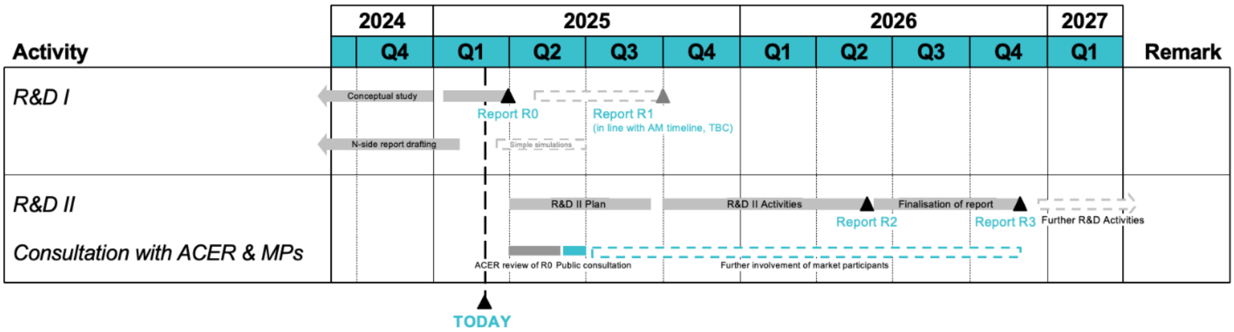
Co-optimisation of energy and balancing capacity in SDAC

Phase 1 R&D report (R0) on bidding products, bid design and pricing

May 16th 2025

EXECUTIVE SUMMARY

Currently, balancing capacity is procured by TSOs mainly on a national basis, with procurement taking place separately from the single day-ahead market (SDAC) in most countries. However, following Electricity Balancing Regulation, SDAC algorithm should incorporate a functionality to allow co-optimisation of energy (SDAC) and balancing capacity. In this case, the resources that supply balancing capacity and energy can be optimised together. Also, cross zonal capacity will be split optimally between energy and balancing capacity. This means that there is no need to use uncertain SDAC price forecasts during bidding and procurement of balancing capacity. However, there are many open issues related to this solution, and ACER Decision 11/2024 on the Algorithm Methodology (AM) therefore requires R&D on co-optimisation in three phases as shown in the figure below.



The present report, referred to as R0 in the Algorithm methodology (AM) is the first of the two reports of the initial Research and Development (R&D) phase, targeting bidding products, bidding formats and pricing. The report builds on a conceptual study performed by N-SIDE but includes relevant NEMO and TSO comments and additions.

The introduction of co-optimisation represents a significant redesign of the existing SDAC framework. This change has substantial implications for market efficiency and will impact the organization that has been in place for over a decade. Therefore, any potential benefits of applying co-optimisation in SDAC must be assessed and evaluated through a step-by-step R&D approach, considering the specificities of the EU energy and balancing capacity markets. Existing markets in, among others, the US have a very different fundamental structure, and do not serve as relevant examples.

The present research is a joint effort between NEMOs and TSOs under the governance of the Market Coupling Steering Committee (MCSC) in close alignment with relevant ENTSO-E working groups.

For co-optimisation to be efficient, it is of crucial importance that bid formats are able to reflect the cost structures of the portfolios or assets providing balancing capacity (and energy). While the cost structure of traditional generation assets is well-known, it is expected that e.g. batteries and demand response will provide significant shares of balancing capacity in the future. To learn more about cost structures, an informal survey with follow-up interviews among market participants was organised, and results are reflected in the report.

Bidding products

Beside the existing energy products in SDAC, it is necessary to include four new balancing capacity products in co-optimised SDAC, respectively automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR), upward and downward.

The cost of providing balancing capacity is normally dominated by an opportunity cost, i.e. the loss of profits by not being able to use the same capacity for energy production. There are two general options to set-up the bidding structures with respect to including balancing capacity bids into SDAC energy bidding structures: implicit bidding and explicit bidding.

With the so-called “implicit bidding”, market participants do not include opportunity costs in their bids. These costs are directly considered by the clearing algorithm. Because provision of balancing capacity sometimes also leads to other, fundamental costs, the possibility to add a premium for balancing capacity to the implicit bids must be given.

Another possibility is “explicit bidding”, where market participants include the opportunity costs in their bids.

There are several issues identified with the explicit approach, and implicit bidding is therefore clearly identified as the preferable option but complemented with a possible premium by the market participants for balancing capacity. This also allows for energy-only or balancing capacity-only bids.

Bid design

To maximize social welfare, it is crucially important that the bid design allows for a correct representation of fundamental costs and technical restrictions of the underlying assets or portfolios. Co-optimisation presents a challenge in terms of identifying a suitable bid design that can adequately capture the intricate interdependencies between balancing capacity and energy. The report considers two different bid design concepts to represent interdependencies, linked bids and combined bids.

Linked bids refer to a family of bids for single products, either for energy or balancing capacity, connected by “links” modelling specific acceptance interdependencies. Two types of links are already available in EUPHEMIA today, and two new types are proposed for further investigation during R&D on co-optimisation. Together, these link types can represent many different cost structures. However, this comes at the cost of significant complexity for market participants, and potentially increased computation times due to many binary variables.

Combined bids offer multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid. Combined bids simplify the task of representing typical cost structures and technical constraints. Such bids would be tailored to specific assets such as thermal generators or storage assets.

The two types of bids are not exclusive, both approaches may be implemented in a clearing mechanism and used by market participants. The concept of linked bids is very flexible and able to describe many different configurations, while combined bids are easier to use because they are directly related to specific assets, and they are expected to be more efficient from a computational perspective.

It is emphasized that combined bids do not imply unit bidding. While combined bids may be used for particular units, they may also refer to a group of units, or entire portfolios.

Pricing

Under marginal pricing, in the absence of “non-convexities”, the welfare-maximizing market outcome ensures that no participant would prefer a different allocation of their bids at the resulting marginal prices. However, several non-convexities exist in power markets and are expected to be even more prevalent for balancing capacities due to the way they are supplied. Non-convexities prevent the straightforward use of marginal pricing and dual variables to determine market-clearing prices, as they preclude in general the existence of uniform market prices supporting a competitive market equilibrium.

Non-convexities often result in so-called Paradoxically Accepted Bids (PABs) or Paradoxically Rejected Bids (PRBs), meaning that e.g. sell bids with bid prices above the market clearing price are accepted, or alternatively sell bids with bid prices below the market clearing price are not accepted. A straightforward solution, also applied in SDAC today, is rejecting all bids that would lead to PABs, and this is the proposed solution for the co-optimised market. However, this has two undesirable effects: a reduction of liquidity (because bids are excluded) and, for the same reason, a reduction in social welfare. Simulations on realistic data sets representing the European market are required during upcoming R&D to find out the severity of these problems. If this solution is not acceptable, a proposed alternative is Non-Uniform Pricing, meaning that PABs will receive some form of side-payment to ensure that they cover their bidding costs. Other alternatives may become relevant in the course of next R&D phases.

NEMOs and TSOs are particularly concerned about the liquidity aspects of the proposed solution. Moreover, while simulations clearly are required to gain insight into this problem, there is a significant challenge in modelling the balancing capacity bids because relevant empirical data does not exist.

Substitutability of mFRR demand by aFRR is assumed. aFRR is seen as the superior product and can therefore be used instead of mFRR in cases where the price of aFRR should be lower than the price of mFRR. TSOs must be given the possibility to define an acceptable level of substitution.

This R0 report will be submitted for public consultation in May 2025. The results from the consultation will be used to evaluate and update the report and by the end of September 2025, a new version of the report (R1), shall be submitted to ACER including a selection of product design, bid design and pricing in line with the AM requirements.

It is important to note that no final statements on feasibility of co-optimisation as foreseen in the underlying regulation can be made based on this R0 report. Although the R&D work is done in several steps, all R&D areas cannot be viewed in isolation. Therefore, choices may be reconsidered upon provision of new insights in the next phases of the R&D work. After all R&D phases are concluded, the provided outcomes will be used for further discussions among NEMOs and TSOs together with ACER on the next steps on co-optimisation. NEMOs and TSOs remain highly sceptical on the technical and market function feasibility of co-optimisation - especially with regard to the appropriate consideration of multiple constraints on the side of balancing service providers in all kind of bidding regimes.

CONTENTS

1 INTRODUCTION

This joint R&D effort of the NEMOs and TSOs of the MCSC in close alignment with relevant ENTSO-E working groups was initiated following the decision of ACER (Decision 11/2024, 23 September 2024[1]) on the AM[2]. Following the regulatory provisions, NEMOs and TSOs hereby submit the first report (R0). This report covers R&D on the bidding products, bidding formats and pricing and is titled as the R0 report. This is the first report of the required four reports of the full R&D. Other aspects will be addressed in subsequent reports as outlined in ACER's decision.

This report builds on a conceptual study performed by N-SIDE commissioned by MCSC, which is included completely in the Appendix A. This R0 report uses the material provided in the N-SIDE report but adds an introductory part as well as NEMO and TSO comments and additions.

The report starts with providing background information in Chapter 2. This chapter begins with an elaborative explanation of both, the motivation for the R&D and previous work on co-optimisation. Hereafter, the scope of the document is clarified by describing the objective of this R0 report and timeline. To ensure a common understanding, the following Section 2 explains the basic principles of co-optimisation in a European market. This background information is complemented with more details on the approach, covering the governance and the assumptions and limitations of this R&D. The report will also provide insight into the feedback of market participants that was collected through an informal survey as part of the work with this report. Following the background information in Chapter 2, the document then continues with describing the highlights and main findings of the performed R&D in Chapter 3. This is done by first discussing the main fundamentals per R&D topic. This is followed by a summary of research carried out by N-SIDE with the respective reflections and open points from NEMOs and TSOs. In Section 3.4 further considerations to be included in the subsequent consultation with market participants are introduced.

Finally, Chapter 4 summarizes the conclusions of the first R&D as basis for this R0 report and explains the next steps in more detail. NEMOs and TSOs emphasize the fact that the R0 report is an intermediate report, and no final conclusions can be drawn without the consideration of future R&D work.

Disclaimer: Previous communication on co-optimisation has used different terminology. To ensure a consistent future communication, new terminology is introduced in this report. In the presented slides in the recent stakeholder meetings in October and December 2024, the terms "integrated bids" and "explicit bids" are used. This will be replaced in the R0 report by implicit and explicit bidding of endogenous opportunity costs[3]. Other previous studies on co-optimisation also discussed a 1-step and a 2-step approach and in addition unilateral and multilateral linking of bids. Since no prioritisations of markets are considered and following the ACER decisions, this report focuses on what previously was called the 1-step, multilateral

[1] Decision No. 11/2024 of the European Union Agency for the cooperation of energy regulators on amendments to the price coupling algorithm and the continuous trading matching algorithm, including the common sets of requirements, 2024. Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER_Decision_11-2024_Algorithm_Methodology.pdf

[2] Methodology for the price coupling algorithm, the continuous trading matching algorithm and the intraday auction algorithm also incorporating a common set of requirements in accordance with Article 37(5) of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, 2024. Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER_Decision_11-2024_Annex_I.pdf

[3] In this report, "opportunity costs" refer to alternative costs in SDAC, unless explicitly otherwise stated. E.g. the "water value", often used as the alternative cost for storage hydro, is a fundamental cost in the context of this report.

linking of bids (but which terminology now is considered irrelevant), considering the total economic surplus of all markets combined.

Additionally, it is to be understood, that energy means scheduled energy in the context of R0.

The N-SIDE report in Appendix A contains a full glossary explaining the terms.

2 BACKGROUND & OBJECTIVE OF THE CURRENT R&D PHASE

2.1 Background

First work on co-optimisation followed from a relevant decision of ACER for the co-optimised allocation process of cross-zonal capacity (Decision 12/2020, 17 June 2020[4]). The TSOs issued on 17 December 2021 an Implementation Impact Assessment (IIA) Report[5], recommending a further roadmap study based on an algorithm prototype to support the updated SDAC algorithm requirements for co-optimisation. This roadmap study, as a first step for prototyping the basic concept and requirements of co-optimisation, was conducted by the day-ahead algorithm service provider, N-SIDE, in co-operation with the NEMOs and the TSOs and was completed in May 2022. The results of the roadmap study were also utilised for the updated set of requirements[6] for the co-optimisation allocation process submitted by All TSOs and the Harmonised Cross-Zonal Capacity Allocation Methodology[7] (HCZCAM). ACER requested from the NEMOs to take into consideration the latest updates and provide an updated proposal for amending the AM with an aim of introducing the co-optimisation of energy and balancing capacity products and cross-zonal allocation of balancing capacity in SDAC.

During the consultation process for updating the AM (Nov 2023 - Sep 2024), it became evident that introducing co-optimisation of energy and balancing capacity in SDAC is not merely a technical update or an exercise to revise the methodology. As stated by the NEMOs, TSOs, and emphasized by Market Participants during webinars organized by ACER, the introduction of co-optimisation represents a significant redesign of the existing SDAC framework. This change has substantial implications for market efficiency and will impact the organization that has been in place for over a decade.

Therefore, any potential benefits of applying co-optimisation in SDAC must be assessed and evaluated through a step-by-step approach, considering the specificities of the EU energy and balancing capacity markets. Additionally, studies on possible welfare benefits[8] of co-optimisation have important modelling drawbacks and simplifications. These studies also do not fully consider pricing implications and focus primarily on the improved scheduling results

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[4] Methodology for a co-optimised allocation process of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves in accordance with Article 40(1) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 2020. Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER%2520Decision%2520on%2520CO%2520CZCA%2520-Annex%2520I_0.pdf
[5] SDAC MSD Co-optimisation Roadmap Study: Explanatory note, 2022. Available on: https://www.nemo-committee.eu/assets/files/co-optimization-roadmap-study-.pdf
SDAC MSD Co-optimisation Roadmap Study: Explanatory note, 2022. Available on: https://www.nemo-committee.eu/assets/files/co-optimization-roadmap-study-.pdf
[7]Methodology for harmonising processes for the allocation of cross-zonal capacity for the exchange of balancing capacity or sharing of reserves in accordance with Article 38(3) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 2023. Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER_Decision_11-2023_on_HCZCAM-Annex%20I.pdf
[8] A. Papavasiliou, D. Avila, 2024. Welfare Benefits of Co-Optimising Energy and Reserves. Available on: https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_Cooptimisation_Benefits_Study_2024.pdf

inherent in a co-optimized allocation process, and moreover, do not consider the future market structure with very high levels of weather-dependent generation and storage.

The updated AM outlined in ACER's Decision 11/2024 acknowledges the need for further research and development before introducing the co-optimisation. This was result of close cooperation at the working level between the NEMOs & TSOs of the MCSC, ENTSO-E and with ACER, as well as review and update of the Common Set of Requirements of SDAC for the introduction of co-optimisation. Thus, the updated AM only contains obligations for R&D but no requirements for the implementation of co-optimisation. This R&D approach is now framed under the updated provisions of Article 4 of the AM.

More details in the background of the AM update may be found in the ACER Decision 11/2024[9].

2.2 R&D objectives and timeline

As discussed during the public consultation and working-level meetings with ACER, an appropriate approach for introducing co-optimisation in SDAC, and subsequently in the AM, would initially involve conducting a relevant R&D phase to assess important missing items as follows:

- Product design, bid design and pricing are the most important theoretical R&D items, fundamental for the whole R&D process and affecting the time plan.
- The timeline of R&D work should be adequate for such an endeavour and divided in a series of milestones (step-by-step approach).
- The relevant methodologies (AM, terms and conditions for SDAC products and for Standard Products for Balancing Capacity (SPBC)) should be revised only once the R&D work is completed and amendments were identified as necessary.
- The scope of R&D work should be extended by including bid information exchange and bid management activities between NEMOs and TSOs.

The above requirements are now included in Article 4, par.15 of the AM mandating all NEMOs, in cooperation with all TSOs, to carry out R&D at least in the following areas:

a) *product design which captures intertemporal and cross-product dependencies between SDAC and SPBC;*

b) *bid design which properly reflects at least variable and fixed costs;*

c) *determination of clearing prices for day-ahead energy and SPBC;*

d) *compatibility of 'COOPT' requirements and functionalities with the requirements laid down in the System Operation Regulation;*

e) *compatibility of 'COOPT' requirements and functionalities with the requirements and functionalities denoted as 'EXISTING' in Annex 1 to this Algorithm methodology;*

f) *where the coordinated net transfer capacity approach applies, the possibility to allow cross-zonal capacity allocated to the day-ahead energy market to free up additional capacity for the exchange of balancing capacity or sharing of reserves, when this would allow to maximise the economic surplus;*

[9] Decision No. 11/2024 of the European Union Agency for the cooperation of energy regulators on amendments to the price coupling algorithm and the continuous trading matching algorithm, including the common sets of requirements, 2024. Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER_Decision_11-2024_Algorithm_Methodology.pdf

g) *curtailment procedures;*

h) *back-up and fallback procedures for both day-ahead energy and balancing capacity; and*

i) *bid information exchanges and governance of operation activities between NEMOs and TSOs, including data governance.*

Considering the high importance of the primary design phase under recitals (a-c), the AM mandates NEMOs, in cooperation with all TSOs, to ensure sufficient involvement of market participants in this R&D work. In addition, all NEMOs, in cooperation with all TSOs, shall ensure continuous involvement of ACER in this R&D work.

The timeline for this new R&D phase, considering the intermediate milestones, reports, public consultations with Market Participants and ACER is now defined in Article 4, par.16 and is illustrated in the following figure:

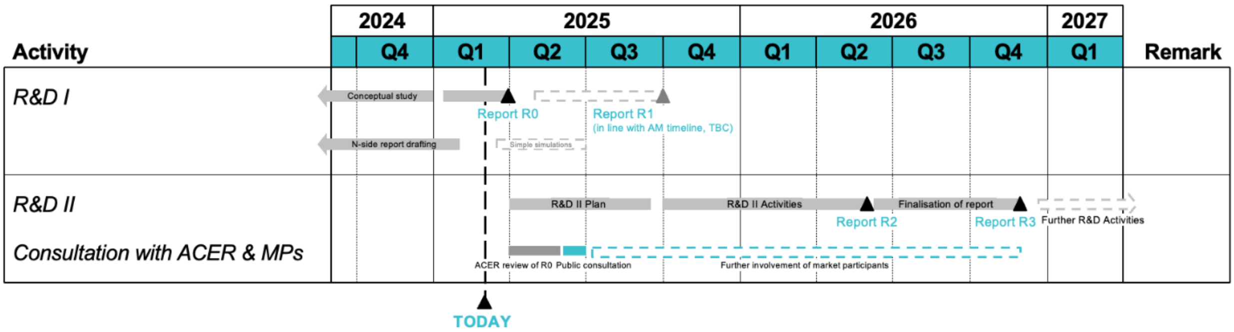

Figure 1 Co-optimisation R&D planning timeline

Although this updated timeline and process may be considered as a more structured and realistic approach, the NEMOs and the TSOs of the MCSC note that as every R&D work, an open-minded procedure would in any case consider possible re-design and allow for additional efforts in case of R&D deadlocks.

2.3 Basic consideration for co-optimisation in the EU integrated markets

2.3.1 The concept of co-optimisation of energy and balancing capacity

The objective of co-optimisation is to achieve a welfare-optimal allocation of Cross Zonal Capacity (CZC) to energy and balancing capacity, by comparing the market values of cross zonal capacity based on the actual day-ahead energy and balancing capacity bids. The concept is illustrated in the figure below.

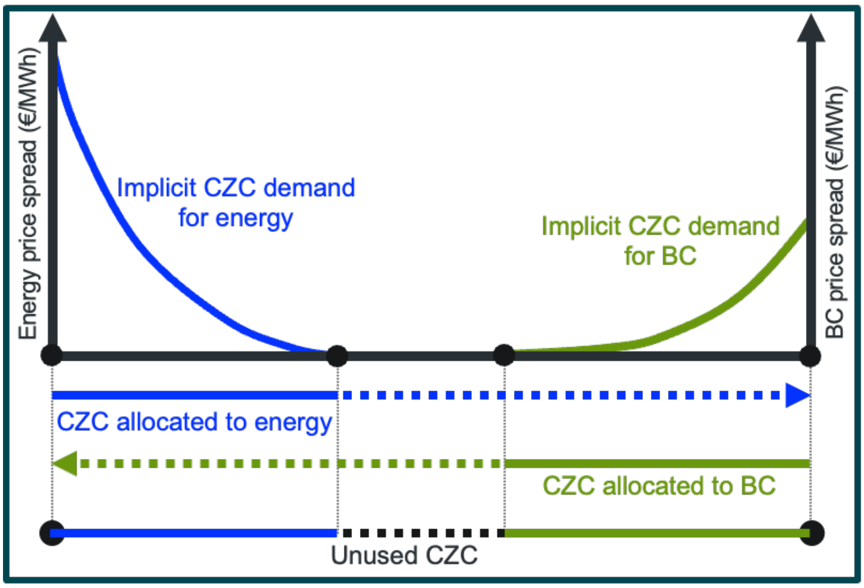

Figure 2 Representation of cross-zonal capacity valuation in a market co-optimizing energy and balancing capacity when the cross zonal capacity between two zones is not fully utilized. The blue line represents the implicit cross zonal capacity demand for energy, and the green line the implicit CZ

Although the figure illustrates price convergence when there is no congestion, prices may still differ between zones because of the inherent non-convex nature of balancing capacity products. For further discussion on this topic, see Section 3.3 or Chapter 3 in the Appendix A.

Note that co-optimisation is not a goal in itself, but a means to provide exchange of balancing capacity between bidding-zones with efficient utilization of cross-zonal exchange capacity as well as the resources providing balancing capacity itself. While co-optimisation is the most efficient solution theoretically, practical implementation has many challenges that are addressed by the current R&D. The (sequential) market-based approach on the other hand, is theoretically less efficient, but does not face the issues related to integration with SDAC, and as such can be seen as lower hanging fruit. In accordance with Article 41 of Electricity Balancing Guideline, both the Nordic and Baltic countries have established the latter approach. To ensure that the market-based approach remains a relevant alternative to co-optimisation, short descriptions of these approaches are given in Section 2.5.

Additionally, in the context of co-optimisation, it is imperative to consider the numerous interdependencies between energy and balancing capacity products. A typical generation unit is a useful example to illustrate these. Such a unit can utilise the same available capacity either for the provision of energy or upwards balancing capacity. The provision of upwards balancing capacity thus reduces the available capacity to provide energy for the same period. In the case of a generation unit, the provision of downward balancing capacity results in a requirement for the unit to provide energy for the same period to enable the reduction of generation. In economic terms, this results in opportunity costs that reflect the lost profit from providing a different energy or balancing product.

The simplified interactions outlined here serve merely as illustrative examples of the underlying interdependencies between energy and balancing capacity products. It is noteworthy that significantly more complex interdependencies emerge when investigating larger portfolios. In theory, co-optimisation enables not only the optimal allocation of cross-zonal transmission capacity, but also the welfare-optimal allocation of resources between energy and balancing products.

In the European electricity market, the concept of co-optimisation has thus far been the subject of R&D and remains in an early stage. There are foreign markets in which co-optimisation has already been established. However, these markets have fundamentally different structures. These include central dispatch and unit-based bidding in particular. When co-optimising energy and balancing capacity products, this makes it easier to account for complex technical constraints and the resulting interdependencies. In addition, co-optimisation in these markets is not limited to the day-ahead timeframe but is carried out in all timeframes. The European market design, on the other hand, is predominantly based on decentralised dispatch and portfolio bidding and co-optimisation, as currently defined in the regulation, is limited to the day-ahead timeframe (while the intraday market still allows trading of energy). This may lead to infeasibility of the implementation in EU market design in case the efficiency of the algorithm suffers too much by handling relevant bids designed to reflect EU market structures.

2.4 Approach of the R&D covering the requirements of the R0 Report

2.4.1 Governance of R&D

The R&D for co-optimisation is a joint effort between NEMOs and TSOs. As the co-optimised approach impacts the Day-Ahead market algorithm (EUPHEMIA), the task was placed under the governance of the MCSC, and under Market and System Design (MSD) for SDAC, and in cooperation with ENTSO-E Market Integration Working Group (MIWG) and Working Group Ancillary Services (WGAS). Co-optimisation also impacts the current procurement of balancing capacity, which is procured differently (if at all) by the TSOs around Europe.

The SDAC MSD Co-opt SG is the working group for the co-optimised market coupling solution design and steering of the contractor, including providing regular updates to stakeholders. The work is periodically reported to the SDAC MSD main group and to ENTSO-E MIWG and WGAS groups. NEMO Technical TF is involved from the AM perspective. SDAC MSD reports the co-optimisation R&D to MCSC and, in cooperation with NEMO Technical TF, in regular meetings with ACER.

The R&D is supported by the algorithm service provider N-SIDE, who is responsible for the conceptual study, included as an Appendix A of this report. The cooperation between the Co-opt SG and N-SIDE is discussed in further detail in Section 2.4.2. covering the R&D approach.

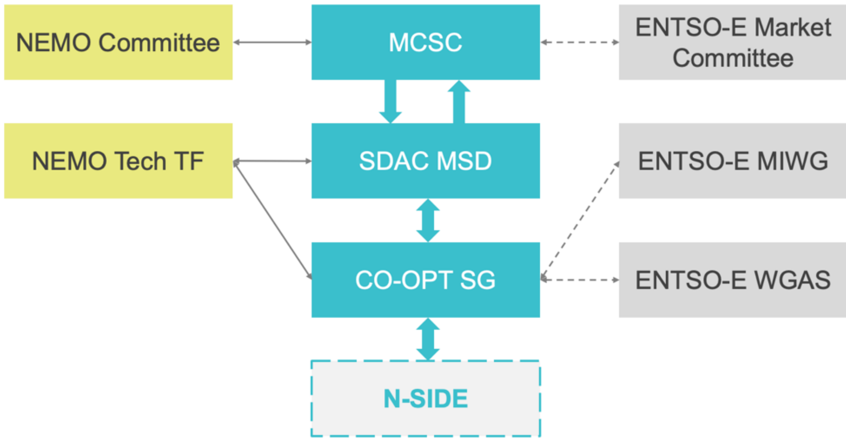

Figure 3 Governance of R&D

2.4.2 R&D approach

As referred in Section 2.2, the present R&D has been initiated based on the ACER Decision 11/2024 on the AM. The first phase of the research is summarised in the present report, which covers the topics: product design, bid design and pricing. The aim of the R&D, especially in this early stage, is not to provide a full-fledged solution for implementation and there is indeed still much to investigate in the future phases of R&D before any steps towards an implementation can be taken.

The relevant research referred to as the Conceptual Study and included in Appendix A of the report, has been conducted by N-SIDE. At an early stage, it was agreed that the work should focus on specific, small sized use cases. On the one hand, this facilitates in-depth, detailed analysis and understanding, while on the other hand such use cases serve a pedagogical purpose in explaining the various concepts. NEMOs and TSOs thus defined a number of use cases, divided in four categories, including a Base Case, Asset Variety, Cross-Zonal Exchange and Balancing Capacity Products and specific questions to address within each category.

N-SIDE subsequently started work with their report, working with the main concepts (product and bid design, pricing), while developing illustrative examples based on the use cases. N-SIDEs report and progress was reviewed regularly by the Co-opt SG under SDAC MSD and was developed in continuous cooperation including several workshops. A timeline of the R&D is shown in Figure 3. Although there were some minor delays, the overall schedule reflects the work reasonably well.

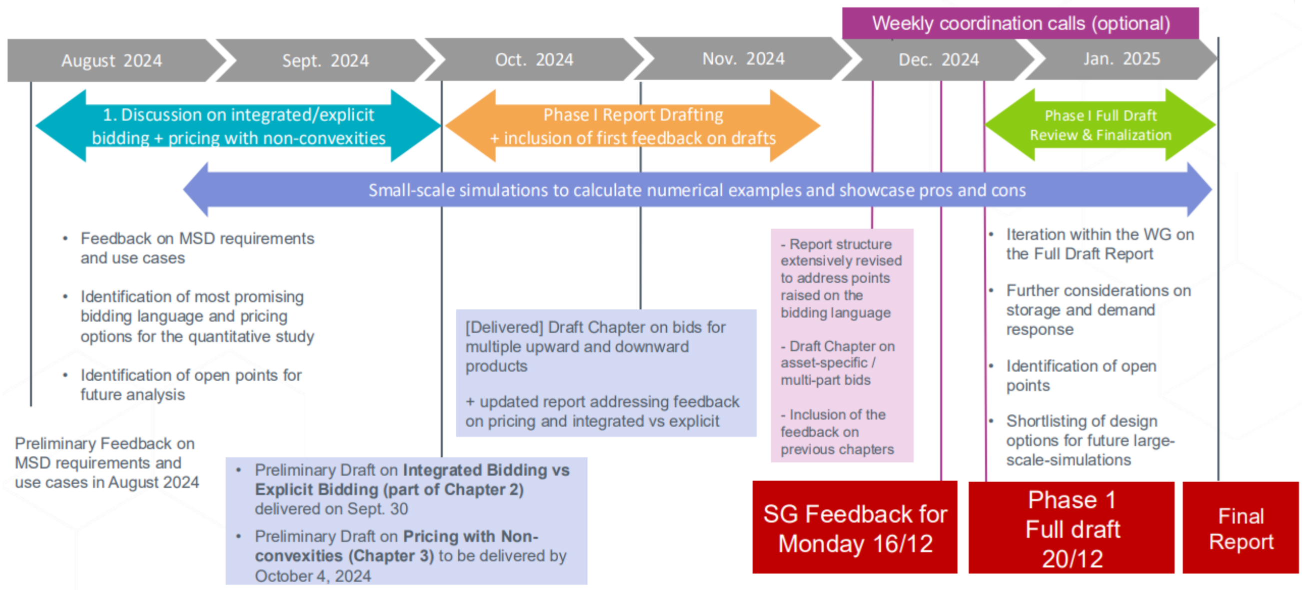

Figure 3 Timeline of the first R&D phase

Most of the objectives for the use cases were met, with the notable exception of the scheduling capabilities of the market participants and the impact of bid design and pricing options on the allocation of cross-zonal capacities.

For co-optimisation to be efficient, it is of crucial importance that bid formats are able to reflect the cost structures of the assets providing balancing capacity (and energy). While the cost structure of traditional generation assets is well-known, it is expected that e.g. batteries and demand response will provide significant shares of balancing capacity in the future. To learn more about cost structures, an informal survey was held, see Section 2.4.4.

The N-SIDE report, included in the Appendix A, has the following main chapters:

1. Introduction
2. Product design – implicit versus explicit bidding
3. Bid design – linked and combined bids
4. Cross-zonal capacity allocation in a co-optimisation setup
5. Pricing with non-convexities
6. Additional topic for future analysis
7. Conclusions

A summary of the N-SIDE report is included in Chapter 3 of this report.

2.4.3 Assumptions and limitations of the study

Assumptions

1. The study focuses on how co-optimisation can be implemented with respect to product and bid design and pricing and does not question if this is technically or otherwise feasible and desirable from a market functioning and welfare economic point of view. Challenges like e.g. computational feasibility will be addressed in later phases of the R&D work.
2. As it has been difficult to obtain in-depth information on cost structures of relevant future assets, it is assumed that the proposed bid formats largely will cover market

participants' needs acknowledging the difficulty to adequately represent their actual physical and technical constraints within the suggested bidding formats. The subsequent consultation will allow market participants to elaborate on such needs and possible concerns.
3. The objective of the market design is to provide market outcomes that maximise social welfare.
4. In general, a well-functioning market with a reasonable level of competition and barriers to entry levels similar to today is assumed.

Limitations

1. The principles of the study are developed based on small examples with few assets. At this point, it is assumed that these are representative also for models of realistic size, and hence that the model outcomes apply to a real world setting with e.g. large portfolio bidders. This needs to be proven at a later stage.
2. While possible strategic bidding behaviour of market participants is discussed several places, no in-depth analysis has been done on this topic.
3. Under pricing options, Non-Uniform Pricing is addressed in general and some examples provided, but without a comprehensive overview over the many approaches from the literature.
4. Chapter 2 of the Electricity Balancing Guideline and in particular Article 40 on the co-optimised allocation process, refer to "the exchange of balancing capacity or sharing of reserves". This report only addresses the exchange of balancing capacity. The sharing of reserves is explicitly mentioned as a topic of research in the AM (Annex 1), and it is the intention of TSOs and NEMOs that the sharing of reserves is looked at in a later stage of R&D work. Both NEMOs and TSOs consider this relevant for the R&D effort to be comprehensive.
5. It is presently not clear whether market participants will be able to adequately represent their actual physical and technical constraints within the suggested bidding formats in order for the co-optimisation to yield actual and not just quasi-optimal solutions.

2.4.4 Collecting Market Participants' feedback

Throughout the initial R&D phase, NEMOs and TSOs were obliged by regulation to incorporate market participants' input to a sufficient degree,[10] although a formal public consultation was not required until the R0 report's completion. NEMOs and TSOs actively sought engagement with market stakeholders, particularly on cost structures and bid design, because early-stage feedback from participants was regarded as highly valuable. Specifically, NEMOs and TSOs have taken an interest in engaging with parties who own assets such as renewable power plants, batteries, and demand response systems, because the cost structures of these assets are less well understood than those of more traditional generation. The objective was to receive input for drafting a robust and efficient bidding language and bid formats, aiming at reflecting the practical insights and requirements of market participants operating a range of different technologies in different EU market areas. Therefore, to inform and develop recommendations for the R&D, including the conceptual

[10] ACER Decision 11-2024 on the AM Annex 1 Article 4(15): https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER_Decision_11-2024_Annex_I.pdf

study by N-SIDE, NEMOs and TSOs engaged with market participants through a survey. The survey was followed by seven in-depth interviews, a webinar and a workshop during September to December 2024.

NEMOs and TSOs consider the engagement of market participants to have positively contributed to the R&D work and are grateful to all stakeholders who have taken an interest. The process has provided many insights relevant for the R&D work. A more detailed description of the inputs received is summarized in Appendix B. While generally useful information was received and different perspectives on necessary parameters for the bid design options were provided, it also appeared difficult to obtain highly specific information on cost structures in detail at this early stage. At a very high level, market participants were explicit about general concerns for co-optimisation. This was fundamentally about market participants questioning whether a single co-optimised bid design may provide the same level of flexibility as current market sequences and bidding structures. Market participants raised the concern that a potential inability to represent their assets effectively might increase the risk of sub-optimal allocation. This is particularly relevant for specific technologies with complex non-linear costs, but it is noted as a general concern. Through the survey and interviews, NEMOs and TSOs thus gathered input regarding the bidding formats and the input that market participants thought would likely need to be included in the bid design. Key points were shared with N-SIDE and have affected the conceptual study. For a description of the involvement of market participants, please refer to Appendix B.

2.5 The market-based approaches in the Nordic and Baltic countries

Although methods for procuring balancing capacity vary considerably across Europe, most countries continue to procure reserves on a national basis. Nevertheless, a few cross-zonal and cross-border capacity markets are already successfully in operation. NEMOs and TSOs view the experience from these markets as valuable inputs to their R&D activities. Accordingly, the following sections offer observations on two existing markets as the lessons learned will help guide the future design of balancing capacity markets, including co-optimisation research.

2.5.1 The Nordic market for FRR capacity

The Nordic balancing capacity market started operation in December 2022. It is an hourly market running on the morning of D-1. For the purpose of transparency, the TSOs use a reference day approach for the forecast of SDAC prices in their valuation of cross-zonal capacity.

Divisible and indivisible hourly bids, as well as block bids, and exclusive links for the same regulation direction are allowed. Market participants can set exclusivity between aFRR and mFRR to prevent double acceptances, as both close at 07:30.

Bids are selected by an algorithm that minimises the total provision cost of selected bids while respecting available cross-zonal capacity values and reservation limits. Congestion rent is used as a proxy for increased total energy costs following the reduced CZC for SDAC, assuming that market prices and volumes are not impacted by the reduction of CZC. Up to 10% of available transmission capacity may be used for the exchange of balancing capacity (EBGL Article 41.2). In case of a lack of bids to satisfy demand in a bidding zone, up to 20 percent of the available transmission capacity can be reserved.

The calculation of market prices is done in the last step of the market algorithm, when bids have been selected and the cross-zonal capacity allocated, and all accepted bids are settled as cleared.

The Nordic experience shows design challenges that are also relevant for co-optimisation:

- It is challenging to design bid formats that facilitate the representation of supply costs. Opportunity costs of balancing capacity are strongly non-convex, mainly due to indivisible cost elements, but also other complex relations.
- Optimal selection of bids is computationally challenging. With non-convex costs, there exist no prices that clear markets efficiently. Market prices depend on chosen principles, not only on supply and demand.

The Nordic balancing capacity market for aFRR has performed satisfactorily and increased social welfare, but several challenges remain, mostly related to a large share of indivisible bids and resulting issues with determining relevant prices.

A trilateral market for mFRR balancing capacity between Energinet, Fingrid and Svenska Kraftnät was also started in 2024.

2.5.2 The Baltic market for FRR capacity

The Baltic TSOs (Elering of Estonia, AST of Latvia and Litgrid of Lithuania) went live with their market-based Baltic Balancing Capacity Market ("BBCM") in February 2025. While inspired by the Nordic markets, the BBCM features several design decisions which adapt the market-based methodology to the needs of the Baltic context.

Baltic TSOs make use of sharing of reserves – one bid can be used in parallel to satisfy the demands of all three TSOs. This allows the Baltic TSOs not only to use the market-based methodology to cover the reserve demands in an efficient way, but also to procure less.

On the Baltic internal borders, up to 50% of available cross-zonal capacity can be allocated for the exchange of balancing capacity and sharing of reserves under normal market circumstances. The possibility to allocate significantly more cross-zonal capacity for balancing capacity products is coupled with a more nuanced cross-zonal capacity value forecast function.

Similarly to the Nordic markets, Baltic TSOs have taken note of challenges related to intuitive price formation and paradoxically rejected bids related to non-convexities in the bid design. The effects are somewhat more pronounced in the Baltic context due to smaller liquidity. Baltic TSOs acknowledge that more intuitive market results could be possible through some arrangements or changes in market design, but every change entails a sacrifice of transparency (due to more complicated side processes) or economic efficiency.

3 CONTENT HIGHLIGHTS AND FINDINGS

Following the overview of co-optimisation and the description of the current R&D process in the preceding chapters, this chapter will elaborate on the main subject of this R&D phase, points a- c of Article 4 par. 15 of the AM:

- *Product design which captures intertemporal and cross-product dependencies between SDAC and (standard product for balancing capacity (SPBC);*
- *Bid design which properly reflects at least variable and fixed costs;*
- *Determination of clearing prices for day-ahead energy and SPBC.*

There is one section dedicated to each of the aspects listed above. Section 3.1 first elaborates on the proposed bidding products. Sections 3.2 and 3.3 then discuss the bid design and pricing under co-optimisation. Each of these sections follows the same structure. The beginning of each section contains an explanation of the fundamental elements considered for the design. Next, the respective content of the N-SIDE report is addressed, including a summary of their proposal. It should be noted that this R0 report intends to only provide an overview of the design considerations. For a more in-depth understanding and detailed explanations also based on numerical examples, the reader is referred to the attached conceptual study by N-SIDE. Although the N-SIDE report was commissioned by NEMOs and TSOs, it does not necessarily reflect the views of NEMOs and TSOs in every aspect. Therefore, NEMOs and TSOs provide their assessment of N-SIDEs proposals in Sections 3.1.3, 3.2.3 and 3.3.3.

NEMOs and TSOs acknowledge that the subject of a European-wide co-optimisation of SDAC and balancing capacity markets for aFRR and mFRR is not a topic easily comprehended in the relatively short time of the public consultation. Consequently, NEMOs and TSOs have suggested several open points and questions at the end of Chapter 3, on which they will specifically ask for the perspective of market participants during the public consultation. From the perspective of NEMOs and TSOs, this is particularly important, given the concerns that market participants have raised in the past.

3.1 BIDDING PRODUCTS

3.1.1 Fundamentals

With co-optimisation, cross-zonal capacity will be allocated in the day-ahead market coupling process for both energy and balancing capacity. While the energy product will be largely unchanged from the present solution, specific products need to be included for balancing capacity in co-optimised SDAC. Moreover, the relations between these products and their constraints need to be described. This is discussed in Section 3.2. Because aFRR and mFRR are defined as asymmetric products in the Energy Balancing Guideline (EB GL)[11], separate products must be defined for up- and downward regulation. Replacement Reserves (RR) are not included because they will be discontinued with the shortening of the gate closure time of the intraday (ID) market in 2026. Standard products for balancing capacity have in principle already been defined at a generic level[12].

