Work Package Market Uptake | Market definition task

Deliverable 3.4: Demand and Supply Potential of Residential Flexibility

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1. Introduction

This deliverable is part of **'Work Package 3: Market Uptake'** and more specifically, '**Task 3.3: Market definition'.** The aim of this report is to investigate the demand and supply potential of residential flexibility. It should be noted upfront that there is no demand for residential flexibility as such, that is to say: the electricity system is agnostic to the source of flexibility as long as it fulfils its needs on the different timescales, different activation times and ramp rates. Residential flexibility therefore is, in most cases, in competition with other sources of flexibility. A study of the demand for residential flexibility is therefore in the first place a study of flexibility needs in general. We perform an analysis of the potential market uptake of residential flexibility by studying the extent to which residential flexibility can fulfil the demand for flexibility in a commercially viable way.

2. Valorisation of (residential) flexibility

Like described in deliverable 3.6 on 'Policy Recommendations for the Uptake of Distributed Flexibility', flexibility can be valorised over the balancing timeline which is formed by a consecutive chain of markets going from day-ahead to real-time. In this deliverable, we will distinguish between day ahead and real time flexibility.

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
Type of flexibility	Day-ahead flexibility	Real time flexibility		

Figure 1: the balancing timeline, adjusted from D3.6

In addition to balancing services, flexibility can also be used to in the context of grid congestion. Grid congestion occurs when a component in the electricity grid faces a power throughput above its designed dimensions, which means the component is insufficient to transfer the necessary power in the grid. Like balancing issues, congestion issues could threaten the security of supply and are closely monitored by grid operators. As the actors involved and product/market design for both issues differ, we treat them separately in this deliverable.

Further in this deliverable, we will discuss the valorisation of residential flexibility in relation to balancing purposes, distinguishing between Day-ahead flexibility (Section 3) and Real-time flexibility (Section 4.1), and grid congestion which is classified as real-time flexibility (Section 4.2).

3. Day-ahead flexibility

3.1. The need for day-ahead flexibility in an energy system in transition

Day-ahead flexibility relates to the supply and demand dynamics of the day-ahead spot market. Having a high liquidity, the spot market is one of the most important power exchanges for producers and offtakers of power. More information can be found in D3.6 'Policy Recommendations for the Uptake of Distributed Flexibility'. As long as the supply and demand curves intersect, the market can clear and there is no problem as such.

Yet, with Belgium and the European Union aiming for a largely decarbonised electricity system by 2035, the day-ahead market can present problematic situations even when it clears successfully:

- Demand that cannot be covered by low carbon energy sources during certain moments for which emission intensive peak power plants need to be switched on – often with high ramp rates.
- Low emission production that needs to be shut down ('curtailed') because there is no sufficient demand to absorb it – wasting low carbon energy and reducing the commercial viability of these power plants.

Flexibility from both the production and offtake side can help reduce such mismatches. Ideally, this leads to a situation where demand can be covered by low carbon production for most of the time while avoiding price spikes on the day-ahead market.

To better understand and investigate these dynamics, it is instructive to have a closer look at the so-called residual load. The residual load is equal to the demand minus generation from intermittent renewable energy sources, must-run capacity (like combined heat and power plants in industry) and nuclear power plants. Residual load usually does not consider imports and exports with neighbouring countries and hence is the load that still needs to be covered with flexibly dispatchable power plants.

Residual Load = Load (+ export – import) – nuclear generation – other must run generation – renewable energy generation

Figure 2 shows an example of the residual load over a typical day in the state of California (Office of Efficient Energy and Renewable Energy, 2017). At noon, especially in the summer, the residual load curve drops significantly due to the large amounts of solar power being generated. Towards the end of the afternoon, the solar power production starts decreasing rapidly and dispatchable generation needs to rapidly come online. This profile is often referred to as 'the duck curve', given its shape. These effects also start to be more and more pronounced in the Belgian grid, as illustrated in Figure 3 by Elia (2023, p 312). On the left-hand side, the projected residual load is shown for the coming years. On the right-hand side, the impact of flexibility in flattening this residual load curve is shown. Elia's prediction of the 'flattened' load curve assumes that of the 2.64 million EVs in 2034 around half of them will be actively delaying charging based on day-ahead prices, while one third will be doing more advanced smart charging based on real-time price signals. Furthermore, Elia predicts that of the 1.8 million heat pumps (HP) projected to be installed in Belgium by 2035, half follow a pre-heated profile and 16 % do smart heating. The simulated flattened duck curves also includes demand response in industry but excludes the impact of batteries.

The graphs in Figure 2 and Figure 3 are yearly averages. On individual days, these graphs can be much more pronounced. On days for which there is an excess of renewable energy around noon, the duck curve can dive below zero, meaning that there is an excess of power that either needs to be curtailed or exported. The ramp rates in the morning and evening can also be much steeper than in the yearly average profile, requiring the use of carbon intensive peak units to cover the higher residual load periods. Flat duck curves usually correspond to system with lower carbon emissions, because renewable energy curtailment and polluting power plants with high ramping are less needed. Flexibility can help flattening the duck curve.

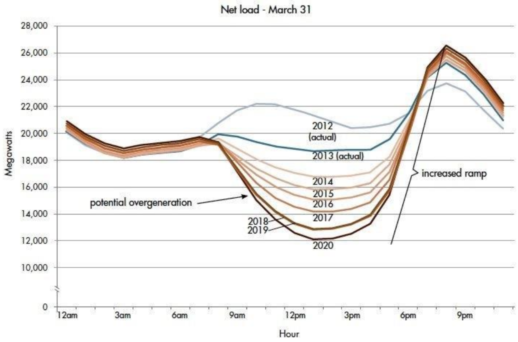


Figure 1: Residual load. Source: US Department of Energy.

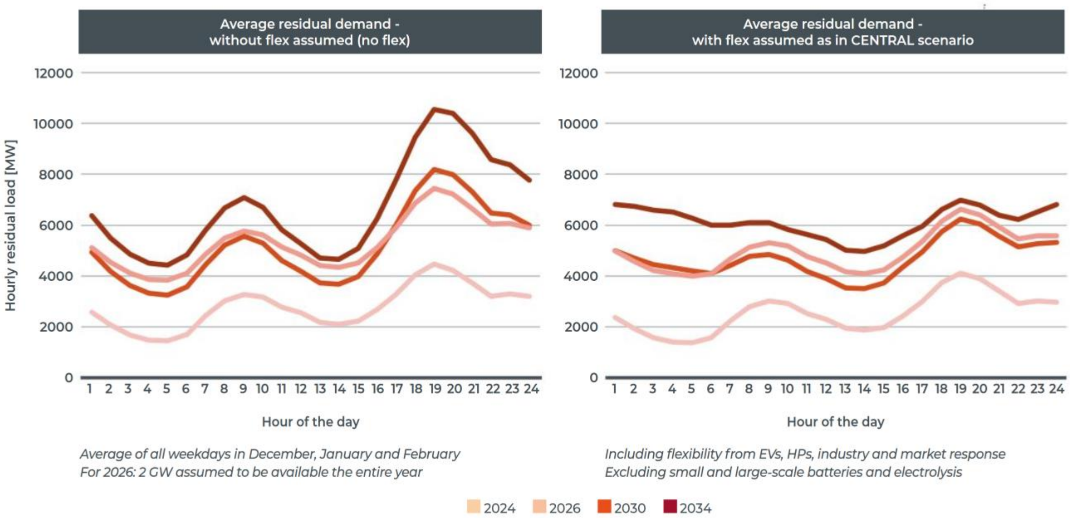


Figure 2: Residual load curves in the winter for low and high flexibility. Source: ELIA (2023, p312).

In the following sections, we try to quantify the amount of day-ahead flexibility that would be needed in Belgium to flatten the residual load curve and we study which role residential flexibility can play to achieve this goal.

3.2. Quantification of the demand for day-ahead flexibility

3.2.1. Definition

It is necessary to define how the demand of day-ahead flexibility can be quantified. Two parameters will be used to characterise this demand:

- The **spread** in residual load: this is the difference between the maximum value and the minimum value of the residual load for each day. This gives a rough estimation of how much flexible power is needed to flatten the residual load curve.
- The **ramp rate** in residual load: this is the derivative of the residual load and gives an idea of how fast day-ahead flexibility providers must change their power output or consumption levels to match the changes in residual load.

For this study, we make the distinction between upward and downward flexibility. In the sections below, we first analyse the spread and ramp rates of the residual load from 2015 until 2022 (§3.2.2). Next, the correlation between the installed capacity of intermittent renewables and these spreads is investigated (§3.2.3). Finally, we extrapolate the spread and ramp rates based on projected growth of renewables (§3.2.4).

3.2.2. Analysing the past

To get a feeling of the size of the residual load, its spreads, and its ramp rates in the Belgian electricity system, Figures 4 and 5 show the residual load for two specific days in the past (01/08/2022 and 10/11/2022), respectively in the summer and winter. The residual load is shown with and without export & import to neighbouring countries. Notice that the duck curve is already strongly visible on the summer day example. The spreads in the examples are between 2.5 and 3 GW, with ramp rates approaching 1 GW/h. Note that the residual load without export is also shown in these and following graphs, as to give an idea about the worst-case scenario when intermittent renewable generation is high in all interconnected countries and export of excess power is not possible.

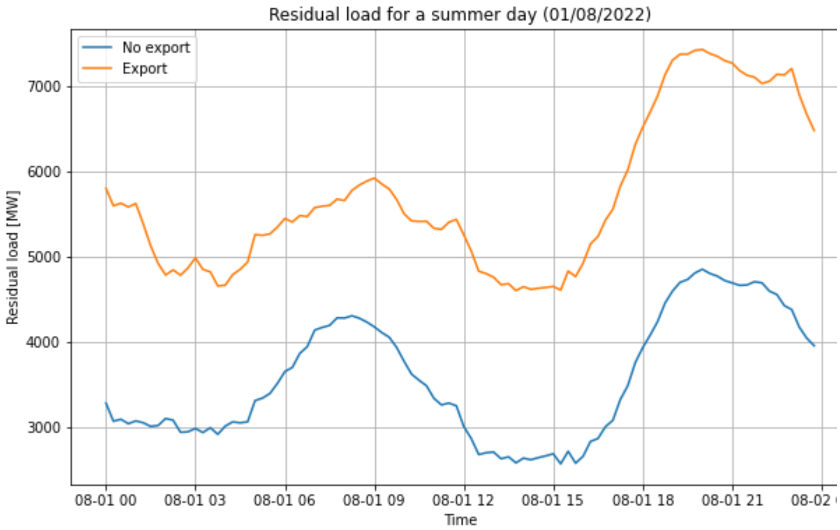


Figure 3: Residual load for a summer day in Belgium (based on Elia and ENTSO-E data)

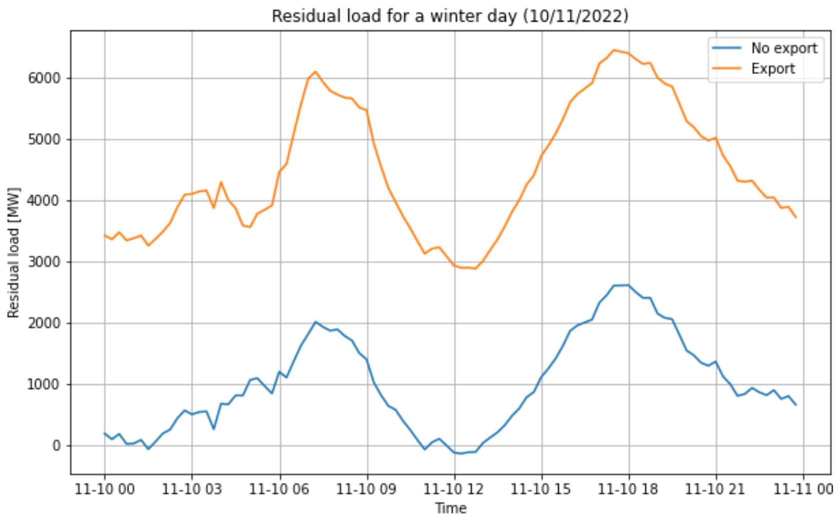


Figure 4: Residual load for a winter day in Belgium (based on Elia and ENTSO-E data)

We now analyse how the spreads and ramp rates have evolved over time by calculating the monthly average of respectively the spread and the ramp rate of the residual load. The results are given in Figure 6 and 7. Using monthly averages allows us to capture some of the seasonal influences. Some important conclusions can be drawn from Figure 6 and 7:

- Historically, the spread and ramp rates have always been higher in the winter months. This can be explained by the household and commercial electricity demand being higher in this season, resulting in the typical morning and evening peaks which lead to high spreads and ramp rates.
- Although the spreads and ramp rates seem to increase for the whole year over the years, this effect is more pronounced in the summer months. This is probably due to the increasing capacity of solar generation in Belgium, due to which the residual load decreases more in the midday when solar production peaks. This results in a higher difference between midday and evening, resulting in a higher observed spread.
- Finally, it can be observed that the differences between the spreads and ramp rates with and without export are increasing over the years. With export, the spreads and ramp rates are generally lower. This shows the benefits of a well interconnected electricity system.

