Deliverable 1.1

Identification of the legal, economic and technical aspects of the demand flexibility in Belgium

Authors in alphabetical order

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Brussels, October 2022

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Acronyms

aFRR	automatic Frequency Restoration Reserve
BRP	Balance Responsible Party
CRM	Capacity Remuneration Mechanism
DR	Demand Response
DSO	Distribution System Operator
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FFR	Firm Frequency Response
FSP	Flexibility Service Provider
LV	Low Voltage
mFRR	manual Frequency Restoration Reserve
RES	Renewable Energy Sources
SO	System Operator
STOR	Short-Term Operating Reserve
TSO	Transmission System Operator
ToE	Transfer of Energy
ToU	Time of Use

1 Introduction

1.1 The need for demand response

Electricity markets are unique among other markets because of the specific constraints associated to power systems. Two main categories of constraints should be emphasized. First, the overall balance between supply and demand must be held at all times. Second, resulting power flows in power system components (e.g., lines and transformers) must not exceed the capability of these elements, and resulting voltages must be kept within acceptable bounds. The violation of these requirements bears a profound impact on the economy and individuals that rely on it, in the form of (partial or total) blackouts. However, both supply and demand are subject to variability and to forecast errors which could lead to imbalances and/or violation of operational constraints if not managed properly.

To ensure that the grid can cope with the variability and forecast errors on both the supply and demand sides, flexibility sources (or means) are essential. Flexibility can be provided by several means. Conventional electricity generation units are the first main source of flexibility, as they can adjust their generation under specific constraints (e.g., technical minimum, ramping constraints). This can be also the case to some extent for renewable generating units. Storage units constitute a second main source of flexibility. Historically provided in the form of hydro pumped storage (e.g., Coo power plant in Belgium), they are now increasingly provided by battery energy storage systems. The grid itself may be a third source of flexibility. For instance, interconnections between different areas can help to balance these areas. Specific grid elements can help to control the flows. Finally, a fourth source of flexibility can come from the demand itself, in the form of Demand Response (DR). For instance, electricity consumption can be decreased, increased, or shifted over time to balance the grid and/or to alleviate the violation of operation constraints.

Historically, flexibility has been provided mainly by the first three main sources mentioned above, with a weak presence of DR. The provision of flexibility by DR is however gaining importance in the context of the ongoing energy transition and is expected to become critical in the upcoming decade(s) for two reasons. First, the deployment of Renewable Energy Sources (RES) in power systems will increase the need to resort to DR, (i) as, on the supply side, it leads to a higher variability and higher absolute forecast errors,[1] and (ii) as it pushes out of the market the conventional generation means, reducing their provision of flexibility services. Second, electrification of mobility and heating will add variability (but also sources of flexibility) on the demand side.

The evolution of the residual (net) load duration curve over the years offers an insightful view of one reason inducing these two issues. A (normal) load duration curve ranks electricity consumption for every hour of the year in decreasing order, from the hour with the highest load to the hour with the lowest load. A residual load duration curve considers then the difference between the load and the available generation from RES, i.e., the residual load, instead of the overall load. Figure 1 shows the difference between the load duration curve and the residual load duration curve. These curves show that the peak load is not strongly impacted by the presence of RES, but that the curves are becoming steeper and the minimum decreases with the integration of RES. They illustrate first the higher expected variability. They show also that the generation required to meet the peak load must run less frequently when RES are massively integrated, which could push them out of the market due to a lack of revenue, entailing then an adequacy problem.

[1] Note that relative forecast errors are expected to decrease thanks to better forecasting tools.

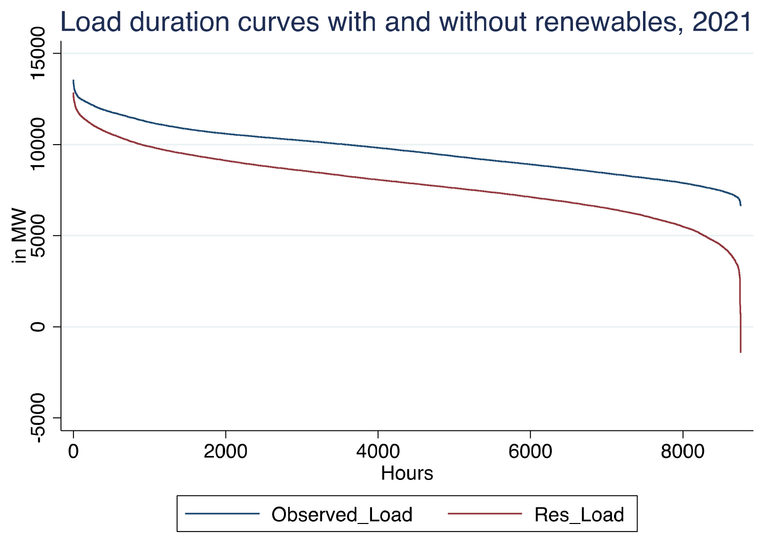

Fig.1 Normal and residual load duration curves. Data: Elia Open Data.

1.2 Benefits of demand response

DR is more and more needed to cope with the increasing variability and forecast errors in power systems due to the massive integration of RES. However, as we will see in this report, the full potential of DR is not yet ready to be used due to numerous obstacles. Before diving into the details of these barriers, it is worth highlighting the main benefits of DR.

1.2.1 Improvement of the grid reliability

Power system reliability can be viewed as "a general concept encompassing all the measures of the ability to deliver electricity to all points of utilization within acceptable standards and in the amount desired".[2] It can be described by two complementary system attributes: adequacy and security. Adequacy can be defined as the ability of the power system to satisfy the consumer demand and system's operational constraints at any time, in the presence of scheduled and unscheduled outages of generation and transmission components or facilities. Security can be defined as the ability of the power system to withstand disturbances arising from faults and unscheduled removal of equipment without further loss of facilities or cascading failures. DR can contribute to improve these two aspects of power system reliability.

Regarding generation adequacy, it was clearly demonstrated recently in Belgium that DR can bring a significant positive contribution. Indeed, with respect to nuclear phase-out legislation and the rapidly changing grid, the Belgian federal government has introduced the Capacity Remuneration Mechanism (CRM) to ensure the security of supply in upcoming years.[3] The CRM aims to compensate capacity holders for the so-called "missing money" problem, i.e., the fact that generating units needed to supply the peak load do not have naturally a positive business case as they will have to run only during a very small number of hours (see residual load curve above). The CRM is fundamentally an insurance for the

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[2] CIGRE WG 38.03 (2014). Power system reliability analysis. Application guide. Part I.

[3] See the Act of 15 March 2021 modifying the Act of 29 April 1999 on the organization of the electricity market and modifying the Act of 22 April 2019 modifying the Act of 29 April 1999 on the organization of the electricity market, on the establishment of a capacity remuneration mechanism. See also *Capacity Remuneration Mechanism*. (2022). Retrieved September 27, 2022, from https://www.elia.be/en/electricity-market-and-system/adequacy/capacity-remuneration-mechanism

Belgian grid to make sure that a certain volume of investment will be made in upcoming years. As grid users are inherently recognized as capacity holders, the demand side has the potential to be one of the important players in CRM by providing flexibility. The results of the CRM auction for the 2025-26 delivery period in Belgium show that the total amount of 287.07 MW of DR was selected, accounting for 6.44% of the capacities selected in the auction.[4] Regarding transmission and distribution adequacy, DR can be used for avoiding the violation of system operational constraints (e.g., no equipment overloads or voltage violations) while satisfying the consumer demand by altering the load pattern and the electricity flow in the power grid (congestion management).

On top of that, DR can enhance system's security by providing ancillary services related to frequency control (e.g., balancing reserves) and/or to voltage control, helping the system to respond to disturbances without further loss of facilities or cascading failures.

1.2.2 Cost-effectiveness in planning and operation of capacity and grid

DR can improve the cost-efficiency of the power grid both in planning and in operation, through a reduction of the peak load. Indeed, the DR can have a pivotal role in peak shaving by adjusting consumption pattern and providing flexibility.[5] This change in consumption can happen either through load shifting or shedding. Under load shifting, customers reduce part of their consumption during peak hours and increase their consumption at earlier or later hours, when the electricity cost is lower (cf. left side of Fig. 2). This includes delaying part of the production process for industries, or the dishwasher for households. Load shifting does not change the overall electricity consumption of customers. Load shifting contributes to peak-shaving, but it can also result in valley-filling, smoothing the demand curve. On the other hand, under load shedding, customers curtail their consumption temporarily. To be considered as shedding, the overall consumption of customers must decrease (cf. right side of Fig. 2), such that load shifting only contributes to peak-shaving.

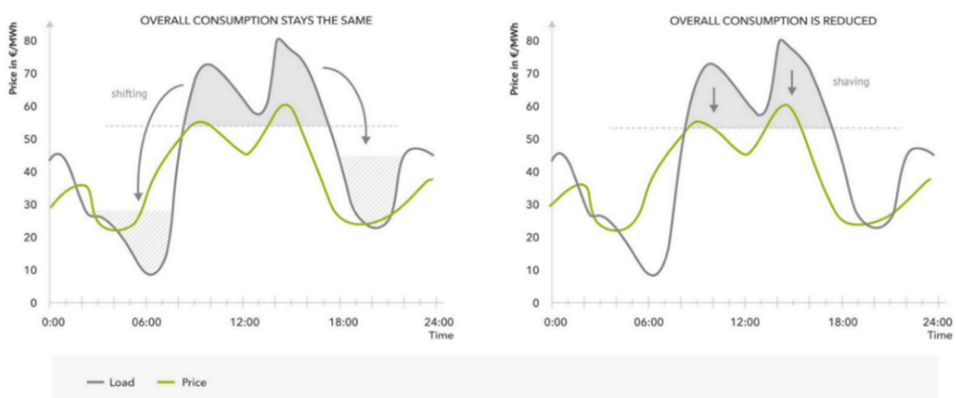

Fig. 2 Peak shaving via load shifting vs. load shedding.[6]

[4] Elia. (2022). *Y-4 Auction Report for 2025 – 2026 Delivery Period - UPDATE*. https://www.elia.be/-/media/project/elia/elia-site/grid-data/adequacy/crm-auction-results/y-4-re-run-auction-report-for-delivery-period-2025-2026.pdf

[5] Golmohamadi, H. (2022). Demand-side management in industrial sector: A review of heavy industries. *Renewable and Sustainable Energy Reviews*, 156, 111963.

[6] *What does Peak shaving mean?* (n.d.-b). Retrieved September 20, 2022, from https://www.next-kraftwerke.com/knowledge/what-is-peak-shaving

This reduction in peak load lowers the investment requirement at the planning stage. Indeed, the foreseen increase in electrification could require additional generating capacity investments to meet demand at peak hours and transmit and distribute the electricity to end-use customers. A large share of power systems capacity is built to fulfil peak load, even though peak hours represent only a few hours over the year as, shown in the load duration curves from Figure 1. Additionally, the successful reduction of the demand peak can obviate or defer the need for grid investments. This can prevent or minimize additional costs on grid operators as well as customers. Limiting (long-term) investments in the grid is particularly relevant with the widespread deployment of decentralized renewable energy resources, which tend to modify the needs of the grid in the short-term.

In addition, rather than investing in new lines to relieve intermittent congestion generated by renewable resources, grid planners can address this issue with DR and storage.[7]

This reduction in peak load also helps lower operating costs. For instance, it can reduce the need for starting up low-efficiency power plants during peak hours.

1.2.3 Contribution to sustainability

DR contributes to the energy transition through two channels. Firstly, the deployment of DR enables the further penetration of renewables into the electricity mix. Secondly, by preventing additional investments in conventional power plants, DR mitigates the carbon lock-in of fossil infrastructure in the energy sector.[8] It is not straightforward that DR automatically reduces emissions in the system, as this is highly contingent on the extent of load shifting and the generation mix at the margin.[9]

1.2.4 Increase in wholesale market competition

Electricity markets are particularly prone to market power. High fixed costs deter entry, and balance requirements creates opportunities for strategic behaviour, e.g., withholding of capacity by producers to increase market prices. An important source of market power in wholesale electricity markets is the inelasticity of demand with respect to price. The development of DR can increase competition, both by mitigating strategic bidding from producers, and by becoming active participants in the market clearing. This is expected to reduce prices on wholesale markets. Furthermore, it enables the entry of new actors in the spot market, namely aggregators. Aggregators are firms who contract a portfolio of small flexible resources "behind the meter" aggregating small consumers and small-scale generation, to sell the flexibility of these units in spot and balancing markets.[10]

1.3 The DemandFlex project

Although DR has many benefits and already plays a role, the full potential is far from being reached, due to various legal, economic, and technical barriers. These barriers might jeopardize the ongoing energy transition, as they prevent an optimal integration of RES while keeping the desired amount of security of supply at an affordable cost. In this context, the DemandFlex project aims to alleviate

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[7] See for example the *Flexplan H2020 Project*, aiming to develop a new grid planning methodology taking into account the introduction of new storage units and DR in transmission and distribution grids as an alternative to building new grid elements (https://flexplan-project.eu/)

[8] Erickson, P., Kartha, S., Lazarus, M., & Tempest, K. (2015). Assessing carbon lock-in. Environmental Research Letters, 10(8), 84023–.

[9] Fleschutz, Bohlayer, M., Braun, M., Henze, G., & Murphy, M. D. (2021). The effect of price-based demand response on carbon emissions in European electricity markets: The importance of adequate carbon prices. Applied Energy, 295, 117040–.

