AUSTRIAN INSTITUTE OF TECHNOLOGY

ANALYSIS OF THE SWEDISH FCR-N MARKET DESIGN – PART 2

Effects of asymmetric bidding & transition phase analysis

Final report

September 2021

Prepared by:
Ksenia Poplavskaya
Stefan Strömer
Clemens Korner
Adolfo Anta
Fabian Leimgruber

Photo credit: Depositphotos (ID: 349331156)

Disclaimer

AIT Austrian Institute of Technology GmbH
Giefinggasse 4 | 1210 Wien, Austria | T +43 (0) 50 550-0 | F +43 (0) 50 550-2201 | office@ait.ac.at | www.ait.ac.at

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report evaluates the implications of switching from a symmetric to an asymmetric product in the Swedish FCR-N market and, on the other hand, on the measures that can be undertaken to ensure a more efficient transition to the target FCR-N market design.

Allowing balancing service providers (BSPs) to bid different volumes for upward and downward regulation, i.e. bidding asymmetrically, coupled with additional measures enabling market entry of new BSPs, can potentially provide more flexibility for market participants. At the same time, this market design change leads to an adjustment of bidding strategies of market actors. In this project Phase 2, the expected changes in the effects on the BSPs and the market have been evaluated and quantified by adjusting the symmetric FCR-N market model developed in project Phase 1[1]. The market model combines agent-based modelling with reinforcement learning and is complimented with a technical hydropower plant simulation.

Project Phase 2 was set up in a way that ensures comparability (as much as it is feasible) with the results obtained during project Phase 1. The main aspects studied and discussed in this report include the impact of 1) a change of the FCR-N product from a symmetric to an asymmetric on the market result, 2) strategic bidding, including capacity withdrawal from either, +FCR-N or -FCR-N[2] market, 3) the impact of new entrants and 4) of BSPs being able to link their bids in the +FCR-N and -FCR-N markets.

The following key points were identified based on the simulation results:

- Based on the historical FCR-N bids and on the results from the technical hydro simulation, we derived asymmetric bids to be used by the true-cost bidding BSPs with hydro-based portfolios, everything else remaining equal. Comparing the scenarios with hydro-based true-cost bidding BSPs in symmetric and asymmetric markets yielded a similar yearly course of marginal prices in the asymmetric +FCR-N market and in the symmetric market. Marginal prices in the -FCR-N market were shown to be substantially lower throughout the year but rising during periods of low day-ahead (DA) market prices.
- Comparing the results from a symmetric market with the ones with an asymmetric market design, most scenarios showed a reduction in total procurement costs and total economic costs (equal to the difference between the total costs and the agents' total profits). In addition, in those scenarios where agents could bid in a profit-maximizing manner, they were shown to behave less strategically i.e. bid closer to their actual costs, under asymmetric bidding as compared to their symmetric analogs.
- While scenarios dominated by strategic hydro-based BSPs resulted in an increase of system cost by 1 to 5%, all scenarios with asymmetric bidding led to an overall efficiency gain by increasing either the producer surplus or consumer surplus.
- Enabling linked bids (i.e. positive and negative bids of a BSP can only be awarded together) for a single BSP showed to not influence the market to a significant extent (an increase in system costs of less than 1%). Assuming that all BSPs link their bids increased system costs and marginal price volatility due to a varying level of supply in the two separate markets, as compared to always offering flexibility symmetrically.

[1] Project Phase 1 conducted at the beginning of 2021 was mainly concerned with the effect of strategic bidding in the FCR-N market with or without new entrants and the applicable pricing rule (pay-as-bid vs. marginal pricing). It assumed current symmetric FCR-N market design. Considering an asymmetric FCR-N market is one of the major adaptations in project Phase 2. Full report of project Phase 1 can be found at https://www.svk.se/contentassets/22a7164df5c2415d9c2a8f69c08498f8/svk_report_analysis_of_fcr-n_market_design.pdf

[2] Here, +/- FCR-N denote positive or negative FCR-N (Frequency Containment Reserve – normal activation), respectively, that is used for upward and downward regulation.

- Allowing new entrants into the market resulted in an improvement of all studied indicators, remarkably also resulting in lower system costs as compared to the original symmetric scenarios.
- The analysis of bid volumes allocated by different agents to the +FCR-N and -FCR-N market yielded the following:
    - as long as hydro-based BSPs pursue a true-cost bidding strategy, their optimal capacity allocation between the two directions is close to 50:50 with a slight preference to the +FCR-N market (54-59% depending on the agent and scenario). However, as soon as these agents are allowed to follow a profit-maximizing strategy, this trend reverses with significant bid volumes shifted from the +FCR-N to the -FCR-N market, partially leading to scarcity in the +FCR-N market;
    - the agent with a battery storage portfolio bids about 45:55 across all scenarios irrespective of the bidding strategy;
    - the agent operating a portfolio of wind generators shows a clear preference for the -FCR-N market, where it allocates 80-90% of its flexibility and only increasing the share of allocated flexibility in the +FCR-N market to about one third of its total available capacity in the scenarios, in which it can bid strategically.
- It was assumed that capacity withholding can only be carried out by a BSP by bidding the available flexibility at a (much) higher price rather than withdrawing this flexibility from the FCR-N market completely. In an asymmetric market, agents have additional flexibility to choose to shift more or less of the flexibility into the other market, *de facto* reducing the total bid volume in the first one. Simulation results revealed scarcity of 1% to 3% only in those scenarios where the hydro-based agents can behave strategically.

The final question investigated in this report was focused on the concrete steps that can be undertaken to ensure a smooth transition to the target FCR-N market design. This question highlights the fact that identifying positive market design changes is not sufficient for ensuring an efficient transition to a more competitive market but that a specific pathway towards it is equally crucial. In this report, we formulated a number of recommendations for improving individual design choices and, more importantly, prioritize them and define a transition pathway for market design adjustments. The short- to medium-term roadmap proposed for the market design adjustments includes several steps, from adjusting formal access criteria, prequalification and market rules. These have been combined with the second approach meant to improve market competition in the concentrated FCR-N market, namely market integration within the Nordic region, and considers planned adjustments concerning other balancing products. We further stress that one of the most detrimental factors for the participants' confidence in the market is regulatory/design uncertainty and frequent changes. Care therefore should be taken with not introducing market changes too often but rather clustering different measures. Finally, while this report focuses mainly on the FCR-N product, a holistic approach considering all frequency-related products and their interaction with short-term electricity markets is needed.

LIST OF ABBREVIATIONS

aFRR	automatic frequency restoration reserve
BESS	battery energy storage system
BSP	balancing service provider
DA	day-ahead
D-1	one day ahead
D-2	two days ahead
EBGL	Electricity Balancing Guideline
Elba-ABM	agent-based model of electricity balancing
FCR-D	frequency containment reserve, disturbances
FCR-N	frequency containment reserve, normal activation
FFR	fast frequency reserve
GCT	gate closure time
GOT	gate opening time
MCP	marginal clearing price
mFRR	manual frequency restoration reserve
PaB	pay-as-bid
POM	operational manager
RL	reinforcement learning
SoC	state of charge
Svk	Svenska kraftnät
TSO	transmission system operator

1 INTRODUCTION

1.1 Background, project rationale and approach

The balancing markets in the Nordic region are undergoing considerable market design changes coupled with an intensified cooperation among the Nordic TSOs. In this report, we primarily focus on the FCR-N market and investigate the implications of a possible introduction of an asymmetric FCR-N product. Asymmetric bidding implies a possibility for balancing service providers (BSPs) to bid different volumes of flexibility for upward and downward regulation. This, arguably, could provide more degrees of freedom to new market entrants, such as wind generators and demand response, facilitating market competition. As shown in project Phase 1[3], to ensure a more efficient market outcome in a fairly concentrated FCR-N market, additional measures enabling market entry of new BSPs and increasing competition is necessary. At the same time, asymmetric bidding increases not only market complexity but also leads to a change of bidding strategies of market actors. These changes will be evaluated and quantified by adjusting the FCR-N market model developed in project Phase 1.

Thus, the following key questions have been posed in this project:

I. What is the impact of a change of the FCR-N product from a symmetric to an asymmetric on the market result?
II. What benefits can different generation technologies obtain from the possibility to bid separately for upward and downward regulation and what is the effect of this change on their bidding strategies?
III. What is the effect of capacity withholding and capacity distribution between the two auctions, for upward and downward regulation?
IV. What concrete steps can be undertaken to ensure a smooth transition to the target design?

To answer the first two questions, we used the agent-based model with machine learning, Elba-ABM[4], developed in-house. In the preceding project Phase 1, Elba-ABM has been adapted to replicate the current FCR-N market design and to study the effect of changing pricing and bidding rules. The study of asymmetric bidding involves the introduction of a separate auction for downward regulation. Elba-ABM is therefore extended by splitting the market model into two independent auctions, adjusting the bidding strategies of BSPs (hydro, storage and wind-based) considering the choice between the two auctions. In particular, a method to approximate the bids of hydro-based BSPs in two asymmetric auctions based on historic data was proposed and involved a detailed technical simulation of hydropower plants of the three modelled BSPs with portfolios of hydro assets. Furthermore, the reinforcement learning (RL) algorithm developed in Phase 1 was adjusted to account for interlinked bidding strategies in the two auctions and a higher bid volume granularity.

Using multiple simulation scenarios, we investigate the effect of design changes of the market outcome, bidder strategies and profits along four planes:

1) symmetric vs. asymmetrical bidding
2) possibility of bid liking, i.e. allowing BSPs to link their bids in the +FCR-N and -FCR-N markets

[3] The previous project Phase 1 focused on FCR-N market design adjustments demonstrated positive changes that can be achieved through the introduction of marginal pricing and a switch from cost-based to free bidding as long as sufficient and more diverse competition is introduced in the market. The report from Phase 1 is available here: https://www.svk.se/contentassets/22a7164df5c2415d9c2a8f69c08498f8/svk_report_analysis_of_fcr-n_market_design.pdf

[4] Agent-based model of Electricity Balancing

3) technological landscape (hydro-only scenarios vs. participation of new actors, especially wind generation, which was shown to have a high impact on the market outcome in the previous project)
4) concentrated market vs. market with a higher level of competition.

Concerning the third question, BSPs were modelled as agents based on true-cost or profit-maximizing strategies with the help of the adapted RL algorithm. In project Phase 1, bid volumes were shown to be a crucial factor impacting the FCR-N market outcome and the different pricing rules affect agents' tendency to withdraw capacity from the market. The effect of capacity withholding on market results was further investigated, in particular considering the comparison between symmetric and asymmetric products and the need for a BSP to decide how to optimally split available flexibility between the two auctions. Assuming that agents bid at true costs and the pricing rule is set to marginal, the RL algorithm was used to quantify the effects of capacity withholding or strategies where bids are distributed in such a way that the bidder can obtain windfall profits. The action space of the learning agents related to bid volumes was discretized to a larger extent to provide a finer picture of agent strategies.

The fourth question highlights the fact that identifying positive market design changes is not sufficient for ensuring an efficient transition to a more efficient and competitive market. We therefore qualitatively analyze the whole scope of technical requirements for FCR-N, of market design variables, the links between them as well as the links between the FCR-N and other balancing products. Using this approach, we formulate a number of recommendations for improving individual design choice and, more importantly, prioritize them and define a transition pathway for market design adjustments.

1.2 Structure of this report

To address the main research questions posed in this project, the report is structured as follows:

Chapter 2 describes the market environment for modelling asymmetric bidding in the FCR-N market. In Chapter 3, we specify the details of modelling agents in an asymmetric FCR-N market and their adjusted bidding strategies for three modelled technologies, hydro and wind generation and battery storage. The reinforcement learning algorithm implemented to simulate profit-maximizing market actors is presented in Chapter 4. In Chapter 5, we provide an overview of all simulated scenarios and then analyze and summarize the results. The transition phase analysis is conducted in Chapter 6 whereas Chapter 7 summarizes the main conclusion and recommendations from the report.

2 MODELLING OF THE MARKET ENVIRONMENT FOR THE FCR-N MARKET CONSIDERING ASYMMETRIC BIDDING

The Swedish FCR-market includes two separate products: FCR-N and FCR-D. The latter is procured in one direction only (upward regulation) and its activation follows FCR-N. In this report, we focus exclusively on the FCR-N market.

The current design of the Swedish FCR-N market is summarized in Table 1 (first column). Based on the discussions with the experts from Svenska kraftnät, a number of assumptions and design choices were made to represent the FCR-N market in the model, considering asymmetric bidding. These are detailed in the table below (second column).

Table 1. FCR-N market design as implemented in Sweden (second column) and model design choices (third column).

Design variable	Choice in the actual FCR-N market	Model choice
Demand	approx. 240MW	approx. 240MW in each direction
Frequency of demand setting	Yearly (+variations based on imports/exports within the Nordic region)	Yearly (import/export variations are taken into account)
Timeframe of procurement	Two-step auction: D-2, GCT15:00 and D-1, GCT 18:00 (i.e. after day-ahead)[5]	D-1 GCT 18:00 (bids from the two auction stages are combined)
Product resolution	Hourly	Hourly
Bid symmetry	Yes	No; two separate auctions for +FCR-N and -FCR-N
Minimum bid size	0.1 MW	0.1 MW
Bid setting (free vs. cost-based)	Cost-based + mark-up / special methodology (for hydro)	Cost-based + mark-up / special methodology (for hydro) and free bidding
Frequency of market clearing	daily	daily
Pricing rule	Pay-as-bid	Marginal pricing
Clearing	Merit-order-based	Merit-order-based
Market information provided to BSPs	Demand for balancing capacity (determined annually), FCR-N prices	Demand for balancing capacity (determined annually), FCR-N prices

[5] Note that the results of the D-2 auction is are notified to the providers pre -D-1 at around 4pm. There is no fixed allocation key for capacity in the D-2 and D-1 auctions. The market operator accepts bids according to reasonable expectations in D-2 whereas any remaining capacity to fulfill the demand is then procured in the D-1 phase. Ergo, the volume accepted in D-2 varies.

Although the procurement of FCR-N is two-stage, conducted in D-2 and D-1 timeframes, we implement a single auction in D-1 timeframe in the model. Noteworthy is that the gate closure time (GCT) of the D-1 auction is at 6pm, i.e. after the publication of the day-ahead (DA) market results around 1pm. Thus, the BSP already knows the DA market clearing price. In addition, some capacities procured in D-1 are traded with the rest of the Nordic region.

To account for asymmetric bidding, the procurement of FCR-N is modelled as two separate auctions, one for positive FCR-N and one for negative FCR-N. This means that two separate merit orders are built and the marginal clearing price (MCP) is determined for each direction. Note that marginal pricing rule is applied in all scenarios simulated in project Phase 2. In addition, we investigate a possibility for BSPs to link their bids in the positive (+FCR-N) and negative (-FCR-N) market. Such bid linking would de facto allow them to keep placing symmetric bids but also to deviate from the 50/50 requirement. Bid linking is described in more detail in Section 2.2 and the results from simulations presented in Sections 5.3.1 and 5.4.

We assume the same amount of procured capacity in each direction. All agents are assumed to participate in both +FCR-N and -FCR-N market with all their prequalified assets, yet their cost structures for the upward and downward regulation will be different, as described in Chapter 3. The day-ahead (DA) market is considered in the model exogenously through (expected) DA prices.

Finally, in the model, we have to account for a situation in which none of the bidders would bid in either direction or not bid sufficiently to cover the reserve requirement. For instance, an 'emergency bidding' procedure may be introduced, which is triggered only if the total procured volume is less than the total FCR-N demand and would oblige the agents to bid nevertheless. The frequency of such events throughout a modelled year could give an estimation of potential scarcity and the conditions that would provoke it. To account for such potential scarcity situations, an additional, 'emergency' bidder is introduced in the model, which, however, is set up in a way not to affect the final market result (e.g. in terms of the market clearing price) but rather serves as a scarcity indicator (see Chapter 4 for more details).

2.1 Symmetric vs. asymmetric bidding

Allowing BSPs to place asymmetric bids (i.e. different volumes for upward and downward regulation has been argued to be an important market design adjustment to enable participation of a broader pool of actors and technologies. This in particular concerns operators of variable renewables that – although able to bid symmetrically – would be able to provide more flexibility in one (likely downward) direction and avoid the need for pre-curtailment. Similarly, demand-side flexibility can be enabled to participate if asymmetric products are auctioned.

As pointed out in the previous project, from the TSO's perspectives asymmetric bidding would have a number of implications:

1) Two auctions need to be conducted and cleared, for +FCR-N (positive market) and -FCR-N (negative market)
2) Empirical evidence from other countries (e.g. Austria, Germany, the Netherlands or Belgium) shows that even at times when BSPs do not face any opportunity costs in the *negative* market, balancing capacity prices in the negative market are hardly ever zero.

3) The introduction of a negative auction requires a decision about its dimensioning[6], whether it is the same as the reserve requirement for +FCR-N or smaller. It is further important to understand whether additional rules in particular to the pricing in the negative auction will be defined.
4) Technical requirements to reserve-providing units in an asymmetric market are likely different from the ones applicable if the product is symmetric and therefore need to be clarified and their implications analyzed further before implementation.
5) In a symmetric auction the procured FCR-N volume is *de facto* two times smaller than for asymmetric auctions (if assumed that the reserve requirement for negative FCR-N is the same as the positive one). It is, however, clear that a BSP would account for the costs of committing the capacity in *both* directions. Then, an asymmetric auction is a more transparent option, in which the BSPs have to explicitly declare their costs for each direction. Conversely, the introduction of asymmetric bidding would increase decision-making complexity as an actor needs to make an explicit decision about which direction to bid its flexibility in or whether to split it in some way.
6) Considering the previous point, one could assume that the costs of procuring symmetric products would be the same as the costs of procuring the same product asymmetrically. However, differences are likely to be observed since even if we assume the exact same total costs for positive and negative regulation, their volumes will differ thus producing different system costs. This will be an interesting aspect of the model simulation to estimate whether the total costs increase or decrease and under what circumstances they do so.

From the point of view of allocative efficiency (i.e. how efficiently resources are allocated to different markets), an asymmetric product may be seen as a market design improvement since a BSP can better control the amount of flexibility in each direction and e.g. avoid running at partial load in order to fulfil the requirement of a symmetric balancing product. Currently, low hydro production creates high FCR-N prices due to the fact that at times of low production, the availability of downward flexibility is low, which is yet needed to offer a symmetrical product. If asymmetric bidding were allowed, this requirement would not hold: this would, for instance, make a better use of wind generation for downward and of hydro generation for upward regulation.

2.2 Bid linking

The changes of market design to an asymmetric FCR-N product investigated by Svk include a possibility for BSPs to link their bids for upward and downward regulation. As a result, a power plant may continue to bid symmetrically in a sense that, if the submitted bids are linked, either both of them get awarded or none[7]. The main difference to symmetric bids is that the BSP is under no obligation to split its available capacity equally between +FCR-N and -FCR-N.

2.2.1 Motivation, expected benefits and concerns

The main motivation of allowing the linking of bids is to:

1) Enable a smoother transition from symmetric to asymmetric bidding

[6] Based on the resource availability, this aspect could potentially be studied with the help of model simulations to observe the extent of expected differences in system costs between 1) a scenario with requirement for +FCR-N = - requirement for -FCR-N and 2) a scenario with requirement for +FCR-N > - requirement for -FCR-N.

[7] Note that balancing capacity bids are considered indivisible and a more expensive bid can potentially be chosen instead of a cheaper one if it fulfills the reserve requirement more precisely and is more economically optimal.

2) Reduce procurement costs: risk premiums for asymmetric bids are expected to be higher because of the chance for a BSP not to be awarded in one direction. The linking of bids would allow a BSP to split the risk premium.
3) Linked bids may offer more favorable conditions from a technical standpoint: for instance, for a hydro with a relatively small reservoir it would be favorable to sell capacity for both upward and downward regulation to maintain the energy balance, i.e. avoid surplus energy that is suboptimal. On the other hand, in a cascade power plant, there is often a “safe side” depending on whether a plant is at maximum or minimum capacity.
4) Facing the risk of only the bids only in one direction being awarded, a BSP would need to include potential start-up costs in both bids. Linking the two bids together (since neither +FCR-N nor -FCR-N can be supplied from a non-running hydro power plant) allows splitting these costs and allows BSPs to place cheaper bids.

Most likely, there are the incumbents that would choose to recur to linking their bids whereas such new actors as operators of wind parks or demand response would find it easier to find in a single direction.

The main concerns of this design choice are:

1) Linking bids might blur the market price signal for +FCR-N and -FCR-N, which in turn would have negative implications in particular for new, less experienced entrants;
2) There could be potential for gaming in those situations, in which a large BSP would expect the market to be tight and exploit it by placing artificially high bids for both directions.

2.2.2 Implications for the implementation

In order to represent the possibility to link bids but at the same time avoid excessive complexity that would make it challenging to interpret simulation results, the following scenarios are proposed and analyzed in Section 5.3.1:

a) a single (large) agent is selected to represent a BSP that would always choose to link its positive and negative bids in all hours of the simulated year. Note that other actors then bid asymmetrically.
b) all BSPs link their bids.

These scenarios are then compared to the one, in which the same agent(s) place(s) unlinked asymmetric bids.

Although these scenarios would not provide an agent the flexibility to *choose* the hours in which it would prefer to link its bids, it should give a good idea of the general effect of the two strategies on the agent’s profits and on the market result.

3 MODELLING OF AGENTS IN THE FCR-N MARKET

3.1 Agent types and bidding decisions

The current Swedish FCR-N market has a rather homogenous and concentrated nature. The product is almost exclusively procured from hydro power plants, most of which belong to three largest market actors.

Similar to Phase 1 of the project, two types of agents have been defined:

1. agents representing incumbent BSPs with a portfolio of hydro-only assets,
2. agents representing new market entrants: these are assumed to be operators of battery storage units and wind generators.

3.2 Changes of BSPs' bidding strategies

In this Section we cover general considerations regarding a BSP participating in an asymmetric market. The decision logic of individual technologies using a true-cost bidding strategy is detailed in Sections 3.4 – 3.6 whereas implementation of the reinforcement learning (RL) algorithm for asymmetric bidding is described in Chapter 4.

From a purely economic perspective, committing capacity for balancing causes foregone profits from other available marketplaces translating into opportunity costs. This is, however, not always true and depends on a number of factors:

1. whether a BSP expects to be inframarginal or extramarginal[8] in the other market(s)
2. whether the bid is meant for upward or downward regulation
3. whether any subsequent marketplaces are available after the gate closure time (GCT) of the balancing capacity market and what prices are expected there

In addition to that – specifically for hydro generation – additional intertemporal opportunity costs should be considered: i.e. the value of water in hour t may be lower than in hour $t + 168$, making it costlier to commit capacity in hour t.

Unlike technology-related costs, opportunity costs are largely dependent on a market sequence applied and limit market actors' strategy space. Market sequence also plays a role in determining whether BSPs that were not awarded in the balancing market can still offer their capacity in the short-term markets or for another balancing product. This consideration is also relevant for the Swedish market design in which FCR-N is procured both *before* and *after* the GCT of the DA market. As a result, for instance, a BSP in D-2 would face an opportunity costs not only with respect to the possible foregone profit from the DA market (or a better point in time in the DA market) but also from not bidding in the D-1 timeframe.

Figure 1 summarizes the general principles determining the cost of providing upward or downward regulation.

[8] Variable costs of inframarginal generators are lower than the marginal price in a given market. In contrast, variable costs of extramarginal participants are higher (e.g. [26], [27]). This characteristic determines in which markets actors can offer their available capacity profitably as well as their cost structures.

Capacity costs include all costs of a BSP for reserving capacity for the balancing market and are included in the balancing capacity bid.

For positive balancing capacity, the operator of an inframarginal power plant needs to consider opportunity costs since the capacity committed to the balancing market cannot be sold in other markets during the reservation period. The opportunity costs are given **by the margin between the relevant market price and the variable costs, multiplied by the length of the reservation period** (Figure 1). The opportunity cost reflect the expected foregone profit of the DA market:

$$c = (\lambda_{DA} - VC) + \varepsilon_{DA}\,.$$

where λ_{DA} corresponds tot he DA price, VC – to variable costs and ε_{DA}- to the risk premium or a markup due to uncertainty.

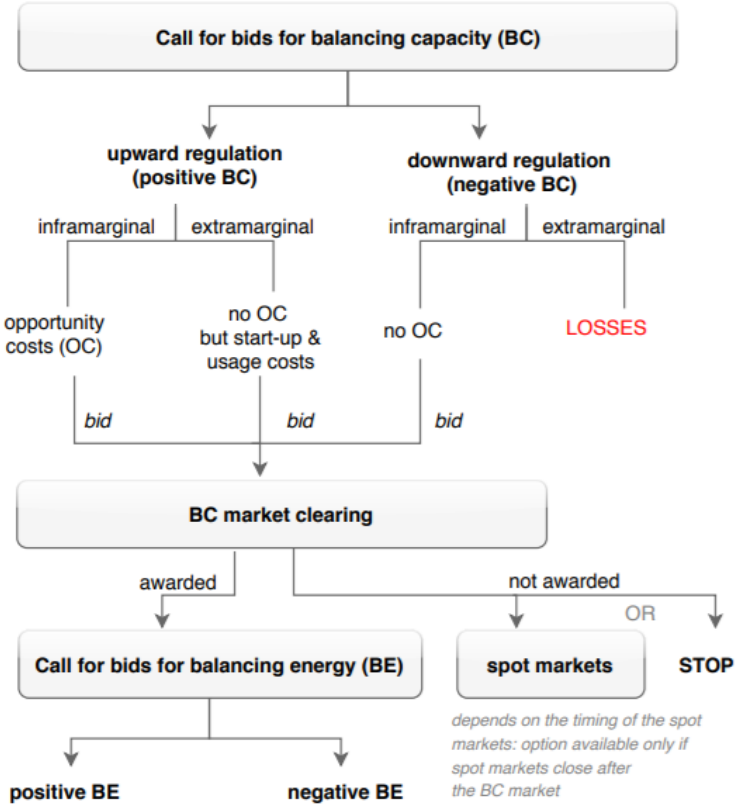


Figure 1. Trading options and associated costs for prequalified BSPs in the balancing market (abridged from [27])

For the operator of an extramarginal power plant several cost components are included in the capacity costs, such as start-up costs, usage costs or maintenance costs when providing upward regulation (Figure 1). These cost components are highly dependent on a specific power plant.

For negative balancing capacity, inframarginal power plants do not face opportunity costs: all the produced energy is sold at a profit because the operator must run the plant on a certain minimum load.

In practice, a BSP with a portfolio of units can allocate different portfolio shares to each market depending on their variable costs and, thus, maximize profits. Given that BSPs have the chance to generate higher profits in the subsequent balancing market, the DA market price now incorporates balancing market opportunity cost.

Depending on the extent of which the DA price is influenced by these opportunity costs, the higher the DA market price, the less attractive is the (positive) balancing market option, and vice versa.

From the empirical perspective (e.g. [28]), the balancing market offers higher profits, even as close as a day-ahead of delivery. Market participants are thus likely incentivized to provide the maximum of their prequalified capacities as BC, potentially driving volumes away from the DA market. As a consequence, this could influence the DA market outcome, which we do not model in this project explicitly.

Based on the experience of other countries using asymmetric bidding (for aFRR and mFRR), in contrast to balancing energy prices, the prices for balancing capacity are always positive, regardless of the direction of the future activation, and the prices in the negative market tend to be substantially lower (see Figure 2).

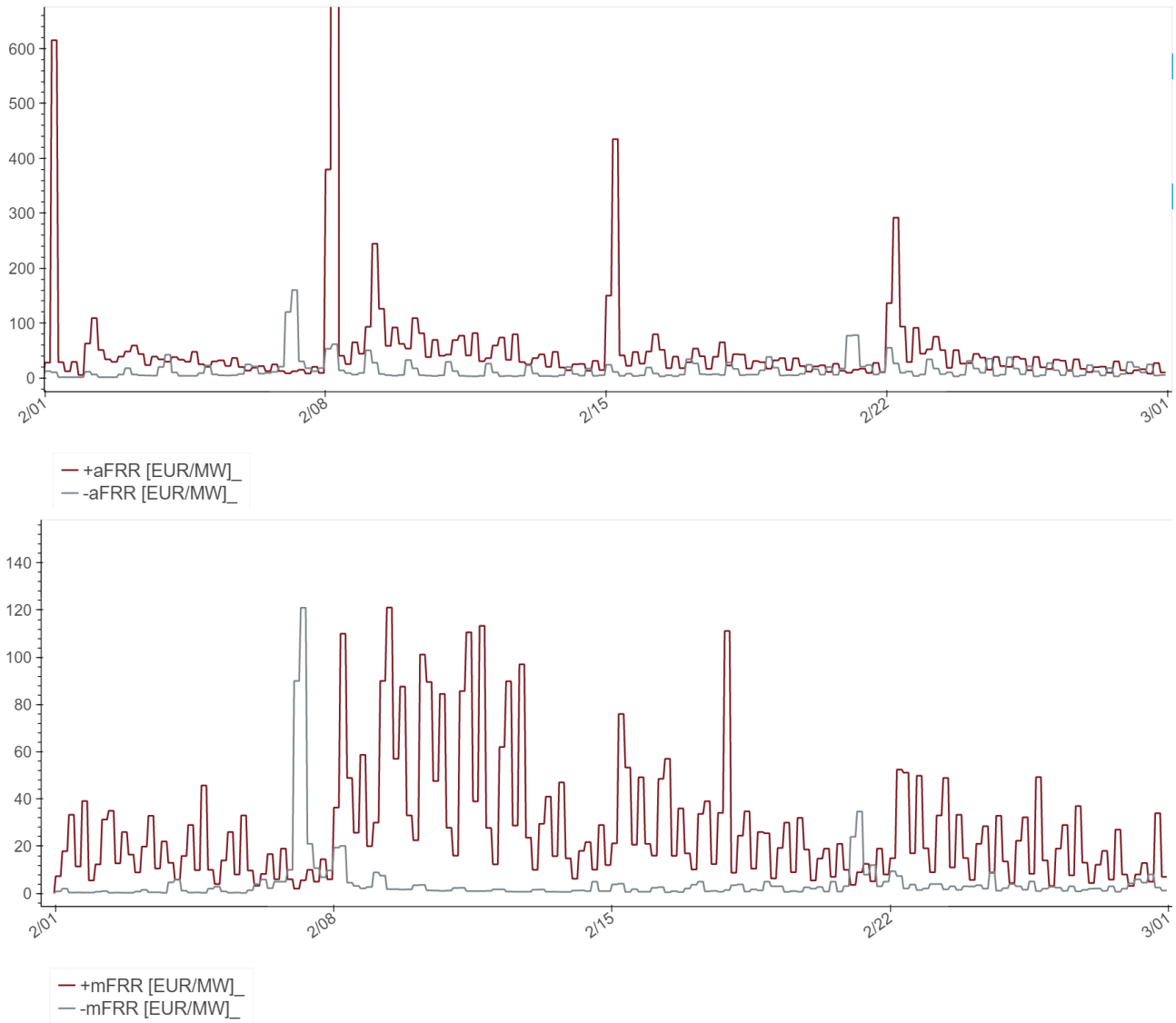


Figure 2. aFRR capacity prices (top) and mFRR capacity prices in Germany in the month of February 2021. Note that in a single hour of February 8th, 2021, the marginal +aFRR capacity price exceeded 6000€/MW and was abridged from the graph for the sake of visibility.

Since DA market prices largely determine the opportunity costs and available volumes on the balancing capacity market, balancing bids correlate with DA prices. E.g. for the month, fairly high DA prices determined higher BC bids:

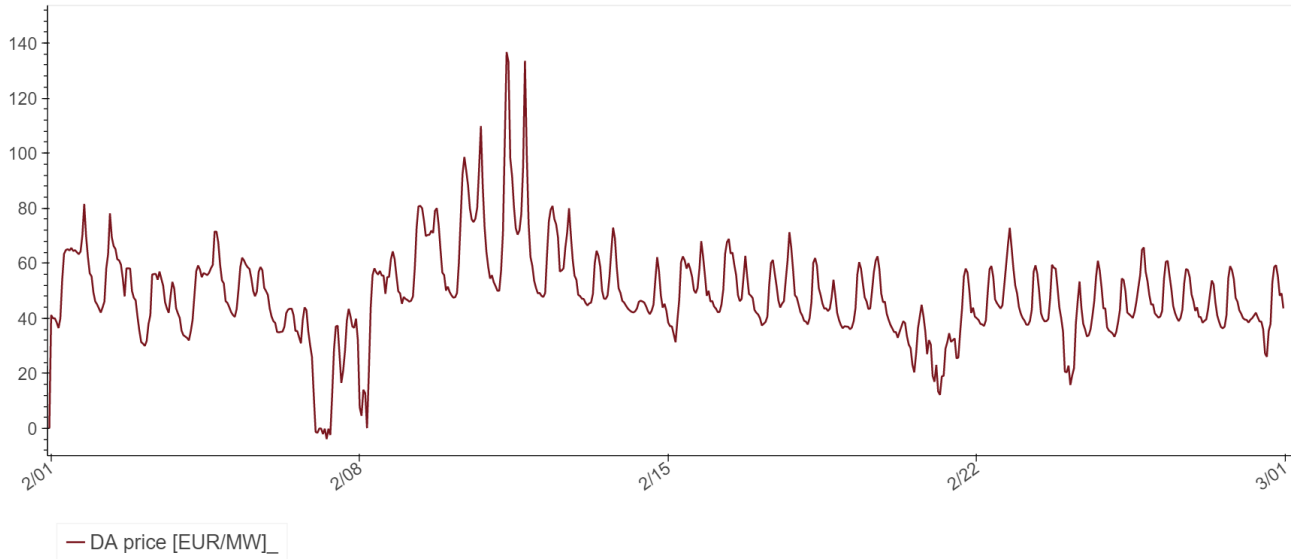


Figure 3. DA market prices in Germany as of February 2021.

Note that in the markets where balancing energy activation is a highly lucrative market (as is the example of the German aFRR and mFRR markets), balancing capacity prices are also partially explained by extremely high balancing energy prices and the BSPs' resulting tendency to 'sponsor' their lucrative bids in the balancing energy market with lower bids in the balancing capacity market.

Compare the costs of (symmetric) FCR for the same month[9]:

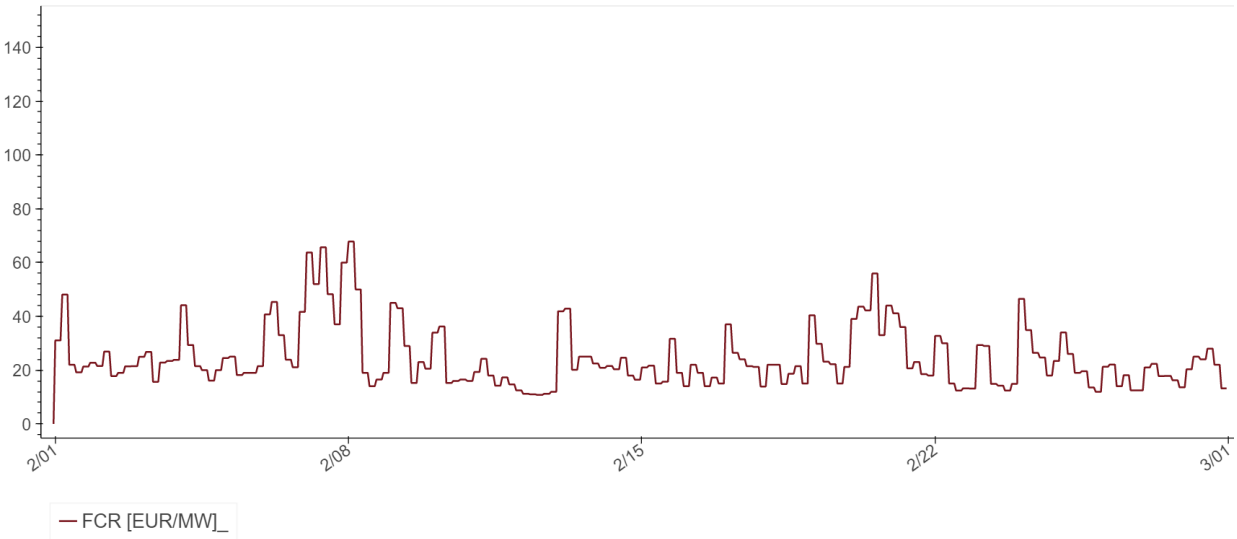


Figure 4. FCR market prices in Germany as of February 2021.

[9] Note that peak/off-peak price fluctuations observable in the Swedish FCR-N market cannot be observed here due to a different project duration used in the German market, namely 4 hours (i.e. 6 products per day). The bidding is symmetric and the auctions take place on a daily basis prior to the GCT of the DA market.

In the FCR market in the graph above, energy activation is not remunerated, thus 'balancing energy bid compensation' in the balancing capacity market does not take place in the FCR market. As a result, the observed FCR capacity prices tend to be higher than those of FRR capacity. It is, however, worth noting that the FCR product used in Central Western Europe possesses technical characteristics quite different from those of the Nordic FCR-N product[10].

3.3 Method to model the bidding strategy of a hydro-based BSP

The resource-specific characteristics of hydro generation make the calculation of opportunity costs for reserve provision more complex. Although the marginal costs of hydro production are relatively low, the opportunity costs determined by the difference between the DA price and the value of water may be quite high depending on the current reservoir levels and hydro production.

The following steps are undertaken to determine the needed model inputs *based on the historical data:*

1. determining the water value (Section 3.3.1)
2. defining the decision logic based on hydro parameters (Section 3.3.2)
3. obtaining the production schedule using the technical hydro model and the available FCR-N volume for both directions (Section 3.3.3)
4. devising an algorithm for bid volume and price distribution between the two directions (Section 3.3.4).