[11] COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 2017. Available on: https://eur-lex.europa.eu/eli/reg/2017/2195/oj/eng

[12] DECISION No 11/2020 OF THE EUROPEAN UNION AGENCY FOR THE COOPERATION OF ENERGY REGULATORS of 17 June 2020 on the Methodology for a list of standard products for balancing capacity for frequency restoration reserves and replacement reserves, Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions/ACER%20Decision%2011-2020%20on%20standard%20products%20for%20balancing%20capacity_0.pdf

The following products are thus relevant for the R&D phase:

- For energy – one product: energy (as in present SDAC)
- For balancing capacity – four products:
  - aFRR up (automatic frequency restoration reserve upward)
  - aFRR down (automatic frequency restoration reserve downward)
  - mFRR up (manual frequency restoration reserve upward)
  - mFRR down (manual frequency restoration reserve downward)

Products for Frequency Control Reserves (FCR) are not included in co-optimisation.

It should be noted that energy and balancing capacity have different characteristics, and that this has an impact in several contexts. Acceptance of an energy product results in an injection or withdrawal (in the day-ahead market) and has a direct impact on the physical flows. Acceptance of a balancing capacity product, on the other hand, results in a reservation that might or might not result in an injection or withdrawal and physical flows – it just results in the obligation of the BSP to submit an equal volume of balancing energy bids of the respective product to its connecting TSO. One important result is that balancing capacity flows cannot be "netted", i.e. a flow in one direction is not annulled by a flow in the opposite direction, which is the case with energy flows.

The balancing capacity bid costs are assumed to include the cost of reservation of balancing capacity. On the other hand, the costs of activation will be included in the subsequent balancing energy bids.

3.1.2 N-SIDE Proposals

The N-SIDE report highlights the clear distinction between providing upward and downward balancing capacity: Upward reserves are activated to solve negative imbalances and vice versa, downwards for positive imbalances. The report also points out the different activation methods between aFRR and mFRR services. Lastly, the report suggests that standardization of the products is key, and no local products should be included in the design.

Bidding products are related to the notion of "implicit" versus "explicit" bidding. In the implicit approach, the market participants do not include opportunity costs in their bids. These costs are directly determined and considered within the clearing mechanism, cf. the previous section. However, provision of balancing capacity may also incur other costs. This may either be purely fundamental costs (e.g. running the unit at lower efficiency to be able to provide the balancing energy) or a loss of flexibility to trade in Intraday (which the SDAC optimisation does not "see" and therefore cannot account for)[13]. Loss of flexibility in ID thus plays a similar role as a fundamental cost for market participants when bidding in co-optimised SDAC because ID opportunities are not included in the co-optimisation. To address this issue, it is proposed to give the possibility to market participants to add a premium for each balancing capacity product to the implicit bid.

In the explicit approach, market participants include at least all opportunity costs in their bids. There are several issues identified with the explicit approach, such as forecasts errors of the day-ahead energy price degrade social welfare, the single-product merit order of bids for given product may not be respected, the market outcomes may be suboptimal for participants ex post, etc. Details are provided in the Appendix A. Due to these issues, implicit bidding is clearly identified as the preferable option in combination with a possible premium and is used in the analysis of the use cases in the remainder of the report.

[13] Having capacity available in the Intraday market is a profit opportunity. If profitable trade options occur, you can utilize them. If not, there is no downside. Consequently, there is an option value in having available capacity for Intraday, and with locking in this capacity for the balancing c apacity market, this value dissapears. This option value is exogenous to SDAC, but it still is a potential cost of offering balancing capacity. Therefore, market participants may require the possibility of a premiom to take into account this option value.

3.1.3 Reflections from NEMOs and TSOs

NEMOs and TSOs agree with the proposal from N-SIDE regarding product design. Full compliance with the established "list of standard balancing products for balancing capacity" in accordance to Article 25(2) of EB GL and the ACER Decision on SPBC[14] may not be possible (due to the explicit requirement to bid volume and price).

NEMOs and TSOs agree with the proposal for implicit bidding, as the issues related to explicit bidding are severe and inconsistent with an efficient market design.

The N-SIDE report in Appendix A differentiates between two categories of costs, "endogenous costs" created within the auction (essentially opportunity costs of balancing capacity for inframarginal and extramarginal SDAC suppliers) and "fundamental costs" including all other costs such as fuel costs, variable maintenance costs and wear&tear (but also lost opportunities in other auctions). The fundamental costs may have different structures:

- Costs per power output and time, typically fuel costs. The average cost per MW typically varies over the range of output, leading to increasing return to scale (IRS) from the minimum generator output. The IRS are a source of non-convex costs from the point of view of a market algorithm.
- Costs per time. This might be the impact on maintenance cost of hours of operation.
- Costs per startup. This might be the impact on maintenance cost of the number of startups, and it might be the energy loss (typically heat) from a generator before it is phased on to the grid, and after it has been phased off. The startup costs also represent non-convex costs for the market algorithm.

Market design as a tool for efficient resource allocation should have economic surplus in focus. For a market to maximize economic surplus, the algorithm needs information on adequate priced bids based on fundamental costs. The opportunity costs, on the other hand, are calculated during the optimisation, i.e. in the assumed co-optimised SDAC market clearing, and they should not be provided by market participants.

It can be assumed that the procurement of balancing capacity has a negligible impact on the consumption of energy. Therefore, the optimization of balancing capacity, wholesale energy and cross-zonal capacity can be considered "total cost minimization" from the balancing capacity point of view.

Furthermore, it is worth mentioning that there will be energy-only and balancing capacity-only bids, that will be fully supported by the proposed structures.

NEMOs and TSOs agree that, with implicit bidding being the preferred option over explicit bidding, an additional premium is necessary to allow for the inclusion of specific fundamental costs for balancing capacity. This allows market participants to include costs such as specific costs for facilitating the specific supply of balancing capacity or the potential loss of profits in the Intraday market. Not offering this possibility, would make it impossible to correctly reflect such costs in the bids. A premium also allows market participants to include other, not presently foreseen costs that are not considered in SDAC. On the other hand, it also allows them to include opportunity costs for balancing capacity, which must be strongly discouraged through clear and concise information. In case of a competitive market, this would in any case not be a profitable strategy for a market participant.

[14] Methodology for a list of standard products for balancing capacity for frequency restoration reserves and replacement reserves in accordance with Article 25(2) of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 2020. Available on: https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER%2520Decision%2520SPBC%2520Annex%2520I_0.pdf

3.2 BID DESIGN

3.2.1 Fundamentals

In principle, within a market design, bids are intended to enable market participants to express their economic preferences and technical constraints. In the simplest case, bids can consist of a price-quantity pair. On the other hand, bids can also contain a large number of parameters to enable a detailed description of underlying physical properties. Either way, the development of a bid design that allows for adequate representation of the relevant economic and technical factors is a prerequisite for optimal market results. While approximations and simplifications will always be necessary and acceptable, every effort should be made to facilitate the provision of fundamental costs as accurately as possible.

Co-optimisation presents a challenge in terms of identifying a suitable bid design that can adequately capture the intricate fundamental interdependencies between balancing capacity and energy. The specific proposals regarding bid design that were developed together with N-SIDE as part of this R&D phase are presented in Section 3.2.2.

It should be noted that NEMOs and TSOs have taken the existing underlying European market design, predominantly portfolio bidding, as a premise. The proposed bid design options are mostly based on the existing bids and established structure in SDAC. It is important to note that even sophisticated market algorithm cannot deliver true maximisation of economic surplus if the input data is suboptimal.

3.2.2 N-SIDE Proposals

The N-SIDE report in Appendix A considers two different bid design concepts to fundamentally represent interdependencies, linked bids and combined bids.

Linked bids refer to a family of bids for single products, either for energy or a given balancing capacity product, connected by "links" modelling specific acceptance interdependencies. Two types of links have already been implemented in EUPHEMIA.

Currently, these links are used to represent advanced portfolio cost structures. They already allow to represent fundamental interdependencies between balancing capacity and energy. In case of a typical generation asset, capacity can either be used to provide energy or upward balancing capacity. This can be represented by an **exclusive link** where the acceptance of one bid is conditioned on the rejection of another. On the other hand, providing downward balancing capacity is conditional on the fact that a generation asset is already running. This results in the need for a **parent-child link** between the corresponding balancing capacity and energy bid. With this type of link the acceptance of the one bid (i.e. the parent) is a prerequisite to the acceptance of another (i.e. the child).

In addition to the existing link types, two new links are proposed to be introduced:

- **Exclusive links with maximum power:** The total accepted power from all the bids linked should not exceed the provided maximum power of the link.
- **Loop Link** (Double sided parent-child link): Both bids should be simultaneously accepted or rejected together.

Together, these link types can represent many different cost structures. However, this comes at the cost of significant complexity for market participants, and potentially high computation times due to many binary variables. A more detailed description of the proposed links including numerical examples is given in Chapter 3.1 of the N-SIDE report.

A **combined bid** simultaneously offers multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid. Combined bids might be able to simplify the task of representing typical cost structures and technical constraints, since they provide fully equivalent but easier to use alternatives to linked bids. The cost structure of a unit with minimum stable generation that is also able to provide upward, and downward balancing capacity can be fully represented by a combined bid modelled as the following example below (reproduced from the N-SIDE report):

Activation Cost	Variable Price	Min. Power (Energy)	Max. Power	Max. Up. BC	Up. BC Price	Max. Down. BC	Down. BC Price
15 €	60 €/MWh	50 MW	250 MW	100 MW	5 €/MWh	100 MW	5 €/MWh

This bid automatically and efficiently resembles the relevant constraints within the algorithm.

The concept of combined bids allows to extend existing bids (Step Bids, Interpolated Bids, Block Bids, etc.) to a co-optimised market including balancing capacity features (see Chapter 3.2.2 of the N-SIDE report in Appendix A). Besides extending the existing bids for co-optimisation, N-SIDE proposes to introduce specific combined bids for thermal assets, storage assets and potentially other assets. It is necessary to define proper types of combined bids, based on input from market participants.

It is worth noting that linked bids and combined bids are not exclusive, both approaches may be implemented in a clearing mechanism and used by market participants. The concept of linked bids is very flexible and able to describe many different configurations, also many that at the same time will be covered by combined bids. However, combined bids will be easier to use because they are directly related to specific assets, and they will also be more efficient from a computational perspective.

It needs to be emphasized that combined bids do not imply unit-based bidding. While combined bids proposed in the Appendix A look like bids for particular units, they do not necessarily refer to particular units, e.g. they may refer to a group of units, or entire portfolios. The proposed bid types are based on the first research done by N-SIDE and feedback from the informal survey and interviews, see Appendix B. Additional feedback from market participants is needed to be certain both fixed and variable costs can be reflected in the bidding language.

3.2.3 Reflections from NEMOs and TSOs

The combination of bid linking and combined bids appears to offer a broad range of possibilities to describe fundamental costs, although it is difficult to see to what extent they are sufficient. This is a very important issue, because the expected efficiency of co-optimisation is totally dependent on the ability of the bid design to describe costs. There is also a concern that a potential inability to represent costs correctly will result in higher bid prices to account for uncertainty, and that this leads to sub-optimal outcomes. This may affect some bidding zones more than others. These concerns need to be addressed in the further R&D. From the perspective of NEMOs and TSOs it is therefore critical to obtain feedback on the proposed bid designs from market participants as well conducting large scale simulations with the proposed formats in later stages of the R&D. NEMOs and TSOs remain highly sceptical on acceptable solution quality of the algorithm in case large number of complex bids are added by co-optimisation.

3.3 PRICING

3.3.1 Fundamentals

Under marginal pricing, in the absence of 'non-convexities', the welfare-maximizing market outcome ensures that no participant would prefer a different allocation of their bids at the resulting marginal prices. Marginal pricing implies that the market price of a product reflects the marginal system cost increase for serving an additional unit of that product. This broad principle also applies in a co-optimisation setting where energy and multiple balancing capacity products are auctioned simultaneously. Following this principle, if a resource that can deliver both energy and balancing capacity is optimally allocated to balancing capacity, the balancing capacity market is more (or at least equally) profitable for that resource than the energy market: otherwise, the allocation would be suboptimal for the market participant.

Consequently, the price in the balancing capacity market is attractive enough to offset any potential lost profits in the energy market. This is the key reason why participants submitting bids for multiple products in a 'combined offer' (e.g. multiple bids linked together for energy, aFRR up, aFRR down, etc.) do not need to explicitly account for the opportunity cost of one product when bidding on another, as argued in section 3.1.2 of Appendix A.

Understandably, most real-life problems, and also power markets, include non-convexities. Examples of non-convexities in power markets include start-up costs, integer decision variables for start-up/shut-down, minimum generation levels, minimum up and down times etc.

Non-convexities pose two major challenges:

- In price formation, they prevent the straightforward use of marginal pricing and dual variables to determine market-clearing prices, as they preclude in general the existence of uniform market prices supporting a competitive market equilibrium.
- From an algorithmic complexity perspective, non-convexities often turn what would have been a simple convex optimization problem, into an intrinsically harder and more time-consuming non-convex problem to solve.

Non-convexities in SDAC are not a "new" issue resulting from the introduction of co-optimisation. However, there is reason to believe that non-convexities become more pervasive due to the cost structure of balancing capacity bids and the inclusion of additional constraints and modelling features and links to represent the interdependencies between energy and balancing capacity. Hence co-optimisation may increase the scale of the problems. Markets with non-convexities often result in what are known as paradoxically accepted or rejected bids:

- **Paradoxically Rejected Bids (PRBs):** These are bids that are economically viable given the calculated market prices (i.e., "in the money") but are rejected due to the non-convex nature of the problem. In the current day-ahead market, PRBs are tolerated.
- **Paradoxically Accepted Bids (PABs):** These are bids that are not economically viable given the calculated market prices (i.e., "out of the money") but are accepted, nonetheless. The current day-ahead market design generally prohibits PABs, which in the following is referred to as the "No PAB" design.

3.3.2 N-SIDE Proposals

To address these issues, the Appendix A proposes the following principles:

No PABs: This approach does not allow for PABs for allocation (as in the current day-ahead market). For a given allocation, prices are determined following classic marginal pricing principles (without considering non-curtailable bids: solutions containing PABs are ruled out, while solutions may contain PRBs).

Non-Uniform Pricing (NUP): This approach allows for PABs, with compensation provided through side-payments to ensure that participants are not economically worse off as a consequence. In this design, economic surplus is optimized without explicitly considering the "in-the-money" rules for the clearing prices during the allocation process. PABs are compensated to avoid losses for the concerned market participants.

Most Expensive Bid (MEB) Pricing (for balancing capacity): To avoid PABs, the clearing price is set at the level of the most expensive accepted bid, ensuring that all accepted bids are remunerated adequately without requiring side-payments. This approach can lead to higher procurement costs but ensures that no bids are paradoxically accepted without proper compensation, while all balancing capacity bids are nonetheless paid uniformly.

Subsequently, the Appendix A proposes the following concrete solutions:

0. No PAB design
1. Non-Uniform Pricing (NUP)
2. NUP for balancing capacity, No PAB for energy
3. MEB for balancing capacity, No PAB for energy
4. As Option 3, with cross-zonal consistency

Only the first two concepts (option 0 and 1) are discussed further in this report, while option 2 also may be relevant. The remaining options are discarded for good reasons that can be verified in the Appendix A. However, there is no "ideal" solution, any solution will be a trade-off between conflicting requirements.

The **No PAB** design appears straightforward and is based on broad experience with SDAC. However, the balancing capacity market is structurally different, and this may result in problems with liquidity and market efficiency, see Section 3.3.3 below.

Non-Uniform Pricing is a general concept where all accepted bids are not necessarily settled at the same uniform price. Different sub-designs can be implemented depending on how prices are effectively set and how side-payments are managed. The main advantage of NUP is that it allows for greater flexibility in the optimization process, which can lead to higher social welfare. By removing the constraint that forces the rejection of beneficial bids, the solution space is expanded, allowing for a more efficient allocation of resources. However, a dedicated settlement mechanism and regulatory frameworks to support these payments are required to safeguard a proper market functioning especially in the long run. There is also a risk that market participants may engage in strategic bidding if they anticipate compensation for PABs. The financing of side-payments is a critical aspect, see below in Section 3.3.3.

On the background of this analysis, the N-SIDE report in Appendix A recommends opting for the implementation of the "No PAB" pricing rule, which aligns with the current day-ahead market rules. This approach ensures coherence and simplicity in pricing. If realistic quantitative simulations reveal a non-negligible risk that the No PAB rule substantially limits social welfare, pose severe liquidity concerns, or leads to material algorithmic challenges, a variant of Non-Uniform Pricing could be reconsidered as a possible alternative (option 2 above).

As a different issue related to pricing, the N-SIDE report in Appendix A proposes a "substitutability rule" for mFRR and aFRR. Because aFRR is considered technically a more valuable product, it is defined by TSOs that aFRR demand can substitute mFRR demand, but not the other way round. This principle implies that it does not make sense to pay more for mFRR as for aFRR, as long as there are unused bids available, and consequently, the mFRR price should in this case be lower than or equal to the aFRR price. Based on this principle, aFRR demand is automatically increased to serve mFRR demand . In case the offered volumes of aFRR do not allow a full potential of substitution of reserves, the mFRR clearing price might be higher than the aFRR clearing price.

A final issue related to pricing relates to cross-zonal aspects. In a co-optimised setup, allocation of cross-zonal capacity takes place as an integrated part of the optimisation process. In case there is no congestion[15] in either direction on an ATC line between two zones, no cross-zonal price differential should be observed for any product in the absence of any other binding constraints[16]. In the presence of congestion on an ATC line between zones in one direction, the resulting price differences are such that the cross-zonal capacity is allocated optimally between all products. In the convex case, and assuming that there are no limits on capacity allocation on individual products, cross-zonal price differences between the various products will be equal for all products with a non-zero exchange level.

Energy flow netting is defined as the ability of energy flows in one direction to release capacity for further balancing capacity flows in the opposite direction. While, in absence of active allocation constraints, energy flows over ATC-based interconnectors always go from low price to higher (or equal) price zones, this may not always be the case under co-optimization. Indeed, as long as the energy cross-zonal spread is smaller than the balancing capacity one, it remains optimal to release cross-zonal capacity with energy to enable further allocation of balancing capacity, including if this implies flowing in opposite direction of the energy price spread. This does not apply in the opposite case where the energy price differential is larger than the one of balancing capacity, because allocating cross zonal capacity to balancing capacity does not lead to a certain flow which can be netted, see Chapter 4.3 in the Appendix A.

A more advanced description of how this high-level principle translates into the specific co-optimisation price formation mechanism under flow-based constraints (including the enforcement of the deterministic reserve deliverability requirement) will be elaborated at a later stage of the R&D.

3.3.3 Reflections from NEMOs and TSOs

The main issue with the **No PAB** design is liquidity. Non-convexities are an inherent property of balancing capacity bids, and a **No PAB** design could potentially disqualify many bids, leading to a shortage of balancing capacity in the co-optimised SDAC market although, in reality, no shortage exists. Moreover, disqualification of large volumes of bids will also reduce the efficiency of the balancing capacity market and possibly the energy market and reduce transparency on price formation. A further concern is that this design can compromise incentives compatibility because the bidders will have incentives to misrepresent their bids or

[15] Note that in this context, balancing capacity is considered to affect an asset in the same way as an energy flow, even if there is not necessarily a physical flow.
[16] Note however that non-convexities still can lead to price differences in such cases.

misrepresent the true links between the bids[17]. If such concerns materialise, the expected increase in economic surplus due to optimisation may become illusory. More realistic quantitative simulations are required as a first step to understand the severity of potential problems with liquidity and efficiency. Modelling of balancing capacity bids in such simulations are however challenging, because no empirical data exists, and the assumptions made will have a significant impact on the results. Using historical balancing capacity bids is not an option, because these bids are based on totally different assumptions, and moreover because it is not known how they are related to SDAC bids. It is also necessary to consider bids from other resources like demand, storage and renewable energy producers, which are expected to become important in the near future for the provision of balancing services. Any pricing rule would need to accommodate these resources efficiently in order to facilitate their participation in the balancing capacity markets. The lack of empirical data will in any case lead to added uncertainties regarding the results.
Referring to the **NUP** design, it is noted that side-payments can be funded from different sources. They may come from a regulatory pocket, such as grid tariffs or other socialized methods, which ensures that market participants do not bear the direct cost of compensating paradoxical acceptances. Alternatively, side-payments can be financed by the surplus generated by other accepted bids. In this approach, the surplus from efficiently allocated bids is used to cover the losses incurred by PABs, creating a self-financing mechanism within the market. However, this effectively reduces the market income for other market-participants, which will have subsequent side effects. Further qualitative and quantitative analyses is necessary to validate if and how non-uniform pricing option should be considered for future implementation.

It should be noted that, although **No-PAB** is presently used in SDAC and **NUP** has been evaluated previously as a measure to increase the algorithmic performance, the proposed methods face several challenges and will have strong impacts that need to be analysed carefully. Large scale simulations are just a first step in these analyses. No conclusions should be drawn at this stage of R&D work. A satisfaction of the TSOs' demand for balancing capacity must be guaranteed by any setup as sufficient reserves are indispensable for secure system operation.

The substitutability principle between aFRR and mFRR appears reasonable, as one would expect that aFRR can be used in most and possibly all cases where mFRR is used. It would also be possible for TSOs to define a minimum level of mFRR that will be provided by mFRR bids, regardless of the resulting prices. The impact of a hybrid approach where some TSOs apply the substitutability principle and some do not, still needs to be investigated.

3.4 Topics for Public Consultation

Although the balancing capacity products for aFRR and mFRR are harmonized, the actual procurement procedures with respect to e.g. time and granularity vary per TSO today, and will necessarily also become harmonized with the introduction of co-optimisation. As market participants indicated these considerations in the past exchanges, NEMOs and TSOs will be

[17] Magnitude of such behaviour can be assessed through simulations in which bidders are maximising their profit, and the market would also need to be cleared. This cannot be done through the normal SCUC model and would need to be assessed through equilibrium analysis such as Mathematical Programme with Equilibrium Constraints (MPEC) or more sophisticated models such as Equilibrium Problems with Equilibrium constraints (EPEC).

gathering market participant views on the conclusions regarding implicit and explicit bidding during the upcoming public consultation.

Market participants also indicated considerations on the bid design in the past exchanges, NEMOs and TSOs will be gathering market participant views on several critical points in the upcoming public consultation especially focusing on:

- Assessment how such bidding formats (both bid linking and the suggested combined bids) are able to adequately consider the actual physical constraints of their assets and portfolios including specify additional bid attributes that might be necessary.
- Necessity and relevance for combined bids for specific technologies i.e. the conceptual study currently displays specific combined bids available for thermal and storage assets.
- Effectiveness of the proposed new links and combined bids in representing complex structures within large portfolios and additional considerations or modifications would ensure that the complexity and variability of large portfolios.
- Proposed bid designs and consideration of very different circumstances at European level, and special characteristics that need to be taken into account.
- Comments about whether the combined and/or linked bids create advantages or disadvantages under different set ups like unit-based bidding vs portfolio-based bidding.
- How do operators of storage facilities see whether the combined and/or linked bids create advantages or disadvantages under different set ups like unit-based bidding vs portfolio-based bidding.

Regarding price convergence between bidding zones in the absence of congestion, non-convexities may still cause price differences in such cases. The market design should carefully consider the detailed pricing options to avoid inadvertent effects of such non-convexities. Based on market participants' feedback, NEMOs and TSOs will be gathering market participant views on:

- The proposed approach with a preference for a pricing solution where Paradoxically Accepted Bids (No-PAB) are removed from the solution, with the potential move to a solution with Non-Uniform Pricing if No-PAB appears detrimental to liquidity and/or efficiency.
- Substitutability rule for aFRR and mFRR, or do you have suggestions to modify or improve it.

4 CONCLUSIONS AND NEXT STEPS

NEMOs and TSOs were jointly tasked to carry out the first phase of the R&D work on co-optimisation as required by ACER Decision 11/2024 on the Algorithm Methodology, exploring the choices for bid design, bid products and pricing. The work was done in cooperation with N-SIDE. The draft R0 report is part of the three R&D milestones of co-optimisation.

Regarding product design, five different products have been recognized, respectively energy (as in the present SDAC) and balancing capacity for aFRR and mFRR, upwards and downwards. The characteristics of the products, as seen from a co-optimised market, are directly related to the bidding language, for which a first, high level draft is provided in the report and its Appendices.

Considering the bidding format, the report elaborated on the cost structure of various assets, opportunity (or alternative) costs are a major element (and often the only element) of the cost of providing balancing capacity. These costs can in principle be provided in two ways: explicit, as part of the bidding price, or implicit, where the optimization will calculate the cost. The report identifies a number of problematic issues for the explicit variant, and clearly recommends implicit bidding of opportunity costs in relation to the day-ahead market.

A further dimension of the bidding language and the possibility to reflect specific cost structures is the distinction between linked bids and combined bids. To a large extent, linked bids use existing bid formats in EUPHEMIA in addition to a few extensions to represent dependencies between energy and balancing capacity bids. Combined bids are tailor made for specific types of assets, e.g. a thermal generator or a storage. Both types of bids have advantages and disadvantages, and it is proposed to implement both types of bids to offer maximum flexibility to market participants. More details need to be developed during the next R&D phases, not at least on the basis of feedback from market participants.

Next, the implications for cross-zonal capacity allocation were considered. In a co-optimised setting, cross-zonal capacity allocation between energy and balancing capacity will be such that, on the margin, the value of exchanging each product is equal, unless other constraints restrict the exchange of certain products.

The final important topic in the report is pricing. This is straight forward for convex problems, but the co-optimisation of energy and balancing capacity has a large share of non-convexities, e.g. startup costs and minimum generation levels. In such cases, there is no ideal solution and trade-offs are necessary. As a first solution it is proposed to reject all offers that lead to Paradoxically Accepted Bids (PAB), which is the same strategy used in EUPHEMIA today. There is however a risk that this may lead to a large number of rejected balancing capacity bids, leading to a lack of liquidity for these products, and/or a reduction of social welfare. If this concern is confirmed by simulations, a solution with so-called Non-Uniform Pricing is recommended, where PABs receive a form for side-payment. However, also this solution has several disadvantages.

This draft R0 report will be submitted for public consultation in May 2025. The results from the consultation will be used to evaluate and update the R0 report. By the end of September 2025, a new version of the report (R1), shall be submitted including a selection of product design, bid design and pricing. The proposed selection will be reviewed by ACER and serve as input to the next R&D phase. The R1 report will conclude the first R&D phase.

It is important to note that no final statements can be made from this first R0 report. Although the R&D work is done in several steps, all R&D areas cannot be viewed in isolation. Therefore, choices may be reconsidered upon provision of new insights in the next phases of the R&D work. After all R&D phases are concluded, the provided outcomes will be used for further discussions among NEMOs and TSOs together with ACER on the next steps on co-optimisation.

5 APENDICES

5.1 APPENDIX A: N-SIDE Report

Co-optimization Conceptual Study

Bidding Language and Pricing Requirements – Annex to the R0 Report

Tuesday May 13, 2025

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Context and Scope of this Study

The need for ancillary services is expected to increase in the coming years, due to the increased uncertainty in both generation and demand closer to real time. This increased uncertainty essentially stems from the transition to more renewable energy in the generation mix combined with improved demand response. In that context, the cross-border procurement of balancing capacity products is being considered by stakeholders, and various options for organizing cross-border balancing capacity markets are described in the COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EBGL). The primary approaches under consideration by stakeholders are the so-called "market-based approach" and the co-optimization approach.

Following ACER's Decision 11/2024, this Conceptual Study on Co-optimization—part of the R0 report under ACER's Decision—focuses on developing an efficient and effective market design for co-optimization in the European context.

In addition to efficiently allocating cross-zonal capacity, the co-optimization of energy and balancing capacity also aims to optimize the allocation of power generation and consumption resources between energy and balancing capacity products[1].

In 2022, the Market Coupling Steering Committee (MCSC) commissioned the first 'Co-optimization Roadmap Study' [1], which addressed first key design issues. This study offered clear recommendations, such as the optimal number of 'steps' in the co-optimization process, concluding that the so-called 'one-step' approach is most effective for ensuring the efficient and robust operation of a co-optimization-based market. It also proposed an effective method to enforce a 'deterministic reserve deliverability requirement', ensuring that any pattern of real-time reserve activations is manageable within the flow-based network representation considered at the day-ahead stage. Although extended numerical experiments to complement the results of [1] are necessary, the qualitative conclusions of that study remain valid.

The present study aims to address various challenges identified in the initial Co-optimization Roadmap Study [1], as well as new design questions raised by TSO and NEMO members and by ACER in its Decision 11/2024.

These considerations include, for instance, the types of bids most suitable for reflecting costs and interdependencies between products auctioned in the co-optimization-based market, while accounting for the specific characteristics of the existing European market design framework. They also include the complex issue of identifying the most suitable pricing mechanism in a context that combines co-optimization with non-convexities arising from indivisible costs and inflexible production constraints.

The study is structured as follows.

[1] In more general economic terms, co-optimization aims to allocate scarce resources efficiently across multiple products while accounting for the interdependencies between these products.

Chapter 1 is an introduction to European balancing capacity markets, highlighting key questions regarding the organization of (cross-border) auctions. It reviews the types of balancing capacity products available in Europe and then explores the interdependencies between balancing capacity and energy offers, highlighting the challenges of designing bids that accurately capture these interdependencies.

Chapter 2 delves into the challenge of bidding product design. It begins by distinguishing between fundamental costs and auction-endogenous costs. Endogenous costs are defined as costs incurred within the auction due to the linkages between products in a given offer, for instance when one product is provided at the exclusion of another, or when one product requires the provision of another. It includes a detailed discussion on how to best represent opportunity costs incurred when an upward balancing capacity offer is accepted at the exclusion of a linked energy offer, or the negative profits arising from accepting a downward balancing capacity offer that necessitates the acceptance of a non-profitable linked energy bid.

Chapter 3, in turn, explores the optimal approach to represent fundamental costs. It specifically examines the use of linked bids, typically suited for portfolio bidding, and combined bids, which allow for a detailed representation of fundamental costs at the unit level (potentially corresponding to a virtual power plant).

Chapter 4 reviews key elements of cross-zonal capacity (CZC) allocation in a co-optimization context, comparing its value for energy exchange with its value for balancing capacity exchange. While the discussion builds on known concepts and a previous SDAC study on co-optimization, it introduces new examples to illustrate the CZC allocation mechanism.

Chapter 5 then explores potential pricing mechanisms within a co-optimization context that accounts for non-convexities and the distinct features of the European power market landscape.

Chapter 6 lists a range of advanced topics for further exploration beyond this study.

Finally, concluding remarks are provided in Chapter 7.

The N-SIDE team would like to acknowledge the engagement and very useful feedback from the SDAC MSD Subgroup on Co-optimization on previous versions of this report. Exchanges within the project have played a key role in shaping this work. We also thank ACER for providing helpful comments on a preliminary version.
Any remaining errors, however, remain the sole responsibility of N-SIDE.

1. Introduction

1.1 Overview of Balancing Capacity Products

Reserves are crucial for maintaining the reliability of the electricity grid by ensuring a real-time balance between supply and demand. Balancing capacity provides a reserve that can be activated quickly to address unexpected imbalances by adjusting generation or consumption levels.

The scope of co-optimization addressed in this study focuses on Balancing Capacity related to Frequency Restoration Reserves (FRR) while Frequency Containment Reserve (FCR) and Replacement Reserve (RR) – which are other key Balancing products – are excluded. However, although these products are out of the scope of this report, the design principles apply to the co-optimization of energy and an arbitrary number of balancing capacity products. Extending the scope to include more balancing capacity products is primarily a matter of algorithm scalability rather than a market design challenge[2].

Balancing capacity is categorized into **upward** and **downward** capacity. Upward balancing capacity is used to increase generation or reduce consumption to address supply shortfalls, while downward balancing capacity reduces generation or increases consumption to manage oversupply. These two complementary products ensure the grid can respond to both positive and negative imbalances.

It is important to note that upward and downward balancing capacities are entirely distinct products; unlike energy transactions, they cannot be netted against each other (whereas energy buys and sells can be directly offset). This is because the value of balancing capacity is its ability (i.e. option) to activate energy in one direction. For example, 3 MW of upward capacity and 1 MW of downward capacity do not equate to 2 MW of upward capacity, because this set of balancing capacity enables the TSO to compensate for imbalances of -3MW to +1MW (while 2MW of upward capacity would only allow to compensate for an imbalance in the range [-2;0]MW).

Balancing products also differ by activation method: **automatic Frequency Restoration Reserve (aFRR)** and **manual Frequency Restoration Reserve (mFRR)**. In normal operations, aFRR is automatically activated in response to ACE (Area Control Error) or frequency deviations, and provides a continuous, dynamic response within seconds. It is highly flexible and suited for correcting smaller, frequent imbalances. In contrast, mFRR is manually activated by the TSO, has a slower response time, and is activated for a longer duration. Many TSOs use mFRR for larger, more sustained disturbances that require more significant correction, while others use it on a more regular basis.

[2] Replacement Reserve standard products are not being assessed, as they will no longer be applicable once the obligation to set the Intraday Cross-Zonal Gate Closure time to 30 minutes before real-time is implemented, given that their activation time is incompatible with ongoing intraday trading until that point. See the *Announcement from Replacement Reserve TSOs*, available at: https://www.entsoe.eu/network_codes/eb/terre/

Both Standard Balancing Capacity Products for aFRR and mFRR are harmonized products across Europe, meaning that their definitions and requirements are standardized, enabling cross-border procurement. While some Member States may have additional local balancing products, these are not considered in this study as they are not harmonized across borders and hence cannot be procured on a cross-border basis.

In this report, we focus on four balancing capacity products that are to be co-optimized with energy:

- **Upward aFRR**: Automatically increases generation or decreases consumption to address shortfalls.
- **Downward aFRR**: Automatically decreases generation or increases consumption to manage oversupply.
- **Upward mFRR**: Manually increases generation or decreases consumption for significant supply shortfalls.
- **Downward mFRR**: Manually decreases generation or increases consumption to address oversupply.

1.2 Balancing Capacity and Energy Offer Interdependencies

The interdependency between offering balancing capacity and energy for a given asset is crucial to understand.

For a typical production asset providing reserves, there is a direct relationship between energy and upward balancing capacity. The available capacity can either be used to deliver energy or upward balancing capacity, but not both simultaneously, as they draw from the same pool of capacity. In other words, generating energy reduces the capacity available for upward balancing and vice versa—they are mutually exclusive. On the other hand, offering downward balancing capacity is conditional on being producing energy and delivering power at a sufficiently high level to allow a reduction: If a production asset is already generating energy, part of that generation can be used to offer downward balancing capacity[3]. This creates a "parent-child" relationship, where energy production acts as the parent, and downward balancing capacity is the child that depends on the energy already being generated. Without a certain level of energy production, there is no possibility to offer downward balancing capacity.

This principle can be easily extended to other types of assets, such as consumption or storage assets. Each asset operates within a bandwidth defined by its minimum and maximum levels of injection or offtake. Within this range, the energy setpoint establishes the volume of available upward and downward balancing capacity. This is why in practice both generation and consumption can in principle provide balancing capacity in either direction. For example, for a baseload consumption unit, offering

[3] From another perspective, certain assets may also need to already be generating energy to provide upward balancing capacity, for instance when minimum stable generation constraints must be satisfied. This type of linkages also leads to parent-child bid links or equivalent linking constraints in the combined bids discussed in Section 3.

upward balancing capacity means offering the possibility of reducing load during a certain period.

This interdependent nature illustrates that the decision to offer energy or balancing capacity is not independent for a given asset, and effective co-optimization must take these relationships into account to maximize value while ensuring grid stability.

1.3 Balancing Capacity Bid Linking and Co-optimization

This interdependency implies that balancing capacity orders and energy orders should be considered together when performing co-optimization. There are several aspects to consider in this context. We first present a simple bid linking approach, where bids for various products keep the format of the current SDAC and FRR BC bidding products, and are linked through "mutual exclusive constraints" or "parent-child constraints". A more advanced bidding language referred to as “combined bids” (also called "multi-part bids” in the literature), is also discussed in Chapter 3. These bid formats are closer to how generation assets are represented in "unit commitment problems."

We demonstrate that, for many elementary use cases, both options offer equivalent opportunities for market participants to express their cost structures and constraints. However, in specific cases, one approach enables market participants to express economic preferences that cannot be expressed with the other approach, sometimes at the expense of a possible impact on market clearing algorithm scalability.

We suggest the use of a broad set of products designed to cover most of the needs participants may have, thereby supporting both portfolio bidding and unit bidding—particularly relevant for participants with only one asset.

It should be emphasized that providing flexible and convenient tools to market participants—whether they bid portfolios or individual assets—does not imply a recommendation to move away from the European paradigm toward a market design based on central dispatch. The European paradigm has proven highly successful in recent years, and the goal is to enhance it to cope with technological, economic, and regulatory evolutions, not to introduce any major shift in this regard.

The design discussed in this document intends to benefit from the support of all products that may make sense and produce efficient prices, allowing market participants to decide which products are the most appropriate for their needs.

1.4 Substitution of Balancing Products

Given that aFRR can be generally used to replace mFRR, there is a compelling reason to consider **enforcing price consistency** between aFRR and mFRR. The principle of substitutability plays a key role here—**"the more flexible product can also address the less demanding needs."** In other words, a product that is more flexible, i.e. aFRR, is also capable of fulfilling the requirements of a less flexible product, i.e. mFRR. Therefore, **when a TSO needs mFRR, it should not be an issue if the need is met by aFRR offers**. If this substitution is allowed and enforced in the market design, it naturally ensures that the price of aFRR cannot be lower than that of mFRR. If mFRR demand can be satisfied by aFRR, and if aFRR was priced lower than mFRR, the procurement algorithm would begin substituting mFRR with aFRR until the increased demand for aFRR drives its price above that of mFRR. As a result, the substitution would automatically prevent a price reversal by equalizing or surpassing the mFRR price[4].

Such an approach helps maintain a logical price hierarchy where more flexible services are always valued at least as highly as their less flexible counterparts.

Thus, the question of whether to let price consistency emerge purely through market forces or to **enforce substitution rules** remains a key design consideration. Enforcing price consistency through substitution mechanically prevents price reversals and may indirectly reduce the short- term balancing capacity procurement costs. On the other hand, it also introduces some sort of market intervention that could limit price signals reflecting actual scarcity of mFRR. **Finding the right balance between these approaches is crucial for an efficient and reliable balancing capacity market[5].**

1.5 Bidding Language and Cost Representation in a Co-optimization Setup

The bidding language allows market participants to articulate their economic preferences and technical constraints through "bidding products". These range from simple bids—consisting of a price-quantity pair—to highly sophisticated bids that provide a detailed representation of the physical and economic characteristics of assets.

Adequately representing costs is both a critical and complex task in modern power markets. The complexity is evident even in energy-only markets—or more broadly, in single-product auctions—where the economic characteristics of various power plant technologies result in what economists refer to as "non-convex costs" (e.g., binary decisions involving fixed costs) or "non-convex production sets" caused by indivisibilities (e.g., minimum stable generation levels)[6].

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[4] Note that our approach is to enable this substitution on the side of the TSO demand, i.e., a demand for mFRR can be **satisfied by** an offer for aFRR. An alternative would be to enable this substitution on the BSP supply side, i.e., an offer for aFRR can be **accepted as** mFRR. Our reasoning is that aFRR and mFRR are distinct products, notably in terms of qualification criteria and activation methods, and that it is up to the TSO to decide to what extent one product can substitute the other one (while it is more intricate to accept an aFRR offer as an mFRR volume, as both products follow different rules).

[5] The chosen approach should also align with the specific operational setups in each region. For instance, EirGrid and SONI do not currently use aFRR; all FRR within their load frequency control block is provided by mFRR.

[6] The terminology distinguishing between “convex” and “non-convex” economies is for instance already used in the work of Arrow and Debreu on general equilibrium theory, where the convexity hypothesis is crucial to prove the existent of a general market equilibrium, see for instance: Debreu, Gerard. *Theory of value: An axiomatic analysis of economic equilibrium*. Vol. 17. Yale University Press, 1959 or the classic reference: Andreu Mass-Colell, Michael Whinston, and Jerry Green. *Microeconomic theory*, Oxford University Press, 1995.

Challenges become even more complex in a co-optimization setup, where multiple products are auctioned simultaneously, considering their interdependencies. In this context, it is essential to differentiate between two categories of costs: endogenous costs, which are “created within the auction” due to linkages in the offers for multiple products (such as opportunity costs of providing upward balancing capacity instead of profitably providing energy), and fundamental costs, which encompass all other costs, such as fuel expenses or possibly costs associated with lost opportunities *in other auctions*[7]. Accurate representation of fundamental costs is particularly critical in a co-optimization context. This can be achieved either through separate bids for different energy and balancing capacity products, linked via exclusive and 'parent-child' (conditional acceptance) conditions, or through 'combined bids.' Combined bids feature a common set of parameters applicable to all products offered by the bid (e.g., the total capacity of an asset) with linkages directly represented within the bid itself.

