Chlorine	Chlorine (HCl)	0.042
CWE	ETO	ETO (Oxygen-based)	1.66
CWE	HVCs	Steam Cracker (Naphtha)	6.854
CWE	HVCs	Steam Cracker (LPG)	0.735
CWE	HVCs	Steam Cracker (LPG/Naphtha)	2.266
CWE	Hydrogen	Steam methane reforming	0.588
CWE	MEG	ETO hydration	1.204
CWE	Methanol	Methanol (NG)	0.5
CWE	PE	PE (Polymerisation)	6.639
CWE	PET	PET	2.369
CWE	PP	PP	5.169
CWE	Propylene**	Propylene (Fluid catalytic cracker)	1.408
CWE	PS	PS	2.09
CWE	PTA	PTA	1.398
CWE	PVC	S-PVC	2.53
CWE	PVC	E-PVC	0.11
CWE	Styrene	Styrene (SM/EB)	2.265
CWE	Styrene	Styrene (SM/PO)	1.005

*Additional scaling has been performed to update the available data based on sector-specific data and information available (Cefic, 2022; Fertilizers Europe, 2023; Petrochemicals Europe, 2023).
** Steam crackers also cover propylene production for a significant portion (56%)

Table C.2 - Initial installed capacities considered for the power sector (WRI, 2023)

Zone	Energy	2018 Nameplate capacity (GW)
CWE	Biomass	10.2
CWE	Hard coal	33.2
CWE	Heavy oils	1.4
CWE	Light oils	2.3
CWE	Lignite	20.8
CWE	Pumped storage	11.9
CWE	Natural gas	71.9
CWE	Non-renewable waste	1.1
CWE	Nuclear	79
CWE	Wind offshore	7.2
CWE	Wind onshore	71.6
CWE	Pure Storage	28
CWE	PV	56.6
CWE	Renewable waste	2.4
CWE	Run of river	20.9
CWE	Other fossil fuels	0.48
CWE	Marine	0.24
CWE	Other renewable energy	0.47

Table C.3 - Power consumption considered for the chemical supply chain model

Process	Main product	2050 Electricity consumption (TWh/Mt_{main})	References
Electrical cracker	Ethylene	5.75	(Boulamanti and Moya, 2017)
Ethylene - Bioethanol dehydration	Ethylene	0.23	(Nitzsche et al., 2016; Uslu et al., 2020)
Methanol-to-Olefins	Ethylene	0.1	(Pinto Mariano et al., 2013; Zhao et al., 2021)
Methane pyrolysis	Hydrogen	8.56	(Kohn and Lenz, 2019)
Alkaline electrolyser	Hydrogen	44.4	(H-vision, 2019)
Auto-thermal reforming	Hydrogen	1.61	(H-vision, 2019)
Haber-Bosch with ASU	Ammonia	0.75	(Morgan et al., 2017)
Plastic Waste pyrolysis	Naphtha	0.44	(Fivga and Dimitriou, 2018)
Styrene (PS recycling by pyrolysis)	Styrene	0.36	(Bassil et al., 2018)
Recycling to B-HET/PTA	PTA, BHET (PET monomer)	0.39	(Muller et al., 2021)
PS (recycling by dissolution)	Polystyrene	4.61	(Muller et al., 2021)
Methanol (Biomass)	Methanol	0.17	(Uslu et al., 2020)
Methanol (Waste gasification)	Methanol	0.05	(Iaquaniello et al., 2017)
Methanol (CO_2 + H_2)	Methanol	0.18	(Nyári et al., 2020)
CCS (High purity)	Captured CO_2	0.18	(Lensink and Schoots, 2021)
CCS (Low purity)	Captured CO_2	0.13	(Lensink and Schoots, 2021)
Haber-Bosch	Ammonia	0.083	(JRC, 2017)
BTX (Reformate)	BTX	0.04	(JRC, 2017)
BTX (Pygas/Coke-oven)	BTX	0.03	(JRC, 2017)
BTX (HDA)	BTX	0.031	(Ouattara et al., 2013)
Chlorine - electrolysis (Hg-	Chlorine	3.5	(JRC, 2017)
Chlorine -electrolysis	Chlorine	2.65	(JRC, 2017)
Chlorine - electrolysis	Chlorine	2.85	(JRC, 2017)
Chlorine (HCl)	Chlorine	1.24	(Bechtel et al., 2018; Motupally et al., 1998)
Steam Cracker (Naphtha)	HVCs	0.14	(JRC, 2017)
Steam Cracker (LPG/ Naphtha)	HVCs	0.14	(JRC, 2017)
Steam Cracker (Naphtha)	HVCs	0.044	(JRC, 2017)
Steam Cracker (LPG)	HVCs	0.3	(JRC, 2017)
ETO (Oxygen-based)	ETO	0.333	(JRC, 2017)
Steam methane reforming	Hydrogen	0.189	(JRC, 2017)
ETO hydration	MEG	0.083	(JRC, 2017)
Methanol (NG)	Methanol	0.054	(JRC, 2017)
PE (Polymerisation)	PE	0.63	(Jones, 2010)
PET	PET	0.056	(Jones, 2010)
PP	PP	0.476	(Jones, 2010)
Propylene (Propane	Propylene	0.028	(CERI, 2022)
Propylene (Fluid catalytic	Propylene	0.978	(JRC, 2017)
Propylene (Metathesis)	Propylene	0.286	(Intratec, 2013)
PS	PS	0.111	(CERI, 2022)
PTA	PTA	0.083	(Shakti, 2013)
S-PVC	PVC	0.426	(JRC, 2017)
E-PVC	PVC	0.676	(JRC, 2017)
Styrene (SM/EB)	Styrene	0.151	(JRC, 2017)
Styrene (SM/PO)	Styrene	0.167	(Yong and Keys, 2021)

Table C.4 - Heat consumption considered in 2018* for the chemical supply chain model

Process	Main product	Heat consumption (PJ/Mt_{main})	References
Haber-Bosch	Ammonia	6.5	(JRC, 2017)
BTX (Reformate)	BTX	16.5	(JRC, 2017)
BTX (Pygas/Coke-oven)	BTX	10.7	(JRC, 2017)
BTX (HDA)	BTX	2.13	(Ouattara et al., 2013)
Chlorine - electrolysis (Hg-CHLR 100%)	Chlorine	-	(JRC, 2017)
Chlorine -electrolysis (Membrane-CHLR 100%)	Chlorine	1.1	(JRC, 2017)
Chlorine - electrolysis (Membrane-CHLR mix)	Chlorine	4	(JRC, 2017)
Chlorine (HCl)	Chlorine	-	(Bechtel et al., 2018; Motupally et al., 1998)
Steam Cracker (Naphtha)	HVCs	19.99	(JRC, 2017)
Steam Cracker (LPG/ Naphtha)	HVCs	19.99	(JRC, 2017)
Steam Cracker (Naphtha)	HVCs	11.84	(JRC, 2017)
Steam Cracker (LPG)	HVCs	23.92	(JRC, 2017)
ETO (Oxygen-based)	ETOCX	3.1	(JRC, 2017)
Steam methane reforming	Hydrogen	25	(JRC, 2017)
ETO hydration	MEG	9.1	(JRC, 2017)
Methanol (NG)	Methanol	10.9	(JRC, 2017)
PE (Polymerisation)	PE	1.4	(International Energy Agency, 2007)
PET	PET	4.1	(International Energy Agency, 2007)
PP	PP	1.4	(International Energy Agency, 2007)
Propylene (Propane dehydrogenation)	Propylene	2.2	(CERI, 2022)
Propylene (Fluid catalytic cracker)	Propylene	18.093	(JRC, 2017)
Propylene (Metathesis)	Propylene	4.25	(Intratec, 2013)
PS	PS	0.5	(International Energy Agency, 2007)
PTA	PTA	2.6	(International Energy Agency, 2007)
S-PVC	PVC	8.715	(JRC, 2017)
E-PVC	PVC	13.715	(JRC, 2017)
Styrene (SM/EB)	Styrene	7.708	(JRC, 2017)
Styrene (SM/PO)	Styrene	5.89	(Yong and Keys, 2021)
Ethanol from sugar fermentation	Bioethanol	8.86	(Danish Energy Agency, 2017)
Low purity	CCS	2.412	(PBL, 2021)
High purity	CCS	-	
Bioethanol dehydration	Ethylene	1.73	(Nitzsche et al., 2016)
Methanol to Olefins	Ethylene	19.4	(Uslu et al., 2020; Zhao et al., 2021)
Chemical recycling to B-HET (PET monomer)	RPET	8.775	(Muller et al., 2021)
PS recycling by pyrolysis	Styrene	13.8	(Bassil et al., 2018)

Table C.5 - Low-emitting alternatives considered for the heat provision of the chemical supply chain model

Technology	Main product	Electricity consumption in 2050 (TWh/PJ)	Feedstock consumption	References
Electric boiler	Heat	0.28		(Lensink and Schoots, 2021)
Biomass boiler	Heat	-	Woody biomass	(Towler and Sinnott, 2012)
Hydrogen boiler	Heat	-	Hydrogen	(Rutten, 2020)

Table C.6 - Overnight Investment Costs in a greenfield site for the power sector, excluding financial costs during construction time in EUR/kW

Energy	Type	2018	2025	2030	2040	2050	References
Biomass	-	2000	1900	1800	1700	1700	Steam turbine biomass solid conventional (Commission et al., 2021)
Natural gas	CCGT	600	590	579	575	570	Gas turbine combined cycle gas advanced (Commission et al., 2021)
Natural gas	OCGT	400	400	386	383	380	Gas turbine with heat recovery (Commission et al., 2021)
Nuclear	-	4800	4500	4500	4500	4500	Nuclear III gen. (incl. economies of scale) (Commission et al., 2021)
Offshore	-	2156	2092	2028	1961	1892	Average of Wind Offshore (Commission et al., 2021)
Onshore	-	1025	1000	975	925	903	Average of Wind Onshore (Commission et al., 2021)
PV	-	492	457	422	407	392	Average of Solar PV (Commission et al., 2021)
Natural gas	CCUS	1750	1688	1625	1500	1500	Gas combined cycle CCS post-combustion (Commission et al., 2021)
Battery	-	1200	980	760	600	600	Large-scale batteries (per 1 MWh electricity), 4h storage (Commission et al., 2021)
Hydrogen	-	1300	1250	1200	1150	1100	(RTE, 2021)

Table C.7 - Overnight Investment Costs* in a greenfield site in the chemical sector in EUR/t

Energy	Main product	2030	2050	References
Electrical cracker	Ethylene	3010.4	3010.4	(Navigant, 2019; Römgens and Dams, 2018)
Ethylene - Bioethanol dehydration	Ethylene	433	433	(Uslu et al., 2020)
Methanol-to-Olefins	Ethylene	1249	1249	(Uslu et al., 2020)
Methane pyrolysis	Hydrogen	3500	2520	(Dechema, 2019)
Alkaline electrolyser	Hydrogen	6988	3161	(IRENA, 2018)
Auto-thermal reforming	Hydrogen	2230	2230	(H-vision, 2019)
Haber-Bosch with ASU	Ammonia	350	350	(Fúnez Guerra et al., 2020; IEA, 2019; Morgan, 2013; Morgan et al., 2017)
Plastic Waste pyrolysis	Naphtha	1514	1230	(Fivga and Dimitriou, 2018; Oliveira Machado Dos Santos, 2020)
Styrene (PS recycling by pyrolysis)	Styrene	1068	867	(Bassil et al., 2018)
Recycling to B-HET/PTA	PTA, BHET (PET monomer)	728	591	(Muller et al., 2021)
PS (recycling by dissolution)	Polystyrene	1340	1088	(Muller et al., 2021)
Methanol (Biomass)	Methanol	1456	1456	(Uslu et al., 2020)
Methanol (Waste gasification)	Methanol	1462	1462	(Iaquaniello et al., 2017)
Methanol (CO_2 + H_2)	Methanol	288	277	(Nyári et al., 2020; Szima and Cormos, 2018)
CCS (High purity)	Captured CO_2	41	41	(SINTEF, 2017)
CCS (Low purity)	Captured CO_2	314	306	(IEAGHG, 2017)
Electric boiler	Electric boiler	109	99	(Lensink and Schoots, 2021)
Biomass boiler	Biomass boiler	115	104	(Towler and Sinnott, 2012)
Hydrogen boiler	Hydrogen boiler	239	239	(Römgens and Dams, 2018; Rutten, 2020)

