



Deliverable 3

Market design to support industrial competitiveness and flexibility

GALILEO 

Deliverable D3

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Executive Summary

The GALILEO project aims to accelerate industrial decarbonization, electrification, and flexibility provision in Belgium by improving the understanding, valorisation, and integration of industrial flexibility into future electricity markets. The project combines detailed industrial process modelling, electricity market modelling, and industrial reference cases to identify technical, economic, and regulatory barriers to flexibility provision and to develop future-proof market and product designs. Within this framework, the project develops integrated market and bidding models to assess the value of industrial flexibility under different market designs, and applies these methodologies to representative industrial business use cases (BUCs) from key Belgian industrial sectors. This deliverable combines a qualitative assessment of the technical compatibility of the GALILEO BUCs with different electricity-market mechanisms, a quantitative evaluation of selected market-design developments using detailed optimization models, and a review of European capacity-market design elements affecting industrial demand response.

Chapter 1 develops a structured framework for assessing the technical fit of industrial assets across eight electricity-market mechanisms: the day-ahead (DA) market, intraday market, imbalance settlement, Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR), manual Frequency Restoration Reserve (mFRR), congestion management, and capacity remuneration mechanisms. The framework evaluates each BUC against the principal technical participation requirements, including minimum bid size, response time, delivery duration, availability, and process constraints. The assessment shows that DA, intraday and imbalance markets are broadly accessible for most GALILEO BUCs, whereas participation in balancing services depends more strongly on the operational characteristics of the industrial process. FCR and congestion management emerge as the most restrictive mechanisms because of their stringent response and locational requirements. The framework provides a consistent methodology for identifying the principal technical barriers that influence market participation and for prioritising mechanisms for more detailed techno-economic assessment.

Chapter 2 reviews ongoing developments in European electricity-market design that may influence the participation of industrial flexibility. Based on this review and their relevance for the GALILEO BUCs, three developments were selected for quantitative assessment: the introduction of Fast Frequency Response (FFR), increasing the temporal granularity of balancing-capacity reservation products, and reducing minimum bid-size requirements for balancing-capacity and balancing-energy markets. These changes were subsequently evaluated using the optimization framework developed in Deliverable D2 [3] while keeping all other market assumptions unchanged, allowing the individual impact of each market-design modification to be assessed in isolation.

Chapter 3 evaluates a hypothetical FFR product design for Tiense Suiker and LCL Data Centers. The results show that its value depends strongly on technical response capability, operational availability, procurement design and remuneration. For LCL's battery storage systems, FFR can be stacked with day-ahead participation and provides material additional revenues in the higher-remuneration scenarios. Tiense Suiker does not participate under annual procurement because its seasonal flexibility does not align with the required availability periods; a seasonal special case produces only limited benefits and assumes sub-second response capability that is not available under the site's assessed technical characteristics. These results are illustrative because the model uses adjusted frequency thresholds, a quarter-hourly representation of sub-second activation and perfect foresight.

The analysis of higher temporal granularity for balancing-capacity reservation demonstrates that reducing reservation periods from the current 4-hour products to hourly products substantially increases the amount of balancing capacity that industrial assets can reserve. For both the Tessengerlo and Nyrstar BUCs, most of the economic benefit is already obtained once hourly reservation products are introduced, while further reductions to 30-minute or 15-minute products provide little additional value. The results further show that increased reserved capacity does not necessarily translate into higher activated balancing energy. Instead, shorter reservation periods primarily improve the alignment between industrial flexibility availability and balancing-capacity products, allowing reserve capacity to be offered during a larger number of suitable time intervals. The resulting profit improvements are therefore mainly driven by improved participation in balancing-capacity markets rather than by increased balancing-energy activations.

The impact of reducing minimum bid-size requirements is evaluated for the Aperam ORC and E-boiler BUCs. Lower bid thresholds consistently increase the amount of balancing capacity that can participate in the market by enabling smaller flexibility volumes to qualify individually. However, the resulting economic benefits remain modest. For the ORC case, reserved balancing capacity increases substantially while annual profit changes only marginally, reflecting the relatively small contribution of balancing-capacity revenues to total annual revenues and the interaction with revenues from other market segments. For the E-boiler, both reserved capacity and activated balancing energy increase only slightly, leading to negligible changes in annual profit. Across both BUCs, the simulations indicate that lowering the minimum bid size primarily improves market accessibility rather than substantially increasing the economic value of industrial flexibility.

Chapter 4 broadens the analysis by examining industrial demand-response participation in European capacity markets. The chapter reviews key design elements including qualification procedures, de-rating methodologies, auction lead times, clearing mechanisms, access to long-term contracts, contract design, secondary markets, penalties, cost allocation and competition with conventional generation. Where relevant, differences between European capacity-market implementations are discussed together with their implications for the Belgian Capacity Remuneration Mechanism. The review highlights how market design influences the accessibility of capacity markets for industrial demand response and identifies aspects that may facilitate greater participation while remaining consistent with applicable European regulatory frameworks.

Taken together, the analyses demonstrate that the ability of industrial flexibility to par-

ticipate in electricity markets depends on both the technical characteristics of industrial processes and the design of the corresponding market products. Among the evaluated market-design changes, increasing the temporal granularity of balancing-capacity procurement provides the most consistent improvement in the utilisation of industrial flexibility. Lower minimum bid sizes primarily reduce participation barriers but produce comparatively limited economic gains for the investigated BUCs. The technical-fit assessment, quantitative market simulations and review of capacity-market design together provide a comprehensive basis for evaluating how future electricity-market developments may facilitate broader participation of industrial demand response within the GALILEO project.

Chapter 1

Technical Fit

Industrial flexibility can be valorised through several electricity-market and system-service mechanisms, each with distinct technical participation requirements. Before assessing revenues, an industrial operator must establish whether an installation can meet the relevant requirements at its normal operating point and under the process conditions in which flexibility would be offered.

This chapter presents a high-level technical-fit framework that compares installation characteristics with the principal technical and contextual requirements of candidate mechanisms. It is a pre-feasibility screen: it identifies apparent fit and binding constraints, but does not replace product-specific prequalification, operational testing, or economic assessment.

Applied to the Galileo BUCs, the framework indicates that response time, controllable headroom, delivery dependence on the industrial process, availability, and locational eligibility are the main differentiators. The results are reported qualitatively to avoid disclosure of company-specific technical parameters. Detailed results from the technical fit analysis are included in Deliverable D2 [3].

1.1 Framework

The framework is a three-step workflow that maps a compact set of installation parameters—power ranges, energy storage capability, ramp rates, availability, activation modes, delivery duration, and recovery periods—to the limiting criteria of eight electricity-market mechanisms. It produces a qualitative fit score and identifies the principal constraint for each installation–mechanism pair (Figure 1.1).

The three steps (industrial installation characteristics, flexibility mechanism characteristics, and the mapping of both) form a structured and relatively quick pre-feasibility checklist. Pay attention that, before market entry, product rules and asset capabilities should be evaluated in greater detail, because both can change and because this pre-feasibility technical fit assessment does not cover all relevant participation conditions.

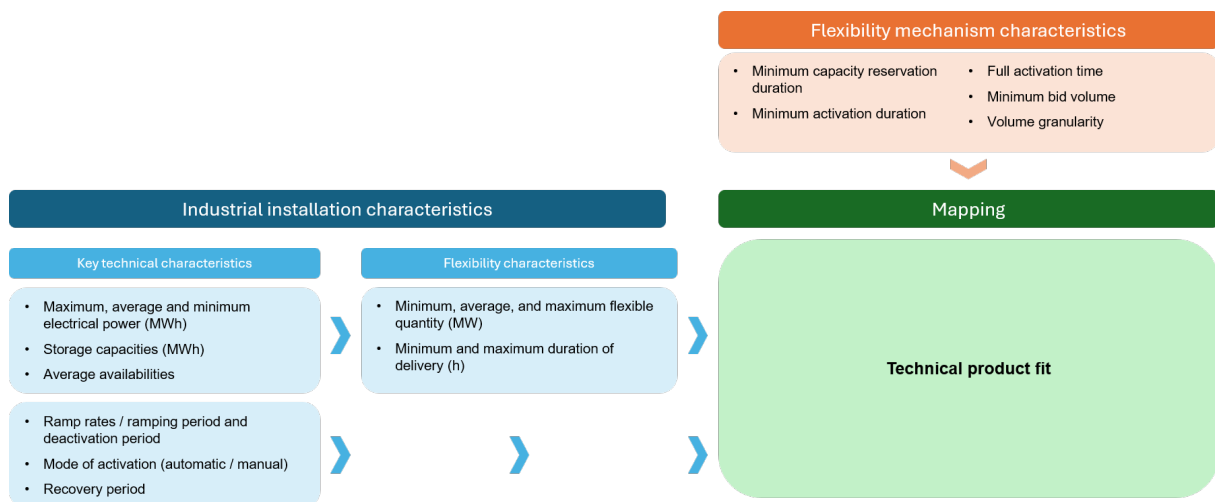


Figure 1.1: Diagram of the three-step technical fit exercise.

1.1.1 Step 1: Characterise the Industrial Installation

First, identify the technical boundaries of the installation—comprising one or more assets—and map energy exchanges (e.g., electricity, heat, gas) between them. A line diagram provides a concise visual summary and makes explicit which assets are in and out of scope.

Then record the parameters of the aggregate installation. *Technical dimensions* comprise maximum, representative operating, and minimum electrical power, together with relevant conversion efficiencies and buffer or storage characteristics. *Flexibility characteristics* comprise ramping capability, full activation time (FAT), deactivation time, minimum and maximum delivery duration, recovery time, and activation mode. FAT includes preparation and ramping and is evaluated in the slower direction. *Availability assumptions* cover operating patterns, planned and unplanned outages, and relevant process dependencies. These inputs are used to derive the upward and downward headroom available at representative operating points. Direction is expressed from the electricity-system perspective: upward flexibility increases net injection or reduces withdrawal, whereas downward flexibility reduces net injection or increases withdrawal.

1.1.2 Step 2: Characterise the Target Flexibility Mechanisms

For each candidate mechanism, identify the criteria most likely to limit participation: minimum bid size, bid granularity, FAT, minimum delivery duration, activation mode, and any relevant availability or locational condition. The purpose is to screen for exclusion criteria, not to reproduce the complete product rules. Table 1.1 lists the requirements used for FCR, aFRR, mFRR, DA and intraday trading, imbalance settlement, congestion management, and the Capacity Remuneration Mechanism (CRM). For mechanisms without a prescribed FAT or delivery duration, the applicable Market Time Unit (MTU), Imbalance Settlement Period (ISP), or submitted energy schedule provides the operational time reference. The requirements must be checked against the applicable market rules when an installation proceeds beyond screening.

Table 1.1: Key Technical Participation Requirements for each Flexibility Mechanism

Flexibility mechanism	Min bid size [MW]	Min bid granularity [MW]	Full activation time [min]	Minimum duration [min]	Other requirements
FCR	1	1	0.5	Indefinite	Automatic activation (frequency measurement)
aFRR	1	1	5	15	Automatic activation (control signal)
mFRR	1	1	12.5	15	
DA market	0.1	0.1	n.a. (<<15 min MTU)	n.a. (~15 min MTU)	
Intraday market	0.1	0.1	n.a. (<<15 min MTU)	n.a. (~15 min MTU)	
Imbalance settlement	0	0	n.a. (<<15 min ISP)	n.a. (~15 min ISP)	
Congestion management	25	25	As submitted in energy bid	Event-driven	Installation in congested area Generation or upward activation. High availability. Demand response exempted from reliability option payback.
CRM	1 ^a	1 ^a	n.a.	SLA-dependent	

^aDerated capacity.

1.1.3 Step 3: Assess Technical Fit

Compare the installation parameters from Step 1 with the mechanism requirements from Step 2, criterion by criterion. Assign **poor** where at least one screened requirement is not met, **moderate** where participation appears possible but a material caveat or unverified capability remains, and **good** where no limiting criterion is identified within the scope of the screen. For each **poor** or **moderate** score, record the principal constraint, such as insufficient headroom, response that is too slow, process-dependent delivery, or locational ineligibility. The score is an assessment outcome, not proof of qualification or commercial readiness.

The scores are then grouped into three accessibility tiers: (i) *broadly accessible*, where no limiting criterion is identified for all or nearly all cases; (ii) *conditionally accessible*, where several cases retain operational caveats or require capability verification; and (iii) *restricted*, where fast response, controllable headroom, or contextual eligibility excludes several cases. The tiers prioritise mechanisms for more detailed technical, contractual, and economic assessment.

1.2 Summary of results

1.2.1 Case Description and Installation Characterisation (Steps 1–2)

The framework is applied to six Galileo BUCs: Aperam (BUC 1A), Aperam (BUC 1B), Nyrstar (BUC 2), Tessenderlo (BUC 3), Tiense Suiker (BUC 4A), and LCL Data Centers (BUC 5). Table 1.2 summarises their asset types. The cases cover generation, consumption, and storage assets in the steel, metallurgy, chemicals, food, and data-centre sectors. All assessed installations are connected to the high-voltage network.

Figure 1.2 illustrates a simple scoping diagram for Aperam (BUC 1A): waste heat

Table 1.2: Asset Types per Galileo BUCs

Asset	Aperam BUC 1A	Aperam BUC 1B	Nyrstar BUC 2	Tessenderlo BUC 3	Tiense Suiker BUC 4A	LCL Data Centers BUC 5
ORC	✓					
Steam turbine				✓	✓	
Solar PV						✓
Onshore wind						✓
E-boiler		✓			✓	
P2E electrolyser			✓			
Heat Pump					✓	
BESS						✓
Thermal buffer	✓	✓				
Material buffer			✓			

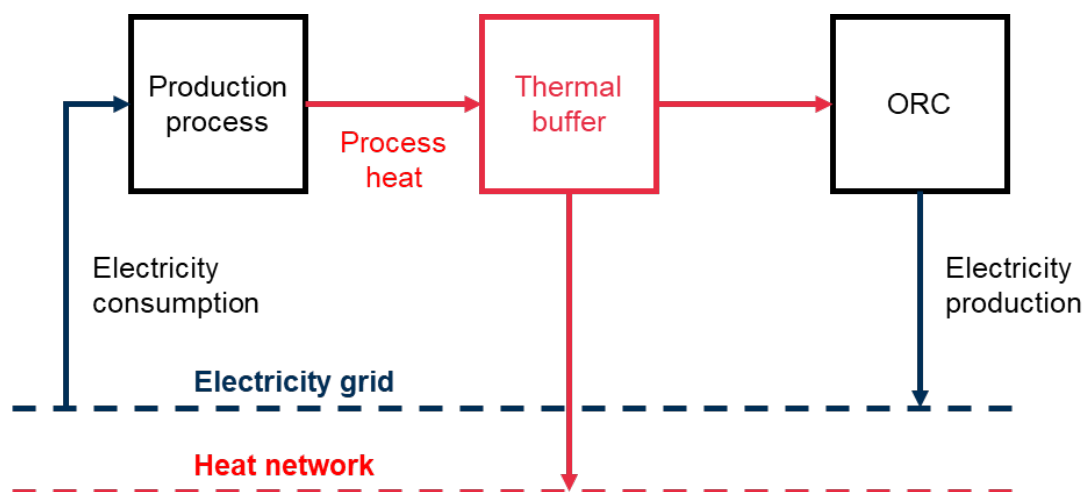


Figure 1.2: Line diagram of Aperam (BUC 1A).

from an industrial production process feeds a thermal buffer and drives an ORC for on-site electricity generation. Equivalent diagrams were produced for all six installations.

The assessment used company-provided operating ranges, response characteristics, delivery constraints, and availability assumptions. These inputs remain confidential; only the resulting qualitative fit and the principal binding constraints are reported. The scores therefore preserve the decision logic of the assessment without disclosing asset-level parameters.

Across the cases, technical fit is governed primarily by controllable headroom at the operating point, response time, and the extent to which delivery depends on upstream or downstream process conditions. Fast storage and highly controllable electrical loads show the strongest response-time fit. Process-coupled generation and seasonally operated installations retain delivery or availability caveats. Buffering can relax process-coupling constraints, but its effect depends on the direction and duration of the requested activation. These observations support mechanism screening; they do not

establish prequalification or firm capacity.

1.2.2 Technical-Fit Scores and Binding Constraints (Step 3)

Table 1.3 presents the qualitative scores obtained by comparing the confidential case inputs with the screening requirements in Table 1.1. The principal constraint is stated for each **poor** or **moderate** score. Scores indicate technical fit within the defined scope and do not disclose the underlying company-specific values.

Aperam 1A

The assessment shows that downward flexibility products are the strongest technical fit. Downward aFRR and downward mFRR are good fits because the ORC can reduce output within the required activation times and can sustain downward activation when sufficient storage and heat-rejection capacity are available. Upward aFRR and upward mFRR are moderate fits: activation is technically feasible, but depends on the availability of thermal storage or excess process heat and may require the ORC to be scheduled at a lower set-point during the reservation period.

Spot-market participation and imbalance settlement are also good technical fits. The ORC and thermal buffer can be used for spot market price arbitrage by shifting electricity production towards higher-price periods and reducing production during lower-price periods. The fast response time also allows opportunistic deviations from the scheduled production profile in response to imbalance prices, provided that the thermal state of the system allows such deviations.

FCR and Transmission System Operator's (TSOs) redispatch are weak fits under the assessed conditions. FCR is constrained by the strict activation time and symmetric delivery requirements, which the ORC cannot reliably guarantee. TSO redispatch is technically possible from an operational perspective, but the current redispatch framework remains difficult to access because of the applicable minimum asset-size threshold and the absence of significant congestion in the relevant grid area. The CRM is a good technical fit because the ORC operates close to baseload conditions with high availability, although any flexible component would need to be treated as energy-limited capacity.

Aperam 1B

The assessment shows that upward balancing services are the strongest technical fit among the reserve products. Upward aFRR and upward mFRR are good fits because the e-boiler can reduce consumption within the required activation times and the thermal buffer can sustain the resulting steam supply for the relevant reservation period when it is pre-filled. Downward aFRR and downward mFRR are moderate fits: activation is technically feasible, but sufficient part-load operating margin must be available because the e-boiler may already be operating close to its maximum power level.

Spot-market participation and imbalance settlement are also good technical fits. The combination of fast e-boiler modulation and thermal storage enables spot market price arbitrage by shifting electricity consumption towards lower-price periods and reducing

consumption during higher-price periods. The same operational flexibility can be used in the intraday market and imbalance settlement, where the installation can adjust its consumption in response to updated price signals, provided that the thermal buffer state allows the deviation.

FCR is only a moderate fit. The e-boiler can potentially meet the fast response requirement when operated in a suitable standby or part-load mode, but the strict activation requirement and the need to keep symmetric reserve available make participation more demanding. TSO redispatch is a poor fit under the current framework because access is constrained by the current redispatch design and local grid context, even though the installation is technically controllable. The CRM is a good technical fit because the e-boiler can provide demand-response capacity through downward modulation of consumption, although the resulting capacity would be subject to derating and depends on the available thermal buffer state.

Nyrstar

The assessment shows that balancing services are a strong technical fit, with the exception of FCR. aFRR and mFRR are good fits in both directions because the electrolysis process can change operating point within the required activation times and the process buffers can sustain activation for durations exceeding the relevant reservation requirements. FCR is only a moderate fit: the process can respond quickly, but only part of the available flexible capacity can reliably meet the strict full-response requirement.

Spot-market participation and imbalance settlement are also good technical fits. The virtual battery can shift electricity consumption between lower-price and higher-price periods in the DA and intraday markets, while the long process-buffer duration gives substantial operational freedom. The same flexibility can be used to respond to imbalance price signals, provided that the buffer state and production constraints allow the deviation. Full exploitation of multi-day storage would require robust multi-day price forecasting and is therefore more uncertain than daily or intraday optimization.

Congestion management through TSO redispatch is a good fit. Nyrstar is located close to a congested area and the available flexibility exceeds the current 25 MW minimum asset-size requirement. The CRM is a very good technical fit because the process behaves as a long-duration demand-side flexibility resource with high availability. Classification and derating treatment remain relevant design considerations, but the long-duration virtual-battery characteristics are technically favourable for CRM participation.

Tessenderlo

The assessment shows that downward balancing services are the strongest technical fit among the reserve products. Downward aFRR and downward mFRR are good fits because the steam turbine can reduce generation within the required activation times through the bypass valve. Upward aFRR and upward mFRR are moderate fits: activation is technically feasible within the required timeframes, but the available flexibility depends on the operating point and the availability of excess steam.

Spot-market participation and imbalance settlement are also good technical fits. The steam turbine can reduce generation during periods of negative or otherwise un-

favourable prices, making downward response particularly relevant for DA, intraday and imbalance-market optimization. Increasing generation during high-price periods is possible only when the turbine is not already operating close to its maximum output and when sufficient excess steam is available.

FCR is a poor fit because the turbine cannot reliably meet the strict activation-time requirement and cannot provide robust symmetric upward and downward delivery. TSO redispatch is also a poor fit under the current framework because access is constrained by the applicable minimum asset-size threshold, although the asset could become more relevant if future redispatch rules allow smaller installations to participate. The CRM is a good technical fit for baseload generation, although availability risk remains relevant because steam availability and generation can vary over the year.

Tiense Suiker 4A

The assessment shows that aFRR and mFRR are strong technical fits. The integrated portfolio can reach the required activation times for both aFRR and mFRR, and the combination of gas-fired generation, electric heating and steam-turbine operation can sustain activation over the relevant reservation periods. Upward reserve is supported by reducing electric heat production and increasing gas-fired heat or steam-turbine output. Downward reserve is supported by increasing electric heat production, reducing steam-turbine generation, or modulating MVR operation. The main operational uncertainty is whether all relevant assets can be controlled automatically and consistently within the required aFRR timeframe.

Spot-market participation and imbalance settlement are also good technical fits. The portfolio can shift electricity consumption and generation in response to day-ahead and intraday price signals, enabling spot market price arbitrage and fuel switching between gas and electricity. The relatively fast modulation capability also allows the installation to respond to imbalance prices, provided that process conditions and asset availability allow the required deviation.

FCR is a poor fit because the full integrated process cannot reliably provide continuous, symmetric and fully automatic response within the strict activation window, even though some individual electric heating assets may be fast enough. TSO redispatch is also a poor fit under the current framework because the site does not meet the current access conditions and the local grid context does not indicate strong redispatch relevance. The CRM is a moderate fit: generation and demand-response capacity could contribute technically, but seasonal availability, derating, autoconsumption and non-availability risk make participation less straightforward.

LCL Data Centers

The assessment shows that LCL Data Centers is best suited for spot-market participation and imbalance-related optimization. The BESS can perform spot market price arbitrage in the day-ahead and intraday markets by charging during low-price periods and discharging during high-price periods, while renewable generation can be curtailed during negative-price or otherwise adverse market conditions. Imbalance settlement is also a strong technical fit because the BESS can react opportunistically to imbal-

ance prices and renewable generation can be curtailed to reduce exposure to adverse imbalance positions.

