Work Package Market Uptake | Market definition task

Deliverable 3.6: Policy Recommendations for the Uptake of Distributed Flexibility

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Contents

1. Introduction

This deliverable is part of **'Work Package 3: Market Uptake'** and more specifically, '**Task 3.3: Market definition'** which covers the discussion on how low voltage, distributed flexibility can be offered to the electricity markets and/or balancing markets, considering technological requirements and constraints, revenue streams and remuneration schemes. To this end, we first elaborate on the design of the Belgian electricity markets. Next, we discuss to what degree this design forms barriers for low voltage, distributed flexibility sourced from households. Finally, we develop policy recommendations to lower such barriers. This deliverable does not perform any techno-economic modelling to evaluate which markets provide the highest opportunities and best business case for the low voltage, distributed flexibility.

The analyses are carried out in the following chapters. Chapter 2 sheds lights on the meaning and definition of low voltage, distributed flexibility from households. In Chapter 3, we provide an overview of the wholesale electricity markets and how flexibility can be valorised in these markets. Chapter 4 elaborates on how household flexibility opens doors for changes in the retail market. Chapter 5 discusses and analyses to what degree the market design forms technological, regulatory and economic barriers for the household flexibility. Next, we develop policy recommendations to reduce these barriers. We conclude in Chapter 6.

2. Low voltage, distributed flexibility services

2.1. Sources of low voltage, distributed flexibility

Historically, flexibility had been provided by large central power plants or pumped hydro storage on the transmission level or higher medium voltage levels. Only within the last decade, flexibility from distributed generation came into the picture from medium voltage level sourced from wind, biogas and industrial demand response. This flexibility has achieved a level of maturity making it a reliable source for managing portfolios and ancillary services supporting grid stability. With the uptake of renewable energy and a diminishing share of flexibility in the generation of electricity (mainly due to closure of gas fired plants), the amount of flexibility will need to be increased.

There is however still a large potential in bringing the low voltage flexibility to the market. Until recently, only the day-night tariff provided incentives for low-voltage flexibility, but the value creation for grid balancing and solving congestion was highly limited. Sourcing costs for more advanced ways of low-voltage flexibility provision are high – e.g for implementing monitoring and control -, and the returns of the single owner of flexible assets are low. Moreover, the lack of regulatory frameworks and data might create additional barriers.

This does not mean that low voltage flexibility is utterly disregarded. There are pilot projects carried out looking at key flexibility sources like e-boilers and electrical vehicles. Although there is hardly a business case for the low voltage flexibility on electricity markets, the general electrification of the energy sector picks up speed and households are an active part of this movement: PV rollout has been further increased, electric vehicles are gaining popularity, electrical heating and air conditioning consumption is growing significantly, etc. As such, it is important to recognize the huge need and potential of low voltage flexibility and prepare for its market participation.

2.2. The valorisation of low voltage, distributed flexibility

We distinguish two types of flexibility which can be seen complementary as they allow for optimal consumer choices and system efficiency (Van der Veen et al., 2018; Smart energy Demand Coalition, 2016).

- **Implicit flexibility** is provided as a household's reaction to strong price incentives, triggering investments into devices that consider time of use and aligning households schedule consumption with PV generation and low market prices.
- **Explicit flexibility** is being steered by a flexibility service provider (FSP), which enables the monitoring and controlling of large volumes of small, flexible assets delivering support to the grid operators or using the flexibility on the energy markets.

3. The value of flexibility across the Belgian wholesale markets

3.1. The electricity market design

The electricity system encompasses a complex multi-market design to supply electricity to consumers while keeping the grid stable. The electricity markets are organised consecutively in time. A distinction can be made between the long- and short-term markets. Flexibility can be valorised on all these markets, but in practice it is only relevant on the short-term markets.

The long-term markets facilitate energy trading from several years until days ahead delivery. There are various reasons for market parties to make use of this long-term energy trade; they might want to fix their budget, hedge risks, secure revenue streams from renewable energy investments etc. The long-term energy trading can be organised either over the counter (bilaterally) with customised forward contracts, or through centralised trade platforms with standardised futures contracts. On the trade platforms, market parties can hedge large volumes at predetermined fixed prices, called power futures. In Belgium, the ICE Endex and EEX are the two most known long-term trade platforms. Products on these platforms are standardised, (e.g. the product "Belgian Cal-23 base power futures" which represents delivery of a baseload volume in MWh for the year 2023) whereas over-the-counter trade allows much more customisation.

Short-term markets are more aimed at energy trading for the purpose of profile matching and portfolio optimisation (see Figure 1). The short-term markets consist of the day-ahead, intraday and real-time reserve power markets, organised respectively one day before delivery, one day up to 5 minutes before delivery on the delivery day and real-time on delivery day. Elia, the Belgian Transmission System Operator (TSO) needs to always balance the grid of its control zone (Elia, 2022a). Although Elia bears the end-responsibility for the grid stability, Balance Responsible Parties (BRP) assist in this task. The BRP's must balance their individual portfolio of access points by delivery. The day-ahead and intraday markets facilitate this portfolio optimisation by enabling short-term trades, and as such help preventing imbalances. To stimulate BRP's in keeping a balanced portfolio, they will be awarded or penalized according to the real-time system imbalance. Often this imbalance settlement is referred to as the imbalance market. BRP's can deliberately create imbalances in their portfolio, which are settled by Elia against the imbalance price. Elia explicitly allows this form of creating an imbalance under the condition that the party can at any time go back to a balanced state. As such, flexibility can be valorised by steering on the expected imbalance price. Yet not all TSO's allow such an imbalance steering. The last market in the chain is the reserve power market, which is organised to solve the real-time imbalances. Usually, the reserve power market is organised again as a consecutive chain of markets that differ in urgency and accuracy.

Market	Day ahead market	Intraday market	Imbalance settlement	Reserve power market
Timing	D – 1 day	Delivery		Time
Purpose and Activities	Balanced portfolio nominations based on day-ahead forecasting	Final portfolio adjustments based on new forecasts	Settlement of the portfolio based on the imbalance in the system and in the portfolio	Restoring the imbalances, depending on urgency and accuracy

Figure 1: The short-term electricity markets

3.1.1. The day-ahead market

The day-ahead market is the first market in the chain of consecutive short-term markets which enable the matching of consumption and production profiles, i.e. one day before delivery. The market is organised as an auction. Although the organisation of day-ahead auctions is liberalised and thus susceptible to competition, the most used platforms in Europe are EPEX SPOT and Nord Pool, of which EPEX SPOT is the most common in Belgium. With a tradable volume of 500 TWh in 2021, the European EPEX day-ahead market is the largest of all short-term markets. Compared to for example the EPEX intraday, day-ahead volumes are about 4 times as big. So, typically, the outcome of the day-ahead market is used as a reference for energy trading and planning the next 24-hours. The day-ahead market is organised in multiple European regions. Although every region has its own market, the cross regional coupling has led to converging prices (EPEX SPOT, 2022; Entso-e, 2022). Differences in prices could occur as the result of limitations on the interconnector capacity between regions.

Day-ahead price settlement process

In Belgium on the EPEX SPOT, market participants can submit their bids for the following day until 12 o' clock. The minimum bid size is 0,1 MW. Depending on their bidding strategies, participants can place hourly bids or multi-hour blocks and conditional or unconditional bids. Whereas unconditional bids are price inelastic, the conditional bids often include a minimum sell or maximum buy price to ensure sufficient revenues or lower costs. Additionally, different profiles are auctioned on the day-ahead market, such as baseload, peak and off-peak profiles, which enables effective short-term profile matching. Every hour, all bids are cleared, after which the market clearing price is calculated. So, day-ahead markets have hourly prices. The market clearing is based on marginal pricing, meaning that all bids are ranked in a merit order (Figure 2): from low to high prices on the supply side and from high to low prices on the demand side. The price equilibrium determines the market price and volume. Producers who had bid a price higher than the market price and consumers who were not willing to pay more than the market price, fall out of the market. All remaining market participants pay or receive the cleared market price, regardless of their own bids. Therefore, the day-ahead price mechanism is referred to as pay-as-cleared.