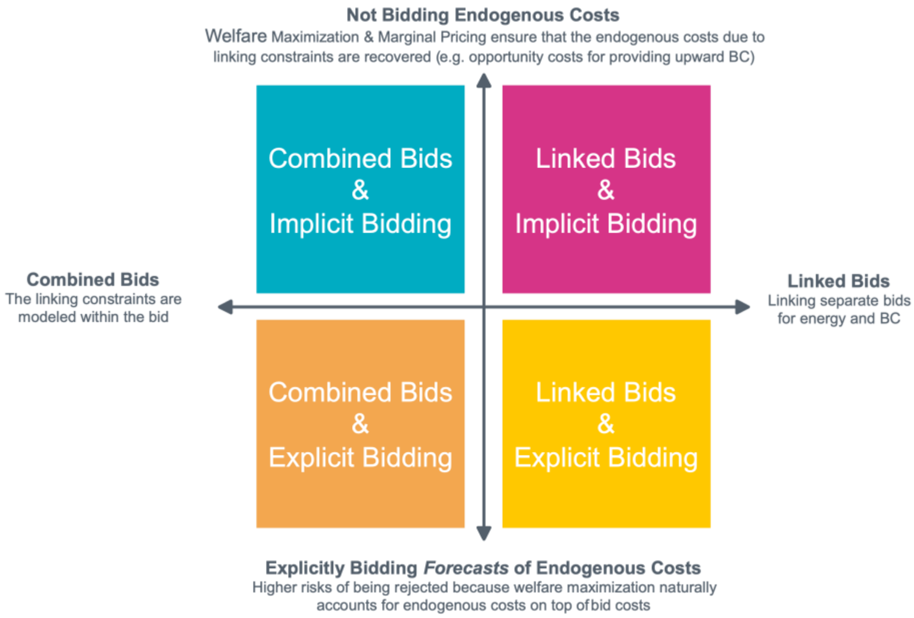

Figure 1: Distinguishing between bid formats (linked versus combined bids) and bid cost representations (explicitly bidding or not a forecast of endogenous costs due to linking constraints such as opportunity costs for providing upward BC).

Definitions of endogenous and fundamental costs, together with the definitions of linked and combined bids, can be found in the Glossary in Annex A for quick reference. These concepts are further explained and illustrated in Chapter 2 and Chapter 3, respectively. The illustrative examples are based on simple cost structures and technical constraints relevant to technologies included in all future generation mix scenarios.

In Chapter 2, we delve into what these endogenous costs correspond to, and how they can be represented in co-optimized auctions. We specifically address the critical question of explicit versus implicit bidding, regarding whether forecasts of these costs should be explicitly included in the input bids provided by market participants in a co-optimization setup. This issue corresponds to the vertical axis in Figure 1 above. The question of whether to bid opportunity costs in a co-optimization setup was already

[7] The notion of fundamental costs used here is synonymous with ‘exogenous costs’ and includes all costs not incurred due to bid-linking constraints, beyond the pure fundamental costs related to fuel, operations, etc.

discussed in [1] and [11], with general conclusions that align with the detailed analysis in the present study.

In Chapter 3, we explore in detail how fundamental costs can be most effectively represented in Europe within a co-optimization context, considering the unique characteristics of European markets. We focus specifically on the key question of when to use linked bids, or 'combined bids' extending the current bidding products available in SDAC, with a menu of possible features similar to those used in unit bidding markets. This issue aligns with the horizontal axis in Figure 1. We argue there that the two choices are not necessarily mutually exclusive, though they have different implications in terms of trading risk management and market monitoring. Note that the importance of fundamental cost representations in a co-optimization context is exacerbated by the need for coordination in the provision of the various energy and ancillary services products.

2. Bid Cost Types in Co-Optimization: Implicit vs. Explicit Bidding

Endogenous costs are costs incurred within the auction due to the linkages between products in a given offer, for instance when one product is provided at the exclusion of another, or when one product requires the provision of another.

Endogenous costs in our co-optimization context can be classified into two types.

- Opportunity costs are incurred when a single asset or portfolio can provide multiple products that are mutually exclusive, and when a product is accepted at the exclusion of another profitable one. This occurs for example if an asset provides upward aFRR though it could profitably have provided energy or upward mFRR. They arise from exclusive bid linking constraints or exclusivity conditions in 'combined bids' discussed in Chapter 3.

- Actual losses (or realized losses) refer to the costs arising when the provision of one product forces the provision of another product that is not profitable. For example, this occurs when an asset provides energy at a loss because it provides downward aFRR. They are caused, in the context of bid linking, by 'parent-child bid linking constraints' that model interdependencies, or, in the context of combined bids (see Chapter 3), by constraints representing the same conditions on the acceptances of the offered volumes for the various products.

In this section, we explore how assets capable of providing both energy and upward or downward balancing capacity can reflect their endogenous costs.

In Section 2.1, we begin by using examples to illustrate that, under standard marginal pricing in a co-optimization setup, marginal market prices ensure that all participants using implicit bidding—i.e., those who do not factor into their offers their endogenous costs, such as opportunity costs—still recover these costs along with their fundamental costs. This is illustrated through examples involving various types of bid linking that express relationships between the provision of energy, upward capacity, and downward capacity. References are also provided to confirm that this result applies broadly and is not limited to the specific examples discussed.

In Section 2.2, we use a simple example to illustrate and explain why market participants employing explicit bidding in relation with linked bids or 'combined bids'—i.e., including for instance an estimation of their opportunity costs in case they are asked to provide upward balancing capacity at the exclusion of profitably providing energy—face a high risk of being uncompetitive and having their bids rejected. This outcome stems from a comprehensive accounting of costs across all products when comparing bid matchings, or, put differently, from properly considering in the analysis both the direct and indirect costs associated with the selection of linked bids (or their combined bid counterparts discussed in Section 3.2).

Section 2.3 explains how a non-standard market mechanism for addressing trader risks using explicit bidding, as identified in Section 2.2, introduces new challenges. We show that it is impossible to enforce a 'single-product merit order' across all products, leading to unavoidable paradoxical bid acceptance or rejection. We also discuss economic and algorithmic implications (and highlight some other disadvantages of explicit bidding).

Conclusions are summarized in Section 2.4.

Throughout this section, we use examples involving linked bids; however, the discussion applies equally to 'combined bids' that are equivalent to the linked bids considered. Further details on the comparison between linked bids and combined bids can be found in Chapter 3.

2.1 Implicit bidding and marginal pricing theory

With Implicit Bidding, market participants only declare their fundamental costs (e.g., production costs for energy and “reservation costs[8]” for balancing capacity) without explicitly adding a forecast of endogenous costs on top.

Market clearing algorithms, based on welfare maximization and marginal pricing principles, automatically ensure that these endogenous costs are recovered through the market prices of energy or balancing capacity products where the linked bids are matched. As further discussed below, this directly results from the fact that under marginal pricing—setting aside the 'non-convexities' due to fixed costs and indivisibilities, covered in Chapter 5—the welfare-maximizing market outcome ensures that no participant would prefer a different allocation of their bids at the resulting marginal prices. By marginal pricing, we mean defining the market price of a product as the marginal system cost increase for serving an additional unit of that product (or the savings for serving one less unit)[9]. In more technical terms, marginal prices correspond to optimal multipliers, or optimal dual variable values, of the power balance conditions, leaving aside the question of non-convexities addressed in Chapter 5.

This broad principle—as already discussed in [1, Section 5.1]—also applies in a co-optimization setting where energy and multiple balancing capacity products are auctioned simultaneously. For example, it represents a specific case – with no commitment (binary) decisions – of Theorem 2 in [2], which is proven using Karush-Kuhn-Tucker (KKT) conditions. A straightforward explanation using "Lagrangian Duality" is provided in [3, Appendix A]. Additionally, [4, Chapter 6 "Ancillary services"] offers a detailed treatment in the context of multi-product auctions and recalls the

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[8] Reservation costs mean all costs incurred by the provision of balancing capacity, that are *not* caused by linking constraints within the auction. Reservation costs may for instance correspond to opportunity costs faced in markets *in other timeframes* such as the intraday markets, or operational costs of various sorts.

[9] The characterization presented here aligns with the standard definition of marginal pricing in economics; see, for example the article "marginal-cost pricing." in *Encyclopedia Britannica*, 25 Dec. 2024, available online: https://www.britannica.com/money/marginal-cost-pricing. While the concept is not explicitly defined in the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, it is referred to as 'marginal pricing (pay-as-cleared),' just evoking the principle of uniform pricing. It is important to note that marginal pricing in the classical economic sense may not always involve the most expensive accepted bid setting the price.

important fact that the converse is also true, i.e. that under the same conditions, a competitive equilibrium necessarily corresponds to a welfare maximizing allocation[10].

This profit optimality principle carries significant implications. In a co-optimization setting, leaving aside the question of pricing with non-convexities addressed in Chapter 5, one can infer from this principle that if a resource that can deliver both energy and balancing capacity is optimally allocated to balancing capacity, the balancing capacity market is more (or at least equally) profitable for that resource than the energy market[11]: otherwise, the allocation would be suboptimal for the market participant. Consequently, for example, if a resource is represented by energy and upward balancing capacity bids linked by an exclusive condition, and the balancing capacity bid is accepted instead of the energy bid, this must be because the balancing capacity market is more profitable. In this case, any 'opportunity costs' of the energy bid in the energy market are compensated by the profits made by the linked BC bid in the balancing capacity market. Similar conclusions apply if the resource is represented by a combined bid, see Chapter 3.

In other words, the price in the BC market is attractive enough to offset any potential lost profits in the energy market. This is the key reason why participants submitting bids for multiple products in a 'joint offer'[12] do not need to explicitly account for the opportunity cost of one product when bidding on another. While they can factor other explicit costs in their bids, including the lost opportunity costs forecasted for the same co-optimized market leads to "double counting", as illustrated in Section 2.2.

Illustration of the principles with energy and upward balancing capacity

We hereby present a simplified example with a few bids in a single zone to illustrate these claims[13]. The illustration uses two linked bids, but all developments would equally apply if these two linked bids were converted into an equivalent combined bid[14]. The scenario includes demands for energy and upward balancing capacity, which can be met by three sources of supply:

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[10] Proofs based on KKT conditions (see given references) rely on the fact that these conditions, which serve as necessary and sufficient optimality conditions for the welfare maximization problem, also embed the KKT optimality conditions of market participants' profit maximization problems (including the transmission network operator whose profit corresponds to the congestion rent). These KKT conditions are necessary and sufficient for convex problems, *provided that certain 'constraint qualifications' are satisfied*— which is always the case for linear programs or convex quadratic programs with linear constraints. Proofs based on Lagrangian Duality rely on the fact that the 'Lagrangian Dual' explicitly reveals the profit maximization problems of market participants (including the transmission network operator). Additionally, the absence of a duality gap between the primal welfare maximization problem and the Lagrangian Dual can be interpreted as the impossibility for market participants to achieve higher profits by re-optimizing under their own constraints (again provided that the constraint qualifications are met). Note that this is directly related to the observation that the Lagrangian duality gap, when nonzero (e.g., due to non-convexities), corresponds to the sum of deviations from a competitive equilibrium. Convex Hull Pricing [7,8], which aims to find prices that minimize these deviations, directly relies on this observation.

[11] Given its cost structure and bid linking constraints (or linking constraints in a combined bid).

[12] Either via multiple bids linked together for energy, aFRR up, aFRR down, or combined bids where the linkages between the offers for different products are 'within the bid' itself.

[13] While price formation with non-convex bids is discussed in depth in Chapter 5, an additional elementary example involving an extra-marginal non-convex bid can be found in Annex D.1.

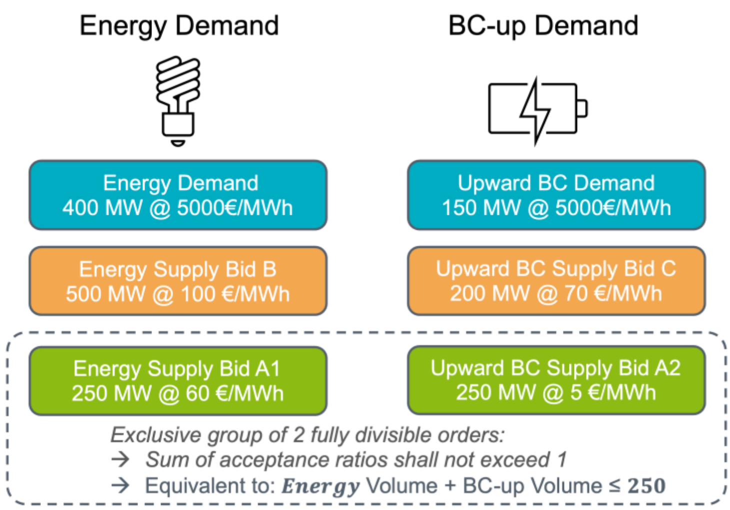
[14] The differences and comparative benefits of combined bids and linked bids are discussed in Chapter 3. See also the definitions in the Glossary in Annex A for quick reference.

- the energy-only Bid B,
- the upward-balancing-capacity-only Bid C, and
- the bid portfolio A, which offers both energy and upward balancing capacity via the mutually exclusive energy bid A1 and upward balancing capacity bid A2.

Energy costs in this simplified example can be assumed to represent marginal costs from fuel. The balancing capacity cost of bid A2 is a reservation cost, which can also be seen as a 'premium'—a minimum marginal return received on top of any endogenous costs which will be automatically recovered (such as opportunity costs of providing balancing capacity instead of profitably providing energy within the auction).

The exclusive bid linking condition is similar to the exclusive conditions in place today in SDAC and requires that the sum of the acceptance percentages of both bids doesn't exceed 100%, which translates in the present context into the condition that the total of the accepted energy and upward balancing capacity doesn't exceed 250MW, corresponding to the total capacity of the asset A. Bid linking options are further discussed in Section 3.1.

The detailed data for the demand and supply bids are given in Figure 2[15]. Note that this example features both a pure "balancing-capacity-only" bid (order C) and linked bids for energy and balancing capacity (A1 and A2). Balancing-capacity-only bids may for instance correspond to providers of demand response.



Market Results	Energy	Upward Balancing Capacity
Market Prices	100 €/MWh	45 €/MWh
Bid A1 Accepted Vol.	100	-
Bid A2 Accepted Vol.	-	150
Bid B Accepted Vol.	300	-
Bid C Accepted Vol.	-	0

Figure 2: Example 1 – Price Formation with Implicit Bidding and Standard Marginal Pricing

[15] Balancing capacity prices can be expressed in €/MW/h or €/MWh, both of which are strictly equivalent. To ensure consistency and simplify price comparisons, the unit €/MWh is used throughout this report.

One can deduce the optimal allocation by solving the corresponding welfare maximization problem given in Figure 3[16], or alternatively via the following intuitive reasoning:

- The energy and upward balancing capacity demands are met since there is no supply shortage, and the demand bid prices are so high that it is welfare optimal to fully accept them.

- The cheapest way to serve the energy and upward balancing capacity demands is by first using Bids A1 and A2 as much as possible: A2 is providing the 150 MW of upward balancing capacity, and the remaining 100 MW of capacity of A1 are matched in the energy market.

- Bid B is serving the rest of the energy demand and sets the energy market price at 100 €/MWh since it is marginal.

- Bid C at 70€/MWh is too expensive and is rejected in the upward balancing capacity (BC-up) market. Using 1 MW of Bid A2 for BC-up is costing 5€/MWh (hence saving 65€/MWh compared to using Bid C) but prevents to substitute 1MW of energy supply at 100€/MWh from Bid B with cheaper supply at 60€/MWh from Bid A1 (hence costing 40€/MWh compared to using Bid B). Allocating 1 MW of Bid A2 to BC-up hence has a net effect of 65€/MWh-40€/MWh = 25€/MWh.

These market results lead to a payment of 150x45 = 6750€ to the balancing capacity bid A2, 100x100 = 10,000€ to the energy bid A1, and 300x100 = 30,000€ to the energy bid B.

Consider now the market prices given by marginal pricing, which are respectively 100 €/MWh for the energy market price (set by the marginal Bid B), and 45 €/MWh for the BC-up market price, implicitly constrained by the *linked* bids A1 and A2.

These prices are marginal prices in the sense that:

- 100 €/MWh corresponds to the marginal welfare decrease of 100 € to meet 1 extra MW of inelastic energy demand (which would be supplied by Bid B), or the marginal welfare increase if one benefits from 1 extra MW of free inelastic energy supply,

- 45 €/MWh corresponds to the marginal welfare decrease of 45 € if one requires to meet 1 extra MW of inelastic BC-up demand (which would be supplied by Bid A2 at +5€/MWh, however also implying to substitute 1MW of energy from Bid A1 at -60€/MWh by 1MW of Bid B at 100€/MWh, hence for a total net effect of 45€/MWh).

[16] Note that the formulation of this optimization model, while equivalent, doesn't necessarily correspond exactly to the one that would be implemented in the SDAC day-ahead market clearing algorithm Euphemia.

The price system (Energy price = 100 €/MWh, BC-up price = 45 €/MWh) is also the price system that makes the matched bid volumes optimal for each market participant. One can intuitively see this as follows:

- The Energy Bid B is partially accepted and must set the energy market price at 100 €/MWh: otherwise Bid B would either prefer to be fully rejected (if the market price is below its bid price), or to be fully accepted (if the price is above its bid price).

- Given that the exclusive bids A1 and A2 are respectively partially matched in the energy market and in the BC-up market, if this is optimal for the market participant, it must be that marginal profits (in €/MWh) made in both markets are equal: otherwise it would be more profitable to either increase the acceptance of bid A1 and reduce the acceptance of bid A2 accordingly, or the opposite, i.e. match the linked bids A1 and A2 where the profit is the highest.

  For the profits of bids A1 and A2 to be equal in both markets, given that the profit in the energy market is 100 €/MWh – 60 €/MWh = 40 €/MWh, the market price in the BC-up market must be exactly equal to 45 €/MWh, which after subtraction of the BC-up bid cost of 5 €/MWh, leads to the same marginal profits as in the energy market.

- Finally, given this BC-up market price of 45 €/MWh, it is indeed optimal to fully reject Bid C, whose bid cost is 70 €/MWh.

The observations above are just an instance of the following general principle evoked at the beginning of this section[17]*: In the absence of "non-convexities"*[18]*, an allocation is welfare optimal if, and only if, there exist "competitive equilibrium prices", i.e., prices such that the allocation is also optimal from the point of view of market participants maximizing their profits (i.e., the bid matchings are profit optimal for market participants, given the market prices of the various products, and the usage of the CZC for imports and exports across locations is also optimal).*

[17] For more information and supporting proofs based on so-called 'KKT conditions', see Chapter 6, Proposition 6.3 in Anthony Papavasiliou. *Optimization models in electricity markets*. Cambridge University Press, 2024 [4].

[18] Non-convexities in power markets are requirements leading to "non-convex" mathematical optimization problems and are essentially introduced by bids with indivisibilities or fixed costs, but also generation assets with "increasing returns to scale". Pricing is a challenge in that context, see Chapter 5.

$$\max Welfare := 5000\, EnergyDemand + 5000\, BCupDemand \\ - 60\, SupplyEnergy_{A1} \ - 5\, SupplyBCup_{A2} \\ - 100\, SupplyEnergy_B \ - 70\, SupplyBCup_C$$

subject to:

$$0 \leq \ EnerggyDemand \leq 400$$
$$0 \leq \ BCupDemand \leq 150$$

$$EnerggyDemand = SupplyEnery_{A1} + SupplyEnery_B \qquad [Energy\ MCP\ = 100\ €/MWh]$$
$$BCupDemand = \ SupplyBCup_{A2} + \ SupplyBCup_C \qquad [BC\ up\ MCP\ = 45€/MWh]$$

$$(*) \quad SupplyEnergy_{A1} \ + SupplyBCup_{A2} \leq 250 \qquad [Bid\ Linking\ ShadowPrice\ = 40€/MWh]$$
$$SupplyEnergy_A, SupplyBCup_A \quad \geq 0$$

$$0 \leq \ SupplyEnergy_B \ \leq 500$$

$$0 \leq \ SupplyBCup_C \ \leq 200$$

Optimal Allocation:
Asset A provides 150 MW of BC-up and 100 MWh of Energy,
Asset B provides 300 MWh of Energy,
Asset C provides 0 MW of BC-up.

Figure 3: Welfare maximization problem of Example 1. The shadow price of the bid-linking constraint $(*)$ represents the marginal profit of bid A1 in the energy market, which is equal to the marginal profit of bid A2 in the upward balancing capacity market. It reflects the opportunity costs incurred in one market (e.g., energy) due to the allocation of volume to another market (e.g., BC). These opportunity costs are recovered through the market price of the corresponding other product.

The constraint $(*)$ in Figure 3 represents the exclusive bid linking condition applying to bids A1 and A2. As highlighted above (see Footnote 16), the formulation of this optimization model in Figure 3, while equivalent, doesn't necessarily correspond exactly to the one that would be implemented in the SDAC day-ahead market clearing algorithm Euphemia.

Illustration of the principles with multiple upward products (or multiple downward products)

Let us consider the example in Figure 4 where the market participant A is offering energy, upward aFRR and upward mFRR. The optimal matching is given in the table in the same figure. Note that the example considers linked bids, though the same conclusions would be reached with equivalent combined bids (see Chapter 3).

Intuitively, the most efficient is to allocate the capacity of market participant A to the upward mFRR market, i.e. to match bid A3, avoiding relying exclusively on the expensive bid D. The bid D is then used to meet the leftover mFRR demand and sets the mFRR-up market price at 80€/MWh. Bid C is used to meet the aFRR demand and sets the aFRR market price at 70€/MWh, while bid B is setting the energy price at 100€/MWh.

We can observe that matching a portion of bid A1 (i.e. a portion of the total capacity of market participant A) in the energy market would be suboptimal from a welfare perspective, given that this would leads to savings of only 100€/MWh – 60€/MWh = 40 €/MWh (compared to using bid B), while matching bid A in the mFRR market enables to save 80€/MWh – 5€/MWh = 75€/MWh (compared to using bid D).

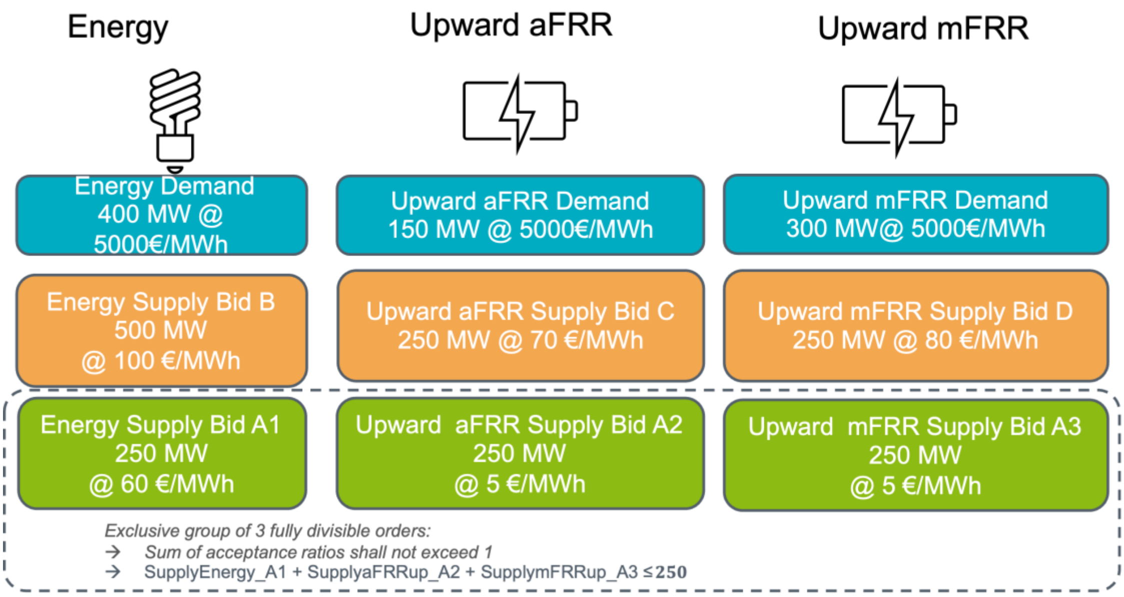
The welfare-optimal allocation and corresponding marginal prices again perfectly align with the profit-maximization problem of the market participants. For instance, considering the linked bids A1, A2 and A3 of market participant A:

- given the market prices of energy, upward aFRR and upward mFRR, its capacity is optimally allocated where it is the most profitable,

- in other words, the missed profits of bid A1 in the energy market (100€/MWh – 60€/MWh = 40€/MWh) or of bid A2 in the aFRR (70€/MWh – 5€/MWh = 65€/MWh) market are exceeded by the profits of bid A3 in the mFRR market (80€/MWh – 5€/MWh =75€/MWh),

- hence, *given the bid linking (volumes of bids A1, A2 and A3 are mutually exclusive)*, market participant A doesn't need to forecast opportunity costs of not being matched either in the energy or in the aFRR market when bidding for mFRR.

For convenience, we also describe in Figure 5 the complete welfare optimization problem corresponding to the example in Figure 4.



Market Results	Energy	Upward aFRR	Upward mFRR
Market Prices	100 €/MWh	70 €/MWh	80 €/MWh
Bid A1 Accepted Vol.	-	-	-
Bid A2 Accepted Vol.	-	-	-
Bid A3 Accepted Vol.	-	-	250
Bid B Accepted Vol.	400	-	
Bid C Accepted Vol.	-	150	
Bid D Accepted Vol.	-	-	50

Figure 4: Example 2 - Linked bids for energy and multiple reserve products of the same direction (upward in the Example)

In the market outcome illustrated in Figure 4, it is noteworthy that the price of upward aFRR is lower than that of mFRR. This is unexpected in practice, as aFRR is considered a higher-quality product. The pricing issue is further addressed in Section 1.4 and Section 6.1, while Annex B provides the results for the same example – would the “substitutability rule”, that ensures that the price of aFRR is always at least equal to the price of mFRR, is applied.

$$
\begin{aligned}
max\ Welfare \coloneqq\ & 5000\ EnergyDemand + 5000\ BCupDemand \\
& - 60\ SupplyEnergy_A\ - 5\ SupplyaFRRup_A\ - 5\ SupplymFRRup_A \\
& - 100\ SupplyEnergy_B\ - 70\ SupplyaFRRup_C\ - 80\ SupplymFRRup_D
\end{aligned}
$$

subject to:

$$
\begin{gathered}
0 \leq\ EnergyDemand \leq 400 \\
0 \leq\ aFRRupDemand \leq 150 \\
0 \leq\ mRRupDemand \leq 300
\end{gathered}
$$

$$
\begin{aligned}
EnergyDemand &= SupplyEnergy_A + SupplyEnergy_B && [Energy\ MCP = 100\ €/MWh] \\
aFRRupDemand &= SupplyaFRRup_A + SupplyaFRRup_C && [aFRR\ up\ MCP = 70€/MWh] \\
mFRRupDemand &= SupplymFRRup_A + SupplymFRRup_D && [mFRR\ up\ MCP = 80€/MWh]
\end{aligned}
$$

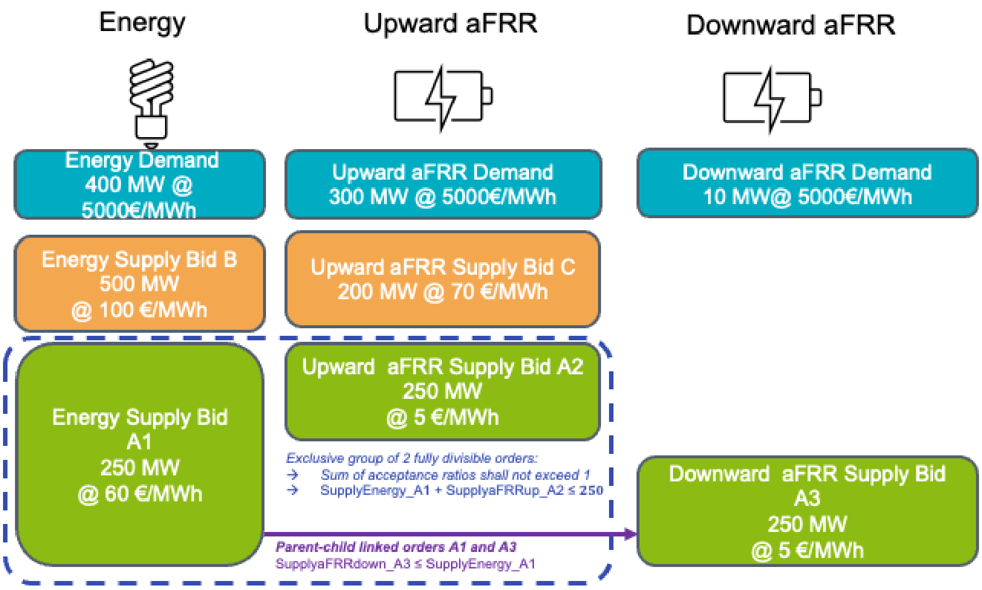
$$
\begin{gathered}
SupplyEnergy_A\ + SupplyaFRRup_A + SupplymFRRup_A \leq 250 \\
SupplyEnergy_A, SupplyaFRRup_A, SupplymFRRup_A \quad \geq 0
\end{gathered}
$$

$$
\begin{gathered}
0 \leq\ SupplyEnergy_B\ \leq 500 \\
0 \leq\ SupplyaFRRup_C\ \leq 200 \\
0 \leq\ SupplyaFRRup_D\ \leq 300
\end{gathered}
$$

Figure 5: Welfare maximization problem of Example 2

Illustration of the principles with both upward and downward products

We now illustrate how bidding and price formation works for a market participant bidding for upward and downward products. To simplify the presentation, we first examine an example – see Figure 6 – where a market participant A is bidding for energy via bid A1, a single upward capacity product via bid A2, and a single downward capacity product via bid A3. Links between the bids A1, A2 and A3 express the interdependencies and are depicted in Figure 6.



Market Results	Energy	Upward aFRR	Downward aFRR
Market Prices	100 €/MWh	70 €/MWh	30 €/MWh
Bid A1 Accepted Vol.	10	-	-
Bid A2 Accepted Vol.	-	240	-
Bid A3 Accepted Vol.	-	-	10
Bid B Accepted Vol.	390	-	-
Bid C Accepted Vol.	-	60	-

Figure 6: Example 3 - Linked bids for energy and balancing capacity products of opposite direction

In this example, if there were no downward aFRR demand, all the capacity of the asset of market participant A would be used to provide upward aFRR, i.e. bid A2 would be fully matched while bids A1 and A3 would be rejected: the reasons why it is the case are similar to the ones given above for the first example in Figure 2.

However, bid A3 of market participant A is required to meet the demand of 10 MW of downward aFRR demand, which is implicitly forcing bid A1 to provide 10 MW of energy in view of the parent-child bid linking. The bid linking requires that the volume of downward balancing capacity accepted from bid A3 be at most the volume of energy accepted from bid A1. This bid linking essentially reflects that an asset should produce energy to be able to provide downward balancing capacity[19].

The upward aFRR market price will be set by the marginal bid C and the energy market price will be set by the marginal bid B. These market prices correspond respectively to the marginal welfare decrease that would result from the request to meet one extra MW of inelastic upward aFRR demand, and one extra MW of energy.

Let us now see why the market price of the downward aFRR is 30 €/MWh, considering again two points of view: (a) the marginal welfare variations that would result from requiring to meet one extra MW of downward aFRR demand, and (b) the optimality of the profit for market participant A bidding the linked bids A1, A2 and A3, considering the marginal market prices as a given.

---

[19] Note that aFRR-down only bids could also be submitted by market participants that do not explicitly provide energy in the day-ahead market.

If an additional MW of downward aFRR would need to be provided by market participant A, this market participant will then need to provide one extra MW of energy via bid A1 (to increase the ability of bid A3 to provide downward balancing capacity, given the bid linking), leading to a reduction of the provision of upward aFRR from bid A2 by one MW in view of the bid linking modeling the total capacity. This leads to an extra cost of 30€/MWh due to

+ 5 €/MWh	additional reservation cost for downward capacity from bid A3
+ 60€/MWh	additional generation cost of from bid A1 for producing 1 extra MW
- 100€/MWh	savings from reduced energy generation of bid B
+70 €/MWh	since one extra MW of upward BC needs to be procured from bid C
- 5€/MWh	savings in reservation costs for upward capacity from bid A2
+30€/MWh	Additional total cost to provide 1 addition MW of downward aFRR

Let us now consider the point of view of market participants. Given the market prices of energy, upward aFRR and downward aFRR, no market participant would prefer another allocation of its bids. We discuss the specific case of market participant A and its linked bids A1, A2 and A3.

A price of 30€/MWh for aFRR downward (together with a price of 70€/MWh for aFRR upward and 100€/MWh for energy, as set by the partially accepted bids in these markets) leads to an optimal allocation for market participant A. Indeed , it earns 100-60=40€/MWh via bid A1 for the energy sold, which also enables an additional revenue of 30-5=25€/MWh via bid A3 for aFRR down, hence pocketing 65€/MWh for energy and downward aFRR. If the aFRR downward price would be lower, the market participant A would be better off not selling energy and downward balancing capacity, and benefit instead from 70-5=65€/MWh by selling upward balancing capacity. If the aFRR downward price would be higher, he would then prefer selling more energy and downward aFRR than obtaining 70-5=65€/MWh to provide aFRR upward capacity.

Welfare optimality and profit maximization in the general case

More generally, and as already highlighted above, under the assumption that there are no "non-convexities" (see Chapter 5), marginal prices will be such that the allocation decided by the maximization of the welfare will also be profit optimal from the point of view of market participants[20]. This means that the allocation of the bids is in general optimizing the profit-maximization problem of a market participant trading via linked bids, or via combined bids(see Chapter 3 for a comparison of linked bids and combined bids). An example of such a profit maximization problem in the presence of multiple products is given in Figure 7.

From this general fact, we can deduce rules such that if an asset is providing strictly positive volumes of energy, downward capacity and upward capacity, then the marginal profits from providing energy and downward capacity must equal the

[20] See the beginning of Section 2.1 and Footnote 10.

marginal profits of providing upward capacity (since these provisions 'energy & downward reserve' versus upward reserve are mutually exclusive, and it should not be more profitable to allocate more to one of these alternatives than what is prescribed by a welfare optimal allocation)[21].

This rule for an asset providing a strictly positive volume of energy and upward and downward balancing capacity can also be deduced from the so-called KKT conditions of the profit maximization problem in Figure 7 below. Assume that mFRR is out of scope. If $AcceptedVolume_{Energy} > 0, AcceptedVolume_{aFRRup} > 0$ and $AcceptedVolume_{aFRRdown} > 0$, we can deduce from the KKT (or dual and complementarity) conditions attached to the problem that:

$$
\begin{aligned}
ShadowPrice1 &= \left(MCP_{aFRRup} - BidPrice_{aFRRup}\right) \\
ShadowPrice2 &= \left(MCP_{aFRRdown} - BidPrice_{aFRRdown}\right) \\
ShadowPrice1 - ShadowPrice2 &= \left(MCP_{Energy} - BidPrice_{Energy}\right)
\end{aligned}
$$

After rearrangement, we obtain the conclusion stated above:

$$
\begin{aligned}
&\left(MCP_{Energy} - BidPrice_{Energy}\right) + \left(MCP_{aFRRdown} - BidPrice_{aFRRdown}\right) \\
&\qquad = \left(MCP_{aFRRup} - BidPrice_{aFRRup}\right)
\end{aligned}
$$

Similar consequences could be deduced for each of the various combinations of products an asset is delivering according to the welfare maximizing allocation (for instance if it delivers energy but no reserve, or only upward capacity, etc.). In view of the large number of possible combinations, we do not exhaustively discuss all of them.

$$
\max_{\substack{AcceptedVolume_{Energy},\\ AcceptedVolume_{aFRRup}\\ AcceptedVolume_{aFRRdown}\\ AcceptedVolume_{mFRRup}\\ AcceptedVolume_{mFRRdown}}}
\begin{aligned}
&\left(MCP_{Energy} - BidPrice_{Energy}\right)AcceptedVolume_{Energy} \\
&+\left(MCP_{aFRRup} - BidPrice_{aFRRup}\right)AcceptedVolume_{aFRRup} \\
&+\left(MCP_{aFRRdown} - BidPrice_{aFRRdown}\right)AcceptedVolume_{aFRRdown} \\
&+\left(MCP_{mFRRup} - BidPrice_{mFRRup}\right)AcceptedVolume_{mFRRup} \\
&+\left(MCP_{mFRRdown} - BidPrice_{mFRRdown}\right)AcceptedVolume_{mFRRdown}
\end{aligned}
$$

<u>Subject to</u>:

$$AcceptedVolume_{Energy} + AcceptedVolume_{aFRRup} + AcceptedVolume_{mFRRup} \leq TotalCapacity \qquad \textit{[ShadowPrice1]}$$

$$AcceptedVolume_{Energy} - AcceptedVolume_{aFRRdown} - AcceptedVolume_{mFRRdown} \geq 0 \qquad \textit{[ShadowPrice2]}$$

$$AcceptedVolume_{Energy}, AcceptedVolume_{aFRRup}, AcceptedVolume_{aFRRdown}, AcceptedVolume_{mFRRup}, AcceptedVolume_{mFRRdown} \geq 0$$

Figure 7: Profit maximization problem of a market participant on the supply side, bidding for energy and multiple upward and downward products.

[21] This specific statement holds as long as there are no additional constraints limiting the volume a bid can provide for a specific product (e.g. the asset can provide at most X MW of upward aFRR balancing capacity). If such limits apply, the specific statement remains valid as long as they are not reached. These conclusions follow again from the general profit optimality principles discussed above.

Finally, additional examples with multiple linked bids, further illustrating co-optimization and price formation in these contexts, are provided in Annex C.

2.2 Explicit bidding

With Explicit Bidding, market participants explicitly add to their bids a forecast of the endogenous costs they expect to face in the co-optimized auction, such as opportunity costs for providing upward balancing capacity instead of energy, or negative profits for producing energy at a loss in order to provide downward balancing capacity.

We have discussed with Example 1 in Figure 2 the fact that a market participant bidding both for energy and balancing capacity, which is required to provide upward balancing capacity, may face missed profits in the day-ahead energy market (reciprocally, may face missed profits in the balancing capacity market if they are matched in the day-ahead energy market despite being profitable in the balancing capacity market).

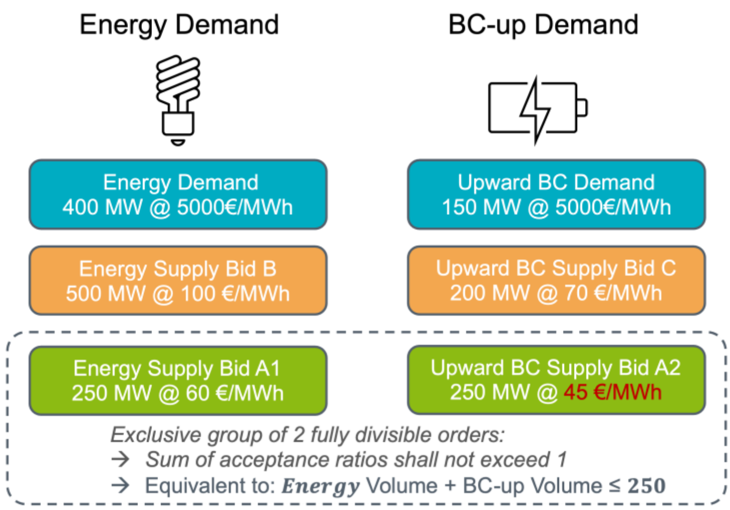
We have also discussed the fact that in all cases, given marginal pricing theory, these lost profits, for example in the energy market, are fully offset by the profits made in the BC market so that there is no need to directly incorporate a forecast of these lost profits into the BC bid price of a "linked BC bid" (or of the BC part of a combined bid, see Chapter 3) representing the combined offer of an asset or portfolio.

Explicit bidding may look more familiar to market participants bidding today in balancing capacity markets, since the underlying idea is to rely on simple price-quantity pairs combined with bid linking, where market participant submit bid prices that would be similar to the ones they would bid today in *sequential* balancing and energy markets.

However, a closer look with simple examples show that several issues would be faced by market participants and stakeholders if they do not correctly adjust their bid prices in the presence of bid linking constraints, which we discuss and illustrate below on toy examples.

Issue 1: the single-product merit order of the bids for a given product may not be respected

Consider Example 1 in Figure *2* but including now in the BC bid cost of bid A2 the (perfect) forecast of the day-ahead energy opportunity cost of 40 €/MWh the bid would be facing if (partially) accepted in the BC market (on top of the 5€/MWh accounting for other costs).