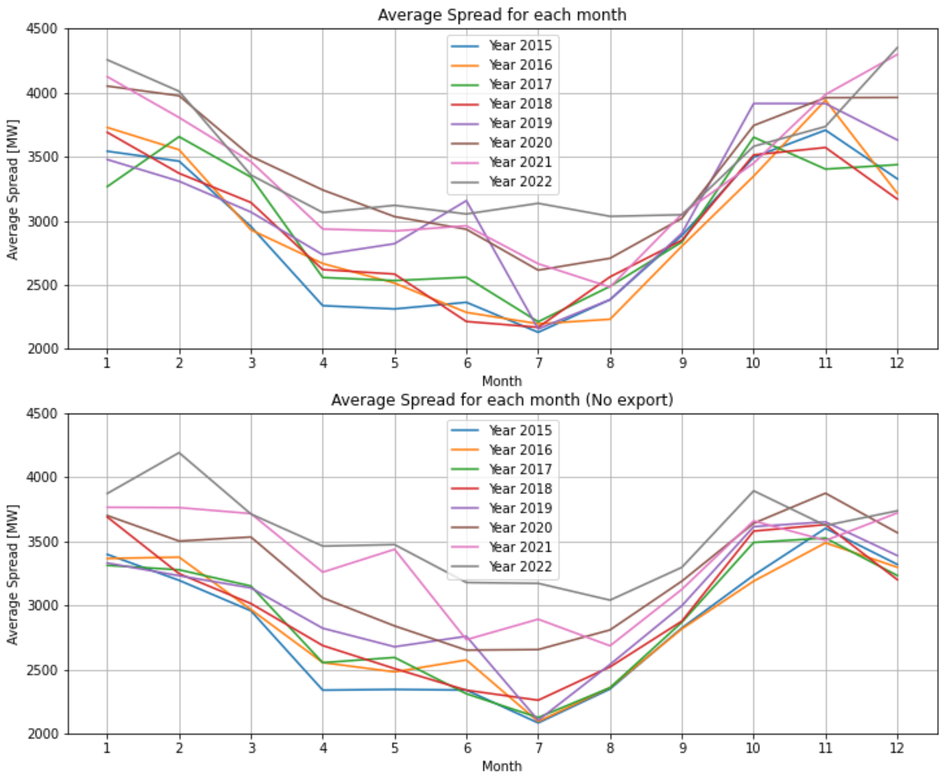


Figure 5: Monthly spread evolution from 2015-2022.

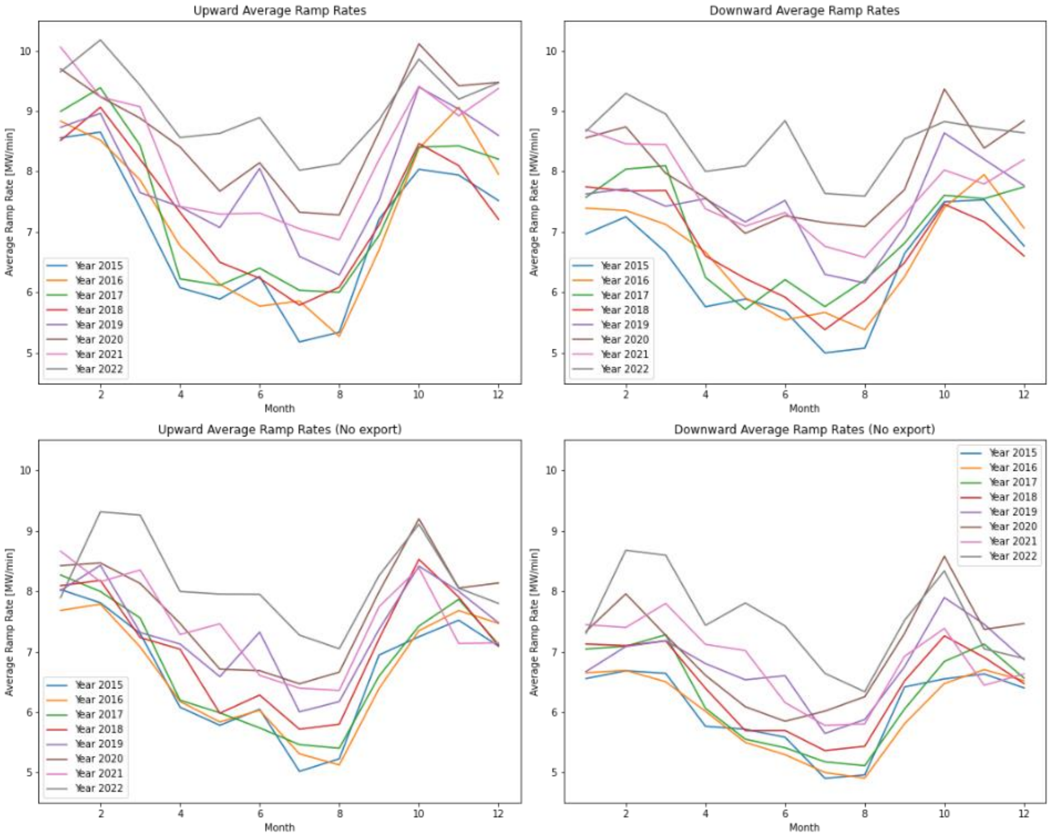


Figure 6: Average, monthly ramp rates of the residual load

3.2.3. Influence of intermittent renewable energy capacity on residual load

In this section, we investigate one possible driver for the increase in ramp rates and spreads in residual load over the years. It has already been suggested that the increasing share of intermittent renewable generation could be the main driver for these increases. This hypothesis has been backed-up by studies like (Huber, Dimkova, & Hamacher, 2014) and (Do, Lycsa, & Molnar, 2021). We investigated this relationship for the specific case of Belgium. We use the installed capacity of renewable energy sources in each calendar year as a proxy for the intermittent energy production and compare it against the evolution of the monthly average spread and ramp rates in the past calendar years from 2015 until 2022. The averaged results are shown per month in Table 1. The evolution of the correlation for March is shown in Figure 8. These results show a strong, linear relationship between the installed capacity of renewable generation in Belgium and spreads in the residual load. Some interesting observations:

- Some months show a lower correlation. The cause for these lower correlations was not investigated in detail in this study. However, there are a lot of external causes that can influence these spreads, such as outages at large must-run assets or nuclear power units.
- The correlations are higher when export is not considered, again showing that interconnections help reduce the effect of intermittent renewables on increasing spreads in the residual load.

The results for the correlation of the average ramp rates with the installed capacity of the intermittent renewables is not shown here, but we observed a similarly high correlation.

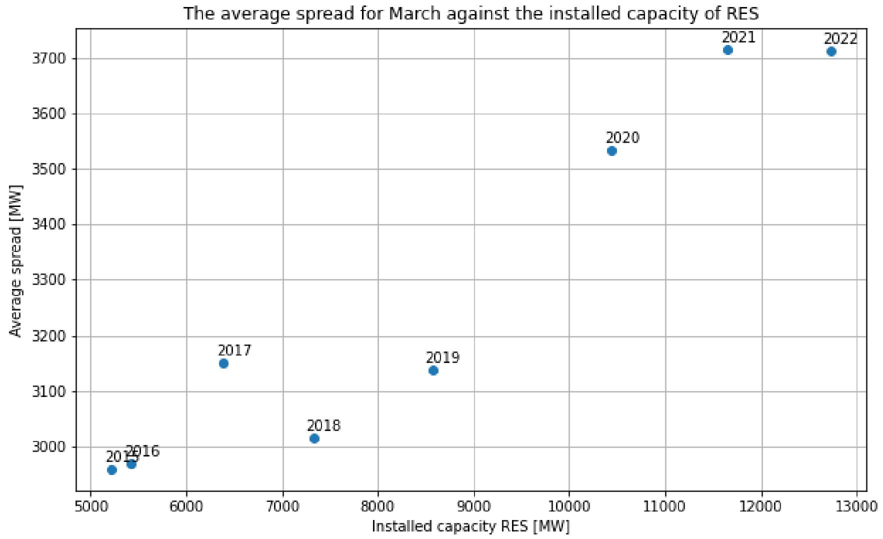


Figure 7: Possible correlation of the installed, renewable capacity with the monthly average spreads

	Correlation	Correlation (no export)
January	0.83	0.82
February	0.72	0.85
March	0.77	0.95
April	0.85	0.98
May	0.96	0.91
June	0.80	0.79
July	0.90	0.91
August	0.77	0.93
September	0.94	0.96
October	0.22	0.91
November	0.37	0.38
December	0.95	0.89

Table 1: Correlations of monthly average spreads with installed capacity RES (2015-2022)

3.2.4. Projection of future demand for day-ahead flexibility

Using the observed linear relation between the installed capacity of intermittent renewable energy sources and the monthly spread and ramp rates in the residual load, one can attempt to project the evolution of the spread and ramp rate in the coming years. For the evolution of the installed capacity, we use the projections from Elia (ELIA, 2023). A summary of the assumptions used in the Elia projections can be found in Annex 6.1. Elia's models fit the installed capacity in previous years well with a maximum of the mean squared error of 5.5% - we therefore consider it a reliable source for these projections. Based on these projections and a linear regression, we extrapolate the spread and ramp rates in the residual load for 2025, 2028, 2030, and 2034.

This analysis looks at the evolution of the spreads and ramp rates in function of the installed capacity of renewable energy ceteris paribus. In reality, other system properties will change too and affect this evolution: the phase out of the Belgian nuclear fleet, the buildout of more interconnections with neighbouring countries, the evolution of renewables in these neighbouring countries, the buildout of energy storage capacity and further unlocking of other flexibility sources.

The results are shown in Figure 9, 10a and 10b. Some interesting observations:

- Barred any exports or imports, the average spread is projected to increase by more than 50% compared to today. In comparison to 2015, the average spread is projected to have more than doubled.
- The trend of increasing spreads in the summer months continues into the future, driven by the projected growth of solar PV in Belgium.
- Once more we notice that exchange with neighbouring countries would significantly reduce the average spread. The seasonal differences are also less pronounced.

The evolution of the ramp rates:

- Here, too, we see roughly an increase of 50% in average ramp rates by 2034 compared to today, and a doubling over the two decades since 2015.
- Whereas ramp rates were historically lower during the summer months, both in upward and downward direction, we project that the reversing trend continues. By 2034, we project to see higher upward and downward ramp rates in summer than in winter. This is again a result of the strong projected growth of solar PV.

These projections, albeit it somewhat rudimentary, point to a strong need for day-ahead flexibility if we want to limit the curtailment of renewable energy and the need for polluting peak power plants in the coming years.