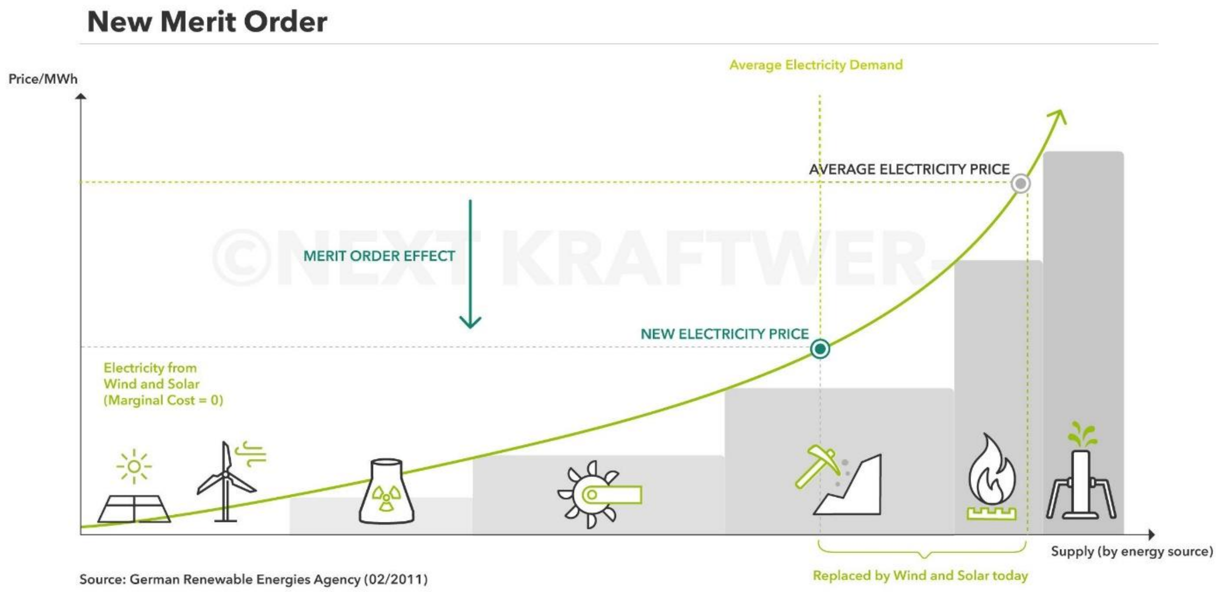
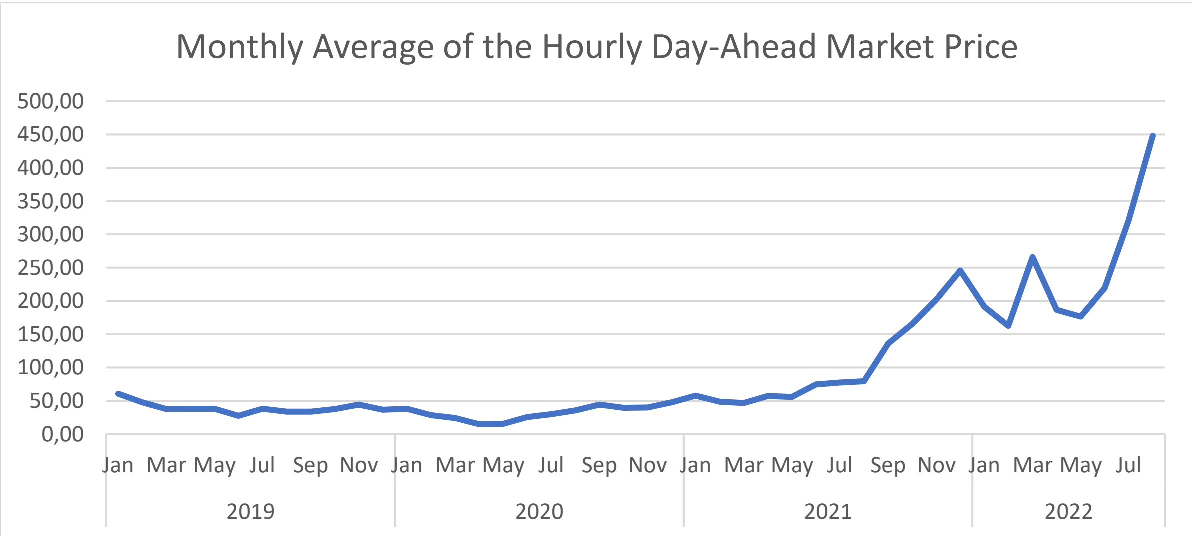


Figure 2: The merit order effect (source: Next-kraftwerke.be)

Discussions of today's high electricity prices relate to the marginal, pay-as-cleared pricing mechanism in the day-ahead market. Currently the high prices are mainly caused by the extreme prices on the gas market, as often gas plants determine the market clearing price (although expensive coal and lignite plants also drive prices up). The gas market suffers under the current geopolitical conflicts, resulting in very high prices for natural gas which are reflected in the electricity prices. Generation units such as renewables, coal and nuclear power that don't rely on natural gas as a resource can earn large inframarginal rents resulting from the difference of their marginal costs versus the clearing price. Although, the pay-as-cleared mechanism is in general considered as very efficient, it has become the subject of a social debate regarding fairness of the system. The graph below illustrates the day-ahead market prices from January 2019 to August 2022.



Graph 1: Evolution of the monthly averaged day-ahead market prices

In 2019, the average day-ahead hourly market price was about 40 €/MWh. As a result of the covid-19 pandemic, prices fell to about 15 €/MWh in April 2020, staying low during the lockdowns and new waves for several months. At the beginning of 2021, prices increased steadily with the revival of economic activity. From summer 2021 *onwards, prices however started increasing exponentially – with from time to time some short time downfalls. Deficiencies in the gas market, market uncertainty and expected cold winter keep current prices extremely high and raise concerns for a more social price policy.*

Implications for low voltage assets

In how far the day-ahead market is interesting for the flexible generation depends on the price spreads and the variability. The official price range of the day-ahead market lies between -500 €/MWh and 4000 €/MWh. So even though current prices are historically high, the price ceiling has not yet been reached. The price variability on the day-ahead market can be considered rather low compared to other short-term markets, as prices show a stable pattern during the day (figure 3). Yet, this variability could increase with increasing share of renewable energy, especially wind energy.

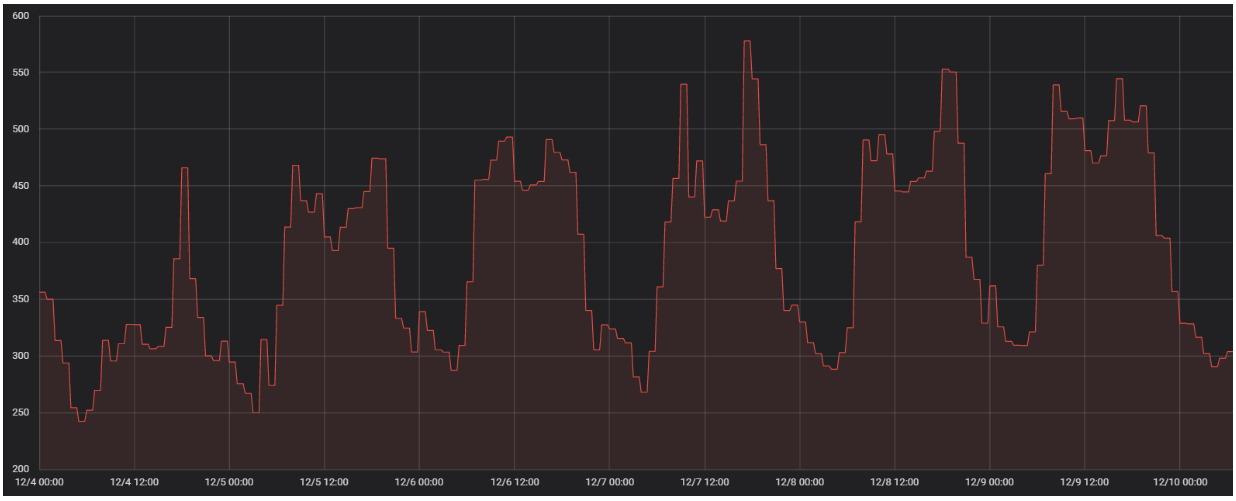


Figure 3: Day-ahead prices from 4/12/22 until 10/12/22

Currently, the volumes for households are procured based on standard load profiles, and not actual hourly volumes. Even if suppliers can procure the volumes for households in the future based on quarterly or hourly profiles, it is highly unlikely that households will plan their consumption day-ahead such that their schedules can be considered on the day-ahead market. The planning consumption will rather be implicit, i.e. load shifting from one hour to another based on price signals. Therefore, suppliers might offer dynamic price contracts in which time of use plays a role. Yet, cost benefits from load shifting would probably be rather limited, although flexibility from societal point of view to solve for example congestion would be highly recommended.