** Excluding financial costs during construction, ownership costs, and indirect costs. An assumption is uniformly made to consider those.*

Table C.8 - Considered fuel price

Feedstock / Fuel	Unit	2018	2025	2030	2040	2050	References
Agricultural waste	EUR/GJ	4.941	5.118	5.294	5.471	5.706	(Ruiz et al., 2019)
CrudeOil	EUR/barrel	56.219	63.477	67.889	75.860	75.860	(IEA, 2021)
LCareWood	EUR/GJ	3.471	3.353	3.235	3.000	2.765	(Ruiz et al., 2019)
Sugar from sugar beet	EUR/GJ	12.412	11.941	11.471	11.824	11.471	(Ruiz et al., 2019)
Manure	EUR/GJ	5.294	5.353	5.353	5.353	5.353	(Ruiz et al., 2019)
Naphtha	EUR/kg	0.447	0.503	0.539	0.602	0.602	(IEA, 2021)
NG*	EUR/MWh	22.875	22.875	25.575	35.025	35.025	(IEA, 2021)
NGL	EUR/MWh	31.195	31.195	34.941	47.891	47.891	(IEA, 2021)
OilCrops	EUR/GJ	4.941	5.118	5.294	5.471	5.706	(Ruiz et al., 2019)
Fuelwood	EUR/GJ	5.059	4.824	4.588	4.176	3.824	(Ruiz et al., 2019)
Secondary Forestry residues - woodchips	EUR/GJ	2.882	2.765	2.647	2.412	2.176	(Ruiz et al., 2019)
Sawdust	EUR/GJ	8.412	8.000	7.588	6.²824	6.118	(Ruiz et al., 2019)
Bioethanol cereals and rye	EUR/GJ	4.412	4.235	4.059	3.824	3.647	(Ruiz et al., 2019)
Sugar from sugar beet	EUR/GJ	4.941	5.118	5.294	5.471	5.706	(Ruiz et al., 2019)
Willow, Poplar	EUR/GJ	4.353	4.118	3.882	3.412	3.176	(Ruiz et al., 2019)

**Sensitivities are performed on natural gas price*

Table C.9 - General assumptions used in the modelling

Parameters	Value
Weighted Average Cost of Capital (WACC)	4.40%
Discount rate	0.55%

Table C.10 - Fixed Operation and Maintenance costs, annually in EUR/kW

Energy	Type	Value	References
Biomass	-	39	Steam turbine biomass solid conventional (Commission et al., 2021)
Natural gas	CCGT	20	Gas turbine combined cycle gas advanced (Commission et al., 2021)
Natural gas	OCGT	12	Gas turbine with heat recovery (Commission et al., 2021)
Nuclear	-	108	Nuclear III gen. (incl. economies of scale) (Commission et al., 2021)
Offshore	-	33	Average of Wind Offshore (Commission et al., 2021)
Onshore	-	16	Average of Wind Onshore (Commission et al., 2021)
PV	-	10	Average of Solar PV (Commission et al., 2021)
Natural gas	CCUS	35	Gas combined cycle CCS post-combustion (Commission et al., 2021)
Battery	-	15	Large-scale batteries (per 1 MWh electricity), 4h storage (Commission et al., 2021)
Hydrogen	-	20	(RTE, 2021)

Table C.11 - Electrical Efficiency (net) in optimal load operation in percentage

Energy	Type	Value	References
Biomass	-	36	(Commission et al., 2021; Lacal Arantegui, 2014)
Natural gas	CCGT	59	(Commission et al., 2021; Lacal Arantegui, 2014)
Natural gas	OCGT	42	(Commission et al., 2021; Lacal Arantegui, 2014)
Nuclear	-	40	(Commission et al., 2021; Lacal Arantegui, 2014)
Offshore	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
Onshore	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
PV	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
Natural gas	CCUS	51	(Commission et al., 2021; Lacal Arantegui, 2014)
Battery	-	100	(Commission et al., 2021; Lacal Arantegui, 2014)
Hydrogen	-	50	(Lacal Arantegui, 2014; RTE, 2021)

Table C.12 - Considered direct fuel emissions* in $tCO_{2(e)}$/MWhPE

Energy	Value	References
Hard coal	0.34	(Wilke, 2013)
Lignite	0.36	(Wilke, 2013)
Natural gas	0.20	(Wilke, 2013)

*Other energy sources are assumed to be zero if based on renewable or biogenic feedstock (Biomass, Wind, Solar).

Table C.13 - Considered process emissions of existing processes (direct emissions)

Product	**Process**	**CO_2 emissions ($tCO_{2(e)}/t$)**	**non-CO_2 emissions ($tCO_{2(e)}/t$)**	**References**
Ammonia	Haber-Bosch	1.25	0	(JRC, 2017)
BTX	BTX (Reformate)	0	0.09	(JRC, 2017)
BTX	BTX (Pyga/Coke-oven)	0	0.19	(JRC, 2017)
BTX	BTX (HDA)	0	0	(JRC, 2017)
HVCs	Steam Cracker (Naphtha)	0.863	0.168	(IPCC, 2006; JRC, 2017)
HVCs	Steam Cracker (LPG/ Naphtha)	0.9425	0.168	(IPCC, 2006; JRC, 2017)
HVCs	Steam Cracker (Naphtha)	1.005	0.084	(IPCC, 2006; JRC, 2017)
HVCs	Steam Cracker (LPG)	1.45	0.084	(IPCC, 2006; JRC, 2017)
ETO	ETO (Oxygen-based)	0.5	0.045	(JRC, 2017)
Hydrogen	Steam methane reforming	8.89	0.78	(JRC, 2017; Spath and Mann, 2000)
MEG	ETO hydration	0.065	0	(JRC, 2017)
Methanol	Methanol (NG)	0.314	0.125	(IPCC, 2006; JRC, 2017)
PET	PET	0.103	0	(Jones, 2010)
PE	PE (Polymerisation)	0.123	0	(Jones, 2010)
PP	PP	0.295	0	(Jones, 2010)
PS	PS	0.148	0	(Jones, 2010)
Propylene	Propylene (Propane dehydrogenation)	0	0	(JRC, 2017)
Propylene	Propylene (Fluid catalytic cracker)	3.423	0	(JRC, 2017)
Propylene	Propylene (Metathesis)	0.009	0	(JRC, 2017)
PTA	PTA	0.676	0	(Akanuma et al., 2014)
PVC	S-PVC	0.062	0	(Jones, 2010)
PVC	E-PVC	0.062	0	(Jones, 2010)
Styrene	Styrene (SM/PO)	0.013	0	(Yong and Keys, 2021)

Table C.14 - Considered process emissions of alternative processes (direct emissions*)

Product	Process	CO_2 emissions ($tCO_{2(e)}/t$)	non-CO_2 emissions ($tCO_{2(e)}/t$)	References
Ethanol	Ethanol (Crops)	0.95	-	(Danish Energy Agency, 2017)
Chlorine	Chlorine (HCl)	-	-	
HVCs	Bioethanol dehydration	-	-	
HVCs	Methanol-to-Olefins	-	-	
Methanol	Methanol (Biomass)	-	-	
PS	PS (recycling by dissolution)	0.25	0	(CE Delft, 2019; Vollmer et al., 2020)
Pyrolysis oil	Plastic Waste pyrolysis	0.99	0	(Fivga and Dimitriou, 2018; Machado dos Santos, 2020)
RPET	Recycling to B-HET/PTA	0.22	0	(CE Delft, 2020; Vollmer et al., 2020)
Styrene	Styrene (PS recycling by pyrolysis)	0.4	0	(Bassil et al., 2018)

*Emissions from heat provisions are not included. Emissions from the incineration of impurities and unconverted materials in the recycling process are considered.

Table C.15 - Considered process emissions for heat and steam generation

Product	Process	CO_2 emissions ($tCO_{2(e)}/GJ$)	non-CO_2 emissions ($tCO_{2(e)}/t$)	References
Heat	Natural gas boiler	0.05	0	(EPA, 2021)
Heat	Oil boiler	0.07	0	(EPA, 2021)
Heat	Electric boiler	-	-	-
Heat	Hydrogen boiler	-	-	-
Heat	Biomass boiler	0.11	0	(EPA, 2021)

Figure C.1 - Simplified Sankey diagram of the PE supply chain (2018)

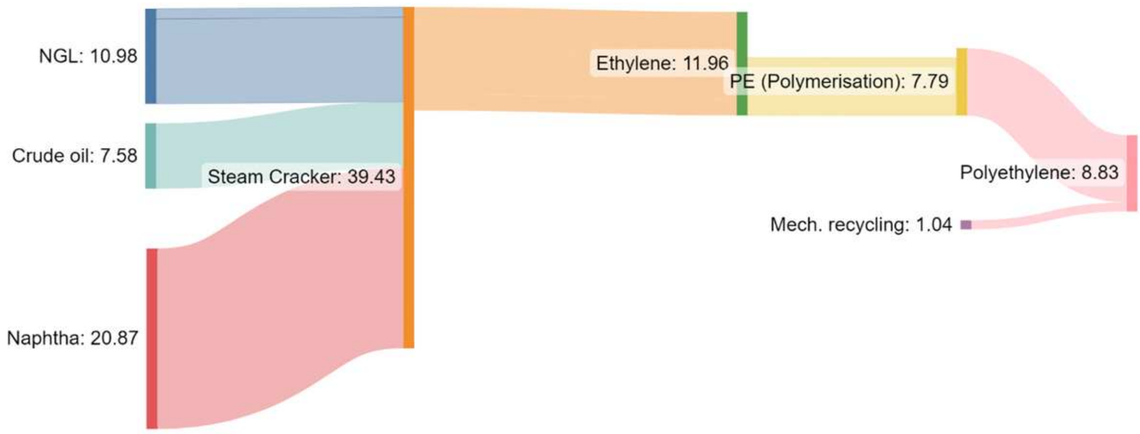


Figure C.2 - Simplified Sankey diagram of the PP supply chain (2018)

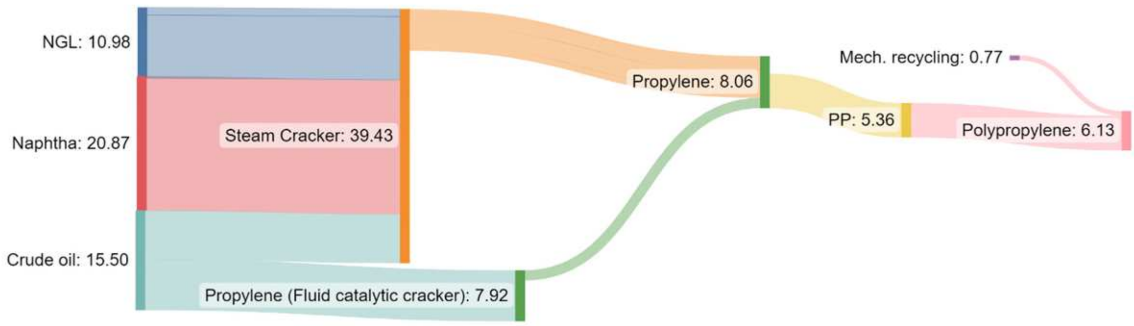


Figure C.3 - Simplified Sankey diagram of the PS supply chain (2018)