[10] Valarezo, Gómez, T., Chaves-Avila, J., Lind, L., Correa, M., Ziegler, D. U., & Escobar, R. (2021). Analysis of new flexibility market models in Europe. Energies (Basel), 14(12), 3521–.

barriers hampering the full exploitation of the DR potential in Belgium by providing relevant solutions, and to demonstrate the beneficial effect of these solutions.

1.4 Purpose and structure of this report

This report corresponds to the first deliverable of the DemandFlex project. Its main aim is to pave the way for the development of solutions tackling legal, economic, and technical barriers hampering the full exploitation of the DR potential in Belgium. For that purpose, it appears important to provide a comprehensive overview on DR in the Belgian electricity market. This is the objective of Chapter 2. Chapter 3 discusses relevant initiatives and mechanisms in European markets. Chapter 4 identifies remaining legal, economic, and technical barriers to the full leverage of DR. Chapter 5 concludes and gives perspectives on the work that will be performed within the DemandFlex project.

2 Demand flexibility: State of affairs in Belgium

In this section, we provide an overview of the state of DR in Belgium. We first introduce the relevant definition of DR at the core of the DemandFlex project. We then discuss current legal and regulatory frameworks both in Belgium and the EU. The chapter then discusses the different types of DR sought and offered in the different electricity markets. Next, we provide estimates on the magnitude of the DR potential in Belgium. Lastly, we discuss ongoing developments related to DR in Belgium.

2.1 Flexibility and demand response – definitions

This section discusses and provides a formal definition of DR, which is suitable for readers with different backgrounds, and is at the core of the research carried out within the DemandFlex project.

Flexibility in electricity system can be defined as "the ability of a power system to cope with variability and uncertainty in both generation and demand, while maintaining a satisfactory level of reliability at a reasonable cost, over different time horizons".[11] Although such flexibility can be provided by the demand side as well as the supply side, we focus only on the former in the scope of our project.

To define DR, we have started with the legal definition of the European electricity directive. The rationale is twofold. The discussion process at the European level involves many stakeholders from the electricity sector, ensuring that it is the most appropriate definition and understood by all. In addition, this definition is shared by 27 Member State and therefore constitutes a broad consensus in Europe.

Under the electricity directive,[12] DR consists in "the change of electricity load by final customers from their normal or current consumption patterns in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market as defined in point (4) of Article 2 of Commission Implementing Regulation (EU) No 1348/2014, whether alone or through aggregation".[13] DR is also sometimes referred to as demand-side flexibility. While we consider that both terms are interchangeable, we will use the term DR in the framework of the DemandFlex project.

Even though the definition is sufficient to understand the concept of DR, it is also necessary to review and add some clarifications on its main components.

- *"the change of electricity load"*

We propose to add "voluntary" to the definition for the purposes of the Demandflex project. This strictly excludes demand rationing, imposed on final consumers, and performed by System Operators (SOs) from the scope of our project, as it is not as such provided by the final customer. We may touch upon demand curtailment required by SOs but only to the extent that they consist in a limitation of the activation of DR. Only changes of load which are agreed upon by the final consumer are considered. Voluntary also includes changes in the load operated by a third party (e.g., an aggregator) based on an agreement with the final customer.

[11] IEEE. (2021). IEEE Guide for *Distributed Energy Resources Management Systems (DERMS) Functional Specification* (pp. 1-61): IEEE Std 2030.11-2021.
[12] Directive 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (hereafter the "electricity directive")
[13] Art. 2.20 of the electricity directive.

- *"by the final customers"*

The concept of final customer excludes producers, as entities whose main purpose is to produce electricity and inject it to the grid; however, it includes "active customers" or "prosumers", which are customers owning or using decentralized production units.

In the framework of this project, we will also analyze how energy communities can participate in DR.

- *"from their normal or current consumption patterns"*

Only considering consumption patterns observed in the grid as DR provides a limited view on the true potential for DR. In the case of consumers who own generation units such as solar PVs, DR can take place behind the meter by adjusting self-consumption to renewable generation. According to this definition, only the resulting change in injection to the grid constitutes DR, even though unobserved self-consumption adjustments from consumers led to this change of consumption patterns, and should therefore also be considered as DR.

Additionally, the use of "normal or current" consumption patterns is ambiguous. The change in current consumption could be restricted to very short-term increases or decreases in the load. This is the case for DR in balancing markets, which provides the required flexibility almost instantly at unexpected times, i.e., not planned, within the framework of a contract with the Transmission System Operator (TSO). In this case, the change in load can be considered as load shedding. Inversely, changes in normal consumption could refer to changes in consumption patterns or profiles over a broader time frame. It meets a less urgent need for flexibility. This type of DR is more relevant for spot markets, which take place the day before up to 30 minutes before delivery. In this case, DR consists of load shifting, i.e., shifting consumption across time, eventually accommodating to the price variation within a day, or even up to a week.

We remove the reference to "normal or current", without any loss of generality. The application of each reference for further research is possible and remains open to other demand-side consumption changes.

- *"in response to market signals, including in response to time-variable electricity prices or incentive payments, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in an organised market as defined in point (4) of Article 2 of Commission Implementing Regulation (EU) No 1348/2014, whether alone or through aggregation"*

In the framework of DemandFlex project, we plan to analyze all forms of DR. We will therefore analyze all signals referred to in the European project. Yet, the following must be noted:

- By "time-variable electricity prices" we refer both to the price of the electricity commodity and to the network tariffs. We indeed include both variabilities in the study of the so-called implicit flexibility (see below).
- Even though incentive payments will indeed be part of our project, to the extent relevant for the different deliverables, we propose to remove the reference to incentive payments from the DemandFlex project definition. Indeed, the use of "incentive" in flexibility can refer to different notions. To avoid confusion, we propose not to refer to incentive in our definition and therefore to remove the reference to "incentive payments".
- The point (4) of Article 2 of the Commission Implementing Regulation (EU) No 1348/2014 entails the definition of "organised market place" and refers to wholesale electricity markets. For the sake of clarity, we propose to remove the reference to the Commission Implementing

Regulation and to replace it by a reference to "wholesale market", taking into account that ancillary markets (including balancing markets) are included in these wholesale markets.

- *"whether alone or through aggregation"*

In the framework of DemandFlex project, both participation to DR alone (mainly for larger final customers) and through intermediaries (the so-called Flexibility Service Provider (FSP)) will be studied.

To summarize, in the framework of this project, we propose the following definition for the DR:

> ***DR is the voluntary change of electricity load by final customers from their consumption patterns in response to market signals, including in response to time-variable electricity price, or in response to the acceptance of the final customer's bid to sell demand reduction or increase at a price in a wholesale market, whether alone or through aggregation.***

Energy communities
Energy communities are new players in the electricity landscape. They aim to gather natural persons, SMEs and local authorities together in order to participate in the electric system. In order word, energy communities enable citizens and SMEs to actively participate in the electricity landscape, either by participating in (renewable) generation, consumption, aggregation, DR or other energy services. Energy communities can therefore participate in DR and are in this respect central to enabling residential-based DR. Under EU law, there are two types of energy communities: citizens energy communities and renewable energy communities. Even though the structure, governance, requirements, and purposes of both types of energy communities are similar, the renewable energy communities focus on projects relating to renewable energy sources.

For the purpose of the DemandFlex project, it is going to be useful to distinguish between two types of DR,[14] namely:

- **Implicit DR** "refers to a situation when consumers can choose to be exposed to time-varying electricity prices or time-varying network grid tariffs that reflect the value and cost of electricity and/or transportation in different periods and react to such signals".
- **Explicit DR** "refers to a situation where consumers [or third-parties] working on their behalf (e.g., aggregators) are allowed to participate and provide demand-side resources on wholesale energy, reserves/balancing, and/or capacity markets".

Implicit and explicit DR are often referred to as price-/ market-based and incentive-based flexibility, respectively. However, the use of the word incentive is ambivalent, as price-based flexibility also relies on incentives in the form of prices. Similarly, explicit flexibility is also "market-based" when it is procured by the TSO on balancing markets. This ambivalence leads us to prefer the use of the terms implicit and explicit flexibility. The distinction between the terms lies in the certainty about the customers' response. Explicit flexibility relies on a contractual obligation to activate a given amount of flexibility, whereas customers can choose whether to react to price-based signals and to which extent.

[14] COWI (2016). *Impact assessment study on downstream flexibility, price flexibility, DR & smart metering*, available at https://energy.ec.europa.eu/document/download/0aef6831-555c-40de-b681-23885db8cce9_en?filename=demand_response_ia_study_final_report_12-08-2016.pdf

Therefore, there is much more uncertainty in the delivery of flexibility with implicit signals, i.e., non-dispatchable signals.

The concept of implicit DR is linked to the prices and tariffs customers face.[15] Inversely, explicit DR is directly activated by dispatchable signals from a third-party and can be offered in the wholesale market, whether alone or through aggregation. In addition, operators can treat explicit DR, in the case of being reliable enough, as negative generation.[16]

Lastly, implicit and explicit DR are not mutually exclusive. They can be implemented in parallel to each other. A customer could face time-varying prices and participate in an aggregator's portfolio, which provides flexibility to the TSO close to real-time.

Energy storage
Energy storage is a particular technology in the electricity market. It consists of small- and large-scale technologies, such as vehicle-to-grid for Electric Vehicles (EVs), batteries behind the meter, large scale batteries or pumped hydro. It is able to withdraw and inject electricity from the grid, so it can behave both as a customer and a producer on electricity markets. In this sense, it is not strictly considered as DR technology, as it can also provide supply-side flexibility similarly to conventional power plants. Independent storage participating in the market strictly derives its profits from price differentials across a day and participation to balancing markets, subject to efficiency and charging constraints, whereas traditional demand-side participants arbitrage between the profits from flexibility and the profits retrieved from their main activity, i.e., their respective industrial processes. The degree of synchronization of storage and customer demand bids might therefore be low, again highlighting the difference but also the possible complementarity of these actors. Storage behind the meter can be coupled with DR behind the meter, such that the customer's demand curve becomes flatter over the day, as self-consumption follows the price.

2.2 Current legal and regulatory framework

The potential of DR is well understood by the various energy lawmakers who have already intervened to (attempt to) create a legal and regulatory framework suitable for its development. This section aims to highlight the main regulatory principles adopted at the different relevant policy levels.

Given the importance of the European Union framework in energy, this section will first analyze the current European framework surrounding DR before analyzing the Belgian framework. Indeed, the European framework is mainly composed of two types of legislations: regulations and directives. While regulations are directly applicable in Belgium and must therefore normally not be implemented by any national act, directive are not directly applicable and must be transposed into national law before they can be relied upon. This is also why regulations are in theory more specific while directives usually

[15] cf. Section 2.3.3 on retail markets

[16] COWI (2016). *Impact assessment study on downstream flexibility, price flexibility, DR & smart metering*, available at https://energy.ec.europa.eu/document/download/0aef6831-555c-40de-b681-23885db8cce9_en?filename=demand_response_ia_study_final_report_12-08-2016.pdf

impose broader goals on Member States. EU Member States must comply with EU law requirements, and, in case of conflict, directly applicable EU law provisions have priority over domestic requirements.

This section then analyzes the Belgian framework. As Belgium is a federal state and as competences with respect to energy are allocated between the federal government and the regions, we will analyze the framework at national as well as regional level.

2.2.1 EU framework

The European Union has adopted provision relating to DR in three instruments: the energy efficiency directive, the electricity regulation, and the electricity directive. These instruments set out general principles to promote DR. These principles are briefly presented in the following paragraphs.

The Union's first attempt to promote DR dates back to 2012 when it adopted the energy efficiency directive.[17] As per this directive, the network regulations and network tariffs must fulfil several criteria, one of them being that they may not "prevent network operators or energy retailers making available system services for demand response measures [and] demand management".[18] In addition, Member States must remove (transmission and distribution) network tariffs incentives that might hamper participation of DR in balancing and ancillary services procurement.[19]

In addition to the energy efficiency directive, the electricity directive[20] and regulation,[21] adopted in 2019 in the framework of the 4th Energy Packet also tackle some questions related to DR. The electricity directive first includes a provision on DR through aggregation.[22] According to article 17 of the electricity directive, Member States must allow and foster DR through aggregation. The directive lists[23] the elements that each Member State's regulatory framework must include with respect to DR, namely:

- the right for aggregators to enter the electricity markets without other market participants' consent;
- non-discriminatory and transparent rules assigning roles and responsibilities to all parties involved and on data exchanges;[24]
- obligation for aggregators to be financially responsible for the imbalances they cause, either by being a Balancing Responsible Parties (BRP) or by delegating this responsibility to a BRP; and
- final customer participating in aggregation may not be subject to undue contractual restriction by their supplier.

[17] Directive 2012/27/EU of the European Parliament and the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC (hereafter the "energy efficiency directive").
[18] Annex XI, point 2 of the energy efficiency directive.
[19] Art. 15.4 of the energy efficiency directive.
[20] directive 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast) (hereafter the "electricity directive")
[21] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) (hereafter the "electricity regulation").
[22] Art. 17 of the electricity directive.
[23] Art. 17.3 of the electricity directive.
[24] Art. 20 and 23 of the electricity directive includes further rules on data management and smart metering.

The electricity directive also allows Member States to provide financial compensation to parties directly affected by the activation of DR.[25] As explained below, the Belgian federal government has adopted such compensation rule.