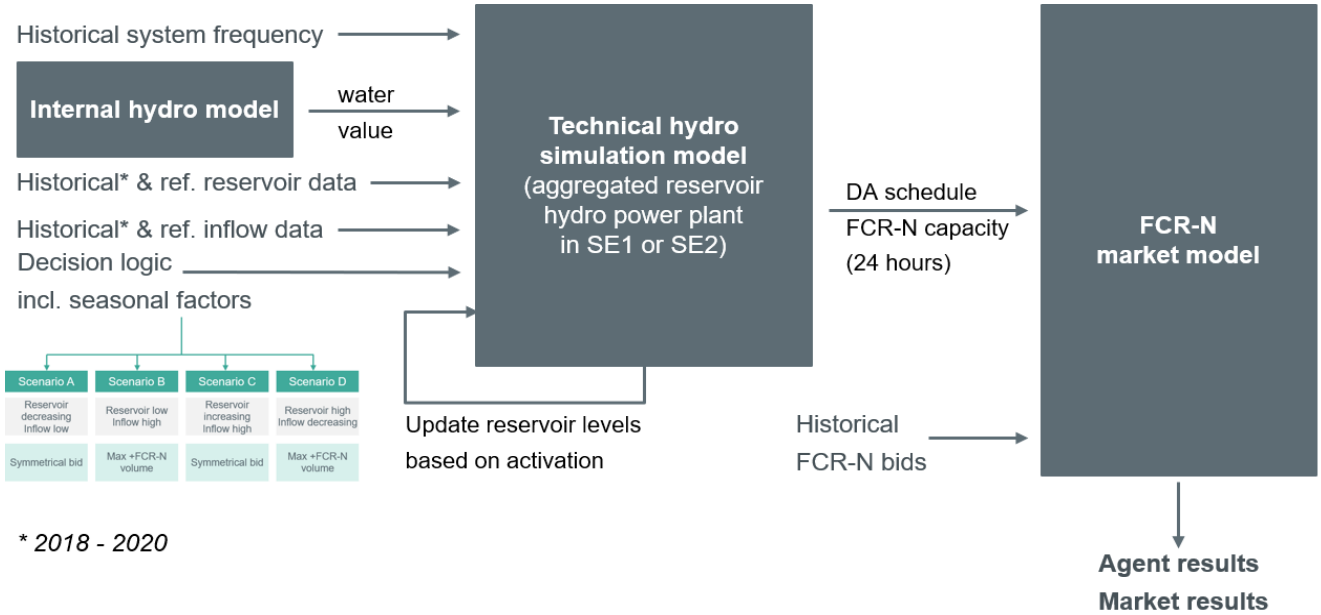


Figure 5. General modelling logic, input and output parameters used to define the bidding behavior of reservoir power plants.

As is illustrated in Figure 5, water values, together with historical system frequencies, hydro data and predefined decision logic are used as inputs for the technical hydro simulation model. The model is used to derive production schedules for several aggregated reservoir hydro power plants located in price zone SE1 (the northmost zone) and SE2, based on the location of actual generation units providing FCR-N. Together with the historical FCR-N bid data for 2018, 2019 and 2020, the production schedules are fed into the FCR-N market model to simulate the introduction of an asymmetric product.

[10] For the area of the German TSOs, the current version of the prequalification requirements for FCR and other products can be found here: https://pq-portal.energy/Download

3.3.1 Calculation of the water value

Based on whether the water value is higher than or lower than the expected DA price, the BSP will have a lower or higher incentive to provide upward or downward regulation (vice versa for negative regulation).

The internal hydro model developed in the previous project stage is updated to include the calculation of the water value that serves as an important input parameter for the technical hydro model. Its main purpose is to help identify the allocation of flexibility to positive and negative FCR-N.

The water-value calculation is based on the methodology proposed by Jahns, Podewski, Weber[11]. The underlying concept bases the water values on possible "future profits to be earned". Since we disregard various other possibilities to accrue profits, these future profits are based on what could be achieved in the future day-ahead market. Besides, we identify three important factors describing the hydrological situation, 1) current reservoir levels, 2) current inflows, and 3) expected hydro production.

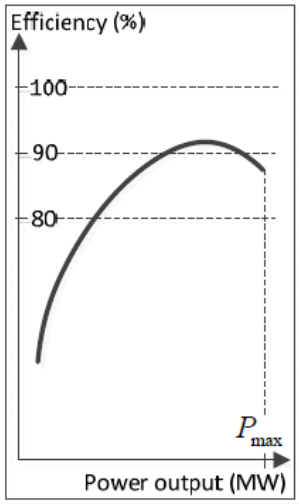


Figure 6. Efficiency vs. power output of a hydropower plant. Source: [4]

The resulting water values (as compared to historic DA prices) for the years 2018-2020 in SE1 and SE2 are illustrated in Figure 7 (bottom) and compared with the historic and reference (long-term average) hydro reservoir and inflow values (top).

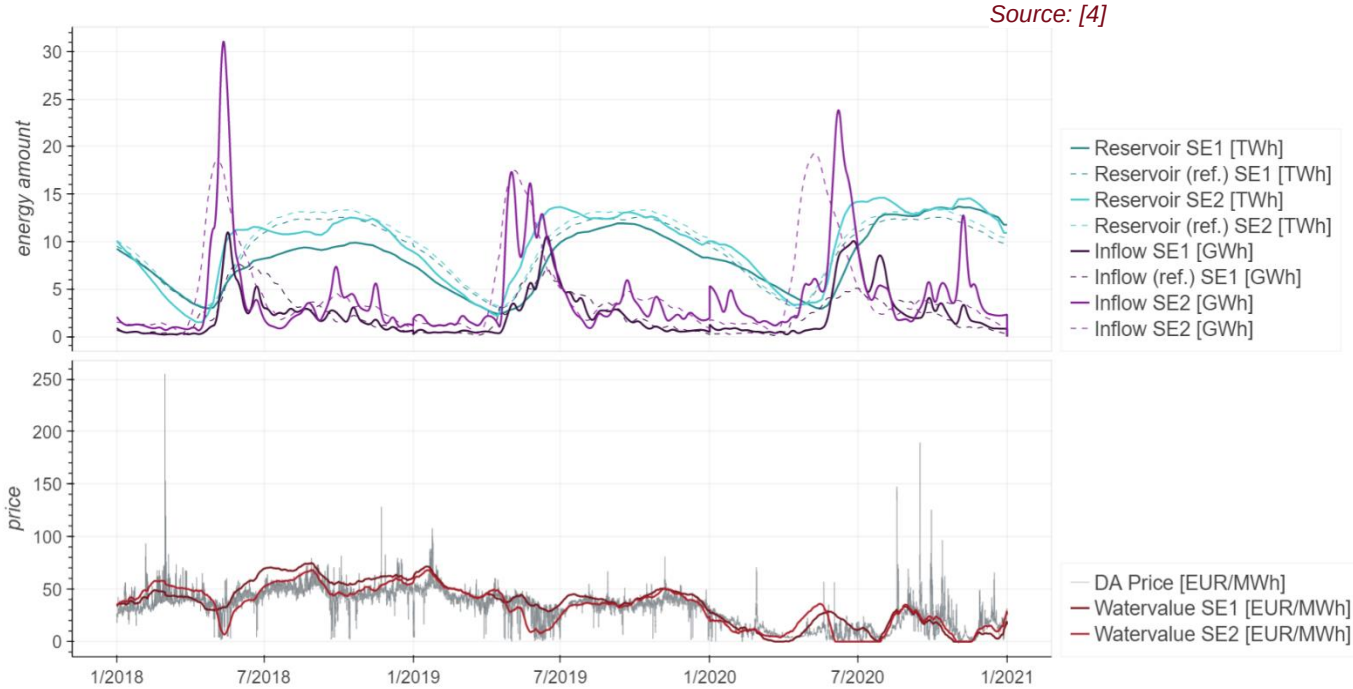


Figure 7. Reservoir and inflow levels in SE1 and SE2 (top) and the corresponding water values for SE1 and SE2 (bottom) for the years 2018-2020. (NB - considering expected DA average price over 3 weeks and the hydro production look-ahead horizon of one week).

[11] Jahns, Christopher; Podewski, Caroline; Weber, Christoph (2019): *Supply curves for hydro reservoirs: Estimation and usage in large-scale electricity market models,* HEMF Working Paper, No. 01/2019, University of Duisburg-Essen, House of Energy Markets & Finance, Essen

The planning horizon of a hydro power plant will depend on the size of its reservoir, defining its degree and duration of flexibility. Thus, for the purpose of the model, we take this factor into account but determining a shorter look-ahead period for smaller hydro power plants.

3.3.2 Decision logic of a hydro power plant

The strategy of a reservoir hydro power plant depends to a large extent on its hydrological balance and how constrained it is in either downward or upward direction. That is, hydro reservoir levels and inflows are crucial for determining its production schedule in the DA and FCR-N markets. Next to the technical constraints of the modelled power plants this decision logic forms a crucial part of the technical model's operational manager (see next sub-section) and is explained here.

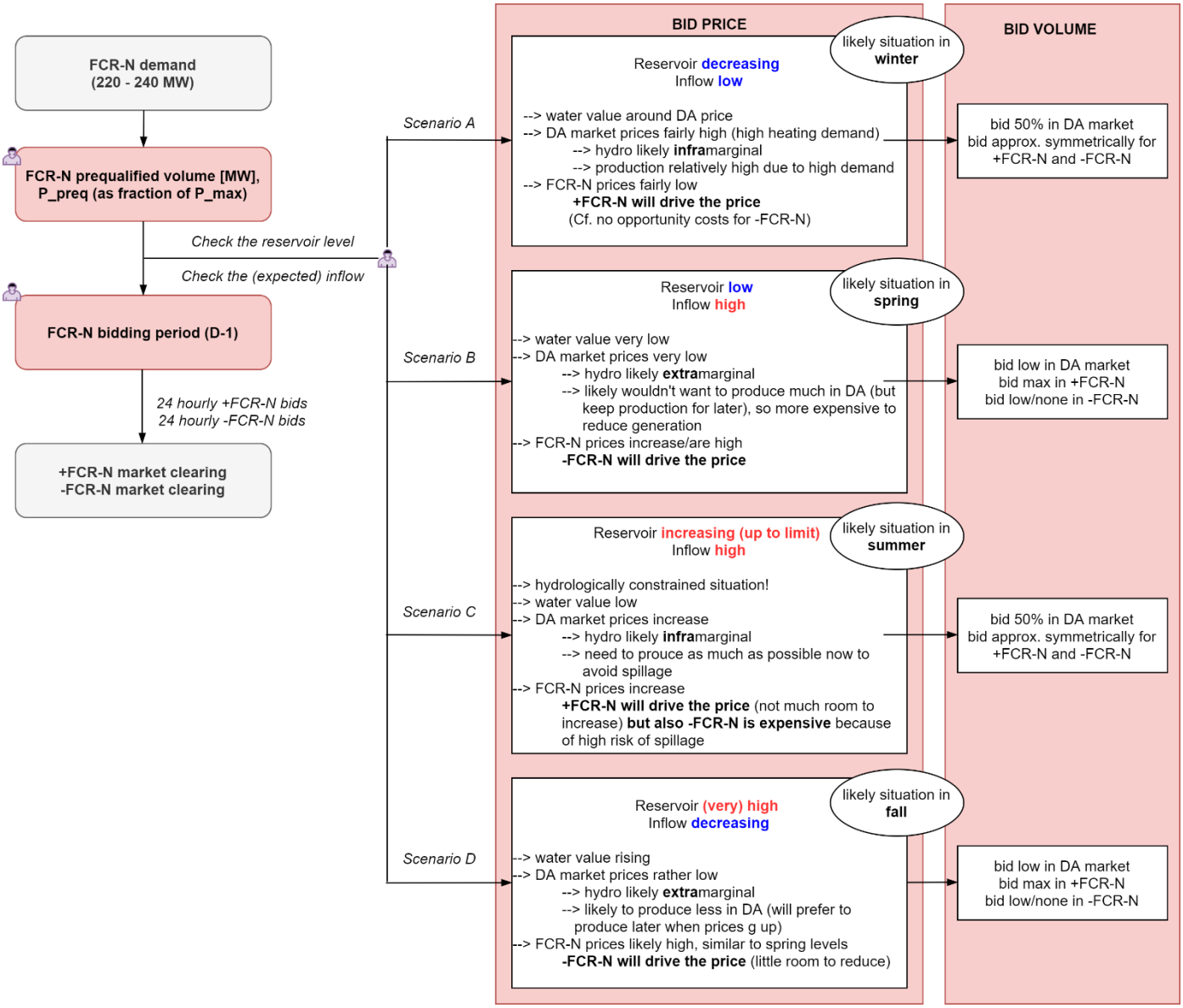


Figure 8. Decision logic for a hydro reservoir power plant used as an input for the technical hydro model.

The inflow and reservoir levels strongly correlate with the different seasons leading, for instance, to an ice cover on the rivers, a spring flood or high reservoir levels in summer. Bearing this in mind, the decision logic can consider these seasonal effects and their impact on the *optimal* production and the costs of FCR-N. In Figure 8, four respective scenarios are identified and briefly described. The decision logic boils down to a number of principles that allow to get the first idea of whether the positive or negative regulation currently drives the opportunity cost.

It is important to note that:

1) the scenarios describe situations *likely to occur* during a given season but are not necessarily limited to it.
2) the logic describes the optimal behavior that does *not* take any hydro constraints into account, these are then factored in using the technical hydro model resulting in the final schedule.

3.3.3 Technical hydro simulation model

The (new) bidding strategies of hydro power plants must be linked to their technical capabilities in order to meaningfully model the change of the FCR-N product from symmetric to asymmetric. It is to be expected that hydro generation will remain the crucial technology in the FCR-N market even after the entry of new market participants. Therefore, we analyze in detail the way in which hydro-based BSPs are affected by the separate up and down procurement from both the technical and the economic perspective.

With the help of the technical hydro simulation model, we determine the production schedules of hydro generators and the available FCR-N volume for both directions. Considering that a lot of hydro generation in Sweden is represented by cascade hydro generation, reasonable assumptions must be made, since modelling specific plant technology is out of scope of the study.

The calculated water values (Section 3.3.1) and the decision logic (described in Section 3.3.2) together with historical reservoir, inflow and frequency data serve as input parameters for the so-called plant's operational manager. The decision logic used by the POM determines the preferred production but it may deviate from it at any time based on the current constraints faced by a given power plant. This ensures that the plant attempts to match the determined setpoint as closely as possible while still making sure it does not run out of water or violate any other modelled technical constraints. Here, water values act as a stabilizing mechanism: draining the modelled reservoir more than it happened in reality will lead to lower reservoir values, leading to higher (individual) water values, leading to a lower production setpoint, leading to rising reservoir values.

The simulated reservoir levels (q_sim) as compared to the historical average (q_ref) and the actual reservoir levels in the price zone for a given year (q_act) are shown for the three modelled hydro-based BSPs in Figure 9. The simulated production setpoints per modelled BSP are shown in Figures 10-12.

The output of the model then is the hourly production plan and the available volume for FCR-N provision, which are fed into the market model and, combined with the bid prices based on the historical bid data, determine the bidding strategy of true-cost-bidding BSPs with portfolios of hydro assets.

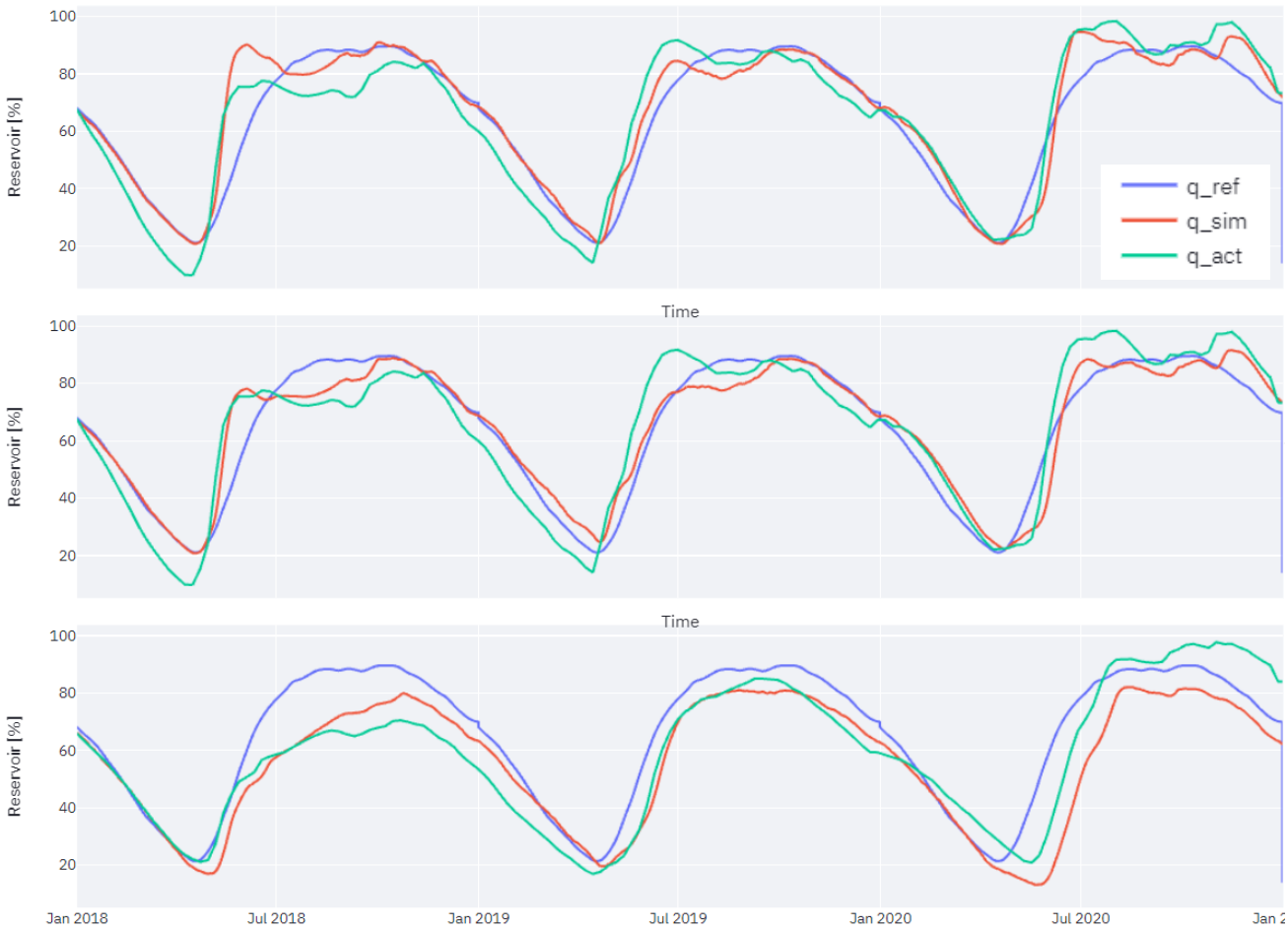


Figure 9. Simulated, historical and reference reservoir values over 2018-2020 for the three modelled BSPs (from top to bottom: agent 1 to agent 3) operating FCR-N-providing reservoir hydropower plants (where q_sim curve corresponds to the simulated reservoir levels as compared q_ref, i.e. to the historical average and q_act, i.e. the actual reservoir levels in the price zone for a given year)

In Figure 9, the blue line visualizes the long-term reservoir average (from 1960 to 2018). This is the baseline that the POM tries to follow to capture annual seasonality effects. The green line depicts the actual historic reservoir level that occurred in the corresponding bidding zone. The orange line is the output of the hydro simulation model, showing the actual simulated reservoir level at every point in time over three years.

Concerning production setpoints, as illustrated in Figures 10-12, the blue curves display the reference production for the corresponding bidding zone, based on the historic total hydro production values. The purple curves in Figures 10-12 visualize the output of the hydro simulation model, the so called “final setpoint”. This is the power that the plant actually produces and that is used to progressively update the reservoir levels. While most differences are subtle and cannot be observed without zooming in (e.g. ramping constraints when increasing/decreasing production), one of the notable differences can, for example, be seen around July 2020, in the figure of agent 1 where some water spillage was prevented by temporarily increasing the production above the planned setpoint.

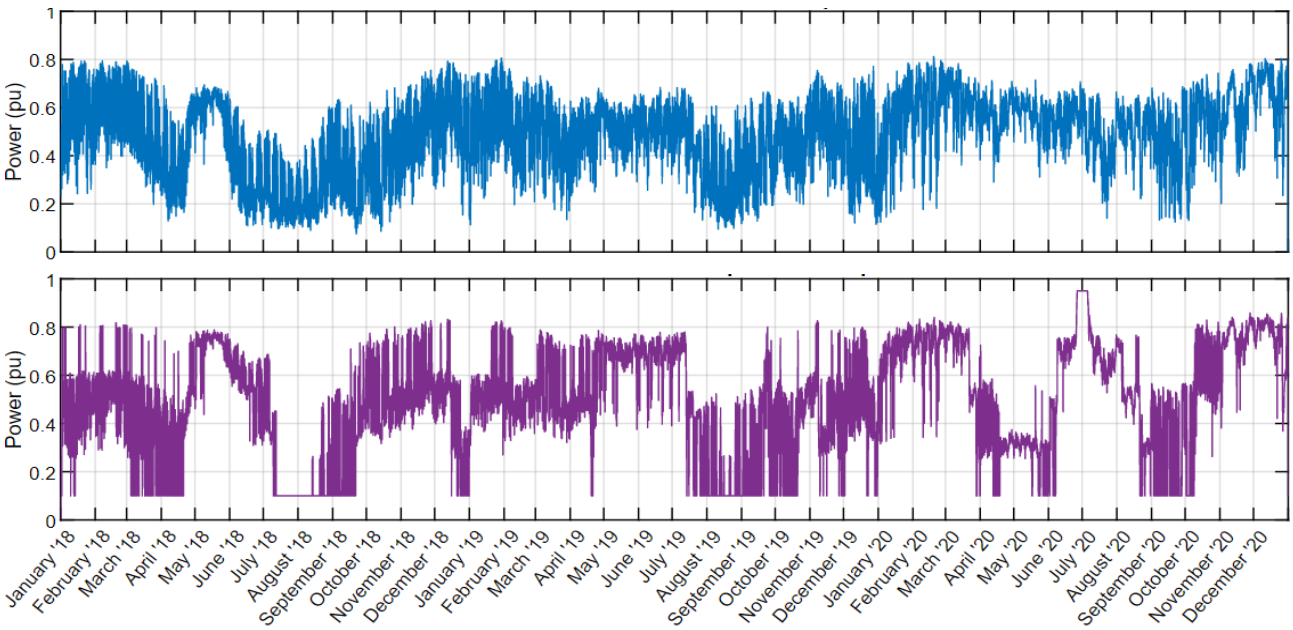


Figure 10. Production setpoint, historical (top) and simulated (bottom), for agent 1 located in SE2.

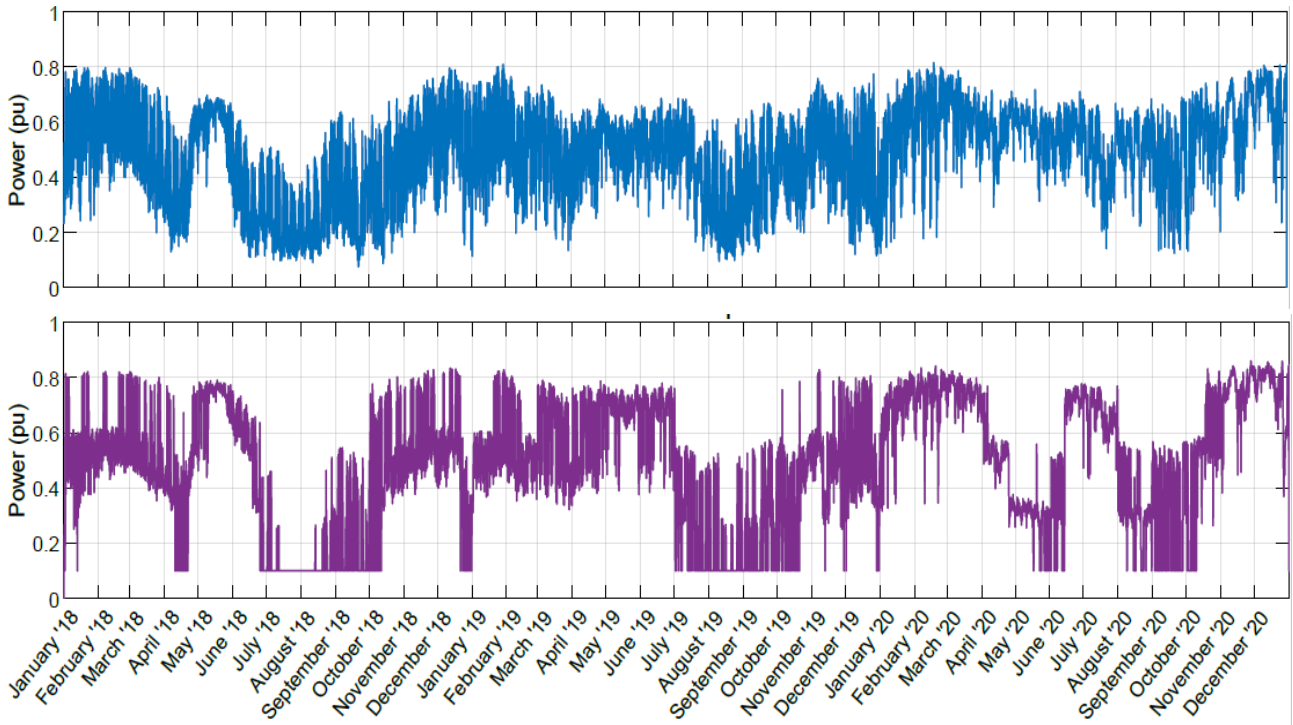


Figure 11. Production setpoint, historical (top) and simulated (bottom), for agent 2 located in SE2.

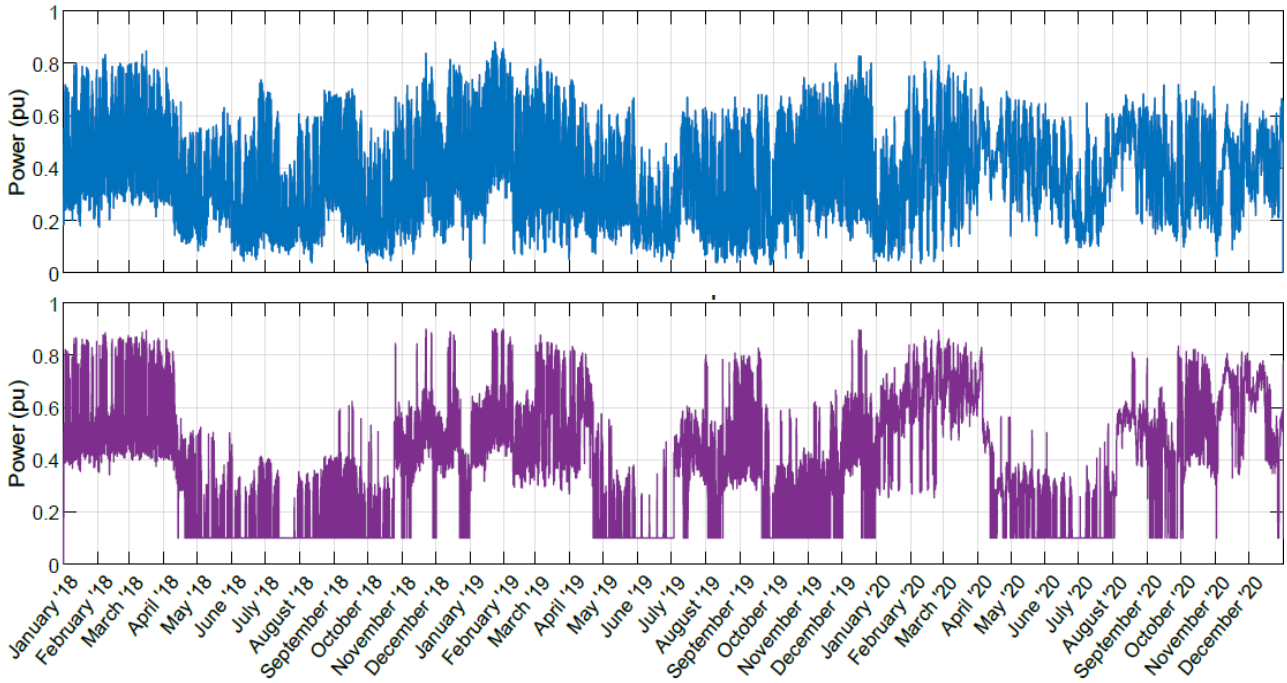


Figure 12. Production setpoint, historical (top) and simulated (bottom), for agent 3 located in SE1.

3.3.4 Algorithm for determining bid and price distribution of hydro bidders based on historical bid data

The goal of the algorithm is to reconcile technical hydro model results with the historical bid volume and price data of the modelled BSPs. Based on it, the actual distribution of historical symmetric bids is mapped to the asymmetric market. This allows us to ensure a high comparability of the historical and simulated results.

For each hour and each BSP, the algorithm is formulated as follows:

(I) Define the initial bid volumes and prices for both pos. and neg. bid

(II) Check whether the BSP would shift the setpoint up or down to maximize FCR-N flexibility

(III) The price is then converted from EUR to EUR/MW, ensuring a minimum price of 1 EUR/MW

(IV) These implicit price and implicit volumes (each for +FCR-N and -FCR-N) are used to determine the share that gets distributed from a historical bid onto the true-cost bids in the asymmetric market

(V) Using the historical bids, three price bands are determined. This is done by clustering all bid prices, weighted by their volume (and a factor that reduces the weight of all unaccepted bids), using a standard k-means clustering approach. If less than three bid prices are available, the clustering is skipped, and the historic prices are used directly. All bids are then assigned to the closest price band and are aggregated, resulting in a sum volume and volume weighted average price, for each band

(VI) Using the shares from (IV) and per-band-data from (V) – the bids are split into an asymmetric positive and negative bid.

3.4 Bidding strategy of a BSP with a storage portfolio

First, it is important to understand whether given the change to an asymmetric bidding, this is an option that battery storage operators would be incentivized to use. Analysis shows that asymmetric bidding is beneficial for storage operation and its business case. With symmetric bidding, the battery must reserve capacity in both directions (charging/discharging) so that in the case of an activation it can provide containment reserve for over- and underfrequency. In the case of asymmetric bidding, the battery operator can reduce the reserved capacity by bidding only in one direction or reducing the bid power in one direction. Moreover, with a symmetric bidding strategy the battery storage system loses energy on average due to inverter losses, standby losses, and the chemical process in the battery. Thus, with an asymmetric bidding strategy, the operator can bid in such a way to compensate the battery losses and thereby minimizing recharging through another market or with another generator.

3.4.1 Assumptions for battery storage

- Arbitrage between different markets will not be considered since we assume the TSO/regulator to prevent extrema (e.g. only charging, i.e. providing downward regulation in the balancing market and selling everything at a spot market)
- The battery is assumed to only take part in the FCR-N market (except for last-resort buying/selling energy in the intraday timeframe to keep up its state of charge (SoC)).
- The battery will place bids during *all* hours of the day.
- We assume all fluctuations in activation volumes (pos. or neg.) to balance out after some time (since the frequency deviates in a symmetric way around 50Hz) and will start the SoC (for a true-cost agent) always at 50% for the day.
- We assume two scaling factors (one for positive, one for negative FCR-N bids) to relate a capacity bid to the actually used balancing energy. This is used to calculate the maximum available positive/negative FCR-N capacity for the day. We base this scaling factor on a statistical analysis of the historic power frequencies, shown in Figure 13.
- Standby-losses of a battery energy storage system (BESS) are not considered in the simulations.
- These will be used together with a scaling factor to define the needed share of charging/discharging per day that is required to (approximately) keep the SoC at 50%.

- BESS efficiency is assumed to be at 90% (Figure 14).

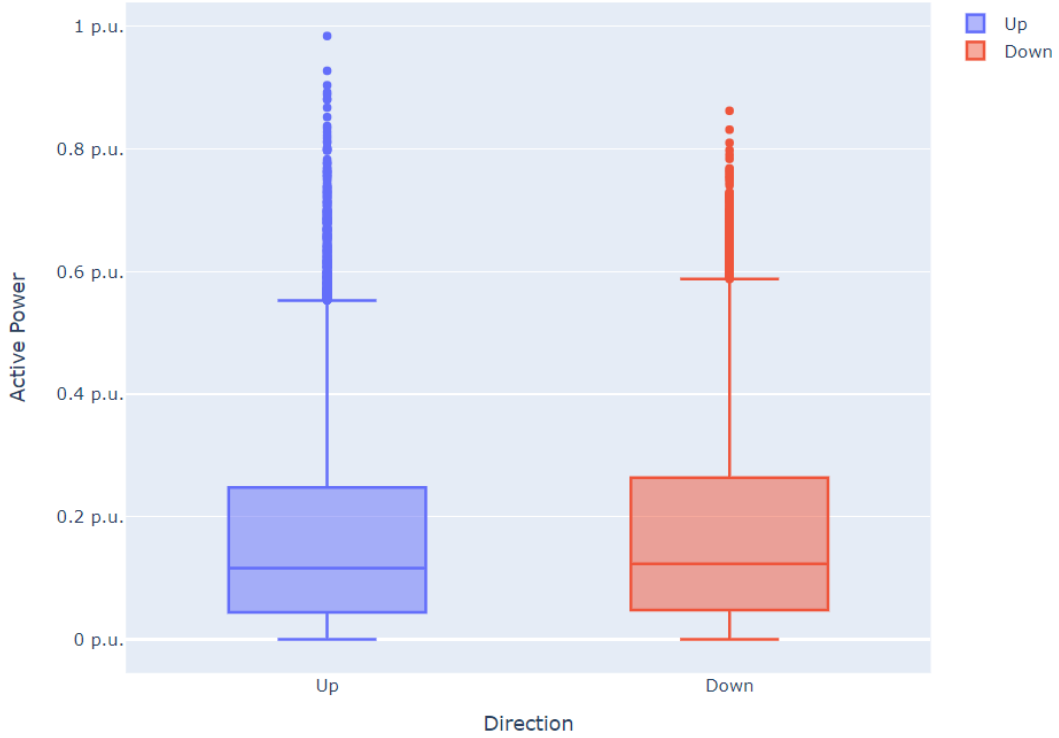


Figure 14. Share of capacity that should be activated based on the system frequency data of the Nordic area.

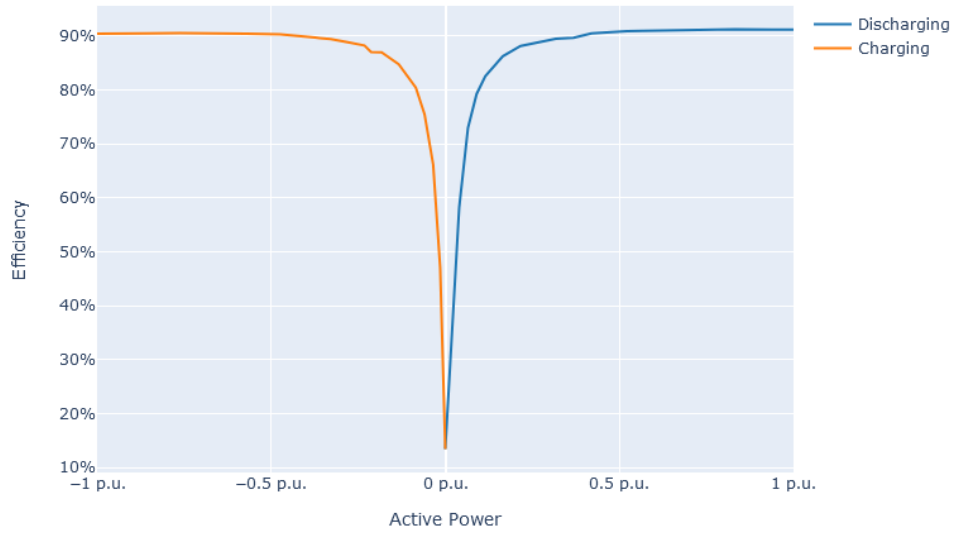


Figure 13. Typical efficiency levels of a battery storage + inverter.

3.4.2 Bid volumes of a true-cost-bidding BSP with a BESS portfolio

Considering that a BESS can choose the 'best' point in time, e.g. throughout the day, to charge or discharge it and thus offer capacity in either negative *or* positive market, a BESS operator will choose different hours to do so. To enable that without running into a battery's constraints, its state of change and its changes throughout the day will be considered in the model.

We assume the initial SoC for the first hour of the first simulation year to be at 50% (same as the optimal SoC used in the first project). For all the subsequent hours, the SoC is adjusted in a rolling manner, making sure that at the end of each day the SoC is back to 50%. Any deviations from this value are offset through energy purchase or sale in the intraday timeframe, affecting its overall profits. This is done in order to minimize the opportunity costs of a BESS over one day, while keeping the SoC relatively fixed.

Since a BESS is expected to be in the money, no matter whether it needs to charge or discharge, we define the opportunity costs for every hour as the difference between the +FCR-N price and the -FCR-N price (which are assumed to be always ≥ 0). The shares of upward and downward regulation may not exceed the total capacity constraints and chosen so that the opportunity costs are minimal over the span of the whole day, i.e. a profit-maximizing deployment of a BESS.

In order to ensure that a true-cost bidding agent returns to the SoC of 50% at the end of the day, we calculate the needed fraction of charging/discharging (taking into account efficiency losses) and force it to honor this fraction in its profit maximization.

3.4.3 Opportunity costs of a BSP with a BESS portfolio

Considering the -FCR-N bid, the opportunity costs of actually placing this capacity bid would in reality most of the time actually be below 0. This is due to the fact, that the opportunity costs respect the compensation from selling the “free” energy afterwards by placing a positive BC bid – effectively driving the opportunity costs below zero. However, due to actual energy activation as part of FCR-N, cycling costs in either direction must be factored in.

As to positive FCR-N, similar to the first project, the opportunity costs for upward regulation are defined as a function of a battery’s cycling costs (now partially accounted for in the negative FCR-N bid), expected intraday price and the risk premium.

A storage unit can profit from asymmetric bidding throughout the day by placing different hourly bids in the upward and downward directions whereas must stay ‘symmetric’ over a day (to maintain the same optimal SoC at the end of the day). It is fair to assume that 50% of the cycling costs will be allocated to either directions.