3.1.2. The intraday market

Three hours after the day-ahead market has closed, the intraday market opens. Enabling profile matching close to real-time, the intraday market provides the final chance for Balance Responsible Parties (BRPs) to adjust their portfolios, e.g. because there is new forecasting data available for renewable assets, unforeseen outages change the demand or generation profile, or high price signals make the increase/decrease of generation/demand attractive. Any differences between the day-ahead nominations and intraday deals on the one hand and the final generation and demand metering data on the other hand result in imbalance. The intraday market is therefore in particular the possibility to reduce the imbalance at known prices, while the prices on the imbalance market are only finally known after the quarter hour of delivery.

Like the day-ahead market, the organisation of intraday markets is liberalised, which has resulted in multiple platform providers throughout Europe. The EPEX SPOT and the Nord Pool platform are best known. Both platforms are used in Belgium. We further discuss the EPEX SPOT intraday market, as this platform is most common in Belgium.

Intraday price settlement process

The intraday market is divided into continuous and auction trading, each with their own rules for bidding and trading processes. For both trading options, the smallest tradable unit is 0,1 MW. The continuous market has the highest liquidity and is the oldest market of the two. Therefore, it is the best known.

The EPEX intraday continuous market is organised as a bid-ask system, which means that buyers can submit bid, sellers can submit offers, and when a bid and an offer match, a trade is done. There is no clearing price as in the day ahead market. Every deal is settled on its own value. in which bids and offers are continuously matched with one another. Consequently, market participants pay or receive their individual bid prices. Prices on the continuous market can range from -9.999 to 9.999 €/MWh. The continuous market opens at 15:00 one day before delivery and closes about 5 minutes before delivery. The short lead time of 5 minutes facilitates portfolio management and the handling of unplanned outages, as forecasting happens closer to real-time. Because of the bid-ask pricing system, it is very difficult to monitor the intraday price evolution. Single prices for specific time intervals usually don't exist, as the price depends on the individual bid-offer matching. Moreover, price variability on the intraday is much higher compared to the day ahead market, because of the urgency and obligation to handle unforeseen portfolio imbalances last-minute.

In addition to the continuous market, intraday trading can also be settled in the EPEX intraday auction. This auction was opened in Belgium in 2020. Here, bids and offers are cleared on a 15-minute basis. The auction prices can range from -3.000 to 3.000 €/MWh. The auction opens already 45 days before delivery and closes at 15h one day before delivery. The intraday auction, however, has very low liquidity compared to the continuous trading, especially because of the early closing time.

Implications for low voltage assets

First, households must have digital meters installed that are billable on 15-minute basis. Without this smart infrastructure or adequate submetering possibilities, flexibility cannot be monitored and valorised.

Second, flexibility service providers might experience difficulties to set-up an appropriate remuneration scheme for intraday flexibility because the missing of a uniform intraday market price. Consequently, it could be unclear how to assign intraday trades with offered flexibility. For example: There is a deal of 1000 euros to buy 1MW at 10 o'clock, while the imbalance price is forecasted to go to 2000 €. If now a FSP acts on behalf of a flexibility owner, he has the conflict to click the deal for his portfolio or for the portfolio of the client. The imbalance market however is a uniform price known to all market parties and valid for all market parties. This problem is not unique for low voltage assets but occurs for all assets on the intraday market.

3.1.3. The imbalance settlement

The imbalance settlement refers to the quarter hourly assessment of the system imbalance and the related costs by Elia. Although Elia coordinates the system balancing, it does not bear the related costs. These costs are reflected in a quarter hourly imbalance price and passed through to the BRP's who have an imbalance between metering and market deals. The imbalance settlement is thus rather a settlement process than a market. Although not organised as a market, the settlement does provide important price signals to BRP's unlocking the value of their flexibility.

The imbalance price settlement process

Because the imbalance prices reflect the costs related to solving system imbalance, they are based on the aFRR and mFRR activation prices (see section 3.1.4). These activation prices can be negative. Consequently, so can the imbalance prices. Depending on the BRP's imbalance position, this can result in a payment to or by the BRP (see Table 1). For example, a BRP with a positive imbalance has more injection than offtake. Downward flexibility would then be needed to restore the imbalance, e.g., switching of a generator. In case the imbalance price is positive, then the BRP must pay Elia. In case of a negative imbalance price, which means that the generator owner paid Elia to switch off, Elia pays the BRP.

		Imbalance BRP	
		Positive	Negative
Imbalance price	Positive	BRP pays Elia	Elia pays BRP
	Negative	Elia pays BRP	BRP pays Elia

Table 1: Price matrix

Because imbalance settlement could result in either a penalty or a remuneration, BRPs may strategically react on the imbalance price signals. Low-risk strategies include the prevention of portfolio imbalances and thus imbalance costs, whereas BRP's with high-risk strategies might speculate on imbalance prices to gain revenues. Yet, imbalance prices are highly volatile and very difficult to predict. Currently, Elia works hard to establish a new imbalance tariff structure with a clear real-time signal incentivizing all the remaining available flexibility to help balance the system. Elia will also publish ex-ante imbalance price forecasts to help BRP's interpreting and reacting on imbalance price signals.

Implications for low voltage assets

First, and like day-ahead and intraday market, households must have digital meters installed that are billable on 15-minute basis or need to be able to make use of submetering possibilities. Without this, flexibility cannot be monitored or valorised.

In theory the imbalance market provides a transparent price signal which allows real-time reactions. This price signal could then also be used by households. However, Elia has experienced that price transparency is too small and market information too limited for small market parties. Therefore, Elia is currently evaluating the communication and publication of imbalance information to alleviate barriers for small parties. Nevertheless, the business case for low voltage assets on the imbalance market is probably best in case of aggregation of multiple assets into a large portfolio and in case of explicit steering as imbalance prices are too unpredictable. Yet, there exists a risk of overreaction when households react uncoordinatedly.

3.1.4. Reserve power markets

The reserve power markets are organised in real-time to stabilise the frequency in the electricity grid and as such ensure the operational reliability of the power system. The reason why the grid frequency should be kept in a narrow band around 50Hz is that consuming and generating assets are designed to operate at this frequency. Outside this frequency, appliances might not work and both consumption and generation units might disconnect from the grid for asset protection. Uncontrolled connection and reconnection of demand and generation units will further destabilize the grid. In the worst case the system imbalance results in a blackout.

Elia, the Belgian TSO and most other European TSOs make use of three products – often referred to as ancillary services - to maintain and restore system imbalance: (1) Frequency Containment Reserve (FCR), (2) automated Frequency Reserve Restoration (aFRR) and (3) manual Frequency Reserve Restoration (mFRR). These ancillary services are organised in three consecutive markets. Frequency deviations first need to be solved on the FCR market. When not solved, frequency restoration is passed through to the aFRR market and finally to the mFRR market, which is the last one in the sequence.