The electricity directive further includes specific provision relating to the procurement, by system operators, of DR services. First, article 32 of the electricity directive states that Member States must provide the necessary regulatory framework to incentivize Distribution System Operators (DSOs) to procure DR, including for congestion management. Second, article 40 of the directive specifies that DR is part of the balancing (as part of ancillary) services and, if economically efficient, for non-frequency ancillary services procured by TSO. Finally, the electricity directive provides that system operators may not treat DR in a discriminatory way when they are procuring those services.[26]

The electricity regulation provides more specific rules on DR and includes the following rules:

- as per article 3 of the electricity regulation, Member States, regulatory authorities, system operators and market operators must ensure that final customers and small enterprises are enabled to access aggregation.
- As per article 6 of the electricity regulation, on balancing markets, DR participants must be treated in a non-discriminatory way, taking into account the technical needs.
- As per article 18, network tariffs may not discriminate, positively or negatively, against energy storage or aggregation and may not create disincentives for self-generation, self-consumption or for participation in DR. This, however, applies without prejudice to the network tariffs rules provided for by the energy efficiency directive (see above).
- As per article 57, DSOs and TSOs must cooperate with respect to access to DR when it may support common needs of both system operators.
- As per article 59.1, the Commission may adopt network code rules for "demand response, including rules on aggregation, energy storage and demand curtailment rules". This relates to the current ongoing process taking place between the European Commission and ACER.[27]

2.2.2 Belgian framework

As the European framework, mainly the directives, only establishes a general framework that the Member States have to implement, they have to have their own framework that promotes DR. They have in this respect room for manoeuvre to complement the European principles This is why Belgium has legal provisions relating to DR.

Yet, in Belgium, legislations and regulations in the energy sector are complicated by the complex institutional structure of Belgium, composed of a federal government, communities and regions. This section starts with some preliminary considerations on the allocation of competences between the federal authority and the regions. In this section, we also discuss the notion of "technical flexibility" which has been developed by the Belgian Constitutional Court and taken over in several legislation.

[25] Art. 17.4 of the electricity directive. As we will further detailed, the federal government did not wait for this explicit authorization to create its own compensation mechanism. See art. 19 of the Electricity Act.

[26] Art. 17.2 of the electricity directive.

[27] See the European Commission's Invitation to ACER to submit framework guidelines for the development of a network code based on Art. 59(1)(e) of the Electricity Market Regulation, 1st June 2022, available at https://www.acer.europa.eu/sites/default/files/documents/Media/News/Documents/2022%2006%2001%20FG%20Request%20to%20ACER_final.pdf.

We then successively analyze the federal, Flemish, Walloon and Brussels frameworks. This analysis shows the willingness of legislators to allow the deployment of DR while having some control over the new actors (namely FSPs, such as aggregators) and preserving the roles of existing actors.

2.2.2.1 Preliminary considerations

Competences to adopt legislations and regulations in the field of energy are allocated between the regions and the federal authority in Belgium.[28] Broadly speaking, regions are competent for the regional aspect of energy which include the distribution of electricity, energy efficiency and new sources of energy. They are also competent for the so-called "local transmission network" which is the network between 70 kV and 30 kV. On the other hand, the federal authority is competent for the national aspects of energy which include the transmission of electricity (excluding the local transmission network), the production of energy and large storage infrastructure.

When it comes to DR, the question of competence allocation is not clear. As a result, all the relevant legislators (federal, Flemish, Walloon and Brussels) have adopted some rules relating to DR. As we will see in section 4.2, the unclear power allocation relating to DR can constitute a barrier to the full deployment of DR.

In addition, when it has had to rule on the allocation of power with respect to DR, the Belgian Constitutional Court has introduced the notion of "technical flexibility" which consists in "limiting injection for reasons of local network security".[29] This notion has then been taken over by some legislators. This notion, however, refers to situations which are more linked to demand curtailment imposed by SOs. As explained above (cf. section 2.1), DemandFlex project analyzes DR as a voluntary change in electricity load. As the so-called technical flexibility does not refer to such voluntary change, it will not be part of our analysis.

2.2.2.2 The federal framework

The Act of 13 July 2017 introduces the notion of DR in the Act of 29 April 1999 on the organization of the electricity market (hereafter the "Electricity Act").

The Electricity Act introduced three basic principles when it comes to DR, some of them are the national equivalent of the European provision:[30]

- Each final customer has the right to valorize their DR, using the FSP of their choice and irrespective of their electricity supplier. This right applies without prejudice to technical restrictions. This right applies to customers connected to the transmission as well as distribution grid.
- Each final customer is the owner of their consumption data and may freely make use of them.
- The flexibility service provider is responsible for the imbalances created by the activation of the DR from the portfolio it is managing.

Article 19*bis* of the Electricity Act also entrusts the national regulator (the CREG) with the responsibility of establishing rules applicable to the so-called "Transfer of Energy" (ToE) which takes place between the FSP and the electricity supplier when the DR is activated, unless they are the same or have the same BRP. These rules must apply for transfers of energy taking place on the balancing, day-ahead and intraday markets. The CREG must also adopt rules on the compensation taking place between the FSP

[28] See art. 6, para. 1, VII of the special law on institutional reforms of 8 August 1980.
[29] Belgian Constitutional Court, 28 April 2016, nr 56/2016, B.5.4.
[30] Art. 19*bis*, para. 1 of the Electricity Act.

and the electricity supplier in the event of a ToE, as well as a default transfer price in the event the parties do not reach a commercial agreement. The CREG has adopted those rules though its decision of 15 March 2018.[31]

Finally, the Electricity Act delegates to the TSO some responsibilities relating to the management of DR data. The TSO is responsible for collecting, verifying, and processing the data required to calculate the volume of flexibility traded. The TSO must, where applicable, align with the regional entity responsible for collecting such data. This relates usually to the DSO who collects the consumption data of final customer connected to the distribution grid. The TSO must also monitor the markets and inform the CREG in the event of potential manipulation.

2.2.2.3 The Flemish framework

The Flemish Decree of 2 April 2021 has modified the decreet of 8 May 2009 laying down general provisions on energy policy (hereafter the "Flemish energy decree"), to introduce some rule on DR. Most of these rules apply to both supply- and demand-side flexibility. As this project focuses on DR, we will analyze these rules from this point of view. As explained above, the notion of technical flexibility as been introduced under Belgian law. The Flemish legislators have taken this notion over in its energy decree. Yet, as explained, we will not study this notion.

There is now a chapter in the Flemish energy decree on flexibility and aggregation. Similarly to the federal Electricity Act, the Flemish energy decree introduces basic principles relating to DR, some of them reflecting the European principles set out above:

- Each final customer, including energy communities has the right to participate to DR, as the case may be, using the FSP of their choice[32] and may freely change from FSP.[33]
- Each final customer retains control on its flexibility data.[34]
- The FSP is responsible for the imbalances they may create. They may however entrust this responsibility to a BRP.[35]

In addition to these principles, the Flemish energy decree also provides that, before entering any electricity market (i.e., intraday, day-ahead, ancillary, balancing, etc.) or congestion management market, FSP must enter a contract with the relevant SO (namely DSO or the so-called TSO which is specific to the Belgian institutional structure). Such SO must communicate to the Flemish regulator (the VREG) the said contract and the VREG will publish a list of the flexibility service providers on its website.

The Flemish energy decree also allows the VREG to adopt, after consultation with, amongst other the TSO and the CREG, rules relating to the financial compensation for transfer of energy between the FSP and electricity supplier (or its BRP), when the DR is traded for congestion management or as ancillary services to the DSO or local TSO.[36] The decree specifies that such compensation may not constitute an

[31] See CREG's decision of 15 March 2018, executing article 19bis, para. 3 to 5 of the law of 29 April 1999 on the organization of the electricity market, in order to enable energy transfer, available at https://www.creg.be/sites/default/files/assets/Publications/Decisions/B1677FR.pdf.
[32] Art. 4.1.17/3 of the Flemish energy decree
[33] Art. 4.1.17/1, para. 1 of the Flemish energy decree
[34] Art. 4.1.17/8 of the Flemish energy decree.
[35] art. 4.1.17/1, para 2 of the Flemish energy decree.
[36] Art. 4.1.17/2 of the Flemish energy decree.

entry barrier on the market of FSP and that it must be strictly limited to the cost caused by the activation of DR.

2.2.2.4 The Walloon framework

The Walloon decree of 19 July 2018 has introduced a specific section on DR in the decree of 12 April 2001 on the organization of the regional electricity market (hereafter the "Walloon electricity decree").[37] The Walloon decree introduces the same basic principles as in Flanders: the right to participate in DR,[38] the access to flexibility data[39] and the responsibility of FSP for its imbalance.[40]

In addition, article 35*quater* of the Walloon electricity decree provides for an obligation for FSPs to get licensed by the Walloon regulator, the CWaPE. Such license obligation does not apply when a FSP offers ancillary services.[41] The Walloon Government has specified the requirement and procedure for such license in an order of 28 March 2019. The order provides, among other things, for conditions for the granting of the license for the company and its directors, such as not having committed an offence, being to pay taxes, being independent of the SO or having the scientific and technical qualities to provide flexibility services. This license is only valid on the Walloon territory. Yet, FSP who have been licensed at federal level, from another Belgian region or from another EU Member State can make use of a simplified licensing procedure.

Finally, the Walloon decree introduces some rules for DR involving a transfer of energy or in the event of regulated product of the DSO or local TSO.[42] In such a situation, the relevant SO must collect the relevant data to valorize DR to verify and process the calculation data in line with the TSO. This refers to the article 19*bis* of the Electricity Act, to which the Walloon decree expressly refers as it provides that the CWaPE must plan with the CREG for the implementation of such provision. The relevant SO must also qualify the access point before it is able to participate in such DR, in order to make sure that the security of the network will not be threatened.[43]

2.2.2.5 The Brussels framework

The ordinance of the Brussels parliament of 23 July 2018 has introduced specific provisions on aggregation and flexibility in the ordinance of 19 July 2001 relating to the organization of the electricity market in the Brussels Region (hereafter the "Brussels electricity ordinance"). These provisions have further been modified in the recent Ordinance of 17 March 2022.

The Brussels electricity ordinance entails similar basic principles for the participation in DR: the right for each final customer to participate in DR and to freely choose a FSP[44] and the responsibility of the FSP to the imbalance it creates.[45] The Brussels electricity ordinance is less clear about the right of final customer to access and make use of their consumption data, but such right can be inferred from some provisions.[46]

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[37] We note that this section has further been updated through the Walloon decree of 5 May 2022.
[38] Art. 35*quinquies*, para. 1 of the Walloon electricity decree.
[39] Art. 35*quinquies*, para. 1 of the Walloon electricity decree.
[40] Art. 35*quinquies*, para. 2 of the Walloon electricity decree.
[41] Art. 35*quater*, para 1 of the Walloon electricity decree.
[42] Art. 35*sexies* of the Walloon electricity decree.
[43] Art. 35*sexies* of the Walloon electricity decree.
[44] Art. 26*bis*, para. 1 and 2 of the Brussels electricity ordinance.
[45] Art. 26*septies* of the Brussels electricity ordinance.
[46] See art. 26*quinquies* and art. 26*tredeies*, para. 1, 4° of the Brussels electricity ordinance.

Similar to the Walloon Region, the Brussels electricity ordinance introduces a license obligation for FSPs.[47] The procedure for such licensing process must be specified by the Brussels government. To the best of our knowledge, such implementation has not taken place yet, which means that the licensing obligation is not effective yet and that FSP operates without a license. We can already note that, unlike the Walloon region, the Brussels electricity ordinance does not plan for a simplified licensing procedure for FSP already licensing in other regions or EU countries. FSP must also enter into a contract with the relevant SO (DSO or local TSO).[48]

*   *

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Under the impetus of the European Union, the federal and regional legislators aim to allow and even promote DR. In particular, they have enshrined the right for all final customers to participate in DR and to have access to their consumption data. These legislators have also shown a desire not to disrupt the functioning of the markets as they currently exist. The players are thus responsible for the imbalances they create, and there is a compensation obligation in the event of transfers of energy. Finally, the regional governments are careful about the suitability of new players in the energy sector. They have therefore introduced licensing obligations or obligations to enter into a contract with the relevant SO.

2.3 Participation to electricity markets

In this section, we discuss how DR participates in electricity markets. In practice, the characteristics of DR vary substantially according to the service it provides, the market in which it is procured and the actors which exchange it.

Firstly, electricity is not exchanged in one market only, as is traditionally the case in markets of goods and services, but in several markets. These are illustrated in Fig. 3 below.

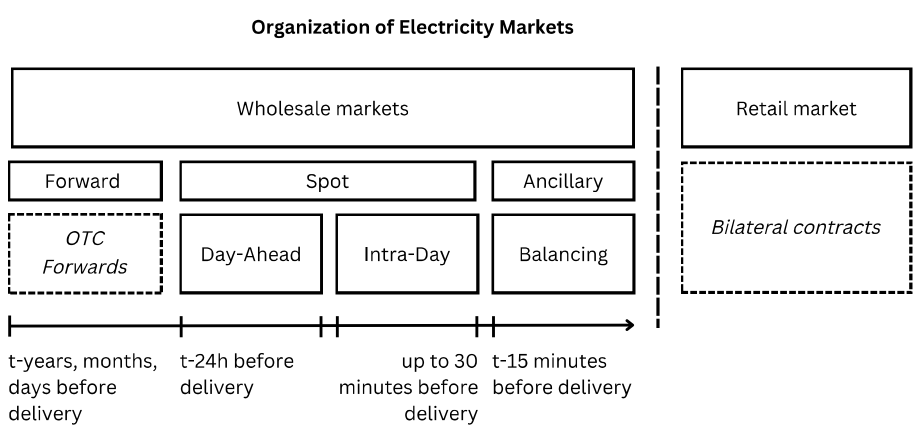

Fig. 3 The organization of electricity markets in Belgium

We can broadly group markets into two types: wholesale and retail markets. Wholesale and retail markets can be differentiated by the actors participating in each. In wholesale markets, a lot of suppliers and buyers exchange large volumes of electricity. In retail, contracts are signed between

[47] Art. 26*ter* of the Brussels electricity ordinance.
[48] Art. 26*quater* of the Brussels electricity ordinance.

suppliers and their customers (households and small firms), who are too small to directly purchase their electricity on the wholesale market. The two are interrelated, and in fact this link is essential to the discussion on DR in the retail market, discussed later in this section.