Balancing-service participation is technically possible but more constrained. FCR is a good technical fit because the BESS can meet the fast response requirements. Downward mFRR is also a good fit, as both the BESS and curtailable renewable generation can contribute downward flexibility. aFRR and upward mFRR are only moderate fits: the response speed and activation duration are technically adequate, but the capacity reservation duration and minimum bid requirements constrain participation, especially for upward services. Participation through aggregation is therefore likely to be preferable for several balancing products.

Congestion management under the current TSO redispatch framework and participation in the CRM are poor fits in the current configuration. For redispatch, the main barrier is the current minimum asset-size threshold, although future implementation steps under iCAROS may improve accessibility for smaller assets. For CRM, the combination of derating, duration requirements and aggregation needs makes participation difficult for the currently considered flexible asset configuration.

1.2.3 Accessibility Tiers

Table 1.3 supports three accessibility tiers within the scope of the technical screen.

Broadly accessible — No limiting criterion was identified for DA trading, intraday trading, or imbalance settlement in any of the six cases. These mechanisms are less restrictive on response time and delivery duration than balancing services. The result indicates technical scheduling potential, not confirmed market access or an economic case.

Conditionally accessible — aFRR, mFRR, and CRM receive predominantly moderate or good scores. For balancing energy, the remaining constraints concern directional headroom at the operating point, automatic control capability, and delivery that depends on process conditions. For CRM, derating, seasonal availability, and service-level obligations require case-specific verification. The screening therefore identifies candidates for follow-up but does not establish prequalification or firm capacity.

Restricted — FCR is the most selective mechanism because it combines very fast response with automatic frequency control and sustained delivery. Only the fast and highly controllable cases avoid a poor score, and some still require control validation. Congestion management receives a poor score for all cases except one because either no relevant congestion need was identified at the assessed location or standalone headroom was below the applicable bid requirement.

1.3 Discussion

1.3.1 Buffer Capacity as a Flexibility Enabler

The cases indicate that process integration can determine usable flexibility as strongly as the electrical asset itself. In the cases with thermal or material buffers, buffering partly decouples electricity consumption or generation from the industrial process and

Table 1.3: Qualitative Technical Fit of the Galileo BUCs with Flexibility Mechanisms

Mechanism	Aperam BUC 1A	Aperam BUC 1B	Nyrstar BUC 2	Tessenderlo BUC 3	Tiense Suiker BUC 4A	LCL Data Centers BUC 5
FCR	poor	moderate	moderate	poor	poor	good
	<i>Principal constraint:</i> Aperam (BUC 1A), Tessenderlo (BUC 3), and Tiense Suiker (BUC 4A): response is too slow and/or upward headroom is insufficient. Aperam (BUC 1B) and Nyrstar (BUC 2): response capability and reliable automatic frequency control require validation.					
aFRR up	moderate	good	good	moderate	good	moderate
	<i>Principal constraint:</i> Aperam (BUC 1A): standalone upward headroom is below the minimum bid requirement. Tessenderlo (BUC 3): delivery depends on excess steam availability. LCL Data Centers (BUC 5): limited by required duration and minimum bid size.					
aFRR down	good	moderate	good	good	good	moderate
	<i>Principal constraint:</i> Aperam (BUC 1B): downward headroom is unavailable at the minimum-load operating point. LCL Data Centers (BUC 5): limited by intermittency of intermittent wind energy.					
mFRR up	moderate	good	good	moderate	good	moderate
	<i>Principal constraint:</i> Aperam (BUC 1A): standalone upward headroom is below the minimum bid requirement. Tessenderlo (BUC 3): delivery depends on excess steam availability. LCL Data Centers (BUC 5): limited by required duration and minimum bid size					
mFRR down	good	moderate	good	good	good	good
	<i>Principal constraint:</i> Aperam (BUC 1B): downward headroom is unavailable at the minimum-load operating point.					
DA	good	good	good	good	good	good
Intraday	good	good	good	good	good	good
Imbalance settlement	good	good	good	good	good	good
Congestion mgmt	poor	poor	good	poor	poor	poor
	<i>Principal constraint:</i> Aperam (BUC 1A), Aperam (BUC 1B), and Tiense Suiker (BUC 4A): no relevant congestion need was identified at the assessed location. Tessenderlo (BUC 3), and LCL Data Centers (BUC 5): standalone headroom is below the minimum bid requirement.					
CRM	good	good	good	moderate	moderate	moderate
	<i>Principal constraint:</i> Tessenderlo (BUC 3): delivery remains process-dependent. Tiense Suiker (BUC 4A): seasonal operation requires SLA-specific availability assessment. LCL Data Centers (BUC 5): derating may reduce qualified capacity below the minimum bid requirement.					

can support a longer delivery window or flexibility in both directions. The screening supports this enabling mechanism qualitatively; it does not quantify the incremental capacity, market access, or business-case effect of adding buffer capacity.

1.3.2 Process Integration of Electrified Loads

Electrified loads provide upward flexibility by reducing withdrawal only where the process can tolerate, shift, or buffer the resulting output reduction. They provide downward

flexibility by increasing withdrawal only where spare electrical capacity and a valid destination for the additional process output are available. In the assessed cases, thermal or material buffering broadens directional flexibility relative to tightly process-coupled operation. Electrification therefore creates a controllable load opportunity, not automatically deliverable flexibility.

1.3.3 Storage as a Potential Fast-Response Enabler

The BESS case confirms that fast, bidirectional control can remove response time as a binding constraint for several short-interval and balancing-energy mechanisms. Access to congestion management nevertheless remains location- and volume-dependent, while CRM participation depends on derating and service-level obligations. Co-location with variable generation may affect dispatch and available headroom, but optimisation and revenue stacking were not assessed here.

1.3.4 Framework Positioning

The proposed framework is a technical pre-feasibility tool for screening the fit between an industrial installation and a selected set of flexibility mechanisms, including CRM and Belgian congestion management. It uses a limited set of asset descriptors and market requirements to structure an early assessment before detailed process modelling, operational testing, prequalification, or economic evaluation.

The accessibility tiering in Section 1.2 distinguishes mechanisms that merit detailed follow-up from those with material caveats or a clear constraint in the current configuration. The recorded constraint indicates what must be validated or mitigated, for example controllability, buffering, aggregation, or locational eligibility. The framework prioritises further assessment; it does not by itself justify an investment or market-entry decision.

1.3.5 Limitations and Future Work

Three limitations bound the interpretation of the results. First, the framework excludes metering and telemetry requirements, baseline methodology, prequalification tests, contractual arrangements, operational coordination, and penalty exposure. Any of these can prevent or materially affect participation even where the technical-fit score is good.

Second, the case scores depend on company-provided data and simplifying assumptions. The case evaluations assume negligible preparation and recovery times, and the reported capabilities were not validated through prequalification or dispatch tests within this assessment. Where start-up, recovery, thermal, or process constraints are material, FAT and delivery-duration estimates require refinement.

Third, the score is qualitative and covers technical screening rather than reservable capacity, dispatch performance, or revenues. It does not show whether a case narrowly or substantially misses a threshold. In this public deliverable, the underlying company values are also intentionally withheld, so the case scores cannot be independently reproduced from the information reported here.

Further work should add (i) a non-technical participation checklist, (ii) an assessment of reliably reservable balancing capacity, (iii) historical backtesting under realistic process constraints, and (iv) investment sizing for any required buffers, controls, or automation. These steps are required before using the screen for bidding, revenue stacking, or investment planning.

Chapter 2

Identification of market and product design changes

The exploratory work in this chapter first mapped the main electricity markets, flexibility mechanisms and products relevant to industrial consumers, together with their key technical and commercial design characteristics. This covered, among others, network tariffs and congestion-management products, ancillary services such as FCR, aFRR and mFRR, imbalance settlement, wholesale energy markets, energy-supply arrangements and the capacity remuneration mechanism. An overview of these products is given in Figure 2.1

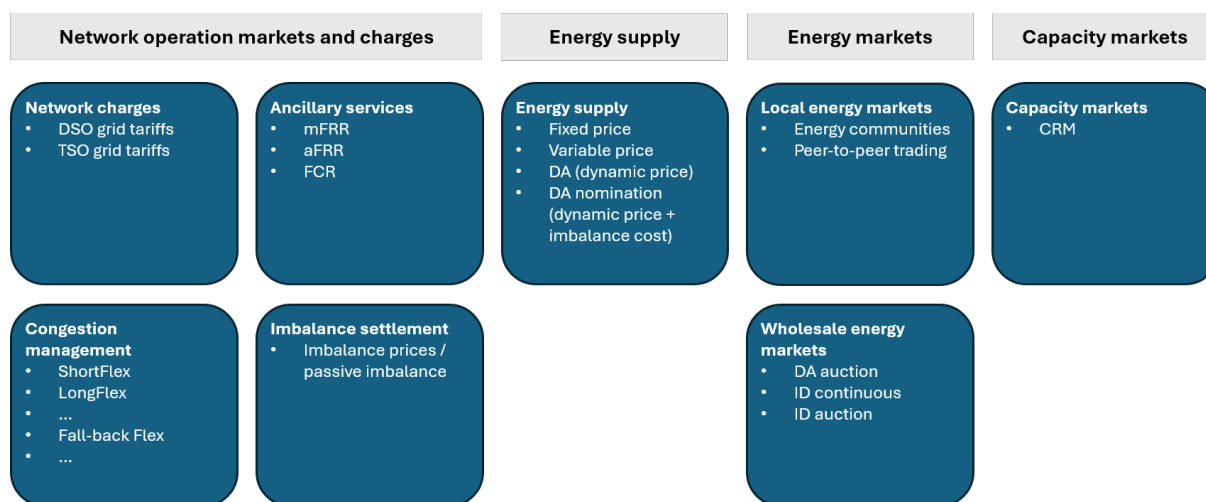


Figure 2.1: Overview of relevant electricity markets and flexibility mechanisms for industrial flexibility

Potential market design changes were identified through a review of relevant policy, market and research documentation. The sources considered included Elia's *Consumer-Centric Market Design* vision and white papers [4, 5], *The Power of Flex* [6], and documentation on its *System Balance Philosophy* [7]; the VREG decision on Fall-Back Flex (BESL-2025-06) [8]; the OneNet work on standardised flexibility products [9]; the EU-SysFlex report on innovative system services [10]; ACER's *Getting the Signals Right: Electricity Network Tariff Methodologies in Europe* [11]; EirGrid's DS3 Programme [12];

the GALILEO T1.4 proposals [13]; and selected academic literature on flexibility-market design, including Heilmann et al. [14]. Based on these sources, additional options were formulated where current designs appeared to restrict industrial participation or value, such as more dynamic and locational network tariffs, flexible connection agreements, lower minimum bid sizes, more granular ancillary-service products, real-time imbalance pricing and longer-duration capacity contracts. An overview of potential market and product design changes is given in Figure 2.2.

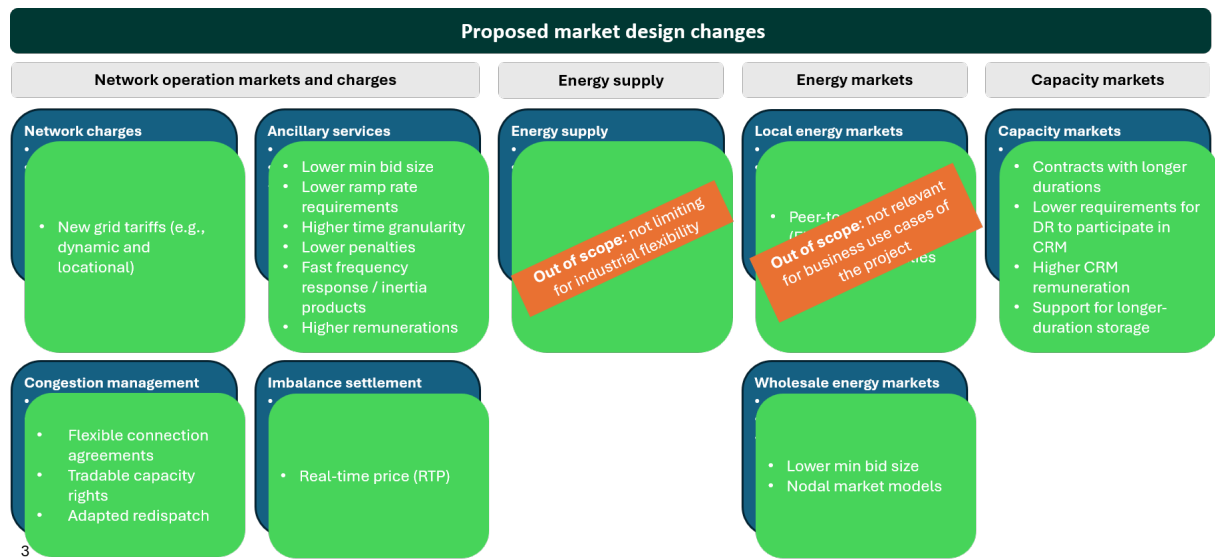


Figure 2.2: Overview of potential design changes to electricity markets and flexibility mechanisms

2.1 Crosscheck with BUCs

To identify the most relevant market and product design changes, they were cross-checked against the description of the industrial BUC's and assigned a qualitative score: "Yes" where a design change is relevant and can clearly improve flexibility activation, "Maybe" where this is uncertain, and "No" where there is no associated benefit expected. The scores constitute an exploratory expert assessment by the project team, based on the documented BUC characteristics and available stakeholder input; they should not be interpreted as quantified impacts or formally validated preferences from the BUC owners. The result is depicted in Figure 2.3.

Some key insights stemming from this analysis:

- **Network charges:** Time- or location-varying network charges would be relevant to investigate for most use cases, as they would allow for additional flexibility valorisation options.
- **Ancillary services:** Reducing barriers for participation, like lower minimum bid size and ramp rate requirements are relevant for most use cases. Also higher time granularity is identified as being potentially interesting for Tessengerlo and

Mechanism type	Mechanism	Aperam		Nyrstar	Tessenderlo	Tiense Suiker		L Data Centre
		1A	1B	2A	3A	4A	4B	5A
Network charges	100% power-based network charges	No	No	No	No	No	No	No
	Dynamic / ToU / locational network charges	Yes	Yes	Yes	Maybe	Maybe	Maybe	No
Ancillary services	Lower min bid sizes	Yes	Yes	No	Yes	Yes	Yes	Yes
	Lower ramp rate requirements	Yes	Yes	No	Yes	Yes	Yes	No
	Higher time granularity	No	No	No	Maybe	Maybe	Maybe	No
	Exchange of energy blocks (EEoB) (Elia)	No	No	No	No	No	No	No
	Direct participation (Elia)	No	No	No	No	No	No	No
	Lower penalties	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	No
	Fast frequency response / inertia products	Maybe	Maybe	No	Yes	Yes	Yes	Yes
	Higher remunerations	Yes	Yes	Yes	Maybe	Yes	Yes	Maybe
Congestion management	MaxUsage (no pilot)	No	No	No	Maybe	No	No	No
	ShortFlex (pilot)	No	No	No	Maybe	No	No	No
	LongFlex (no pilot)	No	No	No	Maybe	No	No	No
	Fall-back Flex (no pilot)	No	No	No	Maybe	No	No	No
	Flexible connection agreements	Yes	Yes	Yes	No	No	No	Maybe
	Tradable capacity rights (SecuLEx)	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe
	Redispatch (adapt on Elia level)	Yes	Yes	Yes	No	No	No	No
Imbalance settlement	Real-time price (RTP)	Yes	Yes	Maybe	Yes	Maybe	Maybe	Maybe
Capacity markets	3-5 year duration contracts	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	No
	Lower requirements for DR to participate in CRM	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	No
	Higher CRM remuneration	Maybe	Maybe	Maybe	Maybe	Maybe	Maybe	Yes
	Support for longer-duration storage	No	No	Yes	No	No	No	No
Wholesale energy markets	Lower minimum bid size	Maybe	Maybe	No	No	Maybe	Maybe	Maybe
	Nodal market models	Maybe	Maybe	Yes	No	No	No	No

Figure 2.3: Overview of relevance of market and product design changes for industrial players and their BUCs

Tiense Suiker use cases. Lower penalties and higher remunerations would of course also impact the business cases, but are not really strong market redesigns. Interestingly, fast frequency response or inertia products are relevant for most BUCs as well.

- **Congestion management:** Low voltage flexibility products (MaxUsage, ShortFlex, LongFlex and Fall-back Flex) are not really relevant, as most BUCs are connected to the high-voltage electricity grid.
- **Imbalance settlement:** The new real-time price design under development by Elia and under discussion with stakeholders [15], is identified as relevant or potentially relevant for all use cases.
- **Capacity markets:** Longer contract durations, less stringent requirements for demand-response, and higher remunerations are all potentially relevant changes to the capacity remuneration mechanism for industrial flexibility, as they make remunerations higher, more easily accessible and applicable for a longer time period. Only Nyrstar would benefit from support for longer-duration storage with its Zinc electrolyser.
- **Wholesale energy markets:** A lower minimum bid size is potentially interesting for Aperam, although the current minimum bid size (0.1 MW) is probably not sufficiently limiting for the majority of the time. Nodal markets could be relevant for

the Aperam and Nyrstar BUCs, as both are located in areas with congestion issues on the high-voltage grid. Nodal pricing could attach a price signal to these congestions.

Four market design changes were selected for the modelling work in Chapter 3. The market design changes were selected based on (i) their relevance to one or more BUCs, (ii) their relevance to the system, and (iii) their implementation feasibility or proximity to existing market developments. The market design changes identified as particularly relevant are the following:

- **Fast Frequency Response (FFR)** – a fast-acting active-power ancillary service for responding to sudden frequency deviations and low-inertia conditions;
- **Higher temporal granularity of capacity reservation markets** – allowing ancillary-service capacity to be procured in shorter time blocks than the current four-hour blocks;
- **Lower minimum bid sizes for ancillary services** – enabling assets with flexible capacities below the current 1 MW threshold to participate;
- **Real-Time Pricing (RTP) for imbalance settlement** – adapting imbalance-price formation so that prices more closely reflect real-time system conditions.

Lower minimum bid sizes, shorter reservation blocks and RTP address identified participation or price-signal limitations, while FFR represents an additional valorisation opportunity for sufficiently fast assets.

The first three design changes were assessed quantitatively within the GALILEO project and are described in more detail in the next chapter. RTP was also identified as a relevant market design change. However, due to ongoing developments by Elia on this topic, it could not be quantitatively assessed within the project's timeframe.

It is also worth mentioning that regarding flexible connection agreements, a qualitative study of the potential impact on LCL Data Centers' operations was performed. This can be retrieved in Deliverable D2: Detailed analysis of industrial reference cases [3].

Chapter 3

Market changes

This chapter evaluates the potential impact of the market-design changes identified in Chapter 2 on the participation and value of industrial flexibility in electricity markets. Three changes were selected for detailed assessment based on their relevance for the GALILEO BUCs and their maturity within ongoing European market developments: the introduction of FFR, higher temporal granularity for balancing-capacity reservation products, and lower minimum bid sizes for balancing-capacity and balancing-energy markets.

For each market-design change, the current market design is first described together with the proposed modification. Subsequently, its impact is evaluated using the market optimization framework developed in Deliverable D2 [3]. The simulations quantify the effects on market participation, flexibility activation, and annual revenues for the selected industrial BUCs, while keeping all other market conditions unchanged. This allows the impact of each individual market-design change to be assessed in isolation.

3.1 Fast Frequency Response

This section discusses the potential impact of a new ancillary service called "fast frequency response" on the bidding behaviour and revenues of industrial players with flexible assets. It first introduces the concept and its current state of implementation in Europe. It then describes the FFR model that was implemented to simulate the potential dispatch of flexible assets participating to this new service, as well as the corresponding revenues. Finally, it discusses the dispatch and revenue impact on BUC 4A of Tiense Suiker and BUC 5 of LCL Data Centers.

3.1.1 What is FFR?

With increasing penetration of converter-interfaced generation and a declining number of online synchronous units, the amount of kinetic energy inherently stored in synchronously connected rotating masses decreases. Under such low-inertia conditions, a large active-power imbalance produces a steeper initial frequency trajectory and a higher rate of change of frequency (RoCoF). This can create a requirement for active-power injection on a timescale shorter than that of conventional frequency-containment

reserves. Accordingly, a number of European system operators are implementing sub-second frequency-response products. FFR is designed to provide this additional, frequency-triggered active-power support and thereby complement slower reserve services during low-inertia operation [16, 17].

FFR is not “real inertia” or a reactive-power service. Synchronous inertia is an inherent and effectively instantaneous active-power response of rotating masses, whereas FFR is a controlled response delivered after frequency deviations have been measured and an asset controller has acted on it. Reactive-power services primarily support voltage rather than system frequency. FFR may nevertheless be delivered by converter-connected generation, storage or demand if the resource meets the applicable response and prequalification requirements [16, 18, 19].

Table 3.1 compares selected operational products and closely related developments as at 23 July 2026. Product names are not harmonised and their parameters are not directly comparable. For example, Great Britain’s Dynamic Containment and Dynamic Moderation require full delivery within 1 s; Ireland’s DS3 FFR definition requires delivery within 2 s but rewards faster contracted response through a scalar; and Nordic FFR permits full-activation times of 0.7, 1.0 or 1.3 s, depending on the selected trigger frequency [18, 20, 21, 17].

Smaller synchronous areas - Great Britain, Ireland, and the Nordics - are more exposed to grid stability issues related to low-inertia situations and have already operationalised fast frequency products with activation times of 0.5-1.3 seconds. Continental Europe’s large synchronous mass has shielded most connected TSOs from the same type of urgency, but this buffer is shrinking: A 2025 analysis by TenneT NL researchers, using TenneT’s synchronous-inertia dashboard, reports that Dutch mean (minimum) synchronous inertia fell from 87 (36) GWs in 2020 to 61 (15) GWs in 2024. [22]. The first inertia products are being launched in Central Europe: Germany launched its *Momentanreserve* inertia service in January 2026, Italy is piloting a Fast Reserve, and Denmark is developing a dynamic FFR product [23, 24, 25, 26].