An introductory video can be found here: website Elia

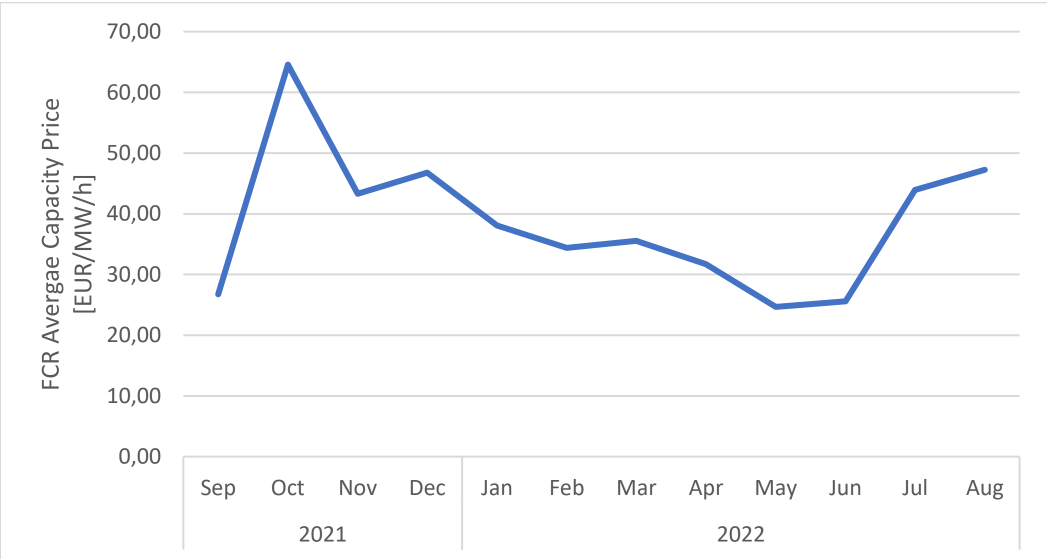
3.1.4.1. FCR (Frequency Containment Reserve)

FCR providing assets continuously monitor the frequency in the grid and will counteract any deviation from the reference frequency (50 Hz in Europe) with a very short response time. FCR services are organised at the European level. To ensure sufficient FCR capacity, every TSO has been allocated a minimum reserved volume which needs to be supplied in case of frequency deviations. For 2022, for example, the Belgian TSO is required to procure about 86 MW FCR volume (87 MW in 2021, 78 MW in 2020), of which at least 30 % needs to be procured on the Belgian market while up to 70% abroad via a common auction organised together with neighbouring countries. (Elia, 2018,2019,2020)

FCR procurement process

FCR is procured via a capacity auction. All bids which have been selected during the auction process, result in an FCR obligation. That means that the service providers need to keep their bid power fully available for the awarded time blocks to provide FCR services to TSOs. The minimum bid size for FCR is 1 MW, with a 1 MW resolution. The service providers receive a capacity remuneration for keeping their power available, equal to the marginally cleared bid (the so-called pay-as-cleared mechanism). No remuneration is foreseen for the energy supplied. (Elia, 2018,2019,2020)

The graph below visualises the FCR prices from September 2021 until September 2022.



Graph 2: Monthly averaged FCR prices

FCR delivery process

FCR aims to contain the grid frequency in a range of 200 mHz around the reference frequency of 50 Hz. Depending on the frequency being above or below 50 Hz, service providers need to reduce or increase power output respectively. Because assets are required to both increase and reduce power (operations in two directions), this product is symmetrical in nature.

The first reaction of an asset on frequency deviation is required within 2 seconds. 50% of the full FCR capacity needs to be delivered after 15 seconds and 100 % at latest after 30 seconds. The ramp to full power needs to be linear. The asset should be able to deliver the flexibility during the full four-hour block.

The data communication with the grid operator is largely set-up and maintained by the flexibility service provider. The provider needs to have a frequency reader installed at their installation and immediately act on frequency deviations. Small assets can be aggregated in an FCR group. For FCR groups with a prequalified FCR capacity < 1.5 MW, centralized frequency measurement is allowed. Yet, regulations are expected to shift towards local or regional measurement. In addition, real-time measurements per installation need to be sent to Elia, with a resolution of 2 seconds. Yet, for groups < 1.5 MW, Elia accepts aggregated measurements. Local measurements should be made available ex-post on request. Power measurements should be of high quality and accuracy, with a rate of 99% (deviation of 10 mHz allowed) and are preferred to be sent directly from the asset. (Elia, 2018,2019,2020)

FCR prequalification process

A prequalification process is initiated to prove an asset's capabilities of providing the FCR service with regards to the technical delivery requirements. As such, prequalification is required for each asset that wants to deliver the FCR service on the market. The prequalification procedure consists of an administrative part, where a set of documents need to be provided and approved, and a real-time test. During the real-time test, the asset is subjected to a predefined power profile and subsequently provides FCR based on the grid frequency for a couple of hours. Elia evaluates the asset's response and determines the prequalified power of the asset. Yet, Elia has developed specific requirements for the prequalification of FCR groups to facilitate this procedure. For example, additional assets can be included to the FCR group without specific prequalification. In that case, the maximum contracted FCR volume remains unchanged. (Elia, 2018,2019,2020)

implications for low voltage assets

Low voltage assets can participate in the FCR market, as long as all administrative and technical requirements have been fulfilled and if prequalification had been successful. The prequalification is a very time-consuming process and could create unnecessary burden for the rather small and standardised low voltage assets. Households and aggregators could bypass the individual prequalification by assigning the asset to an FCR pool.

In addition, the minimum bid size of 1 MW, makes aggregation essential. Household assets need to be aggregated in a pool of about 200 households (assuming you have 5 kW flex available per household) to bid on the market. Combining residential flexibility with (large) industrial flexibility (and thus adding it to an existing pool) seems to be most feasible.

3.1.4.2. aFRR (automatic Frequency Restoration Reserve)

Currently, the aFRR market is organized nationally. In the European PICASSO project, however, ENSTOE together with the European TSO's aim to develop a European platform for aFRR energy exchanges to enhancing economic and technical efficiency within the limits of system security. The connection to the new, European platform requires a review of the current market design, including European-wide product harmonization and standardization of the aFRR products. An example is the standardization of the asset activation time to 5 minutes. The PICASSO platform went live on the 1st of June 2022. According to the latest accession roadmap of the project, Elia should have been connected by August 2022. However, it seems that the connection has not taken place yet, although no official delays were reported. Also, no changes to the activation time were done by Elia. (Elia, 2022b)

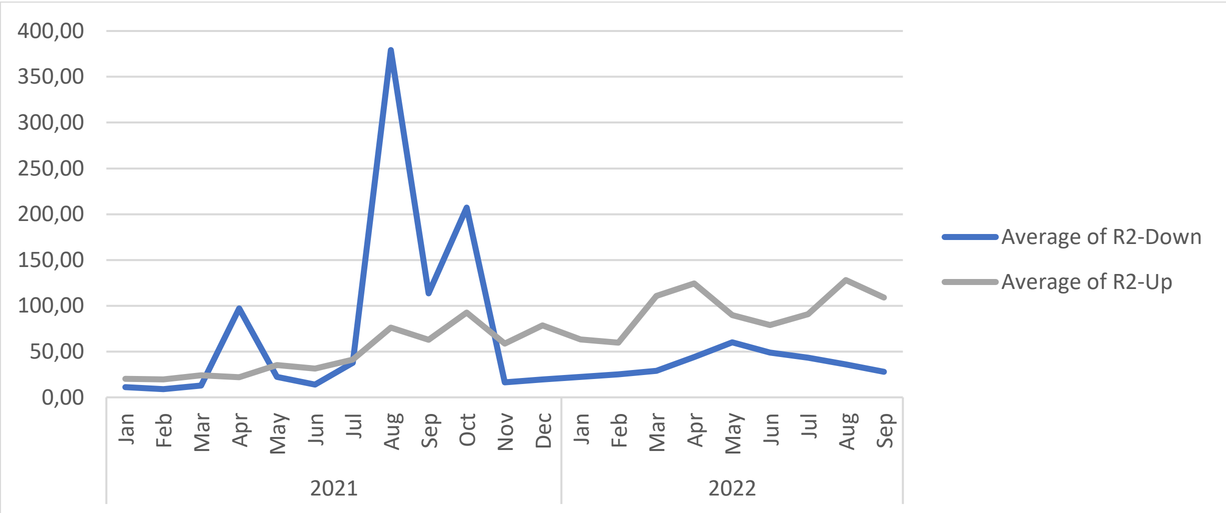
In Belgium, the aFRR product is meant to resolve large imbalances within 7,5 minutes. This product is controlled centrally and automatically activated by the TSO.