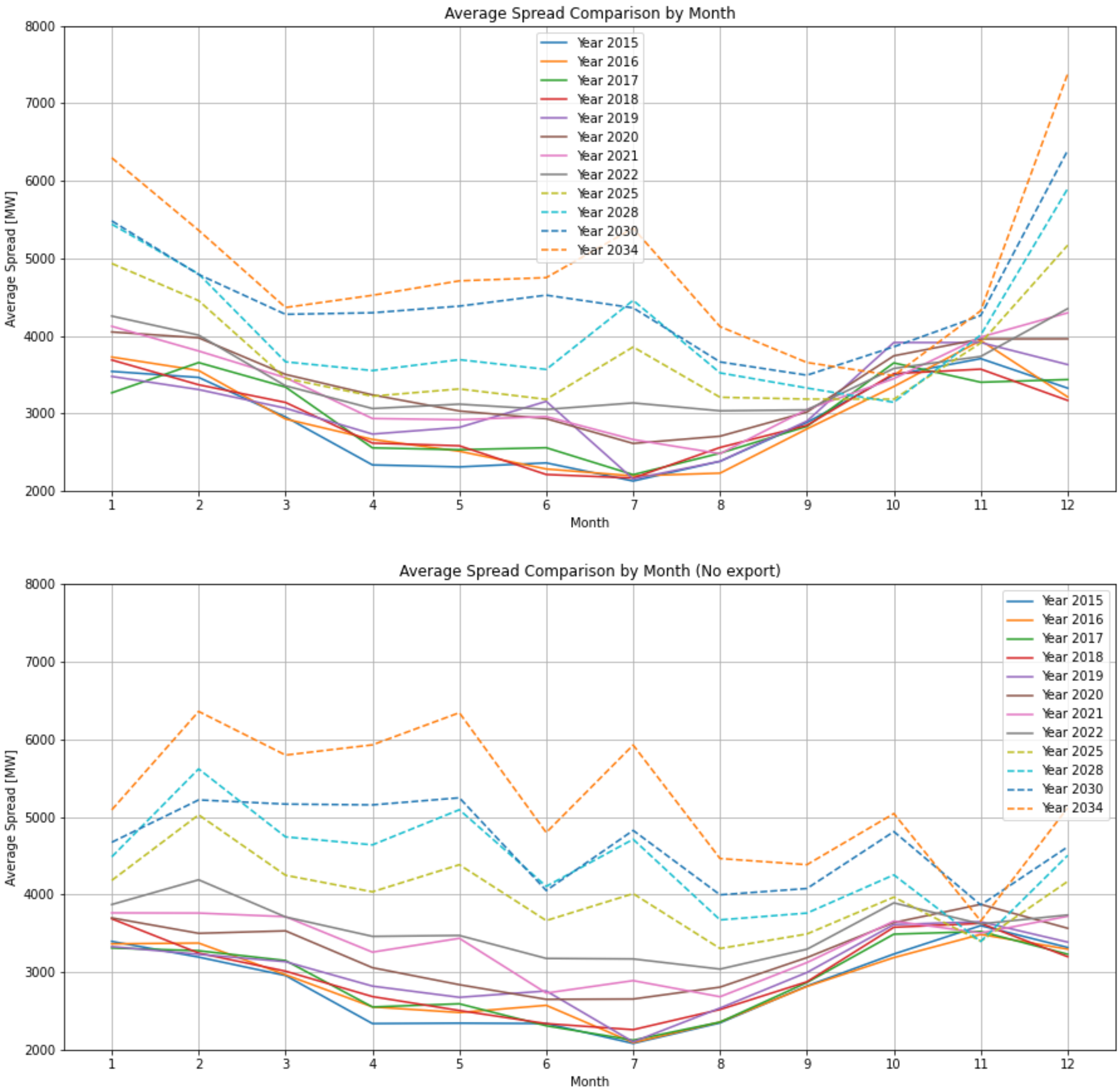


Figure 8: Monthly spreads of the residual load until 2034

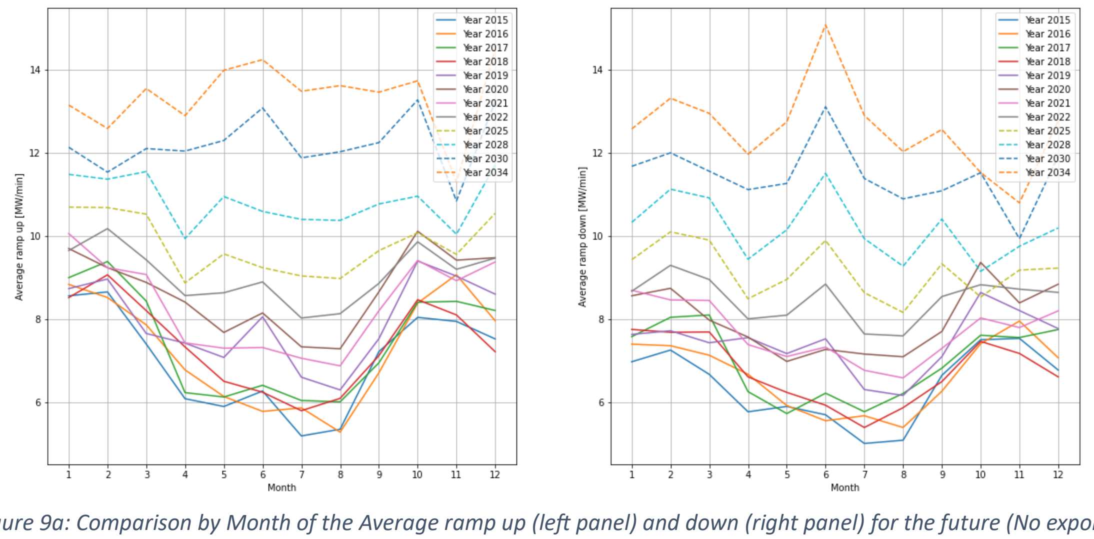


Figure 9a: Comparison by Month of the Average ramp up (left panel) and down (right panel) for the future (No export)

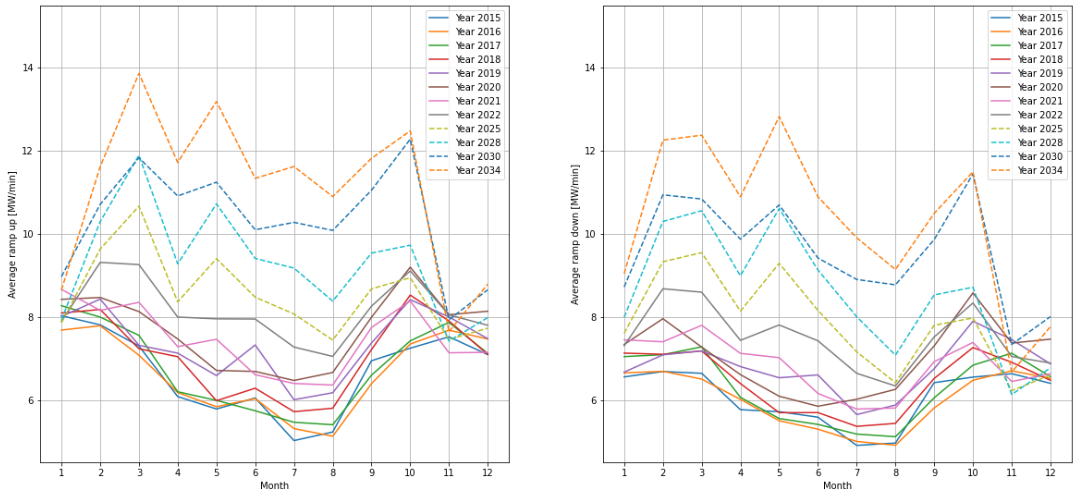


Figure 10b: Comparison by Month of the Average ramp up (left panel) and down (right panel) for the future (With Export)

3.3. Supply of day-ahead flexibility

3.3.1. Incentives for the provision of day-ahead flexibility

As we mentioned before, as long as the day-ahead market clears successfully, there is no explicit need for flexibility. Yet, if we want to decarbonize our electricity system, we argued that flattening the residual load curve is necessary.

Actors on the day-ahead market have only one incentive to act flexibly: the hourly price difference. We therefore investigate whether the changes in the day-ahead market prices over the day would drive flexibility that flattens the residual load curve. To that end, hours with the lower day-ahead prices should coincide with the hours with lower residual load. Hours with higher day-ahead prices should coincide with the hours with higher residual load. There would then be an incentive to shift demand from the high price moments and high residual load to moments with lower prices and low residual load. A market with high day-ahead demand response will see a flattened day-ahead price and residual load curve as a result.

Is this already the case in Belgium? To that end, we investigate how the difference of the hourly price versus the daily average of the day-ahead price, and the difference of the hourly residual load versus the daily average of the residual load, correlate. We investigate both scenarios with and without export, although a scenario including export seems the most relevant because historical day-ahead prices include market coupling. Results are shown in Figure 11. This figure shows that there is some correlation between the periods with higher-than-average residual loads (positive deviations compared to the average) and periods with higher-than-average day-ahead prices (positive deviations compared to the average), and similarly for lower-than-average residual loads and prices. But the correlation is not that pronounced. When calculating the Pearson correlation coefficient, we find a value of 0.51, which confirms this limited correlation. This means that in Belgium, while there are significant spreads in the residual load, the day-ahead market price signal for flexibility is muddled. Sometimes it does give the right incentive, at other times it doesn't or does so only weakly. In D3.3, the potential savings for households that optimise their residential flex assets on the day-ahead market are calculated. In general, the incentive for day-ahead flexibility seemed to be rather low considering the needed investments in smart energy solutions and impact on comfort.

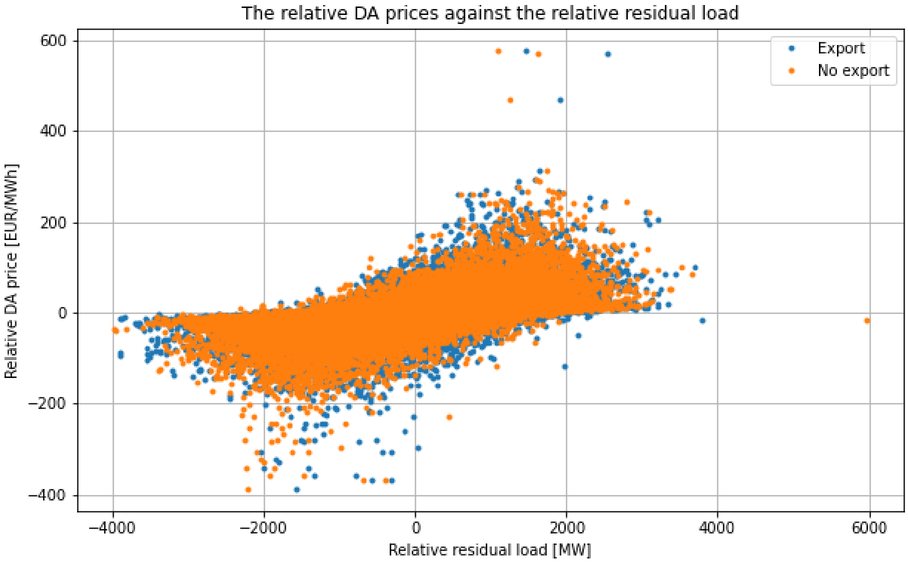


Figure 11: Possible correlation of the relative residual load with the relative DA prices

4. Real-time flexibility

We define real-time flexibility as flexibility anticipating and/or responding to price dynamics after the closure of the day-ahead market. In this chapter, we make the distinction between real-time flexibility for system balancing and congestion relief, as both involve different actors and product/market design.

Note that grid congestion is often the result of structural changes in the installed production capacity or load in a certain grid area. The underlying drivers are therefore long-term phenomena, e.g. the adoption of electric vehicles is steadily increasing the demand in the low voltage grid, which could eventually lead to congestion on the upstream substation during the evening consumption peak. Nonetheless, we discuss grid congestion in this chapter, because it is often only after the day-ahead market has closed and BRPs have submitted their portfolio nominations, that grid operators can determine with a high degree of certainty if and where congestion will occur. The flexibility needed to resolve it, is therefore needed in the timeframe after the day-ahead market, which we classify as real-time flexibility in this study.