3.5 Bidding strategy of a BSP with a wind portfolio

Variable renewables are arguably the biggest beneficiaries of asymmetric bidding along with demand response: as upward activation is generally more complex to provide and requires more planning (to schedule pre-curtailment in due time). In contrast, a wind turbine can be regulated downwards fairly quickly and easily. Consequently, in the model we assume that an agent with a wind portfolio would mostly offer flexibility in the negative FCR-N market as long as expected prices do not favor pre-curtailment to provide +FCR-N.

3.5.1 Bid volumes of a true-cost-bidding BSP with a wind portfolio

A BSP with wind assets is modelled to be able to offer a much higher volume for downward regulation in comparison to upward regulation. We still observe the security band of 20% and wind availability based on the historical generation forecast data, by ENTSO-E. This time, however, the comparison of the expected FCR-N prices with expected DA prices results into two different strategies in the positive and negative FCR-N markets:

- If the expected +FCR-N price < (expected DA price + expected -FCR-N price), the true-cost BSP will attempt to submit max. volume to the DA market.
- If the expected +FCR-N price > (expected DA price + expected -FCR-N price), the true-cost BSP will attempt to maximize the value of its flexibility in both directions.

3.5.2 Opportunity costs of wind-based BSPs

The opportunity costs of wind generators for upward regulation these largely depend on the DA market prices .Considering fairly large assumed prequalified shares of wind in the FCR-N market, it may be the case that zero or close-to-zero prices would be observed for -FCR-N in some simulated hours, potentially giving an optimistic representation of the expected market effects. However, it needs to be considered that, despite high prequalified volumes, wind availability and, ergo, actual hourly bid volumes vary dramatically, barely ever managing to cover the entire FCR-N demand. In addition, the strategy above describes that of true-cost bidders. Additional simulation scenarios will be conducted, in which wind agents will be able to adjust their strategy based on the market conditions (and imperfect competition). Thus, it will be interesting to compare whether, given an imperfect market, wind agents will prefer to deviate from the true-cost strategy.

4 REINFORCEMENT LEARNING ALGORITHM TO MODEL STRATEGIC AGENTS UNDER ASYMMETRIC BIDDING

To account for the asymmetric product in the FCR-N market, we adjust the reinforcement learning (RL) algorithm developed in Phase 1 of the project. The introduction of asymmetric bidding implies two auctions instead of one, which translates into four instead of two decision variables. That is, an agent places 24 hourly bids (price-volume pair) per day per market.

In addition, to estimate the extent of potential capacity withholding, a higher bid volume granularity is introduced for RL agents.

The RL algorithm is used to emulate *strategic bidders* that attempt to maximize their profits based on market information and previous experience.

The RL agent places two bids in the FCR-N market per generator for each hour of the following day considering the available information in both markets. The action space in either market consists of discretized bid price markups and shares of available volume to commit in the FCR-N market. The level of discretization of the action space depends on the number of generators in the agents' portfolio.

In order to limit the state-action space and the computational time and yet obtain meaningful results, the discretization of price actions is set to 7 and of volume actions to 5 per generator per direction for a portfolio of three generators. This means that the combined discretized price-volume action space of an agent with three generators equals 10,500 action pairs in each market, in each time step. In terms of bid prices, the specific discretization of the action space will be different for the positive and the negative markets. In the former, the agent can place a markup of up to 100% on its bid price. In the latter, an agent may choose a coefficient within $\left[0\,,\ \lambda_k^{-FCR-N,exp}\right]$. With regard to the bid volume, the bidder may bid 0%, 30%, 50%, 70% or 100% of the available capacity within $\left[q_g^{min},\ q_g^{max}\right]$ of a generator in its portfolio in the FCR-N market of one

direction. It is assumed that if the total FCR-N volume bid is less than the total available capacity, the rest is bid in the DA market.

Specifically for the storage agent, we further take its state-of-charge (SoC) into account by including it into its state.

Considering two FCR-N markets under asymmetric bidding, a single RL agent takes separate decisions in the positive or in the negative FCR-N market, whereas as the actions are optimized for its entire portfolio in each market. However, already based on the technical constraints, these decisions cannot be fully independent from each other. Hence, the algorithms for the positive and the negative market need to ‘collaborate’ for the RL agent to adjust its strategy based on the two decisions influencing each other. Such ‘collaboration’ is accounted for in the algorithm through the exchange of information between the two markets, as reflected in a RL agent’s state and the profit maximization strategy in *both* markets rather than separately.

5 SCENARIOS AND RESULTS

This Chapter describes the scenarios selected to answer the project's research questions (Section 5.2) and provides an overview of market-level and agent-level results (Sections 5.3 and 5.4.

5.1 Comparability of results from project Phases 1 and 2

In order to investigate the effects of an asymmetric market design on various indicators of market performance, the historical market data as well as the results of project Phase 1, in which a symmetric FCR-N market was modelled with PaB and marginal pricing rules, are used for comparison. To allow a fair comparison, various properties of the simulations are ensured during project Phase 2:

- The same number of bidders (three for hydro-only scenarios and five for the scenarios with new market entrants) were modelled in both project phases
- The modelled agents have the same portfolios in terms of technologies and total prequalified capacities; yet, while the same amount is by default is bid in each direction in the symmetric scenarios, the distribution between the two directions in an asymmetric market differs (see also Section 5.1.1).
- The same minimum load requirement is respected for hydro generation in all scenarios.
- Opportunity costs and variable costs that are used in the calculation for the agents' true-cost bidding strategy are chosen as closely as possibly to Phase 1. Some differences are inevitable due to new bidding strategies considering the asymmetric FCR-N product or the fact that the historical symmetric bids need to be distributed among a positive and a negative bid.
- Although the results for the year 2020 are available for all scenarios studied in project Phase 2, we compare the results of the symmetric and asymmetric markets based on the outcome of the year 2019 (only incomplete data for the year 2020 was available during project Phase 1).

5.1.1 Available flexibility under asymmetric bidding

One of the goals of this project is to understand whether it would be more beneficial for a BSP to be able to provide *different* amounts of the *total* available flexibility to the positive or the negative direction in the two markets, for +FCR-N and for -FCR-N. In this sense, assuming that the two market would be independent from each other and the amount of flexibility in either direction remains the same would be counterproductive since in this case there is no reason for a BSP to bid anything else but a symmetric product. Thus, for the purpose of this project and implementing the bidding logic in the model, the *total* available flexible capacity in both directions is considered to determine the actual distribution that will depend on: 1) the plant's production setpoint (based on the technical hydro model, see Section 3.3.3) and – for the RL agent – 2) additional profit-driven considerations. The point about the total flexible capacity in both directions is illustrated in Figure 15.

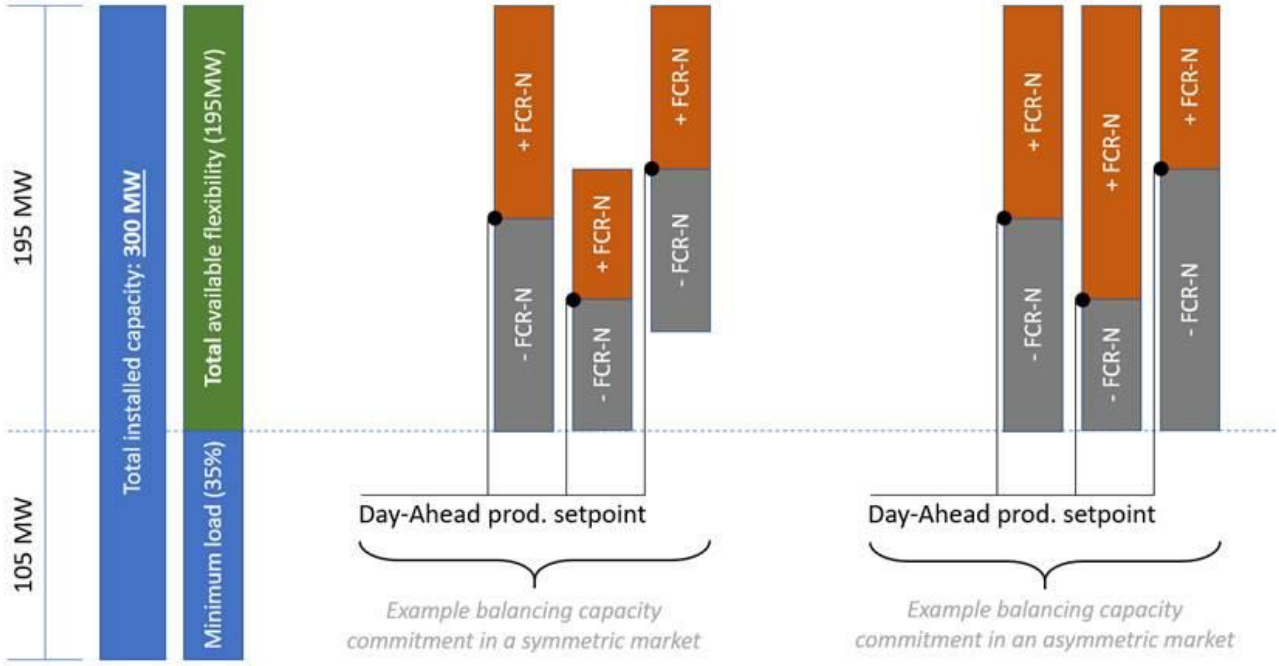


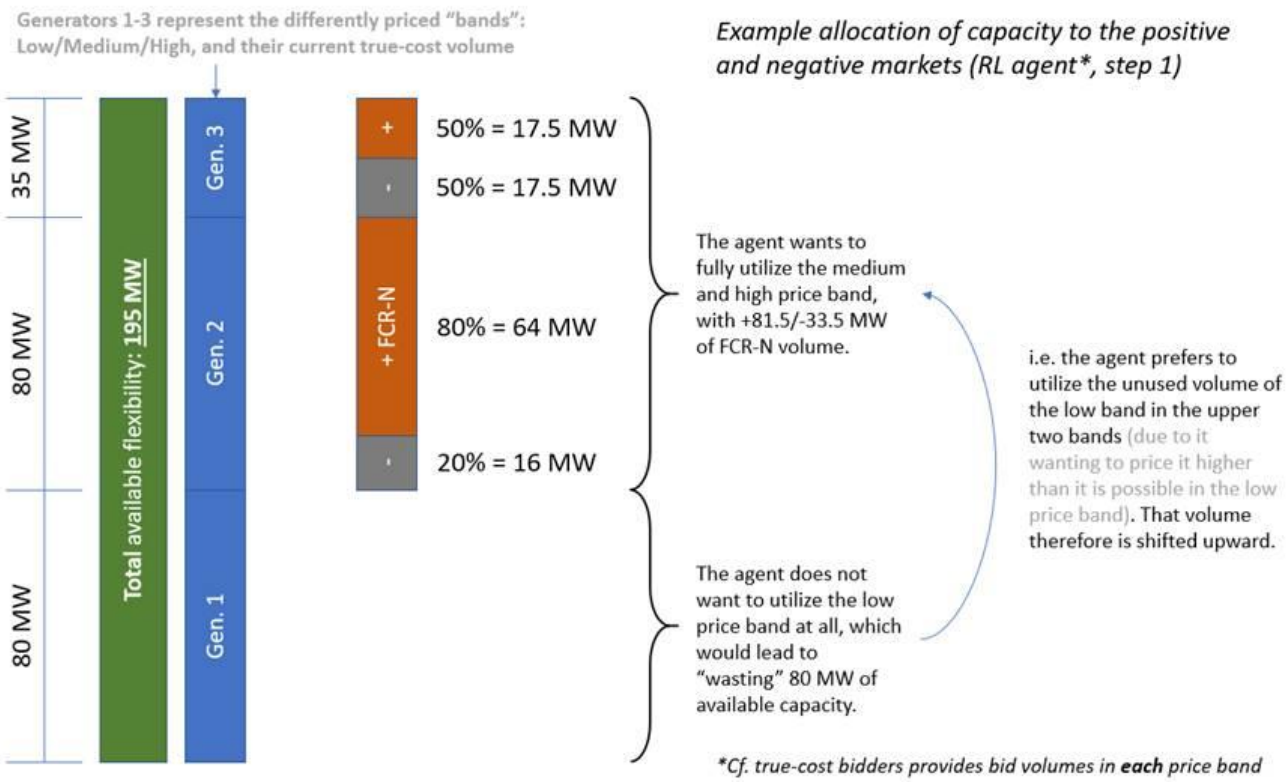
Figure 15. Comparison of the balancing capacity commitments under symmetric and asymmetric bidding using a theoretical example of a hydro power plant with a total installed capacity of 300 MW and a minimum load requirement of 35%.

It is of course possible that due to other technical restrictions, a BSP is unable to prequalify the full amount of flexibility for either direction, these considerations, however, are not part of market design and are not considered in the FCR-N market model. The considerations of how the available flexibility would be quantified would imply that a change from a symmetric to an asymmetric product would inevitably require an adjustment of the prequalification requirements. This aspect, however, is not part of the model simulations and is studied in the transition phase analysis in Chapter 6.

5.1.2 Capacity withholding

One of the important conclusions of project Phase 1 was that capacity withholding, even more than uncompetitive bid prices, largely contributes to the deterioration of the market performance under free bidding, i.e. if the obligation for BSPs to bid their true costs. In this context, capacity withholding did not mean that market actors completely remove their available flexibility from the market but rather do not bid in lower-priced bands. Similar to Phase 1, in this phase the agents cannot withhold capacity from their total available flexibility but rather shift some of it to a more expensive price band (thus withholding more cost-efficient capacity from the market). Based on Figure 15, Figures 16 illustrates an example of the mechanism for a true-cost bidder (top) and for an agent bidding strategically (bottom). Note how the total available volume of flexibility bid in the FCR-N market remains in the same while it is only the volume distribution that changes.

The introduction of asymmetric bidding adds another level of complexity: now an agent faces an additional choice of how to distribute the available flexibility between the two directions in a profit-maximizing manner. This can technically lead to situations, in which an actor is incentivized to bid in one direction only, reducing the total available supply in the other direction. This aspect is explicitly studied using the market model and the results of analysis are summarized in Section 5.4.



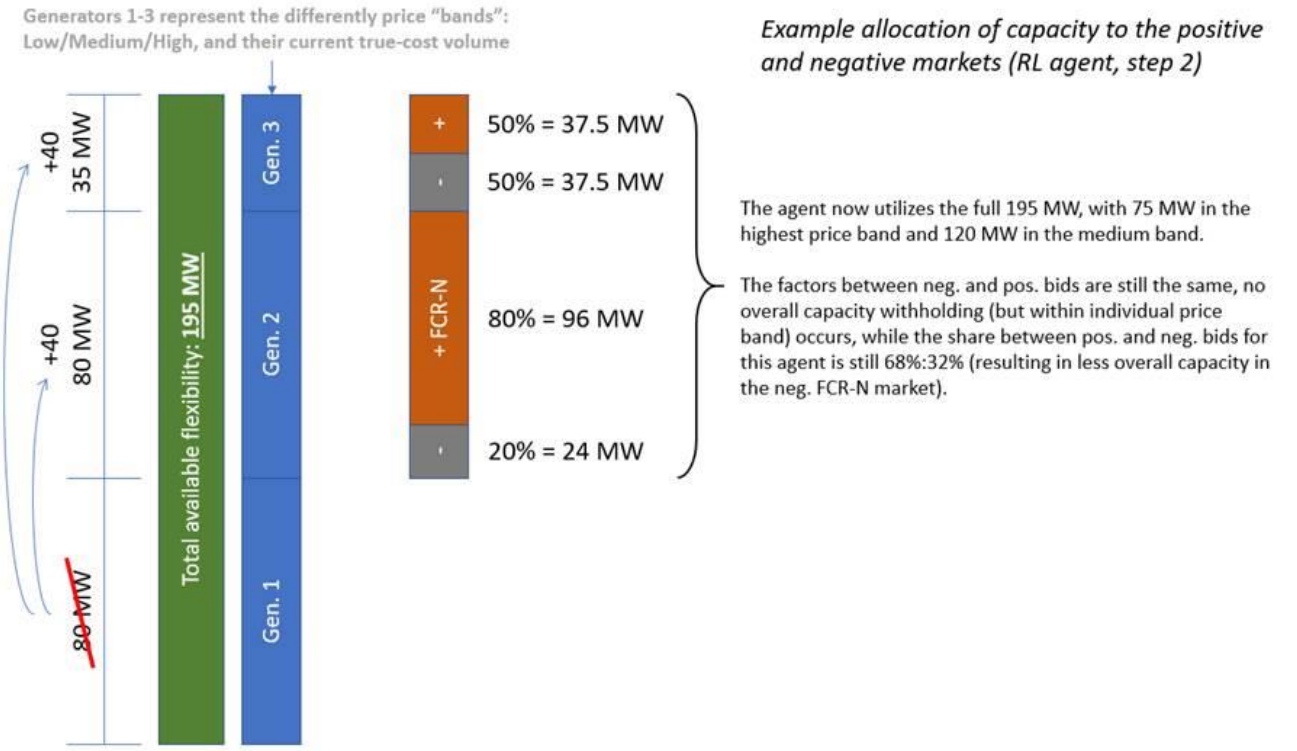


Figure 16. Bidding strategy of a non-strategic bidder (top) and of a strategic one (bottom), where the latter may decide to withdraw cheaper flexibility and shift it to more expensive price bands.

5.2 Overview of the scenarios

This project is aimed at answering a number of interlinked questions related to FCR-N market design changes as well as to the change of bidder landscape:

1. What is the impact of **a change of the FCR-N product from a symmetric to an asymmetric** on the market result?
2. What is the effect of **allowing (some) BSPs to link their bids** – forcing the market to either accept both the positive as well as the negative bid or none at all?
3. What **benefits** can different generation technologies obtain **from the possibility to bid separately for upward and downward regulation** and what is the effect of this change on their bidding strategies?
4. What is the effect of **capacity withholding and capacity distribution between the two auctions**, for upward and downward regulation?
5. What is the **effect of new market entrants and different degrees of competition** on the market outcome?

The answers to these questions are summarized in Section 5.4 while individual scenarios are described in more detail in Sections 5.3.1 and 5.3.2

Based on the questions above, the simulation scenarios defined in project Phase 2 have been clustered into 2 blocks based on market design options, different bidding strategies and numbers of agents.

Block 1 includes scenarios (including their counterparts from phase 1), in which all agents follow a true-cost bidding strategy, whereas **Block 2** contains different setups and combinations of true-cost and strategic bidders. Investigations regarding the effect of bid linking are conducted in **Block 1.**

BLOCK 1								
#	Phase	Scenario	Product	Bid linking	Hydro agents		New entrants	
					True-Cost	Strategic	True-Cost	Strategic
1	1	3TC_hydro_symm_mp	symm.		✓			
2	2	3TC_hydro_asymm	asymm.		✓			
3	2	3TC_hydro_asymm_linked	asymm.	✓	✓			
4	2	3TC_hydro_asymm_linkedallhydros	asymm.	✓	✓			
5	1	3TC_hydro_2TC_new_symm_mp	symm.		✓		✓	
6	2	3TC_hydro_2TC_asymm	asymm.		✓		✓	
7	2	3TC_hydro_2TC_asymm_linked	asymm.	✓	✓		✓	
8	2	3TC_hydro_2TC_asymm_linkedallhydros	asymm.	✓	✓		✓	

BLOCK 2								
#	Phase	Scenario	Product	Bid linking	Hydro agents		New entrants	
					True-Cost	Strategic	True-Cost	Strategic
9	1	1RL_2TC_hydro_symm_mp	symm.		✓	✓		
10	2	1RL_2TC_hydro_asymm	asymm.		✓	✓		
11	1	3RL_hydro_symm_mp	symm.			✓		
12	2	3RL_hydro_asymm	asymm.			✓		
13	1	3RL_hydro_2TC_new_symm_mp	symm.			✓	✓	
14	2	3RL_hydro_2TC_new_asymm	asymm.			✓	✓	

15	1	3TC_hydro_2RL_new_symm_mp	symm.		✓			✓
16	2	3TC_hydro_2RL_new_asymm	asymm.		✓			✓
17	1	2RL_1TC_hydro_1RL_1TC_new_symm_mp	symm.		✓	✓	✓	✓
18	2	2RL_1TC_hydro_1RL_1TC_new_asymm	asymm.		✓	✓	✓	✓
19	2	1RL_2TC_hydro_2RL_new_asymm	asymm.		✓	✓	✓	

Regarding the naming of the scenarios, please observe the following:

- Phase: This identifies whether a scenario was simulated during phase 1 or 2 of the project.
- A number of scenario descriptors have been used:
  - "linked" describes a scenario where agent 2 links all its bids in the +FCR-N and -FCR-N markets
  - "linkedallhydros" describes a scenario where agents 1-3 (all hydro BSPs) link all their bids.
  - for all "3RL_hydro_*" scenarios, all hydro BSP are bidding strategically. For scenarios starting with "1RL_hydro*", it is agent 2 that bids strategically, whereas for the ones starting with "2RL_hydro_*", agent 2 and agent 3 can place strategic bids.
  - Similarly, all scenarios that feature only a single new entrant with strategic bidding it is agent 5, managing the wind portfolio.
- All scenarios in Phase 2 are based on marginal pricing.
- "strategic" refers to the ability of an agent to bid strategically to maximize its cumulative profits.

5.3 Simulation results

The following results – if not stated otherwise – are based on simulation results of 2019 (where results from phase 1 of the project are also available). The "economic cost" is calculated as total system cost (of both markets) minus the total profit of all agents (in both markets, see also Section 5.4 for further explanation and analysis).

5.3.1 Simulation results – Scenario Block 1

Table 2. Summary of market results for the scenarios in Block 1.

Scenario	System Cost [M€]		Avg. Marginal Price [€]		Economic Cost [M€]
	+FCR-N	-FCR-N	+FCR-N	-FCR-N	
3TC_hydro_symm_mp	102.8		51.44		85.0
3TC_hydro_asymm	82.6	9.6	40.77	4.83	76.3
3TC_hydro_asymm_linked	82.7	10.2	40.83	5.12	77.8
3TC_hydro_asymm_linkedallhydros	99.8	10.1	49.42	5.08	76.2
3TC_hydro_2TC_new_symm_mp	89.5		44.84		73.3
3TC_hydro_2TC_new_asymm	67.5	4.6	33.29	2.33	62.7
3TC_hydro_2TC_new_asymm_linked	67.7	5.0	33.40	2.51	63.8
3TC_hydro_2TC_new_asymm_linkedallhydros	80.1	7.5	39.55	3.79	66.8

Historical FCR-N prices 2019

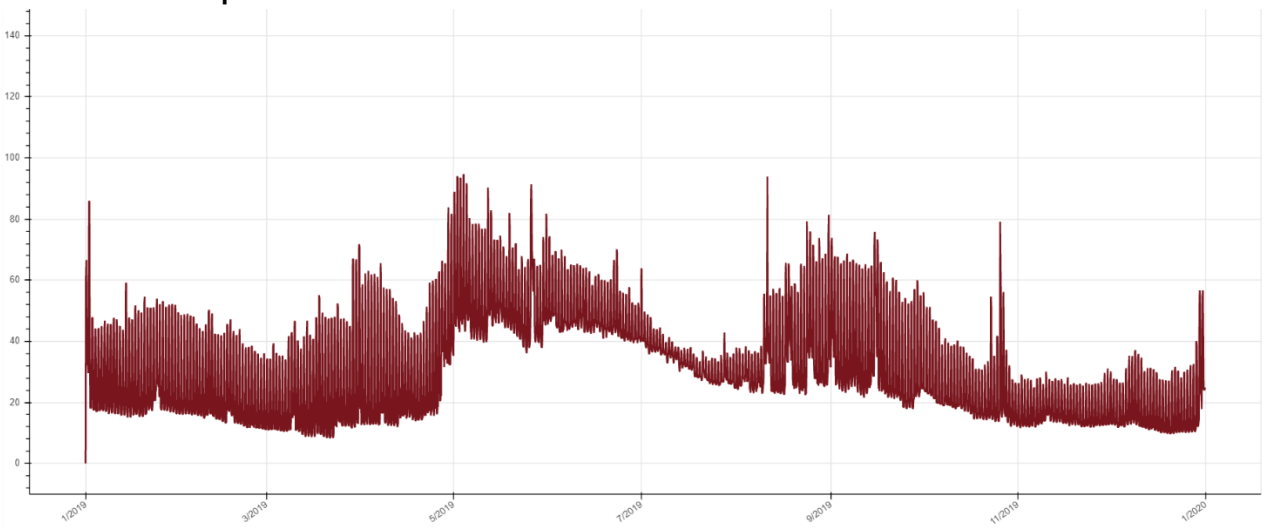


Figure 17. Historical FCR-N prices [€/MW] during the year 2019, cost-based, pay-as-bid.

Figure 17 shows the historical weighted average FCR-N prices throughout 2019, which acts – similar to Phase 1 of the project – as the baseline to compare the modelled scenarios to. From the hydrological perspective, the year 2019 was also closer to the average values, as compared to a very dry year 2018 or a wet year 2020.

Scenario with 3 true-cost bidding hydro-based BSPs, no bid linking *(3TC_hydro_asymm)*

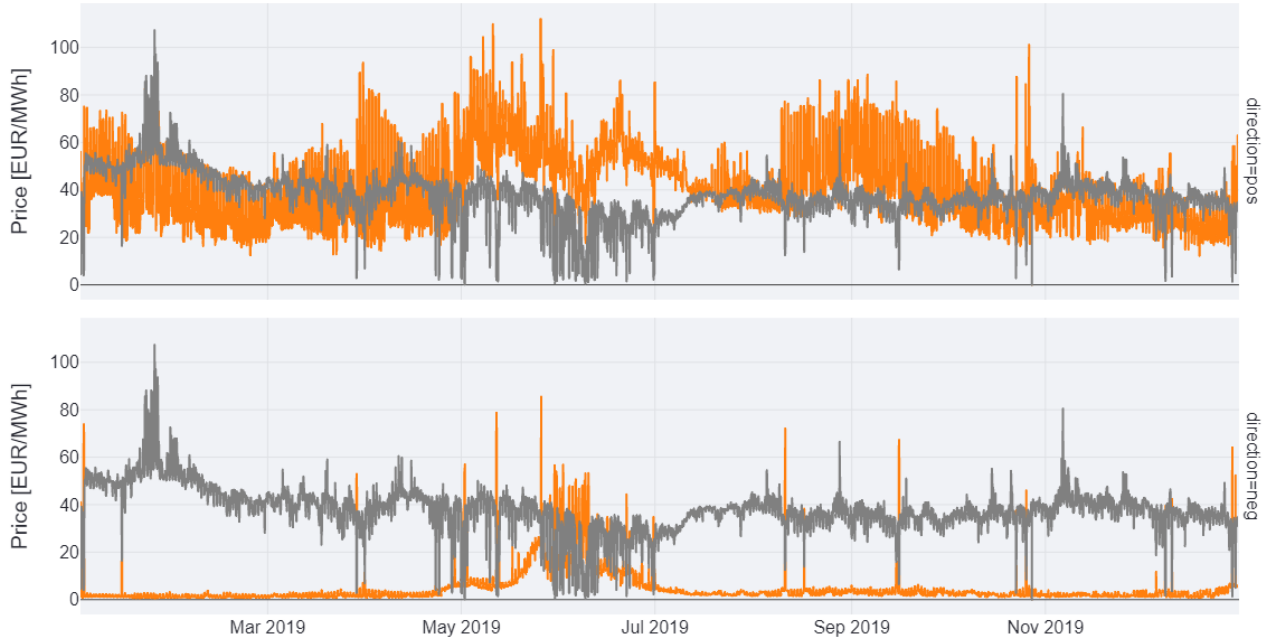


Figure 18. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

The split into an asymmetric market featuring separate +FCR-N and -FCR-N procurement shows a similar price course throughout the year when comparing the historical prices and the marginal prices to the symmetric baseline in scenario *3TC_hydro_symm_mp.* Looking at the intraday price development, an effect similar to historical prices is observed where FCR-N prices tend to be higher during off-peak periods when DA market prices are low and vice versa (see Fig. 19).

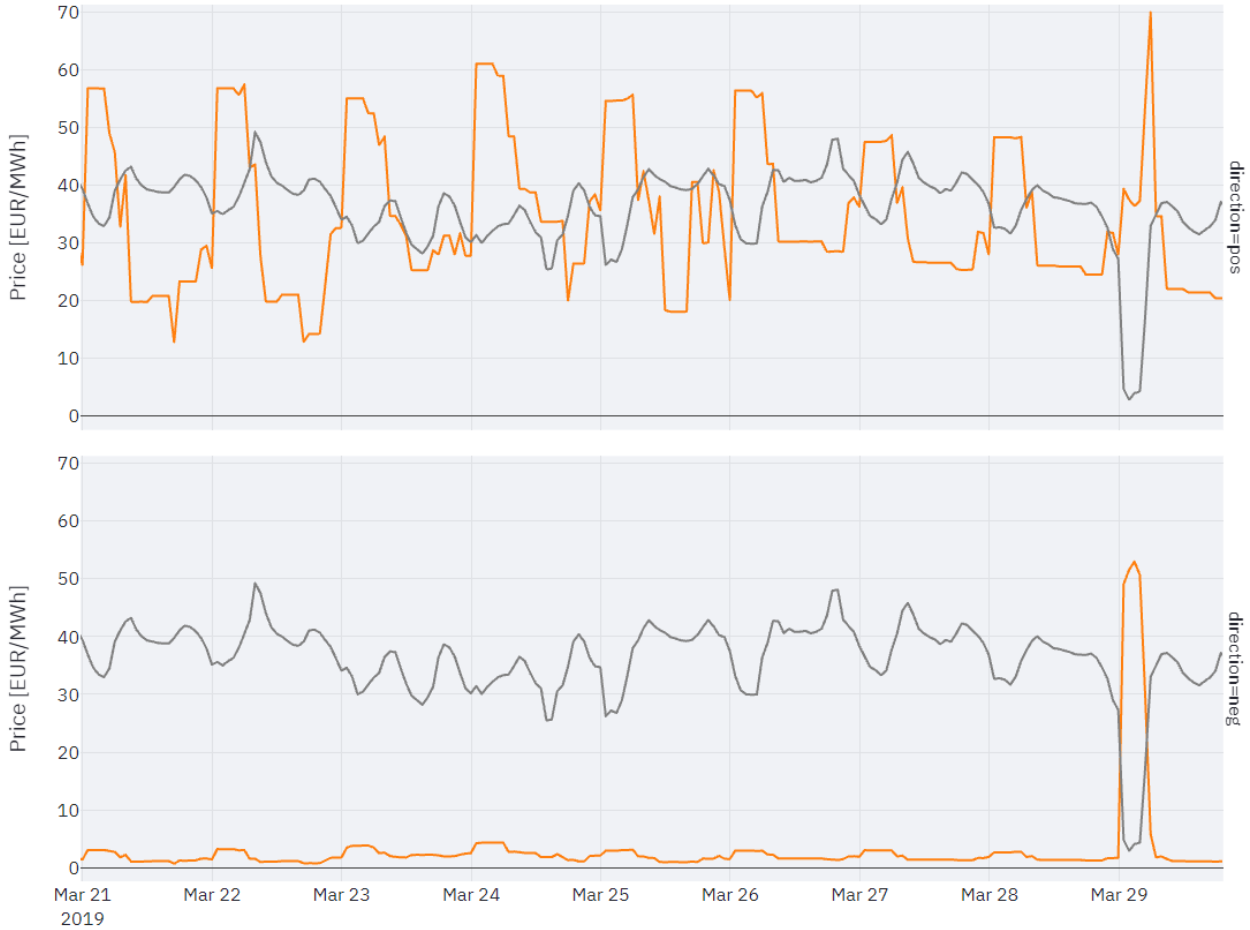


Figure 19. Close-up of intraday price developments in the +FCR-N market (top) and in -FCR-N market (bottom) during a week in March 2019 in scenario 3TC_hydro_asymm.

The average marginal price in the +FCR-N market is about 10EUR/MW lower than in its symmetric counterpart scenario (ca. 41 €/MW vs. ca. 51€/MW, respectively, see Table 2). The marginal prices in the negative FCR-N market tend to be substantially lower with a mean of 4.83 EUR/MW and a median of 2.40 EUR/MWh with occasional exceptions, such as a price spike in the -FCR-N market on March 29th, at 3am, where the DA price was particularly low (Figure 19). Figure 18, bottom, also shows that the largest price increase in the -FCR-N market occurs in the period between May and July 2019, coinciding with very low DA market prices as well as prolonged periods of low production, considerably reducing the amount of flexibility for downward regulation: due to less incentive to produce in the DA market, opportunity costs for an increase of production – and the possibility to supply negative capacity – rise and therefore increase the prices in the -FCR-N market.

Scenario with 3 true-cost bidding hydro-based BSPs, with bid linking *(3TC_hydro_asymm_linked)*

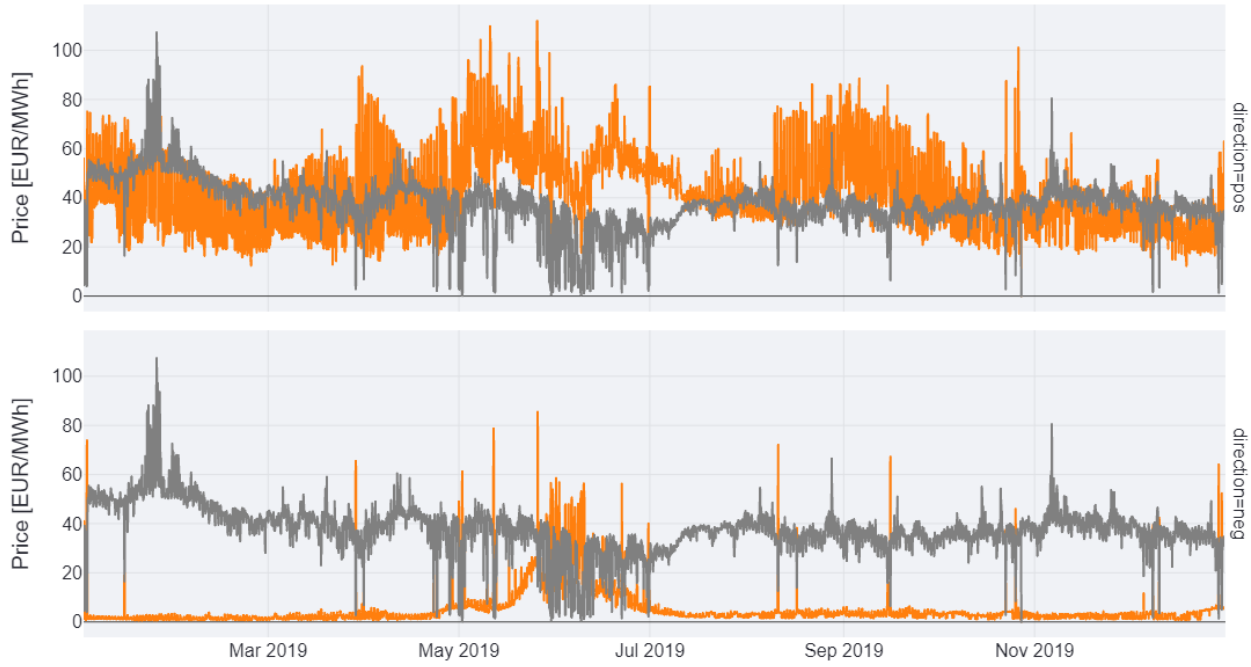


Figure 20. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_asymm_linked in the +FCR-N market (top) and -FCR-N market (bottom).

In scenario *3TC_hydro_asymm_linked*, it is only agent 1 that links all its bids in the positive and the negative market. Note that total system costs are minimized for both the positive and negative FCR-N markets in the clearing function (considering the marginal pricing rule). The bids are linked on per-generator basis.

Overall, the price development in this scenario is almost the same as in previous scenario, in which no linking was allowed. However, larger differences can be observed in a few individual hours, which led to approximately 5% system cost increase in the negative market alone.

Agent and market results for the two true-cost scenarios, with *(3TC_hydro_asymm)* and without bid linking *(3TC_hydro_asymm_linked)*, are presented in Tables 3 (unlinked) and 4 (linked) for a single hour. Following Table 3, total system costs during this hour are 18,998.83 EUR without any linked bids whereas Table 4 shows total system costs of 19,289.39 EUR for the linked scenario. That is equal to an increase of total system costs of 1.5% although (since the outcome of the +FCR-N market stays the same) this is entirely based on an increase in -FCR-N costs by 175% (290.56 EUR).

This hour highlights the effects of bid linking: agent 1 (with generators a, b and c) has 78.9 MW volume awarded in the +FCR-N market in the unlinked scenario. Its second bid (generator b with a price of close to 76 EUR/MW) is marginal (and therefore the most expensive accepted bid). Accepting the next bid in the merit order would increase the marginal bid in the +FCR-N market by close to 30 EUR/MW. Accepting both its bids, that were previously not awarded, in the -FCR-N market increases the marginal price from 0.73 EUR/MW to 2.01 EUR/MW. While this is a much larger increase in relative terms, the increase in total system costs is rather small compared to changing the outcome of the +FCR-N market. In a scenario where bids are linked, it is

therefore beneficial for the market to keep accepting the bids of agent 1's in the +FCR-N – even though this entails awarding bids in the -FCR-N market that are expensive – since this leads to overall lowest total system costs.

Table 3. Detailed agent and market results for the scenario 3TC_hydro_asymm.

+FCR-N AGENT BIDS				
BSP	Gen	Price [EUR/MW]	Volume [MW]	Accepted ?
7	a	32.71	29.9	✔
7	b	75.94	49	✔
7	c	449.32	11.1	
9	d	21.67	30.5	✔
9	e	90.18	78.1	
9	f	123.58	71.3	
10	g	30.42	143.5	✔
10	h	281.93	31.3	
10	i	628.3	5.2	
-	emergency	629.3	650	

-FCR-N AGENT BIDS				
BSP	Gen	Price [EUR/MW]	Volume [MW]	Accepted ?
7	a	0.86	47.8	
7	b	2.01	78.4	
7	c	11.87	17.7	
9	d	0.57	48.8	✔
9	e	2.38	125	
9	f	3.27	114.1	
10	g	0.73	229.6	✔
10	h	6.73	50.1	
10	i	14.99	8.3	
-	emergency	15.99	650	

+FCR-N MARKET RESULT			
Marginal gen	Marginal price	System Cost	Awarded Gens
b	75.94 EUR/MW	18,833.12 EUR	a, b, d, g

-FCR-N MARKET RESULT			
Marginal gen	Marginal price	System Cost	Awarded Gens
g	0.73 EUR/MW	165.71 EUR	d, g

Table 4. Detailed agent and market results for the scenario 3TC_hydro_asymm_linked.