aFRR procurement process

To ensure sufficient capacity for aFRR services, the Belgian TSO is required to procure a reserved volume in advance (currently 117 MW). This reserved power is determined by Elia and approved by the CREG and procured on a capacity auction. Market participants that get selected in the auction receive a capacity remuneration for keeping their asset available for aFRR activations. The market clearing is organized following a pay-as-bid mechanism and through four successive steps that aim to efficiently source aFRR cheaply through 24-hour bids whilst ensuring that competitive 4-hour bids are awarded:

1. 4h-bids are combined into “virtual 24-h” bids by always pairing the next cheapest bid for all six 4h-blocks
2. A total cost optimization clears the aFRR up and aFRR down market using 24h and virtual-24h bids. This clearing only sets a reference cost, and only virtual bids are awarded in this step.
3. All virtual bids with a total price below 120% of the reference cost are awarded.
4. If Elia needs any remaining aFRR volume, a total cost optimization is run again on all remaining (virtual & nonvirtual) bids.

The graph below visualises the aFRR capacity prices from January 2021 until September 2022.



Graph 3: Monthly averaged aFFR capacity auction prices

Next, the TSO organizes a market of energy bids, in which it is decided what assets should be activated first for the actual delivery of the aFRR service. Activation prices are based on a pay-as-bid system, meaning that flexibility providers receive an energy remuneration (€/MWh) equal to their market bid. Market participants receive a remuneration based on the actual activated volume. Energy bids have a minimum bid size of 1 MW and a maximum of 50 MW, with 1 MW resolution. The energy is offered in 15-minute blocks. A distinction is made between aFRR up and down energy bids, concerning activations that respectively increase and reduce power injection.

aFRR delivery process

aFRR aims to restore the grid frequency to the reference value 50 Hz within a time frame of 7,5 minutes. Because assets can choose to offer up (increase power) or down (reduce power) services, this product is called asymmetrical.

The first reaction of an asset is required within 30 seconds, after which the requested energy needs to be fully activated within 7,5 minutes and for as long as needed during the contracted block. Every 4 seconds, Elia measures the system imbalance and automatically activates assets to restore the imbalance. These automatic activations take place through the sending of a single aFRR setpoint per BSP. Thus, the balance service providers must set up efficient and real-time communication with Elia.

aFRR prequalification process

Like FCR, a prequalification process is initiated to prove the asset's capabilities of providing the service with regards to the technical delivery requirements. After prequalification, the additional prequalified volume can be offered on the aFRR capacity market.

implications for low voltage assets

Today, the synergrid code explicitly forbids the delivery of aFRR services by low voltage assets. The market is expected to open for these assets earliest in 2023, but in any case not before the PICASSO project have gone live (van Baelen, 2022). Currently, a solution for the market access of low voltage points is studied in the Flexity demo project. Via this project, low voltage assets may participate in the aFRR free bids, yet not in the capacity auction. Also in the project, all data is allowed to be routed through the aggregator instead of via local gateways, which increases the feasibility of the business case (van Baelen, 2022).

Similar to FCR, the minimum bid size on the aFRR market creates barriers for low voltage assets. Aggregation is essential for these assets to participate.

3.1.4.3. mFRR (manual Frequency Restoration Reserve)

mFRR is used as a last resort in case of large, incidental and prolonged system imbalances. These reserves can support the frequency for minutes to hours and help free up aFRR reserves so that they don't get exhausted. Opposed to aFRR, these reserves are activated manually, by a dispatcher checking the system imbalance for large deviations (e.g. falling out of nuclear plant or gas plants).

Today, the mFRR market is organized nationally. The European MARI project, however, aims to establish a European platform for mFRR energy exchanges to increase the balancing efficiency. The connection to the new, European platform requires a review of the current market design, and product harmonization and standardization within the European zone. The connection of the Belgian mFRR services to the European platform is expected in the first quarter of 2023. (Elia, 2022c)

mFRR procurement process

To ensure sufficient mFRR capacity, Elia is required to procure a reserved volume, i.e. 670 MW in 2022, a number determined by the CREG. This volume is procured on a capacity auction, which is in Belgium only organized for upward activation, because of relatively easy sourcing for downward activation. Because of high energy prices lately, the required upward volume is often not reached in the auction, resulting in the organization of a second auction. As such, the mFRR product is considered a cash cow today. Market participants that get selected in the auction receive a capacity remuneration based on a pay-as-bid pricing.

On delivery day, the TSO organizes a market of free energy bids, in which it is decided what assets should be activated for the actual delivery of the mFRR service. Activation prices are based on a pay-as-cleared system, meaning that all flexibility providers receive the same energy remuneration (€/MWh) equal to the bid price of the last selected unit. Free bids have a minimum bid size of 1 MW, with 1M resolution. Usually, the energy is contracted in 4-hour blocks. Prices lie in the range of -99 999,99€/MWh and +99

999,99€/MWh, which will be lowered to a maximum of 13.500 €/MWh once the MARI project has gone life.

mFRR delivery process

mFRR is an asymmetrical product, meaning that market participants can choose to offer up (increase power) or down (reduce power) services.

The first reaction of an asset is required within 30 seconds, after which the requested energy needs to be fully activated within 15 minutes and for as long as needed during the contracted block. Every 15 minutes, Elia checks whether more mFRR is needed to restore the system imbalance and manually sends setpoints to the BSP's accordingly.

mFRR prequalification process

Like FCR and aFRR, a prequalification process is initiated to prove the asset's capabilities of providing the service with regards to the technical delivery requirements. After prequalification, the additional prequalified volume can be offered on the mFRR capacity market.

Similar to FCR and aFRR, the minimum bid size on the mFRR market creates barriers for low voltage assets. Aggregation is essential for these assets to participate.

implications for low voltage assets

Today, the synergrid code explicitly forbids the delivery of mFRR services by low voltage assets. The market is expected to open for these assets earliest in 2023, but in any case not before the MARI project have gone live.

3.1.4.4. Summarizing table

Process	Parameter	FCR	aFRR	mFRR
Bidding and trading	**Market type**	FCR capacity auction	aFRR capacity auction + energy bids	mFRR capacity auction (only up) + energy bids
	Remuneration	Capacity remuneration	Capacity and energy remuneration	Capacity and energy remuneration
	Pricing mechanism	Auction: pay-as-cleared	Auction: pay-as-bid Free bids: pay-as-bid	Auction: pay-as-bid Free bids: pay-as-cleared
	Minimum bid size	1 MW	1MW	1 MW
Activating	**Activation direction**	Symmetric: Up and down	Asymmetric: Up or down by choice	Asymmetric: Up or down by choice
	Activation speed	50% within 15 seconds and 100% within 30 seconds	100% within 7,5 minutes	100% within 15 minutes
	Response time	2 seconds	30 seconds	30 seconds
	Voltage level	All	Low voltage not allowed	Low voltage not allowed