4.1. Real-time flexibility for system balancing

4.1.1. The need for flexibility

As TSO, Elia is legally responsible for safeguarding the balance in the Belgian grid area. That means that the overall system imbalance needs to be monitored and kept at bay by Elia. Elia does so with a combined strategy of incentivising implicit and explicit flexibility. While in the past the focus had been most on the explicit flexibility strategies, the development of a Consumer Centric Market Design (CCMD) opened the door for more implicit flexibility solutions.

Real-time explicit flexibility for system balancing is procured in the reserve power market from flexibility service providers (FSPs) under three product categories: FCR (Frequency Containment Reserve), aFRR (automatic Frequency Restoration Reserve) and mFRR (manual Frequency Restoration Reserves). These products reflect different ramp rates, desired response accuracies and activation durations. FCR is triggered by measured deviations in the grid frequency, while aFRR and mFRR are triggered by a control signal produced by Elia's control centre. Elia rewards FSPs that provide these services with a capacity and/or energy remuneration. Capacity remunerations reward the availability of flexible assets for reserve power, while energy remunerations reward the actual activations.

Real-time implicit flexibility is incentivised through intraday and/or imbalance price signals. Although Elia is the legal end-responsible for grid balancing, they are being assisted in their balancing activity by Balancing Responsible Parties (BRPs) (see Deliverable 3.6 for more information). By reacting on price signals, BRPs can financially optimise their portfolio. On the one hand, they could trade away differences on the intraday market based on forecast updates from their portfolio. Yet, no flexibility is used in this case. On the other hand, they could broadcast and potentially expose grid users in their portfolio to the intraday and/or imbalance price signal to trigger flexibility reactions. Important to note is that imbalance flexibility holds a risk as imbalance prices are only published at the end of the quarter hour after delivery, meaning that price reactions are based on price forecasts and not on actual prices.

4.1.2. Quantification of the demand

Total demand

The projected total real-time flexibility needs as modelled by Elia are visualized in Figure 13 (Elia, 2023, p 268). Anno 2024, the total flex need is about 7 820 MW (up + down). Until 2028, flexibility needs increase gradually. Between 2028 and 2030 the need accelerates steeper, after which it increases more gradually again until 13 340 MW in 2034. The steeper increase in 2028 can be linked to the expected go-live of the new offshore wind farms in the Belgian Princes Elisabeth Zone. The power output of these wind farms will be strongly correlated due to their geographic proximity and therefore forecast errors will have a significant effect on the real-time balancing needs. Similarly, the outage risk increases because failure in a critical component like the subsea cables or the offshore transformer station would lead to an unavailability of a large amount of production capacity. The overall trend in increasing real-time flexibility needs is driven by the projected changes in demand and production capacity with a further roll-out of renewables.

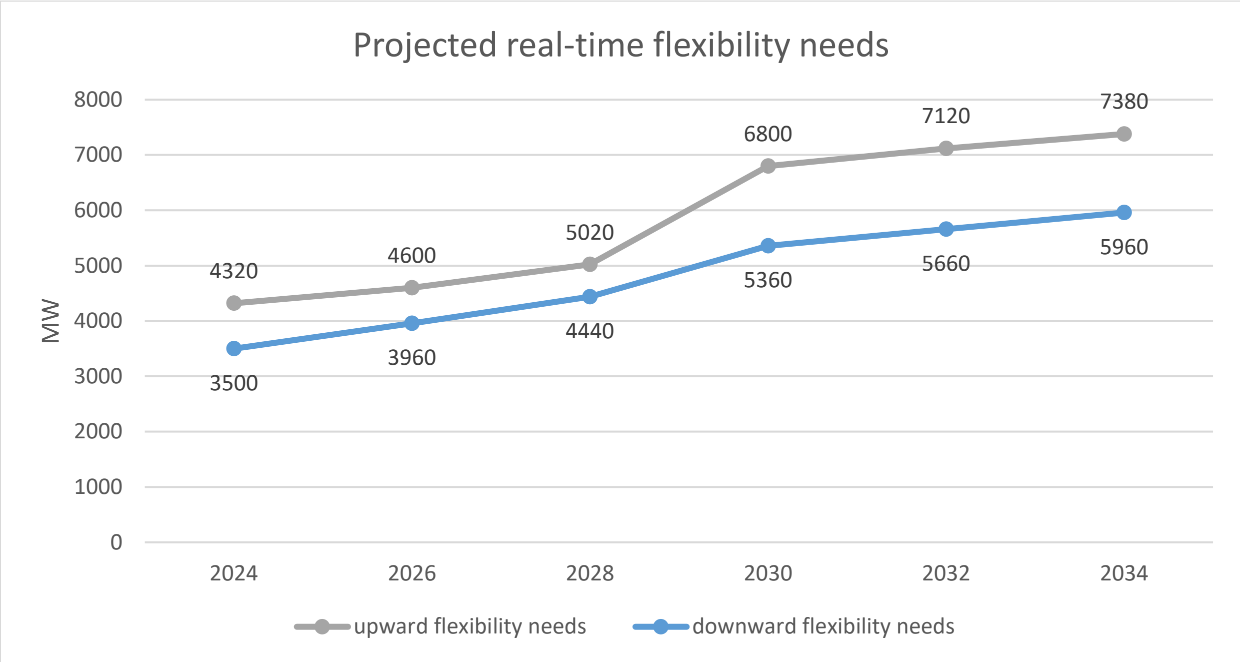


Figure 123 Projection of future, real-time upward and downward flexibility needs. Based on data from ELIA (2023, p 268)

To analyse the flex needs in more depth, Elia distinguishes between slow and fast flex (2023, p51). Slow flex is capacity which can be started or shut down in intraday until a few hours ahead and aims to deal with intraday prediction updates of residual load and forced outages. Oppositely, fast flex is capacity which can be regulated up or downward close-to-real time and aims to deal with unexpected variations of residual load and forced outages in real time. Although this categorisation, we are interested to quantify flexibility in terms of implicit or explicit demand.

Pursuant the above definition, slow flexibility is traded on intraday markets and is therefore assumed to fully fall under implicit demand. Fast flexibility can be covered explicitly by aFRR and mFRR activations on the one hand and implicitly by imbalance price signals on the other hand. FCR doesn't fall under fast flexibility, as it is not part of the restoration reserves to solve unexpected system imbalances, but it rather deals with small frequency variations in the system.

Explicit flexibility demand

Elia uses the Frequency Restoration Reserves (FRR), contracted through aFRR and mFRR, to resolve the real time imbalances explicitly. More information about the procurement, prequalification and delivery process of both products can be found in Deliverable 3.6.

Anno 2024, Elia estimates the FRR need to be about 2150 MW, of which 15% aFRR and 85% mFFR. Following the assumptions pursuant Annex 6.2, this need will increase to about 3 180 MW. Figure 14 shows the outlook of this need for the upcoming 10 years (Elia, 2023, p 294). The total FRR need increases gradually over the years. From 2029 to 2030, the increase is a bit steeper due to the go-live of the new offshore wind parks in the Princess Elisabeth Zone. The aFRR need will remain stable in the future, while mFRR is expected to increase.

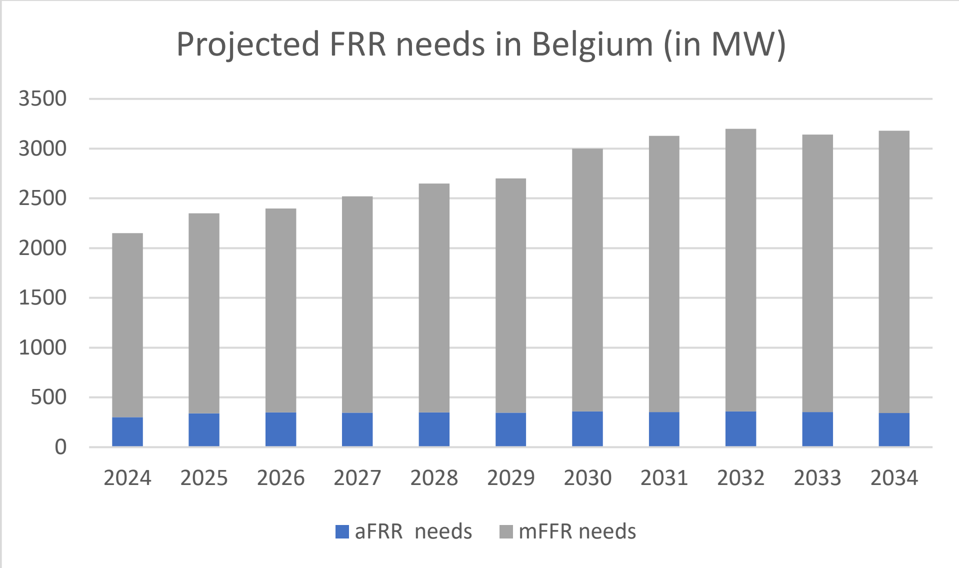


Figure 134 Projection of future, real-time FRR needs (central scenario). Based on data from ELIA (2023, p 294)

Implicit flexibility demand

Because implicit flexibility originates from price signals instead of direct procurements, it is very difficult to quantify the demand. We can, however, estimate the implicit flex needs using the following formula:

Implicit flexibility need = Total flexibility needs – Explicit flexibility needs

These flexibility needs are calculated based on the Elia data of the Adequacy and Flexibility Study (2023) and are plotted in Figure 15. The results show that Elia expects implicit flexibility to cover most of the total flexibility needs. In addition, the share of implicit flexibility is expected to increase with 3% in 10 years. The growing role of implicit flexibility in the coverage of flexibility provision is in line with the objectives of the CCMD Elia is developing (see §4.1.3.1).

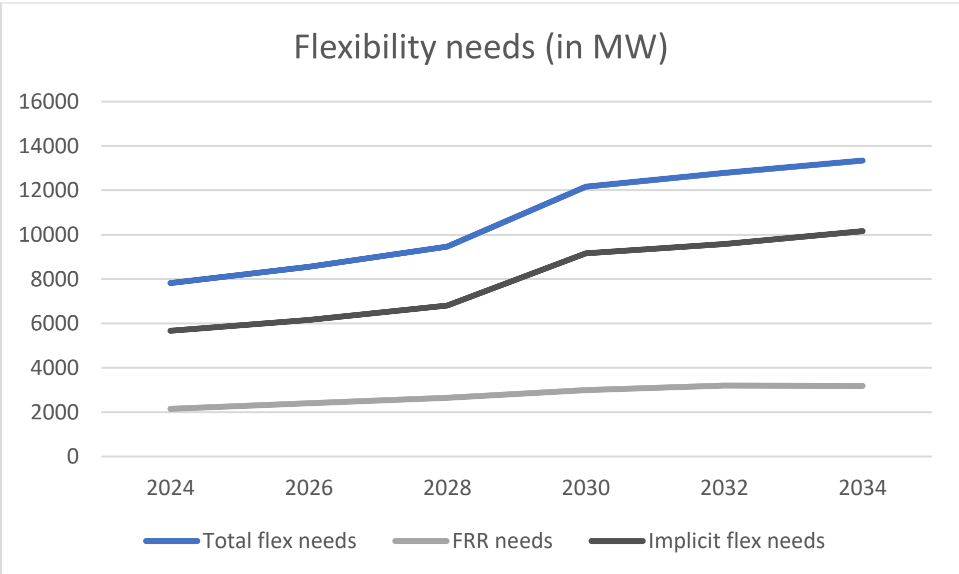


Figure 145 Projection of total, explicit and implicit flexibility needs. Based on data from ELIA

Real-time implicit flexibility can be valorised on the intraday or imbalance market. Using the Elia projections of slow flex, we can derive how much flexibility Elia expects to need on intraday. Recall that slow flex is the capacity which can be started or shut down in intraday until a few hours ahead. Elia estimated the amount of slow flexibility anno 2024 2 600 MW/5h upward and 2 000 MW/5h downward

(Elia, 2023, p 268). These needs are expected to grow for upward and downward flexibility respectively with 70% and 64% by 2034. This raises the question whether the intraday market is sufficiently liquid to fulfil this need. For the 24th of August 2023, the Belgian intraday market of the EPEX spot auctioned 10 732 MWh. Benchmarking this liquidity with the Belgian day-ahead spot market volume of 52 224 MWh shows that this intraday volume is 1/5 of the day-ahead volume (EEX Group, 2023), and thus significantly less liquid. The intraday volume of 10 732 MWh corresponds to approximately 4,13 hours of the slow flexibility needs upwards, demonstrating that a significant portion of these needs is covered by the intraday market. In this calculation we assume bidirectional flexibility, which means that if the upward flex need (2 600 MW) is met than the downward flex need (2 000 MW) as well. Although the intraday market is currently sufficiently liquid to cover the implicit flexibility needs, this cannot necessarily be guaranteed in the future, especially given the projected need increase. Yet, as soon as the intraday market's liquidity becomes insufficient, BRP's cannot sufficiently balance their portfolio before real-time anymore, leaving them susceptible to imbalance. Because Elia reaches out to aFRR and mFFR procurement to solve these imbalances and because their market prices drive imbalance prices, imbalance prices will become more extreme. More expensive imbalances will make the intraday market more attractive after which traded intraday volumes will increase. The market will thus always self-adjust to cover the needs.