Table 3.1: Fast frequency response products and related frequency-containment reserves in Europe (status at 23 July 2026)

Region	Product name	Mechanism type	Trigger	Min. bid size	Response time	Full activation time	Activation duration	Eligible technologies	Maturity	Market type	Market clearing	Remuneration type
Great Britain	Dynamic Containment (DC) [18, 27, 28]	Post-fault FFR	± 0.015 Hz dead-band; 5% delivery at the ± 0.2 Hz knee and 100% at ± 0.5 Hz	1 MW	≤ 0.5 s initiation	≤ 1 s	≥ 15 min	Technology-neutral: generation, demand or storage	Operational (2020)	Daily DA auctions	Uniform market-clearing price	Availability (GBP/MW/h)
Great Britain	Dynamic Moderation (DM) [18, 27, 29]	Pre-fault FFR	± 0.015 Hz dead-band; 5% delivery at the ± 0.1 Hz knee and 100% at ± 0.2 Hz	1 MW	≤ 0.5 s initiation	≤ 1 s	≥ 30 min	Technology-neutral: generation, demand or storage	Operational (2022)	Daily DA auctions	Uniform market-clearing price	Availability (GBP/MW/h)
Great Britain	Dynamic Regulation (DR) [18, 27, 29]	Pre-fault frequency regulation	Linear response between ± 0.015 and ± 0.2 Hz from nominal	1 MW	≤ 2 s initiation; ≤ 0.5 s when stacked with DC and/or DM	≤ 10 s; ≤ 1 s when stacked	≥ 60 min	Technology-neutral: generation, demand or storage	Operational (2022)	Daily DA auctions	Uniform market-clearing price	Availability (GBP/MW/h)
Ireland / Northern Ireland	DS3 FFR [30, 20, 21, 31, 32]	Frequency-triggered fast active-power response	49.80–49.985 Hz (dynamic) or 49.3–49.8 Hz (static)	Not specified in Protocol v4.2	No minimum response time	≤ 2 s (faster contracted response receives a scalar)	≥ 8 s; Protocol performance assessment extends to 20 s	Technology-neutral: generation, demand and storage	Operational since 1 October 2018	Regulated Arrangements; tariff-based contracts awarded through procurement gates	No competitive clearing; regulated tariff and scalars	Regulated FFR tariff (€/MWh) multiplied by performance scalars
Nordic	FFR (joint technical product) [17]	Trigger-based fast reserve	49.5 Hz in 0.7 s, 49.6 Hz in 1.0 s, or 49.7 Hz in 1.3 s	DK2: 0.3 MW; FI: 1 MW; SE: 0.5 MW; NO: 1 MW Profile / 5 MW Flex	No separate initiation time specified	0.7, 1.0 or 1.3 s, matched to the trigger	Long: ≥ 30 s; short: ≥ 5 s followed by $\leq 20\%$ de-activation	Technology-neutral: generation, demand and storage examples	Operational since 2020	NO: seasonal Profile/Flex procurement; SE: annual agreement with weekly call-offs; FI and DK2: national D-1 hourly auctions [33, 34, 35, 36, 19]	Country-specific; marginal pricing in NO, FI and DK2	National availability/capacity payment (currency/MW/h)
Nordic	FCR-D (comparator) [37, 38]	Proportional disturbance reserve	Upward: 49.9–49.5 Hz; downward: 50.1–50.5 Hz	0.1 MW in Norway, Sweden and DK2; 1.0 MW in Finland	Dynamic performance requirement; static activation delay ≤ 2.5 s	Power at 7.5 s $\geq 86\%$; separate energy requirement	≥ 20 min for limited-energy reservoirs	Technology-neutral	Operational; joint requirements v1.1 (2025)	NO: daily procurement; SE/DK2: two D-1 auctions; FI: yearly and hourly markets	Marginal pricing	Capacity payment (national currency/MW/h)
Nordic (future)	Dynamic FFR concept [39]	Dynamic fast active-power response	Design under development	Not specified	Not specified	Not specified	Not specified	Not specified	Requirements under development	Not specified	Not applicable	Not specified
Italy	Fast Reserve [25, 26, 40]	Sub-second bidirectional FFR	Frequency mode: 0–500 mHz dead-band and full response by 1,000 mHz; remote active-power set-point also possible	5 MW	Start ≤ 300 ms	≤ 1 s	≥ 30 s proportional response; energy capability of ± 15 min at full power	Technology-neutral; awarded portfolio was battery storage	Pilot delivery period 2023–2027	One-off 2020 auction for a five-year delivery period	Pay-as-bid	Fixed capacity premium (€/MW/year)

3.1.2 The FFR Model

The market model used to optimize flexibility dispatching by maximizing revenues across markets and services, is expanded with an additional FFR service. This allows industrial players to valorize their asset on an additional ancillary service they can provide to the TSO.

The selected FFR product design is derived from the joint Nordic FFR product Table 3.2. The model assumes annual procurement / reservation of capacity, meaning the industrial player either commits a certain level of capacity for the full year, or does not. In this reference case, capacity cannot be reserved for part of the calendar year. Note that this is different in the Nordic FFR product design: in the case of FFR Flex, capacity is procured for a full year, but the time slots during which this capacity needs to be actually available, is communicated on a weekly basis. This design aspect is not tested here. The model provides a capacity payment (€/MW/h) for this reserved capacity, and activates flexibility capacity based on frequency threshold triggers. Contrary to the Nordic FFR product, which is only an upward capacity reservation product, both upward and downward capacity reservations and activations are allowed. FFR is not designed as a symmetric product, meaning different capacity levels can separately participate in upward FFR and downward FFR reservation.

Table 3.2: FFR product characteristics

Characteristic	Description
Procurement frequency	Annual
Clearing mechanism	Pay-as-cleared
Remuneration	Capacity remuneration (€/MW/h)
Activation	Frequency-trigger-based
Direction	Upward & downward

Table 3.3 summarizes four price and availability scenarios which are simulated, to test the impact of low (scenarios 1 and 3) and high (scenarios 2 and 4) remuneration levels. These price levels are based on historic price levels in Norway. Notice that flexibility is procured during and around the summer season, as this is the period during which typically more renewable generation occurs and less synchronous generation / physical inertia is present in the grid. A distinction is also made between night-time and day-time FFR procurement. This tests two different approaches and reflects a 2026 change in the Nordic FFR design, where initial night-time procurement (22:00 - 7:00) was changed to day-time FFR procurement (10:00 - 17:00), again reflecting the need for high-ramping active power services during high solar PV production periods.

Figure 3.1 shows what these price patterns look like for a sample week in July.

In addition, Figure 3.2 illustrates the periods during which the corresponding capacity prices apply; the price profiles for Scenarios 1 and 3 overlap in the figure. The simulations cover a full calendar year constructed by combining the second half of 2025 with the first half of 2026. This approach was adopted because the publicly available historical frequency data on the Elia website are limited to this period.

Initial activation thresholds of 49.7 Hz and 50.3 Hz were considered for upward and downward FFR, respectively. However, over the simulation horizon, the Belgian sys-

Table 3.3: FFR procurement scenarios

FFR scenario	Capacity procured (MW)	Capacity price (€/MW/h)	Delivery start	Delivery end	Procurement frequency	Availability requirements
1	54.5	10.24	Week 21	Week 35	Annually	10:00–17:00, plus 24 h/day on Saturday and Sunday
2	91.4	46.83	Week 17	Week 43	Annually	10:00–17:00
3	46.6	10.15	Week 21	Week 35	Annually	22:00–07:00, plus 24 h/day on Saturday and Sunday
4	103.4	33.27	Week 17	Week 43	Annually	22:00–07:00

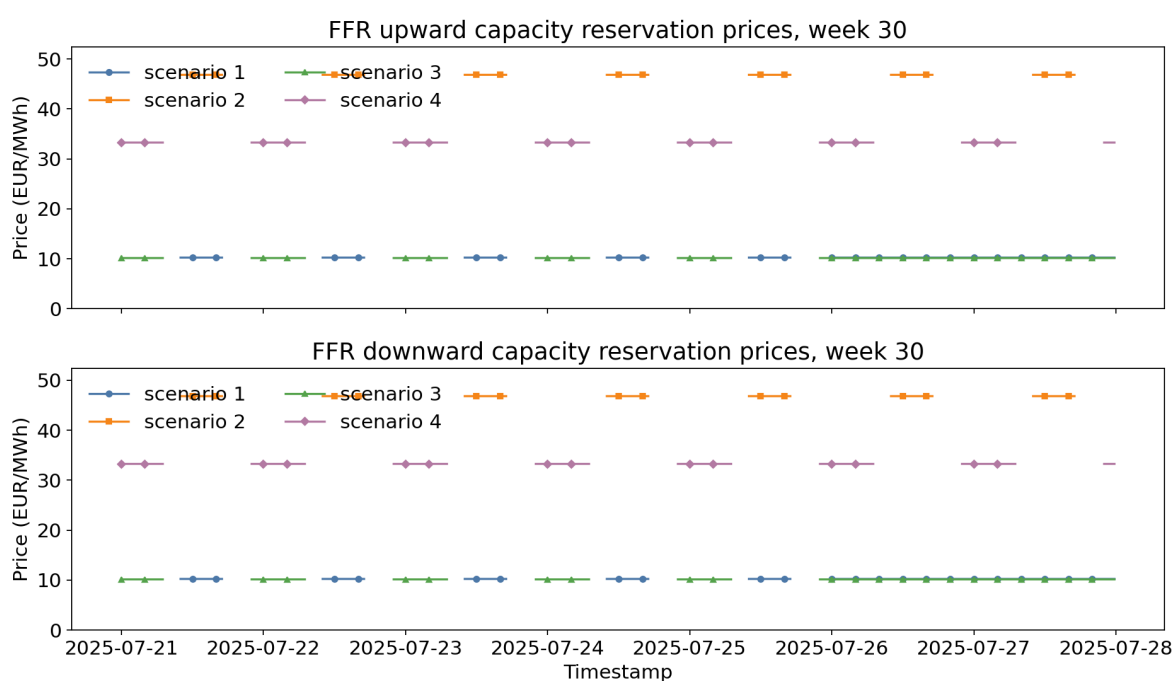


Figure 3.1: FFR capacity price scenarios for a sample week

tem frequency did not reach these threshold values. This is consistent with the current operating conditions of the CE synchronous area, where low-inertia situations are not yet sufficiently frequent to trigger such extreme frequency deviations. To enable an assessment of the operational impact of more frequent FFR activations, the activation thresholds were therefore adjusted to 49.95 Hz for upward FFR and 50.05 Hz for downward FFR. The revised thresholds allow the simulation to capture a sufficient number of activation events and thereby evaluate how repeated FFR provision affects the dispatch schedule of the industrial installation.

Table 3.4 summarizes the number of upward and downward FFR activations over the simulated year for each FFR scenario, which differ in their required availability periods. Scenarios 2 and 4, which are characterized by longer reservation windows, exhibit a higher total number of activations. However, the increase remains relatively limited,

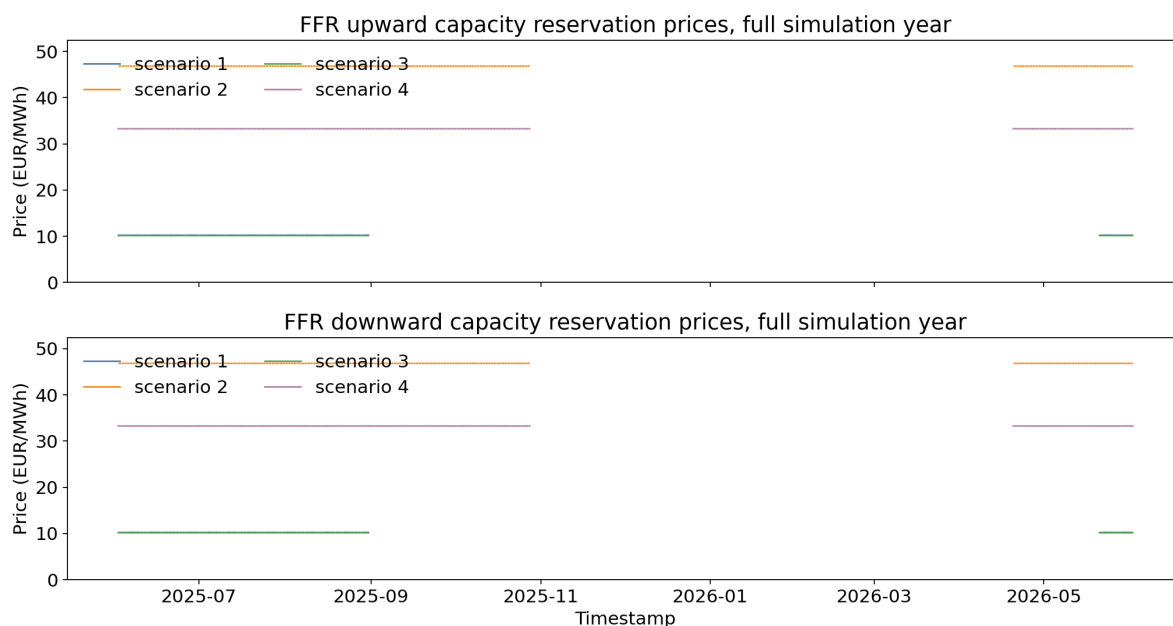


Figure 3.2: FFR capacity price scenarios for a full calendar year

indicating that extending the availability period only moderately increases the number of activation opportunities over the considered simulation horizon.

Table 3.4: Number of FFR activations by scenario

FFR scenario	Upward activations	Downward activations	Total activations
FFR 1	856	312	1,168
FFR 2	1,026	363	1,389
FFR 3	904	291	1,195
FFR 4	1,179	178	1,357

3.1.3 Impact of FFR on Tiense Suiker BUC 4A

Tiense Suiker has assets with significant flexible electric demand and generation potential available on-site. However, ramp rates are too slow to provide sub-second power ramps. To be able to evaluate the impact of providing FFR services on participation to other markets and mechanisms as well as their revenues, an important simplification was made by assuming that the full flexible capacity of Tiense Suiker is able to ramp up in sub-second periods and hence is able to provide FFR services. The reference outcomes of the market model simulation for Tiense Suiker are shown in Figure 3.3.

For each combination of day-ahead and mFFR upward/downward market participation, the impact of additional FFR participation is assessed in the following sections.

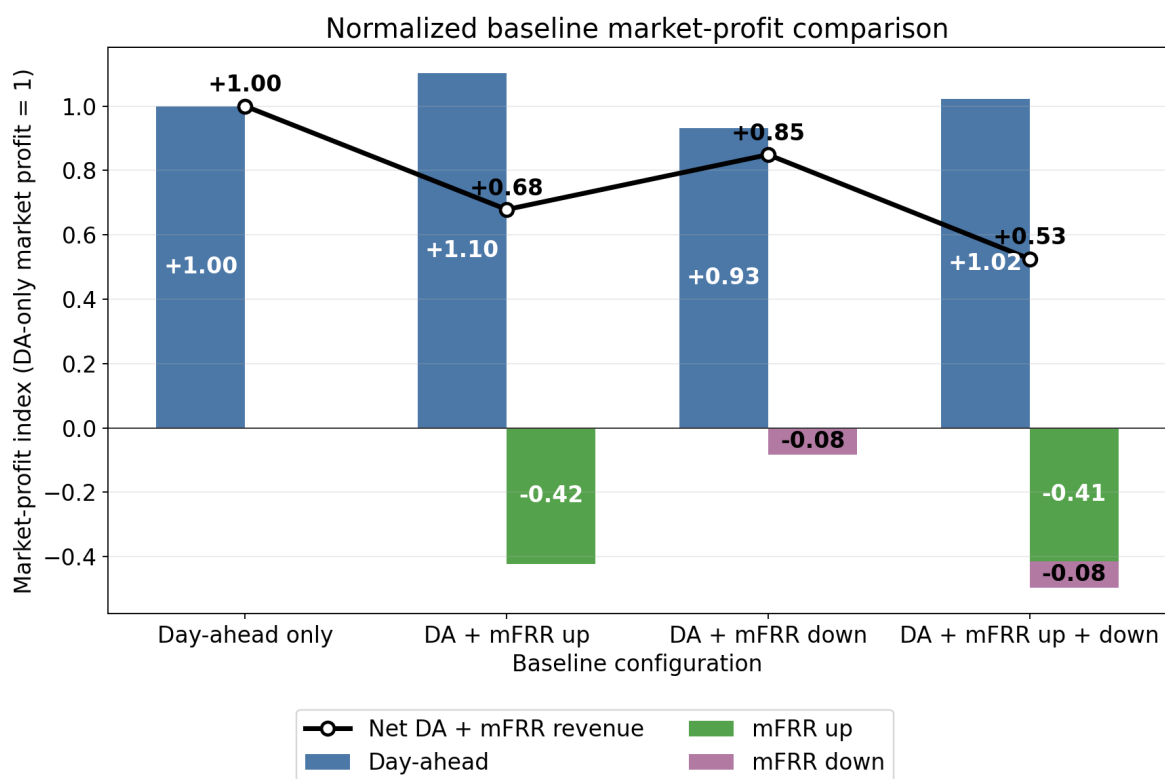


Figure 3.3: Baseline revenues for Tiense Suiker for 4 baseline scenarios: day ahead only, day ahead + mFRR up, day ahead + mFRR down, and day ahead + mFRR up and down.

FFR with annual capacity reservation (default)

Tiense Suiker's operational activity during the winter period does not coincide with the summer-period procurement window for FFR services. Consequently, the market-model simulations with annual capacity reservation result in no FFR participation. No FFR capacity is reserved in any of the considered scenarios, and therefore no FFR energy activations or associated revenues are observed.

Given the highly seasonal activity profile of Tiense Suiker, flexibility is only available during the beet campaign (ca. from mid-April until mid-September). Because FFR is procured/reserved annually, no capacity is reserved for the entire year, as Tiense Suiker cannot provide flexibility across multiple periods in the summer. This is shown in Figure 3.4: maximum flexible capacity (can be used for either upward and downward activation) is roughly available from mid-September until mid-April, while FFR capacity is procured for the periods April - October / May - August (Figure 3.2).

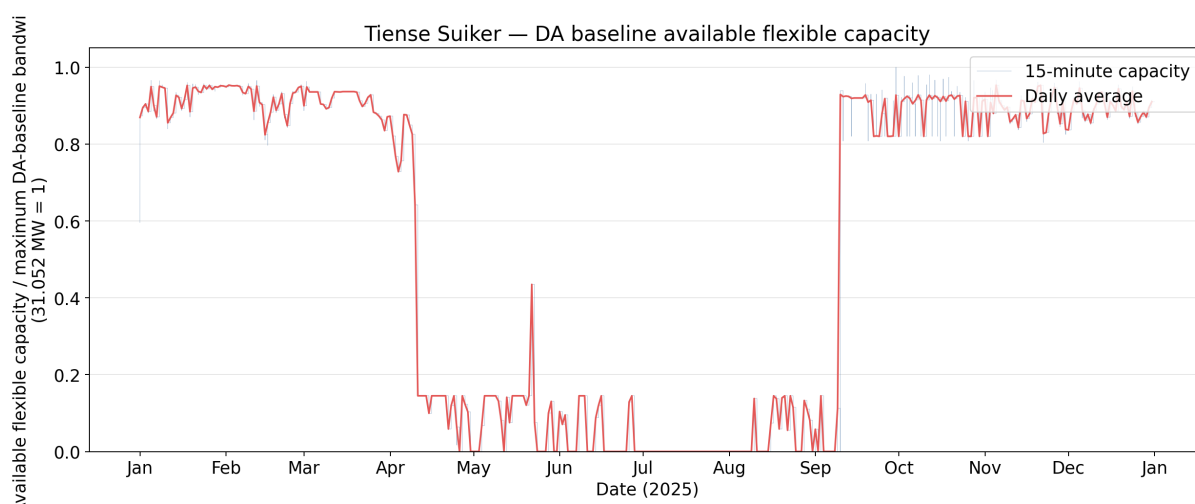


Figure 3.4: Maximum available flexible capacity (either up or down) across the calendar year

As a result, there is no impact on the revenues that were already shown in Figure 3.3. To partially accommodate for this seasonal mismatch, a seasonal procurement of FFR capacity is evaluated in the next section.

FFR with seasonal capacity reservation (special case)

To evaluate how much capacity Tiense Suiker could provide to FFR during the beet campaign (autumn + winter), simulations are performed with procurement split in two seasons: one tranche between mid April and mid September and a complementary tranche between mid September and mid April. Table 3.5 summarizes activations and capacity reservations for this simulation.

FFR scenarios 1 and 3 (refer to Table 3.3 for FFR scenario information) do not lead to capacity reservation, as the procurement period does not overlap with the winter season of Tiense Suiker. Figure 3.5 indeed shows that FFR capacity is only reserved in September and October for scenarios 2 and 4, the only two months of FFR for which

Table 3.5: Tiense Suiker FFR activation counts and normalized reserved capacity by mFRR configuration and FFR case. Capacity is normalized, where 1.000 represents the maximum available capacity.

FFR case	Upward activations [-]	Downward activations [-]	Avg. upward reserved capacity [-]	Avg. downward reserved capacity [-]
<i>DA only</i>				
FFR 1	0	0	0.000	0.000
FFR 2	272	0	0.820	0.000
FFR 3	0	0	0.000	0.000
FFR 4	256	56	0.446	0.362
<i>mFRR up</i>				
FFR 1	0	0	0.000	0.000
FFR 2	272	0	0.808	0.000
FFR 3	0	0	0.000	0.000
FFR 4	256	56	0.446	0.362
<i>mFRR down</i>				
FFR 1	0	0	0.000	0.000
FFR 2	272	94	0.456	0.364
FFR 3	0	0	0.000	0.000
FFR 4	256	56	0.446	0.362
<i>mFRR up+down</i>				
FFR 1	0	0	0.000	0.000
FFR 2	272	0	0.759	0.000
FFR 3	0	0	0.000	0.000
FFR 4	256	56	0.446	0.362

Tiense Suiker can provide flexibility in their winter season. Upward capacity is largest in FFR scenario 2, while upward and downward FFR capacity is more limited in scenario 2 (downward) and in scenario 4 (both upward and downward). This suggests a trade-off with revenues from other markets, as available capacity in Figure 3.4 does not show the same level of capacity reduction.

Figure 3.6 shows the revenue uplift of FFR participation for each DA and mFRR strategy, compared to costs of DA-only participation. Overall, FFR scenarios 2 and 4 generate limited additional revenues compared to the reference cases - about 2 % cost savings compared to the reference cases. This is not significant and is likely explained by the limited availability of Tiense Suiker for FFR participation: only a limited part of capacity is reserved for less than 2 months (capacity reservation starts ca. mid September and ends before the end of October). The optimal overall combination is FFR scenario 4, combined with the already-attractive revenues of the mFRR up- and down-case.