Market Results	Energy	Upward Balancing Capacity
Market Prices	100 €/MWh	70 €/MWh
Bid A1 Accepted Vol.	250	-
Bid A2 Accepted Vol.	-	-
Bid B Accepted Vol.	150	-
Bid C Accepted Vol.	-	150

Figure 8: Example 4 - Explicit bidding of the Lost Opportunity Cost and the Merit Order Issue

The ‘declared’ BC cost of bid A2 is now 45 €/MWh. However, as we will soon see, the true global cost for the welfare optimization function of procuring BC from bid A2 is actually 85 €/MWh as, like in Example 1, the opportunity cost experienced by bid A1 in the energy market – due to the bid linking between bid A1 and bid A2 – is considered as a net welfare loss by the optimization. The reasoning is reproduced here to aid the exposition. For each MW of BC procured from bid A2 instead of using bid C:

1. A direct cost of 45 €/MWh is incurred, corresponding to the explicit bid cost of bid A2 appearing in the welfare objective function (see the market clearing optimization model in Figure 9).
2. *An extra ‘indirect’ cost of 40* €/MWh *is incurred because one now needs to procure one extra MWh of energy from the more expensive bid B at 100 €/MWh instead of the less expensive bid A1 at 60 €/MWh.*
3. 70 €/MWh are saved from not procuring balancing capacity from bid C. The cost savings are smaller than the 40+45 = 85€/MWh extra costs incurred by matching one MW of A2 in the balancing capacity market.

It is this “indirect” *(or “implicit”) welfare cost* in point 2 that leads to a preference for procuring all the upward BC from bid C, even though bid A2 appears to have a lower BC bid cost than bid C.

As a result of this discussion, market participants who incorporate forecasted opportunity costs of providing upward balancing capacity instead of energy will face a higher risk of rejection. This is because it effectively leads to double counting of opportunity costs: the forecast made by the market participant is added to the exact opportunity cost already accounted for by the welfare maximization.

The corresponding welfare maximization problem and the resulting optimal matching are given in Figure 9.

Since the single-product (or 'apparent') merit order for the BC-up product is not followed[22], it becomes inevitable that bids for this product will either be paradoxically rejected or paradoxically accepted based on this 'single-product' merit order. In our example, we will either have bid A2 paradoxically rejected if the upward balancing capacity price is set at 70€/MWh to avoid having bid C paradoxically accepted, or bid C paradoxically accepted if the price is set at 45€/MWh (or below) to avoid having bid A2 paradoxically rejected.

It may be argued that this problem can be fixed by explicitly enforcing the merit order on the BC-up acceptances. Enforcing the merit order on BC-up acceptances means ensuring that BC-up bids are accepted in order, from the seemingly least expensive to the more costly ones. This can be achieved, for example, by using binary variables or employing 'special ordered sets of type 1.'

However, such an approach gives rise to various issues that will be discussed in the next subsections.

$$
\begin{aligned}
max\ Welfare \coloneqq\ & 5000\ EnergyDemand + 5000\ BCupDemand \\
& - 60\ SupplyEnergy_A\ - 45\ SupplyBCup_A \\
& - 100\ SupplyEnergy_B\ - 70\ SupplyBCup_C
\end{aligned}
$$

subject to:

$$0 \le\ EnerggyDemand \le 400$$
$$0 \le\ BCupDemand \le 150$$

$$EnerggyDemand = SupplyEnery_A + SupplyEnery_B \qquad [Energy\ MCP = 100\ €/MWh]$$
$$BCupDemand =\ SupplyBCup_A +\ SupplyBCup_C \qquad [BC\ up\ MCP = 70\ €/MWh]$$

$$SupplyEnergy_A\ + SupplyBCup_A \le 250$$
$$SupplyEnergy_A, SupplyBCup_A\ \ \ge 0$$

$$0 \le\ SupplyEnergy_B\ \le 500$$

$$0 \le\ SupplyBCup_C\ \le 200$$

Optimal Allocation
Asset A provides 0MW of upward balancing capacity and 250 MWh of Energy,
Asset B provides 150 MWh of Energy,
Asset C provides 150 MW of BC-up.

Figure 9: Welfare maximization problem of Example 4

[22] Considering all bids for that BC-up product, whether they are linked or not to bids for other products.

2.3 Inherent limitations of explicit bidding

In this section, we further analyze the inherent limitations of explicit bidding.

We first explore the challenges associated with attempting to enforce merit orders for balancing capacity products to address the issues faced by market participants using explicit bidding, as highlighted in the previous section. Using a basic example, we demonstrate that it is not feasible to enforce merit orders across all products. Consequently, for instance, when upward aFRR and upward mFRR are co-optimized, it becomes impossible to consistently enforce the single-product (or 'apparent') merit order for both products simultaneously.

We then demonstrate that forecast errors in estimating lost opportunity costs can significantly reduce welfare or lead to losses for market participants.

Issue 2: Enforcing single-product merit order acceptance across all products while satisfying bid linking conditions is infeasible in general

This means that, in general, it is mathematically impossible to fully resolve Issue 1 by adding explicit single-product merit order enforcement constraints.

Consider the example further described graphically in Figure 10, where two bids D1 and D2, linked by an exclusive condition similar to the one applicable to bids A1 and A2 above, are now added to the example data given in Figure 8.

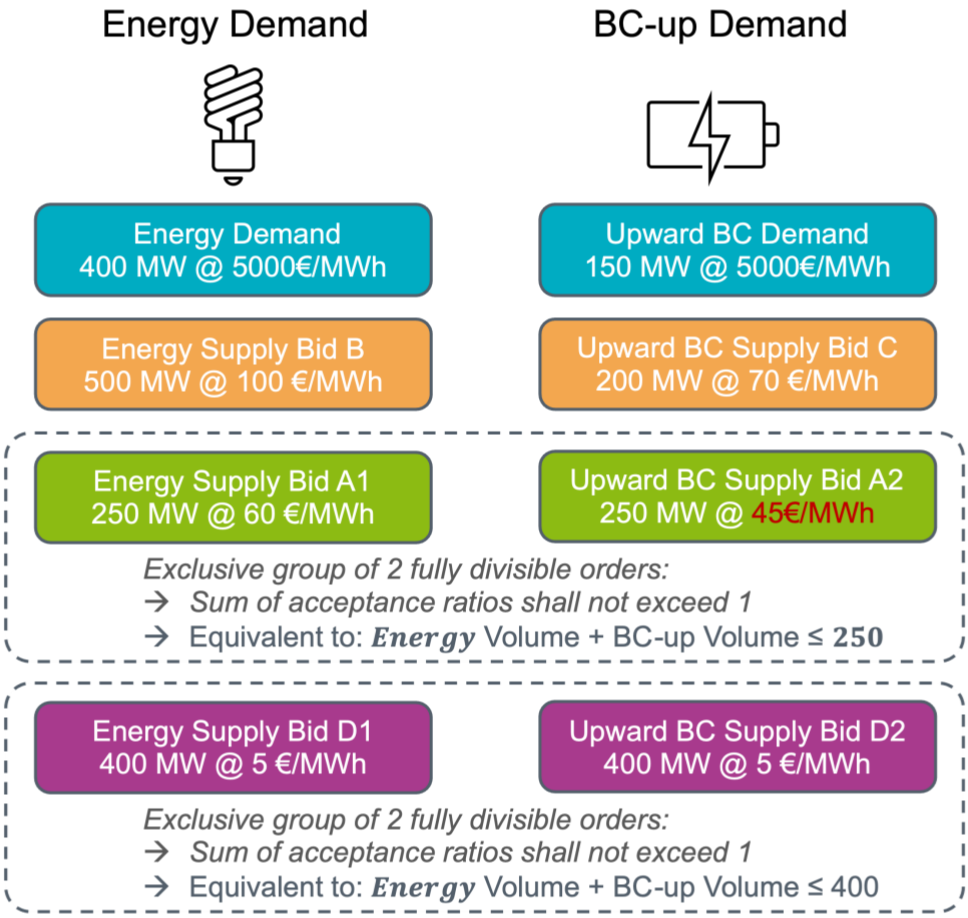


Figure 10: Example 5 on merit orders and bid linking

We can observe that given the "bid linking" attached to bids D1 and D2 – the sum of the provided energy and BC-up must be below 400 MW – if the bid D1 is fully matched in the energy market according to the merit order[23], bid D2 cannot be matched in the BC-up market despite being first in the merit order based on the declared BC-up costs. Vice versa, if bid D2 is matched in the BC-up market (meeting the demand of 150 MW), bid D1 cannot be fully matched in the energy market despite being first there in the single-product merit order.

[23] It is the energy bid with the lowest price.

Option 1: Market results if the cheap exclusive bid D1 is used in the energy market (excluding D2 in the upward BC market)

Market Results	Energy	Upward Balancing Capacity
Market Prices	5 €/MWh	45 €/MWh
Bid A1 Accepted Vol.	-	150
Bid A2 Accepted Vol.	0	-
Bid D1 Accepted Vol.	400	-
Bid D2 Accepted Vol.	-	0
Bid B Accepted Vol.	0	0
Bid C Accepted Vol.	0	0

Option 2: Market results if the cheap exclusive bid D2 is first used in the upward BC market (lower D1 availability in the energy market)

Market Results	Energy	Upward Balancing Capacity
Market Prices	60 €/MWh	5 €/MWh
Bid A1 Accepted Vol.	150	-
Bid A2 Accepted Vol.	-	0
Bid D1 Accepted Vol.	250	-
Bid D2 Accepted Vol.	-	150
Bid B Accepted Vol.	0	0
Bid C Accepted Vol.	0	0

Figure 11: The market outcome in Example 5 depends on which is the product where the merit order is enforced.

In other words, it is not possible to enforce the ‘single-product merit order’ across all co-optimized products while also adhering to the ‘bid linking conditions’ which may require that the total matched volumes of two bids, representing energy and BC-up that an asset can provide, do not exceed the asset's total capacity.

However, bid linking conditions cannot be relaxed because they may represent hard technical constraints that the market participant wants to reflect in its offer.

Because the merit order will not be adhered to for certain products, it will be impossible to define prices avoiding ‘paradoxically rejected’ bids without causing ‘paradoxically accepted’ bids, which is not acceptable: with only divisible bids, there is no good economic justification for market participants to incur losses that would necessitate compensatory payments if that can be avoided by an adequate market design. Paradoxically rejected bids may be seen as bids that are “skipped” in the ‘single-product merit order’ for energy or some balancing capacity products.

Furthermore, enforcing merit orders for certain products while relaxing them for others[24] raises the issue of 'product prioritization.'

However, the core idea behind co-optimization is that conflicting allocation choices are resolved by maximizing welfare. Prioritizing merit orders for certain products disrupts the market-based resolution of these conflicts. As shown above, it also results in price signals that do not align with the allocation.

[24] In other words, allowing the skipping of bids for certain products while ensuring that bid skipping is not permitted for others.

The product prioritization discussed here closely resembles unilateral bid linking, as examined in the SDAC MSD Co-Optimization Roadmap Study [1], which was later discarded by stakeholders for similar reasons.

Issue 3: Forecast errors of day-ahead prices can degrade welfare

Consider Example 4 (see Figure 8 above) and assume that the merit order is applied in the upward BC market. In similar cases where enforcing the single-product merit order for both energy and upward balancing capacity is not feasible, this additional assumption prioritizes the upward BC market and produces results similar to those obtained through sequential market clearing, with the upward BC market cleared first, under the assumption of perfect price forecasts available to market participants.

Given that the opportunity cost forecast of bid A2 is accurate, we can see that the market outcome results in the same welfare-optimal allocation as in the implicit bidding scenario from Example 1.

However, if bid A2 overestimates its opportunity costs with a forecast of 70 €/MWh, resulting in a BC-up bid price of 75 €/MWh, it will be excluded from the allocation determined by the explicit bidding approach, where the merit order is enforced in the upward BC market.

This will result in a suboptimal allocation: the 150 MW of upward BC are now provided by bid C instead of bid A2, with a net welfare loss of 25 €/MWh to be multiplied by 150 MW and the market clearing period:

- In the upward BC market, the more expensive supply from bid C, priced at 70 €/MWh, is utilized instead of bid A2's supply, which had a cost of 5 €/MWh excluding the estimated lost opportunity costs in the energy market, resulting in a net impact of 65 €/MWh.

- In the energy market, replacing the acceptance of 150 MW of bid A2 in the BC-up market by the acceptance of 150 MW from bid A1 in the energy market is resulting in a saving of 40 €/MWh, as 150 MW of expensive energy from bid B at 100 €/MWh is replaced with the less expensive energy from bid A1 at 60 €/MWh.

- The net welfare loss is hence given by the difference between 65 €/MWh and 40 €/MWh, multiplied by 150 MW and the market clearing period, assumed here to be one hour: this results in a total welfare loss of 3,750 € in this example.

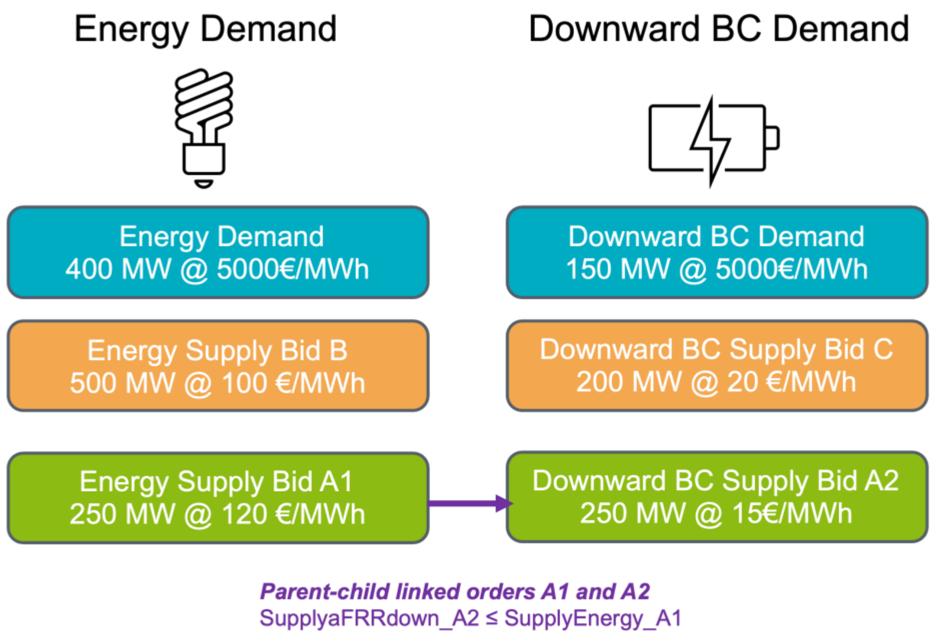
Issue 4: Forecast errors of day-ahead prices can lead to suboptimal or negative profits for market participants

The risk of suboptimal profits in case of forecast errors is also present. Indeed, if, in the context of Example 4 (see Figure 8 above), we consider that bid A2 may underestimate its eventual opportunity cost and ask for a lower price in the BC market: the bid would then collect a lower profit than it could have and only a fraction of the lost opportunity cost faced in the day-ahead energy market is recovered in that case.

The risk of negative profits can be illustrated by considering linked Energy and downward BC bids, corresponding in Figure 12 below to the linked bids A1 and A2: the downward capacity provided must be lower or equal to the provision of energy power. The bids A1 and A2 are linked via a “parent-child link” requiring that the acceptance of A2 be lower or equal to the acceptance of A1. Bid linking options are further discussed in Section 3.1.

With downward capacity, an extramarginal asset (i.e. whose marginal energy generation cost is above the energy market price) might be forced to produce energy at a loss to be able to provide downward reserve: in that case, with implicit bidding, the downward BC price will ensure that the actual losses in the energy market are recovered via the BC-down market price (see the discussion in Section 2.1). With explicit bidding, the market participant would have to explicitly add the estimation of the losses in the energy market, that need to be recovered in the market for downward balancing capacity.

In such a scenario, errors in energy price forecasting can result in actual economic losses, as demonstrated in the following example:



Market Results	Energy	Upward Balancing Capacity
Market Prices	100 €/MWh	15 €/MWh
Bid A1 Accepted Vol.	250	-
Bid A2 Accepted Vol.	-	150
Bid B Accepted Vol.	150	-
Bid C Accepted Vol.	-	0

Figure 12: Example 6, on the economic losses due to explicit bidding

In the above example, it is assumed that the market participant A has a production cost of 120 €/MWh and a downward balancing capacity “reservation cost” of 5 €/MWh[25]. Thus, if the market participant A anticipates the energy price to be 110 €/MWh, the market participant would set a bid price of 15 €/MWh for downward BC for A2.

However, since the actual energy price is eventually 100 €/MWh and bid A2 providing downward BC is activated due to the enforcement of the merit order in the downward BC market (forcing the generation of energy at a loss), we face a situation where the payment bid A2 receives for providing downward BC is ultimately insufficient to cover the losses bid A1 incurs in the energy market.

More precisely, since:

- Bid A2 is accepted for 150 MWh in the downward BC market, collecting 2250 €.
- Bid A1 is also forcefully accepted for 150 MWh in the Energy market, collecting 15000 €.
- Bid A1 has a production cost of energy of 18000 €, and bid A2 has a reservation cost of 750 €.

In total, the market participant bidding the bids A1 and A2 incurs a cost of 18,750 € but can only recover 17,250 €, resulting in a net loss of 1,500 €.

It must be noted that in an implicit bidding scenario, bid A2 would have only provided a BC price of 5 €/MWh to cover its reservation costs: however, it would have been rejected in favor of Bid C. This is because the implicit price of a bid accounts also for all the losses that may derive from the activation of the bid due to bid linking.

Issue 5: Negative performance impact of explicitly imposing the BC single-product merit order

Since welfare maximization alone may not yield solutions that align with the single-product merit order, additional constraints are needed if enforcement is desired. Note, however, that there is no strong rationale for this, given the sound market equilibrium properties under implicit bidding.

These additional constraints act as logical conditions: the acceptance of an order 'n', whether partial or full, depends on whether the previous order 'n-1' has been fully accepted. This full acceptance condition is represented by a binary decision variable, indicating if the condition is satisfied or not[26].

[25] By 'reservation cost,' we refer to all costs, aside from direct costs that Bidder A may incur if it is required to produce energy at a loss in order to provide downward balancing capacity.
[26] Alternatively, a large “Second Ordered Set of type 1” could be used, see for instance the following reference on SOS sets: https://www.ibm.com/docs/en/icos/22.1.1?topic=sos-what-is-special-ordered-set.

In practice, this would pose a significant challenge for any market-clearing approach, unlike the implicit bidding approach, which avoids this additional complexity while offering the market design advantages previously discussed.

Despite the possible intractability of the approach for large scale-instances, it has been implemented in a small prototype – where the merit order for the BC-up product is enforced – and tested on toy examples.

2.4 Conclusions on implicit and explicit bidding

Implicit bidding relies on classical marginal pricing. This approach yields market outcomes consistent with those seen in real-world markets that implement co-optimization, for market instances without 'non-convexities'[27].

This method ensures that market prices reflect the marginal value of energy and various reserve products, and support a competitive market equilibrium (again, in the absence of non-convexities, which are separately treated in Chapter 5).

Achieving competitive market equilibrium eliminates paradoxical acceptance or rejection: the welfare-maximizing market outcome ensures that, at the established marginal prices, no participant would prefer an alternative matching of their bids. Essentially, this means that bids are allocated where they are the most profitable, except for adjustments caused by inherent non-convexities (Chapter 5).

In a co-optimization framework, this principle implies that if a combined offer for energy and upward balancing capacity is assigned to balancing capacity, then the balancing capacity market is equally or more profitable for that asset. This holds whether bid linking or combined bids – both further discussed in Chapter 3 – are used to represent the fundamental costs. Consequently, for instance, market participants able to provide either energy or balancing capacity don't need to anticipate day-ahead energy opportunity costs—the upward balancing capacity price is sufficiently attractive to cover potential lost profits in the energy market.

This interpretation leads to consider the upward balancing capacity cost parameter as a "premium" or "reservation cost" recovered *on top* of the energy opportunity cost. Given this context, market participants should avoid incorporating into their bids opportunity costs that are "endogenous" to the co-optimized auction, i.e. caused by linking between offers for different products (see the discussion of Issue 1 and the supporting example illustrating challenges if the opportunity costs are explicitly included into upward balancing capacity cost parameters).

A similar principle applies to the pricing of downward reserves. It ensures that any potential losses from supplying energy to maintain the ability to supply downward capacity are recovered through the downward balancing capacity price. Otherwise, this would imply a suboptimal allocation for the participant, contradicting the market equilibrium principle.

Explicit bidding, which incorporates energy opportunity costs directly into the upward balancing capacity bid price for combined energy and upward capacity offers[28], introduces several challenges that result in suboptimal outcomes from both a welfare and a market participant perspective:

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[27] Non-convexities, addressed in Chapter 5, are treated differently in various power markets around the world.
[28] Or more generally, a forecast of the endogenous costs that would be caused by linkages in the offers for different products.

- **Issue 1**: The “apparent” (or “single-product”) merit order of linked bids may not be guaranteed unless explicitly enforced.
- **Issue 2**: Enforcing single-product merit order acceptance across all products while satisfying bid linking conditions is infeasible in general, as enforcing merit order acceptance for one product, combined with bid linking, mathematically results in skipped bids and deviations from the merit order for other products. This means that, in general, it is mathematically impossible to fully resolve Issue 1 by adding explicit single-product merit order enforcement constraints.
- **Issue 3**: Forecast errors can reduce overall welfare, as perfect forecasts would be required to achieve welfare levels comparable to a co-optimization setup.
- **Issue 4**: Forecast errors may result in suboptimal or even negative profits for market participants, as perfect forecasts would be required to achieve profit optimality levels comparable to a co-optimization setup.

Also, with explicit bidding, offering a single balancing capacity “bid price” that includes both fundamental costs and costs endogenous to the co-optimized auction complicates market monitoring efforts—for example, making it unclear whether a high bid price results from significant errors in forecasting opportunity costs or from strategic bidding attempts.

On another hand, implicit bidding should appear as more appealing to market participants than explicit linking.

Note that the conclusions still hold in the presence of non-convexities in the following way: fixed costs and indivisibilities bring their own set of challenges, and the specific drawbacks associated with "explicit bidding" would only add on top of the difficulties inherent to the non-convexities. Market rules should ensure that, in the absence of non-convexities, outcomes are robust and grounded in fundamental principles.

In other words, pricing in the presence of non-convexities should be built upon a strong foundation established in the simpler case without non-convexities. This is for example the case for the pricing rule currently applied in SDAC, or the pricing rules used in real-world markets implementing co-optimization.

3. Bid design - linked and combined bids

In this section, we analyze bid designs that enable market participants to offer both energy and balancing capacity, while accounting for the intrinsic linkages between these products to effectively represent their economic preferences and technical constraints[29].

It explores several ways to represent fundamental costs and technical constraints within a co-optimization framework, namely via linked bids, and via combined bids tailored for specific types of assets. Parts of the analysis are relevant to both energy-only markets and markets that co-optimize energy and balancing capacity.

Fundamental costs broadly designate in this study all costs that are not corresponding to endogenous costs as defined in Chapter 2. While an exhaustive description of all possible types of fundamental costs is out of scope, standard fundamental costs usually considered in markets based on unit bidding are further discussed in Section 3.2.3. Fundamental costs may include for instance operational variable costs such as fuel and emission costs, operational fixed costs (indivisible costs such as no load, startup and shutdown costs), policy-related costs, opportunity costs related to the use of storage, e.g. "water values", or opportunity costs related to *other auctions* such as intraday or balancing energy markets.

These fundamental costs are represented quite differently in Europe, Japan, and India compared to the United States and South American countries. This difference stems primarily from the use of portfolio bidding in most countries participating in SDAC, where 'linked bids' are employed to capture advanced portfolio cost structures. In contrast, the United States relies on unit bidding, utilizing detailed 'unit commitment and economic dispatch models' to represent the fundamental costs of individual units with high granularity. Note that unit bidding is also used in a few countries within SDAC. In most of these countries, 'complex orders' or 'scalable complex orders' are currently used, e.g., in Ireland, Spain and Portugal. However, these types of orders do not offer all the features typically found in unit commitment-based markets, with minimum up and down times being one of the key missing features.

Portfolio aims at proposing several simple standardized products allowing to aggregate several resources into a single market offer. These aggregated offers are constructed by portfolio owners based on the set of production and consumption assets present in their portfolio to be then submitted to an electricity exchange. Portfolio bidding enables asset owners to manage technical and economic constraints, as well as risk considerations, across their entire asset portfolio, thereby reducing the need for detailed and exhaustive representation of these aspects within the power exchange model.

The joint clearing of energy and balancing capacity in the day-ahead electricity market is expected to further exacerbate the challenges market participants face in accurately

[29] Note that market participants willing to offer separately energy or balancing capacity without considering specific linkages can use pure energy-only bids or pure balancing-capacity-only bids. For example, the order C in Example 1 in Figure 2 is a balancing-capacity-only order.

modeling their technical and economic constraints through simple offers. To address this increased complexity, it may be useful to ease part of the bidding process by introducing additional constraints within the proposed products, or new types of standardized offers, which we call ‘combined bids’.

In Section 3.1, using concrete examples, we specifically elaborate on the expressiveness of linked bids—similar to those in the examples of Section 2.1—which are commonly used today to represent advanced trading strategies in a portfolio bidding setup in energy-only markets.

In Section 3.2, we discuss 'combined bids', which feature a shared set of parameters, such as the total capacity of an asset, enabling joint bidding into the energy and balancing capacity markets. These combined bids of various types go from the simplest to the most advanced ones representing more specific costs or volume constraints. Section 3.2.2 explores natural extensions of existing Euphemia products to combined bids. In Section 3.2.3, we focus specifically on combined bids for thermal assets, addressing the various types of fundamental costs and technical constraints commonly modeled in markets that rely on unit-based bidding. Finally, the challenges related to the design of combined bids for storage bids are discussed in Section 3.2.4.

Our conclusions are summarized in Section 3.3. Essentially, we propose supplementing linked bids with combined bids to provide simpler bidding options for specific scenarios or to enhance expressiveness for representing complex costs and constraints more effectively.

The primary motivation is that linked bids can sometimes capture intricate interactions that are not feasible with combined bids, and conversely, combined bids, particularly those tailored for thermal or storage assets, enable the representation of specific costs or technical constraints that are challenging to express using linked bids.

Additionally, combined bids for thermal assets could improve algorithm scalability by replacing multiple block bids that describe alternative feasible schedules with a more streamlined representation of those schedules. More generally, from an algorithm scalability perspective, when both linked bids and combined bids can be used interchangeably to bid for the same asset or portfolio, using combined bids instead of linked bids may positively enhance the performance of the optimization algorithm.

3.1 Linked Bids

Linked bids refer to a family of bids for single products, either for energy or a given balancing capacity product, connected to each other by “links” modeling specific acceptance interdependencies[30]. Such interdependencies essentially come in two forms: exclusive relations when two products cannot be simultaneously offered such that one is provided at the exclusion of the other (typically energy and upward balancing capacity), and parent-child relations expressing that a product can only be offered if another product is also offered (typically energy and downward balancing capacity). These two forms of interdependency correspond respectively to two types of links already implemented in Euphemia for energy block orders: exclusive links and parent-child links. Exclusive links are links where the acceptance of one block is conditioned on the rejection of another. Parent-child links are links where the acceptance of one bid is a prerequisite to the acceptance of another[31].

We examine in this section how standard energy and balancing capacity bidding strategies can be expressed via linked bids. While a comprehensive analysis of advanced strategies employed by traders managing large portfolios through linked energy and balancing capacity bids would require a dedicated study, the examples described in
Figure 16 and Figure 17 illustrate that the flexible bid-linking options proposed in this study effectively capture complex interdependencies in the provision of energy and balancing capacity products. The proposed highly flexible bid-linking options, summarized in Section 3.3, essentially enable the application of exclusive or parent-child links to bids of varying volumes and prices across all markets and buy or sell directions[32]. This ability to express bid acceptances conditional on the acceptance of other bids, or as mutually exclusive, should be sufficient to capture all interdependencies arising in the provision of energy and balancing capacity products[33], and is further complemented by ‘combined bids’ discussed in Section 3.2, that can be tailored to specific technologies.

3.1.1 Linking Simple Bids for Energy, Upward and Downward Capacity

[30] All current energy bid formats available in Euphemia can be seamlessly converted into pure balancing capacity bids if required. Bid linking features, akin to those already available in Euphemia, can then enable market participants to define connections between their energy and balancing offers, much as they currently do when establishing linkages in pure-energy portfolio bidding scenarios.

[31] Note that the exclusive or parent-child conditions on the acceptances may apply here to acceptance ratios of divisible bids. The exclusive condition then means that the sum of the acceptance ratios across multiple bids cannot exceed 100% (extended versions can be considered). The parent-child conditions then means that the acceptance ratio of one bid must be lower or equal to the acceptance ratio of another product. Similar links can apply to activation statuses of the bids (discarding whether it is partially or fully accepted): an exclusive condition then for instance means that one bid can be partially or fully accepted (i.e., be activated) only if another bid is fully rejected. This differs from an exclusive condition on acceptance ratios limiting the total acceptance ratios of two or more bids.

[32] Note, however, that as is the case today, restrictions on the number or size of block orders submitted by a market participant may still need to be defined.

[33] Additional examples, complementing the numerous ones in this report and illustrating various portfolio trading use cases, may be provided at a later stage of the R&D process, depending on stakeholders' expressed needs.

In this section, we will discuss how to extend the bid linking capabilities already present in Euphemia to implement an effective bid linking approach to co-optimization for simple divisible bids. Note that we will only consider the case of supply bids: however, whatever is said for the linking of a supply bid with an upward balancing bid will also apply to the linking of a demand bid with a downward balancing bid, and vice versa.

In Example 1 in Section 2.1 (see Figure 2), we have seen how it is possible to offer a certain amount of fully curtailable power in both the energy and the upward balancing market. Similarly, Example 3 described in Figure 6 shows an example of a downward balancing capacity offer being conditioned to the acceptance of an energy volume in the energy market.

The scenario in Example 1 can be represented using exclusive, fully curtailable block bids[34] readily available in Euphemia[35].

Now, consider a variant of Example 1 where the bidder decides to bid only 100 MW out of its total capacity of 250 MW in the upward balancing market. In such a case, the bidder would need three different bids and one exclusive link to represent its offer, as depicted on Figure 13. The volume of bid A0 is now reduced to 150 MW (the portion of capacity where energy is not competing with upward reserve). The energy bid A1 and balancing capacity bid A2, each with a volume of 100 MW, are linked by an exclusive condition and represent the portion of the total capacity for which energy provision competes with the provision of upward balancing capacity. As discussed in Chapter 2, this portion of capacity will be allocated to products which are the most profitable to the market participant.

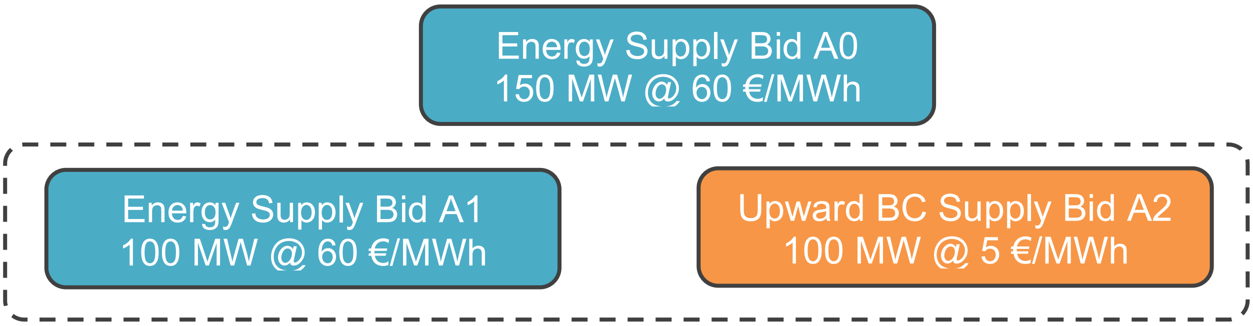

Figure 13: Illustration of the bids required to model a maximum volume of 100 MW in the upward balancing capacity market for an asset with a total capacity of 250 MW. Two exclusive bids of 100 MW model the maximum upward capacity volume, while a separate energy bid of 150 MW represent the portion of the total capacity for which there is no competition between products.

Consider now the scenario where the supply bidder is willing to bid a limited amount of downward capacity of 100 MW while considering the link with energy provision, i.e. the fact that the asset needs to be producing energy for being able to provide this downward capacity. The bidder can express the offer using again three bids and a parent child link as follows:

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[34] Curtailable block orders are block orders with a divisible part, i.e., they can be partially accepted above a minimum acceptance ratio. See, for instance, the Euphemia Public Description [10], p. 41.

[35] However, fully curtailable blocks are defined using binary variables and doing so would unnecessarily increase the computational burden on the algorithm. In practice, there is no need to use binary variables to represent fully curtailable block bids linked by an exclusive condition. In facts, the condition applies to the acceptance ratios, which can take any value between 0% and 100%, and the binary acceptance status of the bids (indicating whether they are at least partially accepted or fully rejected) is not relevant.

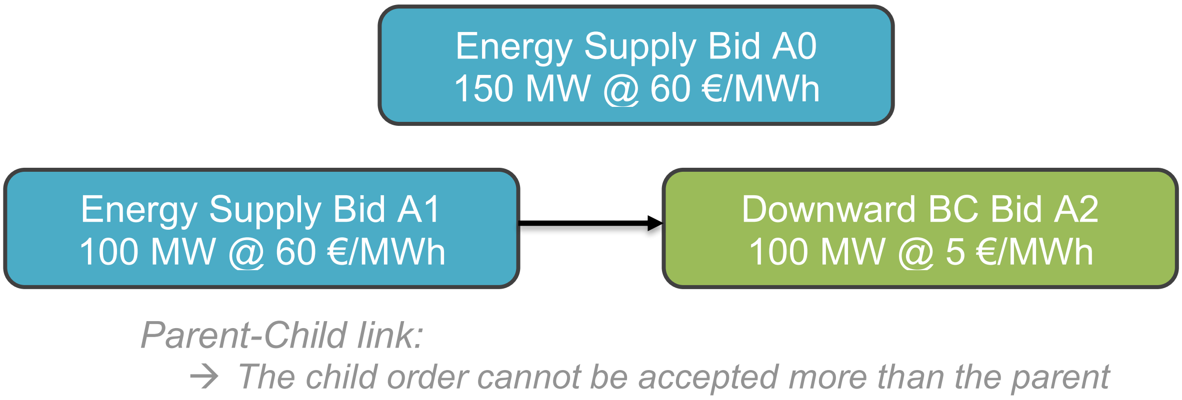

Figure 14: Illustration of the bids required to model a maximum volume in the downward balancing capacity market

It important to note that the above schema works as intended only if the volume of the parent energy bid A1 matches the volume of the child downward BC bid A2[36].

Assume now that the bidder intends to participate in the three markets with different amounts of maximum accepted power. Designing an appropriate bid linking strategy to accommodate such requirement may be less straightforward than it seems at first glance. Specifically, a new type of exclusive condition, defined in terms of power rather than acceptance ratio, must be deployed. The new exclusive condition is necessary to ensure that, for any possible activation scenario, the bid would never be required to deliver more than its maximum output power of 250MW. Additionally, we still need to use the parent-child condition introduced in the last example to ensure that the accepted downward capacity is backed by enough power delivery to be fully executable.

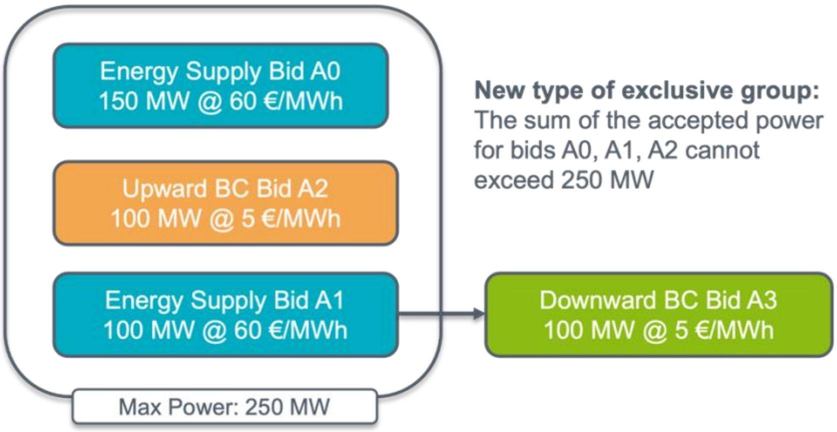

Figure 15: Illustration of the new type of link required to model maximum volumes both for upward and downward capacity.

It is important to note that the obtained linking is fully equivalent to one single combined bid of the type that will be discussed later in this chapter, but it requires four bids, two

36 Currently, no mechanism is foreseen to check or ensure that such a requirement holds, and therefore, the responsibility for verifying the correctness of the bidding strategy falls onto the bidder. Creating such a mechanism would require the algorithm to be able to understand the intent behind the parent-child link. Alternatively, a specialized link imposing the identity of volumes condition could be created, but doing so would be equivalent to the creation of a combined bid.

links, and the ability of the market participant to correctly navigate the intricacies of the new bid linking approach.

3.1.2 Representing indivisibilities and fixed costs

In this section, some strategies to bid fixed costs and indivisibilities with a bid linking approach are proposed. Consider the complete example presented at the end of the previous section and assume that the bidder is now concerned with defining some minimal production level (ex. 50MW) and some activation price to cover its start-up costs.

In this case, we should consider yet another bid: a take-or-leave-it bid, where the bidder will account for the start-up cost into and the minimum output power:

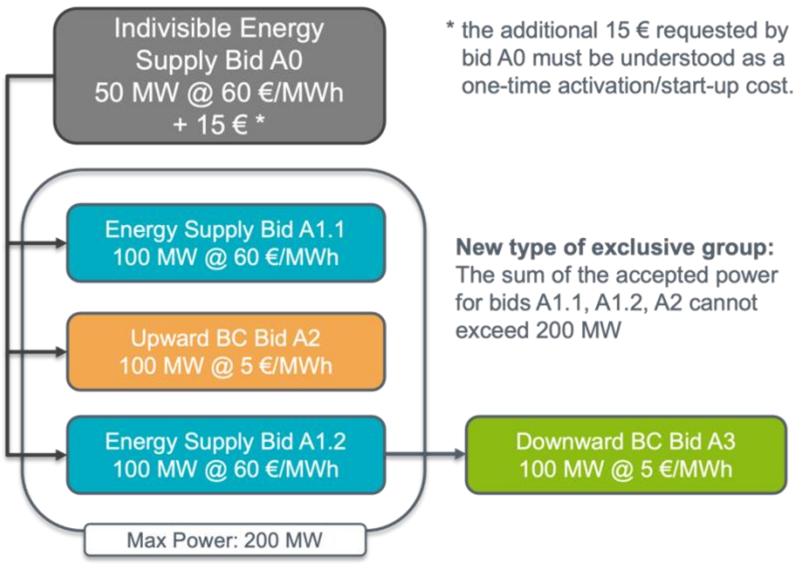

Figure 16: Illustration of bid linking for representing indivisibilities and fixed costs. The rounded frame corresponds to a set of mutually exclusive bids (the total amount of accepted power must not exceed 200 MW), while plain arrows correspond to parent-child links.

With this approach, it is also possible to support activation prices (one-time activation or start-up cost) without minimum accepted power (possibly useful to control the number/duration of storage charging/discharging cycles): this would require allowing for 0MW power blocks acting as parent blocks incurring the activation price[37], or to define a new type of block to which a fixed activation cost is attached[38].

It is worth noting that the approaches presented in the current and the previous section are the simplest but not necessarily the most computationally efficient. This is because bidding schemas like the one above present some symmetry in the possible

[37] Note that having a block with a volume of 0 MW as a parent is currently not allowed in Euphemia.

[38] Such a block would, in most cases, correspond to a specific type of scalable complex order (SCO) already available in Euphemia. The key difference between a block and a similar SCO lies in the intertemporal constraints applied on the acceptance ratio: for a block order, the acceptance ratio remains constant across all periods covered by the order, whereas SCOs with a load gradient of 0 require the *matched volume* to remain constant across the different periods. The conditions are not fully the same for profiled block which have different bid volumes per period.

acceptances. For example, if only 100MW of power is accepted for the above bid group, such power can be accepted either from A1.1, A1.2 or any mixture of the two. This indeterminacy will in turn lower the effectiveness of the convex relaxation of the bidding schema, slowing down the Branch and Bound process usually deployed to obtain the acceptances in presence of non-convex bids. It is possible to design an equivalent bidding schema which does not present this issue, but its representation is more complex, and its explanation would exceed the scope of the current section.

Once again, the above set of bids can be collected in a single integrated bid that, besides being easier to represent, would also solve the indeterminacy issue. An example of such combined bid is presented in Section 3.2.1.

3.1.3 The flexibility advantage of bid linking

It is shown here that bid linking allows for the representation of complex scenarios that may not be achievable with a predefined set of combined bid types. While it is always possible to customize a combined bid to meet specific needs, the example below highlights the flexibility of bid linking, which removes the necessity for excessively tailored combined bids in unique cases. Furthermore, it is worth noting that ensuring comprehensive coverage of all possible portfolio trading strategies through various types of combined bids is inherently challenging or unfeasible.