Demand for residential flexibility

The previous paragraphs showed that the real-time flexibility needs will be growing significantly in 10 years. The highest increase is expected in the need for mFFR (see the above conclusions). In its 'Adequacy and Flexibility Study', Elia investigates the role of residential flexibility to fulfil mFRR capacity needs. Recall that mFRR procurement is organised via a capacity auction for upward flexibility, in which market participants are remunerated for their availability, and via energy bids for both up and downward flexibility, which remunerates activations (see Deliverable 3.6).

Pursuant the analyses of Elia (2023, p 295), we can compare two scenarios: no vs. nearly full participation of residential flex in the real-time frame. The results visualised in Figure 16 show that Elia attributes a big role for residential flexibility. In a scenario without real-time residential flexibility Elia expects to procure an mFRR capacity of around 1 800 MW by 2034, whereas only 200 MW in a scenario with residential flexibility. In addition, in a scenario with no residential flexibility, Elia expects to need around 1 500 MW of mFRR down flexibility, compared to none in a scenario with full participation of residential flexibility.

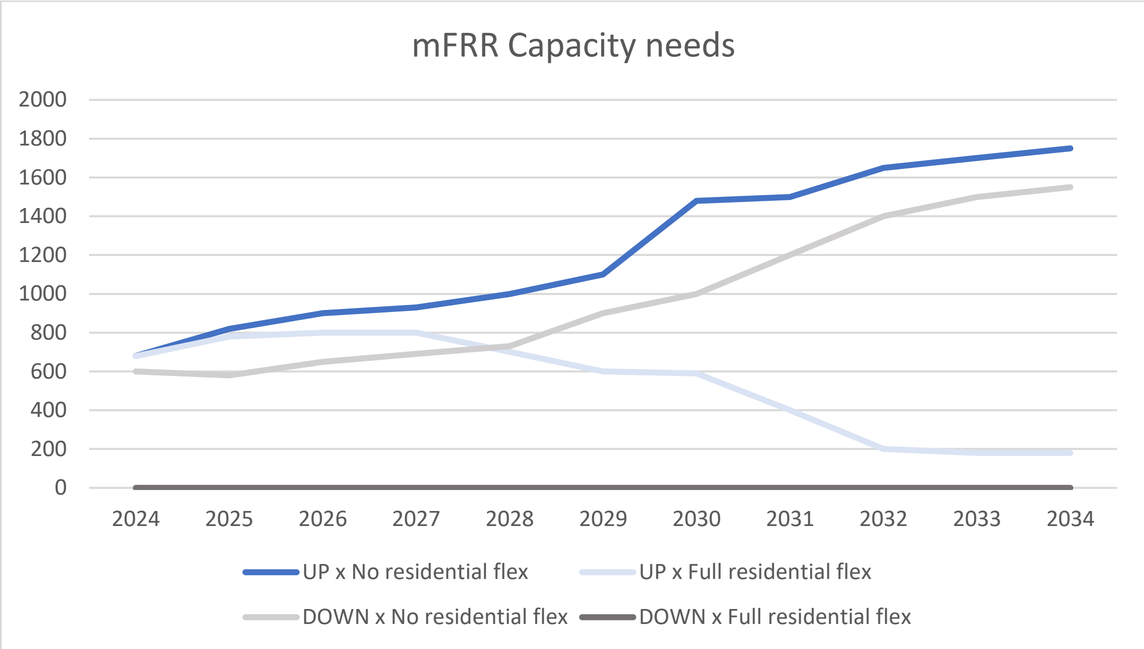


Figure 16: mFRR up and down capacity procurement based on data from Elia (2023, p 295)

4.1.3. Supply of real-time flexibility for balancing

4.1.3.1. Incentives for flexibility providers

Flexibility providers are incentivized in 2 ways to provide real-time flexibility for balancing purposes:

- Implicitly by potential financial gains through the reaction on price signals facilitated by CCMD developments
- Explicitly by remuneration schemes

CCMD Developments as an incentive for implicit flexibility

Implicit flexibility of the residential customers can be unlocked by broadcasting a price signal to residential customers, who can choose to respond either manually or through home automations. For example, the BRP could construct a price signal based on the intraday prices and/or expected imbalance prices to provoke a response from its residential customers.

Since 2021, Elia has started exploring novel ways to incentivize residential flexibility in system balancing. The CCMD, being developed by Elia, should facilitate the existence of multiple BRP's on a metering point, increasing competition for supply and flex services, and broadcast transparent and accurate price signals that cause the correct reaction (ELIA, 2021). As such, the CCMD is built on 2 main initiatives:

1. Decentralised exchange of energy blocks to facilitate the combination of supply and flex services
2. Real-time market price to reveal the true value of flexibility to market parties

In the subsection below, we explain these two initiatives in more detail.

<u>Initiative 1: The Exchange of Energy Blocks (EoEB)</u>

The EoEB implies a decentralised exchange of energy volumes between market parties on a 15-minute basis. This solution facilitates flexibility by third party independent FSP's by enabling multiple BRP's behind the meter, and as such multiple contracts for supply and flex services for assets behind the meter. For example, while a household's supplier is responsible for supplying the consumption of the household, an independent service provider might be contracted to optimize the charging schedule of the household's electric vehicle. The rescheduling has an impact on the supplier's BRP position and can be neutralized through the Exchange of the Energy Blocks. In other words, the Exchange of Energy Blocks would be a scalable alternative to the existing Transfer of Energy framework currently in place at medium/high voltage for addressing similar scenarios. More information of the Transfer of Energy framework can be found in D3.6.

Initiative 2: A real-time market price

The real-time market price is a price signal intended to reflect the system conditions and total value of energy in real-time and would be broadcasted by Elia.

The need for such a price signal is coming from the complex and untransparent nature of the current imbalance price, which makes it difficult to forecast the price and provoke proper reactions. The current imbalance price consists of the following components: a deadband to avoid price reactions at low system imbalance, the marginal mFRR price, the volume-weighted average aFRR price and an alpha factor which increases the price at large system imbalances to provoke stronger implicit reactions (see Annex 1 for more information about the imbalance price). The roll out of Mari and Picasso, projects for the European integration of respectively mFRR and aFRR, increases the complexity even more as new components are added to the formula to avoid unwanted effects from unified mFRR and aFRR market platforms. Although Mari and Picasso are intended to have a positive impact on the imbalance prices by decreasing volatility, the real impact is unknown and increased complexity could hinder the price predictability.
A second reason why a real-time price broadcasted by Elia is needed is because the imbalance price currently reflects the FRR needs rather than the total value of energy because of FRR prices being the main components in the imbalance price formula. Yet, the price signal should also include implicit reactions.
Finally, current imbalance price do not well reflect the system needs, meaning that it actually doesn't provide a representative price signal. Figure 17 shows that extremely negative imbalance prices could occur at low system imbalance and that large system imbalance could lead to moderate imbalance prices, proving that the imbalance price is not always a representative price signal for system imbalance.

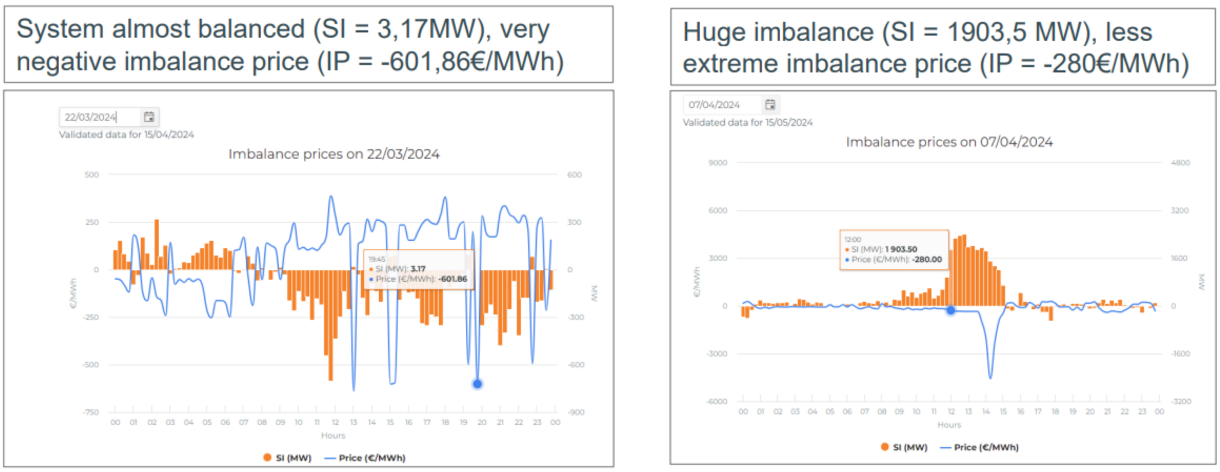


Figure 17: Relation between system imbalance and imbalance price (from Elia, 27/06/2024, WG CCMD, p13)

To cope with the above-mentioned shortcoming, Elia is developing a real time market price based on the pillars as shown in Figure 18 (Elia, 27/06/2024, WG CCMD).

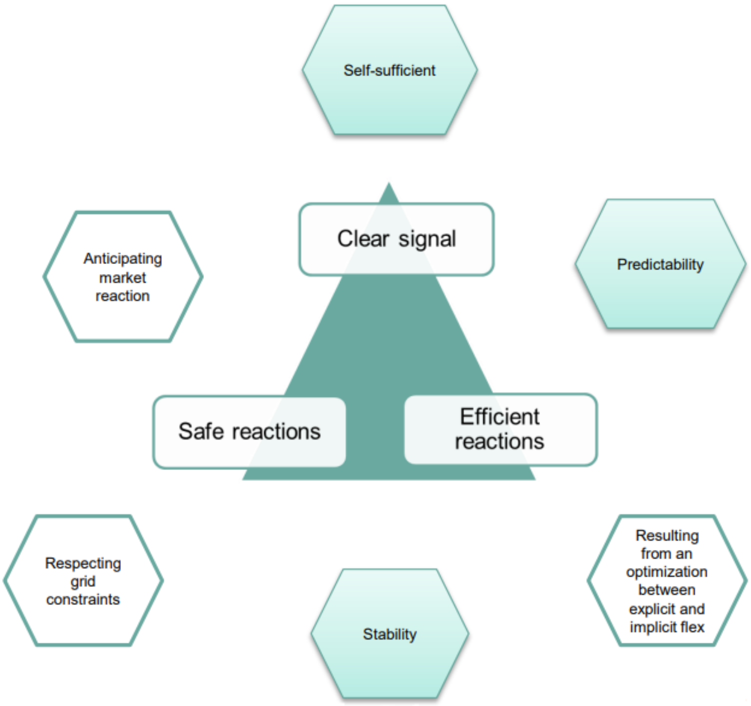


Figure 18: Pillars of the real time market price as being developed by Elia (from Elia, 27/06/2024, WG CCMD, p16)

Although the high need, the implementation of a real-time market price holds a large risk due to the change from ex-post to ex-ante calculation. Furthermore, the signal is supposed to include the implicit reaction, but this reaction is very difficult to predict with a risk to broadcast the wrong signal. If the real-time price prediction, for example, is lower than the actual imbalance price, there is a risk that assets which could have been activated will not be activated. This means lost revenues for those assets. Reversely, real time price predictions higher than the actual imbalance price hold a risk of loss-making activations.