Figure 3.7 shows capacity reservation and energy activation duration curves. As expected with only 2 months during which capacity is reserved, capacity reservations only apply to a very limited share of time in a year (< 5%). Activations, triggered by

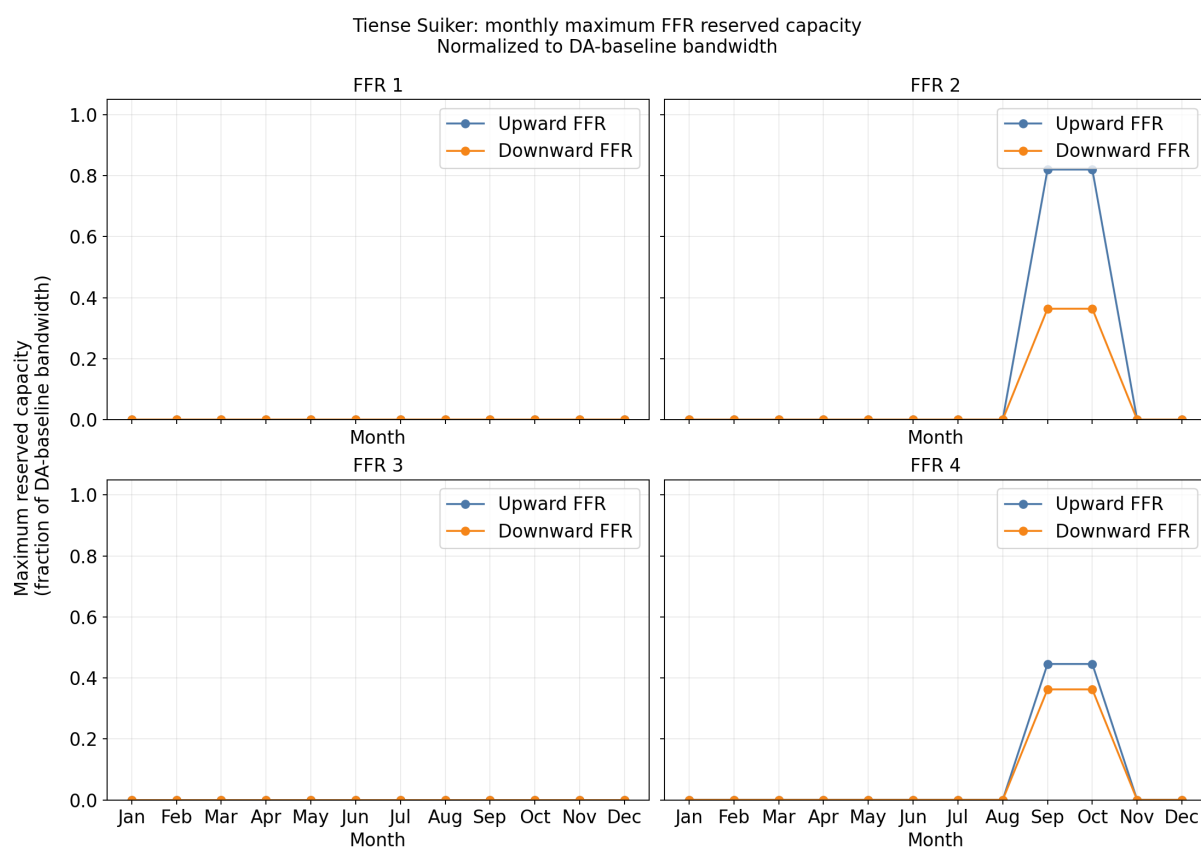


Figure 3.5: Monthly average capacity reservation

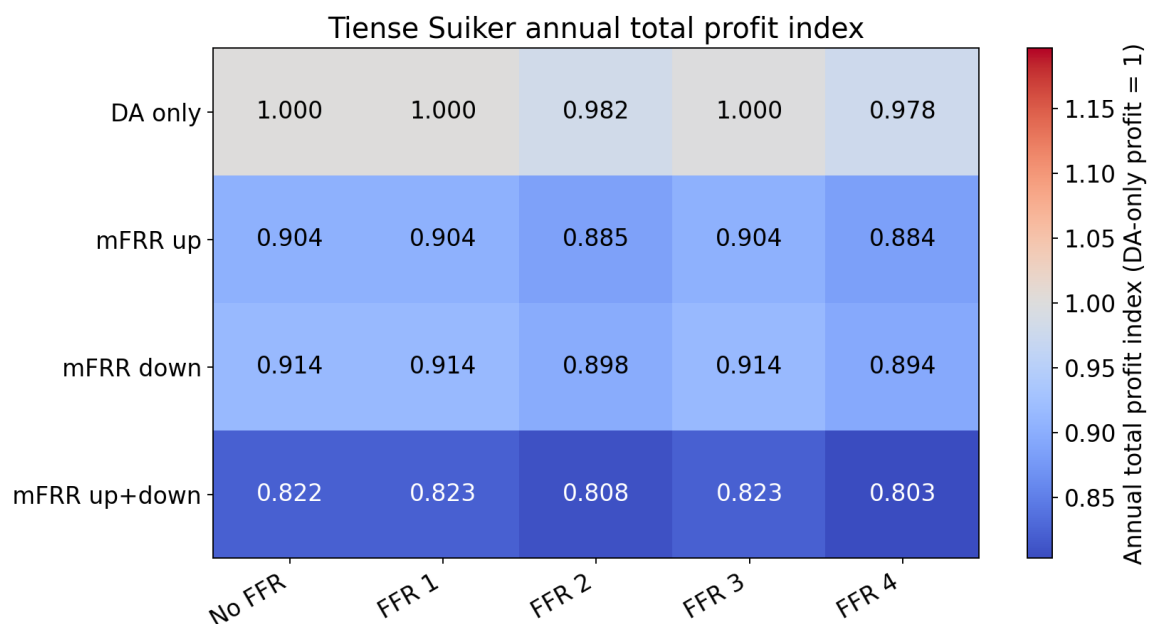


Figure 3.6: Difference in revenues for each mFRR and FFR scenario compared to DA-only revenues

frequency deviations within these capacity reservation time slots, are even rarer ($< 1\%$). This confirms that combining FFR with DA participation (at least under optimisation with the perfect foresight assumption), has a very minor impact on the dispatch profile.

Tiense Suiker FFR capacity and activation duration curves
mFRR up+down; separate FFR2 and FFR4 curves

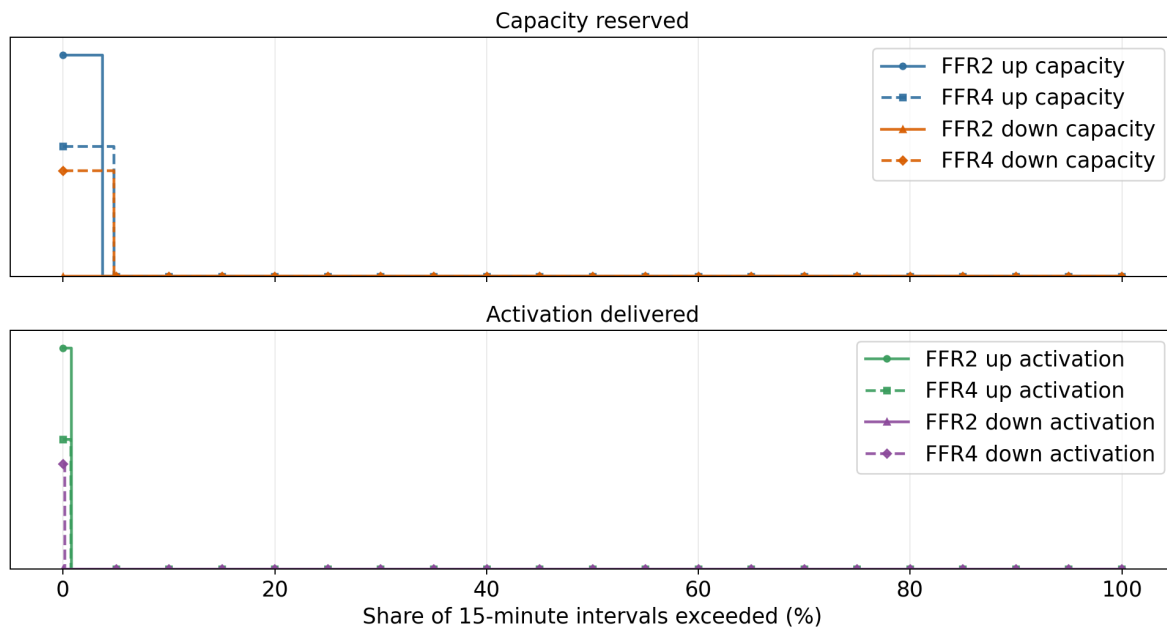


Figure 3.7: Duration curves for capacity reservation and energy activation for FFR 2 and FFR 4 scenarios, for the mFRR up + down case

Figure 3.8 finally shows the distribution of revenues across the year. We calculated these revenues by counting capacity revenue for the moments when capacity must be available. The pattern by consequence corresponds to the price levels and time schedules defined in Table 3.3. Unsurprisingly, revenues are concentrated in September and October. Revenues are higher in October because capacity is reserved for more days than in September.

3.1.4 Impact of FFR on LCL Data Centers BUC 5

Table 3.6 shows the number of activations and the amount of capacity reserved for participation in the FFR market by LCL Data Centers, normalized such that the maximum available capacity of LCL Data Centers equals 1. In all scenarios, the maximum amount of capacity is reserved in both upward and downward directions. This indicates no real trade-off between participation in the DA market and the FFR mechanism. Battery energy storage systems (BESS) are highly flexible, and the number of FFR activations is not sufficiently limiting for DA optimisation. This makes the additional FFR revenues sufficiently attractive to stack with DA revenues.

Figure 3.9 shows the revenue impact for each of the four FFR scenarios, for all LCL Data Centers sites combined. Revenue impact is significant for scenarios 2 and 4 (44%

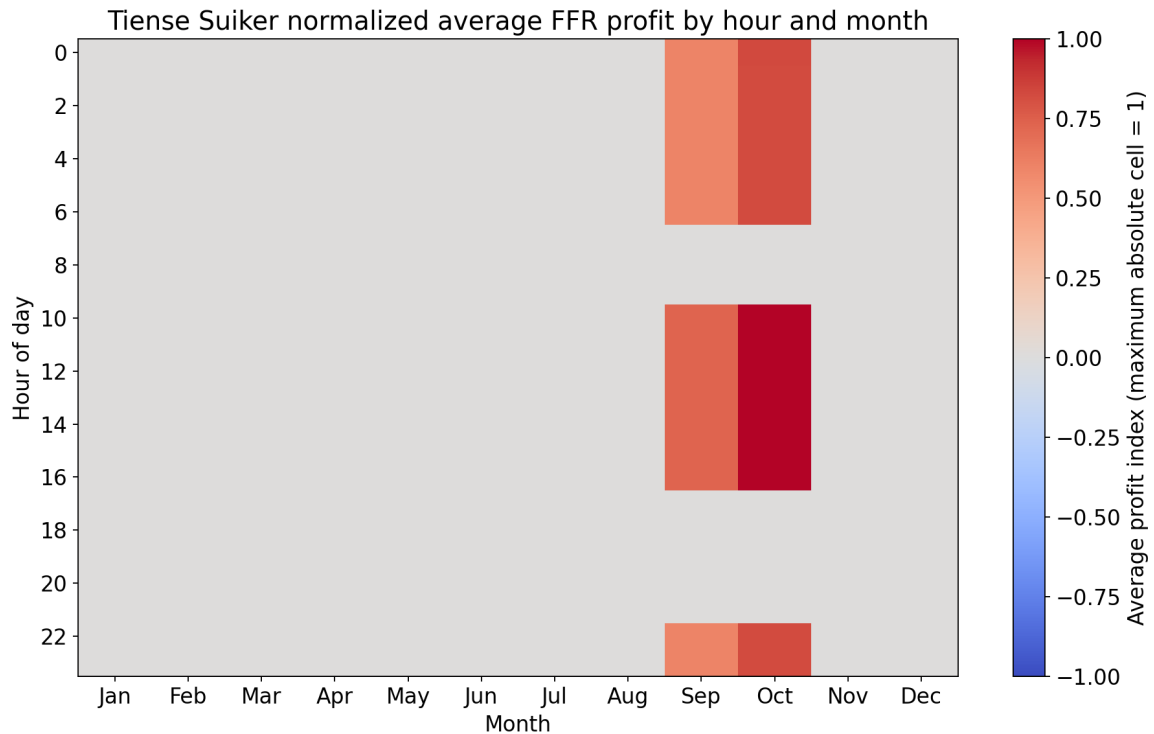


Figure 3.8: Heat map of FFR revenues by month and hour of the day, for all FFR scenarios combined

Table 3.6: Aggregated LCL Data Centers FFR activation and capacity-reservation results across all four sites.

Scenario	Upward act. [-]	Downward act. [-]	Avg. upward reserved cap. [-]	Avg. downward reserved cap. [-]
FFR 1	856	312	1	1
FFR 2	1,026	363	1	1
FFR 3	904	291	1	1
FFR 4	1,179	178	1	1

and 40% revenue uplift, respectively), while the impact on scenarios 1 and 2 is relatively limited (9% and 10% revenue uplift, respectively). This difference between scenarios is largely explained by the higher revenues offered for each MW of reserved capacity and for each hour of availability, which is a similar order of magnitude greater for scenarios 2 and 4 compared to scenarios 1 and 3 (Table 3.3). In all cases, participating to the FFR market is beneficial and does not negatively impact revenues from the DA market.

As FFR is a high-power, short-duration ancillary service, the amount of energy activated for this mechanism is relatively limited. Figure 3.10 shows that only 1-2 % energy is charged and discharged by the BESS for the FFR mechanism, relative to the DA market (FFR scenario 1, normalized).

Capacity reservations only apply to a limited share of time in a year ($< 20\%$). Activations, triggered by frequency deviations within these capacity reservation time slots, occur for an even smaller share of time ($< 5\%$). This is depicted in Figure 3.11.

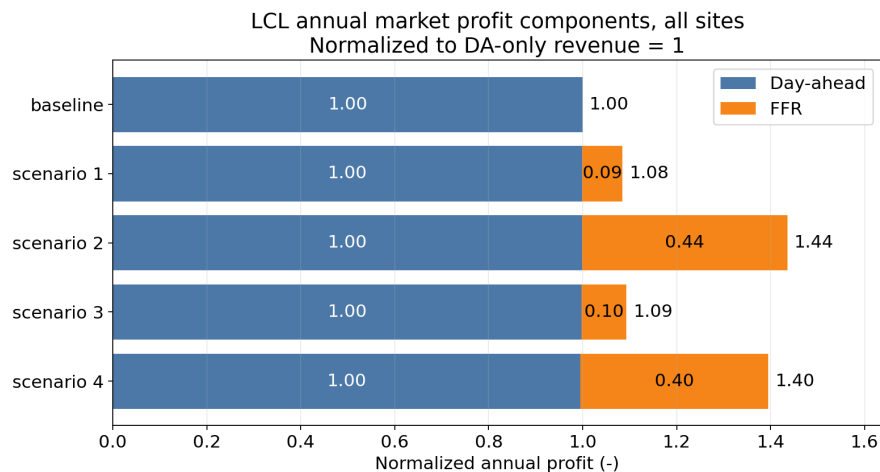


Figure 3.9: Normalized annual revenues from the DA market and FFR, by FFR scenario

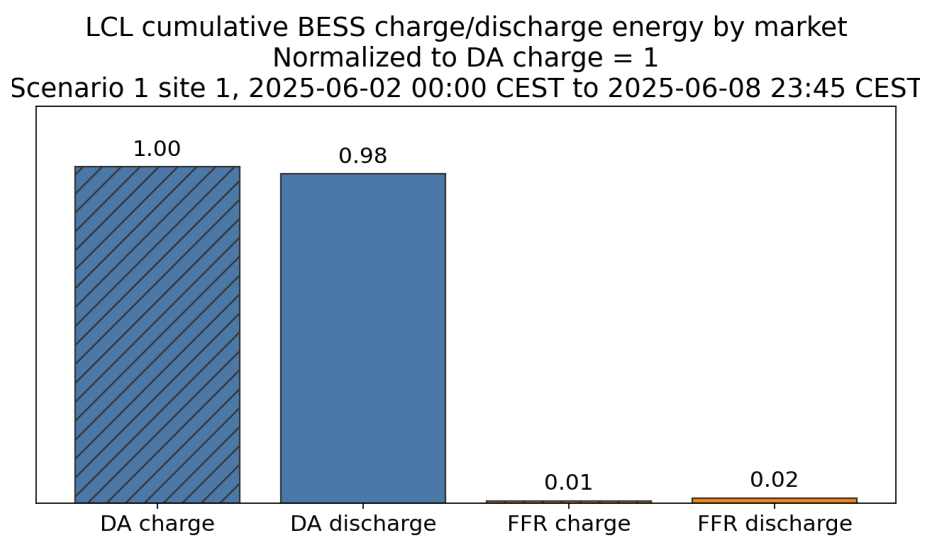


Figure 3.10: Normalized charge and discharge volumes on the DA and FFR markets for FFR scenario 1

LCL FFR capacity and activation duration curves
Pooled across all sites and non-baseline scenarios

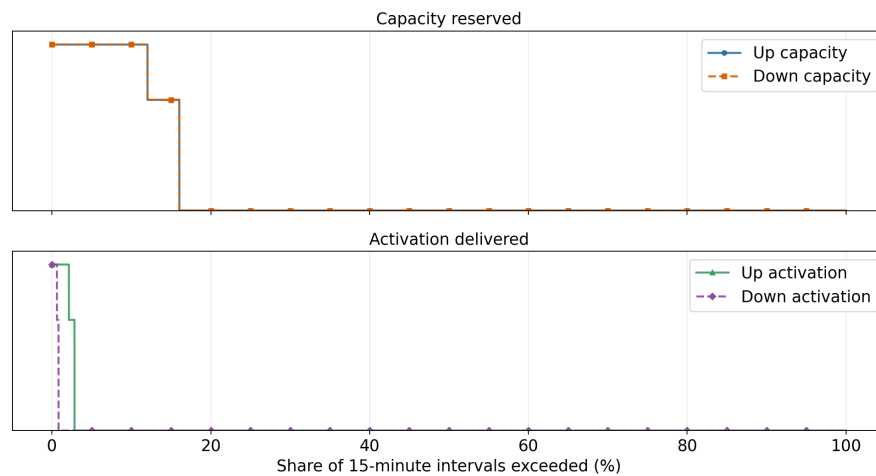


Figure 3.11: Duration curves for capacity reservation and energy activation

Figure 3.10 finally shows the distribution of revenues across the year. We calculated these revenues by counting capacity revenue for the moments when capacity must be available. The pattern by consequence corresponds to the price levels and time schedules defined in Table 3.3. Average revenues are concentrated in summer months, when all four FFR scenarios remunerate reserved capacity. Average revenues are also higher during the day, driven by higher remunerations in scenario 2, than at night, where scenario 4's comparatively lower remunerations dominate.

3.1.5 Limitations and future research directions

The results should be interpreted as illustrative rather than as realistic bidding outcomes. The model constrains only the quarter-hourly integrated FFR activation, i.e., the activation is smoothed out over a full quarter-hour, and hence the activated power is lower but takes a longer time than in reality, where activations last 0.7 seconds. In reality, an actual provider must reserve the full committed capacity throughout each availability block without knowing whether or when activation will occur. This simplification understates the opportunity cost of FFR participation. Perfect foresight further produces optimistic participation and revenue estimates because activations - and hence impact on participation in other markets - are known ex ante.

Future research should enforce full capacity reservation under uncertain activation and backtest bidding strategies that allocate fixed shares of available capacity to FFR (e.g., 10%, 20%, or 30%), with the remainder available to the DA or other markets. The revenue and dispatch effects of alternative product designs and activation thresholds should also be assessed, as the present thresholds of 49.95 Hz and 50.05 Hz were selected to generate sufficient activation events. Finally, a droop-based, piecewise-linear response to frequency deviations would better represent practical FFR implementation than a step response at a single threshold.

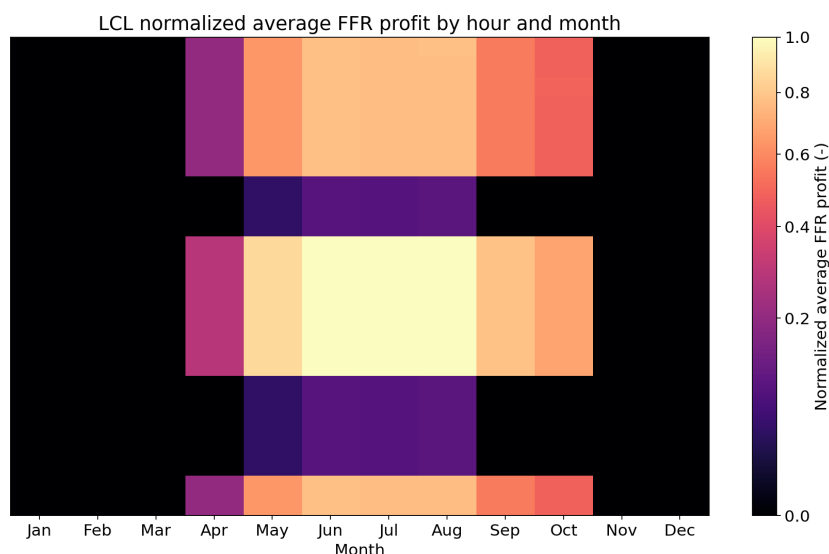


Figure 3.12: Heat map of FFR revenues by month and hour of the day, for all sites of LCL Data Centers and for all FFR scenarios combined

3.2 Higher temporal granularity of capacity reservation products

Traditionally, balancing capacity for aFRR and mFRR has been procured in relatively long reservation blocks. In Belgium, the standard procurement granularity has historically been four hours, requiring balancing service providers to guarantee the contracted reserve capacity throughout the entire reservation period [41]. For industrial consumers, whose flexibility is often constrained by production schedules and process requirements, such long reservation periods may limit participation, as reserve capacity must be continuously available over the full procurement interval.

Elia's *Consumer-Centric Market Design* vision identifies the adaptation of ancillary-service products to the characteristics of flexible demand and the removal of unnecessary participation barriers as important enablers for increasing the contribution of industrial flexibility to system balancing [4, 5]. To assess the potential impact of a higher temporal granularity for balancing-capacity procurement, five reservation granularities are evaluated in this deliverable: the current 4 h product (reference case), together with hypothetical procurement granularities of 2 h, 1 h, 30 min and 15 min. Only the reservation temporal granularity was modified; all market prices, activation signals and technical characteristics of the industrial assets remained identical across the simulations. Consequently, the observed differences in market participation and profitability can be attributed solely to the change in the temporal granularity of the capacity reservation products. Deliverable D2 [3] includes further details on the modelling framework, assumptions, and BUCs description.

The impact of this market-design change is evaluated for the Tessengerlo and Nyrcstar BUCs, as both industrial sites participate in the aFRR and mFRR balancing-capacity markets. Deliverable D2 [3] showed that, under the current 4 h reservation product, their ability to reserve balancing capacity is limited during a substantial share of the

year. These characteristics make both case studies well suited to evaluate the potential impact of shorter balancing-capacity reservation granularities.

3.2.1 Impact of a higher temporal granularity on Tessengerlo BUC

The simulation results for the Tessengerlo BUC are presented in Figures 3.13–3.16. Overall, reducing the reservation temporal granularity for aFRR and mFRR capacity products increases the economic value of industrial flexibility. However, the increase in total annual profit remains relatively modest, indicating that the main benefit lies in improving access to balancing-capacity markets rather than fundamentally changing the operation of the industrial process. As shown in Figure 3.13, annual profit increases gradually as the reservation period is shortened. Moving from the current 4 h market design to 2 h reservation blocks results in a profit increase of approximately 0.4%, while reducing the procurement interval to 1 h increases the annual profit by approximately 1.1%. No further improvement is observed for 30-minute and 15-minute reservation periods, indicating that, for this BUC, hourly reservation products already capture nearly all of the available economic benefit.