+FCR-N AGENT BIDS				
BSP	Gen	Price [EUR/MW]	Volume [MW]	Accepted ?
7	a	32.71	29.9	✔
7	b	75.94	49	✔
7	c	449.32	11.1	
9	d	21.67	30.5	✔
9	e	90.18	78.1	
9	f	123.58	71.3	
10	g	30.42	143.5	✔
10	h	281.93	31.3	
10	i	628.3	5.2	
-	emergency	629.3	650	

-FCR-N AGENT BIDS				
BSP	Gen	Price [EUR/MW]	Volume [MW]	Accepted ?
7	a	0.86	47.8	✔
7	b	2.01	78.4	✔
7	c	11.87	17.7	
9	d	0.57	48.8	✔
9	e	2.38	125	
9	f	3.27	114.1	
10	g	0.73	229.6	✔
10	h	6.73	50.1	
10	i	14.99	8.3	
-	emergency	15.99	650	

+FCR-N MARKET RESULT			
Marginal gen	Marginal price	System Cost	Awarded Gens
b	75.94 EUR/MW	18,833.12 EUR	a, b, d, g

-FCR-N MARKET RESULT			
Marginal gen	Marginal price	System Cost	Awarded Gens
b	2.01 EUR/MW	456.27 EUR	a, b, d, g

This situation is fairly representative for the entire year and demonstrates the influence of a single agent linking all its bids: the +FCR-N market remains mostly unaffected while the -FCR-N market is used to make sure the cheapest bids in the (most expensive) +FCR-N market can still be awarded.

Agent profits in the asymmetric market scenarios with and without bid linking as well as with the one from the symmetric market are compared in Figure 21. It shows that agents generally manage to profit more from the

possibility to links their bids although they do so at the expense of the overall market efficiency, which results in higher market costs both in comparison with the asymmetric market, in which no bid linking was allowed and with the symmetric market. As illustrated in Tables 3 and 4, the TSO is at times compelled to award an economically suboptimal bid in one market in order to be able to award an actually needed bid in the other market.

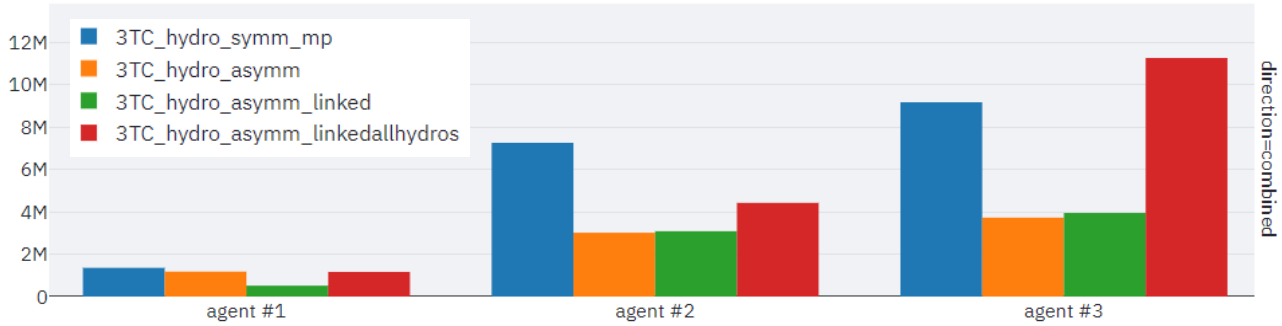


Figure 21. Profits of agents 1-3 in the true-cost scenario with the symmetric market (blue bar) and the asymmetric market with and without (orange bar) bid linking. Green bars represent agent profits in the scenario, in which only agent 2 links its bids whereas the scenario, in which all agents link their bids, is represented with red bar.

Scenario with 3 true-cost bidding hydro-based BSPs, with all BSPs linking their bids *(3TC_hydro_asymm_linkedallhydros)*

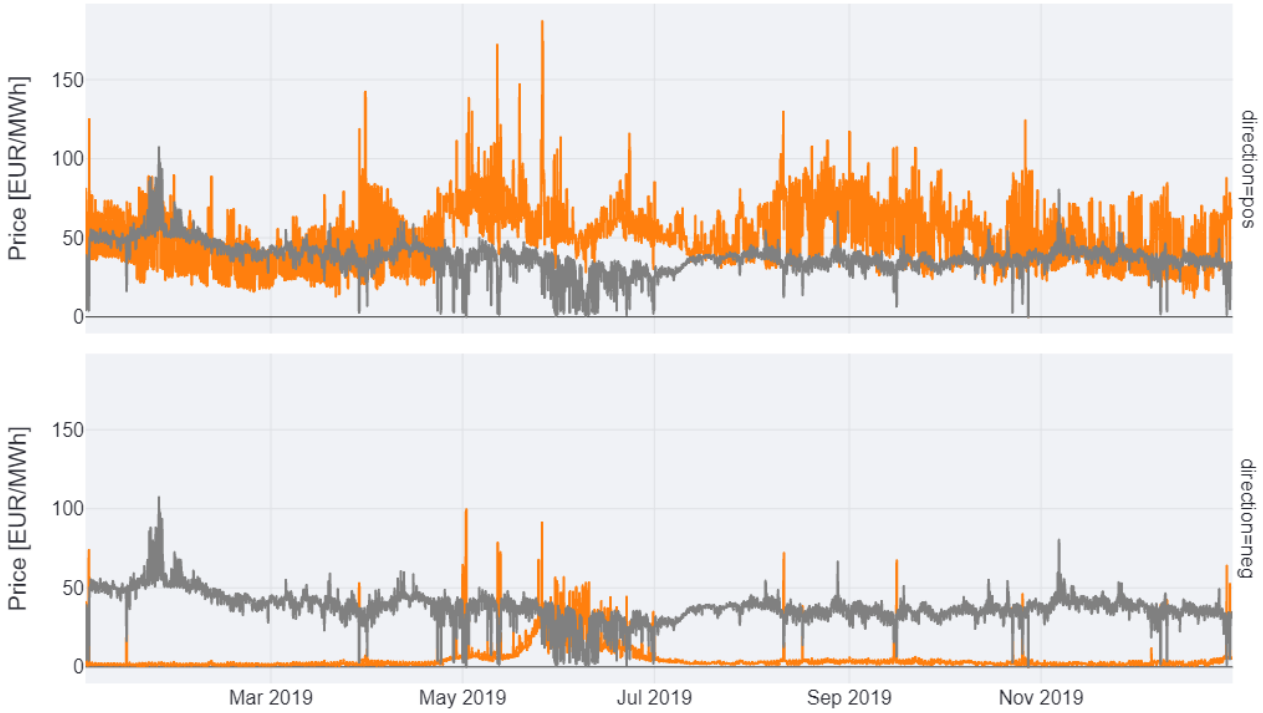


Figure 22. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_asymm_linkedallhydros in the +FCR-N market (top) and -FCR-N market (bottom).

In this scenario, all three BSPs link their bids in the two markets on a per-generator basis. While in scenario *3TC_hydro_asymm_linked* the system costs mostly increased in the negative market (see Table 2), in this scenario the market does not have a possibility to shift less cost-inefficient generation into the negative market to still award the cheapest bids in the positive market. Therefore, the market operator is forced to accept less cost-efficient bids in the FCR-N market, which leads to an overall increase in system costs of about 21%, as compared to the scenario with no bid linking. This can also be observed in the much more volatile and overall higher marginal prices.

Scenario with 3 true-cost bidding hydro-based BSPs and 2 true-cost bidding wind- and storage-based BSPs, no bid linking *(3TC_hydro_2TC_new_asymm)*

Introducing new entrants to the market, two effects can be clearly observed:

1. while price spikes in the periods with low DA market prices of the year still exist in the -FCR-N market, the overall increase during May-July period is much lower (this is due to the increase in competition caused especially by the wind agent) and in the +FCR-N market prices often fall below the DA price levels (e.g. February to April in Figure 23),
2. +FCR-N prices show a much more stable course being essentially centered around the mean of 33 EUR/MW (with a median of 31 EUR/MW).

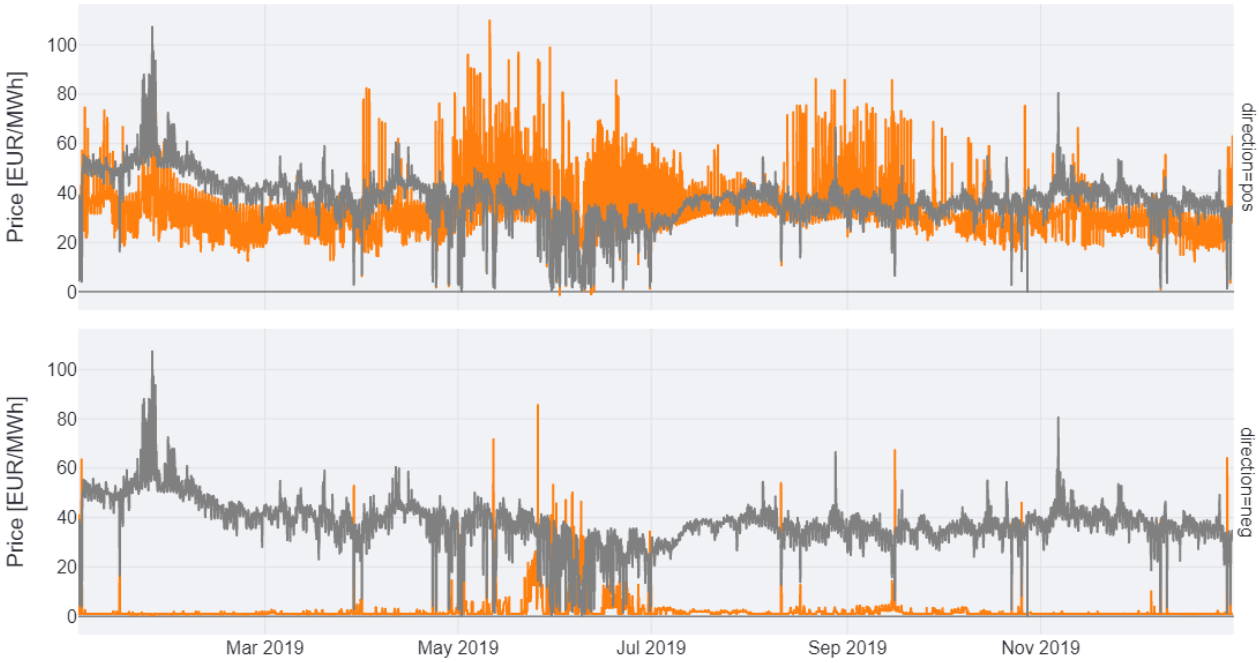


Figure 23. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_2TC_new_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Scenario with 3 true-cost bidding hydro-based BSPs and 2 true-cost bidding wind- and storage-based BSPs, with bid linking *(3TC_hydro_2TC_asymm_linked)*

Figure 24 shows little effect of a single BSP linking its bids on the total system costs and the average prices. Studying the results closer, we observe a few higher price spikes not only in hours with high marginal prices but also in many hours with much lower prices.

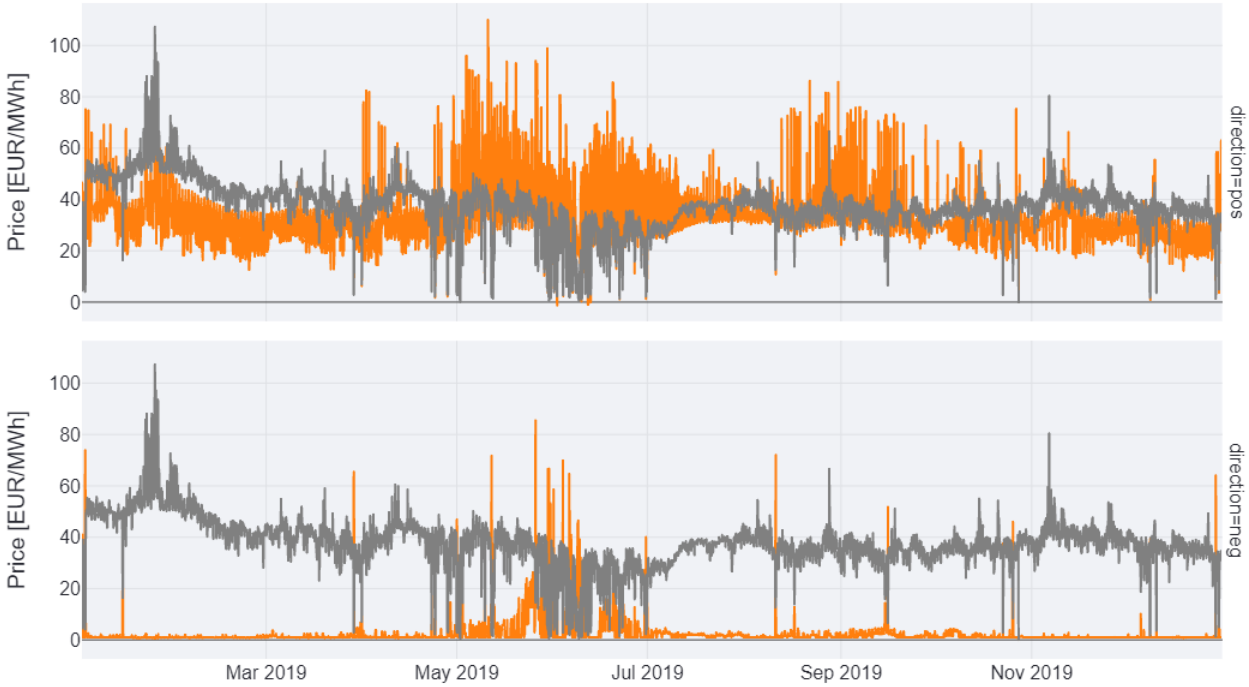


Figure 24. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_2TC_new_asymm_linked in the +FCR-N market (top) and -FCR-N market (bottom).

Scenario with 3 true-cost bidding hydro-based BSPs and 2 true-cost bidding wind- and storage-based BSPs, with all hydro-based BSPs linking their bids *(3TC_hydro_2TC_asymm_linkedallhydros)*

Similar to the results of the scenario *3TC_hydro_asymm_linkedallhydros*, linking all hydro BSPs' bids leads to an increased volatility in both markets, increasing total system costs by 18%. In addition, a noticeably higher economic cost in this scenario (ca. 67Mio.€ vs. ca. 63Mio€ in the scenario with no bid linking, see Table 2), hints at a lower market efficiency.

In sum, bid linking generally leads to higher system costs since fewer degrees of freedom are available for market clearing. Due to high price differences between the positive and negative markets, the results in the former remain almost always the same whereas the major cost increase and changes in the set of awarded bids are observed in the -FCR-N market.

The effect of linking bids is likely to be higher if all bidders can do so: 21% and 18% system cost increase in the scenarios *3TC_hydro_linkedallhydros* and *3TC_hydro_2TC_new_linkedallhydros* with all hydro bidders linking their bids, respectively, as opposed to the same scenarios with no linking.

In case bid linking is introduced, it becomes crucial whether partially awarded bids are allowed or not: due to 'forcibly' awarded bids in one market, the awarded volume can become much larger than the total demand (without partially awarded and using merit-order based clearing).

Based on these simulation results, it was decided to conduct the remaining simulations with strategic bidders in Block 2 assuming that no bid linking is allowed.

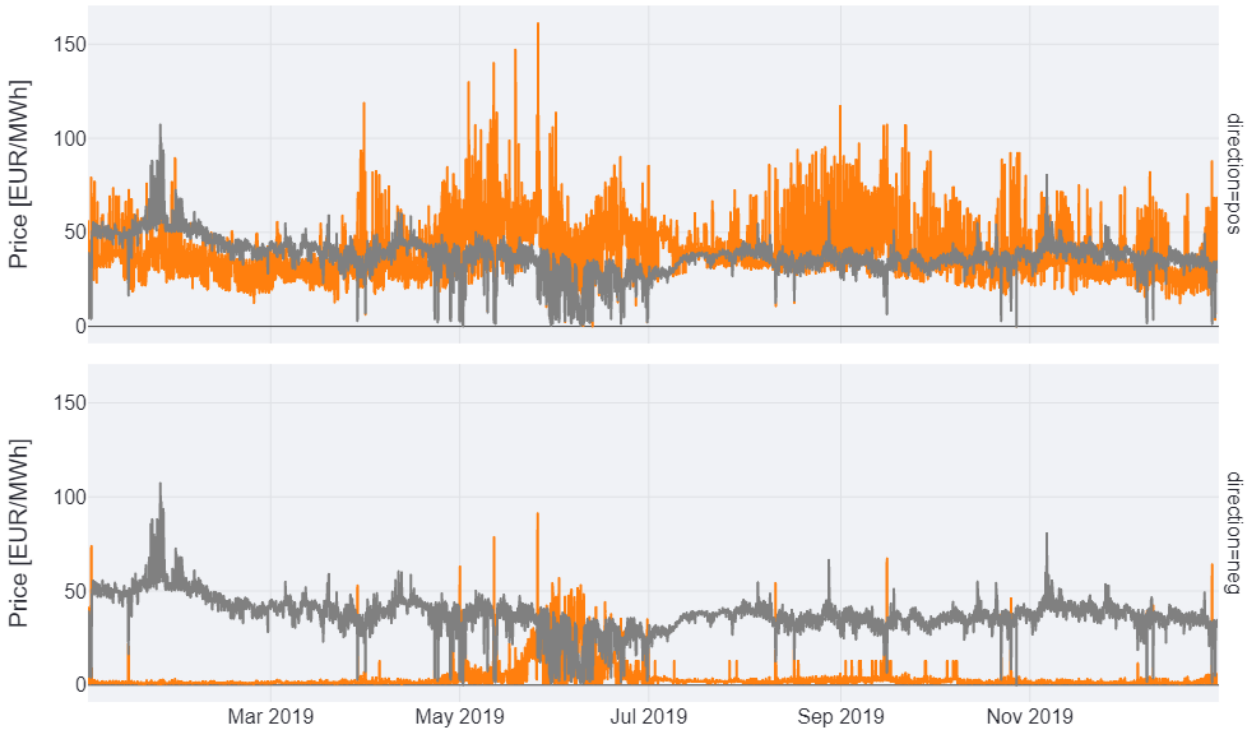


Figure 25. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_2TC_new_asymm_linkedallhydros in the +FCR-N market (top) and -FCR-N market (bottom).

Capacity availability in the scenarios of Block 1

Figure 26 shows that no scarcity events were observed in the simulated scenarios with true-cost bidding agents with or without new market entrants. Note that the values of the x axis represent percentage points.

In almost all cases more than double of the total demand is bid in both markets. Looking at the historical bid data, this is not uncommon: average hourly bid volume *of the 3 modelled BSPs* in any given year tends to be approximately double to triple of the total FCR-N demand:

	2018	2019	2020
Avg. hourly bid volume	486 MW	767 MW	593 MW

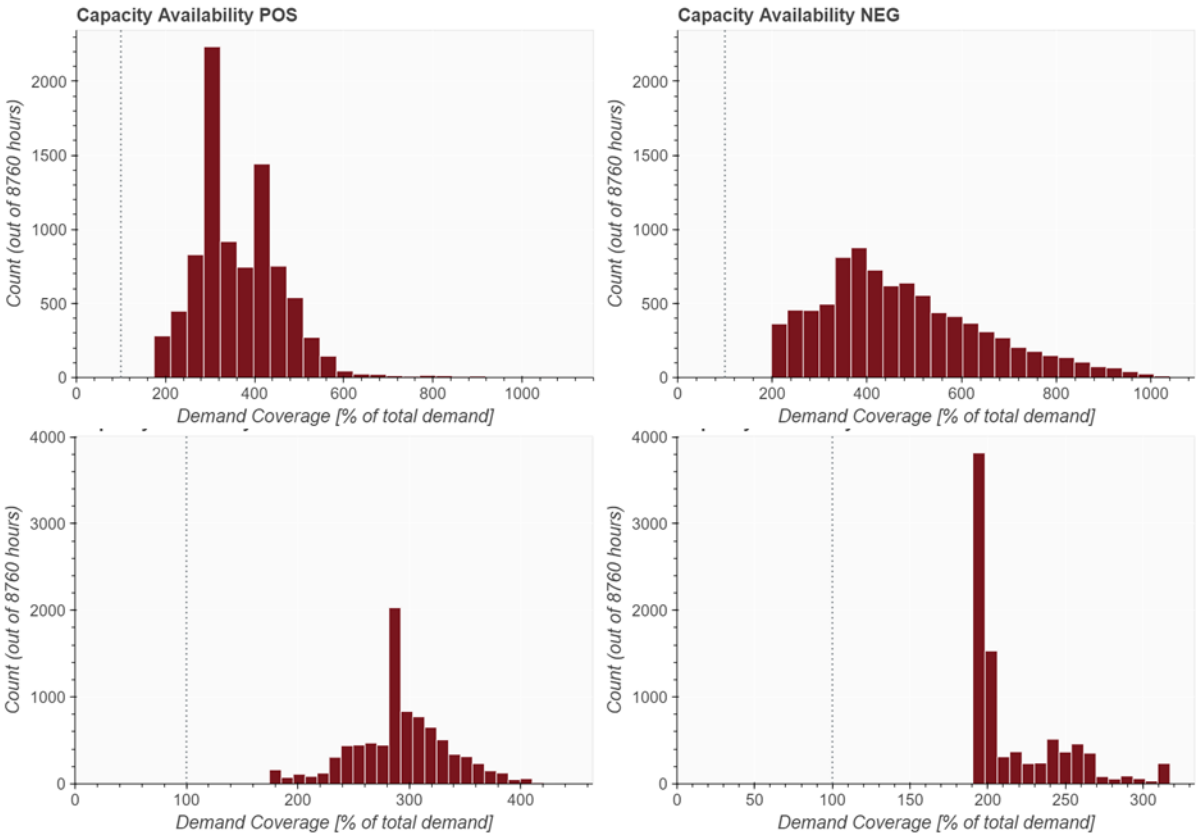


Figure 26. Share of total FCR-N availability (in %; = coverage of demand) in the positive market (left) and the negative market (right) in scenarios 3TC_hydro_2TC_new_asymm (top) and 3TC_hydro_asymm (bottom).

5.3.2 Simulation results – Scenario Block 2

Table 5. Summary of market results for the scenarios in Block 2.

Scenario	System Cost [M€]		Avg. Marginal Price [€]		Economic Cost [M€]
	+FCR-N	-FCR-N	+FCR-N	-FCR-N	
1RL_2TC_hydro_symm_mp	119.4		59.58		87.3
1RL_2TC_hydro_asymm	89.0	17.5	43.94	8.82	77.9
3RL_hydro_symm_mp	226.8		113.50		101.4
3RL_hydro_asymm	223.0	12.8	108.67	6.42	94.8
3RL_hydro_2TC_new_symm_mp	87.2		43.71		71.9
3RL_hydro_2TC_new_asymm	87.0	4.9	42.76	2.47	72.3
3TC_hydro_2RL_new_symm_mp	89.9		45.00		72.3
3TC_hydro_2RL_new_asymm	75.1	5.9	37.10	2.95	65.5
2RL_1TC_hydro_1RL_1TC_new_symm_mp	92.7		46.38		71.5
2RL_1TC_hydro_1RL_1TC_new_asymm	87.1	6.6	42.95	3.32	66.0
1RL_2TC_hydro_2RL_new_asymm	72.8	7.2	35.92	3.63	63.9

Scenario with a single strategic bidder *(1RL_2TC_hydro_asymm)*

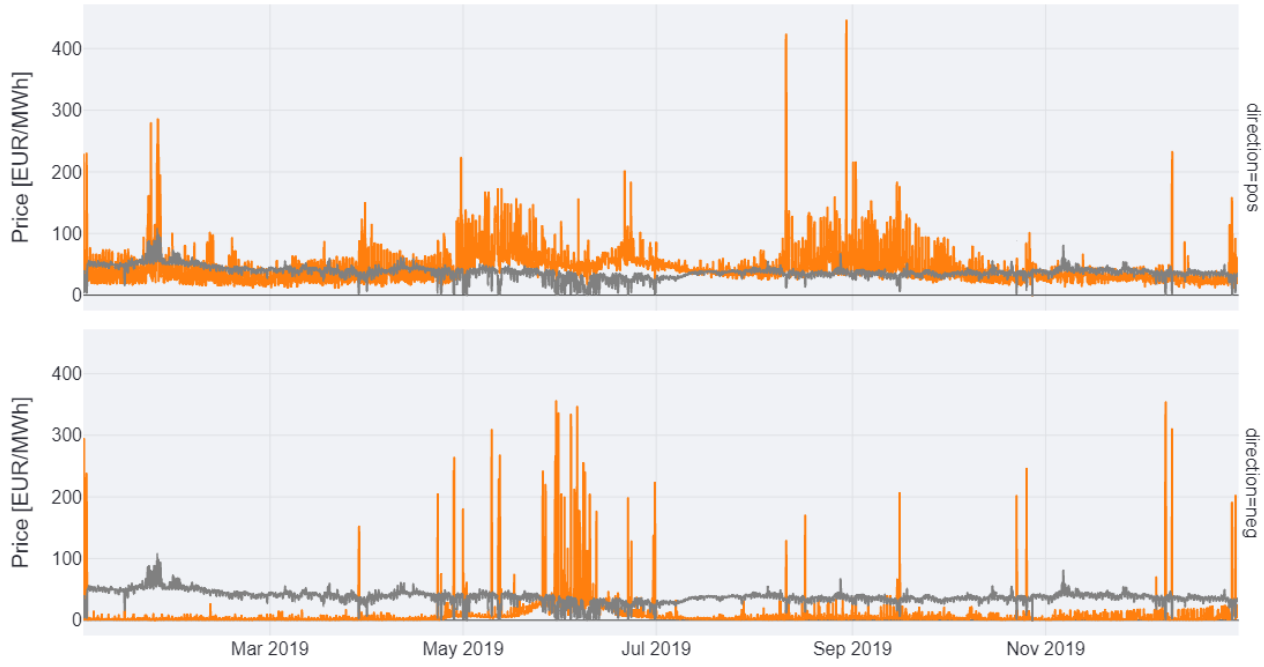


Figure 27. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 1RL_2TC_hydro_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Introducing just a single strategic bidder leads to price spikes close to 400 EUR/MW in both markets. Meanwhile, the overall course of the FCR-N price stays comparable to the previous true-cost scenarios described in Section 5.3.1.

Scenario with three strategic bidders *(3RL_hydro_asymm)*

The introduction of two additional strategic bidders (agents 2 and 3) further increases price spikes, both their frequency and the maximum marginal prices:

- In the +FCR-N market: with a maximum marginal price of 1335 EUR/MW, 3% of all hours result in a price above 500 EUR/MW. Still, 90% of all marginal prices are below 155 EUR/MW.
- With average marginal prices between 85-115 EUR/MW (the annual average is 109 EUR/MW) in the +FCR-N market, the two most expensive months are January (135 EUR/MW) and August (144 EUR/MW).
- The maximum -FCR-N price occurs at the end of May with a price of 688 EUR/MW. Yet, 91% of all hours result in prices up to 10 EUR/MW.
- With average marginal prices of 1-5 EUR/MW (the annual average is 6.5 EUR/MW) in the -FCR-N market, the only two months above that range are May and June with 27 and 19 EUR/MW, respectively.

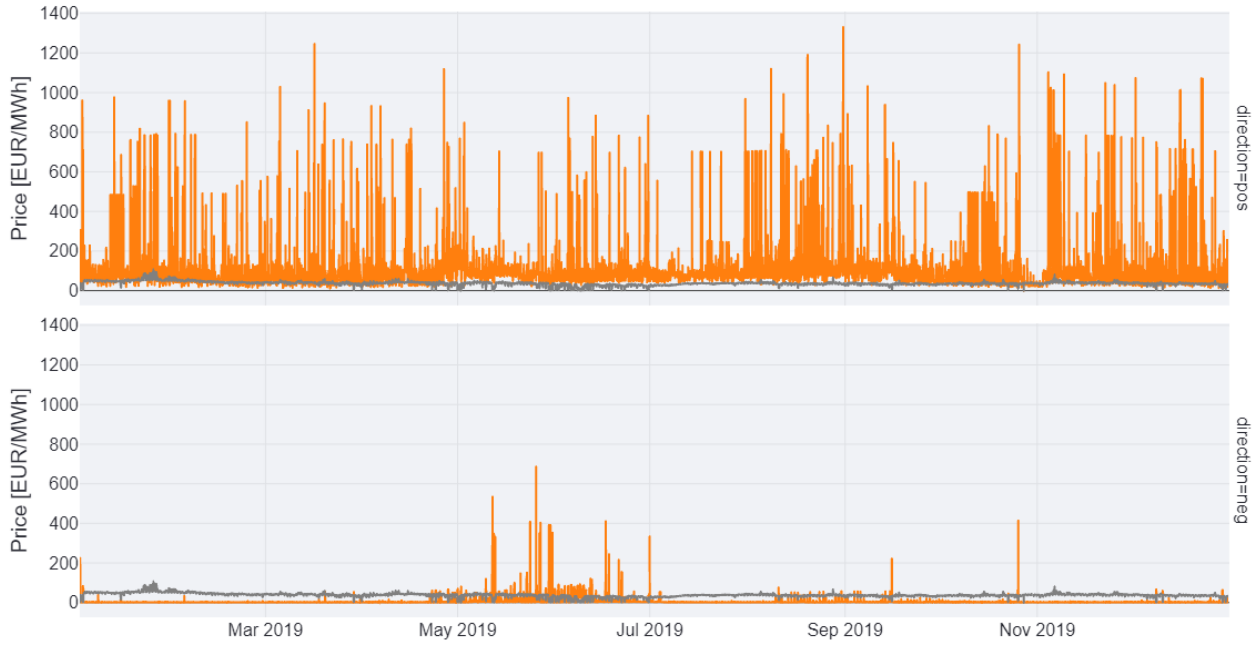


Figure 28. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3RL_hydro_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Apart from the second scenario featuring three strategic hydro agents (*3RL_hydro_2TC_new_asymm,* see below), this scenario is the only one showing an increase in total system costs compared to the symmetric market from Phase 1, which amounts to 9 Mio. EUR. Agents 2 and 3 reducing their bid volume in the +FCR-N market by shifting volume into the -FCR-N market by approximately 20%. At the same time, agent 1 (that has less volume to offer due to a smaller available capacity for each generator) keeps its share fixed. The increase in procurement costs can largely be traced back to capacity withholding:

- 10% of system costs in the +FCR-N (22 Mio. EUR) occur during hours where the emergency bidder was necessary (168 hours).
- The average hourly total bid volume in the -FCR-N is approximately four times the bid volume of the +FCR-N (1988 MW vs. 482 MW).

Scenario with three strategic bidders and two true-cost bidding new entrants *(3RL_hydro_2TC_new_asymm)*

In scenario *3TC_hydro_2TC_asymm,* in which all agents pursue a true-cost bidding strategy, it can be seen that the wind agent (agent 5) bids approximately 90% of its volume into the negative FCR-N market. This, coupled with the low bid price, heavily reduces potential profits for the hydro-based BSPs in the -FCR-N market. To maintain their profits in the *3RL_hydro_2TC_new_asymm* scenario, they fall back onto increasing prices in the positive market via capacity withholding. This means they will shift their flexibility into the -FCR-N market if technically possible – not as much to accrue profits there but rather to limit supply in the +FCR-N market. This leads to:

- a sharp increase of marginal prices in the positive market about 5% of all hours,
- low volume of hydro capacity in the positive market,

- scarcity of supply (with around 250 hours of emergency bidding in 2019) and
- a heavy influence on the wind-based agent that now covers 12% of the positive market as compared to 5% in the true-cost scenario while only covering 34% of the negative market compared to 65% in the true-cost scenario.

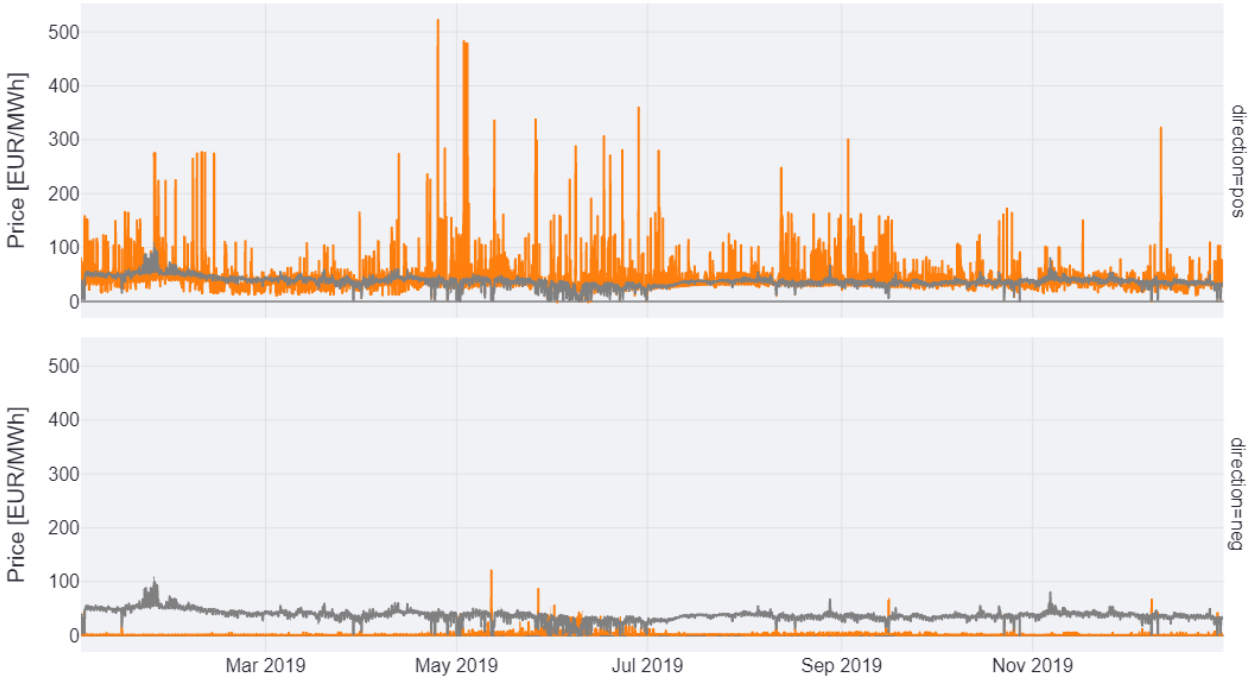


Figure 29. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3RL_hydro_2TC_new_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Comparing these results against the outcome of the previous scenario without the new entrants (*3RL_hydro_asymm*), we can see that a high price volatility is mostly avoided. Especially the introduction of the wind agent (agent 5) leads to only 1% of all prices being above 31 EUR/MW in the -FCR-N market.

Comparing +FCR-N market results (*3RL_hydro_asymm* results in parenthesis) the maximum marginal price is 524 EUR/MW (1335 EUR/MW), 3% of all hours result in a price above 113 EUR/MW (500 EUR/MW) and 90% of all marginal prices are below 62 EUR/MW (155 EUR/MW). This shows that for all occurring price levels (cheap and expensive hours), the introduction of new entrants reduces the marginal price by about 60% - 75%. The total system costs are reduced by 61%.

Scenario with three true-cost bidding hydro-based BSPs and two strategic new entrants *(3TC_hydro_2RL_new_asymm)*

With strategically bidding new entrants entering the market, and one of them (agent 5) managing a large wind portfolio, one could expect its high influence on the negative market. Nevertheless, the market still shows a decrease in total system costs due to the increased supply and competition, which can also be observed through a relatively low impact of the strategic new entrants on the marginal prices in the -FCR-N market.