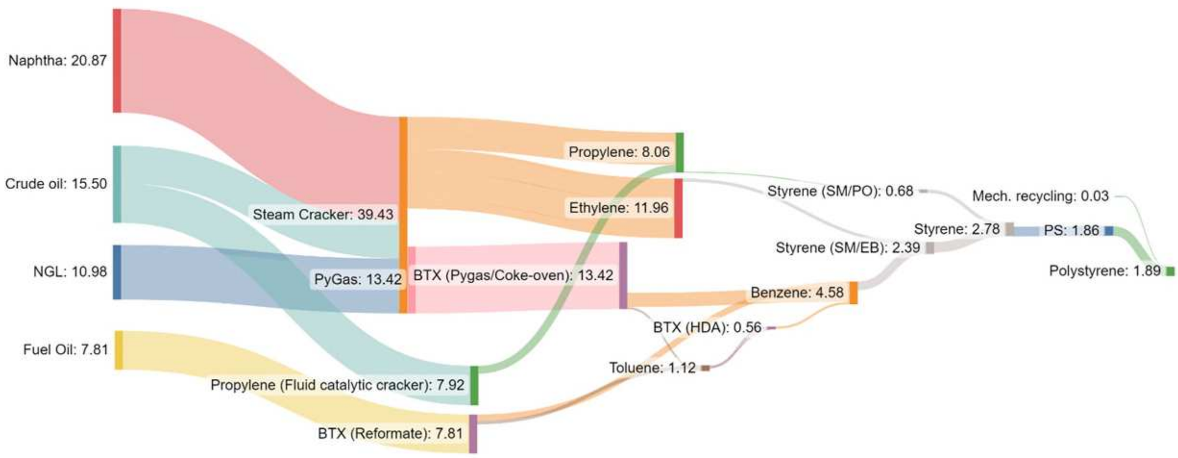


Figure C.4 - Simplified Sankey diagram of the PET supply chain (2018)

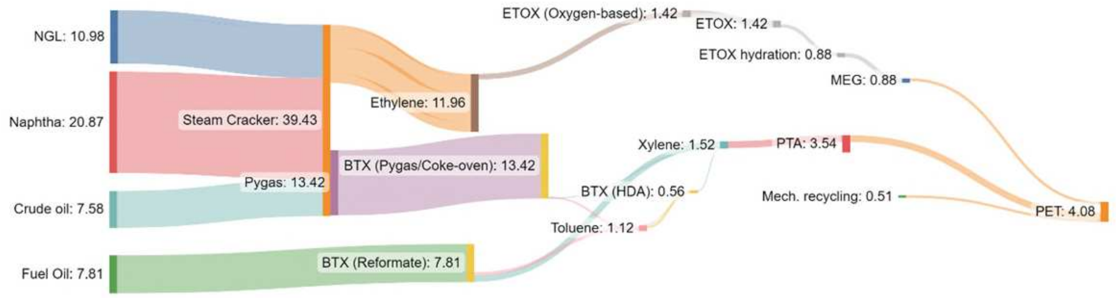


Figure C.5 - Simplified Sankey diagram of the PVC supply chain (2018)

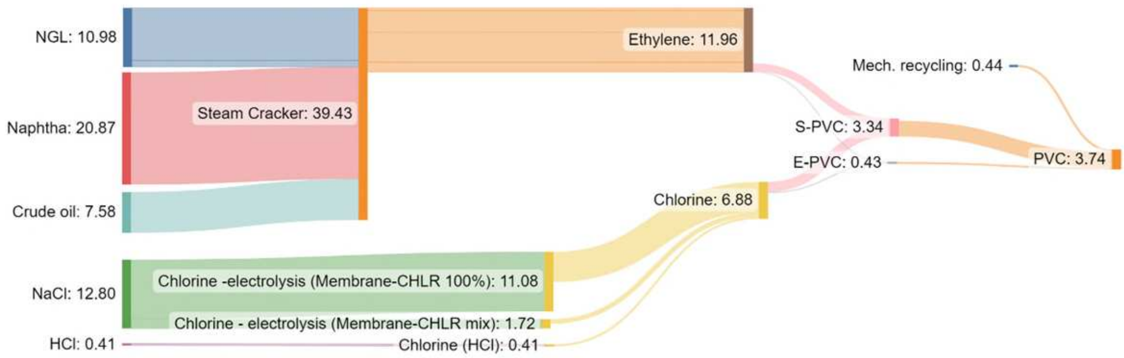
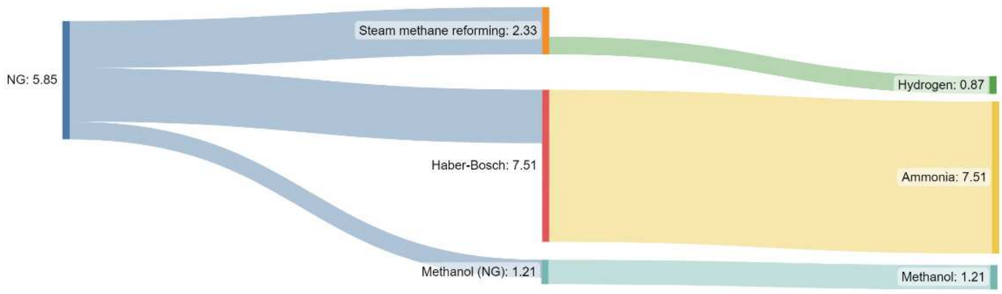


Figure C.6 - Simplified Sankey diagram of the Methanol, Ammonia and Hydrogen supply chain (2018)



C2. Updated formulation of DEEM

a. Sets

Element	Description	Set	Example
	General		
y	Year	$\in$ Y	*2018, 2025…2050*
z, z'	Country or zone considered	$\in \zeta$	*CWE; FR, DE…*
h	Hour of the year	$\in \Theta$	*1, 2, 3,…, 8760*
d	Day of the year	$\in \Lambda$	*1, 2, …, 365*
w	Week	$\in W$	*1, 2, 3, …, 53*
wh	Hour of the week	$\in WH$	*1, 2, …, 168*
	Power		
e	Energy sources	$\in$ E	*Natural gas, Hard coal, Lignite, …*
t	Technology	$\in$ TECH	*CCGT, OCGT, …*
v	Vintage class, based on the year of installation	$\in$ V	*V1, V2, V3, …*
k, k'	Technology considered. A triplet of fuel used, turbine installed, and vintage class	$\in$ K	*(Natural gas, CCGT, V4)...*
$vres, vres'$	Renewable energy sources	$\in$ vRES $\subseteq$ E	*Wind onshore, Solar PV, …*
$therm$	Thermal power plants	$\in$ THERM $\subseteq$ E	*Nuclear, Natural gas, …,*
s	Storage technologies	$\in$ ST $\subseteq$ E	*Battery, PS, Dam…*
b	Battery-type storage	$\in$ B $\subseteq$ B	*Battery, PS, …*
dm	Dam-type storage	$\in$ DM $\subseteq$ B	*Dam, Mixed-Pumped storage*
ror	Run-of-river power plant	$\in$ ROR $\subseteq$ E	*Run-of-river*
	Industry		
i	Set of all technologies considered	$\in \Omega$	*Steam Cracker, Natural gas boiler, …*
p	Set of chemical processes	$\in \Pi \subseteq \Omega$	*Steam Cracker, Haber-Bosch,…*
hh	Set of heating technologies	$\in$ H $\subseteq \Omega$	*Natural gas boiler, ...*
c	Set of industrial products	$\in \Gamma$	*Ammonia, Ethylene*
k	Set of carbon capture technologies	$\in$ K $\subseteq \Omega$	*High purity, Low purity*
fd	Set of feedstock processes	$\in$ F $\subseteq \Omega$	*Biomethane, Bio-naphtha*

b. Parameters

Parameter	Description	Unit
	General	
$WACC$	Weighted Average Cost of Capital	[%]
r	Discount rate	[%]
	Power	
$\mathrm{n}_{k,z}^{0}$	Initial installed capacity of a given technology in a given zone	[MW]
$d_{y,\,h,\,z}$	Hourly electricity demand	[MWh]
$c_{y,\,k,z}^{v}$	Short-run marginal cost of a unit, composed of fuel price and variable O&M	[EUR/MWh]
ef_{k}	Emission factor of a given technology	[$tCO_{2(e)}$/MWh]
$c_{y,z}^{CO2}$	Market price of the carbon emission allowances	[EUR/$tCO_{2(e)}$]
$c_{k,z}^{ie}$	Yearly capital expenditures of a given technology	[EUR/MW]
c_{z}^{ll}	Value of Lost Load, associated with the market price cap in the electricity market	[EUR/MWh]
c_{z}^{i}	Cost of importing power from neighbouring countries	[EUR/MWh]
$e_{y,\,h,\,z,\,z'}^{0}$	Historical power exports between two zones	[MWh]
$i_{y,\,h,\,z,\,z'}^{0}$	Historical power imports between two zones	[MWh]
$\gamma_{y,k,z}$	Yearly installation rate for a given technology	[MW]
$\alpha_{y,k,z}$	Market share of a given vRES technology	[%]
$sm_{y,z}$	Security margin	[MW]
$cc_{k,z}$	Capacity credit	[%]
$avail_{y,h,k,z}$	Hourly availability factor for a given technology	[%]
$must_{y,h,k,z}$	Must-run factor for a given technology	[%]
$\delta_{y,k,z}$	Planned phase-out for a given technology	[MW]
$NTC_{y,d,z,z'}$	Net Transmission Capacity between zones	[MW]
$inflow_{y,h,d,z}$	Hourly water inflows	[MWh]
SoC^{h}	Hourly storage level of storage	[MWh]
$link_{w,h}$	Link between week and hour	[-]
$\eta_{b}^{\frac{in}{out}}$	Storage efficiency factor (charging/discharging)	[%]
dd_{s}	Energy storage capacity	[MWh]
$cf_{y,h,k,z}$	Hourly availability factor	[%]
	Industry	
$\mathrm{n}_{i,z}^{c,0}$	Initial capacity of a given technology or process	[Mt]
lft_{i}	Economic lifetime of a technology or process	[year]
$\omega_{y,z}^{c,\frac{in}{out}}$	Yearly imports/exports of a given product	[Mt]
$v_{y,z}^{c,mech}$	Volume of mechanically recycled product	[Mt]
$c_{y,\,i,}^{ie}$	Yearly capital expenditures of a given technology or process	[EUR/Mt]
$c_{y,\,i}^{v}$	Yearly operational expenditure of a given technology or process	[EUR/Mt]
$c_{z,z'}^{i}$	Cost of importing power from neighbouring countries	[EUR/Mt]