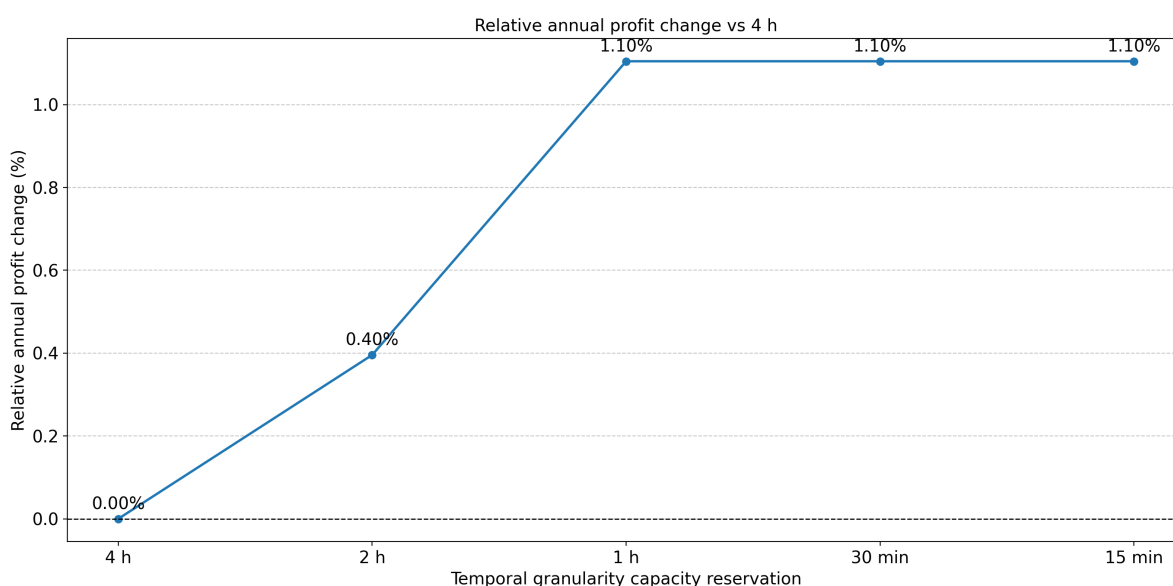


Figure 3.13: Relative annual profit change - Tessengerlo BUC

The underlying reason becomes clear from the evolution of the annual reserved balancing capacity shown in Figure 3.14. Shorter reservation periods substantially increase the amount of capacity that can be offered in the balancing capacity markets, particularly for aFRR upward and downward. The largest increase occurs when moving from the current 4 h products to 1 h products, after which the reserved capacity remains essentially unchanged. This indicates that hourly procurement already unlocks nearly all additional flexibility that can be exploited through shorter reservation intervals.

The reserved-capacity duration curves shown in Figure 3.15 provide further insight into this behaviour. Finer reservation granularity does not significantly increase the maximum reserve capacity that can be offered. Instead, it increases the fraction of the

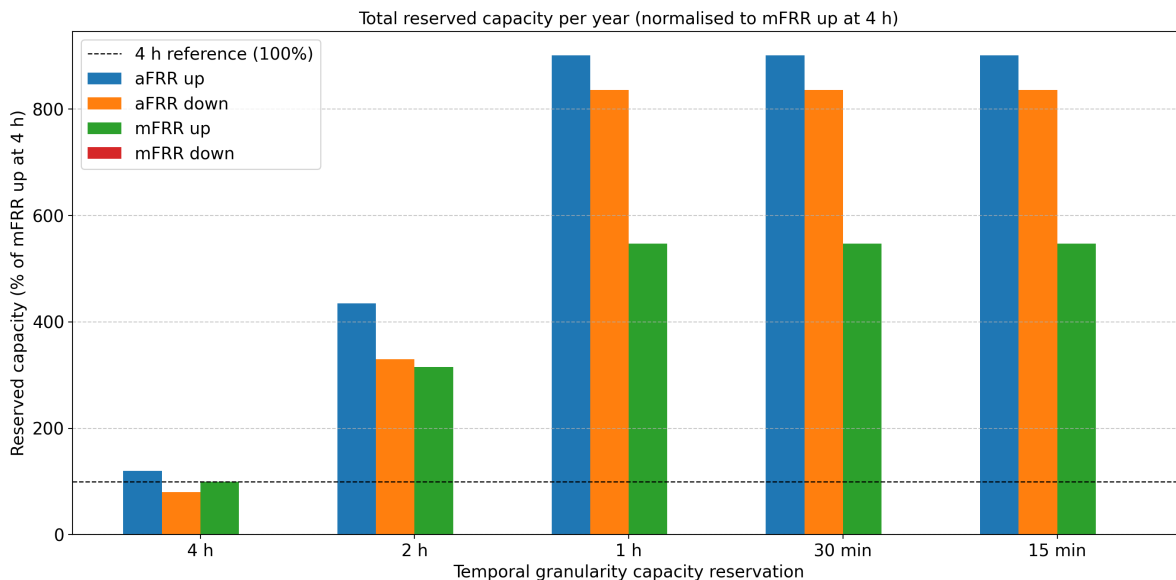


Figure 3.14: Total annual reserved capacity normalized to the mFRR upward reserved capacity under the 4 h design - Tessengerlo BUC

year during which reserve capacity is available. In other words, the same operational flexibility can participate in balancing capacity markets during many more time intervals than under the current 4 h procurement design. This improved temporal allocation explains the substantial increase in total reserved capacity observed in Figure 3.14.

Despite this substantial increase in reserved capacity, the annual activated balancing energy changes only marginally across the simulated reservation granularities. This indicates that shorter reservation periods primarily improve access to balancing-capacity markets rather than increasing the amount of balancing energy activated by the TSO. The reason is that balancing energy activation is driven by the occurrence of system imbalance events, which is independent of the amount of capacity reserved by an individual industrial asset. Under the current 4 h procurement design, reserve capacity is concentrated in a relatively small number of high-value periods with a high probability of activation. As the reservation period is shortened, reserve capacity is distributed over a much larger number of time intervals, including periods with a lower activation needs and prices. Consequently, the activation rate per reserved interval decreases, while the total activated balancing energy over the year remains nearly unchanged.

The impact on the different market segments is shown in Figure 3.16. The increase in annual profit is almost entirely driven by the aFRR upward capacity market, whose contribution increases by approximately 5% relative to the 4 h reference. At the same time, DA market revenues decrease by approximately 2.5%, reflecting the opportunity cost of reserving operational flexibility for balancing services instead of exploiting it in the energy market.

The remaining balancing market segments contribute only marginally to the overall economic improvement. The aFRR downward market exhibits a small positive contribution, whereas the contributions from mFRR upward and downward reserves decrease slightly relative to the 4 h reference. This behaviour reflects the trade-off between addi-

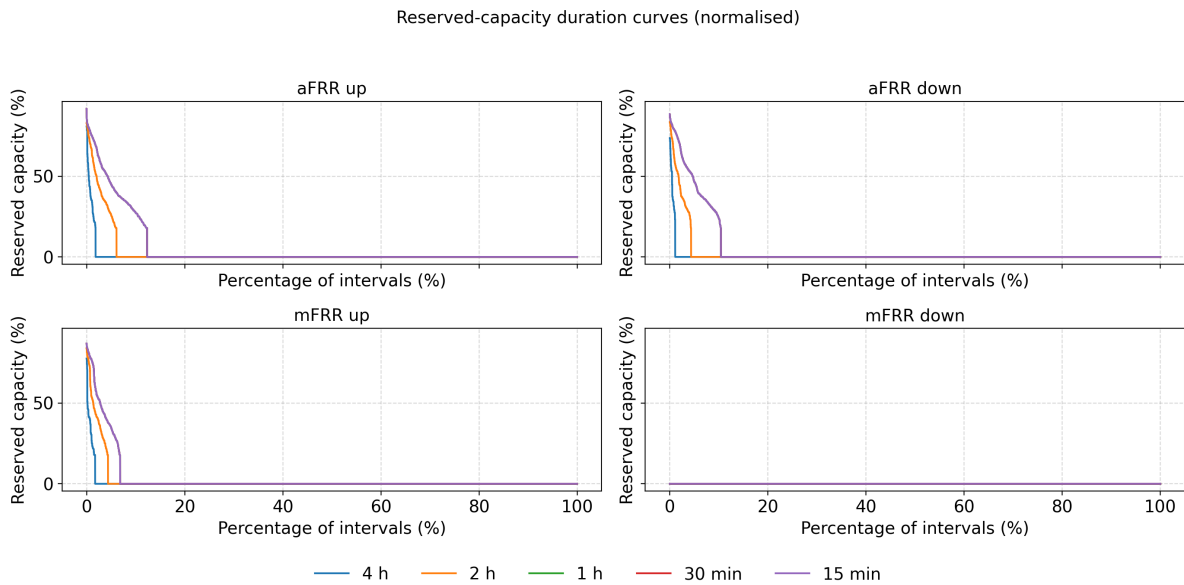


Figure 3.15: Reserved-capacity duration curves normalized to the nominal flexibility of the Tessengerlo BUC.

tional capacity remuneration and the operational constraints associated with reserving flexibility. Although finer reservation granularity enables reserve capacity to be offered during more time intervals, maintaining this reserve headroom also restricts the operational flexibility available for energy arbitrage and balancing energy delivery. For balancing products with relatively low capacity remuneration, these opportunity costs largely offset the additional capacity revenues. By contrast, the higher remuneration available in the aFRR upward capacity market more than compensates for these operational constraints, making it the dominant source of the observed increase in annual profit.

3.2.2 Impact of a higher temporal granularity on Nyrstar BUC

The simulation results for the Nyrstar BUC are presented in Figures 3.17–3.20. Overall, reducing the reservation temporal granularity for aFRR and mFRR capacity products increases the economic value of industrial flexibility, although the improvement remains moderate. As shown in Figure 3.17, the annual profit increases progressively as the reservation interval is reduced from the current 4 h procurement design to 2 h and subsequently to 1 h reservation products. The maximum profit increase is achieved with hourly reservation products (10.85%), after which no additional improvement is observed for 30-minute or 15-minute reservation periods. This indicates that the transition from 4 h to 1 h reservation products represents the meaningful market-design improvement for this industrial asset. Under the observed market prices and activation patterns, sub-hourly reservation products do not unlock additional economic value, suggesting that they would increase market complexity without providing measurable annual profit gains.

The increase in profitability is accompanied by a significant increase in the amount

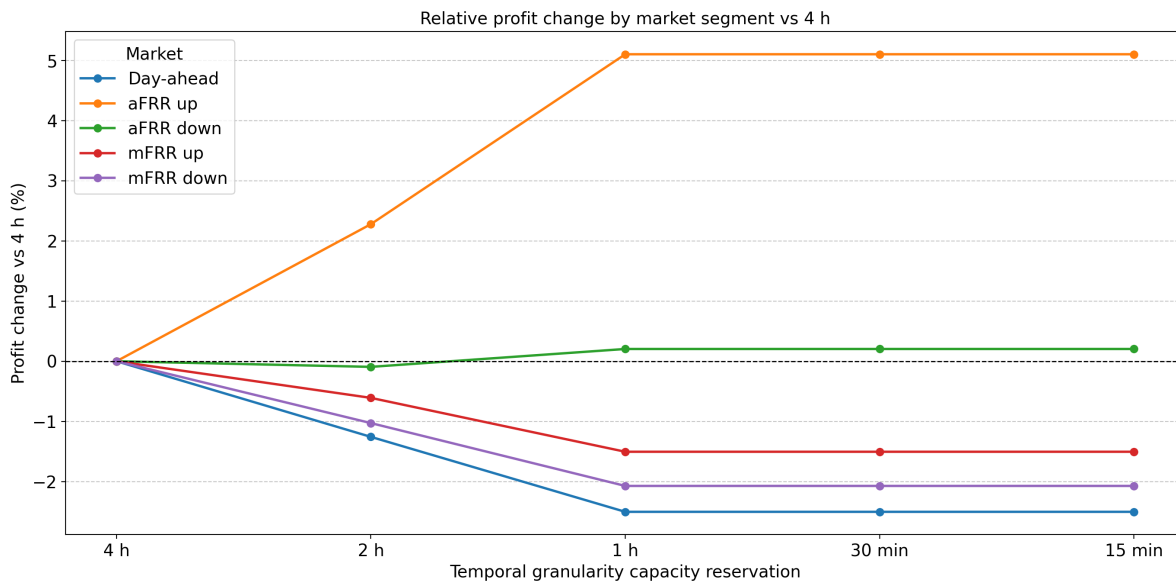


Figure 3.16: Relative annual profit change by market segment with respect to the 4 h procurement design - Tessengerlo BUC.

of balancing capacity that can be reserved, as illustrated in Figure 3.18. The most pronounced increase is observed for the mFRR upward product, while smaller but noticeable increases occur for the aFRR upward and downward products. Similar to the overall profit evolution, the reserved capacities reach a plateau once hourly reservation products are introduced, indicating that nearly all operational flexibility that can be unlocked through shorter reservation periods is already accessible at a 1 h granularity. The duration curves shown in Figure 3.19 provide additional insight into this behaviour. The maximum reserve capacity remains almost unchanged across the different reservation granularities, whereas the duration over which reserve capacity is available increases substantially. In particular, the mFRR upward product can be offered during a much larger fraction of the year when moving from 4 h to 1 h reservation products. This indicates that shorter reservation periods do not increase the instantaneous flexibility of the industrial process, but rather enable the available flexibility to be allocated more frequently throughout the year.

The contribution of the different market segments to the overall profit change is presented in Figure 3.20. Interestingly, the market segment exhibiting the largest increase in reserved capacity is not the one generating the largest economic benefit. While the mFRR upward product shows the largest increase in reserved capacity, it contributes only marginally to the overall profit increase. By contrast, the aFRR upward market becomes the dominant source of additional profit despite a smaller increase in reserved capacity. This demonstrates that the economic value of industrial flexibility is determined not only by the amount of reserve capacity that can be offered, but also by the remuneration structure and the ability of that reserve to generate valuable activations. In other words, additional reserved capacity does not automatically translate into proportional economic value; the profitability of the corresponding balancing product ultimately determines the economic benefit.

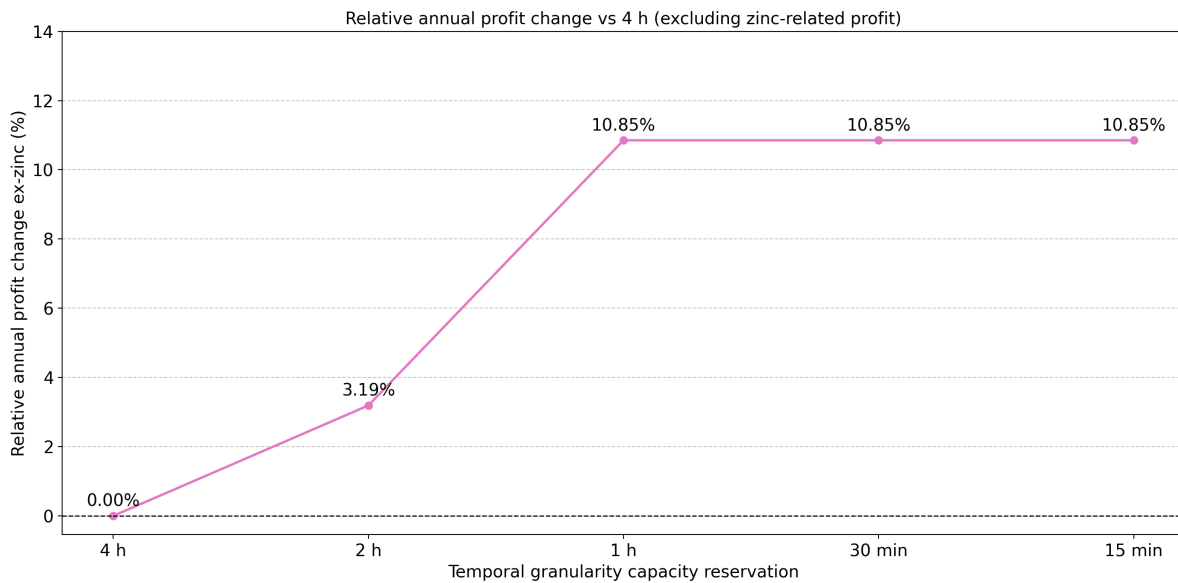


Figure 3.17: Relative annual profit change for the Nyrstar BUC under different reservation temporal granularities.

As observed, the results indicate that hourly reservation products are sufficient to capture nearly the full value of the available flexibility for the Nyrstar BUC. Although finer temporal granularity substantially increases the opportunities to reserve balancing capacity, the resulting economic benefit depends primarily on the value of the balancing product in which that flexibility is deployed. This observation motivates the comparison with the Tessenderlo BUC in the following section, where the influence of different industrial process characteristics on these market responses is discussed.

3.2.3 Comparison of the BUCs and overall conclusions

The results obtained for the Tessenderlo and Nyrstar BUCs demonstrate that both industrial processes benefit from shorter reservation periods for balancing capacity products, although the magnitude of the economic benefit differs. For both case studies, annual profit increases as the reservation granularity is reduced from the current 4 h products to 2 h and subsequently to 1 h products. Beyond hourly reservation products, no additional improvement is observed, indicating that the available flexibility is already fully captured with a 1 h procurement interval under the considered market conditions.

Despite the difference in profit increase, both BUCs exhibit remarkably similar operational behaviour. In both cases, reducing the reservation period substantially increases the amount of balancing capacity that can be reserved. However, the duration curves show that this increase is not caused by a higher maximum reserve capability, but rather by an increase in the fraction of time during which reserve capacity can be offered. Consequently, finer temporal granularity enables industrial flexibility to participate in balancing markets during many more procurement intervals without increasing the instantaneous flexibility of the underlying industrial process. Another common observation is that the increase in reserved capacity does not translate into a comparable increase in

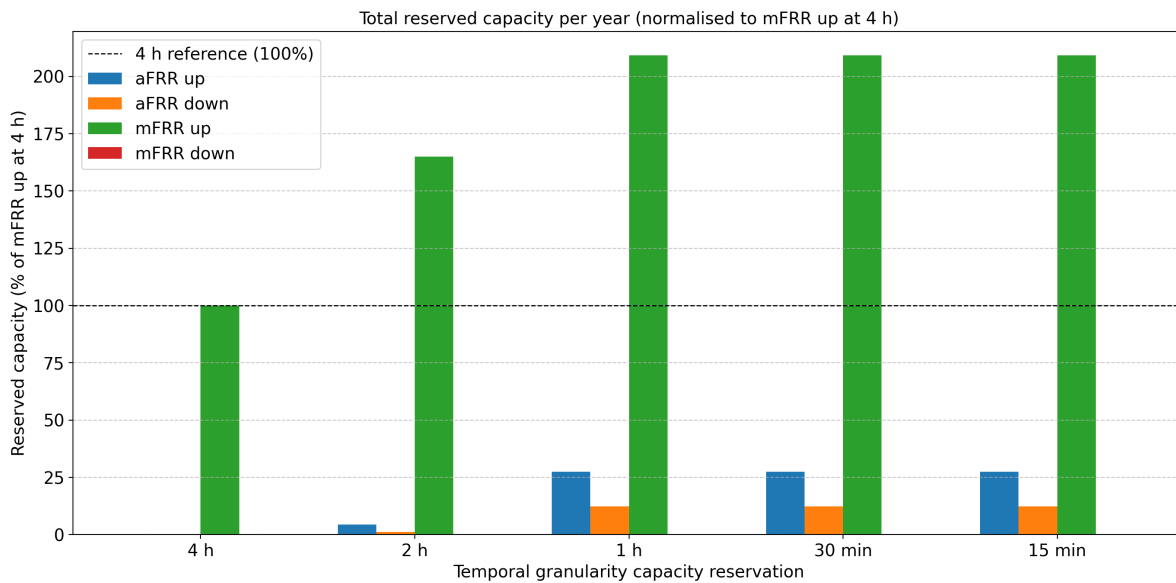


Figure 3.18: Total annual reserved capacity normalized to the mFRR upward reserved capacity under the 4 h reservation product for the Nyrstar BUC.

activated balancing energy. Since balancing activation is determined by system imbalance events rather than by the reservation strategy of an individual market participant, activated energy remains largely unchanged across the different reservation granularities. The principal benefit of shorter reservation products therefore lies in improving access to balancing-capacity markets rather than increasing balancing energy delivery.

The comparison also highlights important differences between the two industrial processes. The Nyrstar BUC exhibits a considerably larger increase in annual profit than the Tessenderlo BUC, indicating that its operational flexibility is more constrained by the current 4 h reservation products and therefore benefits more strongly from shorter procurement intervals. Conversely, the Tessenderlo BUC exhibits a larger relative increase in the availability of reserved capacity, although this translates into a more limited increase in annual profit. These results illustrate that the economic impact of shorter reservation products depends on the operational characteristics of the industrial process and the way in which its flexibility can be allocated across the different balancing products.

A further insight emerging from both case studies is that the amount of reserved capacity alone is not a reliable indicator of economic value. This is particularly evident for the Nyrstar BUC, where the largest increase in reserved capacity is observed for the mFRR upward product, while the largest contribution to the annual profit increase originates from the aFRR upward market. This demonstrates that the economic value of additional flexibility depends not only on the amount of reserve capacity that can be offered, but also on the remuneration structure and activation characteristics of the corresponding balancing product. Consequently, increasing the available reserve volume does not necessarily lead to proportional increases in economic value.

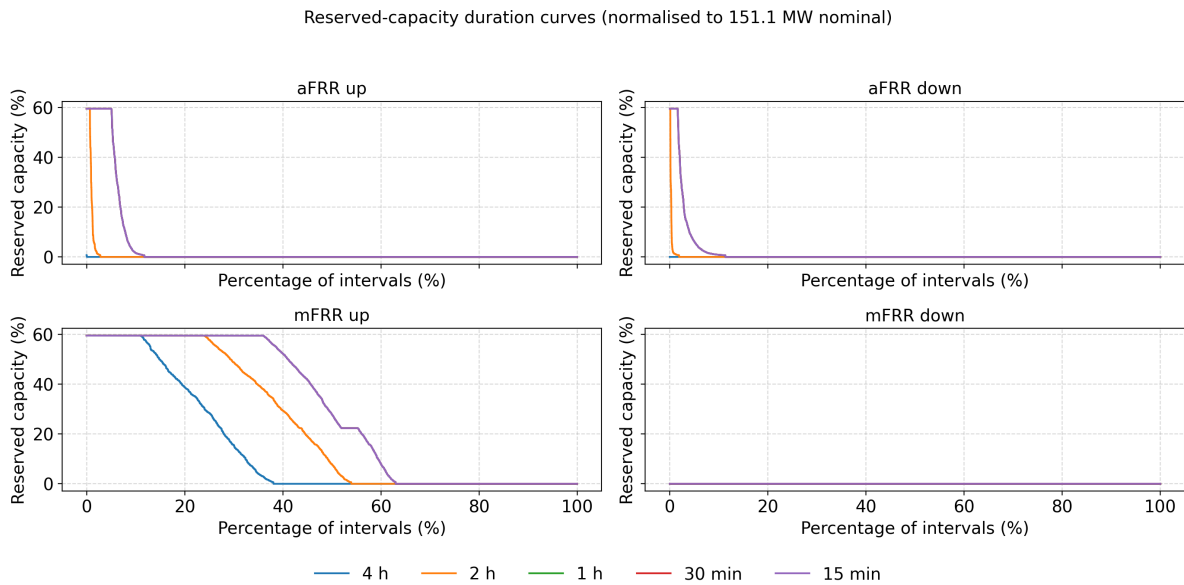


Figure 3.19: Reserved-capacity duration curves for the Nyrstar BUC under different reservation temporal granularities.