Remunerating explicit flexibility

A description of the capacity and energy remuneration mechanisms of the reserve power markets (FCR, aFRR and mFFR) can be found in Project Deliverable D3.6. A detailed calculation of the potential financial revenues expected from reserve power market participation of residential home batteries, PV invertors, heat pumps and electric vehicles can be found in Project Deliverable D3.3.

4.2. Real-time flexibility for grid congestion relief

4.2.1. The need for flexibility

Due to the increasing share of renewable energy, the electrification of the heat, transport and industrial sector and the integration of more and more large connections points (> 1 MW), more power throughput is expected on the electricity grid. When a component in the electricity grid faces a power throughput above its designed dimensions, the component is insufficient to transfer the necessary power, resulting in grid congestion (Pillay, Karthikeyan, & Kothari, 2015). Congestion problems form a risk for reliable and efficient security of supply.

Grid congestion is a location-based problem. It can occur at different grid components, i.e. the grid lines or transformer- and substations, and at both the transmission and distribution level. In Germany, for example, the North-South high voltage grid lines are frequently congested because of too much power in regard to the cable capacity. In the Netherlands, a rapid industrial growth outstrips the demand that the upstream substation can handle. At the same time, the increase of large PV parks in rural areas results in production that outstrips the local demand which results in upstream substations that cannot evacuate the power to higher voltage levels anymore.

Figure 19 shows a graphical representation of the congestion problems that Fluvius is expecting by 2035 on the Flemish distribution grid without intervention (ceteris paribus). Most of the DGO level congestion problems are expected in Limburg, Vlaams Brabant and Antwerp. According to Fluvius, these congestions will be the consequence of high demand during the evening peak. The impact of the PV injection peak at noon is expected to form a rather low congestion risk. (Fluvius, 2024a)

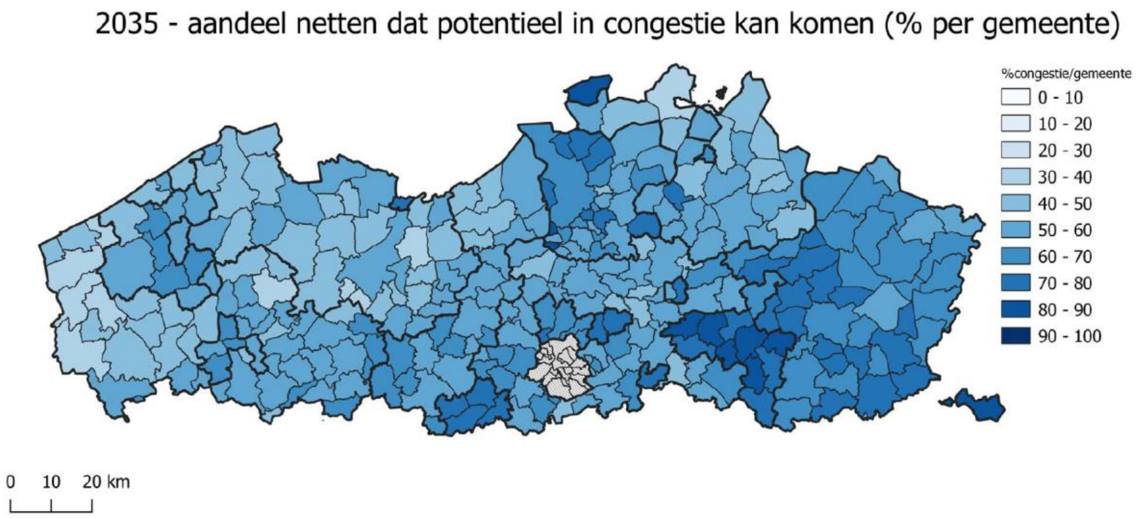


Figure 1915: Number of lines that could potentially go in congestion (% per town). Source: Fluvius (2024).

There exist 2 solutions to cope with congestion: grid reinforcements and flexibility. Physical grid reinforcements include the installation of new and thicker cable lines and of additional transformer- and substations to align power throughput with the grid dimensions. This however is a costly solution. Therefore, grid operators also explore the potential of flexibility as an alternative (Synergrid, 2023), (Fluvius, 2024a), (Ores, 2019) and (Sibelga, 2023). At the high voltage grid, TSO’s are using redispatch to avoid or resolve congestion. Redispatch is a concept that refers to flexibility for congestion purposes. It means adjusting the active power infeed at one location while at the same time reversely adjusting the active power infeed at another location such that the total active power infeed remains virtually unchanged and the grid remains balanced, but the congestion is resolved (50Hertz Elia Group, 2024). This can be implemented within one grid zone or between different grid zones to respectively solve congestion at grid lines or stations. Besides redispatch, all flexibility measures that incentivise the reduction of power peaks, either injection peaks at noon or offtake peaks in the evening, such as curtailment or demand response, could avoid congestion risks.

In its investment plan, Fluvius budgeted 4 billion EUR for grid reinforcements, of which 3 billion EUR for the low-voltage and 1 billion EUR for the medium-voltage distribution grid. On the low-voltage grid the average investment cost is about 25.000 € per project (with a few outliers to €100.000), compared to 300.000 € for grid reinforcements projects on the medium-voltage grid. Currently, 95% of the yearly grid reinforcement projects are low-voltage and 5% medium-voltage. Given the large costs for grid reinforcements and assuming flexibility as a substitute, significant cost savings at DGO level can thus be achieved by incentivizing effective flexibility. Because of the higher potential savings, Fluvius' strategic focus lies on flexibility provision at the medium- instead of low-voltage level. In addition, a roll-out of flexibility services is expected to be more effective at this level because the grid covers a bigger geographical area enlarging the pool of potential flexibility providers. Finally, the avoidance of one grid reinforcement project on low-voltage level is equivalent to a flexibility budget of 300 €/year which needs to cover the remuneration towards flex providers, platform and tendering costs, study costs and other overhead related to the service. Because of the low budget, flexibility as solution to cope with low-voltage congestion seems not to be very lucrative. (Fluvius, 2024a)

4.2.2. Quantification of the Demand

Quantifying the amount of flexibility that grid operators need to avoid congestion, is very challenging. Elia, for example, is not differentiating between balancing and congestion purposes in their flexibility demand nor between domestic and cross border congestion problems. A quantification of the demand at DGO level is even more difficult because of the location specificity and the higher amount of connection points and transformer stations. It is insufficient to only consider total installed capacity, total connector capacity and total load, because these parameters need to be assessed per transformer and grid area. Unfortunately, detailed information about capacity and load per transformer is not publicly available. Until now, the DGO's themselves have not yet succeeded in exactly quantifying the demand for flexibility. Therefore, instead of analysing the demand for flexibility, we evaluate the expected grid reinforcements at DGO level holding the assumption that flexibility and grid reinforcements are substitutes with regards to congestion.

Fluvius has made a prediction of the required low-voltage grid reinforcements using a 3-scenario analysis in which they expect 'High', 'Medium' and 'Low' Impact of heat pump and EV integration on the grid (Fluvius, 2024a).

	High	Medium	Low
Number of electric vehicles	1,9 million	1,5 million	1 million
% of EV's charging simultaneously during evening peak	60%	60%	40%
Heat pump obligation in renovated houses	Starting 2030	Starting 2035	Starting 2040
Heat pump obligation in newly built houses	Starting 2025	Starting 2025	Starting 2025

Table 2: Scenarios Fluvius (2024)

In the "medium impact" scenario (pursuant to Table 2) 15 000 km low voltage grid has to be reinforced by 2030, which is 18% of the total grid length (see Figure 20). Additionally, approximately 18 000 transformer units or 28 % of all units need to be replaced (See Figure 20). Yet, Fluvius points out that smart charging to avoid charging during the evening peak could reduce the need for these reinforcements, requiring only a reinforcement of 5 000 km and 8 000 transformers in the low voltage grid (Fluvius, 2024a). Such smart charging could materialise as day-ahead flexibility. More than 50% of the grid reinforcements could thus already be avoided through day-ahead flexibility, which can be complemented by real-time flexibility to reduce the need for grid reinforcements even further.

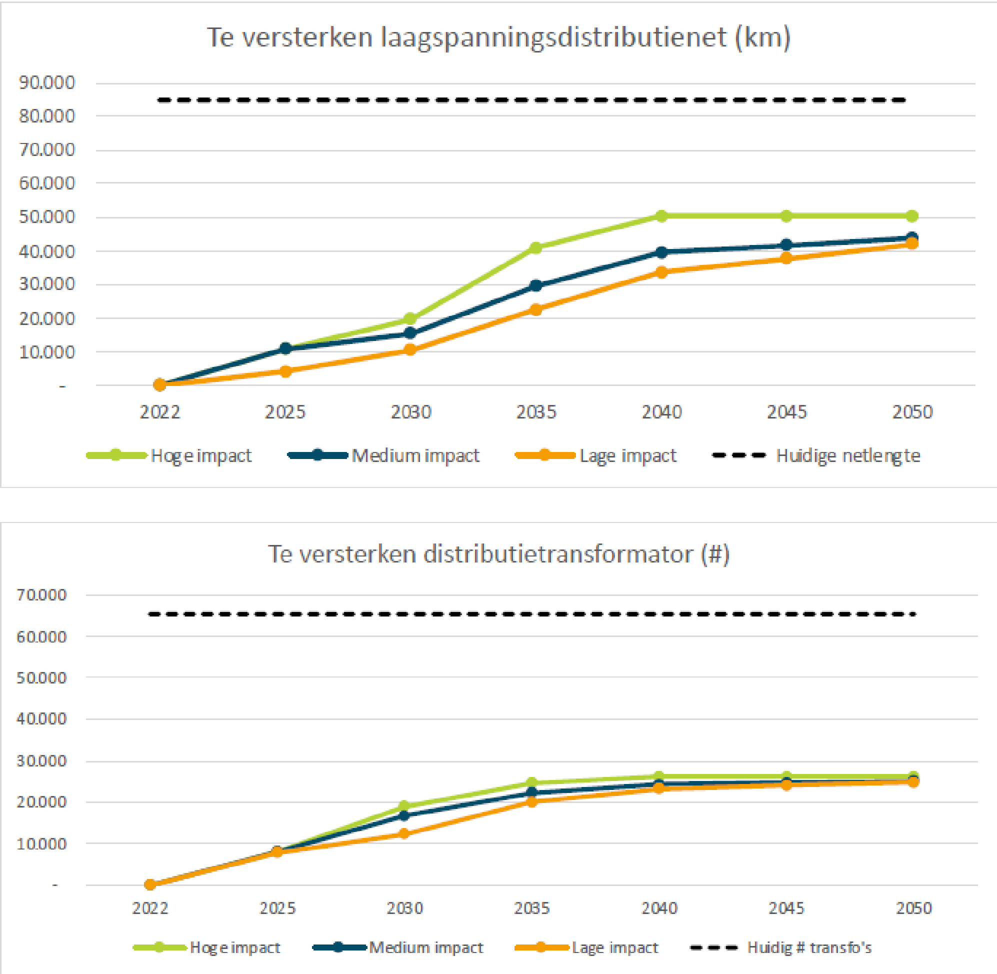


Figure 160: Length of low-voltage nets and distribution transformers to be reinforced. Source: Fluvius.

4.2.3. Supply of real-time flexibility for congestion relief

4.2.3.1. Incentives for flexibility providers

Flexibility providers on the distribution grid are incentivized in 2 ways to provide flexibility for congestion relief:

- Implicitly by the capacity tariff
- Explicitly by remuneration schemes

The capacity tariff as an incentive for implicit flexibility

The capacity tariff is a cost component on the electricity bill based on the rolling average of the monthly peak power over the last 12 months. It has been created to incentivize lower offtake power peaks and it should therefore help preventing congestion problems in the grid. We put this statement to the test by analysing the impact of the capacity tariff on the electricity bill comparing a day-ahead demand response and a peak shaving strategy. We expect the capacity tariff to support the peak shaving strategy best.