$c^{feed}_{y,fd,z}$	Feedstock price	[EUR/Mt]
$ef_{y,i}$	Emissions factor of a given process	[$tCO_{2(e)}$/Mt]
$d^{c}_{i,z}$	Yearly domestic demand for a given chemical product	[Mt]
$h_{y,i}$	Low heat consumption of a given process	[PJ/Mt]
$uf_{y,i}$	Yearly utilisation factor of a given process	[%]
$\gamma^{c}_{y,i}$	Yearly installation rate for a given process	[%]
$\delta^{c}_{y,i}$	Yearly phase-out rate for a given process	[Mt]
$q^{fossil,max}_{y,i,z}$	Resource availability (bio-feedstock)	[Mt]
$q^{bio,max}_{y,i,z}$	Resource availability (fossil feedstock)	[Mt]
$e_{y,i}$	Electricity consumption per production unit of a given chemical process	[MWh/Mt]
$p_{h,i}$	Industrial hourly power demand profile	[%]
$\psi^{\frac{in}{out}}_{y,i}$	Material flow in/out of a given process	[Mt]
$S_{bio-fossil}$	Linkage between fossil feedstock and their bio-based substitute	[-]
$abtmt_{y,i}$	Carbon capture rate	[%]
$dist^{in}_{CO_2}$	Inland CO_2 transportation distance	[km]
$dist^{off}_{CO_2}$	Offshore CO_2 transportation distance	[km]
$cost^{in}_{CO_2}$	Cost of inland CO_2 transportation	[EUR/ $tCO_{2(e)}$/km]
$cost^{off}_{CO_2}$	Cost of offshore CO_2 transportation	[EUR/ $tCO_{2(e)}$/km]
$cost^{st}_{CO_2}$	Cost of offshore CO_2 storage	[EUR/ $tCO_{2(e)}$]
$cap^{off}_{CO_2,y}$	Yearly injection capacity of offshore CO_2	[$tCO_{2(e)}$]

c. Variable

Variable	Description	Unit
	Power	
NPC_{Power}	Net present cost (power sector)	[EUR]
$N_{y,k,z}$	Yearly installed capacity of a given technology in a given zone;	[MW]
$N^{closed}_{y,k,z}$	Closure of capacity for a given year and technology;	[MW]
$G_{y,h,k,z}$	Hourly production of a given technology cluster of a zone;	[MWh]
$LL_{y,h,z}$	Lost load, energy not served in a zone;	[MWh]
$E_{y,h,z,z'}$	Power exports of a given zone	[MWh]
$I_{y,h,z,z'}$	Power imports of a given zone	[MWh]
$S_{y,h,s,z}$	Hourly storage level of storage	[MWh]
$C_{y,h,s,z}$	Hourly charging of storage technologies	[MWh]
	Industry	
NPC_{Chem}	Net present cost (chemical sector)	[EUR]
$CC^{cost}_{y,i,z}$	Carbon capture costs	[EUR]
$N^{c}_{y,i,z}$	Yearly capacity of a given technology or process	[Mt]
$N^{c,new}_{y,i,z}$	Invested capacity for a given year and technology	[Mt]
$N^{c,closed}_{y,i,z}$	Phased-out capacity for a given year and technology	[Mt]

$D_{chem\ y,\,h,z}$	Hourly power demand of the chemical sector	[MWh]
$P^{c}_{y,i,z}$	Yearly production of a given technology for a given product	[Mt]
$P^{h}_{y,hh,i\,,z}$	Yearly heat generation for a given technology	[PJ]
$CCS^{c}_{y,i,z}$	Yearly carbon capture and storage of a given technology for a given product	[Mt]
$CCU^{c}_{y,i,z}$	Yearly carbon capture and usage of a given technology for a given product	[Mt]
$Q^{bio}_{y,i,z}$	Feedstock flow for a given process, bio-based	[Mt]
$Q^{fossil}_{y,i,z}$	Feedstock flow for a given process, fossil-based	[Mt]

d. Complete formulation

Power model

$$NPC_{Power} = \sum_{y}(1+r)^{-(y-Y_0)} * \Big(\sum_{h,k,z} G_{y,h,k,z} * \left(c^{v}_{y,k,z} + ef_{k} * c^{CO2}_{y,z}\right) + \sum_{k,z} N_{y,k,z} * c^{ie}_{k} + \sum_{y,h,z,z'} I_{y,h,z,z'} * c^{i}_{z,z'} + \sum_{y,h,z} LL_{y,h,z} * c^{ll} \qquad \text{(Eq. C. 34)}$$

$$\sum_{k\in K} G_{y,h,k,z} + \sum_{z'\in\zeta,\ z'\neq z} I_{y,h,z,z'} = d_{y,h,z} + D_{chem\ y,h,z} + \sum_{z'\in\zeta,\ z'\neq z} E_{y,h,z,z'} + \sum_{s} C_{y,hs,z} \qquad \forall y,h,z \qquad \text{(Eq. C. 35)}$$

$$N_{0,k,z} = \mathrm{n}^{0}_{y,k,z} \qquad \forall k,z \qquad \text{(Eq. C. 36)}$$

$$N_{y,k,z} = N_{y-1,k,z} + N^{new}_{y,k,z} - N^{closed}_{y,k,z} \qquad \forall y,k \qquad \text{(Eq. C. 37)}$$

$$N^{new}_{y,k,z} \leq \gamma_{y,k,z} \qquad \forall y,k \qquad \text{(Eq. C. 38)}$$

$$N^{closed}_{y,k,z} \geq \delta_{y,k,z} \qquad \forall y,k \qquad \text{(Eq. C. 39)}$$

$$N^{\mathrm{new}}_{y,vres,z} \geq \alpha_{y,k} \times \sum_{vres'} N^{\mathrm{new}}_{y,k,z} \qquad \forall y,h,k \qquad \text{(Eq. C. 40)}$$

$$G_{y,h,k,z} \leq avail_{y,h,k,z} * N_{y,k,z} \qquad \forall y,h,k,z \qquad \text{(Eq. C. 41)}$$

$$G_{y,h,k,z} \geq must_{y,h,k,z} * avail_{y,h,k,z} * N_{y,k,z} \qquad \forall y,h,k,z \qquad \text{(Eq. C. 42)}$$

$\sum_k N_{y,k,z} * cc_{k,z} \geq sm_{y,z}$	$\forall y$	(Eq. C. 43)
$I_{y,\ h,z,\ z'} \leq i^0_{y,h,z,\ z'}$	$\forall y, h, z, z'$	(Eq. C. 44)
$E_{y,h,z,\ z'} = e^0_{y,h,z,\ z'}$	$\forall y, h, z, z'$	(Eq. C. 45)
$I_{y,\ h,z,\ z'} = E_{y,h,z',\ z}$	$\forall y, h, z, z'$	(Eq. C. 46)
$G_{y,h,ror,z} \leq \frac{ror_{y,d,ror,z}}{24}$	$\forall y, h, z$	(Eq. C. 47)
$C_{y,h,s,z} \leq \alpha_s \times N_{y,s,z}$	$\forall y, h, s, z$	(Eq. C. 48)
$S_{y,h,s,z} \leq N_{y,s,z} * dd_s$	$\forall y, h, s, z$	(Eq. C. 49)
$G_{y,h,s,z} \leq S_{y,h,s,z}$	$\forall y, h, s, z$	(Eq. C. 50)
$S_{y,0,s,z} = SoC^0 * N_{y,s,z}$	$\forall y, s, z$	(Eq. C. 51)
$S_{y,8760,s,z} = SoC^{8760} * N_{y,s,z}$	$\forall y, s, z$	(Eq. C. 52)
$S_{y,h,dm,z} = S_{y,h-1,dm,z} + inflow_{y,h-1,dm,z} - G_{y,h-1,dm,z}$	$\forall y, h, d, z$	(Eq. C. 53)
$\sum_{h\mid link_{w,h}} G_{y,h,dm,z} \leq \sum_{h\mid link_{w,h}} inflow_{y,h,dm,z}$	$\forall y, w, dm, z$	(Eq. C. 54)
$S_{y,h,b,z} = S_{y,h-1,b,z} + C_{y,h-1,b,z} * \eta^{in}_k - \frac{G_{y,h-1,b,z}}{\eta^{out}_b}$	$\forall y, h, b, z$	(Eq. C. 55)

Industrial model constraints

The Net Present Cost (NPC) is the present value of the sum of all costs incurred until 2050. These expenses encompass capital and operational expenditures as well as mitigation infrastructure costs. Note that the carbon price is applied only to processes that are not using bio-based feedstock.

$$NPC_{Chem} = \sum_{y,z} (1+r)^{-(y-Y_0)} * \sum_i \left(c^{ie}_{y,\ i} * N^c_{y,i,z} + \left(c^v_{y,i} + ef^{fossil}_{y,i} * c^{CO2}_{y,z} \right) * P^c_{y,i,z} + CC^{cost}_{y,i,z} \right) \quad \text{(Eq. C. 56)}$$

The mitigation infrastructure costs are defined in (Eq. C. 57), considering the average distance between facilities in the case of CCU, and between facilities and carbon sinks in the case of CCS. In addition, emissions captured are not subject to the carbon price.

$$CC_{y,i,z}^{cost} = CCS_{y,i,z}^{c} * \left(cost_{CO_2}^{in} * dist_{CO_2}^{in} + cost_{CO_2}^{off} * dist_{CO_2}^{off} + cost_{CO_2}^{st} - c_{y,z}^{CO2}\right) + CCU_{y,i,z}^{c} * (cost_{CO_2}^{in} * dist_{CO_2}^{in} - c_{y,z}^{CO2}) \qquad \forall y,\ i,\ z \qquad \text{(Eq. C. 57)}$$

The supply-demand (Eq. C. 58) implies that the overall production level should match the net demand for each year and each product, considering the among of mechanically recycled product $v_{y,z}^{c,mech}$, the trade balance $\omega_{y,z}^{c,in/out}$ and the yields of each process $\psi_{y,i}^{c,out}$

$$\sum_{z,p} P_{y,p,z}^{c} + \omega_{y,z}^{c,in} + v_{y,z}^{c,mech} + \sum_{i\epsilon\{\Pi\cup F\}} P_{y,i,z}^{c} * \psi_{y,i}^{c,out} = d_{y,z}^{c} + \omega_{y,z}^{c,out} + \sum_{p} P_{y,p,z}^{c} * \psi_{y,p}^{c,in} \qquad \forall y,\ c \qquad \text{(Eq. C. 58)}$$

The installed capacities are determined each year, calculated based on initial capacities and subsequent expansion and closure of capacities.

$$N_{y,i,z}^{c} = \mathrm{n}_{i,z}^{c,0} + \sum_{\mathrm{y}' \leq \mathrm{y}} N_{y',i,z}^{c,new} - \sum_{\mathrm{y}' \leq \mathrm{y}} N_{y',i,z}^{c,closed} \qquad \forall y,\ i,\ z \qquad \text{(Eq. C. 59)}$$

In order to mitigate stranded assets within the model, a constraint was implemented to prohibit the premature decommissioning of newly constructed capacities before reaching the end of their technical lifespan.

$$\sum_{\mathrm{y}' \leq \mathrm{y}} N_{y',i,z}^{c,closed} \geq \sum_{\mathrm{y}'} N_{y',i,z}^{c,new} \left[\sum_{yy|\ yy \geq y' \,\&\, yy \leq y} 1 \leq lft_{i}\right] \qquad \forall y,\ i,\ z \qquad \text{(Eq. C. 60)}$$

Regarding the rate at which technologies are implemented, the model incorporates limitations on the deployment rate of processes. Following the initial year of availability, the expansion of new low-carbon technology capacities is restricted to a maximum increase of $\gamma_{y,i}^{c}$ compared to the capacity of the previous year.

$$N_{y,i,z}^{c,new} \leq \gamma_{y,i}^{c} \times N_{y-1,i,z}^{c} \qquad \forall y,\ i,\ z \qquad \text{(Eq. C. 61)}$$

The model considers additional restrictions on the rate at which conventional technologies can be replaced, encompassing all production capacities as of 2019.

$N^{c,closed}_{y,i,z} \leq \delta^{c}_{y,i} * \mathrm{n}^{c,0}_{i,z}$ $\forall y,\ i,\ z$ (Eq. C. 62)

The model enables the operation of technologies within a predefined range, considering the utilisation factor $uf_{y,i}$.