3.3 Lower minimum bid size

Balancing markets generally require market participants to submit bids above a predefined minimum bid size for both balancing capacity procurement and balancing energy activation [41]. This minimum bid size is intended to limit market complexity and facilitate system operation, but it may also constitute a barrier for industrial flexibility. Industrial processes often consist of multiple flexible assets or operating states that cannot satisfy the minimum bid threshold. Consequently, part of the technically available flexibility may remain inaccessible to balancing markets solely because the available flexibility is too small to participate in either capacity procurement or balancing energy activation.

Recent European market recommendations and developments therefore aim to reduce minimum bid-size requirements in order to facilitate the participation of smaller and more distributed flexibility resources [42]. Lower bid thresholds allow industrial assets to offer smaller reserve volumes and to participate in balancing energy activations that would otherwise be excluded by the minimum bid requirement. As a result, reducing the minimum bid size is expected to increase market accessibility, improve the utilisation of industrial flexibility, and enhance competition in both balancing capacity and balancing energy markets.

To evaluate the impact of this market-design change, three minimum bid-size thresholds are considered in this chapter: the current 1 MW requirement (reference case), together with hypothetical minimum bid sizes of 0.5 MW and 0.1 MW. The minimum bid size is reduced consistently for both balancing capacity reservation and balancing energy activation, while all balancing market prices, activation signals, and technical characteristics of the industrial assets are kept identical across the simulations. Consequently, the observed differences in market participation and profitability can be at-

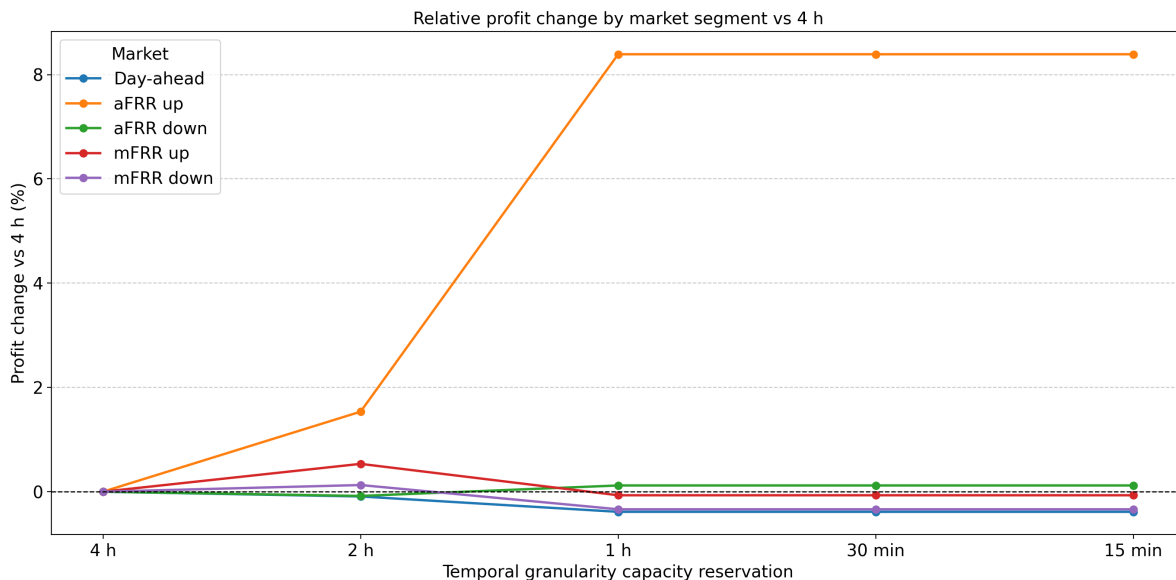


Figure 3.20: Relative profit change by market segment for the Nyrstar BUC under different reservation temporal granularities.

tributed solely to the reduction of the minimum bid-size requirement. Deliverable D2 [3] provides further details on the modelling framework, assumptions, and BUCs. The impact of this market-design change is evaluated for the Aperam ORC BUC 1A and Aperam E-boiler BUC 1B. Both assets participate in balancing markets but exhibit different flexibility characteristics and operational constraints, making them suitable case studies for assessing whether lower minimum bid sizes can unlock additional industrial flexibility and improve the economic value of balancing-market participation.

3.3.1 Impact of a lower minimum bid size on Aperam ORC

The simulation results for the Aperam ORC BUC 1A are presented in Figure 3.21. The figure summarizes the impact of reducing the minimum bid size on the annual profit, the total reserved balancing capacity, and the total activated balancing energy, all expressed relative to the current 1 MW minimum bid-size requirement. Two representative ORC sizing scenarios are considered. ORC-S1 corresponds to Scenario 1 from [3], featuring an ORC with a maximum output of 5 MW, a minimum output of 3 MW, and an 8 MWh thermal buffer. ORC-S14 corresponds to Scenario 14, representing a larger and more flexible design with a maximum output of 6 MW, a minimum output of 4 MW, and a 40 MWh thermal buffer. .

For the ORC-S1 configuration, reducing the minimum bid size from the current 1 MW requirement to 0.5 MW captures almost the entire economic benefit obtainable from this market-design change. As shown in Figure 3.21, the annual profit increases by only approximately 0.18%, while a further reduction to 0.1 MW produces virtually no additional improvement. Although this configuration benefits more than ORC-S14, the overall profit increase remains very limited, suggesting that improved market accessibility alone is insufficient to generate substantial additional value for this BUC. In contrast,

the ORC-S14 configuration exhibits almost no increase in annual profit across all simulated bid sizes. Despite being the larger and more flexible ORC system, lowering the minimum bid size generates only negligible additional revenues, indicating that its profitability is limited by operational characteristics rather than by the bid-size threshold itself.

The effect on balancing market participation is considerably more pronounced. As illustrated in Figure 3.21, reducing the minimum bid size substantially increases the amount of balancing capacity that can be reserved for both configurations. For ORC-S1, the total reserved capacity increases by approximately 4% when the minimum bid size is reduced to 0.5 MW and reaches almost 10% for a 0.1 MW threshold. An even stronger increase is observed for ORC-S14, where the total reserved capacity increases by more than 16%. The larger thermal buffer and higher ORC output of this configuration enable many additional flexibility blocks to satisfy the lower bid-size requirement, thereby significantly increasing the amount of reserve capacity that becomes eligible for market participation. A similar trend is observed for activated balancing energy. Lowering the minimum bid size allows smaller flexibility blocks to participate individually in balancing energy activations, resulting in a gradual increase in activated volumes for both configurations. Nevertheless, the increase remains modest compared with the much larger increase in reserved capacity. Activated balancing energy increases by approximately 0.6% for ORC-S1 and by approximately 0.7% for ORC-S14 relative to the 1 MW reference case, indicating that only a limited fraction of the additional reserved capacity is ultimately activated by the system operator.

Overall, the results demonstrate that reducing the minimum bid size primarily improves market accessibility rather than profitability. Smaller bid thresholds enable considerably more reserve capacity to participate in both balancing capacity and balancing energy markets, particularly for the larger ORC-S14 configuration. However, this substantial increase in reserved capacity translates into only marginal improvements in annual profit. The main reason is that reserve-capacity revenues represent only a very small share of the total annual profit, as shown in [3]. Consequently, even a large relative increase in reserved capacity contributes only marginally to the overall economic performance. For the ORC-S14 configuration, the limited additional reserve revenues are further offset by a slight reduction in DA market revenues, resulting in an almost negligible net profit increase. These findings indicate that, for the ORC BUC, lowering the minimum bid size successfully unlocks previously unavailable flexibility, but the economic value of this additional flexibility remains constrained by the relative importance of balancing-market revenues within the overall revenue portfolio.

3.3.2 Impact of a lower minimum bid size on Aperam E-boiler

Figure 3.22 presents the simulation results for the Aperam E-boiler BUC 1B. Two flexibility configurations are considered to evaluate the influence of the minimum bid-size requirement. The first configuration (Flex1) represents the smallest system considered in [3], consisting of a 10 MW electric boiler combined with a 20 MWh thermal buffer. The second configuration (Flex30) represents the largest system, with a 20 MW electric boiler and a 40 MWh thermal buffer. Similar to the ORC analysis, the minimum bid size is analysed for both balancing capacity and balancing energy products.

For both flexibility configurations, reducing the minimum bid size results in only a very limited increase in annual profit. As shown in Figure 3.22, the annual profit of the Flex1 configuration increases gradually to approximately 0.08% when the minimum bid size is reduced to 0.1 MW, while the larger Flex30 configuration reaches a maximum improvement of only about 0.04%. In contrast to the temporal-granularity analysis, no clear saturation point is observed, although the overall economic benefit remains negligible for all investigated bid-size thresholds. These results indicate that, irrespective of the installed e-boiler and thermal storage capacity, the minimum bid-size requirement is not a major economic limitation for this industrial process.

Reducing the minimum bid size nevertheless increases the amount of balancing capacity that can be reserved. For the Flex1 configuration, the total reserved capacity increases by approximately 5.6% when the minimum bid size is reduced to 0.1 MW, while the larger Flex30 configuration reaches an increase of approximately 3.6%. Compared with the ORC case study, these increases remain relatively modest, suggesting that the E-boiler is already capable of satisfying the existing 1 MW bid-size requirement during most economically attractive reservation periods. Consequently, only a limited amount of additional flexibility becomes accessible when smaller bid thresholds are introduced. The amount of activated balancing energy also increases only slightly, reaching approximately 0.13% for the Flex1 configuration and approximately 0.08% for Flex30. Similar to the ORC results, these increases remain much smaller than the corresponding increase in reserved capacity, indicating that lowering the minimum bid size mainly allows participation during additional reservation intervals without substantially increasing the amount of balancing energy ultimately activated.

Overall, the results demonstrate that reducing the minimum bid size has only a marginal impact on the economic performance of the E-boiler. Although smaller bid thresholds increase market accessibility and enable additional reserve capacity to participate in balancing markets, the resulting increase in reserve revenues represents only a very small fraction of the total annual revenues. Consequently, even the observed increase in reserved capacity translates into only negligible improvements in annual profit. The larger Flex30 configuration benefits even less than Flex1, indicating that, as expected, increasing the installed flexibility of the E-boiler does not make the system significantly more sensitive to the minimum bid-size requirement. These findings suggest that, for the E-boiler BUC, the current minimum bid size is not a major barrier to balancing-market participation.

3.3.3 Comparison of the BUCs and overall conclusions

The results demonstrate that reducing the minimum bid size consistently improves market accessibility by enabling smaller flexibility volumes to participate directly in both balancing-capacity and balancing-energy markets. However, the economic impact remains modest for both investigated BUCs and is strongly asset dependent. For the Aperam ORC, lowering the minimum bid size substantially increases the amount of balancing capacity that can be reserved, particularly for the larger ORC-S14 configuration. Nevertheless, annual profit changes only marginally because balancing-capacity revenues represent only a small share of the total annual revenues and, for ORC-S14, part of the additional reserve revenues is offset by a slight reduction in DA revenues.

The Aperam E-boiler exhibits an even smaller response: the existing 1 MW threshold already allows participation during most economically attractive operating periods, leaving relatively little additional flexibility to be unlocked by smaller bid sizes.

A common observation across both BUCs is that the increase in reserved balancing capacity is much larger than the increase in activated balancing energy and annual profit. Lower bid thresholds primarily allow smaller flexibility blocks to qualify for market participation, thereby increasing the amount of reserve capacity that can be offered. However, the amount of balancing energy ultimately activated remains largely determined by system balancing requirements rather than by the bid-size threshold, limiting the resulting increase in revenues.

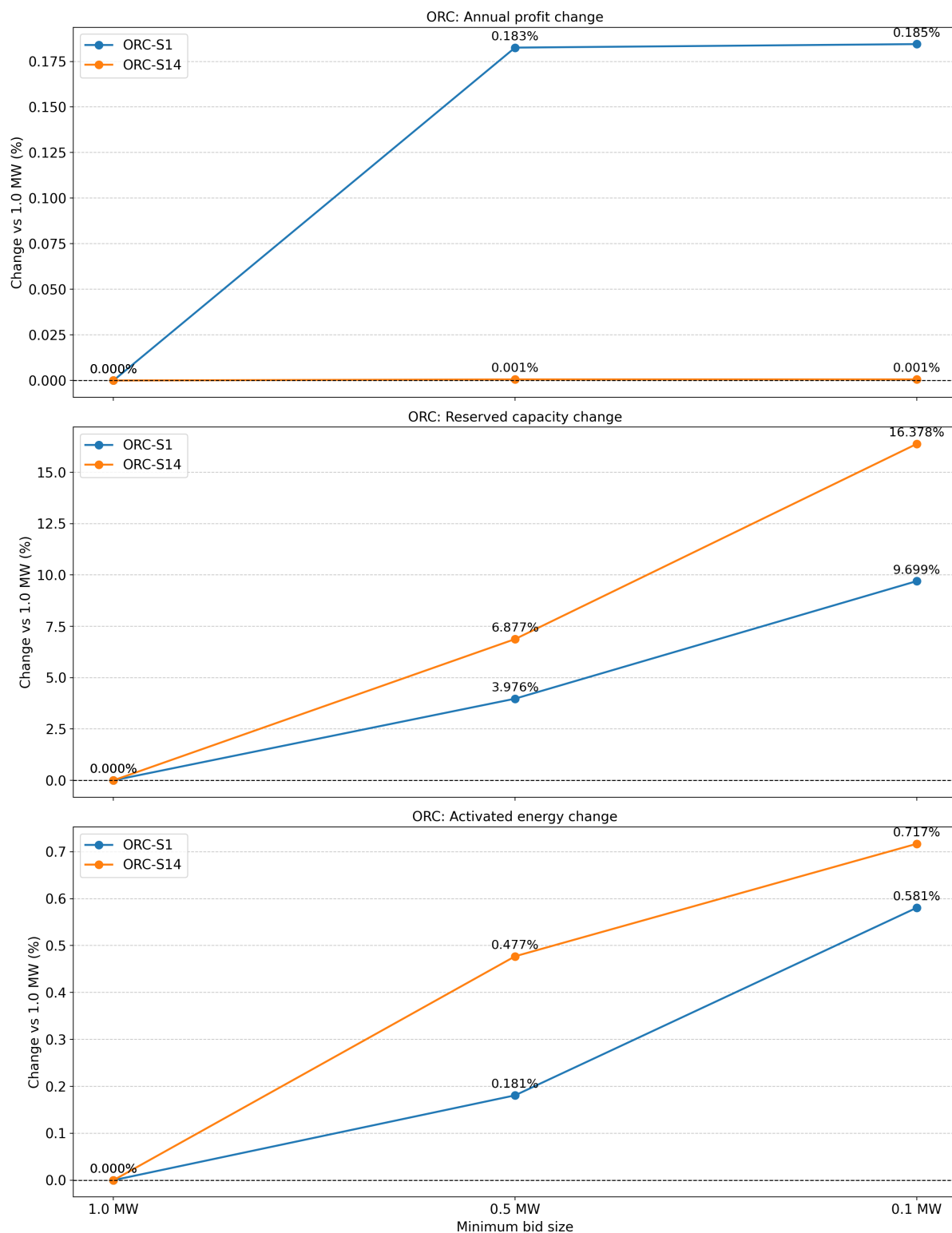


Figure 3.21: Relative changes in annual profit (top), total reserved balancing capacity (middle), and total activated balancing energy (bottom) for the Aperam ORC BUC under different minimum bid-size thresholds. Results are shown relative to the current 1 MW minimum bid-size requirement for the two operating scenarios (ORC-S1 and ORC-S14).

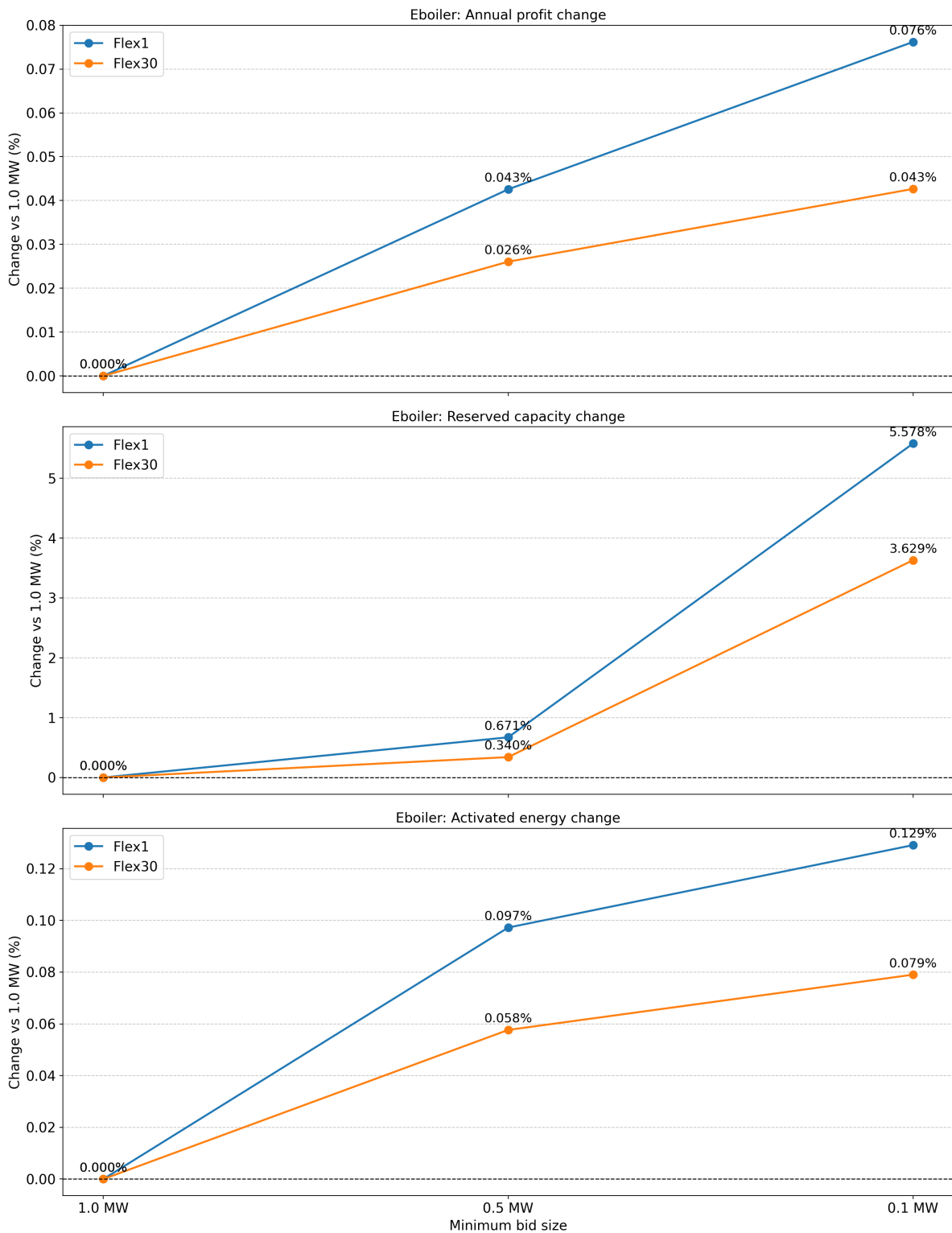


Figure 3.22: Relative changes in annual profit (top), total reserved balancing capacity (middle), and total activated balancing energy (bottom) for the Aperam E-boiler BUC under different minimum bid-size thresholds. Results are shown relative to the current 1 MW minimum bid-size requirement for the two flexibility configurations (Flex1 and Flex30).

Chapter 4

Industrial demand-response participation across EU capacity markets - and reflections for Belgium

In this chapter, we focus on the Belgian capacity market, and its different design components affecting industrial demand-response participation. We discuss chronologically: 1. eligibility and qualification processes, 2. capacity de-rating, 3. auction lead times, 4. clearing processes, 5. access to long-term contracts, 6. contract design and exemptions, 7. secondary market, 8. penalties, 9. cost allocation, 10. competition with fossil resources and 11. beyond capacity remuneration. Where relevant, we introduce the currently applicable State Aid Framework requirements, which would be considered by the European Commission if the Belgian capacity market were to be reformed. Upon availability of data and information, we discuss the differences in implementation across the various EU capacity markets. Finally, we discuss implementation in the Belgian capacity market, and potential adaptations for promoting industrial demand-response participation.

4.1 Eligibility and qualification processes

Qualification constitutes the first step for any unit to participate within a capacity market. To qualify, resources should be eligible, and follow a dedicated qualification process. Qualification processes can be differentiated and adapted to industrial demand-response capacity providers.

Current EU State Aid Framework EU State Aid rules are relatively precise on eligibility. The CEEAG [43] prescribes that *"The aid measure should be open to all beneficiaries or projects technically capable of contributing efficiently to the achievement of the security of supply objective. This includes generation, storage and demand response, as well as the aggregation of small units of these forms of capacity into larger blocks."* The CISAF [44] provides additional requirements for the fast-track State Aid approval process: the *"Minimum size required for participation must not be above 1 MW de-rated or above 1 hour of minimum delivery duration and must allow aggregation."*

The State Aid Framework is less prescriptive, however, on how qualification procedures should be conducted.

Experiences across national Capacity Markets Eligibility of all technologies, including of demand-response and aggregated portfolios is a common standard across EU capacity markets. However, qualification (or prequalification) procedures, i.e. how the capacity is verified to be allowed to participate, differ significantly. Some TSOs rely mainly on historical operational or market participation data (such as the previous French capacity market). Qualification and participation in balancing markets can also be considered (in particular, in Italy). Finally, physical tests are often required, especially for new capacity providers.

Qualification processes can be tailored to accommodate different types of projects and technologies. For demand-response, an interesting example is the Polish capacity market. Poland does verify the technical capabilities of new units through physical tests, and it introduced a simplified qualification process for demand-response. Unproven demand-response units, typically new units, can participate in the capacity auction through a conditional certification process. Instead of following the standard procedure, they initially only provide financial collateral. The unit is then tested later (no later than one month before the delivery period) through a dedicated DSR capability test. Upon successful completion, the collateral is released, the DSR unit is qualified as proven, and certification remains valid for five years. This specific process appears to attract a significant quantity of demand-response providers. For example, in the latest auction for delivery year 2030, 18% of the total contracted capacity was "unproven demand-response" category [45].