Assume now that the bidder in the example illustrated in Figure 17 is also offering to the downward balancing market the possibility of shutting down completely its production. To represent that, we need to account for the indivisibility of the minimum generation level by creating an indivisible downward BC bid that can be activated only when all the divisible production accepted in the energy market has also been accepted in the downward balancing market (so that the net production would be zero if the downward balancing offer is activated).

This option requires that the same amount of power is sold as energy and as downward balancing, and this is not possible to enforce using the bids family that we have built so far. However, we can represent such an option by creating a second alternative bid family connected to the first via an exclusive link. The new bids family requires that all power accepted in the energy market must also be accepted in the downward balancing market and does not allow for accepted upward balancing capacity. The new bidding schema can be represented as follows:

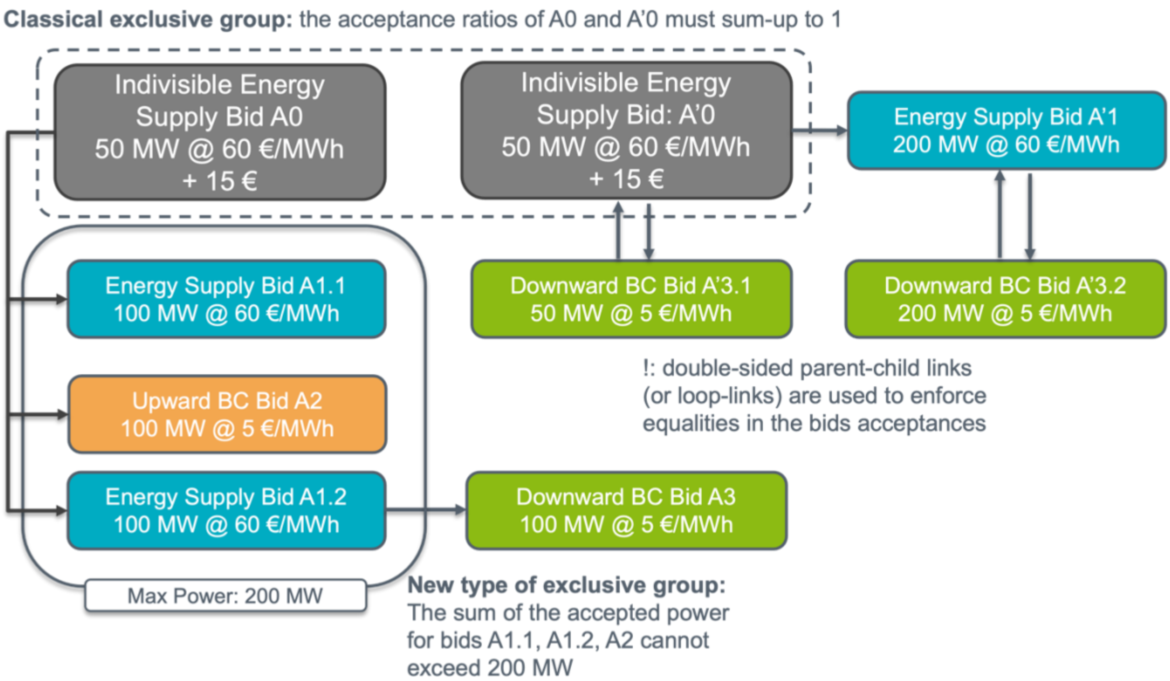

Figure 17: Illustration of a specific scenario not covered by simple combined bids or combined bids tailored for thermal assets. The rounded and dotted frames each correspond to mutually exclusive bids, while plain arrows correspond to parent-child links.

Now, despite being quite complex and using double-sided parent-child links, the above representation expresses exactly the desires of the bidder without requiring specialized bid types.

Once again, using combined bids can help to significantly simplify the above schema, an example of that is given in Section 0. However, getting rid of all the links requires the creation of an ad-hoc combined bid for this specific case, which may be impractical if the represented need is not exceedingly common. For this reason, the ability to link bids should be retained also if combined bids are introduced in the bidding language.

3.2 Combined Bids

A combined bid is a bid that simultaneously offers multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid.

In this section we will show that using combined bids can simplify the task of representing the bid offers discussed in the previous section, since they provide fully equivalent but easier to use alternatives to linked bids for most of these scenarios. The aim is not to suggest the complete replacement of linked bids with combined bids. We rather suggest mixing two approaches to create a rich yet simple and efficient bidding language. Concretely, we suggest complementing the linked bids approach (especially suitable to bid complex portfolios) with combined bids that offer simpler bidding options for basic scenarios[39]. In this context, market participants might prefer to use linked bids for representing complex portfolios or strategies, while leveraging the simplicity of combined bids in specific cases.

3.2.1 A generalized (non-convex) combined bid

Let us take as an example the bid linking presented in Section 3.1.2. This example can be represented by a single "generalized" block bid which allows for the definition of a maximum and minimum upward/downward balancing capacity offer:

Table 1: Example in

Figure 16 represented as a combined bid.

Activation Cost	Variable Price	Min. Power (Energy)	Max. Power	Max. Up. BC	Up. BC Price	Max. Down. BC	Down. BC Price
15 €	60 €/MWh	50 MW	250 MW	100 MW	5 €/MWh	100 MW	5 €/MWh

This generates the following bid:

- Activation/Startup cost: $15\ €$.
- Minimum power (Energy only): $50\ MW\ @\ 60\ €/MWh$.
- Dispatchable range price: $60\ €/MWh\ up\ to\ 200\ MW$.
- Upward BC: $up\ to\ 100\ MW\ @\ 5\ €/MWh\ (+\ energy\ opportunity\ cost^{40})$.

[39] Combined bids tailored for thermal or storage units also enable a finer representation of the fundamental costs and technical constraints of these assets, as discussed in Section 3.2.3 and Section 3.2.4.

[40] The energy opportunity costs refer here to the endogenous costs incurred if, due to the linking constraints, the asset is providing upward balancing capacity at the exclusion of energy that could have

- Downward BC: $up\ 100\ MW\ @\ 5\ €/MWh\ (+\ losses\ in\ the\ energy\ market$[41]).
- Energy and Upward Balancing Capacity linking: $Dispatchable\ Range\ +\ Upward\ Balancing\ Capacity \leq\ 200\ MW$.
- Energy and Downward Balancing Capacity linking: $Dispatchable\ Range\ -\ Downward\ Balancing\ Capacity \geq\ 0$.

Combined bids like the one above can be efficiently handled by the clearing algorithm and are arguably easier to utilize for the market participant than their equivalent linked bids.

What still needs to be identified is the exact list of combined bids that can be offered in the co-optimized market. Such choice should be made considering the actual needs of the market participants in terms of fundamental cost and technical constraints to be represented.

In Section 3.2.2, we first discuss which combined bid counterparts could be proposed for various existing products in SDAC.

In Section 3.2.3, we elaborate on the added value of combined bids tailored for thermal assets, that can represent a large set of fundamental costs and technical constraints, inspired by the features available in markets based on unit bidding. A menu of features can be proposed that could be implemented in a stepwise approach in Euphemia on a need basis.

The challenges related to the design of combined bids for storage bids are discussed in Section 3.2.4.

The bid design presented here is generally non-convex. However, in case both the activation cost (e.g., modeling a start-up cost) and the minimum acceptance power are set to zero by the bidder, the bid becomes convex and can be dealt with accordingly (binary variables are then not required).

3.2.2 Existing bidding products in Euphemia and their combined bid counterpart

The purpose of this section is to establish a baseline for the possible future bidding language for the co-optimized market using combined bids. To this end, we will first go through the main products and features provided by Euphemia to-date and discuss their natural extension to the co-optimized market in the form of combined bids.

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been profitably provided. The endogenous costs are not explicitly bid here where we assume that the market participant proceeds with “implicit bidding”, but they would nonetheless be recovered through the upward balancing capacity market price, see the discussion in Chapter 2.

[41] The losses in the energy market refer here to the endogenous costs incurred if, due to the linking constraints, the asset is forced to produce energy at a loss to be able to provide downward reserve. The endogenous costs are not explicitly bid here where we assume that the market participant proceeds with “implicit bidding”, but they would nonetheless be recovered through the downward balancing capacity market price, see the discussion in Chapter 2.

Step Bids

Step bids, formerly called hourly orders, are the most basic form of product offered by Euphemia. They represent a fully divisible supply/demand offer with a constant price spanning a single period. Extending these bids to allow for the inclusion of balancing capacity for a co-optimized market is straightforward and include the following points:

- On top of the maximum power offered for energy supply or demand, the bidder defines a maximum upward and downward balancing capacity[42].
- The bidder can also declare an upward/downward reservation cost to be considered in the profit computation for the balancing market[43].
- The bid acceptances must satisfy the following conditions:
    - The power sold (bought) in the energy market must not exceed the maximum supply (demand) power for the bid. Both balancing capacities should respect their respective maximum.
    - The power sold (bought) in the energy market plus the upward (downward) capacity reserved must not exceed the maximum power supply (demand) of the bid.
    - The downward (upward) capacity reserved must not exceed the power sold (bought) in the energy market.

Note that, since these are 'well-behaved' or convex products, the profit maximization principle dictates that a step bid can only be (partially) accepted in a way that maximizes its profit, irrespective of the combination of accepted products. This implies that if a bid faces an opportunity cost in one market due to it being accepted in another, the profit the bid collects in the second market will cover the opportunity cost it faces in the first.

The combined bid in Table 1, after dropping the "activation cost" and the "minimum power" for energy, is an example of such a step order generalized to a co-optimization setup. Note that instead of specifying a single variable cost for energy, a stepwise curve with a marginal cost per output level could also be specified.

Interpolated Bids

Interpolated bids operate similarly to step bids with the difference that their price in the energy market is a linear function of their accepted power. The extension of interpolated bids to the co-optimized market follows the same rules than the step bids.

[42] Note that these maximum upward and downward capacities are only valid if they are smaller than or equal to the maximum power demand/production.

[43] A single reservation price (balancing capacity (BC) price), or multiple steps of a stepwise offer curve appear sufficient to represent the fundamental costs associated with providing balancing capacity. Stepwise offer curves have the advantage of allowing different prices for varying output levels, while avoiding the computational complexity of quadratic models resulting from interpolated curves.

An example for interpolated orders can again be given by considering the combined bid in Table 1, dropping the "activation cost" and the "minimum power" for energy, and now considering an interpolated energy supply curve in place of the variable cost for energy.

Block Bids

Block bids are multi-period bids – notably useful to reflect temporal constraints and start-up costs – defined with the following features:

- The maximum power supply (demand) offered for each period.
- Their unique limit price (what matters is the average over all periods).
- Their unique minimum acceptance ratio (the same over all periods).

If a block bid is accepted, its acceptance ratio (the same over all periods) should be greater-or-equal to its minimum acceptance ratio. Note that, due to the different maximum power offered on the different periods, the accepted power and the minimum required power may change from a period to the other.

The extension of existing block bids to fit a co-optimized market is less straightforward than for step and interpolated bids and requires some design choices to be made. The minimum acceptance power applies to the volume offered in the energy market.

Therefore, an accepted block can, in each period, offer to the balancing market all the power comprised between its minimum acceptance and its maximum power[44]. Consequently, we have the following conditions for the extension of block bids to the co-optimized market:

- In every period, the block's minimum acceptance plus the *curtailable* power sold (bought) plus its reserved upward (downward) balancing capacity should be less-or-equal than the maximum power.
- In every period, the reserved downward (upward) balancing power for the block should be less-or-equal to the sold (bought) *curtailable* power.

In addition to these rules, the bidder can specify a reservation cost for the balancing capacity products that will be considered in the profit computation for the balancing markets. The profit maximization condition will then ensure that the curtailable portion of the block's total volume is optimally matched in the different energy, upward and downward balancing capacity markets.

An example of block order generalized to a co-optimization setup is given by the combined bid in Table 1.

[44] Note that in practice, ramping requirements may limit the maximum amount of BC that an asset can offer. Ramping requirements may be expressed via ramp conditions – similar to load gradients for scalable complex orders in SDAC – that are further discussed in Section 3.2.3. Market participants can also limit the total amount of their capacity that can be allocated to balancing capacity, either via linked bids or via combined bids, see for instance Examples in Figure 13,
Figure 16 and Table 1.

Complex Bids

Scalable Complex Orders (SCOs) are multi-bid periods bids characterized by:

- A fixed activation cost.
- A minimum acceptable power for each period.
- Upward and downward load gradients: limits on the matched volume variations from one period to the next.
- A stepwise price curve for the volume in each period.
- A Scheduled Stop: the number of the periods at the beginning of the day where the SCO must be activated regardless of its acceptance for the entire day.

Except for scheduled stops, all features of the (scalable) complex order and their extensions to a co-optimization setup are addressed by functionalities available in markets using unit bidding. These features are discussed in Section 3.2.3, which focuses on combined thermal bids tailored for thermal assets.

In unit-bidding-based markets, features that are not available in scalable complex orders include the ability to start up and shut down multiple times per day while satisfying minimum up- and down-time constraints, as well as incurring start-up and shutdown costs[45]. It is therefore proposed to treat combined scalable complex orders as special combined thermal bids with specific input data, effectively discarding these features when they are not needed by certain market participants. This significantly reduces the number of binary variables required to model the bid. The rules governing load gradients (ramp conditions) in a co-optimization context are similar to those described in Table 2 of Section 3.2.3 below.

Figure 18 illustrates the behavior of a combined scalable complex order within a co-optimized market, specifically highlighting a scenario with a non-zero upward load gradient (i.e., a ramp-up constraint). To further emphasize the impact of intertemporal constraints in a co-optimization framework, an additional example with ramping constraints is provided in Annex C.3.

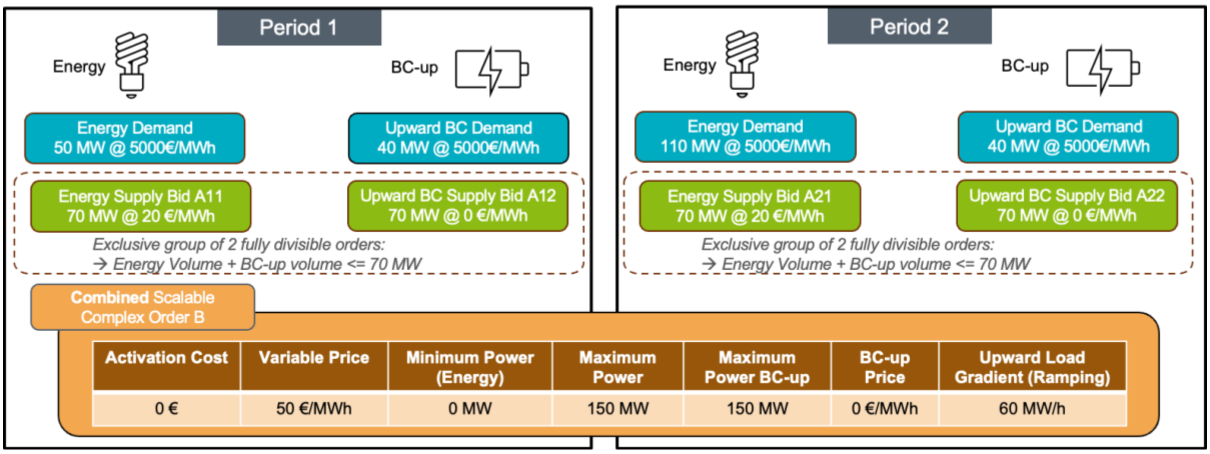

Figure 18: Illustration of the impact of ramping constraints and the usage of a combined scalable complex order in a co-optimized market.

[45] Note that the activation costs mentioned above can be interpreted as start-up costs for a single start. Modeling multiple start-ups and shutdowns over the day requires additional binary variables.

Load gradients in a co-optimization setup are similar to ramp conditions used in markets based on unit-commitment and economic dispatch. In the presence of upward reserves, the ramp-up constraint ensures that the sum of energy output and upward balancing capacity in period 't+1' does not exceed the energy output of period 't' by more than a specified threshold. In the presence of downward reserves, the ramp-down constraint ensures that the energy output in period 't' does not exceed the energy output in period 't+1,' minus the downward reserve, by more than a specified threshold.

If the scenario in Figure 18 is considered **without the upward load gradient limit**, the total social welfare generated by market clearing amounts to 1.1956 M€. In this setting, the energy price is 20 €/MWh in period 1 and 50 €/MWh in period 2. This price difference arises because bid A11 fully meets the energy demand in period 1, whereas in period 2, the combined scalable complex order B is required in addition to bid A21 to satisfy the energy requested in that period. In both periods, the combined scalable complex order B is also used to satisfy the upward balancing capacity demand, keeping the upward balancing capacity price at 0 €/MWh.

However, when an upward load gradient limit of 60 MW/h is applied on bid B, the obtained social welfare decreases by 600 € compared to the case without this constraint. In this setting, 20 MW of bid B must be used in period 1 to ensure sufficient energy and balancing capacity availability in period 2, despite its higher cost compared to bid A11. This requirement arises from the ramping constraint, which limits the sum of the energy produced and the accepted upward balancing capacity for bid B in period 2 to a maximum of 60 MW above the energy this bid delivered in period 1.

As a result, the energy price remains 20 €/MWh in period 1 but rises to 80 €/MWh in period 2. The balancing capacity price remains 0 €/MWh in period 1, increasing to 30 €/MWh in period 2. These higher prices in period 2 reflect the need to increase bid B’s production in period 1 to accommodate additional energy or upward balancing capacity in the following period.

These higher energy and balancing capacity prices in period 2 correspond to the additional costs incurred in the welfare objective, due to the presence of load gradient constraints, for respectively requiring one extra MW of inelastic energy demand (80 €/MWh), or one extra MW of inelastic balancing capacity demand (30 €/MWh).

3.2.3 Combined bids for thermal assets

Accurately representing the fundamental costs and technical operating constraints of thermal units is a complex challenge that has attracted significant attention in markets based on unit bidding as well as in academic literature.

As already mentioned, the co-optimization of balancing capacity and energy in the European day-ahead market will increase the complexity already faced by market participants to model their technical and economic constraints. Relying solely on a direct extension of the current standardized product available in the day-ahead market may not fully meet the future needs of market participants, particularly regarding the features required to accurately represent their assets.

In that spirit, inspired by the practice in markets based on unit bidding, we propose to enlarge the set of combined products presented in the previous section with a new standardized bidding product embodying key constraints of typical thermal units. Such an advanced bid could streamline the process for market participants to represent their technical and economic constraints.

With this new bid, market participants would no longer need to anticipate all the possible ways their assets could operate over 24 hours and submit each operating trajectory as exclusive block bids. Instead of generating a potentially large number of operating scenarios through exclusive offers, the market model handled by the algorithm implicitly describes all possibilities in a compact way. This simplifies the representation of thermal assets in the day-ahead market for traders. Moreover, this representation via a thermal bid is preferrable for the performances of the algorithm to a potentially large number of exclusive block orders enumerating the possible operation trajectories of the asset. However, if the market participant is satisfied with an approximation of the behavior of its asset using only a few numbers of bids (describing for instance only a few possible generation trajectories), performances may be impacted by a potential switch to this new thermal bid.

The suggestion to add such a thermal bid in the set of available products of Euphemia was already made in the past. The aim was to enhance the performances of the algorithm by incentivizing market participants to represent their thermal units via this product to reduce the amount of block bids bid in the day-ahead market[46].

This new standard offer aims to replicate the behavior of unit commitment models for thermal units, where the specific technical constraints and costs of individual physical assets are directly represented in the market clearing algorithm, aligning more closely with the physical operation of a power plant.

Table 2 provides a non-exhaustive list of generic features commonly found in multi-part offers in U.S. markets, showcasing potential enhancements to simple combined offers to develop an advanced combined thermal bid. We refer to the references [4] and [6] for the corresponding standard detailed mathematical formulations of the requirements[47].

[46] See Price Coupling of Regions (PCR), Euphemia Performance, European stakeholder committee, September 2015 for more information on the proposition.
[47] Chapter 7 in [4] also provides pedagogical illustrations of the unit commitment problem features proposed below for 'combined thermal bids'.

Table 2: List of generic features usually encountered for thermal assets in unit commitment models.

Features (technical or economic characteristic)	Description
Startup costs (Possibly 'temperature-dependent', i.e. depending on the number of offline periods)	Startup costs are costs incurred by the asset when starting up. These costs can depend on how much time the asset has been off before being started up again. Indeed, it might be less costly for some units to start up after a small period of downtime (hot startup costs) and more costly to start the unit up after a longer period of time (cold startup costs).
No load costs/ Minimum load costs	Fixed cost incurred in each period the asset is online, or minimum load costs for producing at its minimum power output.
Minimum up time	Minimum time during which the unit should be on after startup, before being able to shut it down.
Minimum down time	Minimum time during which the unit should be off after shutdown, before being able to start up again.
Startup and shutdown profiles	Production profile that a unit should follow during startup or shutdown (before respectively being fully available, or fully shutdown).
Minimum power	Minimum production level of the unit that should be satisfied each time the unit is on. This feature is already available in scalable complex orders.
Ramping	Limits on the variations in generation levels of a unit (increase or decrease) from one period to the next. This feature is already available in scalable complex orders (called 'load gradients'). In the presence of upward reserves, the ramp-up constraint ensures that the sum of energy output and upward balancing capacity in period 't+1' does not exceed the energy output of period 't' by more than a specified threshold. In the presence of downward reserves, the ramp-down constraint ensures that the energy output in period 't' does not exceed the energy output in period 't+1,' minus the downward reserve, by more than a specified threshold.
Maximum number of startups	Maximum number of possible startups of a unit throughout a day.
Maximum up time	Maximum number of time period during which a unit is on
Non-convex piecewise linear marginal cost curves resulting from increasing heat rates	Heat rates increase with higher power outputs, resulting in 'increasing returns to scale,' which are typically represented using 'non-convex piecewise linear marginal cost curves.'
Shutdown cost	Cost incurred by a unit when it is shutdown.

The formulation of a large part of the constraints and costs present in Table 2 require the use of several binary variables. Even though some efficient formulations of these features already exist in the literature[48], the increase of binary variables stemming from the implementation of this new type of bid may imply significant additional computational challenges. These challenges may necessitate an evaluation of the most suitable algorithmic and pricing approaches for this new context (see Chapter 5 for a broader discussion on pricing with non-convexities and their potential implications for computational tractability).

Among the features presented in Table 2, it is suggested to implement such an advanced combined bid focusing on features that are used in almost all US ISOs to facilitate its introduction in the European day-ahead market. The proposed combined thermal bid is defined by the following features[49]:

- a maximum power output;
- a minimum power level;
- minimum up and down times;
- ramping constraints;
- ability to offer downward/upward reserve and reserve limits;
- startup cost;
- minimum load cost;
- variable cost for energy generation (a single price or a stepwise offer curve);
- reservation costs for upward and downward reserve products (single prices or stepwise cost curves)

This proposed combined thermal bid can be enhanced in the future by enlarging the set of features covered from Table 2. This menu of additional components could be implemented in Euphemia using a stepwise approach and on a need basis, after careful research and development to understand their performance and market impacts.

3.2.4 Combined bids for storage

The design of combined bids specifically tailored for storage assets (and possibly also suitable for demand response[50]) is currently undergoing significant development. At N-SIDE, we have identified and addressed several complex challenges associated with the representation of these assets within a co-optimized market

[48] For more information, see for instance: Chapter 7 in Anthony Papavasiliou. Optimization models in electricity markets. Cambridge University Press, 2024 [4], and Knueven, B., Ostrowski, J. and Watson, J.P., 2020. On mixed-integer programming formulations for the unit commitment problem. *INFORMS Journal on Computing*, *32*(4), pp.857-876.

[49] Note that decreasing marginal energy generation cost curves—such as those corresponding to 'increasing heat rates'—are excluded at this stage, as they are absent from most real-world markets implementing co-optimization based on security-constrained unit commitment problems. Additionally, they would introduce complexities better addressed at a later stage, should the demand for such features be confirmed.

[50] To some extent, demand response can be modeled as a specific type of storage bid where all discharging capacities are set to zero, only allowing it to charge, i.e. consume, at the most profitable moment of the day.

framework. Potential solutions are being investigated to overcome these hurdles, with the goal of integrating storage resources seamlessly into the day-ahead market.

Key Considerations for Storage Bids

1. Temporal Dimension: Storage assets inherently operate through inter-temporal energy arbitrage, where they acquire energy during periods of low prices and discharge during high-price intervals. Capturing these inter-temporal dynamics requires bid formats that accurately reflect the temporal constraints. Current day-ahead markets lack explicit mechanisms for accommodating such inter-temporal aspects, implying the absence of a foundational framework within energy-only markets suitable for the co-optimization of energy and balancing capacities.

2. Limited Energy Storage & State of Charge Management: Unlike conventional generation assets, storage inherently has a limited energy capacity, which necessitates precise management of the state of charge (SoC). Accurately determining the volume of energy available at any time in the day-ahead market is further complicated by the procurement of balancing capacity, as the extent of balancing energy activation remains unknown until delivery[51].

3. Coordination of Charging and Discharging Power: Proper coordination between charging and discharging power levels is also essential to guarantee full availability of storage assets. This entails enabling power levels to deliver energy, while reserving headroom or footroom for upward or downward balancing capacity deliveries. Additionally, conservative allowances could be incorporated to manage potential intraday adjustments (see previous item), or other external or exotic constraints.

4. Pricing: The valuation of stored energy is fundamental for efficient modeling. While the initial cost of energy (at t0) may be treated as sunk, and the model inherently captures the value of energy injected or withdrawn during the day, assigning a prospective value to the energy at the end of the trading period (t24) is critical. This valuation reflects the potential gains anticipated in the days following tomorrow, thereby ensuring the storage asset does not end each trading day with a depleted SoC. Currently, economic parameters are limited to estimating future value, while more intricate aspects, such as round-trip efficiency losses, fall beyond the present scope.

5. Computational Complexity: The introduction of novel bidding products tailored for storage assets inevitably adds complexity to the market-clearing process. Thus, the solutions being proposed are designed with computational efficiency as a core priority, ensuring scalability and practicality in a co-optimized market

[51] To mitigate risks, a possibility is to maintain a conservative bandwidth of storage capacity for a specified duration after delivering balancing services. This reserve represents a buffer period, reflecting the time typically required to trade energy on the intraday market, beginning when the exact SoC is known (i.e. the end of the balancing capacity delivery period), and concluding when the traded energy can be successfully delivered to the storage. In addition, the storage operator may add constraints on the minimal or maximal energy level at each period, to account for more exotic constraints (e.g. ecological or touristic in case of dams).

environment. This increased complexity arises from the simultaneous need to optimize both energy and balancing markets, with additional constraints linked to storage operations. Inevitably, certain trade-offs must be made to balance computational efficiency and market complexity.

Our aim is to develop a new bid format that accurately expresses operational constraints, thereby enabling technically feasible and economically optimal dispatch outcomes (while preserving overall market-clearing efficiency, including computational performance). Compared to other asset types, particularly traditional thermal generation, storage assets have seen less detailed exploration in both academic and market contexts (e.g. looped linked bids offered by EPEX SPOT[52] are limited in scope). Furthermore, the methods through which storage assets participate in European balancing markets remain highly unharmonized across Member States, while this appears as a pre-requisite to co-optimization. This underscores the need for more time and effort (as part of the present R&D activity) in developing harmonized and effective combined bids for storage and demand response.

[52] EPEX SPOT is the only power exchange offering "Loop blocks", i.e. families of two blocks which are executed or rejected together. They allow to bundle buy and sell blocks to reflect storage activities.

3.3 Conclusions on linked bids and combined bids

Linked bids refer to a family of bids for single products, either energy or a given balancing capacity product, connected to each other by "links" modeling specific acceptance interdependencies.

A combined bid is a bid that simultaneously offers multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid.

Both linked bids and combined bids can be used to bid in a co-optimization setup, considering the linkages between energy, upward balancing capacity and downward balancing capacity, while allowing to represent indivisibilities and fixed costs.

In a co-optimization setup as in energy-only markets, bid linking can be used to model advanced trading strategies under portfolio bidding. The proposed highly flexible bid-linking options, summarized below, enable the application of exclusive or parent-child links to bids of varying volumes and prices across all markets and buy or sell directions.

Combined bids allow market participants to detail the cost structures and constraints of specific asset types more precisely. For example, bids can be tailored for thermal assets or for storage and demand response—though the detailed design for the latter will be determined later in the R&D process.

We have illustrated in this chapter how several trading options could equivalently be represented via linked bids or via combined bids extending the current energy-only bids offered in Euphemia, while highlighting specific scenarios where bid linking options allow to capture intricate interactions that are not feasible with combined bids. Additional bid linking features (e.g. mutually exclusive baskets of bids) could also be further contemplated.

We have also elaborated on the added value of **combined bids**, which is threefold. First, in specific scenarios, they provide fully equivalent but easier to use alternatives to linked bids. Second, in these scenarios, they may also positively affect the algorithm performances. Third, for specific assets such as thermal assets or storage, tailored combined bids allow for better capturing the specificities of the fundamental costs and the technical constraints of the units. Such tailored combined bids for thermal assets could additionally improve algorithm scalability by replacing multiple block bids that describe alternative feasible schedules with a more streamlined representation of those schedules.

Therefore, we propose supplementing linked bids with combined bids to provide simpler bidding options for specific scenarios or to enhance expressiveness for representing complex costs and constraints more effectively. Figure 19 presents a concise visual comparison of the two options summarizing their key advantages and drawbacks.

Figure 19: Comparison of linked and combined bids highlighting their respective benefits and limitations.

A comprehensive list of features for combined bids can be implemented in Euphemia in a stepwise fashion on a need basis after careful research and development to understand their impact on algorithm scalability.

An executive summary of the different proposed options in terms of combined standard products and links available in a co-optimized European day-ahead market is provided in Table 3 and in Table 4 respectively for bid linking and combined bids.

Table 3: Summary of the proposed options for bid linking for a co-optimized day-ahead electricity market. The linking options can apply to bids of varying volumes and prices across all markets and buy or sell directions

Links	Description	Already Available in EUPHEMIA nowadays?
Parent-child Link	The acceptance of one bid (i.e. the parent) is a prerequisite to the acceptance of another (i.e. the child).	Yes[53]
Loop Link (= Double sided parent-child link)	Both bids should be simultaneously accepted or rejected together.	Yes[53]
Exclusive Link (on acceptance ratio)	The acceptance of one bid is conditioned on the rejection of another.	Yes[53]
Exclusive Link (on maximum power)	The total accepted power from all the bids linked should not exceed the provided maximum power of the link.	No

[53] Adaptations in the implementation may still be required: for instance, to remove unnecessary binary variables when the linked orders are fully divisible, to allow for linking between various types of bids aside blocks, etc.

Table 4: Summary of the proposed options for combined standard products in a co-optimized European day-ahead market.

Type	Description	Already Available in EUPHEMIA nowadays?
Combined Step & Interpolated Bid	The Step/Interpolated Bid with additional features to account for upward and downward balancing capacity.	No
Combined Block Bid	The Block Bid with additional features to account for upward and downward balancing capacity.	No
Combined Scalable Complex Bid	The Scalable Complex Bid with additional features to account for upward and downward balancing capacity.	No
Combined Thermal Bid	Multi-period bid aiming to replicate the behavior of unit commitment models for thermal units, where the specific technical constraints and costs of individual physical assets are directly represented in the market clearing algorithm.	No
Combined Storage/DR Bid	Bids enabling storage and demand response to offer energy and balancing capacity products while properly considering linkages, intertemporal constraints, real-time activation uncertainties and the possibility to 'recharge/discharge' in the intraday to comply to commitments to provide balancing capacity.	No

4. Cross-zonal Capacity Allocation in a Co-optimization Setup

The co-optimization of energy and balancing capacity in the day-ahead electricity wholesale market allocates both generation (or consumption) assets and cross-zonal capacity. An initial assessment of its effects on cross-zonal capacity allocation was conducted in the Co-Optimization Roadmap Study [1], which modeled the entire SDAC, including flow-based allocation in the Core region. Additionally, the study provided a conceptual analysis of how co-optimization allocates CZC using an ATC context.

To ensure the present study is self-contained and comprehensively covers fundamental CZC allocation principles in a co-optimization context, we elaborate on these key concepts here, supported by illustrative examples[54]. Here too, we elaborate on the general principles within an ATC context, while the chapter's conclusion highlights how these principles extend to more general network models.

Day-ahead market coupling is widely recognized as an effective approach to allocating cross-zonal capacity (CZC) within energy markets[55]. Under the ATC grid model, it ensures that either there is no price spread across an interconnector, or that the interconnector operates at full capacity in the direction of the positive price spread. This outcome naturally follows from the non-arbitrage condition: if a price differential existed without congestion, market participants would exploit it by increasing flows toward the higher-priced zone. This process would continue until the price gap disappears or the interconnector is fully utilized.

The co-optimization of energy and balancing capacity provides cross-zonal capacity allocation following the same non-arbitrage equilibrium principles. However, because multiple products are auctioned simultaneously – requiring cross-zonal capacity to be distributed among them – the general principles will remain the same, while the exact equilibrium conditions specific to this context need to be adapted.

The different properties regarding the allocation of cross-zonal balancing capacity and congestion patterns that can be derived from a co-optimized market with ATC network constraints are presented below.

Section 4.1 recalls why, under marginal pricing, there is no price spread in the absence of congestion, while Section 4.2 details and illustrates why CZC is allocated to the product for which the cross-border exchanges are the most valuable. Section 4.3 dives into the important notion of 'flow netting', showing that energy flows against the price difference (i.e. flows from a high price areas to a lower price areas, also sometimes called "adverse" or "non-intuitive" energy flows) could occur if they allow for additional cross-zonal balancing capacity exchanges which generate more value than the losses due to the adverse flow.

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[54] A technically deeper discussion can be found in Appendix C of the Co-Optimization Roadmap Study report [1].

[55] We refer here to the efficiency of the allocation stage, where market coupling—specifically implicit allocation—is widely recognized as more efficient than alternatives like explicit allocation. Another key challenge is accurately representing grid constraints during the capacity calculation stage.

Finally, the translation of these elements into more general setups, such as flow-based models with the so-called 'deterministic requirement' for reserve deliverability[56], is shortly discussed in non-technical terms in Section 4.4 which also concludes with a summary of the key takeaways.

4.1 Absence of congestion implies equal prices in both zones

In case there is no congestion in either direction on a line between two zones, no cross-zonal price differential is observed on any product. Otherwise, there is no equilibrium, as it would generate welfare to further allocate cross-zonal capacity between the two zones by transferring an additional amount of the product with a price difference between the two zones on the line. Equivalently, there would be no market equilibrium in that case. This principle is depicted in Figure 20 in which ε_{FR} and ε_{NL} represent the energy price of two different zones, εR_{FR} and εR_{NL} give the balancing capacity price of both zones and α_{NLtoFR} illustrates the shadow price of the line between the two zones.

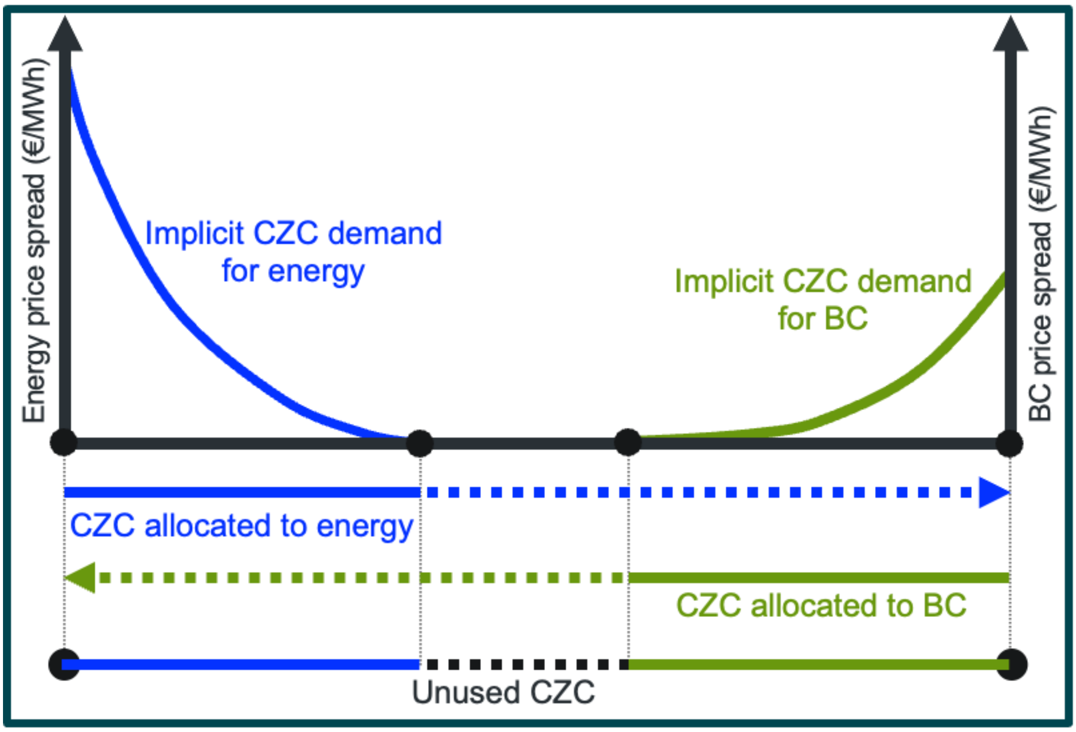


Figure 20: Representation of cross-zonal capacity valuation in a market co-optimizing energy and balancing capacity when the CZC between two zones is not fully utilized. The blue line represents the implicit CZC demand for energy, and the green line the implicit CZC demand for BC. In this example, both demands are fully satisfied by the offered CZC. As a result, the total CZC is not fully used, and the CZC has no value (i.e. no price difference in either energy or BC).

[56] See Chapter 3 of the Co-optimization Roadmap Study [1].

4.2 Product Prioritization in case of congestion

In the presence of congestion on an ATC line between zones in one direction, the price differences are such that the cross-zonal capacity is allocated optimally to the most valuable product. Otherwise, there would be no equilibrium as allocating a portion of the already allocated cross-zonal capacity to the other product would generate more welfare. Indeed, if the cross-zonal balancing capacity price differential is smaller than the energy price differential, the cross-zonal capacity is entirely allocated to energy, i.e. the most profitable product in terms of cross-zonal capacity allocation (measured by its cross-zonal price spread). A representation of the situation in which energy is the most valuable product is illustrated in Figure 21.

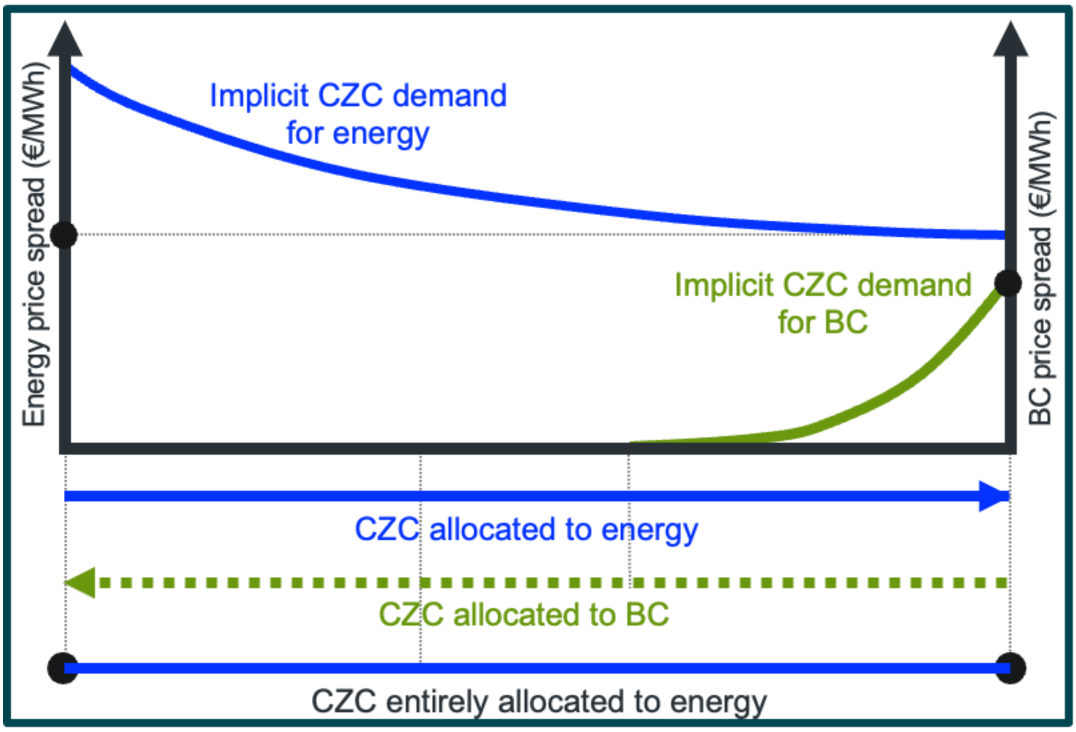


Figure 21: Representation of cross-zonal capacity valuation in a market co-optimizing energy and balancing capacity when the CZC between two zones is fully allocated to energy. The blue line represents the implicit CZC demand for energy, and the green line the implicit CZC demand for BC. In this example, the implicit CZC demand for energy exceeds the CZC demand for BC. As a result, CZC is entirely allocated to energy and is valued at the energy price spread.