$P^{c}_{y,i,z} \leq uf_{y,i} * N^{c}_{y,\,i,z}$ $\forall y,\ i,\ z$ (Eq. C. 63)

$P^{c}_{y,i,z} \geq 0.9 * uf_{y,i} * N^{c}_{y,\,i,z}$ $\forall y,\ i,\ z$ (Eq. C. 64)

A constraint is established to ensure the supply and demand equilibrium of heat, depending on the heat requirements $h_{y,i,z}$ of each process.

$\sum_{hh} P^{h}_{y,hh,i,z} = P^{c}_{y,i,z} * h_{y,i,z}$ $\forall y,\ i,\ z$ (Eq. C. 65)

For all feedstocks not endogenously produced, the model supplies the volumes of feedstock based on exogenous assumptions of prices and quantities available. A distinction is made between bio-based feedstock and non-biobased feedstock.

$Q^{bio}_{y,i,z} = P^{c}_{y,i,z} * \psi^{bio,in}_{y,i,z} - \sum_{k\epsilon\{Z\}} P^{fd}_{y,k,z} * \psi^{bio,out}_{y,k}$ $\forall y,\ i\ ,z$ (Eq. C. 66)

$Q^{fossil}_{y,i,z} = P^{c}_{y,i,z} * \psi^{fossil,in}_{y,i} - \sum_{bio\epsilon\{S_{bio-fossil}\}} Q^{bio}_{y,i,z} - \sum_{k\epsilon Z,bio\epsilon\{S_{bio-fossil}\}} P^{fd}_{y,k,z} * \psi^{bio,out}_{y,k}$ $\forall y,\ i,\ z$ (Eq. C. 67)

The considered feedstock's availabilities limit their usage by the model. No constraints have been considered for fossil fuels and fossil feedstock.

$Q^{bio}_{y,i,z} \leq q^{bio,max}_{y,i,z}$ $\forall y,\ i,\ z$ (Eq. C. 68)

$Q^{fossil}_{y,i,z} \leq q^{fossil,max}_{y,i,z}$ $\forall y,\ i,\ z$ (Eq. C. 69)

The volumes available for carbon capture are limited by the total emission of processes and capture rate considered.

$CCS^{c}_{y,i,z} + CCU^{c}_{y,i,z} \leq P^{c}_{y,i,z} * ef_{y,\,i} * abtmt_{y,i}$ $\forall y,\ i,\ z$ (Eq. C. 70)

The overall volumes of carbon stored are capped by a yearly injection rate, based on (Seck et al., 2022)

$$CCS^{c}_{y,i,z} \leq cap^{off}_{CO_2,y} \qquad \forall y, i, z \qquad \text{(Eq. C. 71)}$$

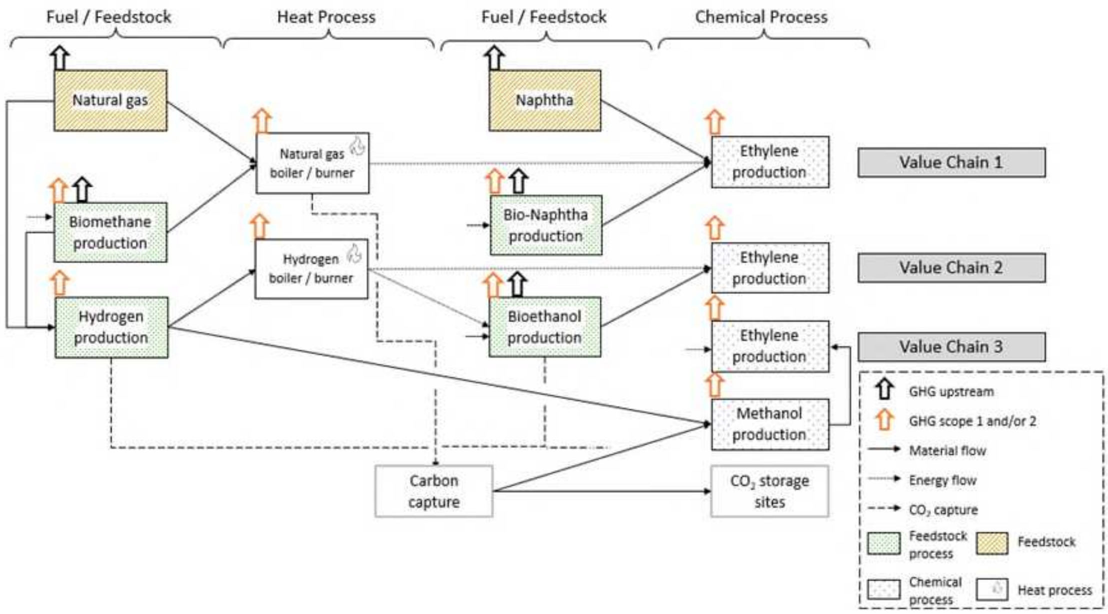
The annual value of electricity consumption resulting from the chemical models is spread to hourly electricity consumption using an hourly load profile representative of the industrial load profile.

$$D_{chem\ y,h,z} = \sum_i P_{y,i,z} * e_{y,i} * p_{h,i} \qquad \forall y, h, i, z \qquad \text{(Eq. C. 72)}$$

It should be noted that in the case of cost equivalent decisions, meaning a case in which a different decision impacts the objective function similarly, a merit order has been considered inside the chemical processes. For example, if two processes can substitute their natural gas consumption with hydrogen without impacting the net present cost, a priority criterion has been implemented based on their relative energy consumption. The model starts with the most significant energy consumer in such a case.

e. Illustration of the model logic

Figure C.7 - Illustrative representation of production routes for ethylene



In value chain 1, ethylene is produced with naphtha that could be purchased from the market or produced inside the model (bio-naphtha, using woody biomass). This process is linked to a heat generation technology using natural gas that could come from the gas grid or be substituted with biomethane produced endogenously. Finally, the model can add carbon capture technologies at different points in the value chain, for example, on the natural gas boiler. In value chain 2, ethylene is produced using bioethanol produced inside the model. The model chooses hydrogen burners to heat bioethanol and ethylene production in this route. Hydrogen for heating is produced on-site, but several options are available for the model. Hydrogen from SMR with carbon capture is used in the illustration, but alternative technologies, such as methane pyrolysis and electrolysers, are included in the model. Finally, in the last value chain, ethylene is produced from methanol, which is both a final product and can be used as an intermediate product within the model (*Methanol-to-Olefins*). In this example, methanol is produced with hydrogen and CO_2 through CO_2 hydrogenation. Hydrogen as a feedstock is produced inside the model, and the CO_2 feedstock could be captured from other processes within the chemical industry or other industries.

C3. Supplementary Results

Figure C.8 - Low-heat provision per scenario in 2030 and 2050, compared to the 2018 reference - SC case

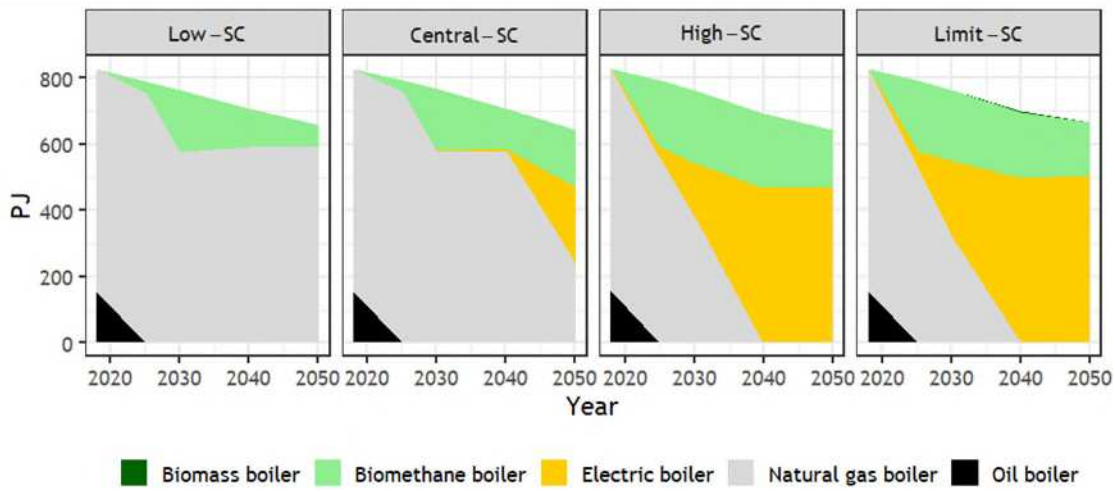


Figure C.9 - Illustration of power generation results for scenario Low in 2050 - SC

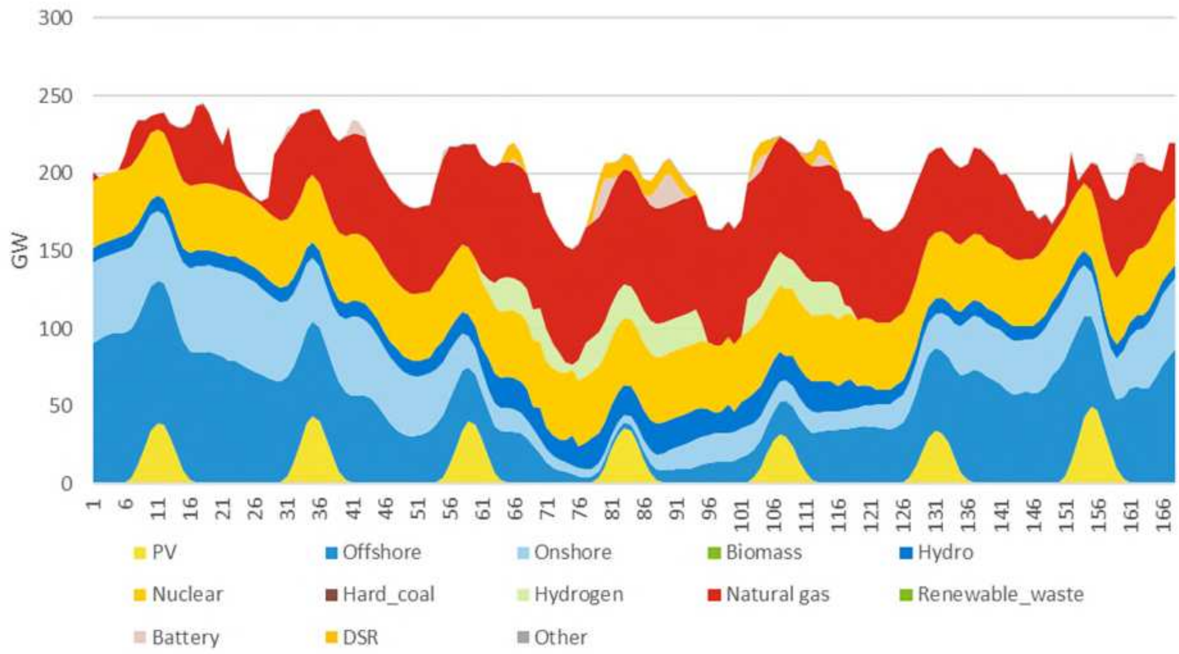


Figure C.10 - Illustration of power generation results for scenario Limit in 2050 – SC (CCS)