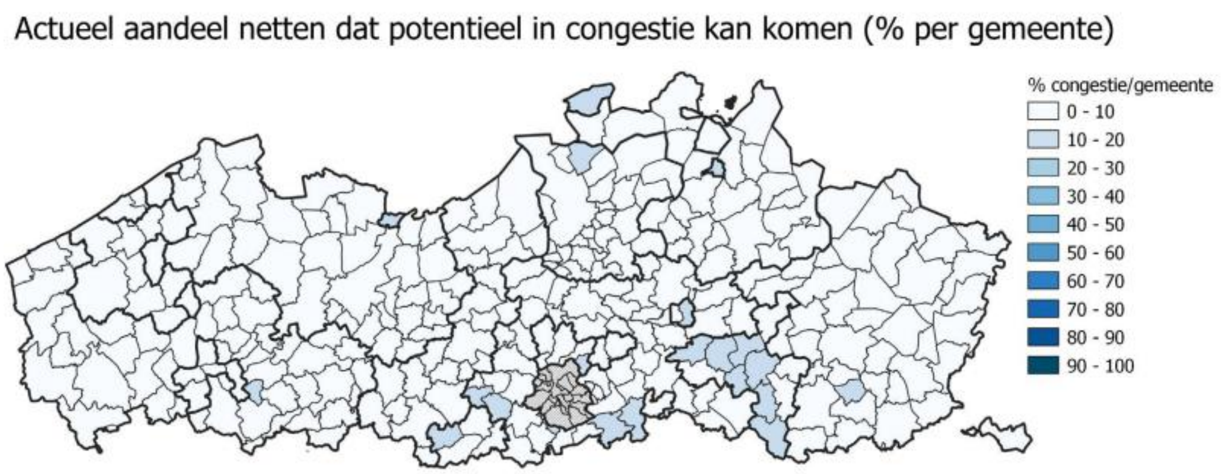
	Measuring resolution	2 seconds	4 seconds	15 minutes
communication	**Data lag: real time or not**	Real time aggregated data, ex post local data	Real time local data per delivery point	Ex-post local data
	Active or passive	Passive: measuring frequency directly through frequency readers	Active: Receiving set points from Elia	Active: Receiving set points from Elia

3.1.5. Markets for congestion management

The goal of congestion management is to relieve grid lines or other components which are threatened to be overloaded. Therefore, grid operators demand or auction the rescheduling of production or offtake to relief the congested grid area. This can be done through curtailment of the power output in the grid area where a solar PV system or wind turbine is connected.

Mid 2018, Elia has started the iCAROS project to define the IT, technical and operational requirements for assets to assist in congestion management.

Implications for low voltage assets
The Flemish distribution grid operator Fluvius performed a study investigating congestion at the low-voltage grid (2022). This analysis shows that today congestion problems are only limitedly present and only occur in areas with long low-voltage feeders (figure 4 panel 1). However, towards 2035, the risk for congestion increases significantly (Figure 4 – panel 2). The results indicate that the largest impact on low-voltage congestion seems to be coming from heat pumps and electric vehicle (EV) charging during the evening peak in the winter. The impact from PV injection at noon in summer seems to be negligible in the analysis. Moreover, on the short run, the impact of EV is higher than heat electrification. Flexible charging strategies will thus become very important in the future. Besides grid expansion and improvement, this study pledges for flexibility provision through e.g. demand response and load shifting to solve the future congestion problems.



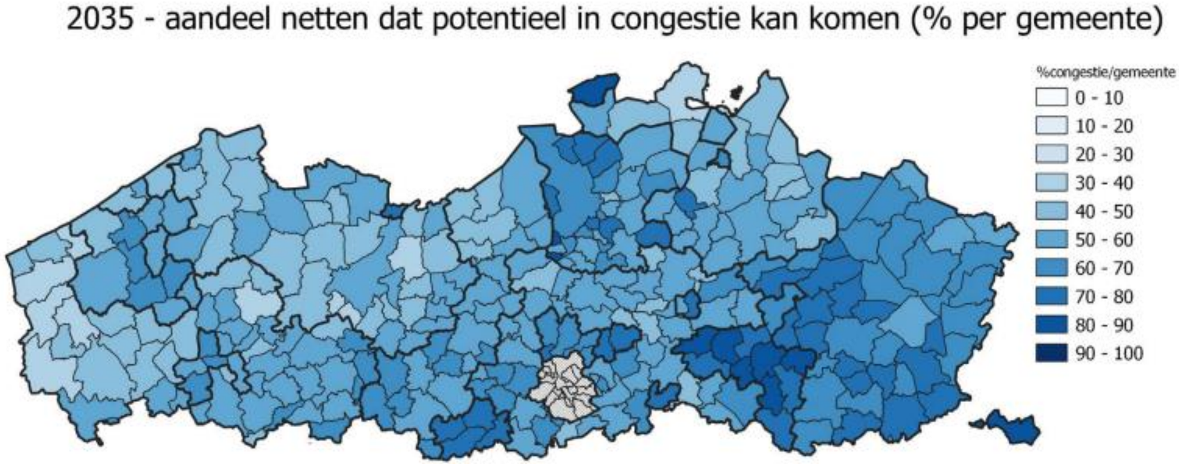


Figure 4: Share of the Flemish low-voltage grid with potential grid congestion risks – Today and in 2035

Today, in case of grid congestion, rooftop PV inverters are automatically switched off by the grid operators. End-consumers and prosumers don't have any control over this. Yet, the creation of local flexibility markets could provide space for new, controllable congestion and curtailment strategies with a win-win for both the grid operator, the end-consumer and the whole society. Although there is a need for local flexibility markets to solve congestion, the actual size of congestion risk remains unclear as vital data are not publicly shared. Unclarity about the market potential, makes it risky to invest in residential flexibility solution for congestion and to develop a feasible business case.

3.2. Transfer of energy as prerequisite for flexibility provision

Flexibility can be valorised on multiple short-term markets by implicit and explicit sourcing. Implicit flexibility holds the reaction to price signals as a way to optimise time of use. As such, no third party needs to be involved for the sourcing. Explicit flexibility, however, follows from real-time activations by BSP. In this case, there will be two contracts: one with a supplier and one with a BSP. The asset will thus appear both in the BRP pool of the supplier and the BSP. This has implications for the imbalance of both parties. Real-time activations for the reserve power influence the metering, and as such actual volumes can deviate from the forecast. Transfer of energy is needed when there are different supplier and BSP active on one access point to neutralize the impact of the activation on the imbalance. The transfer of energy is only relevant for aFRR and mFRR, because FCR activations are symmetric and zero in sum.

To arrange the transfer, two options exist:

- A standardised transfer of energy (ToE) contract, of which the contract rules are determined by the CREG in a legal system. This legal system, however, only exists for mFRR offtake, i.e. upward mFRR activations. In this case, Elia performs a volume correction eliminating the impact of the activations on the imbalance.
- An opt-out contract, bilaterally negotiated between the supplier and FSP. Because there is no legal system for aFRR and downward mFRR, FSP's automatically fall under the opt-out option for these type of activations. Opposed to the standard ToE contract, there is no physical transfer of energy, only a financial correction agreed by the two parties. As part of the prequalification process on the reserve power markets, Elia requires proof of contract. In some cases, the asset provider takes over the imbalance responsibility from the supplier's BRP and then the financial correction can be performed directly by the BSP to the client. Then the opt-out contract becomes redundant. This is called 'pass-through' agreement.

Today, no transfer of energy system exists for low voltage assets. Without such a system, suppliers will experience financial losses and not support the unlocking of household flexibility.

4. Towards a Belgian retail market for flexibility services

4.1. A Consumer Centric Market Design as envisioned by Elia

The consumer centric market design as envisioned by Elia is a market design which puts the consumers central, unleashes the flexibility potential of distributed assets and enables new services such as peer-to-peer trading, energy communities, enhanced energy traceability, multiple supply contracts behind the meter etc. (Elia, 2022d-e-f). As system operator, Elia wants to take the role of facilitator to valorise this flexibility and enable these new services. They have identified two main focus points as a way to accelerate development of a consumer centric market design:

- Development of decentralised exchange of energy blocks between consumers and other parties, both on and behind the meter. To achieve this, Elia has developed a regulated digital infrastructure, the EoEB-hub (Exchange of Energy Blocks hub). This infrastructure covers amongst others real-time measurements, data access management, data sharing options and settlement processes.
- Development of a real-time market price to reveal the true value of flexibility to consumers, including a simplification and transparency of the system imbalance forecasts and a reform of the imbalance price from penalty to incentive and from ex-post to ex-ante calculation.