When cross-zonal capacity is utilized for both energy and balancing capacity markets in a given direction between two zones, the difference in energy prices between the zones will equal the difference in balancing capacity prices between those zones. If this condition is not met, equilibrium is not achieved, as increasing the share of the highest spread product in the cross-zonal capacity generates additional welfare. This phenomenon is represented in Figure 22.

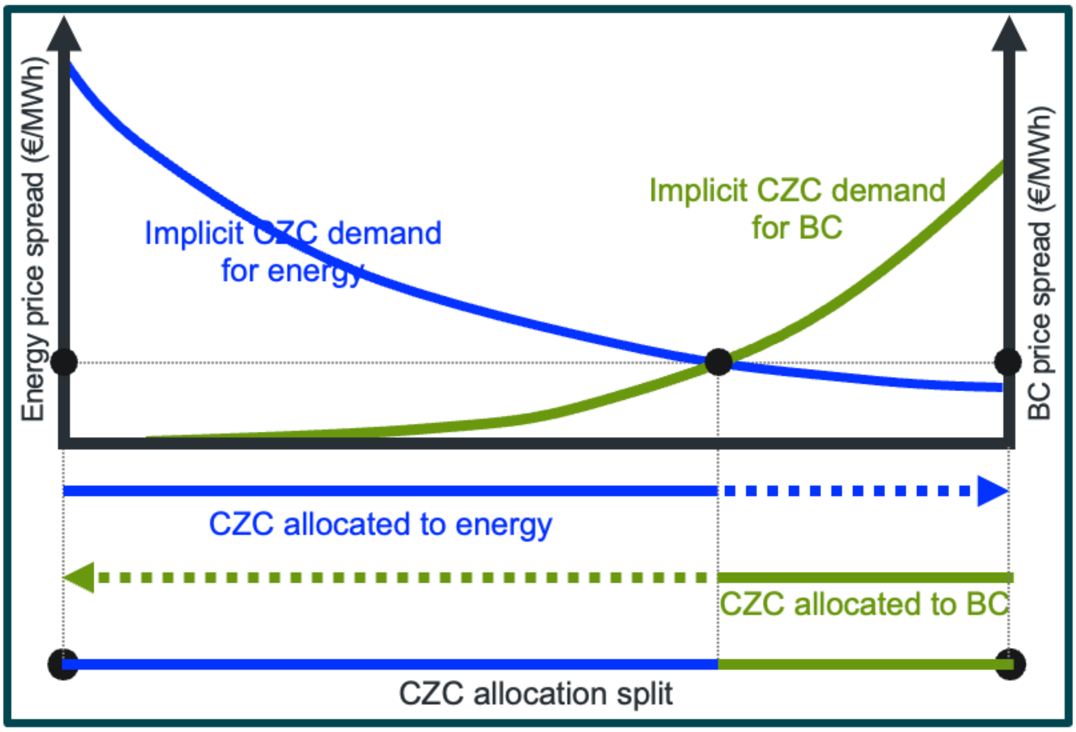
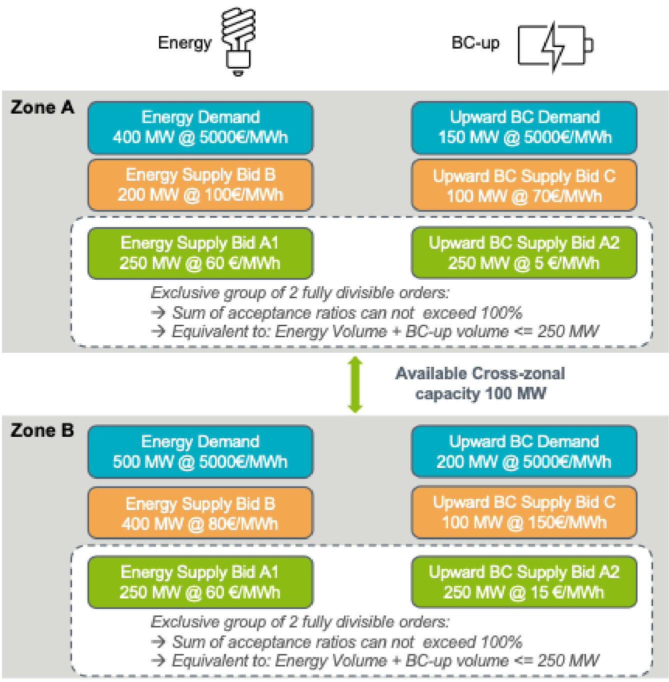


Figure 22: Representation of cross-zonal capacity valuation in a market co-optimizing energy and balancing capacity when the CZC between two zones is allocated to both energy and BC. The blue line represents the implicit CZC demand for energy, and the green line the implicit CZC demand for BC. In this example, the CZC allocation is split between energy and BC. As a result, CZC is valued at the energy and BC price spreads (which must be equal in case of CZC split)

To illustrate the allocation of cross-zonal capacity to the most valuable product in presence of congestion, the example in Figure 23 describes a co-optimized market situation where the cross-zonal capacity of the interconnector would be entirely allocated to energy, and where an interesting observation can be made on price alignments across bidding zones.



Market Results Zone A	Energy	Upward Balancing Capacity
Market Prices	205 €/MWh	150 €/MWh
Linked Bids of Market Participant A	A1: 100 MWh	A2: 150 MWh
Bid B	B: 200 MWh	-
Bid C	-	C: 100 MWh

↑ 100 MW Congestion ↓ 100 MW

Market Results Zone B	Energy	Upward Balancing Capacity
Market Prices	195 €/MWh	150 €/MWh
Linked Bids of Market Participant A	A1: 200 MWh	A2: 50 MWh
Bid B	B: 400 MWh	-
Bid C	-	C: 50 MWh

Figure 23: Illustration of optimal cross-zonal allocation to energy as the product with the highest price spread between the two zones.

In this example, the interconnector is congested, with 100 MW of energy flowing from Market B to Market A. This congestion creates a price spread between the energy markets in Zone A and Zone B, with energy prices at 205 €/MWh in Zone A and 195 €/MWh in Zone B, respectively. However, even though a balancing capacity flow of 100MW is observed from Market A to Market B, the link is not congested in that direction between the zones because of the presence of an energy flow of 100MW in the opposite direction. Therefore, balancing capacity prices remain equal in both zones.

An interesting phenomenon occurs: the BC price in Zone B, set by the marginal bid C at 150€/MWh, propagates through cross-zonal capacity to Zone A. This, in turn, drives up the energy price in Zone A to 205€/MWh due to product linkages.

This energy price ensures that market participant A does not prefer providing more balancing capacity at the expense of dispatching energy, thereby aligning with the welfare-optimal allocation. In other words, the energy price of 205€/MWh ensures that the linked bids A1-A2 recover any opportunity cost incurred by providing energy instead of BC, i.e., it is as profitable in the energy market as it is in the balancing capacity market.

4.3 Energy flow netting

Energy flow netting is defined as the ability of energy flows in one direction to release capacity for further balancing capacity flows in the opposite direction. Indeed, while nowadays energy flows over ATC-based interconnectors always go from low price to higher (or equal) price zones[57], this may not always be the case under co-optimization. Indeed, as long as the energy cross-zonal spread is smaller than the balancing capacity one, it remains optimal to release cross-zonal capacity with energy to enable further allocation of balancing capacity, including if this implies flowing in opposite direction of the energy price spread. This situation is highlighted in Figure 24.

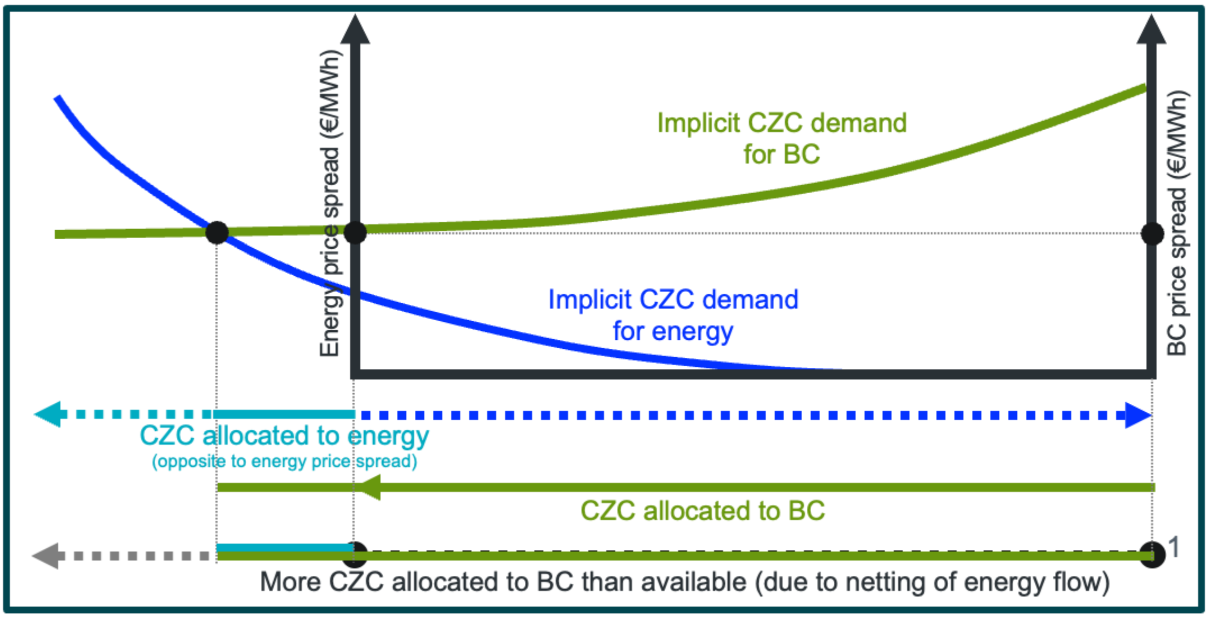


Figure 24: Representation of cross-zonal capacity valuation in a market co-optimizing energy and balancing capacity when the CZC between two zones is fully allocated to BC. The blue line represents the implicit CZC demand for energy, and the green line the implicit CZC demand for BC. In this example, the implicit CZC demand for BC exceeds the CZC demand for energy. As a result, energy flow is allocated against the price difference to enable (through netting) further CZC allocation to the more valuable BC. Cross-zonal capacity is valued at the resulting price spread (which is equal for BC and for energy)

Note that such a reasoning does not apply in the opposite case where the energy price differential is larger than the one of balancing capacity. This is because, by opposition to energy flows, allocating CZC to balancing capacity does not lead to a certain flow which can be netted (i.e. the portion of balancing capacity that will be activated over an interconnector is only known in real time). The graphical intuition behind the impact of energy flow netting over CZC balancing capacity allocation is shown in Figure 25 and further illustrated in the example described in Figure 26.

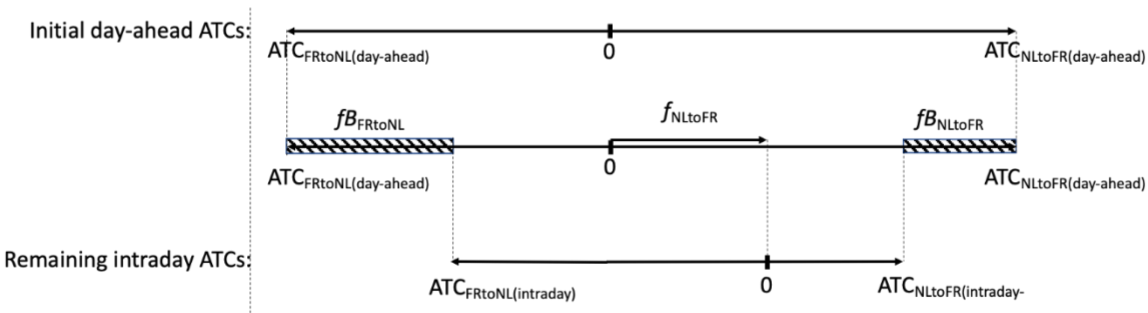
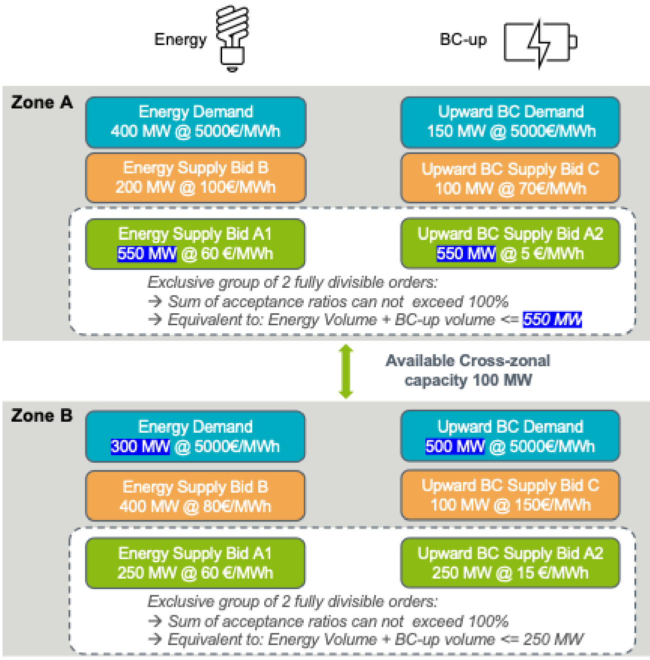


Figure 25: The graphical intuition of the difference between cross-zonal allocation for balancing capacity and energy is that a CZC allocation to balancing capacity (i.e. fB_{FRtoNL} and fB_{NLtoFR}) implies reserving "positive bandwidths of CZC",

[57] Under the assumption that no ramp constraints apply on the interconnector, or other specific network constraints, where intuitively, increasing a cross-border flow could provide a relieving effect. This is the case, for example, with ramp conditions, where increasing the flow in the first period reduces the upward variation across two subsequent periods, thereby alleviating the ramp constraints that limit this variation.

possibly concurrently in both directions; unlike the energy flow setpoint (i.e. f_{NLtoFR}) which is represented by a single value (positive or negative depending on the direction). The figure depicts how the residual intraday ATCs are deducted from the allocations of BC and energy flows.

Figure 26 provides an illustration of a situation in which a non-intuitive energy flow is materializing using a modified version of the two zones example of Figure 23.



Market Results Zone A	Energy	Upward Balancing Capacity
Market Prices	100 €/MWh	45 €/MWh
Linked Bids of Market Participant A	A1: 200 MWh	A2: 350 MWh
Bid B	B: 100 MWh	-
Bid C	-	C: 0 MWh

100 MW Adverse flow — 200 MW Congestion

Market Results Zone B	Energy	Upward Balancing Capacity
Market Prices	195 €/MWh	150 €/MWh
Linked Bids of Market Participant A	A1: 0 MWh	A2: 250 MWh
Bid B	B: 400 MWh	-
Bid C	-	C: 50 MWh

Figure 26: Co-optimized market situation where an adverse energy flow between zones A and B is observed in the optimal solution as it releases further CZC for profitable balancing capacity flows.

In this example, the interconnector is congested in both directions. Indeed, the optimal solution uses the cheap and large balancing capacity supply in Zone A to meet 200MW of the large balancing capacity demand in Zone B. Consequently, a non-intuitive adverse energy flow of 100 MW from the more expensive Zone B to the cheaper Zone A can be observed, enabling to free up additional CZC for this profitable exchange of balancing capacity.

The energy and upward balancing capacity prices are such that the value of assigning cross-zonal capacity to upward balancing capacity (105€/MWh) exceeds the transmission losses incurred on the energy side (95€/MWh), such that network operations are optimal. Additionally, the upward balancing capacity price of Zone A represents the additional cost incurred in the market to provide an additional MW of upward balancing capacity. In that scenario, the energy supply bid B would have to provide 1MWh more of energy with a cost of 100€, releasing 1MWh of the energy supply bid A1 (earning 60€) so that this released MW can be used to fulfill the additional upward balancing capacity (with a cost of 5€). The upward balancing capacity price in Zone A is therefore given by 100€ - 60€ + 5€ = 45€. On the other hand, the balancing capacity price in Zone B is explained by the marginal acceptance of the upward BC supply order bid C. The same types of reasoning can be applied to understand the energy prices in both zones.

4.4 Conclusion

This chapter conceptually analyzes how co-optimization allocates Cross-Zo*nal Capacity (CZC) using Available Transfer Capacity (ATC)*. It expands on the Co-Optimization Roadmap Study [1], where more technical details over the same concepts can be found in Appendix C.

While the discussion is based on an ATC grid model setup, it offers broader insights into the general principles guiding CZC allocation under co-optimization, as well as how market results can be interpreted.

The following general principle remains valid with more sophisticated grid models: marginal pricing guarantees that no additional value can be generated by reallocating CZC differently amongst products while still respecting network constraints. In particular, the principle remains valid under a flow-based grid model[58].

A more advanced description of how this high-level principle translates into the specific co-optimization price formation mechanism under flow-based constraints (including the enforcement of the deterministic reserve deliverability requirement) will be elaborated at a later stage[59].

[58] Regardless of whether the so-called deterministic reserve deliverability requirement (i.e. ensuring that any pattern of balancing capacity activations can be supported by the network in real time) is enforced. This general principle is a consequence of the general market equilibrium principles discussed in Section 2.1.

[59] These aspects will be addressed in the second co-optimization R&D report "R2" listed in ACER Decision 11/2024.

5. Pricing with non-convexities

5.1 Introduction

In this chapter, we explore methods to address non-convexities within a co-optimization framework. Non-convexities introduce complexities that make optimization challenging compared to convex scenarios.

We begin by revisiting the issues related to non-convex bids (Section 5.2), followed by establishing the relevant terminology (Section 5.3). We then present five main design options that have been analyzed illustrating them with simplified examples (Section 5.4). The running example used to illustrate key differences between the various options features an extramarginal unit with a minimum power output and a start-up cost, and has two bidding zones[60]. Finally, we provide a clear recommendation based on the findings (Section 5.5).

5.2 Overview of the challenges

In power markets, non-convexities refer to features in bid structures that deviate from the standard continuous and monotonic supply and demand curves[61], and lead to optimization problems which are "non-convex" [62].

Examples of non-convexities in power markets include start-up costs, minimum generation levels, minimum up and down times, and block bids. These features create discontinuities in the feasible solution space, adding complexity to market clearing and pricing. For instance, accurately modeling start-up costs or minimum generation levels require binary decision variables, which are the main sources of "non-convexities" in our context.

These non-convexities pose two major challenges:

- First, in **price formation**, they prevent the straightforward use of marginal pricing to determine market-clearing prices, as they preclude in general the existence of uniform market prices supporting a competitive market equilibrium[63]. Using the standard SDAC terminology discussed in Section 5.3

[60] Note that another simpler example with an extramarginal unit is provided in Annex D.1. The running example in this chapter, while more involved, allows for the comparison of options that differ in terms of permitted cross-zonal spreads or allowed side payments.

[61] A monotonically increasing marginal cost curve results in a convex total cost function to minimize in the welfare objective function. Similarly, a monotonically decreasing marginal demand utility curve leads to a concave total utility function to maximize, which is equivalent to the convex problem of minimizing a convex function.

[62] A convex optimization problem is a problem where the feasible solution space and the objective function are "convex": a high-level geometric intuition is that any point on a straight line connecting two possible solutions also remains a valid solution, and the objective function has a 'bowl-shaped' form.

[63] In short, a competitive market equilibrium is an allocation and set of market prices where, given these prices, no market participant would prefer a different allocation.

below, this means the impossibility to determine an allocation and market prices avoiding paradoxically accepted or paradoxically rejected bids[64].

- Second, from an **algorithmic complexity** perspective, non-convexities often turn what would have been a simple (often linear or quadratic) convex optimization problem, for which very efficient algorithms have been developed, into a mixed-integer programming (MIP) problem in general intrinsically harder to solve[65].

5.3 Naming of the design elements related to non-convexities

Market clearing algorithms typically determine prices based on the concept of marginal pricing, where clearing prices are derived from the dual variables, or shadow prices, of the equilibrium (balance) constraints. In economic terms, these prices represent the welfare impact of procuring one additional or one fewer unit of the product.

However, in markets with non-convexities, it is often impossible to reach a fully coherent market equilibrium where all allocated volumes and clearing prices align perfectly. This discrepancy leads to what are known as **paradoxically accepted or rejected bids**:

- **Paradoxically Rejected Bids (PRBs)**: These are bids that are economically viable given the calculated market prices (i.e., "in the money") but are rejected due to the non-convex nature of the problem (accepting these bids would modify the market prices such that some accepted bids are no longer economically viable). In the current day-ahead market, PRBs are tolerated.

- **Paradoxically Accepted Bids (PABs)**: These are bids that are not economically viable given the calculated market prices (i.e., "out of the money") but are accepted nonetheless (rejecting the bids could modify the market prices such that they are economically viable but rejected). The current day-ahead market design prohibits PABs, which is referred to as the **"No PAB" design**.

To address these issues in the context of co-optimization, several alternative market design elements have been contemplated, based on the following principles:

- **No PABs:** This approach does not allow for PABs when doing the allocation (as in the current day-ahead market). For a given allocation, prices are determined following classic marginal pricing principles (without considering non-curtailable bids: solutions containing PABs are ruled out, while solutions may contain PRBs).

[64] Technically, the non-existence of a competitive equilibrium arises from a mathematically unavoidable ‘gap’ between the optimal objective value of a ‘primal welfare maximization problem’ and the optimal objective value of a ‘dual pricing problem’ aiming at finding prices that minimize the profits market participants could achieve if they were free to independently choose their bid acceptances, disregarding balance conditions.

[65] There is a well-established theory of computational complexity, and many non-convex problems have been shown to belong to the most challenging classes of problems, while convex problems in general belong to easier classes of problems.

- **Non-Uniform Pricing (NUP)**: This approach allows for PABs, with compensation provided through side-payments to ensure that participants are not worse off. In this design, social welfare is optimized without considering clearing prices during the allocation process. Prices are determined afterward based on specific rules, and PABs are compensated to avoid losses for market participants. There exist several ways to calculate such prices (e.g. Convex Hull Pricing, IP pricing, …), see for instance [7], [8] on Convex Hull Pricing, and [9] on IP Pricing.

- **Most Expensive Bid (MEB) Pricing**: This pricing mechanism is used specifically for balancing capacity markets. To avoid PABs, the clearing price is set at the level of the most expensive accepted bid, ensuring that all accepted bids are remunerated adequately without requiring side-payments. This approach can lead to higher procurement costs but ensures that no bids are paradoxically accepted without proper compensation, while all balancing capacity bids are nonetheless paid uniformly.

These elements are designed to mitigate the challenges posed by non-convexities, either by allowing flexibility in bid acceptance with proper compensation (as in NUP) or by adjusting the price (and/or the allocation) to avoid paradoxical acceptances (as in MEB). Each of these approaches has trade-offs in terms of complexity, cost, and market efficiency, which are considered in the subsequent analysis of design options.

5.4 Shortlisted design options

The shortlisted design options presented here explore different approaches to address the challenges of non-convexities in market clearing. Each option has its own set of benefits and trade-offs.

We illustrate the pricing options described above using a simplified example involving two bidding zones connected by an uncongested line. The example highlights how different pricing options impact the allocation and pricing outcomes.

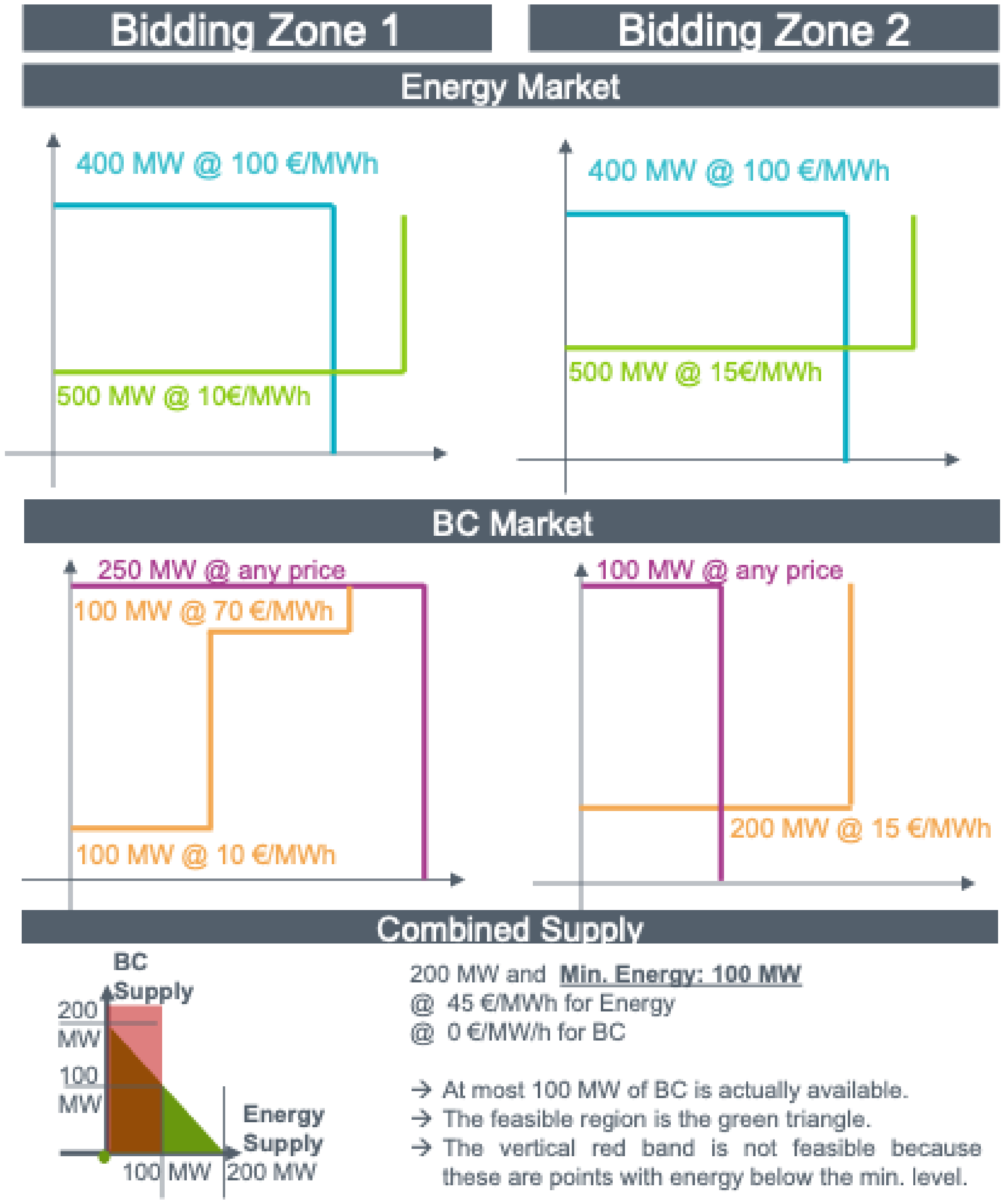


Figure 27: Example data for illustrating the pricing options

Consider two bidding zones (Zone 1 and Zone 2) that are connected by an uncongested transmission line. Both zones have inelastic upward balancing capacity demands, some highly priced energy demand, and a mix of elastic energy and balancing capacity offers. In this example, Zone 1 includes a combined bid which is not entirely curtailable, and which is the sole source of non-convexity. This bid represents a thermal generation unit with a minimum and maximum output level of 100 MW and 200 MW, respectively, and a marginal production cost of 45 €/MWh. The provision of 100 MW of upward balancing capacity is contingent upon a minimum energy output of 100 MW.

5.4.1 Option 0: No PAB design

The default option is to adhere strictly to the "No PAB" rule, as is currently implemented in the day-ahead energy market. Under this design, both energy and balancing capacity markets cannot accept bids that are incurring losses (negative profits) given the calculated clearing prices. By strictly avoiding PABs, this approach seeks to maintain a clear and consistent uniform pricing mechanism.

The main advantage of the No PAB design is that it ensures market coherence, and that all settlements solely depend on the uniform market prices applying to all accepted bids (in contrast with individual side payments varying per bid under NUP discussed below). Since no paradoxically accepted bids are allowed, all *accepted* bids align perfectly with the clearing prices[66], simplifying the interpretation of market outcomes and reinforcing the integrity of the pricing mechanism.

However, this consistency comes at a cost. The No PAB rule adds constraints to the optimization problem, which leads to reduced social welfare by limiting the feasible solution space. There is also the potential for liquidity issues, as rejecting non-convex balancing capacity bids may reduce the available volume to meet TSO demand effectively. Additionally, the concurrent calculation of bid acceptance and clearing prices complicates the optimization, increasing computational challenges.

Under this design, any paradoxically accepted bids are rejected by the market-clearing algorithm. As a result, the combined non (entirely) curtailable bid in Zone 1 may be entirely rejected, leading to higher costs and reduced welfare outcomes due to the exclusion of valuable balancing capacity (we will see in Section 5.4.2 that if the combined non (entirely) curtailable bid is accepted and marginal pricing is applied, the bid would incur a loss). The result reads as follows:

[66] Note however that paradoxically rejected bids may still be present in the market outcome.

Table 5: Market outcome with the No PAB option

<table>
<tr><th colspan="3">Bid Name</th><th>Volume (MW)</th><th>Bid Price (€ /MWh)</th><th>Acceptance (%)</th><th>Surplus (€)</th><th>Side Payment (€)</th></tr>
<tr><td rowspan="7">Bidding Zone 1:
En Price = 15 €/MWh
BC Price = 70 €/MWh</td><td colspan="2">BC Demand</td><td>250</td><td>Price Taking</td><td>250 (100%)</td><td>-</td><td>-</td></tr>
<tr><td colspan="2">Energy Demand</td><td>400</td><td>100</td><td>400 (100%)</td><td>34000</td><td>0</td></tr>
<tr><td colspan="2">Energy Supply</td><td>500</td><td>10</td><td>500 (100%)</td><td>2500</td><td>0</td></tr>
<tr><td rowspan="2">Combined Supply</td><td>En.</td><td>200
(MAR = 50%)</td><td>45</td><td>0 (0%)</td><td>0</td><td rowspan="2">0</td></tr>
<tr><td>BC</td><td>100</td><td>0</td><td>0 (0%)</td><td>0</td></tr>
<tr><td colspan="2">BC Supply 1</td><td>100</td><td>10</td><td>100 (100%)</td><td>6000</td><td>0</td></tr>
<tr><td colspan="2">BC Supply 2</td><td>100</td><td>70</td><td>50 (50%)</td><td>0</td><td>0</td></tr>
<tr><td>Flows:</td><td colspan="3">Energy: 100MW from BZ1 to BZ2</td><td>↓ ↑</td><td colspan="3">BC: 100MW from BZ2 to BZ1</td></tr>
<tr><td rowspan="4">Bidding Zone 2:
En Price = 15 €/MWh
BC Price = 70 €/MWh</td><td colspan="2">BC Demand</td><td>100</td><td>Price Taking</td><td>100 (100%)</td><td>-</td><td>-</td></tr>
<tr><td colspan="2">Energy Demand</td><td>400</td><td>100</td><td>400 (100%)</td><td>34000</td><td>0</td></tr>
<tr><td colspan="2">Energy Supply</td><td>500</td><td>15</td><td>300 (60%)</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">BC Supply</td><td>200</td><td>15</td><td>200 (100%)</td><td>11000</td><td>0</td></tr>
</table>

In this scenario, all energy and all Balancing Capacity are paid equally (uniform pricing), at a clearing price of 15 €/MWh and 70 €/MWh respectively, which apply equally in both bidding zones (because there is no congestion).

Bids are rightfully accepted against these prices, except the Combined Supply which does not provide Balancing Capacity although offered at 0 €/MWh while Balancing Capacity clears at 70€/MWh. To be able to provide Balancing Capacity, this asset must deliver at least 100MW of energy, which it offers at 45€/MWh while energy clears at 15€/MWh. The asset is thus rightfully rejected in the energy market but paradoxically rejected in the Balancing Capacity market [67]. The asset is also paradoxically rejected when profits and losses across both markets are combined, given that profits from the balancing capacity market would offset losses in the energy market.

The cost to supply demand in this solution is 17000€, that is 10x500+15x300=9500€ for the energy part and 10x100+70x50+15x200=7500€ for Balancing Capacity part.

The balancing capacity procurement costs for the TSOs amount to 350x70=24500€.

5.4.2 Option 1: Non-Uniform Pricing (NUP)

The main alternative design is to allow for Non-Uniform Pricing (NUP), which permits paradoxically accepted bids with compensation through side-payments. Under this design, social welfare is optimized without initially considering clearing prices, and prices are then determined based on the allocation results. PABs are compensated in order to ensure that the constraints set in the bid are economically satisfied.

Non-Uniform Pricing is a general concept where all accepted bids are not necessarily settled at the same uniform price. Instead, different sub-designs can be implemented depending on how prices are effectively set and how side-payments are managed.

One such sub-design is **Integer Pricing (IP)**, where marginal prices are computed after having transformed the initial non-convex problem into a convex one by replacing all the binary variables by the value they take in the optimal (or best found) allocation.

Another notable sub-design is **Convex Hull Pricing (CHP), see [7] and [8]**, which aims to determine prices that minimize 'lost opportunity costs' – referring to situations where market participants either incur negative profits or miss out on potential profits – hence reducing the need for side-payments.

The financing of side-payments is also a critical aspect of NUP. Side-payments can be funded from different sources. In some cases, the funds come from a **regulatory pocket**, such as grid tariffs or other socialized methods, which ensures that market participants do not bear the direct cost of compensating paradoxical acceptances. Alternatively, side-payments can be financed by the **surplus generated by other accepted bids**. In this approach, the surplus from efficiently allocated bids is used to cover the losses incurred by paradoxically accepted bids, creating a self-financing mechanism within the market[68].

The main advantage of NUP is that it allows for greater flexibility in the optimization process, which can lead to higher social welfare. By removing the constraint that forces the rejection of beneficial bids, the solution space is expanded, allowing for a more efficient allocation of resources. Furthermore, the separation of volume allocation and price determination simplifies the initial market clearing process, which makes it algorithmically easier to solve. Although the bidding behavior of market participants may be influenced, and gaming risks might exist, an initial qualitative and quantitative analysis conducted within the Euphemia Lab suggested that these risks would be low in practice. However, these elements should be further assessed in an updated market and performance impact analysis, comprehensively considering the new co-optimization setup before actual implementation. However, although it would reduce the computational complexity, the introduction of side-payments adds other types of complexity, as it requires a dedicated settlement mechanism and regulatory frameworks to support these payments. There is also a risk that market participants

[68] Note that – by construction – the total surplus generated by the auction (including the negative surplus implied by paradoxically accepted bids) is necessarily non-negative, such that it is always possible to finance side-payments from the surplus of efficiently allocated bids. Though, a self-financing mechanism may have other impacts in terms of fairness and incentives.

may engage in strategic bidding if they anticipate compensation for paradoxically accepted bids, which could undermine the efficiency gains.

Allowing for paradoxically accepted bids with compensation (side-payments) can lead to increased social welfare, as the combined supply bid in Zone 1 can now be included. This allows the thermal unit to contribute to both energy and balancing capacity demand, but at the cost of additional side-payments to compensate for the inefficiencies introduced by accepting the indivisible energy supply.

For this scenario, we optimize the social welfare without constraints on clearing prices for avoiding paradoxical acceptances. We then deduct prices based on marginal pricing principles[69].

Table 6: Market outcome with NUP Options 1 and 2 and pure Marginal Pricing as NUP sub-design

<table>
<tr><th></th><th colspan="2">Bid Name</th><th>Volume (MW)</th><th>Bid Price (€ /MWh)</th><th>Acceptance (%)</th><th>Surplus (€)</th><th>Side Payment (€)</th></tr>
<tr><td rowspan="7">Bidding Zone 1:
En Price = 15 €/MWh
BC Price = 15 €/MWh</td><td colspan="2">BC Demand</td><td>250</td><td>Price Taking</td><td>250 (100%)</td><td>-</td><td>-</td></tr>
<tr><td colspan="2">Energy Demand</td><td>400</td><td>100</td><td>400 (100%)</td><td>34000</td><td>0</td></tr>
<tr><td colspan="2">Energy Supply</td><td>500</td><td>10</td><td>500 (100%)</td><td>2500</td><td>0</td></tr>
<tr><td rowspan="2">Combined Supply</td><td>En.</td><td>200
(MAR = 50%)</td><td>45</td><td>100 (MAR)</td><td>-3000</td><td rowspan="2">1500</td></tr>
<tr><td>BC</td><td>100</td><td>0</td><td>100 (100%)</td><td>1500</td></tr>
<tr><td colspan="2">BC Supply 1</td><td>100</td><td>10</td><td>100 (100%)</td><td>500</td><td>0</td></tr>
<tr><td colspan="2">BC Supply 2</td><td>100</td><td>70</td><td>0 (0%)</td><td>0</td><td>0</td></tr>
<tr><td>Flows:</td><td colspan="3">Energy 200MW from BZ1 to BZ2</td><td>↓ ↑</td><td colspan="3">BC 50MW from BZ2 to BZ1</td></tr>
<tr><td rowspan="4">Bidding Zone 2:
En Price = 15 €/MWh
BC Price = 15 €/MWh</td><td colspan="2">BC Demand</td><td>100</td><td>Price Taking</td><td>100 (100%)</td><td>-</td><td>-</td></tr>
<tr><td colspan="2">Energy Demand</td><td>400</td><td>100</td><td>400 (100%)</td><td>34000</td><td>0</td></tr>
<tr><td colspan="2">Energy Supply</td><td>500</td><td>15</td><td>200 (40%)</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">BC Supply</td><td>200</td><td>15</td><td>150 (75%)</td><td>0</td><td>0</td></tr>
</table>

The clearing prices for energy (15€/MWh) and for Balancing Capacity (15€/MWh) are both set by partially accepted bids (both located in Zone 2, although the market prices in both zones should be equal given the absence of congestion). Based on these prices, convex bids are rightfully accepted or rejected.

[69] As noted above, several alternative pricing rules (Convex Hull – see [7] and [8], …) can be set for a given allocation. We arbitrarily opted for pure marginal IP pricing (see [9]) to illustrate the example (meaning, in a nutshell, that partially accepted orders set the clearing prices).

However, the Combined Supply is now paradoxically accepted: it is losing money in the energy market (-3000€), and this loss is not compensated in the Balancing Capacity market (+1500€), hence it is compensated by a side payment of 1500€.

It is the optimal solution (in absence of the "No PAB" rule of Option 0) because this solution is the cheapest way to fulfil demand: 15750€ in total, with 10x500+45x100+15x200=12500€ to meet energy demand (which is higher compared to Option 0 due to the more expensive combined energy supply) and 0x100+10x100+15x150=3250€ to meet the balancing capacity demand (which is lower compared to Option 0 due to acceptance of the cheap combined balancing capacity supply, despite paradoxically accepted).

Note that the welfare increase of 1250€ is a "net welfare increase" after subtraction of the side payment (negative surplus of the combined offer). To see this, note that in all options and whatever the market prices are, the total welfare can be decomposed as the sum of the bid surpluses (i.e. the "profit" of the accepted bids, which are in general positive but can be negative in case of paradoxical acceptance), the congestion rent, and the procurement costs to meet inelastic balancing capacity demand. The welfare increase between option 1 and option 0 can hence be recalculated as follows:

- For option 0, the decomposition in terms of surpluses, congestion rent and procurement costs yields: $34000 + 2500 + 6000 + 34000 + 11000 - 70x350 = 63000€$, which indeed corresponds to the welfare calculated as the total utility of the price-sensitive demand (2*400*100 = 80 000€) minus the total costs of supply of 17000€ calculated above.

- For option 1, the decomposition in terms of surpluses, congestion rent and procurement costs yields: $34000 + 2500 + \mathbf{-3000} + \mathbf{1500} + 500 + 34000 - 15x350 = 64250€$, again corresponding to the total utility of the price-sensitive demand (80 000€) minus the total costs of supply of 15750€ calculated above.

The welfare increase corresponds here to the net effect of increased energy supply bid costs and reduced balancing capacity procurement costs.

The example above highlights one of the key challenges associated with non-uniform pricing approaches. Option 1 results in an additional €1250 of net welfare compared to Option 0. However, achieving this would require either redistributing some of the positive surpluses from profitable bids to bids with negative surpluses or collecting the necessary funds through trading fees or other sources of socialized money.

A quantitative analysis performed in the frame of the Euphemia Lab in 2021 indicates that the side-payments required are likely to be relatively small in practice. Consequently, the contributions of in-the-money bids[70]—intended to prevent any bid from becoming out-of-the-money—are expected to be minimal and unlikely to significantly influence the bidding behavior of market participants. However, further

[70] These contributions cannot lead an in-the-money order to become out-of-the-money, because they are bounded by the positive surplus of the order before the redistribution, that should be negligible in practice.

qualitative and quantitative analyses would be necessary to validate this observation if this non-uniform pricing option is considered for future implementation.