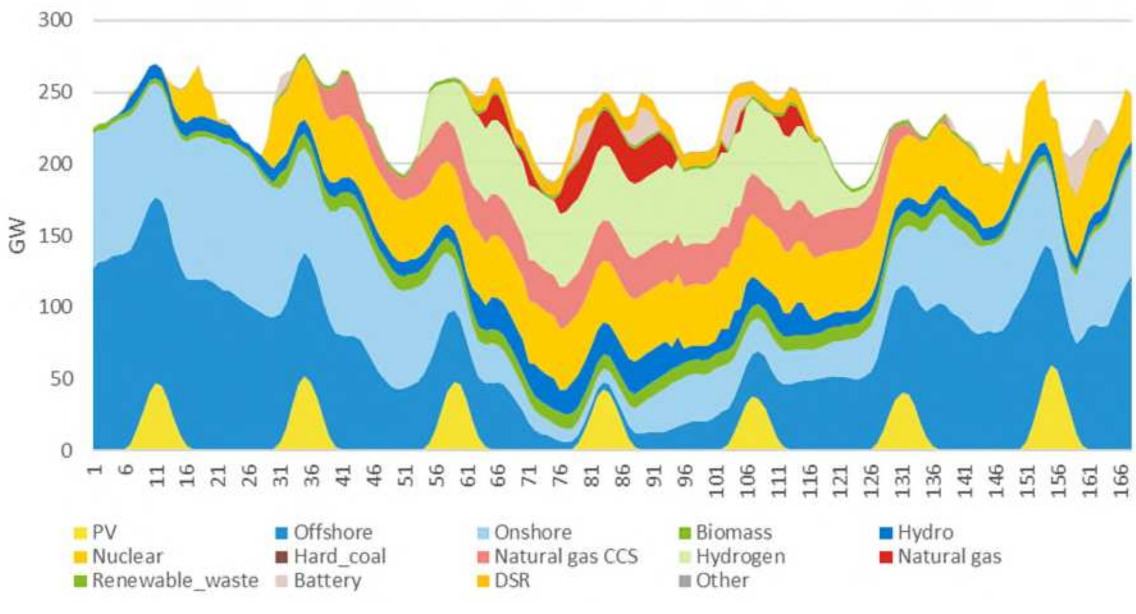


Figure C.11 - Curtailment of renewable energy sources in each scenario

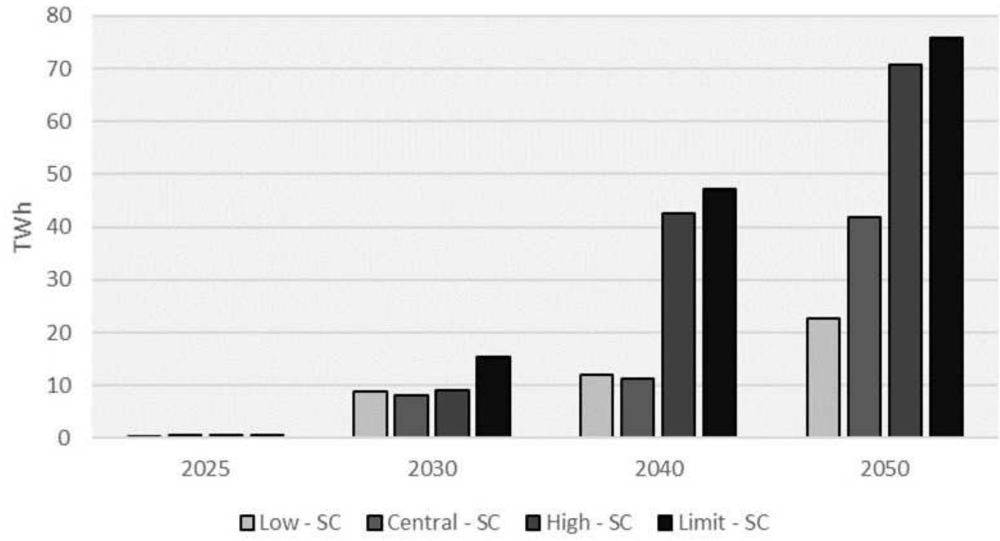


Figure C.12 - Differences in the chemical sector cumulated non-biogenic emissions between "SC" and "IT-1"

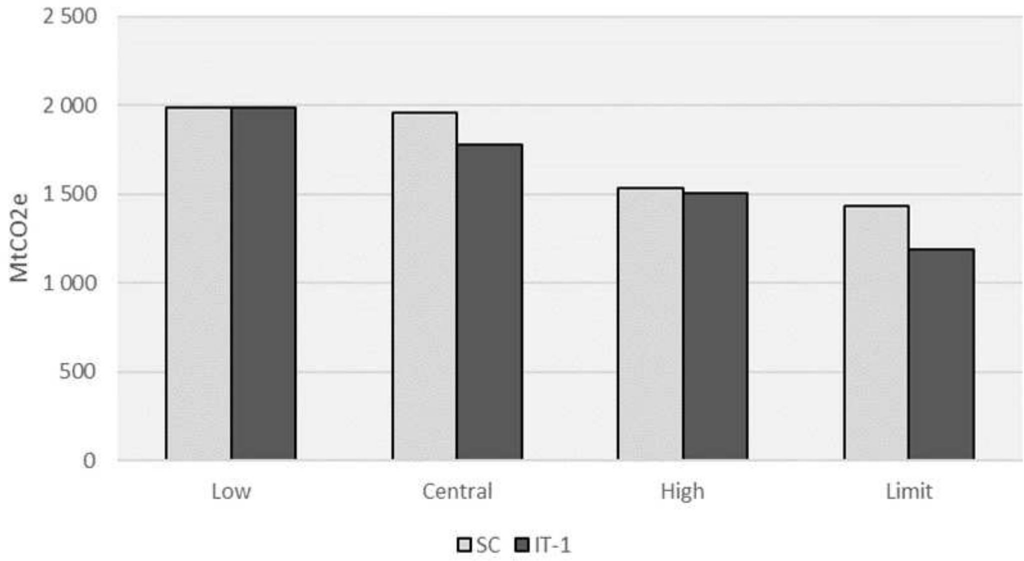


Figure C.13 - Carbon capture installed capacity per process in 2050

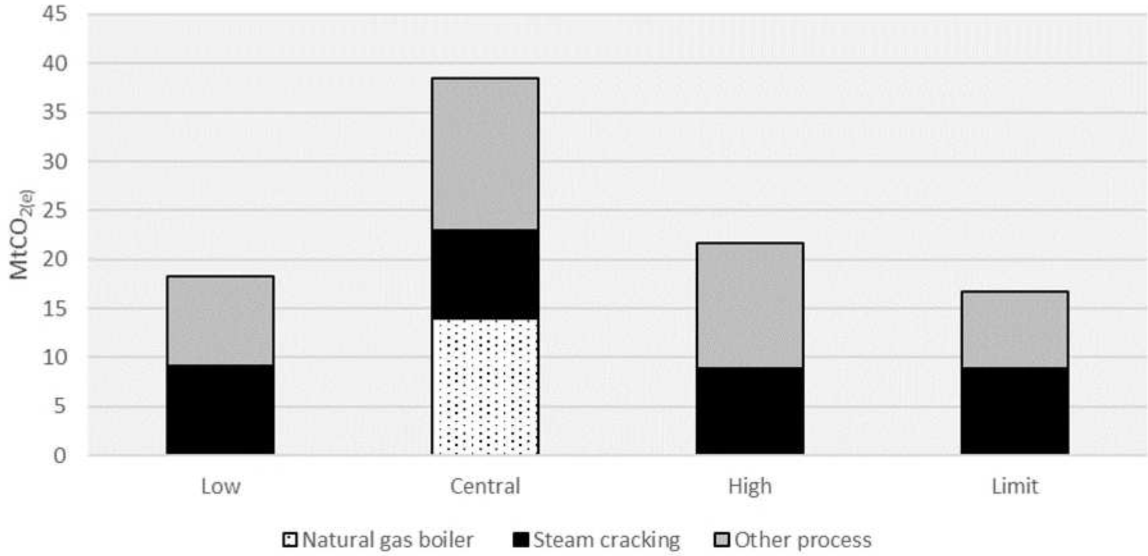


Figure C.14 - Differences between SC and CCS sensitivity in power production by energy sources in 2050

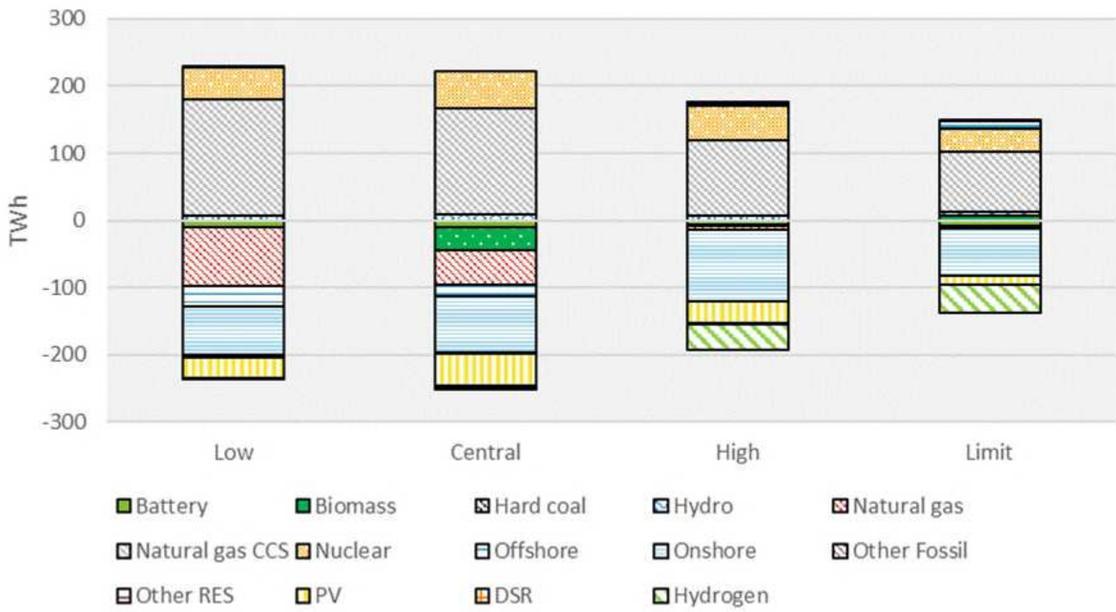


Table C.16 - Key metrics differences between SC and IT cases for the chemical sector

Chemical sector		Low	Central	High	Limit
Cumulated electricity consumption (TWh)	SC	3 852	3 966	5 900	6 201
	IT-1	3 866	5 004	6 188	7 744
	%diff	*0.4%*	*26%*	*4.9%*	*25%*
Cumulated emissions ($MtCO_{2(e)}$)	SC	1 989	1 962	1 535	1 433
	IT-1	1 990	1 782	1 507	1 189
	%diff	*0.0%*	*-9.2%*	*-1.8%*	*-17%*
NPC (BEUR)	SC	1 619	1 716	1 917	2 431
	IT-1	1 619	1 707	1 916	2 416
	%diff	*0.0%*	*-0.5%*	*-0.1%*	*-0.6%*

Table C.17 - Key metrics differences between SC and IT case for the power sector

Power sector		Low	Central	High	Limit
Cumulated electricity production (TWh)	SC	46 154	46 407	48 391	48 694
	IT-2	46 170	47 444	48 682	50 190
	%diff	*0.0%*	*2.2%*	*0.6%*	*3.1%*
Cumulated emissions ($MtCO_{2(e)}$)	SC	3 033	2 744	2 395	2 006
	IT-2	3 035	2 747	2 419	2 177
	%diff	*0.1%*	*0.1%*	*1.0%*	*8.5%*
NPC (BEUR)	SC	2 172	2 253	2 539	2 741
	IT-2	2 173	2 326	2 562	2 936
	%diff	*0.0%*	*3%*	*1%*	*7%*