More information can be found on the website of Elia, in the documentation about the 'Consumer Centric Market design': https://www.eliagroup.eu/en/ccmd and https://www.elia.be/en/users-group/wg-consumer-centric-market-design

4.2. The supplier and the flexibility service provider role

With the evolution towards a more flexible and consumer centric electricity system, new roles have been emerging, such as aggregators and (independent) flexibility service providers. These roles have been defined in the revised Flemish energy decree (2009), as the result of the transposition of the European directives of the Clean Energy Package.

Aggregator: A natural or legal person who, as a service provider, aggregates (combines) multiple energy volumes of offtake, consumption, production or injection of different consumers, intermediaries and producers to buy, sell or auction [these volumes] on the electricity market. (Art 1.1.3 12°/1)

Flexibility service provider (FSP): A natural or legal person who, as a service provider of flexibility, supplies flexibility services to one or more flexibility requesters or who supplies his own flexibility or of one or more flexibility participants as a service to one or more demand parties. (Art 1.1.3 25°/1/2)

Independent flexibility service provider: a flexibility provider who is not connected to the supplier of the consumer or who has a different BRP than the one of the consumer. (Art 1.1.3 92°/5)

The implications of these new roles are threefold:

First, new services will be offered including implicit and explicit flexibility, peer-to-peer trading, smart energy management etc.. Concerning flexibility as a new service, aggregators and FSPs can close contracts with households, being the flexibility participants, to valorise the flexibility from load shifting, demand response, curtailment etc.

European directives (2019/944) and regulations set requirements on digital meter functionalities, data ownership and access to support energy efficiency optimisation, demand response and other services:

- "If final customers request it, data on the electricity they fed into the grid and their electricity consumption data shall be made available to them, (…), through a standardised communication interface or through remote access, or to a third party acting on their behalf, in an easily understandable format allowing them to compare offers on a like-for-like basis." (Art 20/e)
- "Member States shall organise the management of data in order to ensure efficient and secure data access and exchange, as well as data protection and data security. Independently of the data management model applied in each Member State, the parties responsible for data management shall provide access to the data of the final customer to any eligible party. (…) Eligible parties shall have the requested data at their disposal in a non-discriminatory manner and simultaneously. Access to data shall be easy and the relevant procedures for obtaining access to data shall be made publicly available." (Art 23/2)
- "No additional costs shall be charged to final customers for access to their data or for a request to make their data available" (Art 23/5)

The revised energy decree (2009) provides a regulatory framework for the contractual base of the new flexibility services:

- Consumers can close a contract for flexibility provision independently from their supply contract (Art 4.1.17/1). Moreover, suppliers cannot bill them any extra costs, nor apply any administrative, technical or discriminating contract conditions, nor put contractual limitations because of the household having another contract with an aggregator or an FSP (Art 4.1.17/3).
- Consumers have a free choice of supplier, aggregator and FSP (Art 4.1.17/3).
- The aggregator or FSP needs explicit consent from the consumer to use (metering) data that are needed to perform his activities (Art 4.1.17/8).
- At least once per billing period, the consumer can ask for relevant flexibility data or energy sales data without any extra costs being charged. (Art 4.1.17/8)
- Any contract cancellation by the client needs to be processed by the supplier, aggregator or FSP within 3 weeks after request. After 1/1/2026, this process needs to be done within 24 hours (working days only). Consumers can switch suppliers without any costs. (Art 4.1.1) It remains unclear whether this rule also applies to aggregators and FSP's.

In addition to the energy decrees, laws and the technical regulations, the Flemish regulator has developed a code of conduct to protect the end-consumer against misguiding marketing and illegal practices in discussion with the energy suppliers. The code includes rules about aggressive sales, invoicing, contract design etc. It is unclear whether a similar code of conduct will be developed for flexibility services. In general, there is little concrete information available on how the current retail market will evolve and what this new retail market will look like.

Second, having multiple roles in the market that make the connection to the end-consumer could lead to uncertainty and confusion about the levy responsibility. This raises the question who will collect grid fees, taxes and levies in the new, consumer centric market and how this will be done. Today, this is the supplier's responsibility, being the single contact for the end-consumer. In the future consumer centric market design, there will be the possibility for end-consumers to have contracts with different suppliers for their assets behind the meter (e.g. for EV, PV injection, house consumption) and also with FSPs. It is unclear whether the levy responsibility will stay with the main supplier or split between suppliers and FSPs.

Third, transfer of energy is needed when there are different suppliers and FSPs active on one access point to neutralize the impact of the activation on the imbalance (see section 3.2). A ToE system, however, does not exist on the low voltage level. This jeopardises the business case for residential flexibility, as suppliers and FSP's will not be willing to valorise the flexibility without a proper imbalance correction. Elia is however working on the development of a system for the transfer of energy at the low voltage level.

4.3. Tariff structures

Electricity tariff structure on the retail market consists of three main components.

Energy costs

The energy costs are determined by the energy supplier as part of their competitive pricing strategy. Energy costs reflect the energy prices on the wholesale market (long-term and spot). Because of historically high electricity prices and volume risks, many energy suppliers have cancelled their fixed price offers since 1/1/2022, leaving only variable contracts in the market. With the ongoing price increases, this makes end-consumers extra vulnerable.

Since June 2021, every energy supplier who has more than 200 000 access points in the Flemish region, is required to offer dynamic price contracts on specific customer request that reflect the day-ahead and intraday prices on respectively hourly and quarter hourly basis (Energiedecreet, 2009, Art 1.1.3 30°, Art 4.4.1). End-consumers need to have a digital meter installed to make use of this contract type.

Grid costs

The grid costs include all costs related to the management, maintenance and expansion of the distribution and transmission grid. As from 1/1/2023 the day– night grid tariff structure will be partly replaced by a capacity tariff to reduce peaks on the electricity grid. By preventing these peaks, the distribution grid operators intent to reduce the required grid investments that come along with increased deployment of centralized renewable energy, the expected electrification and the bidirectional power flows. The capacity tariff (in Flanders) will be based on the highest monthly peak that is found by comparing all the power averages on a 15-minute base. The minimum power level that will be invoiced is 2.5 kW. High power peaks are expected to come from heat pumps and electric vehicles. For Ferraris meters, for example, a simulation scheme is presented resulting in a virtual peak used for billing.

Levies and taxes

Taxes are imposed to account for public services and to support renewable energy integration. These taxes consist of a contribution to the Flemish energy fund, an energy contribution, renewable energy and CHP contribution, costs for public services and other taxes. All taxes are volumetric, except the contribution to the Flemish energy fund which is a fixed monthly payment. End-consumers also pay VAT, which has been reduced from 21% to 6% because of the current energy crisis.

5. Barriers for the uptake of distributed flexibility in the market context and suggestions for policy recommendations

5.1. Technological barriers

First, to participate in the reserve power markets, flexible assets need to comply to many technological requirements which are not easily attainable for small assets, e.g. real-time data communication. Moreover, the prequalification procedure is demanding and time consuming both for Elia and the FSP, making it difficult to scale up the process to large groups of small assets.

We would recommend Elia to increase scalability of the prequalification process. In that sense, Elia could follow the example of the Dutch TSO Tennet who puts prequalification requirements to asset types rather than individual assets. More concretely, Tennet allows that "all technical installations of the same type with a rated power of less than 1,5 MW and which can be shown to have the same control behaviour as installations that have already been prequalified do not need to undergo an individual prequalification test anymore." Today, the prequalification process is already somewhat replaced by checks of the provision during actual product activations. Of course, the provision frequency differs largely from one product to the next. While aFRR and FCR are frequently activated, mFRR activations might be rare. To limit the risk that there are too large 'untested' volumes, Elia could limit the increase of the maximum allowed capacity bids unless the volume was 'tested' in a real activation.