5.4.3 Option 2: NUP for Balancing Capacity; No PAB for Energy.

The second alternative involves applying Non-Uniform Pricing (NUP) only to the balancing capacity market while maintaining the No PAB rule for the energy market. The rationale behind this mixed approach is that balancing capacity procurement operates as a single-sided market, with TSO acting as the sole buyer, while the energy market is a two-sided market involving both buyers and sellers. This distinction is important because the procurement dynamics and incentives differ substantially between these market types.

In the balancing capacity market, allowing NUP provides additional flexibility to procure resources efficiently. Since the TSO is the only buyer, the use of side-payments to compensate paradoxically accepted bids is more straightforward, and less prone to competitive distortions (at least compared to Options 3 & 4 described below, as such compensations only apply to a limited set of bids). By relaxing the No PAB rule for balancing capacity, this approach can increase overall social welfare by allowing a broader set of bids to participate, leading to potentially more efficient procurement outcomes. This flexibility can also help in ensuring adequate capacity availability, particularly during periods of high system stress.

However, in the energy market, the No PAB rule is retained to maintain coherence and transparency. Energy markets involve multiple buyers and sellers, and enforcing the No PAB rule helps ensure that accepted bids align with market-clearing prices, avoiding complex compensation mechanisms and maintaining price transparency. This distinction helps preserve the integrity of price signals in the energy market, which is crucial for promoting fair competition and ensuring efficient trading behavior.

Despite its advantages, this hybrid approach introduces several challenges and potential risks. One major issue is fairness between bids that are offered jointly for energy and balancing capacity and bids that are solely offered for energy. Market participants who are capable of offering both energy and balancing capacity may have an incentive to manipulate their bids strategically to benefit from side-payments through the balancing capacity market, even if those bids would initially only be offered in the energy market (e.g. by offering a very small volume of balancing capacity, making this bid, which is in principle an energy bid, eligible to side-payments). This can lead to market inefficiencies and introduce undue discrimination against participants who cannot offer both products (i.e. BSP participants being advantaged compared to BRP-only participants).

There is also a theoretical risk that the complexity of managing two distinct pricing rules would increase the computational burden, potentially impacting the overall efficiency of market clearing processes. Such a risk would need to be further assessed in practice.

5.4.4 Option 3: MEB for Balancing Capacity; No PAB for Energy.

Local MEB for Balancing Capacity; No PAB for Energy

The third alternative is to apply the "Most Expensive Bid" (MEB) pricing to balancing capacity while enforcing the No PAB rule for the energy market. In this approach, the clearing price for balancing capacity is set at the level of the most expensive accepted bid, thereby ensuring that no PABs are present without relying on side-payments.

The advantage of using MEB pricing for balancing capacity is that it provides a straightforward mechanism to avoid paradoxically accepted bids. All accepted balancing capacity bids are remunerated at the same high price, ensuring fairness among accepted participants. Additionally, this avoids the need for side-payments, simplifying the financial settlement process. However, this approach can lead to inflated clearing prices and hence inflated balancing capacity procurement costs.

The risk of strategic bidding is also increased with this approach, as the approach mechanically inflates the balancing capacity price for a bid that is otherwise paradoxically accepted. Similarly, as in Option 2, an energy bid that is otherwise paradoxically accepted can be tweaked to also offer one unit of balancing capacity. As a result, the balancing capacity price is inflated (to compensate for the otherwise paradoxical acceptance of the bid) and this price shift applies to all the remainder of this balancing capacity product.

Finally, a major disadvantage of this approach is that cross-zonal price differences are no longer consistent. For example, if the transmission capacity between two zones is not limiting, but that the price in one zone needs to be increased to avoid the paradoxical acceptance of a bid, a price difference is created in an uncongested area. This latter drawback has triggered the following additional design option.

Here, the balancing capacity price in Zone 1 is set at the level of the most expensive accepted bid, ensuring that no PABs are present without side-payments. This leads to a uniform high price for all accepted balancing capacity bids, potentially inflating procurement costs and discouraging efficient bidding.

Table 7: Market outcome with inflated balancing capacity prices in zones with otherwise paradoxically accepted bids

	Bid Name		Volume (MW)	Bid Price (€ /MWh)	Acceptance (%)	Surplus (€)	Side Payment (€)
Bidding Zone 1: En Price = 15€/MWh BC Price = 30 €/MWh	**BC Demand**		250	Price Taking	250 (100%)	-	-
	Energy Demand		400	100	400 (100%)	34000	0
	Energy Supply		500	10	500 (100%)	2500	0
	Combined Supply	**En.**	200 (MAR = 50%)	45	100 (MAR)	-3000	0
		BC	100	0	100 (100%)	3000	
	BC Supply 1		100	10	100 (100%)	2000	0
	BC Supply 2		100	70	0 (0%)	0	0
Flows:	En. 200MW from BZ1 to BZ2			↓ ↑	BC 50MW from BZ2 to BZ1		
Bidding Zone 2: En Price = 15 €/MWh BC Price = 15 €/MWh	**BC Demand**		100	Price Taking	100 (100%)	-	-
	Energy Demand		400	100	400 (100%)	34000	0
	Energy Supply		500	15	200 (40%)	0	0
	BC Supply		200	15	150 (75%)	0	0

The acceptance/rejection for this solution is the same as for Options 1 & 2. Though, instead of remunerating the Combined Supply asset at a different (better) price through a side-payment, the price of the Balancing Capacity is inflated for all accepted bids in Bidding Zone 1. Such an approach allows to uniformly remunerate all accepted bids but may create paradoxically rejected Balancing Capacity offers (and paradoxically accepted elastic TSO demands, in case they exist).

Because it is the same acceptance/rejection as in Options 1 & 2, the welfare is also identical. Though, the TSO procurement cost of Balancing Capacity 200x30+150x15=8250€ is here obviously higher compared to Option 1 & 2 but remains lower than in Option 0. This is because the concept is to compensate all the accepted bids by a price modification, instead of compensating only the paradoxically accepted bid through a side-payment.

It is worth noting that the balancing capacity prices increases from 15€/MWh to 30€/MWh due to the volume of balancing capacity offered by the combined supply. This increase 15€/MWh equals to the loss of 1500 € incurred in Option 1, divided by the balancing capacity volume offered and accepted by the combined supply. Hence, if this combined supply would only have offered 20MWh (instead of 100MWh), the price increase would have been 75€/MWh. In other words, it becomes relatively easier to adjust bids in order to influence the balancing capacity prices with this option, compared to any alternative. This is why this option has not been retained for further analysis.

Note also that, in this scenario, the Balancing Capacity markets in both bidding zones clear at different prices, despite the absence of congestion.

5.4.5 Option 4: same as Option 3 with cross-zonal consistency

Global MEB for Balancing Capacity; No PAB for Energy

The fourth alternative extends the MEB pricing principle across multiple zones, ensuring consistency in cross-zonal capacity pricing while still applying the No PAB rule for energy. In this approach, balancing capacity prices are aligned across interconnected zones, maintaining a consistent pricing signal making sure that the cross-zonal capacity is optimally allocated against the zonal market prices of energy and balancing capacity: for instance, avoiding positive price spreads between zones in the absence of congestion.

In other words, this makes sure that the cross-zonal capacity allocation is fully coherent with the value of this cross-zonal capacity for the exchange of energy compared to its value for the exchange of balancing capacity, where the values for the cross-zonal exchanges are measured by the determined zonal prices of each product.

The primary advantage of this approach is that it maintains uniform pricing across interconnected zones, which is crucial for ensuring efficient cross-border exchanges and avoiding discrepancies in pricing that may occur across zones.

By applying consistent pricing across zones, the design enhances market integration and transparency. However, aligning prices across multiple zones further increases procurement costs compared to applying MEB pricing locally.

This design also creates opportunities for market manipulation, as participants could artificially inflate their bids to benefit from the higher clearing prices across multiple zones, thereby leading to inefficiencies and increased costs for the system.

Table 8: Market outcome with inflated balancing capacity prices and zonal price spreads consistent with the CZC allocation

	Bid Name		Volume (MW)	Bid Price (€ /MWh)	Acceptance (%)	Surplus (€)	Side Payment (€)
Bidding Zone 1: En Price = 15 €/MWh BC Price = 30 €/MWh	**BC Demand**		250	Price Taking	250 (100%)	-	-
	Energy Demand		400	100	400 (100%)	34000	0
	Energy Supply		500	10	500 (100%)	2500	0
	Combined Supply	**En.**	200 (MAR = 50%)	45	100 (MAR)	-3000	0
		BC	100	0	100 (100%)	3000	
	BC Supply 1		100	10	100 (100%)	2000	0
	BC Supply 2		100	70	0 (0%)	0	0
Flows:	En. 200MW from BZ1 to BZ2				BC 50MW from BZ2 to BZ1		
Bidding Zone 2: En Price = 15 €/MWh BC Price = 30 €/MWh	**BC Demand**		100	Price Taking	100 (100%)	-	-
	Energy Demand		400	100	400 (100%)	34000	0
	Energy Supply		500	15	200 (40%)	0	0
	BC Supply		200	15	150 (75%)	2250	0

In this scenario, the total TSO procurement cost for Balancing Capacity increases relative to options 1, 2 and 3, and becomes 350x30=10500€.

This option suffers from the same deficiency as Option 3, except that it has larger impacts given that the effects over prices mechanically spread across zones.

5.5 Conclusions and recommendations on design options

Based on the preliminary qualitative analysis presented in this chapter, no fundamental showstoppers have been identified *at this stage* that would prevent the application of existing day-ahead pricing principles under co-optimization. However, several risks and challenges have been highlighted, especially when considering welfare impacts, liquidity concerns, and computational complexities associated with different pricing rules.

To move forward pragmatically in the design of a co-optimized day-ahead market, we recommend opting for the implementation of the "No PAB" pricing rule (Option 0), which aligns with the current day-ahead market rules. This approach ensures coherence and simplicity in pricing.

However, in case realistic quantitative simulations reveal a non-negligible risk that the No PAB rule substantially limits social welfare, pose severe liquidity concerns, or prove to lead to material algorithmic challenges, a variant of Option 1 (Non-Uniform Pricing) should be reconsidered as a possible alternative.

This careful step-by-step approach would allow the market to evolve toward a more efficient co-optimized framework while managing the inherent complexities of non-convexities in power market pricing. The importance of quantitative analysis cannot be understated; it is essential for determining the true welfare impacts and assessing the practicality of implementing more flexible pricing mechanisms, such as NUP, to enhance price calculation and market outcome.

In other words, N-SIDE's proposal is to progress pragmatically by extending the current price approach for non-convexities to a co-optimized setup, and to first focus on the novelties implied by co-optimization. This is necessary to be able to draw realistic simulations, from which it should become possible to get some clue over whether the specific risks described above (social welfare limitation, liquidity concerns, or calculation tractability) are purely theoretical or more likely to be sufficiently substantial to pose actual problems. Doing so allows to park the complex discussions over alternatives to the current « No PAB » rule until these prove to be required.

6. Additional Topics for Future Analysis

6.1 BC Scarcity: Demand elasticity, BC Substitutability, and Curtailment Management

This section introduces the notion of scarcity and curtailment management, which will be analyzed more in depth at a later stage.

When supply for BC is scarce (in the sense that it cannot meet the price inelastic demand), BC prices should in principle hit the BC price cap. This is illustrated by the example in Figure 28.

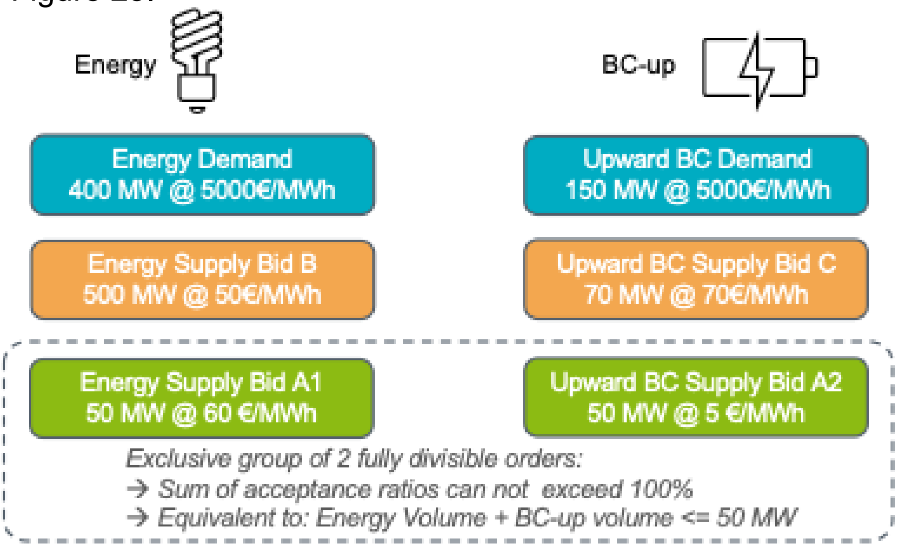
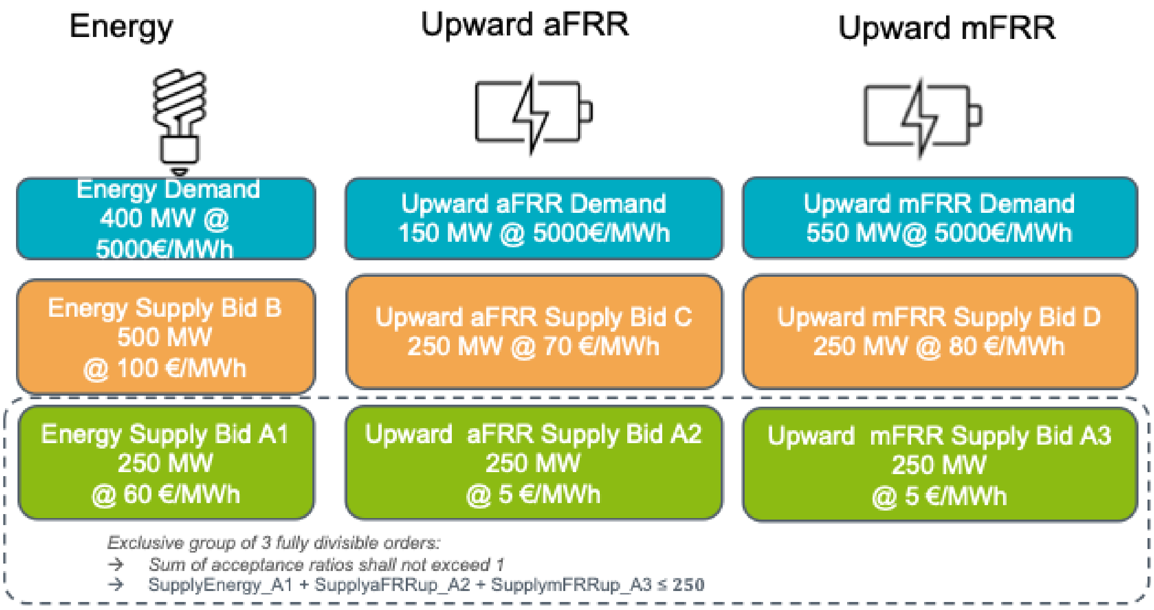


Figure 28: An illustrative example demonstrating scarce BC supply and BC prices reaching the price cap. In this example, Energy Demand is fully met by Energy Supply Bid B being partially accepted (implying that Energy clears at 50€/MWh) while entirely accepting Upward BC Supply Bids C and A2 does not suffice to fully satisfy the Upward BC Demand. As a result, the Upward BC Demand price clears at its upper bound of 5000€/MWh.

Although this can be considered as a correct price signal, it may be relevant to mitigate effects of scarcity on BC procurement costs. This can be achieved by introducing price-sensitive demand for balancing capacity. Alternatively, BC price caps can be adjusted, or BC pricing rules may be adapted to cope with this particular case, where curtailed price-taking demand would not set clearing price.

There is yet another important aspect relating BC scarcity to the question of reserve substitutability discussed in Section 1.4 and illustrated in Annex B. By enabling the pooling of different reserve products, reserve substitutability may help reduce the frequency of mFRR BC scarcity situations.

This is illustrated in the following two examples. The first example in Figure 29 illustrates a situation of mFRR BC scarcity if the reserve substitutability principle is not applied. The second example in Figure 30 shows how BC prices reaching the price cap can be avoided if the substitutability principle is applied. As a result of the substitutability requirement, aFRR and mFRR prices become more closely interlinked.

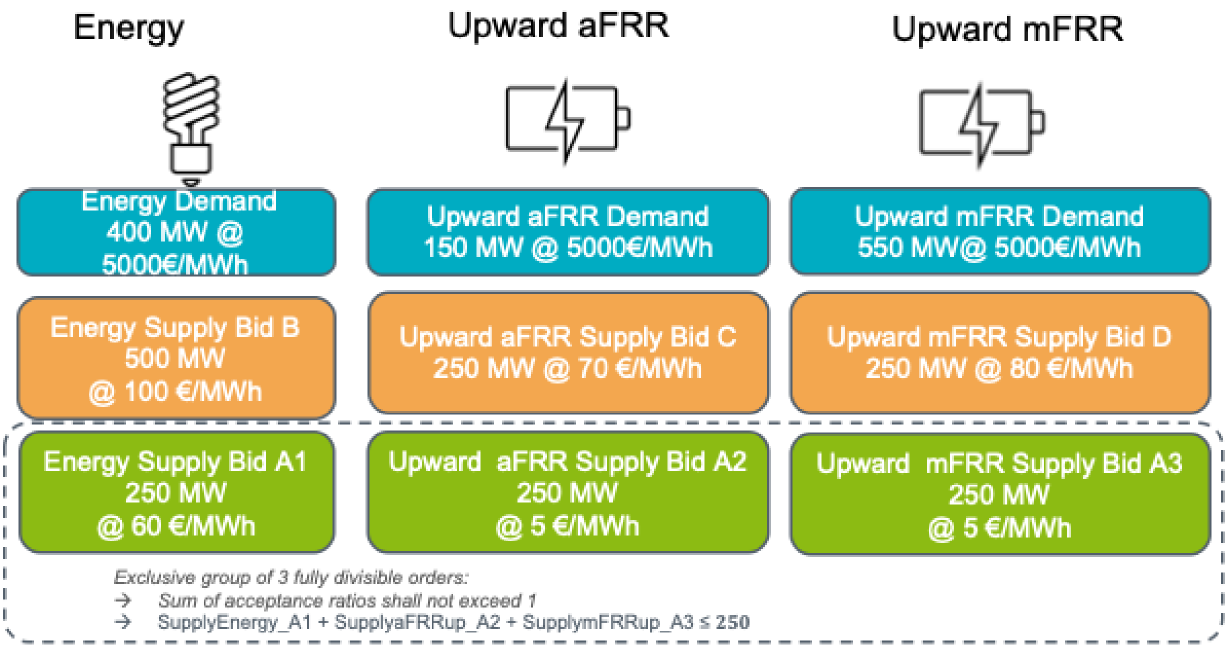


Market Results	Energy	Upward aFRR	Upward mFRR
Market Prices	100 €/MWh	70 €/MWh	5000 €/MWh
Bid A1 Accepted Vol.	-	-	-
Bid A2 Accepted Vol.	-	-	-
Bid A3 Accepted Vol.	-	-	250
Bid B Accepted Vol.	400	-	
Bid C Accepted Vol.	-	150	
Bid D Accepted Vol.	-	-	250

Figure 29: Example without reserve substitutability, where scarcity of mFRR supply results in the mFRR price reaching the price cap set by the price of inelastic demand

If there is no substitutability, mFRR demand exceeds the total mFRR offers and the price cap of 5000€/MWh is reached in the initial example given in Figure 29. Moreover, the mFRR price is above the aFRR price, despite the fact that aFRR is a more demanding product.

Applying the reserve substitutability principle helps prevent such price reversals. As a result of substitutability, it is indeed not possible that mFRR clears at a higher price than the aFRR, and mFRR procurement can therefore only be reduced. Results for the variant of the example in Figure 29 where reserve substitutability is allowed are given in Figure 30. In this example, the demand for mFRR is partly met by aFRR supply (which is more abundant than mFRR supply).



Market Results	Energy	Upward aFRR	Upward mFRR
Market Prices	100 €/MWh	80 €/MWh	80 €/MWh
Bid A1 Accepted Vol.	-	-	-
Bid A2 Accepted Vol.	-	-	-
Bid A3 Accepted Vol.	-	-	250
Bid B Accepted Vol.	400	-	
Bid C Accepted Vol.	-	250	
Bid D Accepted Vol.	-	-	200

Figure 30: Variant of Example in Figure 29 , where the reserve substitutability principle mitigates scarcity of mFRR BC that clears below the price cap.

While a non-harmonized setup may present significant challenges, the feasibility and relevance of a hybrid approach—where some TSOs apply the substitutability principle while others do not—could be assessed at a later stage of the R&D process.
This topic is currently planned to be further assessed as part of R3.

6.2 Further Co-Optimized Storage and Demand Response considerations

The key challenges associated with designing a robust 'combined bid' for storage and demand response mechanisms have been discussed in Section 3.2.4 on combined bids for storage and demand response[71].

Another important attention point relates to the uncertainty surrounding the state of charge of storage assets following the provision of balancing capacity.

Given that the specific activation patterns of balancing capacity remain indeterminate until real-time operations, a sequence of upward or downward balancing activations early in the day may significantly impact the reservoir level and thereby constrain the

[71] Note that balancing-capacity-only bids may also correspond to demand response.

asset's capacity to supply energy or fulfill additional balancing obligations later in the day.

To mitigate this uncertainty, market participants may in practice engage in intraday energy trading to replenish or deplete storage levels and restore their full ability to honor subsequent commitments. When upward balancing capacity has been activated, participants may buy on the intraday market some energy[72]. As a result, while balancing capacity activations create some uncertainty over the reservoir's level, such uncertainty can be (at least partially) mitigated through subsequent intraday trades. Hence such trades in practice increase the ability of energy or balancing capacity obligations later in the day.

The extent to which market participants are assumed capable of "intraday refueling", and how this is modeled within a storage bid, determines the level of conservatism applied to storage orders. The most conservative approach assumes no refueling capability, meaning that a 1 MW battery with a 2.4 MWh storage capacity could only be contracted for a total of 2.4 MW of upward balancing capacity throughout the entire day (e.g. a continuous supply of 0.1MW of balancing capacity). Conversely, an assumption that intraday trades can be executed rapidly after a balancing capacity commitment would allow the same battery to be contracted for 1 MW of continuous balancing capacity supply along the day[73].

Unlike the energy day-ahead market, where the SDAC framework sets clear minimum standards and starting points for co-optimization, the procurement of balancing capacity from storage assets currently lacks standardization at European level (i.e. there exist different rules in the various markets). Establishing such standards is needed to develop a co-optimized bidding framework for storage that is fit for European implementation. Achieving this requires active engagement with stakeholders to create bidding products that align market participants' operational strategies with the need for transmission system operators (TSOs) to ensure reliable balancing capacity, while also maintaining practicality in terms of complexity, performance, and operations.

6.3 Linking of Combined Bids

As highlighted in Chapter 3, the ability to link simple bids already enables market participants to better represent their bidding strategies by allowing them to express dependencies and conditional acceptances in a structured manner that may not be possible via the usage of proposed combined bids. Extending this capability to combined bids can provide the same added value, enabling market participants to articulate more complex strategies while maintaining clarity and efficiency in bid representation by reducing the number of simple bids used. This potential addition would allow for greater flexibility in expressing operational constraints and multi-product interactions, accommodating a broader range of bidding strategies without

[72] Note that the prices at which intraday trades are settled should in principle be reflected in the balancing energy offers.
[73] Another layer of complexity may possibly be considered regarding the asset's power capacity and the interactions between day-ahead energy commitments, the provision of balancing capacity, and intraday energy replenishments.

necessitating an extensive expansion of combined standardized products proposed in a co-optimized day-ahead electricity market. To illustrate the potential benefits of this flexibility, we begin with an example that highlights the value of linking combined bids and should serve as a reference for the subsequent discussion.

The example in Figure 31, repeated for convenience from Section 3.1.3, represents a strategy of a market participant which has been created using only simple linked bids. This schema corresponds to a scenario where the bidder wants to sell a partially curtailable amount of power in the energy market but is also willing to shut down its plant entirely if selected in downward BC at an advantageous price.

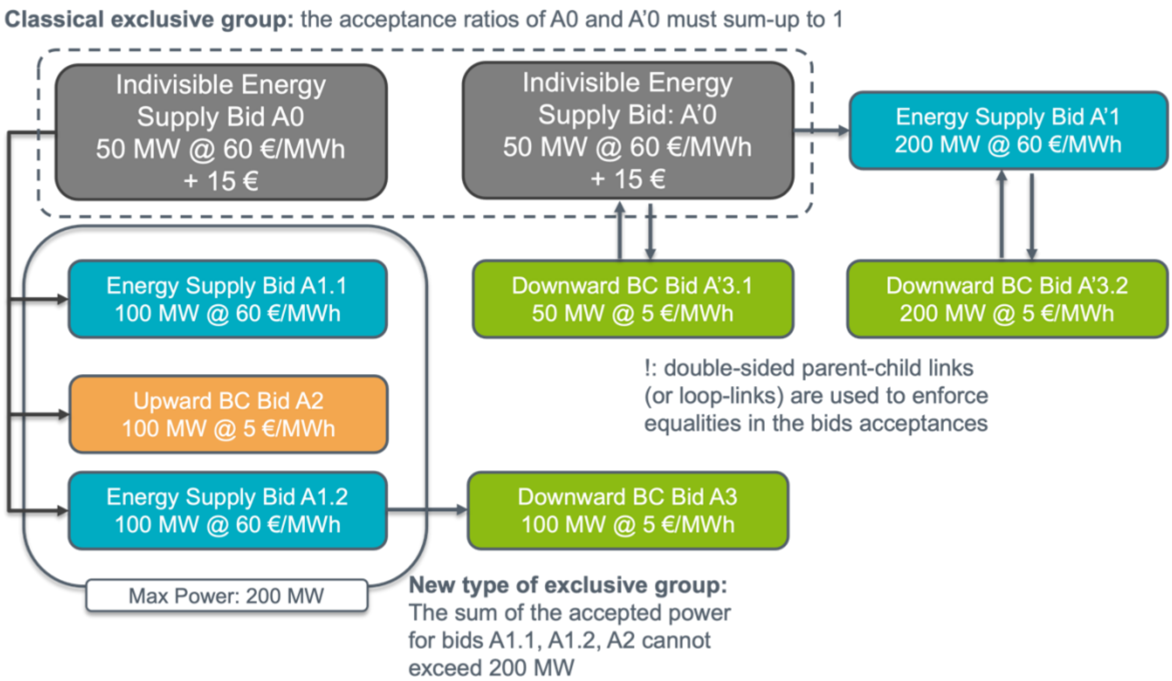


Figure 31: Illustration of a market participant strategy via the unique usage of simple bids and links.

Figure 32 represents more easily the same bidding strategy as the one provided in Figure 31 but using linked combined bids.

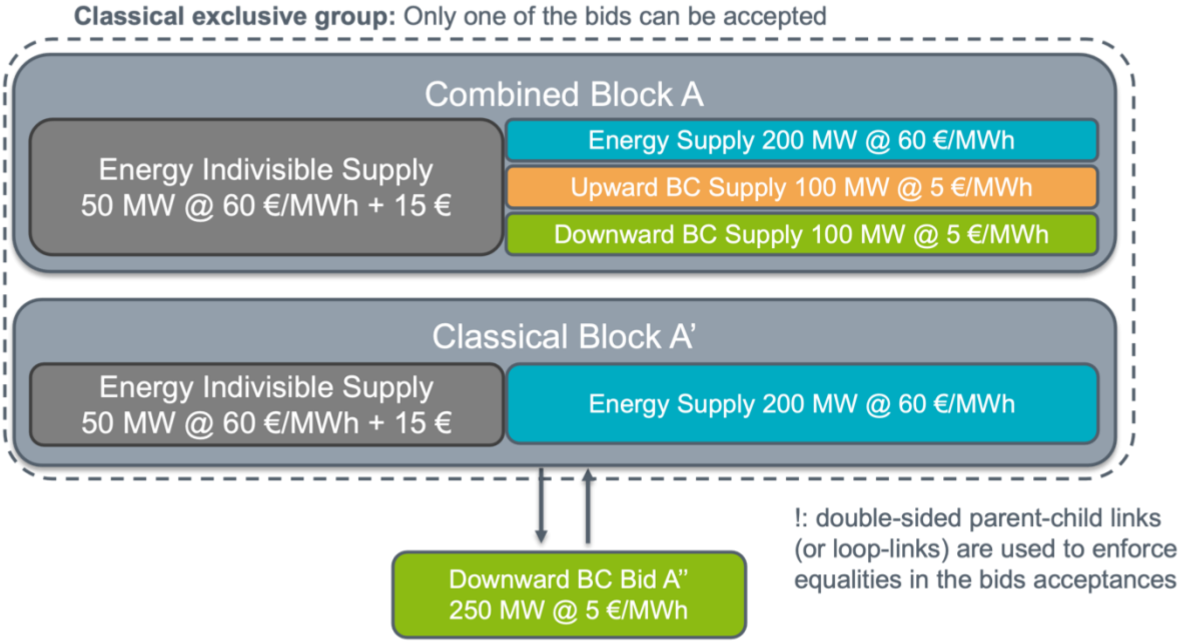


Figure 32: Representation of the bidding strategy of Figure 31 by means of links between combined bids.

With this new format, the bidding strategy can be expressed using only 3 bids and 3 links, as the complexities of the mixing of different products are handled by the design of the combined products.

At this point, we are left with three possible choices.

1. The first choice consists in forbidding the use of links with combined bids constraining ourselves to use single-product bids for linked schemas as, for example, in Figure 31.

2. The second choice consists of allowing the linking of a small set of generic combined bids and consequently utilizing schemas like the one presented in Figure 32.

3. The third choice requires the creation of enough specialized combined bids to cover an expanded set of possible cost structures. For instance, in our example, we would need to create a bid format that can handle "full deactivation" as well as the usual cross-product matching.

If, on the one hand, from a theoretical standpoint, it may not be possible to create a rich enough set of combined bids to cover all possible present and future cost structures, on the other hand, promoting complex linking schemas may have a negative impact on the performance of the solving algorithm (as discussed more in depth in the next section).

Therefore, creating a small set of generic combined bid formats and allowing for the linking of them appears as a reasonable trade-off.

Luckily, the bid linking designs already deployed in the energy-only day-ahead market can be readily extended to combined bids. In facts, current energy-only exclusive and parent-child links are defined in terms of acceptance of the orders involved, and the concept of acceptance can easily be extended to combined bids. Now, the more involved nature of combined bid can give rise to the need for more specialized links.

However, we believe that the design and introduction of those new linking mechanisms should be the product of a collaboration between market participants and market designers, rather than something to be fixed a priori.

6.4 Algorithmic scalability

We highlight here potential performance challenges associated with co-optimization and emphasize the need for a performance impact assessment, along with an anticipation of possible mitigation measures should scalability prove to be an issue.

Before discussing the scalability of the various proposed approaches to co-optimization, it is important to clarify the main sources of complexity in a market clearing algorithm such as Euphemia. In presence of non-convex bids, and requirements such as take-or-leave bids or advanced temporal linking constraints, the market clearing problem needs to be defined using discrete variables (normally binary). Such discrete variables are normally dealt with using algorithms such as a Branch-and-Bound that try to avoid the enumeration of all possible discrete assignment by performing smart searches in the solution space. However, no known algorithm to date can ensure that the complexity of the overall search (up to proven global optimality) would not grow exponentially with the number of discrete variables.

Despite that, the practical performance of a Branch-and-Bound algorithm strongly depends on the quality of the continuous relaxations that can be obtained from the original mixed-integer problem formulation. This means that the smaller the impact of relaxing integrality requirements on the objective function, the faster the solution process. For this reason, it is very important to model the market clearing problem so to obtain the best possible relaxation quality[74].

Furthermore, each of the potentially exponentially many steps of the Branch-and-Bound approach requires the solution of a continuous optimization problem whose complexity depends on the overall size of the problem. Therefore, the overall complexity depends, to a lesser degree, also on the sheer number of variables used to model the market clearing problem.

On top of that, the introduction of non-convex bids interferes with marginal pricing theory in such a way as to create the necessity of explicitly enforcing price-based conditions (e.g., no paradoxical acceptances) that are naturally satisfied by the optimal

[74] Relaxation quality measures how closely the approximate solutions, obtained by relaxing the integrality constraints of certain variables in a model, align with the model's true optimal solution. It primarily depends on the model's structure and implementation approach.

solution of a continuous market clearing problem. While direct formulations of market requirements such as the 'no paradoxically accepted block condition' have been proposed and tested in the academic literature, they turn out to be less scalable than proceeding with a two-level (decomposition) approach. First, we optimize acceptances in the market clearing problem, then we check for the violation of the price conditions and if those are violated, we go back to the market clearing problem looking for an alternative bid matching. This iterative process may require many attempts and adds to the overall complexity of the final algorithm.

Coming back to co-optimization, the problem size is naturally much larger than the one we would have in the classical scenario where we consider only the energy side.

Therefore, it is especially important to take good care of the number of discrete variables introduced and the relaxation quality of the model. In practice, this means avoiding introducing more non-convex bids / requirements than needed and ensuring that the necessary non-convex elements may be somewhat accurately approximated by their relaxed convex counterparts. Ensuring perfectly efficient models is no small feat, especially when dealing with real-world data. However, it is possible to alleviate inefficiencies by limiting the number of non-convex bids each market participant can use per unit of volume offered/demanded[75] to promote "efficient" bidding strategies, and/or providing the market participants with expressive integrated bids that allow them to express their needs using optimized standard components.

Nowadays, the performance of Euphemia evaluated over synthetic data, appears to allow us to comfortably solve the 15MTU energy-only market clearing problem within the allotted 30 minutes of computation time (often much faster than that). This means that in principle, and assuming a good bidding language design, there is enough headroom to make the co-optimized market clearing problem solvable within acceptable time limits. This is especially true if the increment in size would mostly materialize in additional convex components of the market, as for instance curtailable BC-only/combined offers [76], rather than in additional non-convex components, like discrete orders activations. This observation seems to align with the fact that the markets that currently implement co-optimization tend to function on a unit-commitment basis where it is possible to deploy specialized combined bids that in most cases do not require more non-convexities than their energy-only counterparts.

Despite this, we believe that with the right design choices, providing a flexible set of bid-linking options, particularly well-suited for portfolio bidding, on top of combined bids, particularly well-suited for unit bidding, would not be a limiting factor for co-optimization.

Another important aspect to consider with regards to scalability is pricing. Requiring price conditions, like the prevention of paradoxically accepted orders, has a performance cost that depends on a variety of factors but, in all cases, increases with the number of non-convex components in the market.

[75] As is already the case today with restrictions on the number of block orders that can be submitted.
[76] In facts, as shown in the previous chapters, the bidding language one can build by just adding curtailable BC-only/combined offers to the current bidding language is already quite expressive, and might already cover a good portion of the possible use cases.

Whether or not this would be feasible or desirable in the largest co-optimized market in the world can only be assessed with extensive simulations[77]. Such simulations are expected in the next phases of the ongoing R&D process and will play an important part in the formulation of the final market design. Nevertheless, it must also be noted that other computationally cheaper pricing options like non-uniform pricing exist. Either in case of need or per design choice, such options may help to reduce the computational complexity of the market clearing algorithm.

[77] Possibly using real-world 15MTU data considering a large set of different assumptions on market participants' behavior with respect to offering BC.

7. Conclusions

This study has explored key aspects of co-optimization in the European electricity market, focusing on the interactions between energy and balancing capacity, the design of bidding products, cross-zonal capacity allocation, and pricing mechanisms.

The findings presented in this report aim at contributing to a deeper understanding of the potential benefits and challenges associated with implementing co-optimization within the European market framework.

However, the co-optimization research and development process is still in its early stages, and the conclusions drawn in this report are based on the scope investigated so far. They therefore remain conditional on further research, practical testing, and engagement with relevant stakeholders, including market participants.

A significant amount of work remains to refine the design choices, validate theoretical insights through simulations, and assess real-world implications of different bidding and pricing approaches. Furthermore, the successful implementation of co-optimization — should its technical feasibility and benefits in an evolving European context be confirmed in future market and performance impact assessments — will require continuous collaboration to ensure that the framework is both efficient and adaptable to evolving needs.

The main high-level takeaways of the study are summarized below.

7.1 Key Takeaways from the Study

7.1.1 Implicit Bidding vs. Explicit Bidding (Chapter 2)

A core takeaway of this study is that **implicit bidding**—where market participants do not explicitly factor in opportunity costs[78]—provides significant advantages over **explicit bidding**, which requires traders to estimate these costs, and is subject to significant drawbacks summarized in the conclusions of Chapter 2 in Section 2.4.

Implicit bidding leverages the co-optimization market-clearing process, and standard marginal pricing, to ensure that opportunity costs are naturally reflected in market prices, leading to:

- **Higher efficiency**, as it avoids the risk of welfare and market participant's profits suboptimality caused by forecast errors in opportunity cost estimation (which can occur under explicit bidding).
- **Reduced risk of paradoxically rejected bids**, ensuring more acceptable market outcomes.
- **Greater algorithmic scalability**, as explicit bidding complicates the market-clearing process and introduces inefficiencies.

[78] More broadly, this encompasses all endogenous costs incurred through bid linking, including also losses from generating energy unprofitably to facilitate the profitable provision of downward balancing capacity.

Given these benefits, implicit bidding is preferred, especially in a co-optimization context where interdependencies between energy and balancing capacity need to be properly accounted for.

7.1.2 Linked Bids vs. Combined Bids (Chapter 3)

The study also examined different bid structures, namely linked bids and combined bids. Linked bids refer to a family of bids for single products, either energy or a given balancing capacity product, connected to each other by "links" modeling specific acceptance interdependencies. A combined bid is a bid that simultaneously offers multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid.

Both **linked bids** and **combined bids** serve important roles in the co-optimization setup:

- **Linked bids** offer flexibility and can capture complex interactions, particularly useful for portfolio bidding strategies.
- **Combined bids** simplify bidding processes for specific scenarios, by directly integrating interdependencies between products into a single bid format.
- **Tailored combined bids for thermal assets** can enhance efficiency by capturing unit-specific characteristics such as fixed costs, ramping constraints, and other operational constraints.
- **Storage bids** require further refinement to ensure proper state-of-charge management and optimization across multiple time periods. They could also be used to represent demand response, modeled as storage bids, where only charging is allowed and occurs during optimal periods of the day.

A hybrid approach—where linked bids remain available for complex portfolio strategies while combined bids streamline simpler bidding scenarios or allow for the granular representation of asset-specific costs and constraints—is recommended to balance expressiveness and usability for market participants.

7.1.3 Cross-zonal Capacity Allocation (Chapter 4)

This chapter has analyzed the allocation of Cross-Zonal Capacity (CZC) in a co-optimized energy and balancing capacity market, extending insights from the Co-Optimization Roadmap Study. While primarily focused on an Available Transfer Capacity (ATC) grid model, the discussion provides broader insights applicable to more advanced network models, such as flow-based network representations.

A key takeaway is that co-optimization adheres to the same non-arbitrage equilibrium principles as energy market coupling. When there is no congestion, price differences between zones vanish. However, in congested situations, CZC is allocated in the most profitable way across products while considering applicable network constraints[79].

[79] Note that this type of statement implicitly assumes marginal pricing principles, whether or not paradoxically accepted orders and side payments are allowed, i.e. with or without Non-Uniform Pricing (see Chapter 5). Under other Non-uniform Pricing schemes such as Convex Hull Pricing, the price

An important concept explored is **energy flow netting**, where adverse energy flows (non-intuitive flows opposite to the price spread) can enhance balancing capacity allocation. This occurs when the value of cross-zonal balancing capacity exceeds losses incurred by the adverse energy flow.

While the discussion is based on an ATC grid model setup, it offers broader insights into the general principles guiding CZC allocation under co-optimization, as well as how market results can be interpreted.

The following general principle remains valid with more sophisticated grid models: marginal pricing guarantees that no additional value can be generated by reallocating CZC differently amongst products while still respecting network constraints. In particular, the principle remains valid under a flow-based grid model, regardless of whether the so-called deterministic reserve deliverability requirement is enforced.

A more advanced description of how this high-level principle translates into the specific co-optimization price formation mechanism under flow-based constraints (including the enforcement of the deterministic reserve deliverability requirement) will be elaborated at a later stage.