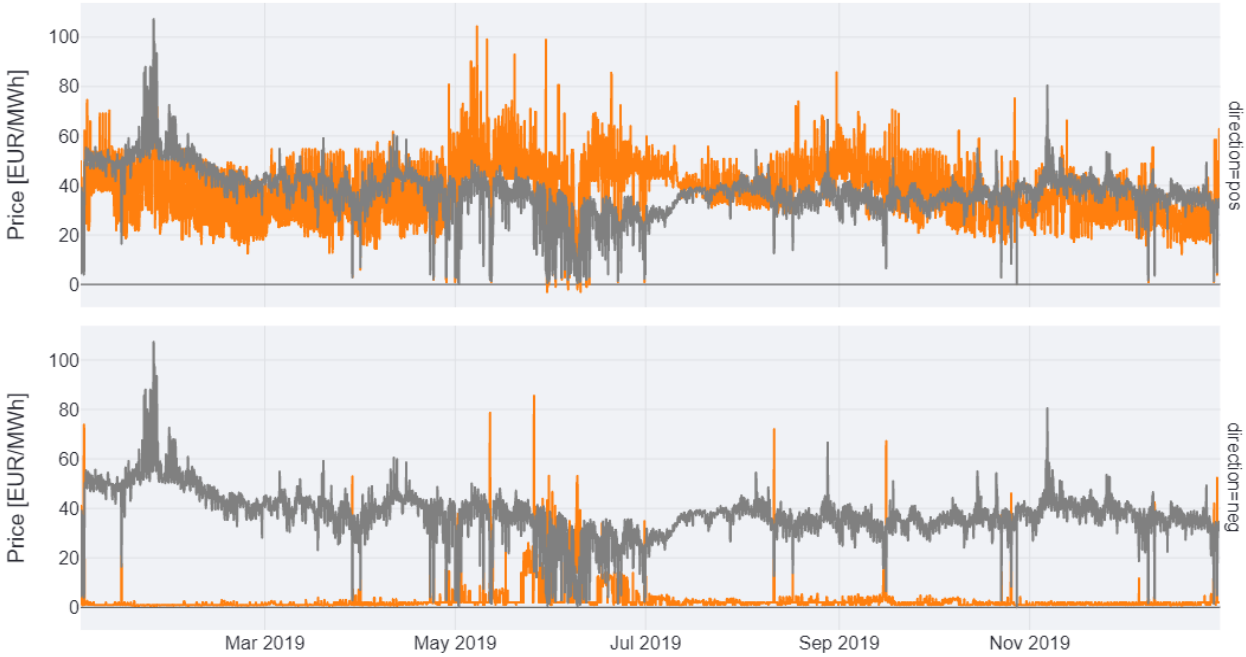


Figure 30. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 3TC_hydro_2RL_new_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Scenarios with true-cost and strategically bidding hydro-based, wind-based and storage-based BSPs *(2RL_1TC_hydro_1RL_1TC_new_asymm and 1RL_2TC_hydro_2RL_new_asymm)*

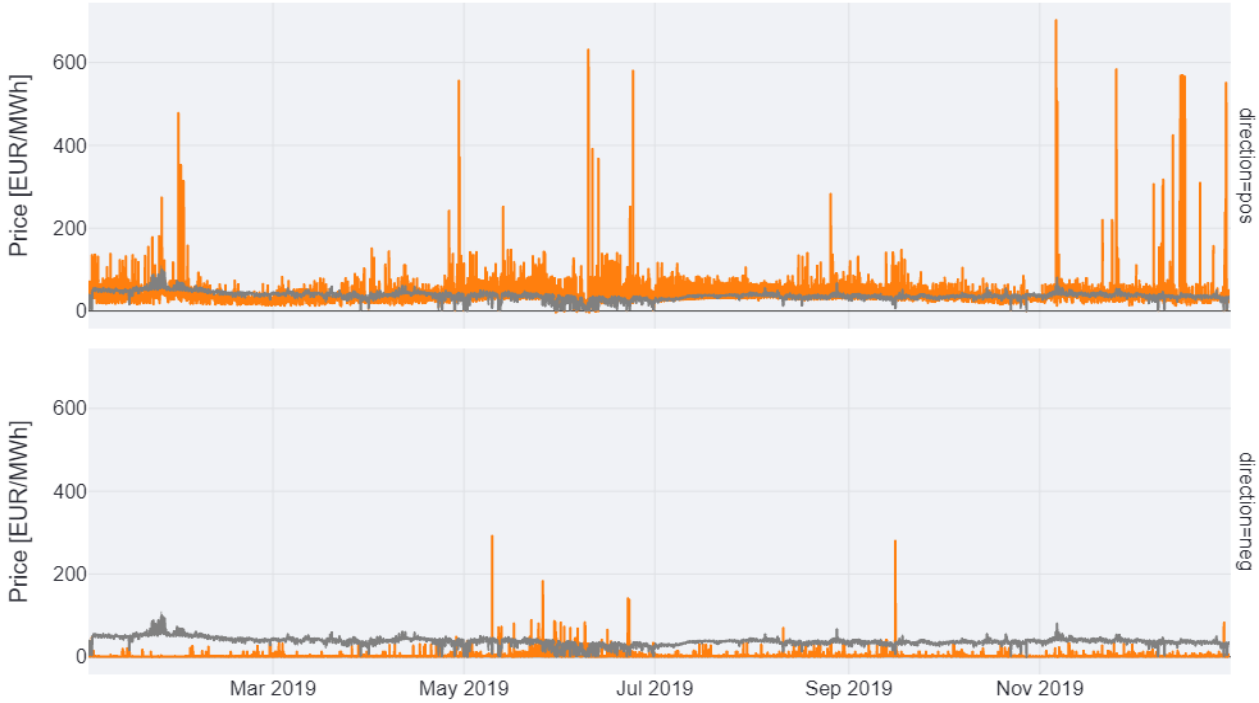


Figure 31. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 2RL_1TC_hydro_1RL_1TC_new_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Increasing the number of strategically bidding hydro BSPs again increases the volatility of marginal prices in both markets. Still, a much more stable price development can be observed, with deviations from the average price occurring often but to a less extreme extent. Compared to scenario *3TC_hydro_2RL_new_asymm,* a large difference can be seen in how stable/unstable the marginal prices in the negative market tend to be.

In contrast to the previous scenario *2RL_1TC_hydro_1RL_1TC_new_asymm,* it can be seen (in both the positive as well as in the negative market) that "removing" a strategic hydro bidder (and replacing it by its true-cost analog) and allowing the BESS to bid strategically has a "stabilizing" influence on marginal prices. Still, the market features marginal prices above 100 EUR/MW (for +FCR-N as well as -FCR-N) during some periods while any prices above 100 EUR/MW were not observed in scenario *3TC_hydro_2RL_new_asymm* (where all hydro BSPs are purely true-cost bidders).

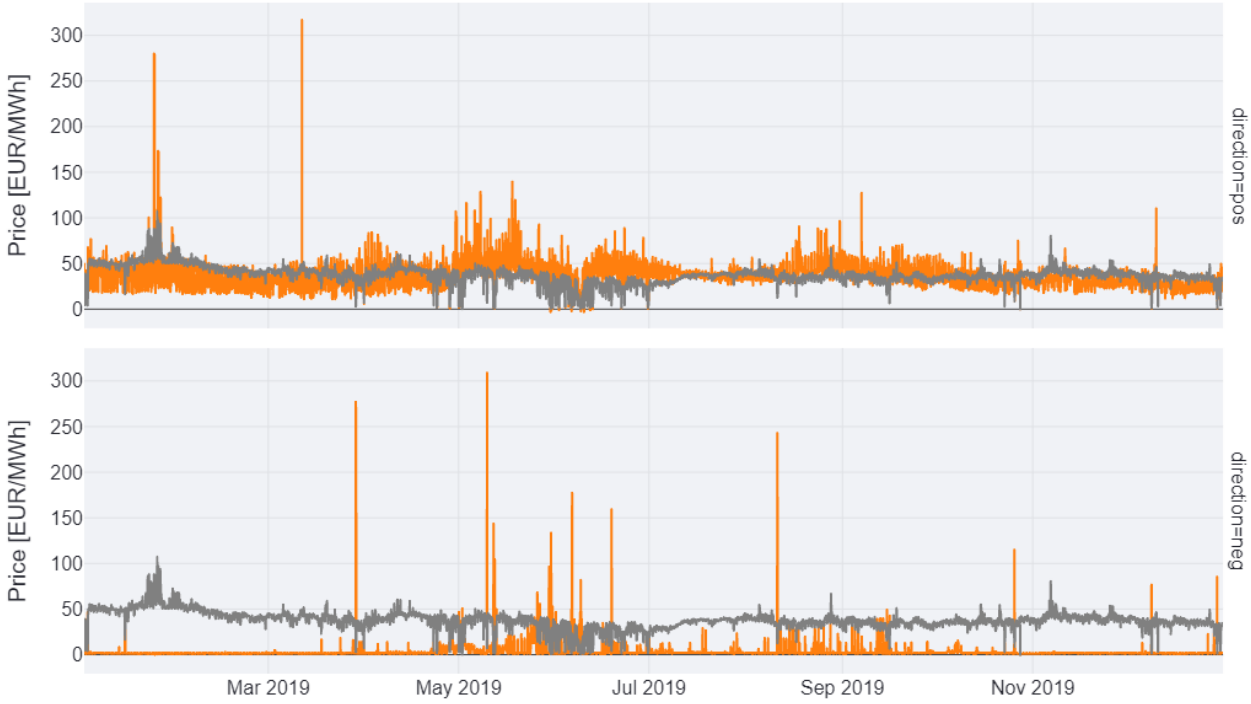


Figure 32. Modelled marginal FCR-N prices 2019 [€/MW] (orange curve) and DA market prices (grey curve) for scenario 1RL_2TC_hydro_2RL_new_asymm in the +FCR-N market (top) and -FCR-N market (bottom).

Summary: Market shares and bid allocation

Despite tangible shares of flexibility introduced in the market with the help of the wind-based and storage-based agents, the relevance of hydro-based BSPs providing the bulk of FCR-N remains significant. In terms of market shares of individual BSPs:

- Agent 1 – with an average market share of 12% (+FCR-N) and 8% (-FCR-N) over all true-cost scenarios[12] - plays a smaller role than its hydro-based counterparts – which is to be expected

[12] This always refers to "all scenarios in which this agent behaves as true-cost bidder". This can be a different set of scenarios for each agent. Only scenarios without bid linking are considered here.

considering the smaller total available capacity (approx. half of that of agent 2 or 3). It still increases its average share to 22% and 11% respectively in all strategic scenarios.

- Agent 2 has a market share of 29% in the +FCR-N and 20% in the -FCR-N market (for all scenarios in which it uses a true-cost bidding strategy) indicating a considerable market power (that can only be explained by the underlying historic bid structure and the hydrological situation of its plants). Agent 2 shows – in contrast to agent 1 – a shift to the negative market with market shares of 20% and 27% for +FCR-N and -FCR-N in the strategic scenarios. This can also be seen looking at the allocated share (between +FCR-N and -FCR-N market) that shifts from 59:41 to 34:66.
- Agent 3 – with the same available modelled FCR-N capacity as agent 2 – has an average market volume share across all true-cost scenarios of 42% in the +FCR-N market and 38% in the -FCR-N market. Similar to agent 2 it shows a shift of bid volume to the negative market from 60:40 to 32:68.
- Storage-based agent (agent 4) bids on average 45:55 (pos : neg) in the true-cost scenarios (Block 1) and does not deviate from this value by a large extent in the scenarios with RL agents. Nevertheless, it manages to increase its profits by a sizeable amount. While it barely gets awarded in the -FCR-N market (less than 5% of all hours of the year resulting in a market share below 2%), it makes up between 10% and 30% of the +FCR-N market volume and gets awarded on average 1/4 to 1/3 of all hours.
- Wind-based agent (agent 5) bids on average 6:94 (pos : neg) in the true-cost scenario (3TC_hydro_2TC_new_asymm) and shows a large shift to the +FCR-N market as soon as strategic bidding is allowed (with a +FCR-N allocated share of 16%, 22% and 26%). It does not make it forego profits: it still manages to achieve an increase of profits compared to TC scenarios by 20% - 85%. Even when the wind-based agent is allowed to bid strategically, the system costs of the -FCR-N market drop below the *3TC_hydro_asymm* benchmark case (without new entrants) – highlighting a considerable market influence of the wind agent (consider its share of market volume in -FCR-N of 29% - 43%)

Note that the change in allocated shares (BSPs shifting bid volumes from +FCR-N to FCR-N) does not immediately indicate the intention to increase profits in the -FCR-N but can (and more likely will) be induced by an attempt to reduce the overall supply in the +FCR-N market while increasing the marginal price there.

Figure 33 shows the change in market volume shares moving from a fully true-cost scenario (with new entrants) to the one where all hydro-based BSPs are behaving strategically. As highlighted in the numerical results above, agent 1 increases its market share considerably while the others stay at approximately the same overall share while shifting volume from the +FCR-N to the -FCR-N market. Agent 5 (the wind agent) losing market share and essentially being “pushed out of the market” can be traced back to its behaving in a true-cost manner.

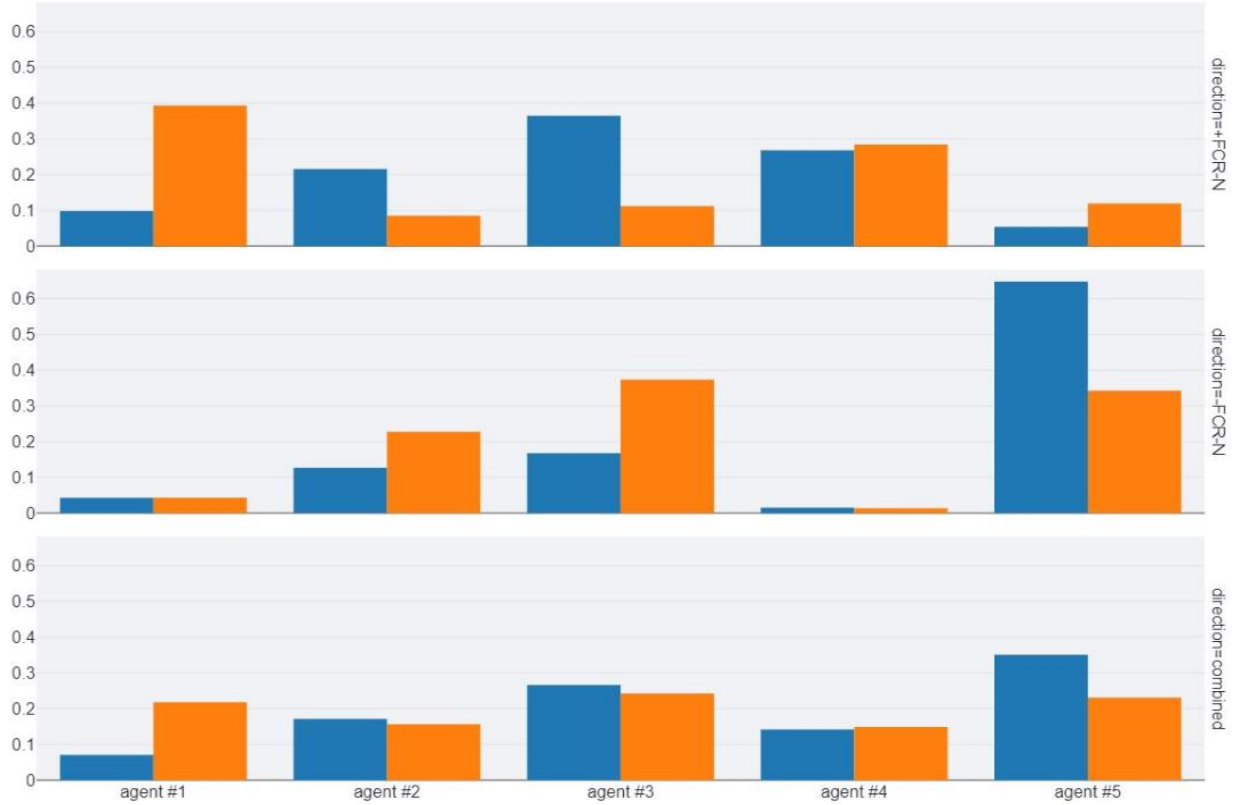


Figure 33: Market volume shares of all agents for +FCR-N (top), -FCR-N (middle) and overall market (bottom). This compares the scenarios 3TC_hydro_2TC_new_asymm (blue) and 3RL_hydro_2TC_new_asymm (orange).

5.4 Summary of results

Symmetric vs. asymmetric FCR-N product

To evaluate symmetric vs. asymmetric bidding, the results of year 2019 from project phase 1 were compared to the results of the same year in this project phase 2. As a quick overview, all scenarios are listed below, showing the total system cost (i.e. the procurement cost of the TSO, as a sum of +FCR-N and -FCR-N) and the total economic cost as an indicator of market efficiency (see Table 6).

The economic cost of a given market direction is defined as
$cost_{econ,*} := cost_{sys,*} - \sum_{i \in agents} profit_{i,*}$ for $* \in \{pos, neg\}$.

The total economic cost is then defined as sum of the economic cost for +FCR-N and -FCR-N.

By definition, and due to the assumption that agent profits are non-negative[13] the following always holds:

$$cost_{econ,*} \leq cost_{sys,*}$$

Comparing total system costs in different scenarios does not factor in that an increase in system cost could be partially or entirely be made up of an increase in agent profits. While this still means an increased cost of

[13] As they would only be negative in the case of the RL algorithm not learning correctly and losing money compared to the true-cost baseline.

clearing the market (from the TSO's perspective), it does not result in an inefficient market and a loss of welfare, but rather a redistribution. In addition comparing the change in total system costs with total agent profits may reveal economic welfare gains if the increase in agent profits is higher than the increase in system costs.

More detailed results for each scenario can be found in Sections 6.3.1 and 6.3.2.
To ease the comparison, each pair of scenarios is listed beneath one another, with the result of the scenario from phase 1 listed first and the current result (from phase 2) listed second and marked in bold while a percentage change is added after each scenario pair. The values for the scenarios in which the asymmetric market performs better are highlighted in green, whereas red values indicate a decrease in efficiency.

Table 6. Comparison of all simulated scenarios from Phase 2 with their symmetric analogs from Phase 1 in terms of overall economic efficiency.

Scenario	Total System Cost [M€]	Total Economic Cost [M€]	Total agent profit [M€]	Result
3TC_hydro_symm_mp	102.8	85.0	17,8	
3TC_hydro_asymm	92.2	76.3	15,9	
% change	-10%	-10%	-10%	**More efficient market: +10.5 Mio. Increase in cons. surplus, but only a loss of 2 Mio. in prod. surplus**
3TC_hydro_2TC_new_symm_mp	89.5	73.3	13,2	
3TC_hydro_2TC_asymm	72.1	62.7	9,4	
% change	- 20%	-14%	-28%	**Economic gain: Increase of cons. surplus (+17 Mio.), but reduction of prod. surplus (-4 Mio.)**
1RL_2TC_hydro_symm_mp	119.4	87.3	32,1	
1RL_2TC_hydro_asymm	106.5	77.9	28,6	
% change	**-11%**	**-11%**	**-13%**	**Economic gain: Increase of cons. surplus (+13 Mio.), but reduction of prod. surplus (-3.5 Mio.)**
3RL_hydro_symm_mp	226.8	101.4	125,4	
3RL_hydro_asymm	235.8	94.8	141	
% change	**+4%**	**-7%**	**+12%**	**Economic gain: Reduction of cons. surplus (-9 Mio.), but greater increase in prod. surplus (+16 Mio)**
3RL_hydro_2TC_new_symm_mp	87.2	71.9	15,3	
3RL_hydro_2TC_new_asymm	91.9	72.3	19,6	
% change	**+5%**	**+<1%**	**+28%**	**No economic change. Redistribution (~4 Mio.) from consumers to producers**
3TC_hydro_2RL_new_symm_mp	89.9	72.3	17,6	
3TC_hydro_2RL_new_asymm	81.0	65.5	15.5	
% change	**-10%**	**-10%**	**-12%**	**Economic gain: Increase of cons. surplus (+9 Mio.), but reduction of prod. surplus (-2 Mio.)**
2RL_1TC_hydro_1RL_1TC_new_symm_mp	92.7	71.5	21,2	
2RL_1TC_hydro_1RL_1TC_new_asymm	93.7	66.0	27,7	
% change	**+1%**	**-8%**	**+30%**	**Economic gain: Reduction of cons. surplus (-1 Mio.), but greater increase in prod. surplus (+ 6.5 Mio)**

Summarizing the table above, there are three out of 7 comparisons, in which the symmetric market leads to slightly higher total system (=procurement) costs. Notably, while the total system cost in the *3RL_hydro* scenario (so only three hydro-based BSPs bidding strategically without any new market entrants) is higher by approximately 4% than the result of the symmetric market, it leads to a 12% increase in agent profits, leading to a net economic benefit. The introduction of new entrants in scenario *3RL_hydro_2TC_new* – that still bid in a true cost manner while hydro BSPs can bid freely – increases system and economic costs by a small margin but lead to a 28% increase in agent profits (in particular in the positive market), which suggests mostly a redistribution from consumers to producers. A similar effect can be observed in scenario *2RL_1TC_hydro_1RL_1TC_new_asymm* in which a marginal increase in procurement costs leads to a 30% increase in agent profits. All other scenarios result in agents losing 10% - 28% of their profits. Yet, all of these scenarios show a reduction in economic costs by 10% - 14%, indicating an overall economic gain due to the increased consumer surplus outweighing the decrease of producer surplus. This indicates that a move from a symmetric to an asymmetric market design can result in a more efficient market and an overall economic gain.

In addition, the agents' proclivity to deviate from their true costs is higher in the scenarios with symmetric bidding, as is shown using the example of agent 1 on the next page:

True cost vs. strategic/free bidding

The previous summary of asymmetric vs. symmetric market design already mentioned a heavy influence of strategic bidding vs. true-cost bidding. The following table compares the two bidding strategies in a similar fashion:

Table 7. Comparison of scenarios with true-cost bidding vs. strategic bidders in terms of system costs.

Scenario	Total System Cost [M€]	Total Economic Cost [M€]
3TC_hydro_asymm	**92.2**	**76.3**
1RL_2TC_hydro_asymm	106.5	77.9
3RL_hydro_asymm	235.8	94.8
3TC_hydro_2TC_asymm	**72.1**	**62.7**
3RL_hydro_2TC_new_asymm	91.9	72.3
3TC_hydro_2RL_new_asymm	81.0	65.5
2RL_1TC_hydro_1RL_1TC_new_asymm	93.7	66.0
1RL_2TC_hydro_2RL_new_asymm	80.0	63.9

For both scenario categories, with or without new entrants, the true cost baseline scenario is highlighted in bold. It can be observed, that scenarios where all hydro BSPs bid strategically are the most expensive. The other scenarios show an increase in system cost while the total economic cost is increased by 5% at most. That suggests that as long as <u>all</u> market entrants are – in a fair way – allowed to bid in a strategic way, the system cost will rise (compared to a full true-cost scenario) but will mostly feature a shift of profits to the BSPs.

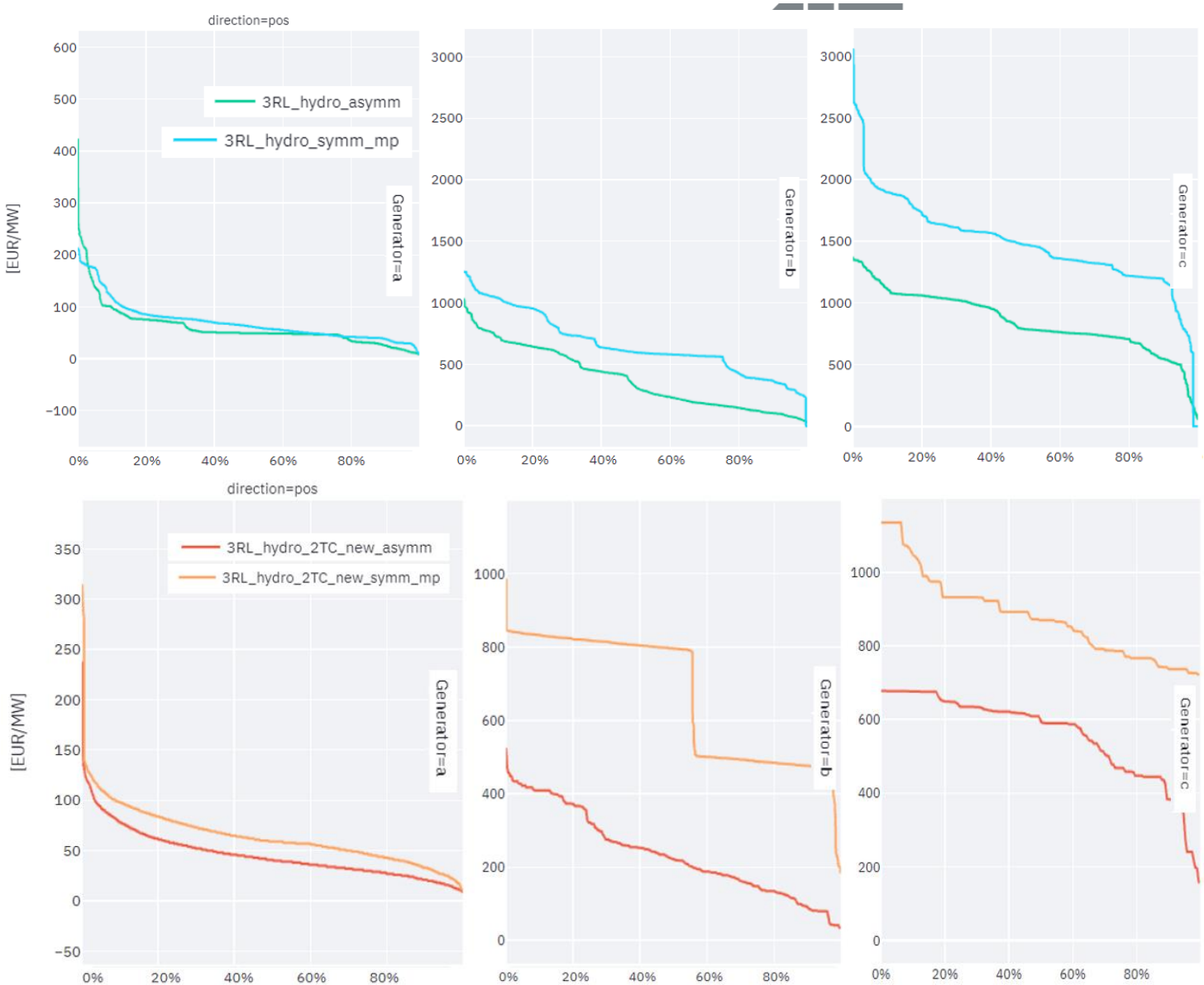


Figure 34. Comparison of bid price duration curves for generators a to c (left to right) of agent 1 in scenarios 3RL_hydro (top) and 3RL_hydro_2TC_new (bottom) in the symmetric vs. asymmetric market.

Effect of new entrants

To better quantify the effect of new entrants participating in the market, the following table can be used for comparison:

Table 8. Comparison of scenarios with and without new entrants in terms of system costs.

Scenario	Total System Cost [M€]	Total Economic Cost [M€]
3TC_hydro_asymm	**92.2**	**76.3**
3TC_hydro_2TC_asymm	72.1	62.7
3TC_hydro_2RL_new_asymm	81.0	65.5
3RL_hydro_asymm	**235.8**	**94.8**
3RL_hydro_2TC_new_asymm	91.9	72.3
1RL_2TC_hydro_asymm	**106.5**	**77.9**
1RL_2TC_hydro_2RL_new_asymm	80.0	63.9

The baseline scenario without new entrants is always marked bold. For all scenarios, the introduction of new entrants in the FCR-N market resulted in a considerable decrease of both total system as well as economic costs. This holds true for also for those scenarios where the new market entrants used strategic bidding.

Bid linking

Due to the computational complexity associated with linked bids, these were only investigated using the scenarios with true-cost bidders. Bids are linked on a per-agent basis, meaning that an agent either links all its bids during every hour or none at all. Then the performance of an agent can be compared to the one in the scenario with no bid linking. Linked bids can either be accepted in both the positive and the negative market or not be accepted in either of them. The market clearing was adapted to account for that and now minimizes total system cost of both market directions instead of minimizing each on its own. For both scenarios marked with “linked”, agent 1 links its bids while for both “linkedallhydros” scenarios, all hydro-based agents (1-3) link all their bids.

Table 9. Comparison of scenarios with and without bid linking in terms of system costs.

Scenario	Total System Cost [M€]	Total Economic Cost [M€]
3TC_hydro_asymm	**92.2**	**76.3**
3TC_hydro_asymm_linked	92.9	77.8
3TC_hydro_asymm_linkedallhydros	109.9	86.2
3TC_hydro_2TC_asymm	**72.1**	**62.7**
3TC_hydro_2TC_asymm_linked	72.7	63.8
3TC_hydro_2TC_asymm_linkedallhydros	87.6	66.8

For both scenario categories, with and without new entrants, the baseline without linked bids is highlighted. Total system costs increase for all cases of bid linking. While only a single hydro BSP linking its bids does not influence the market to a large extent, linking all hydro bids considerably increases total system costs (by 19% and 21%) while slightly increasing total economic costs – which hints at fact that the possibility of linking bids introduces the chance for hydro BSPs to generate additional profits.

Comparing an asymmetric market with linked bids against the symmetric market - which essentially is equal to linked bids with a 1:1 ratio between +FCR-N and -FCR-N markets – yields the following observations:

- The total economic cost is lower for all scenarios in an asymmetric market compared to the symmetric market.
- While the total system costs for a “hydro-only” comparison are higher in the asymmetric market with bid linking compared to the symmetric market, introducing new entrants (with wind agents particularly

benefiting from an asymmetric market design) leads to lower system costs than in the symmetric market[14].

Bid choices

The following figures can be used to analyze the way the reinforcement-learning agents modify their bids. Keep in mind, that the possible discretization of prices is in the range of 1-2 * true cost and agents can choose to bid 0, 30, 50, 70 or 100% of their volume for each generator. Due to the bid volume redistribution that prevents agents from wasting flexibility and compels them to submit the entire available volume to the FCR-N market, and the fact that each hydro BSP manages three different generators, other volume distributions are possible too. The plots below are based on the scenario *3RL_hydro_2TC_new_asymm* and show the decisions of hydro-based agent 3.

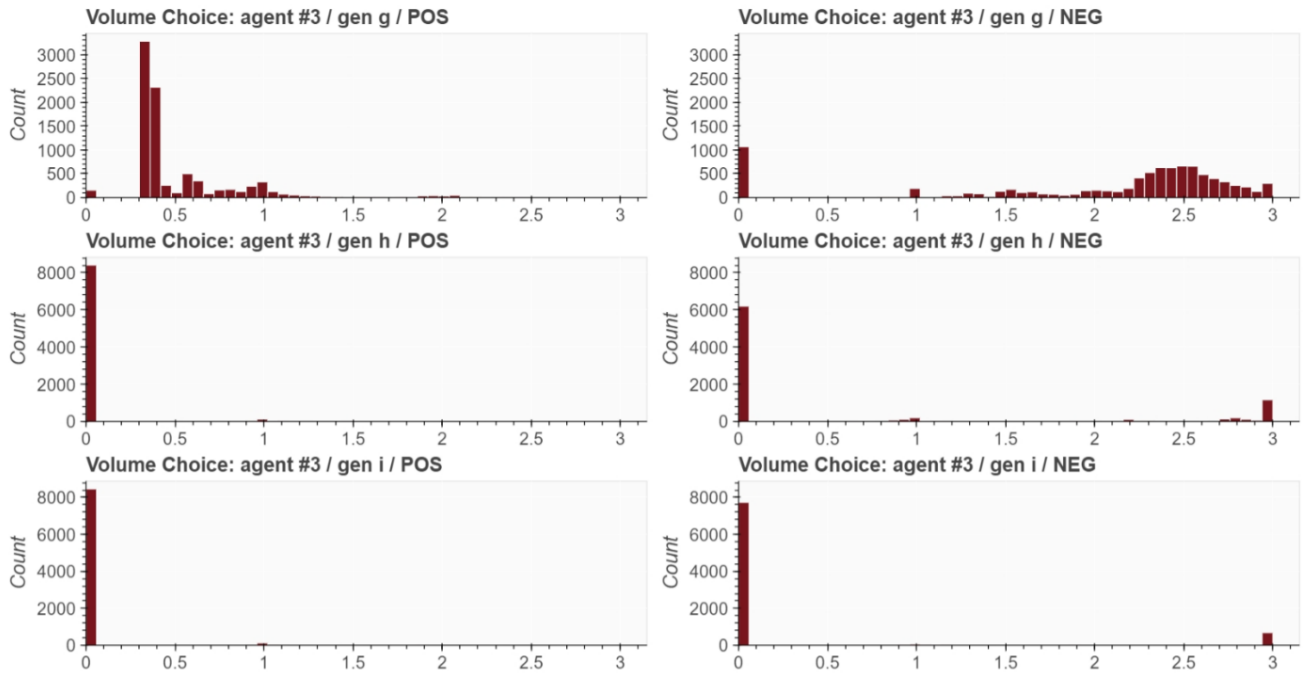


Figure 35: Volume choice in scenario 3RL_hydro_2TC_new_asymm for agent 3

Note that the figures show the bid volume of every hour expressed as multiplicative factor compared to the true cost scenario. For comparison, historical data shows that it is common for the modelled BSPs to bid volumes close to the total FCR-N demand on average:

year		**2019**	
	agent 1	agent 2	agent 3
Average hourly bid volume	217.3 MW	282.2 MW	268.4 MW

The figures show that the agent chooses not to use generator *h* and *i* in the positive market and seldomly use it in the negative market; if it uses them though, it places much more volume than in the true cost scenario (this is possible through simultaneously turning off other generators and redistributing the volume onto *h* and *i*). For all other hours it can be seen, that it bids generator *g* most of the times below half the true-cost volume

[14] Even though this comparison is not entirely "fair" since the new entrants are not linking their bids. This is, however, a good baseline for a possible market design, where new entrants are incorporated into the market, asymmetric bidding is already established but hydro BSPs are – based on the previous symmetric market – allowed and prefer to link their bids.

in the positive market and uses the rest of the volume in the negative market, with often using around 2,5 times the volume of the true cost scenario. This is underpinned by numerical values:

- In the true cost scenario, agent 3 allocates roughly a volume share of 59:41 between the positive and the negative market.
- In the *3RL_hydro_2TC_new_asymm* scenario it bids on average 24:76, a significant shift to the negative market, showing that, given a chance to bid differently, a hydro-based agent does not stick to symmetric bidding.

A similar consideration can be made for bid prices that are chosen by the agents, again show with the help of a multiplicative factor that is used by the agents to increase the true cost bid price:

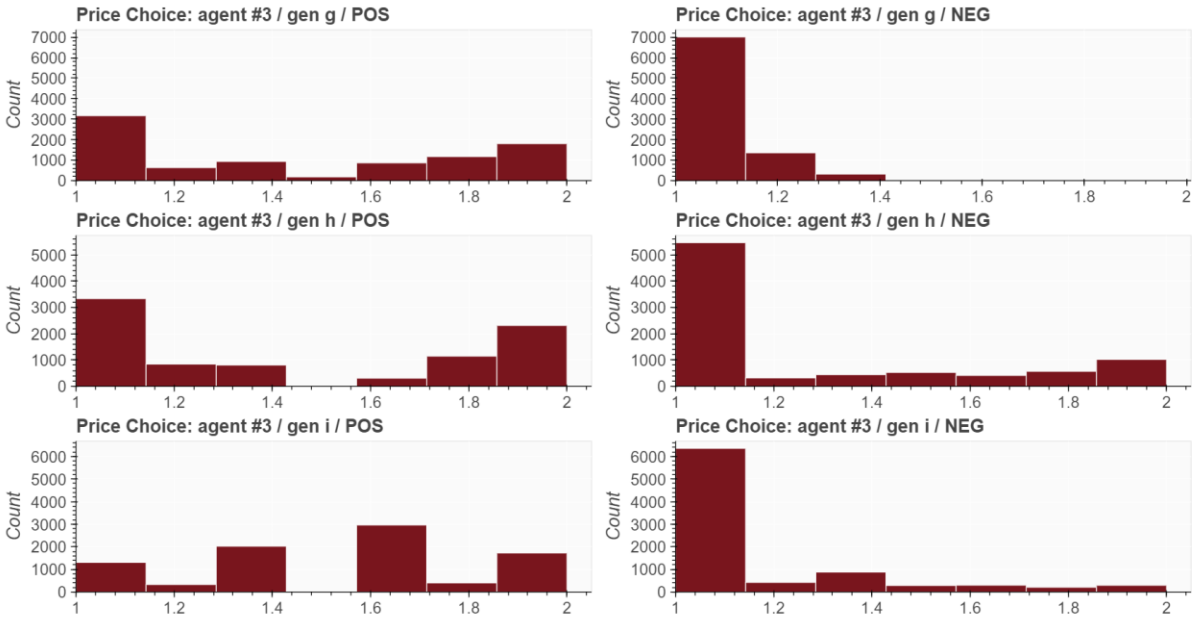


Figure 36. Price choices in scenario 3RL_hydro_2TC_new_asymm for agent 3.

Generators h and i can of course be disregarded (in the positive market), since those do not place volume into the market. It can however be observed that generator g is somewhat uniformly bid between 1x and 2x the true cost price in the positive market, whereas the price is mostly fixed to the true cost price in the negative market.

Scarcity

3RL_hydro_2TC_new_asymm is the scenario with most occurrences of scarcity hours, with 249 hours in the positive market and an average of 58 MW of missing capacity. With 65 hours in January, 24 in February, 10 in March, 24 in April, 25 in May, 12 in June, 15 in July, 28 in August, 5 in September, 16 in October, 20 in November and 5 in December, more than a quarter of all scarcity events take place in January. Apart from that, scarcity hours are somewhat evenly spread throughout the year.

With an average DA price of about 46 EUR/MWh and an average total demand of 240 MW during the hours of scarcity, these events occur (on average) during high price, high demand hours – compared to an average DA price of 38 EUR/MWh and total demand of just above 230 MW for the whole year. This is at least partially explained by lower availability of capacity for upward regulation during periods of higher DA prices (and likely production levels). Scarcity events are spread rather evenly throughout the day but with fewer occurrences between 10pm and 6am.

Table 10. Overview of shares of all hours, in which scarcity was detected, per scenario as well as the average volume shortage in the +FCR-N and -FCR-N markets.

Scenario	% scarcity +FCR-N	% scarcity -FCR-N	avg. missing volume +FCR-N	avg. missing volume -FCR-N
3TC_hydro_asymm_unlinked_mp	0	0		
1RL_2TC_hydro_asymm_unlinked_mp	0	0		
3RL_hydro_asymm_unlinked_mp	2%	1%	26,5	56,6
3TC_hydro_2TC_asymm_unlinked_mp	0	0		
3TC_hydro_2RL_new_mp	0	0		
1RL_2TC_hydro_2RL_new_asymm_unlinked_mp	0	0		
2RL_1TC_hydro_1RL_1TC_new_asymm_unlinked_mp	0.1%	1%	26,5	42,7
3RL_hydro_2TC_new_asymm_unlinked_mp	3%	0	58.4	

6 FCR-N MARKET - TRANSITION PHASE ANALYSIS

This Chapter is aimed at answering the following main question:

What concrete steps can be undertaken to ensure a smooth transition to the target design?

Under target design, we understand a balancing market design that maximizes socio-economic efficiency. In order to dilute concentrated and conservative balancing markets, competition can be increased in two ways, a) through cross-border integration and b) through encouraging the entry of more sources of flexibility, including smaller-scale ones.
Therefore, the two main drivers of efficiency improvements include:

1) measures/design adjustments improving market competition
2) market integration in the Nordic region and beyond.

Both of these drivers are taken into account in this report.