For our analysis we have used a dataset from Fluvius including the quarter hourly offtake and injection metering data of 1300 households in Flanders for the year 2022 (Fluvius, 2024c). Households with a PV installation, a combination of PV and heat pump and of PV and EV were of interest for our analysis, because these technologies have a large flexibility potential. From each group, three households were selected based on their yearly offtake, i.e. offtake close to the average group offtake, the 90th-percentile and the 10th-percentile, leading to a sample of 9 households in total. To calculate the electricity bill, we have used day-ahead prices, grid costs related to DGO area Imewo and taxes and levies (Engie, 2023) but we made abstraction from supplier specific energy price formulas to reduce complexity of the calculations. Because of extreme prices in 2022 as result of the energy crisis, we made use of 2023 assuming that the offtake profile for 2022 and 2023 were similar. The used capacity tariff was 43,50 €/kW and the grid fee was 4,01029 c€/kWh.

We tested two strategies:

- Demand Response strategy: The total offtake of the day is shifted to the hour with the cheapest day-ahead price.
- Peak Shaving strategy: The total offtake of the day is spread from 7 AM until 10 PM to reduce the peaks.

Our results show that households following a demand response strategy could reduce their energy costs with 40% to 50%. Although this energy cost reduction, the total electricity bill increased with 15% to 40%, due to high peaks for which a capacity tariff had to be paid. Households following the peak shaving strategy, on the other hand, could reduce their total electricity bill by 10% to 25%. In this strategy, there were no savings as result of day-ahead market optimisation; almost all savings could be attributed to the capacity tariff. These results support the conclusions that the capacity tariff provides an incentive for peak reduction but at the same time creates a barrier for demand response.

The current capacity tariff as introduced by Fluvius in July 2023, is independent of time of use. That means that consumers are held accountable for their maximum peak power consumption even if this peak was generated during off-peak hours in which there is assumably and according to Fluvius a low congestion risk.

As part of our analysis on capacity tariffs, we also calculated the impact of a time of use (ToU) grid tariff based on a recent Fluvius study (2023b). The ToU structure consisting of a capacity and energy volume component is shown in Table 3. The structure and proposed pricing is in line with the expectation that most congestion will occur during the evening peak.

ToU category	Period	kW component	kWh component
Peak	5 – 8 PM	100% of the peak is considered	3,784 c€/kWh
Normal	8 – 12 AM + 8 – 12 PM	80% of the peak is considered	0,263 c€/kWh
Off-peak	0 – 8 AM + 12AM – 5PM	50% of the peak is considered	0,0117 c€/kWh

Table 3: Time of Use Strategy for distribution grid tariffs based on Fluvius 2023b

The above ToU strategy results in an overall bill reduction of 15% to 30% compared to a scenario with static capacity tariff and one single kWh component. The kWh component in the grid cost was the largest driver in this reduction. Consumers could reduce their bill even more by shifting their consumption to normal and/or off-peak periods. Yet, they should be careful to not create any peaks by doing so. We agree that a time of use component and/or a real time usage of the local grid in the calculation of the capacity tariff could improve the effectiveness of the incentive. However, it's important to remain cautious to avoid an overengineering of the tariff structure design (CEER, 2020).

Remunerating explicit flexibility

Explicit flexibility means that the DSO itself broadcasts a request to the FSP's to solve a local congestion. Such request can be implemented in different ways. All Belgian DSO's are developing flexibility measures to avoid heavy investments in grid reinforcements, although they each have their own vision around flexibility. Whereas Fluvius focuses on explicit flexibility remuneration schemes to reduce evening offtake peaks (Fluvius, 2023), ORES sees most added value in curtailment of renewable energy in a non-market context to cope with injection peaks. A curtailment-based strategy, which is a form of downward flexibility, highly contrasts the strategy of Fluvius, who expects most congestion during the evening offtake peak and thus requires upward flexibility. Such differences in strategic focus points are not abnormal because grid characteristics such as installed distributed capacity and load could differ per region. DSO's have recently started with developing pilot projects to materialize their strategies.

In 2022, Fluvius started with market consultations to assess the interest of market parties to participate in flexibility solutions for congestion purposes. On June 24th 2024, the consulting rounds resulted in the kick-off of a first pilot as Fluvius officially opened prequalification for assets that can deliver reactive power in 2 distribution grid areas, i.e. Burcht & Beveren-Waas (Fluvius, 2024b). The pilot will run for 1 year, including evaluation of flexibility delivery and remuneration. A second pilot for the delivery of active power will be launched at the end of the summer 2024 via the Nodes market platform. This platform is also used in Sweden, Norway and Canada (Nodes, 2024). The technical sheet below provides an overview of the technical requirements for non-frequency related ancillary services at DGO level (Fluvius, 2023; Interview, 2023). These requirements are still under review at the VREG and cannot yet be confirmed.

Technical sheet: non-frequency related ancillary services at DGO level

Scope: access point level

Prequalification: market level (to prequalify as FSP) + access point level (prequalify the asset for a specific product)

Setpoint: Expressed as a percentage of the agreed reference power. To deliver reactive power (Var), production units typically work with setpoints of +33% and -33%. For sending the setpoints, the DSO considers the agreed control range (e.g. the sent setpoint will not exceed the maximum setpoint). However, the provider is responsible for the reaction on the setpoint in function of the availability.

Ramp rate: Period of 12,5 minutes. No Requirements about ramp-up profile within the period.

Accuracy: 3% (of the active power reference)

Data exchange:

Data	Sender	Receiver	Information
Setpoint Q	DGO	FSP	As % of reactive power
Mode	DGO	FSP	Local / Remote
Feedback setpoint	FSP	DGO	Send back the setpoint to indicate availability
Feedback Mode	FSP	DGO	Feedback about activated mode
Measurement P	FSP	DGO	Active Power at access point
Measurement V	FSP	DGO	Voltage at access point
Measurement Q	FSP	DGO	Reactive Power at access point

According to the current requirements defined in the product sheet, residential flexibility could be considered for non-frequency related ancillary services at DGO level. Yet, Fluvius rather focuses on flexibility valorisation on the medium-voltage grid instead of low voltage grid (see §4.2.1.), which lowers the need for residential flexibility. In addition, prequalification of individual assets complicates the offering of residential flexibility, which could thus further reduce the uptake of residential flexibility in the market.

Some of our neighbouring countries are already successfully operating and managing explicit flexibility solutions, opposed to Belgium who is still in the phase of piloting. Below, we discuss two case studies on how grid operators organize flexibility for congestion purposes in the UK and the Netherlands.

Case Study 1: Explicit flexibility in the UK

In the UK, local flexibility markets to avoid congestion are being operated through tendering. FSP's who offer the best pricing combined with compliance to technical characteristics, win the tender and are selected to provide flexibility for congestion purposes. Figure 21 shows the evolution of the size of the UK flexibility services, distinguishing between tendered and contracted capacity. Tendered capacity is the capacity that is being requested by the TSO to the market, while contracted capacity is the capacity that is contractually offered by market parties. Contracted capacity thus needs to be always smaller or equal to tendered capacity, because market parties participate in the tender and could provide an offering for maximally the tendered capacity.

Market results in Figure 21 show that both tendered and contracted capacity have been increasing over the years, supporting the hypothesis that there is an increasing need for flexibility (EAN, 2023). Yet, each year contracted capacity has been significantly lower than the tendered capacity, showing that the market remains rather illiquid, a result which was also found by (S., Vasiljevska, Marinopoulos, Papaioannou, & Flego, 2022). Out of the 4.6 MW tendered capacity in Y5, only 1.8 GW was being contracted (EAN, 2023).

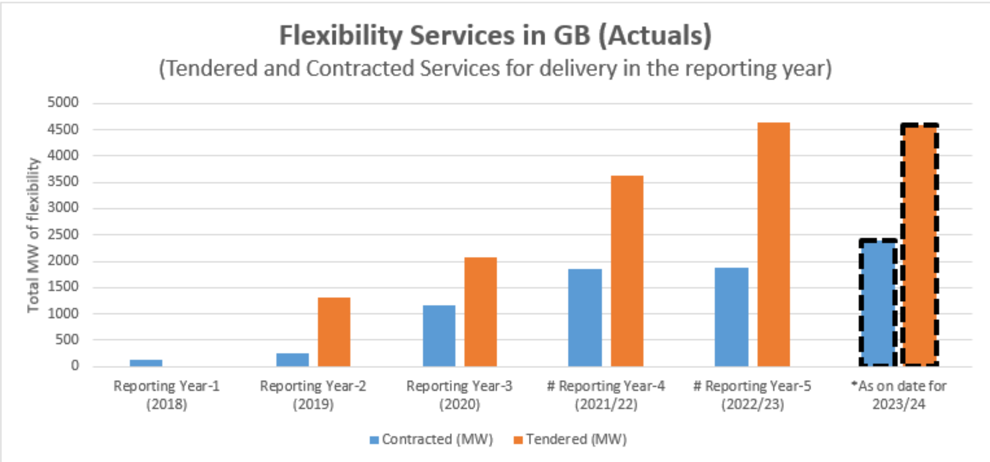


Figure 21: Market results flexibility services in the UK.

Case Study 2: Explicit flexibility in the Netherlands

GOPACS is a TSO-DSO coordination platform aiming to solve network congestions (S., Vasiljevska, Marinopoulos, Papaioannou, & Flego, 2022). GOPACS is developed as an intraday market and is linked to the well-known energy trading platforms ETPA and EPEX SPOT to solve congestion. Market parties that want to provide flexibility for congestion purposes have to become CSP (Congestion Service Provider). When TSO/DSOs detect or forecast congestion they send out a notification to all CSP's active in the congested area. Participating CPSs are asked to place a market order on ETPA or EPEX spot, which will be matched with an opposite market order in another, non-congested region to avoid imbalance at national level. During the matching, GOPACS always checks whether market orders from CSP's do not cause problems at other locations. The TSO/DSO pays the spread between the buy and sell order to conclude the deal. CSPs who want to participate in GOPACS must only add a locational tag to their order such that it can be linked to a congestion zone. In 2021, TSO TenneT activated 142 GWh of flexibility and DSO Liander 111 MWh. The main challenge for GOPACS' success, especially for DSOs, remains the relatively low market liquidity. (GOPACS, 2024)

The case studies of the UK and the Netherlands show that there are multiple ways to organize flexibility for congestion. While the flexibility tendering system in the UK provides long-term contracts, GOPACS is closer to real time. While long-term solutions give more certainty about the availability of the needed capacity and flexibility, short-term solutions are better suited for operational congestion management. Nevertheless, a close to real-time solution is expected to incentivize market parties better because it allows for more flexible and diverse asset optimization strategies. So, a real-time solution could help solve market liquidity issues like experienced in the UK tendering market.

5. Conclusion

This deliverable analysed the demand and supply potential of residential flexibility in different electricity markets and for different purposes, resulting in 3 cases: day-ahead flexibility, real-time flexibility for balancing and real-time flexibility for congestion purposes. Each analysis included a description of the need for flexibility, a quantification of the demand and an exposition of the supply potential.

We can conclude that flexibility is highly needed to ensure the security of supply in a system that is transitioning towards more renewable energy production and increased demand due to the electrification of heat, transport and industry. We estimated the demand for flexibility to increase drastically in all cases by 2034. Meeting this demand is challenging, which is why grid operators try to incentivise the supply through explicit remuneration schemes and the creation of implicit price signals, i.e. real-time price and capacity tariffs.