The organization of electricity markets stems from electricity's singular equilibrium condition: injection and offtake of electricity need to match at all times. This responsibility can be the prerogative of the TSO, as is the case in US markets, but this responsibility can also be decentralized to market participants, as in European markets. Market participants must either become BRPs, or contract with one. BRPs are assigned a balancing perimeter, made of connection points to the grid, for which they need to ensure balance between supply and demand for every hour of the day. They must submit a balanced portfolio to the TSO the day before, which they can adjust up to 30 minutes before the time of delivery/consumption in the intra-day market.[49] Fifteen minutes before delivery, balancing becomes the responsibility of the TSO, for which the relevant markets are ancillary markets.

As illustrated in Fig. 3, wholesale markets also include forward markets. In these markets, participants agree to exchange electricity well before the time of delivery, either through a market (futures market) or through bilateral contracts. The forward markets provide hedging against volatile prices, both for consumers and producers. Given that forward markets effectively remove the incentive to respond to volatile prices, the scope for DR in forward markets is limited and beyond the scope of DemandFlex project.

2.3.1 Demand response in spot markets

Demand-side participants that are also BRPs must procure a volume of generation equal to their forecasted consumption. This is the case for suppliers for example, which are the intermediaries between small consumers such as households and small firms.

Forecasting consumption (or supply) is often subject to some margin of error, which becomes more observable as the time of delivery approaches. Once the day-ahead market closes, imbalances must be settled in the intra-day market, which closes 30 minutes before the time of delivery.

Errors in demand forecasts must be managed by BRPs either by procuring additional generation or selling part of it, or by changing consumption within its own perimeter. The latter is an essential part of the potential of DR. In the case of suppliers, the structure of their contracts with small consumers can enable quick adjustments to short-term imbalances, e.g., through dynamic pricing, or inversely become an obstacle if prices are fixed throughout time, making consumption inelastic. This will be further discussed in the following section on retail markets. This adjustment is at the core of an aggregator's business model.

The potential for DR in spot markets is twofold: either implicit through high prices, or explicit through short-term adjustment within a BRPs' portfolio. In some countries, demand-side participants are even allowed to sell "load shedding" directly in the market, i.e., sell a reduction in their forecasted (and contracted) consumption to other participants in the market (cf. section 3).

Spot markets are organized as two-sided first-price auctions. Put simply, participants submit either supply or demand bids, which are then aggregated into supply and demand curves. Then, the market clears at the point of intersection between demand and supply curves, and each participant in the left-side of the equilibrium sells or buys the volume on which they bid at the price of equilibrium. By

[49] Since March 2022, the balancing obligation of BRPs has been partly relaxed. The absolute difference between injection and offtake must be inferior or equal to 50% of the size of the BRP's portfolio.

submitting joint bids over a day, or *block bids*, participants can indicate their consumption and production preferences through the volume and the price of the bids they submit.

Since 2014, participants can submit complex bids. Complex bids are more advanced than block bids because they allow more specific preferences to be elicited in the bid. For instance, loop bids are complex bids, which allow participants to buy a certain volume at the hour in which it is cheapest and to sell a certain volume at the hour in which it is the most expensive. This type of bid fits very well with batteries' charging constraints, an essential technology in the deployment of DR. There is however limited evidence on whether the bid offer encourages non-storage consumers to sell their intra-day flexibility, which will be one of the topics of research within the framework of the DemandFlex project.

2.3.2 Demand response in ancillary markets

Ancillary markets are implemented to ensure stability in the grid close to or at real-time. We focus on balancing markets, whose function is to maintain the frequency in the grid. In Belgium, balancing markets are divided into three different markets: FCR (Frequency Containment Reserve), aFRR (automatic Frequency Restoration Reserve) and mFRR (manual Frequency Restoration Reserve). Note that FCR, aFRR, and mFRR are sometimes also referred to as primary reserve (R1), secondary reserve (R2), and tertiary reserve (R3), respectively.

Belgium is one of the European countries with the broadest integration of DR in ancillary markets.[50] Demand-side participants can and do participate in each market. The minimum size requirement is 1 MW and can be provided through aggregation of small units, both from the supply- and demand-side. Auctions for each reserve take place daily for the following day, which restricts the commitment of participants over time and therefore mitigates the risk of unavailability of consumers. Furthermore, it is possible to cumulate bids on different reserves, which increases both the volume offered by each participant and the revenues he can expect to obtain.

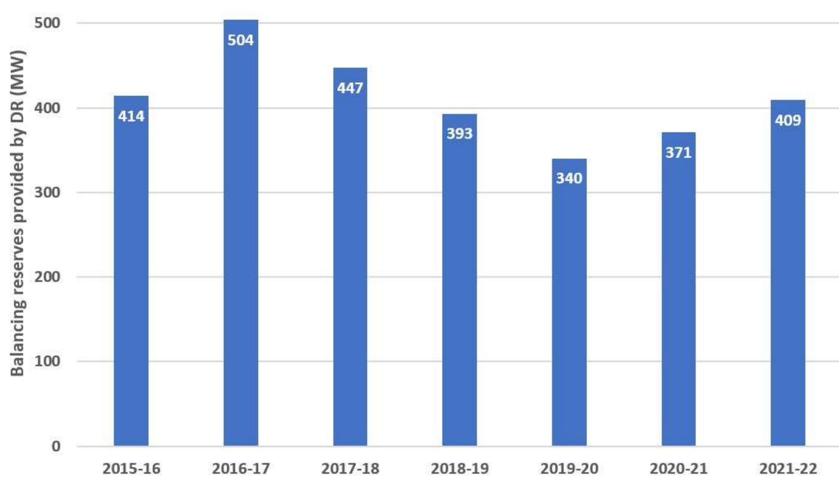

Fig. 4 Evolution of the participation of DR to reserves during winter months in Belgium.[51]

[50] SmartEN (2018) European Balancing Market Edition, available at https://www.smarten.eu/wp-content/uploads/2018/11/the_smarten_map_2018.pdf

[51] Data retrieved from E-CUBE (2022). Working Group Adequacy of 13th September 2022, available at https://www.elia.be/-/media/project/elia/elia-site/users-group/ug/wg-adequacy/2022/20220913/20220913_wg10_updated-presented-slide.pdf

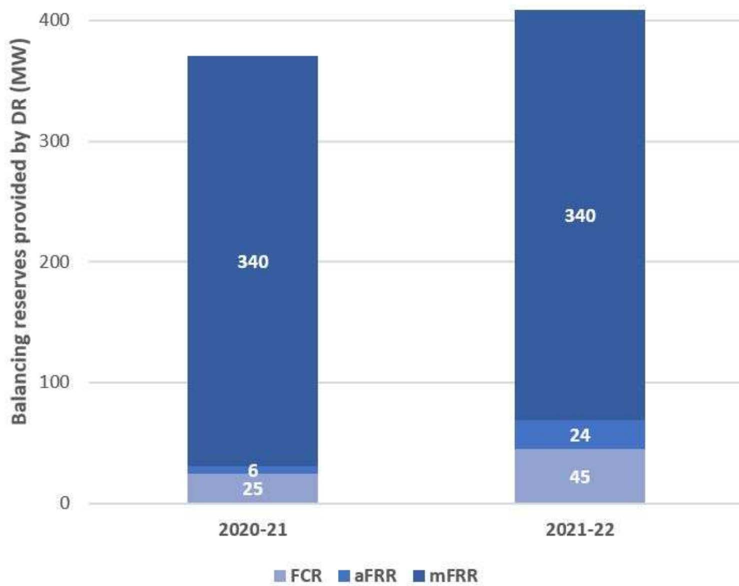

Fig. 5 Contracted DR for each reserve in Belgium.[52]

Figure 4 illustrates the balancing reserves provided by DR from winter 2015 to winter 2021 in Belgium. Figure 5 further depicts balancing reserves provided by DR for each product. As can be seen in Fig. 5, 25% to 50% of FCR is provided by the DR. In practice, the FCR is rarely activated. Therefore, participating in the FCR is attractive for DR participants, as it is almost equivalent to a subsidy for capacity. However, two requirements in the FCR limit the participation of demand-side participation: the unit must be available within 30 seconds and the bids for up- and downward flexibility must be symmetric.[53] Once activated, participants must provide flexibility for a maximum period of 25 minutes. Furthermore, the reservation fee is determined through a pay-as-clear mechanism, i.e., the remuneration provided to all participants in the FCR depends on the marginal bid at which the volume to be procured is filled, similar to the merit-order in spot markets. Hence, if demand-side participants submit the highest bid, it limits the gains from participating in the FCR market. FCR is also the smallest reserve, with 87 MW of contracted capacity.

Inversely, the aFRR is frequently activated. The contracted and activated volumes are respectively 145 MW and 150 MW in 2020 and 2021.[54] The notification period is 7.5 minutes, which provides more time than the FCR for consumers to adjust their consumption accordingly. Furthermore, the reservation fee is set through a pay-as-bid mechanism, which remunerates each contracted unit at the value of the bid they submitted. The activation fee is determined through a pay-as-clear mechanism, which yields the same risk of marginal bidding as in the FCR. Furthermore, the bids must be symmetric,

[52] Ibid

[53] Verpoorten, K., De Jonghe, C., & Belmans, R. (2016). Market barriers for harmonised demand-response in balancing reserves: Cross-country comparison. In 2016 13th International Conference on the European Energy Market (EEM) (pp. 1-5). IEEE.

[54] Elia Open Data Portal, available at https://www.elia.be/en/grid-data/balancing/capacity-volumes-needs

a similar constraint as in the FCR.[55] Day-ahead bids for the activation of aFRR must be submitted in six 4-hour time spans for the following day, with no obligation for the TSO to observe neutralization time between activations, i.e., time for consumers to recover from the activation. This could strongly hinder the participation of DR to this reserve.

The contracted volumes for the mFRR increase yearly, reaching 920 MW in 2021. The notification period is 12.5 minutes, which is better suited to the activation of DR. Similar to the aFRR, the remuneration is based on reservation and activation, respectively determined through pay-as-bid and pay-as-clear mechanisms. Once activated, participants must provide flexibility for periods of 15 minutes, with a minimum activation period of 5 minutes. This is a relatively short period, which accommodates for the type of flexibility provided by shifts in the production process by large consumers. Only upward flexibility can be contracted. The effect of this last requirement on demand-side participation is unclear, as it is strongly technology- and sector-specific.[56] The mFRR reserve has the largest share of demand-side participation, approximately 37% in 2021.[57]

In the winter 2020-2021, the DR accounted for 30%, 4% and 37% of contracted FCR, aFRR and mFRR, respectively.[58] Elia's most recent adequacy study finds that by 2030, 70% of upward reserves and 30% of downward reserves could be provided by the DR, using technologies such as vehicle-to-grid, batteries, load shifting and shedding.[59]

2.3.3 Demand response in retail markets

Suppliers procure electricity in the wholesale markets, which they then sell to customers in the retail market. This market is different from the wholesale market in that the exchanges take place bilaterally between suppliers and their customers, at a price, either fixed or variable, but at the very least, contractually agreed.

DR in this market is enabled through the responsiveness of customers to time varying prices of electricity, defined earlier as implicit flexibility. The responsiveness of customers depends on two main components of their electricity bill: the commodity price, i.e., the "real" cost of electricity and the network tariffs. The rest of the price is made up of the cost of renewable support schemes, VAT, etc. In Belgium in 2021, commodity prices and network tariffs account for 25-30% of the electricity bill each.[60]

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[55] Verpoorten, K., De Jonghe, C., & Belmans, R. (2016). Market barriers for harmonised demand-response in balancing reserves: Cross-country comparison. In 2016 13th International Conference on the European Energy Market (EEM) (pp. 1-5). IEEE.
[56] Gils, H. C. (2014). Assessment of the theoretical DR potential in Europe. Energy, 67, 1-18.
[57] E-Cube (2022) Market Response in 2022. Presented in Elia's Adequacy Working Group on November 13th, 2022, available at https://www.elia.be/-/media/project/elia/elia-site/users-group/ug/wg-adequacy/2022/20220913/20220913_wg10_updated-presented-slide.pdf
[58] *Ibid*
[59] Elia (2021) Adequacy and Flexibility Study for 2022-2032 p253, available at https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications/studies-and-reports/20210701_adequacy-flexibility-study-2021_en_v2.pdf
[60] Forbeg (2021) A European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers, available at https://www.creg.be/sites/default/files/assets/Publications/Studies/F20210517EN.pdf

Traditionally, contracts between suppliers and customers are based on fixed tariffs, which are not always consistent with suppliers' and wholesale market's intra-day cost variation and therefore do not encourage consumption shifts from hours of critical peak load to hours of low-cost generation.[61]

Rise of a more flexible load

Almost 14% of households in Belgium are equipped with solar panels in Belgium in 2020,[62] the second highest value in Europe. They account for roughly 2/3 of total solar capacity in Belgium.[63] These households, also called prosumers, have a more flexible consumption, mostly resulting from the volatility of their renewable generation.