Reflections for the Belgian capacity market In Belgium, the prequalification of demand-response resources is primarily based on the verification of technical documentation rather than systematic physical testing. Existing industrial demand response resources are typically qualified as Existing Capacity Market Units (CMUs) based on a representative Nominal Reference Power (NRP) derived from historical quarter-hourly metering data. The prequalification file includes technical information on the delivery point(s), metering, communication systems and the selected Service Level Agreement (SLA), but does not require a systematic physical capability test. If an industrial consumer undertakes an investment to increase its demand response capability beyond the historically observable flexibility, the additional capacity is treated as an Additional CMU. In this case, the provider must submit a Project Execution Plan and provide financial security (collaterals), which is progressively released as the project reaches predefined milestones and the additional flexibility becomes operational, measurable and eligible to be reclassified as an Existing CMU. Elia may require additional demonstrations or tests where the capability cannot be sufficiently established through the submitted information, which more likely applies to new capacity. Previous participation in balancing or ancillary service markets is not a formal prerequisite for qualification, although it may facilitate the technical assessment by providing evidence of operational capability.

The prequalification process applicable to demand-response in Belgium appears to be already relatively flexible. It is based on "case by case" technical documentation

and does not necessarily require physical testing nor previous participation in balancing markets. It should, however, be noted that the complexity of filing technical qualification files can entail non-negligible human and financial resources. This can be an entry barrier (and in turn, a cost penalty) for industrial demand-response providers which may not typically have internal resources dedicated to offering electricity system services. This barrier (and related costs) may reduce over time, as industrial demand-response capacity providers gain expertise and experience with the related process. To conclude, the TSO should ensure that complex qualification procedures do not entail high entry costs, especially for smaller or new demand-response units.

4.2 Capacity de-rating

A production or demand-side unit cannot offer its full "nameplate" capacity to a capacity market. The latter is de-rated to account for the statistical unavailability of the unit during the system scarcity periods. The capacity remuneration is proportional to capacity clearing (or bid) price and the de-rated capacity. Demand-response units are typically "energy-constrained", i.e., their provision of full capacity is limited in time. They are therefore exposed to a de-rating coefficient which is crucial in determining their capacity revenues.

Current EU State Aid Framework For the fast-track approval process, the CISAF [44] requires Member States to rely on de-rating factors based on the latest ERAA results and computed by ACER. Additionally, it specifies that *Individual capacity providers are allowed to deviate from the default de-rating factor for the technology at issue (up to at least 15 % of the standard de-rating factor of that technology). In this case, capacity providers must face the risk of penalties related to their custom de-rating factor.* . The methodology for computing de-rating factors, and in particular for demand-response, remains to be developed by ENTSO-E and ACER. Currently operational capacity markets have been approved before the CISAF, and rely on heterogeneous de-rating methodologies.

Experiences across national Capacity Markets Across European capacity markets, energy-constrained units are generally de-rated per "technology category" depending on their output duration (e.g. 1h, 4h, unlimited) and sometimes on their size (for example, in Ireland). The de-rating factors are computed ahead of the auction by the TSO through simulations which quantify the statistical contribution of a given technology to adequacy.

The de-rating factor of an energy-constrained unit depends critically on the simulated scarcity periods' duration, frequency, and size. The longer are typical scarcity periods, the more a time-constrained demand-response unit will be de-rated. Figure 4.1 shows the de-rating factors applicable to a set of energy-constrained units (including demand-response) across several EU capacity markets and auction lead times as reported in [46]. De-rating factors for energy-constrained units in Belgium appear to be in the high range when compared to those applied in other countries. Differences are largely explained by the different nature of scarcity periods across those countries.

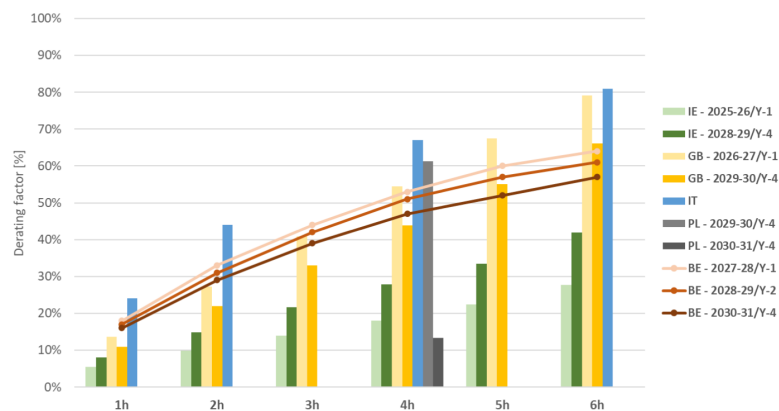


Figure 3-6 : Comparison of derating factors with capacity mechanisms in other countries

Figure 4.1: De-rating factors for energy-constrained units across different EU capacity markets. Source: Elia (2026). 'Preparation of the CRM Y-1 auction with Delivery Period 2027-28, the CRM Y-2 with Delivery Period 2028-29 and the CRM Y-4 auction with Delivery Period 2030-31: Additional analysis regarding the obtained results.'

The scenarios constructed and considered by TSOs can critically affect de-rating factors. This exercise is inherently imperfect, as TSOs must work with uncertainty as regards future electricity system developments including renewable build-out, weather scenarios, demand patterns and price-responsiveness, as well imports' availability. Simulations should therefore strive to capture the diversity of likely scenarios, and TSOs should be transparent about the set of underlying assumptions and their potential evolution. The simulation methodologies used to derive de-rating factors differ significantly across European capacity markets. Ireland, Belgium and Great Britain rely on probabilistic Monte Carlo adequacy simulations (which considers thousands of possible future system states combining, notably, different weather scenarios). De-rating factors are then estimated based on the simulated statistical contribution of a given technology during scarcity events, typically through an Equivalent Firm Capacity (EFC) approach. By contrast, Italy derives de-rating factors from a smaller set of representative adequacy scenarios selected by the TSO, rather than through extensive Monte Carlo sampling. As electricity systems become increasingly weather-dependent, probabilistic chronological simulations are generally regarded as good practice because they better capture the full distribution of scarcity events. This includes, in particular, rare but prolonged periods of low renewable output.

Reflections for the Belgian capacity market The Belgian de-rating methodology, based on exhaustive Monte Carlo simulation appears to be already in line with best practices. In addition, Elia does communicate on the main factors affecting de-rating factors, including for energy-constrained units (see [46]).

However, de-rating factors applicable to demand-response units may evolve significantly over years according to the electricity system conditions. Figure 4.1 illustrates how de-rating factors in the main capacity market auctions are set to decrease over time. According to Elia, this reduction is *"due to the strong growth of storage capacity at both Belgian and European levels, combined with the increasing correlation between*

scarcity situations and periods of low RES infeed at European level". De-rating factors can also evolve for the same delivery year between the Y-4 subsequent auctions. This is illustrated in figure 4.2, showing the difference in de-rating for energy-constrained units between the Y-1 and Y-4 auctions. Such changes in the de-rating factors add an additional "volume" risk for industrial demand-response capacity providers, which are generally granted only 1-year contracts. In effect, they may not be able to participate with, and be remunerated for, the same capacity volume every year. This can be a non-negligible risk, in particular for demand-response capacity requiring new upfront investments. There are different options to mitigate this risk. First is increasing visibility over the evolution of de-rating across future years, and the main drivers for these evolutions. Second is enabling access of demand-response to long-term contracts, where the de-rating factor is fixed for the duration of the contract.

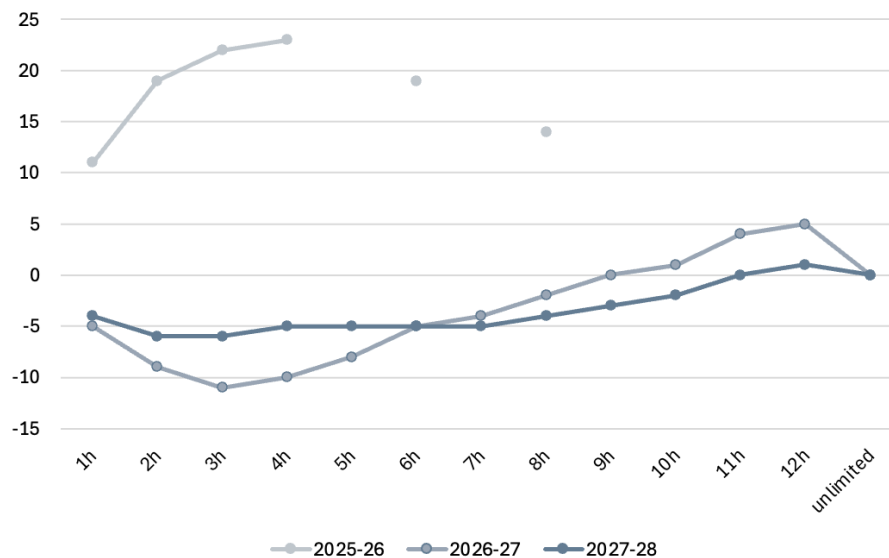


Figure 4.2: De-rating factors per SLA category (%) change between Y-4 and Y-1 for the same delivery year. Source: data extracted from Elia (2025) 'Consolidated derating factors and demand curves parameters workbook'

4.3 Auction lead times

Capacity contracts are allocated to qualified resources following a competitive process. In centralized capacity markets this takes the form of centralized auctions. They are generally split into one main auction held in Y-4 to 5 for most of the volume, and a later adjustment auction in Y-1 for the rest of the volume. It is typically argued that demand response units prefer participating in short lead-time auctions (e.g. Y-1) rather than earlier auctions held several years before delivery (e.g. Y-4 to 5). Compared to new generation capacity, a demand response capacity can typically be deployed within months. Therefore, it does not necessarily require revenue certainty 4 to 5 years ahead. Additionally, the exact available capacity of a demand-response unit depends on its baseline and daily/monthly consumption patterns, which can be affected by changes

in industrial production plans and commodity prices. In this context, shorter lead times reduce uncertainty with regards to the exact quantity of capacity available and lower the risk of non-delivery penalties.

Current EU State Aid Framework For the fast-track approval process, the CISAF (2025) requires that *"One main competitive bidding process for 75 %-90 % of the estimated target demand for the delivery window should take place 4-6 years ahead of the delivery window. Adjustment competitive bidding processes can be organised closer to delivery, taking into account the lead time for developing demand response and storage."*

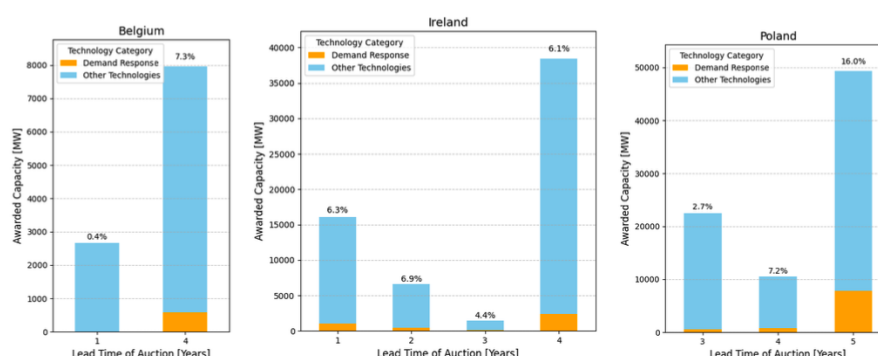


Figure 4.3: Share of demand response based on lead time of the auction in Belgium, Ireland and Poland. Source : [1]

Experiences across national Capacity Markets Figure 4.3 shows the quantity and relative share of demand-response clearing in the Irish, Polish and Belgian capacity market per lead time. Against the expected preference for later auctions, demand-response participation appears higher in proportion in earlier auctions in both Belgium and Poland. This may be explained by a combination of factors. Providing new demand-response capacity can entail significant investments in new assets (monitoring, controlling devices) and changes in production processes, potentially requiring more than one year of implementation. Most importantly, prices in Y-1 auctions tend to be lower than in earlier (e.g. Y-4) auctions due to a smaller demand and higher competition. In practice, preferences may be different across the different categories of demand-response providers, i.e., between an aggregated portfolio of small consumers, and a large industrial consumer.

Reflections for the Belgian capacity market In Belgium, auction lead times used to be limited to Y-4 (bulk of the volume) and Y-1 (adjustment). In past Y-1 auctions, the price was significantly lower than in Y-4 auctions. Industrial demand-response may therefore face a trade-off between participating in later (Y-1) auctions where they have more visibility on their available capacity, and participating in earlier (Y-4) auctions where remuneration may be significantly higher.

There may be adaptations to mitigate this tradeoff. Recently, a Y-2 auction was introduced to update procurement volumes as information on capacity needs is refined, and to accommodate medium lead times investments and new technologies such as demand-response and storage. This new "intermediate" lead time (Y-2) is an interesting development, and its effect on demand-response participation should be monitored. Another solution could be to enable demand-response providers to adjust (opt-in/opt-out) their capacity obligations after clearing in earlier auctions (e.g. Y-4) as their information on their availability is refined. In theory, this is ensured by the presence of a secondary market, which is in practice limited (see dedicated section).

4.4 Clearing process

The clearing process refers to how the submitted bids are ranked, selected by the auctioneer (here, the TSO), and eventually how the contract price is defined. Different choices may impact industrial demand-response participating including the pricing rule, price caps, and targeted minimum volumes.

Current EU State Aid Framework For a fast-track approval process, the CISAF [44] requires that *"Beneficiaries must be identified through a competitive bidding process with bids ranked according only to their price per de-rated unit of available capacity per year, and support paid according to the clearing price"*. This corresponds to a pay-as-clear rule.

In addition, the CEEAG [43] allows Member States to positively discriminate clean technologies in the selection process, which includes demand-response. It states that Capacity mechanisms *"may also be designed to support environmental protection objectives, for example through [...] measures to give more environmentally beneficial capacity an advantage in the selection process"*.

Experiences across national Capacity Markets Most EU capacity markets are cleared following a "pay-as clear" principle. The selection follows the merit order of "de-rated" offered capacity, and beneficiaries receive the same market clearing price. The overall auction price cap, reflected in the capacity demand curve is based on the Cost of New Entry (CONE). It generally applies to new units, as existing units (eligible for 1-year contracts) are generally subject to an intermediate price cap.

Additional considerations can be included in the selection process and potentially promote industrial demand-response. An interesting example is the new French capacity market. In the Y-1 auction, it will reserve a minimum volume for non-fossil flexibilities (demand-response and storage). The latter will clear at a higher price than the rest of capacity providers if the constraint is binding.

Reflections for the Belgian capacity market First, in contrast with all other EU capacity markets and new State Aid requirements, the Belgian capacity market applies a pay-as-bid pricing rule. Selected Capacity providers are remunerated at their own bid price rather than at a uniform clearing price. Originally, pay-as-bid was foreseen to be

applied only for the first two auctions to limit inframarginal rents, before transitioning to a pay-as-cleared design. However, this transition was abandoned and the capacity market still applies pay-as-bid at the time of writing. According to Elia, a capacity market should compensate only participants' missing money. It states *"it is not justifiable to earn inframarginal rents in the Belgian Capacity Mechanism. As the missing-money level is specific to each CMU [...] it makes sense not to reward all Capacity Providers with the same Capacity Remuneration."* [47]. There may be drawbacks to a pay-as-bid clearing rule with regards to industrial demand-response. The main issue with pay-as-bid is that bidders are incentivized to bid higher than their true costs (here, missing money) to earn rents. To do so while being sure to be selected, they need to have appropriate information on the electricity system and their competitor. In turn, it means that market participants with most market intelligence, and dedicated resources, are more likely to earn rents. Industrial demand-response providers, which business is typically less centered on electricity markets than conventional plants' competitors, might therefore be disfavored. The differentiated impact of maintaining pay-as-bid over different categories of capacity providers, including demand-response, should be properly considered.

Second, an intermediate price cap applies for all capacity providers eligible to 1-year contracts. The price cap is defined by Elia based on the missing money of the "worst performing" technology [48]. Industrial demand-response capacity providers systematically fall into the 1-year contract category. Hence, they cannot be subject to the overall, higher, auction price cap even if they engage in substantial - though multifunctional - investments. This specific issue is discussed in more details in the section dedicated to long-term contracts.

Third, to further "favor" non-fossil resources including industrial demand-response, it is also possible to apply additional constraints or criteria in the selection process, as France will do in its future capacity market auction. Such as change is so far, not foreseen.

4.5 Access to long-term contracts

Capacity market contracts can vary in duration, ranging from one to 17 years. On the one hand, short-term contracts avoid locking in fixed payments and capacity, and ensure liquidity, competition, and better price formation in subsequent auctions. On the other hand, long term contracts may be necessary for new investments which benefit from long-term revenue certainty. Ensuring access to long-term contracts can be an enabler for industrial demand-response projects that require substantial investments.

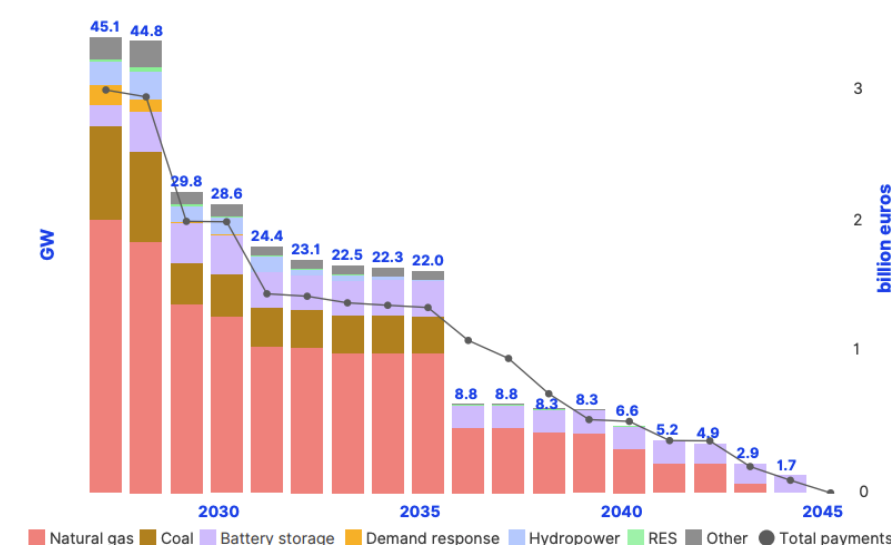
Current EU State Aid Framework For the fast-track approval process, the [44] requires : *"Capacity agreements must in general cover one delivery window. Where beneficiaries undertake capital investments, longer capacity agreements may be made available. For every 25 000 EUR / de-rated MW, an additional year may be offered."*

Experiences across national Capacity Markets In EU capacity markets, access to multi-year contracts is generally restricted to assets categorized as "new investments".

What qualifies as a new investment is generally based on minimum investment thresholds (CAPEX/MW), where the underlying investments must be directly related to capacity provision.

A notable exception was the previous French capacity market. The decentralized capacity certificate mechanism was complemented with targeted long-term auctions open only to non-fossil resources. Initially, these auctions were reserved for demand response ("Appel d'offres Effacements") and were later extended to electricity storage ("Appel d'offres Flexibilités Décarbonées"). Successful bidders were awarded multi-year contracts providing a variable premium on top of the revenues obtained from the decentralized capacity market. This premium was designed as a contract-for-difference (CfD): when capacity certificate prices fell below the strike price established in the auction, the contract paid the difference. In total, close to 3700MW (applicable to 2026) of non-fossil capacity providers were granted long-term contracts [49].

In contrast with France, other EU capacity market have largely granted single-year contracts to demand-response capacity providers. Until 2024, multi-year contracts were to 0% of demand-response providers in Belgium, 3.5% in Ireland (10 years), and 0.3% in Poland (5 years) [1]. This is illustrated in 4.4, in which demand-response represents a very limited share of long-term contract payments (and is mainly located in France).



Source: Calculated by ACER based on NRA data.

Figure 4.4: Total payments and capacities awarded long-term contracts through EU capacity markets. Source : ACER (2024) 'Security of EU electricity supply 2024 Monitoring Report'

Reflections for the Belgian capacity market In Belgium, eligibility for multi-year capacity contracts depends on meeting predefined CAPEX thresholds. Only investment costs that are directly related to enabling participation in the capacity market are counted as eligible CAPEX, while broader investments that primarily serve industrial processes or other commercial functions are generally excluded from the calculation. In a dedicated study, the CREG [50] recognizes that the current design does not adequately

recognize certain industrial flexibility investments. This is in particular the case of "multifunctional" demand-side flexibility projects, which combine capacity market participation with other industrial or market functions. Indeed, existing eligibility criteria and investment thresholds were primarily designed for conventional participants. The CREG concludes that maintaining the current framework would preserve regulatory stability but may continue to exclude valuable flexibility resources and rely on opaque case-by-case assessments. Instead, it recommends targeted adaptations to the existing CRM, such as revising the criteria for access to multi-year contracts and the recognition of eligible investments. The study also assesses a more far-reaching option of granting multi-year contracts to all capacities regardless of investment level, subject to stronger additionality and availability requirements.

4.6 Contract design and exemptions

Capacity contracts are typically structured around a fixed yearly availability payment (eur per de-rated MW). They can also foresee variable payments based on actual market outcomes (for example, with a reliability option contract). The contract structure and potential exemptions are particularly relevant for industrial demand-response participation.

Current EU State Aid Framework The CEEAG [43] indicates that security of supply measures should preferably pay for capacity (eur per MW) to limit distortion on energy markets. The CISAF [44] additionally indicates that capacity markets should pay resources proportionally to their derated capacity. There is no specification on the precise type of payment structure (simple availability payment vs reliability option).

Experiences across national Capacity Markets The payment structure differs across EU Capacity markets. France and Poland grant simple availability payments (euros per de-rated MW available), while Italy, Ireland and Belgium grant reliability options. With a Reliability option contract, the beneficiary receives a fixed availability payment, but should also pay back its scarcity rents. More precisely, when the reference market price (typically day-ahead) raises above a pre-defined strike price, the beneficiary should pay back the difference.

Reliability options have several theoretical advantages. First, they incentivize beneficiaries to be available during scarcity periods. Second, they avoid double remuneration of capacity providers for their missing money (through capacity payments, plus, through scarcity rents if they materialize). In practice, payback clauses may constitute a barrier to demand-response. In contrast with a conventional generator, a demand-response unit does not make direct scarcity rents from selling into wholesale market. Hence, it may have difficulties paying back these rents to the TSO following a reliability option contract. In practice, the demand-side unit can make partial savings from reducing its demand and related wholesale market purchases. Whether these savings are fully equivalent to the scarcity rent depends on its energy procurement strategy. For example, a consumer engaged in a long-term fixed retail contract will not receive

the full value of the energy market savings from curtailing during scarcity periods. This issue is more prevalent for small and aggregated demand-side units, typically under relatively fixed retail agreements, than for large industrial demand units. Indeed, the latter may be directly active on wholesale market and in some case have access to on-site production.