Table C.18 - Key metrics differences between SC and IT cases for both sector

	Low	Central	High	Limit
ΔCumulated electricity production (TWh)	16	1 037	290	1 496
%diff to SC	*0.0%*	*2.2%*	*0.6%*	*3.1%*
ΔCumulated emissions ($MtCO_{2(e)}$)	2.3	-176.9	-4.5	-73.7
%diff to SC	*0.0%*	*-3.8%*	*-0.1%*	*-2.1%*
ΔNPC_{tot} (BEUR)	0.92	65.6	22.7	301.6
%diff to SC	*0.0%*	*2.9%*	*0.9%*	*11.0%*
Net present cost of abatement (EUR/ $tCO_{2(e)}$)	-	426	5 960	4 692

General Conclusion

The combined decarbonisation and liberalisation pursued in the European electricity markets entail significant adjustments to the existing market design to ensure lasting energy security, sustainability and affordability. Embarking power consumers in the ongoing transformation has been regularly presented as an option to be privileged. Multiple benefits are expected from the active participation of consumers, thanks to the mobilisation of private capital and the more efficient utilisation of resources it would enable. More generally, the overarching climate objectives entail a reconfiguration of industrial and residential operations and should not be envisaged from the sole perspective of the supply side. Each power crisis has underscored consumers' critical role in alleviating scarcity episodes. However, those benefits have been systematically hindered by the insufficient incentives and market signals provided to them. This dissertation has aimed to improve the current discussions on the role of consumers in decarbonised power systems. The dissertation is structured into three chapters that analyse key market design issues regarding demand-side incentives, aiming to (i) understand the extent to which existing electricity market designs have encouraged demand-side flexibility, (ii) analyse the adequate price signals to be conveyed towards consumers in decarbonising power systems and (iii) assess the welfare loss due to imperfect price information and pace asymmetry between supply and demand in a context of accelerated demand-side electrification. To answer those research questions, optimisation and simulation models have been developed to represent the short and long-term dynamics on the demand and supply side of power systems. The modelling has enabled to consider each segment of the power systems, from the short-term economic dispatch of wholesale participants and their reaction to price signals, to the long-term electrification trajectory of industrial end-uses subject to ambitious decarbonisation objectives.

In the first part of the thesis, a focus has been made on the existing demand-side market integration in liberalised electricity markets. The chapter sheds light on the demand-side flexibility potential in three different electricity markets: France, Germany and the PJM in the US. It is discussed how major discrepancies in the potential for DR stem from the numerous appliances able to provide operational flexibility and the difficulties in estimating hourly availability for each appliance. More importantly, the duration of the flexibility provision by the demand is a major element defining its technical potential, with significant differences between hour-long load-shedding potential and very short-term load-shifting. In addition, the analysis underlined that the ongoing energy transition would induce a major transformation of electrical appliances, as EVs, heat pumps, electrolysers and electrified heat supply in industries will become the major sources of flexibility from the demand side. Their deployment pace is subject to numerous financing and infrastructural factors, resulting in significant uncertainties concerning the estimation of peaking capacities required in the mid-term. However, the flexibility provided by those appliances is critical to ensure system adequacy in the context of thermal capacity phase-out and might either hamper the investment in peaking units or result in stranded assets. Understanding the challenges of new electricity uses, as well as their potential flexibility for supporting the power system, has become critical. In particular, this first part underlined the necessity to provide a stable market framework enabling the active participation of the demand side in electricity markets. Indeed, this chapter underscored that, while the number of existing programs has continuously increased in the past ten years, no stable and common market design has been established across geographies, despite the similarities of existing liberalised electricity markets. Two options have been primarily studied in the chapter, consisting of price-based and incentives-based programs. The chapter underlines that existing incentive-based programs have not provided the conditions for establishing the use of flexibility in energy-only wholesale markets. On the other hand, while price-based programs have been deployed in most geographies, they face low adoption rates. This first section also sheds light on the various objectives behind the different paradigms pursued with demand response. In addition, the coexistence of multiple programs has resulted in friction between market actors. Based on the analysis framework proposed, several spillovers have been identified concerning the temporal and geographical aspects. The numerous benefits of increased DR require more coordination across all market participants, especially if DR is expected to bid actively in wholesale electricity markets. Nevertheless, no fundamental changes in market design have been found in the literature regarding the integration of DR, leaving the possibility of prompt adoption in the coming years.

In the second part of this dissertation, more evidence is provided on the effectiveness of existing price-based programs in France, both historically and in future power system operations. To assess the role of DR and its economic value, a four-stage modelling methodology has been developed. The methodology allows the representation of each market actor, from power generation economic dispatch to the retailer's rate-setting and the consumer's power consumption, depending on the price signals provided by retailers. The results stemming from the historical analysis have shown that the existing tariffs have been providing effective incentives, encouraging consumption at times of low electricity prices. Interestingly, the tariffs with peak-pricing components, favoured in the economic literature, have performed poorly during the 2021-2023 global energy crisis. Indeed, those tariffs typically target a fixed number of days, where consumers are expected to lower their power consumption. However, in long-lasting episodes of soaring power prices, targeting only the peak power demand might be less effective than indifferently targeting the daily evening peak.

However, in the mid-term, when accounting for multiple weather years in 2025 and 2030, it is found that existing *ToU* tariffs are not future-proof and should be revised timely. Notwithstanding the better performance of the tariffs matching the solar PV production in coming decades, the increased volatility in price calls for fostering tariffs able to cope with the intrinsic variability of renewable energy sources. In particular, tariffs with peak-pricing components capture 25% to 50% of total welfare gains achievable, defined based on the theoretical optimum of real-time pricing. In addition, the results underlined that tariffs with peak-pricing components have the potential to lower power prices by around 10% in 2030 compared to the baseline scenario, depending on the price elasticity achievable and the tariff adoption rate. Eventually, the deadweight loss reaches between 0.5 and 1 bn EUR per year in 2030 for tariffs with peak pricing features, while it is between 1 and 1.2 bn EUR for more static tariff designs such as time-of-use tariffs. Looking at the stability of rates over time, no significant changes have been found in the yearly distribution of peak price episodes, as they remain mostly concentrated in winter periods. However, although the temporal stability is unaffected on a yearly and monthly scale, the absolute hourly rate levels are prone to change. More precisely, the findings underline significant changes in the off-peak-to-on-peak ratio, increasing from a 50% premium to more than 400% by 2030, which represents a significant price spread for consumers and could question its adoption in practice. Notably, private agents might be discouraged from adopting more dynamic tariffs if little possibilities are given to hedge or substitute their power consumption in periods of peak prices. In addition, the loss associated with wrong price incentives would be exacerbated with a higher price spread, requiring assessing not only the correlation of tariffs with day-ahead prices but also their impact on deadweight loss compared to real-time prices. Consequently, policymakers and retailers should carefully gauge the balance between cost-reflectiveness, adoption rate and incentives provided. Paradoxically, the 2021-2023 global energy crisis underlined both the unsustainability of high power price episodes for consumers and the relevance of DR to deflate prices during supply shortages.

The third and last section concentrates on the long-term aspects related to the electrification strategies of end-uses in the industrial sector, and their implications for the development of the power sector. The research focuses on the CWE chemical sector, for which the long-term power consumption is assessed for different carbon price trajectories and for different levels of coordination between the power and the chemicals sectors. Specifically, a distinction is made between a situation where the two sectors operate their energy transition with perfect coordination and foresight, and an iterative situation where the chemical sector actors foresee their investments based on anticipated power prices and carbon intensities of the electricity procured. The assessment is performed by linking an electricity market model with an investment model representing the chemical supply chain. First, the results highlight that the chemical sector had to contend with increasing electrification to reach lower levels of GHG emissions. Assuming a constant demand for chemical products, the power consumption increases by more than two in scenarios with the highest carbon price trajectories. Such electrification trajectories entail significant challenges for the power sector, which faces additional demand growth from other industries, as well as EVs or heat provision from other sectors of the economy. Second, the carbon price required to trigger emissions reduction increases to levels above 250 EUR/tCO_{2e} in 2050 in the scenarios studied. However, the modelling also underlined that the pace of the carbon price increase should relate to the feasible industrial rate of transformation transition. If the number of carbon allowances is reduced too fast or their demand increases too quickly, the increase in carbon prices would be faster than the feasible pace of decarbonisation, leading to a significant cost increase borne by final consumers or risks of lower industrial competitiveness. The typical lead times for investments in the power and chemical sectors have hovered around 5 to 15 years in the previous decades. While it is paramount to ensure the timely competitiveness of low-carbon options, it is essential to consider the cost burden alongside the transition, notably for industrial facilities in which investments require decade-long R&D and facility building. Finally, focusing on welfare losses, we find that the iterative approach results in a net loss reaching 20 bn EUR to more than 280 bn EUR from a social welfare perspective in scenarios where carbon pricing provides enough incentives to start electrification. Indeed, the anticipation of power price and associated carbon intensity of electricity falls short of coordinating investment decisions in the chemical sector. Market failures arise from the imperfect consideration of the dynamic constraints incurred in the power sector and the upstream externalities generated by performing sweeping electrification. Notwithstanding the benefit in overall GHG emission reductions, uncoordinated and accelerated electrification of the chemical industry leads to higher power prices and an abatement cost greater than the initial carbon trajectory assumed. Overall, the potential information and pace asymmetry between the different sectors might undermine the likelihood of having access to clean, abundant, and affordable electricity in the coming decades if relying solely on grid electricity. Therefore, this dissertation underlines the relevance of allowing for long-term electricity provisions for current and future power-intensive industries to achieve emissions reduction targets and ensure sufficient high electricity volumes and low electricity prices are available to engage in decarbonisation pathways. While long-term electricity provisions have been a central element for electro-intensive industries, more sectors will likely need to engage in similar long-term contracts (contracts for differences, power purchase agreements).

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This dissertation complements the growing literature on the electricity market design and underlines the importance of considering the role of the demand side within deep decarbonisation pathways. The upcoming transformation of end-uses and energy supply entails not only a supply-side capital reallocation but a much broader shift of the current operation, involving a profound transformation in industrial end-uses and a broad adoption of new appliances. From an academic perspective, the work performed contributes first to the methodological aspects of modelling the demand side of electricity markets, improving the short-term and long-term dynamic considerations. The price-elastic consumer model provides insights into the economic performance of different dynamic tariff schemes in low-carbon power systems and their ability to cushion power price spikes. It highlights the required paradigm shift associated with the variability of renewables and their impact on price patterns. In particular, long-duration scarcity periods require adopting a foresight approach in rate settings to ensure the possibility of benefiting from demand's responsiveness in such cases.

Moreover, the dissertation complements the existing literature by providing insights into the European chemical sector's decarbonisation, which has been prone to very few studies despite being an important GHG emitter. The interlinks between the sectors in the upstream and in the downstream should not be overlooked when assessing GHG abatement trajectories. This research underscores that an uncoordinated approach would likely negatively impact social welfare. More generally, the developed models provide a valuable framework for future studies on short-term and long-term dynamics concerning the demand-side decarbonisation pathways and associated opportunities.

From a policy perspective, this dissertation provides awareness of the importance of demand-side integration in decarbonising electricity markets. First, the review of existing DR programmes serves as a basis to clarify the existing approach pursued during the progressive market opening. While these programmes aim at bolstering the active participation of consumers, many discrepancies exist regarding the operational framework in place. Notwithstanding their benefits, it is of primary importance to clarify the role of the different actors involved in DR to avoid any risks of spillovers that would undermine the adoption of dynamic tariffs or the aggregator's business model. Notably, regulators should consider the likely interaction between the different DR programmes and the various temporal and geographical features of electricity markets. The results are particularly relevant in the current European discussions on market design overhauling and eventual harmonisation of capacity mechanisms and balancing markets. Moreover, the assessment of the dynamic tariff schemes highlights their necessary revision and provides practical insight regarding the tariff features to be privileged in the near future. While the results focus on the French case, the learning and the framework developed are relevant for any country enforcing dynamic tariffs and deploying smart metering infrastructure.