Furthermore, electric and hybrid vehicles now amount to 5.9% of the total fleet in Belgium.[64] The charging patterns can impact the grid and the market if they are too synchronized on an aggregate level. Given their charging requirements and the correlation of charging patterns across the day at an aggregate level, they represent a strain on the electricity grid, but also a possible solution to the issues in the functioning of the grid related to the intermittency of renewable generation.

Retail Tariffication

The link between prosumers, EV charging, traditional consumers and DR are the tariffs for electricity and use of the electricity network.

For prosumers, retail tariffication used to rely on net metering, i.e., all electricity generated which is not self-consumed is paid back to the household at a given price at the end of the year. This tariffication does not value prosumers who aligned their consumption to the intermittency of their generation, eventually reducing demand at critical times or minimizing a BRP's portfolio real-time imbalances.

For the remaining and more traditional consumers, DR is encouraged through time-varying tariffs. Unlike tariffs for prosumers, tariffs for regular consumers should reflect the cost of procurement of electricity in the wholesale market for suppliers. Dynamic contracts can rely on real-time pricing, Time-of-Use pricing (ToU) or critical peak pricing. Real-time pricing links hourly prices for consumers during a given day directly with the day-ahead wholesale prices. ToU tariffication implements a pre-defined variation of prices over a day, reflecting the average intra-day cost variation in wholesale markets. Critical peak pricing relies on a ToU tariffication but allows for the price to increase significantly for a limited number of hours deemed critical for the supplier, directly derived from critical peak hours in the wholesale market.

In Belgium, fixed tariffs are prevalent and account for 2/3 of households' contracts with their supplier in 2022.[65] Furthermore, the price of the commodity, i.e., the price paid the electricity consumed, only accounts for 1/3 of the total electricity bill.[66] As a result, retail customers are unresponsive to wholesale market price variations and the potential for DR remains largely untapped. The role of smart meters

[61] We consider two-tiered tariffs, i.e., tariffs divided into on- and off-peak hours, highly similar to fixed tariffs, as they only partly internalize intra-day cost variation.

[62] ACER (2021) Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020, available at https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2020_%E2%80%93_Energy_Retail_and_Consumer_Protection_Volume.pdf

[63] IEA (2018) National Survey Report of PV Power Applications in Belgium, available at https://iea-pvps.org/wp-content/uploads/2020/01/NSR_Belgium_2018.pdf

[64] Statbel (2021), available at https://statbel.fgov.be/en/themes/mobility/traffic/vehicle-stock

[65] CREG (2022) Study on the increase in electricity and gas prices in Belgium (F2289), available at https://www.creg.be/sites/default/files/assets/Publications/Studies/F2289EN.pdf

[66] *Ibid.*

to record hourly consumption is also critical to the success of dynamic pricing. In Belgium, Flanders has equipped 1/3 of households with smart meters, while Brussels and Wallonia are just starting to install them on a very small scale.

Evidence from large-scale implementation of real-time pricing in Spain indicates that consumers are largely unresponsive to dynamic prices.[67] Similar results are found for the implementation of ToU in California (US).[68] However, the price variation observed during the day in both studies lies in the range of a few cents per kWh, which is not sufficient to incentivize consumers to shift their consumption within a day. The sustained surge in wholesale electricity prices observed in Belgium but also throughout Europe since 2021, the increasing price differentials within a day and the necessity for suppliers to pass-through part of their increasing procurement costs to their consumers might push forward the use of more dynamic contracts and provide the setting for the deployment of DR in retail markets in the next years.

Network Tariffication

Another component of the electricity bill are network tariffs. These tariffs should in theory reflect the real-time costs of peak consumption and congestion management for the grid. Grid costs driven by prosumers and peak consumption are currently distributed unequally across consumers and mostly paid for by regular consumers, as prosumers have a lower electricity bill, which lowers their network fee and hence reduces their contribution to network costs.[69]

Since 2022, the network tariff is a capacity tariff in Flanders. The individual network fee is computed using the monthly peak capacity use, i.e., the period where the consumer used the most electricity during the month. This requires the use of a smart meter, which is the case of over 1 million households since 2021, roughly 1/3 of the 3 million Flemish households. This provides an economic motive for prosumers to align their peak consumption with their peak generation and maximize self-consumption, consequently reducing network costs for the DSO.

Introducing time-varying for both commodity prices and network tariffs on a large scale would encourage a more elastic demand and mitigate issues in the grid driven by the further penetration of intermittent renewable generation, while also providing a buffer against supply shocks and volatile renewable generation in the wholesale market. However, dynamic pricing is rarely observed in retail markets. There are multiple reasons. This is driven by the dependence of these tariffs on the deployment of smart meters and the risk aversion of customers to the exposure of their electricity bills to real-time wholesale prices, which has only gained more ground since the beginning of the energy crisis in Europe. Country-level implementation is stalled by distributional concerns and the protection of vulnerable consumers.[70]

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[67] Fabra, N., Rapson, D., Reguant, M., & Wang, J. (2021). Estimating the Elasticity to Real-Time Pricing: Evidence from the Spanish Electricity Market. AEA Papers and Proceedings, 111, 425–429.
[68] Ito, K. (2014). Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing. The American Economic Review, 104(2), 537–563.
[69] Batlle, Mastropietro, P., & Rodilla, P. (2020). Redesigning residual cost allocation in electricity tariffs: A proposal to balance efficiency, equity and cost recovery. Renewable Energy, 155, 257–266.
[70] Cahana, M., Fabra, N., Reguant, M., & Wang, J. (2022). The distributional impacts of real-time pricing.

Customers idiosyncracies as parameters in the deployment of DR

The success of DR programs hinges on a sufficient level of consumer participation, stalled by lack or complexity of information, risk aversion and constraints inherent to cultural and behavioral characteristics of consumers[71]. Inversely, heterogeneity in idiosyncratic components of residential and commercial consumption could be coupled to optimize DR as a tool to balance renewable generation. In the long-run, raising public awareness on and acceptance of dynamic pricing is essential to the deployment of DR.

2.4 Potential for demand response in Belgium

In this section, we assess the potential for DR in Belgium, using three different approaches: an approach based on existing DR, a theoretical approach, based on the knowledge of existing electricity-consuming equipment and devices, and an approach based on the observed load profile.

2.4.1 Existing demand response

Existing DR provides a lower bound on the potential for DR and is therefore a natural starting point for assessing the potential for DR. Existing DR is made of contracted DR as part of the management of ancillary services by Elia (explicit DR) and implicit DR that takes the form of the reduced demand at higher prices.

Contracted (explicit) DR amounted to 371 MW in 2020 and 409 MW in 2021.[72]

Assessing the size of existing implicit DR is more difficult because it requires to estimate how much load could be reduced if prices went up enough. Elia and E-Cube, a consultancy, have proposed to use observed aggregated demand from the bids in the day-ahead market (both EPEX and Nordpool) and compute DR for a given hour as the reduction in volume demanded in that hour above a certain price threshold. Beyond a certain price, some demand-side participants prefer to shed their consumption rather than consume at that price or to activate their back-up generation, which reduces their consumption on the grid overall.

One central decision for this approach is the price threshold to use. Clearly, even though demand decreases when an industrial consumer decides to use its back-up generation, this cannot be considered a DR, as defined in section 2.1. Elia and E-Cube have proposed to use 500 €/MWh as the threshold. It corresponds to the price above which no supply-bids are submitted to the market, leaving price-sensitive demand-side bids. It can thus be argued that it captures real DR.

Using this threshold price, implicit DR was estimated to be 485 MW on average between April 2020 and March 2021 (standard deviation: 149) and 881 MW (standard deviation: 335) between April 2021-March 22. [73]

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[71] Torriti, J. (2017). Understanding the timing of energy demand through time use data: Time of the day dependence of social practices. Energy research & social science, 25, 37-47.

[72] Numbers are provided by Elia for the computation of the strategic reserve, but are not publicly available.

[73] These numbers are taken from pages 26 (EPEX) and 31 (Nordpool) of E-Cube (2022) Market Response in 2022. Presented in Elia's Adequacy Working Group on November 13th, 2022, available at https://www.elia.be/-/media/project/elia/elia-site/users-group/ug/wg-adequacy/2022/20220913/20220913_wg10_updated-presented-slide.pdf. Note that the level of demand response varies of course over the course of the day and year. This is the reason why the numbers are averages and a standard deviation is reported. We assume that the two values are independent, such that the standard errors are additive. Furthermore, we use the values from the refined dataset, which includes all days, as opposed to the restricted dataset, which focuses on winter weekday peak load hours.

Adding explicit and implicit DR, existing DR is estimated to be 856 MW in 2020-21 and 1259 MW in 2021-22. These numbers are summarized in Table 1.

	2020-21	2021-22
DR (>500 €/MWh)	485 MW	850 MW
Ancillary Services	371 MW	409 MW
Total existing DR	856 MW	1259 MW

Table 1. Observed DR in Belgium. Data provided in E-Cube (2022)[74]

2.4.2 Theoretical potential

A second approach is to start from data about installed electrical appliances and processes and, for each of them, ask to what extent they can either shed or shift demand. Such an approach is taken by Gil (2014), based on 2010 data for 40 European and African countries and 28 industrial, commercial and residential processes and appliances.[75]

For each process and appliance, Gil uses available aggregate load profiles accounting for weather, seasonal, weekly and daily variation when relevant. For example, the load profile for cooling in food manufacturing is assumed to depend on the season and the hour. Residential air conditioning load is assumed to depend on the hour and temperature. And so on.

Next, Gil considers different sources of DR, namely load shedding, load advancing, load delaying. Load advancing and load delaying are two types of load shifting but, of course, one is more relevant than the other depending on the process or device. For example, both types are considered for the use of washing machines, driers and dish washers, but only advancing load is considered for residential electric storage water.

Aggregating over all processes and appliances, Gil finds an average theoretical upward flexibility of 4.7 GW and an average downward flexibility of 2 GW for Belgium. Upward flexibility consists of advancing the operation of processes and devices. Downward flexibility consists of delaying or shedding the operation of processes and devices. Table 2 summarizes the breakout per sector. As shown in Table 2, the residential sector is the sector with the highest theoretical potential for flexibility. This means that programming devices at home to reduce or increase consumption would yield the most significant volume of DR. The potential in commercial and industry sectors is limited by the fact that there are significant constraints in the production chain and schedule of workers.

Hourly average, MW	Upward Flexibility	Downward Flexibility
Residential sector	4025 (85%)	797 (39%)
Commercial sector	568.5 (12%)	653 (32%)
Industry sector	142 (3%)	633 (31%)
Total	4735.5	2043

Table 2. Sectorial decomposition of the average theoretical potential for up- and downward flexibility in Belgium (2010). Authors' computations based on Gils (2014), Fig. 1 and 2

[74] E-Cube (2022) Market Response in 2022. Presented in Elia's Adequacy Working Group on November 13th, 2022, available at https://www.elia.be/-/media/project/elia/elia-site/users-group/ug/wg-adequacy/2022/20220913/20220913_wg10_updated-presented-slide.pdf

[75] Gils, H. C. (2014). Assessment of the theoretical DR potential in Europe. Energy, 67, 1-18.

Gil (2014) also finds that the flexibility potential of residential and commercial load is highly seasonal. The reason is that their loads are driven by heating and cooling needs, which are themselves highly seasonal. This is interesting because winters are also periods where the value of flexibility is highest.

2.4.3 Load-based potential

As a final approach to assess the potential for DR, we consider observed aggregate load profiles, net of intermittent sources of energy. Load typically varies over the course of the day, with a peak in the morning and a peak in the evening. In electricity markets where prices are driven by the marginal (most expensive) source of generation, this means that prices also vary over the course of the day.

In the load-based approach to evaluate the potential for DR, we focus on intraday flexibility and essentially ask by how much should load be shifted upward or downward to lead to a flat load profile over the course of the day (holding observed load fixed). Note that unlike in the theoretical approach, we do not ask whether there are appliances that could shift their load upwards or downwards. Instead, by taking aggregate load profiles as proxies for intraday price profiles, this approach seeks to get at the *economic* incentives for providing flexibility (implicit DR), *above and beyond* the implicit and explicit DR that have already taken place: shifting consumption from high price periods to low price periods.[76] The load-based estimate is therefore mostly a proxy for unexploited demand response in the form of load shifting and therefore a lower bound estimate of the total potential for DR.

Our analysis relies on data for Belgium for 2020. Because wind and solar sources of electricity are intermittent and have essentially zero marginal costs, we treat them as negative load for the present analysis and consider load, net from intermittent renewable sources.[77] We use data on the hourly load and generation from solar, on- and offshore wind capacity in 2020 in Belgium provided by Elia.[78]

We compute the potential for up- and downward flexibility as follows. For each hour, the potential for flexibility is measured as the absolute difference between the observed load and the mean for the given day. If the observed load is above the mean, we characterize it as a potential for downward flexibility, as consumers could reduce their consumption to the mean under the right price signals and information. We compute upward flexibility in a similar manner. Figure 6 plots for every day of the years 2020 and 2021, the average potential for upward and downward flexibility. The average potential for upward flexibility is typically larger than the maximum potential for downward flexibility, i.e., the potential increase of consumption is larger than the potential decrease in consumption.[79] In 2020 (2021), the average potential for upward and downward flexibility was on average 810 (893) MW and 755 (823) MW respectively.

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[76] Because the approach assumes that total load over the course of the day remains the same, it does not include the potential for load shedding.
[77] Using the load net of intermittent sources brings the intraday load profile closer to the intraday price profile, which motivates the approach.
[78] Total Load as measure of Load, available at https://opendata.elia.be/explore/dataset/ods001/information/, Wind and solar generation available at https://opendata.elia.be/explore/dataset/ods031/information/ and at https://opendata.elia.be/explore/dataset/ods032/information/, respectively..
[79] This does not necessarily imply that downward flexibility is easier or less costly to perform.