Additionally, requirements on data communication could be alleviated, e.g. by only communicating changes in state instead of absolute states in real-time.

Second, the uptake of low-voltage flexibility provision can be accelerated by digital meters that have smart meter allocation. In December 2022, there were about 1,2 million smart electricity meters and 0,8 million smart gas meters installed in Flanders, which accounts for 33% of the total number of meters (VREG Dashboard, 2022). By December 2024, the Flemish government aims to increase that number to 80% and by 2029 to 100%. Less than 1% of all smart meters makes use of the so called "Metering Regime 3" (SMR3) that enables to send quarter hourly metering data from the digital meter to the market and use it in the allocation process. Yet, only digital meters with SMR3 can participate in energy sharing, peer-to-peer sales and make use of dynamic price contracts. Also, smart functionalities like asset steering based on prices or activation signals is only possible with a digital meter that runs on SMR3. Because of the time granularity on the spot and reserve power markets, metering needs to be preferably done on 15-minute basis, and at least on hourly basis. Although a roll-out of 1% is very small, the implementation of SMR3 has doubled from October 2022 to November 2022, indicating a growing interest in exploring and unlocking the value of smart energy management, flexibility and new activities like energy sharing. Customers have the choice to switch to the SMR3 mechanism, which they need to apply for at their energy supplier. Too little information, bad media attention for digital meters and high complexity could be reasons why the roll-out of SMR3 happens rather slow despite the large potential.

The roll-out of the digital meter by the distributor grid operator to support new, smart services such as flexibility, energy sharing etc. has the main advantage that it can be done without too much hassle for the end-customer and at low cost. In the Netherlands, however, the grid operators have developed a centralised platform, called Equigy, which makes use of blockchain technology to support these new services. Although the technology is more advanced, a fully regulated system run by grid operators could be detrimental for free market competition. As such, we deem the digital meter as the best solution compared to other technologies for the uptake of low-voltage flexibility. Yet, standardisation is lacking to deploy private metering activities connecting to the digital meters, which hinders optimal use of the digital meter.

We would recommend the government to better inform the end-customer about the advantages of digital meters with SMR3 mechanism (through for example marketing campaigns) and the application process to speed up its roll-out. Especially because we see the SMR3 digital meter as a minimum requirement for the uptake of low-voltage flexibility.

In addition, we recommend the government to open up the market for measuring and metering activities and standardise protocols to connect to the digital meter.

Third, data ownership by the end-consumer or asset owner should be guaranteed. Today, the end consumer or owner of the flexible asset don't have the ownership of their data, but the manufacturer of the flexible asset has. Yet, European directives (2019/944 Art. 23) state that the data needs to be made available to the consumer without any costs. Often, manufacturers offer paid services to make the flex data available to the end-consumer, which is not complying to European regulations. For fully cloud-based systems, this also holds a risk because of the absence of local control and high dependence on the manufacturers. In addition, innovation by third parties who want to offer new services, such as flexibility provision, smart energy management etc for which the flex data are required as input, is being hold back. Another challenge for these innovators are the diverging standards and protocols for data communication with the flexible assets, which are limiting data accessibility.

In addition, the data transparency should be increased. In local flexibility markets for congestion management, for example, the business case highly depends on the transparency of the market data, as the availability of public congestion data could show the market size and the urge to develop new flex services. This data, however, is not publicly availability, making innovators hesitant to invest in congestion solutions.

We would recommend the government to give end-consumers or asset owners full data ownership in compliance to the European regulations. Moreover, we would recommend making relevant, non-private data publicly available as a way to increase market and data transparency.

5.2. Regulatory barriers

First, the consumer centric market design suggests having multiple contracts with suppliers and aggregators. Therefore, regulations about how to correct flexibility activations for an asset and how to account for taxes, levies and grid costs are needed. Today, there is no specific framework for the transfer of energy on the low voltage grid. Addiontally, it remains unclear who will be responsible for passing through transmission and distribution grid fees to the end-customers and on which volumes taxes and other levies will be raised.

We recommend the federal and Flemish regulators (CREG and VREG) to provide a clear framework for the transfer of energy on the low voltage grid and more clarity about retail tariff structures and responsibilities.

Second, Synergrid has developed a monopoly over important market rules, giving too much decision power. For example, the synergrid code explicitly forbids the provision of aFRR and mFRR services by low voltage assets. As such, these assets are excluded from the market and not able to valorise their flexibility potential. Also, the synergrid code has set power limitation for electric vehicle chargers concerning amongst others droop control, hindering the roll-out of charging stations and the use of electrice vehicles for flexibility provision.

We recommend the the government, and more specifically the Flemish, to more intensively follow up and participate in the synergrid working groups to avoid full decision power by grid operatoring parties.

In addition, the governement could organise more cross-sectoral consultations from both the electricity and gas sector to support democratic decision making.

Third, with new projects and platforms being developed by Elia to support the implementation of a consumer centric market design (e.g. EoEB Hub, IOEnergy project), the seperation between the natural monopoly of grid operators and the market based activities becomes distorted. For example, there is no clear reason why submetering should be a regulated activity carried out by the grid operators, nor should behind the meter services be. Energy companies big and small already provide solutions for such activities in the commercial domain.

We recommend the governement to protect free market competition by guarding the official roles in the energy system and its corresponding mandates, rights and responsibilities. We also warn not to overengineer the new, consumer centric market design and to avoid adding more (complex) roles in the energy system.

5.3. Economic barriers

First, the tariff structure for households on the retail market could create a barrier. Dynamic tariffs (that follow e.g. hourly DA prices) are needed to create the price signals for flexibility valorisation. However, only the largest suppliers are obliged to offer this type of contract, limiting many households in their choice. In addition, many households would not trust dynamic pricing, on the one hand because of the current energy crisis and the fear to be exposed to high price volatility, on the other hand because of miscommunication and lack of showcasing the advantages in marketing campaigns. Other barriers for households to close a dynamic contract could be, for example, the SMR3 application, uploading quarter-hourly data in the v-test to a dynamic price simulation, eligibility procedures by suppliers etc.

We recommend the federal and Flemish regulators to consider the implementation of secondary EAN's on which a second energy contract can be closed. This could help to increase the popularity of dynamic tariffs because households could spread risks and assign dynamic tariffs to the flexible assets.

Second, congestion problems are likely to increase significantly in the future. The capacity tariff is one way to deal with these problems. Yet, flexibility provision can lead to injection or offtake peaks, which could be punished in the system of capacity tariffs. Especially owners of heat pumps and electric vehicles, technologies which are perceived to support and accelerate the energy transition, will be confronted with higher costs. This can be countered by making the grid costs more cost reflective as to moments in which congestion might occur. A potential way of doing so is the introduction of dynamic grid tariffs, not only for offtake but also for injection.

We recommend the federal and Flemish regulators to support the integration of and flexibility provision by smart, green technologies such as heat pumps and electric vehicles by introducing a more cost-reflective grid tariff, e.g. a dynamic tariff based on the actual grid congestion which is also valid for injection.

Third, when providing FCR services with home batteries or EV, there are double grid tariffs and levies, i.e. on both off take and injection, which could jeopardise the business case.

We recommend the federal and Flemish regulators to consider the problem of double levies in the tariff structure design.

Finally, contract cancellations by the client need to be processed by aggregator or FSP within 3 weeks after request, and after 1/1/2026 even within 24 hours. Moreover, it is not allowed to charge any costs for early contract cancellation. Although such regulation is likely to support competition, it also makes it challenging to create a viable business case for explicit, residential flexibility. Explicit flexibility requires the installation of specific hardware that enables asset steering. This hardware is costly to install and sometimes customized to communicate with specific asset types and brands. Therefore, current flexibility contracts are often long-term contracts, i.e. 2-3 years. Imposing costless early contract cancellation and fast aggregator/FSP switch could jeopardise the business case for the aggregator and FSP.

We would recommend the federal and Flemish regulators to consider the challenge of fast and costless aggregator/FSP switch when designing the new retail market for flexibility.

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