Positive results from market design changes understandably will not happen overnight. Regulatory uncertainty and adjustment of market rules, empirical evidence shows, often lead to market shocks as market actors adapt their behavior to new conditions. In this report, we conduct a comprehensive qualitative analysis of the FCR-N market design in Sweden and formulate a roadmap focusing on the process towards a more efficient and robust market design. It is meant to provide recommendations regarding specific steps Svenska kraftnät can undertake to achieve a more competitive balancing market, considering:

1. current national developments
2. planned cooperation mechanisms in the Nordic region
3. the links with other balancing products (FCR-D, aFRR and mFRR)
4. technical requirements for flexibility providers.

As a framework for analysis, the work by Poplavskaya et al. (2019) is used [27]. It describes the ways in which balancing market design variables can be prioritized to maximize efficiency. The authors argue that different design variables can augment or sometimes neutralize each other's effect and some serve as a prerequisite for the implementation of others [27], as is shown in Figure 37. The presented general hierarchy of variables refers to both the balancing capacity and balancing energy markets. It shows that:

I. As the first priority (Step 1), formal market access to all types of generation and demand needs to be guaranteed. This includes, among others, explicitly addressing relevant technologies in the national legal documents, the prequalification documents and contractual agreements (including e.g. lifting the requirement to obtain a BRP's or a supplier's permission in case of an aggregator or a demand response provider)

II. The two main design variables that were identified as crucial for implementation in Step 2 based on the number of other variables dependent on them, are flexible pooling options and procuring balancing capacity and energy separately from each other in two auctions. Flexible pooling options would not only allow in particular smaller BSPs to jointly fulfill the prequalification requirements more easily. This would also help them comply with the minimum bid requirements and ensure delivery even if the frequency of bidding or the product duration is relatively high. Note that, since the second decision variable is irrelevant for the Swedish FCR-N market, it is disregarded in the remainder of the text.

III. In the third step, more detailed design variables, such as the length of the contracting period, product duration and bid symmetry requirement can be adjusted. All these measures combined are meant to ensure that higher levels of competition are enabled in the balancing market.

IV. The last condition, i.e. sufficient levels of competition, are deemed crucial prior to adjusting the pricing rule from pay-as-bid to marginal. Both qualitative analyses and multiple simulation results (including those from Phase 1 of the project) have shown that, in concentrated markets, the application of marginal pricing can produce the opposite of the desired effect, leading to much higher market prices and system costs.

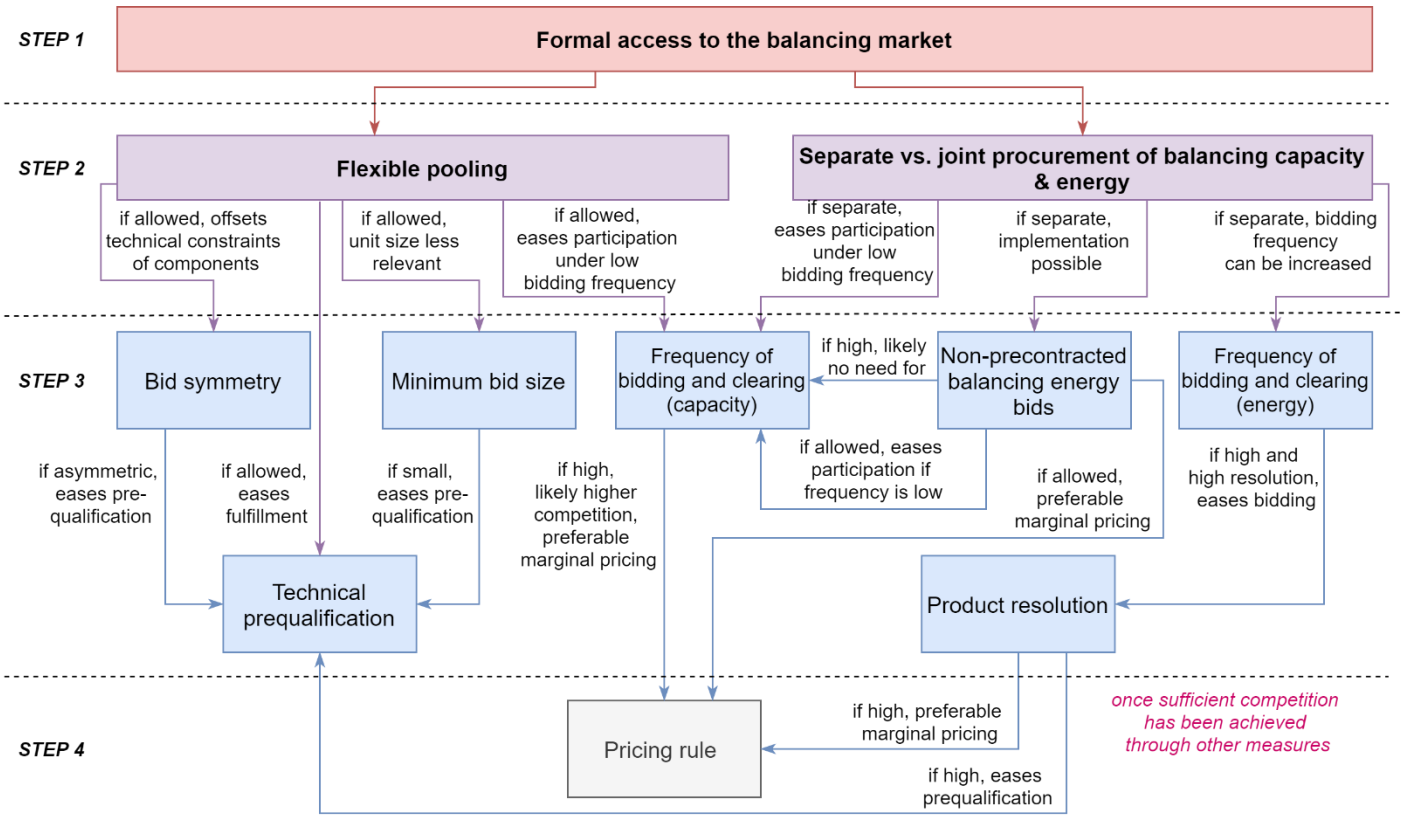


Figure 37. Dependencies among balancing market decision variables and their four-step prioritization (based on [27]).

In sum, this shows that while the Electricity Balancing Guideline (EBGL) has already foreseen multiple improvements to the market design aimed at ensuring a level playing field for different technologies, the pathway towards the multiple changes remains unspecified. As a result, TSOs across the EU follow different implementation paths prioritizing different sets of design variables on the way. This may have a detrimental effect on the harmonization efforts and the speed of market changes but also produce skewed incentives for market actors, especially those operating in several countries.

It is therefore important to understand what the transition from the present situation to the target model can look like and how it can be smoothed.

6.1 Nordic Balancing Model

The Nordic Balancing Model (NBM) is the product of the collaboration of the Nordic TSOs, Svenska kraftnät, Statnett, Energinet and Fingrid. It is aimed at strengthening the existing cooperation in the Nordic region while facilitating energy transition, increasing economic welfare benefits and improving electricity network stability [1]. Furthermore, the NBM includes a roadmap of design adjustments to aFRR and mFRR markets in preparation for the accession to the European balancing platforms PICASSO (for aFRR) and MARI (for mFRR), as is shown in Figure 38.

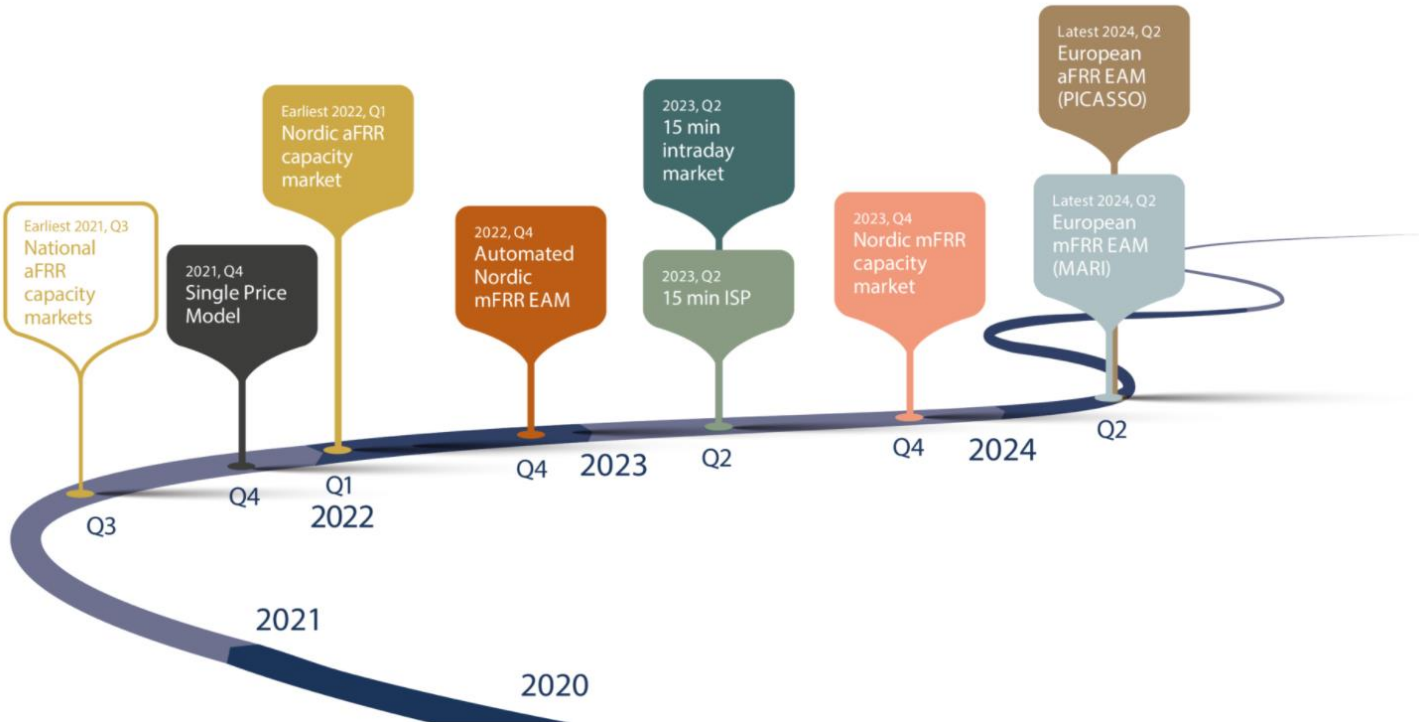


Figure.38. Nordic Balancing Market - Roadmap (Source: NBM 2020)

Although the NBM Roadmap is not directly concerned with the FCR-N market, several planned changes are bound to affect market actors in the FCR-N market indirectly:

- **Update of national aFRR capacity markets (planned Q3 2021):** Based on the technical product requirements, far from all BSPs can necessarily reserve both FCR and aFRR. However, given the Swedish technological landscape, it is safe to say that hydro reservoir plants are well-positioned to offer both services. Such BSPs then face additional opportunity costs from this commercialization opportunity. The exact effect will depend on the adjusted gate closure times (GCTs) of the two markets. It can then affect 1) prices in the two markets; 2) availability of capacity in them. Generally, FCR prices tend to be higher than aFRR capacity prices while at the same time the energy volume activated for aFRR is higher[15]. Providers that are not incentivized to get activated often are more likely to bid in the FCR market, this is, for instance, a common case for battery storage. Further links between the two products are addressed in Section 6.5.
- **Introduction of a Nordic aFRR capacity market (planned Q1 2022):** This change is likely to be highly beneficial in terms of increasing the pool of eligible providers. This might increase the incentive to prefer the FCR-N market to the aFRR market as long as it is not internationalized. However, based

[15] Note that as of July 2021, FCR-N and aFRR energy is reimbursed at the same price derived from the mFRR energy market.

on the information about the NBM and the planned update of the coupled FCR-N market in SE price zones and DK2 at the beginning of 2022, the two processes will run in parallel, which makes the estimation of the net result more complicated.

- **Introduction of a 15-minute imbalance settlement period (ISP) (planned Q2 2023):** The shortening of the ISP is aligned with the harmonization requirements of the EBGL. Coupled with shorter products traded in the wholesale markets, it allows market actors to better tackle their schedule deviations. Shortening of the ISP would not necessarily require a reduction of the product duration in the FCR-N market but is relevant for market price definition (if a whole hour or 15-minute periods are considered) or requirements for activation duration (see also Chapter 5).

6.2 Current national development and planned cooperation mechanisms in the Nordic region

Beyond the NBM, Svenska kraftnät has been engaged in a number of national market design adaptations and cooperation mechanisms.

Beginning of 2021, a stakeholder survey on the future development of the market model for the Nordic balancing products was conducted by Svk and Fingrid [2]. It compared a number of market design variables in the Swedish and Finnish markets and provided stakeholders with a chance to submit their positions.

In April 2021, Energinet and Svenska kraftnät made a proposal for exchange of Frequency Containment Reserve Normal and Disturbance [3]. Based on the consultation, the Swedish and Danish TSOs have proposed a common updated FCR-N and FCR-D[16] market for the two countries (DK2 as part of the Nordic synchronous area for Denmark) to be implemented beginning of 2022. The following characteristics have been proposed:

- D-2/D-1 procurement auction setup is proposed to be changed in terms of gate closure times (GCTs) or converted to a single auction in D-1 timeframe with gate closure at 6pm a day before delivery:
- *"1 - First auction: gate closure 00:30 D-1, second auction: gate closure 18:00 D-1*
- *2 - First auction: gate closure 05:30 D-1, second auction: gate closure 18:00 D-1*
- *3 - First auction: gate closure 07:30 D-1, second auction: gate closure 18:00 D-1*
- *4 – Single auction: gate closure 18:00 D-1 This alternative proposes to have a single auction with the gate closure at 18:00 CET D-1."* [3].
  - Single as well as block bids are allowed with a market time unit (MTU) of 60 minutes with indivisible bids of minimum 0.1 MW (for FCR-N as well as for FCR-D), and thus harmonized in SE1-4 and DK2 (currently 0.3 MW in DK2).
  - Portfolio bidding (within the same bidding zone) is allowed: "*Capacity bids are placed using "portfolio-bidding" during the auction phase, e.g. the provider of FCR capacity does not have to define which physical assets that will be providing FCR capacity during the MTU of delivery"* [3].
  - In the common market, free bidding is foreseen, i.e. no specific cost methodologies ('no price regulation')
  - Pay-as-bid pricing is planned to be kept for the time being
  - Awarding based on a common merit order, respecting minimum volume requirements per control area

[16] Svenska kraftnät currently uses the FCR-D Up product (i.e. increase of generation or load reduction). FCR-D Down is planned to be introduced, in addition to the currently used FCR-D Up. The main difference between FCR-N and FCR-D mainly lies in procured volumes (600 MW vs some 1450 MW in the Nordics) and activation where FCR-N asymmetric yields about 20x more energy compared to that of FCR-D.

- The common market for FCR-N is planned to remain symmetric based on the current technical product requirements.

In addition, Svenska kraftnät is committed to the Nordic coordination process for adjusting the FCR-N market, market harmonization and integration. In this vein, it was engaged in the common FCP project (Revision of the Frequency Containment Reserve)[17], during which the Nordic TSOs reviewed and harmonized the technical requirements for FCR-N, including prequalification requirements, in order to improve the frequency quality in the region. On the market design side, there are still large differences between the Nordic TSO (see e.g. the comparison between balancing product procurements by Svenska kraftnät and Fingrid in the consultation mentioned above [2]). These, however, are expected to be streamlined in the future to facilitate a progressive market integration, which, besides attracting new participants and technologies to the market, is yet another measure able to increase the pool of available flexibility and thus increase competition. Specifically for Sweden, Nordic market integration is also beneficial for 'diluting' currently fairly homogenous technological landscape. For instance, in Denmark, about 3GW of gas-fired generation and more than 4 GW of wind generation are installed and many of these assets are providing balancing. This is a welcome complement of the existing Nordic arrangement, under which up to a third of FCR-N balancing capacity can be exchanged among the Nordic TSOs.

Some of the results of the two consultations are included in Section 6.4 and 6.5, in which we zoom in on individual market design variables and the links between different balancing products.

6.3 Analysis of the technical and prequalification criteria

The planned changes of the Swedish FCR-N market design pave the way for a broader spectrum of technologies and types of balancing resources. Currently, this market allows only symmetric bids and is dominated by hydropower plants. Formally, the market has been open to other technologies, yet the technical requirements and market rules did not necessarily facilitate their actual entry. In the near future, it is planned to adjust the market and its requirements in order to encourage the participation of demand response, wind turbines, storage systems and other energy sources that typically interface with the grid via power electronics.

In this chapter, we analyze the current prequalification criteria for the Swedish FCR-N market, identify factors limiting the potential for the participation of new balancing resources[18] and to provide recommendations for the technical requirements to new flexibility resources based on the new market design. While this chapter focuses mainly on the FCR-N product, a holistic approach considering all frequency-related products is needed considering that their functionalities can overlap and their needs are correlated. For instance, fast frequency response can reduce the need for FCR-N whereas stringent requirements on a product might relax the requirements for another product.

The prequalification and technical product requirements play a crucial role in enabling effective participation of new balancing resources following formal access to the market (see Figure 37). These include a number of characteristics such as activation duration and pooling possibilities, as discussed below.

[17] https://www.svk.se/en/sidor-som-inte-visas-i-meny/nordic-common-project-for-review-of-primary-reserve-requirements/

[18] Similar to the rest of the project, in this analysis we focus on the participation of wind generation and battery storage. However, the recommendations provided here are without prejudice to other new sources of flexibility such as demand response.

6.3.1 General considerations

Ramping time - 63 % after 60 s and 100 % after 3 min [4]

The current requirements of the ramping time are not limiting new technologies from entering the market. Devices which have power-electronic-based inverters like BESS and PVs can react within less than 1s to setpoint changes [5]. Wind turbines can fully ramp up or ramp down in under 10s [6]. For comparison, in Austria [7], Germany [8], France [9], and Belgium [10] after 30s 100 % of the bid power must be available. This is comparable to FCR-D in Sweden, which has the same requirements to the ramping time. It is important to remark that other TSOs set the criterion at 95% instead of the 63%. The latter value in the current requirements seems to assume a linear response from a power plant, similar to a first-order system. However, the requirement of the 63% of the response is not very meaningful for novel technologies. In that sense we believe having a criterion on the 95% is a better choice, since Inverter-based sources will not behave like first-order systems.

It is recommended to define time requirements for values closer to 95% rather than 63%, since it properly characterizes the behavior of the asset for grid stability analysis. In fact, it is common in power electronics to specify desired ramp rates directly.

Activation Duration - 60 min [4]

In the worst case, the bid power must be activated during an entire product period of 60 min. For power plants which have been typically providing FCR-N like reservoir and thermal power plants this condition is not constraining because of their vast capacity[19] [11]. However, for technologies with limited capacity like BESS, the maximum activation duration substantially influences the feasibility of service provisions. It may, for instance, require flexibility providers to bundle multiple storage systems in an overdimensioned pool, which further affects the profitability for trading on this market [12]. In some other EU countries, special conditions for storage systems with limited capacities exist. Popular criteria are the 15 min or 30 min criteria, which means that it must be guaranteed that the devices can deliver the full bid power for a period 15 min or 30 min [13]. A more detailed explanation will be given in Section Current barriers for the participation of battery storage in the FCR-N market. Commission regulations of the European Union address units with limited energy resources in article 156.8 “A FCR providing unit or FCR providing group with an energy reservoir that limits its capability to provide FCR shall activate its FCR for as long as the frequency deviation persists, unless its energy reservoir is exhausted in either the positive or negative direction” [14]. Nevertheless, the regulations for FCR are usually stricter in the EU and restrictions on the minimum activation duration are demanded.

Smaller activation time requirements in combination with small minimum bid size requirements are likely to improve feasibility of service provision of storage systems, encourage sector coupling (thermal, transportation) and promote consumer participation. As shown in [13], reducing the activation duration to a 30 min criterion should not have an effect on other balancing products in the Nordics.

Product Length – 1h [4]

Product length of 1h gives bidders a possibility to participate with one device on the same day in multiple energy markets. This is also the case when the technologies have comparatively small rated active powers and capacities. Depending on the opportunity costs, a BSP can flexibly decide in which hour to participate in

[19] ‘Capacity’ in this context refers to the maximum energy which can be stored. For instance, a BESS can have a nominal capacity of 1 MWh but has, for example, currently only 0.3 MWh energy stored.

which markets. For comparison, the trend in central Europe is to go from weekly transaction (common until 30 June 2019), to hourly auctions (from 1 July 2019 to 30 June 2020) to 6 independent 4h products per (from 1 July 2020) [14].

The currently applied product length enables planning of service provision even for smaller-scale flexible resources and flexible assignment of flexibility to multiple markets. It is further aligned with the requirements to balancing products stipulated in the EBGL. A shorter product length can be considered in the future, following the change of the ISP from 60 to 15 minutes (see Figure 38), as supported by the public consultation and the stakeholder engagement survey.

Minimum bid size – 0.1 MW [4]

With a minimum bid size and a bid step size of 0.1 MW each, it is possible even for devices with small nominal power ratings to participate in the FCR-N market. This is also aligned with the minimum bid sizes for the day-ahead and intraday energy markets [15], which allows providers to maximize the interoperability of their available flexibility. For the sake of comparison, in Austria, Belgium, Germany, France, Netherlands, and Switzerland, the minimum bid size and step size of the bids are 1 MW for FCR [14], which excludes many smaller systems, which are not aggregated.

The currently applied minimum bid size represents an EU-wide best practice and enables participation of even small-scale resources (e.g. consumer flexibility such as EVs if pooled).

Pooling – Allowed within the same bidding zone

Currently, the BRP can pool more units into one group and prequalify it as a whole. Furthermore, as part of the “dynamic prequalification’, it is allowed to add more units to the same group given that the attributes of the new resources are similar to those of the original group. Further specifics of resource aggregation are under discussion in the Nordics. In general terms, the TSOs agreed to aim at allowing flexibility that is possible without endangering the general purpose and the technical requirements.

Due to the small minimum bid size applied to the FCR-N product, the market is already open for many technologies and assets with smaller active power ratings. Nevertheless, allowing flexible pooling of resources (in particular batteries with limited capacities and other small-scale units) is needed to a larger extent if the product activation duration remains unchanged. For wind turbines pooling is essential to allow their operators to offset forecast errors more efficiently – either by adding more turbines to the pool or by coupling it with other supporting technologies [12]. When prequalifying multiple devices for FCR-N in a pool, prequalifying each device individually would result in much additional work for both the TSO and the operator of the flexible resources which should provide balancing services.

One possible solution to reduce the effort for prequalifying a pool is to only prequalify one device of each device type, which should be pooled [16]. For example, when having a pool with 10 batteries of type *A*, 5 batteries of type *B*, and 5 wind turbines of type *C*, it could be possible to have only a detailed prequalification for one device of each type (A, B, and C). Furthermore, introducing a reduced prequalification process for device types which have already been prequalified in another pool would also simplify the prequalification process for the TSO and the balancing service provider.

Flexible pooling options include not only harmonized prequalification of similar technologies but also allowing BSPs decide on the pool size, location of the units in the pool (i.e. not necessarily in close geographical proximity) and the technologies included in the pool, be those supply or demand-side resources. This also represents the current EU best practice, where in a number of countries .e.g. Germany, Belgium and France,

pools of different technologies on the supply and/or the demand side are allowed to provide balancing services.

Flexible pooling is one of the essential design components after formal market access that enables a broader participation of new balancing technologies (see Figure 37 and Figure 45). It is recommended to allow pooling across bidding zones while prequalification of the entire pool (e.g. batch prequalification based on technology class) is likely to save substantial administrative costs to the TSO and the BSPs once more small-scale resources enter the market.

Degrees of Freedom – Partly

In Germany, additional degrees of freedom (DoF) are allowed for the provision of FCR services [8]. They allow the following freedoms:

- Balancing resources must ramp up not slower than linearly within 30s when the full reserve is requested. Additionally, the items *may* ramp up faster than the prescribed 30s.
- An *over-fulfillment* of the requested balancing energy of 120% of the requested power is *allowed*. Underfulfillment is *not* allowed.
- In the deadband (± 10 mHz frequency deviation) balancing power does not need to be provided. However, the service *can* be provided.

These DoFs can be used to operate the devices which provide FCR more optimally from the technical point of view. For example, the DoFs can be used, for example, to better manage the state of charge (SoC) of a battery as described in [17]. Figure 39 shows the current degrees of freedom in Germany, where full balancing power has to be provided at ± 200 mHz.

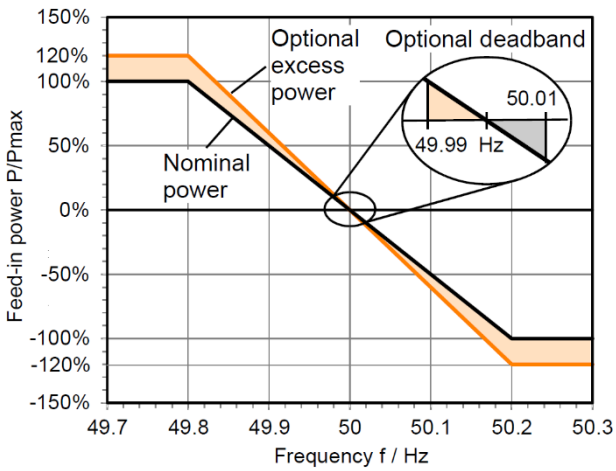


Figure 39: Degrees of Freedom in Germany [17]

In the current prequalification criteria of Sweden, some DoFs already exist. The minimum ramp-up rate is specified, however, no maximum limits are stated for FCR-N. At the same time, it is already possible to ramp up faster than necessary. Furthermore, a minimum requirement for the activated energy within the first 60 s after a frequency deviation are defined [18].This requirement can be used as a freedom to provide more energy in this time than needed. Overfulfillment of the requested power, however, is currently not allowed. Deviations to this requirement are allowed under the following circumstances: “uncertainties in the response, natural variations in production/consumption, or due to fixed step sizes of the resources connected to the relay.” [18]. Under these circumstances, depending on the frequency deviation, 95 % under- or 105 % overfulfillment are allowed.

It might be advisable to include additional DoFs into the prequalification criteria to enable more efficient operation of highly flexible units. Nonetheless, stability analysis is essential before introducing new DoFs since these new possibilities imply time-varying droop coefficients in the Nordic grid.

Asymmetric – No, but being considered

Sweden would be one of the first countries which will open their FCR-N market for asymmetric bidding. Among other EU countries, only France and Denmark (DK1) have asymmetric FCR products [18]. Currently, the prequalification for FCR-N is done symmetrically for upward and downward regulation.

For many technologies, the provision of symmetric power is limiting and does not reflect the constraints and properties of new balancing resources. For example, for wind turbines and PV, the provision of downward reserve does not compromise the normal operation of the devices because they usually produce with the currently maximum possible power and can curtail their production when downward reserves are needed [5]. However, for providing upward flexibility, they must be operated with a non-optimal setpoint, which results in an unused potential creating additional opportunity costs.

Figure 40 shows how these changes can make a more economical use of balancing resources. For example, symmetric bidding in the FCR-N market might be uneconomical because it is operated with a fraction of its possible power output and the opportunity costs may speak against a participation in the FCR-N market (in particular if lower prices are expected). However, when it only provides downward flexibility, it can generate at its maximum possible power and only reduces its power output when downward flexibility is needed so support the grid.

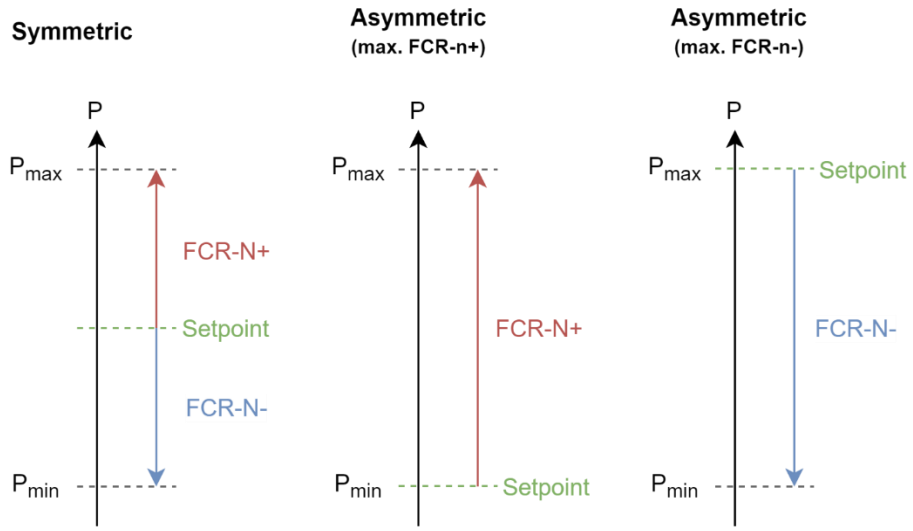


Figure 40: Asymmetric Bidding

Furthermore, asymmetric bidding supports multimodal operation of devices participating in the FCR-N market. For example, for peak-shaving with a BESS, a charged battery is needed to compensate load peaks. Negative FCR-N (in case of overfrequency) requires a low SoC such that the BESS can absorb energy when needed, which contradicts the peak-shaving operation mode. However, positive FCR-N has the same prerequisites as peak-shaving from the SoC point of view. Therefore, depending on the direction for providing balancing, synergies with other operation modes can be exploited [19].

Due to standby-losses, losses of the inverter, and the chemical processes in a BESS, the SoC of a storage tends to decrease over time when providing FCR-N symmetrically[20] [11]. Even though having statistically nearly symmetric frequency deviations, due to inevitable losses, the battery tends to discharge over time. By allowing asymmetric bidding, a BESS operator can bid in a way to best compensate the losses of the system. This can be done by bidding a slightly larger volume upwards than downwards.

Allowing asymmetric bidding of balancing resources will allow certain technologies to participate in the FCR-N market with both a larger volume (at least in one direction) and in a more economically efficient manner (as was also illustrated with the help of the simulation results). The crucial prerequisite is asymmetric prequalification, which would remove the obligation to prequalify capacity 50/50 for upward and downward regulation. Instead, a total volume of flexibility fulfilling balancing requirements can be prequalified to be later activated in either direction or a both direction in not necessarily equal parts. This approach would allow BSPs to better account for the technical and operational constraints of their units and maximize the amount of flexibility provided for FCR-N.

Streamlining prequalification process

The prequalification process for the FCR-N product currently takes up to 21 weeks for a single balancing item when assuming that all stages are passed in the first time [20]. In the case of pooled devices, it might be necessary and beneficial to streamline this to reduce the entry burden for aggregated devices. Applying the process to each individual device separately would result in cumbersome redundancy for both the TSO and the balancing resource operator.

For the exchange of data for the verification of the correct operation of the devices, industry standard interfaces and protocols should be used to avoid the effort for implementing non-standard or 'exotic' solutions [21].

A cumbersome prequalification process has been shown to be one of the major deterrents for the participation of new market entrants and technologies. It is recommended to shorten and streamline the prequalification process by providing clear harmonized procedures for all types of resources as all as by-category grouping of resources in case of a pool prequalification.

Other remarks related to prequalification requirements

- The current documents on technical requirements describe ways to analyze the stability of a power plant based on the so-called Nyquist criterion. We believe there are at present more accurate methods to properly assess plant stability, that with current computational methods do not represent any extra effort (e.g., sensitivity peaks, eigenvalues)
- It is becoming popular to specify the time periods where certain asset is expected to provide a product [22], typically a few days or even one week ahead, based on the expected amount of inertia. In this way, a unit does not need to stay 'on hold' for the entire period. That is, even when the asset is getting remunerated for a certain product, there is no need to provide that service at all times, hence the asset can serve other needs. Given the available capabilities of the Nordic TSOs in terms of inertia estimation, it seems appropriate to fully leverage this to allow for

[20] The standby-losses are rather small and can be (depending on the use case) be neglected. However, the efficiency of the inverter and the storage is around 90 % when charging/discharging close to nominal power. When delivering small power in comparison to the nominal power, the efficiency can go down to e.g. 40 %. This has the effect that the BESS discharges over time also when having symmetrical frequency deviations. Consider the following example: BESS with a capacity of 1 MWh and an SoC of 50 %. Let's assume an efficiency of 90 %. First, it is charged with 0.5 MWh on the AC-side of the converter → ΔSOC = (0.5 MWh * 90 %) / 1 MWh = 0.45 → SOC = 95 %. Then, it is discharged with the same energy (AC-side): ΔSOC = (-0.5 MWh / 90 %) / 1 MWh = -56 %; SOC = 95 % - 56 % = 39 %. As a result, the battery lost 11 % SOC due to symmetrical activations

multimodal operation of certain assets. To the best of our understanding, this is already implemented in the Nordics for the FFR product. This can be extended to other products since the grid is becoming more time-varying and worst-case estimations of reserves can be too conservative.

- At low inertia values, not only is the amount of frequency support relevant but also the location, to avoid issues related to angle stability. An adequate geographical distribution might be desired, to the point that there might be requirements per region rather than at the country level. These are additional constraints that need to be considered, including transmission network congestion.
- Technology-agnostic vs. technology-specific requirements: The definition of technology-specific requirements can pose one concern: given that the characteristics of each source might be dynamically different, grid planning and operation need to monitor the current mix of the units providing FCR-N and account for it. Therefore, we suggest technology-agnostic requirements, that at the same time are friendly enough to welcome the participation of novel technologies. For instance, it has been mentioned how long duration times of FCR-N might restrict storage units from offering this product.
- Nonetheless, while we support such technology-agnostic requirements, a new paradigm in the definition and analysis of frequency response might be needed to accommodate for new technologies. An intrinsic characteristic of novel technologies such as wind or solar is their stochasticity, where the availability of the power source is not guaranteed, especially since forecasts (as of today) are not precise enough. In order to open these products to stochastic sources, it is necessary to accommodate in grid stability studies for this uncertain nature and allow for probabilistic guarantees.

6.3.2 Current barriers for the participation of battery storage in the FCR-N market

The advantages of BESSs are their fast reaction time and versatility. Due to their limited capacities, long activation periods are their main barrier when providing FCR(-N)[21].

Capacity prequalified FCR-power ratio

For storage systems with limited capacities, two criteria have emerged in the EU for defining the minimum ratio between their capacity and their active power to be qualified for FCR: the 15 min and 30 min criteria. With the 15 min criterion, the system must be able to provide the full power for at least 15 min in both directions (injecting and absorbing energy). This results in a minimum ratio of nominal energy capacity E_{nom} to power used for FCR-N P_{FCR} of $E_{\mathrm{nom}}/P_{\mathrm{FCR}} = 0.5\ \mathrm{h}$. For the 30 min criterion, the storage system has to be dimensioned such that it can provide the prequalified power for at least 30 min which is a ratio of $E_{\mathrm{nom}}/P_{\mathrm{FCR}} = 1.0\ \mathrm{h}$.

Both criteria have advantages and disadvantages. On the one hand, the 15 min criterion allows storage operators to reserve less capacity for FCR-N, which opens the market for devices which would not be able to participate otherwise. On the other hand, it presents certain risk for the TSO. In the case of long frequency deviations, storage systems with limited capacities which participate in the provision of FCR might run out of capacity. Thus, they will stop providing balancing energy when the storage systems become completely empty or full, which can be critical during large frequency deviations, unless aFRR is designed to accommodate for this effect.

[21] In the following discussion Swedish FCR-N product and the FCR product used in most EU countries are treated interchangeably.

The opposite is true for the 30 min criterion: more capacity must be reserved for balancing energy which offers more backup capacity for long lasting frequency deviations. However, the reserved capacities of the storage systems cannot be used for other functionalities like optimizing self-consumption, which results in additional opportunity costs when participating in an FCR-N market and, ergo, higher procurement costs.

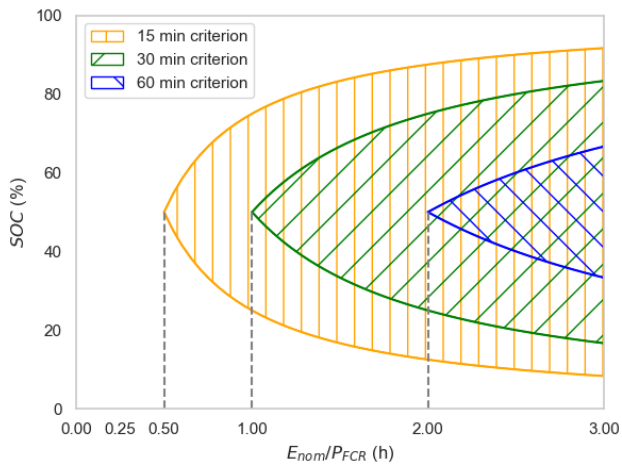


Figure 42: 15-min, 30-min, and 60-min criterion FCR (symmetric) (own illustration)

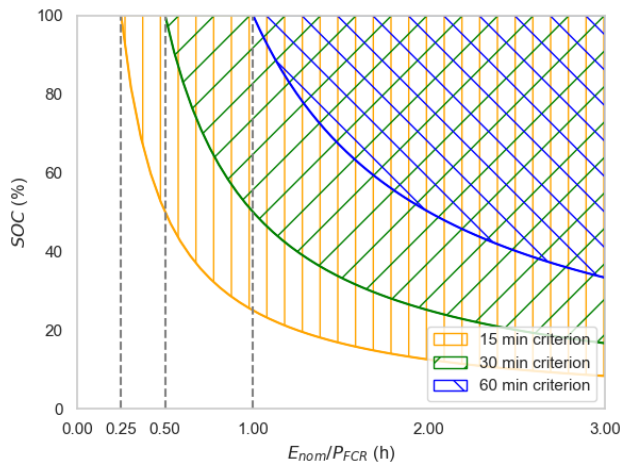


Figure 41: 15-min, 30-min, and 60-min criterion FCR+ (own illustration)

In the current prequalification documents of Svk, the ability to provide the full power for an entire product period of 1h is required. This is equivalent to a 60 min criterion which is a minimum capacity to power ratio of $E_{\mathrm{nom}}/P_{\mathrm{FCR}} = 2.0\ \mathrm{h}$. Thus, a storage with limited capacity which should provide a power of $P_{\mathrm{FCR}} = 1\ \mathrm{MW}$ for FCR-N, must have a capacity with at least $E_{\mathrm{nom}} = 2\ \mathrm{MWh}$. When the market is open for asymmetric bidding, the ratio can be realistically reduced to $E_{\mathrm{nom}}/P_{\mathrm{FCR}} = 1.0\ \mathrm{h}$ when bidding entirely in one direction. Figure 42 gives an overview about these criterions depending on the required capacity to power ratio and the symmetry of the market for the different criteria. The colored patterns indicate the allowed SoC range of a BESS such that the different criteria are fulfilled. The same is also shown in Figure 41 in an asymmetric market and providing only +FCR-N. We can see that a BESS can participate with half the $E_{\mathrm{nom}}/P_{\mathrm{FCR}}$ when having an asymmetric market.