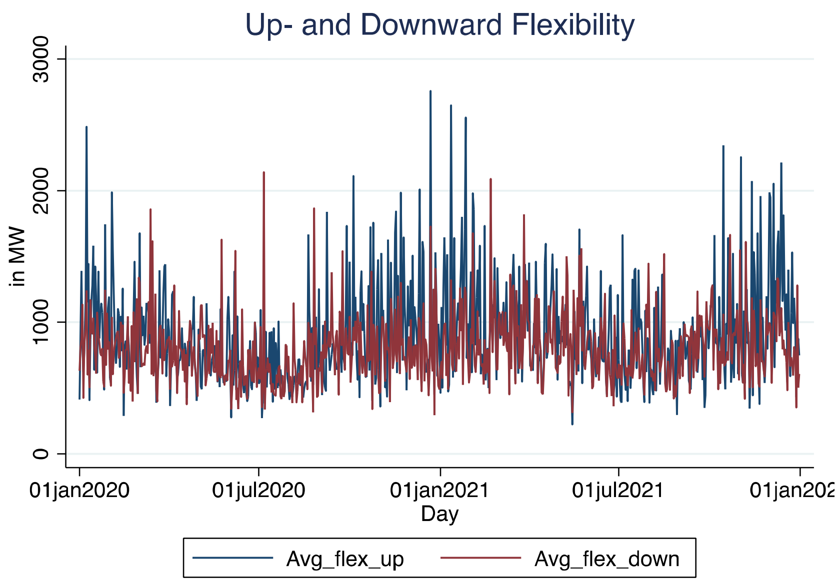

Fig. 6 Average daily potential for up- and downward flexibility. Authors' calculations based on data retrieved from Elia

We next evaluate the impact of this intraday flexibility (i.e. assuming that electricity consumers manage to shift their load such as to smooth the load profile, for each day) on the residual load duration curve.[80] Figure 7 shows that, even though we've restricted ourselves to intraday load shifting, the resulting net duration curve is flatter than the original one.

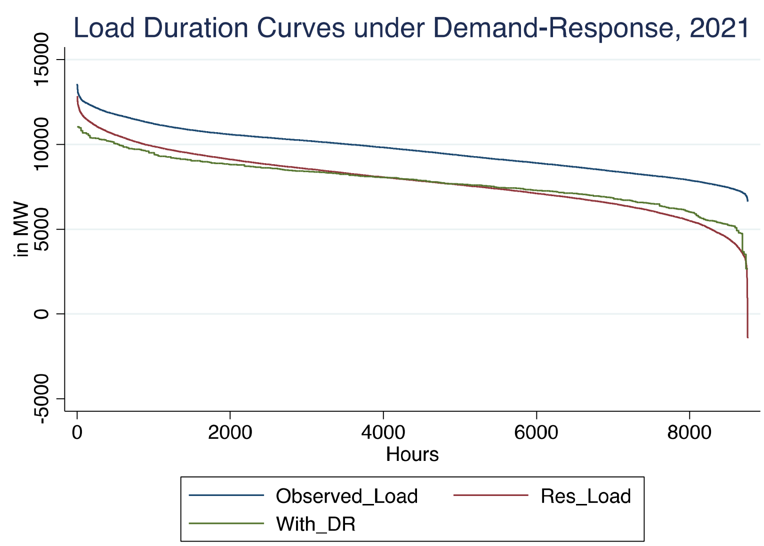

Fig. 7 Load duration curves, with renewables and DR for 2021[81]. Data retrieved from Elia

[80] We refer the reader to the Introduction for the definition of the load duration curve.
[81] We choose to discuss the values for 2021, as 2020 might not be representative due to the Covid crisis.

In Figure 8, we look more into detail into the first 1000 hours of the load duration curve.

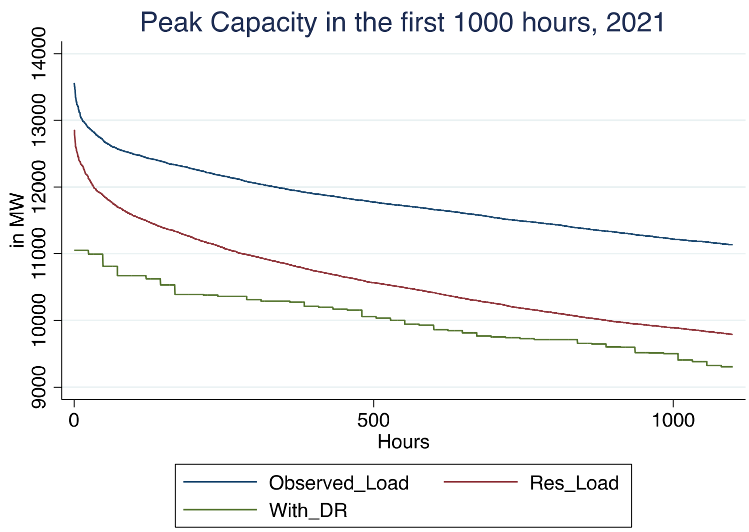

Fig. 8 Peak capacity requirements for the first 1000 hours, for 2021. Data retrieved from Elia

In 2021, leveraging DR lowers the need for peak capacity by 1660 MW at the highest peak hour. Put differently, the cost of not encouraging DR is equal to the maintenance of roughly four 415 MW power plants, which would only be used for 1 hour every year. Even more relevant, the introduction of DR would reduce the need for these additional 1660 MW in the first 53 days of the load duration curve. Put differently, DR could fill the capacity gap during the 53 most critical days of the year, equivalent to 15% of the time.

2.4.4 Conclusion on demand response potential

Table 3 summarizes the findings of the three approaches we have discussed. Each approach has its strengths and limitations. The approach based on existing (activated or not) DR provides a lower bound on the actual potential for DR. It ignores the potential from consumption currently not exposed to the day-ahead market. The theoretical approach is the most optimistic approach since, as pointed out by Gil (2014), it does not account for the technical ability to activate it (information and communication infrastructure), nor whether it is cost-efficient to activate it, or whether it would be socially acceptable. It thus provides an upper bound to the potential for DR.

The load-based approach aims to indirectly get at the cost-effectiveness of DR and economic incentives but it also has limits. First, the net load profile is only a proxy for the price profile and thus it may not be economically profitable for consumers to shift their loads, even if they had the information and price incentive. Second, we have no guarantee that the identified DR is technically feasible or socially acceptable.

The load-based approach focuses on implicit DR through *load shifting* and therefore complements the E-Cube approach based on a price threshold which corresponds to implicit DR through *load shedding*. It is interesting therefore to note that the sum of downward DR using the existing DR and load-based approach reaches the number obtained (for 2010) using the theoretical approach.

	Measure	Upward DR	Downward DR	Year
Existing DR	Observed price-responsive bids by demand-side participants	-	850 MW ± 409	2021
Theoretical	Available facilities and devices	4735 MW	2043 MW	2010
Load-based	Scope for intra-day shifting	893 MW	823 MW	2021

Table 3. Summary of the different measures of demand-response potential for Belgium

Table 3 suggests that almost half of the theoretical DR is already tapped. Existing DR consists of mostly industrial demand. This suggests that the main source of untapped DR in Belgium is residential demand (which Gil (2014) evaluated at approximately half of downward DR potential).

A limitation common to all approaches presented in this section is that they rely on past data and therefore do not account for the likely deployment of EVs and batteries which will contribute to DR in the future.

2.5 Ongoing initiatives in Belgium

In this section, we discuss some ongoing developments which might impact the topics analyzed in our research or the results we provide. Taking those initiatives into account will assure that the results of the project are not obsolete, inaccurate, or irrelevant in coming years. New markets are being continuously designed, new players enter into the space, and new business models are being developed all to be able to accommodate new DR-centered flexible products.

2.5.1 Discussion on the Transfer of Energy (ToE)

Section 2.2.2 explained that the federal framework has been modified in 2017 to introduce the concept of ToE. A framework with associated rules has been developed by Elia since then. The ToE is now in place in the following markets: day-ahead, intraday, aFRR, mFRR. However, ToE is not yet applicable for Low Voltage (LV) consumers, in particular because a 15-minute metering device is necessary, which could act as a barrier for the development of DR at the residential level.

1.2.1 Consumer-Centric Market Design (CCMD)

In order to foster the large-scale participation of retail DR, the Belgian TSO, Elia, is proposing a new market design called the “Consumer-Centric Market Design” (CCMD). The general concept has been published in 2021 and is now being refined. It is based on two main pillars: a real-time pricing reference (instead of a day-ahead pricing reference), and the exchange of energy blocks on a 15-minute basis.

2.5.2 Energy communities and P2P trading

As explained in section 2.1, energy communities are new players that could play a key role in the development of residential DR. Following the electricity directive of 2019, legal frameworks have been adopted in 2022 in Belgium. Energy communities are thus expected to progressively being developed in the upcoming years.

2.5.3 Blockchain technology in energy sector

The Energy Web Chain is the world’s first public blockchain tailored to the energy sector. The aim is to develop an ecosystem where any energy asset, owned by any customer is enabled to participate in any energy market by assigning a digital identity to each asset (stored on the asset’s digital wallet) which can be securely shared. This increases the visibility of different assets in the ecosystem, and thus can unleash the potential flexibility they can provide by dramatically simplifying the process of data exchange between asset owners and participants of the energy sector, such as TSOs, energy suppliers, and FSPs. Notably, Elia, as an active member of the Energy Web Chain which validates the blockchain transactions, has successfully demonstrated a TSO-visible EV charging session, laying the groundwork for improved EV charging, including RES-only charging and fast supplier switching.

3 Relevant practices in other countries

In this section, we present mechanisms that are used in some other European countries to encourage the deployment of DR. Their application or equivalent in the Belgian market design is further discussed.

3.1 Valuation of demand response in days of critical security of supply in France

In France, a capacity market has been introduced to ensure adequacy of the energy mix in the long run. Four years before the year of delivery, suppliers and system operators need to show that they are able to cover their peak demand for that given year and compensate for losses on their networks. To do so, they have three channels:

(i) Four years in advance, they must purchase certificates for generation of electricity from producers, matching the volume of peak demand forecasted for the year of delivery.

(ii) Up to the year before delivery, they can encourage their consumers to reduce their consumption when the TSO signals critical days. For instance, EDF, a French multinational electric utility company, has certified a small volume of implicit DR, which corresponds to the share of their customers under critical peak pricing tariffs.

(iii) Up to the year before delivery, they can procure explicit DR from the capacity market. The "Notification d'Echange de Blocs d'Effacement" (NEBEF) mechanism, encourages large consumers or aggregators to value and sell their DR, such as load shedding and shifting as negative capacity in the capacity market. This encourages consumers who can bring added value relieving the system at critical times of peak consumption to participate and be remunerated for this service.

Peak demand for one supplier can occur on days that are different from critical days of peak demand at aggregate level. Implementing a capacity market should ensure that suppliers cover their consumption, even if all consumption peaks occur at the same time.

The capacity market should be able to support the maintenance of existing peak plants, while also encouraging the deployment of DR, through high certificate prices.

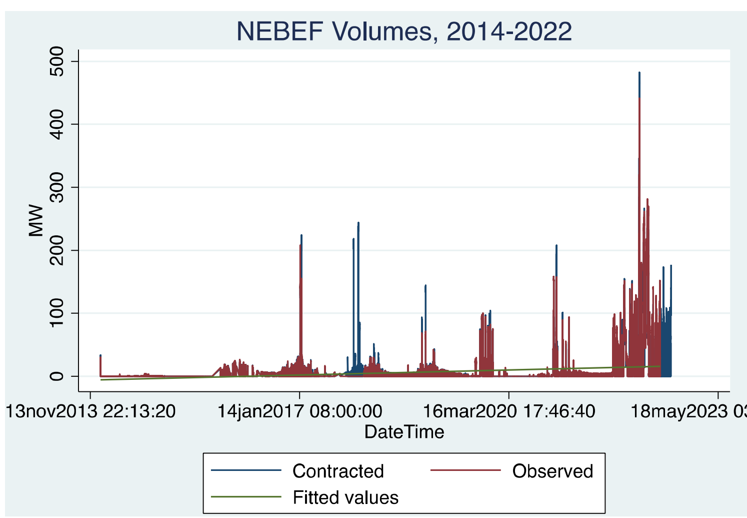

Fig. 9 Volumes contracted and observed in the French market, 2014 to 2022.[82] Data: RTE

[82] Contracted volumes are provided to the TSO ex ante. Observed volumes are the volumes effectively measured on the grid ex post. There are periods where the two differ significantly, but this seems to improve over time.

As can be observed in Fig. 9, since 2014, the contracted volumes have increased annually. In March 2022, the volume contracted on the market exceeded 400 MW, roughly equivalent to the installed capacity of one gas plant.

Contracted DR is equal to 2.8 GW, or 3% of total installed capacity, but 15% of peak capacity.[83] The potential to substitute for peak capacity at critical peak hours is non-negligible.

The implementation of the NEBEF mechanism provides a relevant case study. Firstly, the capacity market is decentralized, as opposed to the Belgian capacity market. Delegating the responsibility to market participants to ensure the adequacy of the energy mix might improve the signals sent through the prices of the certificates and encourage DR more effectively, as BRPs are incentivized to make their own customers flexible. Secondly, if we compare the numbers for France to the measure of market-response in Belgium of 1 GW in 2020 and 1.8 GW in 2021, which are roughly equal to 6-10% of total installed capacity and 14-25% of peak capacity, we argue that the implementation of a similar mechanism in Belgium could positively contribute to the alleviation of the system at critical times of peak consumption and encourage further deployment of DR to substitute for new peak capacity on the long run.