Finally, the coordination issue arising with the electrification trajectories entails several consequences for policymakers. First, the numerous objectives set in the energy package regarding RES share in the final energy consumption should not be disentangled from the required transformation of the demand side. Although RePowerEU sets ambitious targets, those should be considered not only from a supply perspective but also from a consumer standpoint. Both should be articulated to avoid transition risks that could hamper social welfare. Typically, bolstering long-term electricity provision for the industry would be pivotal to achieving the ambitions of the EU Net-zero Industry Act, which relies above all on the availability of clean, affordable and abundant electricity for all sectors of the economy. Consequently, forward contracts spanning over multiple years are instrumental to reaching Net-Zero emissions and securing the price and quantity of future electricity provision. In their absence, an effective coordination mechanism signalling the likely amount of low-carbon electricity the power sector can effectively distribute is essential for the timely adoption of low-carbon, electrified technologies. Developing deep decarbonisation strategies for end-use sectors in silos would necessarily fall short in doing so since the pace for electrification and the availability of clean electricity supply is likely to be overestimated by the individual sectors. In addition, while the demand-side investments would ultimately determine the required pace of renewable deployment, those would also provide valuable flexibility to accommodate them. Indeed, the electrification of heat, hydrogen supply and transport provides numerous opportunities to lower the required investments in the power grid and on-peak generation capacities, provided the electricity market design or tariff schemes provide them with the necessary incentives to operate in a system-supportive manner. Leveraging those opportunities to ease the transformation towards power systems of the future should be a priority.

Finally, policymakers should not obliterate the fact that electricity is, first and foremost, a local good, regional at most. The 2021-2023 global energy crisis underlined the transition risks associated with all-encompassing electrification in case of supply-side disruptions and the cost incurred due to the limited price responsiveness of consumers. Electricity being locally produced and consumed, supply disruptions could only result in price spikes and demand destruction. Therefore, providing hedging opportunities to consumers appears fundamental while the variability of power generation is increasing.

Further research

The work conducted in the thesis underscores several topics that would benefit from additional research related to the demand side in electricity markets.

First, further research could strive to better account for the dynamics of the demand side of electricity. Indeed, while the representation of the supply side is included in energy models with many details and refinements, integrating factors such as permitting lead-time, financial constraints, or social acceptance, equivalent considerations on the demand side are usually disregarded. However, similar caveats exist when deploying abatement technologies on the demand side, arising from risk aversions, the lack of infrastructure or the lack of commercial readiness. Typically, more research would be required to refine the behavioural changes that would be required across all consumer segments, notably with respect to the DR capacity available in decarbonised power systems. Indeed, while there are clear benefits of modulating the demand based on the production pattern of RES, the associated disutility for consumers is important to consider and might hamper the possibility of divesting part of the fossil-fuel-based power plants. The research on electricity tariff preferences among consumers complements the approach adopted in this dissertation and could provide opportunities to study the robustness and efficiency of alternative electricity tariff structures. Moreover, the modelling approach considered in the current research is deterministic, assumes perfectly competitive markets and adopts a social planner perspective. The modelling framework typically disregards economies of scale and learning effects for which we rely on exogenous assumptions. Complementing the analysis with different approaches, such as System Dynamics and Agent-Based Modelling Simulation, would capture additional market outcomes, including out-of-equilibrium situations. Risk aversion, limited foresight and possible negative feedback loops could be further evaluated. Similarly, within the optimisation framework, the least-cost approach could be improved by considering near-optimal trajectories, providing additional insights for policymakers and industries. Factors such as transition risks, social acceptance, labour impact or geopolitical foundations of each scenario are not assessed in the present research. Providing a wider spectrum of scenarios would be a significant policy contribution to consider second or third-best solutions that would be easier to make operational in practice across a wider range of indicators.

Then, the geographical scale of the modelling and the associated infrastructure could be further refined. Notably, considering the power grid in more detail could be relevant, as a copper-plate perspective is used in the dissertation. As a result, grid investments and timing are overlooked in our scenarios. This could hinder the deployment of renewables or slow down industrial electrification. Notably, it would be relevant to understand whether grid congestions would soar in the scenarios considered and assess to what extent active consumers through DR could alleviate those. In addition, it would be interesting to assess whether the incentives provided for grid management significantly diverge from those provided for system imbalances and where the most value for consumers lies. These decisions can provide new opportunities for improving the business case of flexibility or, on the contrary, blur the incentives each market's actor provides.

Finally, this research would benefit from considering more energy-intensive downstream sectors, such as iron and steel or the cement industries. These sectors are also considering electrification of their operations to achieve deep decarbonisation objectives since they are also targeted by energy and climate policies. Extending the modelling to account for more end-uses would provide additional insights into the competition for securing clean, abundant and affordable power. In addition, industrial decarbonisation strategies are not independent insofar as some sectors could act as a carbon sink for others. Typically, the chemical sector could reuse or recycle part of the carbon flow of the cement and steel industries to produce high-added-value products such as methanol or e-fuels. As this possibility has not been considered in this dissertation, questioning the necessary regulatory framework for incentivising circularity is an avenue for further research. Similarly, improving the carbon accounting framework in decarbonisation pathways could broaden the conclusions and their significance. While this dissertation focuses on Scope 1 and 2 emissions, the consideration of the Scope 3 appears critical, notably for the chemical sector. Indeed, the sector is using fossil fuels both as an energy source and as a feedstock. In such cases, accounting for the end-of-life emissions is paramount to evaluate the sector's investments and minimise the risk of stranded assets, as well as to avoid carbon lock-in effects in the coming decades. Once again, providing a stable long-term price coordination mechanism such as the EU ETS is critical to reducing GHG emissions in the short term, but its performance in the long term should be carefully assessed in view of the stringent Net-Zero target of 2050. Extending the models to encompass more emissions would, therefore, provide additional insight into the relevance of instruments in place to incentivise optimal decarbonisation pathways.

RÉSUMÉ

Cette thèse complète la littérature existante sur la conception des marchés de l'électricité en se concentrant sur trois aspects majeurs : (i) analyser dans quelle mesure les conceptions actuelles des marchés de l'électricité ont permis l'émergence de la flexibilité de la demande, (ii) étudier les signaux prix à transmettre aux consommateurs dans un système électrique en transition et (iii) évaluer la perte de bien-être due à une coordination imparfaite entre l'offre et la demande dans un contexte d'électrification rapide. Les principaux résultats sont présentés ci-dessous.

Premièrement, chaque sous-marché de l'électricité témoigne des contraintes géographiques et temporelles différentes. Si l'intégration de la demande améliore l'efficacité économique de l'ensemble des sous-marchés considérés, chacun nécessite une architecture de marché différente en fonction des objectifs poursuivis. Les cas de la France, de l'Allemagne et de la Pennsylvanie-New Jersey-Maryland, soulignent ainsi que les programmes actuels n'ont pas réussi à établir un cadre stable pour l'intégration de la demande dans les marchés de l'électricité. En outre, bien que le gisement de flexibilité de la demande identifié soit important, son intégration actuelle dans les marchés de l'électricité ne fournit que partiellement les services permettant à terme l'intégration des énergies renouvelables, ou la gestion de crise similaire à celle subie en 2021-2023.

Deuxièmement, les tarifs dynamiques existants en France ne fournissent pas des signaux prix adéquats dans un contexte de croissance des énergies renouvelables. En effet, dans la mesure où la production d'énergies renouvelables va déterminer le profil des prix de l'électricité, les tarifs ayant une segmentation horaire fixe perdent progressivement de leur intérêt par rapport aux tarifs plus dynamiques. De fait, les tarifs à pointe mobile constituent une alternative à privilégier afin de réduire les pertes sèches pour les consommateurs. Leur adoption plus large nécessite cependant une flexibilité accrue et des possibilités de couverture de risques pour les consommateurs, sous peine de réduire leur taux d'adoption. En effet, le différentiel de prix entre période de pointe et période creuse est croissant dans les scénarios considérés, augmentant la perception du risque encouru.

Troisièmement, le rythme d'électrification industrielle nécessaire pour atteindre les objectifs de décarbonation nécessite une bonne anticipation des prix à terme de l'électricité pour permettre aussi bien la décarbonation de l'offre que l'électrification de la demande. En effet, un scénario d'électrification accélérée qui ne tiendrait pas compte du rythme réalisable de l'augmentation de la production d'électricité risque d'entraîner une perte sèche de bien-être social. En faisant reposer la charge de la décarbonation sur la production d'électricité, la réduction des émissions des industries pourrait engendrer des effets adverses sur le secteur électrique si les investissements ne sont pas coordonnés, résultant par exemple en une hausse des prix de l'électricité ou un accroissement temporaire des émissions de gaz à effet de serre (GES). De fait, le rythme optimal de réductions de quotas d'émissions doit également être évalué à l'aune des investissements nécessaires du côté de la demande. Une réduction accélérée du nombre des quotas risque d'entraîner une perte de bien-être social si les industries ne sont pas en mesure de suivre un rythme similaire de réduction des émissions de GES, si celui-ci dépend de la capacité à s'approvisionner en électricité.

MOTS CLÉS

Architecture des marchés de l'électricité, Flexibilité de la demande, Energies renouvelables, Optimisation, Décarbonation industrielle

ABSTRACT

This thesis complements the existing literature on electricity market design and decarbonised power systems by focusing on three major issues: (i) understanding to what extent the existing electricity market designs have fostered demand-side flexibility, (ii) analysing the preferred price signals to be conveyed towards consumers in the evolving electricity markets and (iii) assessing the welfare loss due to imperfect information and pace asymmetry between the supply and the demand in a context of accelerated electrification. The main results are outlined below.

First, electricity markets entail different geographical and temporal realities depending on the sub-market considered. Demand-side integration could improve the economic efficiency of the power system by reducing investments in peak power plants or grid reinforcement and providing additional flexibility to accommodate variable renewable energy sources. However, depending on the specific objectives pursued, different market designs must be settled and deployed. The case of France, Germany and Pennsylvania-New Jersey-Maryland shows that none of the current programs has successfully established a steady framework for integrating demand-side in electricity markets. This lag in adoption contrasts with the significant potential capacity and value found in the literature and the numerous empirical evidence underlining the price elasticity of consumers. Eventually, existing programs only partially provide the conditions necessary for managing prolonged power crisis episodes or accommodating the intra-day variability of variable renewable energy sources (vRES).

Second, existing dynamic tariffs in France are no longer expected to provide adequate price signals in decarbonising electricity markets. In a situation where renewables production determines price patterns, fixed schedules will no longer be the most relevant tariff design compared to more flexible dynamic pricing. Conversely, peak pricing performs well in reducing deadweight loss by signalling scarcity episodes. While an increasing gap between on-peak and off-peak power prices increases the strength of price signals conveyed to consumers, it might negatively impact the adoption rate of consumers if those are not provided with sufficient flexibility or hedging possibilities.

Third, the industrial electrification pace requires proper anticipation of forward power prices to ensure timely supply-side decarbonisation through electrification. An accelerated electrification scenario that would not factor in the achievable pace of power generation increase would lead to welfare losses. While electrification strategies shift the emissions burden from the downstream sector towards the power production, adverse effects could arise if investments are uncoordinated, leading to potential power price surges or increased greenhouse gas (GHG) emissions from the power sector. Policymakers should also consider the appropriate pace of carbon price increase while monitoring its effectiveness. Indeed, while carbon pricing provides effective decarbonisation incentives, excessively accelerated trajectories would likely lead to welfare losses if industries are unable to follow a similar rate of deployment of abatement technologies

KEYWORDS

Electricity market design, Demand response, Renewable energy sources, Optimisation, Industrial decarbonisation