In [13], the 15 min and 30 min criterion are analyzed in detail. When assuming the 15 min criterion for FCR in the Nordic synchronous area, the larger the share of storage systems with limited capacities participating in the market, the more FCR power is needed in order to avoid problems in the grid (a power of 2050 MW is needed when assuming a share of 0 % of storage systems with limited capacity participating in the Nordic FCR market and 2400 MW for a share of 100 %). Interestingly, for the 30 min criterion, additional FCR power is not needed at all also when assuming a 100 % share of systems with limited capacity providing FCR. Moreover, in the report, increasing the share of FCR providers with Limited Energy Reservoir (LER) would decrease the costs of FCR.

Thus**, reducing the 60 min criterion to at least a 30 min** criterion makes sense from both economic and technical points of view. It would reduce the yearly costs and would open the market for new participants without the need of additional FCR power when having a LER-share smaller than 60 % or enforcing to have a backup capacity to provide the full power for at least 25 min.

	LER share											
TminLER	0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1	Mean
15′	314	248	194	140	87	61	78	102	119	135	151	148
20′	314	252	199	146	93	68	86	101	117	133	149	151
25′	314	257	204	152	99	75	87	102	118	133	148	154
30′	314	262	210	158	106	83	95	111	127	143	159	161
Mean	314	255	202	149	96	72	86	104	120	136	152	

Figure 43: Total yearly costs to provide FCR-N in Nordic region (M€/year) [13]

BESS degradation

A disadvantage of BESSs in comparison to conventional technologies is their degradation rate and a comparatively short lifetime. Due to frequency fluctuations in the Nordic FCR-N, a BESS must react to these changes, which will result in numerous charging and discharging cycles reducing the remaining lifetime of the system [5], [23] . Moreover, in comparison to the grid in Central Europe, the Nordic grid has more frequency deviations, in part due to its smaller size. As a consequence, more balancing energy is activated. Even though this issue results in barriers for BESSs' participation in the FCR-N market, it cannot not be addressed in the prequalification process since it is a problem of the underlying BESS technology and not of the prequalification conditions themselves.

6.3.3 Current barriers for the participation of wind generation in the FCR-N market

Wind turbines can participate in FCR markets by pitching the blades of the turbine to adjust their power output [24]. It has been shown in pilot projects that wind turbines can reliably provide FCR and also FFR [5]. In Denmark and in Austria and Germany (for FRR), wind generation is already allowed to participate in the balancing market. Yet, there is generally some distrust among system operators, especially towards using wind generation for shorter-term reserves due to their lower output predictability and thus reliability.

Opportunity Costs

In order to provide downward reserves for the FCR-N market, the wind turbines can be operated at full currently possible capacity. When facing overfrequencies in the grid, the power setpoint of the turbines can be reduced to satisfy the reduction of generation required for FCR-N. For upward flexibility, the turbine is operated below the available (optimal) wind power. Then, when encountering underfrequencies, the power generation of the turbine can be increased accordingly. Consequently, the turbines will generate less energy than possible, which results in opportunity costs [24] and underuse of renewable energy in the system. In addition, due to forecast errors, operators of wind generation must account for a significant security band when participating in the markets in the day-ahead timeframe or earlier. A currently illiquid ID market also means that schedule deviations cannot necessarily be offset in the ID market, leading to further inefficiencies. When only symmetric bidding is possible, the wind turbines have to be operated in a sub-optimal curtailed mode when providing FCR-N. However, with asymmetric bidding these opportunity costs of a curtailed operation can be reduced when only providing downward flexibility. The same is also true for PV systems.

Operational Limits

It is stated in [25, p. 212] that wind turbines cannot provide balancing energy at very low or very high wind speeds (also known as cut-in and cut-out speeds). This harbors risks when using wind turbines for FCR-N because the gate closures of the Swedish FCR-N market take place in D-2 and D-1 [4]. The operator of wind

turbines which should provide balancing energy will use forecasts to predict the wind speed for the time of delivery and base its bid sizes on this data. These forecasts are a source of uncertainty. Thus, backup capacity might be needed to avoid the penalization of not providing balancing energy upon receiving an activation request. This, as mentioned in Section 6.1 makes a case for pooling wind generation with other compensating technologies and prequalifying them jointly. It is also likely that, even though two-stage bidding is allowed in the Swedish context, wind operator will bid most of their available flexibility in the D-1 timeframe, maximizing the accuracy of their forecasts.

Strategies like power boost or FFR where the rotor kinetic energy is extracted, should in our opinion be avoided, as they might lead to a significant power decrease a few seconds after an event, leading to a second Nadir in the frequency signal. Hence, active power control should not rely on the inertial response of the wind turbine, which causes the machine to slow down, but rather on pitch control. Accommodating certain services (such as e.g. power boost) to wind at the peril of system stability issues and potential unexpected behavior should, in our view be avoided.

6.4 Analysis of the market design

Based on previous research (see beginning of this Chapter) and the aspects addressed in Svk's stakeholder surveys and consultation documents, the following design variables will be addressed in this section from the market design perspective:

1. Product resolution
2. Bidding type
3. Bid symmetry
4. Timeframe of the FCR-N auction(s), including with respect to the day-ahead market
5. Availability of block bids
6. Bid size minimum and maximum
7. Pricing rule

In addition, several other factors are analyzed below:

- Exchange within and outside the Nordics
- Information availability and time of publication
- Energy settlement
- Transfer of obligation and penalties for non-delivery

6.4.1 Market design variables

Product resolution / market time unit (MTU)[22]

In order to facilitate harmonization with the rest of the European networks, the 15 minute MTU would be preferred. It is also in line with the intention of Nordic Balancing Model to switch from the ISP of 60 minutes to the ISP of 15 minutes in Q2 2023. Aligning the MTU with the ISP would align the MTUs for the balancing and intraday markets facilitating interoperability of flexibility.

[22] The two terms are used interchangeably throughout the report referring to the duration of product delivery.

One of the sources of imbalances is linked purely the choice of accounting: interhour imbalances tend to occur at the end of each hour as balance responsible parties (BRPs) attempt to adjust their portfolios to avoid imbalances at the end of the hour. Changing the ISP to a more granular would smooth this effect as it will be redistributed (and potentially reduced) over quarters of an hour.

It is important to note that the reservation period for balancing capacity might still be longer, e.g. kept at one hour.

MTU is linked to the technical requirements placed on BSPs: as mentioned in Section 6.3.3, the current requirement for battery storage to guarantee delivery flexibility over an entire hour poses a challenge for its participation and requires the units to be substantially overdimensioned. Similarly, aggregated capacities of small-scale flexibilities would benefit from a shorter MTU. This is also the general stakeholder opinion expressed in the survey by Svk-Fingrid of February 2021.

It is recommended to reduce the MTU in the FCR-N market to 15 minutes after the adjustment of the ISP period to 15 minutes and thus align it with the imbalance settlement procedure and the (planned) products in the short-term electricity markets.

Availability of block bids

In general, bid linking can be done within a single product (i.e. block bids over a period longer than the MTU) or between several products (i.e. conditional bids in several markets for the same flexibility). For the latter, see the discussion in Chapter 6).

While simple bids provide for bidding simplicity and cost transparency, lack of linking consecutive bids is likely to force BSPs to “fully internalize all production costs and technical constraints in their hourly price-quantity bids and exposes them to the risk of unfeasible or uneconomic scheduling” [26].

An alternative to block bids could be multi-part/complex bids (e.g. bidding separately for start-up costs, minimum load requirements, as e.g. is done in the Polish balancing market). It makes the costs stemming from delivering flexibility explicit and the bids of different flexibility sources more comparable. These are also easier to harmonize with the neighbouring countries since block bids seem to have different characteristics across neighbouring countries. A stakeholder in the Svk-Energinet consultation further pointed out that “f*rom the point of view of market harmonization, it seems sensible to prefer multi-part bids to block bids. However, an additional quantitative analysis is required to determine the benefits of block bids as compared to simple or multi-part bids or to determine the optimal maximum block length”* [3].

This variable is linked to the choice of MTU. In case the MTU is reduced to 15 minutes, it is not clear what kind of block bids will be allowed in the future. For some market actors, it would be beneficial to provide block bids over several quarters of an hour up to a certain limit, e.g. a few hours in order to align them with the technical capabilities of the balancing resources. This will be particularly important for the technologies with longer start-up times. The overwhelming majority of stakeholders in Svk-Fingrid’s survey supports the possibility of submitting block bids, in particular if the MTU is reduced to 15min [2].

Allowing block bidding, i.e. linking bids in several consecutive time periods, would facilitate participation of technologies with longer start-up periods and/or start-up/shutdown costs in particular if the MTU is reduced to 15 minutes. Alternatively, for the sake of a more transparent cost allocation and easier cross-border harmonization, multi-part bids could also be considered.

Bidding type

This design variable refers to the choice between cost-based bidding and free bidding, i.e. one based on the bid prices specified by BSPs. So far, Svk has awarded successful bidders with portfolios of reservoir hydro power plants, sole providers of FCR-N, based on their costs calculated according to a predefined methodology. Although it is desirable for market actors to bid according to their actual true costs, imposing a complex calculation approach may not be the most optimal solution to achieve this. This approach largely depends on trust between the TSO and the BSP and makes it difficult to track to which extent it is followed unless stringent and frequent audits are used. The latter, in turn, implies high administrative costs for the TSO. Besides, as highlighted in the previous report, a similar cost methodology would need to be developed for each participating technology. As long as this is not the case, other technologies are likely discouraged from entering the market even if they are not formally prohibited from participating. In other words, uncertainty is the main barrier for a potential BSP unaware of the exact procedure or basis of calculation for their technology.

Furthermore, as identified in the previous report[23], the presence of new market entrants, in particular of mostly cheaper and at the same time highly volatile wind generation in combination with marginal pricing effectively deters other BSPs from deviating from their true costs in about 80% of cases. At the same time, allowing BSPs to freely choose their bid prices encourages the participation of the new technologies and reduces the administrative effort on the TSO's side.

Based on the considerations above, it was decided to introduce free pricing in the FCR-N market in January 2022[24].

Allowing free bidding is a meaningful way to encourage effective participation of new actors in the FCR-N market. However, it is recommended to communicate the plan to change the bidding type to free bidding well in advance and, prior to the actual implementation, ensure that new flexibility providers are aware of the planned changes and have passed technical prequalification. This would help avoid a likely price shock from the transition from cost-based to free bidding if only few incumbents are operating in the market. As an additional precautionary measure, a temporary price cap for the duration of the transition period may be considered if competition is still insufficient. It should, however, be noted that empirical evidence demonstrates that in the presence of caps, BSPs often tend to orient themselves to the cap amount.

Bid symmetry

The effects of introducing asymmetric bidding have been discussed in detail in the introduction to this report. In addition, the simulation results presented in Section 5.3 and summarized in Section 5.4 demonstrate some benefits both for the market efficiency by reducing total procurement costs but also for the BSPs, allowing new entrants such as operators of wind generators to 'favor' one direction and place a larger volume of their flexibility there.

An important observation made by a stakeholder in a survey by Svk-Fingrid is that symmetric bidding excludes demand-side flexibility that can offer regulation in one direction and not both. In general, most stakeholders argued for using asymmetric products in the FCR-N market [2].

[23] https://www.svk.se/contentassets/22a7164df5c2415d9c2a8f69c08498f8/svk_report_analysis_of_fcr-n_market_design.pdf

[24] Requirements for cost-based bids will be removed on January 1, 2022, as communicated to market participants in May 2021: https://www.svk.se/press-och-nyheter/nyheter/elmarknad-allmant/2021/andringar-for-fcr-marknaderna-krav-pa-kostnadsbaserade-bud-tas-bort-1-januari-2022/ (in Swedish)

It is recommended to introduce an asymmetric FCR-N product to allow new flexible technologies to maximize the amount of flexibility they can provide in either direction based on their technical constraints (see also Section 4.3). It is crucial to consider the related changes to the prequalification requirements allowing potential BSPs to prequalify a certain total volume of flexibility and decide themselves how much of this flexibility can be offered in each direction (as opposed to the requirement to prequalify the same amount upward and downward). Finally, caution should be exercised when considering allowing the linking of bids in the positive and the negative FCR-N markets. As the simulation results in Chapter 5 have shown, this possibility tends to increase total system costs above the baseline with symmetric bidding through providing much fewer degrees of freedom during market clearing in which the two directions are co-optimized.

Timeframe of the FCR-N auction(s), including with respect to the day-ahead market

D-2/D-1 procurement of FCR-N capacity

Such a two-stage auction is a legacy setup driven by the planning needs of hydro-based BSPs. However, with the entry of new technologies and progressive integration of Nordic balancing markets, it is not immediately evident if the two-stage procurement is still justified.

Market sequence plays a role in determining whether BSPs that were not awarded in the balancing market can still offer their capacity in the short-term markets or for another balancing product. This consideration is also relevant for the Swedish market design, in which FCR-N is procured both *before* and *after* the GCT of the DA market. As a result, for instance, a BSP in D-2 would face opportunity costs not only with respect to the possible foregone profit from the DA market (or a better point in time in the DA market) but also from not bidding in the D-1 timeframe when, for instance, a better production forecast is available. This as a result leads to higher bid prices submitted by BSPs.

If an asymmetric FCR-N product is introduced, decision-making is likely to get more complex compared to symmetric bidding in a two-step-auction (D-2 & D-1) in comparison to a single-step-auction design. Essentially, this results in four separate auctions, two for positive and two for negative capacity. In a single-step auction, a BSP could not bid more than its available capacity: its positive bid plus its negative bid must always be less than its total available capacity, considering minimum load requirements. The two-step process enables a BSP to effectively bid more than the total available capacity *over the two steps* if it did place a bid in the D-2 auction that was *not* awarded and now can place a large bid in D-1. A BSP may place trial bids in D-2 and, if not awarded, still get a second chance in D-1 based on the actual outcome of the DA market.

A generator would be willing to change its way of operation (e.g. from expected generation in the DA to only running at minimum load) if it would get an expensive trial bid awarded already in the D-2. Alternatively, it would offer its available capacity using the planned operation (e.g. a full negative bid if it is willing to run in the DA market).

Potential implications

If a two-step auction is held , especially with the D-1 auction taking place *after* the DA market clearing, a clear advantage arises for BSPs: normally all bids must be placed without the specific knowledge of the DA market results. BSPs can place trial bids during D-2, potentially with a heavy markup. Even if they do not succeed, there are no real disadvantages as they can still bid their ‘logical’ bid after the DA market clearing.

This advantage, however, is heavily influenced by the TSO and the amount of capacity that is procured during each auction. The actual FCR-N demand, i.e. publicly known demand vs. real demand considering the exchanges with the rest of the Nordics, or the distribution of the FCR-N demand volume between the two

phases can vary significantly. Since the actual demand in the two timeframes is unknown, this poses a greater risk since it influences a BSP's calling probability and, ergo, the risk of strategic arbitrage may be lower. This implies that after failing to get the trial bid awarded, it can still happen that the "logical" bid is not accepted either, leaving the BSP with no awarded bids in the FCR-N market.

In general, risk can be seen lower in asymmetric bidding from a BSP's perspective, in a sense that the extrema are less likely to occur. For fully awarded bids, a symmetric bid can either be awarded or not (100 vs. 0). In contrast, if an asymmetric market a negative bid is not awarded, it is still possible that the positive bid is accepted resulting in 50% of the overall bid being awarded. Depending on the extent to which BSPs account for risk in their bids, this would imply lower risk premiums if asymmetric products are used.

GCT of the FCR-N market with regard to the day-ahead market

For balancing capacity products, the EBGL mandated daily procurement without a more specific reference to the GCT. Yet, this requirement implies that FCR-N auctions should take place in the D-1 timeframe and that the current two-stage setup is incompatible with the EBGL[25]. Currently, the second, D-1, auction closes *after* the DA market.

From the market actors' perspective, especially those with portfolios for renewable and other distributed energy resources, bidding day-ahead provides a better opportunity to estimate one's flexibility and rely on better forecasts. A single auction was also the option most respondents in Svk-Fingrid's stakeholder survey of February 2021 were willing to accept [2]. There was, however, no uniform opinion as to whether daily auctions should take place before or after the GCT of the DA market.

From the perspective of allocative efficiency[26], it is sensible to close the FCR-N market after the GCT of the DA market and the publication of its results to ensure that no cost-efficient capacity is withheld from the DA market in the expectation of a higher profit in the balancing market. To the authors' knowledge, all balancing capacity markets in the synchronous area Continental Europe clear *prior to* the day-ahead market and often far in advance although the tendency in the last few years has been to move closer to the day-ahead timeframe. GCT prior to the DA market's GCT is mainly motivated by security concerns, i.e. it can be ensured more safely that sufficient reserve capacity is available prior to the DA market. This, however, comes at a cost, namely at an opportunity cost of not being able to participate in the DA market. Conversely, in the D-1 auction after the DA market's GCT, this opportunity cost no longer applies. However, since hydro-based BSPs are guided by a more complex cost calculation based on the value of water over a longer planning period rather than short-term opportunity costs used by other technologies, this logic does not apply in their case.

For scarcity situations additional measures can be undertaken. For instance, the Austrian TSO, APG - that still procures balancing capacity ahead of the DA market – introduced an additional procedure triggered by insufficient capacity offers. First, an additional auction for the remaining demand is organized; if unsuccessful, a 'last call' is conducted and, as a last resort, BSPs with installed capacity of over 50MW can be forced to provide available flexibility (APG, 2021[27]).

[25] "The contracting should be performed for not longer than one day before the provision of the balancing capacity and the contracting period shall have maximum period of one day" (EBGL, Art. 5.9)

[26] Allocative efficiency refers to how much the value of flexibility used for different purposes is maximized. For instance, the most cost-efficient resources are offered to the DA market whereas those out of the money can still provide their flexibility to the balancing market, i.e. no cost-efficient flexibility is withheld from the DA market.

[27] https://www.apg.at/de/markt/netzregelung/sekundaerregelung/faq

Based on the stakeholder survey conducted by Svk/Fingrid in February 2021, most respondents preferred the option of balancing market GCT after the GCT of the DA market while some supported a GOT farther ahead, i.e. a longer bidding period [2].

An option coinciding with the GCT of the aFRR market was rejected by most participants since, according to them, mostly the same resources participate in both. This can create coordination problems for the BSPs trying to comply with the requirements for both whereas no linkage between aFRR and FCR-N bids is used or foreseen. Similarly, several market participants stressed the need to consider the bidding times for other markets, especially FCR-D, when deciding of the GCT of the FCR-N market (see also Section 6).

In the consultation on the common SE-DK2 FCR-N market, the opinions seemed to split between traditional and new BSPs. While incumbents generally preferred the status quo with a two-step auction, other BSPs strongly favored a single-step option with GCT after the DA market [3]. A large incumbent BSP questioned whether the current GCTs and the two-step auction design needs to be adjusted at all, arguing that the D-2 auction allows a more secure procurement for the TSO. Similarly, another BSP argued that most flexibility is provided in D-2 and thus for the *status quo*. They only accepted Option 4, D-1 at 18:00, as an alternative, but raised system security concerns as the volume of offered FCR-N reduces after the DA clearing.

The other BSPs in favor of setting the GCT as close as possible to real time argued that in this way a one-step auction would in fact facilitate the widest pool of providers and thus liquidity. The authors of this report support this argument. The result of the DA market is known and the flexibility is not ‘blocked’ in any other market. These BSPs also insisted that it would enable participation of new sources of flexibility by allowing for more accurate forecasting and reduced need for energy repurchasing and rescheduling leading to a more balanced situation overall. One incumbent BSP, however, retorted that because of an illiquid ID market, efficient rebalancing will not be possible thus exposing actors to higher imbalance costs.

It is true that hydro generation pays a crucial role in the provision of FCR-N in the Swedish market, something that is likely to continue being the case in the short- to medium-term future (see also the simulation results in Section 5.3 and in the Phase 1 project report). The authors recognize the argument that after-DA-market clearing may pose operational challenges for such BSPs. However, there is an overwhelming evidence from other EU countries, in which hydro-based BSPs, being some of the most flexible technologies, have no trouble participating in a D-1 balancing auction. Deviating from the status quo will understandably require operational adjustments, e.g. those to the trading software. Yet, the benefits of a single-step D-1 auction outweigh possible drawbacks. Following the interests of a single technology goes against the principle of non-discrimination whereas new entrants again are not given a chance to increase their share in the market. We see the option of a single-step auction *prior to* the GCT of the DA market as the only sensible middle ground to on the one hand assuage the concerns of some BSPs while simplifying the market and increasing market liquidity. In addition, it can be considered to extend the bidding period itself, e.g. GOT one or several days ahead: in this way different technologies can better meet their technical requirements and forecasting needs to submit their bids.

Finally, all respondents stressed the importance of publishing the results within office hours. Making results available outside office hours is bound to increase operational and personnel costs and presents a particular challenge for smaller players with less developed trading infrastructure [3].

Concerning the choice between a one-step vs. two-step auction, it is recommended to substitute the two-stage auction model currently used in the FCR-N market for a single-stage model in D-1. This will both to align it with the requirements of the EBGL and lead to a higher expected market liquidity and therefore

competition. For smaller, less experienced BSP this would further assist plannability and reduce decision-making complexity. With regard to the GCT of the FCR-N auction, it is recommended to set the GCT of the FCR-N market in D-1 prior to the GCT of the DA market similar to the common practice in other EU countries while addressing the concerns of some of the incumbent BSPs.

Bid size minimum and maximum

Compared to other EU balancing markets, the minimum bid requirement for FCR-N is Sweden is already the lowest observed. In this way, the market can already accommodate bids of even small-scale providers.

It might make sense to include a maximum bid size similar to Fingrid's practice in order to avoid situations with one BSP monopolizing the market and potentially lift this requirement only in scarcity situations. From the TSO's perspective, having bids in smaller blocks makes the merit order more granular and can make procurement more cost-efficient if bids remain indivisible. Similar arguments were made by a few participants in the Svk-Energinet consultation. A complimentary solution to introducing maximum bid size for single bids is allowing bid divisibility. This is primarily meant to avoid situations in which only a small share of a large-volume bid is in fact required to satisfy the final bit of demand, yet – if bids are indivisible – must be fully awarded leading to overprocurement and substantially higher costs (or to paradoxically rejected bids).

It is recommended to retain the already stipulated minimum bid size for FCR-N rather than indefinitely reducing the minimum bid size to accommodate the smallest players, taking (among other challenges) computational time and complexity into account. Instead, it is advisable to update the pooling conditions and provide sufficient flexibility for BSPs in this way (see a more detailed discussion on pooling of flexibility in Section 4.1).

At the same time, it is recommended introducing a maximum bid size and bid divisibility in order to avoid situations in which large players can fully or to a large extent cover the demand and thus monopolize the market. An additional statistical analysis would be necessary to determine the exact maximum bid size and minimum divisibility levels.

Pricing rule

Unlike the case of aFRR and mFRR, the EBGL does not require TSOs to apply marginal pricing to FCR. Yet, results of research studies as well as those of Phase 1 of the project have demonstrated efficiency gains from introducing marginal pricing [27]. It enables transparent pricing and facilitates participation of smaller or new, less experienced BSPs that have not developed sophisticated price forecasting techniques. Yet, these can be exploited only after achieving a higher competition level in the market.

On the market participant side, there is also an overwhelming support for marginal pricing, according to the results of the survey of February 2021 [2]. Similarly, several respondents to the consultation by Svk and Energinet argued for the need for marginal pricing in the common FCR-N market citing inconsistency of the pricing rule with that required by the EBGL, i.e. marginal pricing and timely publication of results. These are seen as crucial for accurate price signals for better investment decisions [3].

Possible transitional pricing rules, it has been shown, among others, that the introduction of an intermediate rule does not curb strategic behavior but rather changes its character[28]. Concerning specifically a mix of

[28] For example, as a result of such a market change in Germany in October 2018, so-called 'mixed-price settlement' (Ger. *Mischpreisverfahren*), the scoring rule in the balancing capacity market was adjusted from one based purely on the capacity price to the one including a weighting factor based on the submitted balancing energy bid. This change proved to have a disastrous effect for the TSOs leading to constantly high balancing capacity prices and therefore was abolished shortly after in July 2019.

marginal and pay-as-bid pricing, such a rule does not necessarily lead to a better outcome and risks creating strange incentives in the market. If the marginal price can be manipulated, there will still be a strong incentive to do so. It might be somewhat more beneficial to smaller bidders that would get part of the marginal price even if they bid substantially lower, thus improving their business case in the FCR-N market. Conversely, larger incumbent BSPs that do a much better job of assessing the market situation and influencing the marginal price can still use the rule to their advantage. Besides, a mixed-price rule opens up an array of new questions such as, what the weighing factors should be and if they are adjusted over time. Although advised against over a long period of time, temporary price caps is, in our view, a more sensible option to contain possible price spikes given marginal pricing rather than a mixed-price rule.

Based on independent research results (e.g. [26]*) as well as the results from the previous project phase* [27]*, it is recommended to change the pricing rule from pay-as-bid to marginal in the FCR-N market. Based on empirical evidence it is further advised against using other intermediate rules, e.g. one using weighting factors, when transitioning from pay-as-bid to marginal pricing. Instead, it is recommended to change the pricing rule as the very last market design change (see also Figures 37 and 45) after carrying out adjustments to the technical requirements and ensuring higher levels of competition from multiple flexible technologies and/or international market integration.*

6.4.2 Other considerations

Exchange with the Nordics

Stakeholders from the Svk-Fingrid survey are critical about *'taking the cross-border capacity away'* from the DA markets for the balancing markets [2]. Yet, it is our opinion that balancing serves a fundamental purpose of ensuring system stability and therefore must have allocated cross-border capacity for exchanges. Pursuant to Art. 38(1) of the EBGL the cross-border capacity allocation can be organized as a "(a) co-optimized allocation process pursuant to Article 40; (b) market-based allocation process pursuant to Article 41; (c) allocation process based on economic efficiency analysis pursuant to Article 42". So far, the Nordic TSOs have already submitted a proposal for market-based allocation process for aFRR, which was adopted with ACER Decision 22-2020[29] on the market-based allocation process of cross-zonal capacity for the exchange of balancing capacity for the Nordic CCR (A41). According to it, the allocation process is conducted daily in the day-ahead timeframe (in the morning). Pursuant to Article 38(4) of the EBGL, reliability margin shall be used for the exchange of FCR capacity.

Currently, the approach used in the Nordics for the exchanges of FCR-N capacity involves the settlement that is conducted on the TSO level without BSPs' direct participation. The latter are exposed to their control areas prices as well as to variable demand for FCR-N, which depends on the amount of imports/exports. Following the EBGL, the procurement of balancing capacity or balancing energy for standard balancing products may follow a TSO-BSP model (Art. 35) or a TSO-TSO (Art. 33). The TSO-BSP model implies that a BSP provides a service directly to the requesting TSO. The TSO-TSO model involves a higher level of collaboration where BSPs would submit bids to a common market with a common merit order list (CMOL) for all control areas involved, "taking into account the available cross-zonal capacity and the operational limits" (Art. 33(2)). This latter model would be applied if a common FCR-N market were established. Under this model, the prices in the control areas will be different for FCR-N only in case of limited transfer capacity. However, an essential prerequisite for the TSO-BSP model to work is the complete harmonization of the

[29] ACER Decision 22-2020 on the market-based allocation process of cross-zonal capacity for the exchange of balancing capacity for the Nordic CCR (A41) as well as the Annexes can be found here:
https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Pages/Old-Individual-decision.aspx

product across the participating TSOs. This includes not only the auction characteristics but also the technical requirements for BSPs.

For optimal cross-border clearing, a CMOL is necessary as any other solutions would distort the market, e.g. an option proposed by some stakeholders in the Svk-Fingrid survey of prioritizing national BSP by clearing them first. Such a suggestion is contrary to the principle of cost-efficient procurement as in a given hour BSPs from the neighboring TSO's area can potentially provide cheaper bids.

It is further recommended to remove differences in procuring FCR-N from DK2 and from NO/FI. Currently, Danish providers from DK2 are included in the Swedish FCR-N merit order directly as opposed to the exchanges with the other Nordic countries on a purely import/export basis. This creates inconsistencies and gives a competitive advantage to Danish BSPs that can potentially exploit a hydro-heavy Swedish FCR-N market as they are not bound by the same cost calculation requirements but can mimic the hydro strategies in a self-serving manner.

Exchange of reserves with parties outside the Nordics

Market integration understandably leads to higher system flexibility and ergo efficiency gains (the recent cautionary tale of Texas where one of the main reasons for such disastrous consequences of production shortfalls was its lack of interconnection).

Since Sweden is located in the Nordic synchronous area, then it is much more challenging to integrate the markets across different areas (vs Continental Europe or the Baltics) in comparison to the integration within the Nordics. An additional challenge is the fact that FCR markets are not harmonized with other synchronous areas and that FCR-N in the Nordics is not directly comparable to e.g. Continental Europe's FCR. An additional complication are the different technical product requirements applied to the Nordic FCR-N and e.g. Central European one, as well as division into FCR-N and FCR-D. Therefore, a substantial harmonization effort is required before this option can be feasibly addressed. A broader market integration is undoubtedly beneficial, yet in this specific case remains a long-term goal.

At the same time, we do not support the idea of prioritizing Nordic BSPs while using the resources outside the Nordics only as a measure of last resort since, as mentioned above, the Nordic and Continental Europe FCR products are not interchangeable. Critical situations within the synchronous area should preferably be tackled through careful resource dimensioning instead.

Information availability and transparency

Both in the stakeholder survey by Svk-Fingrid and in the Svk-Energinet consultation on a common FCR-N market, many respondents understandably stressed the need for a higher market transparency and availability.

Transparency can be assessed from two perspectives:

1) *what* data is published/publicly available,
2) *when* this data is published.

While not arguing that as much information as possible should be provided to the market, the authors are of the opinion that timely publication of market results and platform-based harmonization of its sources and terminology are priority. Allowing all market results, i.e. market prices, to be published as soon as possible provides a reliable price signal to the actors and facilitates decision-making among smaller or less experienced market participants. Signal robustness is yet another argument for setting the pricing rule to

marginal (see also Section 5.1). In terms of harmonization of data sources, publication requires harmonization either on a common Nordic platform or preferably directly on the ENTSO-E platform. Currently, different approaches create confusion as to whether the exact same data is represented under the same category and why some points are available only on one platform and not on the other, a specific enough legend is often not available. If multiple platforms are used, then such discrepancies should be removed. The more different platforms are used, the more publication times are also likely to differ, creating unnecessary complexity. This should be particularly helpful in supporting cross-border market integration and BSPs' participation in the balancing markets in the other Nordic countries without much additional administrative cost.

We advise against publishing the bidding data, i.e. anonymized bid volumes and prices, as requested by some stakeholders. While it facilitates market analysis for BSPs, it does not seem to contribute to market efficiency and can produce the opposite of the desired effect. Specifically, in a concentrated market, it may provide more venues for market exploitation since having a full bid latter makes it much easier to estimate one's merit order position and influence the market result.

In case the two-step auction setup is preserved for the common SE-DK2 market, we further advise against publishing the exact split of the FCR-N demand in D-2 and D-1 against the calls of some participants in the consultation. Similar to the wholesale markets where the exact demand is unknown, there does not appear to be any valid reason to specify FCR-N demand if it can be avoided. This should help preventing particularly participants with high market shares from orienting themselves to the demand in their bidding decisions. In this context, it is still recommended to apply a single-step auction that is likely to increase transparency, liquidity and ease decision-making.

The time of availability of market results plays a crucial role in the decision-making of market participants and affects the allocation of flexibility to different markets products. To ensure that no flexibility goes 'lost'/unused but can be still offered in a subsequent market for example, the information should be provided as soon as possible after the GCT of the respective market. This allows to improve the allocative efficiency of flexibility. In addition, several respondents in the stakeholder survey conducted by Svk-Fingrid made an important observation that the results should preferably be published within the usual business hours for small actors' sake.

This aspect is tightly linked to the auction timeframe and frequency described above: in order to ensure that flexibility is not lost but committed in any of the available markets, it is important to make market results to BSPs as soon as possible for them to be able to make other trading decisions in case they were not awarded in the FCR-N market (see also Section 6).

Energy settlement

Previous research has shown a clear link between the bidding strategies of BSPs in the balancing capacity and balancing energy markets (e.g. [28]).

In the FCR-N market, activated energy is currently settled based on quarterly netting valued at the mFRR balancing price. Based on the historical data on frequency deviations, FCR energy deliveries are actually not negligible. If that is indeed the case, then regardless of the energy settlement rule and of whether it is applied at all, BSPs will calculate the costs of actual activation in their FCR-N bids. This would go against the goal of increasing market transparency. Depending on the actual activation volumes, it be worth considering a separate energy remuneration based on the activation result in the FCR-N market rather than a different market.

Transfer of obligation

At the moment, transfer of reserve obligation is not allowed in Sweden. Instead, Svk buys back unavailable capacity and procures new capacity instead.

On the EU level, there is a large disparity when it comes to authorizing transfer of obligation. In our view, it can be allowed under two conditions:

1) as long as both providers are prequalified,
2) the price for the TSO remains the same (any financial transaction would be between the parties to that transfer).

Such transfers could be achieved either through continuous bilateral trade up to a few hours after the market results are known, providing the TSO with a leeway to make last-minute adjustments if needed. However, if the two conditions above are fulfilled, the net effect for the TSO should remain the same. In addition, allowing transfer of obligation makes particular sense if penalties for non-delivery are applied (this is also in line with stakeholder opinion in the stakeholder survey). The incentive to use transfer of obligation will to a large extent depend on the size of the penalty and the way it is calculated.

Importantly, transfer of obligation shall be seen as a measure of last resort for the BSP, e.g. in the event of operational incidents, rather than a common practice.

6.5 Links between FCR-N and other markets

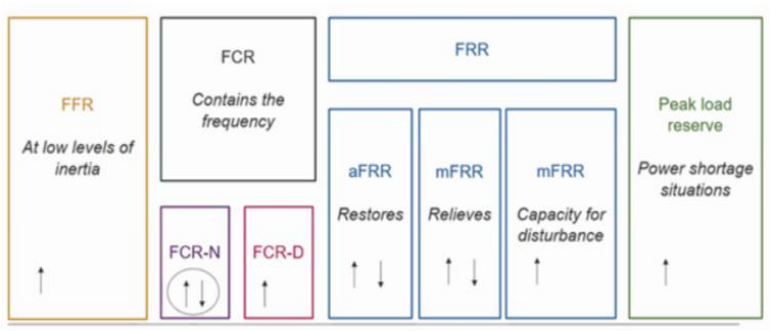


Figure.44. Balancing products currently used in Sweden and their direction (note that the circle around the arrows for FCR-N indicate a symmetric product) (Source: Svk 2021).

Due to inherent similarities in the purposes of FCR-N and FCR-D, aFRR or mFRR, a rough comparison can be conducted. It is important to note that – especially during project Phase 2 – the simulation scenarios already consider marginal-pricing remuneration, while the current markets mostly consider pay-as-bid (with the exception of mFRR, Figure 44). Table 11 summarizes a few important properties of FCR-N, FCR-D, aFRR and mFRR products.

Table 11. Comparison of the products in the Swedish balancing market.

Product	Pricing Rule	Min. Bid Size	Symm. / Asymm.	Activation Time	Procurement
FCR-N	MP (PaB*)	0.1 MW	Asymm. (Symm.*)	100% in 180sec	D-2 (and D-1)
FCR-D	PaB	0.1 MW	Only upregulation**	100% in 30sec	D-2 (and D-1)
aFRR	PaB	5.0 MW	Asymm.	100% in 120sec	1-week ahead
mFRR (energy)	MP	10 MW**(5MW in SE4)*	Asymm.	100% in 15min	Up to 45min ahead

** the market is (currently) different from the assumptions of the simulations runs made by AIT*
*** downregulation (FCR-D down) is planned to go live in 2021/2022 with a specification similar to the current FCR-D*
**** 5 MW in SE4*

FCR-N vs. aFRR

While it seems intuitive to compare an asymmetric FCR-N product to the currently existing aFRR product, there are some key differences:

- Bids must be placed much earlier for aFRR (this should change with Q1 2022 where aFRR will be traded in D-1), where a largely increased uncertainty impacts the prices and most likely results in a larger risk markup. This can affect positive and negative bids to different degrees of magnitude.
- The minimum bid sizes differ by a large amount, with 0.1 MW for FCR-N and 5 MW for aFRR. Considering the historical FCR-N bids during the years 2018-2020, **62.5%** of all bids were placed with a volume smaller than 5 MW. Since it is not clear how current Swedish BSPs would adjust their bid granularity in an asymmetric market, the influence of the minimum bid volume on market results could potentially vary between positive and negative market.
- While the overall properties of aFRR and FCR-N are somewhat similar (automatic activation, similar response time, activation in both directions), the procurement method shows a fundamental difference: While FCR-N acts as a "base supplier product" (being procured during every hour), aFRR is only procured during some hours (and sometimes not procured for a specific day at all), with most auctioned slots being in the early morning (4-8am), late afternoon (4-7pm) and sometimes around midnight. This can also affect bid prices and market results, since a product that is procured during every timestep is more easily plannable from an operational optimization point of view.