EU capacity markets with reliability options have therefore adapted their scheme for demand response. In Italy, demand-response does not receive a usual capacity contract, as it is instead exempted from the capacity fee (see section on cost allocation). In Ireland, the initial Capacity Market exempted demand-side units from the reliability option pay-back. This exemption was justified on the ground that demand-response units do not receive direct energy payments (i.e. scarcity rents) from demand reduction. The European Commission granted approval based on a commitment to eventually end this exemption to provide a level playing field across all technologies. Another issue concerned the reliability option strike price, which could fall below the economic cost of curtailing demand. To address this, the strike price was subject to a floor based on the theoretical cost of a Demand Side Unit. More recently, reforms were introduced to establish energy payments for demand reductions and supplier compensation arrangements [51], which could eventually enable the removal of the historical payback exemption.

Reflections for the Belgian capacity market Unlike Ireland, the Belgian capacity market initially applied the reliability option payback obligation to all capacity providers, including demand-side management and energy storage. However, in its State aid approval, the European Commission required Belgium to exempt demand-side management (and storage) from the payback obligation. The Commission considered that the payback mechanism is intended to recover inframarginal wholesale market revenues earned by generators during scarcity periods, whereas demand-side resources do not receive such energy market revenues. Subjecting these technologies to the same payback obligation could therefore distort competition and discourage their participation. As a result, pure demand-response units contracted from the 2024 auction onwards (and pure storage units contracted from the 2025 auctions onwards), are exempt from the payback obligation, while aggregated unit remain subject to a proportional application reflecting the share of non-exempt capacity [52].

In practice, this can represent a significant advantage for industrial demand-response. Indeed, energy-intensive consumers are typically directly active in wholesale markets. In turn, reducing energy demand during scarcity periods can result in non-negligible energy procurement savings. As an illustration, the estimated wholesale market savings from curtailing demand during scarcity periods (i.e. the value of the payback exemption) in 2024 are within the same order of magnitude as the yearly capacity payments for existing resources ¹. This advantage is eventually reflected in bids, and can eventually favor demand-response in the bid selection. Indeed, a demand-response unit can bid lower than if it had to pay back the scarcity rents, and lower than a conventional counterpart with the same initial missing money.

¹Source: own calculation, considering: a resource paid at the intermediate price cap (29000€/MW/year), and the general reliability option strike price (200€/MWh).

The reliability pay-back exemption may act, in the case of industrial demand-response, as an important advantage and an indirect bidding "bonus". It moreover simplifies participation into the capacity market. If this exemption were to be reformed, careful consideration should be given to the actual value that demand-response providers can capture when curtailing during scarcity periods. Ireland, currently implementing dedicated demand-response frameworks to transition towards the end of the exemption, provides an interesting example of such a reform.

4.7 Secondary market

After being granted their initial capacity obligation contract by the TSO (primary auctions), market participants can be allowed to adjust their positions by trading capacity obligations with counterparts (secondary market). The possibility to sell (or purchase) part of their capacity obligation is important for demand-response capacity providers, which availability may evolve over time. A secondary market helps mitigate the risk of under or over-delivery penalties.

Current EU State Aid Framework The CEEAG [43] requires that a capacity mechanism *"enables capacity obligations to be transferable between eligible capacity providers"*. For the fast-track approval process, the CISAF [44] requires secondary trading to be allowed: *"Beneficiaries must be allowed to sell their capacity agreement to another capacity provider, up to at least 2 months before the start of the delivery window."*

Experiences across national Capacity Markets All centralized European capacity mechanisms provide some form of secondary trading or transfer of capacity obligations, generally through a platform or registry operated by the TSO. These arrangements are primarily intended as risk-management tools, allowing contracted providers to reallocate obligations to other eligible resources when necessary.

However, there is very limited transparency regarding their actual use. Public information on transaction volumes, prices or liquidity is generally unavailable, notably in Italy and Poland. Ireland constitutes an exception, as the SEM publishes all completed secondary transactions. These data suggest that trading activity exists but remains relatively limited, indicating that the secondary market is used mainly as a contingency mechanism rather than as an active trading venue.

Reflections for the Belgian capacity market Belgium's capacity market includes a secondary trading platform operated by Elia, allowing capacity providers to transfer capacity obligations during the delivery period. However, no public information is available regarding the platform's liquidity, traded volumes or frequency of transactions. Feedback from market participants suggests that finding counterparties to buy capacity obligations can be difficult, limiting their ability to adjust their contractual position after the primary auction. This may be particularly challenging for industrial demand response providers, whose availability can evolve over time as production schedules, industrial processes or business conditions change.

4.8 Monitoring and penalties

A capacity contract remunerates its holder for availability to activate during pre-defined or variable periods. Availability, and delivery where relevant, are therefore checked by the capacity market operator. Where the contract holder fails to meet its availability obligation, it may be exposed to penalties. Penalties incentivize market participants to offer strictly the amount of capacity they can provide to the system. Demand-response capacity providers can be particularly exposed to penalties due to their technical characteristics.

Current EU State Aid Framework For the fast-track approval process, the CISAF [44] requires: *"Beneficiaries must face non-availability penalties whenever unavailable in a delivery period or test. The non-availability payment must be the same for all technologies. A beneficiary less than 50 % available in the delivery periods within a delivery window must be exposed to a penalty payment of at least its capacity revenues for the delivery window. Beneficiaries must not face penalties related to a lack of availability outside the delivery periods."*

Experiences across national Capacity Markets Availability and activation are checked during distinct periods. First is the pre-defined delivery period, during which capacity providers should contractually be available (e.g. winter). Availability can be verified by the TSO based on the actual resources' activity, or conducting physical tests notified only a day in advance. Second are the actual scarcity periods, during which capacity providers are expected to activate. In both Poland and Ireland, the TSO determines the "scarcity periods" based on operational reserve criteria and formally declares a scarcity event. Belgium, by contrast, identifies scarcity through an objective market price threshold (the AMT price).

Under-delivery or unavailability generally entails financial penalties. In Ireland, non-performance charges are applied during each System Stress Event and are subject to an annual stop-loss limit. Poland follows a similar approach, penalties are based on the hourly capacity shortfall during declared stress events, with monthly and annual caps. In Italy capacity payments are instead suspended during periods of declared or verified unavailability, with stronger sanctions reserved for prolonged outages or contractual breaches.

Over-delivery is typically not considered (in Ireland, Poland and Italy). Great Britain is a notable exception: providers that deliver more than their obligation become eligible for over-delivery payments, which are calculated at the end of the delivery year and financed entirely from the penalties collected from under-performing providers. The mechanism aims to reward resources that compensate for the shortfalls of other providers, so that capacity revenues better reflect the actual contribution of each resource to system security.

Reflections for the Belgian capacity market In Belgium, availability is checked during during Availability Monitoring Trigger (AMT) periods. AMT moments are any market time unit during which the day-ahead market price raises above a pre-defined trigger

price. Elia may, additionally, conduct availability tests outside AMT periods, in particular if the capacity market unit had instances of unavailability. During an availability test, Elia calculates the missing capacity based on physical delivery, market participation, and announced unavailability. Penalties are then applied proportionally to the unavailable capacity and the duration of the event. Penalties are capped to 20% of the monthly capacity remuneration and 100% of the annual remuneration. The Belgian capacity market also features an escalation procedure : if a capacity unit provides less than 80% of its contracted capacity during three AMTs or availability tests, its certified capacity (and therefore its future capacity payments) is reduced until the provider demonstrates that the availability issue has been resolved.

The Belgian capacity market features a unique system of "declared prices". Physical delivery is not expected during all AMT periods. Instead, it is only expected if the relevant market prices raise above the unit's "declared price". Capacity providers submit "declared prices" and their associated volumes for day-ahead, intraday, and balancing (imbalance price) markets. Declared prices shall correspond to the bid price submitted in those markets, and therefore, the price above which they are expected to activate the relevant volume. This mechanism aims to ensure that resources activate only when economically efficient, i.e., when market prices are higher than their marginal activation costs.

This mechanism can turn into inappropriate incentives, where capacity providers submit very high declared prices to reduce their expected delivery obligation to zero. To prevent this issue, Elia also enforces over-delivery penalties. Over-delivery penalties apply when a capacity provider activates during an AMT period while it was not supposed to, i.e. the relevant market price was below the declared price. Over-capacity penalties may be an issue for industrial demand-response. Indeed, unforeseen issues generally result in reducing or stopping the industrial process consuming electricity. As a result, the demand-response unit appears as fully activated, even during periods where it is not supposed to activate. In turn, it may be exposed to significant over-delivery penalties. Feedback from industrials indicates that over-delivery penalties can represent a 10-30% share of the total capacity payments over the year. They are moreover perceived as unfair, as capacity is, in fact, available and delivered. While over-delivery penalties appear necessary with the system of declared price, particular attention should be given to its compatibility with demand-response providers.

4.9 Cost allocation for implicit demand response

In the previous sections, we have so far focused on explicit demand-response: units participate on the supply side like conventional capacity providers. In this section, we consider implicit demand response: where units reduce their demand to reduce their capacity fee.

Current EU State Aid framework The CEEAG [43] already precised that capacity costs allocation should enable demand response. It states: *"To avoid undermining incentives for demand response [...] the costs of a security of supply measure should be borne by the market participants who contribute to the need for the measure. For*

example, this may be achieved by allocating the costs of a security of supply measure to electricity consumers in periods of peak electricity demand”

For the fast-track approval process, the CISAF [44] introduced more specific criteria, stipulating that *“At least 90 % of the capacity mechanism costs must be allocated to consumers based on their consumption during at least 1 % and at most 5 % of the highest price hours (or market time units) each year (or each delivery window). Charges may be levied on balance responsible parties (such as suppliers)”*.

Experiences across national Capacity Markets Across European capacity mechanisms, the costs of capacity remuneration are generally recovered from electricity consumers through regulated network tariffs or dedicated capacity charges. How these costs are allocated across consumers (or their suppliers) however differs considerably. Most capacity mechanisms recover costs through volumetric charges based on electricity consumption (€/MWh) covering large periods. Some incorporate components focused on consumption during scarcity periods. The latter provide stronger incentives for consumers to reduce demand during periods of system stress, i.e. to provide implicit demand-response. Overall, [53] observes that the current cost recovery methods fail to expose consumers to adequate price signals, and therefore limit the possibility for implicit demand response.

The Italian capacity market is unique in its consideration of demand-response with regard to costs. When introducing its capacity market, Italy argued that payments received for providing explicit demand-response would simply net-out the capacity fee paid by the same consumer. It therefore proposed that qualified demand-response capacity providers should simply be exempted from the capacity fee, rather than both receiving payments and paying for the capacity fee.

Reflections for the Belgian capacity market Unlike other European capacity markets, the Belgian capacity market is currently financed through the federal budget. Capacity providers are remunerated by the TSO, Elia, and the associated capacity costs are covered by the Belgian federal government as part of the financing of public service obligations. This reflects a policy decision intended to shield electricity consumers from a capacity surcharge. As such, cost allocation is neither a barrier nor an enabler for industrial demand-response. In the long term, capacity costs could be allocated to consumers based on their negative contribution to adequacy (i.e. their consumption during scarcity periods). This could constitute a new incentive for implicit demand response, including among some industrial consumers.

4.10 Competition with fossil resources

In the previous sections, we discussed several solutions to adapt to, and potentially favor, demand-response participation in capacity markets. Fossil plants, namely gas-fired plants, remain the major players and competitors in capacity markets. An alternative approach to favoring non-fossil resources for decarbonisation purposes, is restricting (or disfavoring) fossil resources participation.

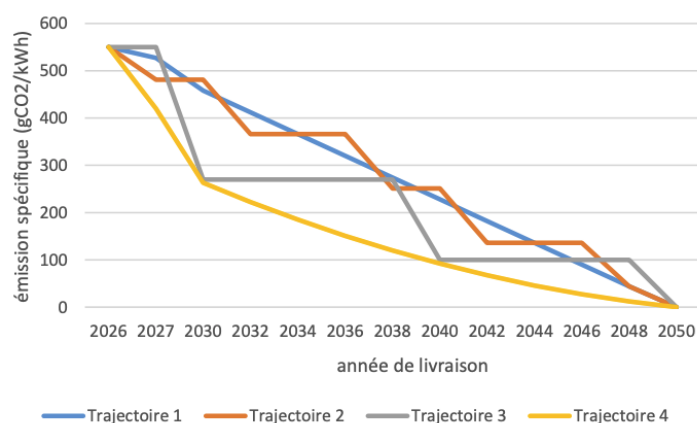


Figure 3: Ensemble des trajectoires de diminution de la limite d'émission spécifique de 2027 à 2050 dont l'analyse est aboutie

Figure 4.5: Proposed trajectories for the CO2 emissions limit. Source: [2]

Current EU State Aid framework The Electricity Regulation introduced two CO2 emissions limits on the energy content (550kgCO2/MWh), and average capacity content (550 kg CO2 of fossil fuel origin on average per year per installed kWe). As of 2019, no new generation capacity breaching the energy content limit was allowed for a new capacity remuneration contract. As of 2026, no existing generation capacity breaching either the energy, or capacity content limit, can be granted a capacity contract.

The CEEAG [43] moreover requires Member States to consider strict requirements for gas-fired plants *"Member States must explain how a lock-in of this gas-fired energy generation will be avoided. For example, this may include binding commitments by the beneficiary to implement decarbonisation technologies such as CCS/CCU or replace natural gas with renewable or low-carbon gas or to close the plant on a timeline consistent with the Union's climate targets."*

Experiences across national Capacity Markets Restricting or disfavoring fossil plants' participation beyond the mandatory EU requirements is not a common feature across EU capacity markets. Most Member States have focused strictly on implementing the CO2 emission limit threshold. A possibility of temporary derogation was introduced in the electricity market design reform, and is currently granted to Poland.

Even if eligible, fossil resources participation can be further framed. Contract duration, for example, can be restricted. The new French capacity market will only grant one-year contracts to fossil resources, while long-term contracts are reserved to non-fossil. Similarly, Poland grants 2-years longer contracts to non-fossil resources. Fossil resources can also be formally required to transition to cleaner alternatives, as suggested by the Electricity Regulation.

Reflections for the Belgian capacity market In Belgium, as in other EU countries, restrictions applied to fossil resources have been limited to the binding EU CO2 emissions limit. Interestingly, Belgium had initially considered and consulted stakeholders on a implementing a more binding CO2 emissions limit. The trajectories proposed in [2]

and illustrated in 4.5 are gradually decreasing towards zero in 2050, to ensure compatibility of the capacity mechanism with carbon neutrality objectives. This proposal was eventually not adopted.

In the long term, further limitations might be necessary to avoid a fossil resources lock-in and achieve carbon neutrality. Further restricting fossil resources, currently the most important players in the Belgian capacity market, could eventually create more opportunities for non-fossil capacity providers such as industrial demand response.

4.11 Beyond capacity markets

Capacity markets focus on the remuneration of a specific system service: availability during scarcity periods. However, the value of industrial demand-response may go beyond this specific service. It can provide, for example, daily, weekly, or long-duration flexibility. If these services become scarce, their provision could be remunerated through a dedicated support payment.

Current EU State Aid framework The Electricity Market Design reform and the CISAF [44] have allowed Member States to introduce "non-fossil flexibility support schemes" (NFFSS). These schemes can help Member States with achieving their indicative non-fossil flexibility objectives. They should be restricted to new investments in non-fossil resources (including demand-response), and target flexibility services. They should also be properly coordinated with capacity procurement.

Experiences across national support schemes "Non fossil flexibility support schemes" are a relatively new concept. At the time of writing, no such scheme was approved under the relevant CISAF article. However, an important number of measures have been introduced to target non-fossil flexibility in the past years, as reported in [54]. These measures were almost systematically restricted exclusively to battery storage. This breach in technology neutrality can eventually disfavor alternative non-fossil resources such as industrial demand-response. The service targeted also varied, ranging from daily flexibility to ancillary services. In the long-term, non-fossil flexibility support schemes (if introduced) could be open to demand-response. This would offer additional, long-term, revenue streams for industrial demand-response units providing valuable flexibility services.

Another example of support scheme are "interruptibility schemes", which specifically target large-scale demand-side demand-response. The contracted capacity agrees to reduce or disconnect its load upon request by the TSO, in exchange for availability payments fixed from one to multiple years. Historically, such schemes were implemented in several Member States, including Germany, France, Greece, Italy, Poland, Portugal, Spain and Ireland, although many have since been phased out or integrated into broader flexibility or balancing market arrangements. The services targeted have varied, including resource adequacy, contingency reserves, balancing services, or congestion management. Most schemes target large industrial consumers capable of providing rapid and reliable load reductions. ACER notes that dedicated interruptibility schemes can

fragment demand-side participation and should preferably be integrated into existing balancing or capacity markets, reserving standalone schemes for cases where no suitable market product exists or where they are needed to kick-start demand response participation.

Reflections for Belgian support schemes In Belgium, the capacity market is currently the main public support scheme available to industrial demand response. However, it remunerates only capacity availability during scarcity periods, addressing specifically the adequacy need. As the energy transition progresses, additional system and network needs are emerging, such as daily/weekly/seasonal/long-term flexibility, congestion management, and other ancillary services. If existing market signals alone are insufficient for the development of flexible resources to meet these new needs, support schemes might be needed to guide and ensure appropriate investments. This Experience is already observed in other European countries. For example, Italy introduced a dedicated storage procurement mechanism to complement its capacity market. Moreover, the introduction of new flexibility support schemes (if limited to "non-fossil" resources) is now formally allowed by the State Aid Framework. Depending on the outcome of Belgium's Flexibility Needs Assessment (FNA), it may therefore become appropriate to introduce additional support schemes targeting these services. If industrial demand response was eligible, it could provide an important additional revenue stream and potentially support new flexibility solutions.

Chapter 5

Conclusion

The technical-fit exercise in Chapter 1 provides a structured, three-step framework for screening industrial flexibility across eight electricity-market mechanisms. Starting from a compact set of installation parameters, it produces a qualitative fit assessment with an identified principal constraint and groups the mechanisms into broadly accessible, conditionally accessible, and restricted tiers.

Across the assessed cases, the principal differentiators are directional headroom, FAT, process-dependent delivery, availability, and, for congestion management, locational eligibility. Day-ahead trading, intraday trading, and imbalance settlement show the broadest technical fit; aFRR, mFRR, and CRM remain case-dependent; and FCR and congestion management are the most restrictive. Buffering and storage can relax specific process or response constraints, but their incremental capacity and economic value were not quantified. The framework is therefore suitable for prioritising detailed assessment, not for confirming qualification, capacity, or revenues.

Chapter 3 evaluated the impact of three market-design developments on the participation of industrial flexibility in electricity markets: the introduction of FFR, the reduction of balancing-capacity reservation periods, and the reduction of minimum bid-size requirements. Using detailed optimization models for multiple industrial BUCs, the analysis quantified how these changes affect operational dispatch, balancing-market participation, and annual revenues under consistent market assumptions. The results demonstrate that the effectiveness of market-design changes strongly depends on the interaction between product design and the operational characteristics of industrial assets. Market reforms that improve the temporal alignment between flexibility availability and market requirements generally provide larger benefits than reforms that merely reduce participation thresholds. Across the investigated BUCs, the economic value of industrial flexibility is therefore determined not only by the amount of technically available flexibility, but also by how well market products match the operational constraints of industrial processes.

Among the evaluated market changes, increasing the temporal granularity of balancing-capacity procurement provides the largest and most consistent benefit. Reducing reservation periods from the current 4 h products to hourly products substantially increases the amount of reserve capacity that industrial assets can offer, leading to measurable improvements in annual profitability for both investigated BUCs. The analysis further shows that reducing the reservation interval below one hour provides negligible addi-

tional value, suggesting that hourly procurement already captures nearly all economically relevant flexibility while avoiding the additional complexity associated with sub-hourly products.

Reducing the minimum bid size also improves market accessibility by allowing smaller flexibility volumes to participate directly in balancing markets. However, its economic impact is considerably smaller than that of shorter reservation periods. Although both the Aperam ORC and E-boiler are able to reserve additional balancing capacity under lower bid-size thresholds, the corresponding increase in annual profit remains limited because balancing-capacity revenues represent only a small fraction of total revenues and the additional reserved capacity results in only modest increases in balancing-energy activations. These findings indicate that lowering minimum bid sizes primarily removes a participation barrier rather than fundamentally improving the business case for industrial flexibility.

The assessment of FFR illustrates that the value of newly introduced ancillary services depends critically on their product design, compatibility with industrial operating patterns and remuneration. Highly flexible assets, such as battery energy storage systems at data centres, can participate with little interference with existing market activities and benefit significantly from attractive capacity remuneration, although the magnitude of the benefit varies substantially with the assumed capacity price. Conversely, industrial processes with seasonal production schedules or limited availability derive little benefit from annually procured FFR products, even when technically capable of providing the required service. These results demonstrate that procurement schedules and availability requirements can be as decisive as technical eligibility. They should nevertheless be interpreted as illustrative: the model uses a hypothetical product design, adjusted frequency thresholds, quarter-hourly representations of sub-second activation, and perfect foresight, which tends to understate capacity opportunity costs. Actual participation would therefore require product-specific technical validation and an assessment under uncertain activation and realistic capacity-reservation obligations.

Across all analyses, a common observation is that increasing balancing-market participation does not necessarily translate into proportional economic gains. In several case studies, large increases in reserved balancing capacity resulted in only marginal improvements in annual profit because the additional flexibility either generated limited activation revenues or displaced revenues from other electricity markets. Consequently, the amount of reserve capacity alone should not be considered an indicator of the economic value of industrial flexibility. The remuneration structure, activation characteristics, and interaction with other electricity markets ultimately determine whether additional flexibility creates meaningful value. The results also suggest that market reforms aimed at improving the accessibility of balancing markets should prioritise reducing temporal participation constraints over lowering minimum bid-size requirements. At the same time, the design of emerging ancillary services, such as FFR, should account for the operational characteristics of industrial demand to maximise participation. These findings provide practical guidance for TSOs, regulators, and market designers seeking to increase the contribution of industrial flexibility to future power systems while maintaining efficient and competitive balancing markets.

Chapter 4 explored the valorisation of Industrial Demand Response in the Belgian CRM. Compared to other European examples, the Belgian CRM already incorporates

several features that facilitate demand-response participation, including a relatively flexible qualification process, advanced probabilistic de-rating methodologies, and the exemption from the reliability option payback obligation. Nevertheless, others barriers remain. These are often not related to market access itself, but to specific design choices that create disproportionate risks, or fail to recognise the characteristics of industrial flexibility. This includes, in particular, limited access to multi-year contracts, uncertainty surrounding de-rating factors, the pay-as-bid auction design, over-delivery penalties linked to declared prices, and the limited liquidity of the secondary market.

Looking ahead, the recent evolution of the EU State Aid framework provides Member States with greater possibilities to adapt support mechanisms as electricity system needs evolve. At present, the Belgian CRM is designed to remunerate availability during yearly scarcity periods, reflecting the current assessment that resource adequacy is the primary system need requiring public support. In the future, other flexibility needs such as long-term storage, ramping, or congestion management, could also require public support. Whether they do require additional remuneration depends notably on future evidence of unmet system needs, i.e. the outcome of Belgium's Flexibility Needs Assessment. Such additional support schemes could open new revenue streams for industrial demand response, and valorize their contribution to system needs beyond adequacy.

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