6. Annexes

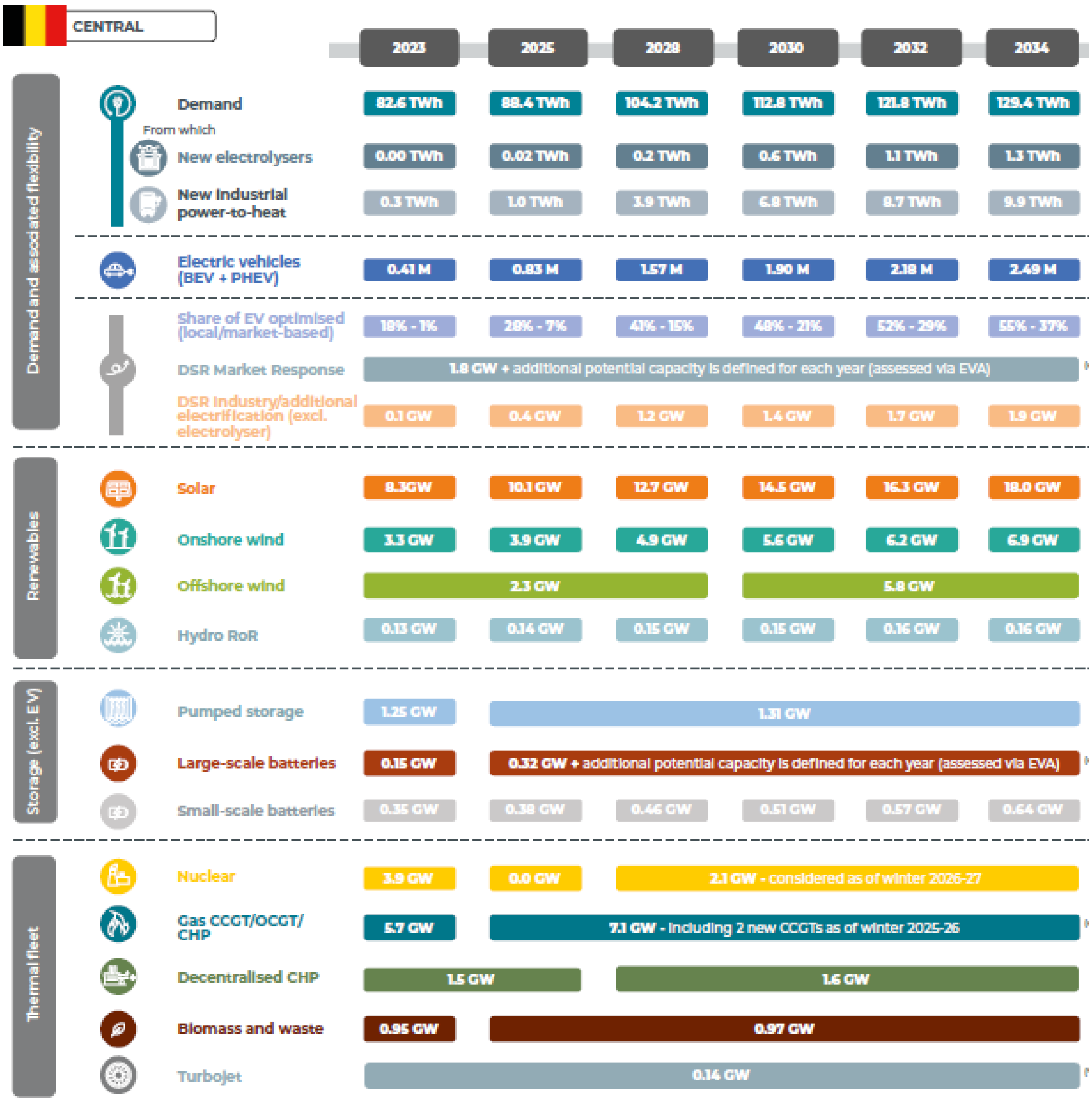
6.1. Projections installed RES capacity in Belgium

Table 4: Assumed evolution of installed capacity in Belgium (in GW)			
	2025	**2030**	**2034**
PV	10,3	14,5	18
Onshore wind	3,9	5,6	6,9
Offshore wind	2,26	5,76	5,76
Large scale batteries	0,95	2,47	3,27

Source: Elia Adequacy Study, 2023

6.2. Scenario analysis Adequacy and Flexibility Study (2024) Elia

Figure 22: Overview of the assumptions taken in the central scenario (page 75)



6.3. Imbalance price

Depending on the direction of the system imbalance, imbalance prices are calculated by either Marginal Incremental Price (MIP) or Marginal Decremental Price (MDP) and corrected with an alpha factor to incentivize stronger implicit reactions. MDP is used at negative system imbalances whether MIP is used at positive system imbalances. MIP and MDP are calculated based on the maximum of the marginal mFRR price and weighted of that quarter hour average aFRR price.

Quarter	Quality status	ACE (MW)	SI (MW)	α (€/MWh)	MIP (€/MWh)	MDP (€/MWh)	Price (€/MWh)
05:30 > 05:45	Non validated	-2,005	-20,800	0,00	**22,78**	-53,97	22,78
05:15 > 05:30	Non validated	-5,255	21,228	0,00	103,31	**62,00**	62,00
05:00 > 05:15	Non validated	8,710	81,388	0,00	102,75	**-0,98**	-0,98
04:45 > 05:00	Non validated	2,764	-42,481	0,00	**102,88**	24,94	102,88
04:30 > 04:45	Non validated	-2,941	-49,855	0,00	**102,07**	10,29	102,07
04:15 > 04:30	Non validated	0,377	-49,868	0,00	**103,26**	23,47	103,26
04:00 > 04:15	Non validated	-35,263	-83,177	0,00	**103,69**	-4,03	103,69
03:45 > 04:00	Non validated	4,424	-5,276	0,00	**54,35**	-50,22	54,35
03:30 > 03:45	Non validated	30,428	34,762	0,00	103,69	**-68,18**	-68,18
03:15 > 03:30	Non validated	-0,207	49,727	0,00	103,69	**-110,99**	-110,99
03:00 > 03:15	Non validated	-58,875	-87,930	0,00	**152,34**	-62,12	152,34
02:45 > 03:00	Non validated	47,870	297,287	0,00	103,69	**-326,84**	-326,84
02:30 > 02:45	Non validated	-4,944	392,741	60,55	103,69	**-80,00**	-140,55
02:15 > 02:30	Non validated	5,091	509,647	18,79	127,85	**1,29**	-17,50
02:00 > 02:15	Non validated	-21,134	95,696	0,00	183,53	**-472,99**	-472,99
01:45 > 02:00	Non validated	86,420	287,561	0,00	103,69	**-603,32**	-603,32
01:30 > 01:45	Non validated	47,621	306,642	0,00	168,00	**-607,58**	-607,58
01:15 > 01:30	Non validated	45,061	-159,550	36,42	**185,00**	-613,38	221,42
01:00 > 01:15	Non validated	-339,259	-545,185	12,27	**185,00**	-52,43	197,27
00:45 > 01:00	Non validated	38,013	0,212	0,00	103,38	**63,29**	63,29

Figure 23: Elia 15-min imbalance prices (16/07/2024)

(https://www.elia.be/nl/grid-data/balancing/onevenwichtprijzen-15-min)

			Incremental Prices					Decremental Prices				
Quarter	SI (MW)	ACE (MW)	MIP (€/MWh)	Floor (€/MWh)	aFRR+ (€/MWh)	mFRR+ (€/MWh)	Reserve Sharing+ (€/MWh)	MDP (€/MWh)	Cap (€/MWh)	aFRR- (€/MWh)	mFRR- (€/MWh)	Reserve Sharing- (€/MWh)
09:15 > 09:30	-406,773	17,986	**322,06**	99,00	322,06	273,00		-51,64	0,00	-51,64		
09:00 > 09:15	-581,969	-246,874	**209,00**	99,00	194,66	209,00		0,00	0,00	0,00		
08:45 > 09:00	-330,266	-86,872	**273,00**	99,00	120,35	273,00		-41,03	0,00	-41,03		
08:30 > 08:45	-270,840	-123,790	**194,99**	99,00	194,99			-22,52	0,00	-22,52		
08:15 > 08:30	-235,185	-39,379	**204,64**	99,00	119,11	204,64		-40,13	25,00	-40,13		
08:00 > 08:15	-283,410	-75,031	**245,22**	99,00	245,22	229,95		-35,20	25,00	-35,20		
07:45 > 08:00	-215,243	-27,452	**209,95**	99,00	106,16	209,95		-43,84	5,00	-43,84		
07:30 > 07:45	-257,832	-62,649	**174,25**	99,00	174,25	169,19		-44,64	5,00	-44,64		
07:15 > 07:30	-119,212	-13,848	**169,19**	99,00	151,18	169,19		-64,50	5,00	-64,50		
07:00 > 07:15	-171,285	-39,950	**212,11**	99,00	159,28	212,11		-59,52	-53,54	-59,52		
06:45 > 07:00	-96,905	1,153	**188,00**	99,00	103,39	188,00		-60,08	-53,54	-60,08		
06:30 > 06:45	-173,402	-34,417	**156,46**	99,00	156,46			-56,40	-53,54	-56,40		
06:15 > 06:30	-100,420	-33,618	**123,38**	99,00	123,38			-59,82	-53,54	-59,82		
06:00 > 06:15	-10,736	-1,971	**22,73**	99,00	103,46			-58,57	-53,54	-58,57		
05:45 > 06:00	-31,991	-7,513	**102,05**	99,00	102,05			-53,96	-53,44	-53,96		
05:30 > 05:45	-20,800	-2,005	**22,78**	99,00	103,38			-53,97	-53,44	-53,97		
05:15 > 05:30	21,228	-5,255	103,31	99,00	103,31			**62,00**	25,00	-6,83		
05:00 > 05:15	81,388	8,710	102,75	99,00	102,75			**-0,98**	25,00	-0,98		
04:45 > 05:00	-42,481	2,764	**102,88**	99,00	102,88			24,94	25,00	24,94		
04:30 > 04:45	-49,855	-2,941	**102,07**	99,00	102,07			10,29	25,00	10,29		
04:15 > 04:30	-49,868	0,377	**103,26**	99,00	103,26			23,47	25,00	23,47		
04:00 > 04:15	-83,177	-35,263	**103,69**	99,00	103,69			-4,03	25,00	-4,03		
03:45 > 04:00	-5,276	4,424	**54,35**	103,69	103,69			-50,22	5,00	-50,22		
03:30 > 03:45	34,762	30,428	103,69	103,69	103,69			**-68,18**	5,00	-68,18		
03:15 > 03:30	49,727	-0,207	103,69	103,69	103,69			**-110,99**	5,00	-110,99		
03:00 > 03:15	-87,930	-58,875	**152,34**	103,69	152,34			-62,12	5,00	-62,12		
02:45 > 03:00	297,287	47,870	103,69	103,69	103,69			**-326,84**	5,00	-326,84	-80,00	
02:30 > 02:45	392,741	-4,944	103,69	103,69	103,69			**-80,00**	5,00	3,14	-80,00	
02:15 > 02:30	509,647	5,091	127,85	127,85	127,85			**1,29**	5,00	1,29		
02:00 > 02:15	95,696	-21,134	183,53	143,00	183,53			**-472,99**	25,00	-472,99	-80,00	
01:45 > 02:00	287,561	86,420	103,69	103,69	103,69			**-603,32**	5,00	-603,32		
01:30 > 01:45	306,642	47,621	168,00	103,69	103,69	168,00		**-607,58**	27,00	-607,58		
01:15 > 01:30	-159,550	45,061	**185,00**	115,71	178,90	185,00		-613,38	27,00	-613,38		
01:00 > 01:15	-545,185	-339,259	**185,00**	99,57	159,02	185,00		-52,43	27,00	-52,43		
00:45 > 01:00	0,212	38,013	103,38	99,57	103,38			**63,29**	27,00	-449,08		
00:30 > 00:45	-148,598	18,706	**185,00**	99,57	99,57	185,00		-575,22	27,00	-575,22		
00:15 > 00:30	-263,885	4,297	**185,00**	99,57	99,57	185,00		-212,13	27,00	-212,13		
00:00 > 00:15	-358,250	0,701	**107,66**	99,57	107,66			-141,53	27,00	-141,53		

Figure 25: Balancing Energy volume and price components 15' – prices (16/07/2024)

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