FCR-N vs. FCR-D

Although there are some key differences between FCR-N and FCR-D, some of them are only technical requirements (e.g. a much faster activation time) that limit the number of possible market participants. With the same procurement timing and same bid size, the current FCR-D can be seen somewhat similar to a FCR-N bid in a positive (asymmetric) market. With an average price during the year 2019 (see Primärreglering.xlsx) of 30.9 EUR/MW for (symmetric) FCR-N and 22.4 EUR/MW for (positive) FCR-D (an average difference of 8.5 EUR/MW, with standard deviation of 11.9 EUR/MW) the FCR-D price is on average close to 75% of the current FCR-N weighted-average price. This suggests that the positive (upwards) regulation could act as main driver of prices in the FCR-N market.

In 2022, it is planned to introduce procurement of negative FCR-D in 2022 in addition to the currently used positive FCR-D. Since the main concern that drives the need for negative FCR-D are unplanned, spontaneous, possibly incident-related outages of consumers – of high importance here are exporting HVDC lines – the question arises whether introducing FCR-D down could potentially render the negative FCR-N somewhat "useless". If that would be the case, prices could potentially drop by a large amount in the positive and negative markets (due to hydro-based BSPs shifting all their flexibility into the positive market), as long as an asymmetric market design is already in use. If this is not the case, this could lead to substantial amounts of awarded capacity (due to the symmetric product) essentially being wasted.

Consider the case of an outage of an exporting HVDC. FCR-D is listed at an endurance of at least 20 minutes. aFRR that is procured during some hours of the day would potentially step in after two minutes with an endurance of one hour. mFRR, with guaranteed activation time of 15 minutes could easily step in in such a case and take over directly from FCR-D without the need for any FCR-N in between. It is important to highlight the significant difference between procured FCR-D (up to 580 MW) vs. FCR-N (around 240 MW), with exports to Poland, Lithuania, Finland, Denmark and Germany that can easily exceed the latter (see aFRR and mFRR in Figure 8).

FCR vs. Fast Frequency Reserve

New frequency-oriented products are being created to address possible frequency stability issues, Fast Frequency Reserve (FFR) being one of them. It is our understanding that in the Nordic grid FFR is seen as a complement to FCR-D rather than FCR-N, and therefore these services are seen as independent products. There are clear synergies and interactions between all frequency support services, and a holistic approach is needed to strike a balance between all products from a technical and market point of view, that is beyond the scope of this report. It is nonetheless important to realize that, to the best of our estimates, most new plants entering the market would be able to provide a FFR-like response at the price of FCR-N. In other words, standard inverter-based generation responds fast enough to fulfill FFR requirements without any additional cost. That is, the expected dynamic technical requirements for FCR-N do not represent any barrier for the unit being prequalified for other products. For instance, a unit providing FCR-D must be able to ramp up within 7.5 s to 93 % [20], which is clearly slower than most fast frequency products across the globe. It is also possible that, if no further incentive is provided, asset managers decide to artificially slow down the plant response to account for reliability aspects, SoC management, reduce mechanical loads, etc.

Time of auction clearing of different products

As shown in [29], it is not only the market design *per se* but also the availability of other commercialization options that affect bidders' strategies. In this context, the sequence of the markets alters bidders' decisions. This, first of all, has to do with additional opportunity costs: the more market options follow after a given market's GCT, the more opportunity costs will have to be factored in. These are, in turn, affected by such factors as the expected price levels in each market and the probability of being awarded [29]. Using theoretical bidder calculus, the authors showed potential benefits of clearing the balancing capacity market *after* the GCT of the DA market (see also Section 5.1). Firstly, it removes the opportunity costs from foregoing participation in the DA market. Secondly, it is preferred from the point of view of allocative efficiency: remaining (more expensive) generators not awarded in the DA market can still support the system by offering upward regulation while the more cost-efficient ones already awarded in the DA market can be available to offer downward regulation at a lower cost.

The discussion above addresses sequential market clearing. Other options include simultaneous clearing with or without co-optimization. Similarly, sequential bidding may also include bid linking (e.g. bid forwarding between FFR and FCR-D markets in Finland). Bid linking may either imply co-optimization or bid substitution/forwarding. Finally, besides linking among different balancing products, it could at least in theory be possible between the DA and balancing markets (as is for example the practice in Italy and in the US). All mentioned alternatives create a large and complex option space (see Table 12), whose analysis is outside the scope of this project. However, some crucial aspects will be addressed below.

Table 12. Simplified option space for considering alternative ways of implementing bid linking and co-optimization.

Product substitution?	**Linking bids for different products if same unit participates?**	**Sequential**	**Simultaneous *without* co-optimization**	**Simultaneous *with* co-optimization (incl. DA market or not)**
No	No	The flexibility not awarded in one market can be freed up for the subsequent market(s) ➔ Implicit bid forwarding	Potentially reduced liquidity in the markets involved, esp. if the same assts participate; more complex decision-making for BSPs &	TSO minimizes costs in all markets; bids are implicitly linked; no possibility for BSPs to choose the 'best-performing' product;

		The sequence of marketplaces matters! Sufficient time in-between the GCTs necessary to make trading decisions (at least 1-2 hours according to stakeholders)	cannibalization of flexibility (through 'tying' resources in different markets)	Co-optimization with the DA markets unrealistic under the current regulatory conditions in the EU
No	Yes	Unallocated flexibilities can be bid/forwarded to the other markets of a BSP's choice; Sufficient time in-between the GCTs are necessary ➔ Explicit bid linking	Flexible bidding for market actors Simplified decision-making BSPs' preferred option: having a possibility to submit either linked or individual bids	Simplified decision-making for market actors but no possibility to choose the preferred market. Optional: whether a single flexibility price or different prices per product can be submitted
Yes	No	Difficult to plan for BSPs, less transparent	Easier to manage for the TSO once all markets move closer to the time of delivery, yet the question of interoperability needs to be considered[30]. Difficult to plan for BSPs, less transparent	Difficult to plan for BSPs, less transparent

Co-optimization of balancing resources and bid forwarding/linking

At the moment, no linking or product co-optimization is foreseen in the Swedish balancing market.
Most BSPs participating in the Svk-Fingrid stakeholder survey preferred so kind of co-optimization of several balancing resources with or without co-optimization with the DA market. Several actors preferred simultaneous clearing, yet deciding themselves, which of the markets they want to participate in with the same flexibility.

It seems different understandings of what co-optimization means are present. For instance, there seems to be a misunderstanding as to the implications of co-optimization: some respondents argued for both introducing product co-optimization and the possibility to choose which product they want to bid based on the one that gives the best result. These two wishes are contradictory since co-optimization implies an integrated process the result of which is the allocation of flexibility to different products based on the optimization result and not on the bidders' wishes.

Respondents in both the stakeholder survey and Svk-Energinet consultation pointed out to the inefficiency of simultaneous procurement of FCR-N and FCR-D where no linking is available, although mostly the same assets are used for the two services. They reasonably point out that this does not only reduce liquidity in both markets but also complicates decision-making for BSPs leading to suboptimal outcomes. The more resources in the balancing market can provide several services, the greater role the possibility to link bids pays.

[30] The reason for having different balancing products is because they differ in purpose (containment vs. restoration) and in terms of technical requirements. If capacities can really be substituted/interchangeable, then the question arises whether two products (and not one) are at all needed.

Forwarding non-selected bids from one market to the next one would indeed be beneficial as it would reduce reserve requirements but at the same time will require a number of prerequisites to be fulfilled:

1) the question of interoperability of balancing resources:
    a. a unit prequalified for FCR is not necessarily prequalified for FRR and vice versa)
    b. how closely to each other are they procured (can BSPs really replan it?).
2) the remuneration levels and rules (PaB or marginal) of the products:
    a. a bidder might not be willing to provide e.g. FRR at its price when the FCR price was expected to be higher,
    b. pricing rules must be harmonized to avoid distorted incentives.

An alternative would be to allow interoperability through sequential bidding times, so a BSP can and has time to freely decide whether the same flexibility could still be offered in the subsequent market.

Regarding possible substitution of different balancing products, most stakeholders in the survey by Svk-Fingrid expressed opinions against product substitution citing different reasons. One stakeholder observed that such substitution makes the market less transparent and will therefore negatively affect BSPs' investment decisions. Similarly, a different stakeholder called for transparent – and fixed - product dimensioning. While such an opinion is understandable from the market actor's perspective, it is not necessarily in the best interest of the system as a whole: rigidity/inelasticity of demand in balancing reserve markets is in purely economic terms one of the factors potentiating strategic behavior. If the demand is more volatile (consider e.g. short-term electricity markets), it is much more difficult for a potentially strategic bidder to accurately estimate his or her merit order position and affect the market result.

Several respondents stressed the need to ensure the lowest impact on the spot markets, most cost-efficient solution system-wise should be a priority. However, it is not immediately evident whether such a solution is better achieved through separate treatment of each product or their linking/interchangeability. One stakeholder notably observed that *"if two products are interchangeable then only one product should exist."*

In sum, it is recommended to avoid simultaneous clearing of several balancing products if no product co-optimization is used as this complicates decision-making for the BSPs and can lead to sub-optimal allocation of flexibility, considering that BSPs assets often provide more than one resource. Sequential market clearing with a possibility for BSPs to explicitly link their bids among different products seems likely to improve the allocation of scarce flexibility. More research, however, is needed to quantify the extent to which balancing products could indeed be substitutable and evaluate the effect of bid linking or co-optimization in sequential or simultaneous markets.

6.6 Summary: Prioritizing decision variables and roadmap

The main goal of the Swedish market design evolution is to achieve a more competitive and thus more efficient balancing market. To achieve this goal, the transition needs to ensure that 1) conditions are created to enable the participation of new actors and technologies and 2) the Nordic market integration is enabled.

In this report, we analyzed the current and future developments in the Swedish and other Nordic balancing markets, the technical requirements for BSPs as well as the aspects of market design. The analysis also includes the issues of links between different balancing products and their complementarity, FCR-N exchange in the Nordics and beyond, information availability and transparency, and others.

Based on the variable priorization approach introduced at the beginning of Chapter 6 and illustrated in Figure 36, we use the following market design variables to adapt Figure 36 to the Swedish context based on the analysis in Sections 6.3-6.4.

1. Formal access (explicit authorization of all flexibility technologies)
2. Adjustments to prequalification and technical requirements (incl. flexible pooling) → wind is prequalified and can enter the market along with hydros
3. Bidding type (cost-based or bid-based)
4. Bidding frequency
    a. Timeframe of the FCR-N auction(s), including with respect to the day-ahead market
5. Product resolution
    a. Availability of block bids
6. Bid size minimum and maximum and bid divisibility
7. Bid symmetry
8. Pricing rule

The priorization and clustering of design variables for the FCR-N market as well as the logic links between them are shown in Figure 44.

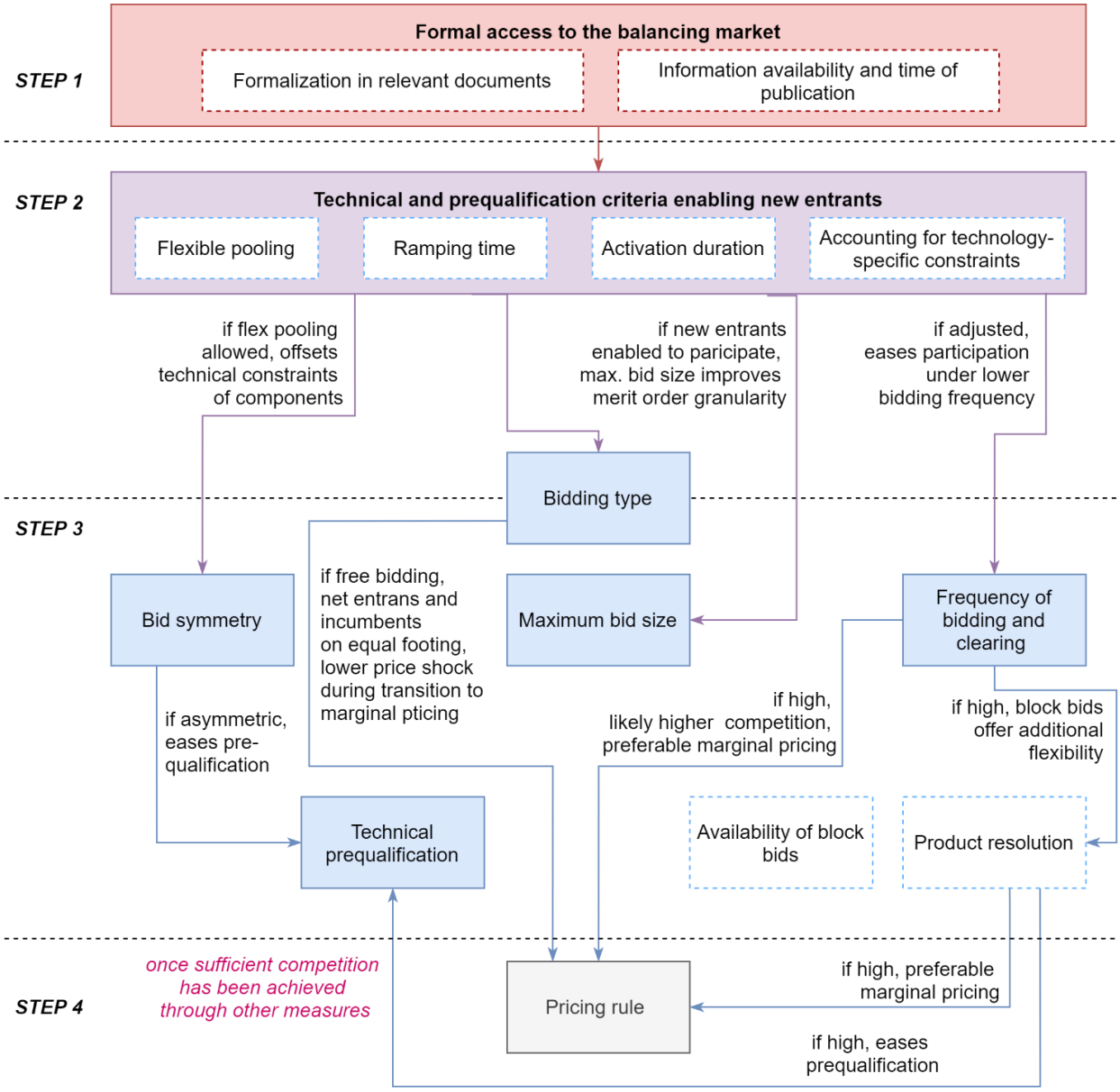


Figure 45. Updated priorization of balancing market design variables tailored to the FCR-N market

Note that technical prequalification is also included in Step 3 in Figure 45 since other design adjustments such as bid symmetry and product resolution are likely to require adjustments to the prequalification procedure. In this context, an important factor is the determination of the prequalified volume. At the moment, given a symmetric product, a BSP must be able to prequalify the same amount for upward and downward regulation. This implies that if a BSP faces a difficulty in providing a certain amount in one direction, this amount automatically caps the prequalified volume in the other direction. This requirement no longer needs to apply if asymmetric bidding is introduced, allowing non-symmetric prequalification, therefore increasing the overall flexibility volume offered in the FCR-N market.

Based on the considerations presented in Figure 45 and the expected medium-term developments in the Nordic region, we design a transition roadmap in Figure 46.

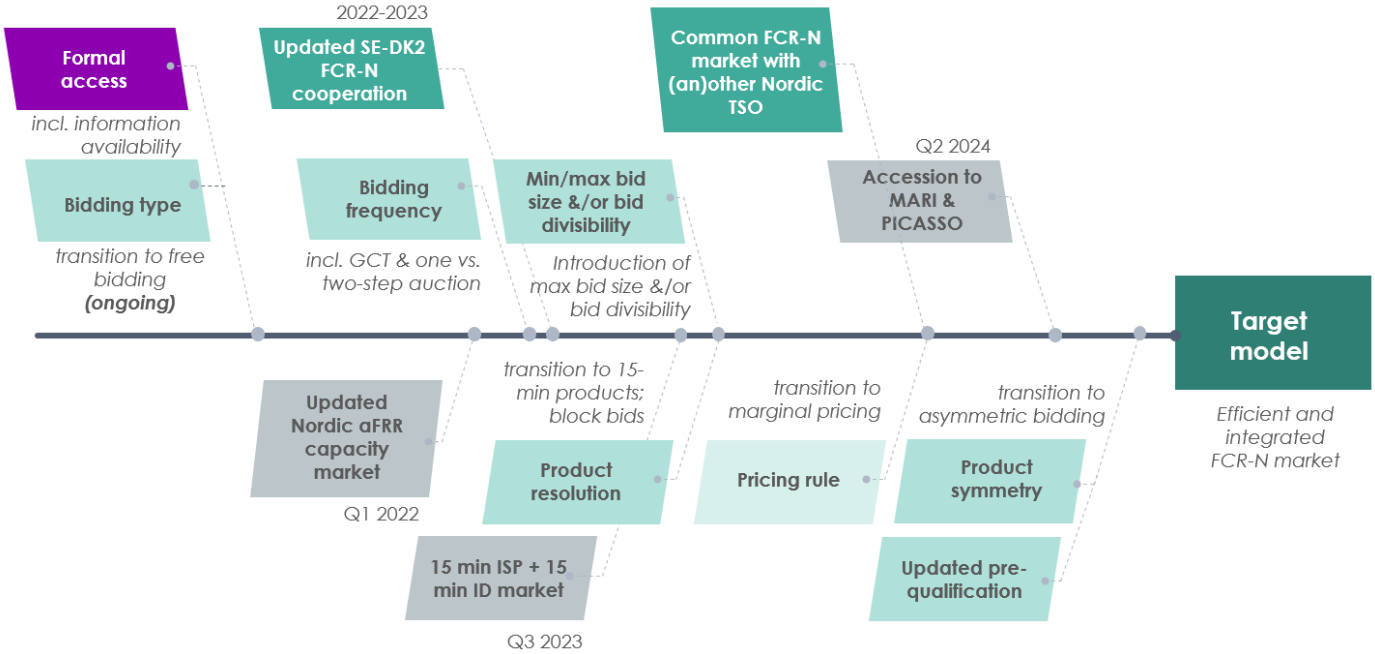


Figure 46. Short- to medium-term roadmap for FCR-N market adjustment

Formal access requirements for new entrants and technologies have been fulfilled to a large extent. Beyond the formalization in the relevant documents (including regulation and BSP contracts), market transparency and information availability crucial for new market entrants and form part of formal access requirements. Section 6.4.2 provided some recommendations for the measures to improve information availability, such as harmonizing and streamlining the information on the Nordic and ENTSO-E platforms and publishing market results within regular office hours. Yet, it was advised against publishing the bid lists and other detailed market results beyond what is necessary.

The change of the bidding rule from cost-based to free bidding is likely to attract more BSPs in the FCR-N market. It has already been communicated, pending implementation.

The updated SE-DK2 FCR-N market design will include, among others, a decision on the GCT of the FCR-N auction and on whether a one- or two-step auction will be conducted in the future. As stated in Section 6.4.1, we argue for the simplification of the auction setup in the form of a one-step auction.

Following the introduction of the 15-minute ISP planned for Q3 2023, in accordance with the NBM, it is recommended to align the MTU to 15 minutes as well. Considering a shorter time resolution, it will be beneficial from the BSP's operational perspective to be able to continue placing block bids in the market while operators of other technologies, such as battery storage, can optimize the dimensioning of their assets thanks to a shorter product. In addition to an already low minimum bid volume setting a best-practice example in the EU, it is recommended to introduce a maximum bid volume in order to limit potential dominance of a few large BSPs. A complimentary measure would be to allow divisible bids, which would help to avoid high procurement costs because of a large-volume bid at the end of the bid ladder.

As mentioned at the beginning of this chapter, two main approaches to improving market competition include market design adjustments (i.e. attracting new BSPs from within the control area) and market integration (i.e. expanding the pool of providers beyond the control area). It is conceivable to apply a combination of the two approaches in the Swedish context, considering an already high level of cooperation among the Nordic TSOs. Thus, the measures mentioned above can encourage the entry of new BSPs within the control area. Coupled with setting up a common FCR-N market with another Nordic TSO (or TSOs) within the next 2 to 3 years will increase competition levels further, paving the way for introducing marginal pricing rule (see also Section 6.4.1 for details).

Although the transition to asymmetric bidding was included in Step 3 in the priorization diagram (see Figure 45), it is proposed to consider it after or in parallel with the integration of the Swedish FCR-N market with the market of another TSO(s). This is proposed due to account for the coordination process among the TSOs and due to additional time needed to operationalize asymmetric bidding on the TSO side (primarily adjustment of pre-qualification requirements) as well as on the BSP side (adjustment of controllers and other hardware as well as bidding strategies).

Note that this roadmap does not include a number of additional design variables, such as the linking of different products or their co-optimization as the optimal choice of those ones is still highly uncertain and requires a numerical analysis and simulation. It is important to keep in mind that a holistic approach considering all frequency-related products as well as wholesale electricity markets is likely necessary as all of them in combination affect bidder incentives and strategies and such an approach is likely to help identify useful cross-product synergies.

In addition, other considerations listed in Section 6.4.2 should be considered separately are seen as complimentary and do not affect the presented timeline.

7 CONCLUSIONS

The balancing markets in the Nordic region are undergoing considerable market design changes coupled with an intensified cooperation among the Nordic TSOs. This report has, on the one hand, been focused on evaluating the implications of switching from a symmetric to an asymmetric product in the Swedish FCR-N market and, on the other hand, on the measures that can be undertaken to ensure a more efficient transition to the target FCR-N market.

Asymmetric bidding implies a possibility for balancing service providers (BSPs) to bid different volumes of flexibility for upward and downward regulation. This, coupled with additional measures enabling market entry of new BSPs, could provide more degrees of freedom to new market entrants, such as wind generators and demand response. At the same time, asymmetric bidding leads to a change of bidding strategies of market actors, which have been evaluated and quantified by adjusting the FCR-N market model developed in project Phase 1, which combines agent-based modelling with reinforcement learning and is complimented with a technical hydropower plant simulation, to answer the following questions:

I. What is the impact of a change of the FCR-N product from a symmetric to an asymmetric on the market result?
II. What benefits can different generation technologies obtain from the possibility to bid separately for upward and downward regulation and what is the effect of this change on their bidding strategies?
III. What is the effect of capacity withholding and capacity distribution between the two auctions, for upward and downward regulation?

Phase 2 of the project was set up in a way that ensures comparability (as much as it is feasible) with the results obtained during project Phase 1, in which the symmetric FCR-N market was modelled. These are later used to compare a symmetric market design with an asymmetric one. Besides that, the following three main aspects were studied and discussed: 1) strategic bidding, including capacity withdrawal from either, +FCR-N or -FCR-N market, 2) the impact of new entrants on the bidding strategies of the incumbent BSPs and the market results and 3) linking of bids in the +FCR-N and -FCR-N markets. All scenarios were split into two blocks, with Block 1 containing scenarios, in which all agents followed a true-cost bidding strategy (with and without bid linking) and Block 2 featuring various levels of competition and strategic bidding.

The following key points of interest were identified based on the simulation results:

- Using the historical FCR-N bids we recalculated, based on the results from the technical hydro simulation, asymmetric bids to be used by the true-cost hydro-based BSPs, everything else remaining equal. Comparing the true-cost bidding scenarios with hydro-based BSPs with symmetric and asymmetric bidding (*3TC_hydro_symm* and *3TC_hydro_asymm,* respectively) yielded a similar course of marginal prices in the +FCR-N market compared to the prices in the scenario with symmetric bidding. Marginal prices in the -FCR-N market were shown to be substantially lower throughout the year but rising with low DA prices mostly in spring.
- Comparing the results from a symmetric market design (phase 1) against the ones obtained during phase 2 (with an asymmetric market design), most scenarios showed a reduction in total procurement costs and total economic costs (equal to the difference between the total costs and the agents' total profits). In addition, profit-maximizing agents were shown to behave less strategically (Figure 34), i.e. bid closer to their actual costs, under asymmetric bidding as compared to their symmetric analogs. As a result, in most studied scenarios, asymmetric bidding leads to lower system costs.

- Similar to phase 1, allowing strategic bidding resulted in significant increases in system costs. While scenarios dominated by strategic hydro-based BSPs resulted in an increase of system cost by 1 to 5%, all scenarios with asymmetric bidding led to an overall efficiency gain by increasing either the producer surplus or consumer surplus (see Table 6).
- Introducing bid linking (i.e. positive and negative bids that can only be awarded together) generates a situation similar to the symmetric market: symmetric bids are essentially linked bids with the additional constraint for BSPs to bid the same volume in both markets. Enabling linked bids for a single BSP showed to not influence the market to a large extent (an increase in system costs of less than 1%). Assuming that all BSPs link their bids increased system costs and marginal price volatility, due to a varying level of supply in the two separate markets, as compared to always offering flexibility symmetrically. Even though some scenarios performed slightly poorer from the system perspective, the total economic cost is actually lower for all scenarios compared to the corresponding symmetric market design scenarios. Considering startup costs (that were not explicitly modelled but can be assumed to be part of the historic bid prices) could potentially reduce bid prices and therefore system costs[31].
- Allowing new entrants into the market resulted in an improvement of all studied indicators, remarkably also resulting in lower system costs as compared to the original symmetric scenarios, including in the scenario with new market entrants, in which bid linking was allowed (*3TC_hydro_2TC_new_symm_mp* vs. *3TC_hydro_2TC_asymm_linkedallhydros).*
- The analysis of bid volumes allocated by different agents to the +FCR-N and -FCR-N markets, we observe that
    - As long as hydro-based BSPs pursue a true-cost bidding strategy, their optimal capacity allocation between the two directions is close to 50:50 with a slight preference to the +FCR-N market (54-59% depending on the agent and scenario). However, as soon as these agents are allowed to follow a profit-maximizing strategy, this trends reverses with significant bid volumes shifted from the +FCR-N to the -FCR-N market, partially leading to scarcity in the +FCR-N market;
    - The agent with a battery storage portfolio bids about 45:55 across all scenarios;
    - The agent operating wind generators shows a clear preference for the -FCR-N market, where it allocates 80-90% of its flexibility and only increasing the share of allocated flexibility in the +FCR-N market to about one third of its total available capacity in the scenarios, in which it can bid strategically.
- Similar to project Phase 1, it is assumed that capacity withholding can only be carried out by a BSP by bidding the available flexibility at a (much) higher price rather than withdrawing this flexibility from The FCR-N market completely. Such behavior was shown to be an important factor in the symmetric market, in which agents can bid strategically. In Phase 2, agents have additional flexibility to choose to shift more or less of the flexibility into the other market, de facto reducing the total bid volume in the first one. Simulation results revealed scarcity of 1% to 3% only in scenarios where the hydro-based agents can behave strategically (*3RL_hydro_asymm* and *3RL_hydro_2TC_new_asymm)*. While no real pronounced seasonality can be observed, scarcity events tend to occur during daytime and hours with a high total demand and (for the +FCR-N market) higher DA market prices.

The fourth question investigated in this report was focused on the qualitative analysis of the transition phase:

IV. What concrete steps can be undertaken to ensure a smooth transition to the target design?

[31] This is due to the fact, that a BSP would face the risk of only getting one of two (unlinked) bids awarded and would therefore need to account for startup costs in both bid prices as opposed to dividing them between two linked bids.

This question highlights the fact that identifying positive market design changes is not sufficient for ensuring an efficient transition to a more efficient and competitive market but the specific pathway towards it is equally crucial. In this report, we formulated a number of recommendations for improving individual design choices and, more importantly, prioritize them and define a transition pathway for market design adjustments. These have been combined with the second approach meant to improve market competition in the concentrated FCR-N market, namely market integration within the Nordic region and considers planned adjustments and cooperation concerning other balancing products. We further stress one of the most detrimental factors for the participants' confidence in the market is regulatory/design uncertainty and frequent changes. Care therefore should be taken with not introducing market changes too often but rather clustering different measures. Finally, while this report focuses mainly on the FCR-N product, a holistic approach considering all frequency-related products is needed taking into account that their functionalities can overlap and their needs are correlated.

The short- to medium term roadmap proposed for the market design adjustments includes several steps, from adjusting formal access criteria, prequalification and market rules. Formal access requirements for new entrants and technologies have been fulfilled to a large extent. Information availability is further crucial for new market entrants and form part of formal access requirements. The planned change of the bidding rule from cost-based to free bidding is likely to attract more BSPs in the FCR-N market. With the updated SE-DK2 FCR-N market design, we argue for the simplification of the auction setup by switching from a two-step to one-step FCR-N auction taking place D-1 prior to the closure of the DA market in order to simplify BSPs' decision-making, increase market liquidity and at the same time address security concerns.

Following the introduction of the 15-minute ISP planned for Q2 2023, it is recommended to align the market time unit to 15 minutes as well while providing for an opportunity to place block bids of up to a few hours. It is further recommended to introduce a maximum bid volume in order to limit potential dominance of a few large BSPs. A complimentary measure would be to allow divisible bids, which would help to avoid high procurement costs because of a large-volume bid at the end of the bid ladder.

To increase competition in the FCR-N market it is proposed to use combination of the two approaches, market design adjustment and integration of the Swedish FCR-N market with the market of (an)other TSOs. The measures mentioned above can encourage the entry of new BSPs within the control area. Coupled with setting up a common FCR-N market with another Nordic TSO (or TSOs) within the next 2 to 3 years will increase competition levels further, paying the ground for introducing marginal pricing rule.

Finally, this report demonstrated a number of benefits linked to the transition to asymmetric bidding. It is proposed to consider it after or in parallel with the integration of the Swedish FCR-N market with the market of another TSO(s) due to account for the coordination process among the TSOs and due to additional time needed to operationalize asymmetric bidding on the TSO side as well as on the BSP side.

REFERENCES

[1] Nordicbalancingmodel, "Nordic Balancing Model," 2021. [Online]. Available: https://nordicbalancingmodel.net/. [Accessed 10 June 2021].

[2] Svenska kraftnät, Fingrid, "(Survey) Future development of market model for Frequency Containment Reserves (FCR) and Fast Frequency Reserve (FFR). Stakeholder Survey.," Stockholm/Helsinki, 2021.

[3] Energinet and Svenska kraftnät, "Proposal for exchange of Frequency Containment Reserve Normal and Disturbance in accordance with article 33(1) of the commission regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing," Stockholm/Copenhagen, 2021.

[4] Svenska kraftnät, "Frekvensreserv Normal drift (FCR-N)," 11 March 2021. [Online]. Available: https://www.svk.se/aktorsportalen/systemdrift-elmarknad/information-om-stodtjanster/fcr-n/. [Accessed 23 April 2021].

[5] Ramboll, "Ancillary Services from New Technologies Technical Potentials and Market Integration," 2019. [Online]. Available: https://energinet.dk/-/media/229625DCEA984813BF322090E7926844.pdf. [Accessed 23 April 2021].

[6] M. Faiella, T. Hennig, N. A. Cutululis and F. Van Hulle, "Capabilities and costs for ancillary services provision by wind power plants. Deliverable D 3.1," Fraunhofer IWES, 30 April 2013. [Online]. Available: https://backend.orbit.dtu.dk/ws/portalfiles/portal/71169605/Capabilities_and_costs_for_ancillary.pdf. [Accessed 28 April 2021].

[7] APG, "Erläuterungen Regelreserven," 9 October 2015. [Online]. Available: https://www.apg.at/markt/-/media/3F8C9277B7684F1FBFC1CFF6D933E1AF.ashx. [Accessed 23 April 2021].

[8] 50Hertz, Amprion, T. TSO and T. BW, "Präqualifikationsverfahren für Regelreserveanbieter(FCR, aFRR, mFRR) in Deutschland ("PQ-Bedingungen")," 29 May 2020. [Online]. Available: https://www.regelleistung.net/ext/download/PQ_Bedingungen_FCR_aFRR_mFRR. [Accessed 23 April 2021].

[9] RTE, "Frequency Ancillary ServicesTerms and Conditions," 30 May 2020. [Online]. Available: https://www.services-rte.com/files/live/sites/services-rte/files/pdf/Service%20systemes%20frequence/SSY_20200530_EN.pdf. [Accessed 23 April 2021].

[10] elia, "General Frameworkfor Frequency Containment ReserveServiceby Non-CIPU Technical Units," July 2019. [Online]. Available: https://www.elia.be/-/media/project/elia/shared/documents/elia-site/customers/20191231-gfa_fcr_noncipu_jul2019_etb-en.pdf. [Accessed 23 April 2021].

[11] A. Zeh, M. Müller, M. Naumann, H. C. Hesse, A. Jossen and R. Witzmann, "Fundamentals of using battery energy storage systems to provide primary control reserves in Germany," vol. 2, 2016.

[12] K. Poplavskaya and L. de Vries, "Distributed energy resources and the organized balancing market: A symbiosis yet? Case of three European balancing markets," *Energy Policy,* vol. 126, pp. 264-276, 2019.

[13] ENTSO-E, "All CE and Nordic TSOs' results of CBA in accordance with Art.156(11) of the Commission Regulation (EU) 2017/1485 of 2 August 2017," 19 February 2020. [Online]. Available: https://consultations.entsoe.eu/system-development/stakeholder-consultation-on-cba-article-156-11/user_uploads/entso-e_all-ce-and-nordic-tsos-results-of-article-156-11--cba_for-consultation.pdf. [Accessed 23 April 2021].

[14] 50Hertz Transmission, Amprion, APG, elia, Energinet, Rte, swissgrid, TenneT TSO and Transnet BW, "Proposal for the establishment of common and harmonised rules and processesfor the exchange and procurement of Balancing Capacity for Frequency Containment Reserves(FCR," 18 October 2018. [Online]. Available: https://www.apg.at/markt/-

/media/2B489DA6719D455B88EE5BCD8AB5E658.ashx?la=de&hash=ACE9B8F88393F752CB9BE97FA9FF837E52582847. [Accessed 23 April 2021].

[15] epexspot, "Trading on EPEX SPOT2019-2020," 2020. [Online]. Available: https://www.epexspot.com/sites/default/files/download_center_files/Trading%20Brochure.pdf. [Accessed 5 May 2021].

[16] Energinet, "Prequalification of Units and Aggregated Portfolios," 16 August 2018. [Online]. Available: https://en2016.energinet.dk/-/media/39AD13F14EEE4C5AAA0DCE72EFA17AEC.pdf. [Accessed 7 May 2021].

[17] E. Waffenschmidt, "Degrees of freedom for primary control with batteries," *Energy Procedia,* vol. 135, pp. 227-235, 2017.

[18] T. M. Mbavarira and C. Imboden, "A Review of the European Grids Services Markets Suitable for Distributed Loads," February 2020. [Online]. Available: https://www.tugraz.at/fileadmin/user_upload/tugrazExternal/4778f047-2e50-4e9e-b72d-e5af373f95a4/files/lf/Session_C6/361_LF_Mbavarira.pdf. [Accessed 23 April 2021].

[19] H. C. Hesse, M. Schimpe, D. Kucevic and A. Jossen, "Lithium-ion battery storage for the grid—A review of stationary battery storage system design tailored for applications in modern power grids," *Energies,* vol. 10, no. 12, p. 2107, 2017.

[20] ENTSO-E, "Supporting Document on Technical Requirements forFrequency Containment Reserve Provision in the Nordic Synchronous Area," 29 March 2021. [Online]. Available: https://www.svk.se/contentassets/20aec45c5ea74f7a9557bf3413d03b16/fcr-supporting-document.pdf?_t_id=qWowEhUA1rBRRNtzXdqH-w==&_t_uuid=wkQbZd_0TZaFpKxwMJC4Mg&_t_q=frequency+containment+reserve+disturbance&_t_tags=language:en,siteid:40c776fe-7e5c-4838-841c-6. [Accessed 23 April 2021].

[21] smartEn, "The smartEn Map - European Balancing Markets Edition 2018," 2018. [Online]. Available: http://www.smarten.eu/wp-content/uploads/2018/11/the_smarten_map_2018.pdf. [Accessed 7 May 2021].

[22] Terna, "Fast Reserve - Information Pack," 2020.

[23] R. Hollinger, A. M. Cortes and T. Erge, "Fast frequency response with bess: A comparative analysis of germany, great britain and sweden," *2018 15th International Conference on the European Energy Market (EEM),* pp. 1-6, 2018.

[24] M. Świerczyński, D. I. Stroe, A. I. Stan and R. Teodorescu, "Primary frequency regulation with Li-ion battery energy storage system: A case study for Denmark," *2013 IEEE ECCE Asia Downunder,* pp. 487-492, 2013.

[25] Danish Energy Agency and Energinet, "Technology Data Generation of Electricity and District heating," April 2020. [Online]. Available: https://ens.dk/sites/ens.dk/files/Statistik/technology_data_catalogue_for_el_and_dh_-_0009.pdf. [Accessed 28 April 2021].

[26] F. Müsgens, A. Ockenfels, und M. Peek, „Economics and design of balancing power markets in Germany“, *Int. J. Electr. Power Energy Syst.*, Bd. 55, S. 392–401, Feb. 2014, doi: 10.1016/j.ijepes.2013.09.020.

[27] K. Poplavskaya, F. Ocker, und K.-M. Ehrhart, „Impact of short-term market sequences on bidding behavior of market participants“, gehalten auf der 3rd European Grid Service Markets Symposium (GSM), Lucerne, Switzerland, Mai 2019, doi: doi: 10.5281/zenodo.3355399.

[28] ENTSO-E, „Price of Reserved Balancing Reserves“, *ENTSO-E Transparency Platform*, 2018. https://transparency.entsoe.eu/.

[29] Y. Gebrekiros, G. Doorman, S. Jaehnert, und H. Farahmand, „Bidding in the Frequency Restoration Reserves (FRR) market for a Hydropower Unit“, in *IEEE PES ISGT Europe 2013*, Lyngby, Denmark, Okt. 2013, S. 1–5, doi: 10.1109/ISGTEurope.2013.6695362.

AIT AUSTRIAN INSTITUTE OF TECHNOLOGY GMBH
Giefinggasse 4, 1221 Vienna, Austria

www.ait.ac.at

Ksenia Poplavskaya
Research Engineer
Integrated Energy Systems
Center for Energy
+43 50550-6227
ksenia.poplavskaya@ait.ac.at

Antony Zegers
Business Manager
Center for Energy
+43 50550- 6092
antony.zegers@ait.ac.at