7.1.4 Pricing in the Presence of Non-Convexities (Chapter 5)

Non-convexities within a co-optimization framework—stemming from bids that involve fixed costs or indivisibilities—complicate the process of price formation. The study evaluated different pricing mechanisms, leading to the following conclusions:

- The **"No PAB" (Paradoxically Accepted Bids) rule**, currently applied in the European day-ahead market, should remain the default to maintain pricing consistency and avoid unnecessary complexities.
- If simulations show that this approach significantly limits social welfare or liquidity, **Non-Uniform Pricing (NUP)** needs to be explored as an alternative.
- The **Most Expensive Bid (MEB) pricing approach** was found to increase procurement costs and pose risks of price manipulation, making it less suitable.
- Ensuring **cross-zonal price consistency** in co-optimization is critical to prevent distortions in market signals and inefficient cross-border exchanges.

While no fundamental barriers have been identified to applying existing day-ahead pricing principles to co-optimization, continued analysis is necessary to assess potential trade-offs between efficiency, fairness, and computational feasibility.

7.2 Next Steps

Specific topics requiring further analysis are listed in Chapter 6 and include (a) addressing remaining questions on balancing capacity scarcity and reserve substitutability, (b) designing combined bids for storage and demand response in a co-

calculation doesn't ensure in general that the CZC is coherently allocated with respect to the locational prices.

optimization context, (c) exploring the potential benefits of bid linking options for combined bids and (d) assessing algorithm scalability under various sets of requirements.

This list of specific topics is non-exhaustive. Future work will, more broadly, focus on:

- Refining **bid structures** to ensure that different types of assets (thermal, storage, demand response) can participate effectively in co-optimization.
- Improving **algorithmic scalability** to accommodate increased market complexity.
- Conducting **real-world simulations** to validate theoretical insights and quantify potential trade-offs.
- Engaging with **stakeholders**, including market participants and regulatory bodies, to refine market designs and ensure practical feasibility.

In conclusion, while this study provides valuable insights, it must be seen as a foundation for further development rather than a definitive set of final conclusions. The findings and recommendations outlined here will need to be continuously revisited and refined as co-optimization R&D progresses and as additional market experience and stakeholder feedback are gathered.

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Annexes

A Glossary

Combined Bids
A combined bid is a bid that simultaneously offers multiple energy and balancing capacity products, with linking constraints capturing the interdependencies between these products included directly within the bid. Certain parameters, such as the total offered capacity, are shared across all products within the bid.

Convex Hull Pricing (CHP)
This approach to pricing with non-convexities aims to determine prices that minimize lost opportunity costs (comprising opportunity costs or negative profits) – hence reducing the need for side-payments, see [7] and the initial description in [8] for more information.

Cross-Product Merit Order or **Co-Optimized Merit Order**: global merit order that is obtained by fully accounting for the cross-product interactions due to the presence of bid linking or cross-product links in combined bids.

Endogenous costs
Endogenous costs are defined as costs incurred within the auction due to the linkages between products in a given offer, for instance when one product is provided at the exclusion of, or in conjunction with, another. Endogenous costs can be classified into two types.

- Opportunity costs are incurred when a single asset or portfolio can provide multiple products that are mutually exclusive, and when a product is accepted at the exclusion of another profitable one. This occurs for example if an asset provides upward aFRR though it could profitably have provided energy or upward mFRR.

- Actual losses (or realized losses) refer to the costs arising when the provision of one product forces the provision of another product that is not profitable. For example, this occurs when an asset provides energy at a loss because it provides downward aFRR.

Explicit Bidding
With Explicit Bidding, market participants explicitly add to their bids a forecast of the endogenous costs they expect to face in the co-optimized auction, such as opportunity costs for providing upward balancing capacity instead of energy, or negative profits for producing energy at a loss in order to provide downward balancing capacity.

Fundamental costs
Fundamental costs refer in this study to all costs that are not corresponding to endogenous costs. Fundamental costs may include for instance operational variable costs such as fuel and emission costs, operational fixed costs (indivisible costs such as no load, startup and shutdown costs), policy-related costs, or opportunity costs related to *other auctions* such as intraday or balancing energy markets. The notion of

fundamental costs used here is synonymous with ‘exogenous costs’ and includes all costs not incurred due to bid-linking constraints, beyond the pure fundamental costs related to fuel, operations, etc.

Integer Pricing (IP)
This approach to pricing with non-convexities consists in outputting the marginal prices obtained by solving the convex market clearing one can obtain by replacing the binary variables defining the acceptance of the non-convex bids by their value in in the best non-convex allocation found. This pricing approach can lead to paradoxically accepted or rejected bids. See [9] for more information on economic aspects of this approach.

Implicit Bidding
With Implicit Bidding, market participants only declare their fundamental costs (e.g., production costs for energy and reservation costs for balancing capacity) without explicitly adding a forecast of endogenous costs on top (such as opportunity costs for providing upward balancing capacity instead of energy, or negative profits for producing energy at a loss in order to provide downward balancing capacity). Market clearing algorithms, based on welfare maximization and marginal pricing principles, automatically ensure that these endogenous costs are recovered through the market prices of energy or balancing capacity products where the linked bids are matched.

Linked Bids
Linked bids refer to a family of bids for single products, either energy or a given balancing capacity product, connected to each other by “links” modeling specific acceptance interdependencies. There are essentially two types of links already implemented in Euphemia for block orders: exclusive and parent-child links. Exclusive links are links where the acceptance of one block is conditioned on the rejection of another. Parent-child links are links where the acceptance of one block is a prerequisite to the acceptance of another. Note that the exclusive or parent-child conditions on the acceptances may apply to acceptance ratios of divisible bids. The exclusive condition then means that the sum of the acceptance ratios across multiple bids cannot exceed 100% (extended versions can be considered). The parent-child conditions then means that the acceptance ratio of one bid must be lower or equal to the acceptance ratio of another product. Similar links can apply to “binary acceptances”, i.e. to the activation status of a bid (discarding whether it is partially or fully accepted).

Marginal Pricing: defining the market price of a product as the marginal system cost increase for serving an additional unit of that product (or the savings for serving one less unit).

Merit Order: ordering of the bids, from the least expensive to the more costly ones.

Most Expensive (Bid) Pricing (MEP): This approach to pricing with non-convexities avoids paradoxically accepted supply bids by increasing the price in the market in such a way that no supplier incurs in economic losses. This approach only makes sense when all the demand is price taking.

Non-Uniform Pricing (NUP): This approach to pricing with non-convexities allows for both paradoxically accepted and rejected bids; however, the paradoxically accepted bids are compensated with side payments to ensure that participants do not incur economic losses.

Paradoxically Accepted/Rejected Bids: A bid is said paradoxically accepted if it is accepted but collects a total profit which is insufficient to cover the bid production and/or reservation costs. A bid is said paradoxically rejected if it is rejected but it is exposed to prices that could make the bid profitable if it was accepted.

Price-Taking Bids: A bid is said to be price-taking if it does not impose any limitation to the acceptance price. This is usually used for bid that must be accepted regardless of the market outcomes.

Reservation costs: All costs incurred by the provision of balancing capacity, that are *not* caused by linking constraints within the auction. Reservation costs may for instance correspond to opportunity costs faced in markets *in other timeframes* such as the intraday markets, or operational costs of various sorts.

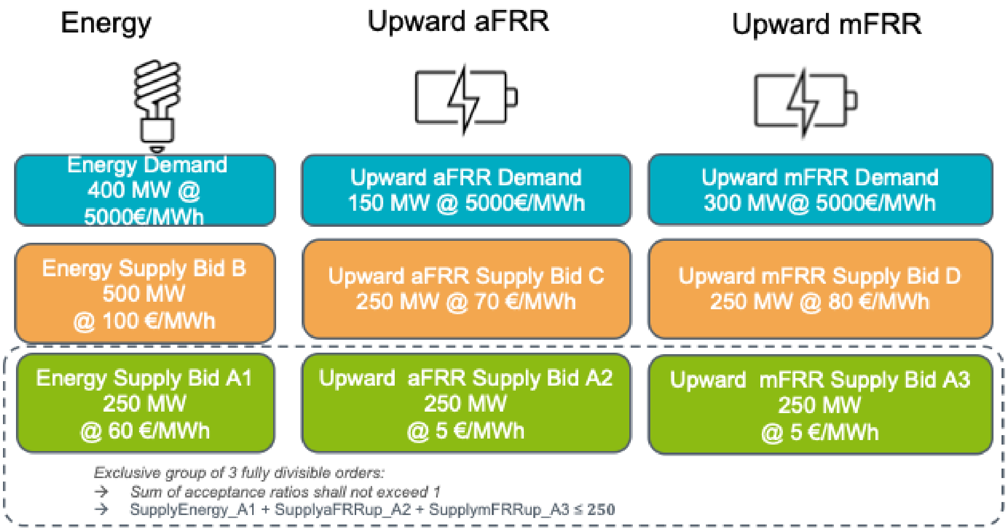
Single-Product Merit Order: merit order for a specific product (e.g. energy or upward BC) that can be obtained by disregarding the possible cross-product links present in the bids.

B Example illustrating the substitutability rule that prevents price reversals

We illustrate here how the "substitutability principle" applied to the Example 2 in Figure Figure 4 prevents the initial price reversal where the price of the upward aFRR is lower than the price of the upward mFRR despite being a higher quality product.

The "substitutability principle" means here that the demand for aFRR is dimensioned as a subset of the total demand for FRR. This translates into the following constraints:

$$Supply_{aFRR} \geq Demand\_aFRR$$
$$Supply_{aFRR} + Supply_{mFRR} \geq Demand\_FRR$$



Market Results	Energy	Upward aFRR	Upward mFRR
Market Prices	100 €/MWh	70 €/MWh	70 €/MWh
Bid A1 Accepted Vol.	0	-	-
Bid A2 Accepted Vol.	-	250	-
Bid A3 Accepted Vol.	-	-	0
Bid B Accepted Vol.	400	-	-
Bid C Accepted Vol.	-	200	-
Bid D Accepted Vol.	-	-	0

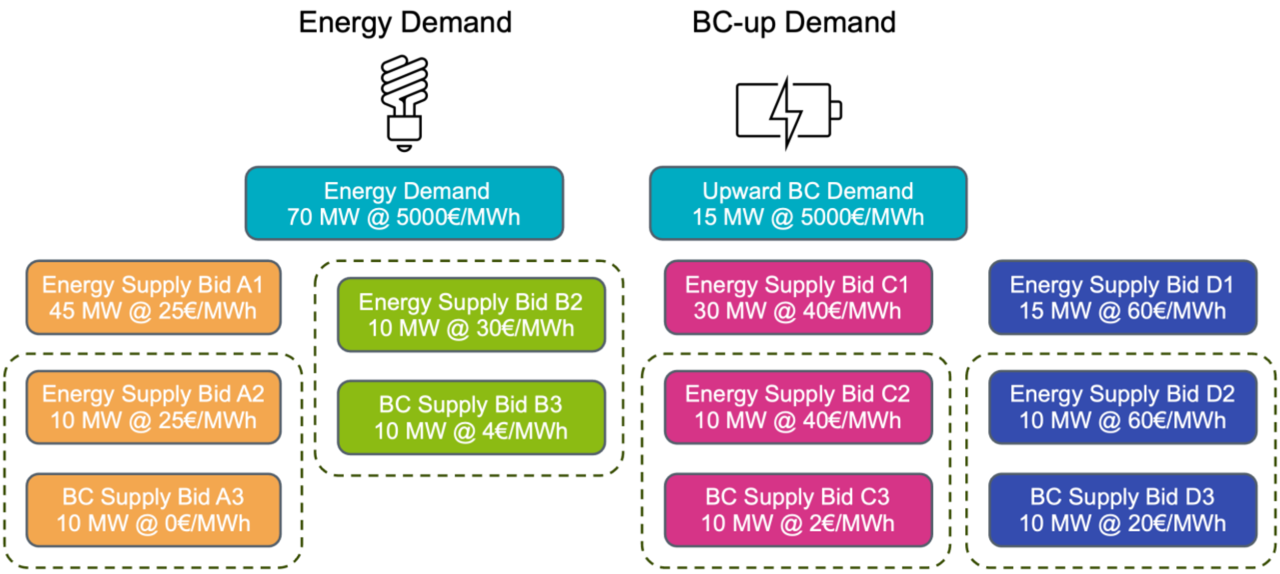
Figure 33: Illustration of the substitutability principle for avoiding price reversals.

All FRR is now satisfied by (cheaper) aFRR and no mFRR is accepted. Consequently, both aFRR & mFRR prices are equal. With such a design, it is thus not possible that mFRR is accepted at a higher price than the aFRR price. This inevitably avoids unnecessary procurement cost increases caused by price reversals that go against natural pricing hierarchy.

C Additional Examples on Marginal Pricing in a Co-Optimization Framework

C.1 Base example illustrating price formation with multiple linked bids

The example below described in Figure 34 illustrates how co-optimization and price formation operate with multiple linked bids, highlighting how endogenous costs—those incurred due to bid linking—are automatically priced by the co-optimization market-clearing process.



Market Results	Energy	Upward Balancing Capacity
Market Prices	40 €/MWh	14 €/MW/h = 14 €/MWh
Linked Bids of Market Participant A	A1: 45 MWh and A2: 10 MWh	A3: 0 MW
Linked Bids of Market Participant B	B2: 5 MWh	B3: 5 MW
Linked Bids of Market Participant C	C1: 10 MWh and C2: 0 MWh	C3: 10 MW
Linked Bids of Market Participant D	D1: 0 MWh and D2: 0 MWh	D3: 0 MW

Figure 34: Base example with multiple linked bids: assuming that the energy market results are known, the merit order for balancing capacity bids considers both the balancing capacity bid prices and the energy opportunity costs (or in other words, consider both fundamental and endogenous costs, see Glossary in Annex A).

A heuristic interpretation of the market results presented in Figure 34 is as follows: Temporarily disregarding bid linking, the single-product merit order for energy bids is A1, A2, B2, C1, C2, D1, D2, while for balancing capacity (BC) bids, the order is C3, B3, D3.

Since bid D3 has a significantly higher BC price compared to the other BC bid prices and potential energy opportunity costs, the BC demand will primarily be met by bids C3 and B3. Between these, C3 is preferred over B3, as it has a lower BC bid price, and market participant C faces lower opportunity costs for providing upward balancing capacity compared to market participant B (given that C's energy generation costs are higher). Consequently, C3 is fully matched, and 5 MW of bid B3 is accepted.

In the energy market, the cheapest energy bids, A1 and A2, are matched first, followed by 5 MW from B2 and 10 MW from C1, which sets the energy market price at 40€/MWh.

Given the energy price, a balancing capacity merit order curve can be constructed. The 'full balancing capacity price,' which determines the merit order for balancing capacity, is composed of both the opportunity cost in the energy market (if applicable) and the balancing capacity bid price. In other words, the relevant prices include both the endogenous costs due to bid linking, and the fundamental costs (see the Glossary in Annex A). For balancing-capacity-only bids, there is, naturally, no energy opportunity cost to consider.

This results in the following merit order curve for balancing capacity (constructed assuming that the part of the energy market results are known and already deducting capacity used in the energy market), which directly explains the matched bid volumes in the balancing capacity market together with the balancing capacity market price given in Figure 34:

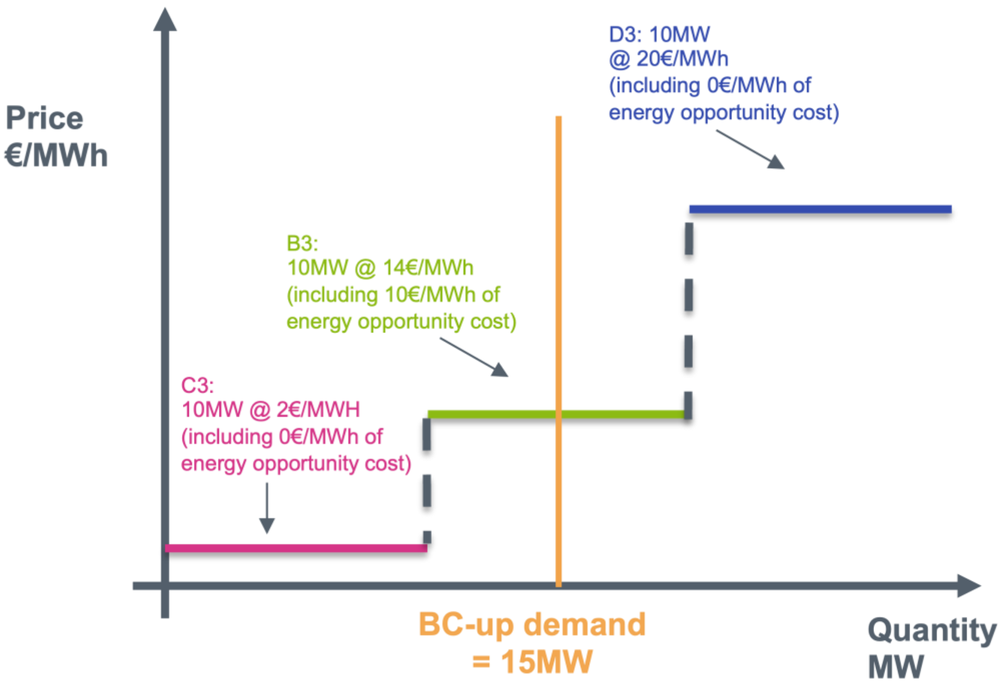
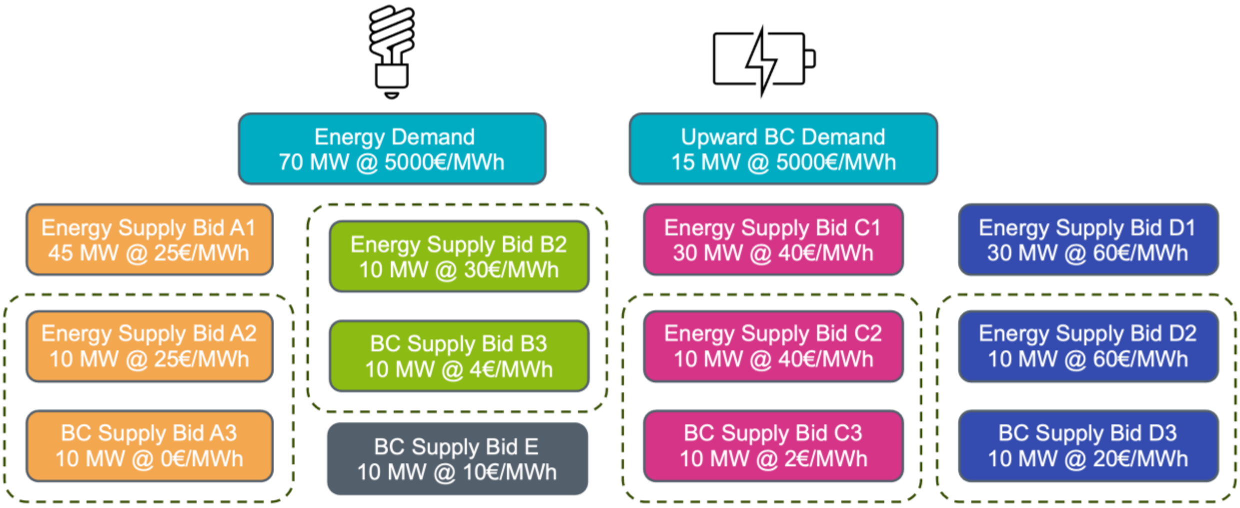


Figure 35: The balancing capacity merit order curve considering bid linking is constructed based on the assumption that the energy part of the co-optimization market results are known, providing insight into the overall market outcomes for balancing capacity.

C.2 Example with multiple linked bids and balancing-capacity-only bids

The example in the preceding section is here extended by adding one balancing-capacity-only supply bid E, see the description in Figure 36.



Market Results	Energy	Upward Balancing Capacity
Market Prices	40 €/MWh	10 €/MW/h = 10 €/MWh
Linked Bids of Market Participant A	A1: 45 MWh and A2: 10 MWh	A3: 0 MW
Linked Bids of Market Participant B	B2: 10 MWh	B3: 0 MW
Linked Bids of Market Participant C	C1: 5 MWh and C2: 0 MWh	C3: 10 MW
Linked Bids of Market Participant D	D1: 0 MWh and D2: 0 MWh	D3: 0 MW
BC Supply Bid E	/	5 MW

Figure 36: Example presented in Figure 34 enhanced with a balancing-capacity-only bid (bid E).

Compared to the previous example described in Figure 34, the new balancing-capacity-only bid E is more interesting than the (linked) balancing capacity bid B3 which was accepted in the previous example. Indeed, as depicted in Figure 35, the true welfare cost of bid B3 is 14€/MWh once its opportunity costs are taken into account, or, from a welfare perspective in this co-optimization context, once the endogenous costs resulting from bid linking are properly considered.

Bid E will hence have priority in the merit order as depicted in Figure 37 (which considers bid linking), which explains the market results presented in Figure 36.

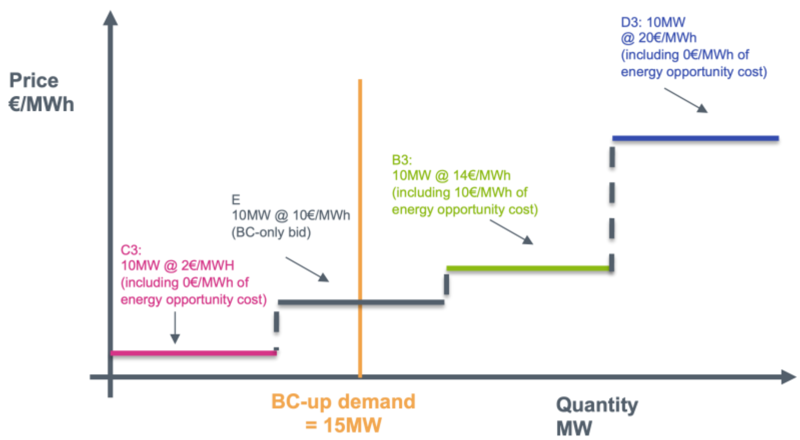


Figure 37: Balancing capacity merit order curve considering bid linking for the example described in Figure 36. The same principles as for the merit order curve in Figure 35 apply.

C.3 Examples on the impact of ramp conditions

This section highlights the impact of intertemporal constraints on price formation and acceptance of bids in a co-optimized market for balancing capacity and energy via the usage of ramp constraints. The example detailed in Figure 38 proposes a two-period horizon co-optimized market for energy and balancing capacity. In this situation, a ramp-up condition applies to the linked bids of market participant A. Indeed, the variation of power output must be less or equal to 20 MW. In practice, it means that the sum of energy output and upward balancing capacity in period 2 cannot exceed the energy output of period 1 by more than 20 MW.

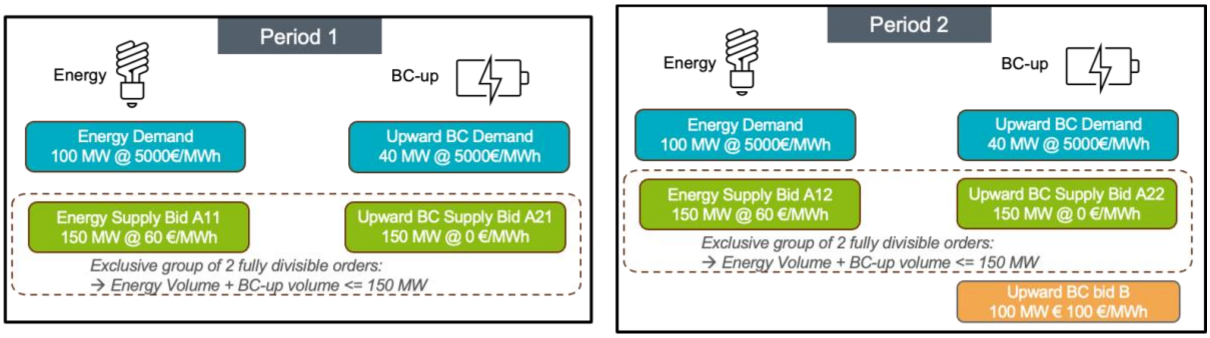


Figure 38: Example illustrating the impact of intertemporal constraints on the acceptance of linked energy and balancing capacity offers and price formation using ramping constraints.

Without this ramp condition, bids from market participant A fully meet the energy and upward balancing capacity demands in both periods. The upward balancing capacity price in this case is 0 €/MWh for both periods since no reservation cost is applied here and there is no opportunity cost in this scenario. Concerning energy, the price is 60 €/MWh in both periods.

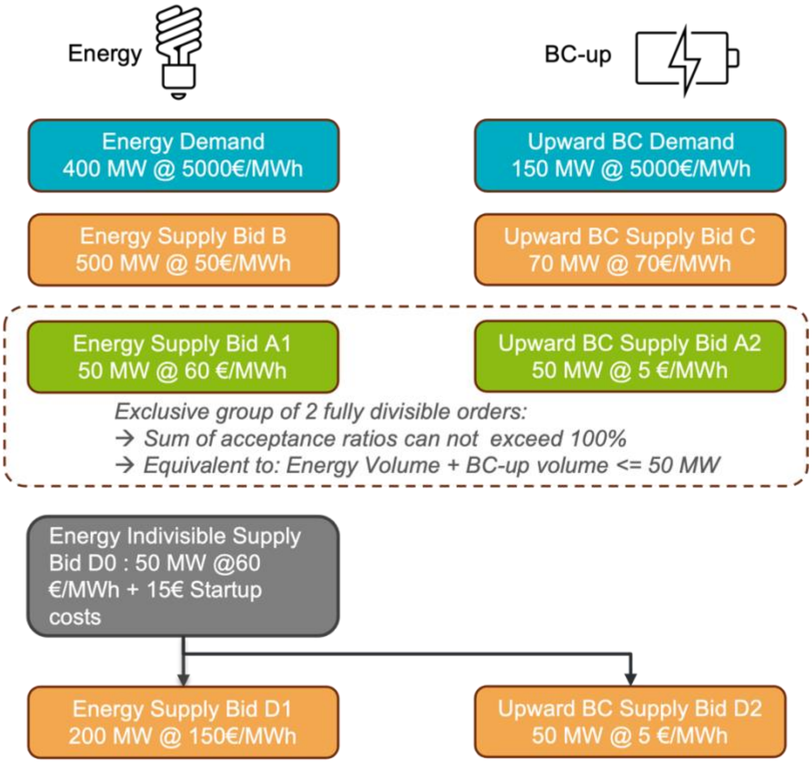
However, **with this ramp condition**, given that 100 MW of bid A11 is accepted in period 1, market participant A can only provide at most 20 MW of upward balancing capacity in period 2. The remaining 20 MW of upward balancing capacity in period is therefore provided by bid B, setting the upward balancing capacity price in period 2 to 100 €/MWh.

D Additional Examples with Indivisibilities and Fixed Costs

In this section, we collect a few additional examples that may be useful to complement the exposition of some of the material presented in this report.

D.1 Additional example of pricing in the co-optimized market

In the co-optimized market, the balancing capacity demand may cause extramarginal energy bids to be accepted. This happens when accepting a bid in energy at a loss frees enough (cheap) BC supply to allow for the satisfaction of the inflexible BC demand or to improve the overall welfare (while, also maximizing the profit collected for the accepted bid). For example, consider the following scenario:



Here bid D is extra-marginal in energy as it requires 60€/MWh plus 15€ of start-up cost to be activated, while the price of energy is set to 50€/MWh by bid B. However, on the BC side, we need the balancing capacity offered by bid D to cover the demand, and we can only access such BC offer if D is accepted in energy. Consequently, the welfare maximizing solution for this scenario is:

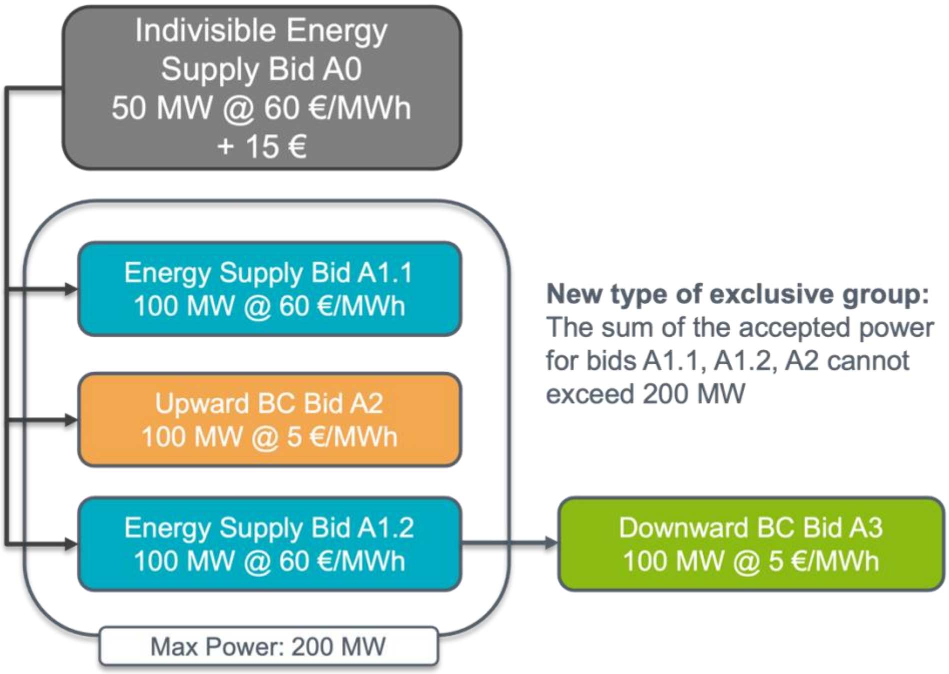
Market Results	Energy	Upward Balancing Capacity
Market Prices	50 €/MWh	70 €/MWh
Linked Bids of Market Participant A	A1: 0 MWh	A2: 50 MWh
Bid B	B: 350 MWh	-
Bid C	-	C: 50 MWh

Linked Bids of Market Participant D	D0: 50 MWh D1: 0 MWh	D2: 50 MWh

In the above table, we see that not only bid D is activated, but also that the balancing capacity D offers is fully accepted as it is cheaper than the capacity offered by bid B. In this scenario, bid D loses 515€ by being accepted in energy, however, it makes up for it by collecting 3250€ of profit in the upward balancing capacity market.

D.2 An example of a simple combined bid summarizing several linked bids

In section 3.1.2: "Representing indivisibilities and fixed costs" the following bid linking schema is presented:



In the section, it is mentioned that such schema can be summarized using a single combined bid. Such a combined bid would look as follows:

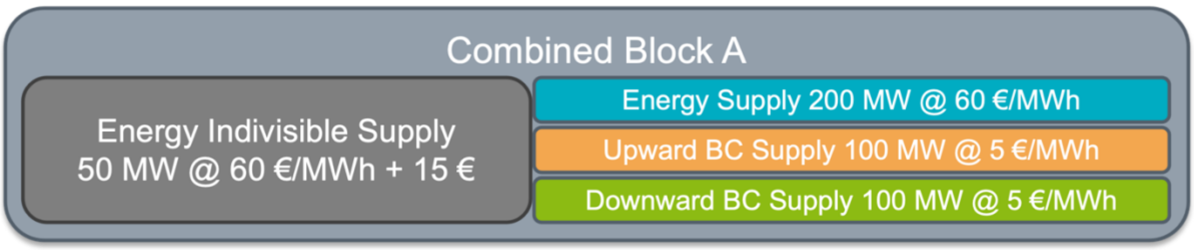


Figure 39: a single combined bid can represent a complex bid linking schema

Where the bidder would have to mention only the start-up cost, the amount of indivisible power, the maximum power and the volumes to be considered in the BC markets instead of creating a complex bid linking schema. The correct relations among the different products would be directly "coded" in the bid design.

As an additional advantage, the combined approach makes easier to algorithmically check the correctness of the bid data. For example, a simple input check can verify that the downward BC volume does not exceed the curtailable energy volume of the bid.

5.2 APPENDIX B: High Level Stakeholder Survey

NEMOs and TSOs have considered it particularly important to consult with market participants at an early stage of the R&D. This naturally complied with the regulatory requirement to ensure sufficient involvement of Market Participants in the R&D work[18]. Given the fundamental impact of a co-optimised allocation process, NEMOs and TSOs agreed on and conducted an informal survey and follow-up interviews among market participants in the last months of 2024. The intention was specifically to collect inputs about cost structures, asset representation and their impact on options for bid design. This was to help guide NEMOs and TSOs in the R&D and the continuous cooperation with N-SIDE. The survey was open to all interested parties and knowledge about it was spread through the news channels of the NEMO-committee and ENTSO-E. Individual NEMOs and TSOs were also encouraged to spread the news through their local channels.

Conduct

To the specific end of including market participants, MCSC NEMOs and TSOs have conducted the following activities in late 2024:

- Survey: 07/10 - 06/11/2024
- Introductory webinar: 11/10/2024
- Interviews: November and December
- Workshop: 19/12/2024

The interviews were conducted in an informal manner, with each market participant selected to discuss and elaborate on specific technical constraints, costs, bidding, and optimisation issues raised by the market participant in the survey. Both the survey and the interviews are anonymous, meaning that any insights extracted and distributed from them are anonymized.

Survey responses

The purpose of the survey was to collect inputs about cost structures, asset representation and their impact on options for bid design from market participants. 31 market participants responded. Of the 31 respondents, NEMO and TSO representatives then selected 7 market participants with which in-depth interviews have been conducted.

The below figure shows the distribution of responses and selected interviewees based on their regional distribution. It should further be noted that several respondents are active in several countries and markets and that, generally there was broad representation, particularly from central Europe and the Nordics. The selected subdivision was chosen to preserve anonymity.

[18] ACER Decision 11-2024 on the AM Annex 1 Article 4(15): https://www.acer.europa.eu/sites/default/files/documents/Individual%20Decisions_annex/ACER_Decision_11-2024_Annex_I.pdf

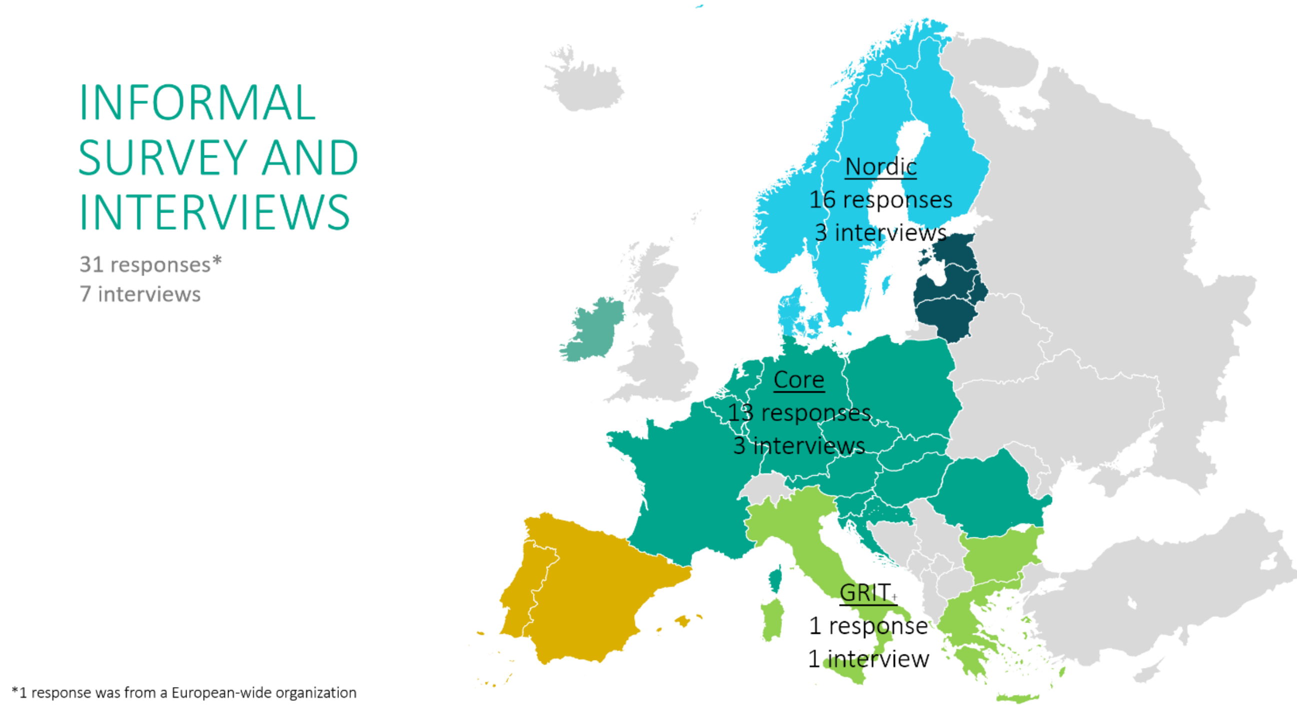


Figure App. B. 1: Geographical distribution of survey respondents and interviewees.

Possible challenges identified by market participants

Market participants have identified a range of challenges throughout the survey and interviews. Some of these challenges were deemed out of scope for the current phase of R&D, such as the complexity of the implementation phase, computational burden for the algorithm, algorithmic complexity, and potential risks like decoupling, delayed results, inferior outcomes, and paradoxical results. Although TSOs and NEMOs consider these points crucial for exploration, it aligns with the AM and stepwise features of the R&D that these topics will be thoroughly investigated in the upcoming phases.

The main objective of the survey and interviews was to collect inputs about market participants' cost structures and their implications for bid designs. Given the still relatively early stage of development, market participants highlighted that they were eager to also provide input at later stages of the R&D. At the current stage, market participants were however still able to provide relevant input within the scope of R&D. These include, but were not limited to:

<u>Representation of assets</u>

1) **Representation of inter-unit and inter-temporal links and cost structures.** Market participants are concerned about their ability to correctly represent the cost structures of their assets in a co-optimisation setup. Particularly, representing inter-unit and inter-temporal constraints in specific technologies like thermal and storage assets are highlighted.
2) **Examples of challenging constraints.** Market participants highlighted multiple constraints and technical features which they were concerned about being able to represent, see section: Tentative suggestions relevant for bid formats.

Continuous optimisation of portfolio

1) **Relative insignificance of DA outcomes for the realized dispatch of large market participants.** The SDAC market clearing is just one step in a continuous sequence that determines the realized dispatch. The utilisation of the asset portfolio is optimised in each step, with dedicated IT solutions at the market participant handling the relevant (non-)linear problems. Consequently, and increasingly with increasing RES, the "optimal" SDAC result can be perceived as less important due to the subsequent re-optimisation processes.
2) **Remaining requirements for price forecasts for inter-temporal and inter-unit interactions modelling.** It is argued that co-optimisation eliminates the need for price forecasts to determine opportunity costs between DA and balancing capacity. However, according to some market participants, this assertion is inaccurate. In their bid preparation, market participants rely on price scenarios as a basis for modelling complex interactions between units as well as intertemporal relations. These scenarios are dependent on price forecasts.

Market transparency concerns

1) **Market transparency, price formation.** Market participants raised concerns about how opaque pricing (e.g. through the introduction of complicated bid formats) could harm transparency and end up discouraging bids for balancing capacity in particular. This could then affect liquidity and create uncertainty around the pricing signals for future investment decisions.

The input from market participants constitutes knowledge used on a continuous basis by NEMOs and TSOs throughout the R&D and served to inform the discussions had with N-SIDE on the consultancy report. Furthermore, anonymized input from the survey and interviews related specifically to bidding products, bidding formats and prices was also shared in anonymized form with N-SIDE.

Tentative suggestions relevant for bid formats

While all interviewees agreed that it is infeasible to capture every relative constraint within integrated SDAC and balancing-capacity bids, several tentative suggestions for relevant attributes nonetheless emerged. These suggestions—voiced by market participants—formed the basis for discussions with N-SIDE regarding the bidding formats currently proposed in this report. The fact that the list below contains more suggestions than are presently incorporated simply underscores the need for further evaluation by market participants to inform the public consultation in May–June 2025 on the most critical elements to include.

The following list describes NEMOs and TSOs summary of the input received and is non-exhaustive and was part of what was shared with N-SIDE.

Thermal

- Startup cost, including dependency of hot/cold start
- Links with gas network and gas costs that have non-linear characteristics
- Links with heating demand for CHP units
- Maximum number of possible changes in unit state

- State dependent duration of startup sequences
- Specific constraints during startup
- For CCGTs: choice to run closed or open cycle depending on price forecasts
- Links with FCR market: providing FCR can be technically linked to FRR provision
- Number of possible starts during a day
- Management of breakdowns or hazards
- Environmental constraints, e.g. constraints during high temperatures, limitation in total annual running hours
- Duration of activations
- Minimum up- and down times
- Constraint on either providing only energy or only balancing capacity
- Increasing efficiency as a function of output
- Ramping limits

Hydro

- Links between plants in the same river with small or no reservoirs
- Complex relations between water values of small reservoirs and short-term prices
- Time delays
- Ramping limits
- Relation between reservoir level and energy volume
- Dependency between reservoir level (plant head) and maximum plant output
- Non-convex characteristics of hydro unit's efficiency curve
- Reservoir overflow characteristics

Storage

- State of charge for batteries
- Energy constraints and dependency of discharging capability