3.2 Demand response in the UK

The UK is one of the pioneers in the integration of DR in the system. Roughly 90% of DR is provided through large industrial and commercial customers, while small to medium customers provide the rest.[84]

The demand side can participate in different electricity markets (whether directly or via aggregation) and provide explicit flexibility. Customers can participate through suppliers in the day-ahead and intra-day markets. The capacity market is also open to DR; however, there have been concerns about the technological neutrality of capacity mechanism in the UK as over-procurement in the UK capacity auction can eventually lead to discrimination against DR and interconnections.[85] National Grid, the British TSO, considers balancing mechanisms as the ultimate flexibility market. There are 20 balancing and ancillary products in the UK, such as reserve services and constraint management services.[86] In particular, DR activity in the adequacy services and balancing markets was high (2.3 GW for Firm Frequency Response (FFR) in 2018 and around 10 GW across 3 tenders for Short-Term Operating Reserve (STOR) in 2018).[87] In 2020, STOR was put on hold and dynamic containment was introduced in October 2020, attracting 300 MW of battery projects in the first year. On the other hand, FFR remains one of the attractive products to DR technologies.[88] Figure 10 shows the participation of DR

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[83] 2.8 GW of contracted demand-response capacity, 139 GW of installed capacity, 18.4 GW of peak fossil capacity (gas-, fioul-fired plants, industrial waste and others) , available at https://www.services-rte.com/fr/visualisez-les-donnees-publiees-par-rte/capacite-installee-de-production.html

[84] Forouli, A., Bakirtzis, E. A., Papazoglou, G., Oureilidis, K., Gkountis, V., Candido, L., ... & Biskas, P. (2021). Assessment of Demand Side Flexibility in European Electricity Markets: A Country Level Review. *Energies*, *14*(8), 2324.

[85] Newbery, D., & Grubb, M. (2014). *The Final Hurdle?: Security of supply, the Capacity Mechanism and the role of interconnectors*. University of Cambridge, Department of Applied Economics, Faculty of Economics.

[86] *Ibid*

[87] Armentero, A. S., Gkogka, A., Løken, I. B., de Heer, H., Bjørndalen, J. (2020). *A state of the art review of demand side flexibility*, Report to the Swedish Energy Markets Inspectorate, available at https://ei.se/download/18.5b0e2a2a176843ef8f56cafe/1611643284198/A-state-of-the-art-review-of-demand-side-flexibility.pdf

[88] National Grid ESO. (2021). 2020 Power Responsive Annual Report, available at https://powerresponsive.com/wp-content/uploads/2021/03/Power-Responsive-Annual-Report-2020.pdf

technologies, mostly belonging to storage, in the FFR market from 2020 to 2021, while DR delivered almost 100% of dynamic FFR services in 2021.[89]

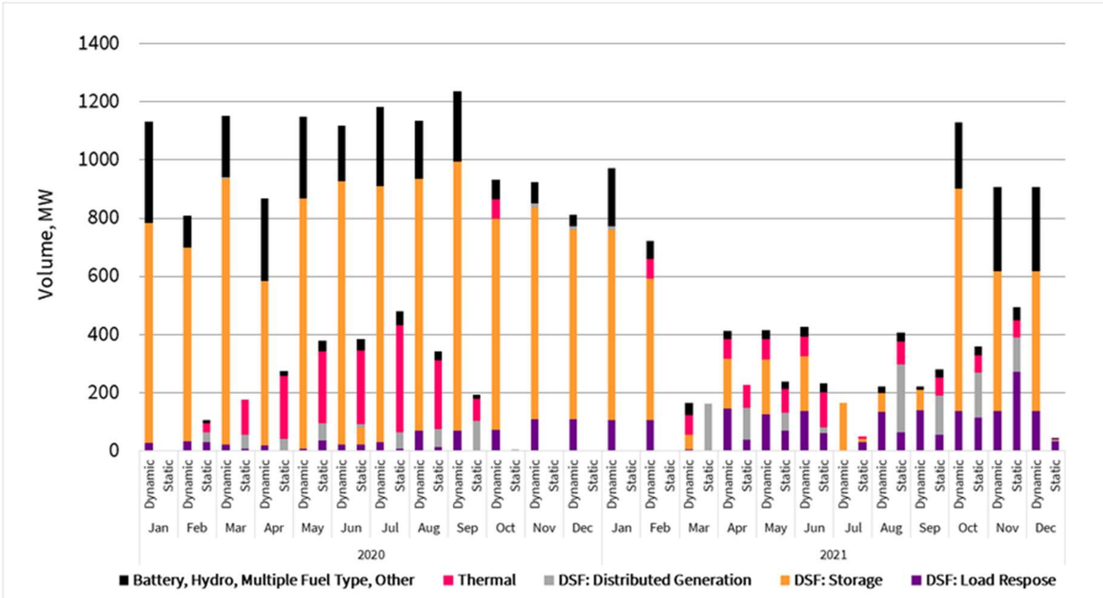

Fig. 10 Dynamic and static FFR contracts secured in the monthly market by technology[90]

For constraint management on distribution level, all six UK DSOs were involved in a trial, Piclo Flex platform, to form the first GB-wide flexibility marketplace; this platform gathered over 4 GW worth of flexibility (or 2.8 million household's worth).[91] In 2021, 2.9 GW of local flexibility services were tendered for constraint management.[92]

Furthermore, DR is stimulated implicitly in the UK by imposing network tariffs at the transmission and distribution level as well as imposing supply tariffs. TSO provides an implicit tariff, namely Triad Avoidance, for large and medium industrial and commercial customers with half-hour metering. The Triad refers to the three half-hour settlement periods with the highest system demand between November and February. National Grid uses the Triad to determine transmission network use of system charges for the participants to incentivize them to reduce their load during peak demand.[93] At the distribution level, DSOs offer tariffs to avoid or delay network investments or reduce losses.[94] The "Distribution Use of System Charge Avoidance" tariff allows customers to aid DSOs in relieving

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[89] National Grid ESO. (2022). 2021 Power Responsive Annual Report, available at https://powerresponsive.maglr.com/annual-report-2021/market-metrics

[90] *Ibid*

[91] Armentero, A. S., Gkogka, A., Løken, I. B., de Heer, H., Bjørndalen, J. (2020). *A state of the art review of demand side flexibility*, Report to the Swedish Energy Markets Inspectorate, available at https://ei.se/download/18.5b0e2a2a176843ef8f56cafe/1611643284198/A-state-of-the-art-review-of-demand-side-flexibility.pdf

[92] National Grid ESO (2022). Power Responsive Summer Event 2022, available at https://www.nationalgrideso.com/document/263811/download

[93] National Grid (2015). *Introduction to Triads*, available at https://www.nationalgrideso.com/sites/eso/files/documents/44940-Triads%20Information.pdf

[94] Ofgem. (2016). Aggregators - Barriers and External Impacts, available at https://www.ofgem.gov.uk/sites/default/files/docs/2016/07/aggregators_barriers_and_external_impacts_a_report_by_pa_consulting_0.pdf

congestion; in return, they are compensated through a discount on their energy bill. Additionally, DSOs offer another tariff called "Flexible Connection". This tariff enables DSOs to enter a bilateral agreement with large customers to encourage them to reduce their demand to avoid grid congestion.[95]

[95] Forouli, A., Bakirtzis, E. A., Papazoglou, G., Oureilidis, K., Gkountis, V., Candido, L., ... & Biskas, P. (2021). Assessment of Demand Side Flexibility in European Electricity Markets: A Country Level Review. *Energies*, *14*(8), 2324.

4 Main barriers hampering demand response in Belgium

This chapter provides a discussion on the potential barriers to the full exploitation of DR in Belgian electricity markets and raises important considerations that policymakers and energy utilities would need to address in the future. Some barriers are pervasive in the legal, economic, and technical fields, which we introduce in section 4.1, before diving into barriers, which are more specific to the legal, economic or technical fields. This section provides the basis for the research that will be carried out within the framework of the DemandFlex project.

4.1 Smart metering as a common barrier to the deployment of DR

Throughout this report, the role of smart metering is evidenced as an essential foundation stone in the deployment of DR. It plays an indispensable role in the retail market (cf. section 4.3) and for the efficient operation of the grid (cf. section 4.4), for both implicit and explicit DR.

Even though smart metering is considered an enabler of DR, its wide-scale implementation in Belgium is hampered by two concerns. Firstly, the large-scale deployment of smart metering raises concerns on interoperability, i.e., "the ability of two or more systems or components to exchange data and use information."[96] Secondly, the access to data and its implications for customers' privacy and security curtails the development of a legal framework. These concerns are further discussed in the legal and technical sections and will be studied in the framework of the DemandFlex project to analyze the extent to which these concerns can be mitigated along the large-scale deployment of smart meters.

4.2 Legal and regulatory barriers

Legal and regulatory barriers can be created by different types of norms. The first situation that comes to mind is when a norm simply prohibits a certain conduct. Yet, when it comes to DR, this type of barrier is not prominent. Indeed, as discussed in Section 2.2, the legal and regulatory framework surrounding DR aims at promoting its development. Yet, there are regulations whose lack of clarity can influence the development of DR or regulations whose observance can be a barrier to its full potential. These are the types of barriers that have been identified and will be analyzed in the framework of the project. More specifically, three main barriers are identified.

- Smart metering, data management, and privacy

The first barrier is the access to smart meters and consumption data. Access to (constant) data is an essential prerequisite to achieve DR deployment. This access is enabled by the deployment of smart meters. Yet, this deployment depends on a cost-benefit analysis performed by each EU Member State and in Belgium, each region. Currently, the deployment of smart meters in Belgium (especially in Wallonia and Brussels) has been very slow. Privacy and data protection requirements are often pointed out as slowing down this deployment.

While data protection legislations, such as the GDPR[97] indeed set conditions for the processing of personal data, it is important to analyze in detail what these conditions are and how it constitutes a barrier to access to consumption data, which is an essential condition for DR.

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[96] Van der Veer, H., & Wiles, A. (2008). *Achieving Technical Interoperability – the ETSI Approach* [White paper]. European Telecommunications Standards Institute, available at https://www.etsi.org/images/files/ETSIWhitePapers/IOP%20whitepaper%20Edition%203%20final.pdf

[97] Regulation 2016/679 of the European Parliament and of the Council of 27 April 2016 on the protection of natural persons with regard to the processing of personal data and on the free movement of such data, and repealing Directive 95/46/EC (General Data Protection Regulation).

The legal part of the DemandFlex project will therefore focus on these issues to determine to what extent privacy issues constitute a barrier to DR.

- The unclear power allocation between the regions and the federal authorities regarding energy matters

The second barrier relates to the Belgian federal architecture and the power allocation between the federal government and the regions. The competence for a government to adopt a regulation relating to DR is at the heart of this regulation. Indeed, the absence of competence to regulate a certain question is sufficient to invalidate the whole legislation.

The power allocation between the federal government and the regions regarding energy matters has mainly been established in the 80s and leaves a lot of room for interpretation. The question of competence with respect to DR is not solved directly in the law.

Governments have therefore interpreted the allocation of competences in the field of energy and today, each government considers itself competent for certain aspects of DR. Therefore, they have all adopted rules that apply to some aspects of DR (cf. section 2.2). Yet, there is still a lot of uncertainty about the allocation of energy competences and how the regulation of DR and its specificities can fit into this allocation. The DemandFlex project aims to shed light on this allocation, to clarify where and when a certain legislator is competent when it comes to DR, in order to avoid legal uncertainty.

Insofar as the federal government is responsible for certain aspects of DR and the regions for others, it is important to analyze the extent to which concerted action between the levels of power needs to take place. The question of cooperation between the levels of government is therefore at the heart of the analysis of this barrier.

- The regulatory framework for network tariffs

The third barrier relates to the regulation on network tariffs. Electricity price and network tariffs can both trigger (implicit) DR, as they constitute a price signal. However, network tariffs are highly regulated and not subject to a market-oriented rationale. The setting of network tariffs independently from the needs for flexibility on the grid could hamper the potential for DR. Inversely, adding a dynamic component could enable further DR, as network tariffs account for 25 to 30% of a customer's final electricity bill.[98]

There is a growing literature on new models of network tariffication, which would trigger implicit flexibility. However, network tariffs must also respond to criteria of public provision, in that they must "be cost-reflective, transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are *applied in a non-discriminatory manner*. Those charges shall not include *unrelated costs supporting unrelated policy objectives*".[99]

In the framework of the DemandFlex project, we will analyze to what extent these principles network tariffs must comply with may prevent or promote the adoption of innovative network tariffs promoting DR.

[98] Forbeg (2021) A European comparison of electricity and natural gas prices for residential, small professional and large industrial consumers, available at https://www.creg.be/sites/default/files/assets/Publications/Studies/F20210517EN.pdf

[99] Art. 18 of the electricity regulation.

4.3 Economic barriers

We define economic barriers as rules in the market, which either does not allow the consumers to value their flexibility on a market, or allows it but does not make it profitable, even though it would improve the efficiency of the system and reduce total system costs. This relates to the more complex discussion of neutral vs inclusive market designs, the difference being that even if a market design is considered as neutral, it might still not encourage the participation of DR with respect to other technologies. The question of neutrality of market design is at the heart of the economic research within the DemandFlex project.

We identify two barriers, which we discuss separately for the wholesale and retail markets.

- Is it possible for consumers to sell flexibility in the market?

In wholesale markets, this question relates to the types of bids available to demand-side participants. We introduced the concept of complex bids in wholesale markets in section 2.3.1. These types of bids allow for the elicitation of intertemporal constraints of generation and demand over a day and the consideration of these constraints into the market clearing algorithm. There is no comprehensive study on the impact of complex bids on demand-side participants' bidding strategy. Identifying the incentives for efficient and competitive bidding on the demand side is critical to the identification of the barriers in the design of the spot market. In Belgium, it is particularly relevant to study this impact on aggregators' bidding strategy. Aggregators contract and value DR from smaller consumers. They therefore act as enablers of DR among participants, which provide value to the system but are too small to participate in the wholesale market. Within the framework of the DemandFlex project, we analyze the bid offer from the perspective of providers of DR, namely aggregators and large industrials.

In the retail market, the slow take-up of smart meters is identified as the main barrier in the deployment of DR among households and small firms.

- Is it profitable for consumers to sell flexibility in the market?

Within the types of complex bids, we identify the loop bid as an enabler for aggregators and storage, as loop bids allow participants to buy electricity when the price is low and to sell it when the price is high. For large industrials, this requires to be able to sell generation, which could be done by buying volumes of electricity in the forward market. However, this entails a significant risk if the loop bid is rejected in the market clearing process. This raises the issue of profitability of DR. Leinauer et al. (2022) further identify insufficient revenues and limited power cost savings of load shifting as obstacles to further DR deployment in industrial sectors.[100][101] This supports the view that the value of DR might be more relevant in critical situations of peak consumption, tight supply and high prices, as identified in France through the NEBEF mechanism.

In the retail market, the direct consequence of the absence of smart metering is the inability and unwillingness of suppliers to offer contracts based on dynamic prices, which would vary across the day to reflect the variation of the cost of buying electricity on the wholesale market in real-time. Consequently, consumers are not exposed to price variation and are not encouraged to adjust their

[100] Leinauer, Schott, P., Fridgen, G., Keller, R., Ollig, P., & Weibelzahl, M. (2022). Obstacles to demand response: Why industrial companies do not adapt their power consumption to volatile power generation. Energy Policy, 165, 112876–.

[101] These results are expected to change significantly, driven by the soaring electricity prices in 2021-2022 and electrification as a vector of decarbonization in industries, bringing electricity to the front stage of industrial's cost minimization strategies.

consumption across the day. The volume of DR missing from the residential sector prevented by the smart-meter barrier is significant, as evidenced by Gils (2014)[102] in section 2.4.1

4.4 Technical barriers

We define technical barriers as technological bottlenecks which partially or fully prevent customers and/or SOs from smart provision and/or utilization of flexibility.

We identify three technical barriers, which we study in the framework of the DemandFlex project.

- Low observability of the LV grid

As previously discussed, DSOs are already facing challenges as renewable energy resources impact the energy flow in the power system: the energy that used to flow in one direction (consumption), is now flowing in both directions (i.e., to and from end-customers). While this flow of energy in both directions exists in the current grid, Belgium foresees a drastic change in the electricity mix (i.e., decommissioning nuclear power plants by 2025).[103] Replacing a large part of this decommissioned power by renewable energies is expected to increase the both-direction flow of energy significantly in upcoming years.

High voltage and medium voltage grids have a higher degree of monitoring and automation in comparison to LV grids due to the magnitude, the cost, and complexity of LV grids automation. With the increasing number of renewables across the grid, there is a pressing need for high observability of LV grids and the provision of real-time data on the demand side. To enable this, a vast roll-out of smart meters is a necessity not only for DSOs but also for TSOs aiming to utilize DR for balancing purposes. Effective measurement provisions are essential for the system to know the potential for flexibility.[104]

Additionally, to enable participation of DR in different markets through various products, there will be a need for smart meters with the appropriate resolution according to the service provided. For example, participation in explicit DR schemes for balancing purposes requires metering with high resolution to provide real time data. Moreover, granular sensing is needed to assess other factors related to the provision of flexibility (e.g., thermal comfort and appliance availability) and to capture the impacts of flexibility on customers, e.g., comfort and cost.[105]

A lack of sufficient data because of the low observability of LV grids does not only hamper distribution monitoring and DR, but also it can adversely affect the quality of service to customers[106]

- Insufficient demand-side estimation and modeling

High quality estimation of demand and generation is an integral part of system operation. Forecasting also helps system operators to identify their flexibility needs as much in advance as possible and

[102] Gils, H. C. (2014). Assessment of the theoretical DR potential in Europe. Energy, 67, 1-18.
[103] Elia. (2021). *Adequacy and Flexibility Study for Belgium 2022 – 2032*, available at https://www.elia.be/-/media/project/elia/shared/documents/elia-group/publications/studies-and reports/20210701_adequacy-flexibility-study-2021_en_v2.pdf
[104] Forouli, A., Bakirtzis, E. A., Papazoglou, G., Oureilidis, K., Gkountis, V., Candido, L., ... & Biskas, P. (2021). Assessment of Demand Side Flexibility in European Electricity Markets: A Country Level Review. *Energies*, *14*(8), 2324.
[105] Good, N., Ellis, K., & Mancarella, P. (2017). Review and Classification of Barriers and Enablers of DR in the Smart Grid. Renewable & Sustainable Energy Reviews.
[106] European Smart Grids Task Force EG3 (2019). *Final Report: Demand Side Flexibility*, available at https://ec.europa.eu/energy/sites/ener/files/documents/eg3_final_report_demand_side_flexiblity_2019.04.15.pdf

procure them on the spot markets, i.e., the day-ahead and intra-day markets.[107] Thus, as customers become more flexible and responsive to both price and direct signals and more RES are connected to the distribution grid, the uncertainty on the demand side increases. Therefore, it will be increasingly difficult and simultaneously even more critical for system operators to accurately make forecasts on the demand side to ensure effective system operation.

At the core of the forecasting ability lies the accuracy of real-time estimations of load, which should be done in the least intrusive manner. Customers' participation in DR requires real-time estimation of their demand as well as forecasting the evolution of their demand in the future. New algorithms and models are needed for effective demand-side estimation to make the implementation of DR feasible. We aim to address this within the framework of DemandFlex project.

Moreover, to reduce the complexity of participating in DR and providing flexibility, automatic programming of consumption can aid customers in obviating the need for manual changes in demand; in addition, optimal programming of consumption can facilitate participation of demand in various flexibility products, e.g., balancing services. To enable this, effective modeling of the demand side is needed to consider customers' preferences, characteristics, and financial benefits. We aim to propose optimal consumption programming within the DemandFlex project while demonstrating the potential of demand-side participation in balancing services.

- Interoperability and cyber security

The development of the smart grid and the vast roll-out of smart meters introduces heterogeneity in the systems, posing technical challenges of interoperability[108], i.e., "the ability of two or more systems or components to exchange data and use information."[109] For instance, smart meters involved in identifying flexibility and its impacts on customers as well as different smart building systems may adopt disparate approaches and protocols at the synthetic, i.e., format, level and semantic, i.e., meaning, level, hampering the interoperability and effective exchange of data for implementing DR. Standardization could be the key to resolve this issue. Yet, despite the need for interoperability to implement DR rapidly and at a large scale, interoperability is a slow-moving process because of competing approaches (e.g., adverse effects on manufacturers' market share and profit) and alliances.[110]

One of the main technical barriers hindering interoperability and DR is the cyber security of smart digital systems. Since interoperability aims to connect multiple systems of multiple vendors, interoperable systems can translate into higher risks of vulnerability to cyber-attacks, e.g., system hacking, fraud, and data theft. However, as open interoperable systems bring large user groups as well as various developers and companies together, they can be open to much more scrutiny in comparison with closed or conventional systems and allow continuous revision of codes and protocols by experts; this means that interoperability may eventually bring about lower overall risks.[111] Hence, the increased

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[107] Ibid
[108] Good, N., Ellis, K., & Mancarella, P. (2017). Review and Classification of Barriers and Enablers of DR in the Smart Grid. Renewable & Sustainable Energy Reviews.
[109] Van der Veer, H., & Wiles, A. (2008). *Achieving Technical Interoperability – the ETSI Approach* [White paper]. European Telecommunications Standards Institute, available at https://www.etsi.org/images/files/ETSIWhitePapers/IOP%20whitepaper%20Edition%203%20final.pdf
[110] Good, N., Ellis, K., & Mancarella, P. (2017). Review and Classification of Barriers and Enablers of DR in the Smart Grid. Renewable & Sustainable Energy Reviews.
[111] Verbeke, S., Laffont, K., & Rua, D. (2022, May). Interoperability as a driver or barrier of smart building technologies?. In CLIMA 2022 conference.

uptake of smart technologies and devices in energy systems highlights the importance of cyber security to mitigate security risks and facilitate the implementation of DR.

5 Conclusions and perspectives

The objective of this report is to provide an exhaustive discussion on the concept of DR and its status in Belgium.

Flexibility is an inherent need of power systems. The deployment of DR provides a cost-effective solution to multiple issues related to the evolution of the power system towards a low-carbon intermittent generation mix, such as concerns of adequacy and security of supply and lack of competition on the different electricity markets.

We have presented a formal definition of DR, which encompasses the diverse forms in which the flexibility from customers can be valued on the existing markets. The definition stems from the European electricity directive. As discussed, the European directives are translated in the legislation of Member States with some leeway.

In addition, in Belgium, the vague allocation of competences across the federal authority and regions with respect to energy matters has allowed each government to consider itself competent for some aspects of DR. As a result, a dense legal framework surrounds DR. Yet, its validity is not certain.

We also analyze the participation of DR in the different electricity markets in Belgium, both in terms of rules of participation and effective participation in the market. In Belgium, similarly to most European countries, splits the wholesale market into forward, spot, and balancing markets. Compared to the rest of the EU, Belgium allows the participation of DR to balancing markets. Inversely, in the retail market, the lack of large-scale smart metering deployment results in a majority of households still having a fixed tariff.

It is difficult to measure the extent to which the current market design encourages the deployment of DR without a consistent measure of the potential of DR in Belgium.

This led us to think about the best measure to quantify the potential for DR. We identify three different approaches, with their own strengths and limitations. The theoretical potential, developed by Gils (2014), which aggregates the potential of the devices and technologies across industrial, commercial, and residential sectors. The load-based potential, which estimates the extent of flexibility that is observed but not valued in the market. Note that it does not consider flexibility that was provided before the market clearing, as is the case of the market-response potential. This measure is computed by Elia to determine the need for strategic reserves during winter, and aggregates price-sensitive bids above a given threshold at which bids are considered as DR, even if some are supply bids. Within the framework of the DemandFlex project, we aim to conduct additional research on this topic, and to provide a consistent measure of DR potential.

We also identified potential sources of disruption of electricity markets in the following years, which would interact with the scope of our research. Energy communities and peer-to-peer trading would decentralize the exchange of electricity. This has significant implications for the existing markets and grid operation, both at distribution and transmission level. Blockchain technology will ease participation of customers in energy market by assigning a digital identity to each asset, and will thus secure and also simplify the process of data exchange between asset owners and participants of the energy sector.

We have analyzed the design of other European electricity markets and identify two relevant cases of study. In France, the responsibility of long-term supply adequacy is delegated from the TSO to market participants, through a capacity market. DR is an essential component of this market, as load shedding and shifting can be valued as negative supply and therefore contribute to security of supply. Furthermore, the mechanism allows DR to be valued at times of critical of tight supply and peak load. This accommodates well with DR, which is relatively costly for large consumers to operate (Leinauer et al., 2022). In the UK, DR participates in every market, either alone or through aggregation. 100% of the dynamic FFR (a type of reserve) was provided by DR, more specifically storage. Furthermore, the UK has implemented dynamic network tariffs at transmission and distribution level, which vary across the type of consumers in the grid and aim to reduce consumption during peak periods as well as congestion periods. These study cases provide relevant insights for Belgium and will be further analyzed within the scope of the DemandFlex project.

Lastly, we identify and discuss barriers to the deployment of DR in Belgium. A common and overriding barrier is the slow deployment of smart meters. Even though concerns on the interoperability between smart meters and other communication devices and the security and privacy of data access are legitime concerns, they should not curtail the implementation of smart metering. The legal and technical alignment of large-scale deployment of smart metering to alleviate these concerns sets the ground for research that will be carried out within the DemandFlex project. Further barriers related to the legal framework are the inconsistent allocation of competences between regions and the federal authorities and the ambivalent role of network tariffs. Additional economic barriers are the implementation of dynamic tariffs in the retail market. In the wholesale market, we aim to ascertain the extent to which customers are incentivized, i.e., remunerated, to put forth their flexibility on the different markets. The underlying scope for research is the extent to which low demand-side responsiveness observed in markets is driven by inherent lack of flexibility or restrictive bid design. One point of attention is the evaluation of the role of the ToE between aggregators and their customers' suppliers as enabler or barrier to the deployment of DR. Lastly, further technical barriers are the currently low observability of the LV grid, which hinders real-time measurement of the load and more accurate forecasts of the load for system operators.

While we focus on the Belgian case, the value of DR also lies beyond national power systems. As power systems become interconnected, reliability becomes a European-wide concern. According to smartEn, a European consortium of demand-side participants in electricity markets, the full deployment of DR would be able to fill the capacity gap in the EU by 2030, substituting the 60 GW of peak capacity that would be otherwise needed to support the further deployment of renewables.[112]

[112] DNV (2022) Demand-side flexibility in the EU: Quantification of benefits in 2030, available at https://smarten.eu/wp-content/uploads/2022/09/SmartEN-DSF-benefits-2030-Report_DIGITAL.pdf